UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

November 4, 2022

Mr. Joshua Roberts
Stakeholder Midstream, LLC
401 E Sonterra Boulevard
Suite 215
San Antonio, Texas 78258

Re: Monitoring, Reporting and Verification (MRV) Plan for 30-30 Gas Plant

Dear Mr. Roberts:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for 30-30 Gas Plant, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by 30-30 Gas Plant on September 13, 2022, as the final MRV plan. The MRV Plan Approval Number is 1013701-1. This decision is effective November 9, 2022 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78.

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

Sincerely,

Julius Banks, Chief
Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for 30-30 Gas Plant

November 2022

Contents

<u>**Appendices**</u>

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) Subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted by the Stakeholder Gas Services, LLC (Stakeholder) 30-30 Gas Plant (30-30) for its treated acid gas (TAG) injection project into the Wristen Group in Yoakum County, Texas approximately seven miles northwest of the town of Plains. Note that this evaluation pertains only to the Subpart RR MRV plan, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations.

1 Overview of Project

30-30 states in the introduction of the MRV plan that it currently has a Class II permit for acid gas injection (AGI), issued by the Texas Railroad Commission (TRRC) in November 2018 under the state's Underground Injection Control (UIC) program for the Rattlesnake AGI #1 well, API No. 42- 501-36998, UIC #000117143. This permit was originally issued to Santa Fe Midstream Permian, LLC in 2018, but the asset was subsequently acquired by Stakeholder in December of 2020. This permit currently authorizes 30-30 to inject up to 4,500 barrels per day (or around 25,266 standard cubic feet per day (scf/d)) of TAG into the Devonian formation at a depth of 11,000 to 12,000 feet with a maximum allowable surface pressure of 2,200 pounds per square inch (psi). 30-30 claims that since being permitted, injection has proceeded without incident. The Rattlesnake AGI #1 well is located in a rural, sparsely populated area of Yoakum County, Texas, approximately seven miles northwest of the town of Plains.

In addition to submitting this MRV plan to the EPA, 30-30 is also applying to the TRRC for an amendment to the Rattlesnake AGI #1 well's Class II permit to increase its authorized injection volume and maximum allowable surface injection pressure (MASIP). The MRV plan states that approval of the permit amendment will allow 30-30 to increase its capacity, which removes H_2S and CO_2 from natural gas production using amine treating. Approval will also increase the injection well capacity for a future gas processing facility which is currently under development by Stakeholder. Additionally, expanded capacity allows 30-30 to potentially provide future disposal in its AGI well for TAG from similar third-party gas processing facilities. The MRV plan states that increased disposal capacity will allow for greater gas processing capacity in the region, ultimately helping to reduce flaring and its associated emissions. Throughout the MRV plan, both in written reference and in modeling inputs, 30-30 has used the applied-for expanded permit capacity of 16 million standard cubic feet per day (MMSCF/d). 30-30 plans to inject CO_2 for approximately 14 more years (17 years in total from the start of injection in 2019).

30-30 states in the MRV plan that the Rattlesnake AGI #1 well is designed in such a way to protect against migration of CO_2 out of the injection interval and to prevent surface releases. The injection interval for Rattlesnake AGI #1 is located over 4,720 feet below the primary producing formation, the San Andres, and 8,593 feet below the base of the lowest useable quality water table, as shown in Figure 2 of the MRV plan. As stated in section 2 of the MRV plan, this well will inject a CO_2 stream that contains 9.20% H_2S, 89.68% CO_2, and 1.12% other gases. For these reasons, the MRV plan states that the well and the facility are designed to minimize any leakage to the surface.

In Section 2 of the MRV plan, 30-30 describes the geologic setting, planned injection volumes and process, and the reservoir modeling performed for the Rattlesnake AGI #1. The target injection formation is the Wristen Group. This formation was deposited in a basin platform setting across the northern half of the Permian Basin. The MRV plan refers to this sequence as Devonian, Silurian-Devonian, or Siluro-Devonian in age. The Silurian-age lithology on the inner platform is dominated by grain-rich skeletal carbonates. The MRV plan states that the thickness of the Silurian-age rock is approximately 1,000 feet thick at the Rattlesnake AGI #1 well location. Carbonate buildups are common within the shallow inner platform, mainly skeletal wackestone, indicating a lower-energy deposition on the inner platform. The Wristen Group is composed of three formations: Fasken, Frame, and Wink. The Frame and Wink Formations are found near the ramp boundary to the south, while the Fasken formation is found predominantly in the inner platform, where the Rattlesnake AGI #1 well is located. The Fasken Formation is predominately dolomite grading to limestone, occurring as cycles, down section. Figure 4 in the MRV plan shows a generalized stratigraphic column of the area underlying the Rattlesnake AGI #1 well.

The MRV plan states that the upper confining interval is the Woodford Shale. The Woodford Shale is a late Devonian-age organic-rich shale deposited as a result of a widespread marine transgression. The flooding event occurred over most of the Permian basin, which produced a low relief, blanket-like shale deposit of the Woodford. Two major lithofacies found within the Woodford are black shale and siltstone. Nutrient-rich surface waters promoted the decay of abundant organic matter within the Woodford, resulting in a high total organic carbon (TOC) percentage.

The MRV plan states that the low-permeability Montoya Formation is a tight limestone/dolomite that will act as the lower confining unit for the injection interval. The MRV plan states that the porosity in the lower section can range from 2-3% with permeabilities below 1 millidarcy (md). The Rattlesnake AGI #1 well drilled six feet into the Montoya formation, but the section was not logged. The MRV plan states that the Montoya Formation is anticipated to be roughly 250 feet thick. The MRV plan states that these petrophysical characteristics represent ideal sealing properties to prohibit any migration of injected fluid outside of the injection interval.

The description of the project is determined to be acceptable and provides the necessary information for 40 CFR 98.448(a)(6).

2 Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA)

As part of the MRV plan, the reporter must identify and delineate both the maximum monitoring area (MMA) and active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines the maximum monitoring area as "the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." Subpart RR defines the active monitoring area as "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) the area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) the area projected to contain the free phase CO_2 plume at the end of year t + 5." See 40 CFR 98.449.

30-30 has indicated in the MRV plan that the initial AMA will cover a 14-year monitoring period, which is equal to the expected time of future injection. The MRV plan states that the AMA itself will be established based on the half-mile buffer around the anticipated plume location at the end of injection in 2036. The area of projected free-phase CO_2 plume after five additional years (t + 5) was also reviewed, but the boundaries of the plume at t + 5 were inside the plume boundary in 2016 plus the ½ mile buffer. Therefore, the MRV plan delineates the AMA as the plume at the end of injection plus the ½ mile buffer. The AMA is shown in Figure 27. 30-30 states that it may submit a revised MRV plan on or before 2036 to amend the AMA if necessary.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation of CO_2 was used to determine the boundary of the plume. When injection ceases in year 2036, the MRV plan states that the areal expanse of the plume will be 1,052 acres. The maximum distance between the wellbore and the edge of the plume is expected to be approximately 0.87 miles to the southeast. After 743 additional years of density drift, the areal extent of the plume is predicted by 30-30 to be 2,177 acres with a maximum distance to the edge of the plume of approximately 1.35 miles to the southeast. A map of the plume boundary can be seen in Figure 26 of the MRV plan.

The MMA is defined in the MRV plan as equal to or greater than the area expected to contain the free-phase CO2 plume until the CO2 plume has stabilized plus an all-around buffer zone of at least one-half mile, and is delineated in Figure 26. The MMA is consistent with Subpart RR requirements because the defined MMA accounts for the expected free phase CO_2 plume, based on modeling results, and incorporates the additional 0.5-mile or greater buffer area. The rationale used to delineate the MMA, as described in 30-30's MRV plan, accounts for the existing operational and subsurface conditions at the site, along with any potential changes in future operations. Therefore, the designation of the MMA is an acceptable approach.

The delineations of the MMA and AMA were determined to be acceptable per the requirements in 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV plan are clearly and explicitly delineated in the plan and are consistent with the definitions in 40 CFR 98.449.

3 Identification of Potential Surface Leakage Pathways

As part of the MRV plan, the reporter must identify potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing of potential surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). 30-30 identified the following as potential leakage pathways in their MRV plan that required consideration:

- Leakage from surface equipment
- Leakage through existing wells within MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from Natural or Induced Seismicity

3.1 Leakage through Surface Equipment

The MRV plan states that 30-30 is designed for injecting acid gas containing H_2S, and is therefore designed and operated to minimize leakage points such as valves and flanges following industry standards and best practices. The MRV plan states that H_2S gas detectors are located around the facility and the well site. These gas detectors trigger alarms at 10 parts per million (ppm) of H_2S. Additionally, all 30-30 field personnel are required to wear H_2S monitors which are triggered at 5 ppm of H_2S. A shut-in valve is located at the wellhead and is locally controlled by pressure, with a high pressure and low pressure shut-off.

Additional safety features noted in this section of the MRV plan include Emergency Shutdown (ESD) valves to isolate portions of the plant and pipeline; pressure relief valves along the pipeline to prevent over pressurization; and flares to allow piping and equipment to be de-pressured rapidly.

The MRV plan states that with the level of monitoring at the 30-30 Facility and the Rattlesnake AGI #1 well, any release of H_2S and CO_2 would be quickly identified, and the safety systems would quickly minimize the volume of the release. It further states that the CO2 injected into the Rattlesnake AGI #1 is injected with H2S at a concentration of 10% (100,000 ppm). At this high level of H2S concentration, even a small leakage would trigger personal and facility H2S monitors set to alarm at 5 ppm and 10 ppm respectively.

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

3.2 Leakage from Existing Wells within MMA

Oil and Gas Operations within Monitoring Area

The MRV plan states that significant number of wells have historically been drilled within the area of the Rattlesnake AGI #1 well. However, production has primarily been from the shallower San Andres Formation in the Wasson Field. The San Andres Formation is separated from the Silurian-Devonian interval by 4,720 feet in this area. The MRV plan states that a few wells have also been producing from the Wolfcamp Formation. The Wolfcamp Formation is separated from the Siluro-Devonian interval by 1,800 feet. The MRV plan concludes that there are no penetrations of the injection interval within the projected plume area of the Rattlesnake AGI #1 well.

The MRV plan also states that a review of the TRRC records for all the wells which penetrate the injection interval within the MMA show that the wells were properly cased and cemented to prevent annular leakage of CO_2 to the surface. The plugged wells are also adequately protected against migration from the Devonian by the placement of the plugs within the wellbores. Additionally, the MRV plan states that the Rattlesnake AGI #1 well was designed to prevent migration from the injection interval to the surface through the casing and cement placed in the well, as shown in Figure 29 of the MRV plan. The plan further states that Mechanical integrity tests ("MIT") required under TRRC rules are run annually to verify the well and wellhead can hold the appropriate amount of pressure. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated quickly to prevent leakage to the atmosphere.

The MRV plan provides a map of all wells within the MMA in Figure 30. Figure 31 shows only those wells which penetrate the injection interval within the MMA. The MMA review maps, a summary of all the wells in the MMA and detailed wellbore schematics for those wells which penetrate the injection interval are provided in Appendix F.

Future Drilling

The MRV plan states that potential leakage pathways caused by future drilling in the area are not expected to occur, in particular noting that the deeper formations, such as the Devonian, have proven to-date to be less productive or non-productive in this area, which is why the location was selected for injection. Furthermore, the MRV plan states that any drilling permits issued by the TRRC in the area of the Rattlesnake AGI #1 well include a list of formations for which oil and gas operators are required to comply with TRRC Rule 13 (entitled "Casing, Cementing, Drilling, Well Control, and Completion Requirements"), 16 TAC § 3.13. As stated in the MRV plan, TRRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under TRRC Rule 9 or immediately above all formations permitted for injection under Rule 46 for any well proposed within a one-quarter mile radius of an injection well. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and/or zones with corrosive formation fluids. The MRV plan states that if any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release.

Groundwater Wells

The MRV plan states that there are seven groundwater wells located within the MMA, as identified by the Texas Water Development Board. All the identified groundwater wells in the area have total depths less than or equal to 265 feet, as shown in Figure 32 and Table 9 of the MRV plan. One of the wells is located on the 30-30 facility property with a total depth of 119 feet and is operated by Stakeholder.

The surface and intermediate casings of the Rattlesnake AGI #1 well, as shown in Figure 29 of the MRV plan, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the GAU letter issued for this location. See GAU letter included within Appendix B of the MRV plan. The wellbore casings and cements also serve to prevent CO_2 leakage to the surface along the borehole.

Thus, the MRV plan provides an acceptable characterization of the CO_2 leakage that could be expected through existing and future oil, gas, and groundwater wells.

3.3 Leakage Through Faults and Fractures

The MRV plan states that faults were interpreted from roughly 9 square miles of 3D seismic indicated by the purple outline in Figure 12 of the MRV plan. This interpreting revealed that faulting in this region terminates vertically below the Pennsylvanian-age rock. Secondary confining shales within the Wolfcampian and younger strata provide additional, redundant confining layers that would prevent CO_2 from migrating into freshwater aquifers. None of the mapped faults project above the Wolfcamp formation; rather, they appear to terminate between the Strawn and the base of the Wolfcamp. The MRV plan states that in the unlikely event the faults' sealing properties are compromised post-injection, secondary confinement is provided by the tight limestones found within the overlying Mississippian Lime formation and the shale layers found in the Atoka and Wolfcamp formations.

As seen in Figure 14 of the MRV plan, the largest fault found southeast (SE) of the Rattlesnake AGI #1 well terminates within the Atoka formation. Though it crosses the Silurian section, this fault thrusts the Mississippian Lime upward against the Atoka shales. The tight reservoir characteristics of the Mississippian Lime and shaley section of the Atoka create a confining environment vertically and laterally to contain potential upward migration of buoyant fluids. Shales within the Wolfcamp formation provide additional confining beds between overlying USDWs and the fault plane.

The MRV plan states that pressures will be kept significantly below the fracture gradient of the injection and confining intervals. Therefore, 30-30 states that upward migration of injected gas through confining bed fractures is unlikely.

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

3.4 Leakage through the Confining Layer

The MRV plan states that the Silurian-Devonian injection zones have competent sealing rocks above and below the porous sub-aerially exposed carbonate. The MRV plan states that the properties of the overlying transgressive Woodford shale (widespread deposition, high illite clay and organic matter composition, and low porosity and permeability) make an excellent sealing rock to the underlying Silurian formation. Furthermore, tight Mississippian Lime of roughly 660 feet lay between Atoka and Woodford shale formations, forming an impermeable upper seal to the injection interval. Above this confining unit, correlative shales of the Wolfcamp, Abo and Tubb formations will prevent any upper fluid migration. The MRV plan states that these impermeable shales are capped by hundreds of feet of the regionally present Salado formation evaporites. The USDW lies above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. The MRV plan states that the low porosity and permeability of the underlying Montoya carbonate minimizes the likelihood of downward migration of injected fluids. It also states that the relative buoyancy of injected gas to the in-situ reservoir fluid makes migration below the lower confining layer unlikely.

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

3.5 Leakage From Natural or Induced Seismicity

The MRV plan states that the location of Rattlesnake AGI #1 is in an area of the Permian Basin that is inactive from a seismicity perspective, whether induced or natural. A review of historical seismic events on the USGS's Advanced National Seismic System site (from 1971 to present) and the Bureau of Economic Geology's TexNet catalog (from 2017 to present), as shown in Figure 33 of the MRV plan, indicates the nearest seismic event occurred more than 60 miles away.

The MRV plan states that a regional analysis of the probabilistic fault slip potential across the Permian Basin (Snee & Zoback 2016) further demonstrates that the Rattlesnake AGI #1 well is located in a seismically inactive area and confirms that this area has little to no potential for an induced seismicity event. Therefore, 30-30 states that there is no indication that seismic activity poses a risk for loss of CO_2 to the surface within the MMA.

Furthermore, the MRV plan states that pressures will be kept significantly below the fracture gradient of the injection and confining intervals. This lowers the risk of induced seismicity. Additionally, continuous well monitoring combined with seismic monitoring will identify any operational anomalies associated with a seismicity event.

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

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

40 CFR 98.448(a)(3) requires that an MRV plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. Section 5 of the MRV plan details 30-30's strategy for monitoring and quantifying potential CO_2 leakage, and section 6 of the MRV plan details strategies for establishing baselines for evaluating potential CO_2 leakage. The MRV plan explains that as the CO_2 stream injected at the 30-30 facility contains both H_2S and CO_2, fixed and personal H_2S monitors will be 30-30's primary method for monitoring CO_2 leakage. The H_2S will serve as a proxy for CO_2. Additional approaches for detecting and quantifying surface leakage of CO_2 primarily include visual inspections, well mechanical integrity tests (MITs), groundwater sampling, continuous monitoring, and seismic monitoring. Monitoring will occur during the planned 17-year injection period, or until cessation of injection operations, plus a proposed 5-year post-injection period. Table 10 of the MRV plan, which has been reproduced below, provides a summary of potential leakage pathway(s) and

their respective monitoring methods.

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed H_2S monitors throughout the AGI facility
	Daily visual inspections
	Personal H_2S monitors
	Distributed Control System Monitoring (Volumes and Pressures)
Leakage through existing wells	Fixed H_2S monitor at the AGI well
	SCADA Continuous Monitoring at the AGI Well
	Annual Mechanical Integrity Tests ("MIT") of the AGI Well
	Visual Inspections
	Quarterly CO_2 Measurements within AMA
Leakage through groundwater wells	Annual Groundwater Samples on Property
Leakage from future wells	H_2S Monitoring during offset drilling operations
Leakage through faults and fractures	SCADA Continuous Monitoring at the AGI Well (volumes and pressures)
	Fixed In-field H_2S monitors
Leakage through confining layer	SCADA Continuous Monitoring at the AGI Well (volumes and pressures)
	Fixed In-field H_2S monitors
Leakage from natural or induced seismicity	Seismic monitoring station to be installed

SCADA – Supervisory control and data acquisition

4.1 Detection of Leakage through Surface Equipment

As described in section 5 of the MRV plan, the H_2S in the injectate serves as a proxy for the release of CO_2. The MRV plan states that the 30-30 Facility and the Rattlesnake AGI #1 well are designed to handle H_2S through a facility design that minimizes leak points and corrosion points. Therefore, the MRV plan states that CO_2 leakage from surface equipment is unlikely to occur and would be quickly detected and addressed if it does occur. 30-30 and the Rattlesnake AGI #1 well site contain numerous H_2S alarms, set with a high alarm setpoint of 10 ppm of H_2S. Additionally, all 30-30 field personnel are required to wear H_2S monitors, which trigger the alarm at 5 ppm H_2S.

The MRV plan also states that 30-30 is continuously monitored through automated systems. Field personnel also conduct daily visual field inspections of gauges, monitors and leak indicators such as vapor plumes. The plan explains that the effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system, analysis of liquids collected from the system, and inspection of the cathodic protection system. The MRV plan states that these inspections, in addition to the automated systems, will allow 30-30 to quickly respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Should leakage be detected, 30-30 will calculate the volume of CO_2 released based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5). The MRV plan states that the mass of any CO_2 released through surface leakage would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak.

Thus, the MRV plan provides adequate characterization of 30-30's approach to detect potential leakage through surface equipment as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage from Wells within the Monitoring Area

As described in section 5 of the MRV plan, 30-30 continuously monitors and collects injection volumes, pressures, temperatures and gas composition data, through their SCADA systems, for the Rattlesnake AGI #1 well. Rattlesnake AGI #1 has a pressure and temperature gauge placed in the injection stream at its wellhead, and a pressure gauge on the casing annulus. The MRV plan states that a change to the pressure on the annulus would indicate the presence of a possible leak. The MRV plan states that these data are reviewed by qualified personnel and will follow response and reporting procedures when data are outside acceptable performance limits. Furthermore, MITs performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated and the leak mitigated.

The MRV plan states that the ten offset penetrating wells within the MMA are adequately cased and cemented to prevent potential leakage of CO_2 from the Rattlesnake AGI #1 well plume. Additionally, the plan states that the plugging of these wells was executed in a way to prevent migration. Details on these procedures are provided in Appendix E of the MRV plan. As discussed in the MRV plan, TRRC Rule 13 would ensure that new wells in the field would be constructed in a manner to prevent migration from the injection interval.

In addition to the fixed and personal monitors described previously, 30-30 will also establish and operate an in-field monitoring program to detect any CO_2 leakage within the AMA. This will include H_2S and CO_2 monitoring at the AGI well site as well at a minimum, quarterly atmospheric monitoring near identified penetrations within the AMA. Upon approval of the MRV and through the post-injection monitoring period, 30-30 will have these monitoring systems in place. Additional monitoring will be added as the AMA is updated over time.

The MRV plan states that, at the well site, H_2S and CO_2 concentrations will be monitored continuously with fixed monitors that detect atmospheric concentrations of H_2S and CO_2. At penetrating well sites, 30-30 will similarly measure atmospheric concentrations of CO_2 and H_2S using mobile gas monitors. This data will be recorded at least quarterly.

According to the MRV plan, 30-30 will also monitor the groundwater quality in fluids above the confining interval by sampling the well on the facility property and analyzing the sample with a third-party laboratory on an annual basis. Any significant changes to the water analysis would be investigated to determine if such change was a result of leakage from the Rattlesnake AGI #1 well. The parameters to be measured will include pH, total dissolved solids, total inorganic and organic carbons, density, temperature and other standard laboratory measurements. Any significant differences in these parameters from the baseline sample will be evaluated to determine if leakage of CO_2 to the USDW may have occurred.

Thus, the MRV plan provides adequate characterization of 30-30's approach to detect potential leakage through existing and future wells as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage Through Faults or Fractures

As described in section 5 of the MRV plan, 30-30 continuously monitors the operations of the Rattlesnake AGI #1 well through automated systems. The MRV plan states that any deviation from normal operating conditions indicating movement into a potential pathway such as a fault or breakthrough of the confining seal would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. Field H_2S monitoring systems would alert field personnel for any release of H_2S/CO_2 caused by such leakage.

Thus, the MRV plan provides adequate characterization of 30-30's approach to detect potential leakage through faults and fractures as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage through Confining Layers

As described in section 5 of the MRV plan, 30-30 plans to use SCADA continuous monitoring at the Rattlesnake AGI #1 well in order to keep track of gas volumes and pressures that might be lost due to leakage through the confining seal. Furthermore, the MRV plan states that fixed H_2S monitors will be used to detect and monitor potential leakage through the confining seal. Any deviation from normal operating conditions indicating a breakthrough of the confining seal would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. Field H_2S monitoring systems would alert field personnel for any release of H_2S/CO_2 caused by such leakage.

Thus, the MRV plan provides adequate characterization of 30-30's approach to detect potential leakage through the confining layers as required by 40 CFR 98.448(a)(3).

4.5 Detection of Leakage from Natural or Induced Seismicity

As described in section 5 of the MRV plan, 30-30 plans to install a seismic monitoring station in the general area of the Rattlesnake AGI #1 well. The installation of this station would start upon approval of the MRV plan, with an expected in-service date within six months after the commencement of the installation project. This monitoring station will be tied into the Bureau of Economic Geology's TexNet Seismic Monitoring Dystem. If a seismic event of 3.0 magnitude or greater is detected, 30-30 will review the injection volumes and pressures at the Rattlesnake AGI #1 well to determine if any significant changes occurred that would indicate potential leakage. Additionally, continuous well monitoring combined with seismic monitoring will identify any operational anomalies associated with a seismicity event.

Thus, the MRV plan provides adequate characterization of 30-30's approach to detect potential leakage through natural or induced seismicity as required by 40 CFR 98.448(a)(3).

4.6 Determination of Baselines and Quantification of Potential CO_2 Leakage

Section 6 of the MRV plan outlines 30-30's methodology for determining expected baselines for monitoring CO_2 surface leakage. 30-30 will use the existing SCADA monitoring systems to identify changes from expected performance that may indicate leakage of CO_2. The MRV plan states that the mass of any CO2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak.

Visual Inspections

The MRV plan states that daily inspections will be conducted by field personnel at the 30-30 facility and the Rattlesnake AGI #1 well. These inspections will aid with identifying and addressing issues timely to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions would be taken to address such issues.

H_2S Detection

The MRV plan implies that known H_2S concentrations of the injectate will be used to determine expected leakage relative to established baselines. As stated in the MRV plan, H_2S will be initially injected into the AGI well at a concentration of approximately ten (10) percent or 100,000 ppm. The concentration will drop to approximately seven percent as additional volumes are added. H_2S gas detectors are located throughout the AGI facility and well site and are set to trigger the alarm at 10 ppm. Additionally, all field personnel are required to wear personal H_2S monitors, which are set to trigger the alarm at 5 ppm. Any alarm would trigger an immediate response to protect personnel and verify that the monitors are working properly.

CO_2 Detection

The MRV plan states that any CO_2 release would be accompanied by H_2S, therefore, the H_2S monitors at the facility would also serve as a CO_2 release warning system. In addition to the fixed and personal monitors described previously, 30-30 states that it will also establish and operate an in-field monitoring program to detect any CO_2 leakage within the AMA and MMA. This will include H_2S and CO_2 monitoring at the AGI well site as well as atmospheric monitoring near identified penetrations within the AMA.

Operational Data

The MRV plan explains that upon starting injection operations, baseline measurements of injection volumes and pressures will be taken. Any significant deviations over time will be analyzed for indication of potential leakage of CO_2.

Continuous Monitoring

The MRV plan states that the mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which would be extremely dangerous for personnel to perform a direct leak survey. Any leakage would be detected and managed as per Texas regulations and 30-30's TRRC approved H_2S Contingency Plan. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. 30-30 notes that this method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation. The MRV plan states that no CO_2 emissions should occur from venting because of the high H_2S concentrations. Blowdown emissions are sent to flares and would be reported as part of the required reporting for the gas plant.

Groundwater Monitoring

The MRV plan states that an initial groundwater sample will be taken from the groundwater well on 30-30 property and analyzed by a third-party laboratory upon the MRV plan's approval to establish the baseline properties of the groundwater.

Given the methodologies listed above, 30-30 provides an acceptable approach for establishing CO_2 leakage monitoring baselines in accordance with 40 CFR 98.448(a)(4).

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

5.1 Calculation of Mass of CO_2 Received

According to the MRV plan, the CO_2 received for this injection well will be wholly injected and not mixed with any other supplies of CO_2, thus the annual mass of CO_2 injected will equal the quantity of CO_2 received at the receiving flow meter. Therefore, in accordance with 40 CFR §98.444(a)(4), 30-30 will use the mass of CO_2 injected as the mass of CO_2 received instead of using Equation RR-1 or RR-2.

30-30's approach to calculating the mass of CO_2 received is acceptable for the Subpart RR requirements.

5.2 Calculation of Mass of CO_2 Injected

Section 7 of the MRV plan states that the mass of CO_2 injected will be calculated using Equation RR-5 in accordance with 40 CFR §98.444(b). The flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, as follows:

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

Where:

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

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

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

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

p = Quarter of the year

u = Flow meter.

30-30 provides an acceptable approach to calculating the mass of CO_2 injected in accordance Subpart RR requirements.

5.3 Mass of CO_2 Produced

The MRV plan states that the Rattlesnake AGI #1 well is not part of an enhanced oil recovery project, thus no CO_2 will be produced.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

The MRV plan states that the mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which would be extremely dangerous for personnel to perform a direct leak survey. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

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

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

Where:

CO_2 = 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

The MRV plan states that calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

30-30 provides an acceptable approach for calculating the mass of CO_2 emitted by surface leakage under the Subpart RR requirements.

5.5 Calculation of Mass of CO_2 Sequestered

The MRV plan states that the mass of CO_2 sequestered in subsurface geologic formations will be calculated based off Equation RR-12, as this well will not actively produce oil or natural gas or any other fluids, as follows:

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

Where:

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

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

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

The plan further states that CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting would occur due to the high H_2S concentrations of the injectate stream, the calculations would be based on the blowdown emissions that would be sent to flares and would be reported as part of the required GHG reporting for the gas plant.

The plan also states that calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

30-30 provides an acceptable approach for calculating the mass of CO_2 sequestered under Subpart RR.

Overall, 30-30 provides an acceptable approach for the considerations used to calculate site-specific variables for the mass balance equation as required by 98.448(a)(5).

6 Summary of Findings

The Subpart RR MRV plan for the 30-30 Facility meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448, which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the MRV plan.

Subpart RR MRV Plan Requirement	30-30 MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 3 of the MRV plan describes the MMA and AMA. 30-30 used CMG's GEM numerical simulation software to determine the areal extent and density drift of the CO_2 plume. Numerical simulation was also used by 30-30 to predict the size and drift of the CO_2 plume. 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. The AMA is based on the superimposition of a one-half mile buffer around the anticipated plume location at the end of injection in 2036 and the area of projected free-phase CO_2 plume after 5 additional years.

40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 4 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: leakage from surface equipment, leakage through existing wells within the MMA, leakage through faults and fractures, leakage through natural or induced seismicity, leakage from drilling through the MMA, and leakage through the confining layer. The MRV plan analyzes the likelihood, magnitude, and timing of potential surface leakage through these pathways.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 5 of the MRV plan describes strategies for how the facility would detect CO_2 leakage to the surface, such as H_2S monitors, visual inspections, and SCADA continuous monitoring of the Rattlesnake AGI #1 well. Section 4 of the MRV plan describes a strategy for how potential surface leakage would be quantified.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 6 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage. 30-30 will use visual inspections, H_2S detection, CO_2 detection, operational data, continuous monitoring, and groundwater monitoring to establish baselines for monitoring potential CO_2 surface leakage.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 7 of the MRV plan describes 30-30's approach to determining the amount of CO_2 sequestered using the Subpart RR mass balance equation, including as related to calculation of total annual mass emitted from equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 1 of the MRV plan provides well identification number for the Rattlesnake AGI #1 well. The MRV plan specifies that the Rattlesnake AGI #1 well has been issued a UIC Class II permit under TRRC Rule 9 and Rule 36.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 8 of the MRV plan states that the 30-30 facility baseline measurements of injection volumes and pressures will be taken upon implementation of this MRV plan. 30-30 will implement the MRV plan upon receiving EPA approval.

Appendix A: Final MRV Plan

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Rattlesnake AGI #1

Yoakum County, Texas

Prepared for *Stakeholder Gas Services, LLC*
San Antonio, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 3
September 2022

INTRODUCTION

Stakeholder Gas Services, LLC ("Stakeholder") currently has a Class II acid gas injection ("AGI") permit, issued by the Texas Railroad Commission ("TRRC") in November 2018, for the Rattlesnake AGI #1 well, API No. 42-501-36998. This permit was originally issued to Santa Fe Midstream Permian, LLC, in 2018 and the asset was subsequently acquired by Stakeholder in December of 2020. This permit currently authorizes Stakeholder to inject up to 4,500 barrels per day ("bbls/d") of treated acid gas ("TAG") into the Devonian formation at a depth of 11,000' to 12,000' with a maximum allowable surface pressure of 2,200 psi. Since being permitted, injection has proceeded without incident. This AGI well is associated with Stakeholder's 30-30 gas treating and processing plant ("30-30") located in a rural, sparsely populated area of Yoakum County, Texas, approximately seven miles northwest of the town of Plains, as shown in Figure 1.

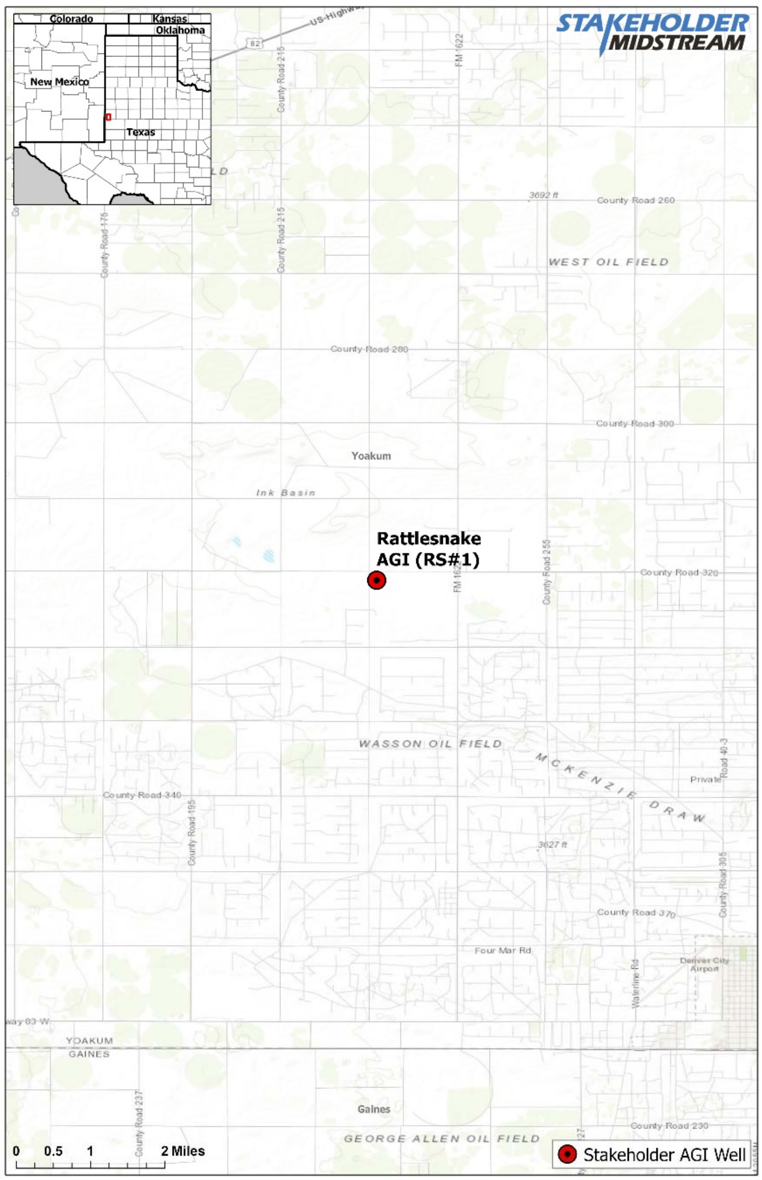

Figure 1 – Location of Rattlesnake AGI #1 Well

Stakeholder is submitting this Monitoring, Reporting, and Verification ("MRV") plan to the EPA for approval under 40 CFR §98.440(a), Subpart RR, of the Greenhouse Gas Reporting Program ("GHGRP"). In addition to submitting this MRV plan to the EPA, Stakeholder is also applying to the TRRC for an amendment to the Rattlesnake AGI #1 well's Class II permit to increase its authorized injection volume and maximum allowable surface injection pressure ("MASIP"). Approval of the permit amendment will allow Stakeholder to increase the capacity of its existing 30-30 Facility, which removes H_2S and CO_2 from natural gas production using amine treating, as well as increase the injection well capacity for a future gas processing facility which is currently under development by Stakeholder. Additionally, expanded capacity allows Stakeholder to potentially provide future disposal in its AGI well for oil and gas waste derived TAG from similar third-party gas processing facilities. Increased disposal capacity will allow for greater gas processing capacity in the region, ultimately helping to reduce flaring and its associated emissions. Throughout this document, both in written reference and in modeling inputs, Stakeholder has used the applied-for expanded permit capacity of 16 million standard cubic feet per day ("MMSCF/d"). Stakeholder plans to inject CO_2 for approximately 14 more years.

ACRONYMS AND ABBREVIATIONS

‘	Feet
%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group’s GEM 2020.11
GHGs	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program
H_2S	Hydrogen Sulfide
md	Millidarcy(ies)
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMCF	Million Cubic Feet
MMSCF	Million Standard Cubic Feet

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

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SECTION 1 – FACILITY INFORMATION

This section contains key information regarding the Acid Gas and CO_2 injection facility.

Reporter number:

- Gas Plant Facility Name: 30-30 Gas Plant
- Greenhouse Gas Reporting Program ID: 574501
    - Currently reporting under Subpart UU
- Operator: Stakeholder Gas Services, LLC

Underground Injection Control (UIC) Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control ("UIC") Class II program. TRRC classifies the Rattlesnake AGI #1 well as a UIC Class II well. A Class II permit was issued to Stakeholder under TRRC Rule 9 (entitled "Disposal into Non-Productive Formations") and Rule 36 (entitled "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas").

UIC Well Identification Number:

Rattlesnake AGI #1, API No. 42-501-36998, UIC #000117143.

SECTION 2 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection volumes and process, and the reservoir modeling performed for the Rattlesnake AGI #1 well. The Class II UIC permit was initially applied for and received by Santa Fe Midstream Permian, LLC. The asset was acquired in 2020 by Stakeholder and has been in operation since that time. Since the original application, Lonquist has revised and updated the geology and the plume modeling within the reservoir in preparing this MRV Plan.

The Rattlesnake AGI #1 well is located and designed to protect against migration of CO_2 out of the injection interval and to prevent surface releases. The injection interval for Rattlesnake AGI #1 is located over 4,720' below the primary producing formation, the San Andres, in the area and 8,593' below the base of the lowest useable quality water table, as shown in Figure 2. This well injects both H_2S and CO_2, therefore the well and the facility are designed to minimize any leakage to the surface.

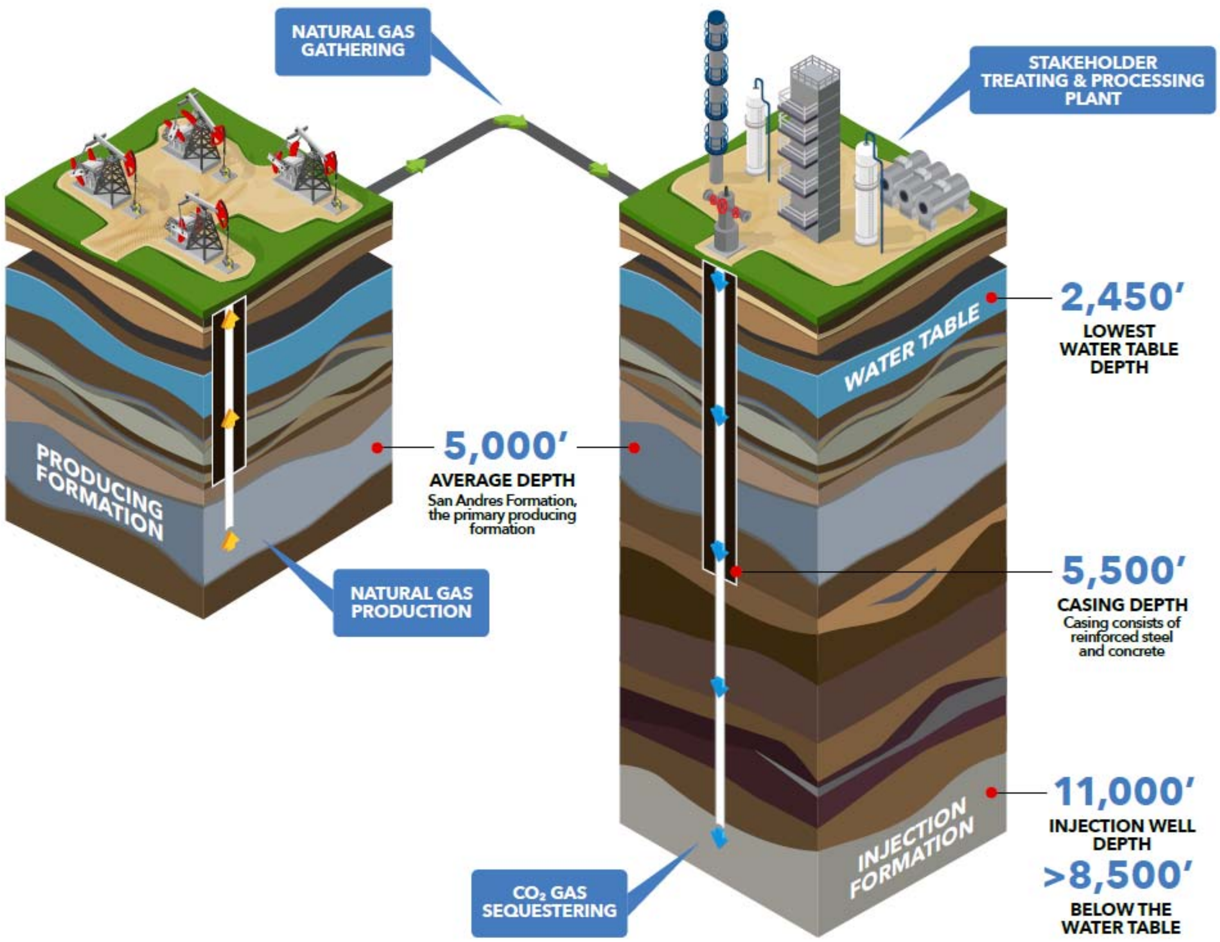


Figure 2 – Illustrative overview of Rattlesnake AGI #1 and 30-30 Facility

Regional Geology

The Rattlesnake AGI #1 well is located on the southern portion of the Northwestern Shelf within the larger Permian Basin as seen in Figure 3. The Northwestern Shelf is a broad marine shelf located in the northern portion of the Permian Basin.

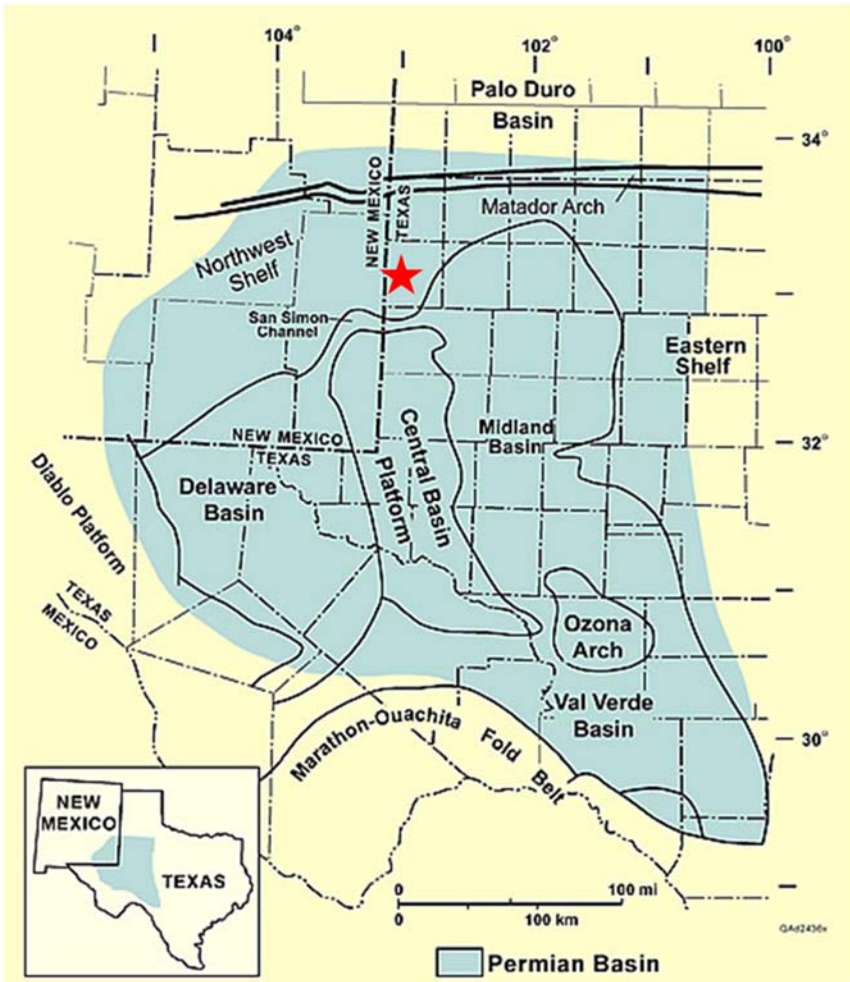


Figure 3 – Regional Map of the Permian Basin. Red Star is approximate location of Rattlesnake AGI #1 well

Figure 4 depicts the stratigraphic column found at the Rattlesnake AGI #1 well location with red stars referencing the injection formation and green stars indicating the productive intervals in the area. The primary injection interval is found within the Wristen group, of Silurian-age, as seen in Figure 5. The TRRC refers to this sequence under the general terms "Devonian", "Silurian-Devonian" or "Siluro-Devonian".

Period	Epoch	Formation	General Lithology
Permian	Ochoan	Dewey Lake	Redbeds/Anhydrite
		Rustler	Halite
		Salado	Halite/Anhydrite
	Guadalupian	Tansil	Anhydrite/Dolomite
		Yates	Anhydrite/Dolomite
		Seven Rivers	Dolomite/Anhydrite
		Queen	Sandy Dolomite/Anhydrite/Sandstone
		Grayburg	Dolomite/Anhydrite/Shale/Sandstone
	Leonardian	★ San Andres	Dolomite/Anhydrite
		Glorieta	Sandy Dolomite
		Yeso: Paddock	Dolomite/Anhydrite/Sandstone
		Yeso: Blinebry	
		Yeso: Tubb	
		Yeso: Drinkard	
		Abo	Dolomite/Anhydrite/Shale
	Wolfcampian	★ Wolfcamp	Limestone/Dolomite
Pennsylvanian	Virgilian	Cisco	Limestone/Dolomite
	Missourian	Canyon	Limestone/Shale
	Des Moinesian	Strawn	Limestone/Sandstone
	Atokan	Bend	Limestone/Sandstone/Shale
	Morrowan	Morrow	
Mississippian		Mississippian Lime	Limestone
Devonian		Woodford	Shale
Silurian		★ Wristen Group	Dolomite/Limestone
		★ Fusselman	Dolomite/Chert
Ordovician	Upper		
		Montoya	Dolomite/Chert
	Middle	Simspson Gp	Limestone/Sandstone/Shale
	Lower	Ellenburger	Dolomite

Figure 4 – Stratigraphic column of the Northwest Shelf. Red stars indicate injection interval. Green stars indicate productive intervals.

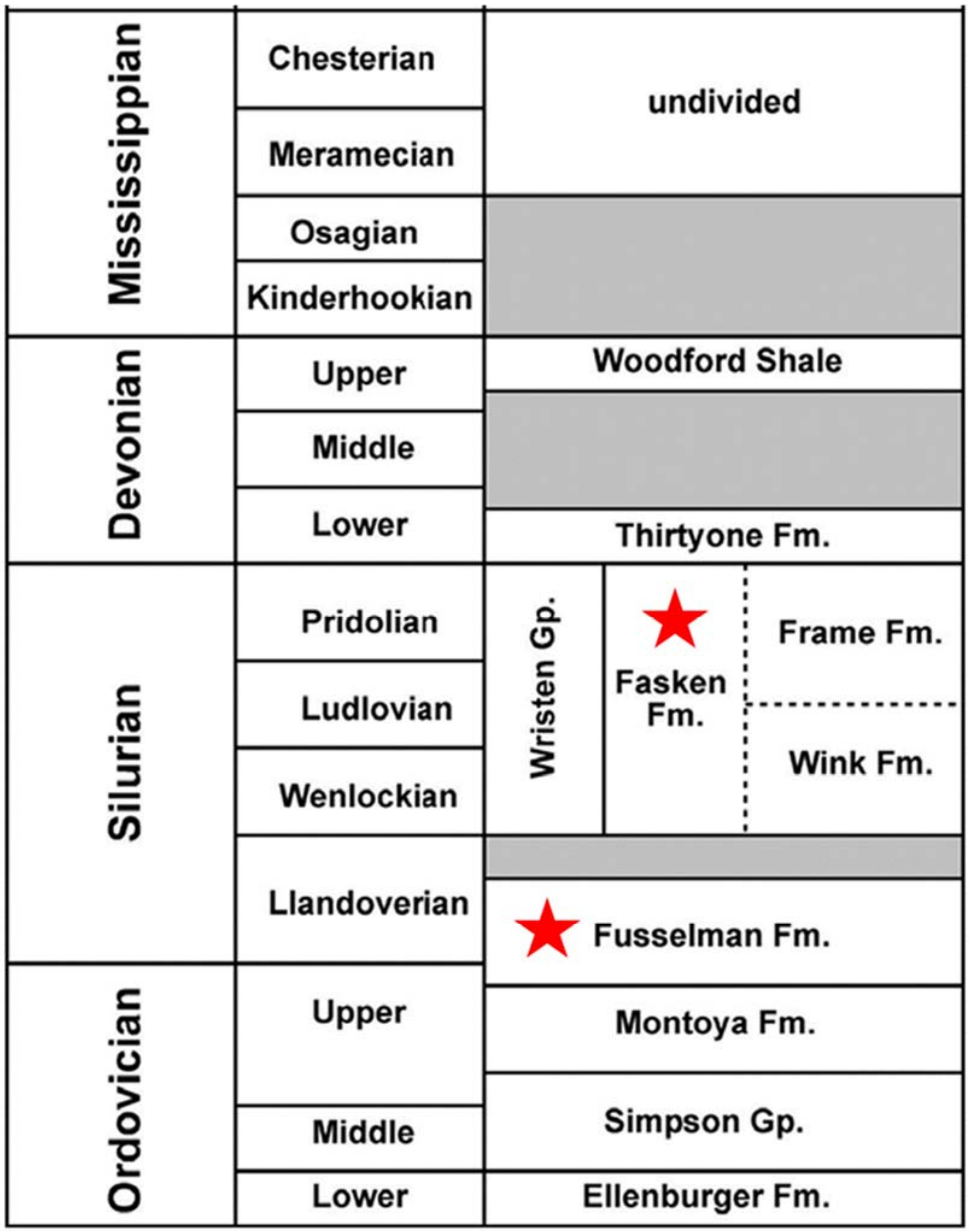


Figure 5 – Stratigraphic column depicting the composition of the Silurian group. Red star indicates injection interval (Broadhead, 2005)

The Wristen group was deposited in a basin platform setting across the northern half of the Permian Basin. The depositional environment over Yoakum County during the Silurian period was a shallow inner platform, the margin of which exists to the south, in southern Andrews County, Texas. The Silurian-age lithology on the inner platform is dominated by grain-rich skeletal carbonates. Carbonate buildups are common within the shallow inner platform, mainly skeletal wackestone, indicating a lower-energy deposition on the inner platform. The carbonate shelf margin to the south acted as a barrier from basin-ward wave energy (Ruppel and Holtz, 1994).

Depositional cycles within the inner platform indicate it was controlled by episodic sea level rise and fall, resulting in sub-areal exposure and diagenesis. The diagenesis of the Silurian-age carbonate rocks initiated

secondary porosity development and increased permeability. Dolomite and solution-related features are the most prominent diagenetic characteristics found within the Silurian. The Wristen Group is composed of three formations: Fasken, Frame, and Wink formations. The Frame and Wink formations are found near the ramp boundary to the south, while the Fasken formation is found predominantly in the inner platform, where the Rattlesnake AGI #1 well is located. The Fasken formation is predominately dolomite grading to limestone, occurring as cycles, down section. This dolomitization is due in part to sub-areal exposure, during which karsts and secondary porosity developed. Additional dolomitization was possible during successive sea level fluctuations via movement of magnesium-rich solution through karsts and vugs, which acted as channels for fluid flow (Ruppel and Holtz, 1994).

Figure 6 shows a regional isopach map of the Silurian (combined Fasken and Fusselman formations) with a red star depicting the Rattlesnake AGI #1 well location. Thickness of the Silurian-age rock is approximately 1,000’ at the Rattlesnake AGI #1 well location.

North of Andrews County there is little differentiation between the Fasken and Fusselman formations which are both carbonate deposits with the potential for sub-areal exposure and porosity development. For purposes of this MRV Plan, the combined Fasken and Fusselman formations are defined as the injection interval, and the underlying Montoya formation serves as the lower confining unit.

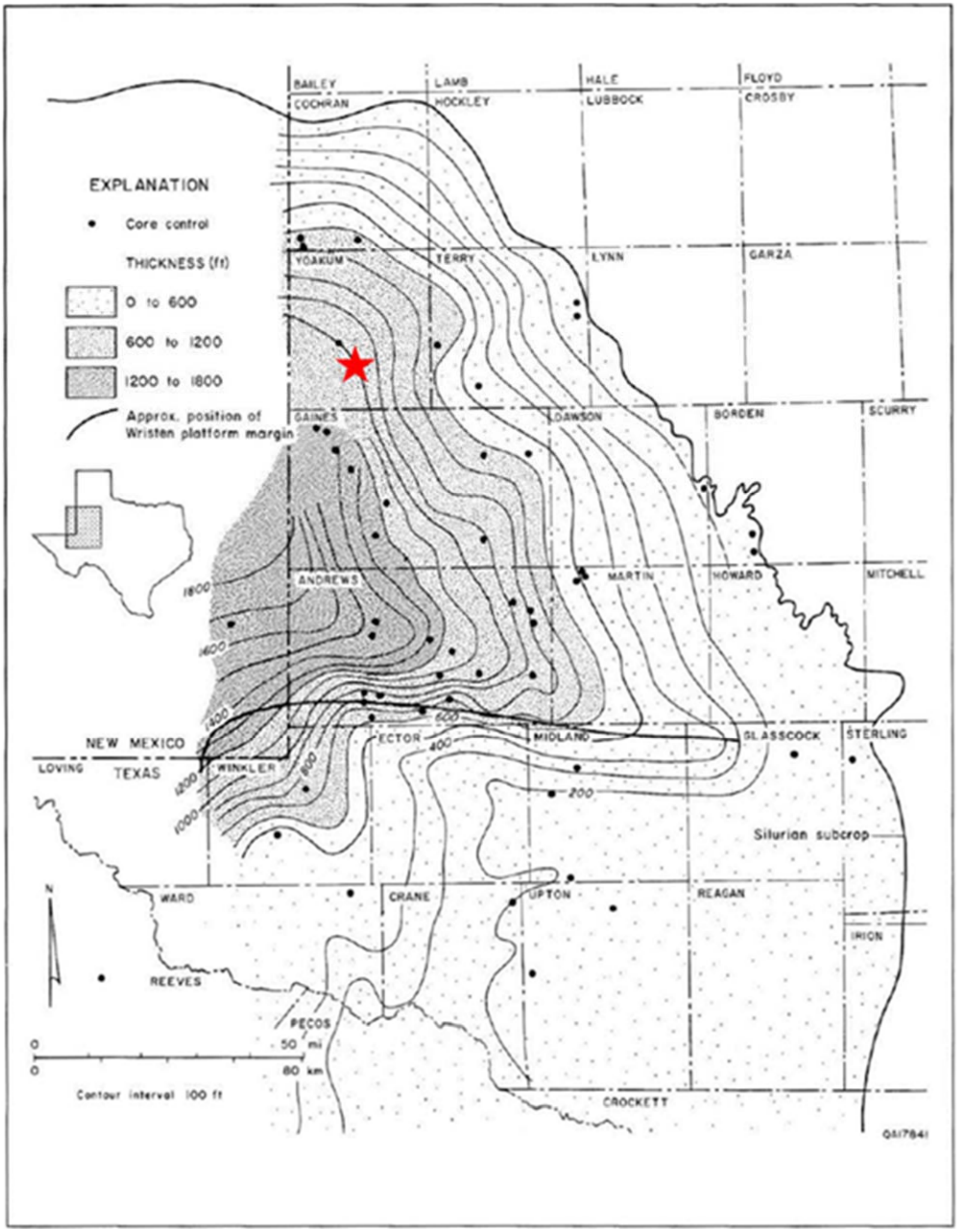


Figure 6 – Thickness map of the Silurian system which composes the Fusselman and Wristen group

Regional Faulting

A major uplift that began during the Pennsylvanian Period to the south, the Central Basin Platform, ceased in the Early Permian (Wolfcampian), which caused a regional unconformity of the underlying formations (Hoak, Sundberg, and Ortoleva). Faulting on the Northwest Shelf can be seen through high angle basement faults that tend to die within the Pennsylvanian strata. These faults predominately represent contractional (thrust) faults that were initiated during the Pennsylvanian as a result of regional tectonics. Hydrocarbon traps within the Wristen group are primarily anticlinal structures dependent upon reservoir development (Broadhead, 2005).

Site Characterization

The Rattlesnake AGI #1 well is located in Section 733, Block D, John H. Gibson Survey, in Yoakum County, Texas. Stakeholder owns the 82.42-acre surface tract where the plant and Rattlesnake AGI #1 well are located. The following discusses the geological character of this site.

Stratigraphy and Lithologic Characteristics

Figure 7 depicts an open hole log from an offset well (API No. 42-501-10238) to the Rattlesnake AGI #1 well indicating the injection and primary upper confining zone. This well is approximately 1.8 miles to the northwest of the Rattlesnake AGI #1 well. An offset well log was used to depict the upper confining intervals as electric logs were only run in the Rattlesnake AGI #1 well across the injection zone.

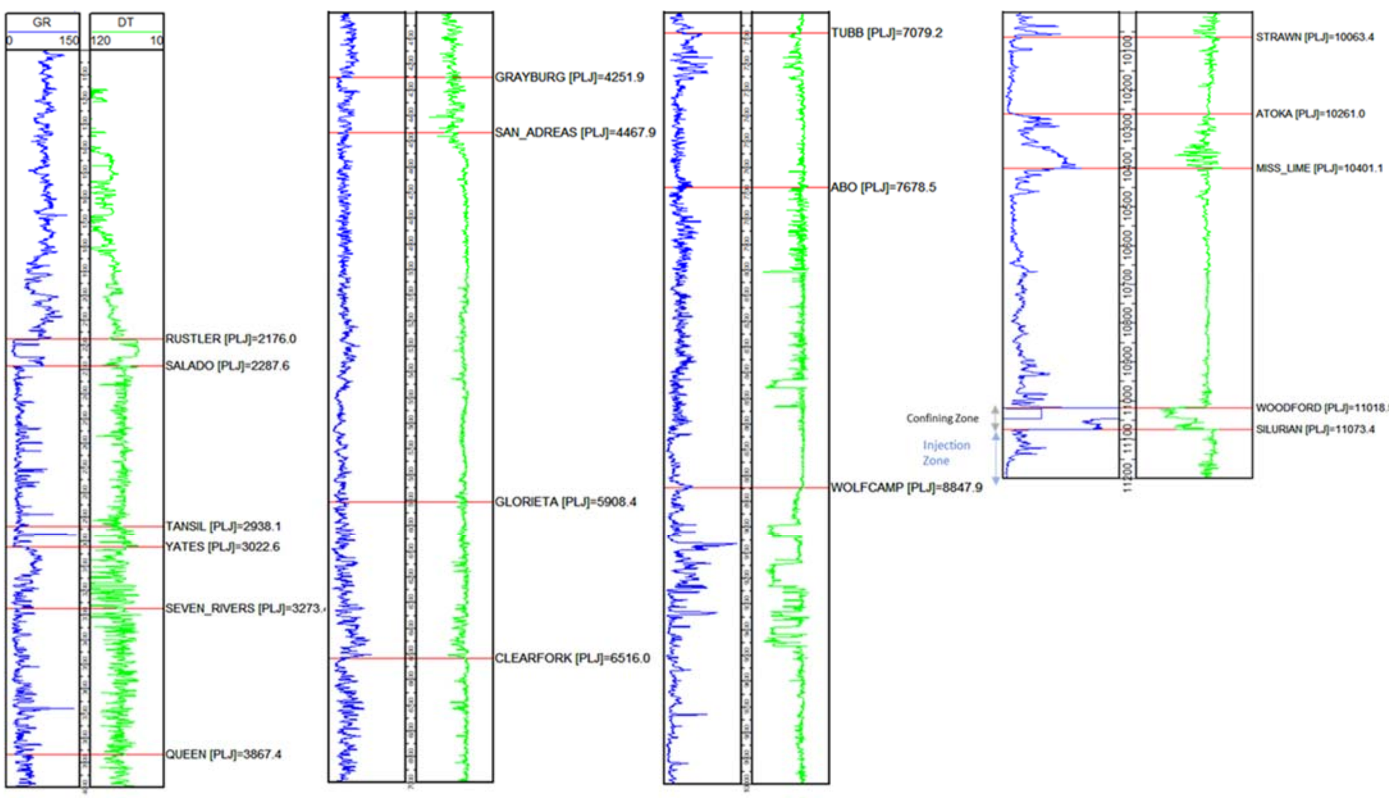


Figure 7 – Type Log (42-501-10238) with tops, confining and injection zones depicted

Upper Confining Interval - Woodford Shale

The Woodford is a late Devonian-age organic-rich shale deposited as a result of a widespread marine transgression. The flooding event occurred over the majority of the Permian basin, which produced a low-relief blanket-like shale deposit of the Woodford. Two major lithofacies found within the Woodford are black shale and siltstone. Nutrient-rich surface waters promoted the decay of abundant organic matter within the Woodford, resulting in a high total organic carbon ("TOC") percentage. The Woodford shale acts as the primary source and sealant rock for the Wristen Group (Comer, 1991).

Figure 8 is a description of a core sample taken in Lea County, New Mexico just southwest of the Rattlesnake AGI #1 well location. This sample is referenced as C9 in the reference map with the blue star representing the Rattlesnake AGI #1 well. In the core description, black shale with abundant illitic clays is observed in the upper section, and medium gray dolomitic siltstone found in the basal section. The mineralogic and lithologic properties recorded in this description serve as excellent sealant characteristics to prohibit any injected fluids from migrating above the injection interval.

The Woodford at the Rattlesnake AGI #1 well location is encountered at 10,973 ft and is approximately 63 ft thick.

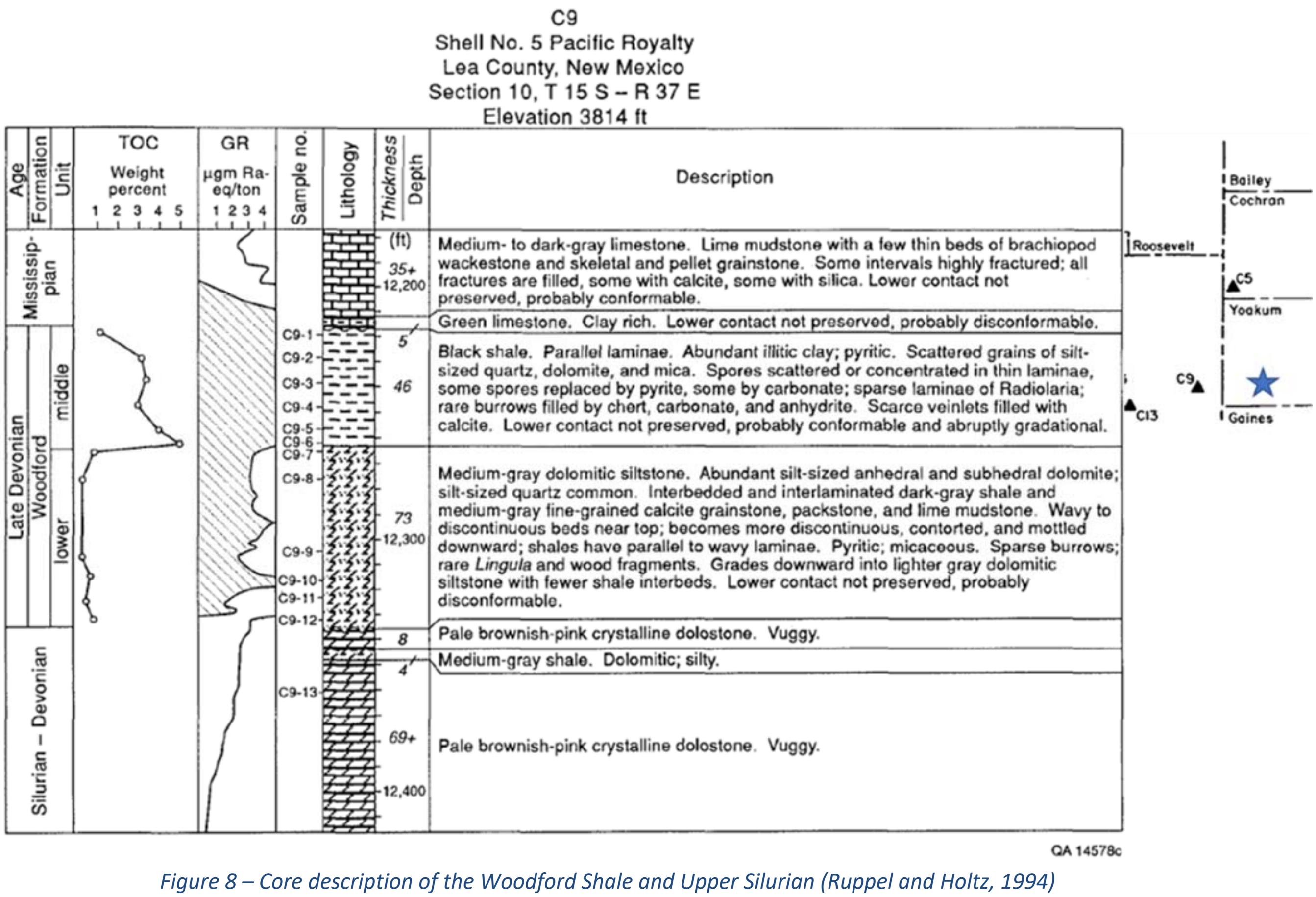


Figure 8 – Core description of the Woodford Shale and Upper Silurian (Ruppel and Holtz, 1994)

Injection Interval – Fasken Formation

The Rattlesnake AGI #1 well reaches total depth in the Fasken/Fusselman formation (Silurian in age), directly below the Woodford formation. Dolomites at the top of the Fasken formation underwent multiple leaching and diagenetic episodes which developed secondary porosity. This is evidenced in offset wells by the practice of only drilling through the top 30’ of the Fasken, in anticipation of encountering the best reservoir quality. In Figure 8, the uppermost Silurian section is described as ‘vuggy dolostone’ in the core description. Beds below the top of the Fasken section may also have similar petrophysical attributes if exposed to multiple diagenetic events. Solution-collapse and karst breccia horizons can be found within inner platform deposits, some occurring as much as 100 ft below the Fasken top (Ruppel and Holtz, 1994).

<u>Porosity/Permeability Development</u>

Porosity in the Fasken formation at the Rattlesnake AGI #1 well location is typically moldic and intercrystalline associated with leaching of allochem-rich intervals. Porosity is directly related to these leaching events which occurred during and post-deposition, resulting in vugs and karst-like features. Figure 9 provides reservoir information from core data within fields in the Wristen buildup and platform carbonate play. The average porosity of these cores is 7.1% with an average permeability of 45.28 millidarcies (Ruppel and Holtz, 1994). The porosity and permeability described in the offset core data indicate the Fasken formation provides sufficient accessible pore space for the amount of fluid injection proposed.

Using the above values as reference points, the Rattlesnake AGI #1 porosity log (API No. 42-501-36998) was evaluated. Figure 10 is the product of the petrophysical analysis performed on the open hole logs run within the injection interval at the Rattlesnake AGI #1 well. A permeability curve was generated from the effective porosity curve using the table in Figure 9 to establish the porosity-permeability relationship. In Figure 10, the majority of the injection interval’s porosity and permeability is found at the top of the Fasken formation, which correlates with the diagenetic processes described above. These curves are extrapolated to the injection site and used to establish reservoir characteristics in the plume model.

	Fusselman Shallow Platform Carbonate play	Wristen Buildups and Platform Carbonate play	Thirtyone Ramp Carbonate play	Thirtyone Deep-Water Chert play
		Porosity (%)		
Number of data points	33	30	16	35
Mean	7.93	7.10	6.41	14.85
Minimum	1.00	2.70	3.50	2.00
Maximum	17.70	14.00	9.50	30.00
Standard deviation	4.01	2.67	1.75	6.76
		Permeability (md)		
Number of data points	21	24	12	33
Mean	11.61	45.28	1.51	8.56
Minimum	0.60	2.90	0.40	1.00
Maximum	84.80	400.00	30.00	100.00
Standard deviation	22.48	99.17	8.36	22.23
		Initial water saturation (%)		
Number of data points	24	28	10	31
Mean	26.96	31.55	24.70	31.46
Minimum	10.00	20.00	16.00	10.00
Maximum	50.00	55.00	40.00	45.00
Standard deviation	9.31	10.45	7.39	8.33
		Residual oil saturation (%)		
Number of data points	8	13	5	22
Mean	34.06	30.54	21.30	29.17
Minimum	30.00	20.00	9.00	14.00
Maximum	50.00	35.00	35.00	48.20
Standard deviation	6.99	4.61	11.66	9.76
		Oil viscosity (cp)		
Number of data points	11	12	5	21
Mean	0.69	1.16	0.33	0.68
Minimum	0.13	0.32	0.04	0.07
Maximum	1.08	2.00	1.00	1.03
Standard deviation	0.81	0.75	0.40	0.42
		Oil formation volume factor		
Number of data points	21	22	6	32
Mean	1.57	1.22	1.65	1.50
Minimum	1.05	1.05	1.31	1.30
Maximum	1.91	1.55	1.66	1.73
Standard deviation	0.28	0.14	0.48	0.16
		Bubble-point pressure (psi)		
Number of data points	9	9	5	19
Mean	2,272	1,055	3,750	2,752
Minimum	798	450	2,660	1,755
Maximum	4,050	2,600	4,440	4,656
Standard deviation	1,300	689	756	667

Figure 9 – Table of reservoir properties found within the Wristen buildups and platform plays (Ruppel and Holtz, 1994)

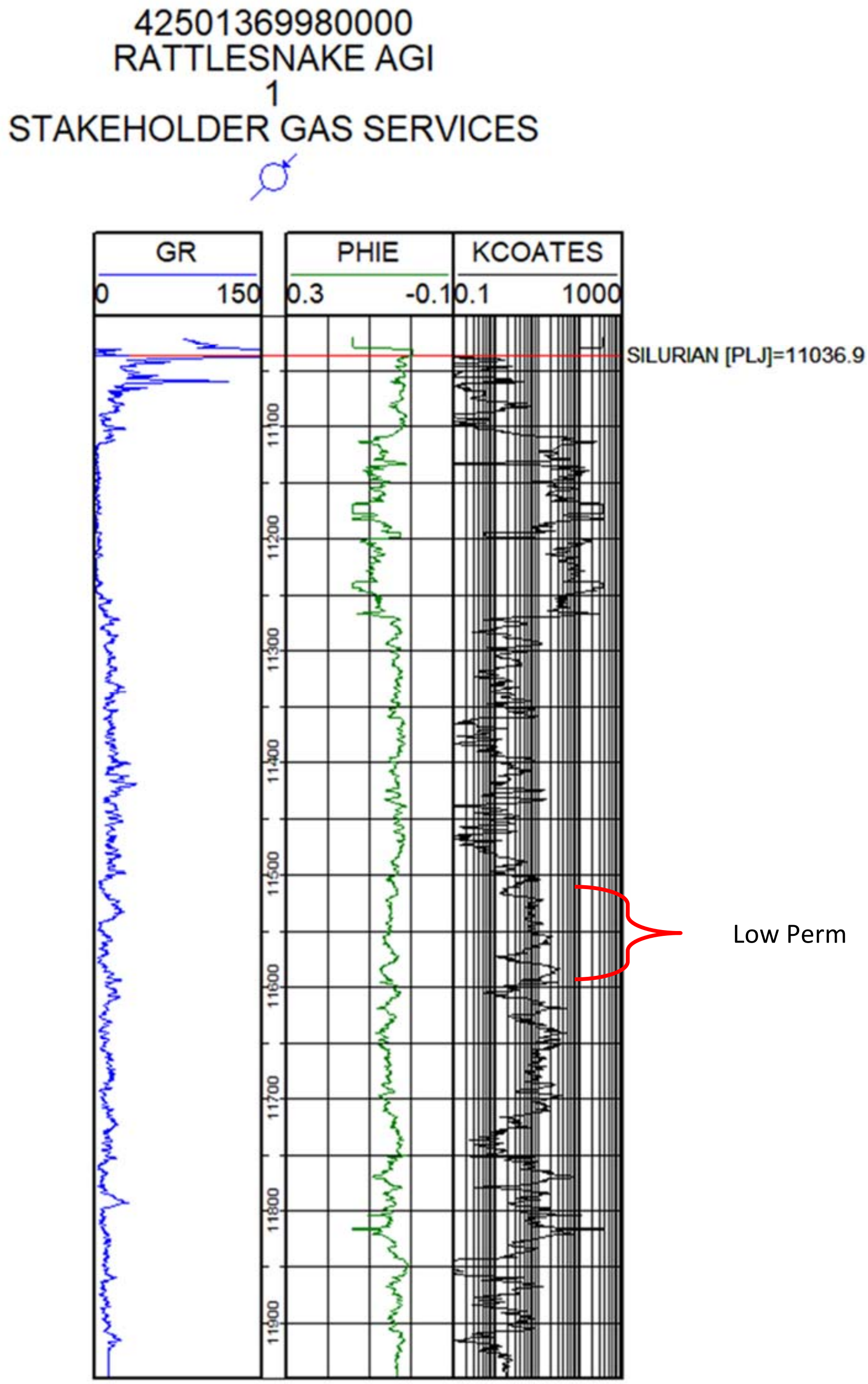


Figure 10 – Rattlesnake AGI #1 open hole log (42-501-36998) with effective porosity (green) and permeability (black)

Formation Fluid

Four wells were identified through a review of chemical analyses of oil-field brines from the U.S. Geological Survey National Produced Waters Geochemical Database v2.1 within the Devonian, Silurian-Devonian, or Fusselman formations within 20 miles of the Rattlesnake AGI #1 well. The location of these wells is shown in Figure 11. Water chemistry analyses conducted on oil-field brines in Gaines County, as reported to the Texas

Water Development Board, provided additional data on Devonian and Silurian reservoir fluids. Results from the synthesis of these two sources are provided in Table 1. The fluids have greater than 20,000 parts per million ("ppm") total dissolved solids, therefore these aquifers are considered saline. These analyses indicate the in-situ reservoir fluid of the Devonian, Silurian, and Fusselman formations are compatible with the proposed injection fluids.

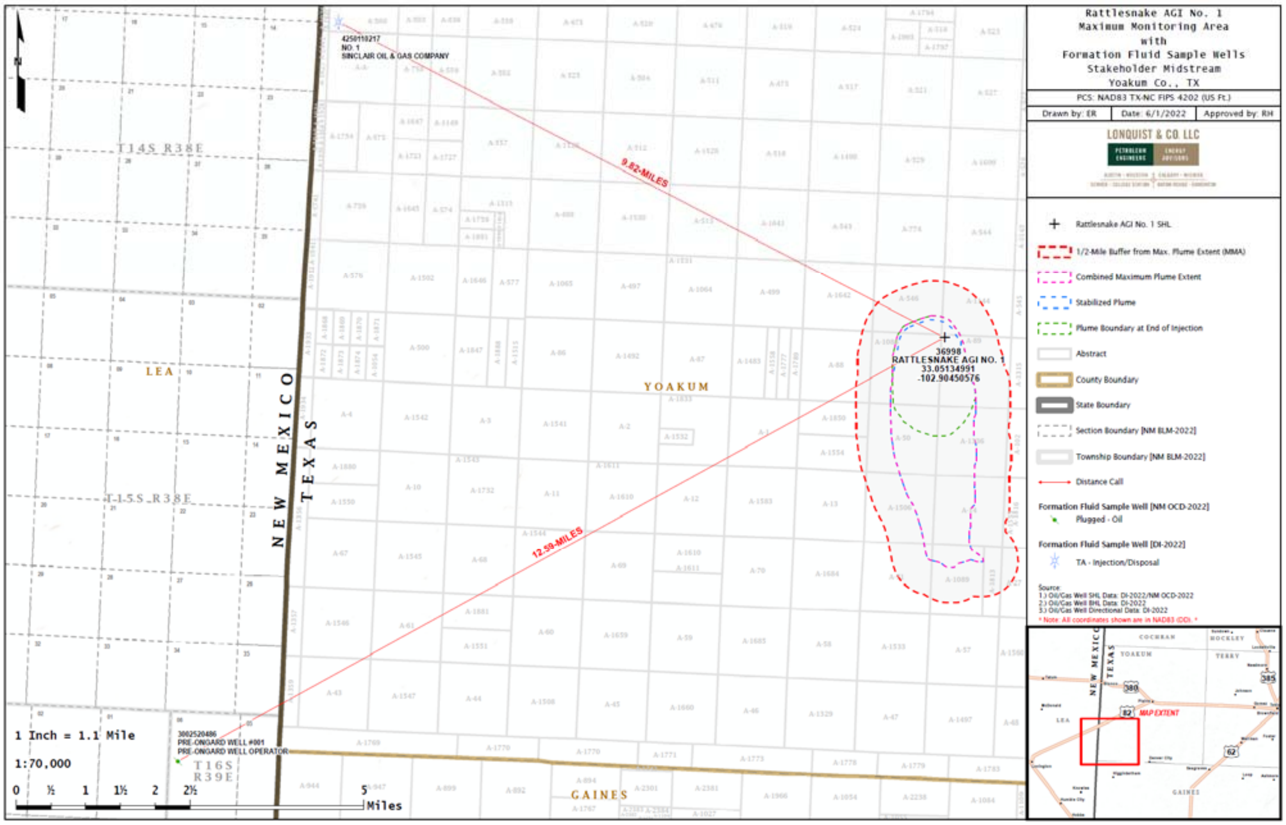


Figure 11 – Offset wells used for Formation Fluid Characterization

Table 1 – Analysis of Silurian-Devonian age formation fluids from nearby oil-field brine samples

	Average	Low	High
Total Dissolved Solids (ppm)	41,428	23,100	55,953
pH	7.2	7.0	7.3
Sodium (ppm)	12,458	7,426	15,948
Calcium (ppm)	1,759	1,010	2,320
Chlorides (ppm)	23,423	12,810	31,930

Fracture Pressure Gradient

Fracture pressure gradient was estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for the determination of fracture gradients. Poisson's ratio ("ν"), overburden gradient ("OBG"), and pore gradient ("PG") are all variables that can be changed to match the site-specific injection zone. Through literature review and industry standards, we are able to determine the expected

fracture gradient. First, 1.05 psi/ft and 0.465 psi/ft were assumed for both the overburden and pore gradients, respectively. These values are considered best practice values when there are no site-specific numbers available. For limestone/dolomite rock, the Poisson's ratio to be assumed to be 0.3 through literature review (Molina, Vilarras, Zeidouni 2016). Using these values in the equation below, a fracture gradient of 0.72 psi/ft was calculated. A 10% safety factor was then applied to this number resulting in maximum allowed bottom hole pressure of 0.64 psi/ft. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

For the upper confining interval, a similar fracture gradient as the limestone was calculated. Shale has an increased chance to vertically fracture if the injection interval is fractured (Molina, Vilarras, Zeidouni 2016), so assuming a Poisson's ratio equal to the injection interval was used as a conservative estimate. The lower confining zone was assumed to be of a similar matrix to that of the injection interval, with the key difference being that the formation is much tighter (lower porosity/permeability). The Poisson's ratio was assumed to be slightly higher in this rock. As seen in Table 2, the fracture gradient is slightly higher than the upper zones.

Table 2 – Fracture Gradient Assumptions

	Injection Interval	Upper Confining	Lower Confining
Overburden Gradient (psi/ft)	1.05	1.05	1.05
Pore Gradient (psi/ft)	0.465	0.465	0.465
Poisson's Ratio	0.30	0.30	0.31
Fracture Gradient psi/ft	0.72	0.72	0.73
FG + 10% Safety Factor (psi/ft)	**0.64**	**0.64**	**0.66**

The following steps were taken to calculate fracture gradient:

$$FG = \frac{\nu}{1 - \nu}(OBG - PG) + PG$$

$$FG = \frac{0.3}{1 - 0.3}(1.05 - 0.465) + 0.465 = 0.72$$

$$FG\ with\ SF = 0.72 \text{ x } (1 - 0.1) = \mathbf{0.64}$$

Lower Confining Zone – Montoya Formation

The low-permeability Montoya Formation is a tight limestone/dolomite that will act as the lower confining unit for the injection interval. Figure 10 shows the decreasing trend in porosity of the limestone rock in the lower section that was not exposed to leaching diagenesis. Porosity in the lower section can range from 2-3% with permeabilities below 1 millidarcy. The Rattlesnake AGI #1 well drilled 6' into the Montoya formation, but the section was not logged. The Montoya is anticipated to be roughly 250' thick. These petrophysical characteristics represent ideal sealing properties to prohibit any migration of injected fluid outside of the injection interval.

Local Structure

Regional structure in the area of the Rattlesnake AGI #1 well is dictated by carbonate buildups and structural events causing anticlinal to synclinal features throughout the area. The Rattlesnake AGI #1 well is specifically located at the base of a syncline with anticlinal features to the northeast, south, and east. Figure 12 is a

structure map of the Silurian formation of subsea depths with the star representing the location of the Rattlesnake AGI #1 well. The red and blue lines represent the cross-section reference lines.

Faulting can be seen to the south and east of the Rattlesnake AGI #1 well location. These faults were interpreted from roughly 9 square miles of 3D seismic indicated by the purple outline in Figure 12. Many of these faults are minor, with offsets less than 50'. The nearest large fault is found southeast of the Rattlesnake AGI #1 well and has an offset of roughly 120'. None of these faults project above the Wolfcamp formation, rather, they appear to terminate between the Strawn and base of the Wolfcamp formation. Production is associated with a hydrocarbon trap set up by the larger fault to the southeast, indicating the fault is vertically sealing in nature. If, in the unlikely event the faults' sealing properties are compromised post-injection, secondary confinement is provided by the tight limestones found within the overlying Mississippian Lime formation along with shale layers found in the Atoka and Wolfcamp formations. As seen in Figure 14, the largest fault found southeast of the Rattlesnake AGI #1 well, terminates within the Atoka formation. Though it crosses the Silurian section, this fault thrusts the Mississippian Lime upward against the Atoka shales. The tight reservoir characteristics of the Mississippian Lime and shaley section of the Atoka create a confining environment vertically and laterally to contain potential upward migration of buoyant fluids. Shales within the Wolfcamp formation provide additional confining beds between overlying USDWs and the fault plane. Figures 13 and 14 are north-south and west-east structural cross sections showing the structural dips. As seen in these figures, the Woodford formation is laterally present above the injection interval, alleviating risk of erosion of the upper sealant formation.

Larger versions of Figures 11, 12, 13 and 14 are provided in Appendix A.

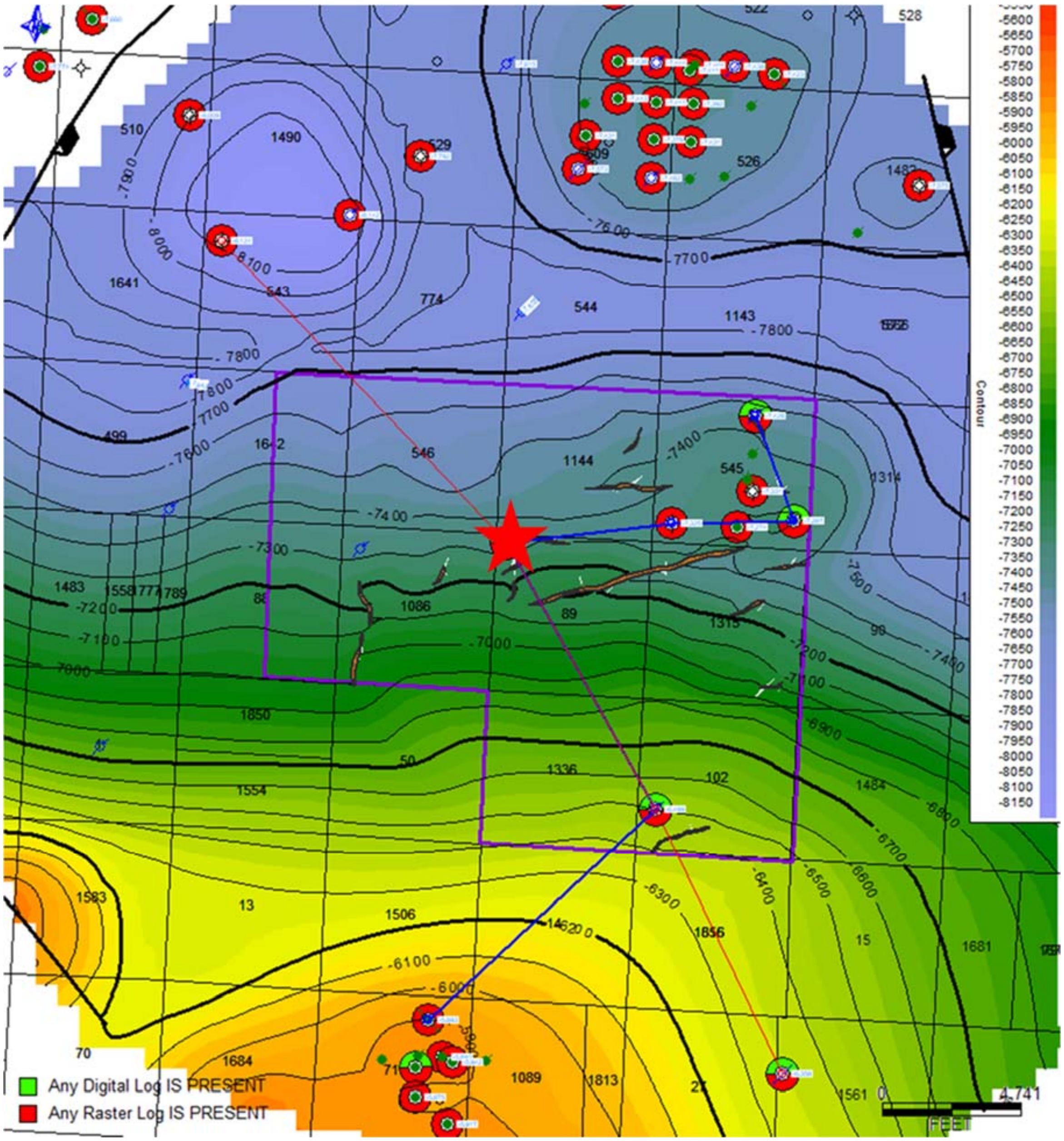


Figure 12 – Silurian Structure Map (subsea depths)

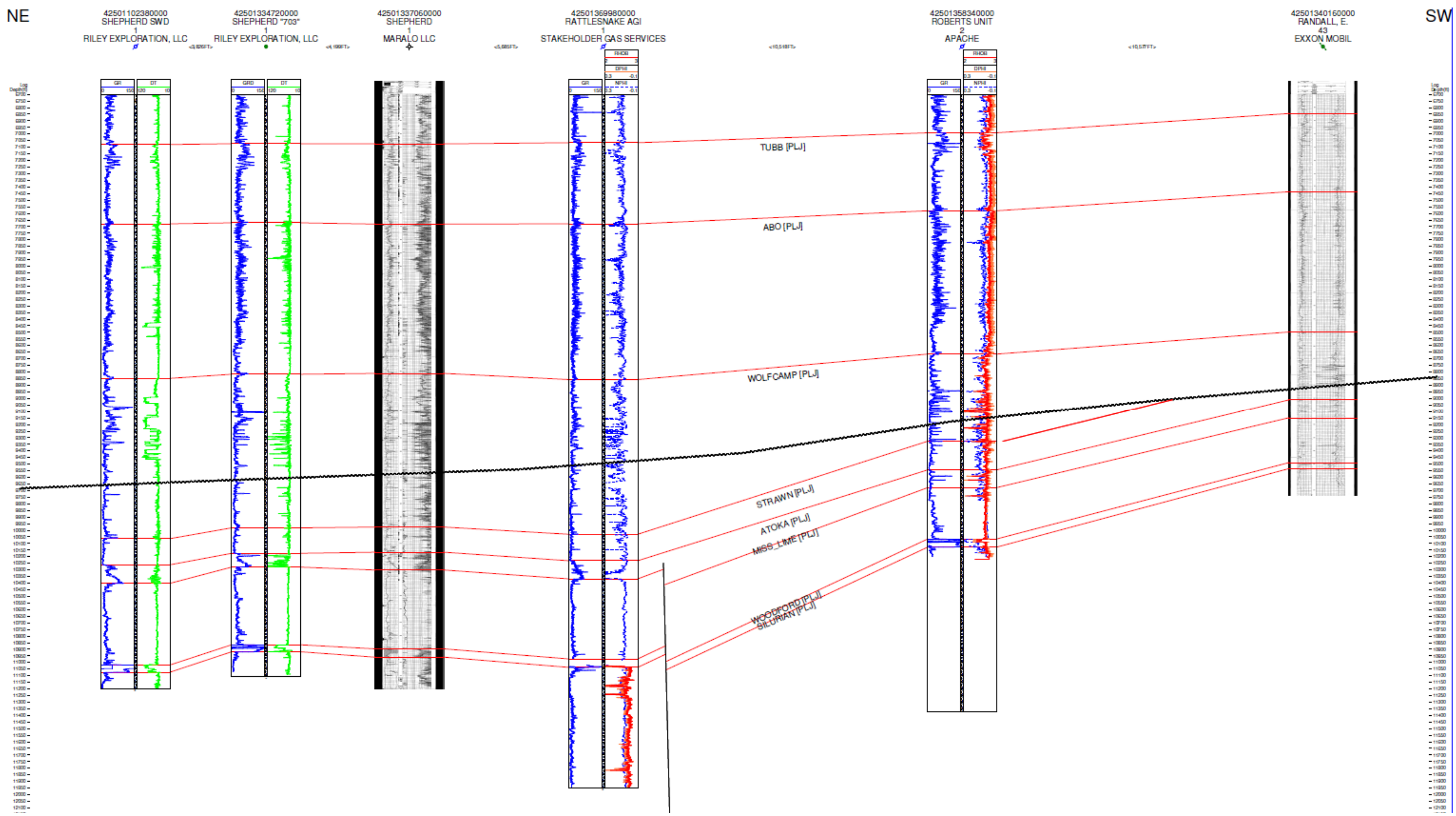
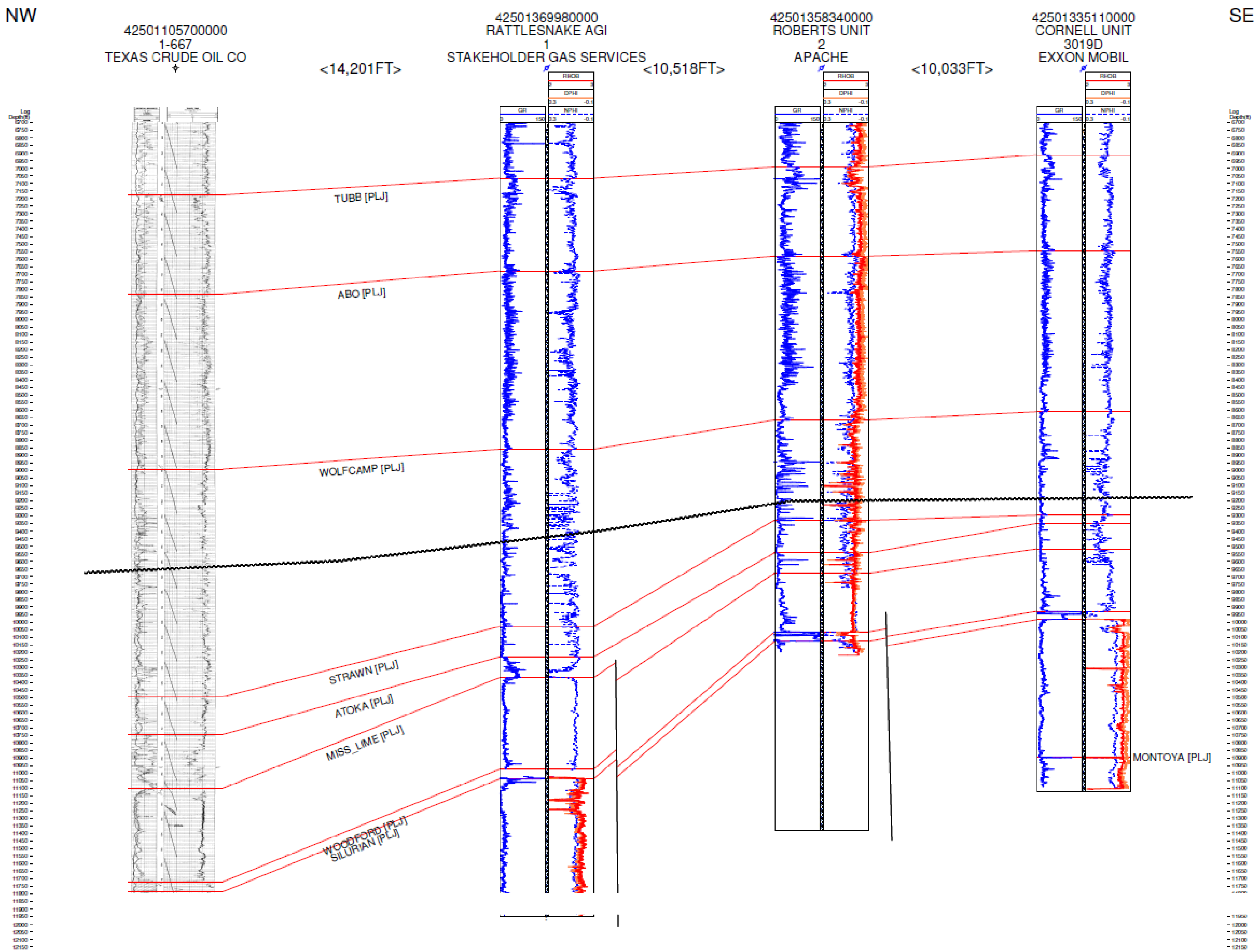


Figure 13 – Structural Northeast-Southwest Cross Section


NW
SE
42501105700000
1-667
TEXAS CRUDE OIL CO
42501369980000
RATTLESNAKE AGI
1
STAKEHOLDER GAS SERVICES
42501358340000
ROBERTS UNIT
2
APACHE
42501335110000
CORNELL UNIT
3019D
EXXON MOBIL
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TUBB [PLJ]
ABO [PLJ]
WOLFCAMP [PLJ]
STRAWN [PLJ]
ATOKA [PLJ]
MISS_LIME [PLJ]
WOODFORD [PLJ]
SILURIAN [PLJ]
MONTOYA [PLJ]

Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Fasken and Fusselman formations at the Rattlesnake AGI #1 well location indicate the formations have sufficient thickness, porosity, permeability, and lateral continuity to accept the proposed injection fluids. The Woodford formation shale at the Rattlesnake AGI #1 well has low permeability and is of sufficient thickness and lateral continuity to serve as the upper confining zone. Beneath the injection interval, the low permeability, low porosity Montoya formation is unsuitable for fluid migration and serves as the lower confining zone. Deeper, laterally continuous formations, including the Simpson Group, provide additional confinement.

Groundwater Hydrology

Yoakum County falls within the boundary of the Sandy Land Underground Water Conservation District. Three aquifers are identified by the Texas Water Development Board's *Aquifers of Texas* report in the vicinity of the proposed Rattlesnake AGI #1 well: the Dockum Aquifer, Edwards-Trinity Aquifer, and Ogallala Aquifer (George, Mace and Petrossian, 2011). Table 3 references the aquifers' positions in geologic time and the associated geologic formations. A schematic cross section in Figure 15, near the proposed Rattlesnake AGI #1 well, illustrates the structure and stratigraphy of these water-bearing formations. Groundwater flow direction is the same for the three aquifers, generally from northwest to southeast, Figure 16 (Teeple, et al., 2021).

Table 3 – Geologic and hydrogeologic units with accompanying lithologic descriptions near Gaines, Terry and Yoakum Counties, Texas (Teeple, et al. 2021)

Era	Period	Epoch or series	Geologic unit group or formation	Lithologic descriptions	Hydrogeologic unit
Cenozoic	Tertiary	Pliocene	Ogallala Formation	Gravel, sand, silt, and clay	High Plains aquifer system (Ogallala aquifer)
		Miocene			
Mesozoic	Cretaceous[1]	Comanchean Series	Washita Group[2]	Shale and limestone	Edwards-Trinity (High Plains) aquifer system
			Fredericksburg Group	Clay, shale, and limestone	
			Trinity Group	Sand and gravel	
	Triassic	Upper	Dockum Group	Siltstone, mudstone, shale, and sandstone	Dockum aquifer

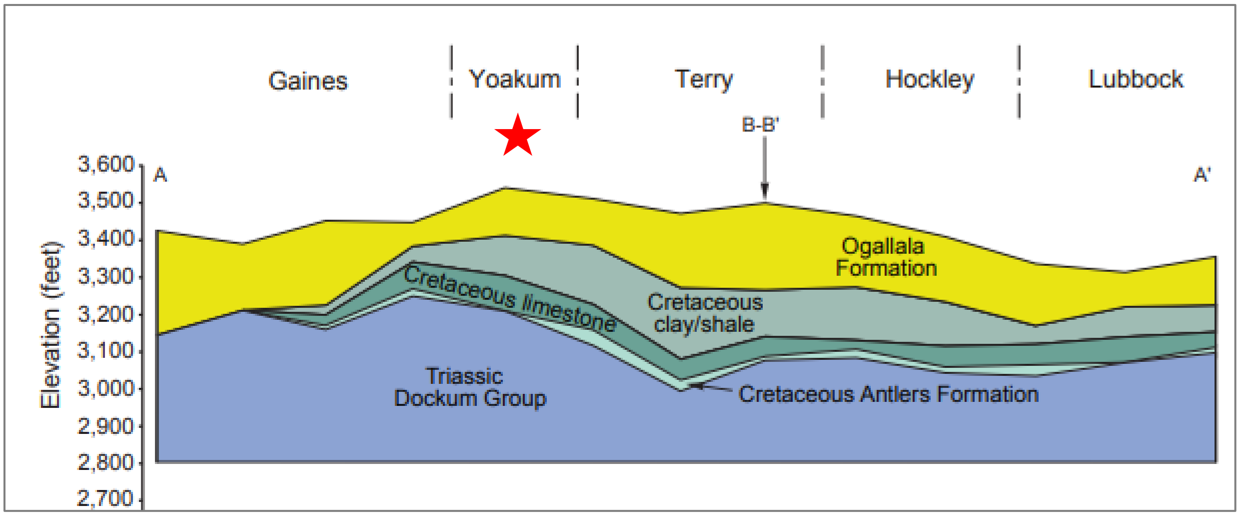


Figure 15 – NW-SE Cross Section of aquifers in the Rattlesnake AGI #1 well area (George, Mac and Petrossian, 2011)

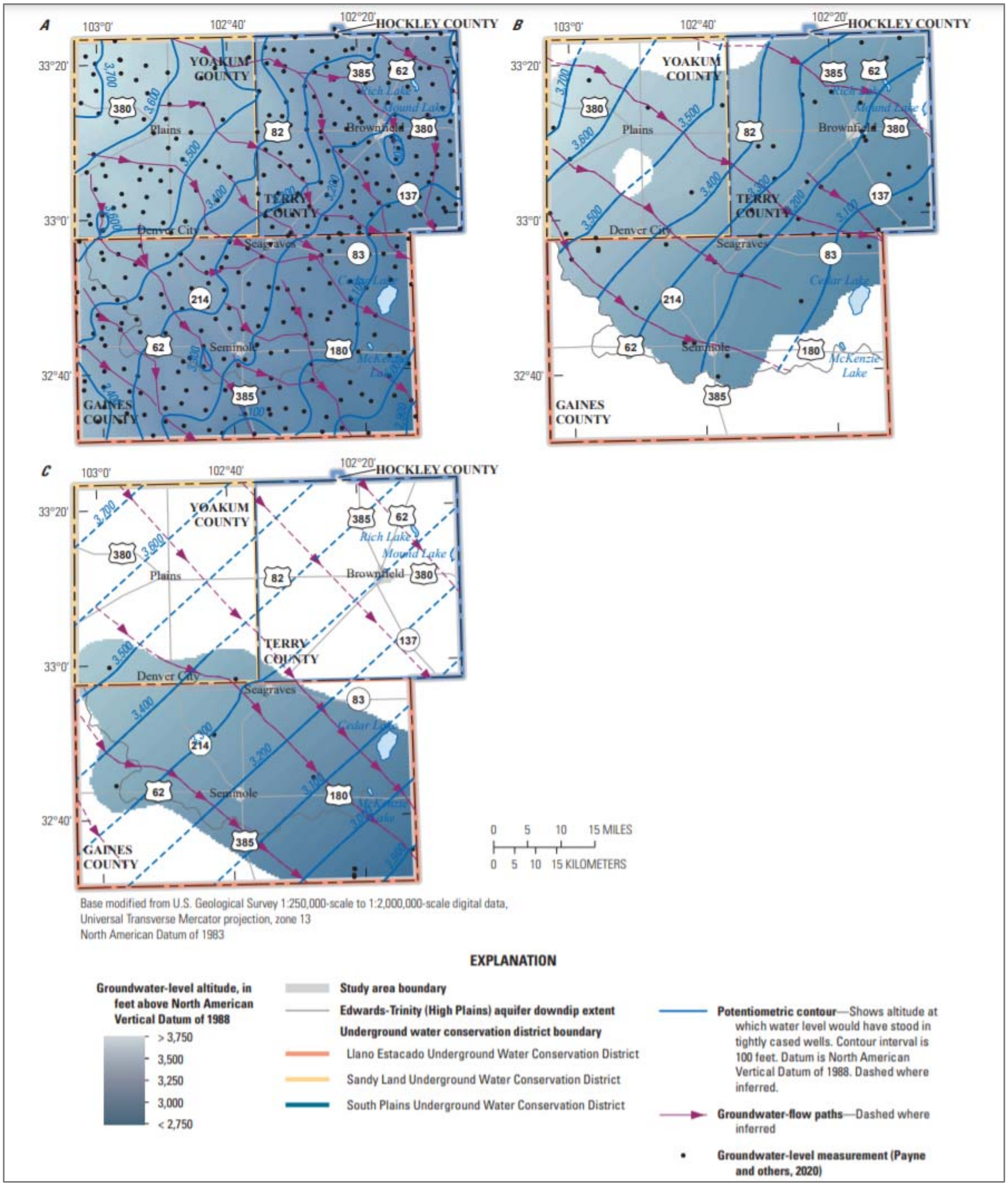


Figure 16 – Potentiometric surfaces from wells completed in A, Ogallala aquifer, B, the Edwards-Trinity aquifer and C, the Dockum aquifer (George, Mace and Petrossian, 2011).

The Dockum Aquifer is the oldest of the three aquifers, formed from Triassic-age Dockum Group sediments, and underlies the Cretaceous Trinity and Fredericksburg Groups (Teeple, et al., 2021). Figure 17 shows the subsurface and outcrop extent of the Dockum Aquifer. As shown in Figure 18, the total dissolved solids in western Yoakum County exceed 5,000 milligrams per liter ("mg/L"), therefore the aquifer is considered brackish.

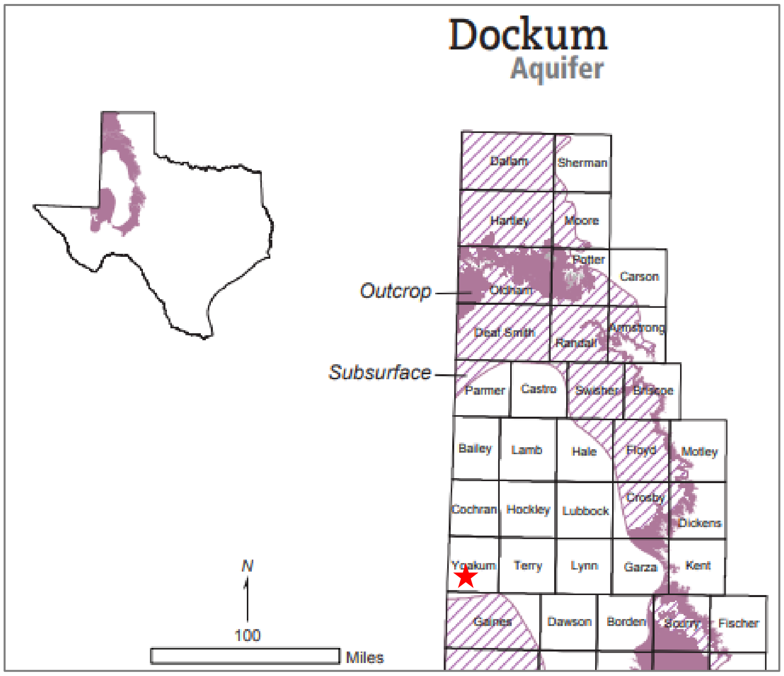


Figure 17 – Regional extent of the Dockum freshwater aquifer (TWDB)

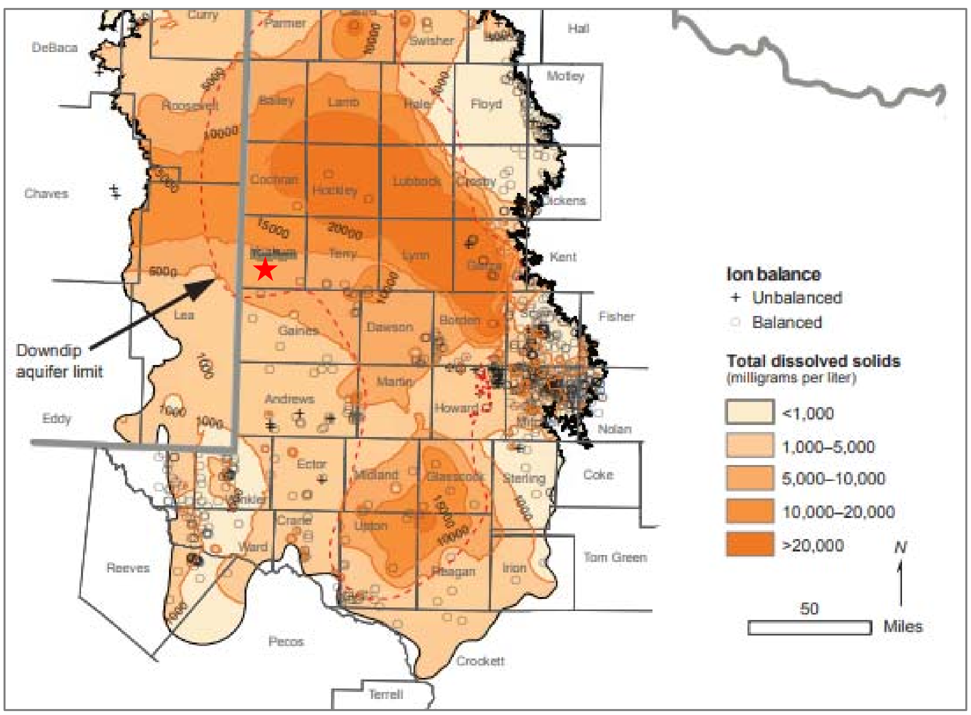


Figure 18 – Total dissolved solids in groundwater from the Dockum Aquifer (Ewing et al, 2008)

The Edwards-Trinity Aquifer is a collection of Cretaceous age sediments – primarily the Trinity Group Antlers formation sandstone and limestones of the Fredericksburg Group, specifically the Comanche Peak and Edwards formations. Figure 19 shows the subsurface and outcrop extent of the Edwards-Trinity Aquifer. Freshwater infiltration to this aquifer is primarily from the overlying Ogallala Aquifer (George, Mace and Petrossian, 2011).

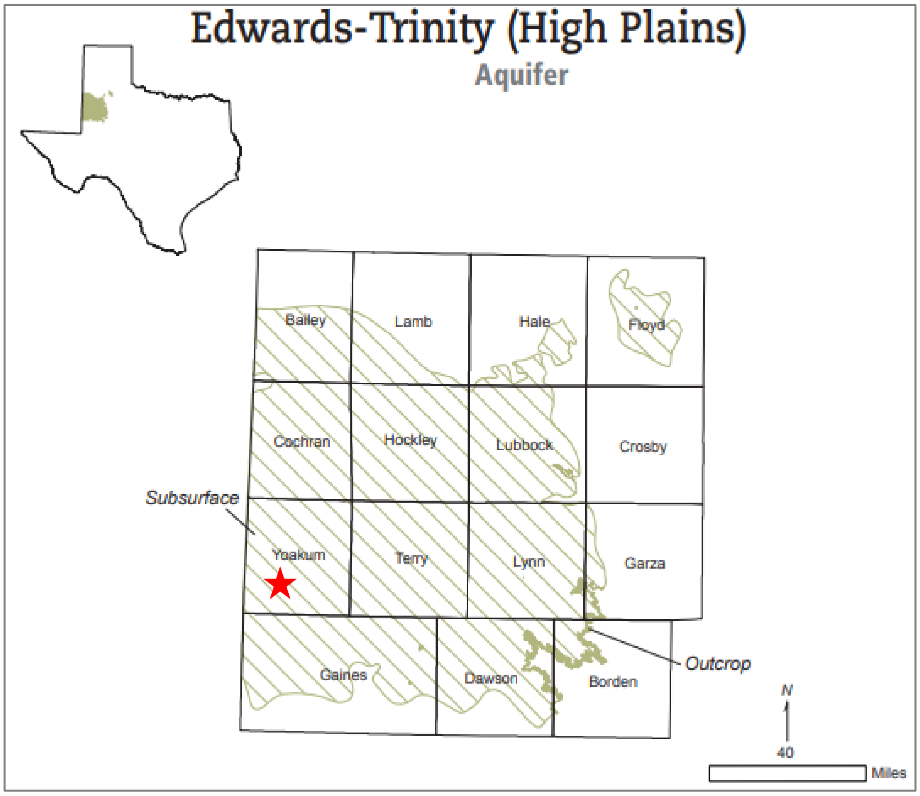


Figure 19 – Regional extent of the Edwards-Trinity freshwater aquifer (George, Mace and Petrossian, 2011)

The Ogallala aquifer consists of sand, gravel, clay and silt sediments (George, Mace and Petrossian, 2011) and produces the majority of the freshwater for Yoakum County. Figure 20 shows the subsurface and outcrop extent of the Ogallala Aquifer.

The base of the deepest aquifer is separated from the injection interval by approximately 8,600' of rock, including 576' of Salado salt. Though unlikely for reasons outlined in the confinement and potential leaks sections, if migration of injected fluid did occur above the Woodford Shale, thousands of feet of tight sandstone, limestone, shale, salt and anhydrite beds occur between the injection interval and the lowest water-bearing aquifer.

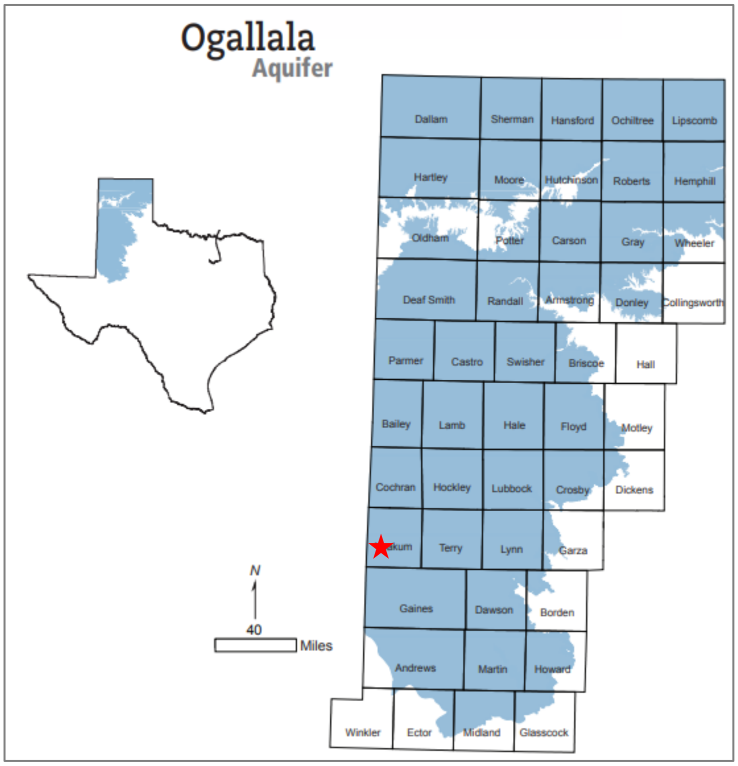


Figure 20 – Regional extent of the Ogallala freshwater aquifer (George, Mace and Petrossian, 2011)

The TRRC's Groundwater Advisory Unit ("GAU") identified the base of Underground Sources of Drinking Water ("USDW") at 375' at the location of the Rattlesnake AGI #1 well. Therefore, there is approximately 10,661' separating the base of the USDW and the injection interval. A copy of the GAU's Groundwater Protection Determination letter issued by the TRRC as part of the Class II permitting process for the Rattlesnake AGI #1 well is provided in Appendix B.

Description of the Injection Process

Current Operations

The 30-30 Facility and its associated Rattlesnake AGI #1 well began operating in March of 2019. Since operations began, 258 million cubic feet ("MMCF") of treated acid gas ("TAG") has been injected, which equates to 12,316 metric tons of CO_2. Over the life of the injection period, the average daily injection rate has been 223 MSCF/d. The approximate current composition of the TAG stream is as follows:

Table 4 – Gas Composition of 30-30 Facility outlet

Component	Mol %
CO2	89.68%
H2S	9.20%
Other	1.12%

The 30-30 Facility is designed to compress, treat, and process natural gas produced from the surrounding counties in Texas and New Mexico. The gas is dehydrated to remove the water content, then processed to separate natural gas liquids which are then sold, along with the pipeline quality natural gas, to various customers. TAG is then directly routed from the plant amine regen system to the Rattlesnake AGI #1 well. The facility is manned 24 hours per day, 7 days per week.

Planned Operations

Stakeholder anticipates increasing the amount of CO_2 injected into Rattlesnake AGI #1 well from the current rate up to 16 MMSCF/d. Additional growth is expected both at Stakeholder facilities and regionally as rising sour gas production and flaring reduction mandates create the need for additional CO_2 and H_2S disposal capacity. Stakeholder plans to inject into this AGI well for another 14 years for a total of 17 years from the start of injection in 2019.

Figure 21 shows a high-level view of the current process flow plus the prospective additional operations over time.

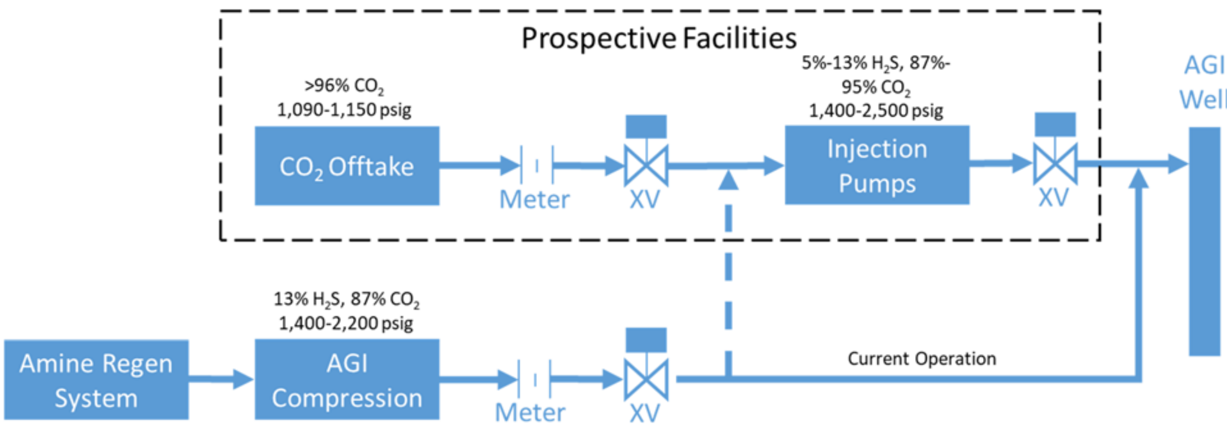


Figure 21 – 30-30 Facility Process Flow Diagram

<u>Reservoir Characterization Modeling</u>

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2020.11 ("GEM") simulator. Computer Modelling Group ("CMG") has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM utilizes equation-of-state ("EOS") algorithms along with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon injection and storage. The GEM model is recognized by the EPA for use in area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Silurian (Fasken/Fusselman) formation is the target formation for Rattlesnake AGI #1 well. The Petra software package was used to create the geologic model of the target formation. The faulting and geologic structure was then imported into GEM and used to create contours for the model grid.

Porosity and permeability estimates were determined using the porosity log from the Rattlesnake AGI #1 well and a petrophysical analysis was performed to correlate porosity values by depth with core porosities

as shown in the Holtz paper. The Coates permeability equation was then used to calculate permeability with depth. Both porosity and permeability are assumed to be laterally homogeneous in the reservoir.

The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. An infinite acting reservoir was created to simulate boundary conditions. The gas injectate is composed of H_2S, CO_2, CH_4, and other components as shown in Table 5. Core data from literature review was used to determine residual gas saturation (Ruppel and Holtz, 1994). The modeled composition only takes into consideration the carbon dioxide and hydrogen sulfide as they comprise nearly 99% of total stream. For the initial injection period, these compositions are normalized up to 100%. For the proposed additional injection period, it is expected that a larger portion of the gas added is carbon dioxide, changing the composition to ~93% CO_2 and ~7% H_2S.

Table 5 – Modeled Initial Gas Composition

Component	Measured Current Composition (mol%)	2019-2024 Model Composition (mol%)	2024-2036 Model Composition (mol%)
Carbon Dioxide (CO2)	89.678	90.696	92.921
Hydrogen Sulfide (H2S)	9.200	9.304	7.079
Methane (C1)	0.303	0	0
Ethane (C2)	0.058	0	0
Propane (C3)	0.108	0	0
N-Butane (NC4)	0.025	0	0
Hexane Plus (C6+)	0.628	0	0

Core data from literature review was used to determine relative permeability curves between carbon dioxide and the connate brine within the Silurian-Devonian carbonates (Ruppel and Holtz, 1994). The key inputs used in the model include an irreducible water saturation of 25% and a maximum residual gas saturation of 21%.

The grid contains 141 blocks in the x-direction (E-W) and 201 blocks in the y-direction (N-S), totaling 28,341 grid blocks per layer. The grid blocks are each 150' by 150' by layer thickness as specified in Table 6. This results in the grid being 21,150' by 30,150' totaling just over a 23-square mile area (14,640 acres). Each layer in the model was determined by identifying higher permeability zones as targets for injection from the logs and assigning each high permeability and intermediary low permeability zone its own layer. One zone was identified as being a karst limestone (layers 2-7). Due to the "karsted" nature of this rock, it was determined that most of the injectate would flow into this zone. Therefore, the karst limestone was further split into layers by permeability to provide higher resolution and more accurately simulate which layer will have more gas flow into it. Figure 22 provides a detailed breakdown of the "karsted" rock.

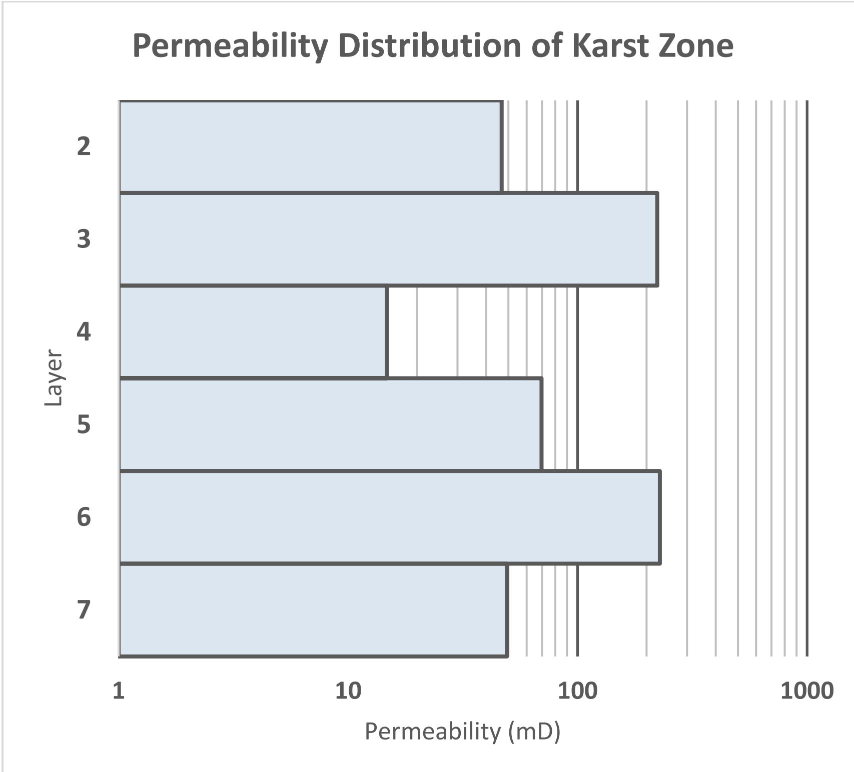


Figure 22 – Permeability Distribution of Karst Limestone

In total, there are sixteen (16) layers in the model, representing ten (10) layers of pay and six (6) layers of intermediary low permeability zones. The properties of each of these layers are summarized in Table 6 below.

