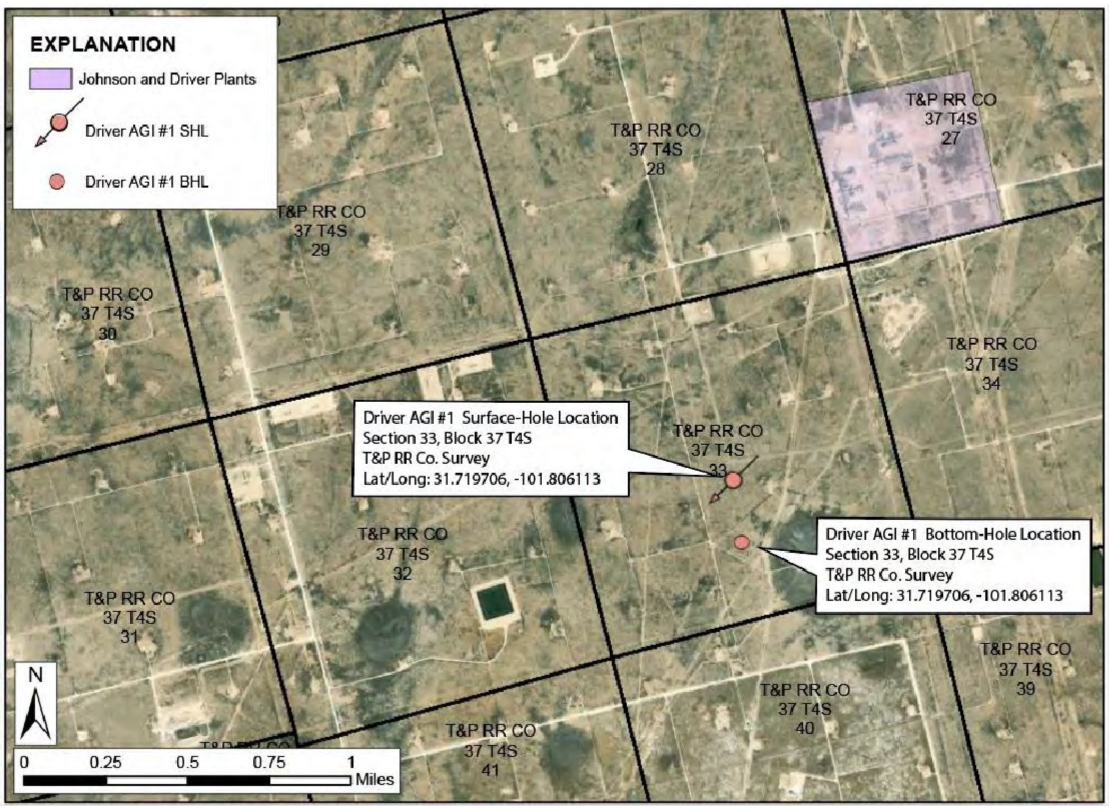
MONITORING, REPORTING AND VERIFICATION (MRV) PLAN

PURSUANT TO [40 CFR 98.448(a)(1) SUB-PART RR]

Driver AGI #1
Midland County, Texas



Submitted to:
The Greenhouse Gas Reporting Program (GHGRP)
implemented by the U.S. Environmental Protection Agency Headquarters

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1.0 INTRODUCTION

Targa Permian CO_2 Sequestration, LLC (Targa) has been authorized by the Railroad Commission of Texas (RRC) to operate one (1) treated acid gas (TAG) injection well, the Driver AGI #1, for the disposal of Underground Injection Control (UIC) Class II waste, consisting of carbon dioxide (CO_2) and hydrogen sulfide (H_2S) from Targa-owned natural gas processing operations. Targa hereby submits this Monitoring, Reporting, and Verification (MRV) Plan to the U.S, Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP) for consideration and approval in conjunction with the issuance of the approved permit for injection (UIC Permit #17479). The acid gas injection (AGI) well, Driver AGI #1, is located in Midland County, Texas, approximately 25 miles southeast of Midland, Texas (Figures 1 and 2), with approximate surface- and bottom-hole locations as follows:

Driver AGI #1:

Surface Legal Location:	2,260' FSL & 2,626' FWL, Sec. 33, Block 37 T4S, T&P RR Co. Survey
Surface Coordinates:	31.722493, -101.806531 (NAD83)
Bottom-Hole Coordinates:	31.719706, -101.806113 (NAD83)

Targa has been authorized to inject up to 20 million standard cubic feet (ft) per day (MMSCFD) of TAG into the Driver AGI #1 well (well API number to be determined), in accordance with RRC Statewide Rule (SWR) 9. This 20 MMSCFD injection rate represents approximately 950 metric tons of CO_2 per day permanently sequestered via this newly approved well. Application to the RRC under the UIC Class II injection permit program was filed on August 4, 2023. Following technical and administrative review of the application by RRC as well as a public hearing to ensure compliance with RRC SWR 36, the application for the Driver AGI #1 well was approved through issuance of UIC Class II Permit #17479.

The Driver AGI #1 well is designed and will be constructed to safely inject up to 20 MMSCFD of TAG produced from surrounding Targa-owned and operated oil and gas processing operations, for a design life of at least 30 years. The target injection interval is within the Ordovician Ellenburger Group, which is a common "deep" and well demonstrated injection target for disposal operations in the Midland Basin of Texas.

The injected TAG stream is anticipated to consist of approximately 90% CO_2 and 10% H_2S, with trace components of hydrocarbons (C_1 – C_7) and nitrogen. Targa has received authorization to inject H_2S, under RRC SWR 36, and has developed and will implement a RRC SWR 36-approved H_2S Contingency Plan designed to protect the public, Targa personnel, and the environment.

Targa has elected to submit this Monitoring, Reporting, and Verification (MRV) Plan for approval in accordance with 40 CFR 98.440 (c)(1), Subpart RR, of the GHGRP administrative rule for the purposes of qualifying for applicable tax credits in Section 45Q of the Federal Internal Revenue Code.

The MRV Plan developed for the Driver AGI #1 well contains all the information required to be submitted by Subpart RR within the following sections:

Section 1: Introduction

Section 2: Facility Information

Section 3: Project Description

Section 4: Delineation of the Maximum Monitoring Area (MMA) and the Active Monitoring Area (AMA), as defined in 40 CFR 98.449, and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

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

Section 6: Methods for detection, verification, and quantification of leakage from the identified potential sources of CO_2 leakage, as required by 40 CFR 98.448(a)(3).

Section 7: 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 8: 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: Estimated schedule for implementation of the MRV Plan, as required by 40 CFR 98.448(a)(7).

Section 10: Description of 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 periods of data loss, as described in 40 CFR 98.445.

Section 11: Description of records retention 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 GHGRP.

Section 12: Appendices supporting the MRV Plan, including information required by 40 CFR 98.448(a)(6).

2.0 FACILITY INFORMATION

The proposed Driver AGI #1 well and associated gas-compression facilities are to be constructed in Midland County, Texas, on privately owned surface lands. Targa has approval to construct and operate the Driver AGI #1 well and construct associated surface equipment and facilities. Specific information regarding the operator, facility, and wells has been included in this section.

The injection facilities will service Targa's gas-processing operations in the area and the proposed Driver AGI #1 well will dispose of only approved UIC Class II treated acid gas containing CO_2 and H_2S derived from these oil and gas facilities. The associated facilities will receive the treated acid gas from nearby Targa gas processing plants, which will then be compressed to a supercritical state at the surface and injected into deep, isolated geologic strata of the Ellenburger Group for permanent sequestration. Thoughout the document "Targa Permian CO_2 Sequestration Well" will be referred to as the "facility".

2.1 OPERATOR INFORMATION AND GREENHOUSE GAS REPORTING PROGRAM ID

Targa Permian CO_2 Sequestration, LLC
811 Louisiana Street, Suite 2100
Houston, Texas 77002
(713) 584-1000

Greenhouse Gas Reporting Program ID: 589381

2.2 INJECTION WELL INFORMATION AND IDENTIFICATION NUMBERS

This MRV Plan is for the Driver AGI #1 well (Appendix 1), for which an Underground Injection Control (UIC) Class II Application has been approved and issued by the RRC. The details of the injection operations process are provided in Section 3.8 of this document and well information is summarized below.

Driver AGI #1:

Surface Legal Location:	2260' FSL & 2626' FWL, Sec. 33, Blk. 37 T4S, T&P RR Co. Survey
Surface Coordinates:	31.722493, -101.806531 (NAD83)
Bottom-Hole Coordinates:	31.719706, -101.806113 (NAD83)
RRC Application Tracking #:	56669
API:	TBD
UIC Permit #:	17479

2.3 UNDERGROUND INJECTION CONTROL (UIC) PERMIT CLASS

For the injection well that is the subject of this MRV Plan, the RRC, having primacy for the Class II UIC injection well program, has approved and will regulate the operation of the Driver AGI #1 well. The subject well application has undergone administrative and technical review by the RRC technical personnel and an approved UIC Class II permit (Permit #17479) has been issued under RRC SWR 16.1.3 §3.9 (see Appendix 2). All oil- and gas-related wells in the vicinity of the Driver AGI #1 well, including injection and production wells, are regulated by the RRC.

3.0 PROJECT DESCRIPTION

The following project description has been developed by Targa, along with a Hydrogen Sulfide Contingency Plan pursuant to RRC SWR 36 (dated September 2023), which has been accepted by the RRC Hydrogen Sulfide Safety Coordinator and will be implemented at the Driver AGI #1 well site. Approval of Targa's Hydrogen Sulfide Contingency Plan, and certification of compliance with RRC SWR 36, was issued on November 11, 2023 (H-9 Certification #128214)

For the purposes of characterizing the proposed injection CO_2 sources or acid gas, the nearest natural gas processing plants to the AGI well are Targa's Johnson and Driver plants, located in Section 27, Block 37 T4S, of the T&P RR Co. Survey. While the Johnson and Driver facilities are nearest to the AGI well, natural gas processing associated with production operations in the basin also occurs at the Legacy, Legacy 2, Midkiff, Pembrook, Pembrook 2, Joyce, Edwards, and Benedum Plants. A map illustrating the location of each of the plants and the Driver AGI #1 well is included as Figure 3. Targa collects gas from multiple sources at a central facility, where it is aggregated before being transported to treatment facilities for processing. All of the referenced facilities will be capable of sending acid gas to the injection well via pipeline. Targa anticipates that additional processing plants may be added, and Targa will report those additional sources if and when, incorporated.

In the following sections, this MRV Plan describes the general geologic setting of the project area, surface and bedrock geology, stratigraphy and structure of the project area, groundwater hydrology, and provides detailed evaluation of the proposed injection zone characteristics and confining strata. Additionally, this MRV Plan assesses the potential risk for injection-induced seismicity and evaluates the impact of injection through geologic modeling and simulation.

3.1 GENERAL GEOLOGIC SETTING AND SURFICIAL GEOLOGY

The Driver AGI #1 well injection site is situated approximately 25 miles southeast of Midland, Texas, within the Midland Basin. The basin in the project area consists of a Paleozoic and Mesozoic sedimentary section of lithologies approximately 13,000 to 14,000 ft thick, with age ranges from the Cambrian (Bliss Sandstone), which lies directly on the Precambrian basement, to the near-surface Cretaceous aquifer (Trinity Edwards Plateau). A Quaternary section lies unconformably above sedimentary rocks from the Cretaceous Period. At the injection site location, and at the nearest Targa gas-processing plant, the surface geology consists of Quaternary, windblown cover sand (Qcs, Figure 4). These sands are composed of fine- to medium-grained quartz and varying, but limited, amounts of silt and caliche. The color of the unit is typically gray-red and may be massive with a typical thickness of 15 ft (Geologic Database of Texas, 2023).

3.2 BEDROCK GEOLOGY

3.2.1 Description of Depositional Basin

Sequestration operations for the approved Driver AGI #1 well will occur within the Permian Basin, which is a large depocenter located in west Texas and southeast New Mexico. Specifically, the Driver AGI #1 well and the associated gas-processing plants, which generate the waste CO_2 and H_2S to be sequestered via the AGI well, are located in the Midland Basin, which is the eastern, westward-dipping subdivision of the Permian Basin (Figure 5).

The Permian Basin is a sedimentary basin primarily comprised of Paleozoic and early Mesozoic strata, lying above crystalline Precambrian basement and below recent Quaternary deposits (Figure 6). Oil and gas production occurs from multiple intervals within the basin, but in the vicinity of the AGI well, production is primarily from the Permian-aged Spraberry, Dean, and Wolfcamp formations, as well as the Strawn (Pennsylvanian) and Devonian geologic strata. Injection operations primarily occur within the Permian San Andres Formation, Silurian through Devonian strata, and within the Ellenburger Group (Ordovician).

3.2.2 Stratigraphy of the Project Area

Within the Midland Basin project area, geologic strata of the Cambrian through Cretaceous are preserved, which are overlain by recent Quaternary deposition. A summary of the anticipated formations that underlie the AGI well project area is included in Table 1 below.

Table 1. Anticipated formation tops underlying the Driver AGI #1 well location

Driver AGI #1	
Formation	Depth (ft)
Dockum	157
Dewey Lake	622
Rustler	1,465
Yates	2,291
Grayburg	3,561
San Andres	3,904
Glorieta	5,065
Clear Fork	5,495
Spraberry	7,068
Wichita-Albany	8,635
Wolfcamp	8,924
Strawn	10,506
Atoka	10,856
Osage	11,367
Woodford	11,378
Devonian	11,476
Wristen	11,807
Fusselman	11,970
Montoya	12,039
Simpson	12,114
Ellenburger	12,259

Within geologic strata overlying the target interval for injection operations (Ellenburger Group), significant oil and gas resources are preserved and are produced in this area of the Permian Basin. As described in the previous section, significant production operations occur to develop the Spraberry through Wolfcamp intervals, with more minor and isolated production operations occurring in the Strawn and Devonian intervals in the area of the Driver AGI #1 well.

The lower Paleozoic sedimentary section of the basin, which includes the proposed Ellenburger Group injection interval, lies atop Precambrian, crystalline basement, with the lowest sedimentary formation being the Cambro-Ordovician Bliss Formation. The Bliss Formation, often referred to as the Bliss Sandstone, is often present in the project area but is deep, underlying the AGI well injection zone, and is rarely penetrated and logged by oil and gas exploration wells. The Bliss Sandstone is typically subarkosic and is comprised of lowstand clastic deposits (Loucks and Anderson,1980) derived from erosion of Cambrian and Precambrian plutons (Stagemen, 1989).

The Ordovician Ellenburger Group, the injection target interval for the Driver AGI #1 well, lies above the Bliss Formation and is overwhelmingly comprised of dolomite, dolomitic limestone, and limestone (Kerans, 1990), for which primary textures are often obscured by multiple diagenetic events (Clemons, 1989). The Ellenburger is broadly subdivided into three stratigraphic units, herein described as the lower, middle, and upper Ellenburger. The lower Ellenburger is interbedded with the Bliss Formation and represents the shoreward gradational facies transition from alluvial fans and coastal sabkha to a high-energy, restricted subtidal facies consisting of ooids, cryptalgal laminae, and cross stratification (Kerans, 1990). The middle Ellenburger represents low energy, restricted subtidal to intertidal facies containing burrows and parallel laminations (Kerans, 1990). The upper Ellenburger primarily contains tidal flat facies with cryptalgal laminites, current ripples, and desiccation cracks (Kerans, 1990).

A pre-Simpson unconformity separates the Ellenburger Group from the Ordovician Simpson Group, which is comprised of fine-grained clastic and clay-rich carbonates deposited over a time when sea level was generally rising (transgression). Sandstone may be present locally in the Simpson Group, likely representing a high-order lowstand or early transgression (Jones, 2009).

The late Ordovician Montoya group lies above the Simpson Group and contains carbonates with varying degrees of dolomitization. The Montoya Group sediments were deposited on a shallow-water platform (Jones, 2009) and are often capped by a subaerial unconformity prior to transitioning to the Sylvan Shale, when it is present. The Sylvan Shale has a gradational contact with the overlying, late Ordovician to early Silurian Fusselman Formation, which contains strata similar to the Montoya Group and is often identifiable only by the presence of the Sylvan Shale between the two units. Karst-collapse breccias from dissolution features can be found in the Fusselman (Mazzullo and Mazzullo, 1992), but do not appear to be prevalent near the Driver AGI #1 project area.

The Wristen Group, above the Fusselman Formation, has a late Silurian age and contains greater facies diversity than the Fusselman Formation and Montoya Group below (Ruppel, 2009). Wristen Group sedimentation occurred in a variety of carbonate depositional environments and include facies from shallow, inner platform, shelf margin, slope, and deeper-water (basinal) facies. In the project area, only the slope and basinal facies are present (Ruppel, 2009), and are comprised of low-porosity, nodular wackestones and argillaceous mudstones.

In the early Devonian, sea levels rose in a transgression, depositing siliceous sands (proximal) and muds (distal), before a progradational high-stand recreated the dominant set of depositional environments resulting in distal, fan-deposited siliceous, to distal, siliceous skeletal sands, and proximal skeletal sands. The skeletal sands from both environments make up the Devonian Thiryone Formation, of which, the dominant facies are crinoid-rich packstones and grainstones and bedded, spiculitic chert (Saller et al., 1991; Ruppel and Holtz, 1994). In the project area, the Thirtyone Formation is dolomitized starting at approximately 100 to 200 ft from the top of the formation. A subaerial unconformity marks the end of Devonian Thirtyone deposition and was responsible for karsting in the upper portion of the interval.

Widespread flooding during the late Devonian resulted in deposition of the Woodford Shale, an aerially expansive unit consisting primarily of pelagic black shale and siltstone. The black shale is the most common rock type and contains abundant organic matter and pyrite (Comer, 1991). Paleo-topography upon the lower, karsted terrains helped control Woodford deposition. Woodford is recognized as a regional seal and source rock, and in the project area, it is approximately 100-ft thick.

Within the sequence of lower Paleozoic strata described above, the target Ellenburger injection zone is overlain by the Simpson Group primary reservoir seal, which is comprised of alternating shales and siltstones which prevent the vertical migration of injectate out of the target reservoir. Furthermore, a secondary regional seal is present in the form of the laterally extensive Woodford Shale. Underlying the injection zone, lower confining strata restrict downward migration as the majority of the Lower Ellenburger (not included as part of the injection zone) is comprised of tight, low-porosity and low-permeability carbonates which do not exhibit the level of porosity and permeability development observed within the Middle and Upper Ellenburger strata.

3.2.3 Faulting and Natural Fracturing

Deformation within the Ellenburger is primarily the result of localized karstification during multiple post-depositional lowstands. Repeated subaerial exposure of Ellenburger strata resulted in the development of significant karst networks and subsequent burial and collapse produced large porosity networks within the collapse breccia, which has made the Ellenburger Group an excellent and well-demonstrated repository for underground Class II oil and gas-processing waste disposal. Tectonic faults and fractures, primarily formed in the Pennsylvanian and post-date the development of karst-collapse features (Loucks and Anderson, 1985; Kerans, 1989; Holtz and Kerans, 1992; Combs et al., 2003).

The brecciated collapse features, previously described, are the most prominent features visible in analysis of three-dimensional (3D) seismic survey data. The overlying seal, comprised of the Simpson Group, is also deformed by the cave collapse, though the magnitude of deformation does not create enough vertical offset to produce a breach or escape pathway across the primary reservoir seal. Tectonic fractures are likely present; however, such features are not resolvable or distinguishable within the 3D seismic volume and do not compromise the seal above the reservoir as the mechanical contrast between the carbonates of the Ellenburger and the bedded clastics of the Simpson Group inhibit upward fracture propagation.

Tectonic faults, interpretable through analysis of 3D seismic, are present in the general vicinity, but are not within the maximum monitoring area (MMA) and are, hence, outside of the expected plume migration pathway. Such faults likely failed with strike-slip motion and exhibit minimal vertical separation and are incapable of offsetting the sealing lithologies and therefore remains a good caprock overlying the target Ellenburger injection interval.

3.3 **LITHOLOGIC AND RESERVOIR CHARACTERISTICS**

3.3.1 Reservoir Containment and Confining Zones

The primary confining zone above the injection reservoir is the fine-grained, bedded lithologies of the Simpson Group. These strata, previously described in Section 3.2.2, dip to the west (approximately 255-degree azimuth dip direction) and have a regional dip magnitude of approximately one (1) degree. Locally, the Simpson Group dip may vary, due to the underlying paleo-karst topography on which the Simpson Group sediments were deposited.

The thickness of the Simpson Group is variable but thickens down dip to the west (Figure 5). In the project area, the Simpson Group is approximately 150-ft thick (Figures 7 and 8). Approximately 13 miles to the west of the MMA, thickness of the interval increases significantly (up to 330 ft thick) and pinch out of the unit occurs approximately 5 miles east of the Driver AGI #1 well.

Secondary reservoir seals and baffles are also present above the Simpson and will inhibit the upward migration of the plume, should there be any minor leakage across the Simpson Group interface. The baffles are present within the low-porosity, low-permeability carbonates of the Montoya Group and the Fusselman Formation, which are approximately 150-ft thick in the project area. This is overlain by approximately 165 ft of Wristen Group containing abundant fine-grained, sealing lithologies. Any injectate that hypothetically migrates above the Wristen will be inhibited by the low-porosity zones within the lower Devonian Thirtyone Formation, or may be trapped within the Devonian reservoir, which is a common alternative injection reservoir target locally, and within the greater Permian Basin. The Devonian Thirtyone is confined above by approximately 100 ft of the expansive and competent Woodford Shale, which is likely over pressured (and unlikely to allow upward migration) due to intraformational hydrocarbon generation.

As discussed in Section 3.2.2, the tight, low-porosity and low-permeability carbonates of the Lower Ellenburger strata underlying the injection zone, restrict downward migration of the TAG stream thereby serving as a lower confining zone.

3.3.2 Characteristics of the Injection Reservoir

The Ellenburger Group is the only geologic interval that will be utilized for the permanent sequestration of acid gas. The three stratigraphic units of the Ellenburger Group, described in Section 3.2.2, were subdivided by Kerans (1990) into six (6) general depositional systems and associated lithologies through extensive review and evaluation of core and wireline log data. These subdivisions include the following:

1. Fan delta and marginal marine setting consisting of litharenite (deepest)
2. Lower tidal flat environment consisting of mixed siliciclastic-carbonate packstone-grainstone
3. High-energy, restricted-shelf environment consisting of ooid-peloid grainstone
4. Low-energy, restricted-shelf environment consisting of mottled mudstone, and
5. Upper tidal flat consisting of laminated mudstone (shallow)
6. Open, shallow-water shelf environment consisting of grainstones and packstone (shallow)

The injection reservoir will be comprised of carbonate lithologies, primarily from the lower tidal-flat and restricted-shelf facies. Due to the complex diagenetic history of the Ellenburger Group, the primary lithology of the injection interval is overwhelmingly dolomite within the project area.

Porosity in the reservoir consists of primary interparticle porosity and secondary porosity related to karst-system development, karst collapse, and natural fractures. The primary porosity is a minor constituent of the entire porosity profile of the Ellenburger, as numerous diagenetic events have resulted in carbonate cement fill. The most prolific porosity is within the paleo-karst and karst-collapse features, which have created a brecciated network of high-quality reservoir, which has maintained suitable reservoir porosity and permeability characteristics, which were further enhanced through continued diagenetic processes. Within natural fractures, porosity development is negligible; however, the fractures likely play a critical role in the effective porosity of the Ellenburger injection reservoir. The Ellenburger Group injection reservoir, within the area of the project MMA, is approximately 464-ft thick, with an average porosity of approximately 7%, and the maximum porosity, as determined in wireline log analysis, is approximately 15%. The distribution of porosity within the injection zone is shown in Figure 9 for the MMA, as derived from wireline log evaluation and high-resolution seismic trace inversion analysis.

Loucks et al. (2007) developed an expected permeability transform based on a thorough analysis of whole-core samples, collected from the Ellenburger Group while drilling the Goldrus Barnhart Unit #3 well. From this baseline analysis, further assessment and injection analyses of nearby Ellenburger injection wells (e.g., Clay Henry SWD #1 [API: 42-329-42349]) near the Targa AGI well project area dictated the need for a permeability multiplier in order to match existing Salt Water Disposal (SWD) well operating conditions. Using this process within the Targa Driver AGI #1 well project area, the following permeability transform was developed:

$$Permeability = 0.6557\ x\ e^{22.521\ (Porosity)}$$

Based on the above permeability transform function and the porosity distribution (derived from acoustic impedance mapping), the average permeability of the reservoir within the MMA is 4.8 millidarcies (mD) and the maximum permeability is 29 mD. Depending on the degree of modification of the reservoir through dissolution processes (i.e., karst development), the ranges of porosity and permeability agree with petrophysical parameters described by Holtz and Kerans, 1992 (Figure 10).

3.4 **FORMATION FLUID CHEMISTRY**

The United State Geological Survey (USGS) Produced Water Database (version 2.3) was used to characterize anticipated formation fluid chemical properties. Utilizing this fluid chemistry database, 16 wells were identified, within approximately 25 miles of the Driver AGI #1 well, for which Ellenburger Group produced water sample analyses were reported (Figure 11). On average, the specific gravity of the formation fluid is 1.10, the pH is 6.79, and the total dissolved solids (TDS) concentration is 152,768 parts per million (ppm). Summary statistics of the data are presented below in Table 2, which also includes major cation and anion concentrations. A complete summary of fluid chemistry data for the 16 wells identified is included in Appendix 3. Based on extensive experience with injection wells into the Ellenburger Group, the formation fluid chemistry is compatible with the proposed injection fluid.

Table 2. Average, maximum, and minimum geochemical values from Ellenburger Group produced water samples. Values are calculated from available data in the USGS Produced Water Database and reflect 16 wells within 25 miles of the project area.

	Specific Gravity	pH	TDS (ppm)	Na (mg/L)	Ca (mg/L)	Mg (mg/L)	K (mg/L)	Sr (mg/L)	Cl (mg/L)	Br (mg/L)	SO_4 (mg/L)	HCO_3 (mg/L)
Avg	1.10	6.79	152768	47481	9264	1755	745	271	93815	190	810	302
Max	1.16	8.05	237447	66482	20216	3394	838	478	146358	190	1768	1414
Min	1.06	5.01	102978	33268	4252	644	652	81	63780	190	494	70

3.5 EVALUATION OF THE POTENTIAL FOR INJECTION-INDUCED SEISMICITY

The Driver AGI #1 well is located approximately six (6) miles north-northeast of Midkiff, Texas, in an area with no significant history of seismic activity, as demonstrated by U.S. Geological Survey records and the TexNet seismic data repository for the State of Texas (Figure 12). Within a 25 km radius, there have been 17 events recorded by USGS and 19 events recorded by TexNet, the largest of which was a magnitude 3.3. The seismic event nearest to the injection wells occurred approximately 8 miles (8 miles) from the project area, on July 25, 2023, and was documented as a magnitude 2.0 event.

Operation of the Driver AGI #1 well is not anticipated to negatively impact the induced-seismicity risk in the area. At reservoir temperature and pressure conditions, the Driver AGI #1 well, which injects a mixture of CO_2 and H_2S as a supercritical fluid, will inject the equivalent of 0.0528 MMSCFD (the 0.0528 MMSCFD value reflects the equivalent injection rate of 20 MMSCFD but in the reservoir condition), whereas it is not uncommon for SWD wells to dispose of greater than 0.22 MMSCFD. Furthermore, the injection well is more than 24 miles (24 miles) from the nearest RRC-designated Seismic Response Area (SRA), which represents areas in which injection operations are monitored to assess their relationship to observed seismic events. In summary, the relatively low injection volume proposed for the Driver AGI #1, coupled with the lower fluid density and viscosity characteristics typical of a TAG stream relative to formation fluid, as well as the absence of historic seismic events, eliminates, or at least minimizes the total risk for induced seismicity related to the operation of the Driver AGI #1 well.

To strengthen and verify the assessment of induced-seismicity risk, a detailed review of a 3D seismic survey was completed, which indicates that there are no resolvable tectonic faults within the areal extent of the mapped project area, including within the MMA. As no faults are identified within the Ellenburger Group, there is no way to simulate the potential for injection-induced slip. Therefore, a fault-slip probability model, or similar suitable simulation method, was not conducted. As proposed, operation of the Driver AGI #1 well is not anticipated to increase the risk for induced-seismic events in the project area.

The Driver AGI #1 well will operate without exceeding the fracture pressure gradient of the Ellenburger Group injection reservoir. The fracture gradient for the Ellenburger is historically difficult to determine in deep-injection settings, such as those present in the project area, due to the scarcity of well data and the consistent ability of the Ellenburger to accept large volumes of fluid under relatively low injection pressures. Injection tests nearby in the Midland Basin, reviewed during development of this application, did not determine the fracture gradient during their tests, even during high injection rates of up to 202 cubic feet per minute (cfm). The Ellenburger Group, being heterogeneous and anisotropic, has both vertical and horizontal variation in its fracture gradient, primarily caused by the prevalence of karst processes and natural fracturing. Publications report varying fracture gradients within single Ellenburger wells ranging from 0.62 psi/ft. to 0.87 psi/ft. (Gibbs, 1968) and 0.50 psi/ft. to 0.85 psi/ft. (Crenshaw and Flippen, 1967). The lowest fracture gradients are most likely due to a high degree of karsting and natural fracturing.

To estimate the average fracture gradient for the Ellenburger near the Driver AGI #1, the reported range of fracture gradients from published and peer-reviewed works was applied to the density porosity log (corrected for dolomite) of the Midkiff SWD #1 (API: 42-329-42597), located approximately 5.1 miles southwest of the Driver AGI #1 well. As the highest density porosity in the Ellenburger corresponds to the highest degrees of natural fracturing, or karsting, it is assumed that such intervals will have the lowest fracture gradients. Therefore, intervals with a density porosity log response above 12% are expected to

have the lowest observed fracture gradient of 0.5 psi/ft. It is important to note that this represents a very small fraction of the gross Ellenburger interval (<3%) and intervals with these lower fracture gradients are consistently bound (above and below) by high fracture gradient intervals. From 1% to 12% density porosity, the fracture gradient of 0.87 psi/ft. to 0.56 psi/ft. was applied, with 0.87 psi/ft. being the greatest fracture gradient observed in literature (Gibbs, 1968) and 0.58 psi/ft. being the average of the lowest-observed fracture gradients reported by Gibbs (1968) and Crenshaw and Flippen (1967).
The resulting average fracture gradient for the project area is estimated to be 0.75 psi/ft. The vertical distribution of fracture gradients, estimated from the Midkiff SWD #1 well can be seen in Figure 13, along with the density porosity data used to calculate them.

The top of the injection interval for the Driver AGI #1 well is anticipated to be at depths of 12,259 TVD (True Vertical Depth). At that depth, and with a fracture gradient of 0.75 psi/ft., the expected fracture pressure will be approximately 9,197 psig, and 90% of that fracture pressure threshold is 8,275 psig. When comparing anticipated fracture pressures to reservoir modeling and simulation results, the Driver AGI #1 well is currently estimated to reach a maximum bottom-hole pressure of approximately 8,200 psi after 30 years of continuous injection operation based on pre-construction simulation results. This demonstrates that the simulated bottom-hole pressure will stay below 90% of the estimated fracture pressure and will not result in formation fracturing or any loss of containment within the Ellenburger disposal zone.

In summary, review of the project area, which included detailed analysis of 3D seismic survey data, did not identify faults in the project area, which may increase the risk for injection induced seismic events. Furthermore, operation of the Driver AGI #1 well, as approved, is not anticipated to exceed formation fracture pressures and poses little risk for loss of containment via the breakdown of Ellenburger Group strata.

3.6 **GROUNDWATER HYDROLOGY IN THE VICINITY OF THE PROPOSED AGI WELLS**

A detailed review of groundwater wells within the MMA was conducted utilizing the Texas Water Development Board (TWDB) online well database. Within the MMA, the TWDB database documents 112 water wells (Figure 14), of which, 28 are recorded as environmental soil borings and have been excluded from statistical summary, as the deepest boring is limited to only 20 ft below the ground surface. The remaining wells are listed as supply for domestic use, stock, fracking, irrigation, monitoring, and industrial use (additional listed uses include unknown, unused, and plugged or destroyed). The average depth of the wells of record is 265 ft, the minimum depth is 120 ft, and the maximum depth is 1,315 ft.

All the wells, with the exception of the deepest well (at 1,315 ft), produce water from the Antlers Sands, which is part of the Cretaceous Edwards-Trinity (Plateau) major aquifer system (Figures 15 and 16). There are no minor aquifer systems identified by the TWDB in the area of the proposed AGI wells.

As a required component of the RRC Class II injection permit application, a TWDB groundwater protection determination was requested and provided by the Groundwater Advisory Unit (GAU) for the Driver AGI #1 well. Following the completion of the groundwater assessment, Targa was issued a "No Harm Letter" stating that construction of the Driver AGI #1 well, as proposed, would not pose a risk to groundwater resources The TWDB protection determination also stated that groundwater resources require protection to a depth of 1,200 ft (Appendix 5). As such, the surface casing for the Driver AGI #1 well will extend a minimum of 50 ft below the base of the Underground Source of Drinking Water

(USDW) identified by TWDB personnel and will be cemented to the surface in order to ensure the protection of groundwater resources. In any case, surface casing will be at approximately 1,600 ft, within the Rustler Formation.

3.7 **HISTORY OF LOCAL PRODUCTION AND INJECTION OPERATIONS**

In the area of the proposed Driver AGI #1 well, production operations have historically occurred, and currently occur, within the overlying Spraberry geologic units (Figure 17), and of the 417 wells within the MMA, most are plugged or producing oil wells (Figure 18). All of these production intervals overlie the target Ellenburger Group injection interval and are separated by multiple intervals of low-porosity and low-permeability geologic units (Figure 19). Generally, the lower Paleozoic strata in the project area dips to the west. There has been no production from the Ellenburger Group within the MMA, however, there is one plugged well (API: 42-329-10125) that penetrates the Ellenburger Group, approximately 0.9 miles from the location of the Driver AGI #1 well (Figure 20). Though this well penetrated the Ellenburger Group, the interval was not productive of oil or gas. The original operator (Mobil Oil Corporation) set and cemented casing across the Ellenburger Group and the well was plugged back to a shallow production target (Spraberry/Wolfcamp). The casing installed across the Ellenburger Group was never perforated and the well was properly plugged and abandoned by Pioneer Natural Res. USA, Inc in July of 2012. All relevant plugging documents associated with this well have been included in Appendix 6 and a list of all wells within the MMA is included in Appendix 7.

Regarding historic injection operations, there are currently no existing or permitted wells that are injecting, or have received authorization to inject, into the Ellenburger Group within the MMA.

3.8 **DESCRIPTION OF THE ACID GAS INJECTION WELL PROCESS**

Operations occurring at the Targa injection facilities, on which the Driver AGI #1 well will be constructed, will include treated acid gas compression processes and disposal of UIC Class II waste gases via the Driver AGI #1 well. The injection facilities will receive, via pipeline transport, a waste gas stream containing CO_2 (90%) and H_2S (10%) generated by natural gas processing operations in the eastern Midland Basin. The Targa facilities that will transport UIC Class II waste gases to the injection facilities are described in Section 3.0 of this document and a map showing the location of the Targa facilities that may transmit waste gases to the injection site is included in Figure 3. Pipeline transmission systems, which will deliver TAG waste streams to the Driver injection site will be constructed in accordance with applicable standards and will be marked with appropriate warning signs along their respective rights-of-way.

The treated acid gas stream, or TAG stream, transported to the Driver AGI #1 injection site at low pressure, will be compressed at the surface utilizing a 4-stage reciprocating compression system to place the TAG in a supercritical fluid state. Supercritical TAG will then feed injection pumps that will pump the now supercritical TAG up to approximately 4,000 psig. The supercritical acid gas will then be injected down the permitted Driver AGI #1 well. In this staged-compression process, dehydration of the gas stream will be attained as residual water fractions will be removed during interstage cooling processes. Following compression, TAG is then routed to the Driver AGI #1, via high-pressure rated and corrosion resistant gas lines. A diagrammatic illustration of the post-compression operations and injection well is shown in Figure 21.

Design considerations for the Driver AGI #1 well includes construction standards and monitoring programs in accordance with AGI well best practices and those required to obtain approval for this MRV Plan. This includes the utilization of corrosion-resistant alloy (CRA) materials along critical subsurface depth intervals, acid-resistant cement slurries, and AGI well completion components (e.g., subsurface safety valve, down-hole pressure/temperature gauges, permanent injection packer, etc.) constructed of appropriate CRA-grade materials (e.g., Inconel 925, or similar). Figure 22 includes the approved well schematic for the Driver AGI #1 well.

In accordance with AGI well best practices, injection parameter monitoring for the Driver AGI #1 well will include continuous monitoring of critical injection parameters, including injection flow rate, surface injection pressure, surface injection temperature, surface annular pressure, bottom-hole injection pressure, and bottom-hole injection temperature. Continuous monitoring and detailed analysis of these parameters and long-term trends serves multiple purposes. Specifically, injection parameter monitoring, and detailed analysis provides an early warning system of conditions that may produce well integrity loss, allows rapid identification of on-going well integrity issues, and provides opportunity to complete a comprehensive reservoir performance evaluation.

3.9 **RESERVOIR MODELING, CHARACTERIZATION, AND INJECTION SIMULATION**

3.9.1 Reservoir Characterization and Geologic Model Development

To evaluate the impact of operation of the proposed Driver AGI #1 well, a detailed reservoir characterization model was created through the analysis of available geophysical log data and a comprehensive analysis of 3D seismic survey data. With existing knowledge of the Ellenburger Group injection interval (see Sections 3.2.2 and 3.3.2), it is apparent that porosity development and distribution within the Ellenburger is often sporadic, reflecting the development of secondary porosity through dissolution processes (i.e., karstification) and karst-collapse events. This variability of porosity development within karst terrains makes the incorporation of 3D seismic survey data critical for confidently resolving the spatial variability of Ellenburger reservoir porosity.

In review of the 3D seismic survey data covering the AGI well project area, Ellenburger Group karst topography is apparent, and was delineated through the completion of structure contour mapping. Natural fractures, including those associated with karst-collapse features, were interpreted through seismic incoherency analysis. These features, often enhanced through continued secondary porosity development (i.e., dissolution), are often critical fluid pathways that make Permian Basin carbonate reservoirs (e.g., San Andres Formation, Thirtyone Formation, Fusselman Formation, and Ellenburger Group) effective and well-demonstrated permanent storage complexes.

When the seismic volume is tied to stratigraphic correlations and wireline log analysis, reservoir quality and geometry can be characterized. This observed geometry of reservoir quality highlights the effect that karst processes had on Ellenburger Group reservoir quality. In developing the high-resolution reservoir characterization model for the Driver AGI #1 project area, which was utilized to determine the optimal well location and was the basis for subsequent dynamic modeling (i.e., injection simulations), seismic trace inversion analysis was completed to determine and map Ellenburger Group acoustic impedance attributes, which are directly related to porosity within the injection reservoir. Mapped acoustic impedance attributes were then transformed to porosity through direct correlation with log porosity. The transform function was capped at a maximum of 15% porosity, which was a common maximum value observed in nearby wireline porosity logs.

The geologic characterization model (i.e., static model) constructed to simulate the proposed Driver AGI #1 injection operations was developed utilizing the Petrel geo-modeling platform and generally contains ten (10) discrete vertical layers with geologic parameters derived from 3D seismic acoustic impedance properties (produced through seismic data analysis and inversion processing). The total model area measures approximately 88.5 square miles and can accommodate the entirety of the expected gas plume without encroaching on model boundaries. In total, the geo-model contains 1,651,410 simulation grid cells, each measuring 150 by 150 ft and having a thickness of 28.3 ft (15 cells make up the total thickness).

As constructed, porosity values within the static model range from 1.0 to 15% with an average model porosity of 6.2%. As described above, porosity attributes for the model were assigned using acoustic impedance data derived from high-resolution seismic trace inversion. Utilizing mapped impedance attributes, an impedance-porosity transform function was developed, which was verified through comparison to existing well logs to confirm accuracy of the transform and inversion model. The range of model porosity and average values agree with those observed in recent published results of whole-core analysis and recent studies relating to the Ellenburger Group injection reservoir (Holtz and Kerans, 1992). Table 3 below summarizes the thickness and average porosity values for each of the ten (10) model layers and the distribution of model porosity, by layer, is included in Figure 9.

Table 3. Summary of geologic model zone thickness and model porosity input parameters

Zone #	Layer Top (Ft. below Ellenburger)	Layer Base (Ft. below Ellenburger)	Thickness (ft.)	Average Porosity (Percent)
1	40	116	76	5.6
2	116	156	40	6.8
3	156	212	56	8.6
4	212	244	32	8.5
5	244	284	40	8.5
6	284	308	24	8.7
7	308	364	56	6.8
8	364	388	24	6.3
9	388	436	48	6.0
10	436	464	28	6.3

Static model permeability attributes were initially assigned utilizing an Ellenburger Group porosity-permeability transform function, which was identified in review of published, peer-reviewed literature relating to Ellenburger Group reservoir characteristics, and inclusive of whole-core analyses in which laboratory measurements of porosity and permeability were reported (Loucks, 2007). Following the incorporation of the initial porosity-permeability transform function, additional review and history matching of existing nearby injection operations indicated that a permeability multiplier was required to match disposal volume and injection pressures observed in the nearest SWD well. As such, the final static model permeability attributes were calibrated to match observed permeability values in nearby SWD wells. The resulting model permeability ranges from 0.8 to 16 mD, with a model average permeability of 3.0 mD. All static model porosity and permeability attributes have been reviewed and fall within expected ranges and average values, based on review of Ellenburger Group published literature, whole-core analyses, and injection well data.

3.9.2 Driver AGI #1 Injection Simulation

With the constructed geologic model, injection operations for the Driver AGI #1 were simulated (i.e., dynamic modeling) utilizing the Schlumberger Eclipse platform. Dynamic modeling was utilized to simulate injection of a mixed acid gas stream containing H_2S (10%) and CO_2 (90%) at a constant rate of 20 MMSCFD into the proposed Ellenburger Group reservoir with normally pressured initial conditions (based on review of existing SWD wells).

To ensure a conservative estimate of plume size, the dynamic model does not consider injectate dissolution into existing formation fluids, and injection has been restricted to the best reservoir intervals (model zones 2-6), which are 116-308 ft. below the top of the Ellenburger Group. Therefore, the entire thickness of the reservoir was not used in the model, which aids in maintaining a conservative estimate of plume size and areal extent. The results of the Driver AGI #1 injection simulation is shown in Figure 23 and 24, which indicate the conservative plume size will extend approximately 1.01 miles from the Driver AGI #1 bottom-hole location. As it is relevant to delineating the MMA (discussed further in Section 4.0), Figure 24 illustrates a one-half mile buffer zone around the resultant gas plume and the extent of free-phase TAG reflects a 30-year active injection period, followed by a 50-year post-injection period. Under these conservative simulation conditions, the Driver AGI #1 well fully sustains active injection operations (at a rate of 20 MMSCFD) for a simulation period of 30 years, while not exceeding or approaching the approved maximum allowable operating pressure (MAOP) or anticipated formation fracture pressure.

4.0 DELINEATION OF PROJECT MONITORING AREAS

In defining the Maximum Monitoring Area (MMA) and the Active Monitoring Area (AMA), reservoir modeling and injection simulation results, described previously in Section 3.9 and initially developed to support AGI well permitting under the UIC Class II injection well program, were utilized as the basis for delineating the relevant monitoring area. As indicated by the results of reservoir modeling and injection simulation, the resultant TAG plume is anticipated to extend a maximum of approximately 1.01 miles from the Driver AGI #1 upon completion of a 30-year active injection period and the post-injection period.

4.1 MAXIMUM MONITORING AREA (MMA)

In accordance with 40 CFR 98.449, the MMA is defined as "equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile". For the Driver AGI #1 project, Figure 24 shows the MMA, as defined by the most conservative simulation results of the TAG plume, after an active injection simulation period of 30 years and post-injection period of 50-years, plus a one-half mile buffer.

Using Schlumberger Petrel and Eclipse modeling and simulation platforms to create the project area geologic model and subsequent injection simulations (described in Section 3.9), a simulated TAG plume aerial distribution was estimated for the 30-year injection period, as well as a 50-year, post-injection period for the Driver AGI #1 well. While sufficient time has elapsed for the resultant gas plume to stabilize (i.e., when annual lateral migration rates became negligible and were observed to be unlikely to migrate beyond the maximum plume area further expanded by a one-half mile buffer zone), after five (5) years), we define the MMA based on results of the 50-year post shut-in period, as it provides a more conservative monitoring approach and is consistent with current UIC Class VI injection well program requirements.

The modeling described in Section 3.9, Figure 23 and Figure 24, indicate that the free phase TAG plume will be contained within the MMA/AMA for the 30-year injection period plus the 50-year post injection monitoring period.

Targa intends to start drilling and injecting in 2025. According to the reservoir modeling results, after 30 years of injection (year=2055) and after 50 years of post-injection (year=2105), the injected gas remained in the reservoir and no expansion of the TAG footprint was observed after 2105. Therefore, the plume extent at year 2105, 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=2105) are mapped in Figure 24.

The results of the Driver AGI #1 injection simulation is shown in Figure 23 and 24, which indicate the conservative plume size will extend approximately 1.01 miles from the Driver AGI #1 bottom-hole location. As it is relevant to delineating the MMA (discussed further in Section 4.0), Figure 24 illustrates a one-half mile buffer zone around the resultant gas plume and the extent of free-phase TAG reflects a 30-year active injection period, followed by a 50-year post-injection period. Under these conservative simulation conditions, the Driver AGI #1 well fully sustains active injection operations (at a rate of 20 MMSCFD), while not exceeding or approaching the approved maximum allowable operating pressure (MAOP) or anticipated formation fracture pressure.

4.2 ACTIVE MONITORING AREA (AMA)

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 bold dark grey line in Figure 24 (30-year plume outline). The area defined by Criteria 1 will be within the MMA, as the plume at t=2055 is smaller than the t=2105 plume.

The area corresponding to Criteria 2 is plotted in Figure 24 and corresponds to the first thin blue line (plume a t+5). According to the superimposition of the areas defined by Criteria 1 and Criteria 2, the AMA will be within the MMA.

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.

As modeling and simulation results of the active TAG plume indicate that the AMA consistently represents a subset of the MMA, Targa proposes defining the AMA and MMA as the same geographic area, as shown in Figure 24.

In general, artificial penetrations (i.e., wellbores penetrating the injection zone) present the most likely risk for potential TAG leakage. These penetrations have been identified within the project area (including only one well) and will be monitored within the MMA for the entirety of the active injection and post-injection period. Leakage by other vectors (i.e., via faults, fractures, groundwater wells, etc.) will therefore be covered by the MMA, which will provide the most conservative monitoring area.

