UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

South Midland CCS Hub

South Midland Facility

Upton County, Texas

Section 1: Site Characterization & Narrative

[40 CFR §146.82, §146.83]

Prepared for:

EPA Region 6

Underground Injection Control Section

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1.0 SITE CHARACTERIZATION [40 CFR 146.82 (a);] [40 CFR 144.31(e)(1-6)]

1.1 Facility Information [40 CFR 146.82 (a)(1)]

Facility Name:	South Midland Facility Midland CCS #2 Well
Facility Contact:	Mr. Adam Haecker/ Director, Geoscience [redacted] Ms. Elizabeth Hartson/ Manager, Environmental Compliance [redacted]
Well Location:	City of Midkiff, Upton County, Texas Lat 31.615788°N, Long -101.990004°W NAD 83 Field Name: Spraberry (Trend Area), TRCC District 7C
Facility Address: (Injection Well)	Milestone Environmental Services – South Midland Facility 27471 Texas State Highway 349 Midkiff, Texas 79755
Owner and Operator Information:	Milestone Carbon Midland CCS Hub, LLC 840 Gessner Rd, Suite 600. Houston, TX 77024 Front Desk Phone: 832-739-6700 Privately Held Delaware Limited Liability Corporation
SIC Codes:	4953 – Refuse Systems 8999 – Environmental Consulting

Key Terms. For the purposes of this permit application, the following terms and their relationship to the proposed Class VI well application are as follows:

- Milestone Carbon Midland CCS Hub, LLC (Milestone) – The Operator of the "Facility," the "Well," and "Operational Area," hereafter referred to simply as "Milestone"
- South Midland Facility – The "Facility"
- Facility – South Midland Facility which includes all injection and monitoring wells
- Midland CCS #2 – The Injection "Well"
- Midland IZM #2 – The In-zone "Monitoring Well"
- Midland USDW #2 – Underground Source of Drinking Water "(USDW) Monitoring Well"
- Midland NSSW #1-5 – Near Surface Seismicity and Water Wells numbers 1 through 5
- Injection Interval – Top of Devonian/Base of Woodford to 100' above basement (**Section 1.5**)
- Injection Unit – Ellenburger and or Siluro-Devonian injection unit, a discrete unit of "Injection Interval"
- Top Seal – Woodford Shale
- Well – Midland CCS #2 only, if no qualifier used
- Injection Well – Midland CCS #2
- Monitoring Wells – Midland IZM #2, Midland USDW #2 and Midland NSSW #1-5
- USDW – Underground Source of Drinking Water, aquifer unit with Total Dissolved Solids (TDS) less than 10,000 ppm or an aquifer designated as protected by the TWDB or RRC
- AoR – Area of Review, the maximum area containing >2% CO2 at 50 years post injection cessation; defined in permit **Section 2**

1.2 Project Introduction [40 CFR 146.82 (a)(1)]

Milestone Carbon Midland CCS Hub, LLC (Milestone) is submitting this application to request authorization of the construction and operation of a Class VI Underground Injection Control (UIC) well in Upton County, Texas. The proposed Midland CCS #2 carbon capture and sequestration (CCS) Class VI well (the Well) will be sited within the Milestone South Midland CCS Facility and is designed to inject carbon dioxide from nearby oil and gas processing sources, power plants and cement plants, into deep underground brine aquifer formations to safely and permanently sequester it.

Milestone has extensive experience with slurry injection and landfill operations associated with energy waste in Upton County, Texas. Accordingly, Milestone understands both the technical and regulatory obligations associated with responsibly managing project operations in this area. This Application demonstrates how Milestone will meet all applicable regulatory and monitoring requirements associated with the proposed Class VI Well in order to protect underground sources of drinking water (USDW) during pre-construction, pre-injection, operation, and post-injection periods.

Objectives and Benefits of the Well include:

1. Climate Change Mitigation: Natural gas combustion accounts for 22% of the world's greenhouse gas (GHG) emissions. Sequestering the carbon dioxide (CO_2) related to these emissions will help mitigate GHG effects on climate change. The Permian Basin, as one of the largest oil and gas producing provinces in the United States, emits approximately 60 million metric tonnes (MMta) of CO_2 annually (IEA, 2020 Report).
2. Energy Security: The Facility will help to ensure energy security by enabling the continued use of fossil fuels while reducing GHG. The Texas electricity market has one of the narrowest supply vs demand ranges in the USA. Therefore, disruptions in energy can have catastrophic effects on property and life in the state (Electric Reliability Council of Texas (ERCOT) Website, 2023).
3. Economic Development: The Facility will support economic development by creating new jobs in the area related to construction, including injection well, monitoring well, pipeline, and capture facility construction. Additional oil and gas service industry jobs related to monitoring such as seismic acquisition and well logging will be created/retained.
4. Technological Advancement: The Facility will help to advance the carbon sequestration industry by demonstrating the effectiveness of long-term brine aquifer CO_2 sequestration while minimizing risk to USDWs in the area. Novel techniques and process efficiencies are likely to be discovered during injection and monitoring operations.

Milestone proposes to inject 1 million metric tonnes of CO_2 per year (1MMta) at the Well, at a rate of 54.5 MMSCF/per day of CO_2, for a period of 12 years. The CO_2 source(s) will be sourced from multiple, nearby facilities including natural gas processing plants, direct air capture facilities, power plants, and cement plants. There is a total of 16.1 MMta of emissions within a radius of 30 miles (Emissions Source: Enverus, 2024). A summary of operational parameters is presented in **Table 1-1**.

Milestone will be the owner and operator of the Well and Facility. It is anticipated that collaborators (i.e., sourcing companies) will include Midstream companies who are capable of developing, constructing, and maintaining subsurface pipelines to the Facility. At the time of this submittal, the pool of emitters and pipeline companies is not finalized.

An aquifer exemption will not be required. The Railroad Commission of Texas (RRC) Groundwater Advisory Unit (GAU) provides Groundwater Protection Determinations for surface casing, underground injection and other underground activities. The GAU has determined the base of USDW is estimated to occur at a depth of 1,250 ft within the area of the Well (GAU Determination letter, permit **Section 13, Appendix I**). The top of the injection unit, at 12,200 ft, 10,950 ft deeper than the lowest known USDW. Additional information on local aquifers, salinity, and water chemistry is detailed subsequently in **Sections 1.4, 1.9** and **1.11**.

The project is not located on, or near, federal Indian lands or Indian reservations. The nearest Indian reservation is the Mescalero Apache reservation, located in New Mexico. The reservation is located over 220 mi northwest (NW) from the calculated area of review (AoR).

Milestone holds no known prior Resource Conservation and Recovery Act (RCRA), Federal UIC, National Pollution Discharge Elimination System (NPDES) or Prevention of Significant Deterioration (PSD) permits.

A list of applicable federal, state and local contacts within the AoR is presented in **Table 1-2** [40 CFR 146.82(a)(20)]. A list of non-UIC federal, state and local permits is presented in **Table 1-3** [40 Code of Federal Regulation (CFR) 146.82 (a) (1)]

Table 1-1: Operational Parameters

Proposed Property	Comment
Injection Rate	1 million metric tonnes per annum (MMta) (54.5 MMScf/d)
Cumulative Injection Mass	11.9 million metric tonnes (MMt)
Injection Units	Ellenburger and Siluro-Devonian
Injection Period	12 years, tentatively commencing in 2027, terminating 2039
Post Site Injection Care Period	50 years, tentatively commencing in 2039, terminating 2089

Table 1-2: Contact Information for Key Local, State and Other Authorities [40 CFR 146.82(a)(20)]

Agency	Phone Number
Upton County Sheriff's Office	432-693-2422
Midland County Emergency Management	432-688-4160
Upton County Emergency Management	432-693-2321 ext. 2
Texas State Police	512- 424-2000 (HQ, Austin) 432-498-2140, Midland
Texas Dept. of Public Safety 24-hour non-Emergency	800-525-5555
Texas Dept. of Transportation	800-558-9368
Texas Division of Emergency Management agency:	512-424-2208
Texas Commission of Environmental Quality / Water Division:	512-239-6696
Texas Commission of Environmental Quality UIC Program Office:	512-239-6466
The Railroad Commission of Texas 24-Hour Emergency reporting line	844-773-0305 (toll free) or 512-463-6788
The Railroad Commission of Texas UIC Program Office	512-463-6792
The Railroad Commission of Texas Ground Water Advisory Unit	512-463-6882
EPA National Response Center (NRC)	800-424-8802
EPA Region 6 Hotline	800-887-6063

Table 1-3: Additional Federal, State and Local Permits Required for Project Completion [40 CFR 146.82(a)(1)]

Agency	Permit
Environmental Protection Agency (EPA)	Monitoring, Reporting and Verification Plan (MRV)
	Spill Prevention Control and Countermeasure Plan (SPCC)
	Environmental Management Plan
Texas Railroad Commission (RRC)	Operator Permit (P-5 and P-5A)
	Geologic Storage Facility Permit
	Permit to Drill (Form W-1)
	Notice of Completion (Form W-2 and G-1)
	Permit to Operate
Texas Commission on Environmental Quality (TCEQ)	Construction General Permit
Upton County	Permit for Installation of County Right of Way, Pipeline and Utility Crossings

Table 1-4: Well Locations for all Injection and Monitoring Wells (Coordinates in NAD 83)

Well	Latitude (NAD83)	Longitude (NAD 83)	Total Depth TVD (Ft)	Type
Midland CCS #2	31.615788	-101.990004	13,897	Injection Well
Midland IZM #2	31.608086	-101.983038	13,785	In-Zone Monitoring Well
Midland USDW #2	31.615586	-101.990004	1,300	USDW Base Monitoring Well
Midland NSSW #1	31.602452	-101.975692	300	Near Surface Seismicity and Water Well
Midland NSSW #2	31.596219	-102.005364	300	Near Surface Seismicity and Water Well
Midland NSSW #3	31.649299	-102.023221	300	Near Surface Seismicity and Water Well
Midland NSSW #4	31.655552	-101.937328	300	Near Surface Seismicity and Water Well
Midland NSSW #5	31.710443	-102.012969	300	Near Surface Seismicity and Water Well
PERMIT PENDING WELLS:				
Dusek AGI #1[1]	31.629814	-101.998922	13,070	Class II Acid Gas Injection Permit Regulated by Texas Railroad Commission[1]
Midland AGI #5[2]	31.655238	-101.937511	13,740	Future Class II Acid Gas Injection Location that has not yet been permitted[2]

[1] Well occurs within the Class VI Plume. It was permitted in 2022, before seismic was acquired and offset penetrations reviewed thoroughly, and is now unlikely to be drilled based on the current geologic understanding. It is included for completeness.

[2] Well occurs to northeast of Midland CCS #2 site. It is an area of future development. The injection was modeled as existing with the Midland CCS#2 at 375 KtA assuming it will be a future permit from RRC

1.3 Overview Maps of AoR [40 CFR 146.82(a)(2)]

Table 1-4 contains the coordinates for all injection and monitoring wells. **Figures 1-1** to **1-6** illustrate the proposed Well location, along with all pertinent items as required in 40 CFR 146.82(a)(2). The information is separated into various maps for ease of reference and discussion. An omnibus map encompassing every element in this section is located in **Section 1.3.5, Figure 1-7**.

1.3.1 Major Roads Nearby Injection Site

The Facility will be situated in the northern part of Upton County, Texas. The property on which the well is located, leased by Milestone, is just to the west of north of State Highway 349 and approximately 12 mi east of RM 1492. It is slightly less than 7 mi south of State Highway 1787 and 6.4 mi north of the intersection of State Highway 2401 and north State Highway 349. The well will be drilled in the southern part of the property at latitude 31.615788° longitude -101.990004°(NAD83) (**Figure 1-1**).

The Well is situated in the unincorporated community of Midkiff, Texas. The nearest named roads to the Well site are Cotton Ln, approximately 1/3 mile (mi) to the north, and County Road 119, approximately 2/3 mi to the south. There are a large number of unnamed lease roads in the vicinity associated with oil and gas activity (**Figure 1-2**).

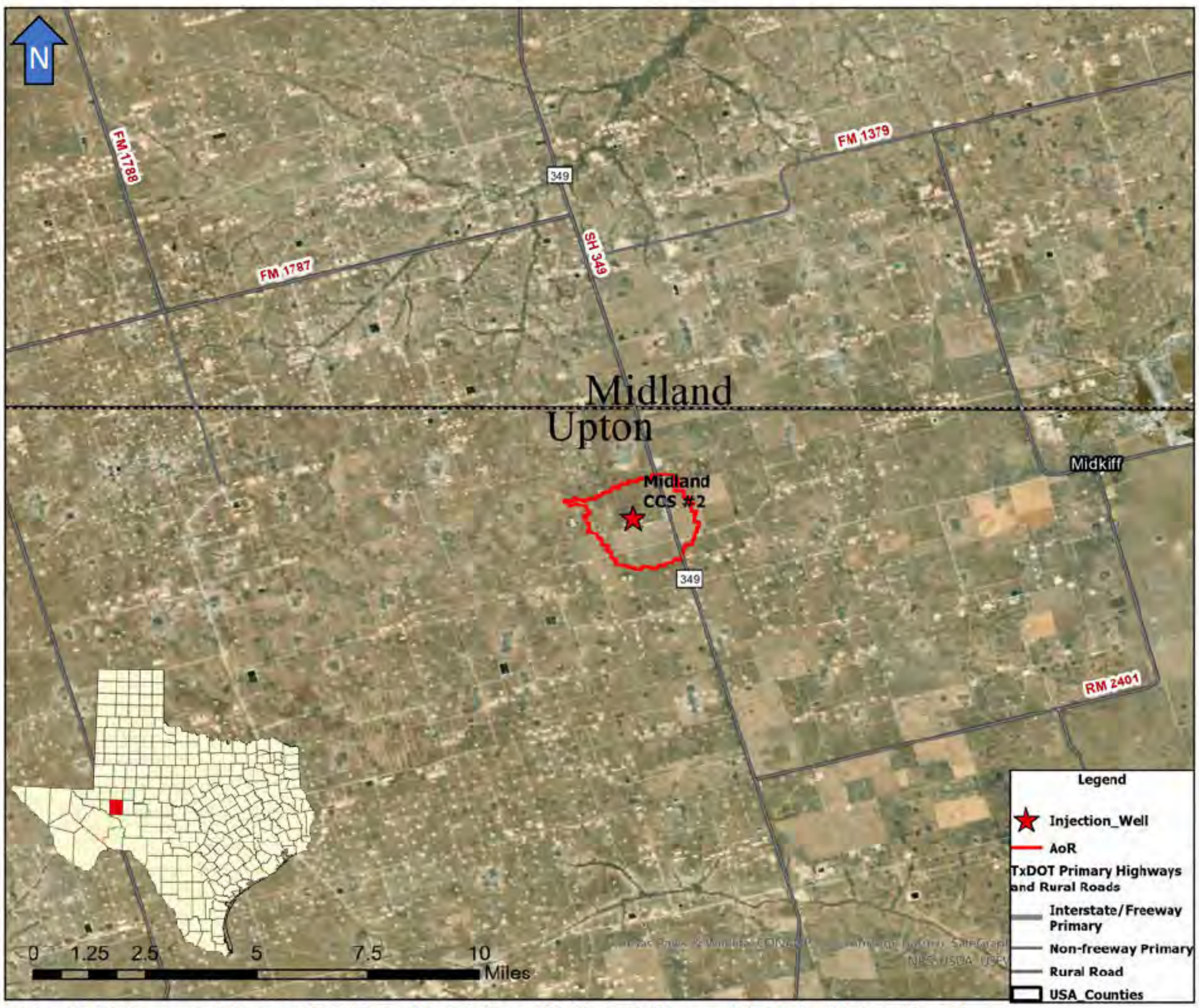


Figure 1-1:Regional Map of AoR and Injection Well and Closest Public Major Roads

Figure 1-2: Map of Injection Well, AoR and Monitoring Wells

1.3.2 Mines, Superfund Sites, Quarries, Other Hazardous Sites

No EPA sites of any kind occur within the AoR. Zero (0) Resource Conservation and Recovery Act (RCRA), mines, Toxic Release Inventory (TRI), Leaking Underground Storage Tanks (LUST), quarries or superfund sites exist within the AoR of the proposed Well location. One quarry exists outside the AoR approximately 1/3 miles north of the AoR. The quarry is a National Pollutant Discharge Elimination System (NPDES) registered site. Additionally, there are no cleanup sites within the AoR. A review of the Texas Commission on Environmental Quality (TCEQ) Central Registry identified the quarry as the Midland South Pit Crushing Plant owned and operated by Victory Rock Texas, LLC. The quarry maintained an active aggregate production operation permit for limestone as well as active air compliance and stormwater permits.

There are seven (7) active Superfund NPLs, and 17 total Superfund sites within approximately 50 mi of the site. There are two (2) mines located within approximately 50 mi of the Well site, both near the town of Odessa. There are 312 active RCRA sites within approximately 50 mi of the Well site.

See **Figure 1-3** for locations of active and inactive hazardous sites, Superfund sites, and mines in the region with respect to the injection well and AoR. Sites are noted by their type in the legend. Active NPDES facilities are noted by brown squares (CWA Facilities).

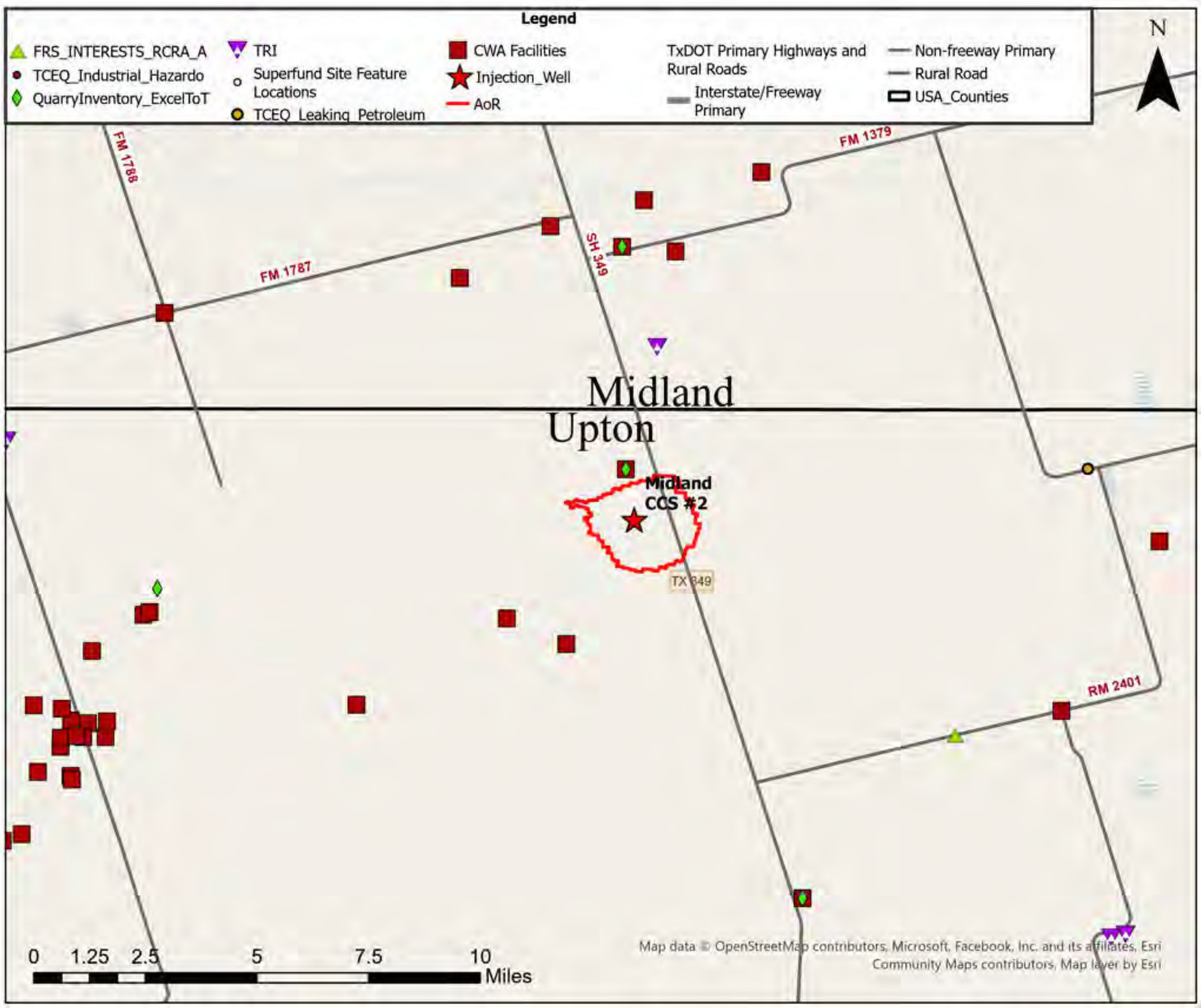


Figure 1-3: Regional Map of Superfund Sites, Hazards and Active Mines in AoR

1.3.3 Map of Rivers, Springs, Wells, Other Water Features

Climate in Upton County is a *hot semi-arid* based on the Koppen climate classification (Beck, et al. 2018). There are limited natural water sources in the vicinity of the AoR. There is a lined artificial retention pond 1,170 ft southeast of the Well. Additionally, one surface pond exists approximately 1/3 mi north of the AoR in A-1494. There are a total of 87 water wells within AoR and an additional 68 water wells within 1 mi away from the AoR (**Figure 1-4**). In total, there are 155 water wells within a 1-mi buffer of the AoR. Many of the wells have unknown depths and are not registered with TCEQ or TWDB. Based on the hydrogeology found in **Section 1.4,** it is almost certain that all wells produce from the Antlers sand member of the Edwards Trinity. All of the wells with documentation produce from the Antlers, and Dockum water is deeper and lower quality in this area. Of the wells with documentation within the AoR, there is one (1) well used for domestic household water, four (4) wells used for oil and gas supply, six (6) wells are abandoned, and the remaining five (5) wells are listed as being used for irrigation. The remaining 71 undocumented wells within the AoR are used for irrigation and oil and gas activities according to the landowner.

Sample records are included in as an appendix attachment, *TWDB Individual Water Well Files*. The wells are labelled with an assigned index number. A table of water wells with locations, index number, and available TWDB information is presented in **Table 1-27, Section 1.14**

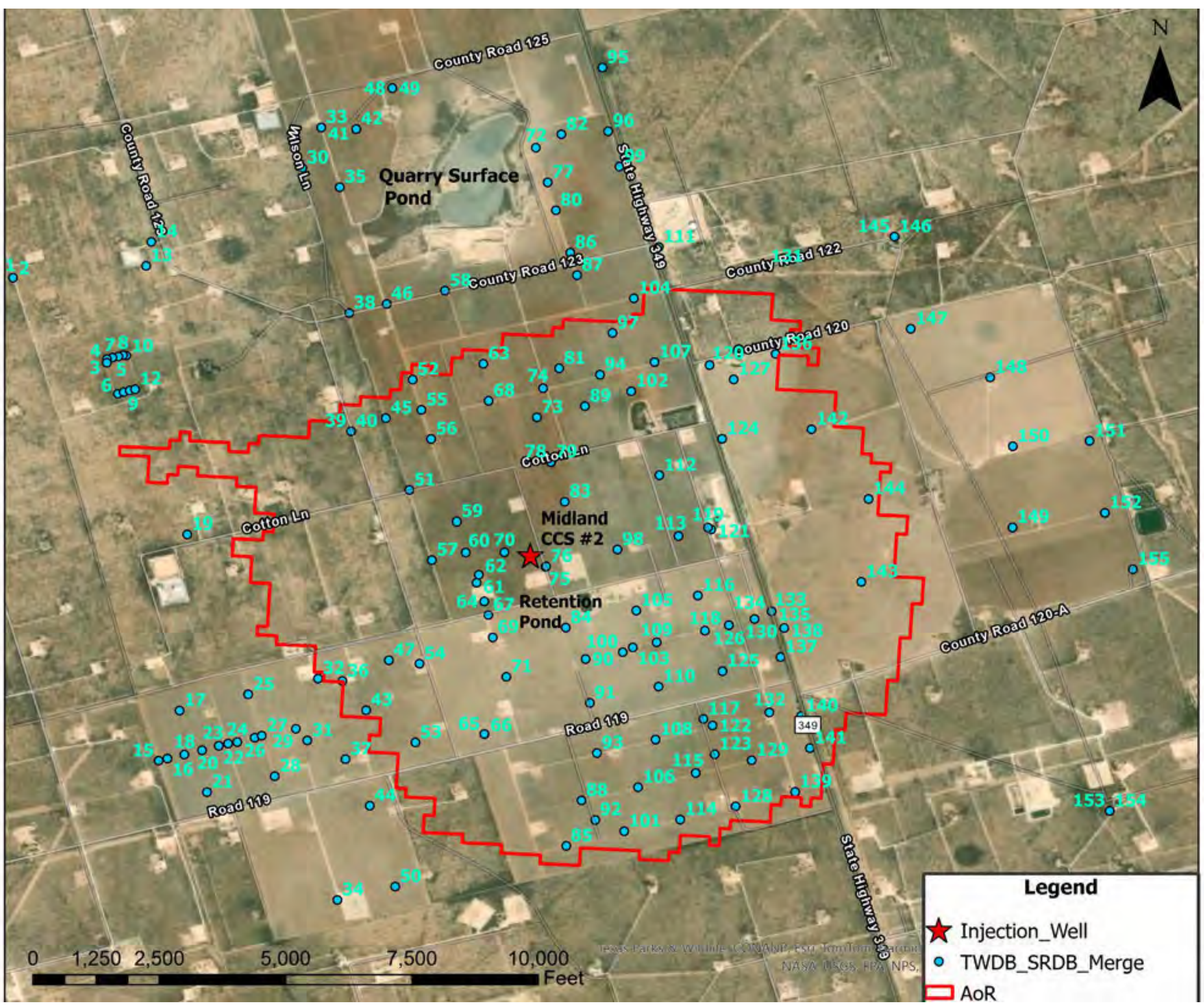
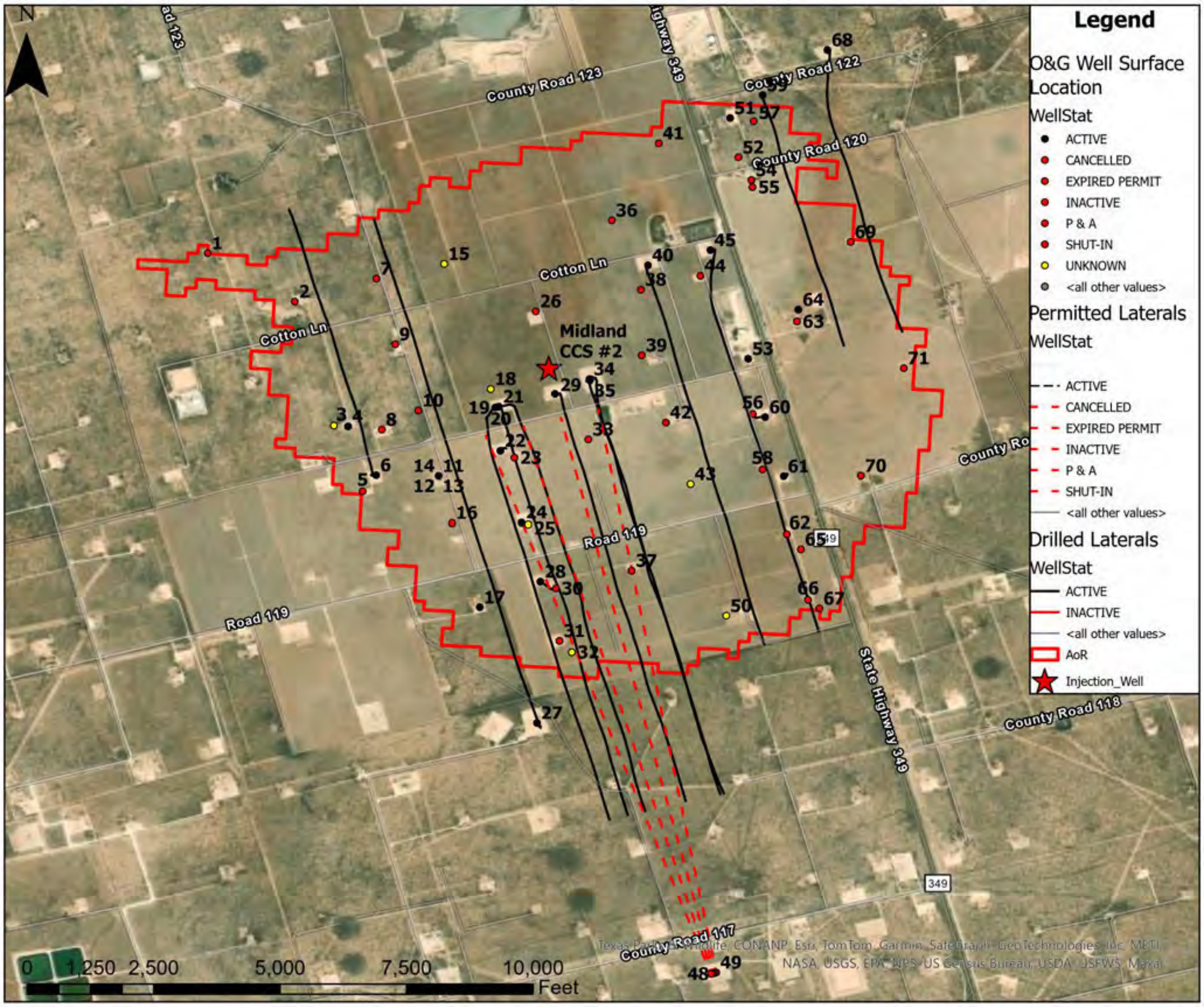


Figure 1-4: Water Sources in AoR

1.3.4 Map of Oil and Gas and Injection Wells in the Area of Review (AoR)

There are 71 deep artificial penetrations in the AoR (water wells previously addressed) (**Figure 1-5**). These include oil and gas wells, stratigraphic test wells, shut-in wells, inactive wells, plugged and abandoned wells, injection wells, and other wells within the AoR. All 71 wells reached total depth (TD) above the primary top seal. No wells within the AoR penetrate the top seal or injection interval. Wells are labeled by an index number presented in **Table 1-28, Section 1.14**. RRC records for all 71 artificial penetrations are included as an appendix attachment, *O&G Individual Well Files*. Well cards, raster logs, and a summary table are also included as appendix attachments.

There are 26 active, 1 cancelled, 11 expired permits, 12 inactive, 13 plugged and abandoned (P&A), 1 shut-in and 7 unknown wells in the AoR.



Type	ACTIVE	CANCELLED	EXPIRED PERMIT	INACTIVE	P & A	SHUT-IN	UNKNOWN
Well Count	26	1	11	12	13	1	7

Figure 1-5: All Artificial Penetrations in AoR, except water wells.

1.3.5 Structures Near AoR

Within the AoR there are fifty-three (53) structures or artificial features of various types (**Figure 1-6**). The majority of the structures are related to oil and gas production. There are four (4) inhabited commercial structures, two (2) temporary oil and gas office buildings, the Burritos Rey Restaurant and the Milestone Energy Waste Facility. There are two (2) residential houses within the AoR. One (1) is a temporary trailer house on the southern end of the AoR and one (1) is a permanent structure on the northeast side of the AoR. The permanent house north of the Milestone Midland Facility has associated barns and storage buildings. There are one-hundred-sixty-eight (168) total structures within a 2-mi radius of the injection well.

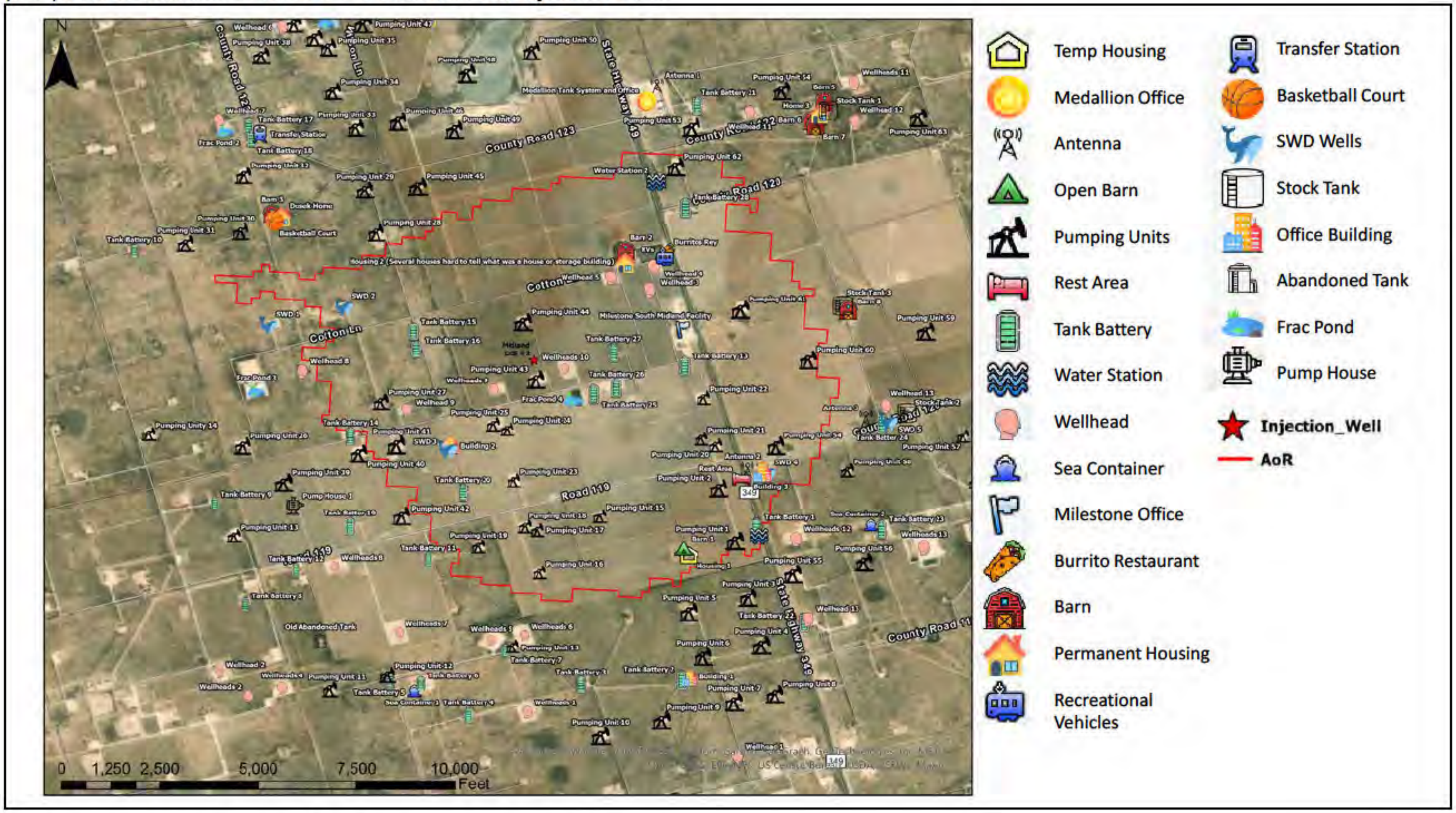


Figure 1-6: All Structures and Features Visible from Surface
Red star denotes Midland CCS #2 Injection Well

1.3.6 Omnibus Map [40 CFR 146.82(a)(2)]

The information contained in **Sections 1.3.1** through **1.3.5** is contained in the map in **Figure 1-7.** Deep penetrations are labeled at the surface location by the well index number is presented in **Table 1-28**. Water wells are labeled with index number is presented in **Table 1-27.** The Plume AoR and the Pressure AoR are identical in this case (plume described in depth in **Section 2**). Therefore, only one AoR is shown and no differentiation is made between artificial penetrations in the pressure front and artificial penetrations in the plume front. Methodology for AoR delineation is covered in detail in **Section 2.**

As noted in previous sections, 87 water wells, 1 lined surface retention pond, 71 deep artificial penetrations (oil and gas wells), and 53 structures are located in the AoR (plume and pressure). No subsurface cleanup, Superfund, RCRA, USTs or other listed hazardous sites of any type are present within the AoR. No known faults are present within the AoR. No state, tribal or territory boundaries are present within the AoR. No mines or springs are present within the AoR. Four (4) inhabited structures are located within the AoR.

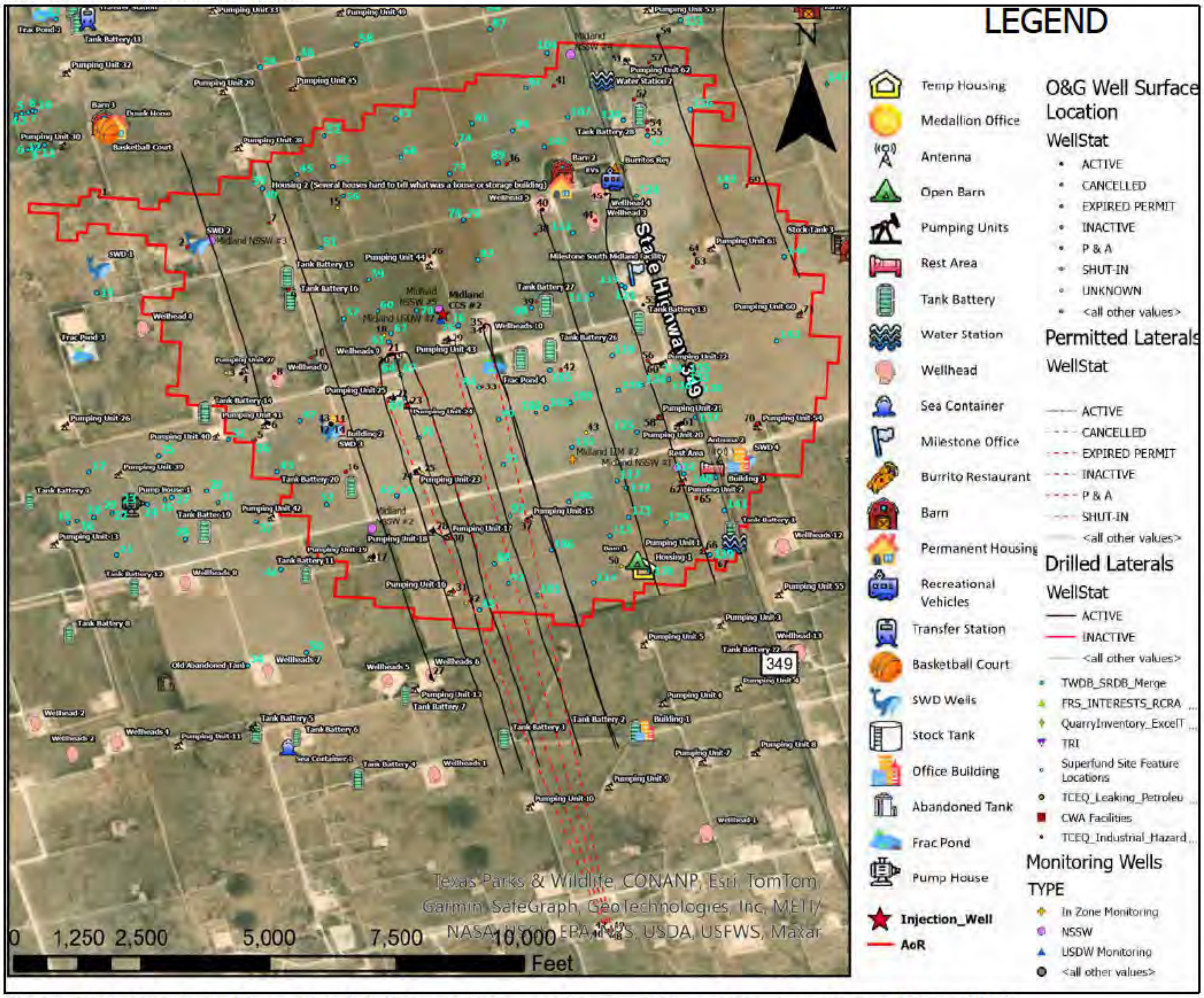


Figure 1-7: Omnibus Map - Artificial Penetrations, Cleanup Sites, Quarries, Mines, Water Wells, Springs etc.

1.4 Regional USDW Characterization and Hydrogeology [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

This section describes the general vertical and lateral limits of all Underground Sources of Drinking Water (USDW), water wells and springs within the AoR, their positions relative to the injection zone, and the direction of water movement, where known.

The Texas Railroad Commission Ground Water Advisory Unit (RRC GAU) has set the base of USDW at 1,250 ft at the proposed well location. (GAU Determination letter, **Section 13, Appendix I**) The proposed Midland CCS #2 Class VI well will set casing at 1,300 ft depth to protect USDW sources. See **Section 3** for a full description of casing sizes, depths and cement. At the proposed well location, the top of the uppermost injection unit (the Devonian) is at a depth of 12,200 ft (see **Section 1.7** for structural tops). Therefore, the base of the USDW is separated from the top of the uppermost injection unit by 10,950 ft, which includes impermeable layers described in more detail below.

The 2011 Aquifers of Texas report and 2016 Texas Aquifers report by the Texas Water Development Board (TWDB) identified two potential aquifers in the vicinity of the proposed Well: the major Edwards-Trinity (Plateau) aquifer and the minor Dockum aquifer (George, Mace and Petrossian, 2011) (TWDB, 2016) (**Figure 1-8**). The Edwards-Trinity (Plateau) and Dockum are separated by an angular unconformity (**Figure 1-9**). The primary water producing aquifer within the AoR is the Antlers sand, a member of the Edwards-Trinity (Plateau) aquifer.

In Upton County, of the two aquifers, the principal source of drinking water is Cretaceous Edwards-Trinity (Plateau) aquifer, which is a shallow freshwater aquifer located at depths of 175-300 ft below the surface. This Edwards-Trinity (Plateau) is semi-confined, with small, confined areas and recharged by rainfall. Water production comes from the Antlers sand member. It is used for domestic, agricultural, and industrial purposes in the county. The Edwards-Trinity (Plateau) aquifer is part of the High Plains aquifer system which contains significant groundwater resources. All water wells in the AoR produce from the Antlers Sand member.

The Dockum formation exists at the well location but is not considered an aquifer at this location by the TWDB due to lithologic changes to shale, salinities greater than 10,000 ppm, and distance from outcrop. It should be noted that the RRC GAU has taken a conservative position and elected to protect the Dockum in northern Upton County, despite these challenges. Therefore, Milestone will treat it as a potential aquifer and also protect it as a potential USDW pending additional data collection.

The Edwards-Trinity (Plateau) and Dockum aquifers are part of the greater High Plains aquifer system in Texas. This aquifer system consists of the southern and northern portions of the major Ogallala aquifer and the southern and northern portions of the Edwards-Trinity aquifers, and the minor Rita Blanca and Dockum aquifers. As noted previously, only the Edwards-Trinity (Plateau) section and Dockum are present in northern Upton County. In some TWDB reports, the upper sands of the Dockum Group are lumped in with the Antlers sand and referred to collectively as the Edwards-Trinity (Plateau) aquifer (**Table 1-5**) (**Figure 1-8**) (TWDB, 2016).

The Fredericksburg, Washita and quaternary deposits exist above the Edwards-Trinity (Plateau) but have not been known to yield sufficient quantities of water to be considered an aquifer (**Table 1-5**).

According to the TWDB, Upton County does not fall within any current Underground Water Conservation Districts (UWCDs). There is a water conservation district north of the facility in Midland County, the Midland Soil and Water Conservation District #244. The AoR does not cross the county line and is not expected to be impacted by this UWCD.

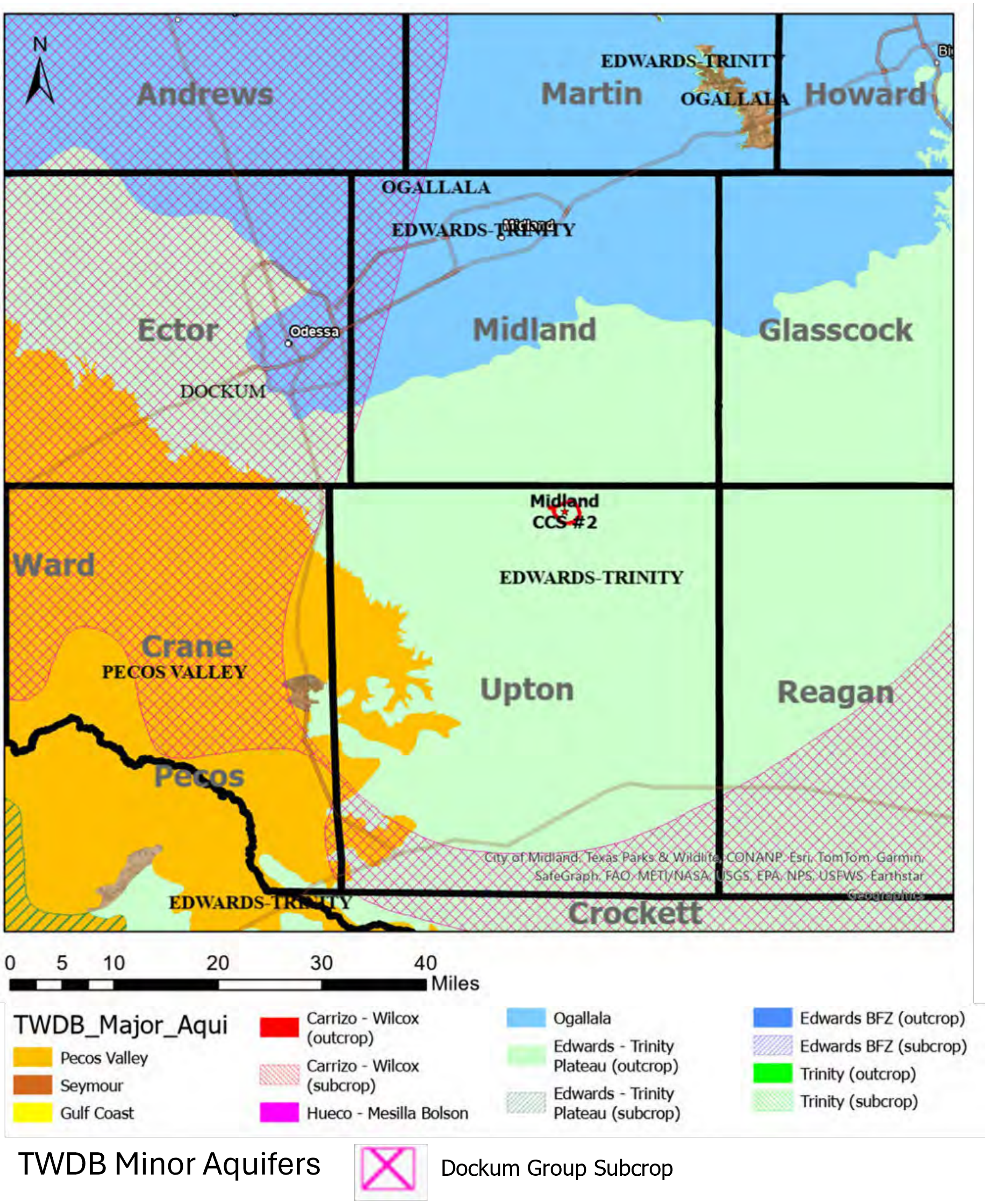


Figure 1-8: Map of TWDB Major and Minor Aquifer Extents
Edward-Trinity (Plateau) (green) and Dockum Group (purple crosshatch) are present in Northern Upton County. Red Star denotes injection well. Red Circle denotes AoR. Dockum group is present at the well location but, salinity is too high for TWDB to consider it an aquifer hence the shapefile does not extend to Northern Upton County.

Table 1-5: Upton County Aquifers

Description of the known aquifers in Upton County and surrounding formations. Texas Water Development Board, Report 78, 1968

ERA	SYSTEM	SERIES	GROUP	STRATIGRAPHIC UNIT	APPROXIMATE MAXIMUM THICKNESS (FT)	CHARACTER OF ROCKS	WATER-BEARING CHARACTERISTICS
Cenozoic	Quaternary	Recent to Pleistocene		Alluvial and eolian deposits	200	Caliche, clay, sand and gravel. Locally mantled with windblown silt and sand.	Yields small quantities of fresh to slightly saline water to livestock and domestic wells along stream courses in the southern and western parts of the county.
Mesozoic	Cretaceous	Comanche	Washita		250	Massive to thin-bedded limestone and calcareous clay and marl.	Not an aquifer in Upton County.
			Fredericksburg	Kiamichi Formation Edwards Limestone Comanche Peak Limestone	270	Calcareous clay, marl, and pale gray to yellowish-brown massive, nodular, fossiliferous limestone. Yellowish-brown argillaceous limestone at base.	All strata are above the water-table except near the southeastern edge of Upton County where the lower beds yield small quantities of fresh water from joints and fractures to a few wells.
			Trinity	Trinity Sand	275	Buff to gray, fine- to medium-grained sand and sandstone interbedded with subordinate amounts of red, gray, and purple shale. Fine gravel at base in some areas.	The principal aquifer in Upton County. Yields small to moderate quantities of fresh to slightly saline water to several hundred wells.
	Triassic		Dockum	Chinle Formation equivalent	570	Brick-red to maroon and purple shale; thin discontinuous beds of red or gray sandstone and siltstone.	Yields small quantities of fresh to moderately saline water to wells in the western and southwestern parts of the county.
				Santa Rosa Sandstone	560	Reddish-brown to gray, medium- to coarse-grained, micaceous, conglomeratic sandstone interbedded with shale.	Yields small quantities of slightly to moderately saline water to shallow wells in the southwestern part of the county. Small to moderate quantities of moderately to very saline water have been pumped from deep wells in the northern part of the county.
				Tecovas Formation	270	Red shale, siltstone, and fine-grained sandstone.	Not known to yield water to wells in Upton County.
Paleozoic	Permian	Ochoa		Dewey Lake Redbeds	230	Thin-bedded siltstone and gypsum.	Not known to yield water to wells in Upton County. Probably capable of yielding small amounts of moderately saline water in the southwestern part of the county.
				Rustler Formation	150	Anhydrite, dolomite, and limestone interbedded with sand and shale.	Not known to yield water to wells in Upton County. Probably capable of yielding small amounts of moderately saline to very saline water.
				Salado Formation	850	Salt (halite), anhydrite, sylvite and polyhalite.	Not known to yield water to wells in Upton County.
		Guadalupe	Artesia	Tansill Formation Yates Sandstone Seven Rivers Formation Queen Formation	2,050	Dolomite, anhydrite, sandstone, shale, and some salt.	Not known to yield water to wells in Upton County. Probably capable of yielding small amounts of very saline or brine water.
				Grayburg Formation	270	Tan to brown dolomite. Fine- to medium-grained sandstone with subordinate amounts of bentonite and anhydrite.	Yields small quantities of moderate to very saline sulfur water in conjunction with oil.
		Guadalupe and Leonard		San Andres Limestone	1,100	Limestone and gray dolomite with sandstone and interbedded black shale.	Yields moderate quantities of a sulfurous brine to wells for waterflood operation in the northern part of the county.

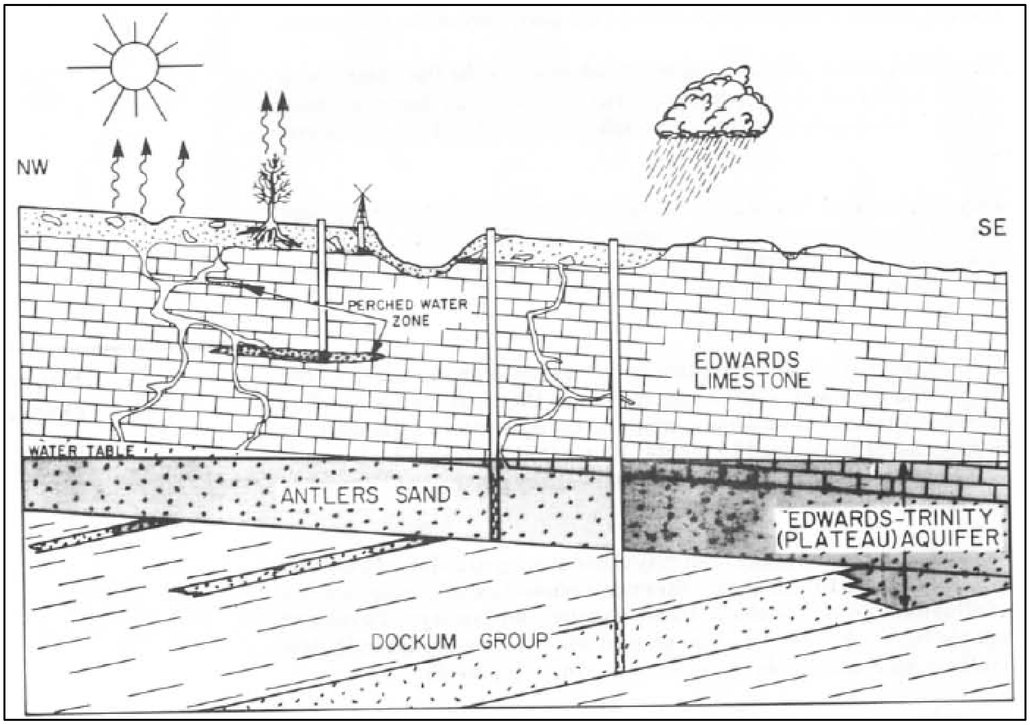


Figure 1-9: Schematic of Structure and Recharge Mechanisms for Edwards-Trinity (Plateau) and the Dockum

Note the angular unconformity separating the base of the Antlers sand and the Dockum Group. Both aquifers are recharged primarily through rainfall. (Ashworth and Christian, 1989)

1.4.1 Edwards-Trinity (Plateau) Aquifer

The Edwards-Trinity (Plateau) aquifer is expected to be encountered at ~175 ft TVD at the Facility. All 87 water wells in the AoR produce from the Antlers sand member at the base of the Edwards-Trinity formation of the Edwards-Trinity (Plateau) aquifer. Depth ranges of the water wells, producing from the Antlers, in the AoR, is from 175-290 ft TVD. In some literature, the Antlers sand is referred to simply as the Trinity sand.

While the Edwards-Trinity formation is typically termed unconfined in literature, the Quaternary alluvium, Cretaceous Washita, Fredericksburg and Edwards limestone have lower permeability compared to the Antlers sand at the base of the formation. Therefore, it appears the aquifer is in fact semi-confined based on local wireline logs and descriptions. Semi-confined aquifers have a low permeability upper bounding layer through which recharge and discharge can still occur. The annual effective recharge to the aquifer is approximately 30,000 acre-ft (Ashworth and Christian, 1989) (**Figure 1-9**).

In Upton County, the Antlers sand forms a narrow band at the base of the irregular yet mostly continuous escarpment that defines the dissected edges of the Edwards-Trinity (Plateau). The Antlers sand outcrop is visible near the base of several isolated mesas and buttes in the southwestern part of the county. Along with the Antlers sand, small amounts of fresh groundwater are found in sandy lenses, joints, fractures, and crevices within the Edwards Limestone, perched above the main water table in some areas. These perched-water zones are generally small and produce limited yields (Ashworth and Christian, 1989).

The Antlers sand consists of buff-to-gray, fine-to-medium-grained, cross-bedded quartz sand and sandstone interbedded with lesser amounts of red, gray, and purple shale. A fine gravel occurs locally at the base of the formation. In some places, the sand is tightly cemented; in other places it is loose or poorly cemented and commonly is referred to as "pack sand" by local drillers.

The Antlers sand dips southeasterly at an average rate of about 10 ft per mi. In most of the northeastern half of the county, the top of the formation ranges from 60 to 150 ft below the land surface; however, in the southern and southwestern parts of the county, where the topography is very irregular, the top is as much as 450 to 500 ft below the summits of the highest mesas and ridges.

Figure 1-10 illustrates the structure of the base of the Edwards-Trinity (Plateau) Antlers sand member. It has a strike of N50E and dips to the SE with an angle of approximately 1/10th of a degree. At the Midland CCS #2 well location, the expected base of the Antlers sand occurs at around 2,520 ft TVD subsea which is approximately 280 ft below ground level. Ground elevation at the injection well is 2,800 ft exactly (Ashworth and Christian, 1989).

The regional direction of groundwater flow in the Edwards-Trinity (Plateau) aquifer is to the southeast in the direction of the hydraulic gradient and in the opposite direction of formation dip. However, heavy pumpage for hydraulic frac and drilling use has created cones of depression around wells which locally alters the direction toward water wells in the region (Ashworth and Christian, 1989).

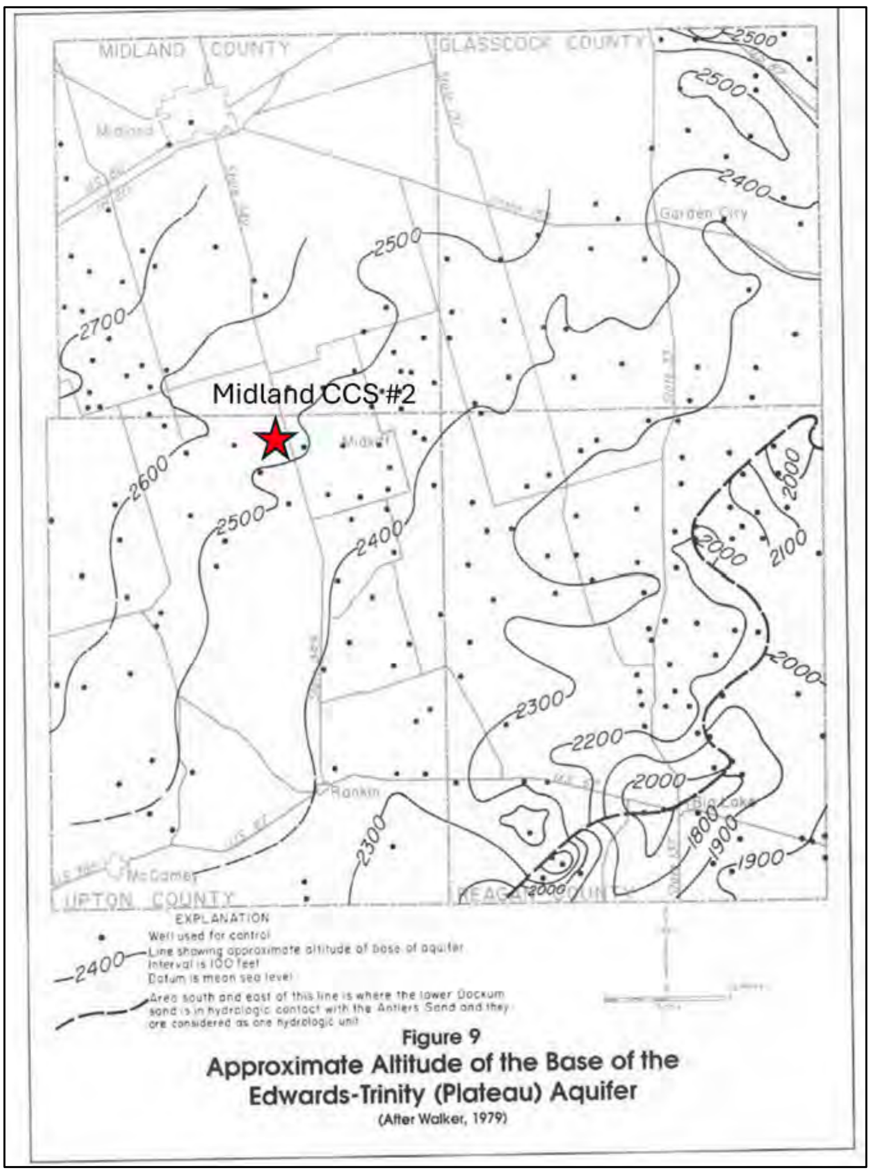


Figure 1-10: Structure map of the Base of the Edward Trinity aquifer (Antlers sand) (TVDSS ft)
After Ashworth and Christian, 1989, Red Star denotes injection well location, expected depth is 2,520 ft at well location

The Antlers sand thickness is expected to be approximately 100 ft thick at the Midland CCS #2 injection well location. If we lump in portion of the Dockum Group, the interval containing USDW water may be as thick 250 ft collectively. The top of the water level is expected to occur at the same depth as the stratigraphic top of the Antlers sand, approximately 2,620 ft TVD subsea or approximately 180 ft below ground level. Regionally, the fresh saturated thickness of the Antlers sand is ~100 ft in northern Upton County and increases up to 800 ft in southern Upton County as the sand deepens and thickens (Ashworth and Christian, 1989).

Except for areas of significant karst-induced permeability, the average hydraulic conductivity of the Edwards-Trinity (Plateau) aquifer sediments is about 10 ft per day (Barker and Ardis, 1996). Wells commonly yield from 50 to 200 gallons per minute. Well yields can vary greatly depending on the amount of development of secondary permeability in the limestone; yields from jointed and cavernous limestone can be as much as 3,000 gallons per minute. Most of the rocks that underlie the Edwards-Trinity (Plateau) aquifer are much less permeable than the aquifer and function as a barrier to groundwater flow. Small sandier areas of the upper Dockum Group may hydraulically connect. (TWDB, 2016) Cha et al., 2022 reported hydraulic conductivity median of 7 ft per day with ranges of 10^{-2} to 10^{2} ft per day for the Trinity (Antler sand) in the North Plateau region (Upton County).

A histogram of total dissolved solids (TDS) for the Edwards-Trinity (Plateau) aquifer is illustrated in **Figure 1-11** and a map of the TDS is illustrated in **Figure 1-12**. These figures suggest the Facility should encounter TDS of 1,000-3,000 ppm with the most probable value being around 1,250 ppm, classifying the aquifer as slightly saline. Water in the unconfined Edwards-Trinity Group is generally fresh but salinity increases to the west where upper confinement is present within the overlying Edwards Group (TWDB, 2016). The nearest wells to the proposed Midland CCS #2 injection well location have TDS values of 2,300-3,300 ppm. The water nearest to the proposed injection well location is locally more saline than the average for the aquifer. Milestone will sample the water within the AoR before beginning drilling operations to verify these historical measurements.

In addition to other contaminants (**Table 1-6**), radionuclides are present in excess of drinking water standards in about 20 percent of the samples from the northwestern portion of the aquifer. Nitrate is present in excess of primary drinking water standards in a smaller number of samples. Groundwater exceeds secondary drinking water standards for total dissolved solids and sulfate in nearly 30 percent of samples, with less frequent exceedances for chloride, fluoride, iron, and manganese. Excessive boron has also been reported in around 50% of samples, higher total dissolved solids (TDS) correlated with higher boron (TWDB, 2016).

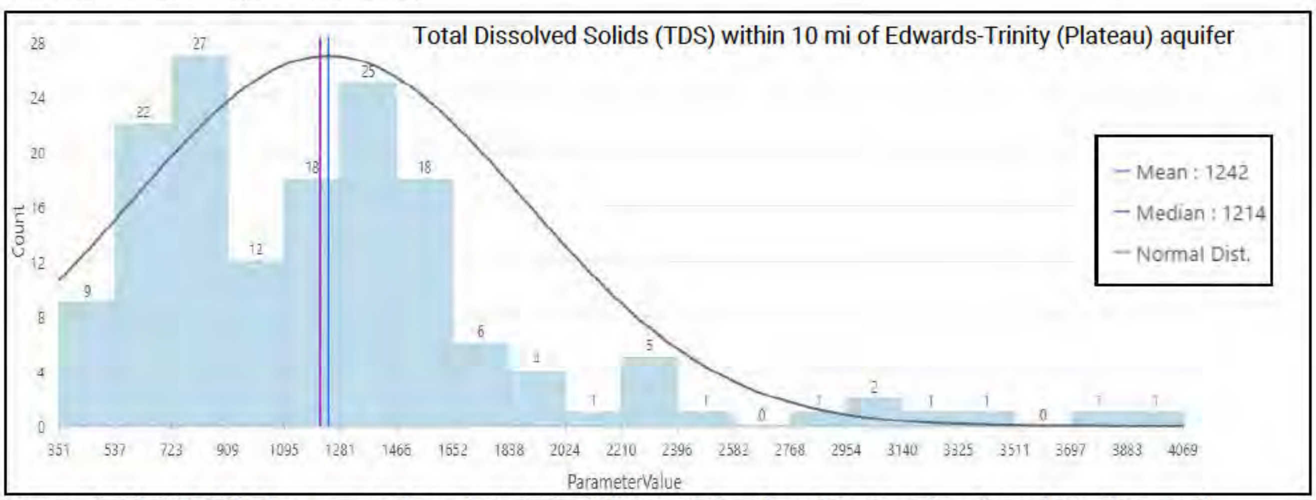


Figure 1-11: TDS Histogram - Edwards-Trinity (Plateau) Aquifer, 10-mi radius from Injection well
Data Source = TWDB Water Quality Measurements

Hydraulic characteristics that influence the effectiveness of an aquifer to yield to water a pumping well include transmissivity and storage coefficient. Average values for these characteristics of the Edwards-Trinity (Plateau) aquifer are transmissivity of 325 square ft per day and storage coefficient of 0.074. Yields of wells producing from the Trinity average approximately 100 gallons per minute with specific capacities of approximately one gallon per minute per foot of drawdown (Ashworth and Christian, 1989). Storativity has a mean of $6x10^{-4}$ (Cha et al., 2022) (**Figure 1-13**).

Total storage in the Edwards-Trinity (Plateau) is estimated to be more than 45 million acre-ft. Recoverable storage is estimated to be between 25 and 75 percent of the total, about 11.3 million to 34.1 million acre-ft. Water levels have remained rather stable because recharge has generally kept pace with the relatively low volume of water pumped from the aquifer, except for areas of heavy pumpage related to oil and gas or agricultural use such as Reagan-Glasscock County (TWDB, 2016).

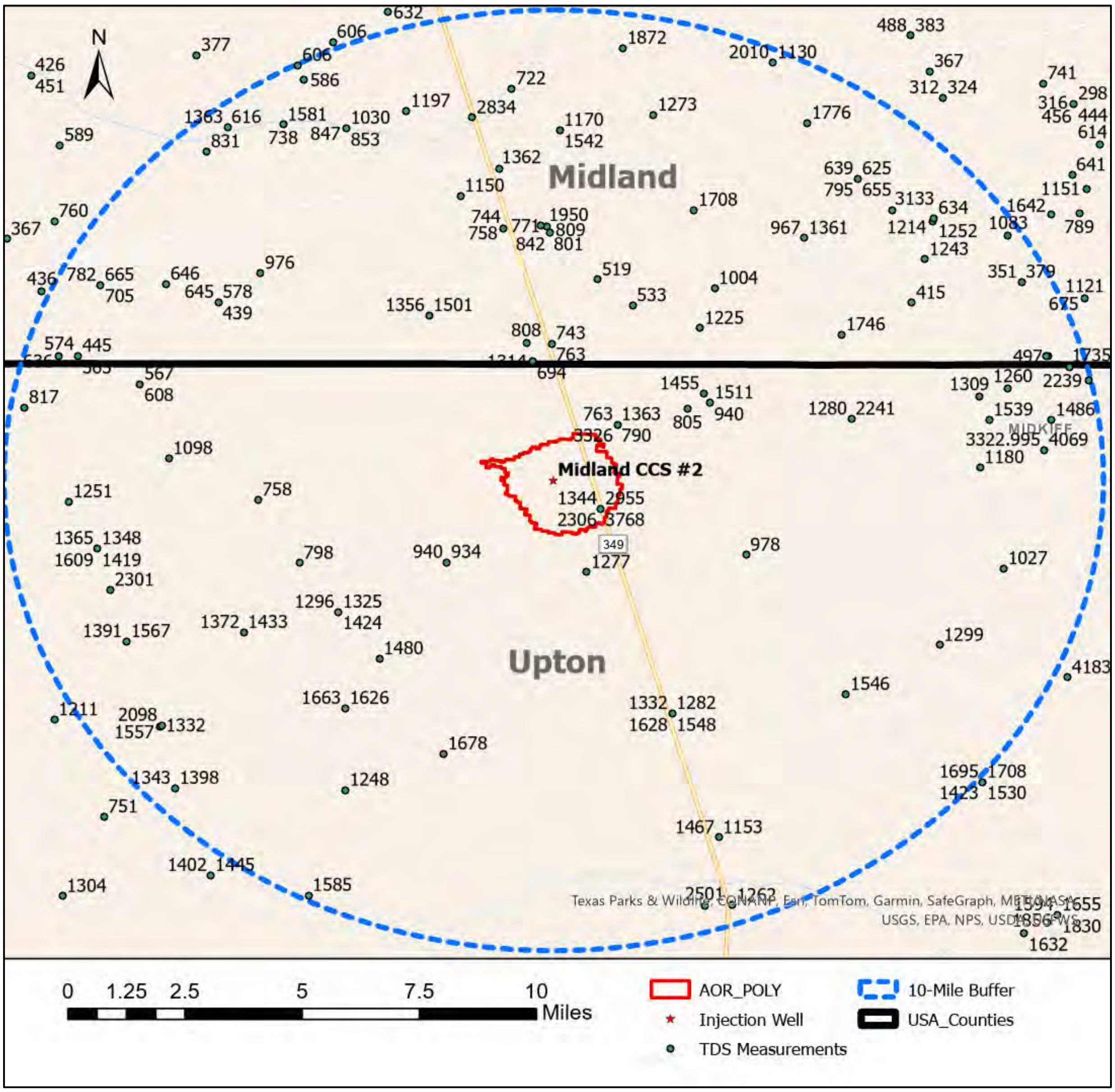


Figure 1-12: Map of Total Dissolved Solids (TDS) for Edwards-Trinity (Plateau), 10-mile radius from Injection Well

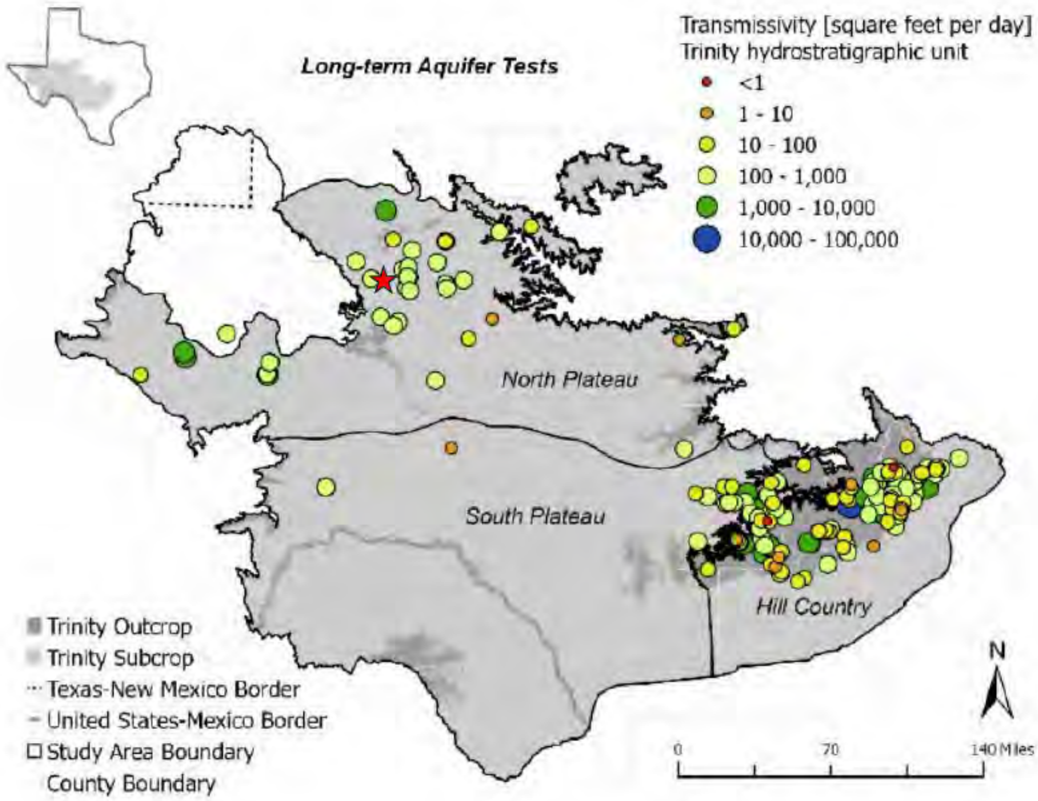
Data Source = TWDB Water Quality Measurements; Labels are Total Dissolved solids in PPM or mg/L; Red Star is the Injection location, Red outline is the AoR. Blue-dashed outline is a 10-mi buffer. All tests, are shown, some wells have multiple tests conducted years apart. They are posted at the same location.

Table 1-6: Water Quality Averages for Edwards-Trinity (Plateau) Aquifer, 10-mi radius of Injection Well

Analyte	Unit	Count	Min	Average	Max	StDev
ALUMINUM, DISSOLVED	UG/L AS AL	60	1	4	20	2.493415
ARSENIC, DISSOLVED	UG/L AS AS	68	1	2.875	30.3	4.094269202
BARIUM, DISSOLVED	UG/L AS BA	68	4	14	51	8.451673023
BICARBONATE ION, CALCULATED	MG/L AS HCO3	155	0	225	394	54.78690181
BORON, DISSOLVED	UG/L AS B	69	31	809	3,390	596.3987592
BROMIDE, DISSOLVED	MG/L AS BR	55	0.2	0.5832727	3	0.545880141
CADMIUM, DISSOLVED	UG/L AS CD	61	1	1.0331147	2	0.179513611
CALCIUM, TOTAL	MG/L	82	32	191	551	99.32243
CARBONATE ION, CALCULATED	MG/L AS CO3	155	0	1.0219354	158	12.72299417
CHLORIDE, TOTAL	MG/L AS CL	95	15	70	570	71.16687
IRON, DISSOLVED	UG/L AS FE	68	4	77	945	134.4788453
MAGNESIUM, TOTAL	MG/L	82	10	46	107	22.74498
MANGANESE, DISSOLVED	UG/L AS MN	67	0.5	17	460	59.6660231
MERCURY, DISSOLVED	UG/L AS HG	27	0.13	0	0.2	0.018682
NITRATE NITROGEN, DISSOLVED, CALCULATED	MG/L AS NO3	144	0.04	31	212	21.21529
PHOSPHORUS, DISSOLVED	MG/L AS P	36	0.02	0.0372916	0.227	0.037295602
POTASSIUM, TOTAL	MG/L AS K	23	3	9	24	4.508775
SILICA, DISSOLVED	MG/L AS SIO2	144	5	13	45	6.141302053
SODIUM, TOTAL	MG/L AS NA	82	12	102	496	71.73519
STRONTIUM, DISSOLVED	UG/L AS SR	68	2,760	6,167	18,600	3140.286538
SULFATE, TOTAL	MG/L AS SO4	95	24	544	1,633	353.0359
ZINC, DISSOLVED	UG/L AS ZN	67	4	151	1,590	335.3535
Non-Cation/Anion Properties						
ALKALINITY, TOTAL	MG/L AS CACO3	155	20	186	323	38.91656
ALPHA, DISSOLVED	PC/L	29	6.8	28.6	85.2	20.01609
HARDNESS, TOTAL, CALCULATED	MG/L AS CACO3	149	170	720	2,018	343.506
TEMPERATURE, WATER	CELSIUS	127	17	21	28	1.742381
TOTAL DISSOLVED SOLIDS, SUM OF CONSTITUENTS	MG/L	155	351	1,242	4,069	651.9665
SPECIFIC CONDUCTANCE, FIELD	UMHOS/CM AT 25C	141	652	1,914	4,620	887.4591
pH Lab	Standard Units	4	7.15	7.4775	7.71	0.25025
pH Field	Standard Units	143	6.62	7.383287	8.2	0.334266

Table 1-6 provides a summary of various water quality analytes, their measurements, and statistical data. Analytes include dissolved metals (such as aluminum, mercury), and other parameters (like pH, alkalinity, hardness, and total dissolved solids (TDS)). The data indicates the number of samples (Count), the minimum (Min), average (Average), maximum (Max), and standard deviation (StDev) for each analyte. For example, dissolved aluminum concentrations range from 1 to 20 µg/L with an average of 4 µg/L, while total dissolved solids range from 351 to 4,069 mg/L, averaging 1,242 mg/L. The pH varies slightly between field and lab measurements, with averages around 7.4. Overall, this table provides insights into the variability of chemical constituents in the sampled water.

The highest average water analyte is sulfate at a value of 544 ppm, the next highest is bicarbonate at 225 ppm followed by calcium at 191 ppm and various metals at less than 100ppm.



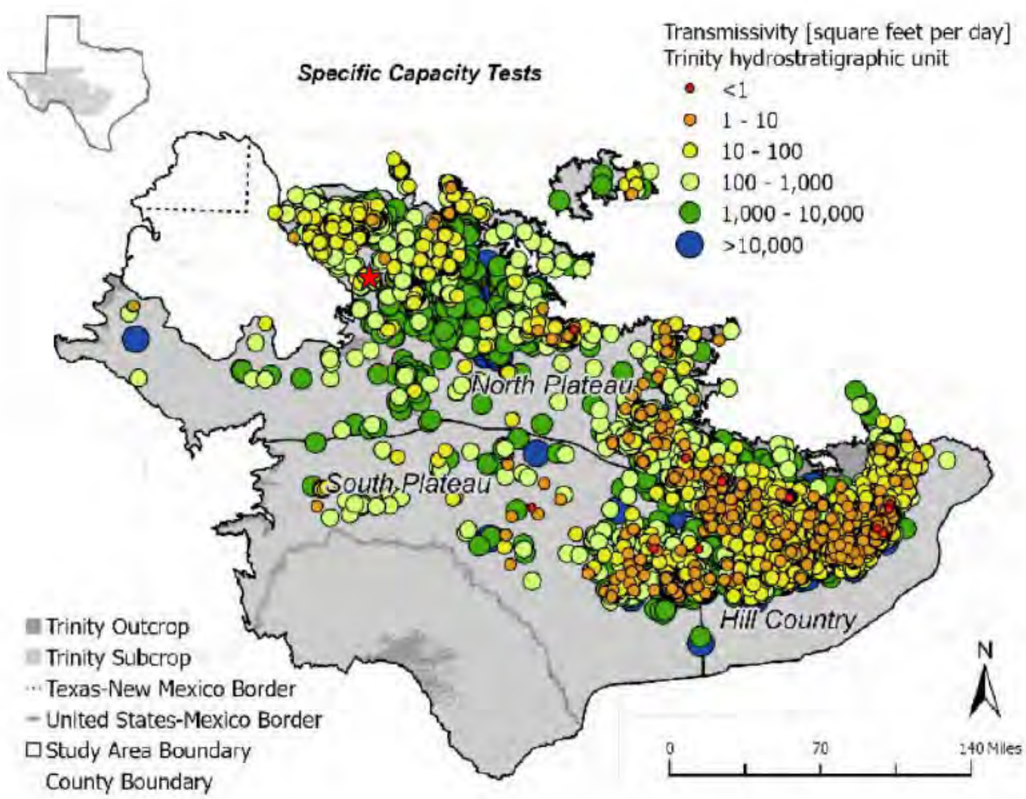


Figure 1-13: Map of Transmissivity and Specific Capacity Tests for Edwards-Trinity (Plateau) Aquifer
Red Stars identify Midland CCS #2 location. Data Source: Cha et al., 2022

1.4.2 Dockum Group Aquifer

The Dockum Group is expected to be encountered at ~300' TVD underlying the Facility. One water historical well is reported (incorrectly) to be producing from the Dockum in the AoR - State Well # 4425107. Since the reported depth is equivalent to nearby Antlers sand wells - it is likely a misinterpretation. Milestone does not currently believe any wells within the AoR are producing from the Dockum Group given the low reported permeability in the upper Dockum. It is possible some wells are comingled with the Dockum and Antlers sand.

The water quality in the aquifer is generally poor and very hard (**Figures 1-14, 1-15**). Estimated total dissolved solids (TDS) in the Dockum at the proposed well location is 11,030 ppm. The median TDS is 10,435 ppm with a range of offset well values from 8,372 ppm to 14,996 ppm (**Table 1-7**). Sulfate greatly exceeds the chloride content in northern Upton County (Ewing et al., 2008).

Naturally occurring radioactivity from uranium present within the aquifer has resulted in gross alpha radiation in excess of the State's primary drinking water standard in about 25 percent of Dockum aquifer wells. Radium-226 and -228 also occur in amounts above acceptable standards. Nitrate is present at concentrations exceeding primary drinking water standards in about 10 percent of the wells, mostly in the outcrop areas, where it is associated with agricultural operations. Dockum aquifer groundwater exceeds secondary drinking water standards for chloride, fluoride, iron, sulfate, and total dissolved solids in about one-third of the wells tested, primarily as the result of the evaporite minerals present in the Dockum Group and underlying formations of the Permian Basin (TWDB, 2016).

The Dockum Group is composed of sandstones, conglomerates, mudstones, and siltstones. In Upton County, the Dockum aquifer is overlain by the Edwards-Trinity (Plateau) aquifer except in areas where it outcrops and the Edwards-Trinity has been eroded away. There is an angular unconformity at the contact between the Edwards-Trinity and Dockum Group. Permian System Ochoan series red-bed shales underlie the Dockum Aquifer, forming a no-flow lower boundary.(Ashworth and Christian, 1989)

As noted previously, the TWDB does not consider the Dockum a minor aquifer in northern Upton County, likely due to shaliness and elevated salinity. There are correspondingly few penetrations of the Dockum in the TWDB database for northern Upton County and southern Midland County.

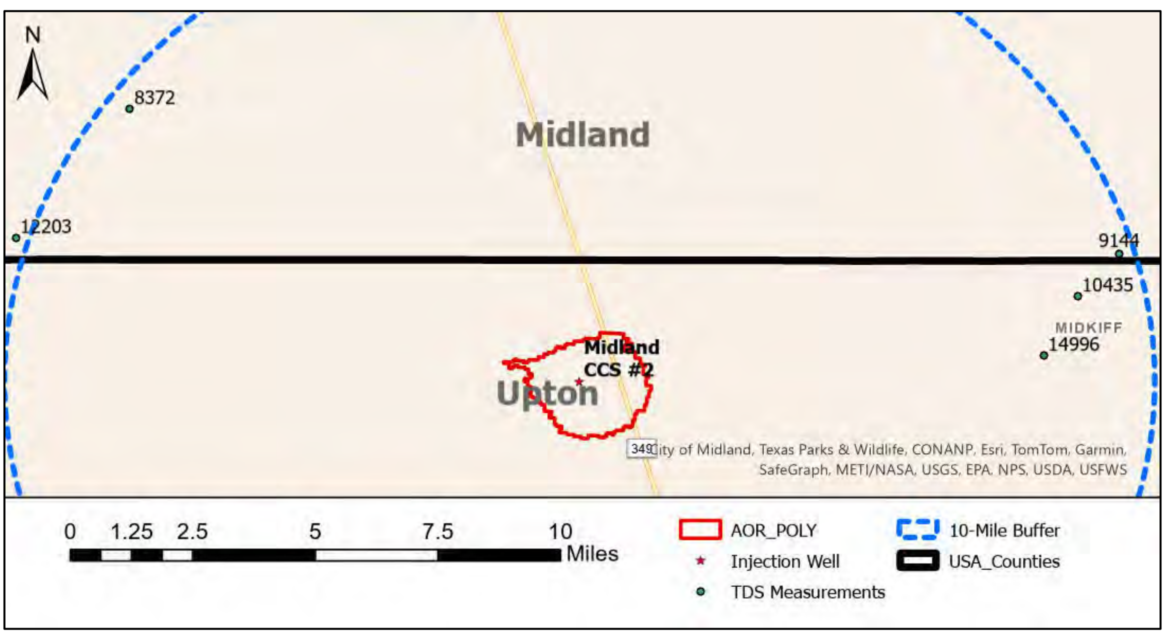


Figure 1-14: Map of Total Dissolved Solids (TDS) for Dockum Group, 10-mi radius from Injection Well
Data Source = TWDB Water Quality Measurements; Labels are Total Dissolved solids in PPM or mg/L; Red Star is the Injection location. Red outline is the AoR. Blue-dashed line is the 10-mi buffer.

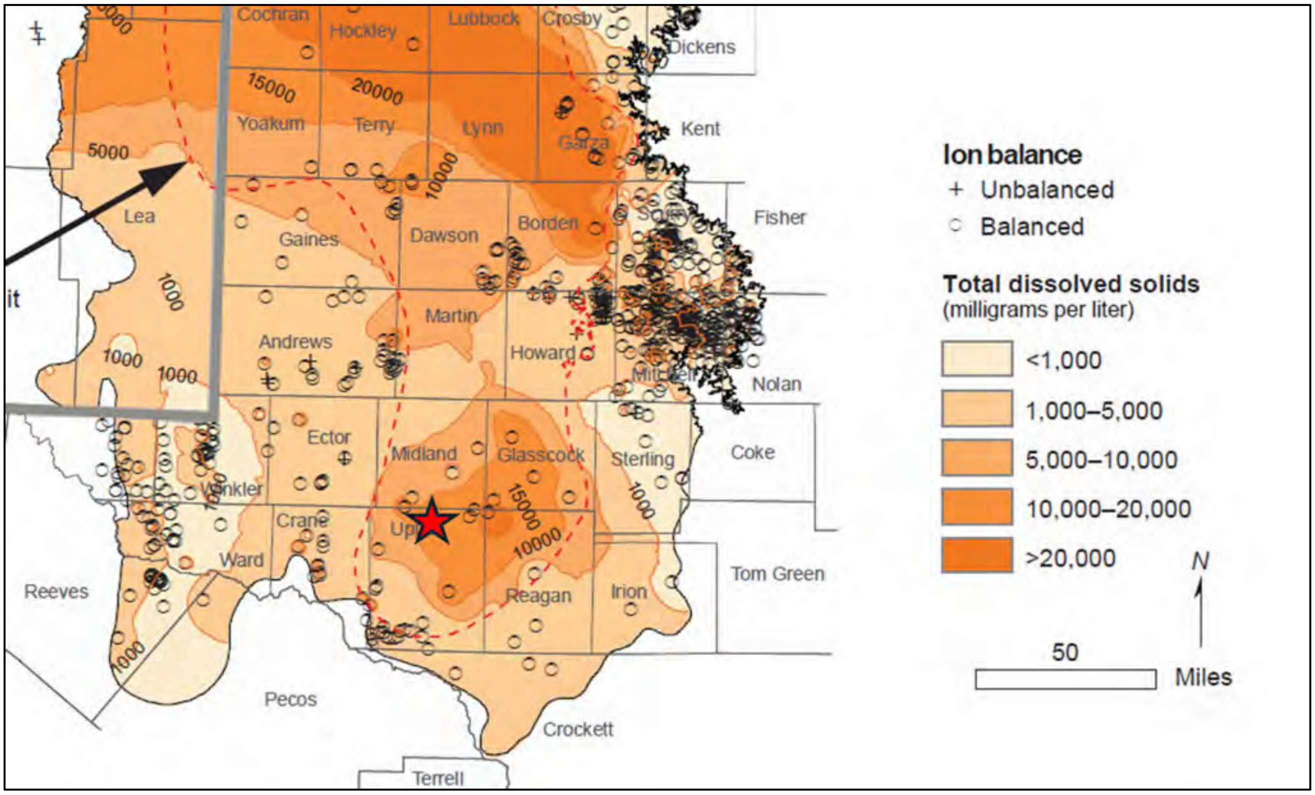


Figure 1-15: Regional Extent Dockum Aquifer and TDS
Regional Extent of the Dockum Aquifer with Total Dissolved Solid (TDS mapped) (George, Mac and Peterson, 2011) Red Star is approximate location of the Midland CCS #2 Well

Recharge of the Dockum Group occurs primarily in counties to the northeast, such as Howard County, where the outcrop is exposed at the surface. Groundwater percolates away from these outcrops at rate of 0.15-0.58 inches per year (TWDB, 2016). There is also some hydrologic communication with the overlying Antlers sand if the Dockum is not shaley at the unconformity (Ashworth and Christian, 1989). Given the great distance from the outcrop in Upton County, and implied long residence time, it should not be surprising that the TDS is quite high near the proposed injection well location.

Total storage in the Dockum aquifer is estimated to be over 1.5 billion acre-ft. Recoverable storage is estimated to be between 25 and 75 percent of the total, about 373.5 million to 1.1 billion acre-ft. (TWDB, 2016) The storativity of the Dockum ranges from $5x10^{-5}$ to $2x10^{-3}$, with a specific yield of 0.3 to 0.28. (Ewing et. al, 2008)

Regional studies of the Dockum aquifer and the southern High Plains indicate a general drainage toward the southeast. It is probable, however, that in much of Upton County, the direction of movement may be easterly, away from the Central Basin Platform. Groundwater movement in the Dockum is slow, a few ft per year, due to low permeability (Ashworth and Christian, 1989). TWDB, 2016 reported a hydraulic conductivity of 0.2-0.4 ft per day for the lower Dockum aquifer with local areas closer to the outcrop of up to 25 ft per day. The expected hydraulic conductivity near the injection well is 0.28 ft per day and low as 5.3×10^{-5} per day in more clay rich intervals (Ewing et al., 2008). The nearest control point reported by Ewing et al, 2008 had a hydraulic conductivity of 3-5 ft per day; however, this was in southern Upton County where the hydraulic properties are expected to be superior to what is found at the injection well location (**Figure 1-16**).

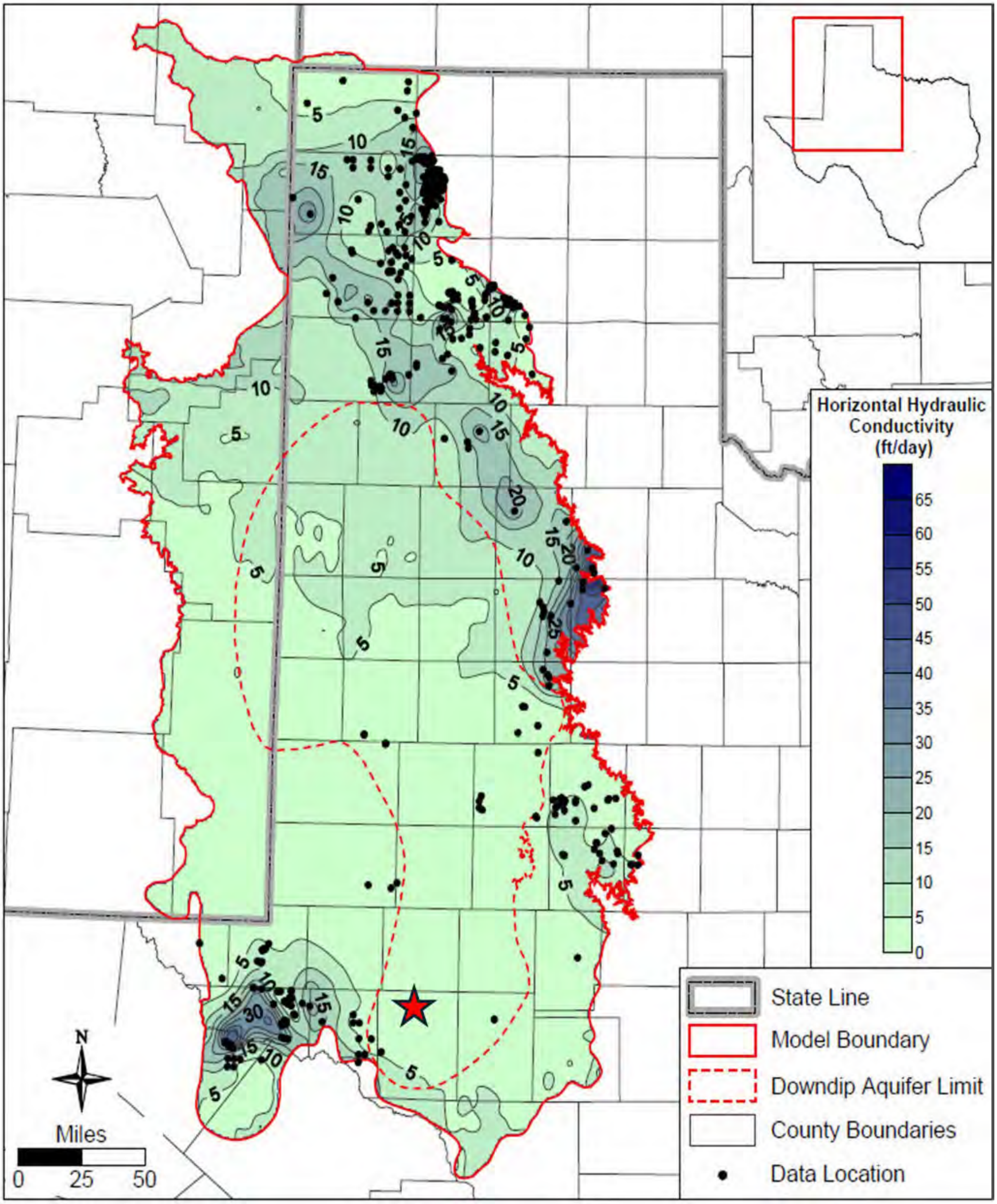


Figure 1-16: Lower Dockum Hydraulic Conductivity
Red Star notes Midland CCS #2 location. Data Source: Ewing et al., 2008; Upper Dockum is eroded in Northern Upton County, TX.

The Dockum Group top is expected to occur at approximately 280 ft below ground level or 2,620 ft TVD SS at the Midland CCS #2 well location (**Figure 1-10**). The lowest Dockum sand is mapped at 1,250 ft below ground level or 1,650 ft TVD SS. The Dockum is approximately 1,070 ft thick, but only around 200 ft has sands that will yield water in any quantity. There is a change in strike and dip below the angular unconformity. The Antlers sand dips southeast (SE) (**Figure 1-10**), while the Dockum dips to the north-northeast (N-NE) towards the basin center (**Figure 1-17, 1-18**).

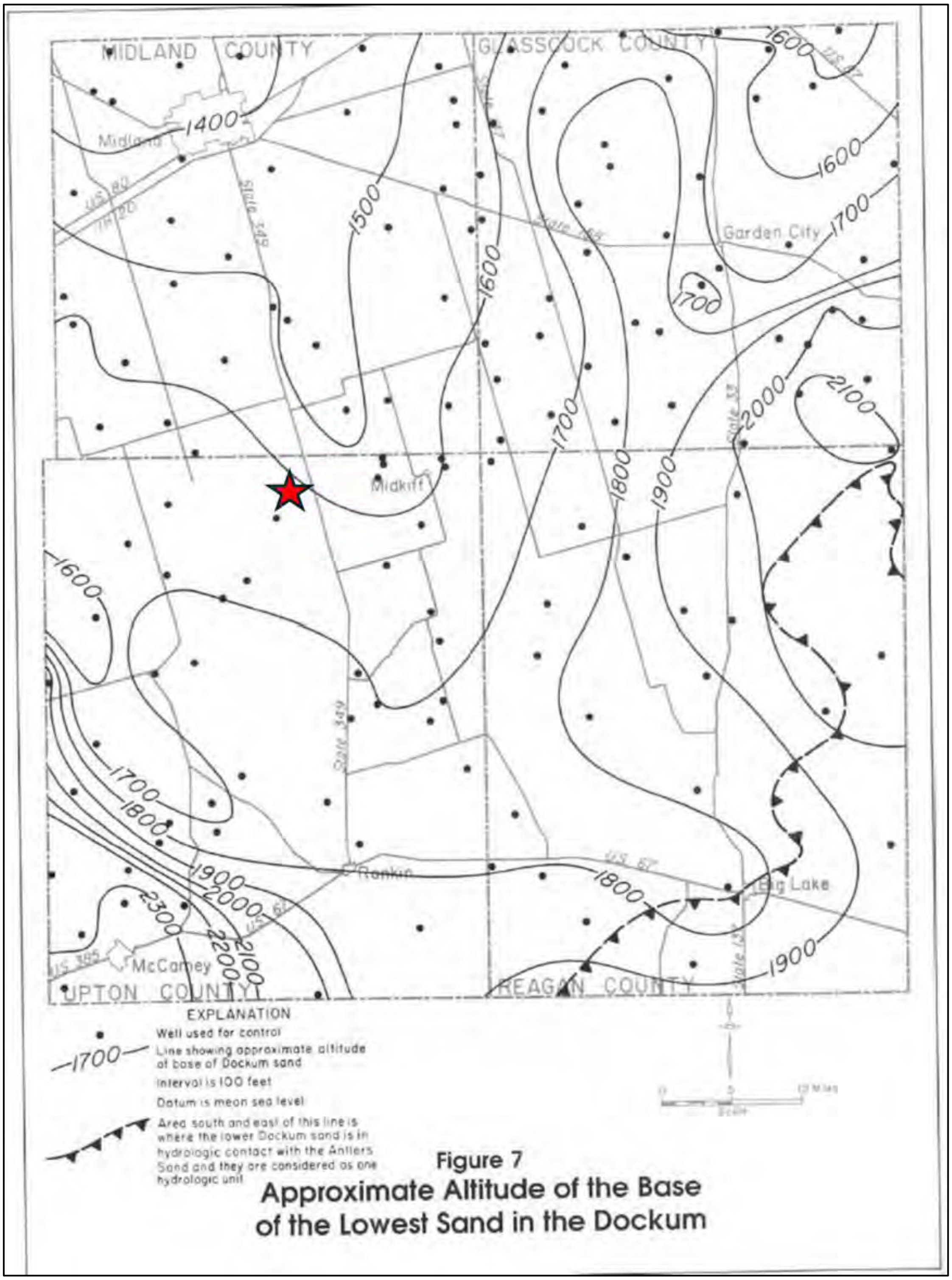


Figure 1-17: Structure Map of Base of Dockum Group, TVD SS
Red Star notes Midland CCS #2 location, Data Source: Ashworth and Christian, 1989

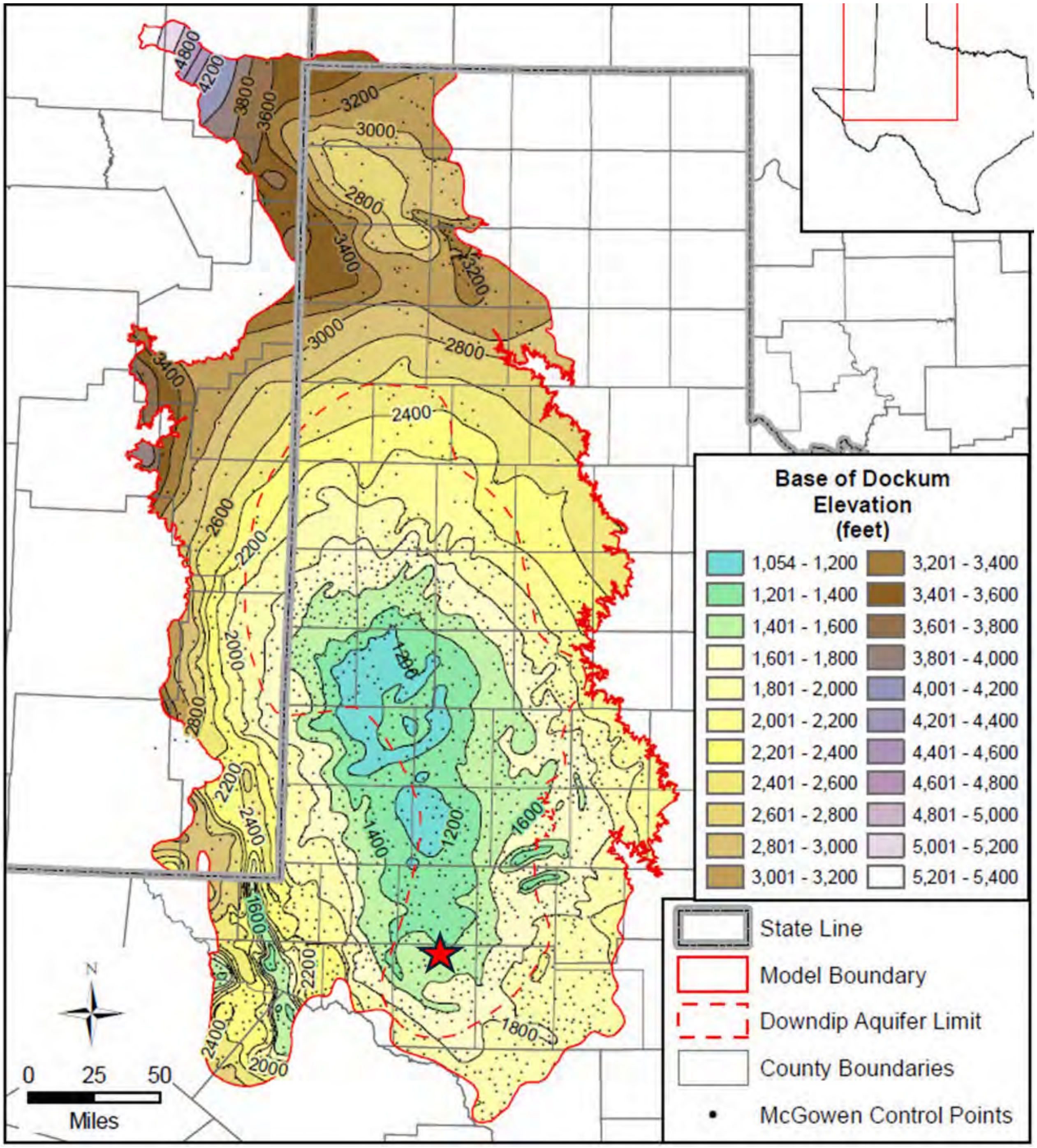


Figure 1-18: Regional Structure Map of Base of Dockum Group, TVD SS
Red Star notes Midland CCS #2 location, Data Source: Ewing et al., 2008

Regionally, the Dockum ranges from 3,200 ft TVD SS where it outcrops on the surface to its deepest extent at 1,000 feet TVD SS. The lower Dockum sands form a large basin that mirrors the structure of the wider Midland Basin. Due to residence time, and recharge through percolation at outcrops, the downdip aquifer limit for total dissolve solids (TDS) is approximately 2400-1800 ft TVD SS (Ewing et al., 2008).

The Midland CCS #2 is positioned beyond the downdip aquifer limit of the Dockum Group as defined by the TWDB. However, as previously noted the RRC considers it a protected USDW.

Table 1-7: Water Quality Averages for Dockum Group Aquifer, 10-mi Radius of Injection Well

Analyte	Unit	Count	Min	Average	Max	StDev
BICARBONATE ION, CALCULATED	MG/L AS HCO3	5	322.17	386.456	418	37.57702
CALCIUM	MG/L	5	110	185.6	319	81.35908
CARBONATE ION, CALCULATED	MG/L AS CO3	4	0	0	0	
CHLORIDE, TOTAL	MG/L AS CL	5	3,290	4,796	7,400	1720.605
HARDNESS, TOTAL, CALCULATED	MG/L AS CACO3	5	484	778	1153	263.4151
IRON, TOTAL	UG/L AS FE	1	4,000	4,000	4,000	
MAGNESIUM	MG/L	5	51	76.6	103	19.96998
RESIDUAL SODIUM CARBONATE, CALCULATED	MG/L	5	0	0	0	
SILICA, DISSOLVED	MG/L AS SI02	3	10	10.66	11	0.57735
SODIUM, CALCULATED, PERCENT	%	5	90	91	92	4.814382
SODIUM, TOTAL	MG/L AS NA	5	2,930	3,827.6	5,248	4.814382
SULFATE, TOTAL	MG/L AS SO4	5	1,680	1,948	2,320	256.0664
Non-Cation/Anion Properties						
ALKALINITY, PHENOLPHTHALEIN	MG/L	4	0	0	0	
ALKALINITY, TOTAL	MG/L AS CACO3	4	264	315.1325	342.53	35.3309
TEMPERATURE, WATER	CELSIUS	1	24	24	24	
TOTAL DISSOLVED SOLIDS, SUM OF CONSTITUENTS	MG/L	5	8,372	11,030	14,996	2,649.579
SODIUM ADSORPTION RATIO, CALCULATED	SAR	5	54.04	59.732	67.21	4.814382
PH, FIELD	STANDARD UNITS, FIELD	5	6.8	7.16	7.4	0.219089
SPECIFIC CONDUCTANCE, FIELD	UMHOS/CM AT 25C	3	12,500	14,400	17,700	2,868.798

Table 1-7 provides a summary of various water quality analytes, their measurements, and statistical data for a 10-mile radius of the proposed injection well location. Analytes include dissolved metals (such as iron, sodium), and other parameters (like pH, alkalinity, and total dissolved solids (TDS)). The data indicates the number of samples (Count), the minimum (Min), average (Average), maximum (Max), and standard deviation (StDev) for each analyte. For example, dissolved calcium concentrations range from 110 to 319 mg/L with an average of 185.6 mg/L, while total dissolved solids range from 8,379 to 14,996 mg/L, averaging 11,030 mg/L. The pH (field) ranges 6.8 to 7.4 with an average of 7.16.

As reported in the literature, this water testing shows elevated levels of sulfate, chloride, and iron, well in excess of primary drinking water standards. The sulfate levels in the Dockum in northern Upton County average 1,948 ppm, while the primary drinking water standard is <300 ppm. The chloride levels in the Dockum average 4,796 ppm, while the primary drinking water standard is <300 ppm and finally the iron averages 4,000 ppm while the primary drinking water standard is <300 ppm. Although not sampled in these proximal wells, Ewing et al., 2008 and others have additionally reported levels of boron, fluoride, manganese, and alpha activity exceeding the primary drinking water standards.

Ewing et al., 2008 reported that the high radiological activity of the Dockum Group aquifer owes its origin to the occurrence of uranium within the aquifer. Uranium is found within the Dockum ranging from 2-300ppm. It has been theorized that the original source of the uranium are granitic rocks from

Oklahoma or Triassic volcanic ash rocks from Mexico and Texas. These original sources of uranium would have been oxidized and mobilized through groundwater systems before being redeposited under reducing conditions. A strong correlation with longer residence time and alpha particle activity has been observed. All samples tested within the downdip aquifer limit outline, found in **Figure 1-16 - Figure 1-18,** have alpha particle activity greater than 15 picoCuries/Liter (pC/L). Therefore, it is probable that any sample from northern Upton County will contain a similar value greater than the primary drinking water standard of 15 pC/L although it has not been tested proximally (Ewing et al., 2008).

1.4.3 Positioning of Monitor Wells Up-Dip

Due to the change in dip between the Antlers sand and the Dockum Group, the offset monitoring wells have been positioned such that each well is updip in the formation it is designed to monitor. The Midland NSSW #5, with a total depth of 300 ft, is positioned northwest (NW) of the injection well location because it is designed to monitor the Antlers sand which dips to the southeast (SE). Meanwhile, the Midland USDW #2 with a total depth of 1,300 ft, which will monitor the base of the USDW, the lowest Dockum Group sand, is positioned south (S) and slightly west (W) of the injection well to account for the Lower Dockum sands dip to the north-northeast (N-NE). This positioning ensures that, in the hypothetical event of a leak, each monitor well is correctly oriented for updip migration of buoyant gas (**Figure 1-19**).

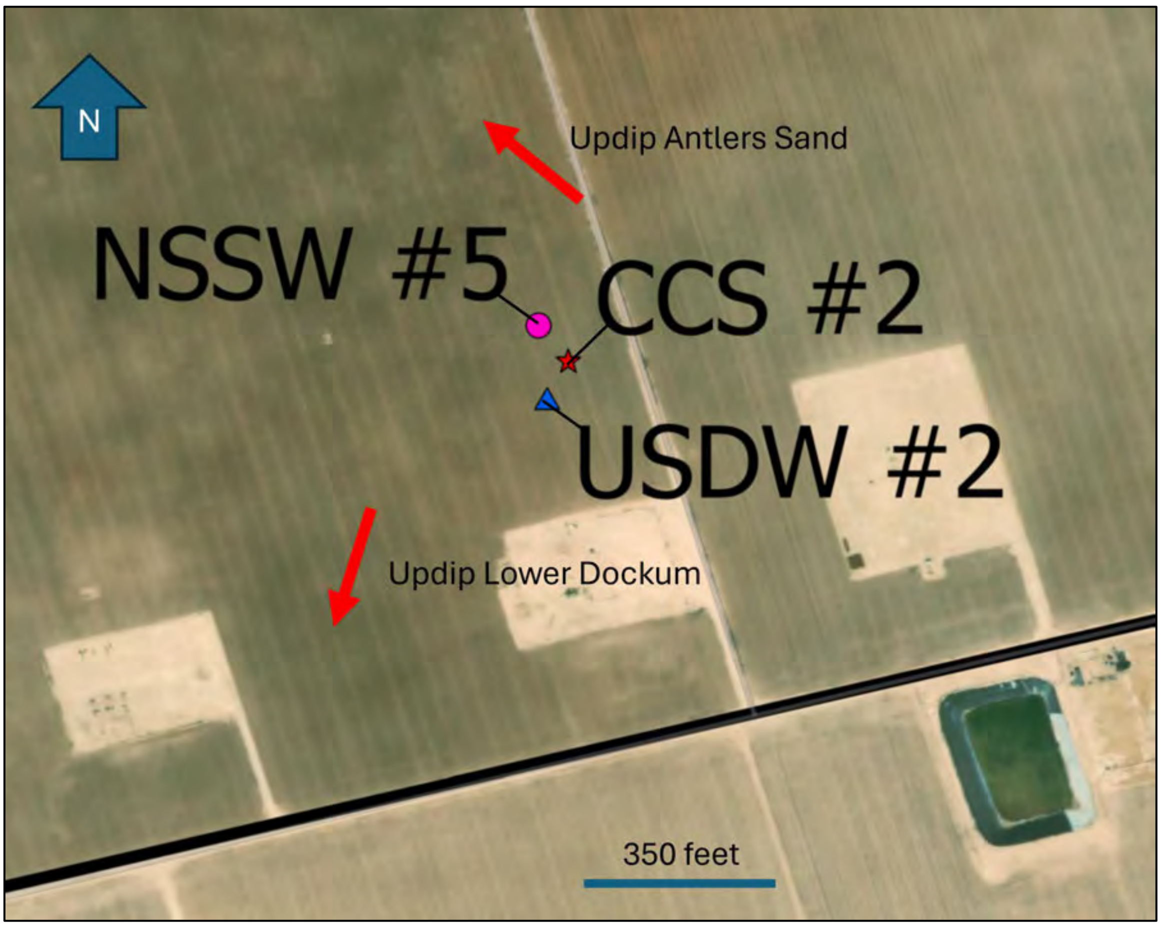


Figure 1-19: Map of Aquifer Dips, Injection and Monitoring Well Locations
Red Star notes Midland CCS #2 location. For additional information on monitoring wells see ***Section 1.3*** *or* ***Section 6***

1.4.4 RRC GAU and TWDB Data

The Texas Railroad Commission Ground Water Advisory Unit (GAU) has set the base of freshwater at 350 ft for all oil and gas production wells in Section 9 of Township 5S Block 39; which is proposed Well location. The depths in this paragraph come from a review of the GAU determinations in RRC records for nearby oil and gas wells.

Milestone submitted an additional request to the GAU (dated 10/18/2024) for a determination of base of USDW; the GAU determined a base depth of 1,250 feet Additionally, in this location, the top of the Devonian, upper most injection unit, is 12,200 ft. Therefore, there is 10,950 ft of rock with many impermeable barriers between the base of USDW and the top of injection. (GAU Determination letter, **Section 13 Appendix I**).

The TWDB has two continuously monitored wells in Upton County to the east of the site near Garden City, Texas. These wells are State Well #4412611 and State Well #4420854. Well #4412611 reports freshwater level at 238' below the surface and Well #4420854 reports freshwater at 227 ft below the surface. Both of these wells are producing from the Trinity aquifer system in the Antlers sand member. Thus, data supports the principle that producible water is between 228-350' in the region. There is a roadside monitoring TWDB well, State Well #4425107, in the AoR but it does not have continuous monitoring data. Files reviewed from the TWDW for well #4425107 show it is producing from the "Dockum" and the last record is from 6/16/2011 (**Section 13 Appendix H**). It reports freshwater at 230 ft below the surface although high concentrations of radium 226 are also reported. A map of the total depth (TD) of all water wells in the AoR are illustrated in **Figure 1-20**. Based on the depth, it is likely that this reported "Dockum" well is actually an Antlers sand well and the water well driller mis-identified it.

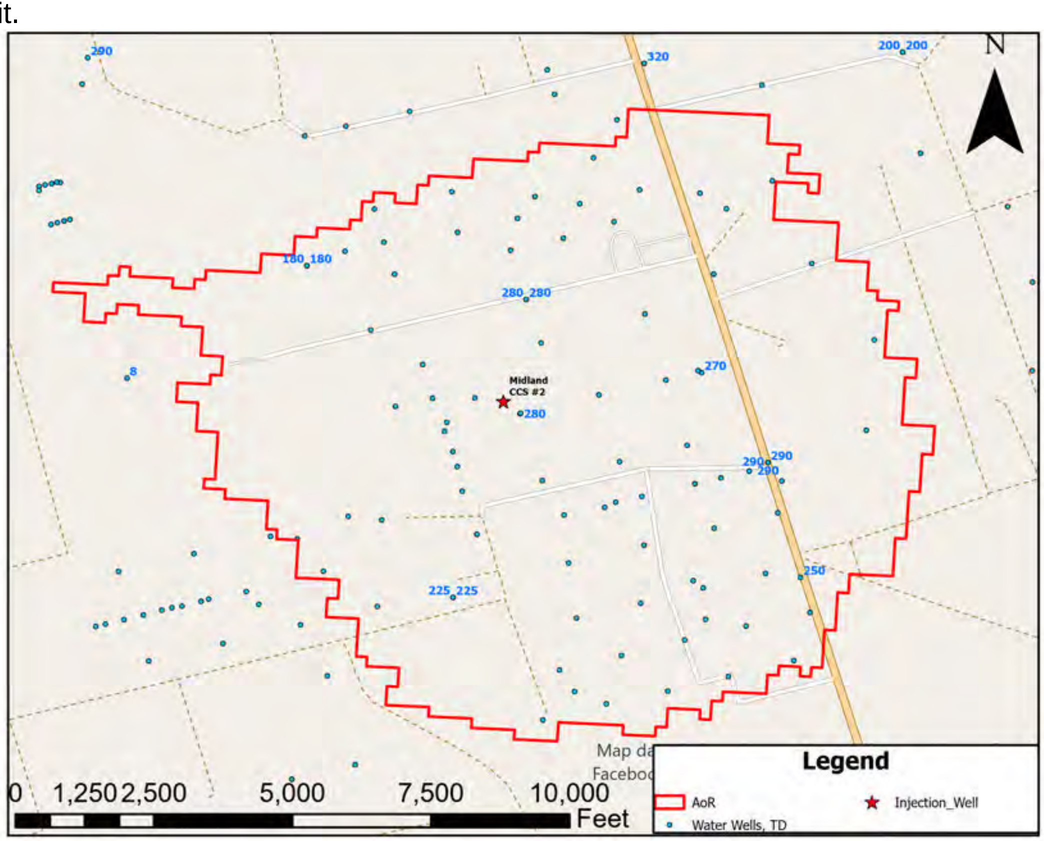


Figure 1-20: Total Depth of All Water Wells in Vicinity of AoR (where TD is known)
Red Star Denotes Midland CCS #2 Injection Well, Blue dots denote water wells in region

1.4.5 Springs and Surface Water

There are zero (0) naturally occurring springs in Upton County. The closest spring occurs in Midland County 15.6 miles northeast of the injection well location. Most of the springs in the region are associated with the outcrop of the Edwards-Trinity (Plateau) aquifer or the Pecos River drainage basin. These springs occur 60 miles southwest (SW) of the injection well, SW of Pecos River, near Fort Stockton, TX; or they occur in the other direction, 60 miles to the northeast (NE) of the injection well near the aptly named Big Spring, TX. There are also zero (0) springs in Crane, Ector, Glasscock, and Reagan Counties, which are the counties bordering Upton (**Figure 1-22**).

There are several surface water features in or near the AoR. Most of the features appear to be oil and gas retention ponds, which are lined. There is one lined retention pond 1,170 feet southeast (SE) of the injection well location adjacent to a natural gas processing station. This lined retention pond is the only (1) surface water feature in the AoR. Additionally, there is a large artificial pond 6,650 ft north-northeast of the injection well location associated with a quarry. This quarry pond is not within the AoR, but it does occur approximately 2,000 ft from the outer boundary of the AoR. All other water features within 1 mile of the outer boundary of the AoR appear to be lined oil and gas retention ponds. They are easily recognizable by their square shape (**Figure 1-21**).

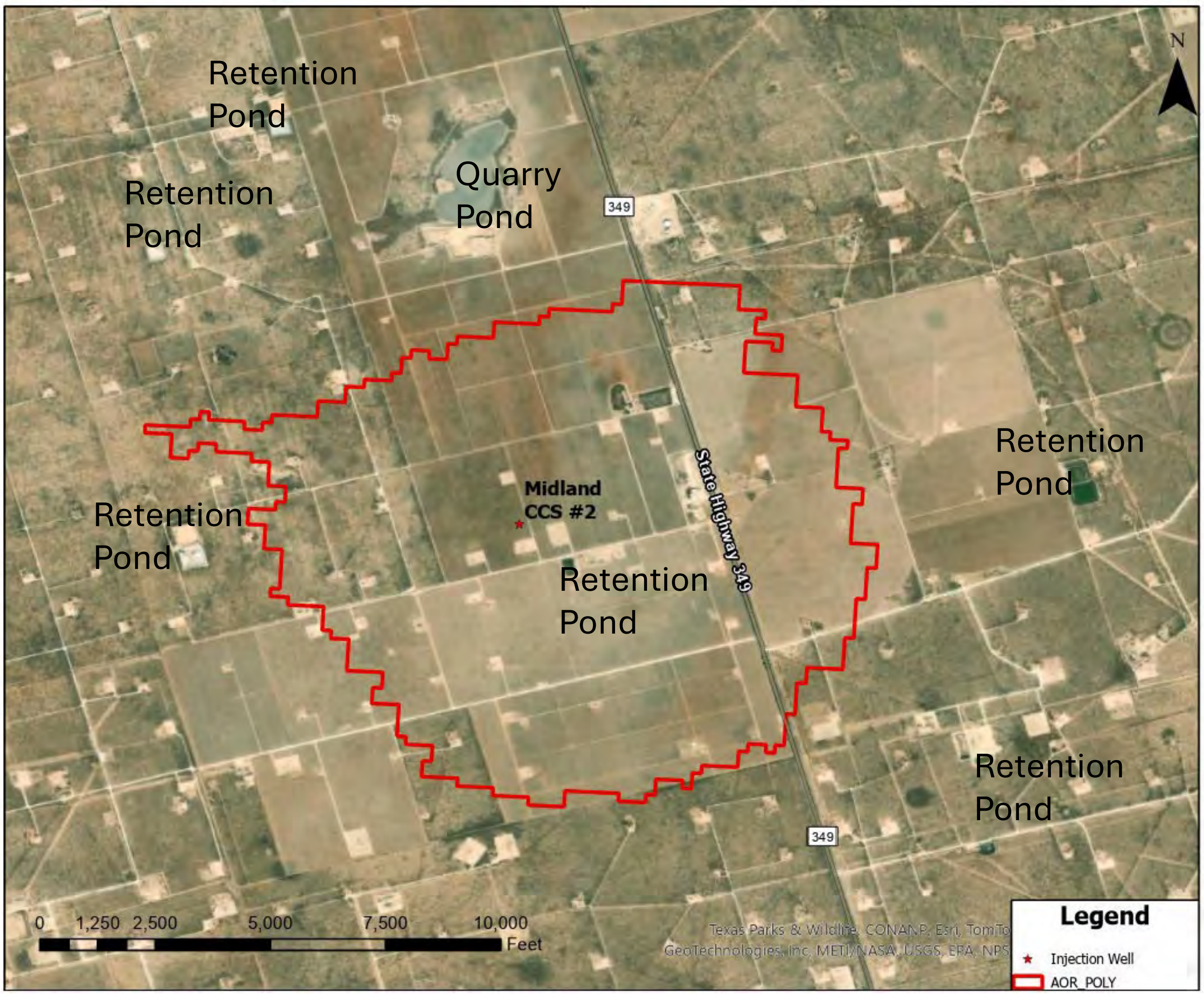


Figure 1-21: Ponds Nearby to Injection Well
Red Star Denotes Midland CCS #2 Injection Well

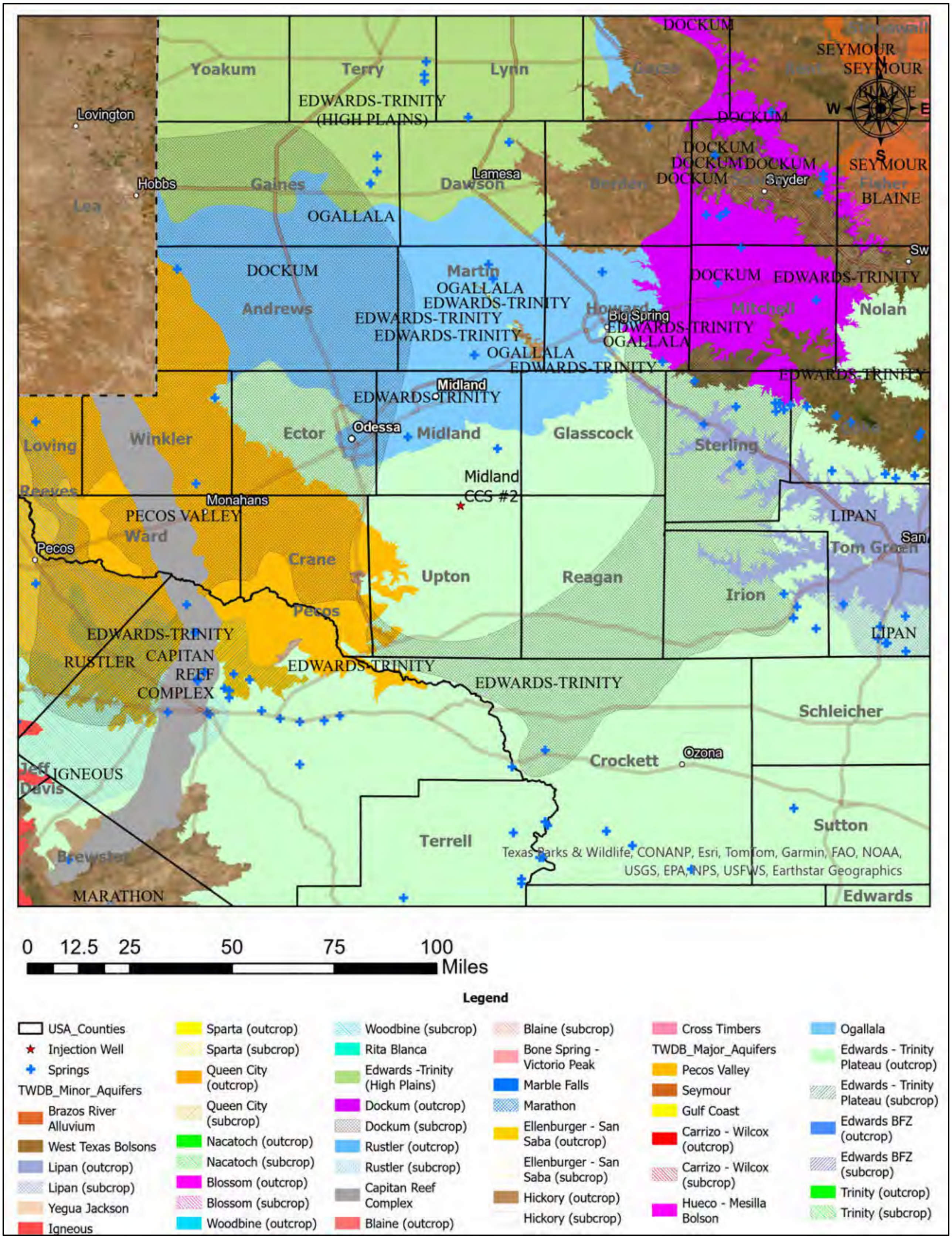


Figure 1-22: Regional Springs Map Compared to Injection Well

Blue crosses are springs mapped by TWDB. Red dot is Injection Well. Color fill is major and minor aquifers

1.5 Regional Geology [40 CFR 146.82(a)(3)(vi)]

The proposed Injection Well is located in the southern portion of the Midland Basin within the larger Permian Basin, as seen in **Figure 1-23**. The Midland Basin is the major eastern structural subdivision of the Permian Basin and is contained by the Central Basin Platform to the west, the Northwest Shelf to the north, the Ozona Arch to the south, and the Eastern Shelf to the east.

The proposed injection units are the Ellenburger formation and a Siluro-Devonian Unit. The age of the Ellenburger formation is Ordovician. Upper Pennsylvanian and Permian formations in the area are heavily penetrated with oil and gas activity and therefore unsuitable for carbon capture and underground storage (CCUS) injection.

Note: A more detailed treatise on Permian geology and regional background information is located in **Section 13 Appendix K**. Please consult for detailed depositional, lithologic and structural information on all formations within the injection zone and top seals. This section of the permit is intended to briefly summarize the extensive volume of work that has been published on the Permian and Midland Basins over the past 120 years. However, the brevity in this section of the permit application, intended for ease of reading, should **not** be construed as a lack of material or extensive research.

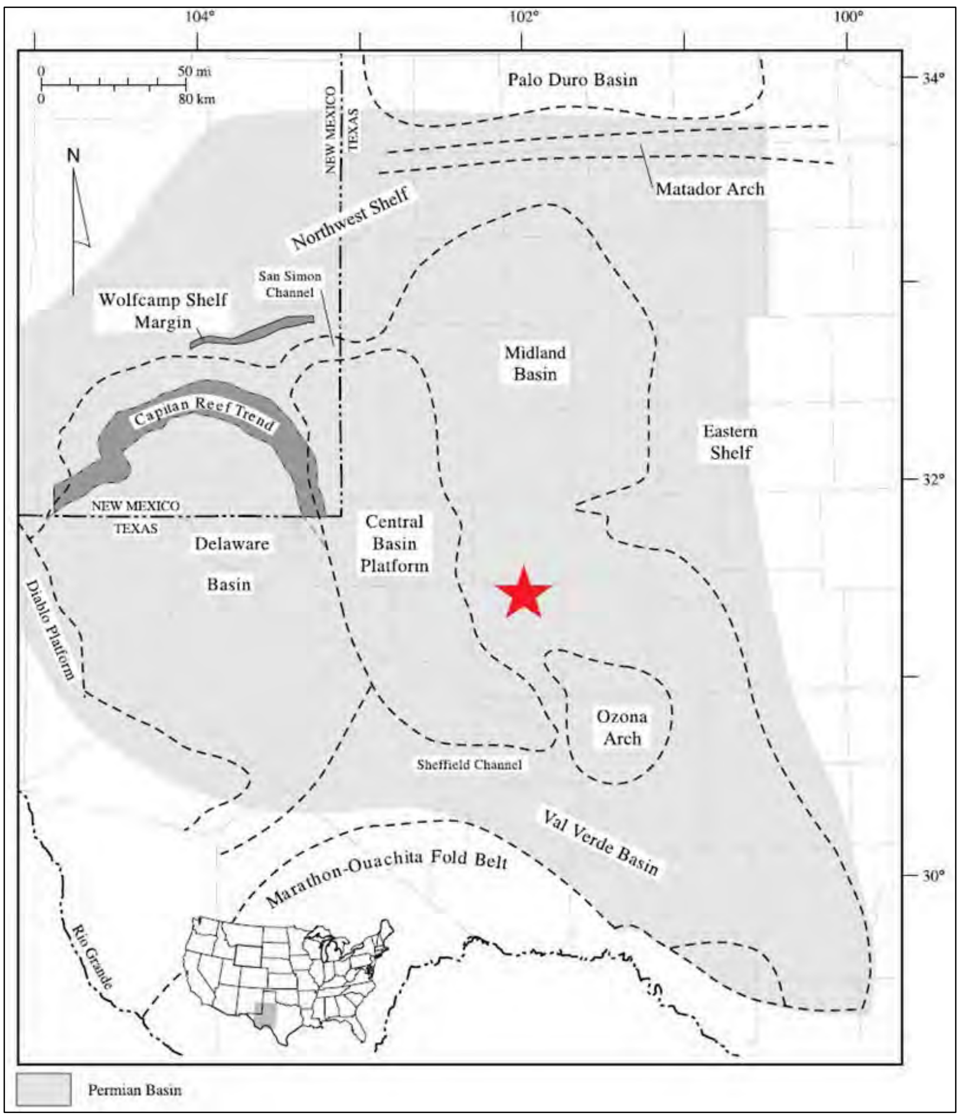


Figure 1-23: Proposed Midland CCS #2 Well Location in the Greater Permian Basin
Red Star Denotes Midland CCS #2 Injection Well

1.5.1 Stratigraphy

The proposed injection interval is from the top of Devonian to 100 ft above Precambrian Basement. The Woodford Shale is the primary top seal. A generalized stratigraphic column for the Midland Basin (right most) is shown in **Figure 1-24**. Omitted from this column (since it is regional) are quaternary sands at surface then Cretaceous Edwards-Trinity (Plateau) aquifer which is described in **Section 1.4** and is included in the USDW resources in the area (**Table 1-5**). The proposed injection interval exactly matches the Lower Paleozoic composite Storage Assessment Unit (SAU) noted in a 2012 USGS open file report on CCUS in the Permian Basin (Merrill et al. 2012) (**Fig. 1-25**).

The Dockum is the lowest known underground source of freshwater but the Edwards-Trinity (Plateau) is the primary aquifer for Upton County. Below the aquifer zones, and forming a no flow boundary, are the Ochoan aged Permian Sands such as the Rustler and Dewey Lake. The base of USDW is expected to be at 1,250 ft based on correspondence with GAU. Below the Permian sands, the Permian and Guadalupian aged Artesia Group is found. The Artesia Group is from Tansill-Grayburg formations.

Next is the San Andres formation, a prodigious wastewater injection zone that has been used continuously in the region since at least 1978, followed by the Leonardian aged Spraberry and Dean formations.

Below the Dean is the Wolfcamp formation. The Spraberry and Wolfcamp formations are currently being drilled for oil and gas wells in the AoR. The majority of the wells producing from these formations are horizontal although there are also legacy vertical wells.

Below the Wolfcamp starts the Pennsylvanian section of rock. The Pennsylvanian aged Cisco and Canyon form a sequence of argillaceous shales and the Strawn and Atoka are predominantly carbonate benches. Following this, the Upper Mississippian Barnett Shale is present, which is equivalent to the Barnett Shale in the Fort Worth Basin. This is underlain by the organic Woodford Shale (**Figures 1-24, 1-25**). The Woodford forms the primary upper confining layer of the injection unit. The shales above it such as the Barnett, Atoka, Cisco and Canyon form secondary seals. The Morrow, although noted on the stratigraphic column, is discontinuous and is not expected to be present in the AoR.

Next, is the Undifferentiated Devonian section which alternates between packstone and chert (S. Ruppel, 2008). The Devonian is the top of the injection interval. The Siluro-Devonian injection unit occurs from the top of Devonian to top of Simpson. At the base of the Devonian is the Thirtyone Formation and then the Silurian Wristen Group. Below the Wristen Group is the Silurian and Ordovician-aged Fusselman formation, the Montoya Group and then the Argillaceous and organic Simpson Group which is expected to act as an intrazonal low flow zone within the injection unit. Below the Simpson is the injection unit of the Ellenburger Group which is a fractured dolomite that has undergone extensive periods of subaerial exposure and cave collapse. The Top of the Ellenburger to the 100 ft above basement comprises the Ellenburger Injection unit. Both the Ellenburger and Devonian injection units combine to form the total injection Interval.

Finally, at the base of the section right above basement, is the Cambrian-aged Bliss sand. It is unknown whether Bliss will occur in the AoR. It has only been observed in one of three log penetrations in the region. There are currently no penetrations to basement within or near the AoR.

Stratigraphic charts found in **Figures 1-24** and **1-25** with injection units, full injection interval and upper confining layers noted on each. A type-log showing the formations from surface to basement can be found in **Figure 1-42** and a type-log focused on only the seals and injection units can be found in **Figure 1-82**.

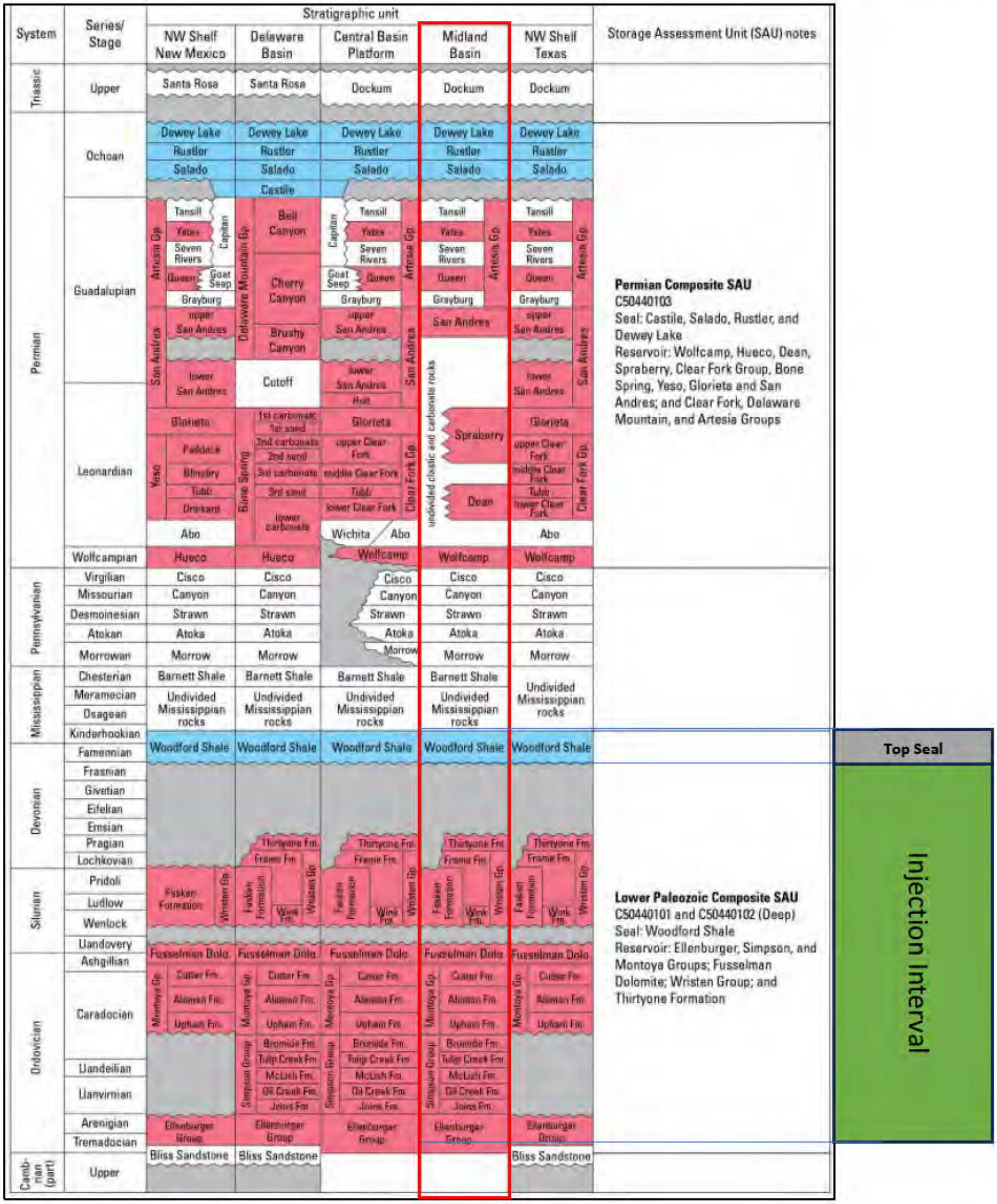


Figure 1-24: Stratigraphic Column Permian Basin

Generalized Stratigraphic Column Permian Basin Province after Merrill et al., 2012 USGS. Open file report on CCUS – 2012-1024-K. Midland Basin stratigraphic column noted in Red Box. Undifferentiated Injection Interval noted in Green. Top seal noted in Grey. Formation thickness not to scale.

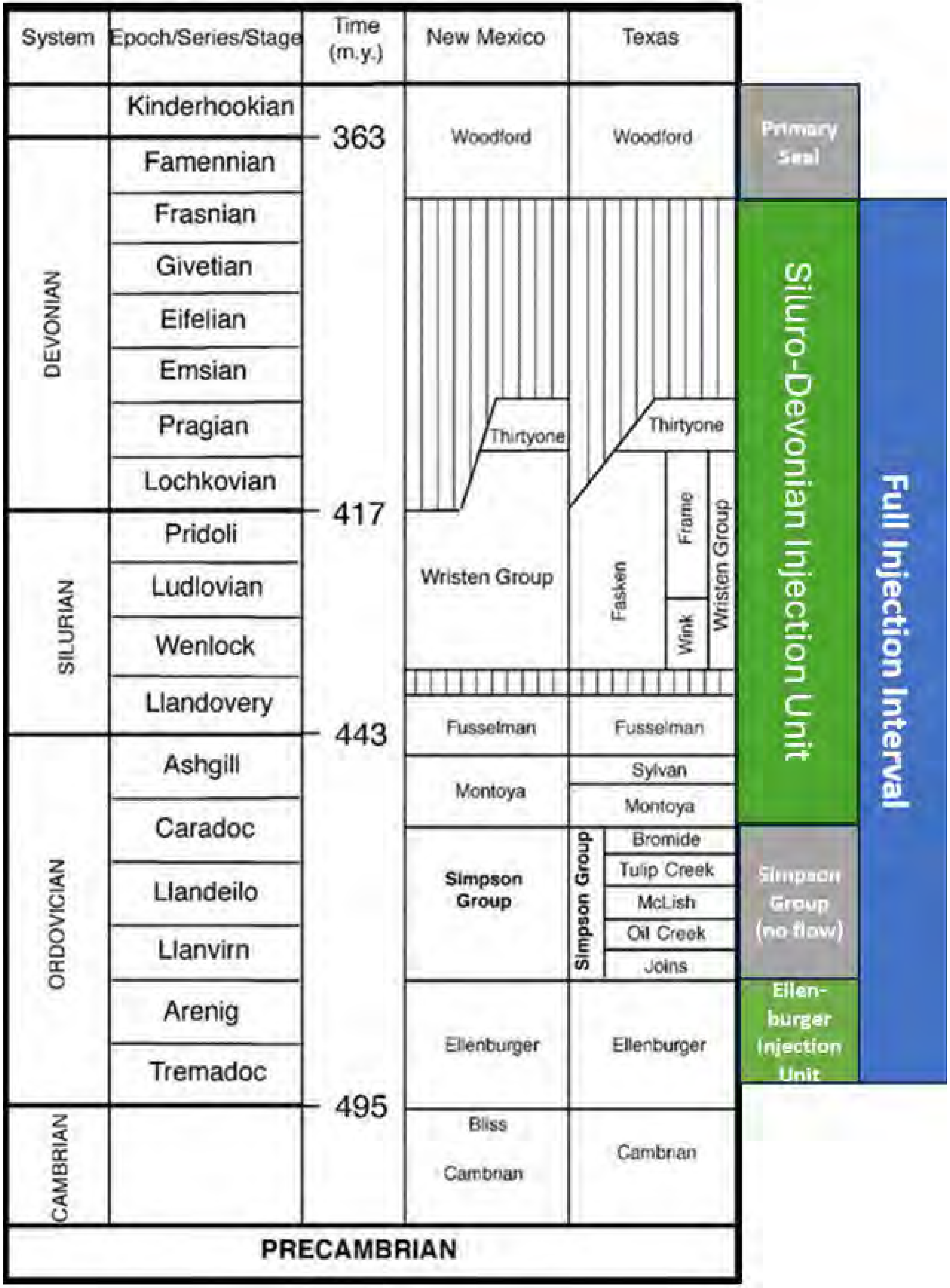


Figure 1-25: Stratigraphic Column Deep Permian Basin

Generalized Stratigraphic Column, Deep Permian Basin, Below the Woodford Formation. Province after Dutton, 2004 and S. Ruppel et al., 2005, Thickness of formations not to scale

1.5.2 Top Seal

At the Facility, the top seal is the Mississippian-Devonian-aged Woodford Shale. The Woodford Shale is the formation that directly overlies the top of the injection zone, and the contact between the Woodford and the undifferentiated Devonian is an unconformity. The Mississippian-aged Barnett Shale and Atoka Shale overlie the Woodford and collectively form secondary seals directly above the primary seal.

1.5.2.1 Mississippian Shale (Barnett) – Secondary Seal

The interval of Mississippian age with high gamma ray is referred to as the Barnett Formation (see type log in **Figure 1-42/Figure 1-82**). The Barnett sits above a Mississippian carbonate which is in turn underlain by the Woodford shale (**Figures 1-24, 1-25**) in most parts of the basin. The Barnett is generally overlain by carbonate rich strata usually termed “Pennsylvanian Limestone” (or Lime) and often referred to as “The Atoka.”

The Mississippian is one of the most poorly known depositional successions in the Permian Basin. This is largely due to the fact that only small volumes of oil and gas have been produced from these rocks and there has thus been little interest in collecting data to interpret them. This has recently changed due to the successful development of the Barnett formation in the nearby Fort Worth Basin as a reservoir of natural gas (Montgomery, 2005; Ruppel and Kane 2008). Also contributing to poor understanding of the Mississippian section is the fact that it often washes out on well logs due to smectite rich clays.

Total Mississippian thickness varies widely across the Permian Basin area. A maximum thickness of more than 2,200 ft was reported by Craig and Connor (1979) in parts of Reeves and Ward Counties, Texas (see **Section 13, Appendix K** for additional maps on regional thickness). Mississippian can be <500 ft thick in areas of New Mexico where it transitions to a carbonate facies.

The mineralogy of the Mississippian shales is primarily quartz, calcite, smectite, and illite in roughly equal abundance. Higher gamma ray intervals increase clay and quartz minerals at the expense of carbonate minerals. Organic matter is present and indicated by intervals of high gamma ray and lower density. The shales are generally very fine grained with no distinguishable grains without the aid of electron microscopes.

Thus, the Mississippian is characterized by thick smectite-rich shales. The expected thickness of the Barnett Shale underlying the Facility is 173 ft. There is a minor carbonate member right above the Woodford that is probably Meramacian to Kinderhookian in age. This carbonate is the eastward extension of the undifferentiated Mississippian Lime.

1.5.2.2 Woodford Shale –Top Seal

In the Permian Basin, lithologic, electric log, and sparse faunal data indicate that the Woodford unconformably overlies rocks ranging in age from Devonian to Ordovician (Lloyd, 1949). The Woodford is overlain disconformably by Mississippian limestone and Barnett Shale (Lloyd, 1949; Wright, 1979) (**Fig.1-24**).

Ellison (1950) divided the Woodford formation into three units using radioactivity, log response, and lithology. The Upper Woodford Shale is defined as brownish-black pyritic fissile shale with few resinous spores and abundant chert. It generally has medium gamma ray response and lower organic matter and clay content. The Middle Woodford Shale is characterized by the highest readings of gamma ray and the most abundant spores. It is generally high in clay and organic matter. The middle unit is also the most widespread unit of the Woodford Shale. The Lower Woodford Shale is characterized as a siliceous shale with few spores, medium chert content, lowest gamma ray and the highest resistivity of the three units.

The composition of the Woodford primarily consists of organic matter and illite, and the silt-sized fraction consists of mostly dolomite, quartz, pyrite, mica, feldspar, glauconite, biogenic pellets, spores, and radiolarians. Other types of fossils, including conodonts, brachiopods, trilobites, sponge spicules, and vertebrate debris, were found locally, but only rarely. Organic carbon content in core samples ranges from 1.4 to 11.6 weight percent total organic carbon (TOC), (mean = 4.5 ± 2.6 wt % TOC for 72 samples), or from roughly 4 to 35 volume percent organic matter.

In terms of texture, parallel laminae are the most characteristic feature of black shale. Other distinguishing features include abundant pyrite, fine grain size, black color, and high radioactivity. The black color is caused by high concentrations of pyrite (as much as 13 vol %) and organic carbon (up to 35% by volume) and high radioactivity is caused by tetravalent uranium bound in the organic matter (R. Comer, 1991), (Haecker, 2016).

In the Midland Basin, the deepest Woodford is nearly 9,800 ft below sea level in northeastern Gaines County within the basin thickness trends which are subtle. The Woodford, at its thickest, is 135 ft in north-central Martin County. Areas greater than 100 ft thick are located in Dawson, Gaines, Andrews, and Martin Counties. Between the thick areas lie an east-west trend of relatively thin Woodford (50 to 100 ft). Another narrow thin trend (<50 ft) lies in southern Martin and southeastern Andrews Counties (**Figure 1-26**).

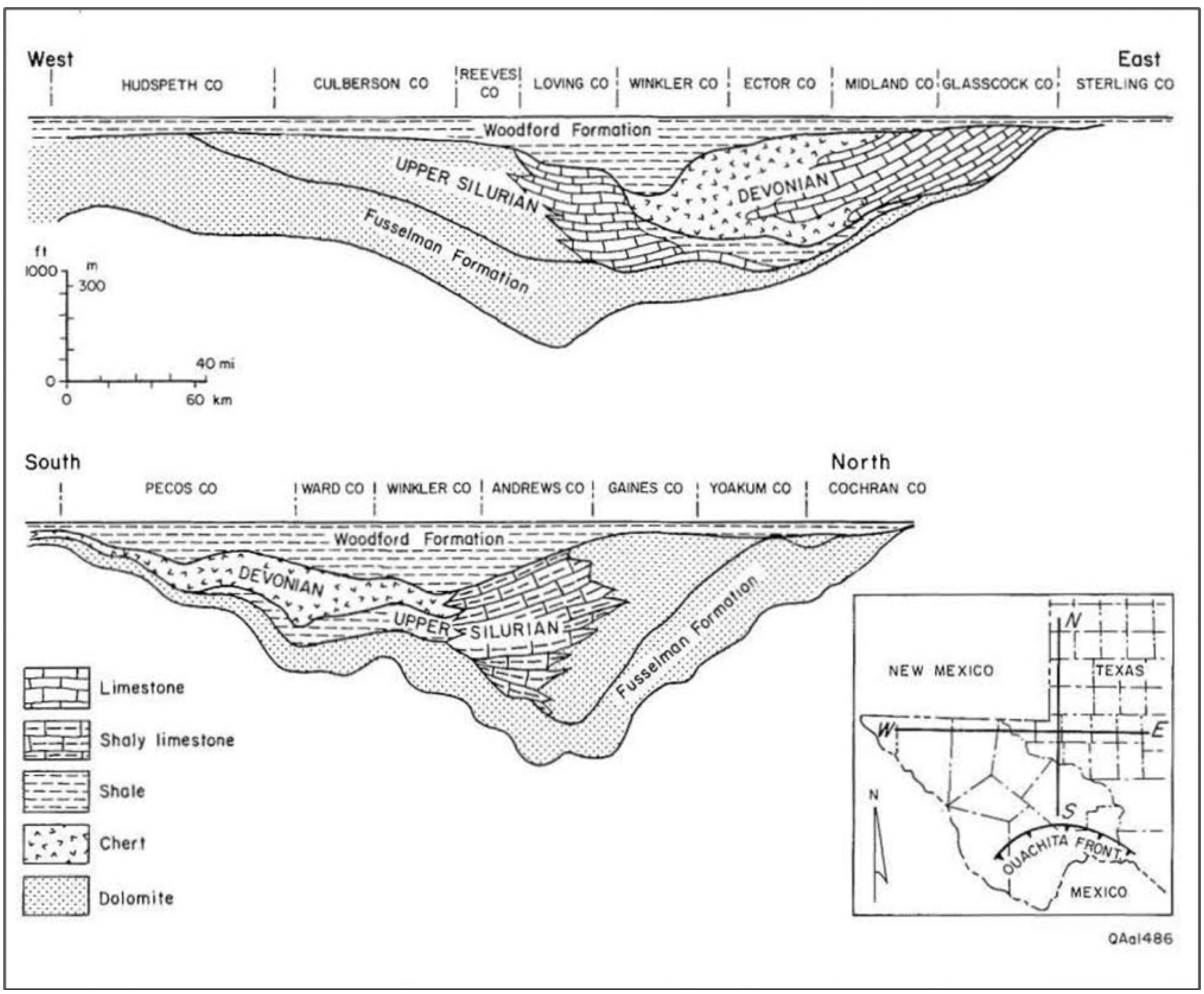


Figure 1-26: Woodford Schematic Cross Section
Schematic Cross Section of the Woodford and below Stratigraphy. (Ruppel and Holtz, 1994)

1.5.3 Siluro-Devonian Injection Unit

The interval defined as the Siluro-Devonian Injection Unit extends from the base of the Woodford to the top of the Simpson Group (**Figure 1-25)**. A much more thorough description of each of the Devonian Injection Unit Formations can be found in **Section 13, Appendix K**.

Devonian aged undifferentiated packstones and cherts are often referred to as 'Devonian' in the remainder of this document, the Woodford is not included in this lithologic grouping even though the lower Woodford is also Devonian in age. The unconformity at the base of the Woodford is used as a lithologic boundary despite using *Devonian* age to name of the deeper rocks.

Throughout most of west Texas, undifferentiated Devonian rocks comprise two distinct facies: (1) skeletal carbonates, primarily pelmatozoan packstones and grainstones, and (2) bedded, commonly spiculitic, chert (Saller and others, 1991). Chert is most abundant in the basin depocenter. In this region, the general stratigraphic succession consists of basal laminated dark cherts and lime mudstones that pass upward into laminated to massive spiculitic cherts overlain by skeletal lime packstones. In other words, generally packstone is found near the Woodford-Devonian unconformity, and chert deeper in the interval (Ruppel et al., 2008).

The Wristen Group is argillaceous and organic with the Frame and Wink members present in the southern Permian Basin and the carbonate rich Fasken member present in the northern Permian Basin. The Fusselman and Montoya Formations are composed of shallow water carbonates, principally ooid grainstones and pelmatozoan packstones.

Open and closed fractures are common in both chert and carbonate facies; however, cherts at Three Bar Field contain two to six times as many fractures as associated limestones. In addition, fractures are more abundant close to identified fault zones (Ruppel and Hovorka, 1995). Later, it is an important point that the chert facies are expected to be heavily fractured in comparison to the packstone facies. This difference was built into the static geomodel using the calculated lithology (**Section 1.7.4**).

Reservoir quality porosity is typically associated with chert facies as opposed to the carbonate facies, and chert of a distal and discontinuous nature has been noted in Upton County in core description.

The Fusselman formation and Montoya Group are carbonate rich and generally lower porosity than the chert facies above.

Mineralogy of the undifferentiated Devonian is primarily quartz in the chert intervals and calcite in the packstone intervals with some illite present. The Silurian-aged Wristen Group is generally finer grained and may contain organic matter. The Wristen Group, Fusselman Formation and Montoya Group are known to contain trace amounts of dolomite as well.

The Siluro-Devonian Injection Unit is expected to be fine-grained and the texture will be dependent on the amount and distribution of carbonate and chert facies. The Packstone facies is generally fine grained and light gray in color, while the chert facies are generally darker grey and easily distinguishable in core sample.

Siluro-Devonian Injection Unit thickness ranges from 1,200 ft in the west of the Midland Basin to less than 700 ft in the eastern shelf.

1.5.4 Simpson Group Intrazone Seal

The Simpson Group is a low permeability group of Ordovician shales and sands located between the Siluro-Devonian Injection Unit and the Ellenburger Injection Unit. It is characterized by multiple formations. It has three (3) sandstone formations and three (3) shale formations, alternating in sequence. Shale is present on top then corresponding sand, then it repeats. The three sandstone members of the Simpson Group—the Connell, Waddell, and McKee—occur at the base of the Oil Creek, McLish, and Tulip Creek formations, respectively, from oldest to youngest. Detailed information on each formation can be found in **Section 13, Appendix K**

Sandstones make up only approximately 5 percent of the total thickness of the Simpson Group in west Texas and southeastern New Mexico. Not all sandstones are likely present in all areas owing to their depositional setting facies changes updip and downdip.

Little-to-no fracturing is expected within the shale members of the Simpson Group forming an effective intrazonal seal of low vertical permeability rock.

The thickness of the Simpson Group ranges from 450-50 ft thick in the Midland Basin. The Bromide and the Tulip Creek pinch out as the formation thins. The Simpson is thickest in the western part of the Midland Basin in Crane County and thins to the east in Reagan County. The Simpson Group is expected to pinch out in Reagan County, approximately 25 miles east of the Injection Well.

1.5.5 Ellenburger Injection Unit

The Ellenburger Injection Unit is defined as the Base of the Simpson Group to 100 ft above granitic basement (**Figure 1-25**). This may include the Cambrian Bliss Sand, although it is unclear whether it is unconformably eroded or not from available well logs.

The Ellenburger Group of the Permian Basin is part of a Lower Ordovician carbonate platform sequence that covers a large area of the United States (Kerans, 1989). It is well known for being one of the largest shallow-water carbonate platforms in the geologic record (covering thousands of square miles (sq. mi) and as much as 500 mi wide in west Texas. Extensive cave collapse features (karsting) lead to pervasive fracturing that occurred shortly after deposition. This fracturing enhances the permeability of the formation. Additional details are found in **Section 13, Appendix K**.

The Ellenburger is extensively fractured due to three stages of karsting that occurred repeatedly for millions of years as sea level rose and fell over an area that covered the entire Permian Basin. When sea level was lower than the carbonate platform, karst features would form. **Figure 1-27** illustrates the various stages of cave collapse. First water infiltrates and dissolves carbonate, after a void is created, the above ceiling collapses into the void due to gravity and weight. Finally, the entire chamber collapses and is compacted. These features are called cave collapse breccias or simply breccias and the process is referred to as brecciation. This process happened shortly after deposition and then the rock was subsequently dolomitized (Loucks, 2019).

Dolomitization favors preserving open fractures and pores because it is mechanically and chemically more stable than limestone. Pores within dolomites are commonly preserved to deeper burial depths and higher temperatures than those of pores in limestone. Also, limestone breccia clasts tend to undergo extensive pressure solution at their boundaries and lose all interclast pores whereas dolomite breccia clasts are more chemically and mechanically stable with burial (R. Loucks, 2007, 2019). Thus, even at extreme depths, pores and fractures are expected to be open and prevalent.

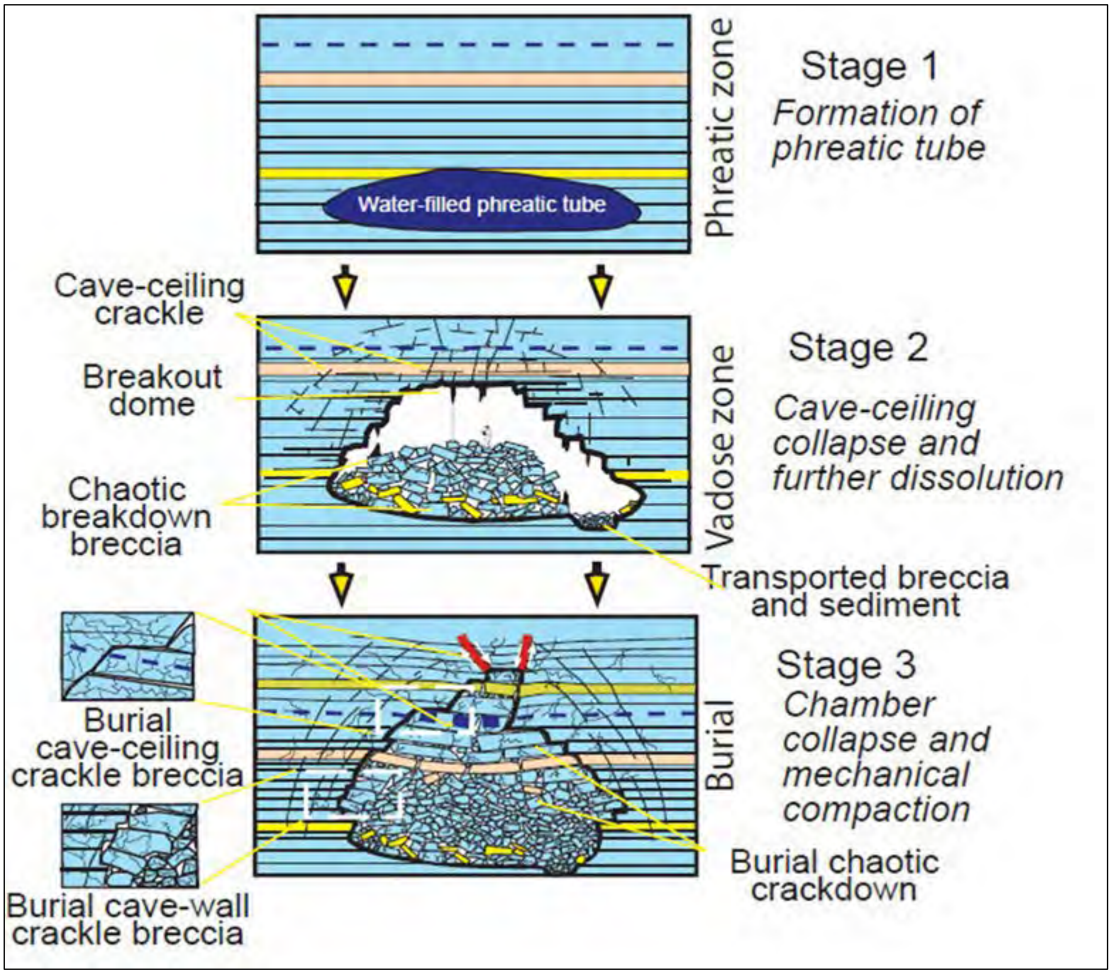


Figure 1-27: Cave Collapse Schematic

Process of Cave collapse that forms paleo cave breccias. First, water infiltrates the subsurface via hydrodynamic processes. Then, after a sufficient void is dissolved in stage 2, the continued burial and weight of overburden causes the cave to collapse (Loucks, 2023).