Table 6 – CMG Model Layer Properties

Layer #	Top (ft)	Thickness (ft)	Permeability (mD)	Porosity
1	11,037	71	1	2.8%
2	11,108	57	47	8.0%
3	11,165	19	223	11.9%
4	11,184	16	15	6.3%
5	11,200	39	70	9.2%
6	11,238	11	228	12.3%
7	11,249	21	49	8.3%
8	11,270	251	2	3.7%
9	11,520	46	9	5.6%
10	11,566	13	3	4.3%
11	11,579	19	17	6.5%
12	11,597	14	2	3.9%
13	11,611	103	13	6.0%
14	11,714	46	2	3.7%
15	11,759	67	23	6.1%
16	11,826	125	2	3.6%

Simulation Modeling

The primary objectives of the model simulation were to:

1) Estimate the maximum areal extent and density drift of the acid gas plume after injection
2) Assess the impact of offset saltwater disposal ("SWD") well injection on density drift of the plume
3) Assess the impact of offset producing wells on the density drift of the plume
4) Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone
5) Assess the likelihood of the acid gas plume migrating into potential leak pathways

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 53,000 ppm (Texas Water Development Board, 1972). The acid gas stream is primarily composed of CO_2 and H_2S as stated previously. Core data was used to help generate relative permeability curves. Cores, from the literature reviews previously discussed, that most closely represent the vuggy carbonate seen in this region were identified and the Corey-Brooks equations were used to develop the curves. The lowest residual gas saturation found in the cores was then used for a conservative estimate of plume size. From offset injection well analysis, the initial reservoir pressure was determined to be 5,132 psi which is equivalent to a 0.465 psi/ft pressure gradient. The fracture gradient of the injection zone was estimated to be 0.72 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottom-hole pressure allowed in the model at 0.64 psi/ft which is equivalent to 7,064 psi.

The model also takes into account offset saltwater disposal ("SWD") injection volumes within five (5) miles of the Rattlesnake AGI #1 well. These SWDs create a pressure front that push the plume further up-dip of the formation. A total of twenty (20) offset wells currently injecting into the target formation were identified. Eleven (11) of these offset SWDs were out of the confines of the grid, but were still accounted for in the model. Nine (9) salt-water disposals were modeled within the boundaries of the 23-square-mile grid. Two (2) of these offset injectors are currently only permitted (not drilled) but were assumed to start active injection within the first year of the model. Both permits were simulated at the forecasted injection rate schedule for 30 years. These forecasts were provided by the operators of these wells. Historical injection rates of each of the other existing wells were analyzed and projected into the model. This simulation includes the effect of water injection on the density drift of the plume and bottom hole pressure.

Further review of the area revealed production wells in the Silurian-Devonian formation that could impact the density drift of the plume by creating a "pressure sink". A "pressure sink" is an area of lower pressure caused by the production of formation fluids. To simulate this effect, nine (9) production wells were grouped together and their respective production rates combined into a single well to add more conservatism into the model. These producers were forecasted an additional 15 years to simulate their potential economic lifespan. This simulation includes the effect of fluid production on the density drift of the plume and bottom hole pressure. Overall, the "pressure sink" has little effect on the density drift and, as discussed below, the plume never reaches the producing wells.

The model runs for a total of 814 years, starting in 1965 with the beginning of offset production until the calculated stabilization of the plume in 2779. The injection of TAG from Rattlesnake AGI #1 is modeled from the beginning of injection in 2019 through the planned 14 years of future injection. The model also includes the 57 years of historical plus 15 years of forecasted future oil and gas production.

Additionally, historical monthly injection rates of all nearby SWDs were incorporated into the model to simulate any additional near-wellbore pressure increase that may occur due to offset injection. The

modelling of the saltwater injection begins in 1984 when the first offset SWD well became operational. The SWDs to the North were grouped into four (4) separate groups to simulate their combined effect on the density drift of the plume. All offset injection wells and their groupings are included in Table 7. All offset production wells are listed in Table 8.

Table 7 – All Offset SWDs included in the model

Grouping	API	Well Name	Well #
Group 1	42-501-32511	SAWYER, DESSIE	1
	42-501-02068	WEST, M. M.	2
	42-501-02053	NORTH CENTRAL OIL CO. "A"	1
	42-501-01453	SMITH, ED S. HEIRS "B"	1
	42-501-02059	SMITH, ED "C"	1W
Group 2	42-501-30051	JOHNSON	2
	42-501-30001	JOHNSON	1D
Group 3	42-501-37066	MISS KITTY SWD 669	1W
	42-501-36650	RUSTY CRANE 604	1W
Group 4	42-501-36745	SUNDANCE 642	1
	42-501-33887	WINFREY 602	3WD
Standalone	42-501-37252	Miller SWD	7
	42-501-37367	BLONDIE 704	1W
	42-501-37206	BRUSHY BILL 707	1WD
	42-501-36622	WISHBONE FARMS 710	1W
	42-501-35834	ROBERTS UNIT	2
	42-501-33297	STATE ELMORE	1
	42-501-10238	SHEPHERD SWD	1
	42-501-33511	CORNELL UNIT	3019D
	42-501-32868	WILLARD UNIT	1WD

Table 8 - All Offset Producers included in the model

API	Well Name	Well #
42-501-10046	ELLIOTT, C.A.	2
42-501-10079	RANDALL, E	32
42-501-337932	RANDALL, E	40
42-501-33885	RANDALL, E	41L
42-501-34016	RANDALL, E	43L
42-501-34017	RANDALL, E.	45L
42-501-34023	RANDALL, E	42L
42-501-34024	RANDALL, E	44
42-501-35418	RANDALL, E	46

Rattlesnake AGI #1 came online in 2019 and the model simulated its historical monthly injection rates until 2024. After this initial period, it is conservatively assumed that the injection rate increases to the maximum permitted rate of 16 MMSCF/d for the remainder of the active injection period in 2036. At this point, the

Rattlesnake AGI #1 well stops injection while the offset SWD injectors continue operations for thirty more years. Density drift then occurs until plume stabilizes, which was determined to be 814 years from the start of the model in 1965. Stabilization of the plume is determined to occur when the model shows no further lateral movement horizontally or vertically. The plume boundary is then defined by a weighted average gas saturation in the aquifer of 3%.

The maximum plume extent during the 17-year Rattlesnake injection period is shown in Figure 23. The final extent after 743 years of density drift after injection ceases is shown in Figure 24. The extensive time of the modeled density drift of the plume is driven by the buoyant forces of the gas, the permeability/porosity of the rock, and the residual gas saturation. Initially, the karsted region takes on most of the injection, but due to the buoyant forces, it is slowly pushed up higher into the less permeable layers of the injection interval. These lower permeable layers, increase the amount of time it takes for the plume to reach its maximum areal extent. As all the inputs to the model were based on the most conservative approach, the maximum extent of the plume will likely be smaller and the effective impact on reaching potential leakage pathways will be minimal as the amount of CO_2 at those far extents will be small.

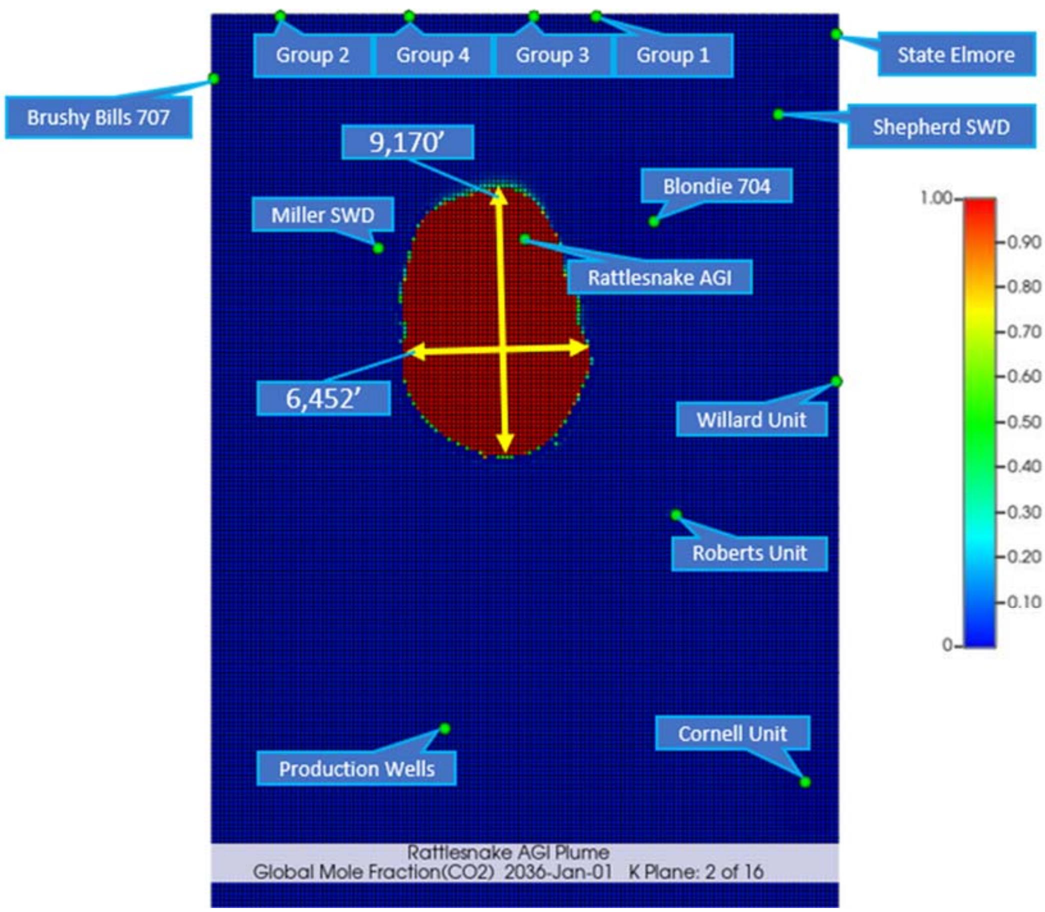


Figure 23 – Areal View Gas Saturation Plume, 2036 (End of Injection)

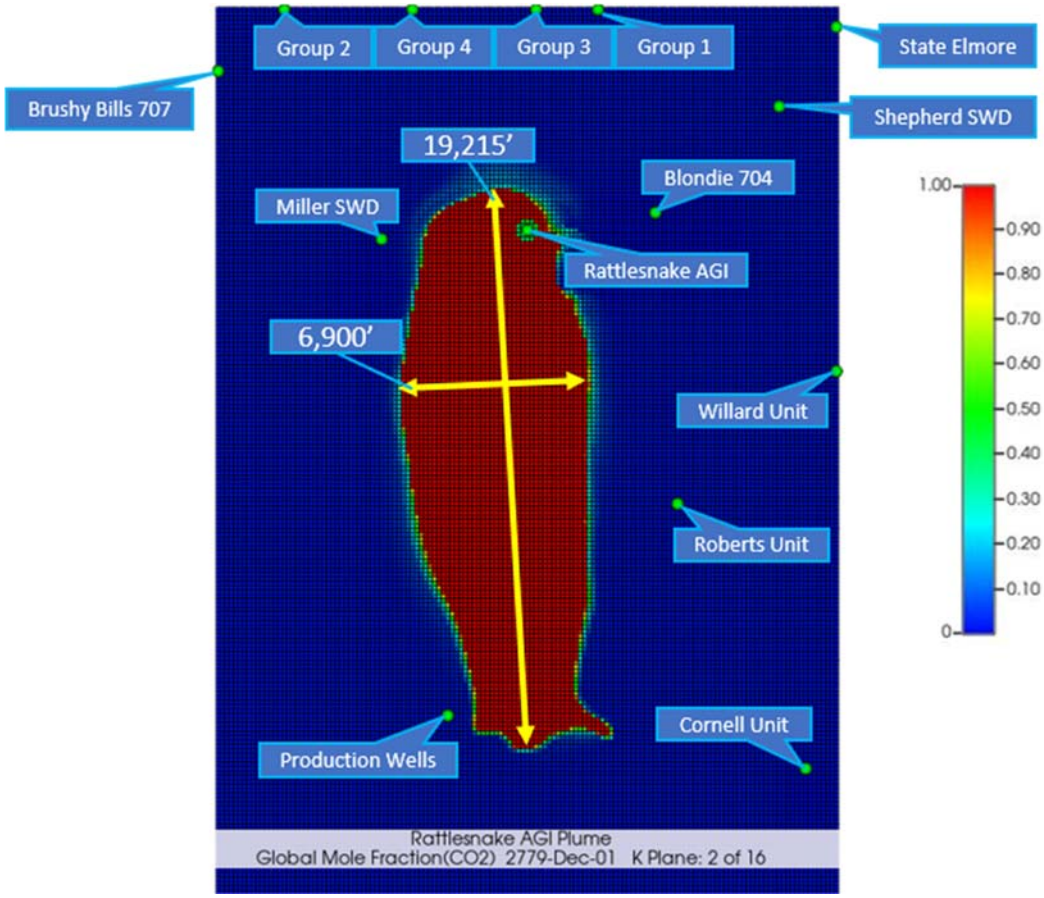


Figure 24 – Areal View Gas Saturation Plume, 2779 (End of Density Drift)

Figure 25 shows the surface injection rate and bottom hole pressure over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate reaches its peak, reaching a maximum pressure of 5,413 psi. This buildup of 280 psi keeps the bottomhole pressure well below the fracture pressure of 7,064 psi. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,494 psi.

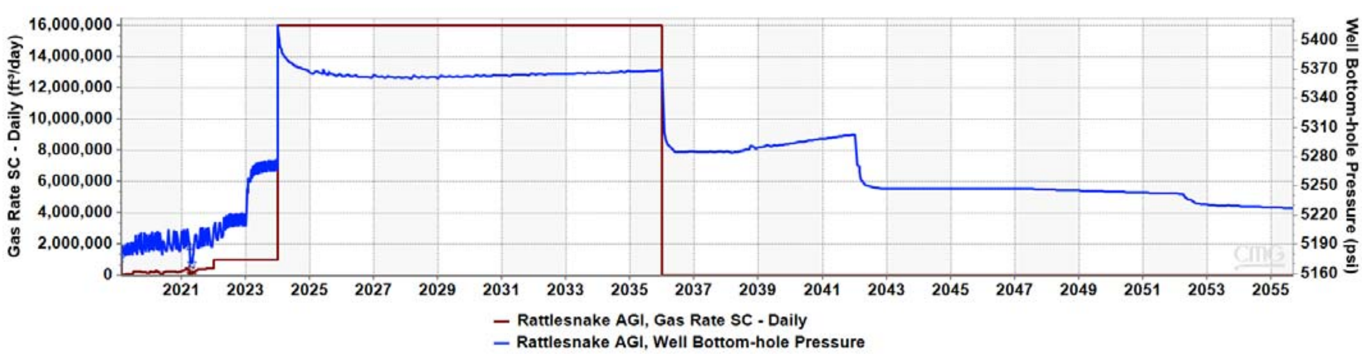


Figure 25 – Well Injection Rate and Bottomhole Pressure over Time

SECTION 3 – DELINATION OF MONITORING AREA

This section discusses the delineation of Maximum Monitoring Area ("MMA") and Active Monitoring Area ("AMA") as described in EPA 40 CFR §98.448(a)(1).

Maximum Monitoring Area

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

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

Acid gas injectate was analyzed by a third-party vendor to determine the initial composition used in the model. The report is provided in Appendix C. The molar composition of the gas is primarily CO_2 with some H_2S and CH_4. The change in molar composition was also incorporated into the model as future predominantly CO_2 streams are added for injection. As discussed in Section 2, the gas was injected into the Silurian formation, specifically, the Fasken/Fusselman formation. The geomodel was created based off the rock properties seen in the Fasken/Fusselman.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in 2036, the areal expanse of the plume will be 1,052 acres. The maximum distance between the wellbore and the edge of the plume is approximately 0.87 miles to the southeast. After 743 additional years of density drift, the areal extent of the plume is 2,177 acres with a maximum distance to the edge of the plume of approximately 1.35 miles to the southeast.

Figure 26 shows the plume boundary at the end of injection, the stabilized plume boundary and the MMA.

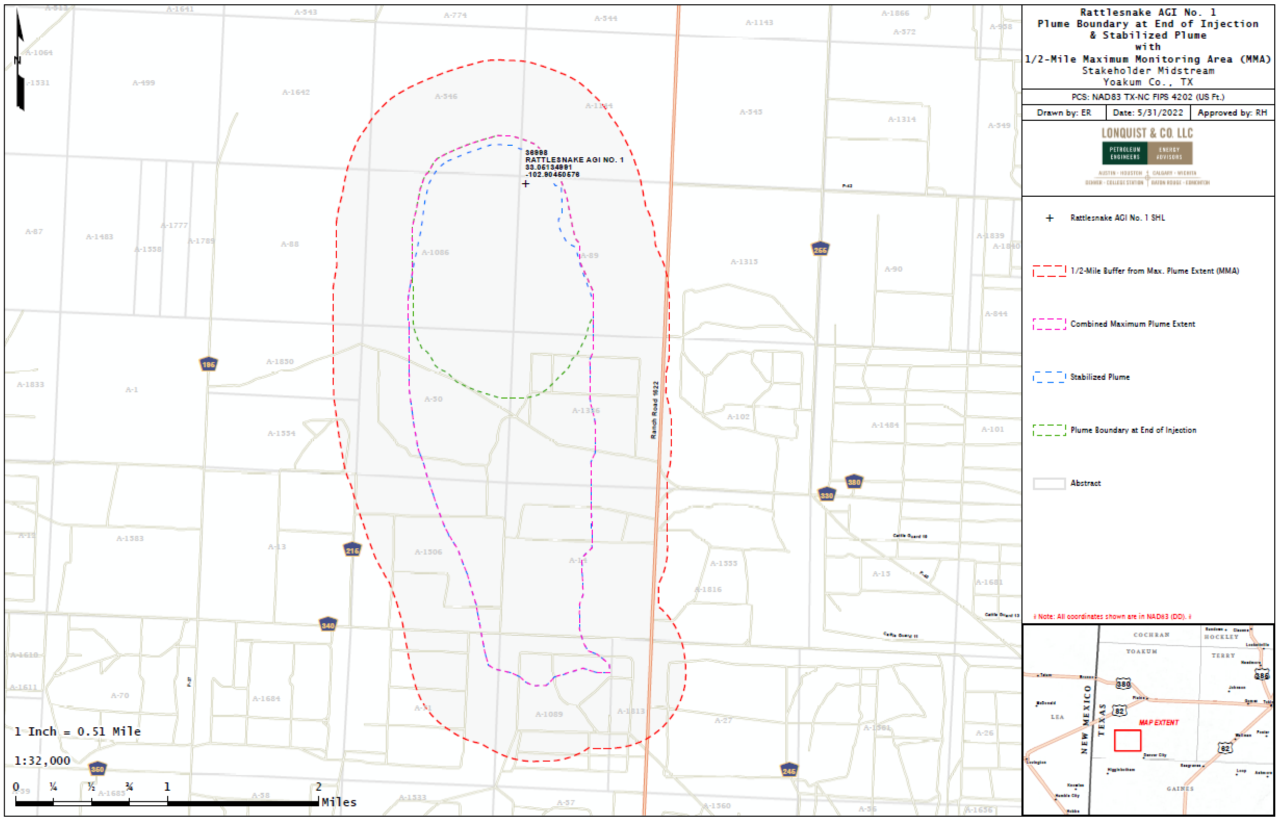


Figure 26 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

Active Monitoring Area

The initial AMA will cover a 14-year monitoring period. This period equates to the time of expected future injection. The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location at the end of injection (2036) with the area of the projected free-phase CO_2 plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume at 2036 plus a half-mile buffer. By 2036 at the latest, a revised MRV plan will be submitted to define a new AMA. Figure 27 shows the area covered by the AMA.

Larger size versions of Figures 26 and 27 are provided in Appendix D.

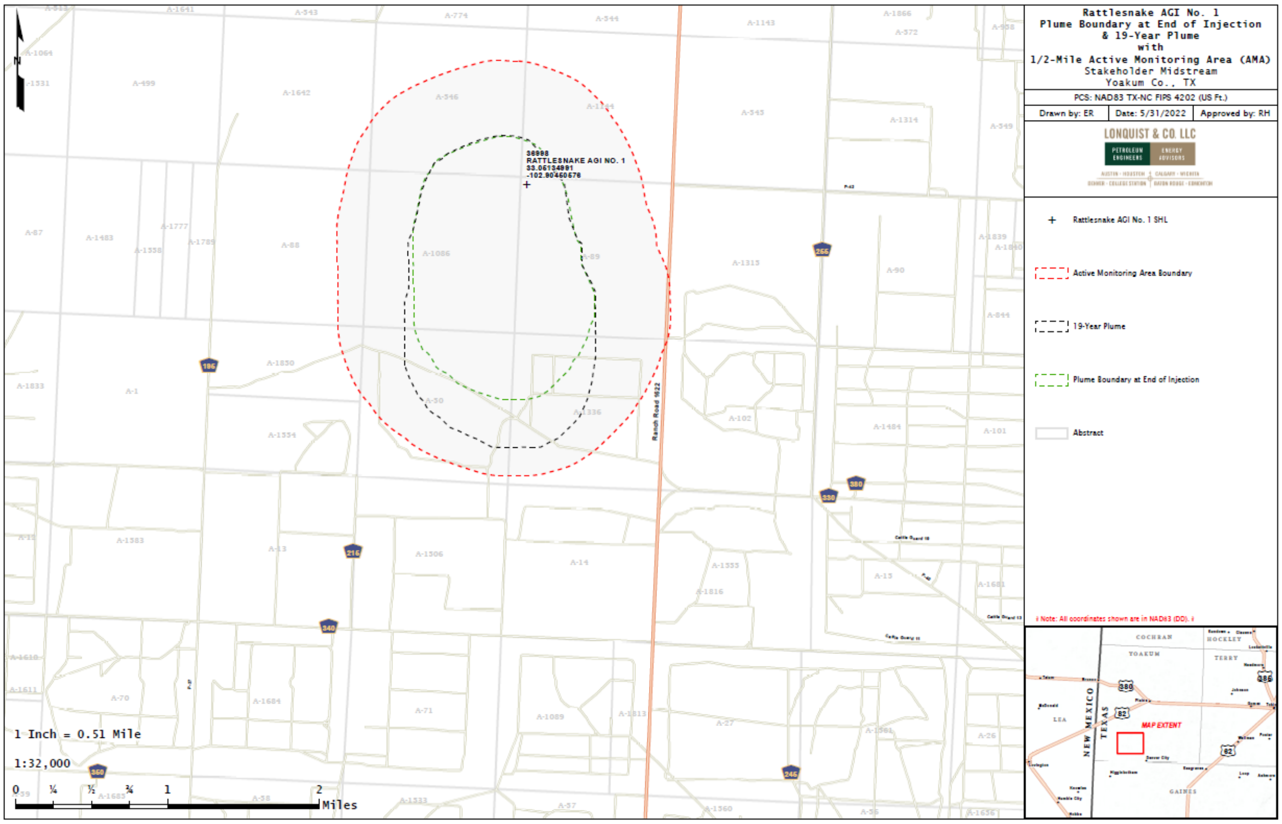


Figure 27 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA and the likelihood, magnitude and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from Natural or Induced Seismicity

Leakage from Surface Equipment

The surface facilities at the 30-30 Facility are designed for injecting acid gas containing H_2S, and therefore minimize leakage points such as valves and flanges following industry standards and best practices. H_2S gas detectors are located around the facility and the well site. These gas detectors trigger alarms at 10 parts per million ("ppm"). Additionally, all Stakeholder field personnel are required to wear H_2S monitors which are triggered at 5 ppm of H_2S. A shut-in valve is located at the wellhead and is locally controlled by pressure, with a high pressure and low pressure shut-off.

The facilities have been designed and constructed with additional safety systems to provide for safe operations. These systems include Emergency Shutdown ("ESD") valves to isolate portions of the plant and pipeline, pressure relief valves along the pipeline to prevent over pressurization, and flares to allow piping and equipment to be de-pressured rapidly under safe and controlled operating conditions in the event of a leak. Figures 28 and 29 display the facility safety plot plan, taken from the 30-30 H_2S Contingency Plan, and show the location of the H_2S monitors in the vicinity of the plant and the Rattlesnake AGI #1 well. Should Stakeholder construct additional CO_2 facilities, as indicated in Figure 21, a separate meter will be installed for the additional stream in order to comply with the 40 CFR §98.448(a)(5) measurement. As this meter will be in close proximity to the existing facilities, it will utilize the existing monitoring programs discussed previously. Additionally, CO_2 monitors will be installed near the new meter and tied into the facility monitoring systems.

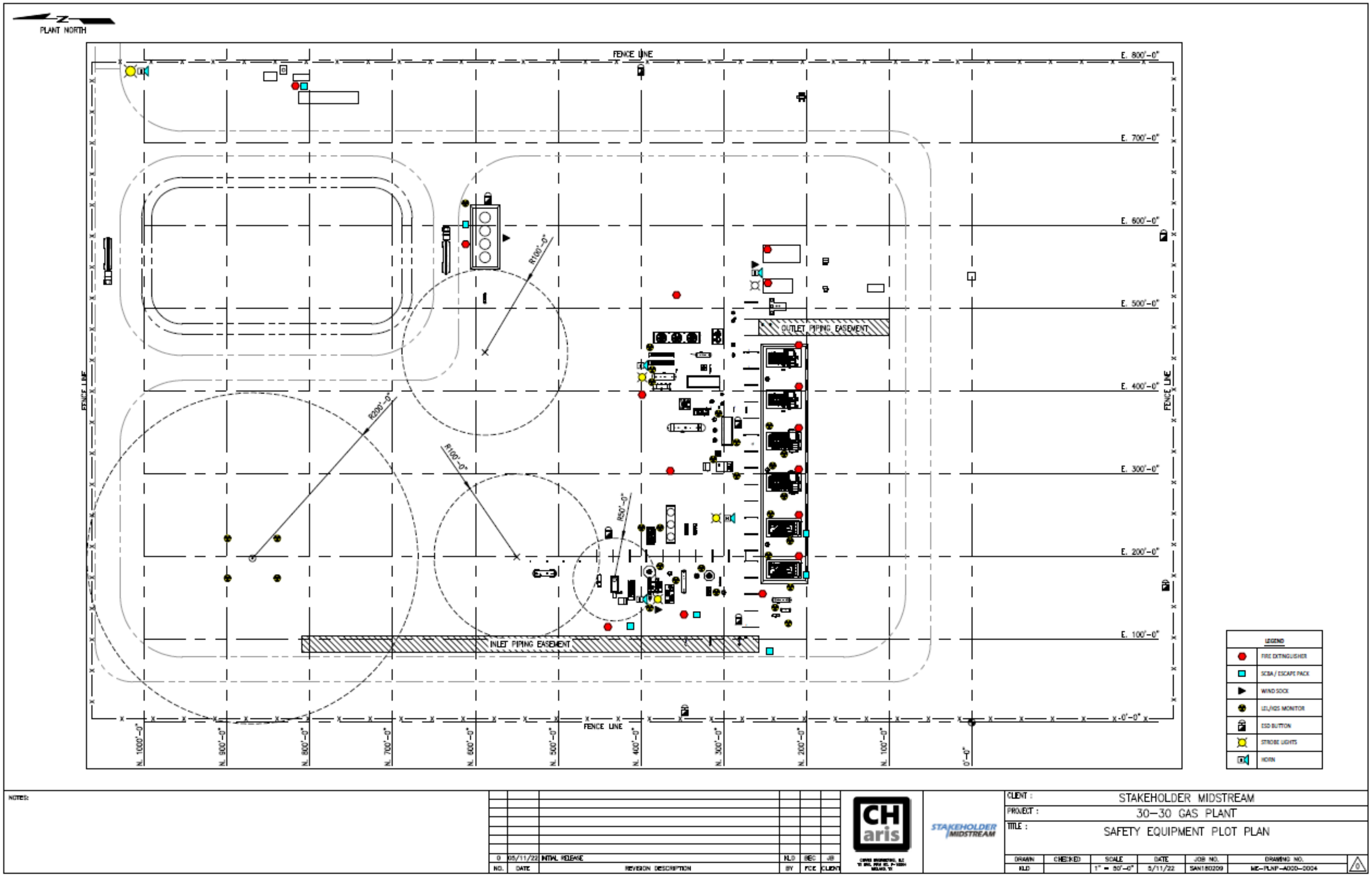


Figure 28 – Site Plan, 30-30 Facility

With the level of monitoring at the 30-30 Facility and the Rattlesnake AGI #1 well, any release of H_2S and CO_2 would be quickly identified, and the safety systems would quickly minimize the volume of the release. The CO_2 injected into the Rattlesnake AGI #1 is injected with H_2S at a concentration of 10% (100,000 ppm). At this high level of H_2S concentration, even a small leakage would trigger personal and facility H_2S monitors set to alarm at 5 ppm and 10 ppm respectively. If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7 in accordance with 40 CFR §98.448(a)(5).

A larger scale version of Figure 28 is provided in Appendix E.

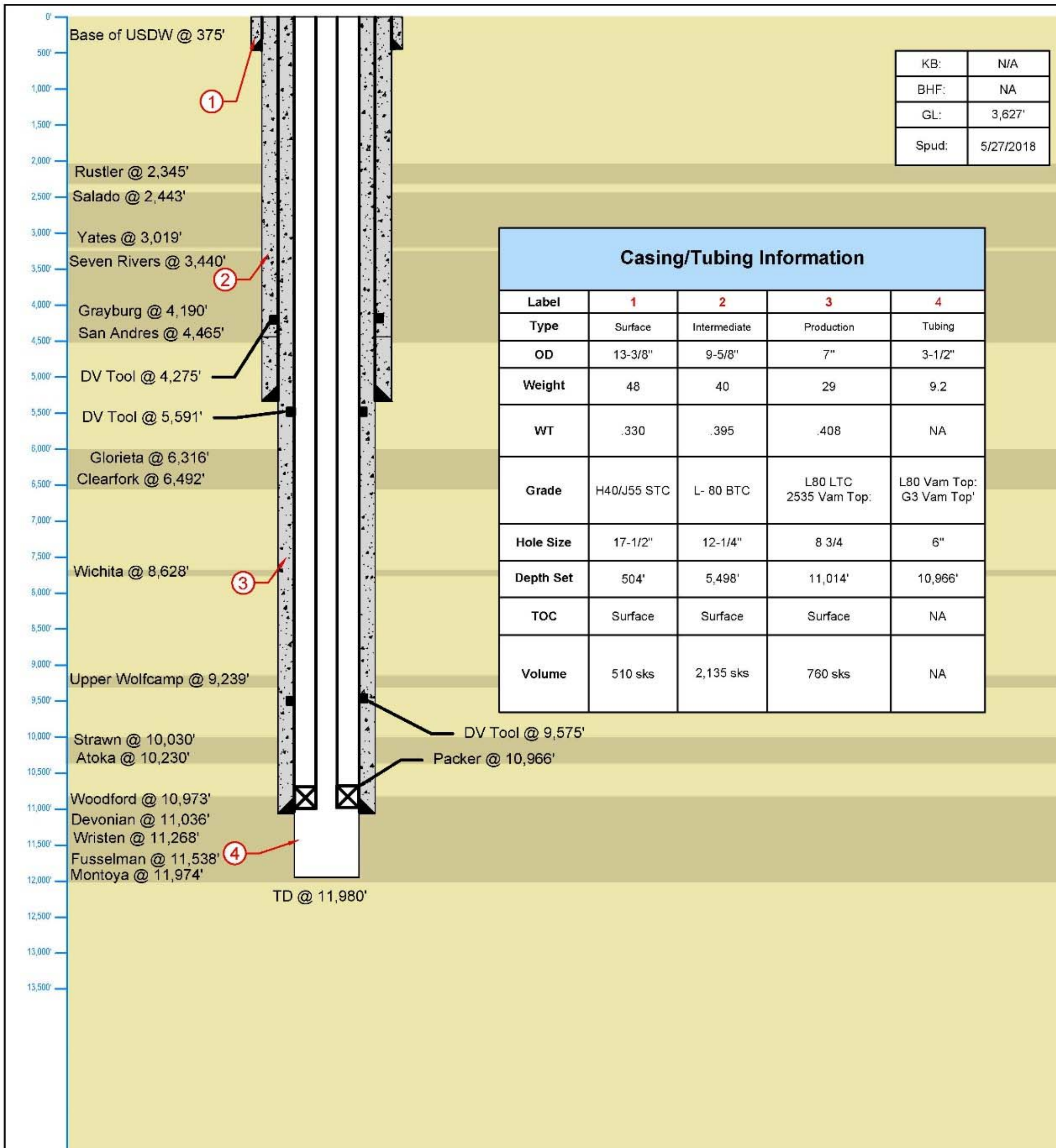
Leakage from Existing Wells within MMA

Oil and Gas Operations within Monitoring Area

A significant number of wells have historically been drilled within the area of the Rattlesnake AGI #1 well, however production has primarily been from the shallower San Andres formation in the Wasson Field. The San Andres is separated from the Silurian-Devonian interval by 4,720' in this area. In addition to the primary San Andres production, a few wells have produced from the Wolfcamp. The Wolfcamp is separated from the Siluro-Devonian interval by is 1,800'. **Within the projected plume area of the Rattlesnake AGI #1 well, there are no penetrations of the injection interval.** There are ten wells within the MMA that penetrate the injection interval.

A review of the TRRC records for all of the wells which penetrate the injection interval within the MMA, shows the wells were properly cased and cemented to prevent annular leakage of CO_2 to the surface. The plugged wells are also adequately protected against migration from the Devonian by the placement of the plugs within the wellbores. Additionally, the Rattlesnake AGI #1 well was designed to prevent migration from the injection interval to the surface through the casing and cement placed in the well, as shown in Figure 29. Mechanical integrity tests ("MIT") required under TRRC rules are run annually to verify the well and wellhead can hold the appropriate amount of pressure. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated quickly to prevent leakage to the atmosphere.

A map of all wells within the MMA is shown in Figure 30. Figure 31 shows only those wells which penetrate the injection interval within the MMA. The MMA review maps, a summary of all the wells in the MMA and detailed wellbore schematics for those wells which penetrate the injection interval are provided in Appendix F.



KB:	N/A
BHF:	NA
GL:	3,627'
Spud:	5/27/2018

Casing/Tubing Information

Label	1	2	3	4
Type	Surface	Intermediate	Production	Tubing
OD	13-3/8"	9-5/8"	7"	3-1/2"
Weight	48	40	29	9.2
WT	.330	.395	.408	NA
Grade	H40/J55 STC	L- 80 BTC	L80 LTC 2535 Vam Top:	L80 Vam Top: G3 Vam Top'
Hole Size	17-1/2"	12-1/4"	8 3/4	6"
Depth Set	504'	5,498'	11,014'	10,966'
TOC	Surface	Surface	Surface	NA
Volume	510 sks	2,135 sks	760 sks	NA

LONQUIST & CO. LLC PETROLEUM ENGINEERS ENERGY ADVISORS HOUSTON CALGARY AUSTIN WICHITA DENVER	Stakeholder Midstream	Rattlesnake No. 1	
	Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
	Location: 33.07884, -103.904514	**Site:**	**Survey:**
	API No: 42-501-36998	**Field:**	**Well Type/Status:** AGI
Texas License F-9147	**RRC District No:**	**Project No:** LS 128	**Date:** 5/27/2022
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** ASG	**Reviewed:** SLP	**Approved:** SLP
	Rev No: 1	**Notes:**	

Figure 29 – Rattlesnake AGI #1 Wellbore Schematic

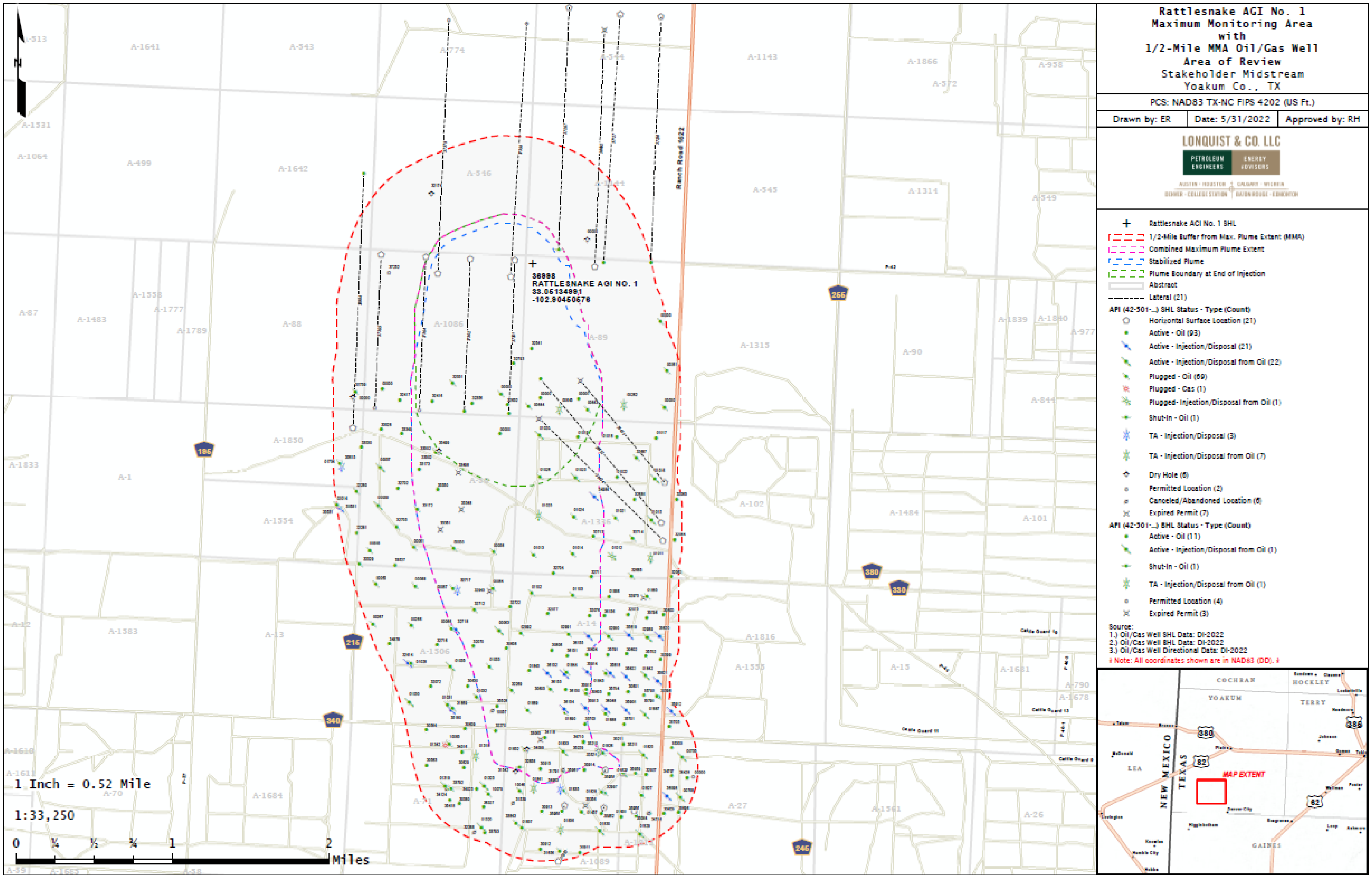


Figure 30 – Oil and Gas Wells within the MMA

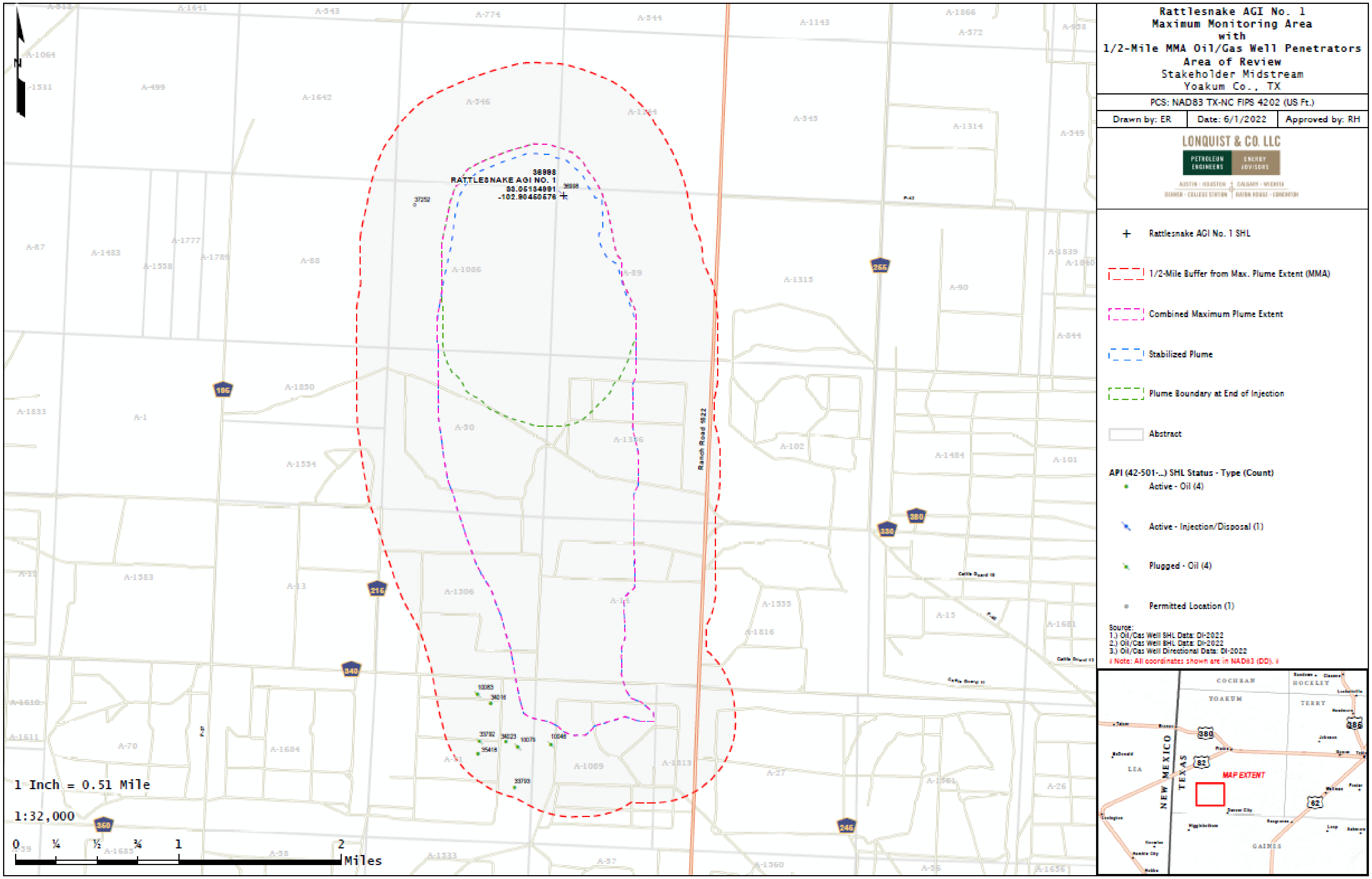


Figure 31 – Penetrating Oil and Gas Wells within the MMA

Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, such as the Devonian, have proven to-date to be less productive or non-productive in this area, which is why the location was selected for injection. Furthermore, any drilling permits issued by the TRRC in the area of the Rattlesnake AGI #1 well include a list of formations for which oil and gas operators are required to comply with TRRC Rule 13 (entitled "Casing, Cementing, Drilling, Well Control, and Completion Requirements"). 16 TAC § 3.13. By way of example, see the Rattlesnake AGI #1 well drilling permit provided in Appendix B. The Devonian is among the formations listed for which operators in Yoakum County (where the Rattlesnake #1 is located) are required to comply with TRCC Rule 13 (Appendix B, pg. 5). TRRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under TRRC Rule 9 or immediately above all formations permitted for injection under Rule 46 for any well proposed within a one-quarter mile radius of an injection well. In this instance, any new well permitted and drilled to the Rattlesnake AGI #1 well's injection zone, and located within a one-quarter mile radius of the Rattlesnake AGI #1 well, will be required under TRRC Rule 13 to set steel casing and cement above the Rattlesnake AGI #1 well injection zone. Additionally, Rule 13 requires operators to case and cement across and above *all* potential flow zones and/or zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued, which is also shown in the above-mentioned permit in Appendix B.

If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release.

Groundwater wells

There are seven groundwater wells located within the MMA, as identified by the Texas Water Development Board. All of the identified groundwater wells in the area have total depths less than or equal to 265', as shown in Figure 32 and Table 9. One of the wells is located on the 30-30 facility property with a total depth of 119'and is operated by Stakeholder.

The surface and intermediate casings of the Rattlesnake AGI #1 well, as shown in Figure 29, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the GAU letter issued for this location. See GAU letter included within Appendix B. The wellbore casings and cements also serve to prevent CO_2 leakage to the surface along the borehole.

A larger scale version of Figure 32 is provided in Appendix F.

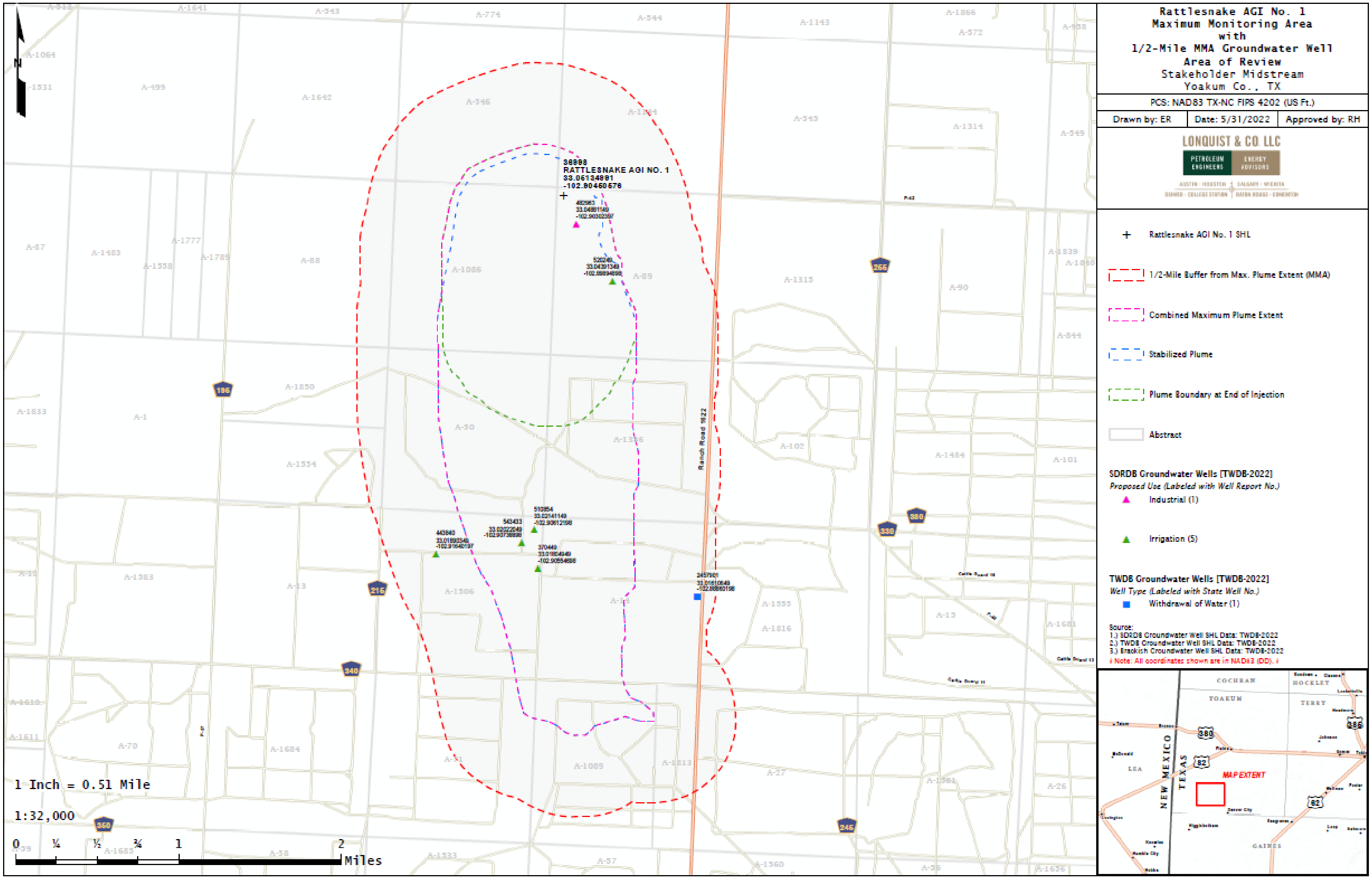


Figure 32 – Groundwater Wells within MMA

Table 9 – Groundwater Well Summary

State Well ID	Owner Name	Primary Use	Well Depth	Data Source
370449	Frances Barbini	Irrigation	237	SDRDB
443840	Frances Jean Barbini	Irrigation	250	SDRDB
482963	Santa Fe Midstream Permian	Industrial	119	SDRDB
510854	FRANCIS BARNINI	Irrigation	255	SDRDB
520249	Thomas Durham	Irrigation	264	SDRDB
543433	FRANCIS BARBIDI	Irrigation	240	SDRDB
84760	TEXACO PRODUCING INC			TWDB_BW

Leakage Through Faults and Fractures

Faults were interpreted from roughly 9 square miles of 3D seismic indicated by the purple outline in Figure 12. Faulting in this region terminates vertically below the Pennsylvanian-age rock. Secondary confining shales within the Wolfcampian and younger strata provide additional, redundant confining layers that would prevent CO_2 from migrating into freshwater aquifers. None of the mapped faults project above the Wolfcamp formation; rather, they appear to terminate between the Strawn and base of the Wolfcamp formation. If, in the unlikely event the faults' sealing properties are compromised post-injection, secondary confinement is provided by the tight limestones found within the overlying Mississippianan Lime formation and the shale layers found in the Atoka and Wolfcamp formations. As seen in Figure 14, the largest fault found SE of the Rattlesnake AGI #1 well, terminates within the Atoka formation. Though it crosses the Silurian section, this fault thrusts the Mississippian Lime upward against the Atoka shales. The tight reservoir characteristics of the Mississippian Lime and shaley section of the Atoka create a confining environment vertically and laterally to contain potential upward migration of buoyant fluids. Shales within the Wolfcamp formation provide additional confining beds between overlying USDWs and the fault plane.

Should an unmapped fault exist within the plume boundary, the offset would be below 3D seismic resolution. The offset would be less than the thickness of the Woodford shale, juxtaposing the Woodford against itself, preventing vertical migration.

Fractures and subsequent subaerial exposure are responsible for porosity development within the injection intervals. Open hole logs show little to no porosity development indicating the Woodford or Mississippian Lime were not exposed at this location. Upward migration of injected gas through confining bed fractures is unlikely.

Leakage Through the Confining Layer

The Silurian-Devonian injection zones have competent sealing rocks above and below the porous sub-aerially exposed carbonate. The properties of the overlying transgressive Woodford shale (widespread deposition, high illite clay and organic matter composition, and low porosity and permeability) make an excellent sealing rock to the underlying Silurian formation. Tight Mississippian Lime of roughly 660 ft, lay between Atoka and Woodford shale formations, forming an impermeable upper seal to the injection interval. Above this confining unit, correlative shales of the Wolfcamp, Abo and Tubb formations will prevent any upper fluid migration. These impermeable shales are capped by hundreds of feet of the regionally present Salado formation evaporites. The USDW lies above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. The underlying low porosity and permeability Montoya carbonate minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injected gas to the in-situ reservoir fluid makes migration below the lower confining layer unlikely.

Leakage from Natural or Induced Seismicity

The location of Rattlesnake AGI #1 is in an area of the Permian Basin that is inactive from a seismicity perspective, whether induced or natural. A review of historical seismic events on the USGS's Advanced National Seismic System site (from 1971 to present) and the Bureau of Economic Geology's TexNet catalog (from 2017 to present), as shown in Figure 33, indicates the nearest seismic event occurred more than 60 miles away.

A regional analysis of the probabilistic fault slip potential across the Permian Basin (Snee & Zoback 2016), as seen in Figure 34, further demonstrates that the Rattlesnake AGI #1 well is located in a seismically inactive area and confirms that this area has little to no potential for an induced seismicity event.

Therefore, there is no indication that seismic activity poses a risk for loss of CO_2 to the surface within the MMA.

Pressures will be kept significantly below the fracture gradient of the injection and confining intervals. Additionally, continuous well monitoring combined with seismic monitoring will identify any operational anomalies associated with a seismicity event.

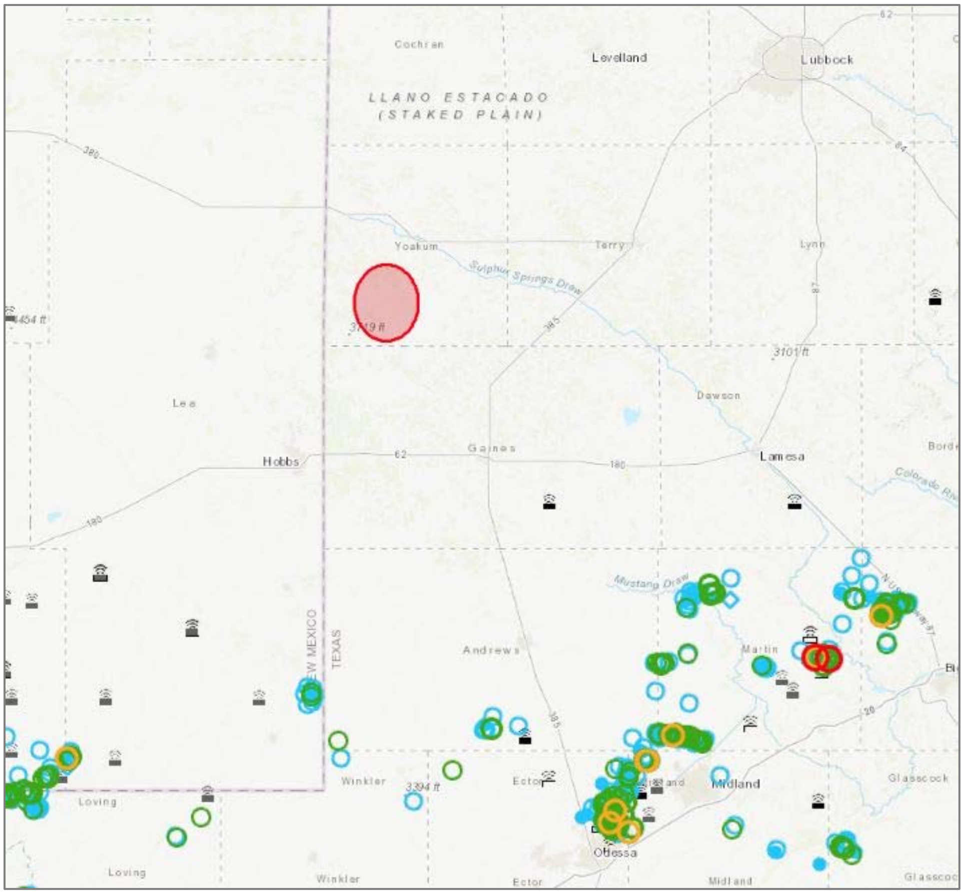


Figure 33 – Seismicity Review (TexNet – 06/01/2022)

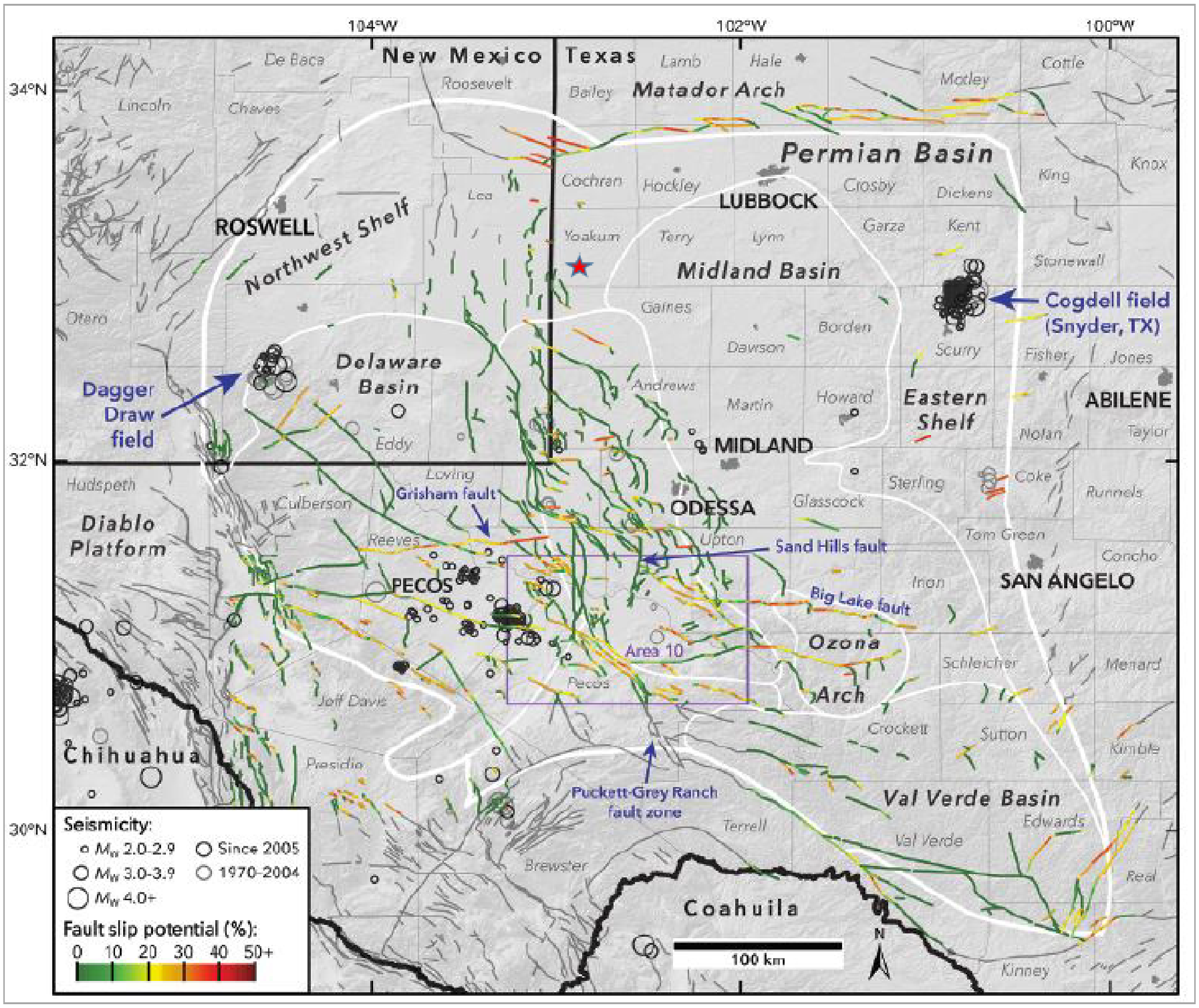


Figure 34 – Probabilistic Fault Slip Potential Analysis with Rattlesnake AGI #1 location (Snee & Zobak 2016)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Stakeholder will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in Section 4 to meet the requirements of 40 CFR §98.448(a)(3). As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 10 summarizes the monitoring of potential leakage pathways to the surface. Monitoring will occur during the planned 17-year injection period, or cessation of injection operations, plus a proposed 5-year post-injection period.

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

Because the acid gas injection stream also contains H_2S, any leakage would be detected by the H_2S alarms located around the facility and would be quickly addressed which would minimize the release of CO_2 into the atmosphere.

Table 10 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed H_2S monitors throughout the AGI facility
	Daily visual inspections
	Personal H_2S monitors
	Distributed Control System Monitoring (Volumes and Pressures)
Leakage through existing wells	Fixed H_2S monitor at the AGI well
	SCADA Continuous Monitoring at the AGI Well
	Annual Mechanical Integrity Tests ("MIT") of the AGI Well
	Visual Inspections
	Quarterly CO_2 Measurements within AMA
Leakage through groundwater wells	Annual Groundwater Samples on Property
Leakage from future wells	H_2S Monitoring during offset drilling operations
Leakage through faults and fractures	SCADA Continuous Monitoring at the AGI Well (volumes and pressures)
	Fixed In-field H_2S monitors
Leakage through confining layer	SCADA Continuous Monitoring at the AGI Well (volumes and pressures)
	Fixed In-field H_2S monitors
Leakage from natural or induced seismicity	Seismic monitoring station to be installed

Leakage from Surface Equipment

As the 30-30 Facility and the Rattlesnake AGI #1 well are designed to handle H_2S, leakage from surface equipment is unlikely to occur and would be quickly detected and addressed. The facility design minimizes leak points through the equipment used and the type of connections are designed to minimize corrosion points. The H_2S in the injectate serves as a proxy for the release of CO_2. The facility and well site contain a number of H_2S alarms, set with a high alarm setpoint of 10 ppm of H_2S, which are shown in Figure 28 above. Additionally, all Stakeholder field personnel are required to wear H_2S monitors, which trigger the alarm at 5 ppm H_2S.

The AGI facility is continuously monitored through automated systems. In addition, field personnel conduct daily visual field inspections of gauges, monitors and leak indicators such as vapor plumes. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system, analysis of liquids collected from the line, and inspection of the cathodic protection system. These inspections, in addition to the automated systems, allow Stakeholder to quickly respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5).

Pressures and flowrates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak.

Leakage from Existing and Future Wells within MMA

Stakeholder continuously monitors and collects injection volumes, pressures, temperatures and gas composition data, through their SCADA systems, for the Rattlesnake AGI #1 well. This data is reviewed by qualified personnel and will follow response and reporting procedures when data is outside acceptable performance limits. Rattlesnake AGI #1 has a pressure and temperature gauge placed in the injection stream at its wellhead, and a pressure gauge on the casing annulus. A change of pressure on the annulus would indicate the presence of a possible leak. Mechanical integrity tests ("MITs") performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated and the leak mitigated.

The ten offset penetrating wells within the MMA are adequately cased and cemented to prevent potential leakage of CO_2 from the Rattlesnake AGI #1 well plume. Additionally, the plugged wells were done so in a way to prevent migration of CO_2 as provided in Appendix E. As discussed previously, Rule 13 would ensure that new wells in the field would be constructed in a manner to prevent migration from the injection interval.

In addition to the fixed and personal monitors described previously, Stakeholder will also establish and operate an in-field monitoring program to detect any CO_2 leakage within the AMA. The scope of work will include H_2S and CO_2 monitoring at the AGI well site as well as minimum, quarterly atmospheric monitoring near identified penetrations within the AMA. Upon approval of the MRV and through the post-injection monitoring period, Stakeholder will have these monitoring systems in place. Additional monitoring will be added as the AMA is updated over time.

At the well site, H_2S and CO_2 concentrations will be monitored continuously with fixed monitors that detect atmospheric concentrations of H_2S and CO_2. At penetrating well sites, Stakeholder will similarly measure atmospheric concentrations of CO_2 and H_2S using mobile gas monitors. This data will be recorded at least quarterly.

Groundwater Quality Monitoring

Stakeholder will monitor the groundwater quality in fluids above the confining interval by sampling the well on the facility property and analyzing the sample with a third-party laboratory on an annual basis. Any significant changes to the water analysis would be investigated to determine if such change was a result of leakage from the Rattlesnake AGI #1 well. The parameters to be measured will include pH, total dissolved solids, total inorganic and organic carbons, density, temperature and other standard laboratory measurements. Any significant differences in these parameters from the baseline sample will be evaluated to determine if leakage of CO_2 to the USDW may have occurred.

Leakage through Faults, Fractures or Confining Seals

Stakeholder continuously monitors the operations of the Rattlesnake AGI #1 well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway such as a fault or breakthrough of the confining seal would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. Field H_2S monitoring systems would alert field personnel for any release of H_2S/CO_2 caused by such leakage.

Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Stakeholder plans to install a seismic monitoring station in the general area of the Rattlesnake AGI #1 well. The installation of this station would start upon approval of the MRV plan, with an expected in-service data within six months after the commencement of the installation project. This monitoring station will be tied in to the Bureau of Economic Geology's TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, Stakeholder will review the injection volumes and pressures at the Rattlesnake AGI #1 well to determine if any significant changes occur that would indicate potential leakage.

SECTION 6 – BASELINE DETERMINATIONS

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

Visual Inspections

Daily inspections will be conducted by field personnel at the 30-30 Facility and the Rattlesnake AGI #1 well. These inspections will aid with identifying and addressing issues timely to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions would be taken to address such issues.

H_2S Detection

H_2S will be initially injected into the AGI well at a concentration of approximately ten (10) percent or 100,000 ppm. The concentration will drop to approximately seven (7) percent as additional volumes are added. H_2S gas detectors are located throughout the AGI facility and well site and are set to trigger the alarm at 10 ppm. Additionally, all field personnel are required to wear personal H_2S monitors, which are set to trigger the alarm at 5 ppm. Any alarm would trigger an immediate response to protect personnel and verify that the monitors are working properly. If monitors are working correctly, immediate actions would be taken to secure the facility and mitigate potential leaks.

CO_2 Detection

Any CO_2 release would be accompanied by H_2S and therefore the H_2S monitors at the facility would also serve as a CO_2 release warning system. In addition to the fixed and personal monitors described previously, Stakeholder will also establish and operate an in-field monitoring program to detect any CO_2 leakage within the AMA. The scope of work will include H_2S and CO_2 monitoring at the AGI well site as well as atmospheric monitoring near identified penetrations within the AMA.

Operational Data

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

Continuous Monitoring

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which would be extremely dangerous for personnel to perform a direct leak survey. Any leakage would be detected and managed as per Texas regulations and Stakeholder's TRRC-approved H_2S Contingency Plan. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

No CO_2 emissions will occur from venting because of the high H_2S concentrations. Blowdown emissions are sent to flares and would be reported as part of the required reporting for the gas plant.

Groundwater Monitoring

An initial sample will be taken from the groundwater well on Stakeholder's property, identified as Well # 482963 in Table 9 above, upon approval of Stakeholder's MRV and prior to increasing injection. The sample will be analyzed by a third-party laboratory to establish the baseline properties of the groundwater.

SECTION 7 – SITE SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

Mass of CO_2 Received

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

Mass of CO_2 Injected

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

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

where:

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

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

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

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

p = Quarter of the year

u = Flow meter

Mass of CO_2 Produced

The Rattlesnake AGI #1 well is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

Mass of CO_2 Emitted by Surface Leakage

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which would be extremely dangerous for personnel to perform a direct leak survey. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

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

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

Where:

CO_2 = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year

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

X = Leakage pathway

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

Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based off Equation RR-12, as this well will not actively produce oil or natural gas or any other fluids, as follows:

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

Where:

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

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

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting would occur due to the high H_2S concentrations of the injectate stream, the calculations would be based on the blowdown emissions that would be sent to flares and would be reported as part of the required GHG reporting for the gas plant.

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The Rattlesnake AGI #1 well currently reports GHGs under Subpart UU, but Stakeholder has elected to submit an MRV plan under, and otherwise comply with, Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31st of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

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

Monitoring QA/QC

CO_2 *Injected*

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer recommendations.

CO_2 *Emissions from Leaks and Vented Emissions*

- Gas detectors will be operated continuously, except for maintenance and calibration.
- Gas detectors will be calibrated according to manufacturer recommendations and API standards.
- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to the requirements in 40 CFR §98.3(i).
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.
- Flow meter calibrations will be traceable to the National Institute of Standards and Technology (NIST).

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

Missing Data

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

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in subpart W of 40 CFR §98.

MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Stakeholder will retain records as required by 40 CFR §98.3(g). These records will be retained for at least three years and include:

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

References

Broadhead, Ronald E., 2005. Regional Aspects of the Wristen petroleum system, southeastern New Mexico: New Mexico Bureau of Geology and Mineral Resources Open File Report, no. 485.

Comer, John B., 1991. Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas and Southeastern New Mexico: Bureau of Economic Geology Report of Investigations, no. 201.

George, Peter G., Mace, Robert E., and Petrossian, Rima, 2011. Aquifers of Texas: Texas Water Development Board Report, no 380.

Hoak, T., Sundberg, K., and Ortoleva, P. Overview of the Structural Geology and Tectonics of the Central Basin Platform, Delaware Basin, and Midland Basin, West Texas and New Mexico: Department of Energy Open File Report.

Molina, Oscar, Vilarras, Victor, and Zeidouni, Mehdi, 2016. Geologic carbon storage for shale gas recovery: 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18.

Ruppel, Stephen C. and Holtz, Mark H., 1994. Depositional and Diagenetic Facies Patterns and Reservoir Development in Silurian and Devonian Rocks of the Permian Basin: Bureau of Economic Geology Report of Investigations, no. 216.

Snee, Jens-Erik Lund and Zoback, Mark D., 2016. State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity.

Teeple, Andrew P., Ging, Patricia B., Thomas, Jonathan V., Wallace, David S., and Payne, Jason D., 2021. Hydrogeologic Framework, Geochemistry, Groundwater-Flow System, and Aquifer Hydraulic Properties Used in the Development of a Conceptual Model of the Ogallala, Edwards-Trinity (High Plains), and Dockum Aquifers In and Near Gaines, Terry, and Yoakum Counties, Texas: USGS Scientific Investigations Report 2021-5009.

APPENDICES

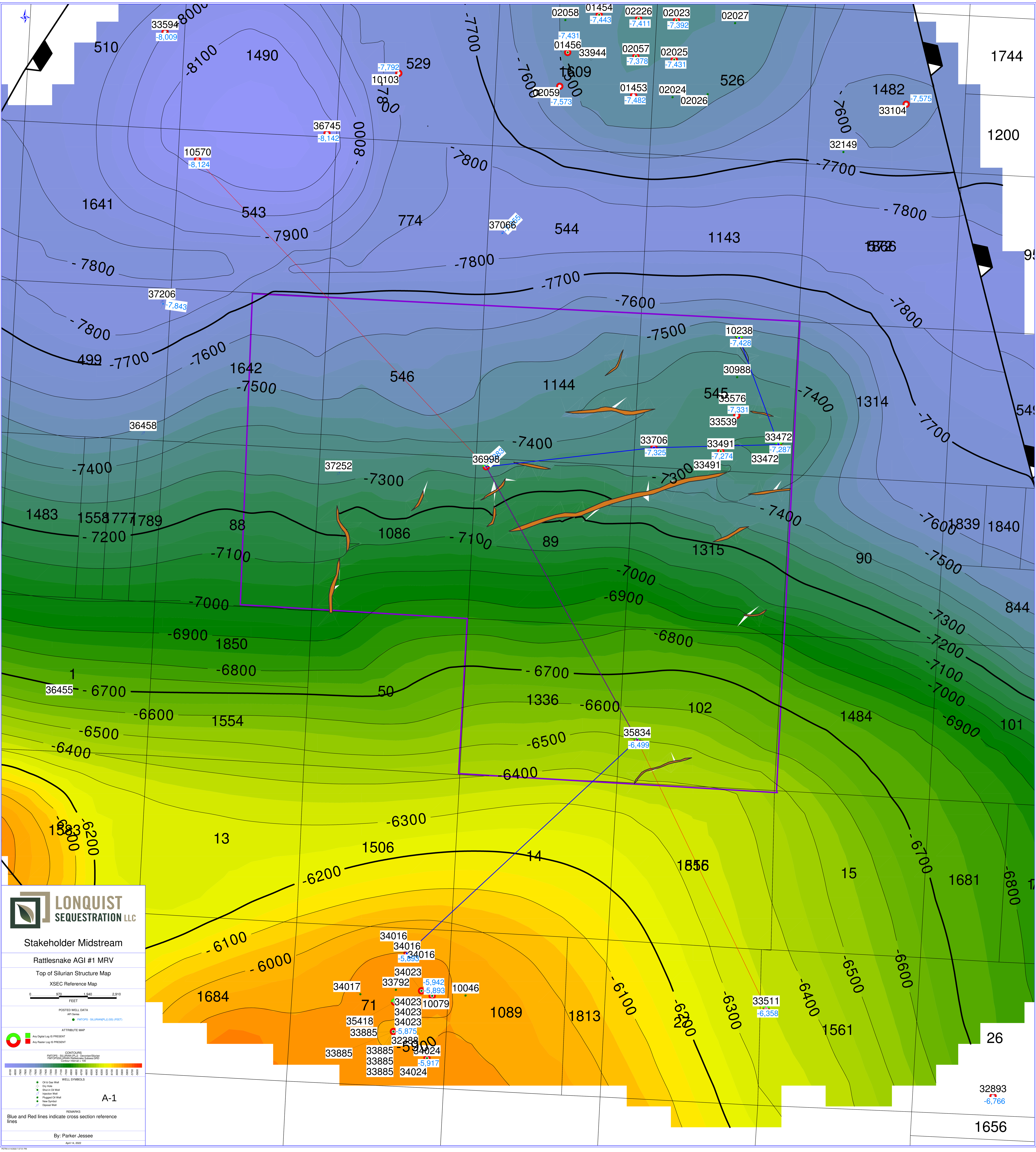
APPENDIX A – GEOLOGY

APPENDIX A-1: SILURIAN STRUCTURE MAP

APPENDIX A-2: NE-SW CROSS SECTION

APPENDIX A-3: NW-SE CROSS SECTION

APPENDIX A-4: FORMATION FLUID SAMPLE WELL MAP


LONQUIST SEQUESTRATION LLC
Stakeholder Midstream
Rattlesnake AGI #1 MRV
Top of Silurian Structure Map
XSEC Reference Map
0 970 1,940 2,910
FEET
POSTED WELL DATA
API Series
FMTOPS - SILURIAN[PLJ] (SS) (FEET)
ATTRIBUTE MAP
Any Digital Log IS PRESENT
Any Raster Log IS PRESENT
CONTOURS
FMTOPS - SILURIAN [PLJ] - Devonian/Silurian
FMTOPSSILURIAN Rattlesnake Subsea.GRD
Contour Interval = 100
-8100 -8000 -7900 -7800 -7700 -7600 -7500 -7400 -7300 -7200 -7100 -7000 -6900 -6800 -6700 -6600 -6500 -6400 -6300 -6200 -6100 -6000 -5900 -5800 -5700 -5600
WELL SYMBOLS
Oil & Gas Well
Dry Hole
Shut-in Oil Well
Injection Well
Plugged Oil Well
New Symbol
Diposal Well
A-1
REMARKS
Blue and Red lines indicate cross section reference lines
By: Parker Jessee
April 14, 2022
PETRA 4/14/2022 7:27:51 PM

A-2

LONQUIST SEQUESTRATION LLC

Stakeholder Midstream

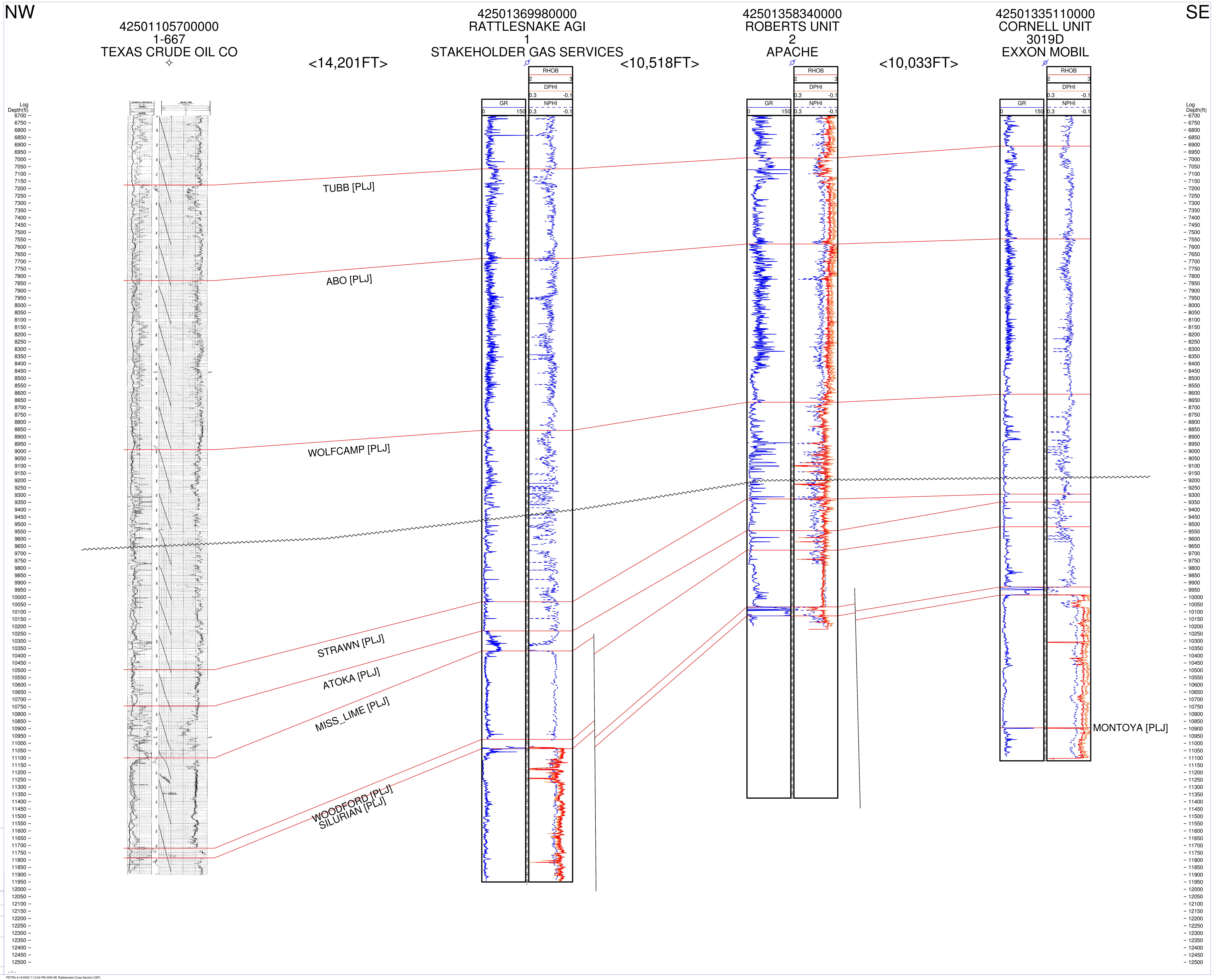
Rattlesnake AGI #1 MRV

NE-SW Structural Cross Section

Horizontal Scale = 193.4
Vertical Scale = 50.0
Vertical Exaggeration = 3.9x

UWI
Well Name
Well Number
Operator

April 14,2022 7:03 PM



A-3

LONQUIST SEQUESTRATION LLC

Stakeholder Midstream

Rattlesnake agi #1 MRV

NW-SE Structural Cross Section

Horizontal Scale = 289.6
Vertical Scale = 50.0
Vertical Exaggeration = 5.8x

UWI
Well Name
Well Number
Operator

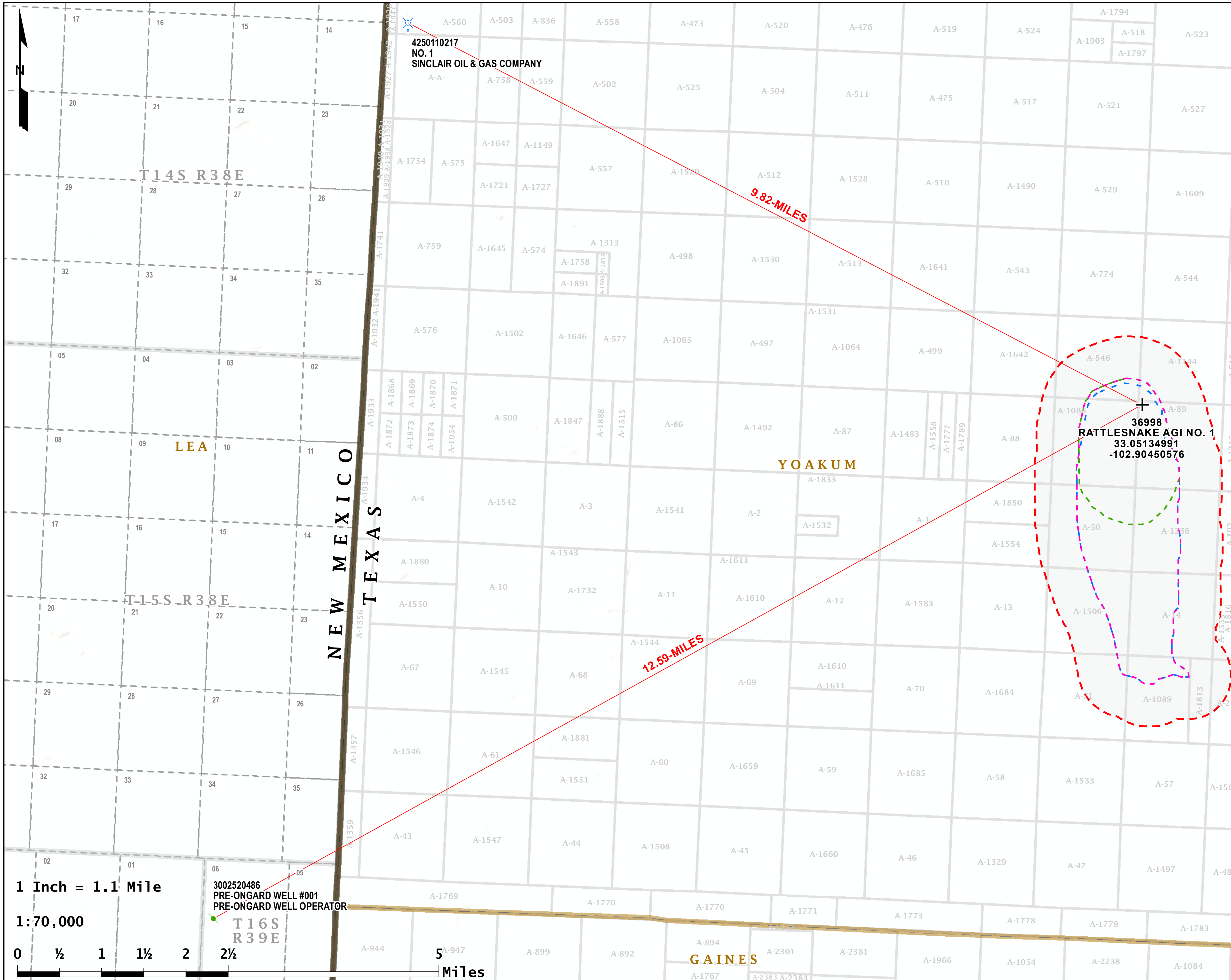
April 14,2022 7:13 PM

Rattlesnake AGI No. 1
Maximum Monitoring Area
with
Formation Fluid Sample Wells
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 6/1/2022	Approved by: RH

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS
AUSTIN • HOUSTON • CALGARY • WICHITA
DENVER • COLLEGE STATION • BATON ROUGE • EDMONTON

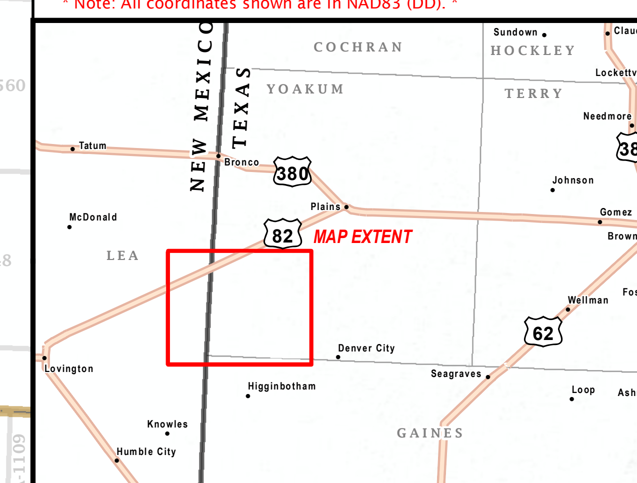


Rattlesnake AGI No. 1 SHL
1/2-Mile Buffer from Max. Plume Extent (MMA)
Combined Maximum Plume Extent
Stabilized Plume
Plume Boundary at End of Injection
Abstract
County Boundary
State Boundary
Section Boundary [NM BLM-2022]
Township Boundary [NM BLM-2022]
Distance Call

Formation Fluid Sample Well [NM OCD-2022]
Plugged - Oil

Formation Fluid Sample Well [DI-2022]
TA - Injection/Disposal

Source:
1.) Oil/Gas Well SHL Data: DI-2022/NM OCD-2022
2.) Oil/Gas Well BHL Data: DI-2022
3.) Oil/Gas Well Directional Data: DI-2022
* Note: All coordinates shown are in NAD83 (DD). *



APPENDIX B – TRRC FORMS Rattlesnake AGI #1

APPENDIX B-1: UIC CLASS II ORDER

APPENDIX B-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX B-3: DRILLING PERMIT

APPENDIX B-4: COMPLETION REPORT

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 15848

SANTA FE MIDSTREAM PERMIAN LLC
5830 GRANITE PKWY STE 1025
PLANO, TX 75024

DOCKET NO. 8A-0312019

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated March 12, 2018 for the permitted interval of the DEVONIAN formation and subject to the following terms and special conditions:

RATTLESNAKE AGI (000000) LEASE
WASSON FIELD
YOAKUM COUNTY, DISTRICT 8A

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
1	50136998	000117143	CO2, and H2S	11,000	12,000	4,500	N/A	N/A	2,200

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	50136998	**1. Open hole completions shall have a plug back depth no deeper than the bottom of the permitted injection interval.** **2. The operator shall provide to the UIC section an annotated electric log, and a mud log if available, of the subject well with the top(s) and bottom(s) of the permitted formation indicated on the log. Top and bottom of the authorized injection interval may be modified based on electric log or mud log indications of the top and bottom of the permitted formations.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;
   c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON November 14, 2018.

Sean Avitt

Sean Avitt, Manager
Injection-Storage Permits Unit

IN-HOUSE AMENDMENT TO CORRECT THE RATE.

Note: This document will only be distributed electronically.

GROUNDWATER PROTECTION DETERMINATION

Groundwater Advisory Unit

Form GW-2

B-2

Date Issued:	31 August 2017	**GAU Number:**	179154

Attention:	SANTA FE MIDSTREAM 5700 GRANITE PARKWAY PLANO, TX 75024	**API Number:**	
		County:	YOAKUM
		Lease Name:	Roberts Unit
		Lease Number:	019212
Operator No.:	748093	**Well Number:**	1
		Total Vertical Depth:	11000
		Latitude:	33.049990
		Longitude:	-102.903464
		Datum:	NAD27

Purpose: New Drill

Location: Survey-Gibson, J H/Poole, J T; Block-D; Section-733

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

The interval from the land surface to a depth of 375 feet must be protected.

Note: Unless stated otherwise, this recommendation is intended to apply only to the subject well and not for area-wide use. This recommendation is for normal drilling, production, and plugging operations only. It does not apply to saltwater disposal operation into a nonproductive zone (RRC Form W-14).

This determination is based on information provided when the application was submitted on 08/30/2017. 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

API No. 42-501-36998

Drilling Permit # 839303

SWR Exception Case/Docket No.

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

APPLICATION FOR PERMIT TO DRILL, RECOMPLETE, OR RE-ENTER

This facsimile W-1 was generated electronically from data submitted to the RRC.
A certification of the automated data is available in the RRC's Austin office.

FORM W-1 07/2004

Permit Status: Approved

B-3

1. RRC Operator No. 748093

2. Operator's Name (as shown on form P-5, Organization Report) SANTA FE MIDSTREAM PERMIAN LLC

3. Operator Address (include street, city, state, zip): 5830 GRANITE PKWY STE 1025 PLANO, TX 75024-0000

4. Lease Name RATTLESNAKE AGI

5. Well No. 1

GENERAL INFORMATION

6. Purpose of filing (mark ALL appropriate boxes): [X] New Drill [ ] Recompletion [ ] Reclass [ ] Field Transfer [ ] Re-Enter [ ] Amended [ ] Amended as Drilled (BHL) (Also File Form W-1D)

7. Wellbore Profile (mark ALL appropriate boxes): [X] Vertical [ ] Horizontal (Also File Form W-1H) [ ] Directional (Also File Form W-1D) [ ] Sidetrack

8. Total Depth 12000

9. Do you have the right to develop the minerals under any right-of-way ? [X] Yes [ ] No

10. Is this well subject to Statewide Rule 36 (hydrogen sulfide area)? [X] Yes [ ] No

SURFACE LOCATION AND ACREAGE INFORMATION

11. RRC District No. 8A

12. County YOAKUM

13. Surface Location [X] Land [ ] Bay/Estuary [ ] Inland Waterway [ ] Offshore

14. This well is to be located 7.3 miles in a NW direction from DENVER CITY which is the nearest town in the county of the well site.

15. Section 733

16. Block D

17. Survey GIBSON, J H

18. Abstract No. A-89

19. Distance to nearest lease line: 200 ft.

20. Number of contiguous acres in lease, pooled unit, or unitized tract: 640

21. Lease Perpendiculars: 200 ft from the NORTH line and 200 ft from the WEST line.

22. Survey Perpendiculars: 200 ft from the NORTH line and 200 ft from the WEST line.

23. Is this a pooled unit? [ ] Yes [X] No

24. Unitization Docket No:

25. Are you applying for Substandard Acreage Field? [ ] Yes (attach Form W-1A) [X] No

FIELD INFORMATION List all fields of anticipated completion including Wildcat. List one zone per line.

26. RRC District No.	27. Field No.	28. Field Name (exactly as shown in RRC records)	29. Well Type	30. Completion Depth	31. Distance to Nearest Well in this Reservoir	32. Number of Wells on this lease in this Reservoir
8A	95397001	WASSON	Injection Well	12000	0.00	1
8A	95399400	WASSON, NORTH (SAN ANDRES)	Injection Well	12000	0.00	1

BOTTOMHOLE LOCATION INFORMATION is required for DIRECTIONAL, HORIZONTAL, AND AMENDED AS DRILLED PERMIT APPLICATIONS

Remarks

[FILER Apr 16, 2018 5:16 PM]: Filing for an acid gas injection well.

Certificate:

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

Jessica Risien, Regulatory Compliance Specialist
Name of filer

Apr 25, 2018
Date submitted

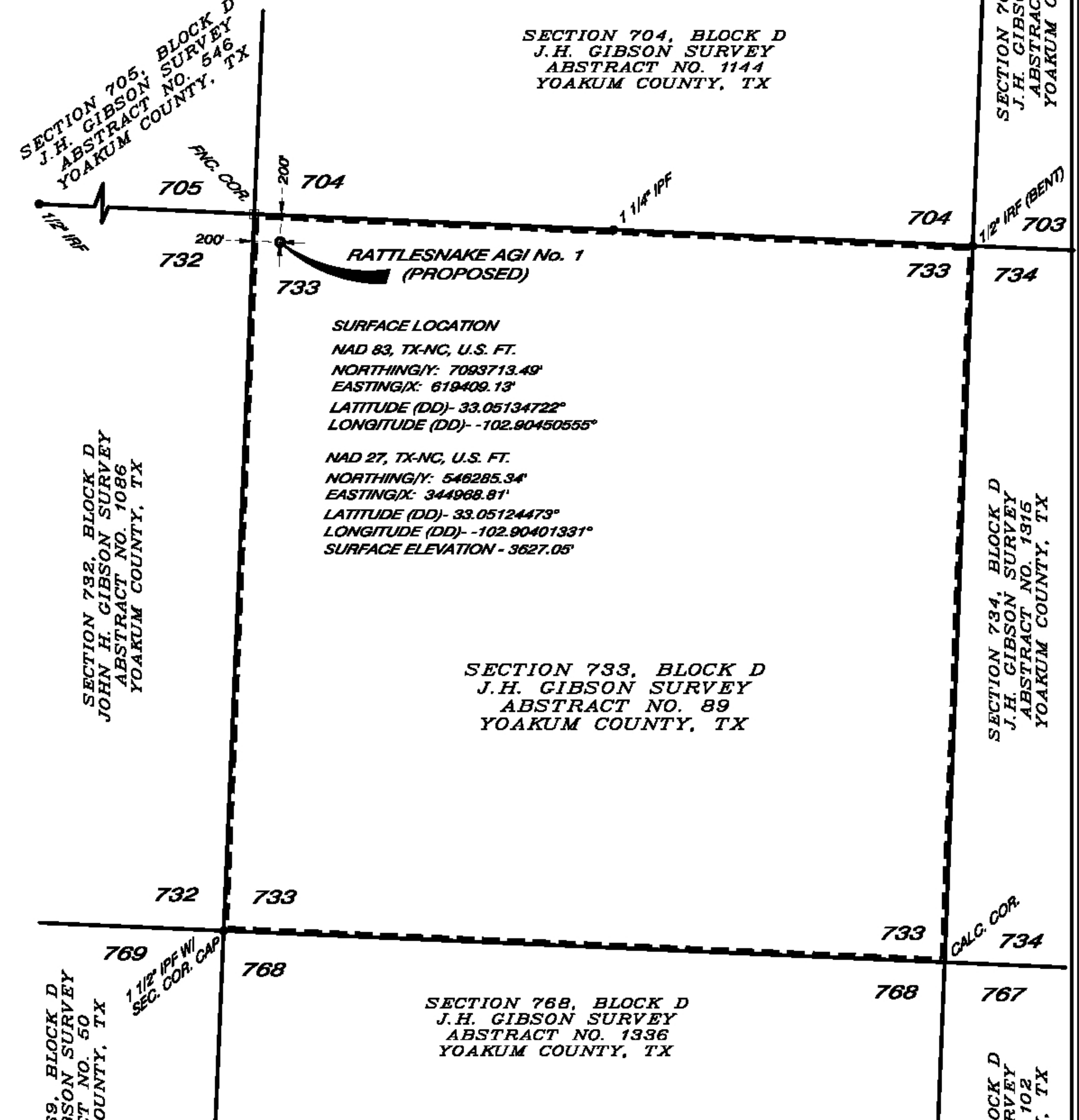
(281)8729300
Phone

jrisien@ntglobal.com
E-mail Address (OPTIONAL)

RRC Use Only Data Validation Time Stamp: Apr 27, 2018 10:36 AM('As Approved' Version)

NOTE: Acreages shown hereon are based on information provided by others.
This plat represents a staked well location and does not represent a boundary survey.
The information shown does not meet the current TBPLS minimum standards for boundary surveys. Limited field measurements were acquired. Lease and tract line information is compiled from record information and additional sources.

NOTES:
1.) ALL BEARINGS, DISTANCES AND COORDINATES SHOWN HEREON WERE DERIVED FROM G.P.S. OBSERVATIONS CONVERTED TO THE TEXAS COORDINATE SYSTEM, NORTH CENTRAL ZONE (NAD 1983), US FOOT AND ARE REFERENCED TO THE LOCAL GNSS RTK NETWORK.
2.) THE PROPOSED WELL LOCATION IS SITUATED N 37°W - 7.3 MILES FROM DENVER CITY, TX.
3.) THE PROPOSED WELL LOCATION IS SITUATED 200' FROM THE NSL AND 200' FROM THE WSL.



WELL LOCATION PLAT
SHOWING
SANTA FE MIDSTREAM PERMIAN LLC
RATTLESNAKE AGI No. 1
J.H. GIBSON SURVEY, A-89
SECTION 733, BLOCK D
YOAKUM COUNTY, TEXAS

SCALE: 1" = 1000'
1000 500 0 1000
SCALE FEET

I, THE UNDERSIGNED, REGISTERED PROFESSIONAL LAND SURVEYOR, DO HEREBY CERTIFY THAT THE PLAT SHOWN REPRESENTS AN ACTUAL SURVEY MADE ON THE GROUND AND IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

BY: ______________________
ANDREW STOUT 03/20/2018
REGISTERED PROFESSIONAL LAND SURVEYOR
STATE OF TEXAS NO. 5970

STATE OF TEXAS
REGISTERED
ANDREW STOUT
5970
PROFESSIONAL
LAND SURVEYOR

INTEGRITY POSITIONS, LLC
14296 FM 314 N.
BROWNSBORO, TX 75756
(903) 595-9385
Firm No. 10194095

Railroad Commission of Texas

PERMIT TO DRILL, RE-COMPLETE, OR RE-ENTER ON REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

CONDITIONS AND INSTRUCTIONS

Permit Invalidation. It is the operator's responsibility to make sure that the permitted location complies with Commission density and spacing rules in effect on the spud date. The permit becomes invalid automatically if, because of a field rule change or the drilling of another well, the stated location is not in compliance with Commission field rules on the spud date. If this occurs, application for an exception to Statewide Rules 37 and 38 must be made and a special permit granted prior to spudding. Failure to do so may result in an allowable not being assigned and/or enforcement procedures being initiated.

Notice Requirements. Per H.B 630, signed May 8, 2007, the operator is required to provide notice to the surface owner no later than the 15th business day after the Commission issues a permit to drill. Please refer to subchapter Q Sec. 91.751-91.755 of the Texas Natural Resources Code for applicability.

Permit expiration. This permit expires two (2) years from the date of issuance shown on the original permit. The permit period will not be extended.

Drilling Permit Number. The drilling permit number shown on the permit MUST be given as a reference with any notification to the district (see below), correspondence, or application concerning this permit.

Rule 37 Exception Permits. This Statewide Rule 37 exception permit is granted under either provision Rule 37 (h)(2)(A) or 37(h)(2)(B). Be advised that a permit granted under Rule 37(h)(2)(A), notice of application, is subject to the General Rules of Practice and Procedures and if a protest is received under Section 1.3, "Filing of Documents," and/or Section 1.4, "Computation of Time," the permit may be deemed invalid.

Before Drilling

Fresh Water Sand Protection. The operator must set and cement sufficient surface casing to protect all usable-quality water, as defined by the Railroad Commission of Texas (RRC) Groundwater Advisory Unit (GWAU). Before drilling a well, the operator must obtain a letter from the Railroad Commission of Texas stating the depth to which water needs protection, Write: Railroad Commission of Texas, Groundwater Advisory Unit (GWAU), P.O. Box 12967, Austin, TX 78711-3087. File a copy of the letter with the appropriate district office.

Accessing the Well Site. If an OPERATOR, well equipment TRANSPORTER or WELL service provider must access the well site from a roadway on the state highway system (Interstate, U.S. Highway, State Highway, Farm-to-Market Road, Ranch-to-Market Road, etc.), an access permit is required from TxDOT. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

Water Transport to Well Site. If an operator intends to transport water to the well site through a temporary pipeline laid above ground on the state's right-of-way, an additional TxDOT permit is required. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

*NOTIFICATION

The operator is **REQUIRED** to notify the district office when setting surface casing, intermediate casing, and production casing, or when plugging a dry hole. The district office MUST also be notified if the operator intends to re-enter a plugged well or re-complete a well into a different regulatory field. Time requirements are given below. The drilling permit number MUST be given with such notifications.

During Drilling

Permit at Drilling Site : A copy of the Form W-1 Drilling Permit Application, the location plat, a copy of Statewide Rule 13 alternate surface casing setting depth approval from the district office, if applicable, and this drilling permit must be kept at the permitted well site throughout drilling operations.

***Notification of Setting Casing :** The operator MUST call in notification to the appropriate district office (phone number shown the on permit) a minimum of eight (8) hours prior to the setting of surface casing, intermediate casing, AND production casing. The individual giving notification MUST be able to advise the district office of the drilling permit number.

***Notification of Re-completion/Re-entry :** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of eight (8) hours prior to the initiation of drilling or re-completion operations. The individual giving notification MUST be able to advise the district office of the drilling permit number.

Completion and Plugging Reports

Hydraulic Fracture Stimulation using Diesel Fuel: Most operators in Texas do not use diesel fuel in hydraulic fracturing fluids. Section 322 of the Energy Policy Act of 2005 amended the Underground Injection Control (UIC) portion of the federal Safe Drinking Water Act (42 USC 300h(d)) to define "underground Injection" to *EXCLUDE* " ...the underground injection of fluids or propping agents *(other than diesel fluels)* pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities." (italic and underlining added.) Therefore, hydraulic fracturing may be subject to regulation under the federal UIC regulations if diesel fuel is injected or used as a propping agent. EPA defined "diesel fuel" using the following five (5) Chemical Abstract Service numbers: 68334-30-5 Primary Name: Fuels, diesel; 68476-34-6 Primary Name: Fuels, diesel, No. 2; 68476-30-2 Primary Name: Fuel oil No. 2; 68476-31-3 Primary Nmae: Fuel oil, No. 4; and 8008-20-6 Primary Name: Kerosene. As a result, an injection well permit would be required before performing hydraulic fracture stimulation using diesel fuel as defined by EPA on any well in Texas. Hydraulic fracture stimulation using diesel fuel as defined by EPA on a well in Texas without an injection well permit could result in enforcement action.

Producing Well : Statewide Rule 16 states that the operator of a well shall file with the Commission the appropriate completion report within thirty (30) days after completion of the well or within ninety (90) days after the date on which the drilling operation is completed, whichever is earlier. Completion of the well in a field authorized by this permit voids the permit for all other fields included in the permit unless the operator indicates on the initial completion report that the well is to be a dual or multiple completion and promptly submits an application for multiple completion. All zones are required to be completed before the expiration date on the existing permit. Statewide Rule 40(d) requires that upon successful completion of a well in the same reservoir as any other well previously assigned the same acreage, proration plats and P-15s (if required) must be submitted with no double assignment of acreage.

Dry or Noncommercial Hole : Statewide Rule 14(b)(2) prohibits suspension of operations on each dry or non-commercial well without plugging unless the hole is cased and the casing is cemented in compliance with Commission rules. If properly cased, Statewide Rule 14(b)(2) requires that plugging operations must begin within a period of one (1) year after drilling or operations have ceased. Plugging operations must proceed with due diligence until completed. An extension to the one-year plugging requirement may be granted under the provisions stated in Statewide Rule 14(b)(2).

Intention to Plug : The operator must file a Form W-3A (Notice of Intention to Plug and Abandon) with the district office at least five (5) days prior to beginning plugging operations. If, however, a drilling rig is already at work on location and ready to begin plugging operations, the district director or the director's delegate may waive this requirement upon request, and verbally approve the proposed plugging procedures.

***Notification of Plugging a Dry Hole :** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of four (4) hours prior to beginning plugging operations. The individual giving the notification MUST be able to advise the district office of the drilling permit number and all water protection depths for that location as stated in the Texas Commission on Environmental Quality letter.

DIRECT INQUIRIES TO: DRILLING PERMIT SECTION, OIL AND GAS DIVISION

PHONE
(512) 463-6751

MAIL:
PO Box 12967
Austin, Texas, 78711-2967

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER 839303	DATE PERMIT ISSUED OR AMENDED 04/27/2018	DISTRICT 8A
API NUMBER 42-501-36998	FORM W-1 RECEIVED 04/25/2018	COUNTY YOAKUM
TYPE OF OPERATION New Drill	WELLBORE PROFILE(S) Vertical	ACRES 640.0
OPERATOR 748093 SANTA FE MIDSTREAM PERMIAN LLC 5830 GRANITE PKWY STE 1025 PLANO, TX 75024-0000		NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. District Office Telephone No: (806) 698-6509
LEASE NAME RATTLESNAKE AGI		WELL NUMBER 1
LOCATION 7.3 miles NW direction from DENVER CITY		TOTAL DEPTH 12000
Section, Block and/or SECTION 733 SURVEY GIBSON, J H	BLOCK D	ABSTRACT 89
DISTANCE TO SURVEY LINES 200.0 ft NORTH 200.0 ft WEST		DISTANCE TO NEAREST LEASE LINE 200.0
DISTANCE TO LEASE LINES 200.0 ft NORTH 200.0 ft WEST		DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL# NEAREST WELL	DIST
WASSON RATTLESNAKE AGI	640.0 200.0	12000	1 0.0	8A

This is a hydrogen sulfide field. This well shall be drilled in accordance with SWR 36.

Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL# NEAREST WELL	DIST
WASSON, NORTH (SAN ANDRES) RATTLESNAKE AGI	640.0 200.0	12000	1 0.0	8A

This is a hydrogen sulfide field. This well shall be drilled in accordance with SWR 36.

Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

This well must comply to the new SWR 3.13 requirements concerning the isolation of any potential flow zones and zones with corrosive formation fluids. See approved permit for those formations that have been identified for the county in which you are drilling the well in.

Railroad Commission of Texas
Oil and Gas Division
SWR #13 Formation Data
YOAKUM (501) COUNTY

Formation	Remarks	Geological Order	Effective Date
RED BED-SANTA ROSA		1	01/01/2014
YATES		2	01/01/2014
SAN ANDRES	high flows, H2S, corrosive	3	01/01/2014
GLORIETA		4	01/01/2014
CLEARFORK	Active CO2 Flood	5	01/01/2014
WICHITA		6	01/01/2014
LEONARD		7	01/01/2014
WOLFCAMP		8	01/01/2014
PENNSYLVANIAN		9	01/01/2014
STRAWN		10	01/01/2014
MISSISSIPPIAN		11	01/01/2014
DEVONIAN		12	01/01/2014
DEVONIAN-SILURIAN		13	01/01/2014

The above list may not be all inclusive, and may also include formations that do not intersect all wellbores. The listing order of the Formation information reflects the general stratigraphic order and relative geologic age. This is a dynamic list subject to updates and revisions. It is the operator's responsibility to make sure that at the time of spudding the well the most current list is being referenced. Refer to the RRC website at the following address for the most recent information. http://www.rrc.texas.gov/oil-gas/compliance-enforcement/rule-13-geologic-formation-info

RAILROAD COMMISSION OF TEXAS

Form G-1

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Approved
Date: 07/25/2019
Tracking No.: 205926

GAS WELL BACK PRESSURE TEST, COMPLETION OR RECOMPLETION REPORT, AND LOG

OPERATOR INFORMATION

Operator Name: SANTA FE MIDSTREAM PERMIAN LLC **Operator No.:** 748093
Operator Address: 5830 GRANITE PKWY STE 1025 PLANO, TX 75024-0000

WELL INFORMATION

API No.: 42-501-36998 **County:** YOAKUM
Well No.: 1 **RRC District No.:** 8A
Lease Name: RATTLESNAKE AGI **Field Name:** WASSON
RRC Gas ID No.: 286838 **Field No.:** 95397001
Location: Section: 733, Block: D, Survey: GIBSON, J H, Abstract: 89

Latitude: **Longitude:**
This well is located 7.3 **miles in a** NW
direction from DENVER CITY,
which is the nearest town in the county.

FILING INFORMATION

Purpose of filing: Well Record Only
Type of completion: New Well
Well Type: Active UIC **Completion or Recompletion Date:** 08/31/2018

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or Deepen	04/27/2018	839303
Rule 37 Exception		
Fluid Injection Permit		
O&G Waste Disposal Permit	11/14/2018	15848
Other:		

COMPLETION INFORMATION

Spud date: 07/16/2018
Date of first production after rig released: 08/31/2018
Date plug back, deepening, recompletion, or drilling operation commenced: 07/16/2018
Date plug back, deepening, recompletion, or drilling operation ended: 08/31/2018
Number of producing wells on this lease in this field (reservoir) including this well: 1
Distance to nearest well in lease & reservoir (ft.): 0.0
Total number of acres in lease: 640.00
Elevation (ft.): 3627 GR
Total depth TVD (ft.): 11980
Total depth MD (ft.):
Plug back depth TVD (ft.): 11980
Plug back depth MD (ft.):
Was directional survey made other than inclination (Form W-12)? Yes
Rotation time within surface casing (hours): 72.0
Is Cementing Affidavit (Form W-15) attached? Yes
Recompletion or reclass? No
Multiple completion? No
Type(s) of electric or other log(s) run: Combo of Induction/Neutron/Density/Sonic
Electric Log Other Description:
Location of well, relative to nearest lease boundaries of lease on which this well is located:
Off Lease: No
200.0 **Feet from the** North **Line and**
200.0 **Feet from the** West **Line of the**
RATTLESNAKE AGI **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

Field & Reservoir	Gas ID or Oil Lease No.	Well No.	Prior Service Type

G1: N/A
PACKET: N/A

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination **Depth (ft.):** 2025.0 **Date:** 01/12/2018

SWR 13 Exception **Depth (ft.):**

GAS MEASUREMENT DATA

Date of test: **Gas measurement method(s):**

Gas production during test (MCF):

Was the well preflowed for 48 hours? No

Run No.	Line size	Orif. or Choke Size (in.)	24 hr. Coeff. Orif. Or Choke (in.)	Static Pm or Choke (in.)	Diff (hw)	Flow Temp (°F)	Temp. (Ftf)	Gravity (Fg)	Compress (Fpv)	Volume (MCF/day)

N/A

FIELD DATA AND PRESSURE CALCULATIONS

Gravity (dry gas): **Gravity (liquid hydrocarbons) (Deg. API):**

Gas-Liquid Hydro Ratio (CF/Bbl): **Gravity (mixture): Gmix=**

Avg. shut in temp. (°F): **Bottom hole temp. and depth:** °F@ FT

Run No.	Time of Run (Min.)	Choke Size (in.)	Wellhead Pressure (PSIA)	Wellhead Flow Temp (°F)

N/A

CASING RECORD

Row	Type of Casing	Casing Size (in.)	Hole Size (in.)	Setting Depth (ft.)	Multi - Stage Tool Depth (ft.)	Multi - Stage Shoe Depth (ft.)	Cement Class	Cement Amount (sacks)	Slurry Volume (cu. ft.)	Top of Cement (ft.)	TOC Determined By
1	Surface	13 3/8	17 1/2	504			C	510	687.5	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5498		5498	C	485	797.0	4275	Circulated to Surface
2	Intermediate	13 3/8	17 1/2	5498	4275		C	1650	3045.0	0	Circulated to Surface
6	Conventional Production	7	8 3/4	11023			WELL LOCK	60	337.0	9575	Calculation
5	Conventional Production	7	8 3/4	11023	5591		PREM PLUS	380	906.5	0	Circulated to Surface
4	Conventional Production	7	8 3/4	11023	9575		PREM PLUS	380	906.5	5591	Calculation

LINER RECORD

Row	Liner Size (in.)	Hole Size (in.)	Liner Top (ft.)	Liner Bottom (ft.)	Cement Class	Cement Amount (sacks)	Slurry Volume (cu. ft.)	Top of Cement (ft.)	TOC Determined By

N/A

TUBING RECORD

Row	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	10966	10966 / HALLIBURTON BWD

PRODUCING/INJECTION/DISPOSAL INTERVAL

Row	Open hole?	From (ft.)	To (ft.)
1	Yes	L 11025	11980

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment performed? No

Is well equipped with a downhole actuation sleeve? No

If yes, actuation pressure (PSIG):

Production casing test pressure (PSIG) prior to hydraulic fracturing treatment:

Actual maximum pressure (PSIG) during hydraulic fracturing:

Has the hydraulic fracturing fluid disclosure been reported to FracFocus disclosure registry (SWR29)? No

Row	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)

N/A

FORMATION RECORD

Formations	Encountered	Depth TVD (ft.)	Depth MD (ft.)	Is formation isolated?	Remarks
YATES	Yes	3019.0		Yes	
SAN ANDRES - HIGH FLOWS, H2S, CORROSIVE	Yes	4465.0		Yes	
GLORIETA	Yes	6316.0		Yes	
CLEARFORK - ACTIVE CO2 FLOOD	Yes	6492.0		Yes	
WICHITA	Yes	8628.0		Yes	
UPPER WOLFCAMP	Yes	9239.0		Yes	
STRAWN	Yes	10030.0		Yes	
ATOKA	Yes	10230.0		Yes	
WOODFORD	Yes	10973.0		Yes	
DEVONIAN	Yes	11036.0		No	DISPOSAL
WRISTEN	Yes	11268.0		No	DISPOSAL
FUSSELMAN	Yes	11538.0		No	DISPOSAL
MONTOYA	Yes	11974.0		No	DISPOSAL
RED BED-SANTA ROSA	No			No	NOT IN AREA
LEONARD	No			No	NOT IN AREA
WOLFCAMP	No			No	NOT IN AREA
PENNSYLVANIAN	No			No	NOT IN AREA
STRAWN	No			No	NOT IN AREA
MISSISSIPPIAN	No			No	NOT IN AREA

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm (SWR 36)? No

Is the completion being downhole commingled (SWR 10)? No

REMARKS

NEW WELL PUTTING ON SCHEDULE.

OPERATOR'S CERTIFICATION			
Printed Name:	Karen Zornes	**Title:**	
Telephone No.:	(281) 872-9300	**Date Certified:**	06/25/2019

APPENDIX C – GAS COMPOSITION

C-1

www.permianls.com
575.397.3713 2609 W Marland Hobbs NM 88240

C6+ Gas Analysis Report

11093G	30/30 Acid Gas	30/30 Acid Gas
Sample Point Code	Sample Point Name	Sample Point Location

Laboratory Services	2021048523	1781	E Benavides - Spot
Source Laboratory	Lab File No	Container Identity	Sampler
USA	USA	USA	Texas
District	Area Name	Field Name	Facility Name
Nov 16, 2021	Nov 16, 2021	Nov 19, 2021 09:59	Nov 19, 2021
Date Sampled	Date Effective	Date Received	Date Reported

		System Administrator	21 @ 129
Ambient Temp (°F)	Flow Rate (Mcf)	Analyst	Press PSI @ Temp °F Source Conditions

Stakeholder Midstream	30/30
Operator	Lab Source Description

Component	Normalized Mol %	Un-Normalized Mol %	GPM
H2S (H2S)	9.2000	9.2	
Nitrogen (N2)	0.0000	0	
CO2 (CO2)	89.6780	98.775	
Methane (C1)	0.3030	0.331	
Ethane (C2)	0.0580	0.063	0.0150
Propane (C3)	0.1080	0.118	0.0300
I-Butane (IC4)	0.0000	0	0.0000
N-Butane (NC4)	0.0250	0.027	0.0080
I-Pentane (IC5)	0.0000	0	0.0000
N-Pentane (NC5)	0.0000	0	0.0000
Hexanes Plus (C6+)	0.6280	0.686	0.2710
TOTAL	100.0000	109.2000	0.3240

Method(s): Gas C6+ - GPA 2261, Extended Gas - GPA 2286, Calculations - GPA 2172

Analyzer Information

Device Type:	Gas Chromatograph	Device Make:	Shimadzu
Device Model:	GC-2014	Last Cal Date:	Nov 14, 2021

Gross Heating Values (Real, BTU/ft³)

14.696 PSI @ 60.00 Â°F		14.65 PSI @ 60.00 Â°F	
Dry	Saturated	Dry	Saturated
98.7	98.00	98.4	97.7

Calculated Total Sample Properties

GPA2145-16 *Calculated at Contract Conditions

Relative Density Real	Relative Density Ideal
1.5042	1.4956

Molecular Weight
43.3157

C6+ Group Properties

Assumed Composition

C6 - 60.000% C7 - 30.000% C8 - 10.000%

Field H2S
92000 PPM

PROTREND STATUS:
Passed By Validator on Nov 21, 2021

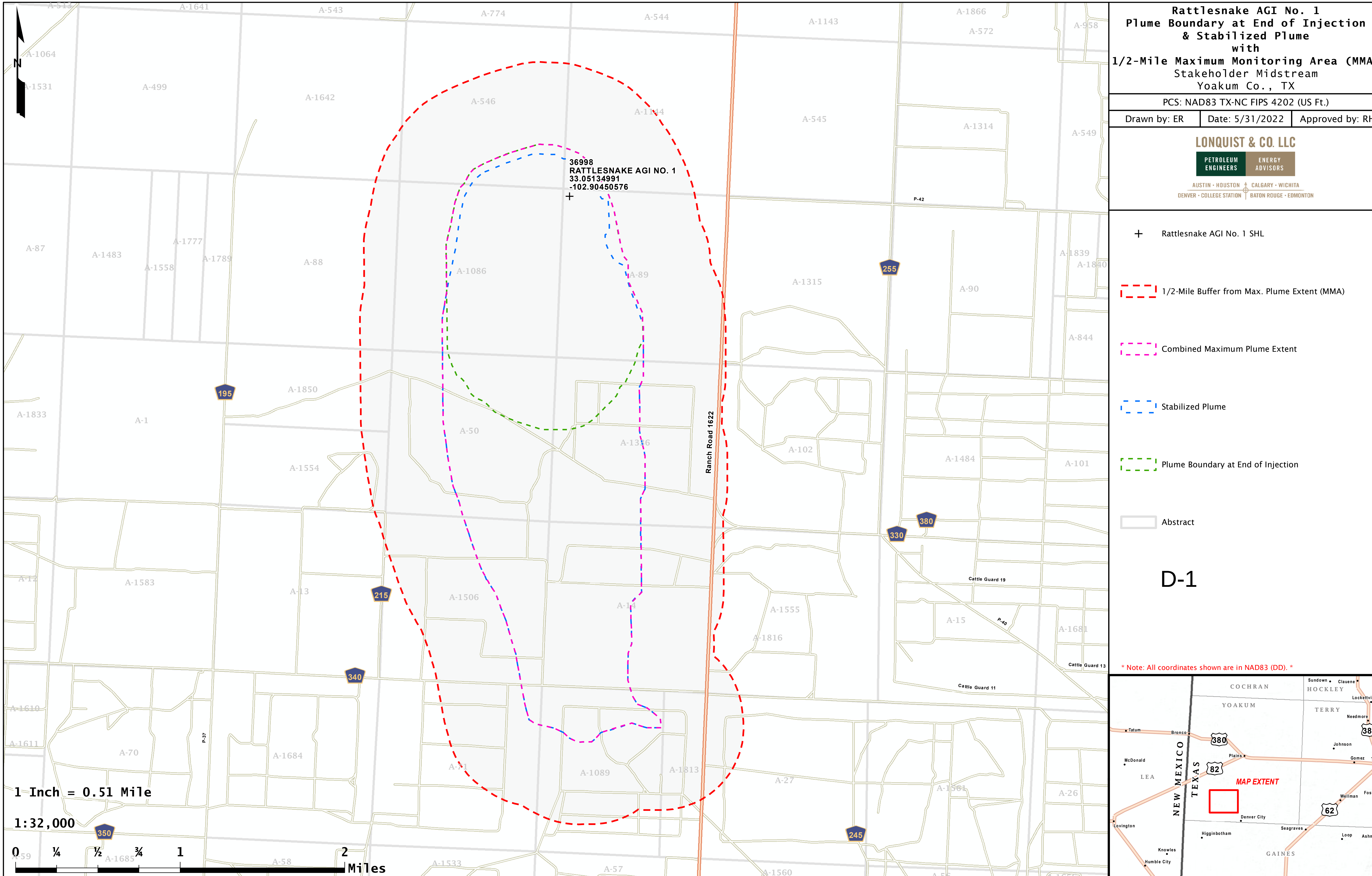
DATA SOURCE:
Imported

PASSED BY VALIDATOR REASON:
Close enough to be considered reasonable.

