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Monitoring, Reporting, and Verification Plan

Wildcat AGI #1 & Wildcat AGI #2

Targa Delaware LLC (Targa)

Version 1.0
November 25, 2024

Contents

1 Introduction

Targa Delaware, LLC (Targa) proposes an underground injection project at the Targa Wildcat Gas Processing Plant (the Plant) located approximately 10 miles west of Kermit in Winkler County, District 08, Texas. The Plant is within the Permian Basin, in the eastern Delaware Basin region **(Figure 1-1)**. The goal of the injection project is to demonstrate the ability of the Bell Canyon and Cherry Canyon formations to accept and safely retain industrial-scale volumes of carbon dioxide (CO_2) for permanent geologic sequestration. The project also explores the potential of the Siluro-Devonian formations for geological storage.

The Plant is the source of the CO_2, and it originates from treated acid gas (TAG) during the gas purification process. The Plant operations include compression, treatment, and processing of natural gas. Major byproducts of the natural gas processing system include CO_2 and hydrogen sulfide (H_2S) and, to a lesser extent, sulfur dioxide (SO_2). Targa will use an acid gas injection (AGI) well to dispose of the acid gas stream generated by the Plant treating system. In case of an emergency or for maintenance purposes, flaring can still potentially occur. The project allows Targa to run the Plant at full capacity without discharging large amounts of CO_2 into the atmosphere. The TAG stream is anticipated to consist of approximately 80% CO_2 and 20% H_2S, with trace components of hydrocarbons (C1 – C7) and nitrogen. Targa is injecting and plans to inject CO_2 in the Bell Canyon and Cherry Canyon formations through Wildcat Acid Gas Injection Well #1 (WC AGI #1) for a design life of 30 years. In addition, the potential for safe geological sequestration of CO_2 in the Siluro-Devonian formations through the recently approved but not drilled Wildcat Acid Gas Injection Well #2 (WC AGI #2) is analyzed for a design life of 30 years.

Targa is currently authorized to inject a total of up to 28 million standard cubic feet per day (MMSCFD) of TAG thanks to the currently approved and drilled WC AGI #1 (API #: 42-495-34153) in accordance with Statewide Rule 9 of the Railroad Commission of Texas (TRRC). Targa received authorization to inject H_2S under the TRRC Rule 36. WC AGI #1 is located on the Plant property in Section 39, PSL Block 27. The permitted injection interval is between the Bell Canyon (top interval of 5,115 feet) and Cherry Canyon (bottom interval of 7,250 feet) formations. Targa received approval in 2023 to drill, complete, and operate WC AGI #2. WC AGI #2 is approved to inject up 15 MMSCFD of TAG at a total depth of approximately 21,450 feet, in the Lower Devonian Thirtyone through Ordovician Ellenburger formations.

Targa submits this Monitoring, Reporting, and Verification (MRV) plan for the operational WC AGI #1 well and the permitted WC AGI #2 well. When Targa decides to proceed with the drilling of WC AGI #2, a revised MRV plan will be submitted to address any material changes (as described in 98.448 (d)(1)) associated with completion of the well and to include a revised risk assessment for the well.

Targa has chosen to submit this MRV plan to the United States Environmental Protection Agency (USEPA) for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. Targa intends to inject CO_2 in WC AGI #1 for another 30 years. Following the operational period, Targa proposes a post-injection monitoring and site closure period of 45 years.

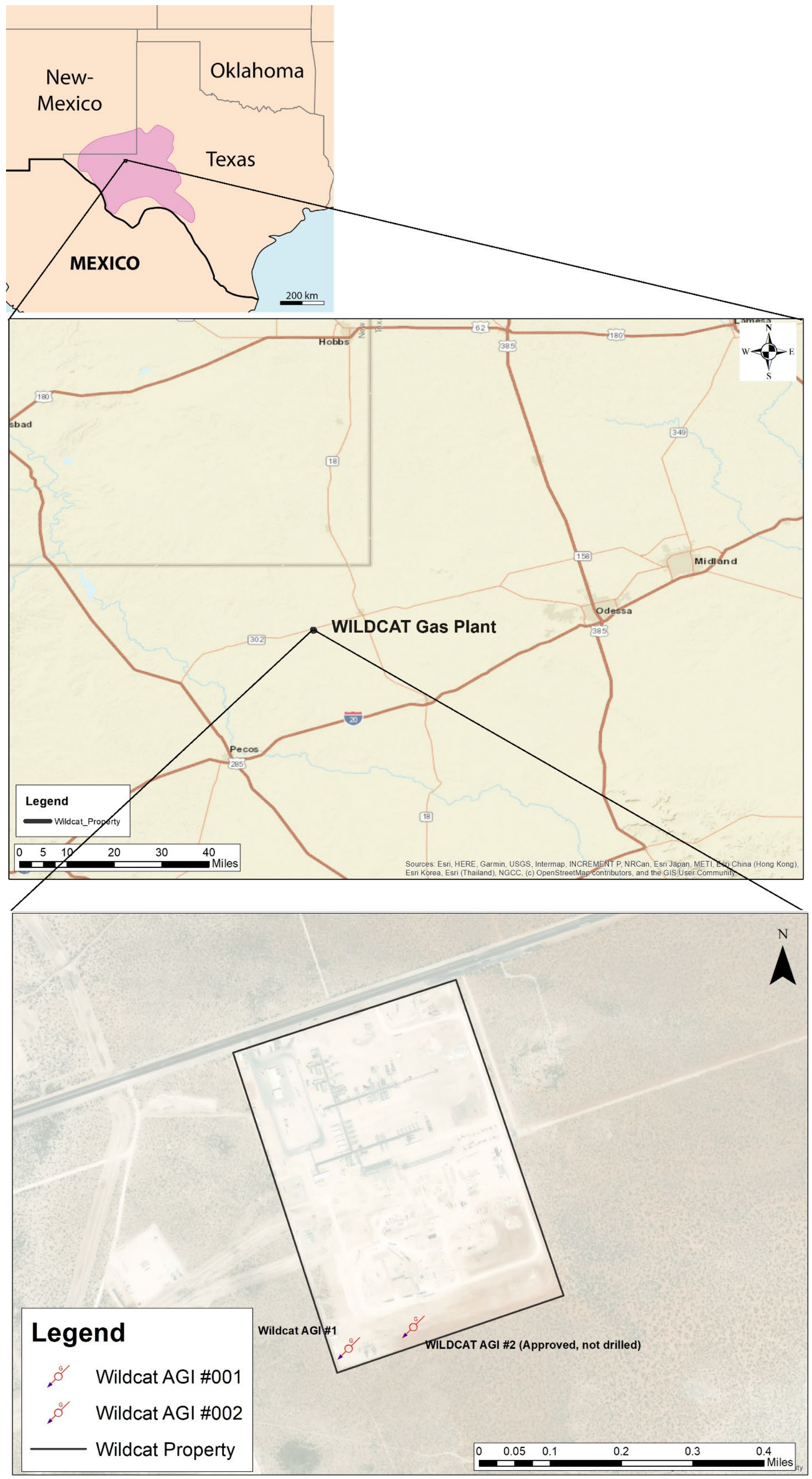


Figure 1-1*: Location of the Wildcat Gas Processing Plant and Acid Gas Injection Wells – Approved and drilled WC AGI #1 and approved but not drilled WC AGI #2*

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449, and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 7 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 11 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is **1013183**.

2.2 UIC injection well identification numbers

This MRV plan is for WC AGI #1 and WC AGI #2(**Appendix 1 Figure 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

The TRRC has issued Underground Injection Control (UIC) Class II permits under its Statewide Rule 9 (see **Appendix 2**) for WC AGI #1and WC AGI #2. All oil- and gas-related wells around WC AGI #1and WC AGI #2, including both injection and production wells, are regulated by the TRRC which has primacy to implement the UIC Class II program.

3 Project Description

The following project description has been developed by the Petroleum Recovery Research Center (PRRC) at New Mexico Institute of Mining and Technology (NMT) for TND. The WC AGI #1 final well report was prepared by Geolex Incorporated (Geolex), in July 2019. Geolex also prepared the documentation for the recently approved WC AGI #2.

3.1 General Geologic Setting / Surficial Geology

The Plant is located in Section 39, PSL Block 27, approximately 9.5 miles west of Kermit in Winkler County, Texas, immediately adjacent to WC AGI #1 and the proposed WC AGI #2. The Plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. The dune sands are locally stabilized with shin oak, mesquite, and some burr-grass. There are no natural surface bodies of water within 1 mile of the Plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes **(Figure 3.1-1)**. There are 13 freshwater wells located within a two-mile radius of WC AGI #1 and WC AGI #2, with 6 wells within half a mile. The Plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

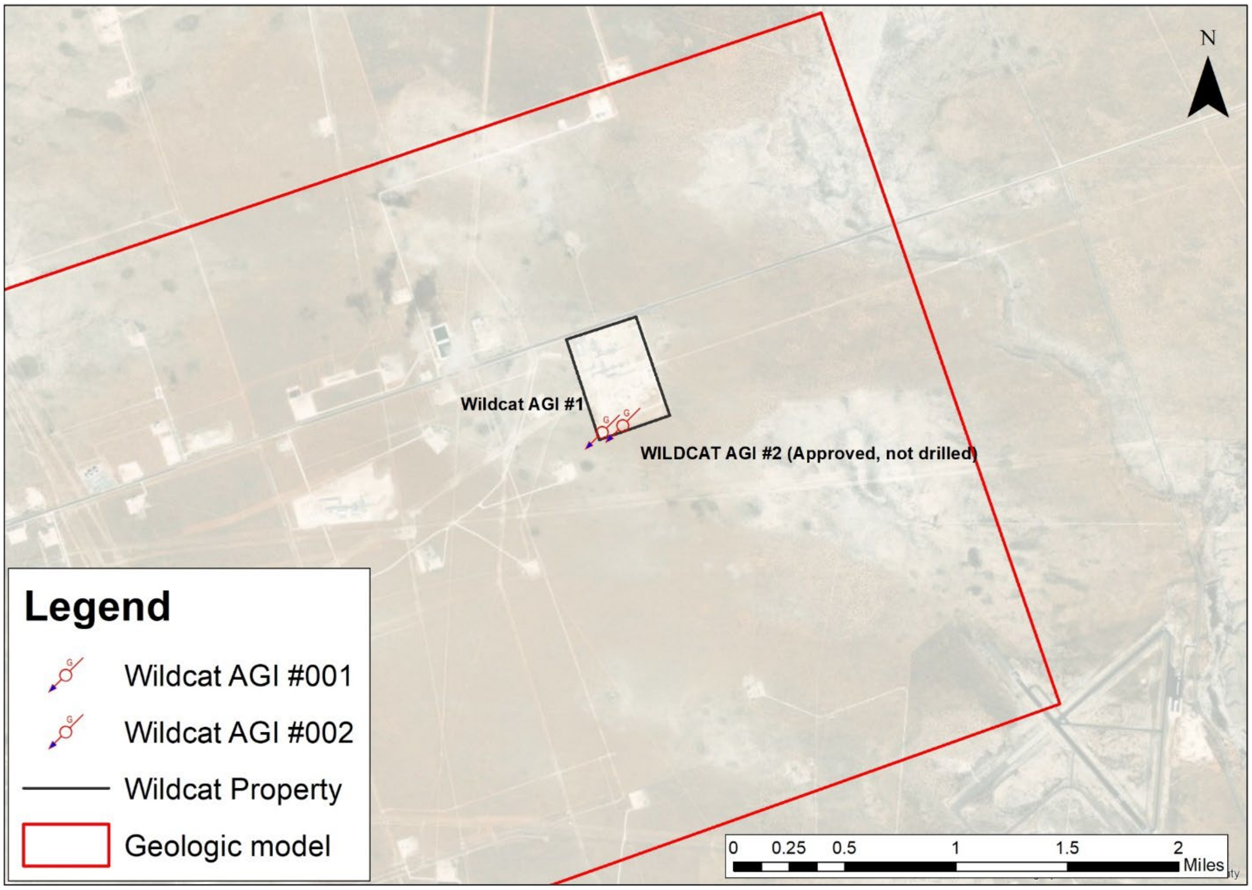


Figure 3.1-1*: Map showing location of Targa Wildcat Gas Processing Plant, existing WC AGI #1 Well as well as permitted WC AGI #2, within a 1-mile buffer zone*

3.2 Bedrock Geology

3.2.1 Depositional Basin

The Plant and the Wildcat AGI wells are located on the eastern margin of the Delaware Basin, a sub-basin of the larger, encompassing Permian Basin (**Figure 3.2-1**), which covers a large area of southeastern New Mexico and west Texas.

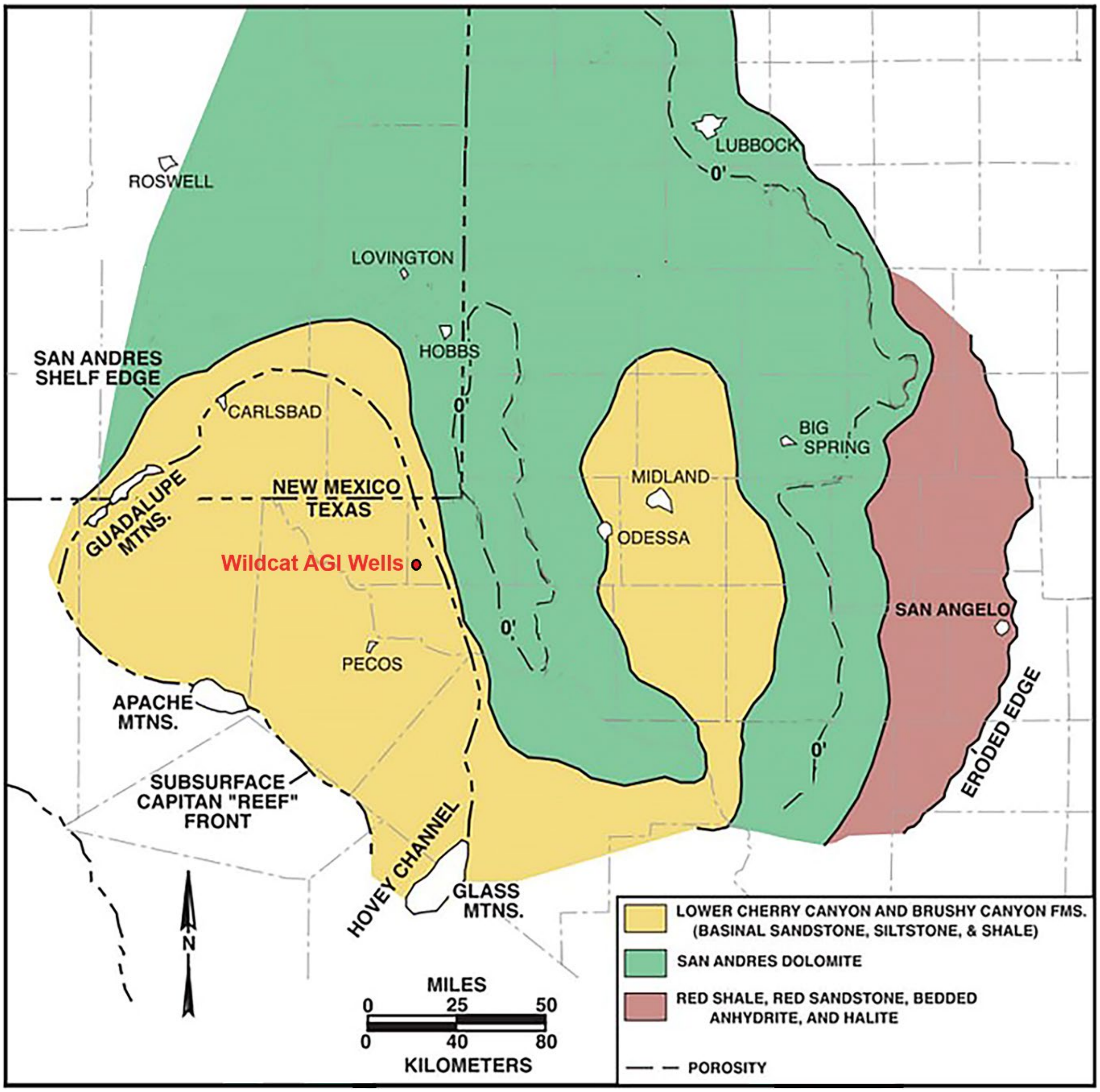


Figure 3.2-1*: Structural features of the Permian Basin during the Late Permian. Location of the Wildcat AGI wells is shown by the red dot (Modified from Ward, et al. (1986)).*

3.2.2 Stratigraphy

Figure 3.2-2 is a generalized stratigraphic column showing the formations that underlie the Plant and WC AGI wells site. The thick sequences of Permian through Cambrian rocks are described below. A general description of the stratigraphy of the area is provided in this section. More detailed discussions of the injection zone and the upper and lower confining zones are presented in Sections 3.3-1 and 3.3-2.

AGE		CENTRAL BASIN PLATFORM-NORTHWEST SHELF		DELAWARE BASIN	
Cenozoic			Alluvium		Alluvium
Triassic			Chinle Formation		Chinle Formation
			Santa Rosa Sandstone		Santa Rosa Sandstone
Permian	Lopingian (Ochoan)		Dewey Lake Formation		Dewey Lake Formation
			Rustler Formation		Rustler Formation
			Salado Formation		Salado Formation
					Castile Formation
	Guadalupian	Artesia Group	Tansill Formation	Delaware Mountain Group	Lamar Limestone
			Yates Formation		Bell Canyon Formation
			Seven Rivers Formation		
			Queen Formation		Cherry Canyon Formation
			Grayburg Formation		
			San Andres Formation		Brushy Canyon Formation
	Cisuralian (Leonardian)		Glorieta Formation		
		Yeso	Paddock Mbr.		Bone Spring Formation
			Blinebry Mbr		
			Tubb Sandstone Mbr.		
			Drinkard Mbr.		
	Wolfcampian		Abo Formation		
			Hueco ("Wolfcamp") Fm.		Hueco ("Wolfcamp") Fm.
Pennsylvanian	Virgilian		Cisco Formation		Cisco
	Missourian		Canyon Formation		Canyon
	Des Moinesian		Strawn Formation		Strawn
	Atokan		Atoka Formation		Atoka
	Morrowan		Morrow Formation		Morrow
Mississippian	*Upper*		Barnett Shale		Barnett Shale
	Lower		"Mississippian limestone"		"Mississippian limestone"
Devonian	*Upper*		Woodford Shale		Woodford Shale
	Middle				
	Lower		Thirtyone Formation		Thirtyone Formation
Silurian	*Upper*		Wristen Group		Wristen Group
	Middle				
	Lower		Fusselman Formation		Fusselman Formation
Ordovician	*Upper*		Montoya Formation		Montoya Formation
	Middle		Simpson Group		Simpson Group
	Lower		Ellenburger Formation		Ellenburger Formation
Cambrian			Bliss Ss.		Bliss Ss.
Precambrian			Miscellaneous igneous, metamorphic, volcanic rocks		Miscellaneous igneous, metamorphic, volcanic rocks

Figure 3.2-2*: Stratigraphic column for the Delaware basin, the Northwest Shelf and Central Basin Platform (modified from Broadhead, 2017).*

The WC AGI #1 is located in the Delaware Basin portion of the broader Permian Basin. Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-1, 3.2-2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland (**Figure 3.2-3**). With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed (the proto-Tobosa Basin). The Ellenburger Group (regional thickness between 0 – 1,000 feet (ft)) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Throughout this narrative, the numbers after the formations indicate the range in thicknesses for that unit within the Delaware Basin. Tectonic activity near the end of Ellenburger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit's overall porosity and permeability.

During Middle to Upper Ordovician time, the seas once again covered the area and deposited the carbonates, sandstones and shales of the Simpson Group (regional thickness between 0 – 1,000 ft) and then the Montoya Group (regional thickness between 0 – 600 ft). This is the period when the Tobosa Basin formed due to the Pedernal uplift and development of the Texas Arch (**Figure 3.2-4**; Harrington, 2019) shedding Precambrian crystalline clasts into the basin. Reservoirs in New Mexico are typically within deposits of shoreline sandstones (Broadhead, 2017). A subaerial exposure and karstification event followed the deposition of the Simpson Group. The Montoya Group marked a return to dominantly carbonate sedimentation with minor siliciclastic sedimentation within the Tobosa Basin (Broadhead, 2017; Harrington and Ruppel, 2019). The Montoya Group, consisting of sandstones and dolomites, have also undergone karstification.

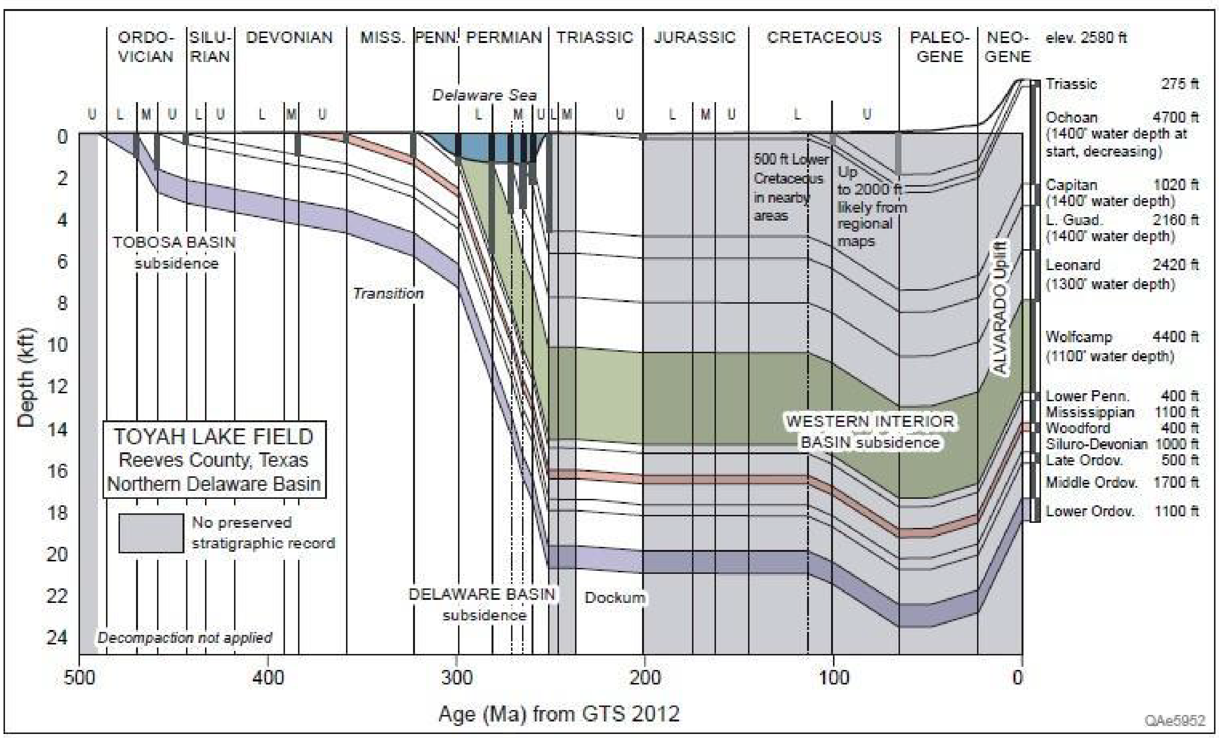


Figure 3.2-3*: A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)*

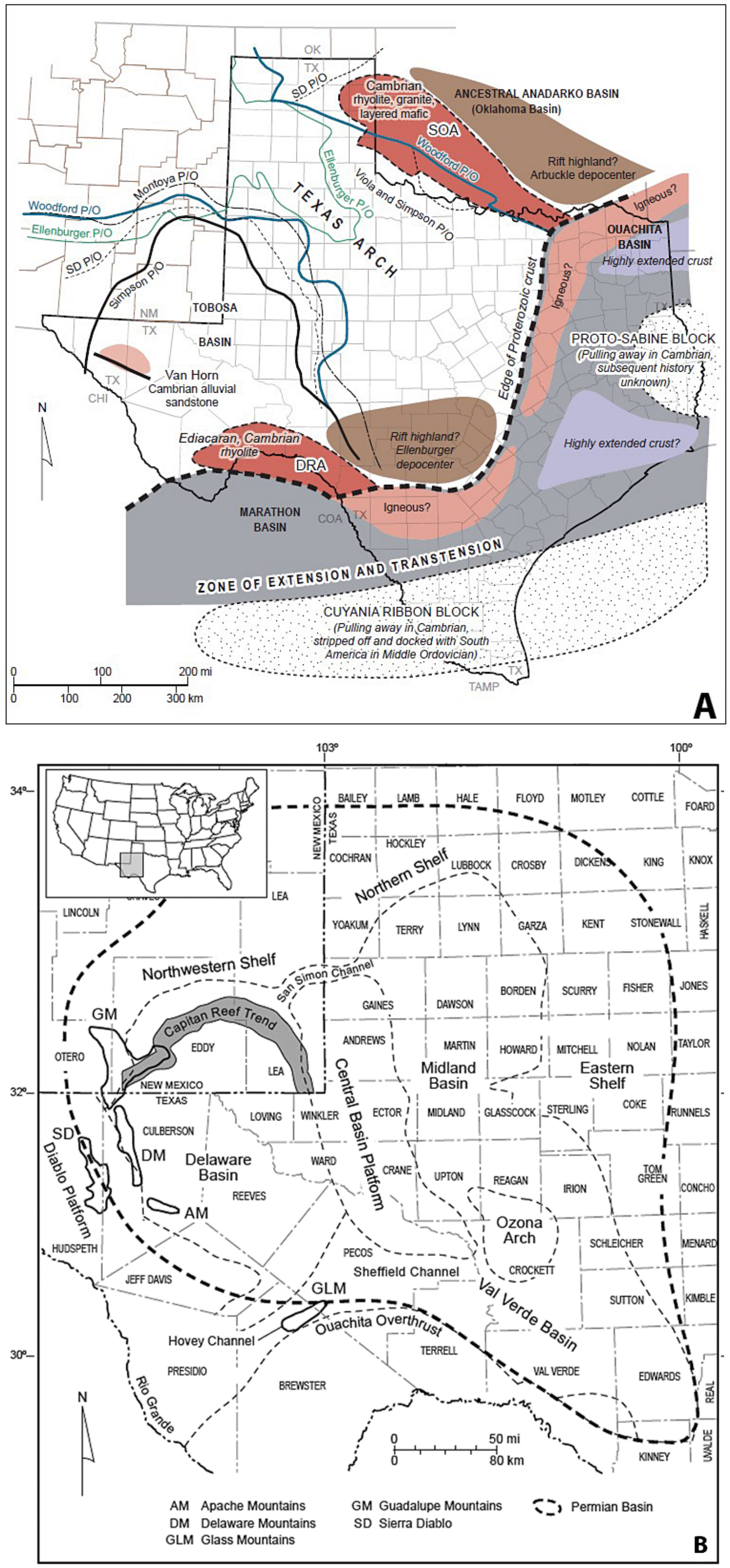


Figure 3.2-4*: Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).*

Siluro-Devonian formations consist of Lower Silurian Fusselman Formation (regional thickness between 0 – 1,500 feet), the Upper Silurian to Lower Devonian Wristen Group (regional thickness between 0 – 1,400 feet), and the Lower Devonian Thirtyone Formation (regional thickness between 0 – 250 feet). The Fusselman Formation are shallow-marine platform deposits of dolostones and limestones (Broadhead, 2017; Ruppel, 2019b). Subaerial exposure and karstification associated with an unconformity at top of the Fusselman Formation as well as intraformational exposure events created brecciated fabrics, widespread dolomitization, and solution-enlarged pores and fractures (Broadhead, 2017). The Wristen and Thirtyone units appear to be conformable. The Wristen Group consists of tidal to high-energy platform margin carbonate deposits of dolostones, limestones, and cherts with minor siliciclastics (Broadhead, 2017; Ruppel, 2020a). The Thirtyone Formation is present in the southeastern corner of New Mexico and appears to be either removed by erosion or not deposited elsewhere in New Mexico (**Figure 3.2-5**). It is a shelfal carbonate with varying amounts of chert nodules and represents the last carbonate deposition in the area during Devonian time (Ruppel et al., 2020b). The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial exposure, karstification and later fracturing/faulting.

The Devonian Woodford Shale (regional thickness between 0 – 700 feet), an un-named Mississippian limestone (regional thickness between 0 – 800 feet), and the Upper Mississippian Barnett Shale (regional thickness between 0 – 500 feet) are seals for the underlying Siluro-Devonian strata. The Woodford Shale ranges from organic–rich argillaceous mudstones with abundant siliceous microfossils to organic-poor argillaceous mudstones (Ruppel et al., 2020b). The Woodford sediments represent stratified deeper marine basinal deposits with their organic content being a function of the oxygenation within the bottom waters – the more anoxic the waters the higher the organic content.

The Mississippian strata within the Delaware Basin consists of an un-named carbonate member and the Barnett Shale that unconformably overlies the Woodford Shale. The lower Mississippian limestones are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoirs limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise it is tight. The Barnett Shale unconformably overlies the Lower Mississippian carbonates and consists of a cycle of shallower to deep marine carbonates to shale deposits (the Barnett Shale).

For potential future injection if WC AGI #2 is drilled, the designated injection targets would encompass the Siluro-Devonian formations, specifically the Thirtyone, Wristen, Fusselman, Montoya, Simpson and Ellenburger. The total thickness of the injection zone is estimated to be approximately 3000 feet (**Table 3.2-1**). The efficacy of carbon capture and storage relies on the geologically secure confinement within these formations. The Woodford Shale of the Devonian, the Mississippian limestone, and the Upper Mississippian Barnett Shale possess low porosity and permeability, serving as effective seals over the injection zone. These formations, acting as geological barriers, are crucial for preventing the escape of injected CO_2. The total thickness of these sealing formations is approximately 1,530 feet (**Table 3.2-1**).