Pore networks in the Ellenburger are complex because of the amount of dolomitization, brecciation, and fracturing associated with karsting and regional tectonic deformation. Pore networks can consist of any combination of the following pore types, depending on depth of burial (Loucks, 1999): (1) matrix, (2) cavernous, (3) interclast, (4) crackle-/mosaic-breccia fractures, or (5) tectonic-related fractures (**Figures 1-28, 1-29**).

The Ellenburger's mineralogy is primarily composed of dolomite (>80% dolomite) but it may contain calcite, anhydrite, chert, gypsum and other minerals in small quantities at a core scale. Many minerals occur in minor quantities related to evaporite deposition or other chemical processes. Over 99% of the non-dolomite mineralogy is contained within the pervasive fractures.

The Ellenburger ranges from 2,500 ft to 500 ft thick in various parts of the Permian Basin. In Upton County, offset log data and regional maps indicate it is greater than 1,200 ft thick at the Midland CCS #2 Well location. However, reliable penetrations that tag basement are sparse. When adjusting for faults the estimated thickness at the Injection Well is 883 ft.

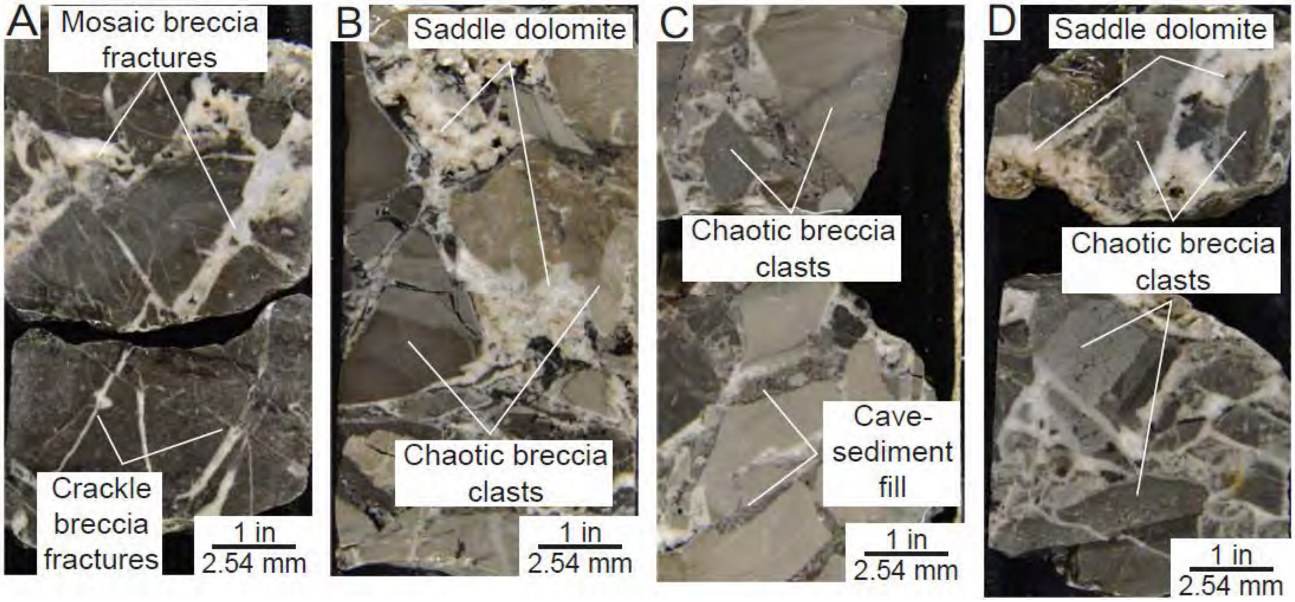


Figure 1-28: Meteoric karst breccias McElroy #1 Crane County, Texas.
Meteoric karst breccias from Mcelroy #1 core in Crane County, Texas. (Loucks, 2023)

Cave Facies	Interpretation	Description	Pore System/ Reservoir Quality
Undisturbed strata	Undisturbed host rock	Excellent bedding continuity for hundreds to thousands of feet.	Minor matrix and fracture pores. Ø < 3% to 5% K < few millidarcys
Disturbed strata	Disturbed host rock	Bedding continuity is high but folded and offset by small faults. Commonly overprinted with crackle and mosaic brecciation.	Minor matrix pores and crackle to mosaic fracture pores. Ø < 5% K is as much as tens of millidarcys
Highly disturbed Strata	Collapsed host rock (cave-roof and cave-wall rock) over passages	Highly disturbed, very discontinuously bedded strata with pockets and layers of chaotic breccia. Small-scale folding and faulting are common. Commonly overprinted with crackle and mosaic brecciation.	Localized pockets or layers of breccia might have porosities in the range of 5% to 15% and permeabilities in the tens to hundreds of millidarcys.
Coarse chaotic breccia	Collapsed-breccia cavern fill	Mass of very poorly sorted, granule- to boulder-sized chaotic breccia clasts 1 to 10 ft long. Commonly clast supported but can contain matrix material. Ribbon- to tabular-shaped body as much as 45 ft across and hundreds of meters long.	Abundant interclast pores. Porosity can exceed 20%, and permeability can be in the darcys.
Fine chaotic breccia	Transported-breccia cavern fill	Mass of clast-supported, moderately sorted, granule- to cobble-sized clasts with varying amounts of matrix. Clasts can be imbricated or graded. Ribbon- to tabular-shaped body as much as 45 ft across and hundreds of feet long.	Abundant interclast pores. Porosity can exceed 20%, and permeability can be in the darcys.
Sediment fill	Cave-sediment cavern fill	Carbonate and/or siliciclastic debris commonly with sedimentary structures.	Siliciclastic fill is commonly tight. Carbonate fill might be permeable.

Figure 1-29: Ellenburger Formation Core Facies
Identified facies from core in the Ellenburger formation. After R. Loucks 2007, 2023

1.5.6 Major Geologic Features and Description on Tectonic History

The Permian Basin is composed of several sub-basins, each with its own unique characteristics (**Figure 1-23**). The Delaware Basin is located in the western part of the Permian Basin and is known for its thick organic-rich source rocks and stacked reservoirs, making it a significant oil and gas producing region. The Midland Basin is located in the eastern part of the Permian Basin and is characterized by relatively few faults and fractures.

The Central Basin Platform is a relatively flat area that separates the Delaware and Midland Basins and contains several oil and gas fields, including the famous Yates Feld (among the most prolific oilfields in the world[3]). The Northwest Shelf is the northernmost portion of the Permian Basin and is primarily a gas-producing area, while the Eastern Shelf is located in the southeastern part of the basin and contains a mix of oil and gas fields. Overall, the Permian Basin is a complex and diverse petroleum province with a long history of hydrocarbon production and several crustal blocks with different tectonic histories.

Hills (1970) used subsurface data to suggest the possibility of extensive lateral displacement along pre-Permian faults in the Permian Basin. Hills' primary objective was to determine the direction of tectonic forces responsible for regional deformation. Hills interpreted two tectonic systems. The first consists of folds and faults possessing orientations of N35W (folds) and N55-80E (right lateral faults), and N50-65 W (left lateral faults). The age of this deformation is thought to be early Late Mississippian to late Middle Pennsylvanian. There also are a series of NNW-trending faults that appear to be right lateral systems with larger displacement that formed synchronous with the other faults. It is this system of conjugate faults that has been interpreted to control the jagged geometry of the Central Basin Platform, especially along its eastern margin (**Figure 1-30**) (T. Hoak et al. 1998).

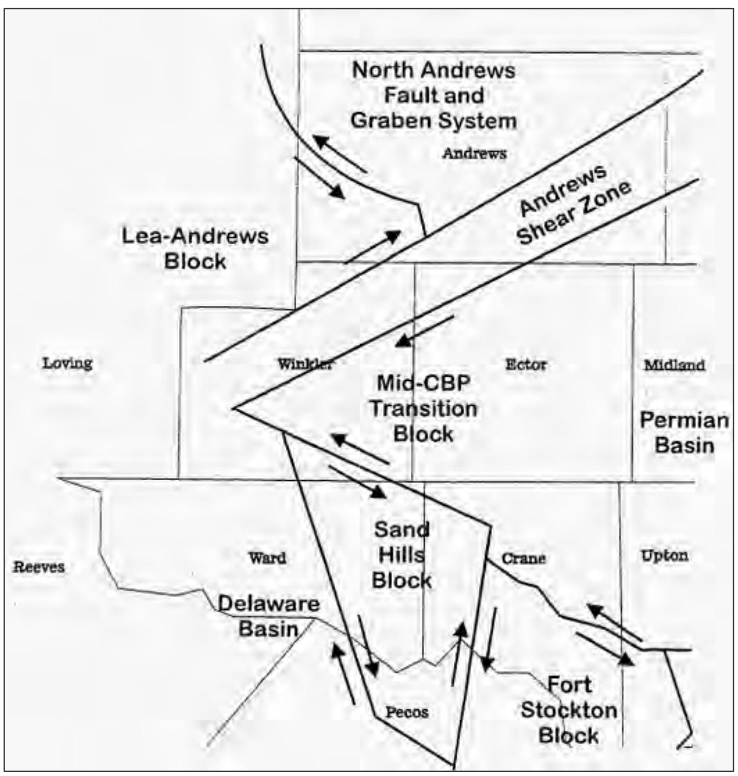


Figure 1-30: Interpreted Crustal Blocks
Interpreted crustal blocks from Gardiner (1990). After (T. Hoak et al. 1998). Midland CCS #2 Well location off eastern edge of map, hence no red star.

[3] Texas State Historical Association (TSHA), an independent nonprofit since 1897

A second, later deformation phase as interpreted by Hills (1970), is marked by the relaxation of stress and normal fault motion reactivation of older fault systems. The timing of this deformation is interpreted to be middle-to-late Permian in age and fault displacements relatively minor.

Finally, during the Tertiary, the western margin of the Permian Basin was uplifted, and Basin-and-Range tectonism commenced in this area. This deformation has apparently been restricted to the western Delaware Basin and the basin margin (T. Hoak et al. 1998).

Hills (1985) describes the eastern boundary of the Midland Basin as possessing little evidence of tectonism. Instead, the Eastern Shelf is largely a stratigraphically controlled boundary with rocks of the Pennsylvanian-Permian-age carbonate shelf dipping gently westward into the basin.

The Midland Basin area is a large area (>-6,000 square miles) that is dominated by small NE and NW-trending faults and related folds. All structures are similar in style but smaller in size to those seen in the Mid-CBP Transition Zone. The majority of uplift occurred prior to the Mississippian with isolated fault block movement during Barnett-Strawn time. Since that time, the region has experienced regional subsidence. Gardiner (1990) outlined the boundaries of six "crustal" blocks that are roughly 40 mi on their longest dimension (**Figure 1-30**). The boundaries of these blocks represent major discontinuities that separate zones of distinct or different structural orientations and /or structural styles.

The Mid-CBP Transition Block is an area of ~ 600 square mi dominated by NW-trending reverse faults in the northern area (including Gandu Unit) and NW-trending reverse faults in the southern area. Both areas contain less dominant NE-trending normal faults. There is a NE-trending sag corresponding to the center of the area. A map of Ellenburger structure (**Figure 1-31**) demonstrates that the majority of deformation occurs along faults that form the boundaries of Gardiner's crustal blocks. The centers of the blocks are relatively undeformed. Erosional limits are markedly affected by the block boundaries and are used to delineate the chronology of block development and interaction.

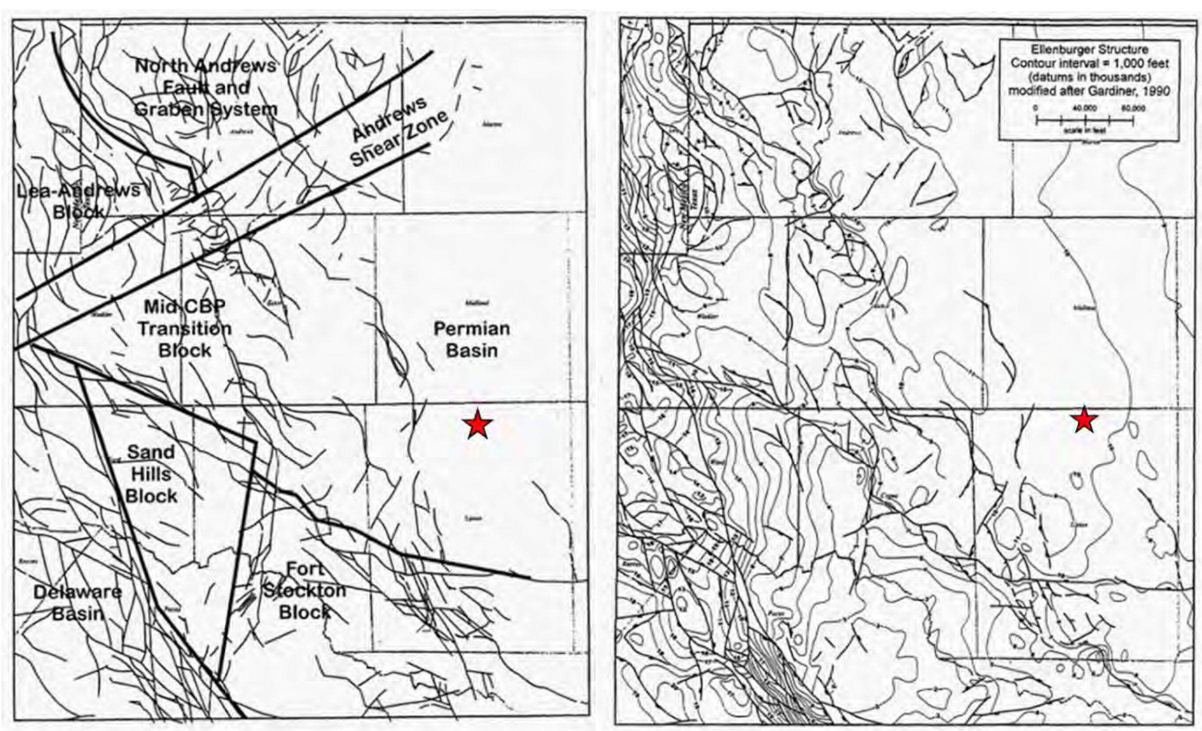


Figure 1-31: Interpreted Crustal Blocks
(Left) Interpreted crustal blocks from Gardiner (1990). With Ellenburger faults superimposed on top of different wrench faulting regimes. (Right) Ellenburger Structure Map with Faults. Red Star - Midland CCS #2 Well.

Building on earlier work, Horne et al., 2024 reported that the Midland Basin contains several new previously unknown fault systems. The main system in the Midland Basin is a N-NW/S-SE trending system that is primarily reverse and forms fault bounded uplifts with propagation folds in Crane, Ector and Andrews Counties. This fault system bounds the eastern edge of the Central Basin Platform. The dips of these faults are 65 degrees ± 5 degrees. Crosscutting this main system is an E-NE basement rooted fault system aligned with the leading edge of the Metaproterozic-age (1200-1000 MA) Grenville front that extends from Loving County, Texas to Abilene, Texas. This regional fault pattern extends from the eastern margin of the Central Basin platform into the Midland Basin with the scale of deformation observed gradually diminishing eastward. The E-NE faults are primarily strike-slip with additional minor reverse movement. The faults are high angle with dips of 80 degrees, ± 10 degrees. Horne et al. 2024 interpreted the data from 3D seismic surveys, horizontal log steering data, and sparse 2D/3D seismic surveys. (**Figures 1-32, Fig. 1-33**) (Horne et al., 2024).

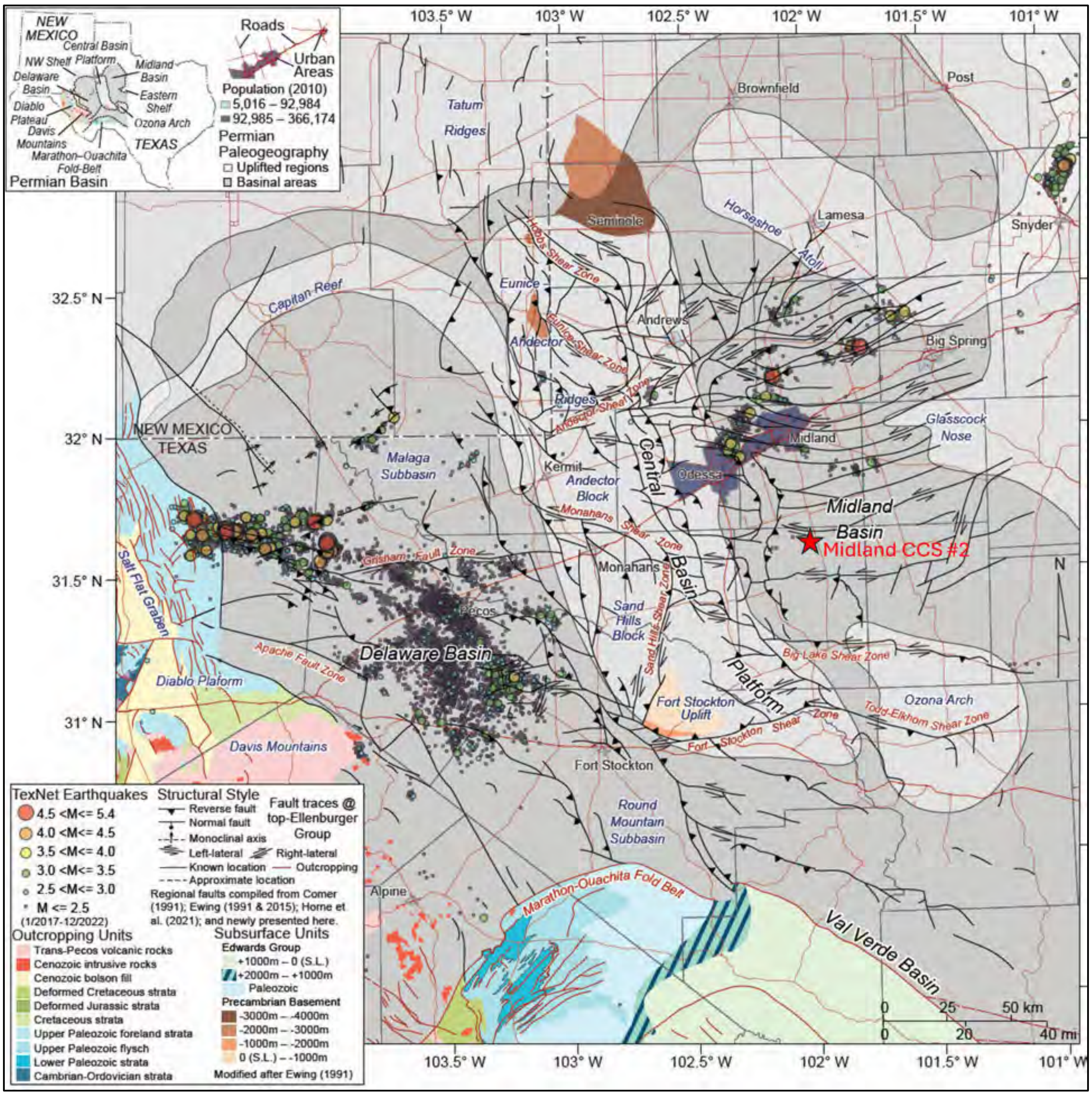


Figure 1-32: Permian Basin Structural Blocks and Major Fault Systems, Horne et al., 2024
Generalized paleogeographic map of the Permian Basin, highlighting the different tectonic provinces labeled in blue. Earthquake dots are supplied from TexNet Earthquake Catalog. Notable fault zones are labeled in Red. Red Star - Midland CCS #2 Well. Sourced from Horne et al., 2024

N-NW/S-SE reverse faults (black and red) are generally ~10 KM (6.2 mi) in length while E-NE (gold and green) strike slip faults can extend up to 50 KM (31 mi) to the eastern edge of the basin (**Figure 1-33**). In all cases, the faults interpreted are likely several smaller faults in aggregate forming a fault system. 3D seismic reflection datasets also show that NNW-SSE and NNE-SSW striking reverse faults became activated in the Pennsylvanian and deformation continued through to the early Wolfcampian (early Permian), but dip-slip motion dissipated after middle Pennsylvanian Strawn deposition (Horne et al., 2024).

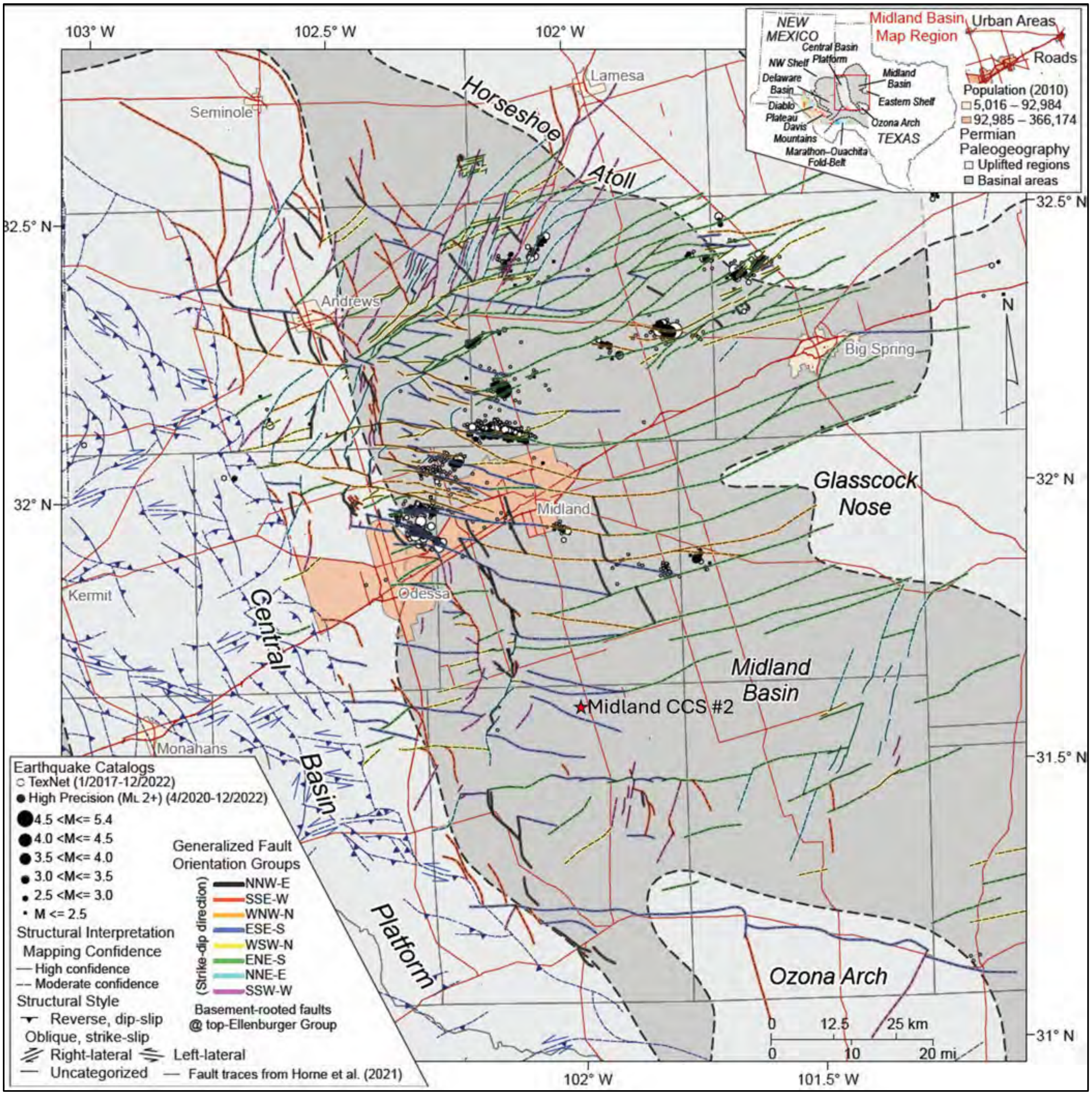


Figure 1-33: Midland Basin Faults, Horne et al., 2024
Interpreted regional faults in the Midland Basin, these are basement rooted faults at the Top Ellenburger surface. Note the different generalized fault orientation groups. Red Star - Midland CCS #2 Well. Sourced from Horne et al., 2024

1.6 Local Geology Introduction

The following **Sections 1.7** through **1.12** discuss the local geology around the proposed Well.

- **Section 1.7** – Structural Geology - Thickness, Lithology
- **Section 1.8** – Faults and Fractures – Faults and Fractures, Seismic History, Regional Stress
- **Section 1.9** – Petrophysical Characterization – Porosity, Permeability, Salinity, Cap Pressure
- **Section 1.10** – Geomechanics – Stress Magnitude, Orientation, Strength, Ductility, Pressure
- **Section 1.11** – Geochemistry – Brine-CO_2 Interactions, Mineral-CO_2 interactions
- **Section 1.12** – Mineral Resources – Petroleum production from Ellenburger or Devonian

The local geology in the area of the proposed Well includes the Ellenburger and the Devonian as injection units and the Woodford as the primary confining layer.

Two 2D seismic lines and four hundred and seventeen (417) wells that penetrate deeper than the Strawn were used to calculate these maps. The Strawn is significant because many drillers set a casing string at that depth. Therefore, logs deeper than the Strawn are relatively sparse in an area, even though there are many penetrations. Strawn is also the formation the RRC uses to delineate shallow and deep Class II injection wells.

Faults are sourced from a variety of academic sources including Hoak et al. (1998), who interpolated seismic, gravity and magnetic data and Horne et al. (2024) who interpreted sparse 3D seismic data. For our interpretation, we utilized multiple academic sources in addition to Milestone's interpreted faults from local 2D seismic data.

The Well location is noted on each map and cross section for reference, typically as a "red star."

1.7 Structural Geology [40 CFR 146.82 (a)(3)(iii)]

The purpose of **Section 1.7** is to demonstrate that within the AoR the structure is laterally continuous with predictable with very low dip (<5 degrees). This section provides data regarding the depth, thickness, structure and lithology of the injection and confining zones.

The injection interval is defined from its base: 100 ft above the basement; to its top: the top of the Devonian/Base of Woodford. The Simpson Group represents a baffle formation in the injection unit. It is expected to function as an intrazonal baffle and internal seal; however, we are not treating it as a seal for this Well as we are injecting above and below it. The Woodford Shale is the upper confining layer. The younger Barnett and Atoka Shales are characterized as additional secondary seals above the primary Top Seal but often included in charts and maps because they directly overlay the Woodford shale.

The structure of the regional area is a large county size basin, as evidenced by the regional subsidence from the Mississippian onward. However, locally, the area approximately 10 miles to the west of the Well begins the North-South trending faults associated with the Central Basin Platform (CBP). To the south as you exit Upton, there is a large regionally uplift associated with the structurally compartmentalized Ozona Arch (**Figure 1-34** – cross section of the Midland Basin).

The Well is situated within a 3-way fault block – a fault 1.91 miles to north, a fault 1.71 miles to the south, and a wrenching fault 3.63 miles to the west. These faults are characterized in **Section 1.8.**

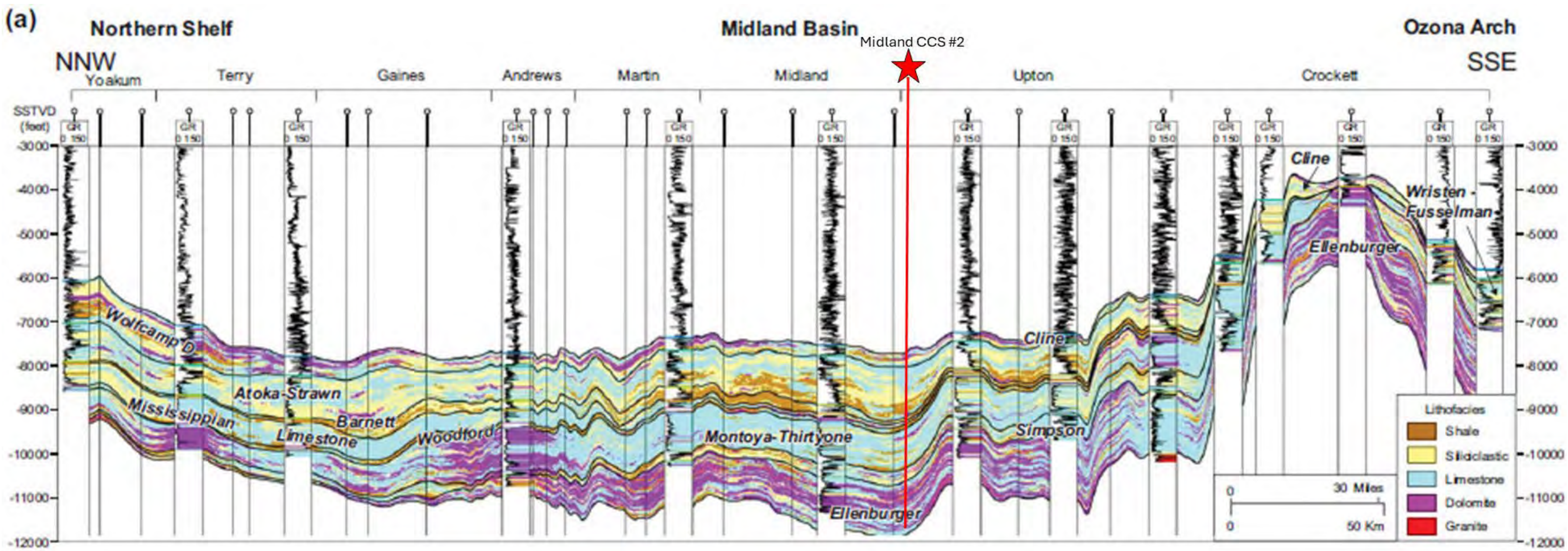


Figure 1-34: Regional Cross Section from NNW to SSE through the project Area
(Calle et. al., 2024) Lithofacies cross section showing depositional dip from the Northern Shelf to the structurally compartmentalized Ozona arch. Logs illustrate GR signature.

Most formations below the Strawn are regionally extensive, conformable and cover both Upton and Midland Counties. The Simpson Group pinches out to the east, in Reagan County (**Figure 1-39**) and some variations in thickness of the Atoka, Simpson Group and Wristen Group are observed across the area (**Figures 1-35** through **1-41**) but all three formations are present in all nearby wells that penetrate deep enough to be observed.

Interpolated depths at the proposed Facility are displayed in **Table 1-8**. These depths were interpolated from offset log data and will be updated as more information such as seismic becomes available.

Table 1-8: Subsea and TVD Depth of Tops at Midland CCS #2 Well Location

Top	Subsea (ft)	TVD from Ground Elevation (ft)	Thickness (ft)
STRAWN	-8,048	10,845	658
ATOKA	-8,706	11,503	430
BARNETT SHALE	-9,136	11,933	173
WOODFORD SHALE	-9,309	12,106	94
DEVONIAN	-9,403	12,200	544
WRISTEN GROUP (SILURIAN)	-9,906	12,703	233
FUSSELMAN	-9,947	12,744	192
SIMPSON	-10,139	12,936	130
ELLENBURGER	-10,269	13,066	883
BASEMENT	-11,152	13,949	

Figures 1-35 through **1-41** illustrate the subsea depths from the top of the Barnett to the Basement. Basement has been estimated through the few well penetrations available in the area, correlated to seismic data, and then gridded. Basement is expected to occur at range relative to AoR below ground level based on offset logs and grids.

The depth of the base of USDW per the RRC Ground Water Advisory Unit correspondence with Milestone is 1,250 ft in the proposed Well (**Section 13, Appendix I**). Therefore, there is 10,950 ft between the deepest USDW source and the top of injection, which is the base of the Woodford and the top of the Devonian interval. Oil and gas operators have been safely disposing of brine wastewater into the San Andres formation at ~4,120 ft since at least 1978 (Lemons, C. et al, 2019).

Indeed, there are a myriad of zones that are impermeable between the USDW base and the injection unit. The first is the Artesia Group at a depth of ~1750 ft which has several anhydrite layers. Next, the Wolfcamp Shale (9,124 ft), Cisco (10,128 ft) and Canyon shales (10,494 ft) are barriers. After that, the Atoka (11,503 ft) also forms a barrier and finally there is the primary seal of the Mississippian Barnett shale on top of the Woodford shale with a top of 11,933 ft and 12,106 ft, respectively. **Figure 1-42** illustrates a log from surface to basement with formations noted. In **Figure 1-42**, note the thick sections of high gamma ray that are likely <1 microdarcy (uD) of permeability and form a vertical barrier. Also, note the extreme distance from base of USDW to the Devonian and Ellenburger.

1.7.1 Structure Maps

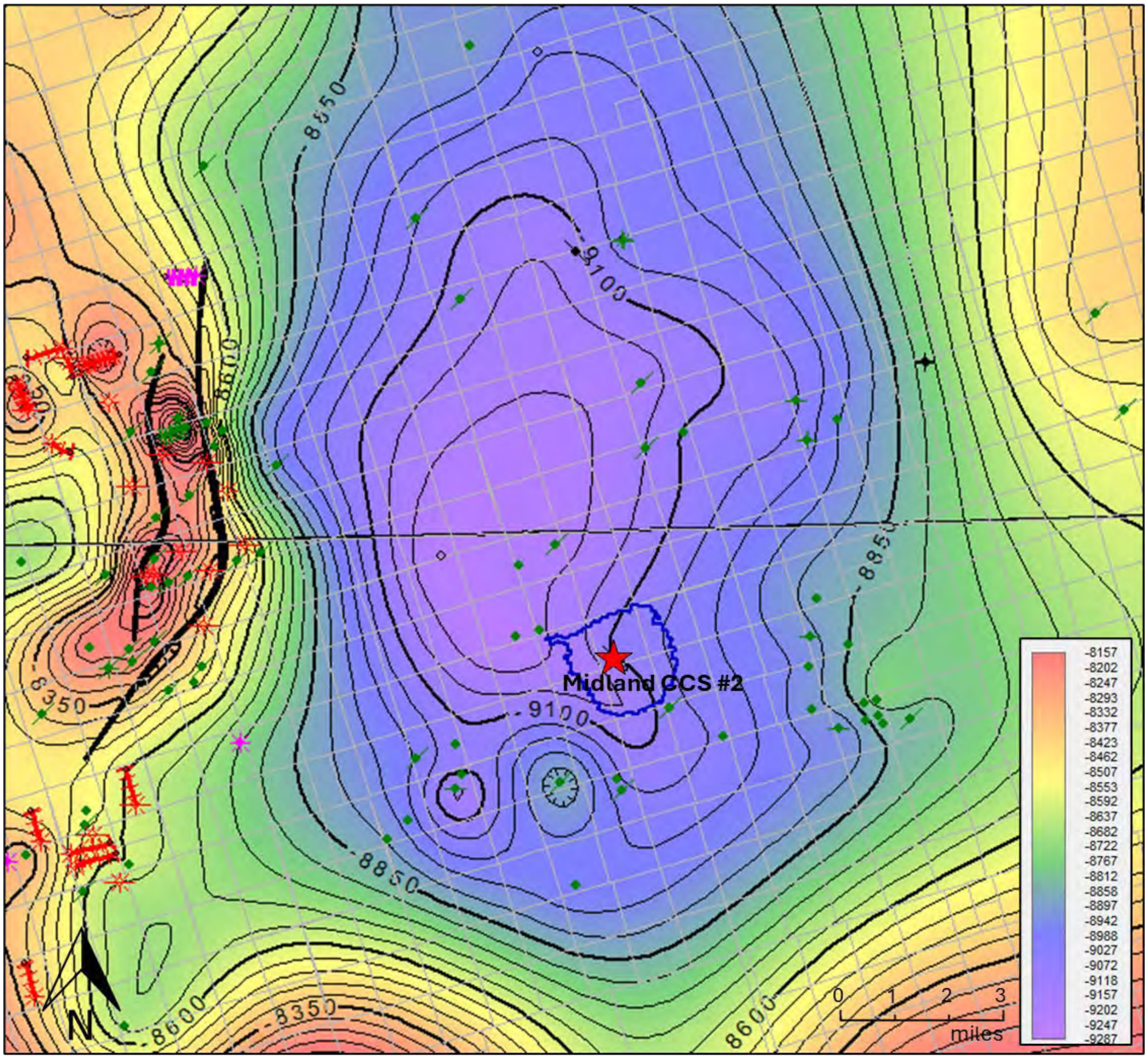


Figure 1-35: Structure - Top of the Barnett Shale Formation in Subsea, ft.
Contour Interval = 50 ft. Localized structure of the top of the Barnett Shale in subsea, ft.

Figure 1-35 represents a structure map of the top of the Barnett shale. The Barnett shale consists of mudrock, carbonate lenses, and shales. The Barnett considered a secondary seal for the purposes of this permit application, however, the lithologic makeup acts as an additional seal on top of the effective confining layer, the Woodford shale. The top of the Barnett shale at the proposed site is expected to be at -9,136 feet true vertical depth subsea (TVD SS) (**FIG. 1-35**). The base of the Barnett shale (The Miss Lime) is expected to occur at -9,309 feet (TVD SS).

The Barnett shale has no known faults penetrating it within the AoR. Due to the lack of faulting at this level, the Barnett structure takes on a bowl shape centric to the county line. The depth and thickness variations are likely due to the underlain faulting below the Barnett.

The strike of the Barnett shale is approximately 355° due to its elongated bowl shape in the Midland Basin. The dip is approximately 0.5° to 1° with steeper dips towards the south associated with the regional high of the Ozona Arch. Given the bowl shape, the strike and dip only hold for approximately 2 miles.

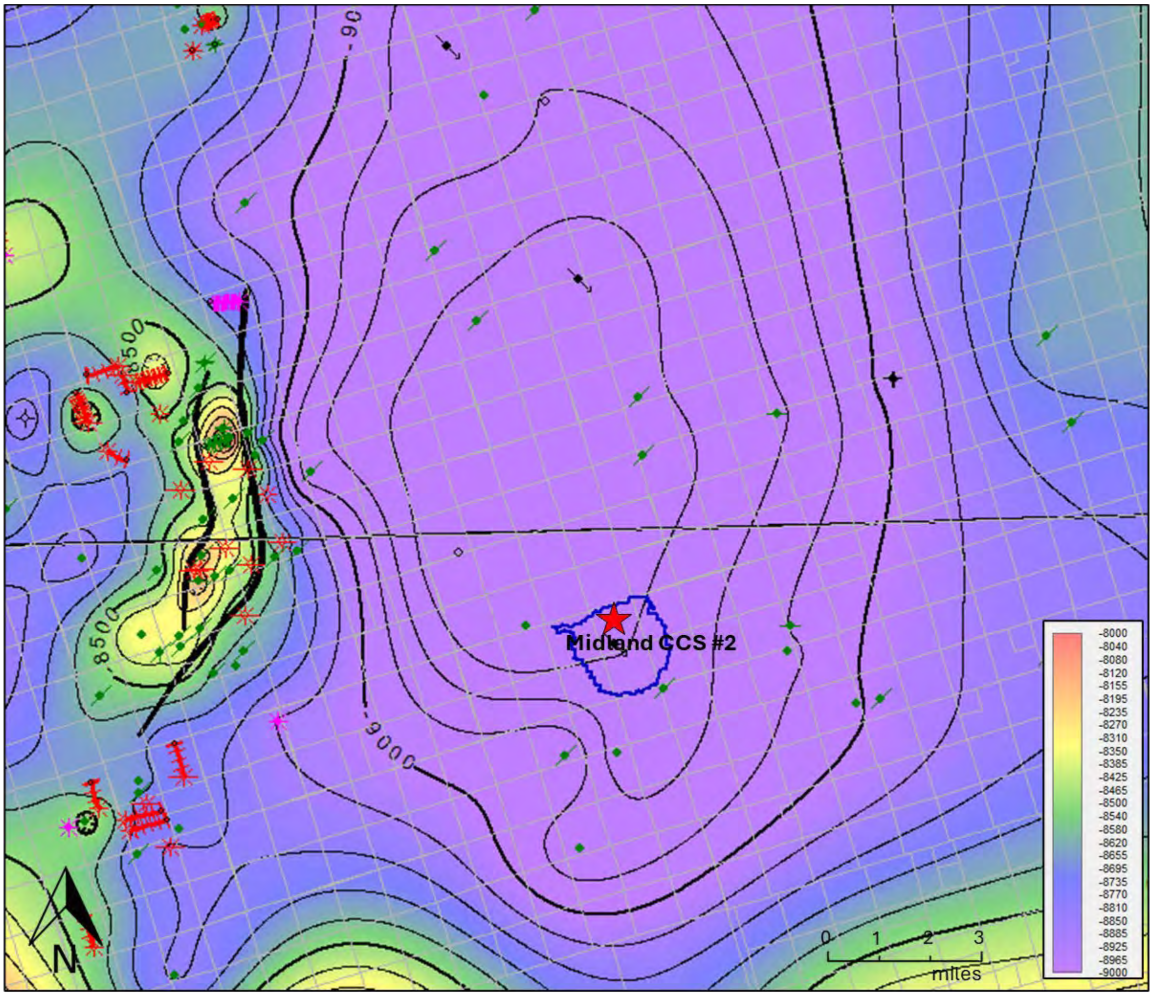


Figure 1-36: Structure - Top of the Woodford Shale in Subsea, ft
Localized structure of the top of the Devonian section and base of the Woodford Shale in Subsea, ft. The base of the Woodford Shale is the primary seal. Contour Interval = 50 ft

The Woodford shale (**Fig 1-36**) is the confining layer above the injection unit. While the Woodford Shale is an effective seal, we recognize the Barnett shale as an additional secondary seal that is encountered prior to productive hydrocarbon bearing intervals. The Woodford shale forms an effective seal due to its low permeability, high capillary injection pressure, and minimum horizontal stress gradient that are all higher than the Devonian rocks below it. There is a small, <10 ft, carbonate layer that contains low porosity and permeability between the Barnett and Woodford. This limestone layer is probably Kinderhook in age and expected to have <.1 millidarcy (mD) of permeability.

The Woodford shale structure map is illustrated in **Figure 1-36**. The Woodford shale has no faults in this AoR, and like the Barnett, the structure takes on a bowl shape. The Woodford depth and thickness variations are likely due to faulting deeper in the subsurface. The nearest faults in the Woodford are found in the Pegasus field, approximately 9 miles to the west of the proposed Injection Well.

The strike of the Woodford shale is approximately N5W due to its oblong bowl shape. The dip is approximately 1°; however, the dip increases to the south towards the regional high of the Ozona Arch.

The top of the Woodford shale is estimated to be at -9,309 ft TVD SS at the proposed location. The range of the Woodford structure across the AoR is -9,339 to -9,254 feet TVD SS.

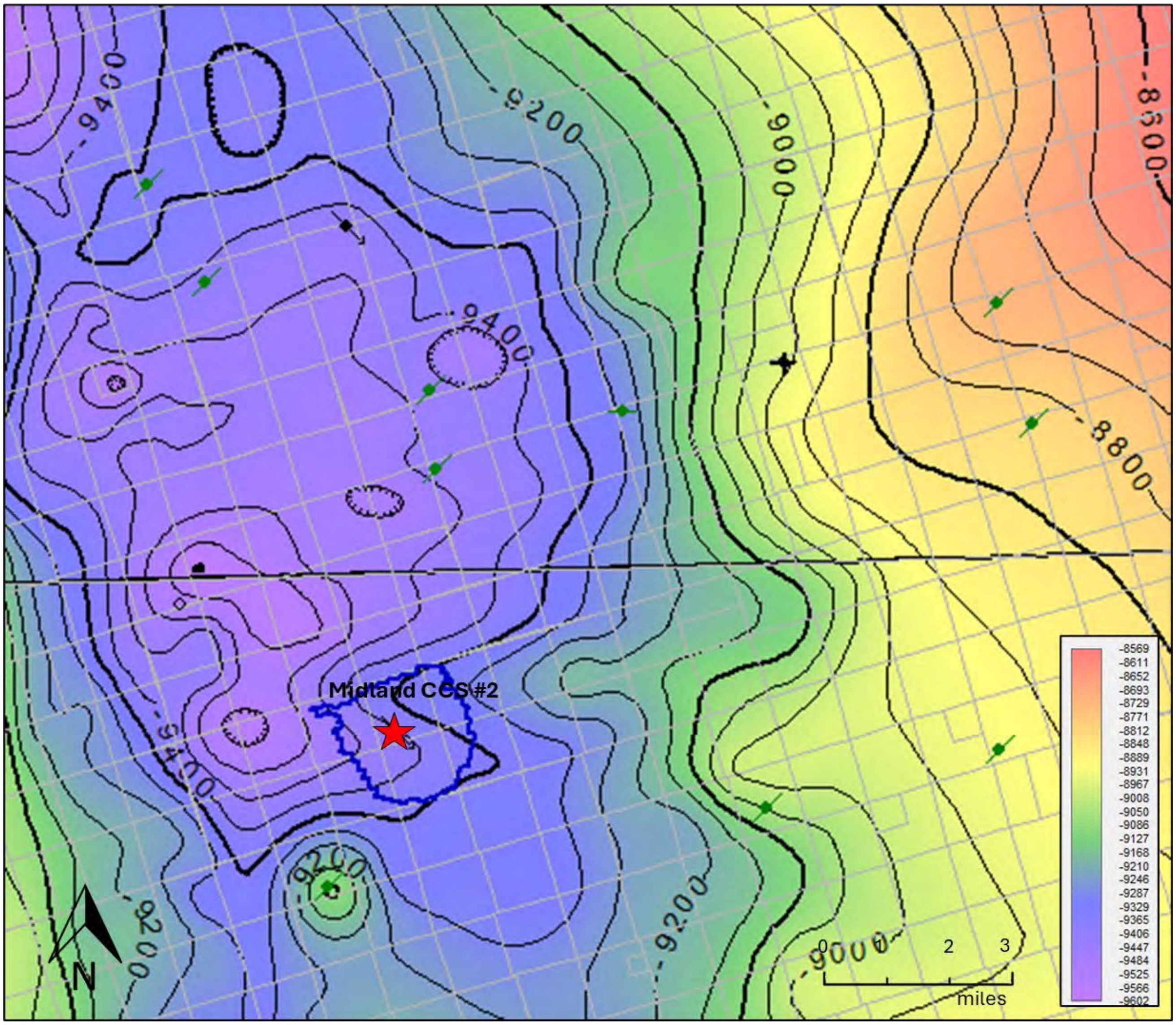


Figure 1-37: Structure - Top of the Devonian Section (Base of the Woodford Shale) in Subsea, ft
Localized structure of the top of the Devonian section and base of the Woodford Shale in Subsea, ft. The base of the Woodford Shale is the base of the confining layer. Contour Interval = 50 ft

The Devonian structure map is illustrated in **Figure 1-37**. The top of the Devonian at the proposed Well location is estimated to be at -9,403 feet TVD SS. The range for the structure across the AoR is from -9,481 to -9,316 feet TVD SS.

There are no faults that penetrate the top of the Devonian since all area faults terminate within the Devonian interval. Thus, no faults penetrate the base of the confining layer, the Woodford shale.

The same bowl shape is illustrated at this depth just as the Woodford and Barnett shales above; however, the depositional apex is shifted to the northwest. Also visible are the expressions of the underlain faults within the contours; the depth and thickness variations that we see in this formation is relative to the deeper aforementioned faults.

The strike of the Devonian varies due to its depositional geometry; however, the localized strike is approximately N22W with a dip that ranges from .5° to 2.5°. Again, steeper dips are found to the south relative to the southern high of the Ozona Arch and also to the west, associated with the CBP.

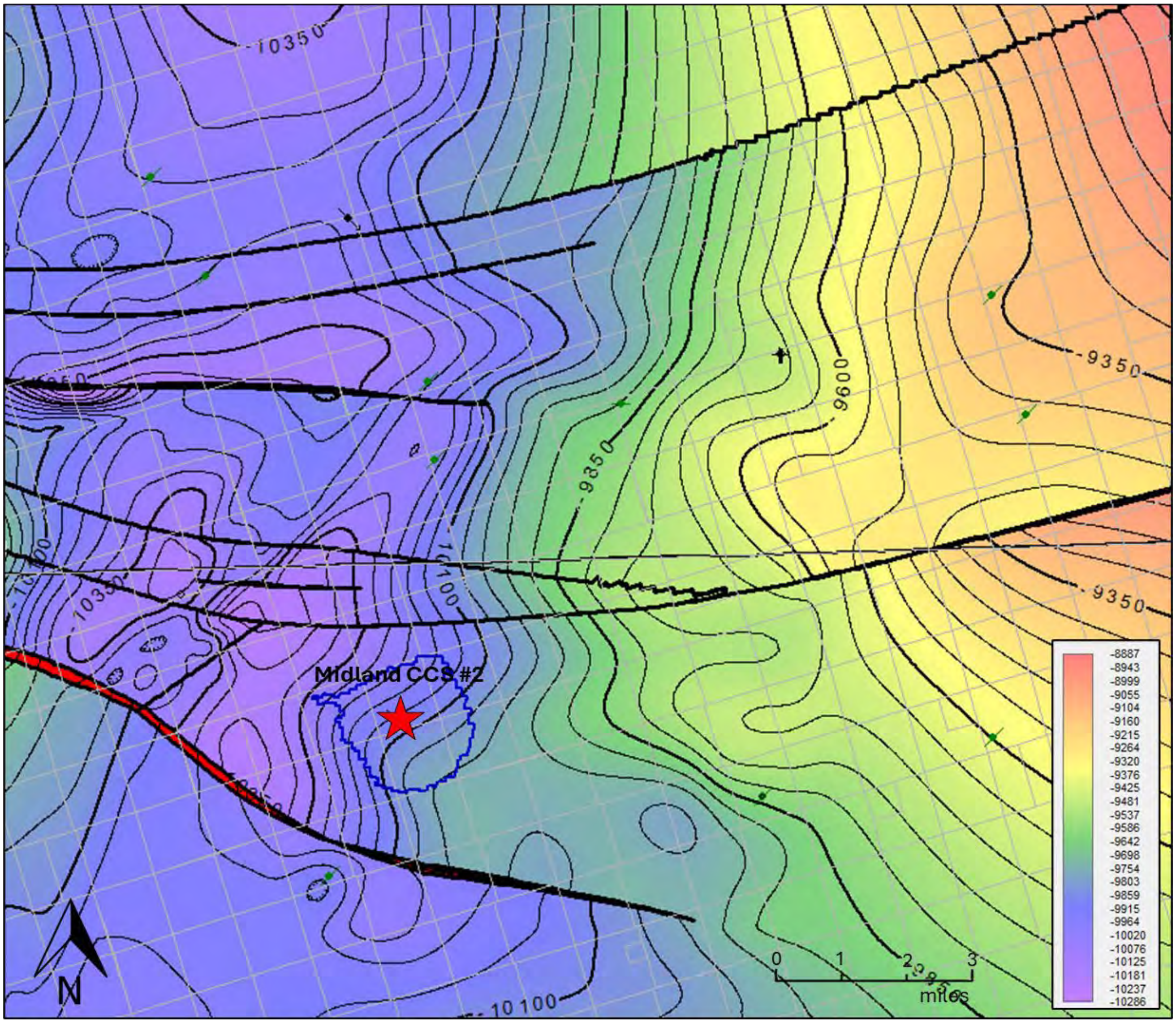


Figure 1-38: Structure - Top of the Simpson Group
The Simpson represents a baffle formation in the injection unit. It is usually defined as a seal between the Ellenburger and Devonian but as injection is above and below it, it is not characterized as a seal for the purposes of this Well. Contour Interval = 50 ft

The structure of the Simpson Group is illustrated in **Figure 1-38**. The Simpson Group is expected to function as an intrazonal baffle within the Injection unit; however, it is not treated as a seal since the injection will be both above and below the Simpson interval.

The Simpson is expected to be -10,139 ft TVD SS at the proposed Well location. The structure of the Simpson is expected to range from -9,996 to -10,336 feet TVD SS. The strike of the Simpson Group is irregular due to the faulting present at this depth. The dip is 2-7 degrees and increases towards the west to the CBP.

The faulting in the Simpson group is greater than the shallower formations, since all terminate before the top of the Devonian. At this depth, the Well is within a 3-way fault block, with faults to the north, south, and west. The northern fault is approximately 1.5 miles away, the fault to the south is approximately 2.1 miles away and the wrenching fault to the west is approximately 3.2 miles away. Details about the faults are included in Section 1.8.

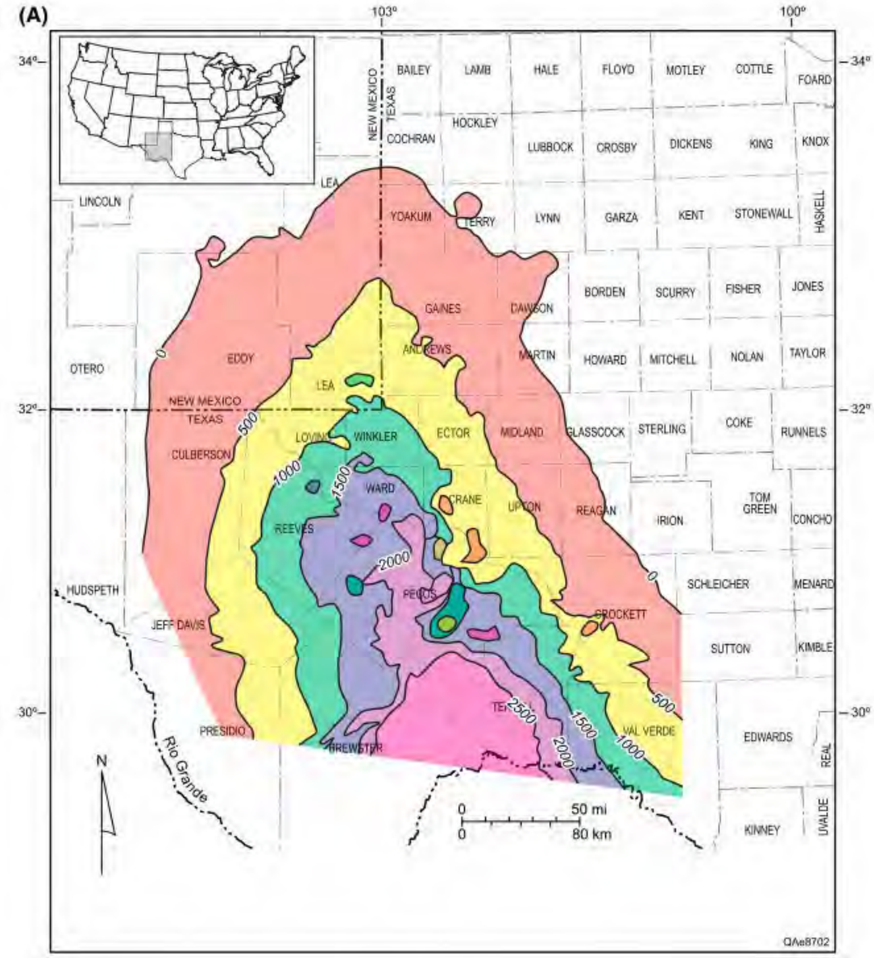


Figure 1-39: Regional Isochore Map of Simpson Group
(Fairhurst et. al., 2021) Isochore map of the Simpson Group (contour interval = 500 ft) modified from Fairhurst (2015). The axis and western margin of the Simpson isochore of the Tabosa Basin are similar to the axis of the current Delaware Basin. The eastern margin through central Martin, southwestern Glasscock, and eastern Regan Counties includes only the western half of the current Midland Basin. Individual beds display thinning onto the margins, and there are indications of erosion along these margins.

The upper members of the Simpson Group are subcropping from south to north in from Upton to Midland County. In the AoR, no formations or members are expected to subcrop within the AoR. The Simpson pinches out to the east of the Injection Well in Reagan County and is thinning gradually across Upton County.

It has also been observed that there are dramatic changes in Simpson thickness in different fault blocks. For example, The Simpson thickness at the nearest well that penetrates the injection interval, the Davidson Unit 1 #0106BH (API# 42-461-40597) is 325 feet while the expected thickness at the Injection Well is only 130 feet and at the Midkiff #1 to the east of the Injection Well the Simpson thickness is 244 feet. This variation is seen in **Figure 1-39** where there are abrupt changes along the Central Basin Platform.

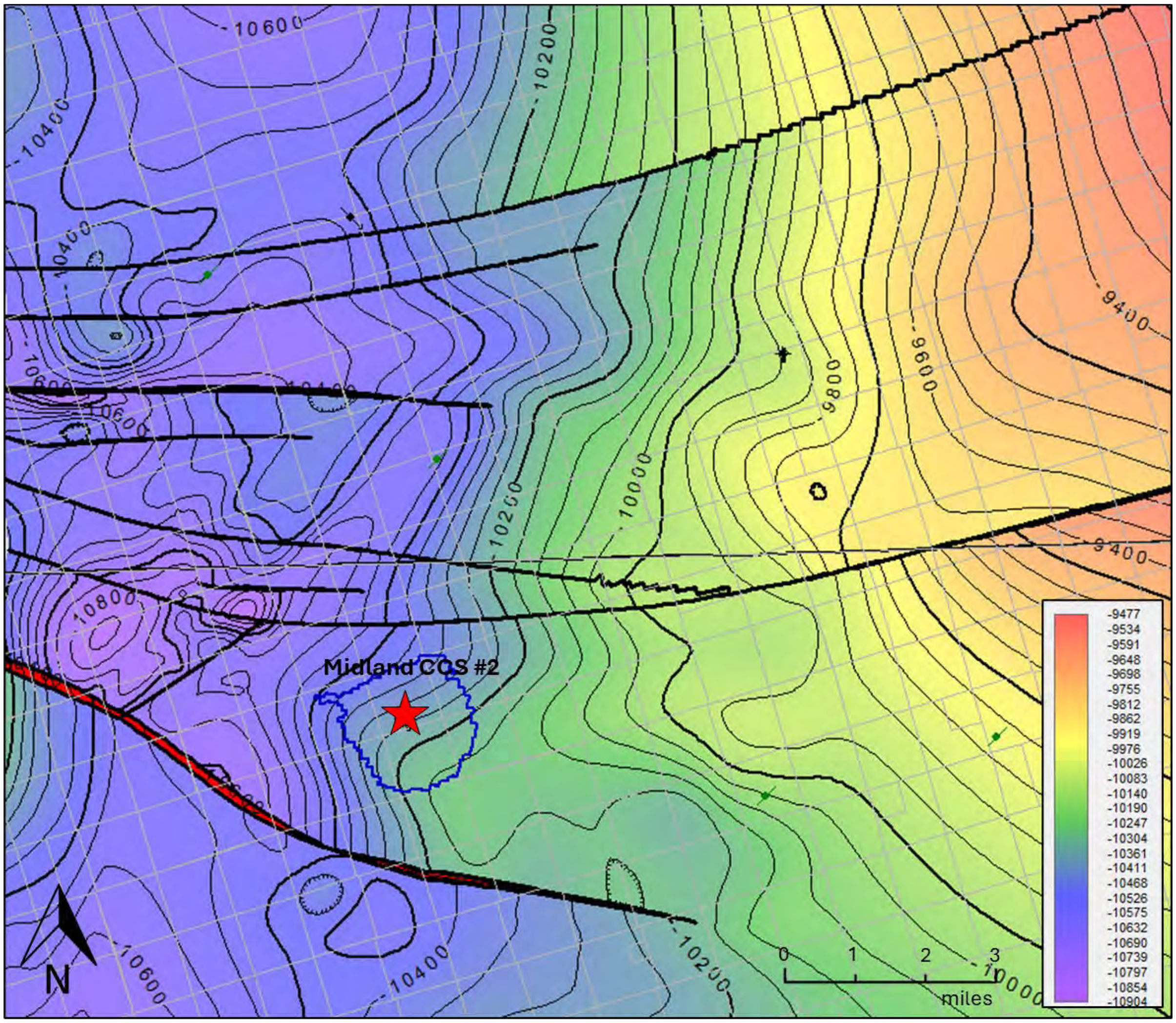


Figure 1-40: Localized Structure -Top of the Ellenburger
The Ellenburger is the lowermost injection zone for the well. Any smoothing at this interval may be due to lack of data in some areas. Ellenburger and Basement are the least often penetrated interval. CI = 50 ft.

The Ellenburger Group's structure is illustrated in **Fig. 1-40**. The Ellenburger top shows less irregularity and smoother contours due to a lack of well log data control. There are few penetrations that go that deep and penetrate the top of the Ellenburger since most of the production is much shallower in section. The top of the Ellenburger at the proposed Well location is -10,269 feet TVD SS. The range of depths across the AoR is from -10,140 to -10,452 feet TVD SS.

The faulting in the Ellenburger is similar to that of the Simpson Group illustrated earlier. At this depth, the Well is within a 3-way fault block, with faults to the north, south, and west. The northern fault is approximately 1.5 miles away, the fault to the south is approximately 2.1 miles away and the wrenching fault to the west is approximately 3.2 miles away, similar to the Simpson Group above. Details about the faults are included in **Section 1.8**. It is observed in seismic that faults cut from basement up through the Ellenburger, through the Simpson, and terminate within the Devonian or Wristen Group.

The depositional shape of the Ellenburger in the illustration is a smooth conical shape roughly N2E in the north to N327W in the south. This could somewhat be due to the lack of data control and the gridding algorithm extrapolating from the last known data points. The dip of the Ellenburger is on average 1.3 degrees to the west as it is deeper towards the CBP to the west.

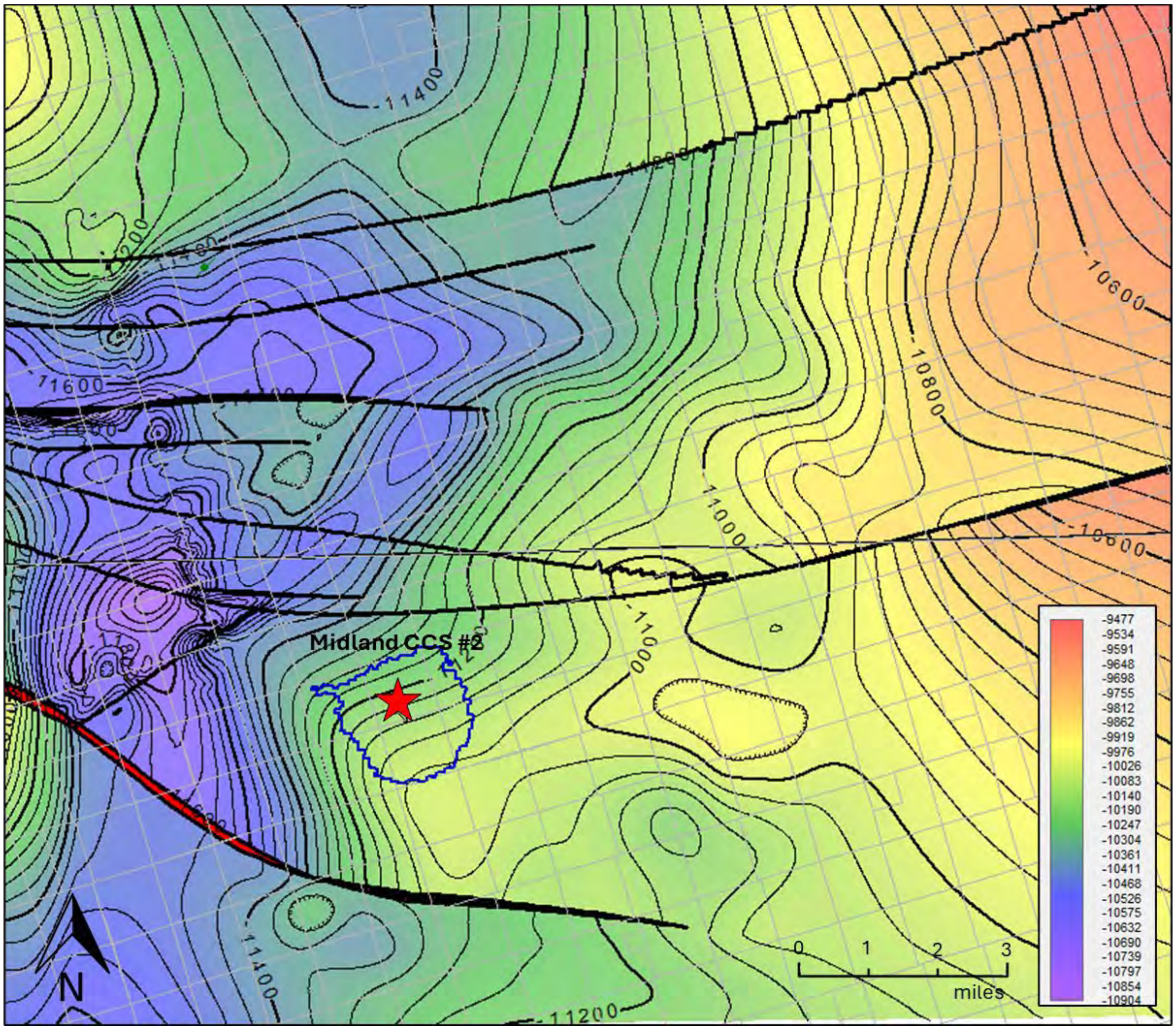


Figure 1-41: Localized Structure -Top of the Precambrian Basement (feet TVD SS)
The base of the injection interval is 100 feet above the base of the Precambrian Basement.

The top of the Precambrian Basement minus 100 feet defines the base of the injection interval. **Figure 1-41** shows somewhat of a smoothed effect due to the lack of control data points. There are very few penetrations in the local area that penetrate the Basement. The map is created by utilizing the few known data points from log penetrations correlated to the two 2D seismic lines. This was then extrapolated and gridded with the known faults to create this structure map. The top of the Precambrian Basement at the proposed location is -11,152 feet TVD SS but the base of the injection interval at our proposed location is 100 feet shallow at -11,052 feet TVD SS. The range of the depths of Basement across our AoR is from -11,032 to -11,298 feet TVD SS. Several authors have published conflicting maps of basement depths in the region, likely also due to lack of available well data.

The strike of the Basement at our proposed location site is N67E and the dip at the site location is approximately 2 degrees.

The faulting within the Ellenburger Group continues into the Basement. At this depth, the Well is still within a 3-way fault block, with faults to the north, south, and west. The northern fault is approximately 1.5 miles away, the fault to the south is approximately 2.8 miles away and the wrenching fault to the west is approximately 2.7 miles away, similar to the Simpson Group above. Details about the faults are included in **Section 1.8.**

1.7.2 Thickness

1.7.2.1 Log From Surface to Basement

Figure 1-42 illustrates an example type log of the local area with relevant thicknesses listed for each formation. The log is of the Peck well (API# 42-461-32673). The Peck is approximately 14.5 miles to the west on the CBP. As such, the depths will be different than our proposed location within the Midland Basin; however, the thicknesses are relatively similar and provide a good analog that illustrates a log section from near surface into the Ellenburger. Note the thick sections of high gamma ray that are likely <1 uD of permeability and form a barrier. Also note the extreme distance from base of USDW to Devonian and Ellenburger.

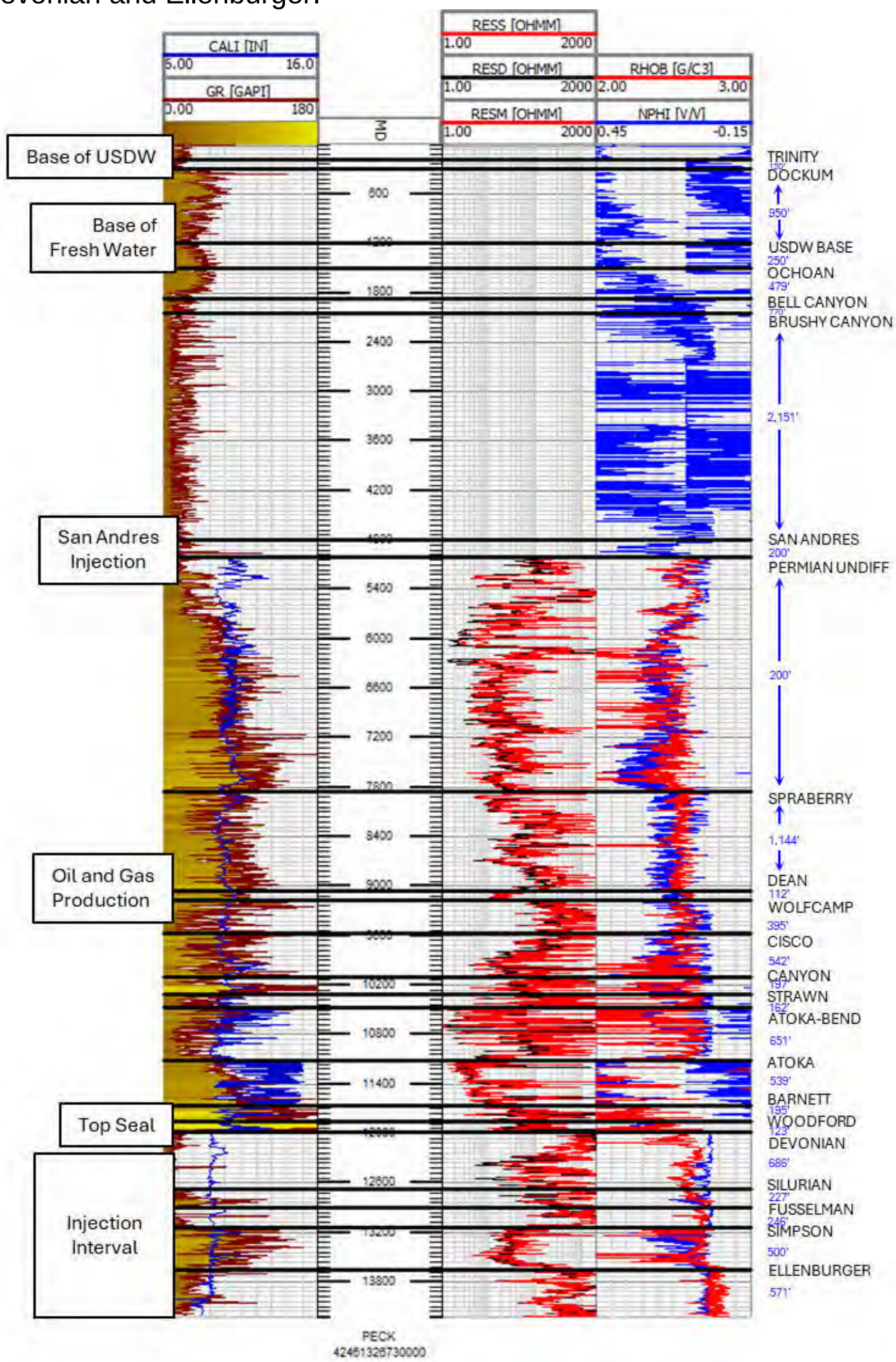


Figure 1-42: Shallow Type Log Down to the Ellenburger

Example type log with continuous logs from near surface to the Ellenburger. Type log. API# 42-461-32673.

1.7.2.2 Thickness Maps for Injection Units

Figures 1-43 to 1-46 illustrate the true vertical thicknesses for the injection intervals and the seal related to the proposed Well location.

Figure 1-43 illustrates a map of the true vertical thickness of the Siluro-Devonian Injection Unit. **Figure 1-43** shows an isopach from the top Devonian (base of the Woodford shale) to top of Simpson Group. The Devonian thickness is variable across fault blocks and irregular over Upton and Midland County ranging from a low of 650 feet to a high of 860 feet. The thickness is heavily influenced by faulting that cuts about half of the Siluro-Devonian and multiple unconformities within the section. There are unconformable surfaces at the base of the Woodford shale, top of the Wristen Group, top of the Fusselman formation and top of the Simpson Group. Notably the thickness of the chert decreases from west to east, likely due to these myriad unconformities.

The faults illustrated in (**Figure 1-43**) terminate within the Devonian interval and do not extend to the top of the Devonian. This isopach figure includes the entire Devonian Injection Unit (**Section 1.5.3**). The expected thickness at the proposed Facility is 736 ft. Within the AoR, the expected thickness of the Siluro-Devonian ranges from approximately 428 to 636 feet thick. There are no discernable pinchouts or terminations of the Devonian Injection Unit within 50 mi of the AoR.

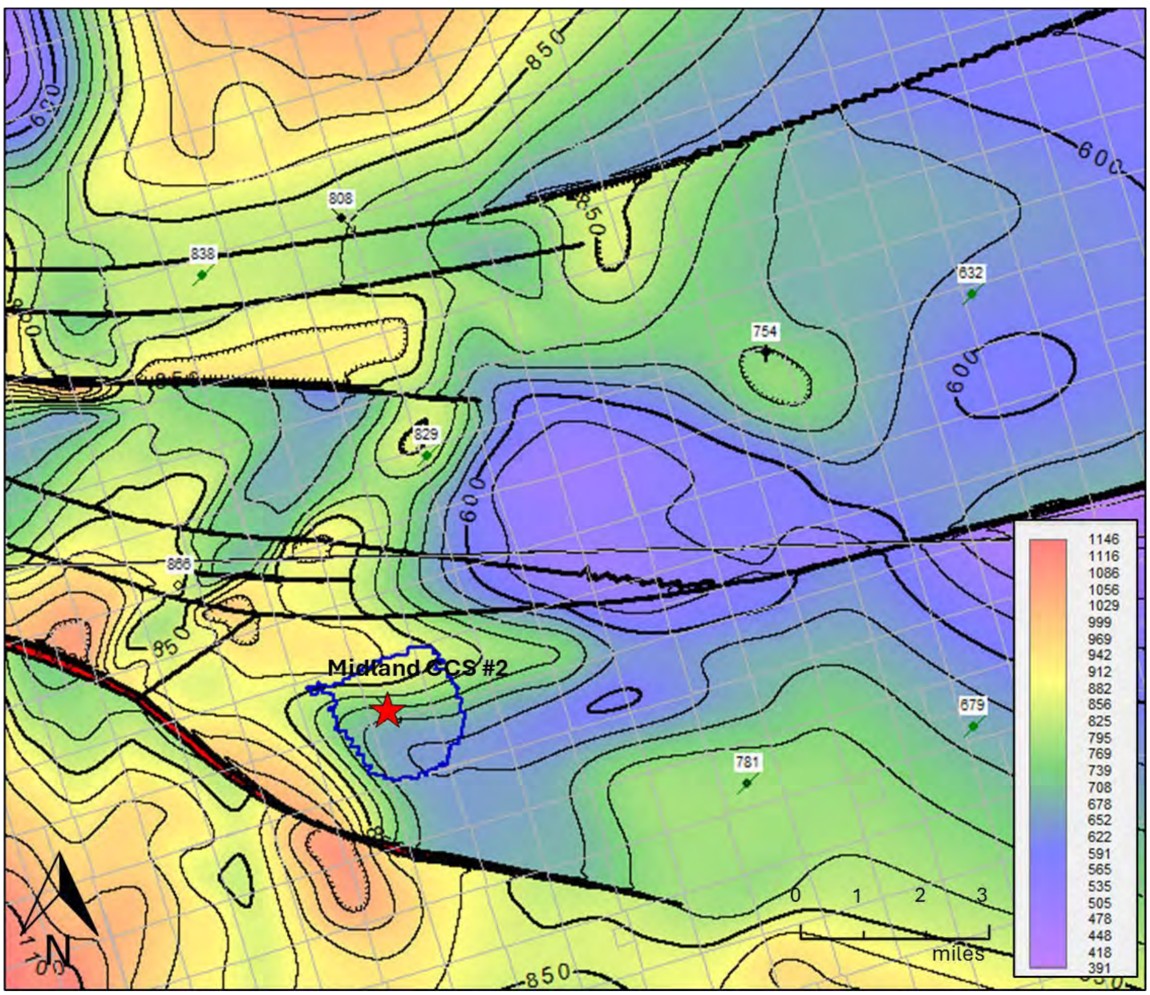


Figure 1-43: Devonian Thickness Map

True vertical thickness map of Top Devonian – Top of Simpson Group. Faults do not extend to the top of the Devonian; however, they are illustrated on the map due to the gross interval. Proposed location denoted by red star. Contour Interval = 50 ft

The Ellenburger thickness (**Fig. 1-44**) is expected to be approximately 883 feet thick at the proposed Well location. The range of thicknesses in the Well's AoR is from 839 feet to 903 feet, thickening to the east. The estimated thickness of 883 feet of the Ellenburger at the proposed location is assumed to be the minimum thickness. There is some uncertainty of total Ellenburger thickness given that most data points in the region show a thickness of >1,000ft, but 2D seismic indicates a local thinning in the area near the proposed location. The difficulty in ascertaining the true thickness of the Ellenburger is that most wells stop short of the base of the Group and do not penetrate the Precambrian basement. Further, due to high velocities, the basement contact is difficult to interpret on seismic data. The Davidson Unit 1 offset well (API# 42-461-40597) did penetrate basement, so it is known that 5 mi to the NW of the Injection Well location, the Ellenburger is 1,171 ft thick. There is an additional well, the Rosenbaum #1 (42-461-32329) approximately 10.3 miles east of the Injection Well location, with a thickness of 1,117 feet thick.

The thickness of the injection interval is 783 feet, and the bottom of the Ellenburger Injection Unit is 100 feet above the Ellenburger base (top of the Basement). The erratic contours towards the west are artifacts of multiple datapoints from the seismic 2D dataset expressed into the grid.

There are no terminations or pinchouts of the Ellenburger in the Midland Basin. In fact, the Ellenburger or Ordovician equivalents are found over much of the South-Central United States.

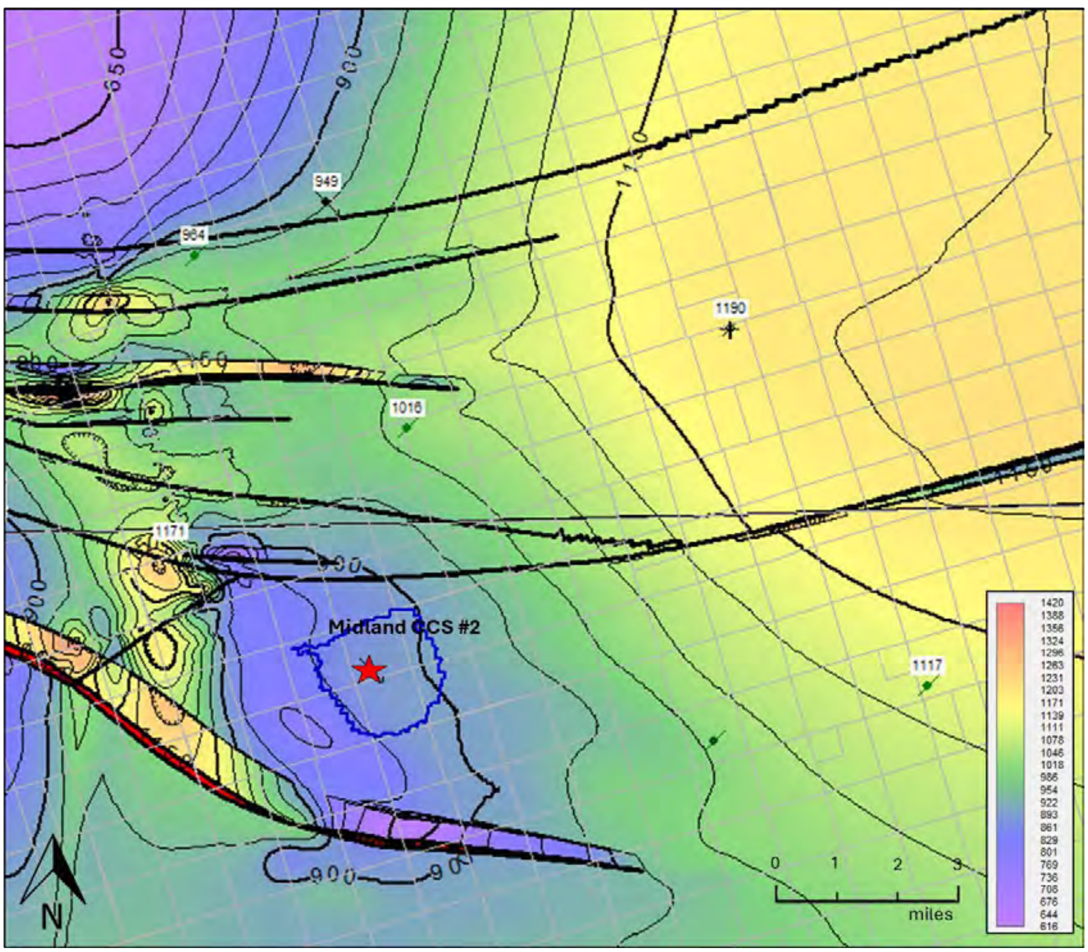


Figure 1-44: Ellenburger Thickness Map
True vertical thickness map of Top Ellenburger – Basement. Expected thickness at Midland CCS #2 site is 883 ft. Proposed location denoted by red star. The map shows the observed thickness of the Ellenburger, and should be regarded as a minimum as it is unclear if certain wells actually penetrate basement.

Since the Ellenburger is one of the deepest formations in the basin, it is not penetrated routinely by wellbores. There are <25 penetrations in Midland and Upton counties, many partial. This allows us to map the top depth fairly accurately, but thickness and facies are limited by lack of penetrations in the region. Fortunately, there is an offset well (Davidson Unit 1, API# 42-461-40597) 3.9 mi to the northwest of the Facility that is believed to have penetrated the basement rock. The Davidson well encountered basement at 14,784 ft and shows a thickness of the Ellenburger of 1,171 ft. While the Davidson well is an analog for this area, it is situated in a downthrown block between two faults. This graben could account for the increased thickness in the Davidson well and the large change in estimated thickness between the Injection Well and the Davidson.

1.7.2.3 Thickness Maps for Seals

The thickness of the primary Top Seal, the Woodford shale, is illustrated in **Figure 1-45**. Unlike the older layers shown in the Simpson-Ellenburger isopach and the Devonian-Simpson Group isopach, there is a stronger NE-SW trend to the change in thickness. This is hypothesized to be due to the unconformity at the base of the Woodford shale, perhaps indicating a change in depositional direction. It is also just as likely that it could be due to the underlying fault resulting in additional accommodation space in thicker areas. Regardless, the thickness of the seal at the proposed Well is 94 ft. There are no discernable pinchouts or terminations of the Woodford shale in Upton or Midland Counties. The seal is continuous over a large regional area. The thickness of the Woodford shale at the proposed Well location is 94 feet thick. The thickness range for the AoR is from 111 feet thick to 87 feet thick towards the south.

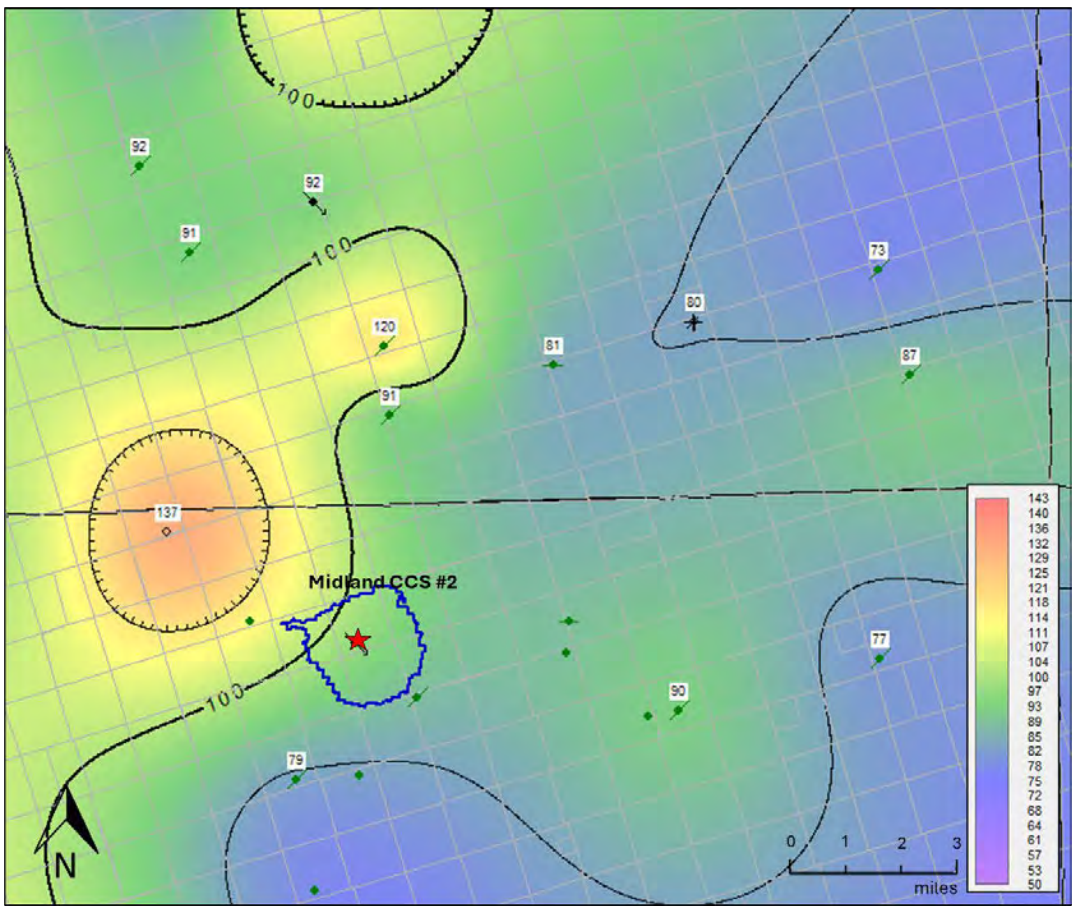


Figure 1-45: Upper Confining Layer Thickness - Woodford Thickness
Map generated by subtracting the subsea Devonian grid from the Woodford surface grids – both generated through modeling. The red star is the proposed location of Midland CCS #2. The expected thickness at the Well location is 94 ft.

The Simpson Group is an interval within the injection zone that is not expected to take any injectate due to low permeability. It serves as an intrazone baffle within the injection unit. While the Simpson group may be an internal seal, we are not utilizing it as a seal for the purposes of this Well since we are injecting both above and below. **Figure 1-46** illustrates the thickness of the Simpson Group around the area. The Simpson Group thickness varies between fault blocks around the area. For example, the Simpson thickness is 324 feet at the Davidson Unit 1 (API# 42-461-40597) well and only 177 feet at the Rosenbaum #1 (42-461-32329) location. The expected thickness of the Simpson at the Injection Well is 130 ft. The thickness within the AoR ranges from 118 feet to 144 feet.

The Bromide formation is not expected to be present at the proposed location (**Fig. 1-47**). There may be a few feet remaining before the Bromide is completely subcropped going into Midland County. The top of the Simpson Group is the Tulip Creek formation near the Midland-Upton County line. Regardless, there are multiple shale formations such as the Oil Creek and the Tulip Creek that form an effective vertical permeability barrier within the Simpson Group.

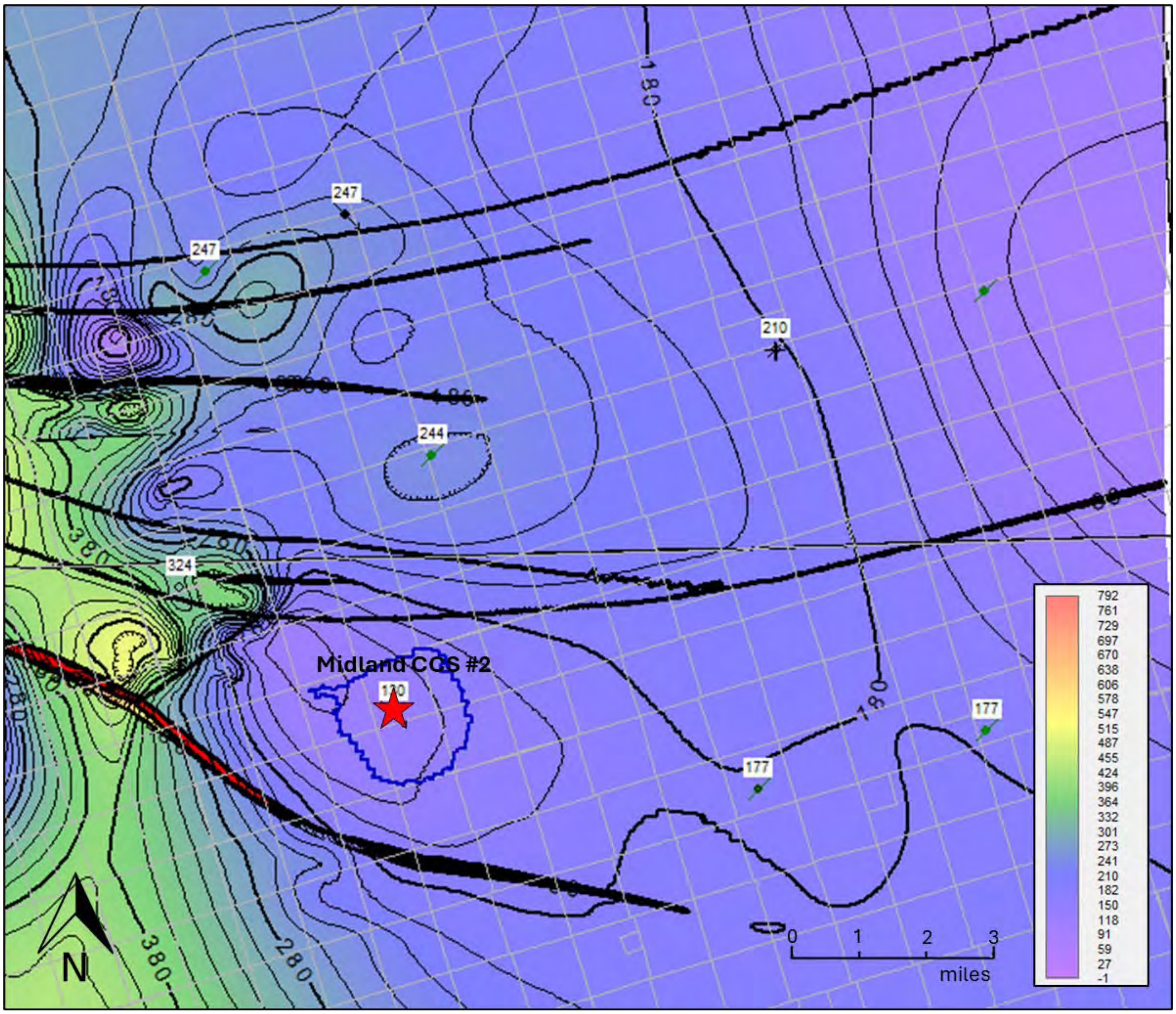


Figure 1-46: True Vertical Thickness of the Simpson Group

Map generated by subtracting surface grids of the Simpson and the Ellenburger Formations – both generated through modeling. The red star is the proposed location of Midland CCS #2. The expected thickness at the proposed location is 130 ft. Data values are from the top of the Simpson Group to the top of the Ellenburger formation.

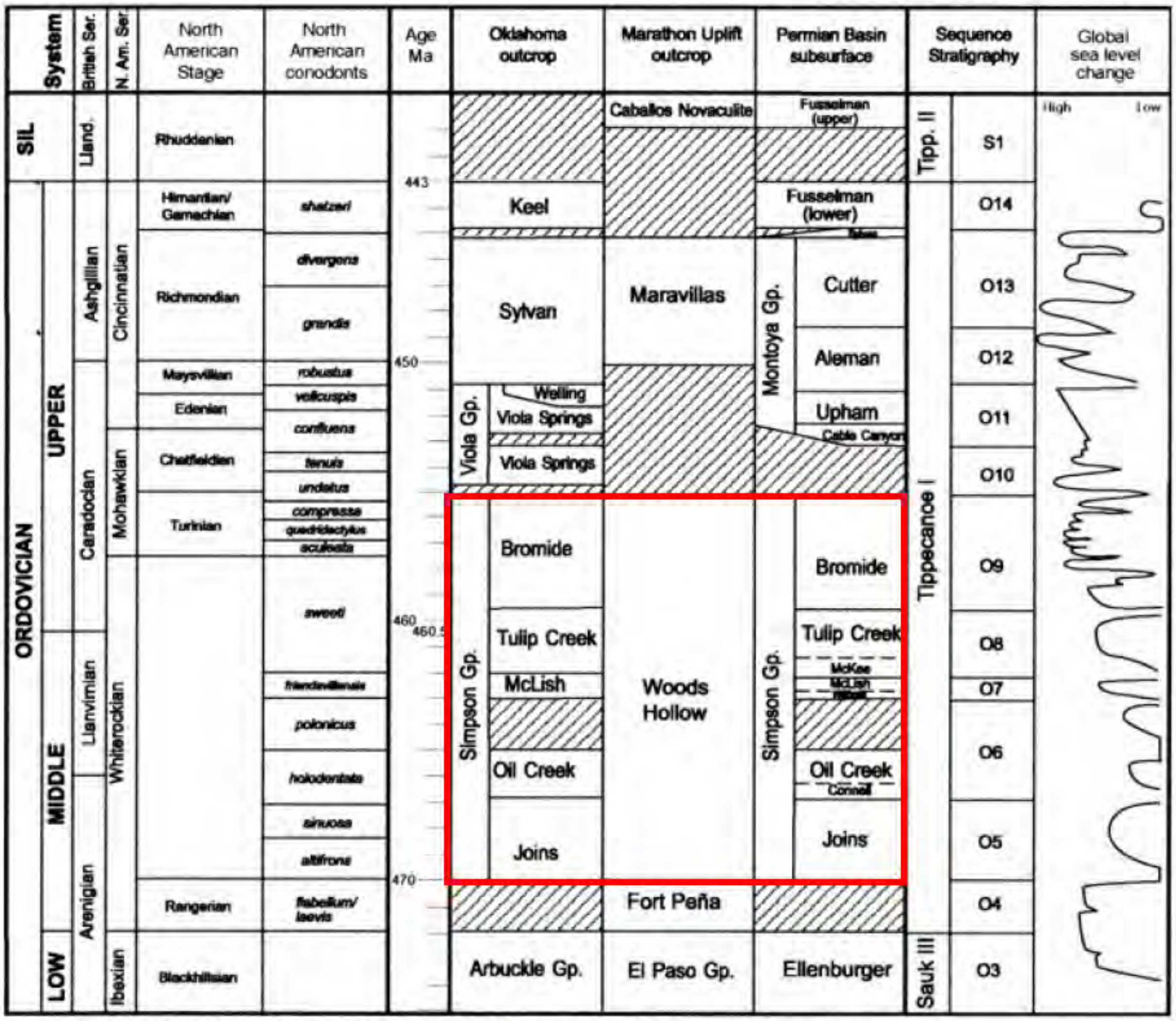


Figure 1-47: Detailed Stratigraphic Column illustrating the Simpson Group
Detailed stratigraphic column illustrating the individual formations that make up the Simpson Group. (Modified from Fairhurst et. al., 2016)

The Barnett shale and Atoka shale are secondary seals that sit directly on top of the Primary Upper Confining Layer (Top Seal) of the Woodford shale. The Atoka, Barnett and Woodford form a package of shales that should inhibit any upward movement of CO_2. The thickness of the Barnett (**Figure 48**) at the Injection Well location is 173 feet and the thickness of the Atoka at the Injection Well location is 430 feet. The thickness of the Woodford is 94 feet. When these thicknesses are combined, a total of 697 feet of shale sits on top of the Injection Interval.

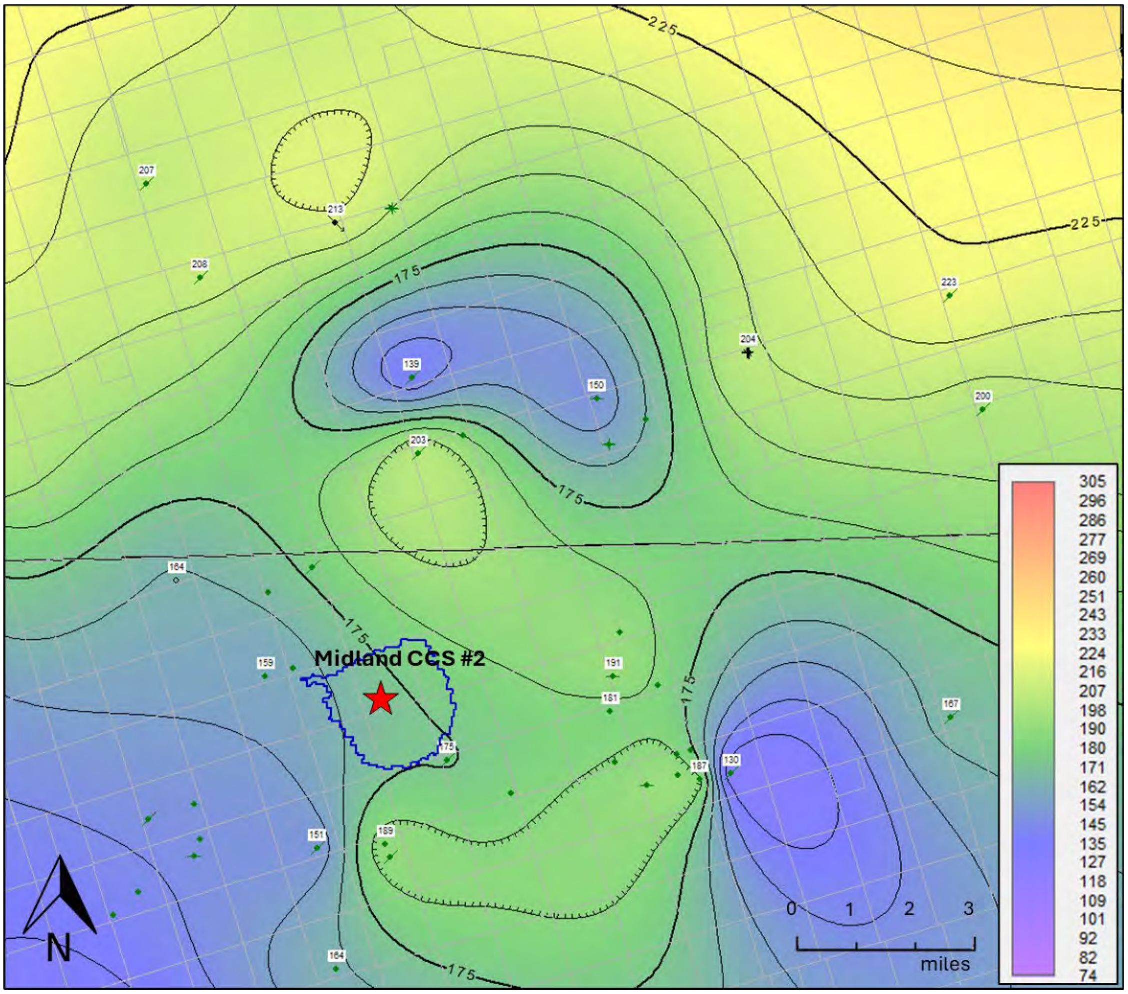


Figure 1-48: True Vertical Thickness of the Barnett shale
Map generated by subtracting surface grids of the Barnett and the Woodford Formations – both generated through modeling. The red star is the proposed location of Midland CCS #2. The expected thickness at the proposed location is 173 ft.

1.7.3 Cross sections

A base map showing the paths of two cross sections is shown in (**Figure 1-49**). The distance between wells is generally 6 mi or greater and crosses fault planes. The cross sections show the lateral depositional continuity of both the injection zone and the confining layers. Both lines of section are flattened on the Simpson Group to make reading easier and to show the lack of pinchouts in injection zone or seals.

Two cross sections were prepared: **Figures 1-50** and **1-51**. The first cross section, (**Figure 1-50**), is from west-to-east across Upton County. The second cross section, (**Figure 1-51**), is from north to south across Midland County and Upton County.

In the west-to-east cross section A-A' illustrated in **Figure 1-50**, there are several observations worth noting. First, the Woodford is thickening to the west with thickness at the Well expected to be 94' thick. The top seal of these combined zones is present across the entire basin with consistent thickness. Next, the Silurian-aged Wristen Group is also thinning to the east.

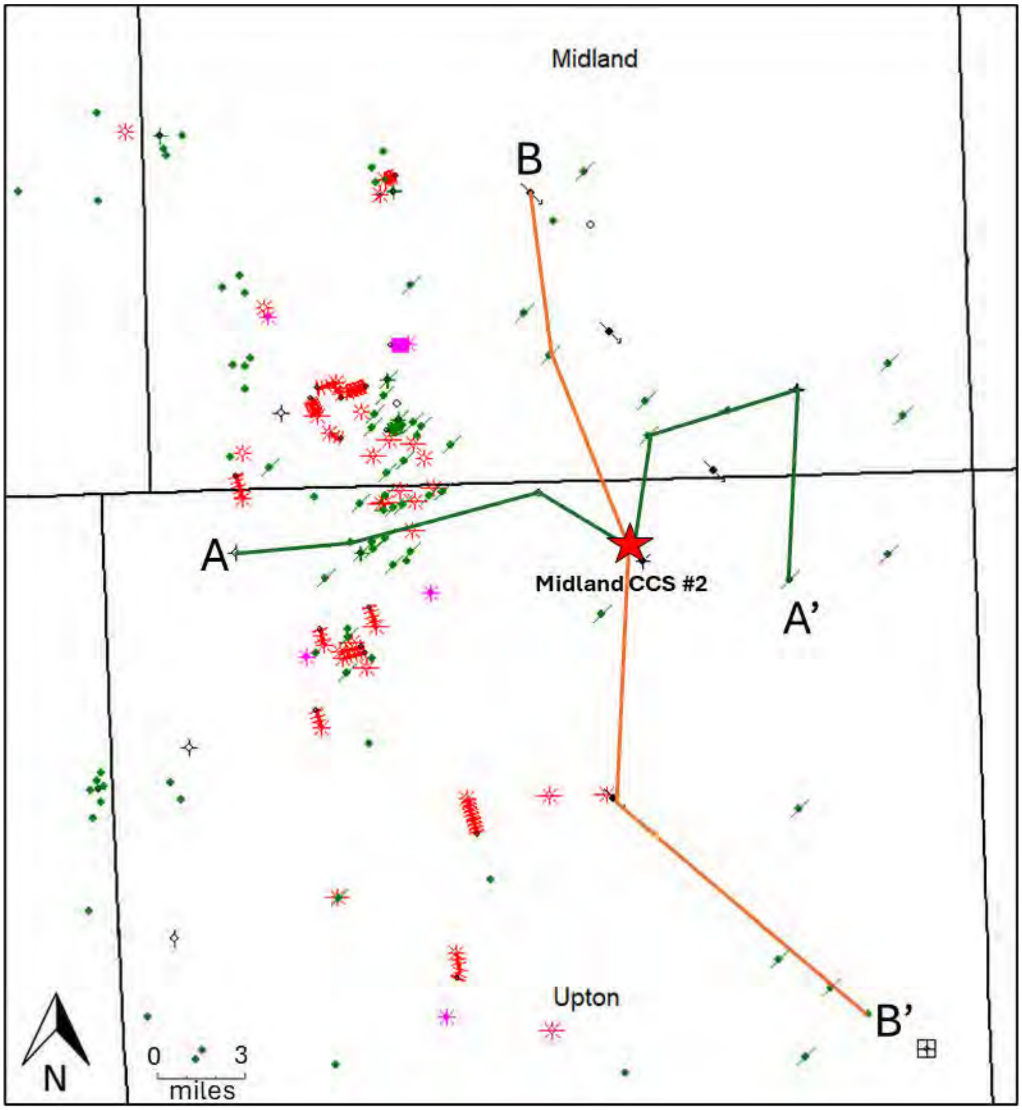


Figure 1-49: A-A' / B-B' Index Map
Base map illustrating path of cross sections A-A' which is the west-to-east cross section, and B-B' which is the north-south cross section. Distances between wells are vast in some cases, typically 6 mi or greater.

The Simpson Group is expected to be only an intraformational baffle as it narrows to a point on the eastern edge of the basin. Also worth noting, there is nearly 1,000 ft of vertical displacement in the Pegasus well. It sits in an upthrown block west of the fault. This faulting is not expected to affect the injection area though as the AoR terminates ~6 mi away from the fault. The basement is not thinning markedly throughout the area. It is merely an artifact of wells stopping short of tagging basement igneous rock. Most wells reach TD in the Ellenburger or Devonian section and did not continue drilling.

An observation, in terms of log response, the resistivity is maxed out to the east but not in the west in the Devonian injection unit. It is surmised that the true porosity is decreasing in the Devonian as movement is east, even in the chert facies. Ellenburger shows consistent dolostone around the area of interest as expected from regional mapping. The porosity and permeability of the Ellenburger is estimated to be uniform across the area while the Devonian may have lower porosity and permeability to the east as evidenced on this cross-section **Figure 1-50**.

In reference to the north-south cross section B-B' in **Figure 1-51**, there are several observations worth noting in this cross section. In this section, evidence of several documented unconformities is observed.

The Devonian top – Simpson Group thickness (Devonian Injection Unit) is nearly constant, but the Simpson Group is thickening toward the south which is consistent with regional literature.

It is difficult to tell if the Bromide member of the Simpson is appearing or disappearing as reported. It is suspected that it remains thin in this region across the cross section.

The Barnett shale begins to thin to the south at the Davidson Unit well. However, there is only significant thinning at the very southern end of Upton County >20 mi outside the injection area. Even in the southern part of Upton, the combined Woodford and Barnett shales are still >300 ft thick.

The surfaces above the Barnett appear to thicken and then thin relative to periods of faulting, subsidence, accommodation, and/or uplift. Once again, the thickness to Basement is not actually changing substantially; it is merely an artifact of well penetrations stopping short. The confining layer is regionally consistent until the very farthest south point in the cross section where it thins slightly as it encroaches upon the Ozona Arch.

These cross sections illustrate that all formations are regionally extensive across both Upton and Midland Counties with no expected pinchouts or unusual structures. The unconformities affect the thickness but are not expected to materially affect storage potential.

Also, the cross sections show that all changes are gradual across the counties of interest even when faults are present. This is evidence that the faulting happened after primary deposition and the faults were not syndepositional. This is consistent with regional tectonic history which puts the major tectonic events in the Mississippian, well after the Devonian and Ordovician layers had been deposited and buried.

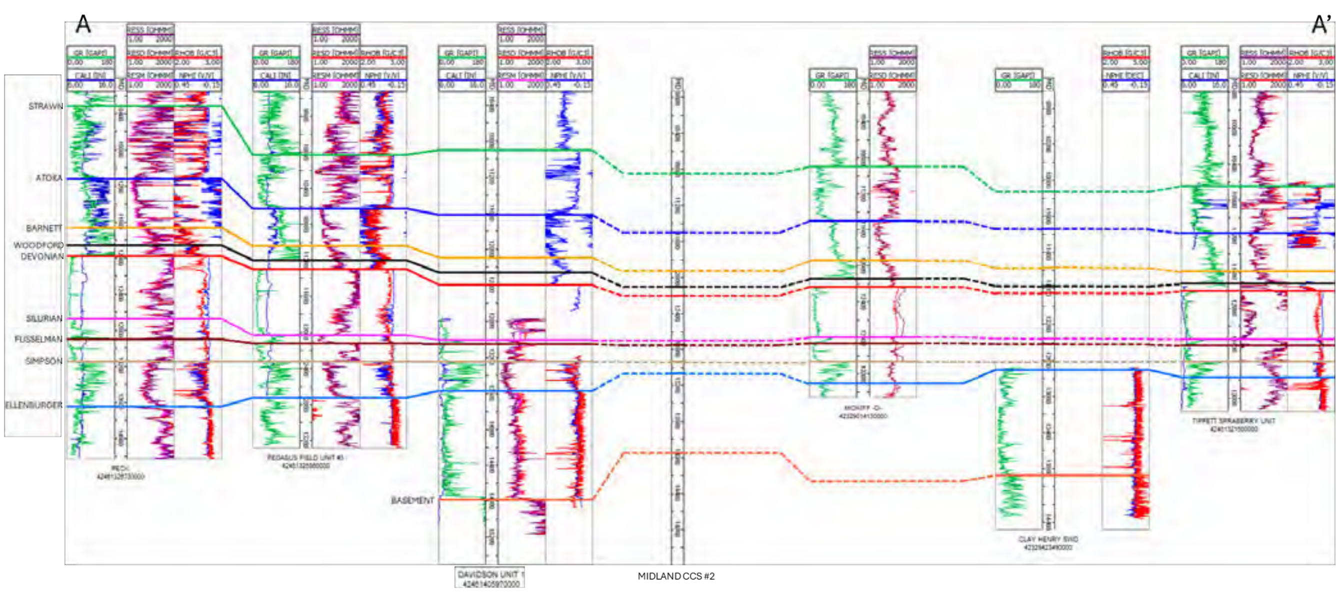


Figure 1-50: A-A' Cross Section West-to-East

West-to-east cross section A-A' across the AoR and through the proposed well location. Flattened on the top of the Simpson Group. Base top is the base of the log which only corresponds to basement on two logs (Davidson and Clay Henry.). Note the thinning of the Simpson Group from west-to-east but it is still at least 130 ft thick. Note how the top seal, Woodford and Barnett, have consistent thickness.

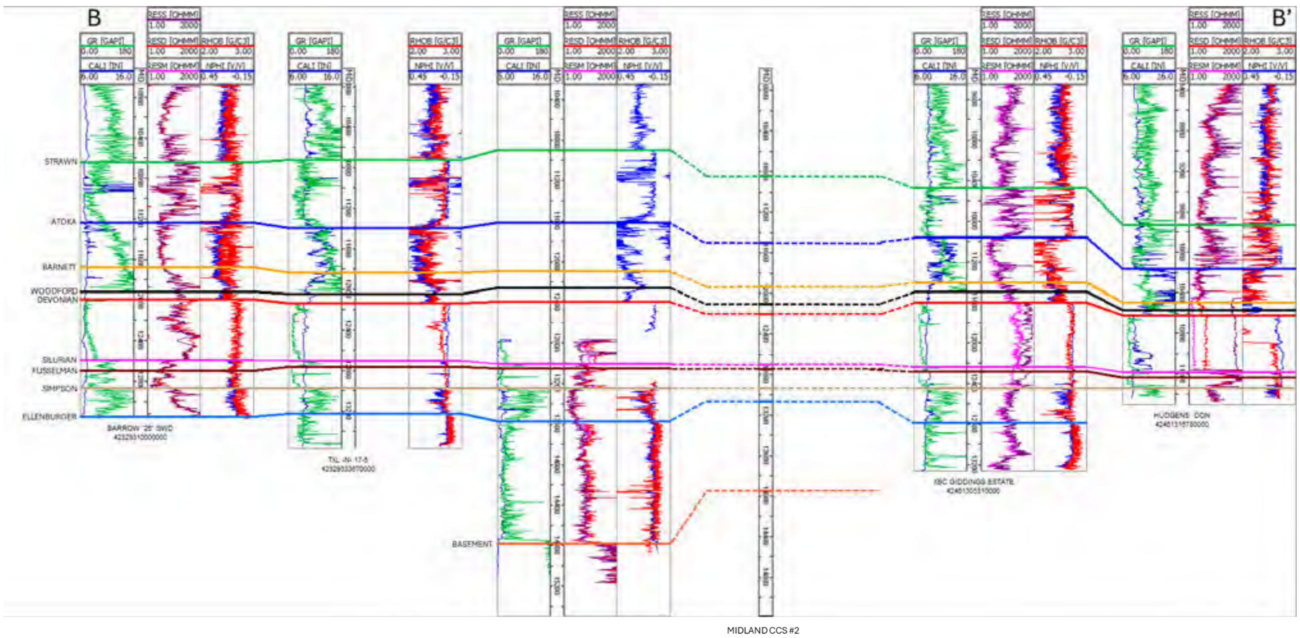


Figure 1-51: B-B' Cross Section North-to-South
North-to-south cross section B-B' across the AoR and through the proposed well location. Flattened on the Simpson Group top. Note how consistent thickness is for most of the AoR. In the far south of Upton County, there is some thinning of all formations. Note how the top seal is regionally pervasive until the very farthest south point in the cross section. In the southern part of Upton County, directly south of the location, there are no penetrations of the Ellenburger with the exception of the Gidding well, therefore, a SE jog was taken on last well.

On both cross-sections, multiple faults are visible; however, no faults penetrate through the top of the Devonian interval into the base of the Woodford shale. The faulting terminates within the Barnett shale (More detail on faults found in **Section 1.8.2**).

1.7.4 Lithology

Four primary lithologic rock types (facies) are observed in the injection and confining units and subsequently utilized in the geologic model (see Static model and AoR Corrective Action, **Section 2.3**): 1) claystone, 2) packstone (grain-supported limestone [Dunham, 1962]), 3) dolostone, and 4) chert. Facies were discretized using well logs with Photoelectric factor (PeF) curves and referenced to available core data described in literature (R. Loucks, 2007, 2023). See **Section 1.5** and **Section 13, Appendix K** for additional lithologic information and geologic background.

PeF and gamma ray (GR) derived clay volume (Vclay) logs were the primary inputs used to discretize facies in each well. The algorithm used to define each is summarized as seen in (**Equation 1-1**) and (**Equation 1-2**):

Equation 1-1: Lithology Calculations from Woodford through Simpson

Woodford through Simpson:

- Chert = PEF < 3 b/e & Vclay <= 0.19 v/v
- Packstone = PEF >= 3 b/e & Vclay <= 0.19 v/v
- Claystone = Vclay > 0.19 v/v or GR > 145 API

Equation 1-2: Lithology Calculations for Ellenburger

Ellenburger:

- Chert = PEF < 3 b/e & Vclay <= 0.19 v/v
- Dolostone = PEF >= 3 b/e & Vclay < 0.19 v/v
- Claystone = Vclay > 0.19 v/v or GR > 145 API

Relative proportions of each facies comprising each zone within the AoR are summarized in **Figure 1-52** and seen in the cross section on **Figure 1-53.** Based on the algorithm above, the Woodford Shale is composed of approximately 98% claystone with chert making up the remainder. The Devonian consists primarily of packstone (28%) and chert (71%) and minor amounts of claystone (1%).

Most of the packstone is observed in the upper half of the section. The Silurian zone is primarily chert (65%) with the remaining being packstone (28%) and claystone (7%). The Fusselman zone contains significant quantities of claystone (27%) however the more permeable facies, packstone (52%) and chert (27%), predominate.

The Simpson is a significant vertical baffle, consisting of 73% claystone with minor packstone (14%) and chert (13%). The lowermost injection unit, the Ellenburger formation, consists of 80% dolostone along with some chert lenses (13%) and minor claystone (7%).

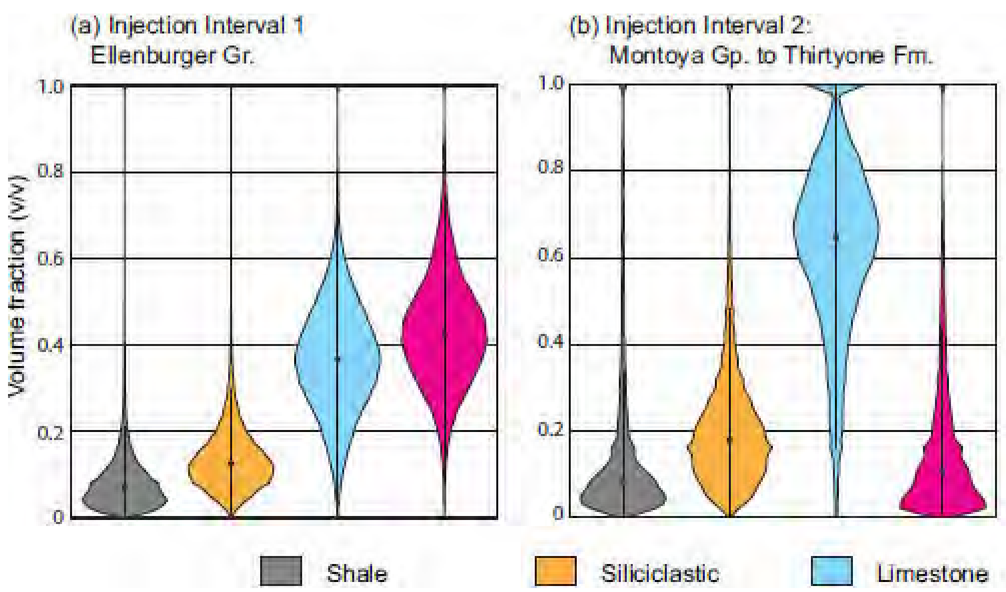


Figure 1-52: Zone Facies in AoR (modified from Calle et. al., 2024)
Violin plots illustrate the distribution of lithofacies in Ellenburger and Silurian-Devonian units.

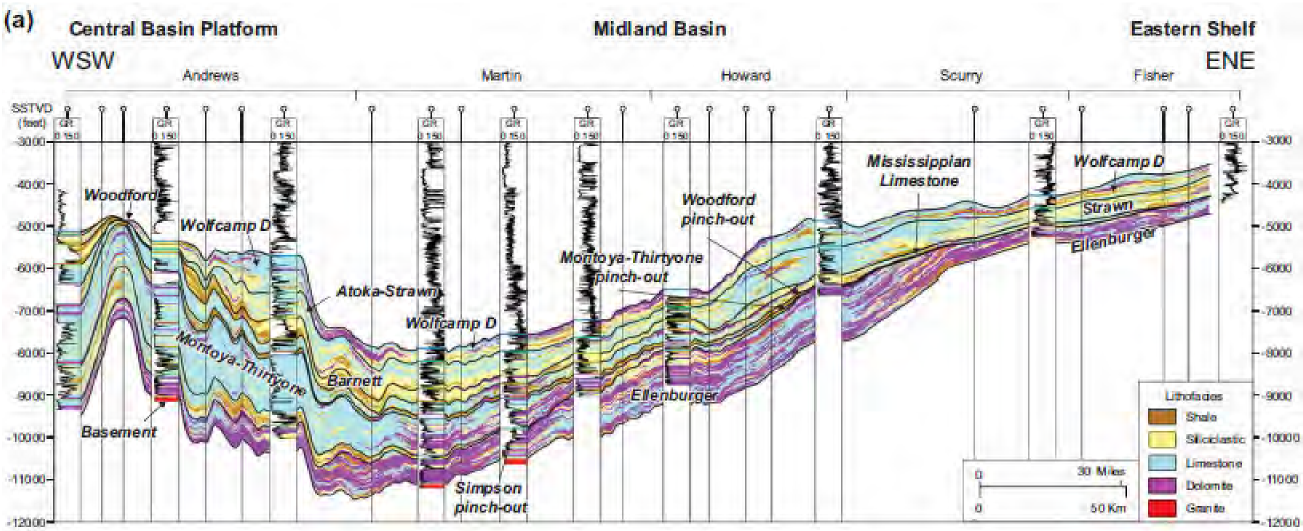


Figure 1-53: Facies Cross Sections (Calle et. al., 2024)
Lithofacies distribution from the northern shelf to the structurally compartmentalized Ozona arch.

No significant lateral change in facies proportions is predicted with the AoR, particularly within the Woodford Shale upper confining zone. Across the static model domain (see cross sections in **Figure 1-58**), some lateral variability is observed in facies proportions within the injection unit, though such variability would not significantly influence the lateral migration of injected CO_2. No significant variability in the sealing facies (claystone) content of the Woodford is observed.

1.8 Faults and Fractures [40 CFR 146,82 (a)(3)(ii)]

This section addresses data regarding faults and fractures in the seals and injection units as well as the seismic history of area. It further documents the regional stress field for the southern Midland Basin and shows fault slippage analyses for nearby faults.

1.8.1 Faulting

This section will address the regional and localized interpreted data regarding the faulting present that affects this area and the Well AOI.

With respect to the regional faulting, the Bureau of Economic Geology (BEG) has performed extensive regional research in the Permian Basin. In this section, we will reference figures and citations from the BEG and their regional analysis in the Midland Basin. In addition to the regional data and analysis, Milestone has acquired two 2D seismic lines (**Figure 1-54**) for interpretation to analyze localized faulting and deposition. We acknowledge that the BEG did not have access to seismic data for characterizing the AoR surrounding the Well. As a result, the localized interpretation based on the two 2D lines will represent the identified fault locations and geometry in that area, while we will rely on regional fault data for the surrounding region.

Milestone identified 5 known or suspected faults within 4 miles of the edge of the AoR using seismic interpretation. However, we illustrate a larger footprint in maps to provide a more inclusive viewpoint. Three of the 6 interpreted faults are correlated to regional faults that are identified also from Horne et. al., 2024. The remaining three faults are interpreted via seismic and deemed to be more localized faulting.

Figure 1-55 illustrates the regional faults (Horne et. al., 2024) for the AoR. These faults are generally referred to as "Horne faults" or "Horne's work" as simply a matter of efficiency but not meant to discredit any additional authors on the publication. This figure is also meant to differentiate the different data sets from Horne's work; however, from this point forward, Horne's faults will be colored in the same manner within our figures unless it's a published illustration that will be cited and referenced.

Figure 1-56 illustrates localized faults interpreted from seismic, many of which correspond to regional faults illustrated from Horne et. al. 2024. Horne et. al. lacked access to seismic data over our AoR (**Figure 1-55**), and thus, our interpreted seismic dataset confirms the local faults relevant to our AoR surrounding our proposed Well location.

[redacted]

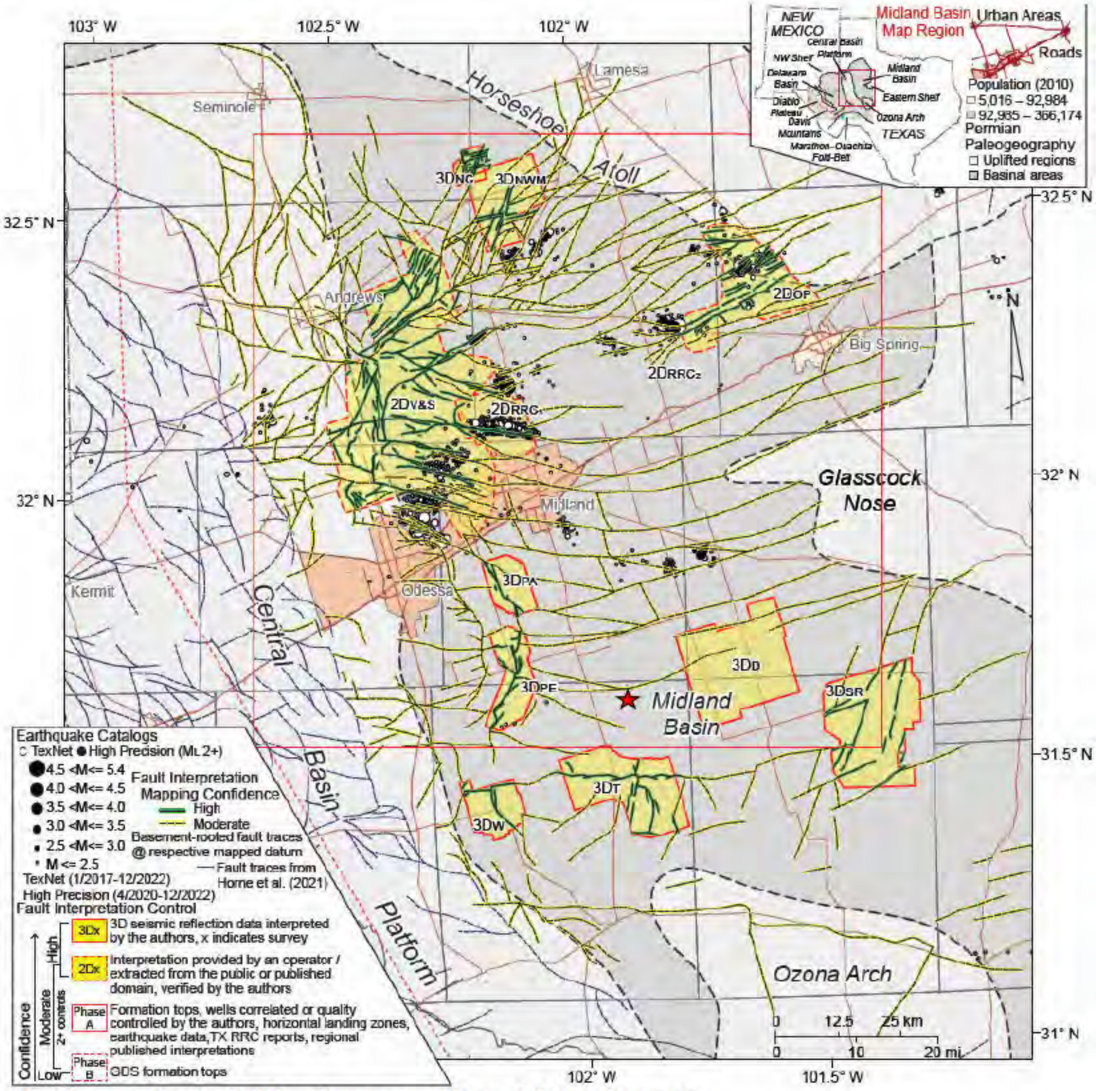


Figure 1-55: Horne et. al., 2024 – Summary Map of Data Sources
Map illustrating the data sources available for Horne et. al. interpretations and fault mapping confidence.

The two 2D lines are illustrated in **Fig. 1-54**. Midland CCS #2 is approximately 2.2 miles from the southern tip of Line 25 and approximately 2.5 miles from the eastern tip of Line 26. **Figure 1-56** illustrates the faults in two different colors to represent the two data sets available. The maroon faults are from a dataset that includes regional, simplified (framework) fault traces (Horne et. al., 2024). The blue faults are mapped fault traces that represent the hanging wall intersection line of the fault surfaces.

Figure 1-57 contains 4 maps with the localized faults expressed to the surface from their respective subsurface depths. This illustrates the fault geometry relative to the Midland CCS #2 well location which is annotated with a red star.

The faults are numbered and maintained relative to each map: meaning that the number 1 fault in one map, is the same fault that is listed as number 1 on additional maps. If a numbered fault is missing from a map, as is the case with the number 4 and 9 faults, then the fault truncated prior to the top of the formation annotated on the map. The number 4 fault is illustrated on the Basement and Ellenburger maps and truncates prior to the top of the Simpson. The number 9 fault is present in the Basement, Ellenburger, and Simpson, yet truncates prior to the top of the Fusselman, therefore it is not illustrated on the Fusselman map.

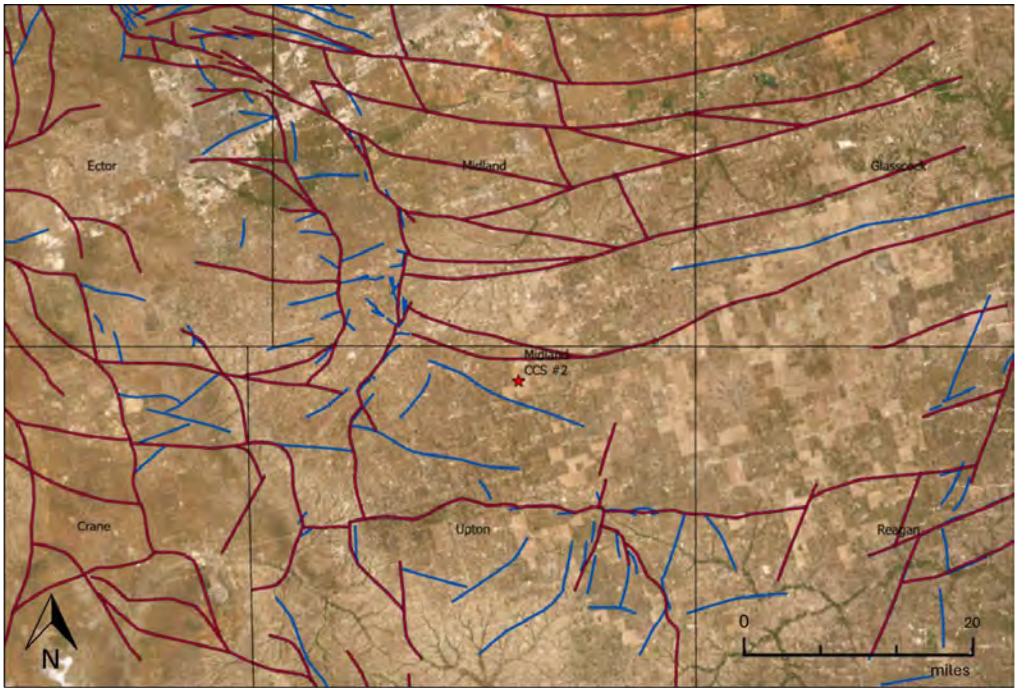


Figure 1-56: Location Map Regional Faults
Fault dataset from Horne GPB-Regional v1 2023 and Horne et al 2023 MB BMST V1 (Horne et. al., 2024) Maroon faults correspond to Horne GPB-Regional v1_2023 and blue faults correspond to Horne_et_al 2023 MB_BSMT_V1 datasets. Both datasets illustrated are represented as "moderate confidence" faults.

[redacted]

[redacted]

The seismic cross-sections are illustrated in **Figure 1-58**. These should be considered **highly confidential and remain confidential** even during the public notice period.

The horizons interpreted on the seismic sections include the Basement, Ellenburger dolomite, Simpson Group, Fusselman limestone, Woodford shale, Barnett shale, Atoka shale, Strawn limestone, Cisco, Wolfcamp, and Spraberry. These horizons were based on well ties, and an average seismic time-depth relationship employing both sonic logs and checkshot survey data was developed as well.

On both cross-sections, multiple faults are visible and were interpreted. It is clear, however, that one of the faults has enough vertical displacement to penetrate high enough upward to cut through the top of the Woodford shale. This is a result of the faults losing displacement upward in the stratigraphic section. As a result, the structure maps generated for the top of the Woodford shale and the top of the overlying Barnett shale contain no fault traces.

1.8.1.1 Fault Details

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

1.8.2 Fractures

Pervasive fractures are expected in both the Devonian and Ellenburger sections due to their relatively high Young's moduli of 8 million pounds per square inch (MPSI+), which indicates these formations strain very little before failure and are very incompressible. Areas of Ellenburger modified by karsting has been mapped by Loucks (2022) (**Figure 1-61**). The Well and Facility are on the edge of the Karst modified area but still within it.

Significant fracturing in the Ellenburger and Devonian has also been observed in core in the Barnhart Ellenburger Unit #3 well from the Bureau of Economic Geology (BEG). A series of cave collapse breccias were observed in this core by Loucks and Kerans (2019) (**Figure 1-62**). These fractures are expected to increase the system permeability within the Ellenburger or Devonian flow unit but not extend into the seals.

The Woodford, Barnett and Simpson have significantly more compliant Young's moduli, 2-4 million psi in the shales compared to 8-12 million psi in the carbonates.

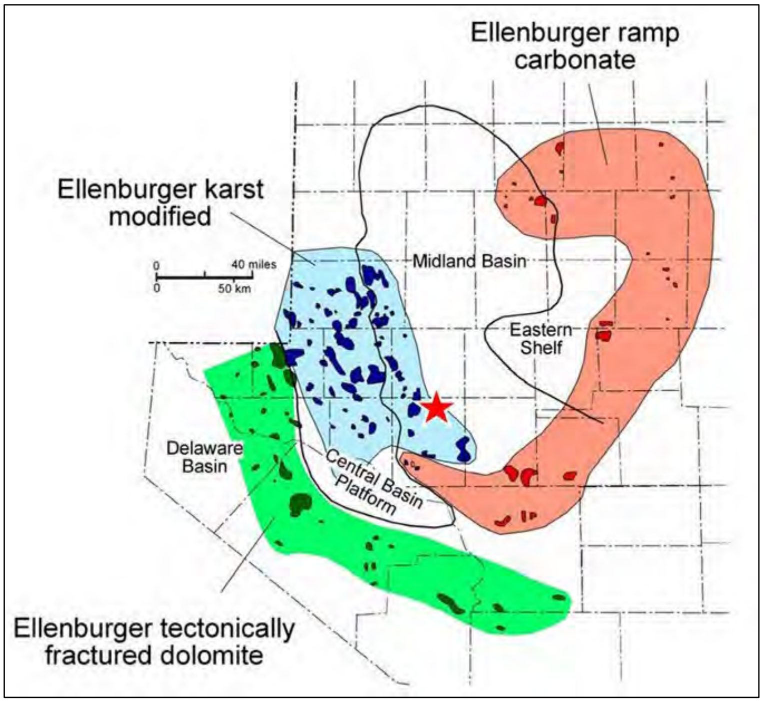


Figure 1-61: Ellenburger Group Reservoir Types
Distribution of Ellenburger Group Reservoir types by Holtz and Kerans (1992) showing Karst Modified areas. (Loucks, 2023) Red Star for Midland CCS #2 Well. Notice how the location is on the edge of the Karst modified area but still within it.

There is little pattern or orientation to the fracture systems. No preferred orientation has been observed. This is likely due to the chaotic nature of karst collapse features with the additional overprint of some tectonic fracturing in the ancient Tobosa Basin.

Shales form an upper boundary to the fracturing and natural fractures are not expected to penetrate the Woodford or Barnett Shale Formation.

The most prominent unknowns regarding the fractures are the quantity and depth range of fracturing at the proposed wellsite. From offset injection and core data it surmised that fractures are pervasive in the area but since there are currently no penetrations; an accurate accounting of the fractures have not been found. Before drilling, three-dimensional (3D) seismic attributes will be used to attempt to determine which areas of the AoR are more heavily fractured. At the conclusion of drilling operations of the test well, an image log will be acquired to determine all of the previous unknowns.

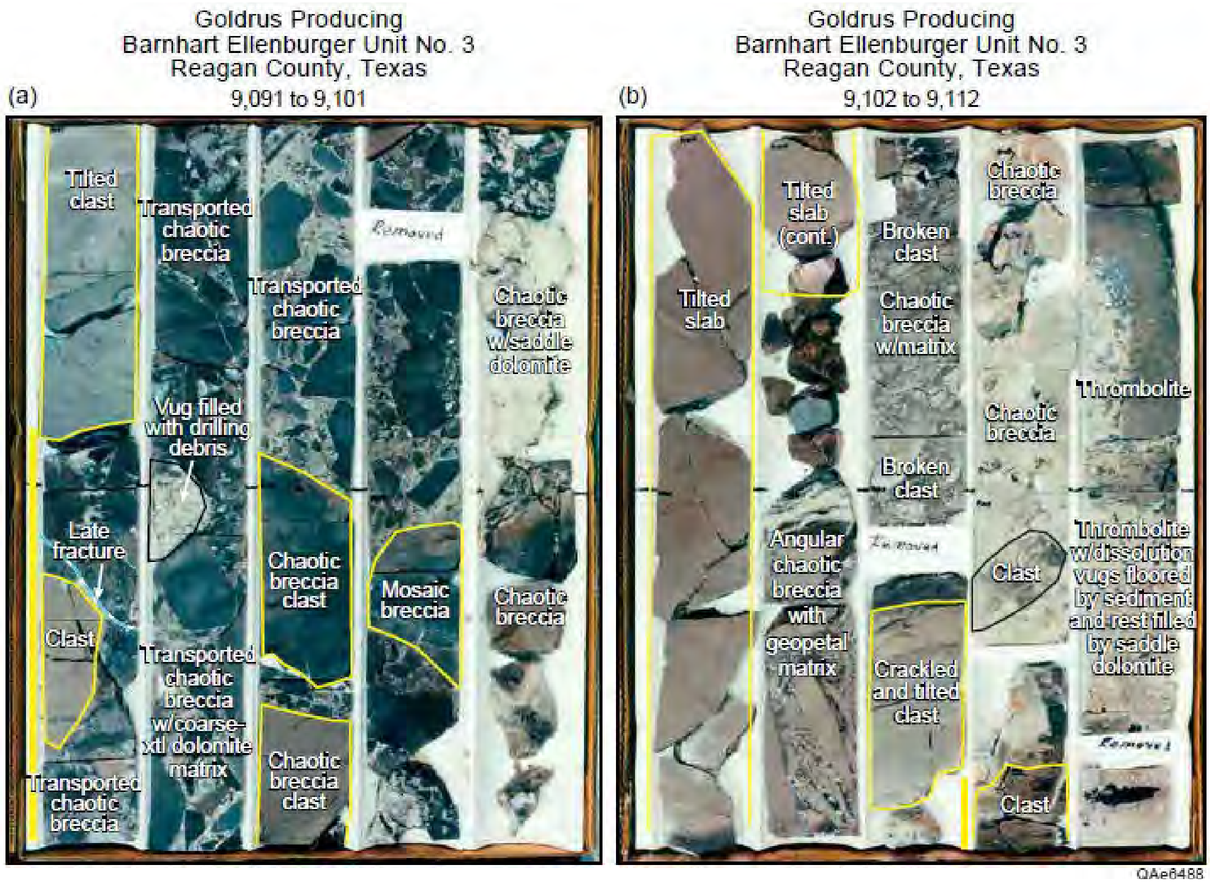


Figure 1-62: Ellenburger Paleocave Facies

Copied from Loucks and Kerans 2019, Example of several Ellenburger paleocave facies from Goldrus Producing Company Barnhart Ellenburger Unit No. 3 core in Reagan County, Texas. Larger clasts are outlined in yellow. (a) Debris-flow chaotic breccia in a paleocave passage. Notice that some clasts show crackle brecciation by compaction. (b) Large deformed blocks with crackle-breccia overprint at far-left column and far right

A workflow has been developed for Ellenburger and Devonian rocks using 3D seismic that has been proven effective in the Fort Worth Basin. McDonnell et al. 2007 was able to show that heavily fractured and karsted areas correlated to sag features that were identifiable on 3-D seismic (**Figures 1-63**).

Horizons were mapped only where the reflection was distinct and continuous (assumed unkarsted host rock). Intervening low-amplitude, chaotic reflections are assumed to be paleocave collapse-brecciated zones.

These areas correlated strongly with observed image log data in the Fort Worth Basin. Milestone will use this seismic analysis scheme to enhance the numerical simulation and static geomodel once 3D seismic is acquired.

Additionally, an image log will be run when the well is drilled to determine the quantity, extent and orientation of fractures and then the results will be compared to the pre-drill model from seismic. Whole core will also be obtained to determine fracture width and provide a secondary source of fracture information although the core will not be oriented. This testing scheme detailed in **Section 4.9** through **4.10** should address any unknowns related to the fracture system at the injection location. This information will further be used to refine the static and dynamic simulation model to attempt to determine if the fractures cause any unusual geometries in the plume.

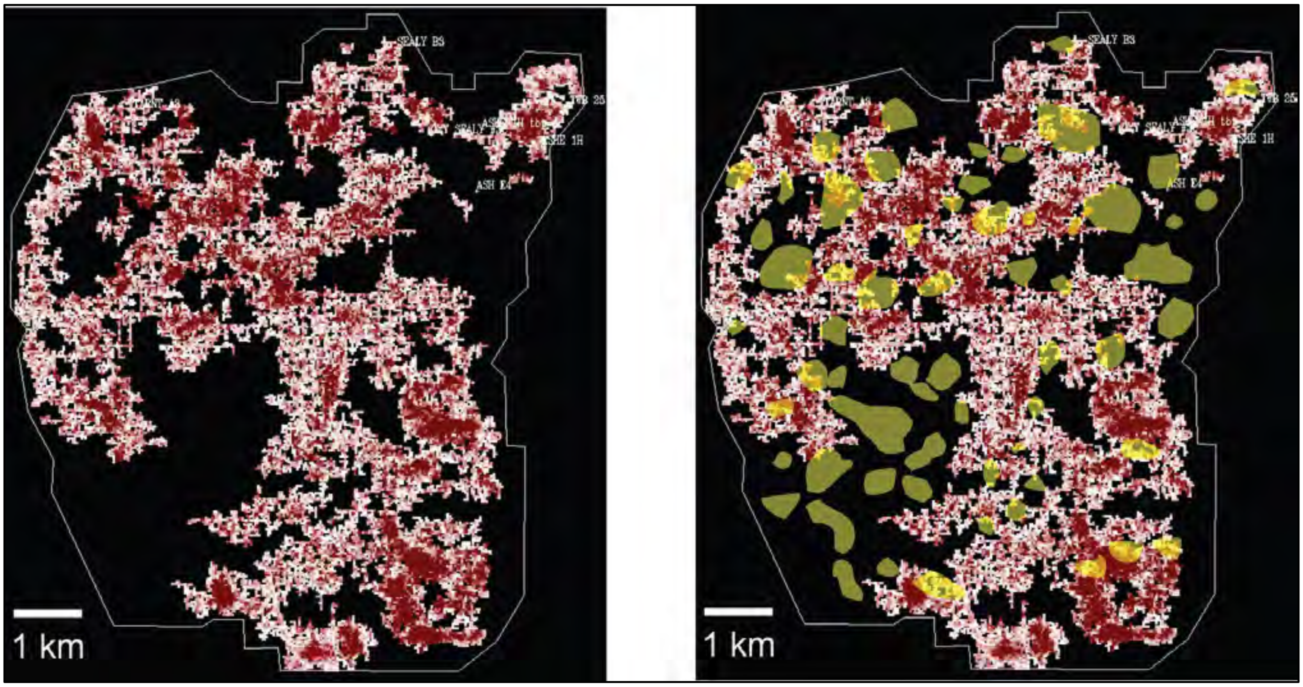


Figure 1-63: Intra-Ellenburger Horizon Amplitude Map

From McDonnell et al. 2007, amplitude map extracted from an intra-Ellenburger horizon. The horizon was mapped only where the reflection was distinct and continuous (assumed unkarsted host rock). (Left) Intervening low-amplitude, chaotic reflections are assumed to be paleocave collapse-brecciated zones. (Right) Overlay of circular sag structure locations shows that they correspond to chaotic Ellenburger zones (i.e., paleocave zones). This suggests a good correlation between collapse feature locations and their causal mechanism

1.8.3 Seismic History [146.82 (a) (3) (v)]

An important consideration in the design and development of all new injection well projects is the determination for the potential of injection activities to induce a seismic event. As shown in more detail below, there is a low probability that seismic activity will interfere with or adversely affect the proposed CCS project.

Studies completed by the United States Geological Survey (USGS) indicate there is a low probability of earthquake events occurring in the Midland Basin of west Texas that would cause damage to infrastructure (**Figure 1-64**) (Geological Survey, 2024). According to the recent updates from the USGS, the proposed Well location is located in a region with the lowest probability of a damaging earthquake in the country.

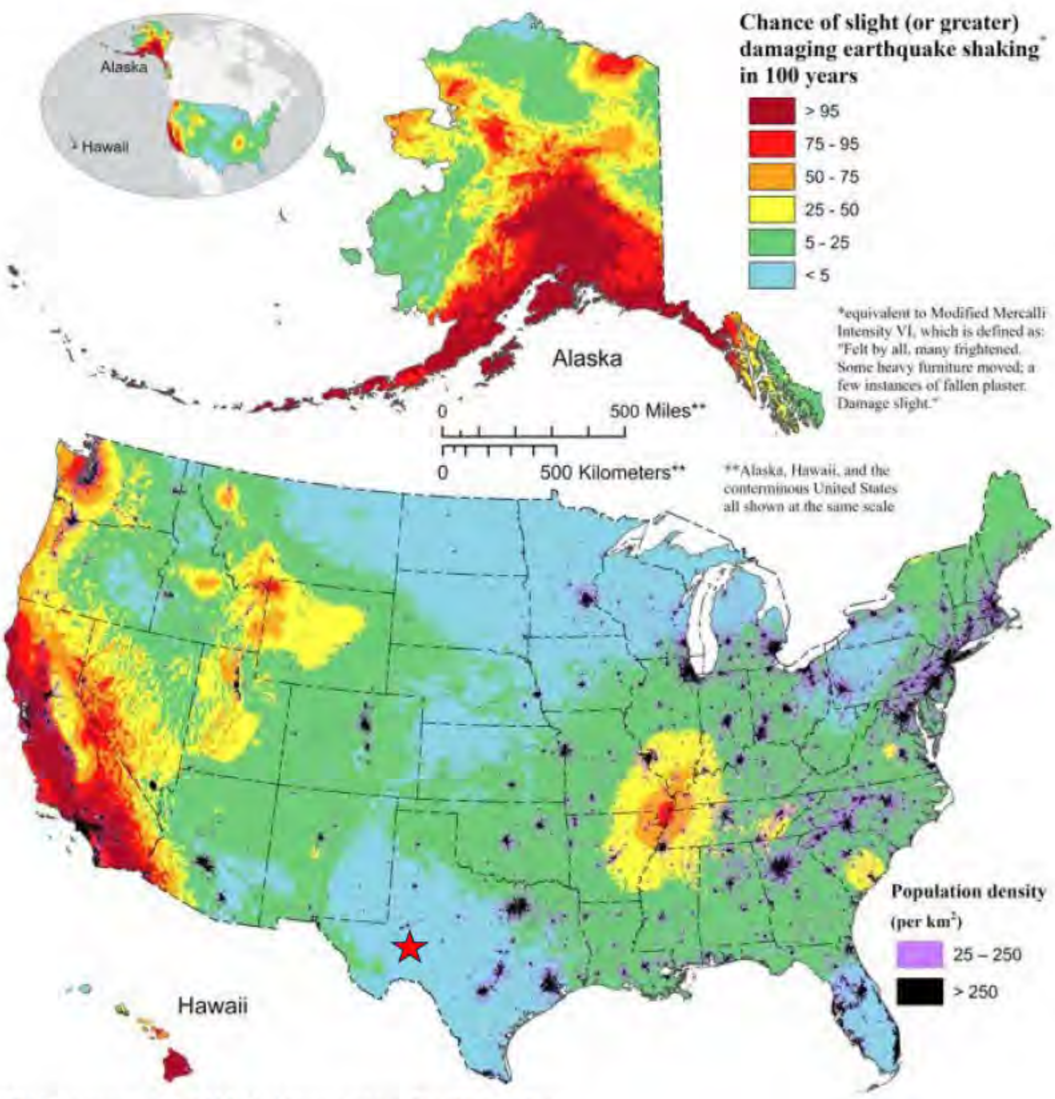


Figure 1-64: Frequency of U.S. Damaging Earthquakes

Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2023). The map illustrates there is a low probability of damaging earthquake events occurring in west Texas area near Midland CCS #2 well (red star).

The USGS also recently updated the Seismic Hazard Map (**Figure 1-65**) in January of 2024. This report illustrates peak ground accelerations having a 2 percent probability of being exceeded in 50 years. The models are based on seismicity and fault-slip rates and take into account the frequency of earthquakes of various magnitudes. The map illustrates that the Midland CCS #2 location was within a region with one of the lowest hazard probabilities within the country.

The Permian Basin is a tectonically stable region of the North American Craton. Most of the relatively larger earthquakes in Texas are associated with the major geological faults and uplifts (**Figure 1-66**). The proposed Facility sits in the middle of Texas and far away from any of these relatively large historical earthquakes.

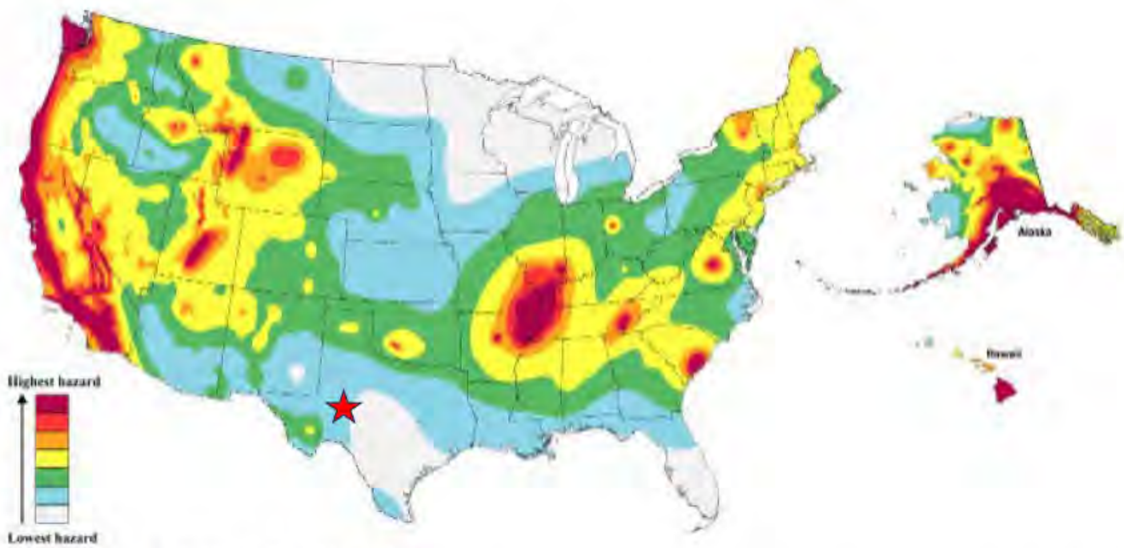


Figure 1-65: USGS Seismic Hazard Map
Hazard map is a simplified 2% in 50-year probability of exceedance map (U.S. Geological Survey, 2024). Red star illustrates the approximate location of Midland CCS #2 Well.

Texas has several distinct structural regions, each with different fault orientations, ages, and architecture (**Figure 1-66**). The Midland CCS #2 Well lies within the Midland Basin, which can be considered part of the Basin and Range province of Texas, distinct from other regions such as the Gulf Coast.

The Basin and Range province of West Texas, in the center of the North American Craton, has fault systems related to past orogenic events and is currently being stressed by several mountain ranges to the west including the Franklin Mountains, the Guadalupe Mountains, the Sacramento Mountains and smaller ranges and the Ouachita-Marathon Thrust belt to the south. The Ouachita-Marathon thrust belt forms the northern terminus of the Balcones Fault Zone and is noted in purple. Mountain ranges are noted in red, yellow, and orange on the USGS map relating to damaging earthquakes. These are to the west of the facility (**Figure 1-65**).

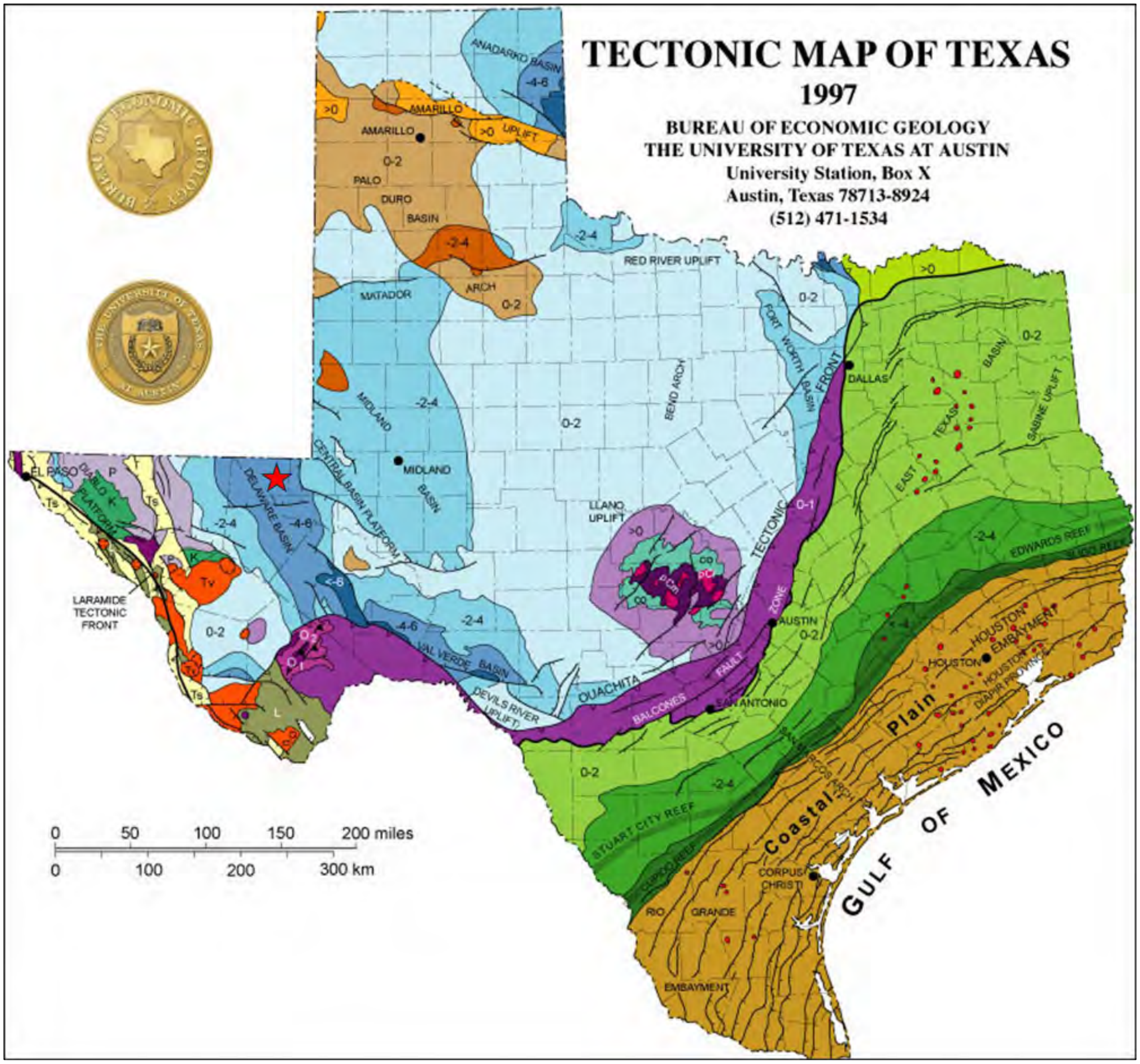


Figure 1-66: Tectonic Map of Texas
Tectonic map of Texas, BEG 1997 illustrating the major structural features of the state.

The local region of the Midland Basin has two Seismic Response Areas (SRA's) north of the location (**Figure 1-67**). The Gardendale Seismic Response Area and the Stanton Seismic Response Area. Both are associated with significant faulting and heavy SWD injection.

Milestone has strategically avoided these areas of high faulting and high seismicity. The Midland CCS #2 well is located over 21 miles away from the nearest SRA, the Gardendale SRA and even farther away from the earthquake swarms of more intense earthquake activity. No earthquake swarms are located within or near the AoR.

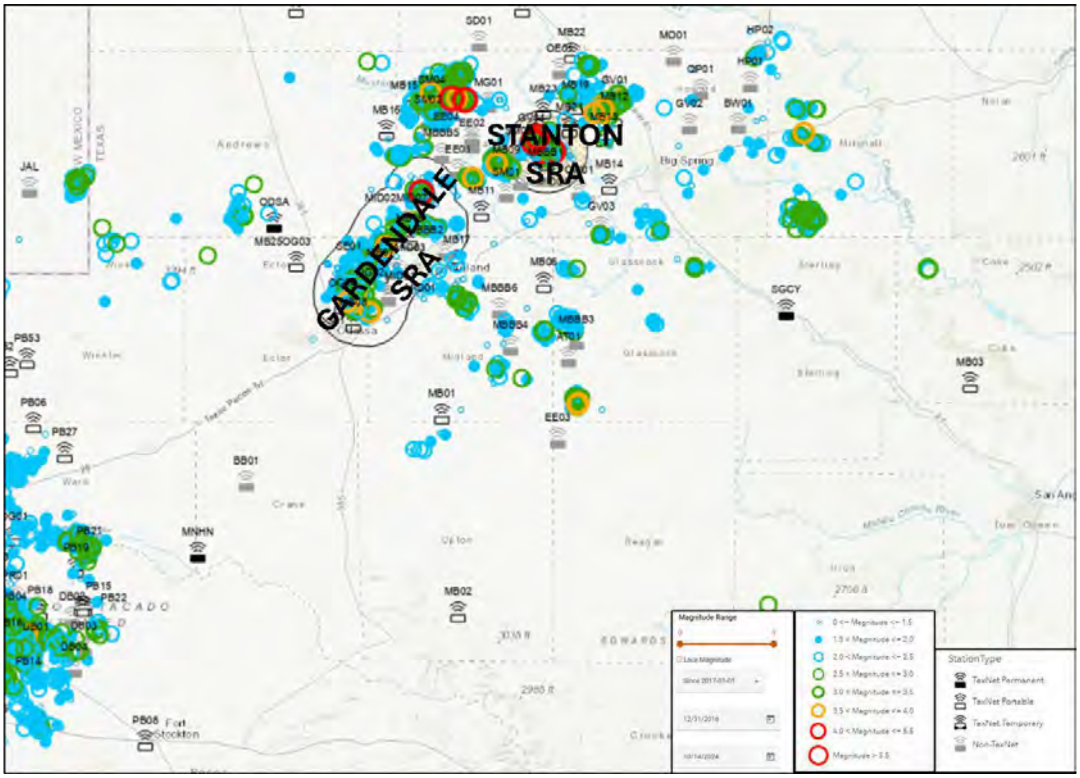


Figure 1-67: TexNet Earthquake Catalog – Nearest SRA
Updated from TexNet to illustrate all earthquakes and SRA's in the area. The Gardendale SRA is located over 21 miles from the Midland CCS #2 location and over 40 miles from the Stanton SRA.