VALIDATOR:
Dustin Armstrong

VALIDATOR COMMENTS:
OK

APPENDIX D – MONITORING AREA MAPS

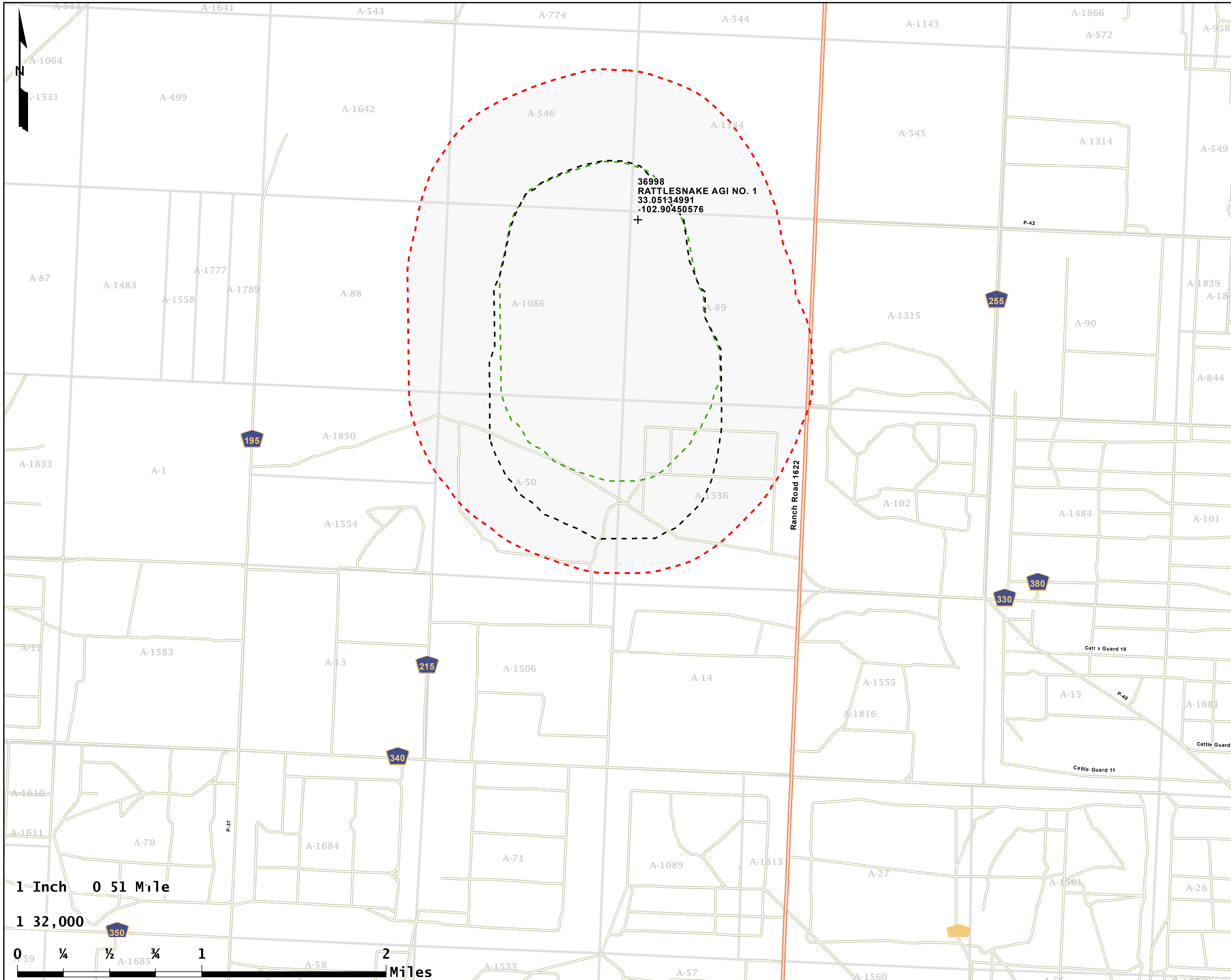

Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& Stabilized Plume
with
1/2-Mile Maximum Monitoring Area (MMA)
Stakeholder Midstream
Yoakum Co., TX
PCS: NAD83 TX-NC FIPS 4202 (US Ft.)
Drawn by: ER
Date: 5/31/2022
Approved by: RH
LONQUIST & CO. LLC
PETROLEUM ENGINEERS
ENERGY ADVISORS
AUSTIN • HOUSTON • CALGARY • WICHITA
DENVER • COLLEGE STATION • BATON ROUGE • EDMONTON
Rattlesnake AGI No. 1 SHL
1/2-Mile Buffer from Max. Plume Extent (MMA)
Combined Maximum Plume Extent
Stabilized Plume
Plume Boundary at End of Injection
Abstract
D-1
* Note: All coordinates shown are in NAD83 (DD). *
36998
RATTLESNAKE AGI NO. 1
33.05134991
-102.90450576
Ranch Road 1622
Cattle Guard 19
Cattle Guard 13
Cattle Guard 11
N
1 Inch = 0.51 Mile
1:32,000
0 ¼ ½ ¾ 1 2
Miles
COCHRAN
HOCKLEY
YOAKUM
TERRY
LEA
NEW MEXICO
TEXAS
GAINES
MAP EXTENT

Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& 19-Year Plume
with
1/2-Mile Active Monitoring Area (AMA)
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS
AUSTIN • HOUSTON • CALGARY • WICHITA
DENVER • COLLEGE STATION • BATON ROUGE • EDMONTON



Rattlesnake AGI No. 1 SHL

Active Monitoring Area Boundary

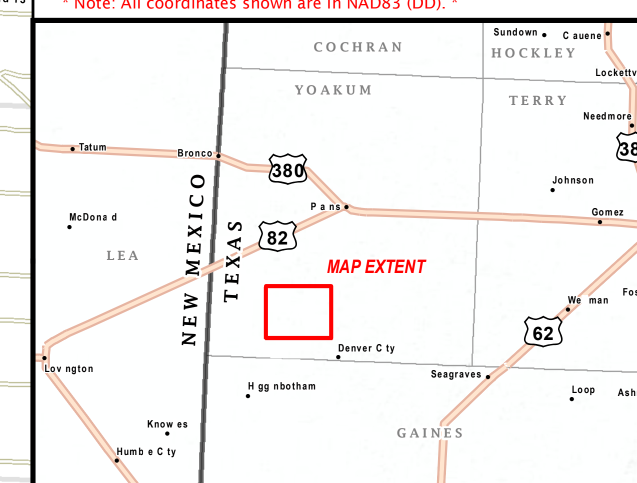
19-Year Plume

Plume Boundary at End of Injection

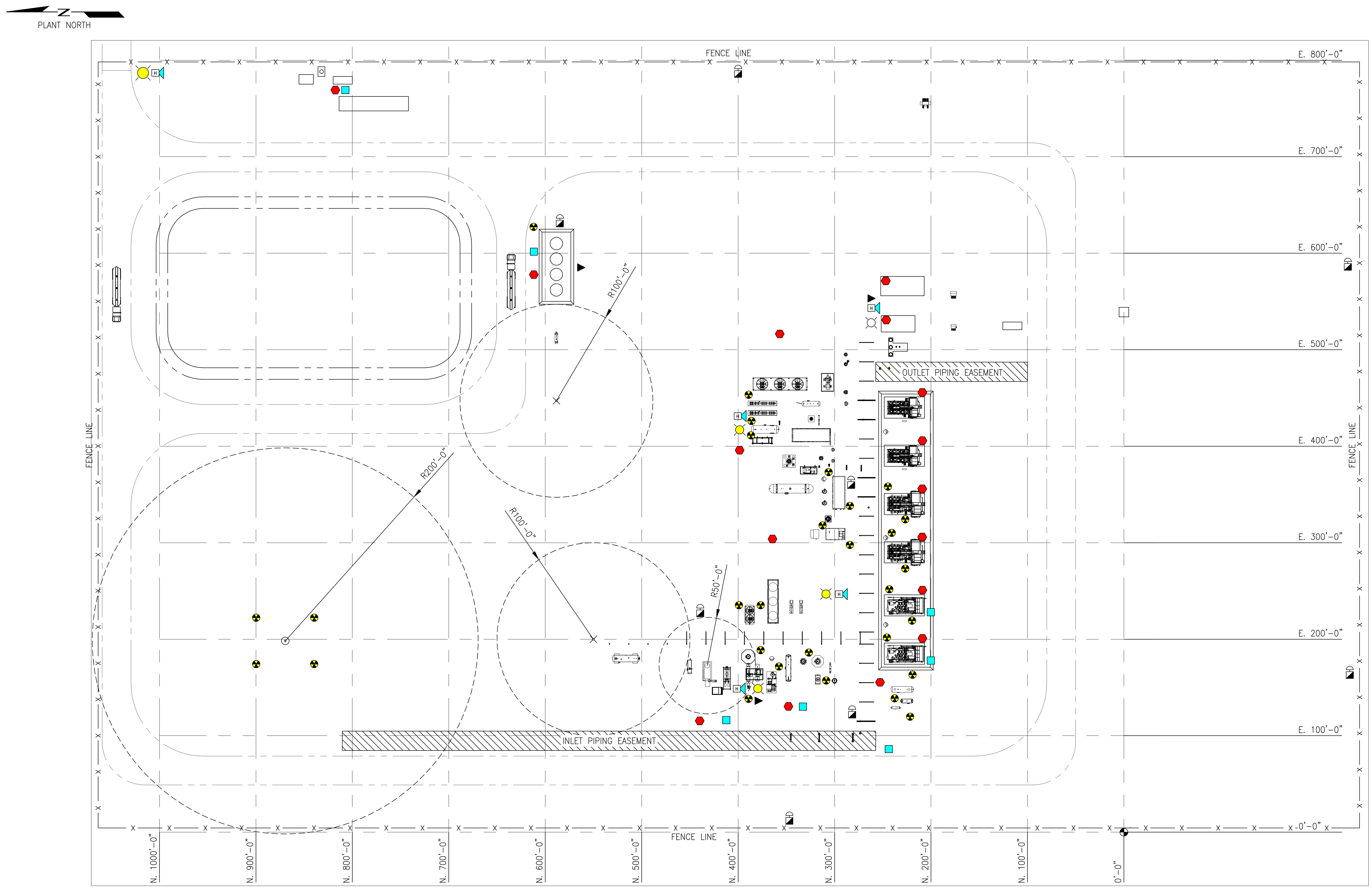
Abstract

D-2

* Note: All coordinates shown are in NAD83 (DD). *



APPENDIX E – FACILITY SAFETY PLOT PLANS



LEGEND

	FIRE EXTINGUISHER
	SCBA / ESCAPE PACK
	WIND SOCK
	LEL/H2S MONITOR
	ESD BUTTON
	STROBE LIGHTS
	HORN

NOTES:

E-1

PRELIMINARY FOR REVIEW

NO.	DATE	REVISION DESCRIPTION	BY	FCE	CLIENT
0	05/11/22	INITIAL RELEASE	KLD	BEC	JB

CHARIS ENGINEERING, LLC
TX ENG. FIRM NO. F-18864
MIDLAND, TX

STAKEHOLDER MIDSTREAM

CLIENT : STAKEHOLDER MIDSTREAM

PROJECT : 30-30 GAS PLANT

TITLE : SAFETY EQUIPMENT PLOT PLAN

DRAWN	CHECKED	SCALE	DATE	JOB NO.	DRAWING NO.
KLD		1" = 50'-0"	5/11/22	SAN180209	ME-PLNP-A000-0004

0

APPENDIX F – MMA/AMA REVIEW MAPS

APPENDIX F-1: PLUME BOUNDARY AT END OF INJECTION, STABILIZED PLUME BOUNDARY AND MAXIMUM MONITORING AREA MAP

APPENDIX F-2: ACTIVE MONITORING AREA MAP

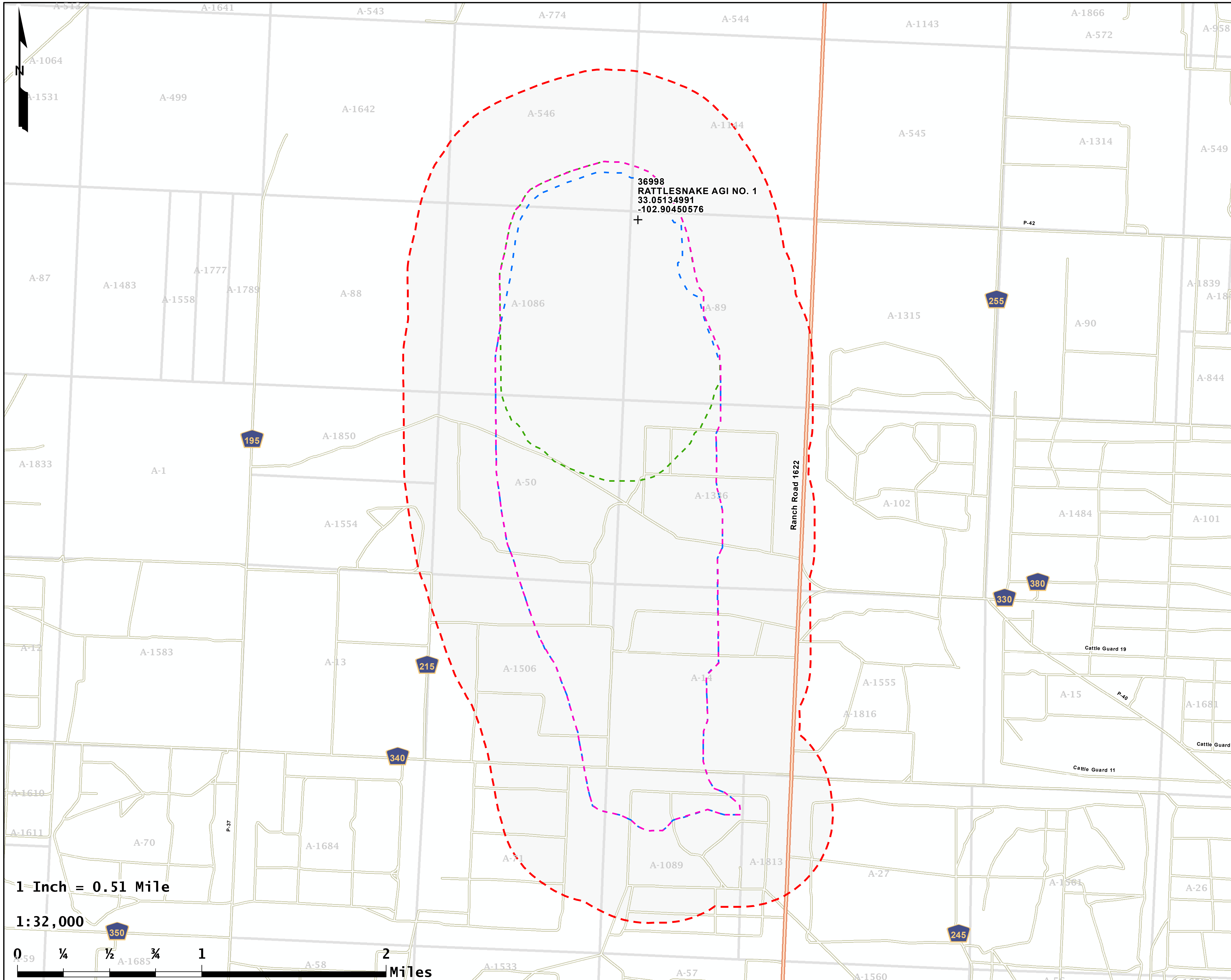
APPENDIX F-3: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX F-4: OIL AND GAS WELLS WITHIN THE MMA LIST

APPENDIX F-5: INJECTION INTERVAL PENETRATING WELLS WITHIN THE MMA MAP

APPENDIX F-6: GROUNDWATER WELLS WITHIN THE MMA

APPENDIX F-7: WELLBORE SCHEMATICS FOR INJECTION INTERVAL PENETRATING WELLS



Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& Stabilized Plume
with
1/2-Mile Maximum Monitoring Area (MMA)
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS
AUSTIN • HOUSTON • CALGARY • WICHITA
DENVER • COLLEGE STATION • BATON ROUGE • EDMONTON

F-1

+ Rattlesnake AGI No. 1 SHL

1/2-Mile Buffer from Max. Plume Extent (MMA)

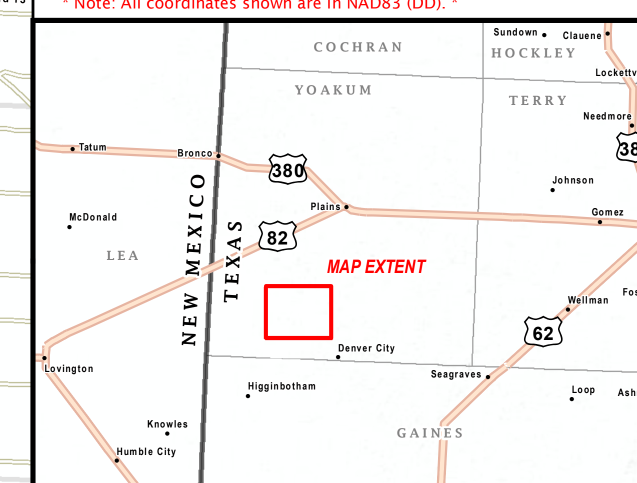
Combined Maximum Plume Extent

Stabilized Plume

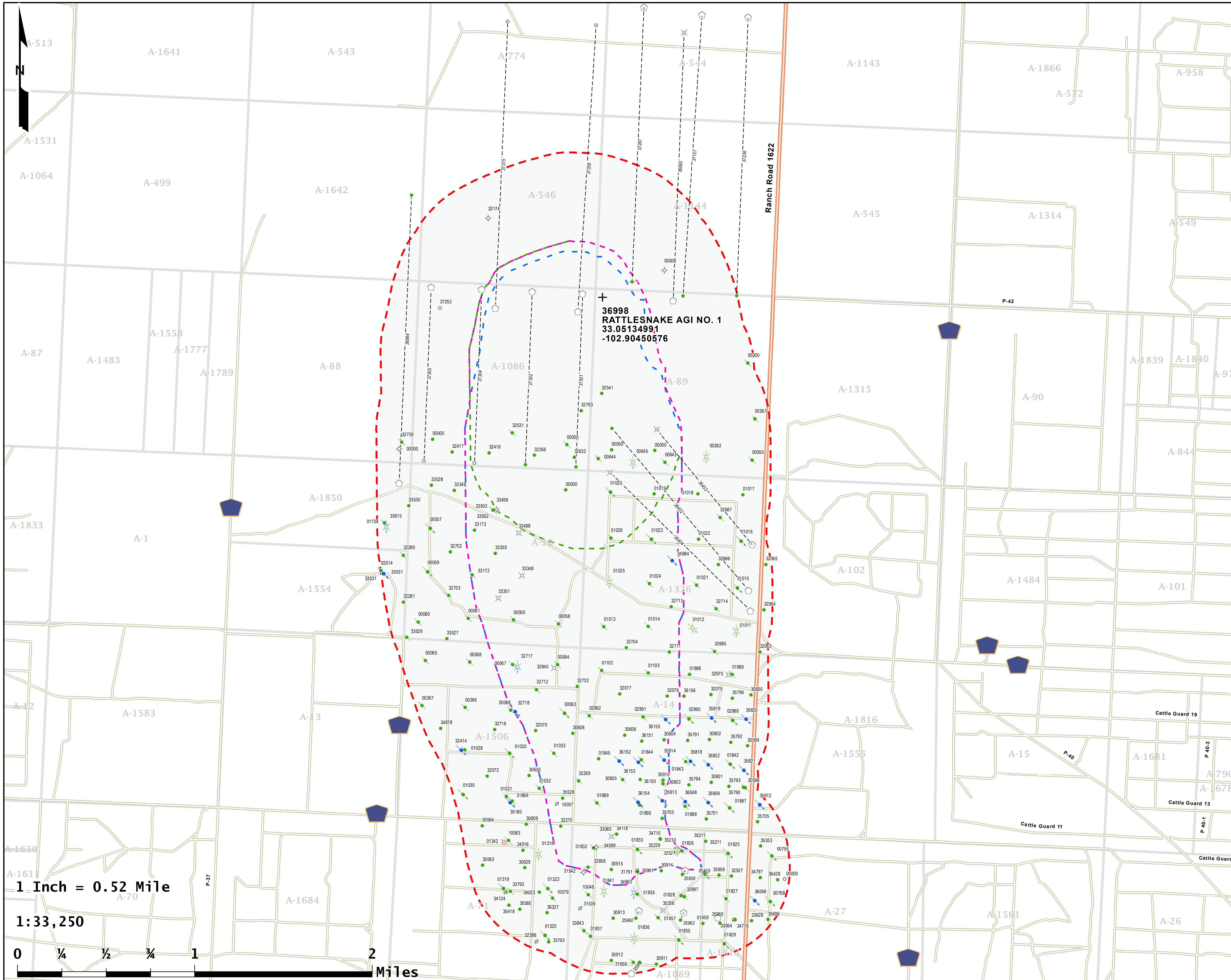
Plume Boundary at End of Injection

Abstract

* Note: All coordinates shown are in NAD83 (DD). *



Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& 19-Year Plume
with
1/2-Mile Active Monitoring Area (AMA)
Stakeholder Midstream
Yoakum Co., TX
PCS: NAD83 TX-NC FIPS 4202 (US Ft.)
Drawn by: ER
Date: 5/31/2022
Approved by: RH
LONQUIST & CO. LLC
PETROLEUM ENGINEERS
ENERGY ADVISORS
AUSTIN • HOUSTON • CALGARY • WICHITA
DENVER • COLLEGE STATION • BATON ROUGE • EDMONTON
F-2
Rattlesnake AGI No. 1 SHL
Active Monitoring Area Boundary
19-Year Plume
Plume Boundary at End of Injection
Abstract
* Note: All coordinates shown are in NAD83 (DD). *
36998
RATTLESNAKE AGI NO. 1
33.05134991
-102.90450576
Ranch Road 1622
N
1 Inch = 0.51 Mile
1:32,000
0
¼
½
¾
1
2
Miles
MAP EXTENT
GAINES
Seagraves
Loop
Ashmore
Hobbs
195
215
340
255
330
380
Cattle Guard 19
Cattle Guard 13
Cattle Guard 11
A-546
A-1144
A-1086
A-89
A-50
A-1336
A-88
A-1850
A-1554
A-1
A-1483
A-1558
A-1777
A-1789
A-87
A-1833
A-1642
A-499
A-1064
A-1531
A-1641
A-543
A-774
A-544
A-1143
A-1866
A-572
A-958
A-545
A-1314
A-549
A-1315
A-90
A-1839
A-844
A-102
A-1484
A-101
A-1583
A-13
A-1506
A-14
A-1555
A-1816
A-15
A-1681
A-70
A-1684
A-1610
A-1611
A-1685
A-58
A-1533
A-57



Rattlesnake AGI No. 1
Maximum Monitoring Area with 1/2-Mile MMA Oil/Gas Well Area of Review

Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS
AUSTIN • HOUSTON • CALGARY • WICHITA
DENVER • COLLEGE STATION • BATON ROUGE • EDMONTON

F-3

Rattlesnake AGI No. 1 SHL
1/2-Mile Buffer from Max. Plume Extent (MMA)
Combined Maximum Plume Extent
Stabilized Plume
Plume Boundary at End of Injection
Abstract
Lateral (21)

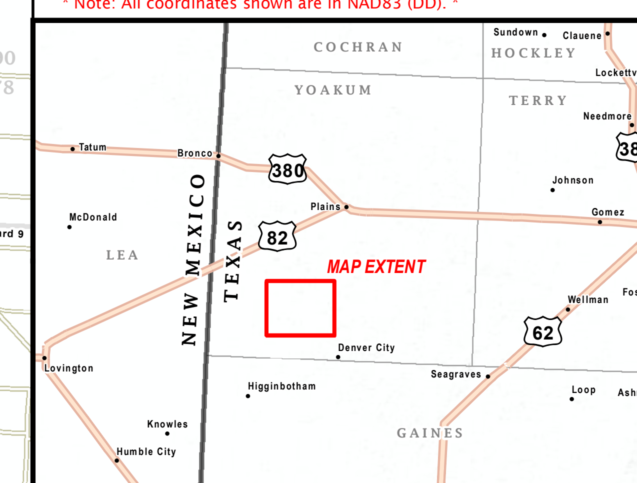
API (42-501-...) SHL Status - Type (Count)

Horizontal Surface Location (21)
Active - Oil (93)
Active - Injection/Disposal (21)
Active - Injection/Disposal from Oil (22)
Plugged - Oil (69)
Plugged - Gas (1)
Plugged- Injection/Disposal from Oil (1)
Shut-In - Oil (1)
TA - Injection/Disposal (3)
TA - Injection/Disposal from Oil (7)
Dry Hole (6)
Permitted Location (2)
Canceled/Abandoned Location (6)
Expired Permit (7)

API (42-501-...) BHL Status - Type (Count)

Active - Oil (11)
Active - Injection/Disposal from Oil (1)
Shut-In - Oil (1)
TA - Injection/Disposal from Oil (1)
Permitted Location (4)
Expired Permit (3)

Source:
1.) Oil/Gas Well SHL Data: DI-2022
2.) Oil/Gas Well BHL Data: DI-2022
3.) Oil/Gas Well Directional Data: DI-2022
* Note: All coordinates shown are in NAD83 (DD). *



Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250101829	DENVER UNIT	2215W	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5300	5300	2215W
4250101835	DENVER UNIT	2207	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5185	5185	2207
4250130914	DENVER UNIT	2222	OCCIDENTAL PERMIAN LTD.	Active - Oil			2222
4250101832	DENVER UNIT	2201W	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5190	5190	2201W
4250101826	DENVER UNIT	2203	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5250	5250	2203
4250101319	ROBERTS UNIT	4532W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5200	5200	4532W
4250130629	ROBERTS UNIT	4535	APACHE CORPORATION	Active - Oil	5280	5280	4535
4250130583	ROBERTS UNIT	4525	APACHE CORPORATION	Active - Oil	5286	5286	4525
4250101318	ROBERTS UNIT	4541	APACHE CORPORATION	TA - Injection/Disposal from Oil	5240	5240	4541
4250101889	ROBERTS UNIT	3614	APACHE CORPORATION	Plugged - Oil	5180	5180	3614
4250130598	Roberts Unit	3647	APACHE CORPORATION	Plugged - Oil	5281	5281	3647
4250130603	ROBERTS UNIT	3626	APACHE CORPORATION	Plugged - Oil	5289	5289	3626
4250102992	ROBERTS UNIT	3612W	APACHE CORPORATION	Plugged - Oil	5226	5226	3612W
4250100066	ROBERTS UNIT	3532	APACHE CORPORATION	Plugged - Oil	5231	5231	3532
4250101886	ROBERTS UNIT	3631	APACHE CORPORATION	Plugged - Oil			3631
4250101885	ROBERTS UNIT	3641	APACHE CORPORATION	Plugged - Oil	5212	5212	3641
4250100068	ROBERTS UNIT	3521	APACHE CORPORATION	Plugged - Oil	5225	5225	3521
4250100064	ROBERTS UNIT	3541	APACHE CORPORATION	Plugged - Oil	5264	5264	3541
4250102014	ROBERTS UNIT	2443	APACHE CORPORATION	Plugged - Oil	5226	5226	2443
4250100050	ROBERTS UNIT	1654	APACHE CORPORATION	Plugged - Oil	5198	5198	1654
4250133531	ROBERTS UNIT	2443A		Active - Injection/Disposal	5325	5325	2443A
4250133502	ROBERTS UNIT	2527A		Plugged - Oil	5308	5308	2527A
4250100000	C. A. ELLIOTT	6	AMERICAN LIBERTY OIL CO	Plugged - Oil	5229	5229	6
4250100000	C. A. ELLIOTT	7	AMERICAN LIBERTY AND ATLANTIC	Active - Oil	5182	5182	7
4250100000	GEO CLEVELAND	1	DELFERN OIL CO	Dry Hole	5071	5071	1
4250100000	JAMES H. LYNN	1614	AMERICAN LIBERTY	Active - Oil	5169	5169	1614
4250100000	J. H. LYNN	1634	AMERICAN LIBERTY	Active - Oil	5160	5160	1634
4250100000	A. T. MORRIS	1	ATLANTIC	Active - Oil	5235	5235	1
4250100000	A. T. MORRIS	2	AMERICAN LIBERTY OIL CO	Plugged - Oil	5179	5179	2
4250100000	W. J. CARPENTER	1642	AMERICAN LIBERTY OIL COMPANY	Plugged - Oil	5183	5183	1642
4250100000	E.S. SMITH	1	CREAT WESTERN FROD	Dry Hole	5216	5216	1
4250130607	ROBERTS UNIT	3546		Active - Oil			3546
4250135958	DENVER UNIT	2247	OCCIDENTAL PERMIAN LTD.	Active - Oil	2333	2333	2247
4250131542	DENVER UNIT	2229	SHELL OIL COMPANY	Dry Hole	2409	2409	2229
4250101320	ROBERTS UNIT	4543	APACHE CORPORATION	Active - Injection/Disposal from Oil	5120	5120	4543
4250137301	MILLER	8H	AMTEX ENERGY, INC.	Active - Oil	5157	5157	8H
4250137304	MILLER 732 C	10H	AMTEX ENERGY, INC.	Permitted Location	5157	5157	10H
4250137305	MILLER 732 D	11H	AMTEX ENERGY, INC.	Permitted Location	5157	5157	11H
4250101888	ROBERTS UNIT	3634W	APACHE CORPORATION	Plugged - Oil	5160	5160	3634W

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250101031	ROBERTS UNIT	3534W	APACHE CORPORATION	Plugged - Oil	5164	5164	3534W
4250101828	DENVER UNIT	2208	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5170	5170	2208
4250101032	ROBERTS UNIT	3544	APACHE CORPORATION	Plugged - Oil	5170	5170	3544
4250101841	DENVER UNIT	2206	OCCIDENTAL PERMIAN LTD.	TA - Injection/Disposal from Oil	5177	5177	2206
4250101842	ROBERTS UNIT	3643W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5180	5180	3643W
4250101035	ROBERTS UNIT	3533W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5180	5180	3533W
4250132704	ROBERTS UNIT	2615	APACHE CORPORATION	Active - Oil	5180	5180	2615
4250100261	ROBERTS UNIT	1643W	APACHE CORPORATION	Plugged - Oil	5180	5180	1643W
4250101323	ROBERTS UNIT	4542W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5182	5182	4542W
4250102989	ROBERTS UNIT	3642W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5182	5182	3642W
4250102991	ROBERTS UNIT	3622W	APACHE CORPORATION	Plugged - Oil	5185	5185	3622W
4250132417	MILLER	3	AMTEX ENERGY, INC.	Active - Oil	5186	5186	3
4250101025	ROBERTS UNIT	2613W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5188	5188	2613W
4250101887	ROBERTS UNIT	3644	APACHE CORPORATION	Active - Injection/Disposal from Oil	5189	5189	3644
4250101830	DENVER UNIT	2214WC	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5190	5190	2214WC
4250101103	ROBERTS UNIT	3621	APACHE CORPORATION	Plugged - Oil	5190	5190	3621
4250101024	ROBERTS UNIT	2623	APACHE CORPORATION	Plugged - Oil	5190	5190	2623
4250101023	ROBERTS UNIT	2622W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5190	5190	2622W
4250101022	ROBERTS UNIT	2632	APACHE CORPORATION	Active - Oil	5190	5190	2632
4250101019	ROBERTS UNIT	2621	APACHE CORPORATION	Active - Oil	5190	5190	2621
4250101030	ROBERTS UNIT	3524W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5193	5193	3524W
4250101829	DENVER UNIT	2205	OCCIDENTAL PERMIAN LTD.	TA - Injection/Disposal from Oil	5195	5195	2205
4250101836	DENVER UNIT	2213WC	OCCIDENTAL PERMIAN LTD.	TA - Injection/Disposal from Oil	5200	5200	2213WC
4250101833	DENVER UNIT	2202WC	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5200	5200	2202WC
4250134099	DENVER UNIT	2239WC	OCCIDENTAL PERMIAN LTD.	Dry Hole	5200	5200	2239WC
4250132717	ROBERTS UNIT	3531A	APACHE CORPORATION	TA - Injection/Disposal	5200	5200	3531A
4250101014	ROBERTS UNIT	2624W	APACHE CORPORATION	Plugged - Oil	5200	5200	2624W
4250101028	ROBERTS UNIT	3523	APACHE CORPORATION	Plugged - Oil	5205	5205	3523
4250101102	ROBERTS UNIT	3611	APACHE CORPORATION	Plugged - Oil	5206	5206	3611
4250101827	DENVER UNIT	2209W	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5210	5210	2209W
4250101015		2643	TEXACO INCORPORATED	Active - Injection/Disposal from Oil	5210	5210	2643
4250100266	ROBERTS UNIT	3522W	APACHE CORPORATION	Plugged - Oil	5211	5211	3522W
4250132632	MILLER	5	AMTEX ENERGY, INC.	Active - Oil	5213	5213	5
4250100057	ROBERTS UNIT	2512W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5213	5213	2512W
4250101890	ROBERTS UNIT	3624W	APACHE CORPORATION	Plugged - Oil	5214	5214	3624W
4250101033	ROBERTS UNIT	3543W	APACHE CORPORATION	Plugged - Oil	5215	5215	3543W
4250101012	ROBERTS UNIT	2634W	APACHE CORPORATION	Plugged- Injection/Disposal from Oil	5215	5215	2634W
4250101734	ROBERTS UNIT	2442	APACHE CORPORATION	Plugged - Oil	5215	5215	2442
4250101020	ROBERTS UNIT	2611W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5215	5215	2611W

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250100067	ROBERTS UNIT	3531	APACHE CORPORATION	Plugged - Oil	5216	5216	3531
4250101013	ROBERTS UNIT	2614W	APACHE CORPORATION	Plugged - Oil	5216	5216	2614W
4250101844	ROBERTS UNIT	3623W	APACHE CORPORATION	Plugged - Oil	5217	5217	3623W
4250131869	ROBERTS UNIT	A3534W	APACHE CORPORATION	Plugged - Oil	5220	5220	A3534W
4250102990	ROBERTS UNIT	3632W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5220	5220	3632W
4250100262	ROBERTS UNIT	1644W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5220	5220	1644W
4250132858	DENVER UNIT	2235	OCCIDENTAL PERMIAN LTD.	Shut-In - Oil	5225	5225	2235
4250100058	ROBERTS UNIT	2544W	APACHE CORPORATION	Plugged - Oil	5225	5225	2544W
4250130584	ROBERTS UNIT	4520	APACHE CORPORATION	Active - Oil	5230	5230	4520
4250130630	ROBERTS UNIT	3535	APACHE CORPORATION	Active - Oil	5230	5230	3535
4250100063	ROBERTS UNIT	3542W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5230	5230	3542W
4250132076	ROBERTS UNIT	3627	APACHE CORPORATION	Active - Oil	5230	5230	3627
4250100267	ROBERTS UNIT	3512W	APACHE CORPORATION	Plugged - Oil	5233	5233	3512W
4250101016	ROBERTS UNIT	2642W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5234	5234	2642W
4250134716	DENVER UNIT	2242	OCCIDENTAL PERMIAN LTD.	Active - Oil	5236	5236	2242
4250100061	ROBERTS UNIT	2524W	APACHE CORPORATION	Plugged - Oil	5238	5238	2524W
4250101021	ROBERTS UNIT	2633	APACHE CORPORATION	Plugged - Oil	5240	5240	2633
4250101011	ROBERTS UNIT	2644W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5241	5241	2644W
4250132541	FUTCH	1	AMTEX ENERGY, INC.	Active - Oil	5244	5244	1
4250101026	ROBERTS UNIT	2612W	APACHE CORPORATION	Plugged - Oil	5245	5245	2612W
4250100059	ROBERTS UNIT	2513W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5246	5246	2513W
4250132531	MILLER	4	AMTEX ENERGY, INC.	Plugged - Oil	5248	5248	4
4250132687	ROBERTS UNIT	2635	APACHE CORPORATION	Plugged - Oil	5248	5248	2635
4250131656	DENVER UNIT	2232WC	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5250	5250	2232WC
4250131791	DENVER UNIT	2231	SHELL OIL COMPANY	Canceled/Abandoned Location	5250	5250	2231
4250134118	DENVER UNIT	2238	OCCIDENTAL PERMIAN LTD.	Active - Oil	5250	5250	2238
4250101342	ROBERTS UNIT		APACHE CORPORATION	Plugged - Gas	5250	5250	
4250132269	ROBERTS UNIT	3601	APACHE CORPORATION	Plugged - Oil	5250	5250	3601
4250101843	ROBERTS UNIT	3633W	APACHE CORPORATION	Plugged - Oil	5250	5250	3633W
4250130608	ROBERTS UNIT	3545	APACHE CORPORATION	Active - Oil	5250	5250	3545
4250132077	ROBERTS UNIT	3617	APACHE CORPORATION	Active - Oil	5250	5250	3617
4250134963	DENVER UNIT	2244WC	OCCIDENTAL PERMIAN LTD.	TA- Injection/Disposal	5251	5251	2244WC
4250100060	ROBERTS UNIT	2514	APACHE CORPORATION	Plugged - Oil	5251	5251	2514
4250101459	DENVER UNIT	2211	OCCIDENTAL PERMIAN LTD.	Active - Oil	5252	5252	2211
4250132521	DENVER UNIT	2233W	OCCIDENTAL PERMIAN LTD.	TA- Injection/Disposal from Oil	5253	5253	2233W
4250135211	DENVER UNIT	2241	OCCIDENTAL PERMIAN LTD.	Active - Oil	5253	5253	2241
4250101837	DENVER UNIT	2212W	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5255	5255	2212W
4250132793	MILLER	6	AMTEX ENERGY, INC.	Active - Oil	5258	5258	6
4250132356	MILLER	1	AMTEX ENERGY, INC.	Active - Oil	5260	5260	1

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250101017	ROBERTS UNIT	2641	APACHE CORPORATION	Active - Oil	5260	5260	2641
4250101825	DENVER UNIT	2204W	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5264	5264	2204W
4250132416	MILLER	2	AMTEX ENERGY, INC.	Active - Oil	5269	5269	2
4250100065	ROBERTS UNIT	3511W	APACHE CORPORATION	Plugged - Oil	5270	5270	3511W
4250101018	ROBERTS UNIT	2631	APACHE CORPORATION	Active - Oil	5270	5270	2631
4250130600	ROBERTS UNIT	3645	APACHE CORPORATION	Active - Oil	5273	5273	3645
4250130580	ROBERTS UNIT	4536	APACHE CORPORATION	Active - Oil	5279	5279	4536
4250130599	ROBERTS UNIT	3646	APACHE CORPORATION	Active - Oil	5279	5279	3646
4250130602	ROBERTS UNIT	3635	APACHE CORPORATION	Active - Oil	5283	5283	3635
4250132997	DENVER UNIT	2208WC	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5284	5284	2208WC
4250130601	ROBERTS UNIT	3636	APACHE CORPORATION	Active - Oil	5286	5286	3636
4250132174	SHEPHERD	1	YOUNG, MARSHALL R., OIL CO.	Dry Hole	5286	5286	1
4250130604	ROBERTS UNIT	3625	APACHE CORPORATION	Active - Oil	5287	5287	3625
4250130912	DENVER UNIT	2224	OCCIDENTAL PERMIAN LTD.	Active - Oil	5288	5288	2224
4250130911	DENVER UNIT	2225	OCCIDENTAL PERMIAN LTD.	Active - Oil	5290	5290	2225
4250130609	ROBERTS UNIT	4530	APACHE CORPORATION	Active - Oil	5291	5291	4530
4250130605	ROBERTS UNIT	3616	APACHE CORPORATION	Plugged - Oil	5291	5291	3616
4250130606	ROBERTS UNIT	3615	APACHE CORPORATION	Active - Oil	5293	5293	3615
4250133172	ROBERTS UNIT	2523	CONOCOPHILLIPS COMPANY	Plugged - Oil	5295	5295	2523
4250132739	CLEVELAND	1	HIGHLAND PRODUCTION COMPANY	Plugged - Oil	5300	5300	1
4250133064	DENVER UNIT	2238	SHELL WESTERN E&P INC.	Canceled/Abandoned Location	5300	5300	2238
4250132927	DENVER UNIT	2236	OCCIDENTAL PERMIAN LTD.	Active - Oil	5300	5300	2236
4250133065	DENVER UNIT	2237	SHELL WESTERN E&P INC.	Expired Permit	5300	5300	2237
4250132270	ROBERTS UNIT	4540	APACHE CORPORATION	Active - Oil	5300	5300	4540
4250132414	ROBERTS UNIT	3523A	APACHE CORPORATION	Active - Injection/Disposal	5300	5300	3523A
4250132712	ROBERTS UNIT	3537	APACHE CORPORATION	Plugged - Oil	5300	5300	3537
4250132722	ROBERTS UNIT	3547	APACHE CORPORATION	Active - Oil	5300	5300	3547
4250132945	ROBERTS UNIT	3541A	TEXACO PRODUCING INC.	Expired Permit	5300	5300	3541A
4250132975	ROBERTS UNIT	3641A	TEXACO PRODUCING INC.	Expired Permit	5300	5300	3641A
4250132711	ROBERTS UNIT	3620	APACHE CORPORATION	Active - Oil	5300	5300	3620
4250133527	ROBERTS UNIT	2518	APACHE CORPORATION	Active - Oil	5300	5300	2518
4250132714	ROBERTS UNIT	2637	APACHE CORPORATION	Plugged - Oil	5300	5300	2637
4250133351	ROBERTS UNIT	2526	TEXACO PRODUCING INC.	Expired Permit	5300	5300	2526
4250132703	ROBERTS UNIT	2516	APACHE CORPORATION	Plugged - Oil	5300	5300	2516
4250133348	ROBERTS UNIT	2533	TEXACO PRODUCING INC.	Expired Permit	5300	5300	2533
4250132702	ROBERTS UNIT	2515	APACHE CORPORATION	Active - Oil	5300	5300	2515
4250133350	ROBERTS UNIT	2525	APACHE CORPORATION	Active - Oil	5300	5300	2525
4250133498	ROBERTS UNIT	2532	TEXACO PRODUCING INC.	Expired Permit	5300	5300	2532
4250133173	ROBERTS UNIT	2522	APACHE CORPORATION	Active - Oil	5300	5300	2522

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250133499	ROBERTS UNIT	2527	TEXACO PRODUCING INC.	Dry Hole	5300	5300	2527
4250133530	ROBERTS UNIT	2507	APACHE CORPORATION	Active - Oil	5300	5300	2507
4250132685	ROBERTS UNIT	2638	APACHE CORPORATION	Plugged - Oil	5302	5302	2638
4250133349	ROBERTS UNIT	2517	APACHE CORPORATION	Active - Oil	5302	5302	2517
4250132718	ROBERTS UNIT	3532A	APACHE CORPORATION	Active - Injection/Disposal	5304	5304	3532A
4250132713	ROBERTS UNIT	2625	APACHE CORPORATION	Active - Oil	5308	5308	2625
4250133502	ROBERTS UNIT	2527A	APACHE CORPORATION	Plugged - Oil	5308	5308	2527A
4250132716	ROBERTS UNIT	3526	APACHE CORPORATION	Active - Oil	5309	5309	3526
4250100645	ROBERTS UNIT	1624W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5309	5309	1624W
4250130913	DENVER UNIT	2223	OCCIDENTAL PERMIAN LTD.	Active - Oil	5310	5310	2223
4250132686	ROBERTS UNIT	2636	APACHE CORPORATION	Active - Oil	5310	5310	2636
4250101457	DENVER UNIT	2210	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5325	5325	2210
4250133529	ROBERTS UNIT	2508	APACHE CORPORATION	Plugged - Oil	5325	5325	2508
4250133531	ROBERTS UNIT	2443A	APACHE CORPORATION	Active - Injection/Disposal	5325	5325	2443A
4250133528	ROBERTS UNIT	2511	APACHE CORPORATION	Active - Oil	5325	5325	2511
4250135912	ROBERTS UNIT	3771W	APACHE CORPORATION	Active - Injection/Disposal	5330	5330	3771W
4250132075	ROBERTS UNIT	3637	APACHE CORPORATION	Active - Oil	5330	5330	3637
4250132063	ROBERTS UNIT	2705	APACHE CORPORATION	Active - Oil	5330	5330	2705
4250135793	ROBERTS UNIT	3672	APACHE CORPORATION	Active - Oil	5334	5334	3672
4250135819	ROBERTS UNIT	3674W	APACHE CORPORATION	Active - Injection/Disposal	5336	5336	3674W
4250135792	ROBERTS UNIT	3671	APACHE CORPORATION	Active - Oil	5339	5339	3671
4250135820	ROBERTS UNIT	3675W	APACHE CORPORATION	Active - Injection/Disposal	5341	5341	3675W
4250135818	ROBERTS UNIT	3633RW	APACHE CORPORATION	Active - Injection/Disposal	5344	5344	3633RW
4250135790	ROBERTS UNIT	3647R	APACHE CORPORATION	Active - Oil	5345	5345	3647R
4250100768	CORNELL UNIT	3107W	XTO ENERGY INC.	Active - Injection/Disposal from Oil	5350	5350	3107W
4250130915	DENVER UNIT	2221	OCCIDENTAL PERMIAN LTD.	Active - Oil	5350	5350	2221
4250136048	ROBERTS UNIT	3634RW	APACHE CORPORATION	Active - Injection/Disposal	5350	5350	3634RW
4250135908	ROBERTS UNIT	3678W	APACHE CORPORATION	Active - Injection/Disposal	5350	5350	3678W
4250132072	ROBERTS UNIT	3525	APACHE CORPORATION	Active - Oil	5350	5350	3525
4250135915	ROBERTS UNIT	3626R	APACHE CORPORATION	Active - Oil	5350	5350	3626R
4250132281	ROBERTS UNIT	2446	APACHE CORPORATION	Active - Oil	5350	5350	2446
4250132064	ROBERTS UNIT	2704	APACHE CORPORATION	Active - Oil	5350	5350	2704
4250132280	ROBERTS UNIT	2445	APACHE CORPORATION	Plugged - Oil	5350	5350	2445
4250135791	ROBERTS UNIT	3670	APACHE CORPORATION	Active - Oil	5351	5351	3670
4250135794	ROBERTS UNIT	3673	APACHE CORPORATION	Active - Oil	5352	5352	3673
4250135821	ROBERTS UNIT	3676W	APACHE CORPORATION	Active - Injection/Disposal	5352	5352	3676W
4250135914	ROBERTS UNIT	3681W	APACHE CORPORATION	Active - Injection/Disposal	5352	5352	3681W
4250100643	ROBERTS UNIT	1634W	APACHE CORPORATION	Plugged - Oil	5353	5353	1634W
4250135796	ROBERTS UNIT	3669	APACHE CORPORATION	Active - Oil	5356	5356	3669

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250100644	ROBERTS UNIT	1614	APACHE CORPORATION	Plugged - Oil	5356	5356	1614
4250135913	ROBERTS UNIT	3680W	APACHE CORPORATION	Active - Injection/Disposal	5357	5357	3680W
4250135705	ROBERTS UNIT	3752	APACHE CORPORATION	Active - Oil	5360	5360	3752
4250135822	ROBERTS UNIT	3677W	APACHE CORPORATION	Active - Injection/Disposal	5362	5362	3677W
4250134984	ROBERTS UNIT	2626W	APACHE CORPORATION	Active - Injection/Disposal	5364	5364	2626W
4250135701	ROBERTS UNIT	3667	APACHE CORPORATION	Active - Oil	5365	5365	3667
4250132070	ROBERTS UNIT	3536	APACHE CORPORATION	Active - Oil	5370	5370	3536
4250132065	ROBERTS UNIT	2703	APACHE CORPORATION	Active - Oil	5370	5370	2703
4250100755	CORNELL UNIT	3101W	XTO ENERGY INC.	Active - Injection/Disposal from Oil	5373	5373	3101W
4250135703	ROBERTS UNIT	3668	APACHE CORPORATION	Active - Oil	5380	5380	3668
4250135229	DENVER UNIT	2240	OCCIDENTAL PERMIAN LTD.	Active - Oil	5388	5388	2240
4250136152	ROBERTS UNIT	3682W	APACHE CORPORATION	Active - Injection/Disposal	5397	5397	3682W
4250131539	DENVER UNIT	2230	SHELL OIL COMPANY	Canceled/Abandoned Location	5400	5400	2230
4250136327	ROBERTS UNIT	4547	APACHE CORPORATION	Active - Oil	5400	5400	4547
4250136154	ROBERTS UNIT	3624RW	APACHE CORPORATION	Active - Injection/Disposal	5400	5400	3624RW
4250136155	ROBERTS UNIT	3683W	APACHE CORPORATION	Active - Injection/Disposal	5402	5402	3683W
4250136156	ROBERTS UNIT	3686	APACHE CORPORATION	Active - Oil	5404	5404	3686
4250134797	CORNELL UNIT	3194	XTO ENERGY INC.	Active - Oil	5405	5405	3194
4250135696	CORNELL UNIT	113	XTO ENERGY INC.	Active - Oil	5406	5406	113
4250136150	ROBERTS UNIT	3684	APACHE CORPORATION	Active - Oil	5421	5421	3684
4250133629	CORNELL UNIT	3156	XTO ENERGY INC.	Active - Oil	5425	5425	3156
4250135961	DENVER UNIT	2246	OCCIDENTAL PERMIAN LTD.	Active - Oil	5425	5425	2246
4250135960	DENVER UNIT	2249	OCCIDENTAL PERMIAN LTD.	Active - Oil	5431	5431	2249
4250136153	ROBERTS UNIT	3623RW	APACHE CORPORATION	Active - Injection/Disposal	5439	5439	3623RW
4250135353	CORNELL UNIT	107	XTO ENERGY INC.	Active - Oil	5450	5450	107
4250135528	ROBERTS UNIT	3549	APACHE CORPORATION	Active - Oil	5452	5452	3549
4250136151	ROBERTS UNIT	3685	APACHE CORPORATION	Active - Oil	5463	5463	3685
4250135963	DENVER UNIT	2252	OCCIDENTAL PERMIAN LTD.	Active - Oil	5476	5476	2252
4250136434	ROBERTS UNIT	263H	APACHE CORPORATION	Expired Permit	5500	5500	263H
4250136433	ROBERTS UNIT	262H	APACHE CORPORATION	Expired Permit	5500	5500	262H
4250136098	CORNELL UNIT	110	XTO ENERGY INC.	Active - Injection/Disposal	5510	5510	110
4250133615	ROBERTS UNIT	2442A	APACHE CORPORATION	TA - Injection/Disposal	5516	5516	2442A
4250135180	ROBERTS UNIT	3534B	APACHE CORPORATION	Active - Injection/Disposal	5517	5517	3534B
4250136428	CORNELL UNIT	124	XTO ENERGY INC.	Active - Oil	5532	5532	124
4250134878	ROBERTS UNIT	3548	APACHE CORPORATION	Active - Oil	5550	5550	3548
4250135966	DENVER UNIT	2251	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2251
4250135962	DENVER UNIT	2250	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2250
4250135356	DENVER UNIT	2246	OCCIDENTAL PERMIAN LTD.	Expired Permit	5600	5600	2246
4250135959	DENVER UNIT	2248	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2248

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250135210	DENVER UNIT	2240	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2240
4250135211		2241	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2241
4250134710		2240	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2240
4250101845	ROBERTS UNIT	3613	APACHE CORPORATION	Active - Oil	7000	7000	3613
4250110083	RANDALL, E.	36	EXXON CORP.	Plugged - Oil	8595	8595	36
4250110046	ELLIOTT, C.A.	2	MCCLURE OIL COMPANY, INC.	Plugged - Oil	9000	9000	2
4250136692	MISS KITTY 704-669	3XH	RILEY EXPLORATION OPG CO, LLC	Expired Permit	9000	9000	3XH
4250133793	RANDALL, E.	39	XTO ENERGY INC.	Active - Oil	9000	9000	39
4250137375	RIP WHEELER 705-668	5XH	RILEY PERMIAN OPERATING CO, LLC	Permitted Location	9000	9000	5XH
4250137358	RIP WHEELER 705-668	1XH	RILEY PERMIAN OPERATING CO, LLC	Permitted Location	9000	9000	1XH
4250133843	ELLIOTT	1	DELTA C02, LLC	Plugged - Oil	9050	9050	1
4250134124	RANDALL, E	46	EXXON CORP.	Canceled/Abandoned Location	9100	9100	46
4250133792	RANDALL, E.	40	XTO ENERGY INC.	Plugged - Oil	9591	9591	40
4250110079	RANDALL, E.	32	EXXON CORP.	Plugged - Oil	9615	9615	32
4250135418	RANDALL, E.	46	XTO ENERGY INC.	Active - Oil	9650	9650	46
4250134023	RANDALL, E.	42	XTO ENERGY INC.	Active - Oil	9660	9660	42
4250134016	RANDALL, E.	43	XTO ENERGY INC.	Active - Oil	9740	9740	43
4250132388	RANDALL, E.	38	EXXON CORP.	Canceled/Abandoned Location	10300	10300	38
4250137302	MILLER 732 B	9H	AMTEX ENERGY, INC.	Active - Oil	5183	10662	9H
4250136432	ROBERTS UNIT	261 H	APACHE CORPORATION	Active - Oil	5151	11117	261 H
4250136998	RATTLESNAKE AGI	1	SANTA FE MIDSTREAM PERMIAN LLC	Active - Injection/Disposal	11980	11980	1
4250137252	MILLER SWD	7	AMTEX ENERGY, INC.	Permitted Location	13000	13000	7
4250136984	MADCAP 731-706	1XH	RILEY PERMIAN OPERATING CO, LLC	Active - Oil	5261	13274	1XH
4250137127	MISS KITTY A 669-704	25XH	RILEY PERMIAN OPERATING CO, LLC	Active - Oil	5321	13428	25XH
4250137287	MISS KITTY A 669-704	4XH	RILEY PERMIAN OPERATING CO, LLC	Shut-In - Oil	5340	13452	4XH
4250137236	MISS KITTY 669-704	2XH	RILEY PERMIAN OPERATING CO, LLC	Active - Oil	5317	13622	2XH

Rattlesnake AGI No. 1
Maximum Monitoring Area
with
1/2-Mile MMA Oil/Gas Well Penetrators
Area of Review
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 6/1/2022	Approved by: RH

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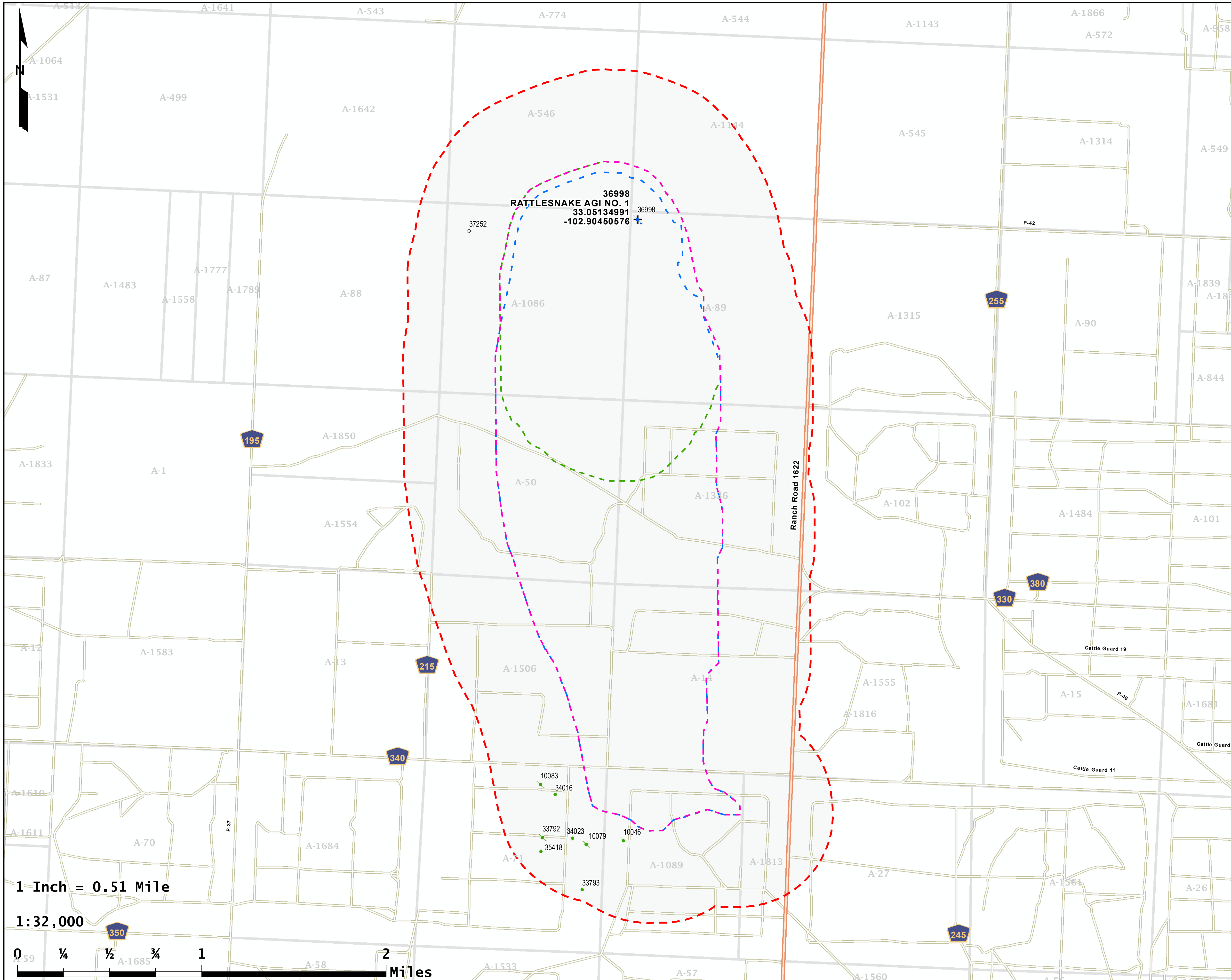


Rattlesnake AGI No. 1 SHL

1/2-Mile Buffer from Max. Plume Extent (MMA)

Combined Maximum Plume Extent

Stabilized Plume

Plume Boundary at End of Injection

Abstract

API (42-501-...) SHL Status - Type (Count)

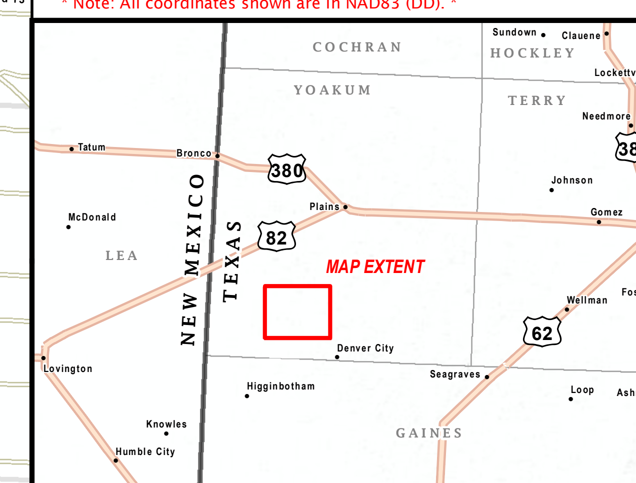
Active - Oil (4)

Active - Injection/Disposal (1)

Plugged - Oil (4)

Permitted Location (1)

Source:
1.) Oil/Gas Well SHL Data: DI-2022
2.) Oil/Gas Well BHL Data: DI-2022
3.) Oil/Gas Well Directional Data: DI-2022
* Note: All coordinates shown are in NAD83 (DD). *



Rattlesnake AGI No. 1
Maximum Monitoring Area
with
1/2-Mile MMA Groundwater Well
Area of Review
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)		
Drawn by: ER	Date: 5/31/2022	Approved by: RH

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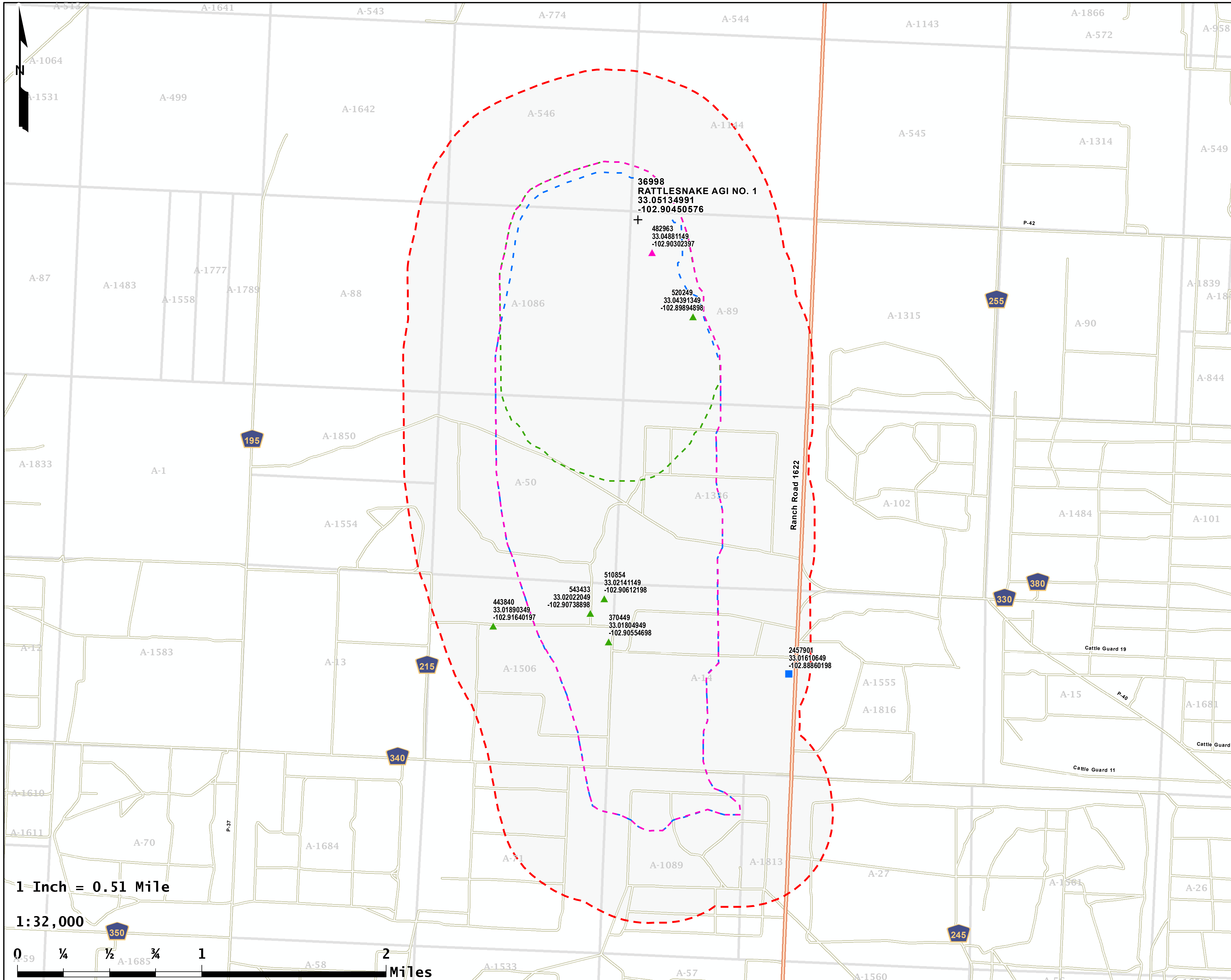


Rattlesnake AGI No. 1 SHL

1/2-Mile Buffer from Max. Plume Extent (MMA)

Combined Maximum Plume Extent

Stabilized Plume

Plume Boundary at End of Injection

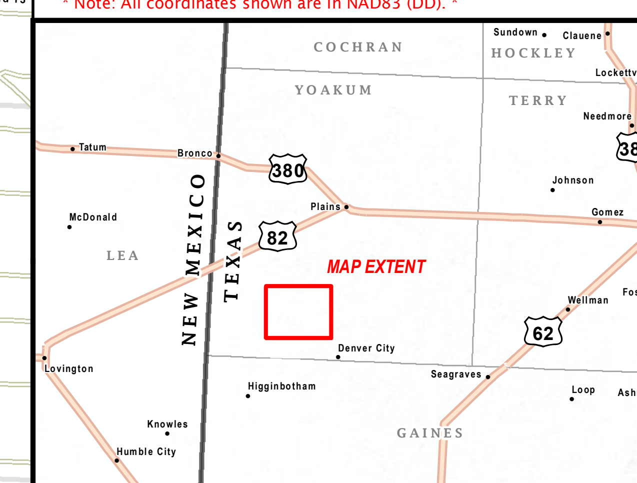
Abstract

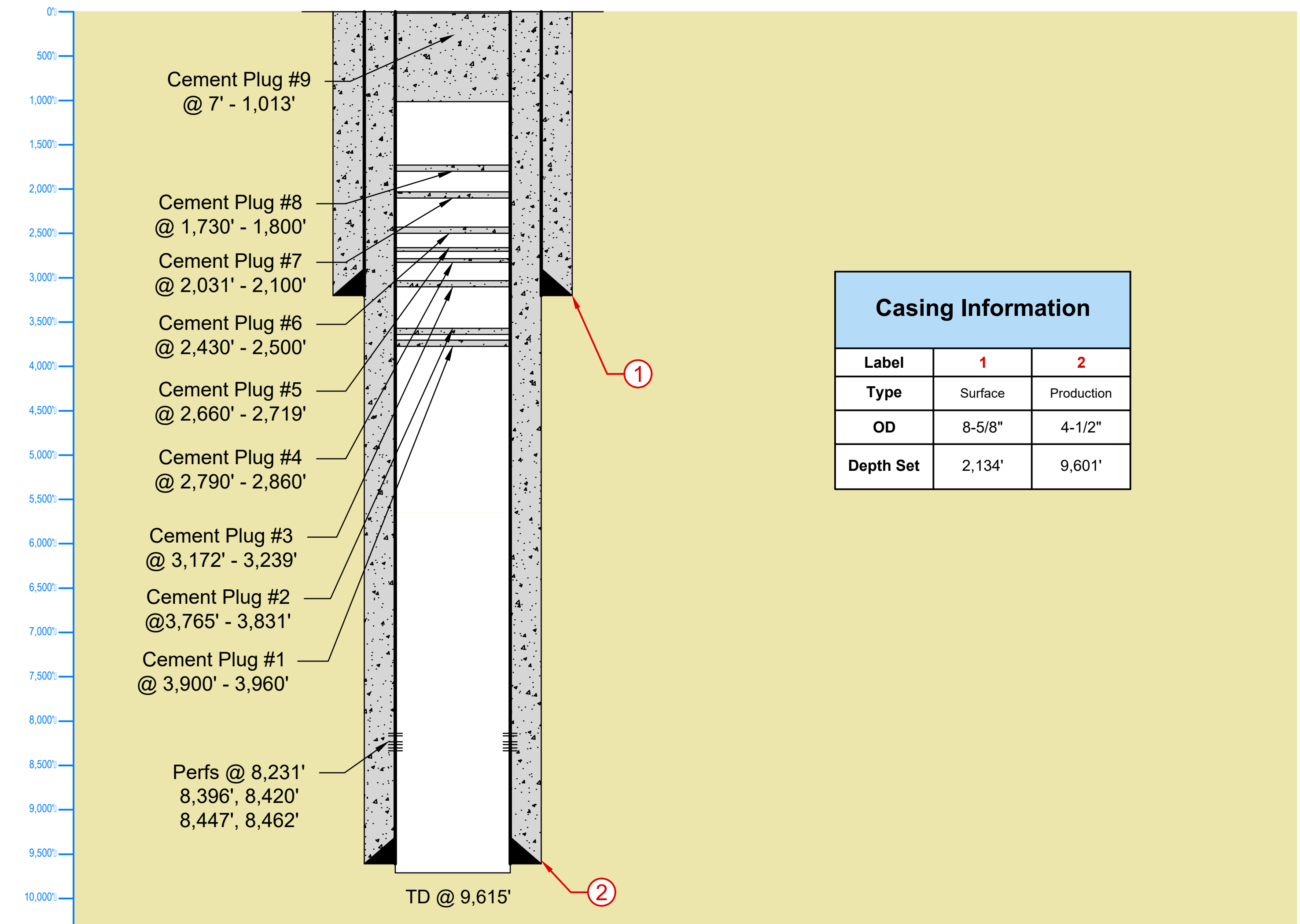
SDRDB Groundwater Wells [TWDB-2022]
Proposed Use (Labeled with Well Report No.)
Industrial (1)

Irrigation (5)

TWDB Groundwater Wells [TWDB-2022]
Well Type (Labeled with State Well No.)
Withdrawal of Water (1)

Source:
1.) SDRDB Groundwater Well SHL Data: TWDB-2022
2.) TWDB Groundwater Well SHL Data: TWDB-2022
3.) Brackish Groundwater Well SHL Data: TWDB-2022
* Note: All coordinates shown are in NAD83 (DD). *

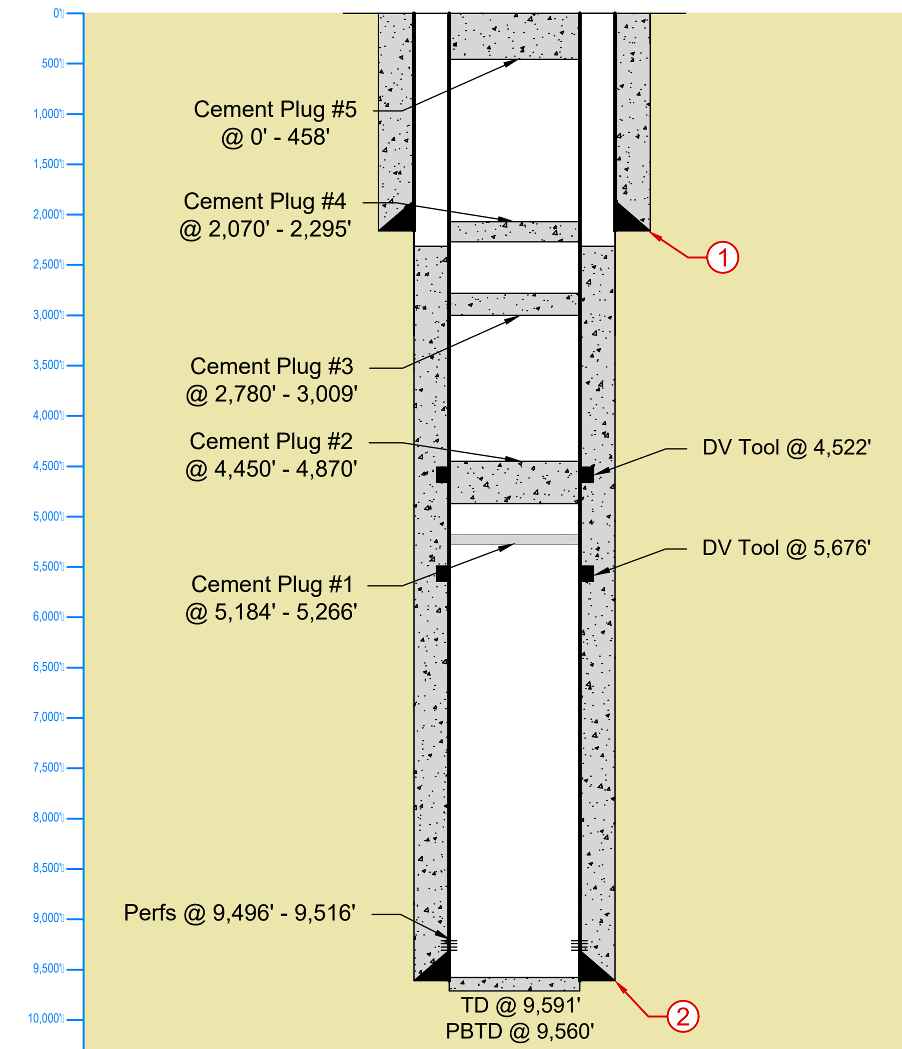




Casing Information

Label	1	2
Type	Surface	Production
OD	8-5/8"	4-1/2"
Depth Set	2,134'	9,601'

LONQUIST & CO. LLC PETROLEUM ENGINEERS ENERGY ADVISORS AUSTIN · HOUSTON CALGARY · WICHITA DENVER · COLLEGE STATION BATON ROUGE · EDMONTON	Exxon Corp.	E. Randall No. 32
Texas License F-9147	**Country:** USA	**State/Province:** Texas / **County/Parish:** Yoakum
	Location: Section 833, Block D	**Spud Date:** 05/10/1965 / **Survey:** John H. Gipson
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**API No:** 42-501-10079	**Field:** Wasson (Wichita Albany) / **RRC Lease Number:** 18231
	RRC District No: 8-A	**Project No:** LS 128 / **Date:** 05/31/2022
	Drawn: KAS	**Reviewed:** RKH / **Approved:** SLP
		Notes:



Casing Information

Label	1	3
Type	Surface	Production
OD	9-5/8"	5-1/2"
Weight	36 lb/ft	UNK
Depth Set	2,162'	9,569'
Hole Size	12-1/4"	7-7/8"
TOC	Surface	2,350'
Volume	880 sks	5,450 sks

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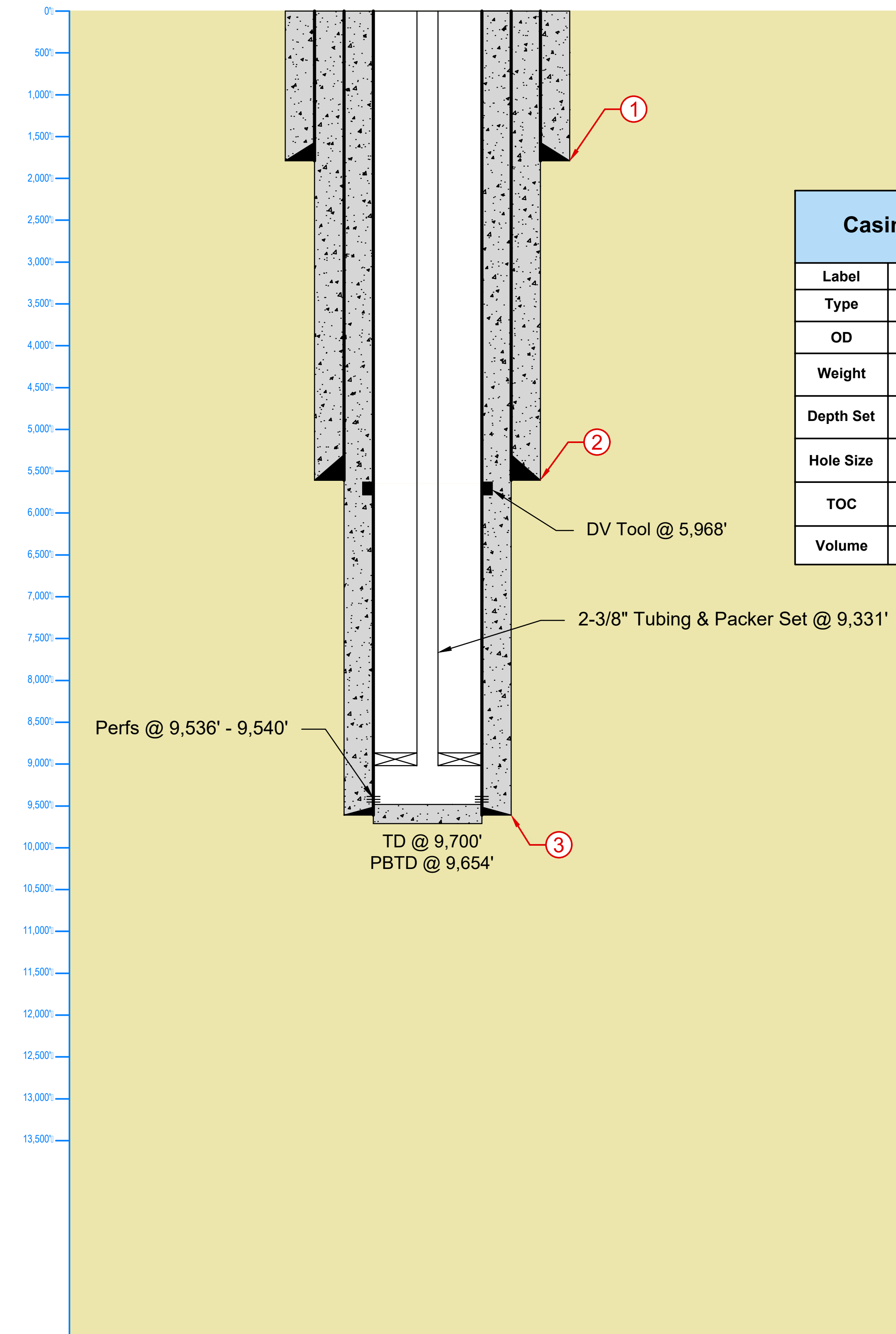
XTO Energy Inc.

E. Randall No. 40

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 12/04/1992	**Survey:** John H. Gipson
API No: 42-501-337932	**Field:** Wasson (Wichita Albany)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54 lb/ft	36 lb/ft 40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,129'	5,606'	9,699'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	Surface
Volume	1,790 sks	2,910 sks	1,590 sks

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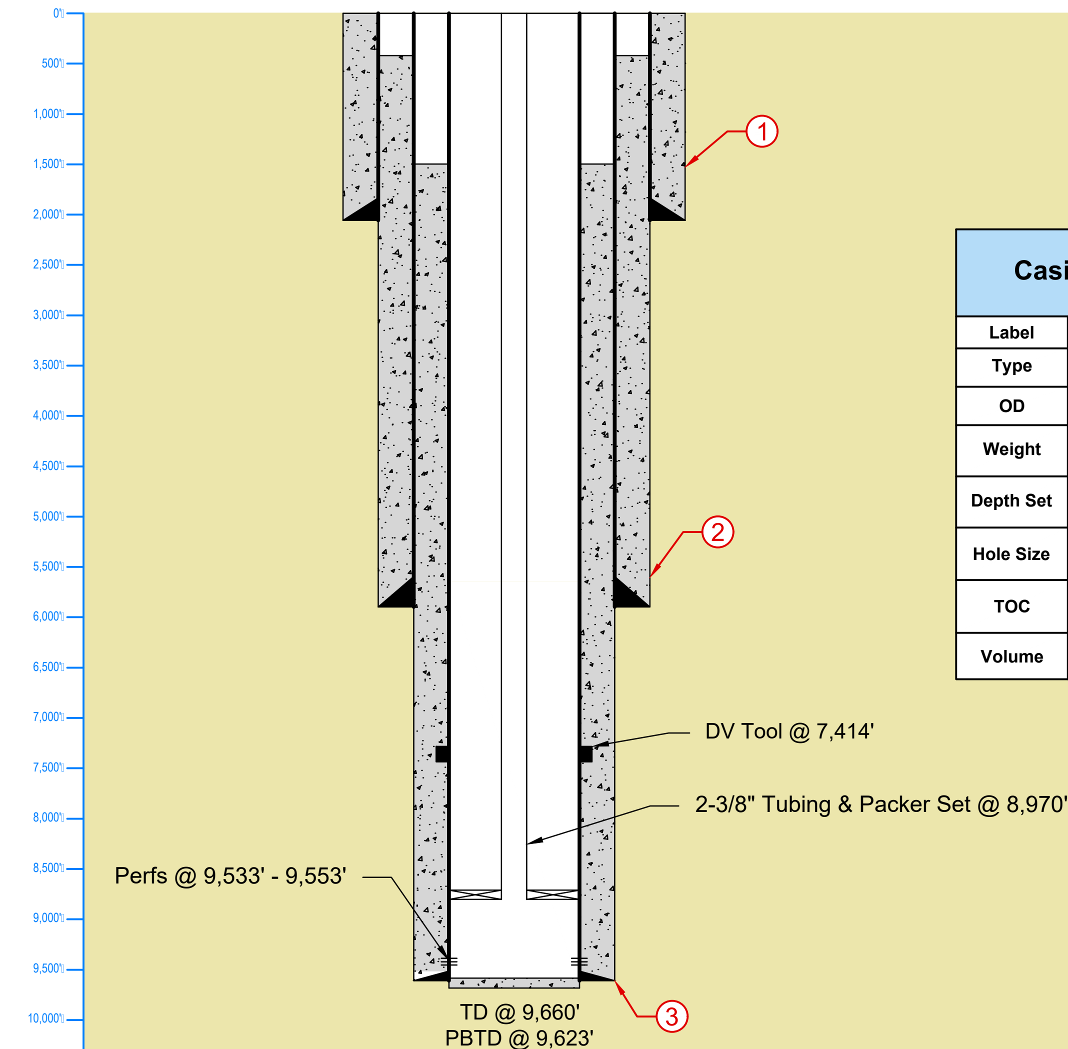
Exxon Corp.	E. Randall No. 41L	
Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 832, Block D	**Spud Date:** 02/05/1994	**Survey:** John H. Gipson
API No: 42-501-33885	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,167'	5,830'	9,658'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	440'	1,800'
Volume	1,530 sks	3,500 sks	1,050 sks

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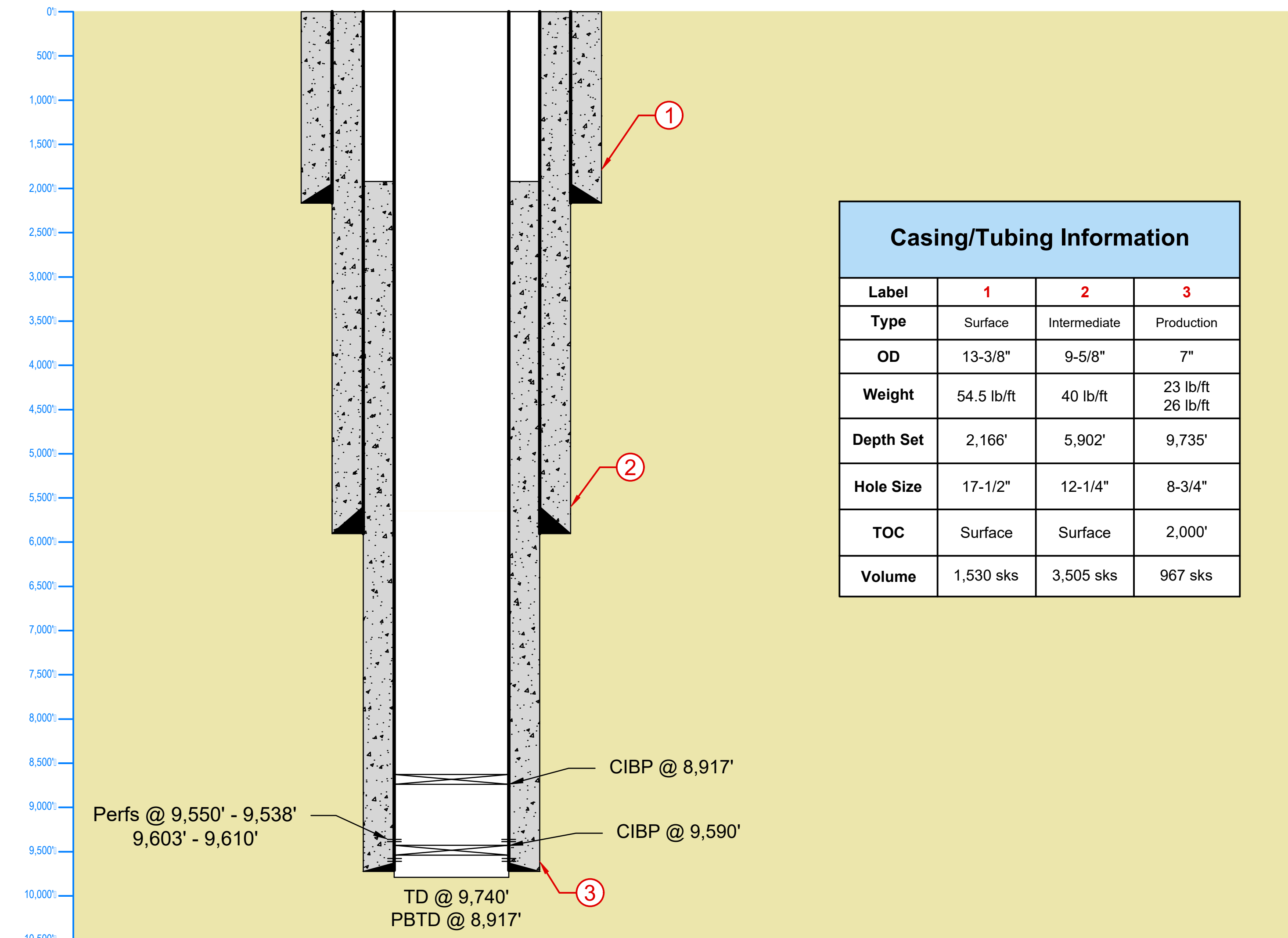
Exxon Corp.

E. Randall No. 42L

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 07/01/1995	**Survey:** John H. Gipson
API No: 42-501-34023	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,166'	5,902'	9,735'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	2,000'
Volume	1,530 sks	3,505 sks	967 sks

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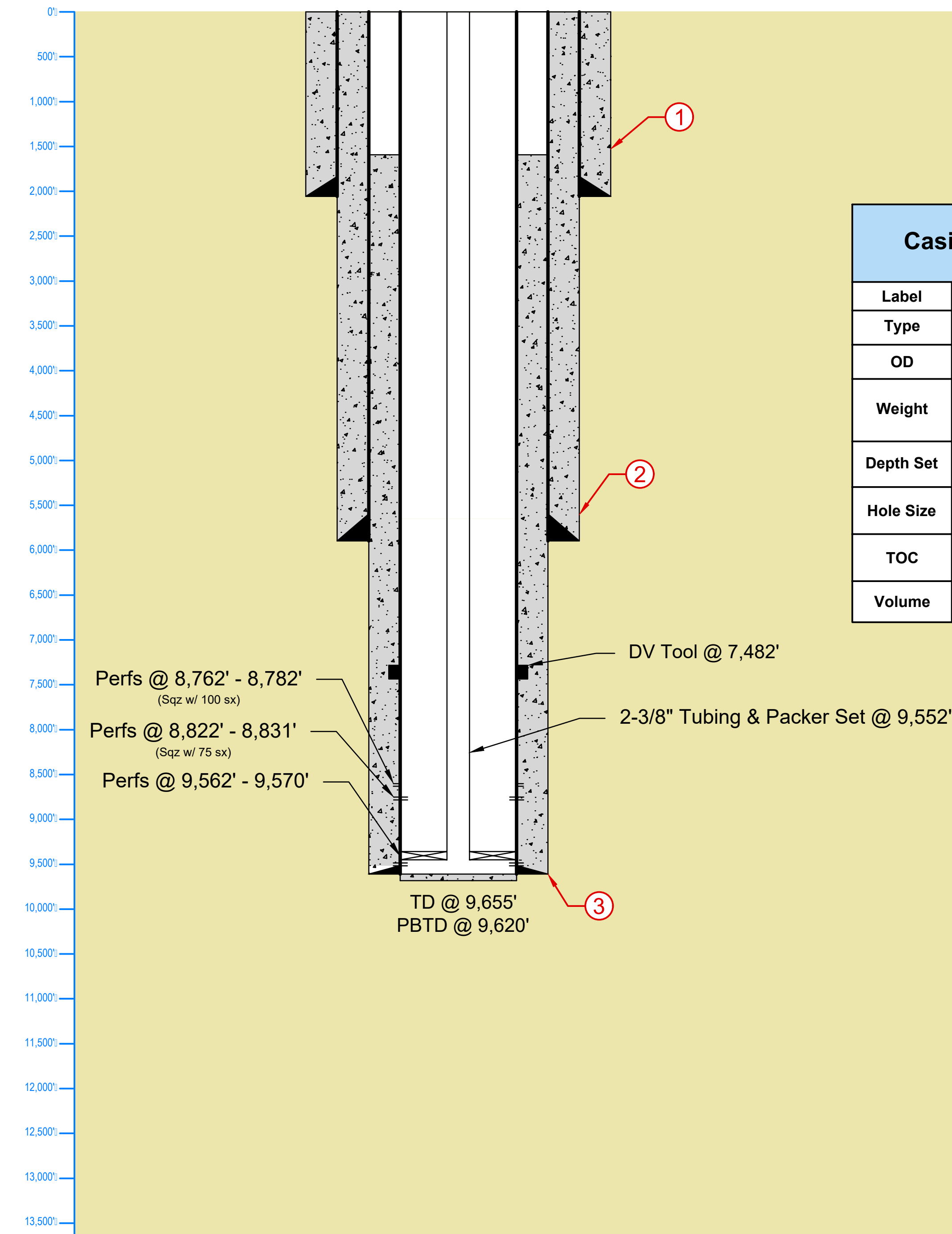
Exxon Corp.

E. Randall No. 43L

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 832, Block D	**Spud Date:** 04/08/1995	**Survey:** John H. Gipson
API No: 42-501-34016	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP

Notes:



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft 29 lb/ft
Depth Set	2,158'	5,904'	9,620'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	1,600'
Volume	1,450 sks	5,190 sks	1,100 sks

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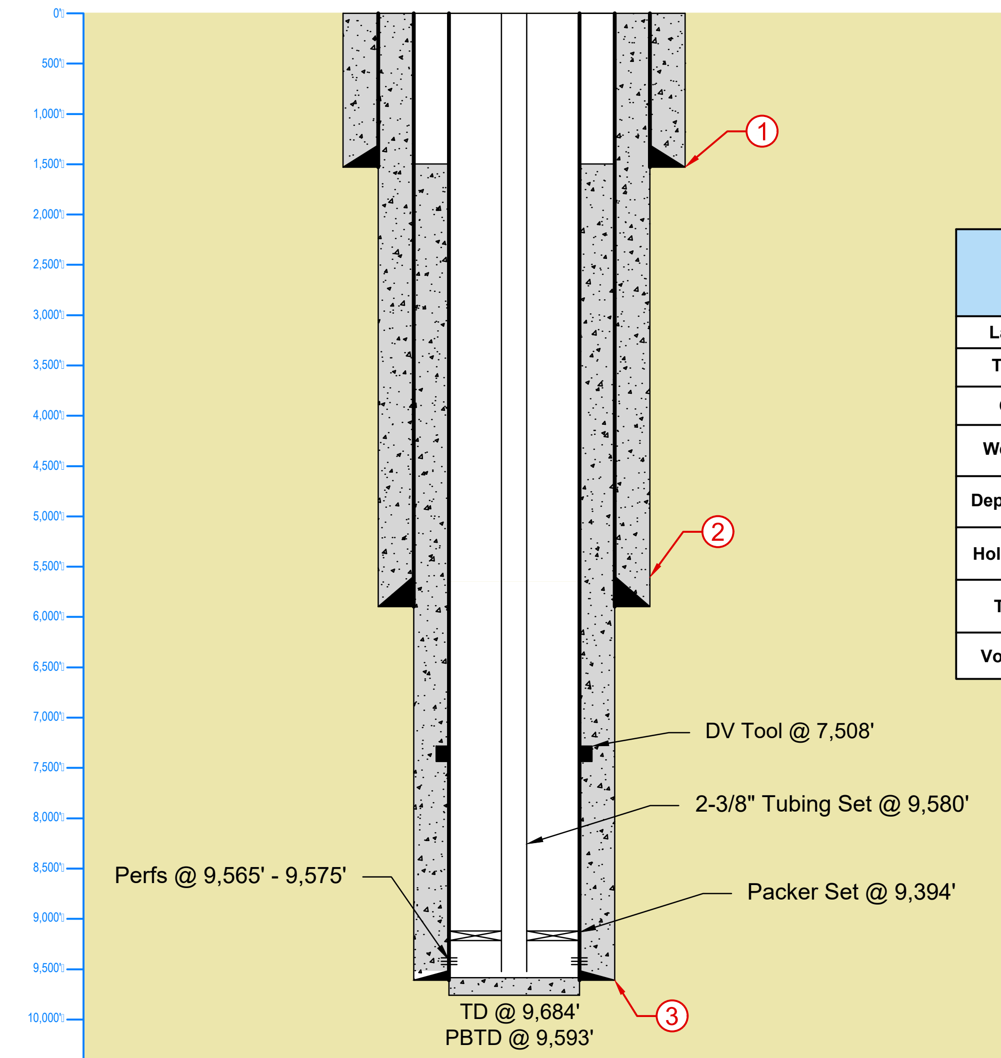
Exxon Corp.

E. Randall No. 44

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 08/09/1995	**Survey:** John H. Gipson
API No: 42-501-34024	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,175'	5,898'	9,615'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	1,500'
Volume	1,530 sks	3,525 sks	1,170 sks

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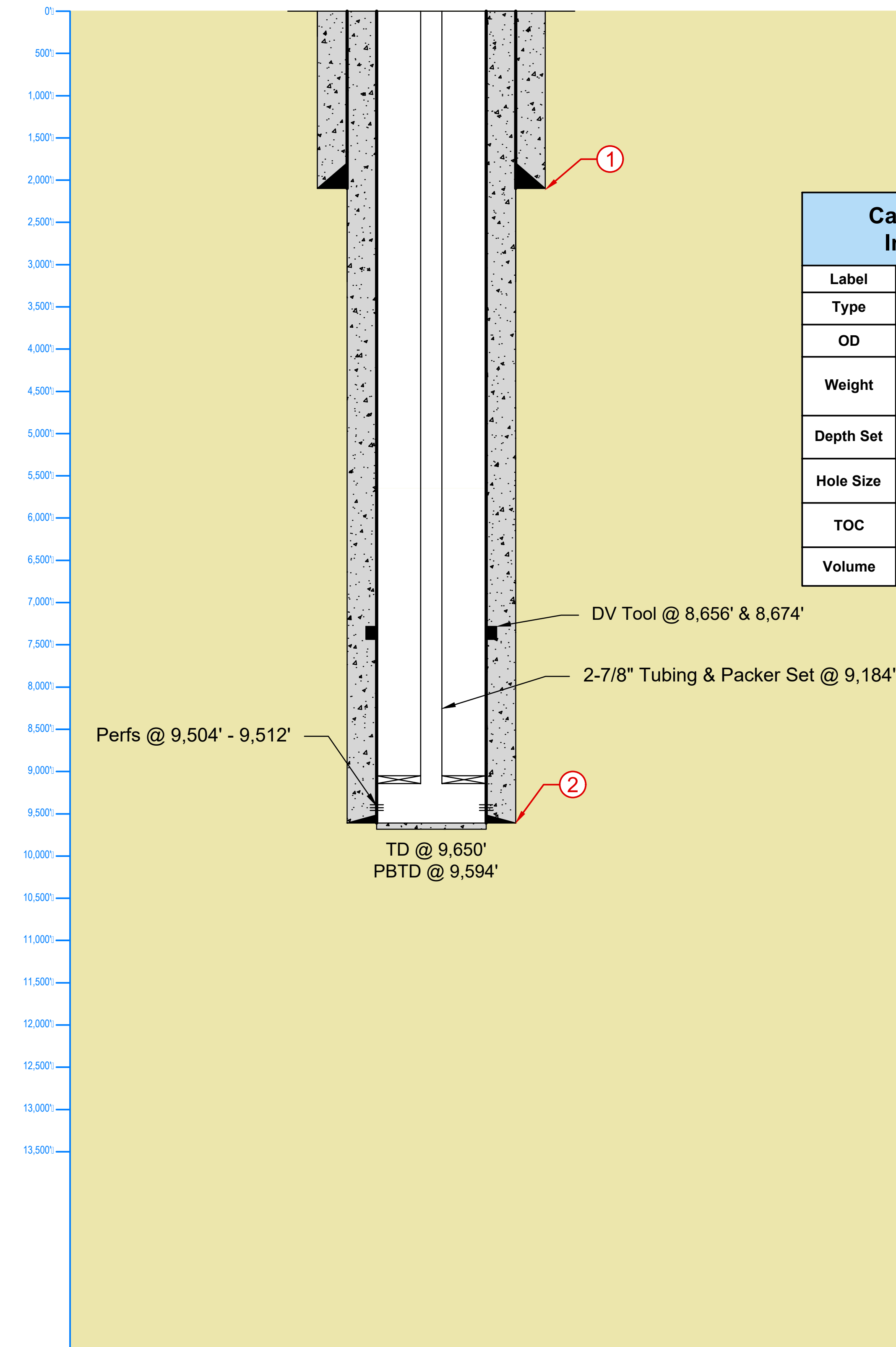
Exxon Corp.	E. Randall No. 45L	
Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 02/05/1994	**Survey:** John H. Gipson
API No: 42-501-34017	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2
Type	Surface	Production
OD	8-5/8"	5-1/2"
Weight	24 lb/ft	17 lb/ft
Depth Set	2,120'	9,650'
Hole Size	11"	7-7/8"
TOC	Surface	Surface
Volume	900 sks	3,400 sks

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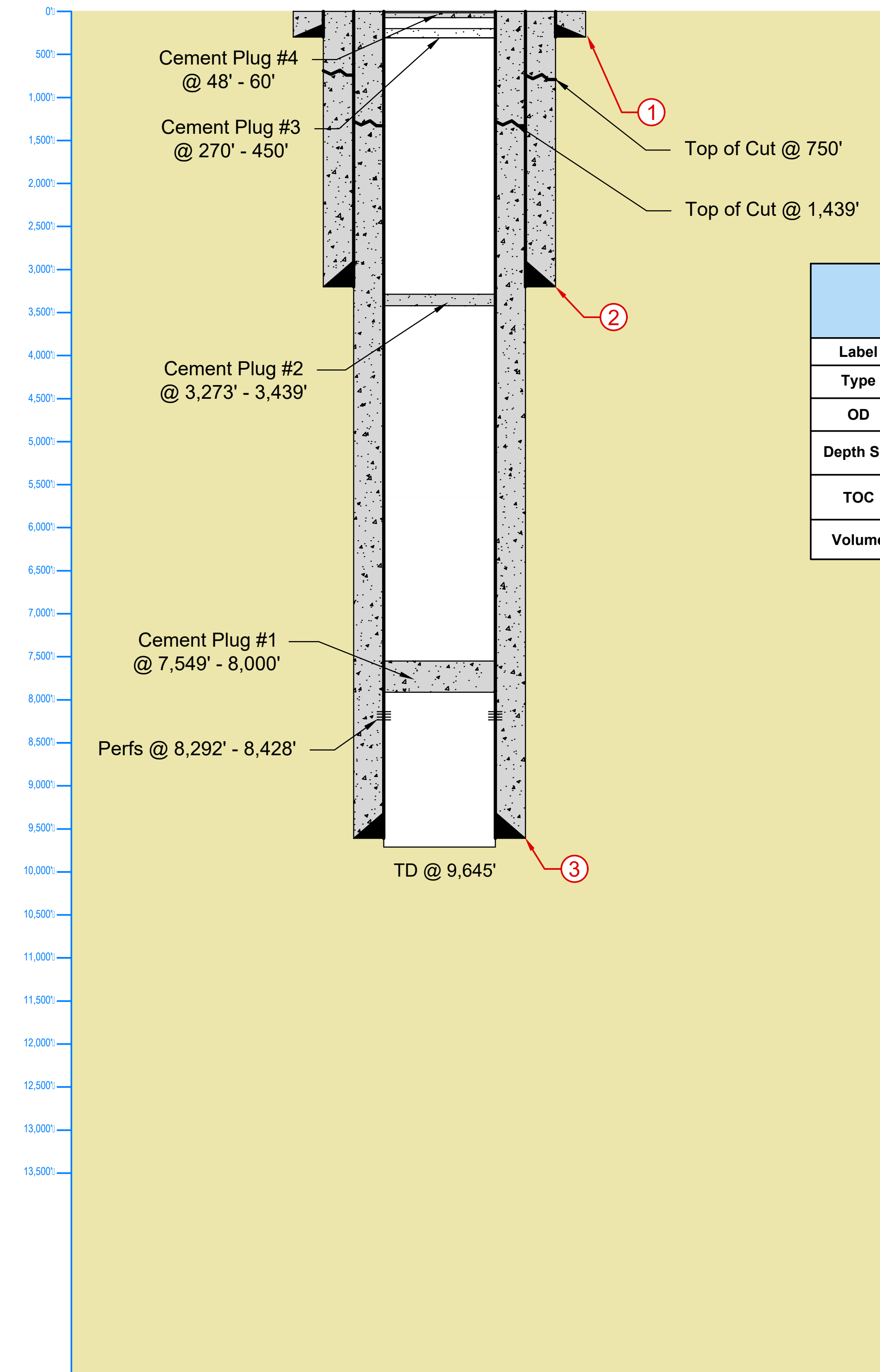
XTO Energy, Inc.

E. Randall No. 46

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 05/23/2007	**Survey:** John H. Gipson
API No: 42-501-35418	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP

Notes:



Casing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	5-1/2"
Depth Set	300'	3,200'	9,610'
TOC	Surface	Surface	Surface
Volume	400 sks	300 sks	425 sks

LONQUIST & CO. LLC
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AUSTIN · HOUSTON · CALGARY · WICHITA
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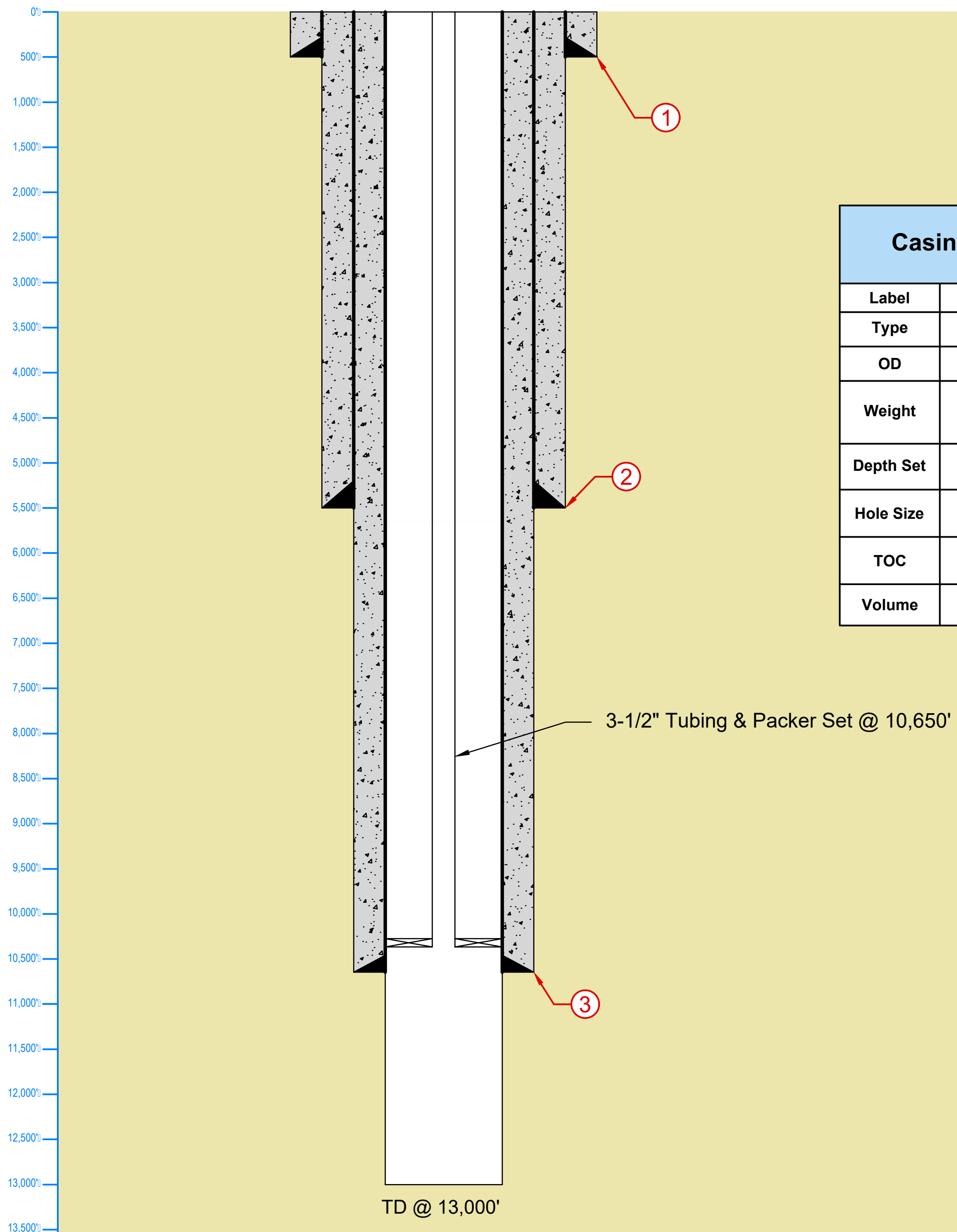
Texas License F-9147

12912 Hill Country Blvd. Ste F-200
Austin, Texas 78738
Tel: 512.732.9812
Fax: 512.732.9816

Bonanza Oil Corp.

C.A. Elliott No. 2

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 832, Block D	**Spud Date:** 05/10/1965	**Survey:** John H. Gipson
API No: 42-501-10046	**Field:** Wasson (Wichita Albany)	**RRC Lease Number:** 18875
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	48 lb/ft	40 lb/ft	26 lb/ft 28 lb/ft
Depth Set	500'	5,500'	10,695'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	Surface
Volume	350 sks	1,705 sks	1,635 sks

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Austin, Texas 78738
Tel: 512.732.9812
Fax: 512.732.9816

Amtex Energy, Inc.

Miller SWD No. 7 (Permitted)

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 732, Block D	**Spud Date:** 08/09/1995	**Survey:** John H. Gipson
API No: 42-501-37252	**Field:** Wasson	**Permit Number:** 16637
RRC District No: 7-C	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	

Appendix B: Submissions and Responses to Requests for Additional Information

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Rattlesnake AGI #1

Yoakum County, Texas

Prepared for *Stakeholder Gas Services, LLC*
San Antonio, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 3
September 2022

INTRODUCTION

Stakeholder Gas Services, LLC ("Stakeholder") currently has a Class II acid gas injection ("AGI") permit, issued by the Texas Railroad Commission ("TRRC") in November 2018, for the Rattlesnake AGI #1 well, API No. 42-501-36998. This permit was originally issued to Santa Fe Midstream Permian, LLC, in 2018 and the asset was subsequently acquired by Stakeholder in December of 2020. This permit currently authorizes Stakeholder to inject up to 4,500 barrels per day ("bbls/d") of treated acid gas ("TAG") into the Devonian formation at a depth of 11,000' to 12,000' with a maximum allowable surface pressure of 2,200 psi. Since being permitted, injection has proceeded without incident. This AGI well is associated with Stakeholder's 30-30 gas treating and processing plant ("30-30") located in a rural, sparsely populated area of Yoakum County, Texas, approximately seven miles northwest of the town of Plains, as shown in Figure 1.

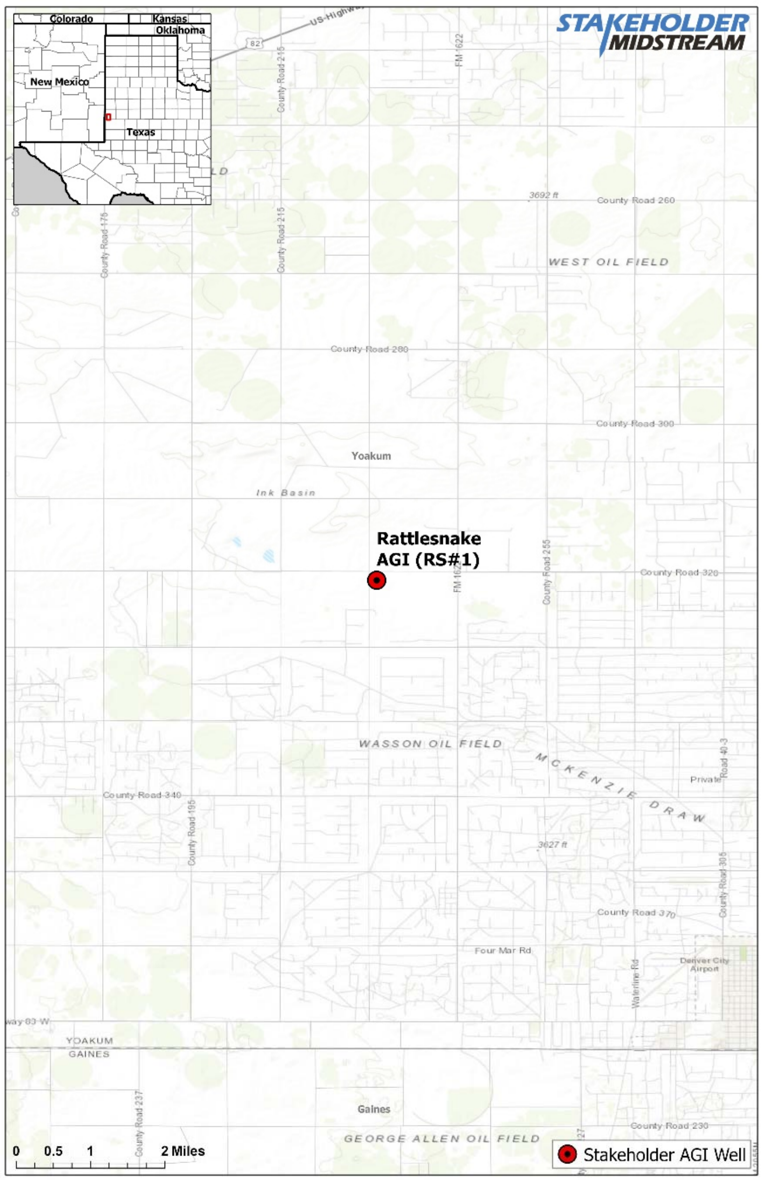

Figure 1 – Location of Rattlesnake AGI #1 Well

Stakeholder is submitting this Monitoring, Reporting, and Verification ("MRV") plan to the EPA for approval under 40 CFR §98.440(a), Subpart RR, of the Greenhouse Gas Reporting Program ("GHGRP"). In addition to submitting this MRV plan to the EPA, Stakeholder is also applying to the TRRC for an amendment to the Rattlesnake AGI #1 well's Class II permit to increase its authorized injection volume and maximum allowable surface injection pressure ("MASIP"). Approval of the permit amendment will allow Stakeholder to increase the capacity of its existing 30-30 Facility, which removes H_2S and CO_2 from natural gas production using amine treating, as well as increase the injection well capacity for a future gas processing facility which is currently under development by Stakeholder. Additionally, expanded capacity allows Stakeholder to potentially provide future disposal in its AGI well for oil and gas waste derived TAG from similar third-party gas processing facilities. Increased disposal capacity will allow for greater gas processing capacity in the region, ultimately helping to reduce flaring and its associated emissions. Throughout this document, both in written reference and in modeling inputs, Stakeholder has used the applied-for expanded permit capacity of 16 million standard cubic feet per day ("MMSCF/d"). Stakeholder plans to inject CO_2 for approximately 14 more years.

ACRONYMS AND ABBREVIATIONS

‘	Feet
%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group’s GEM 2020.11
GHGs	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program
H_2S	Hydrogen Sulfide
md	Millidarcy(ies)
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMCF	Million Cubic Feet
MMSCF	Million Standard Cubic Feet

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

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LIST OF FIGURES

LIST OF TABLES

SECTION 1 – FACILITY INFORMATION

This section contains key information regarding the Acid Gas and CO_2 injection facility.

Reporter number:

- Gas Plant Facility Name: 30-30 Gas Plant
- Greenhouse Gas Reporting Program ID: 574501
    - Currently reporting under Subpart UU
- Operator: Stakeholder Gas Services, LLC

Underground Injection Control (UIC) Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control ("UIC") Class II program. TRRC classifies the Rattlesnake AGI #1 well as a UIC Class II well. A Class II permit was issued to Stakeholder under TRRC Rule 9 (entitled "Disposal into Non-Productive Formations") and Rule 36 (entitled "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas").

UIC Well Identification Number:

Rattlesnake AGI #1, API No. 42-501-36998, UIC #000117143.

SECTION 2 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection volumes and process, and the reservoir modeling performed for the Rattlesnake AGI #1 well. The Class II UIC permit was initially applied for and received by Santa Fe Midstream Permian, LLC. The asset was acquired in 2020 by Stakeholder and has been in operation since that time. Since the original application, Lonquist has revised and updated the geology and the plume modeling within the reservoir in preparing this MRV Plan.

The Rattlesnake AGI #1 well is located and designed to protect against migration of CO_2 out of the injection interval and to prevent surface releases. The injection interval for Rattlesnake AGI #1 is located over 4,720' below the primary producing formation, the San Andres, in the area and 8,593' below the base of the lowest useable quality water table, as shown in Figure 2. This well injects both H_2S and CO_2, therefore the well and the facility are designed to minimize any leakage to the surface.

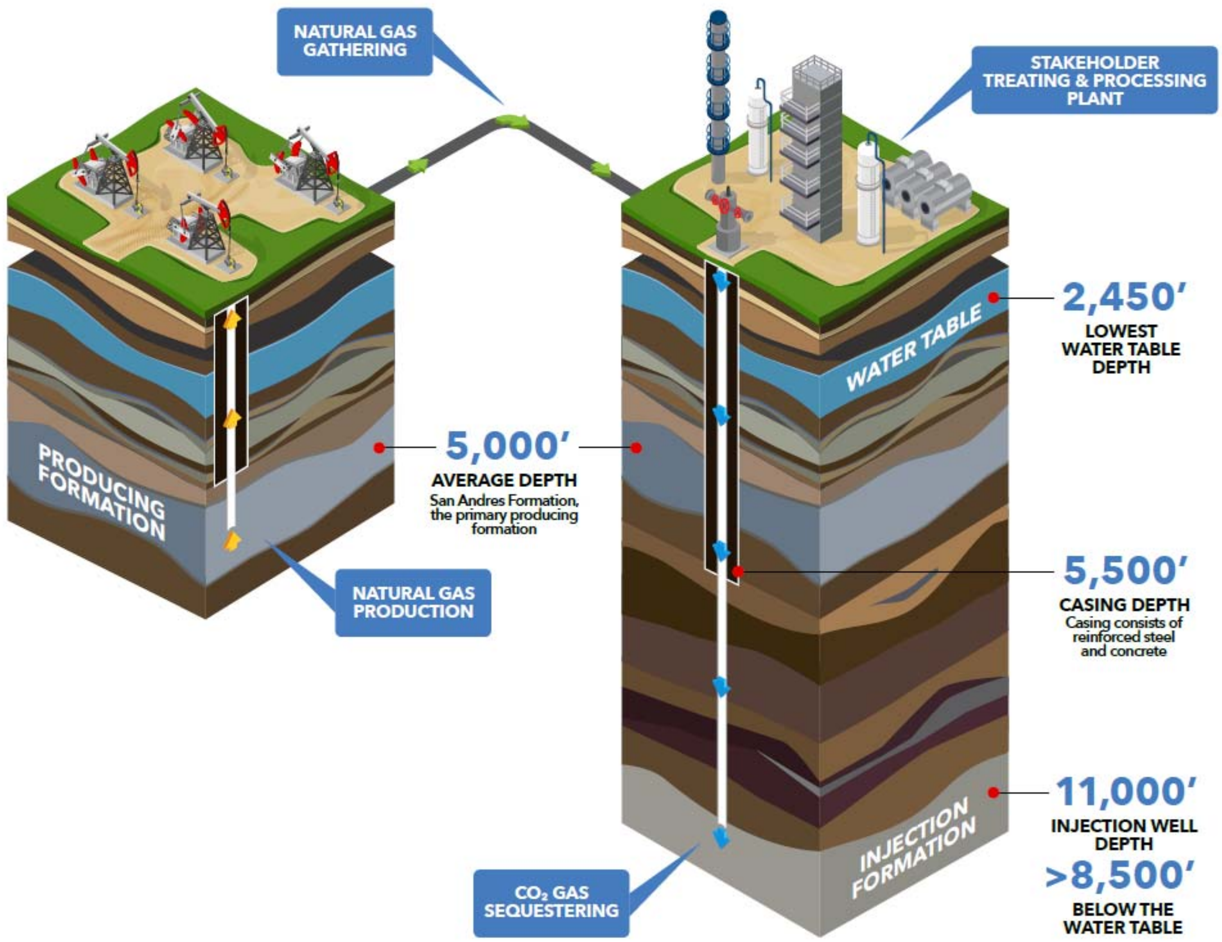


Figure 2 – Illustrative overview of Rattlesnake AGI #1 and 30-30 Facility

Regional Geology

The Rattlesnake AGI #1 well is located on the southern portion of the Northwestern Shelf within the larger Permian Basin as seen in Figure 3. The Northwestern Shelf is a broad marine shelf located in the northern portion of the Permian Basin.

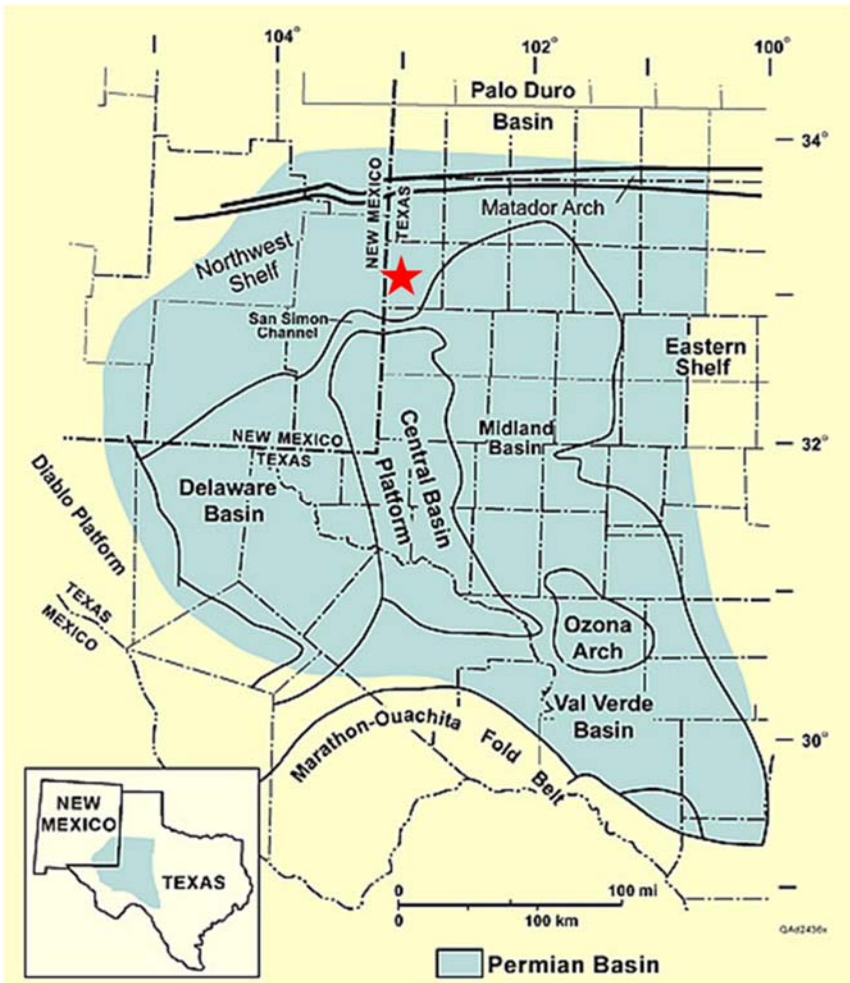


Figure 3 – Regional Map of the Permian Basin. Red Star is approximate location of Rattlesnake AGI #1 well

Figure 4 depicts the stratigraphic column found at the Rattlesnake AGI #1 well location with red stars referencing the injection formation and green stars indicating the productive intervals in the area. The primary injection interval is found within the Wristen group, of Silurian-age, as seen in Figure 5. The TRRC refers to this sequence under the general terms “Devonian”, “Silurian-Devonian” or “Siluro-Devonian”.