Therefore, Targa considers the AMA equal to the MMA.

5.0 IDENTIFICATION AND EVALUATION OF POTENTIAL LEAKAGE PATHWAYS TO THE SURFACE

Subpart RR, specifically 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 UIC Class II injection wells, including the site characterization presented in Section 3.0, and reservoir modeling and simulation described in Section 3.9, Targa has identified and evaluated the following potential CO_2 leakage pathways to the surface.

5.1 POTENTIAL LEAKAGE FROM SURFACE EQUIPMENT

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at all sour-gas facilities. To minimize this potential for leakage, the construction, operation, and maintenance of sour-gas facilities follows industry standards and relevant regulatory requirements. Additionally, RRC SWR 9, which regulates injection operations in reservoirs not productive of oil and gas in Texas, requires injection well operators to operate and maintain facilities such that they will confine injected fluids within approved injection intervals, resolve all well integrity issues, and prevent surface damage or pollution resulting from leaks or loss of integrity in surface equipment.

To further minimize the likelihood of surface CO_2 and H_2S leakage from surface equipment, Targa implements a schedule for regular inspection and maintenance of surface equipment. Several additional methods for detecting gas leaks at the surface and in association with surface process units are implemented by Targa in order to minimize the magnitude and duration (timing) of detected gas leaks at the facility. These methods are described in more detail in Sections 6.0 and 7.0.

Figure 25 includes a general schematic of the Driver AGI #1 facility, which illustrates the location of surface equipment and surface process units, as well as the location of the fixed H_2S monitors, gas analysis sensors, and flow line isolation points. Numerous H_2S sensors are to be installed at the injection facility, and, as H_2S is a major component of the Driver AGI #1 waste stream, ambient H_2S monitoring will be a primary indicator for detecting and confirming leakage of CO_2.

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

Magnitude:
If a leak from the surface equipment between the injection flow meter and the injection wellhead occurs it will be detected immediately by the surveillance mechanisms described 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.

Timing:
During the operation of the injection system, any CO_2 leaks from surface equipment between the 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 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 FROM APPROVED, NOT YET DRILLED WELLS

At the time of the development of this MRV Plan, there are currently no new wells within the MMA that are permitted to drill and are expected to penetrate the Ellenburger Group. There are, however, multiple, shallower horizontal wells that are permitted to drill within the MMA. Based on a review of the drilling permits, these wells will be targeting the Spraberry through Wolfcamp geologic intervals, which is a minimum of approximately 1,800 vertical ft above the Driver AGI #1 injection interval, and separated by multiple, low-porosity and low-permeability geologic units.

While drilling, all operators must comply with RRC SWR 13 which requires the use of blowout preventors, blowout prevention equipment, and sufficient casing to prevent pressure transmission from the subsurface into the borehole. Should any operator encounter the plume from the injection project, the drilling safety equipment will prevent large atmospheric release of injected TAG.

Special precautions will be taken in the monitoring and drilling of any new wells that will penetrate the injection zones, that will include a more frequent monitoring during drilling operations. This applies to Targa and other operators drilling new wells through the injection zone and within the MMA.

5.3 POTENTIAL LEAKAGE FROM EXISTING WELLS

5.3.1 Potential leakage from the Driver AGI #1

As part of its 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, pressure and temperature gauges will be deployed. A leak can be indicated by the gauges. Temperature variation could also be an indicator of leaks.

If operational parameter monitoring, well integrity tests, or surface gas monitoring 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.

Likelihood:
Based on the above discussion, the likelihood of gas leakage through Driver AGI #1 is considered extremely low.

Magnitude:
The magnitude of potential gas leak will depend on operating conditions.

Timing:
Timing evaluations indicate no imminent risk of gas leakage from the well due to monitoring equipment in place.

5.3.2 Surrounding Oil and Gas wells

With the exception of the injection well subject to this MRV, there are two deep-well penetrations within the MMA, of which, one was drilled and penetrates the Ellenburger Group. The well is the Preston 9 (API: 42-329-10125) and has a total depth of 12,503 ft. MD. The Preston, Sam R 28 (API: 42-329-31386) is another deep penetration within the project area, however, the well was only drilled to the depth of Simpson Group geologic strata and does not penetrate the Ellenburger Group injection reservoir. Both wells have been properly plugged to successfully isolate shallower geologic intervals and groundwater resources, however, the area surrounding the wells will be subject to additional monitoring, as artificial penetrations pose the greatest risk for a potential reservoir seal breach.

To provide a clear characterization of the likelihood, magnitude, and timing of leakage risks. Targa used the National Risk Assessment Partnership (NRAP) tool, developed by five national laboratories (NETL, LANL, LBNL, LLNL, and PNNL), which is a key software for this evaluation. It provides an integrated science base, computational tools, and protocols tailored to carbon storage risk assessment. This proactive approach helps identify and mitigate potential risks before they become significant environmental or safety concerns.

One of the most important parameters for accurately modelling with NRAP is the locations of potential leakage pathways within MMA. Taking the Driver AGI #1 injection well as the reference point (0,0) on the field map and the delineated MMA, the surrounding wells were digitized to extract locations (x, y coordinates) with reference to Driver AGI #1. The injection period was set to 60 years to account for both injection and monitoring. This is because the current version of NRAP does not give the leverage to set both injection and monitoring periods. Hence, the worst case scenario was considered. Reservoir and seal confinement properties were incorporated into the model, together with CO_2 properties and injection rates and pressures.

Shallow wells study:

Shallow wells were considered to be at least 1800 vertical feet above the Driver AGI#1 injection interval, separated by multiple, low-porosity, low-permeable geologic units.

Results indicate no leakage of CO_2 into or through these wells throughout the 60-year period. This is expected due to the interval between the completion zones of these wells and the injection interval and the multiple layers of low porosity and low-permeable units separating these wells from the injection zones.

Deep wells study:

Except for the injection well, there are two deep-well penetrations within the MMA. One of these wells, the Preston 9 (API: 42-329-10125), was drilled to a total depth of 12,503 ft. MD and penetrated the Ellenburger Group. The other well, the Preston, Sam R 28 (API: 42-329-31386), was drilled within the project area but only reached the Simpson Group geologic strata and did not penetrate the Ellenburger Group injection reservoir.

The Preston, Sam R 28 well penetrates the Simpson Group. Over a 60-year period, the leakage mass of CO_2 decreases significantly as it moves through stratigraphic layers above the injection zone. In the first layer above the injection zone, the CO_2 mass is approximately $1.0*10^4$ kg, which represents about $1.7*10^{-5}$% of the total injected volume ($5.8*10^{10}$ Kg of CO_2). This reduces to 200 kg of CO_2 by the time it reaches the third layer above the Ellenburger Group. This minimal amount of leakage is negligible. Additionally, the multiple low-porosity and low-permeability stratigraphic layers above the injection zone would effectively prevent any further upward movement of CO_2.

For the Preston 9 well, which penetrates the Ellenburger Group within the MMA and represents the worst-case scenario for potential leakage through wells, the maximum CO_2 leakage after 60 years is observed in the first layer above the injection zone. The CO_2 mass in this layer is approximately $3.5*10^4$ kg, representing about $6.03*10^{-5}$ % of the total injected volume ($5.8*10^{10}$ Kg kg of CO_2). This amount reduces to 7,000 kg of CO_2 by the time it reaches the third layer above the Ellenburger Group. Similar to the Preston, Sam R 28 well, this volume of leakage is insignificant and can be disregarded. The presence of multiple low-porosity and low-permeability stratigraphic layers further ensures the containment of CO_2, as evidenced by the significant reduction in CO_2 mass across layers.

Likelihood:

Based on the above discussion, the likelihood of gas leakage through surrounding 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 that will be applied, reservoir characteristics and proactive monitoring protocols implemented.

5.3.3 Groundwater Wells

Targa identified water wells (labeled with corresponding ID numbers in Figure 14) within the injection plume area after 30 years of injection and the MMA. Nearly all the wells produce water from the Antlers Sands of the Edwards Trinity Major Aquifer. One exception is water well #27, which produces water from the Dewey Lake Formation of the Ochoan Series at a depth of 1,315 feet.

Within the MMA, there are 111 water wells. The deepest groundwater well reaches 1,315 feet. The presence of evaporite seals and thick formations between these groundwater wells and the injection zone significantly reduces the likelihood of these wells serving as a pathway for CO_2 leakage to the surface. Additionally, the CO_2 surface and groundwater monitoring protocols outlined in Sections 6 and 7 will enable early detection of any potential leakage, ensuring prompt response to minimize the impact of such an event.

Given the shallow depth of the groundwater wells relative to the injection zone and considering the results of the NRAP analysis, Targa concludes that the probability of CO_2 emissions to the surface through this pathway is highly unlikely, and any potential leak would have minimal magnitude.

Likelihood:

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

Magnitude:

The NRAP analysis indicates that the magnitude of potential gas leaks through these wells would be minimal.

Timing:

Timing evaluations confirm no imminent risk of gas leakage from the subsurface.

5.4 POTENTIAL LEAKAGE THROUGH FRACTURES, FAULTS, AND BEDDING PLANE PARTINGS

Leakage from the injection zone out of the confining layers due to fractures, faults, and bedding plane partings is unlikely in the Driver AGI #1 project area. While natural fractures and faults, associated with karsting and paleo-cave collapse have enhanced the Ellenburger Group reservoir properties (making the injection interval a more suitable option for permanent sequestration), there are no indications that such features are capable of a seal breach present within the confining layers. Additionally, as demonstrated by the dynamic simulation, the injectate plume will not intersect any features that will transmit fluid from the injection plume through the confining strata (i.e., the reservoir seal).

Because no through-going faults are present within the MMA, the risk of a loss of containment from the injection zone is very low to non-existent. Additionally, the clear presence of multiple baffles and redundant reservoir seals above the injection zone ensures the prevention of any potential for the upward migration of injected fluid that could possibly impact groundwater resources, the base of which are located two miles above the injection zone. These additional confining layers are denoted in the type log included in Figure 19.

For the NRAP analysis, the risk of leakage through faults only occurs if the faults directly cut through the CO_2 plume. For faults that do not directly connect with the CO_2 plume, CO_2 leakage rate and mass are zero.

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.

5.5 POTENTIAL LEAKAGE BASED ON THE COMPETENCY, EXTENT, AND DIP OF THE CONFINING ZONE

The primary seal for the injection zone is the fine-grained, low-permeability lithologies of the Simpson Group. Approximately five (5) miles east of the injection site, the Simpson pinches out and is replaced by a thicker section of the Sylvan Shale. Due to the regional dip of the Simpson (approximately 1 degree), the dynamic simulation (i.e., injection simulations) does not project significant lateral plume migration in the up-dip direction, and the plume is never anticipated to reach the area of Simpson Group pinch-out. Within the MMA, the Simpson is laterally continuous and significantly thick to maintain seal continuity. While it is extremely unlikely that injected fluid could even migrate above the Simpson seal, there are multiple low-permeability intervals, which would ensure there is no transmission of injected gas into intervals of groundwater resources, including the regional-scale Woodford Shale, which is a well- demonstrated interval of confining strata, which will further prevent upward migration of fluids.

For the NRAP analysis, the Simpson group is the primary reservoir seal or caprock layer to the injection zone. Their low porosity and permeability prove their high seal integrity. Leakage through confining zones can occur through low permeability shales containing natural fractures. Cell blocks were created to

cover the MMA, serving as the most prone zone for CO_2 leakage. These cell block locations and CO_2 saturation at the seal and seal properties were incorporated into the model.
The cumulative leakage mass over 60 years of injection is about $1.5*10^3$ /60 years. The total mass of CO_2 injected over 60 years is estimated to be $5.8*10^{10}$ of CO_2. Hence, after 60 years, the percentage of leakage through the confining zone is estimated to be about $2.6*10^{-6}$ %. Considering other stratigraphic strata serving as additional layers above the confining zone, it can be concluded that the risk of leakage through this pathway is highly improbable and insignificant.

Likelihood:
Based on the discussion, Targa considers that CO_2 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.

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

5.6 POTENTIAL LEAKAGE DUE TO NATURAL OR INDUCED SEISMICITY

As discussed in Section 3.5, the risk for induced seismicity within the project area is low, based on a query of documented seismic events within a 15.5 miles radius from the Driver AGI #1 location. Induced seismicity related to injection into the Driver AGI #1 well is also considered low as the properties of acid gas are much less conducive than saltwater disposal operations to producing induced seismic events.

As is also discussed in Section 3.5, it is estimated that the injection well will operate with a bottom-hole pressure below the fracture pressure for the entire life of the well, minimizing the risk of induced fracture generation.

While the operations of the Driver AGI #1 well will not contribute significantly to the risk for induced seismic events, and no faults at risk for induced seismicity have been identified with the MMA, or greater project area, Targa will outfit the wells with equipment to continuously monitoring critical AGI well injection parameters. Through the analysis of this monitoring data, operators are able to rapidly identify potential well-integrity issues. In the event significant seismic events occur in the area (which may be unrelated to disposal operations), Targa will have the ability to confirm well integrity following the event and ensure that fluids are unable to move vertically outside of the target injection reservoir.

Likelihood:
Based on the discussion, the potential for induced seismic activity in the project area is low. Furthermore, the injection well will be operated below fracture pressure, minimizing the possibility of induced fractures. These factors collectively indicate that CO_2 is expected to remain contained within the injection zone near the well, thereby making the likelihood of any gas leakage extremely low.

Magnitude:
From site-specific evaluations (including NRAP analysis), the properties of the target injection zone and its overlying sealing formations are considered well-suited to isolate and mitigate the effects of any potential release. As a result, any leakage that might occur would be minimal in magnitude.

Timing:
Ongoing monitoring of critical injection parameters allows Targa operators to detect and address well-integrity issues rapidly. Given that no faults at risk for induced seismicity have been identified and that operations will remain below fracture pressure, there is no imminent risk or timing concern for gas leakage from the subsurface.

6.0 STRATEGY FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

Pursuant to the 40 CFR 448(a)(3) of Subpart RR, which requires a strategy for detecting and quantifying surface leakage of CO_2, Targa will implement the following procedure for detecting, verifying, and quantifying CO_2 leakage to the surface through potential pathways identified in Section 5.0. Based on the specific operations of the Driver AGI #1 well, which includes disposal of waste gas containing H_2S, Targa considers H_2S to be a proxy for CO_2 leakage to the surface. As such, Targa will employ and expand upon methodologies detailed in their H_2S Contingency Plan to detect, verify, and quantify CO_2 surface leakage. Table 4 below summarizes the leakage monitoring for each identified leakage pathway. All monitoring protocols will continue throughout the full duration of the injection well project and during the post injection period. Additional information regarding potential leakage pathways and Targa detection methods are provided in subsequent Sections 6.1 through 6.6.

Table 4. Summary of leak detection monitoring methods

Identified Leakage Pathway	Detection and Monitoring Method
Facility Surface Equipment	- Continuous control room remote monitoring - Visual inspection of facility and process units - Inline inspections - Fixed, in-field gas monitors and monitoring network - Personal and hand-held gas monitors
New Well Construction by Targa	- Vigilant monitoring of fluid returns during drill operations - Multiple gas monitoring points around drilling operations – personal and hand-held gas monitors
New Wells by Other Operators	- Vigilant monitoring of fluid returns during drilling - Multiple gas monitoring points around drilling operations – personal and hand-held gas monitors
Existing Targa Well	- Continuous control room remote monitoring - Visual inspection of well and related equipment - Routine Mechanical Integrity Testing (MIT) - Fixed, in-field gas monitors - Soil CO_2 flux monitoring - Personal and hand-held gas monitors - Continuous monitoring of surface- and bottom-hole pressure and temperature conditions - Groundwater monitoring
Existing Wells of Other Active Operators or plugged wells	- Monitoring of well operating parameters - Visual inspections - Completion of routine MIT operations - Surface gas detection at nearby plugged Ellenburger-penetrating well and Simpson-penetrating well. - Soil CO_2 flux monitoring - Groundwater monitoring
Fractures and Faults	- Continuous control room remote monitoring - Fixed, in-field gas monitors - Soil CO_2 flux monitoring Injection simulation and history matching to refine plume migration results and confirm anticipated reservoir conditions - Communication with local active operators producing overlying resources - Groundwater monitoring
Confining Zone/Reservoir Seal	- Continuous control room remote monitoring - Fixed, in field gas monitors - Soil CO_2 flux monitoring - Injection simulation and history matching to refine plume

	forecasts and confirm anticipated reservoir conditions - Communication with local active operators producing overlying resources - Groundwater monitoring
Natural/Induced Seismicity	- Continuous control room remote monitoring - Monitoring of public seismic monitoring network to identify events relevant to project area - Injection simulation and history matching to confirm anticipated reservoir conditions - Communication with local active operators producing overlying resources - Groundwater monitoring
Lateral Migration	- Continuous control room remote monitoring - Fixed, in field gas monitors and monitoring network - Injection simulation and history matching to refine plume migration results - Groundwater monitoring

6.1 LEAKAGE FROM SURFACE EQUIPMENT

At the facility, Targa will implement several tiers of monitoring for surface leakage, including frequent periodic visual inspection of the facility and surface equipment, the use of fixed in-field and personal H_2S sensors, and continual monitoring of operational parameters. Permanent sensors and operational parameters are continually monitored, via the facility control systems, and when applicable, alarm and shutdown thresholds are defined should abnormal conditions requiring shutdown and isolation of the wells and facility occur.

Leaks from surface equipment would be 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 by proxy, CO_2. The in-field gas monitors are connected to the distributed control system housed in the on-site control room and monitored by Targa. If an alarm occurs via detection by in-field gas detectors, Targa protocols require those conditions trigger an immediate response to address and characterize the situation and nature of the alarm.

The following gas detection equipment is located across the facility:

- Fixed Monitors – Targa will utilize in-field monitors (see sensors in Figure 25) capable of transmitting detected H_2S measurements for immediate evaluation. At various detection limit thresholds, the significance of the detection alarm is modified in order to generate a proportionate response to a leak, depending on its severity. The lower limit of detection for the in-field monitors is 10 ppm. Gas-detection monitors will be integrated into the facility control system, and if applicable, the facility will initiate emergency shutdown and isolation based on the concentrations of H_2S detected.

Personal and Handheld H_2S Monitors – All personnel on site are required to be equipped with personal or handheld H_2S monitors, which have an alarm threshold of no more than 10 ppm. As dictated by the facility H_2S contingency plan, any detection of 10 ppm, or greater, will be reported to the facility control room for immediate evaluation. Quantification of CO_2 emissions from surface equipment and components will be estimated according to the requirements of 40 CFR 98.444(d) of Subpart RR, as discussed in Sections 8.4 and 10.3.

6.2 LEAKAGE FROM APPROVED, NOT YET DRILLED WELLS

A detailed review of the existing and permitted (i.e., approved, but not yet drilled) wells was conducted within the MMA/AMA and no permitted wells that will penetrate the injection interval, or within the hypothetical secondary containment interval, are currently planned or permitted. Periodic well queries of the public RRC well database will be conducted to identify any wells within the MMA that may pose a containment risk.

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones including more frequent monitoring during drilling operations. This applies to Targa and other operators drilling new wells through the injection zone within the MMA.

6.3 POTENTIAL LEAKAGE FROM EXISTING WELLS

The Driver AGI #1 well subject to this MRV plan will be considered an existing well through which injectate leakage may occur. The well will utilize telescoping strings of casing designed to protect groundwater resources and isolate intervals of active oil and gas production. Each string of casing will be cemented to the surface, and acid-resistant cement blends will be utilized along strategic depth intervals to reduce the risk of cement degradation in zones where corrosive fluids may be present. The well design schematic for the Driver AGI #1 well is included in Figure 22.

Once operational, the well will be installed with down-hole tubing pressure and temperature sensors, down-hole annular pressure and temperature sensors, surface injection tubing pressure and temperature sensors, and surface annular pressure sensors to continuously monitor the health and integrity of the well and subsurface injection interval. To aid in leak detection and confirming wellbore integrity, design considerations for the Driver AGI #1 well include a Distributed Temperature Sensing (DTS) fiber optic line, in addition to down-hole tubing and annular pressure and temperature sensors (i.e., Halliburton ROC PT Gauge). The down-hole gauge is designated to monitor the bottom-hole pressure and temperature, as well as the annular space between the tubing and the long string. A leak is detected 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 a remote control room. DTS (temperature) data is recorded by a separate interrogator that is also housed in the remote 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.

The continuously monitored injection parameter data will be analyzed for potential integrity issues or anomalous reservoir conditions, which may be indicative of a breach. Additionally, the site and personnel at the site will be equipped with H_2S monitors, which will detect atmospheric H_2S concentrations at 10 ppm or greater. In accordance with the RRC SWR 36 H_2S Contingency Plan, produced by Targa and accepted by the RRC, any detection of H_2S (a constituent of the waste gas steam being injected) at thesurface by sensors will be investigated and remedial efforts to contain and fix any integrity issues identified will commence.

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.

Regarding other existing wells within the MMA, in-field gas monitoring described in Sections 6.0 and 6.1 and well surveillance by other operators of existing wells will aid in identifying and confirming potential CO_2 leakage from existing wells within the MMA. Targa's ability to identify potential CO_2 leakage will be further improved through groundwater monitoring and the incorporation of soil CO_2 flux monitoring locations throughout the MMA. Targa is currently working to design and implement soil CO_2 flux monitoring systems at the facility, which is anticipated to be in place by approximately no less than 3 months prior to the commencement of injection activities.

As shown in Figure 20, there is only one artificial penetration that reaches the Ellenburger Group within the MMA/AMA, aside from the Driver AGI #1 injection well. The well penetrating the Ellenburger Group, and located within the MMA, is the Preston 9 (API: 42-329-10125). Another well, the Sam R #4214B (API: 42-329-31386) was drilled to the Simpson Group (the regional primary seal to the Ellenburger injection reservoir). Both wells were properly plugged in accordance with RRC standards and do not appear to pose a risk to the reservoir seal integrity. Both wells will be subject to quarterly atmospheric monitoring using H_2S detection sensors (i.e., in-field gas monitoring) to determine if any injectate is migrating through these wells.

Within the MMA/AMA, 113 water wells have been identified (Figure 14), which have been drilled to depths generally ranging from 250-300 ft and target primarily the Edwards-Trinity Plateau aquifer. The quality of groundwater will be monitored routinely by sampling water from select wells and analyzing samples for potential contamination. Any deterioration in the groundwater will be investigated to determine if the change in quality is a result of the facility injection operations.

The CO_2 monitoring network, i.e. soil flux monitoring, 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. Targa is currently working to install CO_2 flux monitoring systems. Monitoring will be in place, with CO_2 flux monitoring and groundwater well sampling from a shallow well.

6.4 POTENTIAL LEAKAGE THROUGH FRACTURES, FAULTS, AND BEDDING PLANE PARTINGS

As previously described, no faults have been identified within the project MMA/AMA and operation of the Driver AGI #1 well will occur under conditions that do not exceed anticipated formation fracture pressures, and thus will not introduce new fluid pathways in the form of fractures. Though there is expected to be minimal risk of leakage via these types of features, Targa will conduct continuous monitoring via down-hole and surface sensors, and any anomalous injection parameters will be flagged by the injection facility DCS, using threshold criteria for detection and notification. Any threshold parameters that are exceeded will be investigated. Should the anomalous data appear to be related to down-hole conditions, the possibility of a leak through fractures, faults, or bedding plane partings will be scrutinized. Additionally, reservoir characterization modeling and simulation will be updated, including history matching of operating data, in order to confirm anticipated reservoir conditions in response to injection operations.

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 Driver AGI #1 well, 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.

If changes in operating parameters or other monitoring methods indicate leakage of CO_2 through the confining and seal system, Targa will take actions to quantify the amount of CO_2 released based on the operation parameters and take immediate action to stop it, including shutting in the well.

6.5 POTENTIAL LEAKAGE BASED ON THE COMPETENCY, EXTENT, AND DIP OF THE CONFINING ZONE

As identified through detailed geologic characterization of the project area, including the MMA/AMA, the Ellenburger injection reservoir is vertically isolated by competent caprock lithologies of the Simpson Group, and further isolated via the regionally extensive Woodford Shale. Additionally, numerousoverlying low-porosity intervals are present within the stratigraphy and, in general, the risk for confining layer leakage is low. Though there is minimal risk, Targa will continuously monitor AGI operating conditions, via down-hole and surface sensors, and any anomalous injection parameters will be flagged by the plant's DCS, using threshold criteria for detection and notification. Any threshold parameters that are crossed will be investigated, and should the anomalous data appear to be related to down-hole conditions, the possibility of a leak through the confining layers will be scrutinized. The integrity of the confining strata will be further confirmed through periodic completion of additional, history matched, injection simulation analyses.

If monitoring of operational parameters or other monitoring methods indicate that the CO_2 plume extends beyond the maximum monitoring area modeled in Section 3.9 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).

6.6 POTENTIAL LEAKAGE DUE TO NATURAL OR INDUCED SEISMICITY

Following detailed review of historic seismic event records, and analysis of 3D seismic survey data, it has been determined that the risk for injection-induced seismicity within the MMA/AMA and greater project area is minimal, especially as it relates to acid gas injection operations. This is due to the low density and low viscosity of the acid gas injectate, which is significantly lower than those properties of saltwater.
While the risk for induced-seismic events has been determined to be minimal within the project area, Targa will monitor public seismic networks to identify seismic events in close proximity to facility. Combined with monitoring and review of AGI operating parameter data, any well integrity issues that could result from seismicity can be rapidly identified, and if necessary, remedial actions can be initiated. Furthermore, reservoir characterization modeling and simulation will be periodically updated, including history matching of operating data, in order to confirm anticipated reservoir conditions for scenarios in which leakage does not occur as a result of seismic events. This will allow deviations in expected operating conditions to be investigated in association with any seismic events documented.

If the seismic monitoring stations around the well, the operational parameters and the gas monitors indicate surface leakage of CO_2 linked to seismic events, Targa will assess whether the CO_2 originated from the Driver 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.

6.7 STRATEGY FOR QUANTIFYING CO2 LEAKAGE AND RESPONSE

6.7.1 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 4 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.

6.7.2 Subsurface Leakage

Selection of a quantification strategy for leaks that occur in the subsurface will be based on the leak detection method (Table 4) 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.

6.7.3 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.

7.0 STRATEGY FOR ESTABLISHING EXPECTED BASELINES FOR MONITORING CO_2 SURFACE LEAKAGE

At the facility, Targa will utilize automated control systems and monitoring systems to monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO_2. As a proxy for CO_2 leakage to the surface, Targa will utilize H_2S monitoring and detection methods, as it is a significant constituent of the TAG stream that is compressed at the injection facility and injected via the Driver AGI #1 well. As such, Targa will employ and expand upon methodologies detailed in its RRC SWR 36 H_2S Contingency Plan, as well as other related facility response plans, to establish baselines for monitoring CO_2 leakage. The following subsections describe Targa's strategy for collecting baseline information.

7.1 VISUAL INSPECTION OF FACILITY AND FACILITY EQUIPMENT

In accordance with Targa standard protocols and inspection procedures, field personnel will conduct frequent periodic inspections of all surface equipment and facility grounds, which provides opportunity to assess baseline concentrations of H_2S (a proxy for CO_2 leakage) at the facility.
Field reports generated from these routine inspections will be useful in establishing baseline conditions and identifying instances of potential CO_2 leakage within surface process units and/or the AGI well.

7.2 FIXED, IN-FIELD, HANDHELD, AND PERSONAL H_2S MONITORING

7.2.1 Fixed In-Field H_2S Monitoring

Fixed, in-field monitors are utilized at the facility to detect surface leakage via detection of H_2S as a proxy for CO_2 leakage. Fixed monitoring equipment is calibrated prior to installation and will be capable of detecting low concentrations of H_2S. As the TAG stream, which is compressed at the facility and sequestered via the on-site AGI well, is an extremely hazardous substance, the background levels of H_2S should be very low (less than 1 ppm). As such, any detected levels above 10 ppm will merit investigation. It should be noted that atmospheric H_2S is commonly detected in areas of oil and gas production operations, and alarms initiated may not be related to issues with surface equipment, transmission lines, or the AGI well. Upon detection, Targa personnel will ascertain the source of the H_2S to the best of their ability and will take appropriate actions to address the situation, as necessary.

The facility utilizes numerous fixed-point monitors, strategically located throughout the station, to detect the presence of H_2S in ambient air. The sensors are connected to alarm panel Programmable Logic Controllers (PLCs). Upon detection of H_2S at 10 ppm at any detector, visible amber beacons are activated, and horns activated with a continuous warbling alarm. Upon detection of H_2S 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.

7.2.2 Handheld and Personal H_2S Monitoring

Handheld and personal monitors are calibrated prior to activation and will be capable of detecting levels of H_2S at 10 ppm, or greater. As the TAG stream routed through, compressed, and disposed of at the injection facility is an extremely hazardous substance, the background levels of H_2S should be very low (less than 1 ppm), and any levels detected above 10 ppm by a handheld or personal monitor will merit investigation. Similar to the above Section 7.2, it should be noted that atmospheric H_2S is commonly detected in areas of oil and gas production operations, and alarms initiated may not be related to issues with surface equipment, transmission lines, or the AGI well. Upon detection, Targa personnel will ascertain the source of the H_2S to the best of their ability and will take action to address the situation, as necessary.

7.3 DETECTION OF CO_2

As CO_2 transmission, compression, and injection occurs coincident with H_2S at the facility, H_2S is a suitable proxy for CO_2 detection. Within the MMA, a combination of fixed-field monitors and handheld/personal monitors will be utilized to determine the base level H_2S/CO_2 concentrations at the injection sites and near the areas of deep well penetrations. In addition to the handheld gas detection monitors described above, Targa will incorporate a monitoring network for CO_2 leakage detection in the MMA as defined in Section 6.0. The scope of work for the monitoring project includes field sampling activities to monitor CO_2 and H_2S at the Driver 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 is currently anticipated to commence at the facility no less than three months prior to the commencement of injection activities.

7.4 CONTINUOUS INJECTION PARAMETER MONITORING

The Driver AGI #1 will be equipped with down-hole temperature and pressure sensors, surface injection pressure sensors, surface injection temperature sensors, and annular pressure and temperature sensors. These injection parameters are continuously monitored and retained via the facility control system. From these data, baseline measurements from each operational parameter will be confirmed following the commencement of injection operations, when conditions stabilize, as the relationship between each of the injection parameters cannot be determined until well injection operations are established.

7.5 WELL SURVEILLANCE

In accordance with the requirements of RRC SWR 9, which governs the disposal of oil and gas waste by injection into formations not productive of oil or gas, and special conditions of approval authorizing the operations of the Driver AGI #1 well, Targa complies with testing and monitoring requirements for UIC Class II injection wells to ensure they maintain mechanical integrity and that injection operations occur only within authorized geologic disposal intervals. Operational procedures, adhered to by Targa personnel, ensure that frequent inspection of the facility equipment and surface processes occurs to detect and take corrective action if leaks associated with surface facility processes are detected. Furthermore, continuous monitoring and analysis of injection parameter data ensures that anomalous operating conditions, which may be indicative of well integrity issues, are promptly identified and addressed.

7.6 SEISMIC MONITORING

Based on a detailed evaluation of the MMA/AMA and greater project area, which included a review of historic seismic event records, it was identified that the Driver AGI #1 well is not located in an area with a significant history of earthquakes. While assessment of the induced-seismicity risk indicates that injection-induced fault slip potential is low, Targa intends to construct an on-site seismic monitoring station and monitor public seismic network databases to identify seismic events which may occur within the greater project area. In accordance with conditions of the approved UIC Class II injection permit, the on-site seismic monitoring stations will contribute recorded data to the TexNet public seismic event catalog, and Targa will respond to any qualifying seismic events in accordance with their approved Earthquake Response Plan (approved by RRC on October 31, 2023).

Data recorded by the existing monitoring network, within a 10-mile radius of the Driver AGI #1 well will be analyzed by the New Mexico Bureau of Geology seismologist. The seismologist will generate a report and map showing the magnitudes of recorded events from seismic activity. Through integration with the existing TexNet seismic monitoring network, data will be continuously recorded and publicly available. Utilizing this seismic monitoring station data, and through the review of publicly available seismic event records, a seismic event baseline can be 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.

7.7 GROUNDWATER MONITORING

Within the MMA/AMA, near the Driver AGI #1 well, and in close proximity to deep-penetrating oil and gas wells, there are existing water supply wells, from which Targa intends to collect and analyze groundwater samples to determine baseline groundwater geochemical data and monitor periodically for potential indications of leakage. Specific sites for groundwater monitoring will be based on their proximity to key features within the MMA/AMA, including near the Driver AGI #1 injection well and in proximity to other deep well penetrations unrelated to injection.

Groundwater 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 one (1) year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

Groundwater analytes are summarized in Table 5 and will include total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potential (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. 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 Driver AGI #1 well. 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. 5. Summary of groundwater monitoring parameters

Groundwater Parameters Monitored:	
pH	Sodium (mg/L)
Alkalinity as HCO_3 (mg/L)	Potassium (mg/L)
Chloride (mg/L)	Magnesium (mg/L)
Fluoride as F^- (mg/L)	Calcium (mg/L)
Bromide (mg/L)	Total Dissolved Solids (TDS) (mg/L)
Nitrate as NO_3^- (mg/L)	Total cations (meq/L)
Phosphate (mg/L)	Total anions (meq/L)
Sulfate as SO_4^{-2}(mg/L)	Percent difference (%)
Lithium (mg/L)	ORP (mV)
IC (ppm)	NPOC (ppm)

Groundwater sampling and analysis activities will be completed in accordance with EPA guidance procedures (*US EPA, O., 2015, Procedures for Groundwater Sampling in the Laboratory Services and Applied Science Division: https://www.epa.gov/quality/procedures-groundwater-sampling-laboratory-services-and-applied-science-division*)

7.8 SOIL CO_2 FLUX MONITORING

A vital part of the facility monitoring program is to identify potential leakage of CO_2 from the injection horizon into the overlying formations and to the surface. One method that will be 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, 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.

CO_2 soil flux will be collected on a monthly basis for 12 months to establish the baseline and understand seasonal and other variation within the MMA/AMA. After the baseline is established, data will be collected bi-monthly for one year and then quarterly.

CO_2 soil 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 (8-cm 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.

8.0 SITE SPECIFIC CONSIDERATIONS FOR DETERMINING THE MASS OF CO_2 SEQUESTERED

Appendix 8 summarizes the twelve Subpart RR equations utilized to calculate the mass of CO_2 sequestered annually. Appendix 9 includes the twelve equations from Subpart RR. Not all of these equations are relevant to Targa's operations at the facility but are included in the event Targa's operations change in such a way that their utilization is required. To ensure accurate calculation of CO_2 received, emitted, and injected, flow meters and gas analyzers will be utilized to measure and record the volume of TAG and the concentration of CO_2 received by the facilities at the inlet pipeline as well as near the site of injection (Figure 25).

8.1 MASS OF CO_2 RECEIVED BY THE INJECTION FACILITY

The facility will receive gas, via pipeline transport, consolidated from Targa gas- processing facilities in the Midland Basin. Processing facilities that may contribute gas to the injection facility are shown in Figure 3. Gas delivered to the injection facility is processed as described in Section 3.8 to produce compressed TAG which is then routed, by pipeline to the Driver AGI #1 wellhead. Targa will utilize 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.

8.2 MASS OF CO_2 INJECTED AT THE DRIVER INJECTION FACILITY

At the facility, Targa will inject CO_2 into the Driver AGI #1 well. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the well. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the well. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12.

8.3 MASS OF CO_2 PRODUCED AND/OR RECYCLED

Targa does not produce oil, gas, or any other liquid at its facility, and as such, there is no CO_2 produced or recycled in this operation.

8.4 MASS OF 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 8.5 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6 above.

8.5 MASS OF CO_2 SEQUESTERED

Since Targa does not actively produce oil, natural gas, or any other fluid at its facility, Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations. An additional parameter, CO_{2FI} in Equation RR-12, is also accounted for and is the "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."

9.0 ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

In developing the Driver AGI #1 injection well project, Targa has been issued an approved UIC Class II injection permit by the RRC, following technical and administrative review of the Driver AGI #1 project, as well as a public hearing to ensure the project meets the requirements relating to H_2S (i.e., RRC SWR 36). The approved injection permit (Permit #17479) was issued on June 10, 2024.

Following issuance of the UIC Class II injection well permit, Targa has commenced preliminary planning activities to prepare project area surface lands and coordinate drilling and completion operations for the Driver AGI #1 well. The planning process is currently anticipated to require a period of four to six months.

Targa intends to implement this MRV plan immediately following approval by EPA, and upon completion of well drilling and completion operations for the Driver AGI #1, when the well is adequately constructed and can be placed in service.

At the time of approval, the expected baselines, as required by paragraph 98.448(a)(4), will be established and the leak detection and quantification strategy, as required by paragraph 98.448(a)(3), will be implemented. After the wells are drilled, Targa will re-evaluate the MRV plan and if any modifications are a material change, per 40 CFR 98.448(d)(1), Targa will submit a revised MRV plan. Additionally, if at any time any of the conditions listed in 40 CFR 98.448(d)(2)-(4) exist, Targa will submit a revised MRV plan.

10.0 GREENHOUSE GAS MONITORING AND QUALITY ASSURANCE PROGRAM

Targa will meet the monitoring and QA/QC requirements of 40 CFR 98.444 of Subpart RR, including those of Subpart W for emissions from surface equipment, as required by 40 CFR 98.444(d).

10.1 GREENHOUSE GAS (GHG) MONITORING

In accordance with 40 CFR 98.3(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 reports

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 40 CFR 98.444(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 (Greenhouse Gas Reporting Program): Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atm (Appendix 8). 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 the pipeline described in Section 8, using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.3 CO_2 Injected

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

10.1.4 CO_2 Produced

Targa operations at the Driver AGI #1 injection facilities will not include the production of CO_2.

10.1.5 CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2

As required by 98.444(d) of Subpart RR, 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 40 CFR 98.444(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 described in 40 CFR 98.3(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 will be 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 40 CFR 98.445 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 most recent 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 most recent 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 U.S. EPA or the State of Texas. The first anticipated revision of the MRV plan is anticipated to be completed following the completion of well construction, logging, and testing operations of the Driver AGI #1 well.

11.0 RECORDS RETENTION

Targa will meet the recordkeeping requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP. As required by 40 CFR 98.3(g) and 40 CFR 98.447, 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 that were utilized to calculate GHG emissions for each unit, operation, process, and activity. These data include:

    a. The GHG emissions calculations and methods used
    b. Analytical results for the development of site-specific emissions factors, if applicable
    c. The results of all required analyses
    d. 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 GHG reports.

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 MRV Plan.

FIGURES

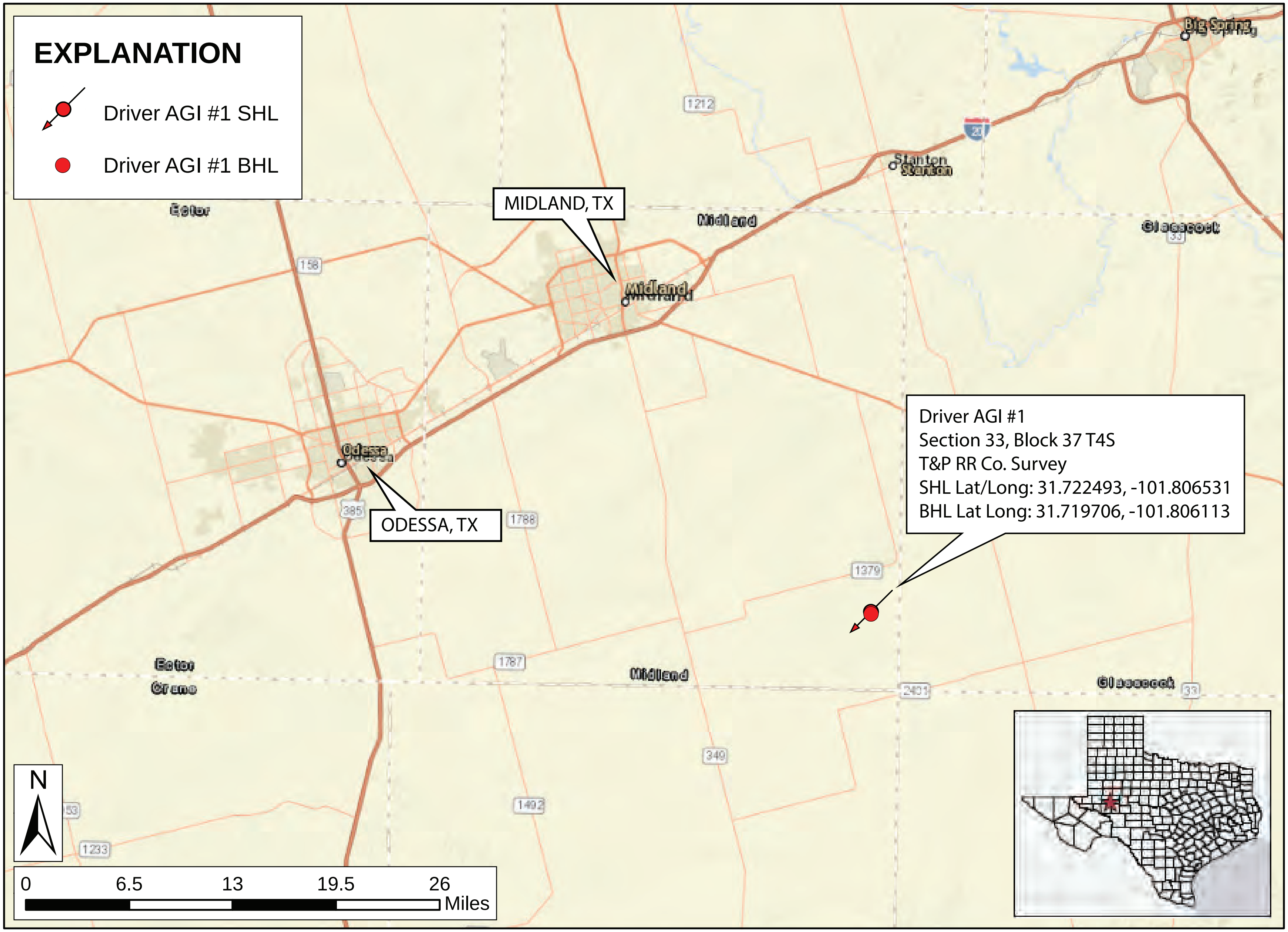

Figure 1. General Location of the Driver AGI #1, located in southeast Midland County approximately 25 miles southeast of Midland, Texas. SHL and BHL coordinates are shown in NAD83.

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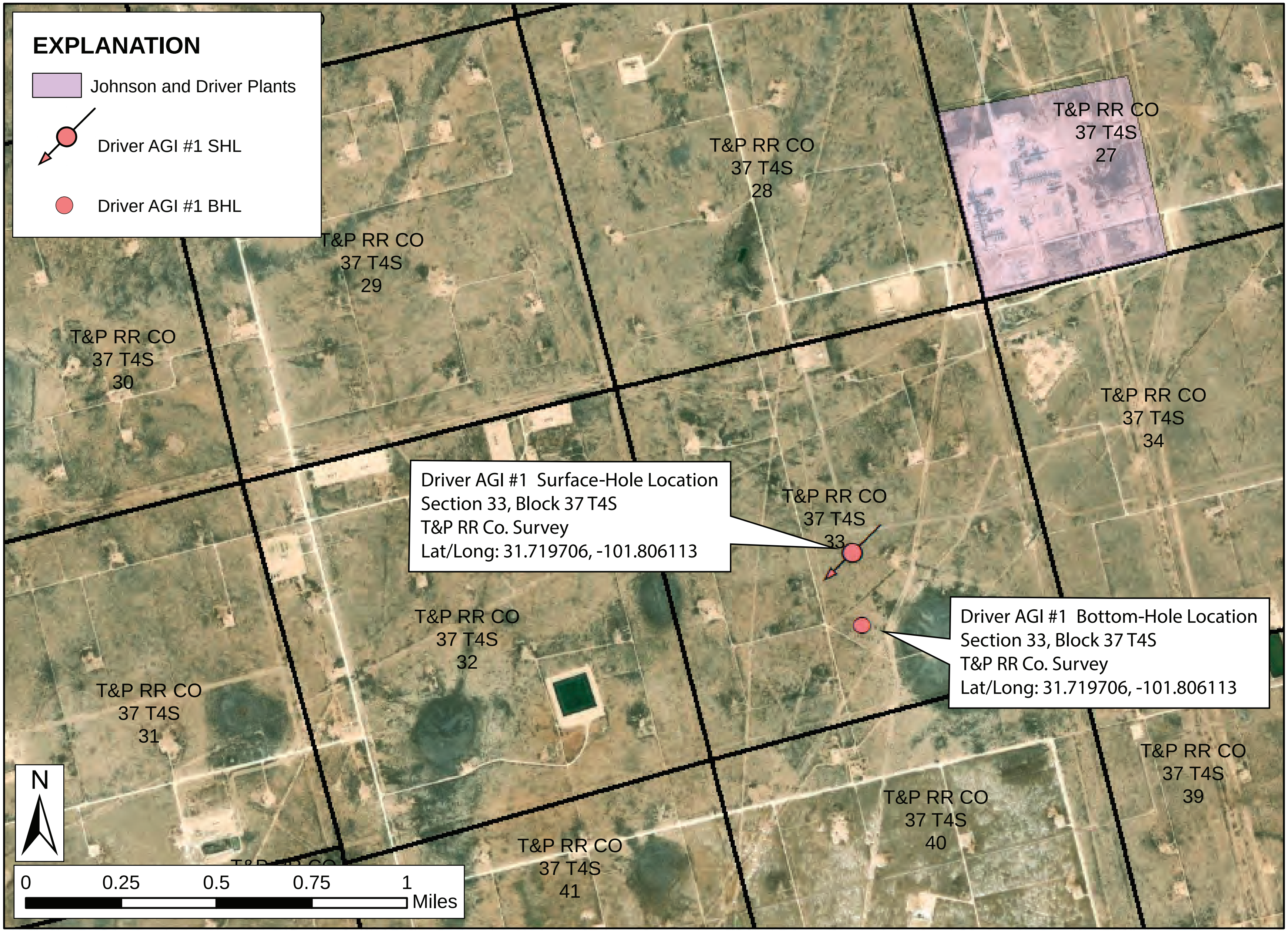

Figure 2. Detailed location map of the Driver AGI #1 surface- and bottom-hole location and the nearest Targa Plant to the AGI well. Geographic coordinates are reported as NAD83.