In the area close to the South Midland Facility, Texas Seismological Network and Seismology Research (TexNet) earthquake catalog search shows very little earthquake activity near the proposed injection site (**Figure 1-68**). According to TexNet, an earthquake catalog, there have been 10 earthquakes reported within a 10-mile radius since 2016, the inception of the catalog (**Figure 1-69**). A detailed look at the most recent earthquakes within that radius is illustrated in **Figure 1-70**. Both events were deep in the Precambrian basement, at 1.1 and 1.2 magnitudes and approximately 10km away. These recent earthquakes are likely due to injection into shallower intervals in the region.

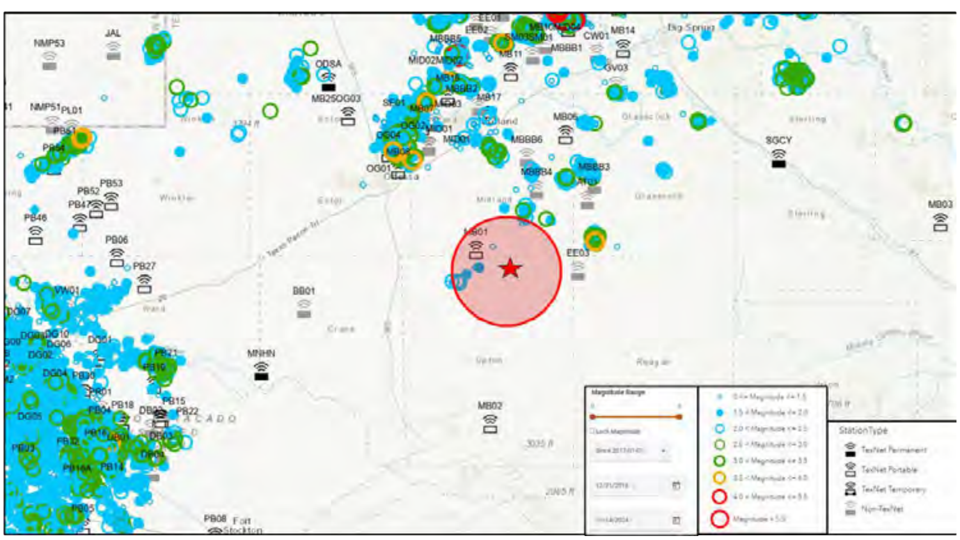


Figure 1-68: West Texas Earthquake Catalog
TexNet Earthquake Catalog query shows the earthquake (M2+) 2016-2023 in the area near Midland CCS #2 Well (red star). (https://www.beg.utexas.edu/texnet-cisr/texnet/earthquake-catalog)

Date / Time		Magnitude	Region Name	Latitude (WGS84)	Latitude Error (km)	Longitude (WGS84)	Longitude Error (km)	Depth (Km. MSL)	Depth (Km. Surface)	Depth Uncertainty
9/23/2024	1:31:10	1.1	Western Texas	31.6214	0.6	-102.0871	0.7	7.3	8.1	1.3
9/3/2024	17:43:34	2	Western Texas	31.5793	0.5	-102.1343	0.5	9.5	10.4	1.2
8/30/2024	2:23:44	1.2	Western Texas	31.6141	0.8	-102.0721	0.4	5.6	6.5	1.6
7/8/2024	9:27:30	1	Western Texas	31.7386	0.5	-101.937	0.4	8.2	9	2.1
4/17/2024	3:42:23	1.4	Western Texas	31.6223	0.4	-102.0689	0.5	5.8	6.6	0.9
2/10/2024	14:40:38	1.2	Western Texas	31.6763	0.4	-102.0292	0.4	7.3	8.1	1.3
1/11/2024	0:19:11	1.7	Western Texas	31.6013	0.7	-102.1128	0.8	13.4	14.2	1.9
10/19/2022	23:53:46	1.9	Western Texas	31.6196	0.5	-102.0742	0.7	5.8	6.7	1.9
3/9/2022	4:22:39	2	Western Texas	31.5829	0.6	-102.1428	0.8	8.8	9.7	1.9

Figure 1-69: Earthquake Catalog 10 miles of Midland CCS #2
TexNet Earthquake Catalog information on all earthquakes within a 10-mile radius of Midland CCS #2 well. (https://www.beg.utexas.edu/texnet-cisr/texnet/earthquake-catalog).

Event Evaluation Status	final
Event ID	texnet2024sscy
Origin Time	2024-09-23 01:31:10 GMT+0
Origin Time (Client Local)	2024-09-22 20:31:10 GMT-5
Location	31.6214° N 102.0871° W
Nearest City	
Depth (Relative to MSL)	7.3 km / 23,800 ft.
Depth (Relative to Ground Surface)	8.1 km / 26,600 ft.
Local Magnitude	1.1
Mode	ML(TexNet)
Maximum Station Distance (km)	119.9
Minimum Station Distance (km)	5.2

Event Evaluation Status	final
Event ID	texnet2024rain
Origin Time	2024-08-30 02:23:44 GMT+0
Origin Time (Client Local)	2024-08-29 21:23:44 GMT-5
Location	31.6141° N 102.0721° W
Nearest City	
Depth (Relative to MSL)	5.6 km / 18,500 ft.
Depth (Relative to Ground Surface)	6.5 km / 21,300 ft.
Local Magnitude	1.2
Mode	ML(TexNet)
Maximum Station Distance (km)	138.6
Minimum Station Distance (km)	6.1

Figure 1-70: Recent earthquakes in Upton County west of Midland CCS#2
TexNet Earthquake Catalog information on the 2 earthquakes about 6.85mi and 5.75mi respectively to the west of Midland CCS #2 well. (https://www.beg.utexas.edu/texnet-cisr/texnet/earthquake-catalog). Both events are deeper earthquakes in the Precambrian basement and much deeper than the Midland CCS #2 injection well.

1.8.4 Regional Stress

The stress regime and maximum horizontal stress orientation is well-studied and understood in west Texas area. **Figure 1-71** displays the regional stress map. At the location of the Well (red star image on the map), the stress regime is characterized by normal faulting, and the maximum horizontal stress is E-W.

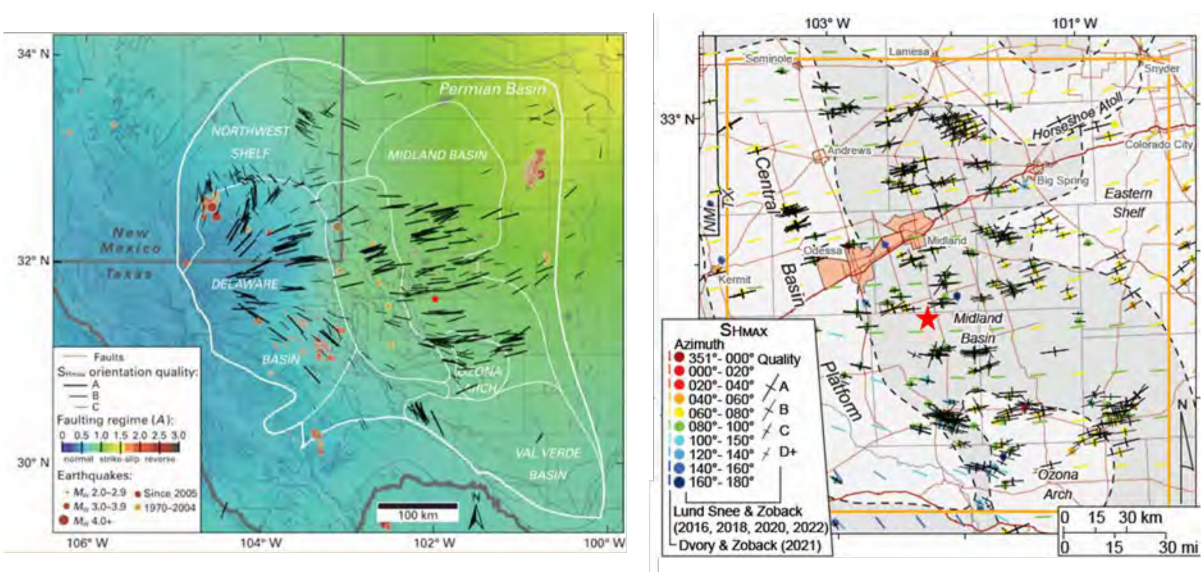


Figure 1-71: West Texas Stress Map
Regional stress map of west Texas, around region of proposed Midland CCS #2 well location (indicated with red star). Normal fault stress regime, and the maximum horizontal stress orientation is E-W (Lund Snee & Zoback, American Geophysical Union, Fall Meeting 2018, abstract #S32A-02).

1.8.5 Fault Slippage Potential Analysis

This section contains a fault slippage potential (FSP) analysis to examine the potential of fault movement caused by an increase in reservoir pressure due to CO_2 injection at the Well. The analysis determined that all nearby faults were very unlikely to move with the estimated <1,598 psi increase in pressure at the wellbore and less than 730 psi at the fault planes. Meanwhile no fault proximal to the injection well has a deterministic slippage pressure of less than 1,900 psi. Ergo there is approximately 1,000 psi or greater difference from the pressure exerted on the faults and the pressure required for the faults to slip. Allegorical historical evidence of this stability is shown by saltwater disposal wells (SWD) very close to faults in the region that has failed to generate any detectable seismicity.

1.8.5.1 Ellenburger Fault Slippage Analysis

Milestone created a two-dimensional (2D) fault slippage potential (FSP) to analyze the pore pressure increase needed to cause the fault slip. **Table 1-9** shows the input parameters used in the Ellenburger FSP model based on current understanding of the regional stress. This model will be updated based on well testing results during the drilling and completion process of the Well.

Figure 1-72 illustrates the localized structure of the Top of the Ellenburger in subsea, ft.. Smoothing may be due to lack of data in some areas. Ellenburger and basement are the least often penetrated intervals in the basin. Regional faults are mainly oriented NNW-SSE and E-NE. There are several faults near the well. The nearest fault is north of the Injection well, 8,500 feet north of the well. The next closest fault is south of the injection well, 10,575 feet south of the Injection Well. All faults near the well are strike-slip faults and are less likely to move with the current day normal faulting regime.

Table 1-9: Input Parameters for Ellenburger FSP Model.

Description (Units)	Model Input Values
Vertical Stress Gradient (psi/foot, psi/ft)	1.1
Max Horizontal Stress Gradient (psi/ft)	0.95
Min Horizontal Stress Gradient (psi/ft)	0.715
Max Horizontal Stress Direction (deg N CW)	79
Initial Reservoir Pressure Gradient (psi/ft)	0.45
Reference Depth for Calculation (ft)	13,066

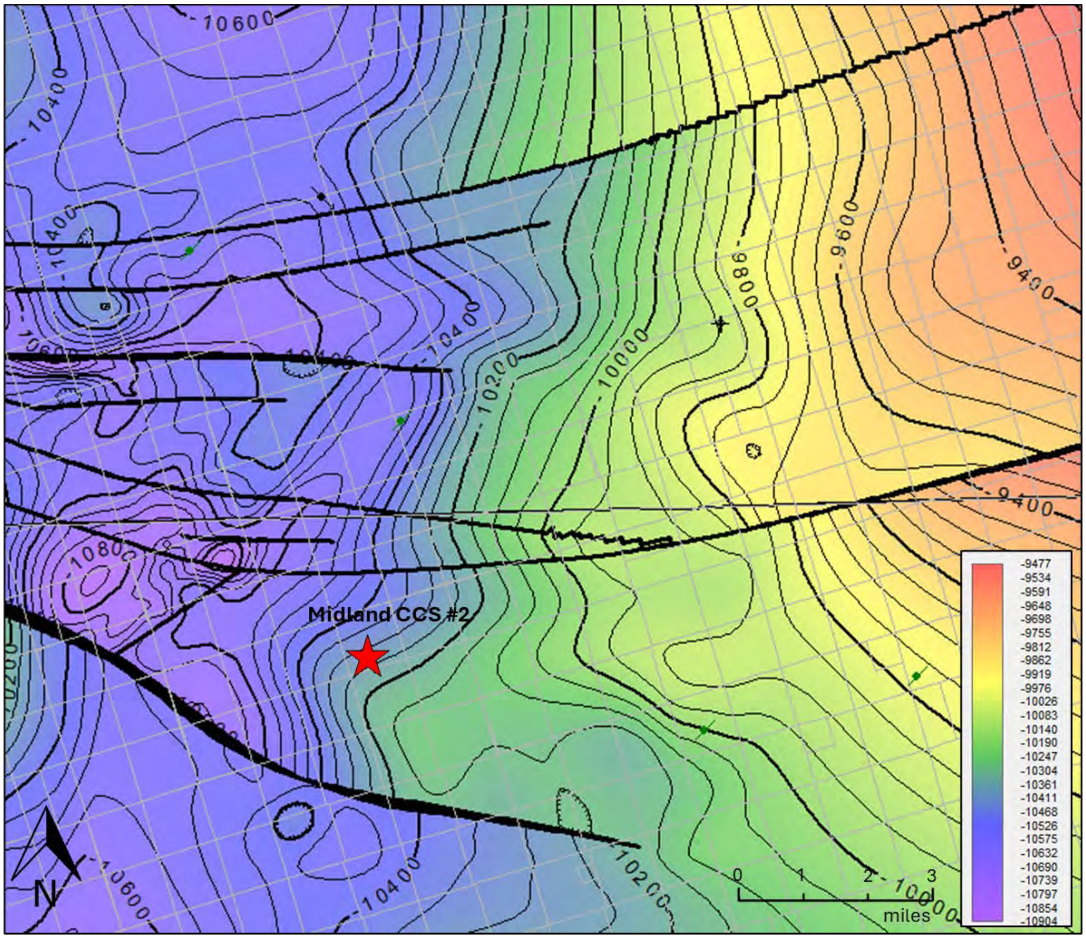


Figure 1-72: Top of Ellenburger Structure
Localized structure of the Top of the Ellenburger in subsea, ft.. Smoothing may be due to lack of data to the east of the wellbore. Ellenburger and Basement are the least often penetrated interval. Local faulting to the east of the CBP tends to orient W-E.

Figure 1-73 illustrates the faults by index reference number used in the FSP model and **Table 1-10** inventories the average fault properties with the same index number. The bearings, dip and length were extracted from the fault shapefile in Arc GIS. In some cases a long fault with changes in strike was broken into multiple segments, such as fault 1,2,3,and 4, which are all the same fault but broken up into four segments to account for changes in strike.

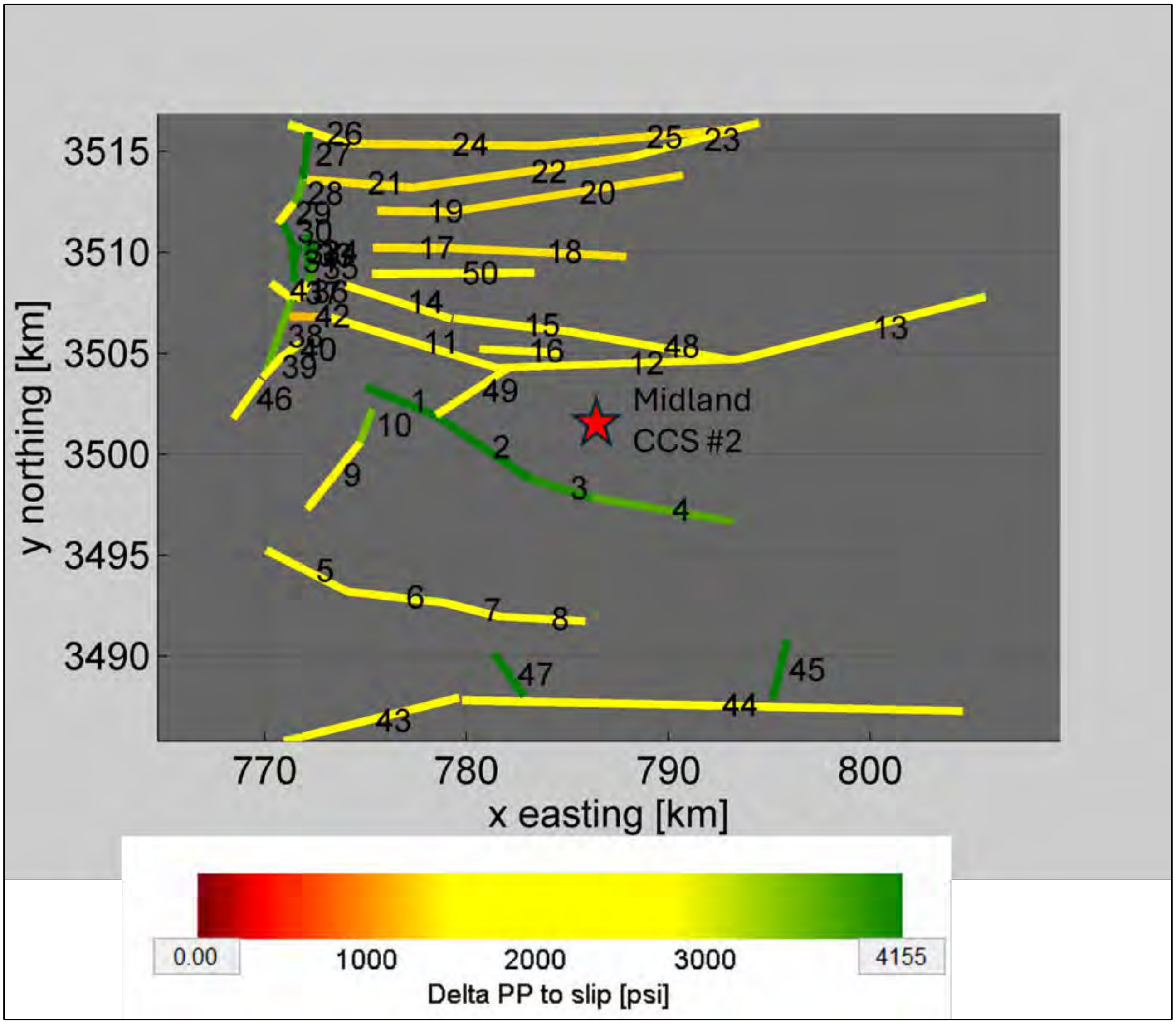


Figure 1-73: Ellenburger Fault Index Number for FSP Analysis
Red Star is Midland CCS #2 Location

Figure 1-74 illustrates the Mohr-Circle FSP deterministic analysis for Ellenburger faults and pore pressure increase needed for the Ellenburger faults to slip. The fault (#12) nearest to the Well (red star) requires an estimated 1,902 psi increase in pore pressure to slip, which is unlikely to be reached because the increase in reservoir pressure from injection activities is only estimated to raise it by 621 psi in any cell along that fault. The next nearest fault (#3) to the south requires an estimated 3,966 psi in pore pressure to slip. The fault to the south (#3) slip pressure is so much higher due to a much flatter dip of 31 degrees compared to nearby faults which are generally steeply dipping. Also unlikely to be reached due to the increase in pore pressure along the fault having a maximum value of 827 psi. NNW-SSE faults (green) in the region are the least likely to slip due to their orientation being perpendicular to current day max stress field. These faults have slip pressures of >3,000 psi in most cases. **Figure 1-75** shows the stereonet of fault poles with slippage pressures colored.

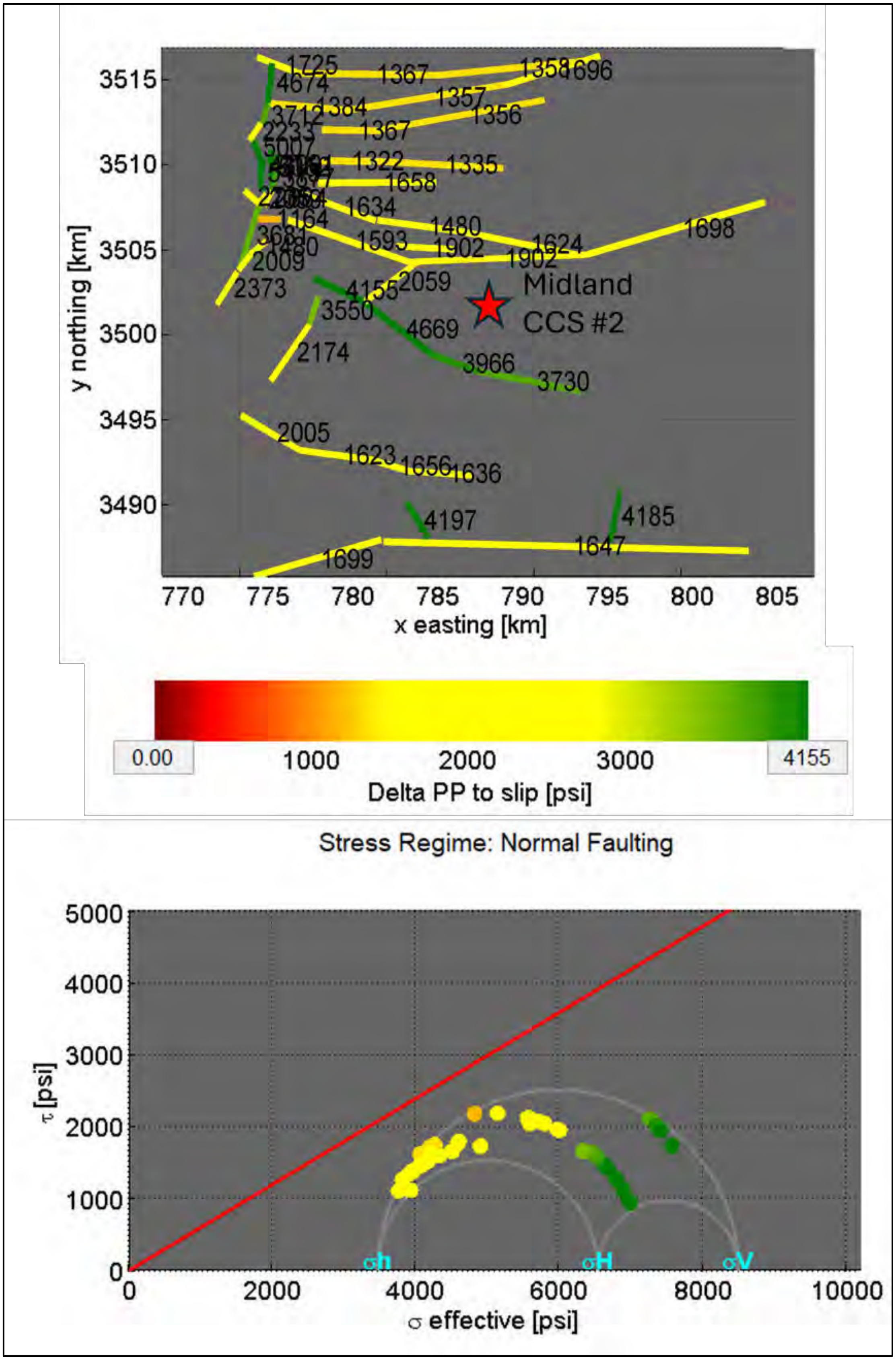


Figure 1-74: Ellenburger Faults Mohr-Circle FSP Analysis

Deterministic Mohr-Circle FSP analysis for Ellenburger faults. Pore pressure increase required for the Ellenburger faults to slip. Red Star is Midland CCS #2 Location

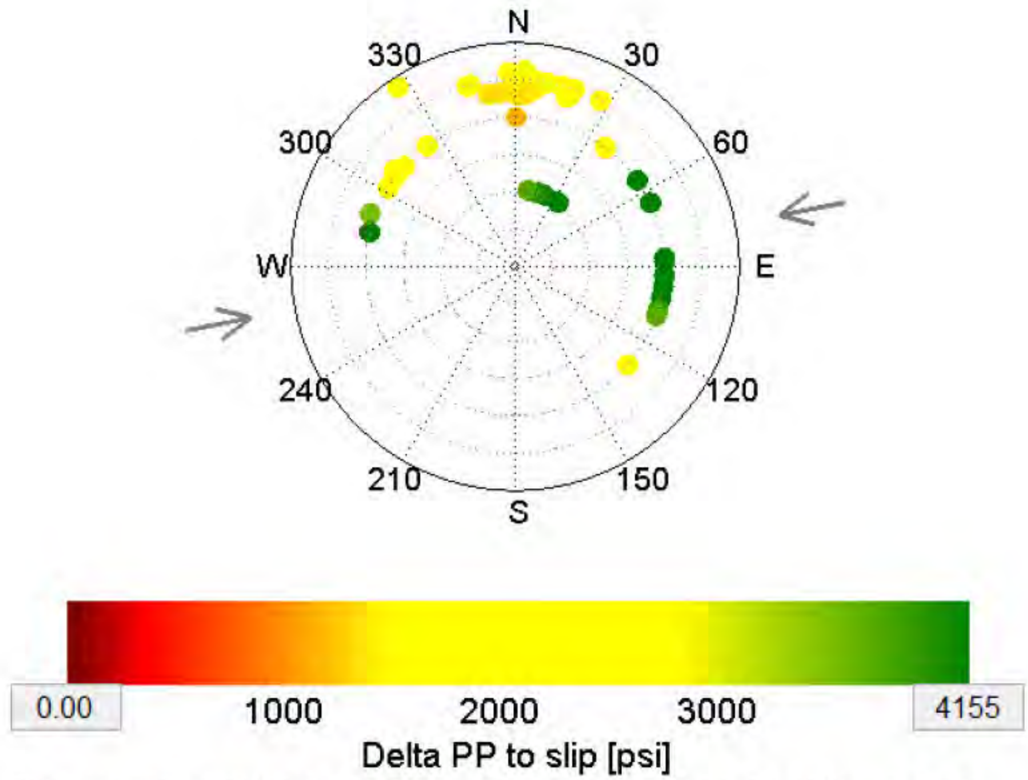


Figure 1-75: Ellenburger Faults Mohr-Circle FSP Analysis Stereonet of Fault Normal Poles
Fault poles colored by deterministic FSP slip pressure

Table 1-10 illustrates the values used in a probabilistic FSP analysis of the faults in the area using values published in Horne et al., 2024 for error ranges on the properties.

Table 1-10: Input Parameters for Probabilistic Ellenburger FSP Model.

Description (Units)	Model Input Values	Plus/Minus
Vertical Stress Gradient (psi/ft)	1.1	0.02
Max Horizontal Stress Gradient (psi/ft)	0.95	0.1
Min Horizontal Stress Gradient (psi/ft)	0.715	0.05
Max Horizontal Stress Direction (deg N CW)	79	7.5
Initial Reservoir Pressure Gradient (psi/ft)	0.45	0.03
Reference Depth for Calculation (ft)	13,066	0
Frictional Coefficient Mu	0.6	0.05
Dip Angle (degrees)	Variable, 70 avg	10
Strike Angle (degrees)	Variable, 105 avg	5

Table 1-11 illustrates the results of the Ellenburger probabilistic FSP analysis. The P10, P50, P90 pressures for each fault segment are shown, with the calculated maximum pressure in the nearest grid cells. Using the output percentiles, a chance to slip was calculated for each fault based on the maximum incremental pressure from the simulator along each fault. This is also displayed in the table. No faults in the Ellenburger have a fault slip chance of greater than 7.5%. Faults too far away to be influenced by injection have max delta P of 0 psi and a corresponding 0% chance. Fault #48 has the highest slip % chance. This is in part due to modeled class II SWD injection along that fault that was included in the simulation as #48 is not the most proximal fault to the injection well. Offset SWD wells injection rates and the Midland AGI #5 rate of 375 KtA were included in the simulation. Fault #12 and #49 are the closest to the injection well that are likely to slip at 3.3% and 1.9% slip chance respectively.

Table 1-11: Results of Ellenburger Probabilistic FSP Model

Fault Number	Strike	Dip	Length	P10 Slip P	P50 Slip P	P90 Slip P	Max Delta P	Chance to Slip
#	degrees	degrees	km	psi	psi	psi	psi	%
1	112.42	31	3.7171	2932.5	4229	5401.9	108.8	0
2	123.86	31	5.5064	3607.3	4652.8	5716.7	729.3	0
3	107.36	31	3.2118	2838.5	3959	5181.3	827.5	0
4	99.62	31	7.0468	2555.8	3776.1	4986.6	513.6	0
5	117.21	75	4.4953	1161.5	1978.8	2855.7	0.0	0
6	96.67	75	5.0156	710.81	1592.5	2509.7	0.0	0
7	104.35	75	2.6772	770.05	1648.7	2532.2	0.0	0
8	93.05	75	4.2319	816.57	1721	2577.9	0.0	0
9	38.43	62	4.2234	1323.2	2233.6	3063.1	0.0	0
10	20.16	62	1.736	2623.6	3487.8	4432.8	11.1	0
11	106.79	71	8.5863	756.05	1617.8	2475.6	93.4	0.4
12	88.03	78	12.092	952.06	1924.1	2869.5	621.6	3.3
13	75.68	75	12.496	760.6	1748.3	2656.8	191.8	1.2
14	107.61	72	5.4604	839.07	1676.8	2489.3	73.9	0.2
15	96.57	72	6.0936	641.9	1554.7	2369.2	334.4	2.7
16	92.87	79	3.9461	884.67	1961.9	2857.8	326.9	1.2
17	90.25	69	3.5661	517.84	1396.3	2249	163.2	2.4
18	92.73	69	8.8265	576.12	1450.4	2285.5	466.3	6.8
19	90.74	70	3.9823	555.92	1429.6	2278.4	181.0	2.7
20	81.08	70	11.332	526.54	1412.5	2299.1	327.2	5.3
21	94.36	70	5.4243	622.87	1509.7	2301.4	0.0	0
22	81.94	70	10.895	553.99	1469.2	2356.7	97.6	2.0
23	75.07	75	6.5548	792.75	1755.9	2629.7	83.0	0.7
24	90.6	70	9.5409	553.08	1449.8	2267.5	52.0	1.0
25	85.2	70	9.7143	536.93	1513.7	2317.6	84.8	1.8
26	108.6	75	3.0292	857.08	1732.2	2633.1	0.0	0
27	187.56	60	2.3416	3497.2	4512.3	5755.2	0.0	0
28	198.84	60	1.4364	2749	3685.8	4646.4	0.0	0
29	38.27	60	1.2563	1380.7	2272	3041.2	0.0	0
30	154.73	60	0.9162	3768.1	4886.7	6155	0.0	0
31	176.7	60	2.0846	3945.6	5364.3	6714.3	0.0	0
32	192.02	60	0.8363	3240.6	4174.1	5321.7	0.0	0
33	177.89	60	2.0583	3956.5	5264.7	6685.6	0.0	0
34	183.48	60	1.2498	3698.7	4932.8	6235.3	0.0	0
35	196.92	60	1.5803	2933.4	3812.4	4871.7	0.0	0
36	31.61	60	0.9984	1870	2739.6	3574	0.0	0
37	221.19	60	0.8408	1266.2	2158.3	2900.4	0.0	0
38	199.2	60	3.8744	2734.9	3622.1	4626.6	0.0	0
39	42.09	60	1.3886	1150.9	2080.3	2870.9	0.0	0

Fault Number	Strike	Dip	Length	P10 Slip P	P50 Slip P	P90 Slip P	Max Delta P	Chance to Slip
#	degrees	degrees	km	psi	psi	psi	psi	%
40	53.94	60	1.1624	632.03	1545.8	2399.5	0.0	0
41	127.08	60	1.2183	1868.5	2756.6	3595.9	0.0	0
42	90.4	60	1.5675	380.53	1217	2077.9	0.0	0
43	76.01	75	9.4737	737.81	1766.4	2701.3	0.0	0
44	91.26	75	24.803	713.72	1682.1	2602.6	0.0	0
45	13.36	60	3.0825	3200.3	4106.5	5250.2	0.0	0
46	36.09	60	2.3508	1506.3	2374.3	3198.6	0.0	0
47	144.77	60	2.5763	3116.3	4140.1	5194.1	0.0	0
48	99.86	75	7.9421	711.21	1633.4	2542.4	632.9	7.5
49	56.78	86	4.3105	1106.5	2049.9	2884.8	638.2	1.9
50	89.59	75	8.0139	759.53	1694.2	2651	295.2	2.0

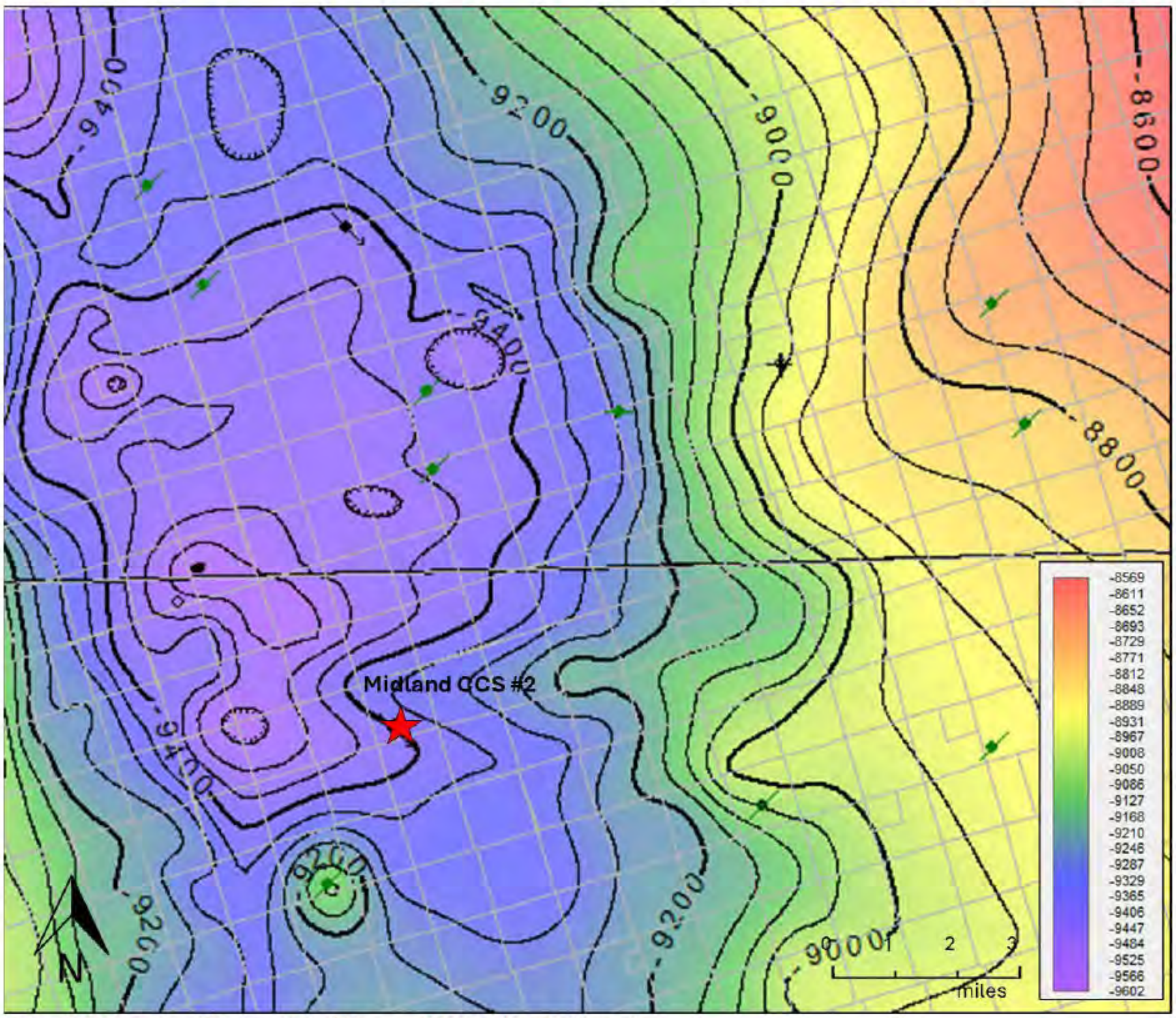


Figure 1-76: Top of Devonian / Base of Woodford Structure

Localized structure of the top of the Devonian section and base of the Woodford Shale in subsea, ft. The base of the Woodford is the primary seal. Note the lack of faults that cut the surface.

1.8.5.2 Siluro-Devonian Fault Slippage Analysis

Figure 1-76 illustrates the structure at the top of the injection interval, Siluro-Devonian top, in subsea, ft. which is un-faulted because no faults extend into the Woodford Shale in the area**. Figure 1-77** illustrates the localized structure of the top of the Wristen Group (Silurian top) in subsea, ft. which does include faults in the Siluro-Devonian injection interval. Most of the faults from the Ellenburger and Basement extend up into the Siluro-Devonian interval and terminate in the Devonian directly above the Wristen Group top. The faults do not cut the Woodford shale (top-seal). (**Fig. 1-76**) Like in the Ellenburger, regional faults are mainly oriented NNW-SSE and E-NE. The Wristen Group is approximately the midpoint of the Siluro-Devonian Injection Unit, so it is ideal for a FSP analysis.

Notable faults that terminate in the Simpson group, below the Siluro-Devonian Injection unit, are faults #49 and #50 from the Ellenburger analysis. (**Table 1-11** and **Fig. 1-78**) These two faults are not included in the Siluro-Devonian FSP because they have not been observed to exist within the injection unit on available seismic data.

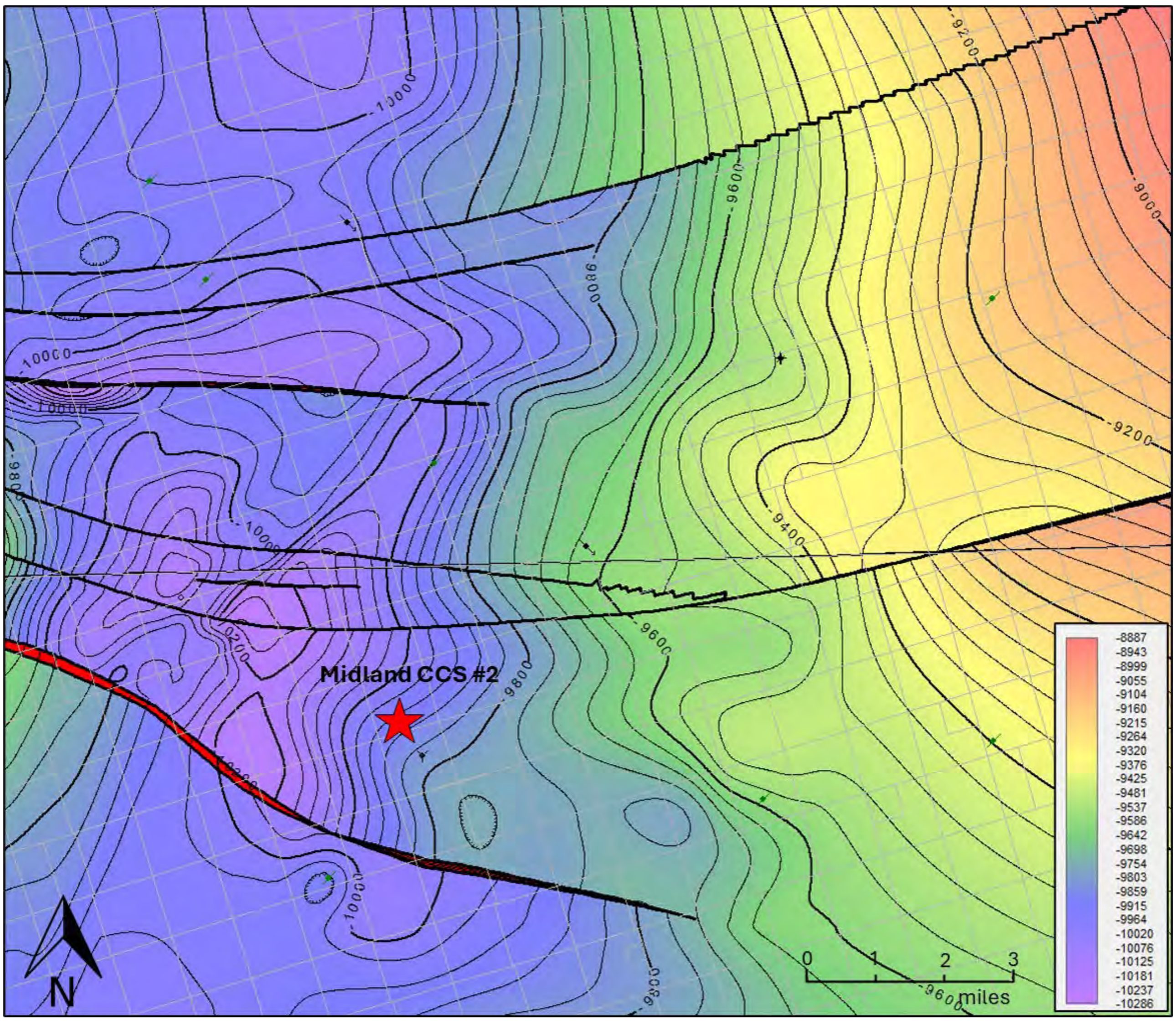


Figure 1-77: Structure - Top of the Wristen Group

The Wristen Group is approximately the midpoint of the Siluro-Devonian injection unit. It is also the last surface where all the Siluro-Devonian faults exist before they terminate vertically. Contour Interval = 50 ft Red star denotes the location of the Injection Well

Milestone created a 2D FSP to analyze the pore pressure increase needed to cause the fault slip.

Table 1-12 presents the input parameters used in the Devonian FSP model based on current understanding of the regional stress. This model will be updated based on well testing results during the drilling and completion process of the Well. The minimum horizontal stress used in the FSP model is the weighted average of all the formations in the Siluro-Devonian Injection Unit. The calculated weighted average for the entire injection unit is 0.730888 psi/ft, ergo 0.731 was utilized.

Table 1-12: Input Parameters for Devonian FSP Model

Description (Units)	Model Input Values
Vertical Stress Gradient (psi/ft)	1.1
Max Horizontal Stress Gradient (psi/ft)	0.95
Min Horizontal Stress Gradient (psi/ft)	0.731
Max Horizontal Stress Direction (deg N CW)	79
Initial Reservoir Pressure Gradient (psi/ft)	0.45
Reference Depth for Calculation (ft)	12,703

Figure 1-78 illustrates the faults by index reference number used in the FSP model and **Table 1-10** inventories the average fault properties with the same index number. The bearings, dip and length were extracted from the fault shapefile in Arc GIS. In some cases a long fault with changes in strike was broken into multiple segments, such as fault 1,2,3, and 4, which are all the same fault but broken up into four segments to account for changes in strike.

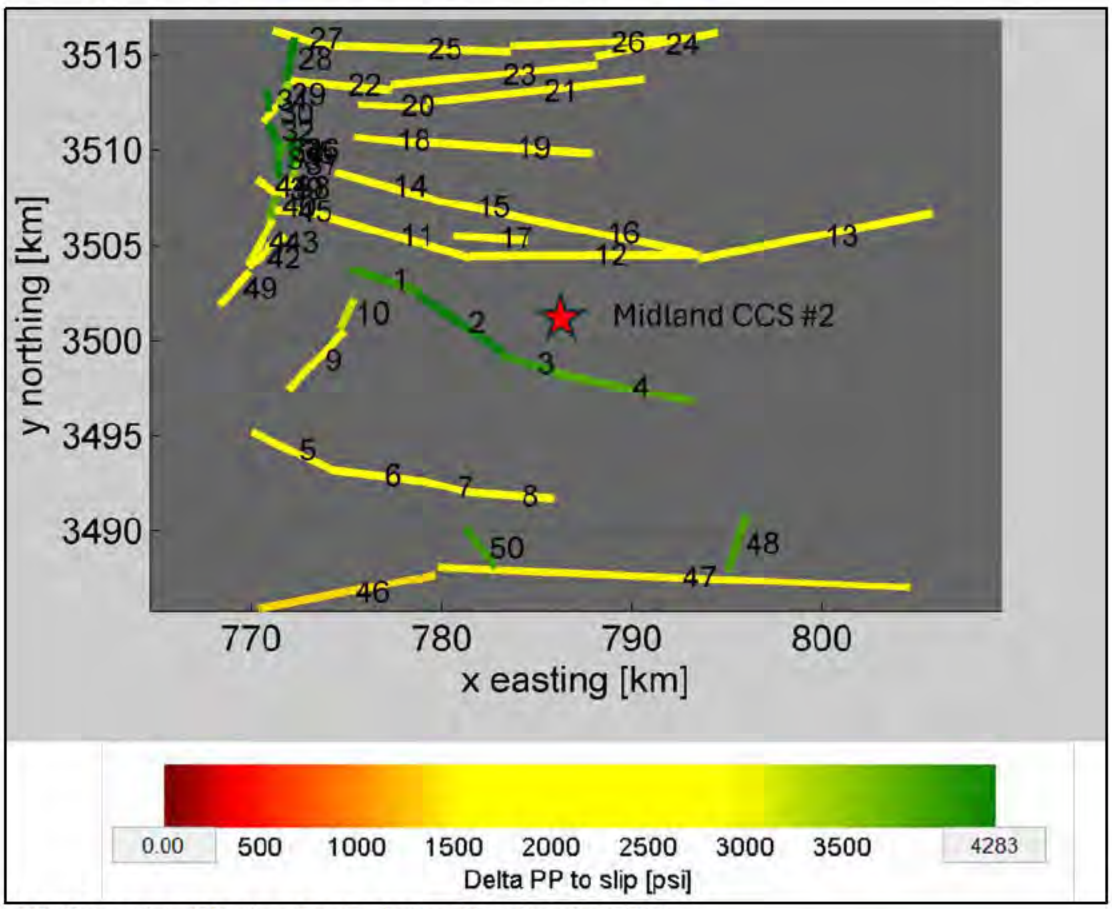


Figure 1-78: Devonian-Silurian Faults Index Number for FSP
Red star denotes the location of the Injection Well, Faults indexed like those found in Ellenburger FSP

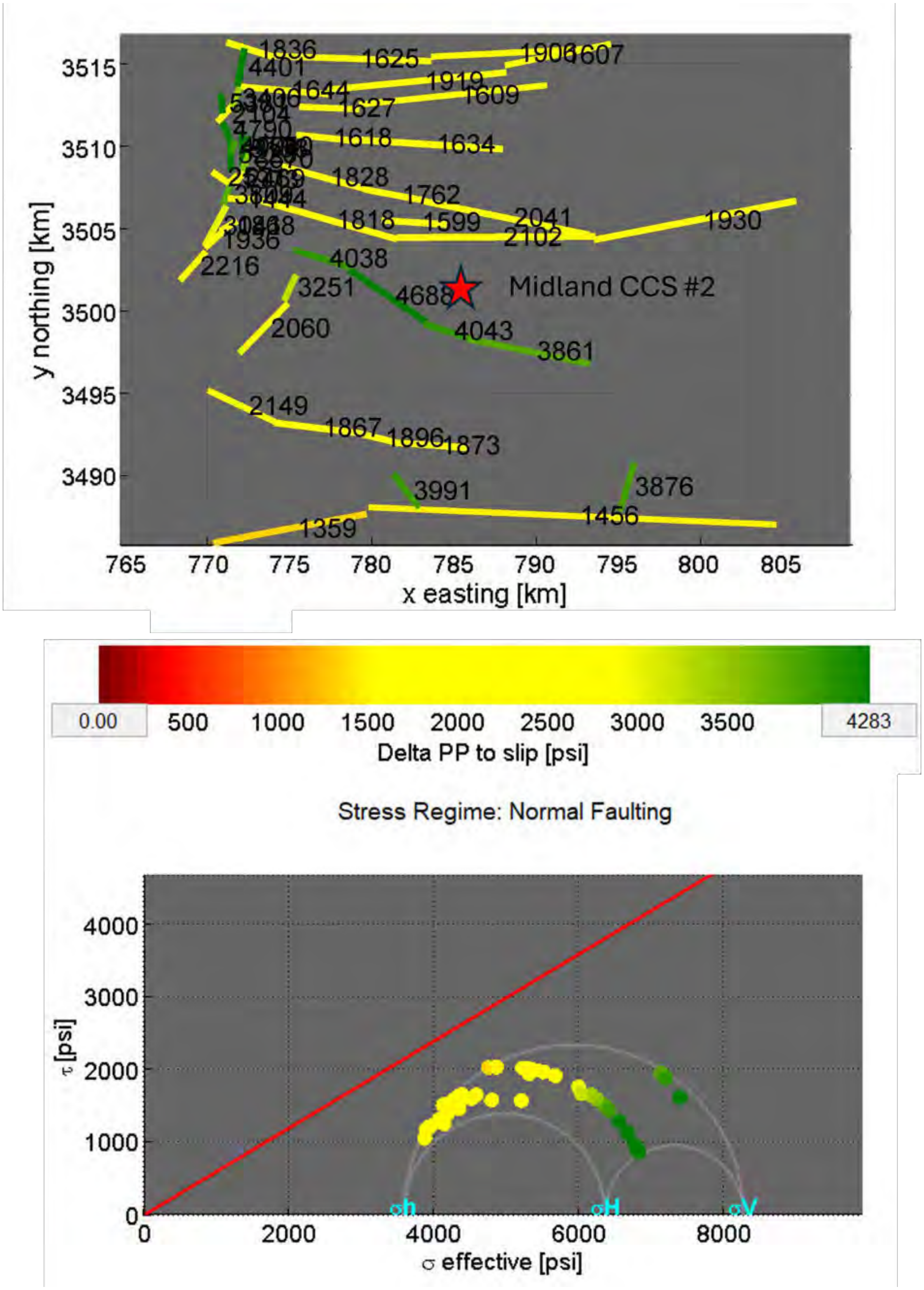


Figure 1-79: Siluro-Devonian Faults Mohr-Circle FSP Analysis

Deterministic Mohr-Circle FSP analysis for Siluro-Devonian faults. Pore pressure increase required for the Siluro-Devonian faults to slip. Red Star is Midland CCS #2 Location

Figure 1-80 illustrates the FSP results for the Siluro-Devonian. Regional faults are mainly oriented NNW-SSE and E-NE. At the Siluro-Devonian level, there are several faults near the well. The nearest fault is north of the Injection well 8,800 feet north of the well, fault segment #12 (**Fig. 1-78**). The next closest fault is south of the injection well, 10,088 feet south of the Injection Well, fault segment #3 (**Fig. 1-78**). All faults near the well are strike-slip faults and are less likely to move with the current day normal faulting regime

Fault segment #12, the nearest fault has a deterministic pressure to slip of 2,102 psi. Fault segment #3 the second closest fault has a deterministic pressure to slip of 4,403 psi. No fault in the Siluro-Devonian is expected to slip with the highest incremental pressure increase equal to 600 psi. The incremental pressure increase compared to the slip pressure at each fault segment still leaves a large amount of pressure capacity before any slippage is likely to occur. Fault segments #1,2,3 and 4 have higher pressure to slip owing to the low angle dip of the fault at 31 degrees. Most other faults in the region are 60 degrees dip or higher. (**Fig. 1-80**)

The Siluro-Devonian faults have higher pressure to slip than Ellenburger faults owing to less depth, higher calculated minimum principal stress gradient and less throw on the faults at this level. The key parameter that could change this evaluation is the minimum principal stress gradient. A breakdown test during well drilling will confirm the predicted value.

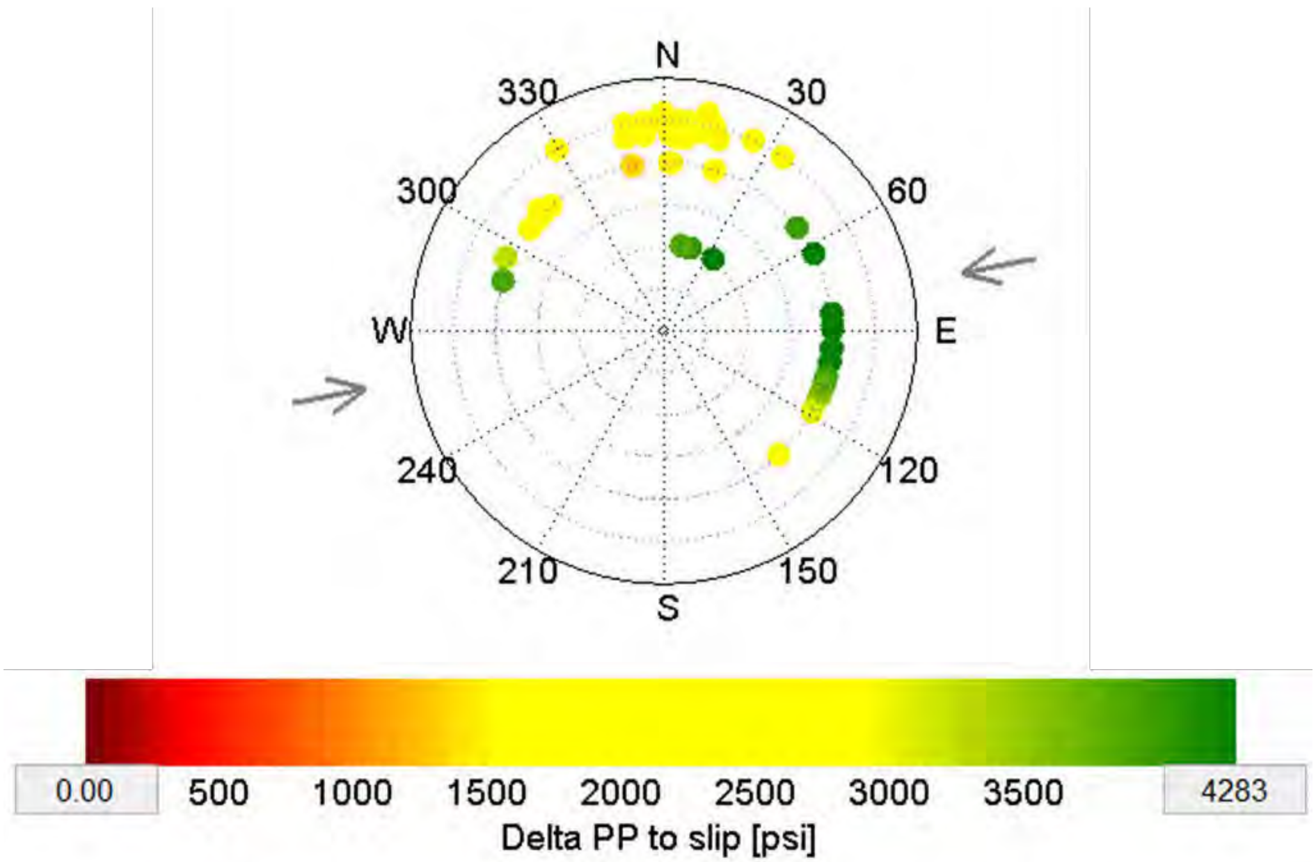


Figure 1-80: Siluro-Devonian Faults Mohr-Circle FSP Analysis Stereonet of Fault Normal Poles
Fault poles colored by deterministic FSP slip pressure

Table 1-13 illustrates the values used in a probabilistic FSP analysis of the Siluro-Devonian faults in the area using values published in Horne et al., 2024 for error ranges on the properties.

Table 1-13: Input Parameters for Probabilistic Siluro-Devonian FSP Model.

Description (Units)	Model Input Values	Plus/Minus
Vertical Stress Gradient (psi/ft)	1.1	0.02
Max Horizontal Stress Gradient (psi/ft)	0.95	0.1
Min Horizontal Stress Gradient (psi/ft)	0.731	0.05
Max Horizontal Stress Direction (deg N CW)	79	7.5
Initial Reservoir Pressure Gradient (psi/ft)	0.45	0.03
Reference Depth for Calculation (ft)	12,703	0
Frictional Coefficient Mu	0.6	0.05
Dip Angle (degrees)	Variable, 70 avg	10
Strike Angle (degrees)	Variable, 105 avg	5

Table 1-14 illustrates the results of the Siluro-Devonian probabilistic FSP analysis. The P10, P50, P90 pressures for each fault segment are shown, with the calculated maximum pressure in the nearest grid cells. Using the output percentiles, a chance to slip was calculated for each fault based on the maximum incremental pressure from the simulator along each fault. This is also displayed in the table. No faults in the Siluro-Devonian have a fault slip chance of greater than 1%. Faults too far away to be influenced by injection have max delta P of 0 psi and a corresponding 0% chance. Based on the model results, no Siluro-Devonian faults have a realistic chance of slipping.

Table 1-14: Results of Siluro-Devonian Probabilistic FSP Model

Fault Number	Strike	Dip	Length	P10 Slip P	P50 Slip P	P90 Slip P	Max Delta P	Chance to Slip
#	degrees	degrees	km	psi	psi	psi	psi	%
1	107.6	31	3.77	2916.7	4047.5	5138.5	18.6	0
2	124.2	31	5.557	3673.5	4742.6	5693.2	566.8	0
3	107.74	31	2.8857	3011.5	4130.6	5226.7	600.3	0
4	101.49	31	7.475	2727.1	3843.2	4973.7	49.6	0
5	115.13	75	4.4976	1330.2	2164.9	2960.4	0.0	0
6	97.028	75	5.0183	940.88	1905.5	2688.3	0.0	0
7	103.7	75	2.6787	1097.9	1939.1	2752.9	0.0	0
8	93.951	75	4.2344	970.11	1924.4	2764.7	0.0	0
9	44.373	62	4.2256	1344.2	2130.9	2906.4	0.0	0
10	24.916	62	1.7369	2393.7	3199.5	4038.6	0.0	0
11	105.82	71	8.591	1018.9	1846.7	2637.4	35.6	0
12	89.678	78	12.1	1147	2121.4	3021.2	368.6	0.3
13	79.121	75	12.505	1047.5	1963	2913.7	100.8	0
14	105.15	72	5.3452	997.65	1897.4	2616.6	21.5	0
15	100.53	72	3.6243	981.4	1812.7	2636	80.5	0
16	101.47	79	10.293	1134.8	1999.8	2818.9	368.0	0.2
17	93.793	69	3.9483	833.63	1710.9	2512.2	174.8	0.6
18	95.981	69	3.5929	869.15	1687.8	2502.2	13.9	0.2
19	93.612	70	8.9981	849.52	1699.3	2483.5	122.2	0.3
20	92.141	70	3.637	829.05	1642.4	2524.7	6.5	0
21	84.183	70	11.468	887.48	1677.3	2515.2	45.4	0.2

Fault Number	Strike	Dip	Length	P10 Slip P	P50 Slip P	P90 Slip P	Max Delta P	Chance to Slip
#	degrees	degrees	km	psi	psi	psi	psi	%
22	95.032	70	5.4272	857	1719.9	2487.1	0.0	0
23	84.45	75	10.901	1031.3	1991.3	2817.1	6.3	0
24	78.573	70	6.5591	787.53	1641.4	2495.4	13.3	0
25	91.835	70	9.5463	895.98	1717.5	2498.3	1.6	0.2
26	87.267	75	9.7204	1030.9	1996.6	2847.8	8.2	0.2
27	107.38	60	3.0308	1074.7	1854.6	2689.6	0.0	0
28	190.58	60	2.3428	3415.7	4299.8	5358.9	0.0	0
29	203.46	60	1.4371	2583.1	3365.1	4313.9	0.0	0
30	44.236	60	1.2569	1301	2135.9	2876.6	0.0	0
31	173.93	60	1.1998	3931.7	5418.5	6754.6	0.0	0
32	152.74	60	0.9167	3651.1	4672.3	5956.7	0.0	0
33	177.9	60	2.0857	3838.5	5155	6484.4	0.0	0
34	195.71	60	0.83671	2980.3	3948.4	4928.9	0.0	0
35	179.29	60	2.0593	3835.9	5075.1	6385.2	0.0	0
36	185.83	60	1.2504	3553.3	4703.4	5888.8	0.0	0
37	201.3	60	1.5811	2705.4	3549.1	4442.1	0.0	0
38	37.337	60	0.99892	1645.7	2455.8	3281.2	0.0	0
39	227.17	60	0.84126	1203.2	1995.9	2775.3	0.0	0
40	198.21	60	1.2845	2871.8	3695.3	4682.2	0.0	0
41	208.48	60	2.7443	2212.1	3009.1	3887.1	0.0	0
42	48.051	60	1.3893	1205.5	2011.1	2823.7	0.0	0
43	59.49	75	1.163	1015	1901.7	2723.9	0.0	0
44	124.3	75	1.2189	1748.8	2638.2	3385	0.0	0
45	91.627	60	1.5684	742.37	1527.4	2277.7	0.0	0
46	79.261	60	9.4788	605.25	1451.6	2229.6	0.0	0
47	92.457	60	24.819	721.42	1536.4	2293.4	0.0	0
48	17.354	60	3.0846	3029.3	3876.8	4784.8	0.0	0
49	41.969	60	2.3519	1410.4	2247.2	3057	0.0	0
50	142.13	60	2.5778	3048	3959.5	4992	0.0	0

1.8.6 Summary

In summary, there are pervasive natural fractures in the but there is very little seismic activity near the injection wells in the west Texas area. Only three small (M 2.0) historic earthquake events happened 10 mi west of the proposed injection site. These events were deep basement earthquakes much deeper than the injection zones of the well and likely associated with SWD injection in the Pegasus Field.

This indicates stable geologic conditions in the region surrounding the potential injection site. The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the small volume of CO_2 injected as part of this project suggest the probability that seismicity interfering with CO_2 containment is low. Seismicity in the region has primarily occurred over 30 miles north in the Midland Basin, or over 90 miles west in the Delaware Basin.

Detailed fault slippage analysis shows at least 1,902 psi pore pressure above hydrostatic is needed to cause the Ellenburger fault (8,500ft north from the injection) to slip. And at least 2,102 psi pore pressure above the hydrostatic is needed to cause the Siluro-Devonian fault (8,800 ft north from the injection) to slip.

Given the small volume and rate of CO_2 injection, numerical simulation has shown that such high reservoir pressure is unlikely to be reached at the fault location. The maximum pressure change at the Well location is 1,598 psi. Therefore, the CO_2 injection proposed in Well is unlikely to cause fault slippage in the Devonian and Ellenburger Injection Units.

Figure 1-81 shows the incremental pressure in the Siluro-Devonian Injection Unit. Note how the pressures along the fault planes are significantly lower than the required ~1900+ psi to cause the faults to slip.

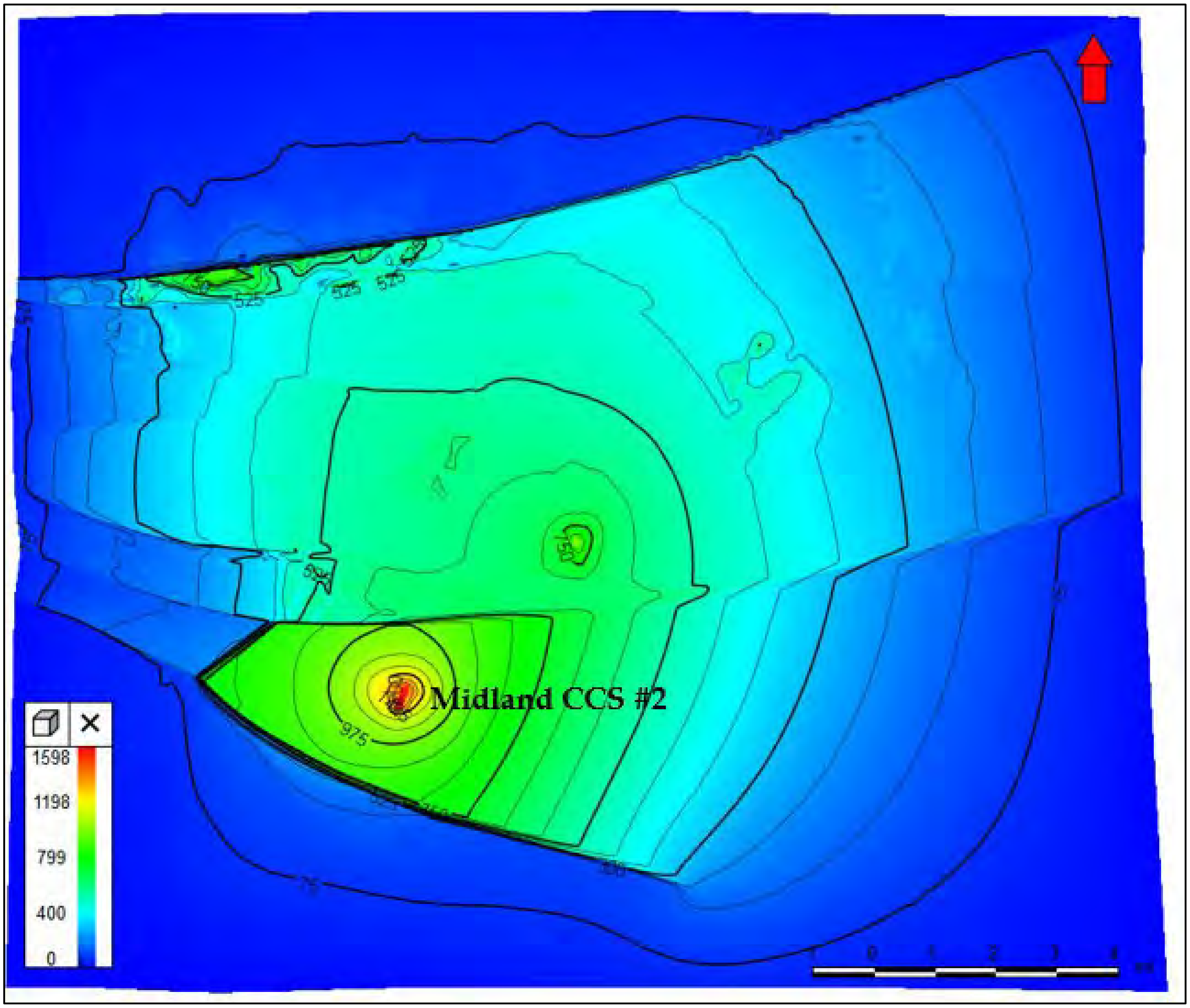


Figure 1-81: Maximum Incremental Pressure in Siluro-Devonian, Year 2039
Midland CCS #2 Location denoted by high pressure area in red next to well label. Color fill is incremental pressure increase from start to end of injection period. Maximum incremental pressure at well is 1,598 psi.

1.9 Petrophysical Characterization [40 CFR 146.82(a)(3)(iii)] [40 CFR 146.82(a)(3)(iv)]

This section includes a petrophysical characterization of the injection and confining zones and includes discussion on porosity, permeability, salinity, capillary pressure and related properties. The petrophysical properties indicate the proposed Well location is suitable for the project due to it having sufficient storage (porosity), ability to inject (permeability) and the in-situ formation waters have a salinity that is significantly higher than the statutory lower limit of 10,000 parts per million (ppm) at an average salinity of 152,704 ppm. Further, the threshold entry pressure of the top seals is greater than the pressure increases from injection activities at 10,000 psi and 7,770 psi.

1.9.1 Type Log

The type-log in **Figure 1-82** is a penetration to the west of the Facility in the Pegasus field (Pegasus Field Unit #20-12; API#: 42-461-32586). This log was chosen due to a full suite of petrophysical curves including a photoelectric factor (PeF) curve. The type-log displays the interval from Atoka Shale to the middle Ellenburger Formation. Basement rock was not penetrated on this well.

<u>From left-to-right:</u>

- **TRACK 1**: Gamma ray and SP;
- **TRACK 2:** Depth;
- **TRACK 3:** Formation Tops;
- **TRACK 4:** Resistivity on log scale 0-2000, logarithmic scale;
- **TRACK 5:** Raw porosity curves such as neutron and bulk density, also photoelectric curve;
- **TRACK 6**: Caliper and density correction;
- **TRACK 7**: Calculated mineral volumes displayed in a cumulative basis:
- **TRACK 8:** Calculated true matrix porosity shaded by fluid type blue for free fluid, grey for bound fluid, red for hydrocarbons, the true porosity is scaled 20% on the left to 0% on the right;
- **TRACK 9**: Water saturation calculated from Indonesian equation scaled from 100%-0%, TRACK 10: Calculated matrix permeability on logarithmic scale, scaled from 0.01 mD to 10,000 mD.

The type-log displays several key points about the seal. First, there are over 700 ft of organic shale that serves as the top seal and secondary seals. The kerogen curve is shaded brown in the mineralogy Track 7. Expected organic volumes are >10% in the Atoka, Barnett and Woodford Shales. This is consistent with regional data. Another item of interest is the change in mineralogy between the Atoka, Barnett and Woodford. The Barnett and Atoka are a mix of clastics, carbonate, illite and smectite, which is one reason they have prevalent hole washouts on most logs in the region.

The Woodford Shale, in contrast, is primarily quartz and illite and typically does not react with water-based mud systems. Average porosity in the Barnett is 5.8% and similarly it is 5.38% in the Woodford Shale. Both shales are expected to have permeability <1 uD consistent with regional core data (Track 10). The Woodford and Barnett are not expected to be fully water saturated but also not contain commercial quantities of hydrocarbons. As with most organic shales, even if the quantities are not commercial, the immature organic porosity will likely contain immobile adsorbed hydrocarbon.

The type-log displays several key points about the injection units. First, the Devonian has two dominant facies as stated in the regional literature. A packstone near the top of the formation is signified by the higher calcite content in the mineralogy track, then a chert facies near the bottom of the Devonian. The porosity of the chert facies is significantly higher and more variable than the packstone facies. The Fusselman, Montoya and Simpson Group all have porosities <1.5% indicating a vertical no-flow barrier. The McKee sand is the only member of the Simpson with elevated porosity. The Ellenburger is almost entirely a dolomite with small punctuations of clay breccias that show up on gamma ray from 12,777-12,850 ft. Low porosity is pervasive with an average of approximately 3% porosity. Since natural fractures are expected to form the primary pathway for injection this is not surprising. Deflections in the resistivity are hypothesized to be sensitive to fractures but this could also just be a change in pore types, presence of vugs, variable M&N or other properties.

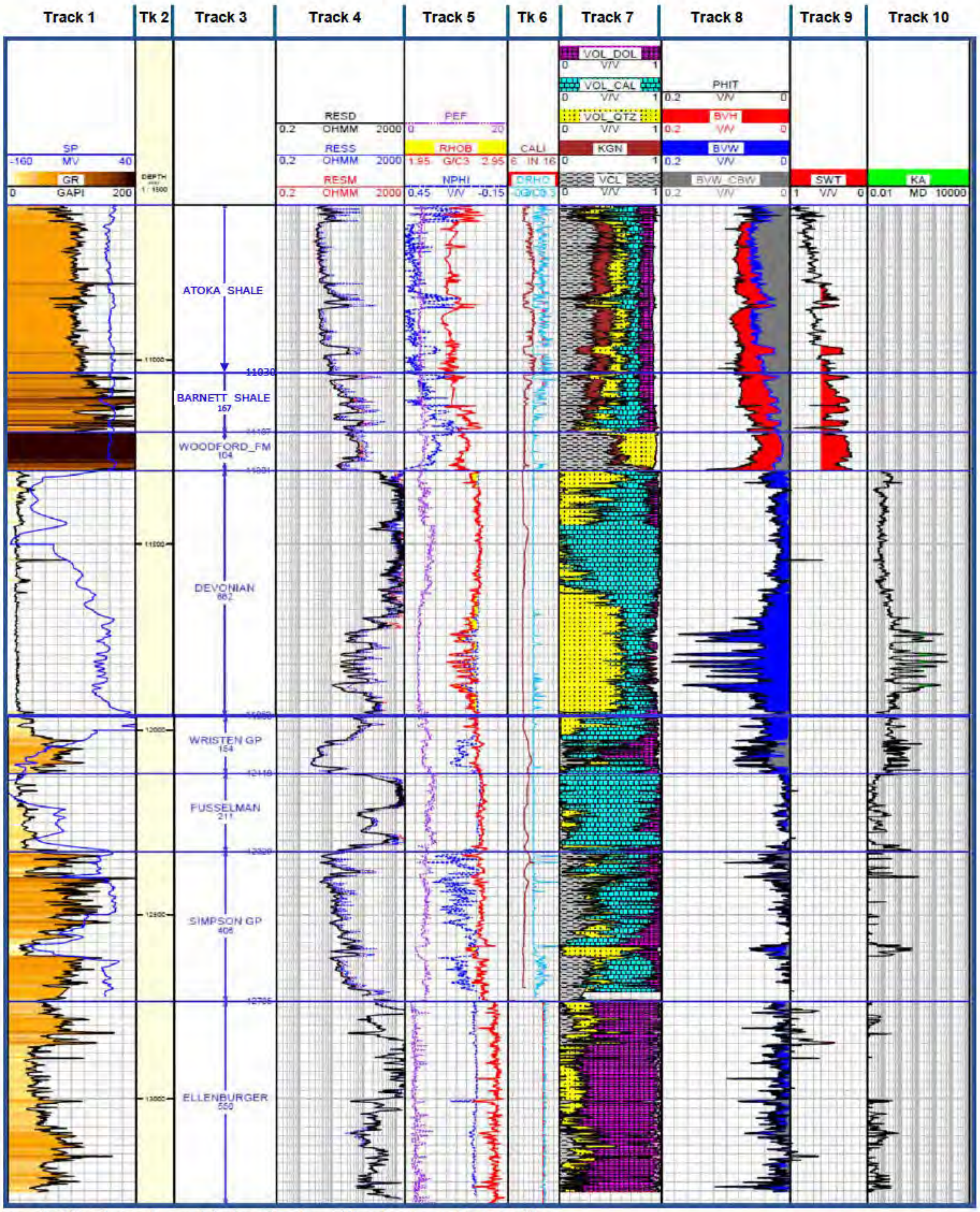


Figure 1-82: Type Log Atoka Shale- Ellenburger Formation

Type log of the section. Atoka Shale- Ellenburger Formation well is Pegasus Field Unit #20-12; API#: 42461325860000. From left to right 1st track: gamma ray and SP, 2nd Track: Depth, 3rd Track: Formation Tops, 4th Track: Resistivity on log scale 0-2000, 5th Track: Raw porosity curves such as neutron and bulk density, also photoelectric curve, 6th Track: Caliper and Density Correction, 7th Track: Calculated Mineral volumes, 8th Track: Calculated true matrix porosity shaded by fluid type blue for free fluid, grey for bound fluid, red for hydrocarbons, 9th Track: Water Saturation calculated from Indonesian equation, 10th track: Calculated matrix permeability on logarithmic scale.

1.9.2 Porosity

The total porosity of the Devonian and Ellenburger injection units is uniformly low across the study area. In general, the total porosity is less than 10% across all formations in the study area with only a few samples that are higher. **Table 1-15** details the statistics on the log derived porosity in the study area. There are several reasons for this, the Paleozoic age of the rocks, the depth of the rocks and compaction plus the lack of overpressure.

As seen in **Figure 1-85**, Devonian/Simpson porosity is uniformly low at ~3% near the proposed well location, on average. There are higher porosities in the cherty facies, indicating the chert facies is the more desirable injection facies. As seen in **Figure 1-86**, Ellenburger-Basement porosity is uniformly low at ~4% near the proposed well location on average.

Organic shales in the Barnett and Woodford have mostly intrakerogen porosity related to thermal maturation of organic matter and a very stable porosity range from 0-5%. Devonian aged rocks porosity is related to the facies. The Packstone facies exhibits porosity from 0-4% while the chert facies can have porosity up to 8% depending on the area with occasional spikes that go higher as seen in the type log in **Figure 1-82** and in a histogram in **Figure 1-83**. Fusselman generally has low porosity <3% and is a carbonate. Ellenburger porosities range from 0-7% and most of the higher porosities are related to fractured dolomite (**Figure 1-84**). Ellenburger porosity is particularly difficult to calculate via log measurements due to the complex nature of its texture and fractures.

The Ellenburger porosity that is measurable with triple combo logs is likely related to vugs or secondary features. Several authors have noted vugs in the Ellenburger (Loucks, Kerans 2008-2019). The vugular features are more prolific in the middle to lower Ellenburger while fractures and brecciation is more common near the top of the Ellenburger. However, vugs and breccia often intermingle in the Ellenburger as there have been multiple stages of porosity and fracture generation.

Porosity within the fractures in the Ellenburger and the specific mineral fill are dependent on cave brecciation processes. However, fractures and these textures are difficult to quantify and distinguish with triple combo logs. An image log will be utilized in the injection well to better identify which textures are present at the proposed location. Cave brecciation is the process by which large blocks of rock within a cave system break apart to form a new feature. The process begins with the fracturing of rock blocks within a cave system, as these blocks break apart, they create a jumbled mass of angular fragments known as breccia. Over time, these fragments can become re-cemented together. There is also a theory that tectonic fracturing occurred in the Ellenburger although this is considered secondary (Loucks, 2019).

Table 1-15: Log Porosity Values in Study Area From Wireline Logs

Formation	POROSITY (%)				
	Avg	P10	P50	P90	COUNT
ATOKA	9.226	4.897	6.580	13.847	8,642
BARNETT	5.804	3.645	5.572	7.204	5,771
WOODFORD	5.387	4.601	5.386	6.445	4,458
DEVONIAN	2.589	0.000	2.089	5.178	29,883
SILURIAN	1.101	0.000	0.402	3.156	2,838
FUSSELMAN	1.242	0.000	0.885	2.880	6,929
SIMPSON	1.547	0.000	0.891	4.146	10,365
ELLENBURGER	3.517	0.522	3.307	6.119	17,102

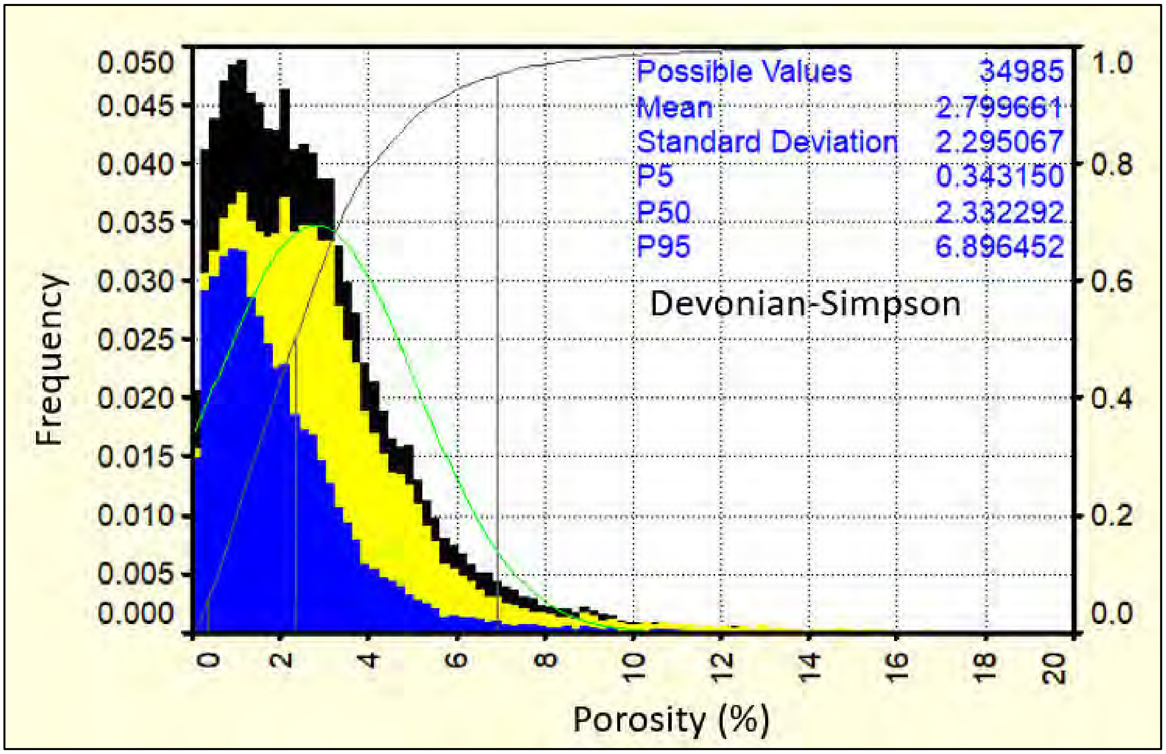


Figure 1-83: Devonian-Simpson Total Porosity Histogram
Histogram of the Devonian-Simpson total porosity scaled from 0% to 20%. The histogram is colored by packstone (blue) and chert (yellow) facies. Black color indicates that no PE log was available and facies are indeterminate. The chert facies clearly have higher porosity range than the packstone which only goes up to around 4% porosity.

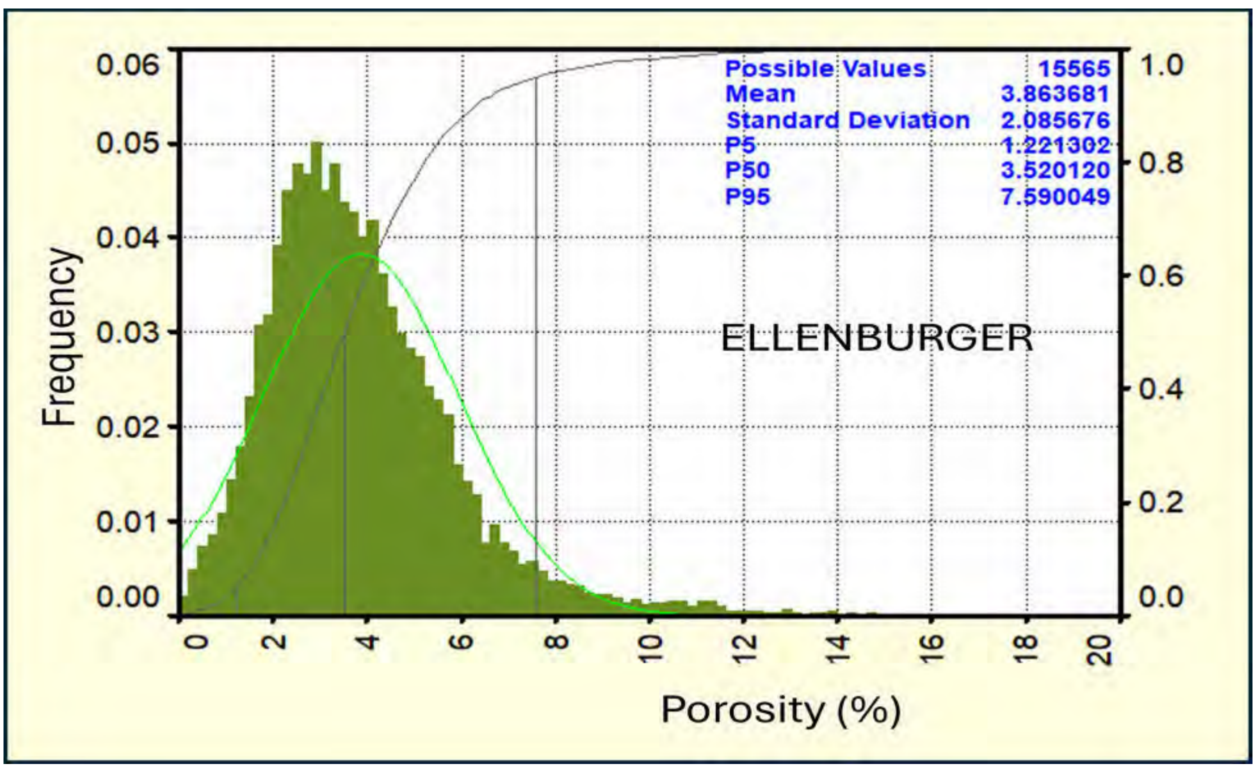


Figure 1-84: Ellenburger Total Porosity Histogram
Histogram of the Ellenburger total porosity scaled from 0% to 20%. Total porosity is generally less than 6% and is normally distributed around slightly less than 4%

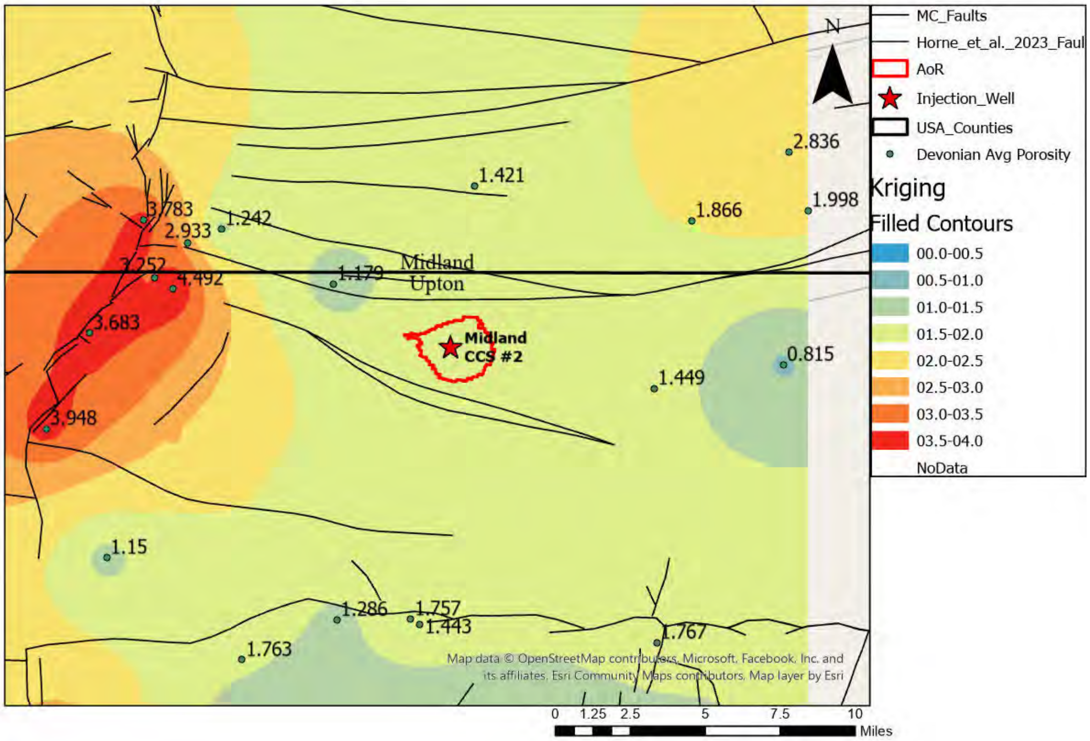


Figure 1-85: Top Devonian/Simpson Group Porosity Map

Porosity map of the Top Devonian – Top Simpson Group. Porosity is uniformly low at ~1.5% near the proposed location on average. There are higher porosities in the cherty facies which are diluted by nearly zero porosity in packstone facies. Red Star is Proposed Midland CCS #2 Well. Values posted are % Porosity.

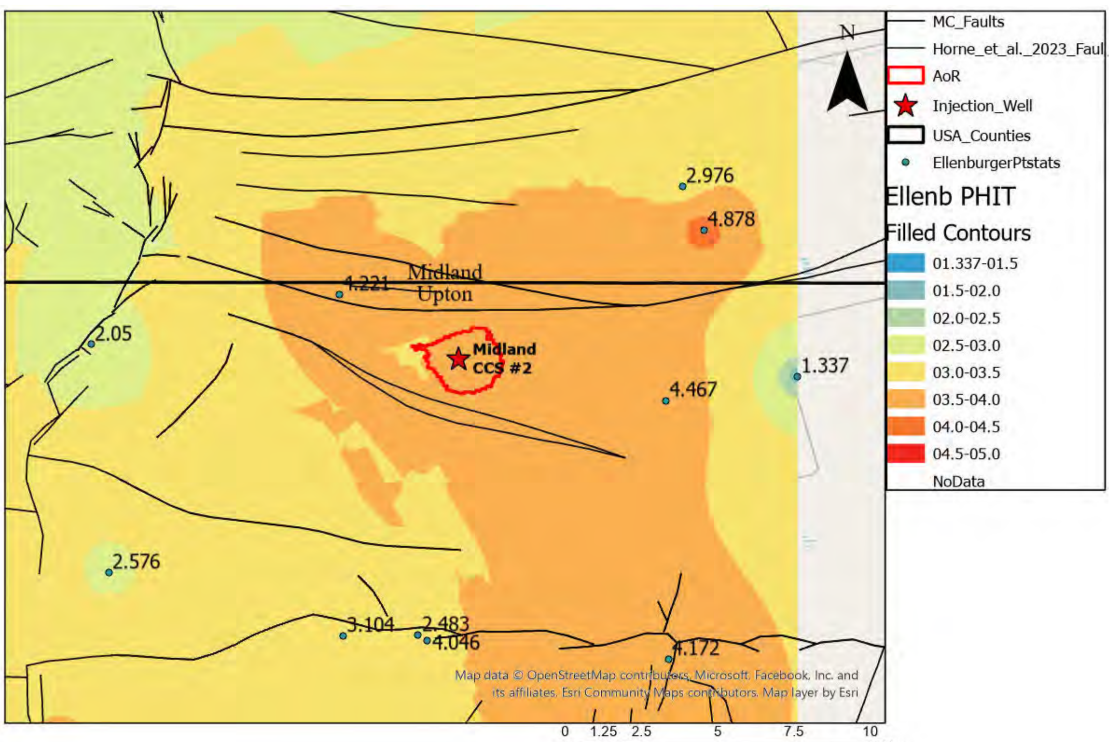


Figure 1-86: Ellenburger-Basement Porosity Map

Porosity map of the Ellenburger-Basement. Porosity is uniformly low at ~4% near the proposed location on average. Red Star is Proposed Midland CCS #2 well. Values posted are % Porosity.

1.9.3 Permeability

The permeability in the system is controlled primarily by fracture count. The number of fractures in the Devonian chert facies is six times what is found the packstone facies (Ruppel and Hovorka, 1995). The brecciation is generally higher near the top of the Ellenburger as well (Loucks and Kerans, 2019).

Brecciation and fractures in the Ellenburger will be related to proximity to cave collapse features. Given the low matrix permeability and Paleozoic age of the rocks, fractures will ultimately control the permeability and injectivity of the proposed Well in both the Devonian and Ellenburger flow units. Background permeability of the unfractured rock is expected to be <0.01 mD for most of the section based on existing core data. Existing core permeability tests show that there is a minimum value of permeability (**Figures 1-87** through **1-89**) but there is high variation vertically due to fractures and geometries found in each plug. Thus, the lower limit is based on the unfractured matrix end member, but the upper limit of the system permeability is a function of fracturing and degree of karsting or tectonic deformation.

Milestone will identify fractures using 3D seismic first using the procedures outlined by McDonnell et al. 2007. Additionally, an electric formation micro imager (FMI) will be run as one of the logs to characterize the site when the well is drilled. Currently, in the dynamic reservoir model, a single porosity and permeability model is utilized to attempt to model matrix and fracture contributions using a combined system perm. Since the fracture geometry is unknown, this is the same as an assumed constant fracture density. The total system permeability in the offset Davidson well appears to be around 3 mD in a combined flow unit of Devonian and Ellenburger.

Average matrix permeabilities are shown in **Table 1-16**. When describing the McElroy #1 core west of the proposed site, Bob Loucks (2023) noted the vertical permeability of the Ellenburger with fracture enhancement. Note how the upper Ellenburger shows more enhanced permeability but also how there is little correlation between the porosity and the permeability. The data shows an upward limit of around 100 mD and a lower limit of around 1 mD for the system permeability (**Figures 1-87** through **1-89**). Log deep resistivity measurements are hypothesized to be weakly sensitive to the degree of fracturing and are used in the petrophysical model to try and capture areas with higher probability of fracture enhancement. **Figure 1-87** illustrates that most Ellenburger porosity values are 5 percent or less in strata deeper than 9,000 ft (3,000 meters, m), but there are still suitable permeability values despite low porosity values. **Figure 1-88** also illustrates that fracture enhanced permeabilities range from 0-100 mD in the Ellenburger formation.

A study by T. Sanchez et al. 2019, showed that the Ellenburger could accept up to 100,000 bbls of brine disposal in areas of heavy karsting (**Figure 1-90**) (1MMta CO_2 ~ 17,000 brine bbls/D). This corresponds to the higher perm ranges of 100 mD reported by Loucks 2019 (**Figure 1-87**). Thus, the Ellenburger and Devonian original permeability was likely low, but due to karsting, the permeability has been enhanced to between 1-100 mD. This coupled with the large vertical footage of the formations, 800+ ft, yield sufficient permeability*height to justify the proposed injected volumes.

Table 1-16: Absolute Permeability Values - Area Logs

Tops	Absolute Permeability (mD) Without Fracture Enhancement				
	Avg	P10	P50	P90	Count
ATOKA	0.005	0.001	0.001	0.006	8,642
BARNETT	0.783	0.000	0.001	0.002	5,771
WOODFORD	0.002	0.001	0.001	0.001	4,451
DEVONIAN	5.895	0.188	2.756	12.418	26,567
SILURIAN	2.770	0.016	1.361	6.650	1,703
FUSSELMAN	2.203	0.043	0.913	4.809	5,421
SIMPSON	0.620	0.000	0.000	0.904	9,931
ELLENBURGER	6.441	0.577	4.104	13.734	15,713

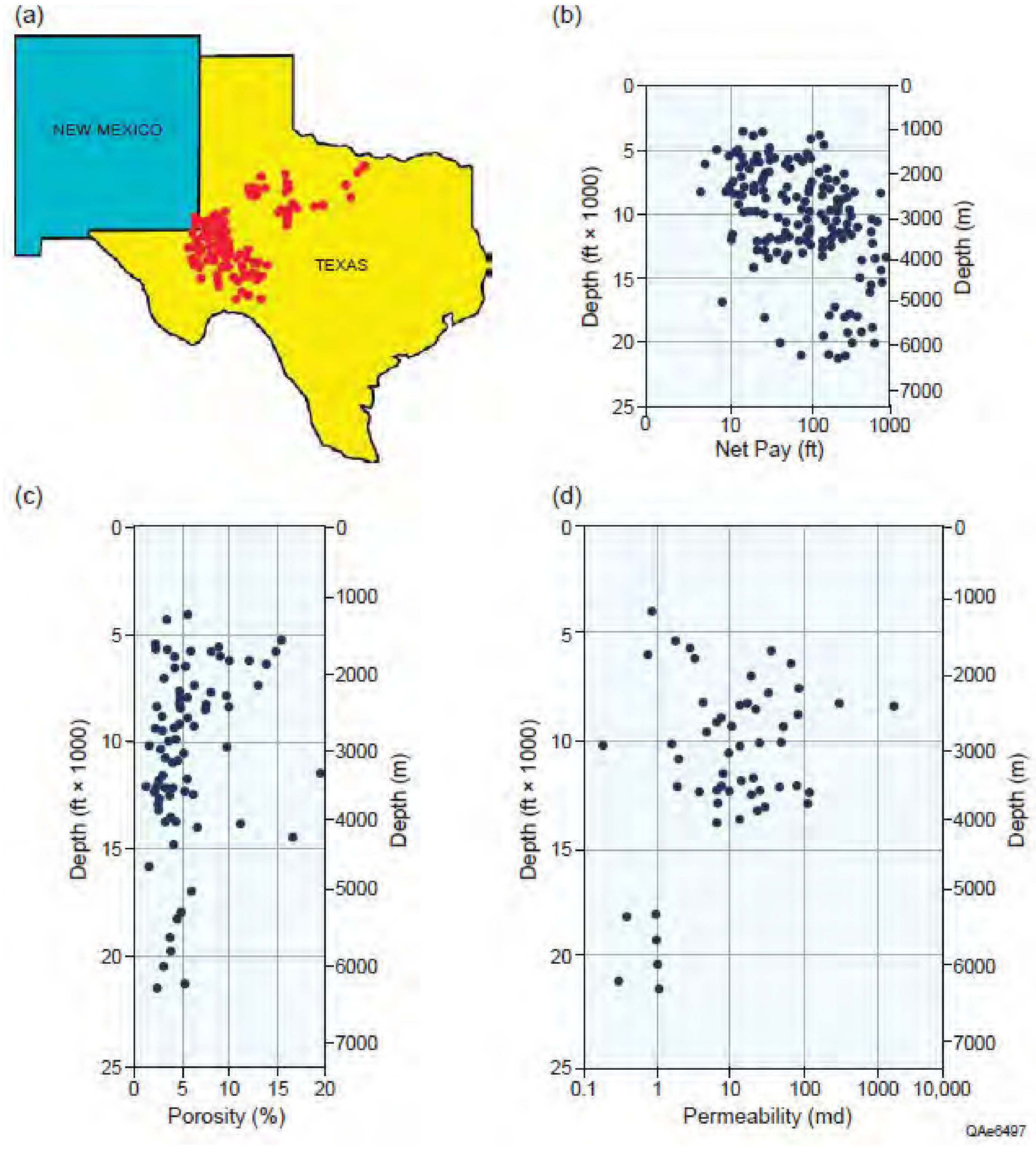


Figure 1-87: Ellenburger Field Data

Ellenburger Field data from NRG Associates (1984) database. (a) Map showing field locations. (b) Thickness of net pay. (c) Average reservoir porosity versus depth. Note that most porosity values are 5 percent or less in most strata deeper than 9,000 ft (3,000 m). (d) Average reservoir permeability versus net pay. Note the many suitable permeability values despite low porosity values (Loucks and Kerans, 2019).

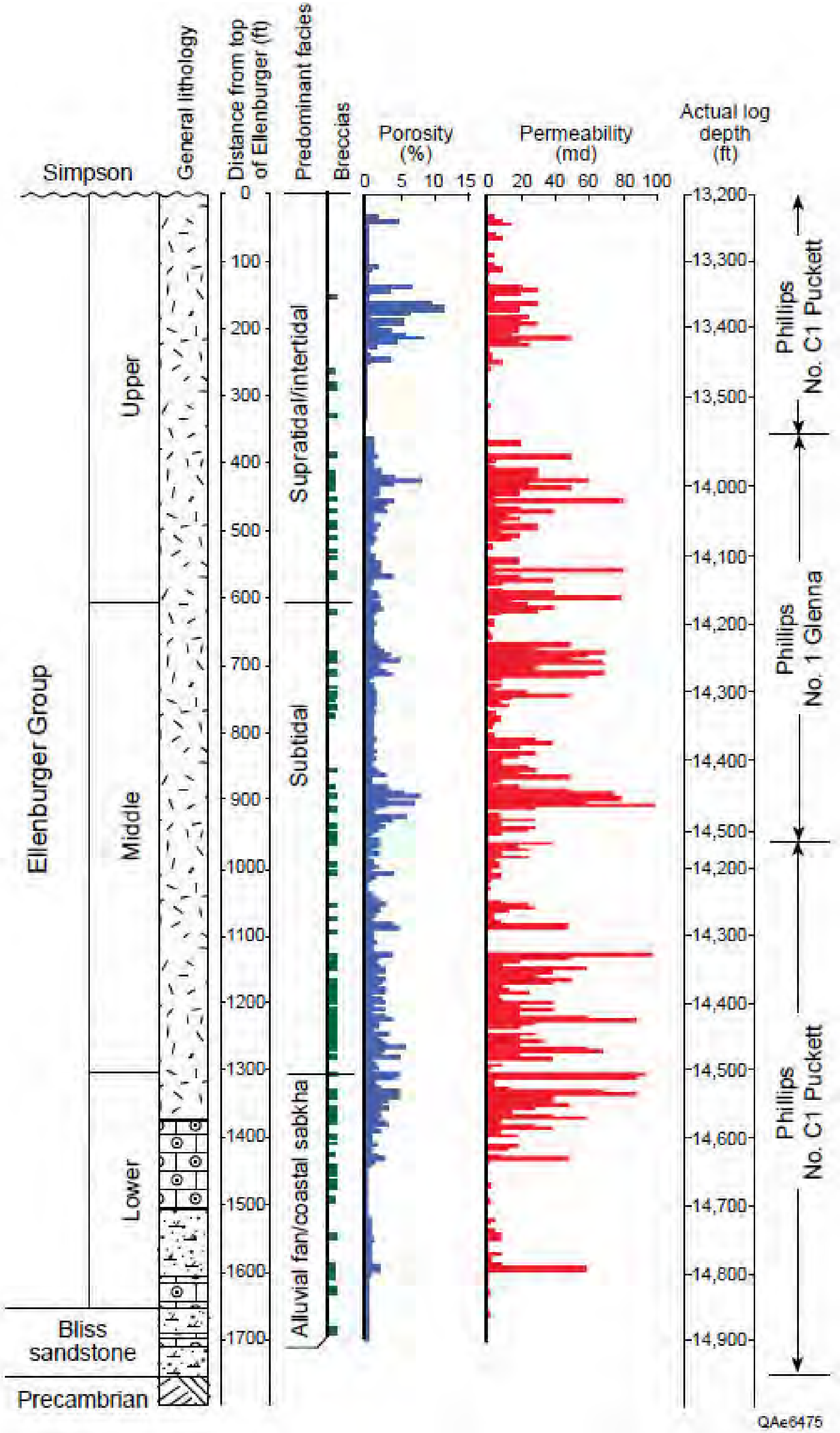


Figure 1-88: Permeability Ranges Ellenburger Formation

From Loucks and Kerans, 2019. Note the fracture enhanced permeabilities that range from 0-100 mD in the Ellenburger Formation. Porosity (blue) and Permeability (red) are shown for the Phillips Puckett and Glenna Cores. Breccias refer to brecciated zones

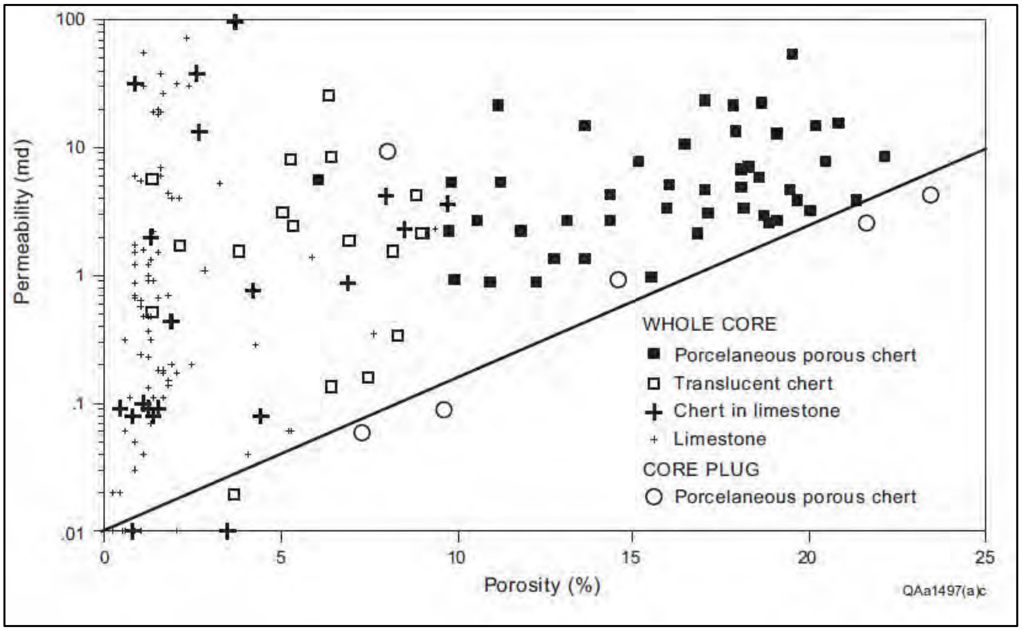


Figure 1-89: Devonian Porosity and Permeability Chart

From Ruppel, 2008, Devonian porosity and permeability chart. Note how there is a lower limit denoted by the black line but there is large upwards scattering. This is due to fracturing of the plugs. Further note how the packstone facies is confined to the left most side of the plot confirming that likely has poorer reservoir quality.

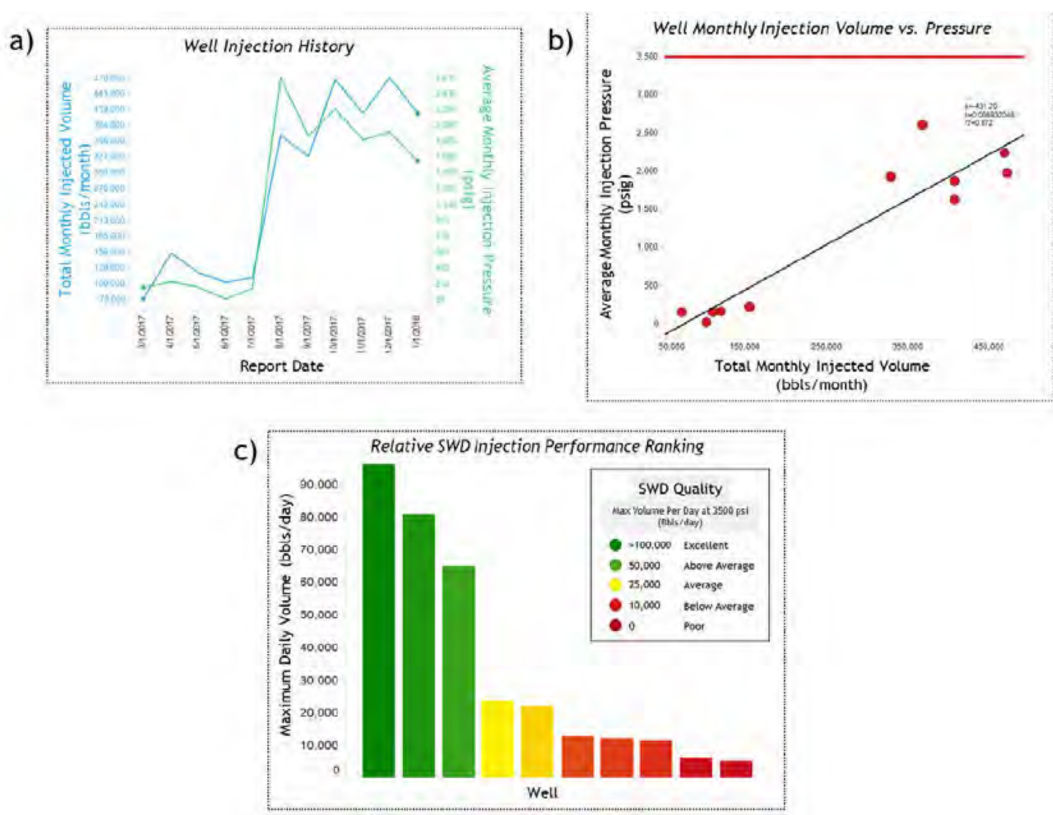


Figure 1-90: Injection Data Ellenburger Wells

From Sanchez et al., 2019, proprietary injection data shows that fractured Ellenburger wells can accept up to 100,000 bbls/month but unfractured rock is limited to less than 10,000 bbls/month. A) Example of Well injection history in Ellenburger, B) Plot of total monthly injection vs Injection pressure, C) Bar Chart of injection in bbls/d at 3500 psi injection

1.9.4 Salinity

The salinity of the injection unit is expected to be high and greater than 100,000 ppm. Offset data has a mean of 152,704 ppm (**Figures 1-92, 1-93**), which is consistent with other Devonian and Ordovician aged waters (USGS Produced Waters Database). Unfortunately, log analysis using Archie's Law (G. Archie, 1942) is of limited use for the following reasons.

- The reservoirs have complex textures leading to a wide range of cementation (*m*) and saturation (*n*) exponent values.
- Features such as vugs, recemented fractures, brecciation, chert and other features make predicting M&N with just a triple combo log hazardous at best. **Figure 1-91** shows a Pickett plot (G.R. Picket, 1973) that illustrates the wide variation in *m*.
- It is unlikely that this resistivity response is due to hydrocarbons but there could also be some trace hydrocarbon content from Simpson Group source rocks.
- Offset water sample data (**Figures 1-92,1-93**) also precludes a freshwater hypothesis confirming that the waters in the deep Paleozoic in the Midland Basin are indeed quite saline. An image log and dielectric log will be run when the proposed Well is drilled to gather more data on cementation exponents with the addition of electrical testing on core samples.

The Pickett Plot data (**Figure1-91**) does indicate that the resistivity in the Devonian-Simpson interval may be lower than the Ellenburger, but this could also very easily be just differences in textures and *m* and *n* as discussed previously. The Ellenburger appears saltier with a resistivity of water (Rw) of ~0.05 ohm while the Devonian-Simpson appears to have a RW of ~0.12 ohm. This corresponds to a salinity of 60,000 ppm and 22,000 ppm, respectively, both of which are well below mean of 152,704 ppm and approximately equal to one standard deviation lower (P16) of 54,000 ppm. Thus, the *m* and *n* are likely greater than 2. *M* & *n* being greater than 2 is common in carbonates, especially dolomitized fractured and vuggy carbonates.

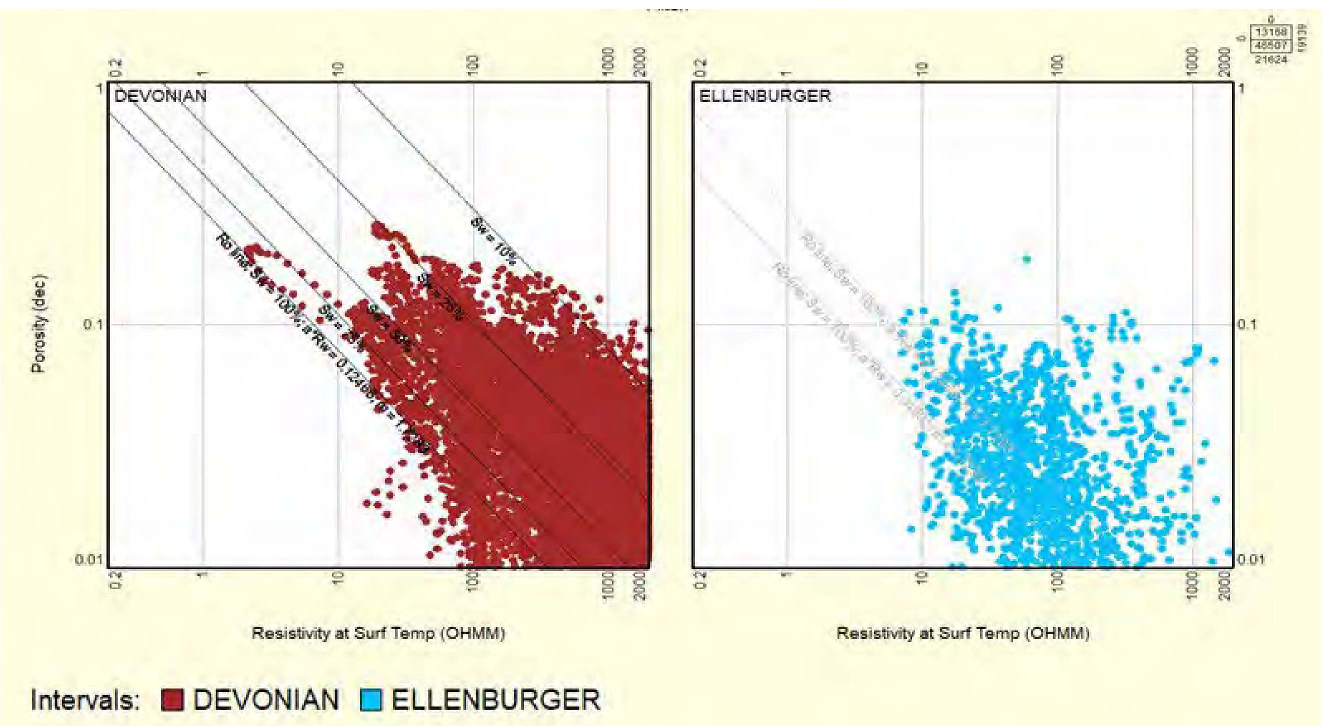


Figure 1-91: Pickett Plots

Pickett plots (G.R. Pickett, 1973) of Devonian (left) and Ellenburger (right). All wells in AoR. Data shows RW of 0.12 ohm left and 0.048 right. Likely affected by high m values

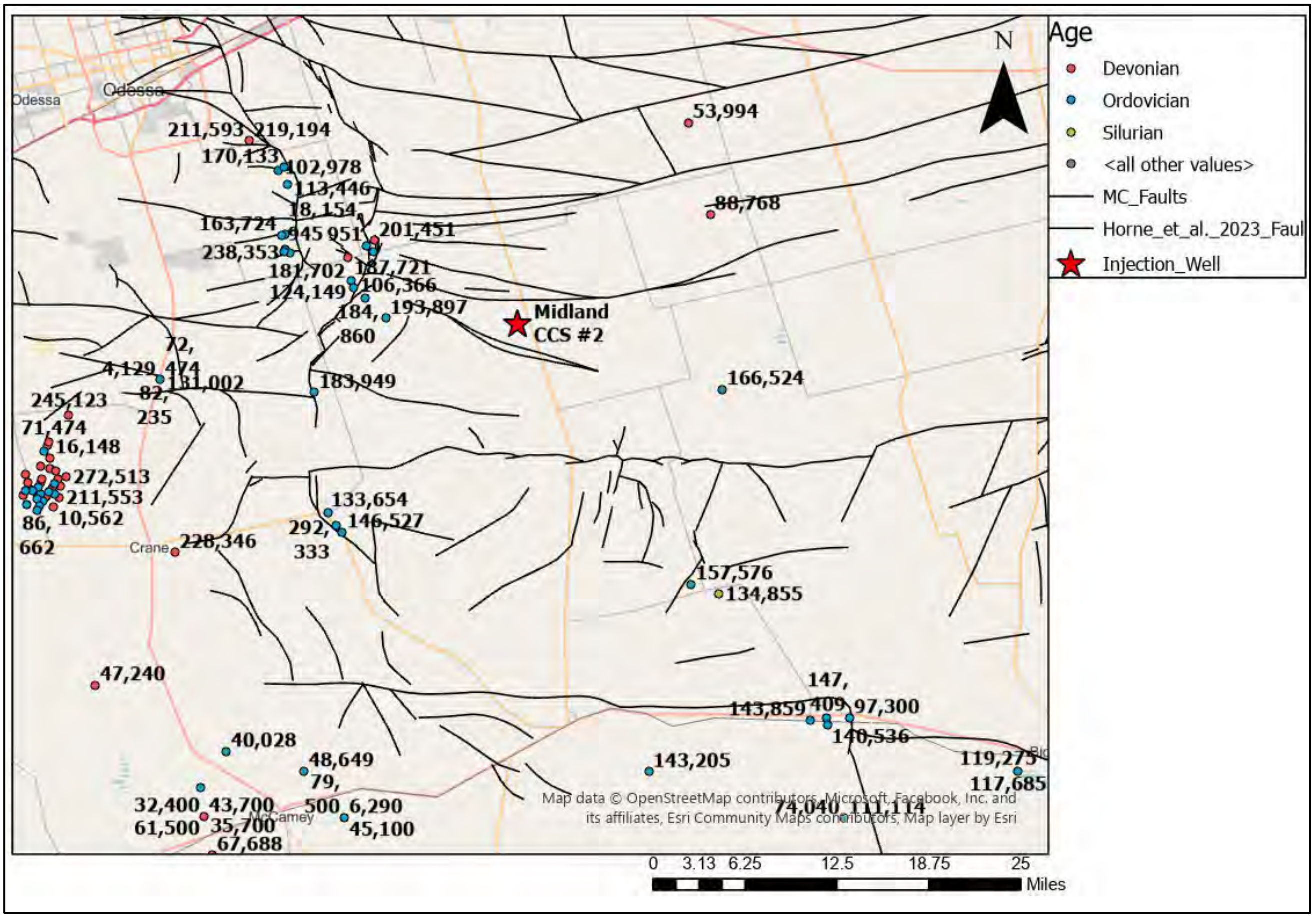


Figure 1-92: Devonian, Ellenburger and Fusselman Dissolved Solids
Map of total dissolved solids (TDS) in ppm for all Devonian, Ellenburger and Fusselman waters in the study area. Red Star is Midland CCS #2 well location. Most waters nearby are greater than 100Kppm. Source of data is USGS Produced Waters Database

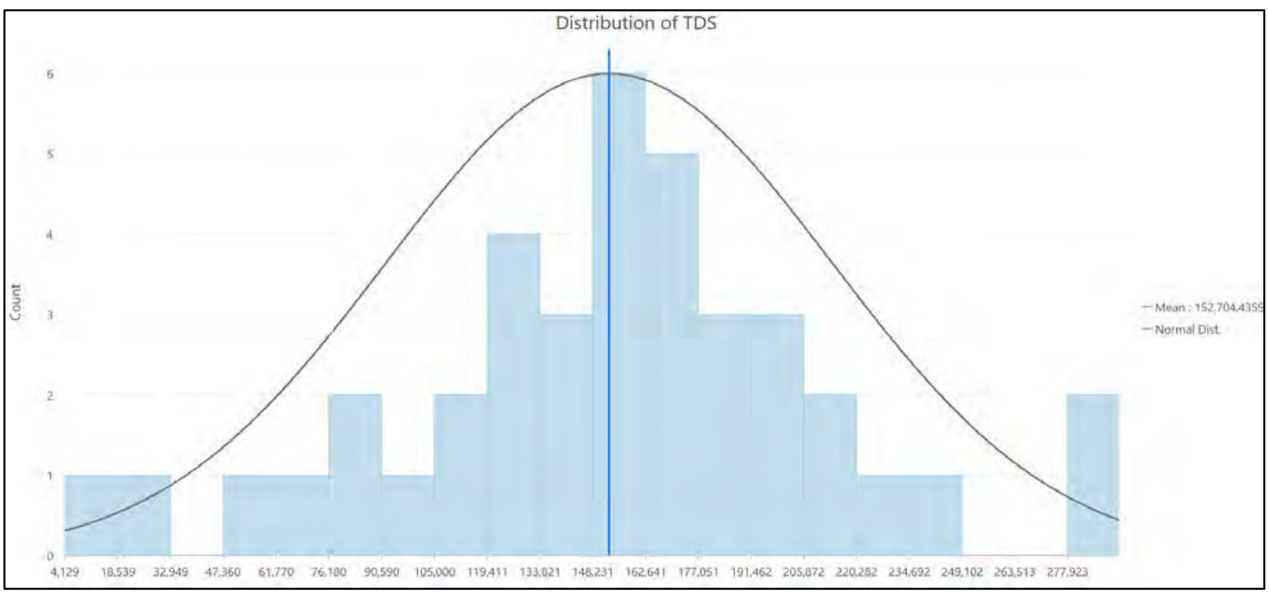


Figure 1-93: Offset Well Penetrations TDS Data
Histogram of TDS data from offset well penetrations in Ellenburger, Devonian and Fusselman Formations. Source of Data is USGS Produced Waters Database. Mean of distribution is 152.7 KPPM, 1 Standard Deviation lower is ~54 KPPM

1.9.5 Capillary Pressure

Porosity and permeability data, but not full capillary pressure data, is available in the literature for Ellenburger and Devonian. After the initial test well, associated with the Well is drilled, more data will be collected. Therefore, this application will focus on the capillary pressure of the Woodford shale primary seal and Barnett shale secondary seal as it is directly related to their sealing capacity and does have published data available.

Existing literature supports the idea that the elevated pressure from injection activity will not exceed the threshold entry pressure of the shales. Thus, the Woodford shale as the primary top seal, in concert with the secondary seal of the Barnett shale, provides an adequate top seal to the system.

Capillary pressure tests in the fractured Devonian and Ellenburger are expected to be bimodal due to the dual pore system. The intracrystline pore network outside of remineralized fractures in the Ellenburger and Devonian is expected to be very minimal.

For the Woodford Shale, published mercury injection capillary pressure (MICP) testing suggests that the threshold entry pressure is between 5-20 Kpsi. One complication of examining MICP data in organic shales is the pore structure is typically deformed before the mercury enters the pore system. This leads to a section of the MICP curve that is related to the bulk modulus of the shale and not actual intrusion (Mastalerz et al., 2021).

Once the mercury enters the organic shale system it typically forms a linear line when plotted against saturation instead of the typical exponential line. M. G. Kibria (2018) reported that MICP analyses show that the median pore-throat diameters for the Woodford shale are 3.7–5.4 nm, and almost 70–80% of pore-throats by volume are smaller than 100nm.

Two Woodford MICP tests that are in the public domain are shown in **Figures 1-94** and **1-95**. The first, in **Figure 1-94**, is from the Delaware Basin in the Reliance Triple Crown, Pioneer core, that is in the public domain (API# 42-371-37790). It shows that no mercury enters the Woodford until at least 6,526 psi incremental pressure is achieved and further this is an unstressed MICP test. Therefore, one can assume the entry pressure in the subsurface would be even higher. The data shows the system would need more than 100 mega pascals (MPa) or 14,503 psi to displace even 20% of the pore-throats in the Woodford shale (M.G. Kibria et al. 2018).

The second Woodford sample, shown in **Figure 1-95**, is from an unknown Chesapeake well from Marshall County, Oklahoma in the Ardmore Basin. Note the similarities to the sample from the Delaware Basin. Many comparisons have shown the Woodford in Anadarko is fundamentally identical to that found in the Permian and Midland Basins once thermal maturity is considered. (Haecker, 2016)

This is consistent with depositional histories where a large epeiric sea existed in the Late Devonian – Early Mississippian. In this sample, the entry pressure is approximately 10,000 psi and it displaces about 20% of the volume at that pressure. It is inferred from the irregularity of the data that perhaps Mr. Ryan did not conformance-correct his sample correctly and misjudged compression or conformance for imbibition. However, his arrows are in the correct positions on the plot (B. Ryan, 2017).

The importance of capillary pressure data cannot be understated. Additional data points from core from the proposed Well will be acquired when core samples are acquired. Brunauer-Emmett-Teller analysis will be run in parallel with MICP tests to accurately predict the pore throat sizes of the Woodford shale in the Midland Basin.

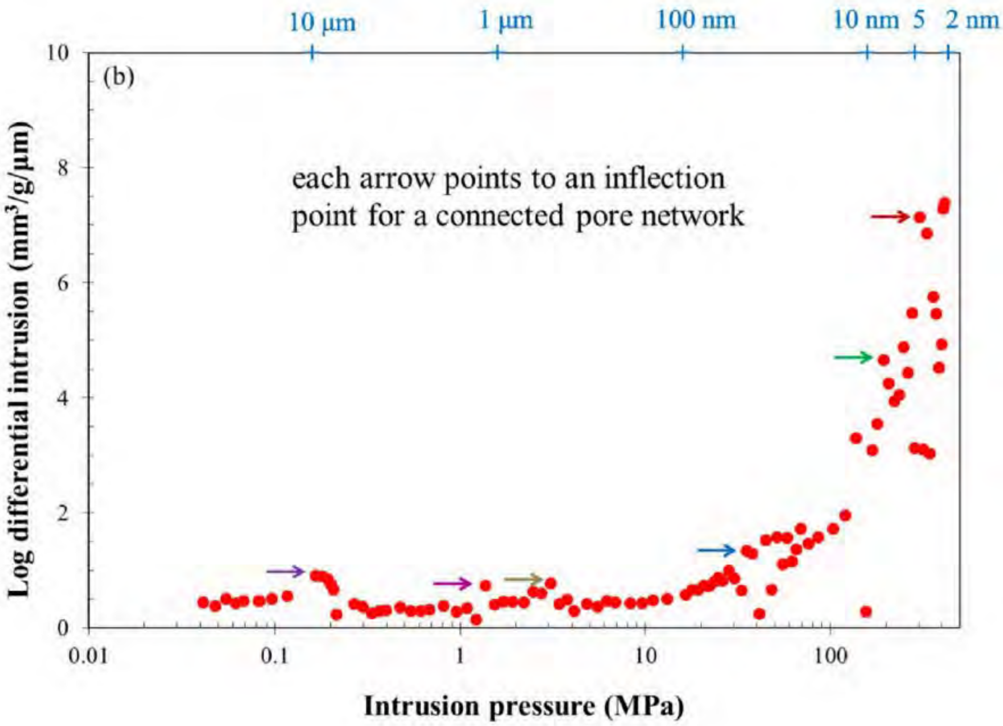


Figure 1-94: Delaware Basin / Woodford Capillary Pressure Test
From M.G. Kibria et al. 2018. Woodford Capillary Pressure test from the Delaware Basin. Note how mercury does not enter the sample until ~45 MPa or 6526 psi (blue arrow)

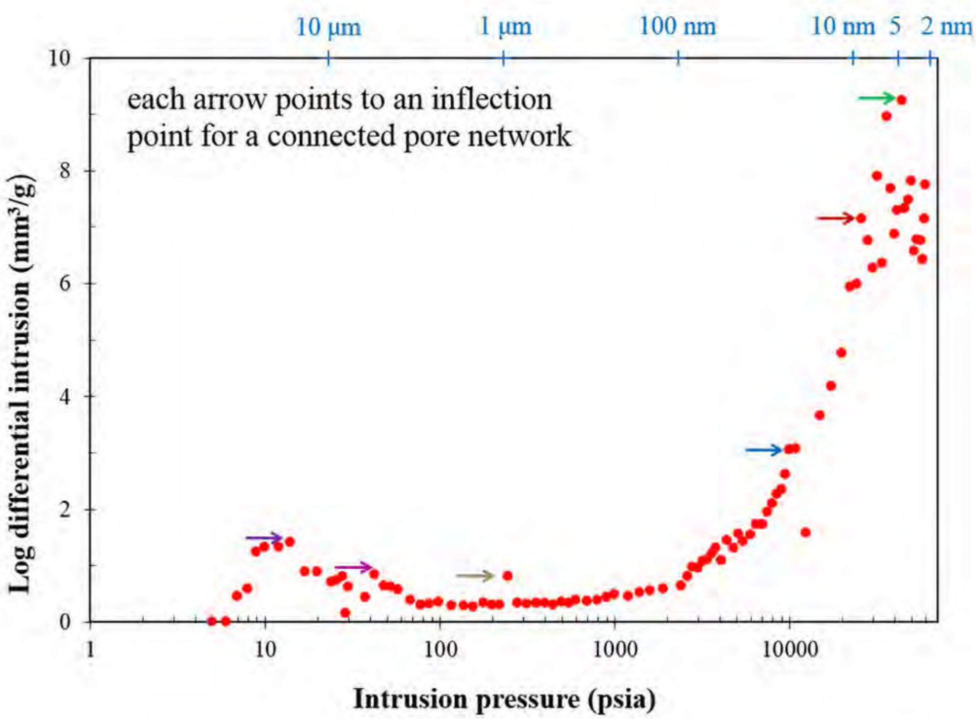


Figure 1-95: Anadarko Basin / Woodford Capillary Pressure Test
From B. Ryan 2017. Woodford Capillary pressure sample from the Anadarko Basin. Note the similarity to the previous Delaware sample, also note how mercury does not enter sample until ~10,000 psi (blue arrow).

1.10 Geomechanics [40 CFR 146.82(a)(3)(iv)]

1.10.1 Methods

Current geomechanical models for the project use offset dipole sonic data to calculate dynamic mechanical properties then published dynamic-static corrections to calculate the two Young's moduli (E_{11} and E_{33}) and three Poisson's ratio (v_{13}, v_{31} and v_{12}) at every foot of the wireline log. These dynamic properties can be used to determine stress magnitude, strength, and other properties. If the rock is not a shale, then it is assumed to be isotropic, and the classical isotropic solution is used. But given the fractured nature of the Devonian and Ellenburger, both formations may alternatively exhibit orthorhombic symmetry. Additional insight on this will be gained once core samples from a test well are tested in a triaxial load frame.

Modeling dynamic mechanical rock properties in a vertically transverse isotropy (VTI) medium requires characterization of five independent stiffness coefficients: C33, C44, C66, C11, and C13. Using the conventional Voigt notation, the 6×6 real symmetric definite positive stiffness tensor of a VTI medium with an axis of symmetry along the x3-axis is shown as follows: (Suarez-Rivera et al. 2009, Gu et al. 2016).

Equation 1-3: VTI Symmetry

Matrix 1, VTI Symmetry

$$\begin{pmatrix} C_{11} & C_{12} & C_{13} & 0 & 0 & 0 \\ C_{12} & C_{11} & C_{13} & 0 & 0 & 0 \\ C_{13} & C_{13} & C_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & C_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & C_{44} & 0 \\ 0 & 0 & 0 & 0 & 0 & C_{66} \end{pmatrix}$$

$$\text{with } C_{12} = C_{11} - 2C_{66}.$$

$$C_{11} > 0; C_{33} > 0; C_{44} > 0; C_{66} > 0; C_{11} > |C_{12}| \text{ and } (C_{11} + C_{12})C_{33} > 2\, C_{13}^2$$

Elastic properties are calculated as follows (**Equation 1-4**) if the rock is isotropic or <10% calculated volume of clay (Gu et al. 2016).

Equation 1-4: Elastic property calculations

$$E_{iso} = \frac{C_{44}(3\, C_{33} - 4\, C_{44})}{C_{33} - C_{44}};$$

$$\nu_{iso} = \frac{C_{33} - 2\, C_{44}}{2\,(C_{33} - C_{44})}.$$

If the rock is anisotropic, as indicated by the volume of clay exceeding 10%, then the more elaborate form of the equations in (**Equation 1-5**) is used to solve for elastic properties. This is due to the change in Tensor matrix. The matrix shown in *matrix 1* is the matrix for VTI symmetry.

E_{vert} corresponds to E_{33}, E_{hor} corresponds to E_{11}, v_{vert} corresponds to v_{31}, v_{hor} corresponds to v_{12} and finally v_{hv} corresponds to v_{13}.

Equation 1-5: Elastic property calculations >10% vclay

$$E_{vert} = \frac{C_{33}(C_{11}+C_{12})-2\,C_{13}^2}{C_{11}+C_{12}};$$

$$E_{hor} = \frac{(C_{11}-C_{12})(C_{33}(C_{11}+C_{12})-2\,C_{13}^2)}{C_{11}\,C_{33}-C_{13}^2};$$

$$\nu_{vert} = \frac{C_{13}}{C_{11}+C_{12}};\nu_{hor} = \frac{C_{33}\,C_{12}-C_{13}^2}{C_{33}C_{11}-C_{13}^2};$$

$$\nu_{hv} = \frac{E_{hor}}{E_{vert}}\nu_{vert}.$$

Once the elastic parameters are obtained minimum horizontal stress and strength are then calculated from the various Young's and Poisson's ratio. Stress is calculated using a modified Eaton equation using the notation from Theirciln and Plumb (1994).

Equation 1-6: Stress calculation

$$\sigma_h - \alpha\,p_p = \frac{E_{hor}\,\nu_{vert}}{E_{vert}(1-\nu_{hor})}\left(\sigma_v - \alpha(1-\xi)\,p_p\right) + \frac{E_{hor}}{1-\nu_{hor}^2}\,\varepsilon_h + \frac{E_{vert}\,\nu_{hor}}{1-\nu_{hor}^2}\,\varepsilon_H$$

The difference between the isotropic and VTI case can be calculated from the following equation (Gu et al. 2016).

Equation 1-7: VTI vs Isotropic

$$\frac{\sigma_h-\alpha\,p_p\,(\mathrm{iso})}{\sigma_h-\alpha\,p_p\,(\mathrm{VTI})} = \frac{C_{33}-2\,C_{44}}{C_{13}}.$$

Stress can also be calculated using an injection test to physically breakdown the rock. When drilling the 1st well, mini hydraulic frac tests will be performed following the procedures from Zoback (2003).

Unconfined compressive rock strength was calculated using a non-linear correlation with Young's Modulus. For the injection units Golubev and Rabinovich (1976) was used, and for shales Chang et al. (2006) was used (**Equation 1-8**).

Equation 1-8: Unconfined Compressive Strength

Shales – $UCS\ (MPA) = 7.22 * E(GPA)^{0.712}$ (Chang et. al. 2006)
Limestones – $UCS\ (MPA) = 13.8 * E(GPA)^{0.51}$ (Golubev and Rabinovich, 1976) (Chang et al. 2006)
Dolomites – $\boldsymbol{UCS\ (MPA) = 25.1 * E(GPA)^{0.34}}$ (Golubev and Rabinovich, 1976) (Chang et al. 2006)

1.10.2 Pore Pressure

The pore pressure was determined from an extensive database of drill stem tests (DSTs) in the Devonian and Ellenburger Formations. The data shows that the pore pressure gradient below the Wolfcamp is <0.49 psi/ft and likely normally pressured at approximately 0.45 psi/ft as this is the P5 of the data. Mud-weights are generally higher than actual pore pressure.

A histogram of the data points in the area is illustrated in **Figure 1-96**. A map of the data points in the area is illustrated in **Figure 1-99**. For the purposes of reservoir modeling and stress modeling, 0.45 psi/ft was used, which represents the P5 of the data in **Figure 1-96**. Mud weights are typically higher than actual reservoir pressure values. All literature and available data suggest the reservoir is normally pressured for its salinity. When multiplied by the expected average depth of 12,568 ft (mid-point depth for the Siluro-Devonian flow unit) a reservoir pressure of 5,655 psi was calculated. The midpoint depth of 13,458 ft is estimated for the Ellenburger, which when multiplied by 0.45 yields a pore pressure of 6,055 psi for Ellenburger formation. Pore pressure will be measured more accurately with a formation testing tool when data is collected after logging.

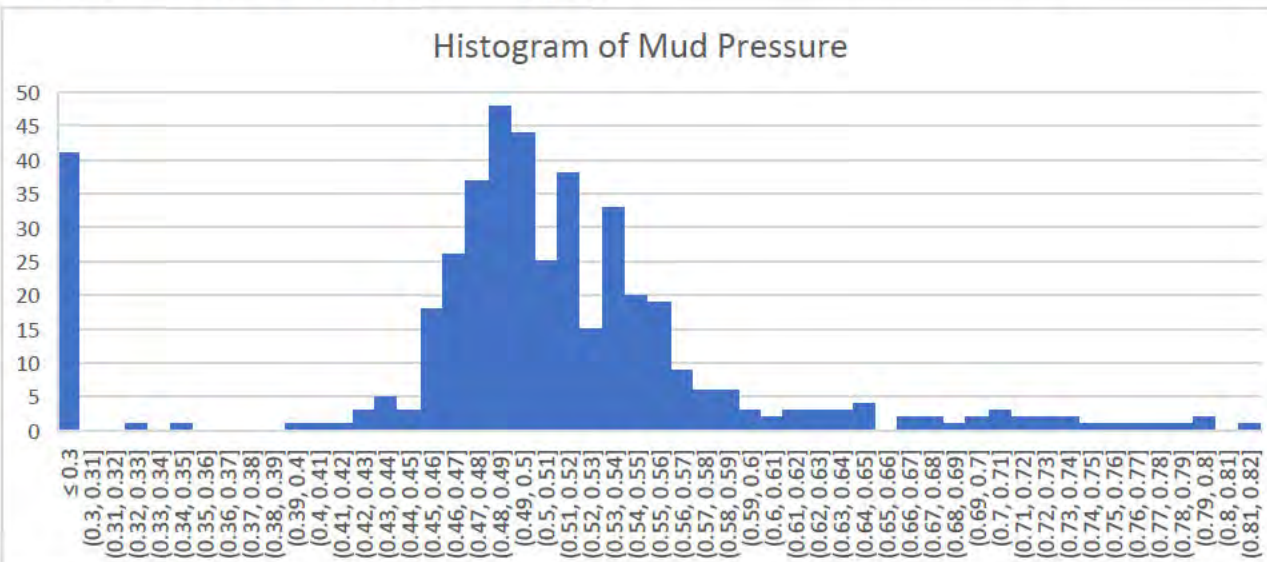


Figure 1-96: DST Tests Mudweights Histogram
Histogram of Mudweights from DST tests within a 50-mi radius of the proposed site, converted to pressure gradients. The data shows that 0.45 psi/ft is the P5 of the data. 403 data points are plotted on this histogram

1.10.3 Stress Magnitude

The minimum horizontal stress magnitude, calculated from offset dipole sonic logs, and extrapolated to the proposed Injection Well are detailed in **Table 1-17**. All closure pressures are greatly in excess of the projected incremental pressure increase of 1,598 psi, therefore no hydraulic fracturing should occur during operations. Woodford Shale and Barnett Shale have been shown repeatedly in literature to be anisotropic with a VTI orientation to the anisotropic tensors. Therefore, the Woodford, Barnett and Simpson minimum horizontal stress was calculated using a VTI matrix. This typically yields higher stress values consistent with testing due to the ratio of E_{vert} to E_{horz} at the beginning of the stress equation. The calculated stress gradient for the three VTI formations is between 0.75 psi/ft-0.8 psi/ft.

Gradients are used since the depth is variable by location. The stress gradients for the non VTI formations or isotropic formations is between 0.71-0.74 psi/ft. At the proposed location the average minimum horizontal stress in the Lower injection zone, the Ellenburger, is 9,663 psi and the weighted average minimum horizontal stress in the upper injection zone, Devonian-Simpson zone, is 8,322 psi (**Figures 1-97, 1-98**). For the simulation, operations and regulatory purposes, 90% of the lowest frac pressure is 7,874.6 psi. This is 90% of the fracture pressure at the very top of the Injection Interval.

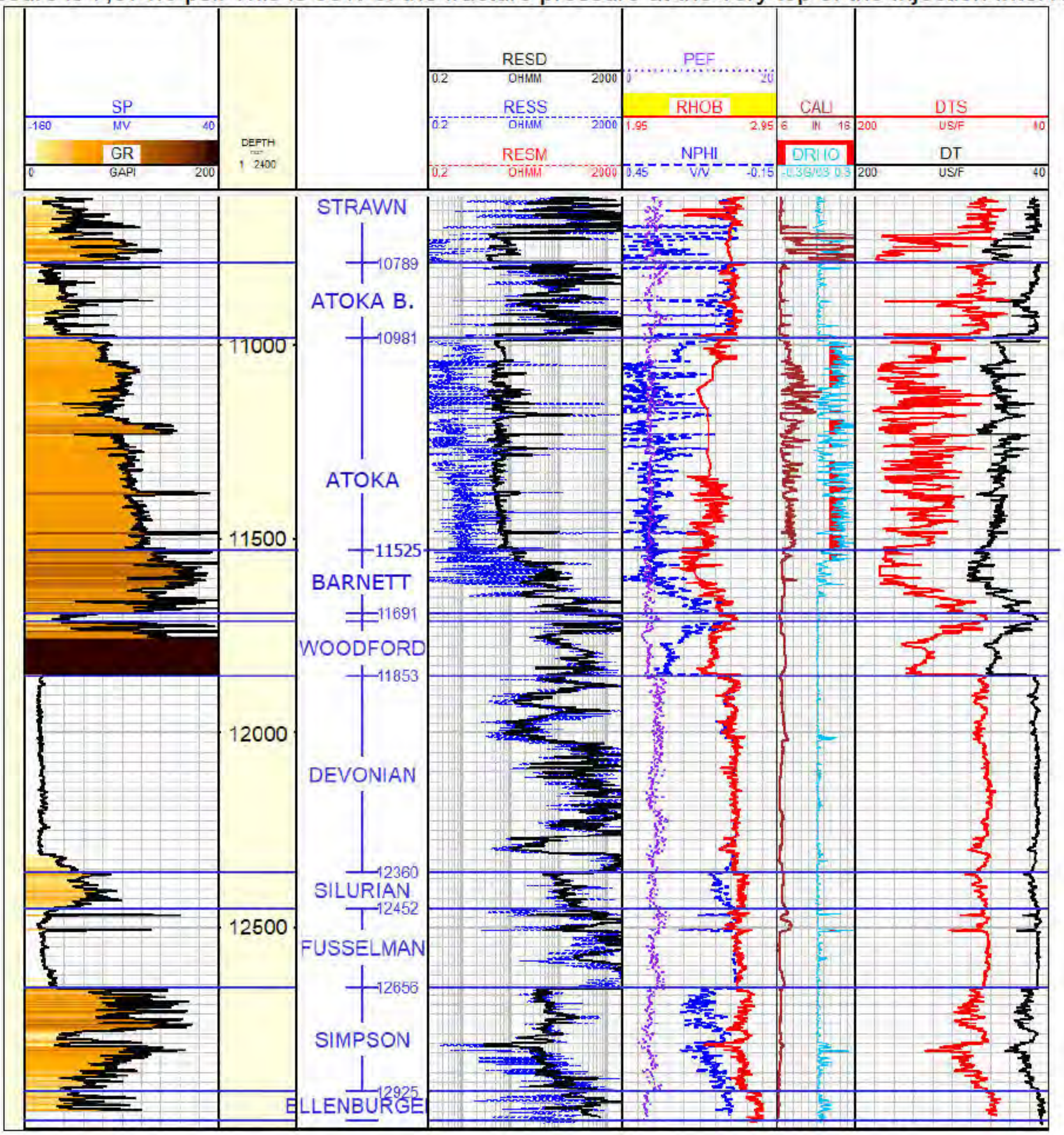


Figure 1-97: Offset dipole well log (*API# 42-329-31741*)

Log plot of an offset dipole well (API# 42-329-31741) to the prospective Midland CCS #2 Well location. Tracks from left to right are gamma ray, depth, formation resistivity, Neutron-Density, caliper, dipole sonic. View in 2-page mode to see full log on next page.

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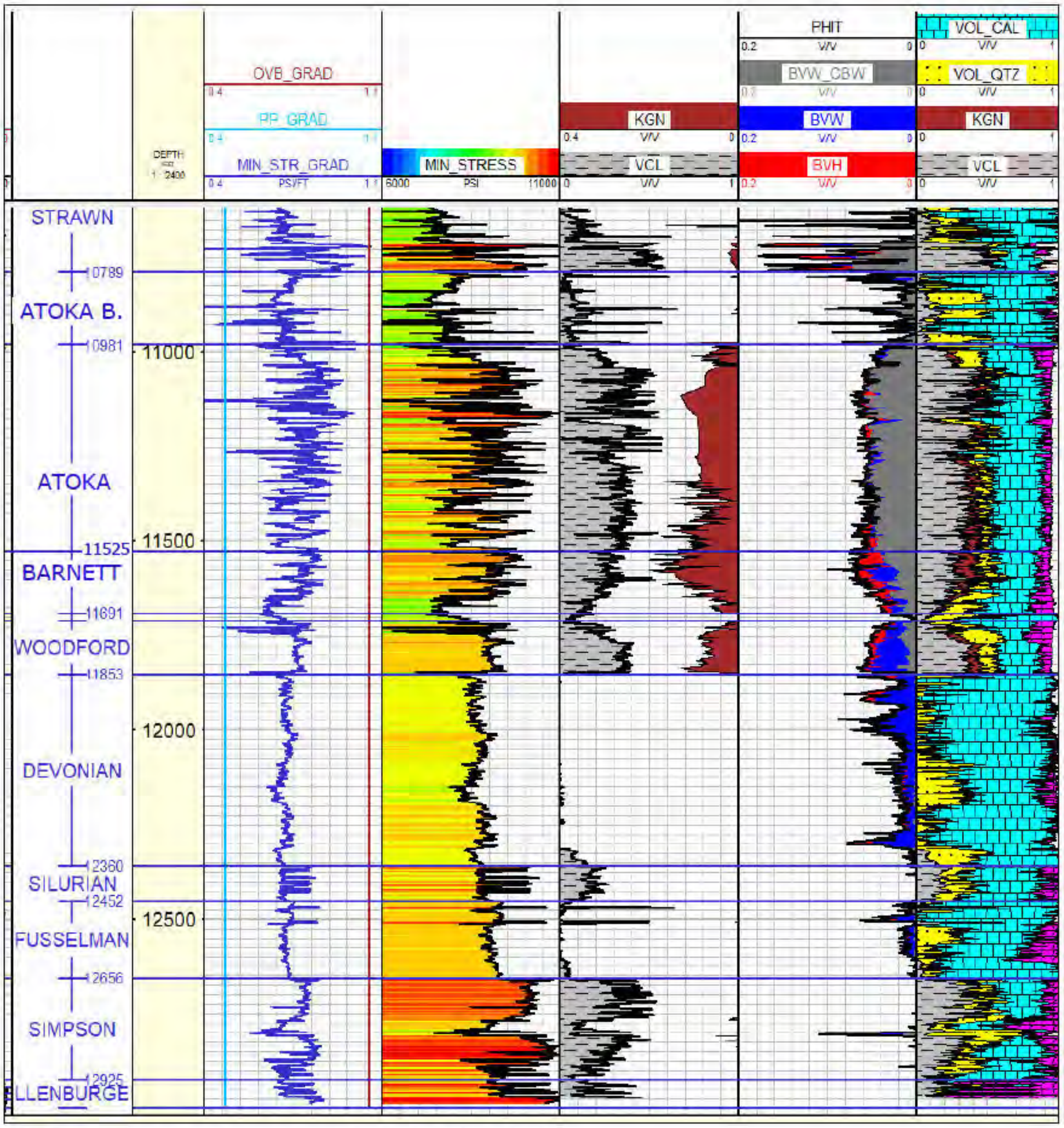

Figure 1-98: Offset dipole well log (API# 42-329-31741)

Log plot of an offset dipole well (API# 42-329-31741) to the prospective Midland CCS#2 Well location. Tracks from left-to-right are: formation tops, Depth, Stress Gradients, Minimum Horizontal Stress, Kerogen and Clay, Porosity and finally mineralogy. View in 2-page mode to see full log on next page with this one. Min. Horz. Stress gradient is scaled from 0.4-1.1 and Min. Horizontal Stress is scaled from 6,000-11,000 psi.

The mechanical properties of the formation are constant with little variation seen within the Devonian section. Ellenburger also is not expected to show significant variation due to its constant dolomitic composition. Minifrac (Zoback et. al., 2003) testing will be done to further explore the stress gradient in the injection unit and seals.

Given the extreme depth of these injection units, it is unlikely that the Injection Well will encounter the fracture gradient.

The maximum simulated bottomhole injection pressure of the injection Well at the top of the Ellenburger is not expected to exceed 7,477 psi which is 1,870 psi below the frac gradient at the top Ellenburger Formation. See **Section 2** for additional information.

Further, even if a 90% minimum horizontal stress threshold is applied, the system would still not approach the limit.

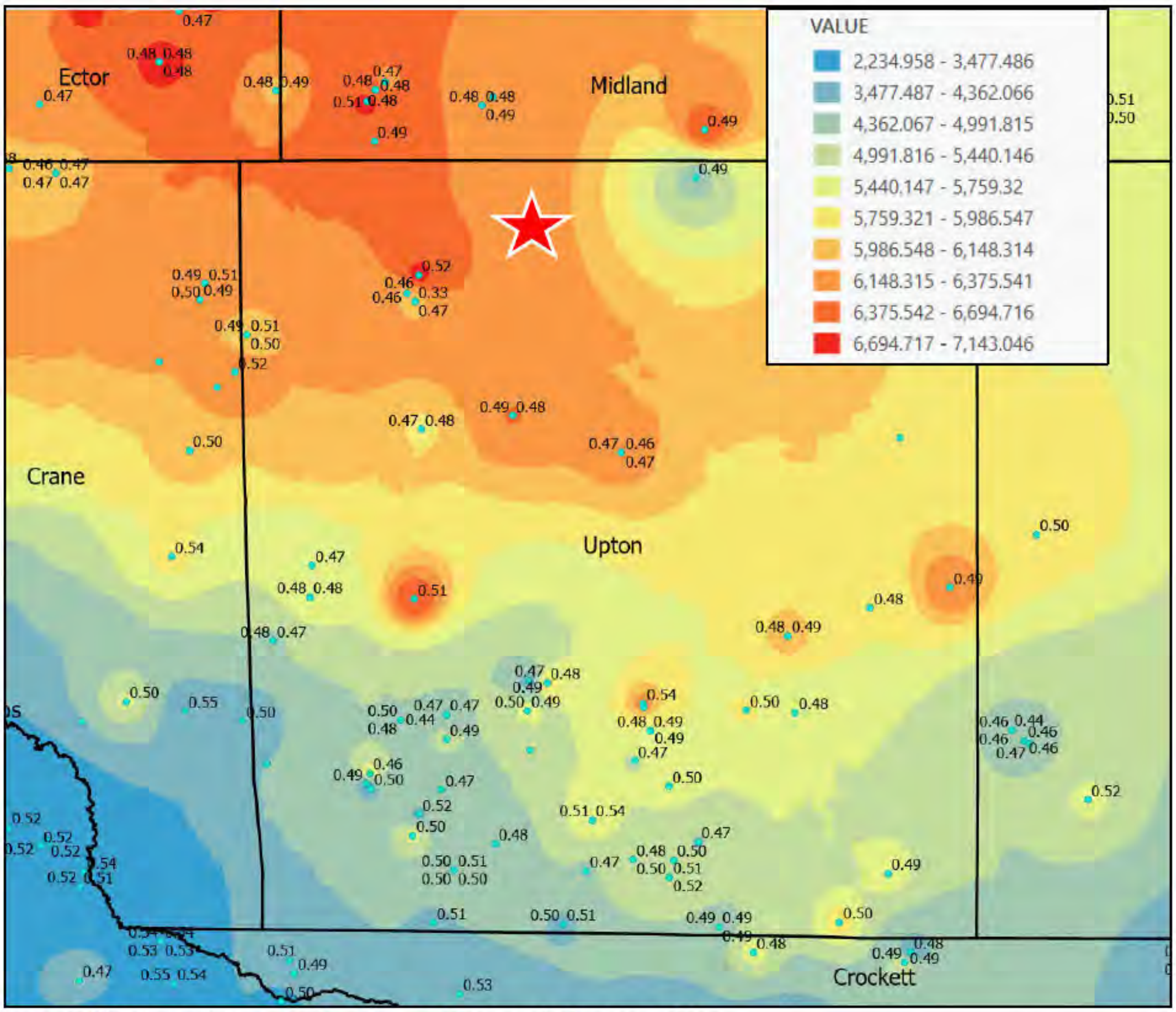

Figure 1-99: Devonian and Ellenburger Reservoir Pressure Map

Map of initial reservoir pressure for Devonian and Ellenburger Formations. Data labels are pore pressure gradients for both intervals. Map is colored by absolute pressure in Devonian. Gradients for each well are posted on map. Local area around Midland CCS #2 shows ~0.45-0.49 psi/ft and ~5900 psi in the Devonian. Red Star indicates proposed location of Midland CCS #2.

Table 1-17: Injection Zones / Seal Stress Gradients & Magnitudes

Table of stress gradients and magnitudes for the Injection units and seals. Stress Magnitudes are calculated from the midpoint depth using the gradients from the offset dipole location. The midpoint is used because the top depth of the formation would be the minimum not the average stress for the formation since stress increases with depth due to Poisson effect. The far-right column is 90% of the minimum stress and assumed to be the upper limit of injection pressure during operations.

Top	Subsea Top (ft)	TVD Top from Ground Elevation (ft)	TVD Mid-Point Depth (ft)	Stress Gradient (psi/ft	Stress Magnitude (psi)	90% of Min Stress (Injection Threshold) (psi)
ATOKA	-8,706	11,503	11,718	0.755838	8,857	7,971
BARNETT SHALE	-9,136	11,933	12,020	0.725989	8,726	7,853
WOODFORD SHALE	-9,309	12,106	12,153	0.781243	9,494	8,545
DEVONIAN	-9,403	12,200	12,452	0.738366	9,194	8,274
WRISTEN GROUP	-9,906	12,703	12,724	0.710537	9,041	8,136
FUSSELMAN	-9,947	12,744	12,840	0.734395	9,430	8,487
SIMPSON	-10,139	12,936	13,001	0.738784	9,605	8,644
ELLENBURGER	-10,269	13,066	13,508	0.715395	9,663	8,697
BASEMENT	-11,152	13,949				

1.10.4 Stress Orientation

Maximum-principal-stress direction is observed to be nearly E-W in the Midland Basin. Most measurements put it at 79 from true N +/- 7.5 in a clockwise direction. (Horne et al., 2024) World Stress Map data shown in **Figure 1-100** illustrates the consistent mostly E-W pattern of stress direction. This has been proven repeatedly by horizontal well development in the basin as well. There is no known stress rotation near the site. Moving farther west, on the Central Basin Platform, and in the Delaware, some rotation is observed to be related to the Guadalupe Mountains and past orogenic events. However, this does not affect the area around the proposed Well. Farther to the east, moving out of the Midland Basin, there is some rotation associated with the Ouachita Thrust Belt that moves through southern Oklahoma. This also is not expected to impact the site. There is high confidence based on repeated tests that the max stress orientation is oriented 79 +/- 7.5° from the north in the Midland Basin in northern Upton County.

1.10.5 Rock Strength

Average unconfined compressive rock strength of the injection and seal intervals is shown in **Table 1-18**. As noted in the methods section, these strength values are correlated from the static vertical Young's modulus. Average rock strength in the injection units is very high given their Paleozoic nature and rigid framework.

All the zones in the injection unit have low porosity ranges. This leads to high unconfined compressive strength values in excess of 14,000 psi. Based on the deep depth ranges, age of the rock, low porosity and high vertical Young's modulus, the expected compressive strength of the rock is very high compared to most sedimentary sections.

The Woodford strength is higher than the Barnett due to the low clay content and high spiculitic chert content of the Woodford Shale. Simpson Group, despite its argillaceous content, exhibits very fast compressional travel times (~58 us/ft) and is expected to have higher strength and Young's modulus than the Woodford or Barnett Shale. The calculated static vertical Young's Modulus for Simpson Group is ~5-8 million psi and calculated strength of Simpson group is 15,618 psi. These values are similar to the Devonian and Ellenburger Injection Unit unconfined compressive strengths.

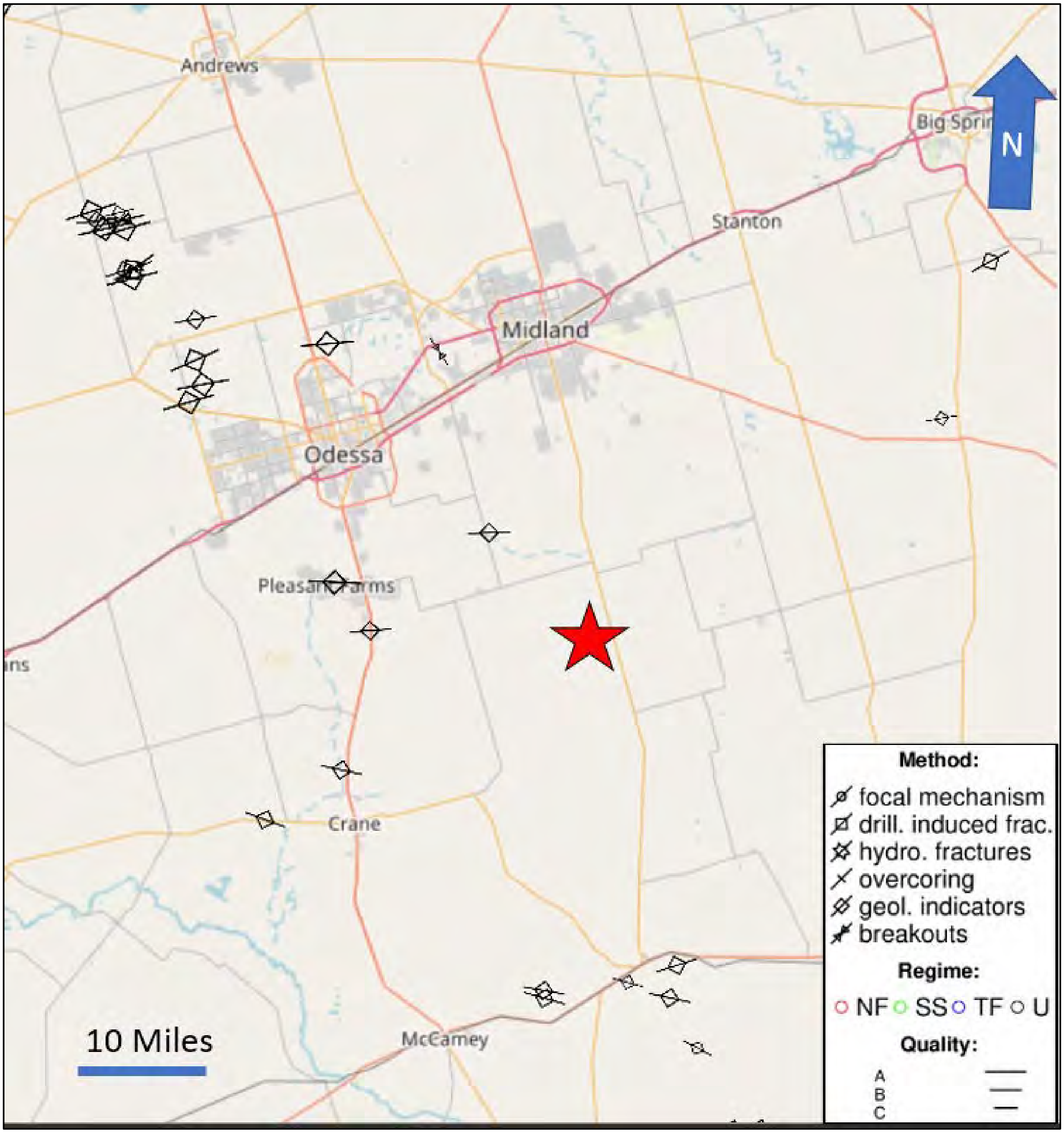

Figure 1-100: Regional Maximum Horizontal Stress Map

Regional maximum horizontal stress direction around the proposed injection Well site. From WorldStressMap.org. Red Star notes proposed location of Midland CCS #2 Well. Observe how all the maximum stress direction measurements are oriented nearly E-W +/- 10 degrees.