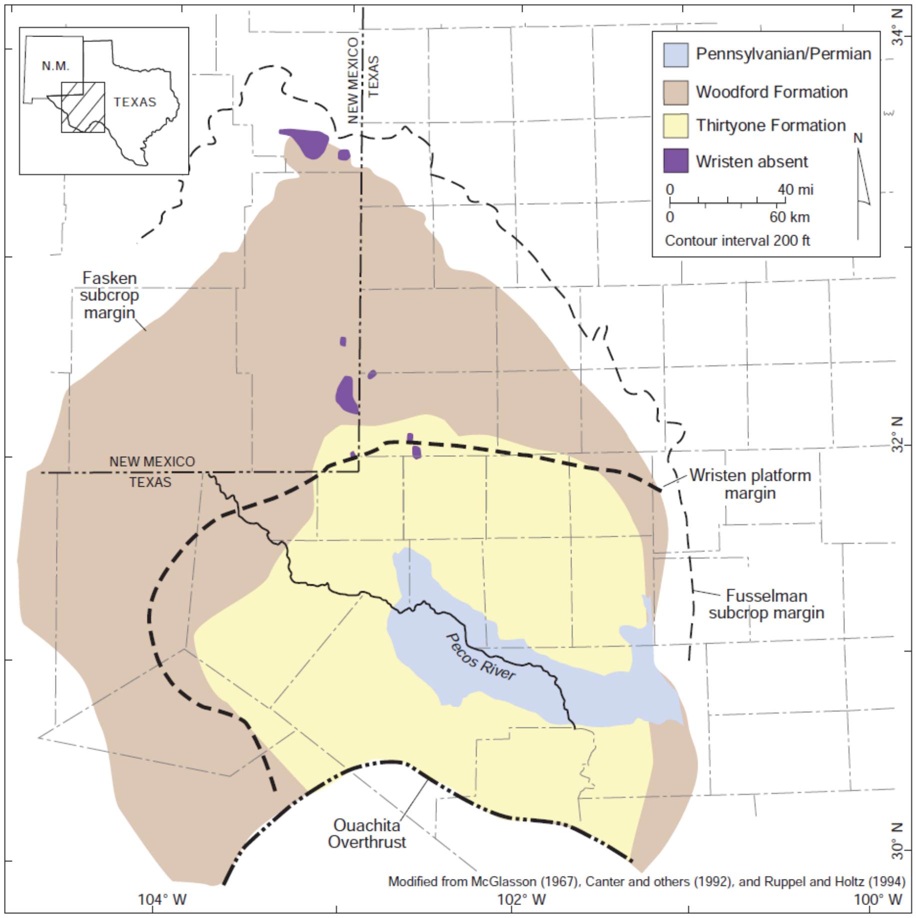


Figure 3.2-5*: A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there is no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

Table 3.2-1: *Table of measured (WC AGI # 1) and estimated (WC AGI # 2) formation top depths, formation thicknesses, seal and reservoir thicknesses (Total), and average porosity, and permeability.*

Formation	AGI Well	Measured Depth (feet)	Formation Thickness (feet)	Total (feet)	Porosity (%)	Permeability (mD)	Behavior
Rustler	1	-1,680	*210*	***3,480***			Seal
Salado	1	-1,890	*525*		2.5	0.2	Seal
Castile	1	-2,415	*2745*		1	0.01	Seal
Lamar	1	-5,160	*45*		15	100	
Bell Canyon	1	-5,205	*1,095*	***2,330***	23	110	Injection zone
Cherry Canyon	1	-6,300	*1,235*		15	12	Injection zone
Brushy Canyon	1	-7,535	*1,380*		12	11	
Bone Spring	1	-8,915	*2,990*		2	0.2	Seal
Wolfcamp	2	-11,905	*2,700*				
Strawn	2	-14,605	*185*				
Atoka	2	-14,790	*200*				
Morrow	2	-14,990	*720*				
Barnett Shale	2	-15,710	*210*	***1,530***	1	0.1	Seal
Mississippian	2	-15,920	*637*		2	0.1	Seal
Woodford	2	-16,557	*683*		1	0.1	Seal
Siluro-Devonian	2	-17,240	*709*	***2,910***	5	1	Injection zone
Fusselman	2	-17,949	*312*		7	1	Injection zone
Montoya	2	-18,261	*473*		3	1	Injection zone
Simpson	2	-18,734	*994*		15	45	Injection zone
Ellenburger	2	-19,729	*940*		6	15	Injection zone/Seal
Bliss/ Precambrian	2	**-20,669**					Seal

Pennsylvanian sedimentation in the Delaware Basin was influenced by glacio-eustatic sea-level cycles producing numerous shallowing upward cycles within the rock record; the intensity and number of cycles increase upward in the Pennsylvanian section and continue into the Permian. The cycles normally start with a sea-level rise that drowns the platform and deposits marine mudstones. As sea-level starts to fall, the platform is shallower and deposition switches to marine carbonates and coastal siliciclastic sediments. Finally, as the seas withdraw from the area, the platform is exposed causing subaerial diagenesis (soils and dissolution) and the deposition of terrestrial mudstones, siltstones, and sandstones in alluvial fan to fluvial deposits. This is followed by the next cycle of sea-level rise and drowning of the platform.

Lower Pennsylvanian units consist of the Morrow and Atoka formations. The Morrow Formation (regional thickness between 0 – 2,000 feet) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). The Atoka Formation (regional thickness between 0 – 500 feet) was deposited during another sea-level transgression within the area. The Atoka sediments are dominated by siliciclastic sediments, and depositional environments range from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020). Middle Pennsylvanian units consist of the Strawn group (an informal name used by industry). Strawn sediments (regional thickness between 250 – 1,000 feet) within the area consists of marine sediments that range from ramp carbonates, containing patch reefs to marine sandstone bars to deeper marine shales (Broadhead, 2017).

Deformation, folding and high-angle faulting, associated with the Upper Pennsylvanian/Early Permian Ouachita Orogeny, created the Permian Basin and its 2 sub-basins, the Midland and Delaware basins (Hills, 1984; King, 1948), the Northwest Shelf (NW Shelf), and the Central Basin Platform (**Figures 3.2-4, 3.2-6, 3.2-7**). The Permian "Wolfcamp" or Hueco Formation was deposited after the creation of the Permian Basin. The Wolfcampian sediments were the first sediments to fill in the structural relief (**Figure 3.2-6**) developed by the creation of the basin. The Wolfcampian Hueco Group (regional thickness around 400 feet on the NW Shelf, and greater than 2,000 feet in the Delaware Basin) consists of shelf margin deposits ranging from barrier reefs and fore slope deposits, bioherms, shallow-water carbonate shoals, to basinal carbonate and siliciclastic mudstones (Broadhead, 2017; Fu et al., 2020). Since deformation continued throughout the Permian, the Wolfcampian sediments were truncated in places like the Central Basin Platform (**Figure 3.2-6**).

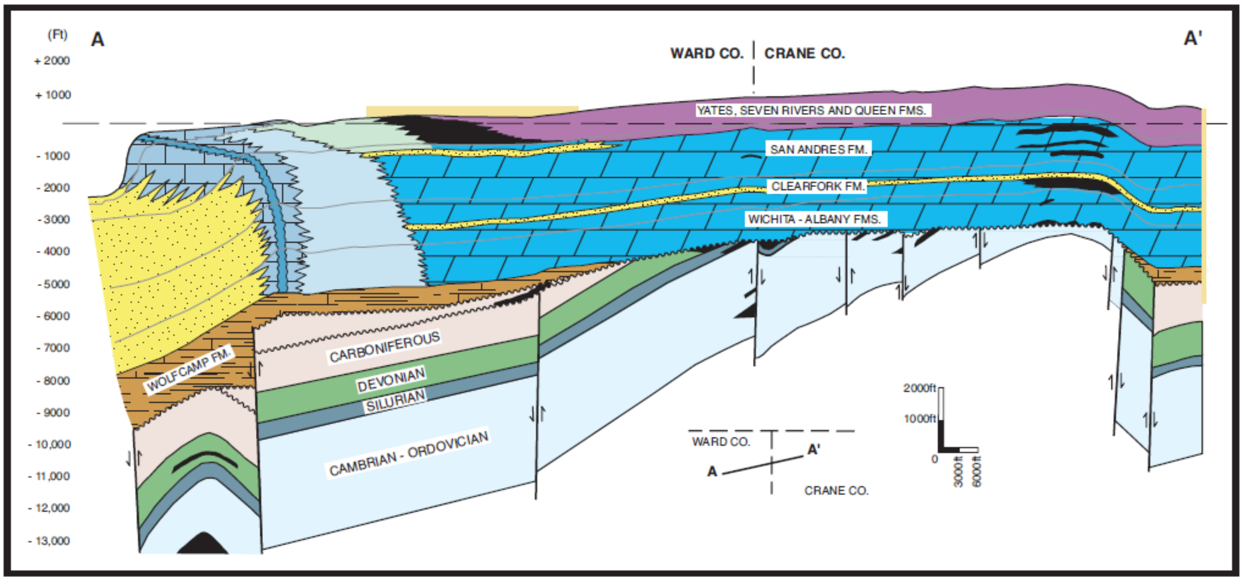


Figure 3.2-6: *Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).*

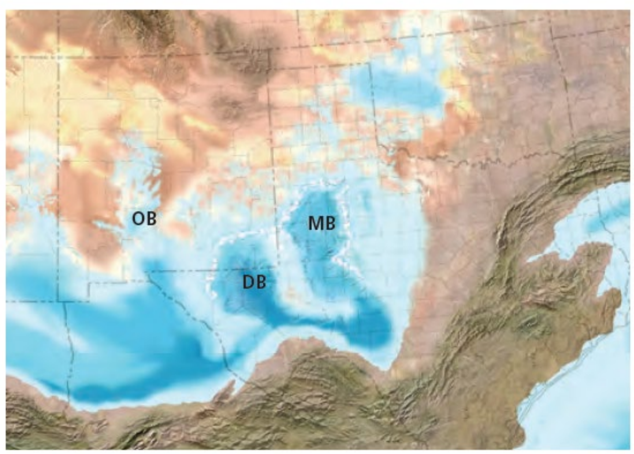


Figure 3.2-7: *Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).*

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco ("Wolfcamp") deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 feet of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, thousands of feet of siliciclastic sediments bypassed the shelves and were deposited in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a "carbonate factory" on the shelf and shelf edge. Carbonate debris beds shedding off the shelf margin were transported into the basin (King 1948; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center.

Within the Delaware Basin, the Bone Spring Formation (approximately 3,000 feet) consists of alternating carbonate and siliciclastic horizons that formed due to sea-level changes; the carbonates during highstands, and siliciclastics during lowstands.

Overlying the Bone Spring Formation, the sediments in the Delaware Mountain Group (descending, Bell Canyon, Cherry Canyon, and Brushy Canyon formations) are deep-water marine units that were deposited within the basin and impacted by numerous changes in sea-level due to both eustacy and tectonics. Most of the Delaware Mountain Group is dominated by siliciclastic sediments. Like the Bone Spring deposits, the siliciclastics represent lowstand deposition, and the thin, interbedded carbonates represent highstand sedimentation. The Delaware Mountain Group will be discussed in greater detail in the Injection Zone section (Section 3.3.2).

The final stage of Permian within the Delaware Basin consists of the Ochoan/Lopingian Castile, Salado, and Rustler formations (~4,000 feet). Within the basin, the Castile formation, a thick sequence (regional thickness between 1,500 – 2,500 feet) of cyclic laminae of deep-water gypsum/anhydrite interbedded with calcite and organics, formed due to the restriction of marine waters flowing into the basin. Gypsum/anhydrite laminae precipitated during evaporative conditions, and the calcite and organic-rich horizons were a result of seasonal "freshening" of the basin waters by both marine and freshwaters. Unlike the Castile Formation, the Salado Formation (less than 2,000 feet) is a relatively shallow water evaporite deposit. Halite, sylvite, anhydrite, gypsum, and numerous potash minerals were precipitated. The Rustler Formation (less than 500 feet) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin. The Rustler Formation was followed by terrestrial sabkha red beds of the Dewey Lake Formation (approximately 350 feet), ending Permian deposition in the area.

Beginning early in the Triassic, uplift and the breakup of Pangea resulted in another regional unconformity and the deposition of non-marine, alluvial Triassic sediments (Santa Rosa Sandstone and Chinle Formation). They are unconformably overlain by Cenozoic alluvium (which is present at the surface). Cenozoic Basin and Range tectonics resulted in the current configuration of the region and reactivated numerous Paleozoic faults.

For WC AGI #1, the designated injection targets are within the Delaware Mountain Group, encompassing the Bell Canyon and Cherry Canyon formations. The efficacy of geological sequestration hinges on the containment within these formations. Serving as crucial geological seals above the injection zone are the Rustler, Salado, and Castile formations, characterized by their low porosity and permeability. This geological barrier is fundamental in preventing the migration and ensuring the secure storage of CO_2. Notably, the estimated total thickness of these sealing formations at the AGI well stands at 4,300 feet, underlining the substantial geological measures in place to facilitate effective carbon storage (**Table 3.2-1**).

3.2.3 Faulting

In this immediate area of the Permian Basin, faulting is primarily confined to the lower Paleozoic section, where seismic data shows major faulting and ancillary fracturing-affected rocks only as high up as the base of the lower Woodford Shale (**Figures 3.2-4 and 3.2-5**).

In Geolex's End-of-Well report for WC AGI #1, the cross-sections show there are no faults close to WC AGI #1 injection and sealing zones, and that the proposed disposal zone is isolated. NMT and Targa geological modeling confirmed that WC AGI #1 geological sequestration activities cannot be affected by faulting because there are no nearby faults close to the injection zone nor the sealing zone.

However, deeper faults have been identified in the area. These deep faults will not be affected by the injection at WC AGI #1. However, the deeper faults may be affected by injection into the approved WC AGI #2. The team carried out a Fault Slip Potential analysis (section 5.5) to evaluate the potential risk associated with potential injection in WC AGI #2. That analysis is described in section 3.8.

3.3 Lithologic and Reservoir Characteristics

3.3.1 Confining Zone

WILDCAT AGI #1

WC AGI #1 Overlying Confining Zone

Permian Ochoan Series.

The youngest of the Permian sediments, the Ochoan- or Lopingian-aged deposits, consists of evaporites, carbonates, and red beds. The Castile Formation is made of cyclic laminae of deep-water precipitated gypsum/anhydrite beds interlaminated with calcite and organics that formed due to the restriction of marine waters flowing into the basin. Gypsum/anhydrite laminae precipitated during evaporative conditions, and the calcite and organic-rich horizons were a result of seasonal "freshening" of basin waters by both marine and freshwaters. This basin-occurring unit can be up to 3,000 feet thick. Due to minor salt movement, the Castile evaporites can be folded and faulted, but due to their very nature, the ability to flow, they are excellent seals. The Castile evaporites are followed by the Salado Formation (< 2,000 feet). The Salado Formation is a shallow water evaporite deposit, when compared to the Castile Formation, and consists of halite, sylvite, anhydrite, gypsum, and numerous potash/bittern minerals. Salado deposits fill the basin and lap onto the older Permian shelf deposits, completely sealing basin and shelf areas. The Rustler Formation (up to 500 feet) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represent the last Permian marine deposits within the Delaware Basin area. The Ochoan evaporitic units are superb seals (usually <1% porosity and <0.01 mD permeability; **Table 3.2-1**) and are the reason that the Permian Basin is such a hydrocarbon-rich region despite its less than promising total organic carbon (TOC) content.

WC AGI #1 Underlying Confining Zone

Permian Leonardian Series.

The Leonardian/Cisuralian Series, located beneath the Guadalupian Series sediments, is characterized by >3,000 feet of basin-deposited carbonate and siliciclastic sediments of the Bone Spring Formation. The Bone Spring Formation is more carbonate rich than the Delaware Mountain Group deposits, but the sea-level-driven cycles of sedimentation and the associated depositional environments are similar with debris flows, turbidites, and pelagic carbonate sediments. The Bone Spring Formation contains conventional and unconventional fields within the Delaware Basin in both sandstone-rich and carbonate-rich facies. Most of these plays usually occur within toe-of-slope carbonate and siliciclastic deposits or the turbidite facies in the deeper sections of the basin (Nance and Hamlin, 2020). The uppermost member if the Bone Spring is a dense carbonate mudstone with limited porosity and low permeability (1 – 2%; 0.01 – 0.02 mD).

WILDCAT AGI #2
WC AGI #2 Overlying Confining Zone

Mississippian.

Mississippian age deposits are commonly divided (from youngest to oldest) into the Barnett Shale and the Mississippian limestone (an un-named unit) of the Lower Mississippian age (**Figure 3.2-2**). The Mississippian section is approximately 800 feet thick in the Wildcat area and is regional extensive. The Lower Mississippian limestone is a dark colored, deep marine limestone with minor cherts and shales and is 637 feet thick. Known production from this limestone consist of one to two well plays that normally have poor porosity (4-9%) and permeability (Broadhead, 2017) in New Mexico and a few isolated fields in the shallow water, high energy limestones in Texas. The Barnett Shale is a widespread, dark, organic shale with very low porosity and permeability and is 210 feet thick. Overall, Mississippian units are good seals to prevent upward fluid movement through the section (**Table 3.2-1**).

Upper Devonian.

Within the Permian Basin, the Upper Devonian Woodford Shale serves as a seal to hydrocarbon migration out of Devonian and older units (Wright, 1979). In combination with the Mississippian section, it makes an excellent seal for potential injection. the Woodford Shale is ~680 feet thick in the Wildcat area and is laterally continuous, organic- and shale-rich, siliceous (radiolarians) mudstone. The porosity that occurs in the Woodford Shale is usually micro-porosity associated with organic material and not connected (i.e., low permeability). Porosity can get up to 10% (Jarvie et al., 2001), but it averages around 1% with very low permeabilities (**Table 3.2-1**).

WC AGI #2 Underlying Confining Zone

Ordovician.

The Ordovician Ellenburger Group which is comprised of dolomites and limestones that are approximately 940 feet thick in the Wildcat area and sits on the basement over a veneer of Cambrian transgressive sandstones and granite wash. The Ellenburger Group sediments were deposited in subtropical to tropical belt of shallow-water platform carbonates that covered most of what is now North America and Greenland. The Ellenburger carbonates in the Permian Basin area have been extensively altered by later diagenesis that includes several intervals of exposure and karstification, dolomitization, and fracturing and faulting during the formation of Tobosa and Permian basins. While most of the Ellenburger Group sediments are also perspective injection zones, the lower 200 – 300 feet are normally less porous and permeability (1 – 2% porosity and <2 mD) due their original depositional environment and depth of burial (Loucks and Kerans, 2019) making those units a potential underlying seal.

Cambrian to Precambrian.

Underlying the Ellenburger Formation, the Cambrian Bliss Sandstone and crystalline Precambrian rocks are potential lower seals. Porosity and permeability data indicate that in shallower wells, the Bliss is an aquifer. Within the Wildcat area, no data could be found on the Bliss Sandstones. Considering their depth, compactional history, and potential diagenetic alteration, these sandstones and granitic debris (from weathering of the basement rock) maybe relatively tight.

3.3.2 Injection Zone

WILDCAT AGI #1

Delaware Mountain Group.

Sediments in the underlying Delaware Mountain Group (descending, Bell Canyon, Cherry Canyon, and Brushy Canyon formations) are marine units that were deposited within the basin at depths that varied because of numerous changes in sea-level due to eustacy and tectonics. Most of the Delaware Mountain Group is dominated by siliciclastic sediments. The quartz-rich sands are fine grained to silt sized and poorly cemented. Deposition occurred within submarine fan complexes encircling the Delaware Basin margin. These deposits are associated with submarine canyons incising the carbonate platform and turbidite channels, splays, and levee/overbank deposits (**Figure 3.3-1**). Debris flows formed by the failure of the carbonate margin and density currents are found as aerially restricted units within the siliciclastic sediments. Isolated coarse-grained to boulder-sized carbonate debris flows and grain falls within the lowstand clastic sediments likely resulted from erosion and failure of the shelf margin during sea-level lowstands or slope failure due to tectonic activity (earthquakes).

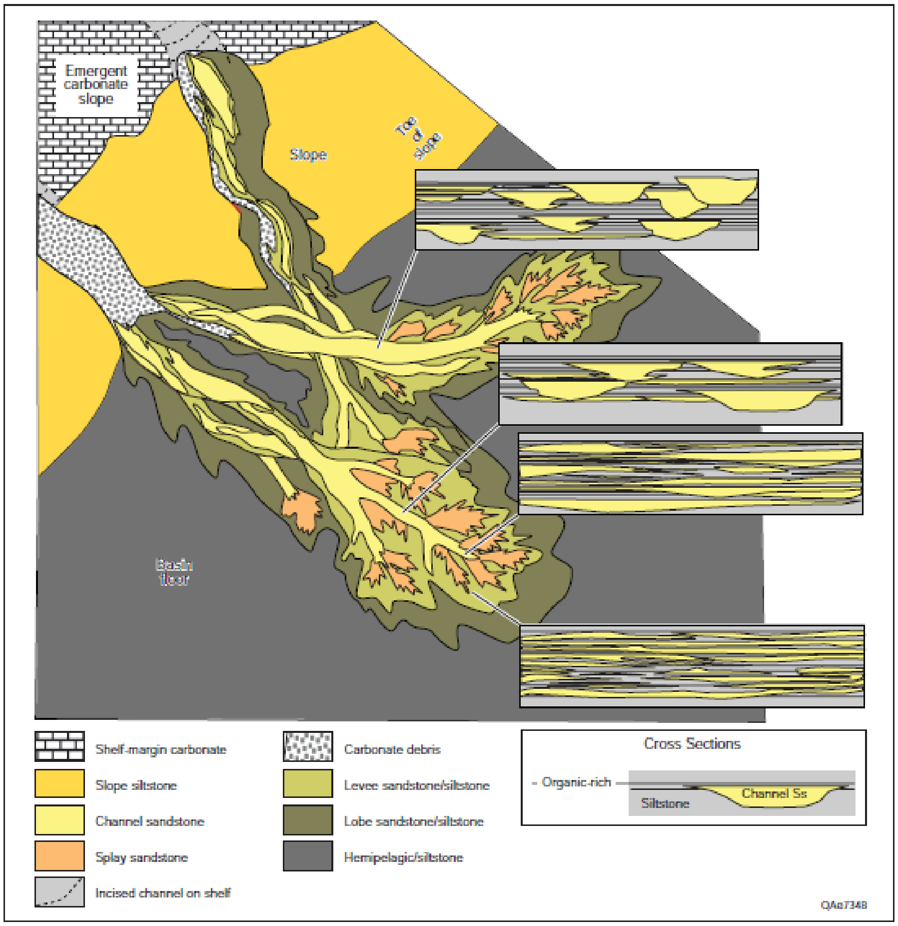


Figure 3.3-1*: A diagram of typical Delaware Mountain Group basinal siliciclastic deposition patterns (from Nance, 2020). The channel and splay sandstones have the best porosity, but some of the siltstones also have potential as injection zones.*

Density current deposits formed within basins that contain highly stratified waters. If the bottom waters are extremely dense due to salinity and/or temperature, then turbidity flows containing sands, silts and clays are unable to displace those bottom waters and instead flowed out over a density interface (**Figure 3.3-2**). Eventually, the entrained sediments will settle out in a constant rain of sediment forming laminated deposits with little evidence of traction (bottom flowing) deposition.

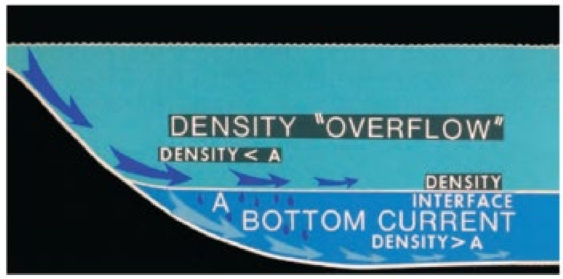
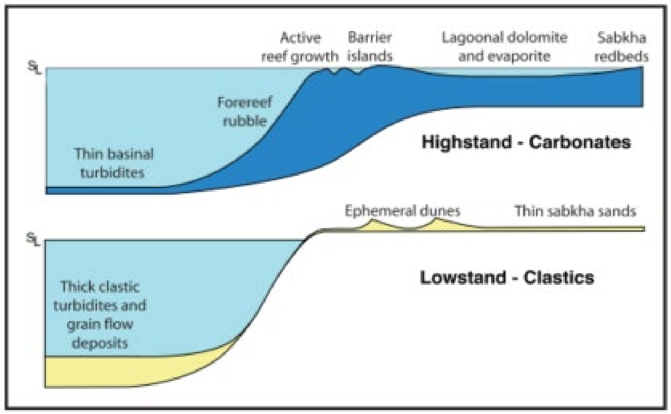
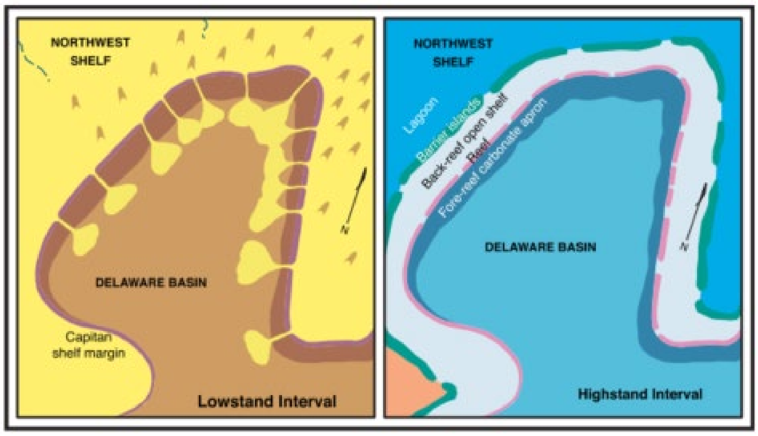


Figure 3.3-2*: Harms' (1974) density overflow model explains the deposition of laminated siliciclastic sediments in the Delaware Basin. Low density sand-bearing fluids flow over the top of dense, saline brines at the bottom of the basin. The sands gradually drop out as the flow loses velocity creating uniform, finely laminated deposits (from Scholle et al., 2007).*

The siliciclastic deposits of the Delaware Mountain Group represent sea-level lowstand deposits. Interbedded with the very thick lowstand sequences are thin, deep-water limestones and mudstones that are thickest around the edge (toe-of-slope) of the basin and thin to the basin center (**Figure 3.3-3**). The limestones are usually dark, finely crystalline, radiolarian-rich micrites to biomicrites and represent highstand deposits. These highstand deposits are a combination of suspension and pelagic sediments that also thin towards the basin center. These relatively thin units are time equivalent to the massive highstand carbonate deposits on the shelf.



A.



B.

Figure 3.3-3*: The impact of sea-level fluctuations (also known as reciprocal sedimentation) on the depositional systems within the Delaware Basin. A) A diagrammatic representation of sea-level variations impact on deposition. B) Model showing basin-wide depositional patterns during lowstand and highstand periods (from Scholle et al., 2007).*

The top of the Guadalupian Series is the Lamar Limestone (<60 feet), which is the probable source of hydrocarbons found in underlying Delaware Sand (the upper member of the Bell Canyon Formation). The Bell Canyon Formation is roughly 1,000 feet thick in the Wildcat area and contains numerous turbidite input points around the basin margin (**Figures 3.3-3, 3.3-4**). During Bell Canyon deposition, the relative importance of discrete sand sources varied (Giesen and Scholle, 1990), creating a network of channel and levee deposits that also varied in their size and position within the basin. Based on well log analyses, the Bell Canyon 2 and 3 had the thickest sand deposits.

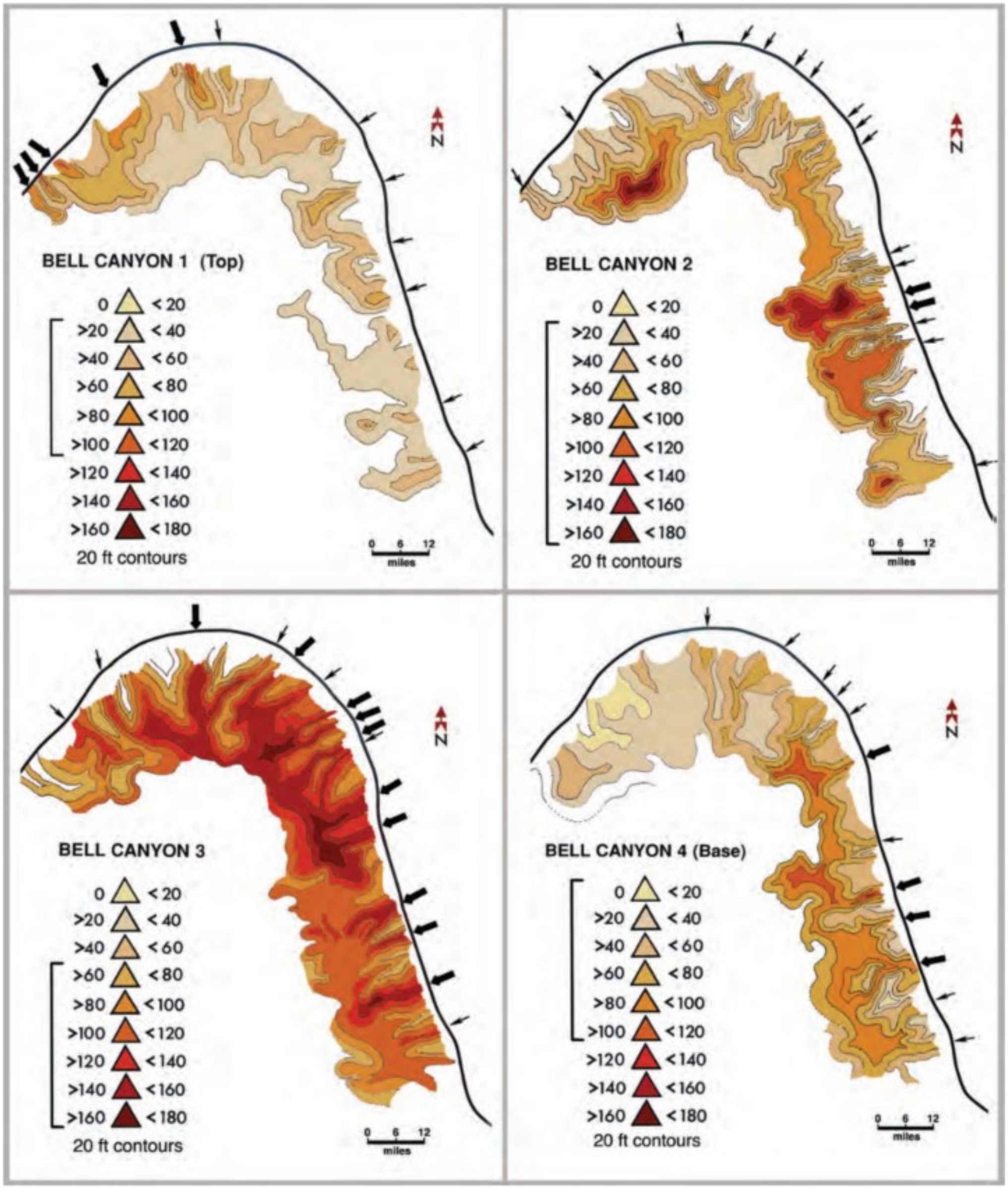


__Figure 3.3-4__: These maps of Bell Canyon Formation were created by measuring sandstone thicknesses on well logs in 4 regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research).