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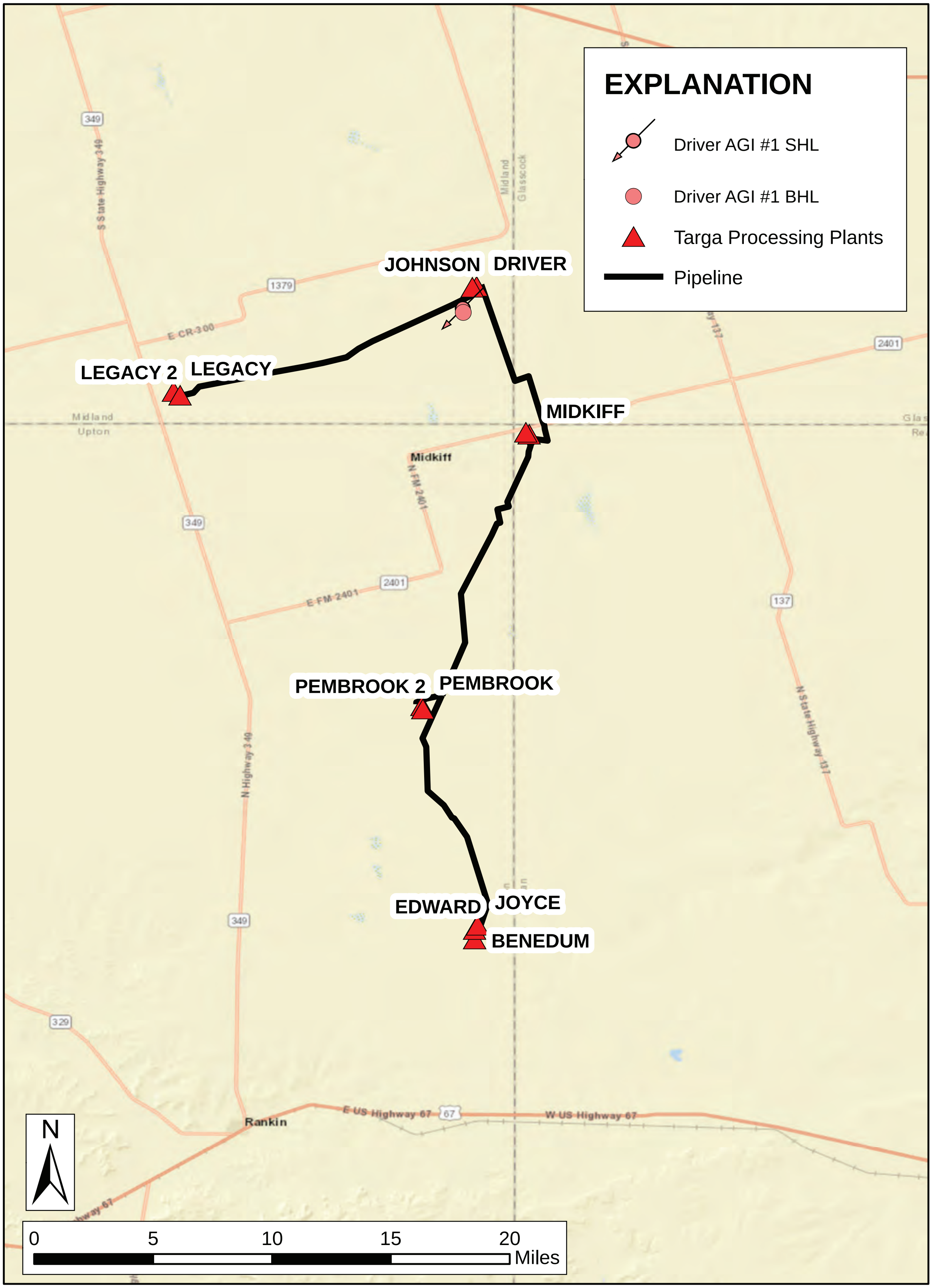

Figure 3. Location of the Driver AGI #1 well in relation to Targa's gas processing operations in the Midland Basin. TAG from any of the plants will be capable of transportation to the injection site, via pipeline

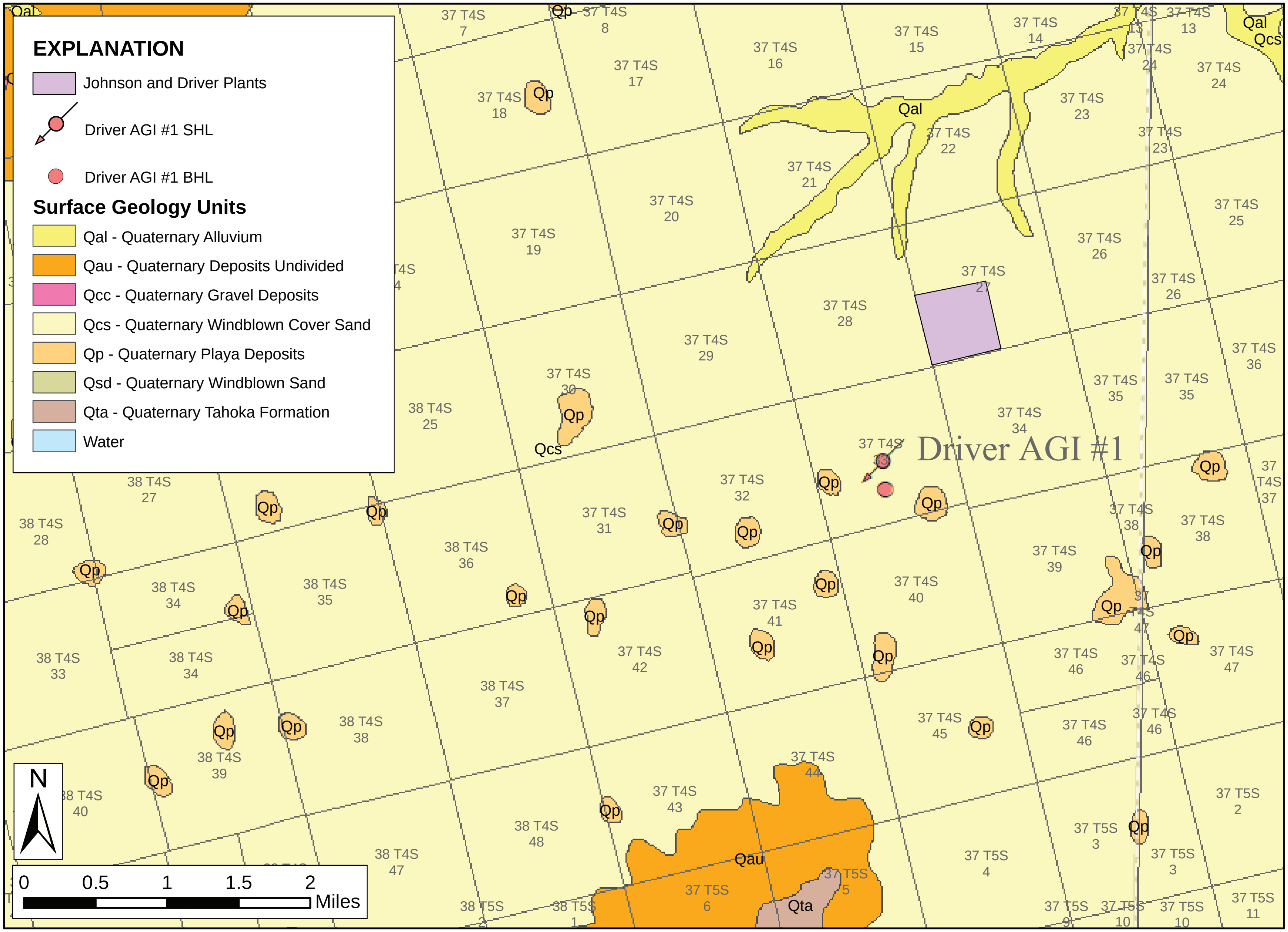

Figure 4. Surface geology at the Driver AGI #1 well site and the plant sites. The locations are directly underlain by the Qcs unit, which is Quaternary-aged windblown cover sand (Geology Atlas of Texas, 2023).

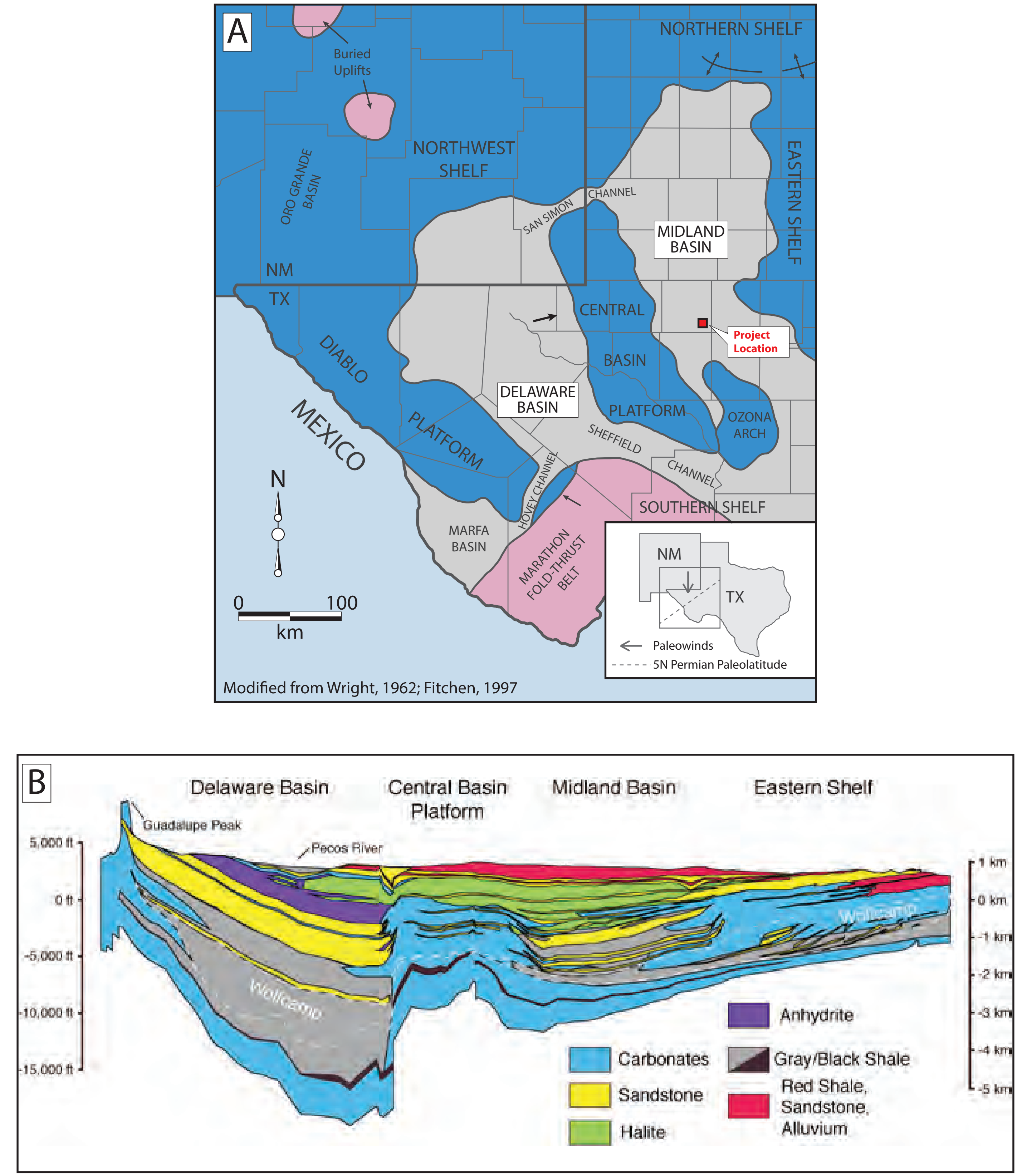

Figure 5. Structural setting and basin geometry (Panel A) and general lithologies and cross-sectional schematic of the Permian Basin (Panel B)

Generalized Stratigraphic Correlation Chart for the Permian Basin Region

SYSTEM	SERIES/ STAGE	NORTHWEST SHELF	CENTRAL BASIN PLATFORM	MIDLAND BASIN & EASTERN SHELF	DELAWARE BASIN	VAL VERDE BASIN
PERMIAN	OCHOAN	DEWEY LAKE RUSTLER SALADO	DEWEY LAKE RUSTLER SALADO	DEWEY LAKE RUSTLER SALADO	DEWEY LAKE RUSTLER SALADO CASTILE	RUSTLER SALADO
	GUADALUPIAN	TANSILL YATES SEVEN RIVERS QUEEN GRAYBURG SAN ANDRES GLORIETA	TANSILL YATES SEVEN RIVERS QUEEN GRAYBURG SAN ANDRES GLORIETA	TANSILL YATES SEVEN RIVERS QUEEN GRAYBURG SAN ANDRES SAN ANGELO	DELAWARE MT. GROUP BELL CANYON CHERRY CANYON BRUSHY CANYON	TANSILL YATES SEVEN RIVERS QUEEN GRAYBURG SAN ANDRES
	LEONARDIAN	CLEARFORK YESO WICHITA ABO	CLEARFORK WICHITA	LEONARD ★ SPRABERRY, DEAN	BONE SPRING	LEONARD
	WOLFCAMPIAN	WOLFCAMP	WOLFCAMP	★ WOLFCAMP	WOLFCAMP	WOLFCAMP
PENNSYLVANIAN	VIRGILIAN	CISCO	CISCO	CISCO	CISCO	CISCO
	MISSOURIAN	CANYON	CANYON	CANYON	CANYON	CANYON
	DESMOINESIAN	STRAWN	STRAWN	★ STRAWN	STRAWN	STRAWN
	ATOKAN	ATOKA BEND	ATOKA BEND	ATOKA BEND	ATOKA BEND	(ABSENT)
	MORROWAN	MORROW	(ABSENT)	(ABSENT ?)	MORROW	(ABSENT)
MISSISSIPPIAN	CHESTERIAN MERAMECIAN OSAGEAN KINDERHOOKIAN	CHESTER MERAMEC OSAGE KINDERHOOK	CHESTER MERAMEC OSAGE "BARNETT" KINDERHOOK WOODFORD	CHESTER MERAMEC OSAGE "BARNETT" KINDERHOOK WOODFORD	CHESTER MERAMEC OSAGE "BARNETT" KINDERHOOK WOODFORD	MERAMEC OSAGE "BARNETT" KINDERHOOK WOODFORD
DEVONIAN		WOODFORD DEVONIAN SILURIAN (UNDIFFERENTIATED)	DEVONIAN	★ DEVONIAN	DEVONIAN	DEVONIAN
SILURIAN			SILURIAN SHALE FUSSELMAN	SILURIAN SHALE FUSSELMAN	MIDDLE SILURIAN FUSSELMAN	MIDDLE SILURIAN FUSSELMAN
ORDOVICIAN	UPPER	MONTOYA	MONTOYA	SYLVAN MONTOYA	SYLVAN MONTOYA	SYLVAN MONTOYA
	MIDDLE	SIMPSON	SIMPSON	SIMPSON	SIMPSON	SIMPSON
	LOWER	ELLENBURGER	ELLENBURGER	ELLENBURGER	ELLENBURGER	ELLENBURGER
CAMBRIAN	UPPER	CAMBRIAN	CAMBRIAN	CAMBRIAN	CAMBRIAN	CAMBRIAN
PRECAMBRIAN						

Figure 6. General stratigraphy and producing zones (red stars) in the immediate area of the proposed injection project well (modified from Yand and Dorobek, 1995)

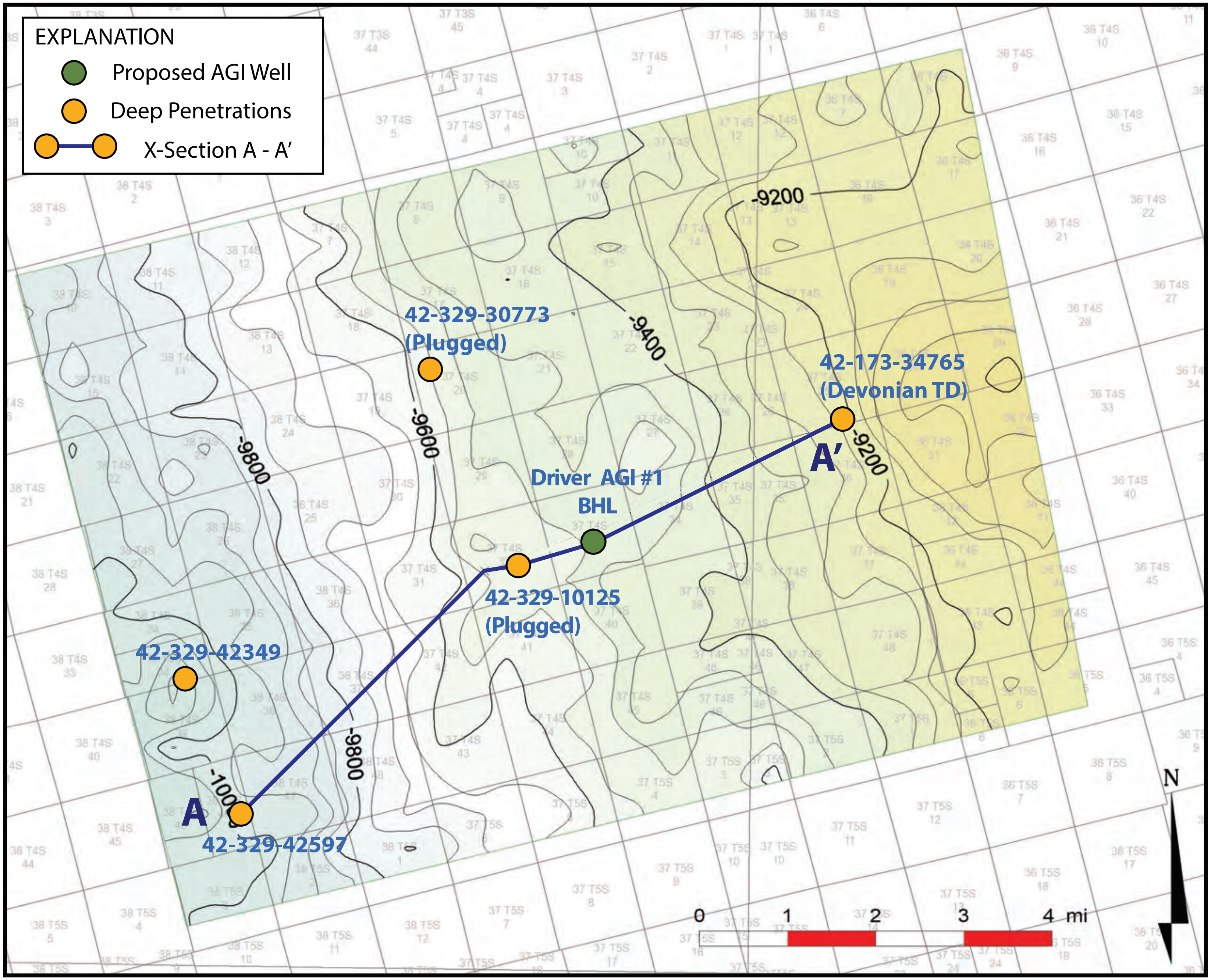

Figure 7. Subsea structural Contour map of the top of the Ellenburger. Wells displayed include the Driver AGI #1 well and nearby wells which were drilled to the Ellenburger Formation. Wells included in the cross section A - A' (Figure 8) are also shown.

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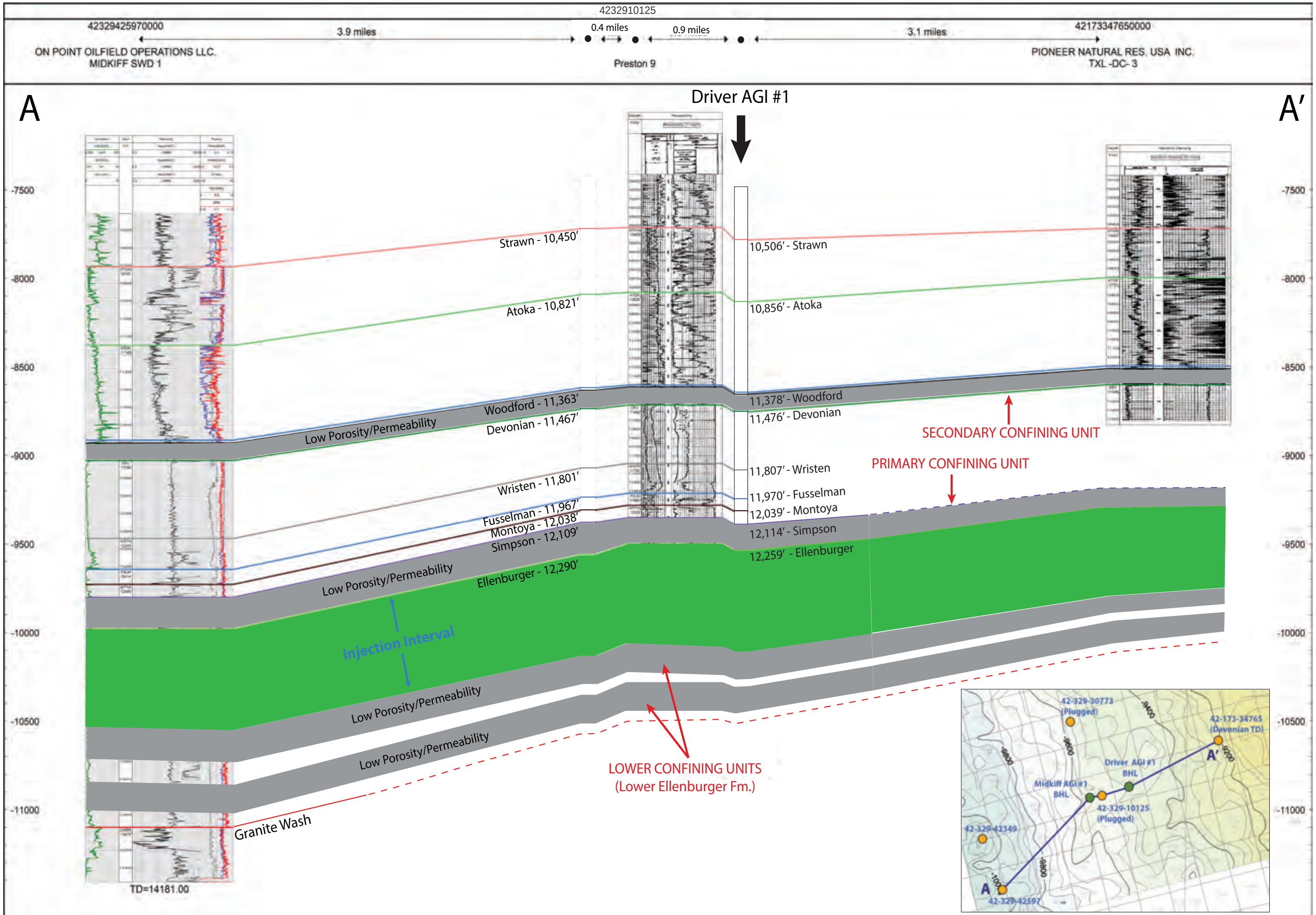


Figure 8. Structural Cross Section A-A' showing lithologic trends from nearby wells penetrating the approved injection interval and regional extent of overlying Woodford Shale and Simpson Group confining strata along with underlying, low permeability lower Ellenburger strata. The approved injection interval include the Ellenburger Formation geologic depth intervals.

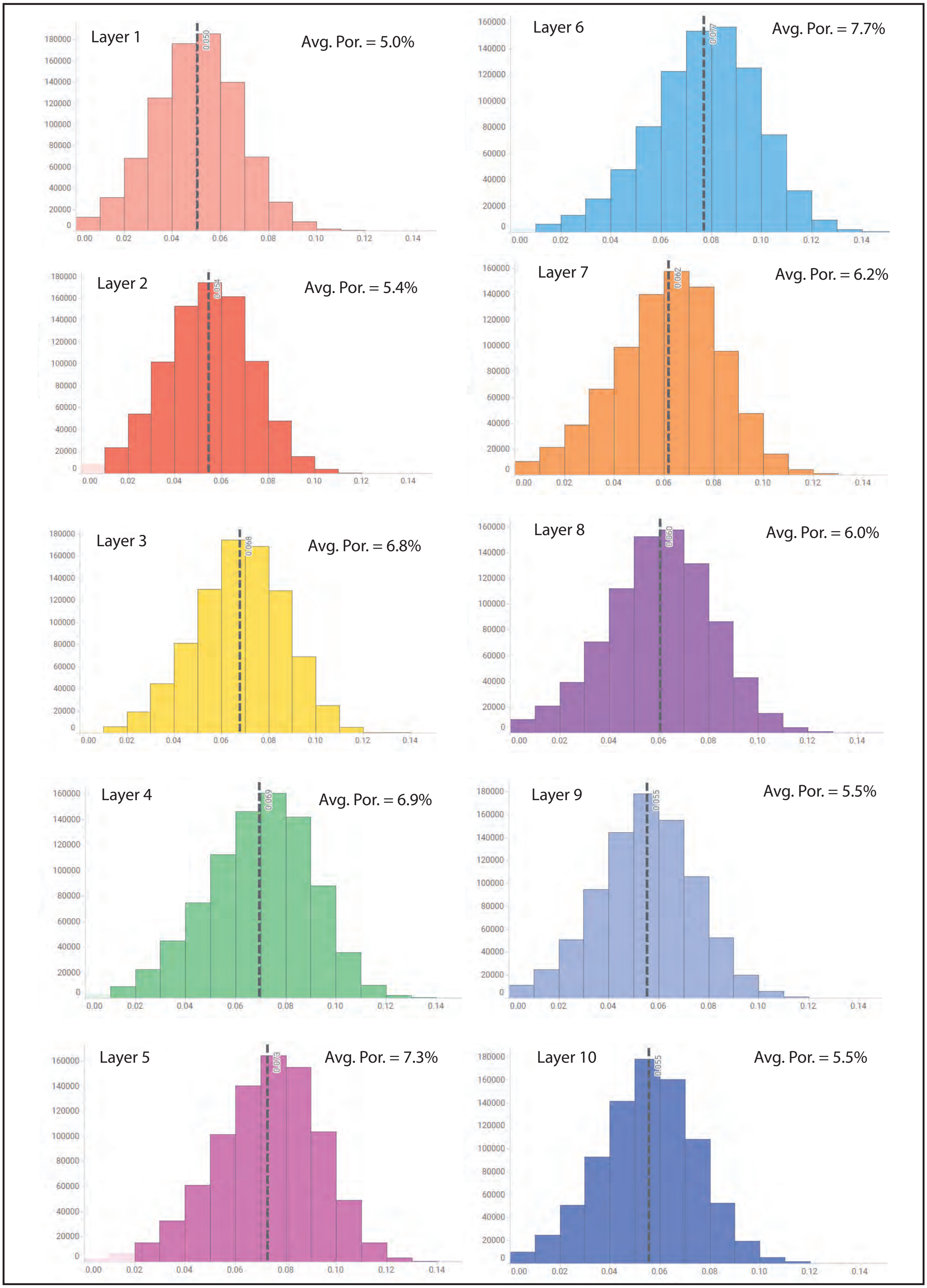
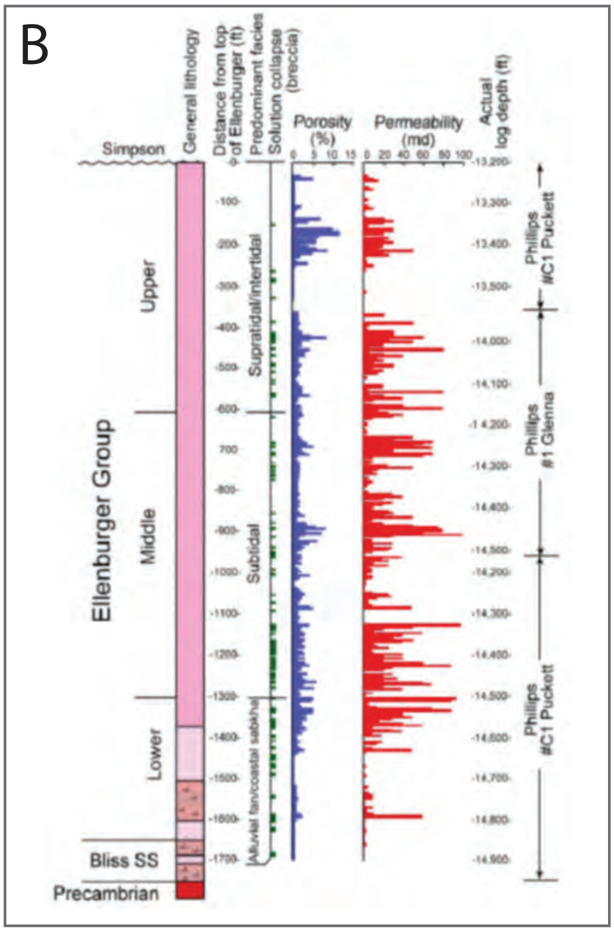


Figure 9. Porosity distribution within each of the 10 model layers for the area approximately within the MMA.

A

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA



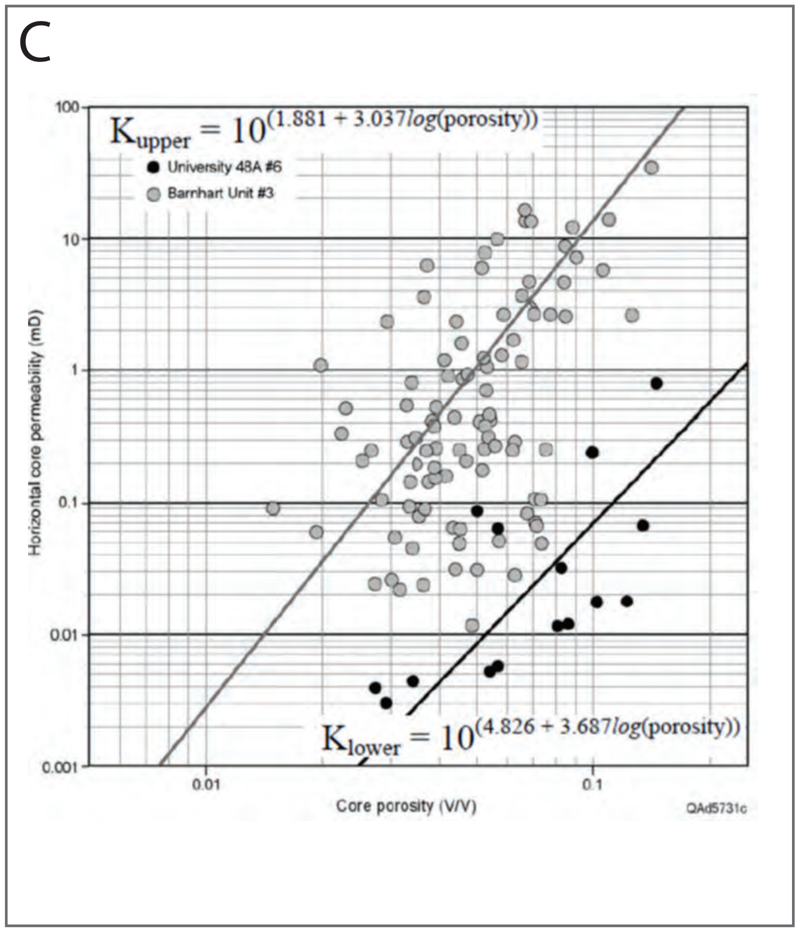


Figure 10. Panel A) Reservoir parameters for the Ellenburger in various reservoir groups (Holtz and Kerans, 1992). Panel B) Porosity and permeability profiles of the Ellenburger with characteristic facies labeled (Loucks and Anderson, 1980). Panel C) Porosity/permeability relationship determined from core analysis (Loucks et al., 2007)

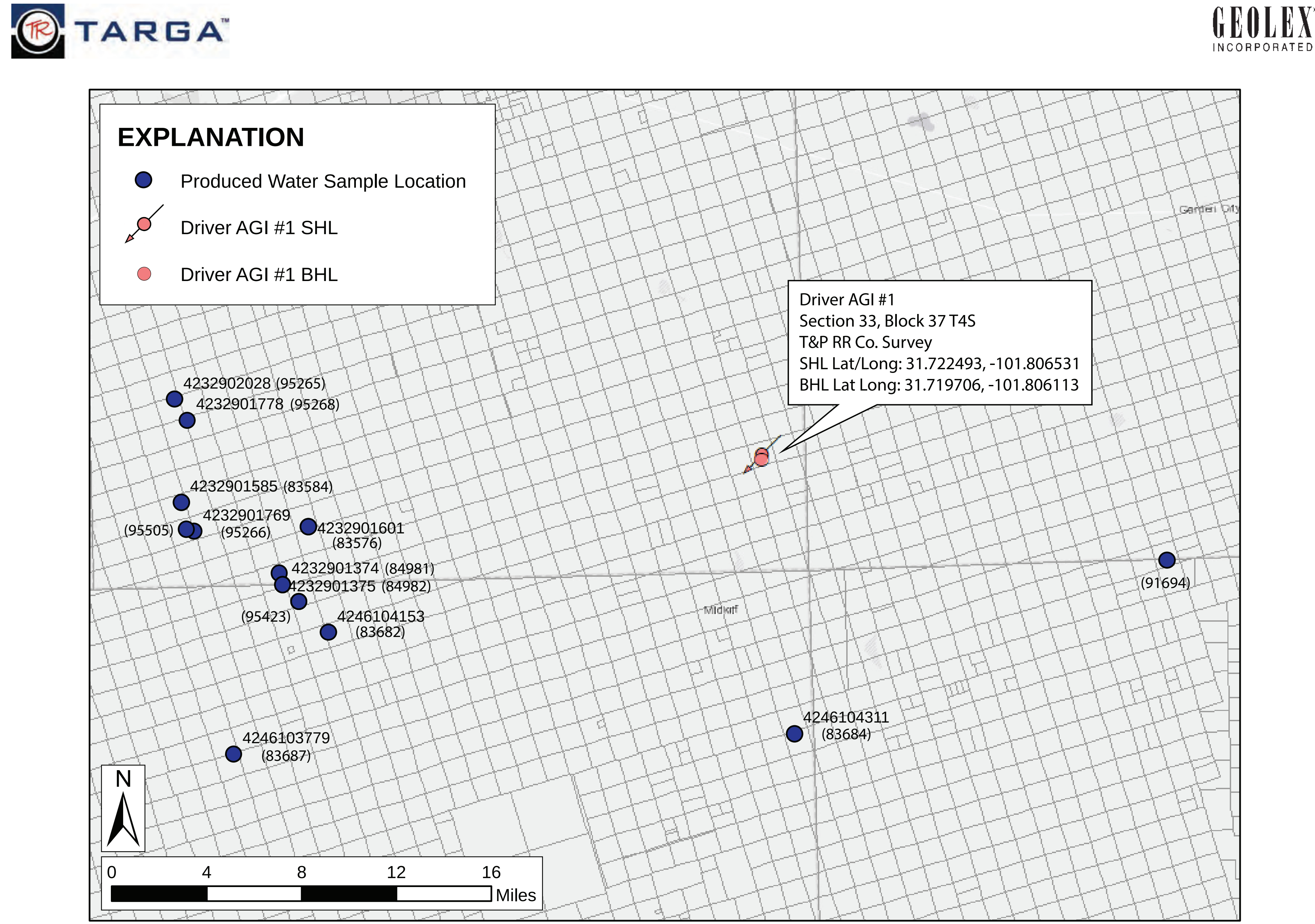


Figure 11. Location of the wells from which water chemistry was reported for produced water from the Ellenburger Group. Selected wells are within 25 miles of the Driver AGI #1. Well APIs and/or USGS IDs are labeled. A summary of the analysis can be found in Appendix 3.

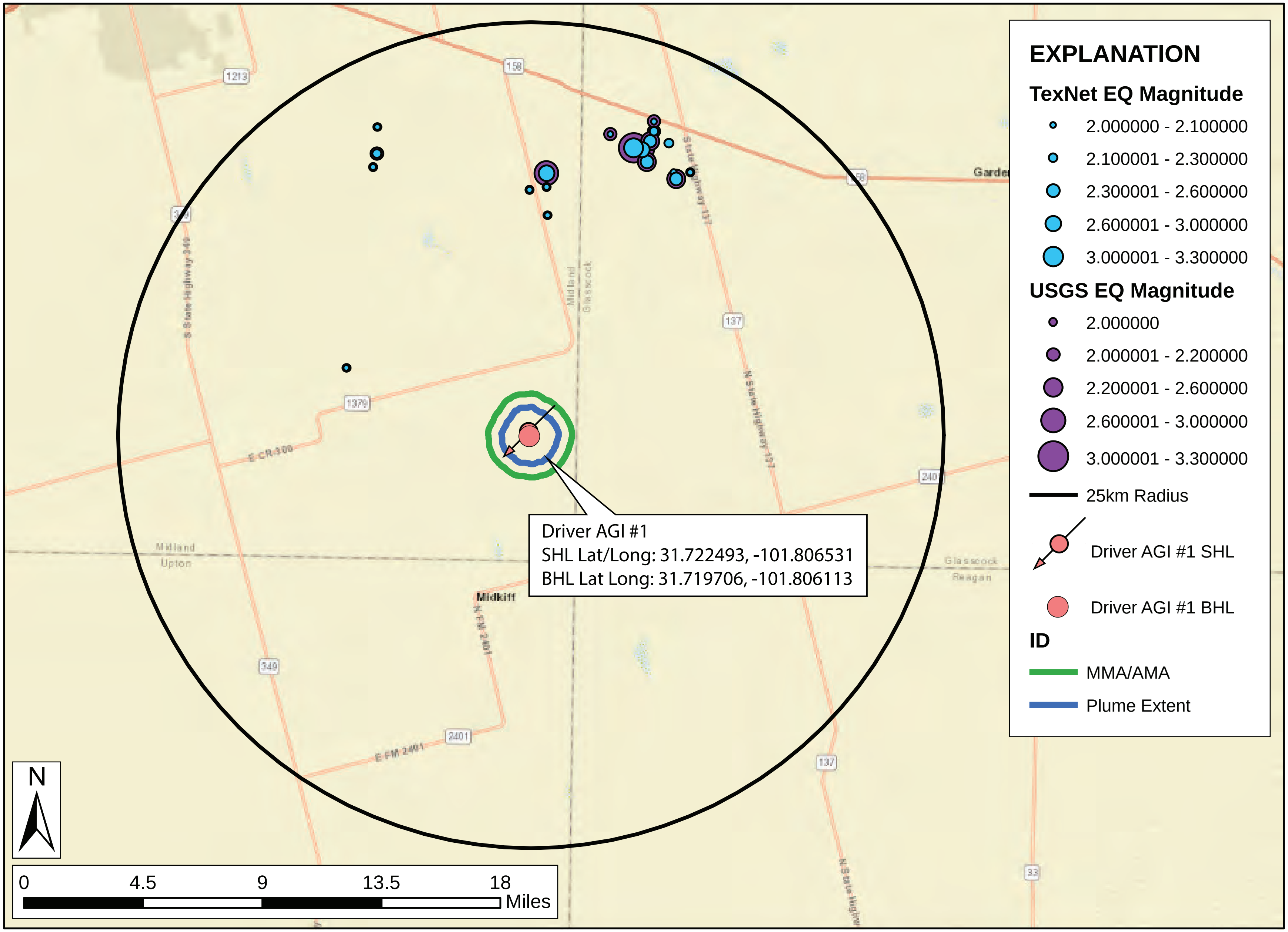


Figure 12. Seismicity records from TexNet (2017 - present) and USGS (1973 - present) for all seismic events with a magnitude greater that 2.0. No events have occured within the MMA/AMA, and within 25 km, there have been 17 events recorded by USGS and 19 events recorded by TexNet, the largest of which was a magnitude 3.3.

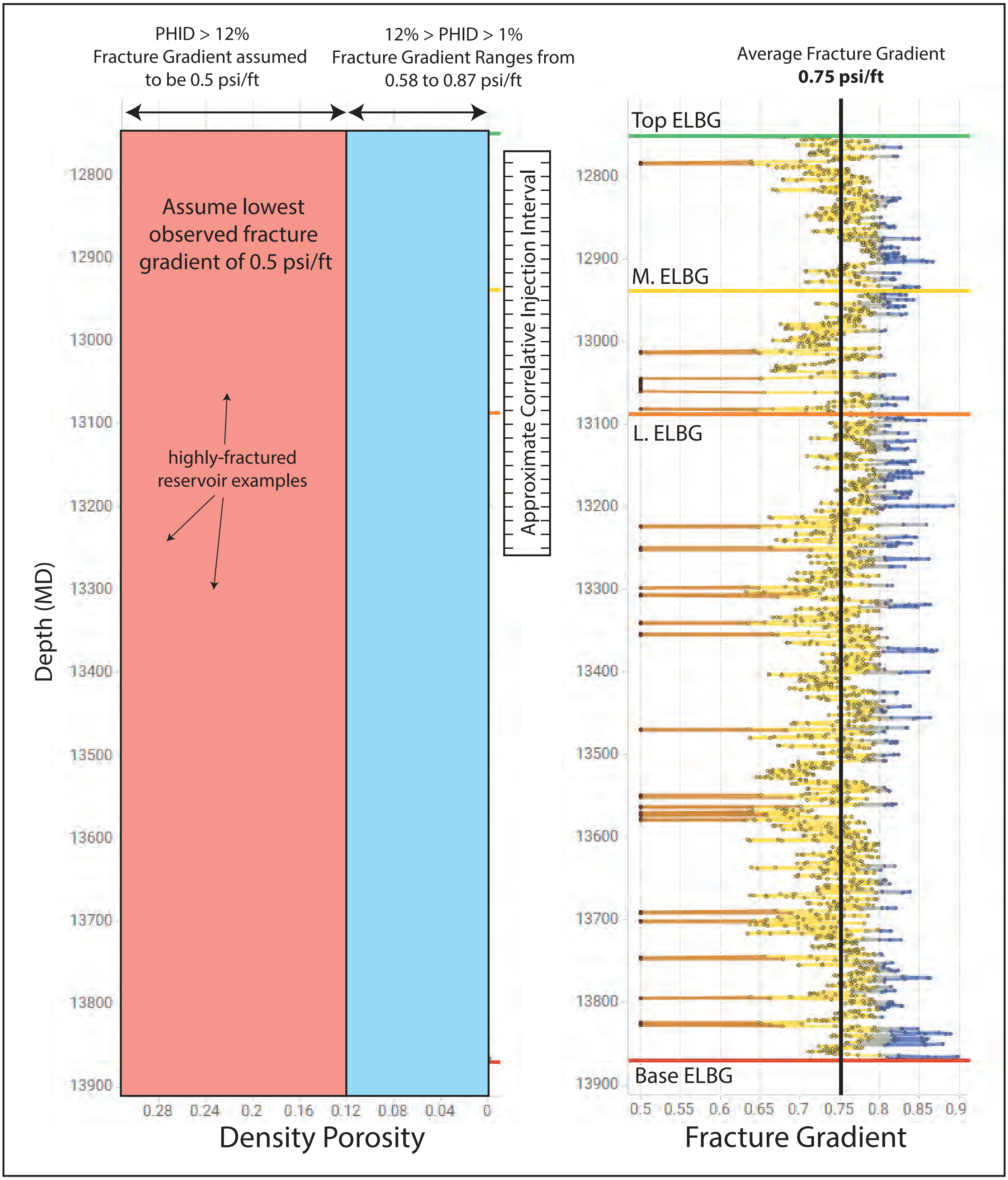


Figure 13. Fracture pressure estimation through transformation of a density porosity log (corrected for dolomitization) from the Midkiff SWD #1, based on reported fracture pressure gradients in published work

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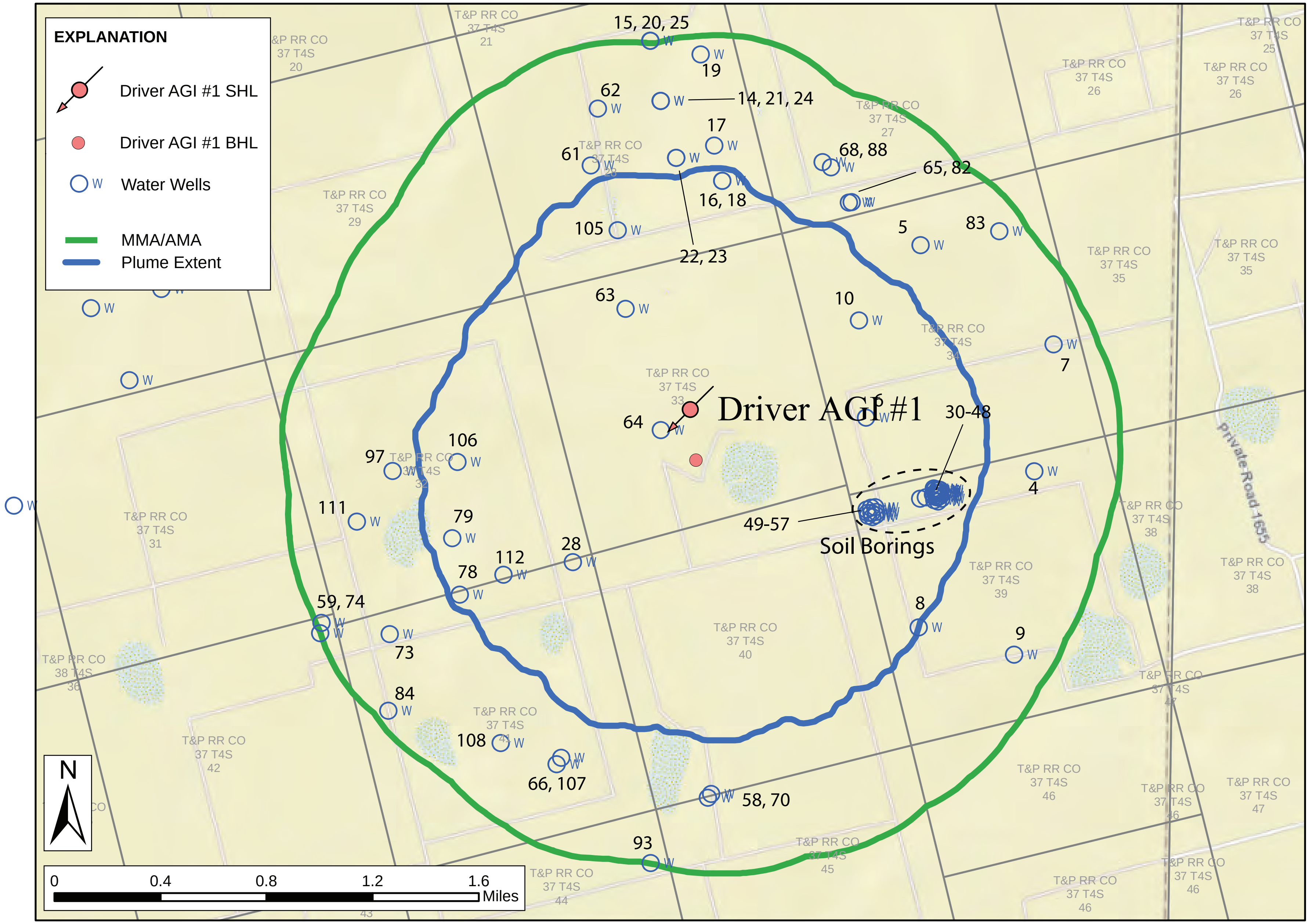

Figure 14. Water wells (labeled with a corresponding ID #) within the injection plume following 30 years of injection plus 50 years of post shut-in stabilization (blue outline) and a 1/2-mile buffer (green outline, MMA/AMA). Nearly all wells produce water from the Antlers Sands of the Edwards Trinity Major Aquifer. A lone water-producing well (#27) has a TD in the Ochoan Series Dewey Lake Formation (1,315 feet deep).