Table 1-18: Avg. Unconfined Compressive Rock Strength of the Injection Unit & Top Seal Formations
Average unconfined compressive strength of the injection and sealing formations in megapascals (MPa) (Left) and pounds per square inch (psi) (Right)

Formation	Average Unconfined Compressive Strength (MPa)	Average Unconfined Compressive Strength (psi)
BARNETT	61.46	8,915
WOODFORD	79.06	11,467
DEVONIAN	106.31	15,419
WRISTEN GP	99.10	14,373
FUSSELMAN	109.88	15,936
SIMPSON GP	107.69	15,618
ELLENBURGER	103.64	15,032

1.10.6 Ductility

The ductility of the two injection units (Devonian and Ellenburger) as well as the top seals (the Woodford, Barnett) and mid injection seals (Simpson) will all be examined in additional detail once whole core is acquired from a stratigraphic test well. Dolomite and chert are expected to have very brittle behavior. An example of dolomite low ductility or brittle behavior is shown in **Figure 1-101** (D. Xu, et. al., 2020). Post-failure behavior has steep fall off indicating brittle behavior at lower confining pressures. At higher net confining pressures, this rock like most, takes on a more ductile behavior as confining stress increases. Expected minimum net stress at initial conditions is estimated at 6,529 psi or 45.5 MPa which is very close to the blue example in **Figure 1-101** of 45 MPa confining stress. Detail of net stress calculation found in **Table 1-19.** Result was generated from (**Equation 1-9)**. Ductility and brittle behavior are expected to have minimal impact on the geomechanical model.

Table 1-19: Est. Minimum Net Confining Stress in Ellenburger Dolomite
Estimated minimum net confining stress in Ellenburger dolomite using σ3 = σ2 assumption
Depth = top of Ellenburger at 13,066 ft TVD

Min Horizontal Stress (PSI)	9,663	Net Stress (PSI)	6,529
Biot Coefficient (v/v)	0.8	Net Stress (MPA)	45.017515
Pore pressure (PSI)	5,880		
vertical stress (PSI)	14,373		

Equation 1-9: Net Stress

$$Net\,Stress = \frac{\left((\sigma v - \alpha pp) + 2(\sigma h - \alpha pp)\right)}{3}$$

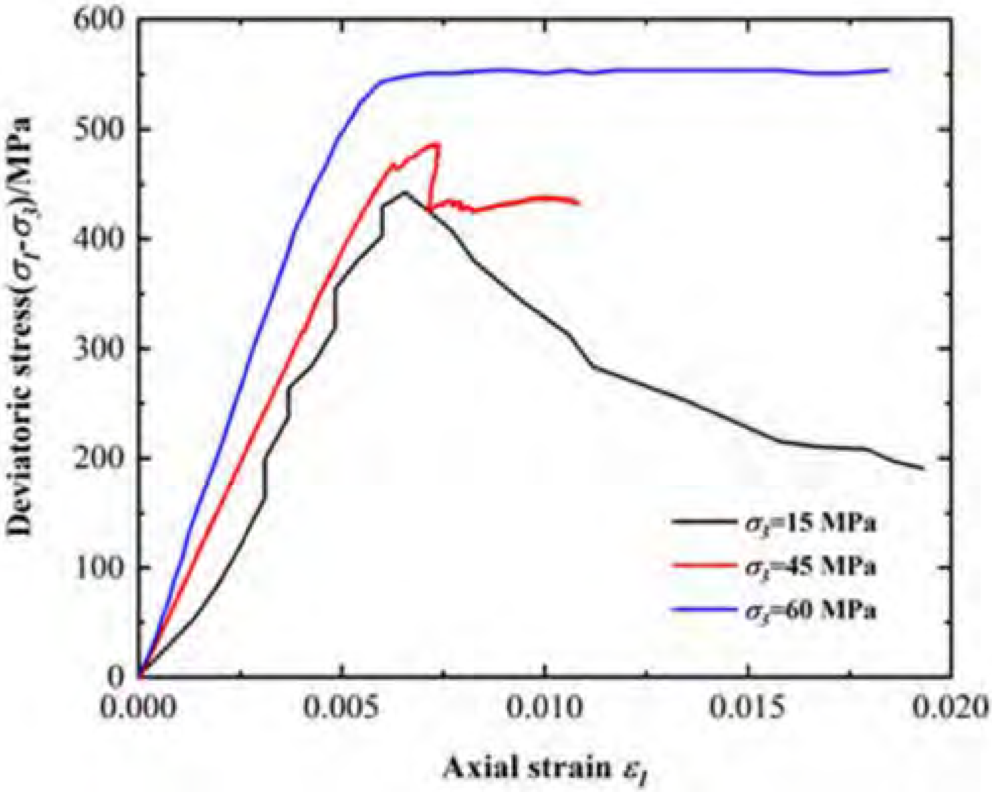

Figure 1-101: Dolomite Triaxial Test from Analogous Low Porosity Dolomite

Dolomite triaxial test from analogous low porosity dolomite found in China. Exhibits brittle behavior at low confining stress (σ3). Red line or 45 MPa is very close to expected initial confining pressure for Ellenburger Formation at proposed Midland CCS #2 Well.

1.10.7 Additional Testing

Extensive additional geomechanics testing will be performed once core material is obtained from a stratigraphic test well. The plan is to conduct full triaxial testing, Brazilian testing, unconfined compressive strength, confined compressive strength, Mohr circle analysis and ultrasonic travel time testing on core plugs obtained from seals and injection units. Multiple confining stresses will be used corresponding to a P10, P50 and P90 confining stress case. This will be used in concert with wireline log measurements and specifically image log data to create a robust geomechanical model at the proposed Midland CCS #2 well location.

1.11 Geochemistry [40 CFR 146.82(a)(6)]

This section covers the fluid and solid-phase geochemistry of subsurface formations in the AoR and modeling of the mineral-brine-CO_2 system across the mineralogical facies associations present for the injection Well.

Milestone Carbon, LLC (Milestone) has requested that Daniel B. Stephens & Associates, Inc. (DBS&A) perform geochemical modeling for a proposed carbon sequestration project in the Midland Basin to help comprehend chemical reactions during carbon dioxide (CO_2) storage in the Siluro-Devonian and the Ellenburger Formations. Information used to perform the modeling was obtained from Milestone's project narrative, the U.S. Geological survey (USGS), and the geologic literature, as well as other data provided by Milestone.

Geochemical modeling was conducted to evaluate the compatibility of the injectate with groundwater and rocks composing the aquifer system. The intent of the modeling is to identify the major potential reactions that may affect injection or containment (U.S. EPA, 2013).

Geochemical modeling using the PHREEQC (pH-REdox-Equilibrium) software was used to calculate the behavior of minerals and changes in aqueous chemistry based on chemical equilibrium conditions (Parkhurst and Appelo, 2013).

1.11.1 Geochemistry for South Midland Facility Project

The Facility is located in the Midland Basin that is part of the Permian Basin. Four geologic units were considered during this evaluation, two for injection and two to act as seals that are briefly described below from deepest to shallowest:

- Ellenburger Group: injection reservoir
- Simpson Group: intrazone sealing unit/low flow unit
- Siluro-Devonian Interval: injection reservoir
- Woodford Formation: Top Seal

The Ellenburger Group consists of rocks formed on a carbonate platform including dolomites and cherts that underwent karstification during the Paleozoic. It is predominantly composed of dolomite and quartz. The Simpson Group consists of marine shale units interbedded with some sand units and is composed of clay minerals including illite. The Siluro-Devonian injection unit is often referred to as simply Devonian. These formations typically consist of two rock types chert or carbonates like packstones. The chert units tend to have greater porosity due to fracturing. The Woodford Shale is the shallowest formation likely to interact with injectate and is a regional series of marine shale units that consist of clay minerals like illite with clasts of calcite, dolomite and quartz. If injectate were to breach the Woodford Shale, the Lower Barnett Shale is likely to act as a secondary seal and have similar reactions to the Woodford Shale due to its high clay content and organic matter. Mississippian Limestones and the carbonate sequence are likely to have similar interactions to the Siluro-Devonian packstone.

While rocks are buried in the Earth's crust, weathering and chemical reactions between the rocks and groundwater are termed diagenesis, which involves the dissolution of minerals into groundwater and precipitation of minerals from solution. Reactions are driven by fluid movement, temperature, and pressure changes due to burial depth and compaction. Over time, minerals and cements may dissolve and form new minerals. Important reactions that have occurred in the rocks of the Midland Basin include the following:

- Precipitation and dissolution of cements and authigenic minerals, consisting of various minerals including quartz, clays, potassium feldspar (K-feldspar), plagioclase feldspar, and particularly calcite, and dolomite
- Dissolution of feldspars, quartz, and carbonates
- Formation of feldspar and quartz overgrowths
- Precipitation of illite, kaolinite, and other clays

1.11.1.1 Brine Geochemistry

Samples were selected from the USGS database for the Ellenburger and Siluro-Devonian injection zones (**Table 1-20**). Sample data includes major ions and pH that were used for geochemical modeling. Concentrations for aluminum (Al), silica (Si), and potassium (K) were not analyzed; therefore, these concentrations were generated based on chemical equilibrium with minerals in the model. With a calculated total dissolved solids (TDS) concentration greater than 100,000 parts per million (ppm), these groundwaters are considered brackish.

The net charge of a water sample may be calculated using the cation and anion analytical results. Because water has a net neutral charge, the sum of the cation and anion charges should be zero. Variations due to sampling and analyses often cause the calculated value to vary, and a value within 5 percent of neutral is considered a "good" balance. The initial charge balances for the samples were good at 0 for the Siluro-Devonian and good at 0 for the Ellenburger. During the modeling, solutions were balanced in PHREEQC by adjusting pH values.

Table 1-20: Composite Brine Chemistry from USGS

Two water samples were selected from the USGS Produced Water Database.

Analyte	Concentration (ppm [a]) Ellenburger USGSID 83694	Concentration (ppm [a]) Siluro-Devonian, USGSID 83572
Bicarbonate	107.8	242.0
Calcium	6,160	10,925
Chloride	95,557.0	95,073.0
Magnesium	490.7	1,524.60
pH (s.u.)	7.02	6.4
Potassium	1045.0	na
Sodium	52,934.2	46,609.2
Sulfate	771.1	577.2
Total dissolved solids	157,576	154,951

[a] Unless otherwise noted

ppm = Parts per million

s.u. = Standard units

na = not analyzed

1.11.1.2 Ellenburger Group and Siluro-Devonian Mineralogy

Mineralogy data were limited for the geologic units of interest. The mineralogy used for the modeling is based on literature descriptions of thin sections and rock cores samples, as well as geophysical logs. The mineral distributions used for this evaluation are based on the literature information. When the stratigraphic test well is drilled, rock core samples will be collected and analyzed for mineralogy and other physical characteristics (**Table 1-21**).

Table 1-21: Mineralogy Input for PHREEQC Selected for South Midland Facility

PHREEQC Mineral	Chemical Formula	Molar Mass (g/mol)	Input for Ellenburger Injection Zone		Input for Simpson Seal Zone		Input for Devonian Injection Zone		Input for Woodford Seal Zone	
			%	mol/L	%	mol/L	%	mol/L	%	mol/L
Quartz	SiO_2	60.08	10	150.1	20	332.9	80	993.0	20	162.4
K-Feldspar	$KAlSi_3O_8$	278.33	0.5	1.6	2	7.2	1	2.7	2	3.5
Calcite	$CaCO_3$	100.09	3	27.0	9	89.9	10	74.5	9	43.9
Dolomite	$CaMg(CO_3)_2$	184.40	80	391.2	20	108.5	2	8.1	20	52.9
Kaolinite	$Al_2Si_2O_5(OH)_4$	258.16	0.5	1.2	3	7.7	1	1.9	3	3.8
Chlorite (14A)	$Fe_2Al_2SiO_5(OH)_4$	664.18	0	0.0	1	2.6	0	0.0	1	1.3
Illite	$K_{0.6}Mg_{0.25}Al_{1.8}Al_{0.5}Si_{3.5}O_{10}(OH)_2$	389.34	6	13.9	45	115.6	6	11.5	45	56.4

g/mol = Grams per mole

mol/L = Moles per liter

1.11.1.3 Injectate Chemistry

For the geochemical modeling, the chemical composition for the carbon dioxide injectate was provided by Milestone (**Table 1-22**).

Table 1-22: Injectate Chemistry Used in Geochemical and Static/Dynamic Models

Gas	Mole Percent	Mass Percent	Volume Percent
Carbon dioxide	95.00	97.72	94.98
Carbon monoxide	0.43	0.28	0.43
Hydrogen sulfide	0.02	0.02	0.02
Nitrogen	1.00	0.65	1.01
Methane	3.56	1.33	3.57

1.11.2 Equilibrium Geochemical Modeling

When modeling groundwater geochemistry, water chemistry, gas chemistry, and mineralogy are used to constrain the model because mineral solubility controls the concentrations of its components in groundwater (Parkhurst and Appelo, 2013). Mineral dissolution-precipitation reactions directly impact the aqueous chemistry. In general, as minerals dissolve, the concentrations in groundwater increase and when minerals precipitate, the concentrations in groundwater decrease. Chemical equilibrium indicates that congruent reactions will appear balanced between reactants and products, with no apparent change in the chemical system.

The PHREEQC model was used to evaluate potential changes to mineralogy and aqueous composition in the subsurface due to carbon dioxide injection. The mineral, gas, and aqueous phases were assumed to be in chemical equilibrium.

1.11.2.1 Geochemical Database

For reactions involving water and minerals, the equilibrium relationship between products and reactant activities (concentrations) can be calculated using known values for parameters like Gibbs free energy found in thermodynamic databases (Parkhurst and Appelo, 2013). Thermodynamic values for these calculations are compiled in databases from several entities including the USGS and Lawrence Livermore National Laboratory (LLNL). A database developed by the USGS for PHREEQC was used (phreeqc.dat) was used for this evaluation. The phreeqc.dat database includes a temperature range for the thermodynamic data provided from 0 to 200-degC and to 1,000 atmospheres pressure (Appelo, 2015). This database is appropriate for the groundwater concentrations, pressure, and temperature used in the modeled scenarios.

When modeling saline waters, the Pitzer database (Parkhurst and Appelo, 2013) is often used, but it has thermodynamic data for a limited number of minerals including calcite, dolomite, gypsum, and quartz. The Ellenburger and Devonian injection zones are composed of some reactive minerals that are not included in the Pitzer database; therefore, the phreeqc.dat database was used because it also includes kaolinite, illite, and the minerals listed in **Table 1-21**.

1.11.2.2 Saturation Indices

Saturation indices (SIs) were calculated to represent whether a particular mineral (e.g., calcite) is in chemical equilibrium with the groundwater (Hem, 1985). SI calculations (**Equation 1-10**) are used to predict if a mineral is likely to precipitate or dissolve in the groundwater and if these reactions changed the concentrations of dissolved elements.

Chemical equilibrium was assumed for the reactions in the model. Equilibrium modeling sets the saturation indices to a zero (0) value for a given mineral. Minerals used in the modeling scenarios were set to their relative abundances. The assumption of chemical equilibrium allows dissolution and precipitation reactions to be quantified in the model.

The formula for calculating SI is as follows:

Equation 1-10: Saturation Index

$$SI = \frac{IAP}{K_{sp}}$$

where SI = saturation index

IAP = ion activity product

K_{sp} = solubility product

Using gypsum as an example (Hem, 1985), the ion activity product of gypsum (IAPgypsum) is the product of the activity (a, activity is approximately equal to concentration in dilute solutions) of calcium (Ca) and sulfate (SO4):

Equation 1-11: Ion Activity Product

$$IAP = a_{Ca^{2+}} \times a_{SO_4{}^{2-}}$$

The solubility product, K_{sp}, is an indication of the relative solubility of a mineral in water. A value less than zero (<0) indicates that the mineral will dissolve and contribute ions to solution and may result in a relatively high activity or concentration. A value greater than zero (>0) indicates that the mineral has a low solubility, may precipitate from solution, and will not contribute many ions to the solution.

For the mineral gypsum, the K_{sp} based on the dissociation reaction of gypsum in water is:

Equation 1-12: Solubility Product

$$CaSO_4 \cdot 2H_2O \leftrightarrow Ca^{2+} + SO_4^{2-} + 2H_2O$$

$$K_{sp} = \frac{a_{Ca^{2+}} + a_{SO_4{}^{2-}} + a_{H_2O}}{a_{gypsum}} = 10^{-4.60}$$

Interpreting the results of the SI calculation is straightforward:

- Log SI > 0 indicates that mineral is supersaturated in solution and may precipitate onto aquifer matrix.
- Log SI = 0 indicates that mineral is at chemical equilibrium with the water.
- Log SI < 0 indicates that mineral is undersaturated in solution and may dissolve from aquifer matrix.

Due to potential systematic errors introduced during sampling and analysis, results within the range of ±0.5 of zero are typically considered in or near chemical equilibrium.

1.11.3 Geochemical Model Pressure and Temperatures

To construct the equilibrium models in PHREEQC, site-specific data were used as input, including measured water chemistry, lithology, and calculated temperature and pressure.

All input data is provided for the water chemistry (**Table 1-20**), the mineralogy (**Table 1-21**), and injectate composition (**Table 1-22**).

Average temperature and pore pressures provided for the project are as follows:

- Ellenburger averages 90-degC with pore pressures beginning at 400.1 atm and increasing to 447.9 atm at the end of injection
- Devonian averages 85-degC with pore pressures beginning at 373.6 atm and increasing to 482.4 atm at the end of injection

1.11.4 Geochemical Modeling Results and Discussion

1.11.4.1 Modeling Steps

Model results showing the changes in mineralogy designated as equilibrium phases in PHREEQC are presented for the modeled geologic units in **Tables 1-23** and **1-24** Model results are presented in **Table 1-25** for the water chemistry based on the equilibrium phases. The modeling steps were as follows:

- Ellenburger Injection Unit: Use the groundwater sample and equilibrate with selected mineralogy (**Table 1-21**) with the given injectate chemistry at initial and final reservoir pressures.

- Simpson Group Intrazone Seal: Use the model results for the Ellenburger at final reservoir pressure and equilibrate with selected Simpson mineralogy dataset (**Table 1-21**) with the injectate chemistry at final reservoir pressure.

- Siluro-Devonian Injection Unit: Use the groundwater sample and equilibrate with selected mineralogy (**Table 1-21**) with the given injectate chemistry at initial and final reservoir pressures.

- Woodford Intrazone Seal: Use the model results for the Devonian at final reservoir pressure and equilibrate with selected Woodford Shale mineralogy dataset (**Table 1-21**) with the injectate chemistry at final reservoir pressure.

1.11.4.2 Equilibrium Modeling Results

Model results showing the changes in mineralogy designated as equilibrium phases in PHREEQC are presented for the modeled geologic units in **Tables 1-23** and **1-24**. Model results are presented in **Table 1-25** for the water chemistry based on the equilibrium phases. Initial results are before injection begins and final results are at the end of injection with elevated pressures.

Equilibrium geochemical modeling of the injection of carbon dioxide indicates that changes in mineralogy and aqueous chemistry are likely to occur, but overall, both geologic units are composed dominantly of silicate minerals such as quartz and feldspar or carbonate minerals that are not expected to be highly reactive during carbon dioxide sequestration.

Although the model indicates that minerals will dissolve and precipitate, the net change in mass is minimal. Based on molar mass, there is a small increase of about 0.3 percent in the injection zones and a small increase of 1.6 to 3.2 percent in the seal intervals. The amount of porosity in the injection zones is not expected to be significantly impacted by mineral precipitation reactions during carbon dioxide sequestration. Mass increase in the seal zones and not expected to dissolve.

The TDS concentration is predicted to increase as dissolved aqueous species increase from the injection gases dissolving in the groundwater. The groundwater is expected to be slightly acidic and to be under reducing conditions.

Based on the modeling, the following reactions are expected to occur in the Ellenburger Group and Devonian Group:

- Illite dissolution may contribute magnesium for the precipitation of dolomite (probably as high magnesium calcite), as well as silica and aluminum that may be at least partially precipitated as other aluminosilicate minerals such as K-feldspar.
- Methane gas is unstable and tends to dissolve.
- Quartz is relatively stable.

- K-feldspar and kaolinite tend to precipitate in the models, removing calcium, magnesium, bicarbonate, silica, aluminum, oxygen, and potassium from solution.
- Calcite dissolves but dolomite (probably as high magnesium calcite) is predicted to precipitate, removing calcium, magnesium, and carbonate from solution.

Based on the modeling, the following reactions are expected to occur in the Simpson Group and Woodford Shale:

- Illite dissolution that may contribute magnesium (Mg) for the precipitation of dolomite (probably as high magnesium calcite), as well as silica and aluminum, which may be at least partially precipitated as other aluminosilicate minerals like k-feldspar.
- K-feldspar and kaolinite tend to precipitate in the models, removing sodium, silica, aluminum, oxygen, and potassium from solution.
- Dolomite (probably as high magnesium calcite) precipitates, removing calcium, magnesium, and carbonate species from solution.

For both geologic units, the formation of carbonates, particularly carbonates, was predicted to occur in every model scenario. The formation of carbonate minerals can be an important mechanism to remove and immobilize carbon dioxide from solution through incorporation in the mineral phase. The CO_2 gas in the injectate will form carbonate minerals, such as dolomite, dissolve into solution, or remain in a gas phase.

Table 1-23: Mineralogy Changes Equilibrium Geochemical Modeling for Ellenburger Injection Unit and Simpson

Mineral	Mineralogical Content (mol/L)											
	Initial	Final	Delta	Initial	Final	Delta	Initial	Final	Delta	Initial	Final	Delta
Sample	*Ellenburger*						*Ellenburger-Simpson*					
Pressure (atm)	*400.1*			*447.9*			*400.1*			*447.9*		
CH4(g)	0.6	0.6	0.0	0.6	0.6	0.0	0.6	0.6	0.0	0.6	0.6	0.0
CO2(g)	16.5	8.1	-8.5	16.5	8.2	-8.3	16.5	0.0	-16.5	16.5	0.0	-16.5
Calcite	27.0	23.7	-3.3	27.0	23.7	-3.3	89.9	68.5	-21.5	89.9	68.7	-21.3
Chlorite(14A)	0.0	0.0	0.0	0.0	0.0	0.0	2.2	0.9	-1.3	2.2	0.9	-1.2
Dolomite	391.2	394.7	3.5	391.2	394.7	3.5	108.5	129.8	21.4	108.5	129.7	21.2
H2S(g)	0.00	0.01	0.01	0.00	0.01	0.01	0.00	0.01	0.00	0.00	0.01	0.00
Illite	13.9	0.0	-13.9	13.9	0.0	-13.9	115.6	55.6	-60.0	115.6	55.7	-59.9
K-Feldspar	1.6	7.2	5.6	1.6	7.2	5.6	7.2	45.6	38.4	7.2	45.6	38.4
Kaolinite	1.2	14.3	13.2	1.2	14.3	13.2	7.7	58.7	51.0	7.7	58.6	50.9
N2(g)	0.17	0.17	-0.0004	0.17	0.17	-0.0004	0.17	0.17	0.00	0.17	0.17	0.0004
Quartz	151.0	156.4	5.5	151.0	156.4	5.5	150.1	146.5	-3.6	150.1	146.4	-3.6

Table 1-24: Mineralogy Changes Equilibrium Geochemical Modeling for Siluro-Devonian Injection Unit and Woodford

Mineral	Mineralogical Content (mol/L)											
	Initial	Final	Delta	Initial	Final	Delta	Initial	Final	Delta	Initial	Final	Delta
Sample	*Siluro-Devonian*						*Siluro-Devonian-Woodford*					
Pressure (atm)	*373.6*			*482.4*			*373.6*			*482.4*		
CH4(g)	0.5	0.5	0.0	0.5	0.5	0.0	0.5	0.5	0.0	0.5	0.5	0.0
CO2(g)	13.4	9.3	-4.1	13.4	9.3	-4.1	13.4	0.0	-13.4	13.4	0.0	-13.4
Calcite	74.5	71.9	-2.6	74.5	71.9	-2.6	43.9	29.5	-14.3	43.9	29.6	-14.3
Chlorite(14A)	0.0	0.0	0.0	0.0	0.0	0.0	1.3	1.2	0.0	1.3	1.2	0.0
Dolomite	8.1	11.0	2.9	8.1	11.0	2.9	52.9	67.2	14.3	52.9	67.2	14.3
H2S(g)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Illite	11.5	0.0	-11.5	11.5	0.0	-11.5	56.4	0.0	-56.4	56.4	0.0	-56.4
K-Feldspar	2.7	8.2	5.5	2.7	8.2	5.5	3.5	38.0	34.5	3.5	38.0	34.5
Kaolinite	1.9	12.4	10.5	1.9	12.4	10.5	3.8	51.4	47.6	3.8	51.4	47.6
N2(g)	0.14	0.14	-0.00003	0.14	0.14	-0.00003	0.14	0.14	0.00003	0.14	0.14	0.00003
Quartz	993.0	995.8	2.8	993.0	995.8	2.8	162.4	161.1	-1.3	162.4	161.1	-1.2

Negative (–) delta value indicates that mineral or gas dissolves into solution, while positive (+) delta value indicates that mineral precipitates from solution.

mol/L = Moles per liter

atm = Atmospheres

Based on the equilibrium modeling, the aqueous chemistry results are provided in **Table 1-25**. Results indicate the following:

- Carbon dioxide will dissolve into solution and is included in the total inorganic carbon (TIC), which also includes bicarbonate and carbonate species. Results indicate that when carbon dioxide is dissolved in solution, the following dissolved species will occur as the following ions and complexes:
  - ✓ carbon dioxide,
  - ✓ bicarbonate ion,
  - ✓ sodium bicarbonate,
  - ✓ calcium bicarbonate ion,
  - ✓ calcium carbonate,
  - ✓ iron bicarbonate.
- The pH values ranged from 4.4 to 5.8.
- The pe remains negative, indicating reducing conditions.
- The calcium in solution includes the following ions and complexes:
  - ✓ calcium,
  - ✓ calcium bicarbonate,
  - ✓ calcium chloride,
  - ✓ calcium carbonate.

Table 1-25: Modeled Equilibrium Aqueous Concentrations

Constituent	Concentration (mg/L [a])							
Geologic Zone	*Ellenburger*		*Ellenburger-Simpson*		*Devonian*		*Devonian-Woodford*	
Pressure (atm)	*400.1*	*447.9*	*400.1*	*447.9*	*373.6*	*482.6*	*373.6*	*482.6*
Al^{3+}	0.005	0.006	7.700	8.404	0.008	0.010	0.014	0.015
TIC	206847	202622	78.646	76.181	38795	37034	50.0	45.9
Ca^{2+}	16	14	2,684	2,657	13	11	442	379
Cl^-	113,334	113,334	113,334	113,334	112,483	112,483	112,483	112,482.9
K^+	108,112	108,112	12,641	12,688	54,701	54,466	29,325	29,450
Mg^{2+}	10	10	90	90	7	7	32	31
Na^+	62832	62832	62832	62832	55,153	55153	55,153	55153
SO_4^{2-}	340	342	0.6	1	140	147	0.1	0.1
SiO_2	5	5	0.000002	0.000002	9	9	0	0
TDS (sum)	491,495	487,271	191,667	191,686	261,301	259,311	197,486	197,542
pH (s.u.)	5.5	4.4	4.4	5.5	5.8	5.8	4.7	4.7
pe (unitless)	-3.1	-2.1	-2.1	-3.1	-3.3	-3.4	-2.4	-2.4

[a] Unless otherwise noted

mg/L = Milligrams per liter

atm = Atmospheres

TDS = Total dissolved solids

s.u. = Standard units

TIC = Total inorganic carbon (CO2, HCO3)

1.11.5 Conclusion

Based on the geochemical equilibrium modeling, the injection of carbon dioxide at the South Midland Facility site into the Ellenburger Group and Siluro-Devonian Interval is not predicted to cause significant water-rock-gas reactions that will affect the injection or containment of the gas.

1.12 Mineral Resources

Milestone performed a review of all wells located within ten (10) mi of the proposed Well location in order to confirm there are no mineral or hydrocarbon resources located within or beneath the proposed CO_2 storage site. There are approximately 43,610 oil and gas wells in Midland and Upton Counties. Fortunately, none of these wells penetrate the Top Seal or the Injection Interval within the AoR.

There are **zero (0) oil and gas wells identified within the AoR** or within the same fault block that produce hydrocarbons from Siluro-Devonian-aged or Ordovician-aged sections. There are eleven (11) saltwater disposal wells (SWD) within a 10-mile radius that inject into the Ellenburger Group. Indicating that the Railroad Commission does not believe producible hydrocarbons are present at the extreme depth of the injection interval.

Additionally, there are also wells within the 10-mile radius that were drilled deep presumably to explore for oil and gas reserves below the Permian or Pennsylvanian strata but then plugged back to the Permian strata for production. These are not included in this analysis, although they are ancillary proof that no hydrocarbons have been discovered in the deep paleozoic strata despite repeated exploration attempts. These negative tests confirm the lack of hydrocarbons in the area. One such well is the Maralo 41 #9 (API# 42-329-37731). It was drilled with a TD of 12,200ft in Midland County, but then plugged back to 9,112 feet-11,970 feet to produce from the Wolfcamp and Strawn formations. It should be noted that these negative tests do not occur within the AoR.

Figure 1-102 illustrates the offset wells with identified production from any formations within the injection interval. The fault layer from Horne et al., 2024 is shown next to production indicating that nearly all Siluro-Devonian and Ordovician production is associated with fault trapping and wells are typically drilled within 1,000 feet of a fault. Since Milestone's proposed Injection Well location is not located within 8,000 feet of any known faults, it is unlikely that hydrocarbons will be discovered in commercial quantities.

The nearest producing well to the Midland CCS #2 Injection Well location is the Meiners F #2 (API# 42-461-32194) well operated by Exxon Mobile. It has been inactive since June of 2020 and is likely scheduled to be plugged and abandoned. Production when the well was shut-in had already collapsed to less than 1 barrel of oil per day. This well does NOT occur within the AoR, and it is separated from the Injection Well by a sealing fault. (**Fig. 1-102**)

The nearest producing well that is still active is the Neal 45 #4502 (API # 42-461-40010) operated by Ovintiv. It is located approximately 8 miles to the southwest from the Injection Well location and unlikely to be impacted by injection operations. It is separated from the Injection Well by two sealing faults. (**Fig. 1-102**) The Midkiff A #2608 and TXL N 17-6 #5 are both inactive.

The only major field in the region is the Pegasus field which is a massive horst block bounded by large NNE-SSW regional fault systems. The Pegasus field is located approximately 9 miles west of the Injection well location and is separated from the injection interval by several sealing reverse faults. It also occurs approximately 500ft above the TVD of the injection location. See **Section 1.7** for additional information on structural geology.

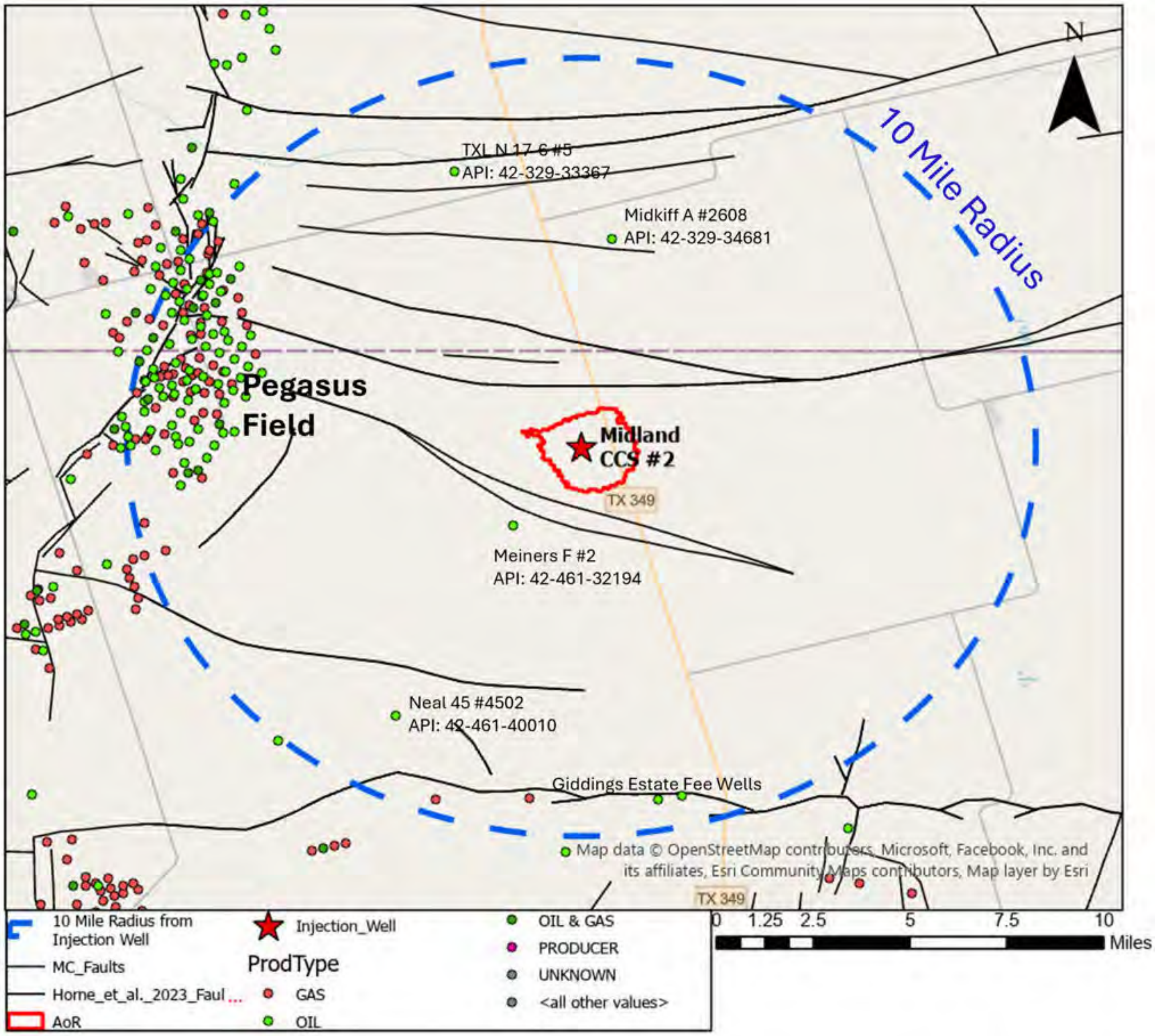

Figure 1-102: Map of Oil and Gas Wells to Penetrate Devonian

Map of wells identified to penetrate Devonian geologic section within 10 mi of Milestone's proposed Midland CCS #2 Well location. Notes differentiate between Devonian and Ellenburger producers, injectors, and dry holes.

1.13 Site Suitability [40 CFR 146.83]

The proposed Well is sited in a geologically suitable area. Specifically, the injection zone is suitable because it is of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream. Additionally, the confining zone is suitable because it is free of transmissive faults or fractures. It is also of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone.

Further, the proposed injection formation is not a USDW and, as previously noted, is 11,000 ft deeper than the nearest USDW. The extreme depth interval and numerous secondary sealing formations indicate this site and injection unit afford Milestone with high certainty that the USDW will not be impacted by injection operations.

1.13.1 Subsurface Distribution of Facies and Fractures – Implications for CO_2 plume migration

See **Section 1.7.4** for additional information on lithology.

See **Section 2** for additional information on plume modeling

There are four (4) major facies expected to be present in the injection reservoir.

1) chert
2) packstone
3) dolostone
4) claystone

Each of these facies is low porosity, probably <10% and often <5% porosity. The main conduit for CO_2 plume migration will be along natural fracture planes within these facies. The degree of fracturing is a function of facies, with dolostone and chert expected to have the most fracturing based on core studies (Loucks and Kerans, 1994).

The claystone in the upper confining layer is expected to be minimally or not fractured due to its much lower elastic moduli. The packstone facies are expected to have 1/3 - 1/6 as many fractures as the chert facies and not contribute as much flow capacity to the system.

Fracturing has been documented in core and corroborated with history matching on existing injectors in the area such as the Davidson well to the NW of the proposed site.

The systemic fracturing of the Ordovician and Devonian intervals may yield some unusual plume geometries if the fracture system is not random.

However, current data indicates that the fracturing is chaotic and should behave like an enhanced permeability system at large scale if there is no directional bias to the fracture network.

Therefore, even though fractures add complexity to the plume modeling, there is strong reason to believe the plume will ultimately take on a radial form around the injection well since the fractures are chaotic and pervasive in the system. Additional image log data will corroborate this hypothesis at the injection site.

Finally, there are eleven (11) saltwater disposal (SWD) wells within 10 miles of the proposed injection well, that have proved the concept of injection at high volumes into the formation. The pressure from these wells will not interfere with injection well due to either fault separation or distance.

Thus, the site is highly suitable for CO_2 sequestration and ultimately behaves like a low permeability continuous reservoir with fracture enhancement. Each facies contribute to the overall injectivity, but the dolomite and chert are expected to take more than the packstone. Finally, the contribution from claystone is minimal, but not zero.

1.13.2 Injectability

As noted in **Section 1.9.3,** regarding permeability, total injectability will ultimately be a function of fracture density and pattern of fractures with a second order contribution from the matrix permeability. Additionally, a history match of the three offset wells, Davidson #0106BH (API: 42-461- 40597), Clay Henry SWD #1 (API:42-329-42349), and Senor Salado SWD #17SD (API: 42-329-42946) brine injection pressure data was performed to attempt to understand the permeability of the system (**Section 2**).

The study results corroborated results found in Sanchez et al., 2019 showing the wells had sufficient permeability and had uplift close to the basin axis. Average apparent permeability was ~4mD. The initial petrophysically modeled permeability was reduced to match the history matches. This will continue to be refined as more test well data becomes available.

Additional information on the history match, permeability multipliers and injection simulation may be found in **Section 2.**

1.13.3 Carbon Dioxide Containment

Carbon dioxide containment in the proposed site is very high for the following reasons

- Thick impermeable shale above injection unit
    - ✓ Woodford, Barnett and Atoka combine to create 700+ ft of vertically impermeable shale. Horizontal perms are <100 nanodarcy (nD) and vertical perms are <10 nD
    - ✓ Observed difference in pressure gradients above and below shales
    - ✓ Pressure and Salinity evidence that the system has been sealed over geologic time
- Lack of nearby faults
    - ✓ Nearest fault is 1.6 miles to the north of the Injection Well.
    - ✓ See **Section 1.8** for additional details
- No historical artificial penetrations or existing artificial penetrations
    - ✓ See **Section 1.3** on AoR for additional details
- Thick, low permeability, laterally continuous reservoir
    - ✓ See **Section 1.9** on Petrophysics for additional details
- Low dip and flat structure
    - ✓ **See Section 1.7** on structural geology for additional details
- 11,000’ between top of injection and base of USDW
    - ✓ Multiple secondary confinement zones between injection zone and USDW
    - ✓ See **Section 1.4** and **Section 1.5** for additional information
- Lack of seismic events in area
    - ✓ Only three (3) M2 events near the site recorded approximately 9 mi west near Pegasus Field fault
    - ✓ Nearest area of significant seismic activity is 25 mi north of the proposed site, just south of the town of Midland, Texas
    - ✓ See **Section 1.8.2** for additional information

1.13.4 Secondary Confinement Zones

Above the primary confining zone of the Woodford shale are several zones that would impede the rise of CO_2 based on low vertical permeability (<100 nD) (Kv) and very high threshold entry pressures (>7500 psi). These zones, in order from bottom to top, that would be difficult for CO_2 to penetrate are:

- Barnett shale – organic shale with high clay content and pore pressure
- Atoka shale – friable argillaceous shale also within the over-pressured window
- Canyon Shale – organic shale with high clay content above Strawn
- Cisco Shale – organic shale with low porosity, low K and high clay content
- Wolfcamp Shale – over pressured organic shale that has oil and gas production within it
- Spraberry Formation – sand shale sequence that has trapped hydrocarbons in the past
- San Andrews – highly permeable but has very high positive pressure due to salt water injection
- Artesia Group – Thick section of Anhydrites and tight carbonates
- Undifferentiated Permian shale above the Artesia Group

Refer to **Section 1.5** and **1.7** for more information on stratigraphy in the region. All of the above formations are likely to impede any CO_2 plume vertical containment breaches due to their low vertical permeability (<100 nD) and very high threshold entry pressures (>7,500 psi). In the infinitesimal chance event that CO_2 were to escape up to the Wolfcamp level, there are a number of hydraulically fractured horizontal oil and gas wells in the region that could create pathways to surface. See **Section 1.3** and **Section 2** for more information on wells penetrating zones above the primary seal. However, given the cumulative vertical thickness of the secondary seals with low Kv before the Wolfcamp, (~3,000 ft) this is extraordinarily unlikely.

Additionally, Milestone has taken steps to directly monitor the Pennyslvanian section for *out of zone* leaks. See **Section 6** for additional information on monitoring.

1.13.5 Carbon Dioxide Interaction with Well Materials and Formation

The well head, tubulars and other components that CO_2 could potentially touch are all designed with rigorous corrosion resistant materials that meet or exceed EPA requirements (**Section 13, Appendix A – Metallurgical Analysis**). Milestone will use 22/25 chrome in all well components that have the possibility of corrosion. Additionally, Milestone will employ cutting edge CO_2 resistant cement and downhole safety valves.

The Ellenburger and chert facies of the Devonian are expected to be resistant to acid. Chert and dolomite are not known to react with weak acids and the geochemistry models reflect that (**Section 1.11**). The Packstone facies in the upper Devonian is modeled to have mild dissolution and the shale facies should actually become an even more effective seal due to mineral precipitation. In summation, the chemical interactions are not expected to alter injection or sealing properties of the formation, nor will the well components have corrosion issues.

See **Section 1.11** for additional information on carbon dioxide – reservoir interactions. See **Section 3** and **Section 6** for additional information on well design and component corrosion resistance as well as corrosion testing. Finally, see **Section 13, Appendix A** for a Metallurgical Analysis.

1.13.6 Total Storage Capacity

The Ellenburger and Devonian are regional, multi-state formations that span hundreds of miles in any direction with similar properties. Therefore, any estimation of total storage capacity must be constrained either by number of wells or surface acreage ownership. Using a methodology from S. Bachu, 2006 and adapted by A. Haecker, 2022 as seen in (**Equation 1-13**), the total storage for the site will be in excess of 12 million tonnes under the area of the of the AoR or maximum CO_2 saturation extent. Parameters for this result are located in **Table 1-26**.

It should be noted that this method does not account for frac gradient pressure, or migration due to buoyancy and is simply a volumetric solution. The area of the AoR has an estimated efficiency of 8.88%. Given the fractured nature of the storage system and the low porosity values, it is not surprising that the system has higher than average efficiency.

Equation 1-13: CO_2 Storage Capacity Equation (Haecker, 2022)

$$CO2 = \frac{43560 * 62.42 * A * H * \emptyset_t * (1 - SW_{irr}) * \rho_{CO2} * E_{CO2}}{Bg_{CO2} * 2204.623}$$

CO_2 is the storage in tonnes/acre or tonnes/square mi if 640 acres is used for A. Where A is the area, H is the reservoir height, Φ is total porosity, Sw_{Irr} is irreducible water saturation, ρ_{co2} is the mean CO_2 density, Eco2 is the injection efficiency, Bg_{Co2} is the formation volume factor (if surface density of CO_2 is used, otherwise set to 1).

Table 1-26: AoR Maximum Plume Extent

		Devonian Injection Unit	Ellenburger Injection Unit
Average Porosity	%	3	4
Thickness	ft	969	783
Pi (midpoint of interval)	psi	5,656	6,078
Pmax (midpoint of interval)	psi	7,254	7,676
Temp	F	189	199
CO_2 Density Pi	g/cc	0.79222	0.79330
CO_2 Density Pmax	g/cc	0.83921	0.85316
Storage @ 10% efficiency	tonnes/square mi	1,925,631	2,109,160
Capacity in Area of Review (3.315 sq. mi)	tonnes	6,383,465	6,991,865

Total Storage in AoR At 10% efficiency	tonnes	13,375,330
Proposed Injection	tonnes	11,876,942
Estimated Efficiency Factor based on Simulation	%	8.8797%

1.14 Well Index Tables

1.14.1 Water Well Index Table

These index numbers are used in **Section 1.3** to delineate wells since it is cumbersome to identify each well with well names or TCEQ# given their concentration. Please refer to **Table 1-27** and the cross reference with maps in **Section 1.3** to determine the water well information, if it is known. There are a number of undocumented water wells on the property that Milestone has located during surveys.

Table 1-27: Water Well Index Table

Water Well Index Number	Latitude (NAD 83)	Longitude (NAD 83)	TWDB Well ID #	County Name	Total Depth Well	Drill Date	OWNER	Well Type
1	31.630828	-102.018046	292926	Upton	280		Carlos Dusek	Rig Supply
2	31.630827	-102.018045	54047	Upton	280	8/17/2010	Carlos Dusek	Withdrawal of Water
14	31.632773	-102.010547	232769	Upton	290		Dusek, Carlos	Irrigation
19	31.616939	-102.008603	64247	Ward	8		Celero Energy	Environmental Soil Boring
39	31.622500	-101.999722	4425108	Upton	180	6/7/1999	Warren Skaggs	Withdrawal of Water
40	31.622494	-101.999712	54297	Upton	180		Warren Skaggs	Withdrawal of Water
41	31.638889	-101.999445	4417702	Upton	271	5/25/1999	Warren Skaggs	Withdrawal of Water
42	31.638883	-101.999435	53465	Upton	271	4/25/1964	Warren Skaggs	Withdrawal of Water
48	31.641106	-101.997491	235530	Upton	265		Dusek, Carlos	Irrigation
49	31.641105	-101.997490	54008	Upton	265	4/13/2009	Dusek, Carlos	Withdrawal of Water
54	31.609933	-101.996016	53786	Upton		1/31/1953	Mobil Oil Company	Oil or Gas
62	31.614753	-101.992801	53552	Upton		7/15/1956	Paul L. Davis	Oil or Gas
65	31.606112	-101.992500	4425103	Upton	225	5/27/1999	Henry F. Neal	Withdrawal of Water
66	31.606106	-101.992490	54299	Upton	225	4/30/1905	Henry F. Neal	Withdrawal of Water
75	31.615189	-101.989185	538973	Upton	280		Carlos Dusek	Irrigation
78	31.620833	-101.988889	4425102	Upton	280	5/27/1999	John Fisher	Withdrawal of Water
79	31.620827	-101.988879	54392	Upton	280	5/14/1905	John Fisher	Withdrawal of Water
82	31.638606	-101.988325	298569	Upton	150		Diana Fox - Lazy A Ranch	Stock
95	31.642217	-101.986102	389264	Upton	300		Hi Roller Wells	Domestic
100	31.610556	-101.985000	4425106	Upton		5/27/1999	Paul L. Davis Windham No. 1-9	Oil or Gas
111	31.632495	-101.983046	402827	Upton	320		Medallion Midsteam	Fracking Supply
121	31.617212	-101.980208	463758	Upton	270		MBA Construction	Domestic

Water Well Index Number	Latitude (NAD 83)	Longitude (NAD 83)	TWDB Well ID #	County Name	Total Depth Well	Drill Date	OWNER	Well Type
127	31.625313	-101.978987	53546	Upton		9/1/1956	Nutter and Wilbanks Brothers	Oil or Gas
133	31.612773	-101.976935	350577	Upton	290		Carlos Dusek	Irrigation
134	31.612773	-101.976935	350579	Upton	290		Carlos Dusek	Irrigation
135	31.612772	-101.976934	54069	Upton	290	12/18/2013	Carlos Dusek	Withdrawal of Water
140	31.607100	-101.975325	4425107	Upton	250	9/28/1999	TxDOT Roadside Park	Withdrawal of Water
145	31.633055	-101.970278	4417701	Upton	200	3/23/1999	Ray Barrett Headquarter s	Withdrawal of Water
146	31.633049	-101.970268	54168	Upton	200	4/20/1905	Ray Barrett	Withdrawal of Water
151	31.621977	-101.959702	53815	Upton		8/10/1980	Tamarack Petroleum	Oil or Gas
153	31.601945	-101.958612	4425101	Upton	220	5/27/1999	Henry F. Neal	Withdrawal of Water
154	31.601939	-101.958602	54301	Upton	220		Henry F. Neal	Withdrawal of Water
155	31.615054	-101.957356	53790	Upton		3/22/1956	J.E. Jones Drilling	Oil or Gas
WATER WELLS WITH NO DOCUMENTS BELOW, LOCATION FOUND BY MILESTONE SURVEYORS								
3	31.626211	-102.012955						
4	31.626419	-102.012952						
5	31.626495	-102.012652						
6	31.624535	-102.012357						
7	31.626554	-102.012329						
8	31.626628	-102.012076						
9	31.624624	-102.012045						
10	31.626606	-102.011905						
11	31.624712	-102.011716						
12	31.624780	-102.011427						
13	31.631471	-102.010827						
15	31.604672	-102.010149						
16	31.604789	-102.009674						
17	31.607390	-102.009017						
18	31.605008	-102.008757						
20	31.605237	-102.007799						
21	31.602968	-102.007532						
22	31.605476	-102.006891						
23	31.605598	-102.006387						
24	31.605678	-102.005887						
25	31.608265	-102.005299						

Water Well Index Number	Latitude (NAD 83)	Longitude (NAD 83)	TWDB Well ID #	County Name	Total Depth Well	Drill Date	OWNER	Well Type
26	31.605915	-102.004945						
27	31.606026	-102.004567						
28	31.603828	-102.003862						
29	31.606399	-102.002713						
30	31.636782	-102.002365						
31	31.605769	-102.002096						
32	31.609126	-102.001512						
33	31.638973	-102.001340						
34	31.597119	-102.000461						
35	31.635734	-102.000335						
36	31.608997	-102.000192						
37	31.604755	-102.000031						
38	31.628915	-101.999821						
43	31.607405	-101.998903						
44	31.602226	-101.998709						
45	31.623213	-101.997834						
46	31.629398	-101.997792						
47	31.610111	-101.997674						
50	31.597843	-101.997332						
51	31.619317	-101.996561						
52	31.625298	-101.996385						
53	31.605659	-101.996233						
55	31.623660	-101.995911						
56	31.622078	-101.995384						
57	31.615547	-101.995340						
58	31.630121	-101.994635						
59	31.617616	-101.993991						
60	31.615953	-101.993507						
61	31.614317	-101.992916						
63	31.626152	-101.992553						
64	31.613312	-101.992501						
67	31.612569	-101.992283						
68	31.624149	-101.992270						
69	31.611354	-101.992042						
70	31.615968	-101.991412						
71	31.609223	-101.991308						
72	31.637874	-101.989708						
73	31.623257	-101.989649						
74	31.624837	-101.989313						

Water Well Index Number	Latitude (NAD 83)	Longitude (NAD 83)	TWDB Well ID #	County Name	Total Depth Well	Drill Date	OWNER	Well Type
76	31.615205	-101.989154						
77	31.635995	-101.989065						
80	31.634483	-101.988627						
81	31.625913	-101.988444						
83	31.618678	-101.988144						
84	31.611882	-101.988087						
85	31.600050	-101.988060						
86	31.632179	-101.987840						
87	31.630967	-101.987475						
88	31.602519	-101.987234						
89	31.623858	-101.987048						
90	31.610180	-101.987010						
91	31.607804	-101.986786						
92	31.601456	-101.986487						
93	31.605088	-101.986397						
94	31.625562	-101.986234						
96	31.638771	-101.985794						
97	31.627831	-101.985556						
98	31.616115	-101.985286						
99	31.636856	-101.985176						
101	31.600848	-101.984920						
102	31.624670	-101.984541						
103	31.610813	-101.984455						
104	31.629706	-101.984398						
105	31.612815	-101.984266						
106	31.603230	-101.984172						
107	31.626248	-101.983276						
108	31.605817	-101.983221						
109	31.611092	-101.983161						
110	31.608687	-101.983059						
112	31.620114	-101.983015						
113	31.616852	-101.981979						
114	31.601478	-101.981885						
115	31.604001	-101.981045						
116	31.613623	-101.980929						
117	31.606934	-101.980628						
118	31.611721	-101.980544						
119	31.617312	-101.980383						
120	31.626082	-101.980294						

Water Well Index Number	Latitude (NAD 83)	Longitude (NAD 83)	TWDB Well ID #	County Name	Total Depth Well	Drill Date	OWNER	Well Type
122	31.606577	-101.980135						
123	31.605019	-101.980017						
124	31.622087	-101.979615						
125	31.609523	-101.979593						
126	31.612015	-101.979252						
128	31.602192	-101.978884						
129	31.604695	-101.978013						
130	31.612351	-101.977858						
131	31.631427	-101.977227						
132	31.607287	-101.977057						
136	31.626697	-101.976717						
137	31.610287	-101.976447						
138	31.611865	-101.976249						
139	31.602982	-101.975655						
141	31.605358	-101.974857						
142	31.622607	-101.974770						
143	31.614366	-101.972068						
144	31.618832	-101.971680						
147	31.628054	-101.969394						
148	31.625420	-101.965087						
149	31.617317	-101.963874						
150	31.621687	-101.963860						
152	31.618074	-101.958870						

1.14.2 Oil and Gas Index Table

These index numbers are used in **Section 1.3** to delineate wells since it is cumbersome to identify each well with well names or API#s given their concentration. Please refer to **Table 1-28** and cross reference with maps in **Section 1.3** to determine the API#, Well Name and Well Number, Well Operator, Well Status, Drill Type and Total Depth of a specific well. WGS84 is used because it is the native coordinate system of Enverus, where the data was sourced from.

Table 1-28: Oil and Gas Well Index Table

Index num	API10	Well Name	W. #	Op Company	TD (FT)	TVD (FT)	Well Stat	Drill Type	Latitude (WGS 84)	Longitude (WGS 84)
1	4246131701	SKAGGS 8	2	EXXON	9350	9350	P & A	V	31.6220229	-102.0084827
2	4246101182	SKAGGS 8	5D	EXXON	8620	8620	P & A	V	31.6194020	-102.0037726
3	4246102833	SKAGGS	1	SOHIO PETRO LEUM	0	0	UNKNOWN	U	31.6126752	-102.0016515
4	4246133482	SKAGGS 8	6	EXXON	9450	9450	ACTIVE	V	31.6126322	-102.0008815
5	4246132812	DUSEK	1	EXXON	9350	9350	P & A	V	31.6091083	-102.0000985
6	4246139324	SKAGGS 8	2H B	EXXON	14970	9744	ACTIVE	H	31.6099861	-101.9993639
7	4246134190	SKAGGS	7	HALLW OOD PETRO LEUM INC	0	10500	EXPIRED PERMIT	V	31.6206479	-101.9993535
8	4246139633	SKAGGS 8	9	EXXON	11439	11439	SHUT-IN	V	31.6124572	-101.9990554
9	4246131699	SKAGGS 8	4	EXXON	9300	9300	P & A	V	31.6170851	-101.9983284
10	4246134198	SKAGGS	9	HALLW OOD PETRO LEUM INC	0	10500	EXPIRED PERMIT	V	31.6134982	-101.9970904
11	4246103986	WINDHAM ""N""	1	EXXON	11467	11467	ACTIVE	V	31.6099513	-101.9959833
12	4246103986	WINDHAM ""N""	1	EXXON	11467	11467	ACTIVE	V	31.6099513	-101.9959833
13	4246103986	WINDHAM ""N""	1	EXXON	11467	11467	ACTIVE	V	31.6099513	-101.9959833
14	4246103986	WINDHAM ""N""	1	EXXON	11467	11467	ACTIVE	V	31.6099513	-101.9959833
15	4246101862	WINDHAM, JOHN	1D	MAGNO LIA OIL & GAS	0	0	UNKNOWN	U	31.6214450	-101.9956813
16	4246132546	WINDHAM ""E""	1	EXXON	9250	9250	P & A	V	31.6074034	-101.9952523
17	4246136389	WINDHAM ""D""	2	EXXON	10910	10910	ACTIVE	V	31.6028585	-101.9937523
18	4246103964	WINDHAM	1	DAVIS, PAUL L.	0	0	UNKNOWN	U	31.6146552	-101.9931612
19	4246140245	ELWOOD '16-21'	440 1H	EXXON	17713	9764	ACTIVE	H	31.6136570	-101.9929140
20	4246140262	ELWOOD 16 AND 21	420 2H	EXXON	17455	9348	ACTIVE	H	31.6136770	-101.9928220
21	4246140268	ELWOOD #16-21	440 3H	EXXON	17825	9814	ACTIVE	H	31.6136990	-101.9927280
22	4246138626	ELWOOD 16	1	EXXON	11790	11788	ACTIVE	V	31.6113110	-101.9926420
23	4246133519	NEAL 16 ""A""	2	CIVITA S	9218	9218	INACTIVE	V	31.6109373	-101.9918802

Index num	API10	Well Name	W. #	Op Company	TD (FT)	TVD (FT)	Well Stat	Drill Type	Latitude (WGS 84)	Longitude (WGS 84)
				RESOU RCES						
24	4246139036	ELWOOD 16	4	EXXON	11715	11714	ACTIVE	V	31.6074270	-101.9914920
25	4246104017	NEAL	1	PETEX	0	0	UNKNOWN	U	31.6073255	-101.9911312
26	4246133170	WINDHAM ""S""	1	EXXON	9400	9400	INACTIVE	V	31.6188681	-101.9907271
27	4246140341	ROBBIE 17A-8	441 5H	EXXON	19902	9839	ACTIVE	H	31.5965810	-101.9906560
28	4246139203	ELWOOD 16	5	EXXON	11748	11743	ACTIVE	V	31.6042400	-101.9904710
29	4246139460	ELWOOD 16-21	1H B	EXXON	17800	9699	ACTIVE	H	31.6143970	-101.9896830
30	4246134000	NEAL 16 ""A""	4	CIVITA S RESOU RCES	9200	9200	INACTIVE	V	31.6038766	-101.9896281
31	4246138830	ELWOOD 16	2	EXXON	11853	11853	INACTIVE	V	31.6010330	-101.9894420
32	4246100822	NEAL	3	PETEX	0	0	UNKNOWN	U	31.6004157	-101.9887711
33	4246131939	ATKINS	2	COX, JOHN L	9180	9180	P & A	V	31.6119304	-101.9878820
34	4246140518	ELWOOD (16-21)	410 7H	EXXON	17391	9285	ACTIVE	H	31.6152020	-101.9878138
35	4246140516	ELWOOD (16-21)	420 7H	EXXON	17636	9469	ACTIVE	H	31.6151240	-101.9877890
36	4246101152	WINDHAM	209	PETRO EXPL INC OF TX	8562	8562	P & A	V	31.6238060	-101.9866060
37	4246133489	NEAL 16 ""A""	1	CIVITA S RESOU RCES	9225	9225	INACTIVE	V	31.6048366	-101.9855370
38	4246134188	WINDHAM ""C""	3	HALLW OOD PETRO LEUM INC	0	10500	EXPIRED PERMIT	V	31.6200492	-101.9850329
39	4246131634	SHAUNA 9	1	EXXON	9300	9300	P & A	V	31.6164853	-101.9849889
40	4246139897	SHAUNA 9-16-16A	1H	EXXON	17260	9751	ACTIVE	H	31.6213660	-101.9846500
41	4246134187	WINDHAM ""B""	2	HALLW OOD PETRO LEUM INC	0	10500	EXPIRED PERMIT	V	31.6279800	-101.9840709
42	4246133518	NEAL 16 ""A""	3	CIVITA S RESOU RCES	9260	9260	INACTIVE	V	31.6128384	-101.9836799
43	4246100051	NEAL	2	PETEX	0	0	UNKNOWN	U	31.6095055	-101.9823408
44	4246133457	SHAUNA 9	2	EXXON	9300	9300	INACTIVE	V	31.6207952	-101.9818088
45	4246140122	SHAUNA '9-16-16A'	441 5H	EXXON	17288	9736	ACTIVE	H	31.6221920	-101.9812720
46	4246141151	NEAL-WINDHAM C 10	201 HL	HUNT	0	8860	EXPIRED PERMIT	H	31.5829783	-101.9812328

Index num	API10	Well Name	W. #	Op Company	TD (FT)	TVD (FT)	Well Stat	Drill Type	Latitude (WGS 84)	Longitude (WGS 84)
47	4246141152	NEAL-WINDHAM C 20	202 HL	HUNT	0	8865	EXPIRED PERMIT	H	31.5829993	-101.9811398
48	4246141153	NEAL-WINDHAM C 30	203 HL	HUNT	0	8865	EXPIRED PERMIT	H	31.5830203	-101.9810468
49	4246141154	NEAL-WINDHAM C 40	204 HL	HUNT	0	8865	EXPIRED PERMIT	H	31.5830453	-101.9809538
50	4246103437	ATKINS, GEORGE	1	WHITWELL & DOTY	0	0	UNKNOWN	U	31.6023958	-101.9804108
51	4246139597	ATKINS 10A	5	EXXON	11715	11715	ACTIVE	V	31.6293540	-101.9802020
52	4246132186	ATKINS	2	SAXON OIL COMPANY	0	9400	CANCELLED	V	31.6272241	-101.9797538
53	4246140590	DUSEK SWD	2	MILESTONE ENVIROSERVICES, LLC	6100	6100	ACTIVE	V	31.6162954	-101.9792307
54	4246133496	ATKINS B	1	CHEVRON	9300	9300	P & A	V	31.6259881	-101.9790487
55	4246100183	ATKINS & KEENEY	1	PETEX	0	0	P & A	V	31.6256071	-101.9789927
56	4246131910	ATKINS	1	COX, JOHN L	9180	9180	P & A	V	31.6133005	-101.9789787
57	4246133499	ATKINS B	2	HALLWOOD PETROLEUM INC	0	9400	EXPIRED PERMIT	V	31.6291830	-101.9789267
58	4246134085	NEAL 16 ""A""	5	CIVITAS RESOURCES	9246	9246	INACTIVE	V	31.6102916	-101.9784537
59	4246139707	ATKINS 10-10B-B	4404H	EXXON	14706	9806	ACTIVE	H	31.6306000	-101.9784420
60	4246138893	ELWOOD 16	3	EXXON	11830	11828	ACTIVE	V	31.6131355	-101.9783079
61	4246139325	ELWOOD 16	6	EXXON	11730	11729	ACTIVE	V	31.6099300	-101.9772996
62	4246132714	NEAL, H. F. "16"	1	CIVITAS RESOURCES	8578	8578	INACTIVE	V	31.6068157	-101.9771327
63	4246101179	ATKINS-KEENEY	310	MESA PETROLEUM	0	8416	P & A	V	31.6183244	-101.9765837
64	4246139696	ATKINS 10A	6	EXXON	9100	9099	ACTIVE	V	31.6189650	-101.9765090
65	4246139430	ELWOOD 16A	2	EXXON	0	11850	EXPIRED PERMIT	V	31.6059947	-101.9763726
66	4246134018	NEAL, H. F. "16"	2	CIVITAS RESOURCES	8600	8600	INACTIVE	V	31.6032518	-101.9759856
67	4246139382	ELWOOD 16A	1	EXXON	0	11850	EXPIRED PERMIT	V	31.6027908	-101.9753716

Index num	API10	Well Name	W. #	Op Company	TD (FT)	TVD (FT)	Well Stat	Drill Type	Latitude (WGS 84)	Longitude (WGS 84)
68	4246140130	ATKINS 10-10B-D	4407H	EXXON	15168	9773	ACTIVE	H	31.6330380	-101.9749330
69	4246132187	ATKINS	3	EXXON	9250	9250	P & A	V	31.6226303	-101.9736776
70	4246132081	NEAL, H. F. -15-	4	CIVITAS RESOURCES	8560	8560	INACTIVE	V	31.6099547	-101.9731225
71	4246133132	NEAL, H. F. -15-	5	CIVITAS RESOURCES	8641	8641	INACTIVE	V	31.6157855	-101.9707964

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Section 2: Area of Review (AoR) and Corrective Action (CA) Plans

[40 CFR §146.82, §146.84]

Prepared for:

EPA Region 6
Underground Injection Control Section

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2.0 AREA OF REVIEW (AoR) AND CORRECTIVE ACTION (CA) PLANS [146.82(a)(13), 146.84 (b) (1)]

2.1 AoR Plume Modeling and Delineation Introduction

The Area of Review (AoR) for the proposed Midland CCS #2 project was delineated using a geologic model developed by Milestone based on publicly available data and proprietary 2D seismic. The model predicts CO_2 plume and pressure migration and supports compliance with Class VI regulatory requirements by demonstrating the presence of a suitable injection interval and confining system. While the model will be refined with future data from a planned stratigraphic test well and 3D seismic, current analysis indicates no wells within the AoR penetrate the confining layer or injection interval, and no corrective action is required

2.2 Computational Modeling Approach

Static geologic modeling and dynamic reservoir simulation were used to estimate key subsurface parameters associated with the injection of supercritical CO_2 into the undifferentiated Devonian Formation, through the base of the Silurian-aged Montoya Group and the Ordovician-aged Ellenburger Group—collectively referred to as the “injection units” (see **Section 1.5** for additional stratigraphic details). Together, these units comprise the “Injection Interval.” The primary confining unit, the Woodford Shale, and a secondary seal, the Barnett Shale, were also incorporated into the model.

Model outputs provide critical insights into the spatial extent of the injection plume, pressure propagation, and operational conditions. These outputs form the basis for delineating the Project’s Area of Review (AoR).

To ensure modeling accuracy and computational efficiency, Milestone used industry-standard software, including SLB’s Petrel™ for 3D geologic modeling and Rock Flow Dynamics’ tNavigator® for reservoir simulation.

SLB’s Petrel™ software is a leading platform for subsurface modeling and reservoir characterization in the oil and gas industry. It offers a unified environment where geoscientists and engineers can collaboratively build, visualize, and interpret geological and geophysical models. Petrel™ integrates workflows across various disciplines, such as seismic interpretation, petrophysics, and reservoir engineering, enabling a seamless approach to interpretation, reservoir characterization, and structural and petrophysical static model development. With advanced features like 3D visualization and automated fault modeling, Petrel provides users with powerful tools to analyze data, assess risks, and optimize reservoir performance. The platform’s versatility and robust data integration capabilities make it a valuable tool for visualizing complex reservoirs and subsurface geometries.

Rock Flow Dynamics (RFD) developed tNavigator software, a comprehensive reservoir simulation platform used in the oil and gas industry. tNavigator® integrates geological modeling, reservoir simulation, and production optimization into a single, user-friendly platform. It allows users to build detailed geological models, run simulations, and predict reservoir behavior under various scenarios. Known for its high-performance parallel computing capabilities, tNavigator® efficiently handles complex models, even for large-scale reservoirs, making it a popular choice for companies that require accurate, fast, and reliable simulations. It supports various types of simulations, such as black oil, compositional, thermal, and fractured reservoirs. The platform's flexibility also extends to well management, surface network modeling, and production forecasting, providing a robust suite of tools for optimizing field development strategies.

2.3 Model Background

A representation of the storage reservoir was constructed using 2D seismic interpretation, available well logs, and interpreted formation tops (see Section 13 – Appendix D). SLB's Petrel™ software was used to build a faulted static geocellular model composed of discrete layers, extending from the top of the Mississippian-aged Barnett Formation and underlying Woodford Shale (upper confining interval) to the Precambrian basement below the Ordovician-aged Ellenburger Group (base injection unit). The model includes the following zones: Barnett, Woodford, Devonian, Silurian, Fusselman, Simpson, and Ellenburger. The model's base is the base of the Ellenburger/top of the basement rock. The Cambrian-aged Bliss Formation is not included in the model, as wellbore and seismic data do not confirm whether it is regionally present or occurs only as isolated sands.

The regional geocellular model ("regional grid") spans 874 square miles (approximately 28 miles [X] by 31 miles [Y]) across northern Upton County and southern Midland County. It consists of approximately 22 million hexahedral grid cells, each 500 by 500 ft in the XY direction (nI = 299, nJ = 326). The model includes 226 layers (K), with layer thickness varying by zone and averaging 10 ft.

A subset of this regional grid was used as input to tNavigator® (the "dynamic grid"), a compositional finite-difference reservoir simulator developed by Rock Flow Dynamics. tNavigator® is well-suited for modeling CO_2 behavior due to its equation-of-state (EOS) algorithms and high-performance computing capabilities. It was used to simulate subsurface behavior of supercritical CO_2, forecast pressure buildup, and generate outputs for evaluating the AoR boundary.

To date, Milestone has not drilled a stratigraphic test well or conducted laboratory testing on core samples to directly measure relative permeability, porosity, capillary pressure, or geomechanical properties of the injection and confining units. Additionally, 3D seismic data have not yet been acquired for the Area of Review (AoR). However, both 3D seismic acquisition and stratigraphic drilling are planned upon reaching key commercial milestones. The current model relies on 2D seismic, existing well logs, and publicly available data and research related to the injection and confining zones. Two 2D seismic lines near the AoR were interpreted to identify faults and refine the structural framework.

Petrophysical log analysis and offset water samples were used to determine formation depth and salinity for key Mississippian through Ordovician units. These logs also informed evaluations of porosity, permeability (see **Table 2-1**), lithology/facies, reservoir quality, and estimated geomechanical properties. Wells with appropriate data were used as control points in the model to distribute these key parameters. The distribution of rock and petrophysical properties (e.g., facies, porosity, and permeability) was modeled using geostatistical estimation from upscaled logs, guided by variograms for each modeled zone.

Table 2-1: Storage Reservoir Petrophysical Wells
Summary of wells used to develop property attributes within the regional static model domain.

API14	Well Name	Zone at TD	Poro. (PHIT)	Perm. (KA)
42-461-31511	AMACKER 1-67	Simpson	✓	✓
42-461-31788	BENEDUM /SPRABERRY/ UNIT 202	Fusselman	✓	✓
42-329-33390	DAVIDSON "27" 1D	Silurian	✓	✓
42-461-40597	DAVIDSON UNIT 1 0106BH	Basement	✓	✓
42-461-33079	GIDDINGS ESTATE FEE 1247	Ellenburger	✓	✓
42-461-34165	HALAMICEK 7901H	Simpson	✓	✓
42-461-31960	MANN28 1	Ellenburger	✓	✓
42-461-30288	MCCUISTION COMMUNITY HOSPITAL 1	Devonian	✓	✓
42-461-33430	MCELROY RANCH 24A	Ellenburger	✓	✓
42-329-34681	MIDKIFF "A" 2608	Devonian	✓	✓
42-461-32196	NEAL, H. F. 1	Simpson	✓	✓
42-461-32673	PECK 1	Ellenburger	✓	✓
42-461-33369	PEGASUS FIELD UNIT #3 1316H	Fusselman	✓	✓
42-461-32586	PEGASUS FIELD UNIT #3 2012	Ellenburger	✓	✓
42-461-32374	PEMBROOK, RALPH 405	Ellenburger	✓	✓
42-461-32788	POWELL 34 1	Ellenburger	✓	✓
42-461-34581	RAILWAY RANCH 9 1H	Devonian	✓	✓
42-461-32329	ROSENBAUM 1	Ellenburger	✓	✓
42-461-32160	TIPPETT SPRABERRY UNIT 208A	Ellenburger	✓	✓
42-461-32444	VAUGHN DEEP 1	Ellenburger	✓	✓
42-461-34568	WINDHAM-CLARK 103 UNIT 1H	Devonian	✓	✓
42-461-30531	XBC GIDDINGS ESTATE 1238D	Ellenburger	✓	✓
Count			**22**	**22**

To model the subsurface behavior of supercritical CO_2, a compositional isothermal simulation was conducted to predict the diffusion of the injectate at pressures below 90% of the fracture gradient. The selected model characterizes CO_2 movement and trapping based on the available data. To evaluate the extent of the AoR, the model was used to assess the incremental change in reservoir pressure and gas saturation[1] within the model domain. The AoR was defined as the area where gas saturation is predicted to exceed two (2) percent from the start of injection through plume stabilization. See **Section 2.9** and **Section 2.10** for additional information on the AoR.

[1] The injectate stream, primarily composed of CO_2 gas at standard temperature and pressure, is modeled in the subsurface under conditions exceeding the critical point. Under modeled reservoir conditions, the CO_2 exists in a supercritical phase. The simulator tracks the inventory of CO_2 mass and other injectate components within the Model domain, categorizing them as "gas" properties. While referred to as "gas" in the simulation output, the physical behavior corresponds to that of a supercritical fluid. Therefore, in this context, references to gas saturation denote the saturation of the entire injection stream, which remains in the supercritical phase throughout the reservoir.

2.4 Static Model Summary

A regional static geocellular model comprising approximately 22 million 500 × 500 ft (XY) hexahedral cells was constructed using SLB's Petrel™ software (**Table 2-2**). Layers were proportionally distributed within each zone, with an average thickness of 10 feet. The model spans roughly 874 square miles across northern Upton County and southern Midland County (**Figure 2-1**). The chosen cell size is sufficient to capture lateral heterogeneity, as it is significantly smaller than the average spacing between wells used for petrophysical property distribution.

Table 2-2: Regional Static Model Domain Information

Coordinate System	NAD 1983		
Horizontal Datum	North American Datum 1983		
Coordinate System Units	ft US		
Zone	Texas Central Zone		
FIPSZONE	4203	**ADSZONE**	5376
Coordinate of X min	2,496,000	**Coordinate of X max**	2,645,500
Coordinate of Y min	11,388,000	**Coordinate of Y max**	11,551,000
Elevation (TVDSS) of bottom of domain	-11,992	**Elevation (TVDSS) of top of domain**	-6,110

TVDSS: True Vertical Depth Subsea

The regional model boundary was selected to encompass a representative number of wells with petrophysical logs, thereby improving constraints on porosity and permeability distributions and supporting a more robust geostatistical framework across the model domain.

A 324 square mile portion of the regional model, shown in **Figure 2-1**, was used to construct the dynamic grid for simulation. This grid retains the same cell dimensions but includes approximately 7.5 million cells. While the regional model incorporates a broad set of wells to improve petrophysical property representation, detailed structural and fault modeling was focused within the dynamic grid to better simulate flow behavior in the injection units.

Structural and stratigraphic mapping was performed by interpreting 2D seismic data and correlating formation tops (**Section 1.7 and Section 13 – Appendix D**) using digital openhole well logs, along with regional mapping and fault interpretations from published literature. Petrophysical analyses were completed on 22 wells within the regional model boundary that penetrate the top of the Woodford Formation or deeper, accounting for facies, porosity, and permeability.

Facies were estimated from log responses but were not used to constrain porosity or permeability due to the absence of core data for model validation. Available core data from the Bureau of Economic Geology in Austin include porosity, permeability, and core descriptions but lack modern electrical logs to tie these measurements to formation depth. The cores and resistivity-SP logs were acquired in the early 1950s. While facies were not used in this model to condition porosity or permeability, they were included in the initial model and are anticipated to be useful in future updates..

[redacted]

2.4.1 Structural Framework

The structural framework model was primarily constructed using formation tops interpreted from openhole well logs across the regional model area. These tops span from above the Barnett Formation to the base of the Ellenburger Group, encompassing all proposed confining and injection units (see type log in **Section 1.9.1**).

Additionally, two 2D seismic lines west of the AoR were reviewed, and their interpreted structural horizons were incorporated into the Model. Seismic-interpreted faults were integrated with regional faults mapped in published literature (Horne et al., 2024), and the combined dataset was used to construct the fault and structural models. All identified faults terminate below the base of the Woodford Formation (upper confining zone), within the undifferentiated Devonian Formation or deeper.

In the pillar gridding[2] methodology used for fault modeling, fault "pillars" must extend through the entire stratigraphic section; however, throw can be adjusted, or faults deactivated, for individual horizons. Fault transmissibility is then assigned for each model zone or layer to ensure faults do not exert hydraulic effects above their termination point. As a result, some figures may show faults extending through the full section, though they are deactivated where appropriate to match seismic interpretation

A total of 202 wells penetrating the Barnett Formation were reviewed. Of these, Milestone interpreted formation markers in 22 wells with digital logs (**Table 2-1**). In total, 827 formation tops were used to generate the Model's structural surfaces (see **Appendix D** for a complete list of wells and picks)

The selected stratigraphic tops served as constraint points for building stratigraphic horizons in the static geologic model. Several iterations of quality control were performed to confirm correct well elevations, verify the geologic accuracy of picks and correlations, and ensure that generated surfaces honored the selected markers at each well location **(Figure 2-2)**.

Table 2-3: Count of Well Top Control by Zone
Summary of the count of well tops for each horizon used to generate the structural framework model.

Horizon	Count
Barnett	151
Woodford	174
Devonian	171
Silurian	97
Fusselman	90
Simpson	80
Ellenburger	62
Basement	2
Total	**827**

[2] Pillar gridding, within a structured corner-point geologic model, is a method where vertical grid lines, or 'pillars,' are aligned with fault geometries across the entire stratigraphic section. These pillars ensure that the grid accurately reflects fault structures, allowing for adjustments in fault throw or deactivation at specific horizons while preserving grid consistency throughout the Model.

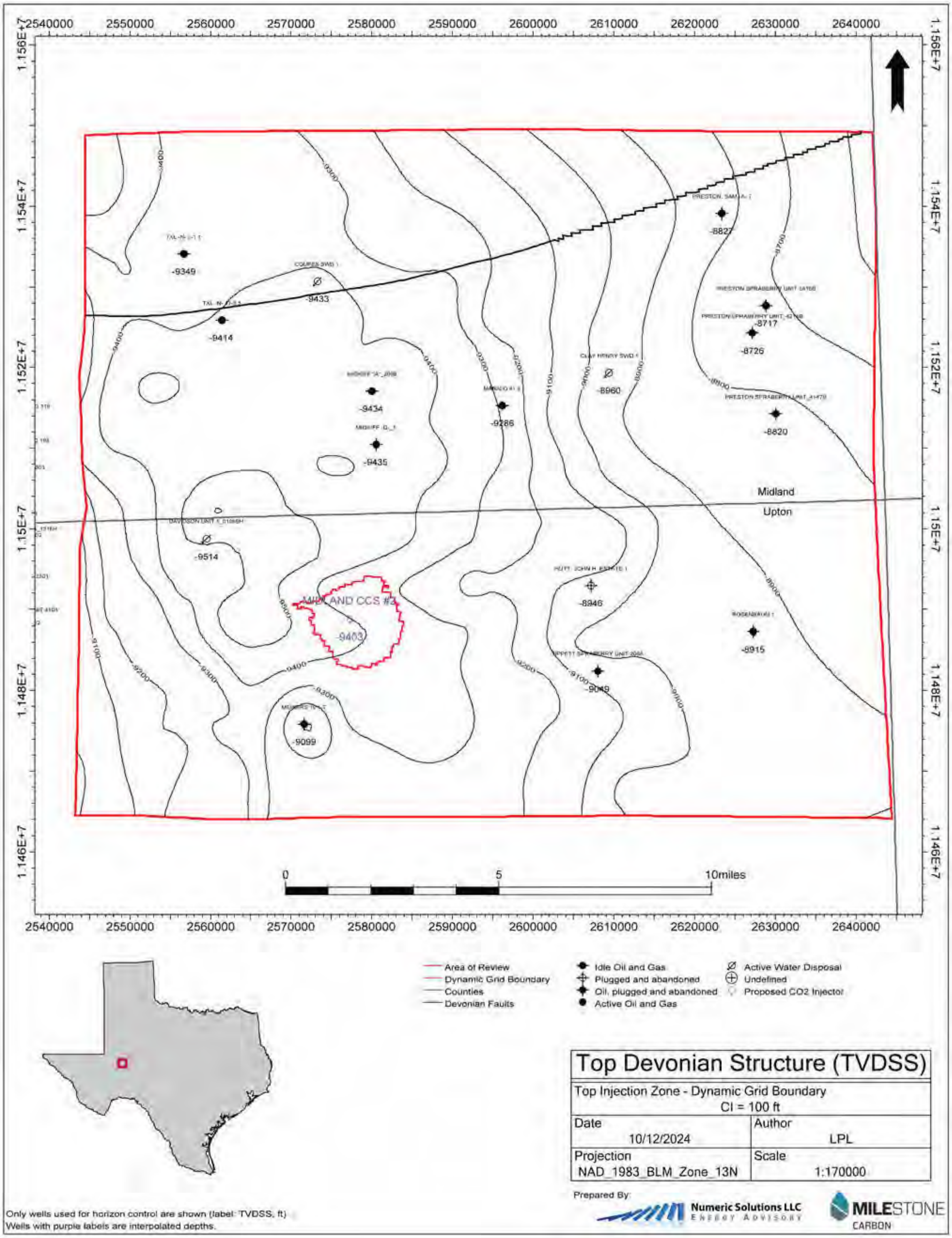


Figure 2-2: Top of Devonian Structure Map

Structure map from the static model on the top of the Devonian Formation (top storage zone). Well symbols are shown with subsea depths indicating control points used to generate the horizon.

As significantly more well penetrations exist in the Model area for the shallower horizons, the top of the Woodford, Devonian, and Fusselman formations were used as reference horizons. All other horizons were generated using conformal gridding and isochore maps (**Figure 2-3**).

The static model includes eight (8) structural horizons and seven (7) units (**Figure 2-3**):

1. Barnett
2. Woodford
3. Devonian
4. Silurian (Wristen Group)
5. Fusselman
6. Simpson
7. Ellenburger

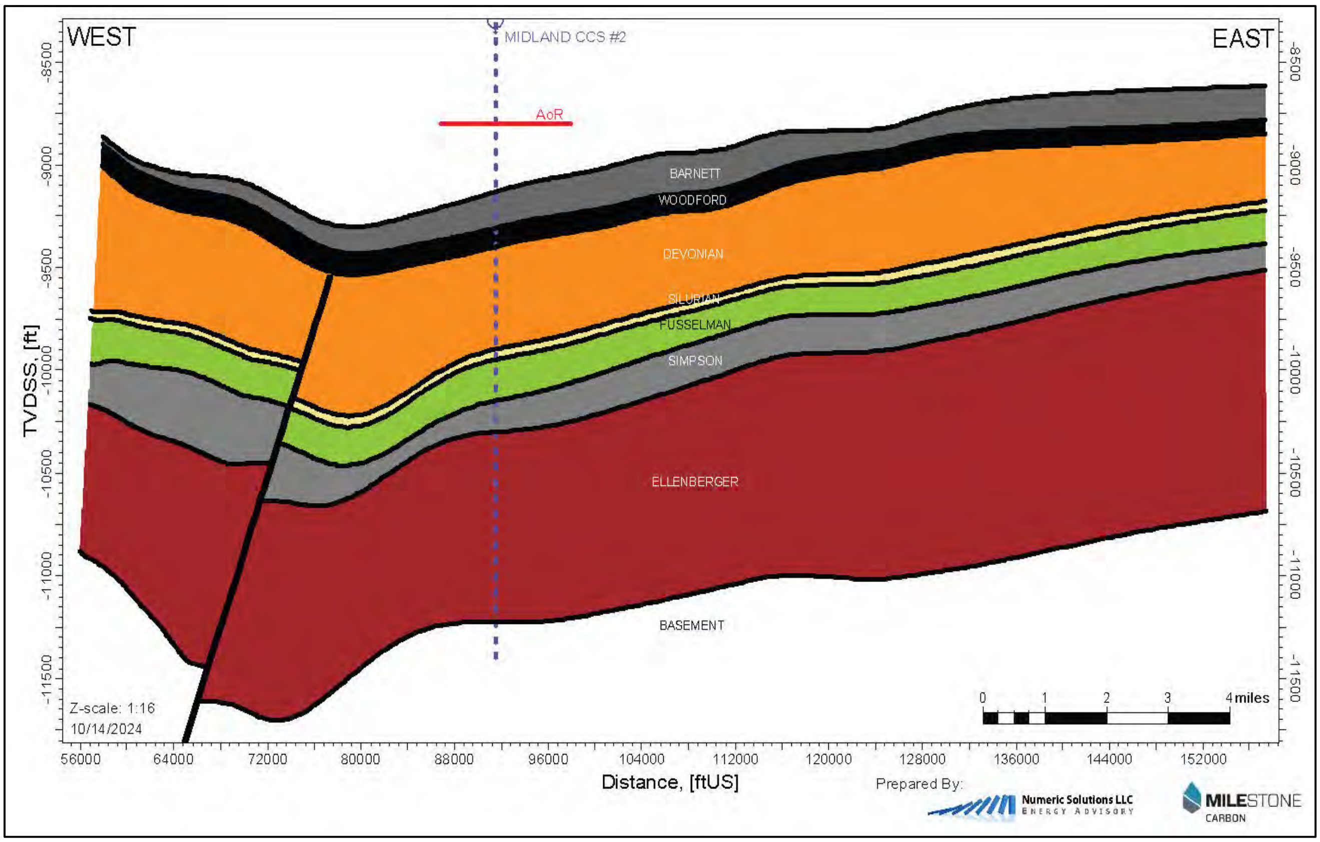


Figure 2-3: West-to-East Cross Section Through the Static Model
West-to-east cross section at the location of the Midland CCS #2 Well through the structural framework mode showing the seven units (zones) included.

2.4.2 Layering

Model layers ("K-layers") were generated using proportional layering with the number of layers assigned to each unit to maintain an average thickness of approximately 10 ft. See **Table 2-4** for the number of layers in each zone.

Table 2-4: Number of K-Layers Per Zone in the Static Model

Unit/Zone	Number of Layers
Barnett	17
Woodford	10
Devonian	52
Silurian	5
Fusselman	18
Simpson	21
Ellenburger	103
Total	**226**

2.4.3 Facies Model

As outlined in **Section 1.7.4**, four primary lithologic rock types, or facies, comprise the proposed injection and confining units across the Devonian, Silurian, Fusselman, Simpson, and Ellenburger formations. These facies include shale, chert, dolostone, and packstone (limestone) (**Table 2-5**). Facies logs (example in **Fig. 2-4**) were developed for 22 wells that penetrate the Woodford Formation, using openhole and petrophysically derived logs and the calculations described below.

Table 2-5: Facies and Facies Codes

Facies Code	Facies Type Name
0	Claystone
1	Packstone
2	Dolostone
3	Chert

Equation 1: Facies Equation Above Ellenburger (Devonian and Silurian):

$$FACIES = if(VCL > 0.19, 0, if(PEF < 4, 3, 1))$$

Equation 2: Ellenburger Facies:

$$FACIES=if(PEF < 3, 3, if(VCL > 0.2, 0, 2), if(VCL > 0.19, 0, if(PEF < 4, 3, 1))$$

Equation 3: GR Correction:

$$FACIES=if(GR > 145, 0, FACIES)$$

PEF is the photoelectric factor openhole log. VCL is the volume of clay petrophysical curve derived from the gamma ray (GR) openhole log.

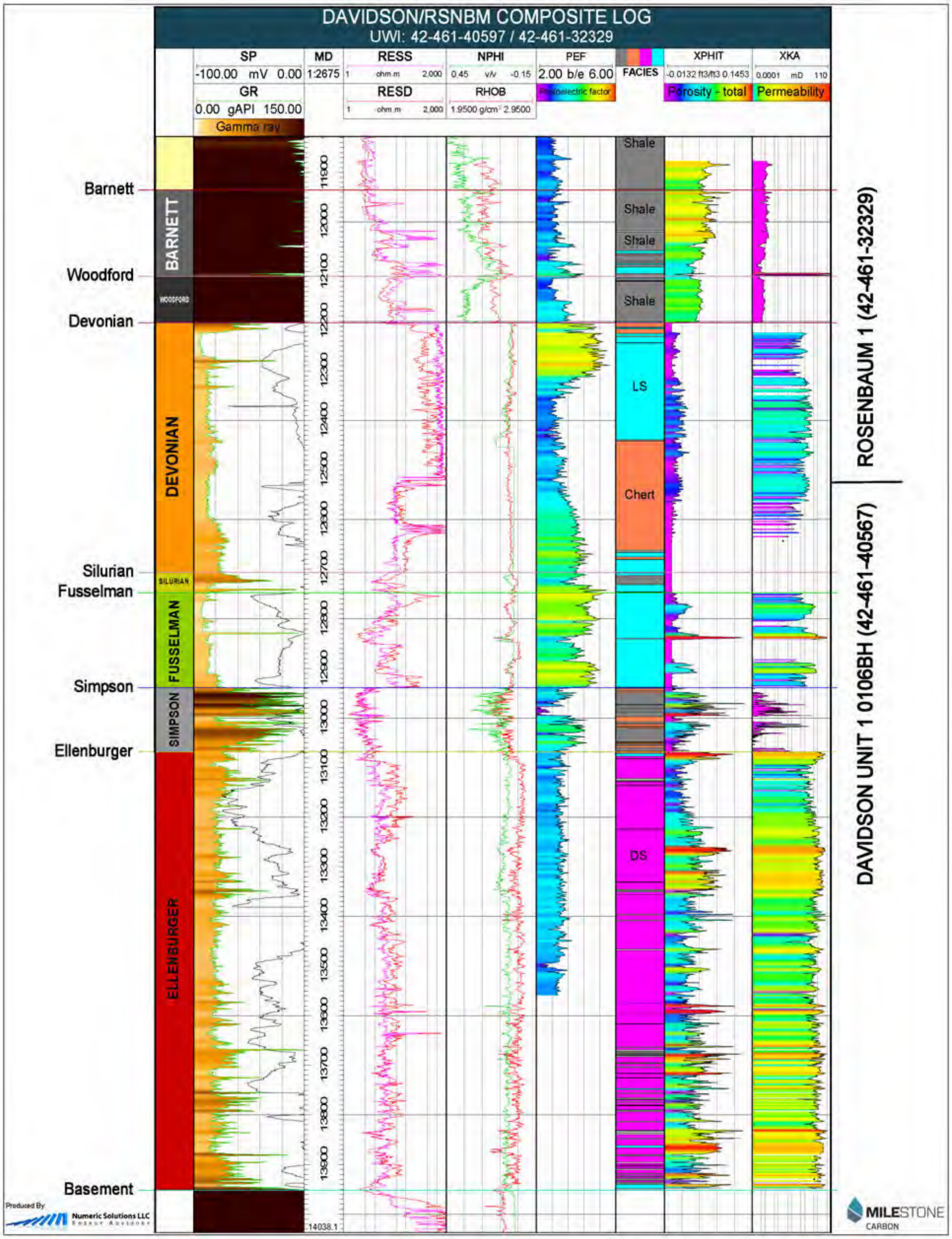


Figure 2-4: Type Well Log Model Area

Composite type well log for the Model area using wells Rosenbaum 1 (42-461-32329) and Davidson Unit 1 0106BH (42-461-40567). Key stratigraphic markers and units from above the upper confining zone to the base of the Injection Interval are shown. Track 1, on the far left, shows the stratigraphic zones. Track 2 contains the SP (Spontaneous Potential) and GR (Gamma Ray) curves. Track 3 shows the RESS (Shallow Resistivity) and RESD (Deep Resistivity) curves. Track 4 displays the NPHI (Neutron Porosity) and RHOB (Bulk Density) logs. Track 5 presents the PEF (Photoelectric Factor) curve. Track 6 shows the facies log (LS = Limestone, DS = Dolostone). Track 7 contains the XPHIT (Total Porosity) log, which was used to distribute porosity in the static model, and Track 8 shows XKA (Permeability).

Facies modeling was conducted using the following methodology based on the facies logs:

1. Well logs were upscaled into the Model by randomly selecting facies log values within each cell intersected by wells containing a facies log.

2. A vertical proportion curve (VPC) was estimated to represent the vertical distribution of the four facies within each model layer.

3. Facies were distributed throughout each Model zone using the Sequential Indicator Simulation (SIS) algorithm[3], with identical isotropic spherical variograms applied (55,000 ft horizontal and 20 ft vertical) for each facies and zone.

The resulting facies distribution for each zone within the AoR is shown in **Figure 2-5**, with east-west and north-south cross sections through the Model at the proposed Midland CCS #2 Well location provided in **Figure 2-6**. It is anticipated that once core data is acquired, relationships between facies and other properties, such as fracturing, may be identified. Therefore, Milestone incorporated facies into the Model in advance, expecting to refine its use in future updates.

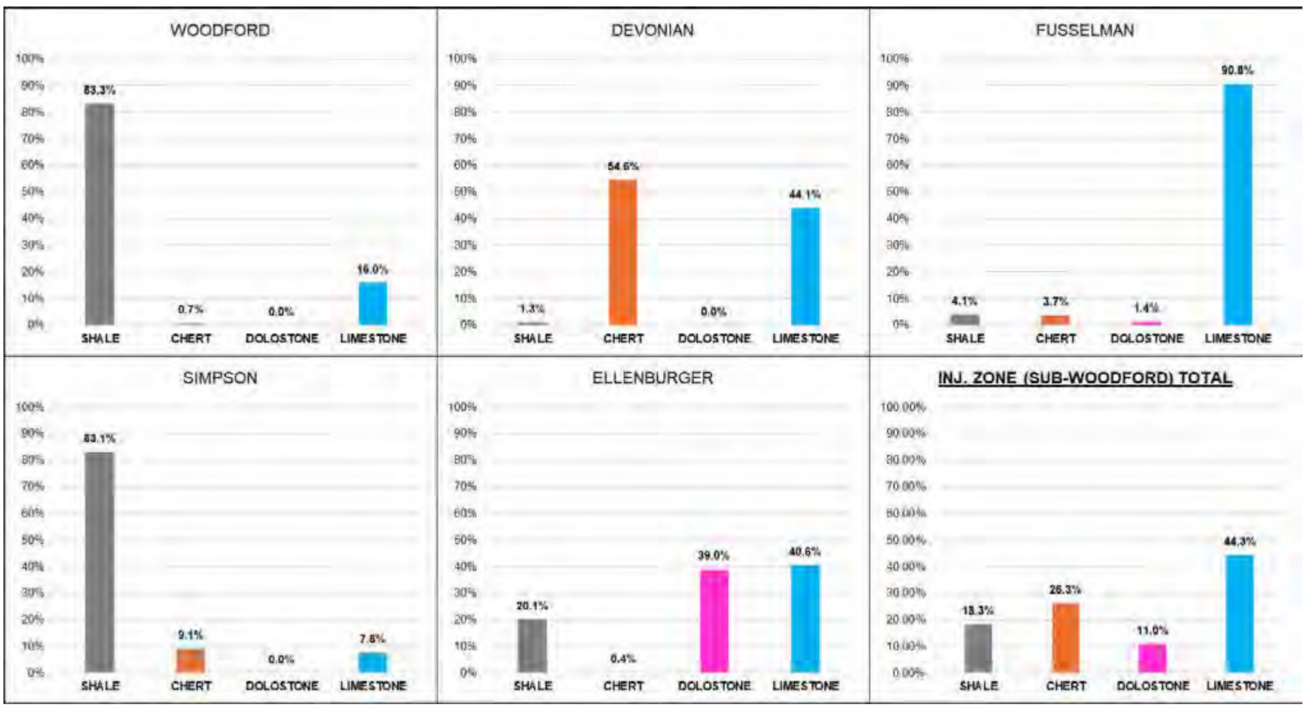


Figure 2-5: Zone Facies in AoR
Histograms show the relative proportion of each facies in each zone within the AoR. The bottom right histogram shows the relative proportion of each facies within the entire injection interval.

3 Sequential Indicator Simulation is a variogram-based geostatistical technique developed by Alabert (1987) that stochastically populates each zone based on the input data distribution while also honoring the well data with the degree of continuity away from data controlled by the variogram via simple kriging.

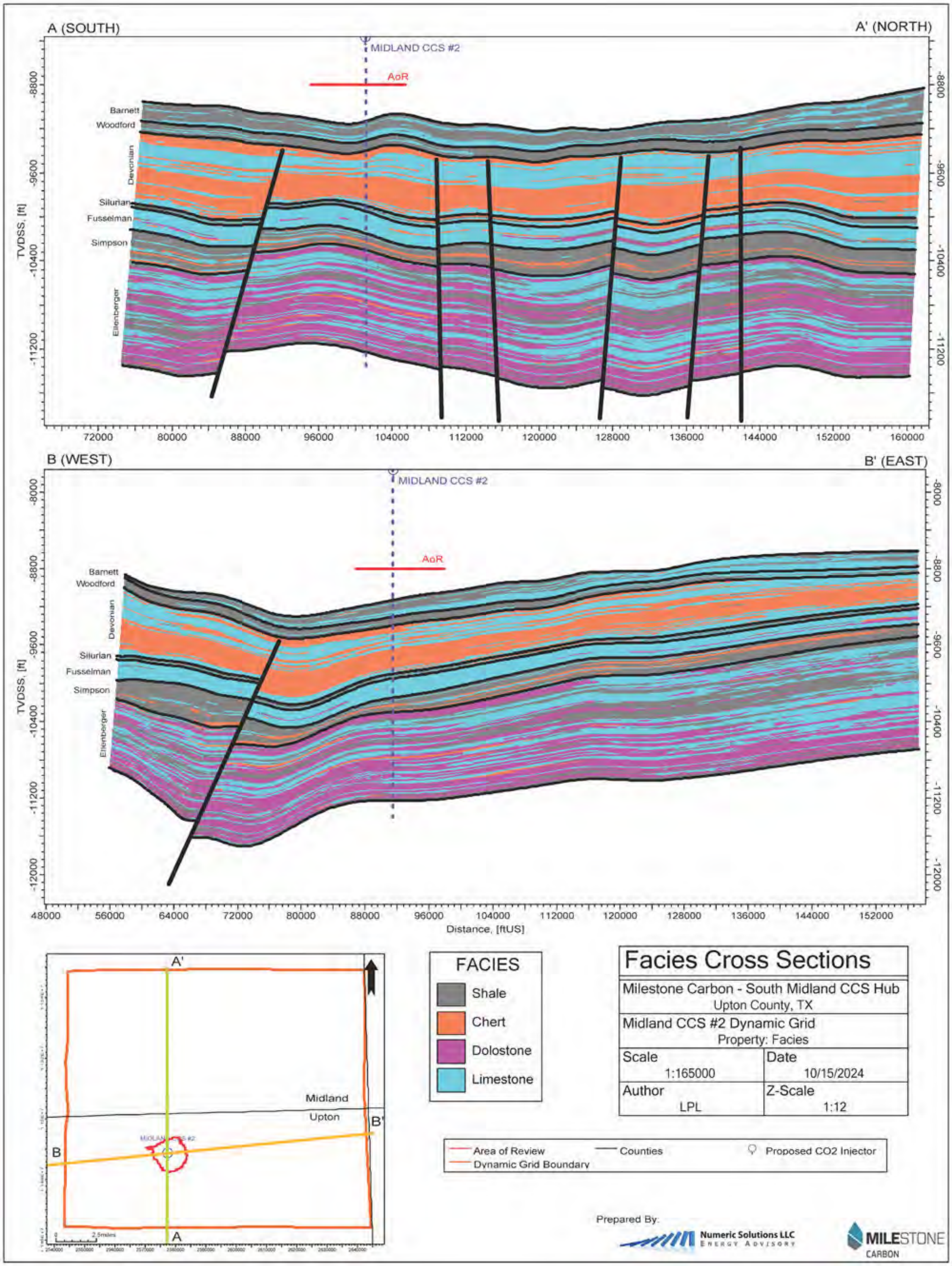


Figure 2-6: Facies Cross Sections A-A' and B-B'

South-to-north (A-A') and west-to-east (B-B') cross sections through the static geologic model showing the distribution of facies within the upper confining and injection units (12x vertical exaggeration).

2.4.4 Porosity

The total pore volume in the injection units (Devonian through Ellenburger Formations) governs the volume of CO_2 that can be stored in the reservoir and is fundamentally related to permeability. Porosity logs—including density, neutron, and sonic logs—from wells within the static model domain were used to determine the regional total porosity of the injection units. A total of twenty-two (22) wells were included, 14 of which contain sonic log data. Porosity and permeability were calculated using Milestone's petrophysical software, Geolog™.

Log analysis and interpretation suggest that porosity decreases in less brittle, and therefore less fractured, facies. The Ellenburger Group is considered the highest-quality injection unit due to its higher degree of fracturing compared to the Devonian (see **Section 1.8.1**). Milestone intends to collect and analyze core data from the stratigraphic test well prior to injection (see **Sections 5.3** and **5.4** for additional information on logging and coring plans).

Petrophysically derived porosity values (total porosity, or PHIT) from the 22 wells (see Table 2-1) were upscaled into the Model grid by sampling log values at the midpoint of each intersecting cell. This approach ensures rare high or low values are preserved, yielding a closer match to the original log distribution than averaging methods. Following upscaling, variogram analysis was conducted using Petrel's data analysis tool. The analysis did not indicate clear anisotropy, so spherical isotropic variograms were applied across all zones.

Based on data density and the variogram analysis, the following parameters were used (see Table 2-6):

- For the Barnett, Woodford, and Simpson zones: horizontal range of 150,000 ft and vertical range of 36 ft
- For the Devonian, Silurian, and Fusselman zones: horizontal range of 60,000 ft and vertical range of 36 ft
- For the Ellenburger zone: horizontal range of 85,000 ft and vertical range of 45 ft

Table 2-6: Summary of Variograms by Zone used for Porosity Modeling

Zone	Variogram Type	Horizontal Range* (ft)	Vertical Range (ft)
Barnett	Spherical	150,000	36
Woodford	Spherical	60,000	36
Devonian	Spherical	60,000	36
Silurian	Spherical	60,000	36
Fusselman	Spherical	60,000	36
Simpson	Spherical	150,000	36
Ellenburger	Spherical	150,000	45

* Isotropic

Porosity was distributed using the variograms described above, with the stochastic Gaussian Random Function Simulation (GRFS) algorithm applied to all zones. The GRFS algorithm honors well data, with spatial continuity controlled by the variogram via kriging, while also stochastically reproducing the target distribution (histogram) of the modeled petrophysical property based on log data.

Below K-layer 166 (lower Ellenburger), porosity data is available only within the dynamic model domain from well Davidson Unit 1 0106BH (API: 42-461-40597). Accordingly, all K-layers below this depth were matched to the upscaled values from the Davidson well.

Figure 2-7 provides a histogram of the input well log data, upscaled cells, and the property model for the injection unit formations. **Figure 2-8** shows the distributions by zone. **Figure 2-9** illustrates average porosity maps by zone, and **Figure 2-10** .presents two cross sections through the injection AoR displaying the porosity model.

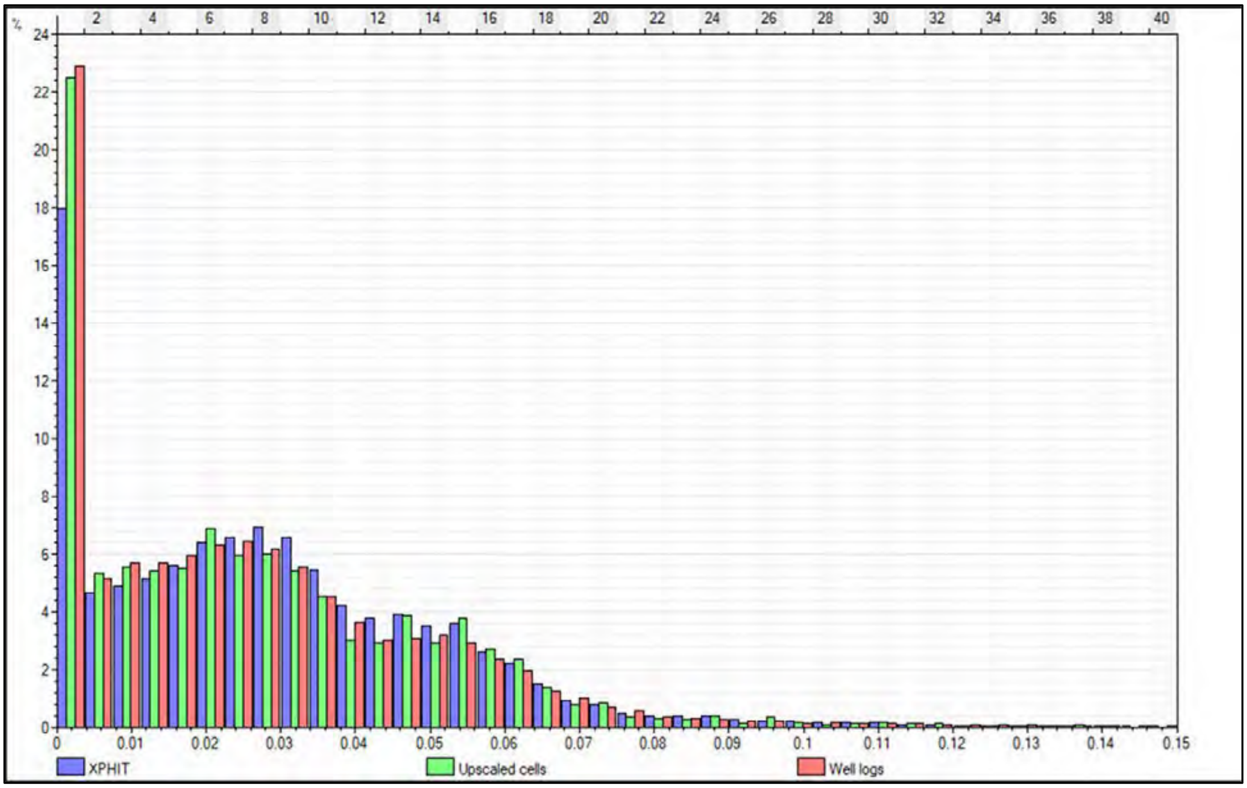


Figure 2-7: Histogram showing PHIT distribution from log data, upscaled cells, and the property model.

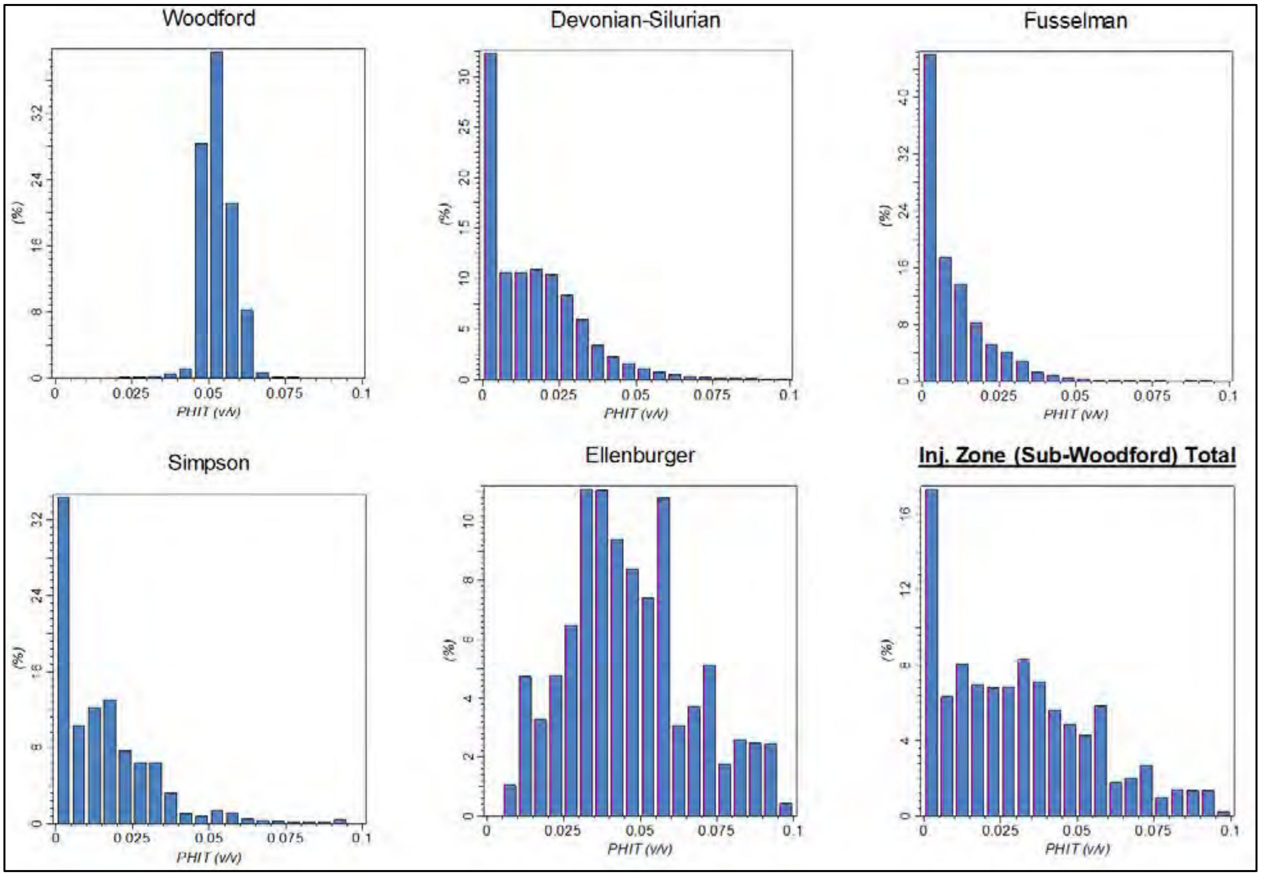


Figure 2-8: Porosity Histograms by Zone

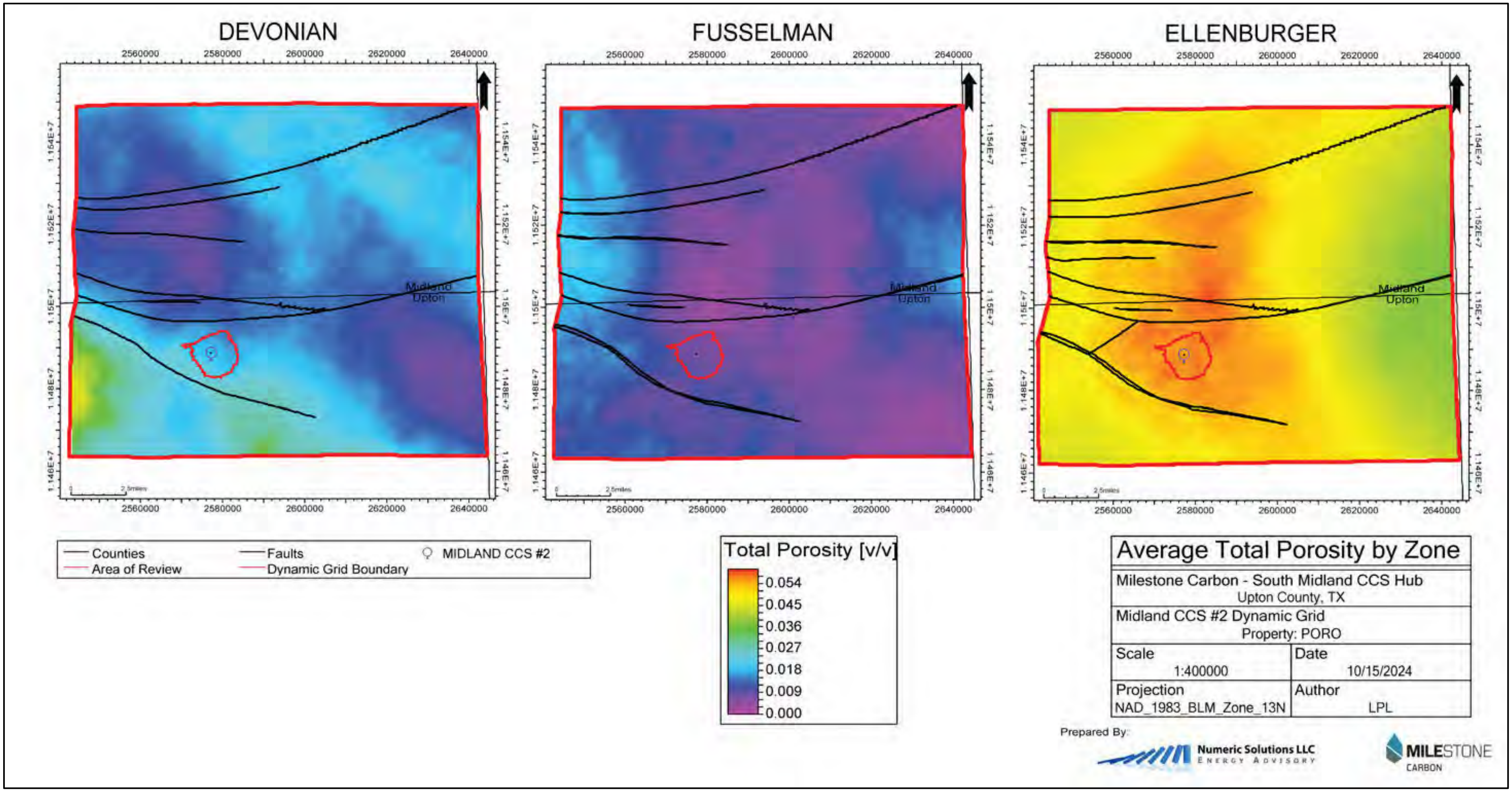


Figure 2-9: Static Model Average Total Porosity by Zone Maps

Average total porosity maps for the static model for the primary injection formations (Devonian, Fusselman, and Ellenburger).

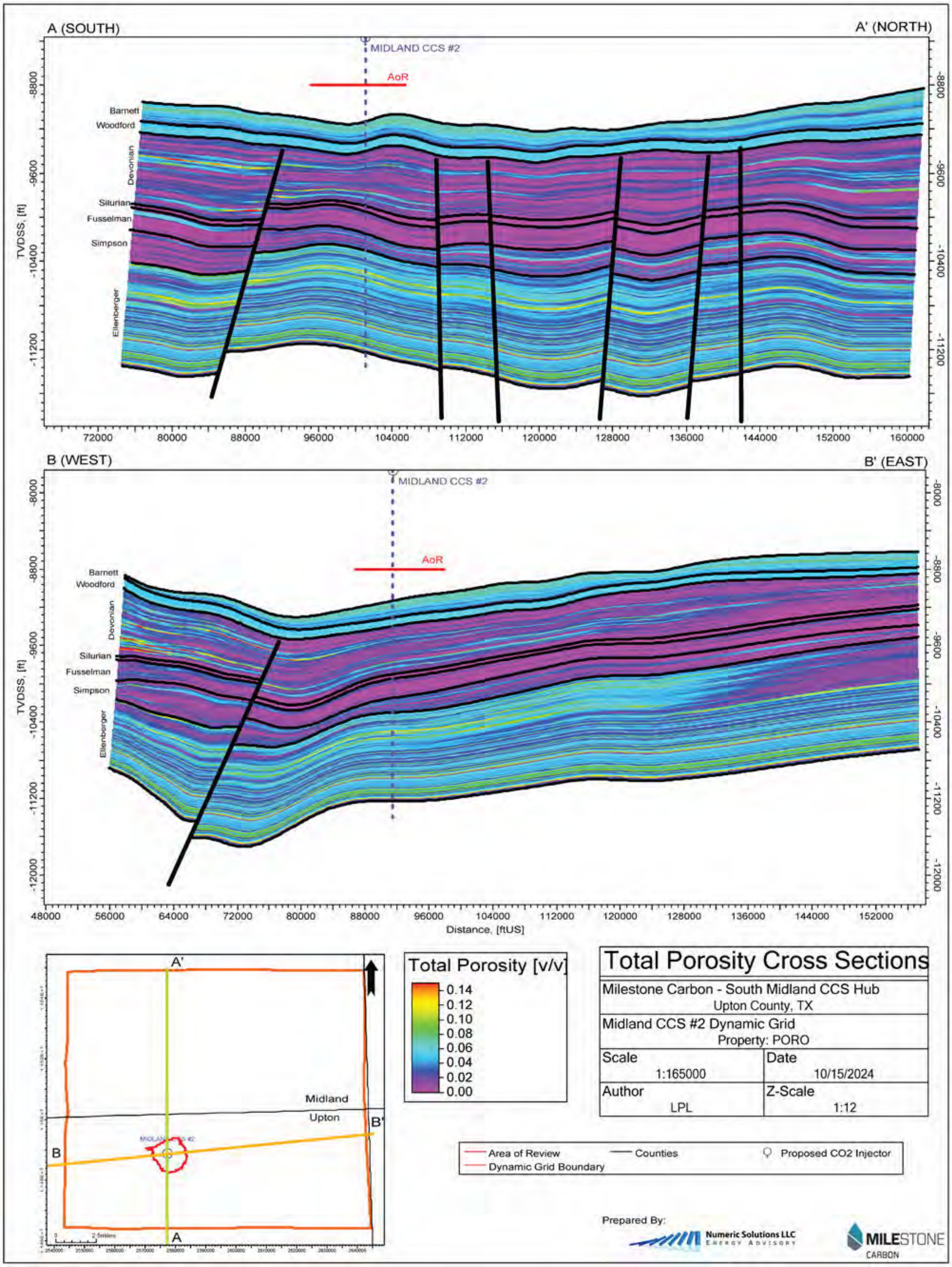


Figure 2-10: Dynamic Model Total Porosity Cross-Section Through AoR

2.4.5 Permeability

Permeability is a critical subsurface parameter in porous media that influences fluid flow rates and resulting injection pressures. Intrinsic permeability is closely related to porosity, pore size, pore structure, and the presence of natural fractures. Milestone has not yet conducted direct measurements of permeability from core samples (Kair, Kbrine) within the Model domain but plans to do so during drilling of the planned stratigraphic test well.

2.4.5.1 Permeability Calculation Methodology

Milestone estimated permeability (KA) using a function that relates porosity, clay volume, and deep resistivity to permeability in 22 openhole well logs penetrating the Devonian (see **Section 1.9.3**). These estimates represent matrix permeability across all formations in the static model and were calculated using the following algorithm based on available core data.

Equation 4: Permeability Calculation - Initial Model – Non-Shale Lithologies

KA = 10^(1.3422 × LN(PHIT) + 4.6392)

Equation 5: Permeability Calculation - Initial Model – Shale Lithologies

For Shale Lithologies, KA = 0.3 × $PHIT^2$

Equation 6: Permeability Calculation - Upwards Limit 110 mD

Limit KA = IF(KA > 110, 110, KA)

2.4.5.2 Upscaling and Distribution

The calculated, petrophysically derived permeability logs were upscaled into the Model grid by computing the arithmetic mean of log values intersecting each model cell. Permeability was then distributed throughout the Model using collocated co-kriging with the porosity model, applying an isotropic spherical variogram with the same horizontal and vertical ranges used for porosity distribution (see **Table 2-6**). he co-kriging coefficients, provided in **Table 2-7**, were set below 1 to introduce known variability into the porosity–permeability relationship.

Table 2-7: Collocated Co-Kriging Coefficients Used for Permeability Distribution

Zone	Collocated Co-Kriging Coefficient
Woodford	0.5
Devonian	0.75
Silurian	0.75
Fusselman	0.6
Simpson	0.6
Ellenburger	0.4

Figure 2-11 provides a histogram of the permeability input well log data, upscaled cells, and the permeability property model for the injection formations. **Figure 2-12** shows modeled porosity and permeability values model and average porosity and permeability values by zone at the proposed well location.

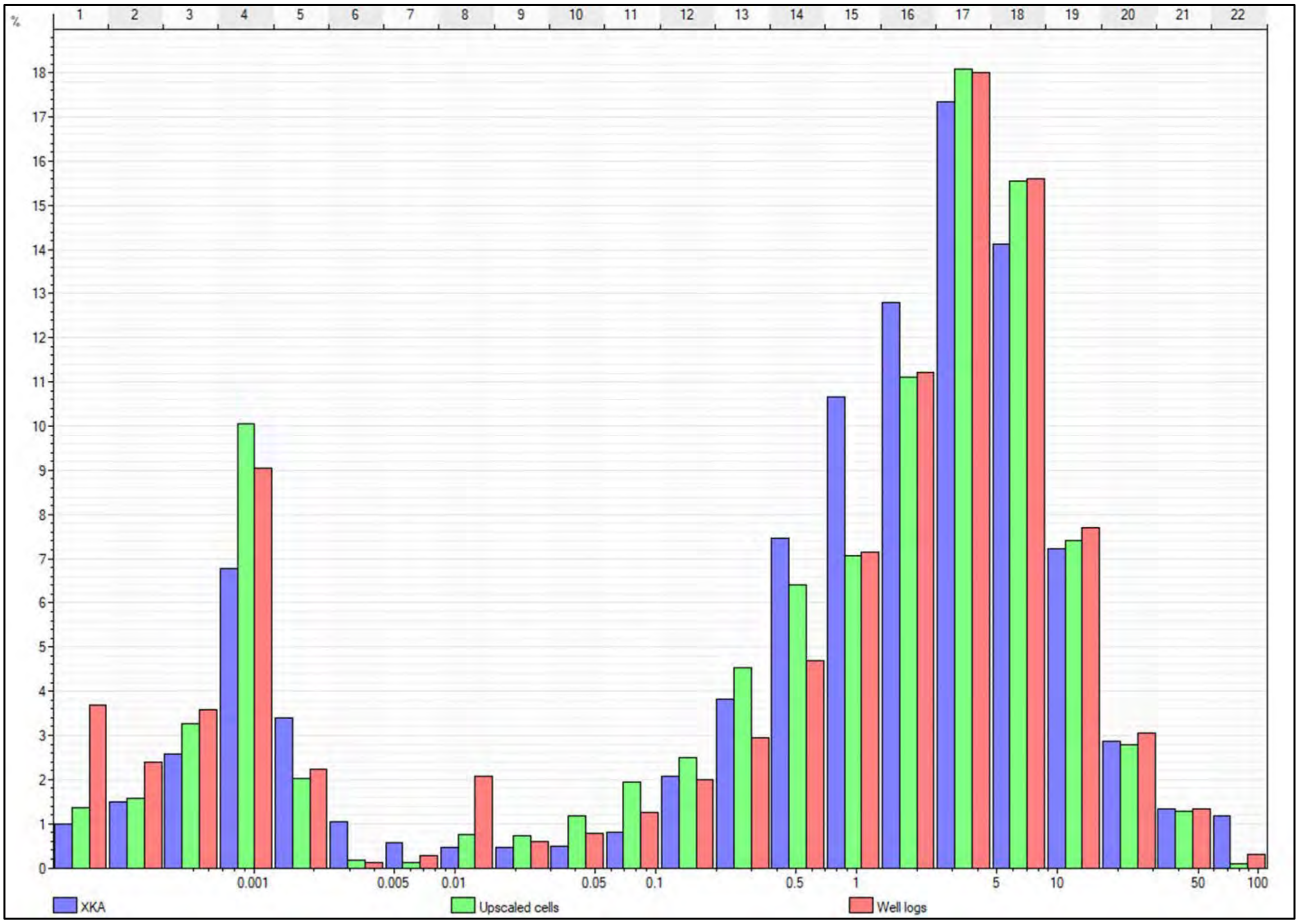


Figure 2-11: Histogram of Permeability Comparing Well Logs, Upscaled and Dynamic Model Data

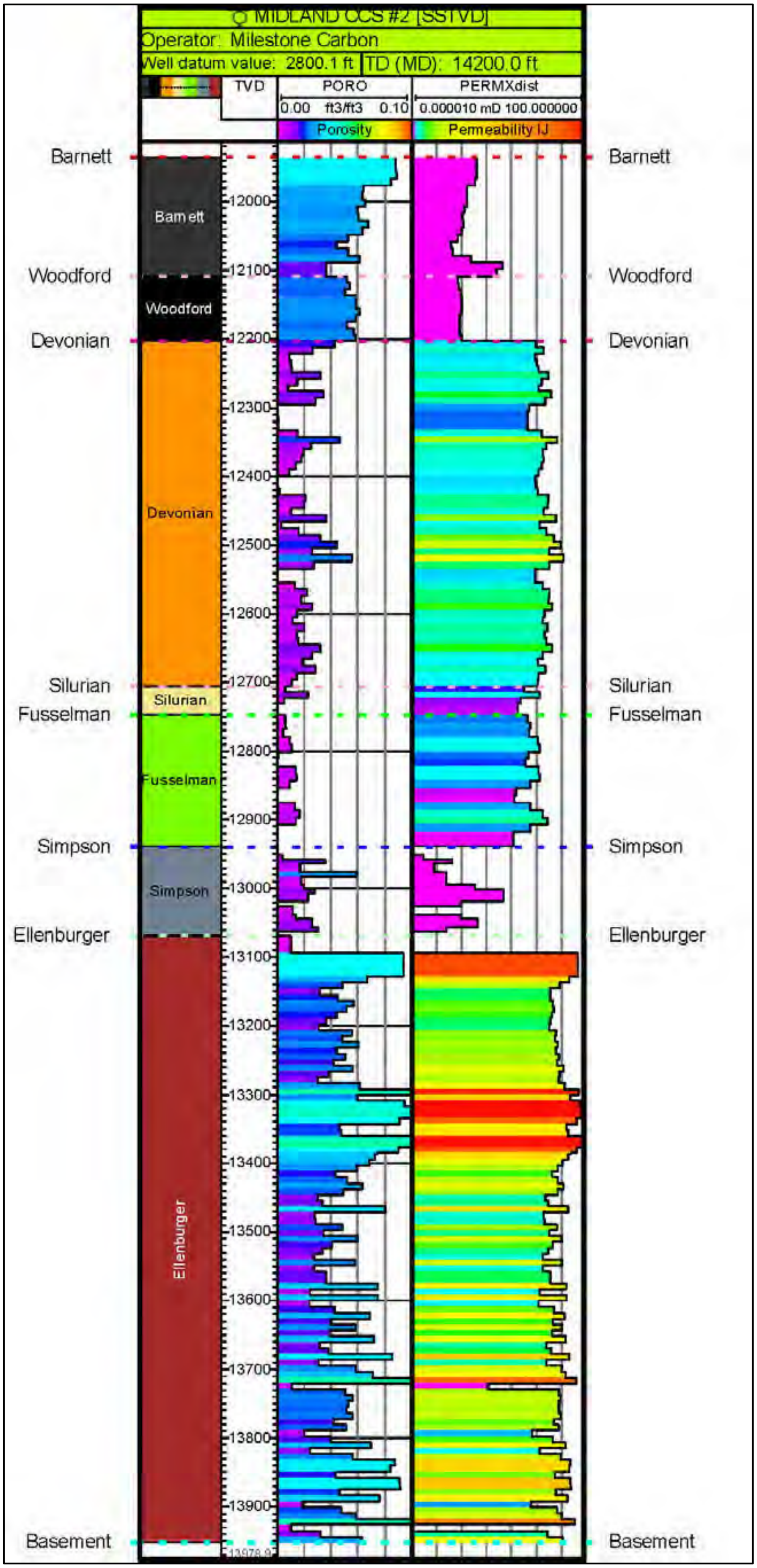


Figure 2-12: Modeled Porosity and Permeability Values at the Midland CCS #2 Well

2.4.5.3 Intrinsic and Effective Permeability

The representative ranges of values for matrix permeability and fracture permeability were sourced from the available literature (see Section 1.9.3). Matrix permeability quantifies fluid flow through the rock's pore spaces in response to pressure changes, while fracture permeability refers to flow through open fractures. In the static model, these two components were combined into a single property representing total intrinsic permeability.

Intrinsic permeability is a fundamental rock property that reflects its ability to transmit fluids through its pore network and fractures. It depends on pore size, pore structure, and the presence of fractures but is independent of the type of fluid flowing through the rock. In this model, intrinsic permeability captures the combined flow capacity of both matrix and fractures, without distinguishing their individual contributions.

Effective permeability, by contrast, is relevant within the dynamic model and represents the rock's ability to transmit a specific fluid in the presence of others—accounting for multi-phase flow conditions (e.g., oil, water, CO_2). During dynamic model calibration (history matching), effective permeability is adjusted based on observed rates and pressures. This approach enables a dual-porosity, dual-permeability system to be represented by a single permeability and porosity model. Calibration bounds effective permeability within a range of measured values, improving the accuracy of fluid flow simulation within the reservoir.

To account for vertical heterogeneity in the Model, a kv/kh ratio of 0.2 was applied to properly scale vertical permeability relative to horizontal permeability.

Average permeability maps for the Devonian, Ellenburger, and Fusselman formations are shown inn **Figure 2-14**. The Ellenburger exhibits higher intrinsic permeability compared to the overlying Devonian and Fusselman formations. No abrupt permeability changes are observed within the dynamic model or AoR.

Figure 2-15 shows north–south and east–west cross sections of intrinsic permeability through the static model (dynamic grid). Most of the higher permeability is concentrated within the lower Devonian and upper Ellenburger formations..

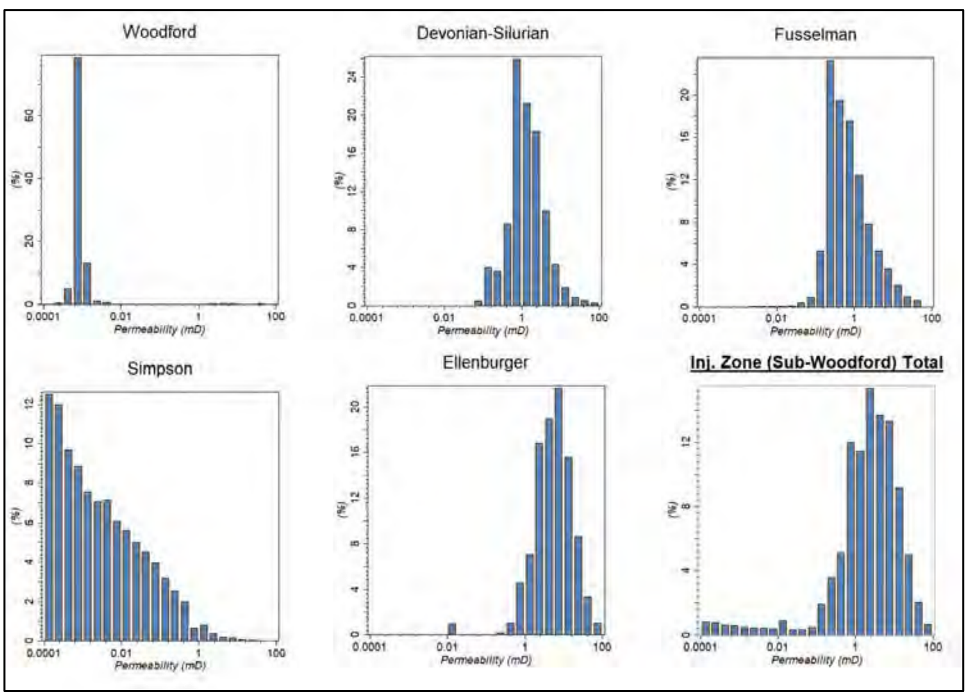


Figure 2-13: Intrinsic Permeability Histograms (IJ direction) for Each Injection and Confining Unit

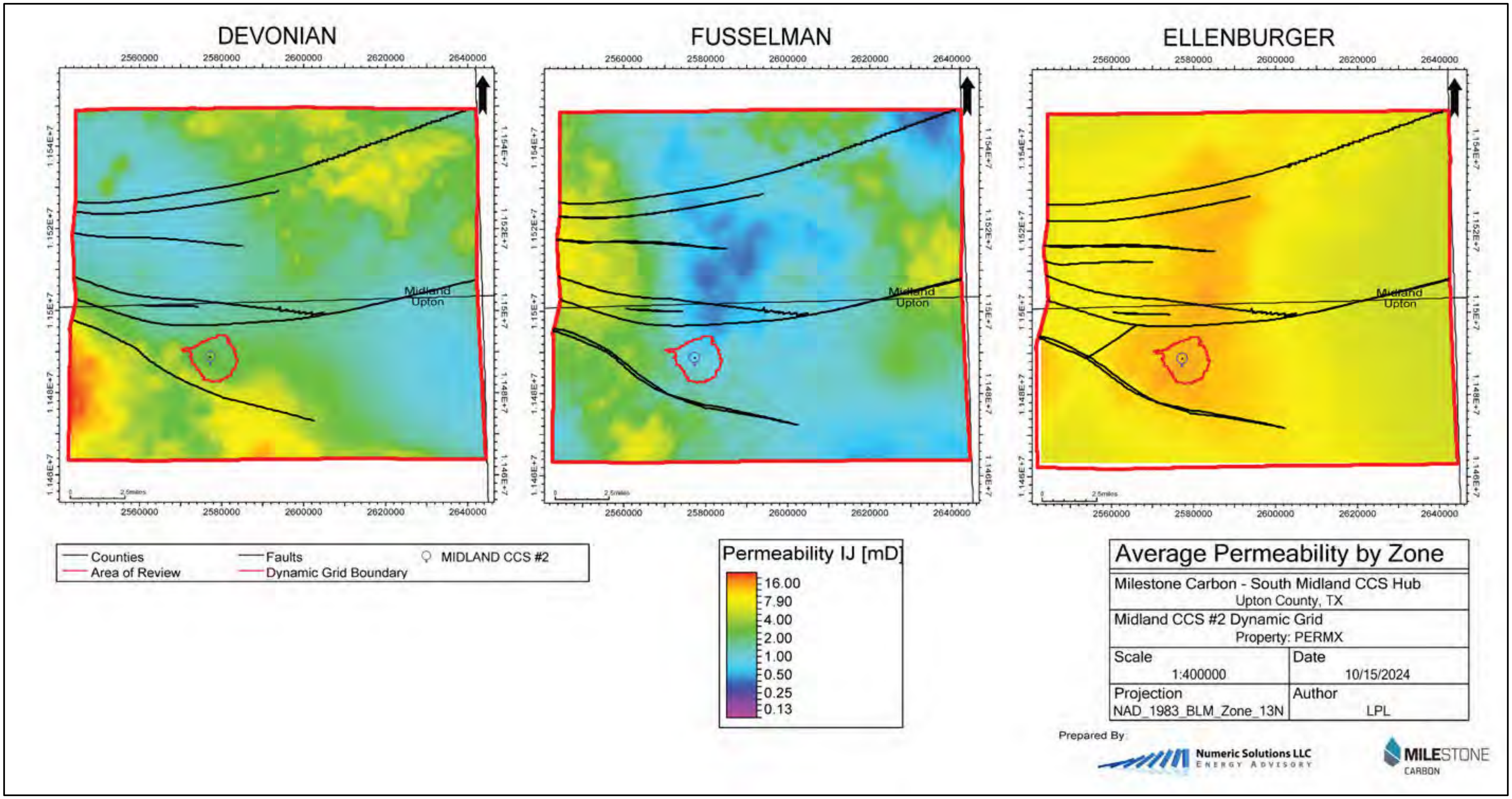


Figure 2-14: Average Intrinsic Permeability Maps for the Devonian, Fusselman, and Ellenburger Zones

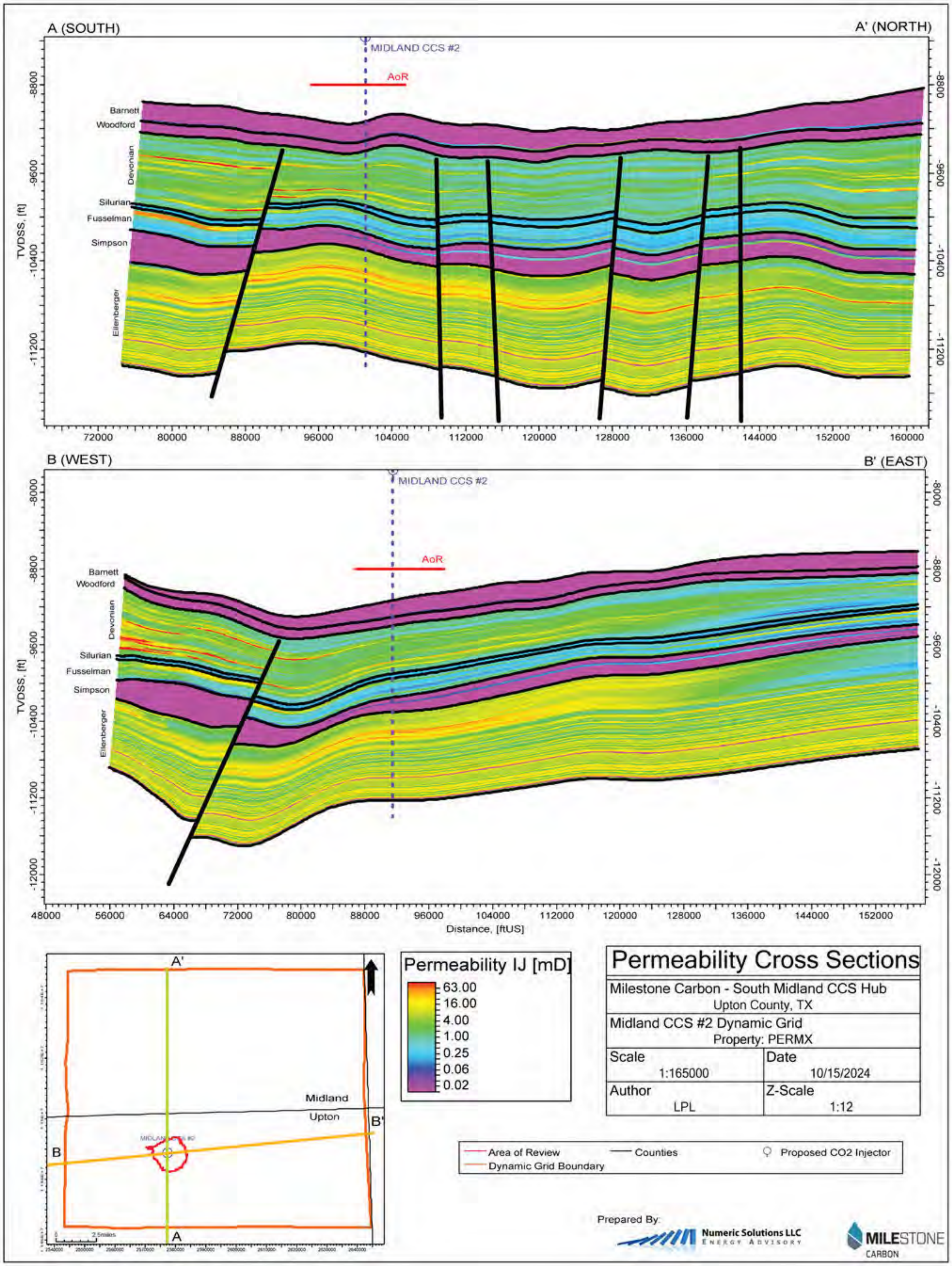


Figure 2-15: Cross Sections of Intrinsic Permeability Property (PERMX) in Static Model Across the Dynamic Grid

2.4.6 Relative Permeability and Other Rock Properties

To account for the interaction of two immiscible fluids in the pore space following the start of CO_2 injection, relative permeability curves were derived from the available literature. Two-phase relative permeability curves for water were loaded into the Model as a function of water saturation and water relative permeability. Supercritical CO_2 was loaded as a function of gas saturation and gas relative permeability.

Drainage relative permeability curves were used to model the injection period, during which non-wetting CO_2 displaces the wetting phase (formation brine). Imbibition curves were applied to simulate the reverse process, where the wetting phase displaces the non-wetting phase, typically occurring after injection ceases.

Site-specific relative permeability data will be incorporated into the revised model once obtained, pursuant to the logging and coring plans described in Sections 5.3 and 5.4.

Published data from Benson et al. (2013) were used to define initial values for relative permeability. These measurements, taken from rock samples believed to be representative of the injection units, provide a reasonable estimate based on the current understanding of the reservoir. **Figure 2-16** shows the relative permeability curves used as inputs to the dynamic simulation model, which will be further calibrated once site-specific data from the stratigraphic test well become available.

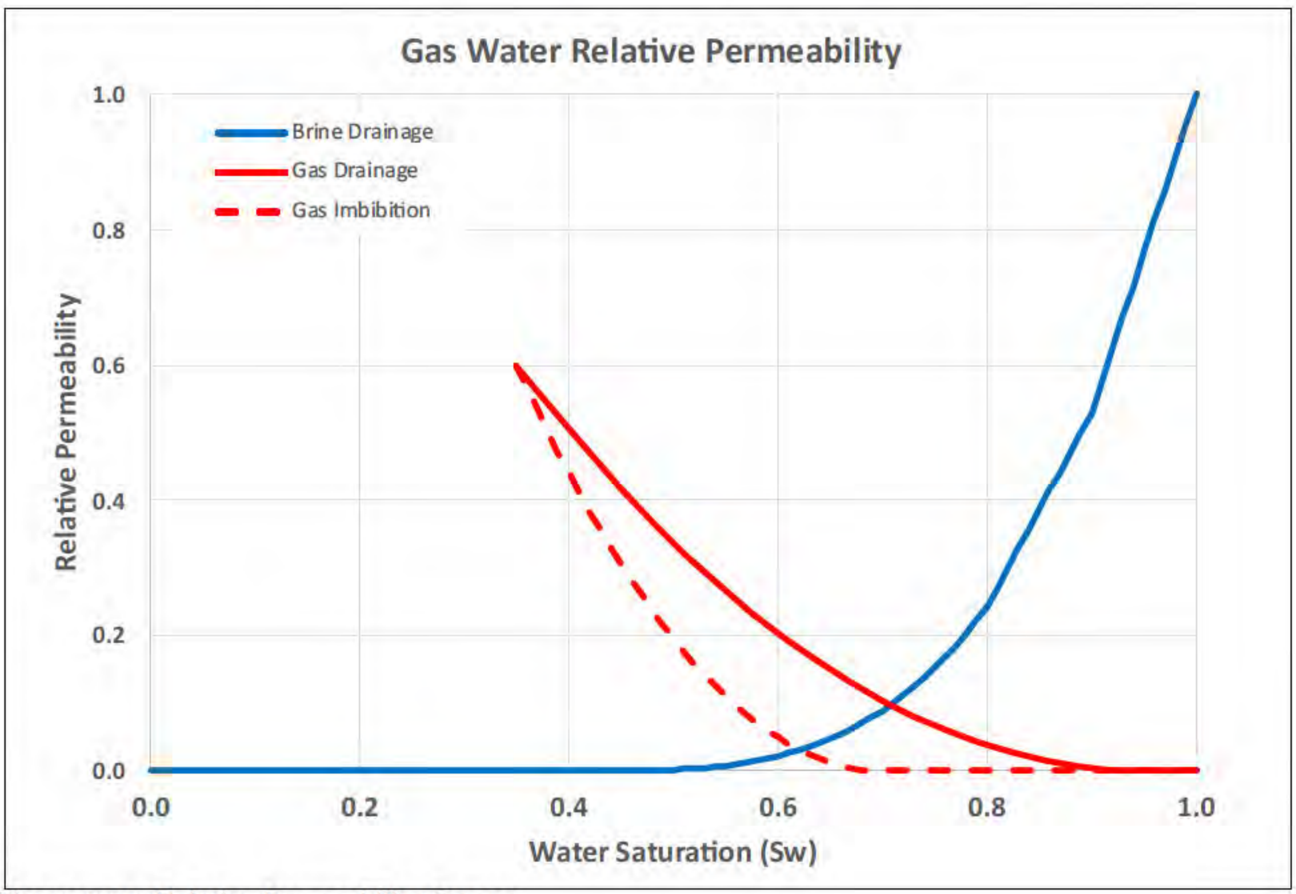


Figure 2-16: Relative Permeability Curves

2.4.7 Stress Gradients

The maximum injection pressure will not exceed ninety percent (90%) of the fracture gradient of the injection units as outlined in **Table 2-8**.

Pore pressure gradients, minimum principle stress gradients (SHmin) and 90% of SHmin for each formation can be found in **Table 2-9**. All values were calculated from wireline logs and are consistent with values reported in the available literature

Additional notes on initial reservoir pressure and stress gradients can be found in **Section 1.10**.

Table 2-8: Injection Units/Seal Stress Magnitudes

Formation	Top Depth (TVD GL, ft)	Midpoint Pore Pressure (psi)	Midpoint Minimum Horizontal Stress (SHmin) (psi)	Midpoint 90% (SHmax) (psi)
Atoka	11,503	6,093	8,857	7,971
Barnett	11,933	6,250	8,726	7,853
Woodford	12,106	6,077	9,494	8,545
Devonian (Undifferentiated)	12,200	5,612	9,209	8,288
Wristen Group (Silurian)	12,703	5,726	9,041	8,136
Fusselman	12,744	5,778	9,123	8,211
Simpson	12,936	5,850	9,548	8,593
Ellenburger	13,066	6,078	9,979	8,981
Basement	13,949			

Table 2-9: Stress and Pore Pressure Gradients by Formation

Formation	Calculated Pore Pressure Gradient (psi/ft)	Calculated SHmin Gradient (psi/ft)	90% SHmin Gradient
Atoka	0.52	0.755838	0.680254
Barnett	0.52	0.725989	0.65339
Woodford	0.5	0.781243	0.703119
Devonian (Undifferentiated)	0.45	0.738366	0.664529
Wristen Group (Silurian)	0.45	0.710537	0.639483
Fusselman	0.45	0.734395	0.639483
Simpson	0.45	0.738784	0.660956
Ellenburger	0.45	0.715395	0.664906

2.4.8 Pore Pressure

Pending direct measurements outlined in the preoperational logging and testing plans (Section 5), the pore pressure gradient has been assumed to be 0.45 psi/ft, based on data from 403 drill stem tests (DSTs) collected in offset wells. **Figure 2-17** shows a histogram of mudweights used in the region. The assumed gradient is derived from the 5th percentile (P5) of the mudweight data and corroborated by DST results. Because mudweights typically exceed actual pore pressure slightly, the mean was not used.

Pore pressure is a critical input parameter for simulation, as it directly influences the calculated plume extent and the volume of CO_2 that can be injected before nearing the fracture gradient of the formation and caprock. The assumed gradient of 0.45 psi/ft is also consistent with brine densities measured in historical water samples..

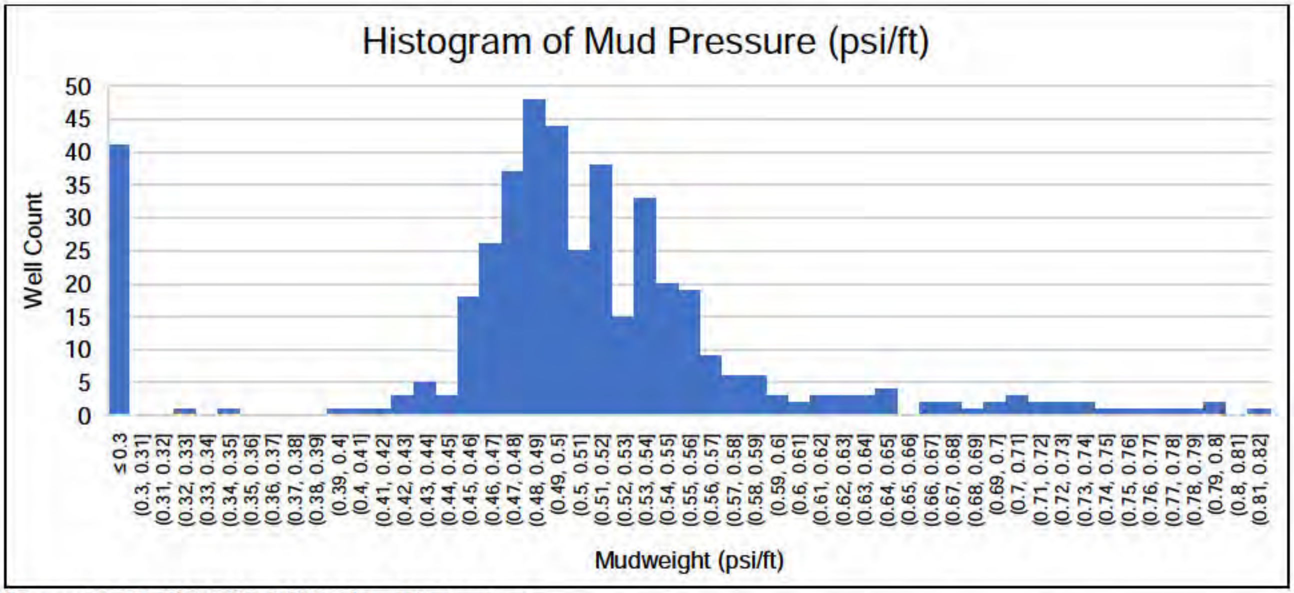


Figure 2-17: DST Mud Weights Histogram
Histogram of mudweights from drill stem tests within a 50-mi. radius of the proposed site, converted to pressure gradients. The data show that 0.49 psi/ft is the mode of the data. 403 data points are plotted on this histogram.

2.4.9 Fluid Properties

2.4.9.1 Gas Properties

To model the phase behavior of the injection stream (**Table 2-10**) and it's interaction with in-situ brine, fluid properties were simulated using the Peng and Robinson (1976) equation of state (**Equation 7** and **Equation 8**).

Table 2-10: Injected Gas Mixture by Mole Percent

Component	Mole %
CO_2	95.000
CO	0.425
H_2S	0.020
N_2	1.000
CH_4	3.555
Sum	**100.000**

Equation 7: Peng-Robinson equation of states

$$P = \frac{RT}{V-b} - \frac{a(T)}{V(V+b)+b(V-b)}$$

Equation 8: Intermediate terms of the Peng-Robinson EOS

$$a(T) = a_c \alpha(T),$$

$$a_c = 0.45724 \frac{R^2 T^2}{P_c}$$

$$b = \frac{0.07780 R T_c}{P_c}$$

$$\alpha(T) = \left(1 + m\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)^2$$

$$m = 0.379642 + 1.48503\omega - 0.164423\omega^2 + 0.016666\omega^3$$

P = Pressure (Pa)

T = Temperature (K)

V = Molar Volume (m^3/mol)

ω = acentric factor

R = Gas constant (8.3145 J/mol-K)

Xc = Denote the critical points for respective terms

For mixtures of pure components, a binary interaction coefficient mixing rule was applied. The input parameters used in the Peng-Robinson equation of state calculation are summarized in **Table 2-11**.

Table 2-11: Peng-Robinson Equation of State Calculation Input Parameters

Component	Pc (psia)	Tc (R)	Acentric fact.	Binary Interaction Coefficients				
				CO_2	C1	H_2S	N_2	CO
CO_2	1,070.7	547.54	0.2280	0.000	0.105	0.000	0.135	0.305
C1	667.0	343.01	0.0120	0.105	0.000	0.025	0.070	0.310
N_2	501.8	227.16	0.0377	0.000	0.025	0.000	0.130	0.300
H_2S	1,300.0	672.35	0.0942	0.135	0.070	0.130	0.000	0.309
CO	513.5	239.26	0.0660	0.305	0.310	0.300	0.309	0.000

2.4.9.2 Brine Properties

The salinity of brine is 152,704 mg/L, based on extensive offset water samples (**Figure 2-18**). This corresponds to a measured brine density of 65.69 lb/ft³ at the conditions of temperatures and pressures at the top of the reservoir at the injection well. Average values throughout the reservoir have a slightly higher value of 67.4 lb/ft3 in the Model domain. The density of the aqueous phase in the model was calculated as a function of composition using the Rowe–Chou method (Rowe and Chou, 1970). See **Section 1.9.4** for additional details on water salinity. Preliminary values used in this application will be updated as future laboratory measurements become available.

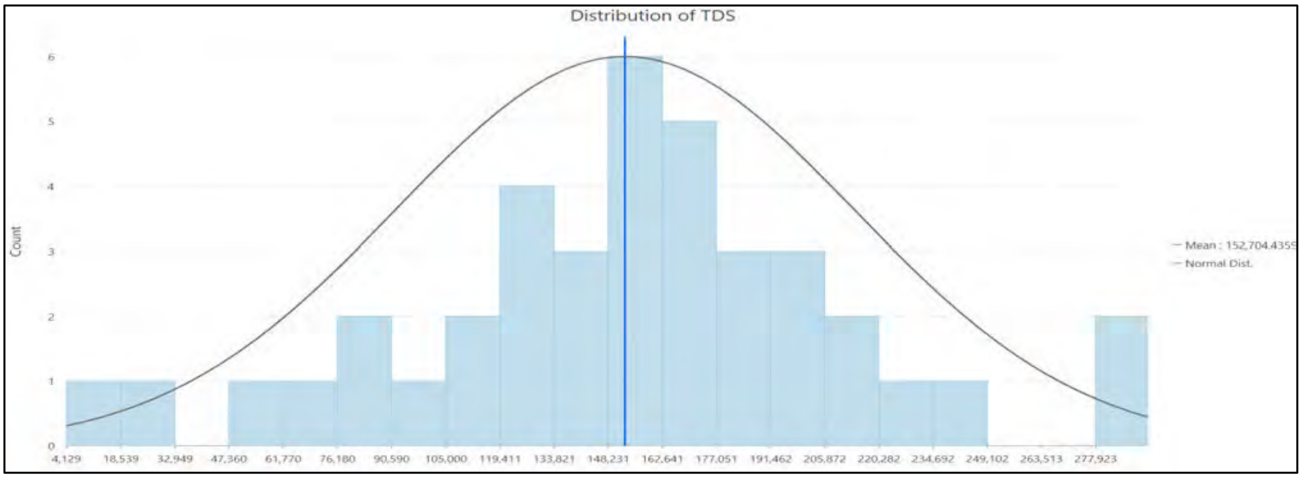


Figure 2-18: Offset Well Penetrations TDS Data

2.4.10 Injection Rate

The CO_2 injection rate was incorporated into the dynamic model as a fixed value constrained by the maximum injection pressure. The rate was programmed to decrease if pressure approached 90% of the minimum horizontal stress (SHmin).

In addition to this pressure constraint, the injection rate was modeled in two phases: a commissioning period and a full injection period. The commissioning period lasted 56 days, beginning with an initial rate of 17,530,651.46 scf/day. The rate was increased to 45,579,693.79 scf/day on Day 28 (model time: 1/29/2026) and again to the full injection rate of 54,516,444.93 scf/day on Day 56 (model time: 2/26/2026). This full rate was sustained for the remaining 11 years and 309 days of injection well operation.

2.4.11 Injection Period

The injection period is 12 years from the commencement of injection. There is a 56-day commissioning period and an 11-year, 309-day full injection period.

2.4.12 Rock Compressibility

Rock grains in the reservoir are subject to external stress from overburden accumulation and internal pressure from fluids stored in the pore space. Rock compressibility quantifies the change in rock volume in response to these forces. A value of 3.33E-06 1/psi was used for the isothermal rock compressibility of generic dolomite throughout the Model domain. This value was estimated from Xu et al. (2020) and will be confirmed through laboratory measurements obtained from the planned stratigraphic test well.

2.4.13 Boundary Conditions

The initial conditions for the dynamic model assumed a pseudo-infinite acting reservoir fully saturated with brine. To simulate this boundary condition, the grid blocks at the edge of the Model were assigned a volume multiplier of 1,000, making them 1,000 times larger than the interior grid blocks (**Figure 2-19**).

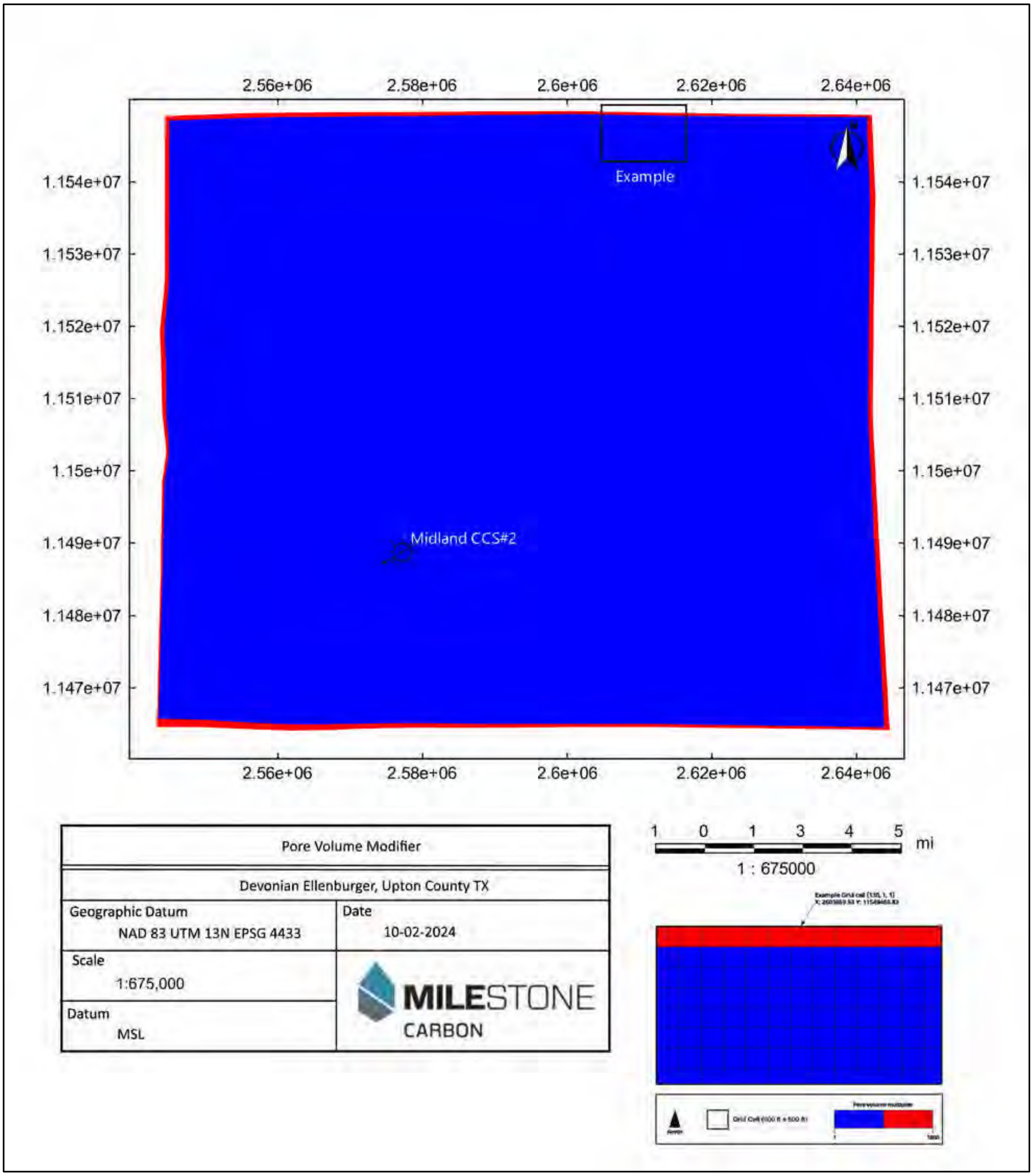


Figure 2-19: Pore Volume Modifier
Red cells represent cells with a volume multiplier of 1,000 times the volume of the grid block in the interior of the Model represented in blue.