The Cherry Canyon Formation is approximately 1,300 feet thick and contains numerous turbidite source points. Unlike the Bell Canyon, the channel deposits are not as large (Giesen and Scholle, 1990), and the source of the sands appears to be dominantly from the eastern margin (**Figure 3.3-5**). Cherry Canyon 1 and 5 have the best channel development and the thickest sands. Overall, based on outcrop analysis, the Cherry Canyon Formation is less influenced by traction current deposition than the rest of the Delaware Mountain Group deposits and is more influenced by sedimentation by density overflow currents (**Figure 3.3-2**).

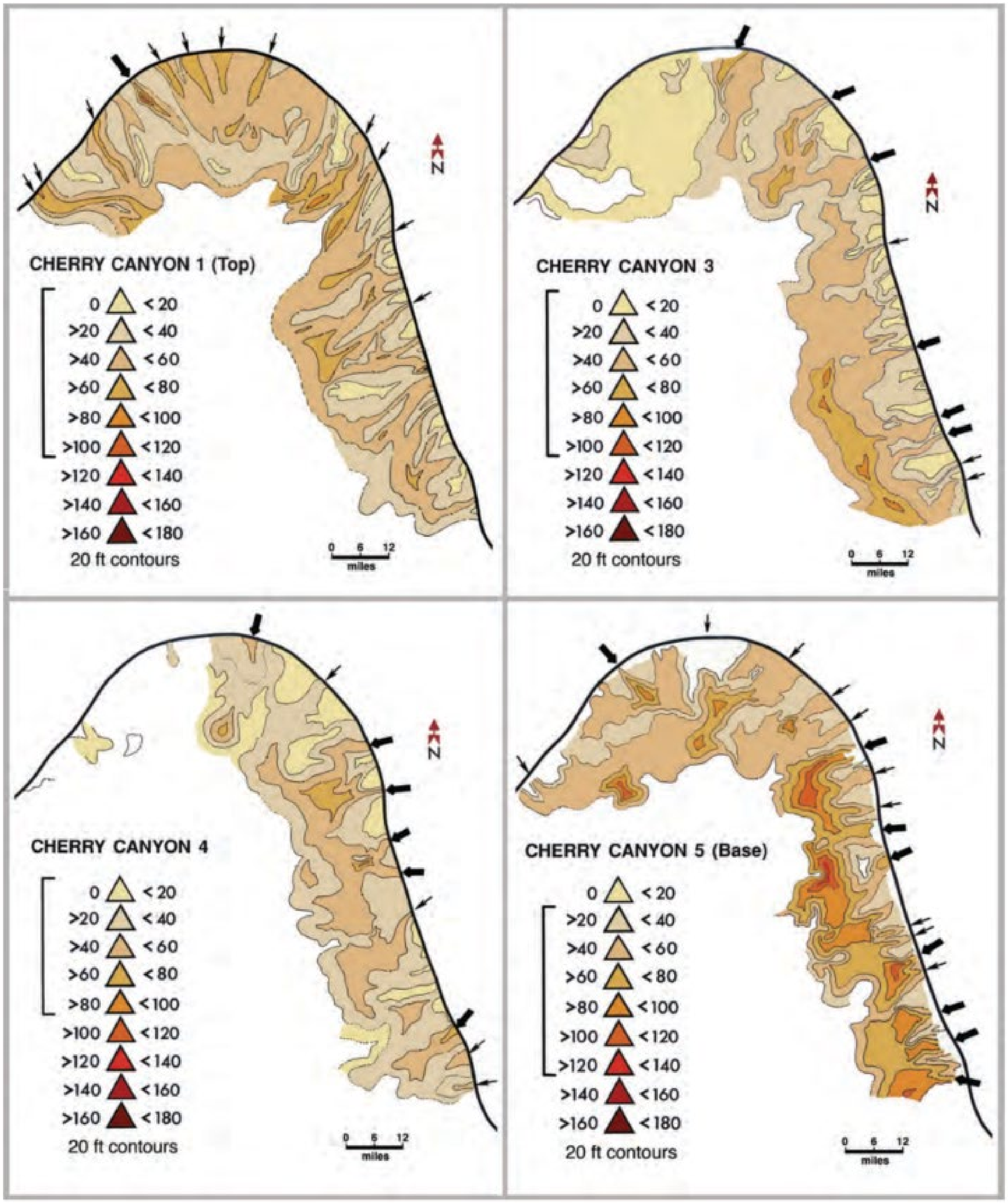


***Figure 3.3-5**: These maps of Cherry Canyon Formation were created by measuring sandstone thicknesses on well logs in 5 regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). Unlike the Bell Canyon sandstones, the Cherry Canyon sands are thinner and contain fewer channels.*

The Brushy Canyon (~1,400 feet) has notably more discrete channel deposits and coarser sands than the Cherry Canyon and Bell Canyon. This makes it more difficult to intersect those sands in the subsurface, and it contains more carbonate that may also cement the unit.

Within the Delaware Mountain Group in the Bull Moose area, the Bell Canyon and Cherry Canyon show the best porosities and permeabilities within channel/splay sandstones. The Bell Canyon porous sandstone porosities range from 11 to 28% and the permeability ranges from 1 to 385 mD (average: 22.8%, 114 mD). The Cherry Canyon sandstone has lower porosities that range from <1 to 25% and <1 to 132 mD (average: 15%, 12 mD), while the Brushy Canyon has an average 12% porosity and <1.0 mD permeability, there may be channels with coarser grained sandstones with higher porosities and permeabilities. Porosity and permeability data (**Table 3.2-1; Figure 3.3-6**) is based on Ge et al. (2022), Smye et al. (2021) and numerous core reports.

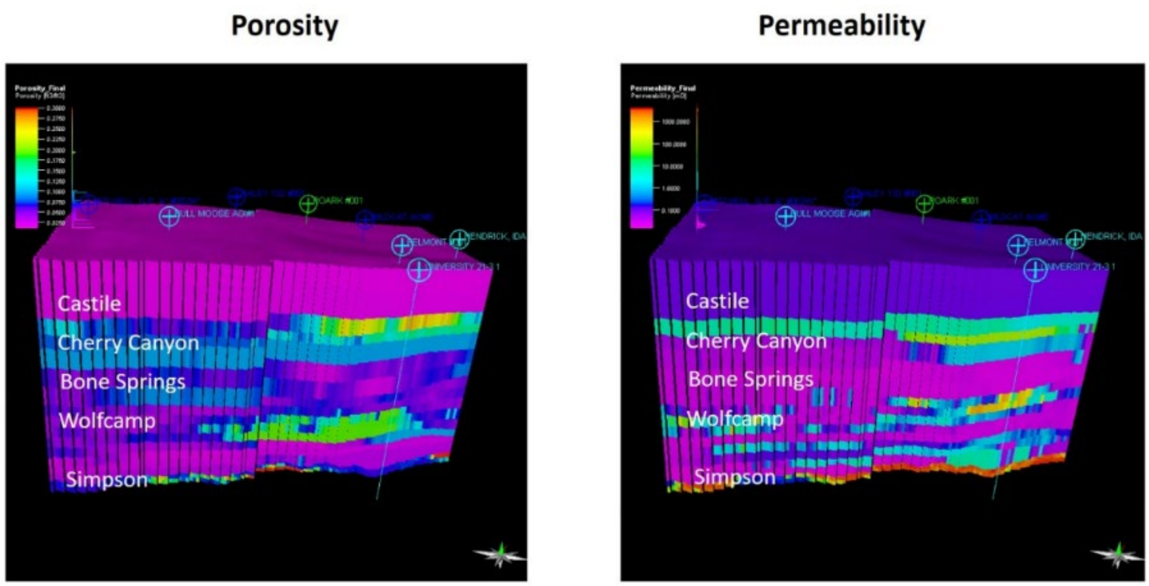


Figure 3.3-6*: Figure of porosity and permeability modeling for WC AGI #1*

WILDCAT AGI #2

Lower Devonian – Silurian.

Thirtyone and Wristen Formations – Underlying the Woodford Shale are the interbedded dolomites and dolomitic limestones of the Devonian Thirtyone Formation and the Silurian Wristen Group, collectively referred to as the Siluro-Devonian section. Unlike the Fusselman, Montoya and Ellenburger carbonates, these deposits represent deposition in deeper waters in the Wildcat area. These deposits range from deeper ramp mudstones and wackestones, to chert- and sponge/radiolarian-rich hemipelagic mudstones (Wristen/Thirtyone) to outer ramp packstones (**Figure 3.3-7**, Thirty-one; Ruppel, 2020; Ruppel et al., 2020a). Porosity and permeability in the Wristen are limited in the main body of the unit (1-2%), but exposure events and carbonate dissolution can improve the porosity (~5%). Within Thirtyone deposits, the chert-rich hemipelagic deposits maintain the best porosity (up to 40%, up to 80 mD), while the limestones have less than 7% porosity and less than 1 mD of permeability (**Table 3.2-1**; Ruppel et al., 2020a).

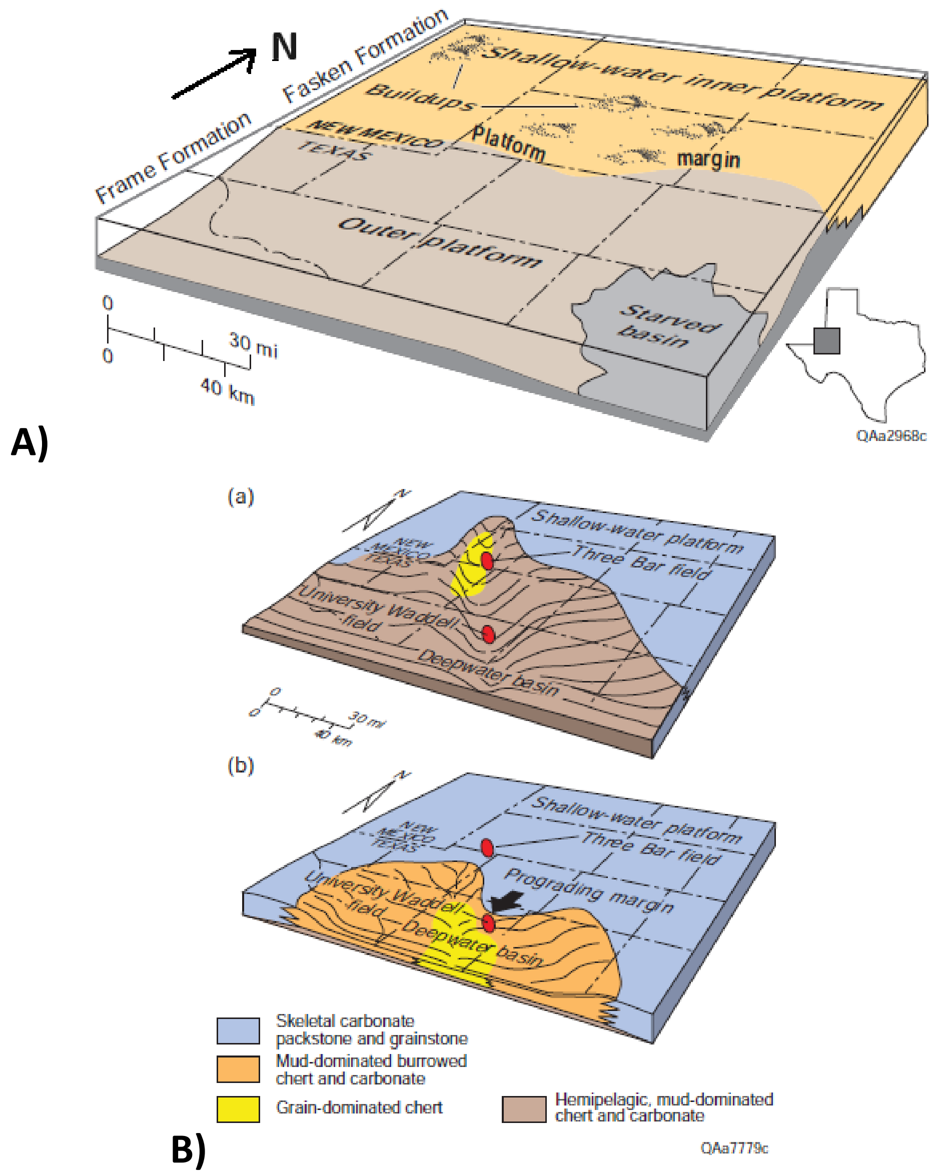


Figure 3.3-7*: A) Generalized paleogeography for the Wristen Group (from Ruppel, 2020). B) Generalized paleogeography for the Thirtyone Formation. (a) represents the earliest deposition and the presence of deep-water environments in the Wildcat area. (b) represents the latter deposition (from Ruppel et al., 2020a).*

Ordovician – Silurian.

Fusselman Formation – The Fusselman Formation is shallow-water carbonate system that was deposited in the Tobosa Basin. In the Wildcat area, the Fusselman thickens to around 300 feet of high-energy packstones to grainstones. Like the Montoya Group, these high-energy sediments started out with the best primary porosity, but diagenesis usually has decreased both the porosity and permeability unless impacted by exposure and dissolution. Based on well logs, the porosity averages around 2%, but there are zones in the well API: 42-495-31047 with over 70 feet of greater than 5% porosity. Reported permeability for shallower sections range from .001 to 10 mD (Ruppel, 2019).

Ordovician.

Montoya Group

The Montoya deposits are dominated by shallow-water, ramp limestones that were deposited in the Tobosa Basin. Like the Ellenburger Group, the porosity within the Montoya group is dependent on depositional environment and diagenesis. The higher energy environments tend to have better initial porosity than the low-energy environments. Compaction destroys the porosity, and dolomitization produces secondary porosity. Based on the well logs, the average porosity is approximately 3%, with scattered zones over 5% (**Table 3.2-1**). The probable average permeability is probably less than 1 mD, but fracturing may enhance it.

Simpson Group.

The deposits of the Simpson group represent a regional transgression after the unconformity at the end of Ellenburger deposition. It is thick sequence of carbonates, sandstones and shales which has a depocenter roughly equivalent to the Delaware Basin/Tobosa Basin. There are several transgressive/regressive cycles within the section, but it is only the transgressive sandstone sections that have significant porosity. The rest of the section typically consists of mud-rich carbonates and shales. Within the sandstones (particularly the McKee Sandstone member), well logs indicate the porosity averages around 15% (**Table 3.2-1**). Permeability is averages 45 mD (Harrington, 2019), though cementation and compaction may decrease that in the area.

Ellenburger Group.

As mentioned in the underlying confining zone, the Ordovician Ellenburger Group is comprised of dolomites and limestones that are approximately 940 feet thick and sits on the basement over a veneer of Cambrian transgressive sandstones and weathered granites. The Ellenburger Group sediments were deposited in subtropical to tropical belt of shallow-water platform carbonates that covered most of what is now North America and Greenland. The Ellenburger carbonates in the Permian Basin area have been extensively altered by later diagenesis that includes several intervals of exposure and karstification, dolomitization, and fracturing and faulting during later tectonic events (**Figure 3.3-8**).

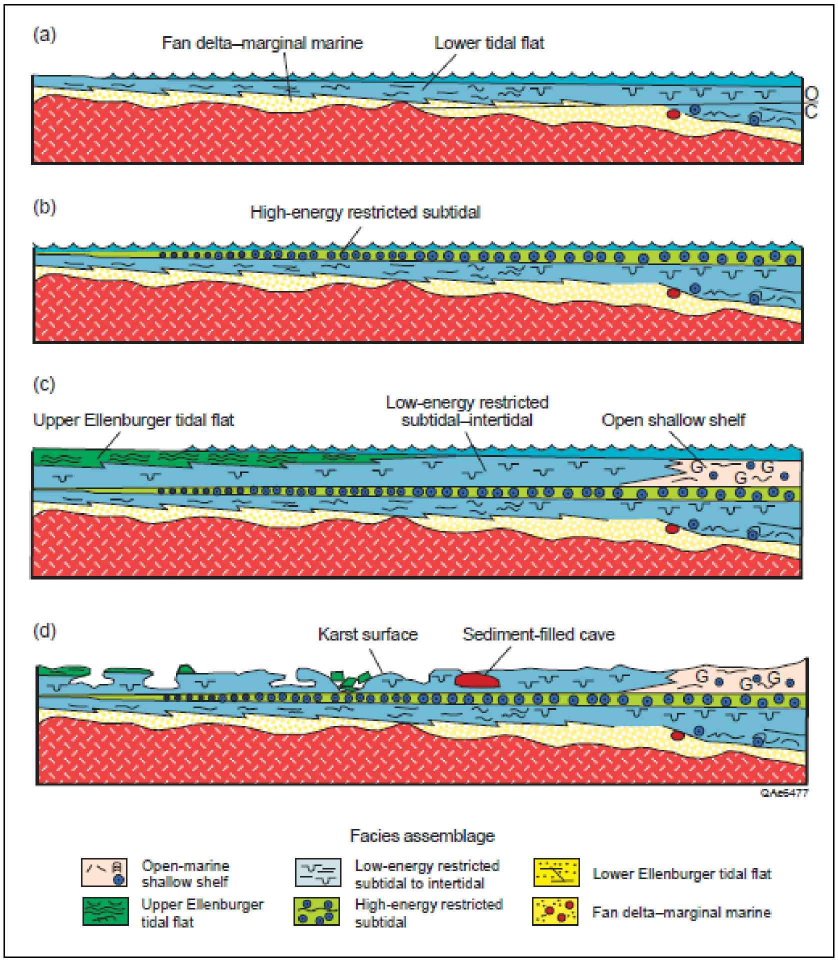
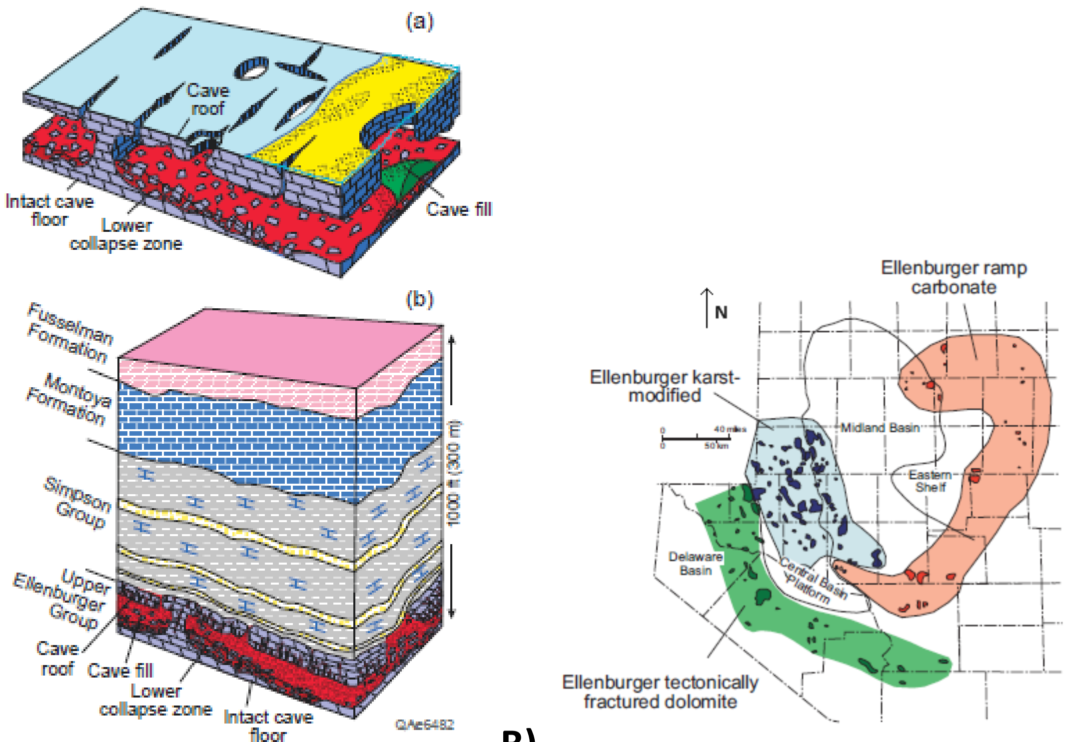


Figure 3.3-8*: Depositional model for the Ellenburger Group deposits. The diagram shows a sequence of transgressive sandstones (Bliss Sandstone, yellow) to carbonates (Panels A through C followed by a regressive sequence (Panels C – D) with exposure and karstification in Panel D (from Loucks and Kerans, 2019).*

Within the Ellenburger Group strata, the upper and middle section typically has the highest porosity and permeability due to karsting and cave development as well as later faulting and fracturing (**Figure 3.3-9**). Late diagenesis plays an important role on porosity destruction and resurrection. Compaction can cause the cave networks to collapse onto themselves, but this later large-scale collapse can also create fractures in the overlying strata increasing the Ellenburger and younger units' permeability. Later faulting appears to have focused deep hydrothermal fluids through the Ellenburger carbonates. This potentially can be good for porosity, by dissolving unstable phases, or can decrease the porosity by precipitating high-temperature phases, like saddle dolomites. Based on work by Loucks (2016, unpublished), the best karst-related porosity is to the east of the Wildcat area, whereas the Wildcat area is in the zone of porosity due to tectonically controlled faulting and fracturing. Porosity and permeability in the Ellenburger section can vary greatly due to the above considerations, but a realistic value for the porosity and permeability, at approximate 20,000 feet depth, is 5-6% and 15 mD (**Table 3.2-1**). Potentially the range of porosity and permeability can range up to 12% and greater than 100 mD (Loucks and Ruppel, 2019).



A) B)

__Figure 3.3-9__: A) Cave development in the upper Ellenburger rocks and their potential impact to produce porosity and permeability (from Loucks and Kerans, 2019). B) Zones of potential porosity creation: karst related (blue), fault and fracture (green) and enhanced primary porosity (orange) (from unpublished manuscript by R. Loucks, 2016).

3.4 Formation Fluid Chemistry

Water data was retrieved from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3 (05/22/2019) to determine formation chemistry in the Bell Canyon-Cherry Canyon, and Siluro-Devonian injection interval for Wildcat AGI #1 and AGI #2 respectively. Chemical data was plotted in a geographical interface and delineated to a 15-mile radius around the Wildcat site to fully constrain each formation's geochemical signature.

3.4.1 Bell-Cherry Canyon

There are 4 wells with analyses collected from the Bell Canyon or Cherry Canyon within approximately 10 to 14 miles of WC AGI #1. Samples taken in the combined Bell-Cherry interval generally fall within a sodium chloride (NaCl) hydrofacies (hydrophilic), and concentrations of total dissolved solids (TDS) range from 223,975 to 317,617 milligram per liter (mg/L); with an average of

255,038 mg/L. High salinity in these formations indicates they are compatible with injection (**Figure 3.4-1; Table 3.4-1**).

3.4.2 Silurian-Devonian

There are 23 wells with analyses collected from the Devonian, Silurian-Devonian, or Fusselman Formations within approximately 4 to 15 miles of WC AGI #2 (Red squares in **Figure 3.4-1**). Similar to the combined Bell-Cherry Canyon Formation, these wells are saline waters. Concentrations of TDS range from 33,791 to 341,260 mg/L with an average of 143,657 mg/L, indicating this interval is also compatible with injection (**Table 3.4-1**).

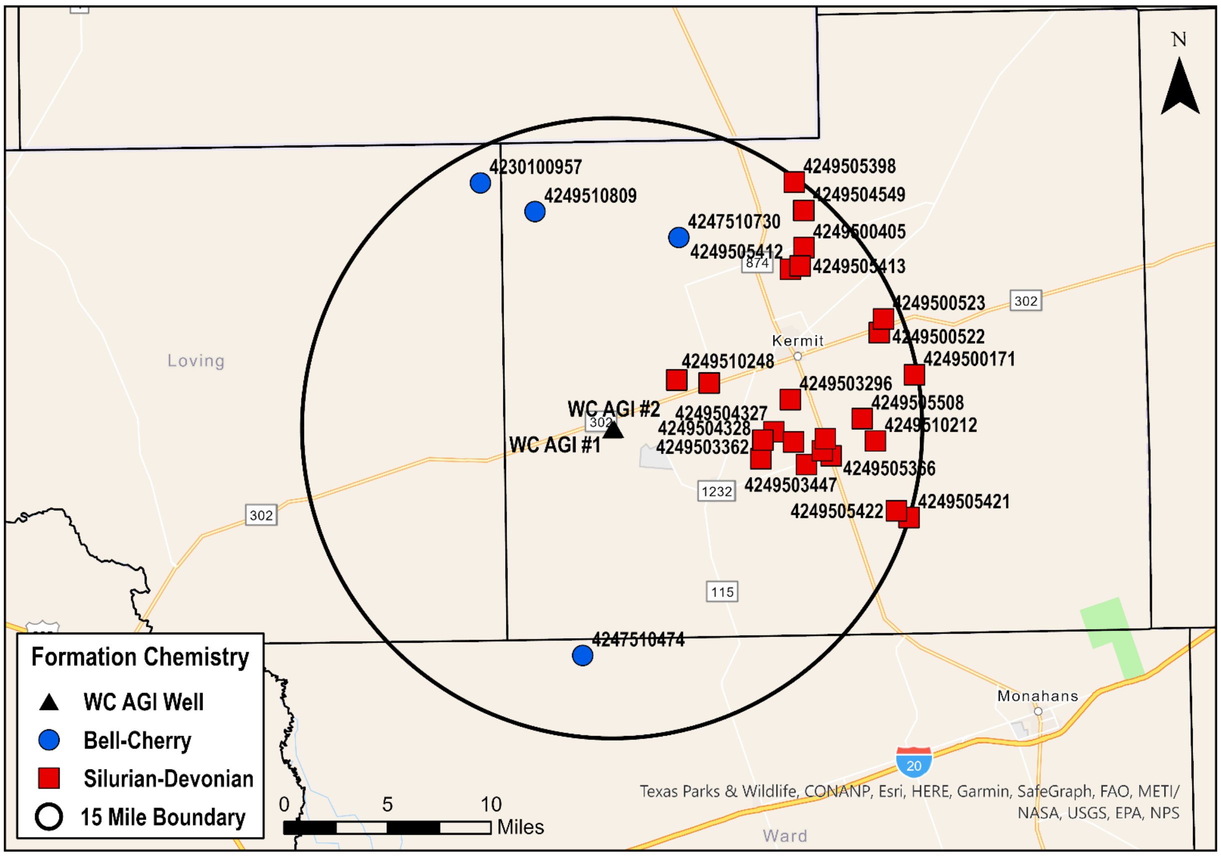


Figure 3.4-1: *Wells with water chemistry in the Bell-Cherry Canyon and Siluro-Devonian Formations within a 15-mile radius of the Wildcat AGI #1 well from the U.S. Geological Survey National Produced Waters Geochemical Database. Data show these formations are NaCl waters with average TDS of 143,657 to 255,038 mg/L.*

***Table 3.4-1**: Wells with water chemistry in the Bell-Cherry Canyon and Siluro-Devonian Formations within a 15-mile radius of Wildcat AGI #1 well from the USGS National Produced Waters Geochemical Database.*

API	LAT	LONG	FORM	HCO_3	Ca	Mg	KNa	Cl	SO_4	TDS
4247510730	31.9322	-103.1808	Bell Cyn	12	5640	1239	116824	192354	1563	317617
4249510809	31.952	-103.2988	Bell Cyn	61	34080	4666	55675	159557	220	254259
4249510809	31.952	-103.2988	Cherry Cyn	293	32160	4374	56252	156011	290	249380
4230100957	31.9728	-103.3435	Cherry Cyn	44	17532	2498	67470	142163	250	229957
4247510474	31.6399	-103.2654	Cherry Cyn	50	17100	2190	66060	138000	575	223975
4249500405	31.9236	-103.078	Devonian	8	21500	4519	64750	147500	938	251600
4249500522	31.863	-103.0173	Devonian	236	2880	933	14910	30040	525	49524
4249500523	31.8725	-103.0136	Devonian	93	14650	2989	61850	129200	1140	209922
4249503296	31.8171	-103.0914	Devonian	1347	12410	1799	10290	40390	2904	69140
4249503296	31.8171	-103.0914	Devonian	97	14610	4052	36590	92530	2480	150359
4249503296	31.8171	-103.0914	Devonian	145	14510	4163	36590	92830	2520	150758
4249503296	31.8171	-103.0914	Devonian	80	14610	4153	36790	92830	2500	150963
4249503296	31.8171	-103.0914	Devonian	122	14600	4028	37050	92940	2437	151177
4249503362	31.7759	-103.1165	Devonian	352	10780	2806	6470	36010	1403	57821
4249503447	31.7713	-103.0791	Devonian	635	2900	300	35500	60000	475	99810
4249505366	31.7771	-103.0587	Devonian	151	11804	2578	59112	118202	1703	193550
4249505421	31.7328	-102.9956	Devonian	342	1696	425	10281	20048	610	33791
4249505421	31.7328	-102.9956	Devonian	130	5686	1361	51377	92215	1394	152221
4249505421	31.7328	-102.9956	Devonian	61	5454	1437	61502	106955	2301	177714
4249505422	31.7377	-103.0059	Devonian	309	5518	1166	33166	62550	1670	104571
4249505508	31.8028	-103.0326	Devonian	509	8424	2239	45971	90239	1134	147931
4249510212	31.787	-103.0221	Devonian	758	4696	1379	33270	62030	1583	103716
4249500171	31.8329	-102.989	Fusselman	100	19200	1180	30600	84000	795	136000
4249500556	31.7808	-103.0659	Fusselman	362	4232	881	29090	53850	2857	91273
4249502061	31.7892	-103.0632	Fusselman	148	6960	4440	118800	208800	2112	341260
4249504327	31.7947	-103.1054	Fusselman	458	4244	706	29620	53810	1568	90406
4249504328	31.789	-103.1145	Fusselman	427	4236	1016	45650	78800	2420	132549
4249505210	31.7873	-103.0894	Fusselman	849	10640	945	24780	59440	460	97114
4249505412	31.9086	-103.0894	Fusselman	202	1733	536	48589	73421	4400	128881
4249505413	31.9108	-103.0814	Fusselman	435	19550	3933	72560	156400	1012	253890
4249505413	31.9108	-103.0814	Fusselman	454	6036	1031	30774	59307	2125	99727
4249505413	31.9108	-103.0814	Fusselman	252	16030	2473	79570	156800	2118	257243
4249510248	31.8322	-103.1845	Fusselman	706	499	386	91284	139300	4317	236491
4249504549	31.9496	-103.0776	Silurian	307	7323	2041	35905	71792	2524	119609
4249505234	31.8297	-103.1579	Silurian	327	4758	962	31960	59200	1625	98832
4249505398	31.9697	-103.085	Silurian	542	7837	1238	23942	69576	1615	115519