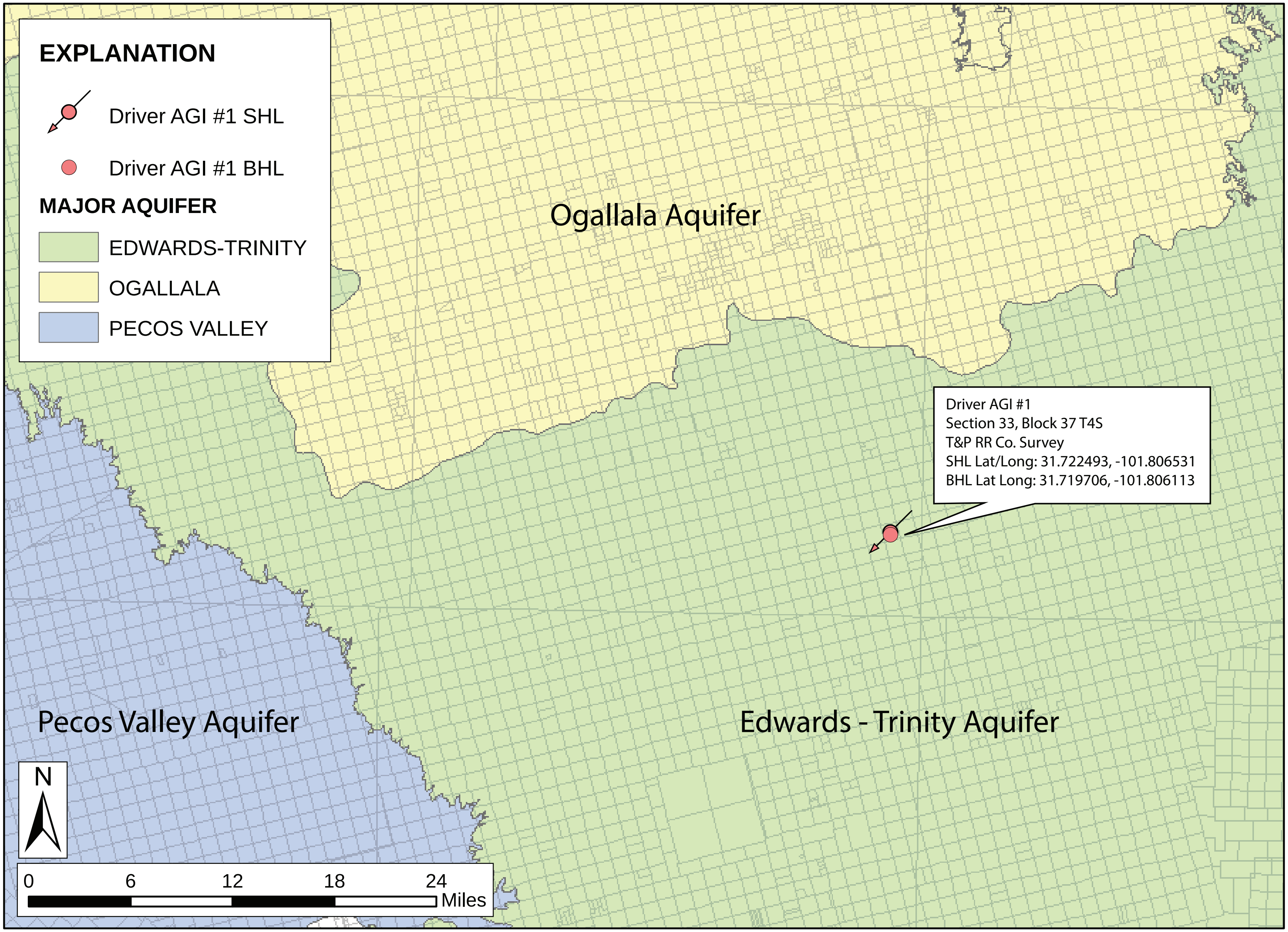

Figure 15. Major aquifers of the project region and the approved Driver AGI #1 well location. The Edwards-Trinity aquifer is the only major aquifer present at the project site. There are no minor aquifers designated.

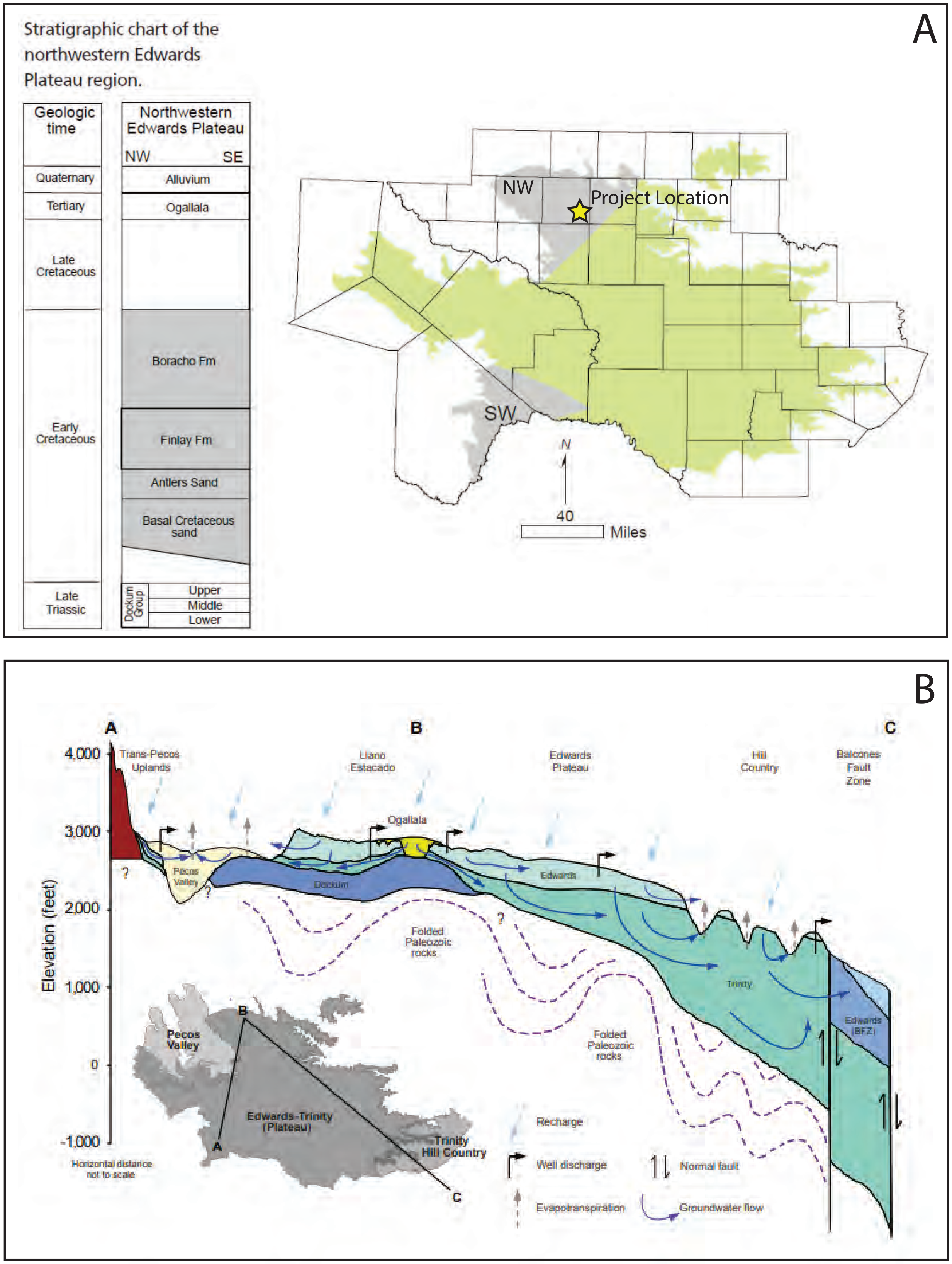

Figure 16. Stratigraphic chart and map of the northwesters Edwards Plateau Region (Panel A, George, et al., 2011), and diagrammatic cross-section of the aquifers through the project and adjacent region (Panel B, George, et al., 2011, after Anaya and Jones, 2004, 2009) .

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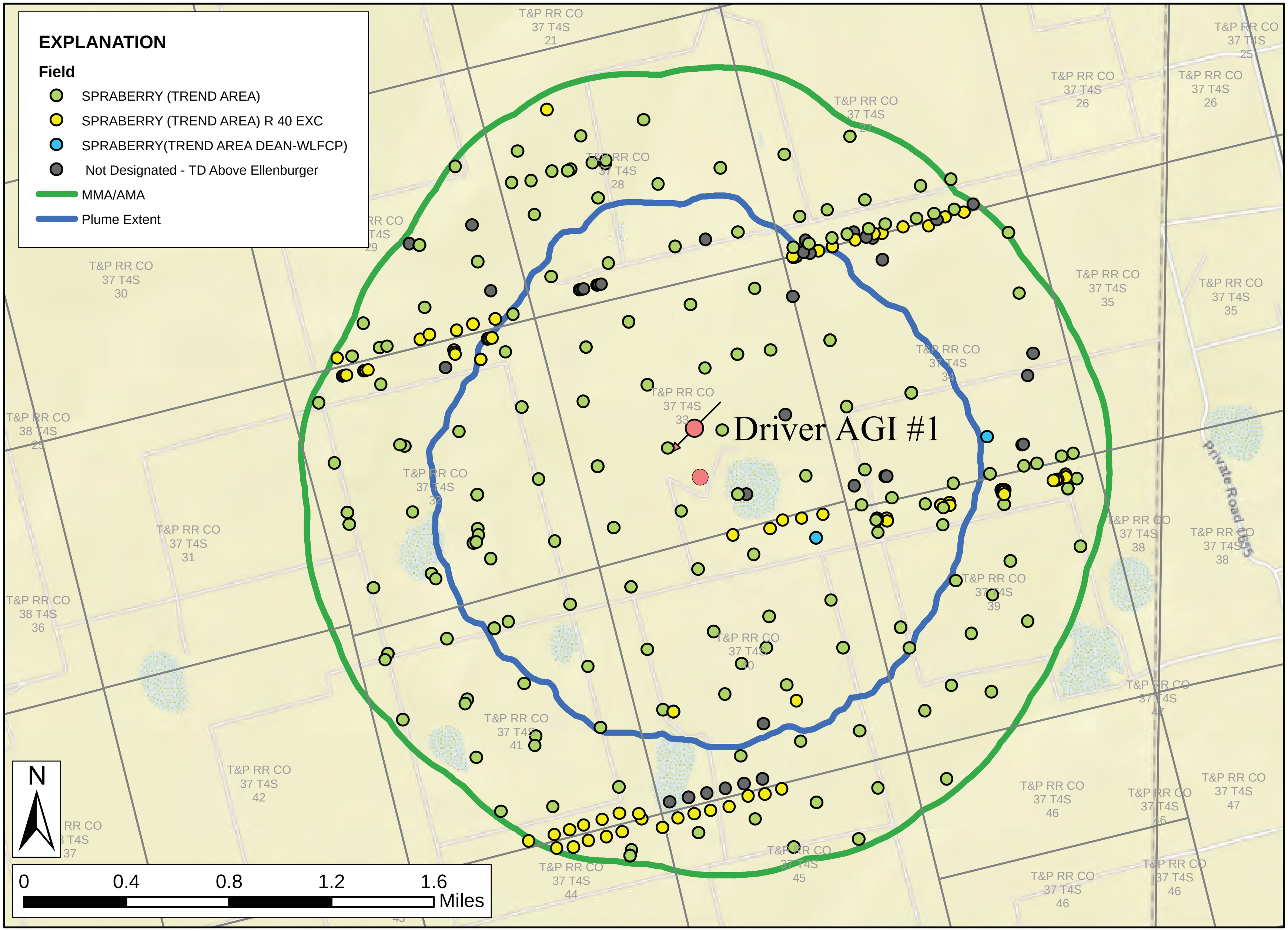


Figure 17. Producing fields within the MMA. Most Wells primarily produce from a variation of the Spraberry (Trend Area) Field. Several wells with no available field information have total depths indicating that they do not penetration the Ellenburger. No Ellenburger (or SIluro-Devonian) production, current or historical, is present within the MMA/AMA.

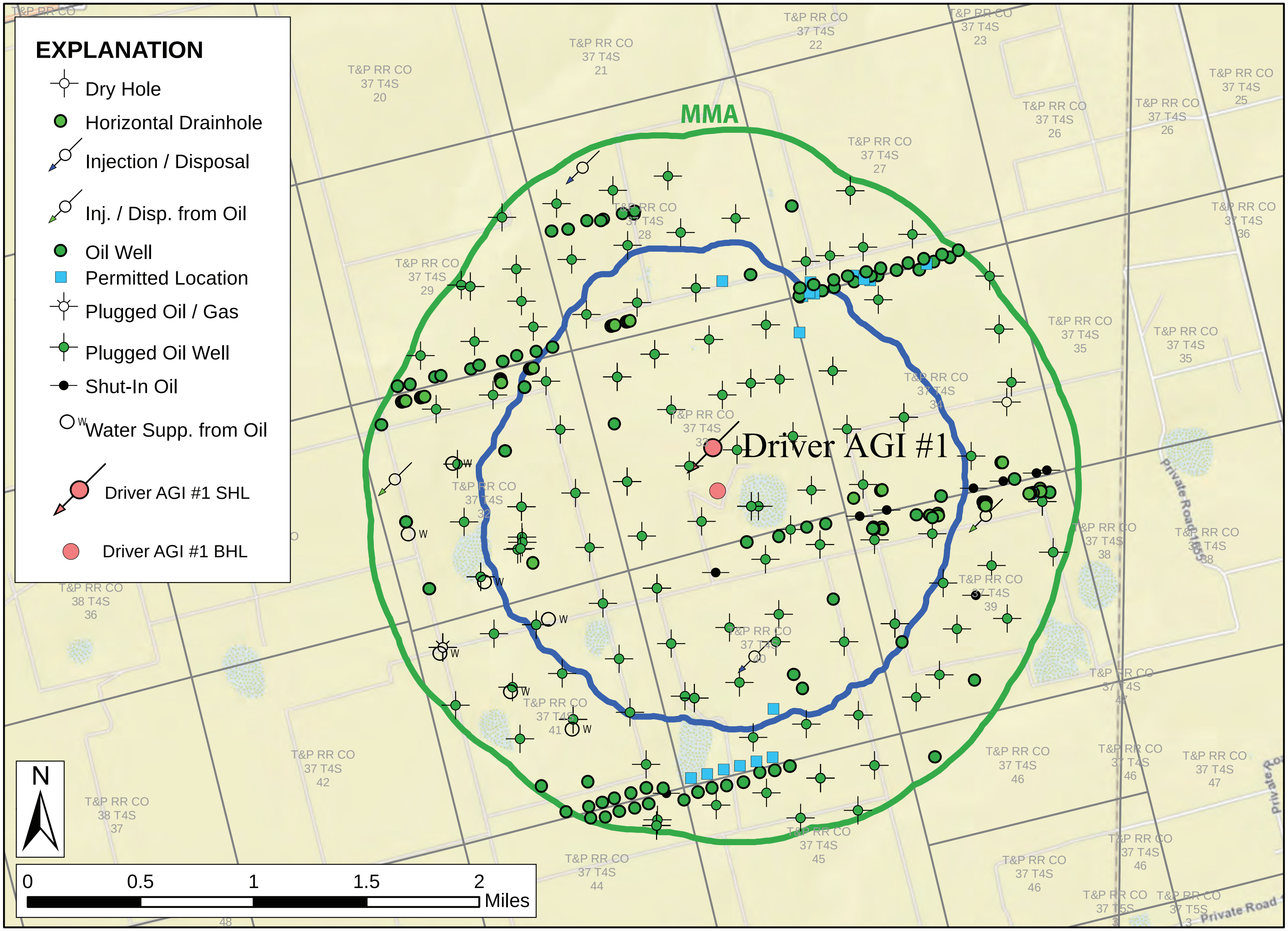
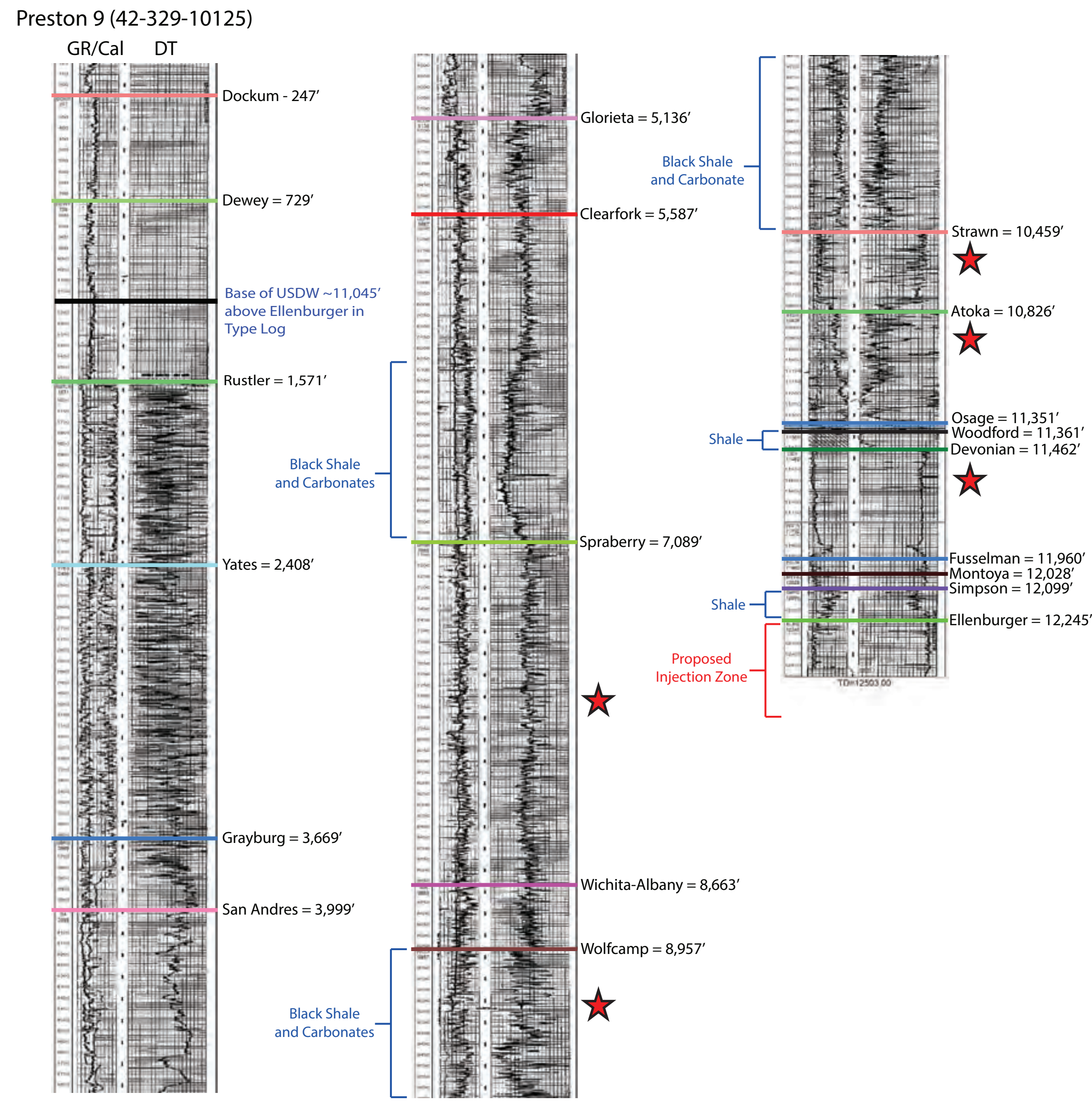


Figure 18. All wells within MMA/AMA. Well statuses are depicted, and a complete list of wells with details (i.e., API, TD, Field, etc.) can be found in Appendix 7. With the exception of two deep-penetrating wells, all wells have total vertical depths thousands of feet above the injection interval and are separated from the injection interval by the primary and secondary regional seals.



ANTICIPATED FORMATION TOPS (TVD)

	DRIVER AGI #1
Dockum	157′
Dewey	621′
Rustler*	1,465′
Yates	2,291′
Grayburg	3,561′
San Andres	3,904′
Glorieta	5,065′
Clearfork	5,495′
Spraberry	7,068′
Wichita-Albany	8,635′
Wolfcamp	8,924′
Strawn	10,506′
Atoka	10,856′
Osage	11,367′
Woodford	11,378′
Devonian	11,476′
Fusselman	11,970′
Montoya	12,039′
Simpson	12,114′
Ellenburger	12,259′

*Driver AGI #1 Base of USDW ~11,059 above Ellenburger

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Figure 19. Type log showing oil and gas producing zones (active and plugged) and major sealing lithologies in the general area of the proposed injection well

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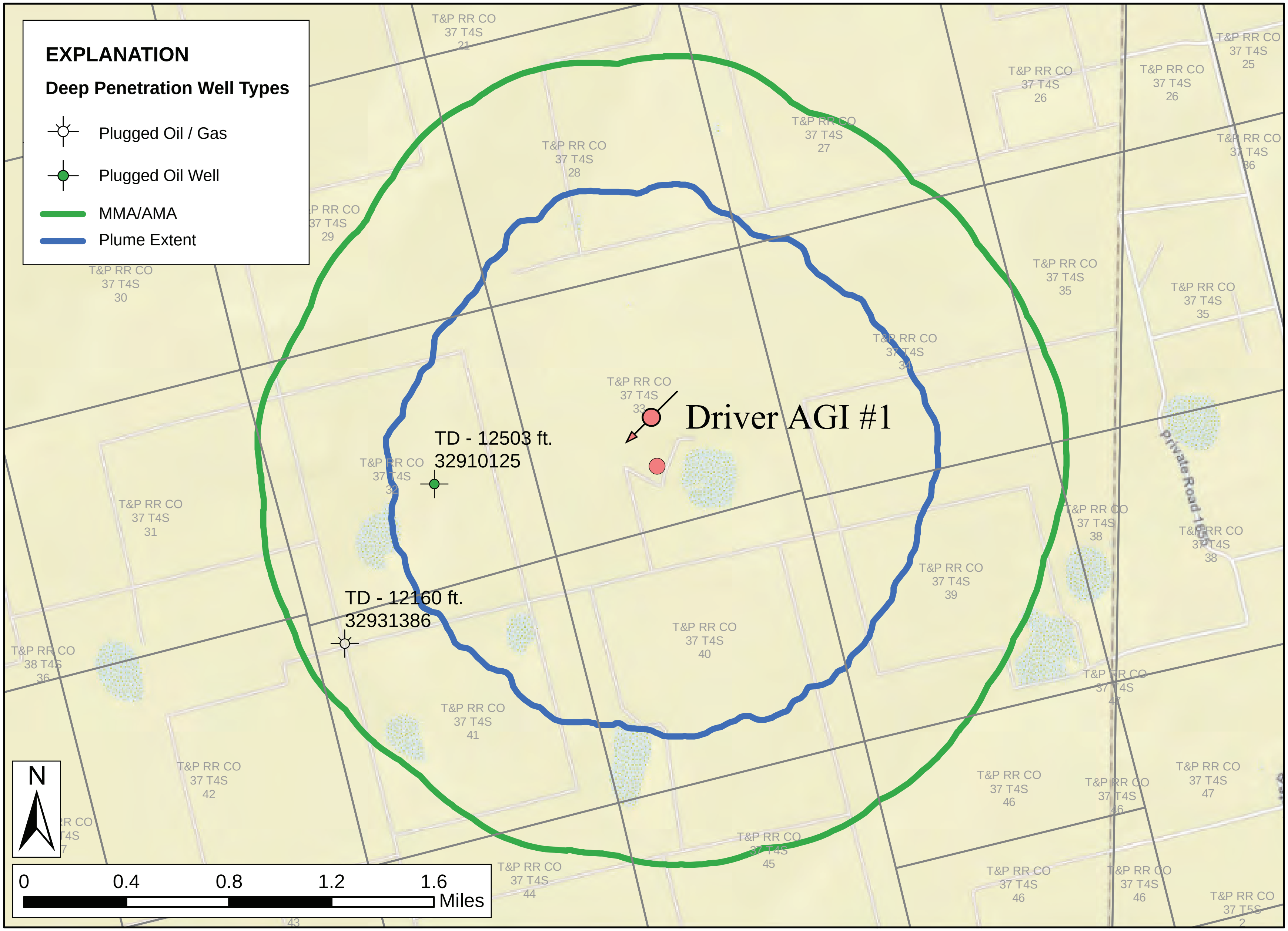

Figure 20. Deep well penetrations within the MMA/AMA. The single well within the MMA that penetrates the Ellenburger is the Preston 9 (API# 42-329-10125) and has a total depth of 12,503 feet. Another deep penetration is the Preston, Sam R. 28 (API# 42-329-31386) and has a total depth of 12,160 within the Simpson Group. The TDs and last 8 digits of the API numbers are labeled.

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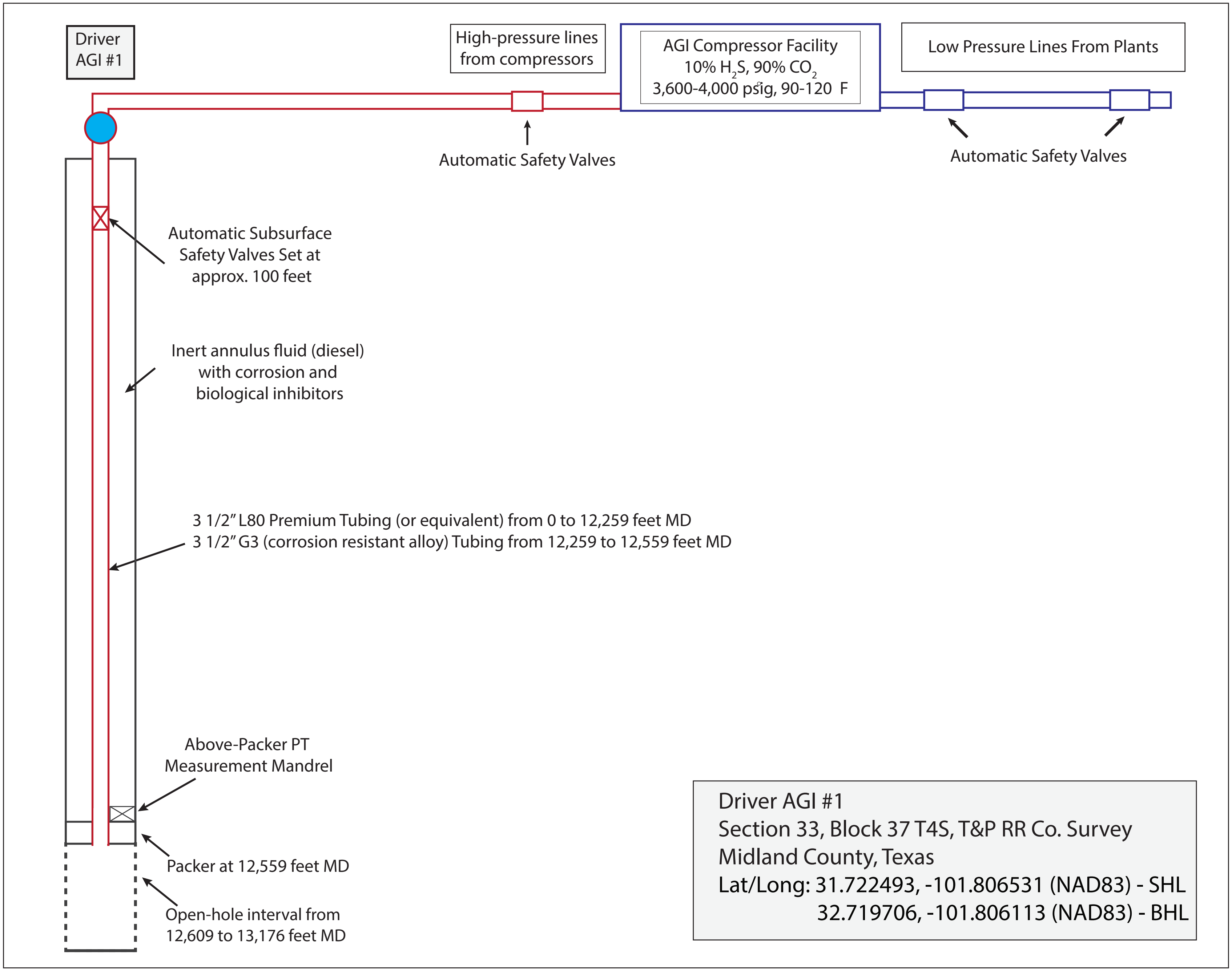
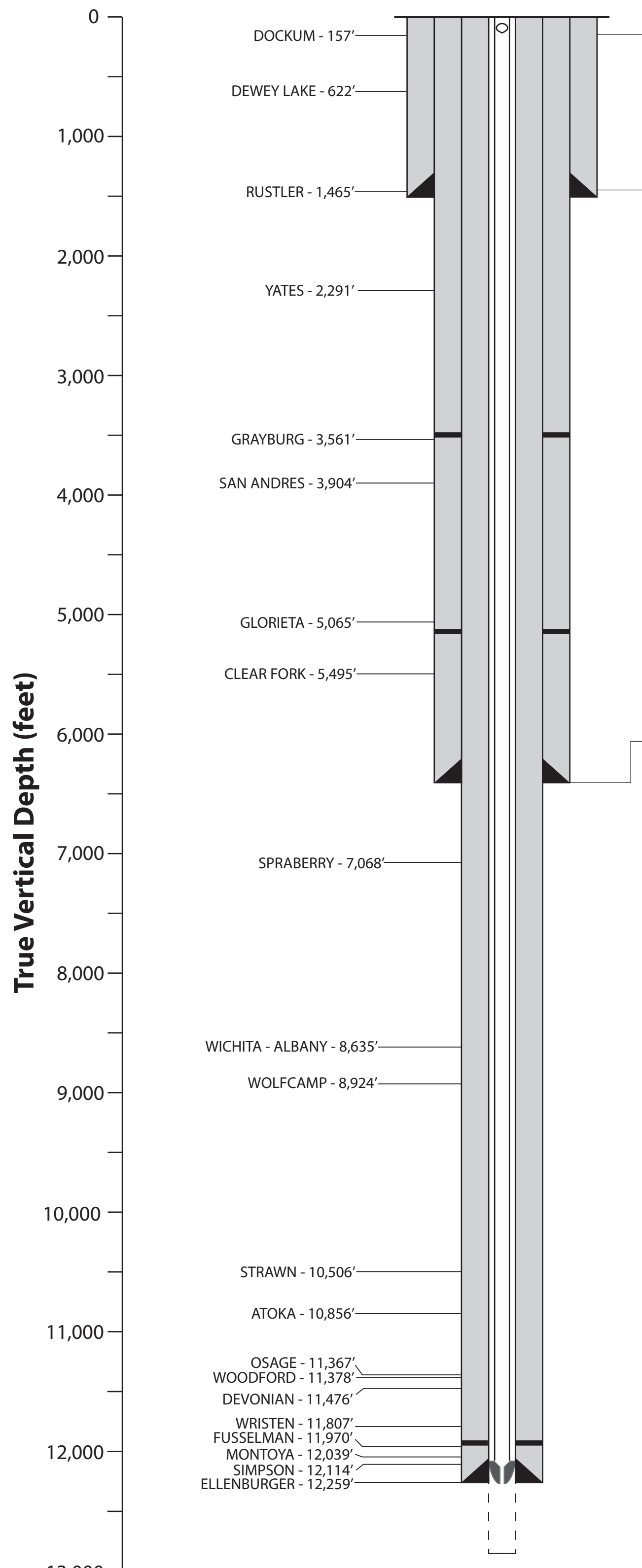


Figure 21. Schematic of surface facilities for the proposed Driver AGI #1 injection well

PROPOSED WELL SCHEMATIC
Driver AGI #1

SHL 31.722493, -101.806531 NAD83
BHL 31.719706, -101.806113 NAD83



Total Vertical Depth = 12,826 (13,176 MD)

24" CONDUCTOR PIPE TO 120'

SURFACE CASING **17.5" OH**
13-3/8", 54.5 #/ft., J-55, BTC from 0' to 1,500'
Subsurface Safety Valve set @ approx. 100'
LEAD: 840 sks EconoCem (12.9 ppg)
TAIL: 340 sks HalCem (14.8 ppg)

1ST INTERMEDIATE CASING **12.25" OH**
9-5/8", 40 #/ft., HCL80, BTC from 0' to 6,400' MD

STAGE 1 CEMENT (5,150' to 6,400')
LEAD: 175 sks NeoCem (11.0 ppg)
TAIL: 105 sks HalCem (14.8 ppg)

STAGE 2 CEMENT (3,500' to 5,150')
318 sks WellLock Resin, or equivalent (15.34 ppg)

STAGE 3 CEMENT (0' to 3,500')
LEAD: 515 sks HalCem (11.0 ppg)
TAIL: 100 sks VersaCem (14.8 ppg)

DVT/ECP at approx. 3,500' and 5,150'

PRODUCTION CASING **8.75" OH**
7", 26 #/ft., HCL80, Prem. Thread from 0' to 11,959'
(0' to 12,309' MD)
7", 26 #/ft., G3 (CRA), Prem. Thread from 11,959 to 12,259'
(12,309' to 12,609' MD)

STAGE 1 CEMENT (11,959' to 12,259 [12,309' to 12,609' MD])
78 sks WellLock Resin, or equivalent (12.0 ppg)

STAGE 2 CEMENT (0' to 11,959' [0' to 12,309' MD])
LEAD: 1,685 sks NeoCem TM (11.0 ppg)
TAIL: 540 sks NeoCem TM (13.2 ppg)

DVT at approx. 11,959' (12,309' MD)

TUBING AND EQUIPMENT
3-1/2", 9.3 #/ft., L80 (or equivalent), Prem. Thread from 0' to 11,909'
(0' to 12,259' MD)
3-1/2", 9.3 #/ft., Inconel G3 (CRA), Prem. Thread from 11,909' to 12,209'
(12,259' to 12,559' MD)

Halliburton BWD Permanent Packer set at approx. 12,209' (12,559' MD)
Halliburton P/T sensors on mandrel above packer
Inert annular fluid (diesel) with corrosion and
biological inhibitors

5-7/8" OPEN-HOLE INTERVAL FROM APPROX. 12,259' to 12,826'
(12,609' to 13,176' MD)

All depths are approximate and subject to change based on drilling and geology encountered

Figure 22. Proposed well schematic of the Driver AGI #1, consisting of a surface string of casing, an intermediate string, and a production string with associated tubing/equipment and cement types.

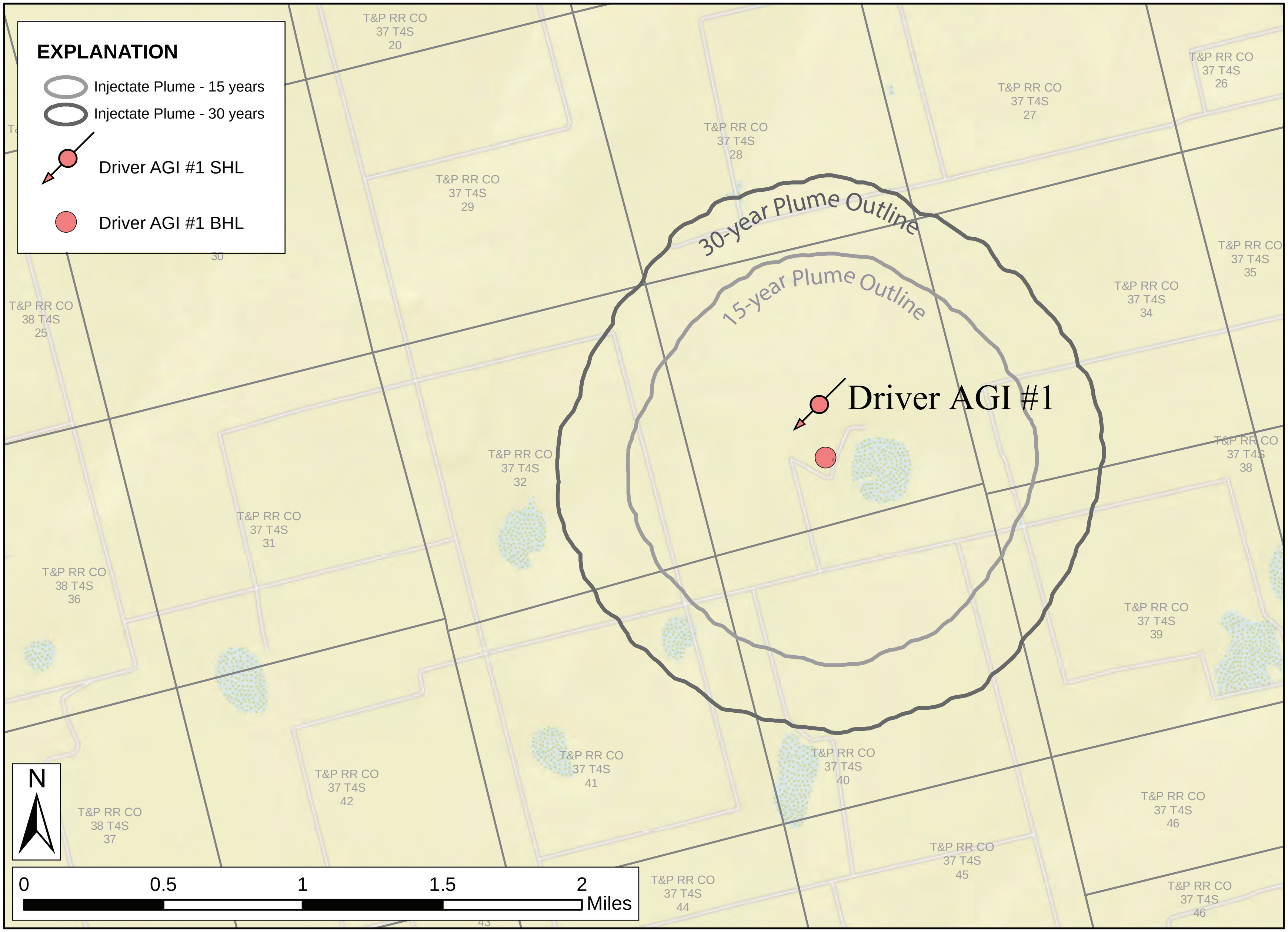


Figure 23. Model simulation results showing the outline of the free-phase injectate plume after 15- and 30 year periods of the Driver AGI #1 well operation and while injecting 20 MMSCFD of treated acid gas.

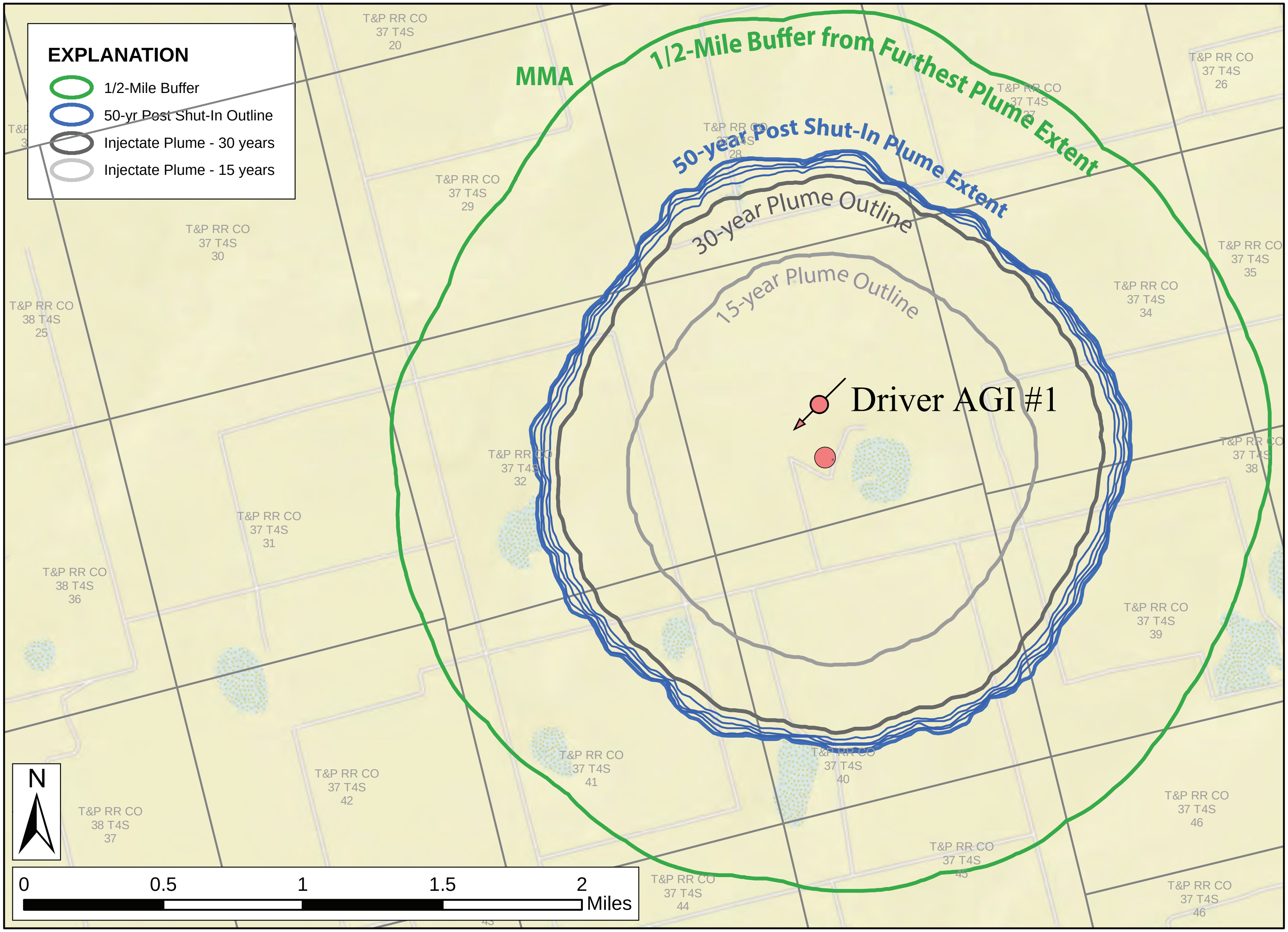


Figure 24. Model simulation results showing the outline of the free-phase injectate for post shut-in periods of 5, 10, 20, 30, 40, and 50 years, represented by the subsequently larger blue plume outlines. The 1/2-mile buffer from the largest post shut-in outline (green line) represents the maximum monitoring area (MMA).

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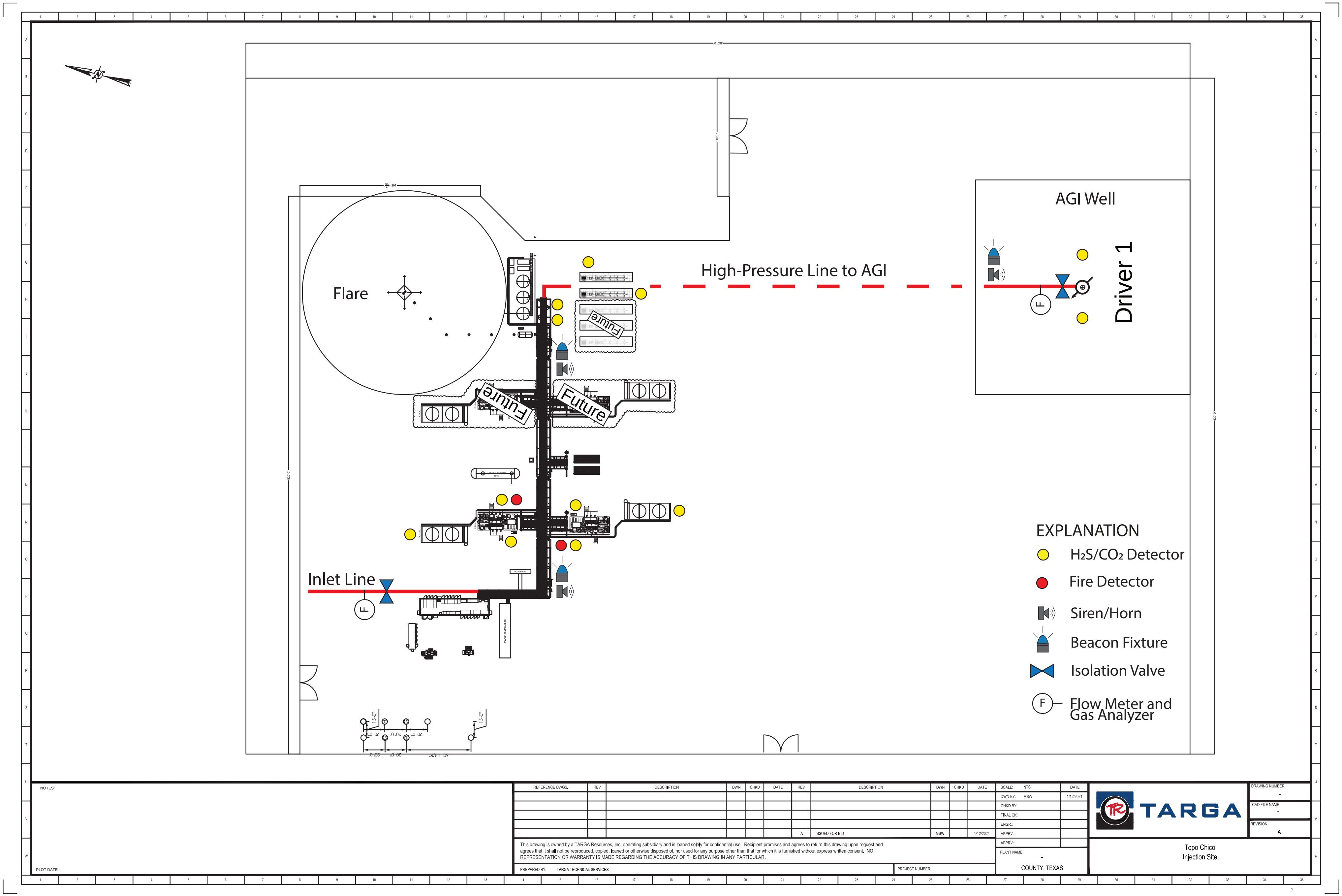

Figure 25 - Preliminary injection site plat and location of emergency equipment, including H2S sensors, which aid in identifying and responding to H2S and CO2 leaks.