<table>
<tr><th>Period</th><th>Epoch</th><th colspan="2">Formation</th><th>General Lithology</th></tr>
<tr><td rowspan="16">Permian</td><td rowspan="3">Ochoan</td><td colspan="2">Dewey Lake</td><td>Redbeds/Anhydrite</td></tr>
<tr><td colspan="2">Rustler</td><td>Halite</td></tr>
<tr><td colspan="2">Salado</td><td>Halite/Anhydrite</td></tr>
<tr><td rowspan="5">Guadalupian</td><td colspan="2">Tansil</td><td>Anhydrite/Dolomite</td></tr>
<tr><td colspan="2">Yates</td><td>Anhydrite/Dolomite</td></tr>
<tr><td colspan="2">Seven Rivers</td><td>Dolomite/Anhydrite</td></tr>
<tr><td colspan="2">Queen</td><td>Sandy Dolomite/Anhydrite/Sandstone</td></tr>
<tr><td colspan="2">Grayburg</td><td>Dolomite/Anhydrite/Shale/Sandstone</td></tr>
<tr><td rowspan="7">Leonardian</td><td colspan="2">★ San Andres</td><td>Dolomite/Anhydrite</td></tr>
<tr><td colspan="2">Glorieta</td><td>Sandy Dolomite</td></tr>
<tr><td rowspan="4">Yeso</td><td>Paddock</td><td rowspan="4">Dolomite/Anhydrite/Sandstone</td></tr>
<tr><td>Blinebry</td></tr>
<tr><td>Tubb</td></tr>
<tr><td>Drinkard</td></tr>
<tr><td colspan="2">Abo</td><td>Dolomite/Anhydrite/Shale</td></tr>
<tr><td>Wolfcampian</td><td colspan="2">★ Wolfcamp</td><td>Limestone/Dolomite</td></tr>
<tr><td rowspan="5">Pennsylvanian</td><td>Virgilian</td><td colspan="2">Cisco</td><td>Limestone/Dolomite</td></tr>
<tr><td>Missourian</td><td colspan="2">Canyon</td><td>Limestone/Shale</td></tr>
<tr><td>Des Moinesian</td><td colspan="2">Strawn</td><td>Limestone/Sandstone</td></tr>
<tr><td>Atokan</td><td colspan="2">Bend</td><td rowspan="2">Limestone/Sandstone/Shale</td></tr>
<tr><td>Morrowan</td><td colspan="2">Morrow</td></tr>
<tr><td>Mississippian</td><td></td><td colspan="2">Mississippian Lime</td><td>Limestone</td></tr>
<tr><td>Devonian</td><td></td><td colspan="2">Woodford</td><td>Shale</td></tr>
<tr><td rowspan="2">Silurian</td><td></td><td colspan="2">★Wristen Group</td><td>Dolomite/Limestone</td></tr>
<tr><td></td><td colspan="2" rowspan="2">★ Fusselman</td><td rowspan="2">Dolomite/Chert</td></tr>
<tr><td rowspan="3">Ordovician</td><td rowspan="2">Upper</td></tr>
<tr><td colspan="2">Montoya</td><td>Dolomite/Chert</td></tr>
<tr><td>Middle</td><td colspan="2">Simspson Gp</td><td>Limestone/Sandstone/Shale</td></tr>
<tr><td>Lower</td><td colspan="2">Ellenburger</td><td>Dolomite</td></tr>
</table>

Figure 4 – Stratigraphic column of the Northwest Shelf. Red stars indicate injection interval. Green stars indicate productive intervals.

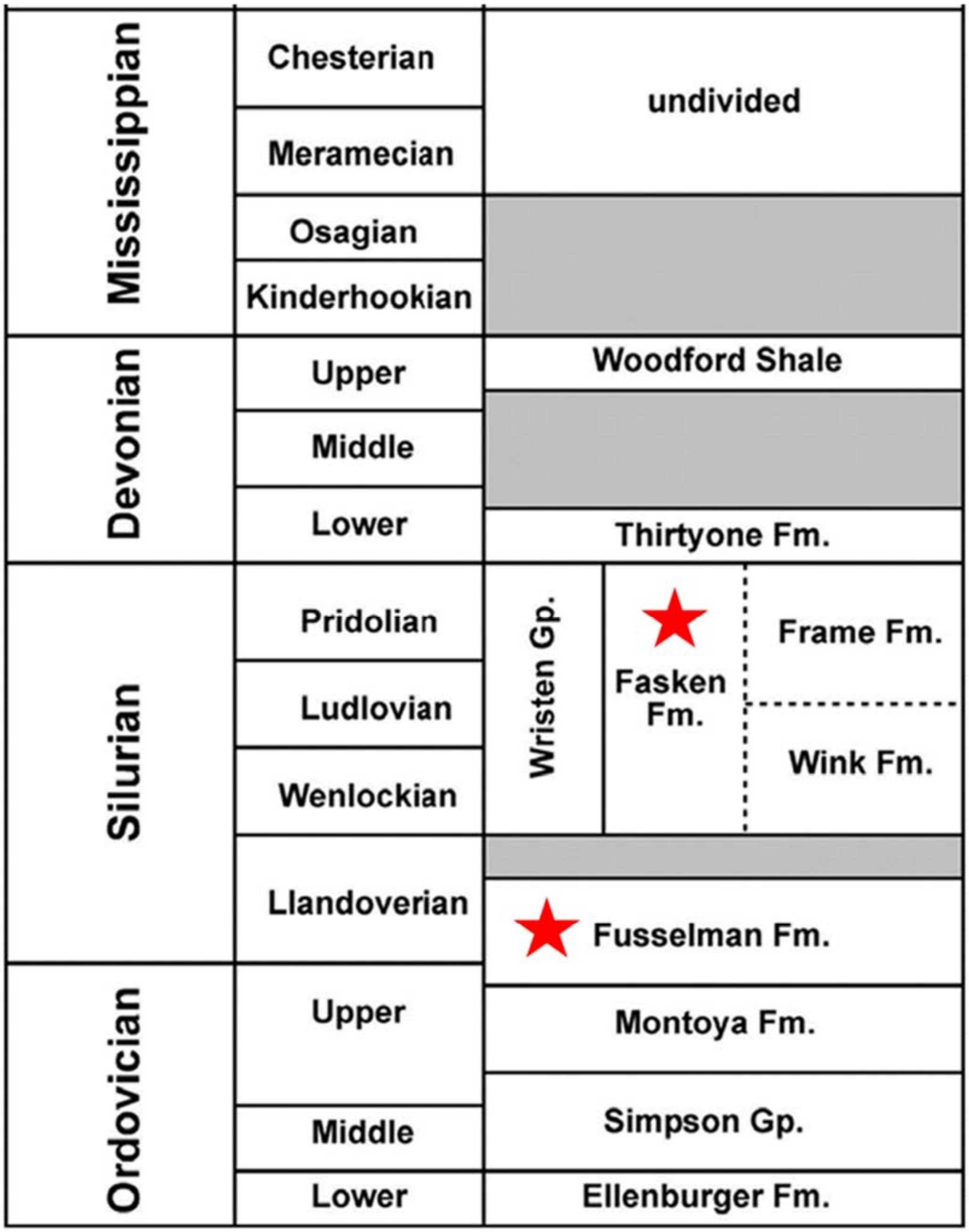


Figure 5 – Stratigraphic column depicting the composition of the Silurian group. Red star indicates injection interval (Broadhead, 2005)

The Wristen group was deposited in a basin platform setting across the northern half of the Permian Basin. The depositional environment over Yoakum County during the Silurian period was a shallow inner platform, the margin of which exists to the south, in southern Andrews County, Texas. The Silurian-age lithology on the inner platform is dominated by grain-rich skeletal carbonates. Carbonate buildups are common within the shallow inner platform, mainly skeletal wackestone, indicating a lower-energy deposition on the inner platform. The carbonate shelf margin to the south acted as a barrier from basin-ward wave energy (Ruppel and Holtz, 1994).

Depositional cycles within the inner platform indicate it was controlled by episodic sea level rise and fall, resulting in sub-areal exposure and diagenesis. The diagenesis of the Silurian-age carbonate rocks initiated

secondary porosity development and increased permeability. Dolomite and solution-related features are the most prominent diagenetic characteristics found within the Silurian. The Wristen Group is composed of three formations: Fasken, Frame, and Wink formations. The Frame and Wink formations are found near the ramp boundary to the south, while the Fasken formation is found predominantly in the inner platform, where the Rattlesnake AGI #1 well is located. The Fasken formation is predominately dolomite grading to limestone, occurring as cycles, down section. This dolomitization is due in part to sub-areal exposure, during which karsts and secondary porosity developed. Additional dolomitization was possible during successive sea level fluctuations via movement of magnesium-rich solution through karsts and vugs, which acted as channels for fluid flow (Ruppel and Holtz, 1994).

Figure 6 shows a regional isopach map of the Silurian (combined Fasken and Fusselman formations) with a red star depicting the Rattlesnake AGI #1 well location. Thickness of the Silurian-age rock is approximately 1,000’ at the Rattlesnake AGI #1 well location.

North of Andrews County there is little differentiation between the Fasken and Fusselman formations which are both carbonate deposits with the potential for sub-areal exposure and porosity development. For purposes of this MRV Plan, the combined Fasken and Fusselman formations are defined as the injection interval, and the underlying Montoya formation serves as the lower confining unit.

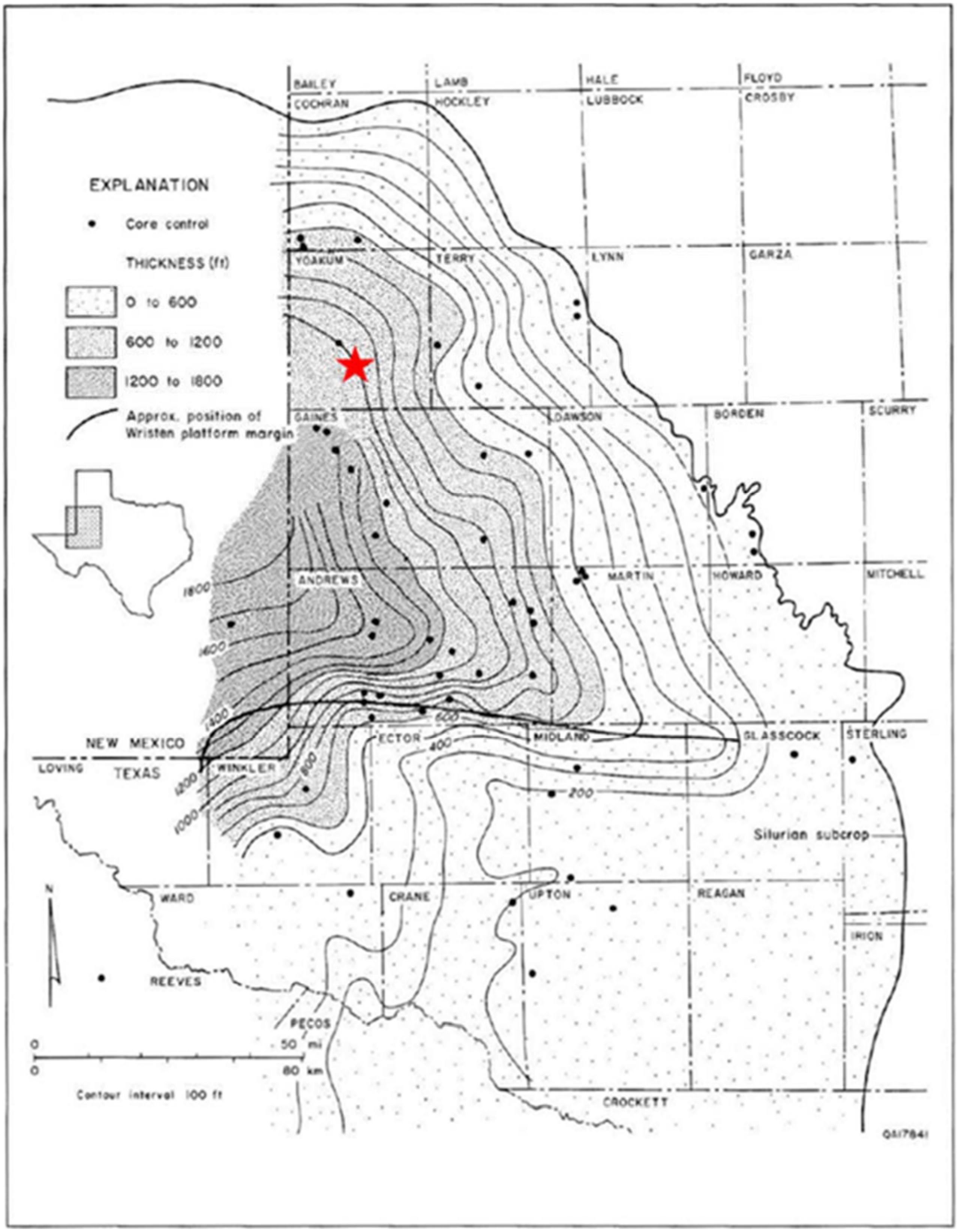


Figure 6 – Thickness map of the Silurian system which composes the Fusselman and Wristen group

Regional Faulting

A major uplift that began during the Pennsylvanian Period to the south, the Central Basin Platform, ceased in the Early Permian (Wolfcampian), which caused a regional unconformity of the underlying formations (Hoak, Sundberg, and Ortoleva). Faulting on the Northwest Shelf can be seen through high angle basement faults that tend to die within the Pennsylvanian strata. These faults predominately represent contractional (thrust) faults that were initiated during the Pennsylvanian as a result of regional tectonics. Hydrocarbon traps within the Wristen group are primarily anticlinal structures dependent upon reservoir development (Broadhead, 2005).

Site Characterization

The Rattlesnake AGI #1 well is located in Section 733, Block D, John H. Gibson Survey, in Yoakum County, Texas. Stakeholder owns the 82.42-acre surface tract where the plant and Rattlesnake AGI #1 well are located. The following discusses the geological character of this site.

Stratigraphy and Lithologic Characteristics

Figure 7 depicts an open hole log from an offset well (API No. 42-501-10238) to the Rattlesnake AGI #1 well indicating the injection and primary upper confining zone. This well is approximately 1.8 miles to the northwest of the Rattlesnake AGI #1 well. An offset well log was used to depict the upper confining intervals as electric logs were only run in the Rattlesnake AGI #1 well across the injection zone.

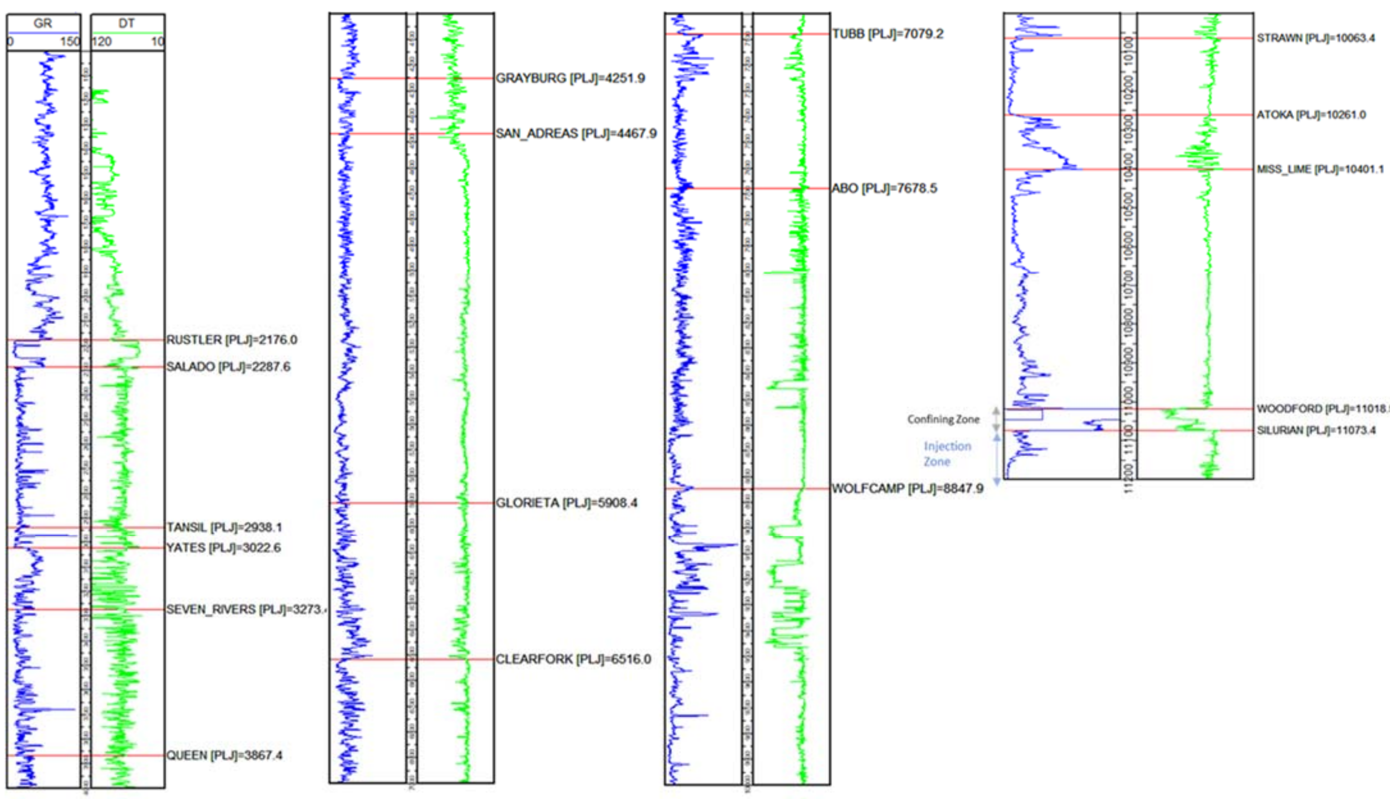


Figure 7 – Type Log (42-501-10238) with tops, confining and injection zones depicted

Upper Confining Interval - Woodford Shale

The Woodford is a late Devonian-age organic-rich shale deposited as a result of a widespread marine transgression. The flooding event occurred over the majority of the Permian basin, which produced a low-relief blanket-like shale deposit of the Woodford. Two major lithofacies found within the Woodford are black shale and siltstone. Nutrient-rich surface waters promoted the decay of abundant organic matter within the Woodford, resulting in a high total organic carbon ("TOC") percentage. The Woodford shale acts as the primary source and sealant rock for the Wristen Group (Comer, 1991).

Figure 8 is a description of a core sample taken in Lea County, New Mexico just southwest of the Rattlesnake AGI #1 well location. This sample is referenced as C9 in the reference map with the blue star representing the Rattlesnake AGI #1 well. In the core description, black shale with abundant illitic clays is observed in the upper section, and medium gray dolomitic siltstone found in the basal section. The mineralogic and lithologic properties recorded in this description serve as excellent sealant characteristics to prohibit any injected fluids from migrating above the injection interval.

The Woodford at the Rattlesnake AGI #1 well location is encountered at 10,973 ft and is approximately 63 ft thick.

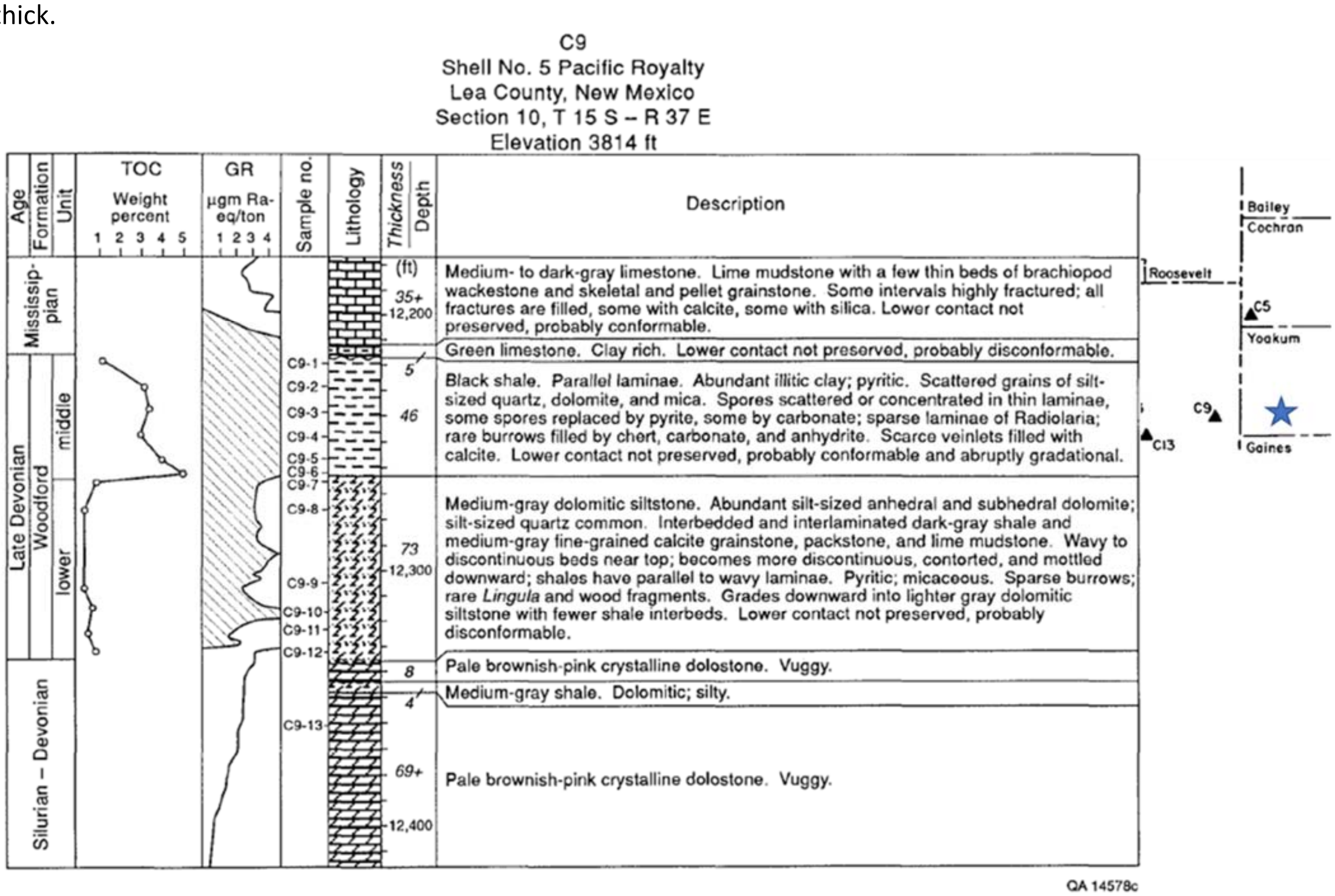


Figure 8 – Core description of the Woodford Shale and Upper Silurian (Ruppel and Holtz, 1994)

Injection Interval – Fasken Formation

The Rattlesnake AGI #1 well reaches total depth in the Fasken/Fusselman formation (Silurian in age), directly below the Woodford formation. Dolomites at the top of the Fasken formation underwent multiple leaching and diagenetic episodes which developed secondary porosity. This is evidenced in offset wells by the practice of only drilling through the top 30’ of the Fasken, in anticipation of encountering the best reservoir quality. In Figure 8, the uppermost Silurian section is described as ‘vuggy dolostone’ in the core description. Beds below the top of the Fasken section may also have similar petrophysical attributes if exposed to multiple diagenetic events. Solution-collapse and karst breccia horizons can be found within inner platform deposits, some occurring as much as 100 ft below the Fasken top (Ruppel and Holtz, 1994).

Porosity/Permeability Development

Porosity in the Fasken formation at the Rattlesnake AGI #1 well location is typically moldic and intercrystalline associated with leaching of allochem-rich intervals. Porosity is directly related to these leaching events which occurred during and post-deposition, resulting in vugs and karst-like features. Figure 9 provides reservoir information from core data within fields in the Wristen buildup and platform carbonate play. The average porosity of these cores is 7.1% with an average permeability of 45.28 millidarcies (Ruppel and Holtz, 1994). The porosity and permeability described in the offset core data indicate the Fasken formation provides sufficient accessible pore space for the amount of fluid injection proposed.

Using the above values as reference points, the Rattlesnake AGI #1 porosity log (API No. 42-501-36998) was evaluated. Figure 10 is the product of the petrophysical analysis performed on the open hole logs run within the injection interval at the Rattlesnake AGI #1 well. A permeability curve was generated from the effective porosity curve using the table in Figure 9 to establish the porosity-permeability relationship. In Figure 10, the majority of the injection interval’s porosity and permeability is found at the top of the Fasken formation, which correlates with the diagenetic processes described above. These curves are extrapolated to the injection site and used to establish reservoir characteristics in the plume model.

	Fusselman Shallow Platform Carbonate play	Wristen Buildups and Platform Carbonate play	Thirtyone Ramp Carbonate play	Thirtyone Deep-Water Chert play
		Porosity (%)		
Number of data points	33	30	16	35
Mean	7.93	7.10	6.41	14.85
Minimum	1.00	2.70	3.50	2.00
Maximum	17.70	14.00	9.50	30.00
Standard deviation	4.01	2.67	1.75	6.76
		Permeability (md)		
Number of data points	21	24	12	33
Mean	11.61	45.28	1.51	8.56
Minimum	0.60	2.90	0.40	1.00
Maximum	84.80	400.00	30.00	100.00
Standard deviation	22.48	99.17	8.36	22.23
		Initial water saturation (%)		
Number of data points	24	28	10	31
Mean	26.96	31.55	24.70	31.46
Minimum	10.00	20.00	16.00	10.00
Maximum	50.00	55.00	40.00	45.00
Standard deviation	9.31	10.45	7.39	8.33
		Residual oil saturation (%)		
Number of data points	8	13	5	22
Mean	34.06	30.54	21.30	29.17
Minimum	30.00	20.00	9.00	14.00
Maximum	50.00	35.00	35.00	48.20
Standard deviation	6.99	4.61	11.66	9.76
		Oil viscosity (cp)		
Number of data points	11	12	5	21
Mean	0.69	1.16	0.33	0.68
Minimum	0.13	0.32	0.04	0.07
Maximum	1.08	2.00	1.00	1.03
Standard deviation	0.81	0.75	0.40	0.42
		Oil formation volume factor		
Number of data points	21	22	6	32
Mean	1.57	1.22	1.65	1.50
Minimum	1.05	1.05	1.31	1.30
Maximum	1.91	1.55	1.66	1.73
Standard deviation	0.28	0.14	0.48	0.16
		Bubble-point pressure (psi)		
Number of data points	9	9	5	19
Mean	2,272	1,055	3,750	2,752
Minimum	798	450	2,660	1,755
Maximum	4,050	2,600	4,440	4,656
Standard deviation	1,300	689	756	667

Figure 9 – Table of reservoir properties found within the Wristen buildups and platform plays (Ruppel and Holtz, 1994)

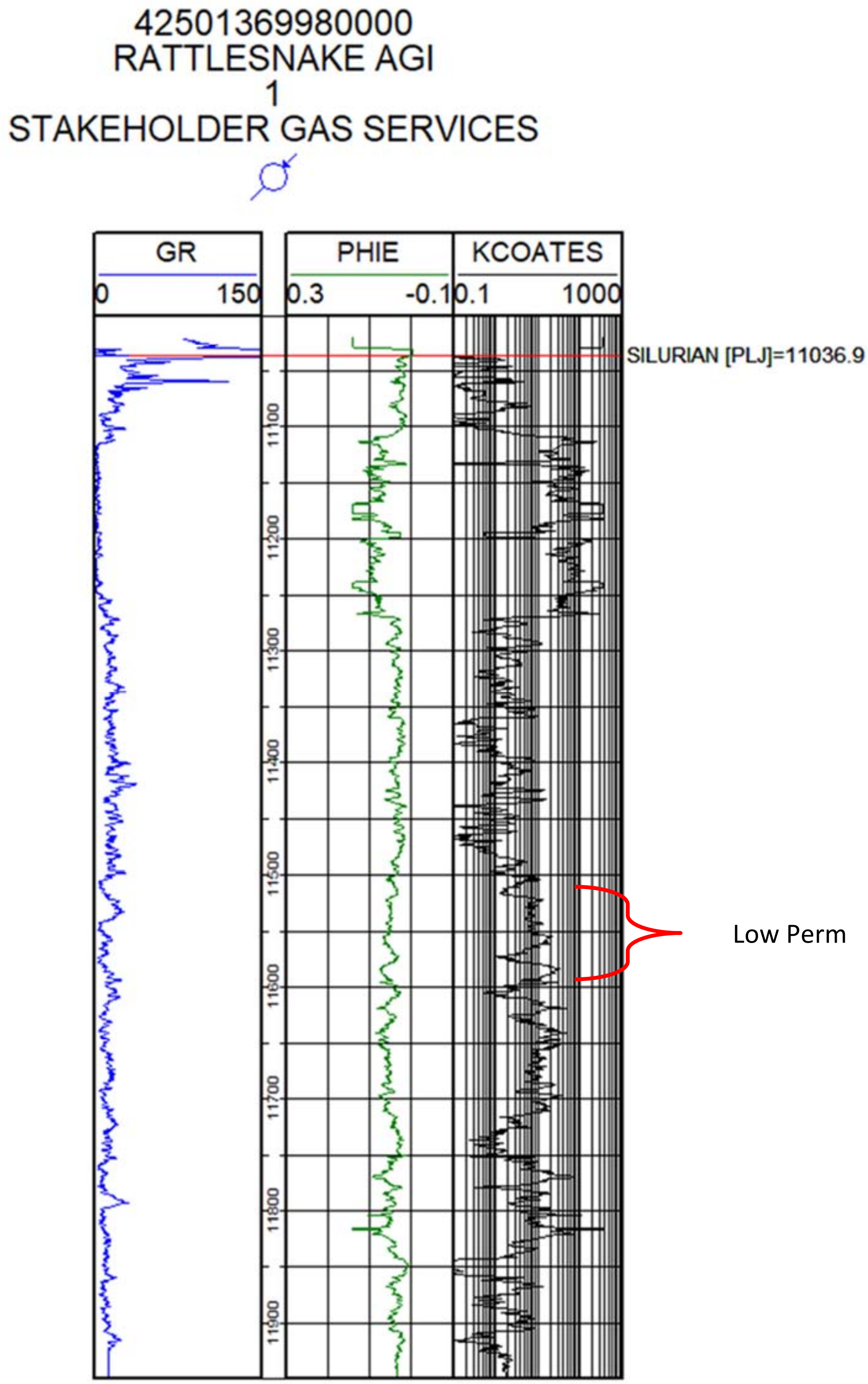


Figure 10 – Rattlesnake AGI #1 open hole log (42-501-36998) with effective porosity (green) and permeability (black)

Formation Fluid

Four wells were identified through a review of chemical analyses of oil-field brines from the U.S. Geological Survey National Produced Waters Geochemical Database v2.1 within the Devonian, Silurian-Devonian, or Fusselman formations within 20 miles of the Rattlesnake AGI #1 well. The location of these wells is shown in Figure 11. Water chemistry analyses conducted on oil-field brines in Gaines County, as reported to the Texas

Water Development Board, provided additional data on Devonian and Silurian reservoir fluids. Results from the synthesis of these two sources are provided in Table 1. The fluids have greater than 20,000 parts per million ("ppm") total dissolved solids, therefore these aquifers are considered saline. These analyses indicate the in-situ reservoir fluid of the Devonian, Silurian, and Fusselman formations are compatible with the proposed injection fluids.

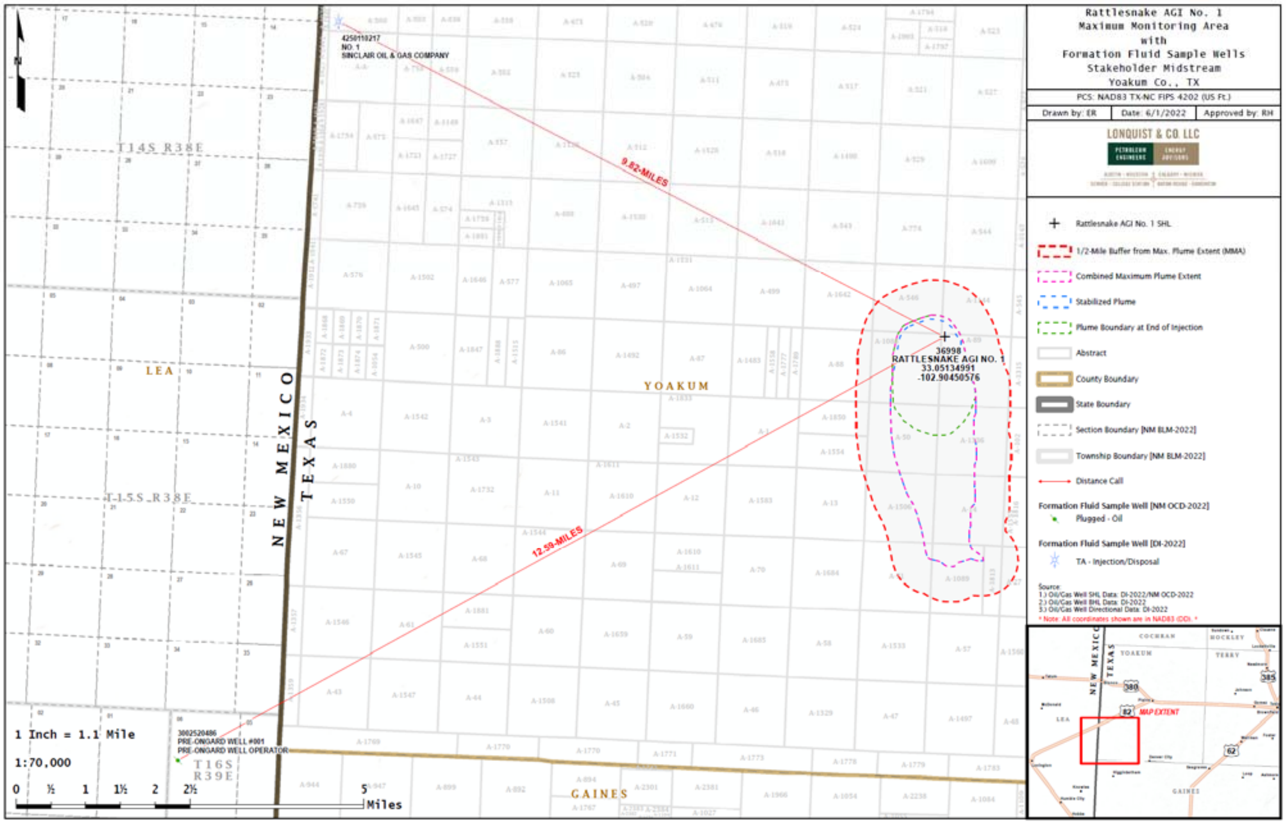


Figure 11 – Offset wells used for Formation Fluid Characterization

Table 1 – Analysis of Silurian-Devonian age formation fluids from nearby oil-field brine samples

	Average	Low	High
Total Dissolved Solids (ppm)	41,428	23,100	55,953
pH	7.2	7.0	7.3
Sodium (ppm)	12,458	7,426	15,948
Calcium (ppm)	1,759	1,010	2,320
Chlorides (ppm)	23,423	12,810	31,930

Fracture Pressure Gradient

Fracture pressure gradient was estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for the determination of fracture gradients. Poisson's ratio ("ν"), overburden gradient ("OBG"), and pore gradient ("PG") are all variables that can be changed to match the site-specific injection zone. Through literature review and industry standards, we are able to determine the expected

fracture gradient. First, 1.05 psi/ft and 0.465 psi/ft were assumed for both the overburden and pore gradients, respectively. These values are considered best practice values when there are no site-specific numbers available. For limestone/dolomite rock, the Poisson's ratio to be assumed to be 0.3 through literature review (Molina, Vilarras, Zeidouni 2016). Using these values in the equation below, a fracture gradient of 0.72 psi/ft was calculated. A 10% safety factor was then applied to this number resulting in maximum allowed bottom hole pressure of 0.64 psi/ft. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

For the upper confining interval, a similar fracture gradient as the limestone was calculated. Shale has an increased chance to vertically fracture if the injection interval is fractured (Molina, Vilarras, Zeidouni 2016), so assuming a Poisson's ratio equal to the injection interval was used as a conservative estimate. The lower confining zone was assumed to be of a similar matrix to that of the injection interval, with the key difference being that the formation is much tighter (lower porosity/permeability). The Poisson's ratio was assumed to be slightly higher in this rock. As seen in Table 2, the fracture gradient is slightly higher than the upper zones.

Table 2 – Fracture Gradient Assumptions

	Injection Interval	Upper Confining	Lower Confining
Overburden Gradient (psi/ft)	1.05	1.05	1.05
Pore Gradient (psi/ft)	0.465	0.465	0.465
Poisson's Ratio	0.30	0.30	0.31
Fracture Gradient psi/ft	0.72	0.72	0.73
FG + 10% Safety Factor (psi/ft)	**0.64**	**0.64**	**0.66**

The following steps were taken to calculate fracture gradient:

$$FG = \frac{\nu}{1 - \nu}(OBG - PG) + PG$$

$$FG = \frac{0.3}{1 - 0.3}(1.05 - 0.465) + 0.465 = 0.72$$

$$FG\ with\ SF = 0.72 \text{ x } (1 - 0.1) = \mathbf{0.64}$$

Lower Confining Zone – Montoya Formation

The low-permeability Montoya Formation is a tight limestone/dolomite that will act as the lower confining unit for the injection interval. Figure 10 shows the decreasing trend in porosity of the limestone rock in the lower section that was not exposed to leaching diagenesis. Porosity in the lower section can range from 2-3% with permeabilities below 1 millidarcy. The Rattlesnake AGI #1 well drilled 6' into the Montoya formation, but the section was not logged. The Montoya is anticipated to be roughly 250' thick. These petrophysical characteristics represent ideal sealing properties to prohibit any migration of injected fluid outside of the injection interval.

Local Structure

Regional structure in the area of the Rattlesnake AGI #1 well is dictated by carbonate buildups and structural events causing anticlinal to synclinal features throughout the area. The Rattlesnake AGI #1 well is specifically located at the base of a syncline with anticlinal features to the northeast, south, and east. Figure 12 is a

structure map of the Silurian formation of subsea depths with the star representing the location of the Rattlesnake AGI #1 well. The red and blue lines represent the cross-section reference lines.

Faulting can be seen to the south and east of the Rattlesnake AGI #1 well location. These faults were interpreted from roughly 9 square miles of 3D seismic indicated by the purple outline in Figure 12. Many of these faults are minor, with offsets less than 50'. The nearest large fault is found southeast of the Rattlesnake AGI #1 well and has an offset of roughly 120'. None of these faults project above the Wolfcamp formation, rather, they appear to terminate between the Strawn and base of the Wolfcamp formation. Production is associated with a hydrocarbon trap set up by the larger fault to the southeast, indicating the fault is vertically sealing in nature. If, in the unlikely event the faults' sealing properties are compromised post-injection, secondary confinement is provided by the tight limestones found within the overlying Mississippian Lime formation along with shale layers found in the Atoka and Wolfcamp formations. As seen in Figure 14, the largest fault found southeast of the Rattlesnake AGI #1 well, terminates within the Atoka formation. Though it crosses the Silurian section, this fault thrusts the Mississippian Lime upward against the Atoka shales. The tight reservoir characteristics of the Mississippian Lime and shaley section of the Atoka create a confining environment vertically and laterally to contain potential upward migration of buoyant fluids. Shales within the Wolfcamp formation provide additional confining beds between overlying USDWs and the fault plane. Figures 13 and 14 are north-south and west-east structural cross sections showing the structural dips. As seen in these figures, the Woodford formation is laterally present above the injection interval, alleviating risk of erosion of the upper sealant formation.

Larger versions of Figures 11, 12, 13 and 14 are provided in Appendix A.

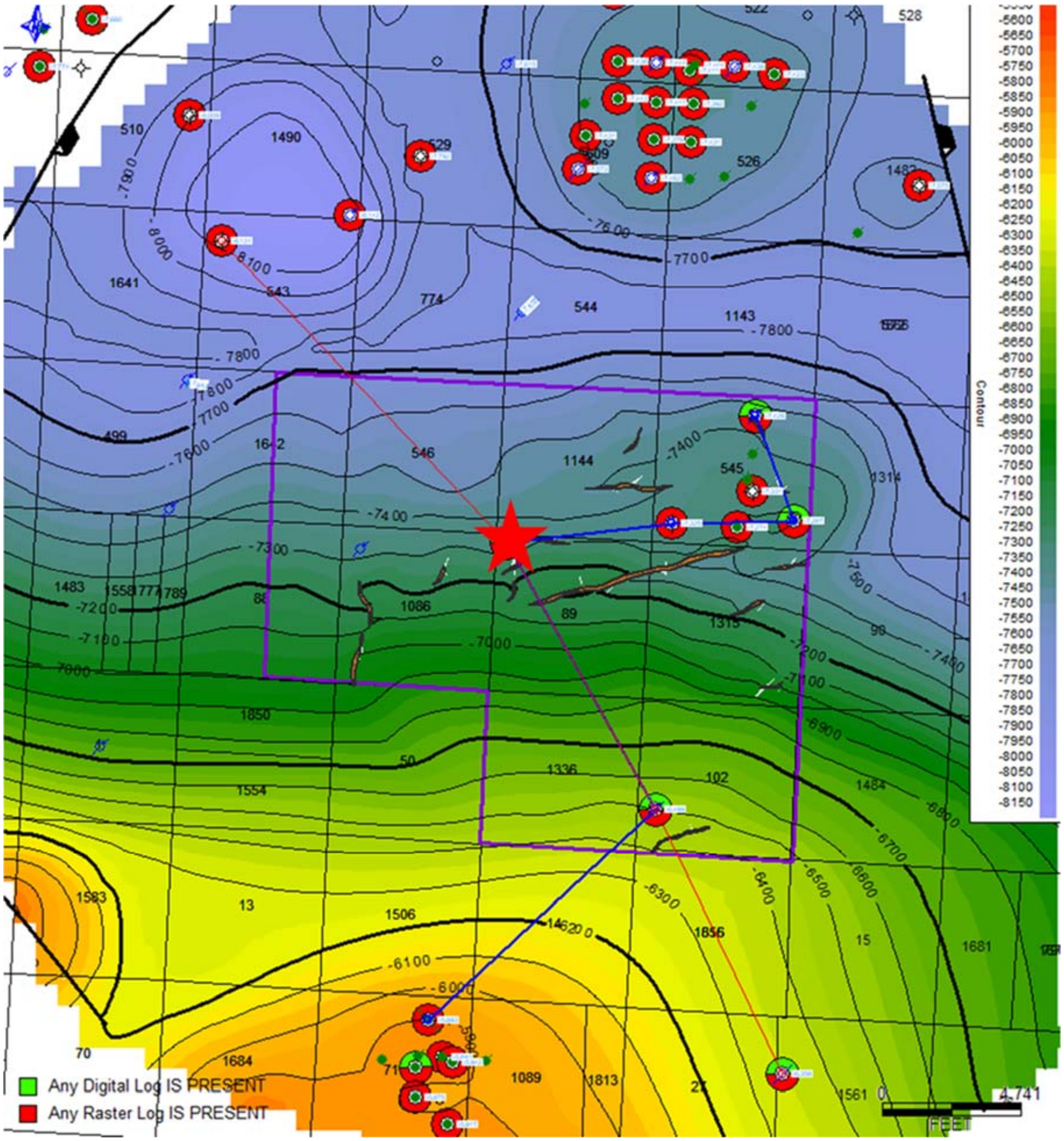


Figure 12 – Silurian Structure Map (subsea depths)

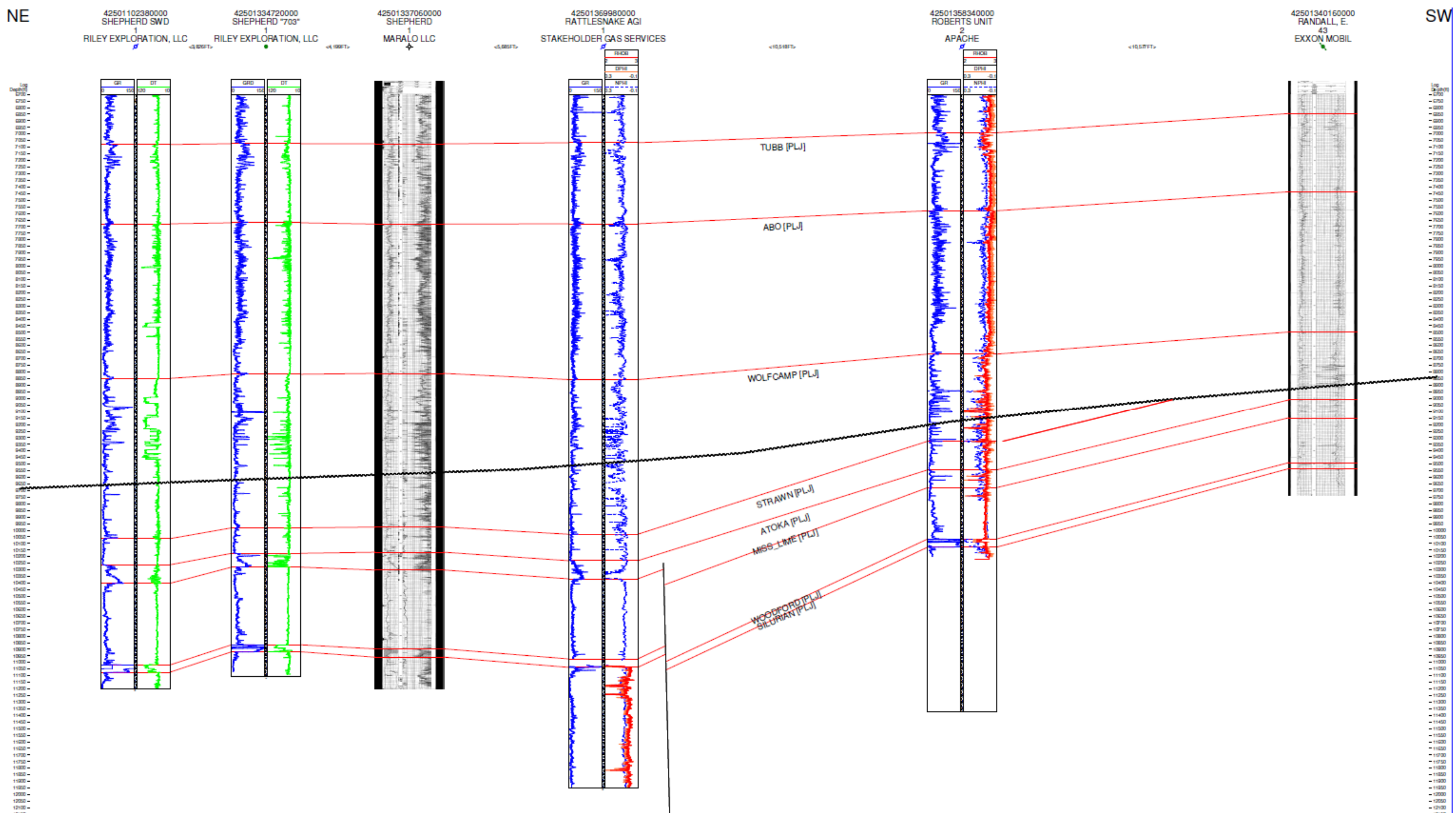
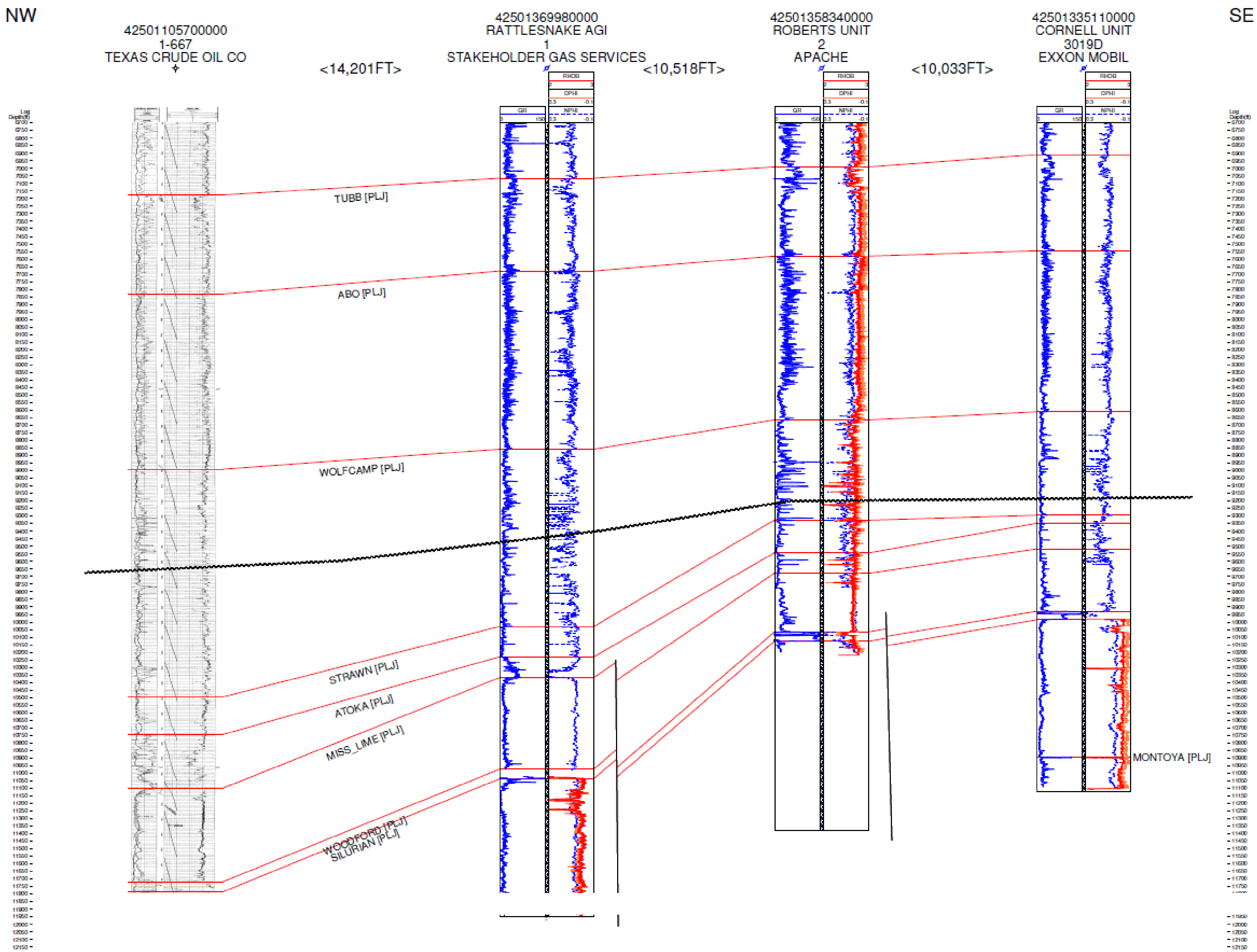


Figure 13 – Structural Northeast-Southwest Cross Section


NW
SE
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CORNELL UNIT
3019D
EXXON MOBIL
TUBB [PLJ]
ABO [PLJ]
WOLFCAMP [PLJ]
STRAWN [PLJ]
ATOKA [PLJ]
MISS_LIME [PLJ]
WOODFORD [PLJ]
SILURIAN [PLJ]
MONTOYA [PLJ]

Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Fasken and Fusselman formations at the Rattlesnake AGI #1 well location indicate the formations have sufficient thickness, porosity, permeability, and lateral continuity to accept the proposed injection fluids. The Woodford formation shale at the Rattlesnake AGI #1 well has low permeability and is of sufficient thickness and lateral continuity to serve as the upper confining zone. Beneath the injection interval, the low permeability, low porosity Montoya formation is unsuitable for fluid migration and serves as the lower confining zone. Deeper, laterally continuous formations, including the Simpson Group, provide additional confinement.

Groundwater Hydrology

Yoakum County falls within the boundary of the Sandy Land Underground Water Conservation District. Three aquifers are identified by the Texas Water Development Board's *Aquifers of Texas* report in the vicinity of the proposed Rattlesnake AGI #1 well: the Dockum Aquifer, Edwards-Trinity Aquifer, and Ogallala Aquifer (George, Mace and Petrossian, 2011). Table 3 references the aquifers' positions in geologic time and the associated geologic formations. A schematic cross section in Figure 15, near the proposed Rattlesnake AGI #1 well, illustrates the structure and stratigraphy of these water-bearing formations. Groundwater flow direction is the same for the three aquifers, generally from northwest to southeast, Figure 16 (Teeple, et al., 2021).

Table 3 – Geologic and hydrogeologic units with accompanying lithologic descriptions near Gaines, Terry and Yoakum Counties, Texas (Teeple, et al. 2021)

Era	Period	Epoch or series	Geologic unit group or formation	Lithologic descriptions	Hydrogeologic unit
Cenozoic	Tertiary	Pliocene	Ogallala Formation	Gravel, sand, silt, and clay	High Plains aquifer system (Ogallala aquifer)
		Miocene			
Mesozoic	Cretaceous[1]	Comanchean Series	Washita Group[2]	Shale and limestone	Edwards-Trinity (High Plains) aquifer system
			Fredericksburg Group	Clay, shale, and limestone	
			Trinity Group	Sand and gravel	
	Triassic	Upper	Dockum Group	Siltstone, mudstone, shale, and sandstone	Dockum aquifer

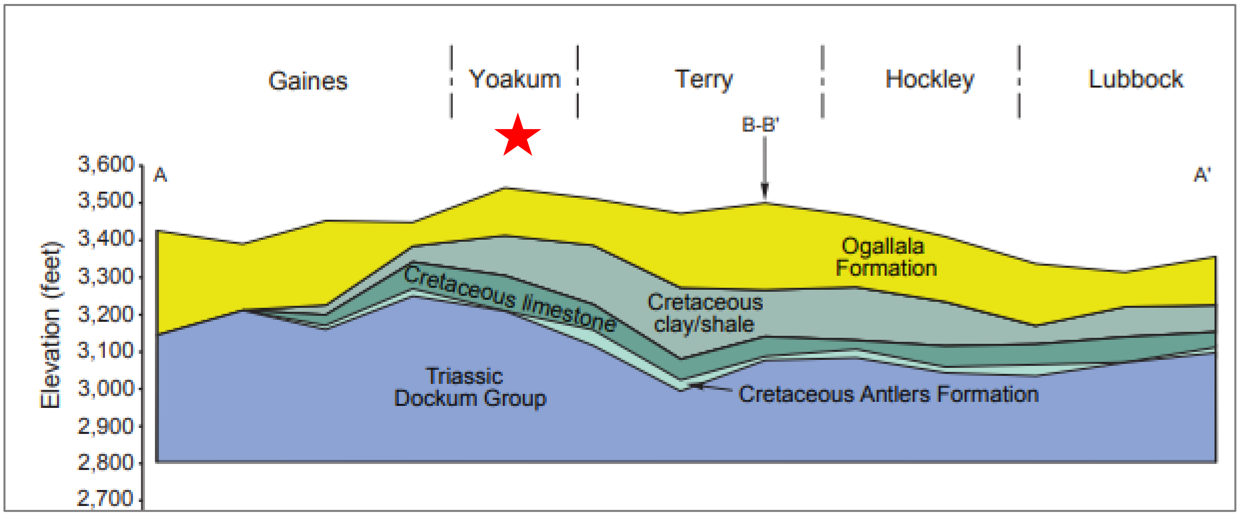


Figure 15 – NW-SE Cross Section of aquifers in the Rattlesnake AGI #1 well area (George, Mac and Petrossian, 2011)

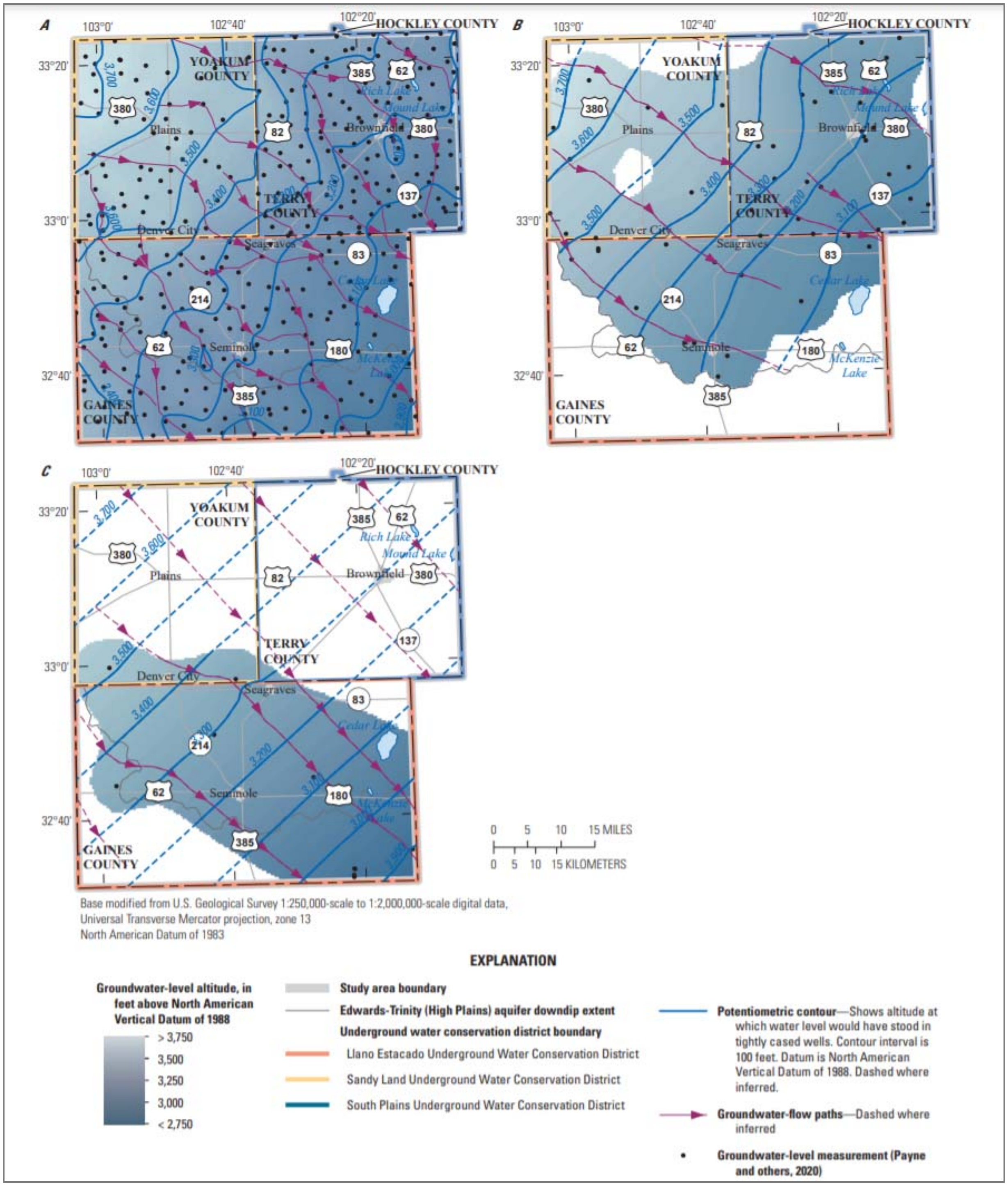


Figure 16 – Potentiometric surfaces from wells completed in A, Ogallala aquifer, B, the Edwards-Trinity aquifer and C, the Dockum aquifer (George, Mace and Petrossian, 2011).

The Dockum Aquifer is the oldest of the three aquifers, formed from Triassic-age Dockum Group sediments, and underlies the Cretaceous Trinity and Fredericksburg Groups (Teeple, et al., 2021). Figure 17 shows the subsurface and outcrop extent of the Dockum Aquifer. As shown in Figure 18, the total dissolved solids in western Yoakum County exceed 5,000 milligrams per liter ("mg/L"), therefore the aquifer is considered brackish.

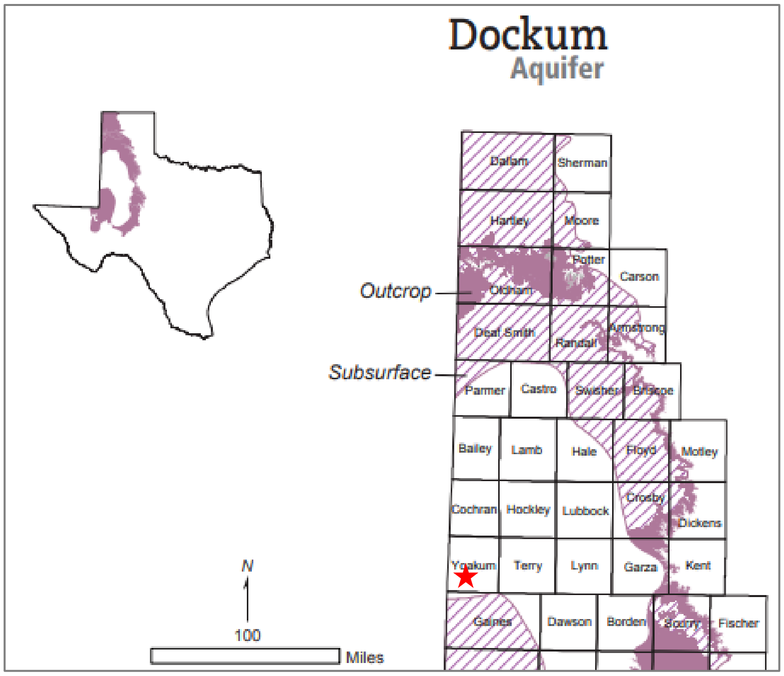


Figure 17 – Regional extent of the Dockum freshwater aquifer (TWDB)

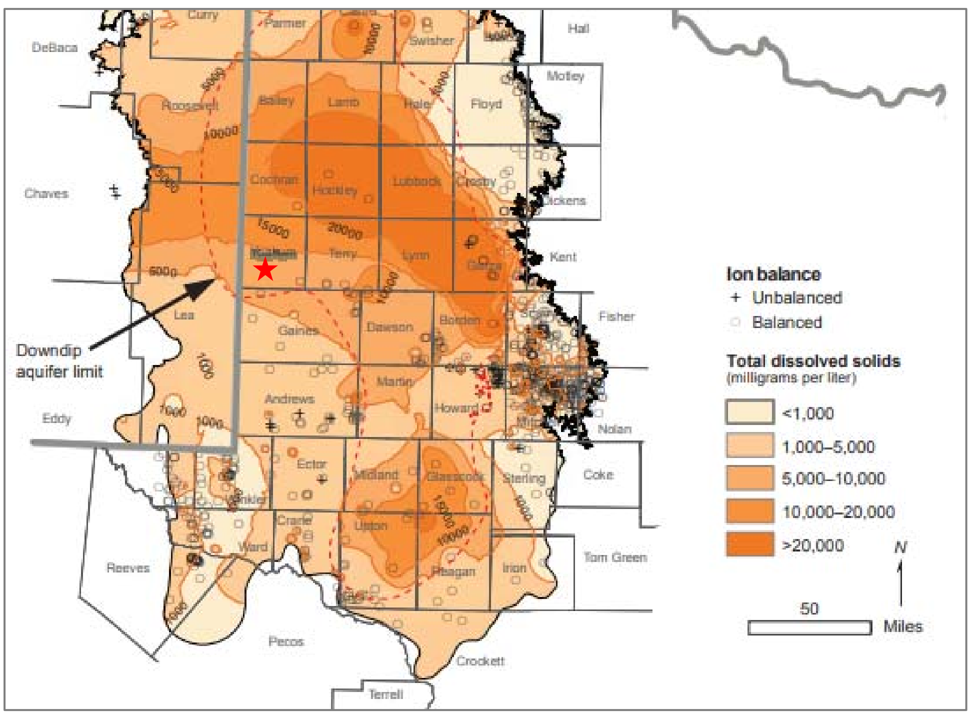


Figure 18 – Total dissolved solids in groundwater from the Dockum Aquifer (Ewing et al, 2008)

The Edwards-Trinity Aquifer is a collection of Cretaceous age sediments – primarily the Trinity Group Antlers formation sandstone and limestones of the Fredericksburg Group, specifically the Comanche Peak and Edwards formations. Figure 19 shows the subsurface and outcrop extent of the Edwards-Trinity Aquifer. Freshwater infiltration to this aquifer is primarily from the overlying Ogallala Aquifer (George, Mace and Petrossian, 2011).

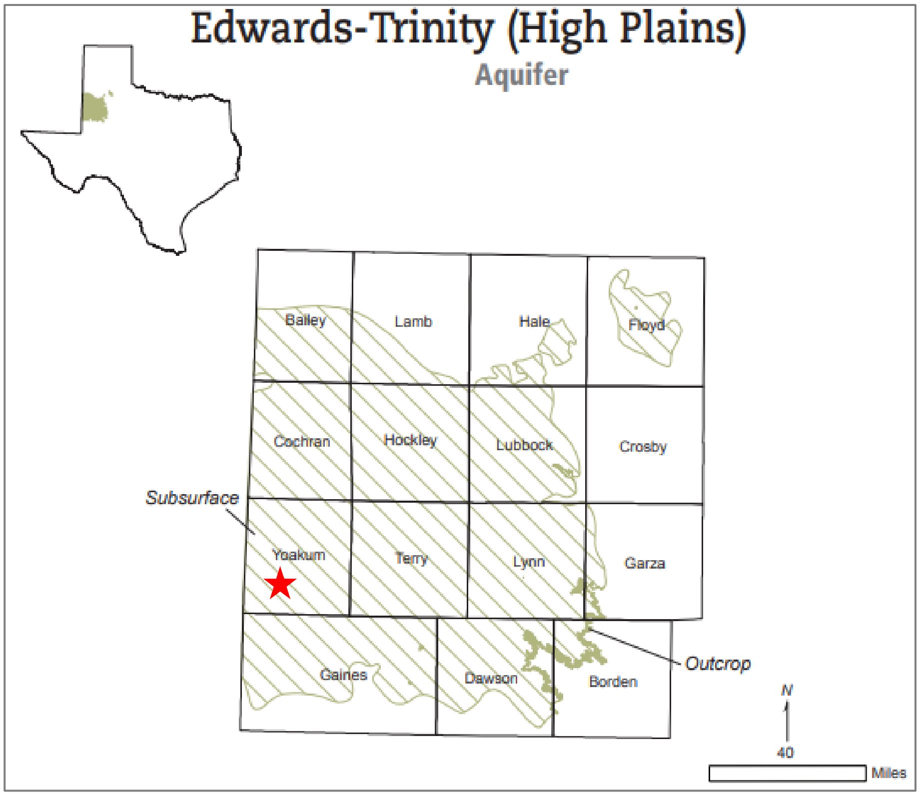


Figure 19 – Regional extent of the Edwards-Trinity freshwater aquifer (George, Mace and Petrossian, 2011)

The Ogallala aquifer consists of sand, gravel, clay and silt sediments (George, Mace and Petrossian, 2011) and produces the majority of the freshwater for Yoakum County. Figure 20 shows the subsurface and outcrop extent of the Ogallala Aquifer.

The base of the deepest aquifer is separated from the injection interval by approximately 8,600' of rock, including 576' of Salado salt. Though unlikely for reasons outlined in the confinement and potential leaks sections, if migration of injected fluid did occur above the Woodford Shale, thousands of feet of tight sandstone, limestone, shale, salt and anhydrite beds occur between the injection interval and the lowest water-bearing aquifer.

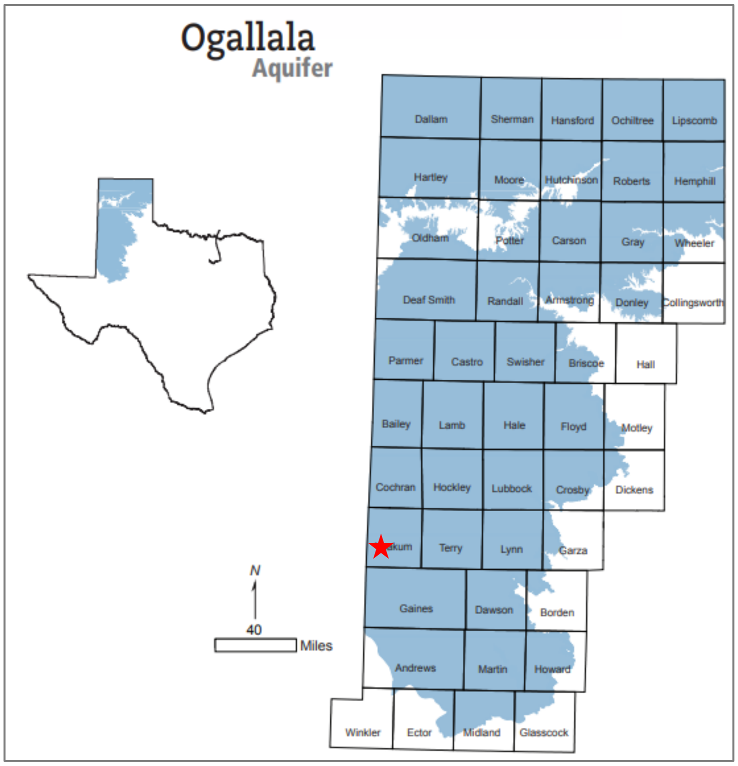


Figure 20 – Regional extent of the Ogallala freshwater aquifer (George, Mace and Petrossian, 2011)

The TRRC's Groundwater Advisory Unit ("GAU") identified the base of Underground Sources of Drinking Water ("USDW") at 375' at the location of the Rattlesnake AGI #1 well. Therefore, there is approximately 10,661' separating the base of the USDW and the injection interval. A copy of the GAU's Groundwater Protection Determination letter issued by the TRRC as part of the Class II permitting process for the Rattlesnake AGI #1 well is provided in Appendix B.

Description of the Injection Process

Current Operations

The 30-30 Facility and its associated Rattlesnake AGI #1 well began operating in March of 2019. Since operations began, 258 million cubic feet ("MMCF") of treated acid gas ("TAG") has been injected, which equates to 12,316 metric tons of CO_2. Over the life of the injection period, the average daily injection rate has been 223 MSCF/d. The approximate current composition of the TAG stream is as follows:

Table 4 – Gas Composition of 30-30 Facility outlet

Component	Mol %
CO2	89.68%
H2S	9.20%
Other	1.12%

The 30-30 Facility is designed to compress, treat, and process natural gas produced from the surrounding counties in Texas and New Mexico. The gas is dehydrated to remove the water content, then processed to separate natural gas liquids which are then sold, along with the pipeline quality natural gas, to various customers. TAG is then directly routed from the plant amine regen system to the Rattlesnake AGI #1 well. The facility is manned 24 hours per day, 7 days per week.

Planned Operations

Stakeholder anticipates increasing the amount of CO_2 injected into Rattlesnake AGI #1 well from the current rate up to 16 MMSCF/d. Additional growth is expected both at Stakeholder facilities and regionally as rising sour gas production and flaring reduction mandates create the need for additional CO_2 and H_2S disposal capacity. Stakeholder plans to inject into this AGI well for another 14 years for a total of 17 years from the start of injection in 2019.

Figure 21 shows a high-level view of the current process flow plus the prospective additional operations over time.

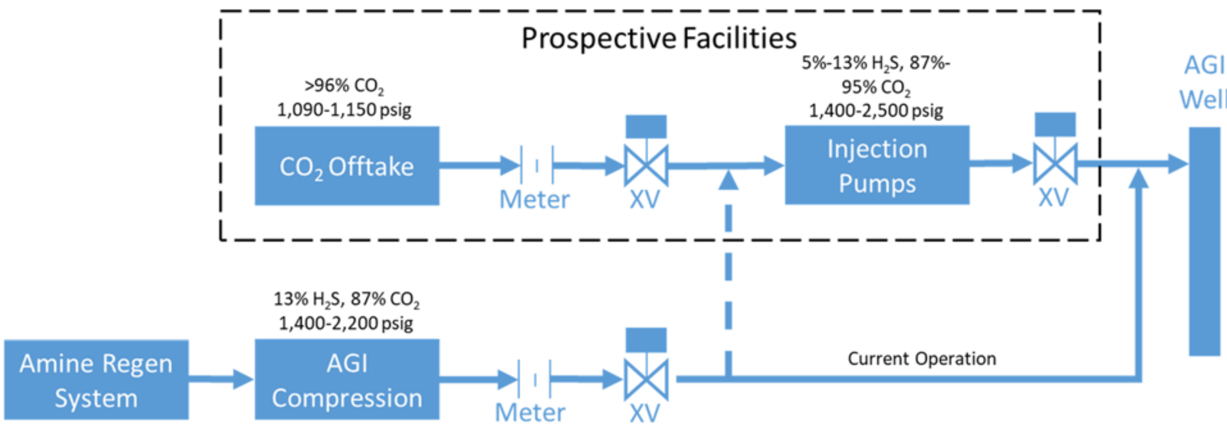


Figure 21 – 30-30 Facility Process Flow Diagram

Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2020.11 ("GEM") simulator. Computer Modelling Group ("CMG") has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM utilizes equation-of-state ("EOS") algorithms along with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon injection and storage. The GEM model is recognized by the EPA for use in area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Silurian (Fasken/Fusselman) formation is the target formation for Rattlesnake AGI #1 well. The Petra software package was used to create the geologic model of the target formation. The faulting and geologic structure was then imported into GEM and used to create contours for the model grid.

Porosity and permeability estimates were determined using the porosity log from the Rattlesnake AGI #1 well and a petrophysical analysis was performed to correlate porosity values by depth with core porosities

as shown in the Holtz paper. The Coates permeability equation was then used to calculate permeability with depth. Both porosity and permeability are assumed to be laterally homogeneous in the reservoir.

The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. An infinite acting reservoir was created to simulate boundary conditions. The gas injectate is composed of H_2S, CO_2, CH_4, and other components as shown in Table 5. Core data from literature review was used to determine residual gas saturation (Ruppel and Holtz, 1994). The modeled composition only takes into consideration the carbon dioxide and hydrogen sulfide as they comprise nearly 99% of total stream. For the initial injection period, these compositions are normalized up to 100%. For the proposed additional injection period, it is expected that a larger portion of the gas added is carbon dioxide, changing the composition to ~93% CO_2 and ~7% H_2S.

Table 5 – Modeled Initial Gas Composition

Component	Measured Current Composition (mol%)	2019-2024 Model Composition (mol%)	2024-2036 Model Composition (mol%)
Carbon Dioxide (CO2)	89.678	90.696	92.921
Hydrogen Sulfide (H2S)	9.200	9.304	7.079
Methane (C1)	0.303	0	0
Ethane (C2)	0.058	0	0
Propane (C3)	0.108	0	0
N-Butane (NC4)	0.025	0	0
Hexane Plus (C6+)	0.628	0	0

Core data from literature review was used to determine relative permeability curves between carbon dioxide and the connate brine within the Silurian-Devonian carbonates (Ruppel and Holtz, 1994). The key inputs used in the model include an irreducible water saturation of 25% and a maximum residual gas saturation of 21%.

The grid contains 141 blocks in the x-direction (E-W) and 201 blocks in the y-direction (N-S), totaling 28,341 grid blocks per layer. The grid blocks are each 150' by 150' by layer thickness as specified in Table 6. This results in the grid being 21,150' by 30,150' totaling just over a 23-square mile area (14,640 acres). Each layer in the model was determined by identifying higher permeability zones as targets for injection from the logs and assigning each high permeability and intermediary low permeability zone its own layer. One zone was identified as being a karst limestone (layers 2-7). Due to the "karsted" nature of this rock, it was determined that most of the injectate would flow into this zone. Therefore, the karst limestone was further split into layers by permeability to provide higher resolution and more accurately simulate which layer will have more gas flow into it. Figure 22 provides a detailed breakdown of the "karsted" rock.

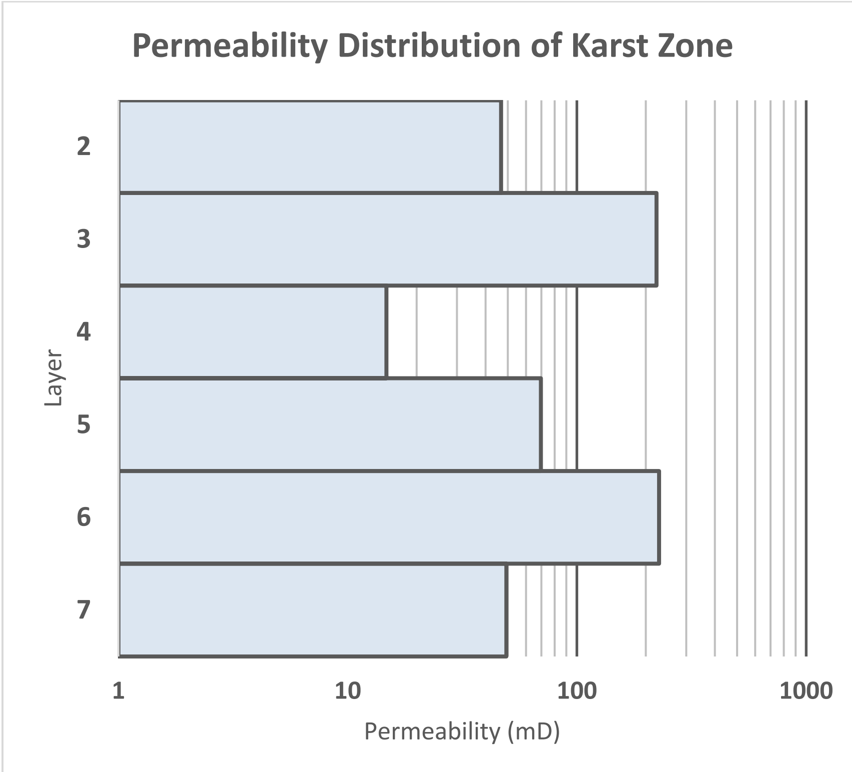


Figure 22 – Permeability Distribution of Karst Limestone

In total, there are sixteen (16) layers in the model, representing ten (10) layers of pay and six (6) layers of intermediary low permeability zones. The properties of each of these layers are summarized in Table 6 below.

Table 6 – CMG Model Layer Properties

Layer #	Top (ft)	Thickness (ft)	Permeability (mD)	Porosity
1	11,037	71	1	2.8%
2	11,108	57	47	8.0%
3	11,165	19	223	11.9%
4	11,184	16	15	6.3%
5	11,200	39	70	9.2%
6	11,238	11	228	12.3%
7	11,249	21	49	8.3%
8	11,270	251	2	3.7%
9	11,520	46	9	5.6%
10	11,566	13	3	4.3%
11	11,579	19	17	6.5%
12	11,597	14	2	3.9%
13	11,611	103	13	6.0%
14	11,714	46	2	3.7%
15	11,759	67	23	6.1%
16	11,826	125	2	3.6%

Simulation Modeling

The primary objectives of the model simulation were to:

1) Estimate the maximum areal extent and density drift of the acid gas plume after injection
2) Assess the impact of offset saltwater disposal ("SWD") well injection on density drift of the plume
3) Assess the impact of offset producing wells on the density drift of the plume
4) Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone
5) Assess the likelihood of the acid gas plume migrating into potential leak pathways

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 53,000 ppm (Texas Water Development Board, 1972). The acid gas stream is primarily composed of CO_2 and H_2S as stated previously. Core data was used to help generate relative permeability curves. Cores, from the literature reviews previously discussed, that most closely represent the vuggy carbonate seen in this region were identified and the Corey-Brooks equations were used to develop the curves. The lowest residual gas saturation found in the cores was then used for a conservative estimate of plume size. From offset injection well analysis, the initial reservoir pressure was determined to be 5,132 psi which is equivalent to a 0.465 psi/ft pressure gradient. The fracture gradient of the injection zone was estimated to be 0.72 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottom-hole pressure allowed in the model at 0.64 psi/ft which is equivalent to 7,064 psi.

The model also takes into account offset saltwater disposal ("SWD") injection volumes within five (5) miles of the Rattlesnake AGI #1 well. These SWDs create a pressure front that push the plume further up-dip of the formation. A total of twenty (20) offset wells currently injecting into the target formation were identified. Eleven (11) of these offset SWDs were out of the confines of the grid, but were still accounted for in the model. Nine (9) salt-water disposals were modeled within the boundaries of the 23-square-mile grid. Two (2) of these offset injectors are currently only permitted (not drilled) but were assumed to start active injection within the first year of the model. Both permits were simulated at the forecasted injection rate schedule for 30 years. These forecasts were provided by the operators of these wells. Historical injection rates of each of the other existing wells were analyzed and projected into the model. This simulation includes the effect of water injection on the density drift of the plume and bottom hole pressure.

Further review of the area revealed production wells in the Silurian-Devonian formation that could impact the density drift of the plume by creating a "pressure sink". A "pressure sink" is an area of lower pressure caused by the production of formation fluids. To simulate this effect, nine (9) production wells were grouped together and their respective production rates combined into a single well to add more conservatism into the model. These producers were forecasted an additional 15 years to simulate their potential economic lifespan. This simulation includes the effect of fluid production on the density drift of the plume and bottom hole pressure. Overall, the "pressure sink" has little effect on the density drift and, as discussed below, the plume never reaches the producing wells.

The model runs for a total of 814 years, starting in 1965 with the beginning of offset production until the calculated stabilization of the plume in 2779. The injection of TAG from Rattlesnake AGI #1 is modeled from the beginning of injection in 2019 through the planned 14 years of future injection. The model also includes the 57 years of historical plus 15 years of forecasted future oil and gas production.

Additionally, historical monthly injection rates of all nearby SWDs were incorporated into the model to simulate any additional near-wellbore pressure increase that may occur due to offset injection. The

modelling of the saltwater injection begins in 1984 when the first offset SWD well became operational. The SWDs to the North were grouped into four (4) separate groups to simulate their combined effect on the density drift of the plume. All offset injection wells and their groupings are included in Table 7. All offset production wells are listed in Table 8.

Table 7 – All Offset SWDs included in the model

Grouping	API	Well Name	Well #
Group 1	42-501-32511	SAWYER, DESSIE	1
	42-501-02068	WEST, M. M.	2
	42-501-02053	NORTH CENTRAL OIL CO. "A"	1
	42-501-01453	SMITH, ED S. HEIRS "B"	1
	42-501-02059	SMITH, ED "C"	1W
Group 2	42-501-30051	JOHNSON	2
	42-501-30001	JOHNSON	1D
Group 3	42-501-37066	MISS KITTY SWD 669	1W
	42-501-36650	RUSTY CRANE 604	1W
Group 4	42-501-36745	SUNDANCE 642	1
	42-501-33887	WINFREY 602	3WD
Standalone	42-501-37252	Miller SWD	7
	42-501-37367	BLONDIE 704	1W
	42-501-37206	BRUSHY BILL 707	1WD
	42-501-36622	WISHBONE FARMS 710	1W
	42-501-35834	ROBERTS UNIT	2
	42-501-33297	STATE ELMORE	1
	42-501-10238	SHEPHERD SWD	1
	42-501-33511	CORNELL UNIT	3019D
	42-501-32868	WILLARD UNIT	1WD

Table 8 - All Offset Producers included in the model

API	Well Name	Well #
42-501-10046	ELLIOTT, C.A.	2
42-501-10079	RANDALL, E	32
42-501-337932	RANDALL, E	40
42-501-33885	RANDALL, E	41L
42-501-34016	RANDALL, E	43L
42-501-34017	RANDALL, E.	45L
42-501-34023	RANDALL, E	42L
42-501-34024	RANDALL, E	44
42-501-35418	RANDALL, E	46

Rattlesnake AGI #1 came online in 2019 and the model simulated its historical monthly injection rates until 2024. After this initial period, it is conservatively assumed that the injection rate increases to the maximum permitted rate of 16 MMSCF/d for the remainder of the active injection period in 2036. At this point, the

Rattlesnake AGI #1 well stops injection while the offset SWD injectors continue operations for thirty more years. Density drift then occurs until plume stabilizes, which was determined to be 814 years from the start of the model in 1965. Stabilization of the plume is determined to occur when the model shows no further lateral movement horizontally or vertically. The plume boundary is then defined by a weighted average gas saturation in the aquifer of 3%.

The maximum plume extent during the 17-year Rattlesnake injection period is shown in Figure 23. The final extent after 743 years of density drift after injection ceases is shown in Figure 24. The extensive time of the modeled density drift of the plume is driven by the buoyant forces of the gas, the permeability/porosity of the rock, and the residual gas saturation. Initially, the karsted region takes on most of the injection, but due to the buoyant forces, it is slowly pushed up higher into the less permeable layers of the injection interval. These lower permeable layers, increase the amount of time it takes for the plume to reach its maximum areal extent. As all the inputs to the model were based on the most conservative approach, the maximum extent of the plume will likely be smaller and the effective impact on reaching potential leakage pathways will be minimal as the amount of CO_2 at those far extents will be small.

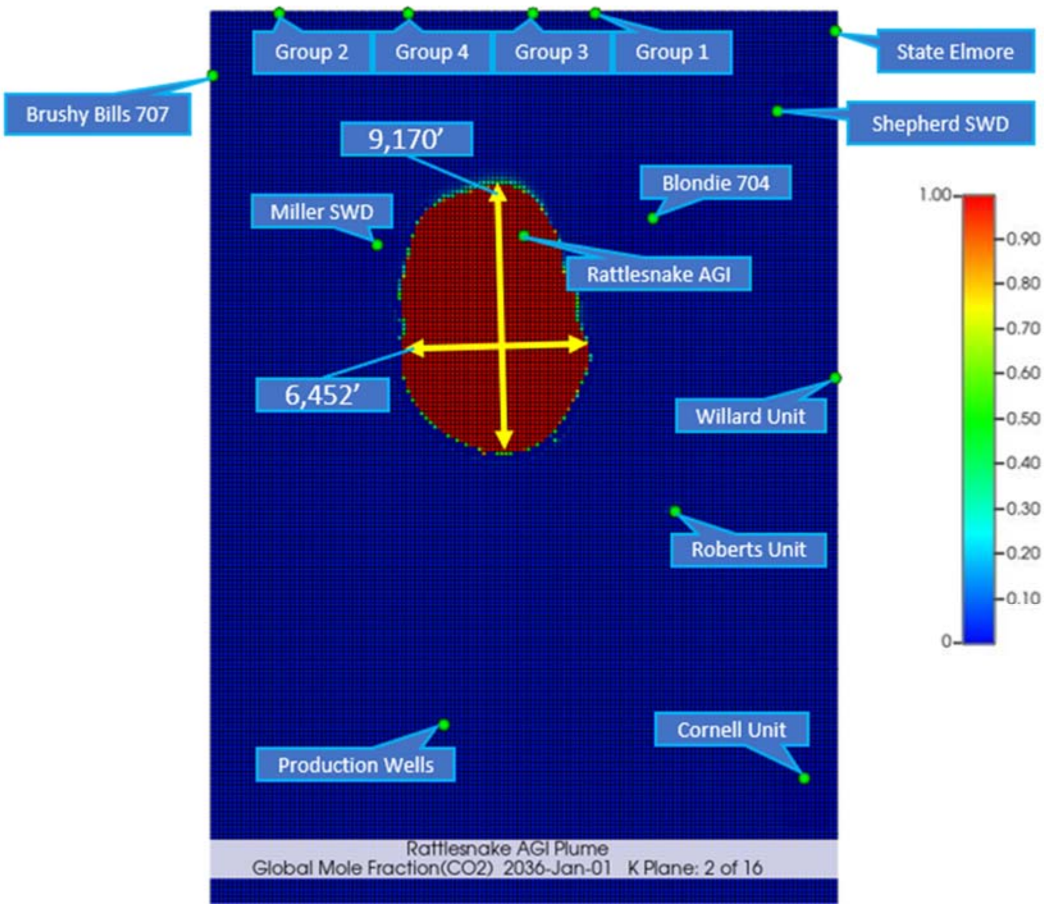


Figure 23 – Areal View Gas Saturation Plume, 2036 (End of Injection)

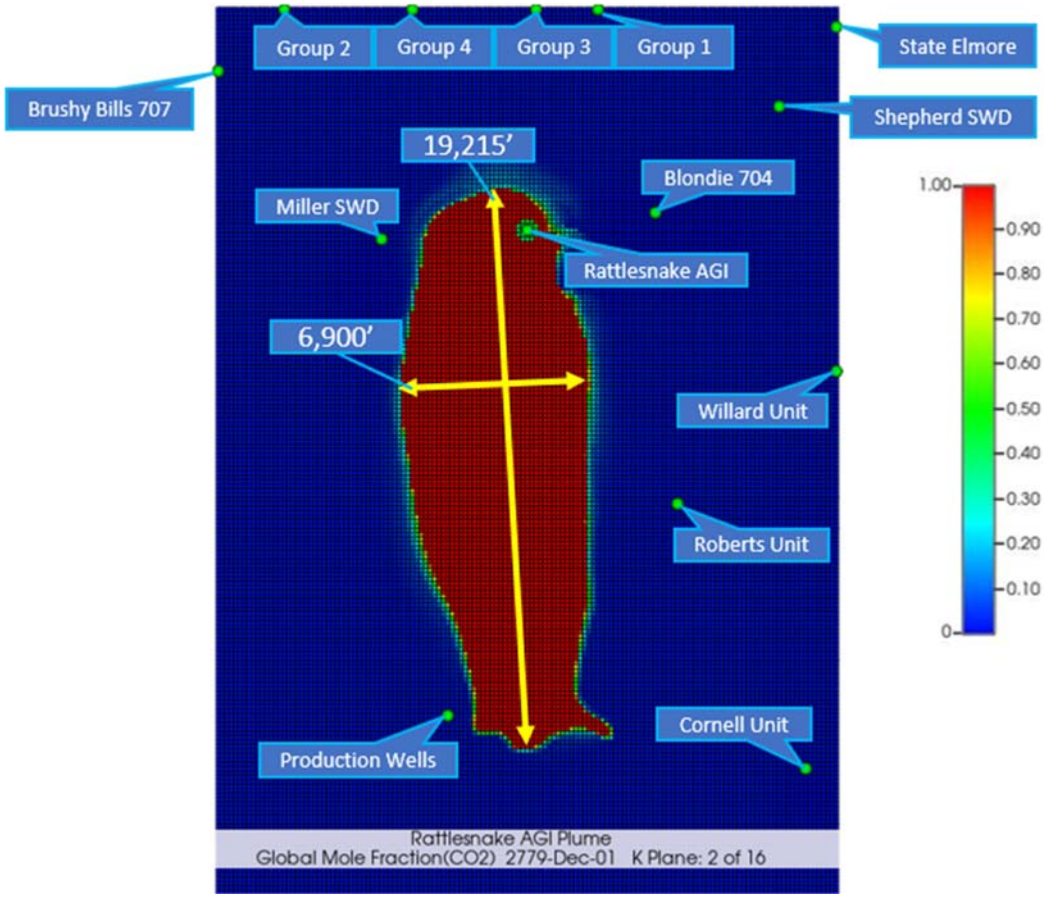


Figure 24 – Areal View Gas Saturation Plume, 2779 (End of Density Drift)

Figure 25 shows the surface injection rate and bottom hole pressure over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate reaches its peak, reaching a maximum pressure of 5,413 psi. This buildup of 280 psi keeps the bottomhole pressure well below the fracture pressure of 7,064 psi. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,494 psi.

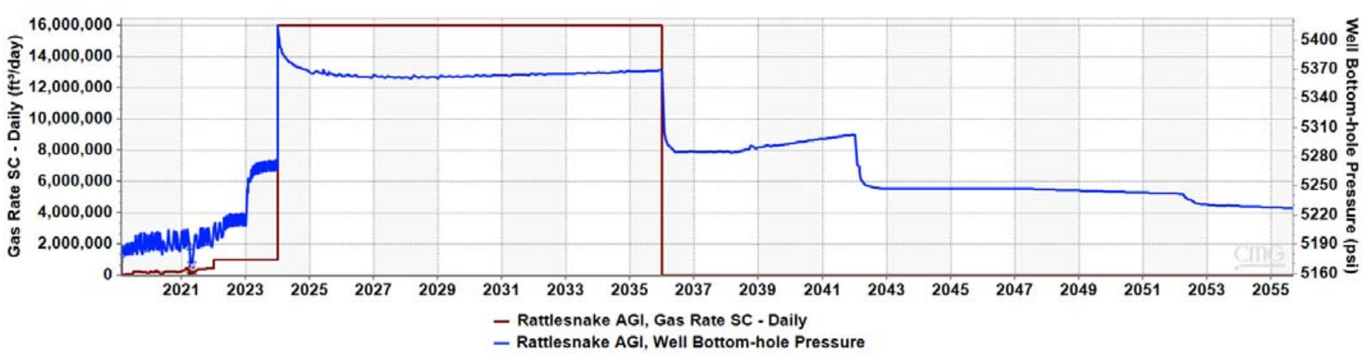


Figure 25 – Well Injection Rate and Bottomhole Pressure over Time

SECTION 3 – DELINATION OF MONITORING AREA

This section discusses the delineation of Maximum Monitoring Area (“MMA”) and Active Monitoring Area (“AMA”) as described in EPA 40 CFR §98.448(a)(1).

Maximum Monitoring Area

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

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

Acid gas injectate was analyzed by a third-party vendor to determine the initial composition used in the model. The report is provided in Appendix C. The molar composition of the gas is primarily CO_2 with some H_2S and CH_4. The change in molar composition was also incorporated into the model as future predominantly CO_2 streams are added for injection. As discussed in Section 2, the gas was injected into the Silurian formation, specifically, the Fasken/Fusselman formation. The geomodel was created based off the rock properties seen in the Fasken/Fusselman.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in 2036, the areal expanse of the plume will be 1,052 acres. The maximum distance between the wellbore and the edge of the plume is approximately 0.87 miles to the southeast. After 743 additional years of density drift, the areal extent of the plume is 2,177 acres with a maximum distance to the edge of the plume of approximately 1.35 miles to the southeast.

Figure 26 shows the plume boundary at the end of injection, the stabilized plume boundary and the MMA.

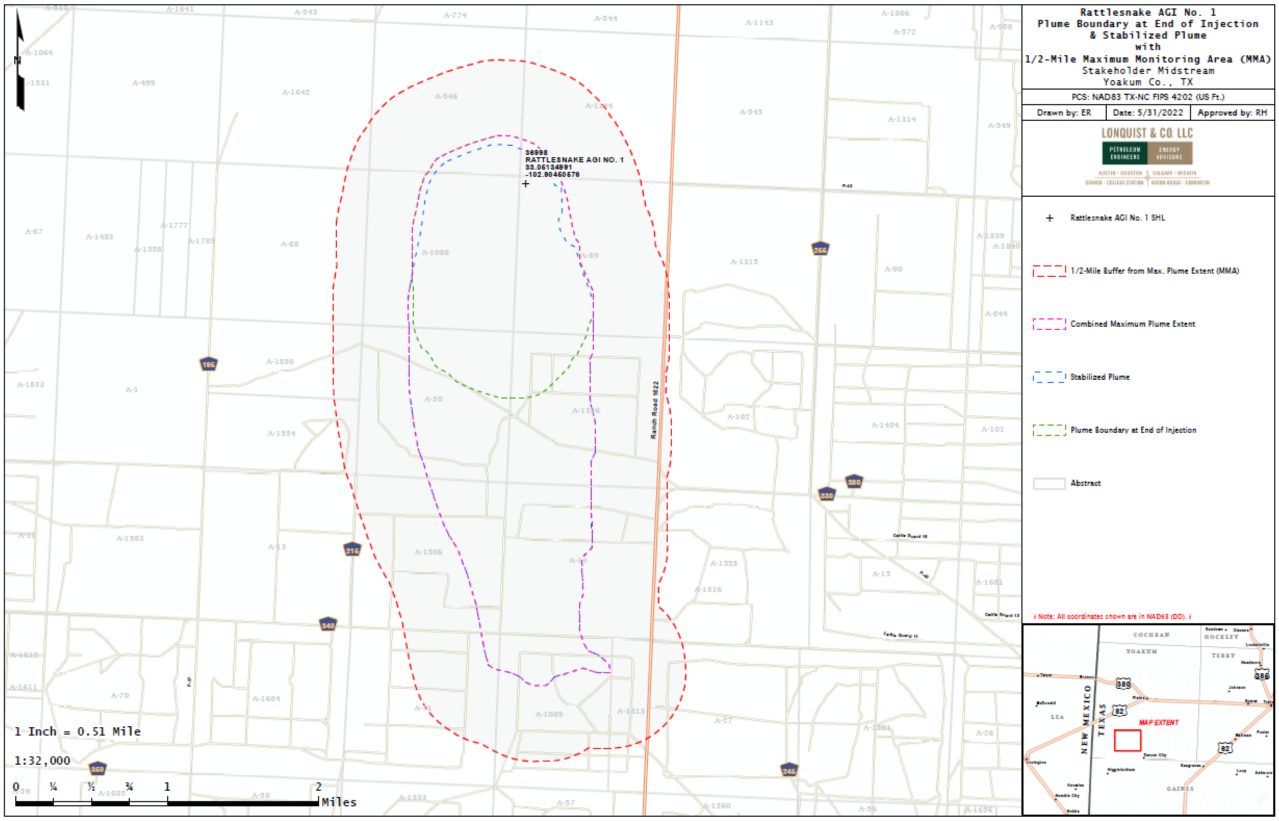


Figure 26 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

Active Monitoring Area

The initial AMA will cover a 14-year monitoring period. This period equates to the time of expected future injection. The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location at the end of injection (2036) with the area of the projected free-phase CO_2 plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume at 2036 plus a half-mile buffer. By 2036 at the latest, a revised MRV plan will be submitted to define a new AMA. Figure 27 shows the area covered by the AMA.

Larger size versions of Figures 26 and 27 are provided in Appendix D.

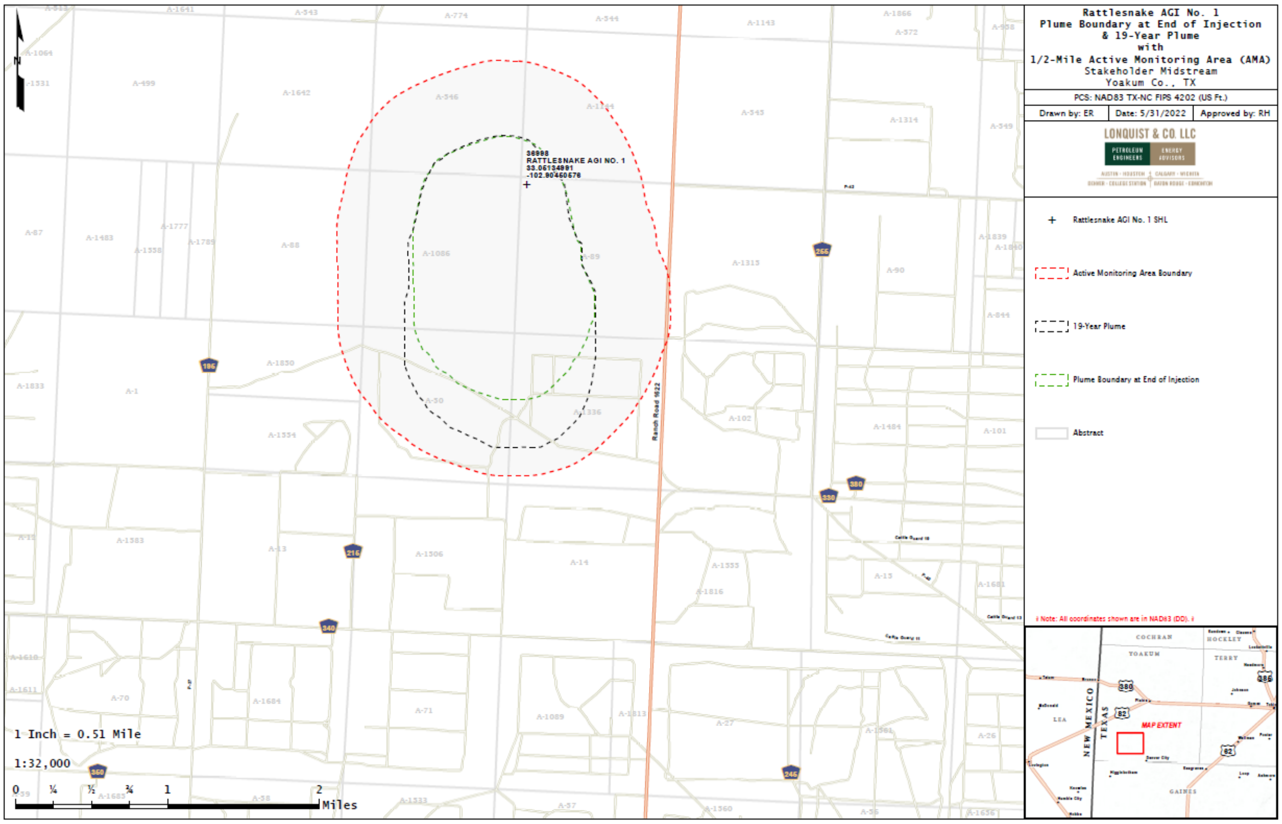


Figure 27 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA and the likelihood, magnitude and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from Natural or Induced Seismicity

Leakage from Surface Equipment

The surface facilities at the 30-30 Facility are designed for injecting acid gas containing H_2S, and therefore minimize leakage points such as valves and flanges following industry standards and best practices. H_2S gas detectors are located around the facility and the well site. These gas detectors trigger alarms at 10 parts per million ("ppm"). Additionally, all Stakeholder field personnel are required to wear H_2S monitors which are triggered at 5 ppm of H_2S. A shut-in valve is located at the wellhead and is locally controlled by pressure, with a high pressure and low pressure shut-off.

The facilities have been designed and constructed with additional safety systems to provide for safe operations. These systems include Emergency Shutdown ("ESD") valves to isolate portions of the plant and pipeline, pressure relief valves along the pipeline to prevent over pressurization, and flares to allow piping and equipment to be de-pressured rapidly under safe and controlled operating conditions in the event of a leak. Figures 28 and 29 display the facility safety plot plan, taken from the 30-30 H_2S Contingency Plan, and show the location of the H_2S monitors in the vicinity of the plant and the Rattlesnake AGI #1 well. Should Stakeholder construct additional CO_2 facilities, as indicated in Figure 21, a separate meter will be installed for the additional stream in order to comply with the 40 CFR §98.448(a)(5) measurement. As this meter will be in close proximity to the existing facilities, it will utilize the existing monitoring programs discussed previously. Additionally, CO_2 monitors will be installed near the new meter and tied into the facility monitoring systems.

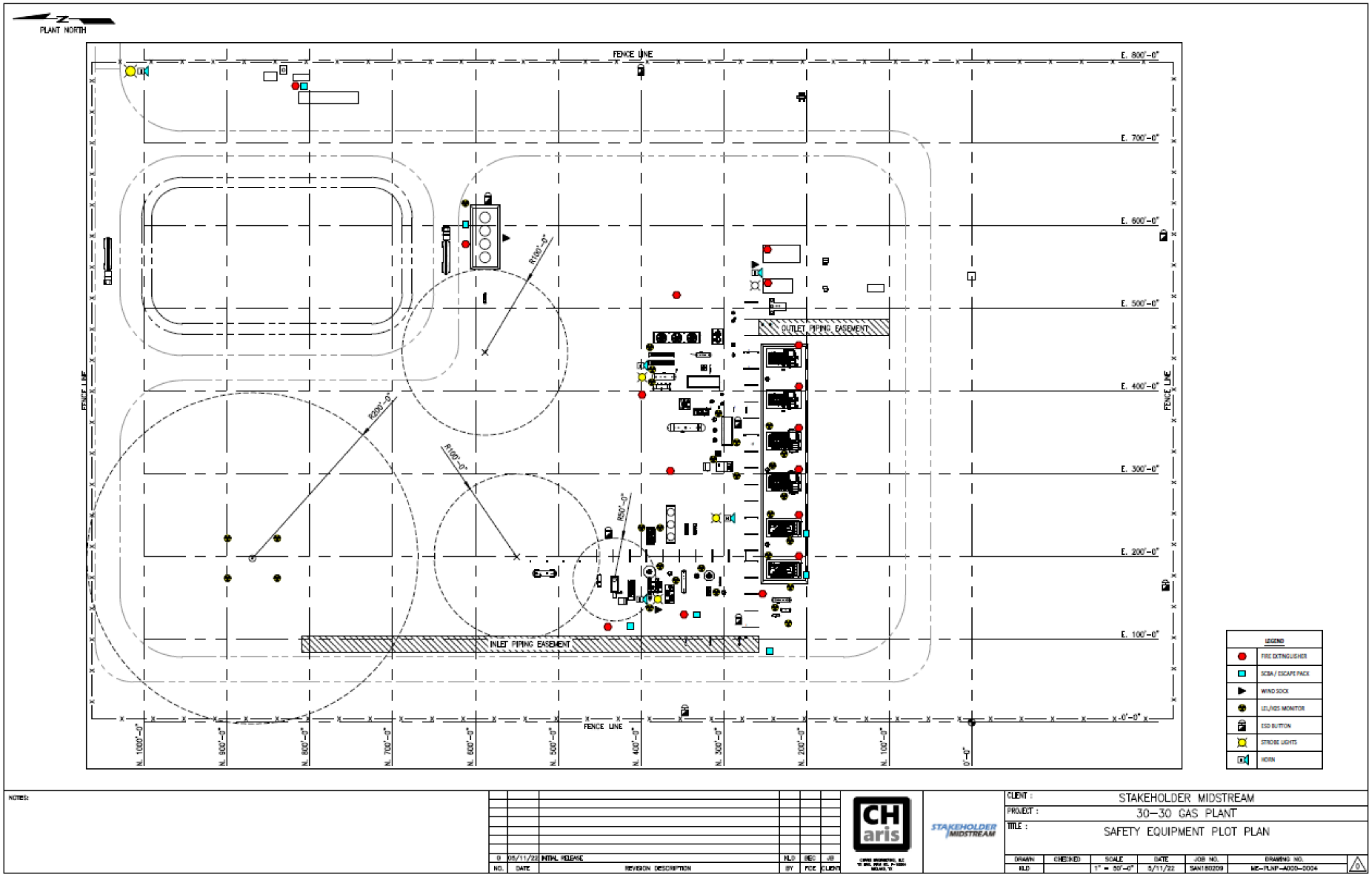


Figure 28 – Site Plan, 30-30 Facility

With the level of monitoring at the 30-30 Facility and the Rattlesnake AGI #1 well, any release of H_2S and CO_2 would be quickly identified, and the safety systems would quickly minimize the volume of the release. The CO_2 injected into the Rattlesnake AGI #1 is injected with H_2S at a concentration of 10% (100,000 ppm). At this high level of H_2S concentration, even a small leakage would trigger personal and facility H_2S monitors set to alarm at 5 ppm and 10 ppm respectively. If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7 in accordance with 40 CFR §98.448(a)(5).

A larger scale version of Figure 28 is provided in Appendix E.

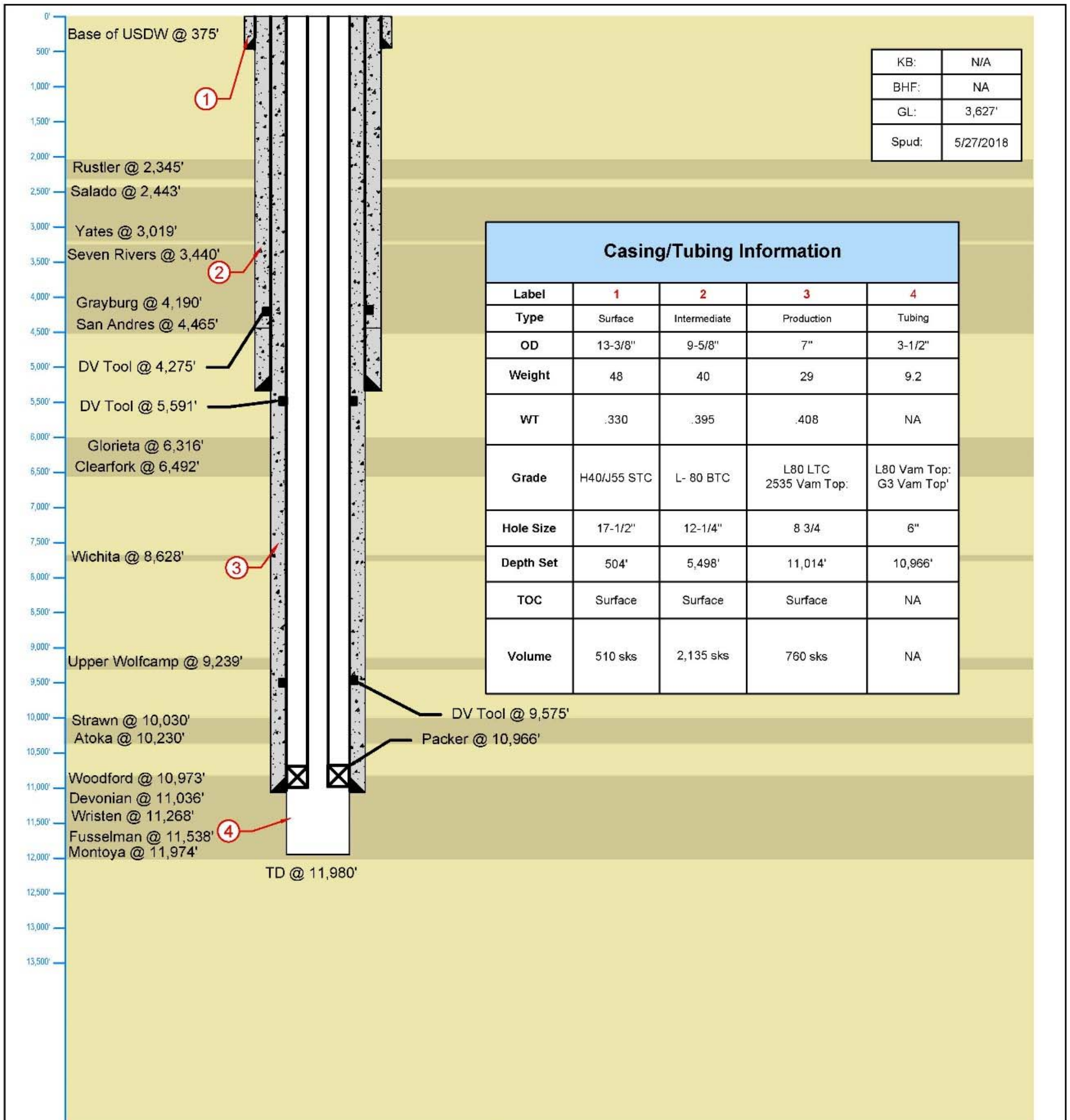
Leakage from Existing Wells within MMA

Oil and Gas Operations within Monitoring Area

A significant number of wells have historically been drilled within the area of the Rattlesnake AGI #1 well, however production has primarily been from the shallower San Andres formation in the Wasson Field. The San Andres is separated from the Silurian-Devonian interval by 4,720' in this area. In addition to the primary San Andres production, a few wells have produced from the Wolfcamp. The Wolfcamp is separated from the Siluro-Devonian interval by is 1,800'. **Within the projected plume area of the Rattlesnake AGI #1 well, there are no penetrations of the injection interval.** There are ten wells within the MMA that penetrate the injection interval.

A review of the TRRC records for all of the wells which penetrate the injection interval within the MMA, shows the wells were properly cased and cemented to prevent annular leakage of CO_2 to the surface. The plugged wells are also adequately protected against migration from the Devonian by the placement of the plugs within the wellbores. Additionally, the Rattlesnake AGI #1 well was designed to prevent migration from the injection interval to the surface through the casing and cement placed in the well, as shown in Figure 29. Mechanical integrity tests ("MIT") required under TRRC rules are run annually to verify the well and wellhead can hold the appropriate amount of pressure. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated quickly to prevent leakage to the atmosphere.

A map of all wells within the MMA is shown in Figure 30. Figure 31 shows only those wells which penetrate the injection interval within the MMA. The MMA review maps, a summary of all the wells in the MMA and detailed wellbore schematics for those wells which penetrate the injection interval are provided in Appendix F.



KB:	N/A
BHF:	NA
GL:	3,627'
Spud:	5/27/2018

Casing/Tubing Information

Label	1	2	3	4
Type	Surface	Intermediate	Production	Tubing
OD	13-3/8"	9-5/8"	7"	3-1/2"
Weight	48	40	29	9.2
WT	.330	.395	.408	NA
Grade	H40/J55 STC	L- 80 BTC	L80 LTC 2535 Vam Top:	L80 Vam Top: G3 Vam Top'
Hole Size	17-1/2"	12-1/4"	8 3/4	6"
Depth Set	504'	5,498'	11,014'	10,966'
TOC	Surface	Surface	Surface	NA
Volume	510 sks	2,135 sks	760 sks	NA

LONQUIST & CO. LLC PETROLEUM ENGINEERS ENERGY ADVISORS HOUSTON CALGARY AUSTIN WICHITA DENVER	Stakeholder Midstream	Rattlesnake No. 1	
	Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
	Location: 33.07884, -103.904514	**Site:**	**Survey:**
	API No: 42-501-36998	**Field:**	**Well Type/Status:** AGI
Texas License F-9147	**RRC District No:**	**Project No:** LS 128	**Date:** 5/27/2022
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** ASG	**Reviewed:** SLP	**Approved:** SLP
	Rev No: 1	**Notes:**	

Figure 29 – Rattlesnake AGI #1 Wellbore Schematic

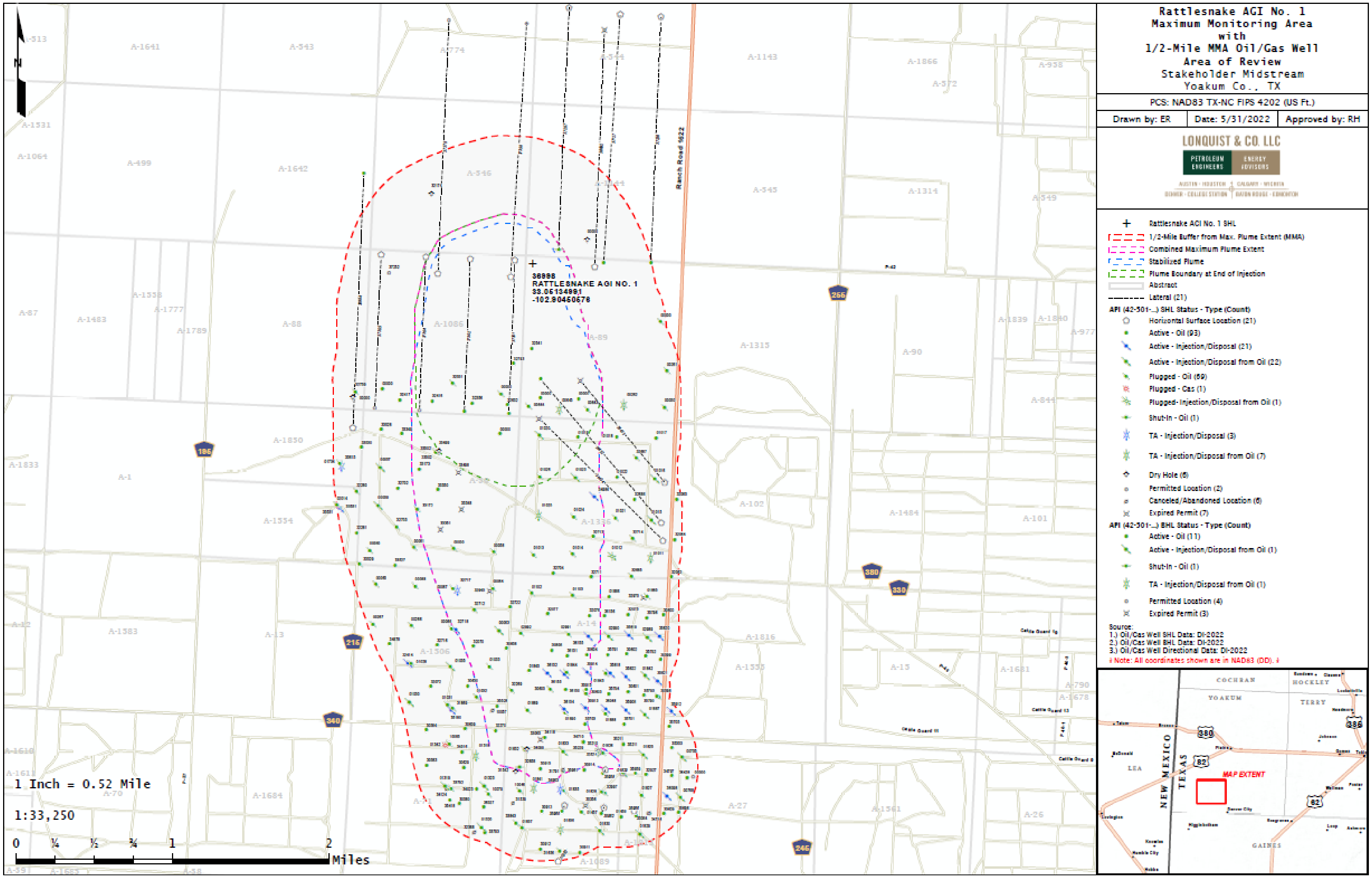


Figure 30 – Oil and Gas Wells within the MMA

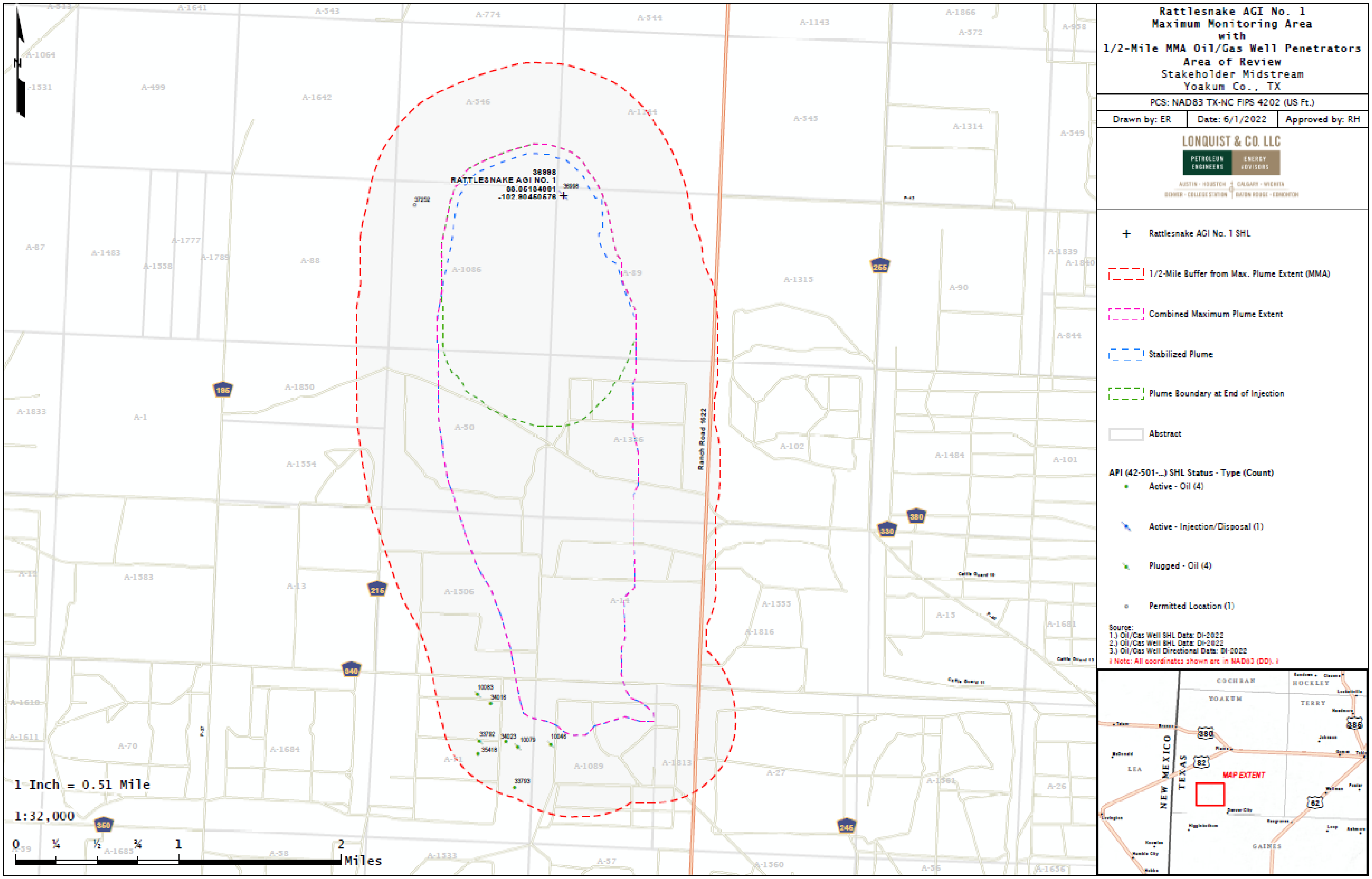


Figure 31 – Penetrating Oil and Gas Wells within the MMA

Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, such as the Devonian, have proven to-date to be less productive or non-productive in this area, which is why the location was selected for injection. Furthermore, any drilling permits issued by the TRRC in the area of the Rattlesnake AGI #1 well include a list of formations for which oil and gas operators are required to comply with TRRC Rule 13 (entitled "Casing, Cementing, Drilling, Well Control, and Completion Requirements"). 16 TAC § 3.13. By way of example, see the Rattlesnake AGI #1 well drilling permit provided in Appendix B. The Devonian is among the formations listed for which operators in Yoakum County (where the Rattlesnake #1 is located) are required to comply with TRCC Rule 13 (Appendix B, pg. 5). TRRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under TRRC Rule 9 or immediately above all formations permitted for injection under Rule 46 for any well proposed within a one-quarter mile radius of an injection well. In this instance, any new well permitted and drilled to the Rattlesnake AGI #1 well's injection zone, and located within a one-quarter mile radius of the Rattlesnake AGI #1 well, will be required under TRRC Rule 13 to set steel casing and cement above the Rattlesnake AGI #1 well injection zone. Additionally, Rule 13 requires operators to case and cement across and above *all* potential flow zones and/or zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued, which is also shown in the above-mentioned permit in Appendix B.