3.5 Groundwater Hydrology in the Vicinity of the Wildcat Injection Site

Data collected from the Texas Water Development Board's (TWDB) Groundwater Database and Submitted Driller Report Database indicate there are 13 freshwater wells located within a two-mile radius of the WC AGI #1 well, with 6 wells within half a mile (**Figure 3.5-1**). All water wells within the two-mile radius are shallow, collecting water from 100 to 600 feet depth in Pecos Alluvium and Triassic redbeds of the Dockum Group (Garza and Wesselman, 1963; Ashworth, 1990; Bradley and Kalaswad, 2003). Well use is typically for domestic or livestock use, or for industrial purposes (**Table 3.5-1**). The shallow freshwater aquifers are protected by the surface and intermediate casings and cements in the WC AGI #1 well (**Appendix 1**). While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

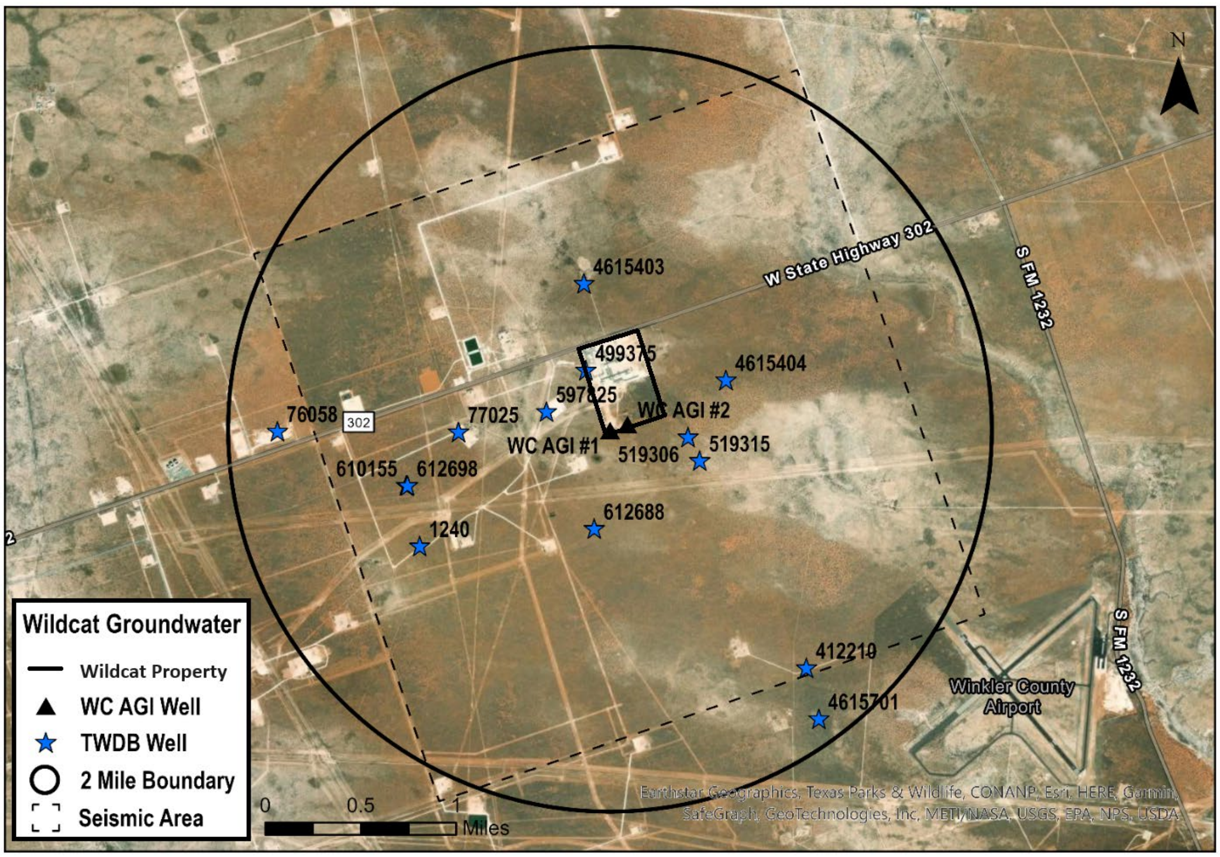


***Figure 3.5-1**: Groundwater wells within a 2-mile radius of the Wildcat AGI #1 well with data from the Texas Water Development Board (TWDB) Groundwater Database (GWDB) and Submitted Driller Report (SDR) Database.*

Table 3.5-1: *Groundwater wells within a 2-mile radius of the Wildcat AGI #1 well with data from the Texas Water Development Board (TWDB) Groundwater Database (GWDB) and Submitted Driller Report (SDR) Database. Well depth is from 100 to 600 ft. and use is typically for domestic or livestock use, or for industrial purposes.*

Well/Report ID	Owner	Water Use	Latitude (Decimal Deg)	Longitude (Decimal Deg)	Well Depth (ft)
4615701	L W Anderson	Stock	31.776944	-103.220555	176
4615404	C E Wilson	Stock	31.802778	-103.228333	290
4615403	L W Anderson	Stock	31.810278	-103.240834	184
1240	Penwell energy	Industrial	31.790556	-103.255834	350
76058	Haley Brine Corp	Industrial	31.799445	-103.268333	280
77025	Chesapeake Operating Inc.	Rig Supply	31.799167	-103.252223	350
412210	XRI	Fracking Supply	31.780833	-103.221603	600
499375	Targa Resources	Industrial	31.8037	-103.2408	400
519306	Kermit Facility	Monitor	31.7985	-103.2318	100
519315	Kermit Facility	Monitor	31.7967	-103.2308	100
597825	Lozoya General Contractors	Domestic	31.800611	-103.244361	310
610155	HPB Construction , Inc	Domestic	31.795167	-103.256944	269
612688	HPB Construction , Inc	Industrial	31.791667	-103.240278	300
612698	HPB Construction , Inc	Industrial	31.795167	-103.256833	308

3.6 Historical Operations

3.6.1 Wildcat Gas Processing Plant

In May 2017, Targa revealed its intentions to construct a new facility and extend the company's gathering presence within the Permian Delaware system. The initiative comprised the development of a novel 250 MMSCFD cryogenic processing plant. Operations at the Plant started in 2018.

The TRRC issued to Targa permit No. 15903 that authorizes the disposal of non-hazardous oil and gas waste by injection into a porous formation not productive of oil and gas, specifically targeting the Bell Canyon and Cherry Canyon formations in the War-Wink (Cherry Canyon) Field, Winkler County, District 08. Key details of the permit include the well identification (WC AGI #1) and the permitted fluids (CO_2, H_2S, and residual hydrocarbons).

The permit was approved and issued on December 10, 2018, marking a significant milestone in the operational history of the Plant.

Special conditions attached to the permit include provisions for the injection of hydrogen sulfide in accordance with Statewide Rule 36(c)(10)(A) and guidelines for wells with long string casing or open hole completions. Standard conditions encompass requirements such as injection through the tubing set on a packer, notification to the District Office for various well operations, wellhead equipment specifications, annulus pressure tests, and monthly monitoring and reporting of injection pressure and volume.

In August, 2022 the TRRC issued an amendment to WC AGI #1 permit No. 15903 that specifies that the packer must be new and be set no higher than 100 feet above the top of the permitted interval with a maximum surface injection pressure of liquid of 2,980 psi.

In 2023, on behalf of TND, Geolex submitted an application seeking approval for the drilling, completion, and operation of an additional TAG disposal well, WC AGI #2, under Underground Injection Control (UIC) Class II Waste regulations at the Targa Wildcat Gas Processing Plant. The well is designed to dispose of CO_2 and H_2S generated by plant operations. The application was granted in 2023 and adheres to TRRC guidelines, requesting a maximum allowable surface injection pressure of 8,950 psi based on approved determination methods. Geologic studies support the suitability of the proposed injection zones for containing TAG volumes within the recommended maximum injection pressures.

Figure 3.6-1 shows a process block flow diagram of the WC AGI #1 and WC AGI #2 wells.

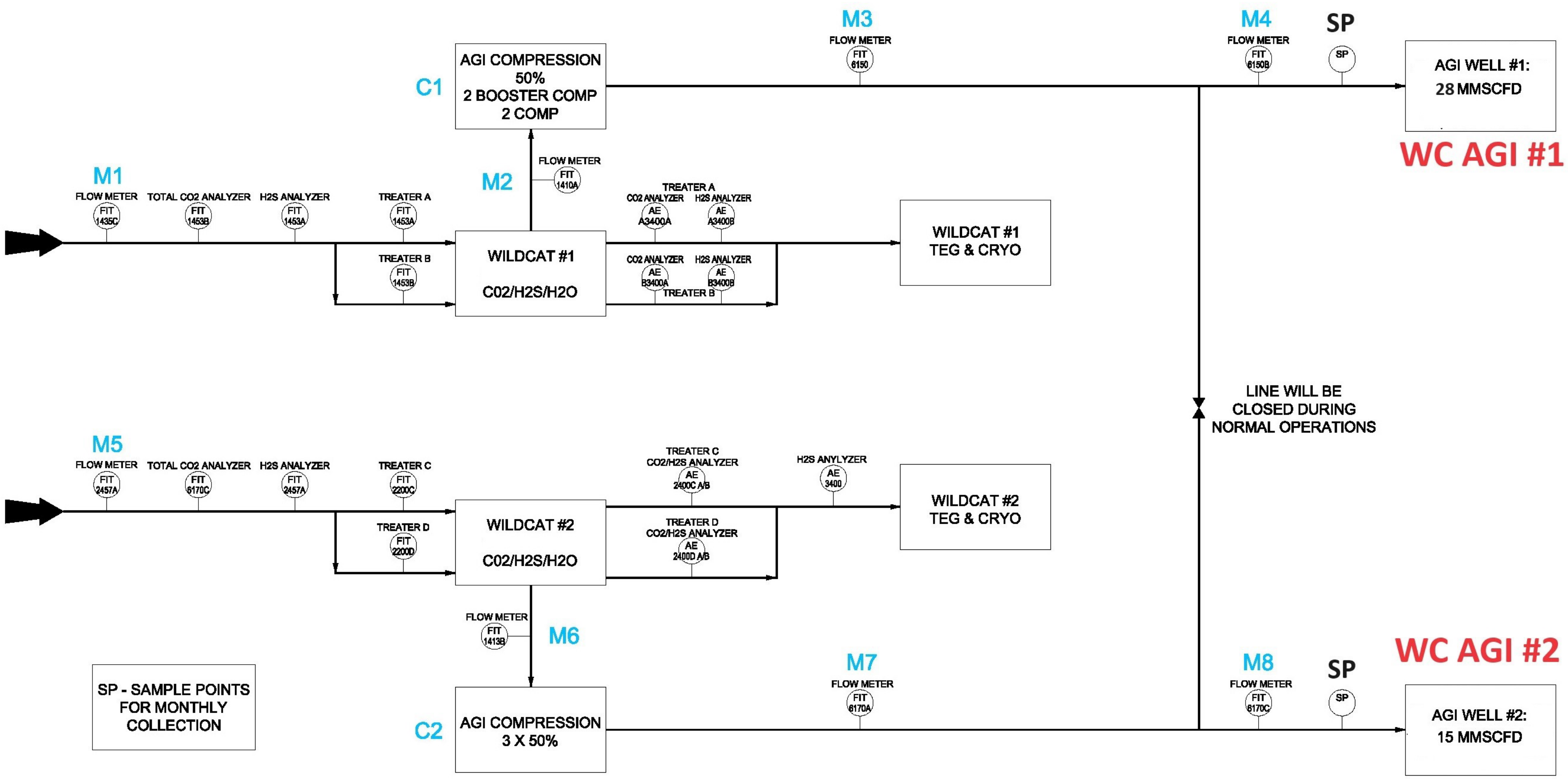


***Figure 3.6-1**: Process Block Flow Diagram for operating WC AGI #1 and permitted WC AGI #2 with: M1 – M8: volumetric flow meters and C1 and C2: compressors. Receiving flow meter corresponds to meters M1 and M5. Volumetric flow meters before injection corresponds to meters M4 and M8. SP are sampling points after the treatment units and before the compressors. There is a valve in the vertical flow between the two injection wells which is closed during normal operations.*

3.6.2 Operations in the Vicinity of the Wildcat Gas Processing Plant

TRRC records and Enverus database identify a total of 23 oil- and gas-related well records within the Maximum Monitoring Area (MMA). **Figure 3.6-2** shows the geometry of producing and injection wells within the MMA with their current status. **Appendix 3** summarizes the relevant information for those wells.

All wells within the MMA that are either producing, injecting, plugged and abandoned (P&A), permitted or Drilled but uncompleted (DUC) are considered in the identification and evaluation of potential leakage pathways. The closest wells from WC AGI #1 and WC AGI #2 are 4 horizontal wells with API number ending with: 34854, 34855, 34856, 34857 (**Figure 3.6-2**). For easier identification, only the last 5 digits of the API are mentioned to refer to wells. The closest wells are permitted oil and gas wells targeting the Wolfcamp with expected True Vertical Depth (TVD) of 12,500 ft. Their surface hole locations (SHL) are North (N) of the Plant but the bottom hole locations (BHL) are South (S). If drilled, these horizontal wells will pass under the Plant.

The next closest well is about 0.25-mile South-West (SW) of WC AGI #1. It is a gas producing well with a TVD of 15,800 ft and it is completed in the Wolfcamp (API 33237).

Then, 3 wells located 0.4-mile North-East of WC AGI #2 are plugged and abandoned (P&A) because they were dry. Still East of the Plant and next to these 3 wells, there is an oil producing horizontal well completed in the Wolfcamp with a TVD of 12,204 ft.

The above-mentioned wells are the closest wells within a 0.5-mile buffer zone around WC AGI #1 and WC AGI #2. There are 23 wells within the MMA that will be discussed in section 5.

Within the 23 wells, 10 of them are horizontal wells all targeting the Wolfcamp formation. Five of these horizontal wells are producing oil and gas and have an average TVD of 12,216 ft. Four are permitted and are planned to be drilled under the Plant. The last one has been drilled 0.6-mile from the Plant.

Still within these 23 wells, 7 are plugged and abandoned wells and targeted various formations. There are 2 vertical producing wells, 1 is in the Wolfcamp producing oil with TVD of 15,800 ft, and the other is in the Atoka producing gas with a TVD of 16,746 ft (**Table 3.6-1**).

Table 3.6-1*: Well status within the Maximum Monitoring Area (MMA)*

Well Status	Count of API
Drilled	1
Inactive Producer	1
Injecting	1 (WC AGI #1)
P & A	7
Permitted	4
Producing	8
Permitted	1 (WC AGI #2)
Grand Total	**23**

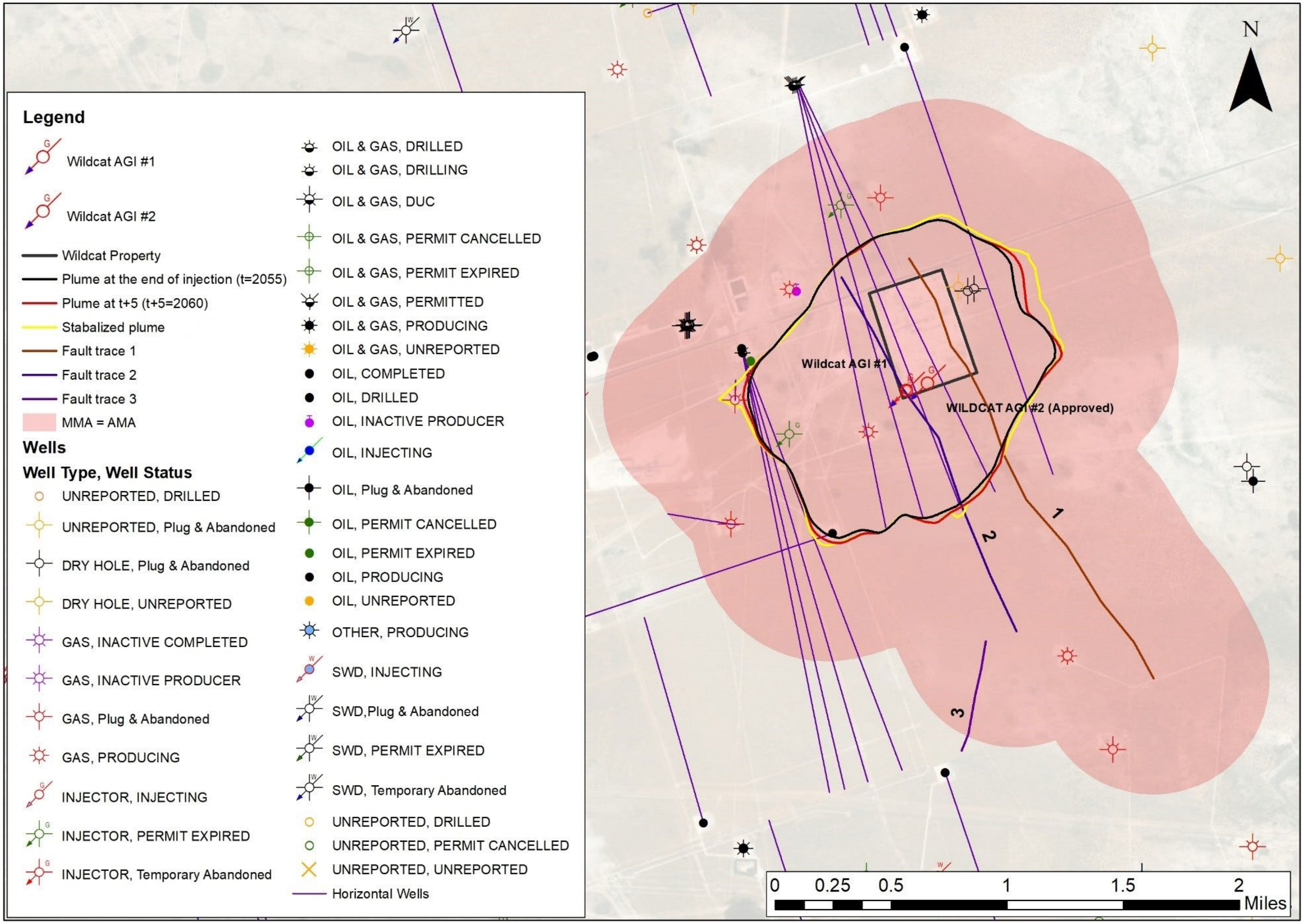


Figure 3.6-2: *Location of all oil- and gas-related wells within the Maximum Monitoring Area (MMA, in red) for the WC AGI #1 and #2 wells.*

3.7 Description of Injection Process

The Wildcat Gas Processing Plant, including the existing WC AGI #1 well, is in operation and staffed 24-hours-a-day, 7-days-a week. The Plant operations include gas compression, treating and processing. The Plant gathers and processes produced natural gas from the Permian Delaware system, Texas and New Mexico. The Permian Delaware system comprises around 7,200 miles of natural gas gathering pipelines and 17 processing plants, collectively capable of processing 3,560 MMSCFD.

Once gathered at the Plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the Plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way.

TAG from the Plant's sweeteners are routed to a central compressor facility. Compressed TAG is then routed to the wells via high-pressure rated lines. The approximate composition of the TAG stream is: 80% CO_2, 20% H_2S, with Trace Components of C_1 – C_6 (methane – hexane) and Nitrogen. The anticipated duration of injection is 30 years.

3.8 Reservoir Characterization Modeling

The modeling and simulation focused on the legacy and forecasting injection of the WC AGI #1 well (API 42-495-34153) to the Bell Canyon and Cherry Canyon formations and that of WC AGI #2 well (API 42-495-34929) to the Fusselman and Montoya formations for the purpose of treated acid gas (TAG) disposal.

The WC AGI #1 well (API 42-495-34153) and the WC AGI #2 well (API 42-495-34929) are acid gas injection (AGI) wells approved by the Texas Railroad Commission of Texas (TRRC). These injectors are simulated in the model under an approved disposal timeframe and maximum allowable injection pressure. WC AGI #1 well is completed in the Bell Canyon and Cherry Canyon formations. WC AGI #2 well is not drilled but simulated according to the applications approved by the TRRC. WC AGI #2 injects in both the Fusselman and Montoya formations between approximately 17,900 feet to 19,200 feet Measure Depth (MD), with the total vertical depth at 21,450 feet.

Schlumberger's Petrel® (Version 2023.1) software was used to construct the geological models used in this work. Computer Modeling Group (CMG)'s CMG-GEM® (Version 2023.10) was used to was used in the reservoir simulations presented in this MRV plan. CMG-WINPROP® (Version 2023.10) was used to perform calculation through Equation of States and properties interactions among various compositions to feed the hydrodynamic modeling performed by CMG-GEM®. The hydrodynamical model considers aqueous, gaseous, and supercritical phases. It simulates the storage mechanisms, including structural trapping, residual gas trapping, and solubility trapping. Injected TAG may exist in the aqueous phase as a dissolved state and the gaseous phase as a supercritical state. The model was validated by matching the historical injection data of WC AGI #1 well and will be reevaluated periodically as required by the State's UIC regulations.

The static model is constructed with well tops and licensed 3D seismic to interpret and delineate the structural surfaces of formations including containing Salado-Castile, Lamar limestone, Bell Canyon, Cherry Canyon, Brushy Canyon, Bone Spring, Wolfcamp, Woodford, Siluro-Devonian, Fusselman, and Simpson. The geologic model covers 3.3 miles by 3.0 miles area in the lateral expand (**Figure 3.8-1**). No distinctive geological structures, such as faults, are identified in shallow injection zones - Cherry Canyon and Bell Canyon formations of the model boundaries. However, 3D seismic data analysis identified 6 potential major faults passing through the lower injection interval for potential WC AGI #2 (**Figure 5.3-1**). In addition to fault slip potential (FSP) analysis for WC AGI #2, 2 scenarios of the faulting system transmissibility were analyzed to predict the possible impact of the proposed TAG injection.

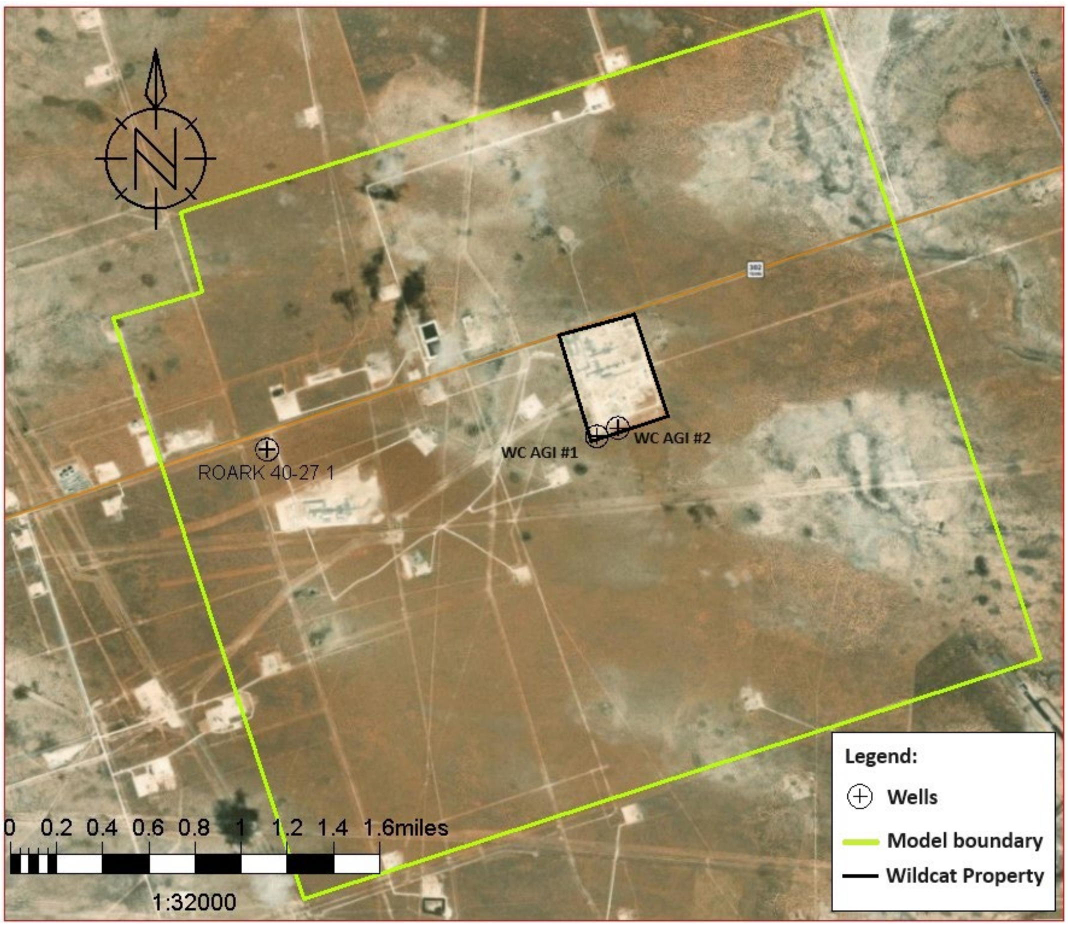


Figure 3.8-1: *Map view of the simulation model of the WC AGI #1 and #2 wells. The boundary of the model (green line) is approximately 3.3 mi (W-E) by 3.0 mi (S-N).*

The model is gridded with cells that have the following dimensions: 210 x 203 x 34, totaling 1,449,420 cells. The average cell dimension of the active injection area is 100 feet square. **Figure 3.8-2** shows the simulation model in 3D view. The porosity and permeability of the model are populated through existing well logs. The range of the porosity is between 0.01 to 0.31. The initial permeability is interpolated between 0.02 to 155 millidarcy (mD), and the vertical permeability anisotropy is 0.1. (**Figure 3.8-3 and Figure 3.8-4**). These values have been validated and calibrated with the historical injection data of WC AGI #1 well since 2019 as shown in **Figures 3.8-5 and 3.8-6**.

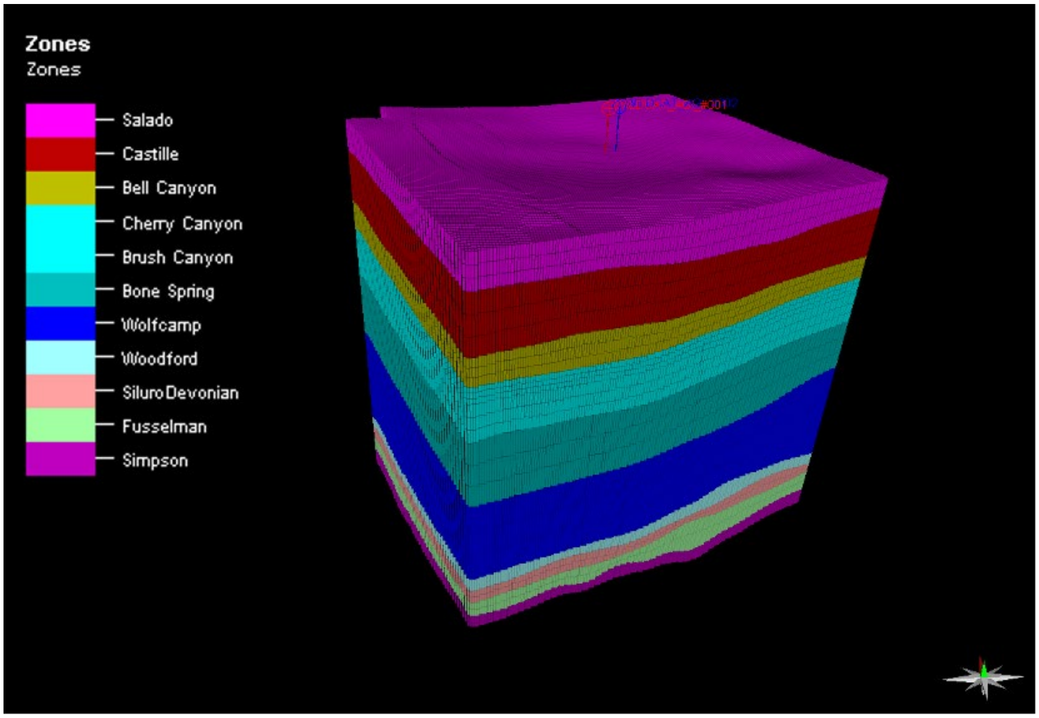


Figure 3.8-2: *3D view of the simulation model of the WC AGI #1 and #2 wells, containing Salado-Castile, Lamar limestone, Bell Canyon, Cherry Canyon, Brushy Canyon, Bone Spring, Wolfcamp, Woodford, Siluro-Devonian, Fusselman, and Simpson formations.*

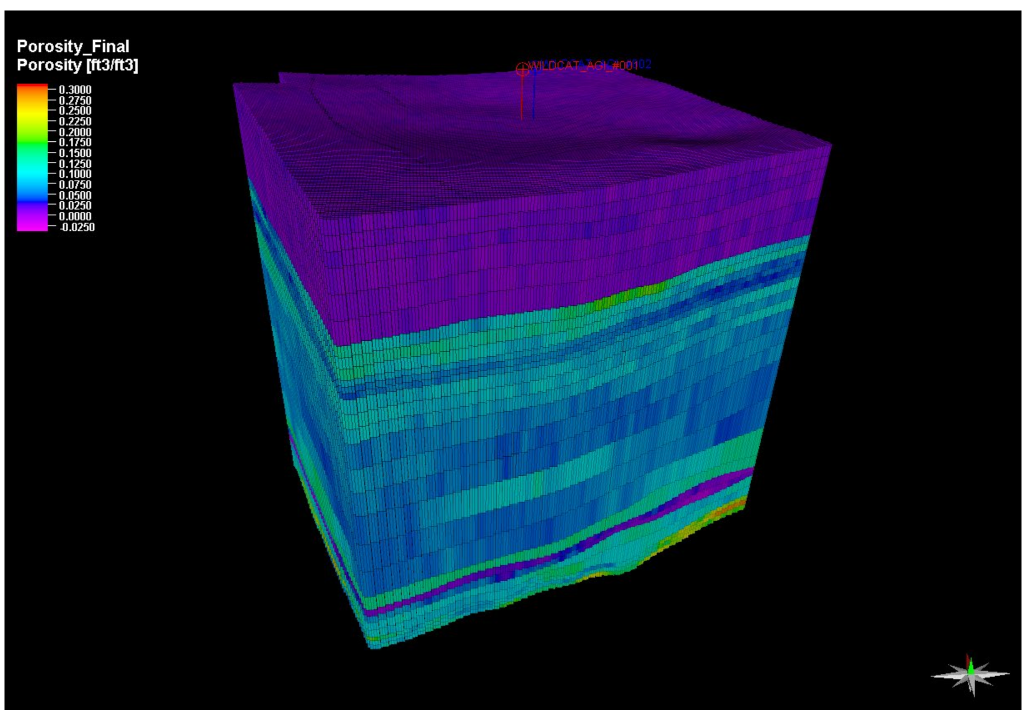


Figure 3.8-3: Porosity estimation using available well data for the simulation domain.