2.4.14 Initial Conditions

Milestone used reservoir pressure, temperature, and brine salinity to initialize the Model. **Table 2-12** summarizes the general model inputs at initial reservoir conditions. The parameters outlined in **Section 2.4** were applied uniformly across a single region encompassing the full extent of the Model domain.

All runs were performed using an isothermal compositional engine. Mass transport and mineral precipitation were not considered in the initial model runs due to a lack of site-specific data. However, these effects may be incorporated and refined in future model updates following laboratory testing.

Milestone initialized the Model under the assumption that CO_2 would be injected at bottomhole conditions in a supercritical phase. Reservoir conditions were modeled to maintain CO_2 in this phase throughout the injection and post-injection periods. Storing CO_2 in a supercritical phase maximizes storage efficiency, as its density is significantly higher than in the gaseous phase—allowing more mass to be stored in an equivalent reservoir volume. Additionally, supercritical CO_2 maintains low viscosity and requires relatively low injection pressures.

Table 2-12: Summary of Initial Conditions

Parameter	Value or Range	Units	Corresponding Elevation	Data Source
Average Brine Density	67.40	lbs/ft^3	All depths	Calculated in AoR
Average Salinity	152,704	mg/L	All depths	Mean of water samples
Average Permeability Devonian	1.3742	mD	Top Devonian	Well logs
Average Permeability Fusselman	0.8	mD	Top Fusselman	Well logs
Average Permeability Ellenburger	3.7055	mD	Top Ellenburger	Well logs
Average Porosity Devonian	1.98	%	Top Devonian	Well logs
Average Porosity Fusselman	1.16	%	Top Fusselman	Well logs
Average Porosity Ellenburger	4.87	%	Top Ellenburger	Well logs
Pore Pressure Gradient	0.45	psi/ft	N/A	DST data in offset wells
Reservoir Pressure at Midland CCS #1 Top of Devonian	5,490	psi	Top of Devonian	Calculated
Frac Gradient Devonian	0.7384	psi/ft	Devonian	Calculated (see section 1.10)
Frac Gradient Fusselman	0.7344	psi/ft	Fusselman	Calculated (see section 1.10)
Frac Gradient Ellenburger	0.7154	psi/ft	Ellenburger	Calculated (see section 1.10)
Temperature Gradient	0.0103	°F/ft	N/A	Well logs
Avg. Reservoir Temp. Ellenburger	194.6	°F	Top Ellenburger	Well logs
Avg. Reservoir Temp. Devonian	185.7	°F	Top Devonian	Well logs
Surface Temperature	60.0	°F	Surface	Assumed
CO_2 Phase	Supercritical		N/A	Calculated
Average Brine Viscosity	0.329	cp	All depths	Calculated in AoR
Rock Compressibility	3.33E-6	1/psi	All depths	Well logs/Newman
Fault Transmissibility	0.01	-	All depths	Assumed

2.4.15 Potential for Future Updates

Both the static geologic model and dynamic reservoir simulation model serve as baselines to which measured laboratory data and field observations can be added. In addition to incorporating new field and laboratory data, the Models can be systematically updated with each measurement to quantify incremental changes across the static model of the South Midland Facility project area.

Once initialized with updated parameters, the Model can be history-matched to recorded injection pressures and volumes, allowing further refinement of model parameters to align with observed field conditions.

2.5 Dynamic Model Geometry and Properties

The upscaled static geologic model was used as input for the dynamic reservoir simulation model, which was designed to simulate the CO_2 plume extent and pressure front resulting from the injection of supercritical CO_2 into the injection units.

The dynamic model consists of 226 layers across the injection units and approximately 7.5 million active cells. Each grid block has an area of 500 by 500 ft, with the model covering an aerial extent of 312 square miles. Grid scaling is consistent across all vectors (IJK). A single Class VI CO_2 injection well was included in the model to simulate the behavior of the plume and pressure front during injection[4].

The model shown in **Figure 2-20** provides the most complete representation of the dynamic reservoir model and the parameters required to simulate subsurface behavior. The figure includes a 3D view of the Model and the location of the Midland CCS #2 Well. Specifications for the Model domain are summarized in **Table 2-13**.

Table 2-13: Dynamic Model Domain Information

Coordinate System	NAD 1983		
Horizontal Datum	North American Datum 1983		
Coordinate System Units	ft US		
Zone	Texas Central Zone		
FIPSZONE	4203	**ADSZONE**	5376
Coordinate of X min	2,541,496	**Coordinate of X max**	2,644,471
Coordinate of Y min	11,461,870	**Coordinate of Y max**	11,549,714
Elevation (TVDSS) of bottom of domain	-11,996	**Elevation (TVDSS) of top of domain**	-8,367

TVDSS: Subsea True Vertical Depth

[4] Injection into the Midland AGI #5, a proposed Class II CO2 disposal well, was also included in the dynamic model.

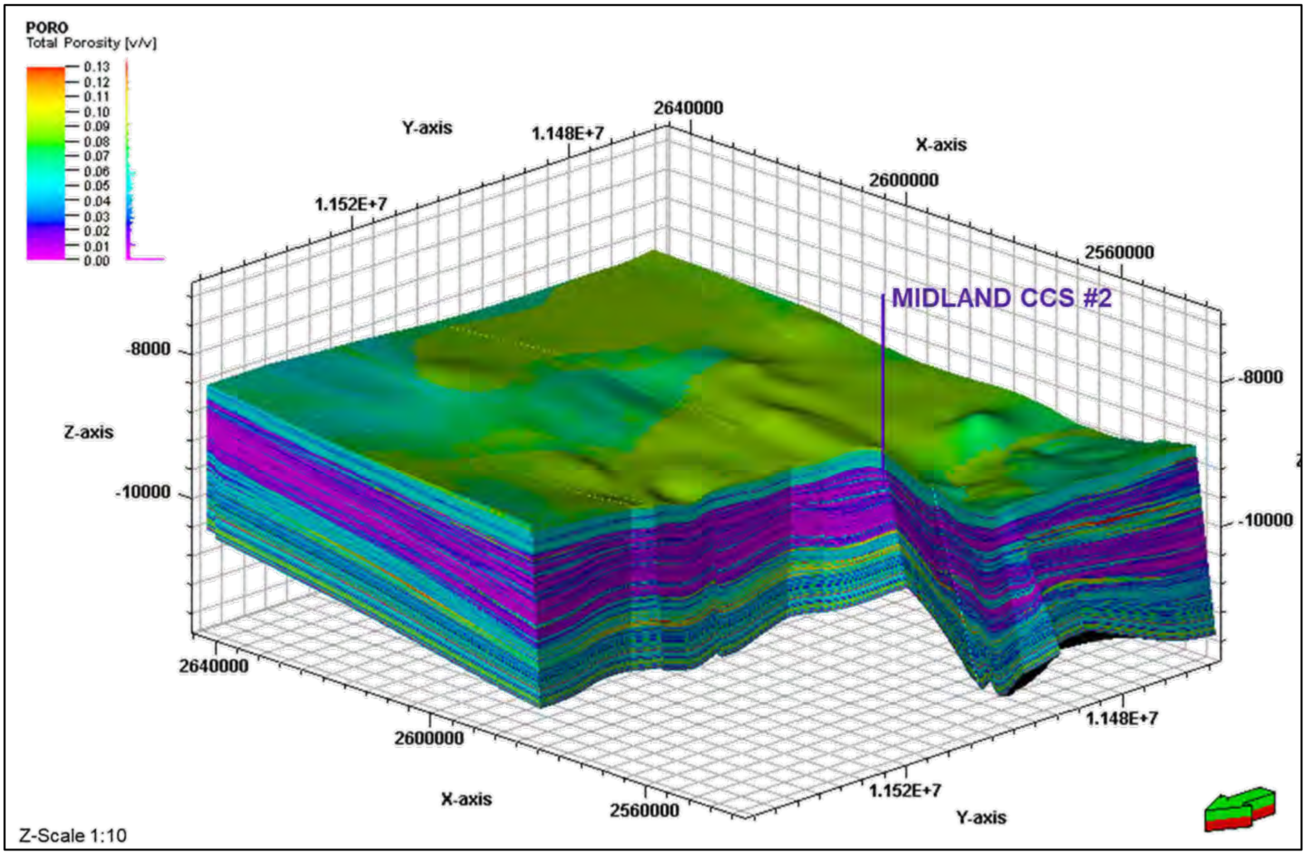


Figure 2-20: Midland CCS #2 Well 3D Dynamic Model Grid
3D view of dynamic model grid and placement of the Midland CCS #2 Well. The Midland CCS #2 Well is positioned at the center of the cutaway. Color fill is the porosity of the reservoir.

2.6 Computational Modeling Results

2.6.1 Predictions of System Behavior

Milestone generated a dynamic reservoir model to delineate the CO_2 plume and characterize the extent and geometry of the Area of Review (AoR). The model also identified the extent of the pressure disturbance and the point at which pressure changes and diffusion become negligible. In addition to calculating the plume extent and AoR (**Table 2-14**), the simulation demonstrates the optimized storage capacity of the reservoir. The cumulative volume of CO_2 injected during the simulation was 223.1 Bcf, or 11.8 million tonnes, at standard conditions (60°F and 1 atm).

The extent of the plume at the end of the injection period (modeled year 2039, after 12 years of injection) is shown in **Figure 2-21.** After injection ceases, the plume continues to expand gradually in all directions, though post-injection growth is limited (**Table 2-14**). A drop in bottomhole pressure is observed at the end of injection, as CO_2 begins to diffuse into the surrounding pore space.

The temporal progression of the CO_2 plume is shown in map view in **Figure 2-21**. By model year 2089 (50 years post-injection), the plume reaches a horizontal radius of approximately 11,823 ft. At this time, the gas saturation at the outer edge of the plume is approximately 2.0%.

Table 2-14: Change in Plume Dimensions Through Time

Year	Plume Area (ft^3)	Avg Plume Radius (ft)	Percent Change In Area Per Year (%)
2039	66,408,131	4,598	-
2041	70,473,355	4,736	5.77%
2045	73,856,303	4,849	2.23%
2055	80,906,482	5,075	1.76%
2065	85,483,412	5,216	2.76%
2075	88,041,944	5,294	0.71%
2089	92,533,590	5,427	0.06%
Total Change	**+26,125,459**	**+830**	**+28.2%**

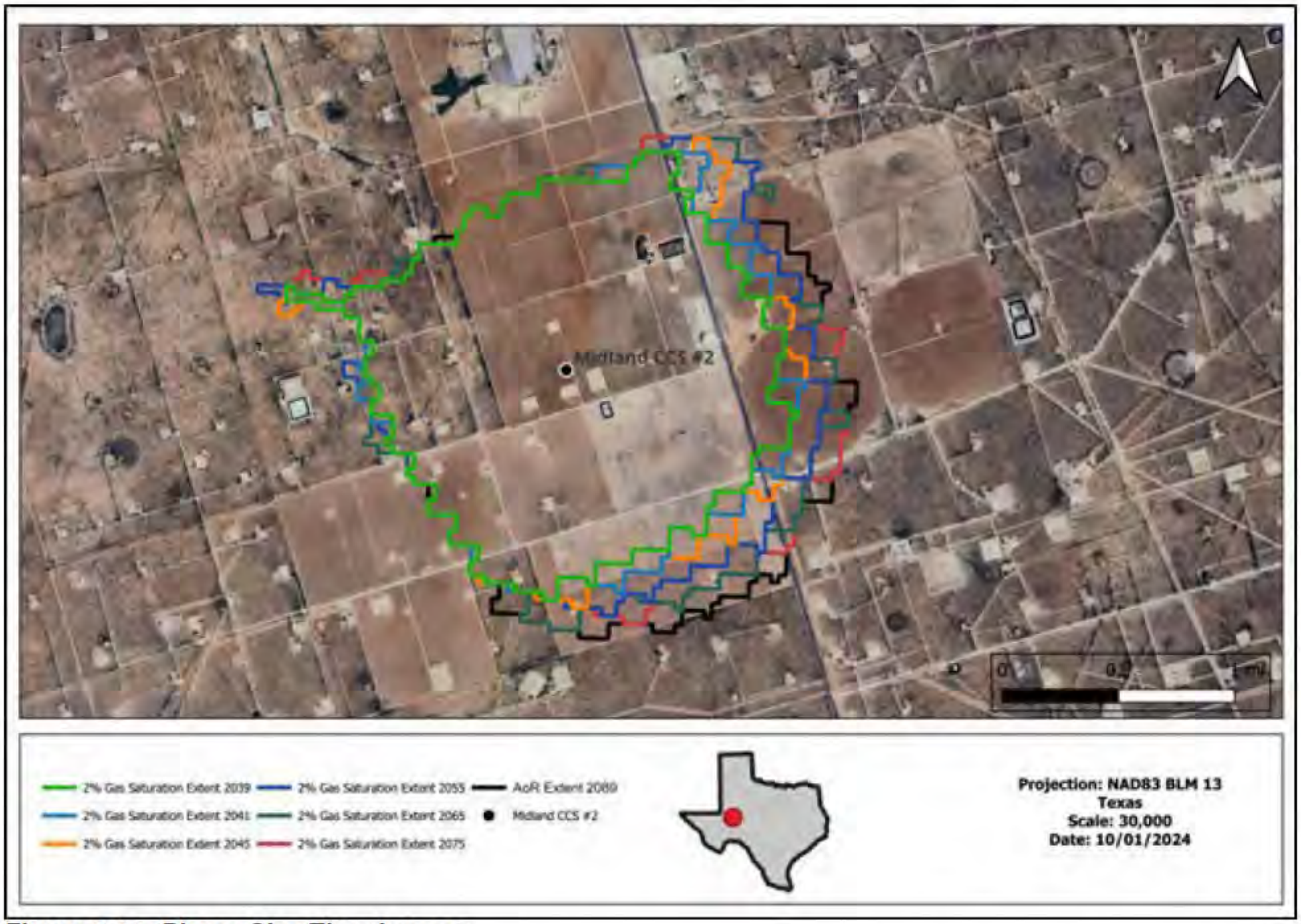


Figure 2-21: Plume Size Time Lapses
"Cooler colors" (i.e. dark green/dark red) are late time, "hotter colors" (i.e. green/orange) are early time

Figure 2-23 shows the plume in cross-sectional view. The plume varies in width vertically based on the porosity and permeability in each formation of the injection unit of the reservoir. The Model shows that most of the supercritical CO_2 (sc-CO_2) migrates into the upper Ellenburger and middle-upper Devonian, following areas of higher permeability and fracturing, and continues to expand horizontally under the Simpson Formation and the packstones of the upper Devonian.

After injection ceases in model year 2039, the Model continues to simulate plume expansion, as shown in **Figure 2-23** and **Figure 2-24**. Post-injection plume growth is minimal—less than 1% change per year and less than 830 ft of total expansion between 2039 and 2089 (**Figure 2-22** and **Table 2-14**). The Ellenburger Formation, due to its higher permeability, receives a larger proportion of the injected supercritical CO_2 **Figure 2-23**. Most post-injection migration occurs in the vertical direction, with CO_2 occupying additional pore space in the Devonian. No injectate is observed to migrate through the overlying Woodford Shale or Barnett Shale.

After model year 2065, the incremental change in plume area remains below 1% per year (**Table 2-14**), corresponding to an average lateral expansion of approximately 105 ft per year. This limited movement indicates the plume has reached a quasi-stable state, significantly reducing the risk of upward migration to the surface or into underground sources of drinking water.

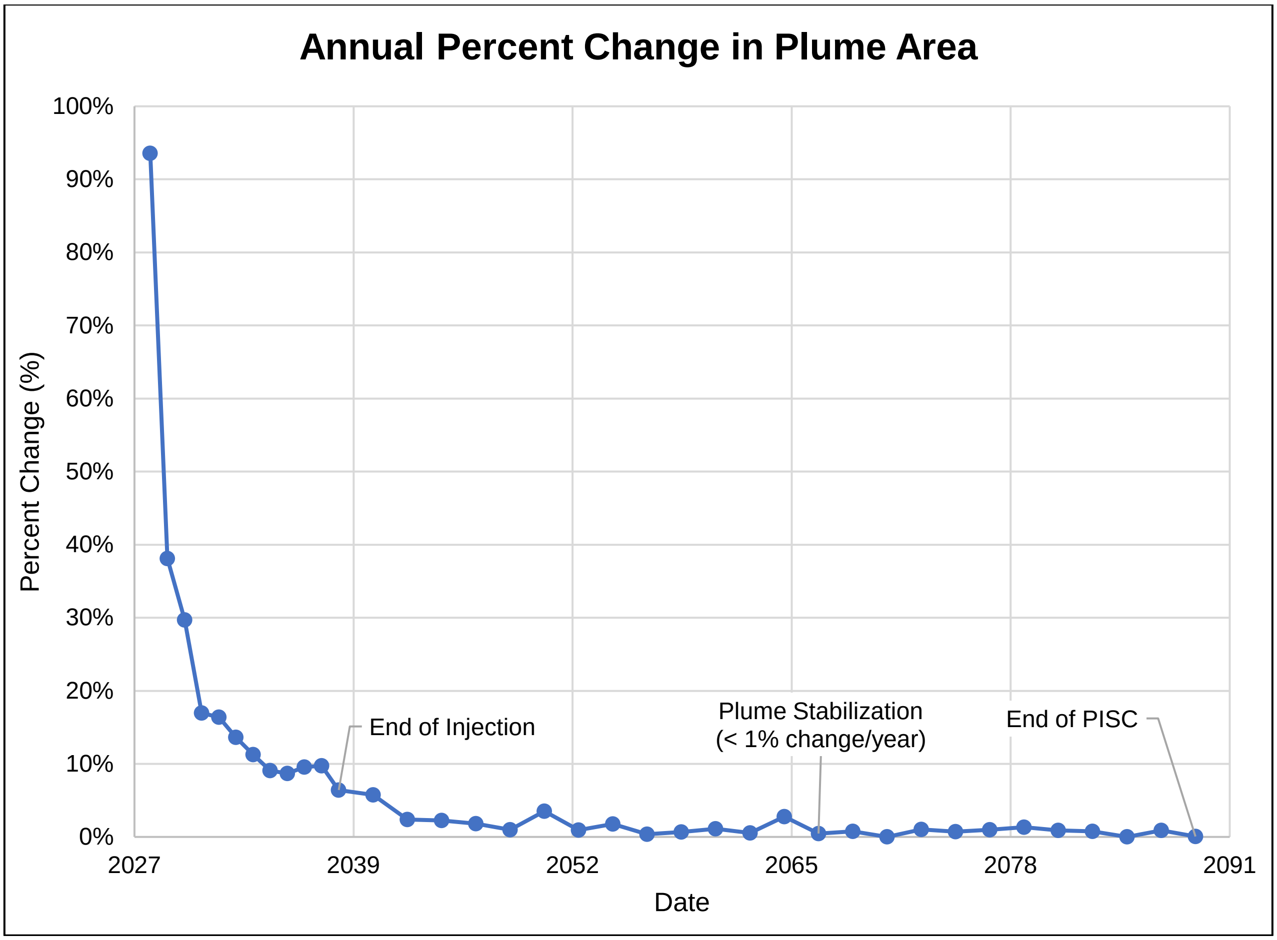


Figure 2-22: Annual Percent Change in Plume Area Through the End of PISC

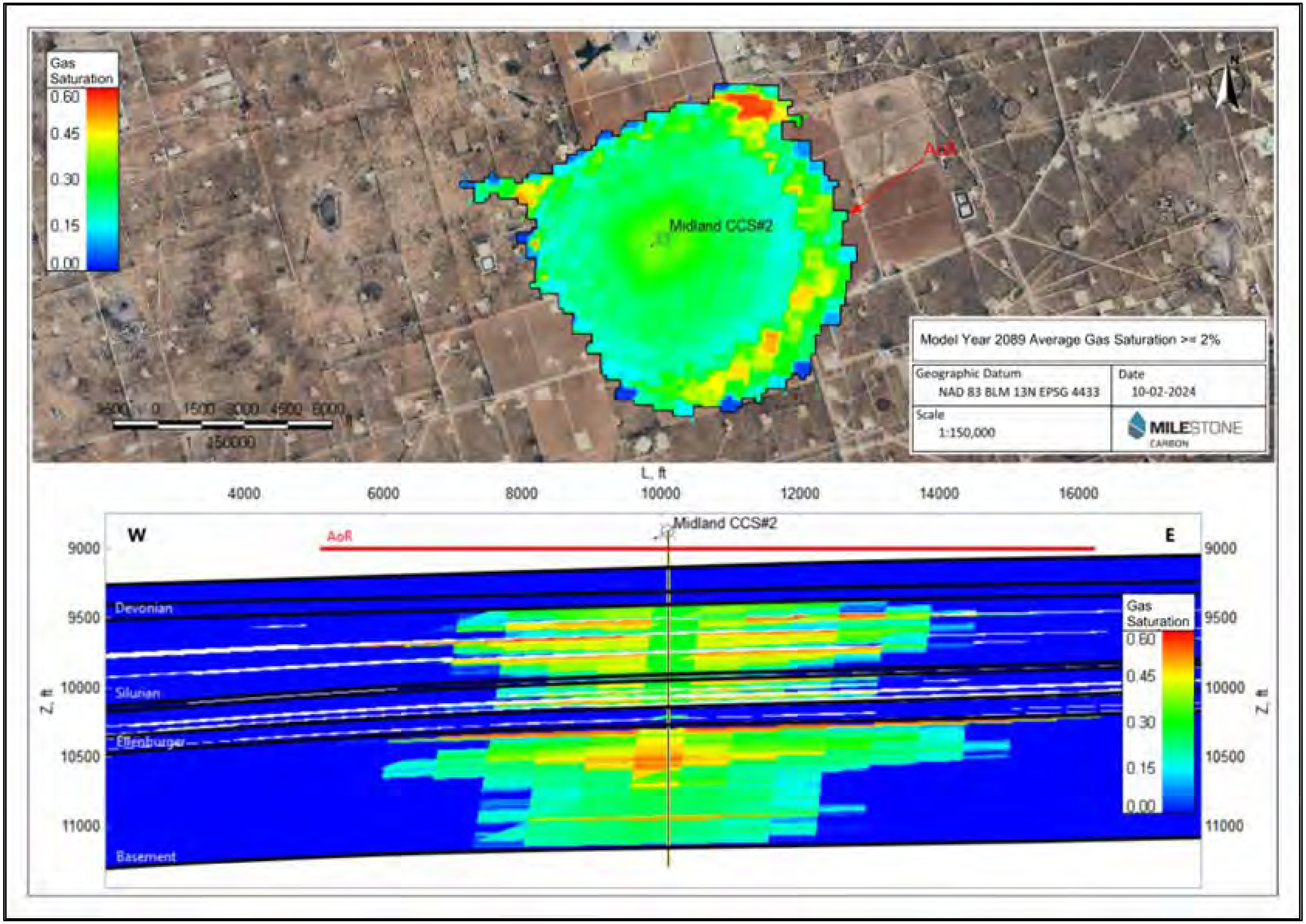


Figure 2-23: Modeled sc-CO_2 Saturation in Model Year 2089

Modeled sc-CO_2 saturation in year 2089 or 50-years post-injection. Top: aerial view; Bottom: cross-sectional view. sc-CO_2 saturation shown in the aerial view is the vertical average saturation for the entire system. Red outline encompasses any sc-CO_2 saturation in any cell greater than 2%.

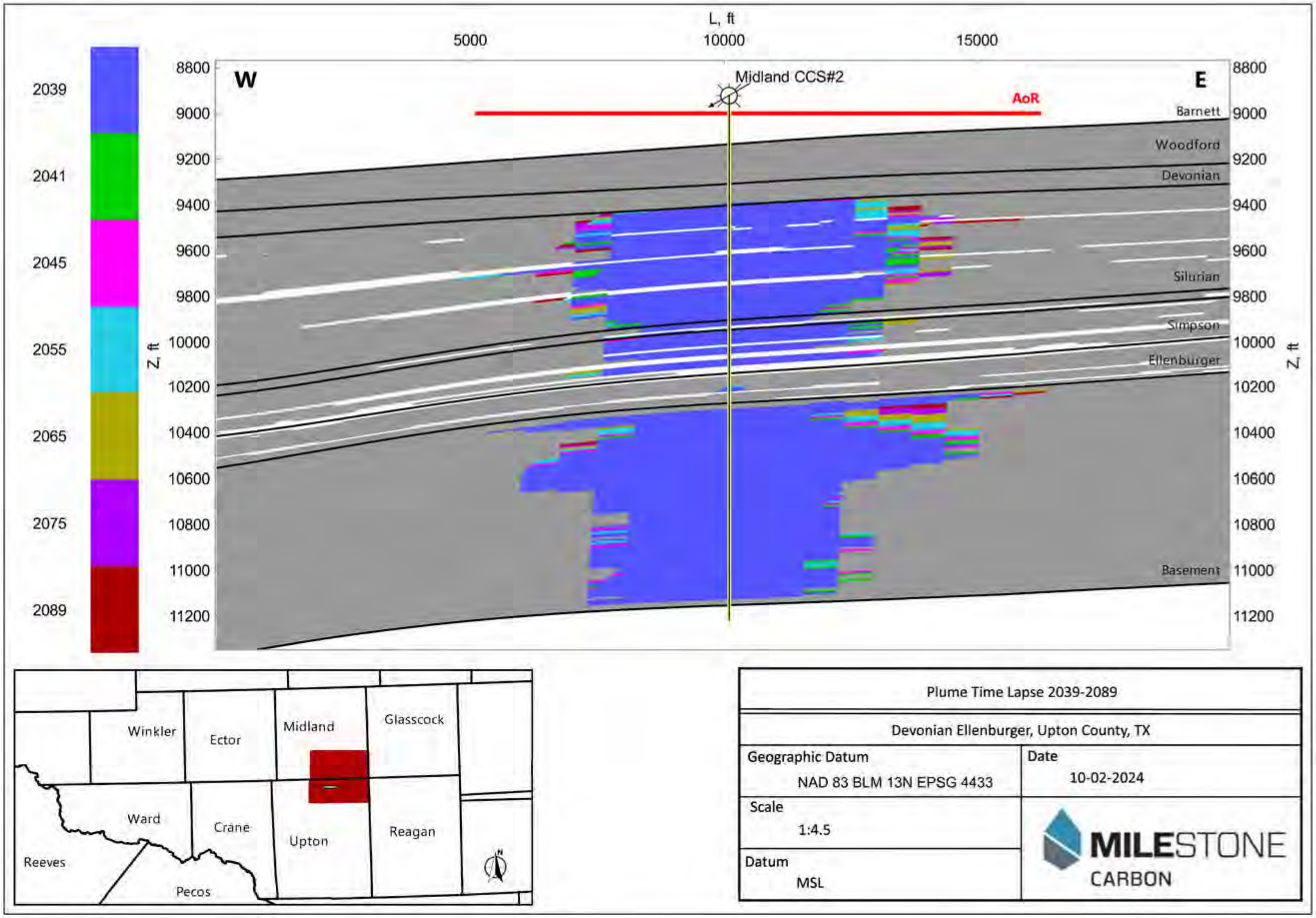


Figure 2-24: CO_2 Saturation Cross Section
Cross-section view of sc-CO_2 saturation from west to east showing the migration of CO_2 over time post-injection. Red is the furthest extent of the CO_2 plume at the Model year 2089 (50 years post-injection), and blue is the position at model year 12, at the end of injection.

2.7 Change in Bottomhole Pressure

As shown in **Figure 2-25**, the bottomhole injection pressure at the Midland CCS #2 well rises gradually during injection as CO_2 diffuses through the system. The pressure reaches a maximum of 7,499 psi just before the end of injection in modeled year 2039.

Reference depths corresponding to the bottomhole pressure values in **Figure 2-25** are provided in **Table 2-15**. The maximum change in modeled bottomhole pressure (ΔBHP) at the end of injection (model year 12) is 1,598 psi at Midland CCS #2. This peak pressure occurs at the well and decreases exponentially with distance from the wellbore (**Table 2-16**).

The bottomhole pressure shown in **Figure 2-25** differs from grid block pressure, which represents the average pressure within the reservoir cell. These pressures are linked by the well index, a simulator-internal calculation that represents the ratio of well flow rate to the pressure difference between the reservoir block and the wellbore. A comparison of grid block and wellbore pressures at the top of the Devonian Injection Interval is also shown in **Figure 2-25**, where the observed difference is attributed to the well index.

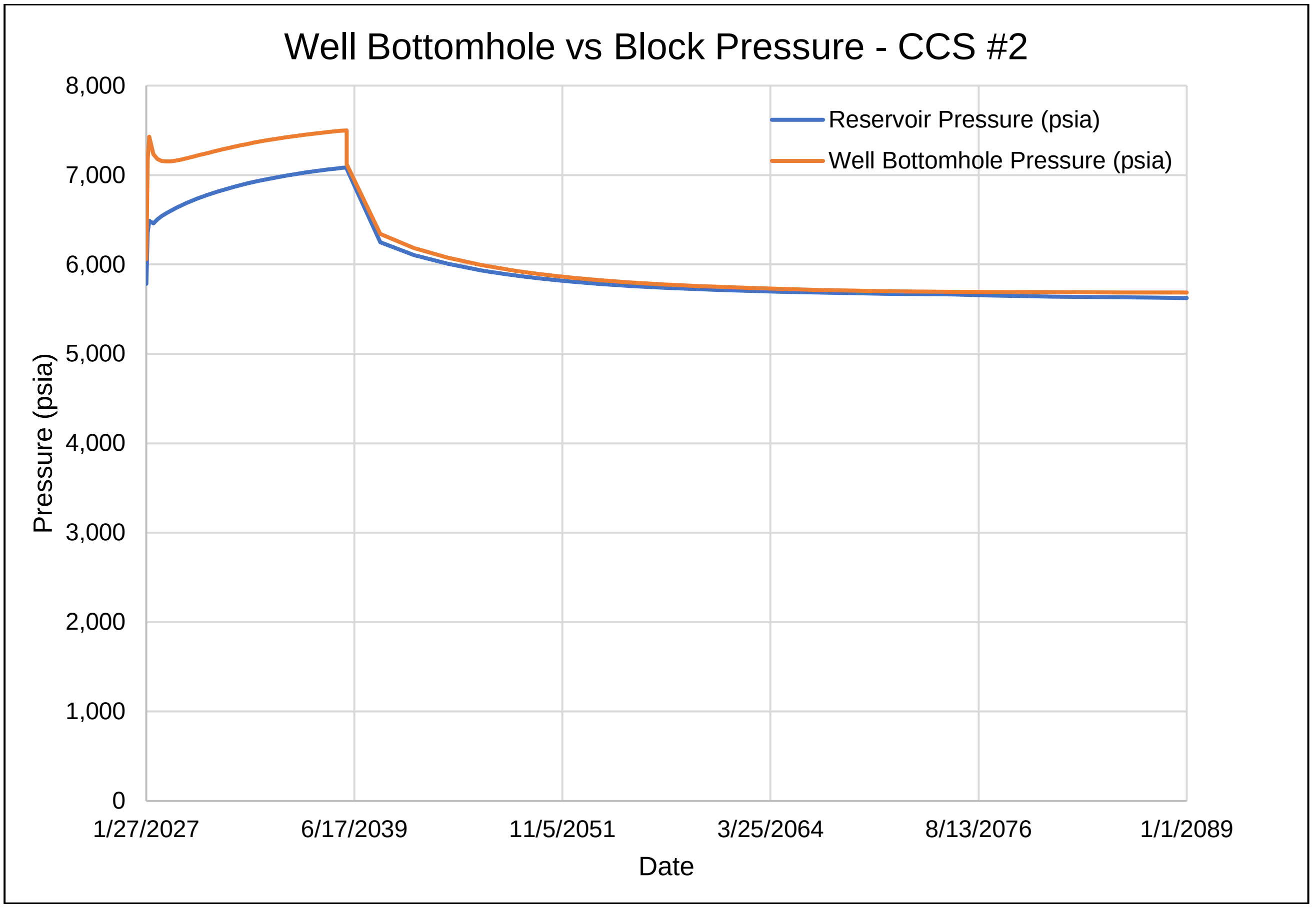


Figure 2-25: Well Bottomhole vs. Block Pressure Comparison
Values shown are from the Midland CCS #2 at the top of the Devonian interval.

Table 2-15: Reference Depths for Modeled Bottomhole Pressures in the Midland CCS #2

Well	Reference Depth (ft TVDSS)	Reference Depth Formation	Reference Depth Model Domain (k-layer)
Midland CCS #2	-9,403	Top of Devonian	28

To model the tubing head injection pressures, tubing tables were developed incorporating the proposed downhole tools and well configuration. The wellbore hydraulics model used to generate these tables includes the proposed injection stream (**Table 2-10**) and applies an equation of state (EoS) approach to calculate phase behavior, density, viscosity, and other relevant properties within the injection tubing. The modeled average tubing head injection pressure is 2,949 psi (see additional notes in ***Section 3**.)*

Following the end of injection in model year 2039, pressure within the reservoir begins to decline and gradually return to initial conditions. The maximum pressure change occurs immediately after injection ceases. The corresponding hypothetical incremental leakage rate, as defined in **Section 2.10 and Appendix L**, is 8.63E-06 bbl/day or 0.0031 bbl/yr, calculated at the Midland CCS #2 well—this is the highest leakage rate observed during the simulation. As pressure diffuses over the subsequent 50 years, the hypothetical leakage rates within the AoR decrease.

The principal source of uncertainty identified during the modeling and simulation process is the lack of direct measurements for key parameters, such as fracture width, fracture density, and other site-specific characteristics. These uncertainties will be addressed through the development of a stratigraphic test well and the associated evaluation of log and core data collected there and at future monitoring wells.

2.7.1 Operational Information

In this section, several tables and figures related to operational parameters and dynamic simulation results of the Well are presented.

- **Figure 2-26** shows the forecasted injection pressure at surface and bottomhole conditions at the top of the Devonian interval.
- **Figure 2-27** shows the gas injection schedule and cumulative gas injection over time.
- **Figure 2-28** presents the inventory of CO_2 by phase throughout the modeled timeframe, including trapped, supercritical, and dissolved CO_2.
- **Table 2-16** summarizes annual gas injection, cumulative gas injection, bottomhole pressure, and wellhead pressure for the site.
- Finally, **Table 2-17** provides the perforated intervals, injection schedule, and coordinates of the Well.

Additional details regarding plume diameter and CO_2 saturation can be found in **Section 2.6**.

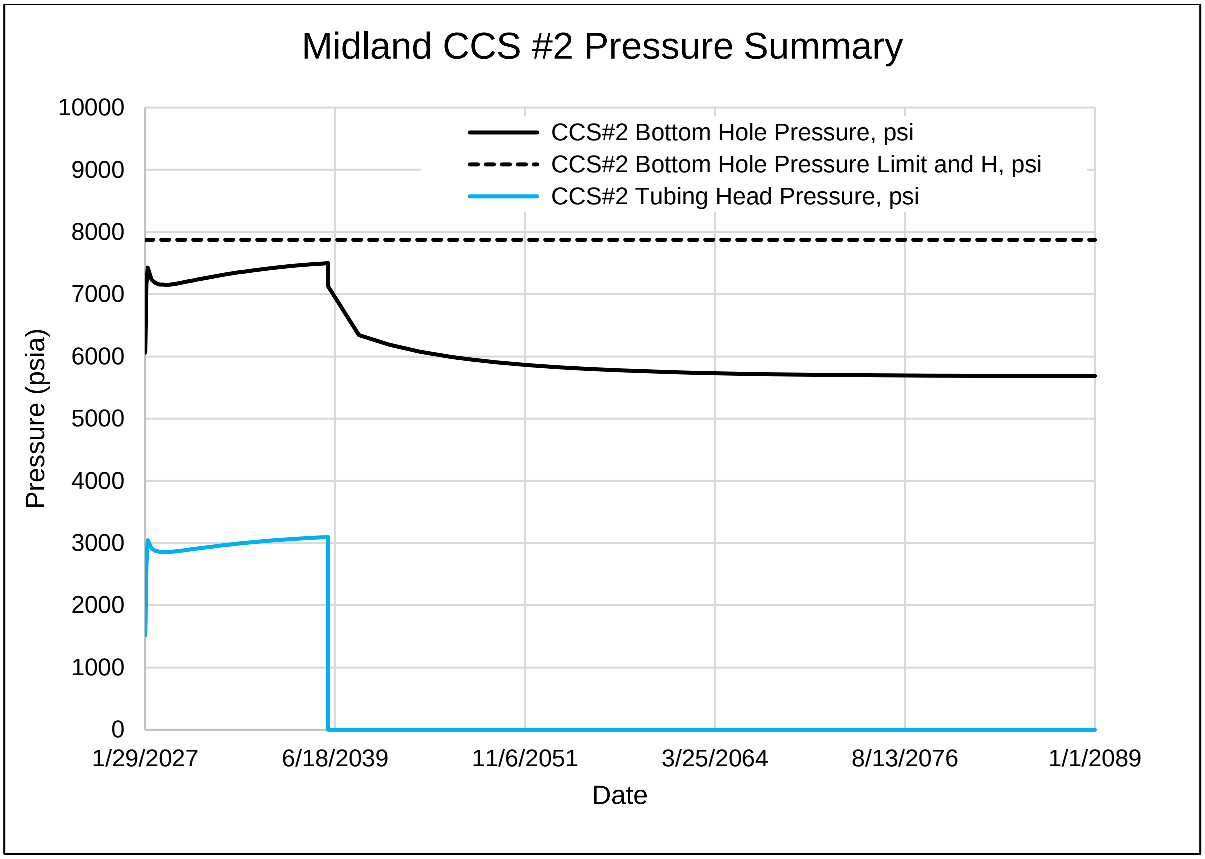


Figure 2-26: Midland CCS #2 Modeled Well Injection Pressures

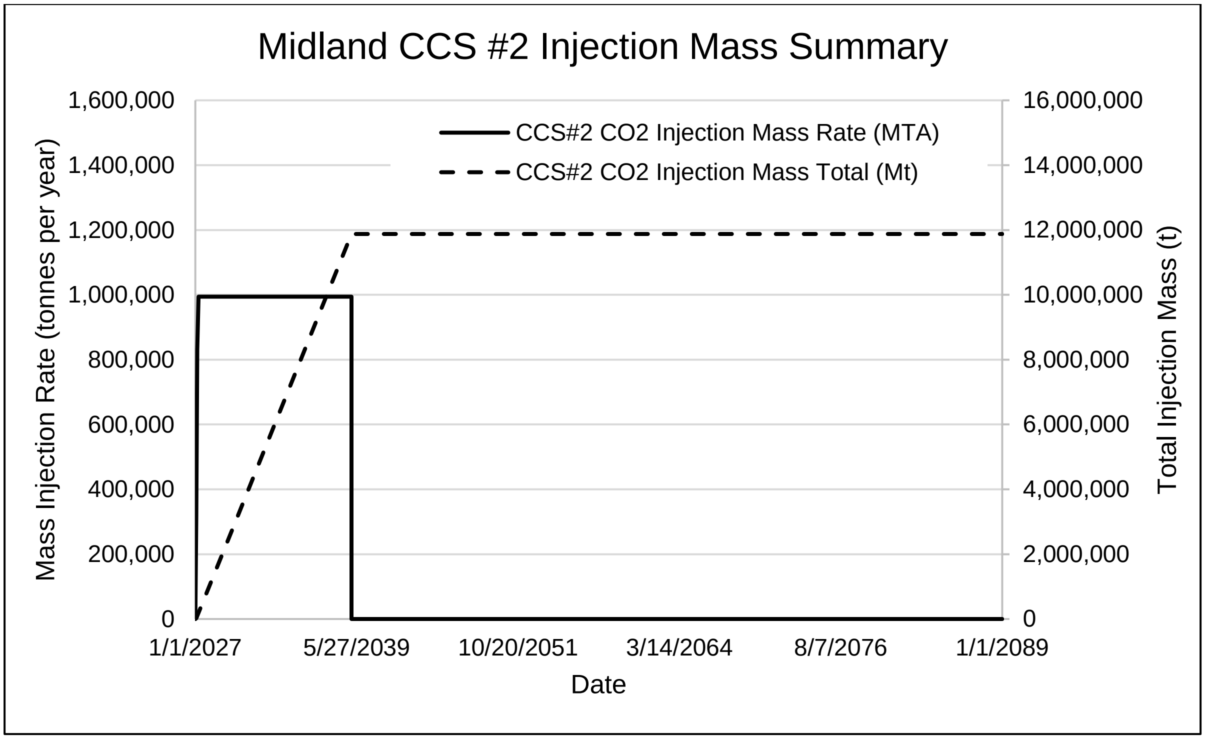


Figure 2-27: Midland CCS #2 Forecasted Injection Mass Rate and Cumulative Injection Mass

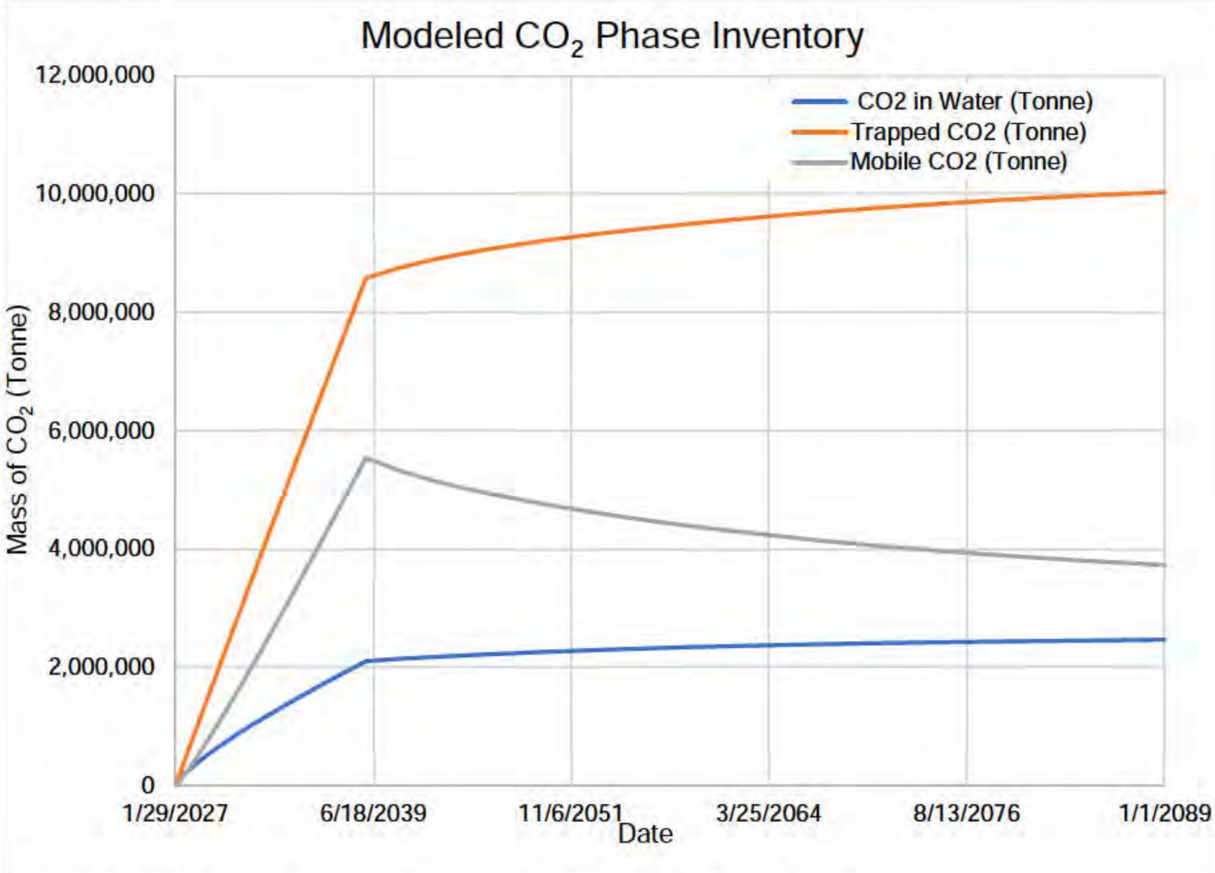


Figure 2-28: CO_2 Phase Inventory Model Over Time up to Year 2089

Table 2-16: Tabular Forecast Details for Midland CCS #2

Year	CO_2 Injection Rate (MMta)	Cumulative Gas Injected (MMt)	Well Head Pressure (psi)	Bottom Hole Pressure (psi)
2027	1.0[5]	1	1,519	6,059
2028	1.0	2	2,858	7,157
2029	1.0	3	2,865	7,167
2030	1.0	4	2,896	7,212
2031	1.0	5	2,929	7,259
2032	1.0	6	2,960	7,304
2033	1.0	7	2,988	7,344
2034	1.0	8	3,012	7,380
2035	1.0	9	3,034	7,411
2036	1.0	10	3,053	7,438
2037	1.0	11	3,070	7,462
2038	1.0	12	0	7,483
2039	SHUT-IN	12	0	7,499
2039	0	12	0	7,122

[5] Injection rate will be 1.0 MMta after initial buildup to that rate. There will be a conditioning period.

Year	CO_2 Injection Rate (MMta)	Cumulative Gas Injected (MMt)	Well Head Pressure (psi)	Bottom Hole Pressure (psi)
2041	0	12	0	6,342
2043	0	12	0	6,186
2045	0	12	0	6,076
2047	0	12	0	5,994
2049	0	12	0	5,930
2051	0	12	0	5,881
2053	0	12	0	5,841
2055	0	12	0	5,810
2057	0	12	0	5,785
2059	0	12	0	5,766
2061	0	12	0	5,749
2063	0	12	0	5,736
2065	0	12	0	5,725
2067	0	12	0	5,716
2069	0	12	0	5,709
2071	0	12	0	5,703
2073	0	12	0	5,698
2075	0	12	0	5,695
2077	0	12	0	5,693
2079	0	12	0	5,691
2081	0	12	0	5,690
2083	0	12	0	5,689
2085	0	12	0	5,688
2087	0	12	0	5,687
2089	0	12	0	5,687

Table 2-17: Operating Details

Operating Information	Midland CCS #2
Location (global coordinates) X Y	 2,541,496.16 11,461,870.27
Model Coordinates (ft) X Y	 2,541,496.16 11,461,870.27
No. of perforated intervals	3
Perforated interval 01/01/2027 (ft, TVDSS) Z top Z bottom	 8,367 11,996
Wellbore diameter (ft)	0.5104
Planned injection period Start End	 01/01/2027 01/01/2039
Injection duration (years)	12
Injection rate (scf/day)*	54,516,445

TVDSS: True Vertical Depth Subsea

2.7.2 Fracture Pressure and Upper Limits for Injection

Calculated fracture gradients and maximum injection pressures are provided in **Table 2-18**. Derived from log analysis (**Section 1**), a fracture gradient of 0.72 psi/ft was calculated for the Ellenburger, and 0.74 psi/ft for the Devonian. These gradients correspond to pressure ranges of 9,500–10,500 psi in the Ellenburger and 8,500–9,500 psi in the Devonian. (see **Table 2-8** and **Table 2-9**)

The maximum bottomhole injection pressure used in the dynamic simulation was set at 90% of the calculated fracture gradient for both formations. The simulated maximum bottomhole pressure, recorded at the top of the Devonian interval at -9,403 ft TVDSS in the Midland CCS #2 well, was 7,499 psi.

At no point during the simulation did the modeled reservoir pressure exceed 90% of the fracture gradient in either the Ellenburger or the Devonian. **Figure 2-26** displays the calculated bottomhole pressure over time in relation to this 90% threshold at the top of the Devonian interval; reference depths are provided in **Table 2-15**.

Table 2-18: Injection Pressure Details

Injection Pressure Details	Unit	Midland CCS #2 Well
Minimum Fracture gradient Devonian	psi	0.72
Maximum injection pressure Devonian (90% of fracture pressure)	psi	0.65
Elevation (TVDSS) corresponding to maximum injection pressure Devonian	ft	-9,403
Elevation (TVDSS) at the top of the perforated interval Devonian	ft	-9,403
Elevation (TVDSS) at the bottom of the perforated interval Ellenburger	ft	-11,052
Calculated maximum allowable injection pressure (90% of frac pressure) at the top of the perforated interval Devonian	psi	7,875
Observed maximum bottom hole pressure from dynamic simulation model	psi	7,499

TVDSS: True Vertical Depth Subsea

2.7.3 Model Calibration and Validation

Milestone used extensive publicly available data compiled from the Railroad Commission of Texas (RRC) to calibrate its dynamic model by history matching the performance of adjacent saltwater disposal (SWD) wells, as listed in **Table 2-19**. In addition to these wells, three additional SWD wells were incorporated into the Model to further refine the impact of offset brine injection on initial reservoir pressure, both prior to and during CO_2 injection.

The six SWD wells listed in **Table 2-19** were incorporated into the dynamic simulation using reported historical injection volumes and estimated remaining injection capacity. Each well was projected to have an approximate 20-year lifespan, with a constant injection rate equal to the average of the last 12 months of reported data (see **Table 2-20**). The location of the SWD wells within the dynamic model domain is shown in **Figure 2-1** and **Figure 2-29**. Three of the wells were history matched to validate the model.

Table 2-19: List of Offset Injection Wells Used in the Dynamic Simulation Model

Well Name	API	Use	Completed Formation
Senor Salado SWD 17SD	42-329-42946-00	History Match	Ellenburger
Davidson Unit 1 0106BH	42-461-40597-01	History Match	Ellenburger
Clay Henry SWD 1	42-329-42349-00	History Match	Ellenburger
Coupes SWD 1	42-329-43582-00	SWD	Ellenburger
Midkiff SWD 1	42-329-42597-00	SWD	Devonian-Silurian + Ellenburger
Greg Midkiff SWD 1501	42-329-42371-00	SWD	Ellenburger

Table 2-20: Offset Injection Well Data

Well Name	Injection Start Date	Injection Stop Date	Assumed Future Injection Rate (bbl/day)
Senor Salado SWD 17SD	8/1/2019	1/1/2039	13,330
Davidson Unit 1 0106BH	7/1/2018	1/1/2037	5,074
Clay Henry SWD 1	2/1/2019	1/1/2039	12,536
Coupes SWD 1	2/1/2021	6/1/2022	0
Midkiff SWD 1	2/1/2019	1/1/2039	3,678
Greg Midkiff SWD 1501	4/1/2019	1/1/2039	2,786

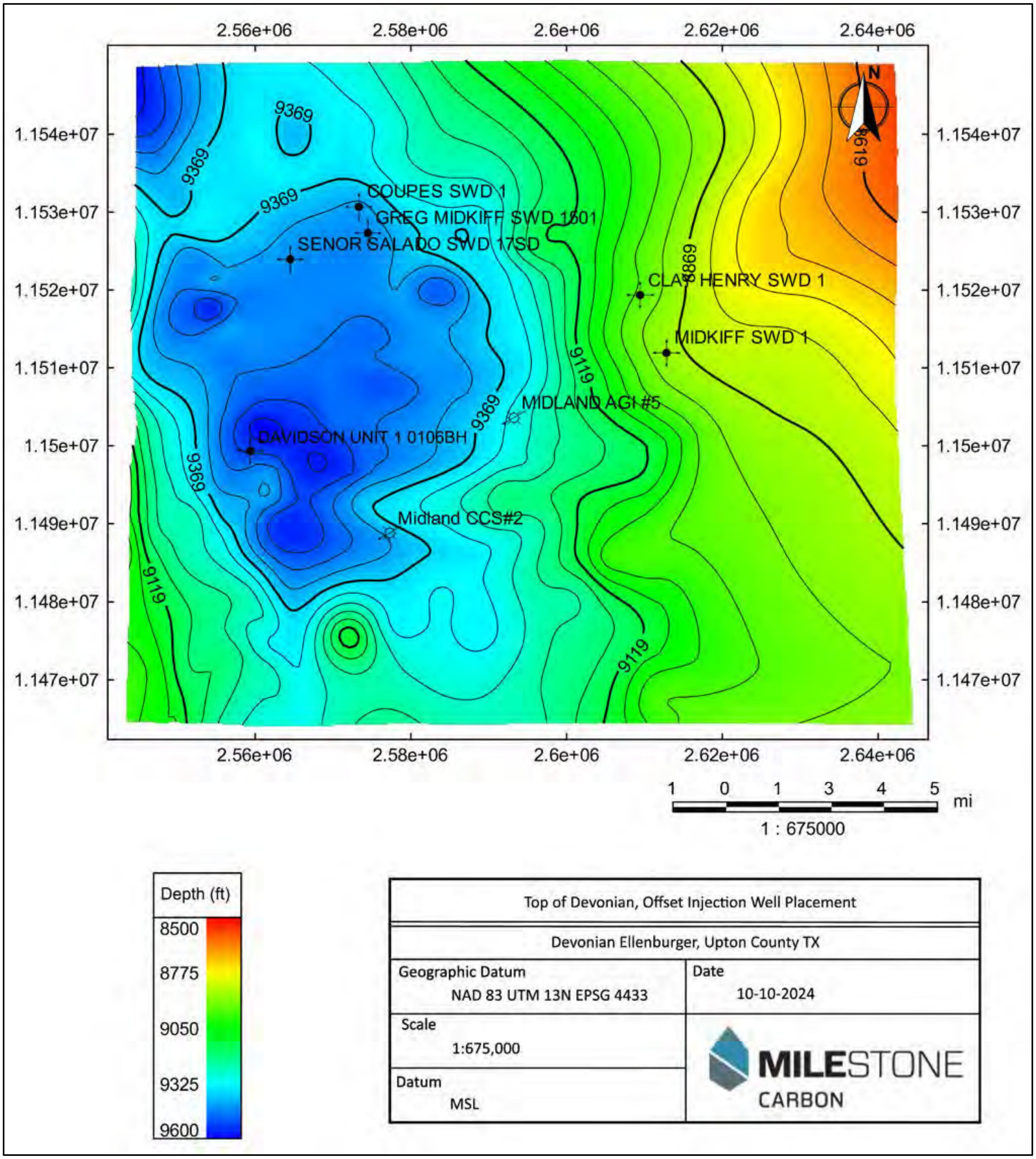


Figure 2-29: Location of Offset Injection Wells, Structure Map Top (TVDSS) of Devonian

The primary objective of history-matching the offset injection wells was to calibrate the static model's intrinsic permeability and fault transmissibility. Historical injection volumes and completion details from the RRC were loaded into the dynamic simulation model. Various combinations of permeability and fault transmissibility were iterated to achieve the best fit with the reported tubing head pressures. The calibrated model's resulting tubing head pressures are shown in **Figure 2-30**.

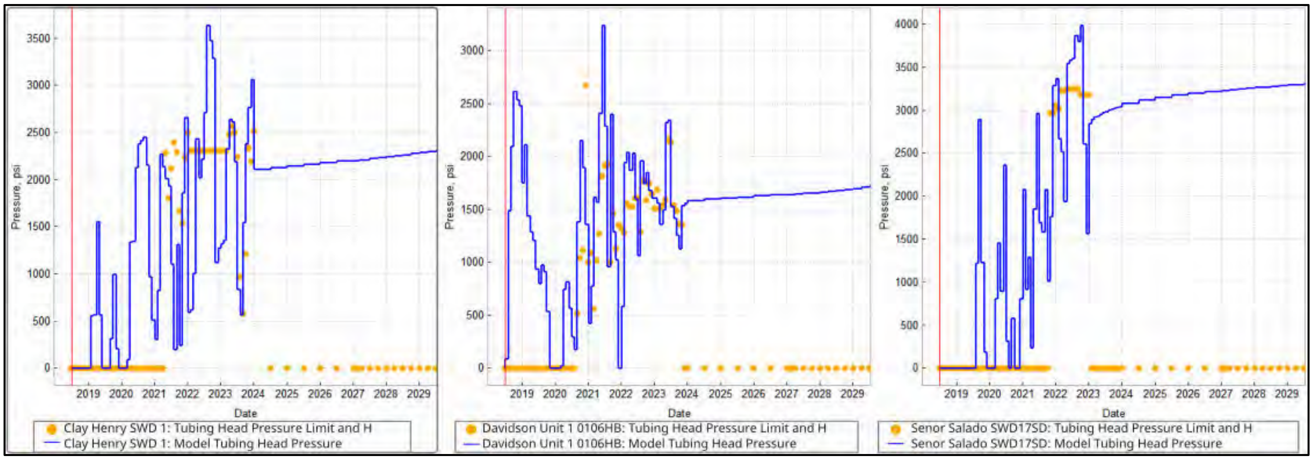


Figure 2-30: Tubing Head Pressures
Historical tubing head pressures (orange dots) compared to simulated tubing head pressures (blue lines).

The Model domain was subdivided into four regions as shown in **Figure 2-31**. The aerial segmentation honors the geobodies described by Holtz and Kerans (1992) and Sanchez et al. (2019). The geobody located in the eastern half of the dynamic simulation model domain (Regions 3 and 4) represents areas with increased fracturing or karsting. Vertically, strata above the Ellenburger Group were assigned to Regions 1 and 4, while the Ellenburger itself was assigned to Regions 2 and 3.

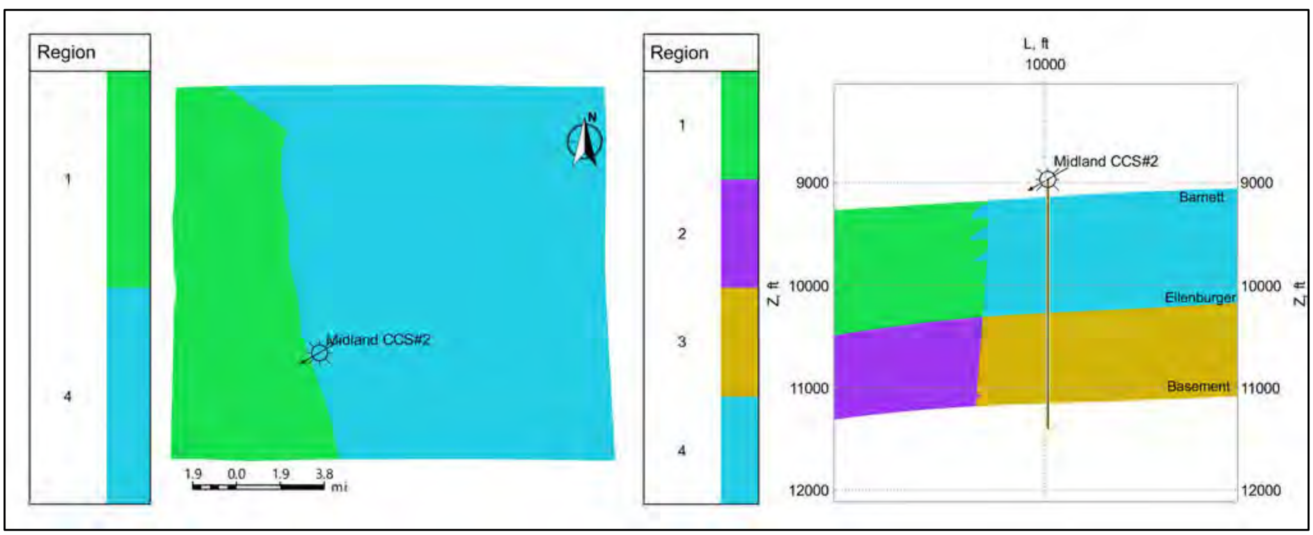


Figure 2-31: Model Regions Used in History Matching

Utilizing the historical injection volumes from the Midkiff SWD 1 well (API: 42-329-42597), an initial effort was made to calibrate the permeability of the interval above the Ellenburger independently from the Ellenburger itself. Midkiff SWD 1 is the only known historical dual-zone completion—including both the Devonian–Silurian and Ellenburger formations—within the Model domain. However, it was ultimately determined that insufficient data are available from Midkiff SWD 1 to support this additional segmentation. A summary of the resulting permeability multipliers used in the Model is provided in **Table 2-21**.

Table 2-21: Summary of Permeability Multipliers

Model Region	Permeability Multiplier
Region 1	0.250
Region 2	0.250
Region 3	0.475
Region 4	0.475

Well performance in Regions 1 and 2 was best approximated using a 75% reduction in the static model's permeability. In Regions 3 and 4, performance was best matched with a 52.5% reduction. The variability in effective permeability is likely attributed to natural fracturing or localized karsting.

The impact of low fault transmissibility was evident in the elevated tubing head injection pressures observed at the Davidson Unit 1 0106BH SWD well (API: 42-461-40597) and the Senior Salado SWD 17SD well (API: 42-329-42946). No additional data were available at the time of this permit to further quantify fault transmissibility or to differentiate transmissibility values between individual faults within the Model domain. The performance of both wells was best approximated with a fault transmissibility value of 0.01, which was applied uniformly to all faults in the Model pending the availability of further data.

2.8 Corrective Action Introduction

Milestone utilized the results of the numerical modeling and critical pressure analysis to conservatively delineate the Area of Review (AoR) for the Midland CCS facility. Given the negative calculated critical pressure threshold, and the presence of offset saltwater disposal activity contributing to regional overpressure, reliance on analytical methods alone was not considered sufficiently protective. Instead, the AoR was defined using a dual-criteria approach based on (1) the lateral extent of the modeled pressure front exceeding the threshold for potential leakage through a hypothetical borehole, and (2) the extent of supercritical CO_2 saturation exceeding 2% at plume stabilization. This methodology is consistent with EPA Class VI guidance and follows conservative practices employed in similar approved permits.

Following delineation of the AoR, Milestone reviewed all artificial penetrations—wells and stratigraphic borings— within the AoR to assess the need for corrective action. Based on this review, zero (0) wells were identified as requiring corrective action. A full table of all wells within the AoR can be found in **Section 1.14.2** of the permit.

As specified in **Section 2.12**, and at least once every 5 years, or when monitoring and operational conditions warrant, Milestone will:

1) Reevaluate the AoR consistent with previous modeling methodology.
2) Identify all wells in the re-evaluated AoR that may require corrective action.
3) Perform corrective action on wells requiring corrective action in the reevaluated Area of Review.
4) Submit an amended Area of Review and Corrective Action Plan or demonstrate to the Director—based on monitoring data and modeling results—that no amendment is necessary.

Any amendments to the Area of Review and Corrective Action Plan must be approved by the Director, incorporated into the permit, and are subject to the permit modification requirements at 40 CFR § 144.39 or § 144.41, as applicable.

2.9 Critical Pressure Calculations

The critical pressure threshold defines the minimum increase in pressure within the injection interval that would be sufficient to drive formation fluids through a hypothetical conduit into the lowermost USDW. This concept is central to EPA's Class VI Area of Review (AoR) delineation methodology, as described in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* (USEPA, 2013). For this project, the threshold was calculated using a modified version of the Thornhill et al. (1982) approach (**Equation 9**), which estimates the pressure required to equalize hydraulic head between two stratigraphic intervals, updated here with site-specific pressure gradients. The critical pressure at the interface between the injection interval and a hypothetical conduit to the USDW is calculated as:

Equation 9: Thornhill 1982 Pressure

$$\Delta P_c = P_u + \rho_i g * (z_u - z_i)$$

Where:

$P_c = Critical\ Pressure\ Threshold\ (Pa)$
$P_u = Initial\ Fluid\ Pressure\ in\ the\ USDW\ (Pa)$
$\rho_i = Injection\ Interval\ Fluid\ Density\ (kg/m^3)$
$g = Acceleration\ Due\ to\ Gravity\ \ (9.81\ m/s^2)$
$z_u = Elevation\ of\ the\ Lowermost\ USDW\ (m)$
$z_i = Elevation\ of\ the\ Injection\ Interval\ (m)$

The pressure increase that the injection interval can accommodate before exceeding the critical threshold is:

Equation 10: Critical Pressure

$$\Delta P_c = P_u + \rho_i g * (z_u - z_i) - P_i$$

Where:

$$\boldsymbol{P_i = Initial\ Reservoir\ Pressure\ in\ the\ Injection\ Interval\ (Pa)}$$

In the Midland CCS #2 well, the base of the USDW is expected to occur at 1,250 ft TVD, based on a Groundwater Advisory Unit (GAU) determination (**Section 1.4**). The critical pressure calculation was performed for the top of the Devonian injection interval, located at 12,200 ft TVD. The fluid in the injection interval is assumed to be formation brine with a salinity of 152,704 mg/L, corresponding to a fluid density of 1,052 kg/m³ (as shown in **Table 2-22**). This value is derived using 207 water samples from nearby Devonian and Ellenburger wells and using McCain's temperature correction to correct the density to reservoir conditions. (McCain, 1999)

The initial reservoir pressure, immediately prior to the start of injection, was calculated using a pressure gradient of 0.45699 psi/ft, resulting in an expected pressure of approximately 5,575 psia. As shown below, the initial pressure gradient used in the simulation is 0.45 psi/ft (initialized in 2018); however, this gradient has been increased by offset SWD activity prior to the commencement of CO_2 injection and is not consistent with the fluid density of the injection interval. Therefore, a more precise value of 0.45699 psi/ft is utilized to calculate the critical pressure.

In contrast, the fluid within the lowermost USDW is assumed to have a pressure gradient of 0.4370 psi/ft and a salinity of 11,030 mg/L, consistent with Dockum Group brines (see **Section 1.4.2** for salinity assumptions). A summary of the inputs used in the critical pressure threshold calculation is provided in **Table 2-22**.

Far-offset Class II SWD injection wells appear to have increased the pore pressure gradient prior to any injection activities associated with this Class VI permit. SWD wells included in the numerical model have increased the pressure gradient. Milestone used the value of the reservoir pressure consistent with the density, immediately prior to the start of injection are used to calculate the critical pressure.

Table 2-22: Inputs for Critical Pressure Calculation at conditions directly before Injection[6]

Input	Variable	Value	SI Value
Depth (TVD) to Base of USDW	z_u	- 1,250 ft	- 381.0 m
Depth (TVD) to Top of Injection Unit (Devonian)	z_i	- 12,200 ft	- 3,718.56 m
Fluid Density in Injection Unit (Devonian)	ρ_i	8.78087 ppg	1,052.18 kg/m^3
Initial Pressure at Base of USDW	P_u	546.25 psia	3,766,261.16 Pa
Initial Pressure at Top of Injection Unit	P_i	5,575.24 psia	38,439,948.98 Pa

The initial conditions used in the pressure threshold analysis are based on a comprehensive review of published literature, analog well data, offset water data, and regional geologic studies. While no site-specific data has been collected to date, a stratigraphic test well is planned to confirm reservoir properties and validate model assumptions. Formation temperature at the top of the Devonian injection interval is estimated to be 188.4°F, sufficient to maintain supercritical CO_2 conditions under the modeled pressure regime. Porosity and permeability values used in the model—1.98% and 0.8 to 3.7 mD, respectively—were derived from regional analogs and log-based estimates from nearby Devonian-age reservoirs. These values are described in **Section 2.4.9.2** of the Site Characterization Report and reflect conservative inputs pending site-specific validation.

To evaluate the critical pressure threshold between the injection interval and the USDW, values from **Table 2-22** were substituted into **Equation 10**, provided below. (it is important to maintain rounding)

$$\Delta P_c = P_u + \rho_i g * (z_u - z_i) - P_i$$

$$\Delta P_c = 3{,}766{,}261.16\ Pa + 1{,}052.18\ kg/m^3 * 9.80665\ m/s^2 * (-381.0m - (-3{,}718.56\ m)) - 38{,}439{,}948.98\ Pa$$

$$\Delta P_c = 3{,}766{,}261.16\ Pa + 1{,}052.18\ kg/m^3 * 9.80665\ m/s^2 * (3{,}337.56\ m) - 38{,}439{,}948.98\ Pa$$

$$\Delta P_c = 3{,}766{,}261.16\ Pa + 10{,}318.36\ Pa/m * (3{,}337.56\ m) - 38{,}439{,}948.98\ Pa$$

$$\Delta P_c = 3{,}766{,}261.16\ Pa + 34{,}438{,}145.60\ Pa - 38{,}439{,}948.98\ Pa$$

$$\Delta P_c = 38{,}204{,}406.76\ Pa - 38{,}439{,}948.98\ Pa$$

$$\Delta P_c = -235{,}542.22\ Pa$$

$$\Delta P_c = \frac{-235{,}542.22\ Pa}{6{,}894.76} = -34.1625\ psia\ \pm 1$$

The resulting critical pressure prior to injection from **Equation 10** is a negative value of **-34.1625 psia**. Because the calculated pressure threshold is negative and the injection interval is known to be over pressured under baseline conditions, a more conservative approach was adopted to ensure robust protection of Underground Sources of Drinking Water (USDWs). The calculated critical pressure was likely positive before being altered by historic and ongoing saltwater disposal activities. Additionally, it is highly likely that as the project moves forward additional SWD wells will be drilled into the Ellenburger, and even though they are far from the Midland CCS #2 well, they will still influence the pressure of the formation.

To assess this risk, a conservative numerical modeling approach was applied to evaluate whether pressure increases could result in vertical fluid migration into a USDW. This threshold analysis supports the need to define the Area of Review using a methodology that accounts for both pressure-driven transport potential and the spatial distribution of injected CO_2. The outcome of this analysis informed the approach to AoR delineation.

[6] 1 psia = 6894.75728 Pa; 1 foot = 0.3048 meters; 1 kg/m3 = 0.00834540445 ppg

2.10 Area of Review Delineation

Given the negative calculated critical pressure, reliance on Method 1 alone is not sufficient to support the delineation of the Area of Review (AoR) for this project. As recommended in the EPA Class VI AoR guidance (USEPA, 2013), for over-pressured or negative critical pressure conditions, a more conservative and site-specific modeling approach was adopted to ensure robust protection of Underground Sources of Drinking Water (USDWs).

This approach incorporates EPA's Methods 2 and 3, which are designed to evaluate leakage through hypothetical boreholes and simulate solute transport within overlying aquifers. The modeling framework follows a methodology similar to those used in other approved Class VI projects in the region, where conservative bounding-case scenarios were applied to evaluate the impact of pressure propagation and potential fluid migration. In this case, four representative borehole scenarios were evaluated: the injection well (CCS #2), which is anticipated to see the highest reservoir pressure, and three conservatively placed hypothetical open boreholes located radially along the CO_2 plume edge.

To address these concerns, a site-specific, multiphase flow and solute transport model was developed using the MODFLOW-SEAWAT (Version 4) platform, developed by the U.S. Geological Survey. This platform supports variable-density flow, salinity and temperature effects on viscosity and density, and multiphase pressure transport. The model incorporated detailed site-specific stratigraphy and petrophysical properties, including porosity and permeability values from core data and literature. **Table 2-23** summarizes the modeled formations and associated hydrogeological parameters.

Table 2-23 Stratigraphic column and hydrogeologic properties for modeled formations

Formation	Type	Measured Depth	Thickness	Permeability (mD)	Porosity	TDS (mg/L)
Trinity	USDW	0	280	3000	10.0%	1242
Dockum	USDW	280	970	93	10.0%	11030
Dewey Lake and Rustler	Confining	1250	1234	0.005	10.0%	n/a
Tansill-Grayburg	Dissipation	2484	1636	11	13.3%	n/a
San Andres	Dissipation	4120	1160	9.49	10.3%	n/a
Glorieta	Confining	5280	2291	0.090169	1.6%	n/a
Spraberry	Confining	7571	1361	0.001032	4.6%	n/a
Dean	Confining	8932	192	0.000578	4.3%	116466
Wolfcamp	Dissipation	9124	1004	0.000591	4.3%	n/a
Cisco	Confining	10128	367	0.000819	5.0%	n/a
Canyon	Confining	10494	350	0.000607	4.3%	n/a
Strawn	Dissipation	10845	658	2	4.7%	n/a
Atoka	Confining	11503	430	0.001152	6.1%	n/a
Barnett shale	Confining	11933	134	0.000001	5.8%	n/a
Woodford shale	Confining	12066	104	0.00015	5.4%	n/a
Devonian	Reservoir	12170	532	5.895	2.6%	152704
Silurian	Confining	12703	41	2.77	1.0%	n/a
Fusselman	Confining	12744	192	2.2203	1.2%	n/a
Simpson	Confining	12936	130	0.62	1.5%	n/a
Ellenburger	Reservoir	13066	883	6.441	3.5%	152704

The conceptual model represents a fully open 8-inch borehole extending from the Devonian Injection Unit to the water table, without any cement isolation. A highly conservative permeability value of 1×10^{-10} m² (approximately 101,325 mD) was assigned to the borehole to simulate a worst-case leakage condition. This value exceeds those associated with even the highest-leakage abandoned well categories reported in the literature (Celia et al., 2011) and reflects a bounding-case assumption consistent with EPA Method 2. The borehole configuration and permeability assignment are shown in **Figure 2-32**.

Table 2
Mapping of well score to mean effective well permeability. Data in columns marked with * from Watson and Bachu (2008).

Deep leakage potential*	Score range*	Well effective permeability mean [mD]
Low	<2	0.01–0.02
Medium	2–6	0.02–0.5
High	6–10	0.5–8
Extreme	>10	8–10,000

M.A. Celia et al. / International Journal of Greenhouse Gas Control 5 (2011) 257–269

Figure 2-32: Conceptual representation of borehole permeability used in the AoR model.

In each simulation scenario, the injection interval was designated as the source zone for upward pressure propagation through the hypothetical borehole. To standardize the model and prevent inconsistencies related to formation thickness, the uppermost 33 feet (10 meters) of the injection unit was assumed to be hydraulically connected to the USDW, irrespective of the actual thickness of the Ellenburger or Devonian formations at a given location.

Simulations were conducted using a 600 psia pressure increase in the San Andres Formation over a 70-year injection period. This pressure was derived from present-day aggregate offset shallow injection pressure data reported to TRRC through Texnet reporting system, Milestone's operated wells nearby, and B3 data. An additional case with no pressure increases in the San Andres was tested, to be conservative, even though increases are probable and have been verified by well data.

The pressure associated with injection is assumed to propagate vertically through a sequence of confining and dissipation layers (including Dewey Lake, Rustler, and Dockum formations). The model applied general head boundary conditions at 1,000 meters from the model edge and a west-to-east regional hydraulic gradient to reflect ambient groundwater flow (**Figure 2-33**).

Table 2-24: Results of Modflow Simulation of Hypothetical Leakage at Various Locations

Simulation	Injection Unit	Maximum Incremental Concentration Increase of TDS (mg/L)							
		CCS #2 Well		JRS Farms Well		North Location #1		SW Location #2	
		Trinity	Dockum	Trinity	Dockum	Trinity	Dockum	Trinity	Dockum
Base Case	Devonian	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.01
	Ellenberger	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01
No Dissipation Zones	Devonian	0.36	23.92	0.11	7.58	0.06	5.99	0.11	10.31
	Ellenberger	0.20	11.48	0.12	6.88	0.07	5.91	0.11	8.54

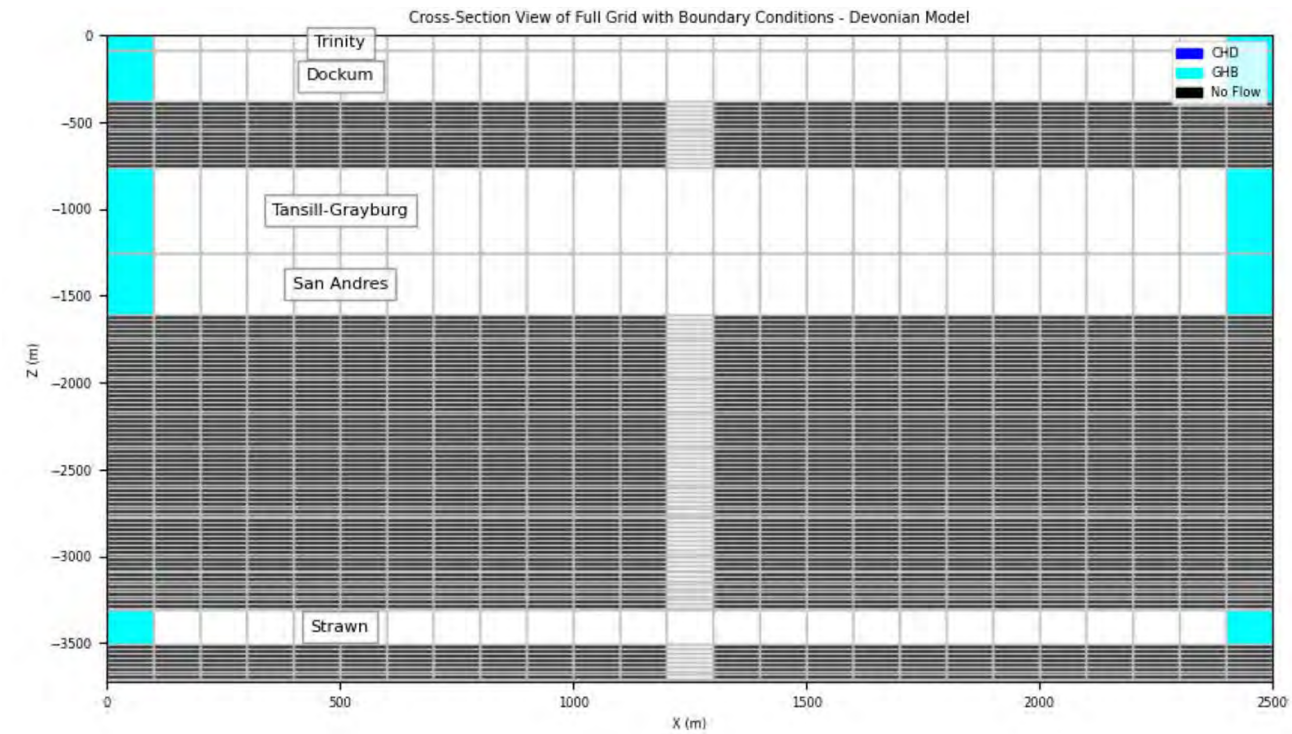


Figure 2-33: Numerical grid used in the Devonian borehole model (distances in meters)

Model outputs were used to evaluate potential fluid migration and changes in water quality in the overlying USDWs. Results from both baseline and elevated pressure simulations demonstrated no net increase in TDS above 1 mg/L in either the Trinity or Dockum USDWs after 70 years of injection in deeper intervals. Dissipation zones effectively attenuated both pressure and solute transport, and all observed TDS changes remained confined to subsurface intervals below the USDWs. (**Table 2-24**).

Model results also indicate that, under the worst-case scenario involving an abandoned borehole located within close proximity to the injection well and assuming no intervening dissipation zones, the maximum total dissolved solids (TDS) increase within the USDW is less than 24 mg/L. This impact is highly localized, confined to an area within approximately 100 meters of the well pad. Beyond this immediate vicinity, changes in TDS within the aquifer are negligible, remaining below 1 mg/L (**Figure 2-34**).

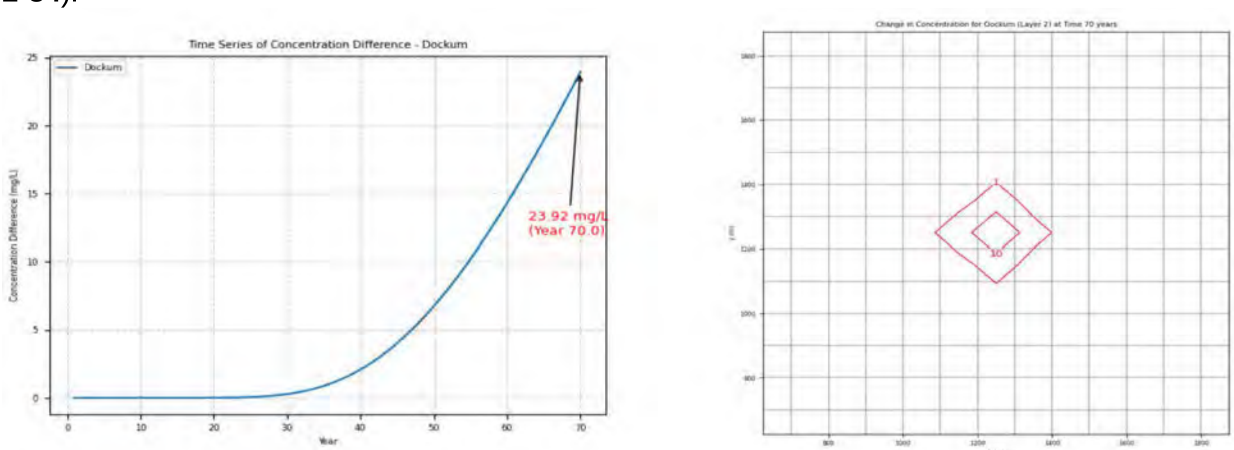


Figure 2-34: SEAWAT Results for Dockum, No Dissipation Zones, Worst Case Scenario, Highest ΔP

Accordingly, delineation of the AoR was based not solely on the analytical critical pressure threshold but rather on modeled pressure front extents and plume behavior. This dual-criteria approach provides a more technically robust and protective delineation strategy. Specifically, the AoR is defined by:

1. The modeled extent of the supercritical CO_2 plume, where saturation exceeds 2% at 50 years post-injection; and
2. The lateral extent of modeled pressure increase associated with the onset of potential leakage through a hypothetical high-permeability borehole(s).
    a) Since the lateral extent of the potential leakage is <100 M from the injection well, and <1M at locations along the edge of the CO_2 plume, the AoR is less than or equal to #1.

Figure 2-35 presents the modeled incremental pressure increase shown in equivalent mud weight between 2027 and end of 2039 at the top of the injection interval. **Figure 2-36** presents the modeled incremental pressure increase shown in equivalent mud weight between 2027 and 2039 at the top of the Ellenburger Injection Unit. **Figure 2-37** shows the pressure at the top of the Injection unit in PSI with the Class VI AOR only. These figures demonstrates that pressure changes remain laterally constrained and rapidly attenuate away from the injection point due to the site's low-permeability injection reservoir. Note that 0.45699 psi/ft, the regional pore pressure gradient (**Figure 2-17**), is equivalent to 8.78 ppg mud weight. Additional maps of pressure are included in the Modflow Appendix.

The results also indicate that pressure encroachment from nearby Class II Saltwater Disposal (SWD) and Acid Gas Injection (AGI) wells varies across different K-layers, complicating the delineation of a distinct pressure boundary associated with the Class VI injection well. Due to the lack of a clearly defined pressure boundary—attributable to cumulative effects from surrounding Class II injection activity—advanced leakage modeling was undertaken to better assess potential impacts. Additionally, the figures illustrate that future SWD wells, even those located at considerable distances from the Class VI well, could influence regional pressure conditions. As a result, reliance on Method 1 is not appropriate for this site. Milestone cannot ensure that the Texas Railroad Commission (TRRC) will restrict future deep injection activities outside the current CO_2 plume footprint.

This pressure front approach is consistent with methods used in previously approved Class VI permits, where the AoR was delineated using modeled sensitivity to pressure-induced leakage under conservative assumptions. In the Midland CCS case, four boreholes, including the injection well and three strategically placed hypotheticals, were simulated under bounding-case conditions using SEAWAT. Even with assumed borehole permeabilities exceeding those associated with high-risk legacy wells, no net increase in TDS was observed in either the Trinity or Dockum USDWs over the 70-year simulation period.

These findings confirm that the modeled CO_2 plume and associated pressure front provides a protective and site-specific basis for identifying at-risk artificial penetrations and informing corrective action planning.

Furthermore, the MODFLOW-SEAWAT model defines the zone of elevated pressure associated with CO_2 injection—representing the area of potential risk to USDWs—as being less than or equal to the spatial extent of the CO_2 plume, as delineated by a 2% saturation threshold. This outcome reflects the negligible leakage rates predicted for a hypothetical wellbore under conservatively modeled pressure conditions, which are insufficient to produce detectable impacts within the USDW.

This AoR delineation method provides a conservative, transparent, and technically defensible framework consistent with EPA Class VI expectations. Additional MODFLOW-SEAWATT model inputs, sensitivity cases, and configuration details are provided in **Appendix L**.

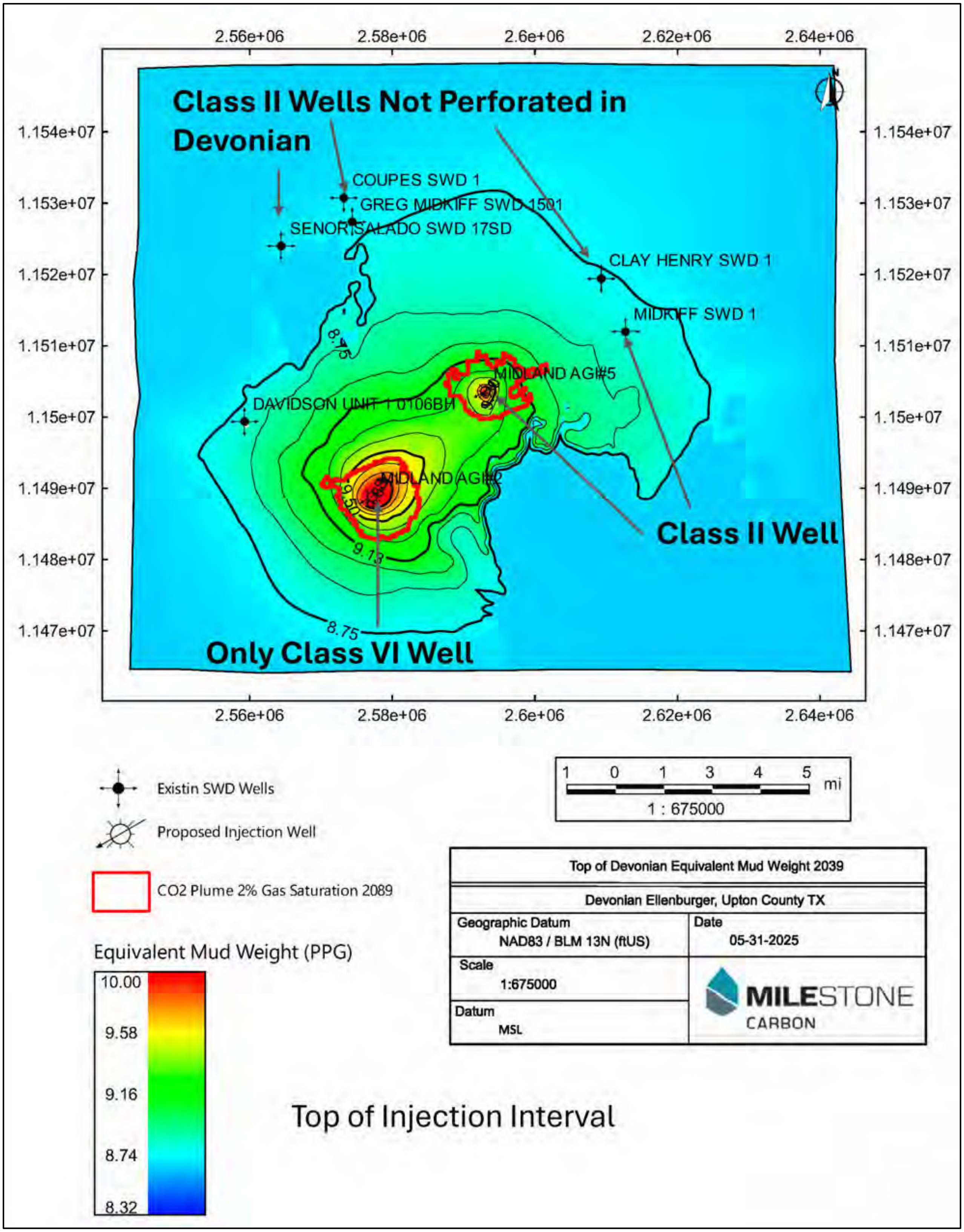


Figure 2-35: Maximum change in reservoir pressure at Top of Devonian formation

Maximum change in reservoir pressure across in 1st K-layer in the Injection Interval from model years 2027 (start of injection) to 2039 (end of injection). Contours shown in equivalent Mud Weight PPG. Not all wells perforated in Devonian. No faults shown because faults do not intersect top K-layer of Devonian.

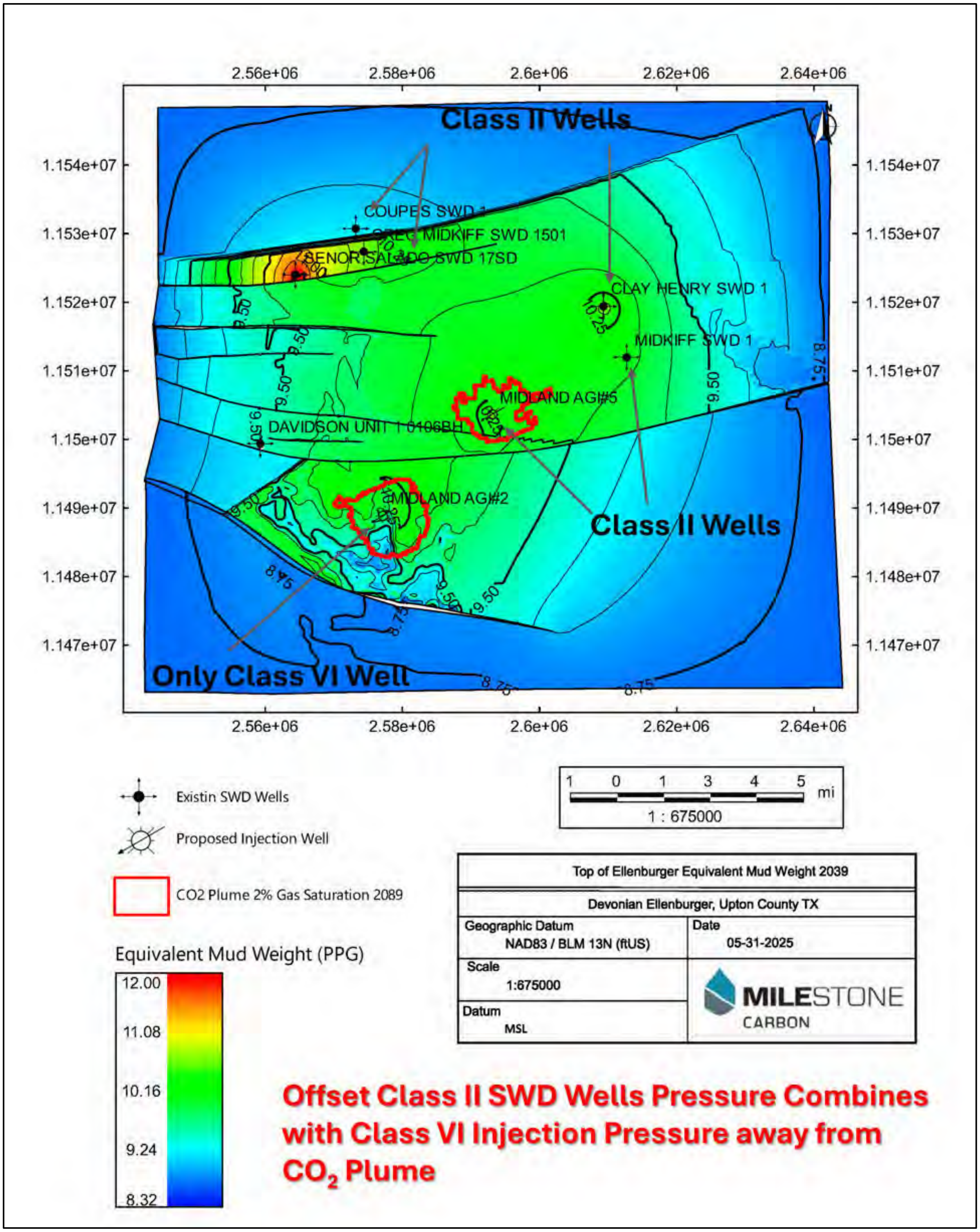


Figure 2-36: Maximum change in reservoir pressure at Top of Ellenburger Group

Maximum change in reservoir pressure across in 1st K-layer in the Injection Interval from model years 2027 (start of injection) to 2039 (end of injection). Contours shown in equivalent Mud Weight PPG. All wells perforated in Ellenburger. Faults baffle but do not completely seal off pressure changes.

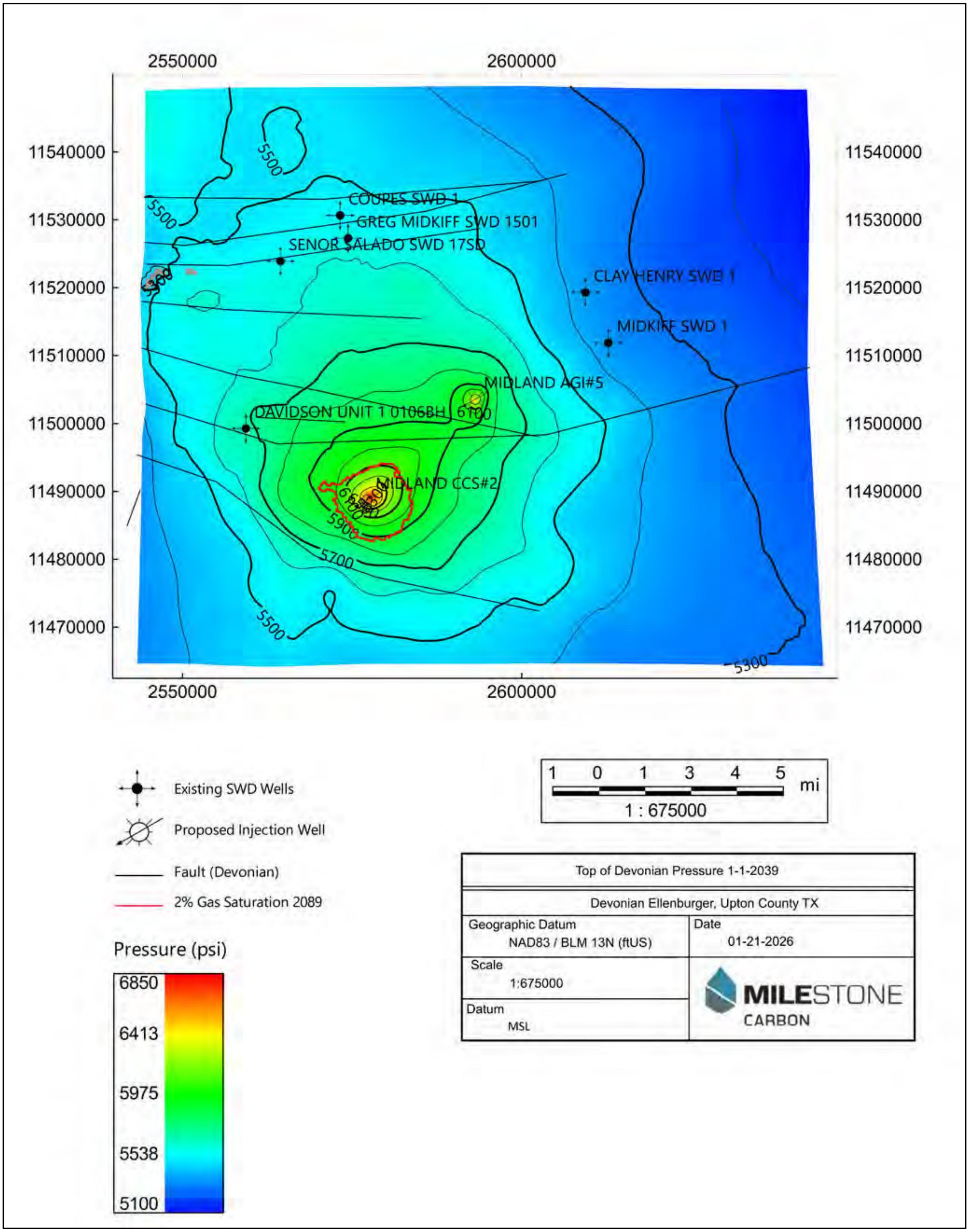


Figure 2-37: Maximum Pressure in PSI (2039) with Maximum CO_2 Plume (2089)

2.11 AoR Corrective Action Plans

2.11.1 Tabulation of Wells Within the AoR [40 CFR 146.82(a)(4); 40 CFR 146.84(c)(2)]

Milestone evaluated all oil and gas wells, water disposal wells, stratigraphic boreholes, dry holes, and plugged and abandoned wells within the AoR using data from proprietary and commercially operated databases. Well locations and associated attributes were sourced primarily from the Enverus DrillingInfo™ (DI) well database (**Sections 1.3 and 1.14**). The tables and maps reflect well data current as of October 2, 2024. Full maps of all features are provided in **Section 1.3**. Based on this review, zero (0) wells were found to penetrate the top seal or injection interval within the AoR.

For all identified wells, available records from the Railroad Commission of Texas (RRC) were downloaded and reviewed to confirm total depth and penetrated zones. Milestone also submitted a request to the RRC for non-digitized records and reviewed microfilm/microfiche files to confirm that no additional artificial penetrations exist within the AoR. Based on this review, 71 wells or potential wells were identified, though not all had complete records available.

Of these, 59 are existing oil and gas wells within the AoR (**Figure 2-38**):

- 26 Active, (including 3 shallow disposal wells)
- 12 Inactive,
- 13 Plugged and Abandoned,
- 1 Shut-in,
- 7 Unknown.

In addition, 12 wells were identified at various stages of development or permitting:

- 11 Expired permits,
- 1 Cancelled.

A comprehensive list of all wells within the AoR, including total depths and the deepest formation penetrated, is provided at the end of Permit **Section 1**, in **Appendix E**, and in the file **uploaded to GSDT** titled:

O&G Wells Summary Files (includes spreadsheet and shapefile)

All publicly available well files from the RRC for wells within the AoR and beyond, each of which Milestone reviewed to determine whether corrective action is necessary, are provided in the following file **uploaded to the GSDT**:

Well Files: *O&G Individual Well Files*

Wireline Logs: *O&G Raster Logs*

In addition, there are 87 water wells located within the AoR, a total of 155 water wells within 1 mile of the AoR. These water wells generally have depths of less than 300 feet. A list of the water wells within the AoR and within 1 mile outside the AoR can be found in the following file **uploaded to the GSDT:**

TWDB Water Well Summary Data

Individual well files from the Texas Water Development Board (TWDB) have been uploaded as well, in a file titled:

TWDB Individual Water Well Files

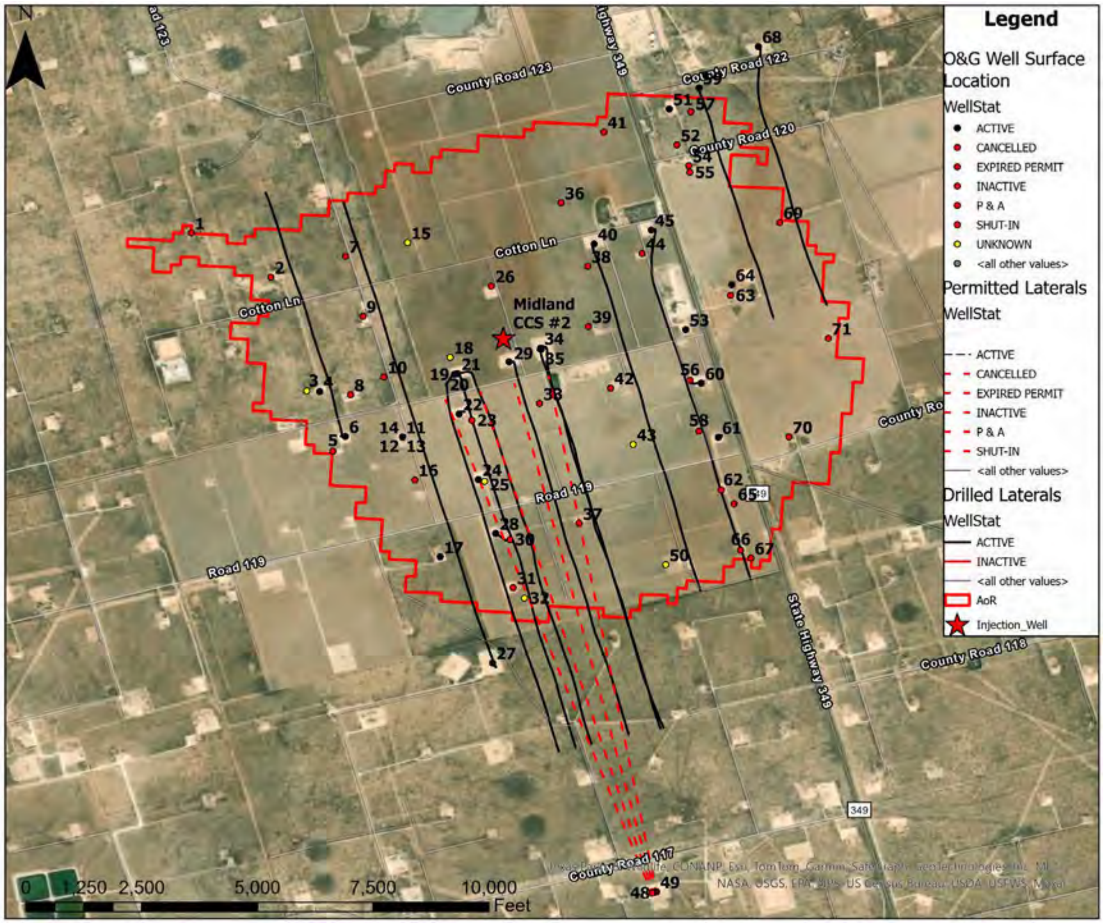


Figure 2-38: All Oil and Gas Wells Map of the AoR
See Section 1.14 for the index table.

2.11.2 Corrective Action Schedule [146.82 (a)(4)]

Wells that do not penetrate either the confining or injection unit pose negligible risk to underground sources of drinking water (USDWs) and therefore do not require corrective action. Based on available RRC records, zero (0) wells known to Milestone require corrective action. Milestone specifically positioned the Midland CCS #2 AoR to avoid any wells that penetrate the Top Seal or Injection Interval.

Out of an abundance of caution, Milestone identified all wells that penetrate the top seal or injection interval within 1 mile beyond the AoR boundary. **(Figure 2-39, Table 2-25).**

- Two (2) wells—Dusek 5 and Dusek 4—penetrate within 100 ft of the Devonian and are believed to penetrate the Barnett and possibly the upper portion of the Woodford.
- Two (2) additional wells—Windham R and JRS Farms 22—penetrate the Woodford Shale (primary top seal) and may approach within 50 ft of the top of the Siluro-Devonian injection unit. These wells were originally drilled to deeper intervals, likely as stratigraphic tests, but were later plugged back to produce from shallower Pennsylvanian and Permian zones.

None of these four wells fall within the AoR of the injection well, and none produce from deep Paleozoic intervals such as the Ellenburger or Devonian. Notably, Milestone positioned the Midland IZM #1 in the direction of JRS Farms 22 to assist with monitoring, as the plume is expected to migrate updip to the southeast.

Given their proximity to the AoR, Milestone carefully reviewed records for all four wells. While wireline logs do not confirm penetration into the Devonian, drilling records and completion reports using driller-reported depths indicate that some wells approached the contact before being plugged back into the Woodford. The plugged-back total depth (PBTD) for each is shown on wellbore diagrams and recorded in the RRC database. The difference between reported TD and the top of the Devonian is summarized in **Table 2-25**.

Due to the distance from the injection well and the low permeability of the upper Devonian packstones, it is unlikely that CO_2 will migrate to these wells over the life of the project. As shown in **Section 2.6**, the majority of the injectate remains in the lower Devonian and Ellenburger, where fracture concentration and permeability are significantly higher.

Milestone will continue to assess the potential risk posed by these wells as the AoR is recalculated following the acquisition of 3D seismic and stratigraphic test well data. Complete RRC well files for these penetrations are provided in the *Potential Penetration outside AOR appendix file.* For additional information on other wells, please see *O&G Well Individual Files*

Table 2-25: Wells within a 1-mile buffer of the AoR that potentially penetrate Top Seal
Note, zero of these wells occur within the AoR

Well Name	Well No.	API14	Operating Company	Total Depth (ft, TVD)	Devonian Top (ft, TVD)	Estimated Distance Above Devonian (ft)
WINDHAM "R"	3	4246139609	PIONEER NATURAL RESOURCES	12,376	12,347	-29
DUSEK	5	4246137895	PIONEER NATURAL RESOURCES	12,230	12,293	63
DUSEK 4	4	4246137841	PIONEER NATURAL RESOURCES	12,200	12,243	43
JRS FARMS 22	1	4246137740	PIONEER NATURAL RESOURCES	12,152	12,141	-11

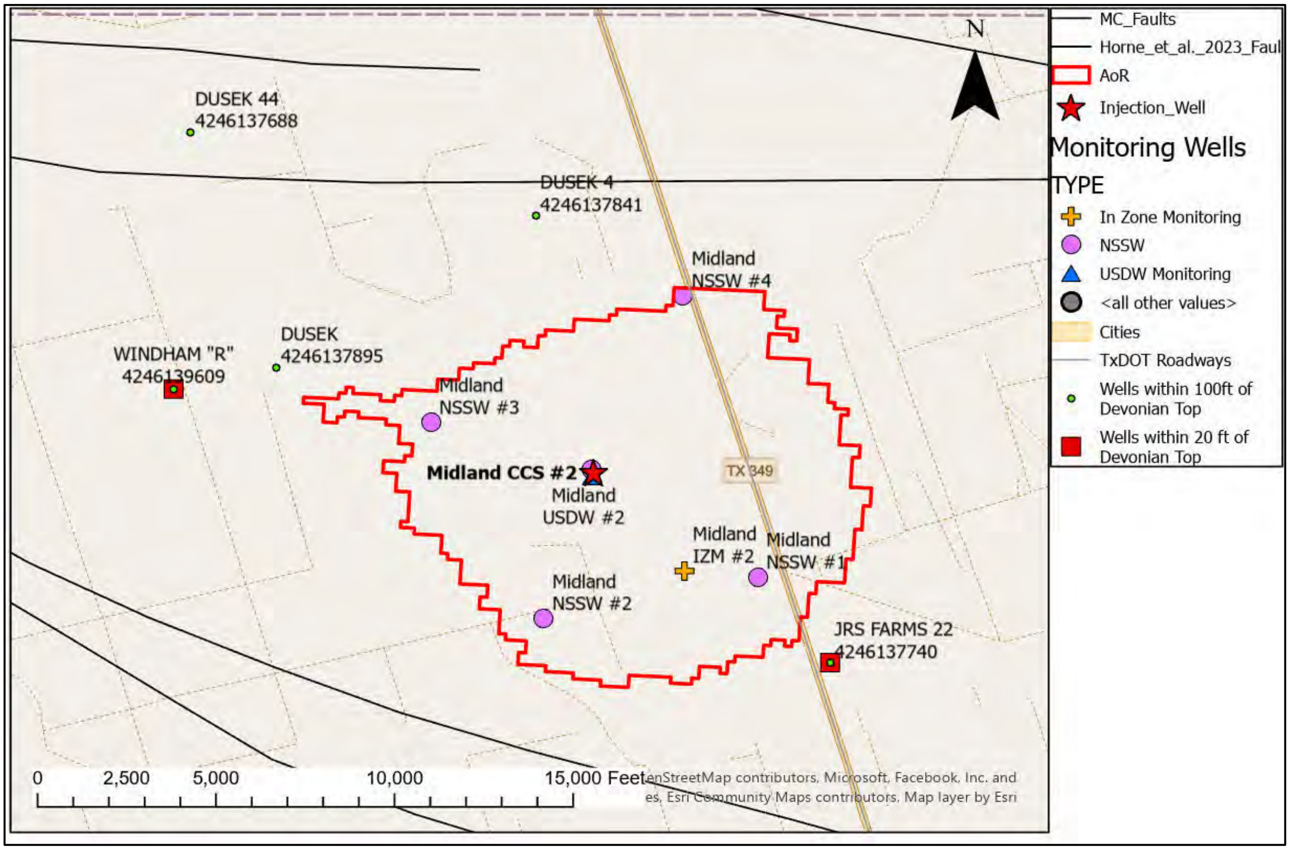


Figure 2-39: **Wells Near the AoR that Potentially Penetrate Woodford (Green) or Devonian (Red)**

A cross-section of the wireline logs of the four wells is shown in **Figure 2-40**. Note the lack of Devonian tops on the cross section, because the wireline logs do not observe the contact.

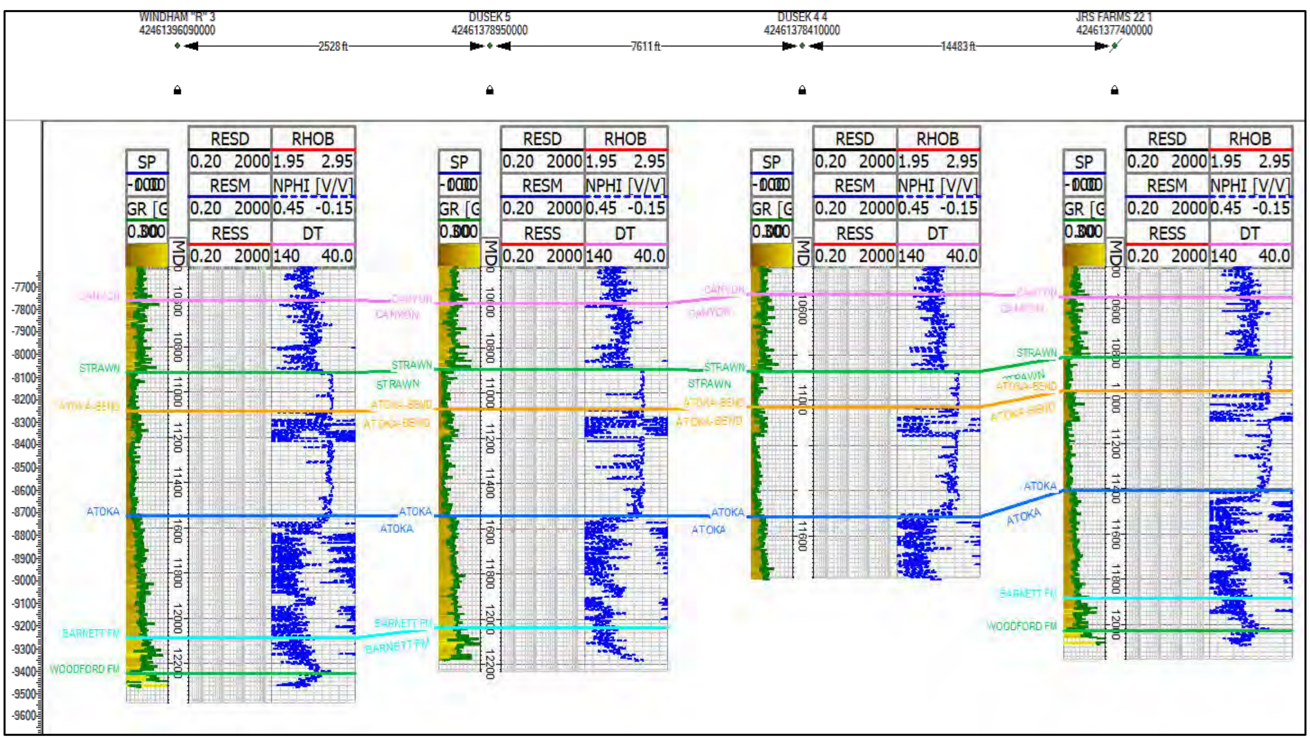


Figure 2-40: Cross Section of Wells Near the AoR that Potentially Penetrate Woodford

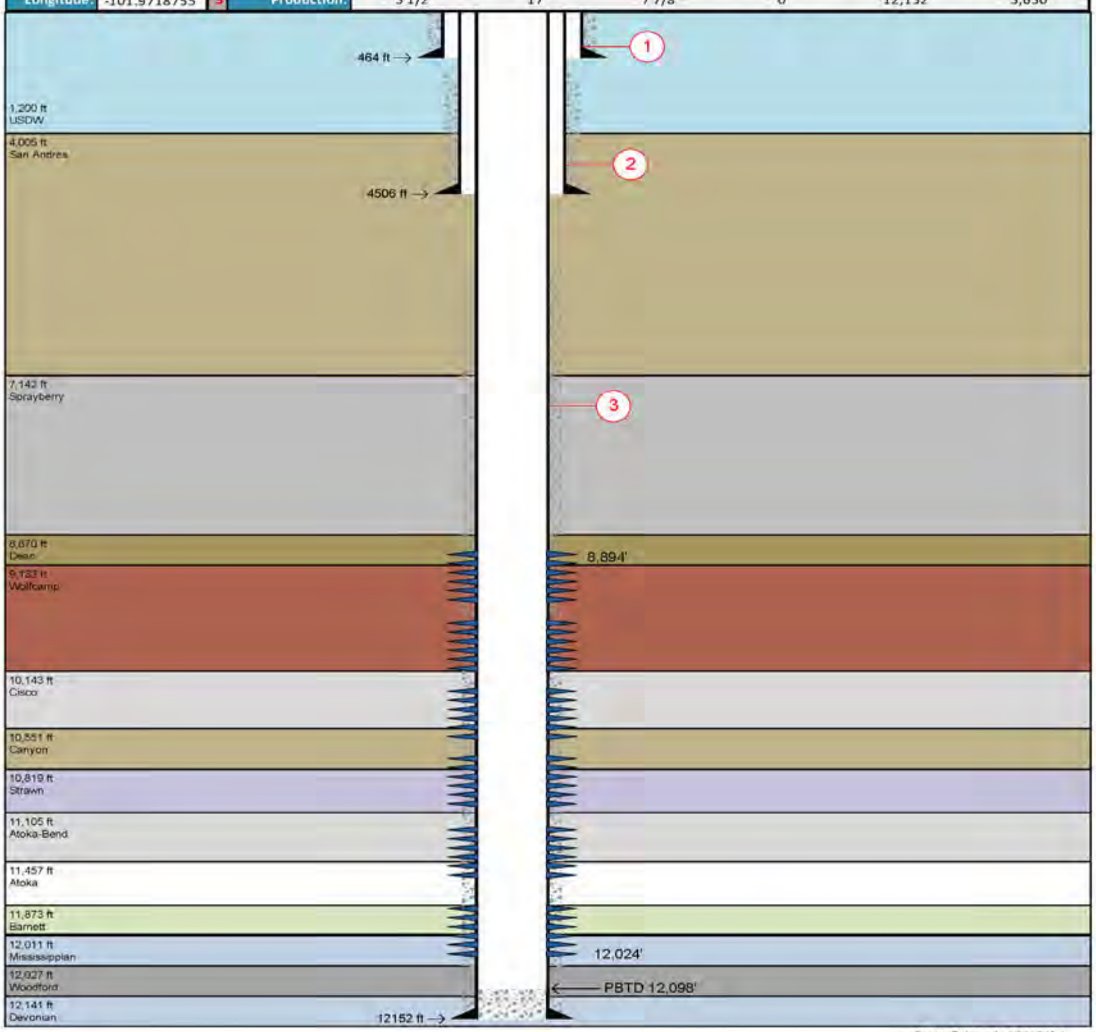
Wellbore diagrams for the JRS Farms 22 and Windham R wells are provided in **Figure 2-41** and **Figure 2-42**, respectively. Note the Plugged Back Total Depth (PBTD) at the bottom of each well. Even if these wells hypothetically penetrated the Devonian, both were plugged back into the Woodford or higher formations and are unlikely to come into contact with injected CO_2, as they are located outside the AoR.

Although these wells fall outside the AoR, Milestone is including the wellbore diagrams for EPA review to demonstrate that these wells have been evaluated and that appropriate remedial actions will be taken if the plume unexpectedly migrates toward them. The plume and pressure monitoring plan is provided in **Section 6** of the permit application, which includes additional details on monitoring strategies and frequency.

Well Name:	JRS Farms 22 #1
API:	42-46137740
State:	TX
County:	Upton
Field:	Spraberry
Elevation:	2,793'
Depth (TVD):	12,152'
Texas Central NAD 83	
Lattitude:	31.6009339°
Longitude:	-101.9718755°

Casing Program

		OD (in)	Weight (lb/ft)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1	Surface:	13 3/8	48	17 1/2	0	464	0
2	Intermediate:	8 5/8	32	11	0	4,506	516
3	Production:	5 1/2	17	7 7/8	0	12,152	5,650



Date Printed: 10/16/24

Figure 2-41: JRS Farms 22 Wellbore Schematic (Not to Scale)

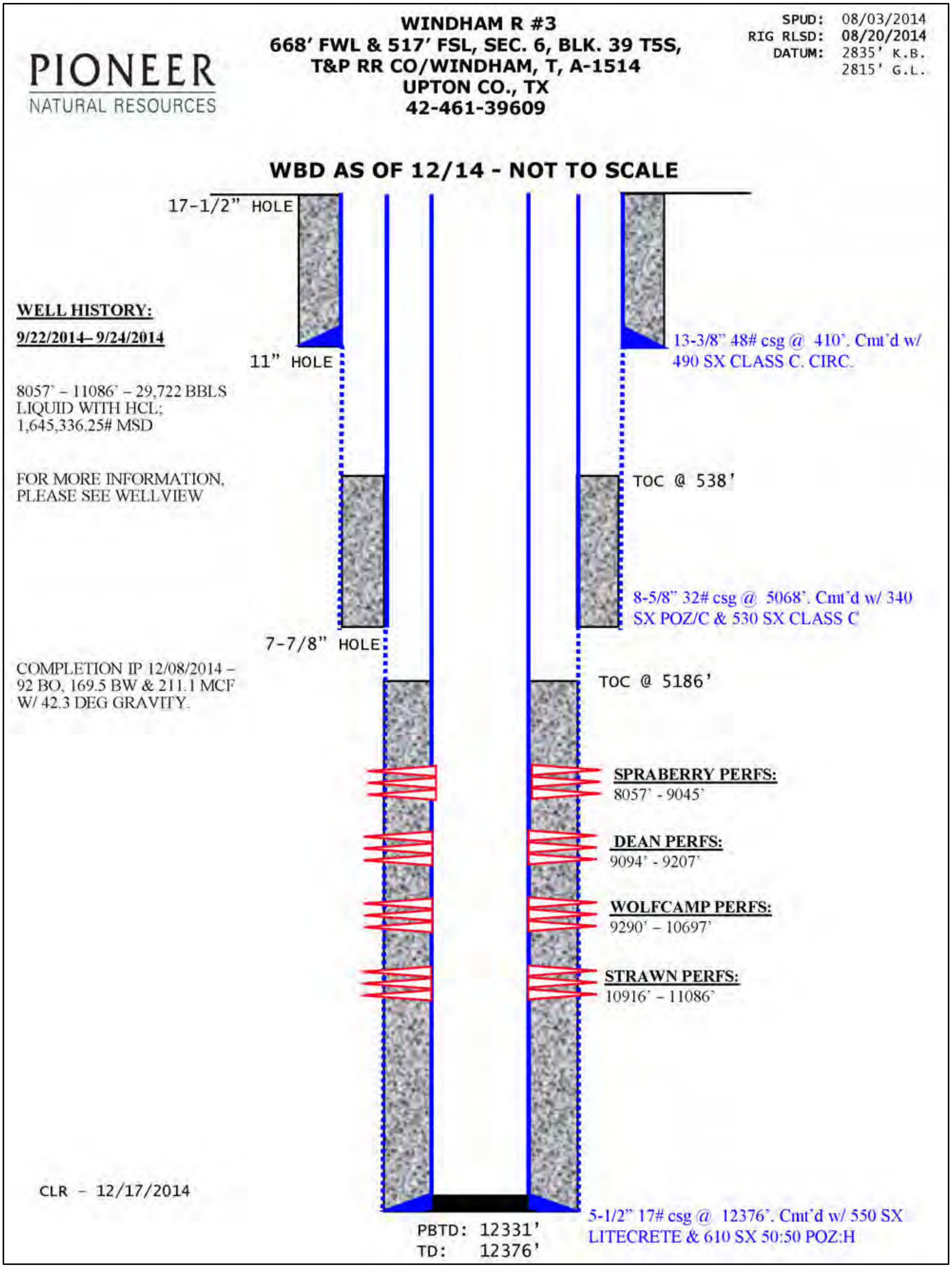


Figure 2-42: Windham R #3 Wellbore Schematic (Not to Scale)

2.11.3 Re-Evaluation Schedule and Criteria

Milestone will reevaluate the Area of Review (AoR) at least once every five (5) years during both the injection and post-injection phases.

The reevaluation procedure will be based on data collected between reevaluations and the well conditions at the time of review. Measured data will include injection rates, pressures, and other relevant operating conditions from the Midland CCS #2 Well, which will be used to inform and update the dynamic model.

History matching will be conducted by inputting recorded injection data into the dynamic model and adjusting model parameters to align with observed pressures. This process calibrates and validates the model to actual site conditions. In addition to history matching the Midland CCS #2 Well, performance data from offset saltwater disposal (SWD) wells, including the Davidson Unit #1, will continue to inform model refinements.

Sensitivity analysis will be performed to identify the parameters that most significantly influence plume behavior and AoR extent. Input parameters will be modified incrementally to assess their impact on predicted plume size and AoR boundaries.

Each AoR reevaluation will include discussion of the following:

- Changes in monitoring or operational data since the previous evaluation.
- How updated monitoring and operational data (e.g., injection rate, pressure) were used to revise the geologic model and computational simulations.
- Any triggers that warranted an unscheduled AoR reevaluation.

If any observations or measurements are determined to materially affect plume size or AoR extent, Milestone will update the Model and perform a reevaluation. Any newly identified wells within the updated AoR will be assessed for corrective action requirements. If needed, corrective action will be undertaken in accordance with applicable federal, state, and local regulations.

Milestone will submit either an amended AoR and Corrective Action Plan or documentation supporting that no changes are required, based on modeling results and monitoring data. Any such events will be discussed with the UIC Program Director to determine whether a formal AoR reevaluation is necessary.

- If an unscheduled reevaluation is triggered, Milestone will take the following steps:
- Evaluate the static model assumptions in light of new data or measurements.
- Run the updated static model and compare outputs to prior predictions.
- Evaluate the dynamic model assumptions using the new data.
- Run the updated dynamic model and compare results to previous simulations.

See **Section 6** for more information on the testing and monitoring program, and **Section 10** for details on emergency criteria and response.

2.11.4 Re-evaluation Events

Milestone Environmental recognizes the importance of defining clear, enforceable triggers for AoR re-evaluation. However, because subsurface pressure and plume migration behavior are subject to spatial heterogeneity, monitoring uncertainty, and model uncertainty, re-evaluation triggers cannot be defined as rigid, single-value thresholds without professional interpretation of baseline data. Examples of events that may trigger an unscheduled AoR reevaluation, with guidance from the UIC Program Director are found in **Table 2-26**. Milestone will be pro-active in working with the UIC team to determine when an AoR re-evaluation is necessary.

Table 2-26: Re-evaluation Trigger Events

Parameter	Trigger Type	Quantitative Threshold	Action
Earthquake	Seismicity Monitoring Alert	Magnitude 3.5+ within 10 km	Notify agency, shut-in well, review AoR and Pressures along faults; see ERRP for earthquake procedures.
CO_2 Saturation	Wireline Logging	CO2 Saturation +/- 25% from modeled amount at IZM #1 or CCS #2	Notify agency, Model Update, AOR reassessment
Leak Event	Leak Detected	More than 100 tonnes leaks out of injection zone	Notify agency, shut-in well, evaluate potential leakage pathways, review AoR and Pressures, AoR reassessment
Surface pressure	SCADA Monitoring Alert	≥500 psi above predicted	Notify agency, internal review
Surface pressure	SCADA Monitoring Alert	≥1,000 psi above predicted, sustained	Notify agency, Model update, AoR reassessment
CO_2 plume area	Technical evaluation	≥20% greater than modeled CO_2 plume area is calculated	Notify agency, AoR reassessment
CO_2 plume	Indirect Monitoring Alert	Any detected CO_2 plume migration >2% saturation beyond 2039 AoR during injection period	Notify agency, Model update, AoR reassessment
TDS	Water Testing Monitoring Alert	≥20% deviation from baseline of Major Cation and Anions	Notify agency, Review sampling, Evaluate potential leakage pathways, AoR Reassessment
TDS	Water Testing Monitoring Alert	≥25% change in other properties such as pH or sustained deviation inconsistent with model	Notify agency, Review Sampling, Evaluate potential leakage pathways, AoR Reassesment
CO_2 detected in USDW	Water Testing Monitoring Alert	Unexplained CO2 discovered in ground water in quantities greater than 500 mg/L above baseline	Notify agency, shut-in well, evaluate potential leak pathways, review AoR and Pressures, AoR reassessment

Milestone will discuss any such events with the UIC Program Director to determine if an AoR revaluation is required. If an unscheduled reevaluation is triggered, Milestone will perform the steps described at the beginning of this section of this Plan. Milestone will also monitor trends in measurements and advise the agency of any going concerns. In addition to the triggers above, Milestone would also like to provide additional guidance regarding trends below.

Consistent with the EPA Class CI Testing and Monitoring Guidance, Milestone evaluates the following trends that may indicate potential fluid leakage. **If two or more of these trends** (relative to baseline data) are noted over a period of three or more sampling events, Milestone will initiate further coordination with EPA or TRRC to assess the potential for fluid leakage above the confining zone and if an AoR re-evaluation is necessary. Indicators of potential fluid leakage include:

- Increasing TDS: An increasing TDS trend may indicate that native brines have migrated from the injection zone, or an intervening zone, into the monitored zone. A change in the overall TDS trend may indicate fluid exchange between adjacent formations.

- Increasing CO2 concentration: An increase in the concentration of dissolved CO2 may indicate leakage of the dissolved-phase plume into the monitoring zone. Increasing CO2 concentrations may also be observed due to other factors, including increasing groundwater recharge. These other factors may be evaluated to ascertain if the observed increasing CO2 concentrations are due to migration from the injection zone.

- Decreasing pH: A decreasing pH trend may indicate migration of carbonic acid and other fluids into the monitoring zone. Similar to increasing CO2 concentrations, other factors may be evaluated that would cause an observed decrease in pH.

- Increasing concentration of injectate impurities: An increase in the concentration of any impurities in the injectate may be indicative of injectate migration into the monitoring zone.

- Increasing concentration of leached constituents: The presence of CO2 may leach certain inorganics from the formation matrix due to lowered pH. Increasing trends may be indicative of fluid migration.

- Increased reservoir pressure and/or static water levels.

Trends will be evaluated using the Mann-Kendall statistical test, following standard methods described in EPA (2009). A trend will be considered significant if it meets the following criteria:

- For increasing trends: The Mann-Kendall test indicated an upward trend at the 95% confidence level and the most recent value is at least 25% higher than baseline.

- For decreasing trends (i.e., pH): The test indicated a downward trend at the 95% confidence level and the most recent value is at least 25% lower than baseline.

- In addition, a change in the signature of dissolved groundwater constituents in the monitored zone as compared to that of the injection zone or confining zone may indicate leakage. The anion/cation signature may be evaluated through the construction and use of ion diagrams, including piper and stiff diagrams.

2.12 Additional Pressure Maps

To aid in the review of the dynamic model, Milestone has included the following maps from **Figure 2-43 to Figure 2-54** showing pressure at various time steps and various k-layers.

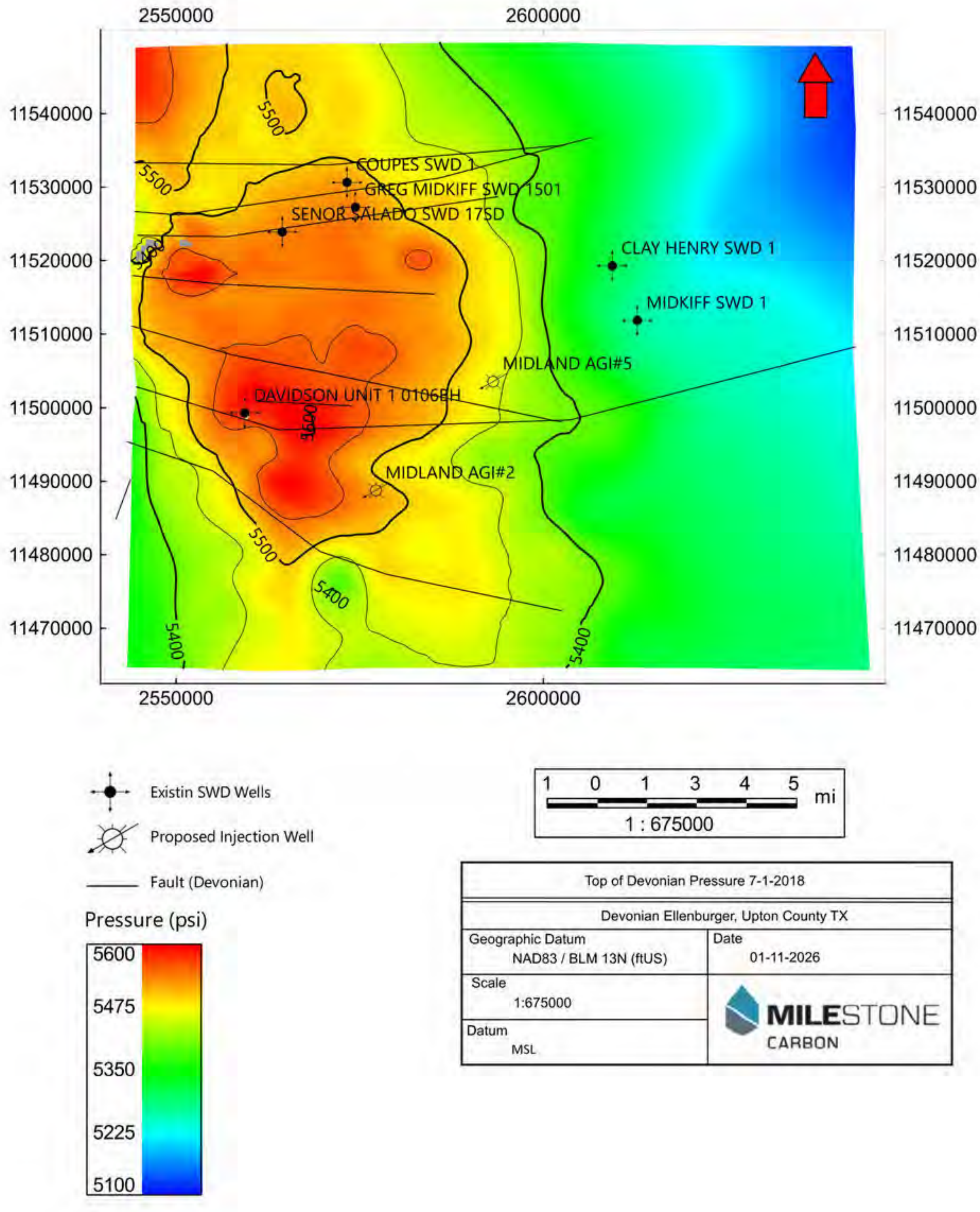


Figure 2-43: Pressure in psi at initial conditions, Top of Devonian, in 2018 prior to any injection, SWD or CO2

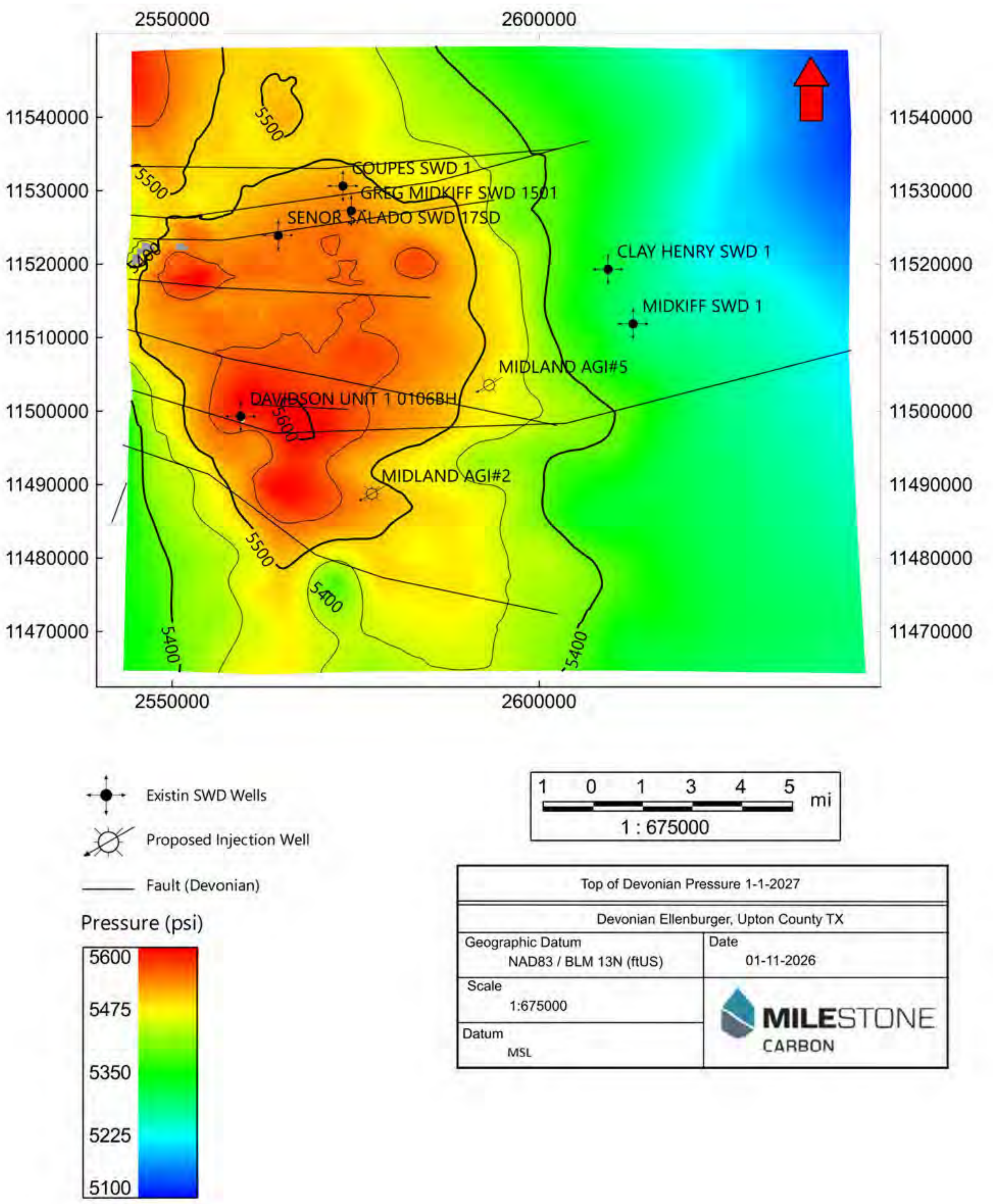


Figure 2-44: Pressure in psi, Top of Devonian, in 2027, just prior to CO2 injection commencing

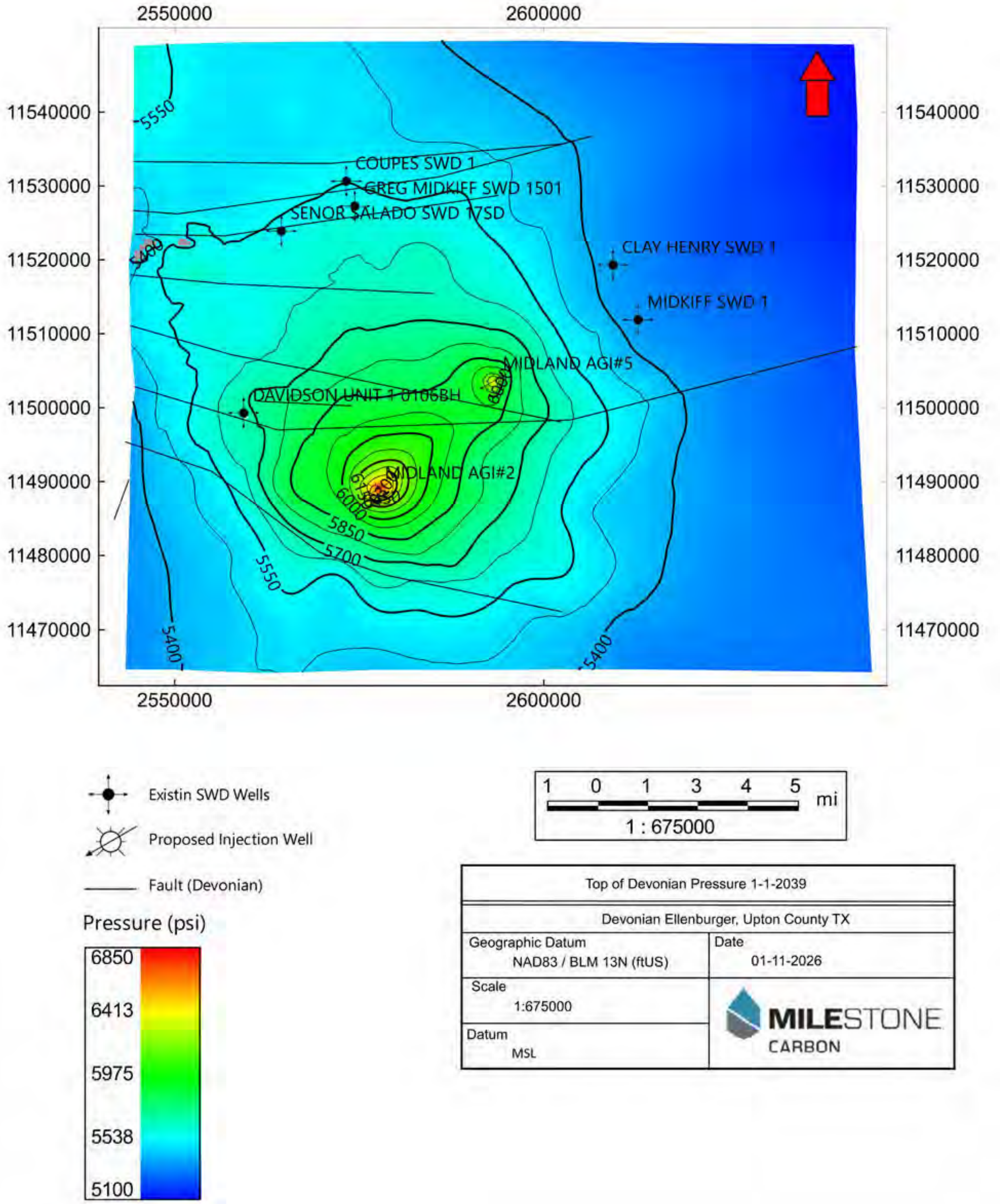


Figure 2-45: Pressure in psi, Top of Devonian, in 2039 when injection terminates

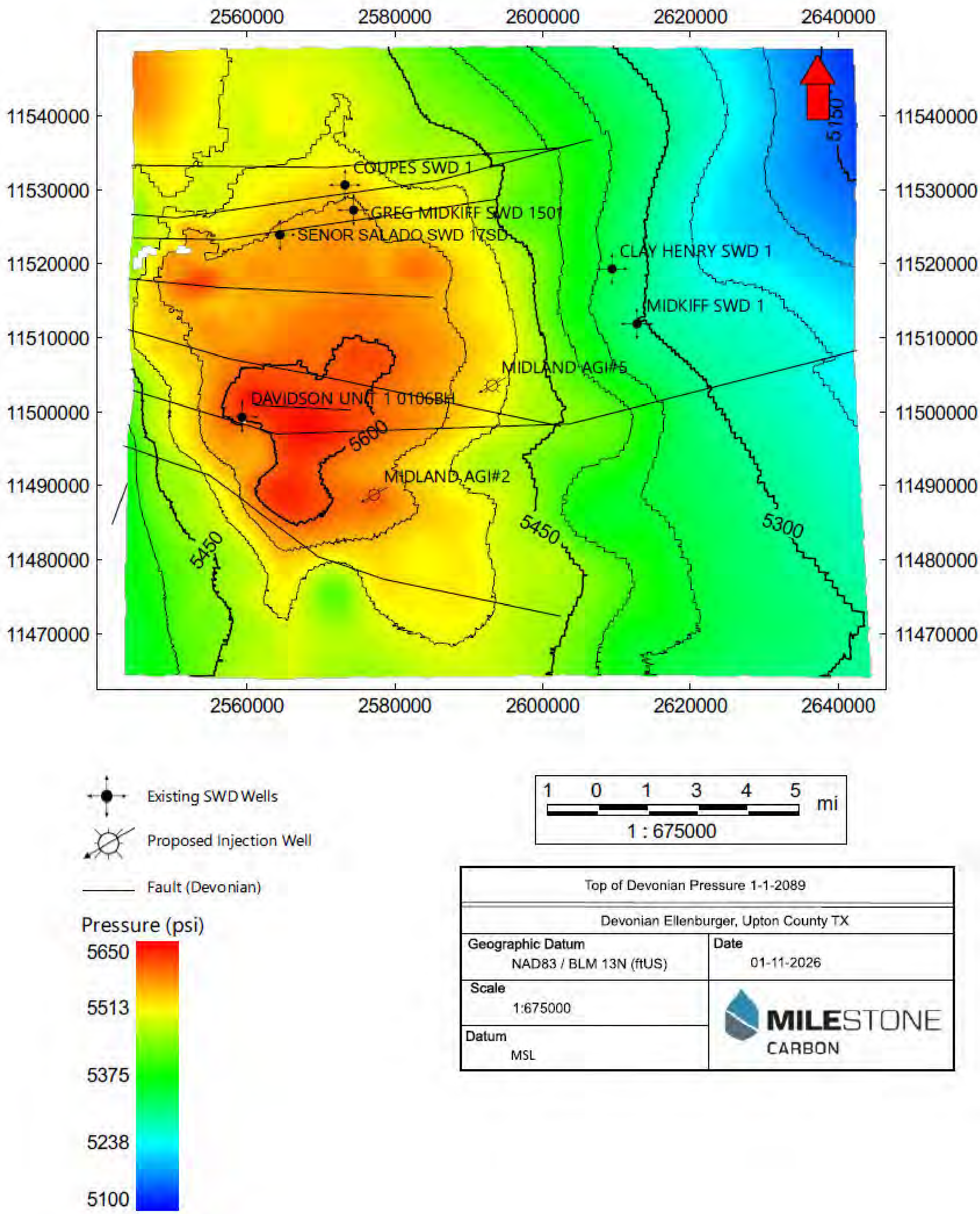


Figure 2-46: Pressure in psi, Top of Devonian, in 2089 at the end of the PISC period

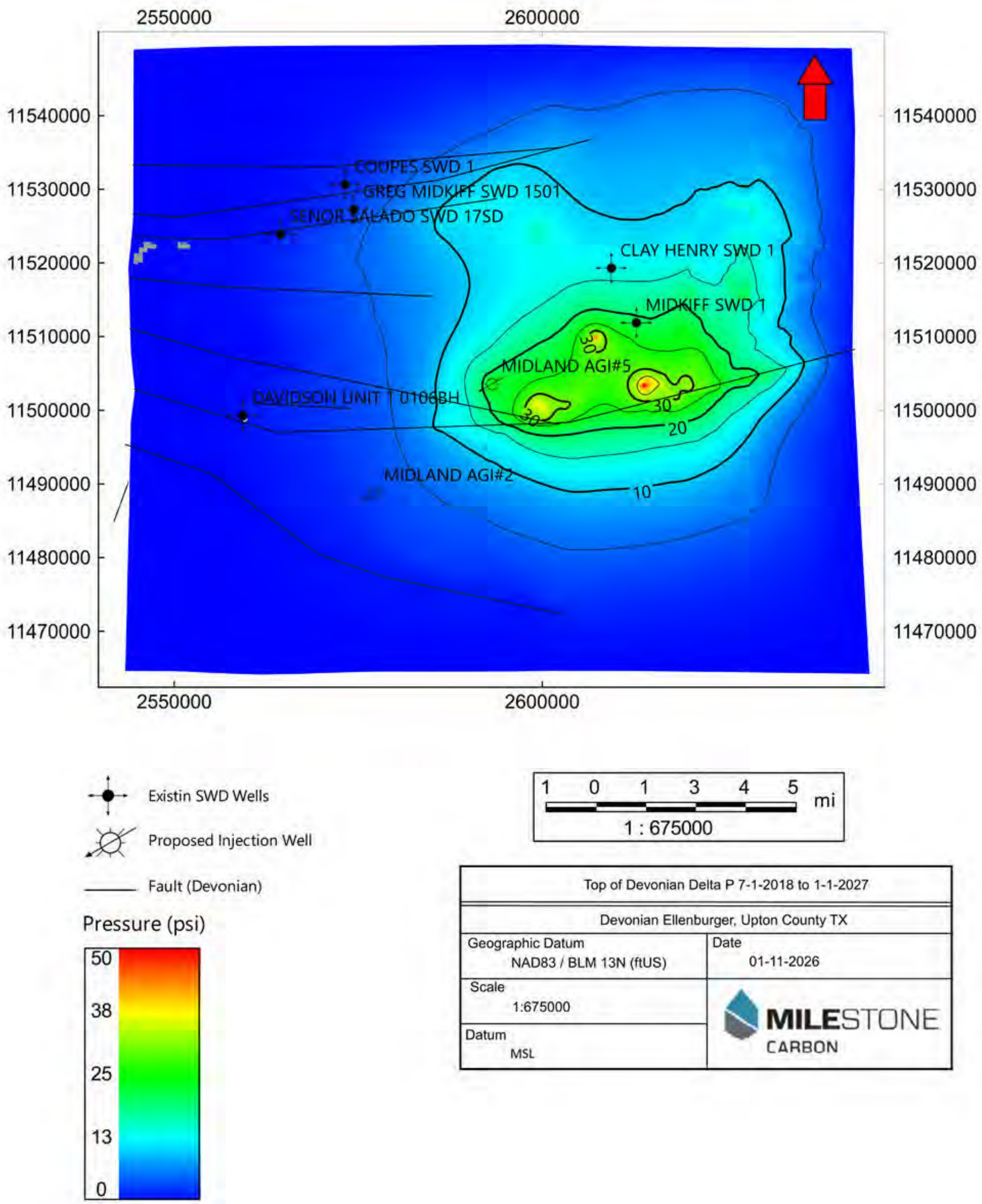


Figure 2-47: Pressure differential in psi, Top of Devonian, from start of simulation in 2018 to start of CO2 injection in 2027

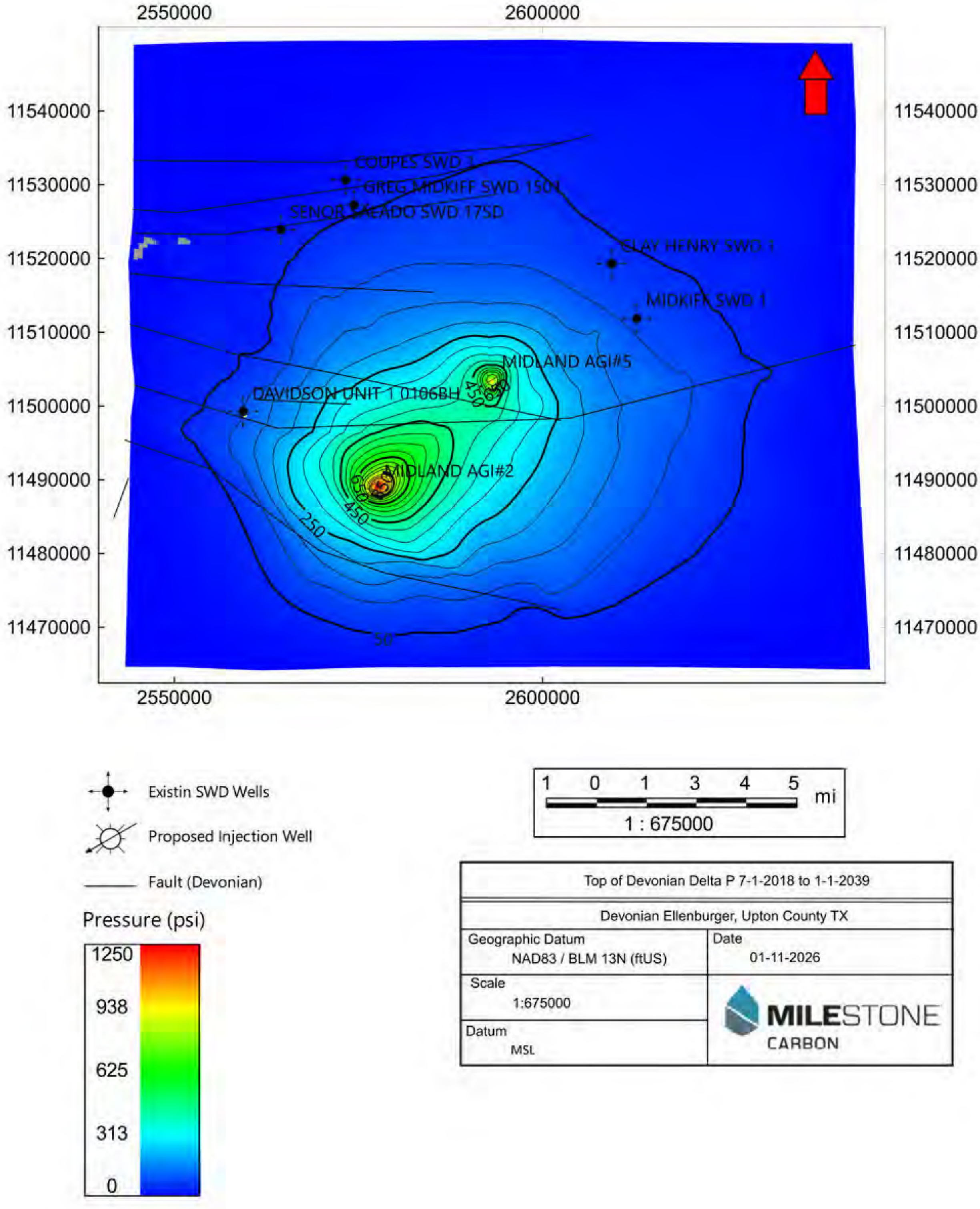


Figure 2-48: Pressure differential in psi, Top of Devonian, from start of simulation in 2018 to termination of injection of CO2 in 2039

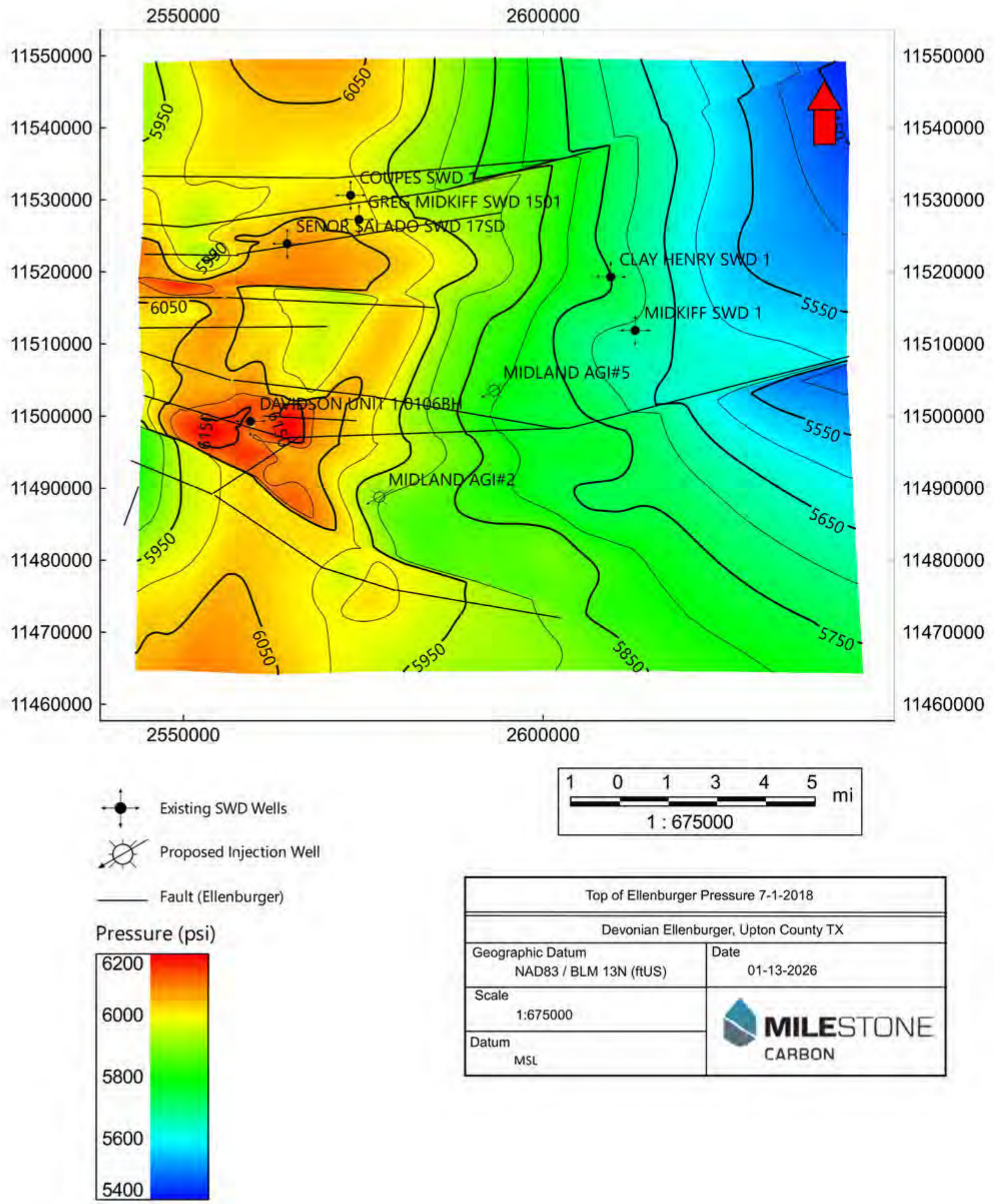


Figure 2-49: Pressure in psi, Top of Ellenburger, at the start of simulation in 2018, prior to any injection, SWD or CO2

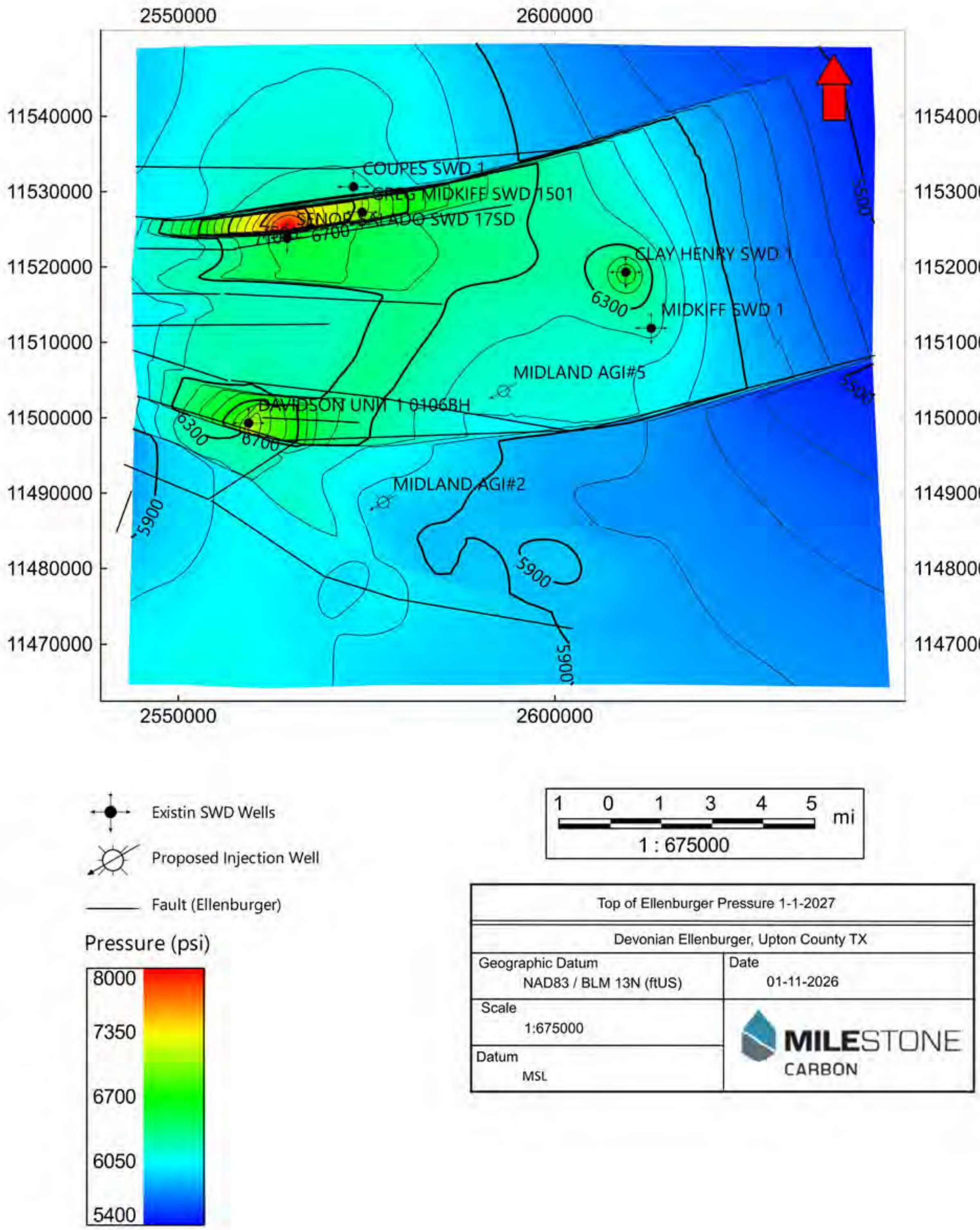


Figure 2-50: Pressure in psi, Top of Ellenburger, just prior to of CO2 injection commencing in 2027

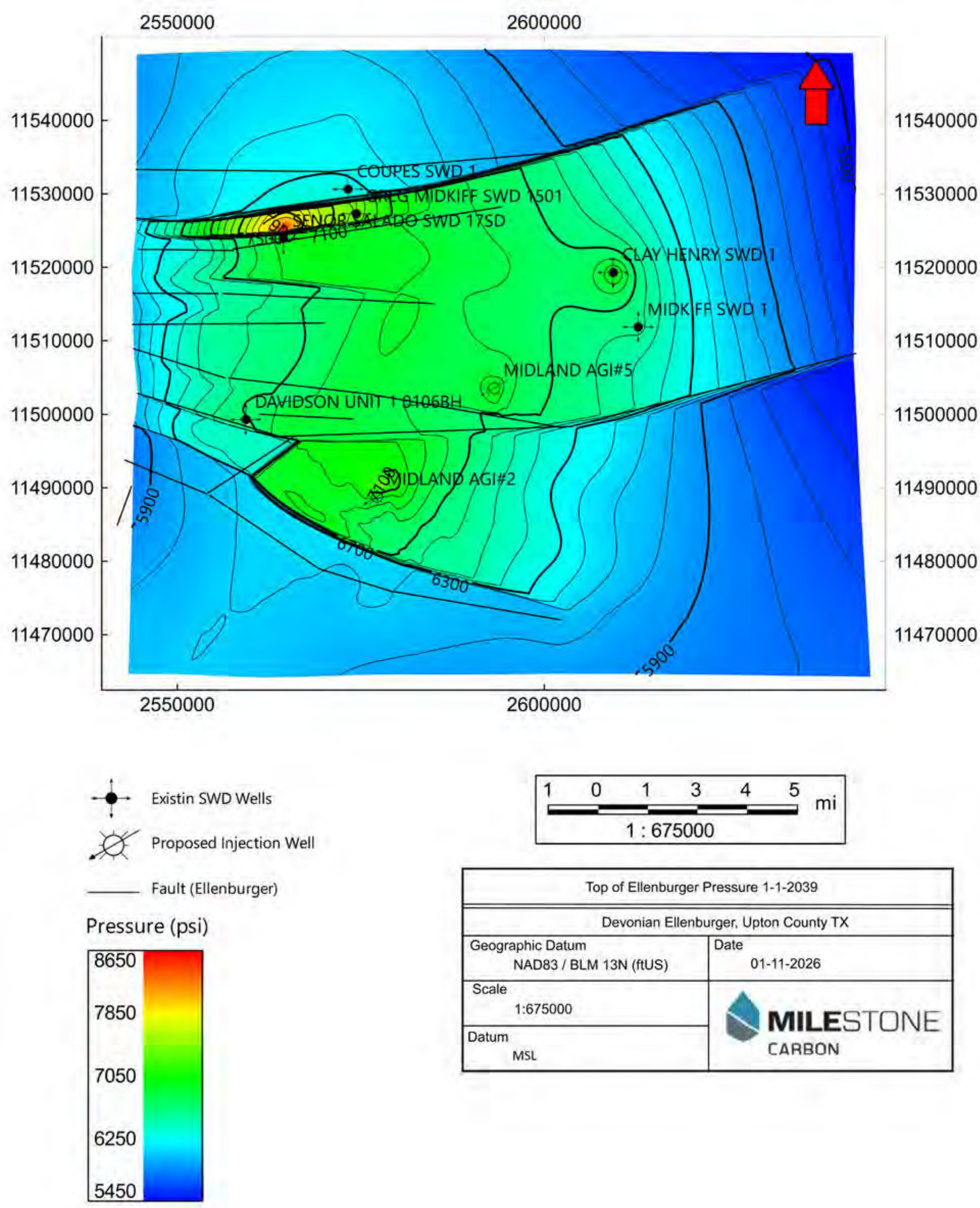


Figure 2-51: Pressure in psi, Top of Ellenburger, at the termination of CO2 injection in 2039

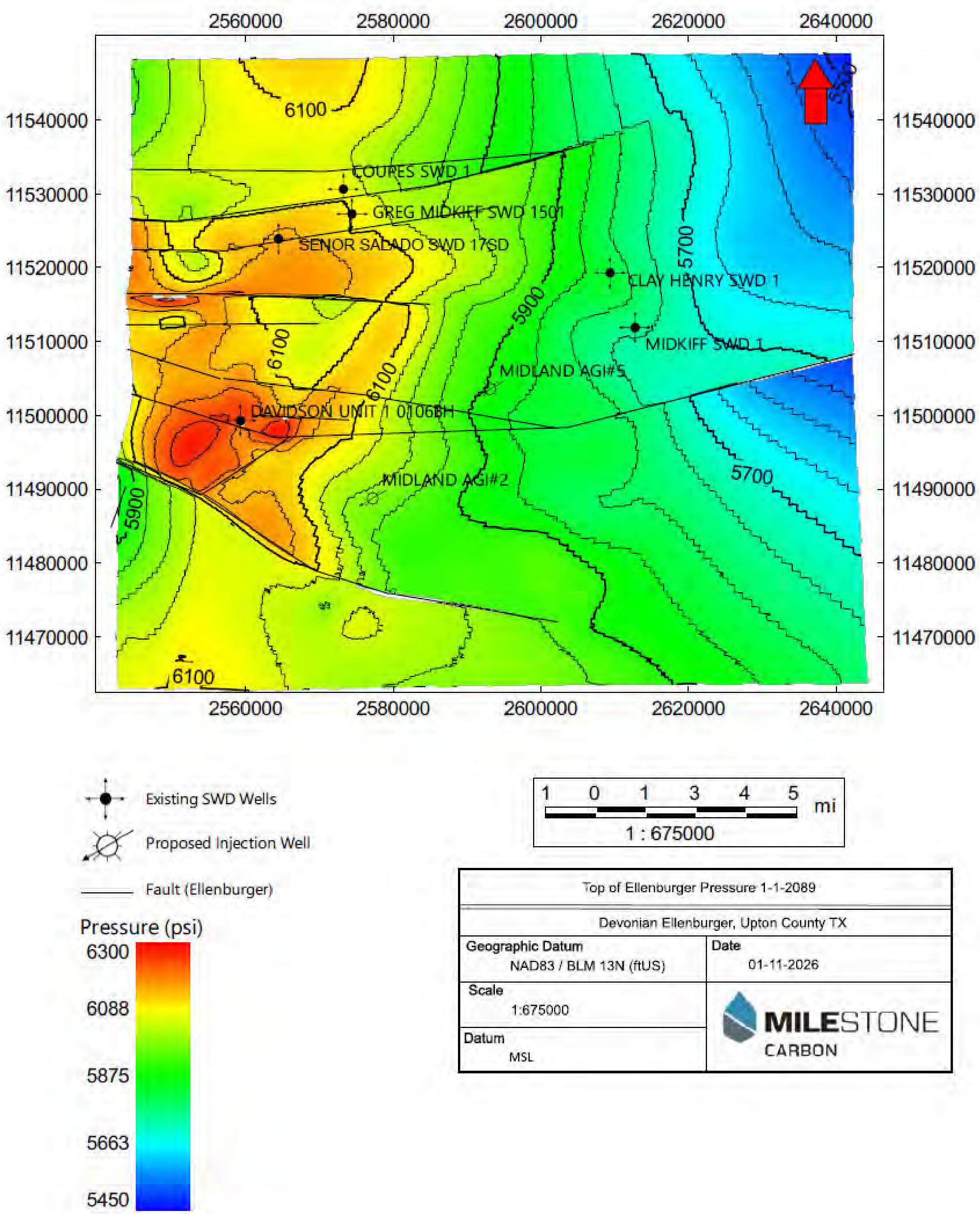


Figure 2-52: Pressure in psi, Top of Ellenburger, end of PISC period in 2089

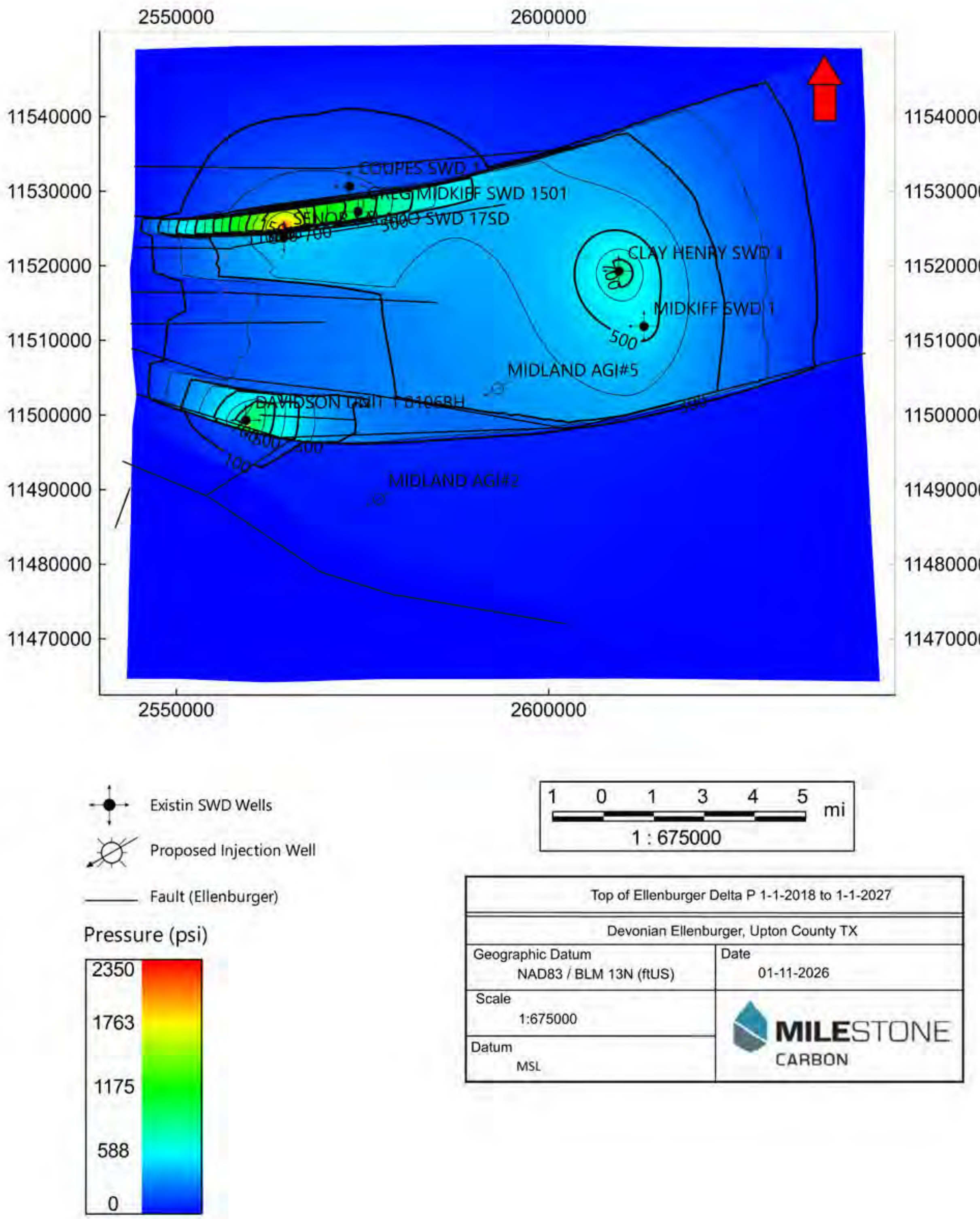


Figure 2-53: Pressure differential in psi, Top of Ellenburger, from start of simulation in 2018 to the start of CO2 injection in 2027

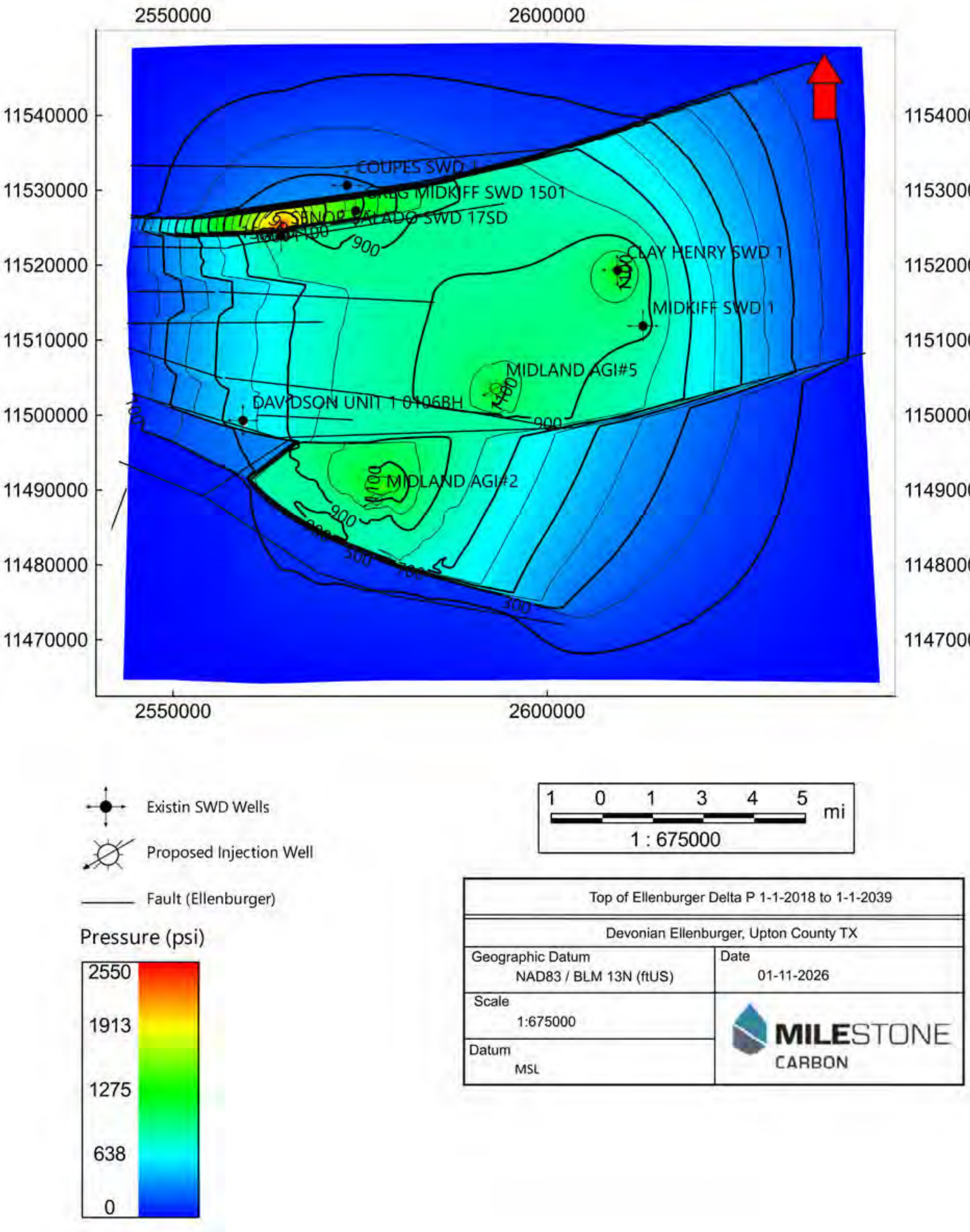


Figure 2-54: Pressure differential in psi, Top of Ellenburger, from start of simulation in 2018 to the end of CO2 injection in 2039

2.13 Plume and Pressure TRRC Time Periods

To satisfy Statewide Rule TAC §5.203 (d)(1)(A) requiring that using computational modeling the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods. Milestone has prepared the maps in **Figures 2-55** through **Figure 2-58.** A summary of the area and radii of the plume at each time step is illustrated in **Table 2-27**. The vertical extent of the plume is confined within the injection interval. See **Section 2.6** for cross sections of the plume over time.