APPENDIX 1

Targa Wells Subject to Monitoring, Reporting and, Verification

Appendix 1 – Targa’s Wells Subject to the MRV

Well Name	API #	Surface Legal Location	County	Spud Date	Total Depth	Packer
Driver AGI #1	TBD	2,260’ FSL, 2,626’ FWL Section 33, Block 37 T4S, T&P RR Co. Survey	Midland County, Texas	TBD	12,826 (TVD) 13,176 (MD)	12,209 (TVD) 12,559 (MD)

APPENDIX 2

Referenced Regulations

Appendix 2 – Referenced Regulations

U.S. Code >

Title 26: IRS 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 >

§ 45Q: Credit for Carbon Oxid Sequestration

Code of Federal Regulations >

Title 40: Protection of the Environment >

Chapter I: Environmental Protection Agency >

Subchapter C: Air Programs >

Part 98: Mandatory Greenhouse Gas Reporting >

Subpart RR: Geologic Sequestration of Carbon Dioxide

§ 98.440: Definition of the Source Category

§ 98.441: Reporting Threshold

§ 98.442: GHGs to Report

§ 98.443: Calculating CO2 Geologic Sequestration

§ 98.444: Monitoring and QA/QC requirements

§ 98.445: Procedures for Estimating Missing Data

§ 98.446: Data Reporting Requirements

§ 98.447: Records that Must Be Retained

§ 98.448: Geologic Sequestration Monitoring, reporting, and verification (MRV) plan

§ 98.449 Definitions

Subpart W: Petroleum and Natural Gas Systems

§ 98.230: Definition of the Source Category

§ 98.231: Reporting Threshold

§ 98.232: GHGs to Report

§ 98.233: Calculating GHG Geologic Sequestration

§ 98.234: Monitoring and QA/QC requirements

§ 98.235: Procedures for Estimating Missing Data

§ 98.236: Data Reporting Requirements

§ 98.237: Records that Must Be Retained

§ 98.238: Definitions

Texas Administrative Code >

Title 16: Economic Regulation >

Part 1: Railroad Commission of Texas >

Chapter 3: Oil and Gas Division >

§ 3.9: Disposal Wells

§ 3.13: Casing, Cementing, Drilling, Well Control, and Completion Requirements

§ 3.36: Oil, Gas, or Geothermal Resource Operations in Hydrogen Sulfide Areas

APPENDIX 3

Tables of Produced Water Geochemistry

A-1 – Well Information

A-2 – Major Cation and Anion Concentrations

Table A-1 – Ellenburger Produced Water Well Description Information

ID USGS	LAT (NAD83)	LONG (NAD 83)	API	FIELD	WELL NAME	SAMPLE DATE	WELL DEPTH
83576	31.6857	-102.1318	4232901601	Sweetie Peck	June Tippett #16	1/26/1956	13080
83577	31.6857	-102.1318	4232901601	Pegasus	J. Tippett #16	1/7/1963	13080
83584	31.7025	-102.2223	4232901585	War San	June Sanders 21a	1/3/1962	13330
84981	31.6578	-102.1536	4232901375	Pegasus Penn	1	1/27/1951	13236
84982	31.6507	-102.1513	4232901374	Pegasus Ellenburger	1	1/2/1950	13706
84983	31.6507	-102.1513	4232901374	Pegasus Ellenburger	1	1/24/1950	13706
95265	31.7657	-102.2253	4232902028	Virey	#1 Wallen	1/30/1954	13424
95266	31.6846	-102.2136	4232901769	Sweetie Peck	Sanders #2	1/11/1958	13230
95268	31.7526	-102.2165	4232901778	Virey	Midland C Fee #1	1/9/1956	13315
95423	31.64	-102.14		Pegasus	11-2	1/26/1959	
95498	31.64	-102.14		Pegasus	Windom 2-16	1/15/1953	
95499	31.64	-102.14		Pegasus	Windham 12-16	1/23/1953	
95505	31.686	-102.219		Sweetie Peck	Sanders A-13	1/11/1958	
91694	31.65	-101.519		Saunders	J. E. Zachary #1	1/18/1942	
83682	31.6207	-102.1197	4246104153	Pegasus, South	V.g. Powell #2	1/20/1950	13226
83684	31.5509	-101.7888	4246104311		D.l. Alford #1	1/20/1956	12022
83687	31.5478	-102.1895	4246103779		G.r. Davis #1	1/27/1956	13363

Table A-2 – Ellenburger Produced Water Analysis of Major Cations and Anions

IDUSGS	SG	PH	TDS	Na (mg/L)	Ca (mg/L)	Mg (mg/L)	K (mg/L)	K/Na (mg/L)	Sr (mg/L)	Cl (mg/L)	Br (mg/L)	SO4 (mg/L)	HCO3 (mg/L)
83576	1.099	7.87	155455	49130.87	8792	1174.83	651.71		478.07	94690.94	190.13	881.4	230.79
83577	1.094	5.01	133894	39764	9040	1311	838		358	81600		780	183
83584	1.013	7.2	18945	6287.69	632.11	79.01	174.24		20.26	10028.7		1215.6	506.5
84981	1.085		124149	38374.07	7041	1706.08				76005.51		772.24	198.48
84982	1.073		106366	34541.19	5485	742.17				64463.69		687.47	409.7
84983	1.101		146799	38917.77	12095	3394.21				90061.01		718.05	1414.07
95265	1.063	7.4	102978	33268.1	4252	1678.48				63780			
95266	1.095	6.6	149122		9526	1752		45223.5		91542		657	421.58
95268	1.08	7.4	113446		5520	1750		36151		68400		1335	290
95423	1.125	5.2	184860		11250	1800		56250		114750		675	135
95498	1.105	6.9	167029		9016	2331.55		52487.5		101218		1768	207.74
95499	1.09	7	158791		10028	1641.54		43600		102460		816.41	245.25
95505	1.055	6.5	119589		5697	1329.3		38613		72795		801.8	353.43
91694	1.164		237447	66482	20216	2844				146358		637	70
83682	1.122	6.4	193897	59436.83	12072	2344.98				119348.26		580.07	114.44
83684	1.105	8.05	166524	57543.98	6895	644.22			80.67	100692.02		539.24	129.29
83687	1.121	7.19	183949	57349.24	11299	1634.42			165.91	112882.46		494.36	123.31

APPENDIX 4

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APPENDIX 5

TWDB Groundwater Determination and Letter of No Harm

GROUNDWATER PROTECTION DETERMINATION

Form GW-2

Groundwater Advisory Unit

Date Issued:	19 July 2023	**GAU Number:**	370096

Attention:	TARGA PERMIAN CO2	**API Number:**	
	ATTN JULIE PABON	**County:**	MIDLAND
	HOUSTON, TX 77002	**Lease Name:**	Driver AGI
		Lease Number:	
Operator No.:	101078	**Well Number:**	1
		Total Vertical	12826
		Latitude:	31.722358
		Longitude:	-101.806126
		Datum:	NAD27

Purpose: Injection into Non-producing Zone (W-14)

Location: Survey-T&P RR CO; Abstract-484; Block-37; Township-4S; Section-33

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

The base of usable-quality water-bearing strata is estimated to occur at a depth of 325 feet at the site of the referenced well.

The BASE OF UNDERGROUND SOURCES OF DRINKING WATER (USDW) is estimated to occur at a depth of 1200 feet at the site of the referenced well.

This recommendation is applicable to all wells within a radius of 200 feet of this location.

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

This determination is based on information provided when the application was submitted on 07/17/2023. If the location information has changed, you must contact the Groundwater Advisory Unit, and submit a new application if necessary. If you have questions, please contact us at 512-463-2741 or gau@rrc.texas.gov.

Groundwater Advisory Unit, Oil and Gas Division

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

July 19, 2023

Targa Permian CO2 Sequestration LLC
Attn Julie Pabon
811 Louisiana St Ste 2100
Midland, TX 77002

Attn: Santiago Flores

Re: Application to Dispose of Oil and Gas Waste by Injection (RRC Form W-14)
Targa Permian CO2 Sequestration LLC, Driver AGI Well #1
T&P RR CO. Survey, Block 37, T-4-S, Section 33, A-484
Midland County, Texas (D452) (API#32900000) (GAU #370096)

Dear Mr. Flores:

This letter is in response to your referenced application for a Railroad Commission of Texas permit to dispose of oil and gas waste into strata in the depth interval from 12,259 feet to 12,826 feet. Our review of the data contained in the application and of other available geologic data indicates, if otherwise compliant with Railroad Commission of Texas rules and guidelines, that drilling and using this disposal well and injecting oil and gas waste into the subsurface stratum will not endanger the freshwater strata in that area.

The base of usable-quality groundwater occurs to a depth of approximately 325 feet in accordance with GAU Letter No. 370096. The base of the Underground Source of Drinking Water (USDW) is estimated to be 1,200 feet. Geologic isolation from the Base of Usable-Quality Water and the USDW is at 1,250 feet. If you have any questions about this letter, please contact Katy Ward, P.G., Groundwater Advisory Unit, by telephone at (512) 463-2937, by e-mail at Kathryn.Ward@rrc.texas.gov, or in writing at the address shown on the letterhead (specify Mail Code MC 455-19 on the first line of the address).

W14_329_DriverAGI_D452_20230718

APPENDIX 6

Plugging Documents for Relevant Wells

WATER BOARD LETTER DATED

Depth

Type or print only

13(A) Exception Dated 488-047 13 3/8 @ 443

Surface Casing 4096

D.V. @ 8528 0 500

[redacted] RAILROAD COMMISSION OF TEXAS [redacted]

Oil and Gas Division

Form G-1
Rev. 4/1/83

API No. 42- 329-31386

Gas Well Back Pressure Test, Completion or Recompletion Report, and Log

1 FIELD NAME (as per RRC Records or Wildcat): Spraberry (Trend Area Dean Wlfcp)	2 LEASE NAME: Preston, Sam R.	7 RRC District No.: 8
3 OPERATOR'S NAME (Exactly as shown on Form P-5, Organization Report): Mobil Producing TX & N.M. Inc.	RRC Operator No: 572550	8 RRC Gas ID No.: N/A 114856
4. ADDRESS: Nine Greenway Plaza, Suite 2700, Houston, Texas 77046		9 Well No: 28
5 Location (Section, Block, and Survey): Section 41, Blk.37, T & P RR Co, T4S	5b Distance and direction to nearest town in this county: 24 miles S.E. of Midland	10. County of well site: Midland
6 If operator has changed within last 60 days, name former operator	12. If workover or reclass, give former field (with reservoir) & Gas ID or oil lease no — FIELD & RESERVOIR / GAS ID or OIL LEASE # / Oil—O Gas—G / WELL #	11 Purpose of filing: Initial Potential [X]; Retest [ ]; Reclass [ ]; Well record only (Explain in remarks) [ ]
13 Pipe Line Connection		
14 Completion or recompletion date: 12-23-84	15. Any condensate on hand at time of workover or recompletion? [ ] Yes [ ] No	16. Type of Electric or other Log Run: DLL, CNL, CDL Cal, BHC-Accoustic, CBL, sonic spectra.

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Section I — GAS MEASUREMENT DATA

Date of Test: 1-10-85

Gas Measurement Method (Check One): Orifice Meter [X] ▶ Flange Taps [X] Pipe Taps [ ]; Positive Choke [ ]; Orifice Vent Meter [ ]; Pitot Tube [ ]; Critical-flow Prover [ ]

Gas produced during test: MCF

Run No	Line Size	Orif or Choke Size	24 Hr Coeff Orif or Choke	Static P_m or Choke Press	Diff h_w	Flow Temp. °F	Temp Factor F_{tf}	Gravity Factor F_g	Compress Factor F_{pv}	Volume MCF/DAY
1	4.026	1.500	14355.64	105	3	60	1.0000	.9122	1.016	236
2										
3										
4		DUE TO EXTREME DRAWDOWN, UNABLE TO OBTAIN MORE THAN ONE POINT.								

Section II — FIELD DATA AND PRESSURE CALCULATIONS

Gravity (Dry Gas)	Gravity Liquid Hydrocarbon	Gas-Liquid Hydro Ratio	Gravity of Mixture	Avg Shut-in Temp	Bottom Hole Temp.
.721	0 Deg. API	0 CF/Bbl	G_{mix} = .721	111.5 °F	183°F @ 11555 (Depth)

$D_{eff}^{8/3}$ = $\sqrt{T_f}$ = $\sqrt{}$ = $\sqrt{GL}$ = $\sqrt{}$ =

$C = \frac{1118 \times (D_{eff})^{8/3}}{\sqrt{T}}$ = = $\sqrt{\frac{GL}{C}}$ = =

Run No	Time of Run Min	Choke Size	Wellhead Press. PSIA P_w	Wellhead Flow Temp °F	P_w^2 (Thousands)	R	R^2 (Thousands)	P_1	P_w/P_1
Shut-In			1100	40					
1	45	.188	105	58					
2									
3									
4									

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Run No.	F	K	$S = \frac{1}{z}$	E^{ks}	P_f and P_s	P_f^2 and P_s^2 (thousands)	$P_f^2 - P_s^2$ (thousands)
Shut—In					3227	10413	
1	AMEREDA PRESSURE RECORDER RPG-3				2617	6849	3564
2	SERIAL # 37209						
3	CLOCK 48 hr.						
4	RANGE 0-7000						

Angle of Slope

θ ~~45~~

n ~~1.000~~ OK

Absolute Open Flow ~~705~~ 236 MCF/DAY

Return to Central Records

WELL TESTER'S CERTIFICATION I declare under penalties prescribed in Sec 91.143, Texas Natural Resources Code, that I conducted or supervised this test and that data and facts shown in Sections I and II above are true, correct, and complete, to the best of my knowledge Bottomhole temperature and the diameter and length of flow string were furnished by the operator of the well.

Signature: Well Tester	Name of Company	RRC Representative
[signature]	"WELL TESTING" WIRE LINE SERVICE CO., INC.	RECORD CODIFICATION MAR 13 1985

OPERATOR'S CERTIFICATION I declare under penalties prescribed in Sec 91.143, Texas Natural Resources Code, that I am authorized to make this report, that I prepared or supervised and directed this report, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge

Signature. Operator's representative	Title	Date	Tel A/C Number
Gladys M. Sullivan	Authorized Agent	01-17-85	(713) 871-5502

329-31386

Appr Prod OK GBW 3/5/85

85280500

PRODUCTION ALLOCATION

FEB 14 1985

SECTION III — DATA ON WELL COMPLETION AND LOG (Not Required on Retest)

17 Type of Completion: New Well [X] Deepening [ ] Plug Back [ ] Other [ ]

18. Permit to Drill, Plug Back or Deepen — DATE 8-28-84 — PERMIT NO. 249837

Rule 37 Exception — CASE NO.

Water Injection Permit — PERMIT NO.

Salt Water Disposal Permit — PERMIT NO.

Other — PERMIT NO.

19. Notice of Intention to Drill this well was filed in Name of

Mobil Producing TX & N.M. Inc.

20. Number of producing wells on this lease in this field (reservoir) including this well: 1

21 Total number of acres in this lease: 160 (2360)

22 Date Plug Back, Deepening, WorkOver or Drilling Operations: Commenced 10-8-84 — Completed 11-24-84

23. Distance to nearest well, Same Lease & Reservoir: N/A

24. Location of well, relative to nearest lease boundaries of lease on which this well is located: 4550 Feet From East Line and 4650 Feet from South Line of the Preston, Sam R. Lease

25 Elevation (DF, RKB, RT, GR, ETC.): GR-2729

26. Was directional survey made other than inclination (Form W—12)? Yes [ ] No [X]

27 Top of Pay: 11476

28. Total Depth: 12160

29 P B. Depth: 11868

30. Surface Casing Determined by: Field Rules [X] Recommendation of T.D.W.R. [ ] Dt. of Letter — Railroad Commission (Special) [ ] Dt. of Letter

31 Is well multiple completion? Yes [ ] No [X]

32. If multiple completion, list all reservoir names (completions in this well) and Oil Lease or Gas ID No

FIELD & RESERVOIR	GAS ID or OIL LEASE #	Oil—O Gas—G	WELL #

33. Intervals Drilled by: Rotary Tools X — Cable Tools

34 Name of Drilling Contractor: Britton Indus. Rig#1

35. Is Cementing Affidavit Attached? Yes [X] No [ ]

36 CASING RECORD (Report All Strings Set in Well)

CASING SIZE	WT #/FT.	DEPTH SET	MULTISTAGE TOOL DEPTH	TYPE & AMOUNT CEMENT (sacks)	HOLE SIZE	TOP OF CEMENT	SLURRY VOL. cu. ft.
13-3/8	48	443		425X C	17-1/2	Circ.	561
9-5/8	36	5600	4096	1905X C	12-1/4	Circ.	5669
					8-3/4		
					6-3/4		

37. LINER RECORD

Size	TOP	Bottom	Sacks Cement	Screen
7-5/8 26.4#	5386	9600	850 X C	
5-1/2 16.87#	9385	12,159	705 X H	

38. TUBING RECORD

Size	Depth Set	Packer Set
2-7/8	11,420	11,420

39. Producing Interval (this completion) Indicate depth of perforation or open hole

From	To
11,476	11,634

40. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

Depth Interval	Amount and Kind of Material Used
12042-12066 W/IJSPF (13 holes) Acidize w/6000	gal 15% NEFe HCL acid + 30 RCNBS.
" " Set CMT.ret.@	12035 & sqz. perfs w/250X H CMT.
11982-12009 Acidize w/6000	gal 15% NEA Fe + 30 RCNBS
" " Set CMT. ret @	11888 + sqz.perfs w/250X H CMT.

11476-11634 W/IJSPF (28 holes) Acidize w/13000 gal.NEfe Acid + 60 RCNBS.

41 FORMATION RECORD (LIST DEPTHS OF PRINCIPAL GEOLOGICAL MARKERS AND FORMATION TOPS)

Formations	Depth	Formations	Depth
Strawn	10462	Devonian	11465
Atoka	10649	Fusselman	11970
Woodford	11374	Montoya	12039

REMARKS #47 Contined: 11476-11634 Frac w/56,000 gal MCY-T Acid + 15 RCNBS

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form G–5
Rev. 12/11/75

GAS WELL CLASSIFICATION REPORT

1 FIELD NAME (as per RRC Records): Spraberry (Trend Area Dean Wolfcamp)	2 LEASE NAME: Preston, Sam R.
3 OPERATOR: MOBIL PRODUCING TX. & NM	
4. ADDRESS: 9 GREENWAY PLAZA, SUITE 2700, HOUSTON, TX 77046	
5. LOCATION (Section, Block, and Survey): SEC. 41, BLK 37, T&P RR CO. SURVEY	
6 Pipeline Connection or Use of Gas:	

7 RRC District	8
8 RRC Identification Number	N/A 14856
9 Well Number	28
10 County	MIDLAND.
11 Utilized for	
12. Acres Allocated to this Well	

Section I — PRODUCTION TEST AT RATE ELECTED BY OPERATOR (Data on 24-hour basis)

A. Gas Volume	1358	(MCF)	E Casing Pressure		(PSI)
B. Oil or Condensate Volume	0	(BBLS)	F Color of Liquid		
C Gas/Liquid-Hydrocarbon Ratio		(CF/BBL)	G Gravity of Liquid	0	°API
D Flowing Tubing Pressure	200	(PSI)	H Specific Gravity of the Gas (AIR = 1)	0.721	

Section II — POTENTIAL TEST DATA

A. Absolute Open Flow	705	(MCF/DAY)	C Shut-In Wellhead Pressure	1100	(PSI)
B Date of Test	1-10-85		D. Length of Time Well Shut-In Prior to Test	48 HRS.	

Section III — A.S.T.M. DISTILLATION OF LIQUID SAMPLE

Distillation Test is required only on Gas Wells producing with a Gas-Liquid Ratio of less than 100,000 Cubic Feet per Barrel.

DATE LIQUID SAMPLE OBTAINED:

PER CENT OVER	TEMPERATURE (DEG. F.)
IBR	
10	
20	
30	
40	
50	
60	
70	
80	
90	
95	
E.P.	

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FEB 13 1985
O.G.
MIDLAND TEXAS

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

B. K. Jones
SIGNATURE

1-21-85
DATE

Engineer
TITLE

AREA CODE AND TELEPHONE NUMBER 915 6881553

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form W-12
(1-1-71)

6. RRC District: 8

INCLINATION REPORT
(One Copy Must Be Filed With Each Completion Report.)

7. RRC Lease Number. (Oil completions only): ~~20120~~

1. FIELD NAME (as per RRC Records or Wildcat): Spraberry (Trend Area Dean-Wlfcp)

2. LEASE NAME: Preston , Sam R.

8. Well Number: 28

3. OPERATOR: Mobil Producing Texas & New Mexico, Inc.

9. RRC Identification Number (Gas completions only): 114856

4. ADDRESS: Nine Greenway Plaza Suite 2700 Houston, TX 77046

10. County: Midland

5. LOCATION (Section, Block, and Survey): Sec. 41, Blk. 37, T&P RR. Co. Survey

RECORD OF INCLINATION

*11. Measured Depth (feet)	12. Course Length (Hundreds of feet)	*13. Angle of Inclination (Degrees)	14. Displacement per Hundred Feet (Sine of Angle X100)	15. Course Displacement (feet)	16. Accumulative Displacement (feet)
218	2.18	1/2	0.87	1.90	1.90
443	2.25	3/4	1.31	2.95	4.85
936	4.93	1	1.75	8.63	13.48
1465	5.29	1	1.75	9.26	22.74
1961	4.96	3/4	1.31	6.50	29.24
2461	5.00	3/4	1.31	6.55	35.79
2525	.64	3/4	1.31	0.84	36.63
3005	4.80	3/4	1.31	6.29	42.92
3500	4.95	3/4	1.31	6.48	49.40
3995	4.95	1/2	0.87	4.31	53.71
4515	5.20	1/2	0.87	4.52	58.23
5007	4.92	3/4	1.31	6.45	64.68
5137	1.30	3/4	1.31	1.70	66.38
5600	4.63	1	1.75	8.10	74.48
6095	4.95	1	1.75	8.66	83.14
6600	5.05	1 1/4	2.18	11.01	94.15

If additional space is needed, use the reverse side of this form.

17. Is any information shown on the reverse side of this form? [X] yes [ ] no

18. Accumulative total displacement of well bore at total depth of 12.160 feet = 213.10 feet.

*19. Inclination measurements were made in – [ ] Tubing [ ] Casing [ ] Open hole [X] Drill Pipe

20. Distance from surface location of well to the nearest lease line 4550 feet.

21. Minimum distance to lease line as prescribed by field rules 660 feet.

22. Was the subject well at any time intentionally deviated from the vertical in any manner whatsoever? No

(If the answer to the above question is "yes", attach written explanation of the circumstances.)

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INCLINATION DATA CERTIFICATION

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have personal knowledge of the inclination data and facts placed on both sides of this form and that such data and facts are true, correct, and complete to the best of my knowledge. This certification covers all data as indicated by asterisks (*) by the item numbers on this form.

T.G. Carman

Signature of Authorized Representative

T.G.Carman, Drilling Superintendent

Name of Person and Title (type or print)

Britton Industries Drilling

Name of Company

Telephone: 915 684 4891
Area Code

OPERATOR CERTIFICATION

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have personal knowledge of all information presented in this report, and that all data presented on both sides of this form are true, correct, and complete to the best of my knowledge. This certification covers all data and information presented herein except inclination data as indicated by asterisks (*) by the item numbers on this form.

Gladys M. Sullivan

Signature of Authorized Representative

G.M. Sullivan - Authorized Agent

Name of Person and Title (type or print)

Mobil Production TX & N.M. Inc.

Operator

Telephone: (713) 871-5502
Area Code

Railroad Commission Use Only:

Approved By: Gerry Young Title: G.O. Tech I Date: 2-13-85

* Designates items certified by company that conducted the inclination surveys.

RECORD OF INCLINATION (Continued from reverse side)

*11. Measured Depth (feet)	12. Course Length (Hundreds of feet)	*13. Angle of Inclination (Degrees)	14. Displacement per Hundred Feet (Sine of Angle X100)	15. Course Displacement (feet)	16. Accumulative Displacement (feet)
7073	4.73	1 1/4	2.18	10.31	104.46
7200	1.27	1	1.75	2.22	106.68
7674	4.74	1	1.75	8.30	114.98
8148	4.74	1 1/4	2.18	10.33	125.31
8652	5.04	3/4	1.31	6.60	131.91
9160	5.08	3/4	1.31	6.65	138.56
9600	4.40	1/2	0.87	3.83	142.39
10039	4.39	3/4	1.31	5.75	148.14
10515	4.76	1	1.75	8.33	156.47
10840	3.25	1	1.75	5.69	162.16
11400	5.60	2	3.49	19.54	181.70
11652	2.52	2	3.49	8.79	190.49
11811	1.59	2 1/4	3.93	6.25	196.74
11900	.89	2 1/2	4.36	3.88	200.62
12160	2.60	2 3/4	4.80	12.48	213.10

If additional space is needed, attach separate sheet and check here. ☐

REMARKS: ______

– INSTRUCTIONS –

An inclination survey made by persons or concerns approved by the Commission shall be filed on a form prescribed by the Commission for each well drilled or deepened with rotary tools or when, as a result of any operation, the course of the well is changed. No inclination survey is required on wells that are drilled and completed as dry holes that are plugged and abandoned. (Inclination surveys are required on re-entry of abandoned wells.) Inclination surveys must be made in accordance with the provisions of Statewide Rule 11.

This report shall be filed in the District Office of the Commission for the district in which the well is drilled; by attaching one copy to each appropriate completion for the well. (except Plugging Report)

The Commission may require the submittal of the original charts, graphs, or discs, resulting from the surveys.

Cementer: Fill in shaded areas.
Operator: Fill in other items

Form W-15
Cementing Report
Rev 4/1/83
483-045

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

1 Operator's Name (As shown on Form P-5, Organization Report)	2 RRC Operator No.	3. RRC District No	4 County of Well Site
Mobil Producing Tx & N.M., Inc.	572550	8	Midland

5 Field Name (Wildcat or exactly as shown on RRC records)	6 API No.	7 Drilling Permit No
Spraberry (Trend Area Dean Wolfcamp)	42- 329-31386	249837

8 Lease Name	9 Rule 37 Case No	10 Oil Lease/Gas ID No	11 Well No
Preston, Sam R.	N/A	~~20120~~ 114856	28

CASING CEMENTING DATA:		SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING		MULTI-STAGE CEMENTING PROCESS	
				Single String	Multiple Parallel Strings	Tool	Shoe
12. Cementing Date		10/9/84					
13 •Drilled hole size		17-1/4					
•Est % wash or hole enlargement		27%					
14 Size of casing (in O D)		13-3/8					
15 Top of liner (ft)							
16 Setting depth (ft)		443					
17 Number of centralizers used		4					
18 Hrs waiting on cement before drill-out		12-3/4					
1st Slurry	19 API cement used. No of sacks	425					
	Class	"C"					
	Additives	2% Calcium Chloride.					
2nd Slurry	No of sacks						
	Class						
	Additives						
3rd Slurry	No of sacks						
	Class						
	Additives						
1st	20. Slurry pumped: Volume (cu ft)	561					
	Height (ft)	808					
2nd	Volume (cu ft)						
	Height (ft)						
3rd	Volume (cu ft)						
	Height (ft)						
Total	Volume (cu. ft.)	561					
	Height (ft)	808					
21. Was cement circulated to ground surface (or bottom of cellar) outside casing?		YES					

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FEB 13 1985
O.G.
MIDLAND TEXAS

22 Remarks

OVER

CEMENTING TO PLUG AND ABANDON	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	PLUG # 8
23. Cementing date								
24. Size of hole or pipe plugged (in.)								
25. Depth to bottom of tubing or drill pipe (ft.)								
26. Sacks of cement used (each plug)								
27. Slurry volume pumped (cu. ft)								
28. Calculated top of plug (ft.)								
29. Measured top of plug, if tagged (ft)								
30. Slurry wt. (lbs/gal)								
31. Type cement								

CEMENTER'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my supervision, and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers cementing data only.

James R. Williams - Cementer — HALLIBURTON SERVICES — James R. Williams

Name and title of cementer's representative — Cementing Company — Signature

Drawer Y — Monahans, Texas 79756 — 915/943-2721 — 10/9/84

Address — City, State, Zip Code — Tel.: Area Code Number — Date: mo. day yr.

OPERATOR'S CERTIFICATE: I declare under penalties prescribed in Sec. 91 143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data.

G.M. Sullivan — Authorized Agent — Gladys M. Sullivan

Typed or printed name of operator's representative — Title — Signature

Nine Greenway Plaza, Suite 2700 — Houston, TX. 77046 — (713) 871-5502 — 01-16-85

Address — City, State, Zip Code — Tel.: Area Code Number — Date: mo. day yr.

Instructions to Form W-15, Cementing Report

IMPORTANT: Operators and cementing companies must comply with the requirements of the Commission's Statewide Rules 8 (Water Protection), 13 (Casing, Cementing, Drilling, and Completion), and 14 (Well Plugging). For **offshore** operations, see the requirements of Rule 13 (c).

A. **What to file.** An operator should file an original and one copy of the completed Form W-15 for each cementing company used on a well. The cementing of different casing strings on a well by one cementing company may be reported on one form. Form W-15 should be filed with the following:

- An initial oil or gas completion report, **Form W-2 or G-1**, as required by Statewide or special field rules;
- Form **W-4**, Application for Multiple Completion, if the well is a multiple parallel casing completion; and
- Form **W-3**, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting **dry** holes, operators must complete Form **W-15, in addition to Form W-3, to show any casing cemented in the hole.**

B. **Where to file.** The appropriate Commission District Office for the county in which the well is located.

C. **Surface casing.** An operator must set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Texas Department of Water Resources, Austin. Before drilling a well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable rules, an operator must obtain a letter from the Department of Water Resources stating the protection depth. Surface casing should not be set deeper than 200 feet below the specified depth without prior approval from the Commission.

D. **Centralizers.** Surface casing must be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, a centralizer must be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers must meet API specifications.

E. **Exceptions and alternative casing programs.** The District Director may grant an exception to the requirements of Statewide Rule 13. In a written application, an operator must state the reason for the requested exception and outline an alternate program for casing and cementing through the protection depth for strata containing usable-quality water. The District Director may approve, modify, or reject a proposed program. **An operator must obtain approval of any exception before beginning casing and cementing operations.**

F. **Intermediate and production casing.** For specific technical requirements, operators should consult Statewide Rule 13 (b) (3) and (4).

G. **Plugging and abandoning.** Cement plugs must be placed in the wellbore as required by Statewide Rule 14. The District Director may require additional cement plugs. For onshore or inland wells, a 10-foot cement plug must be placed in the top of the well, and the casing must be cut off three feet below the ground surface. All cement plugs, except the top plug, must have sufficient slurry volume to fill 100 feet of hole, plus ten percent for each 1,000 feet of depth from the ground surface to the bottom of the plug.

To plug and abandon a well, operators must use only cementers approved by the Director of Field Operations. Cementing companies, service companies, or operators can qualify as approved cementers by demonstrating that they are able to mix and pump cement in compliance with Commission rules and regulations.

Cementer: Fill in shaded areas. Operator: Fill in other items

Form W-15
Cementing Report
Rev 4/1/83
483-045

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

1 Operator's Name (As shown on Form P-5, Organization Report)	2 RRC Operator No	3 RRC District No.	4 County of Well Site
Mobil Producing TX & N.M. Inc.	572550	8	Midland
5 Field Name (Wildcat or exactly as shown on RRC records)	**6. API No**	**7 Drilling Permit No**	
Spraberry(Trend Area Dean Wolfcamp)	42- 329-313386	249837	
8 Lease Name	**9. Rule 37 Case No**	**10 Oil Lease/Gas ID No**	**11 Well No**
Preston, Sam R.		~~20120~~ 114856	28

CASING CEMENTING DATA: 7 5/8 Liner job	SURFACE CASING	INTER-MEDIATE CASING		Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS Tool	Shoe
12. Cementing Date			10-3-84			
13 •Drilled hole size			8 3/4			
•Est % wash or hole enlargement			35%			
14 Size of XXXXXXXXX Liner			7 5/8			
15. Top of liner (ft)			5386			
16 Setting depth (ft)			9600			
17 Number of centralizers used						
18. Hrs waiting on cement before drill-out			8 hr.			
1st Slurry — 19. API cement used: No. of sacks ▶			550			
Class ▶			C			
Additives ▶			4% Gel. ½#F.G. .3%Halad-9			
2nd Slurry — No. of sacks ▶			300			
Class ▶			C			
Additives ▶			.3%Halad-9			
3rd Slurry — No. of sacks ▶						
Class ▶						
Additives ▶						
1st — 20 Slurry pumped: Volume (cu ft.) ▶			929.5			
Height (ft) ▶			9250.5			
2nd — Volume (cu ft.) ▶			396			
Height (ft) ▶			3941			
3rd — Volume (cu ft) ▶						
Height (ft.) ▶						
Total — Volume (cu ft) ▶			1325.5			
Height (ft.) ▶			13191			
21. Was cement circulated to ground surface (or bottom of cellar) outside casing?			no			

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22 Remarks

OVER ▶

CEMENTING TO PLUG AND ABANDON	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	PLUG # 8
23. Cementing date								
24. Size of hole or pipe plugged (in)								
25. Depth to bottom of tubing or drill pipe (ft.)								
26. Sacks of cement used (each plug)								
27. Slurry volume pumped (cu. ft.)								
28. Calculated top of plug (ft.)								
29. Measured top of plug, if tagged (ft.)								
30. Slurry wt. (lbs/gal)								
31. Type cement								

CEMENTER'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my supervision, and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers cementing data only.

James Hughes Cementer — Name and title of cementer's representative
Halliburton — Cementing Company
James Hughes — Signature

Drawer 3746 Odessa Tx. 79760 — Address, City, State, Zip Code
915-381-2040 — Tel.: Area Code Number
10-30-84 — Date: mo. day yr.

OPERATOR'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data

Joe Oekerman — Typed or printed name of operator's representative
Drlg. Supv. II — Title
Signature

P.O. Box 633 Midland Tx. 79702 — Address, City, State, Zip Code
915-684-8211 — Tel.. Area Code Number
10-30-84 — Date: mo. day yr.

Instructions to Form W-15, Cementing Report

IMPORTANT: Operators and cementing companies must comply with the requirements of the Commission's Statewide Rules 8 (Water Protection), 13 (Casing, Cementing, Drilling, and Completion), and 14 (Well Plugging). For **offshore** operations, see the requirements of Rule 13 (c).

A. **What to file.** An operator should file an original and one copy of the completed Form W-15 for each cementing company used on a well. The cementing of different casing strings on a well by one cementing company may be reported on one form. Form W-15 should be filed with the following:

- An initial oil or gas completion report, **Form W-2 or G-1**, as required by Statewide or special field rules;
- Form W-4, Application for Multiple Completion, if the well is a multiple parallel casing completion; and
- Form **W-3**, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting **dry** holes, operators must complete Form **W-15, in addition to Form W-3, to show any casing cemented in the hole.**

B. **Where to file.** The appropriate Commission District Office for the county in which the well is located.

C. **Surface casing.** An operator must set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Texas Department of Water Resources, Austin. Before drilling a well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable rules, an operator must obtain a letter from the Department of Water Resources stating the protection depth. Surface casing should not be set deeper than 200 feet below the specified depth without prior approval from the Commission

D. **Centralizers.** Surfacc casing must be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, a centralizer must be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers must meet API specifications.

E. **Exceptions and alternative casing programs.** The District Director may grant an exception to the requirements of Statewide Rule 13. In a written application, an operator must state the reason for the requested exception and outline an alternate program for casing and cementing through the protection depth for strata containing usable-quality water. The District Director may approve, modify, or reject a proposed program. **An operator must obtain approval of any exception before beginning casing and cementing operations.**

F. **Intermediate and production casing.** For specific technical requirements, operators should consult Statewide Rule 13 (b) (3) and (4).

G. **Plugging and abandoning.** Cement plugs must be placed in the wellbore as required by Statewide Rule 14 The District Director may require additional cement plugs. For onshore or inland wells, a 10-foot cement plug must be placed in the top of the well, and the casing must be cut off three feet below the ground surface. All cement plugs, except the top plug, must have sufficient slurry volume to fill 100 feet of hole, plus ten percent for each 1,000 feet of depth from the ground surface to the bottom of the plug.

To plug and abandon a well, operators must use only cementers approved by the Director of Field Operations. Cementing companies, service companies, or operators can qualify as approved cementers by demonstrating that they are able to mix and pump cement in compliance with Commission rules and regulations.

Cementer Fill in shaded areas
Operator Fill in other items

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

Form W-15
Cementing Report
Rev 4/1/83
483-045

1 Operator's Name (As shown on Form P-5 Organization Report) Mobil Producing TX & N.M. Inc.	2 RRC Operator No 572550	3 RRC District No 8	4 County of Well Site Midland
5 Field Name (Wildcat or exactly as shown on RRC records) Spraberry (Trend Area Dean Wolfcamp)	6 API No 42- 329-31386	7 Drilling Permit No 249837	
8 Lease Name Preston, Sam R.	9 Rule 37 Case No N/A	10 Oil Lease/Gas ID No ~~20120~~ 114856	11 Well No 28

CASING CEMENTING DATA:		SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING Single String	PRODUCTION CASING Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS Tool	MULTI-STAGE CEMENTING PROCESS Shoe
12 Cementing Date						10-19-84	10-19-84
13 •Drilled hole size						12 1/4	12 1/4
•Est % wash or hole enlargement						124%	96%
14 Size of casing (in O D)						9 5/8	9 5/8
15 Top of liner (ft)							
16 Setting depth (ft)						4096	5600
17 Number of centralizers used						20 in two	stages
18 Hrs waiting on cement before drill-out						12	
1st Slurry	19. API cement used No of sacks					1280	325
	Class					"C"	"C"
	Additives					*A	*B
2nd Slurry	No of sacks					100	200
	Class					"C"	"C"
	Additives					neat	2% $CaCl_2$,¼#FC
3rd Slurry	No of sacks						
	Class						
	Additives						
1st	20 Slurry pumped. Volume (cu. ft.)					3290	621
	Height (ft)					10505	1983
2nd	Volume (cu ft.)					132	264
	Height (ft)					421	843
3rd	Volume (cu ft)						
	Height (ft)						
Total	Volume (cu ft.)					3422	2247
	Height (ft)					10926	2826
21 Was cement circulated to ground surface (or bottom of cellar) outside casing?						YES	YES

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MIDLAND TEXAS

22 Remarks

OVER

CEMENTING TO PLUG AND ABANDON	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	PLUG # 8
23. Cementing date								
24. Size of hole or pipe plugged (in.)								
25 Depth to bottom of tubing or drill pipe (ft.)								
26. Sacks of cement used (each plug)								
27. Slurry volume pumped (cu. ft)								
28. Calculated top of plug (ft.)								
29. Measured top of plug, if tagged (ft.)								
30. Slurry wt. (lbs/gal)								
31. Type cement								

CEMENTER'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my supervision, and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers cementing data only.

L. Stuckey, Secretary — HALLIBURTON SERVICES — Lori Stuckey

Name and title of cementer's representative — Cementing Company — Signature

Drawer 3746 — Odessa, Texas 79760 — 915/381-2040 — 10-25-84

Address — City, State, Zip Code — Tel.: Area Code Number — Date: mo. day yr.

OPERATOR'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data

G. M. Sullivan — Authorized Agent — Gladys M. Sullivan

Typed or printed name of operator's representative — Title — Signature

Nine Greenway Plaza-Ste.2700, Houston, Tx. 77046 — (713) 871-5502 — 01-16-85

Address — City, State, Zip Code — Tel.: Area Code Number — Date: mo. day yr.

Instructions to Form W-15, Cementing Report

IMPORTANT: Operators and cementing companies must comply with the requirements of the Commission's Statewide Rules 8 (Water Protection), 13 (Casing, Cementing, Drilling, and Completion), and 14 (Well Plugging). For **offshore** operations, see the requirements of Rule 13 (c).

A. **What to file.** An operator should file an original and one copy of the completed Form W-15 for each cementing company used on a well. The cementing of different casing strings on a well by one cementing company may be reported on one form. Form W-15 should be filed with the following:

- An initial oil or gas completion report, **Form W-2 or G-1**, as required by Statewide or special field rules;
- Form **W-4**, Application for Multiple Completion, if the well is a multiple parallel casing completion; and
- Form **W-3**, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting **dry** holes, operators must complete Form **W-15, in addition to Form W-3, to show any casing cemented in the hole.**

B. **Where to file.** The appropriate Commission District Office for the county in which the well is located.

C. **Surface casing.** An operator must set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Texas Department of Water Resources, Austin. Before drilling a well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable rules, an operator must obtain a letter from the Department of Water Resources stating the protection depth. Surface casing should not be set deeper than 200 feet below the specified depth without prior approval from the Commission.

D. **Centralizers.** Surface casing must be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, a centralizer must be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers must meet API specifications.

E. **Exceptions and alternative casing programs.** The District Director may grant an exception to the requirements of Statewide Rule 13. In a written application, an operator must state the reason for the requested exception and outline an alternate program for casing and cementing through the protection depth for strata containing usable-quality water. The District Director may approve, modify, or reject a proposed program. **An operator must obtain approval of any exception before beginning casing and cementing operations.**

F. **Intermediate and production casing.** For specific technical requirements, operators should consult Statewide Rule 13 (b) (3) and (4).

G. **Plugging and abandoning.** Cement plugs must be placed in the wellbore as required by Statewide Rule 14. The District Director may require additional cement plugs. For onshore or inland wells, a 10-foot cement plug must be placed in the top of the well, and the casing must be cut off three feet below the ground surface. All cement plugs, except the top plug, must have sufficient slurry volume to fill 100 feet of hole, plus ten percent for each 1,000 feet of depth from the ground surface to the bottom of the plug.

To plug and abandon a well, operators must use only cementers approved by the Director of Field Operations. Cementing companies, service companies, or operators can qualify as approved cementers by demonstrating that they are able to mix and pump cement in compliance with Commission rules and regulations.

Cementer. Fill in shaded areas.
Operator: Fill in other items

Form W-15
Cementing Report
Rev 4/1/83
483-045

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

1 Operator's Name (As shown on Form P-5, Organization Report) Mobil Producing TX & N.M. Inc.	2 RRC Operator No 572550	3 RRC District No 8	4 County of Well Site Midland
5 Field Name (Wildcat or exactly as shown on RRC records) Spraberry (Trend Area Dean Wolfcamp		6 API No 42-329-31386	7 Drilling Permit No 249837
8 Lease Name Preston, Sam R.	9. Rule 37 Case No N/A	10 Oil Lease/Gas ID No ~~20120~~ 11485 6	11 Well No 28

CASING CEMENTING DATA:		SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING Single String	PRODUCTION CASING Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS Tool	MULTI-STAGE CEMENTING PROCESS Shoe
12 Cementing Date				11-22-84			
13 •Drilled hole size				6 3/4			
•Est % wash or hole enlargement				57%			
14 Size of ~~casing (in O.D.)~~ Liner				5 1/2			
15 Top of liner (ft)				9385			
16 Setting depth (ft)				12159			
17 Number of centralizers used							
18 Hrs waiting on cement before drill-out				144			
1st Slurry	19 API cement used: No of sacks			705			
	Class			"H"			
	Additives			2% Halad-22A, 3% CFR-2, .1% HR-7			
2nd Slurry	No of sacks						
	Class						
	Additives						
3rd Slurry	No of sacks						
	Class						
	Additives						
1st	20 Slurry pumped: Volume (cu. ft)			747			
	Height (ft)			8944			
2nd	Volume (cu ft.)						
	Height (ft)						
3rd	Volume (cu ft)						
	Height (ft)						
Total	Volume (cu ft)			747			
	Height (ft)			8944			
21. Was cement circulated to ground surface (or bottom of cellar) outside casing?				NO			

22 Remarks

Tagged TOC @ 9240

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OVER

CEMENTING TO PLUG AND ABANDON	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	PLUG # 8
23. Cementing date								
24. Size of hole or pipe plugged (in.)								
25. Depth to bottom of tubing or drill pipe (ft.)								
26. Sacks of cement used (each plug)								
27. Slurry volume pumped (cu. ft)								
28. Calculated top of plug (ft.)								
29. Measured top of plug, if tagged (ft.)								
30. Slurry wt. (lbs/gal)								
31. Type cement								

CEMENTER'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my supervision, and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers cementing data only.

Lori Stuckey, Secretary — Name and title of cementer's representative
HALLIBURTON SERVICES — Cementing Company
Lori Stuckey — Signature

Drawer 3746 — Address
Odessa, Texas 79760 — City, State, Zip Code
915/381-2040 — Tel.: Area Code Number
12-4-84 — Date: mo. day yr.

OPERATOR'S CERTIFICATE. I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge This certification covers all well data.

G.M. Sullivan — Typed or printed name of operator's representative
Authorized Agent — Title
Gladys M. Sullivan — Signature

Nine Greenway Plaza, Ste.2700, Houston, Tx. 77046 — Address, City, State, Zip Code
(713) 871-5502 — Tel.: Area Code Number
01-16-85 — Date: mo. day yr.

Instructions to Form W-15, Cementing Report

IMPORTANT: Operators and cementing companies must comply with the requirements of the Commission's Statewide Rules 8 (Water Protection), 13 (Casing, Cementing, Drilling, and Completion), and 14 (Well Plugging). For **offshore** operations, see the requirements of Rule 13 (c).

A. **What to file.** An operator should file an original and one copy of the completed Form W-15 for each cementing company used on a well. The cementing of different casing strings on a well by one cementing company may be reported on one form. Form W-15 should be filed with the following:

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- Form **W-4**, Application for Multiple Completion, if the well is a multiple parallel casing completion; and
- Form W-3, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting **dry** holes, operators must complete Form **W-15, in addition to Form W-3, to show any casing cemented in the hole.**

B. **Where to file.** The appropriate Commission District Office for the county in which the well is located.

C. **Surface casing.** An operator must set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Texas Department of Water Resources, Austin. Before drilling a well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable rules, an operator must obtain a letter from the Department of Water Resources stating the protection depth. Surface casing should not be set deeper than 200 feet below the specified depth without prior approval from the Commission.