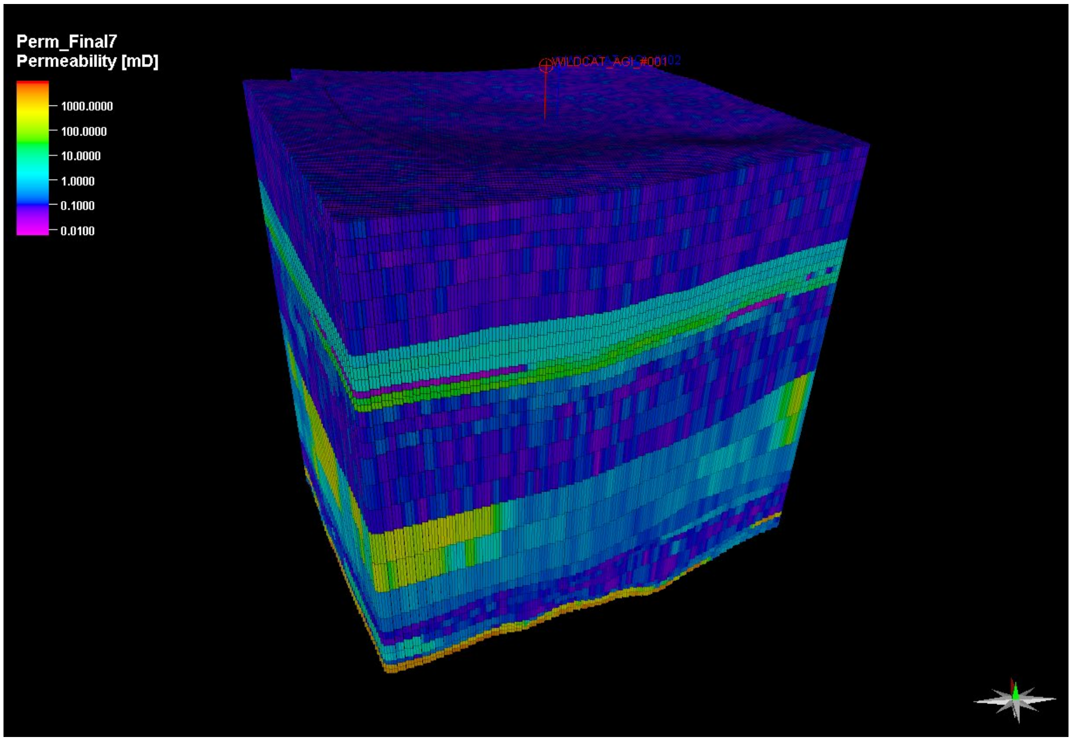


***Figure 3.8-4**: Permeability estimation using available well data for simulation domain.*

The simulation model is calibrated with the injection history of WC AGI #1 well since 2019. Simulation studies were further performed to estimate the reservoir responses when predicting TAG injection for 30 years through both WC AGI #1 well (2019 – 2049) and potentially WC AGI #2 (2025 - 2055). During the prediction phase, WC AGI #1 and #2 are simulated to inject with the approved injection rate and pressure permitted by TRRC (**Table 3.8-1**). The simulation is terminated in the year 2255 to estimate the maximum impacted area post-injection.

***Table 3.8-1**: Well operations input of reservoir simulation*

API	Well Name	Injection Starting Date	Shut-In Date	Permitted Injection Rate	Permitted Injection Pressure	UIC Permitting Agency
42-495-34153	WC AGI #1	2019	2049 (expected)	28 MMSCFD (Reservoir Condition)	2,980 psi	TXRRC
42-495-34929	WC AGI #2	2025 (expected)	2055 (expected)	15 MMSCFD (Surface Condition)	8,950 psi	TXRRC

During the calibration period (2018 – 2023), the historical injection rates were used as the primary injection control, and the maximum bottom hole pressures (BHP) were imposed on wells as the constraint, calculated based on the approved maximum injection pressure. This restriction is also estimated to be less than 90% of the formation fracture pressure calculated at the shallowest perforation depth of each well to ensure safe injection operations. The reservoir properties are tuned to match the historical injection until it is reasonably matched. **Figure 3.8-5** shows the historical injection rates from the WC AGI #1 well in the Bell Canyon and Cherry Canyon formations. **Figure 3.8-6** shows the wellhead injection pressure response of WC AGI #1 during the history matching phase.

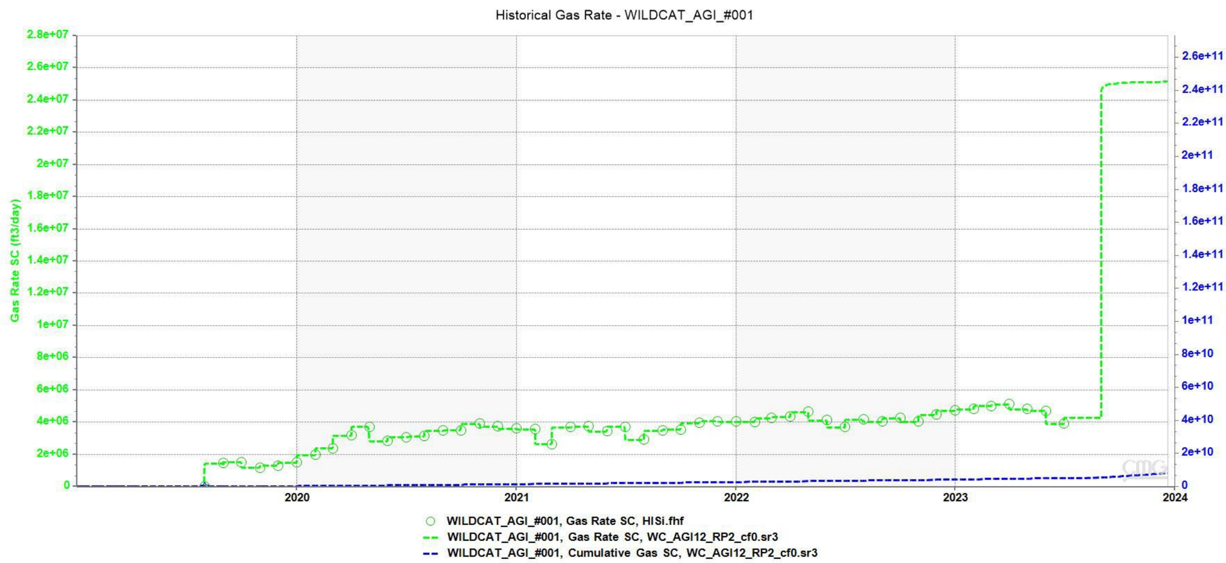


Figure 3.8-5: Historical injection rate and total gas injected from WC AGI #1 well (2019 to 2023)

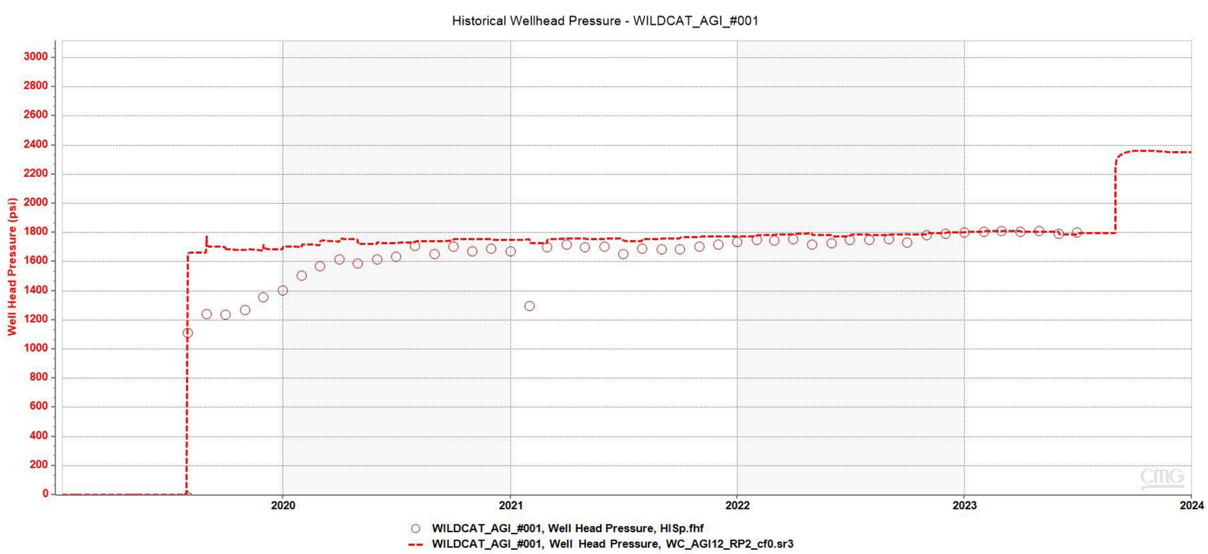


Figure 3.8-6: Historical injection pressure of WC AGI #1 well (2019 to 2023)

During the forecasting period, the injection rate profiles indicate that the Cherry Canyon and Bell Canyon formations may store the TAG stream freely from WC AGI #1. It is the same for the simulated WC AGI #2 well in the Fusselman formation (**Figure 3.8-7**). Therefore, the modeling results indicate that the proposed shallow and deep storage intervals can store and contain the proposed gas volume without violating the permitted rate and pressure.

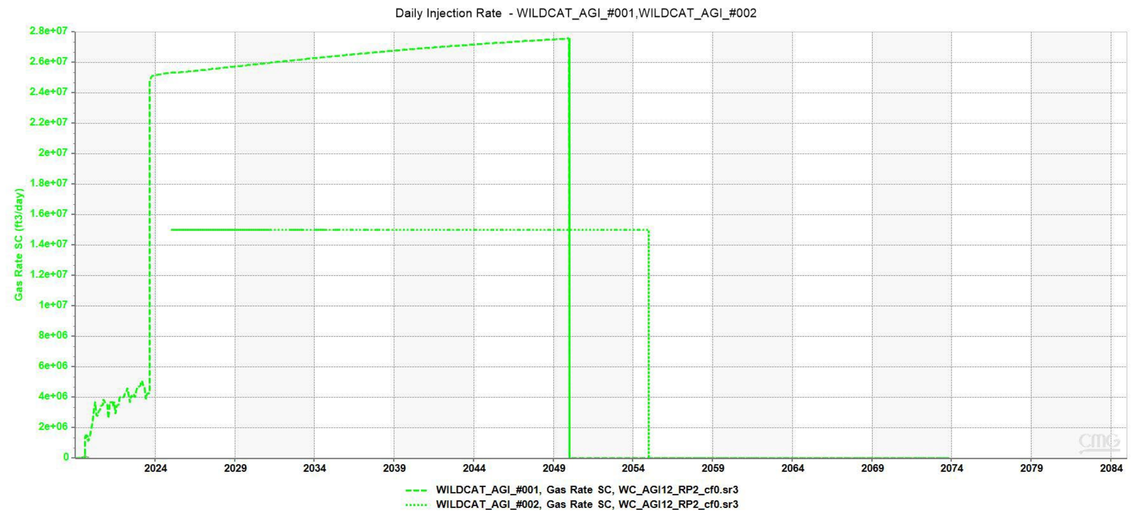


Figure 3.8-7: *Prediction of surface-condition gas injection rate of WC AGI #1 (dashed) and #2 (dotted) wells (2018 to 2054).*

Figure 3.8-8 shows the extent of the plume migration in a map view at 9 key time steps in the years 2025, 2030, 2035, 2040, 2045, 2050, 2055, 2060, and 2065. The extent of the plume is notably restricted, with its maximum diameter measuring 1.47 miles at the end of injection. The injected gas remained trapped in the reservoir and no significant plume migrations were observed.

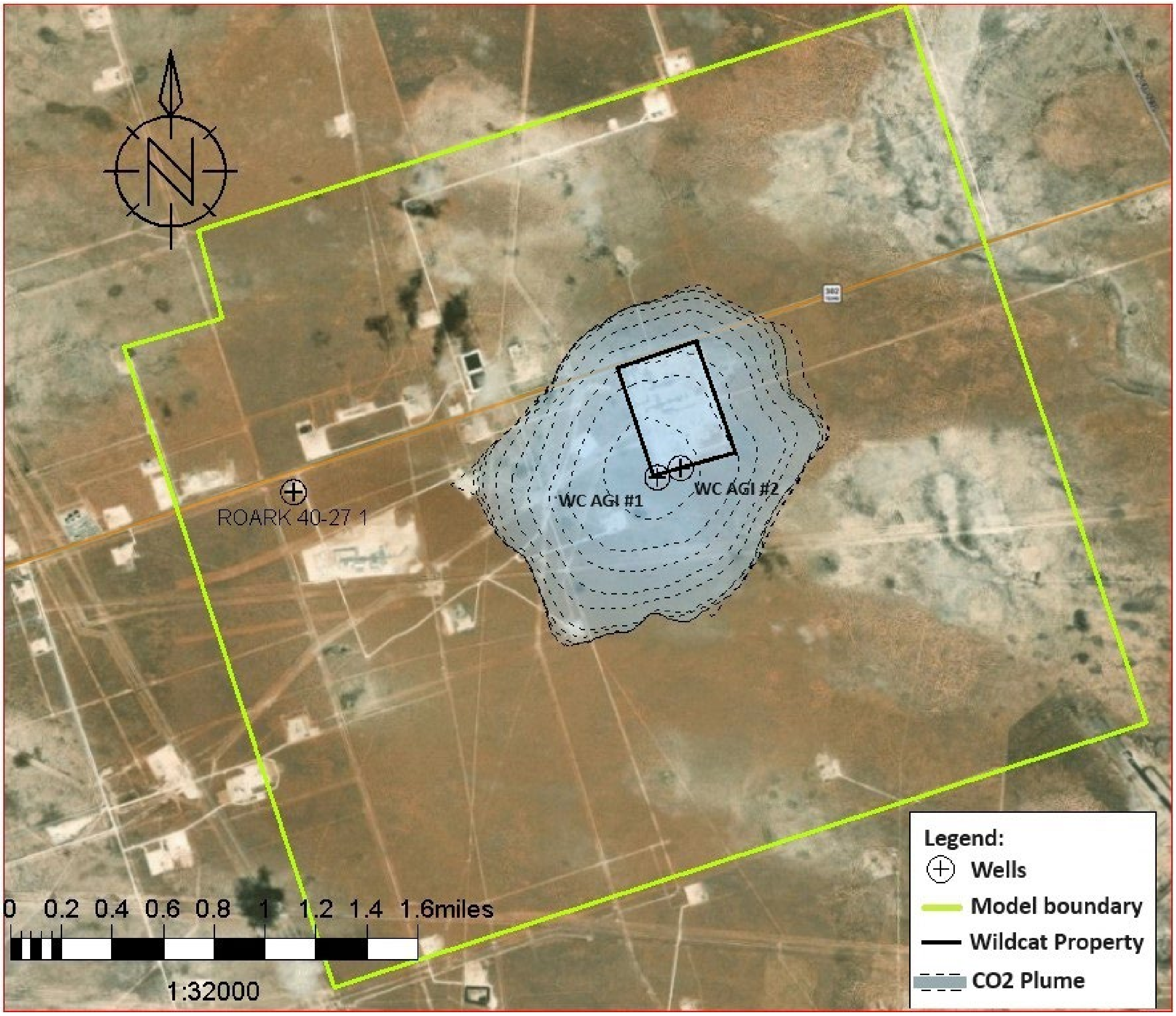


Figure 3.8-8: *TAG plume (represented by gas saturation) at the years 2025, 2030, 2035, 2040, 2045, 2050, 2055 (end of injection), 2060, and 2065 in map view.*

A closer inspection of scenarios with the faulting system to be open (transmissibility = 1) or closed (transmissibility = 0) indicates that the conditions of the faults will not significantly alter the distribution of injected TAG. As shown in **Figure 3.8-9**, when the faulting system is assumed to be closed, TAG plume in the deeper interval appears to be more confined laterally as the near-vertical faults stalled the expansion across the faulting interfaces.

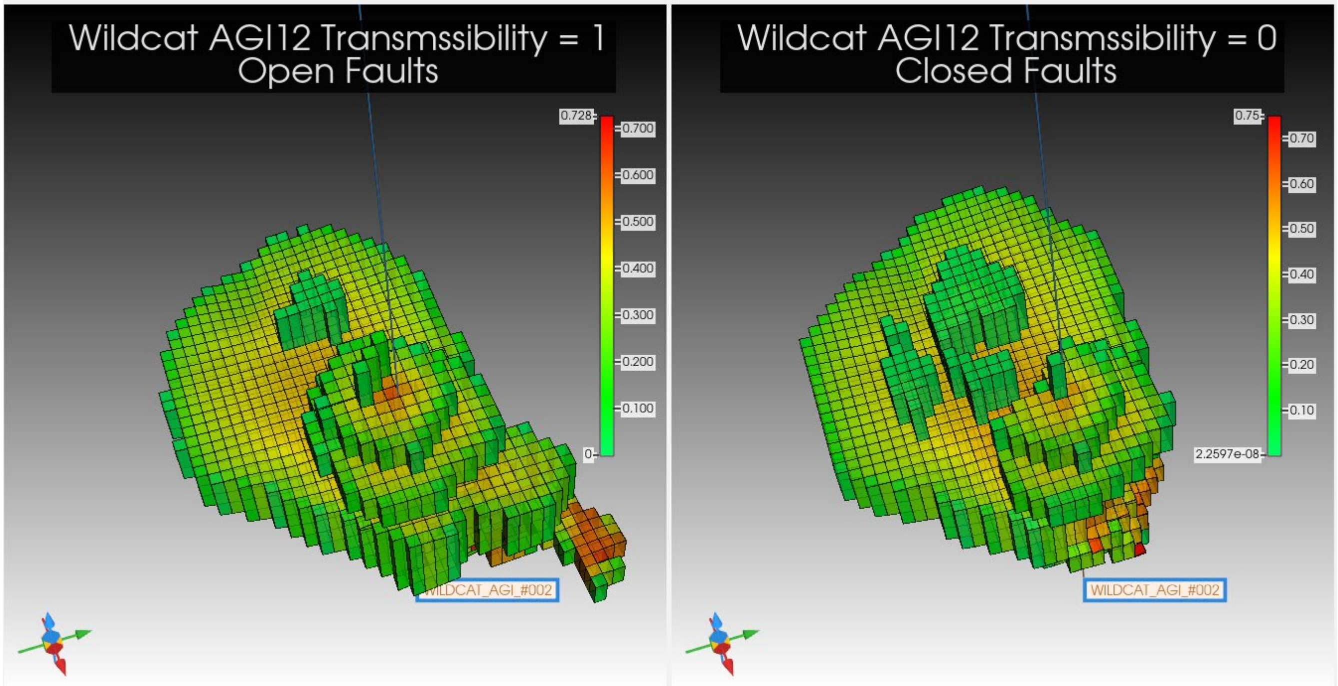


Figure 3.8-9: *Display the free phase TAG injected by WC AGI #2 well in the Fusselman and Montoya formations at the end of 30-year active injection (2055) in 3D view. Two scenarios represent the condition when the faulting system assumed to be open (left) or closed (right)*

In summary, after careful reservoir engineering review and numerical simulation study, it shows that the Bell Canyon and Cherry Canyon formations of the shallow storage interval and the Fusselman and Montoya formations of the deep storage interval can receive treated acid gas (TAG) at the proposed injection rates and permitted maximum surface injection pressures approved by the Railroad Commission of Texas. The formation will safely contain the injected TAG volume within the proposed injection and post-injection timeframe. The proposed injection well will allow for the sequestration while preventing associated environmental impacts.

4 Delineation of the Monitoring Areas

In delineating the maximum monitoring area (MMA) and the active monitoring area (AMA), Targa began by assessing the information provided in the UIC Class II permit application. The modeling described in Section 3.8 indicates that the free phase TAG plume will be contained within the MMA/AMA for the 30-year injection period plus the 45-year post injection monitoring period.

In determining the monitoring areas below, the extent of the TAG plume is equal to the superposition of plumes in any layer for any of the model scenarios described in Section 3.8.

4.1 MMA – Maximum Monitoring Area

As defined in Section 40 CFR 98.449 of Subpart RR, the maximum monitoring area (MMA) is "equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." A CO_2 saturation threshold of 1% is used in the reservoir characterization modeling in Section 3.8 to define the extent of the plume.

According to the reservoir modeling results, after 45 years of post-injection monitoring (year=2100), the injected gas remained in the reservoir and no expansion of the TAG footprint was observed after 2100. Therefore, the plume extent at year 2100, plus a one-half-mile buffer, is the initial area with which to define the MMA. The plume at the end of injection (year=2055) and the stabilized plume (year=2100) are mapped in **Figure 4.2-1**.

In addition, according to EPA technical support document: "The buffer is intended to encompass leaks that might migrate laterally as they move towards the surface. EPA has determined that a buffer zone of at least one-half mile will have an acceptable probability of encountering leaks in many circumstances." Therefore, Targa considered the identified faults to define the MMA and extended the MMA to incorporate the faults plus a one-half-mile buffer around the faults. By doing so, the MMA encompasses the union of two areas:

1. The area covered by the stabilized plume plus an all-around buffer zone of one-half mile
2. The area covered by the lateral extent of known potential leakage pathways (the trace faults 1 and 2, **Figure 4.2-1**) plus an all-around buffer zone of one-half mile around the traces.

Figure 4.2-1 shows the MMA as defined by Section 40 CFR 98.449 of Subpart RR. The MMA is expected to contain the free phase CO_2 plume once it has stabilized at year 2100 (yellow line **Figure 4.2-1**) and the lateral extent of potential leakage pathway plus a one-half mile buffer.

4.2 AMA – Active Monitoring Area

As defined in Subpart RR, the AMA is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the AMA is established by superimposing 2 areas:

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

(Criteria 2) The area projected to contain the free phase CO_2 plume at the end of year t + 5.

Targa has chosen t=2055, which corresponds to the end of a 30-year injection period, for the purpose of calculating the AMA. The plume at t=2055 is plotted in a black line in **Figure 4.2-1**. The area defined by Criteria 1 is plotted and delineated by a black dotted line in **Figure 4.2-1**. The area corresponding to Criteria 2 is plotted in **Figure 4.2-1** and corresponds to the red line (plume a t+5). According to the superimposition of the areas defined by Criteria 1 and Criteria 2, the AMA will correspond to the area delineated by the black dotted line in **Figure 4.2-1**.

By applying the criteria defined by Subpart RR, Targa estimates that there are no advantages to establishing an AMA that is less than the MMA. The analysis with t=2055 demonstrates that the AMA is contained within the MMA. Therefore, Targa considers the AMA equal to the MMA.

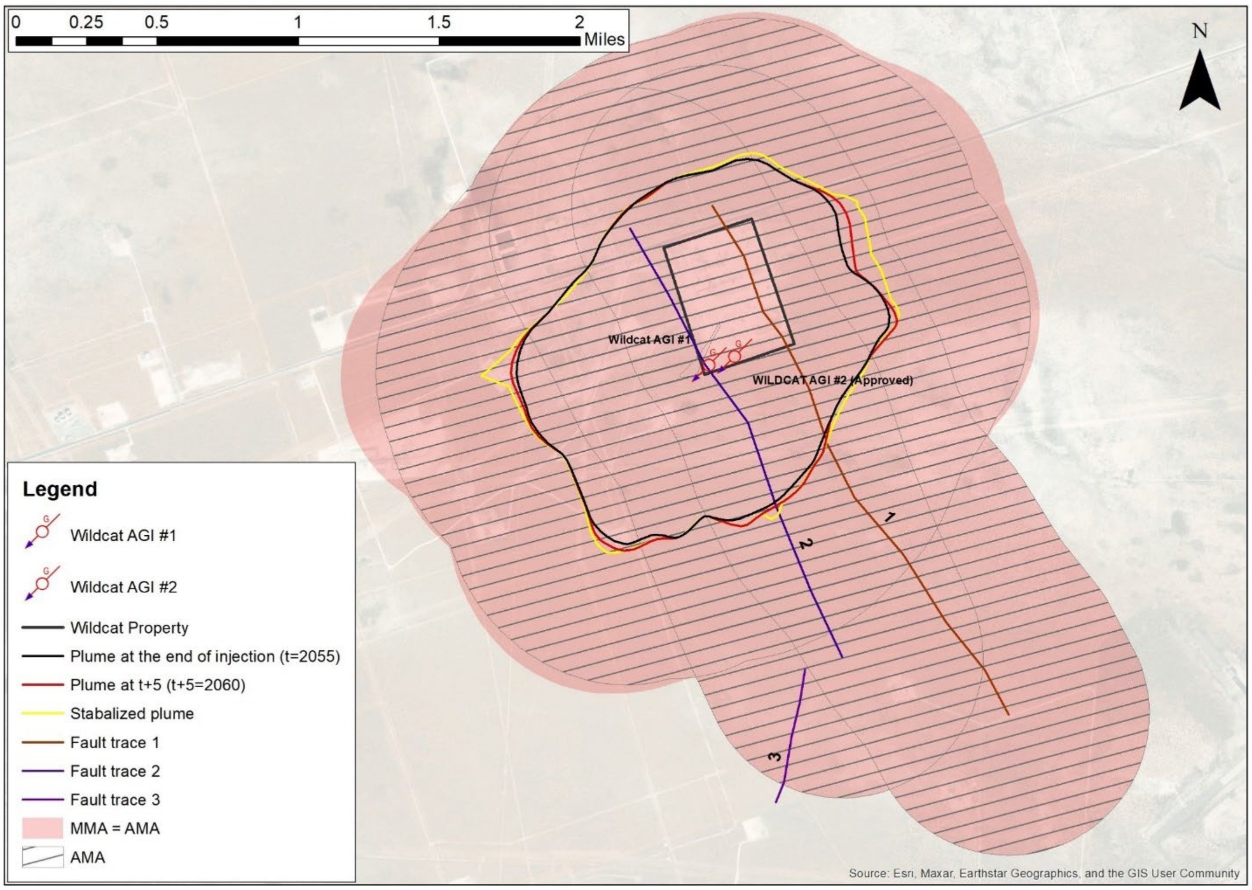


Figure 4.2-1*: Display of the Maximum Monitoring Area (shaded red area) and the Active Monitoring Area (simple black hatch area) for WC AGI #1 and #2. In addition, the plume at end of injection (t), at t+5 and, the stabilized CO_2 plume (yellow line) are plotted.*

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

Subpart RR at 40 CFR 448(a)(2) requires the identification of potential surface leakage pathways for CO_2 in the MMA and the evaluation of the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways.

Through the site characterization required by the application process for Class II injection wells, the site characterization presented in Section 3, and the reservoir modeling described in Section 3.8, Targa has identified and evaluated the following potential CO_2 leakage pathways to the surface:

1. Surface components (pipeline and wellhead)
2. Surrounding oil and gas wells
3. Faults, fractures, and bedding plane partings
4. Leakage through the confining zone
5. Potential leakage due to natural / induced seismicity

To assess the risk of surface emissions through these potential leakage pathways, Targa has notably employed the open-source computational risk assessment tools developed by the National Risk Assessment Partnership (NRAP).

A qualitative evaluation of each of the potential leakage pathways is described in the following paragraphs. Risk estimates were made utilizing the NRAP tools, developed by 5 national laboratories: NETL, Los Alamos National Laboratory (LANL), Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), and Pacific Northwest National Laboratory (PNNL). The NRAP collaborative research effort leveraged broad technical capabilities across the Department of Energy (DOE) to develop the integrated science base, computational tools, and protocols required to assess and manage environmental risks at geologic carbon storage sites. Utilizing the NRAP tool, Targa conducted a risk assessment of CO_2 leakage through various potential pathways including surface equipment, existing and approved wellbores within MMA, faults and fractures, and confining zone formations.

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of the TAG stream, there is a potential for leakage from surface equipment at sour gas processing facilities. To minimize this potential for leakage, the construction, operation, and maintenance of gas plants follow industry standards and relevant regulatory requirements.

Operational risk mitigation measures relevant to potential CO_2 emissions from surface equipment include a schedule for regular inspection and maintenance of surface equipment. Additionally, Targa implements several methods for detecting gas leaks at the surface. Detection is followed up by immediate response. These methods are described in more detail in sections 6 and 7.

The WC AGI #1 injection well and the pipeline that carries CO_2 to it are the most likely surface components of the system to allow CO_2 to leak to the surface. Leakage is most likely to be the result of aging and use of the surface components over time. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable cause of the leakage. Another possible cause of leakage is the release of air through relief valves, which are designed to alleviate pipeline overpressure. Leakage can also happen when the surface components are damaged by an accident or natural disaster, which releases CO_2. Therefore, we infer that there is a potential for leakage via this route.

Depending on the component's failure mode, the magnitude of the leak can vary greatly. For example, a rapid break or rupture could release large amount of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only few quantities of CO_2 over several hours or days. Surface component leakage or venting is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

<u>Likelihood:</u>

Although leakage from surface equipment between the volumetric injection flow meter and the injection wellhead is possible, the mitigative measures described above and in Sections 6 and 7 are in place to minimize the likelihood of a leakage event.

<u>Magnitude:</u>

If a leak from the surface equipment between the volumetric injection flow meter and the injection wellhead occurs it will be detected immediately by the surveillance mechanisms described in Section 6.1 for surface equipment. The magnitude of a leak depends on the failure mode at the point of leakage, the duration of the leak, and the operational conditions at the time of the leak. A sudden and forceful break or rupture may discharge thousands of pounds of CO_2 into the atmosphere before it is brought under control. On the other hand, a gradual weakening of a seal at a flanged connection may only result in the release of a few pounds of CO_2 over a period of several hours or days.