- five years after initiation of injection;
- from initiation of injection to the end of the injection period proposed by the applicant; and
- from initiation of injection until the movement of the CO_2 plume and associated pressure front stabilizes.

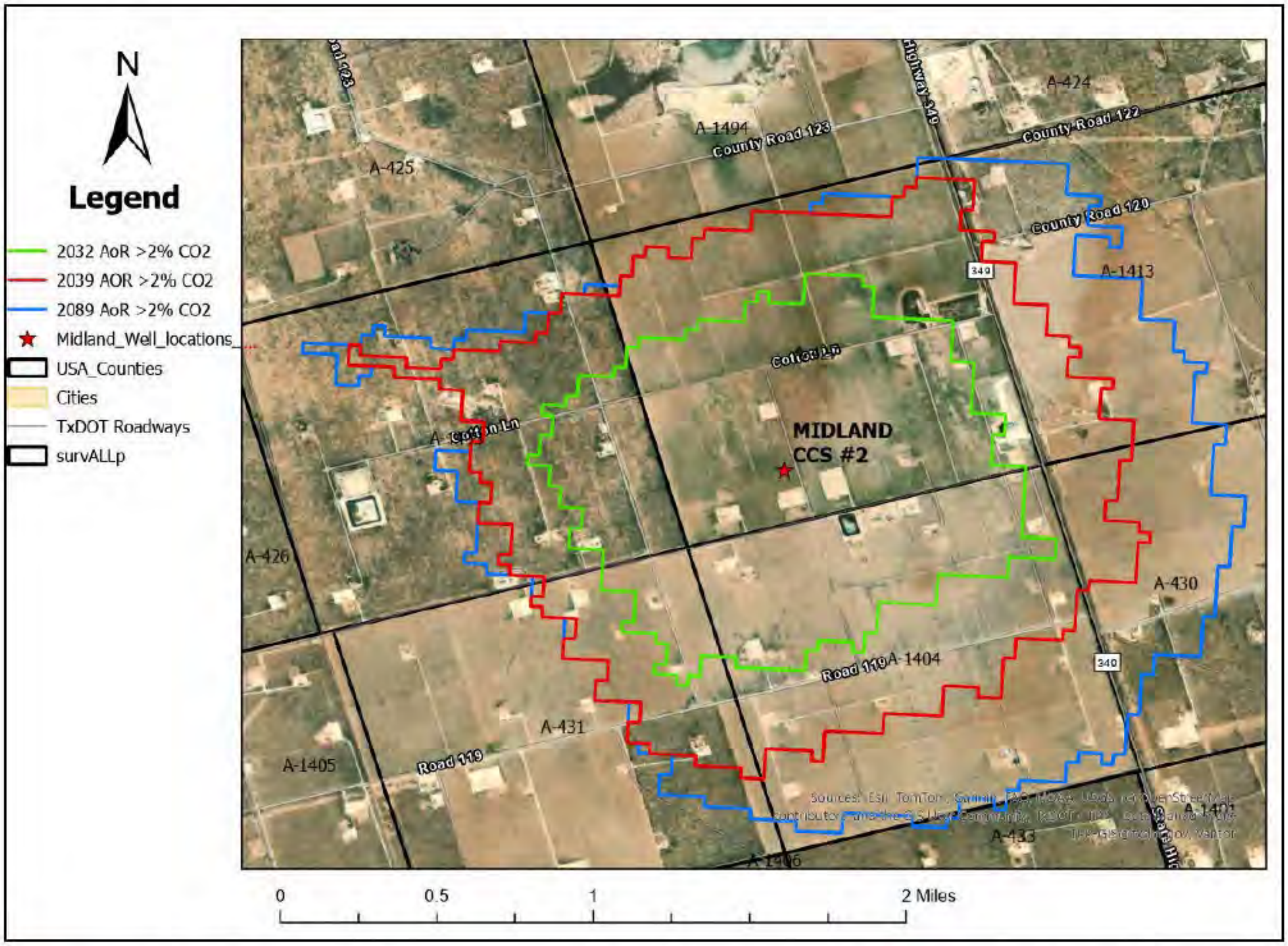


Figure 2-55: Plume Dimensions, (GREEN) 2032 - 5 years after injection; (RED) 2039 - at end of Injection; (BLUE) 2089 - at end of PISC period

Table 2-27: Radius and Area of AoR at Each Model Year

AoR Year	AoR Average Radius (ft)	AoR Area (ft^2)	AoR Area (Acres)
2032	3,192.95	32,028,246.01	735.27
2039	4,594.86	66,327,705.43	1,522.67
2089	5,423.89	92,421,218.76	2,121.70

The following figures from **Figure 2-56** to **2-58** show the pressure at the top of the injection interval (top of Devonian) at the time steps for 5 years after injection, end of injection and end of PISC period.

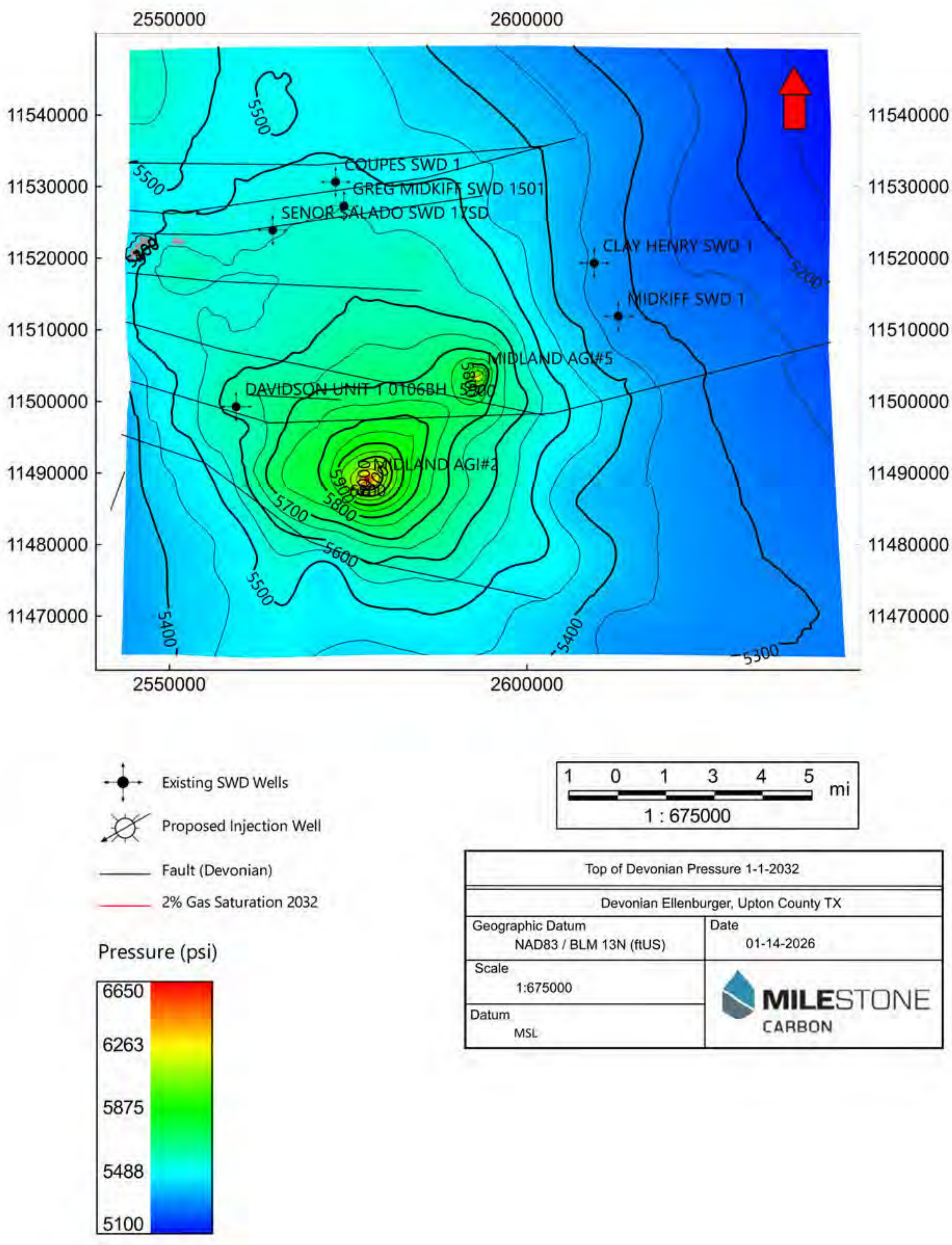


Figure 2-56: Pressure at the Top of Devonian, in PSI, Year 2032, 5 years after Injection Commences

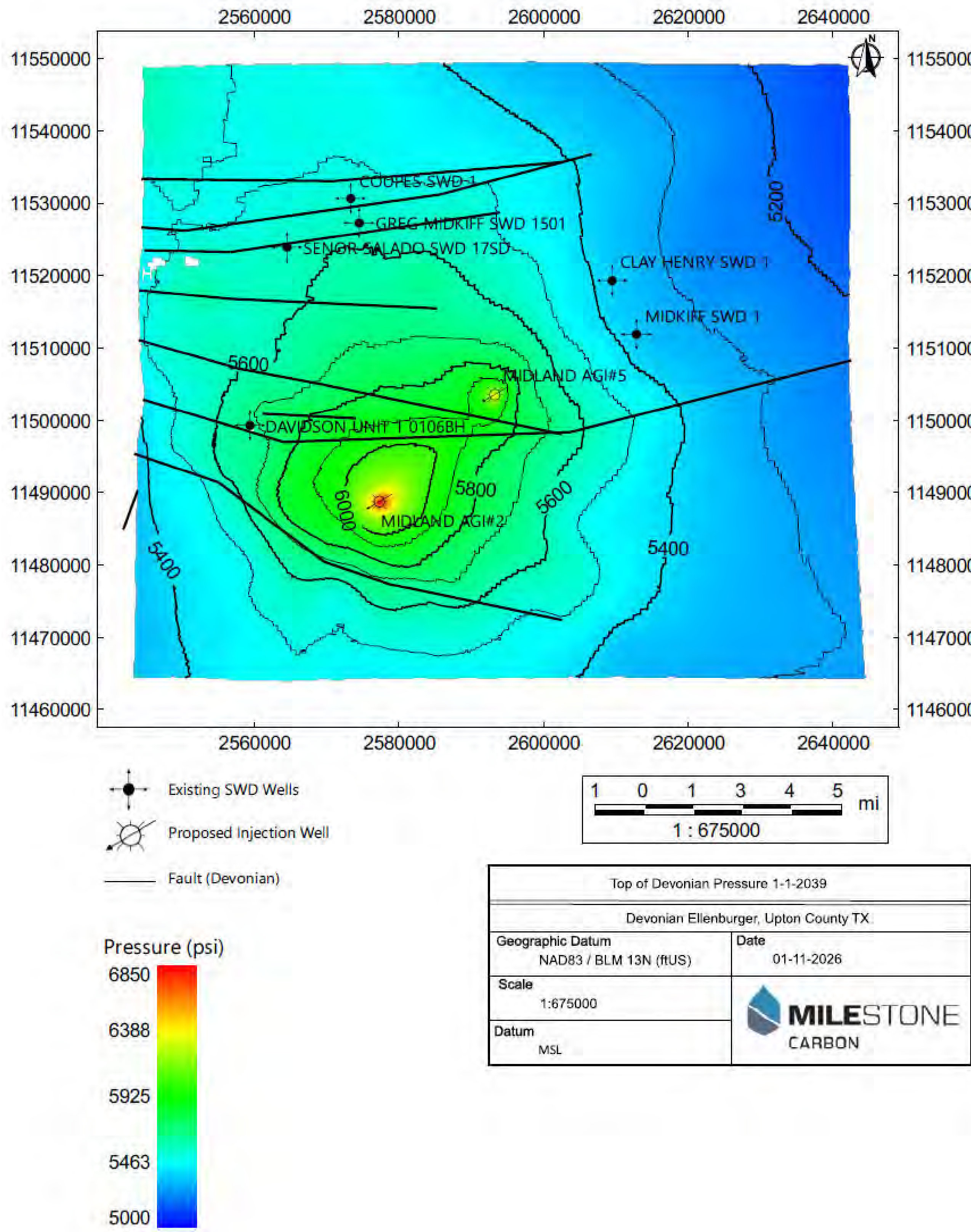


Figure 2-57: Pressure at the Top of Devonian, in PSI, Year 2039, End of Injection Period

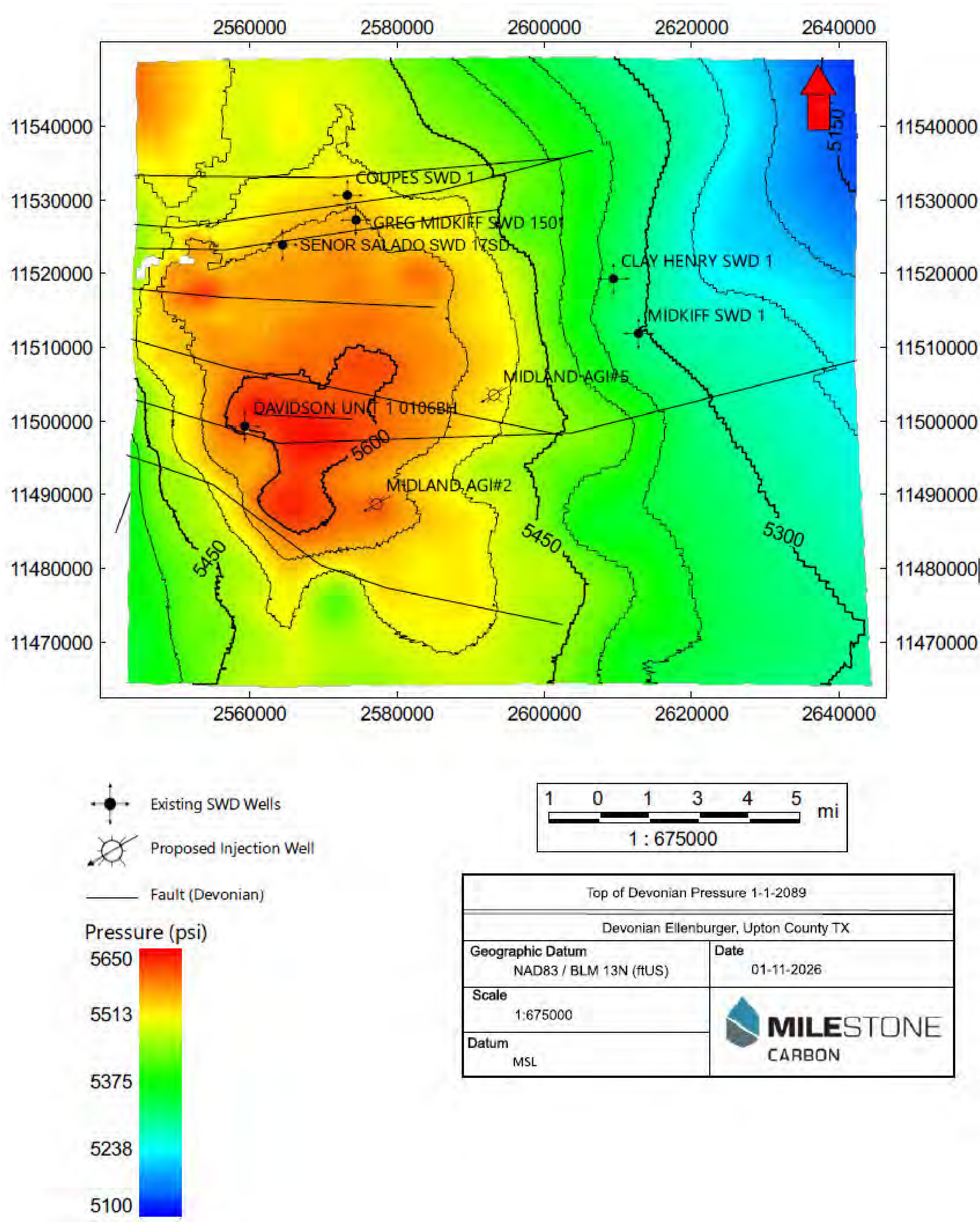


Figure 2-58: Pressure at the Top of Devonian, in PSI, Year 2089, End of PISC Period

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Section 3: Construction Details / Engineering Design

[40 CFR §146.82, §146.86, §146.87]

Prepared for:

EPA Region 6

Underground Injection Control Section

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Updated 14 January 2026

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3.0 CONSTRUCTION DETAILS / ENGINEERING DESIGN [40 CFR 146.82(a)(7), (a)(8), (10), (11), (12) 146.86, 146.87]

Milestone's permit **Section 3** describes the engineering design details, and permit **Section 4** includes operational strategies employed during the planning of the proposed Midland CCS #2 Injection Well which will be completed at a total depth (TD) of ~13,849 ft TVD. This section also features the design and construction of the planned monitoring wells that will be drilled to support injection into the proposed injection wells. Milestone plans to drill one in-zone monitor well, the Midland IZM #2, and one USDW monitoring well, the Midland USDW #1. The Midland IZM #2 will be completed at ~13,785 ft TD TVD in the Devonian and Ellenburger formations. The USDW monitoring well will be completed at ~1,300 ft in the base of the USDW and/or the first permeable zone above 1,250 ft. Additionally, Milestone plans to drill five (5) near surface seismic monitoring and water wells (NSSW), Midland NSSW #1-5. These wells will be completed at ~300 ft each in the Edwards-Trinity (Plateau) aquifer.

3.1 Engineering Design [40 CFR 146.82(a)(11), (12), 146.86]

The design of the injection wells is optimized to permanently sequester CO_2, prevent the movement of CO_2 and subsurface fluids into USDWs, and account for various operational factors, such as injection volume, rate, chemical composition, metallurgical evaluations, physical properties of the injectate fluid, and the corrosive nature of the injectate fluid and its impact on wellbore components. The operation of the wells will be managed to ensure efficient use of pore space in the reservoir and to contain the CO_2 within the authorized injection unit both during and post-injection.

The Midland CCS #2 well and Midland IZM #2 are designed to withstand the corrosiveness of the injectate. Special metallurgies, such as 22CR/25CR, and coatings will be used for the casing, tubing, wellhead equipment, and downhole tools. Additionally, the wellbore cement design and products used to cement the well are designed to create good, reliable bonding between the casing and formations while withstanding the corrosive nature of the injectate. The casings are designed with a sufficient cement sheath to protect the wellbore from developing any channeling out of the injection interval and to maintain the CO_2 below the Top Seal (Woodford Shale).

The wellbore will be designed with production casing including the following tubulars: 7-5/8-in P-110 casing with premium connections from surface to ~500 ft above the Top Seal, the Woodford, a galvanic 7-5/8-in P-110 x 7-5/8-in 22CR/25CR crossover, 7-5/8-in 22CR/25CR casing with premium connections from the crossover to ~60 ft into the top of the injection interval, the Devonian, and finally openhole to TD, ~100 ft above basement (see permit **Section 1** for stratigraphic column). **Figure 3-1** illustrates the proposed injection wellbore schematic.

The production tubing will be 4-½-in P-110 with premium connections installed from surface to 162 ft above the production casing shoe set into an upper sealbore assembly just above a 4-½-in x 7-5/8-in fixed permanent production packer. The upper sealbore will allow the 4-½" tubing to be retrieved without pulling the packer. The packer should be located approximately +/-150 ft above the production casing shoe provided there is at least 60% good cement bonding across the isolating shale directly above the top of the injection interval. The production packer will be made of 22CR/25CR or equivalent material. Included below the packer assembly will be a 4-½-in safety valve, 4-½-in blast joint, and a wireline re-entry guide all made of 22CR/25CR or equivalent material extending beyond the production casing shoe. The 4-½-in safety valve made of 22CR/25CR, or equivalent material.

The tubing and casing annulus pressures will be continuously monitored to ensure that well integrity is maintained. The SCADA system will measure and record downhole temperatures and pressures in the injection interval and assist in monitoring the CO_2 plume's size. The monitoring system includes running a fiber optic cable (red line on **Figure 3-1**) and tubing encapsulated conductor (pressure gauge / yellow line on **Figure 3-1**) with downhole pressure gauges as the production casing is run in the hole. The cable and sensors will then be cemented into place. See permit **Section 6** for additional information regarding monitoring plan.

MILESTONE CARBON

Well Name:	Midland CCS #2
API:	
UIC:	
State:	TX
County:	Upton
Field:	Midland
Lease:	Dusek
Elevation:	2,800'
Depth (TVD):	13,849'
Texas Central NAD 83	
Location X:	1780908.86
Location Y:	10555246.59
Latitude:	31.615788°
Longitude:	-101.990004°

Casing Program

		OD (in)	Weight (lb/ft)	Grade	Connection	ID (in)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1	Surface:	13 3/8	54.5	J-55	BTC	12.615	17 1/2	0	1,300	0
2	Intermediate:	10 3/4	51	P110HC	BTC	9.85	12 1/4	0	9,000	0
3	Production:	7 5/8	39	P110EC	VAM 21	6.625	9 1/2	0	11,600	0
				25CRW	SFJ			11,600	12,260	11,600
4	Injection Tbg:	4 1/2	15.1	P-110	SLIJ-II	3.826		0	12,098	
5		4 1/2	15.1	25CRW	SFJ	3.826	6 1/8	12,098	12,270	

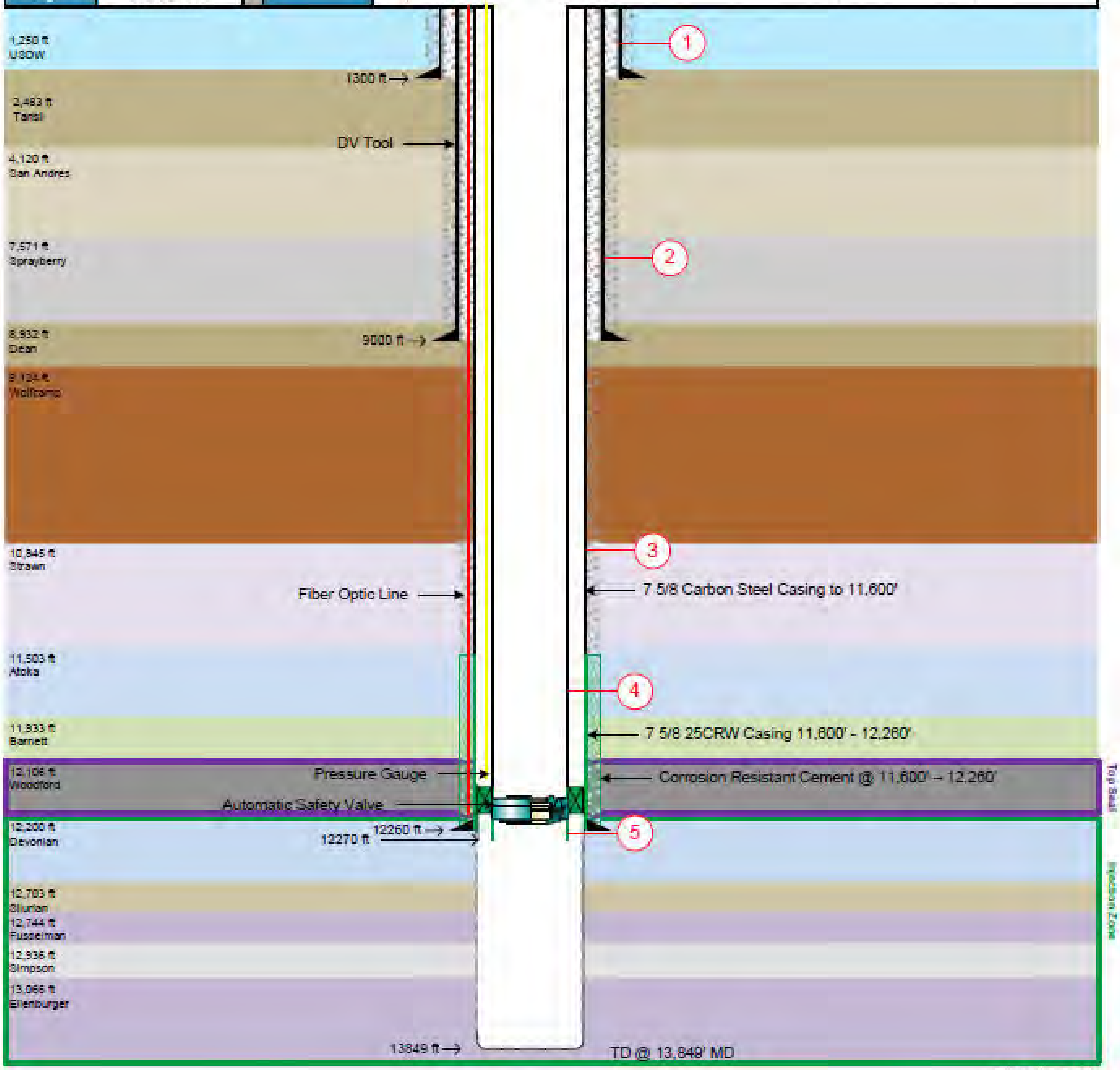

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Figure 3-1: Proposed Midland CCS#2 Wellbore Schematic

The proposed wellbore schematic illustrates geologic formation tops, including the upper confining zone (Top Seal) and injection intervals and units, well construction elements to best suit the storage of CO_2, such as CRA materials, and proposed monitoring equipment.

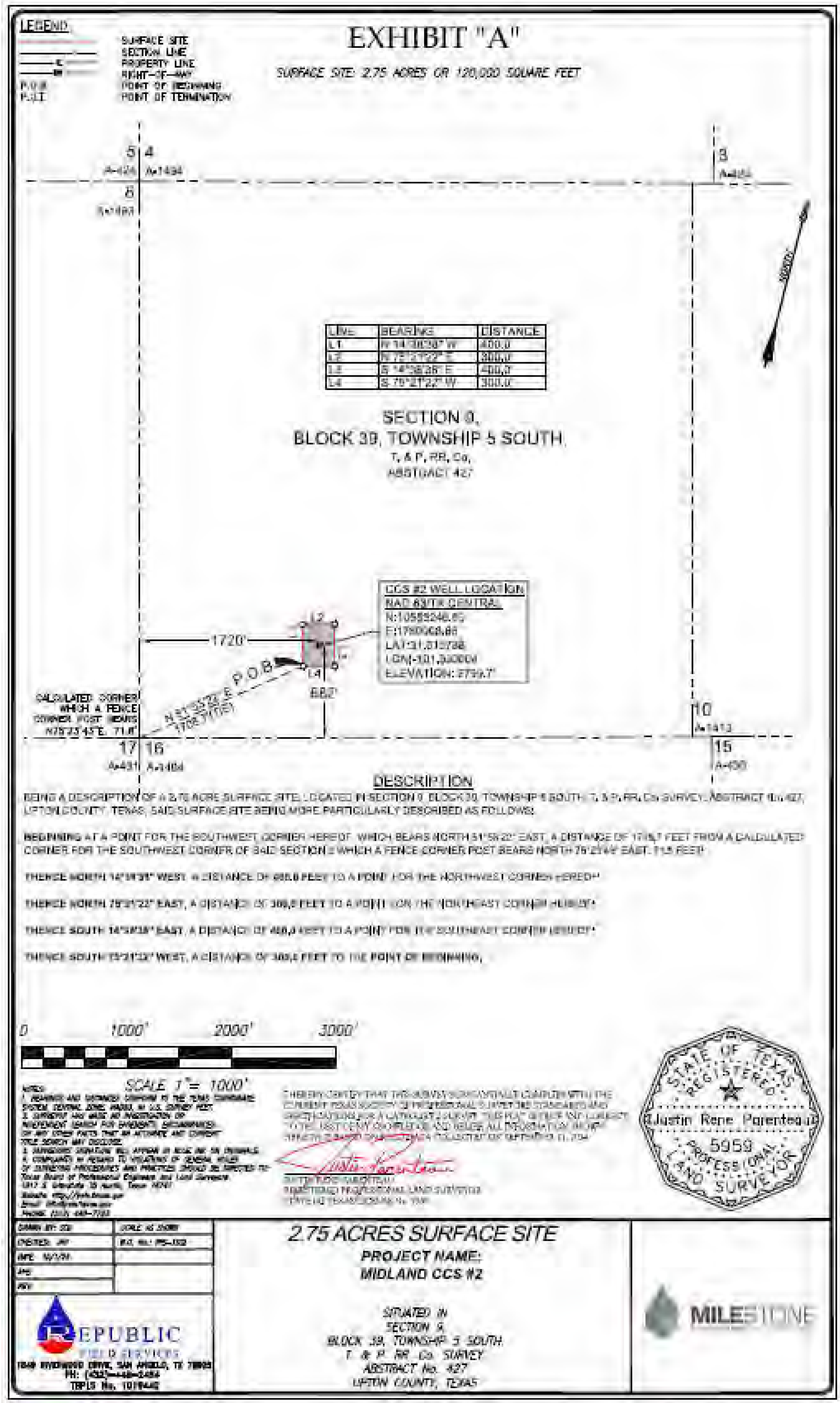


Figure 3-2: Well Location Plat CCS#2

The surveyed well location plat shows the proposed Midland CCS #2 Well location in Section 9, Block 39, Township 5 South, Abstract No. 427, T&P RR Co. Survey, Upton County, Texas.

3.2 General Outline of Injection Well Design and Completion Schematic

The Midland CCS #2 Well is designed with the following specifications:

1. Conductor Pipe
    a. Size: 20 inches (in)
    b. Depth: 120 ft (ft)
2. Surface Casing
    a. To be set below the lowermost Underground Source of Drinking Water (USDW)
        i. Currently estimated: 1,250 ft
            1. Based on offset GAU Determination letters **(Appendix I)** issued by the RRC.
        ii. USDW depth and location will be further confirmed via openhole logging during drilling of the well
    b. 13-3/8-in casing set at ~1,300 ft
    c. J-55 grade tubulars
    d. 17-½-in hole size
    e. Cement to surface
3. Intermediate Casing
    a. 10-3/4-in casing set into top of Dean @ ~9,000 ft
    b. P110HC grade tubulars
    c. 12-¼-in hole size
    d. Cement to surface
        i. DV Tool set at ~4,100 ft
4. Production Casing
    a. 7-5/8-in casing set into top of Devonian @ ~12,260 ft
        i. P-110EC grade tubulars from surface to 11,600 ft
        ii. Galvanic crossover (X-O) between P-110EC & 22CR/25CR
        iii. 22CR/25CR, 110 ksi grade tubulars from 11,600 ft to 12,260 ft
        iv. 9-½-in hole size
    b. Cement to surface
        i. Cement to be comprised of the following make-up:
            1. From surface to ~500 ft above the top seal – (light weight acid resistant cement)
            2. From ~500 ft above the top seal, throughout the injection interval, to shoe – (acid resistant cement)
5. Injection Tubing
    a. 4-½-in tubing set on packer at 12,270 ft
        i. Tubing P-110 grade
        ii. Packer 22CR/25CR or equivalent
        iii. Coated with H2S and CO2 resistant coating
    b. Subsurface Tejas InjectGARD Variable Orifice Safety Valve at ~12,262 ft
        i. 22CR/25CR or equivalent
        ii. API-14A, V3 rated
        iii. Wireline retrievable
    c. 4-½-in blast joint and re-entry guide to 12,270 ft
    d. Annular fluid to consist of corrosion inhibited fluid
6. Packer Configuration
    a. 4-½-in x 7-5/8-in permanent packer set at 12,098 ft
        i. 22CR/25CR or equivalent, Inconel-lined (flow-wetted) anchor, mandrel, and cylinder for corrosion resistance
            1. Minimum ID: 3.875-in
            2. Elastomer options – Nitrile, HNBR, Aflas (CO_2 resistant)
7. Wellhead
    a. 13-3/8-in SOW x 13-5/8-in 5M – conventional casing head
    b. 13-5/8-in 10-3/4-in – casing hanger
    c. 13-5/8-in 5M x 13-5/8-in 10M – casing spool
    d. 13-5/8-in 7-5/8-in – casing hanger
    e. 13-5/8-in 10M x 13-5/8-in 10M DSA for Fiber Optic Line Exit
    f. 13-5/8-in 10M x 11-in 10M – tubing spool
    g. 11-in 10M x 2-9/16-in 10M Temporary Abandonment Cap + Valve with 11-in isolation busing assembly for vertical dual barrier isolation
8. Completion Injection Tree
    a. 11-in x 4-½-in – tubing hanger (FF1.5 trim, 410 Stainless Steel)
9. Production Tree
    a. 11-in x 4-1/16-in 10M – adapter spool (EE trim, Xylan Coated Internally)
    b. 4-1/16-in 10M, gate valve, manual (FF trim)
    c. 4-1/16-in 10M, gate valve, manual (EE trim, Xylan Coated Internally)
    d. 4-1/16-in X 5-1/8-in 10M flow cross with 4-1/16-in 10M pneumatic wing valve (EE trim, Xylan Coated Internally)
    e. 4-1/16-in 10M, gate valve, manual for crown with cap (EE trim, Xylan Coated Internally)
    f. See schematic for details (**Figure 3-7**)

A complete drilling and completion prognosis has been included in **Section 13 Appendix B**.

3.3 Detailed Discussion of Injection Well Design

The Facility is designed to inject a volume of 1.0 MMT/yr of CO_2 which translates to a yearly injection rate of approximately 54.5 million standard cubic ft per day (MMscf/d) at standard conditions. The source of the injectate will be gas processing facilities in the Midland Basin or Direct Air Capture facilities. **Table 3-1** shows the standard conditions of CO_2 which are used in the modeling and flow calculations.

Table 3-1: CO_2 Standard Conditions

CO_2 Mixture Standard Conditions				
Temperature deg-F	Pressure Psia	Density lbm/cuft	Z-Factor	Molecular Weight g/mol
60	14.696	0.1134	0.9942	42.786

An analysis was conducted on the tubing design utilizing various factors such as pipe friction losses, exit velocities, compression requirements, and economic evaluations. Using the results of a detailed nodal analysis, the tubing head injection pressure was determined. Simulation surface pressure outputs were used to identify the point during the project's lifespan when the maximum flowing pressure at the surface occurs. This information is used to properly design the casing, tubing, and wellhead configurations. The nodal analysis inflection point of both plots shows that a 4-½-in tubing was determined to be the appropriate tubing size necessary to move the desired volumes of supercritical CO_2 in this well based on the results from the model. The results also show that ~60 MMSCF/d is the maximum rate the 4-½" tubing can sustain without significant frictional losses.

The composition specifications for the CO_2 stream to be injected in Well are presented in **Table 3-2**. A specification is provided for maximum and minimum values of the gas stream as it may vary over the life of injection. Milestone will monitor the gas stream over time. See permit **Section 6** for information about injectate stream monitoring. For the purposes of modeling a gas composition consisting of 95% CO_2 was utilized.

Table 3-2: CO_2 Stream Composition Specifications

Composition	Composition Max/Min		Composition Used in Modeling Mole %
CO_2	>=	95 mol%	95.0%
Water	<	30 lb/MMscf	
H_2S	<	20 ppmv	0.02%
N_2	<	4 mol%	1.0%
Sulfur	<	35 ppmv	
O_2	<	10 ppmv	
Hydrocarbon	<	5 mol%	3.555% CH_4
Glycol	<	.3 gal/MMscf	
CO	<	4,250 mg/kg	0.425%
NOx	<	1 mg/kg	
SOx	<	1 mg/kg	
Particulates	<	1 mg/kg	
Amines	<	1 mg/kg	
H_2	<	1 mol%	
Hg	<	5 ng/l	
NH_3	<	50 mg/kg	
Ar	<	1 vol%	
Comp. Lube Oil	<	50 mg/kg	

Table 3-3 shows the calculated injection parameters from the tubing size evaluation based on the inputs described in **Table 3-1**:

Table 3-3: Calculated Injection Parameters

Location	Pressure	Temperature	Density	Phase
	PSI	deg-F	lb/ft3	
Pipeline Take Point	3,100	60	57.6	Liquid
Wellhead Surface Pressure	2,949	60	57.4	Liquid
Well Midpoint Midland CCS #2	5,149	131	53.2	Supercritical
Bottomhole Conditions Midland CCS #2, Midpoint Siluro-Devonian Injection Unit	6,741	188	50.8	Supercritical
Bottomhole Conditions Midland CCS #2, Midpoint Ellenburger Injection Unit	7,101	199	50.7	Supercritical

A 4-½-in tubing was determined to be the appropriate tubing size necessary to move the desired volumes of supercritical CO_2 in this well based on the results from the nodal analysis model. The model also verified that the CO_2 would remain in supercritical state (**Figure 3-3**) in the wellbore. The CO_2 is in a liquid state when it enters the wellbore but converts to supercritical state once the critical temperature is reached at approximately 2,000 feet below surface and continues to stay supercritical throughout the path of the wellbore as it is being injected. The change from liquid to supercritical has minimal changes in density and viscosity which are accounted for in the model.

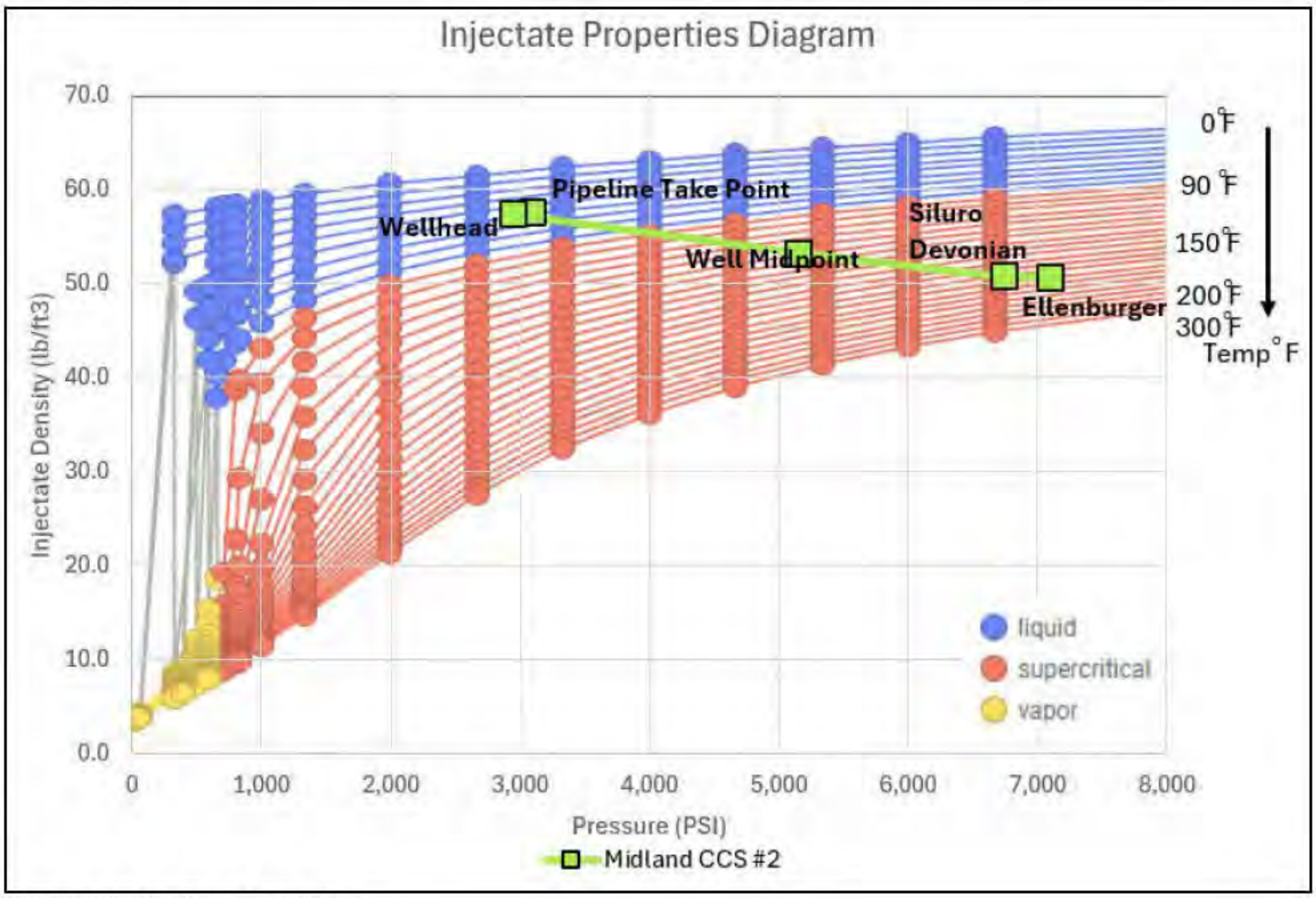


Figure 3-3: CO_2 Flow Conditions

3.3.1 Casing Summary

The Midland CCS #2 Well will use the following casing sizes and lengths (**Table 3-4**):

- 20-in conductor pipe drilled to 120 ft
- 17-½-in openhole with 13-3/8-in surface casing drilled to 1,300 ft
- 12-¼-in openhole with 10-¾-in intermediate casing drilled to 9,000 ft
- 9-½-in openhole with 7-5/8-in production casing drilled to 12,260 ft
- 6-1/8-in openhole drilled to 13,849 ft

Table 3-4: Casing Summary (CCS #2)

Casing String	Set Depth (ft)	Borehole Diameter (in)	Wall Thickness (in)	Outer Diameter (in)	Casing Weight (lb/ft)	String Weight (lbs)
Conductor (X-42, Welded)	120	20.000	0.750	20.000	78.6	9,432
Surface (J55, BTC)	1,300	17.500	0.760	13.375	54.5	70,850
Intermediate (P110HC, BTC)	9,000	12.250	0.450	10.750	51.0	459,000
Production (P110EC/25CRW, VAM 21/SFJ)	12,260	9.500	0.500	7.625	39.0	478,140

3.3.2 Conductor Pipe

Due to the loose and unconsolidated nature of the sediments found near the surface, a 20-in conductor pipe will be required down to a depth of 120 ft to maintain the integrity of the hole during initial drilling of the Well. This will be the outermost casing string. Tubular specifications for the conductor pipe are summarized and presented in **Table 3-5**:

Table 3-5: Conductor Pipe Specifications (CCS #2)

Conductor Pipe								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in)**	**Drift ID (in.)**
20", 78.6#, X-42, Welded	78.6	120	971,000	320	1,380	0.36	19.25	NA

3.3.3 Surface Casing

The surface casing section of the Well will be drilled and completed using 13-3/8-in casing, which will create enough annular space to securely cement the casing to surface. The surface hole will be drilled with casing set at 1,300 ft which exceeds the RRC minimum required depth of 100 ft below USDW measured from ground level. This casing string will provide two (2) barriers to prevent contamination of USDW during drilling operations. A cement bond logging tool will be used to evaluate the quality of cement bond and ensure surface casing was successfully set.

Tubular specifications for the surface casing are presented in **Tables 3-6: A** through **D.**

Table 3-6: A through D: Surface Casing Specifications (CCS #2)

A: Surface Casing								
Description	Casing Wt. (lb/ft)	Length (ft)	Tensile (1k lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
13-3/8", 54.5#, J55, BTC	54.5	1,300	853	1,130	2,740	0.1546	12.615	12.459

B: Annular Geometry			
Section	ID	MD	TVD
	(in)	(ft)	(ft)
Drive Pipe	19.25	120	120
Open Hole	17.5	1,300	1,300

C: Casing					
Section	OD	ID	Weight	MD	TVD
	(in)	(in)	(lb/ft)	(ft)	(ft)
Surface	13.375	12.615	54.5	1,300	1,300

D: Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(CF)
Lead	0	1,000	1,347
Tail	1,000	1,300	452

Table 3-7: Surface Casing Cement Calculations (CCS #2)

Volume Calculations				
Section	Footage	capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Drive Pipe/Casing Annulus Lead Cement	120	1.0454	0%	125
Openhole/Casing Annulus Lead Cement	880	0.6946	100%	1,222
Openhole/Casing Annulus Tail Cement	300	0.6946	100%	417
Shoe Track	40	0.8680	0%	35

To ensure cement returns to surface are achieved, 100% excess of openhole volumes were used.

3.3.4 Intermediate Casing

The intermediate casing section will be drilled and completed using 10-¾-in casing to provide sufficient annular space to securely cement the casing to surface. This casing string alone will provide an additional two (2) barriers to USDW during drilling operations. After the surface and intermediate casing are set, there will be four (4) barriers between the USDW and fluid in the wellbore. A cement bond logging tool will be used to evaluate the quality of cement bond and ensure intermediate casing was successfully set.

Tubular specifications for the intermediate casing are presented in **Tables 3-8** and **3-9.**

Table 3-8: A through D: Intermediate Casing Specifications (CCS #2)

A: Intermediate Casing								
Description	Casing Wt. (lb/ft)	Length (ft)	Tensile (1k lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
10-¾-in, 51#, P110HC, BTC	51.0	9,000	1,820	4,900	9,420	0.0943	9.850	9.694

B: Annular Geometry			
Section	ID	MD	TVD
	(in)	(ft)	(ft)
Surface Casing	12.615	1,300	1,300
Openhole	12.25	9,000	9,000

C: Casing					
Section	OD	ID	Weight	MD	TVD
	(in)	(in)	(lb/ft)	(ft)	(ft)
Intermediate	10.750	9.850	51.0	9,000	9,000

D: Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(CF)
Stage 2	0	4,500	1,092
Stage 1	4,500	9,000	1,149

Table 3-9: Intermediate Casing Cement Calculations (CCS #2)

Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Stage 2 Intermediate Casing/Casing Annulus Lead Cmt	1,300	0.2377	0%	309
Stage 2 Openhole/ 10-¾-in Casing Annulus Lead Cmt	2,700	0.1882	30%	661
Stage 2 Openhole/ 10-¾-in Casing Annulus Tail Cmt	500	0.1882	30%	122
Stage 1 Openhole/ 10-¾-in Casing Annulus Lead Cmt	4,000	0.1882	30%	979
Stage 1 Openhole/ 10-¾-in Casing Annulus Tail Cmt	500	0.1882	30%	122
Shoe Track	90	0.5292	0%	48

To ensure cement returns to surface are achieved, 30% excess of openhole volumes were used.

3.3.5 Production Casing

Production casing (long-string casing) runs from surface into the injection interval at 12,260 ft and is cemented to surface. After the surface, intermediate and production casing are set, there will be six (6) barriers between USDW and fluid in the wellbore. Design criteria of production casing include P-110EC material, 22CR/25CR material, acid resistant cement, and downhole tools such as centralizers, float equipment, galvanic crossover (X-O), and fiber optic cable (FOC).

A comprehensive metallurgical analysis, which considered the chemical composition of the CO_2 injectate and downhole conditions, was conducted and is included in **Section 13 Appendix A**. The analysis determined that the CO_2 injectate is not corrosive on its own. However, to protect against the potential of water from the reservoir entering the wellbore, and to guard against potential corrosion issues or failures, a subsurface safety valve will be installed just below the packer isolating the tubulars above. The safety valve and all tubulars below it will include 22CR/25CR material which was determined to be the appropriate metallurgy for downhole tubulars that will contact the injectate stream and reservoir fluids.

Acid resistant cement (**Section 3.3.11**) will be used to protect the cement sheath from degradation due to exposure to an acidic environment, thereby improving wellbore integrity and extending the lifespan of the well. As illustrated in **Figure 3-1**, corrosion resistant cement will be placed from approximately 500 ft above the top of the Top Seal, across the injection interval, to casing shoe. The entire cement column will be circulated to surface using a single-stage cement job.

Finally, an FOC will be installed with the production casing and cemented into place. The FOC will be used to record downhole temperatures in the injection intervals and tied into a SCADA system at surface.

To facilitate long-term monitoring, after plugging, the openhole section in abandoned injection intervals will remain open, below corrosion-resistant bridge plugs, for continuous monitoring of reservoir temperature and pressure. However, the lifetime of FOC is debatable and may not extend beyond 20 years. Milestone will follow all manufacturer guidelines and best practices regarding FOC installation and maintenance to extend the life of the FOC.

The wellbore will be designed with production casing including the following tubulars. 7-5/8-in P-110EC casing with premium connections from surface to 11,600 ft, a galvanic 7-5/8-in P-110 x 7-5/8-in 22CR/25CR crossover at 11,600 ft, and 7-5/8-in 22CR/25CR casing with premium connections from 11,600 ft to 12,260 ft. **Figure 3-1** illustrates the proposed wellbore schematic. Tubular specifications for the production casing are presented in **Tables 3-10** and **3-11**:

Table 3-10: A through D: Production Casing Specifications (CCS #2)

A: Production Casing								
Description	Casing Wt. (lb/ft)	Length (ft)	Tensile (1k lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
7-5/8-in, 39#, P-110EC, VAM 21	39.0	11,600	1,399	12,180	14,340	0.0426	6.625	6.500
7-5/8-in, 39#, 22CR/25CR-110, SFJ	39.0	660	1,399	12,180	14,340	0.0426	6.625	6.500

B: Annular Geometry			
Section	ID	MD	TVD
	(in)	(ft)	(ft)
Intermediate Casing	9.850	9,000	9,000
Openhole	9.50	12,260	12,260

C: Casing					
Section	OD	ID	Weight	MD	TVD
	(in)	(in)	(lb/ft)	(ft)	(ft)
Production	7.625	6.625	39.0	12,260	12,260

D: Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(CF)
Lead	0	11,900	2,501
Tail	11,600	12,260	172

Table 3-11: Production Casing Cement Calculations (CCS #2)

Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Production Casing/Intermediate Casing Annulus Lead Cement	9000	0.2121	0%	1,909
Production Openhole/7-5/8" x 9-½" Casing Annulus Lead Cement	2600	0.1751	30%	592
Production Openhole/7-5/8" x 9-½" Casing Annulus Tail Cement	660	0.1751	30%	150
Shoe Track	90	0.2394	0%	22

To ensure cement returns to surface are achieved, 30% excess of openhole volumes were used. The production casing will be installed using premium connections.

3.3.6 Centralizers

Centralizer selection and installation for the referenced well will have two (2) separate functions. The bow-spring centralizer design for the 13-3/8-in surface casing will be planned to protect any shallow aquifer zones per state regulations. The specific placement is also to ensure a continuous, uniform, column of cement is present throughout the 1,300 ft of 13-3/8-in x 17-½-in annular space. The recommended locations are:

(1) – Above Shoe Joint
(1) – Above Float Collar
(1) – Subsequent (5) joints of casing
(1) – Every 4th joint (160 ft) to surface
Total Centralizers – 13

The bow spring centralizer design for the 10-¾-in intermediate casing will be planned to ensure a continuous, uniform, column of cement is present throughout the 9,000 ft of 10-¾-in x 12- ¼-in annular space. The recommended locations are:

(1) – Above Shoe Joint
(1) – Above Float Collar
(1) – Subsequent (5) joints of casing
(1) – Every 4th joint (160 ft) to surface
Total Centralizers – 61

The selection and installation of centralizers for the 7-5/8-in production casing will consider the installation of the FOC. Both clamp centralizers and eccentric centralizers, made from the same material as the production casing, will be used to ensure the FOC are not damaged during the installation process.

1. Utilize two (2) eccentric centralizers (slide on) across a two (2) joint shoe track. Install cable clamp above top eccentric centralizer for cable security.
2. Install clamp centralizers every 160 ft or four (4) joints to surface, cable detection clamps every three (3) to four (4) joints.
3. Fiber module protectors every five (5) to six (6) joints.

3.3.7 Injection Tubing

As previously stated, the size of the injection tubing was chosen based on the injection volume, rate, and injectate composition. It is important to consider the injectate and the potential for a corrosive environment when selecting the material of the tubing, similar to the casing string. The injectate stream is expected to be dry and non-corrosive, but the design allows for the possibility of the invasion of connate water from the reservoir. A comprehensive summary of the metallurgical analysis is included in **Section 13 Appendix A** of this application. Considering the potential for the presence of carbonic acid in a mixture of water and CO_2, tubing made of 22CR/25CR material or equivalent is recommended below the safety valve. Since the safety valve will be closed any time injection is stopped, there will be no connate water from the reservoir above the safety valve and P-110 tubulars will be utilized above. Injection tubing specifications are presented in **Table 3-12**. Coatings also discussed below.

The tubing and production casing annulus will be filled with a corrosion inhibited fluid as approved by UIC Program Director, prior to setting the packer. The annular fluid will contain brine made up with CaCl, an oxygen scavenger, a corrosion inhibitor, and a biocide. Milestone may add additional chemicals to the annular fluid based on recommendations of vendors. The technology in this area is evolving rapidly and Milestone intends to use best in class annular fluids tailored to our injection wells.

During operation, positive pressure of +100 psi will be maintained and monitored on the annulus (see permit **Section 6.2** for additional notes on annular pressure).

Finally, a Tubing Encapsulated Cable (TEC) will be installed with the injection tubing. The TEC will contain pressure gauges installed just above the packer and will be used to record pressures in the injection stream inside the tubing as well as the annular pressure of the tubing and tied into a SCADA system at surface. The combination of these pressure values will aid in tubing leak detection.

Table 3-12: Injection Tubing Specifications (CCS #2)

Tubing								
Description	Casing Wt. (lb/ft)	Length (ft)	Tensile (1k lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
4-½", 15.1#, P-110, SLIJ-II	15.1	12,098	485	14,350	14,420	0.0149	3.826	3.701
4-½", 15.1#, 22CR/25CR-80, SFJ	15.1	172	250	11,090	10,480	0.0149	3.826	3.701

The tubing will be installed using semi-flush joint connections.

The 4.5" diameter, 15.1 lb/ft, P-110 injection tubing with VAM SLIJ-II couplings has sufficient axial strength and meets and/or exceeds the design tension safety factor of 1.4. The tension safety factor was analyzed using Halliburton's WellCat software and was evaluated for expected operating conditions and a worst case scenario using fully evacuated casing (tubing in air) at different overpulls of 0, 25,000, and 50,000 lbs. The axial strengths of the 4.5", 15.1 lb/ft, P-110 pipe body and the 4.5", 15.1 lb/ft, P-110 VAM SLIJ-II connections are 484,818 and 344,000 lbf, respectively. The lower value, corresponding to the strength of the connections, was used in the calculation of the safety factor. An expected maximum axial load of 235,247 lbf, corresponding to the fully evacuated, 50,000 lbf overpull scenario, results in a minimum calculated safety factor of 1.46. The axial load plot is shown in **Figure 3-4**. The Triaxial load plot for the tubulars is shown in **Figure 3-5**.

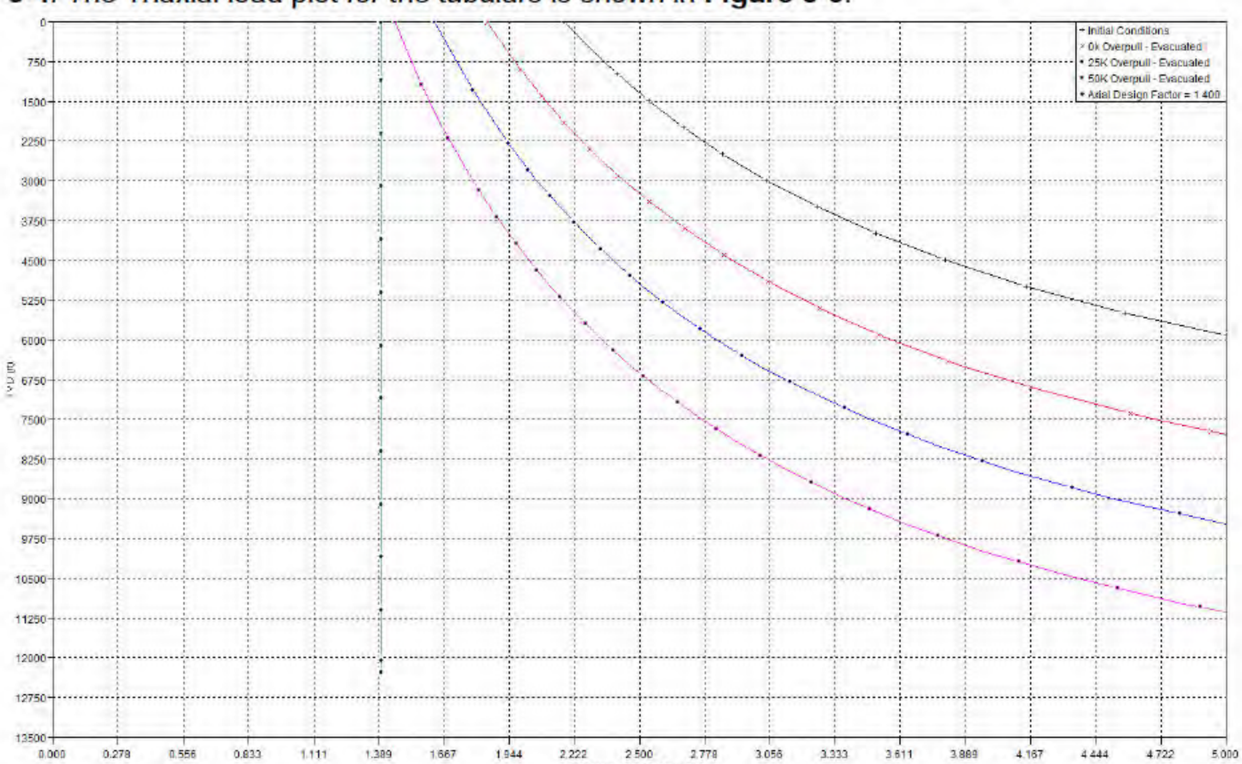


Figure 3-4: Axial Load and Safety Factor vs TVD (FT) for 4.5" Tubing

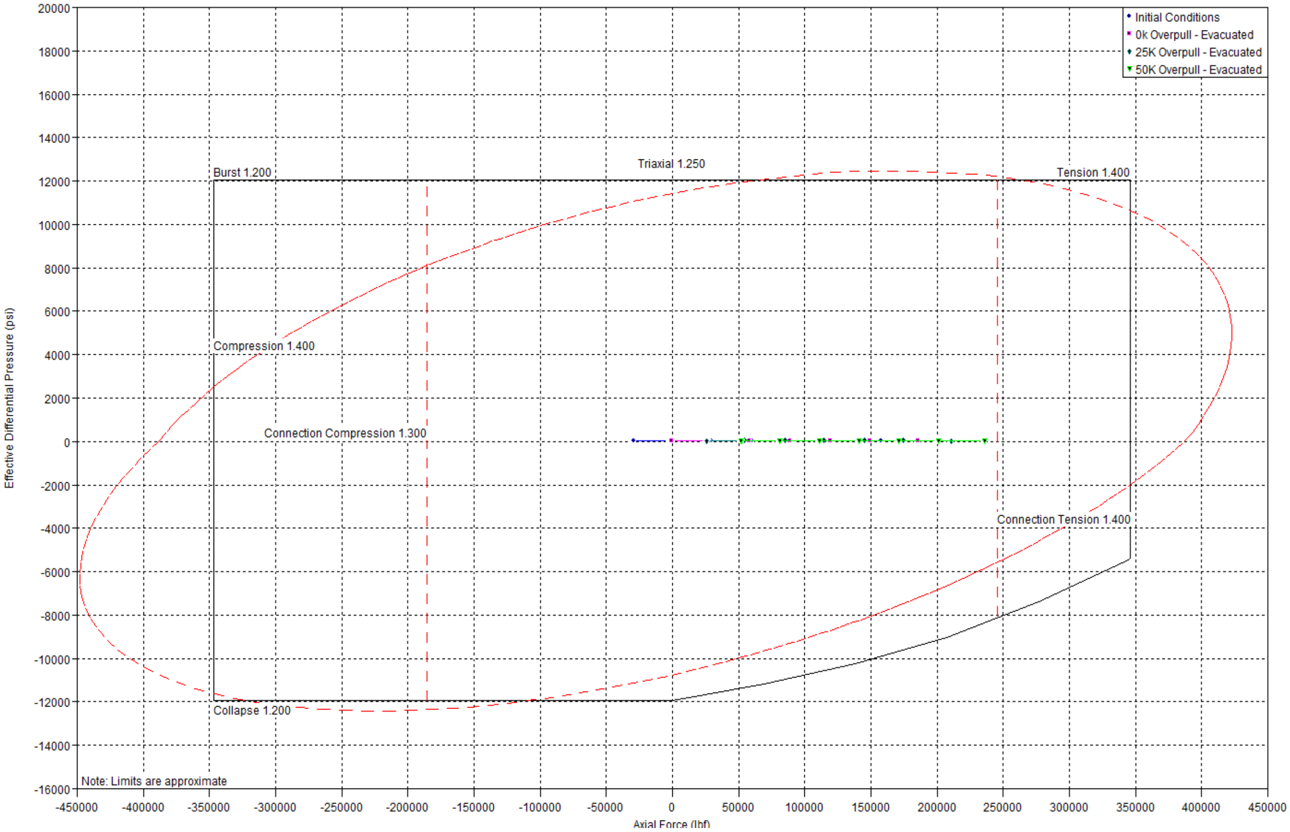


Figure 3-5: Triaxial Load Plot, Axial Load vs Effective Differential Pressure for 4.5" Tubing

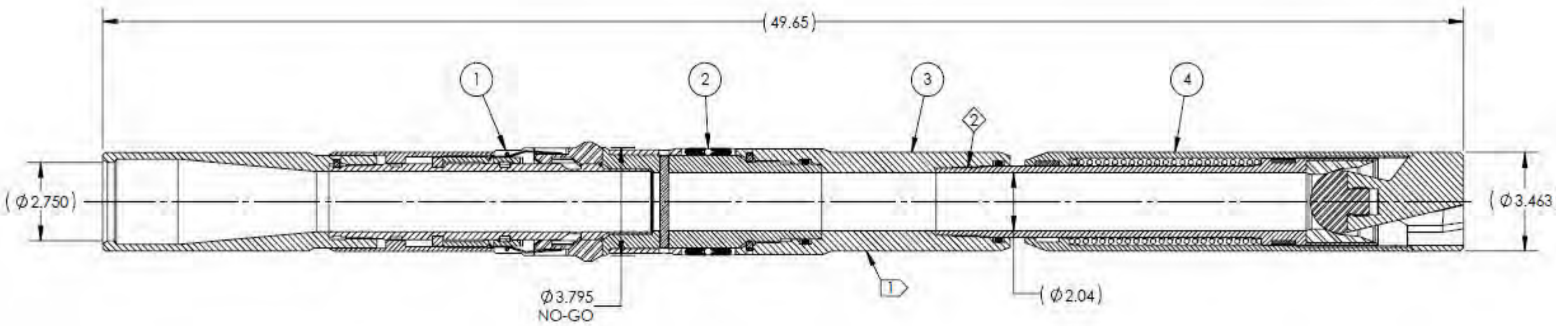
3.3.7.1 Tubular Coatings

Due to the possible presence of low concentrations of H_2S (<20 ppm) and also to mitigate corrosion from any potential CO_2 interactions, Milestone will coat the inside of the P-110 4.5" injection tubing with a H_2S and CO_2 resistant coating. Even though it is unlikely water will be able to migrate above the safety valve, this will form a secondary or backup method of mitigation for corrosion and also protect the tubulars from the low concentrations of H_2S. Milestone will apply a coating that has been proven effective through testing under conditions containing CO_2 and H_2S, consistent with the gas specifications outlined in **Table 3-2**. Milestone is currently evaluating NOV Tuboscope coatings such as TK7, TK15-XT and TK805. Milestone will apprise the UIC director of the final coating selection.

3.3.8 Safety Valve

A safety valve (**Figure 3-6**) will be installed in the 4-½-in tubing near the packer **(Figure 3-1)**. This valve will automatically close when injection is stopped and will aid in the running of logging and recompletion tools when necessary. If logging or recompletion tools need to be run below the valve, the valve can be removed via wireline. The valve is a variable orifice design controlled by flow rate and only opens when there is a positive injection flow rate and a differential pressure above the valve. The valve is validated to API-14L and consists of CRA materials. It has a 10,000-psi pressure rating. Additional engineering drawings and details are included as a supplemental attachment.

REV.	VECN#	DATE	APPROVED
D	01237	10/17/2023	MBJ



DIMENSIONAL AND ENGINEERING DATA	
FLOW AREA	3.27 SQ. IN.
MAX OD	3.800 IN.
OVERALL LENGTH	49.65 IN.
OPERATING DATA	
RATED WORKING PRESSURE (RWP)	10,000 PSI
MAXIMUM INTERMITTENT FLOW RATE (BBL/DAY)	30,000 BBL/DAY
FLOW WETTED MATERIAL	718, 925, TC
RATED TEMPERATURE RANGE	40° - 350°F
RUNNING TOOL ASSEMBLY	018905
PULLING TOOL ASSEMBLY	018927

ITEM NO.	QTY.	DESCRIPTION	TSN-BOM
1	1	4.500 X 3.750 F HIFLO LOCK ASSY	020586
2	1	4.500 X 3.750 HIFLO PACKING ASSEMBLY (FKM)	022277
3	1	4.500 X 3.750 HIFLO InjectGARD SPACER ASSY	022288
4	1	4.500 X 3.500 InjectGARD ASSY	018641

NOTES :

1. ETCH PART PER TSP - QA - 7.55
2. MASK BOTH ENDS OF THE VALVE SPRING CAVITY, GLASS BEAD PEEN THREADS PER TSP-001, AND MOLY-COAT THREADS PRIOR TO REMOVING THE MASKING MATERIAL FOR FINAL ASSEMBLY

Approved for Manufacture

O-RING DETAILS

45° X .01 TYP — 0° 5° TYP — 32 — R.015 TYP

UNLESS OTHERWISE SPECIFIED

TOLERANCE ON:

X.X	± 0.1	[2.5]
X.XX	± 0.01	[0.25]
X.XXX	± 0.005	[0.127]
ANGLES	± 0.5°	
ALL ROUNDS (MAX)	0.03	[0.76]
ALL FILLETS (MAX)	0.06	[1.52]
THD ENTRY	65-75°	
THD EXIT	30-45°	

ALL DIAMETERS TO BE WITHIN 0.010" T.I.R.
UNMARKED ANGLES TO BE 45°± 2°
REMOVE ALL BURRS AND SHARP EDGES .005 [0.127] MIN - .030 [0.76] MAX
MACHINED SURFACES 125 RMS

DIMENSIONAL LIMITS APPLY BEFORE PROCESSES. PARENTHETICAL INFO FOR REFERENCE ONLY. (X.XXX) INDICATES CRITICAL DIMENSION TO BE INSPECTED PER QSP W5.43-CC

	SIGNATURES	DATE
DRAWN:	MBJ	2023-06-01
CHECKED:	CB	2023-10-17
APPROVED:	MBJ	2023-10-17
WEIGHT:	81.4	LBS

THIRD ANGLE PROJECTION

DIMENSIONS IN INCHES [MM] — DO NOT SCALE DRAWING

Tejas

4.500 X 3.750 F
HiFLO InjectGARD ASSY

018950.D-D

SCALE 1:4 — SHEET: 1:2

DO NOT MANUFACTURE WITHOUT APPROVAL STAMP

PRINT STATUS: Revision Released

Figure 3-6: Safety Valve

3.3.9 Wellhead Discussion

The wellhead proposal should be designed to combat working pressures (**Figure 3-7**). The wellhead equipment will be manufactured with a combination of alloy steel internally Xylan coated, stainless-steel and Inconel components across the hanger, casing spool, trims, stems, gates, valves, etc. The wellhead is designed with a 10,000-psi working pressure rating, FF1.5 trim tubing hanger and FF trim lower master valve, and EE trim production tree with internal Xylan coating. The wellhead equipment will contain wing valves that can be automatically controlled to shut the well in when a tubing leak is detected. Additionally, the production tree and master valve are sized to provide unrestricted access to the 4-½-in completion. Additional engineering drawings are included as a supplemental attachment.

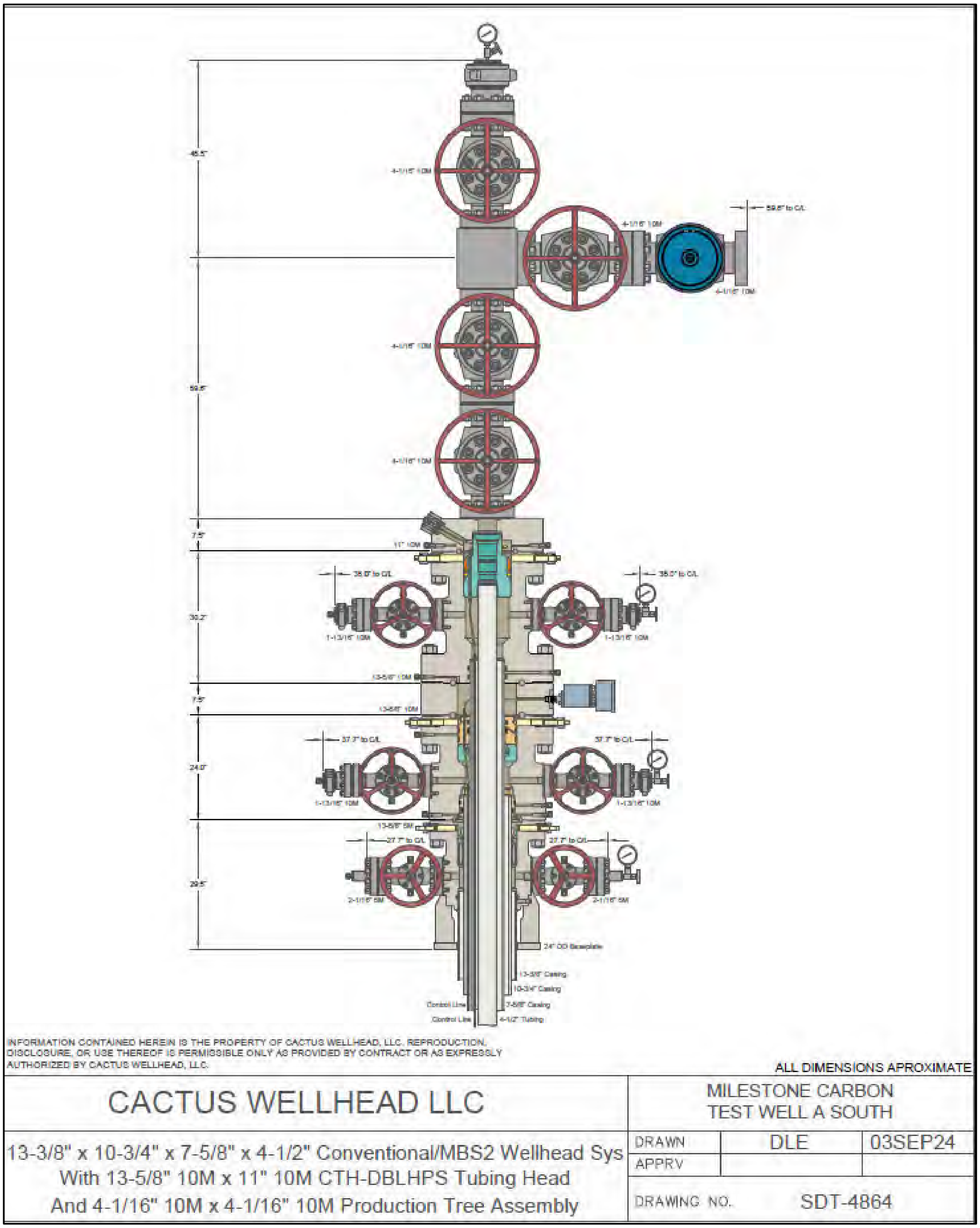
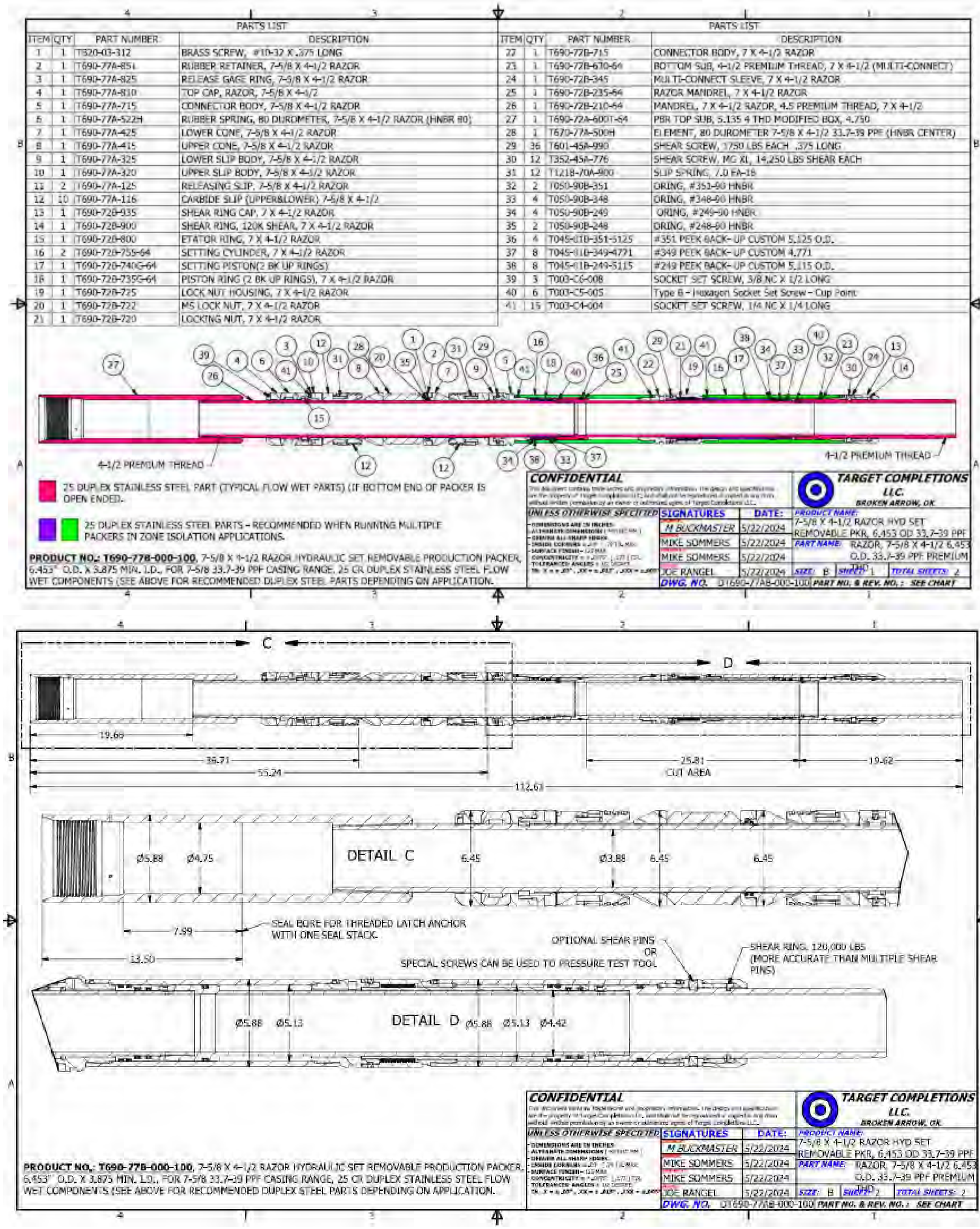


Figure 3-7: Midland CCS #2 Well Preliminary Wellhead Design

3.3.10 Packer Discussion

The production tubing will be run into the well with a 4-½-in x 7-5/8-in 22CR/25CR or equivalent permanent packer with premium connections (**Figure 3-8**). A more detailed schematic of the completion including the packer and safety valve can be seen in **Figure 3-9.**



PARTS LIST

ITEM	QTY	PART NUMBER	DESCRIPTION
1	1	T520-03-312	BRASS SCREW, #10-32 X .375 LONG
2	1	T690-77A-851	RUBBER RETAINER, 7-5/8 X 4-1/2 RAZOR
3	1	T690-77A-825	RELEASE GAGE RING, 7-5/8 X 4-1/2 RAZOR
4	1	T690-77A-810	TOP CAP, RAZOR, 7-5/8 X 4-1/2
5	1	T690-77A-715	CONNECTOR BODY, 7-5/8 X 4-1/2 RAZOR
6	1	T690-77A-522H	RUBBER SPRING, 80 DUROMETER, 7-5/8 X 4-1/2 RAZOR (HNBR 80)
7	1	T690-77A-425	LOWER CONE, 7-5/8 X 4-1/2 RAZOR
8	1	T690-77A-415	UPPER CONE, 7-5/8 X 4-1/2 RAZOR
9	1	T690-77A-325	LOWER SLIP BODY, 7-5/8 X 4-1/2 RAZOR
10	1	T690-77A-320	UPPER SLIP BODY, 7-5/8 X 4-1/2 RAZOR
11	2	T690-77A-125	RELEASING SLIP, 7-5/8 X 4-1/2 RAZOR
12	10	T690-77A-116	CARBIDE SLIP (UPPER&LOWER) 7-5/8 X 4-1/2
13	1	T690-72B-935	SHEAR RING CAP, 7 X 4-1/2 RAZOR
14	1	T690-72B-900	SHEAR RING, 120K SHEAR, 7 X 4-1/2 RAZOR
15	1	T690-72B-800	ETATOR RING, 7 X 4-1/2 RAZOR
16	2	T690-72B-755-64	SETTING CYLINDER, 7 X 4-1/2 RAZOR
17	1	T690-72B-740G-64	SETTING PISTON(2 BK UP RINGS)
18	1	T690-72B-735G-64	PISTON RING (2 BK UP RINGS), 7 X 4-1/2 RAZOR
19	1	T690-72B-725	LOCK NUT HOUSING, 7 X 4-1/2 RAZOR
20	1	T690-72B-722	MS LOCK NUT, 7 X 4-1/2 RAZOR
21	1	T690-72B-720	LOCKING NUT, 7 X 4-1/2 RAZOR
22	1	T690-72B-715	CONNECTOR BODY, 7 X 4-1/2 RAZOR
23	1	T690-72B-670-64	BOTTOM SUB, 4-1/2 PREMIUM THREAD, 7 X 4-1/2 (MULTI-CONNECT)
24	1	T690-72B-345	MULTI-CONNECT SLEEVE, 7 X 4-1/2 RAZOR
25	1	T690-72B-235-64	RAZOR MANDREL, 7 X 4-1/2 RAZOR
26	1	T690-72B-210-64	MANDREL, 7 X 4-1/2 RAZOR, 4.5 PREMIUM THREAD, 7 X 4-1/2
27	1	T690-72A-600T-64	PBR TOP SUB, 5.135 4 THD MODIFIED BOX, 4.750
28	1	T670-77A-500H	ELEMENT, 80 DUROMETER 7-5/8 X 4-1/2 33.7-39 PPF (HNBR CENTER)
29	36	T601-45A-990	SHEAR SCREW, 1750 LBS EACH .375 LONG
30	12	T352-45A-776	SHEAR SCREW, MG XL, 14,250 LBS SHEAR EACH
31	12	T1218-70A-900	SLIP SPRING, 7.0 FA-18
32	2	T050-90B-351	ORING, #351-90 HNBR
33	4	T050-90B-348	ORING, #348-90 HNBR
34	4	T050-90B-249	ORING, #249-90 HNBR
35	2	T050-90B-248	ORING, #248-90 HNBR
36	4	T045-01B-351-5125	#351 PEEK BACK-UP CUSTOM 5.125 O.D.
37	8	T045-01B-349-4771	#349 PEEK BACK-UP CUSTOM 4.771
38	8	T045-01B-249-5115	#249 PEEK BACK-UP CUSTOM 5.115 O.D.
39	3	T003-C6-008	SOCKET SET SCREW, 3/8 NC X 1/2 LONG
40	6	T003-C5-005	Type B - Hexagon Socket Set Screw - Cup Point
41	15	T003-C4-004	SOCKET SET SCREW, 1/4 NC X 1/4 LONG

Figure 3-8: Seal Assembly, 4-½-in x 7-5/8-in Permanent Packer

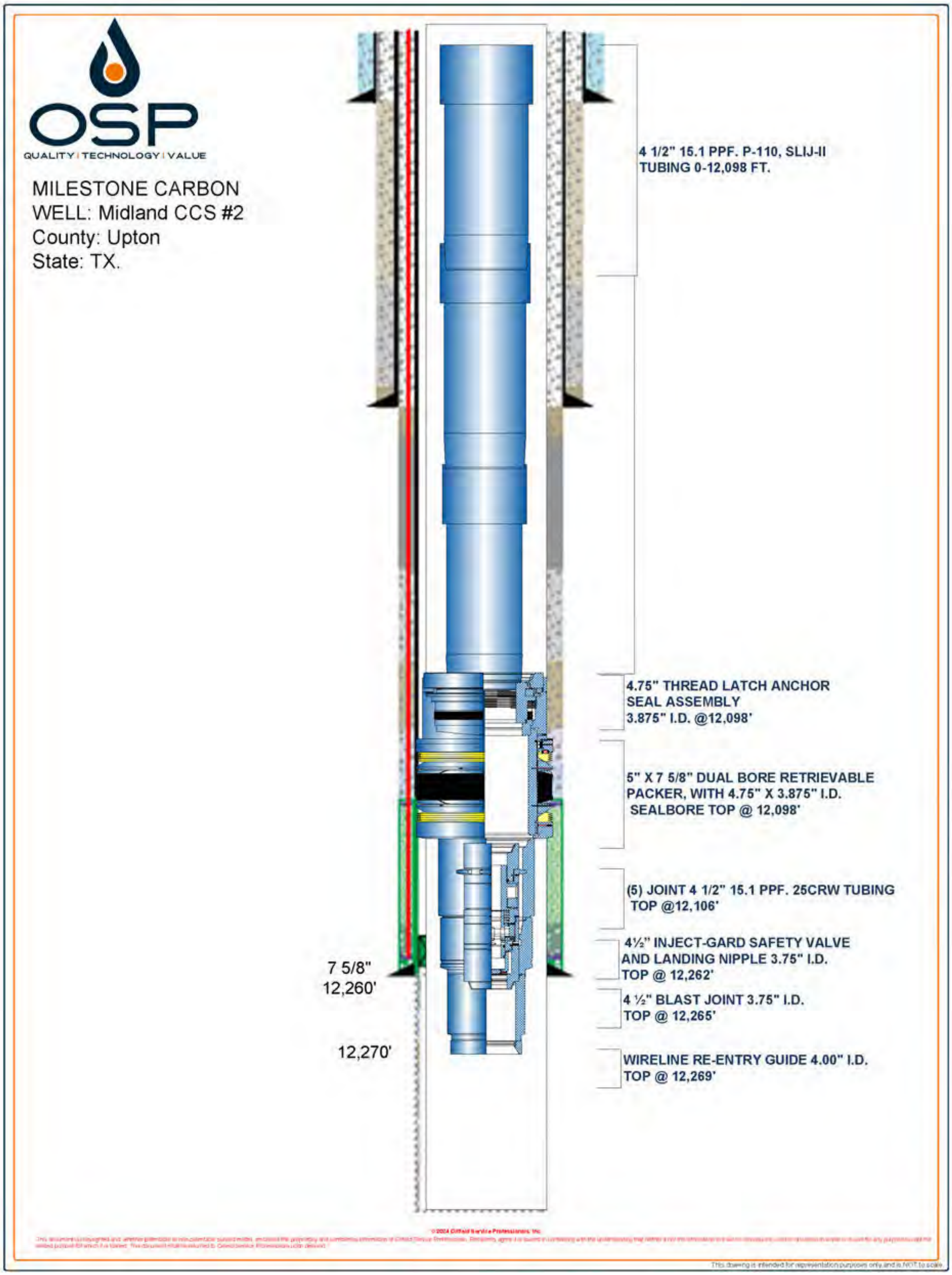


Figure 3-9: Injection Well Completion Schematic

3.3.11 Cement Discussion

Milestone will use corrosion resistant cement over any intervals that might contact injectate and formation brine in the Midland CCS #2 and Midland IZM #2. These include the Top Seal and the Injection Interval. Formations above the top-seal will use Portland cement as they are unlikely to contact corrosive fluids. No corrosive resistant cement will be utilized in wells that only penetrate the local aquifers I.E. the USDW or NSSW wells (**Figures 3-1** and **3-11**).

Milestone is currently evaluating CO_2 resistant cement from the industry's leading suppliers, Halliburton and SLB. ThermaLock is an option from Halliburton. EverCrete and Ecoshield are two (2) options from SLB. All the cement solutions have been thoroughly tested and are designed to maintain reliable corrosion resistant properties throughout the life of an injection or monitoring well exposed to CO_2. The products listed above are all rated for the temperature and pressure ranges of the injection and monitoring wells. They will provide long lasting zonal isolation.

ThermaLock is a non-Portland based cement that is a specially formulated calcium aluminate phosphate system which gives it resistant properties to CO_2 corrosion.

Evercrete has long been the reliable workhorse for CO_2 injection wells. Its low permeability allows it to withstand corrosive effects of supercritical CO_2 and has self-healing properties if a fracture is formed. **Figure 3-10** illustrates the compressive strength of Evercrete compared to Portland Cement when exposed to CO_2 and brine or carbonic acid over time. Ecoshield is a geopolymer cement free system that provides an alternative to Portland cement while delivering comparable performance. EcoShield system matches the rheology, thickening time, and compressive strength properties of Portland cement-based systems. The technology fits within standard oilfield cementing workflows without major changes to the design process, onsite execution, or post-job evaluation.

This is an evolving science, and Milestone will continue evaluating the most suitable corrosion resistant cement product for the proposed well construction. Cement and cement additives will be compatible with the injectate stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.

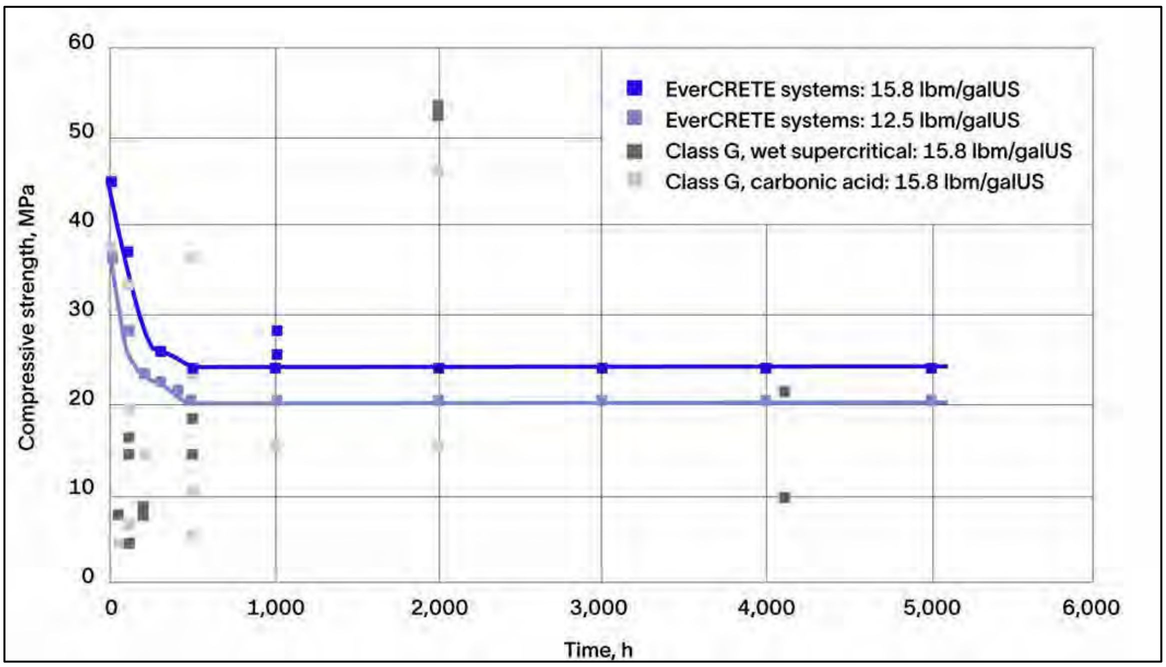


Figure 3-10: Comparison of Evercrete Compressive Strength
Evercrete(Blue) vs Portland Cement (Grey) over time when exposed to Supercritical CO2 and Brine or Carbonic Acid

3.4 In-Zone Monitoring Well

Milestone intends to drill and complete an in-zone monitoring well, Midland IZM #2, to monitor the injection zone in the Devonian and Ellenburger Formations and monitor above the Top Seal in the Pennsylvanian section. The well will utilize three (3) U-tube fluid sampling systems. One (1) in the first permeable zone above the Top Seal, likely the Strawn, one (1) in the Devonian, and one (1) in the Ellenburger group and completed with fiber optic cables. The Midland IZM #2 will be positioned approximately 3,500 feet southeast of the Injection Well. Location information can be found in **Section 1.** This well will be drilled into the injection interval; therefore, it will require corrosion-resistant materials for construction. The proposed design for Midland IZM #2 is depicted in **Figure 3-11**. See permit **Section 6** for additional information on Fiber Optic Cables. The Midland IZM #2 is currently not planned to be perforated as all testing will be performed via u-tubes or indirect methods through casing.

3.4.1 General Outline of In-Zone Well Design and Completion Schematic

Midland IZM #2 was designed with the following specifications:

1. Conductor Pipe
    a. Size: 20-in
    b. Depth: 120 ft
2. Surface Casing
    a. To be set below the lowermost USDW
        i. Currently estimated setting depth: 1,300 ft
            1. Based on offset GAU Determination letters (**Section 13, Appendix I**) issued by the RRC.
            2. Base of USDW located at 1,250 ft
    b. 13-3/8-in casing set at 1,300 ft
    c. J-55 grade tubulars
    d. 17-½-in hole size
    e. Cement to surface
3. Intermediate Casing
    a. 9-5/8-in casing set at 9,000 ft
    b. L80 grade tubulars
    c. 12-¼-in hole size
    d. Cement to surface
        i. DV Tool set at ~4,100 ft
4. Production Casing
    a. 4-½-in casing set at 13,785 ft
    b. L80 grade tubulars to 11,600 ft
    c. 25CRW or equivalent to 13,785 ft
    d. 7-7/8-in hole size
    e. Cement to surface
        i. Cement to be comprised of the following make-up:
            1. From surface to ~500 ft above the top seal – (light weight acid resistant cement)
            2. From ~500 ft above the top seal, throughout the injection interval, to shoe – (acid resistant cement)

MILESTONE CARBON

Casing Program

Well Name:	Midland IZM #2
API:	
UIC:	
State:	TX
County:	Upton
Field:	Midland
Lease:	Dusek
Elevation:	2,796'
Depth (TVD):	13,785'
Texas Central NAD 83	
Lattitude:	31.608086°
Longitude:	-101.983038°

		OD (in)	Weight (lb/ft)	Grade	Connection	ID (in)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1	Surface:	13 3/8	54.5	J-55	BTC	12.615	17 1/2	0	1,300	0
2	Intermediate:	9 5/8	53.5	L80	VAM 21	8.583	12 1/4	0	9,000	0
3	Production:	4 1/2	15.1	L80	SLIJ-II	3.826	7 7/8	0	11,600	0
4				25CRW	SFJ			11,600	13,785	11,600

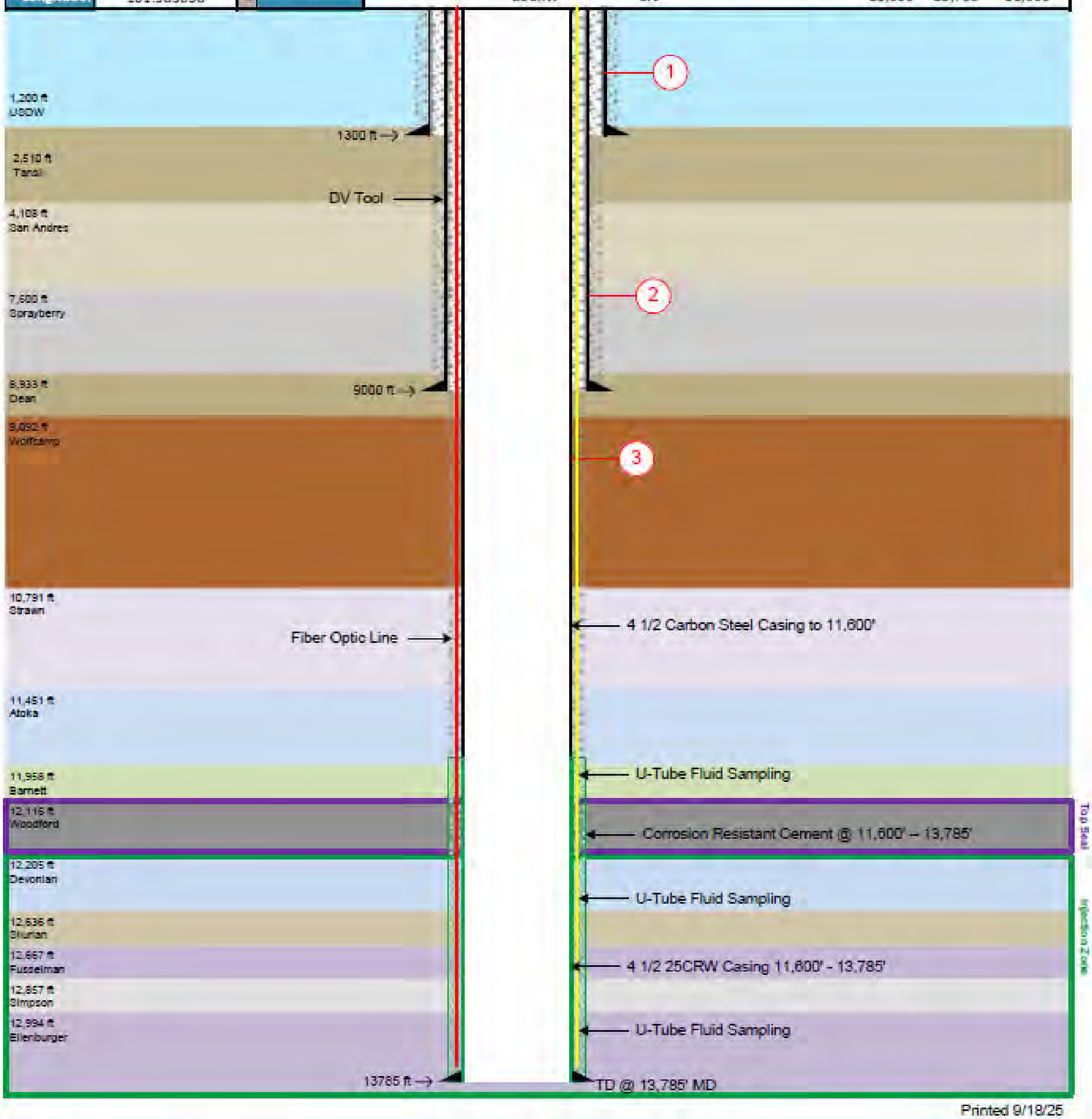


Figure 3-11: Midland IZM #2 Wellbore Schematic

3.5 USDW Monitor Well Design

Milestone intends to drill and complete one (1) USDW monitoring well, Midland USDW #2, to monitor the lowermost USDW intervals, the base of the Dockum aquifer. The Midland USDW #2 well will be positioned within 1,000 ft laterally of the Midland CCS #2 injection well and will monitor for signs of CO_2 escaping from the confinement zone and traveling up into the USDW. This well will not be drilled into the Top Seal; therefore, it will not require acid-resistant materials for construction. The well location may change pending results of hydrogeologic testing. Milestone intends to drill it updip of the injection well in the most likely path of a potential leak. The proposed design for Midland USDW #1 is depicted in **Figure 3-12**. The updip direction based on literature and testing is southwest from the proposed Midland CCS #2 injection well. This will be confirmed after drilling the NSSW wells. The proposed location of Midland USDW #1 is found in **Section 1**.

Well Name:	Midland USDW #2
County:	Upton
State:	TX
Depth (TVD):	1,300

Casing Program

		OD (in)	Weight (lb/ft)	Grade	Connection	ID (in)	Drift (in)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1	Surface:	5 1/2	14	J-55	BTC	5.012	4.887	7 7/8	0	1,300	0

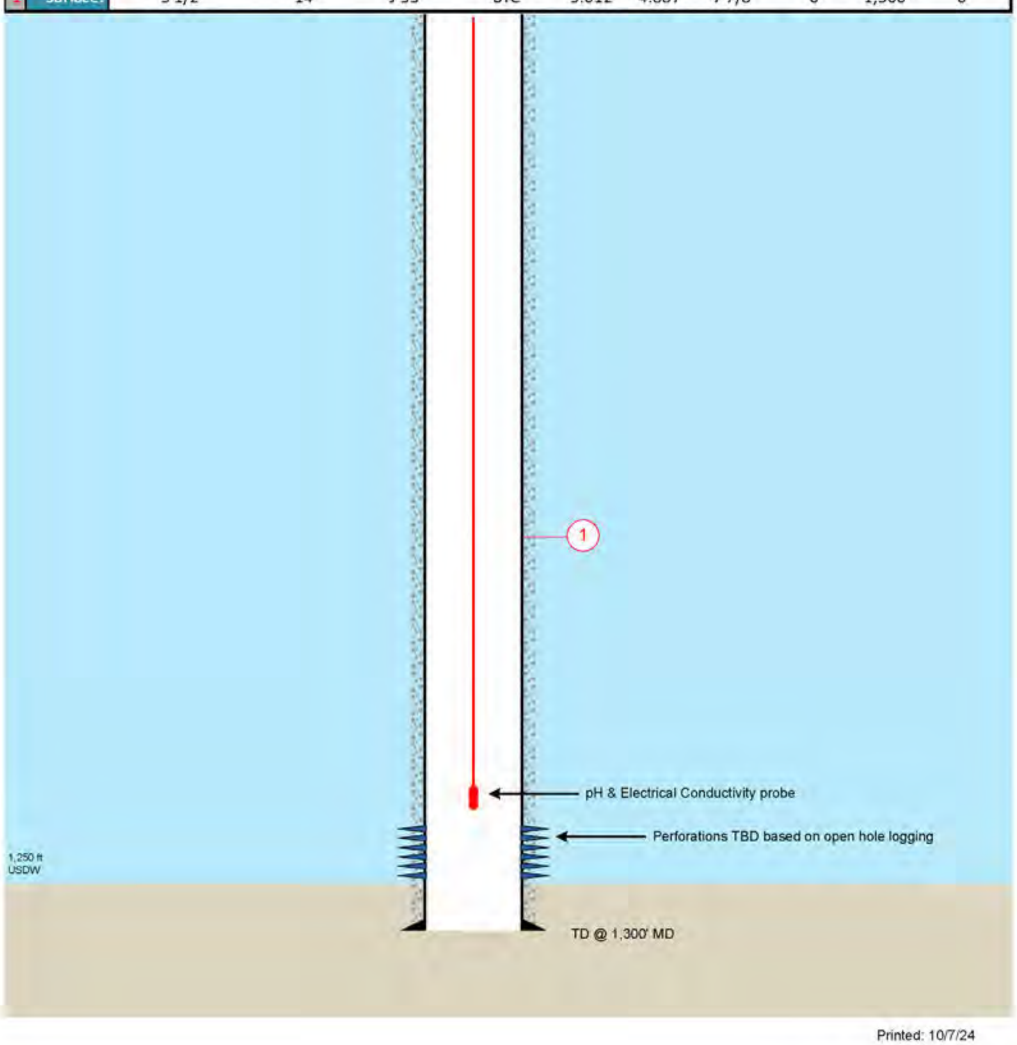


Figure 3-12: Midland USDW #2 Wellbore Schematic

3.6 Near Surface Seismometer (NSSW) Monitor Wells

Milestone intends to drill, and complete, five (5) shallow water monitoring wells with Near Surface Seismometer wells (NSSW), described further in permit **Section 6.5.2** and illustrated in **Figure 3-13**. The total depth (TD) of each well is expected to be approximately 300 feet, determined by the base of the Edwards-Trinity (Plateau) aquifer. The hole size of each NSSW will be 6-in and will contain two (2) 1.4-in PVC cementation pipes, one (1) 0.6-in seismic sensor line, one (1) 1.85-in water probe sensor, and one (1) 2-in PVC casing. The water quality probe will be set at a depth determined by logs in a slotted screen, illustrated in **Figure 3-13**. The seismometer will be cemented in place at the bottom of the well to enhance coupling with the bedrock. Baker Hughes, or equivalent, service provider will be utilized.

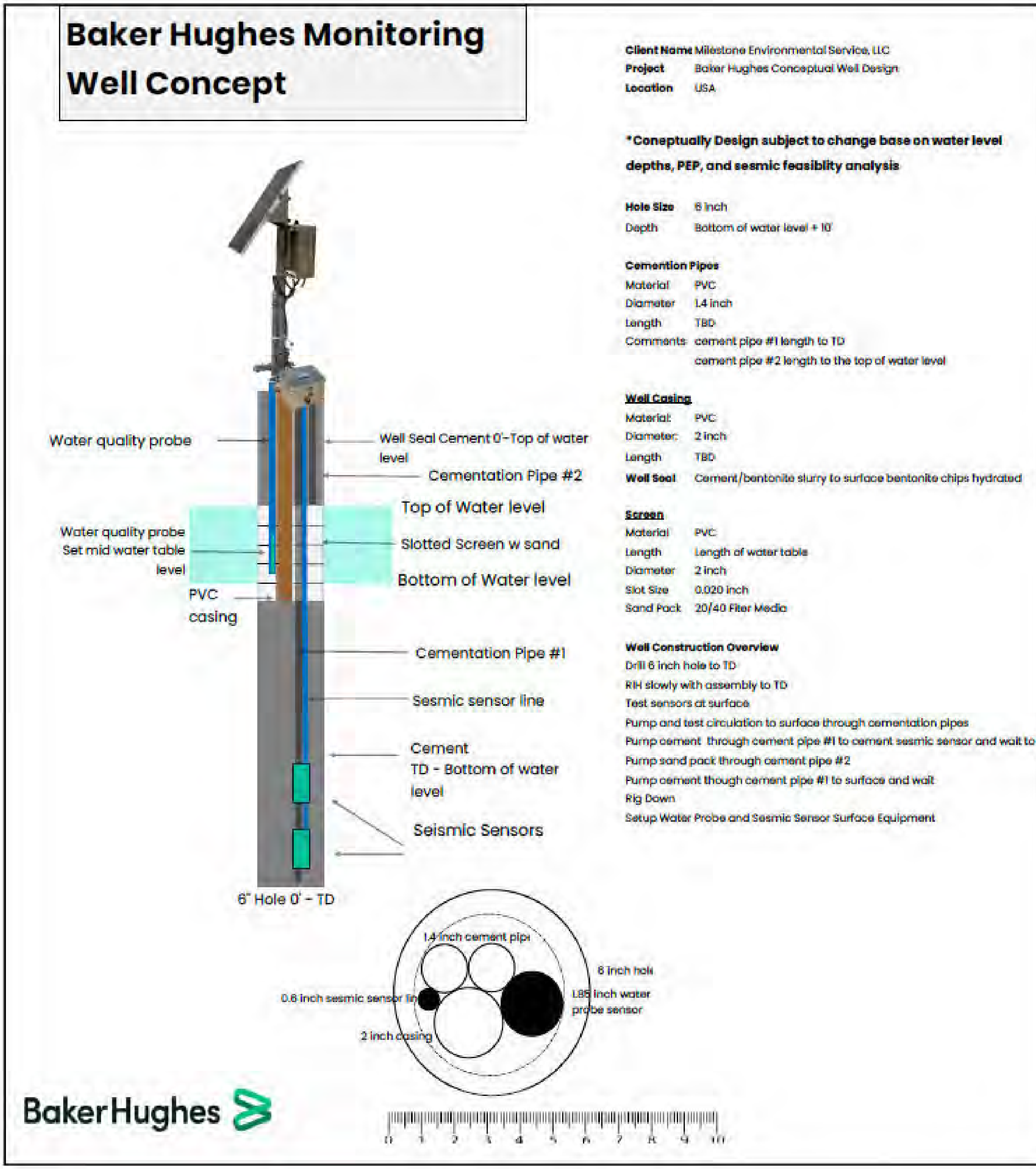


Figure 3-13: Midland NSSW Water Monitoring Wells

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Section 4: Operational Strategy

[40 CFR §146.82, §146.86, §146.87]

Prepared for:

EPA Region 6

Underground Injection Control Section

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Prepared and submitted by:

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Prepared by

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Updated 18 October 2024

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4.0 OPERATIONAL STRATEGY [40 CFR 146.82(a)(7), (a)(8), (10), (11), (12) 146.86, 146.87]

Milestone's permit **Section 3** describes the engineering design details, and **Section 4** includes operational strategies employed during the planning of the Midland CCS #2 Injection Well proposed by Milestone.

4.1 Injection Well Operating Strategy

Injection is planned for an average of 1.0 MMt/yr of CO_2, which will remain in the supercritical state through the entirety of the project. **Table 4-1** summarizes the maximum wellhead and bottomhole pressures. See relevant modeling figures in **Section 2** for additional information on expected pressure increases. After the commissioning period is complete (**Section 4.2**), the injection strategy is to inject into the openhole portion of the Midland CCS #2 Well for 12 years at 54,526,360.6 standard cubic feet per day (SCF/D). This gas volume and rate is equivalent to 1 million metric tons of CO_2 per year.

Milestone proposes the project be limited to 1 million metric tons of CO_2 per year. However, given that there may be days with downtime due to maintenance or monitoring activities, the daily injection rate may be variable. The maximum allowable rate should be slightly higher than the modeled rate of 54.5 MMscf/d. Milestone proposes a maximum rate of 60 MMscf/d assuming the maximum allowable surface and bottomhole pressures are not exceeded, and the annular pressure is increased to compensate for the increase in tubing pressure. This rate aligns with specifications of the tubing.

Bottomhole pressure will not exceed 90% of the fracture pressure of the injection interval, which will limit surface injection pressure. The anticipated bottomhole injection pressure (BHIP), frac gradient with 90% safety factor and injection rate plot over time is 7,875 psi as shown in **Table 4-1**.

Values in **Table 4-1** are the proposed operating parameters for the Midland CCS #2 injection well. Average pressure values are likely to be adjusted once the test well is drilled. Maximum pressure and rate values are not expected to change substantially since they are linked to the fracture gradient and pipe size constraints. However, the fracture gradient may change pending pre-operational testing results.

Milestone will perform any manufacturer recommended maintenance to coincide with the schedule of monitoring activities in **Section 6** to limit downtime.

Table 4-1: Proposed Operational Procedures

Parameters / Conditions	Limit or Permitted Value
Maximum Injection Pressure	
Surface (Wellhead)	4000 psi
Bottomhole- Top of Siluro-Devonian (90% of Frac Gradient)	7,875 psi
Average Injection Pressure	
Surface (Wellhead)	2,949 psi
Bottomhole	7,311 psi
Maximum Injection Rate	3,086 tonnes/day, 60 MMscf/d
Average Injection Rate	2,740 tonnes/day, 54.5 MMscf/d
Maximum Injection Mass	1 MMt (per year)
Average Injection Mass	1 MMt (per year)
Average Annulus Pressure	3,049 psi
Annulus Pressure / Tubing Differential	+100 psi

Table 4-2: Injection Intervals

Completion Unit	Completion Timing	Injection Duration (years)	Top of Interval (TVD ft)	Bottom of Interval (TVD ft)	Net Pay (ft)
Siluro-Devonian and Ellenburger	Year 2027	12	12,200	13,849	1,649

4.2 Commissioning Period

Milestone will not immediately achieve full injection rates. There will be a 90-day commissioning period where rates will be increased gradually at approximately 4.5 MMSCFD per week. This will be performed to:

- Test the surface infrastructure gradually
- Alleviate any initial relative permeability effects in the reservoir
- Fully understand pressure response at different rates.

The first monitoring report, submitted to the UIC Director, will include data on the commissioning period in addition to other normal monitoring data.

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Section 5: Pre-Operational Testing Program

[40 CFR §146.82(c)]

Prepared for:

EPA Region 6

Underground Injection Control Section

1201 Elm Street, Suite 500 | Dallas, Texas 75270

Prepared and submitted by:

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Updated 18 October 2024

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5.0 PRE-OPERATIONAL TESTING PROGRAM [40 CFR 146.82(c)]

Section 5 features the pre-operational testing to be undertaken by Milestone prior to commencing injection. Permit **Section 6** details monitoring activities to be performed after injection commences. Testing in this section is meant to act as a baseline for all subsequent monitoring activities.

During, and prior to, the drilling and construction of the Class VI injection wells, Milestone will run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared.

5.1 Initial Reporting Requirements

Per 40 CFR 146.87(a), within six (6) months after completion of drilling operations of any wells that penetrate the injection interval, Milestone will submit to the UIC Director a descriptive report prepared by a knowledgeable, experienced log analyst, or petrophysicist, that includes an interpretation of the results of logs, core analysis, water testing, seismicity, and any additional tests required by the Director.

Milestone will provide the Director with the opportunity to witness all logging and testing. Milestone will submit a schedule of such activities to the Director 30 days prior to conducting the first test, and if necessary, submit any changes to the schedule 30 days prior to the next scheduled test.

5.2 Initial Near Surface Water Testing

Milestone will install five (5) near-surface water sampling stations (NSSW Wells) designed to monitor water quality in the Edwards-Trinity (Plateau) aquifer. These will be installed before drilling commences. Milestone will test the water at each station at least twice in the six months preceding drilling operations and then at least once before injection commences. Water testing will follow the procedures presented in **Table 5-1** and permit **Section 13 Appendix C-QASP**. Locations of NSSW wells are located in permit **Section 1**.

Table 5-1: Pre-Operational Near Surface Water Testing Matrix

Parameter	Analytical Methods
Dissolved CO_2	Coulometric Titration, ASTM D513-11
Total dissolved solids	Gravimetry, APHA 2540C
pH (field)	EPA 150.1
Specific conductivity (SC) (field)	APHA 2510
Temperature	Thermocouple
Water Density	Oscillating body method
Cations – Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020
Cations – Ca, Fe, K, Mg, Na and Si	ICP-OES, EPA Method 6010B
Anions – Br, Cl, F, NO_3, HCO_3 and SO_4	Ion Chromatography, EPA Method 300.0
δ 2H and δ 18O isotope analysis	Isotope ratio mass spectrometry
δ13 C dissolved inorganic carbon	Isotope ratio mass spectrometry
Alkalinity	APHA 2320B

5.2.1 Sampling and Analytical Methods

Fluid samples in NSSW Monitoring Wells will be collected at the monitored formation temperatures and maintained at the formation pressures within a pressurized sample container to prevent any losses of dissolved gases. Prior to sampling, the well will be purged of any fluid stored in the wellbore. Static fluid level and temperature will be measured prior to purging the well. A U-tube sampling system will be lowered to the monitored zone via wireline or slickline and the rate of sample collection should not exceed the rate at which the well was purged.

Water samples will be tested, and the results maintained for the parameters listed above. If any impurities exist in the injectate, they should also be tested within the groundwater samples to detect any concentrations beyond the baseline. Results from the samples will be maintained in an electronic database. All samples will be individually numbered, and EPA/TCEQ best practices will be used.

5.2.2 Laboratory Chain of Custody Procedures

Water samples will be sent to a third-party commercial water testing laboratory. Standard chain-of-custody procedures will be followed, and records will be maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

5.3 Testing and Logging During Drilling and Completion Operations

5.3.1 Ancillary Testing during Drilling Operations Prior to TD

Table 5-2 reflects tests and logs that will be conducted during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a) and (c).

Per 40 CFR 146.87 (a)(1), deviation measurements will be conducted approximately every 100 ft during construction of the well using a gyro tool or similar device. Azimuth, inclination, offset, measured depth (MD) and TVD will be reported. Additionally, deviation will subsequently be sampled at 0.5-ft increments during wireline logging using the orientation tool in the image log.

Experienced mudloggers will be on location to take samples at approximately every 500 ft above the top seal and approximately every 20 ft in the top seal and injection units. C1-C5 gas, H_2, He, CO_2, N_2 and H_2S measurements will also be obtained as part of the mud logging. Isotubes® of gas samples will be acquired and retained for later isotopic and chemical testing to verify geologic seals.

Measurement while drilling (MWD) gamma ray measurements will be obtained during drilling operations to aid in offset well correlation. This measurement data will also be indispensable for determining core point.

Table 5-2: Ancillary Testing During Drilling Operations
Not including Wireline and Coring

Ancillary Testing	Main Objective
Mud Logging	Take physical samples of Rock while Drilling, early warning of changes in thickness or lithology
Gas Chromatography	Measure mud gas, Hydrocarbons and Inert gasses, Samples will be preserved in isotubes®
Deviation Measurements	Measure inclination, azimuth, and TVD of well
MWD gamma ray	Validate offset well correlation of formation tops

5.3.2 Wireline Logging Program

Per 40 CFR 146.87(a)(2)(i) and 40 CFR 146.87(a)(3)(i), before casing is installed, openhole log data will be acquired reflecting in-situ, structural, stratigraphic, physical, chemical, and geomechanical information for 1) the Woodford shale top-seal, 2) the Siluro-Devonian and Ellenburger injection units and, 3) other zones of interest above or within the injection and confining units/intervals.

Wireline conveyed openhole logs will be acquired at the surface casing point, intermediate casing points, and production casing point. Openhole logs will not be acquired in the conductor casing hole.

Milestone will log the Midland CCS #2 and Midland IZM #2 wells. There are several logging requirements necessary to meet EPA standards and responsible operation which include standard logs (Triple Combo) advanced logs and mechanical integrity logs (MIT) (**Figure 5-1**).

The logging program consists of four separate logging jobs: one for surface hole, two for first and second intermediate holes and one for production hole (**Figure 5-1**).

- **STANDARD LOGS** include the gamma ray or spectral gamma ray, resistivity, neutron, density, caliper, and spontaneous potential. These data are used for primary reservoir and fluid characterization including lithology, porosity, salinity, fracture identification, indications of permeability, and fluid saturations. Standard logs can answer most of the primary reservoir questions related to storage volume.
- **ADVANCED LOGS** include monopole and dipole sonic tools, resistivity imaging, nuclear magnetic resonance (NMR), neutron spectroscopy, formation pressure testing and fluid sampling. These are used to complement the standard logs and give additional formation information such as pore body sizes, detailed chemical and elemental information, and finally geomechanical information. These advanced tools are necessary to meet the requirements of documents 40 CFR 146.87 and 40 CFR 146.86.

The sonic tool is a secondary porosity tool, but is also key in understanding geomechanics, stress direction, and existence of fractures in the reservoir and confining layers. The sonic tool will be used to acquire a 3-D shear survey for approximately 50 ft around the wellbore.

The geomechanical interpretation is bolstered by the image logs which can be interpreted for fracture identification, stratigraphy, stress direction, and dip. The image log can also be used to calculate maximum principal stress magnitude in conjunction with sonic data. ***The image log will be critical to identify fracture frequency and fracture aperture and evolve the reservoir model accordingly.***

The NMR tool can be used to approximate pore body geometry in conjunction with MICP or Brunauer-Emmett-Teller (BET) data. It is very useful for estimating permeability as well since it measures hydrogen precession and pore relaxation effects.

The neutron spectroscopy tool gives detailed highly accurate measurements of several elements such as Si, Ca, Mg, Al etc. and can be used with a mixing model and in conjunction with XRD and XRF data to create a detailed vertically continuous mineral model.

The dielectric log will be run to measure bulk volume water and give an additional continuous measure of salinity that can be used in conjunction with other measurements to calculate water resistivity (R_w), the cementation/porosity exponent (m) and the saturation exponent (n).

The formation tester will be used to determine formation pore pressure and mobility through pretests. The gradient produced through the interpretation of individual pore pressures indicate zones of over- or under-pressure, and the potential for different reservoir compartments. With viscosity as a known variable, the permeability can be easily estimated from mobility or through post sample buildups.

In-situ samples acquired at multiple depths will determine the physical and chemical properties of the water, as well as flowing temperature of the fluid. Using a formation testing tool, in concert with a dual packer, will allow the acquisition of a fracture gradient for the confining layers and injection units. This will allow for management of injection rates to maintain an effective seal. The advanced logs can answer most of the remaining borehole questions including vertical connectivity, producibility, fluid chemistry, and geomechanics.

Milestone will exhaust all efforts to source tools that fit within the inner diameter of the tubulars. However, there remains a slight/unlikely chance that tools of the appropriate size may be unavailable.

5.3.2.1 Surface and First Intermediate Logging Program

The surface and intermediate hole logging program, as shown in **Table 5-3**, includes the five (5) logs, along with the main objectives. In the initial phases, a triple combo with spectral gamma ray, in addition to dipole sonic will be utilized. This will give estimates of uphole porosity, clay content and yield a useful seismic tie as well as indications of pore pressure and geomechanical properties. After the casing is set, a cement bond long (CBL), temperature, and noise log will be run for mechanical integrity.

Table 5-3: First Intermediate and Surface Hole Logging Program Objectives

Intermediate Hole Logging Programs	Main Objective
Triple Combo and Spectral Gamma Ray and Caliper	Characterize the Spraberry and Wolfcamp Formation
Cross Dipole Sonic	Characterizing rock geomechanics properties of Spraberry and Wolfcamp including anisotropy
CBL	Cement evaluation
Temperature and Noise Log	Initial leak detection of tubing or casing

5.3.2.2 Second Intermediate Logging Program

In the second intermediate logging run, as presented in **Table 5-4**, triple combo with spectral gamma ray, dipole sonic, image logs, nuclear magnetic resonance (NMR) and neutron spectroscopy logs will be conducted. Resistivity and an ultrasonic micro imager will yield fracture frequency, orientation, and aperture as well as borehole induced tensile fractures plus breakout. Sidewall cores will be acquired if a whole core cannot be obtained in the Top Seal – Woodford Shale.

If drilling conditions permit, fluid and pressure samples will be taken in the Strawn or other permeable zone above the top seal as an additional baseline fluid sample. If a fluid sample cannot be obtained above the Top Seal while logging, it will be captured after completion from one of the permanent U-tube systems installed in the monitoring well.

Table 5-4: Second Intermediate Logging Program and Objectives

Intermediate Hole Logging Programs	Main Objective
Triple Combo and Spectral gamma ray and caliper	Characterize the Spraberry and Wolfcamp Formation
Cross dipole Sonic	Characterizing rock geomechanics properties of Spraberry and Wolfcamp including anisotropy
USIT and CBL	Cement evaluation
Resistivity and Ultrasonic Imager	Identify fractures, faults, wellbore breakouts and tensile fractures. Improve the characterization of geomechanics properties, stress orientation, amplitude, and anisotropy
Neutron Spectroscopy	Elemental composition to characterize lithology
Nuclear Magnetic Resonance	Pore size, pore geometry, porosity and permeability
Formation Tester	Directly measure the pore pressure and take fluid sample from the Strawn
Temperature and Noise Log	Initial leak detection of tubing or casing
Dielectric Log	Additional measure of formation salinity (Rw), *m* and *n*
Rotary Sidewall Cores	Side wall cores will be taken if whole coring fails or is not safe

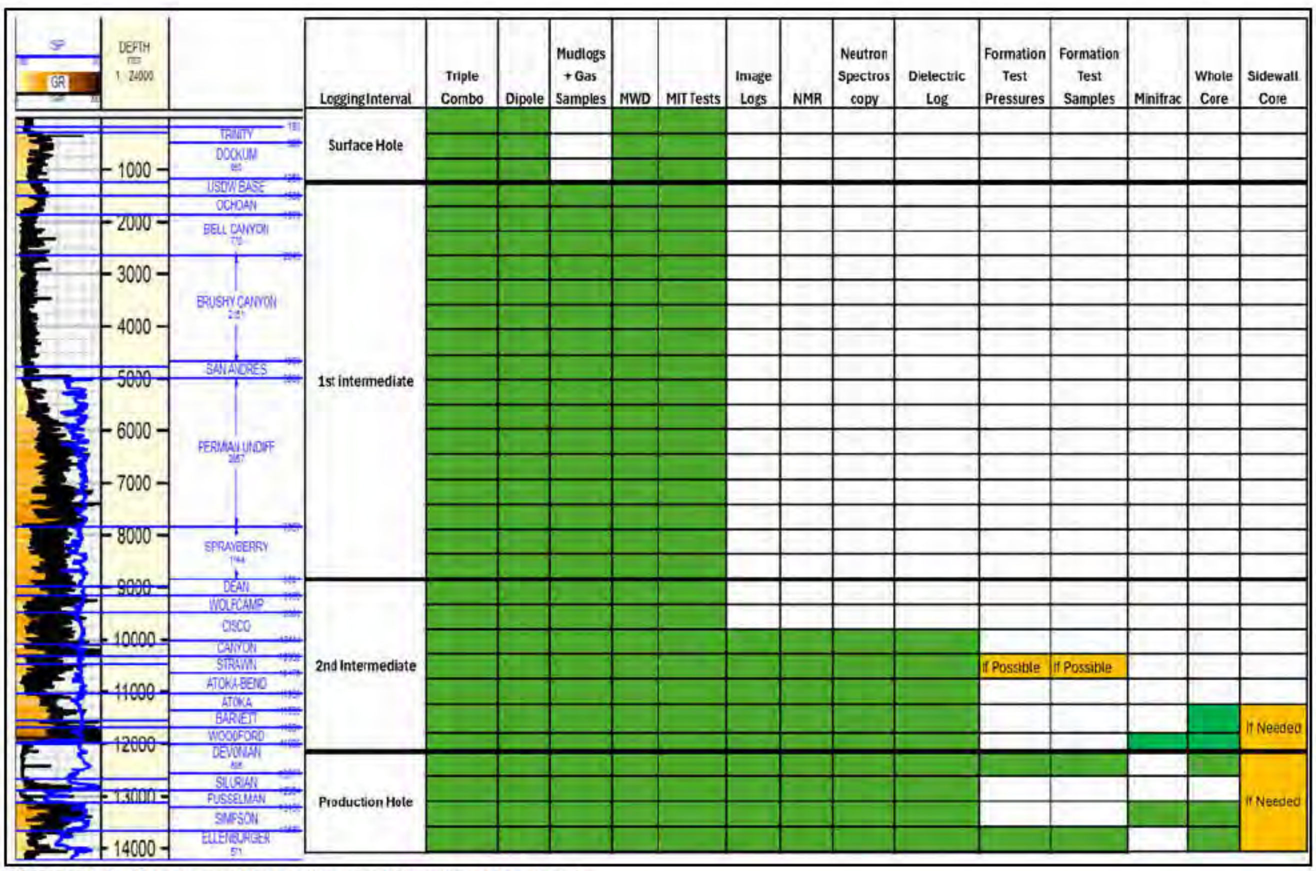

Figure 5-1: Proposed Logging and Coring Program

5.3.2.3 Program Production Hole Logging Program

The production hole logging program includes the logs, and their main objectives, presented in **Table 5-5** and **Figure 5-1**. This is the most comprehensive logging program in the project. A triple combo with spectral gamma ray will be used for standard properties such as density and resistivity. A neutron spectroscopy will be used for elements and minerals. NMR will characterize pore size and permeability index. A dipole sonic will be used to estimate geomechanical properties, tie the 3D seismic, indirectly measure pore pressure, detect vugs, and measure fractures away from the borehole using a far-field shear survey. Sonic tools can also be used as secondary porosity measurement. Sidewall cores will be acquired if the whole core fails to recover or cannot safely be achieved.

Resistivity and the ultrasonic micro imager will yield fracture frequency, orientation, aperture as well as borehole induced tensile fractures plus breakout. The imager logs are critical to future modeling as the injection interval is expected to be heavily fractured.

Formation testing will take pressure tests, fluid samples and finally minifrac the formation at the conclusion of the logging job. If a fluid sample cannot be obtained while logging, it will be captured after completion from one of the permanent U-tube systems installed in the monitoring well or by producing the completed injection well prior to injection.

Cement will be evaluated for bond, consistency, and height using cement bond log, ultrasonic casing inspection tool, magnetic flux leakage and a multi-finger caliper. A pulse neutron log will be used to measure initial gas saturation before injection. Additionally, an oxygen activation log will be performed using the pulse neutron as a baseline and a temperature noise log will be obtained as a baseline and to calibrate Distributed Acoustic Sensing/Distributed Temperature Sensing (DAS/DTS).

Table 5-5: Production Hole Logging Program and Objectives

Production Hole Logging Programs	Main Objective
Triple Combo and Spectral Gamma Ray and Caliper	Determine lithology, resistivity, porosity, and fluid salinity. Triple combos are the backbone of any petrophysical interpretation.
Neutron Spectroscopy	Elemental composition to characterize lithology
Nuclear Magnetic Resonance	Pore size, pore geometry, porosity and permeability
Cross-Dipole Sonic	Velocities for geophysical ties, geomechanical attributes, indirect pore pressure, secondary porosity log, vugs, acoustic anisotropy, far field shear survey for fractures away from well
Resistivity and Ultrasonic Imager	Identify fractures, faults, wellbore breakouts and tensile fractures. Improve the characterization of geomechanics properties, stress orientation, amplitude, and anisotropy
Formation Tester	Directly measure the pore pressure and take fluid sample from the Siluro-Devonian, and Ellenburger units
Microfrac	Microfrac testing seal and reservoir for fracture gradient
Ultrasonic Casing Inspection Tool (USIT) and Cement Bond Log (CBL)	Initial cement integrity
Multifinger Caliper	Initial casing geometry

EM Flux	Initial casing corrosion
Pulse Neutron	Initial gas saturation near the wellbore before injection begins, also oxygen activation log for MIT
Temperature and Noise Log	Initial leak detection of tubing or casing
Dielectric Log	Additional measure of formation salinity, *m* and *n*
Additional Mechanical Integrity Tests	See **Table 5-7**
Rotary Sidewall Cores	Side wall cores will be taken if whole coring fails or is deemed unsafe

5.3.3 Formation Fluid Testing

Prior to setting the production casing string, samples of formation fluid will be obtained by running an openhole formation testing tool after successful pre-pressure tests. Recovery sections and sample depths in the injection interval will be determined based on openhole evaluations.

Milestone will work with logging vendors to utilize the best possible approach to formation testing design. Within the Ellenburger and Siluro-Devonian units, it is likely a dual packer configuration will be utilized to maximize surface area across fractured intervals. Smaller probes may be used in the intermediate section of the hole to reduce testing time.

Milestone will strive to collect the maximum number of samples; however, potential tool malfunctions may necessitate adjustments to the operational plan. Milestone will make the best possible efforts to acquire the number of samples listed below in a) through c) (see permit **Section 1** for definition of units):

a) Two samples in Ellenburger injection unit
b) Two samples in Siluro-Devonian injection unit
c) Two samples above Woodford, likely in Strawn formation

Per 40 CFR 146.87(d)(3), all samples will use rigorous fluid testing programs that include cations, anions, salinity, specific conductance, hydrogen isotopes, oxygen isotopes, and carbon isotopes as well as additional parameters. Samples will be held in sealed containers and opened in a qualified commercial lab. Formation gases will be captured. Initial testing will be identical to the proposed water testing matrix during monitoring period in order to measure proper baselines (**Table 5-6**).

Per 40 CFR 146.87(c) Milestone will record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of all tests during field operations.

Table 5-6: Water Testing for Water Samples Acquired from Formation Testing

Parameter	Analytic Method
Dissolved CO_2	Coulometric Titration, ASTM D513-11
Total dissolved solids	Gravimetry, APHA 2540C
pH (field)	EPA 150.1
Specific conductivity (SC) (field)	APHA 2510
Temperature	Thermocouple
Water Density	Oscillating body method
Cations – Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020
Cations – Ca, Fe, K, Mg, Na and Si	ICP-OES, EPA Method 6010B
Anions – Br, Cl, F, NO_3, HCO_3 and SO_4	Ion Chromatography, EPA Method 300.0
δ 2H and δ 18O isotope analysis	Isotope ratio mass spectrometry
δ13 C dissolved inorganic carbon	Isotope ratio mass spectrometry
Alkalinity	APHA 2320B

5.3.4 Minifrac Testing

Per 40 CFR 146.87 (d)(1), during the openhole logging program and prior to any stimulation work, a minifrac test will be completed to measure the fracture gradient of the confining and various injection unit(s) in the Well. This test will be conducted using a formation pressure and fluid recovery tool. Testing parameters will follow Zoback et al., 2003. American Society for Testing and Materials (ASTM) Method D 4645-08, Standard Test Method for Determination of In-Situ Stress in Rock Using Hydraulic Fracturing Method (ASTM, 2008). Minifracs will be performed at depths that will not endanger the primary seal or secondary seal. A 100ft buffer zone will be utilized, or an alternative prudent buffer zone will be identified where the probability of fractures growing out of the seal is low. This buffer zone will be identified using dipole sonic and image logs.

5.3.5 Initial Mechanical Integrity Demonstration and Hydrogeologic Testing

Table 5-7 is a summary of the Mechanical Integrity Tests (MIT) and pressure fall-off tests to be performed prior to injection.

Milestone will notify EPA at least 30 days prior to conducting the test(s) and provide a detailed description of each testing procedure. Notice, and the opportunity to witness these tests/logs, shall be provided to EPA at least 48 hours in advance of a given test/log.

All tests will utilize the latest EPA guidelines. See permit **Section 6** and **Section 13 Appendix C: QASP** for pressure fall-off testing procedures and guidelines.

Table 5-7: Pre-Operational Mechanical Testing Schedule

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.87(a)(4)(i) 40 CFR 146.89 (b)	MIT	Annulus Pressure Test	1 hour after isolation
40 CFR 146.87(a)(4)(ii) 40 CFR 146.89(c)(1)	MIT	Tracer Log Pulse Neutron (Oxygen Activation)	8 Hours
40 CFR 146.87(a)(4)(iii)	MIT	Temperature and Noise log	8 Hours
40 CFR 146.87(a)(4)(iv) 40 CFR 146.87(a)(2)(ii) 40 CFR 146.87(a)(3)(ii)	MIT	Multifinger Caliper, EM flux, Cement Bond Log, Ultrasonic Inspection Tool	8 Hours
40 CFR 146.87(e)(3)	Verify Hydrogeologic Characteristics of Zone	Step Rate Injection Test	60 minutes per step, at least 5 steps
40 CFR 146.87(e)(1)	Verify Hydrogeologic Characteristics of Zone	Pressure Fall-Off Test	1 Week, or until radial flow achieved for 24 hours
40 CFR 146.87(e)(2)	Surface Equipment Test	Pump Test	1 Hour

Per 40 CFR 146.87 and 40 CFR 146.89, the planned cased-hole logs that will be run include several tools meant to establish baselines for future mechanical integrity monitoring. These casing inspection baseline logs include cement bond logs, noise log, temperature log, ultrasonic inspection tool, a pulse neutron log, an EM flux log, multi-finger caliper and an oxygen-activation log. Future logging of this unit, with the same technology, will allow for monitoring of the plume and the mechanical integrity of the wellbore. Minimum tool diameter may limit some of the proposed logging activities and will be reviewed when a vendor is selected. Best efforts will be made to source a viable tool.

5.4 Coring Testing Program [146.87 (b)]

5.4.1 Core Acquisition

Core acquisition is planned to include four (4) discrete runs of whole core and infill, if necessary, by rotary sidewall coring conveyed from wireline. The entire core program is shown in **Table 5-8**. Depths may be altered as additional information becomes available from 3D seismic data, uphole surface logging, as well as MWD measurements during drilling.

Milestone will core the first well in the injection interval, but may not core subsequent wells if previous cores and wireline surveys prove representative of new well conditions or if drilling conditions make core retrieval impossible. Core thicknesses may be reduced if drilling conditions deteriorate or if recovery is low. If whole coring cannot be completed due to adverse drilling conditions, sidewall cores will be utilized as an alternative.

Coring intervals are prescribed as: 1) primary Top Seal of the Woodford Shale; 2) Fusselman where the most intense fracturing is expected in the Siluro-Devonian injection unit; 3) Lower Simpson Group into Ellenburger to characterize the seal-injection interface and, 4) the Middle Ellenburger where the most intense fracturing is expected. The basement will not be sampled due to the technical challenges with coring granite, as well as the potential hazards of creating conduits in the basement rock. Since the primary Top Seal of the Woodford is not 180 ft thick, but the core barrel assembly is 180 ft, sections of the Barnett and Devonian will likely be sampled in the first coring run. Depths of coring intervals are illustrated in **Figure 5-1.**

Table 5-8: Coring Program

Interval	Lithology	Approximate Depth (ft)	Approximate Thickness of Core (ft)
Top Seal – Woodford Shale; Additional core coverage of Barnett and Devonian top	Organic Shale, Packstone	12,040	180
Silurio-Devonian	Chert-Packstone	12,500	180
Base of Simpson Group-Top of Ellenburger Group	Shale-Dolostone	13,000	180
Ellenburger Formation	Dolostone	13,300	180
Rotary Sidewall Coring	Various	Rotary Sidewall Coring throughout Production Hole, some samples may be above primary seal. Samples will be selected based on openhole logs.	50 Samples

5.4.2 Special Note on Lower Confining Layer

Since the lower confining layer of the Ellenburger formation is the Cambrian-aged Bliss sandstone or granitic or rhyolite basement, the core analysis and drilling program plan is to stop drilling 100 ft above basement rock. This stoppage is intended to reduce seismicity risk. In this plan, we will not have core or log analyses over the granitic basement, but the borehole will also not interact with basement rock unless CO_2 saturated water moves against buoyancy and travels downward due to gravity through fractures. While this downward migration is possible, the 100 ft. buffer zone is intended to mitigate this potential risk. Therefore, Milestone will not core or log the lower confining layer, which is granitic basement, in an effort to reduce seismicity risk.

This project is **not** applying for a depth waiver under [40 CFR 146.95] and [40 CFR 146.95a]. Therefore, the requirements under [40 CFR 146.95 and 146.95a] do not apply. The injection interval is 10,950 ft below the base of USDW. See permit **Section 1.4** for additional information on the base of USDW in the region.

5.4.3 Core Analysis Program

As part of the appraisal well program within the South Midland Facility, core and reservoir fluid analysis programs are planned. The core and fluid analysis programs are meant to help minimize the risk and reduce the uncertainties within the subsurface data and provide a complete dataset for the second generation static and dynamic models. The current subsurface model lacks data density in nearby area. The nearest core data is from older 1950s cores that were extracted from the Midland Basin and are presently housed at BEG.

The objective of the core and fluid analysis program is to close data gaps that impact the three principal drivers (i.e., capacity, injectivity and containment) for confirming the Siluro-Devonian and Ellenburger as a safe and secure CO_2 sequestration complex within the area. Based on log analysis results this campaign may be amended to include additional tests. The data gathering campaign is designed to:

a) Better define formation-specific permeability and porosity as well as the degree of connectivity between the Siluro-Devonian and Ellenburger units (capacity and injectivity)
b) Determine the extent to which the Woodford Shale will act as a seal to the upward migration of CO_2 (containment)
c) Provide data to calibrate well logs
d) Confirm reasonable similarity with the 1st generation static and dynamic models
e) Provide rock mechanical information
f) Provide information about threshold entry pressures and other SCAL properties
g) Provide geochemical information and fluid reactivity information
h) Further constrain mineralogy and fracturing

The analytical program will consist of two major phases as follows:

1. **Phase I**: Core analysis, fluid characterization, core description and petrography
2. **Phase II:** Special core analysis

5.4.4 Phase I: Core Analysis, Fluid Characterization, Core Description and Petrography

The main objective of this phase is to evaluate the integrity of the core and characterize both the seal and the main injection Interval along with reservoir fluids. This should yield a breakdown of the different facies that supports sample selection for special core analysis tests. The steps related to this phase are as follows and illustrated in **Figure 5-2**.

a) Core gamma measurements and CT scans are conducted on the entire core upon arrival in the lab, to review core condition and for plug selection.
b) Plug CT scan and micro-CT for shale plugs prior to SCAL
c) Plug Cleaning using Soxhlet extraction.
d) Basic rock properties for reservoir section are measured via conventional core analysis at ambient and stress conditions.
e) Klinkenberg and brine permeability, grain density, porosity. Establish Kv/Kh relation.
f) Unconventional Reservoir Workflow for shale sections- Plug Sample Includes micro-CT image AR gas saturations and total porosity by NMR. Steady State permeability and dry bulk density, porosity, and grain density by Boyle's Law.
g) Basic petrography work on selected sand and shale samples to support operational and well evaluation key needs (SEM, Thin Sections)
h) Upon plug selection and core slabbing, a core geological description should be carried out that includes fracture identification and count.
i) MICP for both reservoir sections and shale.
j) Geochemical characteristics via XRD, XRF and FTIR
k) Brine Chemistry and Salinity.

Conventional Core frequency of sampling will be at one sample 3-ft for reservoir and seal section subject to review and adjustment once the core is retrieved.

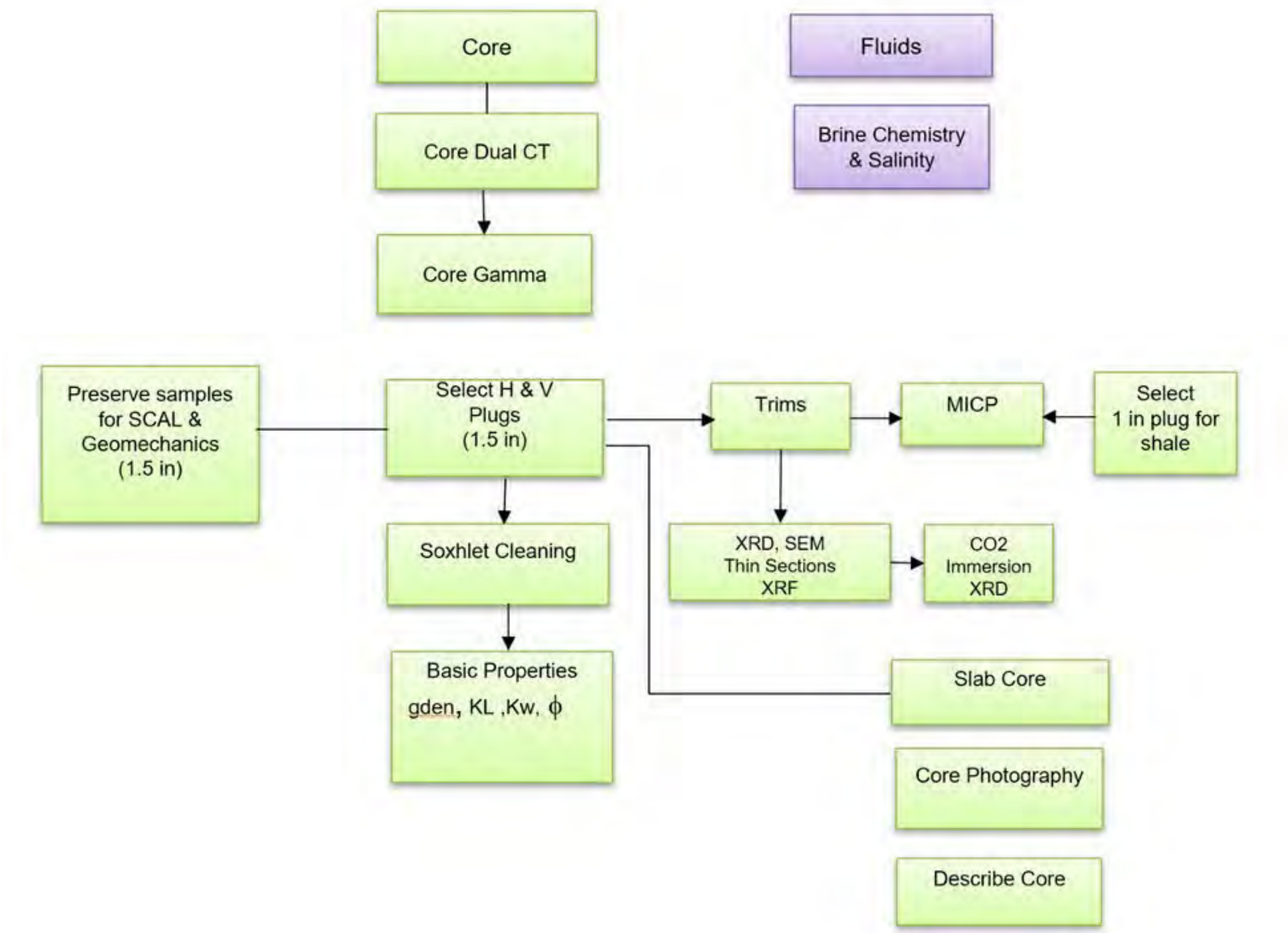

Figure 5-2: Phase I Core Analysis Program Flow Diagram*
** May be amended in consultation with an experienced commercial core laboratory*

5.4.5 Phase II: Special Core Analysis

This is the most comprehensive analytical effort, consisting of special core analysis measurements for static and dynamic data of sand facies and seals. Workflow diagramed in **Figure 5-3**. See **Section 13 Midland Appendices, "Glossary of Acronyms, Abbreviations and Terms."**

Reservoir Carbonates:

- Additional petrography work (TS, SEMs, XRDs) on trims from SCAL samples
- Flow through cleaning
- Brine preparation and properties (Resistivity, PH, density, viscosity and IFT)
- Sample saturation
- Electrical properties (FRF, RI, CoCw, m, n)
- Air-Brine Pc by centrifuge and measure Kair@Swi
- CO_2 flooding and Kg@Swi
- Brine-oil centrifuge
- CO_2 immersion XRD test to assess CO_2 effect on minerals
- Threshold entry pressure to CO_2
- CO_2 flood to assess halite precipitation (post SEM is required)
- USS Kr supercritical CO_2/brine and Brine/CO_2 end point relative permeability (followed by Dean & Stark for mass balance)

- SS Kr supercritical CO_2/brine with ISSM full relative permeability curve on few samples. Collect effluent samples for IC and ICP
- SS Kr Brine/supercritical CO_2 with ISSM full relative permeability curve on few samples. Karl Fisher is performed after the test for mass balance.
- Rock Mechanics: Triaxial, TWC, UCS, Ductility and Tensile Strength
- Rock Physics: Pore Volume Compressibility, Compressional & Shear Velocity

Seal Characterization:

- Additional shale petrography work: TS, SEMs, XRDs, XRF
- CO_2 immersion XRD test to assess CO_2 effect on minerals.
- Rock Mechanics: Triaxial, UCS, Ductility and Tensile Strength
- Rock Physics: Compressional & Shear Velocity
- Brunner Emmet Teller (BET): the specific surface area and porosity distribution

Dozens of selected samples will be acquired for SCAL testing from the reservoir section and seal section. The sampling strategy will be guided by geological rock types. Whole core sections should be preserved for geomechanics sampling. SCAL should always be prioritized over conventional core analysis, and it is recommended that samples be acquired before slabbing.