D. **Centralizers.** Surface casing must be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, a centralizer must be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers must meet API specifications.

E. **Exceptions and alternative casing programs.** The District Director may grant an exception to the requirements of Statewide Rule 13. In a written application, an operator must state the reason for the requested exception and outline an alternate program for casing and cementing through the protection depth for strata containing usable-quality water. The District Director may approve, modify, or reject a proposed program. An **operator must obtain approval of any exception before beginning casing and cementing operations.**

F. **Intermediate and production casing.** For specific technical requirements, operators should consult Statewide Rule 13 (b) (3) and (4).

G. **Plugging and abandoning.** Cement plugs must be placed in the wellbore as required by Statewide Rule 14. The District Director may require additional cement plugs. For onshore or inland wells, a 10-foot cement plug must be placed in the top of the well, and the casing must be cut off three feet below the ground surface. All cement plugs, except the top plug, must have sufficient slurry volume to fill 100 feet of hole, plus ten percent for each 1,000 feet of depth from the ground surface to the bottom of the plug.

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Cementer Fill in shaded areas
Operator Fill in other items

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

Form W-15
Cementing Report
Rev 4/1/83
483-045

1 Operator's Name (As shown on Form P-5, Organization Report) Mobil Producing TX & N.M.	2. RRC Operator No 572550	3. RRC District No 8	4 County of Well Site Midland
5 Field Name (Wildcat or exactly as shown on RRC records) Spraberry (Trend Area Dean Wolfcamp)		6 API No 42- 329-31386	7 Drilling Permit No 249837
8 Lease Name Preston, Sam R.	9 Rule 37 Case No N/A	10. Oil Lease/Gas ID No. ~~20120~~ 114856	11. Well No. 28

CASING CEMENTING DATA:			SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING		MULTI-STAGE CEMENTING PROCESS	
					Single String	Multiple Parallel Strings	Tool	Shoe
12. Cementing Date								
13 •Drilled hole size								
•Est % wash or hole enlargement								
14 Size of casing (in O D)								
15 Top of liner (ft)								
16 Setting depth (ft)								
17 Number of centralizers used								
18 Hrs waiting on cement before drill-out								
1st Slurry	19. API cement used:	No. of sacks						
		Class						
		Additives						
2nd Slurry		No. of sacks						
		Class						
		Additives						
3rd Slurry		No of sacks						
		Class						
		Additives						
1st	20 Slurry pumped:	Volume (cu ft.)						
		Height (ft.)						
2nd		Volume (cu. ft.)						
		Height (ft.)						
3rd		Volume (cu ft)						
		Height (ft.)						
Total		Volume (cu. ft.)						
		Height (ft)						
21. Was cement circulated to ground surface (or bottom of cellar) outside casing?								

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MIDLAND TEXAS

22. Remarks P & A Montoya perfs. 12042 - 12066 throught cement rentainer set on wire line @ 12035. Squeezed cemented perfs. down 2 7/8 tbg. w/ 200 sx. H .3% Halad-9 And 50 sx. H 5# No. 3 sd. Squeezes too 800 psi.

OVER

CEMENTING TO PLUG AND ABANDON	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	PLUG # 8
23. Cementing date	12-7-84							
24. Size of hole or pipe plugged (in.)	5½							
25. Depth to bottom of tubing or drill pipe (ft)	12035							
26. Sacks of cement used (each plug)	250							
27. Slurry volume pumped (cu. ft.)	265							
28. Calculated top of plug (ft.)	12035							
29. Measured top of plug, if tagged (ft.)	"							
30. Slurry wt. (lbs/gal)	16.4							
31. Type cement	H							

CEMENTER'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my supervision, and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers cementing data only.

D.R. Gaddis Cementer — Name and title of cementer's representative
Halliburton — Cementing Company
D. R. Gaddis — Signature

Drawer 3746 Odessa Tx. 79760 — Address, City, State, Zip Code
912-381-2040 — Tel.: Area Code Number
12-7-84 — Date: mo. day yr.

OPERATOR'S CERTIFICATE: I declare under penalties prescribed in Sec 91 143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers all well data.

Joe Oekerman — Typed or printed name of operator's representative
Drlg. Foreman — Title
Signature

P.O. Box 633 Midland Tx. 79702 — Address, City, State, Zip Code
915-684-8211 — Tel.: Area Code Number
12-7-84 — Date: mo. day yr.

Instructions to Form W-15, Cementing Report

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F. **Intermediate and production casing.** For specific technical requirements, operators should consult Statewide Rule 13 (b) (3) and (4).

G. **Plugging and abandoning.** Cement plugs must be placed in the wellbore as required by Statewide Rule 14. The District Director may require additional cement plugs. For onshore or inland wells, a 10-foot cement plug must be placed in the top of the well, and the casing must be cut off three feet below the ground surface. All cement plugs, except the top plug, must have sufficient slurry volume to fill 100 feet of hole, plus ten percent for each 1,000 feet of depth from the ground surface to the bottom of the plug.

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Cementer: Fill in shaded areas.
Operator: Fill in other items.

Form W-15
Cementing Report
Rev. 4/1/83
483-045

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

1. Operator's Name (As shown on Form P-5, Organization Report)	2 RRC Operator No	3. RRC District No	4. County of Well Site
Mobil Producing TX. & N.M., Inc.	572550	8	Midland

5 Field Name (Wildcat or exactly as shown on RRC records)	6 API No	7 Drilling Permit No
Spraberry (Trend Area Dean Wolfcamp)	42- 329-31386	249837

8 Lease Name	9 Rule 37 Case No	10 Oil Lease/Gas ID No	11 Well No
Preston, Sam R.	N/A	~~20120~~ 114856	28

CASING CEMENTING DATA:		SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING Single String	PRODUCTION CASING Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS Tool	MULTI-STAGE CEMENTING PROCESS Shoe
12. Cementing Date							
13. •Drilled hole size							
•Est % wash or hole enlargement							
14. Size of casing (in. O.D.)							
15 Top of liner (ft.)							
16. Setting depth (ft)							
17 Number of centralizers used							
18 Hrs waiting on cement before drill-out							
1st Slurry	19. API cement used: No. of sacks						
	Class						
	Additives						
2nd Slurry	No. of sacks						
	Class						
	Additives						
3rd Slurry	No. of sacks						
	Class						
	Additives						
1st	20. Slurry pumped: Volume (cu. ft)						
	Height (ft.)						
2nd	Volume (cu. ft.)						
	Height (ft)						
3rd	Volume (cu. ft.)						
	Height (ft.)						
Total	Volume (cu. ft.)						
	Height (ft.)						
21 Was cement circulated to ground surface (or bottom of cellar) outside casing?							

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R.R.C. OF TEXAS
FEB 13 1985
O.G.
MIDLAND TEXAS

22 Remarks

OVER

CEMENTING TO PLUG AND ABANDON	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	PLUG # 8
23. Cementing date	12-14							
24. Size of hole or pipe plugged (in.)	2 7/8							
25. Depth to bottom of tubing or drill pipe (ft.)	11888							
26. Sacks of cement used (each plug)	250							
27. Slurry volume pumped (cu. ft.)	295							
28. Calculated top of plug (ft.)	11868							
29. Measured top of plug, if tagged (ft)								
30. Slurry wt. (lbs/gal)	15.6							
31. Type cement	"H"							

CEMENTER'S CERTIFICATE: I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this certification, that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my supervision, and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge. This certification covers cementing data only.

Lori Stuckey, Secretary — Name and title of cementer's representative
HALLIBURTON SERVICES — Cementing Company
Lori Stuckey — Signature

Drawer 3746 — Address
Odessa, Texas 79760 — City, State, Zip Code
915/381-2040 — Tel.: Area Code Number
12-28-84 — Date: mo. day yr.

OPERATOR'S CERTIFICATE: I declare under penalties prescribed in Sec 91 143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge This certification covers all well data

G. M. Sullivan — Typed or printed name of operator's representative
Authorized Agent — Title
Gladys M. Sullivan — Signature

Nine Greenway Plaza, Ste.2700, Houston, Texas 77046 — Address, City, State, Zip Code
(713) 871-5502 — Tel.: Area Code Number
01-16-85 — Date: mo. day yr.

Instructions to Form W-15, Cementing Report

IMPORTANT: Operators and cementing companies must comply with the requirements of the Commission's Statewide Rules 8 (Water Protection), 13 (Casing, Cementing, Drilling, and Completion), and 14 (Well Plugging). For **offshore** operations, see the requirements of Rule 13 (c).

A. **What to file.** An operator should file an original and one copy of the completed Form W-15 for each cementing company used on a well. The cementing of different casing strings on a well by one cementing company may be reported on one form. Form W-15 should be filed with the following:

- An initial oil or gas completion report, **Form W-2 or G-1**, as required by Statewide or special field rules;
- Form W-4, Application for Multiple Completion, if the well is a multiple parallel casing completion; and
- Form **W-3**, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting **dry** holes, operators must complete Form **W-15, in addition to Form W-3, to show any casing cemented in the hole.**

B. **Where to file.** The appropriate Commission District Office for the county in which the well is located.

C. **Surface casing.** An operator must set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Texas Department of Water Resources, Austin. Before drilling a well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable rules, an operator must obtain a letter from the Department of Water Resources stating the protection depth. Surface casing should not be set deeper than 200 feet below the specified depth without prior approval from the Commission

D. **Centralizers.** Surface casing must be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, a centralizer must be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers must meet API specifications.

E. **Exceptions and alternative casing programs.** The District Director may grant an exception to the requirements of Statewide Rule 13. In a written application, an operator must state the reason for the requested exception and outline an alternate program for casing and cementing through the protection depth for strata containing usable-quality water. The District Director may approve, modify, or reject a proposed program. **An operator must obtain approval of any exception before beginning casing and cementing operations.**

F. **Intermediate and production casing.** For specific technical requirements, operators should consult Statewide Rule 13 (b) (3) and (4).

G. **Plugging and abandoning.** Cement plugs must be placed in the wellbore as required by Statewide Rule 14. The District Director may require additional cement plugs. For onshore or inland wells, a 10-foot cement plug must be placed in the top of the well, and the casing must be cut off three feet below the ground surface. All cement plugs, except the top plug, must have sufficient slurry volume to fill 100 feet of hole, plus ten percent for each 1,000 feet of depth from the ground surface to the bottom of the plug.

To plug and abandon a well, operators must use only cementers approved by the Director of Field Operations. Cementing companies, service companies, or operators can qualify as approved cementers by demonstrating that they are able to mix and pump cement in compliance with Commission rules and regulations.

Form P-15
(5-5-71)

STATEMENT OF PRODUCTIVITY OF ACREAGE ASSIGNED TO PRORATION UNITS

The undersigned states that he is authorized to make this statement; that he has knowledge of the facts concerning the MOBIL PRODUCING TEXAS & NEW MEXICO INC. (OPERATOR), SAM R. PRESTON ~~(20120)~~ 114856 (LEASE), No. 28 (WELL); that such well is completed in the SPRABERRY (TREND AREA DEAN-WOLFCAMP) Field, MIDLAND County, Texas and that the acreage claimed, and assigned to such well for proration purposes as authorized by special rule and as shown on the attached certified plat embraces 160 acres which can reasonably be considered to be productive of hydrocarbons.

– CERTIFICATE –

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

Date January 18, 1985   Signature Walter H Evans   Walter H. Evans

Telephone (713) (AREA CODE) 871-5209   Title Engineering Technician III

RECEIVED
R.R.C OF TEXAS
FEB 13 1985
O.G.
MIDLAND TEXAS

114856

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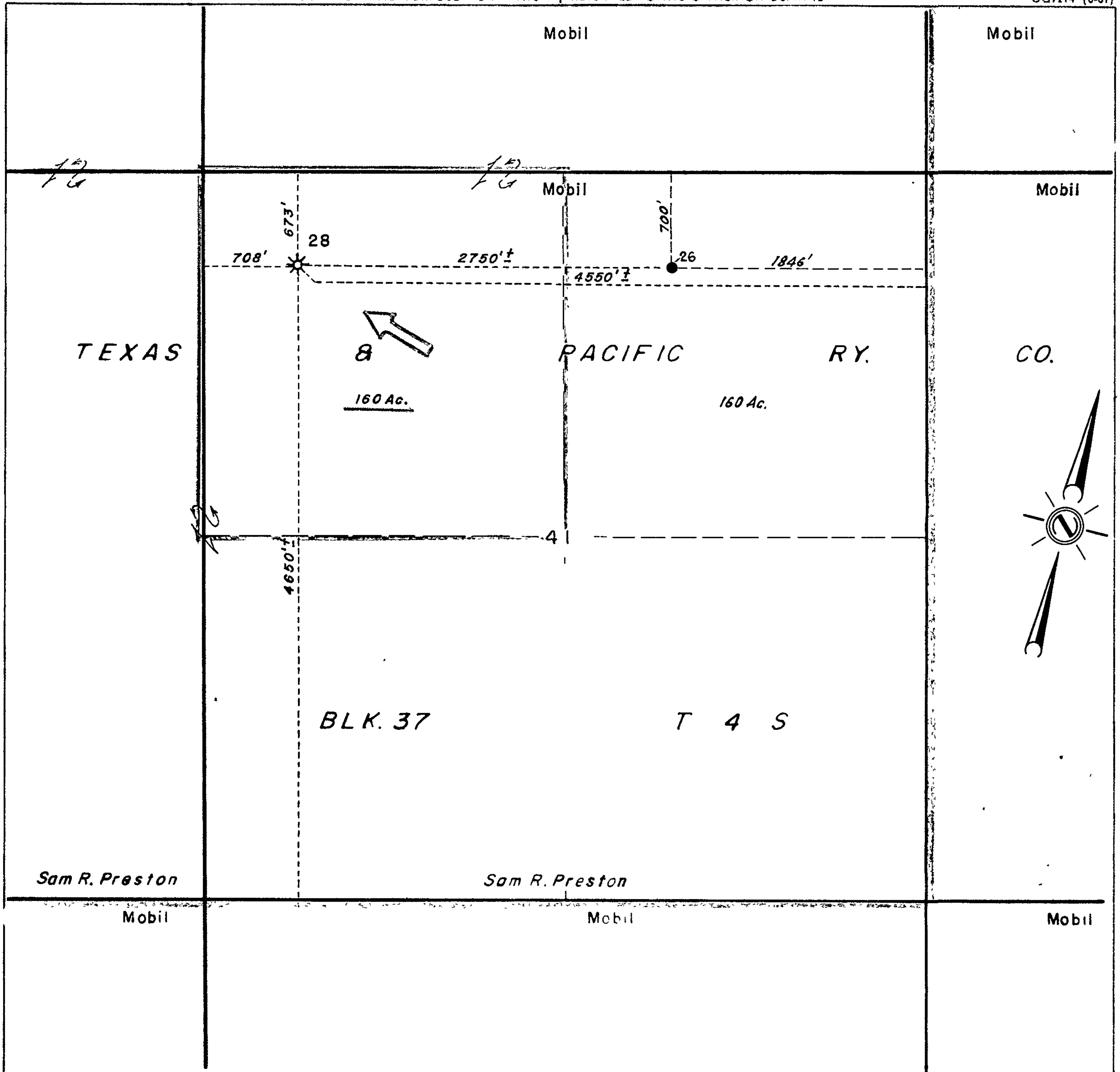
CQ7214 (8-61)



Reserve 200' Around Bldgs. Permit depth

Special Instructions

- LOC. OR DRLG. WELL
- ABANDONED LOC.
- DRY & ABANDONED
- OIL WELL
- ABD. OIL WELL
- GAS WELL
- ABD. GAS WELL
- S.W. DISPOSAL WELL
- GAS INPUT WELL
- WATER INPUT WELL

This map is submitted by Mobil Producing, TX. & NM Inc. at the request of the Railroad Commission of Texas for the purpose of allocating allowables to the leases covered thereby and for no other purpose. Mobil Producing TX & NM Inc shall not be bound by this map nor by the boundaries, measurements and figures thereon except to the extent that may be used for the above mentioned purpose, and it is particularly understood that Mobil Producing TX. & N M. Inc shall not be bound if an attempt is made to use this map in any suit involving title to said lease or leases or property adjacent thereto, or involving boundaries or vacancies thereon or adjacent thereto, or in similar actions.

Date work is commenced __________ 19__ __________ Supt

Location approved by __________ Plat by __________ Surveyed by __________

THE STATE OF TEXAS
COUNTY OF HARRIS

I hereby certify that this plat truly represents conditions as they actually exist on this lease that said plat which is drawn to the scale indicated hereon, is to the best of my knowledge true and correct that it accurately shows said lease with all wells on same that number and locations of said wells are as indicated hereon; and that this plat correctly reflects all pertinent and required data.

Mobil Producing Texas & New Mexico Inc.
Houston, Texas

LEASE Sam R. Preston RRC No. 20120

WELL NO 28 DATE January 18, 1985

DISTRICT __________ LEASE NO. T-21961A

TOTAL ACRES IN LEASE 2560 ACRES COVERED BY PLAT __________

DESCRIPTION Sec. 31, 32, 41, & 42, Blk 37, T4S, T.& P. Ry. Co. Sur.

24 Mi. SE of Midland, Texas

Midland County, Texas

DRAWN A D Bond	DATE 7-7-65	FIELD Spraberry Trend Area
SCALE 1" = 1000'	FILE NO. 575	(Dean-Wolfcamp)

114856

Return each W-1 with plat and $100.00 fee
Make a check or money order payable to the
State Treasurer of Texas. Address to:
Railroad Commission of Texas
Oil and Gas Division, Drilling Permits
P. O Drawer 12967, Capitol Station
Austin, Texas 78711
▶ File a copy of W-1 and plat in RRC District Office.

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division
Application for Permit to Drill, Deepen, Plug Back, or Re-Enter

▶ Read Instructions on Back

Form W-1
Rev. 9/1/83
483-060

Purpose of filing (mark appropriate boxes):
[XX] Drill [ ] Deepen (below casing) [ ] Deepen (within casing) [ ] Plug Back [ ] Re-Enter
[ ] Directional Well [ ] Sidetrack [ ] Amended Permit (enter permit no at right & explain fully in Remarks)

Enter here, if assigned: API No. 42-329-31386
Permit No. 249837
Rule 37 Case No.

1. Operator's Name (exactly as shown on Form P-5, Organization Report): MOBILE PRODUCING TX. & N.M. INC.
3. RRC Operator No: 572550
4. RRC District No: 8
5. County of Well Site: MIDLAND

2. Address (including city and zip code):
NINE GREENWAY PLAZA, SUITE 2700
HOUSTON, TX 77046

014752

6. Lease Name (32 spaces maximum): SAM R. PRESTON
7. RRC Lease/ID No.: 20120
8. Well No: 28
9. Total Depth: 12,400'

10. Location
- Section 41 Block 37 Survey T. & P. RR CO. Abstract No. A-
- This well is to be located 24 miles in a SE direction from MIDLAND, which is the nearest town in the county of the well site.

11. Distance from proposed location to nearest lease or unit line 4550 ft

12. Number of contiguous acres in lease, pooled unit, or unitized tract 2560 (OUTLINE ON PLAT.)

Amended 8/12/84

13. FIELD NAME (Exactly as shown on RRC proration schedule). List all established and wildcat zones of anticipated completion. Attach additional Form W-1's as needed to list these zones. One zone per line.	14. Completion depth	15. Spacing pattern (ft.)	16. Density pattern (acres)	17. Number of acres in drilling unit for this well. OUTLINE ON PLAT.	18. Is this acreage assigned to another well on this lease & in this reservoir? If so, explain in Remarks.	19. Distance from proposed location to nearest applied for, permitted, or completed well, this lease & reservoir. (ft.)	20. Oil, gas, or other type well (Specify)	21. No. of applied for, permitted, or completed locations (including this one) on lease in this reservoir. OIL	GAS
85280500 SPRABERRY (TREND AREA DEAN WOLFCAMP)	8650 8700	660/1320	160	160	NO	2750'	OIL	3	0
WILDCAT 00018001	BELOW 8700	467/1200	40	40	NO	NONE	OIL	1	0

22. Perpendicular surface location from two nearest designated lines:
- Lease/Unit 4550' FEL & 4650' FSL
- Survey/Section 673' FNL & 708' FWL SEC 41

If a directional well, show also projected bottom-hole location:
- Lease/Unit ---
- Survey/Section ---

Code 0 12,400

23. Is this a pooled unit? Yes [ ] ▶ (Attach Form P-12 and certified plat) No [X]

24. Is Item 17 less than Item 16 (substandard acreage for any field applied for)? Yes [ ] ▶ (Attach Form W-1A) No [X]

25. Is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes [ ] No [X]*
If subject to Rule 36, is Form H-9 filed? Yes [ ] No [ ] ▶ If not filed, explain in Remarks.

26. Do you have the right to develop the minerals under any right-of-way that crosses, or is contiguous to, this tract? Yes [X] No [ ]
If not, and if the well requires a Rule 37 or 38 exception, see Instructions for Rule 37

I certify that information stated in this application is true and complete, to the best of my knowledge.

Signature: A D Bond
A. D. BOND
Regulatory Technician Supervisor
Name and title of operator's representative

Date: August 22, 1984
Tel.: 713-871-5352

Remarks
Map of entire lease attached.
*As per conversation with RRC Dist. 8 Office, Mr. Wayne McClung, on 8-21-84

• RRC Use Only •
231775 AUG 27 84
254915

MAPPING
329-31386

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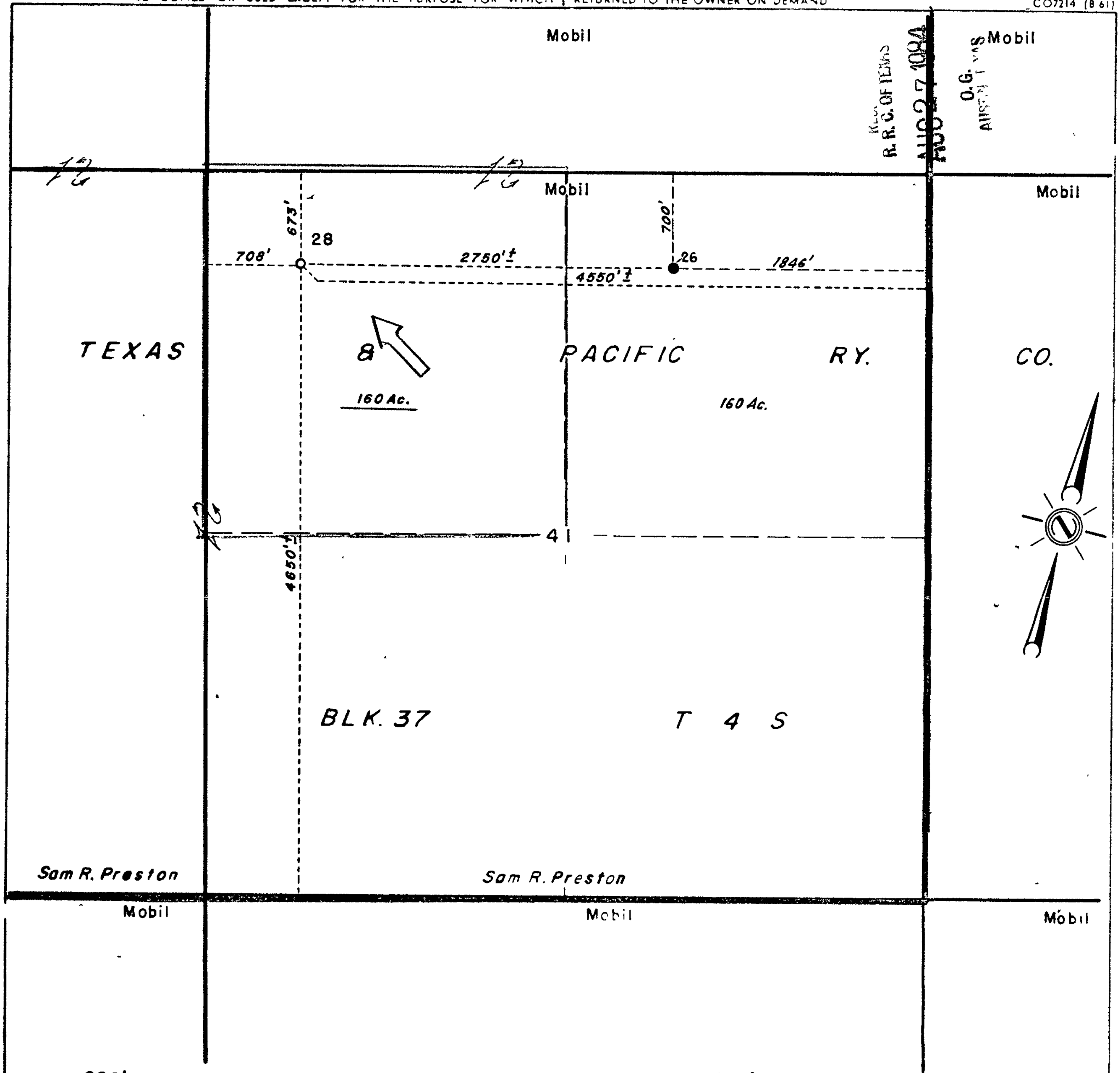
C07214 (8 61)



Reserve 200' Around Bldgs. Permit depth 12,400'

Special Instructions

Date work is commenced 19 Supt

Location approved by Plat by Surveyed by

THE STATE OF TEXAS
COUNTY OF HARRIS

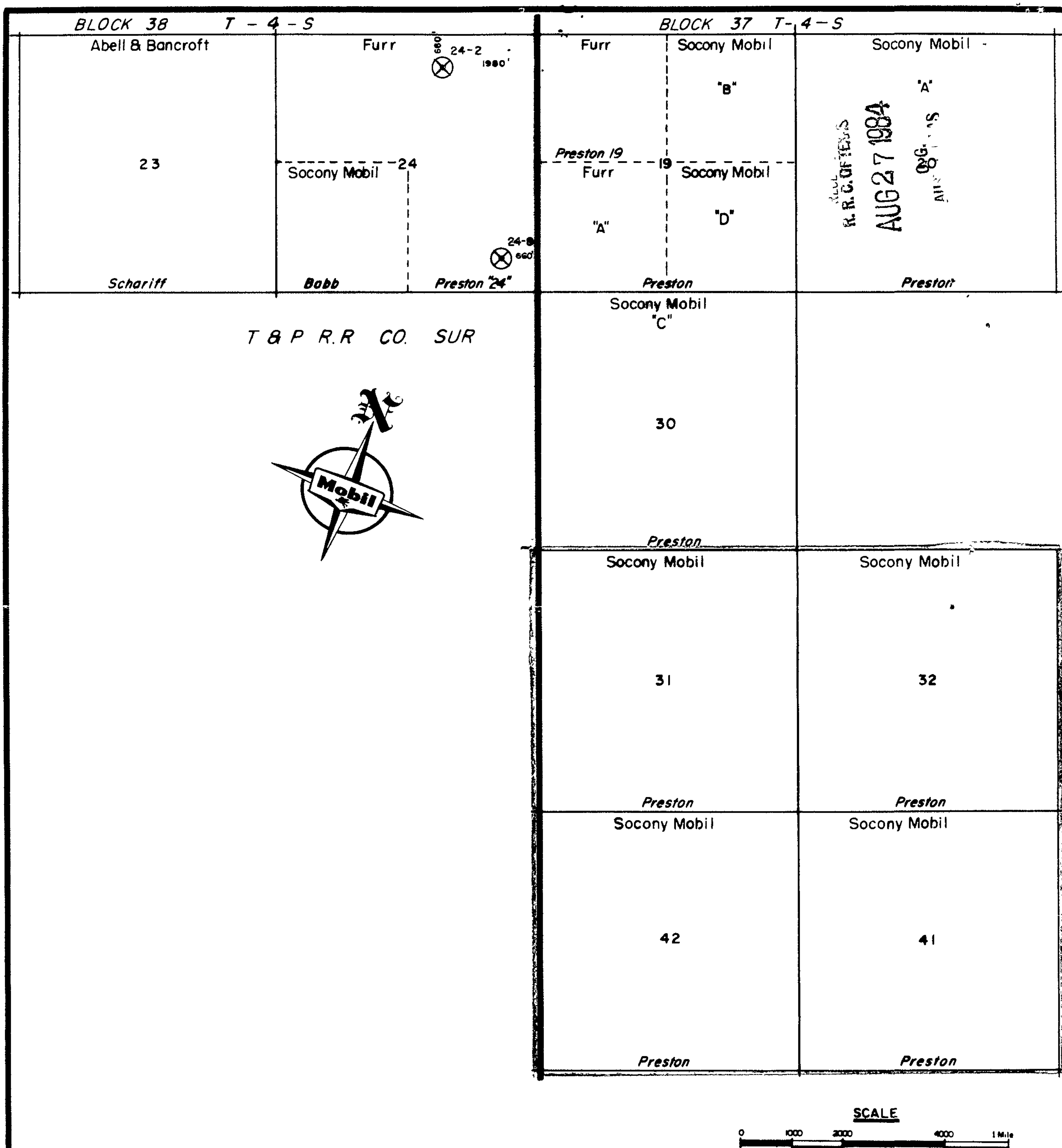
I hereby certify that this plat truly represents conditions as they actually exist on this lease that said plat which is drawn to the scale indicated hereon, is to the best of my knowledge true and correct, that it accurately shows said lease with all wells on same, that number and locations of said wells are as indicated hereon, and that this plat correctly reflects all pertinent and required data.

A D Bond

Mobil Producing Texas & New Mexico Inc.
Houston, Texas

LEASE Sam R. Preston RRC No 20120
WELL NO 28 DATE August 22, 19 84
DISTRICT LEASE NO T-21961 A
TOTAL ACRES IN LEASE 2560 ACRES COVERED BY PLAT
DESCRIPTION Sec. 31, 32, 41, & 42, Blk 37, T4S, T. & P. Ry. Co. Sur
24 Mi. SE of Midland, Texas
Midland County, Texas

DRAWN A. D. Bond DATE 7-7-65 FIELD Spraberry Trend Area
SCALE 1" = 1000' FILE NO 575 (Dean-Wolfcamp)



LEGEND

⊗ PROPOSED WATER SUPPLY WELL TO BE DRILLED

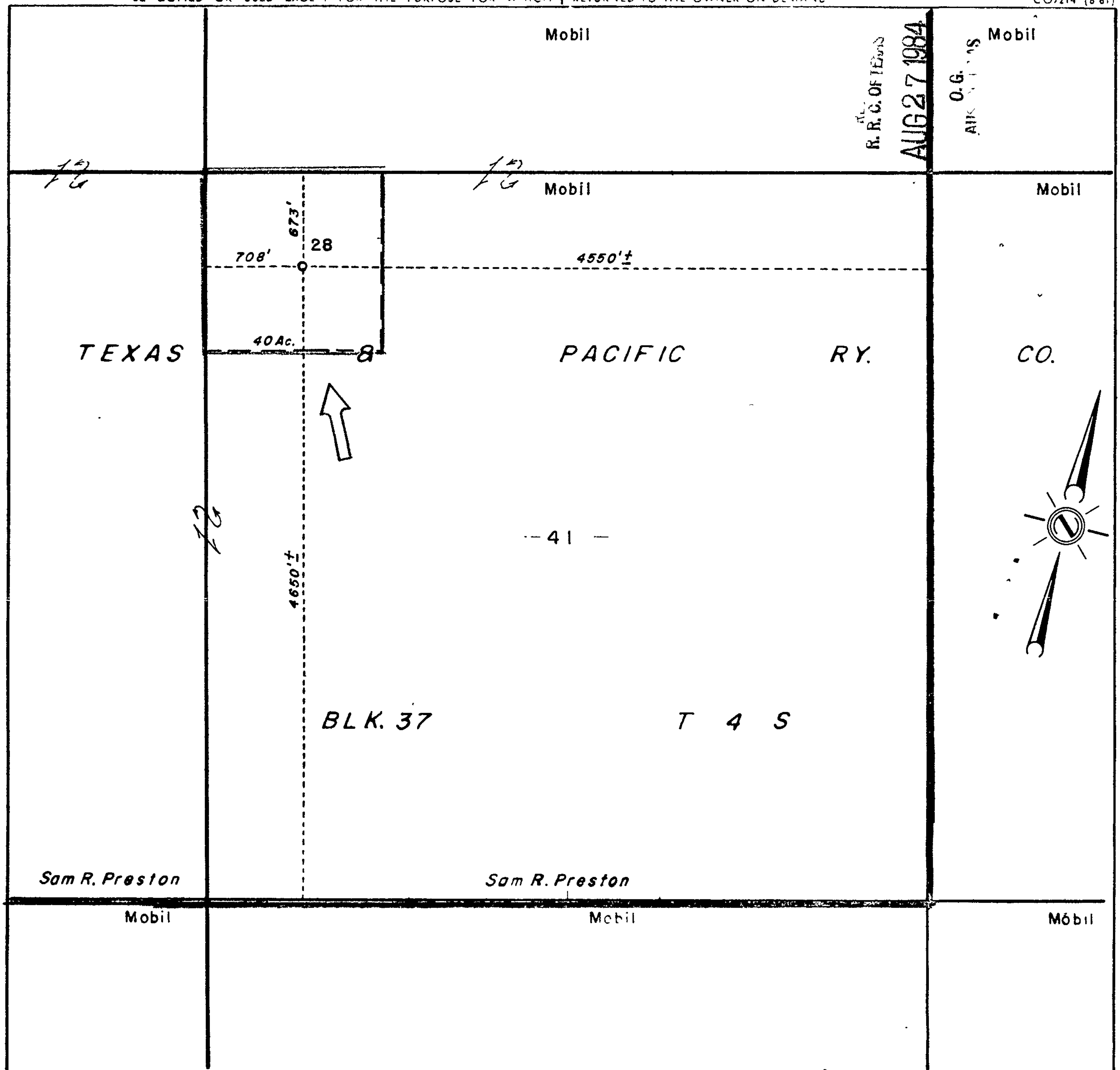
WATER SUPPLY

SOCONY MOBIL OIL COMPANY INC
EXPLORATION AND PRODUCING DEPARTMENT
MIDLAND DIVISION
MIDLAND PRODUCING DISTRICT
MIDLAND, TEXAS

Mobil's
PRESTON RANCH (Water Rights) LEASE
SPRABERRY TREND AREA FIELD
MIDLAND COUNTY, TEXAS

B-HO-7805

CO7214 (8-61)



Reserve 200' Around Bldgs. Permit depth 12,400'

Special Instructions

Date work is commenced ____ 19__ ____ Supt

Location approved by ____ Plat by ____ Surveyed by ____

THE STATE OF TEXAS
COUNTY OF HARRIS

I hereby certify that this plat truly represents conditions as they actually exist on this lease: that said plat which is drawn to the scale indicated hereon, is to the best of my knowledge true and correct, that it accurately shows said lease with all wells on same that number and locations of said wells are as indicated hereon; and that this plat correctly reflects all pertinent and required data.

A D Bond

Mobil Producing Texas & New Mexico Inc.
Houston, Texas

LEASE Sam R. Preston RRC No

WELL NO 28 DATE August 22, 19 84

DISTRICT ____ LEASE NO T-21961A

TOTAL ACRES IN LEASE 2560 ACRES COVERED BY PLAT ____

DESCRIPTION Sec. 31, 32, 41, & 42, Blk 37, T4S, T. & P. Ry Co Sur

24 Mi. SE of Midland, Texas

Midland County, Texas

DRAWN A. D. Bond DATE 7-7-65 FIELD Wildcat

SCALE 1" = 1000' FILE NO 575

PERMIT CORRECTION

Permit No. 249837

Date: 11-6-84

From: [x] Map Dept.

[ ] Rec'ds. Codif.

Survey Name:

Correct to – Sec. 41 Blk. 37 Survey T&P R.R. Co., T-4-S Abstract

Distances:

Lease:

Correct to –

Survey:

Correct to –

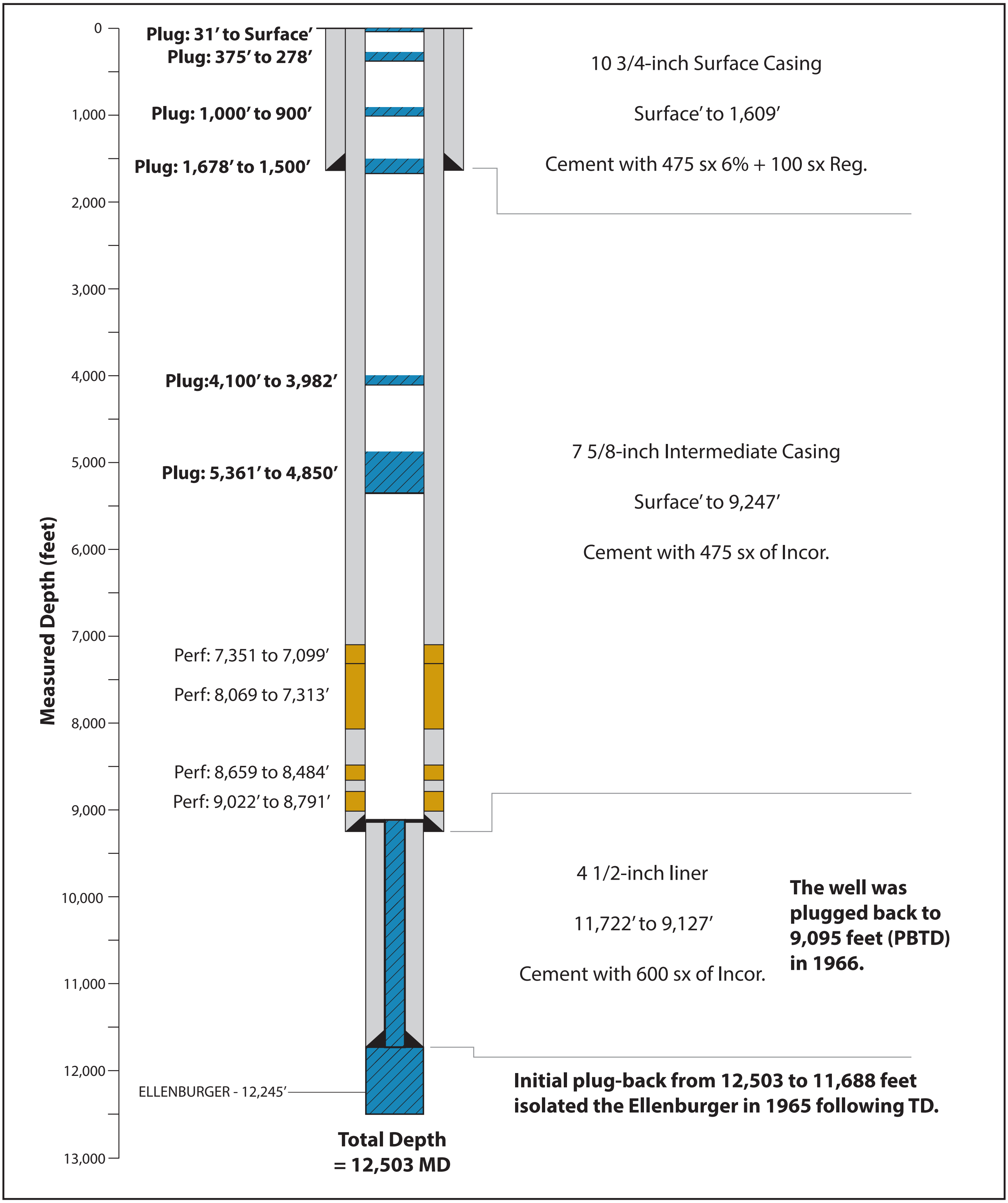
Signed: DH

Authorized by:

Company Representative

PLUGGED WELL SCHEMATIC
PRESTON SPRABERRY UNIT 3816B (Preston 9)
42-329-10125

LAT/LONG: 31.718414, -101.820867 NAD83



Well schematic generated from descriptions within RRC reporting documents found on-line and within the physical records

RECEIVED
RRC OF TEXAS
OCT 10 2012
OIL & GAS WELL COMPLIANCE
AUSTIN, TX

Plugging Record

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 12/92 (99)

Job#2012-6486

	API No. (if available) 42- 329-10125	1. RRC District 08
FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING		4. RRC Lease or ID Number 18551
2. FIELD NAME (as per RRC records) Spraberry (Trend Area)	3. Lease Name Preston Spraberry Unit	5. Well Number 3816B
6. OPERATOR Pioneer Natural ~~Resources~~ Res. USA, Inc.	6a. Original Form W-1 filed in name of: Mobil Oil Corp	10. County Midland
7. ADDRESS 5205 N. O'Connor Blvd, Ste.1400, Irving TX 75039-3736	6b. Any subsequent W-1's filed in name of:	11. Date Drilling Permit Issued 7-7-1965
8. Location of well, relative to nearest lease boundaries of lease on which this well is located	1980 feet from S line and 1980 feet from E line of the Preston Spby Unit	12. Permit Number N/A
9a. SECTION, BLOCK and SURVEY 32-37-T&P Survey T-4-S	9b. Distance and direction from nearest town in this county 24 Miles SE Midland	13. Date Drilling Commenced 7-28-1965
16. Type Well (oil, gas, or dry) Oil — Total Depth 12,503'	If multiple completion list all field names and oil lease or gas id no.'s — Gas ID or Oil Lease # — Oil - O Gas - G — Well #	14. Date Drilling Completed 10-9-1965
18. If gas, amt. of cond. on hand at time of plugging		15. Date Well Plugged 6/1/12

CEMENTING TO PLUG AND ABANDON DATA:	P#1	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	11/09/14	5/29/12	5/30/12	5/31/12	5/31/12	6/1/12			
20. Size of Hole or Pipe in which Plug Placed (inches)	7 1/2	7 5/8"	7 5/8"	7 5/8"	7 5/8"	7 5/8"			
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	5361	4100'	1678'	1000'	375'	31'			
*22. Sacks of Cement Used (each plug)	100	90	50	150	50	20			
*23. Slurry Volume Pumped (cu. ft.)	132	118.8	66	198	66	26.4			
*24. Calculated Top of Plug (ft.)	4850	-----	-----	~~900~~	-----	surf			
25. Measured Top of Plug (if tagged) (ft.)	—	3982'	1500'	900	278'	-----			
*26 Slurry Wt. # / Gal.	14.8	14.8	14.8	14.8	14.8	14.8			
*27. Type Cement	C	C	C	C	C	C			

RECEIVED
RRC OF TEXAS
JUL 05 2012
O&G
MIDLAND

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT.# / FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (in.)
10 3/4"		1628'	1628'	17 1/2"
7 5/8"		9247'	9247'	12 1/4"
4 1/2"L		11,722		
		9127'		7 7/8"

29. Was any non-drillable material (other than casing) left in this well? ☐ Yes ☐ No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use reverse side of form if more space is needed.)

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO
7099'	7351'		
7313'	8069'		
8484'	8659'		
8791'	9022'		

RECEIVED
CENTRAL RECORDS
NOV 08 2013
AUSTIN, TEXAS

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

Signature of Cementer or Authorized Representative

Sunset Well Service Inc
Name of Cementing Company

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

Phillip Hamilton
REPRESENTATIVE OF COMPANY

Ops Foreman
TITLE

6-14-2012
DATE

PHONE 432 664-8955
A/C NUMBER

Not Witnessed / av / 10-9-12
SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

MAPPING 203

C.A.

31. Was well filled with mud-laden fluid, according to the regulations of the Railroad Commission? ☑ Yes ☐ No	32. How was mud applied? RCM Circ	33. Mud Weight LBS/GAL 10#

34. Total Depth 12,503'	Other Fresh Water Zones by T.D.W.R. TOP: surf BOTTOM: 325'	35. Have all abandoned wells on this lease been plugged according to R R C Rules? ☐ Yes ☐ No
Depth of Deepest Fresh Water 325'		36. If No, Explain

37. Name and address of cementing or service company who mixed and pumped cement plugs in this well
Sunset Well Service, P.O. Box 7139, Midland, Texas 79708

Date RRC District Office notified of plugging
5/29/12

38. Name(s) and address(es) of surface owners of well site
Marvin Smith
PO Box 217
Midkiff TX 79755

39 Was notice given before plugging to the above?
yes

FILL IN BELOW FOR DRY HOLES ONLY

40. For dry holes, this form must be accompanied by either a driller's, electric, radioactivity, or acoustical/sonic log or such log must be released to a commercial log service.

☐ Log Attached ☐ Log released to ______________ Date ______________

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

41 Date FORM P-8 (Special Clearance) filed:

42. Amount of oil produced prior to plugging __________ bbls *
File FORM P-1 (Oil Production Report) for month this oil was produced

R R C USE ONLY

Nearest field ______________________________

REMARKS

Cementer: Fill in shaded areas
Operator: Fill in other items

Form W-15
Cementing Report
Rev 4/1/83
483-045

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

1 Operator's Name (As shown on Form P-5 Organization Report) Pioneer Natural Resources USA INC	2 RRC Operator No 665748	3 RRC District No 08	4 County of Well Site Midland
5 Field Name (Wildcat or exactly as shown on RRC records) Spraberry (Trend area)		6 API No. 42-329-10125	7 Drilling Permit No N/A
8 Lease Name Preston Spraberry UNIT	9 Rule 37 Case No	10 Oil Lease/Gas ID No 18551	11 Well No. 3816B

CASING CEMENTING DATA:			SURFACE CASING	INTER-MEDIATE CASING	PRODUCTION CASING Single String	PRODUCTION CASING Multiple Parallel Strings	MULTI-STAGE CEMENTING PROCESS Tool	MULTI-STAGE CEMENTING PROCESS Shoe
12 Cementing Date								
13 •Drilled hole size								
•Est % wash or hole enlargement								
14 Size of casing (in O D)								
15 Top of liner (ft)								
16 Setting depth (ft)								
17 Number of centralizers used								
18 Hrs waiting on cement before drill-out								
1st Slurry	19 API cement used	No of sacks						
		Class						
		Additives						
2nd Slurry		No of sacks						
		Class						
		Additives						
3rd Slurry		No. of sacks						
		Class						
		Additives						
1st	20 Slurry pumped	Volume (cu. ft)						
		Height (ft)						
2nd		Volume (cu. ft)						
		Height (ft)						
3rd		Volume (cu ft)						
		Height (ft)						
Total		Volume (cu ft)						
		Height (ft)						
21 Was cement circulated to ground surface (or bottom of cellar) outside casing?								