<u>Timing:</u>

During the operation of the injection system, any CO_2 leaks from surface equipment between the volumetric injection flow meter and the injection wellhead will be emitted immediately to the atmosphere. Mitigative measures are in place at the plant to minimize the duration and magnitude of any leaks. Leakage from surface equipment between the volumetric injection flow meter and the injection wellhead will only be possible during the operation of the injection system. Once injection ceases, surface injection equipment will be decommissioned thereby eliminating any potential for CO_2 leakage to the atmosphere.

5.2 Potential Leakage through Surrounding Oil and Gas Wells

Approval and construction of oil and gas-related wells, including injection wells, are regulated by TRRC rules (**Appendix 2**), specifically Rule 13 for casing, cementing, drilling, well control, and completion, which require that wells be constructed in such a manner as to prevent vertical migration of fluids, including gases, behind the casing. Adherence to these requirements will mitigate the risk of potential CO_2 emissions to the surface. In addition, these wells have strict requirements and are actively or will be monitored for integrity on a regular basis.

5.2.1 Potential interaction between WC AGI #1 and WC AGI #2

Acid gas injection wells are designed, constructed, operated, maintained, and continuously monitored to ensure the injected TAG stream is contained within the permitted injection zone. WC AGI #2 is being proposed to be completed at a total depth of 21,450 feet with the primary injection zone intended to be in the Siluro-Devonian units. Details of the proposed well construction are presented in **Appendix 1 Figure 2**. Design, construction, operation, maintenance, and monitoring plans for the injection-zone wells will be developed in accordance with Class II standards. Additionally, Targa has extensive expertise in well construction, operations, maintenance, and monitoring.

The magnitude and timing of such a leak, if it were to occur, would be dependent on the wellbore or cement damage of WC AGI #2. If such an event occurs, the maximum leakage rate of CO_2 through injection wellbore is estimated to be 1.58e-6 kg/s (**Figure 5.2-1**) or 22 kg at year 14, then gradually reduce to 17 kg at the end of monitoring (**Figure 5.2-2**). This amount of leakage is equivalent to 0.000015% of the weight of CO_2 injection per year. Therefore, Targa concludes that the risk of a significant leakage through injection wells event in the Wildcat project area is minimal. As a result, we conclude that the risk of leakage through this pathway is highly improbable.

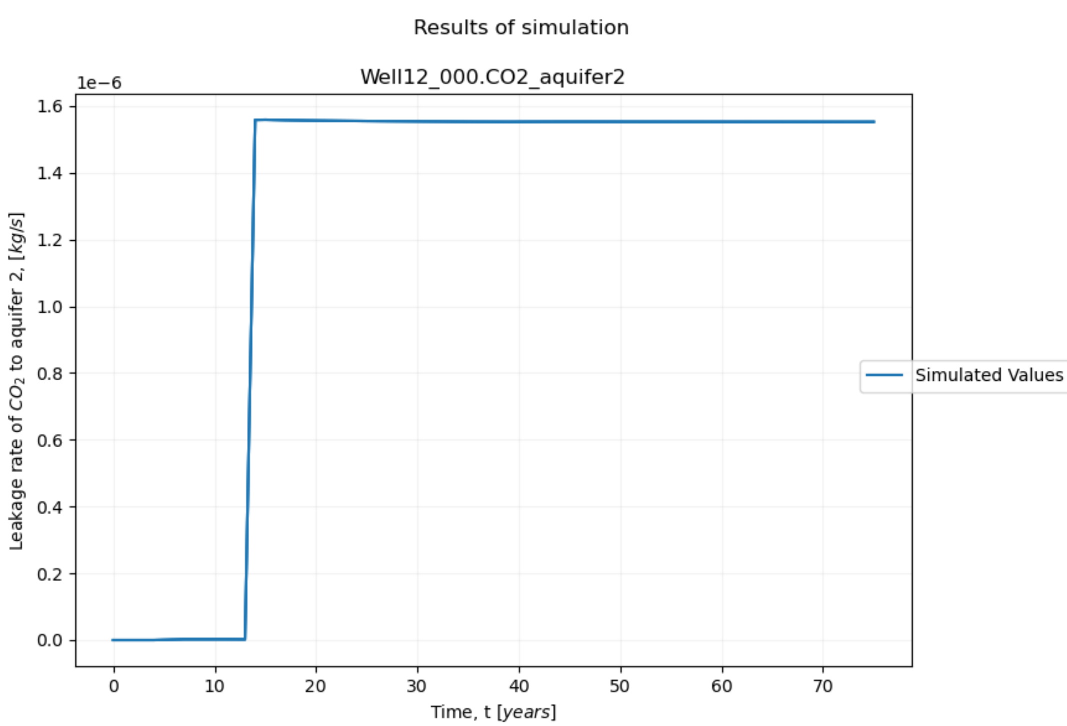


Figure 5.2-1*: Leakage rate quantification simulation using NRAP tools for leakage through nearby Injection well (either WC AGI #1 leak to WC AGI #2 or vice versa)*

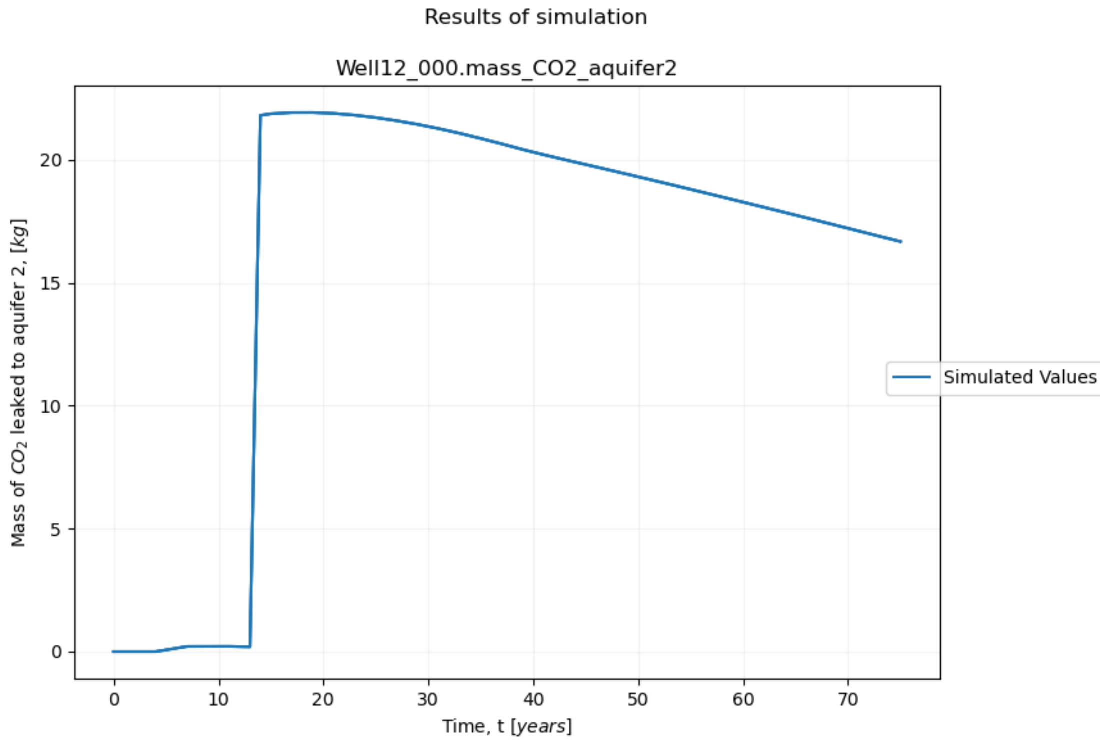


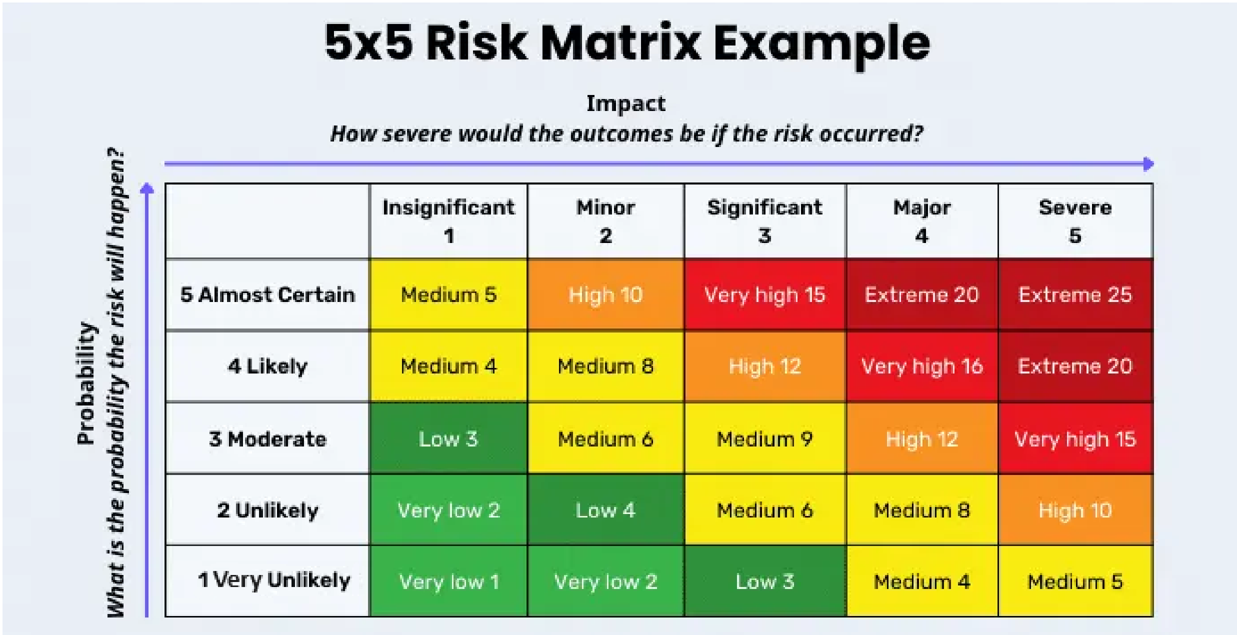
Figure 5.2-2*: Leakage quantification (kg) simulation using NRAP tools for leakage through nearby Injection well (either WC AGI #1 leak to WC AGI #2 or vice versa)*

5.2.2 Other Oil and Gas Wells

Within the MMA, there are 4 horizontal wells permitted to be completed at a projected depth of 12, 500 feet in the Wolfcamp Formation for oil and gas production. The SHL for these wells is located north-northwest of the WC AGI wells outside the MMA with the 4 laterals extending to the south-southeast of the WC AGI wells. Since the vertical portions of these wells will be outside the simulated plume extent and the MMA, Targa estimates that the risk of CO_2 surface emission through these wells to be very low.

According to previous estimates, Targa concludes that the risk of a significant leakage through the existing horizontal wells in the Wildcat project area is minimal. As a result, we conclude that the risk of leakage through this pathway is highly improbable.

In order to evaluate the risk associated with all oil and gas wells within the MMA, a risk matrix was used (**Figure 5.2-3**)



5x5 Risk Matrix Example

Impact

How severe would the outcomes be if the risk occurred?

Probability

What is the probability the risk will happen?

	Insignificant 1	Minor 2	Significant 3	Major 4	Severe 5
5 Almost Certain	Medium 5	High 10	Very high 15	Extreme 20	Extreme 25
4 Likely	Medium 4	Medium 8	High 12	Very high 16	Extreme 20
3 Moderate	Low 3	Medium 6	Medium 9	High 12	Very high 15
2 Unlikely	Very low 2	Low 4	Medium 6	Medium 8	High 10
1 Very Unlikely	Very low 1	Very low 2	Low 3	Medium 4	Medium 5

Figure 5.2-3: 5x5 Matrix to evaluate risk based on probability and impact.

Table 5.2-1 shows wells within the MMA and parameters used to determine the relative risk of CO_2 surface leakage through the wells using a risk matrix approach. The final risk rating considers the likelihood and magnitude of potential leakage to rank the risk from 1 to 5

***Table 5.2-1**: Risk Matrix with list of wells that are Producing, Injecting, Plugged & Abandoned (P&A), Drilled and, Drilled but Uncompleted (DUC), within the MMA with parameters used to determine relative risk of CO_2 surface leakage.*

Well API#	**Well Status**	**Trajectory**	**Intersects Confining Zones (CZ) or Injection Zone (IZ)?** **Y=Yes**	**Within Simulated Plume Extent?**	**Is vertical portion within plume extent? (horizontal wells only)**	**Is lateral crossing plume extent? (horizontal wells only)**	**Risk Rating**
10241	P&A	Vertical	Y, CZ for #1	Yes	-	-	4
10242	P&A	Vertical	Y, CZ for #1	Yes	-	-	4
10247	P&A	Vertical	Y, CZ & IZ for #1	No	-	-	2
30270	P&A	Directional	Y, CZ & IZ for #1	No	No	No	2
32725	Producing	Vertical	Y, CZ & IZ for #1	No	-	-	2
32752	Inactive Producer	Vertical	Y, CZ & IZ for #1	No	-	-	2
33160	P&A	Vertical	Y, CZ & IZ for #1	No	-	-	2
33237	Producing	Vertical	Y, CZ & IZ for #1	Yes	-	-	4
33727	Producing	Horizontal	Y, CZ & IZ for #1	Yes	Yes	No	4
34019	Producing	Horizontal	Y, CZ & IZ for #1	No	No	Yes	2
34020	Producing	Horizontal	Y, CZ & IZ for #1	No	No	Yes	2
34021	Producing	Horizontal	Y, CZ & IZ for #1	No	No	Yes	2
34077	Drilled	Horizontal	Y, CZ & IZ for #1	No	No	Yes	2
34153	Injecting (WC AGI #1)	Vertical	Y, CZ & IZ for #1 and #2	Yes	-	-	4

Well API#	Well Status	Trajectory	Intersects Confining Zones (CZ) or Injection Zone (IZ)? Y=Yes	Within Simulated Plume Extent?	Is vertical portion within plume extent? (horizontal wells only)	Is lateral crossing plume extent? (horizontal wells only)	Risk Rating
34236	Producing	Horizontal	Y, CZ & IZ for #1	No	No	Yes	2
34681	DUC	Horizontal	Y, CZ & IZ for #1	No	No	No	2
34785	DUC	Horizontal	Y, CZ & IZ for #1	No	No	No	2
34786	DUC	Horizontal	Y, CZ & IZ for #1	No	No	No	2
34787	DUC	Horizontal	Y, CZ & IZ for #1	No	No	No	2
34788	DUC	Horizontal	Y, CZ & IZ for #1	No	No	No	2
34929	Permitted (WC AGI #2)	Vertical	Y, CZ & IZ for #1	Yes			4
70808	P&A	Vertical	Y, CZ for #1	Yes	-	-	4
30240	Producing	Vertical	Y, CZ & IZ for #1	No	No	No	2
30446	P&A	Vertical	Y, CZ & IZ for #1	No	No	No	2

Targa simulated the worst-case scenario to quantify the risk of leakage through all existing wells within the MMA. All wells (including WC AGI #1 and #2) identified within the MMA (**Table 5.2-1**) and completed below, within and above the injection zone have been considered and studied in the NRAP analysis presented in section 5.2, because they could present potential pathways should CO_2 migration through the seal occur. Even though the risk of CO_2 leakage through the wells that are not penetrating the confining zones is highly improbable, we do not omit any potential source of leakage.

If leakage through wellbores event happens, worst and most likely scenarios are predicted using NRAP tool, to quantitatively assess the amount of CO_2 leakage through oil and gas wells. The reservoir pressure and CO_2 distribution over 75 years of injection and monitoring were incorporated into NRAP tool, to forecast the rate and mass of the leakage CO_2. The worst case is all wells were located right at the source of CO_2 – the location of injection well. In this case, the maximum leakage rate of one well is 1.56e-6 kg/s. This value constitutes the maximum amount of CO_2 leakage, which is 49 kg/year, and occurs in year #13, then gradually reduces to 33 kg at the end of year #75. Comparing the total amount of CO_2 injected, the leakage mass occupies 0.00051% of total CO_2 injected. According to the calculation from the NRAP studies, the risk of leakage is highly improbable. In addition, in the worst-case scenario, the NRAP analysis demonstrates that, each well inside the MMA could generate a leakage rate of 2.3e-9 kg/s or a total of 103 kg CO_2 leakage to the atmosphere over 75 years (**Figure 5.2-4**).

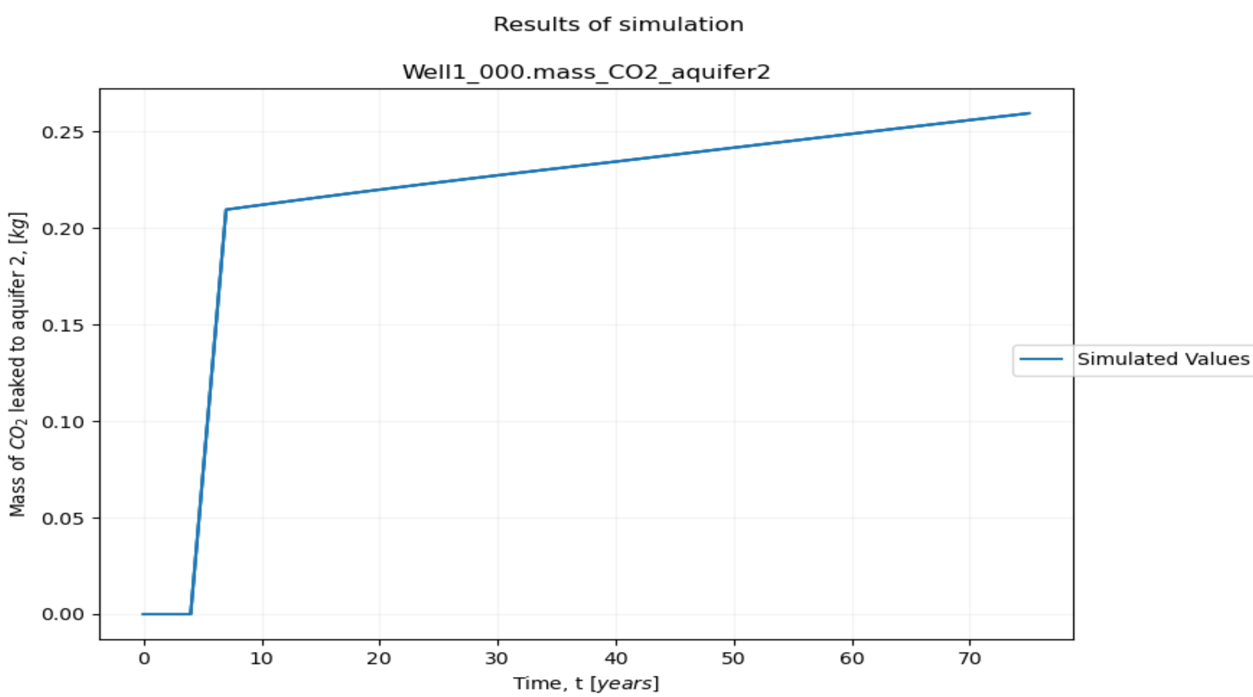


***Figure 5.2-4**: Cumulative leakage of CO_2 through wells within the MMA.*

Likelihood:

Based on the above discussion, the likelihood of gas leakage through surrounding oil and gas wells is considered extremely low.

Magnitude:

Based on the NRAP analysis, the magnitude of potential gas leaks through these wells is minimal.

Timing:

Timing evaluations indicate no imminent risk of gas leakage from the subsurface, given the stable operational conditions, reservoir characteristics and proactive monitoring protocols implemented.

5.2.3 Groundwater Wells

Targa identified 13 water wells within a 2-mile radius of the WC AGI wells, 11 of which are within the MMA for the WC AGI wells. The deepest groundwater well is 600 ft deep. The evaporite sequence of the Permian Ochoan Salado and Castile Formations (see Section 3.2.2) provides an excellent seal between these groundwater wells and the Bell and Cherry Canyon injection zone of the WC AGI #1 well. The WC AGI #2 well is deeper and has several other confining zones separating the CO_2 injection zone and groundwater wells. Therefore, it is very unlikely that these groundwater wells are a potential pathway of CO_2 leakage to the surface. Nevertheless, the CO_2 surface monitoring and groundwater monitoring described in Sections 6 and 7 will provide early detection of CO_2 leakage followed by immediate response, thereby minimizing the magnitude of CO_2 leakage volume via this potential pathway.

Due to the shallow depth of the groundwater wells within the MMA relative to the depth of the WC AGI #1 and #2 wells and considering the NRAP analysis, Targa considers that the likelihood of CO_2 emissions to the surface via this potential leakage pathway is improbable and the magnitude of such a leak would be minimal.

Likelihood:

Based on the above discussion, the likelihood of gas leakage through surrounding groundwater wells is considered extremely low.

Magnitude:

Based on the NRAP analysis, the magnitude of potential gas leaks through these wells is minimal.

Timing:

Timing evaluations indicate no imminent risk of gas leakage from the subsurface, given the stable operational conditions, reservoir characteristics and proactive monitoring protocols implemented.

5.3 Potential Leakage through Fractures, Faults and Bedding Plane Partings

As mentioned in section 3.2.3, no faults have been identified close to the injection zone and sealing formations for WC AGI #1. Therefore, the risk of leakage through faults and fractures is considered highly improbable.

For WC AGI #2, a total of 6 faults located in the injection and the sealing formations were identified within the MMA and surrounding area (**Figure 5.3-1**). These are all considered in the NRAP analysis for risk assessment.

For the 4 faults that are outside the plume maximum extent or MMA: fault trace 3 (0.7 miles from the stabilized plume), fault trace 4 (1 mile from the stabilized plume), fault trace 5 (2 miles from the stabilized plume) and fault trace 6 (3.1 miles from the stabilized plume), the risk of leakage has been assessed and is considered highly improbable.

Only 2 faults (fault trace 1 and 2 in **Figure 5.3-1**) cut through the plume area for Wildcat AGI #2.

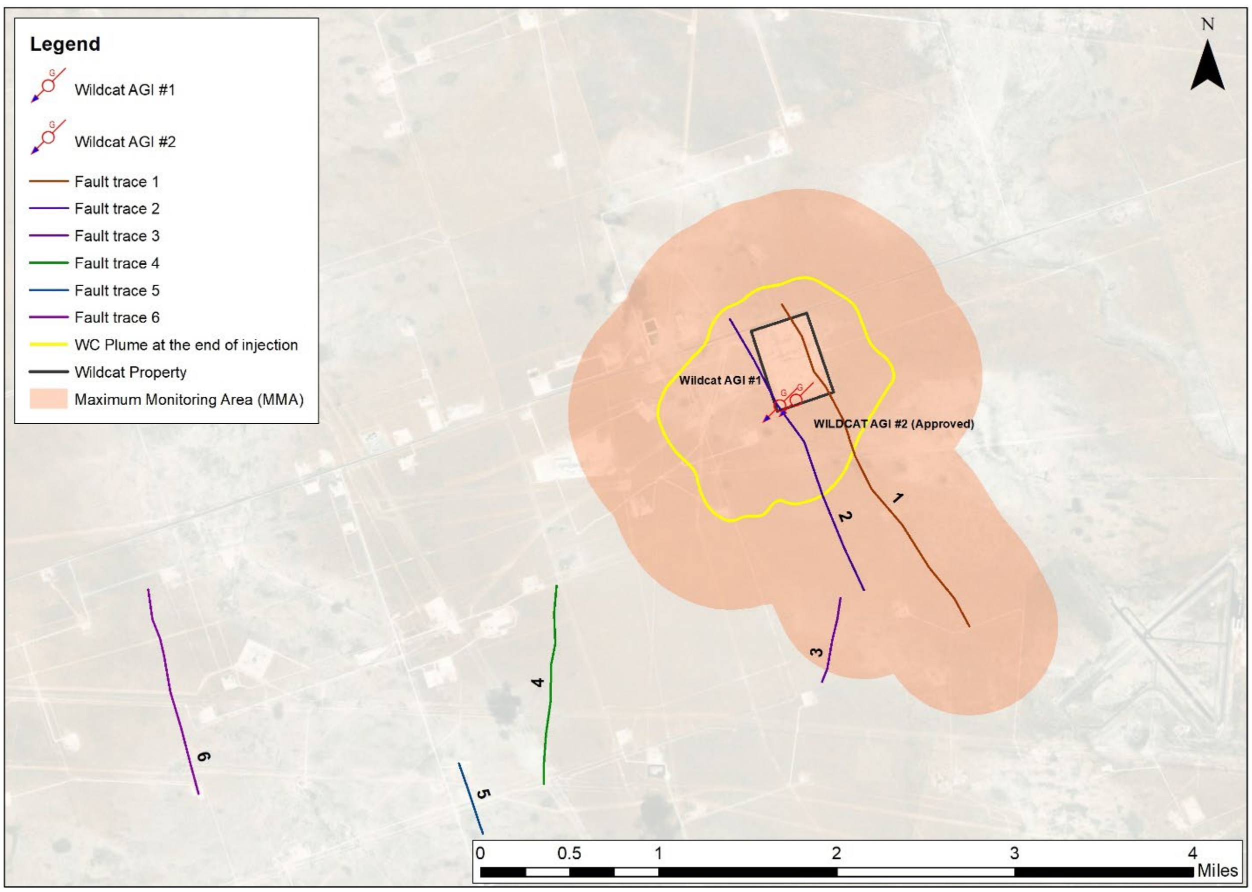


***Figure 5.3-1**: Fault trace of faults identified in the Siluro-Devonian formations relative to the Wildcat Plant and the MMA.*

The location, geometry, and direction of the faults that connect with the CO_2 plume of Wildcat AGI #2 were utilized in quantifying leakage through faults. Even in the worst-case scenario, where the faults are transmissive and connect to the injection zone, the risk of CO_2 leakage to the above shale formations and other strata is only 3.5e-11 kg/s or 0.002 kg of CO_2 over 75 years of monitoring

(**Figure 5.3-2**). This leakage rate is negligible and understandable because of the sealing formation properties and thickness: 1,530 feet of Barnett Shale, Mississippian and Woodford (**Table 3.2-1**). The analysis has been confirmed during the injection simulation results, where the TAG remained contained.

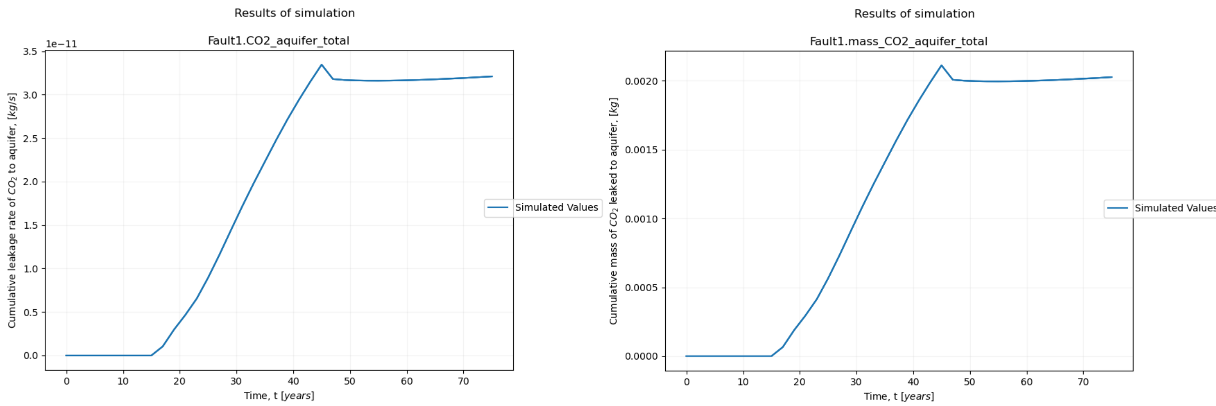


Figure 5.3-2: *NRAP simulation for leakage rate (kg/s) and leakage mass (kg) for risk assessment of leakage through the fault cutting the maximum plume extent for WC AGI #2.*

To conclude, as it stands now, the lower faults do not represent an issue with the operation of WC AGI #1. The WC AGI #1 injection zone is significantly shallower that the depth of the faults. However, if Targa decide to drill WC AGI #2, the MRV plan will be revised to further address the risk of leakage from WC AGI #2 through the identified faults.

Likelihood:

Based on the above discussion, the likelihood of gas leakage through fractures or faults is considered extremely low.

Magnitude:

Based on the NRAP analysis, the magnitude of potential gas leaks is minimal.

Timing:

Timing evaluations indicate no imminent risk of gas leakage from the subsurface, given the stable operational conditions, reservoir characteristics and proactive monitoring protocols implemented.

5.4 Potential Leakage based on the Competency, Extent, and Dip of the Confining Zone

The injection zone for WC AGI #1 consists of the Bell and Cherry Canyon formations. The overlying Rustler, Salado, and Castile Formations, collectively totaling over 3,400 feet in thickness, comprise the upper confining zone for this well. The evaporite sequences in these formations are described in Sections 3.2.2 and 3.3.1 as having low porosity and permeability providing an effective preventative barrier to surface emissions of CO_2 from the injection zone.

The proposed injection zone for WC AGI #2 consists of the Siluro-Devonian through the Ellenburger. The overlying Barnett Shale, Mississippian limestone, and Woodford Shale, collectively totaling over 1,500 feet in thickness, comprise the upper confining zone for this well. These units have been described in Sections 3.2.2 and 3.3.1 as having minor to extremely low porosity and permeability providing an effective preventative barrier to surface emissions of CO_2 from the injection zone.

Leakage through a confining zone happens at low-permeability shale formations containing natural fractures. WC AGI #1 is injecting in the Delaware Group Formation, which underlies the Castile and Salado formations with 0.2 mD permeability acting as the seals. Meanwhile, the proposed Lower Devonian Thirtyone through the Ordovician Ellenburger injection zone for WC AGI #2 underlies the naturally fractured Woodford shale which has a permeability of 1 mD. Therefore, we took leakage through confining zones into consideration. CO_2 saturation at the seal and seal properties was incorporated into the NRAP model.

The worst scenario is defined as leakage through the seal happens right above the injection wells, where CO_2 saturation is highest. However, the worst case of leakage only shows 0.038% of total CO_2 injection in 30 years was leaked from the injection zone to the seals. As we go further from the source of CO_2, the likelihood and magnitude of such an event will reduce proportionally with the distance from the source. Considering it is the worst amount of CO_2 leakage potentially released, if an event happens, and the leak must pass upward through the confining zones, then, the secondary confining strata that are also low permeability geologic units, and other geologic units, will prevent the upward propagation. Therefore, Targa concludes that the risk of leakage through this pathway is highly improbable.