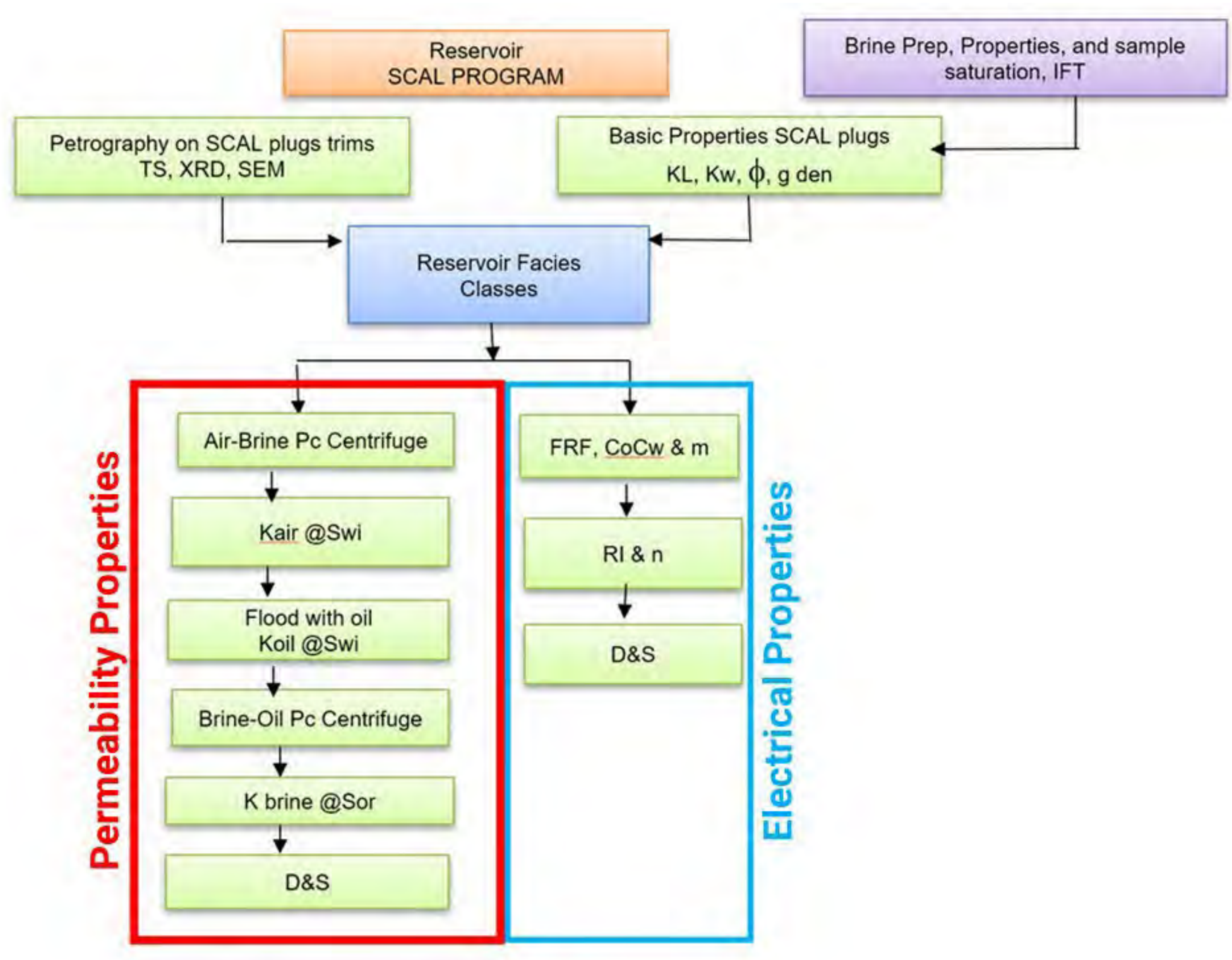

Figure 5-3: Special Core Analysis (SCAL) Flow Diagram*
** May be Amended in Consultation with an Experienced Commercial Core Testing Laboratory*

5.5 Initial Seismicity Monitoring

Before injection well drilling operations commence, five (5) near surface seismicity and water sampling stations will be installed. These wells will record seismicity continuously for at least (6) months before drilling the injection wells. Locations of the NSSW wells are noted in permit **Section 1**.

In addition to Milestone-owned stations, existing TexNet seismicity stations will also be utilized to locate any seismic events within 10km of the AoR. If a seismic event over magnitude 4.0 is recorded within 10km of the AoR and within the six-month period preceding drilling, the EPA UIC Director will be notified within 72 hours. See permit **Section 6** for more information on seismicity monitoring and magnitude of completeness modeling in the area.

5.6 Artificial Penetration Search

Milestone will conduct ground-based and aerial reconnaissance to attempt to locate additional artificial penetrations. Drone-based magnetometer surveys will be used to locate undocumented wells and personal gas detection equipment will be used to identify leaking historical wells. Milestone has completed a survey of structures, visible wells in the area, and a paper records review.

Within the AoR, Milestone has already located 71 oil and gas wells and 87 water wells. Milestone will attempt to locate any additional wells that are not recorded.

See permit **Section 1** for additional information on the locations of these wells. None of the currently known wells penetrate the Top Seal or injection interval.

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Section 6: Testing and Monitoring Plan

[40 CFR §146.90]

Prepared for:

EPA Region 6

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6.0 TESTING AND MONITORING PLAN [146.82(a)(15), 40 CFR 146.90]

This Testing and Monitoring Plan describes how Milestone will monitor the Injection Well (Well), pursuant to [40 CFR § 146.90]. In addition to demonstrating that the Injection Well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs, the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the injection unit to support AoR re-evaluations and a non-endangerment demonstration. Additional applicable testing methods may be added to reconcile observed and actual results.

Results of the testing and monitoring activities described herein may trigger action according to the AoR Re-Evaluation Criteria (**Section 2**) and or the Emergency and Remedial Response Plan (**Section 10**).

6.1 Overall Strategy and Approach for Testing and Monitoring

The operating plans for the proposed Well will include a robust testing and monitoring program. Milestone will report the results of all testing and monitoring activities to EPA in compliance with the requirements under 40 CFR § 146.91. This section discusses the key details of this program.

Milestone will access the site via a lease road. The injection well facility is adjacent to an existing Milestone class II injection facility that handles oilfield liquid waste. Milestone does not anticipate any barriers to, or issues with, accessing the site to conduct monitoring activities.

6.1.1 Quality Assurance Procedures [146.93]

Section 13, Appendix C reflects Milestone's QASP for testing and monitoring activities pursuant to the requirements in 40 CFR 146.90(k). This performance-based plan sets forth the procedures and guidelines the EPA will use in evaluating the technical performance of Milestone. Procedures for measurement of various sections of this document are found in **Section 13 Appendix C – QASP**.

6.1.2 Reporting Requirement [146.91]

Per the requirement of 40 CFR 146.91, Milestone will provide semi-annual reports to the UIC Director containing the following:

1. Any changes to the physical, chemical and other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data (**CO_2 Specs - Section 3**).
2. Monthly average, maximum and minimum values of injection pressure, flow rate and volume, and annular pressure.
3. Description of any event that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit.
4. Description of any event which triggers a shut-off device and the response taken plus any effect it had on the volume or mass of CO_2 injected.
5. Monthly volume and/or mass of the CO_2 stream injected over the reporting period and the volume injected cumulatively over the life of the project and reporting period.
6. Monthly annulus fluid volume added.
7. Results of any monitoring as described in this section or under 40 CFR 146.90.

In addition, reports will be submitted within thirty (30) days after the following events:

1. Periodic tests of mechanical integrity.
2. Any well workover.
3. Any other test of the injection well conducted if required by the Director.

Reports will be submitted to the Director, within 24 hours of the following:

1. Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW.
2. Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs.
3. Any triggering of a shut-off system, either downhole or at the surface.
4. Any failure to maintain mechanical integrity.
5. Any anomalous release of carbon dioxide to the atmosphere outside of normal engineering tolerances for operations.

Notification will be made to the UIC Program Director, in writing, 30 days in advance of:

1. Any planned workover.
2. Any planned stimulation activities as defined in **Section 7.**
3. Any other planned non-routine test of the injection well.

All reports, submittals and notifications will be submitted to EPA UIC Program Director and or relevant state agencies in compliance with all applicable regulations. All records will be retained by Milestone throughout the life of the project and for ten (10) years following site closure. Data on the nature and composition of all injected fluids collected will be retained as well for ten (10) years after site closure. The records will be delivered to the Director after the retention period if required by the Director. Monitoring data as described in this Section will be retained for ten (10) years after it is collected. Well plugging reports, post-injection site care data and the site closure report itself will be retained for ten (10) years following site closure. Any records that the EPA UIC Program Director requires will be retained longer than 10 years after site closure.

6.1.3 Testing Plan Review and Updates [146.90 (j) (1) (2) (3)]

This testing and monitoring plan will be reviewed and updated to incorporate monitoring data collected as described at least once every five (5) years. An amended testing and monitoring plan will also be submitted within one year of an area of review re-evaluation, following any significant changes to the facility such as the addition of monitoring wells or newly permitted injection wells within the area of review; or as required by the Director (re-evaluation criteria found in **Section 2**).

6.2 Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b),146.90(b)]

6.2.1 Continuous Monitoring of Injection Wells

Milestone will install and use continuous measurement devices to monitor injection pressure, rate, and volume, the pressure on the annulus between the tubing and the long string casing, the annulus fluid volume added, and the temperature of the CO_2 stream, as required under 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b) (**Table 6-1**) within the Injection Wells.

Data interfaces will be created for equipment that is not linked directly to the SCADA system, to be integrated into a unique surveillance platform. In the monitoring program, the sensors, transducers and controllers will be connected in a central platform to monitor the operating conditions, set alarms for malfunction, and establish safety protocols in case of abnormal conditions. Alarms will additionally be set for pressures outside described tolerances which is generally 90% of fracture gradient, maximum permitted wellhead pressures, and changes in annular pressure and fluid volumes. The operating parameters, monitoring values, laboratory results, reports, and surveillance documents for the project will be stored in a central database to provide support for AoR reviews, QA programs, and reporting.

Table 6-1. Sampling devices, locations, and frequencies for continuous monitoring in Injection Wells

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Surface Injection Pressure	Wellhead Pressure Logger	Surface	5 seconds	5 minutes
Bottom Hole pressure	Pressure Gauges	Wellbore	5 seconds	5 minutes
Injection rate	Metering Device	Wellhead	5 seconds	5 minutes
Injectate density	Metering Device	Wellhead	5 seconds	5 minutes
Injection volume	Calculated from rate and density	N/A	N/A	N/A
Annular pressure	Pressure Guage	Wellhead	5 seconds	5 minutes
Annulus fluid volume	Volume Added Meter	Wellhead	5 seconds	5 minutes
CO_2 stream temperature	Metering Device /WPL	Wellhead	5 seconds	5 minutes
CO_2 stream temperature	DTS	Wellbore	5 minutes	See **Table 6-5**
Induced Seismicity	DAS and Near Surface Geophones	Wellbore and Near Surface	5 milliseconds for NSSW; Fiber See **Table 6-5**	5 milliseconds for NSSW; Fiber See **Table 6-5**
Strain	DAS	Wellbore	2 seconds	See **Table 6-5**
Gas Composition	Gas Analyzer	Pipeline	5 seconds	5 minutes

6.2.1.1 Well Temperature

Wellbore and the surrounding formation temperatures will be measured using Distributed Temperature Sensing (DTS) data acquired through a fiber optic cable, embedded in the cemented annulus behind the long string casing. The fiber optic cable location in the injection well and In-zone Monitoring well is illustrated in the wellbore diagrams in **Section 3**. In addition to DTS, Low-Frequency Distributed Acoustic Sensing (LF-DAS) data will also be used to indirectly measure the wellbore temperature and any fluid movement behind the casing as fiber is sensitive to both temperature and pressure fluctuations in the wellbore. For specialized data such as fiber optic DAS and DTS, the project will have additional support from the provider of the selected technologies to perform QC and verification of the data as well as calibration of the systems as needed. The wellhead pressure logger (WPL) and Coriolis Meter will also continuously measure the temperature at surface and can be used as a backup in case the DTS fails. DTS and DAS data recording practices will be discussed further in the fiber optic section.

6.2.1.2 Injection Rate, Temperature, Density and Volume

At the injection well, a metering device such as a coriolis mass flowmeter will be utilized to measure injection rate, injectate temperature, injectate density, and energy inputs. Volume will be calculated from the density and rate. The meter will be placed at a location based on manufacturer specifications immediately upstream of the injector wellhead and downstream of any capture facilities. The meter will be calibrated to manufacturer specifications

6.2.1.3 Injection Pressure

Injection pressure will be monitored using wellhead and downhole pressure gauges. The injection well will be equipped with permanent downhole gauges above the packer (illustrated in **Section 3**) that will continuously monitor the injection pressure and annular pressure at that depth and transmit the data via a tubing encapsulated conductor (TEC) cable. The pressure gauges will continually monitor the injection pressure to ensure that it does not exceed 90% of the fracture gradient as required by 40 CFR 146.88(a). Additionally, the Well will be equipped with a wellhead surface pressure logger to ensure the surface pressure remains below allowable wellhead pressures.

6.2.1.4 Annular Pressure and Volume

The annular pressure between the tubing and the injection casing strings and the annular fluid volumes also will be monitored on a continuous basis at gauges located in the wellhead and above the packer. The pressure gauge on the annulus will be tied into the SCADA system and set to alarm if pressure or volumes move outside set tolerances.

6.2.1.5 Positive Annular Pressure

Per 40 CFR 146.88(c), Milestone will maintain pressure in the annulus of at least 100 psi greater than the injection pressure. Milestone will fill the annulus with a non-corrosive fluid approved by the UIC Program Director. A system will be set up to maintain pressure in the Annulus using compressed non-corrosive fluid or gas and it will be tied into the SCADA alarms if pressure drops below tolerances.

6.2.1.6 Gas Composition

Gas stream composition will be measured continuously upstream of the wellhead but after the last stage of compression in the pipeline. Milestone will employ a continuous gas analyzer device that meets the temperature, pressure and rate requirements of the project. This is discussed further in permit **Section 6.12**.

6.3 Testing and Monitoring Techniques QA/QC [40 CFR 146.90(k)]

6.3.1 Casing and Tubing Inspection Tools

For mechanical integrity evaluation, Milestone will use Ultrasonic Casing Inspection Tool (USIT), Electromagnetic Pipe Examiner (EM Flux tool), Cement Bond Logs (CBL) and a MultiFinger caliper that evaluates the conditions of the tubulars and casing in the well and provides information about thickness, ovality, ruptures, potential corrosion, etc. Inner diameter restrictions of tubing will be considered when selecting logging tools. More information about these casing inspection tools may be located in **Section 13 – Appendix C, the QASP**.

6.3.2 Pulsed-Neutron Logging

Pulsed-neutron logging is considered a proven technique to detect gas saturation in reservoirs. Advances in technology have improved the accuracy of the tool to track the movement of the CO_2 plumes in the reservoir and evaluate flow conformance. **Figure 6-1** illustrates time-lapse PNX log response in an example injection well after CO_2 injection.

The red area indicates CO_2 replacing formation brine in the near wellbore region. It can be observed on the apparent neutron porosity (TNPH), the Sigma (SIGM) and especially on the fast neutron cross section (FNXS) log. Since the neutron log primarily responds to hydrogen, found in water, the gas displacing the water alters all these logs.

In formations with CO_2, or any gas, there is a reduction in the neutron capture rate because gas has a lower neutron absorption cross-section than water or oil. This results in fewer interactions with neutrons, and due to a change in spectrum the tool can detect the lower neutron capture response associated with gas as represented by the FNXS and Sigma log. (**Figure 6-1**)

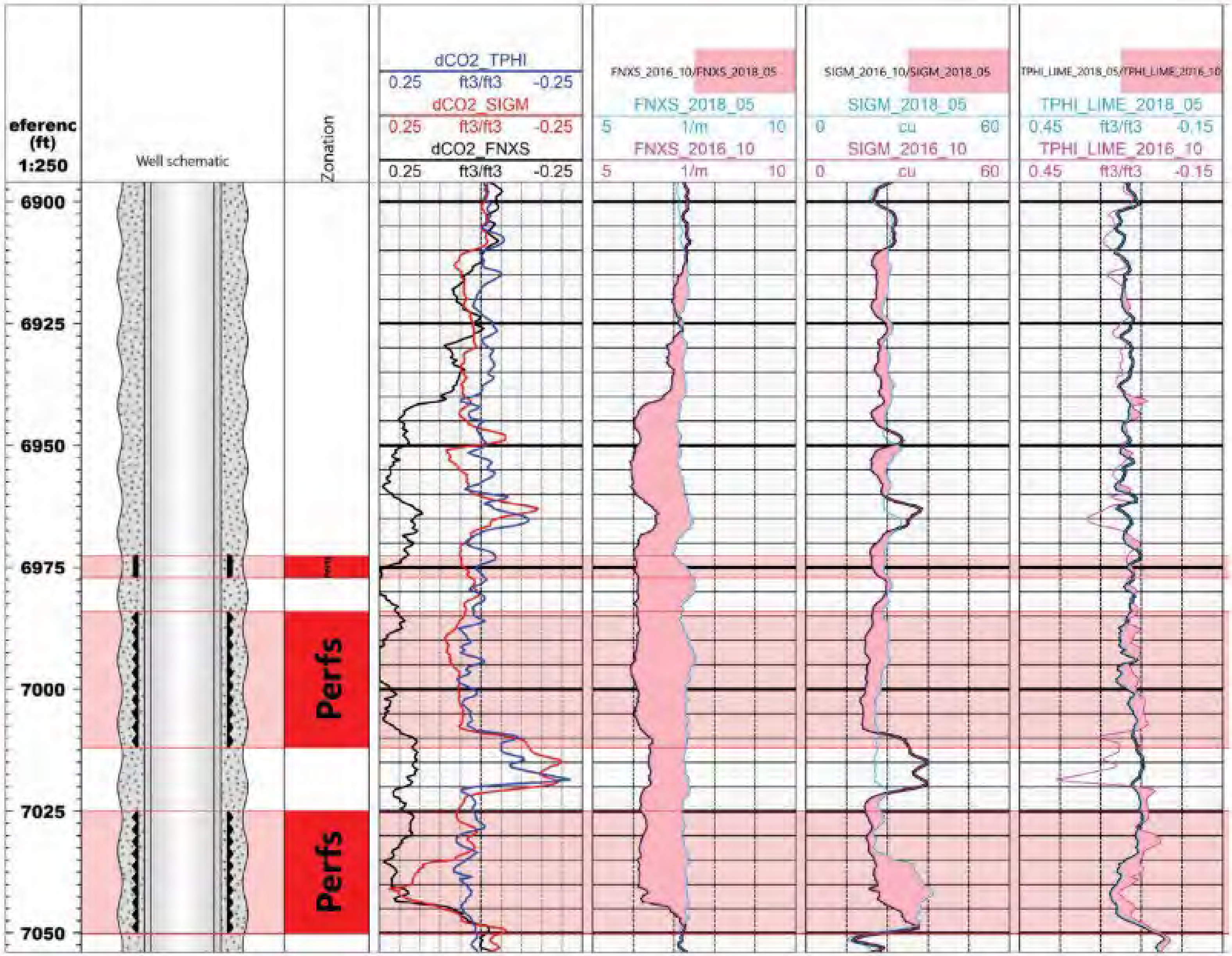

Figure 6-1: Time lapse PNX log response (Laronga et al., 2023

6.4 Corrosion Monitoring [40 CFR 146.90 (c)]

To meet the requirements of [40 CFR 146.90(c)], Milestone will monitor the tubing and casing materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. Data will be reported semi-annually as part of the report described in **Section 6.1.2**

6.4.1 Monitoring Location and Frequency

Milestone will monitor corrosion using a corrosion coupon method and collect samples according to the description below. Milestone will examine the coupons quarterly.

Milestone will measure temperature and strain on the fiber continuously using the DAS and DTS data acquired through the fiber installed in the cemented annulus behind the long string casing of the injection well. 40 CFR 146.89(c) requires that at least once per year the operator will run a temperature, noise or an oxygen activation log. The results of the DAS and DTS data will be interpreted, collated, and submitted to the EPA UIC Director at least twice per year (Semi-annually as part of the report in **Section 6.1.2**) in lieu of running one of the aforementioned wireline logs.

Milestone will perform mechanical integrity logs (i.e., USIT, EM, CBL, Multifinger Caliper) every five (5) years. Inner diameter restrictions of tubing will be considered when selecting logging tools. If continuous well measurements indicate well integrity has been compromised, and the continuously recorded data cannot be used to determine the cause, Milestone will run wireline logs to further evaluate the cause of the mechanical integrity event in consultation with the EPA UIC Director.

6.4.2 Coupon Sampling Methods

Corrosion coupons, made of the same material as the production casing, wellhead and the injection tubing will be placed in the CO_2 injection pipeline in a flow through pipe arrangement or testing loop downstream of all compression, dehydration, and pumping equipment to ensure the coupons are exposed to representative downhole conditions. The coupons will be removed quarterly and assessed for corrosion using American Society for Testing and Materials (ASTM) and Association for Materials Protection and Performance (AMPP) standards for evaluating corrosion tests. When the coupons are removed, they will be inspected visually for any signs of corrosion, including pitting. The weight and size of the coupons will be measured each time they are removed. The rate of corrosion will be calculated using a weight loss method where the rate equals the weight loss during the exposure period divided by the duration of the period. Data will be reported semi-annually.

Coupon initial baseline and periodic measurements will follow the recommendations of AMPP NACE SP0775-2023 (included in **Section 14 References** and **Section 13 Appendix C - QASP**). A brief summary of those requirements is presented here.

Coupons will be prepared from the material used to construct the injection well. A method of coupon preparation will be chosen that does not alter the properties of the metal. Grinding operations will be controlled to avoid high surface tensions/temperatures that could change the microstructure of the coupon. Coupons will be prepared by smooth grinding with 120 grit paper, by tumbling with loose grit, or blasting with abrasive blasting material. A consistent finish will be obtained by blasting with glass beads. All abrasives will be free of metallic particles. A permanent serial number will be etched or stamped on each coupon. Milestone will machine or polish the edges of the coupon to remove cold-worked metal if the cold-worked edges adversely affect the data. Milestone will dry, measure length, measure width, measure thickness, and weigh the coupons to within ± 0.5 mg., record the mass, serial number, and exposed dimensions, calculate the surface area (including the edges) and record. The areas covered by the coupon holder and shielded areas of flush-mounted coupons will be excluded.

6.5 Above Confining Zone Water Monitoring [40 CFR 146.90 (d); 40 CFR 146.82(a)(6)]

Milestone will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of [40 CFR 146.90(d)]. The purpose of the groundwater monitoring is to detect potential changes that may result from fluid leakage out of the injection unit.

6.5.1 Location of In-zone Monitoring Wells

Milestone will construct one (1) In-zone monitoring well near the edge of the projected AoR and oil and gas wells of interest such as JRS Farms 22. Details on these active oil and gas wells may be located within permit **Section 1 and Section 2**. Out of an abundance of caution, this will allow Milestone to monitor plume and pressure changes in proximity to active oil and gas wells even though the oil and gas wells are not within the AoR. Monitoring well locations are illustrated in **Figure 6-2**.

6.5.2 Location of USDW Monitoring Wells

Milestone will construct five (5) water wells that are co-located with near surface seismometers. The water-seismometer wells will be drilled in a grid pattern around the AoR with four (4) on the edges and one (1) in the approximate center.

Since there is a substantial depth difference between the top of the aquifer and the USDW depth, Milestone will also construct one (1) USDW monitoring well, Wellbore Diagram is found in **Section 3**. In order to maximize detection, the Midland NSSW #5 will be located in the updip direction for the Edwards-Trinity (Plateau) aquifer (NW). Meanwhile, the Midland USDW #2 will be located in the updip direction of the Dockum aquifer (SW). More about aquifer structure is described in **Section 1.4.**

Monitoring well locations are illustrated in **Figure 6-2**.

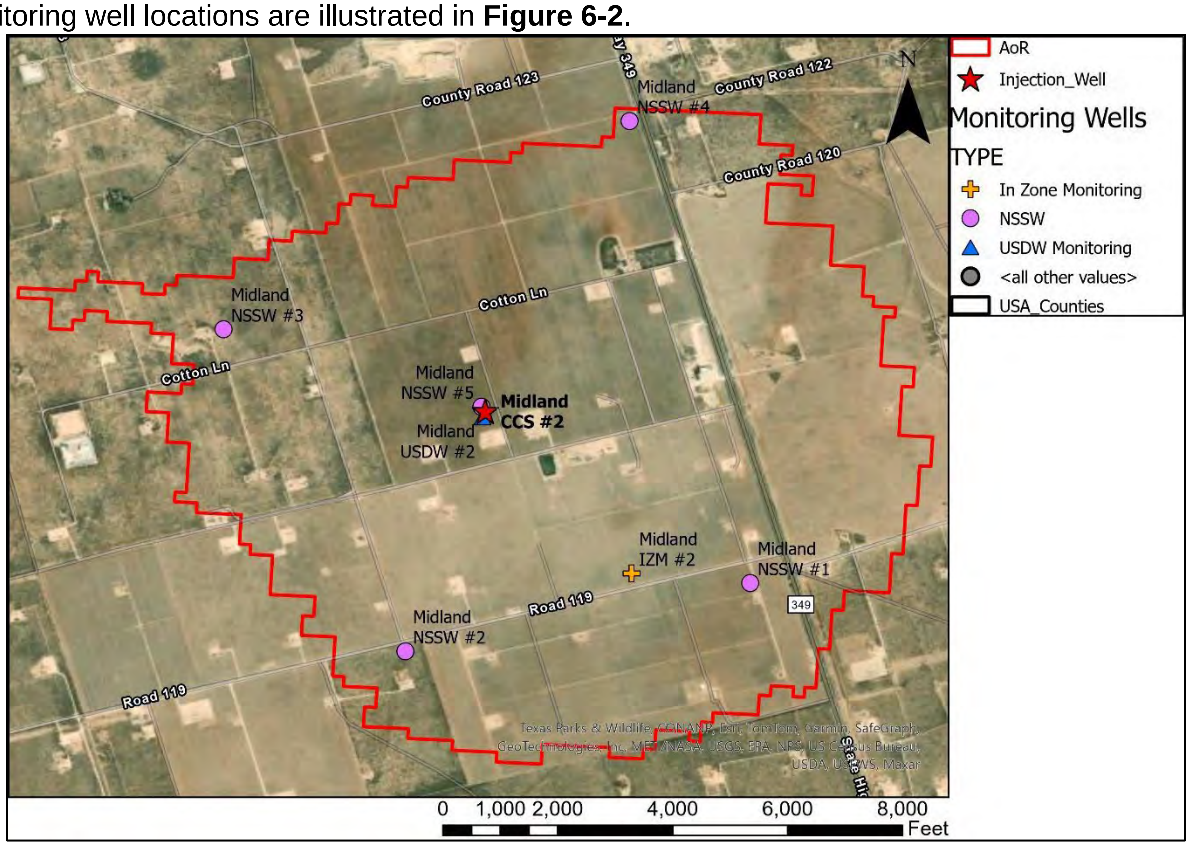

Figure 6-2: Map of Monitoring wells in relation to Injection Wells

6.5.3 USDW and Above Zone Water Quality Monitoring

All samples in this section will be having a testing schedule outlined in **Table 6-2** and a testing matrix found in **Table 6-3**.

Before drilling, and again before commencing injection, per 40 CFR 146.82(a)(6), Milestone will acquire baseline water samples from five (5) wells that are co-located with near-surface seismometers. The water well's locations will be selected to encompass the area of review. All aquifers within the area of review will be sampled, in this case Dockum and Edwards-Trinity (Plateau) aquifers. Water samples will be taken from the same near-surface seismometer/water wells as a baseline, then once quarterly during the injection phase of the project. Seismometer/water-sampling wells will have electrical probes installed for continuous monitoring of alkalinity, pH and electrical conductivity (EC). These probes will be used to monitor potential contamination of the Edwards-Trinity (Plateau) aquifer which is closer to the surface than the deepest USDW. A schematic, not to scale, of the seismometer/water well design can be found at the end of **Section 3.**

Within the USDW monitoring wells, electrical probes will be used for continuous monitoring of alkalinity, pH and electrical conductivity (EC). These probes will be used to monitor potential contamination of the lowermost USDW, the Dockum aquifer. Milestone will acquire water samples from the USDW monitoring wells before injection begins as a baseline then at least once (1) quarterly during the injection phase of the project to monitor for changes in brine chemistry. The number of monitoring locations and frequency of sampling is detailed in **Table 6-2**. A schematic of the USDW monitoring well can be found in **Section 3**.

Milestone will install a U-tube system on offset In-zone Monitor wells (IZM Wells) to monitor brine chemistry and gas concentration in the first permeable zone above the Top Seal. The monitored formation is expected to fall within the Pennsylvanian section below the Wolfcamp but above the top-seal, probably the Strawn formation. Well schematic for IZM Wells may be located within **Section 3**. Milestone will acquire a baseline water sample before injection begins and then once (1) every year during the injection phase of the project.

A decrease or increase in value beyond seasonal variation and/or the measurement accuracy could be an indication of potential CO_2 entering the hydrosphere and will be further investigated. Values that spur investigation are found in **Section 6.5.6.**

Table 6-2: Monitoring of groundwater quality and geochemical changes above the confining zone

Target Formation	Approximate Depth	Monitoring Activity	Monitoring Location(s)	Water Sample Frequency
Edwards-Trinity (Plateau)	300 ft	Sampling, Probes	5	Baseline, then Quarterly
Lowermost USDW (Dockum base)	1250 ft	Sampling, Probes	1	Baseline, then Quarterly
Pennsylvanian	11000 ft	Sampling (U-tube)	1	Baseline, then Annual

6.5.4 Discrete Chemistry and Isotope Analysis

Water samples taken during and before the injection phase of the project will be tested for the chemistry and isotope analysis contained in **Table 6-3**. Post injection, water testing will be conducted in exactly the same manner, but it is duplicated for ease of reading in **Section 9**.

Table 6-3: Summary of analytical and field parameters for groundwater samples

Parameter	Frequency	Analytical Methods
Dissolved CO_2	Annual	Coulometric Titration, ASTM D513-11
Total dissolved solids	Annual	Gravimetry, APHA 2540C
pH (field)	Annual	EPA 150.1
Specific conductivity (SC) (field)	Annual	APHA 2510
Temperature	Annual	Thermocouple
Water Density	Annual	Oscillating body method
Cations – Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	Annual	ICP-MS, EPA Method 6020
Cations – Ca, Fe, K, Mg, Na and Si	Annual	ICP-OES, EPA Method 6010B
Anions – Br, Cl, F, NO_3, HCO_3 and SO_4	Annual	Ion Chromatography, EPA Method 300.0
δ 2H and δ 18O isotope analysis	Annual	Isotope ratio mass spectrometry
δ13 C dissolved inorganic carbon	Annual	Isotope ratio mass spectrometry
Alkalinity	Annual	APHA 2320B

6.5.5 Sampling and Analytical Methods

Fluid samples in NSSW monitoring wells and the USDW monitoring well will be collected at the monitored formation temperatures and maintained at the formation pressures within a pressurized sample container to prevent any losses of dissolved gases. Prior to sampling, the well will be purged of any fluid stored in the wellbore. Static fluid level and temperature will be measured prior to purging the well. A U-tube sampling system will be lowered to the monitored zone, via wireline or slickline, and the rate of sample collection should not exceed the rate at which the well was purged.

For In-zone Monitoring well, a permanent U-tube sampling system will be installed within the annulus and used to sample the brine above the Top Seal.

Water samples will be tested, and results maintained for the parameters listed above. If any impurities exist in the injectate, they should also be tested within the groundwater samples to detect any concentrations beyond the baseline. Results from the samples will be maintained in an electronic database. All samples will be individually numbered, and EPA/TCEQ best practices will be used.

6.5.6 Values that May Indicate Leakage

Trends that may indicate fluid leakage and will trigger an investigation, include:

- Major change in TDS, minus seasonal variation
- Major change in signature of major cations and anions, minus seasonal variation
- Major change in carbon dioxide concentration, minus seasonal variation
- Major change in Carbon 13 and Oxygen 18 isotopic values
- Major change in pH
- Major increase in concentration of injectate impurities.

6.5.7 Laboratory Chain of Custody Procedures

Water samples will be sent to a third-party commercial water testing laboratory. Standard chain-of-custody procedures will be followed, and records will be maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

6.5.8 Quality Assurance and Surveillance Measures [40 CFR 146.90(k)]

Water samples will be sent to a third-party commercial water testing laboratory. Standard chain-of-custody procedures will be followed, and records maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

6.6 External Mechanical Integrity Testing [40 CFR 146.89, 40 CFR 146.90(e)]

Continuous DAS and fiber strain data will be utilized to verify external mechanical integrity. Results of DAS and strain data will be interpreted, collated and submitted to the director at least once per year. DAS/strain data will be submitted in lieu of wireline logging. Wireline noise and temperature logging or oxygen activation logs will not be conducted unless a probable mechanical integrity leak is detected. The results of DAS/strain will demonstrate the absence of significant fluid movement into the USDW, and no significant leak in casing, tubing or packer as required by 40 CFR 146.89(a)(c) and 40 CFR 146.90(e).

Additionally, Milestone will utilize USIT, CIT, CBL and EM tools (casing inspection tools) at least once every five (5) years during the injection phase to verify mechanical integrity pursuant to 40 CFR 146.89(d). Milestone will conduct casing inspection logging on both Injection Wells and In-Zone Monitoring Wells but not USDW or NSSW monitoring wells.

Additionally Internal mechanical integrity of the injection wells will be demonstrated via a tubing-casing annulus pressure test prior to injection and at least once every five (5) years. Continuous annular pressure monitoring to satisfy 40 CFR 146.89(b) is described in **Section 6.2**.

In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, Milestone will apply methods and standards generally accepted in the industry. When Milestone reports the results of mechanical integrity tests to the Director, it will include a description of the test(s) and the method(s) used when making evaluations per 40 CFR 146.89(f).

6.7 Pressure Falloff Testing [40 CFR 146.90 (f)]

Milestone will perform pressure falloff tests during the injection phase as described below to meet the requirements of [40 CFR 146.90(f)]. A pressure falloff test will be performed in the injection well prior to initiation of CO_2 injection activities and at least once every five (5) years thereafter to demonstrate storage reservoir injectivity. The results of these tests will be reported to the UIC Division on Form UIC-5 within 30 days of the test. These tests will be used to measure formation properties near the injection well and to monitor for any changes in the near-well bore environment that may impact injectivity and increase pressures.

6.7.1 Testing Method

Prior to beginning the pressure falloff test, injection rate and pressure will be maintained as constant as possible, while continuously recorded. Upon shutting in the well, pressure measurements will be taken continuously through the use of at least two bottomhole pressure gauges, with one serving as a backup and for verification in cases of questionable data quality (see **Section 3** for location of bottomhole permanent pressure gauges). The falloff period will continue until radial flow conditions are observed, as indicated by a straight line of pressure decay on a semi-log plot.

6.7.2 Analytical Methods

Standard diagnostic log-log and semi-log plots will be generated with observed pressure changes and/or pressure derivative plots. The purpose of these tests is to determine specific near-wellbore conditions, such as well skin, the prevailing flow-regimes and hydraulic property and boundary conditions. Comparison of pressure falloff tests prior to beginning injection operations with those performed subsequently can indicate whether significant changes in the well or reservoir conditions have occurred. Analysis will consider the effects of two-phase flow effects, and parameters determined from the falloff test will be compared to those used in the site computational modeling and AoR determination. Any significant changes in reservoir properties may result in a reevaluation of the AoR (see **Section 2-AoR Re-Evaluation Criteria**). Results of the pressure fall of test will be reported to the UIC Division within 30 days of the test.

6.7.3 Quality Assurance/Control

All field equipment will be inspected and tested prior to use. Pressure gauges used in the falloff test will be calibrated in accordance with manufacturers' recommendations and calibration certificates will be provided with the test results. The use of the second bottom-hole pressure gauge will further provide validation of the test results.

6.8 Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.90 (g)]

Milestone will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of [40 CFR 146.90(g)]. A summary of direct and indirect methods is found in **Table 6-4**.

6.8.1 Direct Monitoring Methods

To directly monitor and track the extent of the CO_2 plume within the storage reservoir, the Injection Well and the In-zone Monitoring (IZM) well will be equipped with fiber optic cable cemented behind the annulus of the casing, (**Section 3** - Well Schematics). The In-zone monitoring well will additionally be equipped with U-tube sampling systems. Monitoring of the overlying interval can provide an early warning of out-of-zone migration of fluids, which provides sufficient time for the development and implementation of mitigation strategies to ensure these migrating fluids do not impact a USDW or reach the surface.

The fiber optic sensing system installed within the Injection Wells will be used to acquire continuous high-resolution temperature (DTS) and acoustic data (DAS). The fiber optic sensing system in the Injection well will not cover the injection zone, only the Top Seal. Having the fiber along the Top Seal allows monitoring the integrity of the seal and CO_2 leak behind the casing.

The fiber optic system in the IZM wells will be used to acquire DTS and DAS data prior to injection as a baseline survey and yearly once (1) for the first two (2) years and every six (6) months from 3rd year onwards. DTS and DAS data from the IZM wells will be used to track CO_2 plume and pressure front when it migrates to the IZM wells. This data provides both horizontal extent and vertical extent of the plume at the fiber well (see **Section 6.9** Fiber Optic Monitoring Section for more information).

Pulse Neutron Log (PNLs) of the injection and monitoring wells will also be performed at least once every five (5) years to demonstrate that fluids are not moving beyond the sealing formations. Pre-operational baseline PNL data will be collected in the Injection and In-zone Monitoring wells. These time-lapse saturation data will be used to monitor for potential CO_2 in the formation directly above the storage reservoir, utilizing data from both the Injection wells and In-Zone Monitoring wells as an assurance-monitoring technique.

Milestone will take injection zone fluid samples from IZM wells utilizing two (2) separate U-tube sampling systems that are installed within the annulus. The U-tube sampling systems will be designed to take samples from the Siluro-Devonian interval and the Ellenburger interval, both of which are within the injection interval. Fluid samples from the IZM wells will be taken prior to the start of injection and at least once (1) annually during the injection period.

Fluid samples from injection wells will only be taken once (1) every five (5) years when the downhole valve is removed for MIT testing. Fluid sample laboratory testing program is summarized in **Table 6-3** and In-zone samples testing will use identical procedures to Above-zone fluid samples.

Table 6-4: Summary of Direct and Indirect Plume and Pressure Front Monitoring

Monitoring Activity	Property to Measure	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PLUME MONITORING				
DAS/DSS/DTS	CO_2 Leakage	Injection Well	Wellbore	Continuous[1]
DAS/DSS	Pressure and Plume Front	In-zone Monitoring Well	Wellbore	Before Injection, then yearly for the first two years and then every 6 months
Pressure Gauges	BH Injection Pressure, BH Annular Pressure	Injection Well	Wellbore	Continuous[1]
Pulse Neutron	CO_2 Saturation (Plume front)	Injection Well, In-zone Monitor Well	Wellbore	Before Injection, then every 5 years
Water Sampling	Plume Front; CO_2 Leakage	Injection Well, In-zone Monitor Well	Wellbore	Monitor Well - 1 Year prior to Injection then Annually; Every 5 years in Injection Well
INDIRECT PLUME MONITORING				
Microseismic Monitoring	Pressure Front (Mode 2 Deformation)	Wellbores DAS, Sparse Near-Surface Array	Wellbore Locations, Estimated edge of the Area of Review	NSSW Wells – Continuous at 5 Milliseconds; DAS see above DAS entry
Surface Electromagnetic Survey (CSEM)	Plume Front (Conductivity)	Surface EM Array	Estimated Area of Review (AoR) at that time to a maximum of 9 sq. mi area	Before Injection, 1 year after injection starts, then every 5 years
PASSIVE SEISMICITY MONITORING				
Passive Seismicity	Earthquakes	5 Surface Seismometers	Operator owned stations within AoR; TexNet + USGS	Continuous[1] from 6 months prior to injection

[1] Continuous is defined more precisely in **Table 6-1** and in **Table 6-5**

6.8.2 Indirect Monitoring Methods

Indirect monitoring methods will track the extent of the CO_2 plume front and pressure front within the storage reservoir. The fractured nature of the injection interval renders traditional 4D seismic and Vertical Seismic Profiles (VSP) methods ineffective. Therefore, Milestone will forgo more traditional 4D seismic methods in lieu of methods more suitable for fractured carbonates. Microseismic monitoring surveys and Electromagnetic surveys will be utilized to determine pressure and plume front respectively.

At the conclusion of the injection phase of the project, the monitoring program will permit an assessment of the long-term containment and stability of the injected CO_2 within the storage complex. This assessment is required to secure a certificate of project completion from EPA. To this end, monitoring of the storage complex will continue following the cessation of CO_2 injection until it can be established that the injected CO_2 plume is stable.

6.8.2.1 Microseismic Surveys

Milestone will conduct a microseismic survey at the start of injection for a maximum duration of three (3) months and then subsequently once every five (5) years for a maximum duration of one (1) month. Milestone will utilize existing near-surface seismometers and cemented DAS during the surveys. Milestone may also utilize additional temporary surface stations, and a temporary lowered vertical geophone array in one or both of the monitoring wells at the time of the survey if existing permanent equipment is not sufficient to detect and locate events. Milestone does not expect to see microseismic events induced from the injection wells at the start of injection. However, Milestone does expect to see events from offset oil and gas operations such as hydraulic fracturing of the overlying Wolfcamp and Spraberry formations (data supporting this is found **Section 6.10.3**). See **Section 6.9 and 6.10** for additional information on fiber optic monitoring and passive seismicity respectively.

6.8.2.2 Controlled Source Electromagnetic Surveys

Controlled-source electromagnetic (CSEM) method is a proven geophysical technique for exploration, production and monitoring of oil and gas resources and natural mineral deposits. In this remotely sensing method, usually a grounded electric bipole (via two electrodes) energizes the subsurface with an alternative current containing a variety of spectrum of frequency to produce time-varying electric and magnetic fields that can be measured on the earth's surface. The measured electromagnetic (EM) data can be processed and interpreted to infer the information about the electric conductivity or its reciprocal resistivity of the subsurface (**Figure 6-3**).

According to Archie's law (G. Archie, 1942), the electrical resistivity of formation rocks is highly sensitive to changes in water/brine saturation (Sw). Consequently, this high sensitivity to Sw in a reservoir can be exploited by EM techniques. Since electric resistivity is primarily a function of pore fluid rather than rock matrix, EM methods may have higher sensitivity in some cases than other geophysical methods, for example, the seismic method. EM methods have been shown to be effective in fractured reservoirs as they are often employed to track hydraulic fracturing of low porosity, low permeability formations.

When CO_2 is injected to the reservoir formation, assuming no hydrocarbons are present, the water saturation S_W is directly related to the injected CO_2 saturation by $S_W = 1 - S_{CO2}$. In terms of its EM effects, as illustrated in **Figure 6-3**, there are two consequences: increase the volume of the CO_2 plume and change the CO_2 resistivity. For example, if the CO_2 saturation is 0.05 (or 5%), it will result in 10.8% change in CO_2 resistivity, compared with the virgin formation resistivity ρ_f. For a CO_2 saturation of 0.2 (or 20%), the resistivity will be changed by 56.3%. Indeed, EM response shows higher sensitivity to CO_2 saturation.

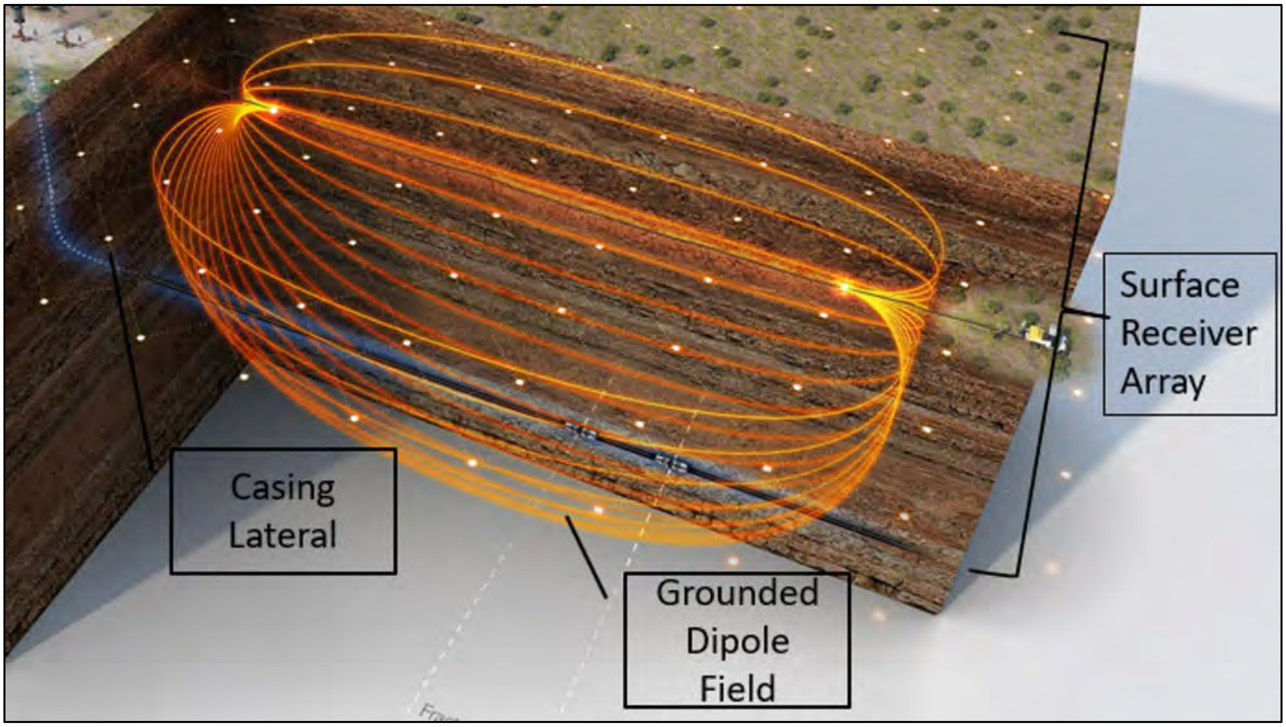

Figure 6-3: Schematic Example of EM survey
CSEM survey of a horizontal hydraulically fractured well showing the detectors, transmitters and electric field produced during a CSEM survey

Two orthogonal transmitter electrodes connected by a cable, are deployed on the surface, providing up to 200 kW power to energize the subsurface. To effectively suppress the noise and increase signal-to-noise ratio, a unique pseudorandom current waveform is injected into the ground. A set of sensitive receivers are distributed on the survey area (the yellow dots) on a regular grid and can register the two orthogonal components of the electric field in both time and frequency domains (**Figure 6-3**). The scattered electric fields, which are the difference between the post-injection and pre-injection measurements, are sensitive to the conductivity or resistivity change in the injection zone. Therefore, by continuously measuring these field changes with time, the injected fluid or CO_2 movement could be monitored through 3D EM forward modeling and inversion.

Tx-Rx layout is displayed in **Figure 6-4**, where about 300 receivers are deployed in a circle of radius of 2,000 ft around the injection well. Two orthogonal electric components will be picked up by these sensors, and the Rx spacing is about 300 ft. One of the transmitter electrodes is positioned close to the cased injection well, hoping enough EM energy will reach out to the injection zone of interest at depth of 12-14,000 ft. The other transmitter electrode will be put 3,600 ft away from the injection well. We expect that using this Tx-Rx layout will cover the injection scenarios within 10 years of operation. Receiver density and spacing will be adjusted as the plume model and front evolves over time.

Milestone will conduct a CSEM survey once before injection, then once at year one (1) after injection begins and finally subsequently once every five (5) years from the start of injection, until injection terminates. Each survey will utilize static and variable injection rates. Milestone will ramp up injection rates over a period of 12 hours while measuring the CSEM survey then measure for 12 hours of sustained constant rate. Measurements will be compared to petrel simulations of CO_2 plumes.

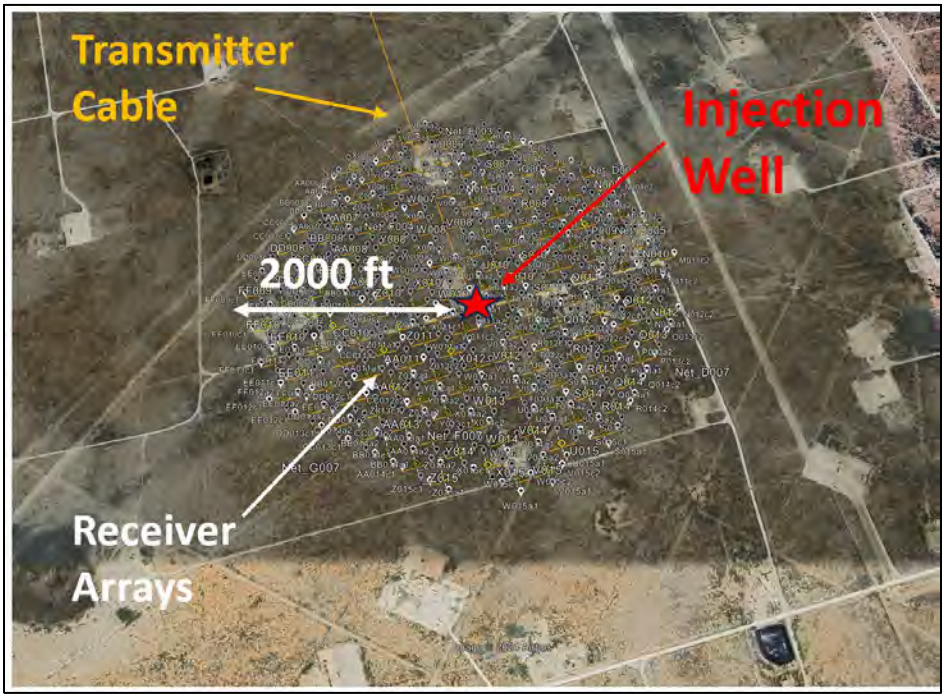

Figure 6-4: Schematic Example of CSEM Survey Transmitter and Receiver spacing

6.8.2.3 Ineffectiveness of Active Seismic Methods

Milestone undertook forward modeling to test the negative hypothesis: *CO_2 injection would not alter the 3D seismic response*. Using Hampson Russel® Software, Milestone conducted fluid substitution using the Pegasus Field Unit #20-12 log (API#: 42-461-32586). Milestone simulated 1) initial conditions, where the injection interval is filled with reservoir brine; and, 2) fully saturated with injectate (60% CO_2 saturation) and displayed them side-by-side to compare the endmembers (**Figure 6-6**).

The fluid substitution forward model was generated using a wavelet that was extracted from the 2D seismic data. It has a frequency content of 13 Hz to 37 Hz (**Figure 6-5**) in the deep stratigraphic section of Fusselman and Ellenburger. Note that the maximum amplitude in the power spectrum occurs at 20 Hz, and that the amplitudes diminish from there to 37 Hz. It was important to use this wavelet, as it represents the actual frequency distribution of the recorded seismic data in the area, rather than a hypothetical frequency distribution. The results were compared against a theoretical wavelet with 5-50 Hz and uniform frequency content as a baseline, but the result was the same.

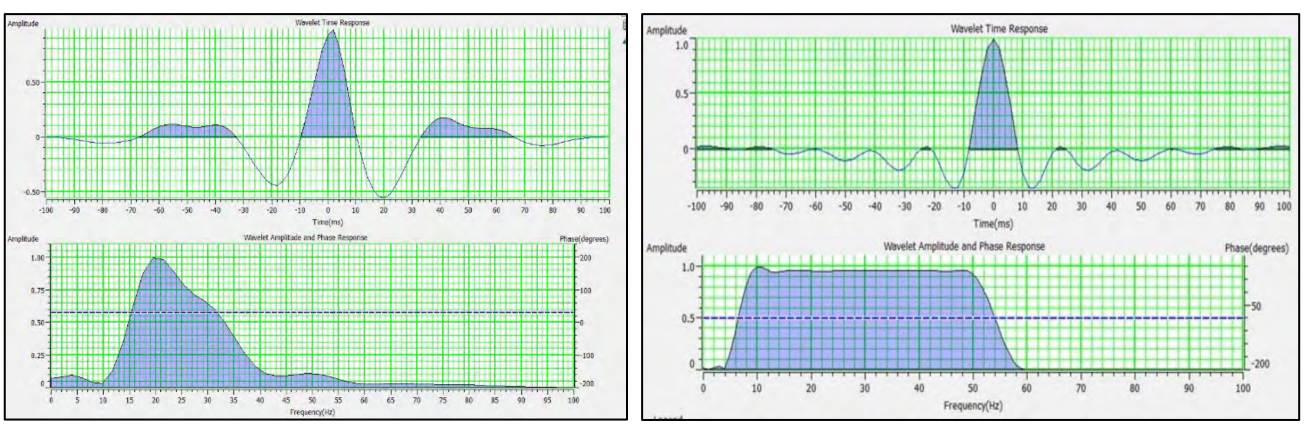

Figure 6-5: Wavelet and Power Spectrum Extracted from Seismic Dataset
(Left) is the actual seismic data from the 2D lines in the area. (Right) is the theoretical wavelet with 5-50hz

The basic data used in the generation of the models were:

A. Ellenburger
   a. Mineralogy: 90% Dolomite, 10% Calcite
   b. Kdry (Bulk Modulus): 50 GPa
   c. Threshhold Porosity: 0.5%
   d. Fluid Saturation Post Injection: 60% CO_2 + 40% Brine
   e. CO_2 Density: 0.8 g/cc
   f. Bulk Modulus CO_2 : 0.5 GPa

B. Siluro-Devonian
   a. Mineralogy: 40% Quartz, 60% Calcite
   b. Kdry (Bulk Modulus): 29 GPa
   c. Threshhold Porosity: 0.5%
   d. Fluid Saturation Post Injection: 60% CO_2 + 40% Brine
   e. CO_2 Density: 0.8 g/cc
   f. Bulk Modulus CO_2 : 0.5 GPa

The models show that there is no discernable change between the two fluid endmembers. Because there is no change, it is highly unlikely that 4D seismic or VSP measurements would be able to effectively monitor the migration of the CO_2 plume. Therefore, Milestone will not undertake any active seismic shoots during monitoring. This model will be updated with new data after the test well is drilled to continue to verify the negative hypothesis.

This lack of observable alteration to the seismic response by the change of fluids is likely due to the following factors: 1) low porosity for the fluid to occupy, thereby changing the total bulk modulus very little; 2) dolomite has one of the highest frame bulk moduli - in laymen's terms it is a rigid frame that has a very low strain response to stress; and, 3) low seismic frequency content due to very deep depths, seismic compressional waves and shear waves are attenuated with depth, therefore as depth increases frequency content decreases.

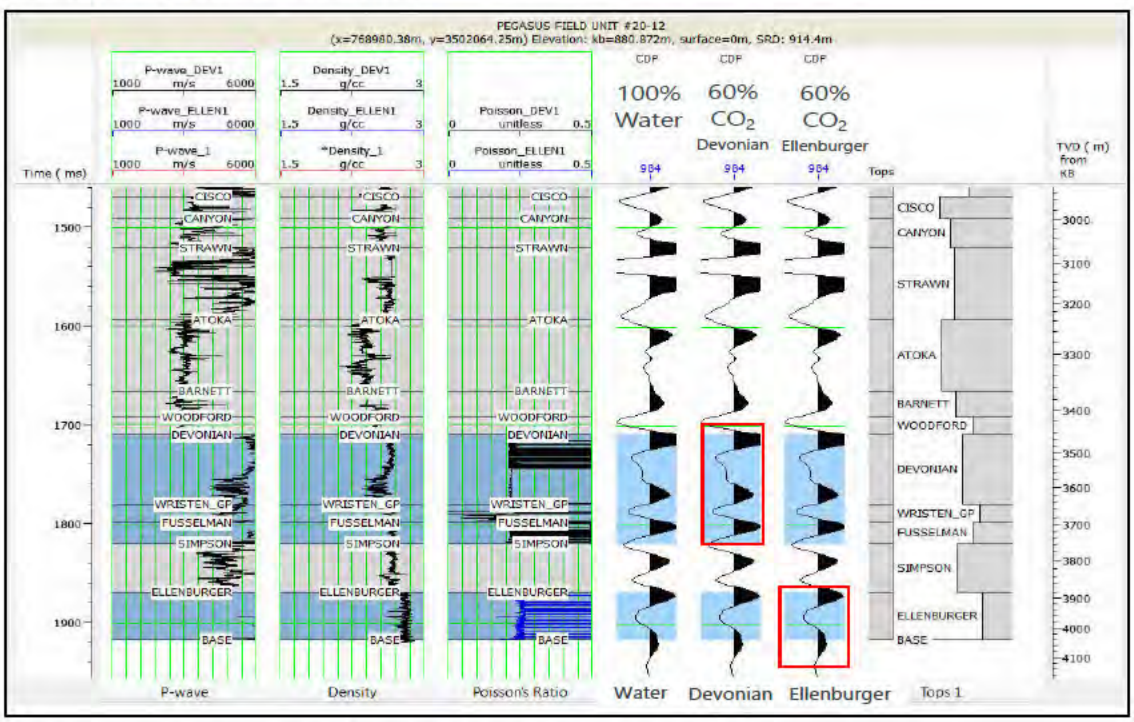

Figure 6-6: Fluid Substitution Forward Model of Pegasus Field Unit #20-12

6.9 Fiber Optic Monitoring

Milestone will deploy a downhole fiber optic cable behind the casing in the Injection Well and the In-Zone monitoring well. Each well will be equipped with a single cable containing five (5) fiber strings in three (3) tubes. There are three tubes inside the cable, each tube containing fibers for specific sensing technologies. Among these, there will be (1) dedicated buffered single mode DSS fiber, two (2) will be single-mode (SM) fibers, while the remaining two (2) will be multi-mode (MM) fibers. One SM fiber will serve for both Distributed Acoustic Sensing (DAS), while one MM fiber will be designated for Distributed Temperature Sensing (DTS). The other two fibers will act as backups in the event of damage. In the event the dedicated DSS SM fiber is damaged, the SM fiber(s) will serve as backup.

In the realm of distributed sensing technologies such as DAS, DSS and DTS, fiber optic serves as the fundamental medium for data collection and analysis. These systems employ fiber optic cables as distributed sensors, enabling the continuous monitoring of physical parameters such as acoustic signals, strain distribution, and temperature variations along the length of the fiber. In DAS, the fiber acts as a sensitive microphone, detecting acoustic disturbances through changes in backscattered light. DSS utilizes the fiber's intrinsic capability to measure strain by monitoring changes in its optical properties caused by mechanical deformation. Similarly, DTS relies on the fiber's sensitivity to temperature-induced changes in light signal transmission, allowing for precise temperature measurements along the entire length of the fiber.

6.9.1 Distributed Acoustic Sensing (DAS)

DAS data can be utilized for two applications. One is to monitor the microseismicity using the higher frequencies (> 10 Hz), called DAS Microseismic data and lower frequencies (< 0.1 Hz), also called low-frequency DAS (LF-DAS) data for strain monitoring.

6.9.1.1 DAS Microseismic

DAS microseismic data is very similar to geophone microseismic data with a difference being the number of components and number of sensors (array aperture). Downhole geophones have three components (perpendicular to each other) that are used to constrain the azimuth of the microseismic events, whereas fiber is equivalent to a single component (along the fiber cable) geophone. Because of its single component nature, there is an uncertainty in the azimuth of the events recorded by a single fiber cable. However, the uncertainty in the azimuth can be resolved in two scenarios.

- Having DAS data acquired from multiple fiber wells: Milestone will have DAS data continuously acquired in two injection wells and periodically acquired in two monitoring wells.
- Combine DAS data with downhole and/or surface geophones/seismometers: Milestone will have continuous fiber data from both injection wells and near surface seismometers/geophones.

Combining the microseismic data from fiber(s) with near surface seismometers and/or downhole geophones will increase both precision and accuracy of microseismic event locations.

6.9.1.2 DAS Strain (LF-DAS)

DAS strain data serves various applications contingent upon the fiber's installation location, be it within an injection or offset monitoring well. It entails a near-field direct assessment of stress alterations in the rock encircling the fiber. Strain data acquired within the injection well is termed In-well Strain (IWS), while that obtained in the offset well is denoted as Cross-well Strain (CWS).

CWS data serves to monitor the CO_2 pressure front, plume, and any strain proximal to the fiber stemming from fracture dilation, pore pressure changes, or fracture openings and closures. Moreover, the monitoring well fiber can detect any CO_2 leakage through its casing. Pre-injection CWS data establishes a baseline for strain and noise in the vicinity of the fiber. Deviations from this baseline signal treated as an anomaly in the data, prompting a thorough analysis to ascertain the underlying causes. This analysis will include integration with other datasets to corroborate whether these anomalies indicate the migration of the CO_2 pressure front or plume to the offset well, or if there is a CO_2 leak through the casing, or any other potential causes.

In the monitoring wells, baseline CWS data will be acquired for seven (7) days prior to the injection. Based on the CO_2 dynamic reservoir simulation models, it will take approximately three (3) years for CO_2 pressure front and seven (7) years for plume to migrate from CCS #2 to IZM #2 well. Post-injection, CWS data will be acquired yearly once (1) for the first two years and every six (6) months from third year onward as it takes about 3 years for the CO_2 pressure front to travel to the monitoring well from the injection well **(Section 2).**

IWS data will be continuously acquired in the injection wells, commencing with pre-injection baseline measurements. Unlike CWS data, IWS strain will exhibit abnormal signals whenever injection starts and stops due to pressure and temperature fluctuations in the wellbore. If abnormal strain signals originate from the top and propagate downward over time, it suggests that the signal's source is at the wellhead, likely caused by CO_2 entering the wellbore. Conversely, if the abnormal signal initiates from the bottom of the fiber and progresses upward with time, it indicates that the signal's source is at the bottom of the wellbore. This signal will undergo careful analysis by qualified experts to detect any potential CO_2 leaks through the casing or tubing.

In addition to direct DAS strain data, we will derive additional attributes, including Frequency Band Extracted (FBE) data across various frequency bands (1-10, 10-50, 50-200 Hz, etc.) and cumulative strain to aid in monitoring potential casing leaks, and a deeper comprehension of stress changes in proximity to the fiber.

6.9.2 Distributed Strain Sensing (DSS)

Distributed Strain Sensing (DSS) is another fiber technology that requires a special interrogator other than DAS interrogator. Both DAS and DSS measures strain on the fiber but using different scattering mechanisms. DAS works based on Rayleigh back scattering while DSS works on Brillouin back scattering. DSS measures absolute strain with high spatial resolution whereas DAS measures relative strain. DSS provides continuous measurements over long periods (timelapse measurements), making it suitable for static strain monitoring. DAS relies on the interaction between laser light and acoustic disturbances along the fiber. As a result, it is particularly effective in capturing dynamic strain events, such as microseismic events.

Another distinction between DAS strain and DSS lies in the fiber requirement. DSS necessitates a tight-buffered single mode (SM) fiber cable to accurately detect mechanical strain changes. Milestone will deploy a dedicated DSS fiber cable within a separate tube. If the DSS cable is damaged, the SM DAS cable can serve as a backup, but the data quality may be poorer. The DSS cable does not have a backup line due to the buffering.

6.9.3 Distributed Temperature Sensing (DTS)

Distributed Temperature Sensing (DTS) technology offers precise measurements of absolute temperatures within and around the wellbore, employing a high spatial resolution of 1 meter and a temperature resolution of 0.01-degC. DTS utilizes a multi-mode (MM) fiber, distinguishing it from DAS and DSS, which utilize single-mode (SM) fiber. In injection wells, the fiber spans from the well's top to the bottom of the seal, and throughout the entire wellbore in monitoring wells, providing a comprehensive temperature profile over time, and used to monitor CO_2 leaks and casing integrity.

Prior to commencing DTS recording, calibration occurs using known temperature measurements obtained either from the surface fiber or downhole temperature logs planned to run before injection commencement.

For monitoring CO_2 injection effects, pre-injection measurements establish the geothermal gradient within the wellbore, serving as baseline temperature. Any deviations from this baseline are deemed abnormal, potentially attributed to external factors such as CO_2 ingress from the wellhead or leakage along the casing from the reservoir.

Interpreting DTS data is straightforward. Temperature changes starting from the top of the fiber (typically the wellhead) and descending with time indicate CO_2 movement from wellhead. Conversely, changes originating from the fiber's bottom suggest CO_2 movement upwards, potentially through annuli or casing leaks. Abnormal temperature observations are cross-referenced with DAS strain and pressure gauge data installed in the annulus between casing and tubing.

LF-DAS Strain data from DAS or DSS are influenced by both temperature and rock stress changes surrounding the fiber. To accurately identify stress changes, temperature effects are removed from the strain data. Establishing a temperature-strain relationship facilitates this removal, given the direct proportionality between temperature and strain.

DTS data acquisition occurs at 5-minute intervals due to potential temperature stability over short durations. In injection wells, continuous DTS acquisition begins from the pre-injection baseline. In In-zone monitoring wells, data is acquired pre-injection and annually for the initial two (2) years, transitioning to biannual acquisitions thereafter.

6.9.4 Fiber Optic Data Retention

Fiber optic data recording frequency, recording interval, storage and deletion schedule of raw and processed data is presented in **Table 6-5**. It should be noted that raw fiber data will be kept for only one year due to the massive amount of data that is expected to be generated. Processed data will be retained for 10 years.

Data will be overwritten on a rolling basis. This retention strategy of raw and processed data is designed to align with the reporting schedule in **Section 6.1** to give the EPA UIC director and Milestone both time to respond to any anomalous fiber optic readings. It is expected that results from the processed data will answer nearly any historical questions.

It is expected that with the sampling frequency in **Table 6-5,** the interrogators will generate over 80 terabytes (TB) of raw data in the one-year retention timeframe.

Fiber optic cables generate significant data volumes due to their ability to perform high-resolution, continuous, and distributed sensing over long distances. They collect data at high frequencies and with fine spatial resolution, sometimes down to one meter (3.28 feet) or less. This results in numerous data points, as each segment of the cable acts as an individual sensor across potentially miles of infrastructure. Additionally, fiber optic systems can measure various parameters—such as temperature, strain, and pressure—simultaneously, contributing to the overall data load. When monitored continuously over extended periods, often years, the data generated becomes immense, requiring advanced storage, processing, and analysis to provide insights into subsurface conditions, optimize production, and maintain operational safety. Once the data is processed, any insights are likely to come from the processed data. It would take an extraordinary event or error in processing workflow to have to go back to the raw data and reprocess it. Milestone will keep the raw data for 1 year to account for the chance such an error or event occurs.

Table 6-5: Fiber Optic Data Parameters, Acquisition and Storage Timeline

Data Type	Min. Sampling Frequency	Min. Recording Frequency	Raw Data Storage Time	Processed Data Storage Time
DAS (Microseismic and Strain)	2 seconds	**Injection well:** Continuous. **In-Zone Monitoring well:** yearly once (1) for the first two years and every six months thereafter	1 year	10 years (strain data and located microseismic event waveform data only)
DSS	5 min	**Injection and In-Zone Monitoring wells:** yearly once (1) for the first two years and every six months thereafter contingent upon the usefulness of the data as fiber may not be suitable for DSS measurements	1 year	10 years
DTS	5 min	**Injection well:** Continuous. **In-Zone Monitoring well:** yearly once (1) for the first two years and every six months thereafter	1 year	10 years

6.10 Passive Seismicity Monitoring

6.10.1 Near Surface Seismometers

Throughout the operational phase of injection operations, continuous monitoring of seismicity will be performed. Existing seismometer stations within Texnet will be utilized. There is currently only one (1) Texnet station within 10 miles of the Injection Well (**Figure 6-9**). Five (5) additional Milestone owned broadband stations will be installed ("array" of near-surface seismometers) sufficient to confidently measure baseline seismicity 10 km (6.2 mi) radially from injection down to a magnitude of completeness of less than zero (<0) (**Figure 6-7**). The array will have a vertical uncertainty of <1,080 ft and a horizontal uncertainty of <1,500 ft (**Figure 6-8**). This magnitude of completeness and uncertainty analysis is based on forward modeling Milestone conducted through a consultant ISTI which is an expert in seismicity. Milestone owned stations will be deployed in a circular pattern around the AoR and one station will be deployed roughly in the center of the AoR.

The data collected in the near-surface seismometers will be continuously recorded at 200 Hz and monitored for potential seismicity magnitudes and hypocenter locations. The detectors will be co-located with water sampling locations and the detectors cemented below the surface to avoid surface noise and signal losses. Given the high sensitivity of this array, it is likely that real-time microseismic events will also be detected. See permit **Section 3** for NSSW well construction details.

Seismometers will record at a 5-millisecond frequency, or 200 Hz and data will be kept for the life of the project. Data will only be included in the report to UIC Director when a seismic event greater than magnitude one (1) is measured. Earthquakes less than magnitude 2.5, with hypocenters within 10 km of site, may not be analyzed by staff. Hypocenters within 10 km of site, over magnitude 2.5, will be reviewed by qualified seismologists. Baseline passive seismic data will be collected six (6) months prior to injection. If increasing trends of seismicity are observed, or a linear pattern is observed, a report on the trend will be submitted to the EPA UIC Director.

Seismicity risk is low in northern Upton County, see permit **Section 1** for further details on historical seismicity. There is a trend of earthquakes, mostly less than M2.0, located 5 miles west of the Well associated with Pegasus Field injection. This fault will not be affected due to low pressure change.

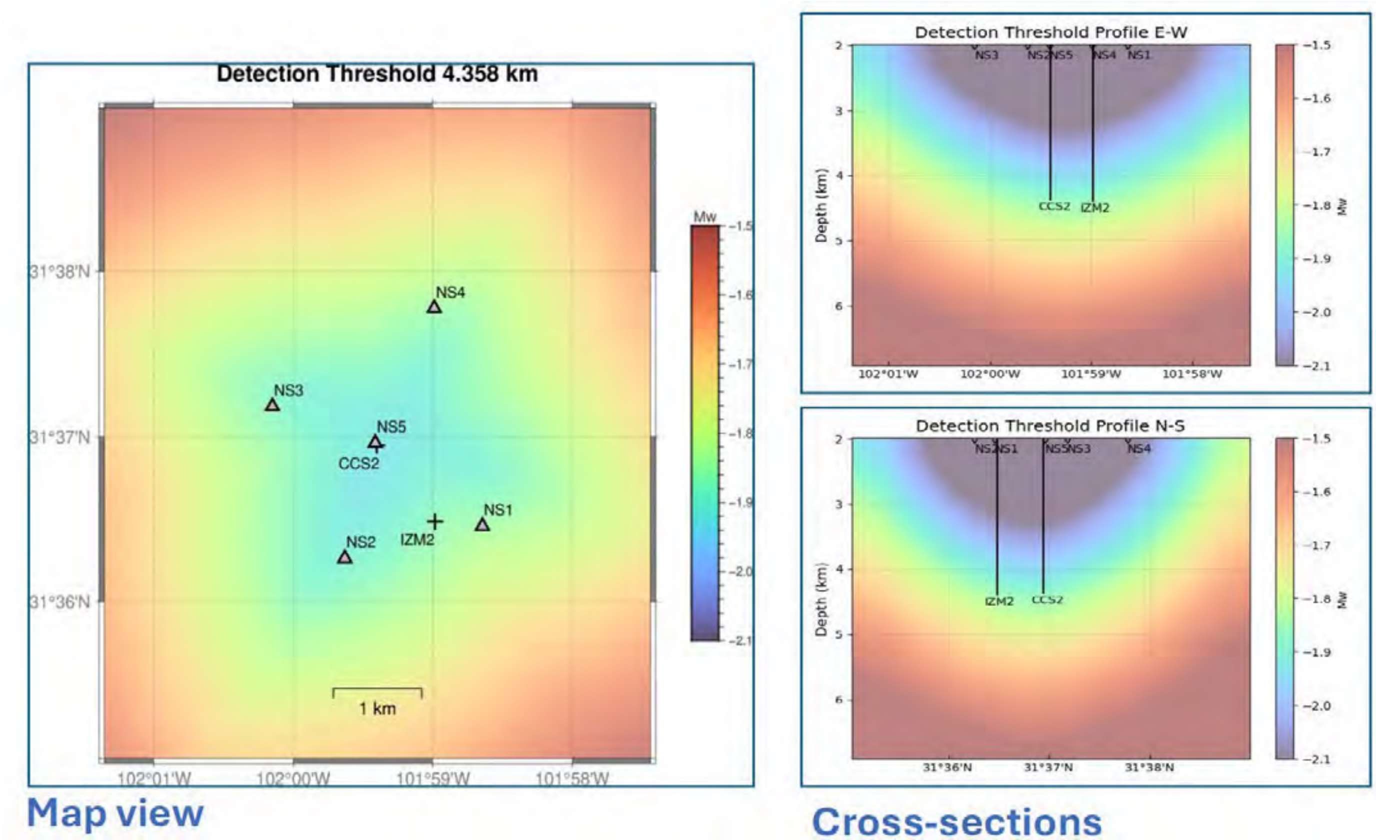

Figure 6-7: Forward Modeled Magnitude of Completeness
(Left) Map View of average magnitude of completeness at all depths, (Right) Cross Section views from N-S and E-W showing magnitude of completeness at depth, NS Wells = NSSW wells. Midland CCS2 in center

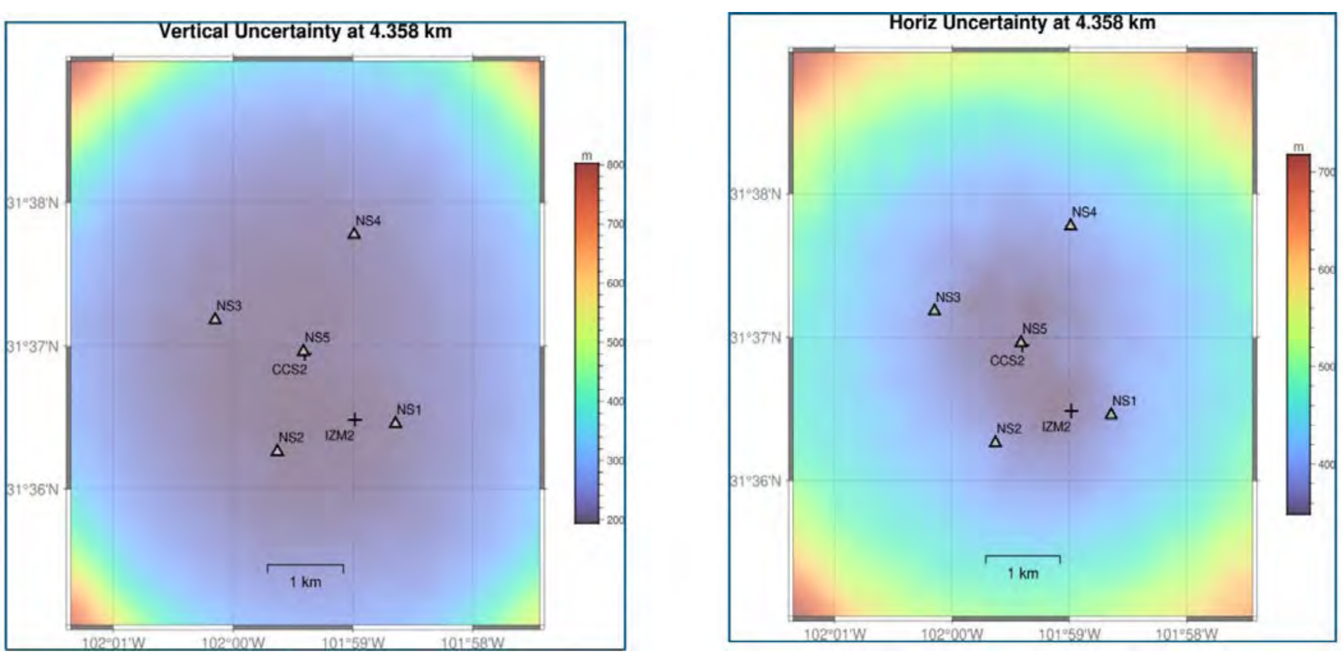

Figure 6-8: Forward Modeled Vertical and Horizontal Uncertainty for Earthquake Hypocenter
(Left) Vertical Uncertainty of Earthquake Hypocenters, (Right) Horizontal Uncertainty of Earthquake Hypocenters, NS Wells = NSSW wells. Midland CCS2 in center

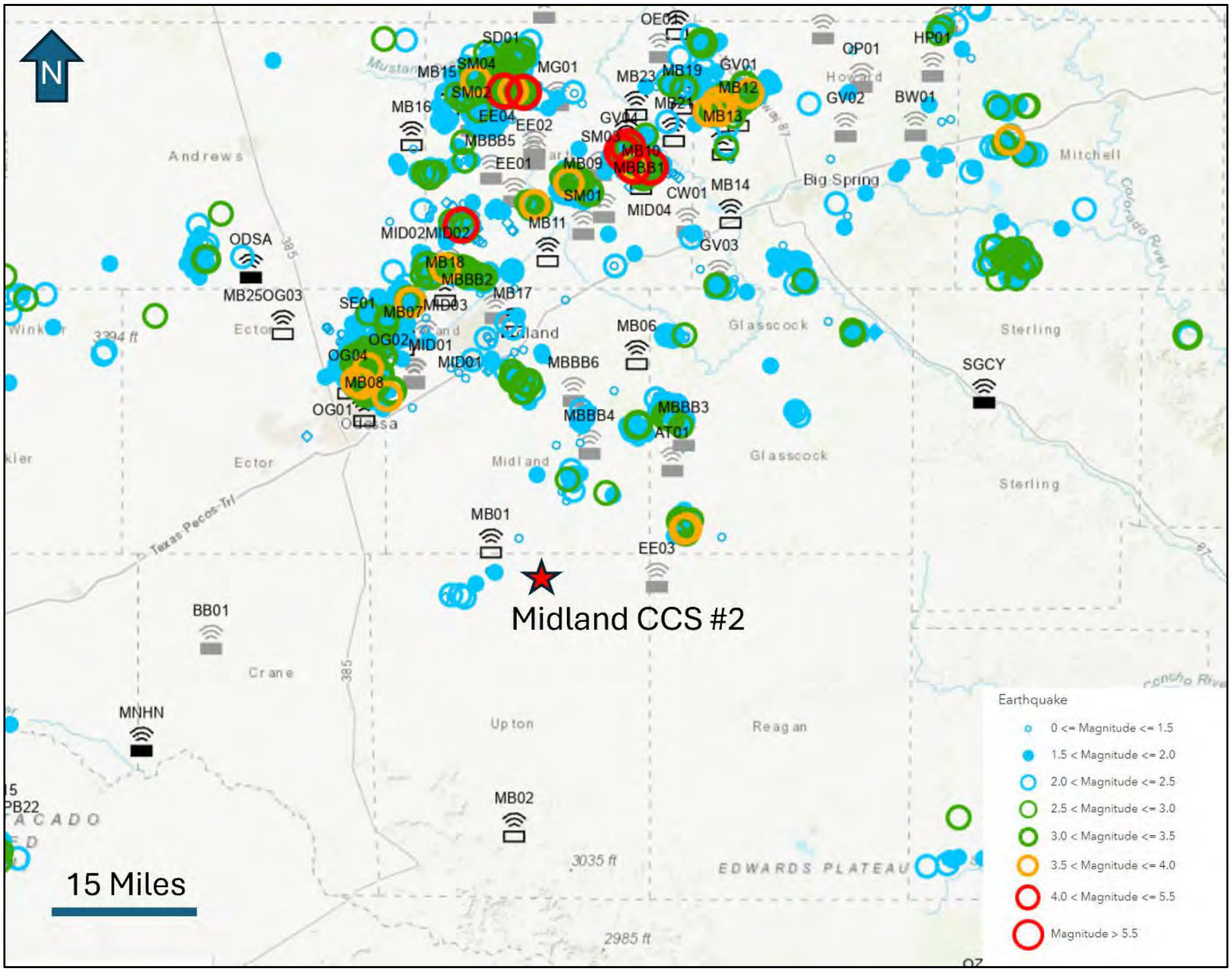

Figure 6-9: Map of Existing Texnet Detectors at time of application and Earthquakes Since 1/1/2017

6.10.2 Downhole Fiber (DAS Microseismic)

Fiber installed in the injection wells will continuously gather Distributed Acoustic Sensing (DAS) data to monitor induced seismicity. However, due to sensitivity limitations, the fiber can only detect events with a moment magnitude of +0.5 or higher. Any event detected by both the fiber and surface and near surface stations above magnitude 2.5 will undergo co-location to enhance depth accuracy. Conversely, if an event is detected solely by one of the downhole fibers, it will carry a 360-degree uncertainty in location azimuth, attributable to the single-component nature of the fiber. This azimuth uncertainty can be reduced if the event is recorded by multiple fiber wells.

6.10.3 Downhole Geophones (Microseismic)

Both near-surface seismometers and downhole fiber have limitations on detecting small magnitude events. Based on the previous experiences at Carbon Capture and Storage (CCS) sites, such as Shell Quest facility in Canada, it typically takes several years for induced seismicity, if any, to occur, usually within the basement (Briam et al., 2023). As depicted in **Figure 6-10**, seismicity distribution at the Shell Quest CCS facility indicates that most of the seismic events occurred after 2 years of injection initiation. Continuous monitoring of seismic activity using fiber optics and surface stations allows us to discern seismicity trends. In the event of heightened seismic activity, Milestone will deploy a retrievable geophone array in one or both monitoring wells. The depth of the geophone array will be determined based on observed seismicity from the fiber optics and surface stations. This measure aids in detecting any small-magnitude events (Mw ≥ -0.8) induced by injection and monitors the integrity of the Top Seal.

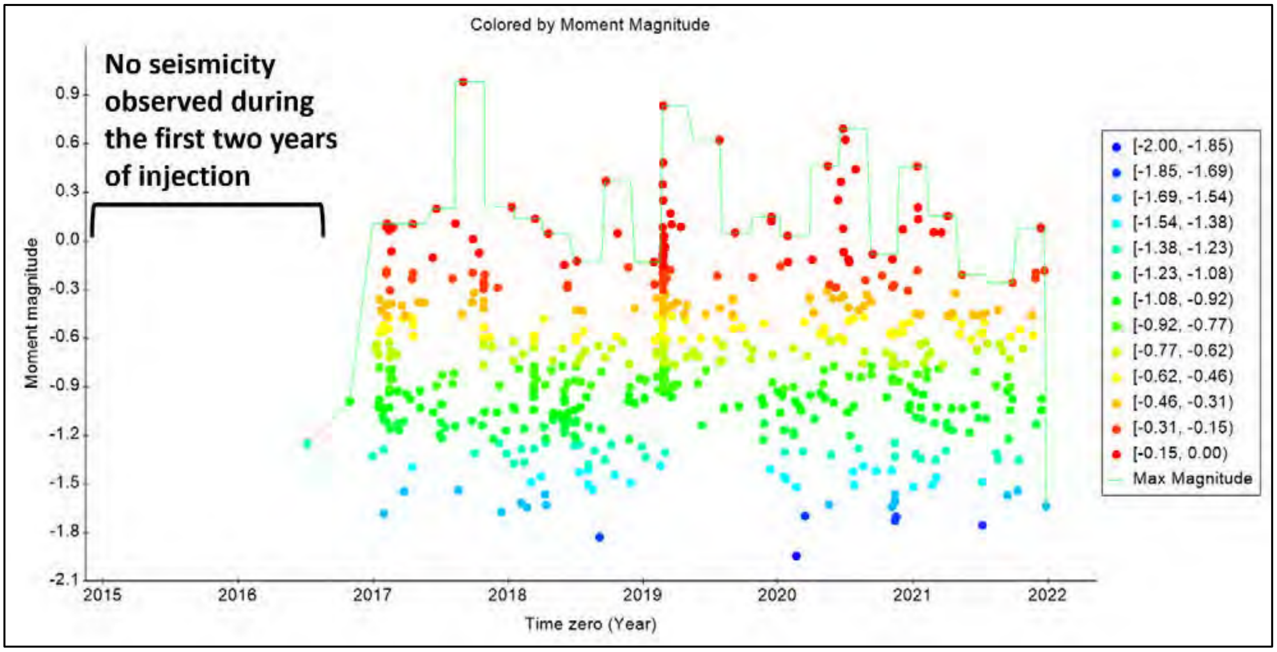

Figure 6-10: Seismicity distribution over time from Shell Quest facility (modified after Braim et al., 2023)

6.11 Soil Gas Monitoring / Other Testing and Monitoring [40 CFR 146.90 (h)]

Surface and near-surface environments will be monitored within the delineated AoR via groundwater wells (see **Section 6.5**) and vadose zone soil gas-sampling prior to CO_2 injection and during the injection phase of the project.

Milestone will test the soil for changes in CO_2 concentration. Six (6) soil gas profile stations will be installed: One at each of the Midland NSSW Wells (#1-#5) and one at the Midland IZM #1. The Midland NSSW #5 is within 100 ft laterally of the Injection Well. Baseline soil gas analyses will be provided to EPA prior to CO_2 injection operations. Once injection commences, soil gas will be measured at least once annually.

Milestone will amend the monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring using baseline data, and the amended monitoring plan will describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under 40 CFR 144.12. An amended soil gas monitoring or surface air monitoring plan will be submitted to the EPA UIC Director within 90 days of receipt of baseline samples.

6.12 Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

Milestone will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a).

Milestone will analyze the CO_2 stream continuously using a continuous gas analysis device after the last stage of compression but before the wellhead. Milestone will employ a device that meets the temperature, pressure and rate requirements of the project. This could include any of the following but is not limited to the following: photometry-based methods, laser-based methods, gas chromatography, mass spectrometry or other suitable devices selected by the surface engineering team. The continuous gas analysis device will record data at least once every five (5) seconds and store data at least once every five (5) minutes.

6.12.1 Validation Sampling frequency

Milestone will sample the gas using a continuous gas analysis device. In addition, Milestone will sample the gas four (4) times annually, every three (3) months, using sample containers, in order to verify continuous field results.

6.12.2 Validation Sampling methods and Location

Milestone will sample the gas using a continuous gas analysis device. In addition, a sampling station will be installed downstream at the last stage of compression in the compressor building (or equivalent structure if a compressor is not needed). The sampling station will have the ability to purge and collect samples into a container that will be sealed and sent to the commercial third-party laboratory for analysis. All sample containers will be labeled with indestructible labels and ingrained markings. A unique sample identification number and sampling date will be recorded on the sample containers.

6.12.3 Validation Sample Analysis Methods

Samples will be analyzed by a third-party commercial laboratory using standardized analytical procedures outlined in **Table 6-6**. Milestone will use the International Society of Beverage Technologists (ISBT) best practices and guidelines for gas testing for each gas species and recommendations from a commercial laboratory on gas standards. Additionally, the isotopic analyses will be outsourced to a separate third-party specialized commercial laboratory that will employ standard analytical QA/QC protocols used in the industry.

Table 6-6: Summary of analytical and field parameters for groundwater samples

Parameter	Frequency	Analytical Methods
Carbon Dioxide (CO_2 Purity)	Twice Annually	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
Oxygen		ISBT 4.0 (GC/DID) GC/TCD
Nitrogen		ISBT 4.0 (GC/DID) GC/TCD
Water Vapor		ISBT 3.0
Hydrogen Sulfide		ISBT 14.0 (GC/SCD)
Sulfur Dioxide		ISBT 14.0 (GC/SCD)
Carbon Monoxide		ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID)
Oxides of Nitrogen		ISBT 7.0 Colorimetric
Total Hydrocarbons		ISBT 10.0 THA (FID)
Methane		ISBT 10.1 (GC/FID)
Acetaldehyde		ISBT 11.0 (GC/FID)
Ethanol		ISBT 11.0 (GC/FID)
Carbon Isotope		Isotope Ratio Mass Spectrometry

6.13 Data Validation of All Processes [16 Texas Statewide Rule §5.203 (a)(4)]

In accordance with Statewide Rule §5.203(a)(4), Milestone affirms that all descriptive reports included in this application have been prepared by qualified and knowledgeable professionals with relevant expertise in subsurface characterization and engineering standards. All future reports to be submitted to the director, as described in **Section 6.1.2**, will similarly be prepared by qualified and knowledgeable professionals with relevant expertise.

6.13.1 Professional Seals and Qualified Experts

Where appropriate and required, the reports have been signed and sealed by either a professional geologist (P.G) or professional engineer (P.E.). It is Milestone's understanding that in the state of Texas, there is unfortunately no legal definition of a professional log analyst. Therefore, where documents are required to be prepared by a professional log analyst, a professional geologist (P.G.) instead has prepared the documents and reports. It should be noted that the P.G. who supervised the work contained in this permit is a longstanding member of the Society of Petrophysicists and Well Log Analysts (SPWLA) and has previously served on the board of directors of the aforementioned society.

This work has been conducted as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, or Chapter 1002, relating to Texas Geoscientists Practice Act, respectively, a licensed professional engineer or geoscientist has conducted the geologic and hydrologic evaluations required in this permit and has affixed the appropriate seal on the resulting reports of such evaluations.

6.13.2 QASP Additional description

As required, a comprehensive Quality Assurance and Surveillance Plan (QASP) has been included in **Section 13- Appendix C**, outlining procedures for validating analytical laboratory data and calibrating field instruments. The QASP also provides a detailed explanation of the sampling methodologies and data acquisition techniques employed to ensure accuracy, reliability, and consistency throughout the project. Documentation of data validation and verification protocols is enclosed to demonstrate the integrity and rigor of the testing and monitoring program.

6.13.3 Data Validation and Verification

To the extent this information is not provided elsewhere in the application, it is hereby submitted in response to the requirements of Statewide Rule §5.203(a)(4). Milestone has established procedures for laboratory data validation and verification, including the use of standard reference materials, duplicate sample analysis, and method blanks to ensure accuracy and precision. Field instruments such as pressure gauges, flow meters, and multi-parameter water quality sondes are subject to routine calibration against NIST-traceable standards. Sampling and data acquisition protocols follow EPA SW-846 and ASTM guidelines, with chain-of-custody documentation maintained throughout all sample handling. All logging tools will be calibrated at the base and in the field prior to measurement. Logs will have a repeat pass to ensure data verification. Fiber-optic cables will be regularly tested for changes in signal to noise ratios, return loss and attenuation as well as drift over time.

These measures collectively ensure the reliability, traceability, and scientific defensibility of all collected data, consistent with the requirements of Rule §5.203(a)(4).

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility
Upton County, Texas

Section 7: Stimulation Program

[40 CFR §146.82 (a)(9)]

Prepared for:

EPA Region 6
Underground Injection Control Section
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MILESTONE
CARBON

Prepared and submitted by:

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Updated 18 October 2024

7.0 STIMULATION PROGRAM [40 CFR 146.82(a)(9)]

Stimulation to enhance the injectivity potential of the injection zone may be necessary. Stimulation may involve, but is not limited to, flowing fluids, including acid, into or out of the well, increasing or connecting pore spaces in the injection formation, or other activities that are intended to allow the injectate to move more readily into the injection formation. Advance notice of all proposed stimulation activities must be provided to the Director, as detailed herein, prior to conducting the stimulation.

Milestone (the permittee) will describe any fluids to be utilized for stimulation activities and will demonstrate that the stimulation will not interfere with containment. Milestone will submit proposed procedures for all stimulation activities to the Director in writing at least 30 days in advance, per 40 CFR 146.91(d)(2). It is understood that within the 30-day notice period, EPA may:

1. Deny the stimulation
2. Approve the stimulation as proposed
3. Approve the stimulation with conditions

Milestone will carry out the stimulation procedures, including any conditions, as approved or set forth by EPA.

Notice and the opportunity to witness the stimulation activities will be provided to EPA at least 48 hours in advance.

Historically, operators have stimulated the Siluro-Devonian and Ellenburger with 15% hydrochloric acid. For example, the nearest saltwater disposal (SWD) well that penetrates the Ellenburger, the Davidson Unit 1 #0106BH (API#:42-461-40597), was stimulated using 1,500 gallons of 15% NEFE HCl acid when it was completed on 12/23/2017. (**Figure 7-1**)

Once core samples are acquired, Milestone will work with best-in-class service companies to determine an appropriate stimulation program, should one become necessary.

47.	ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.	
Depth Interval		Amount and Kind of Material Used
13600.0	14592.0	ACID WITH 1,500G 15% NEFE HCl ACID

48.	FORMATION RECORD (LIST DEPTHS OF PRINCIPAL GEOLOGICAL MARKERS AND FORMATION TOPS)		
Formations	Depth	Formations	Depth
YATES	2730.0 MD: 2731.0	STRAWN	10884.0 MD: 10901.0
GRAYBURG	4491.0 MD: 4493.0	DEVONIAN	
SAN ANDRES - SALTWATER FLOW	4764.0 MD: 4767.0	FUSSELMAN	13021.0 MD: 13051.0
SPRABERRY	7400.0 MD: 7405.0	ELLENBURGER	13537.0 MD: 13568.0
WOLFCAMP	9283.0 MD: 9289.0		
REMARKS: [RRC Staff 2018-06-07 16:36:58.465]: shut-in UIC well type; operator must comply with			

Figure 7-1: Excerpt from Davidson Unit 1 #0106BH W-2 Completion form
Submitted to Railroad Commission of Texas; It is likely that Milestone will have to use a similar acid completion of the Injection Well. Source: Enverus / Railroad Commission of Texas Records

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Section 8: Injection Well Plugging Plan

[40 CFR §146.92]

Prepared for:

EPA Region 6

Underground Injection Control Section

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Updated 16 April 2025

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8.0 INJECTION WELL PLUGGING PLAN [40 CFR 146.82(a)(16),146.92(b) 146.92]

Injection well plugging and abandonment will be conducted according to the procedures herein. Upon completion of the Project, or at the end of the life of the Well, the Well will be plugged and abandoned to meet the requirements of 40 CFR 146.92 and all state and local regulations. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, to resist the corrosive aspects of carbon dioxide/water mixtures, and to protect USDWs. Prior to plugging the injection well, any necessary procedural revisions to address new information will be submitted to the UIC Program Director for review and approval. The final plugging plan will be submitted to the UIC Program Director no later than 60 days prior to plugging of the Well.

Following receipt of the approved plugging plan, the Well will be flushed with a kill weight buffer fluid. A minimum of three (3) tubing volumes will be injected without exceeding fracture pressure.

Bottomhole pressure measurements will be recorded, and the well will be logged, and pressure tested to ensure mechanical integrity prior to plugging. If a loss of mechanical integrity is discovered, it will be repaired prior to proceeding with plugging operations. The plugging procedure is presented herein.

All casing in this well will be cemented to surface at the time of construction and will not be retrievable at abandonment. The injection tubing, valves inside tubing and packer will be removed. After the tubing and packer are removed, a combination of bridge plugs and cement plugs will be set to plug the well.

All casing strings will be cut at least three feet below ground level. A steel plate, with the required permit information, will be welded to the top of the casing.

8.1 Planned Tests / Measures to Determine Bottomhole Reservoir Pressure [146.92 (b)(1)]

Milestone will record bottomhole pressure from a downhole pressure gauge and calculate kill fluid density.

8.2 Planned External Mechanical Integrity Test(s) [146.92 (b) (2)]

Milestone will conduct at least one of the tests listed in **Table 8-1** to verify external mechanical integrity prior to plugging the injection well as required in 40 CFR 146.92(a).

Table 8-1: Pre-Plugging External Tests

Test Description	Location
Temperature Log	Along wellbore using DTS or wireline well log
Noise Log	Wireline Well Log
Oxygen Activation Log	Wireline Well Log

8.3 Plugging Procedures

Notification, regulatory and plugging procedures will include:

8.3.1 Pre-Plugging Activities

1) In compliance with 40 CFR 146.92(c) and 16 TAC §5.203(k), notify the regulatory agency at least 60 days before plugging the well and provide updated plugging plan, if applicable.
2) Bottomhole reservoir pressure will be measured using downhole pressure gauges permanently installed behind the production casing.
3) External mechanical integrity will be demonstrated with temperature, noise or oxygen activation logging.
4) Mechanical Integrity of the tubing-casing annulus will be demonstrated by pressure testing, as described in **Section 6**.
5) The wellbore will be flushed with a kill weight buffer fluid, 9 ppg minimum, prior to pulling the tubing and packer. Minimum of three (3) tubing volumes.
6) The tubing and packer will be removed. A packer milling and retrieval bottomhole assembly will be run to mill the packer slips and pull the packer assembly.
7) Casing inspection and cement bond logs will be performed prior to plugging. Log evaluation will determine if revision to the plugging procedure is necessary.
8) In compliance with 16 TAC §5.203(k), file a notice of intention to plug and abandon (Form W-3A) a well with the RRC at least five (5) days prior to the beginning of plugging operations.

8.3.2 Plugging Activities

1) Run and position workstring at 12,200 feet and pump a 1,649-foot balanced corrosion resistant cement plug from TD to the Devonian top from 13,849 feet to 12,200 feet.
2) Wait on cement, tag and pressure test the corrosion resistant cement plug.
    a. If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 12,200 feet.
3) Pull out of hole and make up a corrosion resistant bridge plug.
4) Run CRA bridge plug and set with workstring in the Woodford shale at 12,160 feet.
    a. Tag and pressure test bridge plug.
5) Position workstring to bridge plug at 12,160 feet and pump a 300-foot corrosion resistant cement plug across the Woodford from 12,160 feet to 11,860 feet.
6) Wait on cement, tag and pressure test the corrosion resistant cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 11,860 feet.
7) Position workstring at 11,603 feet and pump a 200-foot balanced corrosion resistant cement plug across the Atoka top from 11,603 feet to 11,403 feet.
8) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 11,403 feet.
9) Position workstring at 10,945 feet and pump a 200-foot balanced cement plug across the Strawn top from 10,945 feet to 10,745 feet.
10) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional cement plug will be set up to 10,745 feet.
11) Position workstring at 9,224’ and pump a 324-foot balanced corrosion resistant cement plug

across the Wolfcamp top and across the intermediate casing shoe from 9,224 feet to 8,900 feet.

12) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 8,900 feet.
13) Position workstring at 7,671 feet and pump a 200-foot corrosion resistant cement plug across the Sprayberry from 7,671 feet to 7,471 feet.
14) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 7,471 feet.
15) Position workstring at 4,220 feet and pump a 200-foot balanced corrosion resistant cement plug across the San Andres top from 4,220 feet to 4,020 feet.
16) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 4,020 feet.
17) Pull out of hole and make up a cast iron bridge plug.
18) Run cast iron bridge plug and set with workstring at 1,350 feet.
    a. Tag and pressure test bridge plug.
19) Pump a 50-foot corrosion resistant cement plug across the surface casing shoe and USDW from 1,300 feet to 1,250 feet.
20) Wait on cement, tag and pressure test the cement plug.
    a. If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 1,250 feet.
21) Position workstring at 400 feet and pump a 100-foot cement plug 400 feet to 300 feet.
22) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional cement plug will be set up to 300 feet.
23) Pump a 100-foot balanced corrosion resistant cement plug from 100 feet to surface.
24) Cut and cap casing 3 feet to 4 feet below ground level.

A certified plugging report will be submitted to the UIC Program Director within 60 days after plugging pursuant to 40 CFR §146.91(e). The plugging report will be retained for 10 years following site closure.

8.4 Plug Information

The CRA bridge plug, 22CR/25CR or equivalent, and all corrosion resistant cement will be compatible with the injection stream and downhole conditions. The corrosion resistant cement blend, and required certification documents, will be submitted with the final plugging procedure. The operator will report cement densities and retain samples of the cement used for each plug. For all cement plugs, 0% excess will be used to ensure isolation is achieved. All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1k feet of depth from the ground surface to the bottom of the plug. Milestone is currently evaluating CO_2 resistant cement from the industry's leading suppliers, Halliburton and SLB. ThermaLock is an option from Halliburton. EverCrete and Ecoshield are two (2) options from SLB. All the cement solutions have been thoroughly tested and are designed to maintain reliable corrosion resistant properties throughout the life of an injection or monitoring well exposed to CO_2. The products listed above are all rated for the temperature and pressure ranges of the injection and monitoring wells. They will provide long lasting zonal isolation.

ThermaLock is a non-Portland based cement that is a specially formulated calcium aluminate phosphate system which gives it resistant properties to CO_2 corrosion.

Evercrete has long been the reliable workhorse for CO_2 injection wells. Its low permeability allows it to withstand corrosive effects of supercritical CO_2 and has self-healing properties if a fracture is formed. Ecoshield is a geopolymer cement free system that provides an alternative to Portland cement while delivering comparable performance. EcoShield system matches the rheology, thickening time, and compressive strength properties of Portland cement-based systems. The technology fits within standard oilfield cementing workflows without major changes to the design process, onsite execution, or post-job evaluation.

This is an evolving science, and Milestone will continue evaluating the most suitable corrosion resistant cement product for the proposed well plugging. Cement and cement additives will be compatible with the injectate stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project.

Table 8-2 and **Figure 8-1** present details for each plug and the proposed plugging schematic, respectively.

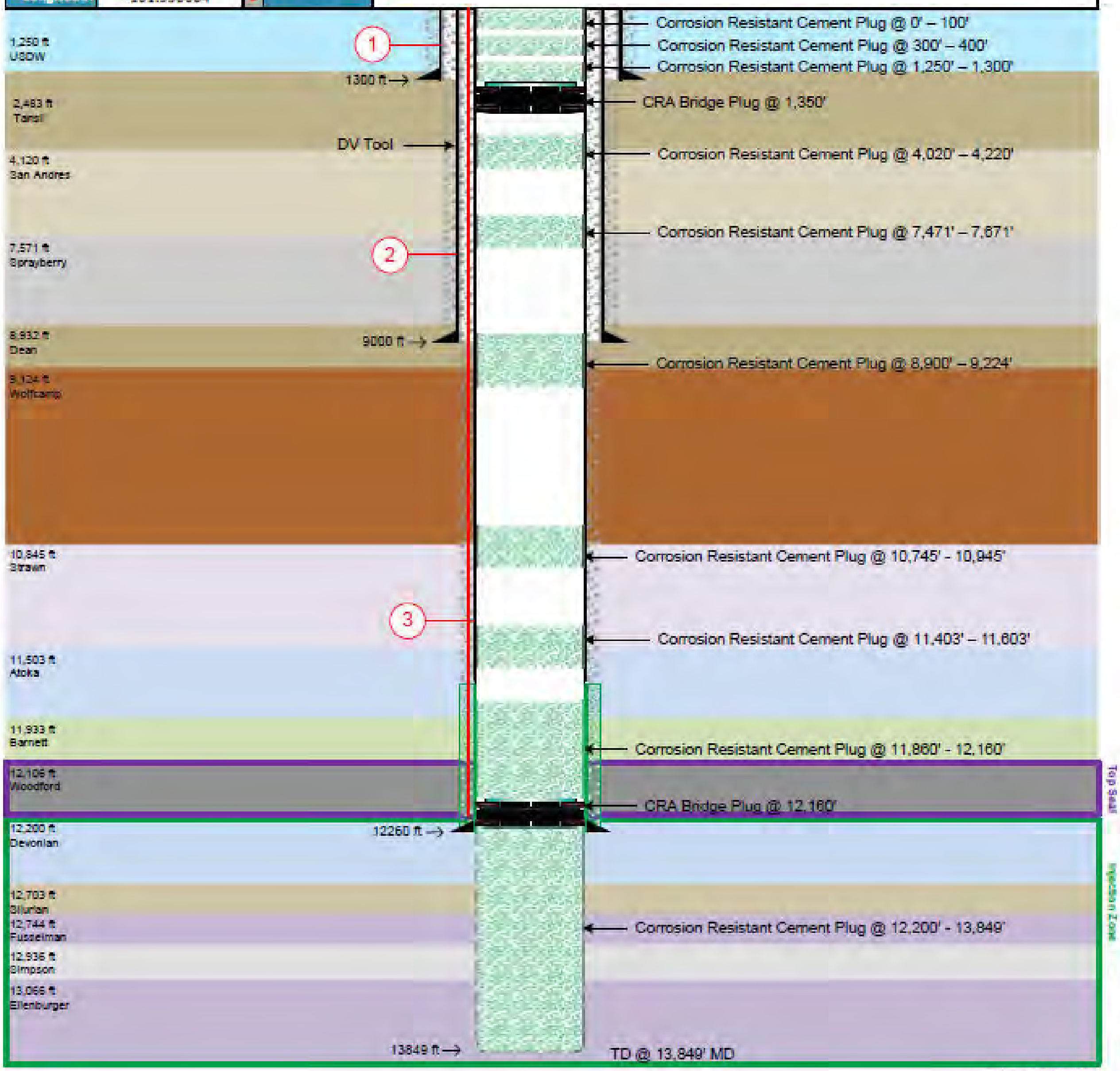
Table 8-2: Midland CCS #2 Well Proposed Plugging Program Detail

Test Description	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7	Plug #8	Plug #9	Plug #10	Plug #11	Plug #12
Diameter of boring in which plug will be Placed (inches)	6.125	6.625	6.625	6.625	6.625	6.625	6.625	6.625	6.625	6.625	6.625	6.625
Sacks of cement to be used (sks)	322	NA	68	45	45	73	45	45	NA	12	23	23
Slurry volume to be Pumped (cu.ft.)	337	NA	71.8	47.9	47.9	77.6	47.9	47.9	NA	12	23.9	23.9
Slurry Weight (lb/gal)	16.4	NA	16.4	16.4	16.4	16.4	16.4	16.4	NA	16.4	16.4	16.4
Length of cement	1,649	NA	300	200	200	324	200	200	NA	50	100	100
Calculated top of Plug (ft)	12,200	12,160	11,860	11,403	10,745	8,900	7,471	4,020	1,350	1,250	300	0
Bottom of plug (ft)	13,849	NA	12,160	11,603	10,945	9,224	7,671	4,220	NA	1,300	400	100
Type of cement or other material	Corrosion Resistant	CRA Bridge Plug	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	CRA Bridge Plug	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant
Method of emplacement	Circulation	Workstring	Circulation	Circulation	Circulation	Circulation	Circulation	Circulation	Workstring	Circulation	Circulation	Circulation

Well Name:	Midland CCS #2
API:	
UIC:	
State:	TX
County:	Upton
Field:	Midland
Lease:	Dusek
Elevation:	2,800'
Depth (TVD):	13,849'
Texas Central NAD 83	
Location X:	1780908.86
Location Y:	10555246.59
Lattitude:	31.615788°
Longitude:	-101.990004°

Casing Program

#		OD (in)	Weight (lb/ft)	Grade	Connection	ID (in)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1	Surface:	13 3/8	54.5	J-55	BTC	12.615	17 1/2	0	1,300	0
2	Intermediate:	10 3/4	51	P110HC	BTC	9.85	12 1/4	0	9,000	0
3	Production:	7 5/8	39	P110EC	VAM 21	6.625	9 1/2	0	11,600	0
				25CRW	SFJ			11,600	12,260	11,600
4	Injection Tbg:									
5										



Printed 3/27/25

Figure 8-1: Midland CCS #2 Well Plugging Schematic

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Section 9: Post-Injection Site Care and Site Closure Plan

[40 CFR §146.93]

Prepared for:

EPA Region 6

Underground Injection Control Section

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Updated 14 January 2026

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9.0 POST-INJECTION SITE CARE & SITE CLOSURE PLAN [40 CFR 146.82(a)(17), 146.93(a)]

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Milestone, the operator of South Midland Facility, will perform to meet the requirements of 40 CFR 146.93. Milestone will monitor groundwater quality and track the position of the CO_2 plume and pressure front for 50 years. Furthermore, Milestone may not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b) (3). Following approval for site closure, Milestone will plug all monitoring wells and submit a *Site Closure Report* and associated documentation.

Please note - Milestone is ***not*** applying for an Alternative Post Site Injection Care Timeline.

9.1 Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

The formation pressure at the Injection Well is predicted to decline rapidly within the first four (4) years following cessation of injection. Based on the modeling of the pressure front as part of the AoR delineation, pressure is expected to decrease to less than 135 psi above pre-injection levels by the end of the PISC (50-year) timeframe.

The maximum predicted injection pressure differential in the wellbore over the life of the project is 1,812 psi over pre-injection levels. The maximum predicted injection pressure differential in the reservoir is 1,594 psi over pre-injection levels. Both pressures occur within one (1) year after the start of injection, likely due to relative permeability effects. Additional information on the projected post-injection pressure declines and differentials is presented in the plume modeling and the Area of Review and Corrective Action Plan, **Sections 2.**

9.2 CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 9-1 shows the predicted extent of the plume and pressure front at the end of the 50-year PISC timeframe (model year-2089), representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results, pursuant to 40 CFR 146.84.

9.3 Post-Injection Monitoring Plan [40 CFR 146.93(a)(2)(iii)]

Performing groundwater quality monitoring and plume and pressure front tracking as described in the following sections during the post-injection phase will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 60 days of the anniversary date of the date on which injection ceases, as described under "Schedule for Submitting Post-Injection Monitoring Results," herein.

Groundwater monitoring will be conducted using the NSSW #1-5, USDW #2 and IZM #2 monitoring wells, as well as the Well. The NSSW wells penetrate the Edwards-Trinity Plateau aquifer at approximately 250 feet. The USDW #2 is a shallow monitoring well that targets the deepest recorded USDW zone, the Dockum aquifer base, located approximately 1,250 feet below the surface. The IZM #2 is a deep In-Zone Monitoring Well that penetrates to the Siluro-Devonian and Ellenburger. All of the monitoring wells are located on Milestone leasehold near roads, so access to the monitoring wells will be guaranteed.

A description of direct and indirect monitoring is covered in **Section 6**. A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the **Appendix C** to the Testing and Monitoring Plan.

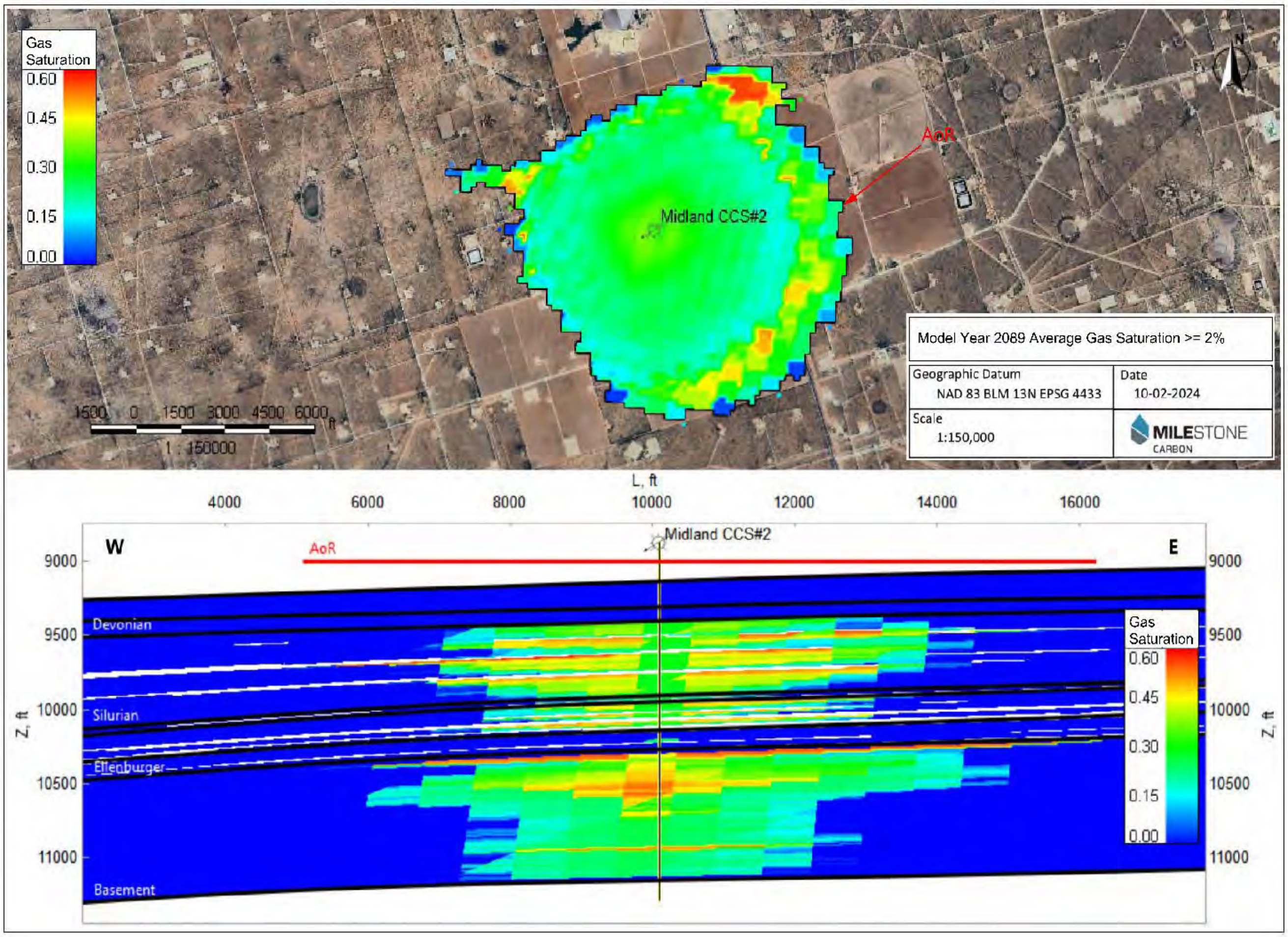

Figure 9-1: Map of the predicted extent of the CO_2 plume 50 years post-closure
Map of the predicted extent of the CO_2 plume at site of closure 50 years after the cessation of injection model year 2089.

9.4 Monitoring Above Confining Zone [40 CFR 146.93(a)(2)(iii)]

9.4.1 Ground Water Testing Frequency

Tables 9-1 and **9-2** present the planned direct and indirect monitoring methods, locations, and frequencies for monitoring of groundwater quality and geochemical changes above the confining zone, in USDW zone, and Pennsylvanian section after injection ceases. **Figure 9-2** shows the locations of the monitoring wells. Continuous monitoring data will be measured at 5-second frequency and recorded at 5-minute intervals unless otherwise specified.

As noted in **Section 6,** the Midland USDW #2 and Midland NSSW #1-5 will be installed with pH and electrical conductivity (EC) water probes for continuous measurement of these properties.

Water sampling and analysis will occur at the end of injection and then annually thereafter until year 10 when sampling and analysis will transition to every five (5) years. Sampling and monitoring will occur up to 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the UIC Program Director.

Logging surveys will occur within 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the UIC Program Director.

Milestone will also employ fiber-optic cable measuring DTS and DAS/DSS to monitor for leakage and pressure directly from the Midland CCS#2 and IZM #2. Milestone will measure DTS continuously and DAS/DSS annually for the first ten (10) years, then every five (5) years thereafter or until the fiberoptic cable fails. The expected lifetime of fiberoptic cable is only approximately 15-20 years as described in **Appendix C** (QASP). The QASP includes a description of the groundwater sampling methods, sample handling and custody protocols and quality control.

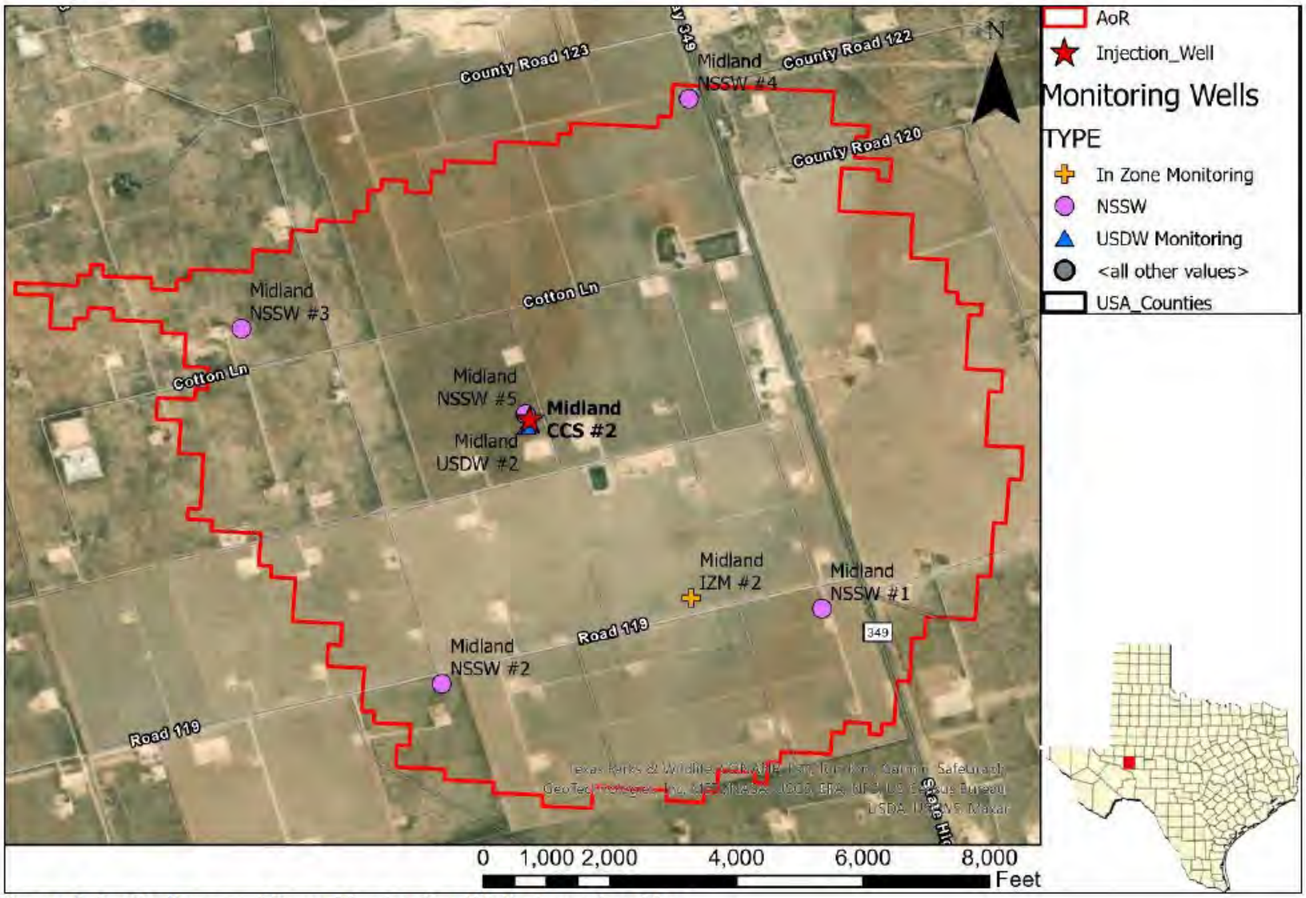

Figure 9-2: Shallow and Deep Monitoring Wells Location Map

Table 9-1: Post-Injection Direct Groundwater and Geochemical Changes Monitoring Above Confining Zone

<table>
<tr><th rowspan="2">Target Formation</th><th rowspan="2">Monitoring Activity</th><th rowspan="2">Locations</th><th colspan="4">Frequency</th></tr>
<tr><th>1st Quarter Post Injection</th><th>Year 2-5</th><th>Year 5-10</th><th>Year 10-50</th></tr>
<tr><td rowspan="2">Edwards-Trinity (Plateau)</td><td>Fluid Sampling</td><td rowspan="2">NSSW #1-6</td><td rowspan="2">Within three (3) months of cessation of Injection</td><td>Annual</td><td rowspan="7">Annual</td><td rowspan="7">Every 5 Years</td></tr>
<tr><td>pH and EC</td><td>Continuous</td></tr>
<tr><td rowspan="2">Dockum</td><td>Fluid Sampling</td><td rowspan="2">USDW #2</td><td rowspan="2">Within three (3) months of cessation of Injection</td><td>Annual</td></tr>
<tr><td>pH and EC</td><td>Continuous</td></tr>
<tr><td rowspan="3">Pennsylvanian</td><td>U-tube Fluid Sampling</td><td rowspan="3">IZM #2; and CCS #2 if possible</td><td rowspan="3">Within three (3) months of cessation of Injection</td><td>Annual</td></tr>
<tr><td>DAS/DSS Pressure/Strain</td><td>Annual</td></tr>
<tr><td>DTS Temperature</td><td>Continuous</td></tr>
</table>

Table 9-2: Post-Injection Indirect Groundwater and Groundwater Changes Monitoring Above the Confining Zone

Target Formation	Monitoring Activity	Locations	Frequency		
			1st Quarter Post Injection	Year 2-10	Year 10-50
Pennsylvanian	Pulse Neutron Logging	IZM #2; CCS #2 If Not Plugged	Within three (3) months of cessation of injection	Annual	Every 5 years

9.4.2 Ground Water Testing Matrix

Table 9-3 identifies the parameters to be monitored, and the analytical methods Milestone will employ to analyze groundwater samples taken from any depth. The table is organized based on interval. Sampling will be performed as described in permit **Section 13 Appendix C** (QASP). The QASP includes a description of the groundwater sampling methods, sample handling and custody protocols and quality control.

In general, Milestone will analyze all water samples for cations, anions, dissolved CO_2, total dissolved solids, alkalinity, pH, specific conductance and temperature.

In deeper intervals, not within the USDW, if dissolved CO_2 is detected above baseline levels, isotopic analysis will be undertaken to attempt to verify the origin. Further the water density will be tested for deeper samples.

9.4.3 Sampling and Analytical Methods

Fluid samples in NSSW wells and USDW monitoring wells will be collected at the monitored formation temperatures and maintained at the formation pressures within a pressurized sample container to prevent any losses of dissolved gases. Prior to sampling, the well will be purged of any fluid stored in the wellbore. Static fluid level and temperature will be measured prior to purging the well. A U-tube sampling system will be lowered to the monitored zone via wireline or slickline and the rate of sample collection should not exceed the rate at which the well was purged.

For In-zone Monitoring well, a permanent U-tube sampling system will be installed within the annulus and used to sample the brine above the Top Seal.

Water samples will be tested, and results maintained for the parameters listed above. If any impurities exist in the injectate, they should also be tested within the groundwater samples to detect any concentrations beyond the baseline. Results from the samples will be maintained in an electronic database. All samples will be individually numbered, and EPA/TCEQ best practices will be used.

9.4.4 Laboratory Chain of Custody Procedures

Water samples will be sent to a third-party commercial water testing laboratory. Standard chain-of-custody procedures will be followed, and records will be maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

9.4.5 Quality Assurance and Surveillance Measures [40 CFR 146.90(k)]

Water samples will be sent to a third-party commercial water testing laboratory. Standard chain-of-custody procedures will be followed, and records maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

Table 9-3: Summary of Analytical and Field Parameters for Groundwater Samples

Parameters	Analytical Methods (1)
USDW (Edwards-Trinity (Plateau) and Dockum)	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3, HCO_3 and SO_4	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Total Dissolved Solids	Gravimetry; APHA 2540C
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Above Confining Zone (Pennsylvanian)	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, HCO_3 and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Note 1*: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with prior approval of the UIC Program Director.*

9.5 Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

9.5.1 Direct and Indirect Monitoring of Plume and Pressure

Milestone will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure. **Table 9-4** presents the direct and indirect methods to monitor the *CO_2 plume* after injection ceases, including the activities, locations, and frequencies to be employed. **Table 9-6** presents the direct and indirect methods used to monitor *CO_2 pressure* after injection ceases.

Direct methods that Milestone will employ are water sampling from the two (2) U-tube systems within the injection interval of the In-Zone Monitoring well. Milestone will sample the Midland CCS #2 and if it is not plugged via a U-tube sampling system lowered on wireline. Milestone will sample the injection interval annually for the first ten (10) years then every five (5) years thereafter. The parameters to be analyzed as part of fluid sampling (and associated analytical methods) are presented in **Table 9-5**. Milestone will also employ fiber-optic cable measuring DTS and DAS/DSS to monitor for leakage and pressure directly from the CCS #2 and IZM #2. Milestone will measure DTS continuously and DAS/DSS annually for the first ten (10) years, then every five (5) years thereafter or until the fiberoptic cable fails. The expected lifetime of fiberoptic cable is only approximately 15-20 years from installation during construction.

Indirect monitoring activities will include pulse neutron logging, electromagnetic (CSEM) surveys, Microseismic surveys, passive seismicity and computational modeling. See permit **Section 6** for more discussion on these techniques. Milestone will undertake pulse neutron logging annually for the first ten (10) years post injection cessation, then transition to every five (5) years thereafter. Milestone will conduct geophysical surveys in year 1, then in years that are prime numbers, years 2,3,5,7 and then discontinue thereafter.

Geophysical surveys may include one or more of the following surface-based indirect measurements:

- Electromagnetic (CSEM) surveys
- Passive Microseismic Surveys
- Other geophysical techniques developed by Milestone during the injection period that have been shown to be effective at indirectly measuring plume and pressure fronts.

Fluid sampling and wireline logging will occur within 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the UIC Program Director. Geophysical surveys will be performed in the 4th quarter before, or the 1st quarter of, the calendar year shown or alternatively scheduled with the prior approval of the UIC Program Director.

Passive seismic monitoring using five (5) near surface seismic stations (NSSW Wells) to detect local events over M 1.0 within the AoR will be measured by Milestone after injection ceases. Passive seismic data will be monitored continuously at 200 Hz, 5 millisecond frequency. Seismicity data will be reported annually unless an event of 2.5 or greater occurs within 10km of the injection wells.

Following the end of injection, the plume is expected to grow slightly as CO2 rises with gravity. Computational modelling throughout the injection period calibrated by recorded data and history matching the injection rates and pressures will be used to further predict the movement of the plume. The CO2 plume measured by geophysical surveys will be integrated into the post-injection dynamic modeling to validate the predicted rate of change in the plume size. Modeling will be updated after new surface geophysical measurements are made.

Table 9-4: Post-Injection Plume Monitoring

Target Formation	Monitoring Activity	Location(s)		Frequency		
				1st Quarter Post Injection	Years 2-10	Years 10-50
Direct Plume Monitoring						
Siluro-Devonian and Ellenburger	Fluid sampling	IZM #2; CCS #2 if not plugged	Within 3 Months of Injection Cessation	Annual		Every 5 Years
IZM #2 – Surface to Basement; CCS #2- Surface to Base of Top-Seal	Leakage Detection DTS Temperature	IZM #2, CCS #2		Continuous Until Fiberoptic Cable Fails		
Indirect Plume Monitoring						
1000ft above Top-Seal, Top-Seal, and Injection Interval	Pulse Neutron Logging	IZM #2; CCS #2 if not plugged		Within 3 Months of Injection Cessation	Annual	Every 5 Years
Surface to Basement	Geophysical Survey(s)	AoR		Within 3 Months of Injection Cessation	Years that are Prime Numbers; Years 2, 3, 5, 7	None
Surface to Basement	Passive Seismicity	AoR		Continuous Until Equipment Fails		
Entire Injection Interval	Computational Modelling Updates	AoR		After Geophysical Surveys		Every 5 years

Table 9-5: Summary of Analytical and Field Parameters for Fluid Sampling

Parameters	Analytical Methods [1]
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3, HCO_3 and SO_4	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density(field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 9-6: Post-Injection Pressure Front Monitoring

Target Formation	Monitoring Activity	Locations		Frequency		
				1st Quarter Post Injection	Years 2-10	Years 10-50
Direct Pressure Front Monitoring						
Entire Injection Interval	DAS/DSS Pressure/Strain	IZM #2; CCS #2 if possible	Within 3 Months of Injection Cessation	Annual Or Until Fiberoptic Cable Fails		Every 5 Years if Cable Usable
Indirect or Ancillary Pressure Front Monitoring						
Entire Injection Interval	DTS Temperature	IZM #2; CCS #2 if possible		Continuous Until Fiberoptic Cable Fails		
Surface to Basement	Microseismic Survey & other Geophysical Surveys	AoR		Within 3 Months of Injection Cessation	Years that are Prime Numbers; Years 2, 3, 5, 7	None

9.5.2 Plume Predictions at Various Time Stamps

Predicted plume geometry relative to the injection well at various time steps post injection is shown in **Figures 9-3** through **9-7**. Changes in plume geometry over the Injection phase, year 2027-2039, are covered in permit **Section 2**.

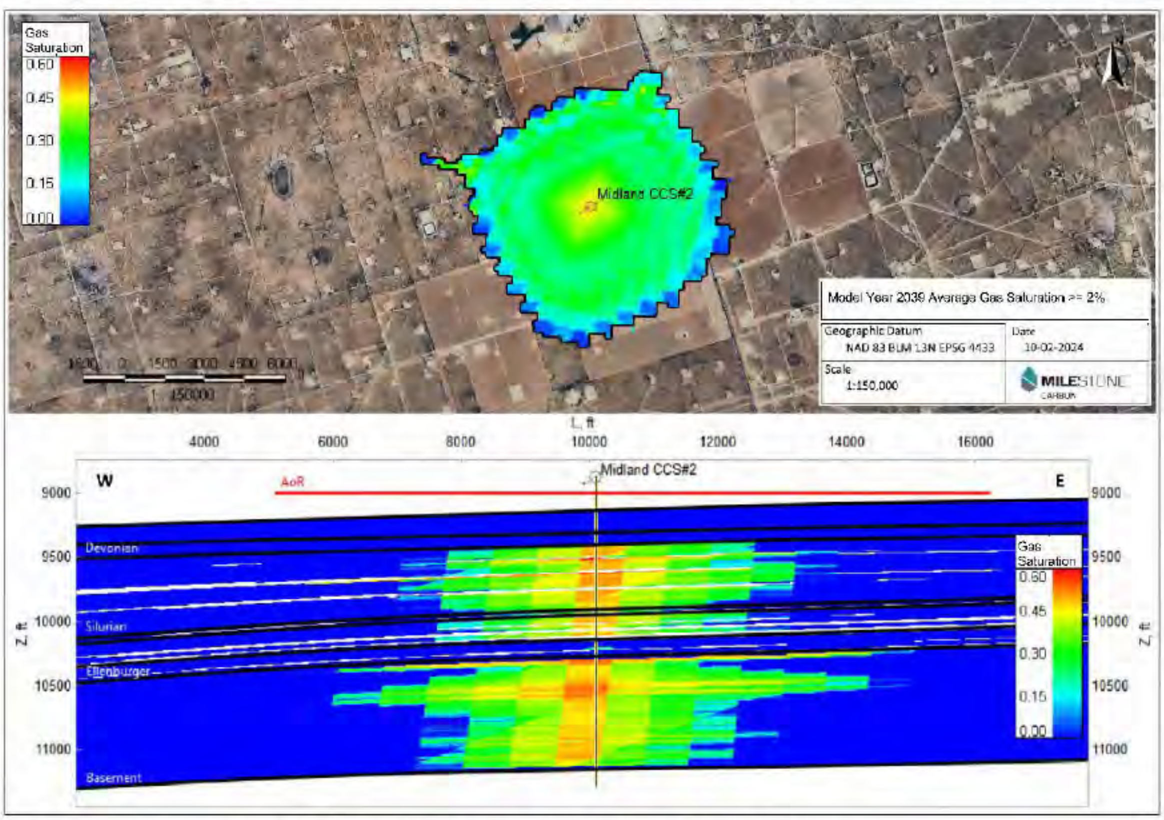

Figure 9-3: Predicted extent of the CO_2 plume – year 2039 – Start of PISC Period
Map of the predicted extent of the CO_2 plume and pressure front relative to monitoring locations at the end of the injection period, model year 2039.

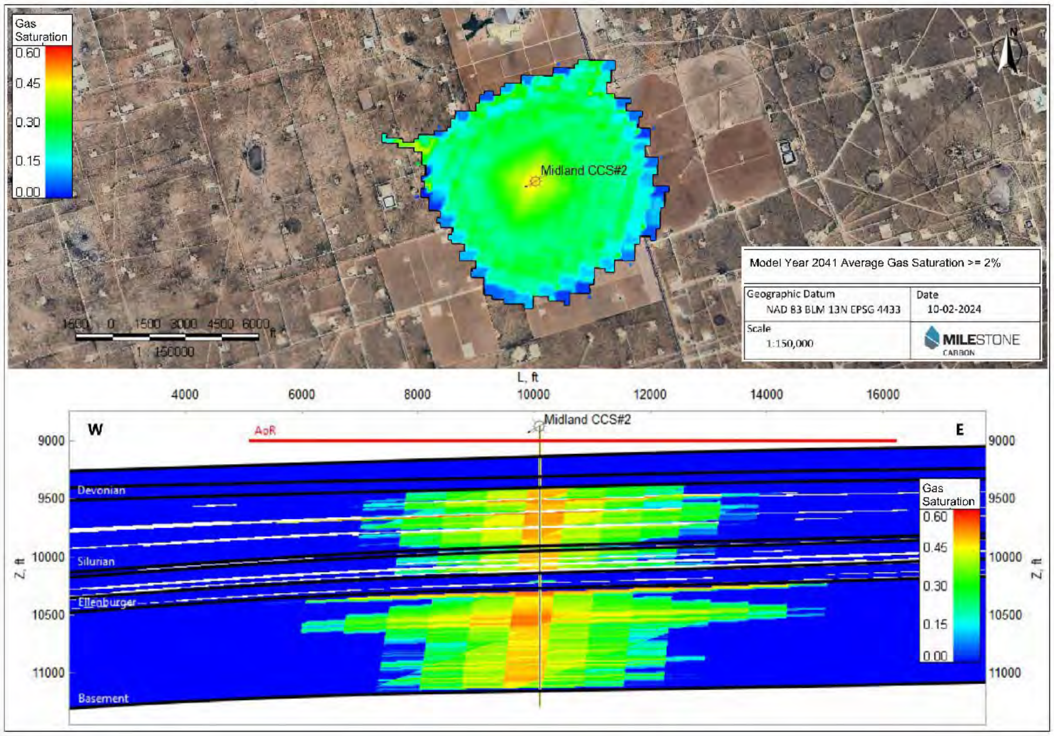

Figure 9-4: Predicted extent of the CO_2 plume – year 2041

Map of the predicted extent of the CO_2 plume and pressure front relative to monitoring locations 3 years after cessation of injection – modeled year 2041.

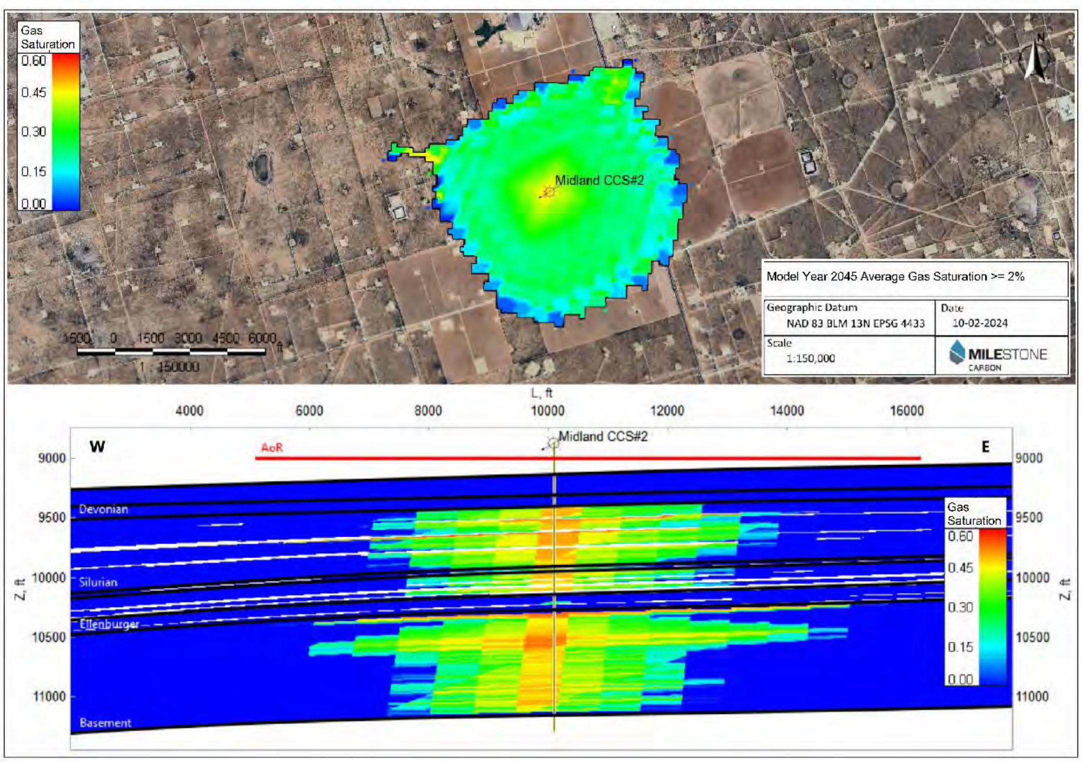

Figure 9-5: Predicted extent of the CO2 plume - est. year 2045

Map of the predicted extent of the CO_2 plume and pressure front relative to monitoring locations at the end of 8 years after the cessation of injection – estimated year 2045

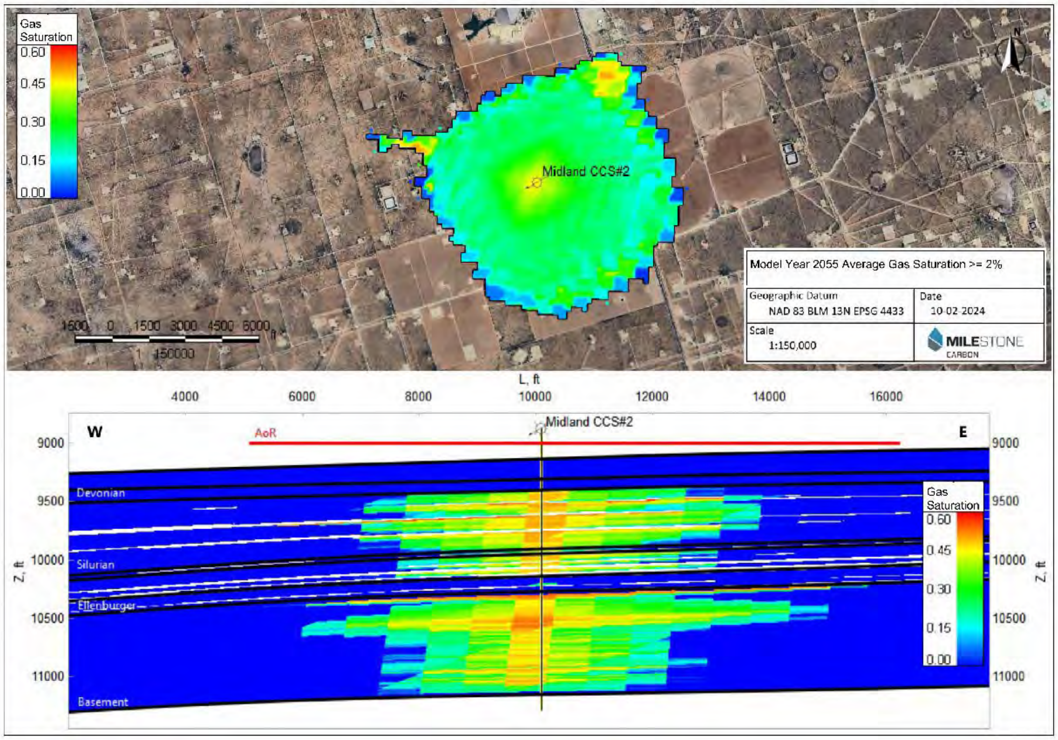

Figure 9-6: Predicted extent of the CO_2 plume - est. year 2055 (site closure)
Map of the predicted extent of the CO_2 plume and pressure front relative to monitoring locations at the end of 18 years after the cessation of injection (predicted time of site closure) – estimated year 2055

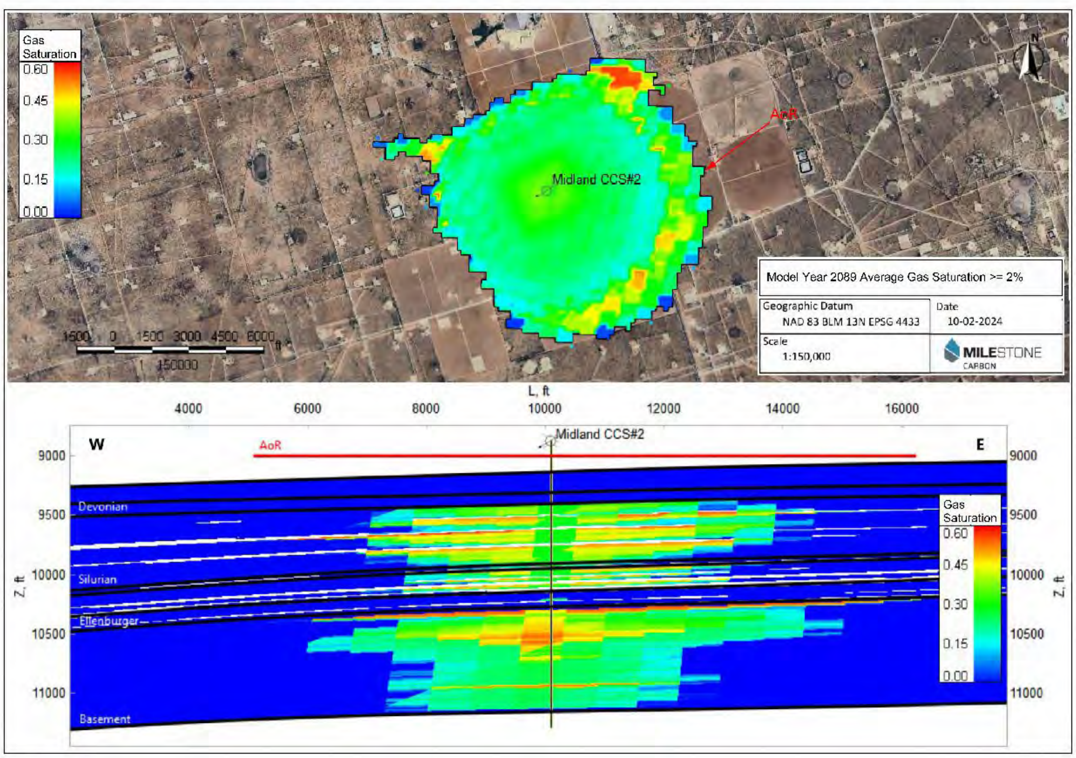

Figure 9-7: Predicted extent of the CO_2 plume – est. year 2089 – End of PISC Period
Map of the predicted extent of the CO_2 plume and pressure front relative to monitoring locations 50 years after the cessation of injection – estimated year 2089

9.5.3 Pressure and Phase Predictions

Predicted pressure profiles at the surface and bottomhole pressure at the injection wells for 50 years after the cessation of injection are shown in **Figures 9-8**. The bottomhole pressure reference depth is at the top of the injection interval. The predicted amount of CO_2 in the mobile gas, trapped gas, and dissolved (aqueous) phases for 50 years after the cessation of injection is in **Figure 9-9**. The maximum incremental well bottomhole pressure in the reservoir for the Midland CCS #2 is 1,598 psi. The pressure decays rapidly to less than 200 psi above the initial pressure within 5 years of the end of injection. Initial pressure for the Midland CCS #2 is 5,491 psi in the reservoir at the top of the Injection interval.

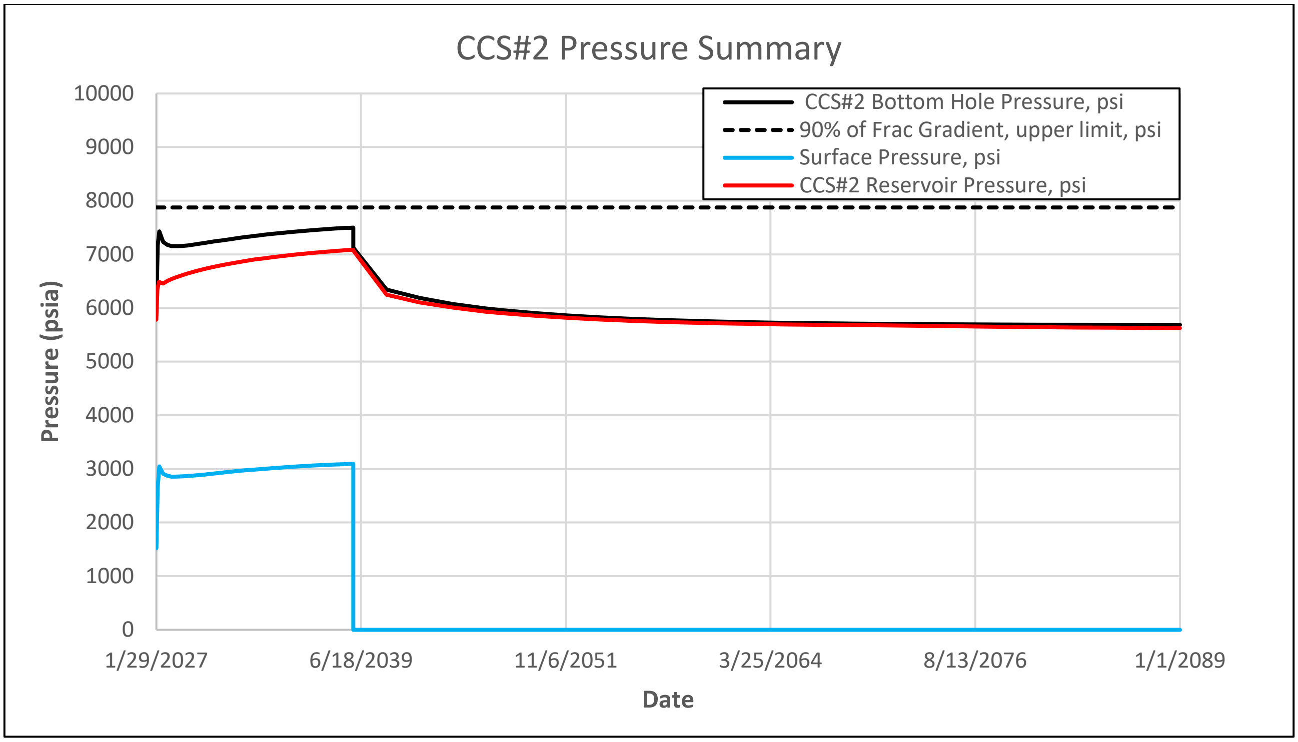

Figure 9-8: Predicted pressure profile from start-up until 50 years after cessation of injection

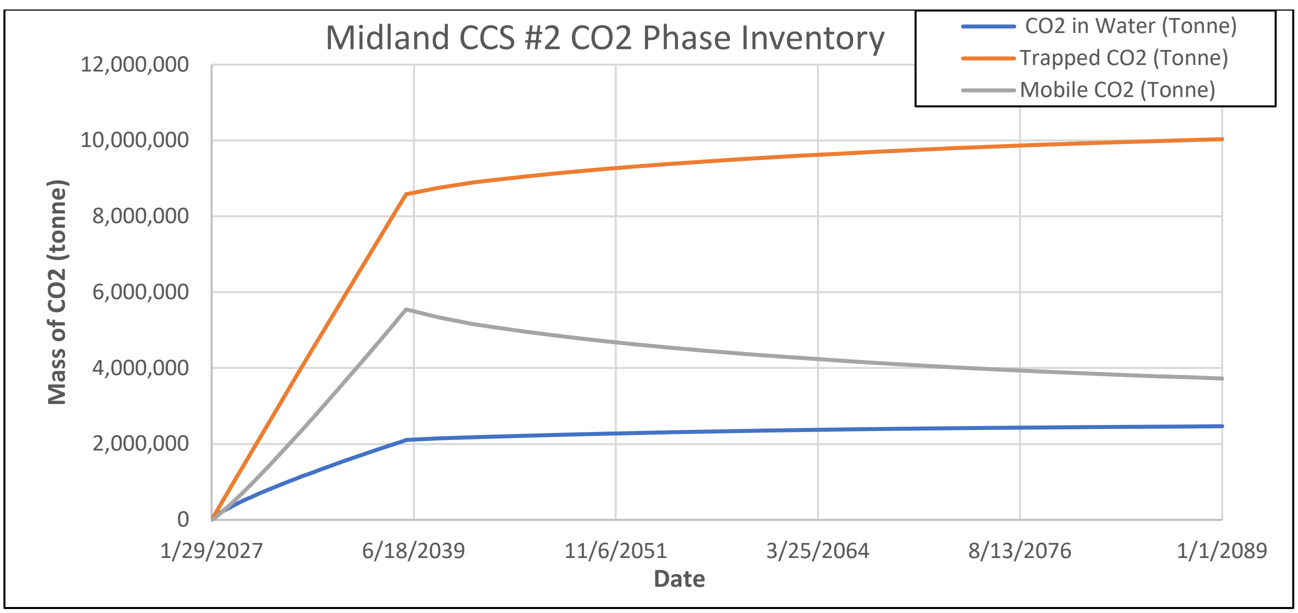

Figure 9-9: Predicted phase distribution from start-up until 50 years after cessation of injection

9.6 Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

Results of the latest monitoring data will be submitted annually within 60 days of the anniversary date of the cessation of injection. Any amendments to the post site injection care and monitoring plan will be submitted and if approved by the UIC Program Director, will be incorporated into the permit. This plan will also be reviewed and submitted to the UIC Program Director within six months of an area of review evaluation event (see **Section 2**), any significant emergency event (**see Section 10**), following any significant changes to the facility, such as addition of injection or monitoring wells; changes in injection rate; or when required by the UIC Program Director. From years 10 to 50 after cessation of injection, reporting frequency will decrease to every 5 years if no anomalous activity has been detected within the preceding 10 years.

If the review indicates that no amendments to the post site care plan or monitoring strategy are necessary, Milestone will provide the permitting agency with the documentation supporting the "no amendment necessary" determination at least annually within 60 days of the anniversary of the date of cessation of injection.

9.7 Duration of Post Site Injection Care and Alternative Post-Injection Site Care Timeframe [40 CFR 146.93(a)(2)(v)]

Milestone is **not** applying for an alternative post-injection site care timeframe at this time. The duration of the post site injection care (PISC) will be 50 years from the cessation of injection operations.

9.8 Non-Endangerment Demonstration Criteria [40 CFR 146.93(b)]

Prior to approval of the end of the post-injection phase, Milestone will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR 146.93(b)(2) and (3). The owner or operator will issue a report to the UIC Program Director. This report will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Program Director to review the analysis. The report will include the following sections:

9.8.1 Introduction and Overview

A summary of relevant background information will be provided, including the operational history of the injection project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

9.8.2 Summary of Existing Monitoring Data

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan of this permit and this PISC and Site Closure Plan, including data collected during the injection and post-injection phases of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the UIC Program Director 40 CFR 146.91(e), and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization 40 CFR 146.82(a)(6) and 146.87(d)(3).

9.8.3 Computational Modeling Calibration and Validation

A series of data sources detailed in **Section 6** will be used to update the computational model at least once every 5 years, if not more frequently. The following measured data will be utilized to update the computational model to demonstrate non-endangerment:

- Temperature and pressure data
- Pulse Neutron Logging
- Geophysical Surveys
- Injection surface pressure and downhole pressure

The procedure used to reevaluate the AoR will be based upon the data collected between reevaluations and the well conditions at the time of reevaluation. Post Injection data will include historical injection rates, pressures, pressure fall-off, historical operational parameters of the Midland CCS #2 Well that will inform the dynamic model. History matching the dynamic model to measured data, where recorded data is used as an input to the dynamic model and the input parameters adjusted to match the recorded pressures will be performed by Milestone. By history matching the recorded data, calibration and validation of the model to recorded data will be established. History matching the Midland CCS #2 Well, and any offset injection at the Davidson Unit #1 saltwater disposal (SWD), Clay Henry SWD, Midkiff #1 SWD and any new SWD wells, will continue to inform the dynamic simulation.

9.8.4 Evaluation of Reservoir Pressure

The extent of the pressure front will be evaluated using surface and bottomhole pressure gauges from the injection well, and In-zone monitoring well. Reported pressures from the offset SWD wells that are reported to the RRC will also be utilized. This information will be history matched in the dynamic model at least once every 5 years, and more frequently if there is major disagreement. If no valid solution can be found, Milestone may perform additional testing to attempt to reconcile measured vs modeled data.

9.8.5 Evaluation of Carbon Dioxide Plume

Remote sensing techniques detailed in **Section 6** will be used to monitor the aerial and vertical extent of the CO_2 plume. These may include the following:

- Temperature and pressure data
- Pulse Neutron Logging
- EM Surveys
- Microseismic

This information will be compared to the model predictions to attempt to match modeled pressure, gas saturation and vertical/aerial extent to measured values.

9.8.6 Evaluation of Emergencies or Other Events

Water testing noted in **Section 6** will be used to demonstrate that USDWs are not impacted by injection activities. Deviation from water measurements taken by Milestone prior to the start of injection will indicate that the USDW is potentially being impacted. Seasonal variation will be considered when analyzing for deviation.

Artificial penetrations of the reservoir are noted in **Section 1**. There are **zero** artificial penetrations of the injection interval within the AoR. If any subsequent artificial penetrations are discovered, they will be remediated with proper CRA material and soil testing as detailed in permit **Section 6** and subsequent testing will be performed annually to verify no leakages within the hypothetical plugged wellbores.

9.9 Site Closure Plan [146.93 (d) – (h)]

Milestone will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described herein. Milestone will submit a final Site Closure Plan and notify the permitting agency at least 120 days prior to its intent to close the site. Once the permitting agency has approved closure of the site, Milestone will plug the all the monitoring wells to restore the site and move out all equipment; and submit a site closure report to the UIC Program Director. The activities, as described below, represent the planned activities. The actual site closure plan may employ different methods and procedures. A final site closure plan will be submitted to the UIC Program Director for approval with the notification of the intent to close the site.

9.9.1 Plugging Monitoring Well(s)

Plugging of the injection well will be completed in accordance with procedures in **Section 8**. Plugging of the in-zone monitoring and USDW monitoring wells will be conducted according to procedures herein.

After injection in the injection well ceases and after the appropriate post-injection monitoring period is complete, the in-zone monitoring and USDW monitoring wells will be plugged and abandoned to meet the requirements at 40 CFR 146.92 and all state and local regulations. The plugging procedure and materials will be designed to prevent any unwanted fluid movement and to protect any USDWs. Prior to plugging the wells, any necessary procedural revisions to address new information will be submitted to the UIC Program Director for review and approval. The final plugging plans will be submitted to the UIC Program Director no later than 60 days prior to plugging of the wells.

Following receipt of the approved plugging plans, the wells will be wireline logged, and pressure tested to ensure mechanical integrity. If a loss of mechanical integrity is discovered, it will be repaired prior to proceeding with plugging operations. The plugging procedures are presented herein. All casing in these wells will be cemented to surface at the time of construction and will not be retrievable at abandonment. A combination of bridge plugs and cement plugs will be set to plug the wells.