22 Remarks

RECEIVED
RRC OF TEXAS
JUL 05 2012
O&G
MIDLAND

OVER

CEMENTING TO PLUG AND ABANDON	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	PLUG # 8
23 Cementing date	11/1/11							
24 Size of hole or pipe plugged (in)	7 7/8"							
25 Depth to bottom of tubing or drill pipe (ft)	5361							
26 Sacks of cement used (each plug)	100							
27 Slurry volume pumped (cu ft)	132							
28 Calculated top of plug (ft)	4850'							
29 Measured top of plug, if tagged (ft)	—							
30 Slurry wt (lbs/gal)	14.8							
31. Type cement	C							

CEMENTER'S CERTIFICATE I declare under penalties prescribed in Sec 91 143, Texas Natural Resources Code, that I am authorized to make this certification, that the cementing of casing and/or the placing of cement plugs in this well as shown in the report was performed by me or under my supervision, and that the cementing data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge This certification covers cementing data only

JIMMY BAGLEY / MANAGER — Name and title of cementer's representative
SUNSET WELL SERVICE INC — Cementing Company
[signature] — Signature

P.O. BOX 7139 — Address
MIDLAND — City
TX 79708 — State, Zip Code
432-561-8600 — Tel · Area Code Number
11-2-11 — Date. mo day yr

OPERATOR'S CERTIFICATE I declare under penalties prescribed in Sec. 91 143, Texas Natural Resources Code, that I am authorized to make this certification, that I have knowledge of the well data and information presented in this report, and that data and facts presented on both sides of this form are true, correct, and complete, to the best of my knowledge This certification covers all well data.

Phillip HAmilton — Typed or printed name of operator's representative
OPS FOREMAN — Title
Phillip Hamilton — Signature

5205 N. OConnor — Address
Irving — City
TX 75039 — State, Zip Code
972-969-3752 — Tel . Area Code Number
7-3-12 — Date mo day yr

Melinda Pinkerton Eng. Tech Melinda Pinkerton

Instructions to Form W-15, Cementing Report

IMPORTANT Operators and cementing companies must comply with the requirements of the Commission's Statewide Rules 8 (Water Protection), 13 (Casing, Cementing, Drilling, and Completion), and 14 (Well Plugging). For offshore operations, see the requirements of Rule 13 (c).

A **What to file.** An operator should file an original and one copy of the completed Form W-15 for each cementing company used on a well The cementing of different casing strings on a well by one cementing company may be reported on one form Form W-15 should be filed with the following:

- An initial oil or gas completion report, **Form W-2 or G-1**, as required by Statewide or special field rules,
- Form W-4, Application for Multiple Completion, if the well is a multiple parallel casing completion; and
- Form W-3, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting **dry** holes, operators must complete Form W-15, **in addition to Form W-3, to show any casing cemented in the hole.**

B **Where to file.** The appropriate Commission District Office for the county in which the well is located.

C **Surface casing.** An operator must set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Texas Department of Water Resources, Austin Before drilling a well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable rules, an operator must obtain a letter from the Department of Water Resources stating the protection depth Surface casing should not be set deeper than 200 feet below the specified depth without prior approval from the Commission

D **Centralizers.** Surface casing must be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones In nondeviated holes, a centralizer must be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar All centralizers must meet API specifications

E **Exceptions and alternative casing programs.** The District Director may grant an exception to the requirements of Statewide Rule 13 In a written application, an operator must state the reason for the requested exception and outline an alternate program for casing and cementing through the protection depth for strata containing usable-quality water The District Director may approve, modify, or reject a proposed program **An operator must obtain approval of any exception before beginning casing and cementing operations.**

F **Intermediate and production casing.** For specific technical requirements, operators should consult Statewide Rule 13 (b) (3) and (4)

G **Plugging and abandoning.** Cement plugs must be placed in the wellbore as required by Statewide Rule 14 The District Director may require additional cement plugs For onshore or inland wells, a 10-foot cement plug must be placed in the top of the well, and the casing must be cut off three feet below the ground surface All cement plugs, except the top plug, must have sufficient slurry volume to fill 100 feet of hole, plus ten percent for each 1,000 feet of depth from the ground surface to the bottom of the plug

To plug and abandon a well, operators must use only cementers approved by the Director of Field Operations Cementing companies, service companies, or operators can qualify as approved cementers by demonstrating that they are able to mix and pump cement in compliance with Commission rules and regulations

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division
READ INSTRUCTIONS ON BACK

PRODUCER'S TRANSPORTATION AUTHORITY AND CERTIFICATE OF COMPLIANCE

FORM P-4 5/90

1. Field name exactly as shown on proration schedule: Spraberry (Trend Area)
2. Lease name: Preston, Sam R. 33707
3. Operator name exactly as shown on P-5 Organization Report: Parker & Parsley Development Co.
4. Operator P-5 no.: 640889
5. Oil lease no.: 20120
6. RRC district no.: 08
7. Operator address including city, state, and zip code: P.O. Box 3178, Midland, TX 79702
8. County in which oil lease or gas well is actually located: Midland
9. Gas ID no.:
10. Gas well no.:
11. Effective date: 3-1-93

12. GAS WELL GAS OR CASINGHEAD GAS. Additional space and example on reverse side.

Type Operation: gatherer	purchaser	nominator	Name of gatherer, purchaser, and/or nominator as indicated in type operation columns. NOTE: For each purchaser, give its RRC-assigned system code and identify the market. If applicable, place an "X" in the full-well stream column for the gatherer.	RRC USE ONLY G/P/N Code	Purchaser's RRC Assigned System Code	Purchaser's Market: inter-state	intra-state	Percent of Take	Full-well stream
	X	X	WGR, Inc.	WGRIN	0001	X		100	
X			Parker & Parsley Development co.	PARPD				100	

13. NAME OF OIL OR CONDENSATE GATHERER — List highest volume gatherer first

Name	Percent of Take	RRC USE ONLY Gath. code
Mobil Pipeline Co.	90	
Scurlock-Permian	10	

14. PURPOSE OF FILING. Remarks:

a. ☐ New oil lease ☐ New gas well
☐ Reclassification (oil to gas or gas to oil)
☐ Consolidation, unitization or subdivision

b. CHANGE ☐ Gatherer ☐ Nominator
☐ Purchaser ☐ Purchaser's system code

c. CHANGE FROM
☐ Operator 20120
XX Field Name Spraberry (Trend Area Dean-Wlfcp)
☐ Lease Name

RRC USE ONLY
Approved (initials) ll Oper. No.
Date 3-16-93 Field No.
Remarks:

15. OPERATOR CHANGE. Being the PREVIOUS OPERATOR, I certify that operating responsibility for wells located on the subject lease has been transferred in its entirety to the above named Current Operator. I understand, as Previous Operator, that designation of the above named operator as Current Operator is not effective until this certificate is approved by the Commission.

Previous Operator ______ Date ______
Signature ______ Name (Print) ______
Title ______ Phone ( )
Address with city/state/zip ______

16. CURRENT OPERATOR'S CERTIFICATION. By signing this certificate as the CURRENT OPERATOR, I acknowledge responsibility for the regulatory compliance of the subject lease, INCLUDING PLUGGING OF WELLS if required under Statewide Rule 14. I also acknowledge that I will remain designated as the Current Operator until a new certificate designating a new Current Operator is approved by the Commission.

Signature Sharon McDaniel Name (Print) Sharon McDaniel
Title Proration Analyst Date 3-15-93 Phone (915) 686-4818

I, the Current Operator, certify that the above agent is authorized to transport the above specified percentage of the allowable oil or gas produced from the above described property in accordance with the regulations of the Railroad Commission of Texas, and that this authorization will be valid until further notice or until cancelled by the Railroad Commission of Texas, and further certify that the conservation laws of the State of Texas and all rules, regulations and orders of the Railroad Commission of Texas have been complied with in respect to the property covered by this report.

☐ check if listings are continued on reverse side

X-REFERENCE

File this sheet: OP 08

Spraberry (Trend Area)

33707

Description of Material

- [x] Consolidation
- [ ] Subdivision
- [ ] Field Name Change
- [ ] Dual Packet

OPERATOR: Parker & Parsley Development Co.

LEASE: Preston Spraberry Unit

EFFECTIVE DATE: 12-1-94

COUNTY: Midland

WELL: 25 → 3816B

28 → 4214B

30 → 3817B

31 → 3818B

32 → 3912B

33 → 4313B

36 → 3913B

39 → 3914B

35 → 4216B

See File: OP 08

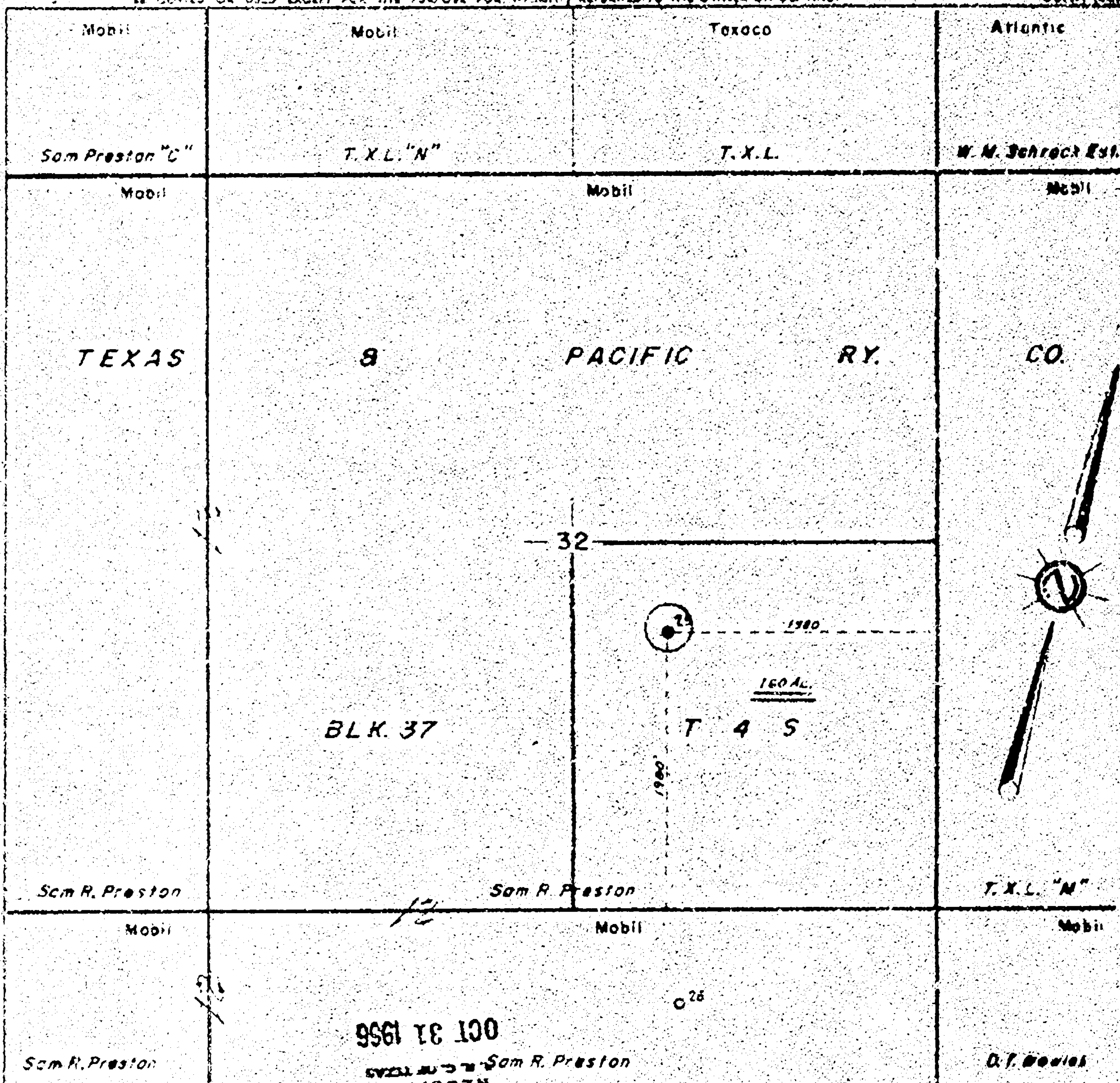
Spraberry (Trend Area)

18551

0031 0053

THIS DRAWING AND ALL INFORMATION THEREON IS THE PROPERTY OF MOBIL OIL AND SHALL NOT BE COPIED OR USED EXCEPT FOR THE PURPOSE FOR WHICH IT IS EXPRESSLY FURNISHED. THE DRAWING AND ANY COPIES THEREOF (PARTIAL OR COMPLETE) SHALL BE RETURNED TO THE OWNER ON DEMAND.

COTM (841)



Reserve 200' Around Bldgs. Permit depth

Special Instructions

- LOC. OF DRLG. WELL
- ABANDONED LOC.
- DRY & ABANDONED
- OIL WELL
- ABD. OIL WELL
- GAS WELL
- ABD. GAS WELL
- S.W. DISPOSAL WELL
- GAS INPUT WELL
- WATER INPUT WELL

This map is submitted by Mobil Oil Corporation at the request of the Railroad Commission of Texas for the purpose of allocating allowables to the leases covered thereby and for no other purpose. Mobil Oil Corporation shall not be bound by this map nor by the boundaries, measurements and acreages thereon, except to the extent that may be used for the above mentioned purpose, and it is particularly understood that Mobil Oil Corporation shall not be bound if an attempt is made to use this map in any suit involving title to said lease or leases or property adjacent thereto, or involving boundaries or vacancies thereon or adjacent thereto, or in similar matters.

Date work is commenced 19

Location approved by Plat by Surveyed by

THE STATE OF TEXAS
COUNTY OF MIDLAND

I hereby certify that this plat truly represents conditions as they actually exist on this lease; that said plat which is drawn to the scale indicated hereon, is to the best of my knowledge true and correct; that it accurately shows said lease with all wells on same; that number and locations of said wells are as indicated hereon; and that this plat correctly reflects all pertinent and required data.

Oct. 27, 1966

MOBIL OIL CORPORATION
EXPLORATION & PRODUCING DEPARTMENT
MIDLAND DIVISION—MIDLAND, TEXAS

LEASE Sam R. Preston RRC No. 20120
WELL NO. DATE
DISTRICT LEASE NO. T-21961 A
TOTAL ACRES IN LEASE 2560 ACRES COVERED BY PLAT
DESCRIPTION Sec. 31, 32, 41 & 42, Blk 37, T4S, T & P Ry. Co. Sur.
24 Mi. SE of Midland, Texas
Midland County, Texas

DRAWN A D Bond	DATE 7-7-65	FIELD Spraberry Trend Area (Dean-Wolfcamp)
SCALE 1" = 1000'	FILE NO. 53	

8791 0 0 3 1-90 AH-8211 C. Tucker RECEIVED 1

This Form must be filed in District Office not later than ten days after date of completion of test or penalty enforced. Do not take test for period of time less than specified by Rule.

REPOTENTIAL

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

SEP 2 8 1966

FORM 2
Potential Test Form
Date of Receipt in District Office

Railroad Commission of Texas
Gas Division

FURNISH ALL DATA IN FULL—DO NOT USE ESTIMATES
(See Instructions on Reverse Side)

FIELD NAME: ~~Spraberry Trend Wolfcamp~~ Trend Area (Wolfcamp) DISTRICT NUMBER: 8
(Use Field Name by which this Field designated on current Proration Schedule.)

NAME OF OPERATOR: Mobil Oil Corporation
(Use name you will use on Proration Report in typewriting)

NAME OF LEASE: Sam Preston LEASE NUMBER: 20126 WELL NO. 2

ADDRESS: Midland, Texas (City and State) SECTION 32 BLOCK 37 T-4-S

P. O. BOX NO. 633 SURVEY T&P RRy Co ELEVATION 2742 DF

COUNTY IN WHICH WELL IS LOCATED Midland Unit Designation Ac. in Unit

19 Miles Southeast direction from Midland nearest postoffice or town.

Date potential test commenced 9-25-, 1966 Hour 7:00 A. M.

Date potential test completed 9-26-, 1966 Hour 7:00 A. M.

Has this lease changed operating names within the last 60 days? No If so, what was the previous operating name?

Has the Log of this well been filed with Deputy Supervisor? Yes Date Log filed May 31, 1966

DATA ON POTENTIAL TEST

Data Necessary on Flowing Well

Flowing pressure on csg.

Flowing pressure on tbg.

Length of test Hrs. Mins.

Size choke Make choke

Was this well flowed for the entire duration of this test without the use of swab or other artificial flowing device?

Is this well being jetted?

If being jetted, how many cubic feet of gas is being used to ...

Barrel of oil recovered?

Data Necessary on Pumping Well

Make of Pumping unit Parkin

Length of stroke used 100"

No. strokes per minute 10

Size working barrel 2" x 1 1/2" x 18

Length of test 24 Hrs. 0 Mins.

Data Necessary for Bottom-Hole Centrifugal Pumping Wells

Motor Size H.P. Pump Model

Pump Rating B.P.D. Total Fluid at Head

Setting Depth Tubing Size

Length of test Hrs. Mins.

Was any oil produced from this well during this test lifted from the reservoir to the surface of the ground by the use of any device or means the use of which is not authorized by the Railroad Commission in establishing potentials?

Oil producing during this test into Tank (Tank or Pit) Name of P.L. Connection Phillips P. L. Co.

Date this well was last shot or acidized 9-21-66 If Shot No. Quarts used If Acidized No. Gallons used 5000

Barrels of oil produced from this well since shot or treatment to time this test was started 79
(Answer only if this Test was occasioned by shooting or treating this Well.)

Barrels of oil produced from this well from its completion date or recorded completion date to the beginning of this test
(Applies to new and reworked wells only.)

Per cent water produced during this test 1% Total depth of this well 9095 PBTD Ft.

Is this a test of a new well for which no previous allowable has been assigned? No

Is this a plain retest (not a workover job) of a well which has a current allowable assigned? Yes

What is the 24-hour potential at which it is carried currently on proration schedule? 121 MER

If this test is the result of a workover what was the nature of the job? Acidize Well

Hour well completed 6:30 P. M. Date well completed 9-20-, 1966

TEST PRODUCTION DATA

(Furnish Tank Numbers, Size, Avg. Bbls. per Ft., and all Gauges in Ft. and In. and Bbls.)
(Indicate manner in which production arrived at by placing result in proper column.)

TANK No.	SIZE	BBLS. PER FOOT	GAUGE LOW Feet	GAUGE LOW In.	GAUGE HIGH Feet	GAUGE HIGH In.	PRODUCTION COMPUTED Feet	PRODUCTION COMPUTED In.	PRODUCTION COMPUTED Bbls.	PRODUCTION 90% Tank Tables	PRODUCTION 100% Tank Tables
4	8-300	33.12	1	4	7	3	5	11			195.96

RESULT OF THIS POTENTIAL TEST (Bbls. of Crude oil per 24 hours) 195.96 196 (100% Tank Tbs.)

GAS-OIL RATIO OF THIS WELL IS 675 Cubic ft. of gas per barrel of Crude Oil

Gravity of oil produced during this test (Corrected to A.P.I. 60 degrees) 38.3

(OVER)

707

P-1196 P-1022 196 BOPD 9/1 P1 #3

DATA ON WELL COMPLETION

"Notice of Intention to Drill" this well was filed in the name of Mobil Oil Corp.

Date "Drilling, Plug Back or Deepening Permit" was issued 4-20-66

Is Location "REGULAR," or was "SPECIAL PERMIT" required? Regular

If special permit was secured what is permit number? No

Total number of acres in this lease 640

Number of crude oil producing wells on this lease in this field, including the well on which this potential was taken 1

Location of well, relative to lease boundaries of lease on which this well is located: 1980 feet from East line and 1980 feet from South line of the Sec. 32 Blk. 37 T-4-S lease

Size of surface casing 10 3/4 Number feet of surface casing set 1609

Size of oil string 7 5/8" - 4 1/2" Number of feet of oil string run 9247' 2595'

Type of tubing head Rector Type of Bradenhead Rector

Top of pay 8484 Ft. Total Depth 9095 PBTD Ft. Size tubing run 2

Perforated from 8484 to 9022 No. Shots 32 No. ft. tubing run 8230

Kind of fuel used to drill this well Unknown Amt. of fuel used Unknown

Where fuel was secured Furnished by contracter

INSTRUCTIONS: All potential test forms, WITH ALL INFORMATION REQUESTED THEREON FILLED IN, shall be filed in the District Office of the Railroad Commission not later than ten (10) days after the test is completed and, should the operator fail to file potential test in an acceptable form within the ten (10) days as specified then the effective date of the allowable resulting from such test shall not extend back more than ten (10) days prior to receipt and acceptance of the potential test form in the office of the Deputy Supervisor. This ten-day provision shall govern regardless of whether the potential test is taken during the month in which it is received in the office of the Deputy Supervisor or any prior month.

EACH WITNESS MUST SIGN IN HIS OWN HANDWRITING.

We, the undersigned, witnessed this test and the top and bottom gauges of each tank into which production was run during duration of this test.

C. A. Barnes
Representative of Company making test

[illegible] for Roy Furr, Inc.
Representative of Offset Operator — Offset Operator

[illegible] for British American Oil Co.
Rep. of Offset Operator — Offset Operator

Representative of the Railroad Commission

AFFIDAVIT:

I HEREBY CERTIFY that all conditions prescribed by the Railroad Commission of Texas for this potential test were complied with and carried out in full, and that all data and facts set forth on both sides of this form are true and correct.

Christine O. Tucker for Mobil Oil Corporation
Representative of Company making test — Company making test

SWORN TO AND SUBSCRIBED before me this the 27 day of September, 19 66

(Notary Seal)

Notary Public in and for County, Texas

REMARKS: Request 196 bbls NPX

210. No 2213 00031 003 RECEIVED

This Form must be filed in District Office not later than ten days after date of completion of test or penalty enforced. Do not take test for period of time less than specified by field rules.

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

MAY 31 1966

FORM 3
Potential Test Form
Date of Receipt in District Office
1—1958

FURNISH ALL DATA IN FULL—DO NOT USE ESTIMATES
(See Instructions on Reverse Side)

Railroad Commission of Texas

FIELD NAME: ~~Undesignated~~ Spraberry Trend Area Wolfcamp — DISTRICT NUMBER: 8
(Use Field Name by which this field is designated on proration schedule)

NAME OF OPERATOR: MOBIL OIL CORPORATION ~~FORMERLY SOCONY~~ MOBIL OIL COMPANY, INC.
(Use Names you will use on your E.B. Report in reporting Production.)

NAME OF LEASE: Sam Preston LEASE NUMBER: 20920 WELL NO. 9

ADDRESS: Midland, Texas (City and State) SECTION 32 BLOCK 37 T-4-S

P. O. BOX NO. 633 SURVEY T&P RWY.CO. ELEVATION 2742 D.F.

COUNTY IN WHICH WELL IS LOCATED Midland Unit Designation — Ac. in Unit —

29 Miles Southeast direction from Midland nearest postoffice or town.

Date potential test commenced 5-23, 19 66 Hour 7:00 A. M.

Date potential test completed 5-24, 19 66 Hour 7:00 A. M.

Has this lease changed operating names within the last 60 days? yes If so, what was the previous operating name? SOCONY MOBIL OIL CO., INC.

Has the Log of this well been filed with Deputy Supervisor? No Date Log filed May 31, 1966

DATA ON POTENTIAL TEST

Data Necessary on Flowing Well

Flowing pressure on csg

Flowing pressure on tbg

Length of test Hrs. Mins.

Size choke Make choke

Was this well flowed for the entire duration of this test without the use of swab or other artificial flowing device?

Is this well being jetted?

If being jetted, how many cubic feet of gas is being used to one barrel of oil recovered?

Data Necessary on Pumping Well

Make of Pumping unit Parkersburg

Length of stroke used 100"

No. strokes per minute 11

Size working barrel 2 x 1¼" - 18'

Length of test 24 Hrs. -0- Mins.

Data Necessary for Bottom-Hole Centrifugal Pumping Wells

Motor Size H.P. Pump Make

Pump Rating B.P.D. Total Fluid Head

Setting Depth Tubing Size

Length of test Hrs. Mins.

Was any oil produced from this well during this test lifted from the reservoir to the surface of the ground by the use of any device or means the use of which is not prescribed by the Railroad Commission in establishing potentials?

Oil producing during this test into Tank (Tank or Pit)

Name of P.L. Connection Phillips P. L. Co.

Date this well was last shot or acidized 5-3-66

If Shot No. Quarts used — If Acidized Frac. No. Gallons used 40,000

Barrels of oil produced from this well since shot or treatment to time this test was started 36
(Answer only if this Test was occasioned by shooting or treating this Well.)

Barrels of oil produced from this well from its completion date or reworked completion date to the beginning of this test 36
(Applies to new and reworked Wells only.)

Percent water produced during this test — Total depth of this well 9095 PBTD Ft.

Is this a test of a new well for which no previous allowable has been assigned? Yes

Is this a plain retest (not a workover job) of a well which has a current allowable assigned? No

What is the 24-hour potential at which it is carried currently on proration schedule? 0

If this test is the result of a workover what was the nature of the job? Wildcat Wolfcamp Zone

Hour well completed 4:35 P. M. Date well completed May 3, 19 66

TEST PRODUCTION DATA

(Furnish Tank Numbers, Size, Avg. Bbls. per Ft., and all Gauges in Ft. and In. and Bbls.)
(Indicate manner in which production arrived at by placing result in proper column.)

TANK No.	SIZE	BBLS. PER FOOT	GAUGE LOW Feet	GAUGE LOW In.	GAUGE HIGH Feet	GAUGE HIGH In.	PRODUCTION COMPUTED Feet	PRODUCTION COMPUTED In.	PRODUCTION COMPUTED Bbls.	PRODUCTION 99% Tank Tables	PRODUCTION 100% Tank Tables
	H-500		1	8	5	4	3	8	121		121

RESULT OF THE POTENTIAL TEST (Bbls. of Crude oil per 24-hours) 121 #IIIDK (100% Tank. Tbl.)

GAS/OIL RATIO OF THIS WELL IS 1495/1 Cubic Feet of Gas per Barrel of Crude Oil

Gravity of oil produced during this test (Corrected to A.P.I. 60 degrees) 38°

RECEIVED JUN 8 1966 O.G. AUSTIN, TEXAS

707

(OVER)

DCL Hot 360
D-8721
5/22 1/21
1# 9@121NX

DATA ON WELL COMPLETION

"Notice of Intention to Drill" this well was filed in the name of SOCONY MOBIL OIL CO., INC.

Date "Drilling, Plug Back or Deepening Permit" was issued 4-20-66

Is Location "REGULAR," or was "SPECIAL PERMIT" required? Regular

If special permit was secured what is permit number? None

Total number of acres in this lease 640

Number of crude oil producing wells on this lease in this field, including the well on which this potential was taken 1

Location of well, relative to lease boundaries of lease on which this well is located: 1980 feet from South line and 1980 feet from East line of the Sec. 32, Blk. 37-T-4-S lease

Size of surface casing 10-3/4" Number feet of surface casing set 1609'

Size of oil string 7-5/8" 4½" Number of feet of oil string run 9247' 2595'

Type of tubing head Rector Type of Bradenhead Rector

Top of pay 8791 Ft. Total Depth 9095 PBTD Ft. Size tubing run 2"

Perforated from 8791 to 8022 No. Shots 16 No. ft. tubing run 7600'

Kind of fuel used to drill this well Unknown Amt. of fuel used Unknown

Where fuel was secured Furnished by Contractor

INSTRUCTIONS: All potential test forms, WITH ALL INFORMATION REQUESTED THEREON FILLED IN, shall be filed in the District Office of the Railroad Commission not later than ten (10) days after the test is completed and, should the operator fail to file potential test in an acceptable form within the ten (10) days as specified then the effective date of the allowable resulting from such test shall not extend back more than ten (10) days prior to receipt and acceptance of the potential test form in the office of the Deputy Supervisor. This ten-day provision shall govern regardless of whether the potential test is taken during the month in which it is received in the office of the Deputy Supervisor or any prior month.

EACH WITNESS MUST SIGN IN HIS OWN HANDWRITING.

We, the undersigned, witnessed this test and the top and bottom gauges of each tank into which production was run during duration of this test.

J. M. Barry

Representative of Company making test

[signature]

Representative of Offset Operator for ______ Offset Operator

[signature]

Rep. offset operator for ______ offset operator

Representative of the Railroad Commission

AFFIDAVIT:

I HEREBY CERTIFY that all conditions prescribed by the Railroad Commission of Texas for this potential test were complied with and carried out in full, and that all data and facts set forth on both sides of this form are true and correct.

[signature]

Representative of Company making test for Mobil Oil Corp

Company making test

SWORN TO AND SUBSCRIBED before me this the 31 day of May, 1966

(Notary Seal)

Notary Public in and for ______ County, Texas

REMARKS:

0 0 3 1 0 0 4 0

RAILROAD COMMISSION OF TEXAS **RECEIVED** Form I-1
OIL AND GAS DIVISION 1-2-62

INCLINATION REPORT

MAY 31 1966

ONE COPY MUST BE FILED WITH EACH COMPLETION REPORT

Railroad Commission of Texas
Oil & Gas Division
Midland

Field Name ~~[illegible]~~ Spraberry (Trend Area, Wolfcamp) County Midland RRC Dist. No. 8

FORMERLY SOCONY MOBIL OIL COMPANY, INC.

Operator Mobil Oil Corporation Address Box 633 City Midland

Lease Name & No. Sam C. Preston Well No. 9 Survey T&P RR Co

RECORD OF INCLINATION

Depth (feet)	Angle of Inclination (degrees)	Displacement (feet)	Accumulative Displacement (feet)
250	1/4	1.10	1.10
750	1/2	4.35	5.45
1250	3/4	6.55	12.00
1640	1/2	3.39	15.39
1931	1-1/2	7.62	23.01
2170	1-1/2	6.26	29.27
2420	1-1/2	6.55	35.82
2670	3/4	3.28	39.10
2916	1/2	2.14	41.24
3200	1	4.97	46.21
3496	1-1/2	7.76	53.97
3652	1-1/4	3.42	57.39
3992	1	4.20	61.59
4503	1-1/4	13.38	74.97
4552	1-1/4	.64	75.61
4750	3/4	2.86	78.47
5104	1	6.20	84.67
5260	1-3/4	4.77	89.44
5594	2-3/4	16.03	105.47
5920	2	11.38	116.85
6222	1/2	2.68	119.52

0 0 3 1 0 0 4 1

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

RECEIVED
MAY 31 1966
Railroad Commission of Texas
Oil & Gas Division
Midland, Texas

Form I-1
11-2-62

INCLINATION REPORT

ONE COPY MUST BE FILED WITH EACH COMPLETION REPORT

Field Name Undesignated County Midland RRC Dist. No. 8

FORMERLY SOCONY MOBIL OIL COMPANY, INC.
Operator Mobil Oil Corporation Address Box 633 City Midland

Lease Name & No. Sam R. Preston Well No. 9 Survey T&P RR Co

RECORD OF INCLINATION

Depth (feet)	Angle of Inclination (degrees)	Displacement (feet)	Accumulative Displacement (feet)
6594	1/2	3.18	122.71
7065	3/4	6.17	128.88
7343	1	4.87	133.75
7421	1	1.37	135.12
7625	1/2	1.77	136.89
7851	1/2	1.97	138.86
8065	1/2	1.86	140.72
8256	3/4	2.50	143.22
8459	1/2	1.77	144.99
8621	1	2.84	147.83
8786	1	2.89	150.72
9050	1/2	2.30	153.02
9242	1/2	1.67	154.69
9426	1/2	1.60	156.29
9669	1/4	1.07	157.36
10179	1-3/4	15.60	172.96
10295	3/4	1.52	174.48
10355	1-1/2	1.57	176.05
10378	2	.80	176.85
10455	1	1.35	178.20
10538	1	1.45	179.65

3

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form I-2
2-62

RECEIVED
MAY 31 1966
Railroad Commission of Texas
Oil & Gas Dist. No. 8
Midland, Texas

INCLINATION REPORT

ONE COPY MUST BE FILED WITH EACH COMPLETION REPORT

Field Name Undesignated County Midland R.R. Dist. No. 8

FORMERLY SOCONY MOBIL OIL COMPANY, INC.
Operator Mobil Oil Corporation Address Box 633 City Midland

Lease Name & No. Lucas R. Preston Well No. 9 Survey T&P RR Co

RECORD OF INCLINATION

Depth (feet)	Angle of Inclination (degrees)	Displacement (feet)	Accumulative Displacement (feet)
10657	1-1/4	2.61	182.26
10711	1-1/2	1.41	183.67
10808	1-1/2	2.54	186.21
11117	2-3/4	14.93	201.14
11273	1-3/4	4.71	205.85
11643	1/2	3.22	209.07
11809	1-3/4	5.08	214.15
11996	2-1/4	7.35	221.50
12073	2-1/2	3.31	224.81
12181	2-1/4	4.28	229.09
12444	1-3/4	8.05	237.14

Total Displacement 237.14

Was survey run in Tubing ________ Casing ________ Open Hole X
Distance to nearest lease line 1980 feet
Distance to lease lines as prescribed by field rules 467 feet

Certification of personal knowledge Inclination Data:

I hereby certify that I have personal knowledge of the data and facts placed on this form, and that such information given above is true and complete.

J M Barry
Signature

Mobil Oil Corporation
Company

Operator Affidavit:

(Note: Party making affidavit must strike out inapplicable phrases, and must file explanatory statement when applicable.)

Before me, the undersigned authority, on this day, personally appeared C. M. Grimes known to me to be the person whose name is subscribed hereto, who, after being duly sworn, on oath states ~~that he is the operator of the well identified in this instrument~~ (that he is acting at the direction and on behalf of the operator of the well identified in this instrument), and that such well was not intentionally deviated from the vertical whatsoever. ~~(and that such well was deviated at random for the reason described in the attached statement).~~

C. Grimes Proration Clerk
Signature and Title of Affiant

Sworn and Subscribed to before me, this the 31 day of May 1966.

Ernest H. Murphy
Notary Public in and for Midland County, Texas.

ERNEST H. MURPHY, Notary Public
in and for Midland County, Texas

RRC Use Only:

Approved By: Vada Legendre
Title: Clerical Engineer
Date: 5-31-66

RECEIVED
R. R. C. OF TEXAS
JUN 8 1966
O. G.
AUSTIN, TEXAS

RRC District 8 04/W [redacted] 0031 0036 [redacted] JAN 13 1967

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form SW-1 (Amended 1-13-61)

PRODUCER'S CERTIFICATE OF COMPLIANCE AND AUTHORIZATION TO TRANSPORT OIL OR GAS FROM LEASE

FIELD Spraberry Trend Area (Dean-Wolfcamp) SURVEY Blk 37, T-4-S, T & P RR Co. COUNTY Midland

OPERATOR Mobil Oil Corporation LEASE (No. 20120) Sam R. Preston LEASE NAME

RESERVOIR (For Gas Wells) ______ WELL NO. (For Gas Wells) ______

ADDRESS ALL CORRESPONDENCE CONCERNING THIS FORM TO: Mobil Oil Corporation

STREET P.O. Box 633 CITY Midland STATE Texas

The above named operator hereby authorizes Phillips Pipe Line Company whose principal place of business

is Room B-2, Phillips Bldg., Odessa, Texas (Street) (City) (State) and whose field address is Same

______ to transport 100 % of the OIL ~~CONDENSATE GAS WELL GAS CASINGHEAD GAS~~ produced from the lease designated above until

further notice. Other gatherers transporting OIL CONDENSATE GAS WELL GAS CASINGHEAD GAS from this lease are:

None % None %
(Name of Gatherer) (Name of Gatherer)

The undersigned certifies that the above agent is authorized to transport the above specified percentage of the allowable oil or gas produced from the above described property in accordance with the regulations of the Railroad Commission of Texas, and that this authorization will be valid until further notice or until cancelled by the Railroad Commission of Texas, and the undersigned further certifies that the conservation laws of the State of Texas and all rules, regulations, and orders of the Railroad Commission of Texas have been complied with in respect to the property covered by this report.

EXECUTED THIS THE 26th DAY OF October, 1966.

Mobil Oil Corporation
Christine O. Zucker
(Affiant)

STATE OF TEXAS,
COUNTY OF Midland

Before me, the undersigned authority, on this day personally appeared ______ known to me to be the person whose name is subscribed to the above instrument, who being by me duly sworn on oath states that he is authorized to make this report and has knowledge of the facts stated herein and that said report is true and correct.

SUBSCRIBED and sworn to before me this the 26th day of October, 1966

(Seal) ______ Notary Public in and for Midland County, Texas

Registered in office of Railroad Commission of Texas at Austin, this ______ day of NOV 22 1966, 19__

899313

RAILROAD COMMISSION OF TEXAS
By Harry M Botha
Agent

INSTRUCTIONS: Separate authorization is required for each person transporting oil or gas from the lease, and in the event of a split connection show in authorization what portion of the oil or gas each person is authorized to transport. Each and every producer of crude oil and natural gas in the State of Texas shall execute under oath a report on Form SW-1 authorizing a gatherer (whether himself or some one else) to transport the oil or gas from the properties of such producer and shall file said report in the office of the Railroad Commission of Texas in the District in which such properties are located in FOUR DUPLICATE ORIGINALS. After the Railroad Commission agent in charge has registered such report and placed thereon the Commission's SW-1 Serial Number, two copies of such report shall be returned to the producer making the report or his duly authorized agent, one of such copies so returned to be delivered by the producer to the gatherer authorized to transport oil or gas. Each producer shall file a separate report for each lease and for each gatherer transporting oil or gas from said lease. After the producer has filed with the Commission said report on Form SW-1, it shall bind said producer until cancelled by him, and it shall not be necessary for the producer after filing his first report on Form SW-1 to file with the Commission any subsequent authorization report on said Form until (a) operating ownership changes, (b) the lease is subdivided or consolidated in which event SW-1 must be accompanied by a revised lease plat showing the changes, (c) gatherer is to be changed, or (d) the certificate of compliance and authorization to transport oil or gas has been cancelled by the Commission. No oil or gas shall be moved from any lease until said report on Form SW-1 is completely executed, filed with, and registered by the Commission's agent. This Certificate and Authorization may be revoked by the Railroad Commission of Texas at any time for failure to comply with the oil and gas conservation laws of the State of Texas and the rules, regulations and orders of the Railroad Commission of Texas.

Form 1 Notice of Intention to Drill Filed in the Name of Socony Mobil Oil Company, Inc. (Operator) Sam R. Preston (Lease)

INDICATE PURPOSE OF FILING

NEW LEASE: ______

CHANGE OF OPERATING NAME FROM: ______

CHANGE OF LEASE NAME FROM: ______

RECEIVED
OCT 28 1966
Railroad Commission of Texas
Oil & Gas Division
Midland, Texas

CHANGE OF GATHERER FROM: ______

CONSOLIDATION/SUBDIVISION OF LEASE/S: ______

EFFECTIVE DATE: November 1, 1966
(Required on all except new lease)

REMARKS: Change of field name from Spraberry Trend Area (Wolfcamp) to Spraberry Trend Area (Dean-Wolfcamp)

If an SW-1 Form has been executed on this lease previously, show in the space below the serial number then assigned to it by the Commission. COMMISSION'S SERIAL NUMBER SW-1 ... previous ... form.

868960

0031 0043

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No. ....

FORMERLY SOCONY MOBIL OIL COMPANY, INC.

Operator: Mobil Oil Corporation Address: Box 633, Midland, Texas

County: Midland Survey: T&P RR Co. Block No. 37 Sec. No. 12

Lease Name: Sam R. Preston 20130 Well No. 9 Elevation: 2762 D.F.

Name of Field in which well is located: ~~Undesignated~~ Spraberry Trend Area Wolfcamp

Form 1 (Notice of Intention to Drill) Was Filed in Name of: Socony Mobil Oil Company, Inc.

Is this a NEW WELL? .... DEEPENING? .... or a WORK-OVER? Yes

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

(Work-Over) Commenced 4-28-66, 19.. (Work-Over) Completed 5-3- 1966

Correspondence regarding this well should be sent to: Name Mobil Oil Corporation Address Box 633, Midland, Tex.

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL Ft.	In.	PULLED OUT Ft.	In.	LEFT IN WELL Ft.	In.	PACKERS AND SHOES
10-3/4	1609				1609		Cem. W/650 sx 6% + 100 sx Reg.
7-5/8	9247				9247		Cem. W/475 sx Incor.
4-1/2	2595				2595		Cem. W/600 sx Incor.
2"	7600				7600		

Initial Production of Gas—Volume 181 MCF 24 hrs. Pressure 14.65 lbs. per square inch

Initial Production of Oil: Barrels 121

Initial Production of Distillate: Barrels -

Is this an OIL well? Yes, a GAS well? ...., or a Dry HOLE? ....

DESCRIPTION OF PROPERTY
NORTH

WEST

EAST

SOUTH

GENERAL REMARKS

RECEIVED
MAY 31 1966
Railroad Commission of Texas
Oil & Gas Division
Midland, Texas

RECEIVED
R. R. C. OF TEXAS
JUN 6 1966
O. G.
AUSTIN, TEXAS

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Caliche & Red Bed	0	150	
Red Bed	150	1510	
Red Bed & Anhy.	1510	1640	
Anhy.	1640	1659	
Red Bed & Salt	1659	2585	
Anhy. & Salt	2585	3382	
Anhy.	3382	3838	
Lime	3838	5304	
Lime & Shale	5304	5944	
Lime	5944	6173	
Lime & Shale	6173	6228	
Lime	6228	6476	
Lime & Shale	6476	7625	
Lime	7625	7777	
Lime & Shale	7777	8444	
Shale	8444	8459	
Lime	8459	8657	
Lime & Shale	8657	10089	
Lime	10089	10179	
Lime & Shale	10179	10491	
Lime	10491	10533	
Shale & Lime	10533	10583	
Lime & Chert	10583	10668	
Shale, Lime & Chert	10668	10711	
Lime & Chert	10711	10788	
Lime, Chert & Shale	10788	10808	
Shale	10808	11504	
Lime	11504	11529	
Lime & Chert	11529	11713	
Lime	11713	11906	
Lime & Shale	11906	11941	
Lime	11941	12073	
Lime & Chert	12073	12120	
Lime & Shale	12120	12122	
Shale	12122	12167	
Lime, Sand & Shale	12167	12335	
Dolomite	12335	12357	
Lime	12357	12503	
T.D.	12503		
PBTD	9095		

Method of shutting off water Csg. Cemented Is water completely shut off? Yes

Amount of water with oil — per cent --

I, ...

being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

[signature]

Representative of Company.

Subscribed and sworn to before me this 31st day of May, 19 66

Notary Public

County, Texas.

52011

Application to Drill, Deepen or Plug Back.

RECEIVED
APR 8 1966
Railroad Commission of Texas Oil & Gas Division Midland, Texas

Form 1
Rev. 4/60

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

STATE WHETHER THIS IS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK: PLUG BACK
SHALL BE FILED IN DUPLICATE (IN TRIPLICATE IF RULE 37) WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED
DATA FURNISHED ON THIS FORM AND ANY ATTACHMENT HERETO MUST BE CLEARLY LEGIBLE.
ANY ILLEGIBLE FORM WILL BE RETURNED WITHOUT COMMISSION ACTION.
(Black Ink or Black Typewriter Ribbon Preferable)

READ CAREFULLY AND COMPLY FULLY

SPS

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, fo this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines. Also show the nearest wells on all sides of this location and the distance from the proposed location to those wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equaling 1000 feet; if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THIS PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line 1,980 feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease --- feet.

IS THE ACREAGE ON WHICH THIS WELL IS TO BE LOCATED, PRESENTLY ASSIGNED TO ANOTHER WELL IN ANY RESERVOIR FOR WHICH THIS PERMIT IS REQUESTED? NO

Date April 6, 19 66

Name of company or operator
Name Socony Mobil Oil Company, Inc.
Address P. O. Box 633
City Midland, Texas 79701

Description of farm or lease:
Name of Lease Sam R. Preston Sec. 32
Number of Acres 640 Well No. 9 (PB)*
Number of wells on lease 0
Elevation --- (Ft. above sea level) Section No. 32 Block No. 37
Survey T. & P. Ry. Co.
Zone or Reservoir Dean & Wolfcamp
To be Located in Undesignated Field
(If Wildcat state above, also state Distance and Direction from nearest Survey Lines.)
Midland County
24 Miles Southeast direction from
Midland, Texas nearest post office or town
Rotary or Cable Tools Rotary
Date work will start drilling when permit granted
Depth to which you propose to drill 9,100 feet.
Date work will start deepening ---

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?
Name
Address

RECEIVED
R. R. C. OF TEXAS
APR 11 1966
AUSTIN, TEXAS

*This well was originally drilled to a total depth of 12,503 ft. with a plug back total depth of 11,688 ft. Request permit to plug back to 9100 ft. and test the Dean and Wolfcamp formations.

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

7MD #6175

Application to Drill, Deepen or Plug Back.

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

RECEIVED
JUL 8 1965
Railroad Commission of Texas
Oil & Gas Division
Midland, Texas

Form 1
Rev. 4/60

STATE WHETHER THIS IS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK: **Drill**
SHALL BE FILED IN DUPLICATE (IN TRIPLICATE IF RULE 37) WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED.
DATA FURNISHED ON THIS FORM AND ANY ATTACHMENT HERETO MUST BE CLEARLY LEGIBLE.
ANY ILLEGIBLE FORM WILL BE RETURNED WITHOUT COMMISSION ACTION.
(Black Ink or Black Typewriter Ribbon Preferable)

SPS

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, of this lease, block or lot locating thereon the proposed site for this location with reference to the two nearest lease lines. Also show the nearest wells on all sides of this location and the distance from the proposed location to those wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit use scale of one inch equaling 1000 feet, if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THIS PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line 1980 feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease — feet.