Lateral migration of the injected TAG was addressed in detail in Section 3.3. Therein, it states that the units dip gently with no significant relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the 2 units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales and are being encased by them.

Likelihood:

Based on the discussion of the channeled sands in the injection zone, Targa considers that the likelihood of CO_2 to migrate laterally along the channel axes is possible. However, the turbidite sands are encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity. Therefore, the injectate is projected to be contained within the injection zone close to the injection well, which minimizes the likelihood that CO_2 will migrate laterally. The likelihood of gas leakage is considered extremely low.

Magnitude:

Based on NRAP analysis, the magnitude of potential gas leaks is minimal, as the injection zone and sealing formations are suited to contain and mitigate any releases effectively.

Timing:

Timing evaluations indicate no imminent risk of gas leakage from the subsurface, given the stable operational conditions, reservoir characteristics and proactive monitoring protocols implemented.

To conclude, the analyses suggest that the risks of lateral migration and potential leakage through the confining zone are highly improbable.

5.5 Potential Leakage due to Natural / Induced Seismicity

We stated in section 3.2.3 that no faults have been identified close to the injection zone and sealing formations for WC AGI #1. Therefore, the risk of fault activation and induced seismicity is considered extremely low and highly improbable.

As regards WC AGI #2, faults have been identified and therefore Targa conducted a Fault Slip Potential (FSP) analysis for the injection of CO_2 in the Siluro-Devonian. This information helps to refine the understanding of the fault distribution and its relevance to the reservoir, enabling more accurate assessments and risk management for the well and associated activities. The analysis of the faults identified from the 3D seismic data, as shown in **Figure 5.5-1**, reveals that 6 major faults pass through the reservoir interval. These faults are subdivided into 41 sub-faults in order to be analyzed for fault slip potentials.

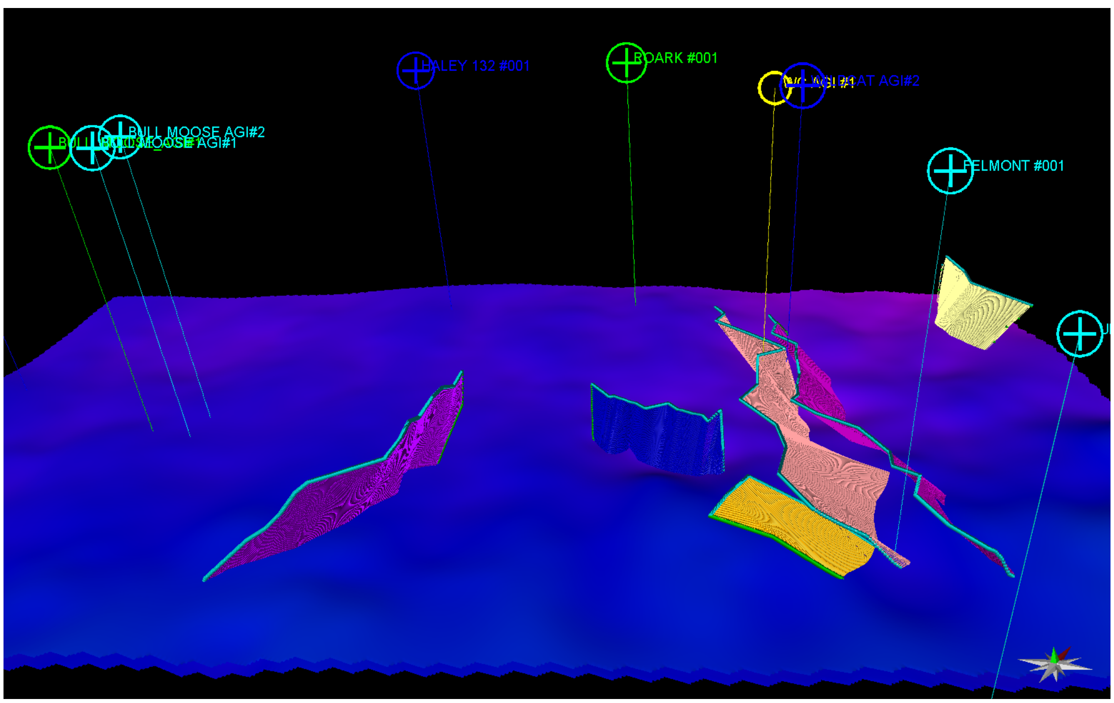


***Figure 5.5-1**: Structure and fault system picked from 3D seismic data on Siluro-Devonian to Ellenburger.*

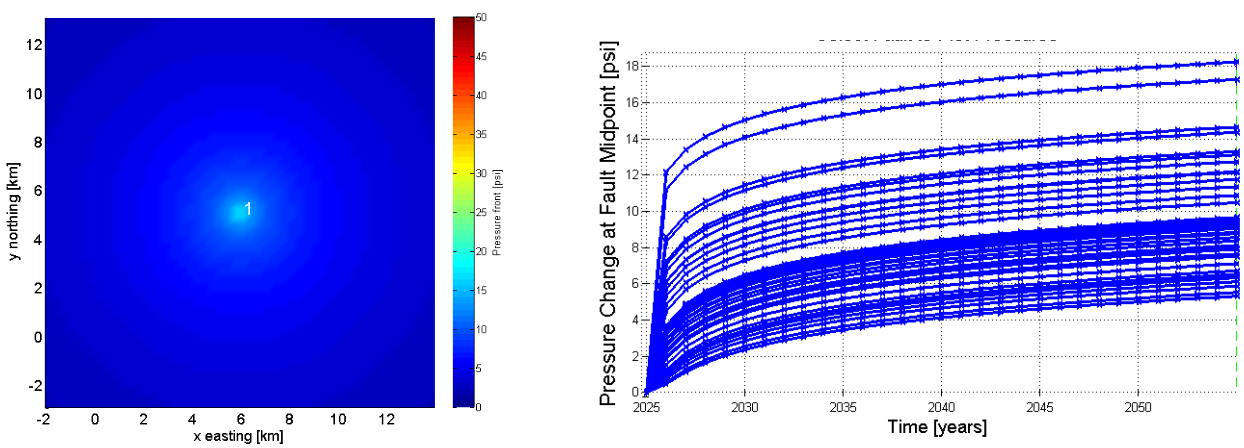
Input parameters

The evaluation of Fault Slip Potential (FSP) using the FSP software version 1.07 involved the utilization of specific parameters. The software required various inputs or parameters to assess the potential for fault slippage. These parameters are fundamental in assessing the likelihood of fault slippage. The FSP software version 1.07 would have incorporated and processed these inputs to generate an estimation or analysis of the potential for faults to slip under the given conditions. These parameters (**Table 5.5-1**) include factors such as: Pressure Changes (the magnitude and direction of pressure changes within the geological formations), fault geometry (details about the fault, including its orientation, size, and geometry), stress conditions (information on stress distribution within the rock formations, including the magnitudes and orientations of principal stresses), rock properties (data regarding the mechanical properties of the rocks, such as porosity, permeability, and strength) and, seismic data (3D seismic data used to identify and characterize faults).

Table 5.5-1*: Parameters used as inputs for Fault Slip Potential analysis*

Maximum Horizontal Stress Direction (deg)	82.5 +/- 7.5
Initial Reservoir Pressure Gradient (psi/ft)	0.43 +/- 0.05
Minimum Horizontal Stress Gradient (psi/ft)	0.65
Maximum Horizontal Stress Gradient (psi/ft)	0.98
A-Phi Parameter	0.8+/-0.1
Reference Friction Coefficient (mu)	0.58+/-.005
Porosity (%)	23
Permeability (mD)	165
Injection Rate (MMSCFD)	15
Injection Years	2025 to 2055
Vertical Stress Gradient (psi/ft)	1.07+/-0.01
Injection density (kg/m^3)	700

It appears that the results of the FSP analysis indicate that over a 30-year injection period, faults have experienced a pressure drop in effective stress of approximately less than 18 psi (**Figure 5.5-2**). The slippage of fault walls is contingent on having sufficient pore pressure to raise the effective stress to a level that would induce slippage. According to the analysis, 95% of interpreted faults require more than 100 psi effective pressure to induce slippage. This information suggests that the fault system may be relatively stable or that the pore pressure changes have not been significant enough to cause fault activation. It's important to continue monitoring and analyzing these factors to ensure the safety and integrity of the geological formations and structures in the area, especially if there are any injection or extraction activities taking place.



a) b)

Figure 5.5-2*: Visualization of pressure distribution (a) and pressure values at fault midpoints (b) after 30 years of injection.*

Figure 5.5-2 illustrates that fault slippage has a low probability as the current prediction of pressure changes (**Figure 5.5-2.a**), which is approximately 18 psi, and results in (**Figure 5.5-2.b**) a fault slip potential probability of less than 0.01% on a scale of 0 (minimum) to 1 (maximum). This indicates a relatively low fault slip potential at the current pressure change.

In summary, Targa has determined that the likelihood of leakage due to natural or induced seismicity is extremely low, ranging from improbable to highly improbable. The scale and occurrence of any potential leak, if a seismic event does happen, would be contingent upon the magnitude of a seismic event. If such an event were to occur during or after the injection period, there is a possibility that the entire volume of CO_2 injected into the reservoir up to that point could eventually be discharged to the surface. The timing of such a leak would span several months to years following the seismic event.

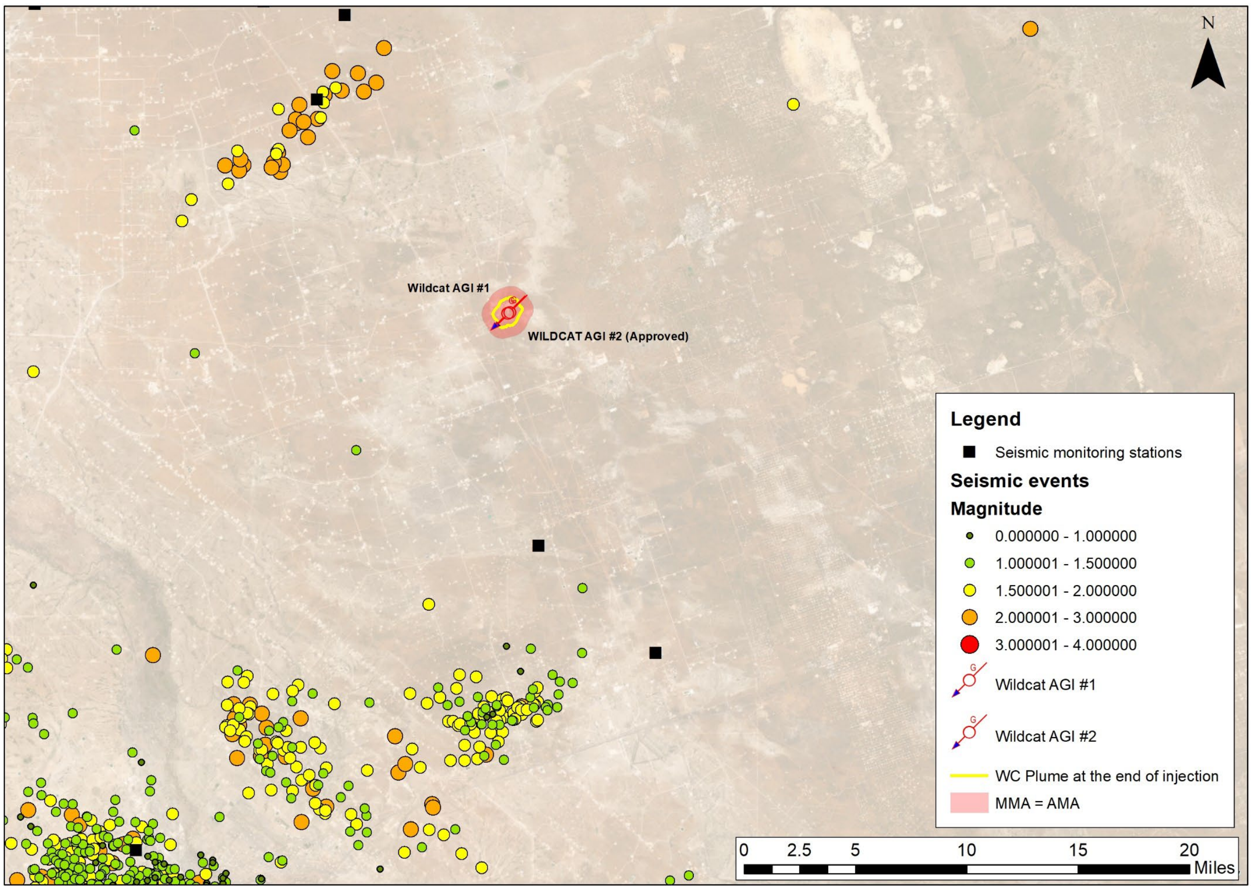


***Figure 5.5-3**: Seismic events and seismic monitoring stations surrounding the Wildcat AGI Wells*

The Texas Seismological Network and Seismology Research (TexNet) is an online tool that helps to locate and determine the origins of earthquakes in Texas and where they are possibly caused by human activities. TexNet displays recent seismic events and monitoring stations on an online platform and shares the data.

The team plotted the seismic events and the surrounding monitoring stations that were registered on TexNet (**Figure 5.5-3**). There are no major seismic activities close to the WC AGI #1 and #2 wells. The closest seismic events are regrouped in 2 distinct areas that are located 12 miles North-West and 17 miles South-East of WC AGI wells. The RRC of Texas recognizes that oil and gas activities, notably saltwater disposal (SWD) well activity, can induce seismic events. To prevent them, the RRC of Texas put in place several response plans in the region to monitor and control SWD activities. The events surrounding Wildcat are of less than magnitude 3 and will not affect the Wildcat operations.

Due to the distance between the Wildcat AGI wells and the recent seismic events, the magnitude of these events, and the fact that Targa controls injection pressures, Targa considers the likelihood of CO_2 emissions to the surface caused by seismicity to be improbable. Monitoring of seismic events in the vicinity of the Wildcat AGI wells is discussed in Section 6.6.

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

Subpart RR at 40 CFR 448(a)(3) requires a strategy for detecting and quantifying surface leakage of CO_2. Targa will employ the following strategy for detecting, verifying, and quantifying CO_2 leakage to the surface through the potential pathways for CO_2 surface leakage identified in Section 5. Targa considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to detect, verify, and quantify CO_2 surface leakage. **Table 6-1** summarizes the leakage monitoring of the identified leakage pathways. Monitoring will occur for the duration of injection and the 45-year post-injection period.

Table 6-1*: Summary of Leak Detection Monitoring*

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	● Distributed control system (DCS) surveillance of plant operations ● Visual inspections ● Inline inspections ● Fixed in-field gas monitors ● CO_2 flux monitoring network (35 collars installed) ● Personal and hand-held gas monitors
Drilling of new WC AGI #2 well	● Vigilant monitoring of fluid returns during drilling ● Multiple gas monitoring points around drilling operations – personal and hand-held gas monitors
Existing WC AGI #1 Well	● DCS surveillance of well operating parameters ● Visual inspections ● Mechanical integrity tests (MIT) ● Fixed in-field gas monitors ● CO_2 flux monitoring network (35 collars installed) ● Personal and hand-held gas monitors ● In-well P/T sensors ● Groundwater monitoring

Fractures and Faults	● DCS surveillance of well operating parameters ● Fixed in-field gas monitors ● CO_2 flux monitoring network (35 collars installed) ● Groundwater monitoring
Confining Zone / Seal	● DCS surveillance of well operating parameters ● Fixed in-field gas monitors ● CO_2 flux monitoring network (35 collars installed) ● Groundwater monitoring
Natural / Induced Seismicity	● DCS surveillance of well operating parameters ● Seismic monitoring
Lateral Migration	● DCS surveillance of well operating parameters ● Fixed in-field gas monitors ● CO_2 flux monitoring network (35 collars installed) ● Groundwater monitoring
Additional Monitoring	● Groundwater monitoring ● Soil flux monitoring

6.1 Leakage from Surface Equipment

Targa implements several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S sensors, and continual monitoring of operational parameters.

Leaks from surface equipment are detected by Targa field personnel, wearing personal H_2S monitors, following daily and weekly inspection protocols which include reporting and responding to any detected leakage events. Targa also maintains in-field gas monitors to detect H_2S and CO_2. The in-field gas monitors are connected to the DCS housed in the onsite control room. If one of the gas detectors sets off an alarm, it would trigger an immediate response to address and characterize the situation.

The following description of the gas detection equipment was extracted from Wildcat Gas Processing Plant H_2S Contingency Plan:

> **"WILDCAT PLANT AGI LEAK CONTROL, EQUIPMENT SAFEGUARDS, AND SHUTDOWNS**
> The Wildcat Plant will use an acid gas injection well to dispose of acid gas stream generated by the Plant treating system and an AGI Flare located in the acid gas well and compressor area to safely burn acid gas in case of an emergency and for maintenance purposes. Emergency Shutdown valves are located at the Plant inlet and automatic activation valves at the AGI Wellsite to move any gas from piping to flare. The acid gas compressor area is equipped with a fixed H_2S detector system. This detection system alarms on site and in the Wildcat Plant Control Room, which is occupied 24 hours a day, at 10 parts per million (ppm) and activates the acid gas compressor shutdown at 50 ppm.

> The acid gas well has a Subsurface Safety Valve located approximately 250 feet below the ground surface and is activated automatically when well pressure is detected below 300 pounds or higher than 2,000 psi. The valve shuts off any flow from the well to prevent backflow to the surface in case of a failure of piping or equipment on the ground surfaces."

Personal and Handheld H_2S Monitors

In addition, all personnel working at the Plant wear personal H_2S monitors. The personal monitors are set to alarm and vibrate at 10 ppm. Handheld gas detection monitors are available at strategic locations around the Plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and carbon dioxide (CO_2).

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the monitoring and drilling of any new wells that will penetrate the injection zones as described in Section 5.2. Notably for WC AGI #2, that will include a more frequent monitoring during drilling operations (see **Table 6-1**). This applies to Targa and other operators drilling new wells through the WC AGI injection zones within the MMA.

6.3 Leakage from Existing Wells

6.3.1 WC AGI Wells

As part of ongoing operations, Targa continuously monitors and collects flow, pressure, temperature, and gas composition data in the data collection system. These data are monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits.

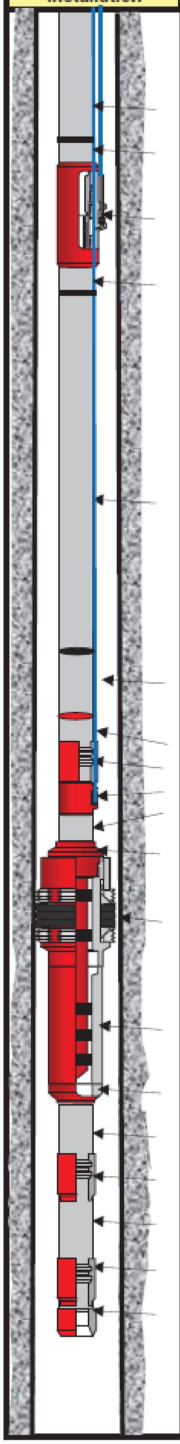
To monitor leakage and wellbore integrity, 1 pressure and temperature (ROC PT Sensor Mandrel 3 1/2" 9.2# VAMTOP Box x Pin, **Figure 6.3-1**) gauge as well as Distributed Temperature Sensing (DTS) were deployed in Targa's WC AGI #1 well. The gauge is designated to monitor the tubing ID (reservoir) pressure and temperature as well as the annular space between the tubing and the long string. A leak is indicated by monitoring the pressure. DTS is clamped to the tubing, and it monitors the temperature profiles of the annulus. DTS can detect variation in the temperature profile events throughout the tubing and or casing. Temperature variation could be an indicator of leaks. Data from temperature and pressure gauges is recorded by an interrogator housed in an onsite control room. DTS (temperature) data is recorded by a separate interrogator that is also housed in the onsite control room. Data from both interrogators are transmitted to a remote location for daily real time or historical analysis.

If operational parameter monitoring and Mechanical Integrity Test (MIT) failures indicate a CO_2 leak has occurred, Targa will take actions to quantify the leak based on operating conditions at the time of the detection including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site.

HALLIBURTON

Installation

GEOLEX INC		
Wildcat AGI #1	Company Rep.	Terry Dickman
Winkler County Texas	Service Specialist	Carlos Chavez
2/5/2019	Office	682-333-6369



Installation	Length	Depth	Jts.	Description	OD	ID
	11.47	11.47		HANGER + KB (4.37' + 7.1').		
	32.59	44.06	1	3 1/2" 9.3# L-80 Tubing slick joint.	3.540	2.959
	18.00	62.06		3 1/2" 9.3# L-80 Tubing pup joints. (8', 10').	3.540	2.959
	228.00	290.06	7	3 1/2" 9.3# L-80 Tubing	3.540	2.959
	6.00	296.06		6' x 3 1/2" 9.3# L-80 VAMTOP Tubing Sub	3.540	2.959
	5.30	301.36		3 1/2" NE HES SSSV Nickel Alloy 925 w/Alloy 825 Control Line 3 1/2" 9.2# VAMTOP Box x Pin	5.300	2.813
	6.00	307.36		6' x 3 1/2" 9.3# L-80 VAMTOP Tubing Sub	3.540	2.959
				Per wireline: Center elements set @ 5,072.50 Tubing Run: Center elements @ 5,085.65 Ran 4 sheer screws @ 520# ea.		
	4,438.37	4,745.73	137	3 1/2" 9.2# L-80 Tubing	3.540	2.959
	315.11	5,060.84	9	3 1/2" 9.3# G-3 VAM TOP CHROME TUBING.	3.540	2.959
	6.68	5,067.52		6' x 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy G3 Sub	3.540	2.959
	1.14	5,068.66		2.813" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	4.073	2.813
	4.57	5,073.23		ROC PT Sensor Mandrel 3 1/2" 9.2# VAMTOP Box x Pin	4.660	2.959
	6.68	5,079.91		6' x 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy G3 Sub	3.540	2.959
	1.77	5,081.68		4.00" Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925	4.470	2.959
	3.97	5,085.65		7" 26-32# x 4.00" BWD Packer Nickel Alloy 925	5.875	4.000
	7.45	5,093.10		4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
	1.42	5,094.52		4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
	7.49	5,102.01		8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
	1.93	5,103.94		2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925	4.073	2.562
	7.46	5,111.40		8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
	1.29	5,112.69		2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925	4.078	2.329
	0.74	5,113.43		3 1/2" 9.2# VAMTOP Nickel Alloy 925 Pump Out Plug w/Standard Insert	3.937	2.920
			154	TOTAL JOINTS.		

***Figure 6.3-1**: Well Schematic for WC AGI #1 showing installation of P/T sensors*

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. Additionally, groundwater and soil CO_2 flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details. Targa and NMT are currently working together to install CO_2 flux monitoring systems at the Wildcat facility. Monitoring will be in place and start February 9th 2024, with CO_2 flux monitoring and groundwater well sampling from a shallow well located on Wildcat property.

6.4 Leakage through the Confining / Seal System

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the WC AGI #1 well, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA, starting February 9th 2024, will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If changes in operating parameters or other monitoring listed in **Table 6-1** indicate leakage of CO_2 through the confining and seal system, Targa will take actions to quantify the amount of CO_2 released and take immediate action to stop it, including shutting in the well (see Section 6.8).

6.5 Leakage due to Lateral Migration

Continuous operational monitoring of the WC AGI well #1 during and after the period of the injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The CO_2 monitoring network that will be implemented, and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If monitoring of operational parameters or other monitoring methods listed in **Table 6-1** indicates that the CO_2 plume extends beyond the maximum monitoring area modeled in Section 3.8 and presented in Section 4, Targa will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 release to the surface. As this scenario would be considered a material change per 40CFR98.448(d)(1), Targa will submit a revised MRV plan as required by 40CFR98.448(d). See Section 6.8 for additional information on quantification strategies.

6.6 Leakage from Fractures and Faults

As discussed in Section 5.3, it is very unlikely that CO_2 leakage to the surface will occur through faults because there are no faults around the geological sequestration system for WC AGI #1 and the drilling and operation of WC AGI #2 are indefinitely postponed. However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, Targa will identify which of the pathways listed in this section are responsible for the leak, including the possibility of heretofore unidentified faults or fractures within the MMA. Identifying the leakage pathway will allow Targa to take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details. See Section 6.8 for additional information on quantification strategies.

6.7 Leakage due to Natural / Induced Seismicity

In order to monitor the influence of natural and/or induced seismicity, Targa will use the established TexNet seismic network and add an additional seismic monitoring station around the Wildcat Plant with the support of the Bureau of Economic Geology (BEG) that developed TexNet. BEG and Targa already identified a site location for the seismic monitoring station. NMT also support seismic data acquisition, treatment and reporting for TND.

TexNet network consists of seismic monitoring stations that detect and locate seismic events. Continuous monitoring and easy access help differentiate between natural and induced seismicity. The seismic monitoring network surrounding the Wildcat Gas Processing Plant has been mapped on **Figure 5.5-3.** The monitoring network records 24 hours per day and 7 days per week. The data are plotted daily. These plots can be browsed either by station or by day. The data are streamed continuously to the TexNet webpage and archived at the Incorporated Research Institutions for Seismology Data Management Center (IRIS DMC).

If monitoring of the TexNet seismic monitoring stations, the operational parameters and the fixed infield gas monitors indicates surface leakage of CO_2 linked to seismic events, Targa will assess whether the CO_2 originated from the WC AGI #1 well and, if so, take measures to quantify the mass of CO_2 emitted to the surface based on operational conditions at the time the leak was detected. See Section 7.6 for details regarding seismic monitoring and analysis. See Section 6.8 for additional information on quantification strategies.

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

For normal operations, quantification of emissions of CO_2 from surface equipment located between the flow meter used to measure injection quantity and the injection wellhead will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR. Quantification of major leakage events from surface equipment as identified by the detection techniques listed in **Table 6-1** will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified the leakage location will be isolated to prevent additional emissions to the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. Targa has standard operating procedures to report and quantify all pipeline leaks in accordance with the Texas Railroad Commission regulations. Targa will use this procedure to quantify the mass of carbon dioxide from each leak discovered by Targa or third parties. Additionally, Targa may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

6.8.2 Subsurface Leakage

Selection of a quantification strategy for leaks that occur in the subsurface will be based on the leak detection method (**Table 6-1**) that identifies the leak. **Leaks associated with the point sources, such as the injection wells**, and identified by failed MITs, variations of operational parameters outside acceptable ranges, and in-well P/T sensors can be addressed immediately after the injection well has been shut in. Quantification of the mass of CO_2 emitted during the leak will depend on characterization of the subsurface leak, operational conditions at the time of the leak, and knowledge of the geology and hydrogeology at the leakage site. Conservative estimates of the mass of CO_2 emitted to the surface will be made assuming that all CO_2 released during the leak will reach the surface. Targa can estimate the emissions to the surface more accurately by employing transport, geochemical, or reactive transport model simulations.

Other wells within the MMA will be monitored with the atmospheric and CO_2 flux monitoring network placed strategically in their vicinity.

Nonpoint sources leaks, such as **leaks through the confining zone, due to lateral migration, along faults or fractures, initiated by seismic events** can be identified by variations of operational parameters outside acceptable ranges and will require further investigation to quantify such leakage. If a leak is suspected through these potential leakage pathways, reevaluation of the geology and reservoir characterization modeling will be conducted. If leaks through these potential pathways is suspected of causing CO_2 emissions to the surface, the methods described in Section 6.8.3 will be deployed.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage by academic experts (Xiao et al., 2024) discussed monitoring techniques and risk assessment for sequestered CO_2 leaking back to the surface, emphasizing the importance of monitoring network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO_2 flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 6.8.1, or from the subsurface. In the latter case, CO_2 flux monitoring data and quantification methodologies will be employed to quantify the surface leaks.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

Targa uses the existing automatic distributed control system to continuously monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO_2 at WC AGI #1. Targa considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to establish baselines for monitoring CO_2 surface leakage. The following describes Targa's strategy for collecting baseline information.

7.1 Visual Inspection

Targa field personnel conduct frequent periodic inspections of all surface equipment providing opportunities to assess baseline concentrations of H_2S, a proxy for CO_2, at the Wildcat Gas Processing Plant.

7.2 Fixed In-Field, Handheld, and Personal H_2S Monitors

Compositional analysis of Targa's gas injectate at the Wildcat Gas Processing Plant indicates an approximate H_2S concentration of 20% thus requiring Targa to develop and maintain an H_2S Contingency Plan (Plan) according to the TRRC regulations. Targa considers H_2S to be a proxy for CO_2 leaks at the Plant. The Plan contains procedures for an organized response to an unplanned release of H_2S from the plant or the associated WC AGI Well, as well as documents of procedures that would be followed in case of such an event.

7.3 Fixed In-Field H_2S Monitors

The Wildcat Gas Processing Plant utilizes numerous fixed-point monitors, strategically located throughout the Plant, to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the DCS. Upon detection of H_2S at 10 ppm at any detector, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of hydrogen sulfide at 90 ppm at any monitor, an evacuation alarm is sounded throughout the Plant at which time all personnel will proceed immediately to a designated evacuation area.

7.4 Handheld and Personal H_2S Monitors

Handheld gas detection monitors are available at strategic locations around the Plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and CO_2.

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the Plant must wear personal H_2S monitoring devices to assist them in detecting the presence of unsafe levels of H_2S. Personal monitoring devices will give an audible alarm and vibrate at 10 ppm.

7.5 CO_2 Detection

In addition to the handheld gas detection monitors described above, New Mexico Tech will assist Targa in setting up a monitoring network for CO_2 leakage detection in the AMA as defined in Section 4.2. The scope of work for the monitoring project includes field sampling activities to monitor CO_2/H_2S at the WC AGI #1 well. These activities include periodic well (groundwater and gas) and atmospheric sampling around the injection wells. Once the network is set up, Targa will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

The monitoring network will be installed and sampling will start at the Wildcat Gas Processing Plant on February 9th 2024.

7.6 Continuous Parameter Monitoring

The DCS of the Plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS, and engineering and operations are alerted if a parameter is outside the allowable window. If a parameter is outside the allowable window, this will trigger further investigation to determine if the issue poses a leak threat. Also, see Section 6.2 for continuous monitoring of P/T in the well.

7.7 Well Surveillance

Targa adheres to the requirements of TRRC rules governing the construction, operation and closing of an injection well. It includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, TRRC regulations include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. Targa's Routine Operations and Maintenance Procedures for the WC AGI #1 ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.8 Seismic (Microseismic) Monitoring Stations

Targa is installing a seismometer and a digital recorder with BEG support in order to monitor for and record data for any seismic event at the Wildcat Gas Processing Plant (see **Figure 5.5-3)**. The seismic station meets the requirements of the TRRC Rules to install, operate, and monitor for the life of the Class II AGI permit a seismic monitoring station or stations.