If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release.

Groundwater wells

There are seven groundwater wells located within the MMA, as identified by the Texas Water Development Board. All of the identified groundwater wells in the area have total depths less than or equal to 265', as shown in Figure 32 and Table 9. One of the wells is located on the 30-30 facility property with a total depth of 119'and is operated by Stakeholder.

The surface and intermediate casings of the Rattlesnake AGI #1 well, as shown in Figure 29, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the GAU letter issued for this location. See GAU letter included within Appendix B. The wellbore casings and cements also serve to prevent CO_2 leakage to the surface along the borehole.

A larger scale version of Figure 32 is provided in Appendix F.

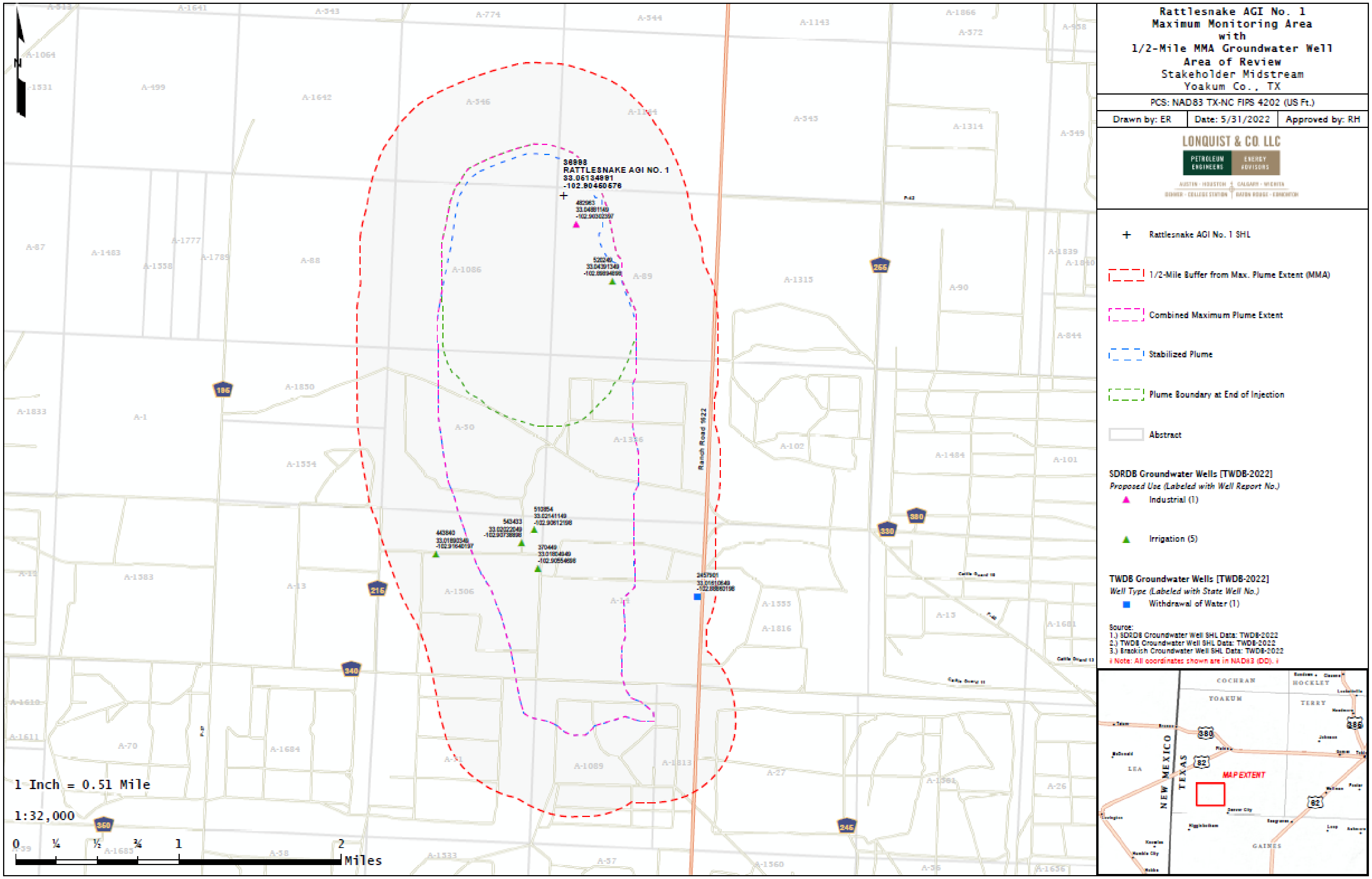


Figure 32 – Groundwater Wells within MMA

Table 9 – Groundwater Well Summary

State Well ID	Owner Name	Primary Use	Well Depth	Data Source
370449	Frances Barbini	Irrigation	237	SDRDB
443840	Frances Jean Barbini	Irrigation	250	SDRDB
482963	Santa Fe Midstream Permian	Industrial	119	SDRDB
510854	FRANCIS BARNINI	Irrigation	255	SDRDB
520249	Thomas Durham	Irrigation	264	SDRDB
543433	FRANCIS BARBIDI	Irrigation	240	SDRDB
84760	TEXACO PRODUCING INC			TWDB_BW

Leakage Through Faults and Fractures

Faults were interpreted from roughly 9 square miles of 3D seismic indicated by the purple outline in Figure 12. Faulting in this region terminates vertically below the Pennsylvanian-age rock. Secondary confining shales within the Wolfcampian and younger strata provide additional, redundant confining layers that would prevent CO_2 from migrating into freshwater aquifers. None of the mapped faults project above the Wolfcamp formation; rather, they appear to terminate between the Strawn and base of the Wolfcamp formation. If, in the unlikely event the faults' sealing properties are compromised post-injection, secondary confinement is provided by the tight limestones found within the overlying Mississippianan Lime formation and the shale layers found in the Atoka and Wolfcamp formations. As seen in Figure 14, the largest fault found SE of the Rattlesnake AGI #1 well, terminates within the Atoka formation. Though it crosses the Silurian section, this fault thrusts the Mississippian Lime upward against the Atoka shales. The tight reservoir characteristics of the Mississippian Lime and shaley section of the Atoka create a confining environment vertically and laterally to contain potential upward migration of buoyant fluids. Shales within the Wolfcamp formation provide additional confining beds between overlying USDWs and the fault plane.

Should an unmapped fault exist within the plume boundary, the offset would be below 3D seismic resolution. The offset would be less than the thickness of the Woodford shale, juxtaposing the Woodford against itself, preventing vertical migration.

Fractures and subsequent subaerial exposure are responsible for porosity development within the injection intervals. Open hole logs show little to no porosity development indicating the Woodford or Mississippian Lime were not exposed at this location. Upward migration of injected gas through confining bed fractures is unlikely.

Leakage Through the Confining Layer

The Silurian-Devonian injection zones have competent sealing rocks above and below the porous sub-aerially exposed carbonate. The properties of the overlying transgressive Woodford shale (widespread deposition, high illite clay and organic matter composition, and low porosity and permeability) make an excellent sealing rock to the underlying Silurian formation. Tight Mississippian Lime of roughly 660 ft, lay between Atoka and Woodford shale formations, forming an impermeable upper seal to the injection interval. Above this confining unit, correlative shales of the Wolfcamp, Abo and Tubb formations will prevent any upper fluid migration. These impermeable shales are capped by hundreds of feet of the regionally present Salado formation evaporites. The USDW lies above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. The underlying low porosity and permeability Montoya carbonate minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injected gas to the in-situ reservoir fluid makes migration below the lower confining layer unlikely.

Leakage from Natural or Induced Seismicity

The location of Rattlesnake AGI #1 is in an area of the Permian Basin that is inactive from a seismicity perspective, whether induced or natural. A review of historical seismic events on the USGS's Advanced National Seismic System site (from 1971 to present) and the Bureau of Economic Geology's TexNet catalog (from 2017 to present), as shown in Figure 33, indicates the nearest seismic event occurred more than 60 miles away.

A regional analysis of the probabilistic fault slip potential across the Permian Basin (Snee & Zoback 2016), as seen in Figure 34, further demonstrates that the Rattlesnake AGI #1 well is located in a seismically inactive area and confirms that this area has little to no potential for an induced seismicity event.

Therefore, there is no indication that seismic activity poses a risk for loss of CO_2 to the surface within the MMA.

Pressures will be kept significantly below the fracture gradient of the injection and confining intervals. Additionally, continuous well monitoring combined with seismic monitoring will identify any operational anomalies associated with a seismicity event.

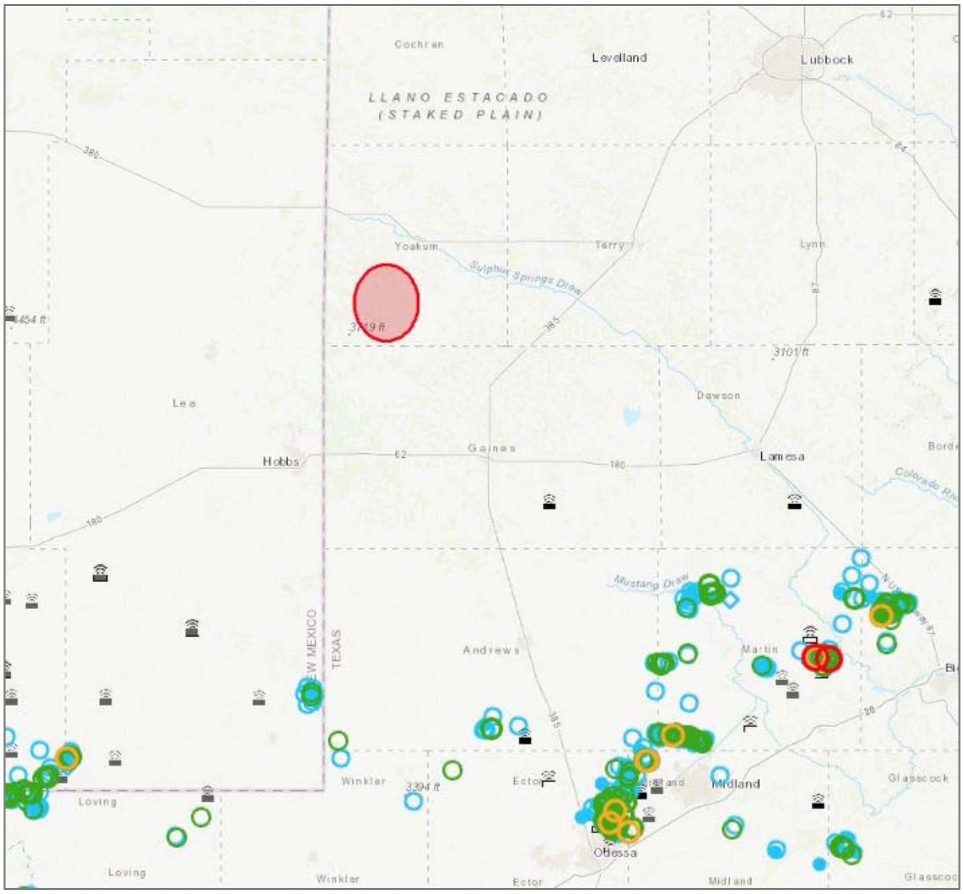


Figure 33 – Seismicity Review (TexNet – 06/01/2022)

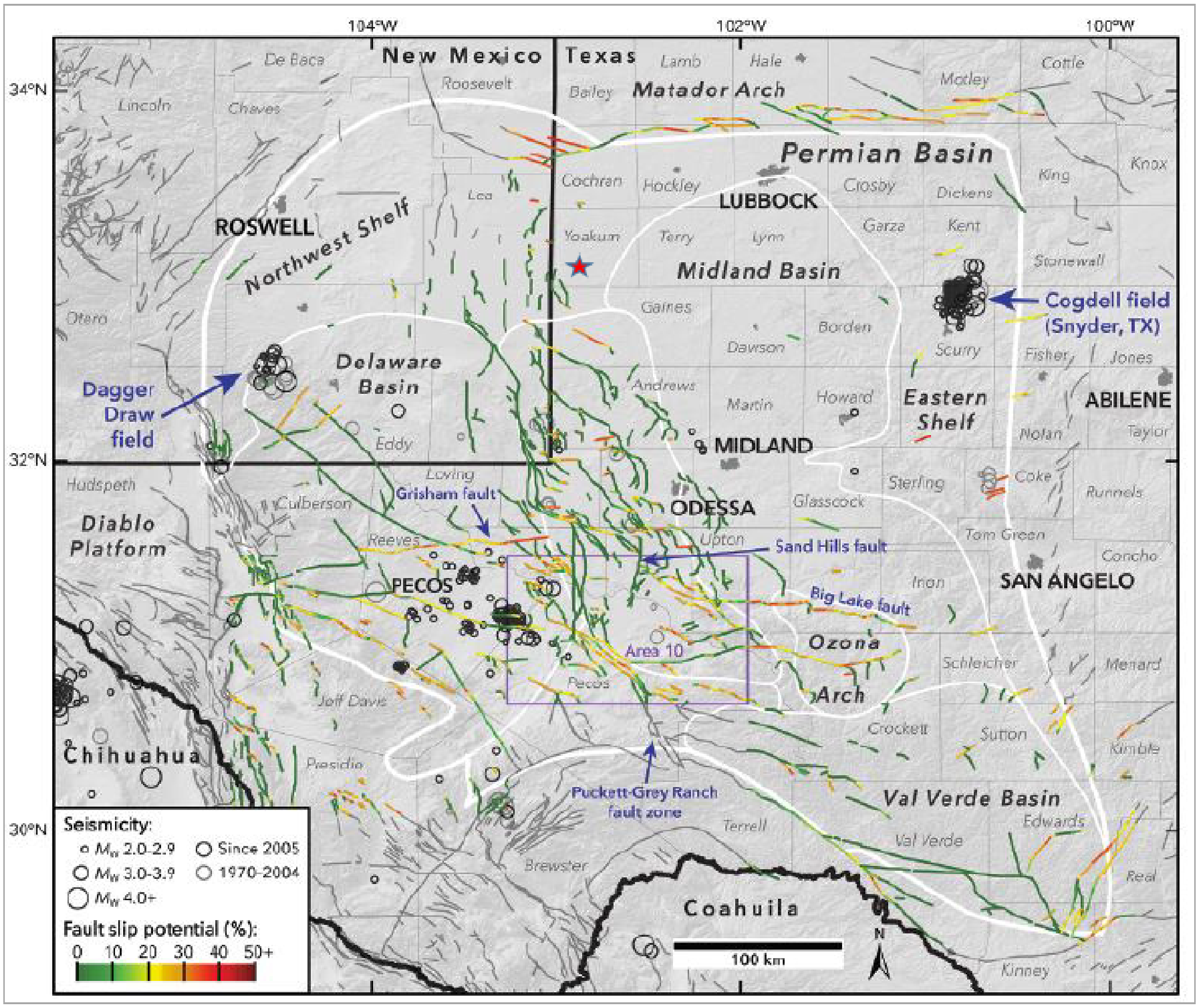


Figure 34 – Probabilistic Fault Slip Potential Analysis with Rattlesnake AGI #1 location (Snee & Zobak 2016)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Stakeholder will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in Section 4 to meet the requirements of 40 CFR §98.448(a)(3). As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 10 summarizes the monitoring of potential leakage pathways to the surface. Monitoring will occur during the planned 17-year injection period, or cessation of injection operations, plus a proposed 5-year post-injection period.

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

Because the acid gas injection stream also contains H_2S, any leakage would be detected by the H_2S alarms located around the facility and would be quickly addressed which would minimize the release of CO_2 into the atmosphere.

Table 10 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed H_2S monitors throughout the AGI facility
	Daily visual inspections
	Personal H_2S monitors
	Distributed Control System Monitoring (Volumes and Pressures)
Leakage through existing wells	Fixed H_2S monitor at the AGI well
	SCADA Continuous Monitoring at the AGI Well
	Annual Mechanical Integrity Tests ("MIT") of the AGI Well
	Visual Inspections
	Quarterly CO_2 Measurements within AMA
Leakage through groundwater wells	Annual Groundwater Samples on Property
Leakage from future wells	H_2S Monitoring during offset drilling operations
Leakage through faults and fractures	SCADA Continuous Monitoring at the AGI Well (volumes and pressures)
	Fixed In-field H_2S monitors
Leakage through confining layer	SCADA Continuous Monitoring at the AGI Well (volumes and pressures)
	Fixed In-field H_2S monitors
Leakage from natural or induced seismicity	Seismic monitoring station to be installed

Leakage from Surface Equipment

As the 30-30 Facility and the Rattlesnake AGI #1 well are designed to handle H_2S, leakage from surface equipment is unlikely to occur and would be quickly detected and addressed. The facility design minimizes leak points through the equipment used and the type of connections are designed to minimize corrosion points. The H_2S in the injectate serves as a proxy for the release of CO_2. The facility and well site contain a number of H_2S alarms, set with a high alarm setpoint of 10 ppm of H_2S, which are shown in Figure 28 above. Additionally, all Stakeholder field personnel are required to wear H_2S monitors, which trigger the alarm at 5 ppm H_2S.

The AGI facility is continuously monitored through automated systems. In addition, field personnel conduct daily visual field inspections of gauges, monitors and leak indicators such as vapor plumes. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system, analysis of liquids collected from the line, and inspection of the cathodic protection system. These inspections, in addition to the automated systems, allow Stakeholder to quickly respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5).

Pressures and flowrates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak.

Leakage from Existing and Future Wells within MMA

Stakeholder continuously monitors and collects injection volumes, pressures, temperatures and gas composition data, through their SCADA systems, for the Rattlesnake AGI #1 well. This data is reviewed by qualified personnel and will follow response and reporting procedures when data is outside acceptable performance limits. Rattlesnake AGI #1 has a pressure and temperature gauge placed in the injection stream at its wellhead, and a pressure gauge on the casing annulus. A change of pressure on the annulus would indicate the presence of a possible leak. Mechanical integrity tests (“MITs”) performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated and the leak mitigated.

The ten offset penetrating wells within the MMA are adequately cased and cemented to prevent potential leakage of CO_2 from the Rattlesnake AGI #1 well plume. Additionally, the plugged wells were done so in a way to prevent migration of CO_2 as provided in Appendix E. As discussed previously, Rule 13 would ensure that new wells in the field would be constructed in a manner to prevent migration from the injection interval.

In addition to the fixed and personal monitors described previously, Stakeholder will also establish and operate an in-field monitoring program to detect any CO_2 leakage within the AMA. The scope of work will include H_2S and CO_2 monitoring at the AGI well site as well as minimum, quarterly atmospheric monitoring near identified penetrations within the AMA. Upon approval of the MRV and through the post-injection monitoring period, Stakeholder will have these monitoring systems in place. Additional monitoring will be added as the AMA is updated over time.

At the well site, H_2S and CO_2 concentrations will be monitored continuously with fixed monitors that detect atmospheric concentrations of H_2S and CO_2. At penetrating well sites, Stakeholder will similarly measure atmospheric concentrations of CO_2 and H_2S using mobile gas monitors. This data will be recorded at least quarterly.

<u>Groundwater Quality Monitoring</u>

Stakeholder will monitor the groundwater quality in fluids above the confining interval by sampling the well on the facility property and analyzing the sample with a third-party laboratory on an annual basis. Any significant changes to the water analysis would be investigated to determine if such change was a result of leakage from the Rattlesnake AGI #1 well. The parameters to be measured will include pH, total dissolved solids, total inorganic and organic carbons, density, temperature and other standard laboratory measurements. Any significant differences in these parameters from the baseline sample will be evaluated to determine if leakage of CO_2 to the USDW may have occurred.

Leakage through Faults, Fractures or Confining Seals

Stakeholder continuously monitors the operations of the Rattlesnake AGI #1 well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway such as a fault or breakthrough of the confining seal would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. Field H_2S monitoring systems would alert field personnel for any release of H_2S/CO_2 caused by such leakage.

Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Stakeholder plans to install a seismic monitoring station in the general area of the Rattlesnake AGI #1 well. The installation of this station would start upon approval of the MRV plan, with an expected in-service data within six months after the commencement of the installation project. This monitoring station will be tied in to the Bureau of Economic Geology's TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, Stakeholder will review the injection volumes and pressures at the Rattlesnake AGI #1 well to determine if any significant changes occur that would indicate potential leakage.

SECTION 6 – BASELINE DETERMINATIONS

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

Visual Inspections

Daily inspections will be conducted by field personnel at the 30-30 Facility and the Rattlesnake AGI #1 well. These inspections will aid with identifying and addressing issues timely to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions would be taken to address such issues.

H_2S Detection

H_2S will be initially injected into the AGI well at a concentration of approximately ten (10) percent or 100,000 ppm. The concentration will drop to approximately seven (7) percent as additional volumes are added. H_2S gas detectors are located throughout the AGI facility and well site and are set to trigger the alarm at 10 ppm. Additionally, all field personnel are required to wear personal H_2S monitors, which are set to trigger the alarm at 5 ppm. Any alarm would trigger an immediate response to protect personnel and verify that the monitors are working properly. If monitors are working correctly, immediate actions would be taken to secure the facility and mitigate potential leaks.

CO_2 Detection

Any CO_2 release would be accompanied by H_2S and therefore the H_2S monitors at the facility would also serve as a CO_2 release warning system. In addition to the fixed and personal monitors described previously, Stakeholder will also establish and operate an in-field monitoring program to detect any CO_2 leakage within the AMA. The scope of work will include H_2S and CO_2 monitoring at the AGI well site as well as atmospheric monitoring near identified penetrations within the AMA.

Operational Data

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

Continuous Monitoring

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which would be extremely dangerous for personnel to perform a direct leak survey. Any leakage would be detected and managed as per Texas regulations and Stakeholder's TRRC-approved H_2S Contingency Plan. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

No CO_2 emissions will occur from venting because of the high H_2S concentrations. Blowdown emissions are sent to flares and would be reported as part of the required reporting for the gas plant.

Groundwater Monitoring

An initial sample will be taken from the groundwater well on Stakeholder's property, identified as Well # 482963 in Table 9 above, upon approval of Stakeholder's MRV and prior to increasing injection. The sample will be analyzed by a third-party laboratory to establish the baseline properties of the groundwater.

SECTION 7 – SITE SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

Mass of CO_2 Received

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

Mass of CO_2 Injected

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

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

where:

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

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

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

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

p = Quarter of the year

u = Flow meter

Mass of CO_2 Produced

The Rattlesnake AGI #1 well is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

Mass of CO_2 Emitted by Surface Leakage

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which would be extremely dangerous for personnel to perform a direct leak survey. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

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

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

Where:

CO_2 = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year

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

X = Leakage pathway

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

Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based off Equation RR-12, as this well will not actively produce oil or natural gas or any other fluids, as follows:

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

Where:

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

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

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting would occur due to the high H_2S concentrations of the injectate stream, the calculations would be based on the blowdown emissions that would be sent to flares and would be reported as part of the required GHG reporting for the gas plant.

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The Rattlesnake AGI #1 well currently reports GHGs under Subpart UU, but Stakeholder has elected to submit an MRV plan under, and otherwise comply with, Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31st of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

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

Monitoring QA/QC

CO_2 *Injected*

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer recommendations.

CO_2 *Emissions from Leaks and Vented Emissions*

- Gas detectors will be operated continuously, except for maintenance and calibration.
- Gas detectors will be calibrated according to manufacturer recommendations and API standards.
- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to the requirements in 40 CFR §98.3(i).
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.
- Flow meter calibrations will be traceable to the National Institute of Standards and Technology (NIST).

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

Missing Data

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

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in subpart W of 40 CFR §98.

MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Stakeholder will retain records as required by 40 CFR §98.3(g). These records will be retained for at least three years and include:

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

References

Broadhead, Ronald E., 2005. Regional Aspects of the Wristen petroleum system, southeastern New Mexico: New Mexico Bureau of Geology and Mineral Resources Open File Report, no. 485.

Comer, John B., 1991. Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas and Southeastern New Mexico: Bureau of Economic Geology Report of Investigations, no. 201.

George, Peter G., Mace, Robert E., and Petrossian, Rima, 2011. Aquifers of Texas: Texas Water Development Board Report, no 380.

Hoak, T., Sundberg, K., and Ortoleva, P. Overview of the Structural Geology and Tectonics of the Central Basin Platform, Delaware Basin, and Midland Basin, West Texas and New Mexico: Department of Energy Open File Report.

Molina, Oscar, Vilarras, Victor, and Zeidouni, Mehdi, 2016. Geologic carbon storage for shale gas recovery: 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18.

Ruppel, Stephen C. and Holtz, Mark H., 1994. Depositional and Diagenetic Facies Patterns and Reservoir Development in Silurian and Devonian Rocks of the Permian Basin: Bureau of Economic Geology Report of Investigations, no. 216.

Snee, Jens-Erik Lund and Zoback, Mark D., 2016. State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity.

Teeple, Andrew P., Ging, Patricia B., Thomas, Jonathan V., Wallace, David S., and Payne, Jason D., 2021. Hydrogeologic Framework, Geochemistry, Groundwater-Flow System, and Aquifer Hydraulic Properties Used in the Development of a Conceptual Model of the Ogallala, Edwards-Trinity (High Plains), and Dockum Aquifers In and Near Gaines, Terry, and Yoakum Counties, Texas: USGS Scientific Investigations Report 2021-5009.

APPENDICES

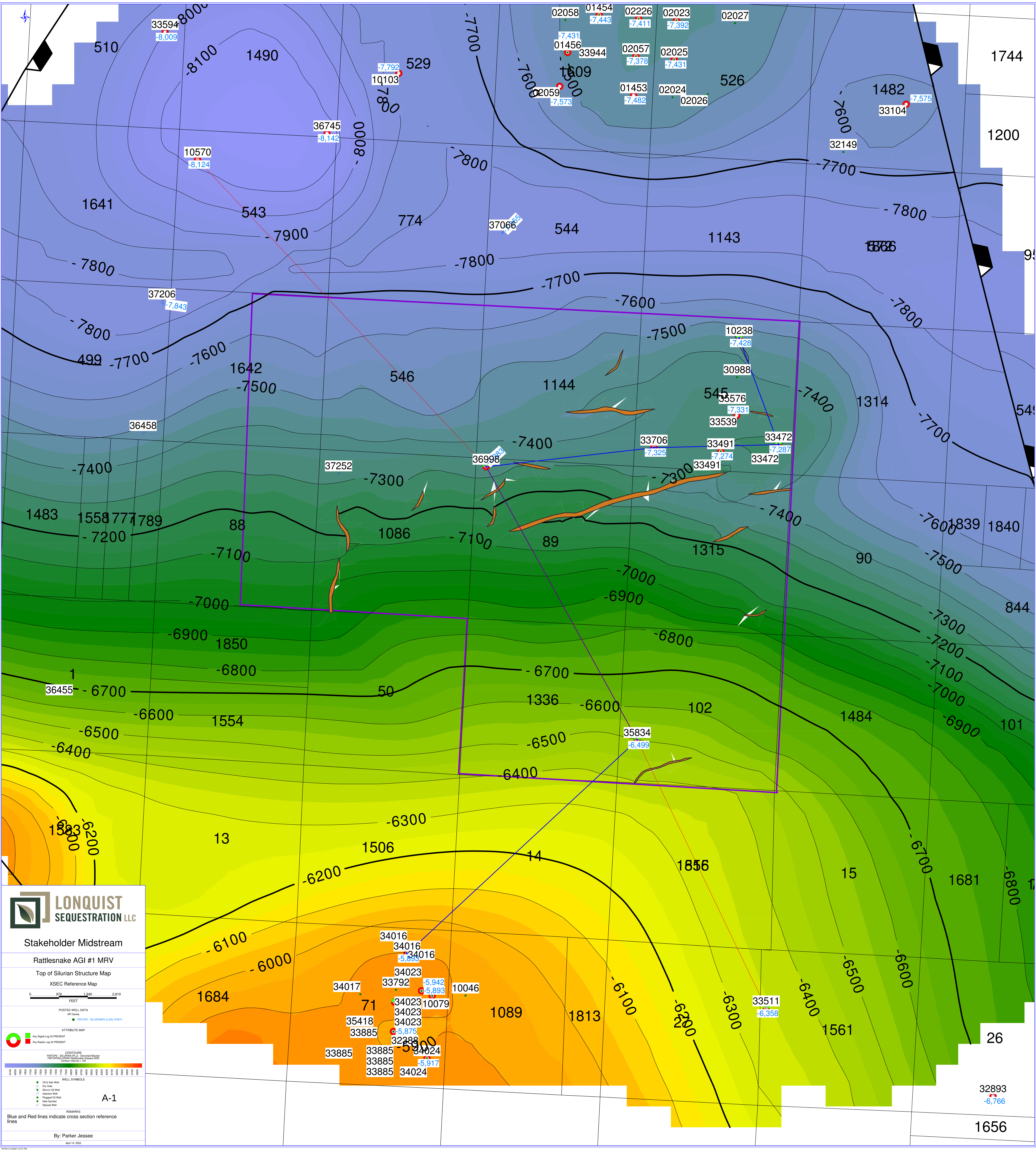
APPENDIX A – GEOLOGY

APPENDIX A-1: SILURIAN STRUCTURE MAP

APPENDIX A-2: NE-SW CROSS SECTION

APPENDIX A-3: NW-SE CROSS SECTION

APPENDIX A-4: FORMATION FLUID SAMPLE WELL MAP



LONQUIST SEQUESTRATION LLC
Stakeholder Midstream
Rattlesnake AGI #1 MRV
Top of Silurian Structure Map
XSEC Reference Map
0 970 1,940 2,910
FEET
POSTED WELL DATA
API Series
FMTOPS - SILURIAN[PLJ] (SS) (FEET)
ATTRIBUTE MAP
Any Digital Log IS PRESENT
Any Raster Log IS PRESENT
CONTOURS
FMTOPS - SILURIAN [PLJ] - Devonian/Silurian
FMTOPSSILURIAN Rattlesnake Subsea.GRD
Contour Interval = 100
WELL SYMBOLS
Oil & Gas Well
Dry Hole
Shut-in Oil Well
Injection Well
Plugged Oil Well
New Symbol
Diposal Well
A-1
REMARKS
Blue and Red lines indicate cross section reference lines
By: Parker Jessee
April 14, 2022
PETRA 4/14/2022 7:27:51 PM

A-2

LONQUIST SEQUESTRATION LLC

Stakeholder Midstream

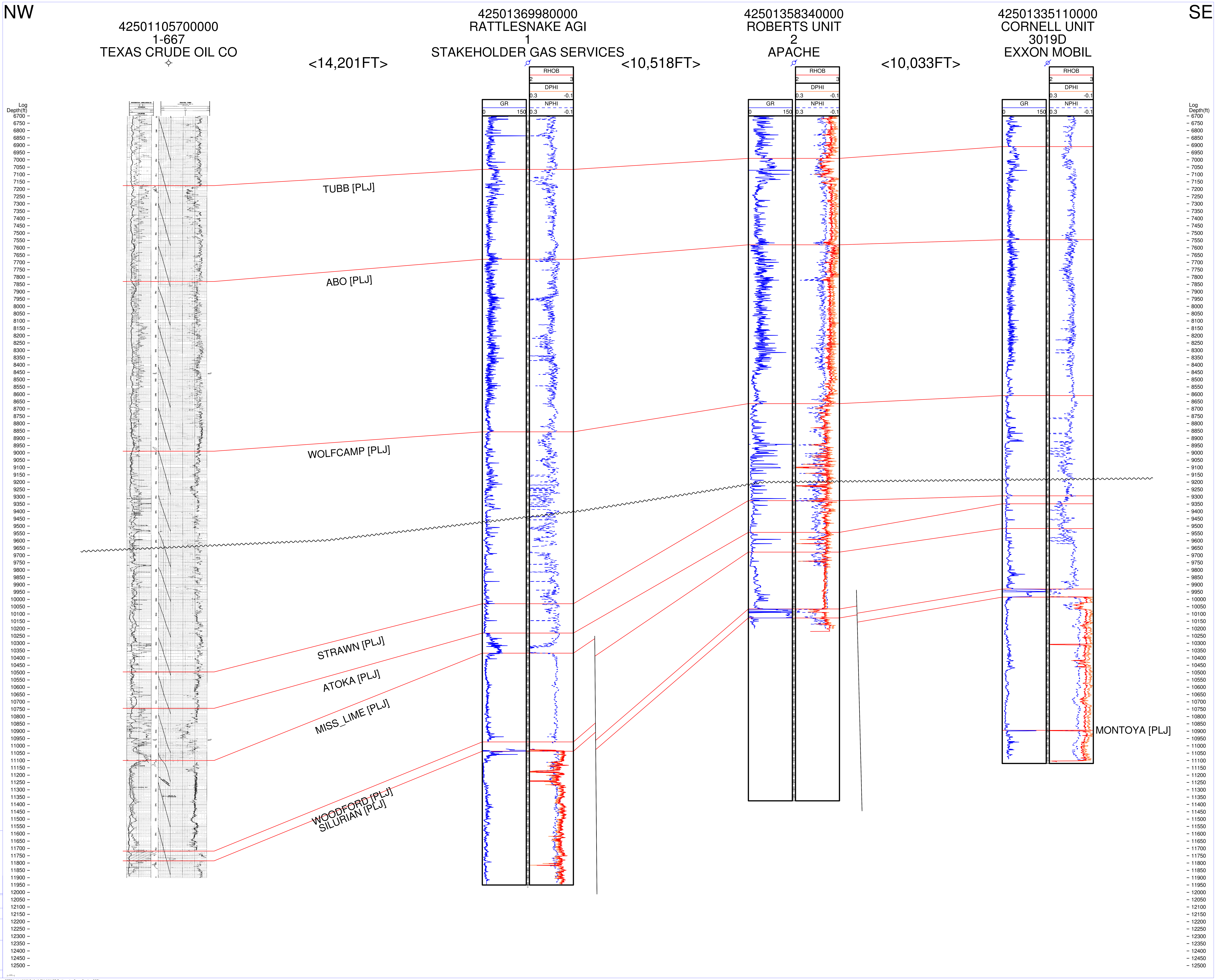
Rattlesnake AGI #1 MRV

NE-SW Structural Cross Section

Horizontal Scale = 193.4
Vertical Scale = 50.0
Vertical Exaggeration = 3.9x

UWI
Well Name
Well Number
Operator

April 14,2022 7:03 PM



A-3

LONQUIST SEQUESTRATION LLC

Stakeholder Midstream

Rattlesnake agi #1 MRV

NW-SE Structural Cross Section

Horizontal Scale = 289.6
Vertical Scale = 50.0
Vertical Exaggeration = 5.8x

UWI
Well Name
Well Number
Operator

April 14,2022 7:13 PM

PETRA 4/14/2022 7:13:40 PM (NW-SE Rattlesnake Cross Section.CSP)

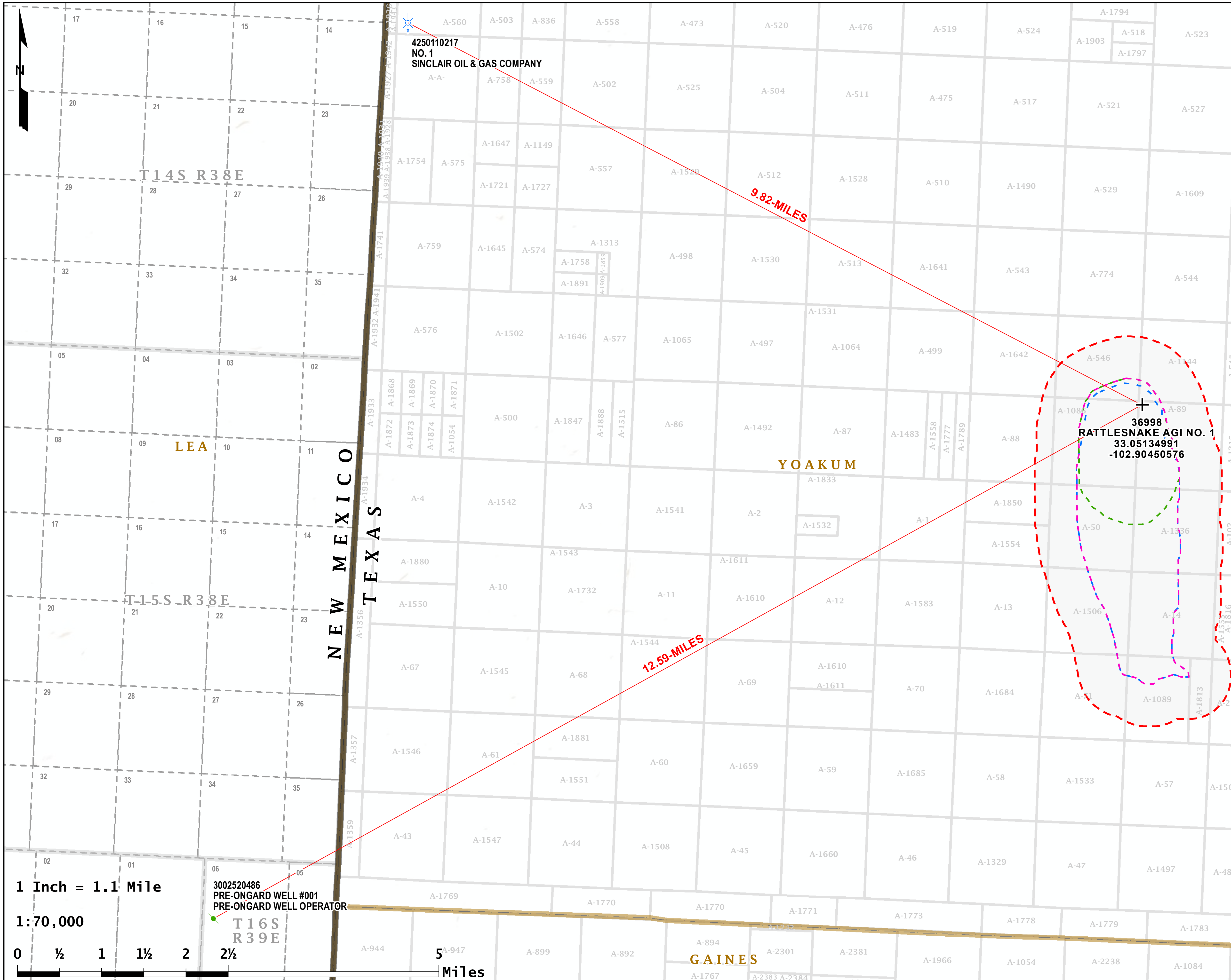
Rattlesnake AGI No. 1
Maximum Monitoring Area
with
Formation Fluid Sample Wells

Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 6/1/2022	Approved by: RH

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS
AUSTIN • HOUSTON • CALGARY • WICHITA
DENVER • COLLEGE STATION • BATON ROUGE • EDMONTON

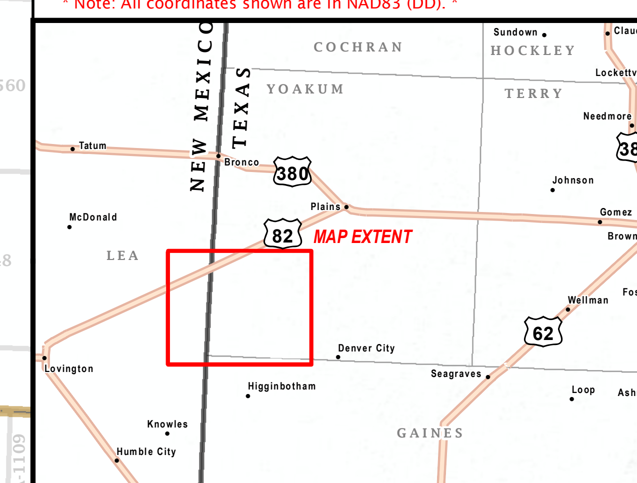


Legend:
- Rattlesnake AGI No. 1 SHL
- 1/2-Mile Buffer from Max. Plume Extent (MMA)
- Combined Maximum Plume Extent
- Stabilized Plume
- Plume Boundary at End of Injection
- Abstract
- County Boundary
- State Boundary
- Section Boundary [NM BLM-2022]
- Township Boundary [NM BLM-2022]
- Distance Call

Formation Fluid Sample Well [NM OCD-2022]
- Plugged - Oil

Formation Fluid Sample Well [DI-2022]
- TA - Injection/Disposal

Source:
1.) Oil/Gas Well SHL Data: DI-2022/NM OCD-2022
2.) Oil/Gas Well BHL Data: DI-2022
3.) Oil/Gas Well Directional Data: DI-2022
* Note: All coordinates shown are in NAD83 (DD). *



APPENDIX B – TRRC FORMS Rattlesnake AGI #1

APPENDIX B-1: UIC CLASS II ORDER

APPENDIX B-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX B-3: DRILLING PERMIT

APPENDIX B-4: COMPLETION REPORT

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 15848

SANTA FE MIDSTREAM PERMIAN LLC
5830 GRANITE PKWY STE 1025
PLANO, TX 75024

DOCKET NO. 8A-0312019

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated March 12, 2018 for the permitted interval of the DEVONIAN formation and subject to the following terms and special conditions:

RATTLESNAKE AGI (000000) LEASE
WASSON FIELD
YOAKUM COUNTY, DISTRICT 8A

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
1	50136998	000117143	CO2, and H2S	11,000	12,000	4,500	N/A	N/A	2,200

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	50136998	**1. Open hole completions shall have a plug back depth no deeper than the bottom of the permitted injection interval.** **2. The operator shall provide to the UIC section an annotated electric log, and a mud log if available, of the subject well with the top(s) and bottom(s) of the permitted formation indicated on the log. Top and bottom of the authorized injection interval may be modified based on electric log or mud log indications of the top and bottom of the permitted formations.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;
   c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON November 14, 2018.

Sean Avitt, Manager
Injection-Storage Permits Unit

IN-HOUSE AMENDMENT TO CORRECT THE RATE.

Note: This document will only be distributed electronically.

GROUNDWATER PROTECTION DETERMINATION

Form GW-2

Groundwater Advisory Unit

B-2

Date Issued:	31 August 2017	**GAU Number:**	179154

Attention:	SANTA FE MIDSTREAM 5700 GRANITE PARKWAY PLANO, TX 75024	**API Number:**	
		County:	YOAKUM
		Lease Name:	Roberts Unit
		Lease Number:	019212
Operator No.:	748093	**Well Number:**	1
		Total Vertical Depth:	11000
		Latitude:	33.049990
		Longitude:	-102.903464
		Datum:	NAD27

Purpose: New Drill

Location: Survey-Gibson, J H/Poole, J T; Block-D; Section-733

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

The interval from the land surface to a depth of 375 feet must be protected.

Note: Unless stated otherwise, this recommendation is intended to apply only to the subject well and not for area-wide use. This recommendation is for normal drilling, production, and plugging operations only. It does not apply to saltwater disposal operation into a nonproductive zone (RRC Form W-14).

This determination is based on information provided when the application was submitted on 08/30/2017. 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

API No. 42-501-36998

Drilling Permit # 839303

SWR Exception Case/Docket No.

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

APPLICATION FOR PERMIT TO DRILL, RECOMPLETE, OR RE-ENTER

This facsimile W-1 was generated electronically from data submitted to the RRC.
A certification of the automated data is available in the RRC's Austin office.

FORM W-1 07/2004

Permit Status: Approved

B-3

1. RRC Operator No. 748093

2. Operator's Name (as shown on form P-5, Organization Report) SANTA FE MIDSTREAM PERMIAN LLC

3. Operator Address (include street, city, state, zip): 5830 GRANITE PKWY STE 1025 PLANO, TX 75024-0000

4. Lease Name RATTLESNAKE AGI

5. Well No. 1

GENERAL INFORMATION

6. Purpose of filing (mark ALL appropriate boxes): [X] New Drill [ ] Recompletion [ ] Reclass [ ] Field Transfer [ ] Re-Enter [ ] Amended [ ] Amended as Drilled (BHL) (Also File Form W-1D)

7. Wellbore Profile (mark ALL appropriate boxes): [X] Vertical [ ] Horizontal (Also File Form W-1H) [ ] Directional (Also File Form W-1D) [ ] Sidetrack

8. Total Depth 12000

9. Do you have the right to develop the minerals under any right-of-way ? [X] Yes [ ] No

10. Is this well subject to Statewide Rule 36 (hydrogen sulfide area)? [X] Yes [ ] No

SURFACE LOCATION AND ACREAGE INFORMATION

11. RRC District No. 8A

12. County YOAKUM

13. Surface Location [X] Land [ ] Bay/Estuary [ ] Inland Waterway [ ] Offshore

14. This well is to be located 7.3 miles in a NW direction from DENVER CITY which is the nearest town in the county of the well site.

15. Section 733

16. Block D

17. Survey GIBSON, J H

18. Abstract No. A-89

19. Distance to nearest lease line: 200 ft.

20. Number of contiguous acres in lease, pooled unit, or unitized tract: 640

21. Lease Perpendiculars: 200 ft from the NORTH line and 200 ft from the WEST line.

22. Survey Perpendiculars: 200 ft from the NORTH line and 200 ft from the WEST line.

23. Is this a pooled unit? [ ] Yes [X] No

24. Unitization Docket No:

25. Are you applying for Substandard Acreage Field? [ ] Yes (attach Form W-1A) [X] No

FIELD INFORMATION List all fields of anticipated completion including Wildcat. List one zone per line.

26. RRC District No.	27. Field No.	28. Field Name (exactly as shown in RRC records)	29. Well Type	30. Completion Depth	31. Distance to Nearest Well in this Reservoir	32. Number of Wells on this lease in this Reservoir
8A	95397001	WASSON	Injection Well	12000	0.00	1
8A	95399400	WASSON, NORTH (SAN ANDRES)	Injection Well	12000	0.00	1

BOTTOMHOLE LOCATION INFORMATION is required for DIRECTIONAL, HORIZONTAL, AND AMENDED AS DRILLED PERMIT APPLICATIONS

Remarks

[FILER Apr 16, 2018 5:16 PM]: Filing for an acid gas injection well.

Certificate:

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

Jessica Risien, Regulatory Compliance Specialist
Name of filer

Apr 25, 2018
Date submitted

(281)8729300
Phone

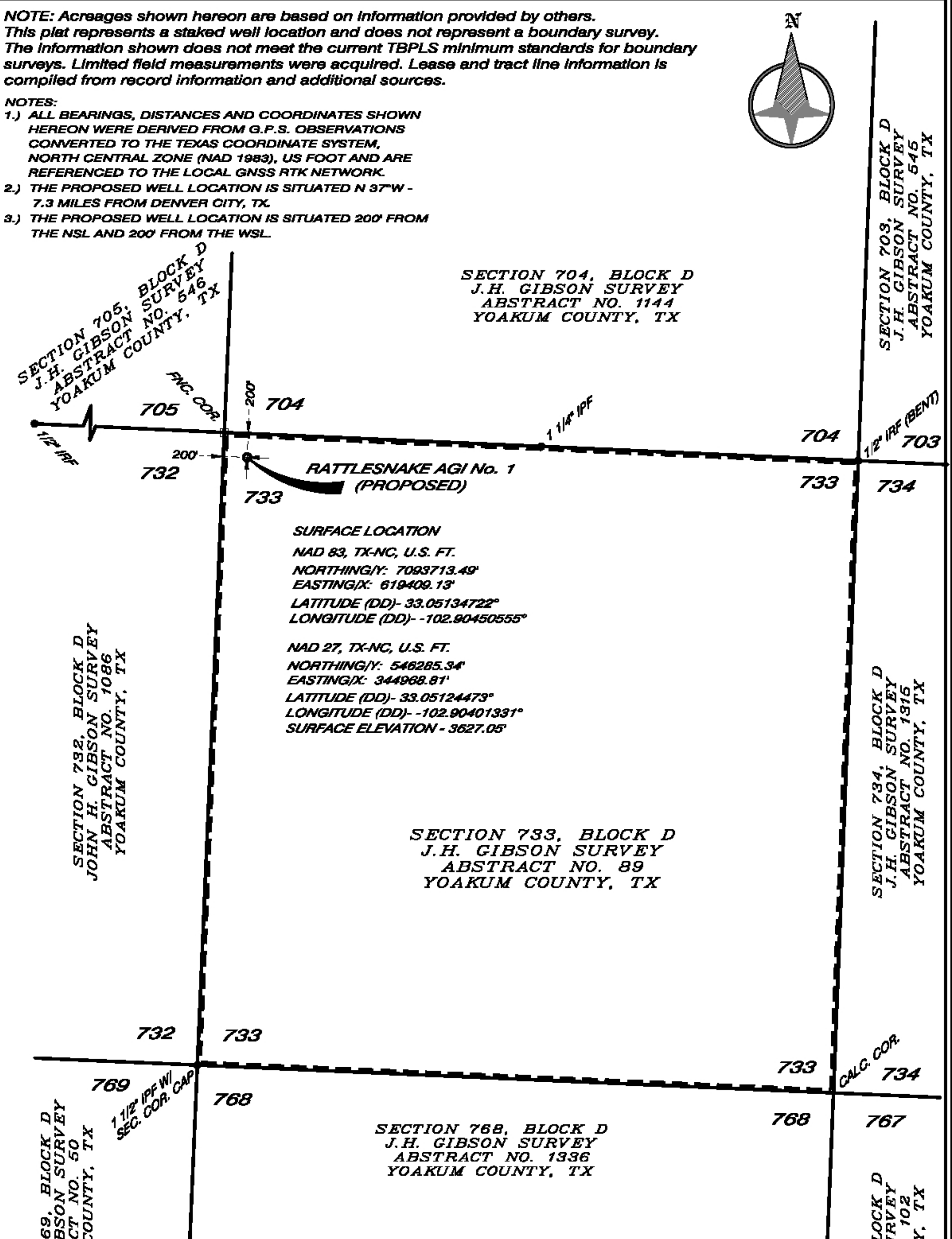
jrisien@ntglobal.com
E-mail Address (OPTIONAL)

RRC Use Only Data Validation Time Stamp: Apr 27, 2018 10:36 AM('As Approved' Version)

NOTE: Acreages shown hereon are based on information provided by others. This plat represents a staked well location and does not represent a boundary survey. The information shown does not meet the current TBPLS minimum standards for boundary surveys. Limited field measurements were acquired. Lease and tract line information is compiled from record information and additional sources.

NOTES:

1.) ALL BEARINGS, DISTANCES AND COORDINATES SHOWN HEREON WERE DERIVED FROM G.P.S. OBSERVATIONS CONVERTED TO THE TEXAS COORDINATE SYSTEM, NORTH CENTRAL ZONE (NAD 1983), US FOOT AND ARE REFERENCED TO THE LOCAL GNSS RTK NETWORK.
2.) THE PROPOSED WELL LOCATION IS SITUATED N 37°W - 7.3 MILES FROM DENVER CITY, TX.
3.) THE PROPOSED WELL LOCATION IS SITUATED 200' FROM THE NSL AND 200' FROM THE WSL.



WELL LOCATION PLAT

SHOWING

SANTA FE MIDSTREAM PERMIAN LLC
RATTLESNAKE AGI No. 1
J.H. GIBSON SURVEY, A-89
SECTION 733, BLOCK D
YOAKUM COUNTY, TEXAS

SCALE: 1" = 1000'

1000 500 0 1000

SCALE FEET

I, THE UNDERSIGNED, REGISTERED PROFESSIONAL LAND SURVEYOR, DO HEREBY CERTIFY THAT THE PLAT SHOWN REPRESENTS AN ACTUAL SURVEY MADE ON THE GROUND AND IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

BY: ____________________

ANDREW STOUT 03/20/2018

REGISTERED PROFESSIONAL LAND SURVEYOR

STATE OF TEXAS NO. 5970

STATE OF TEXAS REGISTERED PROFESSIONAL LAND SURVEYOR ANDREW STOUT 5970

INTEGRITY POSITIONS, LLC

14296 FM 314 N.
BROWNSBORO, TX 75756
(903) 595-9395
Firm No. 10194095

Railroad Commission of Texas

PERMIT TO DRILL, RE-COMPLETE, OR RE-ENTER ON REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

CONDITIONS AND INSTRUCTIONS

Permit Invalidation. It is the operator's responsibility to make sure that the permitted location complies with Commission density and spacing rules in effect on the spud date. The permit becomes invalid automatically if, because of a field rule change or the drilling of another well, the stated location is not in compliance with Commission field rules on the spud date. If this occurs, application for an exception to Statewide Rules 37 and 38 must be made and a special permit granted prior to spudding. Failure to do so may result in an allowable not being assigned and/or enforcement procedures being initiated.

Notice Requirements. Per H.B 630, signed May 8, 2007, the operator is required to provide notice to the surface owner no later than the 15th business day after the Commission issues a permit to drill. Please refer to subchapter Q Sec. 91.751-91.755 of the Texas Natural Resources Code for applicability.

Permit expiration. This permit expires two (2) years from the date of issuance shown on the original permit. The permit period will not be extended.

Drilling Permit Number. The drilling permit number shown on the permit MUST be given as a reference with any notification to the district (see below), correspondence, or application concerning this permit.

Rule 37 Exception Permits. This Statewide Rule 37 exception permit is granted under either provision Rule 37 (h)(2)(A) or 37(h)(2)(B). Be advised that a permit granted under Rule 37(h)(2)(A), notice of application, is subject to the General Rules of Practice and Procedures and if a protest is received under Section 1.3, "Filing of Documents," and/or Section 1.4, "Computation of Time," the permit may be deemed invalid.

Before Drilling

Fresh Water Sand Protection. The operator must set and cement sufficient surface casing to protect all usable-quality water, as defined by the Railroad Commission of Texas (RRC) Groundwater Advisory Unit (GWAU). Before drilling a well, the operator must obtain a letter from the Railroad Commission of Texas stating the depth to which water needs protection, Write: Railroad Commission of Texas, Groundwater Advisory Unit (GWAU), P.O. Box 12967, Austin, TX 78711-3087. File a copy of the letter with the appropriate district office.

Accessing the Well Site. If an OPERATOR, well equipment TRANSPORTER or WELL service provider must access the well site from a roadway on the state highway system (Interstate, U.S. Highway, State Highway, Farm-to-Market Road, Ranch-to-Market Road, etc.), an access permit is required from TxDOT. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

Water Transport to Well Site. If an operator intends to transport water to the well site through a temporary pipeline laid above ground on the state's right-of-way, an additional TxDOT permit is required. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

*NOTIFICATION

The operator is **REQUIRED** to notify the district office when setting surface casing, intermediate casing, and production casing, or when plugging a dry hole. The district office MUST also be notified if the operator intends to re-enter a plugged well or re-complete a well into a different regulatory field. Time requirements are given below. The drilling permit number MUST be given with such notifications.

During Drilling

Permit at Drilling Site : A copy of the Form W-1 Drilling Permit Application, the location plat, a copy of Statewide Rule 13 alternate surface casing setting depth approval from the district office, if applicable, and this drilling permit must be kept at the permitted well site throughout drilling operations.

***Notification of Setting Casing :** The operator MUST call in notification to the appropriate district office (phone number shown the on permit) a minimum of eight (8) hours prior to the setting of surface casing, intermediate casing, AND production casing. The individual giving notification MUST be able to advise the district office of the drilling permit number.

***Notification of Re-completion/Re-entry :** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of eight (8) hours prior to the initiation of drilling or re-completion operations. The individual giving notification MUST be able to advise the district office of the drilling permit number.

Completion and Plugging Reports

Hydraulic Fracture Stimulation using Diesel Fuel: Most operators in Texas do not use diesel fuel in hydraulic fracturing fluids. Section 322 of the Energy Policy Act of 2005 amended the Underground Injection Control (UIC) portion of the federal Safe Drinking Water Act (42 USC 300h(d)) to define "underground Injection" to *EXCLUDE* " ...the underground injection of fluids or propping agents *(other than diesel fluels)* pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities." (italic and underlining added.) Therefore, hydraulic fracturing may be subject to regulation under the federal UIC regulations if diesel fuel is injected or used as a propping agent. EPA defined "diesel fuel" using the following five (5) Chemical Abstract Service numbers: 68334-30-5 Primary Name: Fuels, diesel; 68476-34-6 Primary Name: Fuels, diesel, No. 2; 68476-30-2 Primary Name: Fuel oil No. 2; 68476-31-3 Primary Nmae: Fuel oil, No. 4; and 8008-20-6 Primary Name: Kerosene. As a result, an injection well permit would be required before performing hydraulic fracture stimulation using diesel fuel as defined by EPA on any well in Texas. Hydraulic fracture stimulation using diesel fuel as defined by EPA on a well in Texas without an injection well permit could result in enforcement action.

Producing Well : Statewide Rule 16 states that the operator of a well shall file with the Commission the appropriate completion report within thirty (30) days after completion of the well or within ninety (90) days after the date on which the drilling operation is completed, whichever is earlier. Completion of the well in a field authorized by this permit voids the permit for all other fields included in the permit unless the operator indicates on the initial completion report that the well is to be a dual or multiple completion and promptly submits an application for multiple completion. All zones are required to be completed before the expiration date on the existing permit. Statewide Rule 40(d) requires that upon successful completion of a well in the same reservoir as any other well previously assigned the same acreage, proration plats and P-15s (if required) must be submitted with no double assignment of acreage.

Dry or Noncommercial Hole : Statewide Rule 14(b)(2) prohibits suspension of operations on each dry or non-commercial well without plugging unless the hole is cased and the casing is cemented in compliance with Commission rules. If properly cased, Statewide Rule 14(b)(2) requires that plugging operations must begin within a period of one (1) year after drilling or operations have ceased. Plugging operations must proceed with due diligence until completed. An extension to the one-year plugging requirement may be granted under the provisions stated in Statewide Rule 14(b)(2).

Intention to Plug : The operator must file a Form W-3A (Notice of Intention to Plug and Abandon) with the district office at least five (5) days prior to beginning plugging operations. If, however, a drilling rig is already at work on location and ready to begin plugging operations, the district director or the director's delegate may waive this requirement upon request, and verbally approve the proposed plugging procedures.

***Notification of Plugging a Dry Hole :** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of four (4) hours prior to beginning plugging operations. The individual giving the notification MUST be able to advise the district office of the drilling permit number and all water protection depths for that location as stated in the Texas Commission on Environmental Quality letter.

DIRECT INQUIRIES TO: DRILLING PERMIT SECTION, OIL AND GAS DIVISION

PHONE
(512) 463-6751

MAIL:
PO Box 12967
Austin, Texas, 78711-2967

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER	DATE PERMIT ISSUED OR AMENDED	DISTRICT
839303	04/27/2018	8A
API NUMBER 42-501-36998	FORM W-1 RECEIVED 04/25/2018	COUNTY YOAKUM
TYPE OF OPERATION New Drill	WELLBORE PROFILE(S) Vertical	ACRES 640.0

OPERATOR 748093
SANTA FE MIDSTREAM PERMIAN LLC
5830 GRANITE PKWY STE 1025
PLANO, TX 75024-0000

NOTICE
This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored.
District Office Telephone No:
(806) 698-6509

LEASE NAME	WELL NUMBER
RATTLESNAKE AGI	1
LOCATION 7.3 miles NW direction from DENVER CITY	TOTAL DEPTH 12000

Section, Block and/or
SECTION 733 BLOCK D ABSTRACT 89
SURVEY GIBSON, J H

DISTANCE TO SURVEY LINES	DISTANCE TO NEAREST LEASE LINE
200.0 ft NORTH 200.0 ft WEST	200.0
DISTANCE TO LEASE LINES 200.0 ft NORTH 200.0 ft WEST	DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME / LEASE NAME	ACRES / NEAREST LEASE	DEPTH	WELL# / NEAREST WELL	DIST
WASSON	640.0	12000	1	8A
RATTLESNAKE AGI	200.0		0.0	

This is a hydrogen sulfide field. This well shall be drilled in accordance with SWR 36.

Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

FIELD NAME / LEASE NAME	ACRES / NEAREST LEASE	DEPTH	WELL# / NEAREST WELL	DIST
WASSON, NORTH (SAN ANDRES)	640.0	12000	1	8A
RATTLESNAKE AGI	200.0		0.0	

This is a hydrogen sulfide field. This well shall be drilled in accordance with SWR 36.

Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

This well must comply to the new SWR 3.13 requirements concerning the isolation of any potential flow zones and zones with corrosive formation fluids. See approved permit for those formations that have been identified for the county in which you are drilling the well in.

Railroad Commission of Texas
Oil and Gas Division
SWR #13 Formation Data
YOAKUM (501) COUNTY

Formation	Remarks	Geological Order	Effective Date
RED BED-SANTA ROSA		1	01/01/2014
YATES		2	01/01/2014
SAN ANDRES	high flows, H2S, corrosive	3	01/01/2014
GLORIETA		4	01/01/2014
CLEARFORK	Active CO2 Flood	5	01/01/2014
WICHITA		6	01/01/2014
LEONARD		7	01/01/2014
WOLFCAMP		8	01/01/2014
PENNSYLVANIAN		9	01/01/2014
STRAWN		10	01/01/2014
MISSISSIPPIAN		11	01/01/2014
DEVONIAN		12	01/01/2014
DEVONIAN-SILURIAN		13	01/01/2014

The above list may not be all inclusive, and may also include formations that do not intersect all wellbores. The listing order of the Formation information reflects the general stratigraphic order and relative geologic age. This is a dynamic list subject to updates and revisions. It is the operator's responsibility to make sure that at the time of spudding the well the most current list is being referenced. Refer to the RRC website at the following address for the most recent information. http://www.rrc.texas.gov/oil-gas/compliance-enforcement/rule-13-geologic-formation-info

RAILROAD COMMISSION OF TEXAS

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Form G-1

Status: Approved
Date: 07/25/2019
Tracking No.: 205926

GAS WELL BACK PRESSURE TEST, COMPLETION OR RECOMPLETION REPORT, AND LOG

OPERATOR INFORMATION

Operator Name: SANTA FE MIDSTREAM PERMIAN LLC **Operator No.:** 748093
Operator Address: 5830 GRANITE PKWY STE 1025 PLANO, TX 75024-0000

WELL INFORMATION

API No.: 42-501-36998 **County:** YOAKUM
Well No.: 1 **RRC District No.:** 8A
Lease Name: RATTLESNAKE AGI **Field Name:** WASSON
RRC Gas ID No.: 286838 **Field No.:** 95397001
Location: Section: 733, Block: D, Survey: GIBSON, J H, Abstract: 89

Latitude: **Longitude:**

This well is located 7.3 **miles in a** NW **direction from** DENVER CITY, **which is the nearest town in the county.**

FILING INFORMATION

Purpose of filing: Well Record Only
Type of completion: New Well
Well Type: Active UIC **Completion or Recompletion Date:** 08/31/2018

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or Deepen	04/27/2018	839303
Rule 37 Exception		
Fluid Injection Permit		
O&G Waste Disposal Permit	11/14/2018	15848
Other:		

COMPLETION INFORMATION

Spud date: 07/16/2018
Date of first production after rig released: 08/31/2018
Date plug back, deepening, recompletion, or drilling operation commenced: 07/16/2018
Date plug back, deepening, recompletion, or drilling operation ended: 08/31/2018
Number of producing wells on this lease in this field (reservoir) including this well: 1
Distance to nearest well in lease & reservoir (ft.): 0.0
Total number of acres in lease: 640.00
Elevation (ft.): 3627 GR
Total depth TVD (ft.): 11980
Total depth MD (ft.):
Plug back depth TVD (ft.): 11980
Plug back depth MD (ft.):
Was directional survey made other than inclination (Form W-12)? Yes
Rotation time within surface casing (hours): 72.0
Is Cementing Affidavit (Form W-15) attached? Yes
Recompletion or reclass? No
Multiple completion? No
Type(s) of electric or other log(s) run: Combo of Induction/Neutron/Density/Sonic
Electric Log Other Description:
Location of well, relative to nearest lease boundaries of lease on which this well is located: **Off Lease:** No
200.0 **Feet from the** North **Line and**
200.0 **Feet from the** West **Line of the**
RATTLESNAKE AGI **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

Field & Reservoir	Gas ID or Oil Lease No.	Well No.	Prior Service Type

G1: N/A
PACKET: N/A

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination **Depth (ft.):** 2025.0 **Date:** 01/12/2018

SWR 13 Exception **Depth (ft.):**

GAS MEASUREMENT DATA

Date of test:

Gas measurement method(s):

Gas production during test (MCF):

Was the well preflowed for 48 hours? No

Run No.	Line size	Orif. or Choke Size (in.)	24 hr. Coeff. Orif. Or Choke (in.)	Static Pm or Choke (in.)	Diff (hw)	Flow Temp (°F)	Temp. (Ftf)	Gravity (Fg)	Compress (Fpv)	Volume (MCF/day)

N/A

FIELD DATA AND PRESSURE CALCULATIONS

Gravity (dry gas):

Gravity (liquid hydrocarbons) (Deg. API):

Gas-Liquid Hydro Ratio (CF/Bbl):

Gravity (mixture): Gmix=

Avg. shut in temp. (°F):

Bottom hole temp. and depth: °F@ FT

Run No.	Time of Run (Min.)	Choke Size (in.)	Wellhead Pressure (PSIA)	Wellhead Flow Temp (°F)

N/A

CASING RECORD

Row	Type of Casing	Casing Size (in.)	Hole Size (in.)	Setting Depth (ft.)	Multi - Stage Tool Depth (ft.)	Multi - Stage Shoe Depth (ft.)	Cement Class	Cement Amount (sacks)	Slurry Volume (cu. ft.)	Top of Cement (ft.)	TOC Determined By
1	Surface	13 3/8	17 1/2	504			C	510	687.5	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5498		5498	C	485	797.0	4275	Circulated to Surface
2	Intermediate	13 3/8	17 1/2	5498	4275		C	1650	3045.0	0	Circulated to Surface
6	Conventional Production	7	8 3/4	11023			WELL LOCK	60	337.0	9575	Calculation
5	Conventional Production	7	8 3/4	11023	5591		PREM PLUS	380	906.5	0	Circulated to Surface
4	Conventional Production	7	8 3/4	11023	9575		PREM PLUS	380	906.5	5591	Calculation

LINER RECORD

Row	Liner Size (in.)	Hole Size (in.)	Liner Top (ft.)	Liner Bottom (ft.)	Cement Class	Cement Amount (sacks)	Slurry Volume (cu. ft.)	Top of Cement (ft.)	TOC Determined By

N/A

TUBING RECORD

Row	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	10966	10966 / HALLIBURTON BWD

PRODUCING/INJECTION/DISPOSAL INTERVAL

Row	Open hole?	From (ft.)	To (ft.)
1	Yes	L 11025	11980

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment performed? No

Is well equipped with a downhole actuation sleeve? No

If yes, actuation pressure (PSIG):

Production casing test pressure (PSIG) prior to hydraulic fracturing treatment:

Actual maximum pressure (PSIG) during hydraulic fracturing:

Has the hydraulic fracturing fluid disclosure been reported to FracFocus disclosure registry (SWR29)? No

Row	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)
N/A			

FORMATION RECORD

Formations	Encountered	Depth TVD (ft.)	Depth MD (ft.)	Is formation isolated?	Remarks
YATES	Yes	3019.0		Yes	
SAN ANDRES - HIGH FLOWS, H2S, CORROSIVE	Yes	4465.0		Yes	
GLORIETA	Yes	6316.0		Yes	
CLEARFORK - ACTIVE CO2 FLOOD	Yes	6492.0		Yes	
WICHITA	Yes	8628.0		Yes	
UPPER WOLFCAMP	Yes	9239.0		Yes	
STRAWN	Yes	10030.0		Yes	
ATOKA	Yes	10230.0		Yes	
WOODFORD	Yes	10973.0		Yes	
DEVONIAN	Yes	11036.0		No	DISPOSAL
WRISTEN	Yes	11268.0		No	DISPOSAL
FUSSELMAN	Yes	11538.0		No	DISPOSAL
MONTOYA	Yes	11974.0		No	DISPOSAL
RED BED-SANTA ROSA	No			No	NOT IN AREA
LEONARD	No			No	NOT IN AREA
WOLFCAMP	No			No	NOT IN AREA
PENNSYLVANIAN	No			No	NOT IN AREA
STRAWN	No			No	NOT IN AREA
MISSISSIPPIAN	No			No	NOT IN AREA

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm (SWR 36)? No

Is the completion being downhole commingled (SWR 10)? No

REMARKS

NEW WELL PUTTING ON SCHEDULE.

OPERATOR'S CERTIFICATION

Printed Name: Karen Zornes	**Title:**
Telephone No.: (281) 872-9300	**Date Certified:** 06/25/2019

APPENDIX C – GAS COMPOSITION

LABORATORY SERVICES
Natural Gas Analysis

www.permianls.com
575.397.3713 2609 W Marland Hobbs NM 88240

C6+ Gas Analysis Report

11093G	30/30 Acid Gas	30/30 Acid Gas
Sample Point Code	Sample Point Name	Sample Point Location

Laboratory Services	2021048523	1781	E Benavides - Spot
Source Laboratory	Lab File No	Container Identity	Sampler
USA	USA	USA	Texas
District	Area Name	Field Name	Facility Name
Nov 16, 2021	Nov 16, 2021	Nov 19, 2021 09:59	Nov 19, 2021
Date Sampled	Date Effective	Date Received	Date Reported

		System Administrator	21 @ 129
Ambient Temp (°F)	Flow Rate (Mcf)	Analyst	Press PSI @ Temp °F Source Conditions

Stakeholder Midstream	30/30
Operator	Lab Source Description

Component	Normalized Mol %	Un-Normalized Mol %	GPM
H2S (H2S)	9.2000	9.2	
Nitrogen (N2)	0.0000	0	
CO2 (CO2)	89.6780	98.775	
Methane (C1)	0.3030	0.331	
Ethane (C2)	0.0580	0.063	0.0150
Propane (C3)	0.1080	0.118	0.0300
I-Butane (IC4)	0.0000	0	0.0000
N-Butane (NC4)	0.0250	0.027	0.0080
I-Pentane (IC5)	0.0000	0	0.0000
N-Pentane (NC5)	0.0000	0	0.0000
Hexanes Plus (C6+)	0.6280	0.686	0.2710
TOTAL	100.0000	109.2000	0.3240

Method(s): Gas C6+ - GPA 2261, Extended Gas - GPA 2286, Calculations - GPA 2172

Analyzer Information

Device Type:	Gas Chromatograph	Device Make:	Shimadzu
Device Model:	GC-2014	Last Cal Date:	Nov 14, 2021

Gross Heating Values (Real, BTU/ft³)

14.696 PSI @ 60.00 Â°F		14.65 PSI @ 60.00 Â°F	
Dry	Saturated	Dry	Saturated
98.7	98.00	98.4	97.7

Calculated Total Sample Properties

GPA2145-16 *Calculated at Contract Conditions

Relative Density Real	Relative Density Ideal
1.5042	1.4956

Molecular Weight
43.3157

C6+ Group Properties

Assumed Composition

C6 - 60.000% C7 - 30.000% C8 - 10.000%

Field H2S
92000 PPM

PROTREND STATUS:
Passed By Validator on Nov 21, 2021

DATA SOURCE:
Imported

PASSED BY VALIDATOR REASON:
Close enough to be considered reasonable.

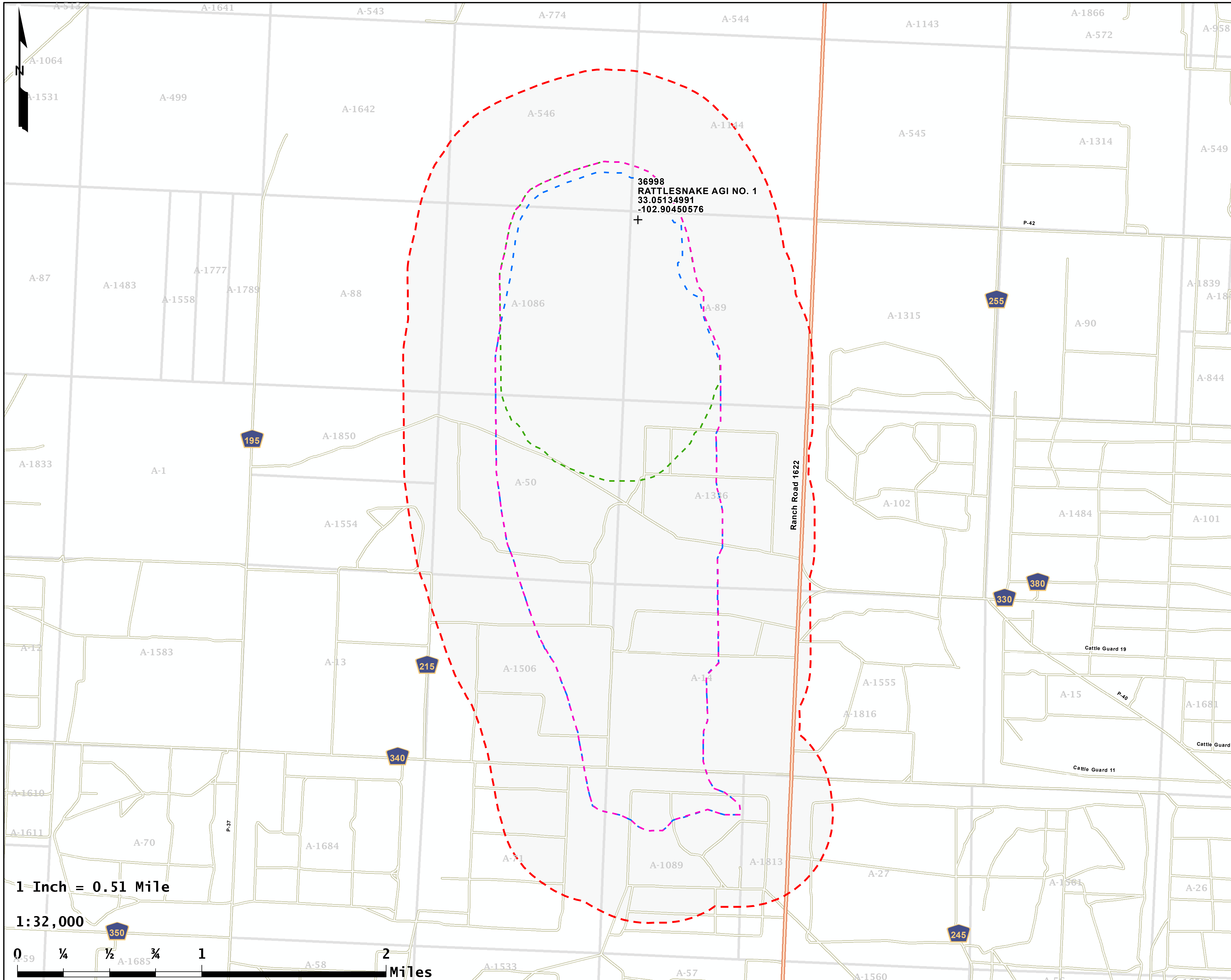
VALIDATOR:
Dustin Armstrong

VALIDATOR COMMENTS:
OK

APPENDIX D – MONITORING AREA MAPS

APPENDIX D-1: MMA MAP

APPENDIX D-2: AMA MAP



Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& Stabilized Plume
with
1/2-Mile Maximum Monitoring Area (MMA)
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS
AUSTIN • HOUSTON • CALGARY • WICHITA
DENVER • COLLEGE STATION • BATON ROUGE • EDMONTON

+ Rattlesnake AGI No. 1 SHL

1/2-Mile Buffer from Max. Plume Extent (MMA)

Combined Maximum Plume Extent

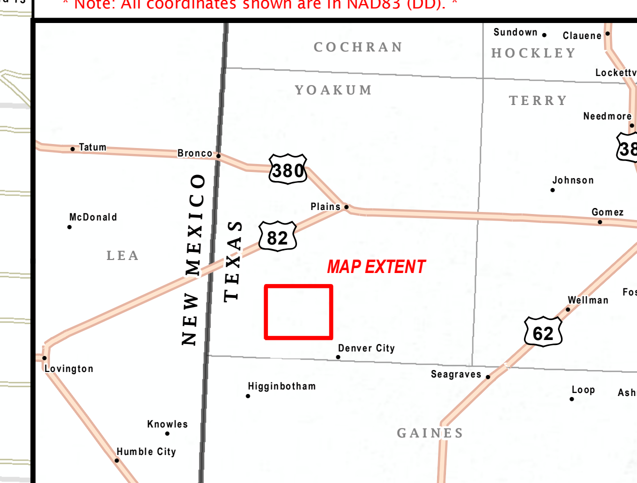
Stabilized Plume

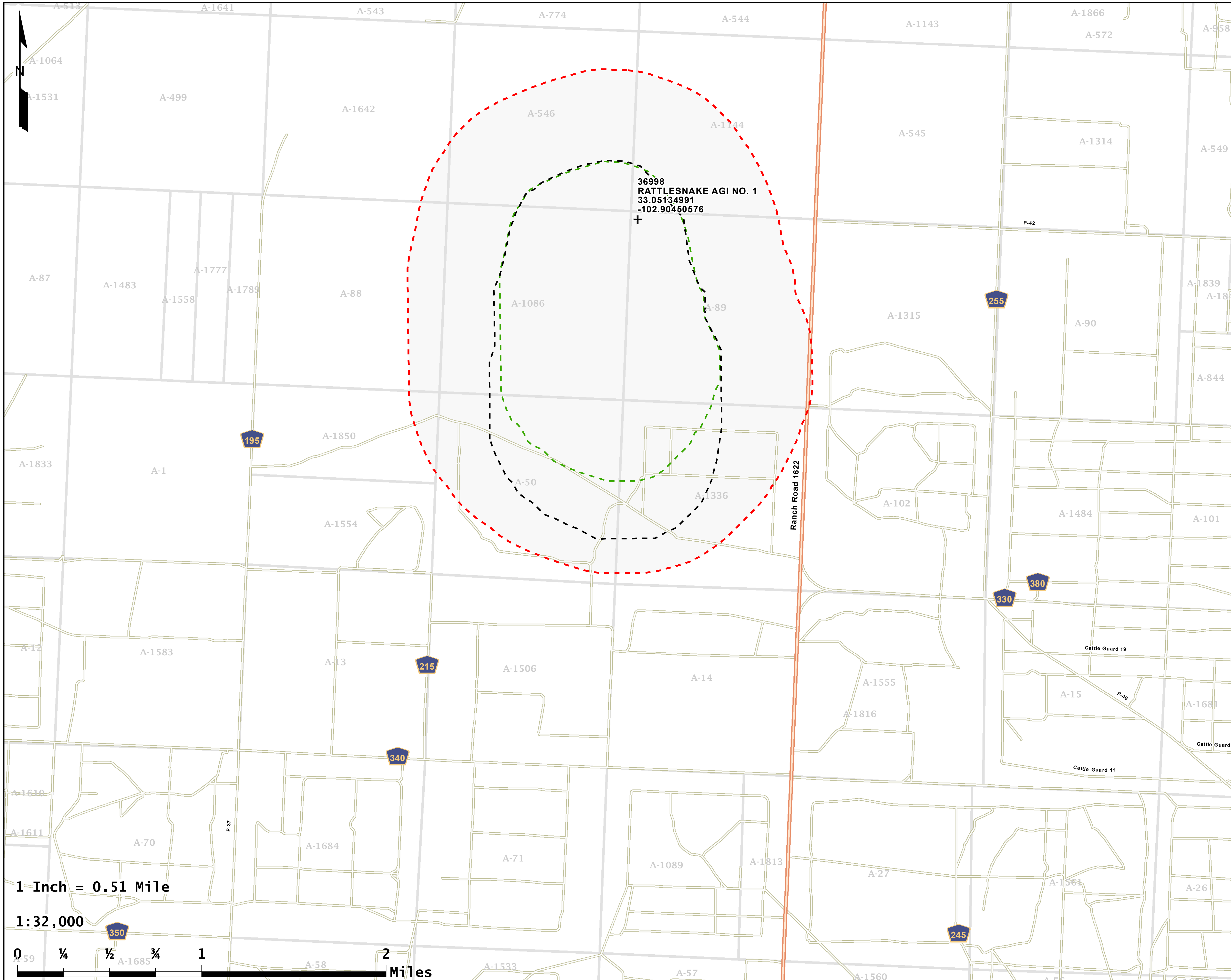
Plume Boundary at End of Injection

Abstract

D-1

* Note: All coordinates shown are in NAD83 (DD). *





Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& 19-Year Plume
with
1/2-Mile Active Monitoring Area (AMA)
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

LONQUIST & CO. LLC
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+ Rattlesnake AGI No. 1 SHL

Active Monitoring Area Boundary

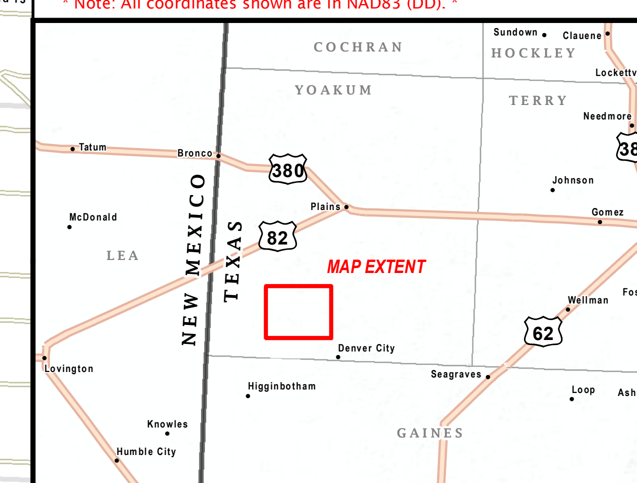
19-Year Plume

Plume Boundary at End of Injection

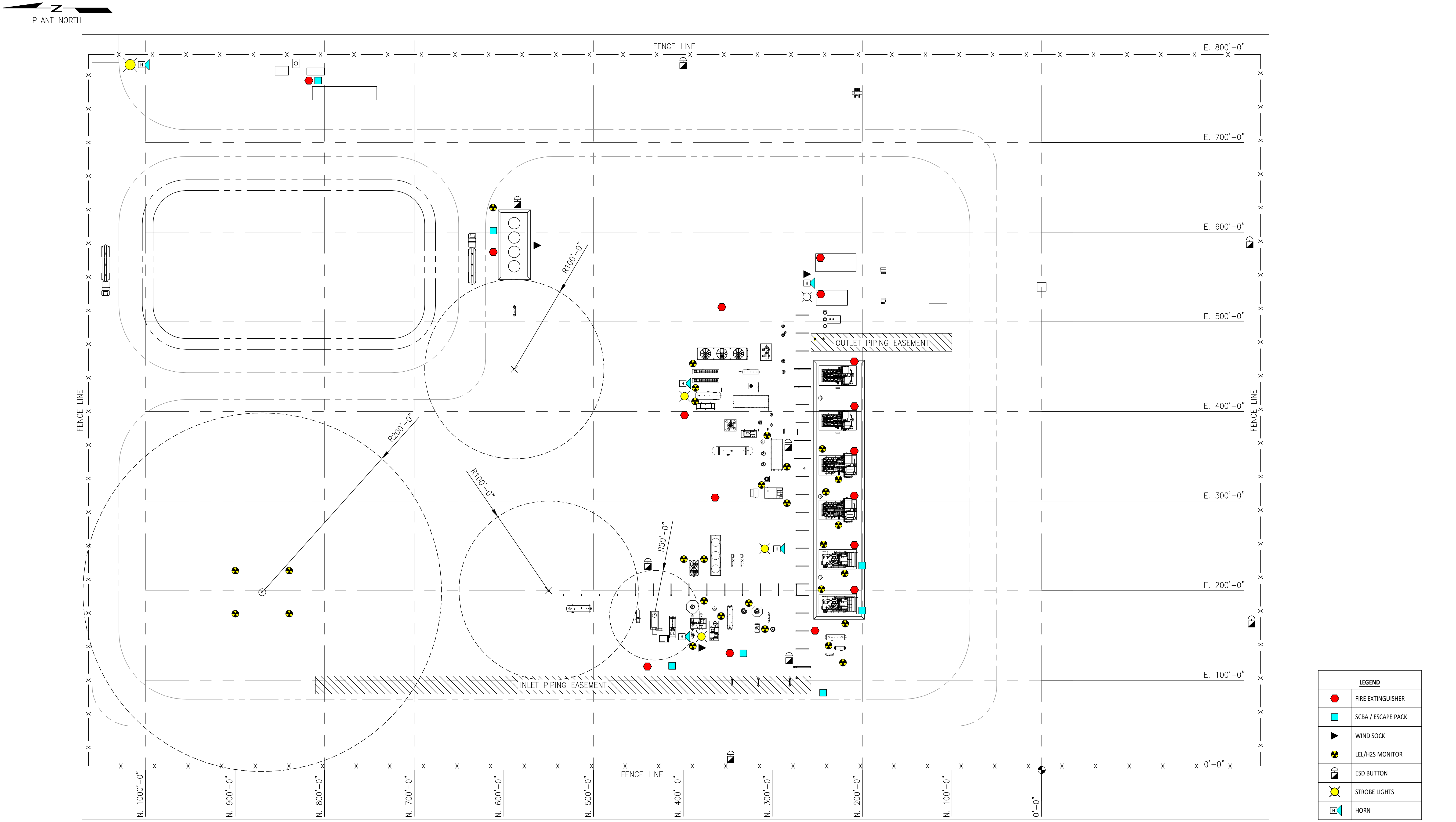
Abstract

D-2

* Note: All coordinates shown are in NAD83 (DD). *



APPENDIX E – FACILITY SAFETY PLOT PLANS



NOTES:

E-1

PRELIMINARY FOR REVIEW

NO.	DATE	REVISION DESCRIPTION	BY	FCE	CLIENT
0	05/11/22	INITIAL RELEASE	KLD	BEC	JB

CHARIS ENGINEERING, LLC
TX ENG. FIRM NO. F-18864
MIDLAND, TX

STAKEHOLDER MIDSTREAM

CLIENT : STAKEHOLDER MIDSTREAM
PROJECT : 30-30 GAS PLANT
TITLE : SAFETY EQUIPMENT PLOT PLAN

DRAWN	CHECKED	SCALE	DATE	JOB NO.	DRAWING NO.
KLD		1" = 50'-0"	5/11/22	SAN180209	ME-PLPN-A000-0004

0

APPENDIX F – MMA/AMA REVIEW MAPS

APPENDIX F-1: PLUME BOUNDARY AT END OF INJECTION, STABILIZED PLUME BOUNDARY AND MAXIMUM MONITORING AREA MAP

APPENDIX F-2: ACTIVE MONITORING AREA MAP

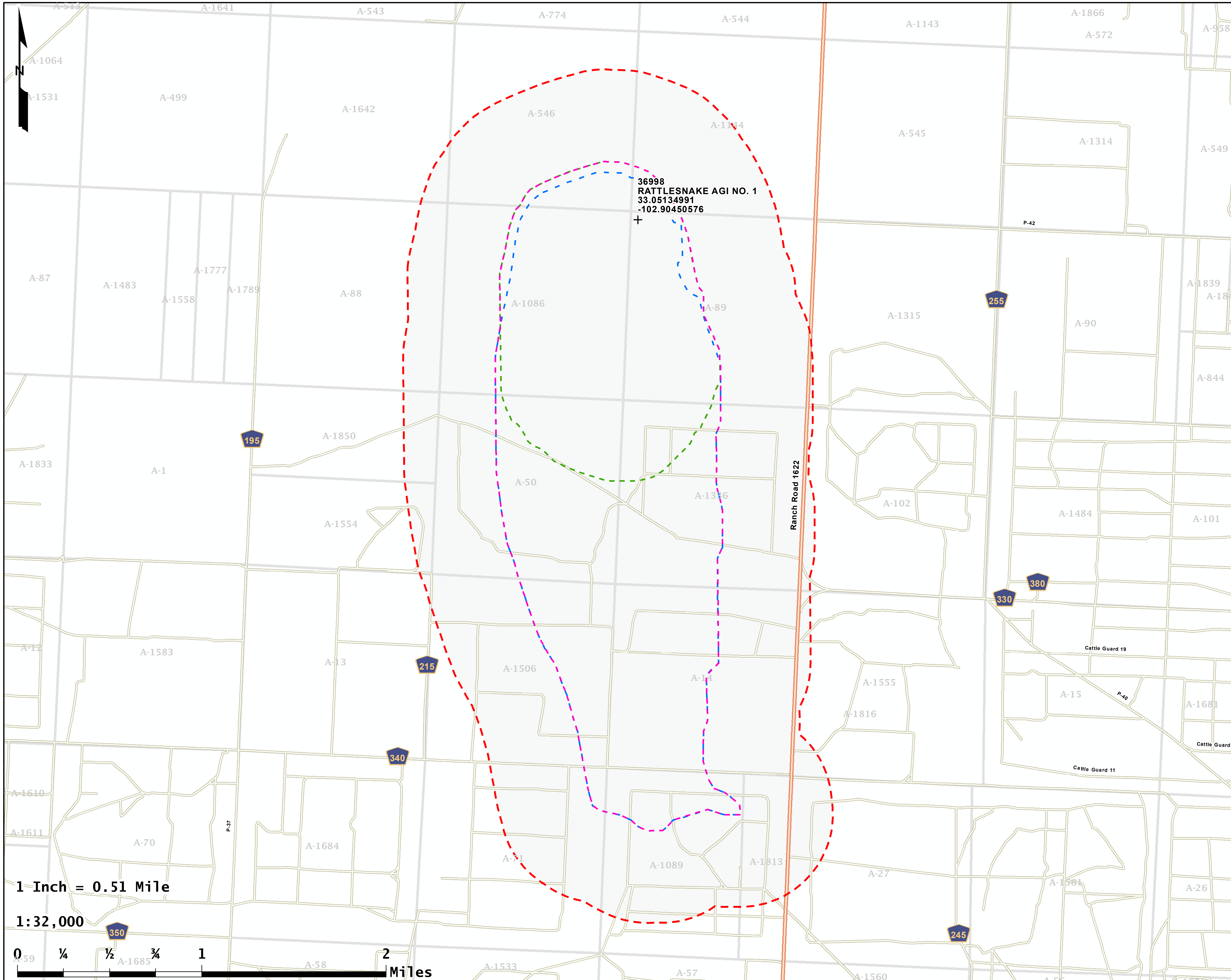
APPENDIX F-3: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX F-4: OIL AND GAS WELLS WITHIN THE MMA LIST

APPENDIX F-5: INJECTION INTERVAL PENETRATING WELLS WITHIN THE MMA MAP

APPENDIX F-6: GROUNDWATER WELLS WITHIN THE MMA

APPENDIX F-7: WELLBORE SCHEMATICS FOR INJECTION INTERVAL PENETRATING WELLS



Rattlesnake AGI No. 1
Plume Boundary at End of Injection & Stabilized Plume with 1/2-Mile Maximum Monitoring Area (MMA)

Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

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F-1

+ Rattlesnake AGI No. 1 SHL

1/2-Mile Buffer from Max. Plume Extent (MMA)

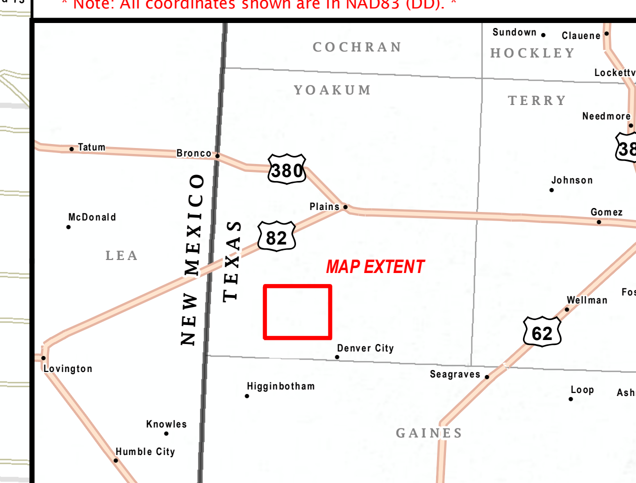
Combined Maximum Plume Extent

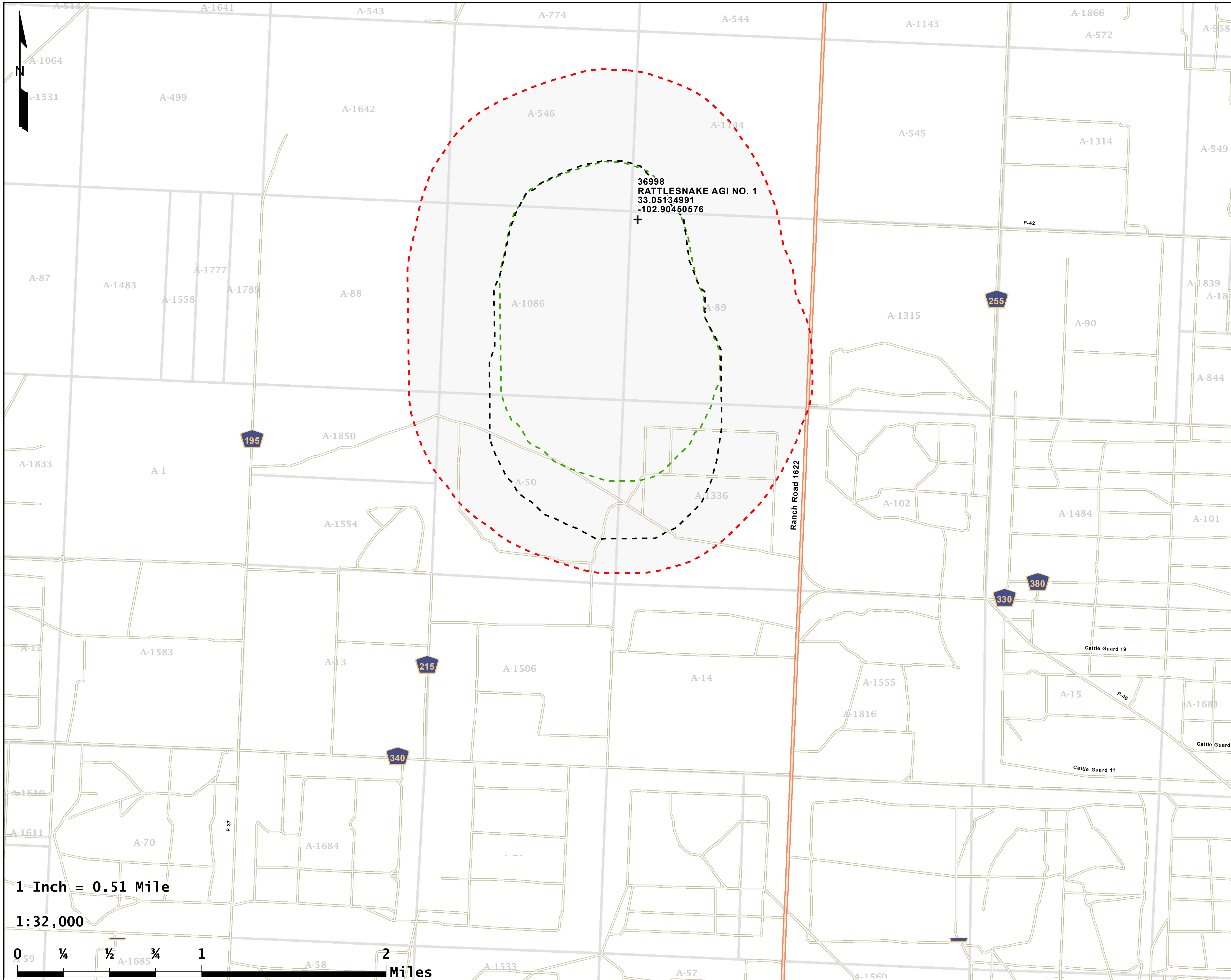
Stabilized Plume

Plume Boundary at End of Injection

Abstract

* Note: All coordinates shown are in NAD83 (DD). *





Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& 19-Year Plume
with
1/2-Mile Active Monitoring Area (AMA)
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

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F-2

+ Rattlesnake AGI No. 1 SHL

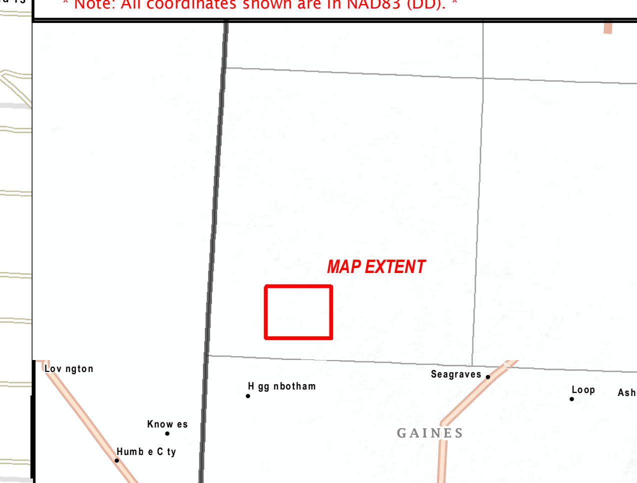
Active Monitoring Area Boundary

19-Year Plume

Plume Boundary at End of Injection

Abstract

* Note: All coordinates shown are in NAD83 (DD). *



Rattlesnake AGI No. 1 Maximum Monitoring Area with 1/2-Mile MMA Oil/Gas Well Area of Review

Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

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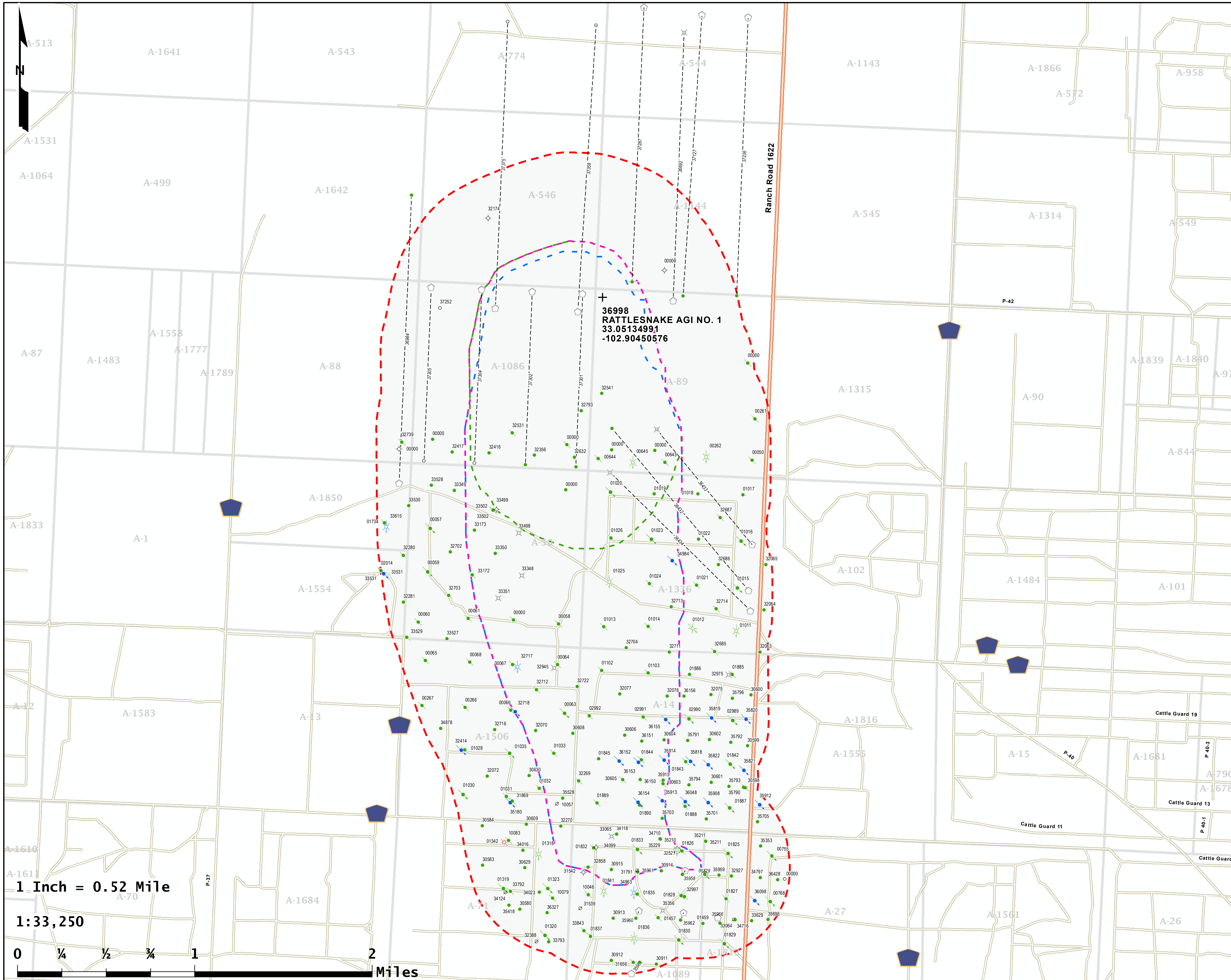
F-3



Rattlesnake AGI No. 1 SHL
1/2-Mile Buffer from Max. Plume Extent (MMA)
Combined Maximum Plume Extent
Stabilized Plume
Plume Boundary at End of Injection
Abstract
Lateral (21)

API (42-501-...) SHL Status - Type (Count)

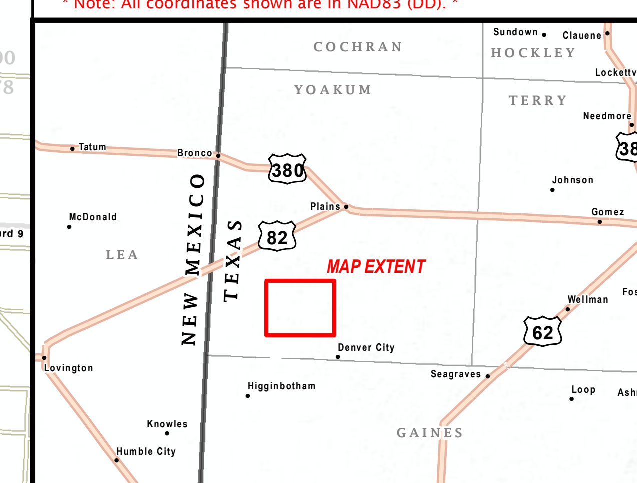
- Horizontal Surface Location (21)
- Active - Oil (93)
- Active - Injection/Disposal (21)
- Active - Injection/Disposal from Oil (22)
- Plugged - Oil (69)
- Plugged - Gas (1)
- Plugged- Injection/Disposal from Oil (1)
- Shut-In - Oil (1)
- TA - Injection/Disposal (3)
- TA - Injection/Disposal from Oil (7)
- Dry Hole (6)
- Permitted Location (2)
- Canceled/Abandoned Location (6)
- Expired Permit (7)

API (42-501-...) BHL Status - Type (Count)

- Active - Oil (11)
- Active - Injection/Disposal from Oil (1)
- Shut-In - Oil (1)
- TA - Injection/Disposal from Oil (1)
- Permitted Location (4)
- Expired Permit (3)

Source:
1.) Oil/Gas Well SHL Data: DI-2022
2.) Oil/Gas Well BHL Data: DI-2022
3.) Oil/Gas Well Directional Data: DI-2022

* Note: All coordinates shown are in NAD83 (DD). *



Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250101829	DENVER UNIT	2215W	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5300	5300	2215W
4250101835	DENVER UNIT	2207	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5185	5185	2207
4250130914	DENVER UNIT	2222	OCCIDENTAL PERMIAN LTD.	Active - Oil			2222
4250101832	DENVER UNIT	2201W	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5190	5190	2201W
4250101826	DENVER UNIT	2203	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5250	5250	2203
4250101319	ROBERTS UNIT	4532W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5200	5200	4532W
4250130629	ROBERTS UNIT	4535	APACHE CORPORATION	Active - Oil	5280	5280	4535
4250130583	ROBERTS UNIT	4525	APACHE CORPORATION	Active - Oil	5286	5286	4525
4250101318	ROBERTS UNIT	4541	APACHE CORPORATION	TA - Injection/Disposal from Oil	5240	5240	4541
4250101889	ROBERTS UNIT	3614	APACHE CORPORATION	Plugged - Oil	5180	5180	3614
4250130598	Roberts Unit	3647	APACHE CORPORATION	Plugged - Oil	5281	5281	3647
4250130603	ROBERTS UNIT	3626	APACHE CORPORATION	Plugged - Oil	5289	5289	3626
4250102992	ROBERTS UNIT	3612W	APACHE CORPORATION	Plugged - Oil	5226	5226	3612W
4250100066	ROBERTS UNIT	3532	APACHE CORPORATION	Plugged - Oil	5231	5231	3532
4250101886	ROBERTS UNIT	3631	APACHE CORPORATION	Plugged - Oil			3631
4250101885	ROBERTS UNIT	3641	APACHE CORPORATION	Plugged - Oil	5212	5212	3641
4250100068	ROBERTS UNIT	3521	APACHE CORPORATION	Plugged - Oil	5225	5225	3521
4250100064	ROBERTS UNIT	3541	APACHE CORPORATION	Plugged - Oil	5264	5264	3541
4250102014	ROBERTS UNIT	2443	APACHE CORPORATION	Plugged - Oil	5226	5226	2443
4250100050	ROBERTS UNIT	1654	APACHE CORPORATION	Plugged - Oil	5198	5198	1654
4250133531	ROBERTS UNIT	2443A		Active - Injection/Disposal	5325	5325	2443A
4250133502	ROBERTS UNIT	2527A		Plugged - Oil	5308	5308	2527A
4250100000	C. A. ELLIOTT	6	AMERICAN LIBERTY OIL CO	Plugged - Oil	5229	5229	6
4250100000	C. A. ELLIOTT	7	AMERICAN LIBERTY AND ATLANTIC	Active - Oil	5182	5182	7
4250100000	GEO CLEVELAND	1	DELFERN OIL CO	Dry Hole	5071	5071	1
4250100000	JAMES H. LYNN	1614	AMERICAN LIBERTY	Active - Oil	5169	5169	1614
4250100000	J. H. LYNN	1634	AMERICAN LIBERTY	Active - Oil	5160	5160	1634
4250100000	A. T. MORRIS	1	ATLANTIC	Active - Oil	5235	5235	1
4250100000	A. T. MORRIS	2	AMERICAN LIBERTY OIL CO	Plugged - Oil	5179	5179	2
4250100000	W. J. CARPENTER	1642	AMERICAN LIBERTY OIL COMPANY	Plugged - Oil	5183	5183	1642
4250100000	E.S. SMITH	1	CREAT WESTERN FROD	Dry Hole	5216	5216	1
4250130607	ROBERTS UNIT	3546		Active - Oil			3546
4250135958	DENVER UNIT	2247	OCCIDENTAL PERMIAN LTD.	Active - Oil	2333	2333	2247
4250131542	DENVER UNIT	2229	SHELL OIL COMPANY	Dry Hole	2409	2409	2229
4250101320	ROBERTS UNIT	4543	APACHE CORPORATION	Active - Injection/Disposal from Oil	5120	5120	4543
4250137301	MILLER	8H	AMTEX ENERGY, INC.	Active - Oil	5157	5157	8H
4250137304	MILLER 732 C	10H	AMTEX ENERGY, INC.	Permitted Location	5157	5157	10H
4250137305	MILLER 732 D	11H	AMTEX ENERGY, INC.	Permitted Location	5157	5157	11H
4250101888	ROBERTS UNIT	3634W	APACHE CORPORATION	Plugged - Oil	5160	5160	3634W

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API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250101031	ROBERTS UNIT	3534W	APACHE CORPORATION	Plugged - Oil	5164	5164	3534W
4250101828	DENVER UNIT	2208	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5170	5170	2208
4250101032	ROBERTS UNIT	3544	APACHE CORPORATION	Plugged - Oil	5170	5170	3544
4250101841	DENVER UNIT	2206	OCCIDENTAL PERMIAN LTD.	TA - Injection/Disposal from Oil	5177	5177	2206
4250101842	ROBERTS UNIT	3643W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5180	5180	3643W
4250101035	ROBERTS UNIT	3533W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5180	5180	3533W
4250132704	ROBERTS UNIT	2615	APACHE CORPORATION	Active - Oil	5180	5180	2615
4250100261	ROBERTS UNIT	1643W	APACHE CORPORATION	Plugged - Oil	5180	5180	1643W
4250101323	ROBERTS UNIT	4542W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5182	5182	4542W
4250102989	ROBERTS UNIT	3642W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5182	5182	3642W
4250102991	ROBERTS UNIT	3622W	APACHE CORPORATION	Plugged - Oil	5185	5185	3622W
4250132417	MILLER	3	AMTEX ENERGY, INC.	Active - Oil	5186	5186	3
4250101025	ROBERTS UNIT	2613W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5188	5188	2613W
4250101887	ROBERTS UNIT	3644	APACHE CORPORATION	Active - Injection/Disposal from Oil	5189	5189	3644
4250101830	DENVER UNIT	2214WC	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5190	5190	2214WC
4250101103	ROBERTS UNIT	3621	APACHE CORPORATION	Plugged - Oil	5190	5190	3621
4250101024	ROBERTS UNIT	2623	APACHE CORPORATION	Plugged - Oil	5190	5190	2623
4250101023	ROBERTS UNIT	2622W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5190	5190	2622W
4250101022	ROBERTS UNIT	2632	APACHE CORPORATION	Active - Oil	5190	5190	2632
4250101019	ROBERTS UNIT	2621	APACHE CORPORATION	Active - Oil	5190	5190	2621
4250101030	ROBERTS UNIT	3524W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5193	5193	3524W
4250101829	DENVER UNIT	2205	OCCIDENTAL PERMIAN LTD.	TA - Injection/Disposal from Oil	5195	5195	2205
4250101836	DENVER UNIT	2213WC	OCCIDENTAL PERMIAN LTD.	TA - Injection/Disposal from Oil	5200	5200	2213WC
4250101833	DENVER UNIT	2202WC	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5200	5200	2202WC
4250134099	DENVER UNIT	2239WC	OCCIDENTAL PERMIAN LTD.	Dry Hole	5200	5200	2239WC
4250132717	ROBERTS UNIT	3531A	APACHE CORPORATION	TA - Injection/Disposal	5200	5200	3531A
4250101014	ROBERTS UNIT	2624W	APACHE CORPORATION	Plugged - Oil	5200	5200	2624W
4250101028	ROBERTS UNIT	3523	APACHE CORPORATION	Plugged - Oil	5205	5205	3523
4250101102	ROBERTS UNIT	3611	APACHE CORPORATION	Plugged - Oil	5206	5206	3611
4250101827	DENVER UNIT	2209W	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5210	5210	2209W
4250101015		2643	TEXACO INCORPORATED	Active - Injection/Disposal from Oil	5210	5210	2643
4250100266	ROBERTS UNIT	3522W	APACHE CORPORATION	Plugged - Oil	5211	5211	3522W
4250132632	MILLER	5	AMTEX ENERGY, INC.	Active - Oil	5213	5213	5
4250100057	ROBERTS UNIT	2512W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5213	5213	2512W
4250101890	ROBERTS UNIT	3624W	APACHE CORPORATION	Plugged - Oil	5214	5214	3624W
4250101033	ROBERTS UNIT	3543W	APACHE CORPORATION	Plugged - Oil	5215	5215	3543W
4250101012	ROBERTS UNIT	2634W	APACHE CORPORATION	Plugged- Injection/Disposal from Oil	5215	5215	2634W
4250101734	ROBERTS UNIT	2442	APACHE CORPORATION	Plugged - Oil	5215	5215	2442
4250101020	ROBERTS UNIT	2611W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5215	5215	2611W

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API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250100067	ROBERTS UNIT	3531	APACHE CORPORATION	Plugged - Oil	5216	5216	3531
4250101013	ROBERTS UNIT	2614W	APACHE CORPORATION	Plugged - Oil	5216	5216	2614W
4250101844	ROBERTS UNIT	3623W	APACHE CORPORATION	Plugged - Oil	5217	5217	3623W
4250131869	ROBERTS UNIT	A3534W	APACHE CORPORATION	Plugged - Oil	5220	5220	A3534W
4250102990	ROBERTS UNIT	3632W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5220	5220	3632W
4250100262	ROBERTS UNIT	1644W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5220	5220	1644W
4250132858	DENVER UNIT	2235	OCCIDENTAL PERMIAN LTD.	Shut-In - Oil	5225	5225	2235
4250100058	ROBERTS UNIT	2544W	APACHE CORPORATION	Plugged - Oil	5225	5225	2544W
4250130584	ROBERTS UNIT	4520	APACHE CORPORATION	Active - Oil	5230	5230	4520
4250130630	ROBERTS UNIT	3535	APACHE CORPORATION	Active - Oil	5230	5230	3535
4250100063	ROBERTS UNIT	3542W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5230	5230	3542W
4250132076	ROBERTS UNIT	3627	APACHE CORPORATION	Active - Oil	5230	5230	3627
4250100267	ROBERTS UNIT	3512W	APACHE CORPORATION	Plugged - Oil	5233	5233	3512W
4250101016	ROBERTS UNIT	2642W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5234	5234	2642W
4250134716	DENVER UNIT	2242	OCCIDENTAL PERMIAN LTD.	Active - Oil	5236	5236	2242
4250100061	ROBERTS UNIT	2524W	APACHE CORPORATION	Plugged - Oil	5238	5238	2524W
4250101021	ROBERTS UNIT	2633	APACHE CORPORATION	Plugged - Oil	5240	5240	2633
4250101011	ROBERTS UNIT	2644W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5241	5241	2644W
4250132541	FUTCH	1	AMTEX ENERGY, INC.	Active - Oil	5244	5244	1
4250101026	ROBERTS UNIT	2612W	APACHE CORPORATION	Plugged - Oil	5245	5245	2612W
4250100059	ROBERTS UNIT	2513W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5246	5246	2513W
4250132531	MILLER	4	AMTEX ENERGY, INC.	Plugged - Oil	5248	5248	4
4250132687	ROBERTS UNIT	2635	APACHE CORPORATION	Plugged - Oil	5248	5248	2635
4250131656	DENVER UNIT	2232WC	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5250	5250	2232WC
4250131791	DENVER UNIT	2231	SHELL OIL COMPANY	Canceled/Abandoned Location	5250	5250	2231
4250134118	DENVER UNIT	2238	OCCIDENTAL PERMIAN LTD.	Active - Oil	5250	5250	2238
4250101342	ROBERTS UNIT		APACHE CORPORATION	Plugged - Gas	5250	5250	
4250132269	ROBERTS UNIT	3601	APACHE CORPORATION	Plugged - Oil	5250	5250	3601
4250101843	ROBERTS UNIT	3633W	APACHE CORPORATION	Plugged - Oil	5250	5250	3633W
4250130608	ROBERTS UNIT	3545	APACHE CORPORATION	Active - Oil	5250	5250	3545
4250132077	ROBERTS UNIT	3617	APACHE CORPORATION	Active - Oil	5250	5250	3617
4250134963	DENVER UNIT	2244WC	OCCIDENTAL PERMIAN LTD.	TA- Injection/Disposal	5251	5251	2244WC
4250100060	ROBERTS UNIT	2514	APACHE CORPORATION	Plugged - Oil	5251	5251	2514
4250101459	DENVER UNIT	2211	OCCIDENTAL PERMIAN LTD.	Active - Oil	5252	5252	2211
4250132521	DENVER UNIT	2233W	OCCIDENTAL PERMIAN LTD.	TA- Injection/Disposal from Oil	5253	5253	2233W
4250135211	DENVER UNIT	2241	OCCIDENTAL PERMIAN LTD.	Active - Oil	5253	5253	2241
4250101837	DENVER UNIT	2212W	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5255	5255	2212W
4250132793	MILLER	6	AMTEX ENERGY, INC.	Active - Oil	5258	5258	6
4250132356	MILLER	1	AMTEX ENERGY, INC.	Active - Oil	5260	5260	1

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API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250101017	ROBERTS UNIT	2641	APACHE CORPORATION	Active - Oil	5260	5260	2641
4250101825	DENVER UNIT	2204W	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5264	5264	2204W
4250132416	MILLER	2	AMTEX ENERGY, INC.	Active - Oil	5269	5269	2
4250100065	ROBERTS UNIT	3511W	APACHE CORPORATION	Plugged - Oil	5270	5270	3511W
4250101018	ROBERTS UNIT	2631	APACHE CORPORATION	Active - Oil	5270	5270	2631
4250130600	ROBERTS UNIT	3645	APACHE CORPORATION	Active - Oil	5273	5273	3645
4250130580	ROBERTS UNIT	4536	APACHE CORPORATION	Active - Oil	5279	5279	4536
4250130599	ROBERTS UNIT	3646	APACHE CORPORATION	Active - Oil	5279	5279	3646
4250130602	ROBERTS UNIT	3635	APACHE CORPORATION	Active - Oil	5283	5283	3635
4250132997	DENVER UNIT	2208WC	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5284	5284	2208WC
4250130601	ROBERTS UNIT	3636	APACHE CORPORATION	Active - Oil	5286	5286	3636
4250132174	SHEPHERD	1	YOUNG, MARSHALL R., OIL CO.	Dry Hole	5286	5286	1
4250130604	ROBERTS UNIT	3625	APACHE CORPORATION	Active - Oil	5287	5287	3625
4250130912	DENVER UNIT	2224	OCCIDENTAL PERMIAN LTD.	Active - Oil	5288	5288	2224
4250130911	DENVER UNIT	2225	OCCIDENTAL PERMIAN LTD.	Active - Oil	5290	5290	2225
4250130609	ROBERTS UNIT	4530	APACHE CORPORATION	Active - Oil	5291	5291	4530
4250130605	ROBERTS UNIT	3616	APACHE CORPORATION	Plugged - Oil	5291	5291	3616
4250130606	ROBERTS UNIT	3615	APACHE CORPORATION	Active - Oil	5293	5293	3615
4250133172	ROBERTS UNIT	2523	CONOCOPHILLIPS COMPANY	Plugged - Oil	5295	5295	2523
4250132739	CLEVELAND	1	HIGHLAND PRODUCTION COMPANY	Plugged - Oil	5300	5300	1
4250133064	DENVER UNIT	2238	SHELL WESTERN E&P INC.	Canceled/Abandoned Location	5300	5300	2238
4250132927	DENVER UNIT	2236	OCCIDENTAL PERMIAN LTD.	Active - Oil	5300	5300	2236
4250133065	DENVER UNIT	2237	SHELL WESTERN E&P INC.	Expired Permit	5300	5300	2237
4250132270	ROBERTS UNIT	4540	APACHE CORPORATION	Active - Oil	5300	5300	4540
4250132414	ROBERTS UNIT	3523A	APACHE CORPORATION	Active - Injection/Disposal	5300	5300	3523A
4250132712	ROBERTS UNIT	3537	APACHE CORPORATION	Plugged - Oil	5300	5300	3537
4250132722	ROBERTS UNIT	3547	APACHE CORPORATION	Active - Oil	5300	5300	3547
4250132945	ROBERTS UNIT	3541A	TEXACO PRODUCING INC.	Expired Permit	5300	5300	3541A
4250132975	ROBERTS UNIT	3641A	TEXACO PRODUCING INC.	Expired Permit	5300	5300	3641A
4250132711	ROBERTS UNIT	3620	APACHE CORPORATION	Active - Oil	5300	5300	3620
4250133527	ROBERTS UNIT	2518	APACHE CORPORATION	Active - Oil	5300	5300	2518
4250132714	ROBERTS UNIT	2637	APACHE CORPORATION	Plugged - Oil	5300	5300	2637
4250133351	ROBERTS UNIT	2526	TEXACO PRODUCING INC.	Expired Permit	5300	5300	2526
4250132703	ROBERTS UNIT	2516	APACHE CORPORATION	Plugged - Oil	5300	5300	2516
4250133348	ROBERTS UNIT	2533	TEXACO PRODUCING INC.	Expired Permit	5300	5300	2533
4250132702	ROBERTS UNIT	2515	APACHE CORPORATION	Active - Oil	5300	5300	2515
4250133350	ROBERTS UNIT	2525	APACHE CORPORATION	Active - Oil	5300	5300	2525
4250133498	ROBERTS UNIT	2532	TEXACO PRODUCING INC.	Expired Permit	5300	5300	2532
4250133173	ROBERTS UNIT	2522	APACHE CORPORATION	Active - Oil	5300	5300	2522