All casing strings will be cut at least three (3) feet below ground level. A steel plate, with the required permit information, will be welded to the top of the casing.

9.9.2 Plugging the In-Zone Monitoring Well

Notification, regulatory and plugging procedures will include:

9.9.2.1 Pre-Plugging Activities

1) In compliance with 40 CFR 146.92(c), notify the regulatory agency at least 60 days before plugging the well and provide updated plugging plan, if applicable.
2) Bottomhole reservoir pressure will be measured using the downhole pressure gauge.
3) Retrieve downhole pressure gauge and geophone.
4) External mechanical integrity will be demonstrated with temperature, noise or oxygen activation logging.
5) Casing inspection and cement bond logs will be performed prior to plugging. Log evaluation will determine if revision to the plugging procedure is necessary.
6) The wellbore will be displaced with a kill weight fluid, 9 ppg minimum.

9.9.2.2 Plugging Activities

1) Position workstring at 13,780 feet and pump a 1,580-foot balanced corrosion resistant cement plug from TD to 12,205 feet.
2) Wait on cement, tag and pressure test the corrosion resistant cement plug.
3) If the corrosion resistant cement plug is tagged deeper than planned, an additional cement plug will be set up to 12,205 feet.

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4) Pull out of hole and make up a corrosion resistant bridge plug.
5) Run CRA bridge plug and set with workstring in the Woodford shale at 12,160 feet.
    a. Tag and pressure test bridge plug.
6) Position workstring to bridge plug at 12,160 feet and pump a 300-foot corrosion resistant cement plug across the Woodford from 12,160 feet to 11,860 feet.
7) Wait on cement, tag and pressure test the corrosion resistant cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 11,860 feet.
8) Position workstring at 11,551 feet and pump a 200-foot balanced corrosion resistant cement plug across the Atoka top from 11,551 feet to 11,351 feet.
9) Wait on cement, tag and pressure test the cement plug.
10) If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 11,351 feet.
11) Position workstring at 10,891 feet and pump a 200-foot balanced corrosion resistant cement plug across the Strawn top from 10,891 feet to 10,691 feet.
12) Wait on cement, tag and pressure test the cement plug.
13) If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 10,691 feet.
14) Position workstring at 9,192 feet and pump a 200-foot balanced corrosion resistant cement plug across the Wolfcamp top and intermediate casing shoe from 9,192 feet to ,900 feet.
15) Position workstring at 7,700 feet and pump a 200-foot balanced corrosion resistant cement plug across the Sprayberry top from 7,700 feet to 7,500 feet.
16) Wait on cement, tag and pressure test the cement plug.
17) If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 7,500 feet.
18) Position workstring at 4,208 feet and pump a 200-foot balanced corrosion resistant cement plug across the San Andres top from 4,208 feet to 4,008 feet.
19) Wait on cement, tag and pressure test the cement plug.
20) If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 4,008 feet.
21) Pull out of hole and make up a corrosion resistant bridge plug.
22) Run CRA bridge plug and set with workstring at 1,350 feet.
    a. Tag and pressure test bridge plug.
23) Pump a 50-foot corrosion resistant cement plug across the surface casing shoe and USDW from 1,300 ft to 1,250 feet.
24) Wait on cement, tag and pressure test the cement plug.
    a. If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 1,250 feet.
25) Position workstring at 400 feet and pump a 100-foot balanced corrosion resistant cement plug from 400 feet to 300 feet.
26) Wait on cement, tag and pressure test the cement plug.
27) If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 300 feet.
28) Pump a 100’ balanced corrosion resistant cement plug from 100 feet to surface.
29) Cut and cap casing 3 to 4 feet below ground level.

A certified plugging report will be submitted to the UIC Director within 60 days after plugging pursuant to 40 CFR §146.91(e). The plugging report will be retained for 10 years following site closure. Also note that a complete well plugging record (Form W-3), pursuant to 16 TAC §5.203, will be filed within 30 days after plugging to the appropriate TRRC District Office.

9.9.2.3 Plug Information

The operator will report cement densities and retain duplicate samples of the cement used for each plug. For all cement plugs, 0% excess will be used. All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1k feet of depth from the ground surface to the bottom of the plug. Milestone is currently evaluating CO_2 resistant cement from the industry's leading suppliers, Halliburton and SLB. ThermaLock is an option from Halliburton. EverCrete and Ecoshield are two (2) options from SLB. All the cement solutions have been thoroughly tested and are designed to maintain reliable corrosion resistant properties throughout the life of an injection or monitoring well exposed to CO_2. The products listed above are all rated for the temperature and pressure ranges of the injection and monitoring wells. They will provide long lasting zonal isolation.

ThermaLock is a non-Portland based cement that is a specially formulated calcium aluminate phosphate system which gives it resistant properties to CO_2 corrosion.

Evercrete has long been the reliable workhorse for CO_2 injection wells. Its low permeability allows it to withstand corrosive effects of supercritical CO_2 and has self-healing properties if a fracture is formed. Ecoshield is a geopolymer cement free system that provides an alternative to Portland cement while delivering comparable performance. EcoShield system matches the rheology, thickening time, and compressive strength properties of Portland cement-based systems. The technology fits within standard oilfield cementing workflows without major changes to the design process, onsite execution, or post-job evaluation.

This is an evolving science, and Milestone will continue evaluating the most suitable corrosion resistant cement product for the proposed well plugging. Cement and cement additives will be compatible with the injectate stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project.

Table 9-7 and **Figure 9-10** present details for each plug and the proposed plugging schematic, respectively.

Table 9-7: Midland IZM #2 Well Proposed Plugging Program Detail

Test Description	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7	Plug #8	Plug #9	Plug #10	Plug #11	Plug #12
Diameter of boring in which plug will be Placed (inches)	3.826	3.826	3.826	3.826	3.826	3.826	3.826	3.826	3.826	3.826	3.826	3.826
Sacks of cement to be used (sks)	121	NA	23	15	15	22	15	15	NA	4	8	8
Slurry volume to be Pumped (cu.ft.)	126.2	NA	24	16	16	23.3	16	16	NA	4	8	8
Slurry Weight (lb/gal)	16.4	NA	16.4	16.4	16.4	16.4	16.4	16.4	NA	16.4	16.4	16.4
Length of cement	1,580	NA	300	200	200	292	200	200	NA	50	100	100
Calculated top of Plug (ft)	12,205	12,160	11,860	11,351	10,691	8,900	7,500	4,008	1,350	1,250	300	0
Bottom of plug (ft)	13,785	NA	12,160	11,551	10,891	9,192	7,700	4,208	NA	1,300	400	100
Type of cement or other material	Corrosion Resistant	CRA Bridge Plug	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	CRA Bridge Plug	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant
Method of emplacement	Circulation	Workstring	Circulation	Circulation	Circulation	Circulation	Circulation	Circulation	Workstring	Circulation	Circulation	Circulation

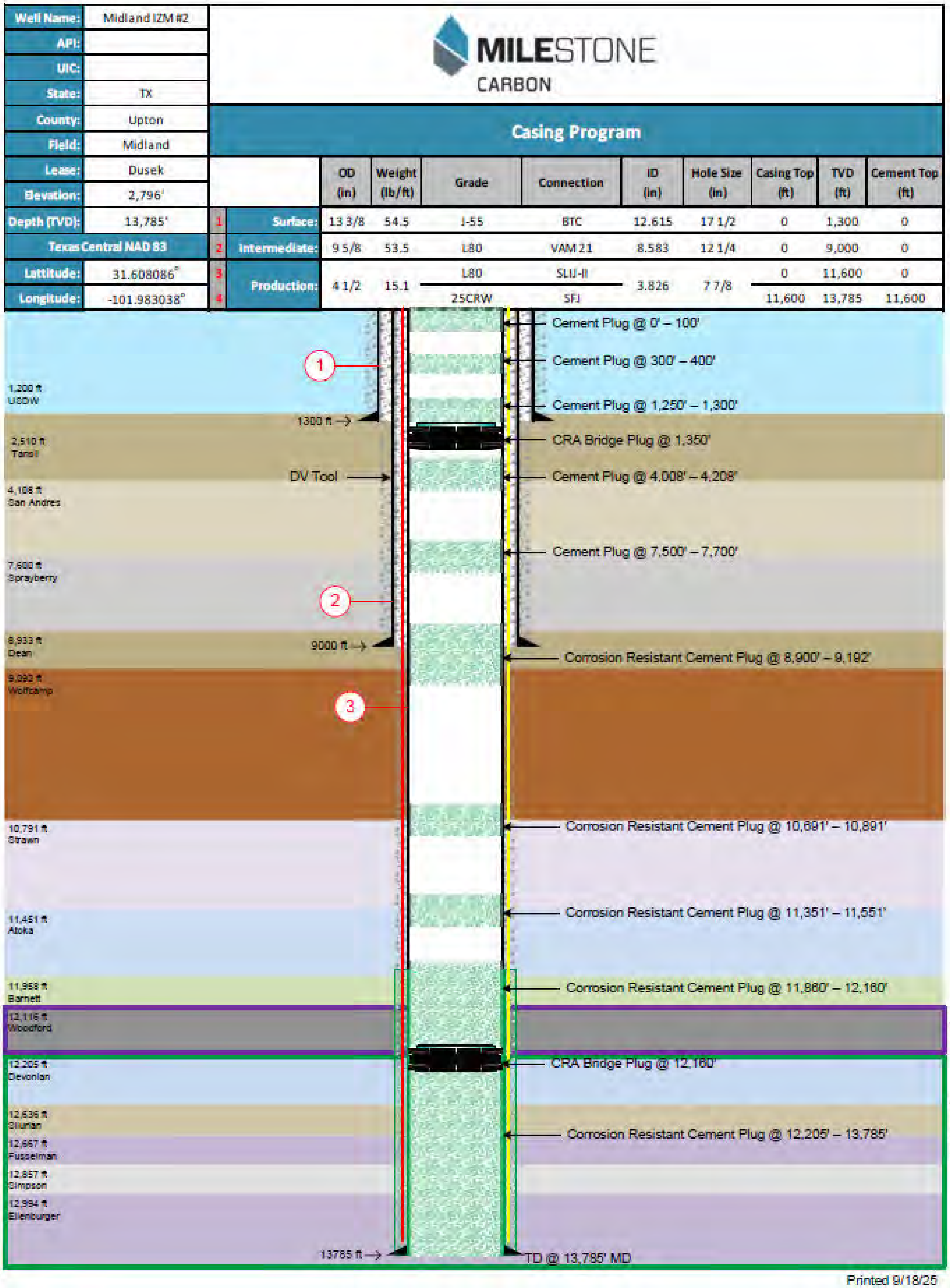

Figure 9-10: Representative Plugging Schematic In-Zone Monitoring Well

9.9.3 Plugging the USDW Well(s)

Notification, regulatory and plugging procedures will include:

9.9.3.1 Pre-Plugging Activities

1) In compliance with 40 CFR 146.92(c), notify the regulatory agency at least 60 days before plugging the well and provide updated plugging plan, if applicable.
2) External mechanical integrity will be demonstrated with temperature, noise or oxygen activation logging.
3) Casing inspection and cement bond logs will be performed prior to plugging. Log evaluation will determine if revision to the plugging procedure is necessary.

9.9.3.2 Plugging Activities

1) Make up and run corrosion resistant bridge plug and set with workstring above perforations at 1,000 feet.
    a. Tag and pressure test bridge plug.
2) Pump a 20' corrosion resistant cement plug above bridge plug from 1,000 to 980 feet.
3) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 980 feet.
4) Position workstring at 400 feet and pump a 100-ft balanced corrosion resistant cement plug from 400 feet to 300 teet.
5) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 300 feet.
6) Position workstring at 100 feet and pump a 100-ft balanced corrosion resistant cement plug from 100 feet to surface.
7) Cut and cap casing 3 to 4 ft below ground level.

A certified plugging report will be submitted to the UIC Director within 60 days after plugging pursuant to 40 CFR §146.91(e). The plugging report will be retained for 10 years following site closure. Also note that a complete well plugging record (Form W-3), pursuant to 16 TAC §5.203, will be filed within 30 days after plugging to the appropriate TRRC District Office.

9.9.3.3 Plug Information

The operator will report cement densities and retain duplicate samples of the cement used for each plug. For all cement plugs, 20% excess will be used to ensure isolation is achieved. All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1k feet of depth from the ground surface to the bottom of the plug. Milestone is currently evaluating CO_2 resistant cement from the industry's leading suppliers, Halliburton and SLB. ThermaLock is an option from Halliburton. EverCrete and Ecoshield are two (2) options from SLB. All the cement solutions have been thoroughly tested and are designed to maintain reliable corrosion resistant properties throughout the life of an injection or monitoring well exposed to CO_2. The products listed above are all rated for the temperature and pressure ranges of the injection and monitoring wells. They will provide long lasting zonal isolation.

ThermaLock is a non-Portland based cement that is a specially formulated calcium aluminate phosphate system which gives it resistant properties to CO_2 corrosion.

Evercrete has long been the reliable workhorse for CO_2 injection wells. Its low permeability allows it to withstand corrosive effects of supercritical CO_2 and has self-healing properties if a fracture is formed. Ecoshield is a geopolymer cement free system that provides an alternative to Portland cement while delivering comparable performance. EcoShield system matches the rheology, thickening time, and compressive strength properties of Portland cement-based systems. The technology fits within standard oilfield cementing workflows without major changes to the design process, onsite execution, or post-job evaluation.

This is an evolving science, and Milestone will continue evaluating the most suitable corrosion resistant cement product for the proposed well plugging. Cement and cement additives will be compatible with the injectate stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project.

Table 9-8 and **Figure 9-11** present details for each plug and the proposed plugging schematic, respectively.

Table 9-8: Midland USDW #2 Proposed Plugging Program Detail

Test Description	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be Placed (inches)	5.012	5.012	5.012	5.012
Sacks of cement to be used (sks)	NA	3	13	13
Slurry volume to be Pumped (cu.ft.)	NA	2.8	13.8	13.8
Slurry Weight (lb/gal)	NA	16.4	16.4	16.4
Length of cement	NA	20	100	100
Calculated top of Plug (ft)	1,000	980	300	Surface
Bottom of plug (ft)	NA	1,000	400	100
Type of cement or other material	CRA Bridge Plug	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant
Method of emplacement	Workstring	Circulation	Circulation	Circulation

Well Name:	Midland USDW #2
County:	Upton
State:	TX
Depth (TVD):	1,300

MILESTONE CARBON

Casing Program

		OD (in)	Weight (lb/ft)	Grade	Connection	ID (in)	Drift (in)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1	Surface:	5 1/2	14	J-55	BTC	5.012	4.887	7 7/8	0	1,300	0

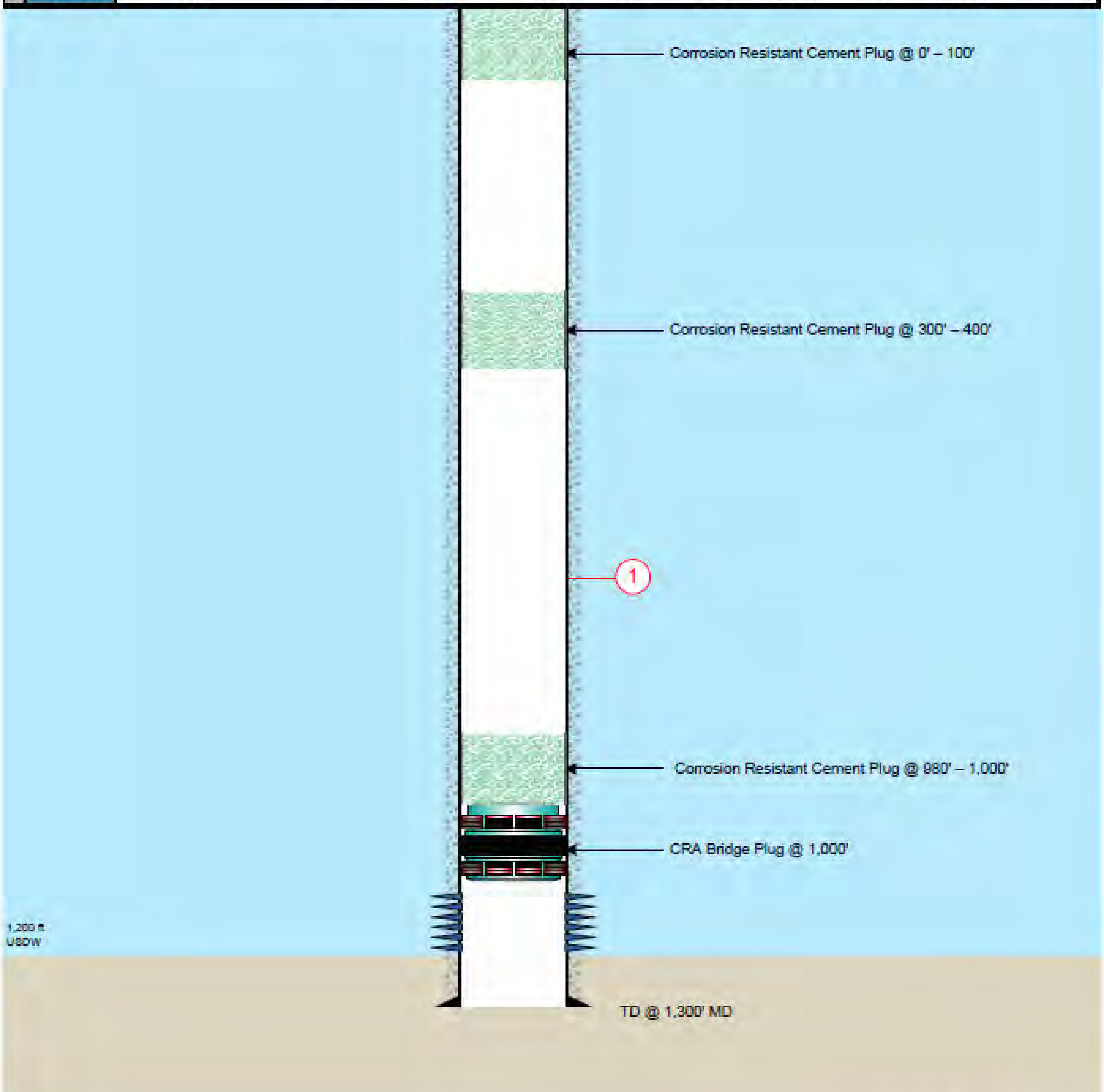

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Figure 9-11: Representative Plugging schematic – USDW Monitoring Well

9.9.4 Plugging the Near Surface Seismometer-Water (NSSW) Wells

If the near surface seismometer water wells (NSSW) wells are still serviceable and the seismicity equipment still useful, the wells will not be plugged at the completion of the project. Instead, they will be assigned to the landowner or TexNet for their private use.

If the landowner or TexNet declines to take ownership of the NSSW wells. The wells will be plugged according to the following procedure found in TCEQ Regulatory Guidance, Texas Groundwater Protection Committee, RG-347, Rev. April 2021, "Landowner's Guide to Plugging and Abandoned Wells." **Figure 9-12** illustrates the details of the proposed plugging.

9.9.4.1 NSSW Plugging Activities

1) Milestone will hire a water well drilling company licensed and bonded in the state of Texas
2) Water level will be measured to calculate proper mixtures of disinfection and plugging materials
3) Well will be disinfected with bleach to ensure microorganisms are not sealed in the aquifer
4) As much casing as possible will be removed from the wells
5) Using a tremie tube, the well will be pressure filled with a Bentonite grout and then capped with a cement cap at least two (2) feet thick and within four (4) feet of the ground surface. It will then be topped off with native soils
6) A report will be submitted to the TCEQ - Department of Licensing and Regulation.
7) TLDR Plugging report form WWD004N will be submitted to the TLDR
    a. Within the Plugging report form the licensed water well driller will certify the plugging of the well in section D. Milestone's licensed contractor will use an updated form if one is available at that time.

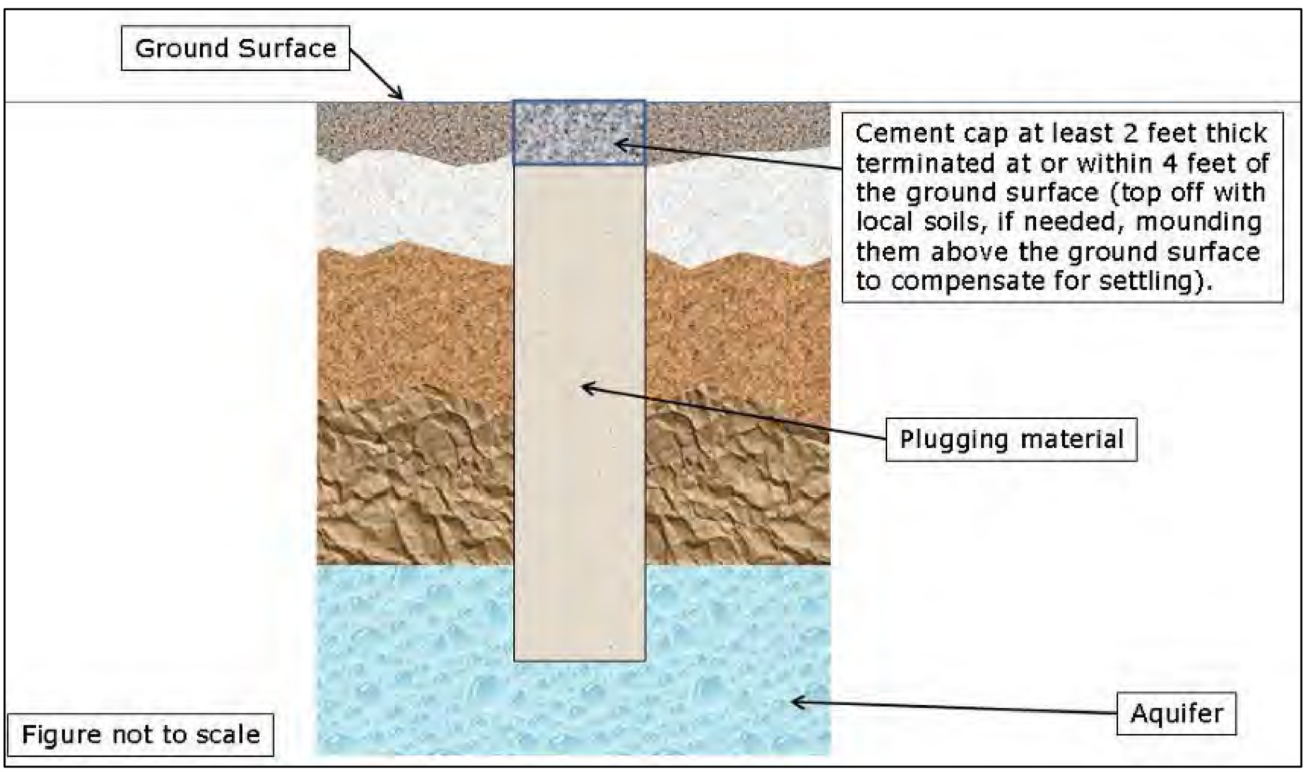

Figure 9-12: Approximate Plugging schematic – NSSW Monitoring Well (Source: TCEQ)

9.9.5 Planned Remedial/Site Restoration Activities [146.93 (a)]

To restore the site to its pre-injection condition following site closure, Milestone will be guided by the State rules for plug and abandonment of wells located on leased property under TCEQ Regulatory Guidance, Texas Groundwater Protection Committee, RG-347, Rev. April 2021, "Landowner's Guide to Plugging and Abandoned Wells."

The following steps will be taken:

1) The free liquid fraction of the plugging fluid waste, which may consist of produced water and/or crude oil, shall be removed from the pit and disposed of in accordance with state and federal regulations (e.g., injection or in above ground tanks or containers pending disposal) prior to restoration. The remaining plugging fluid wastes shall be disposed of by injection in Milestone Environmental Services (MES) owned/operated slurry site or if solids, MES owned/operated landfill.
2) All plugging pits shall be filled and leveled in a manner that allows the site to be returned to original use with no subsidence or leakage of fluids, and where applicable, with sufficient compaction to support farm machinery.
3) All drilling and production equipment, machinery, and equipment debris shall be removed from the site.
4) Casing shall be cut off at least four (4) feet below the surface of the ground, and a steel plate welded on the casing or a mushroomed cap of cement approximately one (1) foot in thickness shall be placed over the casing so that the top of the cap is at least three (3) feet below ground level.
5) Any drilling rat holes shall be filled with cement to no lower than four (4) feet, and no higher than three (3) feet, below ground level.
6) The well site and all excavations, holes and pits shall be filled, and the surface leveled.

9.9.6 Site Closure Report [146.93(a)(2)(iii)]

A site closure report will be prepared and submitted within 90 days following site closure, documenting the following:

- Plugging of the Midland IZM #2 and USDW #2 monitoring wells (and the injection well if it has not previously been plugged),
- Location of sealed injection well on a plat of survey that has been submitted to the local zoning authority,
- Notifications to State and local authorities as required at 40 CFR 146.93(f)(2),
- Records regarding the nature, composition, and volume of the injected CO_2, and
- Post-injection monitoring records.

Milestone will record a notation to the property's deed on which the injection well was located that will indicate the following:

- That the property was used for carbon dioxide sequestration,
- The name of the local agency to which a plat of survey with injection well location was submitted,
- The volume of fluid injected,
- The formation into which the fluid was injected, and
- The period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by the operator for a period of 10 years following site closure. Additionally, the operator will maintain the records collected during the PISC period for a period of 10 years after which these records will be delivered to the UIC Program Director.

9.10 Quality Assurance and Surveillance Plan (QASP)

The primary goal of the testing and monitoring plan (**Section 6**) of this storage facility permit application is to ensure that the geologic storage project is operating as permitted and is not endangering USDWs. In compliance with applicable Texas statewide rules regarding Testing and Monitoring Requirements, this quality assurance and surveillance plan (QASP) – **Section 13 Appendix C** was developed and is provided as part of the testing and monitoring plan.

Appendix C reflects Milestone's Quality Assurance Surveillance Plan (QASP) for testing and monitoring activities is pursuant to the requirements listed in 40 CFR §146.90(k), 146.93(c)(2)(i) and §146.93(c)(2)(vii) addressed in detail in Milestone permit application **Sections 6** and **Section 9**. This performance-based plan sets forth the procedures and guidelines the Environmental Protection Agency (EPA) will use in evaluating the technical performance of Milestone. The operating plans for the proposed Well will include a robust testing and monitoring program. Milestone will report the results of all testing and monitoring activities to EPA in compliance with the requirements under 40 CFR 146.91.

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Section 10: Emergency and Remedial Response Plan (ERRP)

[40 CFR §146.94(a) - (d)(3)]

Prepared for:

EPA Region 6

Underground Injection Control Section

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Updated 14 January 2026

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10.0 EMERGENCY AND REMEDIAL RESPONSE PLAN (ERRP) [40 CFR 146.82(a)(19), 146.94(a)]

This Emergency and Remedial Response Plan (ERRP) for the Well is provided to meet the requirements of 40 CFR 146.94(a). The comprehensive plan describes potential adverse events that could occur in the development, operation and post-closure phases of the project and the actions to be taken in the unlikely event of such an emergency at the South Midland Facility or within the identified AoR. The ERRP describes the potential affected resources, lists entities and individuals to be notified, and provides actions to be taken expeditiously to mitigate any emergency and protect human health and safety of the environment, including USDWs.

This plan describes actions that Milestone will take in the event of an emergency that could endanger any USDW within the AoR during construction, operation, or post-injection site care. Such events may include unplanned CO_2 release or detection of unexpected subsurface movement of CO_2 or fluids in or from the injection zone.

If Milestone obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, Milestone will perform the following actions:

1) Initiate shutdown plan for the injection well.
2) Take all steps reasonably necessary to identify and characterize any release.
3) Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4) Implement applicable portions of the approved ERRP.

Where the phrase “initiate shutdown plan” is used, the following protocol will be employed:

> Milestone will immediately cease injection. However, given the high injection pressures, supercritical fluid within the wellbore, and high injection rates, Milestone will, in consultation with the UIC Program Director, determine appropriate pre-planned shut-down procedures that allow for safe shutdown of the well and associated mid-stream infrastructure that does not endanger human health, equipment, or the environment.

10.1 Local Resources and Infrastructure in AoR

10.1.1 Description of Project Area

The Facility is located in the near the city of Midkiff, which is an unincorporated desert village in northeastern Upton County, Texas, United States. It lies along Farm-to-Market (FM) 2401 and FM 3095 north of the city of Rankin, the county seat of Upton County, and is primarily an agricultural and petroleum-related community with a total population of 780 and 21 businesses.

The closest highly populated area is Midland, Texas which is about 45 miles northwest of the Facility (**Figure 10-1**). However, there are a large number of oilfield related structures in the vicinity.

There are over 53 identified structures within the AOR. These buildings are utilized for either residential, oil and gas, industrial, or agricultural use. There are four (4) inhabited commercial structures, two (2) temporary oil and gas office buildings, the Burritos Rey Restaurant and the Milestone Energy Waste Facility. There are two (2) residential houses within the AoR. One (1) is a temporary trailer house on the southern end of the AoR and one (1) is a permanent structure on the northeast side of the AoR. The permanent house north of the Milestone Midland Facility has associated barns and storage buildings. There are one-hundred-sixty-eight (168) total structures within a 2-mi radius of the injection well. (**Figure 10-2**)

Additionally, there are 71 oil and gas wells within the AoR and 68 water wells within the AoR, listed in Section 1.14. Many of these wells have associated surface facilities, although sometimes there are multiple wells on a single surface facility. Industrial equipment associated with oil and gas such as compressors, pipeline facilities, pumpjacks, antennas are located in the area.

Water and mineral resources in the vicinity of the Facility that may be affected by a potential emergency event from the Well are described in maps located in **Section 1.3**.

There are no drinking water treatment plants or other water-related infrastructure in the vicinity of the Facility that may be affected as a result of an emergency associated with the Well.

In addition to the proposed facility, Milestone operates two (2) affiliate oilfield waste facilities within 3 miles of the proposed facility.

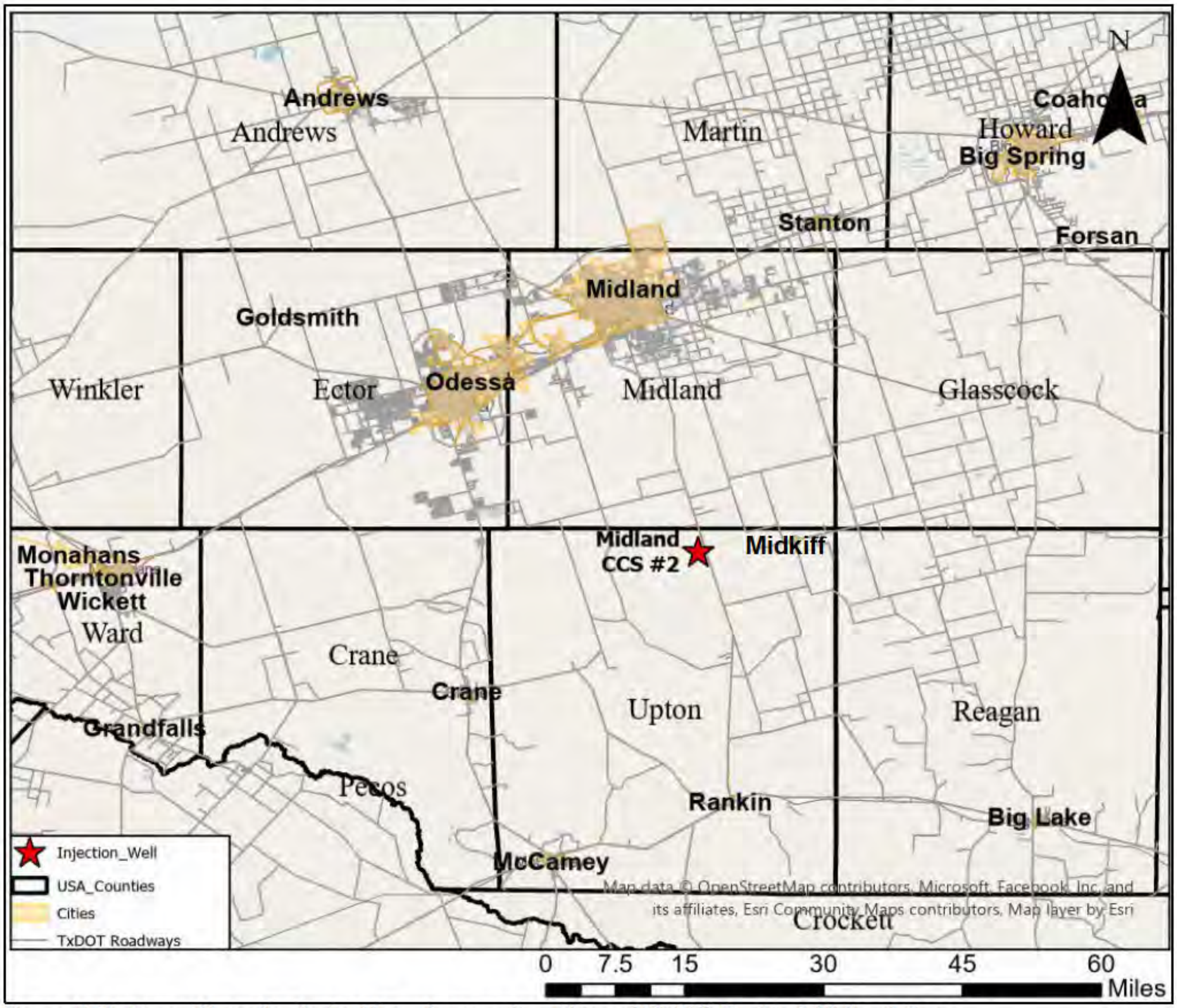

Figure 10-1: General Location Index Map – Surrounding Cities of Midkiff, Rankin & Midland, Texas
The Midland CCS #2 Well will be situated in the northern part of Upton County, Texas. The Well will be drilled at latitude 31.615788°N, longitude -101.990004°W (NAD83).

Resources and infrastructure addressed in this plan are shown in **Figure 10-2**

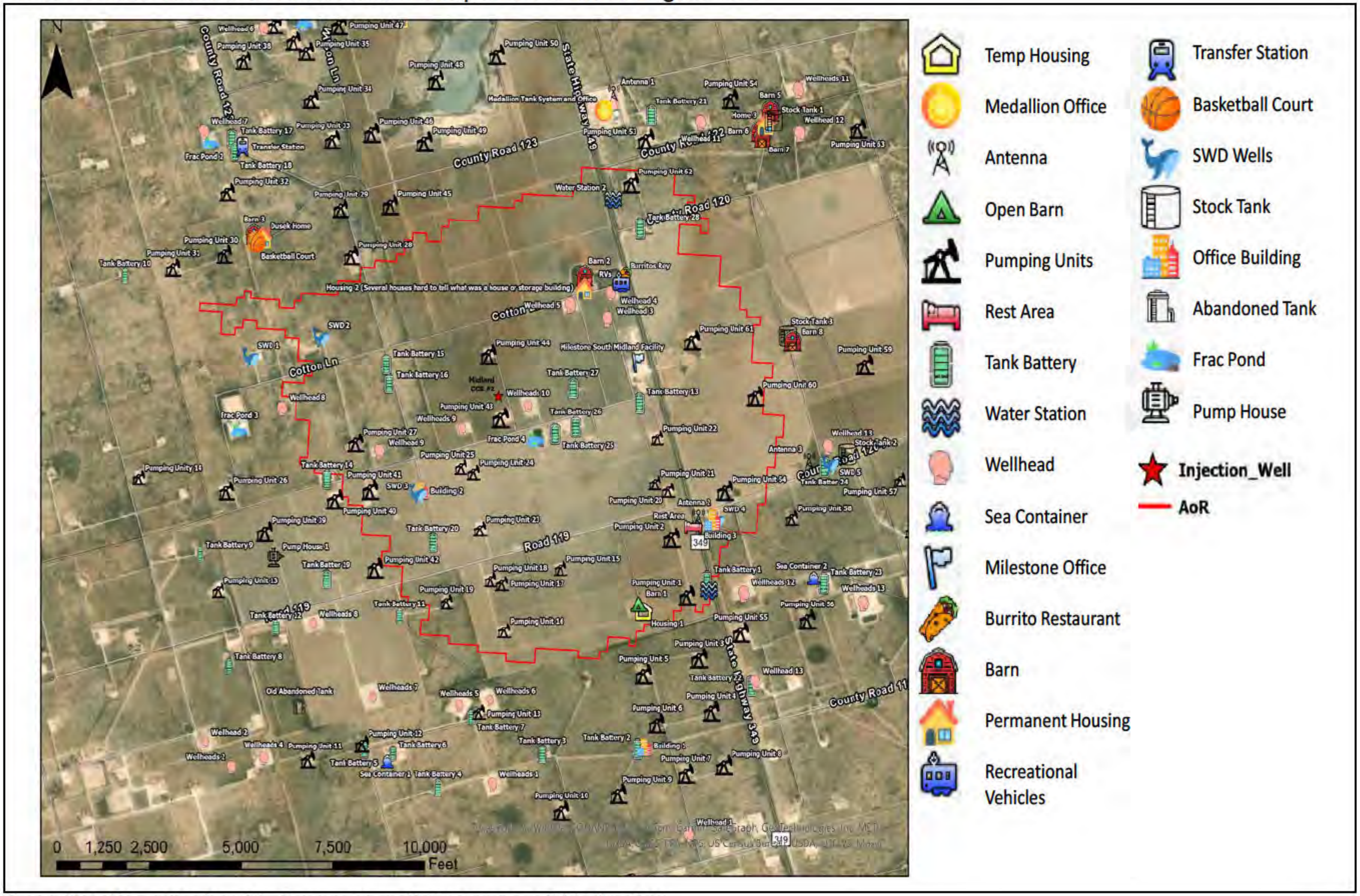

Figure 10-2: Map of Surface Site Resources and Infrastructure within the AoR

10.2 Potential Risk Scenarios

Several scenarios could activate an emergency response. This ERRP considers any adverse incident with the potential of causing personal injuries, USDW contamination, or property damage as an "event."

The scope of response, response actions, and order of activities will be proportionate to the severity and impacts of the event and implemented as outlined in this ERRP. "Emergency events" are categorized as shown in **Table 10-1**.

The protocols may be modified and refined based on the specific circumstances and conditions of the event as well as any discussion with governmental authorities having jurisdiction.

Table 10-1: Degrees of Risk for Emergency Events

Emergency Condition	Definition
Major Emergency	Poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated. ***Example***: well blowout while injecting
Serious Emergency	Poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken. ***Example:*** malfunction of monitoring equipment for pressure or temperature that may indicate a problem with the injection well and possible endangerment of public health and the environment
Minor Emergency	Poses no immediate risk to human health, resources, or infrastructure. ***Example***: higher pressure reading observed in monitoring wells with no potential to move fluid.

Discovery of an event triggers the corresponding response plan proposed herein. Response plan actions and activities will depend upon the circumstances and severity of the event. Milestone will address an event immediately and, when required, will communicate the event to the UIC Program Director within 24 hours of discovery. Tables of emergencies and responses are found in **Tables 10-2 to 10-7.**

The protocols described in this document are conceptual and may be adjusted based on actual circumstances and conditions of the event and any previous communication with governmental authorities having jurisdiction.

If an event triggers cessation of injection and remedial actions, Milestone will demonstrate the efficacy of the response actions to the satisfaction of the UIC Program Director before resuming injection operations. Injection operations will only resume upon receipt of written authorization of the UIC Program Director. See permit **Section 10.8**.

10.2.1 Event Description: Well Integrity Failure

Integrity loss of the injection well and/or a monitoring well may endanger USDWs. Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
  - ✓ Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
  - ✓ Annulus pressure indicates a loss of external or internal well containment.
  - ✓ Pursuant to 40 CFR 146.91(c)(3), Milestone must notify UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

If CO_2 escapes to the surface:

- If there is a report or indication of a leak from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated.
- A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak.
- Local wind speed, direction, and H_2S monitors will be used to determine the potentially affected areas.
- Emergency shutdown systems will be utilized as necessary to isolate the leak. Pressure from the system will be relieved, not vented, due to the dangerous composition of the gas.

Table 10-2: Event Description & Response Scenario 1 | Well Integrity Failure

Emergency ID	Response
Risk Level:	**Medium**
Timing / Phase of Event: *(Construction, pre-injection, during injection, and/or post-injection).*	Any Phase
Prevention and Detection:	• Proper wellbore design, including proper cement and metallurgy of the casing and tubing will be implemented in the construction phase • Pressure, rate, and mechanical integrity monitoring, pressure fall-off tests, annulus pressure tests, etc., will all be performed per the Testing and Monitoring Plan.
Potential Response Actions:	• Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c) • Determine the severity of the event, based on the information available, within 24 hours of notification • For a Major or Serious emergency: ✓ Initiate shutdown plan. Steps could include: ▪ Close wellhead valve. ▪ Monitor well and annulus pressures. ▪ Determine the cause and severity of failure to determine if any release of the CO_2 stream or formation fluids may have been released into any unauthorized zone. ▪ Pull and replace the tubing or the packer. ▪ Install chemical sealant barrier and or attempt cement squeeze to block leaks. ▪ Demonstrate Mechanical Integrity per the methods discussed in Testing and Monitoring Plan. ✓ If contamination is detected, identify and implement appropriate remedial actions (in consultation with the UIC Program Director) • For Minor emergency:

Emergency ID	Response
	✓ Conduct assessment to determine whether there has been a loss of mechanical integrity ✓ If there has been a loss of mechanical integrity, initiate shutdown plan
Response Personnel:	Drilling / workover crews or operations personnel
Equipment:	BOP. Cement. Pressure, rate, and mechanical integrity monitoring instrumentation

10.2.2 Event Description: Injection Well Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Table 10-3: Event Description & Response Scenario 2 | Injection Well Monitoring Equipment Failure

Emergency ID	Response
Risk Level:	**Low**
Timing/Phase of Event: *(Construction, pre-injection, during injection, and/or post-injection).*	During injection and Post-injection
Prevention and Detection:	• Well maintenance and monitoring will be conducted continuously to avoid this scenario • Pressure and mechanical integrity monitoring instrumentation will be deployed for well maintenance and monitoring • Maintenance will be performed in accordance with manufacturer's recommended schedule • Periodic calibration checks will be performed on equipment in accordance with manufacturer's recommended schedule
Potential Response Actions:	• Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c) • Determine the severity of the event, based on the information available, within 24 hours of notification • For a Minor emergency: ✓ Conduct assessment to determine whether there has been a loss of mechanical integrity and determine event severity ✓ If there has been a loss of mechanical integrity, initiate shutdown plan ✓ Implement and repair/replacement plan if needed ✓ Calibrate repaired or new equipment ✓ Evaluate resumed injection at reduced pressure
Response Personnel:	Facility operations personnel
Equipment:	• Pressure and mechanical integrity monitoring instrumentation • Calibration equipment • Repair equipment

10.2.3 Event Description: Spill

This event could occur during the drilling of the wellbore due to an accidental release of drilling fluids, hydrocarbons, chemicals, brine etc. during drilling and completion or workover operations.

Table 10-4: Event Description & Response Scenario 3 | Spill

Emergency ID	Response
Risk Level:	**Low**
Timing/Phase of Event: *(Construction, pre-injection, during injection, and/or post-injection).*	Drilling or Workover of Injection or Monitoring Wells
Prevention and Detection:	• Maintain appropriate mud weights as expected for the area based on offset well data Monitor rate of drilling fluid returns versus rates pumped, penetration rates, pump pressures, etc. • Properly maintained blowout preventers to prevent accidental release of drilling fluids or hydrocarbons • Spill prevention equipment on drilling or workover rig
Potential Response Actions:	• Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c) • Determine the severity of the event, based on the information available, within 24 hours of notification • For Minor emergency: ✓ Stop drilling; close the blowout preventer; insert rams into the well; read and record stabilized shut-in pressures. ✓ Kill the well by pumping fluid down the wellbore that is heavier than the current fluid until the well stops flowing. ✓ Contain spill using available equipment such as absorbents, booms, etc. ✓ Notify appropriate regulatory authority and supervisory personnel ✓ Immediately take samples around the point of entry ✓ Initiate Spill Prevention, Control and Countermeasures Plan for facility
Response Personnel:	Onsite drilling personnel and supervisors
Equipment:	Drilling rig, mud logging equipment, blowout preventers with annular rams, drilling fluid materials to increase mud weight adequately. Spill kit

10.2.4 Event Description: CO_2 or Subsurface Fluid Migration

This event could occur if the plume or other subsurface fluids reach faults or fractures that allow migration into another zone, including the USDW, or to the surface. Failure of the confining zone could also cause CO_2 or subsurface fluids to migrate.

Table 10-5: Event Description & Response Scenario 4 | CO_2 or Subsurface Fluid Migration

Emergency ID	Response
Risk Level:	**Medium**
Timing/Phase of Event: *(Construction, pre-injection, during injection, and/or post-injection).*	During injection and Post-injection
Prevention and Detection:	The CO_2 plume will be monitored as described in the Testing and Monitoring Section (**Section 6**)
Potential Response Actions:	• Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c) • Determine the severity of the event, based on the information available, within 24 hours of notification • For all emergencies (Major, Serious, or Minor): ✓ Initiate shutdown plan ✓ Notify emergency contacts ✓ Use Ambient Reservoir Monitoring system and/or Vertical Seismic Profile system to assess location and degree of CO_2 movement, as described in the Testing and Monitoring Plan ✓ If the presence of indicator parameters are confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to: ▪ Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of the impact; and ▪ Remediate unacceptable impacts to the affected USDW ✓ If groundwater/USDW is impacted: ✓ Pump carbon dioxide-contaminated groundwater to the surface and aerate it to remove carbon dioxide. ✓ Apply "pump and treat" methods to remove trace elements. ✓ Drill relief wells that intersect the accumulations in groundwater and extract carbon dioxide. ✓ Provide alternative water supply if ground water-based public water supplies are contaminated. ✓ If surface water is impacted: ✓ Shallow lakes will quickly release dissolved carbon dioxide back into the atmosphere. ✓ Create a hydraulic barrier by increasing reservoir pressure upstream of the leak. ✓ Continue monitoring of plumes at a more frequent interval (frequency to be determined by Milestone and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed ✓ If the plume continues to migrate out of the zone or beyond the expected plume extent, recomplete up hole into the next planned injection interval.
Response Personnel:	Operations personnel
Equipment:	Depends on the cause of leak, hydraulic barrier, pump, water testing kit

10.2.5 Event Description: Natural Disaster

A natural disaster could impact the normal operation of the injection well. For example, weather-related disasters (e.g., tornado or lightning strike) may impact surface facilities.

Table 10-6: Event Description & Response Scenario 5 | Natural Disaster

Emergency ID	Response
Risk Level:	**Low**
Timing/Phase of Event: *(Construction, pre-injection, during injection, and/or post-injection).*	Any phase.
Prevention and Detection:	• Proper wellbore design, including proper cement and metallurgy of the casing and tubing will be implemented in the construction phase • Pressure and rate monitoring, pressure fall-off tests, annulus pressure tests, etc., will all be performed per the Testing and Monitoring Plan • Weather event monitoring and communication will be implemented
Potential Response Actions:	• Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c) • Determine the severity of the event, based on the information available, within 24 hours of notification • For a Major or Serious emergency: ✓ Initiate shutdown plan. Steps could include: ▪ Close wellhead valve. ▪ Monitor well and annulus pressures. ▪ Determine the cause and severity of failure to determine if any release of the CO_2 stream or formation fluids may have been released into any unauthorized zone. ▪ Pull and replace the tubing or the packer. ▪ Install chemical sealant barrier and or attempt cement squeeze to block leaks. ▪ Demonstrate Mechanical Integrity per the methods discussed in Testing and Monitoring Plan. ✓ Notify emergency contacts ✓ If contamination is detected, identify and implement appropriate remedial actions (in consultation with the UIC Program Director) • For Minor emergency: ✓ Conduct assessment to determine whether there has been a loss of mechanical integrity ✓ If there has been a loss of mechanical integrity, initiate shutdown plan and notify emergency contacts
Response Personnel:	Operations personnel, local Fire and or Sheriff's Department or Other Emergency Contacts
Equipment:	Depends on the type of Natural Disaster

10.2.6 Event Description: Induced Seismic Event

Induced seismic events typically refer to minor seismic events that are caused by human activity which alter the stresses and fluid pressures in the earth's crust. Induced seismicity could potentially result from the injection of fluids into subsurface formations that change the stress state of pre-existing faults, which causes fault plane movement and energy release.

Most induced seismic events are extremely small (microseismic), but in some instances are great enough to be felt by humans. Case histories of induced seismic events associated with fluid disposal wells show seismic events as far away as about 10 to 12km (6.2 to 7.4 miles). Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside a 10km (6.2) radius from the wellhead. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a 10km (6.2 mile) radius of the injection well.

To monitor the area for seismicity, the site will install five (5) near surface seismic monitoring stations and borehole monitoring stations that continuously record (at 5 millisecond frequency) the site's seismic activity (see permit **Section 6**). In addition to these stations, Milestone will monitor for seismicity using distributed acoustic sensing fiber optic cable (DAS) cemented within wellbore annuli. Finally, the USGS and TexNet have deployed a network of surface seismic monitoring stations and borehole monitoring stations in this area (Map of TexNet stations can found in permit **Section 6**)

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events (**Figure 10-3**), the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions. In **Table 10-7**, the Milestone Seismic Monitoring System is presented. The table corresponds each level of operating status with the threshold conditions and operational response actions.

Table 10-7: Event Description & Response Scenario 6 | Induced Seismic Event

Emergency ID	Response
Risk Level:	**Low**
Timing/Phase of Event: *(Construction, pre-injection, during injection, and/or post-injection).*	During Construction, During injection, Post Injection
Prevention and Detection:	Near Surface Seismometer Water well: Cemented Geophones Injection well: DAS microseismic monitoring Monitoring well: DAS microseismic monitoring
Potential Response Actions:	Follow the seismicity response plan **Tables 10-8**
Response Personnel:	Operations personnel, third party seismologists, Milestone geology team, Milestone regulatory team.
Equipment:	Near surface seismometer network. Injection well fiber-optic cable based seismic monitoring.

Table 10-8: South Midland Facility Seismic Monitoring System

South Midland Facility Seismic Monitoring System: Green thru Red for seismic events > M1.0 with an epicenter within an 6.2-mile radius of the injection Well

Operating State	Threshold Condition	Response Action
GREEN	Seismic events less than or equal to M2.0[1]	1. Continue site activities per permit conditions
YELLOW	Five (5) or more seismic events within a 30-day period having a magnitude greater than M2.0[1] but less than or equal to M2.5[1]	1. Continue site activities per permit conditions. 2. Within 24 hours of the incident, notify the UIC Program Director and TXRRC of the operating status of the facility.
ORANGE	Seismic event M2.5-3.0[1] with local observation or felt report[2] OR Seismic event M3.0-3.5[1] but no felt report[2]	1. Continue site activities per permit conditions. 2. Within 24 hours of the incident, notify the UIC Program Director and TXRRC of the operating status of the facility. 3. Review seismic operational data. 4. Report findings to the UIC Program Director and issue corrective actions[3]
MAGENTA	Seismic events M3.0-3.5[1] with local observation report or felt report[2] OR Seismic events greater than M3.5[1] but no local observation or felt report[2]	1. Within 24 hours of the incident, notify the UIC Program Director and TXRRC of the operating status of the facility. 2. If M3.5+, Shut-in injection well while an investigation can be performed 3. Limit facility access to authorized personnel only. 4. Communicate with Milestone personnel and local authorities to initiate evacuation plans, as necessary. 5. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 6. Determine if leaks to groundwater or surface water occurred. 7. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. b. Identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 8. Review the seismic and operational data. 9. Report findings to the UIC Program Director and issue corrective actions[3]
RED	Seismic events greater than M3.5[1]· with local observation or felt report[2] and local report and confirmation of damage[4].	1. Within 24 hours of the incident, notify the UIC Program Director and TXRRC of the operating status of the facility. 2. Shut in injection well while an investigation can be peformed 3. Limit facility access to authorized personnel only. 4. Communicate with Milestone personnel and local authorities to initiate evacuation plans, as necessary. 5. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 6. Determine if leaks to groundwater or surface water occurred. 7. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. b. Identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 8. Review the seismic and operational data. 9. Report findings to the UIC Program Director and issue corrective actions[3]

[1] Determined by the local Milestone or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.
[2] Confirmed by the local report of felt ground motion or reported on the USGS *"Did You Feel It?"* reporting system.
[3] Within 25 business days (five weeks) of change in operating state.
[4] Onset of damage is defined as cosmetic damage to structures – such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves and cabinet.

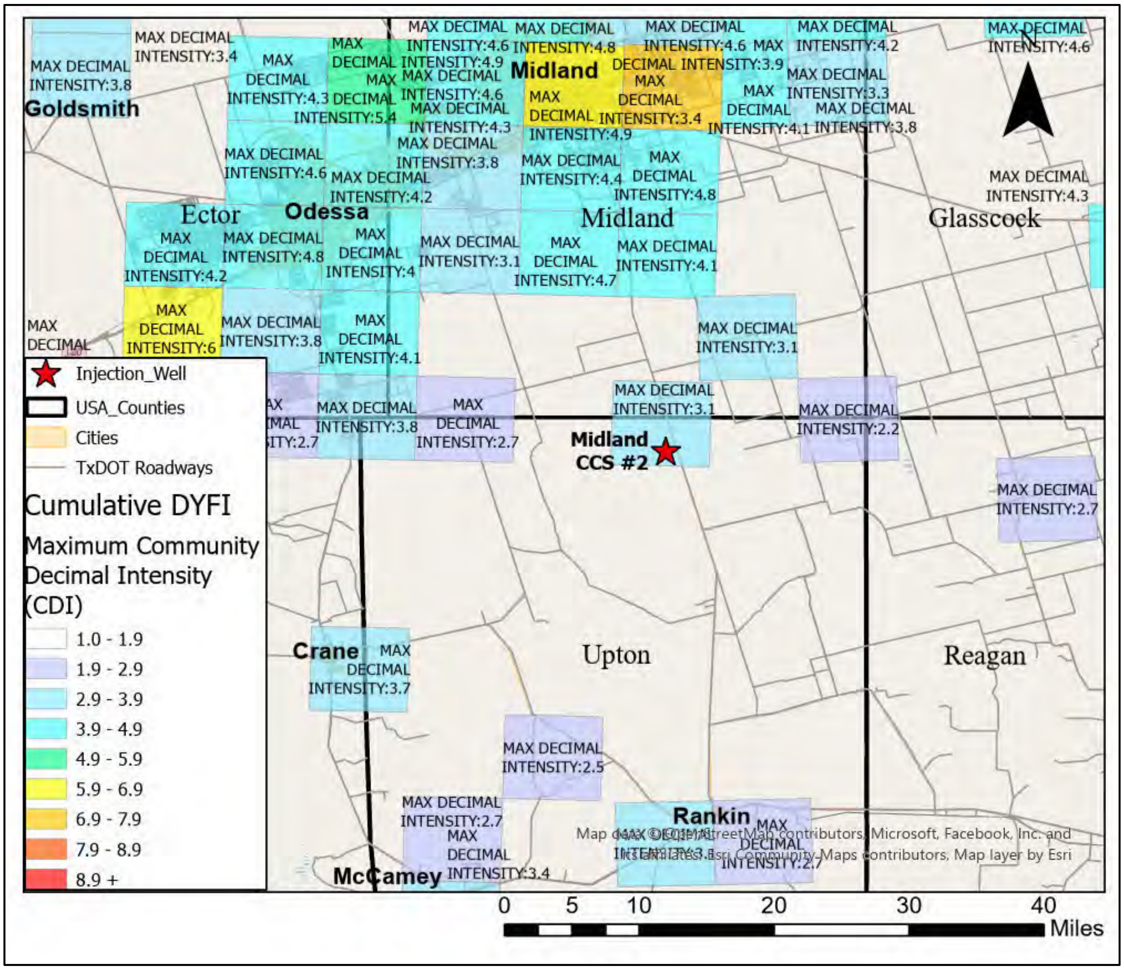

Figure 10-3: "Did you Feel It" Internet-based Macroseismic Intensity Map for Upton County
Data is Cumulative from the year 2001 to present. DYFI polygon at the well location has a max decimal intensity of 3.1

10.2.6.1 Did you Feel It Analysis

The "Did You Feel It" (DYFI) internet-based macroseismic intensity map in **Figure 10-3** shows the proposed injection well location has a value of M3.1. This supports Milestone's proposed seismicity operational states alert status of M2.5-3.0 (orange) and higher response categories of M3.0+ (magenta) and M3.5+ (red). Given that there have been events in the M2.0-M2.5 (Yellow) range historically, this will permit the Milestone site to continue to operate if baseline seismicity occurs, but not if elevated levels of seismicity begin to happen. Milestone selected these ranges based on the observed DYFI reports in the area for the last twenty-four (24) years in addition to other historical seismicity data. Please review historical seismicity sections of permit **Section 1** and **Section 6** for additional information.

10.3 Response Personnel and Equipment

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (e.g., cessation of injection, well shut-in, etc.) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, Milestone will be responsible for its procurement.

Milestone health and safety professionals will make appropriate emergency response equipment available for probable events, this may include the following: SCBA breathing equipment, electric vehicles, personal CO_2 monitors and other personal protective equipment.

10.4 Emergency Communication Plan

As appropriate, if related to health and safety, Milestone's director of health and safety, [redacted], or if environmentally related, Milestone's Vice President of Sustainability and Communications, [redacted] will communicate with the public and first responders regarding events that require an emergency response, including the impact of the event on drinking water, potential atmospheric releases or the severity of the event, actions taken or planned, etc. Milestone's manager of Regulatory and Environmental Compliance, [redacted], will communicate with EPA Region 6, TCEQ and RRC officials regarding regulatory matters.

Milestone will also communicate with other entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, Oil and Gas Operators and Regional Response Teams (as part of the National Response Team).

Additionally, prior to the commencement of CO_2 injection operations, Milestone, via Milestone's Sr. Land Manager, [redacted] will communicate in writing with landowners residing/living adjacent to the storage site to provide a summary of the information contained within this ERRP, including but not limited to information about the nature of the operations, size of the AoR, hazards and characteristics of injectate, operator contact list, potential risks, and possible response approaches.

An emergency contact list (**Table 10-9**) will be maintained during the life of the project and posted at all Milestone Carbon facilities. In the unlikely occurrence of an emergency event, the director of operations or a field superintendent will immediately start the contact list and ensure that responsible, essential Milestone and local emergency personnel are contacted. The operator's designated personnel will handle all event communications with the public. A list of contractors (**Table 10-10**) will be maintained during the life of the project.

The appropriate amount of information, timing, and communications method(s) will be based upon the circumstances and severity of the event, which may include, but are not limited to:

1) Event description and location.
2) Event investigation process and response status (e.g., actions taken).
3) Whether there is any known impact to the drinking water, surface atmospheric release of CO_2 or other environmental impacts
4) Any known injury to person or property or probable risk to person or property.

For protracted responses (e.g., passive monitoring or ongoing cleanups), the project will provide periodic updates on the progress of the response action(s). Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP. Site personnel to be notified (not listed in order of notification):

Table 10-9: Contact Information for Key Local, State and Other Authorities

Agency	Phone Number
Upton County Sheriff's Office	432-693-2422
Upton County Emergency Management Department	432-693-2321 ext. 2
Upton County 911 Coordinator	432-693-2014
Texas State Police	512- 424-2000 (HQ, Austin) 432-498-2140, Midland
Texas Dept. of Public Safety 24-hour non-Emergency	800-525-5555
Texas Dept. of Transportation	800-558-9368
Local Midkiff Volunteer Fire Department	PO Box 130, Midkiff, TX 79755
Midland Fire Department	432-685-7332
Angel MedFlight – advanced air transport-DOT and FAA provider	855-827-8890
Texas Division of Emergency Management agency:	512-424-2208
Texas Commission of Environmental Quality / Water Division:	512-239-6696
The Railroad Commission of Texas 24-Hour Emergency reporting line	844-773-0305 (toll free) or 512-463-6788
UIC Texas Program Director:	512-239-6466
EPA National Response Center (24 hours)	800-424-8802
EPA Region 6 (South Central, *serving AR, LA, OK, and TX)* Customer Service Hot Line	toll-free line - 800-887-6063; Outside Region 6 call 214-665-2760
Milestone Environmental South Midland Facility Emergency Hotline	432-305-4360
Rankin County Hospital District	432-693-1200
Midland Memorial Hospital	432-221-1111

Table 10-10: Potential Contractor and Service Providers

Agency	Phone Number
Permian Paving | Excavation and Dirt Work / Hauling	432-214-2317
Midland County Emergency Management | Temporary Housing & Rentals	432-688-4160
Schlumberger Cementing	720-272-5288
Schlumberger Core Analysis	801-232-5799
Schlumberger Direction & Measurements	484-522-8434
Schlumberger Products & Services	517-755-9050
Schlumberger Bits	517-755-9050
Schlumberger Completions	440-391-2711
MI SWACO Drilling Fluids	661-549-3645
Hazardous Waste Disposal in Midland Texas	708-263-0756

10.5 Plan Review [40 CFR 146.94(d)]

This ERRP will be reviewed and updated at least once every five (5) years. Any amendments to the plan will be approved by the UIC Program Director and will be incorporated into the permit. This plan will also be reviewed and re-submitted to the UIC Program Director given the following:

- Within one (1) year of an AoR re-evaluation
- Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by UIC Program Director
- Change in key personnel
- Or when required by the UIC Program Director.

If the review indicates that no amendments to the ERRP are necessary, Milestone will provide the UIC Program Director with the documentation supporting the “no amendment necessary” determination. If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the UIC Program Director within sixty (60) days following an event that initiates the ERRP review procedure.

10.6 Staff Training and Exercise Procedures

Personnel responsible for implementing this ERRP will be trained in their duties and responsibilities during annual onsite and/or table-top training exercises. All Milestone personnel, visitors, and contractors must attend an overview orientation before obtaining permission to enter any of the facilities. A refresher course on this training will be required annually.

Before starting CO_2 injection operations, Milestone will provide a copy of the ERRP to local first responders and discuss potential response scenarios. Milestone will proactively work with local first responders to determine appropriate procedures in the event of an emergency event including removing the public from the affected area or controlling access to the site. These procedures will include the use of specialty equipment. The Milestone incident commander will work with first responders on the scene to direct what responses are required on location, e.g. fire suppression, evacuation of injured personnel, access to the location.

10.7 Site Security and Access Control

Milestone will control access to the well facilities and any associated surface infrastructure such as SCADA control panels or surface pumps. A fence will be built around the site with locked gates. All panels that do not contain emergency stops will be locked.

Security cameras and motion detectors will be installed at the facility to alert Milestone personnel of any unauthorized activity. These will be monitored 24/7 by a commercial alarm company that operates in the area. There will be Milestone staff on site 24/7 at the Milestone Environmental services office.

10.8 Resume Operations [40 CFR 146.94(c)]

If the injection wells are shut-in or suspended for an emergency event, after all events have been declared resolved, Milestone will restart injection operations after demonstrating the injection operations will not endanger the underground sources of drinking water (USDW).

If remediation is required Milestone will submit a remediation plan within (30) thirty days of such notice from the UIC Director. This plan will include follow-up monitoring and testing regarding the emergency event.

Milestone will submit a notice of intent to resume injection to the Director at least five (5) business days before injection is to resume if there are no remaining events and no endangerment of USDW. Injection operations will only resume upon receipt of written authorization of the UIC Program Director.

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Section 11: Financial Assurance Demonstration Plan (FADP)

[40 CFR §146.82 (a), §146.85]

Prepared for:

EPA Region 6

Underground Injection Control Section

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MILESTONE CARBON

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Updated 4 February 2026

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11.0 FINANCIAL ASSURANCE DEMONSTRATION PLAN (FADP) [CFR 146.82(a)(14) and 146.85; 16 Texas Admin Code § 5.205]

Milestone is providing financial responsibility (Financial Assurance or FA) pursuant to 40 CFR 146.85 and 16 Texas Admin Code § 5.205 and proposes the use of a Surety Bond to cover the costs of: corrective action, emergency and remedial response, injection well plugging, post-injection site care, routine monitoring/reporting activities, and site closure. In compliance with 40 CFR 146.85(a)(4) and Texas Statewide Rule 5.205 (c)(2)(D)(iii), these instruments will provide that they may not be cancelled or terminated except due to failure to make payment and, in such event, the cancellation or termination may not be final until 120 days after receipt of cancellation or termination notice mailed to Milestone and the permitting authority. All cost estimates were generated by an independent third party, Petrotek, of Littleton, Colorado.

11.1 Independent Third-Party Cost Estimation [CFR 146.85 (C) (1); 16 Texas Admin Code § 5.205 (C)(2)(C)]

Milestone contracted an independent third-party professional engineering firm to perform all cost estimates, Petrotek, of Littleton, Colorado. Petrotek employs professional engineers licensed in the state of Texas

The cost estimate was performed for each phase separately and was based on the costs required for the regulatory agency to hire a third party to perform the required activities. Petrotek is not within the corporate structure of Milestone.

Petrotek, on Milestone's behalf, provides a tabular detailed written estimate, in current dollars, of the cost necessary to perform corrective action on wells in the area of review, plugging of injection wells, post-injection monitoring and closure of the facility, and emergency and remedial response that shows all assumptions and calculations used to develop the estimate.

Petrotek employs qualified professional engineers licensed by the State of Texas, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, and has prepared or supervised the preparation of a written estimate under seal of the highest likely amount necessary to close the geologic storage facility. Included in the FA appendix is a separate letter that seals the estimate as required under 16 Texas Admin Code § 5.205 (C)(2)(C)(ii).

11.2 Approach to Meeting Financial Assurance Requirements

Milestone will secure a surety bond to meet FA requirements for any corrective action, injection well plugging, post-injection site care, site closure, and emergency and remedial response activities.

Milestone will secure a surety bond necessary to perform corrective action, emergency and remedial response/remedial action, post-injection monitoring and site care, and closure of the geologic storage facility, including plugging of injection or monitoring wells at any time during the permit term in accordance with all applicable EPA regulations, Texas state laws, Railroad Commission rules and orders, and the permit.

If there are any remaining components required for financial assurance demonstration, these will also be secured by a Surety Bond and/or by Letter of Credit. A standby trust will be established for the surety company to make payments.

11.2.1 Financial Mechanism: Surety Bond

To satisfy its financial responsibility obligations for corrective action, injection well plugging, post injection site care, site closure, emergency and remedial response activities and, other than items covered by Surety Bond as described herein, Milestone will secure either a payment or performance bond using the forms – **Section 13 Appendix J.** The bond will be issued by a surety company that meets the requirements of 40 CFR 146.85(a)(6)(ii). It is understood that should Milestone fail to meet the requirements specified in the bond; the surety company is liable for the costs. Milestone will also establish a standby trust into which the surety company will make payments if Milestone fails to comply with its financial responsibilities. The trust agreement form (**Section 13 Appendix J**) will be used to establish the standby trust. Money deposited into the trust fund established by standby trust can then be used to pay a third party to perform corrective action, closure/post-closure activities and emergency and remedial response.

Milestone may use one of the following two types of bonds to meet the financial assurance requirements:

1. **Payment Bond** - guarantees that if the owner/operator fails to pay for corrective action, injection well plugging, post injection site care and site closure, and/or emergency and remedial response, the surety company will pay the costs into the fund established by the standby trust.
2. **Performance Bond** - guarantees that if the owner/operator fails to perform all the required corrective action, injection well plugging, post injection site care and site closure, and/or emergency and remedial response activities, the surety company will either perform the required activities or pay sufficient funds into the fund established by standby trust.

The issuer of any geologic storage facility bond filed in satisfaction of the requirements of this subsection will be a corporate surety authorized to do business in Texas. The form of bond filed under this subsection will provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the director.

In case it is unclear, the bond amount will be the composite p90 of the total FA distribution.

11.3 Corrective Action Plan

The detailed AoR and Correction Action Plan are located in **Section 2** of this permit application. Milestone has determined that there are zero (0) wells in the proposed AoR for which corrective action is required prior to, or during, the course of this project operation or post-closure period. However, in the event wells within the AoR are determined to require correction action, Milestone will demonstrate its financial responsibility for such actions by including the projected costs in the surety bond to be provided as set forth in **Section 11.2.1**. The AoR will be re-evaluated every five (5) years to determine if any new penetrations have occurred and whether such penetrations require corrective action.

Even though there are zero (0) wells within the AoR that penetrate the Injection Interval or Top Seal and require corrective action, there are ongoing monitoring activities that require cost estimation. Milestone has assigned a cost to monitoring future permits and possibly plugging and testing heretofore undiscovered wells. Therefore, Corrective Action costs contemplate the low probability future event that a deficient well is permitted by the RRC to drill into the AoR or a historical well is discovered to penetrate the Top Seal or Injection Interval in the future.

11.4 Injection Well-Plugging Program

Plug and abandonment (P&A) of the Midland CCS #2 Well is included within the project operating cost and is covered within this Financial Assurance Demonstration Plan and proposed surety bond. The specifics of the plugging program can be found in **Section 8 – Injection Well Plugging** of the permit application. Costs were estimated using work scopes provided by third-party industry experts and comparable third-party costs for performance of services and procurement of associated material and equipment. The estimate covers the aggregated P&A cost of one (1) injection well, including rig mobilization, rig and equipment rentals, cementing, logging, haulage, and P&A reporting. To ensure a conservative estimate, no cost deductions were made to salvage the value of materials. The projected cost of Injection Well Plugging will be included in the surety bond to be provided as set forth in **Section 11.2.1**.

11.5 Post-injection Site Care (PISC)

PISC and facility closure estimates include site monitoring and periodic reassessment of the AoR, facilities maintenance and power costs, overhead and support costs. Details of the activities and actions contained in the PISC can be found in permit **Section 9 – Post Injection Site Care**. The largest element of the PISC cost estimate relates to geophysical surveys and wells' subsurface data capture carried out at periodic intervals and which will cover the USDW and IZM monitoring wells, the five (5) NSSW monitoring wells, and an AoR area of up to 8.4 mi^2. Costs for PISC were developed using historical data, SME estimates, and Vendor estimates for specific materials and equipment. The estimates cover mobilization, detector arrays' installation, surveying, field-sampling, lab analyses, data processing, land agreements, and data interpretation-reporting. The post injection regulatory fee of $50K per year is also included in this amount. The projected cost of PISC will be included in the surety bond to be provided as set forth in **Section 11.2.1**.

11.6 Facility Closure

Facility closure includes casing evaluation, mechanical integrity verification, P&A activities and site reclamation costs for all sampling and geophysical monitoring wells including the Midland USDW #2, Midland IZM #2, and Midland NSSW #1-5 wells. It also includes fieldwide removal of surface equipment and remediation of inter-well sites soil and/or aquifer contamination. Site Closure reporting costs are included in the Site Closure total estimate. The projected cost of Site Closure will be included in the surety bond to be provided as set forth in **Section 11.2.1**.

11.7 Emergency & Remedial Plan

The Emergency and Remedial Response Plan (ERRP) and associated detailed assessment can be found in **Section 10 – Emergency and Remedial Response Plan** of this permit application.

Milestone conservatively estimated costs associated with emergency and remedial response related to each of the emergency events described in **Section 10** (ERRP) of this application, including well integrity failure or loss of mechanical integrity, injection well monitoring equipment failure, a spill, CO_2 or subsurface fluid migration out of the injection zone, damage due to a natural disaster, and damage due to induced seismicity. Most of these emergencies fall under site shut down, well control or other emergency remedial implementations, mechanical integrity event. The activities related to these ERRP events, as provided by Milestone, are presented in **Section 10 - Table 10-1** to **Table 10-7**. Estimated costs associated with ERRP events are shown in **Table 11-6**.

The cost estimates for well integrity failure or loss of mechanical integrity, CO_2 or subsurface fluid migration out of the injection zone, damage due to a natural disaster, and damage due to induced seismicity are conservatively based on a Monte Carlo analysis of the costs associated with a hypothetical worst-case scenario wherein a significant volume of briny water or CO_2 escapes to the surface. The scenario contemplates a reactive response approach – for example – mobilization of response personnel and equipment upon discovery of such an event. This approach is considered appropriate because of the remoteness of the residual risk. Specific post-occurrence action is not determinable until occurrence; thus, actual response to such an event would be based on its severity level. Costs associated with this scenario are intended to account for the outer-limit estimate to satisfy event response. The cost estimate is based on the optimal operating conditions (10 years' operation) requiring outer-limit response and remediation costs.

The cost estimates also account for a scenario in which CO_2 or subsurface fluids migrate and potentially endanger an underground source of drinking water (USDW). The risk of endangerment to USDWs is considered remote and unlikely given the large number of impermeable layers between the injection zone and USDW. However, as part of the reactive response scenario contemplated in the ERRP cost estimate, Milestone assessed the specific response actions and cost data to represent the likely impact of such an event on sources of drinking water.

Milestone will utilize its Spill Control and Prevention Plan in combination with the response strategy to minimize this portion of environmental repair. This subsurface migration and USDW endangerment have primary costs related to groundwater delineation and an extended period (10 years) of quarterly monitoring and reporting after emergency remedial actions are taken. The projected cost of emergency and remedial response will be included in the surety bond to be provided as set forth in **Section 11.2.1**.

11.8 Methodology – Monte Carlo Simulation

As a way of addressing and managing cost-estimation input-data uncertainties, FA analysis employed Monte Carlo simulation for stochastic modeling. From the EPA we note: "*It is the policy of the U.S. Environmental Protection Agency that such probabilistic analysis techniques as Monte Carlo analysis, given adequate supporting data and credible assumptions, can be viable statistical tools for analyzing variability and uncertainty in risk assessments*." (Fred Hansen, EPA, 1997, p. 1.)

The specific simulator used was RiskAMP™, a full-featured Monte Carlo simulation engine add-in for Microsoft Excel written by, and sourced-through, Structured Data LLC. The RiskAMP add-in includes more than 40 random distribution functions allowing for good, practical, contextual application specific to intuited or estimated project and/or FA activities operational constraints.

Basic to FA, is knowing the cost of effectively meeting the compliance mandates listed and described in Project Financial Assurance section above. The purpose and scope of this FA assessment (Fred Hansen, EPA, 1997, p. 2) is a composite and accurate estimate of the costs of that compliance. Such estimation is challenged on three fronts: data uncertainties, sourcing, and assumptions.

11.8.1 Uncertainties

For FA estimation, the first uncertainty is the lack - that comes with a relatively new industry - of corresponding historical cost data. The geologic sequestration of CO_2 via the method of deep subsurface injection remains a relatively new undertaking. This applies most directly to data sets worthy of parametrization in the service of cost estimation. Data useful for infrastructure and operational costs evaluation continues to be scarce, and thereby subject to application only through indirect comparison and analogy – in particular, through the use of data reflecting oil and gas (O&G) fields' subsurface infrastructure development and operations costs. Such O&G costs reflect global markets, are affected politically, and have a history of price/cost volatility. Accordingly, the nature of volatile cost-data comparisons brings compound uncertainties; and inevitably, extended ranges.

The second uncertainty is the evolving cost of applied technologies, materials, and their associated operational changes to be employed for compliant management of CO_2 geologic sequestration. As the subsurface carbon sequestration industry grows and matures, changes to regulatory design and operational standards are probable, and are equally likely to materially impact the cost of doing business – even post-injection.

The third is the uncertainty with shifting EPA, TRRC, or TCEQ standards regarding FA, FA costs estimation, associated risks assessment, and practical assessment of risk-underwriting scale and scope.

11.8.2 Data Sources

This FA analysis aligned with EPA's UIC Program Class VI Financial Responsibility Guidance (EPA, 2011) as the basis to define the activities required to be included in the cost estimate. Supported by that guidance, Milestone Carbon's FA-relevant Permit Application sections (EPA phases) were reviewed for operational and technical approach, for CO_2 injection model output, and post-injection FA activities' durations and periodicities.

Additionally, for FA required activities, both estimated costs and their stochastic treatments were guided by a variety of Agencies', National Laboratories', Universities', and Industries' data and expertise. Sources included:

- Historic price data from other Petrotek managed UIC projects and FA analyses;
- Cost quotations from third-party service providers;
- Academic investigation and assessment of distribution functions application;
- PNL's Assessment of the Geomechanical Risks Associated with CO2 Injection at the FutureGen 2.0 Site (PNL, 2019);
- EPA's Geologic CO_2 Sequestration Technology and Cost Analysis (EPA, 2008);
- DOE's Final Risk Assessment Report for the FutureGen Project Environmental Impact Statement (NETL, 2007);
- NETL's Overview of Potential Failure Modes and Effects Associated with CO2 Injection and Storage Operations in Saline Formations (DOE/NETL, 2020); and
- Petrotek professional engineering, project management, and estimation expertise.

11.8.3 Data Assumptions

Almost by definition, estimation of FA cost looks far into future technologies and operational cost relationships. Realities of carbon sequestration industry price escalation and general macroeconomic inflation are important factors. However, aligned with EPA Class VI Permit Application submission requirements (EPA, 2011, p7) for initial FA analysis, "current dollars" (April 2025) are employed.

11.8.4 Monte Carlo Simulation

Monte Carlo simulation has been used for estimating FA costs in the current evaluation. While this overview does not aim to be a comprehensive guide on the technique, a brief explanation of Monte Carlo simulation will help contextualize its application for this Milestone Carbon FA evaluation, which focuses on future events.

Monte Carlo simulation is a computational method that uses random sampling to model and analyze uncertain systems or processes. In cost forecasting, this technique involves running numerous iterations with varying input values and assumptions to generate a range of possible cost estimates. By examining different combinations of input variables, such as FA cost drivers, (e.g. probability of events, ranges of costs), Monte Carlo simulation captures the inherent uncertainty in forecasting.

The core idea behind Monte Carlo simulation is that any uncertain variable, such as the cost of an unanticipated event, can be represented by a probability distribution. This distribution describes the range of possible values and their likelihood. For example, a probabilistic cost estimate of an FA operational activity might be appropriately modeled using a parameterized distribution reflecting Gaussian (normal), Weibull, beta-PERT, Gamma, etc. distributions. According to the particular activity modeled, each distribution would be chosen and parameterized specific to the nature of the activity's estimated scale, scope, periodicity, duration, and probability. By assigning crafted probability distributions to specifically uncertain variables in the FA cost analysis, we create a mathematical model of the total FA cost estimate.

The process involves using a random number generator to sample values from each distribution and calculate a total event cost. Repeating this process many times produces a large set of simulated event costs, which form a frequency distribution. This distribution reveals the most likely FA total cost, percentiles of cost, as well as the minimum and maximum possible costs. It also shows the probability of achieving a specific cost target or staying within a certain range. This information helps assess the likelihood or probability of the FA cost based on the model.

Monte Carlo simulation is particularly useful for addressing and quantifying uncertainties in complex, future, and non-linear systems. In the context of FA, it combines multiple cost and probability estimates - first individually and then aggregated through Monte Carlo analysis - to provide a range of possible FA costs and associated probabilities. Compared to other forecasting methods, such as deterministic or single-point estimates, Monte Carlo simulation offers several advantages. It:

- Captures the complexity and interdependence of multiple variables and factors that affect FA cost, such as resource availability, quality issues, and external risks;
- Provides a realistic and comprehensive view of the uncertainty and variability of FA cost, and quantifies the level of confidence and accuracy of the estimate;
- Identifies the key drivers and contributors of FA cost and highlights potential areas of high risk and/or opportunity;
- Supports decision making and risk management by providing quantitative treatments and metrics. These include FA total and FA phases' costs range, mean, median, mode, standard deviation, confidence intervals, percentile distributions, cumulative distributions, probability density distributions, and expected values; and
- Facilitates communication and presentation of the results by using graphical and numerical tools, (e.g., Probabilities and Costs) graphics and tables.

As noted, the RiskAMP Monte Carlo simulation engine was employed for all FA costs estimation simulation work. For this analysis, **250,000 iterations per model run** were used to assess the total FA cost impact generated by a set of **74 specific FA-related activities**. Each Monte Carlo simulation when run delivered a set of statistical metrics used to evaluate, compare, and contrast costs across the scale and range of Class VI operational activities addressed through FA estimation and assessment.

For FA costing and management, Milestone has elected to use model Monte Carlo distributions' "most probable cost" or Statistical Mode to represent FA costs for each major FA Phase (e.g., Injection Well Plugging, ERRP, etc.) as well for the Total Project FA cost. For the current Total Project model output with 250,000 iterations, the Mode of the FA Total Project equates to approximately a P63 value.

The mode is considered the "most probable value" from a distribution, because it occurs most often; in the same way that rolling a sum of 7 is the most probable value when rolling 2 six-sided dice and all other values have less combinations and are less likely. Said another way, the mode occurs at the peak of the probability distribution histogram, and it is the value or amount around which outcomes are most densely packed. 16 Texas Administrative Code § 5.205 (C)(2)(C)(ii) requires applicants to provide the *highest likely amount necessary* to close the geologic storage facility. Milestone interprets this phrase to be the statistical mode because it is the *highest likely* or *highest probability* value in the simulation.

11.9 Cost Estimates

Tables in this section provide a detailed estimate, in 2025 (April) dollars, of the cost of performing corrective actions on wells in the AoR, plugging the injection well, post-injection site care, facility closure, and emergency and remedial response. **Table 11-1** is a summary of the cost estimates underlying the FADP document, identifying proposed financial instrument(s) that will provide the appropriate assurance to regulatory agencies of Milestone's intent and ability to fulfill its responsibilities. Petrotek Corporation of Littleton, Colorado, an independent third party, provided the estimates herein.

Cost estimates assume that these costs would be incurred if a third party were contracted to perform these activities. For that reason, the estimate includes costs such as project management and oversight, general and administrative costs, and overhead during the post-injection period, (e.g., the use of post-injection seismic surveys). Cost estimates are based on the Monte Carlo analysis previously described. These values are subject to change. Additionally, these values are driven by market forces such as changes in energy prices, inflation, contractor availability, materials costs etc. If the cost estimates change, Milestone will adjust the value of the financial instruments, and any adjustment will be submitted for approval as required under 40 CFR §146.85(a)(5).

The total estimated costs of each of these activities, as provided by Milestone, are presented in **Table 11-1**. Detailed estimates for major EPA Class VI phases are found in **Table 11-2** to **Table 11-7**. As noted above, even though there are zero (0) wells within the AoR, there is a non-zero chance that in the future Milestone could be required to perform corrective action. Therefore, a cost is provided for this low probability event.

Presented here **in Tables 11-1 through 11-7** are Monte Carlo model estimate statistics for each FA Activity, each FA Phase, as well as the FA for the Total Project. Except for *the Mean* (or *average*), *statistical* metrics (e.g., *median, mode, maximum,* etc.) do not sum to the same number/cost as the total distribution of the entire Phases' and Project Total reflected in Composite Statistical metrics. Statistical mathematics and Monte Carlo simulation algorithms do not work that way. In other words, the p90 of the parts does not sum to the p90 of the total.

Therefore, instead of the sum of the preceding column, shown at the bottom of each of FA Phases' **Tables 11-3 through 11-7** are composite statistical metrics taken directly from the *whole* of the Monte Carlo model run. **Table 11-2** reflects combined statistics of all FA phases as a composite.

Table 11-1: Aggregate Cost Estimates for Activities to be Covered by Financial Responsibility

Activity	Phases' P90 Cost Estimates ($USD)	Covered by Surety Bond
Corrective Action on Wells in AoR	**$329,625**	x
Plugging Injection Wells	**$1,895,586**	x
Post-Injection Site Care and Monitoring	**$7,443,774**	x
Site Closure and Plugging Monitoring Wells	**$8,787,996**	x
Emergency and Remedial Response (including Endangerment of USDWs)	**$8,488,440**	x
FA Composite Statistical p90 Estimate:	**$20,957,610**	**x**

11.9.1.1 Composite Statistical Estimates for Total Project Table

Table 11-2: Composite Statistical Estimates for Total Project FA Costs

Total Project FA Cost Statistics Types	Total Project FA Cost Estimate - USD
Mean	$17,991,169
Median	$17,496,690
Mode	$16,162,525
Standard Deviation	$2,490,764
Minimum	$13,244,831
P10	$15,520,527
P25	$16,346,083
P50	$17,496,685
P75	$19,028,498
P90	$20,957,610
Max	$52,147,417

11.9.2 Tables of Monte Carlo Outputs by Category

11.9.2.1 Corrective Action Table

Table 11-3: Cost Estimate for Corrective Action on Wells in AoR Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Maximum
Ongoing AoR monitoring/modeling and Corrective Action on deficient well(s) in AoR.						
(Annual) Gather and organize operating data obtained during the CO2 injection phase.	$58,784	$59,271	$61,545	$4,486	$42,301	$67,133
(Annual) History match, update the model, and potentially-revise the AoR based on operational and monitoring data.	$73,439	$71,186	$62,835	$15,496	$47,412	$135,543
With AoR unexpected drift or growth, identify deficient well(s).						
Operational or post-injection phase well(s) database search.	$1,301	$875	$2,387	$1,366	$0	$19,097

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Maximum
Operational or post-injection phase other well(s) surveys.	$58,176	$31,576	$191,011	$77,072	$0	$1,528,086
Operational or post-injection well(s) evaluation.	$15,106	$10,014	$7,120	$16,078	$0	$284,791
Well(s) evaluation report and submittal to EPA/State.	$14,846	$10,281	$27,562	$14,885	$0	$220,493
Address newly identified deficient wells.						
Research and purchase legacy, newly-identified deficient wells.	$194,094	$122,686	$616,372	$219,978	$0	$4,930,972
Purchased well(s)' cement remediation, plugging, and MIT.	$104,357	$62,477	$295,493	$125,947	$0	$2,363,940
Document and Report remediated well(s) plugging and MIT.	$7,733	$5,156	$16,589	$8,198	$0	$132,711
Composite Statistics: Ongoing AoR and Corrective Action on deficient well(s) in AoR	**$527,836**	**$462,467**	**$257,094**	**$265,831**	**$128,510**	**$5,271,900**

11.9.2.2 Plugging Injection Well Table

Table 11-4: Cost Estimates for Plugging the Injection Well Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Maximum
Flush injection wells with buffer fluid						
MIRU/RDMO	$50,238	$50,446	$50,594	$5,330	$34,455	$62,524
Casing Evaluation	$80,690	$80,192	$80,537	$10,662	$56,763	$112,701
Flushing fluid	$53,164	$52,303	$49,552	$5,590	$44,002	$75,714
Flush injection well	$13,741	$13,103	$11,543	$4,757	$5,503	$32,346
Perform MIT, assess BHP/reservoir pressure						
Assess BHP	$109,206	$108,294	$105,052	$12,276	$83,681	$149,440
External MIT (Tracer, temperature logs, specific other(s).	$143,450	$141,863	$135,235	$17,051	$110,031	$201,684
Plugging South Midland Facility CCS #2						
Engineering	$42,586	$42,562	$43,512	$6,146	$26,631	$58,785
MIRU/RDMO	$22,911	$22,810	$22,478	$3,103	$15,516	$31,897
Rig time and equipment rental	$504,549	$488,954	$429,756	$126,791	$275,088	$962,503
Miscellaneous services and labor costs	$82,019	$81,326	$79,777	$11,711	$56,737	$118,177
Cement cost	$399,925	$399,904	$395,560	$37,776	$301,720	$499,279
Plugging report	$39,400	$39,179	$37,706	$5,147	$27,555	$54,624
Composite Statistics: Injection Well Plugging Costs	**$1,541,880**	**$1,528,217**	**$1,478,480**	**$135,468**	**$1,185,142**	**$2,087,721**

11.9.2.3 Post Injection Site Care and Monitoring Table

Table 11-5: Cost Estimates for Post-Injection Site Care and Monitoring Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Max
Acquire data: geochemistry, temperature, pressure, & CO2 saturation. (USDW, IZM, & CCS) #2 wells						
USDW #2 Fluid Sampling, Including U-tube installation cost/wireline cost. Includes captured-data periodic reporting costs.	$74,883	$74,028	$73,241	$12,440	$48,496	$114,483
USDW #2: pH and Electrical Conductivity (EC) detector array installation. Includes captured-data periodic reporting costs.	$42,269	$41,960	$39,920	$7,211	$25,779	$63,487
IZM #2 Fluid Sampling, U-tube installation, including estimated wireline cost. Includes captured-data periodic reporting costs.	$114,809	$113,720	$110,138	$13,593	$86,641	$158,941
NSSW #1-5 Fluid Sampling, U-tube, including wireline cost. Includes captured-data periodic reporting costs.	$46,090	$46,260	$47,059	$6,104	$28,647	$60,667
NSSW #1-5 pH and Electrical Conductivity (EC) monitoring detector array installation. Includes captured-data periodic reporting costs.	$38,520	$38,505	$37,939	$6,175	$22,602	$54,890
Midland CCS #2 & IZM #2 Pressure (DAS/DSS) & Temperature (DTS) monitoring (for IZM and USDW intervals). Includes captured-data periodic reporting costs.	$243,171	$240,030	$224,985	$29,111	$188,903	$349,268
Midland CCS #2 & IZM #2 Pulse Neutron Logging/RST (for IZM and USDW intervals). Includes captured-data periodic reporting costs.	$3,721,473	$3,601,324	$3,215,721	$657,828	$2,734,020	$6,587,625
Midland CCS #2 Fluid Sampling, Including U-tube installation cost/wireline cost. Includes captured-data periodic reporting costs.	$100,310	$98,469	$90,788	$9,529	$86,502	$143,646
Lab analyses and reporting (USDW, IZM, & CCS) #2 wells	$245,166	$233,118	$201,884	$72,824	$129,609	$542,608

Table 11-5 (continued): Cost Estimates for Post-Injection Site Care and Monitoring Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Max
Post-Injection Direct and Indirect Plume Monitoring						
AoR Geophysical Surveys	$258,291	$255,378	$239,825	$46,169	$159,466	$406,725
Periodic AoR Computational Modeling and reporting costs.	$644,786	$637,222	$613,338	$72,805	$505,538	$897,539
Lab analyses and reporting (Midland CCS #2 well). Includes captured-data periodic reporting costs.	$241,667	$230,579	$186,033	$65,317	$139,899	$508,973
Other EPA required PISC Site management, monitoring, data analyses, data recording, & reporting.						
Potential other EPA required PISC Site management, monitoring, data analyses, data recording, data storage, and reporting. (Annual).	$255,420	$255,261	$249,642	$57,242	$107,788	$406,429
Composite Statistics: Post-Injection Site Care	**$6,026,856**	**$5,911,397**	**$5,805,841**	**$674,248**	**$4,607,704**	**$8,964,567**

11.9.2.4 Site Closure Table

Table 11-6: Cost Estimates for Site Closure Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Max
Non-endangerment demonstration	$173,291	$169,824	$162,470	$30,789	$116,597	$283,409
Field-wide, remove surface equipment, remediate/restore surface, groundwater, and/or soil contamination.						
Field-wide, remove surface equipment.	$374,842	$362,733	$327,056	$77,664	$249,322	$693,515
Field-wide, remediate inter-well sites.	$495,428	$483,689	$457,572	$105,016	$300,358	$872,047
Field-wide, remediate groundwater and/or soil contamination.	$325,466	$149,024	$1,136,400	$488,530	$0	$9,091,202
Plug USDW #2 Monitoring Well						
Casing evaluation.	$20,834	$20,755	$20,720	$1,873	$16,528	$26,392
Engineering.	$15,060	$15,045	$14,934	$1,818	$10,416	$19,927
MIRU/RDMO.	$11,318	$10,844	$9,670	$2,877	$6,754	$23,418
Rig time & equipment rental.	$9,325	$9,201	$8,614	$1,110	$7,253	$13,304
Miscellaneous services & labor costs.	$27,191	$26,110	$22,200	$7,337	$15,003	$56,129
Cement cost.	$9,998	$9,995	$10,262	$1,890	$5,070	$14,959
Plugging report.	$14,992	$14,992	$15,276	$1,888	$10,077	$19,979
Plug IZM #2 Monitoring Well						
Casing evaluation.	$79,761	$79,245	$76,791	$10,903	$55,104	$112,936
Engineering.	$38,601	$38,575	$37,993	$6,136	$22,906	$54,669
MIRU/RDMO.	$22,406	$22,311	$21,913	$3,105	$15,034	$31,219
Rig time & equipment rental.	$505,180	$489,898	$431,646	$127,006	$275,305	$970,153
Miscellaneous services & labor costs.	$80,498	$79,750	$78,400	$11,692	$55,088	$117,252
Cement cost.	$400,148	$400,229	$404,864	$37,755	$300,889	$498,936
Plugging report.	$39,414	$39,192	$39,085	$5,143	$27,600	$54,625

Table 11-6 (continued): Cost Estimates for Site Closure Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Max
Plug NSSW Monitoring Wells						
Well(s)' mechanical integrity testing.	$152,481	$150,765	$139,670	$28,082	$91,363	$240,002
Rig time & equipment rental	$132,224	$129,619	$117,883	$36,631	$54,956	$248,579
Miscellaneous services & labor costs.	$79,229	$79,302	$76,648	$16,096	$37,140	$120,315
Cement cost.	$600,009	$600,128	$607,615	$56,645	$452,398	$748,049
Plugging report.	$25,502	$24,803	$22,502	$4,570	$18,002	$43,714
Site Closure Report						
Site Closure Report: Site closure report includes subsurface injectate plumes' nature, composition, and volume, injection interval and period, all Injection, IZM and USDW wells closure status, post-injection monitoring records, and final surface remediation and restoration.	$64,352	$64,084	$61,603	$7,469	$46,994	$85,952
Texas State Fees related to Site Closure						
TRRC-specific Post Injection Care Fee of $50,000 per year for 50 years	$2,500,000	$2,500,000	$2,500,000	$0	$2,500,000	$2,500,000
Composite Statistics: Site Closure	**$6,197,550**	**$6,079,425**	**$6,854,279**	**$529,476**	**$5,188,780**	**$14,705,919**

11.9.2.5 Emergency and Remedial Response Table

Table 11-7: Cost Estimates for Emergency and Remedial Response Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Max
Site shutdown						
Site assessment, Initial reporting	$1,392	$875	$630	$1,572	$0	$25,201
Well control or other emergency remedial implementations	$184,001	$95,359	$460,457	$252,214	$0	$6,139,420
Well(s) mechanical Integrity testing.	$1,116	$730	$2,516	$1,199	$0	$20,127
Scenarios : Post-injection USDW contamination						
USDW acidification due to CO2 migration	$252,708	$108,349	$318,174	$400,636	$0	$12,726,972
USDW toxic metal dissolution and mobilization	$649,492	$281,092	$1,575,045	$1,021,472	$0	$21,000,601
Displacement of USDW with brine due to CO2 injection	$1,150,674	$494,580	$2,562,262	$1,827,746	$0	$34,163,488
Critical scenarios : post-injection Failure						
Confinement interval failure (non-seismic)	$219,734	$102,801	$526,238	$326,704	$0	$7,016,510
Confinement interval or well integrity failure due to seismic event	$218,344	$102,738	$471,905	$320,948	$0	$6,292,061
Injection-monitoring equipment failure	$9,715	$5,362	$28,090	$12,538	$0	$224,721
Undefined surface spill	$315,115	$131,965	$383,560	$509,223	$0	$15,342,392
Undefined natural disaster	$315,212	$149,198	$692,573	$464,601	$0	$9,234,300
Chronic scenarios : post-injection Failure						
CO2 release through induced faults due to effects of injection increased-pressure	$68,624	$29,842	$182,607	$107,166	$0	$2,434,756
Well Integrity Failure: upward leakage through CO2 injection well	$140,202	$70,018	$329,684	$196,707	$0	$4,395,786

Table 11-7 (continued): Cost Estimates for Emergency and Remedial Response Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Max
Well Integrity Failure: upward leakage through undocumented, abandoned, or substandard legacy wells	$97,333	$49,224	$236,821	$135,938	$0	$3,157,617
Final and/or Corrective Action reporting to EPA						
Final Corrective Action reporting to EPA	$73,385	$67,608	$45,560	$33,536	$21,263	$215,637
Composite Statistics: Emergency & Remedial Response	**$3,697,048**	**$3,127,948**	**$6,620,638**	**$2,320,011**	**$316,050**	**$36,342,264**

11.9.3 Charts of Monte Carlo Output Distributions

Associated charts for each major category and the final project output displayed in **Figures 11-1** through **11-6** which contain the output distributions for each FA Phase. Several of the distributions contain long-tails indicating worst-case scenario(s) were contemplated but they are low probability event(s).

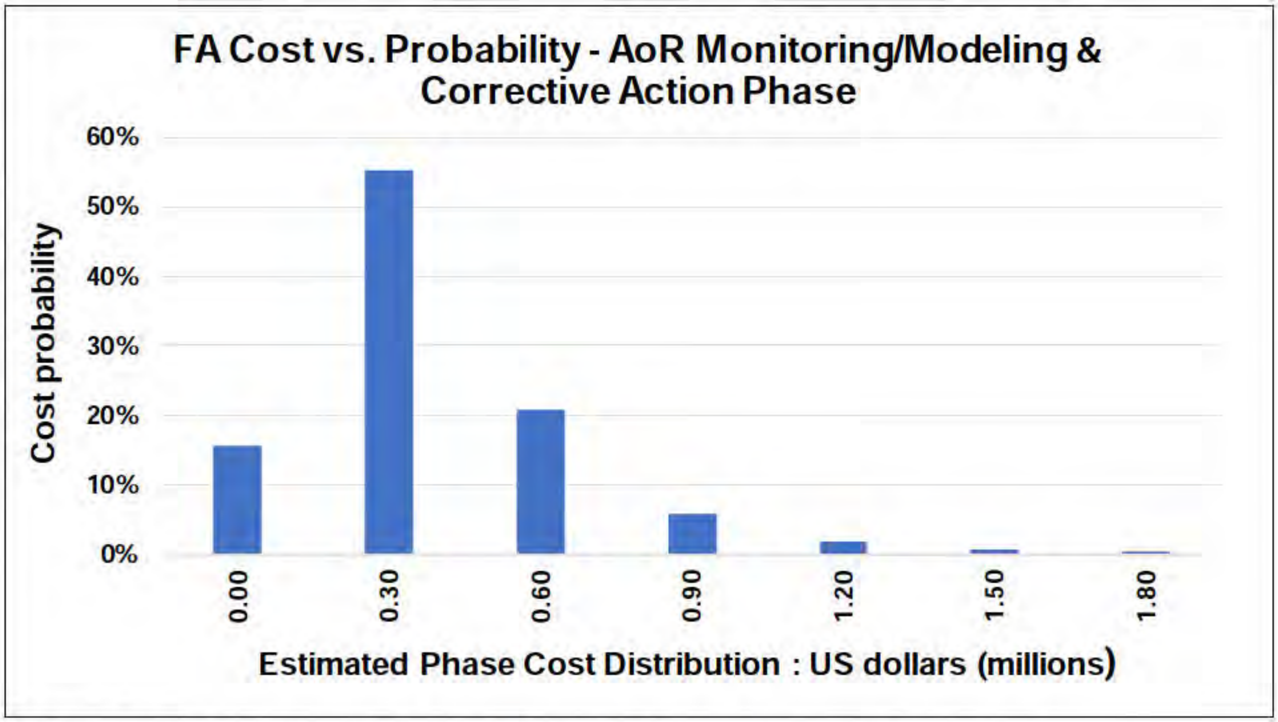

Figure 11-1: ***AoR and Corrective Action*** **Estimated Cost vs. Probability Distribution**

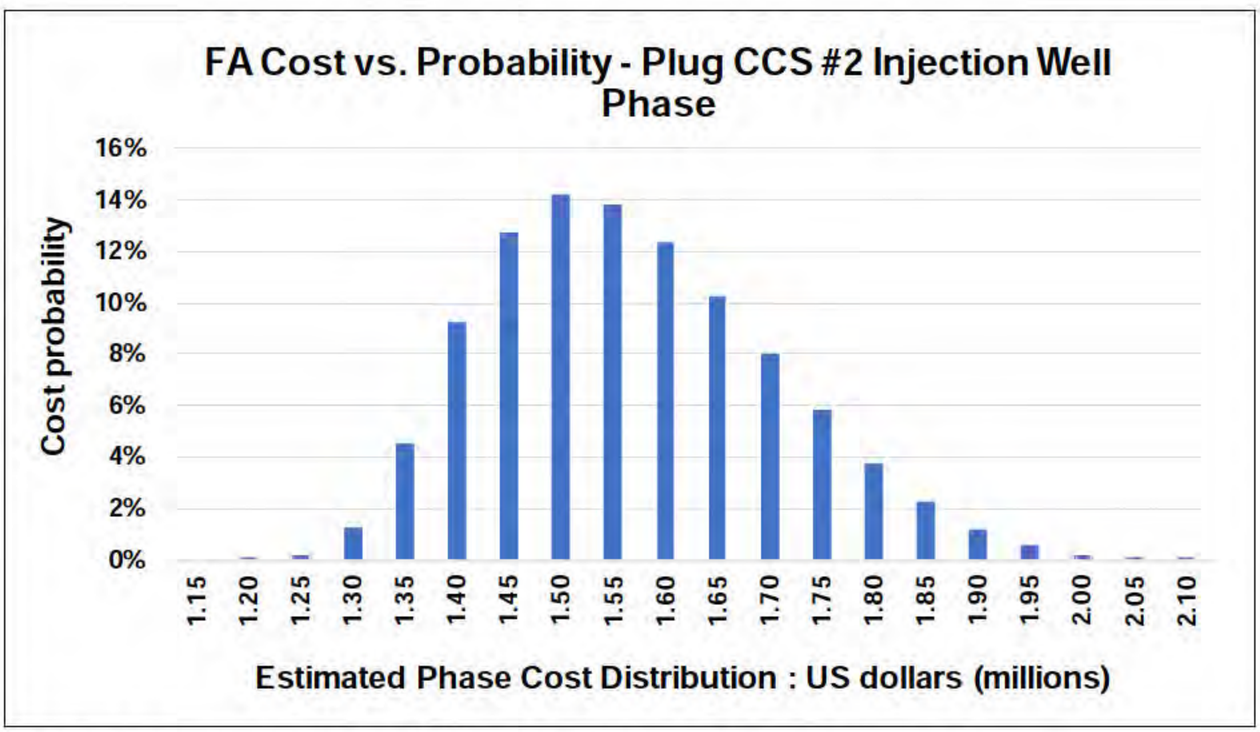

Figure 11-2: ***Plugging Injection Well*** **Estimated Cost vs. Probability Distribution**

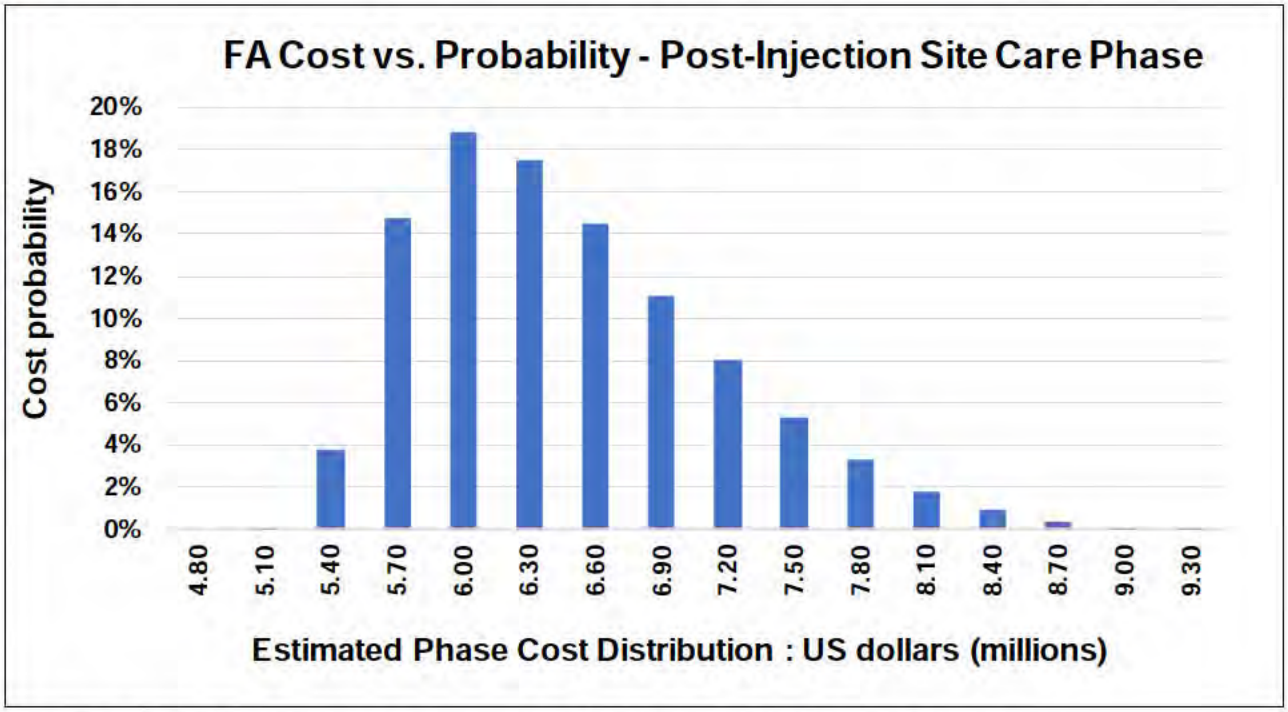

Figure 11-3: ***Post Site Injection Care*** **Estimated Cost vs. Probability Distribution**

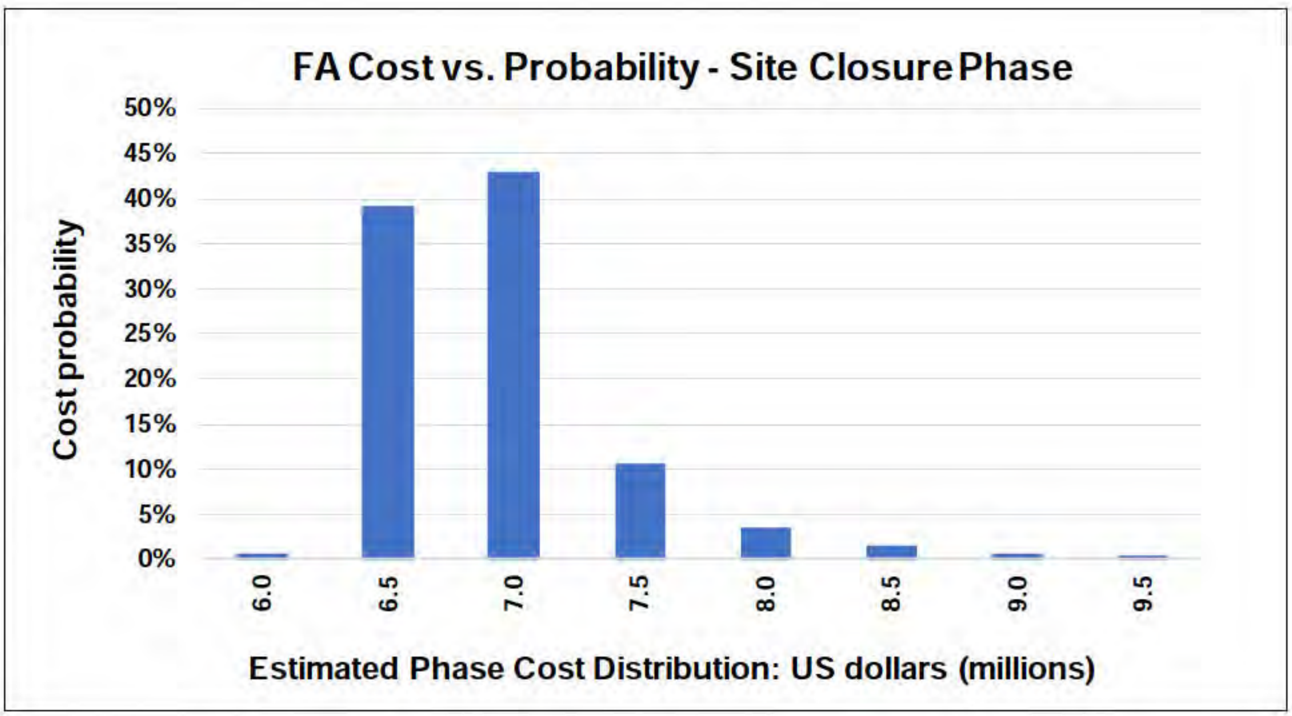

Figure 11-4: ***Site Closure*** **Estimated Cost vs. Probability Distribution**

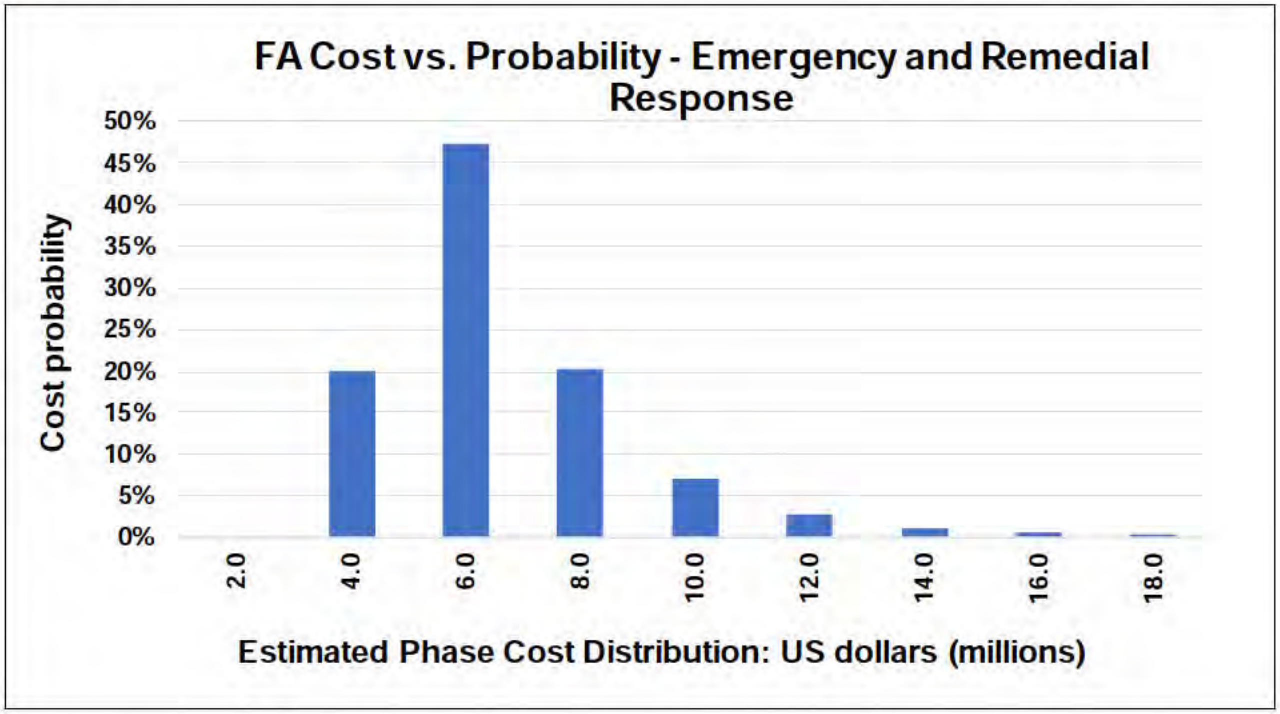

Figure 11-5: *Emergency and Remedial Response* Estimated Cost vs. Probability Distribution

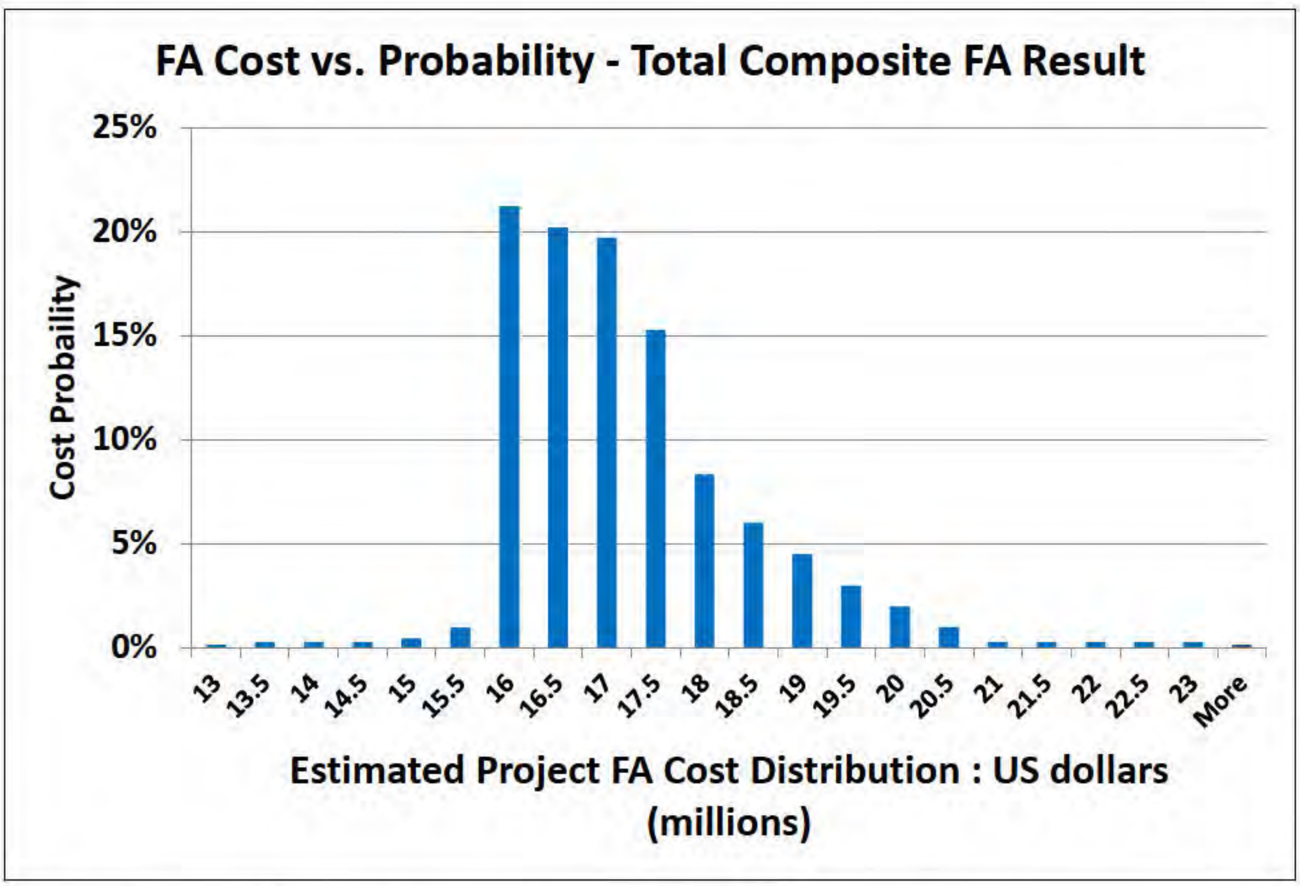

Figure 11-6: *Project Financial Assurance* Estimated Cost vs. Probability Distribution

11.10 Update and Reporting Schedule

On an annual basis, Milestone will provide a report to the UIC Director. If there are changes to the financial assurance estimate amount, Milestone will adjust the Financial Assurance amount within 60 days after changes are approved by the Director. Milestone will maintain financial instruments during the review period. If permit sections or cost estimates change regarding area of review and corrective action plan, injection well plugging plan, post-injection site care and or site closure plans, and or emergency response plan, then the associated FA section and costs will be updated. Changes with written estimates under PE seal will be submitted to the UIC Director within 60 days.

If there are no changes, Milestone will submit a letter stating that no changes are needed at this time, except for inflation adjustments.

If the UIC Director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, or emergency and remedial response. Milestone will provide to the UIC Director, within 60 days of notification by the Director, with a revised cost estimate under PE seal. Milestone will then adjust the amount of the Financial Assurance instruments within 60 days of approval of the new estimate by the UIC Director.

11.10.1 Inflation Adjustments

Milestone will automatically adjust the FA instruments for inflation based on CPI tables for the preceding calendar year. This adjustment will be included in the annual update.

11.11 Duration

Milestone will maintain adequate FA instruments and renew instruments for the entire duration of the geologic sequestration project until the UIC Director receives and approves a completed post-injection site care and site closure plan and approves the site closure plan.

Milestone may request release of FA obligations if it has completed a phase of the geologic sequestration project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the UIC Director.

11.12 Third Party Instruments

When using a third-party instrument to demonstrate financial responsibility, Milestone will provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

The issuer of any geologic storage facility bond filed in satisfaction of the requirements of this FA section will be a corporate surety authorized to do business in Texas. The issuer's name address and evidence of authority to issue bonds in Texas have been provided as an FA appendix item.

11.13 Increases or Decreases

The UIC Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, Milestone will revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan, the injection well plugging plan, the post-injection site care and site closure plan, and the emergency and response plan, if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate will be adjusted for inflation (**Section 11.10.1**).

Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, Milestone, within 60 days after the increase, will either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the Director.

After the injection period of the project terminates, and the post-injection period begins, Milestone may apply for a reduction in the FA requirements required for post-injection site care and monitoring based on current monitoring results. It will be at the UIC Directors discretion whether to approve or deny the reduction.

Milestone will maintain the previously approved required Financial Assurance amounts until the new amount is approved by the UIC Director.

11.14 Adverse Financial Conditions

Milestone will notify the UIC Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.

Milestone will also notify the UIC Director of any third-party financial instrument providers that are going through bankruptcy or incapacity or any unforeseen event that would result in inability for the bond provider to do business in the state of Texas by certified mail. Milestone will notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming Milestone as debtor, within 10 days after commencement of the proceeding.

If due to incapacity by third party financial institutions such as surety bond companies, the UIC Director deems Milestone to be “without bond coverage” and issues an official notice to that effect, Milestone will respond to the UIC Director with a proposed plan to find a replacement provider and a reasonable period to replace bond coverage within 60 days of the notice. If the UIC Director specifies the period in the official notice, Milestone will still respond with a plan to find a replacement provider within 60 days.

11.15 Injection Fees and Post Injection Regulatory Fees [16 Texas Admin Code § 5.205 (A)]

Milestone will remit the required fees to the Comptroller of the State of Texas as stipulated in 16 Texas Admin Code § 5.205(A). Milestone will remit an initial permit application fee of $50,000 for a geologic storage facility. Milestone will remit an annual fee of $0.025 per metric ton of CO2 injected at the geologic storage facility. Further Milestone will remit an annual fee of $50,000 each year that Milestone does not inject any injectate into the geologic storage facility until the UIC Director has authorized storage facility closure.

Only the annual fee of $50,000 during the post-injection site care period has been included in the Monte Carlo analysis and the third-party estimate. A total of $2.5 Million, for fifty (50) years of post-injection site care, has been added as a line-item cost to the post-injection site care cost estimate. The initial application fee is paid at the time of application submission, and is therefore not necessary to assure, and the injection fee of $0.025 per metric ton will be remitted based on actual well results and remitted to the Comptroller of Texas concurrently with the annual report that is submitted to the UIC Director.

11.16 Protective Conditions [16 Texas Admin Code § 5.205 (D)(III)]

As noted previously, the surety bond will have certain protective conditions.

The surety bond will contain protective conditions of coverage. Protective conditions of coverage will include at a minimum cancellation, renewal, and continuation provisions; specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument; and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

11.16.1 Cancellation

Milestone will provide that the surety bond may not cancel, terminate, or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the director. The cancellation will not be final until at least 120 days after the Commission receives the cancellation notice. In that event Milestone will provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable or possible, any funds from the instrument being cancelled will be released within 60 days of notification by the director.

11.16.2 Renewal

If the surety bond expires, Milestone will renew the previous instrument or contract a new financial instrument of sufficient value prior to the expiration date. Milestone will hold a FA instrument for the entire term of the geologic storage project. The instrument may be automatically renewed as long as Milestone has the option of renewal at the face amount of the expiring instrument. The form of bond filed by Milestone will be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the director.

11.16.3 Remain in Effect

The surety bond shall remain in effect and cannot be canceled, terminated, or left unrenewed if, on or before its expiration date, any of the following conditions occur: the director deems the facility abandoned; the permit is terminated, revoked, or a new permit is denied; closure is ordered by the director, a United States district court, or another court of competent jurisdiction; the owner or operator becomes a debtor in a voluntary or involuntary bankruptcy proceeding under Title 11 of the U.S. Code; or the amount due is paid.

11.17 Summary

Milestone will employ surety bonds to meet Financial Assurance requirements. Milestone proposes a total FA cost of **$20,957,610** for the South Midland Facility. The entire amount will be provided by a surety bond.

To determine FA cost estimates subject to forecasting uncertainties, Milestone employed an EPA Class VI operations-tailored Monte Carlo simulation. This iterative costs-scenario approach generated a distributed range of possible FA estimates through simulations using 250,000 iterations addressing 74 activities inputs related to FA costs. This stochastically-modeled method enables us to assess the probabilities of specific events - that include worst case scenarios - and provides a comprehensive range of potential FA numbers. Consequently, Monte Carlo simulation offers a detailed understanding of the financial assurance requirements, accounting for various uncertainties and helping to make informed financial decisions.

Milestone will comply with all state and federal regulations for financial responsibility regarding the geologic sequestration project.

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Section 12: Environmental Justice

Prepared for:

EPA Region 6

Underground Injection Control Section

1201 Elm Street, Suite 500 | Dallas, Texas 75270

MILESTONE CARBON

Prepared and submitted by:

Milestone Carbon Midland CCS Hub, LLC

840 Gessner Rd, Suite 600

Houston, Texas 77024

Updated 18 October 2024

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12.0 ENVIRONMENTAL JUSTICE

The EPA Class VI requirements have been developed to protect underground sources of drinking water (USDW). These requirements aim to minimize potential health risks, especially risks to populations in or near the delineated area of review (AoR) for the injection well or in the anticipated direction of the carbon dioxide plume and pressure front. The Regional EPA UIC Directors have a role in protecting public health and should consider the risks of a proposed Class VI injection well within their jurisdiction to identify and address any environmental impacts on minority and low-income populations (i.e., Environmental Justice (EJ) screening)[1].

Milestone has prepared this EJ Screening Report (the Report) to review any potential impacts to EJ within the carbon dioxide plume area/project AoR. Based on the current modeling efforts associated with this application, the plume area is anticipated to be less than 3-miles in diameter. Milestone, with guidance from EPA, Region 6 UIC department, selected a 5-mile radius around the proposed Well for EJ screening. Data supporting Milestone's EJ review was developed using the EPA's EJScreen tool (https://ejscreen.epa.gov/mapper/).

Consideration and guidance, as per EPA memo dated 17 August 2023[1], was used to develop this permit application. Milestone and EPA Regions will work collaboratively and proactively with State of Texas, tribal, and local partners to facilitate consideration and application of this guidance in our UIC permitting actions.

12.1 2020 Census Population and Race Data

Upton County, Texas is the 222nd most populous county in Texas with a total population of 3,308 people (Source: US 2020 Census) and 1,363 total households. It is a rural county of Texas with 91 businesses and an employment rate of 55.2%. The County Seat of Upton County is Rankin, Tx with a total population of 780. The Median Household Income of Upton County is $55,284 which is lower than the national median household income of $74,580 (Source: 2022 CPS ASEC Report, US Census Bureau).

Table **12-1** shows the racial profile of Upton County and the 5-mile radius around the proposed Injection well location. Upton County is 56% white, a majority of which are of Hispanic descent. The next largest racial group is "two or more races" at approximately 30%, followed by "some other race alone" at approximately 12%, which means the person identifies as a race not listed on the census.

Table 12-1: 2020 Census P1 Race Data for Upton County, Texas and 5-Mile Radius of Injection Well

Population by Race	Upton County		5 Mile Radius	
Total Population	3,308	100%	82	100.0%
White	1,849	55.9%	58	70.7%
Two or More Races	987	29.8%	8	9.8%
Some Other Race Alone	380	11.5%	14	17.1%
African American	74	2.2%	0	0.0%
American Indian or Alaskan Native	13	0.4%	1	1.2%
Asian	5	0.2%	1	1.2%
Hispanic and Latino				
Hispanic	1,849	55.9%	36	43.9%
Non-Hispanic	1,435	43.4%	46	56.1%

[1] https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf

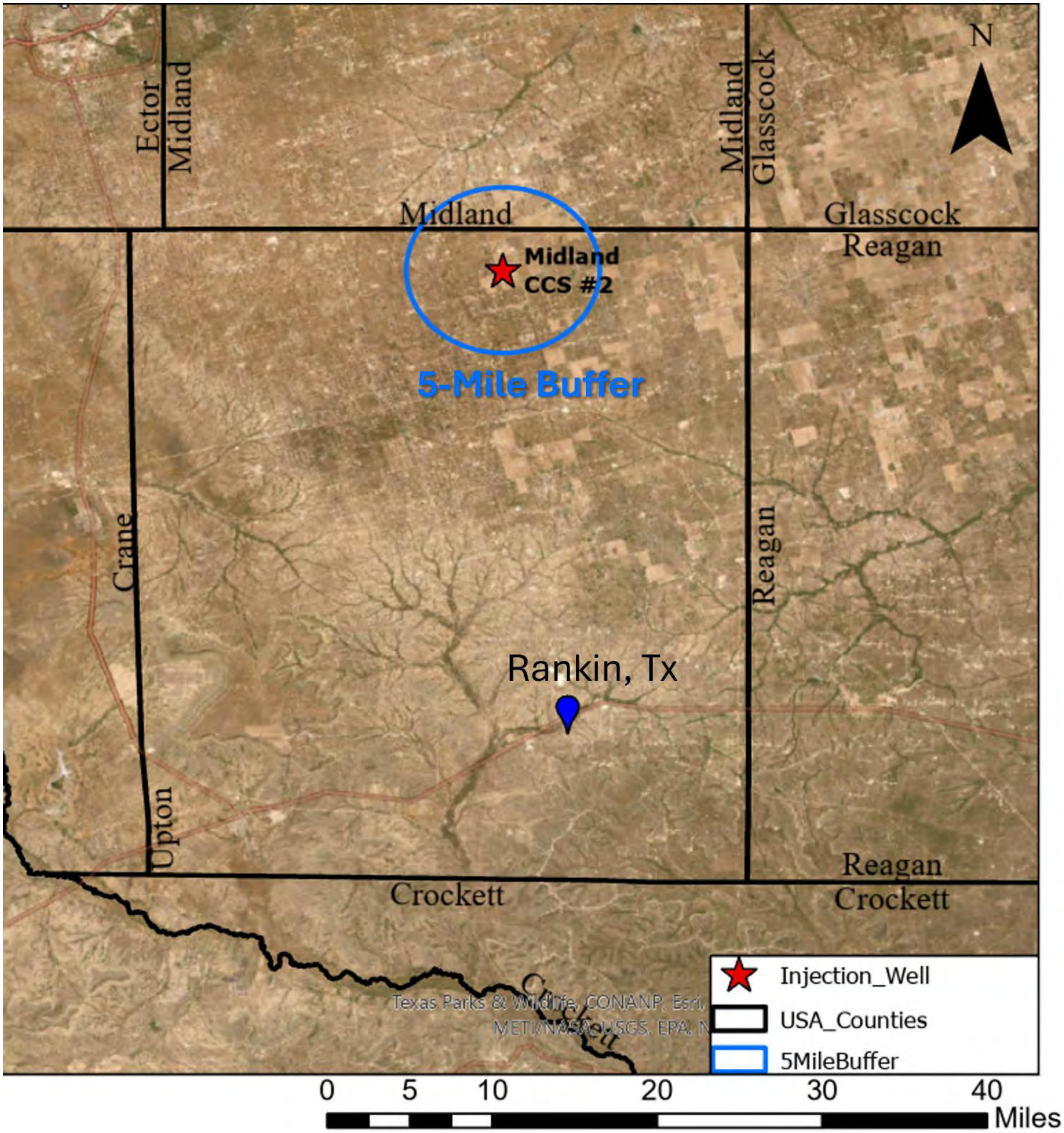

Figure 12-1: Map of Area with 5-mile Radius Buffer Shown in Relation to Rankin, Tx

12.2 Environmental Justice Screen Results

12.2.1 EJ Screen Census (2020) Summary and American Community Survey Report(s) (2018 – 2022)

The EJ Screen (2018-2022) Summary Report indicated the population within the 5-mile radius of the proposed Well was 82. Of this total number, 38 people (46%) identified as persons of color. The Census Report identified that 83% of the area was over the age of 18 years old and 74% of the households were owned versus 26% of households rented. A copy of this Census Report may be viewed in **Figure 12-2**. The ACS Report indicated that less than 0.04 sq. mi. of the AoR was considered water area (accounting for 0%) and the land area was 77.96 sq. mi. (100%).

The ACS Report indicated a majority of the population (roughly 72%) had an education background between high school (non-diploma) and some college, no degree). 19% had a 9-12th grade education and 8% had an education level below this. Additionally, roughly 91% of the population was noted to be able to speak English. Of these, 63% speak only English and 28% speak English "very well." Lastly, the household income within the AoR was identified 70% of households as earning $50,000 +. A copy of the ACS Report can be found in **Figure 12-2** to **Figure 12-4.**

12.2.2 EJScreen Report

The EJScreen Report includes an evaluation of twelve (12) EJ Indexes that combine environmental and socioeconomic information. The results of the screening report is a comparison of the individuals within the screening area to both State (Texas) and U.S. percentiles. A listing of the EJ Indexes is as follows:

1) Particulate Matter 2.5,
2) Ozone,
3) Nitrogen Dioxide,
4) Diesel Particulate Matter,
5) Toxic Releases to Air,
6) Traffic Proximity,
7) Lead Paint,
8) Superfund Proximity,
9) RMP Facility Proximity,
10) Hazardous Waste Proximity,
11) Underground Storage Tanks (UST) Proximity,
12) Wastewater Discharge, and
13) Drink Water Non-Compliance.

The results indicate residents within the 5-mile radius were exposed to a greater risk of Ozone (in parts-per-billion, ppb), Diesel Particulate Matter (in micro-grams per meters cubed, $\mu g/m^3$), and Air Toxics Cancer Risk (lifetime risk per million). The remaining risks included Lead Paint (% of pre-1960 housing) and Superfund Proximity (site count/kilometer distance). There were no Superfunds or Hazardous Waste TSDFs within the 5-mile radius. The remaining indexes were shown to be lower than the State and U.S. percentiles. A copy of the EJScreen Community Report is included in **Figures 12-5** to **Figure 12-8**.

12.3 Interpretation of Results

In reviewing the pollution risk sources from the EJScreen Report, the development and operation of the proposed Well will benefit the immediate population by sequestering carbon dioxide that would otherwise be emitted. This could improve the index results for Particulate Matter 2.5, Ozone, Diesel Particulate Matter, Air Toxics Cancer Risk, and Air Toxics Respiratory HI. The remaining comparative indexes would not be impacted as a Class VI well operation would not increase any of those indexes.

EPA United States Environmental Protection Agency

EJSCREEN ACS Summary Report

Location: User-specified point center at 31.615788, -101.990005
Ring (buffer): 5-miles radius
Description: Midland CCS #2

Summary of ACS Estimates	2018 - 2022
Population	82
Population Density (per sq. mile)	1
People of Color Population	38
% People of Color Population	46%
Households	36
Housing Units	41
Housing Units Built Before 1950	1
Per Capita Income	32,017
Land Area (sq. miles) (Source: SF1)	79.61
% Land Area	100%
Water Area (sq. miles) (Source: SF1)	0.04
% Water Area	0%

	2018 - 2022 ACS Estimates	Percent	MOE (±)
Population by Race			
Total	82	100%	782
Population Reporting One Race	74	90%	1,185
White	58	71%	853
Black	0	0%	15
American Indian	1	1%	21
Asian	1	1%	56
Pacific Islander	0	0%	15
Some Other Race	14	17%	225
Population Reporting Two or More Races	8	10%	489
Total Hispanic Population	36	44%	773
Total Non-Hispanic Population	46		
White Alone	44	54%	579
Black Alone	0	0%	15
American Indian Alone	1	1%	21
Non-Hispanic Asian Alone	1	1%	56
Pacific Islander Alone	0	0%	15
Other Race Alone	0	0%	15
Two or More Races Alone	0	0%	15
Population by Sex			
Male	43	52%	417
Female	39	48%	468
Population by Age			
Age 0-4	4	5%	241
Age 0-17	23	28%	418
Age 18+	60	72%	494
Age 65+	9	11%	136

Data Note: Detail may not sum to totals due to rounding. Hispanic population can be of any race.
N/A meansnot available. **Source:** U.S. Census Bureau, American Community Survey (ACS) 2018 - 2022 .

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Figure 12-2: American Community Survey Report(s) (ACS) (2018 – 2022), Page 1

EPA United States Environmental Protection Agency

EJSCREEN ACS Summary Report

Location: User-specified point center at 31.615788, -101.990005
Ring (buffer): 5-miles radius
Description: Midland CCS #2

	2018 - 2022 ACS Estimates	Percent	MOE (±)
Population 25+ by Educational Attainment			
Total	53	100%	546
Less than 9th Grade	5	8%	150
9th - 12th Grade, No Diploma	10	19%	259
High School Graduate	16	29%	312
Some College, No Degree	11	21%	154
Associate Degree	5	9%	126
Bachelor's Degree or more	7	13%	157
Population Age 5+ Years by Ability to Speak English			
Total	78	100%	738
Speak only English	49	63%	543
Non-English at Home[1+2+3+4]	29	37%	704
[1]Speak English "very well"	22	28%	696
[2]Speak English "well"	3	4%	141
[3]Speak English "not well"	4	5%	153
[4]Speak English "not at all"	0	0%	52
[3+4]Speak English "less than well"	4	5%	162
[2+3+4]Speak English "less than very well"	7	9%	201
Limited English Speaking Households*			
Total	2	100%	124
Speak Spanish	2	100%	121
Speak Other Indo-European Languages	0	0%	15
Speak Asian-Pacific Island Languages	0	0%	15
Speak Other Languages	0	0%	15
Households by Household Income			
Household Income Base	36	100%	295
< $15,000	4	11%	97
$15,000 - $25,000	2	7%	153
$25,000 - $50,000	4	12%	123
$50,000 - $75,000	6	16%	136
$75,000 +	19	54%	280
Occupied Housing Units by Tenure			
Total	36	100%	295
Owner Occupied	26	74%	184
Renter Occupied	9	26%	234
Employed Population Age 16+ Years			
Total	63	100%	596
In Labor Force	40	64%	534
Civilian Unemployed in Labor Force	1	3%	33
Not In Labor Force	23	36%	226

Data Note: Detail may not sum to totals due to rounding. Hispanic population can be of any race.
N/A means not available. **Source:** U.S. Census Bureau, American Community Survey (ACS)
*Households in which no one 14 and over speaks English "very well" or speaks English only.

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Figure 12-3: ACS (2018-2022) Report Page 2

EJSCREEN ACS Summary Report

Location: User-specified point center at 31.615788, -101.990005
Ring (buffer): 5-miles radius
Description: Midland CCS #2

	2018 - 2022 ACS Estimates	Percent	MOE (±)
Population by Language Spoken at Home*			
Total (persons age 5 and above)	N/A	N/A	N/A
English	N/A	N/A	N/A
Spanish	N/A	N/A	N/A
French, Haitian, or Cajun	N/A	N/A	N/A
German or other West Germanic	N/A	N/A	N/A
Russian, Polish, or Other Slavic	N/A	N/A	N/A
Other Indo-European	N/A	N/A	N/A
Korean	N/A	N/A	N/A
Chinese (including Mandarin, Cantonese)	N/A	N/A	N/A
Vietnamese	N/A	N/A	N/A
Tagalog (including Filipino)	N/A	N/A	N/A
Other Asian and Pacific Island	N/A	N/A	N/A
Arabic	N/A	N/A	N/A
Other and Unspecified	N/A	N/A	N/A
Total Non-English	N/A	N/A	N/A

Data Note: Detail may not sum to totals due to rounding. Hispanic popultion can be of any race.
N/A meansnot available. **Source:** U.S. Census Bureau, American Community Survey (ACS) 2018 - 2022.
*Population by Language Spoken at Home is available at the census tract summary level and up.

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Figure 12-4: ACS (2018-2022) Report Page 3

10/14/24, 10:11 AM EJScreen Community Report

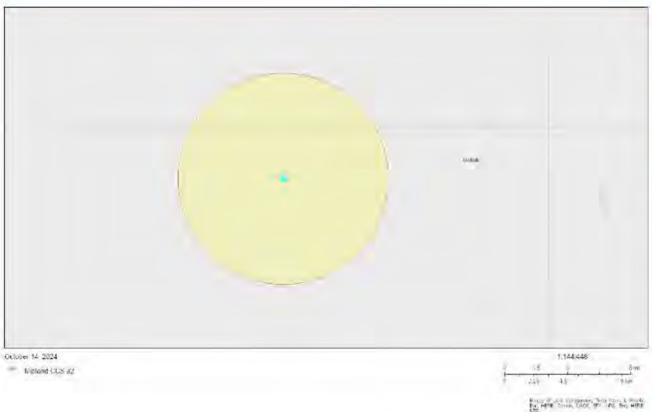
EPA

EJScreen Community Report

This report provides environmental and socioeconomic information for user-defined areas, and combines that data into environmental justice and supplemental indexes.

Midland CCS #2

5 miles Ring Centered at 31.615788,-101.990005
Population: 82
Area in square miles: 78.53



COMMUNITY INFORMATION

Low income: 31 percent	People of color: 46 percent	Less than high school education: 28 percent	Limited English households: 7 percent
Unemployment: 3 percent	Persons with disabilities: 14 percent	Male: 52 percent	Female: 48 percent
78 years Average life expectancy	$32,017 Per capita income	Number of households: 36	Owner occupied: 74 percent

BREAKDOWN BY RACE

White: 54%	Black: 0%	American Indian: 1%	Asian: 1%
Hawaiian/Pacific Islander: 0%	Other race: 0%	Two or more races: 0%	Hispanic: 44%

BREAKDOWN BY AGE

From Ages 1 to 4	5%
From Ages 1 to 18	28%
From Ages 18 and up	72%
From Ages 65 and up	11%

LIMITED ENGLISH SPEAKING BREAKDOWN

Speak Spanish	100%
Speak Other Indo-European Languages	0%
Speak Asian-Pacific Island Languages	0%
Speak Other Languages	0%

Notes: Numbers may not sum to totals due to rounding. Hispanic population can be of any race.
Source: U.S. Census Bureau, American Community Survey (ACS) 2018-2022. Life expectancy data comes from the Centers for Disease Control.

LANGUAGES SPOKEN AT HOME

LANGUAGE	PERCENT
No language data available.	

Report for 5 miles Ring Centered at 31.615788,-101.990005
Report produced October 14, 2024 using EJScreen Version 2.3

https://ejscreen.epa.gov/mapper/ejscreen_SOE.aspx 1/4

Figure 12-5: EJ Screen Community Report, p1

10/14/24, 10:11 AM EJScreen Community Report

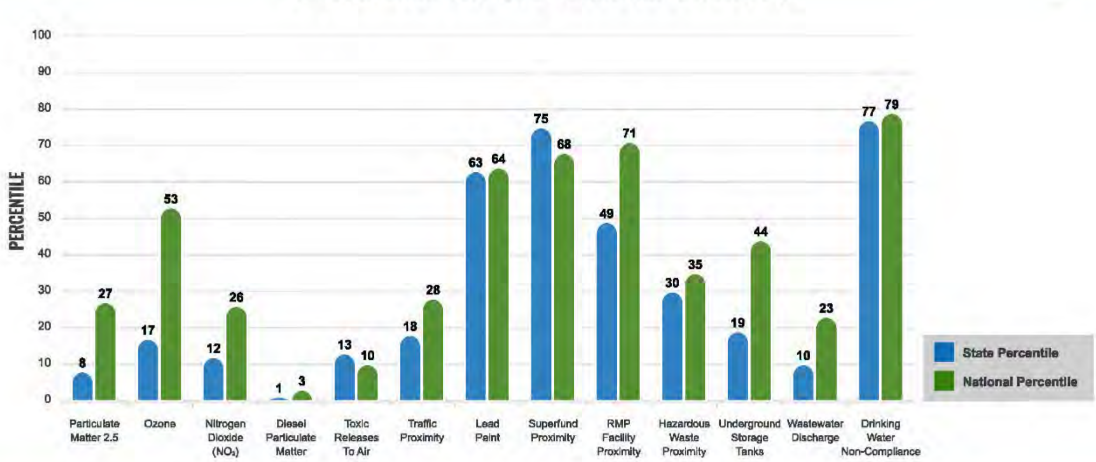
Environmental Justice & Supplemental Indexes

The environmental justice and supplemental indexes are a combination of environmental and socioeconomic information. There are thirteen EJ indexes and supplemental indexes in EJScreen reflecting the 13 environmental indicators. The indexes for a selected area are compared to those for all other locations in the state or nation. For more information and calculation details on the EJ and supplemental indexes, please visit the EJScreen website.

EJ INDEXES

The EJ indexes help users screen for potential EJ concerns. To do this, the EJ index combines data on low income and people of color populations with a single environmental indicator.

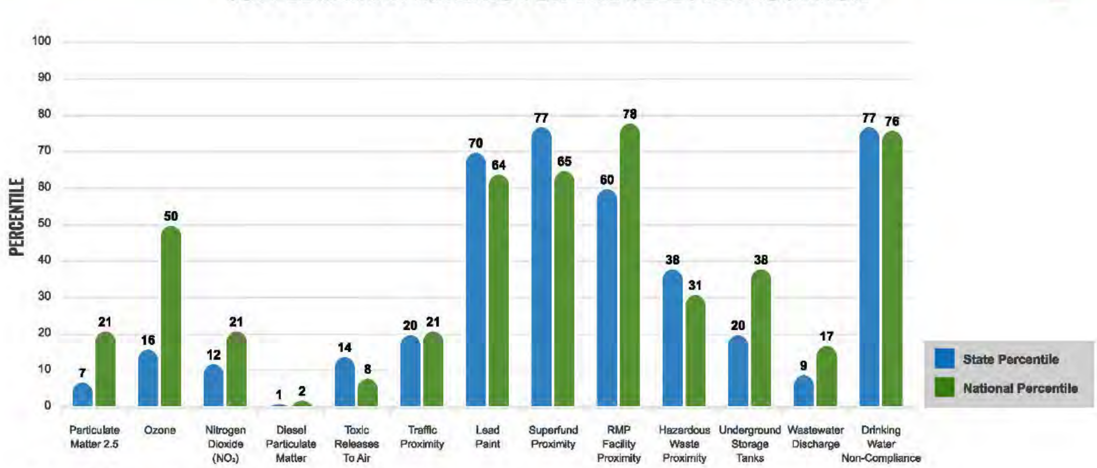
EJ INDEXES FOR THE SELECTED LOCATION



SUPPLEMENTAL INDEXES

The supplemental indexes offer a different perspective on community-level vulnerability. They combine data on percent low income, percent persons with disabilities, percent less than high school education, percent limited English speaking, and percent low life expectancy with a single environmental indicator.

SUPPLEMENTAL INDEXES FOR THE SELECTED LOCATION



Report for 5 miles Ring Centered at 31.615788,-101.990005
Report produced October 14, 2024 using EJScreen Version 2.3

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Figure 12-6: EJ Screen Community Report, p2

10/14/24, 10:11 AM EJScreen Community Report

EJScreen Environmental and Socioeconomic Indicators Data

SELECTED VARIABLES	VALUE	STATE AVERAGE	PERCENTILE IN STATE	USA AVERAGE	PERCENTILE IN USA
ENVIRONMENTAL BURDEN INDICATORS					
Particulate Matter 2.5 ($\mu g/m^3$)	6.77	8.86	5	8.45	14
Ozone (ppb)	57.3	63	12	61.8	34
Nitrogen Dioxide (NO_2) (ppbv)	3.8	9.5	7	7.8	12
Diesel Particulate Matter ($\mu g/m^3$)	0.0243	0.151	0	0.191	1
Toxic Releases to Air (toxicity-weighted concentration)	4.3	12,000	10	4,600	6
Traffic Proximity (daily traffic count/distance to road)	110,000	1,000,000	16	1,700,000	18
Lead Paint (% Pre-1960 Housing)	0.3	0.16	79	0.3	59
Superfund Proximity (site count/km distance)	0.15	0.11	81	0.39	66
RMP Facility Proximity (facility count/km distance)	0.61	0.95	47	0.57	68
Hazardous Waste Proximity (facility count/km distance)	0.38	1.5	34	3.5	30
Underground Storage Tanks (count/km^2)	0.019	2.3	14	3.6	28
Wastewater Discharge (toxicity-weighted concentration/m distance)	0.085	3800	8	700000	14
Drinking Water Non-Compliance (points)	1.6	2.3	89	2.2	84
SOCIOECONOMIC INDICATORS					
Demographic Index USA	1.45	N/A	N/A	1.34	61
Supplemental Demographic Index USA	1.95	N/A	N/A	1.64	71
Demographic Index State	1.45	1.72	42	N/A	N/A
Supplemental Demographic Index State	1.61	1.49	60	N/A	N/A
People of Color	46%	58%	37	40%	63
Low Income	31%	34%	49	30%	57
Unemployment Rate	3%	5%	49	6%	47
Limited English Speaking Households	5%	8%	62	5%	76
Less Than High School Education	28%	16%	79	11%	90
Under Age 5	5%	6%	50	5%	57
Over Age 64	11%	15%	41	18%	27

*Diesel particulate matter index is from the EPA's Air Toxics Data Update, which is the Agency's ongoing, comprehensive evaluation of air toxics in the United States. This effort aims to prioritize air toxics, emission sources, and locations of interest for further study. It is important to remember that the air toxics data presented here provide broad estimates of health risks over geographic areas of the country, not definitive risks to specific individuals or locations. More information on the Air Toxics Data Update can be found at: https://www.epa.gov/haps/air-toxics-data-update.

Sites reporting to EPA within defined area:

Superfund	0
Hazardous Waste, Treatment, Storage, and Disposal Facilities	0
Water Dischargers	5
Air Pollution	3
Brownfields	0
Toxic Release Inventory	1

Other community features within defined area:

Schools	0
Hospitals	0
Places of Worship	0

Other environmental data:

Air Non-attainment	No
Impaired Waters	No

Selected location contains American Indian Reservation Lands*	No
Selected location contains a "Justice40 (CEJST)" disadvantaged community	No
Selected location contains an EPA IRA disadvantaged community	Yes

Report for 5 miles Ring Centered at 31.615788,-101.990005
Report produced October 14, 2024 using EJScreen Version 2.3

https://ejscreen.epa.gov/mapper/ejscreen_SOE.aspx 3/4

Figure 12-7: EJ Screen Community Report, p3

10/14/24, 10:11 AM EJScreen Community Report

EJScreen Environmental and Socioeconomic Indicators Data

HEALTH INDICATORS					
INDICATOR	VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Low Life Expectancy	20%	20%	50	20%	55
Heart Disease	5.9	5.4	61	5.8	56
Asthma	9.5	9.8	38	10.3	27
Cancer	6	5.5	63	6.4	40
Persons with Disabilities	13.8%	12.6%	63	13.7%	56

CLIMATE INDICATORS					
INDICATOR	VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Flood Risk	11%	10%	77	12%	69
Wildfire Risk	35%	30%	65	14%	84

CRITICAL SERVICE GAPS					
INDICATOR	VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Broadband Internet	17%	13%	68	13%	72
Lack of Health Insurance	12%	18%	30	9%	74
Housing Burden	No	N/A	N/A	N/A	N/A
Transportation Access Burden	Yes	N/A	N/A	N/A	N/A
Food Desert	No	N/A	N/A	N/A	N/A

Report for 5 miles Ring Centered at 31.615788,-101.990005
Report produced October 14, 2024 using EJScreen Version 2.3

www.epa.gov/ejscreen

https://ejscreen.epa.gov/mapper/ejscreen_SOE.aspx 4/4

Figure 12-8: EJ Screen Community Report, p4

12.4 EJ Memo Responses

Pursuant to the EPA Memorandum on Environmental Justice Guidance for UIC Class VI Permitting and Primacy dated August 17th, 2023, Milestone has prepared the following responses to the items therein.

Milestone has publicly disclosed its sustainability efforts and related performance since 2020. All information provided below is available on our website. https://www.milestone-es.com/Sustainability/

Milestones' 2023 sustainability report can be found on link: Sustainability Report

Milestone's sustainability program has components to ensure the company identifies and comprehensively manages potential environmental and social risks and concerns.

12.4.1 Environmental and Social Risk Management

Milestone's approach to risk management was evaluated in 2022 to ensure it is disciplined, systematic, comprehensive, and aligned with international sustainability reporting frameworks. We conducted a sustainability materiality and risk assessment exercise to identify the most material issues to our industry, and to clearly evaluate and rank the risks these issues pose to our value-creation efforts. We also align all issues and risks to applicable stakeholders. As part of this exercise, we identify relevant business opportunities to further mitigate risks posed to the company. Identifying and prioritizing our risks and opportunities enables Milestone to drive informed business decisions about resource allocation, align our organizational priorities, and monitor emerging issues that may shape our future risk exposure. It also facilitates the selection of the most impactful sustainability metrics to measure and manage our performance. This process will allow us to continue analyzing and identifying any emerging risks regarding Environmental Justice in our future projects (**Fig. 12-9**).

Figure 12-9: Environmental and Social Risk Management Process

12.4.2 Stakeholder Engagement

We recognize the influence our operations can have on the environment and communities, and we understand the importance of actively considering issues important to our stakeholders in our decision-making processes. Milestone defined an engagement process to guide it in its dialogue with stakeholders on important issues. This process centers our engagement efforts on a series of principles while following six steps to foster action-oriented and mutually beneficial outcomes. This commitment to stakeholder engagement complements Milestone's dedication to sustainable practices and minimizing its environmental footprint. This process proactively considers the needs of our stakeholders to foster connection, trust, confidence, and alignment with our organization's operations. As our business grows, continuing to meet the needs of our stakeholder groups will be an essential part of our strategic planning.

Figure 12-10 illustrates Milestone's Stakeholder Engagement Process and the 6 Principles that guide it. 1) Prepare, 2) Plan, 3) Design, 4) Engage, 5) Evaluate, 6) Apply.

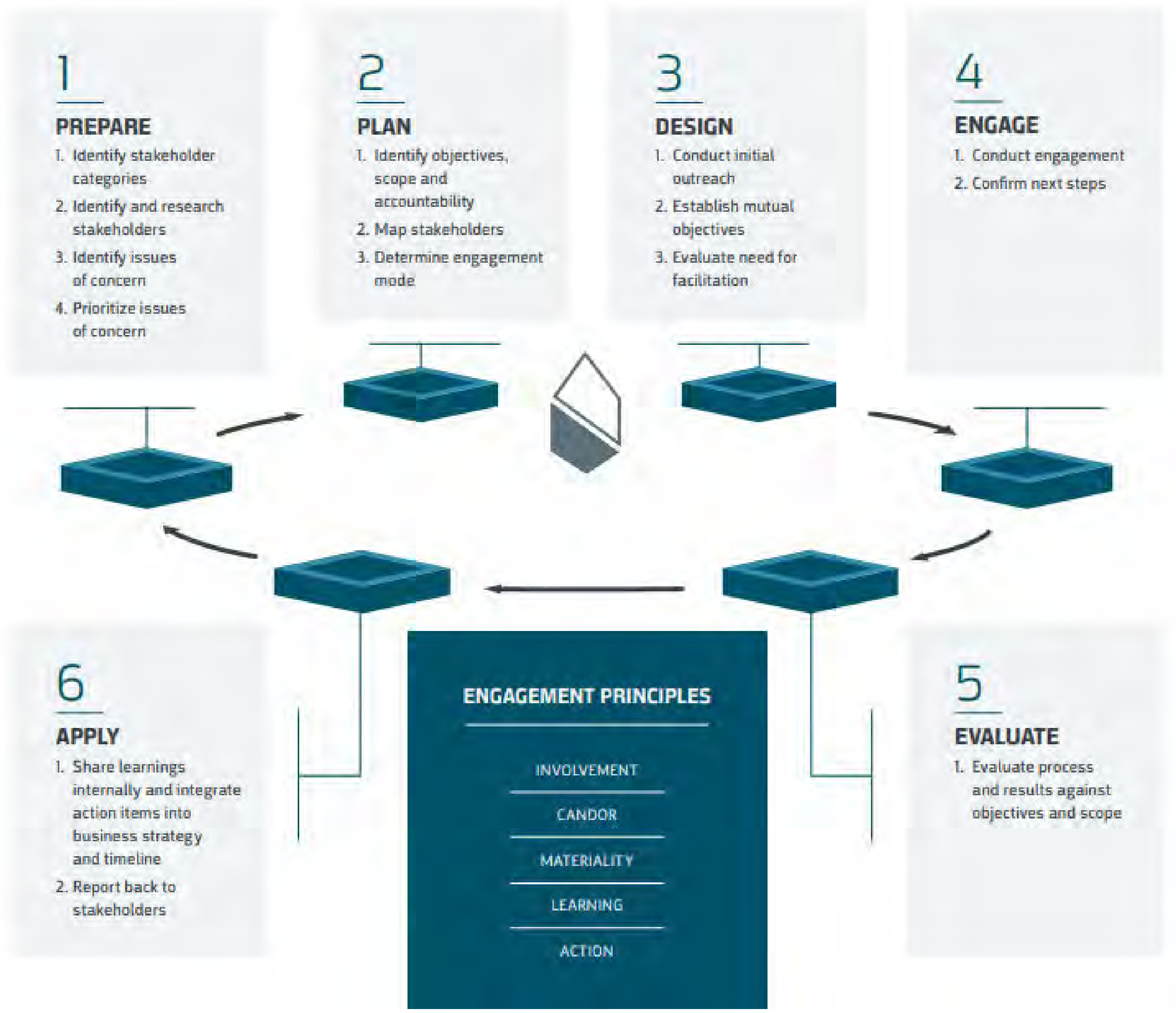

Figure 12-10: Stakeholder Engagement Process

12.4.3 Identify Communities with Potential EJ Concerns

Milestone has reviewed census data, EJSCREEN data, interviewed residents/landowners and contacted local community leaders regarding the proposed project. Milestone has met with community leaders such as the Mayor of Midland, State Senators, and adjacent County Commissioners to describe the project. The EJScreen data indicates the AoR, and 5 miles around it, is sparsely populated and the local population is predominantly White. Milestone's process described above to identify and manage environmental and social risk will allow the company to proactively identify communities potentially adversely, and disproportionately affected by human health, environmental, climate-related, and/or other cumulative harms or risks – that is, affected communities with potential EJ concerns – to help ensure proactive community engagement and promote the just treatment and meaningful involvement of the affected community in UIC permitting actions.

12.4.4 Enhance Public Involvement

Milestone is committed to implementing an inclusive public participation process to enhance community engagement. Milestone's efforts to engage with key stakeholders in the AoR began in 2022 and will continue to involve local leaders, residents, landowners, mineral owners, community and industry organizations, state/local government and offset oil and gas operators as the project continues to develop.

12.4.5 Enhance Transparency Throughout the Permitting Process

Milestone is committed to a transparent permitting process with the EPA and Texas State Regulators such as the Railroad Commission of Texas (RRC) and Texas Commission on Environmental Quality (TCEQ). Milestone will be proactive in posting compliance, monitoring test results, records, and reports required by the permit in a publicly available, understandable, and readily accessible format for the community. Milestone will post test results, records and reports that are submitted to the EPA during the monitoring and post-injection site care period on our corporate website. Reports will be provided in English and Spanish language format. Additionally, information will be included in Milestone's annual sustainability report on the latest monitoring results.

Milestone will make data and reports available to the general public to promote awareness and show that permanent CO_2 sequestration is safe, effective and does not harm USDWs, the environment, or human health.

12.4.6 Minimize Adverse Effects to USDWs and Communities We Serve

Milestone will partner with EPA and RRC regulators as well as community leaders, emergency first responders, hospitals, emergency management districts and other local entities to proactively work to prevent any adverse impacts to USDWs from all activities throughout the life of the project.

12.5 Conclusions

Milestone utilized the data from the EPA's EJScreen tool, Census Bureau, interviews with local landowners and residents plus other methods to develop this Report.

The EJScreen and Census Bureau report are consistent, data-based screening tools. The tools don't raise any EJ-related issues of concern given the sparsely populated region surrounding the AoR.

Though the Interpretation of Results indicate the development and operation of a Class VI well would have benefits to the immediate population by sequestering carbon dioxide that would otherwise be emitted and improving air quality. Milestone understands that additional efforts may be undertaken to ensure the surrounding community is not adversely affected.

In addition, the development of this Project may provide socio-economic benefits to the surrounding area(s) such as employment and apprenticeship programs during the construction phase, procurement of local goods and/or services, and improving infrastructure and workforce skills.

Milestone is committed to ensuring and supporting an ongoing dialogue between the community and Milestone. Furthermore, the development of an MRV Plan (Subpart RR Monitoring, Reporting, and Verification Plan – Greenhouse Gas Reporting Program, 40 CFR Part 98), will help ensure the safety and continuous review of activities within the Project.