In addition, data that is recorded by the existing seismic monitoring network within a 10-mile radius of the Wildcat Gas Processing Plant will be analyzed by the New Mexico Bureau of Geology (NMBGMR), see **Figure 5.5-3**. The NMBGMR seismologist will create a report and map showing the magnitudes of recorded events from seismic activity. The data is being continuously recorded and is available on TexNet. By examining historical data (section 5), a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

7.9 Groundwater Monitoring

New Mexico Tech, will monitor groundwater wells for CO_2 leakage which are located within the AMA as defined in Section 4.2. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for 1 year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 7-1**. Baseline analyses will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Wildcat Gas Processing Plant. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

Table 7-1: Groundwater Monitoring Parameters

Parameters
pH
Alkalinity as HCO3- (mg/L)
Chloride (mg/L)
Fluoride (F-) (mg/L)
Bromide (mg/L)
Nitrate (NO3-) (mg/L)
Phosphate (mg/L)
Sulfate (SO42-) (mg/L)
Lithium (Li) (mg/L)
Sodium (Na) (mg/L)
Potassium (K) (mg/L)
Magnesium (Mg) (mg/L)
Calcium (Ca) (mg/L)
TDS Calculation (mg/L)
Total cations (meq/L)
Total anions (meq/L)
Percent difference (%)
ORP (mV)
IC (ppm)
NPOC (ppm)

7.10 Soil CO_2 Flux Monitoring

A vital part of the monitoring program is to identify potential leakage of CO_2 and/or brine from the injection horizon into the overlying formations and to the surface. One of the methods that has been deployed is to gather and analyze soil CO_2 flux data which serves as a means for assessing potential migration of CO_2 through the soil and its escape to the atmosphere. By taking CO_2 soil flux measurements at periodic intervals and from strategic locations, Targa can continuously characterize the interaction between the subsurface and surface to understand potential leakage pathways. Actionable recommendations can be made based on the collected data.

Soil CO_2 flux will be collected on a monthly basis for 12 months to establish the baseline and understand seasonal and other variation at the Wildcat Gas Processing Plant. After the baseline is established, data will be collected bi-monthly for 1 year and then quarterly.

Soil CO_2 flux measurements will be taken using a LI-COR LI-8100A flux chamber, or similar instrument, at pre planned locations at the site. PVC soil collars (8cm diameter) will be installed in accordance with the LI-8100A specifications. Measurements will be subsequently made by placing the LI-8100A chamber on the soil collars and using the integrated iOS app to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. The soil collars will be left in place such that each subsequent measurement campaign will use the same locations and collars during data collection.

8. Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 6 summarizes the twelve Subpart RR equations used to calculate the mass of CO_2 sequestered annually. **Appendix 7** includes the twelve equations from Subpart RR. Not all of these equations apply to Targa's current operations at the Wildcat Gas Processing Plant but are included in the event Targa's operations change in such a way that their use is required.

Figure 3.6-1 shows the location of all surface equipment and points of venting listed in 40CFR98.232(d) of Subpart W that will be used in the calculations listed below.

All the meters cited in the MRV plan and in **Figure 3.6-1** are in accordance with 40 CFR 98.444(b)(1).

8.1 CO_2 Received

Currently, Targa receives gas to its Wildcat Gas Processing Plant through a network of pipelines. Then the gas is processed as described in Section 3.6 to produce compressed TAG which is then routed to the WC AGI #1 wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection. Targa will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3. Receiving flow meter r in the following equations corresponds to meters M1 and M5 in **Figure 3.6-1**. All the meters cited in the MRV plan and in **Figure 3.6.1** are in accordance with 40 CFR 98.444(b)(1).

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}}$$

(Equation RR-2 for Pipelines)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

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

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

p = Quarter of the year.

r = Receiving flow meter.

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r}$$

(Equation RR-3 for Pipelines)

where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 or RR-2 for flow meter r.

r = Receiving flow meter.

Although Targa does not currently receive CO_2 in containers for injection, they wish to include the flexibility in this MRV plan to receive gas from containers. When Targa begins to receive CO_2 in containers, Targa will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. Targa will adhere to the requirements in 40CFR98.444(a)(2) for determining the quarterly mass or volume of CO_2 received in containers.

If CO_2 received in containers results in a material change as described in 40CFR98.448(d)(1), Targa will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Targa injects CO_2 into the existing WC AGI #1. Upon completion, Targa will commence injection into WC AGI #2. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into both wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Volumetric flow meter u in the following equations corresponds to meters M4 and M8 in **Figure 3.6-1**. All the meters cited in the MRV plan and in Figure 3.6.1 are in accordance with 40 CFR 98.444(b)(1).

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) though all injection wells.

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

u = Flow meter.

8.3 CO_2 Produced / Recycled

Targa does not produce oil or gas or any other liquid at its Wildcat Gas Processing Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.6 below. Quantification strategies for leaks from the identified potential leakage pathways are discussed in Section 7.

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

(Equation RR-10)

where:

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

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

As required by 98.444(d) of Subpart RR, Targa will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases. Parameter CO_{2FI} in Equation RR-12 is the total annual CO_2 mass emitted or vented from equipment located between the flow meter for measuring injection quantity and the injection wellhead. A calculation procedure is provided in subpart W.

8.6 CO_2 Sequestered

Since Targa does not actively produce oil or natural gas or any other fluid at its Wildcat Gas Processing Plant, Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations.

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

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

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

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

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

9. Estimated Schedule for Implementation of MRV Plan

The baseline monitoring and leakage detection and quantification strategies described herein have been established since several years. It is the same for the data that has been collected by Targa for several years and continues to the present. Targa will begin implementing this MRV plan as soon as it is approved by EPA. After WC AGI #2 is drilled, Targa will reevaluate the MRV plan and if any modifications are a material change per 40CFR98.448(d)(1), Targa will submit a revised MRV plan as required by 40CFR98.448(d).

10. GHG Monitoring and Quality Assurance Program

Targa will meet the monitoring and QA/QC requirements of 40CFR98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 40CFR98.444(d).

10.1 GHG Monitoring

As required by 40CFR98.3(g)(5)(i), Targa's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

Measurement of CO_2 Concentration – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GPA) standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40CFR98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2 and RR-5, of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. Targa will adhere to the American Gas Association (AGA) Report #3 – Orifice Metering.

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines and using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1 3 CO_2 injected.

Daily CO_2 injected is recorded by totalizers on the volumetric flow meters on the pipelines to the WC AGI #1 well using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.4 CO_2 produced.

Targa does not produce CO_2 at the Wildcat Gas Processing Plant.

10.1.5 CO_2 emissions from equipment leaks and vented emissions of CO_2.

As required by 98.444(d), Targa will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

As required by 98.444(d) of Subpart RR, Targa will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used.

10.1.6 Measurement devices.

As required by 40CFR98.444(e), Targa will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40CFR98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.2 QA/QC Procedures

Targa will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

10.3 Estimating Missing Data

Targa will estimate any missing data according to the following procedures in 40CFR98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in Subpart RR, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

10.4 Revisions of the MRV Plan

Targa will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of Texas. If any operational changes constitute a material change as described in 40CFR98.448(d)(1), Targa will submit a revised MRV plan addressing the material change. Targa intends to update the MRV plan after WC AGI #2 has been drilled and characterized.

11. Records Retention

Targa will meet the recordkeeping requirements of paragraph 40CFR98.3(g) of Subpart A of the GHGRP. As required by 40CFR98.3(g) and 40CFR98.447, Targa will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:

(i) The GHG emissions calculations and methods used

(ii) Analytical results for the development of site-specific emissions factors, if applicable

(iii) The results of all required analyses

(iv) Any facility operating data or process information used for the GHG emission calculations

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, Targa will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) A copy of the most recent revision of this MRV Plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(9) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(10) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

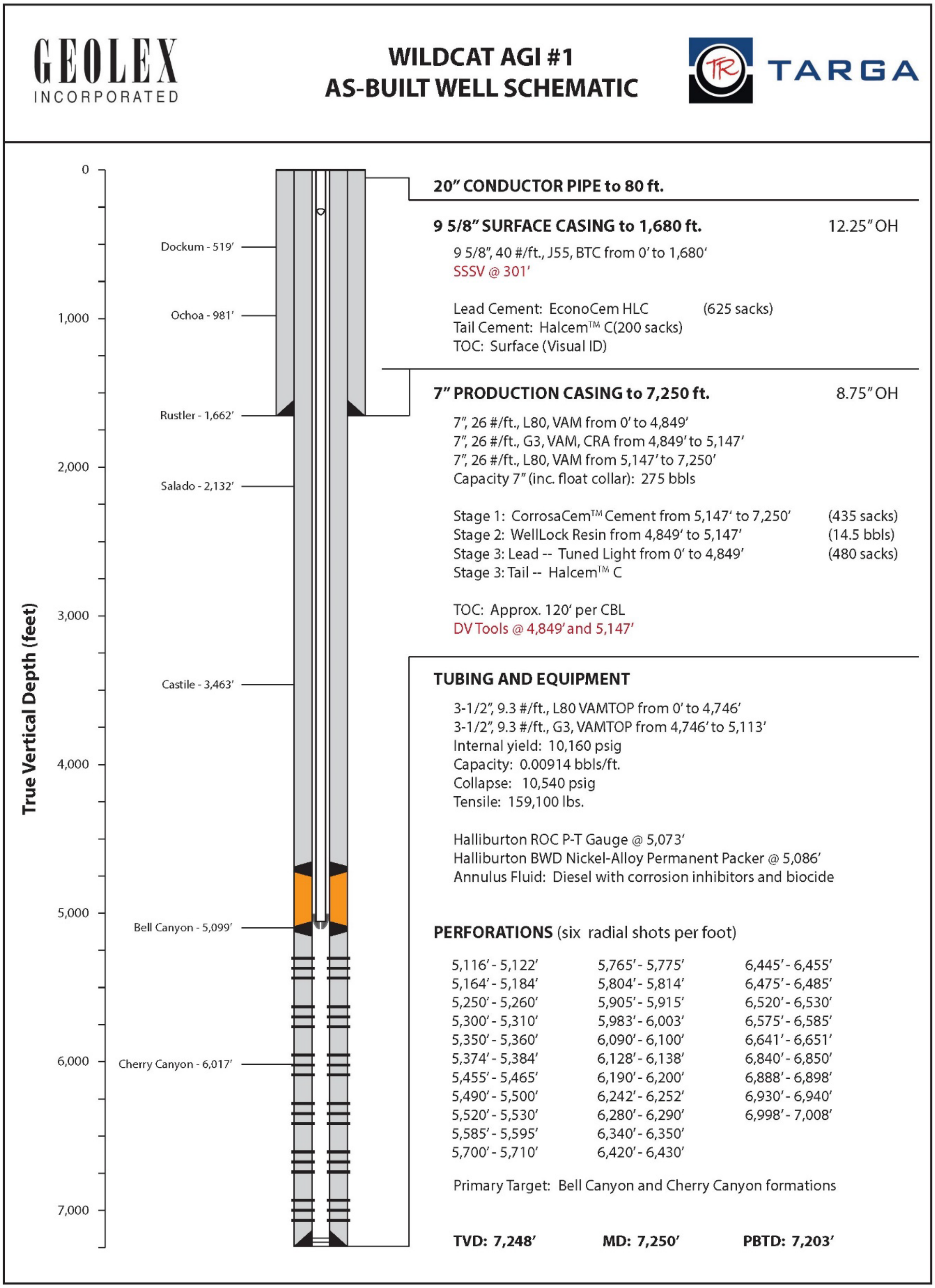
(12) Any other records as specified for retention in this EPA-approved MRV plan.

12 Appendices

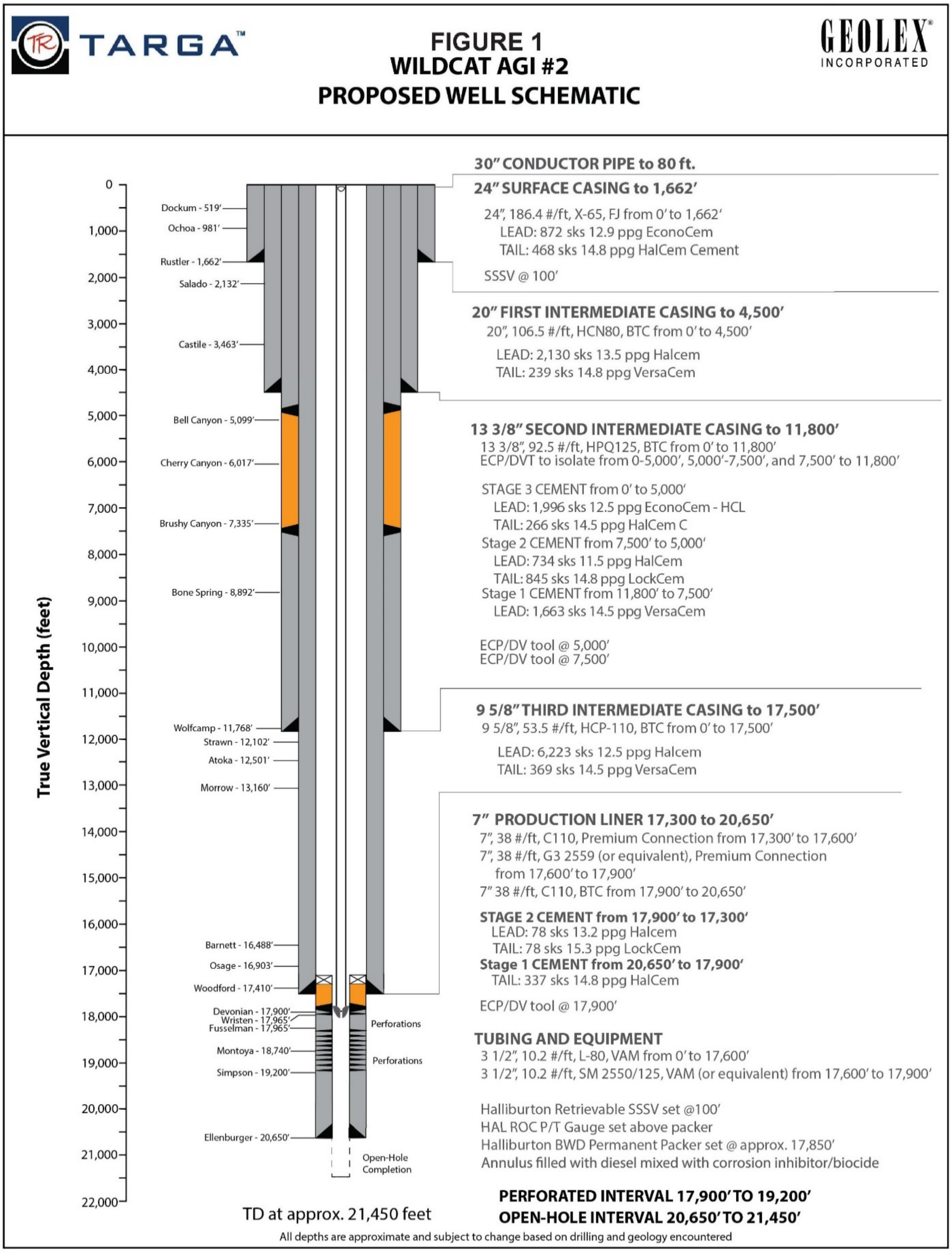
Appendix 1 Targa's WC AGI #1 and approved WC AGI#2 Wells Information and Schematics

***Appendix 1 Table 1**: WC AGI #1 and WC AGI #2 wells information*

Well Name	API #	Location	County	Spud Date	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (MMSCFD)	Maximum Surface Injection Pressure for Liquid (PSIG)
Wildcat AGI #1	42-495-34153	2,350' FNL & 2,450' FWL SECTION 39, BLOCK 27, SL/WADSWORTH	WINKLER, TEXAS	12/11/2018	5,115	7,250	28	2,980
Wildcat AGI #2	42-495-34929	2455' FNL & 2204 FEL, Section 39, Block 27, PSL Survey	WINKLER, TEXAS	Not Drilled	Not Drilled	Not Drilled	15	8,950



Appendix 1 Figure 1*: Schematic of Targa WC AGI #1 Well*



Appendix 1 Figure 2: *Schematic of approved Targa WC AGI #2 Well*

Appendix 2 Referenced Regulations

U.S. Code > Title 26. INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1. NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits > Section 45Q - Credit for carbon oxide sequestration

Texas Administrative Code > Title 16, Economic Regulation, > Part 1 Railroad Commissions of Texas > Chapter 3, Oil and Gas Division

CHAPTER 3 - OIL AND GAS

§3.1	Organization Report; Retention of Records; Notice Requirements
§3.2	Commission Access to Properties
§3.3	Identification of Properties, Wells, and Tanks
§3.4	Oil and Geothermal Lease Numbers and Gas Well ID Numbers Required on All Forms
§3.5	Application To Drill, Deepen, Reenter, or Plug Back
§3.6	Application for Multiple Completion
§3.7	Strata To Be Sealed Off
§3.8	Water Protection
§3.9	Disposal Wells
§3.10	Restriction of Production of Oil and Gas from Different Strata
§3.11	Inclination and Directional Surveys Required
§3.12	Directional Survey Company Report
§3.13	Casing, Cementing, Drilling, Well Control, and Completion Requirements
§3.14	Plugging
§3.15	Surface Equipment Removal Requirements and Inactive Wells
§3.16	Log and Completion or Plugging Report
§3.17	Pressure on Bradenhead
§3.18	Mud Circulation Required
§3.19	Density of Mud-Fluid
§3.20	Notification of Fire Breaks, Leaks, or Blow-outs
§3.21	Fire Prevention and Swabbing

§3.22	Protection of Birds
§3.23	Vacuum Pumps
§3.24	Check Valves Required
§3.25	Use of Common Storage
§3.26	Separating Devices, Tanks, and Surface Commingling of Oil
§3.27	Gas to be Measured and Surface Commingling of Gas
§3.28	Potential and Deliverability of Gas Wells to be Ascertained and Reported
§3.29	Hydraulic Fracturing Chemical Disclosure Requirements
§3.30	Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)
§3.31	Gas Reservoirs and Gas Well Allowable
§3.32	Gas Well Gas and Casinghead Gas Shall Be Utilized for Legal Purposes
§3.33	Geothermal Resource Production Test Forms Required
§3.34	Gas To Be Produced and Purchased Ratably
§3.35	Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned
§3.36	Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas
§3.37	Statewide Spacing Rule
§3.38	Well Densities
§3.39	Proration and Drilling Units: Contiguity of Acreage and Exception Thereto
§3.40	Assignment of Acreage to Pooled Development and Proration Units
§3.41	Application for New Oil or Gas Field Designation and/or Allowable
§3.42	Oil Discovery Allowable

§3.43	Application for Temporary Field Rules
§3.45	Oil Allowables
§3.46	Fluid Injection into Productive Reservoirs
§3.47	Allowable Transfers for Saltwater Injection Wells
§3.48	Capacity Oil Allowables for Secondary or Tertiary Recovery Projects
§3.49	Gas-Oil Ratio
§3.50	Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive
§3.51	Oil Potential Test Forms Required
§3.52	Oil Well Allowable Production
§3.53	Annual Well Tests and Well Status Reports Required
§3.54	Gas Reports Required
§3.55	Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering
§3.56	Scrubber Oil and Skim Hydrocarbons
§3.57	Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials
§3.58	Certificate of Compliance and Transportation Authority; Operator Reports
§3.59	Oil and Gas Transporter's Reports
§3.60	Refinery Reports
§3.61	Refinery and Gasoline Plants
§3.62	Cycling Plant Control and Reports
§3.63	Carbon Black Plant Permits Required
§3.65	Critical Designation of Natural Gas Infrastructure
§3.66	Weather Emergency Preparedness Standards
§3.70	Pipeline Permits Required
§3.71	Pipeline Tariffs
§3.72	Obtaining Pipeline Connections
§3.73	Pipeline Connection; Cancellation of Certificate of Compliance; Severance

§3.76	Commission Approval of Plats for Mineral Development
§3.78	Fees and Financial Security Requirements
§3.79	Definitions
§3.80	Commission Oil and Gas Forms, Applications, and Filing Requirements
§3.81	Brine Mining Injection Wells
§3.83	Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells
§3.84	Gas Shortage Emergency Response
§3.85	Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle
§3.86	Horizontal Drainhole Wells
§3.91	Cleanup of Soil Contaminated by a Crude Oil Spill
§3.93	Water Quality Certification Definitions
§3.95	Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations
§3.96	Underground Storage of Gas in Productive or Depleted Reservoirs
§3.97	Underground Storage of Gas in Salt Formations
§3.98	Standards for Management of Hazardous Oil and Gas Waste
§3.99	Cathodic Protection Wells
§3.100	Seismic Holes and Core Holes
§3.101	Certification for Severance Tax Exemption or Reduction for Gas Produced From High-Cost Gas Wells
§3.102	Tax Reduction for Incremental Production
§3.103	Certification for Severance Tax Exemption for Casinghead Gas Previously Vented or Flared
§3.106	Sour Gas Pipeline Facility Construction Permit
§3.107	Penalty Guidelines for Oil and Gas Violations

Appendix 3 Oil and Gas Wells within the Maximum Monitoring Area (MMA) of the Wildcat Gas Processing Plant

API	Well Name	Operator	Well Type	Well Status	Trajectory	Formation	TVD_FT
42-495-34077	GRIZZLY STATE 4045-27 3HR	DEVON	OIL & GAS	DRILLED	HORIZONTAL	WOLFCAMP	14,000
42-495-32752	ROARK ""34"" 2	PERCUSSION PETROLEUM II LLC	OIL	INACTIVE	VERTICAL	BONE SPRING	9,890
42-495-34153	WILDCAT AGI 1	Targa RESOURCES	INJECTOR	INJECTING	VERTICAL	CHERRY CANYON	7,248
42-495-10241	BAKWIN RUTH M. A 1	PAN AMERICAN PETROLEUM CORP.	DRY HOLE	P & A	VERTICAL		5,158
42-495-10242	BAKWIN RUTH M. A 2	PAN AMERICAN PETROLEUM CORP.	DRY HOLE	P & A	VERTICAL		1,896
42-495-10247	HENDRICK, T. G. 1	PAN AMERICAN PETROLEUM CORP.	GAS	P & A	VERTICAL	PENNSYLVANIAN	13,350
42-495-30270	WILSON 40 1	SHELL	GAS	P & A	DIRECTIONAL	BONE SPRING	15,426
42-495-33160	WILSON 40 2	SHELL	GAS	P & A	VERTICAL	ATOKA 6	15,633
42-495-70808	1A	PAN AMERICAN PETROLEUM CORP.		P & A	UNDETERMINED		0
42-495-34854	CHUCKWAGON B 27-34-39 WA 2H	PERCUSSION PETROLEUM II LLC	OIL & GAS	PERMITTED	HORIZONTAL	WOLFCAMP	12,500

42-495-34855	CHUCKWAGON C 27-34-39 WB 3H	PERCUSSION PETROLEUM II LLC	OIL & GAS	PERMITTED	HORIZONTAL	WOLFCAMP	12,500
42-495-34856	CHUCKWAGON D 27-34-39 WA 4H	PERCUSSION PETROLEUM II LLC	OIL & GAS	PERMITTED	HORIZONTAL	WOLFCAMP	12,500
42-495-34857	CHUCKWAGON E 27-34-39 WB 5H	PERCUSSION PETROLEUM II LLC	OIL & GAS	PERMITTED	HORIZONTAL	WOLFCAMP	12,500
42-495-32725	ROARK ""34"" 1	PERCUSSION PETROLEUM II LLC	GAS	PRODUCING	VERTICAL	ATOKA	16,746
42-495-33237	WADSWORTH 39 1	PERCUSSION PETROLEUM II LLC	GAS	PRODUCING	VERTICAL	WOLFCAMP	15,800
42-495-33727	THREE ELK STATE 4041-27 2H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,222
42-495-34019	GRIZZLY STATE 4045-27 A 1H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,193
42-495-34020	GRIZZLY STATE 4045-27 B 2H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,161
42-495-34021	GRIZZLY STATE 4045-27 C 3H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,303
42-495-34236	CHUCKWAGON A 27-34-39 6201H	PERCUSSION PETROLEUM II LLC	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,204

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Appendix 5 Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
API – American Petroleum Institute
CFR – Code of Federal Regulations
CO_2 – carbon dioxide
DCS – distributed control system
EPA – US Environmental Protection Agency, also USEPA
FSP - Fault Slip Potential modeling package of the Stanford Center for Induced and Triggered Seismicity
ft – foot (feet)
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MMSCF – million standard cubic feet
MMSCFD – million standard cubic feet per day
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NIST - National Institute of Standards and Technology
PPM – Parts Per Million
psia – pounds per square inch absolute
QA/QC – quality assurance/quality control
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TexNet - Texas Seismological Network and Seismology Research
TVD – True Vertical Depth
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water
WC – Wildcat
WC AGI #1 – Wildcat Acid Gas Injection number 1
WC AGI #2 – Wildcat Acid Gas Injection number 2
XRD – x-ray diffraction

Appendix 6 Targa's AGI Wells - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

	Subpart RR Equation	Description of Calculations and Measurements*	Pipeline	Containers	Comments
CO_2 Received	RR-1	calculation of CO_2 received and measurement of CO_2 mass…	through mass flow meter.	in containers. **	
	RR-2	calculation of CO_2 received and measurement of CO_2 volume…	through volumetric flow meter.	in containers. ***	
	RR-3	summation of CO_2 mass received …	through multiple meters.		
CO_2 Injected	RR-4	calculation of CO_2 mass injected, measured through mass flow meters.			
	RR-5	calculation of CO_2 mass injected, measured through volumetric flow meters.			
	RR-6	summation of CO_2 mass injected, as calculated in Equations RR-4 and/or RR-5.			
CO_2 Produced / Recycled	RR-7	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through mass flow meters.			
	RR-8	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through volumetric flow meters.			
	RR-9	summation of CO_2 mass produced / recycled from multiple gas-liquid separators, as calculated in Equations RR-7 and/or RR8.			
CO_2 Lost to Leakage to the Surface	RR-10	calculation of annual CO_2 mass emitted by surface leakage			
CO_2 Sequestered	RR-11	calculation of annual CO_2 mass sequestered for operators ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, produced, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head, and emitted from surface equipment between production well head and production flow meter.			Calculation procedures are provided in Subpart W of GHGRP.
	RR-12	calculation of annual CO_2 mass sequestered for operators NOT ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head.			Calculation procedures are provided in Subpart W of GHGRP.

* All measurements must be made in accordance with 40 CFR 98.444 – Monitoring and QA/QC Requirements.
** If you measure the mass of contents of containers summed quarterly using weigh bill, scales, or load cells (40 CFR 98.444(a)(2)(i)), use RR-1 for Containers to calculate CO_2 received in containers for injection.
*** If you determine the volume of contents of containers summed quarterly (40 CFR 98.444(a)(2)(ii)), use RR-2 for Containers to calculate CO_2 received in containers for injection.

Appendix 7 Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

RR-1 for Calculating Mass of CO_2 Received through Pipeline Mass Flow Meters

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}}$$

(Equation RR-1 for Pipelines)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).

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

p = Quarter of the year.

r = Receiving flow meter.

RR-1 for Calculating Mass of CO_2 Received in Containers by Measuring Mass in Container

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}}$$

(Equation RR-1 for Containers)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

$Q_{r,p}$ = Quarterly mass of contents in containers r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass of contents in containers r redelivered to another facility without being injected into your well in quarter p (metric tons).

p = Quarter of the year.

r = Containers.

RR-2 for Calculating Mass of CO_2 Received through Pipeline Volumetric Flow Meters

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}}$$

(Equation RR-2 for Pipelines)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

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

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

p = Quarter of the year.

r = Receiving flow meter.

RR-2 for Calculating Mass of CO_2 Received in Containers by Measuring Volume in Container

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}}$$

(Equation RR-2 for Containers)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

$Q_{r,p}$ = Quarterly volume of contents in containers r in quarter p (standard cubic meters).

$S_{r,p}$ = Quarterly volume of contents in containers r redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

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

p = Quarter of the year.

r = Containers.

RR-3 for Summation of Mass of CO_2 Received through Multiple Flow Meters for Pipelines

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r}$$

(Equation RR-3 for Pipelines)

where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 or RR-2 for flow meter r.

r = Receiving flow meter.

RR-4 for Calculating Mass of CO_2 Injected through Mass Flow Meters into Injection Well

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

(Equation RR-4)

where:

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

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

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

p = Quarter of the year.

u = Flow meter.

RR-5 for Calculating Mass of CO_2 Injected through Volumetric Flow Meters into Injection Well

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

RR-6 for Summation of Mass of CO_2 Injected into Multiple Wells

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) though all injection wells.

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

u = Flow meter.

RR-7 for Calculating Mass of CO_2 Produced / Recycled from a Gas-Liquid Separator through Mass Flow Meters

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

(Equation RR-7)

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Quarterly gas mass flow rate measurement for separator w in quarter p (metric tons).

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

p = Quarter of the year.

w = Separator.

RR-8 for Calculating Mass of CO_2 Produced / Recycled from a Gas-Liquid Separator through Volumetric Flow Meters

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

(Equation RR-8)

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Volumetric gas flow rate measurement for separator w in quarter p (standard cubic meters).

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

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

p = Quarter of the year.

w = Separator.

RR-9 for Summation of Mass of CO_2 Produced / Recycled through Multiple Gas Liquid Separators

$$CO_{2P} = (1+X) * \sum_{w=1}^{W} CO_{2,w}$$ (Equation RR-9)

where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) though all separators in the reporting year.

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO_2 in produced oil or other liquid divided by the CO_2 separated through all separators in the reporting year (wt. percent CO_2 expressed as a decimal fraction).

w = Separator.

RR-10 for Calculating Annual Mass of CO_2 Emitted by Surface Leakage

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$ (Equation RR-10)

where:

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

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

RR-11 for Calculating Annual Mass of CO_2 Sequestered for Operators Actively Producing Oil or Natural Gas or Any Other Fluid

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \quad \text{(Equation RR-11)}$$

Where:

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

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

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

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

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

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

RR-12 for Calculating Annual Mass of CO_2 Sequestered for Operators NOT Actively Producing Oil or Natural Gas or Any Other Fluid

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad \text{(Equation RR-12)}$$

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

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

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

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