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API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250133499	ROBERTS UNIT	2527	TEXACO PRODUCING INC.	Dry Hole	5300	5300	2527
4250133530	ROBERTS UNIT	2507	APACHE CORPORATION	Active - Oil	5300	5300	2507
4250132685	ROBERTS UNIT	2638	APACHE CORPORATION	Plugged - Oil	5302	5302	2638
4250133349	ROBERTS UNIT	2517	APACHE CORPORATION	Active - Oil	5302	5302	2517
4250132718	ROBERTS UNIT	3532A	APACHE CORPORATION	Active - Injection/Disposal	5304	5304	3532A
4250132713	ROBERTS UNIT	2625	APACHE CORPORATION	Active - Oil	5308	5308	2625
4250133502	ROBERTS UNIT	2527A	APACHE CORPORATION	Plugged - Oil	5308	5308	2527A
4250132716	ROBERTS UNIT	3526	APACHE CORPORATION	Active - Oil	5309	5309	3526
4250100645	ROBERTS UNIT	1624W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5309	5309	1624W
4250130913	DENVER UNIT	2223	OCCIDENTAL PERMIAN LTD.	Active - Oil	5310	5310	2223
4250132686	ROBERTS UNIT	2636	APACHE CORPORATION	Active - Oil	5310	5310	2636
4250101457	DENVER UNIT	2210	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5325	5325	2210
4250133529	ROBERTS UNIT	2508	APACHE CORPORATION	Plugged - Oil	5325	5325	2508
4250133531	ROBERTS UNIT	2443A	APACHE CORPORATION	Active - Injection/Disposal	5325	5325	2443A
4250133528	ROBERTS UNIT	2511	APACHE CORPORATION	Active - Oil	5325	5325	2511
4250135912	ROBERTS UNIT	3771W	APACHE CORPORATION	Active - Injection/Disposal	5330	5330	3771W
4250132075	ROBERTS UNIT	3637	APACHE CORPORATION	Active - Oil	5330	5330	3637
4250132063	ROBERTS UNIT	2705	APACHE CORPORATION	Active - Oil	5330	5330	2705
4250135793	ROBERTS UNIT	3672	APACHE CORPORATION	Active - Oil	5334	5334	3672
4250135819	ROBERTS UNIT	3674W	APACHE CORPORATION	Active - Injection/Disposal	5336	5336	3674W
4250135792	ROBERTS UNIT	3671	APACHE CORPORATION	Active - Oil	5339	5339	3671
4250135820	ROBERTS UNIT	3675W	APACHE CORPORATION	Active - Injection/Disposal	5341	5341	3675W
4250135818	ROBERTS UNIT	3633RW	APACHE CORPORATION	Active - Injection/Disposal	5344	5344	3633RW
4250135790	ROBERTS UNIT	3647R	APACHE CORPORATION	Active - Oil	5345	5345	3647R
4250100768	CORNELL UNIT	3107W	XTO ENERGY INC.	Active - Injection/Disposal from Oil	5350	5350	3107W
4250130915	DENVER UNIT	2221	OCCIDENTAL PERMIAN LTD.	Active - Oil	5350	5350	2221
4250136048	ROBERTS UNIT	3634RW	APACHE CORPORATION	Active - Injection/Disposal	5350	5350	3634RW
4250135908	ROBERTS UNIT	3678W	APACHE CORPORATION	Active - Injection/Disposal	5350	5350	3678W
4250132072	ROBERTS UNIT	3525	APACHE CORPORATION	Active - Oil	5350	5350	3525
4250135915	ROBERTS UNIT	3626R	APACHE CORPORATION	Active - Oil	5350	5350	3626R
4250132281	ROBERTS UNIT	2446	APACHE CORPORATION	Active - Oil	5350	5350	2446
4250132064	ROBERTS UNIT	2704	APACHE CORPORATION	Active - Oil	5350	5350	2704
4250132280	ROBERTS UNIT	2445	APACHE CORPORATION	Plugged - Oil	5350	5350	2445
4250135791	ROBERTS UNIT	3670	APACHE CORPORATION	Active - Oil	5351	5351	3670
4250135794	ROBERTS UNIT	3673	APACHE CORPORATION	Active - Oil	5352	5352	3673
4250135821	ROBERTS UNIT	3676W	APACHE CORPORATION	Active - Injection/Disposal	5352	5352	3676W
4250135914	ROBERTS UNIT	3681W	APACHE CORPORATION	Active - Injection/Disposal	5352	5352	3681W
4250100643	ROBERTS UNIT	1634W	APACHE CORPORATION	Plugged - Oil	5353	5353	1634W
4250135796	ROBERTS UNIT	3669	APACHE CORPORATION	Active - Oil	5356	5356	3669

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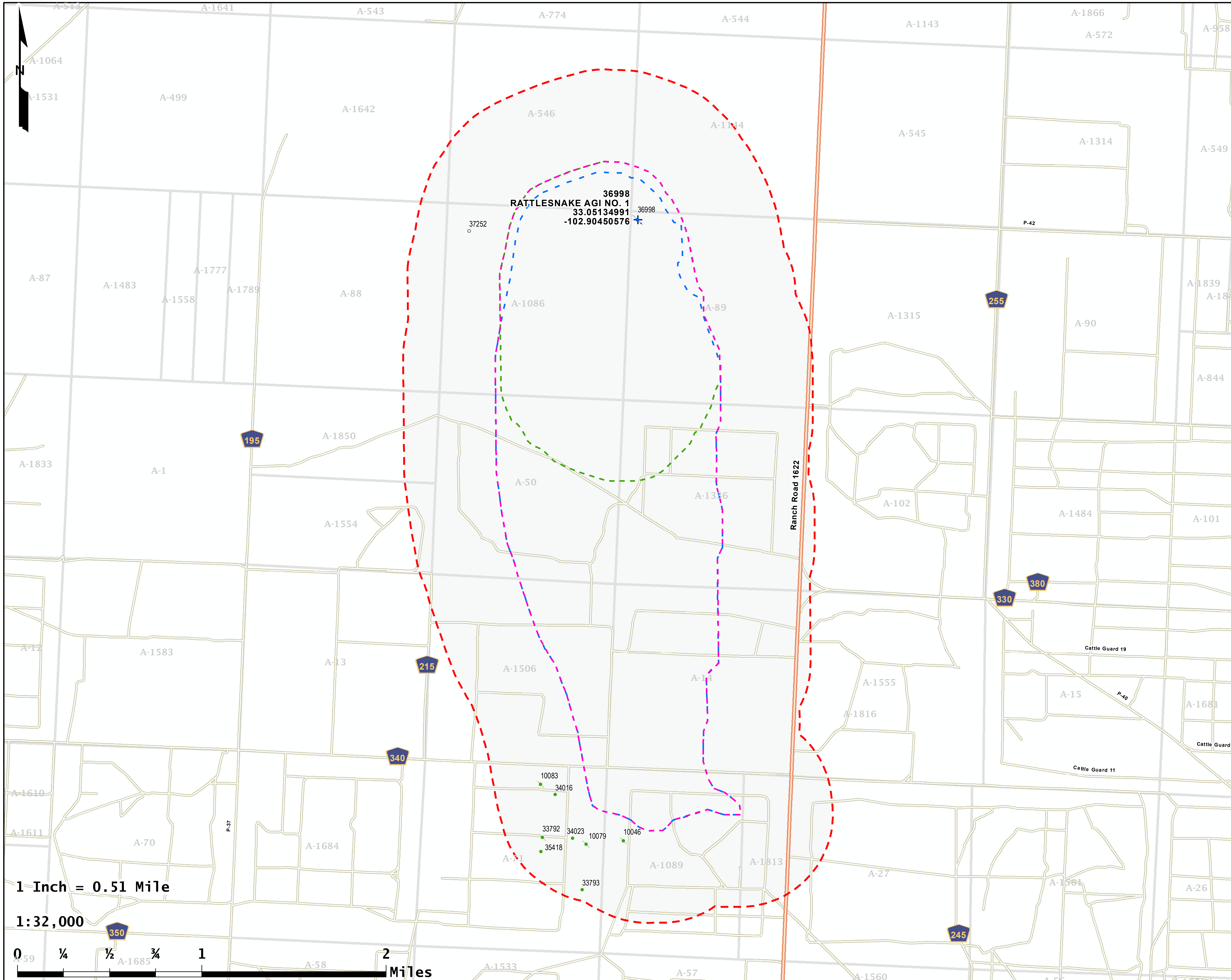
API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250100644	ROBERTS UNIT	1614	APACHE CORPORATION	Plugged - Oil	5356	5356	1614
4250135913	ROBERTS UNIT	3680W	APACHE CORPORATION	Active - Injection/Disposal	5357	5357	3680W
4250135705	ROBERTS UNIT	3752	APACHE CORPORATION	Active - Oil	5360	5360	3752
4250135822	ROBERTS UNIT	3677W	APACHE CORPORATION	Active - Injection/Disposal	5362	5362	3677W
4250134984	ROBERTS UNIT	2626W	APACHE CORPORATION	Active - Injection/Disposal	5364	5364	2626W
4250135701	ROBERTS UNIT	3667	APACHE CORPORATION	Active - Oil	5365	5365	3667
4250132070	ROBERTS UNIT	3536	APACHE CORPORATION	Active - Oil	5370	5370	3536
4250132065	ROBERTS UNIT	2703	APACHE CORPORATION	Active - Oil	5370	5370	2703
4250100755	CORNELL UNIT	3101W	XTO ENERGY INC.	Active - Injection/Disposal from Oil	5373	5373	3101W
4250135703	ROBERTS UNIT	3668	APACHE CORPORATION	Active - Oil	5380	5380	3668
4250135229	DENVER UNIT	2240	OCCIDENTAL PERMIAN LTD.	Active - Oil	5388	5388	2240
4250136152	ROBERTS UNIT	3682W	APACHE CORPORATION	Active - Injection/Disposal	5397	5397	3682W
4250131539	DENVER UNIT	2230	SHELL OIL COMPANY	Canceled/Abandoned Location	5400	5400	2230
4250136327	ROBERTS UNIT	4547	APACHE CORPORATION	Active - Oil	5400	5400	4547
4250136154	ROBERTS UNIT	3624RW	APACHE CORPORATION	Active - Injection/Disposal	5400	5400	3624RW
4250136155	ROBERTS UNIT	3683W	APACHE CORPORATION	Active - Injection/Disposal	5402	5402	3683W
4250136156	ROBERTS UNIT	3686	APACHE CORPORATION	Active - Oil	5404	5404	3686
4250134797	CORNELL UNIT	3194	XTO ENERGY INC.	Active - Oil	5405	5405	3194
4250135696	CORNELL UNIT	113	XTO ENERGY INC.	Active - Oil	5406	5406	113
4250136150	ROBERTS UNIT	3684	APACHE CORPORATION	Active - Oil	5421	5421	3684
4250133629	CORNELL UNIT	3156	XTO ENERGY INC.	Active - Oil	5425	5425	3156
4250135961	DENVER UNIT	2246	OCCIDENTAL PERMIAN LTD.	Active - Oil	5425	5425	2246
4250135960	DENVER UNIT	2249	OCCIDENTAL PERMIAN LTD.	Active - Oil	5431	5431	2249
4250136153	ROBERTS UNIT	3623RW	APACHE CORPORATION	Active - Injection/Disposal	5439	5439	3623RW
4250135353	CORNELL UNIT	107	XTO ENERGY INC.	Active - Oil	5450	5450	107
4250135528	ROBERTS UNIT	3549	APACHE CORPORATION	Active - Oil	5452	5452	3549
4250136151	ROBERTS UNIT	3685	APACHE CORPORATION	Active - Oil	5463	5463	3685
4250135963	DENVER UNIT	2252	OCCIDENTAL PERMIAN LTD.	Active - Oil	5476	5476	2252
4250136434	ROBERTS UNIT	263H	APACHE CORPORATION	Expired Permit	5500	5500	263H
4250136433	ROBERTS UNIT	262H	APACHE CORPORATION	Expired Permit	5500	5500	262H
4250136098	CORNELL UNIT	110	XTO ENERGY INC.	Active - Injection/Disposal	5510	5510	110
4250133615	ROBERTS UNIT	2442A	APACHE CORPORATION	TA - Injection/Disposal	5516	5516	2442A
4250135180	ROBERTS UNIT	3534B	APACHE CORPORATION	Active - Injection/Disposal	5517	5517	3534B
4250136428	CORNELL UNIT	124	XTO ENERGY INC.	Active - Oil	5532	5532	124
4250134878	ROBERTS UNIT	3548	APACHE CORPORATION	Active - Oil	5550	5550	3548
4250135966	DENVER UNIT	2251	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2251
4250135962	DENVER UNIT	2250	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2250
4250135356	DENVER UNIT	2246	OCCIDENTAL PERMIAN LTD.	Expired Permit	5600	5600	2246
4250135959	DENVER UNIT	2248	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2248

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250135210	DENVER UNIT	2240	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2240
4250135211		2241	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2241
4250134710		2240	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2240
4250101845	ROBERTS UNIT	3613	APACHE CORPORATION	Active - Oil	7000	7000	3613
4250110083	RANDALL, E.	36	EXXON CORP.	Plugged - Oil	8595	8595	36
4250110046	ELLIOTT, C.A.	2	MCCLURE OIL COMPANY, INC.	Plugged - Oil	9000	9000	2
4250136692	MISS KITTY 704-669	3XH	RILEY EXPLORATION OPG CO, LLC	Expired Permit	9000	9000	3XH
4250133793	RANDALL, E.	39	XTO ENERGY INC.	Active - Oil	9000	9000	39
4250137375	RIP WHEELER 705-668	5XH	RILEY PERMIAN OPERATING CO, LLC	Permitted Location	9000	9000	5XH
4250137358	RIP WHEELER 705-668	1XH	RILEY PERMIAN OPERATING CO, LLC	Permitted Location	9000	9000	1XH
4250133843	ELLIOTT	1	DELTA C02, LLC	Plugged - Oil	9050	9050	1
4250134124	RANDALL, E	46	EXXON CORP.	Canceled/Abandoned Location	9100	9100	46
4250133792	RANDALL, E.	40	XTO ENERGY INC.	Plugged - Oil	9591	9591	40
4250110079	RANDALL, E.	32	EXXON CORP.	Plugged - Oil	9615	9615	32
4250135418	RANDALL, E.	46	XTO ENERGY INC.	Active - Oil	9650	9650	46
4250134023	RANDALL, E.	42	XTO ENERGY INC.	Active - Oil	9660	9660	42
4250134016	RANDALL, E.	43	XTO ENERGY INC.	Active - Oil	9740	9740	43
4250132388	RANDALL, E.	38	EXXON CORP.	Canceled/Abandoned Location	10300	10300	38
4250137302	MILLER 732 B	9H	AMTEX ENERGY, INC.	Active - Oil	5183	10662	9H
4250136432	ROBERTS UNIT	261 H	APACHE CORPORATION	Active - Oil	5151	11117	261 H
4250136998	RATTLESNAKE AGI	1	SANTA FE MIDSTREAM PERMIAN LLC	Active - Injection/Disposal	11980	11980	1
4250137252	MILLER SWD	7	AMTEX ENERGY, INC.	Permitted Location	13000	13000	7
4250136984	MADCAP 731-706	1XH	RILEY PERMIAN OPERATING CO, LLC	Active - Oil	5261	13274	1XH
4250137127	MISS KITTY A 669-704	25XH	RILEY PERMIAN OPERATING CO, LLC	Active - Oil	5321	13428	25XH
4250137287	MISS KITTY A 669-704	4XH	RILEY PERMIAN OPERATING CO, LLC	Shut-In - Oil	5340	13452	4XH
4250137236	MISS KITTY 669-704	2XH	RILEY PERMIAN OPERATING CO, LLC	Active - Oil	5317	13622	2XH



Rattlesnake AGI No. 1
Maximum Monitoring Area
with
1/2-Mile MMA Oil/Gas Well Penetrators
Area of Review
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 6/1/2022	Approved by: RH

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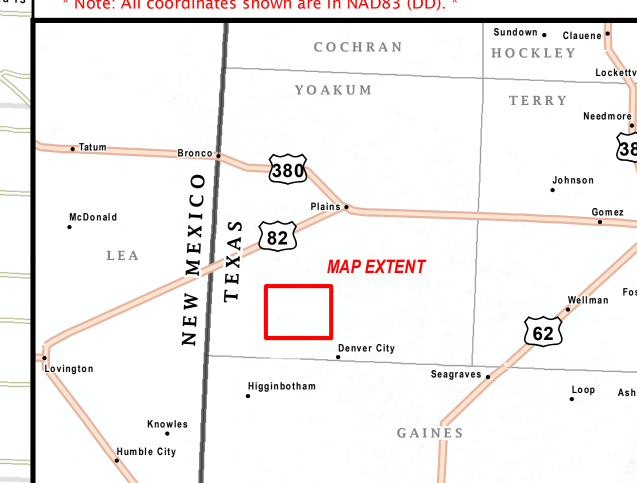
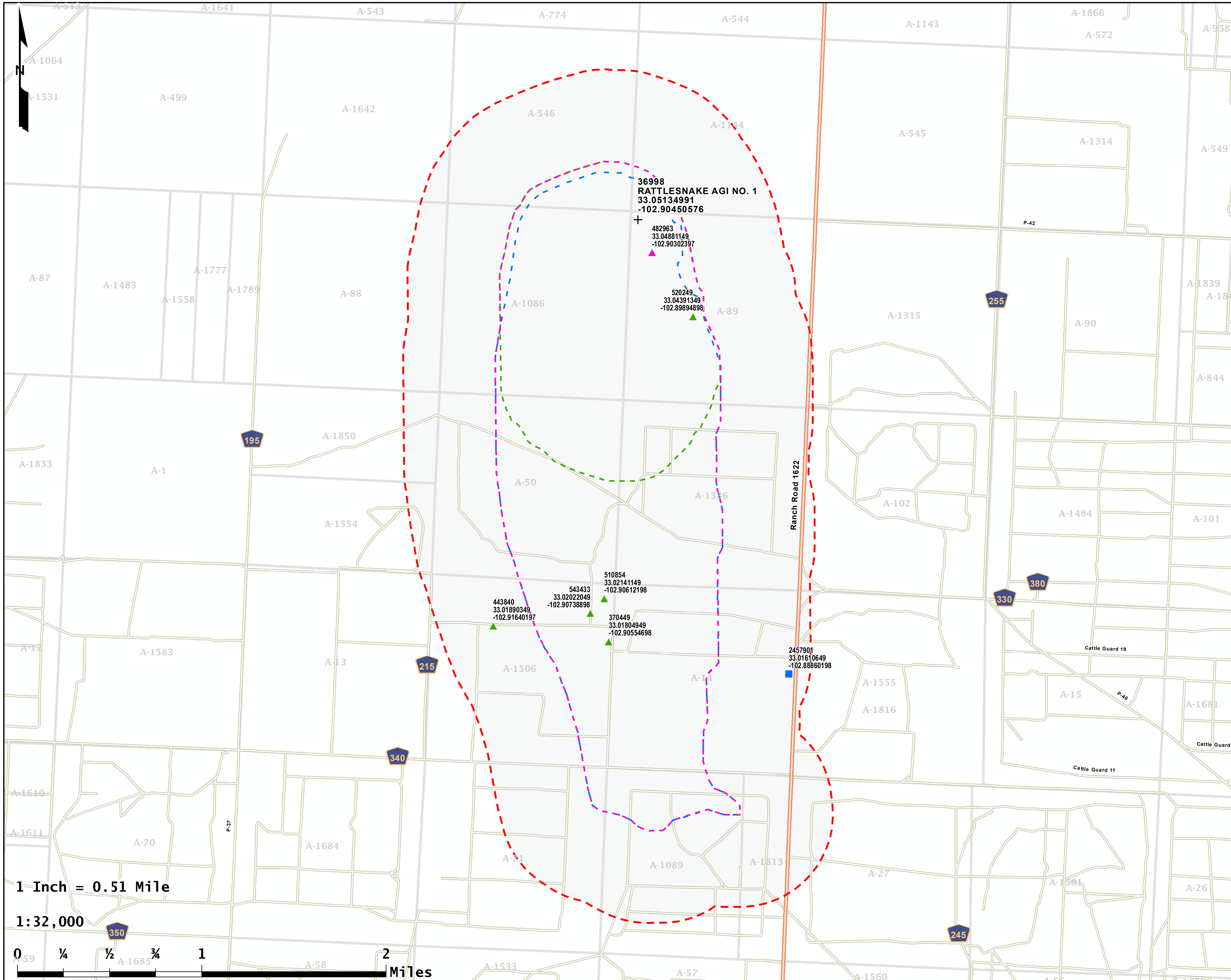
+ Rattlesnake AGI No. 1 SHL
1/2-Mile Buffer from Max. Plume Extent (MMA)
Combined Maximum Plume Extent
Stabilized Plume
Plume Boundary at End of Injection
Abstract

API (42-501-...) SHL Status - Type (Count)
Active - Oil (4)
Active - Injection/Disposal (1)
Plugged - Oil (4)
Permitted Location (1)

Source:
1.) Oil/Gas Well SHL Data: DI-2022
2.) Oil/Gas Well BHL Data: DI-2022
3.) Oil/Gas Well Directional Data: DI-2022
* Note: All coordinates shown are in NAD83 (DD). *





Rattlesnake AGI No. 1 Maximum Monitoring Area with 1/2-Mile MMA Groundwater Well Area of Review

Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

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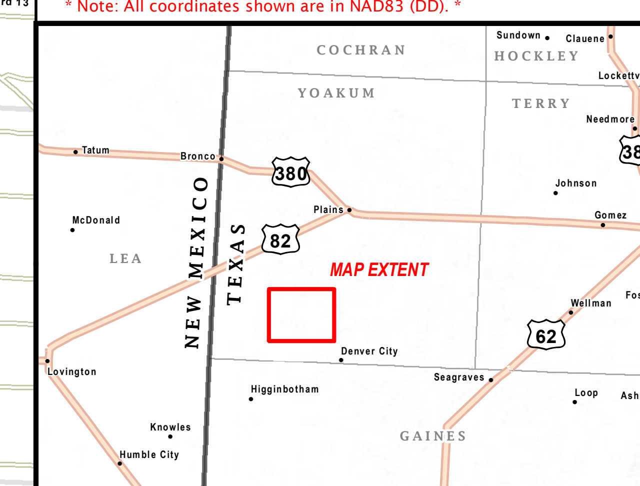
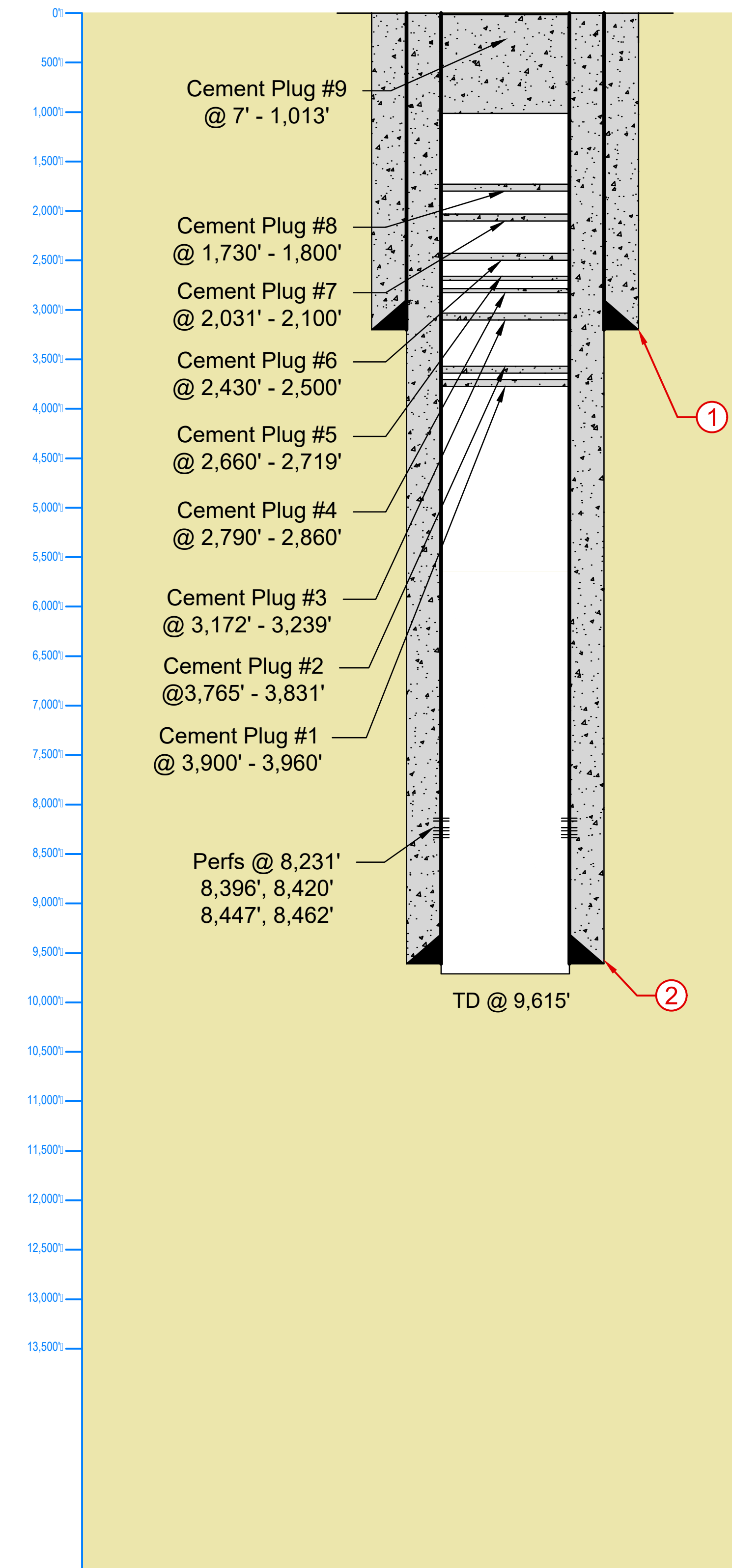
- Rattlesnake AGI No. 1 SHL
- 1/2-Mile Buffer from Max. Plume Extent (MMA)
- Combined Maximum Plume Extent
- Stabilized Plume
- Plume Boundary at End of Injection
- Abstract

SDRDB Groundwater Wells [TWDB-2022]
Proposed Use (Labeled with Well Report No.)
- Industrial (1)
- Irrigation (5)

TWDB Groundwater Wells [TWDB-2022]
Well Type (Labeled with State Well No.)
- Withdrawal of Water (1)

Source:
1.) SDRDB Groundwater Well SHL Data: TWDB-2022
2.) TWDB Groundwater Well SHL Data: TWDB-2022
3.) Brackish Groundwater Well SHL Data: TWDB-2022
* Note: All coordinates shown are in NAD83 (DD). *





Casing Information

Label	1	2
Type	Surface	Production
OD	8-5/8"	4-1/2"
Depth Set	2,134'	9,601'

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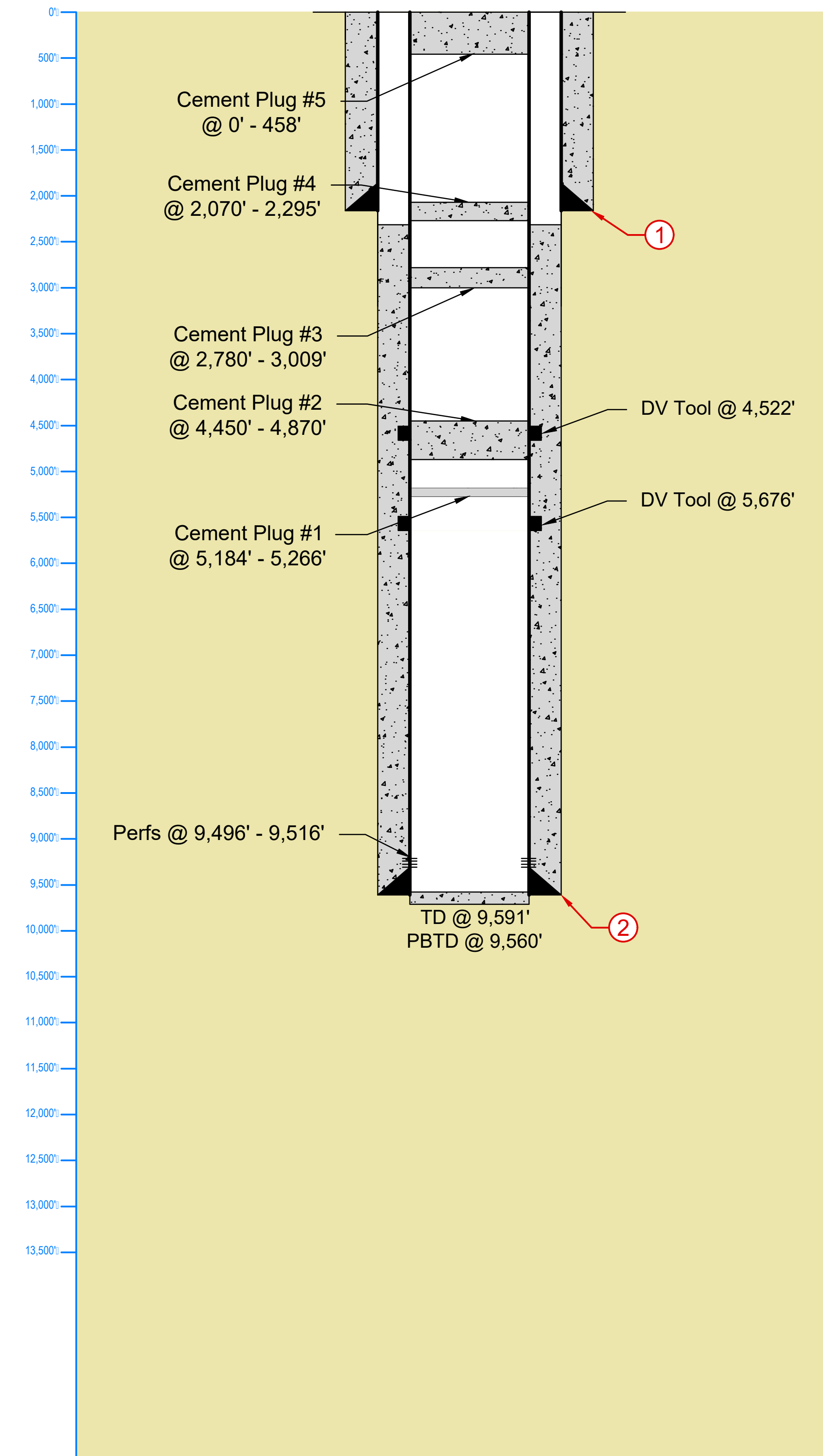
Exxon Corp.

E. Randall No. 32

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 05/10/1965	**Survey:** John H. Gipson
API No: 42-501-10079	**Field:** Wasson (Wichita Albany)	**RRC Lease Number:** 18231
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP

Notes:



Casing Information

Label	1	3
Type	Surface	Production
OD	9-5/8"	5-1/2"
Weight	36 lb/ft	UNK
Depth Set	2,162'	9,569'
Hole Size	12-1/4"	7-7/8"
TOC	Surface	2,350'
Volume	880 sks	5,450 sks

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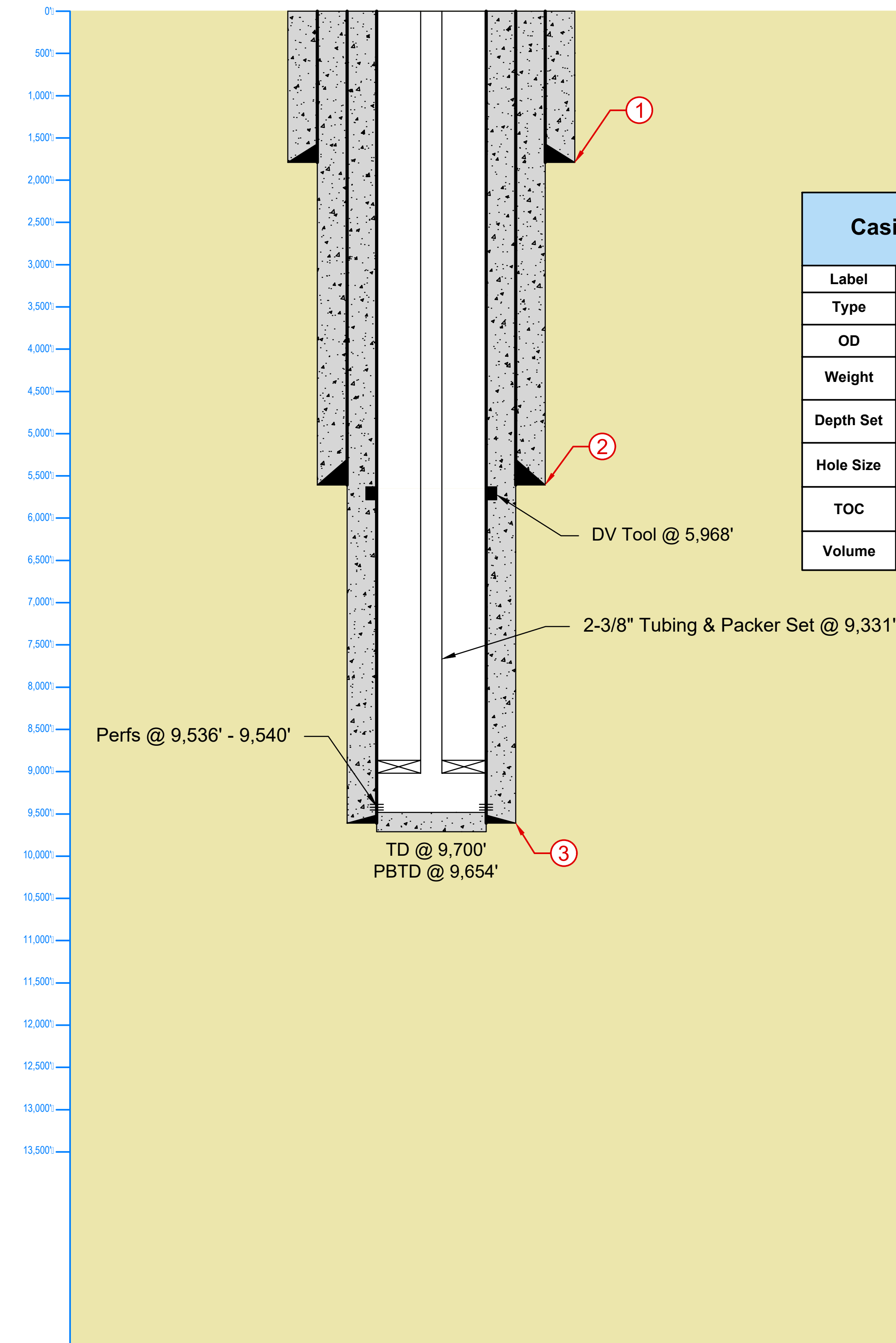
XTO Energy Inc.

E. Randall No. 40

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 12/04/1992	**Survey:** John H. Gipson
API No: 42-501-337932	**Field:** Wasson (Wichita Albany)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54 lb/ft	36 lb/ft 40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,129'	5,606'	9,699'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	Surface
Volume	1,790 sks	2,910 sks	1,590 sks

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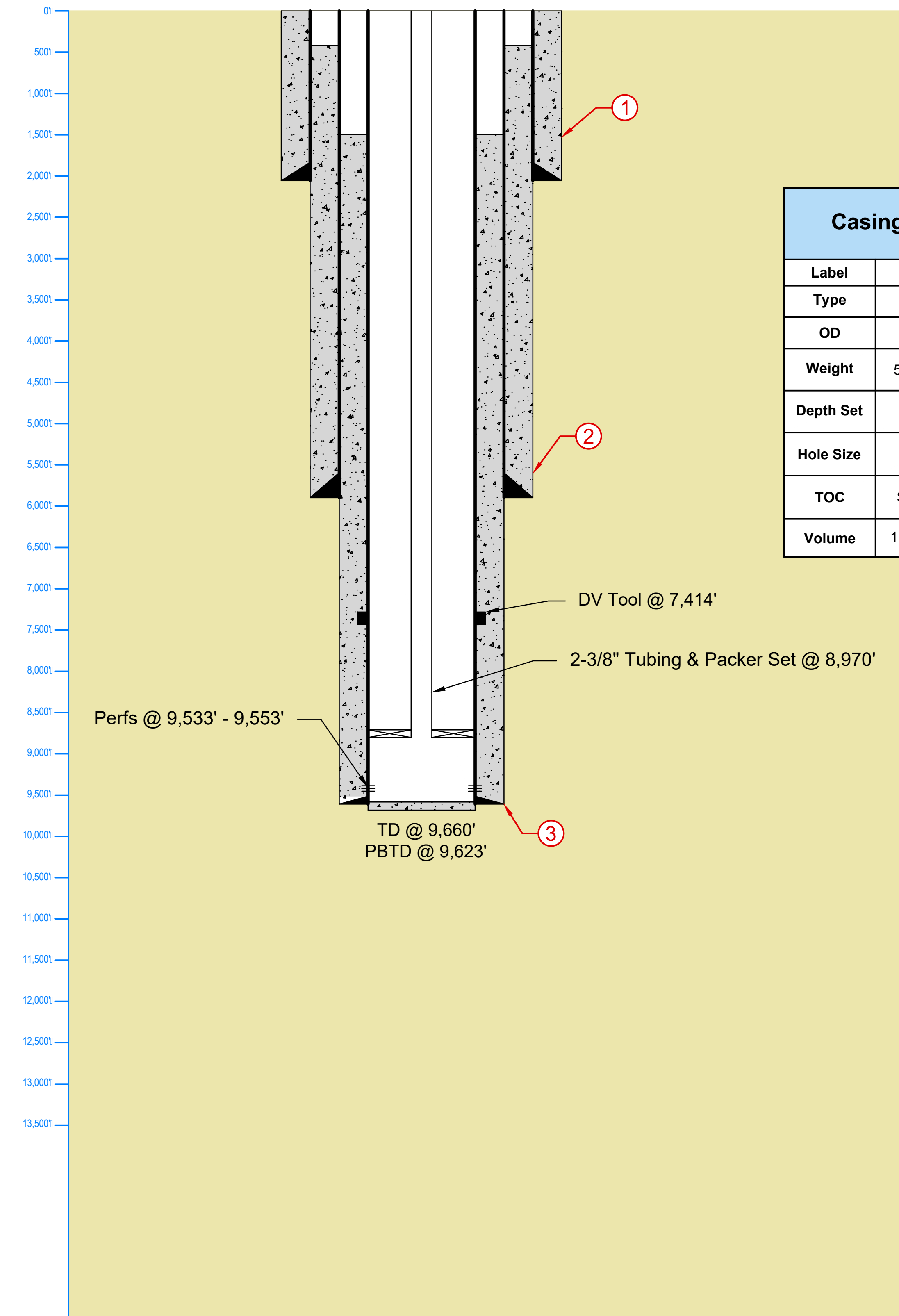
Exxon Corp.	E. Randall No. 41L	
Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 832, Block D	**Spud Date:** 02/05/1994	**Survey:** John H. Gipson
API No: 42-501-33885	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,167'	5,830'	9,658'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	440'	1,800'
Volume	1,530 sks	3,500 sks	1,050 sks

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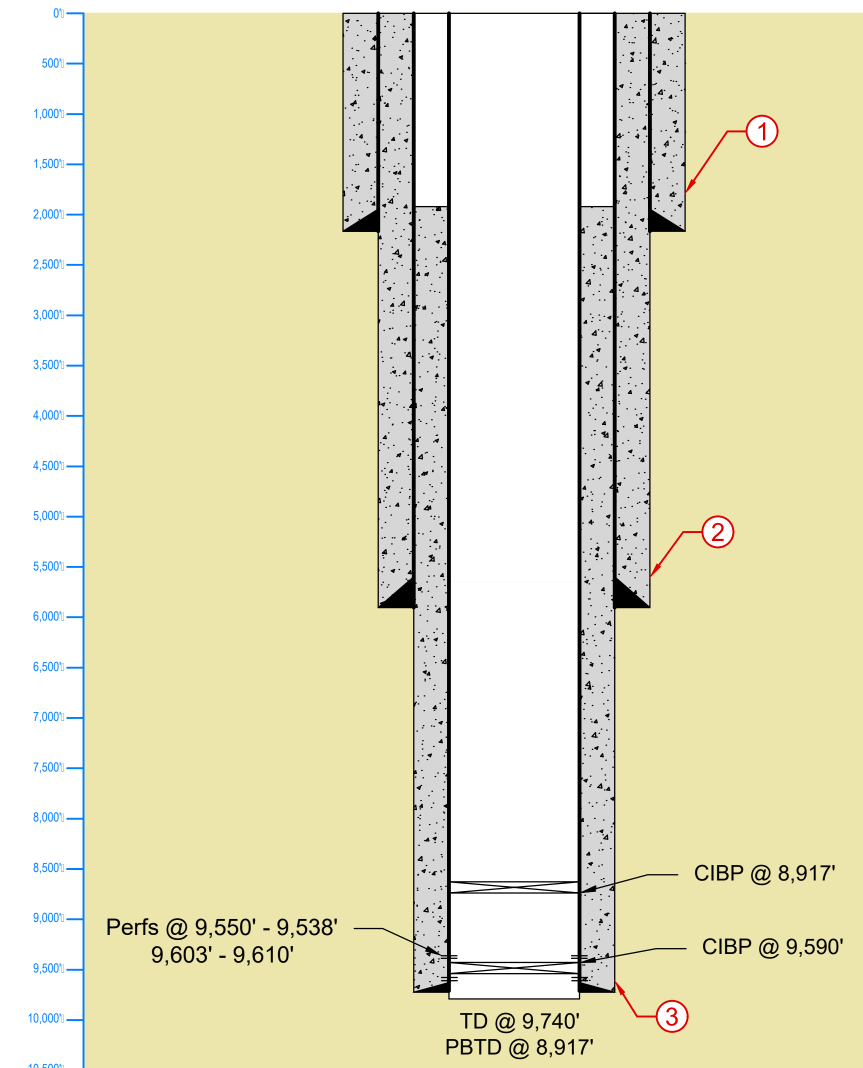
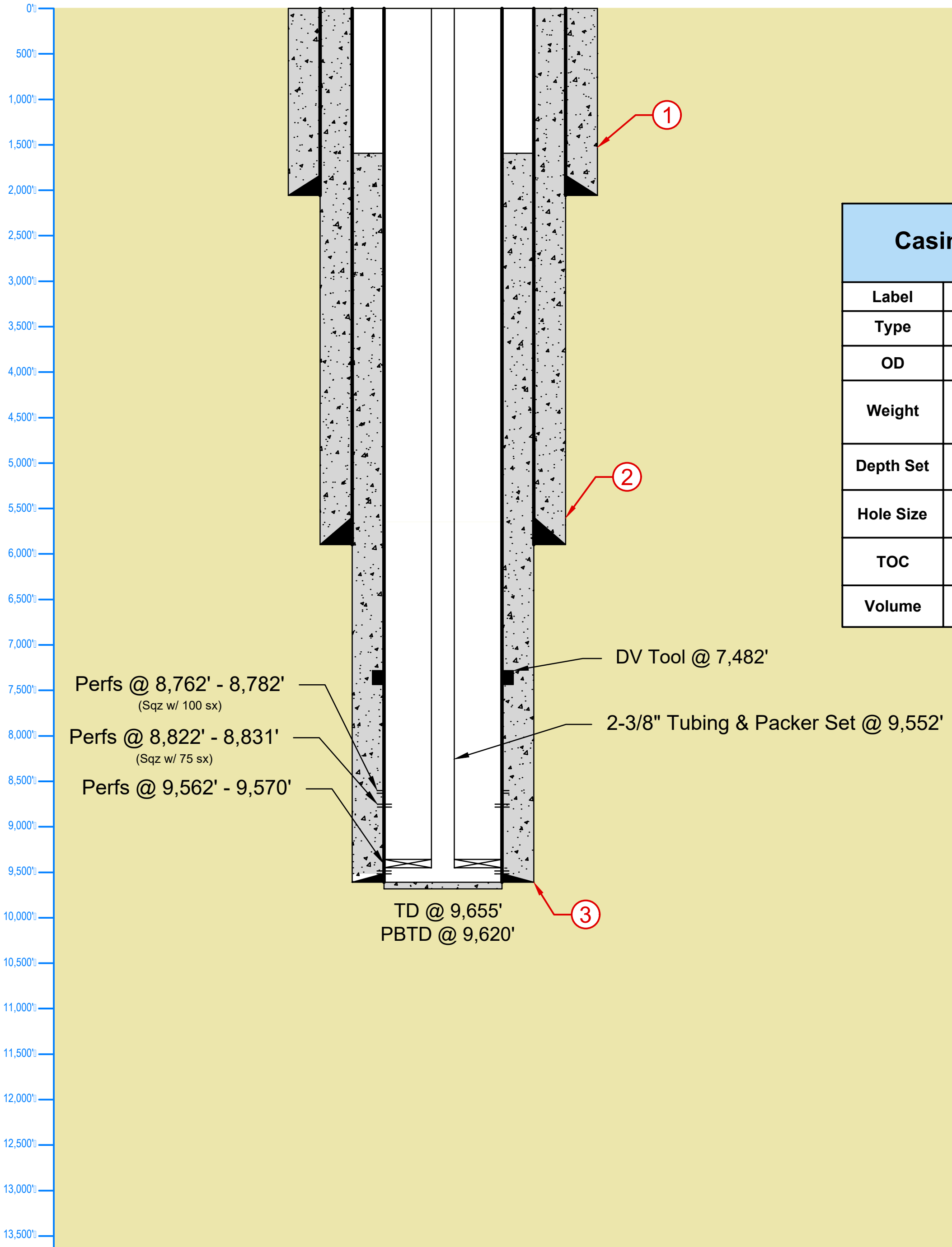
Exxon Corp.	E. Randall No. 42L	
Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 07/01/1995	**Survey:** John H. Gipson
API No: 42-501-34023	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,166'	5,902'	9,735'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	2,000'
Volume	1,530 sks	3,505 sks	967 sks

LONQUIST & CO. LLC PETROLEUM ENGINEERS / ENERGY ADVISORS AUSTIN · HOUSTON · CALGARY · WICHITA DENVER · COLLEGE STATION · BATON ROUGE · EDMONTON	Exxon Corp.	E. Randall No. 43L	
Texas License F-9147	**Country:** USA	**State/Province:** Texas	**County/Parish:** Yoakum
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Location:** Section 832, Block D	**Spud Date:** 04/08/1995	**Survey:** John H. Gipson
	API No: 42-501-34016	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
	RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
	Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
		Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft 29 lb/ft
Depth Set	2,158'	5,904'	9,620'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	1,600'
Volume	1,450 sks	5,190 sks	1,100 sks

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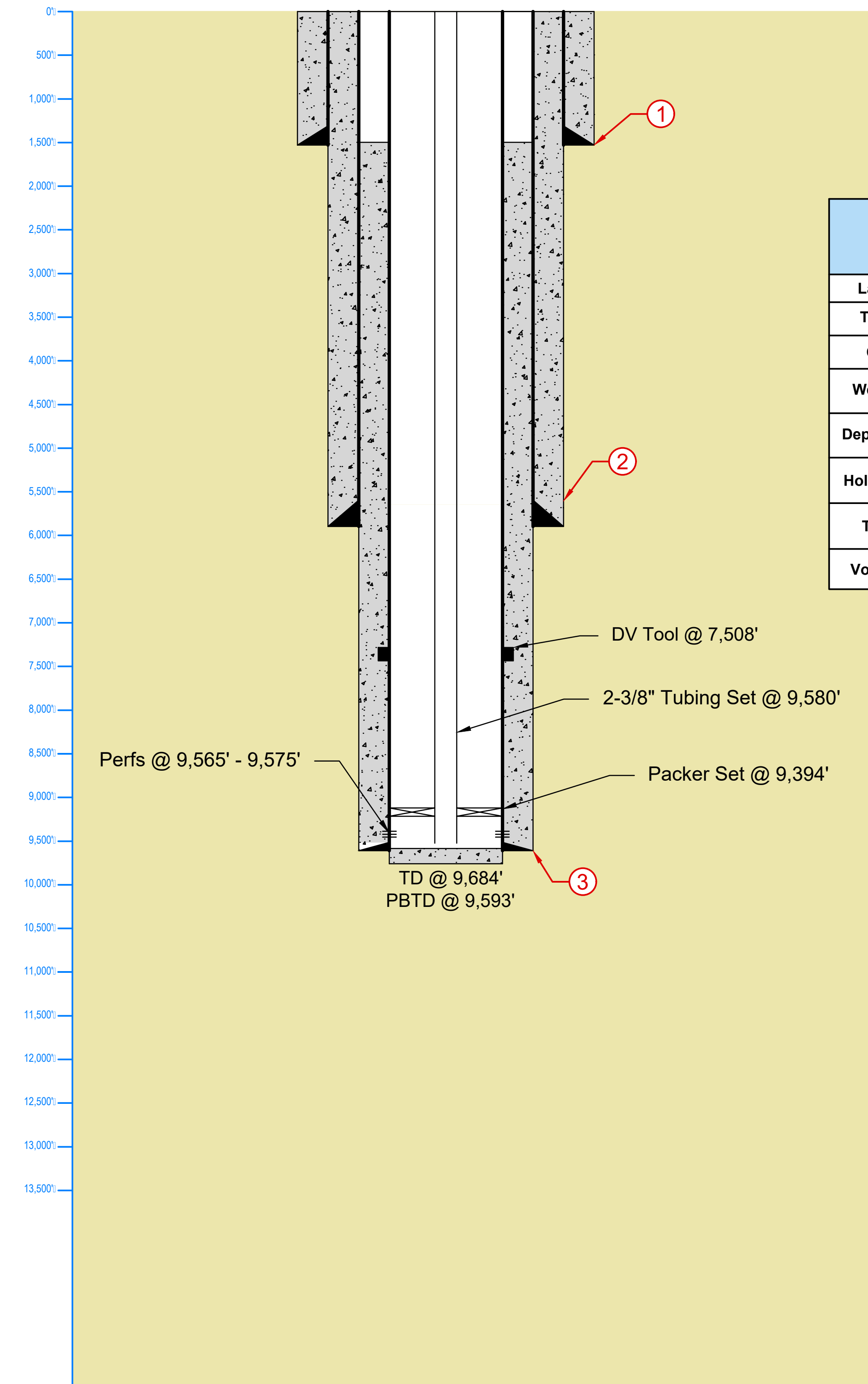
Exxon Corp.	E. Randall No. 44	
Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 08/09/1995	**Survey:** John H. Gipson
API No: 42-501-34024	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,175'	5,898'	9,615'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	1,500'
Volume	1,530 sks	3,525 sks	1,170 sks

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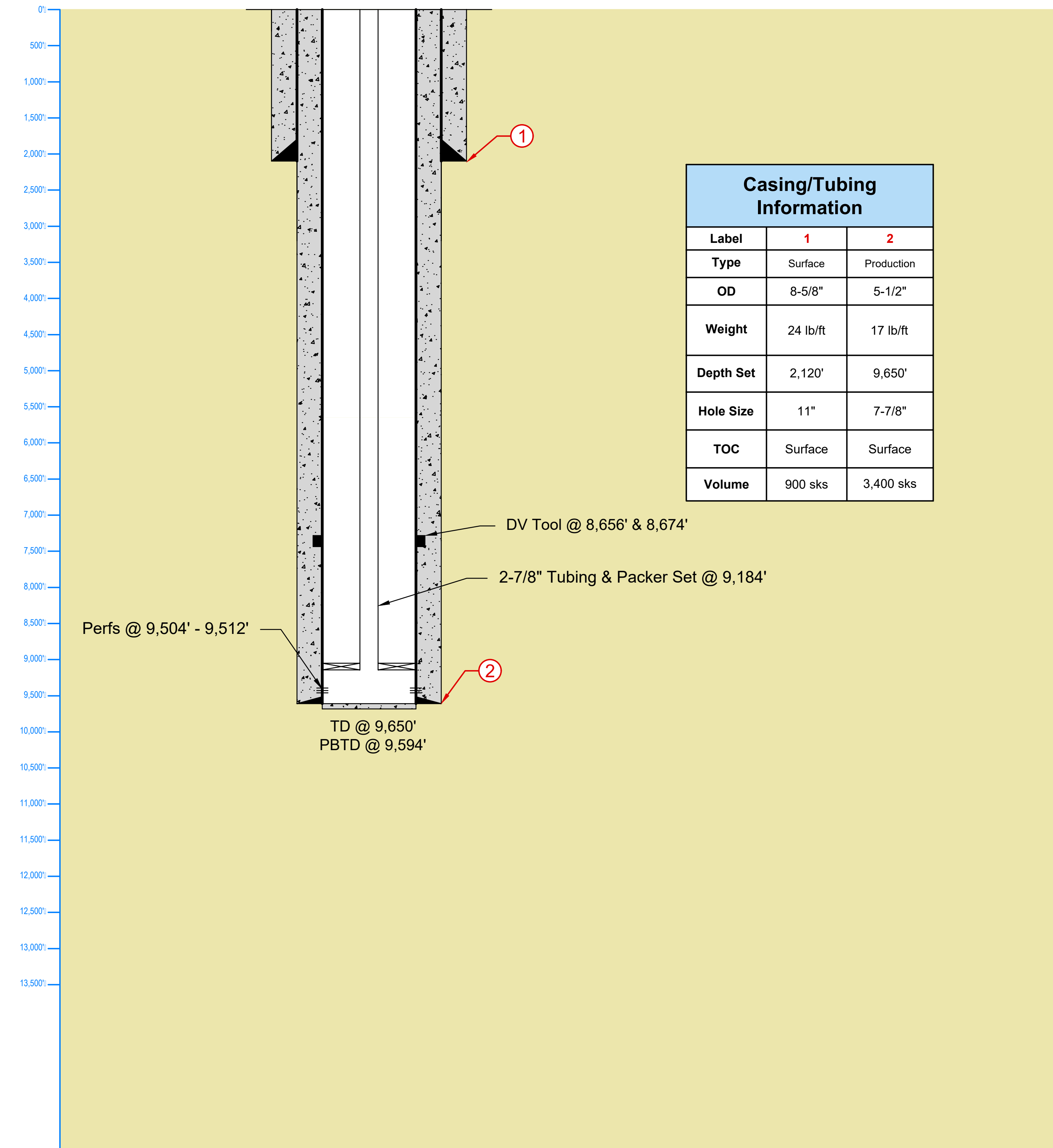
Exxon Corp.

E. Randall No. 45L

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 02/05/1994	**Survey:** John H. Gipson
API No: 42-501-34017	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2
Type	Surface	Production
OD	8-5/8"	5-1/2"
Weight	24 lb/ft	17 lb/ft
Depth Set	2,120'	9,650'
Hole Size	11"	7-7/8"
TOC	Surface	Surface
Volume	900 sks	3,400 sks

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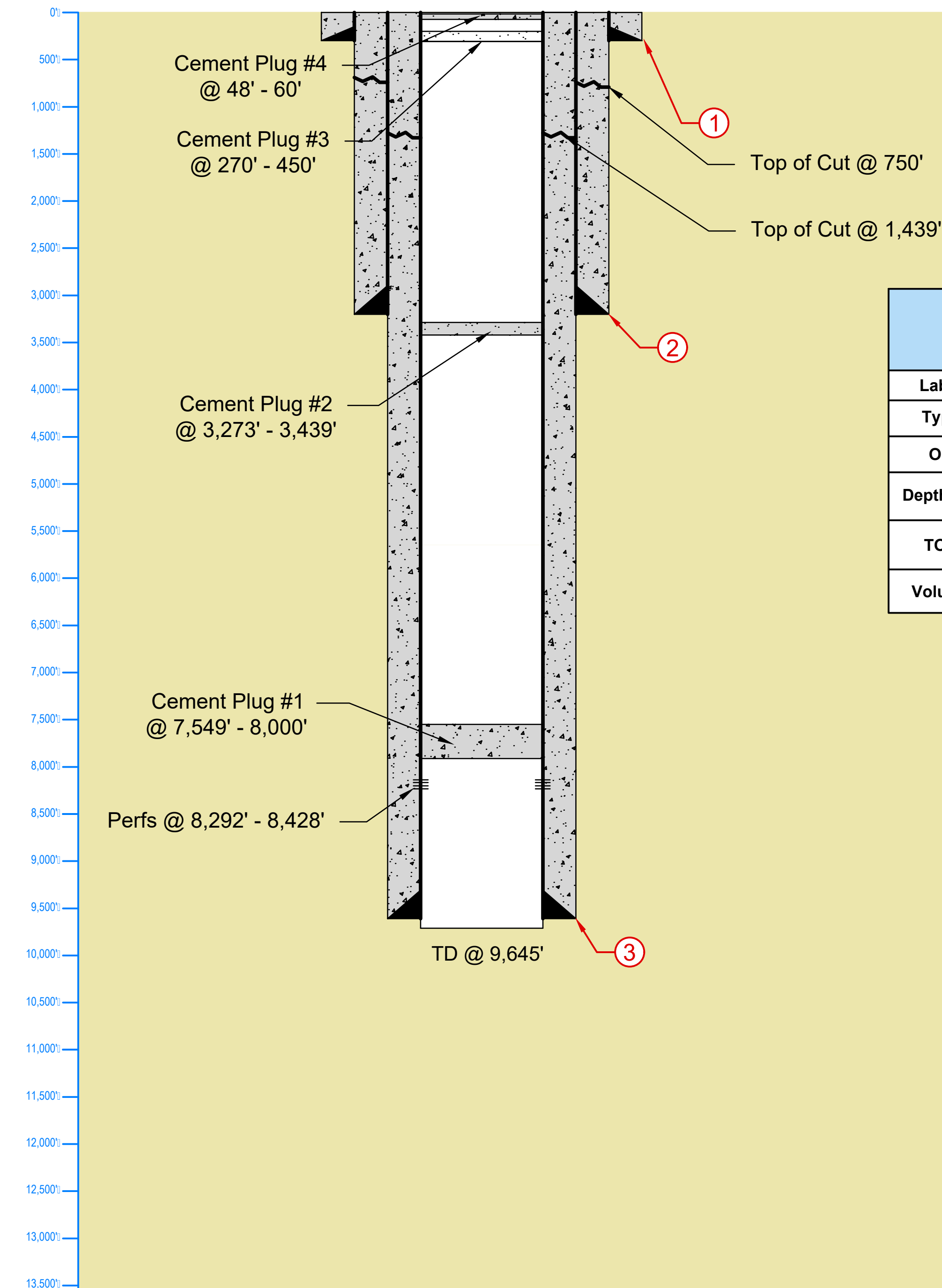
XTO Energy, Inc.

E. Randall No. 46

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 05/23/2007	**Survey:** John H. Gipson
API No: 42-501-35418	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	5-1/2"
Depth Set	300'	3,200'	9,610'
TOC	Surface	Surface	Surface
Volume	400 sks	300 sks	425 sks

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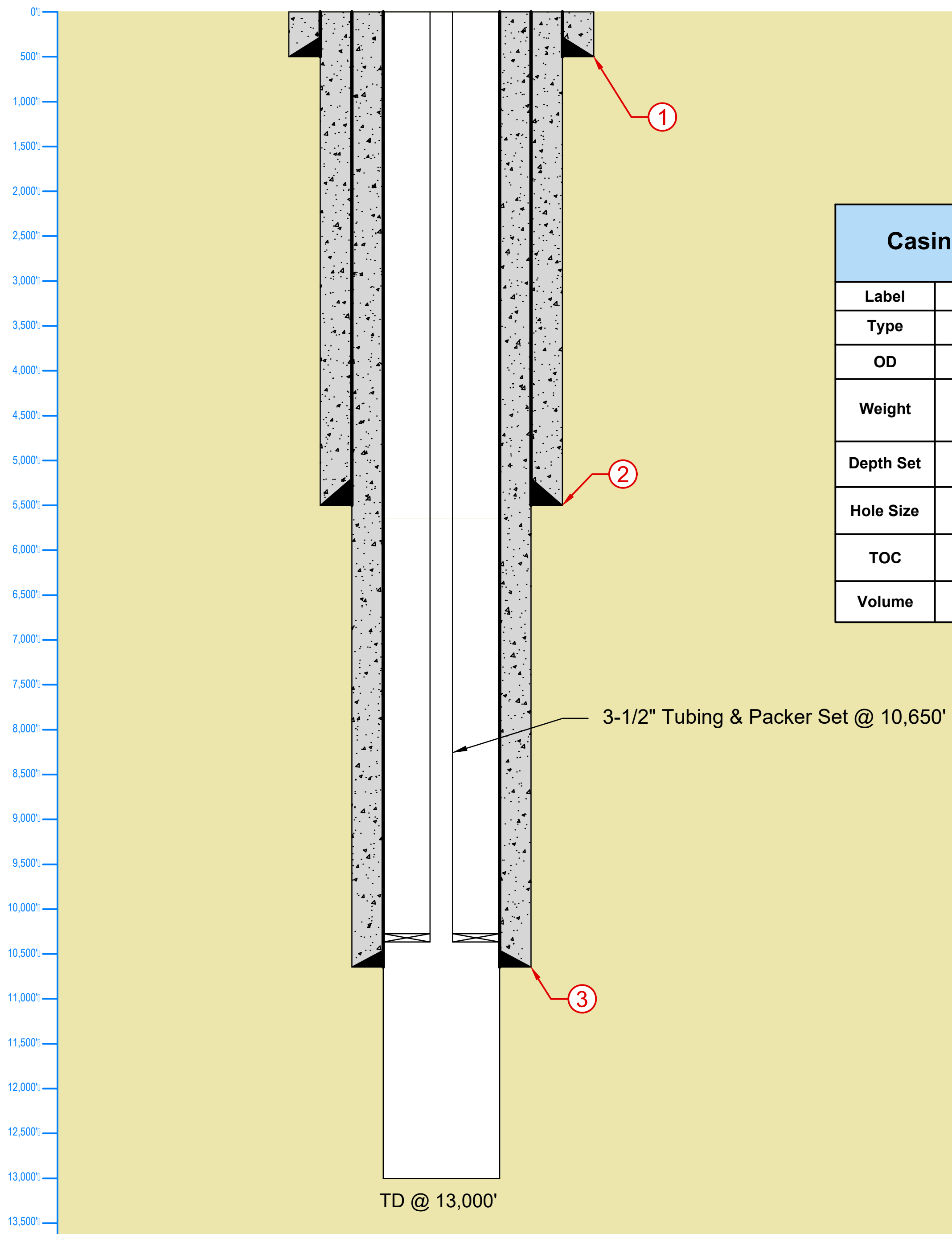
Bonanza Oil Corp.	C.A. Elliott No. 2	
Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 832, Block D	**Spud Date:** 05/10/1965	**Survey:** John H. Gipson
API No: 42-501-10046	**Field:** Wasson (Wichita Albany)	**RRC Lease Number:** 18875
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	48 lb/ft	40 lb/ft	26 lb/ft 28 lb/ft
Depth Set	500'	5,500'	10,695'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	Surface
Volume	350 sks	1,705 sks	1,635 sks

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Amtex Energy, Inc.

Miller SWD No. 7 (Permitted)

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 732, Block D	**Spud Date:** 08/09/1995	**Survey:** John H. Gipson
API No: 42-501-37252	**Field:** Wasson	**Permit Number:** 16637
RRC District No: 7-C	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	

Request for Additional Information: 30-30 Gas Plant
August 31, 2022

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1	4	42	• **Leakage from surface equipment** • **Leakage through existing wells within MMA** • **Leakage through faults and fractures** • **Natural or induced seismicity** • **Drilling through the MMA** • **Leakage through the confining layer** Is this bullet list intended to represent the upcoming subsections within section 3 of the MRV plan? If so, EPA recommends that 30-30 revise so that this list matches the sub-section headings. There are some slight differences between the two.	List and Subsection headings synchronized (pg 42-51)
2	5	54	"This section discusses the strategy that Stakeholder will employ for detecting and **quantifying** surface leakage of CO2 through the pathways…" 40 CFR 98.448(a)(3) requires that the MRV plan contain "A strategy for detecting and quantifying any surface leakage of CO_2." While the above sentence references quantification, the subsequent section does not appear to identify quantification strategies for the identified leakage pathways. In the MRV plan, please ensure that you have provided a strategy for quantifying surface leakage of CO_2.	Added paragraph "Pressures and flowrates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO2 released would be quantified based on the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak." (pg 55)

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3	6	57	"H2S will be initially injected into the AGI well at a concentration of approximately ten (10) percent or 100,000 ppm. The concentration will drop to approximately six (6) percent as additional volumes are added." Page 33 states that, "...It is expected that a larger portion of the gas added is carbon dioxide, changing the composition to ~93% CO2 and ~7% H2S." These statements potentially conflict with each other. Please clarify.	Concentration of H2S corrected to "seven (7) percent" (pg 57)
		54		List and Subsection headings synchronized (pg 54-56)

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Rattlesnake AGI #1

Yoakum County, Texas

Prepared for *Stakeholder Gas Services, LLC*
San Antonio, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 2
August 2022

INTRODUCTION

Stakeholder Gas Services, LLC ("Stakeholder") currently has a Class II acid gas injection ("AGI") permit, issued by the Texas Railroad Commission ("TRRC") in November 2018, for the Rattlesnake AGI #1 well, API No. 42-501-36998. This permit was originally issued to Santa Fe Midstream Permian, LLC, in 2018 and the asset was subsequently acquired by Stakeholder in December of 2020. This permit currently authorizes Stakeholder to inject up to 4,500 barrels per day ("bbls/d") of treated acid gas ("TAG") into the Devonian formation at a depth of 11,000' to 12,000' with a maximum allowable surface pressure of 2,200 psi. Since being permitted, injection has proceeded without incident. This AGI well is associated with Stakeholder's 30-30 gas treating and processing plant ("30-30") located in a rural, sparsely populated area of Yoakum County, Texas, approximately seven miles northwest of the town of Plains, as shown in Figure 1.

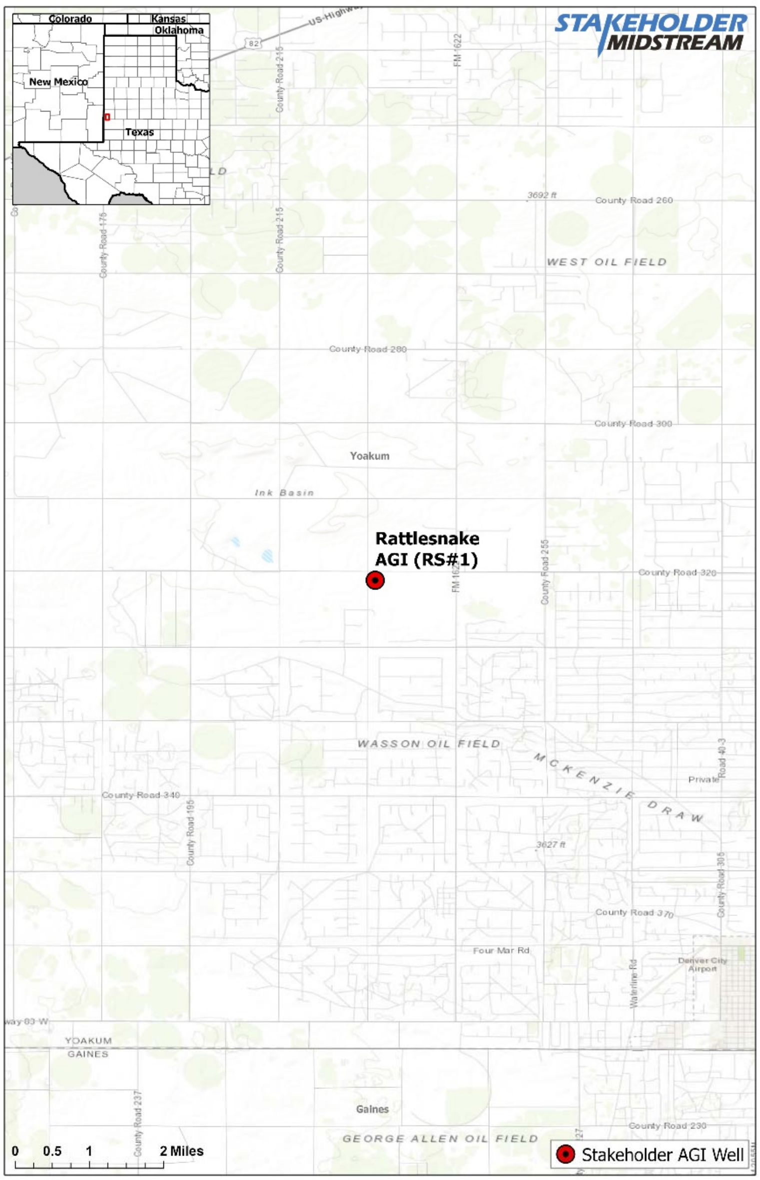

Figure 1 – Location of Rattlesnake AGI #1 Well

Stakeholder is submitting this Monitoring, Reporting, and Verification ("MRV") plan to the EPA for approval under 40 CFR §98.440(a), Subpart RR, of the Greenhouse Gas Reporting Program ("GHGRP"). In addition to submitting this MRV plan to the EPA, Stakeholder is also applying to the TRRC for an amendment to the Rattlesnake AGI #1 well's Class II permit to increase its authorized injection volume and maximum allowable surface injection pressure ("MASIP"). Approval of the permit amendment will allow Stakeholder to increase the capacity of its existing 30-30 Facility, which removes H_2S and CO_2 from natural gas production using amine treating, as well as increase the injection well capacity for a future gas processing facility which is currently under development by Stakeholder. Additionally, expanded capacity allows Stakeholder to potentially provide future disposal in its AGI well for oil and gas waste derived TAG from similar third-party gas processing facilities. Increased disposal capacity will allow for greater gas processing capacity in the region, ultimately helping to reduce flaring and its associated emissions. Throughout this document, both in written reference and in modeling inputs, Stakeholder has used the applied-for expanded permit capacity of 16 million standard cubic feet per day ("MMSCF/d"). Stakeholder plans to inject CO_2 for approximately 14 more years.

ACRONYMS AND ABBREVIATIONS

‘	Feet
%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group’s GEM 2020.11
GHGs	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program
H_2S	Hydrogen Sulfide
md	Millidarcy(ies)
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMCF	Million Cubic Feet
MMSCF	Million Standard Cubic Feet

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

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LIST OF FIGURES

LIST OF TABLES

SECTION 1 – FACILITY INFORMATION

This section contains key information regarding the Acid Gas and CO_2 injection facility.

Reporter number:

- Gas Plant Facility Name: 30-30 Gas Plant
- Greenhouse Gas Reporting Program ID: 574501
    - Currently reporting under Subpart UU
- Operator: Stakeholder Gas Services, LLC

Underground Injection Control (UIC) Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control ("UIC") Class II program. TRRC classifies the Rattlesnake AGI #1 well as a UIC Class II well. A Class II permit was issued to Stakeholder under TRRC Rule 9 (entitled "Disposal into Non-Productive Formations") and Rule 36 (entitled "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas").

UIC Well Identification Number:

Rattlesnake AGI #1, API No. 42-501-36998, UIC #000117143.

SECTION 2 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection volumes and process, and the reservoir modeling performed for the Rattlesnake AGI #1 well. The Class II UIC permit was initially applied for and received by Santa Fe Midstream Permian, LLC. The asset was acquired in 2020 by Stakeholder and has been in operation since that time. Since the original application, Lonquist has revised and updated the geology and the plume modeling within the reservoir in preparing this MRV Plan.

The Rattlesnake AGI #1 well is located and designed to protect against migration of CO_2 out of the injection interval and to prevent surface releases. The injection interval for Rattlesnake AGI #1 is located over 4,720' below the primary producing formation, the San Andres, in the area and 8,593' below the base of the lowest useable quality water table, as shown in Figure 2. This well injects both H_2S and CO_2, therefore the well and the facility are designed to minimize any leakage to the surface.

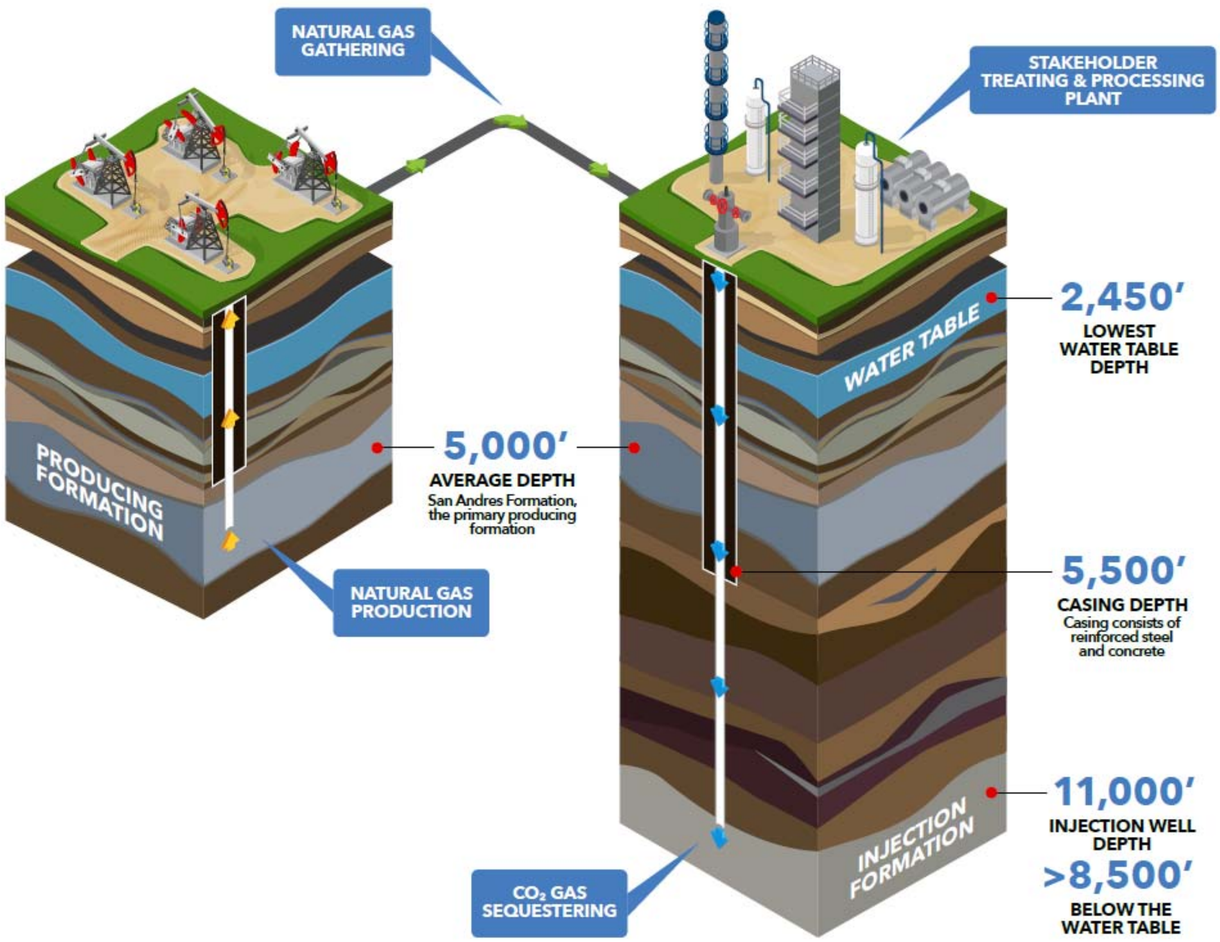


Figure 2 – Illustrative overview of Rattlesnake AGI #1 and 30-30 Facility

Regional Geology

The Rattlesnake AGI #1 well is located on the southern portion of the Northwestern Shelf within the larger Permian Basin as seen in Figure 3. The Northwestern Shelf is a broad marine shelf located in the northern portion of the Permian Basin.

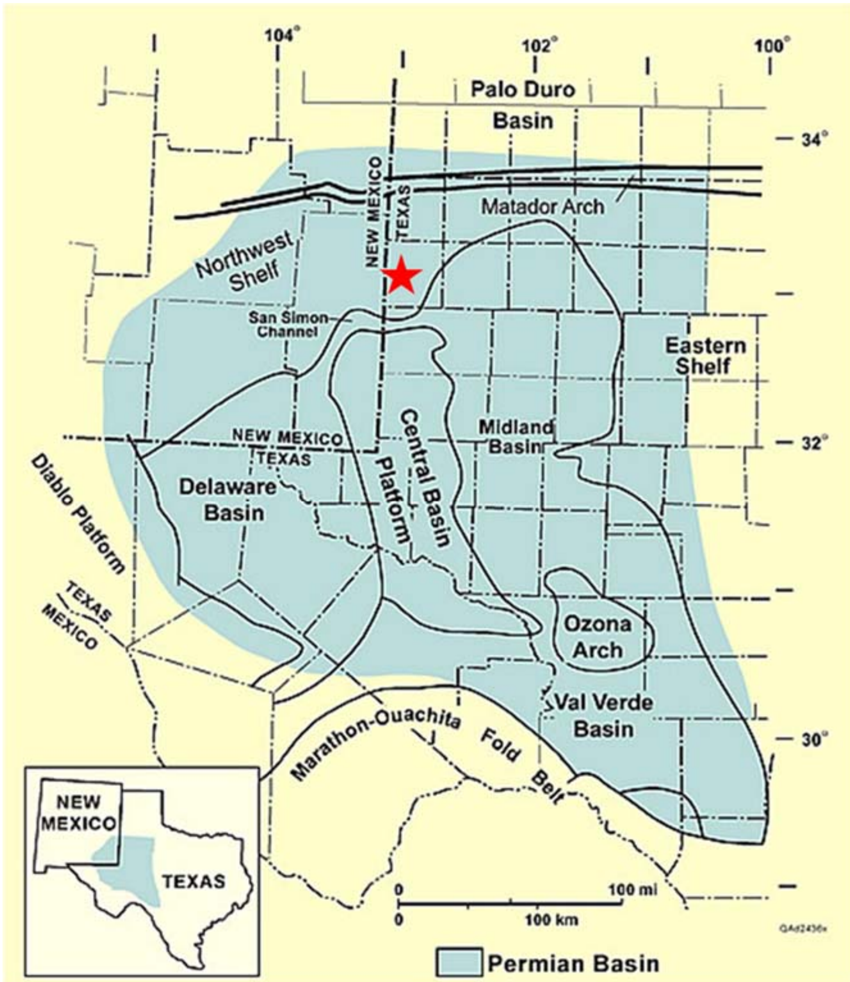


Figure 3 – Regional Map of the Permian Basin. Red Star is approximate location of Rattlesnake AGI #1 well

Figure 4 depicts the stratigraphic column found at the Rattlesnake AGI #1 well location with red stars referencing the injection formation and green stars indicating the productive intervals in the area. The primary injection interval is found within the Wristen group, of Silurian-age, as seen in Figure 5. The TRRC refers to this sequence under the general terms “Devonian”, “Silurian-Devonian” or “Siluro-Devonian”.

Period	Epoch	Formation	General Lithology
Permian	Ochoan	Dewey Lake	Redbeds/Anhydrite
		Rustler	Halite
		Salado	Halite/Anhydrite
	Guadalupian	Tansil	Anhydrite/Dolomite
		Yates	Anhydrite/Dolomite
		Seven Rivers	Dolomite/Anhydrite
		Queen	Sandy Dolomite/Anhydrite/Sandstone
		Grayburg	Dolomite/Anhydrite/Shale/Sandstone
	Leonardian	★ San Andres	Dolomite/Anhydrite
		Glorieta	Sandy Dolomite
		Yeso: Paddock	Dolomite/Anhydrite/Sandstone
		Yeso: Blinebry	
		Yeso: Tubb	
		Yeso: Drinkard	
		Abo	Dolomite/Anhydrite/Shale
	Wolfcampian	★ Wolfcamp	Limestone/Dolomite
Pennsylvanian	Virgilian	Cisco	Limestone/Dolomite
	Missourian	Canyon	Limestone/Shale
	Des Moinesian	Strawn	Limestone/Sandstone
	Atokan	Bend	Limestone/Sandstone/Shale
	Morrowan	Morrow	
Mississippian		Mississippian Lime	Limestone
Devonian		Woodford	Shale
Silurian		★ Wristen Group	Dolomite/Limestone
		★ Fusselman	Dolomite/Chert
Ordovician	Upper		
		Montoya	Dolomite/Chert
	Middle	Simspson Gp	Limestone/Sandstone/Shale
	Lower	Ellenburger	Dolomite

Figure 4 – Stratigraphic column of the Northwest Shelf. Red stars indicate injection interval. Green stars indicate productive intervals.

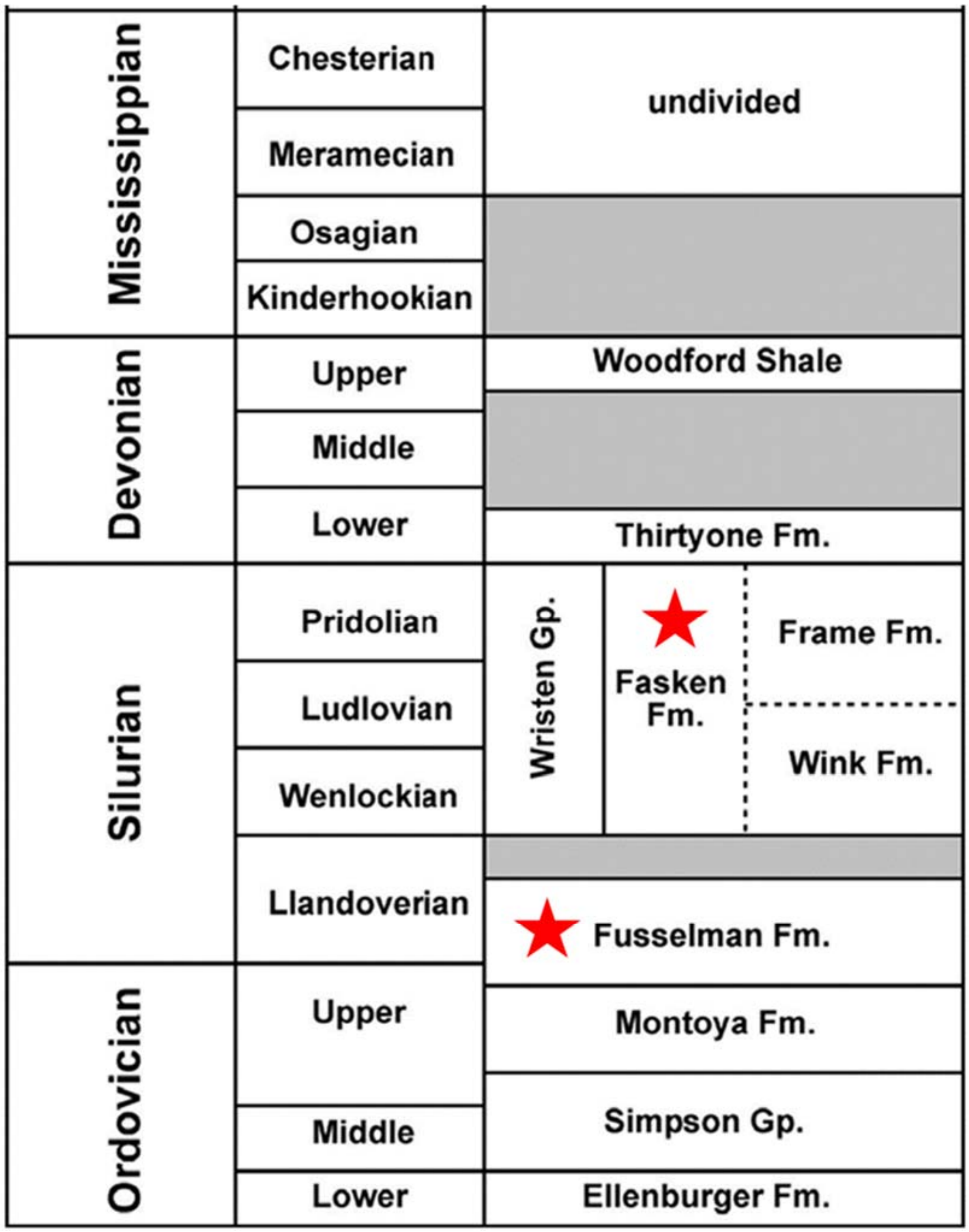


Figure 5 – Stratigraphic column depicting the composition of the Silurian group. Red star indicates injection interval (Broadhead, 2005)

The Wristen group was deposited in a basin platform setting across the northern half of the Permian Basin. The depositional environment over Yoakum County during the Silurian period was a shallow inner platform, the margin of which exists to the south, in southern Andrews County, Texas. The Silurian-age lithology on the inner platform is dominated by grain-rich skeletal carbonates. Carbonate buildups are common within the shallow inner platform, mainly skeletal wackestone, indicating a lower-energy deposition on the inner platform. The carbonate shelf margin to the south acted as a barrier from basin-ward wave energy (Ruppel and Holtz, 1994).

Depositional cycles within the inner platform indicate it was controlled by episodic sea level rise and fall, resulting in sub-areal exposure and diagenesis. The diagenesis of the Silurian-age carbonate rocks initiated

secondary porosity development and increased permeability. Dolomite and solution-related features are the most prominent diagenetic characteristics found within the Silurian. The Wristen Group is composed of three formations: Fasken, Frame, and Wink formations. The Frame and Wink formations are found near the ramp boundary to the south, while the Fasken formation is found predominantly in the inner platform, where the Rattlesnake AGI #1 well is located. The Fasken formation is predominately dolomite grading to limestone, occurring as cycles, down section. This dolomitization is due in part to sub-areal exposure, during which karsts and secondary porosity developed. Additional dolomitization was possible during successive sea level fluctuations via movement of magnesium-rich solution through karsts and vugs, which acted as channels for fluid flow (Ruppel and Holtz, 1994).

Figure 6 shows a regional isopach map of the Silurian (combined Fasken and Fusselman formations) with a red star depicting the Rattlesnake AGI #1 well location. Thickness of the Silurian-age rock is approximately 1,000’ at the Rattlesnake AGI #1 well location.

North of Andrews County there is little differentiation between the Fasken and Fusselman formations which are both carbonate deposits with the potential for sub-areal exposure and porosity development. For purposes of this MRV Plan, the combined Fasken and Fusselman formations are defined as the injection interval, and the underlying Montoya formation serves as the lower confining unit.

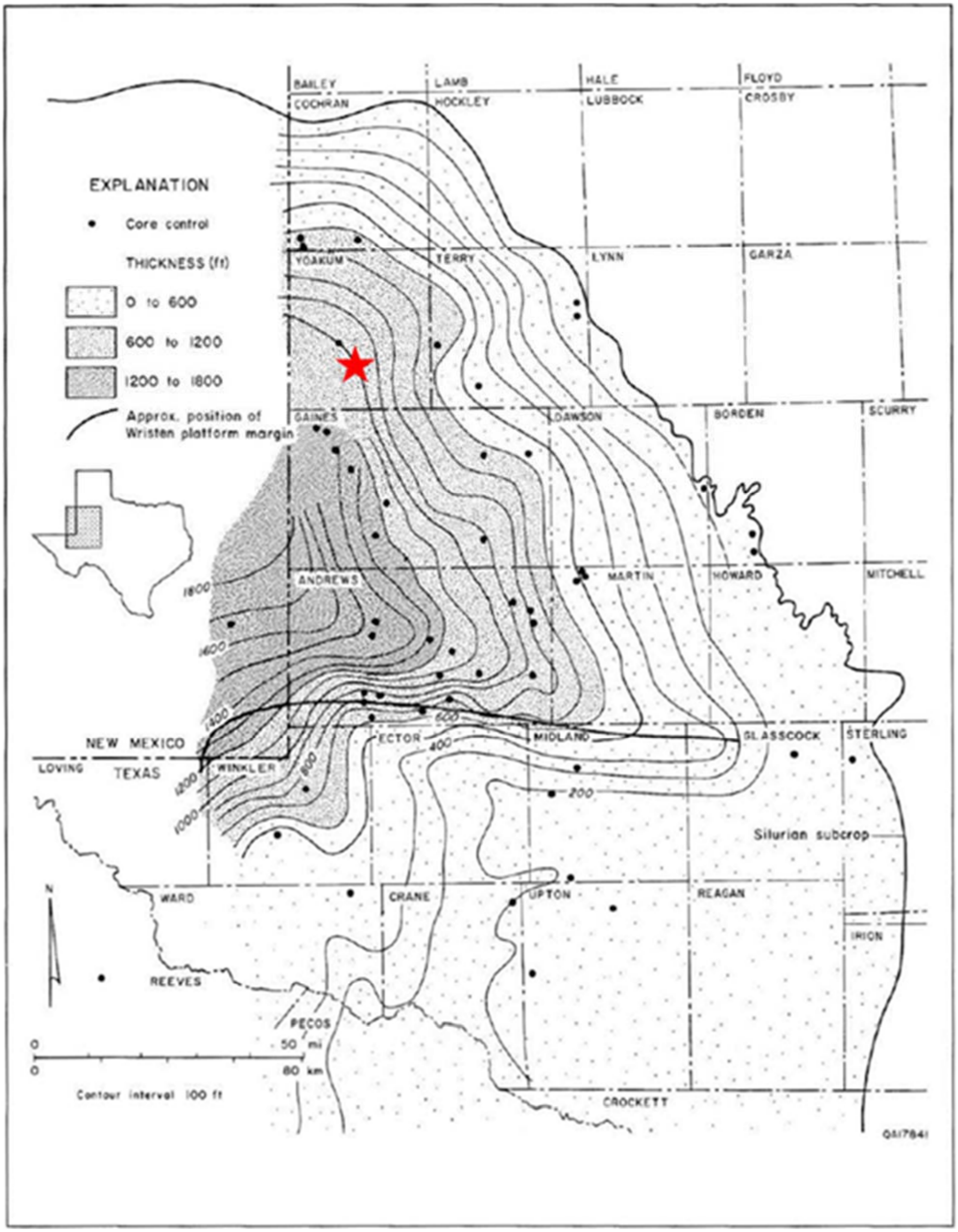


Figure 6 – Thickness map of the Silurian system which composes the Fusselman and Wristen group

Regional Faulting

A major uplift that began during the Pennsylvanian Period to the south, the Central Basin Platform, ceased in the Early Permian (Wolfcampian), which caused a regional unconformity of the underlying formations (Hoak, Sundberg, and Ortoleva). Faulting on the Northwest Shelf can be seen through high angle basement faults that tend to die within the Pennsylvanian strata. These faults predominately represent contractional (thrust) faults that were initiated during the Pennsylvanian as a result of regional tectonics. Hydrocarbon traps within the Wristen group are primarily anticlinal structures dependent upon reservoir development (Broadhead, 2005).

Site Characterization

The Rattlesnake AGI #1 well is located in Section 733, Block D, John H. Gibson Survey, in Yoakum County, Texas. Stakeholder owns the 82.42-acre surface tract where the plant and Rattlesnake AGI #1 well are located. The following discusses the geological character of this site.

Stratigraphy and Lithologic Characteristics

Figure 7 depicts an open hole log from an offset well (API No. 42-501-10238) to the Rattlesnake AGI #1 well indicating the injection and primary upper confining zone. This well is approximately 1.8 miles to the northwest of the Rattlesnake AGI #1 well. An offset well log was used to depict the upper confining intervals as electric logs were only run in the Rattlesnake AGI #1 well across the injection zone.

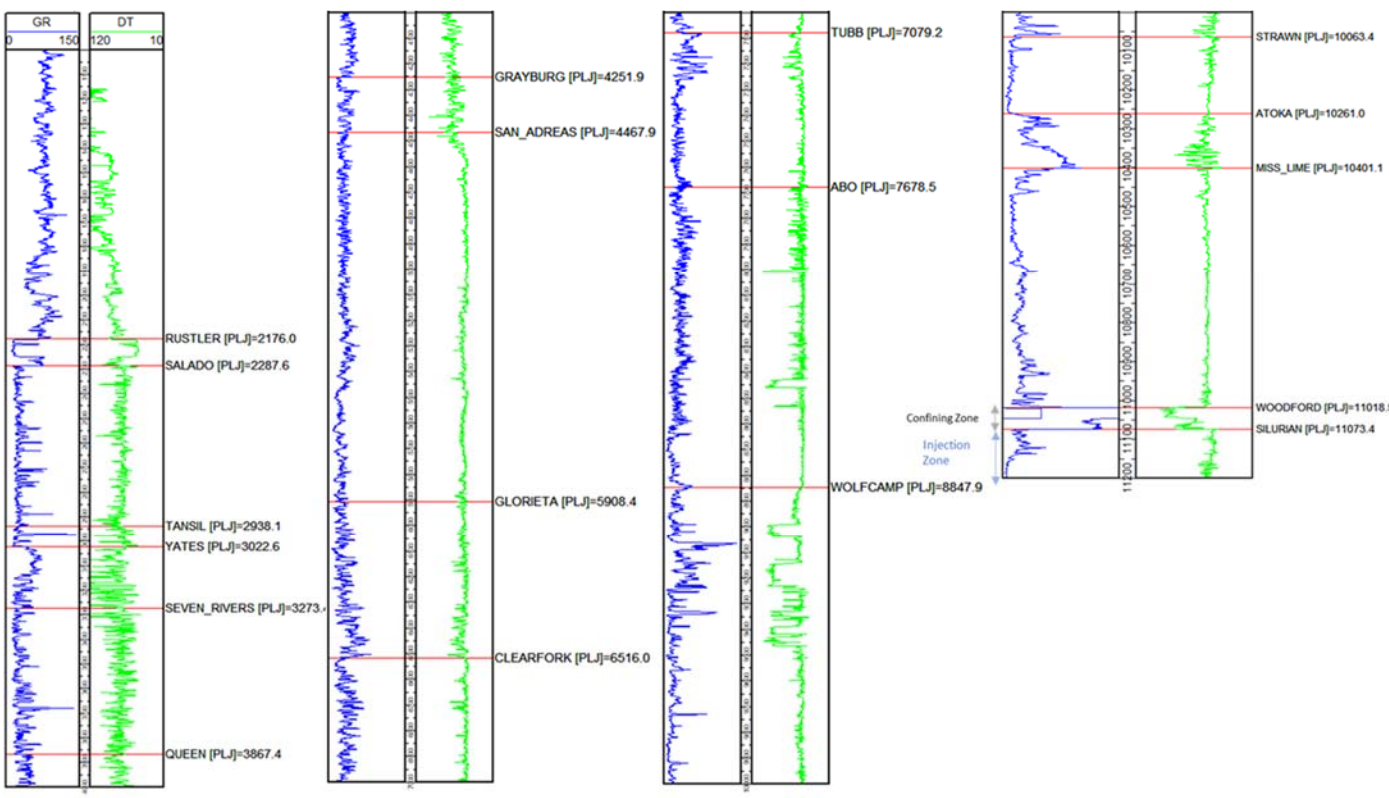


Figure 7 – Type Log (42-501-10238) with tops, confining and injection zones depicted

Upper Confining Interval - Woodford Shale

The Woodford is a late Devonian-age organic-rich shale deposited as a result of a widespread marine transgression. The flooding event occurred over the majority of the Permian basin, which produced a low-relief blanket-like shale deposit of the Woodford. Two major lithofacies found within the Woodford are black shale and siltstone. Nutrient-rich surface waters promoted the decay of abundant organic matter within the Woodford, resulting in a high total organic carbon ("TOC") percentage. The Woodford shale acts as the primary source and sealant rock for the Wristen Group (Comer, 1991).

Figure 8 is a description of a core sample taken in Lea County, New Mexico just southwest of the Rattlesnake AGI #1 well location. This sample is referenced as C9 in the reference map with the blue star representing the Rattlesnake AGI #1 well. In the core description, black shale with abundant illitic clays is observed in the upper section, and medium gray dolomitic siltstone found in the basal section. The mineralogic and lithologic properties recorded in this description serve as excellent sealant characteristics to prohibit any injected fluids from migrating above the injection interval.

The Woodford at the Rattlesnake AGI #1 well location is encountered at 10,973 ft and is approximately 63 ft thick.

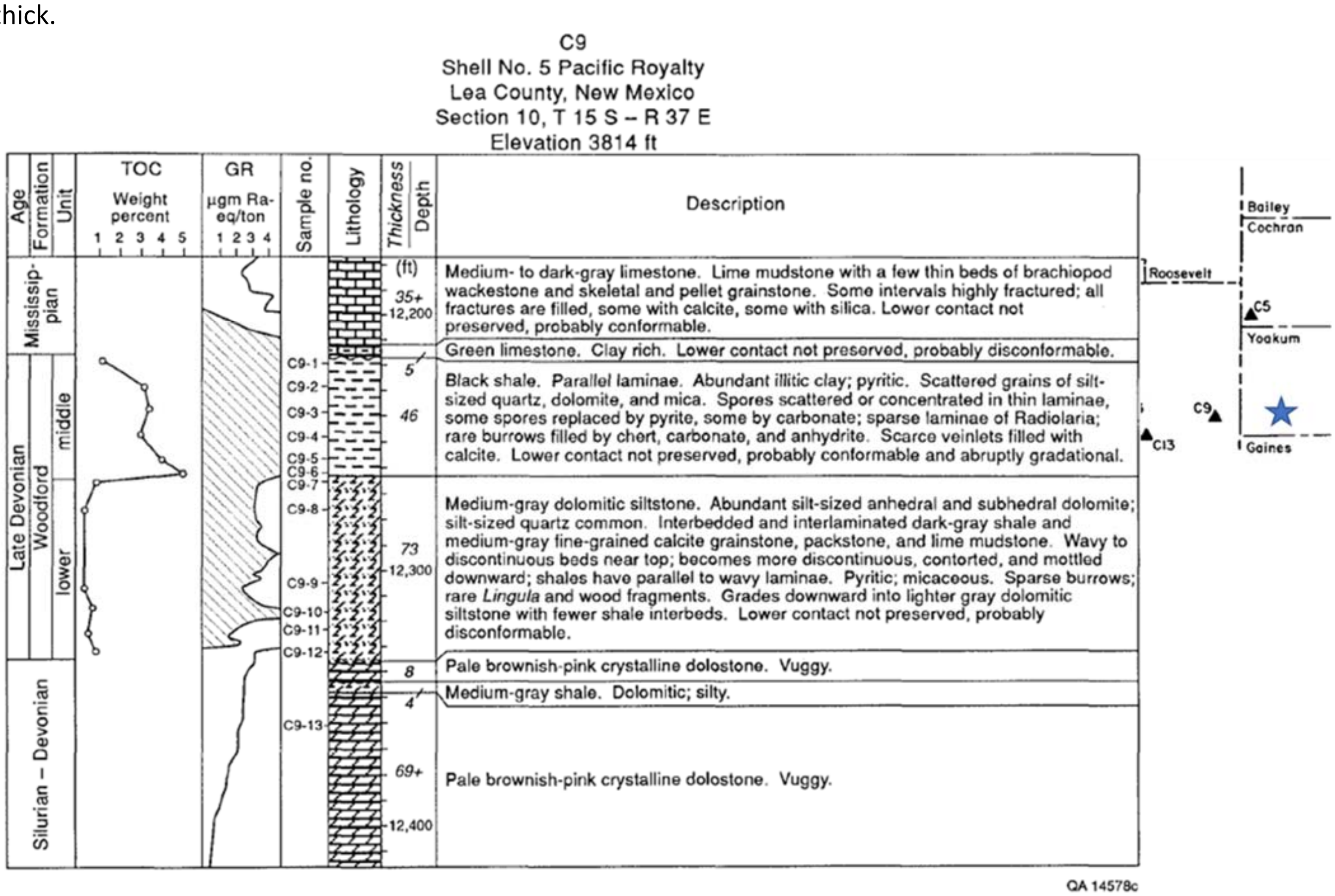


Figure 8 – Core description of the Woodford Shale and Upper Silurian (Ruppel and Holtz, 1994)

Injection Interval – Fasken Formation

The Rattlesnake AGI #1 well reaches total depth in the Fasken/Fusselman formation (Silurian in age), directly below the Woodford formation. Dolomites at the top of the Fasken formation underwent multiple leaching and diagenetic episodes which developed secondary porosity. This is evidenced in offset wells by the practice of only drilling through the top 30’ of the Fasken, in anticipation of encountering the best reservoir quality. In Figure 8, the uppermost Silurian section is described as ‘vuggy dolostone’ in the core description. Beds below the top of the Fasken section may also have similar petrophysical attributes if exposed to multiple diagenetic events. Solution-collapse and karst breccia horizons can be found within inner platform deposits, some occurring as much as 100 ft below the Fasken top (Ruppel and Holtz, 1994).

Porosity/Permeability Development

Porosity in the Fasken formation at the Rattlesnake AGI #1 well location is typically moldic and intercrystalline associated with leaching of allochem-rich intervals. Porosity is directly related to these leaching events which occurred during and post-deposition, resulting in vugs and karst-like features. Figure 9 provides reservoir information from core data within fields in the Wristen buildup and platform carbonate play. The average porosity of these cores is 7.1% with an average permeability of 45.28 millidarcies (Ruppel and Holtz, 1994). The porosity and permeability described in the offset core data indicate the Fasken formation provides sufficient accessible pore space for the amount of fluid injection proposed.

Using the above values as reference points, the Rattlesnake AGI #1 porosity log (API No. 42-501-36998) was evaluated. Figure 10 is the product of the petrophysical analysis performed on the open hole logs run within the injection interval at the Rattlesnake AGI #1 well. A permeability curve was generated from the effective porosity curve using the table in Figure 9 to establish the porosity-permeability relationship. In Figure 10, the majority of the injection interval’s porosity and permeability is found at the top of the Fasken formation, which correlates with the diagenetic processes described above. These curves are extrapolated to the injection site and used to establish reservoir characteristics in the plume model.

	Fusselman Shallow Platform Carbonate play	Wristen Buildups and Platform Carbonate play	Thirtyone Ramp Carbonate play	Thirtyone Deep-Water Chert play
		Porosity (%)		
Number of data points	33	30	16	35
Mean	7.93	7.10	6.41	14.85
Minimum	1.00	2.70	3.50	2.00
Maximum	17.70	14.00	9.50	30.00
Standard deviation	4.01	2.67	1.75	6.76
		Permeability (md)		
Number of data points	21	24	12	33
Mean	11.61	45.28	1.51	8.56
Minimum	0.60	2.90	0.40	1.00
Maximum	84.80	400.00	30.00	100.00
Standard deviation	22.48	99.17	8.36	22.23
		Initial water saturation (%)		
Number of data points	24	28	10	31
Mean	26.96	31.55	24.70	31.46
Minimum	10.00	20.00	16.00	10.00
Maximum	50.00	55.00	40.00	45.00
Standard deviation	9.31	10.45	7.39	8.33
		Residual oil saturation (%)		
Number of data points	8	13	5	22
Mean	34.06	30.54	21.30	29.17
Minimum	30.00	20.00	9.00	14.00
Maximum	50.00	35.00	35.00	48.20
Standard deviation	6.99	4.61	11.66	9.76
		Oil viscosity (cp)		
Number of data points	11	12	5	21
Mean	0.69	1.16	0.33	0.68
Minimum	0.13	0.32	0.04	0.07
Maximum	1.08	2.00	1.00	1.03
Standard deviation	0.81	0.75	0.40	0.42
		Oil formation volume factor		
Number of data points	21	22	6	32
Mean	1.57	1.22	1.65	1.50
Minimum	1.05	1.05	1.31	1.30
Maximum	1.91	1.55	1.66	1.73
Standard deviation	0.28	0.14	0.48	0.16
		Bubble-point pressure (psi)		
Number of data points	9	9	5	19
Mean	2,272	1,055	3,750	2,752
Minimum	798	450	2,660	1,755
Maximum	4,050	2,600	4,440	4,656
Standard deviation	1,300	689	756	667

Figure 9 – Table of reservoir properties found within the Wristen buildups and platform plays (Ruppel and Holtz, 1994)

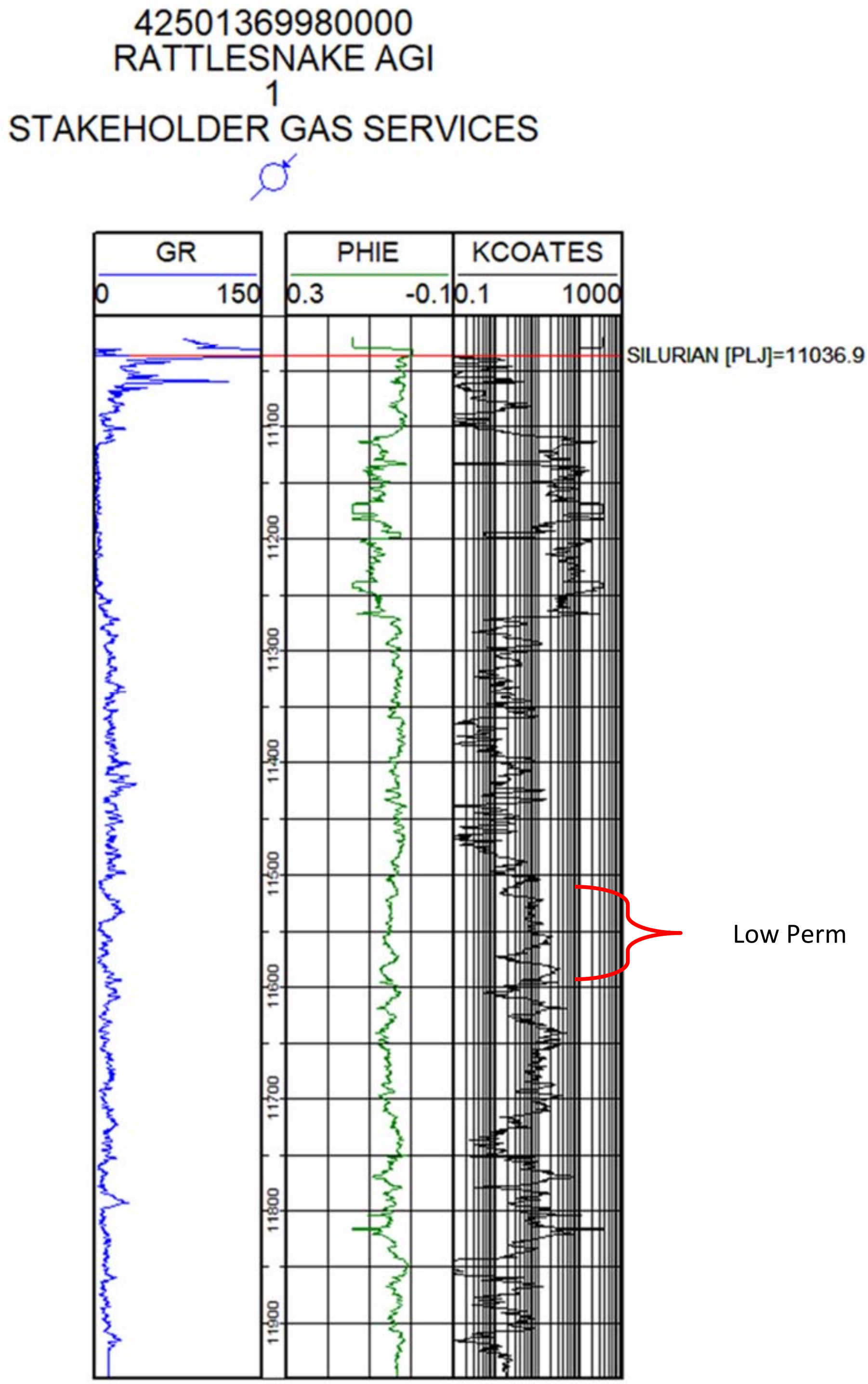


Figure 10 – Rattlesnake AGI #1 open hole log (42-501-36998) with effective porosity (green) and permeability (black)

Formation Fluid

Four wells were identified through a review of chemical analyses of oil-field brines from the U.S. Geological Survey National Produced Waters Geochemical Database v2.1 within the Devonian, Silurian-Devonian, or Fusselman formations within 20 miles of the Rattlesnake AGI #1 well. The location of these wells is shown in Figure 11. Water chemistry analyses conducted on oil-field brines in Gaines County, as reported to the Texas

Water Development Board, provided additional data on Devonian and Silurian reservoir fluids. Results from the synthesis of these two sources are provided in Table 1. The fluids have greater than 20,000 parts per million ("ppm") total dissolved solids, therefore these aquifers are considered saline. These analyses indicate the in-situ reservoir fluid of the Devonian, Silurian, and Fusselman formations are compatible with the proposed injection fluids.

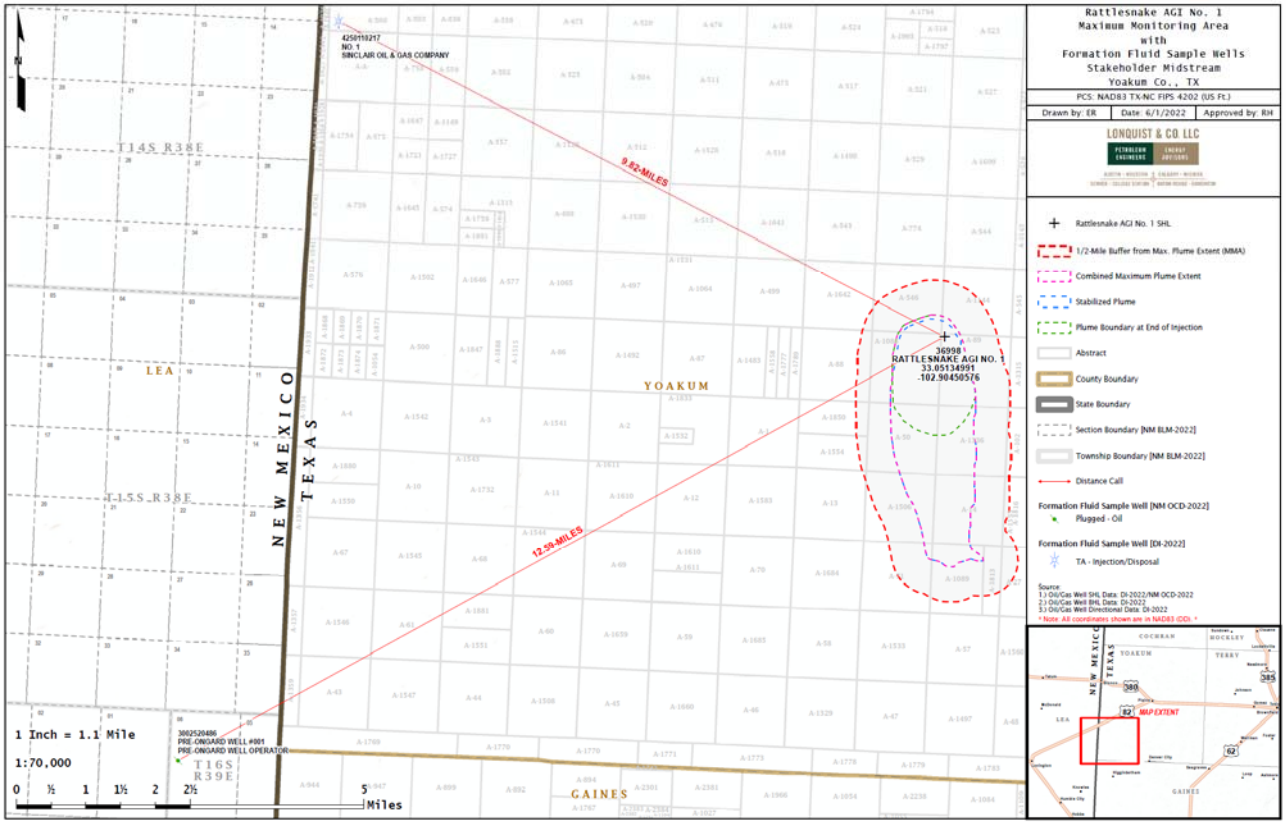


Figure 11 – Offset wells used for Formation Fluid Characterization

Table 1 – Analysis of Silurian-Devonian age formation fluids from nearby oil-field brine samples

	Average	Low	High
Total Dissolved Solids (ppm)	41,428	23,100	55,953
pH	7.2	7.0	7.3
Sodium (ppm)	12,458	7,426	15,948
Calcium (ppm)	1,759	1,010	2,320
Chlorides (ppm)	23,423	12,810	31,930

Fracture Pressure Gradient

Fracture pressure gradient was estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for the determination of fracture gradients. Poisson's ratio ("ν"), overburden gradient ("OBG"), and pore gradient ("PG") are all variables that can be changed to match the site-specific injection zone. Through literature review and industry standards, we are able to determine the expected

fracture gradient. First, 1.05 psi/ft and 0.465 psi/ft were assumed for both the overburden and pore gradients, respectively. These values are considered best practice values when there are no site-specific numbers available. For limestone/dolomite rock, the Poisson's ratio to be assumed to be 0.3 through literature review (Molina, Vilarras, Zeidouni 2016). Using these values in the equation below, a fracture gradient of 0.72 psi/ft was calculated. A 10% safety factor was then applied to this number resulting in maximum allowed bottom hole pressure of 0.64 psi/ft. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

For the upper confining interval, a similar fracture gradient as the limestone was calculated. Shale has an increased chance to vertically fracture if the injection interval is fractured (Molina, Vilarras, Zeidouni 2016), so assuming a Poisson's ratio equal to the injection interval was used as a conservative estimate. The lower confining zone was assumed to be of a similar matrix to that of the injection interval, with the key difference being that the formation is much tighter (lower porosity/permeability). The Poisson's ratio was assumed to be slightly higher in this rock. As seen in Table 2, the fracture gradient is slightly higher than the upper zones.

Table 2 – Fracture Gradient Assumptions

	Injection Interval	Upper Confining	Lower Confining
Overburden Gradient (psi/ft)	1.05	1.05	1.05
Pore Gradient (psi/ft)	0.465	0.465	0.465
Poisson's Ratio	0.30	0.30	0.31
Fracture Gradient psi/ft	0.72	0.72	0.73
FG + 10% Safety Factor (psi/ft)	**0.64**	**0.64**	**0.66**

The following steps were taken to calculate fracture gradient:

$$FG = \frac{\nu}{1 - \nu}(OBG - PG) + PG$$

$$FG = \frac{0.3}{1 - 0.3}(1.05 - 0.465) + 0.465 = 0.72$$

$$FG\ with\ SF = 0.72 \text{ x } (1 - 0.1) = \mathbf{0.64}$$

Lower Confining Zone – Montoya Formation

The low-permeability Montoya Formation is a tight limestone/dolomite that will act as the lower confining unit for the injection interval. Figure 10 shows the decreasing trend in porosity of the limestone rock in the lower section that was not exposed to leaching diagenesis. Porosity in the lower section can range from 2-3% with permeabilities below 1 millidarcy. The Rattlesnake AGI #1 well drilled 6' into the Montoya formation, but the section was not logged. The Montoya is anticipated to be roughly 250' thick. These petrophysical characteristics represent ideal sealing properties to prohibit any migration of injected fluid outside of the injection interval.

<u>Local Structure</u>

Regional structure in the area of the Rattlesnake AGI #1 well is dictated by carbonate buildups and structural events causing anticlinal to synclinal features throughout the area. The Rattlesnake AGI #1 well is specifically located at the base of a syncline with anticlinal features to the northeast, south, and east. Figure 12 is a

structure map of the Silurian formation of subsea depths with the star representing the location of the Rattlesnake AGI #1 well. The red and blue lines represent the cross-section reference lines.

Faulting can be seen to the south and east of the Rattlesnake AGI #1 well location. These faults were interpreted from roughly 9 square miles of 3D seismic indicated by the purple outline in Figure 12. Many of these faults are minor, with offsets less than 50'. The nearest large fault is found southeast of the Rattlesnake AGI #1 well and has an offset of roughly 120'. None of these faults project above the Wolfcamp formation, rather, they appear to terminate between the Strawn and base of the Wolfcamp formation. Production is associated with a hydrocarbon trap set up by the larger fault to the southeast, indicating the fault is vertically sealing in nature. If, in the unlikely event the faults' sealing properties are compromised post-injection, secondary confinement is provided by the tight limestones found within the overlying Mississippian Lime formation along with shale layers found in the Atoka and Wolfcamp formations. As seen in Figure 14, the largest fault found southeast of the Rattlesnake AGI #1 well, terminates within the Atoka formation. Though it crosses the Silurian section, this fault thrusts the Mississippian Lime upward against the Atoka shales. The tight reservoir characteristics of the Mississippian Lime and shaley section of the Atoka create a confining environment vertically and laterally to contain potential upward migration of buoyant fluids. Shales within the Wolfcamp formation provide additional confining beds between overlying USDWs and the fault plane. Figures 13 and 14 are north-south and west-east structural cross sections showing the structural dips. As seen in these figures, the Woodford formation is laterally present above the injection interval, alleviating risk of erosion of the upper sealant formation.

Larger versions of Figures 11, 12, 13 and 14 are provided in Appendix A.