IS THE ACREAGE ON WHICH THIS WELL IS TO BE LOCATED, PRESENTLY ASSIGNED TO ANOTHER WELL IN ANY RESERVOIR FOR WHICH THIS PERMIT IS REQUESTED? No

Date July 7 1965

Name of company or operator
Name Socony Mobil Oil Company, Inc.
Address Box 633
City Midland, Texas

Description of farm or lease:
Name of Lease Sam R. Preston Sec. 32
Number of Acres 640 Well No. 9
Number of wells on lease 0
Elevation ____ (Ft. above sea level) Section No. 32 Block No. 37, T4S
Survey T. & P. Ry Co.
Zone or Reservoir Devonian
To be Located in Wildcat Field
(If Wildcat state above, also state Distance and Direction from nearest Survey Lines.) 1980' FS & EL
Midland County
24 Miles Southeast direction from
Midland, Texas nearest post office or town.
Rotary or Cable Tools Rotary
Date work will start drilling When permit granted
Depth to which you propose to drill 12,700 feet.
Date work will start deepening ____

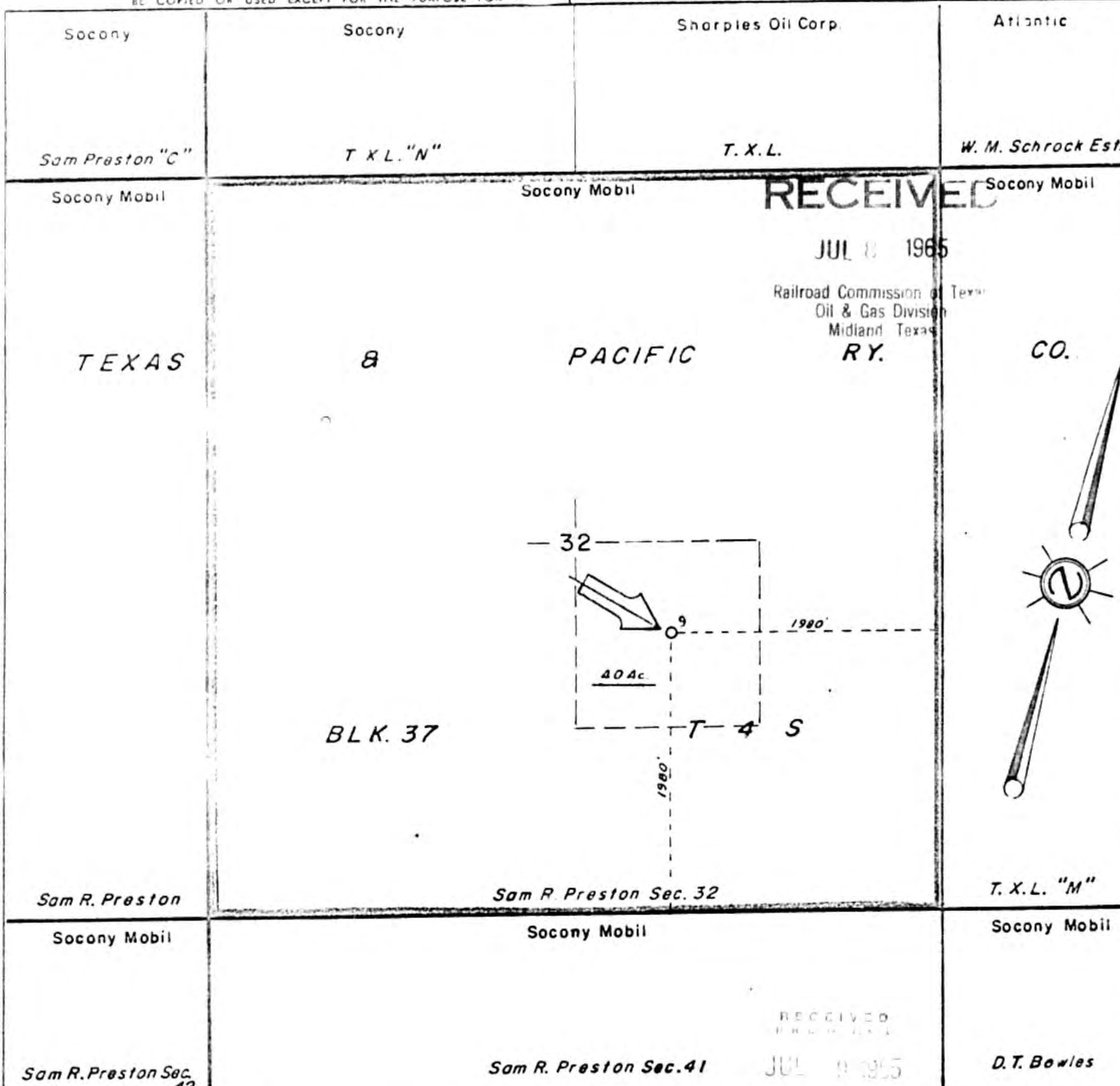
IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?
Name ____
Address ____

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

THIS DRAWING AND ALL INFORMATION THEREON IS THE PROPERTY OF SOCONY MOBIL OIL CO., INC. AND SHALL NOT BE COPIED OR USED EXCEPT FOR THE PURPOSE FOR WHICH IT IS EXPRESSLY FURNISHED. THE DRAWING AND ANY COPIES THEREOF (PARTIAL OR COMPLETE) SHALL BE RETURNED TO THE OWNER ON DEMAND.

CO7214 (8-61)



Reserve 200' Around Bldgs. Permit depth 12,650

Special Instructions

- ○ LOC. OR DRL'G. WELL
- ~~ABANDONED LOC.~~
- DRY & ABANDONED
- ~~OIL WELL~~
- ABD. OIL WELL
- ~~GAS WELL~~
- ABD. GAS WELL
- ~~S.W. DISPOSAL WELL~~
- GAS INPUT WELL
- WATER INPUT WELL

Date work is commenced ______, 19____ ______ Supt.

Location approved by ______ Plat by A. D. Bond Surveyed by ______

THE STATE OF TEXAS
COUNTY OF MIDLAND

I hereby certify that this plat truly represents conditions as they actually exist on this lease; that said plat which is drawn to the scale indicated hereon, is to the best of my knowledge true and correct; that it accurately shows said lease with all wells on same; that number and locations of said wells are as indicated hereon; and that this plat correctly reflects all pertinent and required data.

J. T. Godfrey Jr.

SUBSCRIBED AND SWORN TO before me this the 7 day of July 19 65

A D Bond

My commission expires June 1, 1967

A. D. BOND, Notary Public
In and for Midland County, Texas

SOCONY MOBIL OIL COMPANY, INC.
EXPLORATION & PRODUCING DEPARTMENT
MIDLAND DIVISION—MIDLAND, TEXAS

LEASE Sam R. Preston Sec. 32 RRC No.

WELL NO. 1 DATE July 7, 19 65

DISTRICT Midland LEASE NO. T-21961A

TOTAL ACRES IN LEASE 640 ACRES COVERED BY PLAT 640

DESCRIPTION Sec. 32, Blk. 37, T4S, T. & P. Ry. Co. Sur.

24 Mi. SE of Midland, Texas
Midland County, Texas

DRAWN A. D. Bond	DATE 7-7-65	FIELD "Wildcat"
SCALE 1" = 1000'	FILE NO. 53	

APPENDIX 7

Complete List of Wells and Relevant Descriptive Attributes
Within the MMA

Appendix 7 – All wells in MMA

API	Lease Name	Well_ Number	Status	Lat83	Long83	Operator	Field	Total Depth	Plug Date	Plug Depth
32980911	PRESTON SPRABERRY UNIT	11WS	Water Supply from Oil	31.70667149	-101.82143	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	260		0
32980906	PRESTON SPRABERRY UNIT	18WS	Water Supply from Oil	31.711338	-101.818668	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	260		0
32980890	PRESTON SPRABERRY UNIT	20WS	Water Supply from Oil	31.7212208	-101.826068	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	260		0
32980888	PRESTON SPRABERRY UNIT	17WS	Water Supply from Oil	31.71368916	-101.823522	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	260		0
32980887	PRESTON SPRABERRY UNIT	16WS	Water Supply from Oil	31.71667738	-101.829344	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	260		0
32980884	PRESTON SPRABERRY UNIT	12WS	Water Supply from Oil	31.70434103	-101.81675	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	260		0
32980883	PRESTON SPRABERRY UNIT	10WS	Water Supply from Oil	31.70903874	-101.826789	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	260		0
32945742	DRIVER 4C-W 3-46F	6H	Oil Well	31.71957465	-101.789272	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9193		0
32945741	DRIVER 4C-W 3-46E	5H	Oil Well	31.7181705	-101.789896	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8755		0
32945740	DRIVER 4C-W 3-46D	4H	Oil Well	31.71835596	-101.791095	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9131		0
32945739	DRIVER 4C-W 3-46C	3H	Shut-In Oil	31.71866388	-101.793355	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8736		0
32945738	DRIVER 4C-W 3-46B	2H	Oil Well	31.71741509	-101.794358	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9168		0
32945737	DRIVER 4C-W 3-46A	1H	Shut-In Oil	31.71823561	-101.795363	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8786		0
32945497	PRESTON-FREEMAN 15J	110H	Oil Well	31.73535247	-101.788256	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9171		0
32945495	PRESTON-FREEMAN 15I	109H	Oil Well	31.7350554	-101.789502	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8796		0
32945494	PRESTON-FREEMAN 15H	108H	Oil Well	31.73477439	-101.790838	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9184		0
32945493	PRESTON-FREEMAN 15G	107H	Oil Well	31.73449498	-101.791994	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8793		0
32945492	PRESTON-FREEMAN 15F	106H	Oil Well	31.73414058	-101.79408	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9175		0
32945491	PRESTON-FREEMAN 15E	105H	Oil Well	31.73387495	-101.795175	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8804		0
32945490	PRESTON-FREEMAN 15D	104H	Oil Well	31.73356208	-101.796569	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9188		0
32945489	PRESTON-FREEMAN 15C	103H	Oil Well	31.73333248	-101.79759	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8813		0
32945488	PRESTON-FREEMAN 15B	102H	Oil Well	31.73298917	-101.799128	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9197		0
32945487	PRESTON-FREEMAN 15A	101H	Oil Well	31.73275725	-101.800155	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8813		0
32945145	PRESTON SPRABERRY UNIT	902H	Oil Well	31.73687268	-101.815212	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8054		0
32945144	PRESTON SPRABERRY UNIT	901H	Oil Well	31.7375173	-101.81267	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8365		0
32945057	ARCO 7111 34	4H	Horizontal Drainhole	31.72181908	-101.78467	BTA OIL PRODUCERS, LLC		8571		0
32945056	ARCO 7111 34	3H	Horizontal Drainhole	31.72179828	-101.784764	BTA OIL PRODUCERS, LLC		8571		0
32945055	ARCO 7111 34	2H	Permitted Location	31.73341137	-101.795334	BTA OIL PRODUCERS, LLC		8595		0
32945054	ARCO 7111 34	1H	Permitted Location	31.73250064	-101.799444	BTA OIL PRODUCERS, LLC		8595		0
32944264	PRESTON 9E	105H	Oil Well	31.73733254	-101.812695	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9255		0
32944223	PRESTON 9F	106H	Oil Well	31.73696562	-101.815038	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9257		0

32944222	PRESTON 9D	104H	Oil Well	31.73628459	-101.817643	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9276		0
32944221	PRESTON 9C	103H	Oil Well	31.73735011	-101.813594	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8854		0
32944220	PRESTON 9B	102H	Oil Well	31.73684186	-101.816258	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8861		0
32944219	PRESTON 9A	101H	Oil Well	31.73616204	-101.81891	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8863		0
32943934	PRESTON E17F	106H	Oil Well	31.72871347	-101.818677	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9287		0
32943933	PRESTON E17E	105H	Oil Well	31.72811607	-101.821338	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9315		0
32943932	PRESTON E17D	104H	Oil Well	31.72748319	-101.824212	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9301		0
32943931	PRESTON E17C	103H	Oil Well	31.72842338	-101.819883	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8868		0
32943930	PRESTON E17B	102H	Oil Well	31.72776378	-101.822421	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8891		0
32943929	PRESTON E17A	101H	Oil Well	31.72721969	-101.824815	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8917		0
32943928	PRESTON W17F	6H	Oil Well	31.72678611	-101.827028	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9333		0
32943927	PRESTON W17E	5H	Oil Well	31.72618855	-101.829346	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9348		0
32943925	PRESTON W17C	3H	Oil Well	31.72669284	-101.82751	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8943		0
32943924	PRESTON W17B	2H	Oil Well	31.72606702	-101.83029	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8961		0
32942749	PRESTON 5	27H	Oil Well	31.71743747	-101.799315	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8740		0
32942748	PRESTON 5	26H	Oil Well	31.71682932	-101.801404	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8750		0
32941628	PRESTON 28	1D	Injection / Disposal	31.74032683	-101.816662	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	5700		0
32941335	PRESTON 5	25H	Oil Well	31.71643203	-101.803827	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8764		0
32941334	PRESTON 5	24H	Oil Well	31.70183122	-101.801453	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8768		0
32941322	SCHROCK W.M. 34 DEEP	21H	Oil Well	31.73224396	-101.800184	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	8715		0
32941320	SCHROCK W.M. 34 DEEP	20H	Oil Well	31.73283512	-101.797547	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	8702		0
32941319	SCHROCK W.M. 34 DEEP	19H	Oil Well	31.73359381	-101.794793	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	8711		0
32941089	PRESTON 33F	6H	Permitted Location	31.70267342	-101.801629	PIONEER NATURAL RES. USA INC.		11000		0
32941088	PRESTON 33E	5H	Permitted Location	31.7021163	-101.804076	PIONEER NATURAL RES. USA INC.		11000		0
32941087	PRESTON 33D	4H	Permitted Location	31.70155707	-101.806531	PIONEER NATURAL RES. USA INC.		11000		0
32941086	PRESTON 33C	3H	Permitted Location	31.70239591	-101.802848	PIONEER NATURAL RES. USA INC.		11000		0
32941085	PRESTON 33B	2H	Permitted Location	31.70183669	-101.805304	PIONEER NATURAL RES. USA INC.		11000		0
32941084	PRESTON 33A	1H	Permitted Location	31.70127746	-101.807759	PIONEER NATURAL RES. USA INC.		11000		0
32941077	SCHROCK W.M. 34 DEEP	18H	Oil Well	31.73401463	-101.792875	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	9297		0
32941073	SCHROCK W.M. 34 DEEP	17H	Oil Well	31.73461555	-101.790075	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	9255		0
32941072	SCHROCK W.M. 34 DEEP	16H	Oil Well	31.73408411	-101.791187	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	8958		0
32941071	SCHROCK W.M. 34 DEEP	15H	Oil Well	31.73489182	-101.788872	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	8941		0
32941070	SCHROCK W.M. 34 DEEP	14H	Permitted Location	31.71984905	-101.782486	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	9278		0
32941068	SCHROCK W.M. 34 DEEP		Horizontal Drainhole	31.71988025	-101.782346	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	8950		0

32940867	PRESTON B	3212H	Oil Well	31.70058239	-101.809789	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8820		0
32940866	PRESTON B	3211H	Oil Well	31.70023856	-101.812213	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8828		0
32940865	PRESTON B	3210H	Oil Well	31.69960551	-101.814372	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8836		0
32940864	PRESTON B	3209H	Oil Well	31.69894779	-101.81707	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8861		0
32940861	PRESTON B		Horizontal Drainhole	31.72540435	-101.828397	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8869		0
32940860	PRESTON B		Horizontal Drainhole	31.72537295	-101.828537	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8882		0
32940792	PRESTON 5	23H	Oil Well	31.70106195	-101.803797	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8783		0
32940791	PRESTON 5	22H	Oil Well	31.70064532	-101.806118	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8799		0
32940790	PRESTON 5	21H	Oil Well	31.69982675	-101.808229	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8781		0
32940750	PRESTON B	3206H	Oil Well	31.70059395	-101.811076	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9255		0
32940749	PRESTON B	3205H	Oil Well	31.69987806	-101.81345	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9255		0
32940748	PRESTON B	3204H	Oil Well	31.69931996	-101.815389	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9244		0
32940747	PRESTON B		Horizontal Drainhole	31.72511764	-101.829675	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9267		0
32940746	PRESTON B		Horizontal Drainhole	31.72508613	-101.829815	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9275		0
32940745	PRESTON B		Horizontal Drainhole	31.72505463	-101.829955	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9287		0
32940625	PRESTON 5	20H	Oil Well	31.71766662	-101.79788	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9179		0
32940624	PRESTON 5	19H	Plugged Oil Well	31.71730593	-101.800552	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9197	5/24/2023	9197
32940504	7111 JV-D ARCO	3401H	Permitted Location	31.73224321	-101.799964	BTA OIL PRODUCERS, LLC		8271		0
32940435	PRESTON 5	18H	Oil Well	31.70713153	-101.799448	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9183		0
32940434	PRESTON 5	17H	Oil Well	31.70212978	-101.800317	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9184		0
32940433	PRESTON 5	16H	Oil Well	31.701692	-101.80256	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9204		0
32940432	PRESTON 5	15H	Oil Well	31.70082687	-101.805017	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9223		0
32940431	PRESTON 5	14H	Oil Well	31.70037146	-101.807184	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9226		0
32940412	PRESTON 5	13H	Shut-In Oil	31.70028306	-101.809595	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9231		0
32940411	PRESTON 5	12H	Oil Well	31.69955547	-101.810875	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8787		0
32940410	PRESTON 5	11H	Oil Well	31.69904549	-101.813109	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8799		0
32940409	PRESTON 5	10H	Oil Well	31.69856852	-101.815205	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	8817		0
32940271	PRESTON 5	6H	Oil Well	31.69927913	-101.811919	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9205		0
32940270	PRESTON 5	5H	Oil Well	31.69865379	-101.814121	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9213		0
32939713	SCHROCK W.M. 34 DEEP		Horizontal Drainhole	31.72000635	-101.781775	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	10319		0
32939712			Horizontal Drainhole	31.72016555	-101.781825			11000		0
32939710			Horizontal Drainhole	31.71906241	-101.78602			11000		0
32939703			Horizontal Drainhole	31.71922161	-101.78607			11000		0
32939698	SCHROCK W.M. 34 DEEP	6HC	Permitted Location	31.73336146	-101.794889	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	11000		0

32939694	SCHROCK W.M. 34 DEEP	5HM	Oil Well	31.73322745	-101.796042	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	9309		0
32939694	SCHROCK W.M. 34 DEEP		Horizontal Drainhole	31.71829848	-101.789455	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	9309		0
32939691	SCHROCK W.M. 34 DEEP	3HC	Permitted Location	31.73243722	-101.799064	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	11000		0
32939689	SCHROCK W.M. 34 DEEP	4HU	Oil Well	31.73364447	-101.794277	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	8858		0
32939689	SCHROCK W.M. 34 DEEP		Horizontal Drainhole	31.71845757	-101.789506	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	8858		0
32939688	SCHROCK W.M. 34 DEEP	2HM	Oil Well	31.73219091	-101.800109	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	9264		0
32939688	SCHROCK W.M. 34 DEEP		Horizontal Drainhole	31.71737094	-101.793625	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	9264		0
32939683	SCHROCK W.M. 34 DEEP	1HU	Oil Well	31.73259393	-101.798475	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	8857		0
32939683	SCHROCK W.M. 34 DEEP		Horizontal Drainhole	31.71753003	-101.793676	APACHE CORPORATION	SPRABERRY (TREND AREA) R 40 EXC	8857		0
32939311	PRESTON SPRABERRY UNIT	4102D	Injection / Disposal	31.70916051	-101.803132	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	4655		0
32935990	PRESTON SPRABERRY UNIT	4181A	Permitted Location	31.70578973	-101.801623	PIONEER NATURAL RES. USA INC		9175		0
32935989	PRESTON SPRABERRY UNIT	4021A	Plugged Oil Well	31.7081393	-101.789187	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8897	8/2/2019	8897
32935983	PRESTON SPRABERRY UNIT	4180A	Plugged Oil Well	31.69937532	-101.79517	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8872	10/19/2015	8872
32935980	PRESTON SPRABERRY UNIT	4179A	Plugged Oil Well	31.69883896	-101.799469	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8902	10/26/2013	8902
32935979	PRESTON SPRABERRY UNIT	4020A	Shut-In Oil	31.71328229	-101.786541	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8880		0
32935386	FREEMAN BESSIE	11	Oil Well	31.73800164	-101.800862	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9937		0
32935259	PRESTON SPRABERRY UNIT	4102A	Oil Well	31.70800426	-101.800138	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	87600		0
32935258	PRESTON SPRABERRY UNIT	4177A	Plugged Oil Well	31.70228206	-101.79396	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8750	1/16/2020	8750
32935094		1000	Permitted Location	31.73365734	-101.796131	WESTERN GAS RESOURCES-TEXAS, INC.		500		0
32934917	PRESTON SPRABERRY UNIT	4019A	Oil Well	31.71019166	-101.79202	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8750		0
32934742	PRESTON SPRABERRY UNIT	4169A	Shut-In Oil	31.7144786	-101.806143	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8840		0
32934053	PRESTON SPRABERRY UNIT	4220A	Plugged Oil Well	31.71031229	-101.822743	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8890	3/11/2020	8890
32934026	PRESTON SPRABERRY UNIT	3205A	Plugged Oil Well	31.7316689	-101.821109	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8820	6/22/2021	8820
32934025	PRESTON SPRABERRY UNIT	4168A	Plugged Oil Well	31.70743405	-101.80422	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8790	11/15/2013	8790
32934020	PRESTON SPRABERRY UNIT	4018A	Oil Well	31.7078151	-101.786519	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8745		0
32934010		11A	Oil Well	31.70285811	-101.789396		SPRABERRY (TREND AREA)	8730	6/19/2015	8730
32933983	PRESTON SPRABERRY UNIT	3821A	Oil Well	31.72201884	-101.822129	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8935		0
32933983	PRESTON SPRABERRY UNIT	3821A	Oil Well	31.72201884	-101.822129	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8935		0
32933815	PRESTON SPRABERRY UNIT	4017A	Plugged Oil Well	31.71183728	-101.784176	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8765	4/28/2023	8765
32933810	PRESTON SPRABERRY UNIT	2910	Plugged Oil Well	31.7398106	-101.810247	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8380	4/6/2023	8380
32933761	PRESTON SPRABERRY UNIT	4159A	Plugged Oil Well	31.69955734	-101.805812	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8800	2/17/2000	8800
32933757	PRESTON SPRABERRY UNIT	4158A	Plugged Oil Well	31.71187184	-101.801354	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8780	8/18/2021	8780
32933714	PRESTON SPRABERRY UNIT	2909A	Plugged Oil Well	31.73169893	-101.812397	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8800	7/14/2010	8800
32933696	PRESTON SPRABERRY UNIT	3710A	Oil Well	31.72386943	-101.813914	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8920		0

32933570	PRESTON SPRABERRY UNIT	2908A	Plugged Oil Well	31.73437169	-101.817372	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8800	4/24/2023	8800
32933558	PRESTON SPRABERRY UNIT	4219A	Oil Well	31.7005827	-101.818953	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8810		0
32933553	PRESTON SPRABERRY UNIT	4013A	Plugged Oil Well	31.71611628	-101.780771	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8571	9/16/2014	8810
32933535	PRESTON SPRABERRY UNIT	3820	Plugged Oil Well	31.71654592	-101.820794	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8820	11/1/2013	8820
32933535	PRESTON SPRABERRY UNIT	3820	Plugged Oil Well	31.71621783	-101.820751	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8820	11/1/2013	8820
32933535	PRESTON SPRABERRY UNIT	3820	Plugged Oil Well	31.71574724	-101.82108	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8820	11/1/2013	8820
32933535	PRESTON SPRABERRY UNIT	3820	Plugged Oil Well	31.71581214	-101.820882	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8820	11/1/2013	8820
32933535	PRESTON SPRABERRY UNIT		Horizontal Drainhole	31.71488788	-101.819906	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8820	11/1/2013	8820
32933166	PRESTON SPRABERRY UNIT	3003A	Plugged Oil Well	31.73794328	-101.818567	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8800	1/28/2021	8800
32933120	PRESTON SPRABERRY UNIT	4217A	Plugged Oil Well	31.70783819	-101.817561	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8800	1/23/2020	8800
32932892	PRESTON SPRABERRY UNIT	4146A	Plugged Oil Well	31.70039595	-101.802058	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8800	7/19/2017	8800
32932831	PRESTON SPRABERRY UNIT	4012A	Plugged Oil Well	31.71403711	-101.789	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8750	2/26/2019	8750
32932786	PRESTON SPRABERRY UNIT	4011A	Plugged Oil Well	31.71719489	-101.789903	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8775	3/26/2021	8775
32932778	PRESTON SPRABERRY UNIT	2907A	Plugged Oil Well	31.73621287	-101.809197	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8850	2/9/2022	8850
32932721	PRESTON SPRABERRY UNIT	4010A	Plugged Oil Well	31.7152202	-101.785413	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8750	2/20/2019	8750
32932715	DRIVER	1000	Permitted Location	31.7331629	-101.799351	WGR, INC		500		0
32932683	PRESTON SPRABERRY UNIT	4140A	Plugged Oil Well	31.71097402	-101.805029	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8750	1/8/2021	8750
32932679	PRESTON SPRABERRY UNIT	2906A	Plugged Oil Well	31.73719469	-101.805096	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	7/16/2014	9100
32932678	PRESTON SPRABERRY UNIT	4139A	Oil Well	31.7128482	-101.797249	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8750		0
32932667	PRESTON SPRABERRY UNIT	2803A	Plugged Oil Well	31.7348937	-101.797947	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	8/5/2021	9100
32932666	PRESTON SPRABERRY UNIT	4009A	Plugged Oil Well	31.71109268	-101.787912	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8750	4/28/2021	8750
32932648	PRESTON SPRABERRY UNIT	4213A	Plugged Oil Well	31.70208993	-101.81116	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8800	12/17/2021	8800
32932643	PRESTON SPRABERRY UNIT	4212A	Plugged Oil Well	31.70690614	-101.8213	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8800	6/3/2021	8800
32932635	PRESTON SPRABERRY UNIT	4131A	Plugged Oil Well	31.71015838	-101.796414	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8750	5/4/2021	8750
32932634	PRESTON SPRABERRY UNIT	3815A	Plugged Oil Well	31.72114596	-101.825731	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	12/29/2021	9100
32932634	PRESTON SPRABERRY UNIT	3815A	Plugged Oil Well	31.72114596	-101.825731	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	12/29/2021	9100
32932633	PRESTON SPRABERRY UNIT	4132A	Plugged Oil Well	31.70547259	-101.79523	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8750	11/11/2022	8750
32932628	PRESTON SPRABERRY UNIT	3814A	Plugged Oil Well	31.72347666	-101.818025	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	5/14/2021	9100
32932626	PRESTON SPRABERRY UNIT	4133A	Plugged Oil Well	31.7039366	-101.803112	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8750	5/20/2021	8750
32932615	SCHROCK "28"	1	Permitted Location	31.73313329	-101.806003	QUALIA, C. F. OPERATING, INC.		9150		0
32932574	FREEMAN ""A""	3	Plugged Oil Well	31.7354871	-101.795445	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	7/5/2013	9100
32932572	FREEMAN "A"	1	Plugged Oil Well	31.73675795	-101.789754	PARKER & PARSLEY DEV CO.	SPRABERRY (TREND AREA)	10500	6/12/2013	9100
32932560	TEXACO	1	Plugged Oil Well	31.7266363	-101.803751	QUALIA C. F. OPERATINGINC.	SPRABERRY(TREND AREA DEAN-WLFCP)	9100	5/12/2023	9100
32932560	TEXACO	1	Plugged Oil Well	31.7266363	-101.803751	ENDEAVOR ENERGY RESOURCES L.P.	SPRABERRY (TREND AREA)	9100	5/12/2023	9100

32932178	RECTIFIER	1647	Permitted Location	31.72995578	-101.800136	EL PASO NATURAL GAS COMPANY		650		0
32932108	MIDLAND H-TT FEE	5	Plugged Oil Well	31.7325363	-101.824979	TEXACO E & P INC.	SPRABERRY(TREND AREA DEAN-WLFCP)	9100	11/13/2013	9100
32932108	MIDLAND H-TT FEE	5	Plugged Oil Well	31.7325363	-101.824979	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	11/13/2013	9100
32931819	PRESTON SPRABERRY UNIT	3819B	Oil Well	31.71734786	-101.829487	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100		0
32931819	PRESTON SPRABERRY UNIT	3819B	Oil Well	31.71734786	-101.829487	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100		0
32931819	PRESTON SAM R.	3819B	Oil Well	31.71734786	-101.829487	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9100		0
32931819	PRESTON SAM R.	3819B	Oil Well	31.71734786	-101.829487	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100		0
32931714	PRESTON SPRABERRY UNIT	4152B	Plugged Oil Well	31.71340443	-101.810536	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9500	5/23/2018	9500
32931714	PRESTON SPRABERRY UNIT	4152B	Plugged Oil Well	31.71340443	-101.810536	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9500	5/23/2018	9500
32931714	BOWLES D. T.	4152B	Plugged Oil Well	31.71340443	-101.810536	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9500	5/23/2018	9500
32931714	BOWLES D. T.	4152B	Plugged Oil Well	31.71340443	-101.810536	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9500	5/23/2018	9500
32931712	PRESTON SPRABERRY UNIT	27	Plugged Oil Well	31.70640906	-101.807615	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	10300	12/8/2022	10300
32931712	BOWLES D. T.	27	Plugged Oil Well	31.70640906	-101.807615	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	10300	12/8/2022	10300
32931712	BOWLES D. T.	27	Plugged Oil Well	31.70640906	-101.807615	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	10300	12/8/2022	10300
32931712	PRESTON 5	27	Plugged Oil Well	31.70640906	-101.807615	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	10300	12/8/2022	10300
32931620	PRESTON SPRABERRY UNIT	4216B	Plugged Oil Well	31.70489111	-101.816708	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9200	8/13/2021	9200
32931620	PRESTON SAM R.	4216B	Plugged Oil Well	31.70489111	-101.816708	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9200	8/13/2021	9200
32931620	PRESTON SAM R.	4216B	Plugged Oil Well	31.70489111	-101.816708	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9200	8/13/2021	9200
32931618	PRESTON SPRABERRY UNIT	3708B	Plugged Oil Well	31.72019384	-101.812915	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9200	2/26/2021	9200
32931618	T.X.L.M.	3708B	Plugged Oil Well	31.72019384	-101.812915	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9200	2/26/2021	9200
32931618	TXL -M-	3708B	Plugged Oil Well	31.72019384	-101.812915	PARKER & PARSLEY DEVELOPMENT L.P	SPRABERRY (TREND AREA)	9200	2/26/2021	9200
32931613	PRESTON SPRABERRY UNIT	4151B	Plugged Oil Well	31.70140091	-101.798026	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9200	6/5/2018	9189
32931613	PRESTON SPRABERRY UNIT	4151B	Plugged Oil Well	31.70140091	-101.798026	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9200	6/5/2018	9189
32931613	BOWLES D. T.	4151B	Plugged Oil Well	31.70140091	-101.798026	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9200	6/5/2018	9189
32931613	BOWLES D. T.	4151B	Plugged Oil Well	31.70140091	-101.798026	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9200	6/5/2018	9189
32931542	PRESTON SPRABERRY UNIT	3709B	Plugged Oil Well	31.72690505	-101.813793	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	1/7/2022	9100
32931542	T.X.L.M.	3709B	Plugged Oil Well	31.72690505	-101.813793	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9100	1/7/2022	9100
32931542	TXL -M-	3709B	Plugged Oil Well	31.72690505	-101.813793	PARKER & PARSLEY DEVELOPMENT L.P	SPRABERRY (TREND AREA)	9100	1/7/2022	9100
32931538	FREEMAN BESSIE	8	Plugged Oil Well	31.73908308	-101.796489	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9098	4/8/2013	9098
32931538	FREEMAN BESSIE	8	Plugged Oil Well	31.73908308	-101.796489	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9098	4/8/2013	9098
32931528	PRESTON SPRABERRY UNIT	4162B	Plugged Oil Well	31.69820667	-101.810311	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	3/18/2021	9100
32931528	PRESTON SPRABERRY UNIT	4162B	Plugged Oil Well	31.69820667	-101.810311	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	3/18/2021	9100
32931528	BOWLES D. T.	4162B	Plugged Oil Well	31.69820667	-101.810311	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9100	3/18/2021	9100
32931528	BOWLES D. T.	4162B	Plugged Oil Well	31.69820667	-101.810311	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	3/18/2021	9100

32931527	PRESTON SPRABERRY UNIT	3817B	Plugged Oil Well	31.713961	-101.823816	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	5/20/2021	9100
32931527	PRESTON SAM R.	3817B	Plugged Oil Well	31.713961	-101.823816	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9100	5/20/2021	9100
32931527	PRESTON SAM R.	3817B	Plugged Oil Well	31.713961	-101.823816	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	5/20/2021	9100
32931526	PRESTON SPRABERRY UNIT	3818B	Oil Well	31.72354345	-101.831469	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100		0
32931449	PRESTON SAM R.	29	Oil Well	31.72612915	-101.820755	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9100	8/11/2023	9100
32931449	PRESTON SAM R.	29	Oil Well	31.72612915	-101.820755	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	8/11/2023	9100
32931449	PRESTON B	29	Oil Well	31.72612915	-101.820755	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA) R 40 EXC	9100	8/11/2023	9100
32931387	YAKIRA	1	Dry Hole	31.72571085	-101.784452	FLOYD, TIMBER INC		6500	4/2/1985	6505
32931386	PRESTON SAM R.	4214B	Plugged Oil / Gas	31.70938909	-101.826606	MOBIL PRODUCING TX. & N.M. INC.	SPRABERRY(TREND AREA DEAN-WLFCP)	12160	1/13/2020	12160
32931386	PRESTON SPRABERRY UNIT	4214B	Plugged Oil / Gas	31.70938909	-101.826606	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	12160	1/13/2020	12160
32931386	PRESTON SAM R.	4214B	Plugged Oil / Gas	31.70938909	-101.826606	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	12160	1/13/2020	12160
32931386	PRESTON SAM R.	4214B	Plugged Oil / Gas	31.70938909	-101.826606	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	12160	1/13/2020	12160
32931386	PRESTON SAM R.	4214B	Plugged Oil / Gas	31.70938909	-101.826606	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	12160	1/13/2020	12160
32930991	PRESTON SPRABERRY UNIT	2905	Plugged Oil Well	31.73535311	-101.813177	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8000	1/2/2014	8000
32930858	PRESTON SPRABERRY UNIT	4014B	Plugged Oil Well	31.71136532	-101.792615	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9010	4/24/2007	9010
32930858	PRESTON SPRABERRY UNIT	4014B	Plugged Oil Well	31.71136532	-101.792615	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9010	4/24/2007	9010
32930858	SNYDERMAGGIE	4014B	Plugged Oil Well	31.71136532	-101.792615	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9010	4/24/2007	9010
32930858	SNYDER MAGGIE	4014B	Plugged Oil Well	31.71136532	-101.792615	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9010	4/24/2007	9010
32910352	PRESTON SPRABERRY UNIT	4218	Plugged Oil Well	31.7109492	-101.819601	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9070	12/10/2013	9070
32910352	PRESTON SAM R.	4218	Plugged Oil Well	31.7109492	-101.819601	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9070	12/10/2013	9070
32910352	PRESTON SAM R.	4218	Plugged Oil Well	31.7109492	-101.819601	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9070	12/10/2013	9070
32910336	PRESTON SPRABERRY UNIT	4119	Plugged Oil Well	31.71009891	-101.801517	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8025	2/10/1982	8025
32910125	PRESTON SPRABERRY UNIT	3816B	Plugged Oil Well	31.71849447	-101.820867	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	12503	6/1/2012	12503
32910125	PRESTON SAM R.	3816B	Plugged Oil Well	31.71849447	-101.820867	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	12503	6/1/2012	12503
32910125	PRESTON SAM R.	3816B	Plugged Oil Well	31.71849447	-101.820867	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	12503	6/1/2012	12503
32901730	DRIVER E.P. -34-	2	Plugged Oil Well	31.73035961	-101.785098	ENDEAVOR ENERGY RESOURCES L.P.	SPRABERRY (TREND AREA)	8700	9/3/2002	8700
32901729	DRIVER E.P. -34-	1	Plugged Oil Well	31.73376684	-101.785883	ENDEAVOR ENERGY RESOURCES L.P.	SPRABERRY (TREND AREA)	8700	8/29/2017	8700
32901511	PRESTON SPRABERRY UNIT	3201	Plugged Oil Well	31.72902421	-101.824587	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8075	12/29/2011	8075
32901182	PRESTON SPRABERRY UNIT	4202	Plugged Oil Well	31.71236754	-101.814597	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8900	12/10/2014	8505
32901179	PRESTON SPRABERRY UNIT	4104	Plugged Oil Well	31.71535815	-101.802431	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7945	8/23/1995	7945
32901176	PRESTON SPRABERRY UNIT	4201	Plugged Oil Well	31.70569135	-101.825565	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8020	7/19/2012	8020
32901170	PRESTON SPRABERRY UNIT	4203	Plugged Oil Well	31.70540997	-101.81244	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7288	12/24/2013	7288
32901166	PRESTON SPRABERRY UNIT	3801D	Oil Well	31.71311261	-101.827668	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7325		0
32901166	PRESTON SPRABERRY UNIT	3801D	Oil Well	31.71311261	-101.827668	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7325		0

32901165	PRESTON SPRABERRY UNIT	4204W	Plugged Oil Well	31.70885446	-101.81332	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7996	6/1/1989	7996
32901163	PRESTON SPRABERRY UNIT	3807	Plugged Oil Well	31.7194257	-101.816787	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7995	1/8/1993	7995
32901162	PRESTON SPRABERRY UNIT	15WS	Oil Well	31.70090505	-101.815488	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7990	10/19/1992	7990
32901161	PRESTON SPRABERRY UNIT	3806	Injection / Disposal from Oil	31.72013887	-101.830393	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7307		0
32901158	PRESTON SPRABERRY UNIT	3805	Plugged Oil Well	31.72655606	-101.819139	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7995	1/13/1993	7995
32901156	PRESTON SPRABERRY UNIT	3804	Plugged Oil Well	31.72464249	-101.827397	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8050	2/5/2014	8050
32901155	PRESTON SPRABERRY UNIT	3803	Plugged Oil Well	31.71593112	-101.815677	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8024	7/13/2012	8024
32901153	PRESTON SPRABERRY UNIT	3808W	Plugged Oil Well	31.71744463	-101.82515	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8000	5/24/1989	8000
32901152	PRESTON SPRABERRY UNIT	4207	Plugged Oil Well	31.70361669	-101.820656	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7280	5/12/1980	7280
32901095	PRESTON SPRABERRY UNIT	4006	Plugged Oil Well	31.70668438	-101.790922	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7930	12/30/1983	7930
32901094	PRESTON SPRABERRY UNIT	4016B	Plugged Oil Well	31.71936057	-101.781661	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	12/23/2004	9100
32901094	PRESTON SPRABERRY UNIT	4016B	Plugged Oil Well	31.71936057	-101.781661	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	12/23/2004	9100
32901094	PRESTON SPRABERRY UNIT	4016B	Plugged Oil Well	31.71936057	-101.781661	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	12/23/2004	9100
32901094	SNYDERMAGGIE	4016B	Plugged Oil Well	31.71936057	-101.781661	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9100	12/23/2004	9100
32901094	SNYDER MAGGIE	4016B	Plugged Oil Well	31.71936057	-101.781661	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9100	12/23/2004	9100
32901093	PRESTON SPRABERRY UNIT	4004	Injection / Disposal from Oil	31.71841183	-101.785876	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7935	9/2/1988	7935
32901093	PRESTON SPRABERRY UNIT	4004	Injection / Disposal from Oil	31.71841183	-101.785876	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7935	9/2/1988	7935
32901091	PRESTON SPRABERRY UNIT	4001	Plugged Oil Well	31.71671734	-101.794234	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7960	12/7/1994	7960
32901075	PRESTON SPRABERRY UNIT	3102	Plugged Oil Well	31.73701271	-101.822669	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8010	3/25/2005	8010
32901074	PRESTON SPRABERRY UNIT	3702	Plugged Oil Well	31.72128149	-101.808285	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7285	5/27/2004	7285
32901067	PRESTON SPRABERRY UNIT	3101	Plugged Oil Well	31.72805807	-101.82862	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7345	7/29/1981	7345
32901066	PRESTON SPRABERRY UNIT	3701	Plugged Oil Well	31.71672156	-101.811771	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7970	10/22/2003	7970
32900994	PRESTON SPRABERRY UNIT	3705	Plugged Oil Well	31.72485067	-101.809704	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7240	3/10/1987	7240
32900989	PRESTON SPRABERRY UNIT	3704	Plugged Oil Well	31.71772671	-101.807282	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7245	2/9/1999	7245
32900980	PRESTON SPRABERRY UNIT	3703W	Plugged Oil Well	31.72839474	-101.811005	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7922	11/10/2011	7970
32900980	PRESTON SPRABERRY UNIT	3703W	Plugged Oil Well	31.72839474	-101.811005	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7922	11/10/2011	7970
32900879	FREEMAN BESSIE	3	Plugged Oil Well	31.73449595	-101.799758	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY (TREND AREA)	7277		0
32900877	FREEMAN BESSIE	1	Plugged Oil Well	31.73634033	-101.79176	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY (TREND AREA)	7260		0
32900864	PRESTON SPRABERRY UNIT	4118W	Plugged Oil Well	31.7048347	-101.799137	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7265	12/15/1986	7960
32900857	PRESTON SPRABERRY UNIT	4110	Plugged Oil Well	31.6985525	-101.810226	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7970	12/19/1980	7970
32900822	PRESTON SPRABERRY UNIT	4103	Plugged Oil Well	31.70649931	-101.808324	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7275	5/21/2014	7975
32900821	PRESTON SPRABERRY UNIT	4102	Plugged Oil Well	31.71635579	-101.798347	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9000	12/18/1990	9000
32900821	BOWLES D. T.	4102	Plugged Oil Well	31.71635579	-101.798347	PARKER & PARSLEY DEVELOPMENT CO.	SPRABERRY(TREND AREA DEAN-WLFCP)	9000	12/18/1990	9000
32900820	PRESTON SPRABERRY UNIT	4101	Plugged Oil Well	31.70987939	-101.809401	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7285	12/29/1992	7951

32900504	PRESTON SPRABERRY UNIT	3503	Plugged Oil Well	31.725855	-101.805871	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7044	7/18/2012	8014
32900501	PRESTON SPRABERRY UNIT	3502	Plugged Oil Well	31.7269132	-101.80157	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8072	2/4/2021	8072
32900498	PRESTON SPRABERRY UNIT	3501	Plugged Oil Well	31.72940478	-101.806916	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8014	8/25/2011	8013
32900441	PRESTON SPRABERRY UNIT	3504	Plugged Oil Well	31.73038362	-101.802668	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7269	11/19/2013	7269
32900330	PRESTON SPRABERRY UNIT	3601W	Plugged Oil Well	31.71985128	-101.799047	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7980	1/6/1982	7980
32900325	PRESTON SPRABERRY UNIT	3603	Plugged Oil Well	31.72235761	-101.804683	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7078	2/22/2021	7078
32900323	PRESTON SPRABERRY UNIT	4	Plugged Oil Well	31.71874704	-101.80356	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8791	10/23/2019	8791
32900323	TXL ""B""	4	Plugged Oil Well	31.71874704	-101.80356	QUALIA C. F. OPERATINGINC.	SPRABERRY(TREND AREA DEAN-WLFCP)	8791	10/23/2019	8791
32900323	TXL B	4	Plugged Oil Well	31.71874704	-101.80356	ENDEAVOR ENERGY RESOURCES L.P.	SPRABERRY (TREND AREA)	8791	10/23/2019	8791
32900144	PRESTON SPRABERRY UNIT	3001	Plugged Oil Well	31.73884899	-101.814367	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8050	8/18/2003	8050
32900111	SCHROCK W.M. ""34""	5	Plugged Oil Well	31.72025893	-101.795174	ATLANTIC RICHFIELD CO.	SPRABERRY (TREND AREA)	7081	10/16/1971	7081
32900108	7111 JV-D ARCO	4	Plugged Oil Well	31.722205	-101.787079	BTA OIL PRODUCERS	SPRABERRY(TREND AREA DEAN-WLFCP)	8605	2/3/1987	8675
32900106	SCHROCK W.M. ""34""	7	Plugged Oil Well	31.72381231	-101.79643	ATLANTIC RICHFIELD CO.	SPRABERRY (TREND AREA)	7964		0
32900103	PRESTON SPRABERRY UNIT	2901W	Oil Well	31.73357011	-101.803858	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8030	1/7/1983	8030
32900100	7111 JV-D ARCO	3	Plugged Oil Well	31.72752669	-101.797588	BTA OIL PRODUCERS	SPRABERRY(TREND AREA DEAN-WLFCP)	8675	4/5/2022	8675
32900100	7111JV-D ARCO	3	Plugged Oil Well	31.72752669	-101.797588	BTA OIL PRODUCERS LLC	SPRABERRY (TREND AREA)	8675	4/5/2022	8675
32900097	PRESTON SPRABERRY UNIT	2903D	Plugged Oil Well	31.73268957	-101.808002	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7094	12/17/2020	7094
32900097	PRESTON SPRABERRY UNIT	2903D	Plugged Oil Well	31.73268957	-101.808002	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7094	12/17/2020	7094
32900094	PRESTON SPRABERRY UNIT	2904	Plugged Oil Well	31.73086389	-101.816204	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	7095	7/13/2012	7095
32900093	7111 JV-D ARCO	2	Plugged Oil Well	31.72462685	-101.792179	BTA OIL PRODUCERS	SPRABERRY(TREND AREA DEAN-WLFCP)	7084	7/22/2014	8675
32900093	7111JV-D ARCO	2	Plugged Oil Well	31.72462685	-101.792179	BTA OIL PRODUCERS LLC	SPRABERRY (TREND AREA)	7084	7/22/2014	8675
17338768	DRIVER 4C-E 3-46F	106H	Oil Well	31.71993052	-101.781053	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9140		0
17338768		106H	Shut-In Oil	31.72135088	-101.781355		SPRABERRY (TREND AREA)	9140		0
17338767	DRIVER 4C-E 3-46E	105H	Shut-In Oil	31.72118025	-101.782123	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8732		0
17338766	DRIVER 4C-E 3-46D	104H	Oil Well	31.72075902	-101.783757	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9146		0
17338765	DRIVER 4C-E 3-46C	103H	Shut-In Oil	31.72062657	-101.784613	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8745		0
17338764	DRIVER 4C-E 3-46B	102H	Oil Well	31.71923401	-101.785866	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	9198		0
17338763	DRIVER 4C-E 3-46A	101H	Shut-In Oil	31.72012808	-101.786855	PIONEER NATURAL RES. USA INC.	SPRABERRY (TREND AREA)	8747		0
329		8	Permitted Location	31.73106187	-101.798568			0		0
329		4206	Oil Well	31.70118945	-101.815251			0		0
329		4X	Plugged Oil Well	31.71876694	-101.803021			6010		0
329		1	Plugged Oil Well	31.73213091	-101.794239			7091		0
329		3204	Plugged Oil Well	31.73261609	-101.825652			7341		0
329		3203	Plugged Oil Well	31.73370172	-101.82152			7309		0

329		1	Plugged Oil Well	31.72698512	-101.784115			7064		0
329		3202	Plugged Oil Well	31.73001575	-101.820191			7306		0
329		3802	Plugged Oil Well	31.72562973	-101.823134			7620		0
329		3602	Plugged Oil Well	31.72330126	-101.800504			7100		0
329		2803	Oil Well	31.74253295	-101.798622			0		0

APPENDIX 8

Description of Subpart RR Equations for Calculating CO_2 Geologic Sequestration

Appendix 8 – Subpart RR Description of Equations for Sequestration Calculations

GHGs to Report § 98.442	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 9

Subpart RR Equations for Calculating CO_2 Geologic Sequestration

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 at standard conditions (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

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

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 fluid 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

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

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 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.