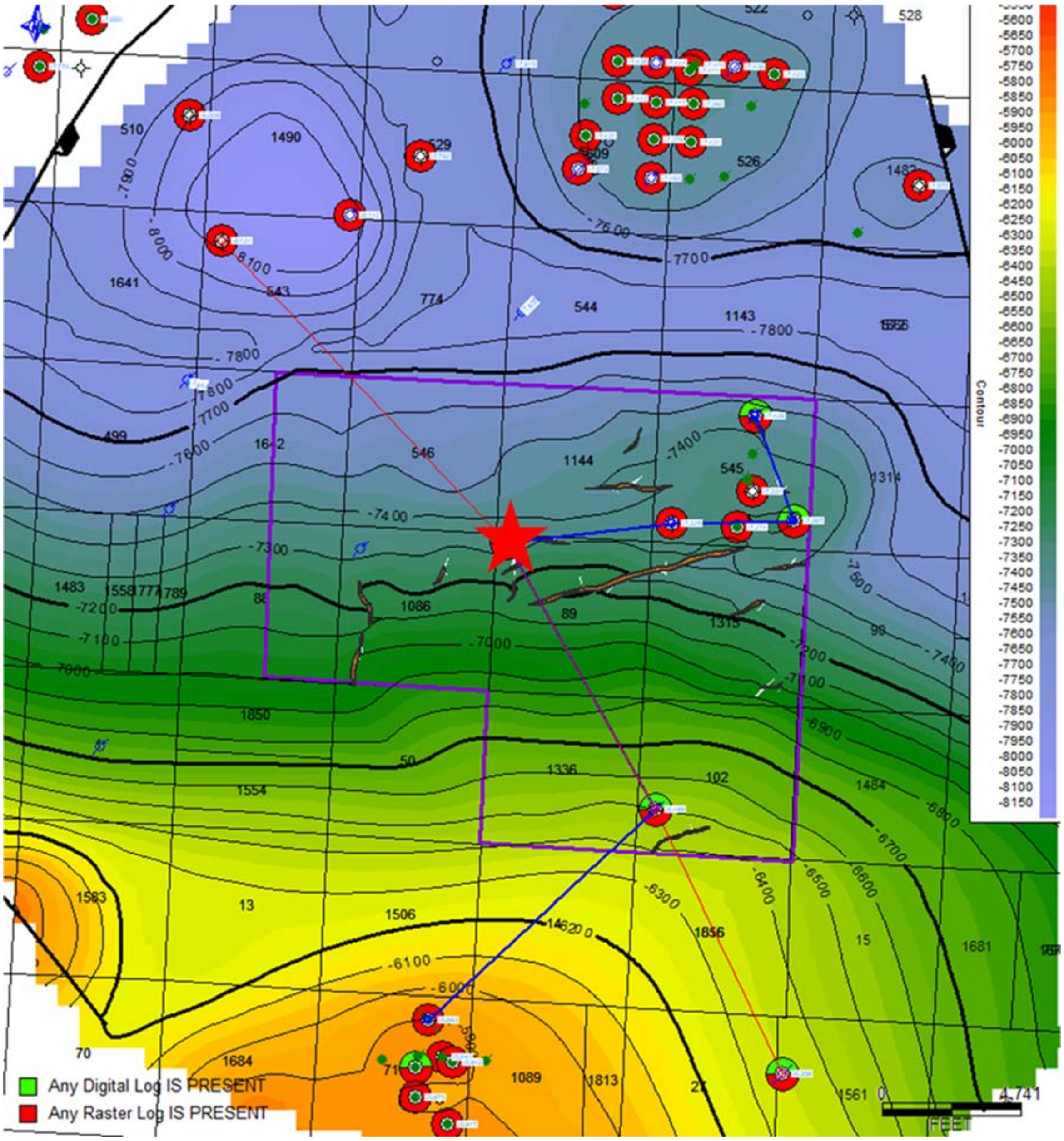


Figure 12 – Silurian Structure Map (subsea depths)

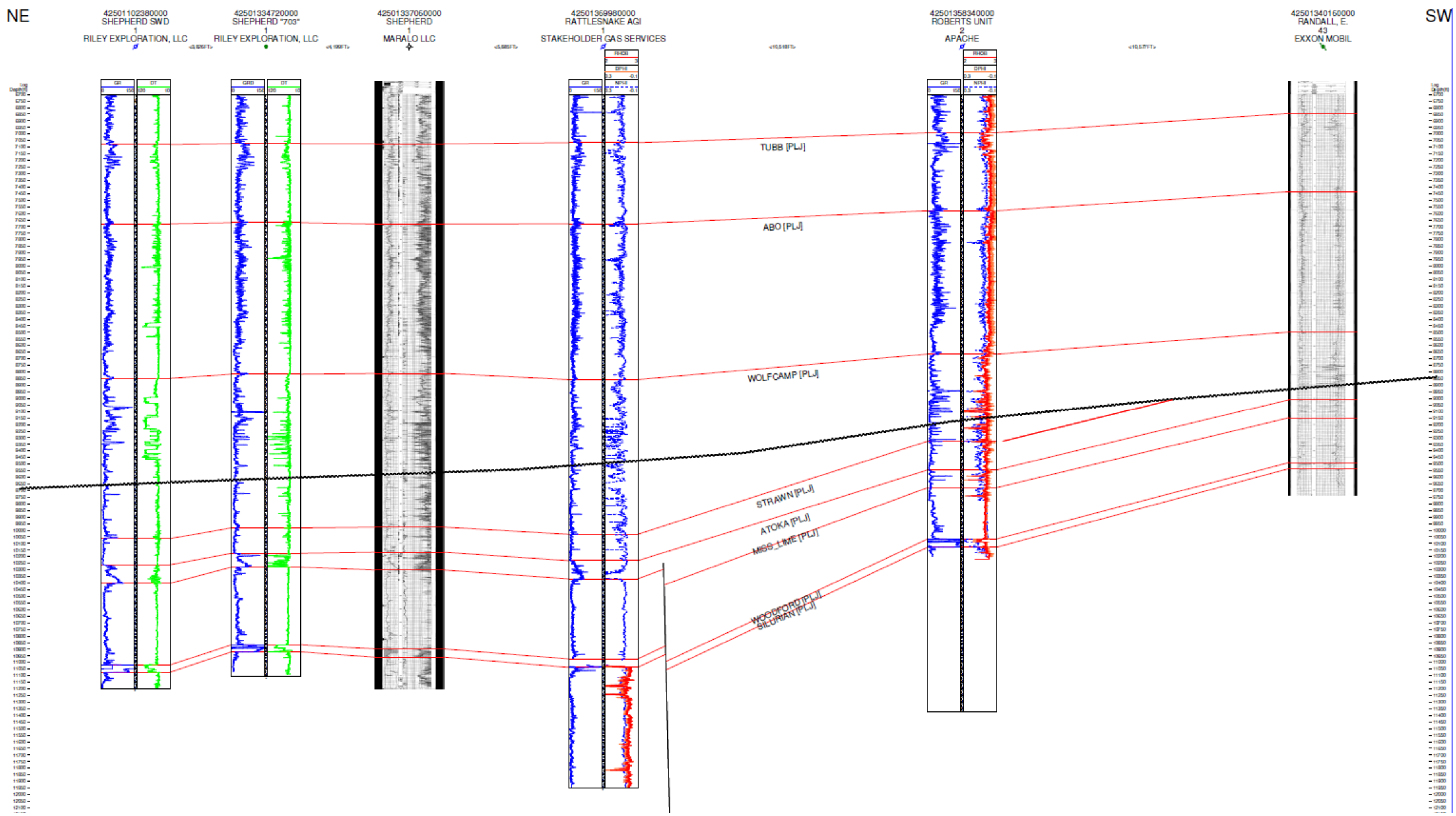
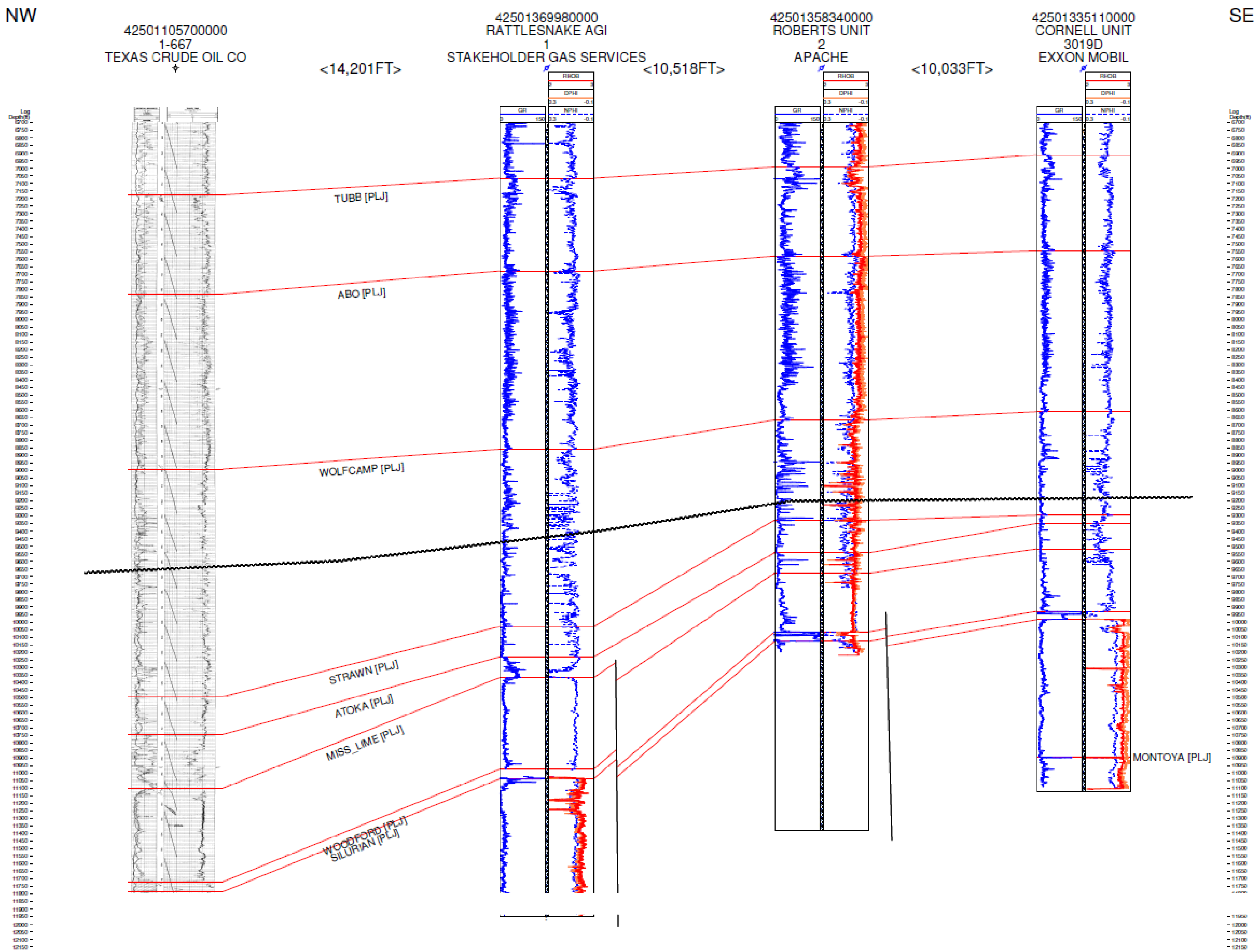


Figure 13 – Structural Northeast-Southwest Cross Section



NW
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STAKEHOLDER GAS SERVICES
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<14,201FT>
<10,518FT>
<10,033FT>
TUBB [PLJ]
ABO [PLJ]
WOLFCAMP [PLJ]
STRAWN [PLJ]
ATOKA [PLJ]
MISS_LIME [PLJ]
WOODFORD [PLJ]
SILURIAN [PLJ]
MONTOYA [PLJ]

Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Fasken and Fusselman formations at the Rattlesnake AGI #1 well location indicate the formations have sufficient thickness, porosity, permeability, and lateral continuity to accept the proposed injection fluids. The Woodford formation shale at the Rattlesnake AGI #1 well has low permeability and is of sufficient thickness and lateral continuity to serve as the upper confining zone. Beneath the injection interval, the low permeability, low porosity Montoya formation is unsuitable for fluid migration and serves as the lower confining zone. Deeper, laterally continuous formations, including the Simpson Group, provide additional confinement.

Groundwater Hydrology

Yoakum County falls within the boundary of the Sandy Land Underground Water Conservation District. Three aquifers are identified by the Texas Water Development Board's *Aquifers of Texas* report in the vicinity of the proposed Rattlesnake AGI #1 well: the Dockum Aquifer, Edwards-Trinity Aquifer, and Ogallala Aquifer (George, Mace and Petrossian, 2011). Table 3 references the aquifers' positions in geologic time and the associated geologic formations. A schematic cross section in Figure 15, near the proposed Rattlesnake AGI #1 well, illustrates the structure and stratigraphy of these water-bearing formations. Groundwater flow direction is the same for the three aquifers, generally from northwest to southeast, Figure 16 (Teeple, et al., 2021).

Table 3 – Geologic and hydrogeologic units with accompanying lithologic descriptions near Gaines, Terry and Yoakum Counties, Texas (Teeple, et al. 2021)

Era	Period	Epoch or series	Geologic unit group or formation	Lithologic descriptions	Hydrogeologic unit
Cenozoic	Tertiary	Pliocene	Ogallala Formation	Gravel, sand, silt, and clay	High Plains aquifer system (Ogallala aquifer)
		Miocene			
Mesozoic	Cretaceous[1]	Comanchean Series	Washita Group[2]	Shale and limestone	Edwards-Trinity (High Plains) aquifer system
			Fredericksburg Group	Clay, shale, and limestone	
			Trinity Group	Sand and gravel	
	Triassic	Upper	Dockum Group	Siltstone, mudstone, shale, and sandstone	Dockum aquifer

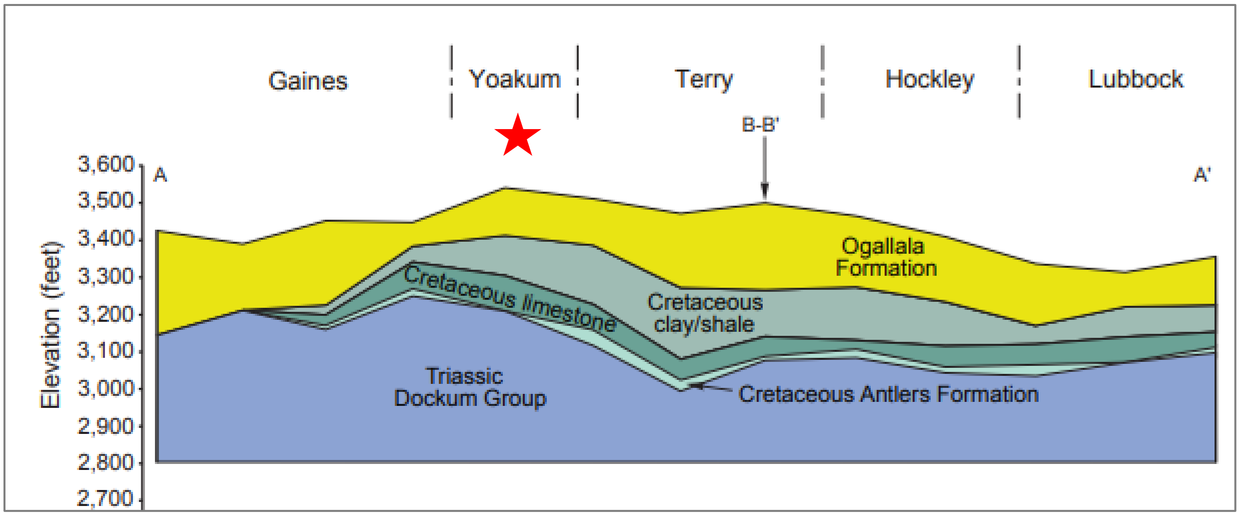


Figure 15 – NW-SE Cross Section of aquifers in the Rattlesnake AGI #1 well area (George, Mac and Petrossian, 2011)

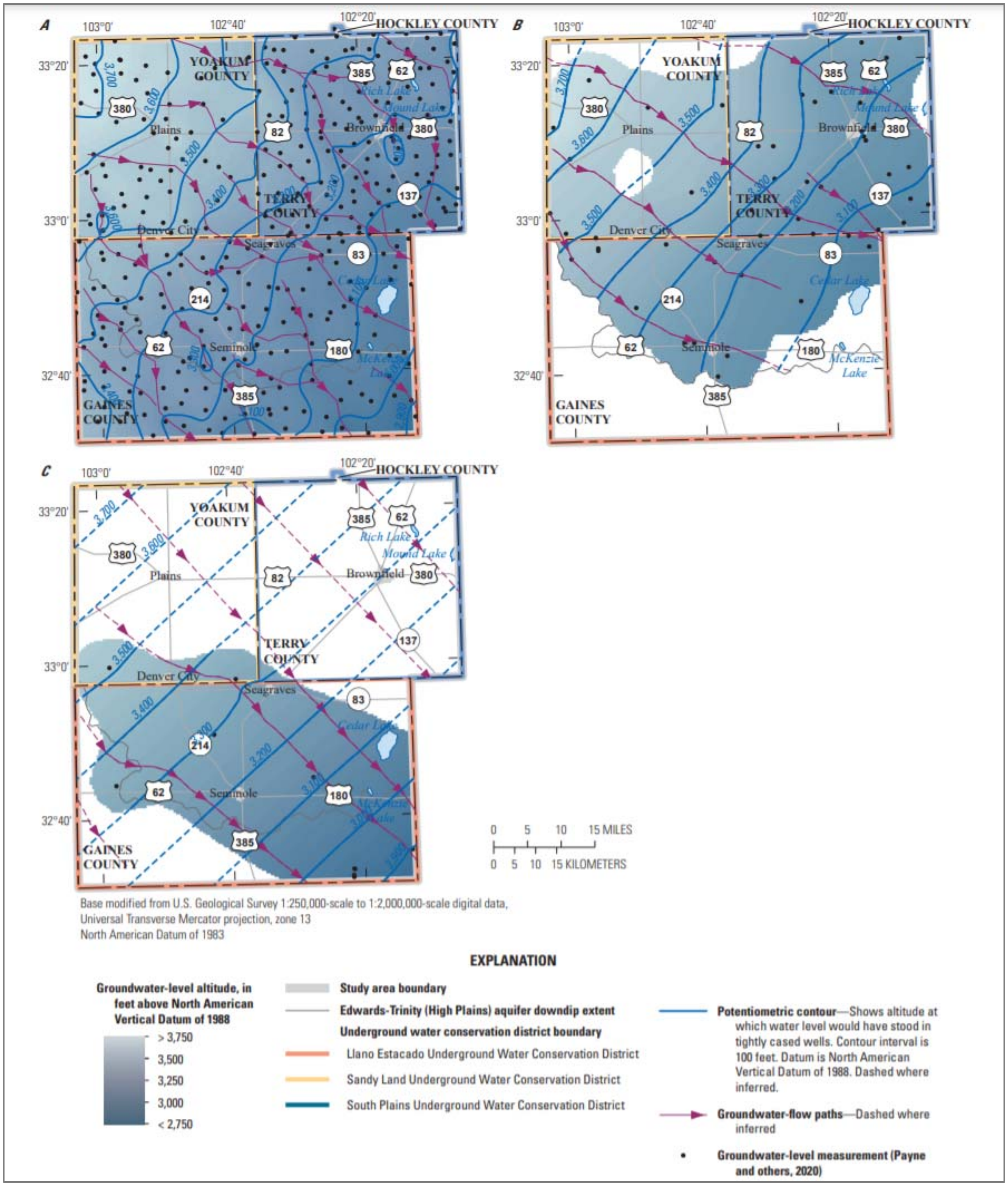


Figure 16 – Potentiometric surfaces from wells completed in A, Ogallala aquifer, B, the Edwards-Trinity aquifer and C, the Dockum aquifer (George, Mace and Petrossian, 2011).

The Dockum Aquifer is the oldest of the three aquifers, formed from Triassic-age Dockum Group sediments, and underlies the Cretaceous Trinity and Fredericksburg Groups (Teeple, et al., 2021). Figure 17 shows the subsurface and outcrop extent of the Dockum Aquifer. As shown in Figure 18, the total dissolved solids in western Yoakum County exceed 5,000 milligrams per liter ("mg/L"), therefore the aquifer is considered brackish.

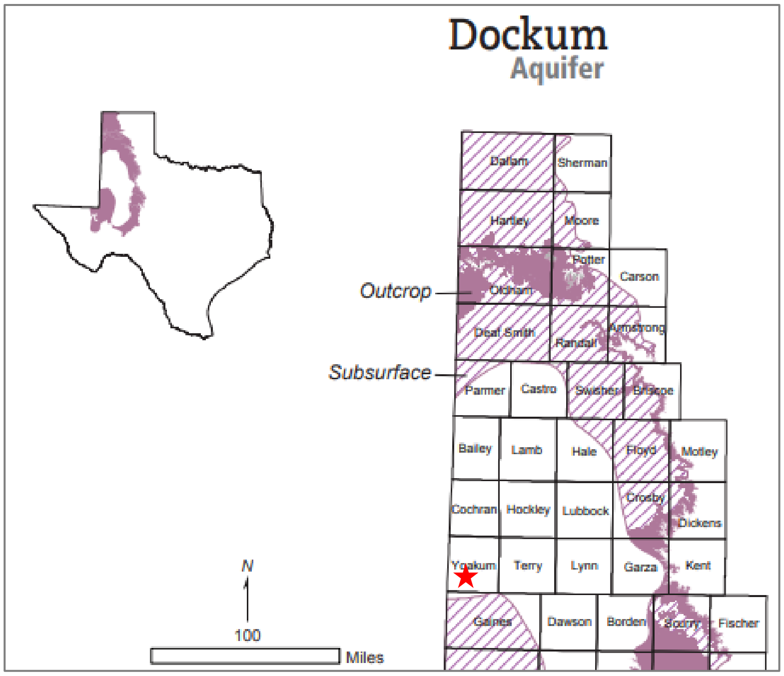


Figure 17 – Regional extent of the Dockum freshwater aquifer (TWDB)

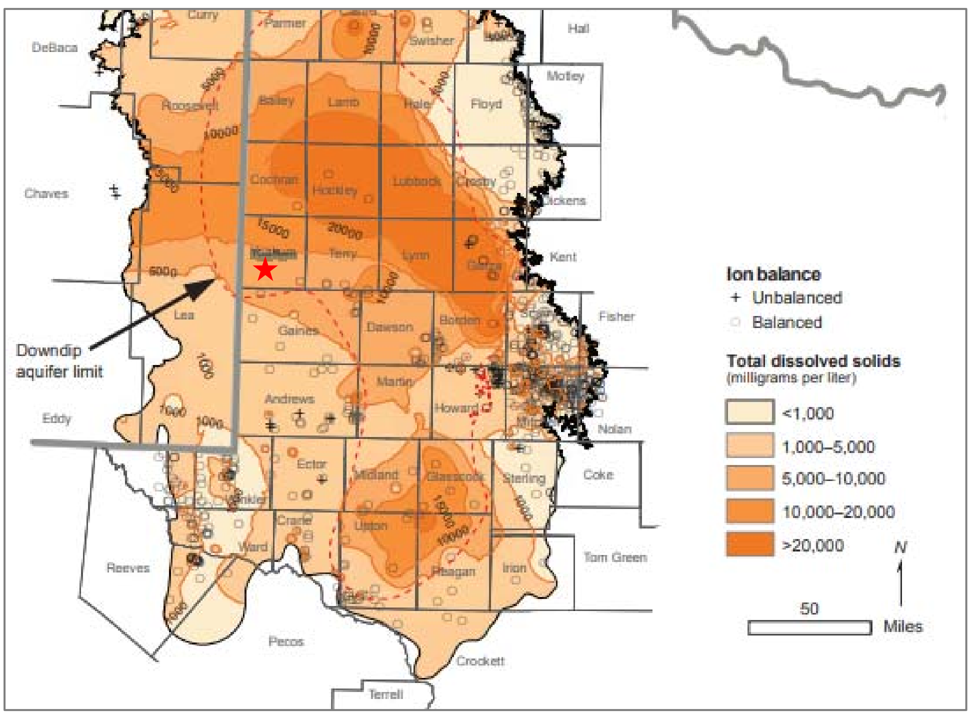


Figure 18 – Total dissolved solids in groundwater from the Dockum Aquifer (Ewing et al, 2008)

The Edwards-Trinity Aquifer is a collection of Cretaceous age sediments – primarily the Trinity Group Antlers formation sandstone and limestones of the Fredericksburg Group, specifically the Comanche Peak and Edwards formations. Figure 19 shows the subsurface and outcrop extent of the Edwards-Trinity Aquifer. Freshwater infiltration to this aquifer is primarily from the overlying Ogallala Aquifer (George, Mace and Petrossian, 2011).

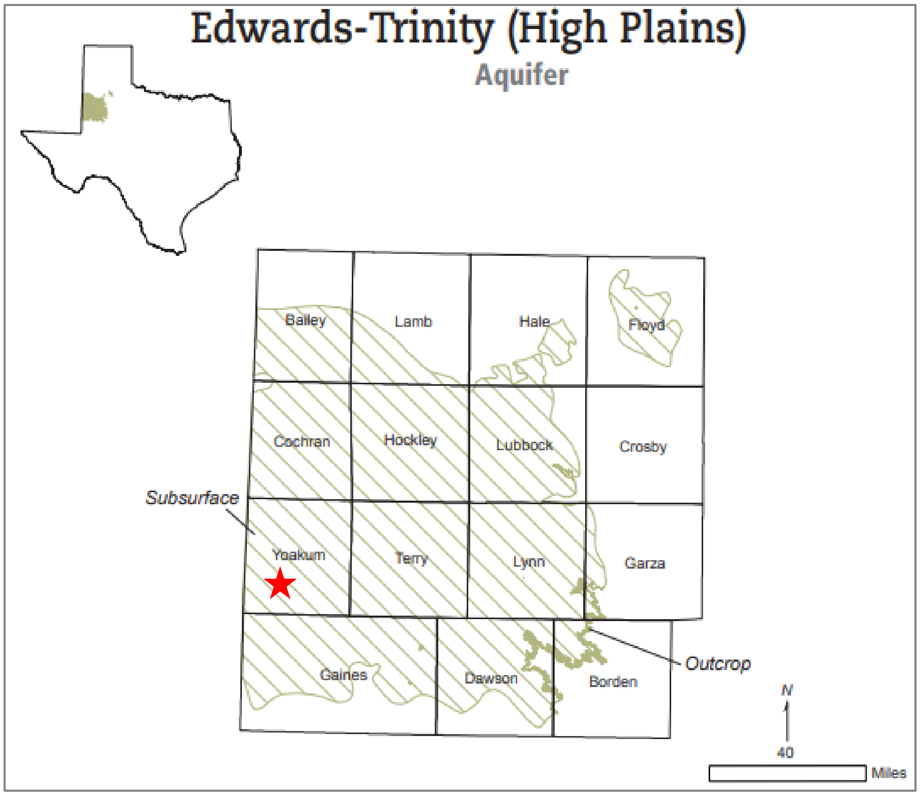


Figure 19 – Regional extent of the Edwards-Trinity freshwater aquifer (George, Mace and Petrossian, 2011)

The Ogallala aquifer consists of sand, gravel, clay and silt sediments (George, Mace and Petrossian, 2011) and produces the majority of the freshwater for Yoakum County. Figure 20 shows the subsurface and outcrop extent of the Ogallala Aquifer.

The base of the deepest aquifer is separated from the injection interval by approximately 8,600' of rock, including 576' of Salado salt. Though unlikely for reasons outlined in the confinement and potential leaks sections, if migration of injected fluid did occur above the Woodford Shale, thousands of feet of tight sandstone, limestone, shale, salt and anhydrite beds occur between the injection interval and the lowest water-bearing aquifer.

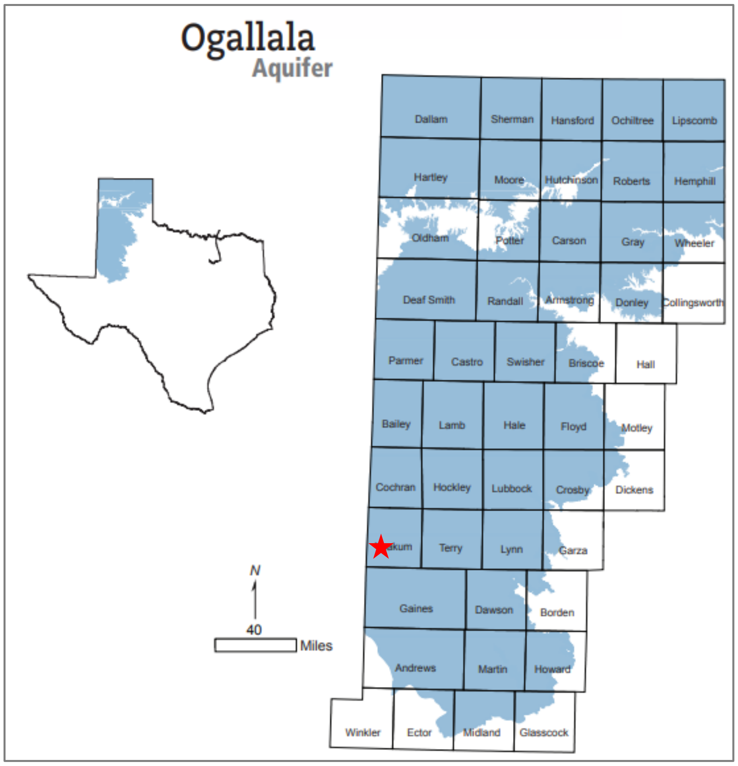


Figure 20 – Regional extent of the Ogallala freshwater aquifer (George, Mace and Petrossian, 2011)

The TRRC's Groundwater Advisory Unit ("GAU") identified the base of Underground Sources of Drinking Water ("USDW") at 375' at the location of the Rattlesnake AGI #1 well. Therefore, there is approximately 10,661' separating the base of the USDW and the injection interval. A copy of the GAU's Groundwater Protection Determination letter issued by the TRRC as part of the Class II permitting process for the Rattlesnake AGI #1 well is provided in Appendix B.

Description of the Injection Process

Current Operations

The 30-30 Facility and its associated Rattlesnake AGI #1 well began operating in March of 2019. Since operations began, 258 million cubic feet ("MMCF") of treated acid gas ("TAG") has been injected, which equates to 12,316 metric tons of CO_2. Over the life of the injection period, the average daily injection rate has been 223 MSCF/d. The approximate current composition of the TAG stream is as follows:

Table 4 – Gas Composition of 30-30 Facility outlet

Component	Mol %
CO2	89.68%
H2S	9.20%
Other	1.12%

The 30-30 Facility is designed to compress, treat, and process natural gas produced from the surrounding counties in Texas and New Mexico. The gas is dehydrated to remove the water content, then processed to separate natural gas liquids which are then sold, along with the pipeline quality natural gas, to various customers. TAG is then directly routed from the plant amine regen system to the Rattlesnake AGI #1 well. The facility is manned 24 hours per day, 7 days per week.

Planned Operations

Stakeholder anticipates increasing the amount of CO_2 injected into Rattlesnake AGI #1 well from the current rate up to 16 MMSCF/d. Additional growth is expected both at Stakeholder facilities and regionally as rising sour gas production and flaring reduction mandates create the need for additional CO_2 and H_2S disposal capacity. Stakeholder plans to inject into this AGI well for another 14 years for a total of 17 years from the start of injection in 2019.

Figure 21 shows a high-level view of the current process flow plus the prospective additional operations over time.

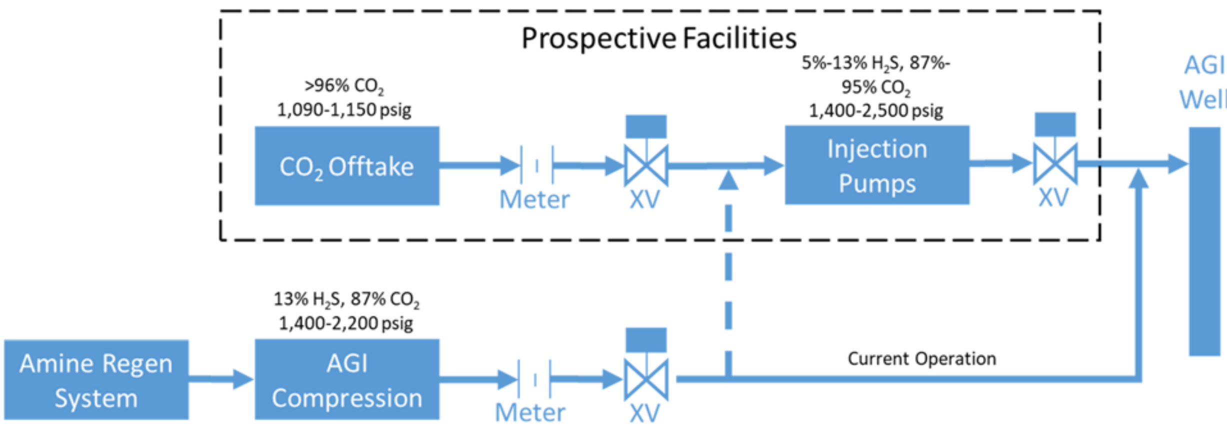


Figure 21 – 30-30 Facility Process Flow Diagram

Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2020.11 ("GEM") simulator. Computer Modelling Group ("CMG") has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM utilizes equation-of-state ("EOS") algorithms along with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon injection and storage. The GEM model is recognized by the EPA for use in area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Silurian (Fasken/Fusselman) formation is the target formation for Rattlesnake AGI #1 well. The Petra software package was used to create the geologic model of the target formation. The faulting and geologic structure was then imported into GEM and used to create contours for the model grid.

Porosity and permeability estimates were determined using the porosity log from the Rattlesnake AGI #1 well and a petrophysical analysis was performed to correlate porosity values by depth with core porosities

as shown in the Holtz paper. The Coates permeability equation was then used to calculate permeability with depth. Both porosity and permeability are assumed to be laterally homogeneous in the reservoir.

The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. An infinite acting reservoir was created to simulate boundary conditions. The gas injectate is composed of H_2S, CO_2, CH_4, and other components as shown in Table 5. Core data from literature review was used to determine residual gas saturation (Ruppel and Holtz, 1994). The modeled composition only takes into consideration the carbon dioxide and hydrogen sulfide as they comprise nearly 99% of total stream. For the initial injection period, these compositions are normalized up to 100%. For the proposed additional injection period, it is expected that a larger portion of the gas added is carbon dioxide, changing the composition to ~93% CO_2 and ~7% H_2S.

Table 5 – Modeled Initial Gas Composition

Component	Measured Current Composition (mol%)	2019-2024 Model Composition (mol%)	2024-2036 Model Composition (mol%)
Carbon Dioxide (CO2)	89.678	90.696	92.921
Hydrogen Sulfide (H2S)	9.200	9.304	7.079
Methane (C1)	0.303	0	0
Ethane (C2)	0.058	0	0
Propane (C3)	0.108	0	0
N-Butane (NC4)	0.025	0	0
Hexane Plus (C6+)	0.628	0	0

Core data from literature review was used to determine relative permeability curves between carbon dioxide and the connate brine within the Silurian-Devonian carbonates (Ruppel and Holtz, 1994). The key inputs used in the model include an irreducible water saturation of 25% and a maximum residual gas saturation of 21%.

The grid contains 141 blocks in the x-direction (E-W) and 201 blocks in the y-direction (N-S), totaling 28,341 grid blocks per layer. The grid blocks are each 150' by 150' by layer thickness as specified in Table 6. This results in the grid being 21,150' by 30,150' totaling just over a 23-square mile area (14,640 acres). Each layer in the model was determined by identifying higher permeability zones as targets for injection from the logs and assigning each high permeability and intermediary low permeability zone its own layer. One zone was identified as being a karst limestone (layers 2-7). Due to the "karsted" nature of this rock, it was determined that most of the injectate would flow into this zone. Therefore, the karst limestone was further split into layers by permeability to provide higher resolution and more accurately simulate which layer will have more gas flow into it. Figure 22 provides a detailed breakdown of the "karsted" rock.

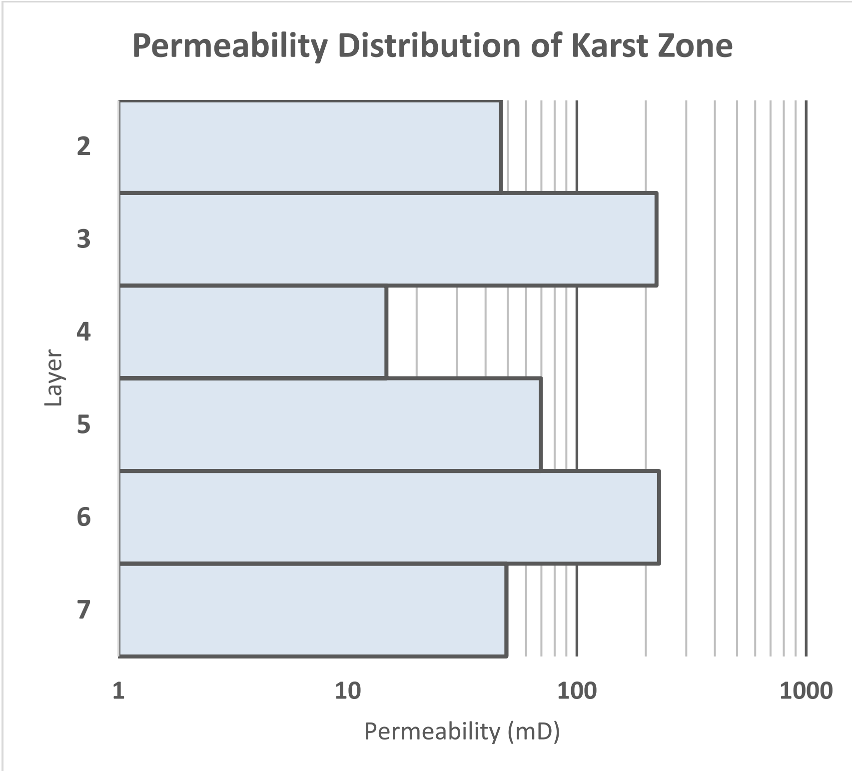


Figure 22 – Permeability Distribution of Karst Limestone

In total, there are sixteen (16) layers in the model, representing ten (10) layers of pay and six (6) layers of intermediary low permeability zones. The properties of each of these layers are summarized in Table 6 below.

Table 6 – CMG Model Layer Properties

Layer #	Top (ft)	Thickness (ft)	Permeability (mD)	Porosity
1	11,037	71	1	2.8%
2	11,108	57	47	8.0%
3	11,165	19	223	11.9%
4	11,184	16	15	6.3%
5	11,200	39	70	9.2%
6	11,238	11	228	12.3%
7	11,249	21	49	8.3%
8	11,270	251	2	3.7%
9	11,520	46	9	5.6%
10	11,566	13	3	4.3%
11	11,579	19	17	6.5%
12	11,597	14	2	3.9%
13	11,611	103	13	6.0%
14	11,714	46	2	3.7%
15	11,759	67	23	6.1%
16	11,826	125	2	3.6%

Simulation Modeling

The primary objectives of the model simulation were to:

1) Estimate the maximum areal extent and density drift of the acid gas plume after injection
2) Assess the impact of offset saltwater disposal ("SWD") well injection on density drift of the plume
3) Assess the impact of offset producing wells on the density drift of the plume
4) Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone
5) Assess the likelihood of the acid gas plume migrating into potential leak pathways

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 53,000 ppm (Texas Water Development Board, 1972). The acid gas stream is primarily composed of CO_2 and H_2S as stated previously. Core data was used to help generate relative permeability curves. Cores, from the literature reviews previously discussed, that most closely represent the vuggy carbonate seen in this region were identified and the Corey-Brooks equations were used to develop the curves. The lowest residual gas saturation found in the cores was then used for a conservative estimate of plume size. From offset injection well analysis, the initial reservoir pressure was determined to be 5,132 psi which is equivalent to a 0.465 psi/ft pressure gradient. The fracture gradient of the injection zone was estimated to be 0.72 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottom-hole pressure allowed in the model at 0.64 psi/ft which is equivalent to 7,064 psi.

The model also takes into account offset saltwater disposal ("SWD") injection volumes within five (5) miles of the Rattlesnake AGI #1 well. These SWDs create a pressure front that push the plume further up-dip of the formation. A total of twenty (20) offset wells currently injecting into the target formation were identified. Eleven (11) of these offset SWDs were out of the confines of the grid, but were still accounted for in the model. Nine (9) salt-water disposals were modeled within the boundaries of the 23-square-mile grid. Two (2) of these offset injectors are currently only permitted (not drilled) but were assumed to start active injection within the first year of the model. Both permits were simulated at the forecasted injection rate schedule for 30 years. These forecasts were provided by the operators of these wells. Historical injection rates of each of the other existing wells were analyzed and projected into the model. This simulation includes the effect of water injection on the density drift of the plume and bottom hole pressure.

Further review of the area revealed production wells in the Silurian-Devonian formation that could impact the density drift of the plume by creating a "pressure sink". A "pressure sink" is an area of lower pressure caused by the production of formation fluids. To simulate this effect, nine (9) production wells were grouped together and their respective production rates combined into a single well to add more conservatism into the model. These producers were forecasted an additional 15 years to simulate their potential economic lifespan. This simulation includes the effect of fluid production on the density drift of the plume and bottom hole pressure. Overall, the "pressure sink" has little effect on the density drift and, as discussed below, the plume never reaches the producing wells.

The model runs for a total of 814 years, starting in 1965 with the beginning of offset production until the calculated stabilization of the plume in 2779. The injection of TAG from Rattlesnake AGI #1 is modeled from the beginning of injection in 2019 through the planned 14 years of future injection. The model also includes the 57 years of historical plus 15 years of forecasted future oil and gas production.

Additionally, historical monthly injection rates of all nearby SWDs were incorporated into the model to simulate any additional near-wellbore pressure increase that may occur due to offset injection. The

modelling of the saltwater injection begins in 1984 when the first offset SWD well became operational. The SWDs to the North were grouped into four (4) separate groups to simulate their combined effect on the density drift of the plume. All offset injection wells and their groupings are included in Table 7. All offset production wells are listed in Table 8.

Table 7 – All Offset SWDs included in the model

Grouping	API	Well Name	Well #
Group 1	42-501-32511	SAWYER, DESSIE	1
	42-501-02068	WEST, M. M.	2
	42-501-02053	NORTH CENTRAL OIL CO. "A"	1
	42-501-01453	SMITH, ED S. HEIRS "B"	1
	42-501-02059	SMITH, ED "C"	1W
Group 2	42-501-30051	JOHNSON	2
	42-501-30001	JOHNSON	1D
Group 3	42-501-37066	MISS KITTY SWD 669	1W
	42-501-36650	RUSTY CRANE 604	1W
Group 4	42-501-36745	SUNDANCE 642	1
	42-501-33887	WINFREY 602	3WD
Standalone	42-501-37252	Miller SWD	7
	42-501-37367	BLONDIE 704	1W
	42-501-37206	BRUSHY BILL 707	1WD
	42-501-36622	WISHBONE FARMS 710	1W
	42-501-35834	ROBERTS UNIT	2
	42-501-33297	STATE ELMORE	1
	42-501-10238	SHEPHERD SWD	1
	42-501-33511	CORNELL UNIT	3019D
	42-501-32868	WILLARD UNIT	1WD

Table 8 - All Offset Producers included in the model

API	Well Name	Well #
42-501-10046	ELLIOTT, C.A.	2
42-501-10079	RANDALL, E	32
42-501-337932	RANDALL, E	40
42-501-33885	RANDALL, E	41L
42-501-34016	RANDALL, E	43L
42-501-34017	RANDALL, E.	45L
42-501-34023	RANDALL, E	42L
42-501-34024	RANDALL, E	44
42-501-35418	RANDALL, E	46

Rattlesnake AGI #1 came online in 2019 and the model simulated its historical monthly injection rates until 2024. After this initial period, it is conservatively assumed that the injection rate increases to the maximum permitted rate of 16 MMSCF/d for the remainder of the active injection period in 2036. At this point, the

Rattlesnake AGI #1 well stops injection while the offset SWD injectors continue operations for thirty more years. Density drift then occurs until plume stabilizes, which was determined to be 814 years from the start of the model in 1965. Stabilization of the plume is determined to occur when the model shows no further lateral movement horizontally or vertically. The plume boundary is then defined by a weighted average gas saturation in the aquifer of 3%.

The maximum plume extent during the 17-year Rattlesnake injection period is shown in Figure 23. The final extent after 743 years of density drift after injection ceases is shown in Figure 24. The extensive time of the modeled density drift of the plume is driven by the buoyant forces of the gas, the permeability/porosity of the rock, and the residual gas saturation. Initially, the karsted region takes on most of the injection, but due to the buoyant forces, it is slowly pushed up higher into the less permeable layers of the injection interval. These lower permeable layers, increase the amount of time it takes for the plume to reach its maximum areal extent. As all the inputs to the model were based on the most conservative approach, the maximum extent of the plume will likely be smaller and the effective impact on reaching potential leakage pathways will be minimal as the amount of CO_2 at those far extents will be small.

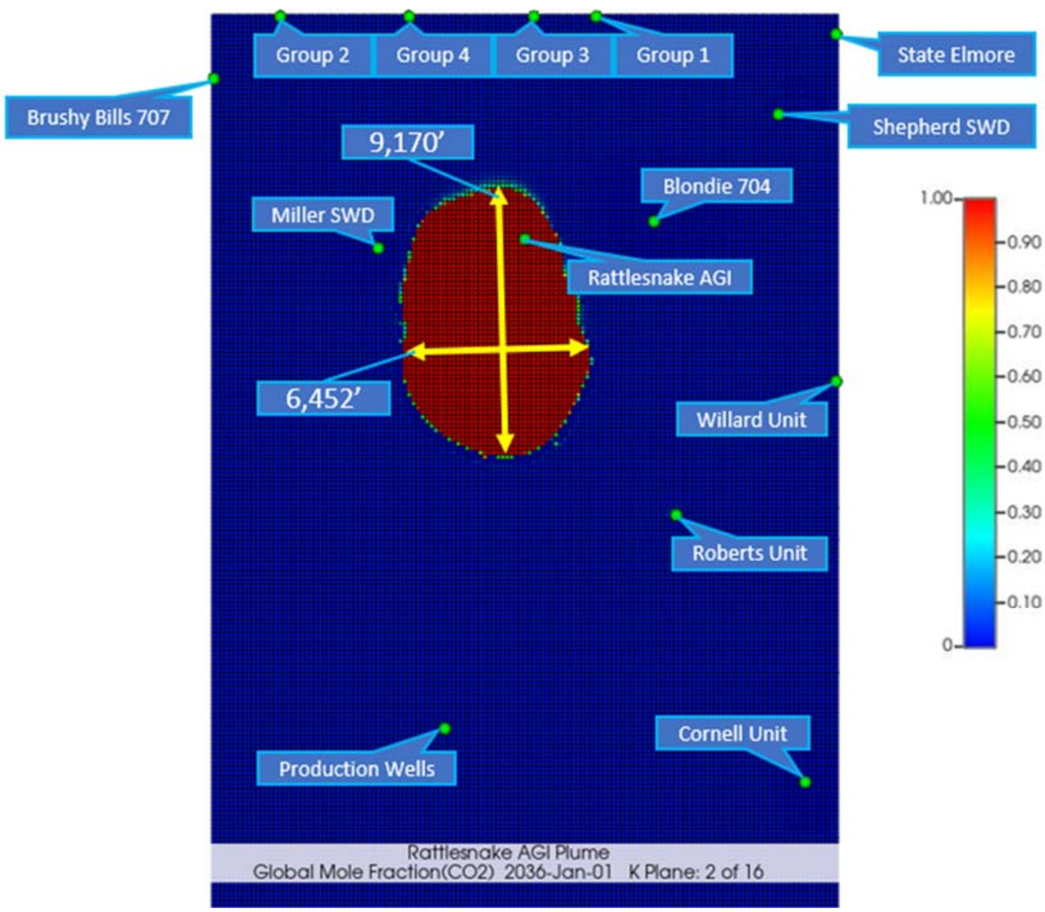


Figure 23 – Areal View Gas Saturation Plume, 2036 (End of Injection)

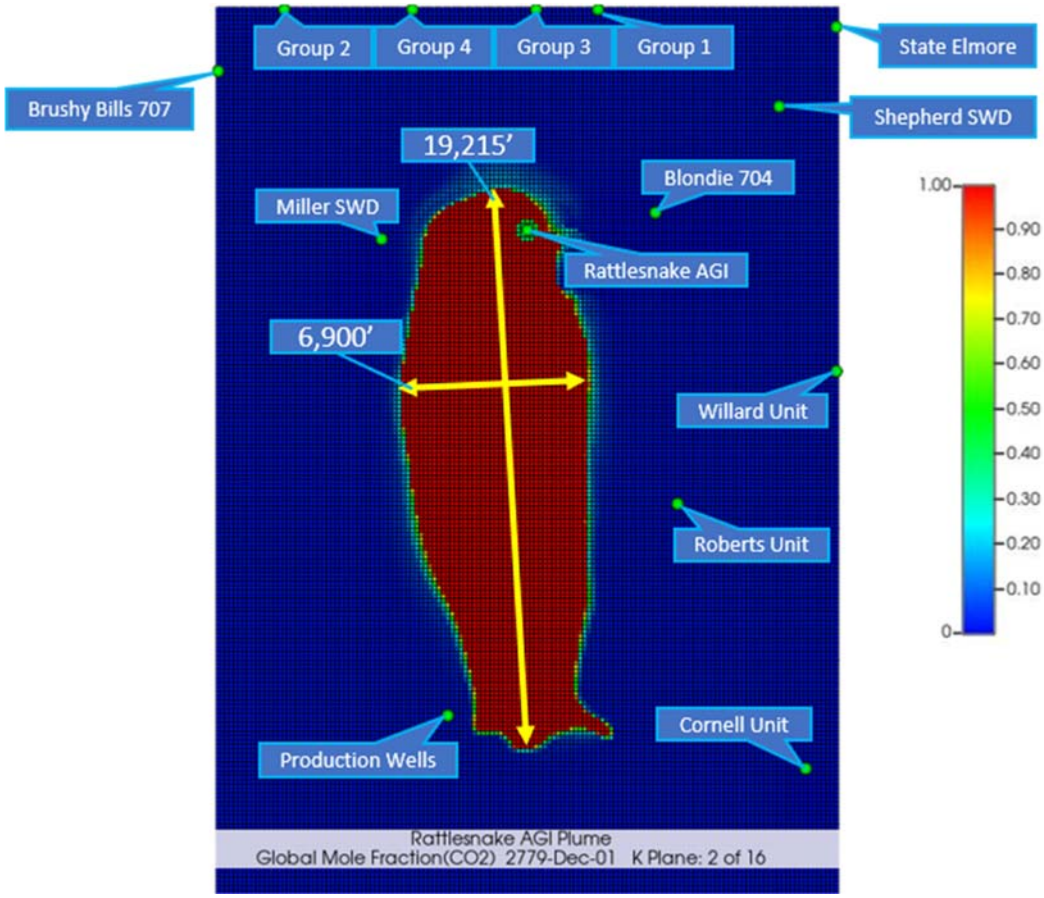


Figure 24 – Areal View Gas Saturation Plume, 2779 (End of Density Drift)

Figure 25 shows the surface injection rate and bottom hole pressure over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate reaches its peak, reaching a maximum pressure of 5,413 psi. This buildup of 280 psi keeps the bottomhole pressure well below the fracture pressure of 7,064 psi. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,494 psi.

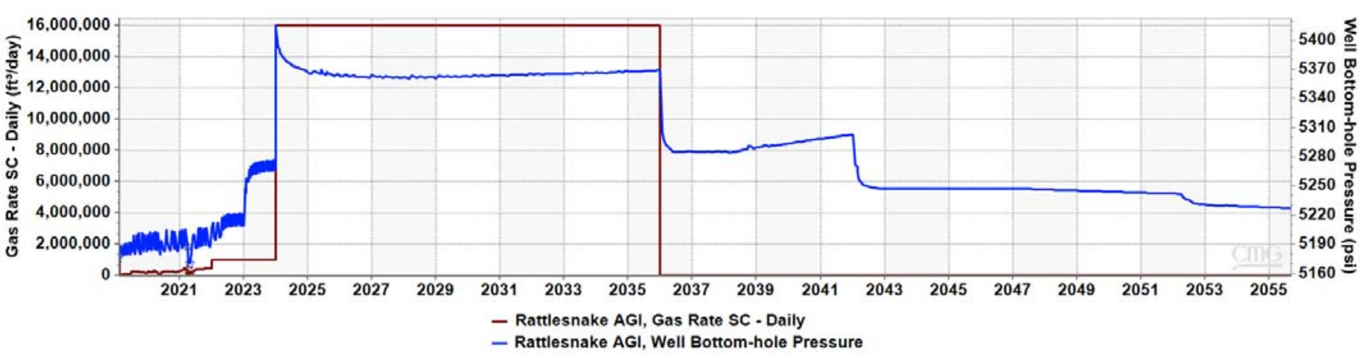


Figure 25 – Well Injection Rate and Bottomhole Pressure over Time

SECTION 3 – DELINATION OF MONITORING AREA

This section discusses the delineation of Maximum Monitoring Area ("MMA") and Active Monitoring Area ("AMA") as described in EPA 40 CFR §98.448(a)(1).

Maximum Monitoring Area

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

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

Acid gas injectate was analyzed by a third-party vendor to determine the initial composition used in the model. The report is provided in Appendix C. The molar composition of the gas is primarily CO_2 with some H_2S and CH_4. The change in molar composition was also incorporated into the model as future predominantly CO_2 streams are added for injection. As discussed in Section 2, the gas was injected into the Silurian formation, specifically, the Fasken/Fusselman formation. The geomodel was created based off the rock properties seen in the Fasken/Fusselman.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in 2036, the areal expanse of the plume will be 1,052 acres. The maximum distance between the wellbore and the edge of the plume is approximately 0.87 miles to the southeast. After 743 additional years of density drift, the areal extent of the plume is 2,177 acres with a maximum distance to the edge of the plume of approximately 1.35 miles to the southeast.

Figure 26 shows the plume boundary at the end of injection, the stabilized plume boundary and the MMA.

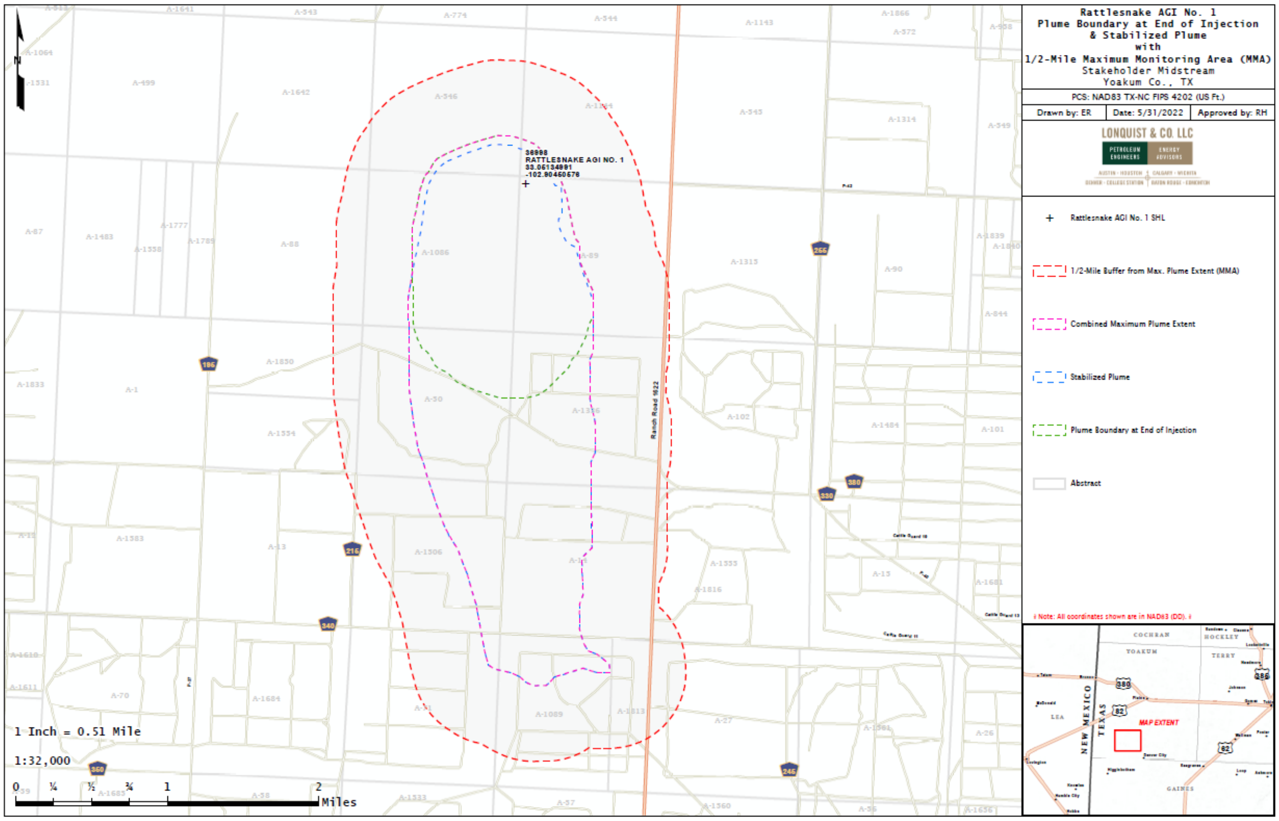


Figure 26 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

Active Monitoring Area

The initial AMA will cover a 14-year monitoring period. This period equates to the time of expected future injection. The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location at the end of injection (2036) with the area of the projected free-phase CO_2 plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume at 2036 plus a half-mile buffer. By 2036 at the latest, a revised MRV plan will be submitted to define a new AMA. Figure 27 shows the area covered by the AMA.

Larger size versions of Figures 26 and 27 are provided in Appendix D.

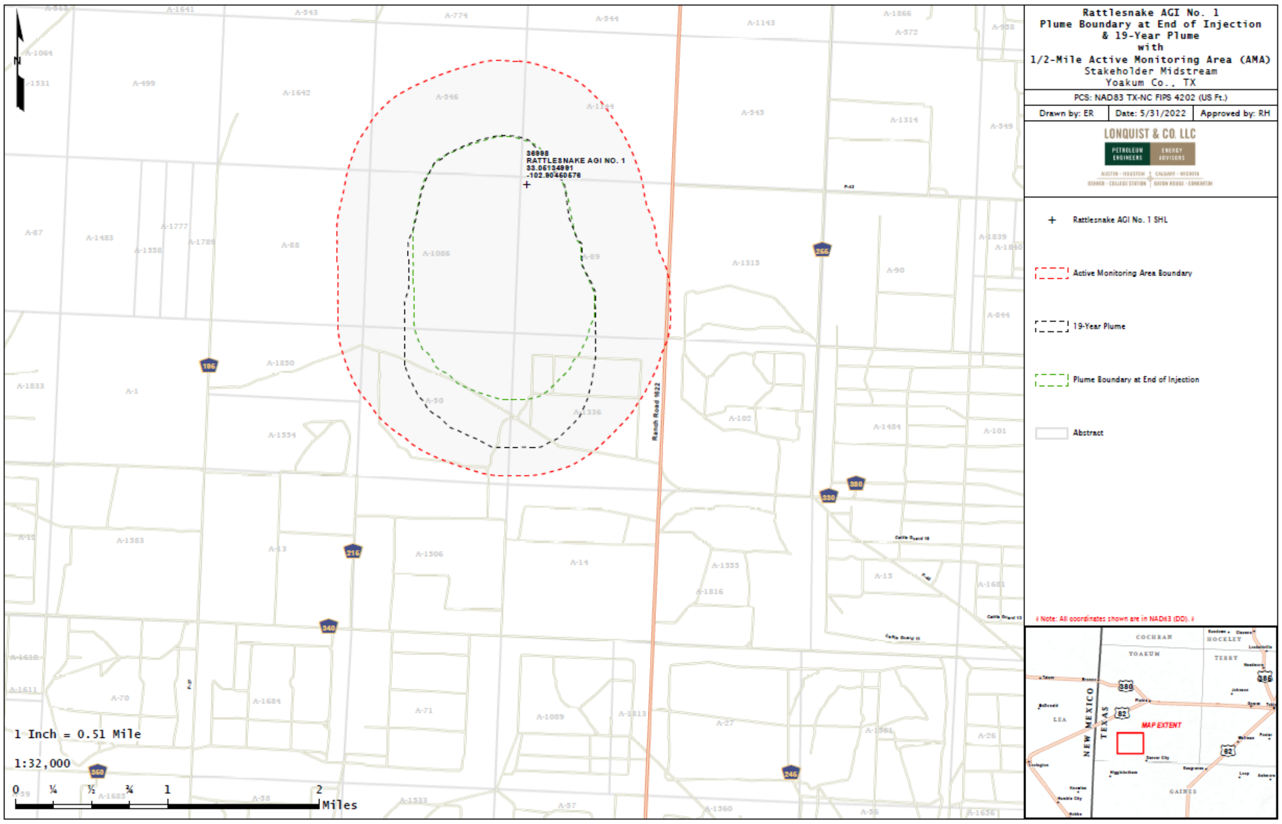


Figure 27 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA and the likelihood, magnitude and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within MMA
- Leakage through faults and fractures
- Natural or Induced Seismicity
- Drilling through the MMA
- Leakage through the confining layer

Leakage from Surface Equipment

The surface facilities at the 30-30 Facility are designed for injecting acid gas containing H_2S, and therefore minimize leakage points such as valves and flanges following industry standards and best practices. H_2S gas detectors are located around the facility and the well site. These gas detectors trigger alarms at 10 parts per million ("ppm"). Additionally, all Stakeholder field personnel are required to wear H_2S monitors which are triggered at 5 ppm of H_2S. A shut-in valve is located at the wellhead and is locally controlled by pressure, with a high pressure and low pressure shut-off.

The facilities have been designed and constructed with additional safety systems to provide for safe operations. These systems include Emergency Shutdown ("ESD") valves to isolate portions of the plant and pipeline, pressure relief valves along the pipeline to prevent over pressurization, and flares to allow piping and equipment to be de-pressured rapidly under safe and controlled operating conditions in the event of a leak. Figures 28 and 29 display the facility safety plot plan, taken from the 30-30 H_2S Contingency Plan, and show the location of the H_2S monitors in the vicinity of the plant and the Rattlesnake AGI #1 well. Should Stakeholder construct additional CO_2 facilities, as indicated in Figure 21, a separate meter will be installed for the additional stream in order to comply with the 40 CFR §98.448(a)(5) measurement. As this meter will be in close proximity to the existing facilities, it will utilize the existing monitoring programs discussed previously. Additionally, CO_2 monitors will be installed near the new meter and tied into the facility monitoring systems.

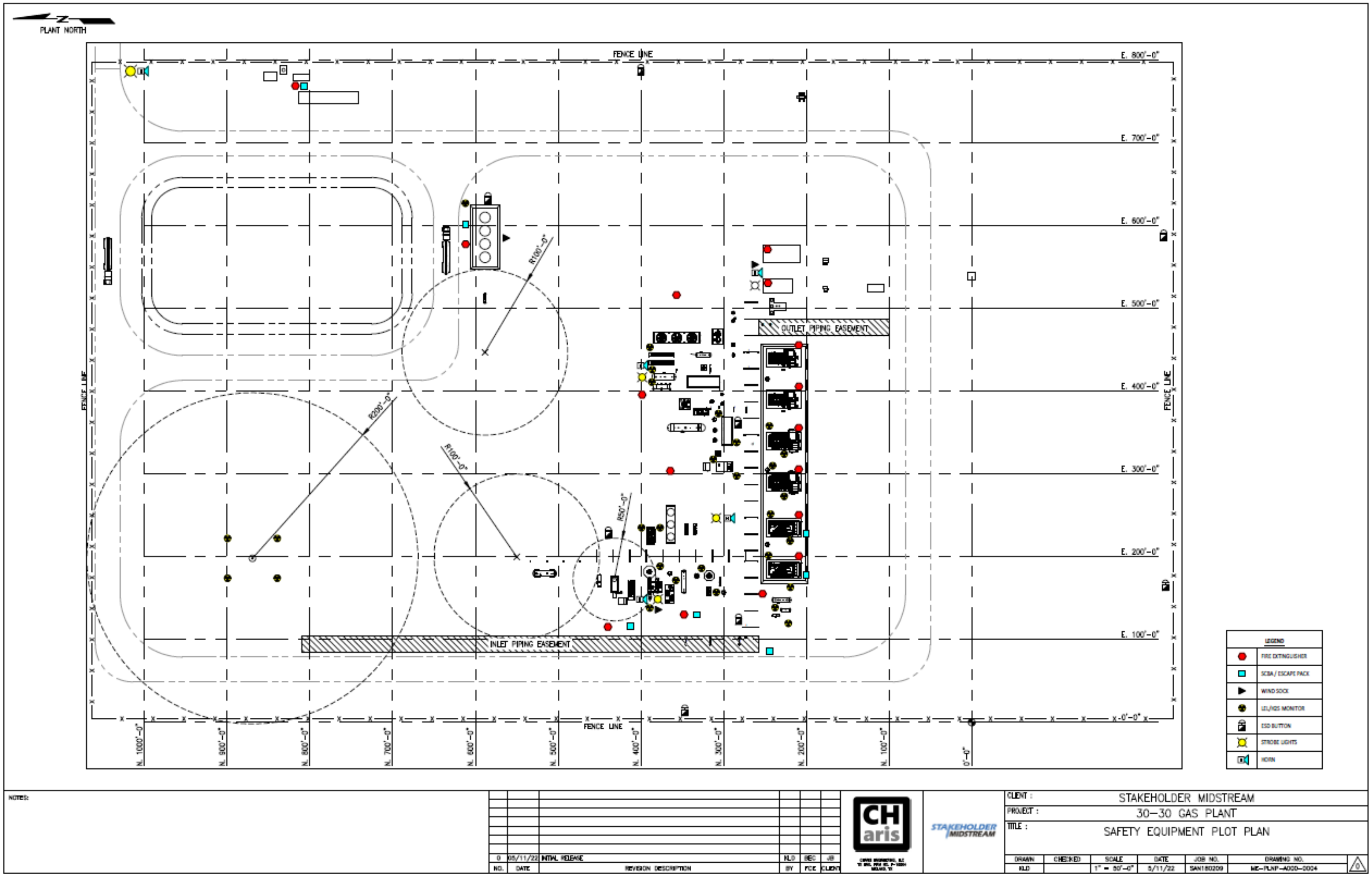


Figure 28 – Site Plan, 30-30 Facility

With the level of monitoring at the 30-30 Facility and the Rattlesnake AGI #1 well, any release of H_2S and CO_2 would be quickly identified, and the safety systems would quickly minimize the volume of the release. The CO_2 injected into the Rattlesnake AGI #1 is injected with H_2S at a concentration of 10% (100,000 ppm). At this high level of H_2S concentration, even a small leakage would trigger personal and facility H_2S monitors set to alarm at 5 ppm and 10 ppm respectively. If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7 in accordance with 40 CFR §98.448(a)(5).

A larger scale version of Figure 28 is provided in Appendix E.

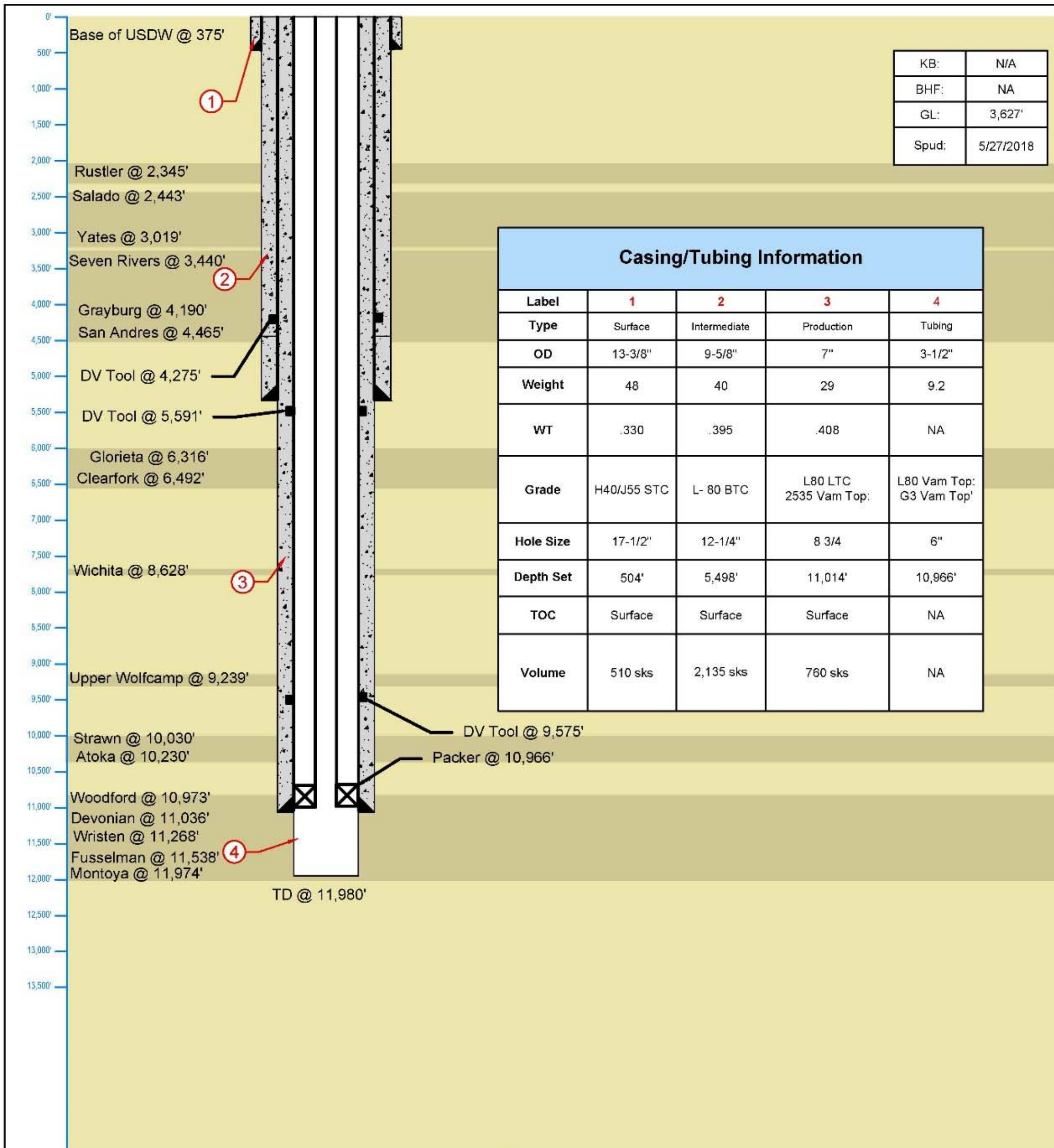
Leakage from Wells in the Monitoring Area

Oil and Gas Operations within Monitoring Area

A significant number of wells have historically been drilled within the area of the Rattlesnake AGI #1 well, however production has primarily been from the shallower San Andres formation in the Wasson Field. The San Andres is separated from the Silurian-Devonian interval by 4,720' in this area. In addition to the primary San Andres production, a few wells have produced from the Wolfcamp. The Wolfcamp is separated from the Siluro-Devonian interval by is 1,800'. **Within the projected plume area of the Rattlesnake AGI #1 well, there are no penetrations of the injection interval.** There are ten wells within the MMA that penetrate the injection interval.

A review of the TRRC records for all of the wells which penetrate the injection interval within the MMA, shows the wells were properly cased and cemented to prevent annular leakage of CO_2 to the surface. The plugged wells are also adequately protected against migration from the Devonian by the placement of the plugs within the wellbores. Additionally, the Rattlesnake AGI #1 well was designed to prevent migration from the injection interval to the surface through the casing and cement placed in the well, as shown in Figure 29. Mechanical integrity tests ("MIT") required under TRRC rules are run annually to verify the well and wellhead can hold the appropriate amount of pressure. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated quickly to prevent leakage to the atmosphere.

A map of all wells within the MMA is shown in Figure 30. Figure 31 shows only those wells which penetrate the injection interval within the MMA. The MMA review maps, a summary of all the wells in the MMA and detailed wellbore schematics for those wells which penetrate the injection interval are provided in Appendix F.



KB:	N/A
BHF:	NA
GL:	3,627'
Spud:	5/27/2018

Casing/Tubing Information

Label	1	2	3	4
Type	Surface	Intermediate	Production	Tubing
OD	13-3/8"	9-5/8"	7"	3-1/2"
Weight	48	40	29	9.2
WT	.330	.395	.408	NA
Grade	H40/J55 STC	L- 80 BTC	L80 LTC 2535 Vam Top:	L80 Vam Top: G3 Vam Top'
Hole Size	17-1/2"	12-1/4"	8 3/4	6"
Depth Set	504'	5,498'	11,014'	10,966'
TOC	Surface	Surface	Surface	NA
Volume	510 sks	2,135 sks	760 sks	NA

LONQUIST & CO. LLC PETROLEUM ENGINEERS ENERGY ADVISORS HOUSTON CALGARY AUSTIN WICHITA DENVER	Stakeholder Midstream	Rattlesnake No. 1	
	Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
	Location: 33.07884, -103.904514	**Site:**	**Survey:**
	API No: 42-501-36998	**Field:**	**Well Type/Status:** AGI
Texas License F-9147	**RRC District No:**	**Project No:** LS 128	**Date:** 5/27/2022
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** ASG	**Reviewed:** SLP	**Approved:** SLP
	Rev No: 1	**Notes:**	

Figure 29 – Rattlesnake AGI #1 Wellbore Schematic

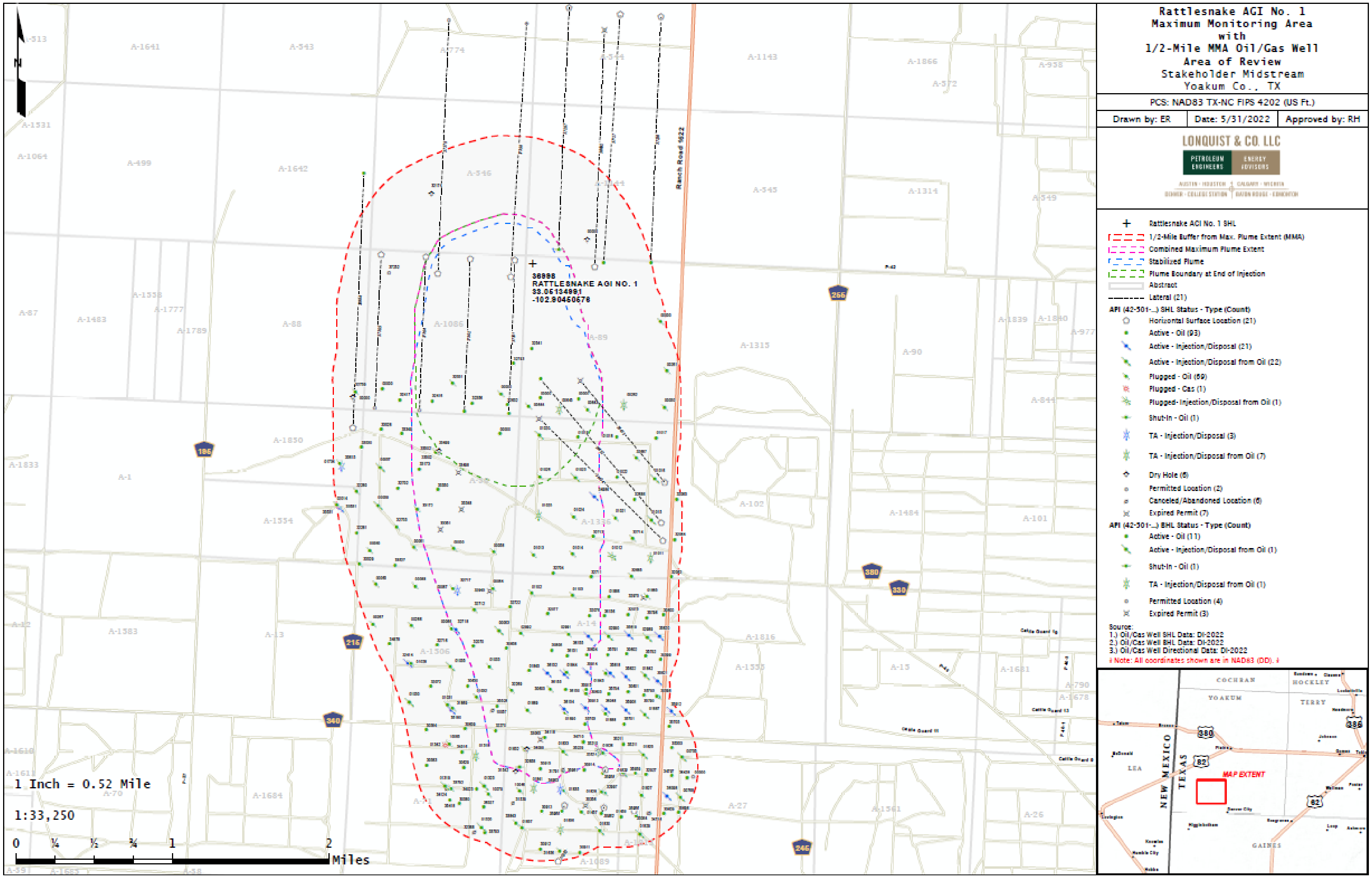


Figure 30 – Oil and Gas Wells within the MMA

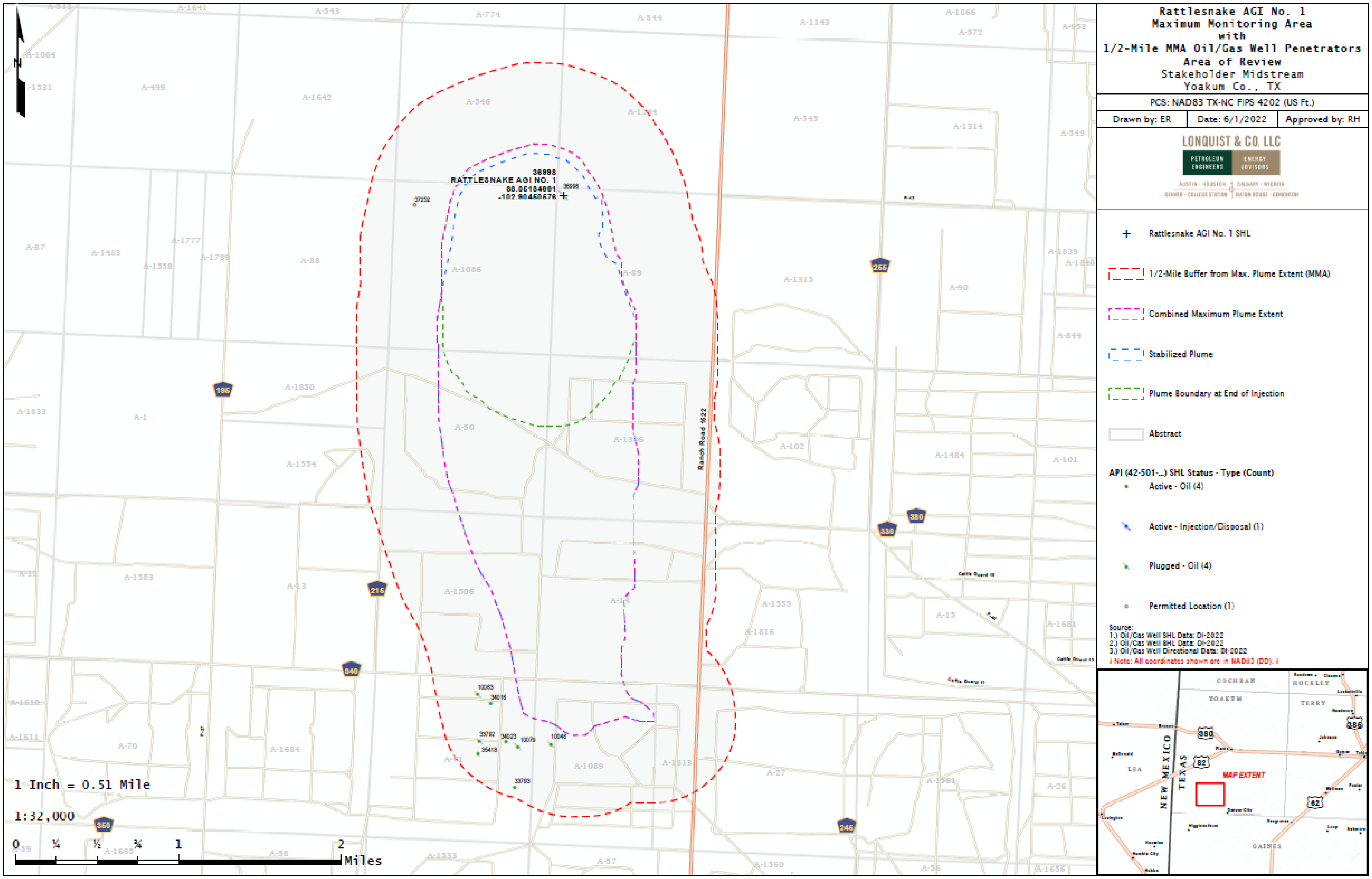


Figure 31 – Penetrating Oil and Gas Wells within the MMA

Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, such as the Devonian, have proven to-date to be less productive or non-productive in this area, which is why the location was selected for injection. Furthermore, any drilling permits issued by the TRRC in the area of the Rattlesnake AGI #1 well include a list of formations for which oil and gas operators are required to comply with TRRC Rule 13 (entitled "Casing, Cementing, Drilling, Well Control, and Completion Requirements"). 16 TAC § 3.13. By way of example, see the Rattlesnake AGI #1 well drilling permit provided in Appendix B. The Devonian is among the formations listed for which operators in Yoakum County (where the Rattlesnake #1 is located) are required to comply with TRCC Rule 13 (Appendix B, pg. 5). TRRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under TRRC Rule 9 or immediately above all formations permitted for injection under Rule 46 for any well proposed within a one-quarter mile radius of an injection well. In this instance, any new well permitted and drilled to the Rattlesnake AGI #1 well's injection zone, and located within a one-quarter mile radius of the Rattlesnake AGI #1 well, will be required under TRRC Rule 13 to set steel casing and cement above the Rattlesnake AGI #1 well injection zone. Additionally, Rule 13 requires operators to case and cement across and above *all* potential flow zones and/or zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued, which is also shown in the above-mentioned permit in Appendix B.

If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release.

Groundwater wells

There are seven groundwater wells located within the MMA, as identified by the Texas Water Development Board. All of the identified groundwater wells in the area have total depths less than or equal to 265', as shown in Figure 32 and Table 9. One of the wells is located on the 30-30 facility property with a total depth of 119'and is operated by Stakeholder.

The surface and intermediate casings of the Rattlesnake AGI #1 well, as shown in Figure 29, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the GAU letter issued for this location. See GAU letter included within Appendix B. The wellbore casings and cements also serve to prevent CO_2 leakage to the surface along the borehole.

A larger scale version of Figure 32 is provided in Appendix F.

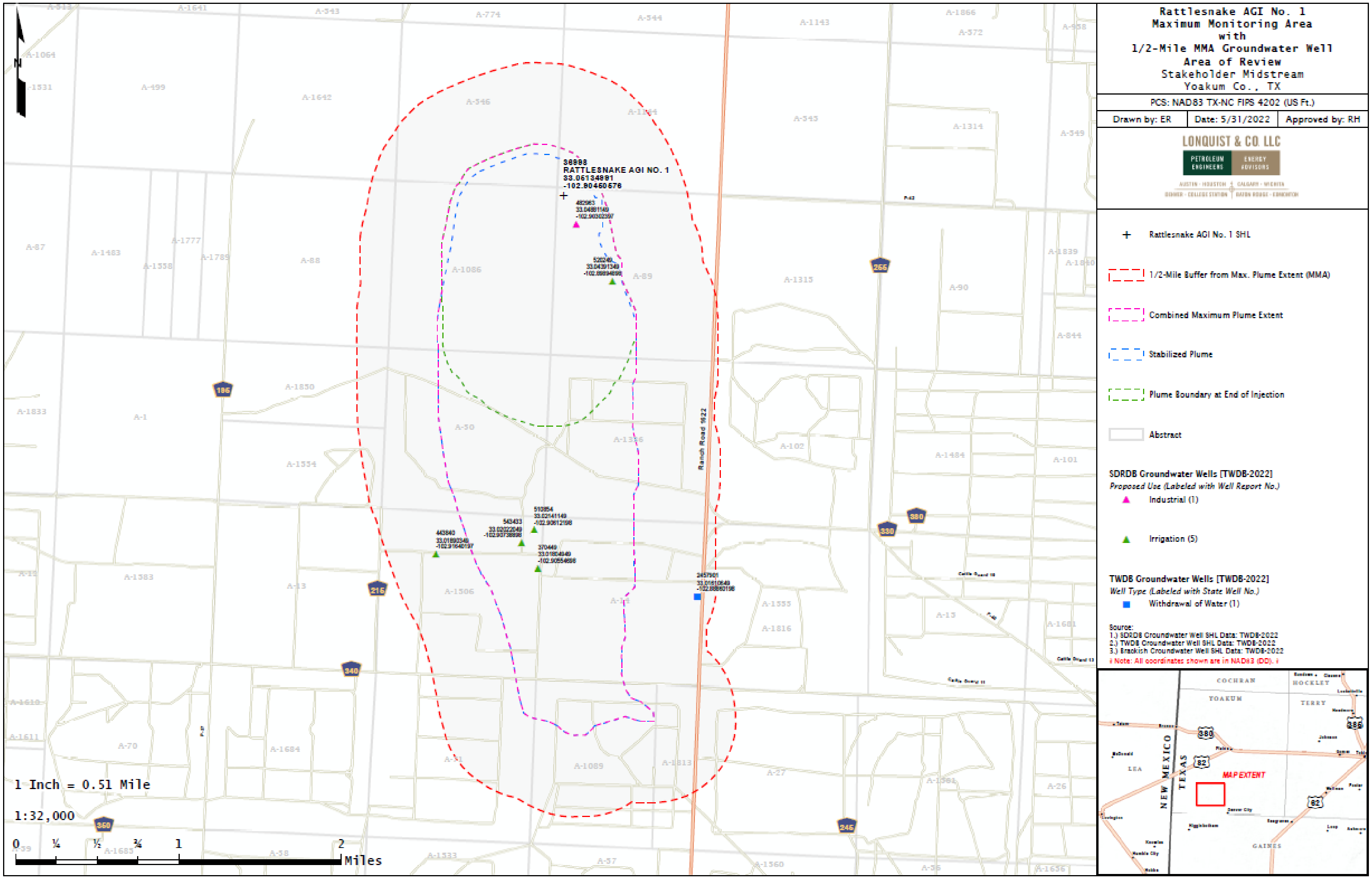


Figure 32 – Groundwater Wells within MMA

Table 9 – Groundwater Well Summary

State Well ID	Owner Name	Primary Use	Well Depth	Data Source
370449	Frances Barbini	Irrigation	237	SDRDB
443840	Frances Jean Barbini	Irrigation	250	SDRDB
482963	Santa Fe Midstream Permian	Industrial	119	SDRDB
510854	FRANCIS BARNINI	Irrigation	255	SDRDB
520249	Thomas Durham	Irrigation	264	SDRDB
543433	FRANCIS BARBIDI	Irrigation	240	SDRDB
84760	TEXACO PRODUCING INC			TWDB_BW

Leakage Through Faults or Fractures

Faults were interpreted from roughly 9 square miles of 3D seismic indicated by the purple outline in Figure 12. Faulting in this region terminates vertically below the Pennsylvanian-age rock. Secondary confining shales within the Wolfcampian and younger strata provide additional, redundant confining layers that would prevent CO_2 from migrating into freshwater aquifers. None of the mapped faults project above the Wolfcamp formation; rather, they appear to terminate between the Strawn and base of the Wolfcamp formation. If, in the unlikely event the faults' sealing properties are compromised post-injection, secondary confinement is provided by the tight limestones found within the overlying Mississippianan Lime formation and the shale layers found in the Atoka and Wolfcamp formations. As seen in Figure 14, the largest fault found SE of the Rattlesnake AGI #1 well, terminates within the Atoka formation. Though it crosses the Silurian section, this fault thrusts the Mississippian Lime upward against the Atoka shales. The tight reservoir characteristics of the Mississippian Lime and shaley section of the Atoka create a confining environment vertically and laterally to contain potential upward migration of buoyant fluids. Shales within the Wolfcamp formation provide additional confining beds between overlying USDWs and the fault plane.

Should an unmapped fault exist within the plume boundary, the offset would be below 3D seismic resolution. The offset would be less than the thickness of the Woodford shale, juxtaposing the Woodford against itself, preventing vertical migration.

Fractures and subsequent subaerial exposure are responsible for porosity development within the injection intervals. Open hole logs show little to no porosity development indicating the Woodford or Mississippian Lime were not exposed at this location. Upward migration of injected gas through confining bed fractures is unlikely.

Leakage Through Confining Layers

The Silurian-Devonian injection zones have competent sealing rocks above and below the porous sub-aerially exposed carbonate. The properties of the overlying transgressive Woodford shale (widespread deposition, high illite clay and organic matter composition, and low porosity and permeability) make an excellent sealing rock to the underlying Silurian formation. Tight Mississippian Lime of roughly 660 ft, lay between Atoka and Woodford shale formations, forming an impermeable upper seal to the injection interval. Above this confining unit, correlative shales of the Wolfcamp, Abo and Tubb formations will prevent any upper fluid migration. These impermeable shales are capped by hundreds of feet of the regionally present Salado formation evaporites. The USDW lies above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. The underlying low porosity and permeability Montoya carbonate minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injected gas to the in-situ reservoir fluid makes migration below the lower confining layer unlikely.

Leakage from Natural or Induced Seismicity

The location of Rattlesnake AGI #1 is in an area of the Permian Basin that is inactive from a seismicity perspective, whether induced or natural. A review of historical seismic events on the USGS's Advanced National Seismic System site (from 1971 to present) and the Bureau of Economic Geology's TexNet catalog (from 2017 to present), as shown in Figure 33, indicates the nearest seismic event occurred more than 60 miles away.

A regional analysis of the probabilistic fault slip potential across the Permian Basin (Snee & Zoback 2016), as seen in Figure 34, further demonstrates that the Rattlesnake AGI #1 well is located in a seismically inactive area and confirms that this area has little to no potential for an induced seismicity event.

Therefore, there is no indication that seismic activity poses a risk for loss of CO_2 to the surface within the MMA.

Pressures will be kept significantly below the fracture gradient of the injection and confining intervals. Additionally, continuous well monitoring combined with seismic monitoring will identify any operational anomalies associated with a seismicity event.

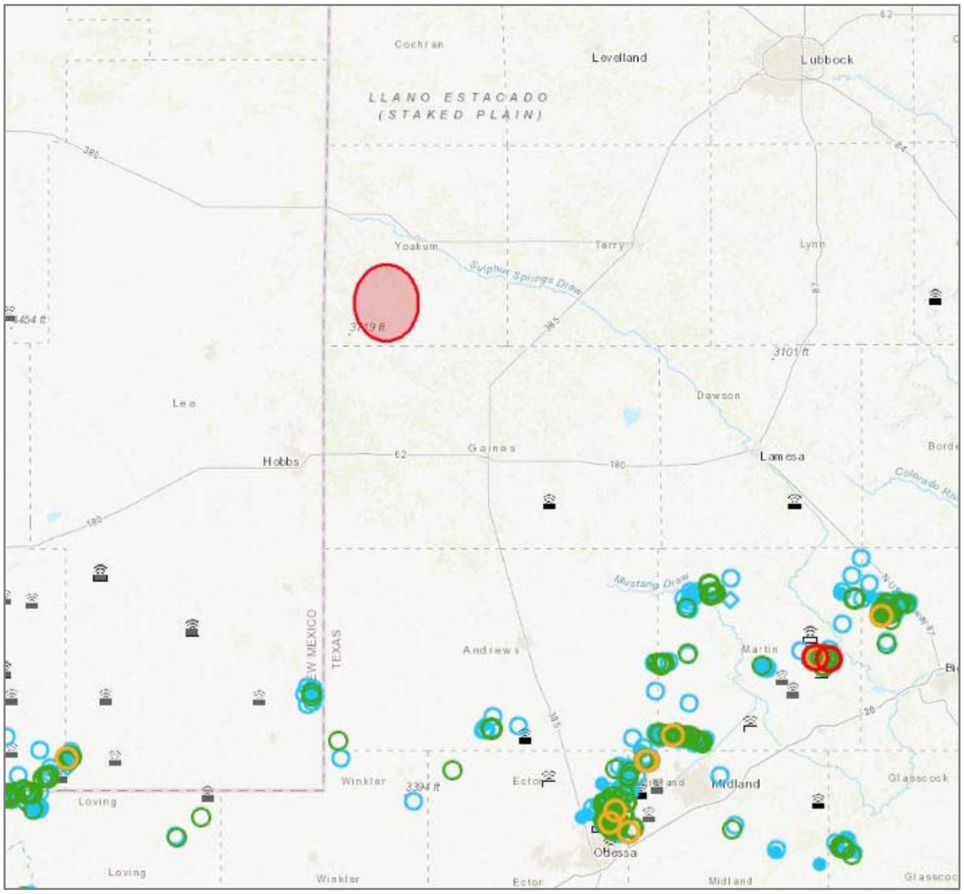


Figure 33 – Seismicity Review (TexNet – 06/01/2022)

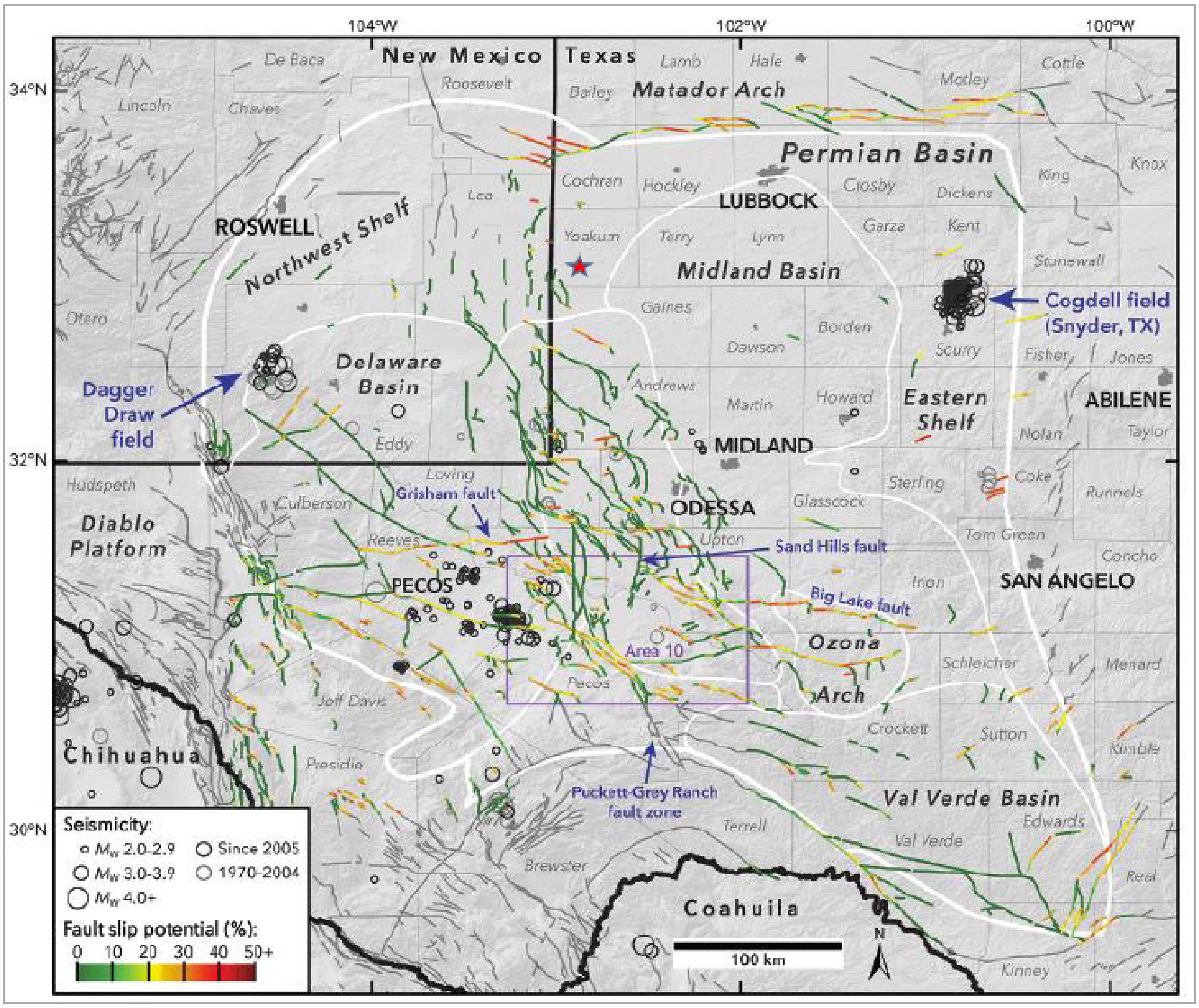


Figure 34 – Probabilistic Fault Slip Potential Analysis with Rattlesnake AGI #1 location (Snee & Zobak 2016)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Stakeholder will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in Section 4 to meet the requirements of 40 CFR §98.448(a)(3). As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 10 summarizes the monitoring of potential leakage pathways to the surface. Monitoring will occur during the planned 17-year injection period, or cessation of injection operations, plus a proposed 5-year post-injection period.

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

Because the acid gas injection stream also contains H_2S, any leakage would be detected by the H_2S alarms located around the facility and would be quickly addressed which would minimize the release of CO_2 into the atmosphere.

Table 10 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed H_2S monitors throughout the AGI facility
	Daily visual inspections
	Personal H_2S monitors
	Distributed Control System Monitoring (Volumes and Pressures)
Leakage through existing wells	Fixed H_2S monitor at the AGI well
	SCADA Continuous Monitoring at the AGI Well
	Annual Mechanical Integrity Tests ("MIT") of the AGI Well
	Visual Inspections
	Quarterly CO_2 Measurements within AMA
Leakage through groundwater wells	Annual Groundwater Samples on Property
Leakage from future wells	H_2S Monitoring during offset drilling operations
Leakage through faults and fractures	SCADA Continuous Monitoring at the AGI Well (volumes and pressures)
	Fixed In-field H_2S monitors
Leakage through confining layer	SCADA Continuous Monitoring at the AGI Well (volumes and pressures)
	Fixed In-field H_2S monitors
Leakage from natural or induced seismicity	Seismic monitoring station to be installed

Leakage from Surface Equipment

As the 30-30 Facility and the Rattlesnake AGI #1 well are designed to handle H_2S, leakage from surface equipment is unlikely to occur and would be quickly detected and addressed. The facility design minimizes leak points through the equipment used and the type of connections are designed to minimize corrosion points. The H_2S in the injectate serves as a proxy for the release of CO_2. The facility and well site contain a number of H_2S alarms, set with a high alarm setpoint of 10 ppm of H_2S, which are shown in Figure 28 above. Additionally, all Stakeholder field personnel are required to wear H_2S monitors, which trigger the alarm at 5 ppm H_2S.

The AGI facility is continuously monitored through automated systems. In addition, field personnel conduct daily visual field inspections of gauges, monitors and leak indicators such as vapor plumes. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system, analysis of liquids collected from the line, and inspection of the cathodic protection system. These inspections, in addition to the automated systems, allow Stakeholder to quickly respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5).

Leakage from Existing and Future Wells within Monitoring Area

Stakeholder continuously monitors and collects injection volumes, pressures, temperatures and gas composition data, through their SCADA systems, for the Rattlesnake AGI #1 well. This data is reviewed by qualified personnel and will follow response and reporting procedures when data is outside acceptable performance limits. Rattlesnake AGI #1 has a pressure and temperature gauge placed in the injection stream at its wellhead, and a pressure gauge on the casing annulus. A change of pressure on the annulus would indicate the presence of a possible leak. Mechanical integrity tests ("MITs") performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated and the leak mitigated.

The ten offset penetrating wells within the MMA are adequately cased and cemented to prevent potential leakage of CO_2 from the Rattlesnake AGI #1 well plume. Additionally, the plugged wells were done so in a way to prevent migration of CO_2 as provided in Appendix E. As discussed previously, Rule 13 would ensure that new wells in the field would be constructed in a manner to prevent migration from the injection interval.

In addition to the fixed and personal monitors described previously, Stakeholder will also establish and operate an in-field monitoring program to detect any CO_2 leakage within the AMA. The scope of work will include H_2S and CO_2 monitoring at the AGI well site as well as minimum, quarterly atmospheric monitoring near identified penetrations within the AMA. Upon approval of the MRV and through the post-injection monitoring period, Stakeholder will have these monitoring systems in place. Additional monitoring will be added as the AMA is updated over time.

At the well site, H_2S and CO_2 concentrations will be monitored continuously with fixed monitors that detect atmospheric concentrations of H_2S and CO_2. At penetrating well sites, Stakeholder will similarly measure atmospheric concentrations of CO_2 and H_2S using mobile gas monitors. This data will be recorded at least quarterly.

Groundwater Quality Monitoring

Stakeholder will monitor the groundwater quality in fluids above the confining interval by sampling the well on the facility property and analyzing the sample with a third-party laboratory on an annual basis. Any significant changes to the water analysis would be investigated to determine if such change was a result of leakage from the Rattlesnake AGI #1 well. The parameters to be measured will include pH, total dissolved solids, total inorganic and organic carbons, density, temperature and other standard laboratory measurements. Any significant differences in these parameters from the baseline sample will be evaluated to determine if leakage of CO_2 to the USDW may have occurred.

Leakage through Faults, Fractures or Confining Seals

Stakeholder continuously monitors the operations of the Rattlesnake AGI #1 well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway such as a fault or breakthrough of the confining seal would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. Field H_2S monitoring systems would alert field personnel for any release of H_2S/CO_2 caused by such leakage.

Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Stakeholder plans to install a seismic monitoring station in the general area of the Rattlesnake AGI #1 well. The installation of this station would start upon approval of the MRV plan, with an expected in-service data within six months after the commencement of the installation project. This monitoring station will be tied in to the Bureau of Economic Geology's TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, Stakeholder will review the injection volumes and pressures at the Rattlesnake AGI #1 well to determine if any significant changes occur that would indicate potential leakage.

SECTION 6 – BASELINE DETERMINATIONS

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

Visual Inspections

Daily inspections will be conducted by field personnel at the 30-30 Facility and the Rattlesnake AGI #1 well. These inspections will aid with identifying and addressing issues timely to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions would be taken to address such issues.

H_2S Detection

H_2S will be initially injected into the AGI well at a concentration of approximately ten (10) percent or 100,000 ppm. The concentration will drop to approximately six (6) percent as additional volumes are added. H_2S gas detectors are located throughout the AGI facility and well site and are set to trigger the alarm at 10 ppm. Additionally, all field personnel are required to wear personal H_2S monitors, which are set to trigger the alarm at 5 ppm. Any alarm would trigger an immediate response to protect personnel and verify that the monitors are working properly. If monitors are working correctly, immediate actions would be taken to secure the facility and mitigate potential leaks.

CO_2 Detection

Any CO_2 release would be accompanied by H_2S and therefore the H_2S monitors at the facility would also serve as a CO_2 release warning system. In addition to the fixed and personal monitors described previously, Stakeholder will also establish and operate an in-field monitoring program to detect any CO_2 leakage within the AMA. The scope of work will include H_2S and CO_2 monitoring at the AGI well site as well as atmospheric monitoring near identified penetrations within the AMA.

Operational Data

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

Continuous Monitoring

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which would be extremely dangerous for personnel to perform a direct leak survey. Any leakage would be detected and managed as per Texas regulations and Stakeholder's TRRC-approved H_2S Contingency Plan. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

No CO_2 emissions will occur from venting because of the high H_2S concentrations. Blowdown emissions are sent to flares and would be reported as part of the required reporting for the gas plant.

Groundwater Monitoring

An initial sample will be taken from the groundwater well on Stakeholder's property, identified as Well # 482963 in Table 9 above, upon approval of Stakeholder's MRV and prior to increasing injection. The sample will be analyzed by a third-party laboratory to establish the baseline properties of the groundwater.

SECTION 7 – SITE SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

Mass of CO_2 Received

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

Mass of CO_2 Injected

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

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

where:

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

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

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

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

p = Quarter of the year

u = Flow meter

Mass of CO_2 Produced

The Rattlesnake AGI #1 well is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

Mass of CO_2 Emitted by Surface Leakage

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which would be extremely dangerous for personnel to perform a direct leak survey. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

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

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

Where:

CO_2 = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year

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

X = Leakage pathway

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

Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based off Equation RR-12, as this well will not actively produce oil or natural gas or any other fluids, as follows:

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

Where:

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

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

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting would occur due to the high H_2S concentrations of the injectate stream, the calculations would be based on the blowdown emissions that would be sent to flares and would be reported as part of the required GHG reporting for the gas plant.

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

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA and the likelihood, magnitude and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within MMA
- Leakage through faults and fractures
- Natural or Induced Seismicity
- Drilling through the MMA
- Leakage through the confining layer

Leakage from Surface Equipment

The surface facilities at the 30-30 Facility are designed for injecting acid gas containing H_2S, and therefore minimize leakage points such as valves and flanges following industry standards and best practices. H_2S gas detectors are located around the facility and the well site. These gas detectors trigger alarms at 10 parts per million ("ppm"). Additionally, all Stakeholder field personnel are required to wear H_2S monitors which are triggered at 5 ppm of H_2S. A shut-in valve is located at the wellhead and is locally controlled by pressure, with a high pressure and low pressure shut-off.

The facilities have been designed and constructed with additional safety systems to provide for safe operations. These systems include Emergency Shutdown ("ESD") valves to isolate portions of the plant and pipeline, pressure relief valves along the pipeline to prevent over pressurization, and flares to allow piping and equipment to be de-pressured rapidly under safe and controlled operating conditions in the event of a leak. Figures 28 and 29 display the facility safety plot plan, taken from the 30-30 H_2S Contingency Plan, and show the location of the H_2S monitors in the vicinity of the plant and the Rattlesnake AGI #1 well. Should Stakeholder construct additional CO_2 facilities, as indicated in Figure 21, a separate meter will be installed for the additional stream in order to comply with the 40 CFR §98.448(a)(5) measurement. As this meter will be in close proximity to the existing facilities, it will utilize the existing monitoring programs discussed previously. Additionally, CO_2 monitors will be installed near the new meter and tied into the facility monitoring systems.

SECTION 9 – QUALITY ASSURANCE

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

Monitoring QA/QC

CO_2 *Injected*

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer recommendations.

CO_2 *Emissions from Leaks and Vented Emissions*

- Gas detectors will be operated continuously, except for maintenance and calibration.
- Gas detectors will be calibrated according to manufacturer recommendations and API standards.
- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to the requirements in 40 CFR §98.3(i).
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.
- Flow meter calibrations will be traceable to the National Institute of Standards and Technology (NIST).

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

Missing Data

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

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in subpart W of 40 CFR §98.

MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Stakeholder will retain records as required by 40 CFR §98.3(g). These records will be retained for at least three years and include:

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

References

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APPENDICES

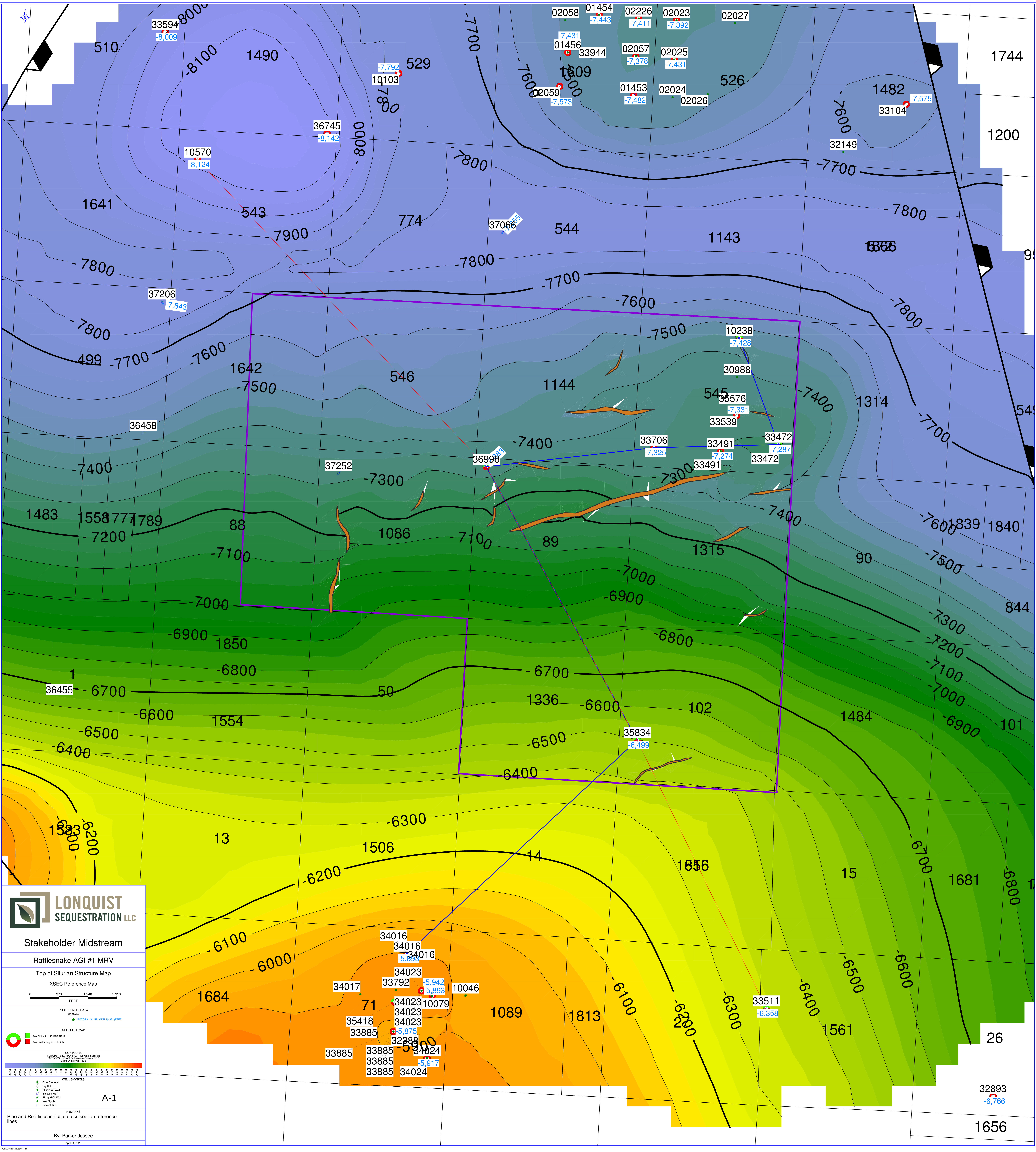
APPENDIX A – GEOLOGY

APPENDIX A-1: SILURIAN STRUCTURE MAP

APPENDIX A-2: NE-SW CROSS SECTION

APPENDIX A-3: NW-SE CROSS SECTION

APPENDIX A-4: FORMATION FLUID SAMPLE WELL MAP


LONQUIST SEQUESTRATION LLC
Stakeholder Midstream
Rattlesnake AGI #1 MRV
Top of Silurian Structure Map
XSEC Reference Map
0 970 1,940 2,910
FEET
POSTED WELL DATA
API Series
FMTOPS - SILURIAN[PLJ] (SS) (FEET)
ATTRIBUTE MAP
Any Digital Log IS PRESENT
Any Raster Log IS PRESENT
CONTOURS
FMTOPS - SILURIAN [PLJ] - Devonian/Silurian
FMTOPSSILURIAN Rattlesnake Subsea.GRD
Contour Interval = 100
-8100 -8000 -7900 -7800 -7700 -7600 -7500 -7400 -7300 -7200 -7100 -7000 -6900 -6800 -6700 -6600 -6500 -6400 -6300 -6200 -6100 -6000 -5900 -5800 -5700 -5600
WELL SYMBOLS
Oil & Gas Well
Dry Hole
Shut-in Oil Well
Injection Well
Plugged Oil Well
New Symbol
Diposal Well
A-1
REMARKS
Blue and Red lines indicate cross section reference lines
By: Parker Jessee
April 14, 2022
PETRA 4/14/2022 7:27:51 PM

A-2

Stakeholder Midstream

Rattlesnake AGI #1 MRV

NE-SW Structural Cross Section

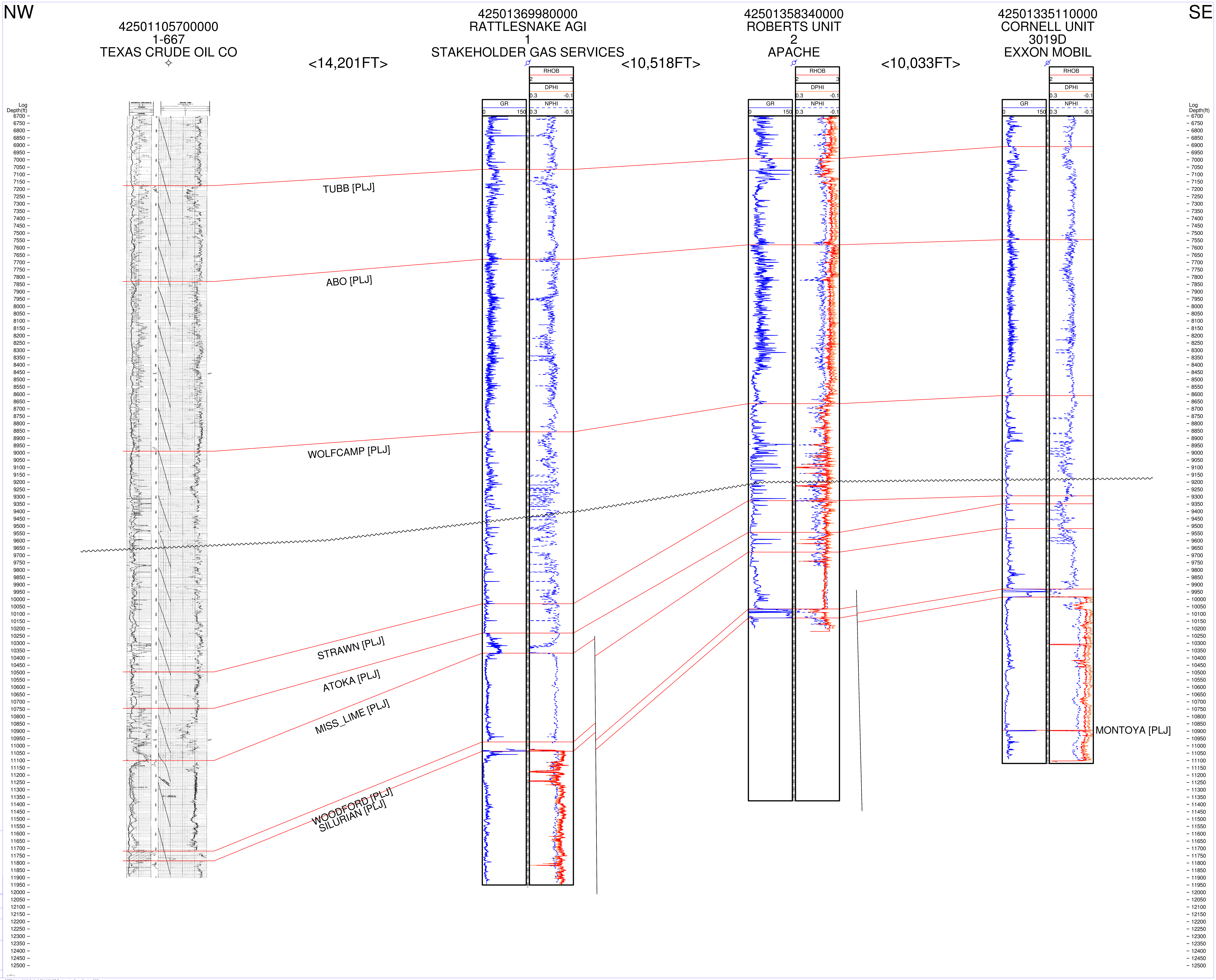
Horizontal Scale = 193.4
Vertical Scale = 50.0
Vertical Exaggeration = 3.9x

UWI
Well Name
Well Number
Operator

April 14,2022 7:03 PM

PETRA 4/14/2022 7:03:06 PM

A-3



LONQUIST SEQUESTRATION LLC

Stakeholder Midstream

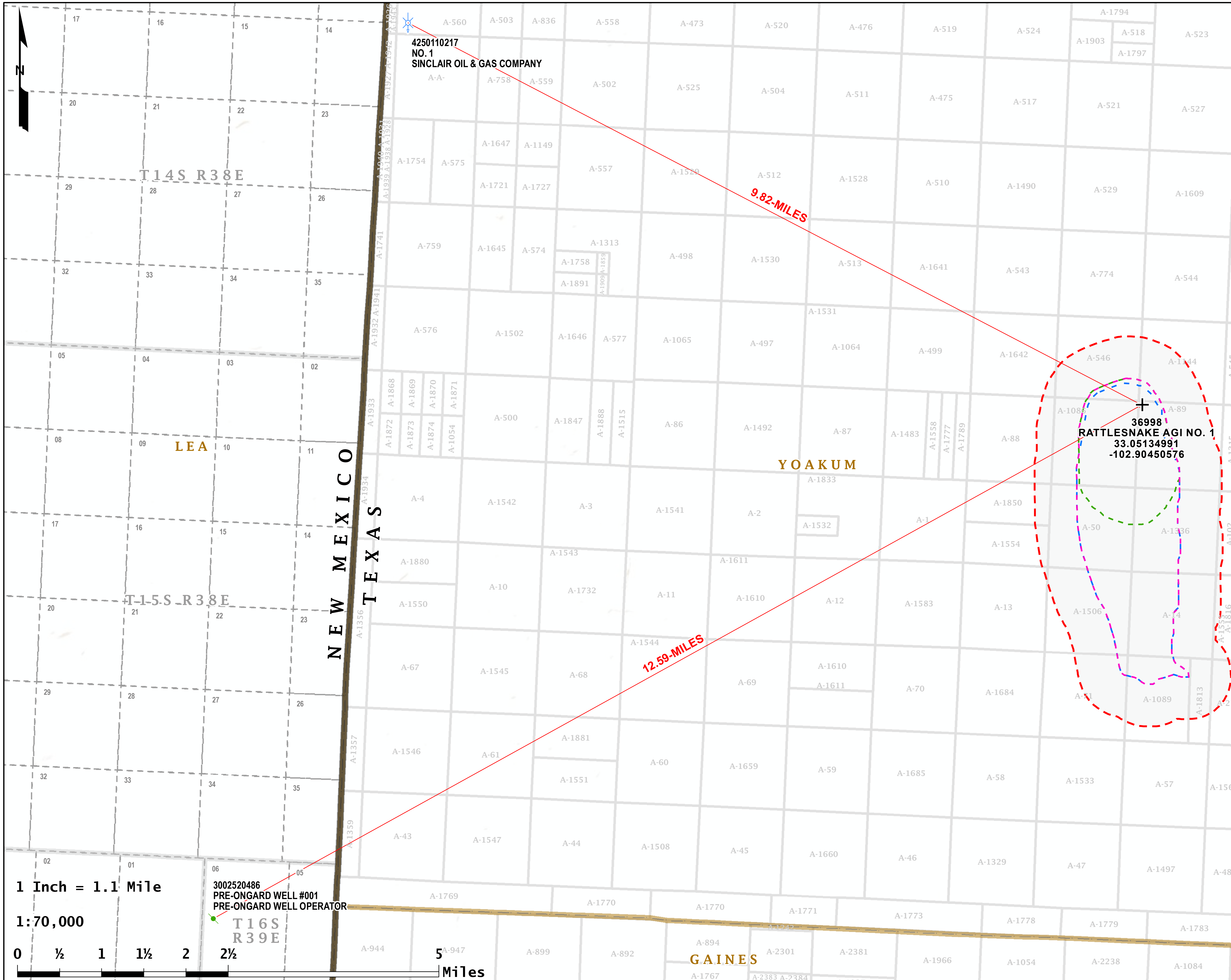
Rattlesnake agi #1 MRV

NW-SE Structural Cross Section

Horizontal Scale = 289.6
Vertical Scale = 50.0
Vertical Exaggeration = 5.8x

UWI
Well Name
Well Number
Operator

April 14,2022 7:13 PM



Rattlesnake AGI No. 1
Maximum Monitoring Area
with
Formation Fluid Sample Wells
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 6/1/2022	Approved by: RH

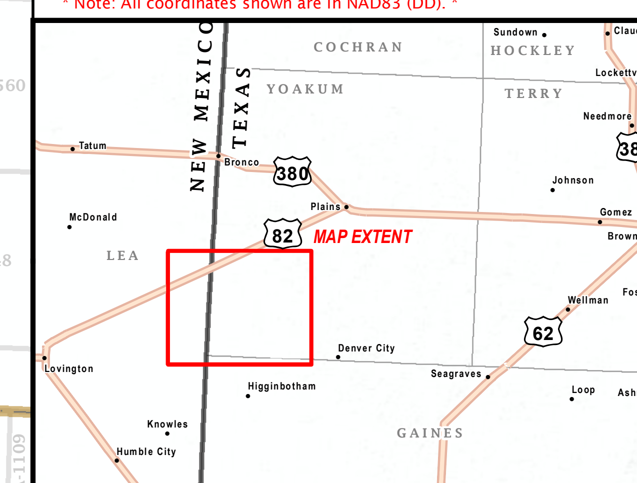
LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS
AUSTIN • HOUSTON • CALGARY • WICHITA
DENVER • COLLEGE STATION • BATON ROUGE • EDMONTON

- Rattlesnake AGI No. 1 SHL
- 1/2-Mile Buffer from Max. Plume Extent (MMA)
- Combined Maximum Plume Extent
- Stabilized Plume
- Plume Boundary at End of Injection
- Abstract
- County Boundary
- State Boundary
- Section Boundary [NM BLM-2022]
- Township Boundary [NM BLM-2022]
- Distance Call

Formation Fluid Sample Well [NM OCD-2022]
- Plugged - Oil

Formation Fluid Sample Well [DI-2022]
- TA - Injection/Disposal

Source:
1.) Oil/Gas Well SHL Data: DI-2022/NM OCD-2022
2.) Oil/Gas Well BHL Data: DI-2022
3.) Oil/Gas Well Directional Data: DI-2022
* Note: All coordinates shown are in NAD83 (DD). *



APPENDIX B – TRRC FORMS Rattlesnake AGI #1

APPENDIX B-1: UIC CLASS II ORDER

APPENDIX B-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX B-3: DRILLING PERMIT

APPENDIX B-4: COMPLETION REPORT

CHRISTI CRADDICK, CHAIRMAN
RYAN SITTON, COMMISSIONER
WAYNE CHRISTIAN, COMMISSIONER

DANNY SORRELLS
ASSISTANT EXECUTIVE DIRECTOR
DIRECTOR, OIL AND GAS DIVISION
LESLIE SAVAGE
ASSISTANT DIRECTOR, TECHNICAL PERMITTING

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 15848

SANTA FE MIDSTREAM PERMIAN LLC
5830 GRANITE PKWY STE 1025
PLANO, TX 75024

DOCKET NO. 8A-0312019

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated March 12, 2018 for the permitted interval of the DEVONIAN formation and subject to the following terms and special conditions:

RATTLESNAKE AGI (000000) LEASE
WASSON FIELD
YOAKUM COUNTY, DISTRICT 8A

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
1	50136998	000117143	CO_2, and H_2S	11,000	12,000	4,500	N/A	N/A	2,200

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	50136998	**1. Open hole completions shall have a plug back depth no deeper than the bottom of the permitted injection interval.** **2. The operator shall provide to the UIC section an annotated electric log, and a mud log if available, of the subject well with the top(s) and bottom(s) of the permitted formation indicated on the log. Top and bottom of the authorized injection interval may be modified based on electric log or mud log indications of the top and bottom of the permitted formations.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;
   c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON November 14, 2018.

Sean Avitt

Sean Avitt, Manager
Injection-Storage Permits Unit

IN-HOUSE AMENDMENT TO CORRECT THE RATE.

Note: This document will only be distributed electronically.

GROUNDWATER PROTECTION DETERMINATION

Form GW-2

Groundwater Advisory Unit

B-2

Date Issued:	31 August 2017	**GAU Number:**	179154

Attention:	SANTA FE MIDSTREAM	**API Number:**	
	5700 GRANITE PARKWAY	**County:**	YOAKUM
	PLANO, TX 75024	**Lease Name:**	Roberts Unit
Operator No.:	748093	**Lease Number:**	019212
		Well Number:	1
		Total Vertical Depth:	11000
		Latitude:	33.049990
		Longitude:	-102.903464
		Datum:	NAD27

Purpose: New Drill

Location: Survey-Gibson, J H/Poole, J T; Block-D; Section-733

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

The interval from the land surface to a depth of 375 feet must be protected.

Note: Unless stated otherwise, this recommendation is intended to apply only to the subject well and not for area-wide use. This recommendation is for normal drilling, production, and plugging operations only. It does not apply to saltwater disposal operation into a nonproductive zone (RRC Form W-14).

This determination is based on information provided when the application was submitted on 08/30/2017. 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

API No. 42-501-36998

Drilling Permit # 839303

SWR Exception Case/Docket No.

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

APPLICATION FOR PERMIT TO DRILL, RECOMPLETE, OR RE-ENTER

This facsimile W-1 was generated electronically from data submitted to the RRC.
A certification of the automated data is available in the RRC's Austin office.

FORM W-1 07/2004

Permit Status: Approved

B-3

1. RRC Operator No.: 748093

2. Operator's Name (as shown on form P-5, Organization Report): SANTA FE MIDSTREAM PERMIAN LLC

3. Operator Address (include street, city, state, zip): 5830 GRANITE PKWY STE 1025 PLANO, TX 75024-0000

4. Lease Name: RATTLESNAKE AGI

5. Well No.: 1

GENERAL INFORMATION

6. Purpose of filing (mark ALL appropriate boxes): [X] New Drill [ ] Recompletion [ ] Reclass [ ] Field Transfer [ ] Re-Enter [ ] Amended [ ] Amended as Drilled (BHL) (Also File Form W-1D)

7. Wellbore Profile (mark ALL appropriate boxes): [X] Vertical [ ] Horizontal (Also File Form W-1H) [ ] Directional (Also File Form W-1D) [ ] Sidetrack

8. Total Depth: 12000

9. Do you have the right to develop the minerals under any right-of-way ? [X] Yes [ ] No

10. Is this well subject to Statewide Rule 36 (hydrogen sulfide area)? [X] Yes [ ] No

SURFACE LOCATION AND ACREAGE INFORMATION

11. RRC District No.: 8A

12. County: YOAKUM

13. Surface Location: [X] Land [ ] Bay/Estuary [ ] Inland Waterway [ ] Offshore

14. This well is to be located 7.3 miles in a NW direction from DENVER CITY which is the nearest town in the county of the well site.

15. Section: 733

16. Block: D

17. Survey: GIBSON, J H

18. Abstract No.: A-89

19. Distance to nearest lease line: 200 ft.

20. Number of contiguous acres in lease, pooled unit, or unitized tract: 640

21. Lease Perpendiculars: 200 ft from the NORTH line and 200 ft from the WEST line.

22. Survey Perpendiculars: 200 ft from the NORTH line and 200 ft from the WEST line.

23. Is this a pooled unit? [ ] Yes [X] No

24. Unitization Docket No:

25. Are you applying for Substandard Acreage Field? [ ] Yes (attach Form W-1A) [X] No

FIELD INFORMATION — List all fields of anticipated completion including Wildcat. List one zone per line.

26. RRC District No.	27. Field No.	28. Field Name (exactly as shown in RRC records)	29. Well Type	30. Completion Depth	31. Distance to Nearest Well in this Reservoir	32. Number of Wells on this lease in this Reservoir
8A	95397001	WASSON	Injection Well	12000	0.00	1
8A	95399400	WASSON, NORTH (SAN ANDRES)	Injection Well	12000	0.00	1

BOTTOMHOLE LOCATION INFORMATION is required for DIRECTIONAL, HORIZONTAL, AND AMENDED AS DRILLED PERMIT APPLICATIONS

Remarks

[FILER Apr 16, 2018 5:16 PM]: Filing for an acid gas injection well.

Certificate:

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

Jessica Risien, Regulatory Compliance Specialist — Name of filer

Apr 25, 2018 — Date submitted

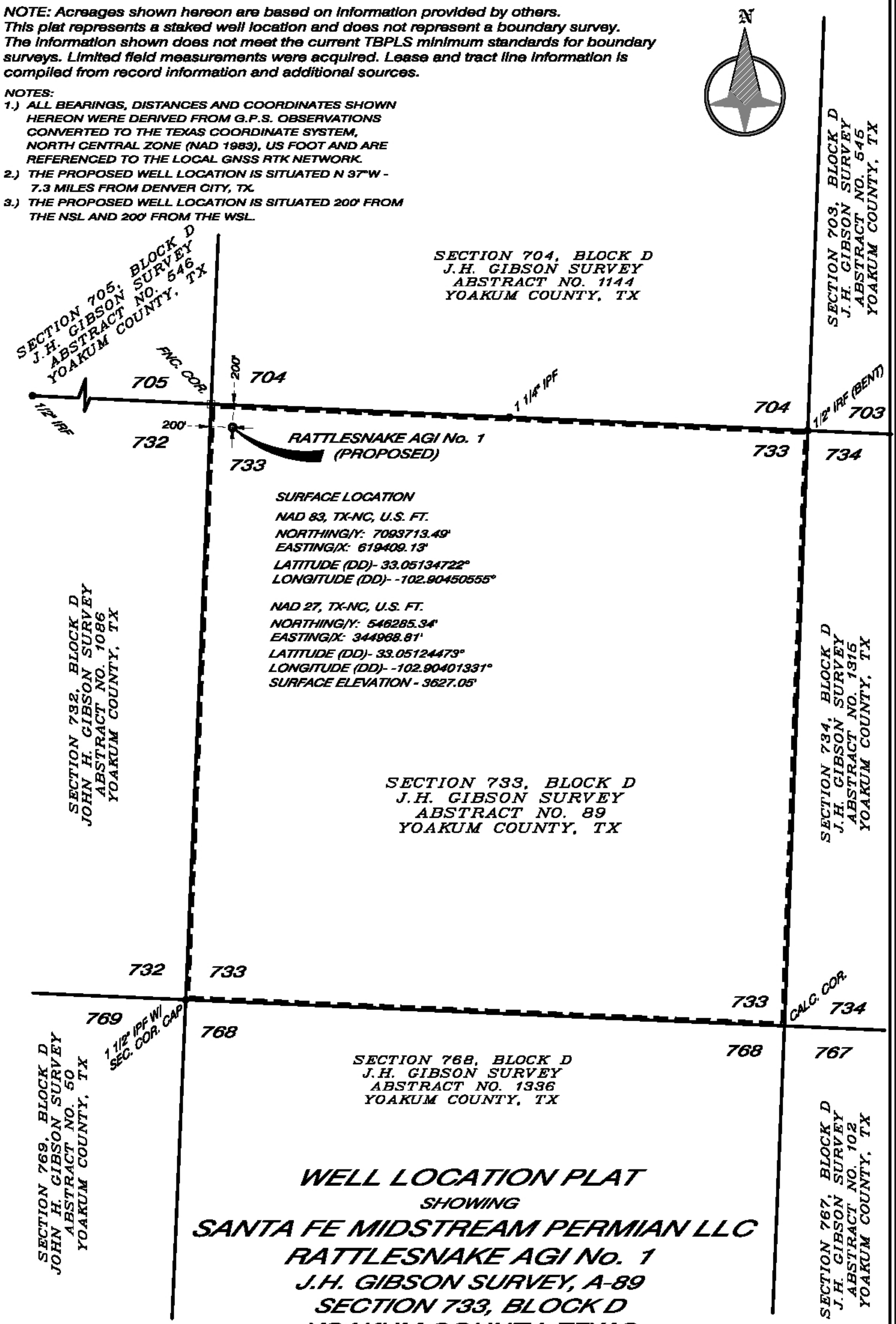
(281)8729300 — Phone

jrisien@ntglobal.com — E-mail Address (OPTIONAL)

RRC Use Only Data Validation Time Stamp: Apr 27, 2018 10:36 AM('As Approved' Version)

NOTE: Acreages shown hereon are based on information provided by others.
This plat represents a staked well location and does not represent a boundary survey.
The information shown does not meet the current TBPLS minimum standards for boundary surveys. Limited field measurements were acquired. Lease and tract line information is compiled from record information and additional sources.

NOTES:
1.) ALL BEARINGS, DISTANCES AND COORDINATES SHOWN HEREON WERE DERIVED FROM G.P.S. OBSERVATIONS CONVERTED TO THE TEXAS COORDINATE SYSTEM, NORTH CENTRAL ZONE (NAD 1983), US FOOT AND ARE REFERENCED TO THE LOCAL GNSS RTK NETWORK.
2.) THE PROPOSED WELL LOCATION IS SITUATED N 37°W - 7.3 MILES FROM DENVER CITY, TX.
3.) THE PROPOSED WELL LOCATION IS SITUATED 200' FROM THE NSL AND 200' FROM THE WSL.



WELL LOCATION PLAT
SHOWING
SANTA FE MIDSTREAM PERMIAN LLC
RATTLESNAKE AGI No. 1
J.H. GIBSON SURVEY, A-89
SECTION 733, BLOCK D
YOAKUM COUNTY, TEXAS

SCALE: 1" = 1000'

1000 500 0 1000

SCALE FEET

I, THE UNDERSIGNED, REGISTERED PROFESSIONAL LAND SURVEYOR, DO HEREBY CERTIFY THAT THE PLAT SHOWN REPRESENTS AN ACTUAL SURVEY MADE ON THE GROUND AND IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

BY: ____________________

ANDREW STOUT 03/20/2018
REGISTERED PROFESSIONAL LAND SURVEYOR
STATE OF TEXAS NO. 5970

STATE OF TEXAS REGISTERED PROFESSIONAL LAND SURVEYOR ANDREW STOUT 5970

INTEGRITY POSITIONS, LLC

14296 FM 314 N.
BROWNSBORO, TX 75756
(903) 595-9385
Firm No. 10194085

Railroad Commission of Texas

PERMIT TO DRILL, RE-COMPLETE, OR RE-ENTER ON REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

CONDITIONS AND INSTRUCTIONS

Permit Invalidation. It is the operator's responsibility to make sure that the permitted location complies with Commission density and spacing rules in effect on the spud date. The permit becomes invalid automatically if, because of a field rule change or the drilling of another well, the stated location is not in compliance with Commission field rules on the spud date. If this occurs, application for an exception to Statewide Rules 37 and 38 must be made and a special permit granted prior to spudding. Failure to do so may result in an allowable not being assigned and/or enforcement procedures being initiated.

Notice Requirements. Per H.B 630, signed May 8, 2007, the operator is required to provide notice to the surface owner no later than the 15th business day after the Commission issues a permit to drill. Please refer to subchapter Q Sec. 91.751-91.755 of the Texas Natural Resources Code for applicability.

Permit expiration. This permit expires two (2) years from the date of issuance shown on the original permit. The permit period will not be extended.

Drilling Permit Number. The drilling permit number shown on the permit MUST be given as a reference with any notification to the district (see below), correspondence, or application concerning this permit.

Rule 37 Exception Permits. This Statewide Rule 37 exception permit is granted under either provision Rule 37 (h)(2)(A) or 37(h)(2)(B). Be advised that a permit granted under Rule 37(h)(2)(A), notice of application, is subject to the General Rules of Practice and Procedures and if a protest is received under Section 1.3, "Filing of Documents," and/or Section 1.4, "Computation of Time," the permit may be deemed invalid.

Before Drilling

Fresh Water Sand Protection. The operator must set and cement sufficient surface casing to protect all usable-quality water, as defined by the Railroad Commission of Texas (RRC) Groundwater Advisory Unit (GWAU). Before drilling a well, the operator must obtain a letter from the Railroad Commission of Texas stating the depth to which water needs protection, Write: Railroad Commission of Texas, Groundwater Advisory Unit (GWAU), P.O. Box 12967, Austin, TX 78711-3087. File a copy of the letter with the appropriate district office.

Accessing the Well Site. If an OPERATOR, well equipment TRANSPORTER or WELL service provider must access the well site from a roadway on the state highway system (Interstate, U.S. Highway, State Highway, Farm-to-Market Road, Ranch-to-Market Road, etc.), an access permit is required from TxDOT. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

Water Transport to Well Site. If an operator intends to transport water to the well site through a temporary pipeline laid above ground on the state's right-of-way, an additional TxDOT permit is required. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

*NOTIFICATION

The operator is **REQUIRED** to notify the district office when setting surface casing, intermediate casing, and production casing, or when plugging a dry hole. The district office MUST also be notified if the operator intends to re-enter a plugged well or re-complete a well into a different regulatory field. Time requirements are given below. The drilling permit number MUST be given with such notifications.

During Drilling

Permit at Drilling Site : A copy of the Form W-1 Drilling Permit Application, the location plat, a copy of Statewide Rule 13 alternate surface casing setting depth approval from the district office, if applicable, and this drilling permit must be kept at the permitted well site throughout drilling operations.

***Notification of Setting Casing :** The operator MUST call in notification to the appropriate district office (phone number shown the on permit) a minimum of eight (8) hours prior to the setting of surface casing, intermediate casing, AND production casing. The individual giving notification MUST be able to advise the district office of the drilling permit number.

***Notification of Re-completion/Re-entry :** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of eight (8) hours prior to the initiation of drilling or re-completion operations. The individual giving notification MUST be able to advise the district office of the drilling permit number.

Completion and Plugging Reports

Hydraulic Fracture Stimulation using Diesel Fuel: Most operators in Texas do not use diesel fuel in hydraulic fracturing fluids. Section 322 of the Energy Policy Act of 2005 amended the Underground Injection Control (UIC) portion of the federal Safe Drinking Water Act (42 USC 300h(d)) to define "underground Injection" to *EXCLUDE* " ...the underground injection of fluids or propping agents *(other than diesel fluels)* pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities." (italic and underlining added.) Therefore, hydraulic fracturing may be subject to regulation under the federal UIC regulations if diesel fuel is injected or used as a propping agent. EPA defined "diesel fuel" using the following five (5) Chemical Abstract Service numbers: 68334-30-5 Primary Name: Fuels, diesel; 68476-34-6 Primary Name: Fuels, diesel, No. 2; 68476-30-2 Primary Name: Fuel oil No. 2; 68476-31-3 Primary Nmae: Fuel oil, No. 4; and 8008-20-6 Primary Name: Kerosene. As a result, an injection well permit would be required before performing hydraulic fracture stimulation using diesel fuel as defined by EPA on any well in Texas. Hydraulic fracture stimulation using diesel fuel as defined by EPA on a well in Texas without an injection well permit could result in enforcement action.

Producing Well : Statewide Rule 16 states that the operator of a well shall file with the Commission the appropriate completion report within thirty (30) days after completion of the well or within ninety (90) days after the date on which the drilling operation is completed, whichever is earlier. Completion of the well in a field authorized by this permit voids the permit for all other fields included in the permit unless the operator indicates on the initial completion report that the well is to be a dual or multiple completion and promptly submits an application for multiple completion. All zones are required to be completed before the expiration date on the existing permit. Statewide Rule 40(d) requires that upon successful completion of a well in the same reservoir as any other well previously assigned the same acreage, proration plats and P-15s (if required) must be submitted with no double assignment of acreage.

Dry or Noncommercial Hole : Statewide Rule 14(b)(2) prohibits suspension of operations on each dry or non-commercial well without plugging unless the hole is cased and the casing is cemented in compliance with Commission rules. If properly cased, Statewide Rule 14(b)(2) requires that plugging operations must begin within a period of one (1) year after drilling or operations have ceased. Plugging operations must proceed with due diligence until completed. An extension to the one-year plugging requirement may be granted under the provisions stated in Statewide Rule 14(b)(2).

Intention to Plug : The operator must file a Form W-3A (Notice of Intention to Plug and Abandon) with the district office at least five (5) days prior to beginning plugging operations. If, however, a drilling rig is already at work on location and ready to begin plugging operations, the district director or the director's delegate may waive this requirement upon request, and verbally approve the proposed plugging procedures.

***Notification of Plugging a Dry Hole :** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of four (4) hours prior to beginning plugging operations. The individual giving the notification MUST be able to advise the district office of the drilling permit number and all water protection depths for that location as stated in the Texas Commission on Environmental Quality letter.

DIRECT INQUIRIES TO: DRILLING PERMIT SECTION, OIL AND GAS DIVISION

PHONE
(512) 463-6751

MAIL:
PO Box 12967
Austin, Texas, 78711-2967

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER	DATE PERMIT ISSUED OR AMENDED	DISTRICT
839303	04/27/2018	8A
API NUMBER 42-501-36998	FORM W-1 RECEIVED 04/25/2018	COUNTY YOAKUM
TYPE OF OPERATION New Drill	WELLBORE PROFILE(S) Vertical	ACRES 640.0

OPERATOR 748093
SANTA FE MIDSTREAM PERMIAN LLC
5830 GRANITE PKWY STE 1025
PLANO, TX 75024-0000

NOTICE
This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored.
District Office Telephone No:
(806) 698-6509

LEASE NAME	WELL NUMBER
RATTLESNAKE AGI	1
LOCATION 7.3 miles NW direction from DENVER CITY	TOTAL DEPTH 12000

Section, Block and/or
SECTION 733 BLOCK D ABSTRACT 89
SURVEY GIBSON, J H

DISTANCE TO SURVEY LINES	DISTANCE TO NEAREST LEASE LINE
200.0 ft NORTH 200.0 ft WEST	200.0
DISTANCE TO LEASE LINES 200.0 ft NORTH 200.0 ft WEST	DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME / LEASE NAME	ACRES / NEAREST LEASE	DEPTH	WELL# / NEAREST WELL	DIST
WASSON	640.0	12000	1	8A
RATTLESNAKE AGI	200.0		0.0	

This is a hydrogen sulfide field. This well shall be drilled in accordance with SWR 36.

Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

FIELD NAME / LEASE NAME	ACRES / NEAREST LEASE	DEPTH	WELL# / NEAREST WELL	DIST
WASSON, NORTH (SAN ANDRES)	640.0	12000	1	8A
RATTLESNAKE AGI	200.0		0.0	

This is a hydrogen sulfide field. This well shall be drilled in accordance with SWR 36.

Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

This well must comply to the new SWR 3.13 requirements concerning the isolation of any potential flow zones and zones with corrosive formation fluids. See approved permit for those formations that have been identified for the county in which you are drilling the well in.

Railroad Commission of Texas
Oil and Gas Division
SWR #13 Formation Data
YOAKUM (501) COUNTY

Formation	Remarks	Geological Order	Effective Date
RED BED-SANTA ROSA		1	01/01/2014
YATES		2	01/01/2014
SAN ANDRES	high flows, H2S, corrosive	3	01/01/2014
GLORIETA		4	01/01/2014
CLEARFORK	Active CO2 Flood	5	01/01/2014
WICHITA		6	01/01/2014
LEONARD		7	01/01/2014
WOLFCAMP		8	01/01/2014
PENNSYLVANIAN		9	01/01/2014
STRAWN		10	01/01/2014
MISSISSIPPIAN		11	01/01/2014
DEVONIAN		12	01/01/2014
DEVONIAN-SILURIAN		13	01/01/2014

The above list may not be all inclusive, and may also include formations that do not intersect all wellbores. The listing order of the Formation information reflects the general stratigraphic order and relative geologic age. This is a dynamic list subject to updates and revisions. It is the operator's responsibility to make sure that at the time of spudding the well the most current list is being referenced. Refer to the RRC website at the following address for the most recent information. http://www.rrc.texas.gov/oil-gas/compliance-enforcement/rule-13-geologic-formation-info

RAILROAD COMMISSION OF TEXAS

Form G-1

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Approved
Date: 07/25/2019
Tracking No.: 205926

GAS WELL BACK PRESSURE TEST, COMPLETION OR RECOMPLETION REPORT, AND LOG

OPERATOR INFORMATION

Operator Name: SANTA FE MIDSTREAM PERMIAN LLC **Operator No.:** 748093
Operator Address: 5830 GRANITE PKWY STE 1025 PLANO, TX 75024-0000

WELL INFORMATION

API No.: 42-501-36998 **County:** YOAKUM
Well No.: 1 **RRC District No.:** 8A
Lease Name: RATTLESNAKE AGI **Field Name:** WASSON
RRC Gas ID No.: 286838 **Field No.:** 95397001
Location: Section: 733, Block: D, Survey: GIBSON, J H, Abstract: 89

Latitude: **Longitude:**

This well is located 7.3 **miles in a** NW **direction from** DENVER CITY, **which is the nearest town in the county.**

FILING INFORMATION

Purpose of filing: Well Record Only
Type of completion: New Well
Well Type: Active UIC **Completion or Recompletion Date:** 08/31/2018

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or Deepen	04/27/2018	839303
Rule 37 Exception		
Fluid Injection Permit		
O&G Waste Disposal Permit	11/14/2018	15848
Other:		

COMPLETION INFORMATION

Spud date: 07/16/2018
Date of first production after rig released: 08/31/2018
Date plug back, deepening, recompletion, or drilling operation commenced: 07/16/2018
Date plug back, deepening, recompletion, or drilling operation ended: 08/31/2018
Number of producing wells on this lease in this field (reservoir) including this well: 1
Distance to nearest well in lease & reservoir (ft.): 0.0
Total number of acres in lease: 640.00
Elevation (ft.): 3627 GR
Total depth TVD (ft.): 11980
Total depth MD (ft.):
Plug back depth TVD (ft.): 11980
Plug back depth MD (ft.):
Was directional survey made other than inclination (Form W-12)? Yes
Rotation time within surface casing (hours): 72.0
Is Cementing Affidavit (Form W-15) attached? Yes
Recompletion or reclass? No
Multiple completion? No
Type(s) of electric or other log(s) run: Combo of Induction/Neutron/Density/Sonic
Electric Log Other Description:
Location of well, relative to nearest lease boundaries of lease on which this well is located: **Off Lease:** No
200.0 **Feet from the** North **Line and**
200.0 **Feet from the** West **Line of the**
RATTLESNAKE AGI **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

Field & Reservoir	Gas ID or Oil Lease No.	Well No.	Prior Service Type

G1: N/A

PACKET: N/A

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination **Depth (ft.):** 2025.0 **Date:** 01/12/2018

SWR 13 Exception **Depth (ft.):**

GAS MEASUREMENT DATA

Date of test: **Gas measurement method(s):**

Gas production during test (MCF):

Was the well preflowed for 48 hours? No

Run No.	Line size	Orif. or Choke Size (in.)	24 hr. Coeff. Orif. Or Choke (in.)	Static Pm or Choke (in.)	Diff (hw)	Flow Temp (°F)	Temp. (Ftf)	Gravity (Fg)	Compress (Fpv)	Volume (MCF/day)

N/A

FIELD DATA AND PRESSURE CALCULATIONS

Gravity (dry gas): **Gravity (liquid hydrocarbons) (Deg. API):**

Gas-Liquid Hydro Ratio (CF/Bbl): **Gravity (mixture): Gmix=**

Avg. shut in temp. (°F): **Bottom hole temp. and depth:** °F@ FT

Run No.	Time of Run (Min.)	Choke Size (in.)	Wellhead Pressure (PSIA)	Wellhead Flow Temp (°F)

N/A

CASING RECORD

Row	Type of Casing	Casing Size (in.)	Hole Size (in.)	Setting Depth (ft.)	Multi - Stage Tool Depth (ft.)	Multi - Stage Shoe Depth (ft.)	Cement Class	Cement Amount (sacks)	Slurry Volume (cu. ft.)	Top of Cement (ft.)	TOC Determined By
1	Surface	13 3/8	17 1/2	504			C	510	687.5	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5498		5498	C	485	797.0	4275	Circulated to Surface
2	Intermediate	13 3/8	17 1/2	5498	4275		C	1650	3045.0	0	Circulated to Surface
6	Conventional Production	7	8 3/4	11023			WELL LOCK	60	337.0	9575	Calculation
5	Conventional Production	7	8 3/4	11023	5591		PREM PLUS	380	906.5	0	Circulated to Surface
4	Conventional Production	7	8 3/4	11023	9575		PREM PLUS	380	906.5	5591	Calculation

LINER RECORD

Row	Liner Size (in.)	Hole Size (in.)	Liner Top (ft.)	Liner Bottom (ft.)	Cement Class	Cement Amount (sacks)	Slurry Volume (cu. ft.)	Top of Cement (ft.)	TOC Determined By

N/A

TUBING RECORD

Row	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	10966	10966 / HALLIBURTON BWD

PRODUCING/INJECTION/DISPOSAL INTERVAL

Row	Open hole?	From (ft.)	To (ft.)
1	Yes	L 11025	11980

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment performed? No

Is well equipped with a downhole actuation sleeve? No

If yes, actuation pressure (PSIG):

Production casing test pressure (PSIG) prior to hydraulic fracturing treatment:

Actual maximum pressure (PSIG) during hydraulic fracturing:

Has the hydraulic fracturing fluid disclosure been reported to FracFocus disclosure registry (SWR29)? No

Row	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)

N/A

FORMATION RECORD

Formations	Encountered	Depth TVD (ft.)	Depth MD (ft.)	Is formation isolated?	Remarks
YATES	Yes	3019.0		Yes	
SAN ANDRES - HIGH FLOWS, H2S, CORROSIVE	Yes	4465.0		Yes	
GLORIETA	Yes	6316.0		Yes	
CLEARFORK - ACTIVE CO2 FLOOD	Yes	6492.0		Yes	
WICHITA	Yes	8628.0		Yes	
UPPER WOLFCAMP	Yes	9239.0		Yes	
STRAWN	Yes	10030.0		Yes	
ATOKA	Yes	10230.0		Yes	
WOODFORD	Yes	10973.0		Yes	
DEVONIAN	Yes	11036.0		No	DISPOSAL
WRISTEN	Yes	11268.0		No	DISPOSAL
FUSSELMAN	Yes	11538.0		No	DISPOSAL
MONTOYA	Yes	11974.0		No	DISPOSAL
RED BED-SANTA ROSA	No			No	NOT IN AREA
LEONARD	No			No	NOT IN AREA
WOLFCAMP	No			No	NOT IN AREA
PENNSYLVANIAN	No			No	NOT IN AREA
STRAWN	No			No	NOT IN AREA
MISSISSIPPIAN	No			No	NOT IN AREA

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm (SWR 36)? No

Is the completion being downhole commingled (SWR 10)? No

REMARKS

NEW WELL PUTTING ON SCHEDULE.

OPERATOR'S CERTIFICATION

Printed Name:	Karen Zornes	**Title:**	
Telephone No.:	(281) 872-9300	**Date Certified:**	06/25/2019

APPENDIX C – GAS COMPOSITION

C-1

LABORATORY SERVICES Natural Gas Analysis

www.permianls.com
575.397.3713 2609 W Marland Hobbs NM 88240

C6+ Gas Analysis Report

11093G	30/30 Acid Gas	30/30 Acid Gas
Sample Point Code	Sample Point Name	Sample Point Location

Laboratory Services	2021048523	1781	E Benavides - Spot
Source Laboratory	Lab File No	Container Identity	Sampler
USA	USA	USA	Texas
District	Area Name	Field Name	Facility Name
Nov 16, 2021	Nov 16, 2021	Nov 19, 2021 09:59	Nov 19, 2021
Date Sampled	Date Effective	Date Received	Date Reported

		System Administrator	21 @ 129
Ambient Temp (°F)	Flow Rate (Mcf)	Analyst	Press PSI @ Temp °F Source Conditions

Stakeholder Midstream	30/30
Operator	Lab Source Description

Component	Normalized Mol %	Un-Normalized Mol %	GPM
H2S (H2S)	9.2000	9.2	
Nitrogen (N2)	0.0000	0	
CO2 (CO2)	89.6780	98.775	
Methane (C1)	0.3030	0.331	
Ethane (C2)	0.0580	0.063	0.0150
Propane (C3)	0.1080	0.118	0.0300
I-Butane (IC4)	0.0000	0	0.0000
N-Butane (NC4)	0.0250	0.027	0.0080
I-Pentane (IC5)	0.0000	0	0.0000
N-Pentane (NC5)	0.0000	0	0.0000
Hexanes Plus (C6+)	0.6280	0.686	0.2710
TOTAL	100.0000	109.2000	0.3240

Method(s): Gas C6+ - GPA 2261, Extended Gas - GPA 2286, Calculations - GPA 2172

Analyzer Information

Device Type:	Gas Chromatograph	Device Make:	Shimadzu
Device Model:	GC-2014	Last Cal Date:	Nov 14, 2021

Gross Heating Values (Real, BTU/ft³)

14.696 PSI @ 60.00 Â°F		14.65 PSI @ 60.00 Â°F	
Dry	Saturated	Dry	Saturated
98.7	98.00	98.4	97.7

Calculated Total Sample Properties

GPA2145-16 *Calculated at Contract Conditions

Relative Density Real	Relative Density Ideal
1.5042	1.4956

Molecular Weight
43.3157

C6+ Group Properties

Assumed Composition

C6 - 60.000% C7 - 30.000% C8 - 10.000%

Field H2S
92000 PPM

PROTREND STATUS:
Passed By Validator on Nov 21, 2021

DATA SOURCE:
Imported

PASSED BY VALIDATOR REASON:
Close enough to be considered reasonable.

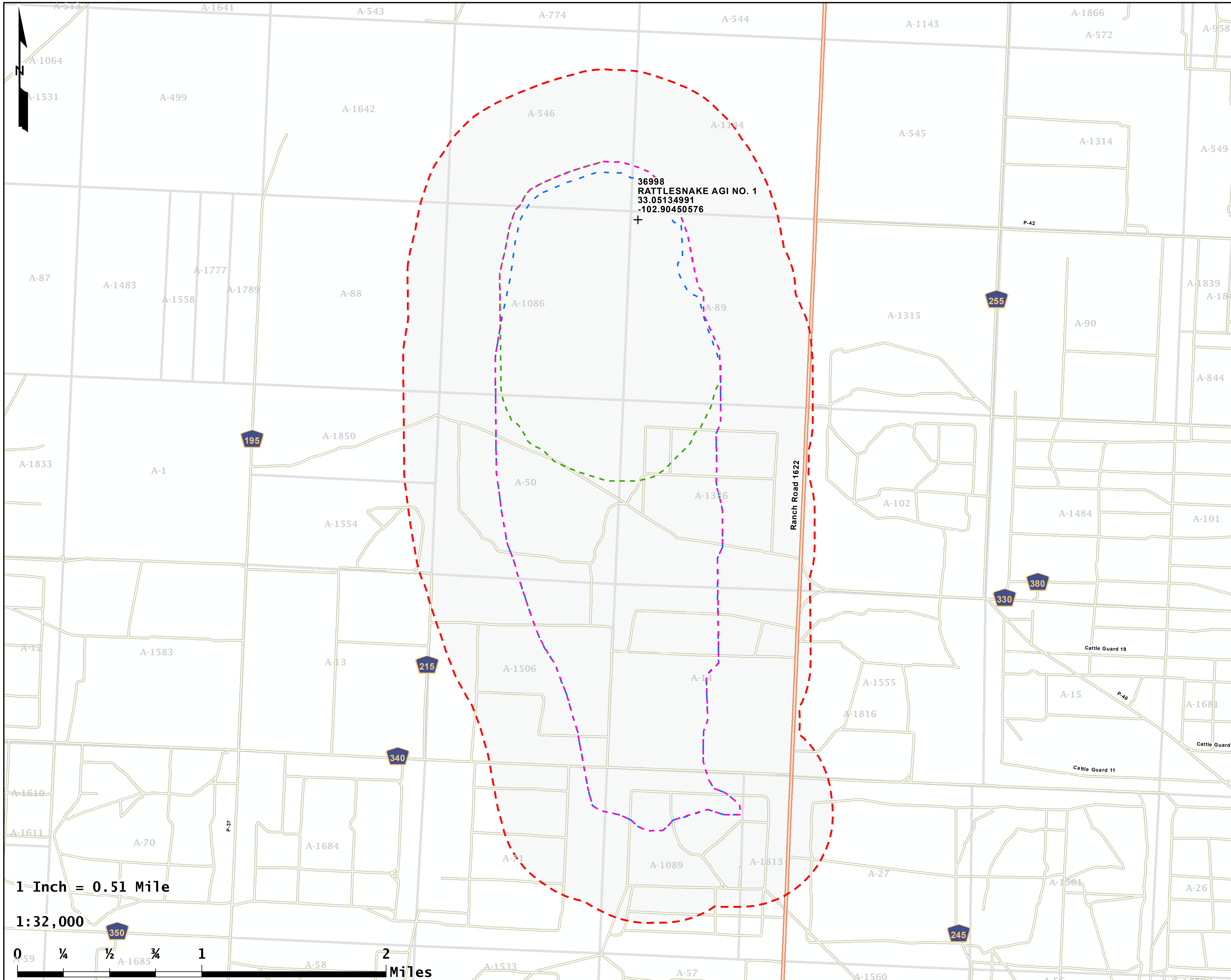
VALIDATOR:
Dustin Armstrong

VALIDATOR COMMENTS:
OK

APPENDIX D – MONITORING AREA MAPS

APPENDIX D-1: MMA MAP

APPENDIX D-2: AMA MAP



Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& Stabilized Plume
with
1/2-Mile Maximum Monitoring Area (MMA)
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS
AUSTIN · HOUSTON · CALGARY · WICHITA
DENVER · COLLEGE STATION · BATON ROUGE · EDMONTON

+ Rattlesnake AGI No. 1 SHL

1/2-Mile Buffer from Max. Plume Extent (MMA)

Combined Maximum Plume Extent

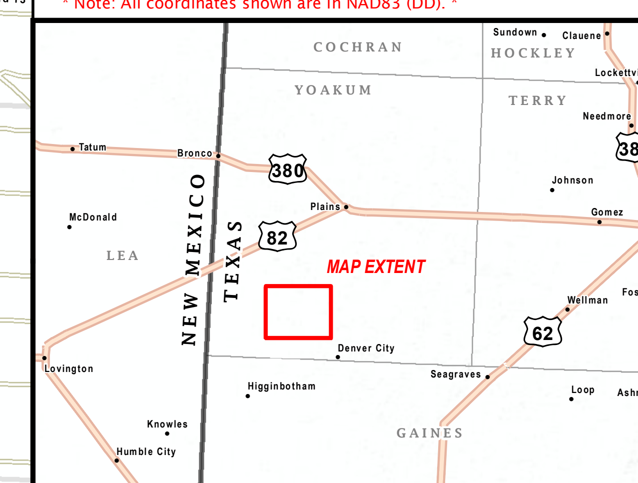
Stabilized Plume

Plume Boundary at End of Injection

Abstract

D-1

* Note: All coordinates shown are in NAD83 (DD). *



Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& 19-Year Plume
with
1/2-Mile Active Monitoring Area (AMA)
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

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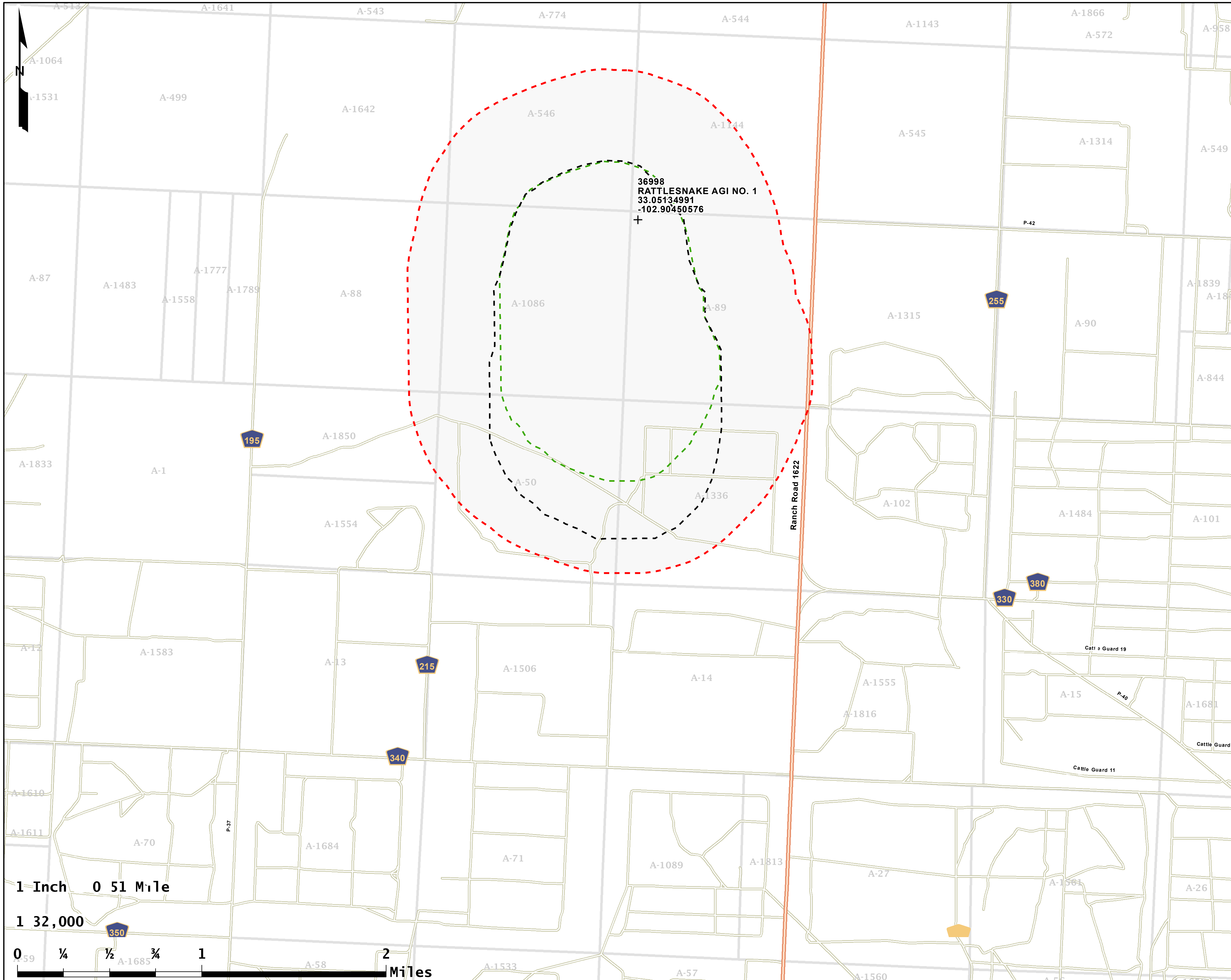


Rattlesnake AGI No. 1 SHL

Active Monitoring Area Boundary

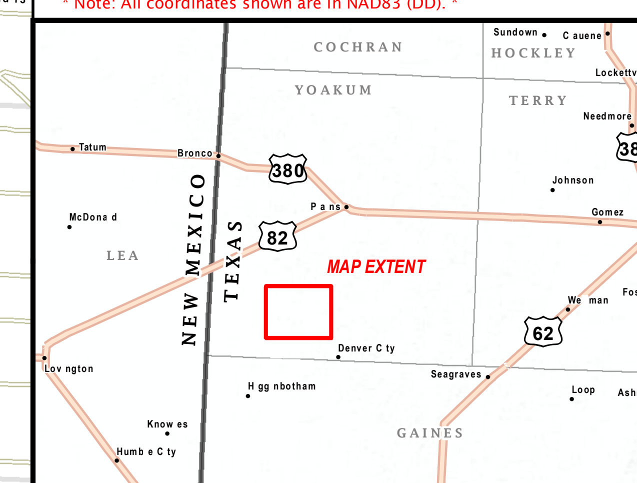
19-Year Plume

Plume Boundary at End of Injection

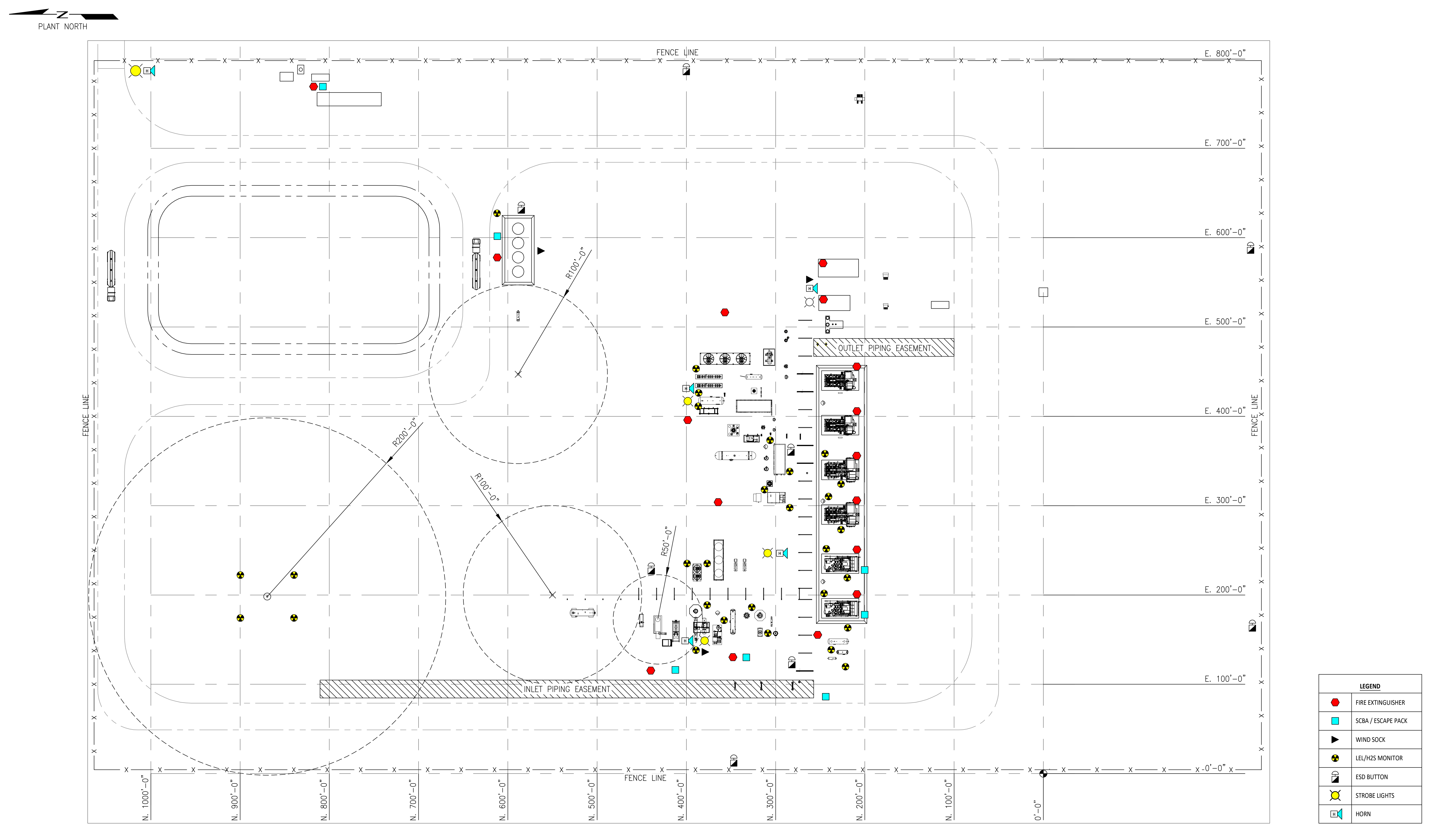
Abstract

D-2

* Note: All coordinates shown are in NAD83 (DD). *



APPENDIX E – FACILITY SAFETY PLOT PLANS



NOTES:

E-1

PRELIMINARY FOR REVIEW

NO.	DATE	REVISION DESCRIPTION	BY	FCE	CLIENT
0	05/11/22	INITIAL RELEASE	KLD	BEC	JB

CHARIS ENGINEERING, LLC
TX ENG. FIRM NO. F-18864
MIDLAND, TX

STAKEHOLDER MIDSTREAM

CLIENT : STAKEHOLDER MIDSTREAM
PROJECT : 30-30 GAS PLANT
TITLE : SAFETY EQUIPMENT PLOT PLAN

DRAWN	CHECKED	SCALE	DATE	JOB NO.	DRAWING NO.	
KLD		1" = 50'-0"	5/11/22	SAN180209	ME-PLNP-A000-0004	0

APPENDIX F – MMA/AMA REVIEW MAPS

APPENDIX F-1: PLUME BOUNDARY AT END OF INJECTION, STABILIZED PLUME BOUNDARY AND MAXIMUM MONITORING AREA MAP

APPENDIX F-2: ACTIVE MONITORING AREA MAP

APPENDIX F-3: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX F-4: OIL AND GAS WELLS WITHIN THE MMA LIST

APPENDIX F-5: INJECTION INTERVAL PENETRATING WELLS WITHIN THE MMA MAP

APPENDIX F-6: GROUNDWATER WELLS WITHIN THE MMA

APPENDIX F-7: WELLBORE SCHEMATICS FOR INJECTION INTERVAL PENETRATING WELLS

Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& Stabilized Plume
with
1/2-Mile Maximum Monitoring Area (MMA)
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

LONQUIST & CO. LLC
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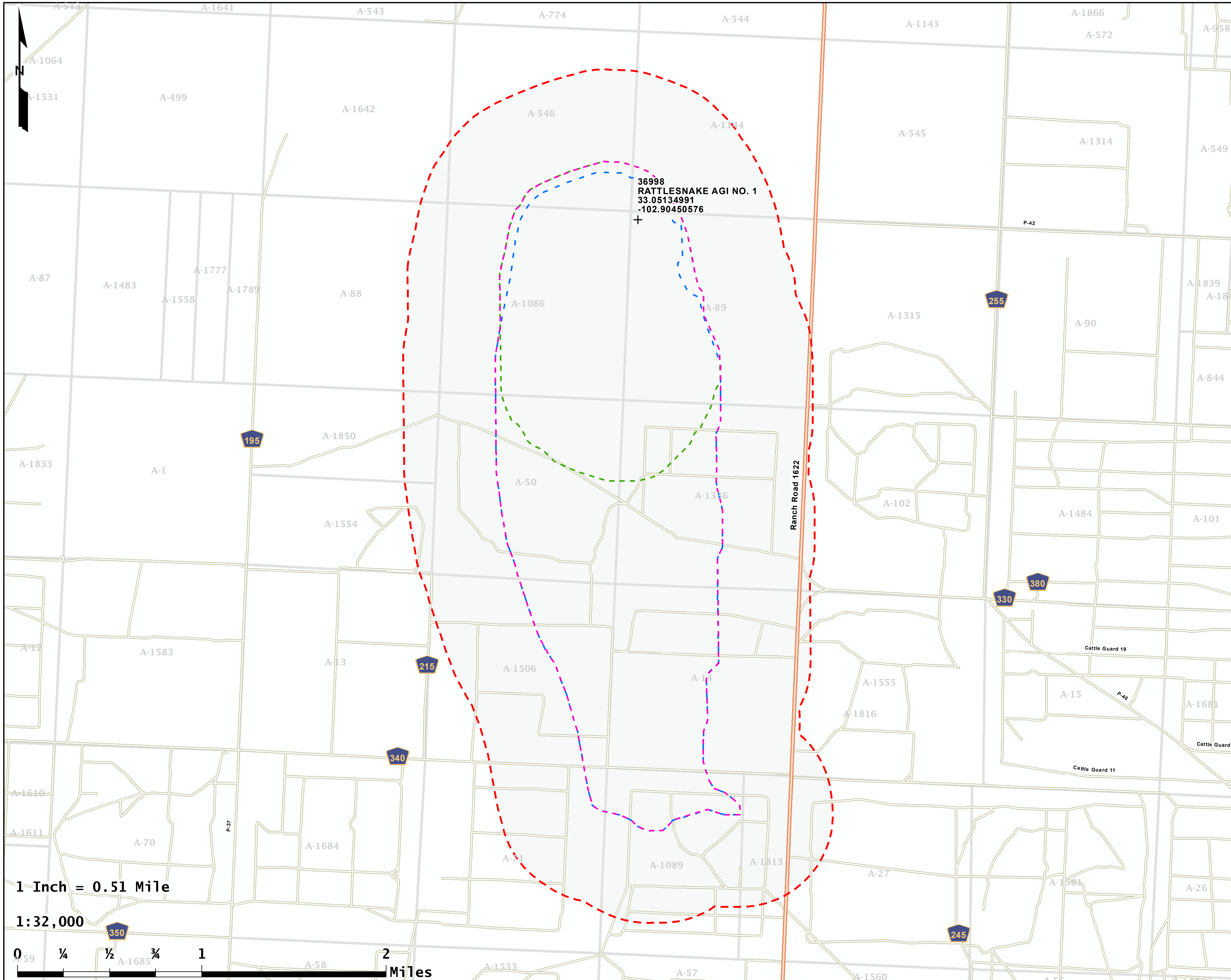
F-1



+ Rattlesnake AGI No. 1 SHL

1/2-Mile Buffer from Max. Plume Extent (MMA)

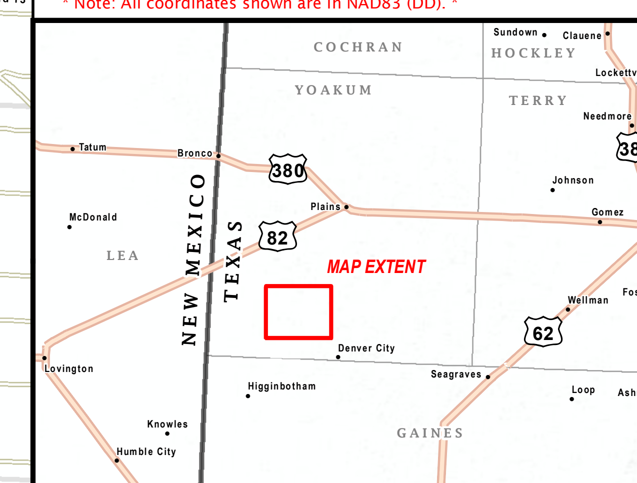
Combined Maximum Plume Extent

Stabilized Plume

Plume Boundary at End of Injection

Abstract

* Note: All coordinates shown are in NAD83 (DD). *



Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& 19-Year Plume
with
1/2-Mile Active Monitoring Area (AMA)
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

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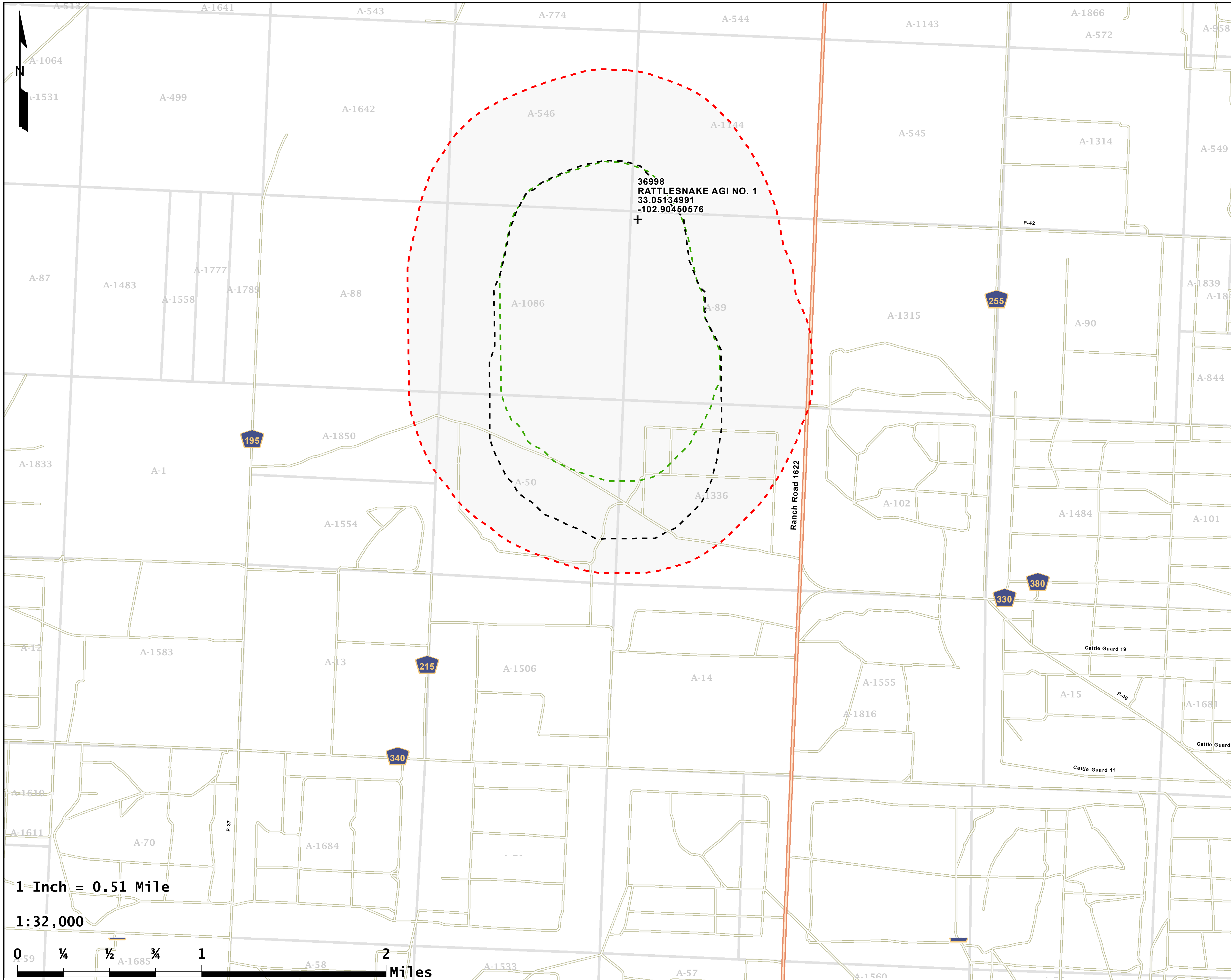
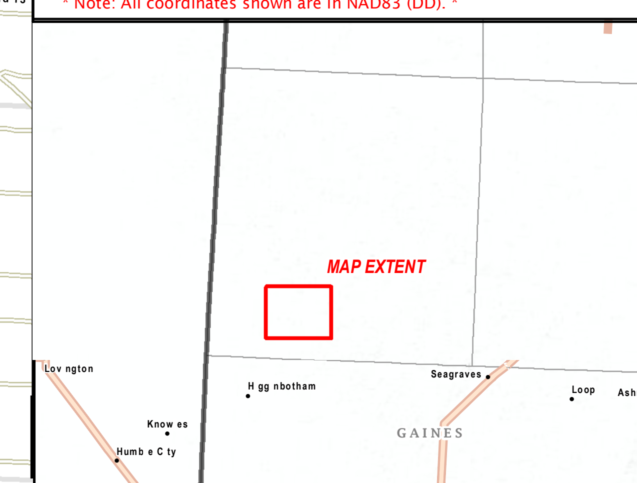
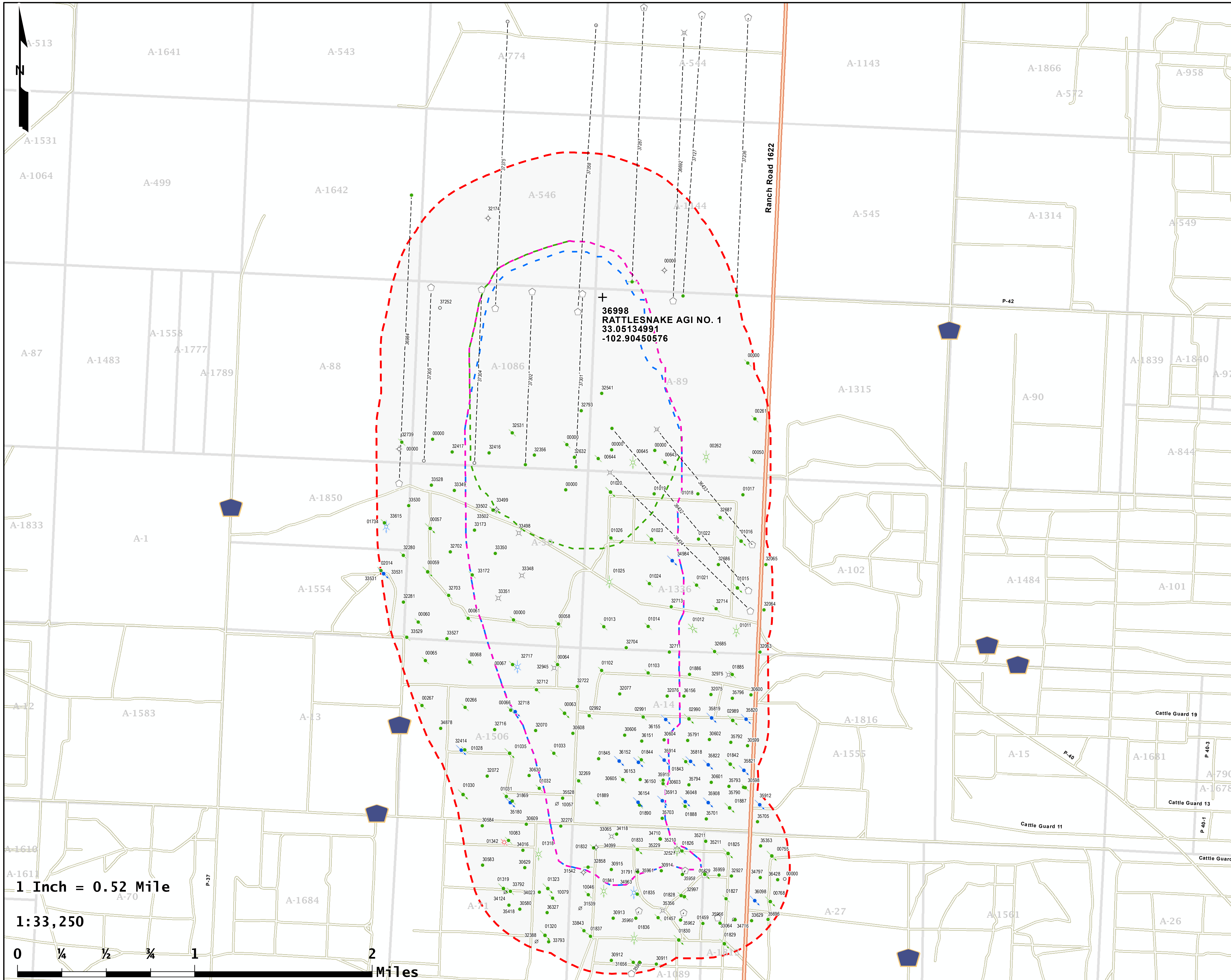
F-2



- + Rattlesnake AGI No. 1 SHL
- Active Monitoring Area Boundary
- 19-Year Plume
- Plume Boundary at End of Injection
- Abstract

* Note: All coordinates shown are in NAD83 (DD). *





Rattlesnake AGI No. 1
Maximum Monitoring Area
with
1/2-Mile MMA Oil/Gas Well
Area of Review

Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

LONQUIST & CO. LLC
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F-3

- Rattlesnake AGI No. 1 SHL
- 1/2-Mile Buffer from Max. Plume Extent (MMA)
- Combined Maximum Plume Extent
- Stabilized Plume
- Plume Boundary at End of Injection
- Abstract
- Lateral (21)

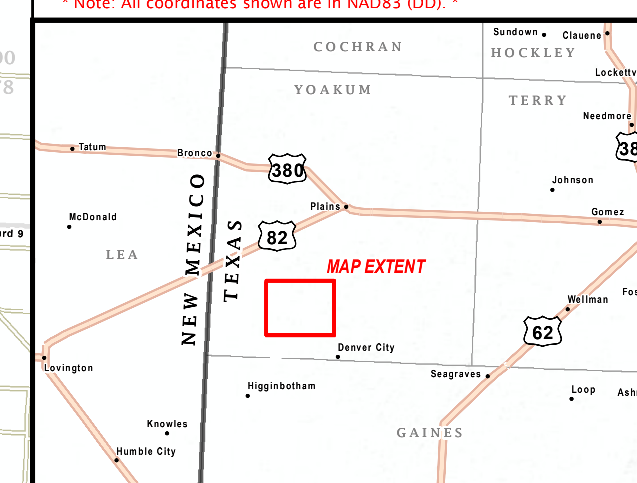
API (42-501-...) SHL Status - Type (Count)

- Horizontal Surface Location (21)
- Active - Oil (93)
- Active - Injection/Disposal (21)
- Active - Injection/Disposal from Oil (22)
- Plugged - Oil (69)
- Plugged - Gas (1)
- Plugged- Injection/Disposal from Oil (1)
- Shut-In - Oil (1)
- TA - Injection/Disposal (3)
- TA - Injection/Disposal from Oil (7)
- Dry Hole (6)
- Permitted Location (2)
- Canceled/Abandoned Location (6)
- Expired Permit (7)

API (42-501-...) BHL Status - Type (Count)

- Active - Oil (11)
- Active - Injection/Disposal from Oil (1)
- Shut-In - Oil (1)
- TA - Injection/Disposal from Oil (1)
- Permitted Location (4)
- Expired Permit (3)

Source:
1.) Oil/Gas Well SHL Data: DI-2022
2.) Oil/Gas Well BHL Data: DI-2022
3.) Oil/Gas Well Directional Data: DI-2022
* Note: All coordinates shown are in NAD83 (DD). *



Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250101829	DENVER UNIT	2215W	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5300	5300	2215W
4250101835	DENVER UNIT	2207	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5185	5185	2207
4250130914	DENVER UNIT	2222	OCCIDENTAL PERMIAN LTD.	Active - Oil			2222
4250101832	DENVER UNIT	2201W	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5190	5190	2201W
4250101826	DENVER UNIT	2203	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5250	5250	2203
4250101319	ROBERTS UNIT	4532W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5200	5200	4532W
4250130629	ROBERTS UNIT	4535	APACHE CORPORATION	Active - Oil	5280	5280	4535
4250130583	ROBERTS UNIT	4525	APACHE CORPORATION	Active - Oil	5286	5286	4525
4250101318	ROBERTS UNIT	4541	APACHE CORPORATION	TA - Injection/Disposal from Oil	5240	5240	4541
4250101889	ROBERTS UNIT	3614	APACHE CORPORATION	Plugged - Oil	5180	5180	3614
4250130598	Roberts Unit	3647	APACHE CORPORATION	Plugged - Oil	5281	5281	3647
4250130603	ROBERTS UNIT	3626	APACHE CORPORATION	Plugged - Oil	5289	5289	3626
4250102992	ROBERTS UNIT	3612W	APACHE CORPORATION	Plugged - Oil	5226	5226	3612W
4250100066	ROBERTS UNIT	3532	APACHE CORPORATION	Plugged - Oil	5231	5231	3532
4250101886	ROBERTS UNIT	3631	APACHE CORPORATION	Plugged - Oil			3631
4250101885	ROBERTS UNIT	3641	APACHE CORPORATION	Plugged - Oil	5212	5212	3641
4250100068	ROBERTS UNIT	3521	APACHE CORPORATION	Plugged - Oil	5225	5225	3521
4250100064	ROBERTS UNIT	3541	APACHE CORPORATION	Plugged - Oil	5264	5264	3541
4250102014	ROBERTS UNIT	2443	APACHE CORPORATION	Plugged - Oil	5226	5226	2443
4250100050	ROBERTS UNIT	1654	APACHE CORPORATION	Plugged - Oil	5198	5198	1654
4250133531	ROBERTS UNIT	2443A		Active - Injection/Disposal	5325	5325	2443A
4250133502	ROBERTS UNIT	2527A		Plugged - Oil	5308	5308	2527A
4250100000	C. A. ELLIOTT	6	AMERICAN LIBERTY OIL CO	Plugged - Oil	5229	5229	6
4250100000	C. A. ELLIOTT	7	AMERICAN LIBERTY AND ATLANTIC	Active - Oil	5182	5182	7
4250100000	GEO CLEVELAND	1	DELFERN OIL CO	Dry Hole	5071	5071	1
4250100000	JAMES H. LYNN	1614	AMERICAN LIBERTY	Active - Oil	5169	5169	1614
4250100000	J. H. LYNN	1634	AMERICAN LIBERTY	Active - Oil	5160	5160	1634
4250100000	A. T. MORRIS	1	ATLANTIC	Active - Oil	5235	5235	1
4250100000	A. T. MORRIS	2	AMERICAN LIBERTY OIL CO	Plugged - Oil	5179	5179	2
4250100000	W. J. CARPENTER	1642	AMERICAN LIBERTY OIL COMPANY	Plugged - Oil	5183	5183	1642
4250100000	E.S. SMITH	1	CREAT WESTERN FROD	Dry Hole	5216	5216	1
4250130607	ROBERTS UNIT	3546		Active - Oil			3546
4250135958	DENVER UNIT	2247	OCCIDENTAL PERMIAN LTD.	Active - Oil	2333	2333	2247
4250131542	DENVER UNIT	2229	SHELL OIL COMPANY	Dry Hole	2409	2409	2229
4250101320	ROBERTS UNIT	4543	APACHE CORPORATION	Active - Injection/Disposal from Oil	5120	5120	4543
4250137301	MILLER	8H	AMTEX ENERGY, INC.	Active - Oil	5157	5157	8H
4250137304	MILLER 732 C	10H	AMTEX ENERGY, INC.	Permitted Location	5157	5157	10H
4250137305	MILLER 732 D	11H	AMTEX ENERGY, INC.	Permitted Location	5157	5157	11H
4250101888	ROBERTS UNIT	3634W	APACHE CORPORATION	Plugged - Oil	5160	5160	3634W

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250101031	ROBERTS UNIT	3534W	APACHE CORPORATION	Plugged - Oil	5164	5164	3534W
4250101828	DENVER UNIT	2208	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5170	5170	2208
4250101032	ROBERTS UNIT	3544	APACHE CORPORATION	Plugged - Oil	5170	5170	3544
4250101841	DENVER UNIT	2206	OCCIDENTAL PERMIAN LTD.	TA - Injection/Disposal from Oil	5177	5177	2206
4250101842	ROBERTS UNIT	3643W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5180	5180	3643W
4250101035	ROBERTS UNIT	3533W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5180	5180	3533W
4250132704	ROBERTS UNIT	2615	APACHE CORPORATION	Active - Oil	5180	5180	2615
4250100261	ROBERTS UNIT	1643W	APACHE CORPORATION	Plugged - Oil	5180	5180	1643W
4250101323	ROBERTS UNIT	4542W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5182	5182	4542W
4250102989	ROBERTS UNIT	3642W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5182	5182	3642W
4250102991	ROBERTS UNIT	3622W	APACHE CORPORATION	Plugged - Oil	5185	5185	3622W
4250132417	MILLER	3	AMTEX ENERGY, INC.	Active - Oil	5186	5186	3
4250101025	ROBERTS UNIT	2613W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5188	5188	2613W
4250101887	ROBERTS UNIT	3644	APACHE CORPORATION	Active - Injection/Disposal from Oil	5189	5189	3644
4250101830	DENVER UNIT	2214WC	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5190	5190	2214WC
4250101103	ROBERTS UNIT	3621	APACHE CORPORATION	Plugged - Oil	5190	5190	3621
4250101024	ROBERTS UNIT	2623	APACHE CORPORATION	Plugged - Oil	5190	5190	2623
4250101023	ROBERTS UNIT	2622W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5190	5190	2622W
4250101022	ROBERTS UNIT	2632	APACHE CORPORATION	Active - Oil	5190	5190	2632
4250101019	ROBERTS UNIT	2621	APACHE CORPORATION	Active - Oil	5190	5190	2621
4250101030	ROBERTS UNIT	3524W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5193	5193	3524W
4250101829	DENVER UNIT	2205	OCCIDENTAL PERMIAN LTD.	TA - Injection/Disposal from Oil	5195	5195	2205
4250101836	DENVER UNIT	2213WC	OCCIDENTAL PERMIAN LTD.	TA - Injection/Disposal from Oil	5200	5200	2213WC
4250101833	DENVER UNIT	2202WC	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5200	5200	2202WC
4250134099	DENVER UNIT	2239WC	OCCIDENTAL PERMIAN LTD.	Dry Hole	5200	5200	2239WC
4250132717	ROBERTS UNIT	3531A	APACHE CORPORATION	TA - Injection/Disposal	5200	5200	3531A
4250101014	ROBERTS UNIT	2624W	APACHE CORPORATION	Plugged - Oil	5200	5200	2624W
4250101028	ROBERTS UNIT	3523	APACHE CORPORATION	Plugged - Oil	5205	5205	3523
4250101102	ROBERTS UNIT	3611	APACHE CORPORATION	Plugged - Oil	5206	5206	3611
4250101827	DENVER UNIT	2209W	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5210	5210	2209W
4250101015		2643	TEXACO INCORPORATED	Active - Injection/Disposal from Oil	5210	5210	2643
4250100266	ROBERTS UNIT	3522W	APACHE CORPORATION	Plugged - Oil	5211	5211	3522W
4250132632	MILLER	5	AMTEX ENERGY, INC.	Active - Oil	5213	5213	5
4250100057	ROBERTS UNIT	2512W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5213	5213	2512W
4250101890	ROBERTS UNIT	3624W	APACHE CORPORATION	Plugged - Oil	5214	5214	3624W
4250101033	ROBERTS UNIT	3543W	APACHE CORPORATION	Plugged - Oil	5215	5215	3543W
4250101012	ROBERTS UNIT	2634W	APACHE CORPORATION	Plugged- Injection/Disposal from Oil	5215	5215	2634W
4250101734	ROBERTS UNIT	2442	APACHE CORPORATION	Plugged - Oil	5215	5215	2442
4250101020	ROBERTS UNIT	2611W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5215	5215	2611W

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API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250100067	ROBERTS UNIT	3531	APACHE CORPORATION	Plugged - Oil	5216	5216	3531
4250101013	ROBERTS UNIT	2614W	APACHE CORPORATION	Plugged - Oil	5216	5216	2614W
4250101844	ROBERTS UNIT	3623W	APACHE CORPORATION	Plugged - Oil	5217	5217	3623W
4250131869	ROBERTS UNIT	A3534W	APACHE CORPORATION	Plugged - Oil	5220	5220	A3534W
4250102990	ROBERTS UNIT	3632W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5220	5220	3632W
4250100262	ROBERTS UNIT	1644W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5220	5220	1644W
4250132858	DENVER UNIT	2235	OCCIDENTAL PERMIAN LTD.	Shut-In - Oil	5225	5225	2235
4250100058	ROBERTS UNIT	2544W	APACHE CORPORATION	Plugged - Oil	5225	5225	2544W
4250130584	ROBERTS UNIT	4520	APACHE CORPORATION	Active - Oil	5230	5230	4520
4250130630	ROBERTS UNIT	3535	APACHE CORPORATION	Active - Oil	5230	5230	3535
4250100063	ROBERTS UNIT	3542W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5230	5230	3542W
4250132076	ROBERTS UNIT	3627	APACHE CORPORATION	Active - Oil	5230	5230	3627
4250100267	ROBERTS UNIT	3512W	APACHE CORPORATION	Plugged - Oil	5233	5233	3512W
4250101016	ROBERTS UNIT	2642W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5234	5234	2642W
4250134716	DENVER UNIT	2242	OCCIDENTAL PERMIAN LTD.	Active - Oil	5236	5236	2242
4250100061	ROBERTS UNIT	2524W	APACHE CORPORATION	Plugged - Oil	5238	5238	2524W
4250101021	ROBERTS UNIT	2633	APACHE CORPORATION	Plugged - Oil	5240	5240	2633
4250101011	ROBERTS UNIT	2644W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5241	5241	2644W
4250132541	FUTCH	1	AMTEX ENERGY, INC.	Active - Oil	5244	5244	1
4250101026	ROBERTS UNIT	2612W	APACHE CORPORATION	Plugged - Oil	5245	5245	2612W
4250100059	ROBERTS UNIT	2513W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5246	5246	2513W
4250132531	MILLER	4	AMTEX ENERGY, INC.	Plugged - Oil	5248	5248	4
4250132687	ROBERTS UNIT	2635	APACHE CORPORATION	Plugged - Oil	5248	5248	2635
4250131656	DENVER UNIT	2232WC	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5250	5250	2232WC
4250131791	DENVER UNIT	2231	SHELL OIL COMPANY	Canceled/Abandoned Location	5250	5250	2231
4250134118	DENVER UNIT	2238	OCCIDENTAL PERMIAN LTD.	Active - Oil	5250	5250	2238
4250101342	ROBERTS UNIT		APACHE CORPORATION	Plugged - Gas	5250	5250	
4250132269	ROBERTS UNIT	3601	APACHE CORPORATION	Plugged - Oil	5250	5250	3601
4250101843	ROBERTS UNIT	3633W	APACHE CORPORATION	Plugged - Oil	5250	5250	3633W
4250130608	ROBERTS UNIT	3545	APACHE CORPORATION	Active - Oil	5250	5250	3545
4250132077	ROBERTS UNIT	3617	APACHE CORPORATION	Active - Oil	5250	5250	3617
4250134963	DENVER UNIT	2244WC	OCCIDENTAL PERMIAN LTD.	TA- Injection/Disposal	5251	5251	2244WC
4250100060	ROBERTS UNIT	2514	APACHE CORPORATION	Plugged - Oil	5251	5251	2514
4250101459	DENVER UNIT	2211	OCCIDENTAL PERMIAN LTD.	Active - Oil	5252	5252	2211
4250132521	DENVER UNIT	2233W	OCCIDENTAL PERMIAN LTD.	TA- Injection/Disposal from Oil	5253	5253	2233W
4250135211	DENVER UNIT	2241	OCCIDENTAL PERMIAN LTD.	Active - Oil	5253	5253	2241
4250101837	DENVER UNIT	2212W	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5255	5255	2212W
4250132793	MILLER	6	AMTEX ENERGY, INC.	Active - Oil	5258	5258	6
4250132356	MILLER	1	AMTEX ENERGY, INC.	Active - Oil	5260	5260	1

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API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250101017	ROBERTS UNIT	2641	APACHE CORPORATION	Active - Oil	5260	5260	2641
4250101825	DENVER UNIT	2204W	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5264	5264	2204W
4250132416	MILLER	2	AMTEX ENERGY, INC.	Active - Oil	5269	5269	2
4250100065	ROBERTS UNIT	3511W	APACHE CORPORATION	Plugged - Oil	5270	5270	3511W
4250101018	ROBERTS UNIT	2631	APACHE CORPORATION	Active - Oil	5270	5270	2631
4250130600	ROBERTS UNIT	3645	APACHE CORPORATION	Active - Oil	5273	5273	3645
4250130580	ROBERTS UNIT	4536	APACHE CORPORATION	Active - Oil	5279	5279	4536
4250130599	ROBERTS UNIT	3646	APACHE CORPORATION	Active - Oil	5279	5279	3646
4250130602	ROBERTS UNIT	3635	APACHE CORPORATION	Active - Oil	5283	5283	3635
4250132997	DENVER UNIT	2208WC	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5284	5284	2208WC
4250130601	ROBERTS UNIT	3636	APACHE CORPORATION	Active - Oil	5286	5286	3636
4250132174	SHEPHERD	1	YOUNG, MARSHALL R., OIL CO.	Dry Hole	5286	5286	1
4250130604	ROBERTS UNIT	3625	APACHE CORPORATION	Active - Oil	5287	5287	3625
4250130912	DENVER UNIT	2224	OCCIDENTAL PERMIAN LTD.	Active - Oil	5288	5288	2224
4250130911	DENVER UNIT	2225	OCCIDENTAL PERMIAN LTD.	Active - Oil	5290	5290	2225
4250130609	ROBERTS UNIT	4530	APACHE CORPORATION	Active - Oil	5291	5291	4530
4250130605	ROBERTS UNIT	3616	APACHE CORPORATION	Plugged - Oil	5291	5291	3616
4250130606	ROBERTS UNIT	3615	APACHE CORPORATION	Active - Oil	5293	5293	3615
4250133172	ROBERTS UNIT	2523	CONOCOPHILLIPS COMPANY	Plugged - Oil	5295	5295	2523
4250132739	CLEVELAND	1	HIGHLAND PRODUCTION COMPANY	Plugged - Oil	5300	5300	1
4250133064	DENVER UNIT	2238	SHELL WESTERN E&P INC.	Canceled/Abandoned Location	5300	5300	2238
4250132927	DENVER UNIT	2236	OCCIDENTAL PERMIAN LTD.	Active - Oil	5300	5300	2236
4250133065	DENVER UNIT	2237	SHELL WESTERN E&P INC.	Expired Permit	5300	5300	2237
4250132270	ROBERTS UNIT	4540	APACHE CORPORATION	Active - Oil	5300	5300	4540
4250132414	ROBERTS UNIT	3523A	APACHE CORPORATION	Active - Injection/Disposal	5300	5300	3523A
4250132712	ROBERTS UNIT	3537	APACHE CORPORATION	Plugged - Oil	5300	5300	3537
4250132722	ROBERTS UNIT	3547	APACHE CORPORATION	Active - Oil	5300	5300	3547
4250132945	ROBERTS UNIT	3541A	TEXACO PRODUCING INC.	Expired Permit	5300	5300	3541A
4250132975	ROBERTS UNIT	3641A	TEXACO PRODUCING INC.	Expired Permit	5300	5300	3641A
4250132711	ROBERTS UNIT	3620	APACHE CORPORATION	Active - Oil	5300	5300	3620
4250133527	ROBERTS UNIT	2518	APACHE CORPORATION	Active - Oil	5300	5300	2518
4250132714	ROBERTS UNIT	2637	APACHE CORPORATION	Plugged - Oil	5300	5300	2637
4250133351	ROBERTS UNIT	2526	TEXACO PRODUCING INC.	Expired Permit	5300	5300	2526
4250132703	ROBERTS UNIT	2516	APACHE CORPORATION	Plugged - Oil	5300	5300	2516
4250133348	ROBERTS UNIT	2533	TEXACO PRODUCING INC.	Expired Permit	5300	5300	2533
4250132702	ROBERTS UNIT	2515	APACHE CORPORATION	Active - Oil	5300	5300	2515
4250133350	ROBERTS UNIT	2525	APACHE CORPORATION	Active - Oil	5300	5300	2525
4250133498	ROBERTS UNIT	2532	TEXACO PRODUCING INC.	Expired Permit	5300	5300	2532
4250133173	ROBERTS UNIT	2522	APACHE CORPORATION	Active - Oil	5300	5300	2522

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API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250133499	ROBERTS UNIT	2527	TEXACO PRODUCING INC.	Dry Hole	5300	5300	2527
4250133530	ROBERTS UNIT	2507	APACHE CORPORATION	Active - Oil	5300	5300	2507
4250132685	ROBERTS UNIT	2638	APACHE CORPORATION	Plugged - Oil	5302	5302	2638
4250133349	ROBERTS UNIT	2517	APACHE CORPORATION	Active - Oil	5302	5302	2517
4250132718	ROBERTS UNIT	3532A	APACHE CORPORATION	Active - Injection/Disposal	5304	5304	3532A
4250132713	ROBERTS UNIT	2625	APACHE CORPORATION	Active - Oil	5308	5308	2625
4250133502	ROBERTS UNIT	2527A	APACHE CORPORATION	Plugged - Oil	5308	5308	2527A
4250132716	ROBERTS UNIT	3526	APACHE CORPORATION	Active - Oil	5309	5309	3526
4250100645	ROBERTS UNIT	1624W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5309	5309	1624W
4250130913	DENVER UNIT	2223	OCCIDENTAL PERMIAN LTD.	Active - Oil	5310	5310	2223
4250132686	ROBERTS UNIT	2636	APACHE CORPORATION	Active - Oil	5310	5310	2636
4250101457	DENVER UNIT	2210	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5325	5325	2210
4250133529	ROBERTS UNIT	2508	APACHE CORPORATION	Plugged - Oil	5325	5325	2508
4250133531	ROBERTS UNIT	2443A	APACHE CORPORATION	Active - Injection/Disposal	5325	5325	2443A
4250133528	ROBERTS UNIT	2511	APACHE CORPORATION	Active - Oil	5325	5325	2511
4250135912	ROBERTS UNIT	3771W	APACHE CORPORATION	Active - Injection/Disposal	5330	5330	3771W
4250132075	ROBERTS UNIT	3637	APACHE CORPORATION	Active - Oil	5330	5330	3637
4250132063	ROBERTS UNIT	2705	APACHE CORPORATION	Active - Oil	5330	5330	2705
4250135793	ROBERTS UNIT	3672	APACHE CORPORATION	Active - Oil	5334	5334	3672
4250135819	ROBERTS UNIT	3674W	APACHE CORPORATION	Active - Injection/Disposal	5336	5336	3674W
4250135792	ROBERTS UNIT	3671	APACHE CORPORATION	Active - Oil	5339	5339	3671
4250135820	ROBERTS UNIT	3675W	APACHE CORPORATION	Active - Injection/Disposal	5341	5341	3675W
4250135818	ROBERTS UNIT	3633RW	APACHE CORPORATION	Active - Injection/Disposal	5344	5344	3633RW
4250135790	ROBERTS UNIT	3647R	APACHE CORPORATION	Active - Oil	5345	5345	3647R
4250100768	CORNELL UNIT	3107W	XTO ENERGY INC.	Active - Injection/Disposal from Oil	5350	5350	3107W
4250130915	DENVER UNIT	2221	OCCIDENTAL PERMIAN LTD.	Active - Oil	5350	5350	2221
4250136048	ROBERTS UNIT	3634RW	APACHE CORPORATION	Active - Injection/Disposal	5350	5350	3634RW
4250135908	ROBERTS UNIT	3678W	APACHE CORPORATION	Active - Injection/Disposal	5350	5350	3678W
4250132072	ROBERTS UNIT	3525	APACHE CORPORATION	Active - Oil	5350	5350	3525
4250135915	ROBERTS UNIT	3626R	APACHE CORPORATION	Active - Oil	5350	5350	3626R
4250132281	ROBERTS UNIT	2446	APACHE CORPORATION	Active - Oil	5350	5350	2446
4250132064	ROBERTS UNIT	2704	APACHE CORPORATION	Active - Oil	5350	5350	2704
4250132280	ROBERTS UNIT	2445	APACHE CORPORATION	Plugged - Oil	5350	5350	2445
4250135791	ROBERTS UNIT	3670	APACHE CORPORATION	Active - Oil	5351	5351	3670
4250135794	ROBERTS UNIT	3673	APACHE CORPORATION	Active - Oil	5352	5352	3673
4250135821	ROBERTS UNIT	3676W	APACHE CORPORATION	Active - Injection/Disposal	5352	5352	3676W
4250135914	ROBERTS UNIT	3681W	APACHE CORPORATION	Active - Injection/Disposal	5352	5352	3681W
4250100643	ROBERTS UNIT	1634W	APACHE CORPORATION	Plugged - Oil	5353	5353	1634W
4250135796	ROBERTS UNIT	3669	APACHE CORPORATION	Active - Oil	5356	5356	3669

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API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250100644	ROBERTS UNIT	1614	APACHE CORPORATION	Plugged - Oil	5356	5356	1614
4250135913	ROBERTS UNIT	3680W	APACHE CORPORATION	Active - Injection/Disposal	5357	5357	3680W
4250135705	ROBERTS UNIT	3752	APACHE CORPORATION	Active - Oil	5360	5360	3752
4250135822	ROBERTS UNIT	3677W	APACHE CORPORATION	Active - Injection/Disposal	5362	5362	3677W
4250134984	ROBERTS UNIT	2626W	APACHE CORPORATION	Active - Injection/Disposal	5364	5364	2626W
4250135701	ROBERTS UNIT	3667	APACHE CORPORATION	Active - Oil	5365	5365	3667
4250132070	ROBERTS UNIT	3536	APACHE CORPORATION	Active - Oil	5370	5370	3536
4250132065	ROBERTS UNIT	2703	APACHE CORPORATION	Active - Oil	5370	5370	2703
4250100755	CORNELL UNIT	3101W	XTO ENERGY INC.	Active - Injection/Disposal from Oil	5373	5373	3101W
4250135703	ROBERTS UNIT	3668	APACHE CORPORATION	Active - Oil	5380	5380	3668
4250135229	DENVER UNIT	2240	OCCIDENTAL PERMIAN LTD.	Active - Oil	5388	5388	2240
4250136152	ROBERTS UNIT	3682W	APACHE CORPORATION	Active - Injection/Disposal	5397	5397	3682W
4250131539	DENVER UNIT	2230	SHELL OIL COMPANY	Canceled/Abandoned Location	5400	5400	2230
4250136327	ROBERTS UNIT	4547	APACHE CORPORATION	Active - Oil	5400	5400	4547
4250136154	ROBERTS UNIT	3624RW	APACHE CORPORATION	Active - Injection/Disposal	5400	5400	3624RW
4250136155	ROBERTS UNIT	3683W	APACHE CORPORATION	Active - Injection/Disposal	5402	5402	3683W
4250136156	ROBERTS UNIT	3686	APACHE CORPORATION	Active - Oil	5404	5404	3686
4250134797	CORNELL UNIT	3194	XTO ENERGY INC.	Active - Oil	5405	5405	3194
4250135696	CORNELL UNIT	113	XTO ENERGY INC.	Active - Oil	5406	5406	113
4250136150	ROBERTS UNIT	3684	APACHE CORPORATION	Active - Oil	5421	5421	3684
4250133629	CORNELL UNIT	3156	XTO ENERGY INC.	Active - Oil	5425	5425	3156
4250135961	DENVER UNIT	2246	OCCIDENTAL PERMIAN LTD.	Active - Oil	5425	5425	2246
4250135960	DENVER UNIT	2249	OCCIDENTAL PERMIAN LTD.	Active - Oil	5431	5431	2249
4250136153	ROBERTS UNIT	3623RW	APACHE CORPORATION	Active - Injection/Disposal	5439	5439	3623RW
4250135353	CORNELL UNIT	107	XTO ENERGY INC.	Active - Oil	5450	5450	107
4250135528	ROBERTS UNIT	3549	APACHE CORPORATION	Active - Oil	5452	5452	3549
4250136151	ROBERTS UNIT	3685	APACHE CORPORATION	Active - Oil	5463	5463	3685
4250135963	DENVER UNIT	2252	OCCIDENTAL PERMIAN LTD.	Active - Oil	5476	5476	2252
4250136434	ROBERTS UNIT	263H	APACHE CORPORATION	Expired Permit	5500	5500	263H
4250136433	ROBERTS UNIT	262H	APACHE CORPORATION	Expired Permit	5500	5500	262H
4250136098	CORNELL UNIT	110	XTO ENERGY INC.	Active - Injection/Disposal	5510	5510	110
4250133615	ROBERTS UNIT	2442A	APACHE CORPORATION	TA - Injection/Disposal	5516	5516	2442A
4250135180	ROBERTS UNIT	3534B	APACHE CORPORATION	Active - Injection/Disposal	5517	5517	3534B
4250136428	CORNELL UNIT	124	XTO ENERGY INC.	Active - Oil	5532	5532	124
4250134878	ROBERTS UNIT	3548	APACHE CORPORATION	Active - Oil	5550	5550	3548
4250135966	DENVER UNIT	2251	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2251
4250135962	DENVER UNIT	2250	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2250
4250135356	DENVER UNIT	2246	OCCIDENTAL PERMIAN LTD.	Expired Permit	5600	5600	2246
4250135959	DENVER UNIT	2248	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2248

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API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250135210	DENVER UNIT	2240	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2240
4250135211		2241	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2241
4250134710		2240	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2240
4250101845	ROBERTS UNIT	3613	APACHE CORPORATION	Active - Oil	7000	7000	3613
4250110083	RANDALL, E.	36	EXXON CORP.	Plugged - Oil	8595	8595	36
4250110046	ELLIOTT, C.A.	2	MCCLURE OIL COMPANY, INC.	Plugged - Oil	9000	9000	2
4250136692	MISS KITTY 704-669	3XH	RILEY EXPLORATION OPG CO, LLC	Expired Permit	9000	9000	3XH
4250133793	RANDALL, E.	39	XTO ENERGY INC.	Active - Oil	9000	9000	39
4250137375	RIP WHEELER 705-668	5XH	RILEY PERMIAN OPERATING CO, LLC	Permitted Location	9000	9000	5XH
4250137358	RIP WHEELER 705-668	1XH	RILEY PERMIAN OPERATING CO, LLC	Permitted Location	9000	9000	1XH
4250133843	ELLIOTT	1	DELTA C02, LLC	Plugged - Oil	9050	9050	1
4250134124	RANDALL, E	46	EXXON CORP.	Canceled/Abandoned Location	9100	9100	46
4250133792	RANDALL, E.	40	XTO ENERGY INC.	Plugged - Oil	9591	9591	40
4250110079	RANDALL, E.	32	EXXON CORP.	Plugged - Oil	9615	9615	32
4250135418	RANDALL, E.	46	XTO ENERGY INC.	Active - Oil	9650	9650	46
4250134023	RANDALL, E.	42	XTO ENERGY INC.	Active - Oil	9660	9660	42
4250134016	RANDALL, E.	43	XTO ENERGY INC.	Active - Oil	9740	9740	43
4250132388	RANDALL, E.	38	EXXON CORP.	Canceled/Abandoned Location	10300	10300	38
4250137302	MILLER 732 B	9H	AMTEX ENERGY, INC.	Active - Oil	5183	10662	9H
4250136432	ROBERTS UNIT	261 H	APACHE CORPORATION	Active - Oil	5151	11117	261 H
4250136998	RATTLESNAKE AGI	1	SANTA FE MIDSTREAM PERMIAN LLC	Active - Injection/Disposal	11980	11980	1
4250137252	MILLER SWD	7	AMTEX ENERGY, INC.	Permitted Location	13000	13000	7
4250136984	MADCAP 731-706	1XH	RILEY PERMIAN OPERATING CO, LLC	Active - Oil	5261	13274	1XH
4250137127	MISS KITTY A 669-704	25XH	RILEY PERMIAN OPERATING CO, LLC	Active - Oil	5321	13428	25XH
4250137287	MISS KITTY A 669-704	4XH	RILEY PERMIAN OPERATING CO, LLC	Shut-In - Oil	5340	13452	4XH
4250137236	MISS KITTY 669-704	2XH	RILEY PERMIAN OPERATING CO, LLC	Active - Oil	5317	13622	2XH

Rattlesnake AGI No. 1
Maximum Monitoring Area
with
1/2-Mile MMA Oil/Gas Well Penetrators
Area of Review
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 6/1/2022	Approved by: RH

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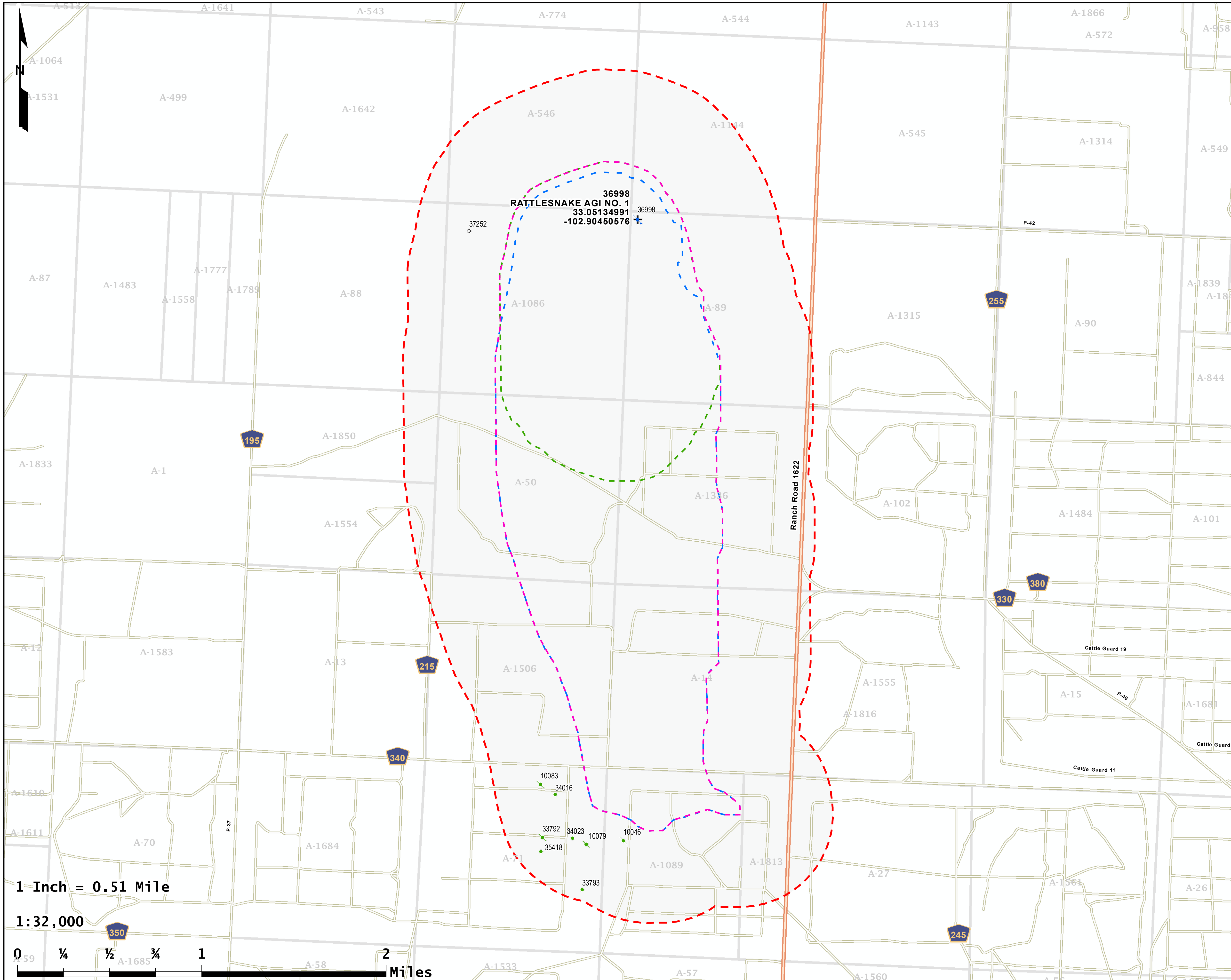


+ Rattlesnake AGI No. 1 SHL

1/2-Mile Buffer from Max. Plume Extent (MMA)

Combined Maximum Plume Extent

Stabilized Plume

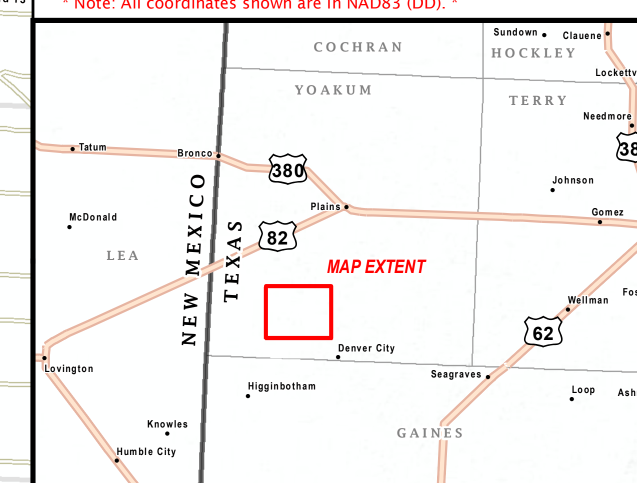
Plume Boundary at End of Injection

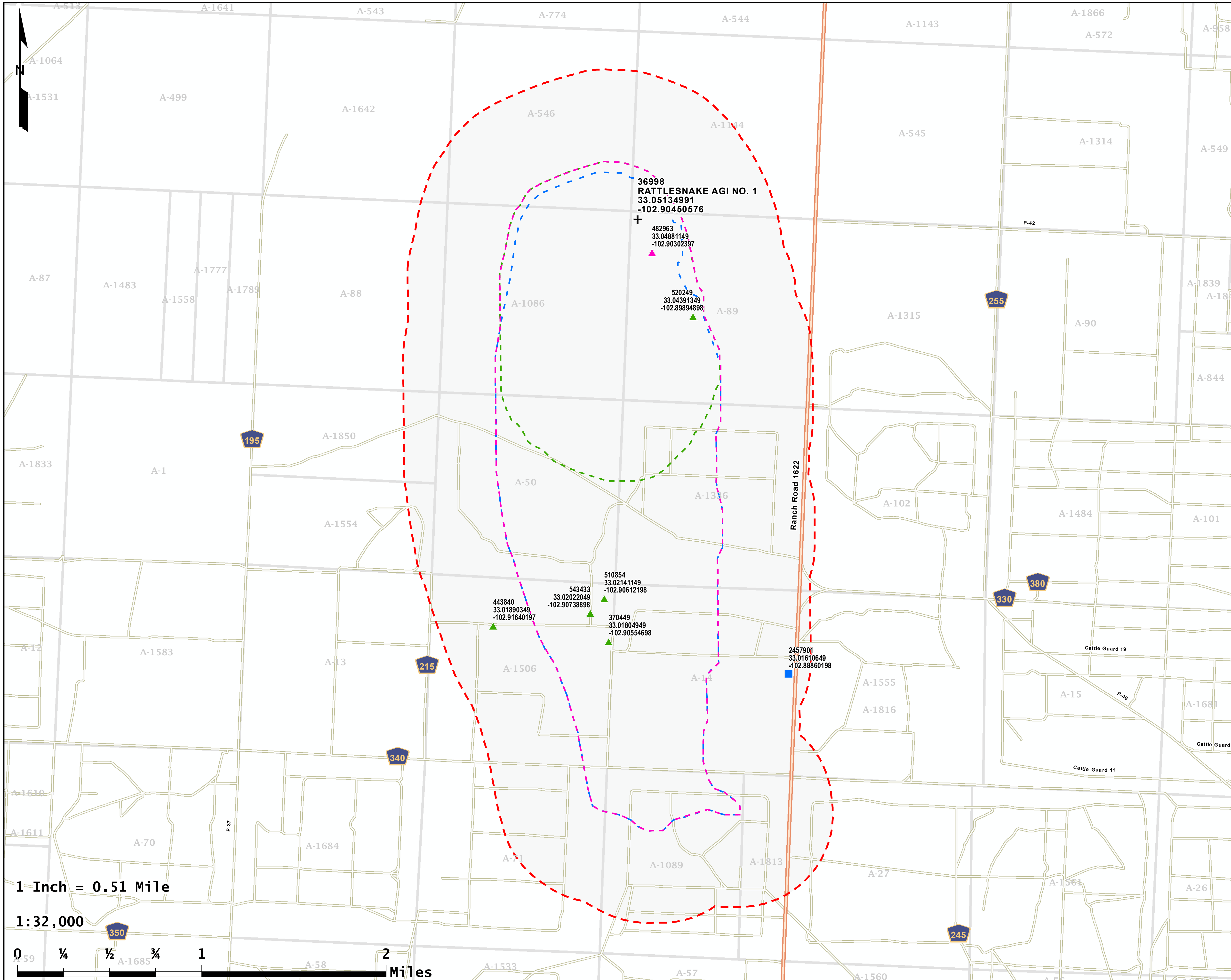
Abstract

API (42-501-...) SHL Status - Type (Count)

- Active - Oil (4)
- Active - Injection/Disposal (1)
- Plugged - Oil (4)
- Permitted Location (1)

Source:
1.) Oil/Gas Well SHL Data: DI-2022
2.) Oil/Gas Well BHL Data: DI-2022
3.) Oil/Gas Well Directional Data: DI-2022
* Note: All coordinates shown are in NAD83 (DD). *





Rattlesnake AGI No. 1
Maximum Monitoring Area
with
1/2-Mile MMA Groundwater Well
Area of Review
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

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+ Rattlesnake AGI No. 1 SHL

1/2-Mile Buffer from Max. Plume Extent (MMA)

Combined Maximum Plume Extent

Stabilized Plume

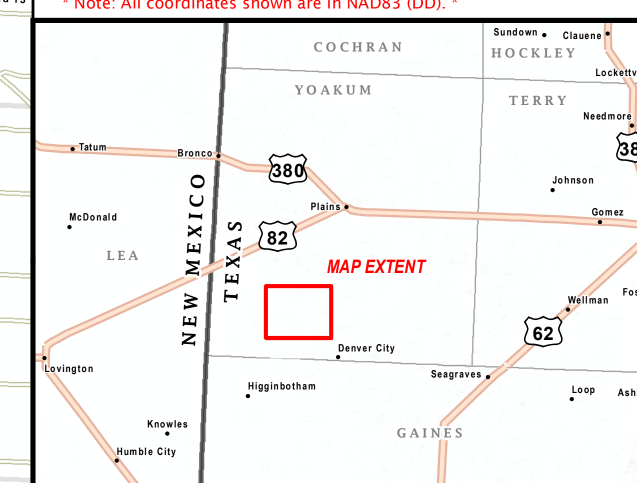
Plume Boundary at End of Injection

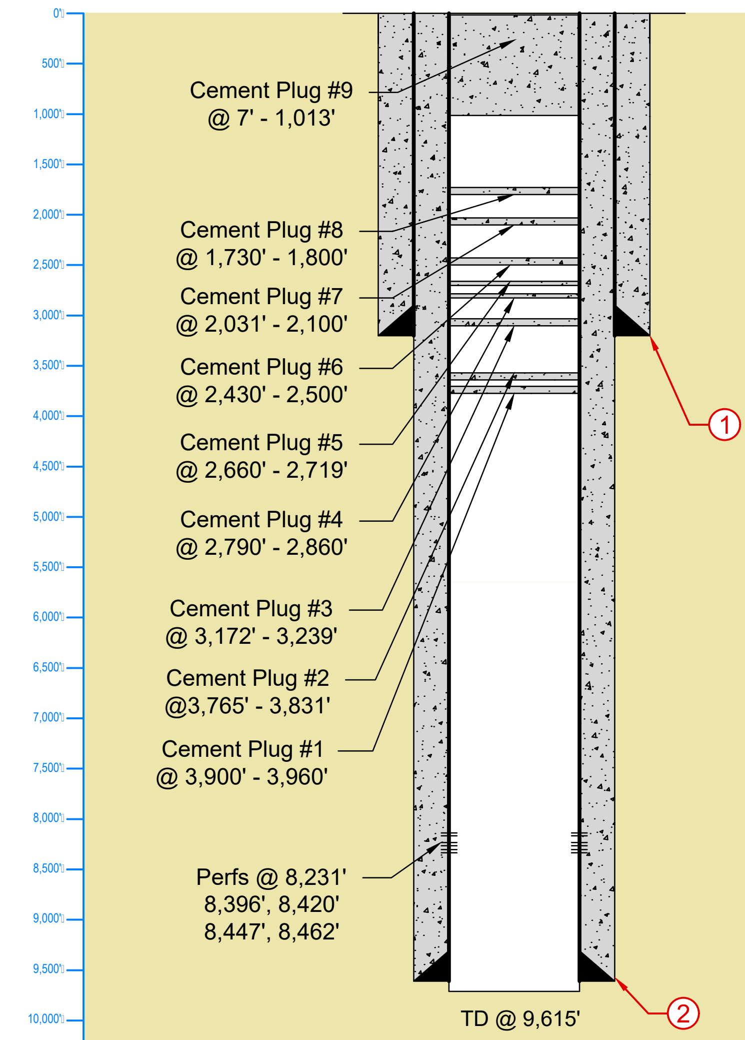
Abstract

SDRDB Groundwater Wells [TWDB-2022]
Proposed Use (Labeled with Well Report No.)
Industrial (1)
Irrigation (5)

TWDB Groundwater Wells [TWDB-2022]
Well Type (Labeled with State Well No.)
Withdrawal of Water (1)

Source:
1.) SDRDB Groundwater Well SHL Data: TWDB-2022
2.) TWDB Groundwater Well SHL Data: TWDB-2022
3.) Brackish Groundwater Well SHL Data: TWDB-2022
* Note: All coordinates shown are in NAD83 (DD). *

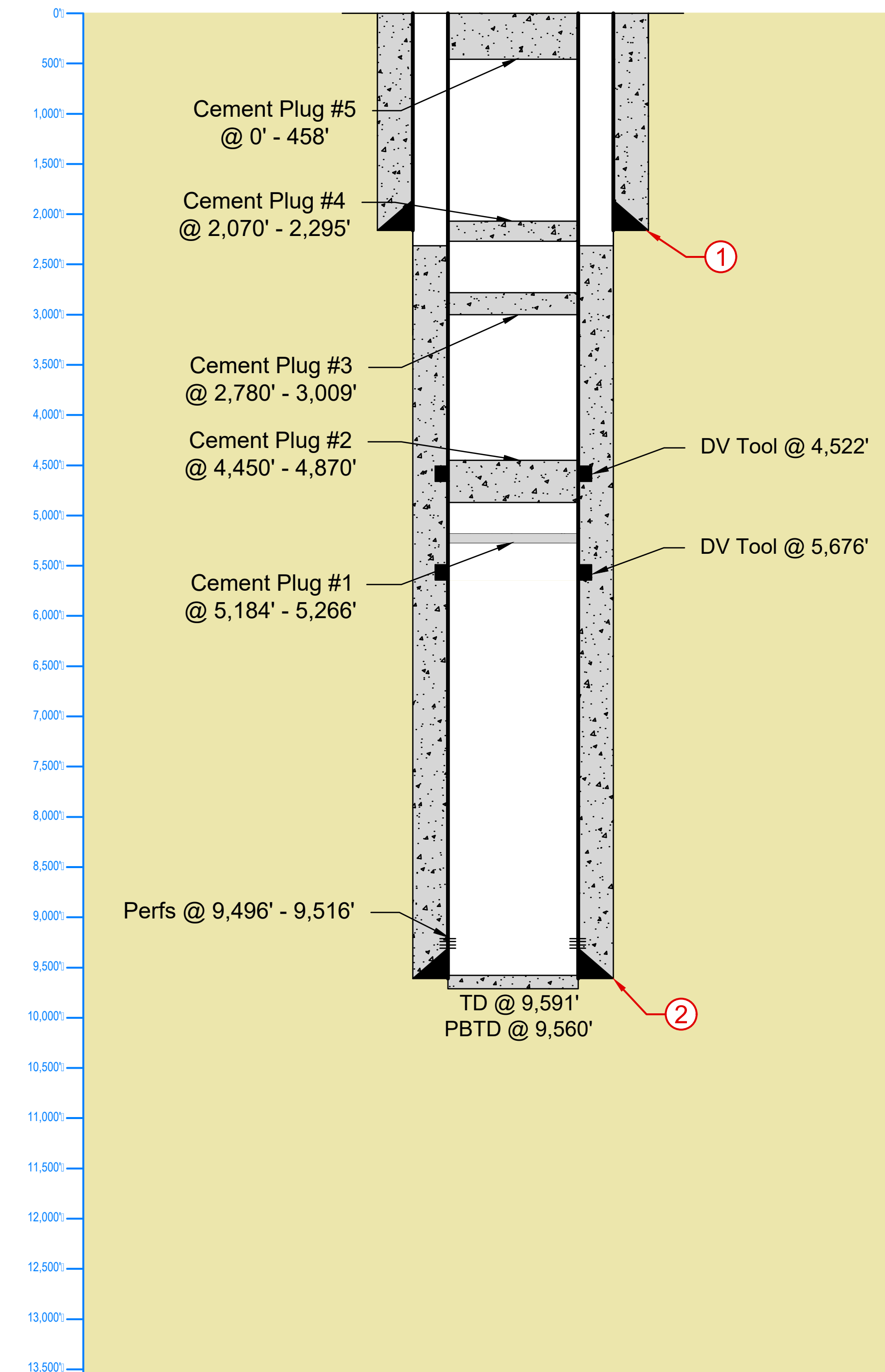




Casing Information

Label	1	2
Type	Surface	Production
OD	8-5/8"	4-1/2"
Depth Set	2,134'	9,601'

LONQUIST & CO. LLC PETROLEUM ENGINEERS · ENERGY ADVISORS AUSTIN · HOUSTON · CALGARY · WICHITA DENVER · COLLEGE STATION · BATON ROUGE · EDMONTON	Exxon Corp.	E. Randall No. 32	
	Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Texas License F-9147	**Location:** Section 833, Block D	**Spud Date:** 05/10/1965	**Survey:** John H. Gipson
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**API No:** 42-501-10079	**Field:** Wasson (Wichita Albany)	**RRC Lease Number:** 18231
	RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
	Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
		Notes:	



Casing Information

Label	1	3
Type	Surface	Production
OD	9-5/8"	5-1/2"
Weight	36 lb/ft	UNK
Depth Set	2,162'	9,569'
Hole Size	12-1/4"	7-7/8"
TOC	Surface	2,350'
Volume	880 sks	5,450 sks

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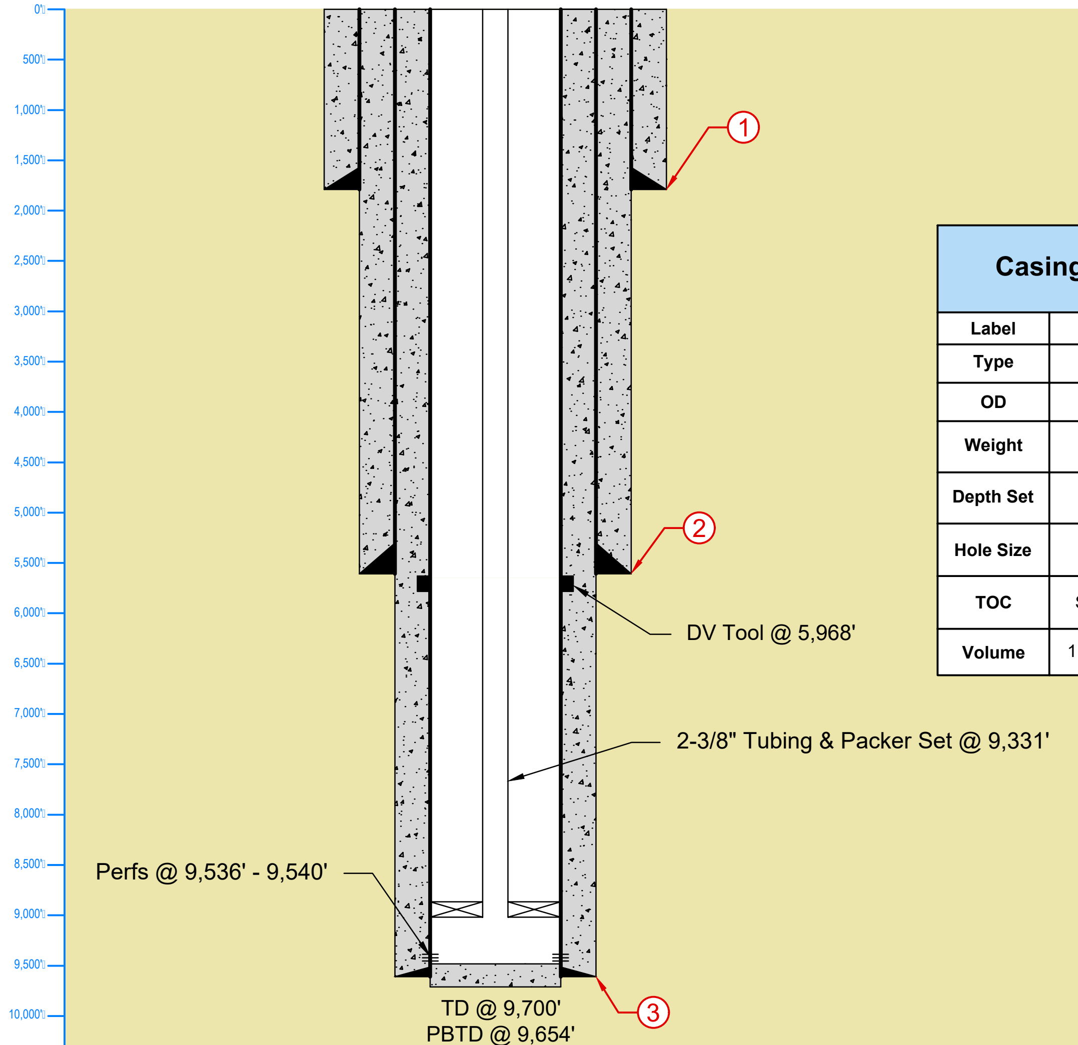
XTO Energy Inc.

E. Randall No. 40

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 12/04/1992	**Survey:** John H. Gipson
API No: 42-501-337932	**Field:** Wasson (Wichita Albany)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54 lb/ft	36 lb/ft 40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,129'	5,606'	9,699'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	Surface
Volume	1,790 sks	2,910 sks	1,590 sks

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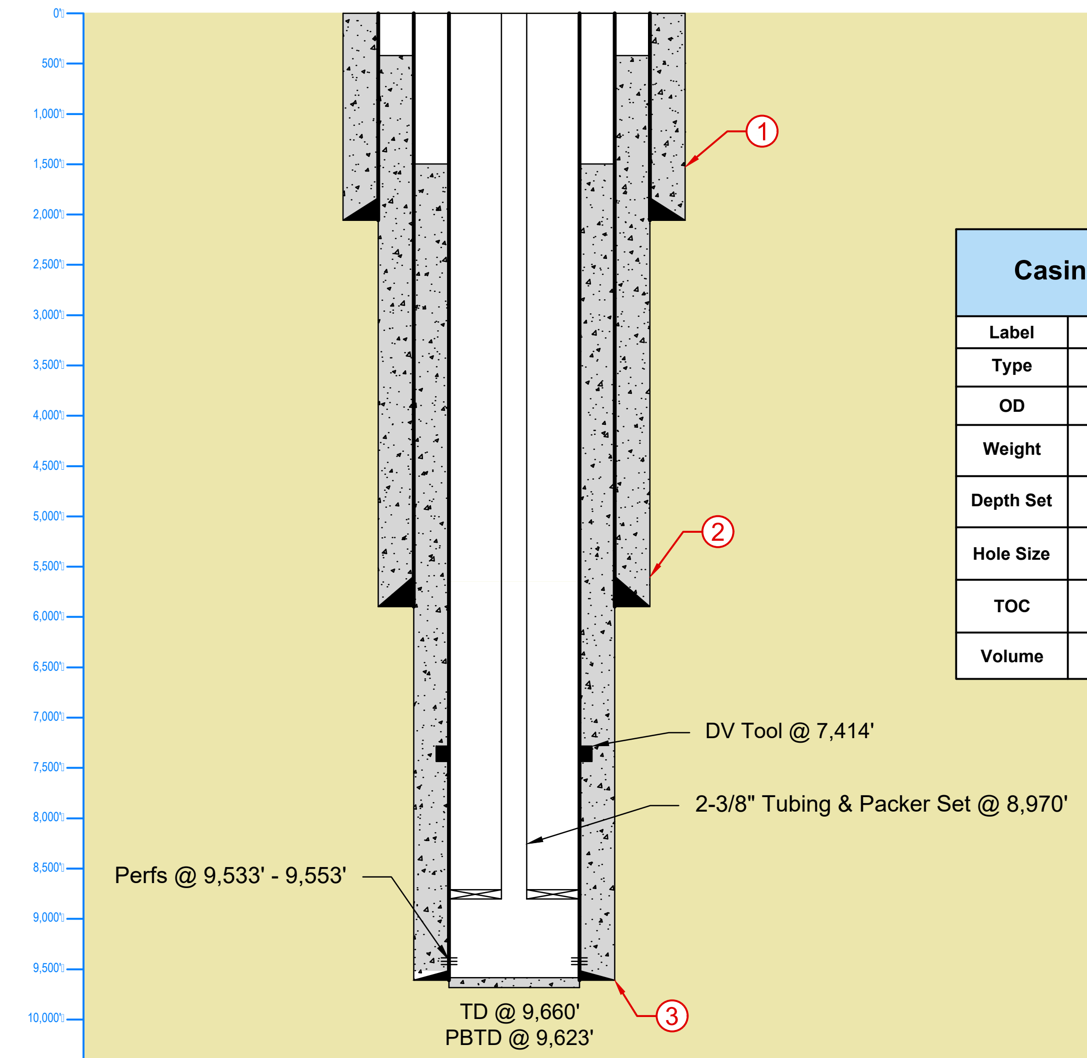
Exxon Corp.	E. Randall No. 41L	
Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 832, Block D	**Spud Date:** 02/05/1994	**Survey:** John H. Gipson
API No: 42-501-33885	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,167'	5,830'	9,658'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	440'	1,800'
Volume	1,530 sks	3,500 sks	1,050 sks

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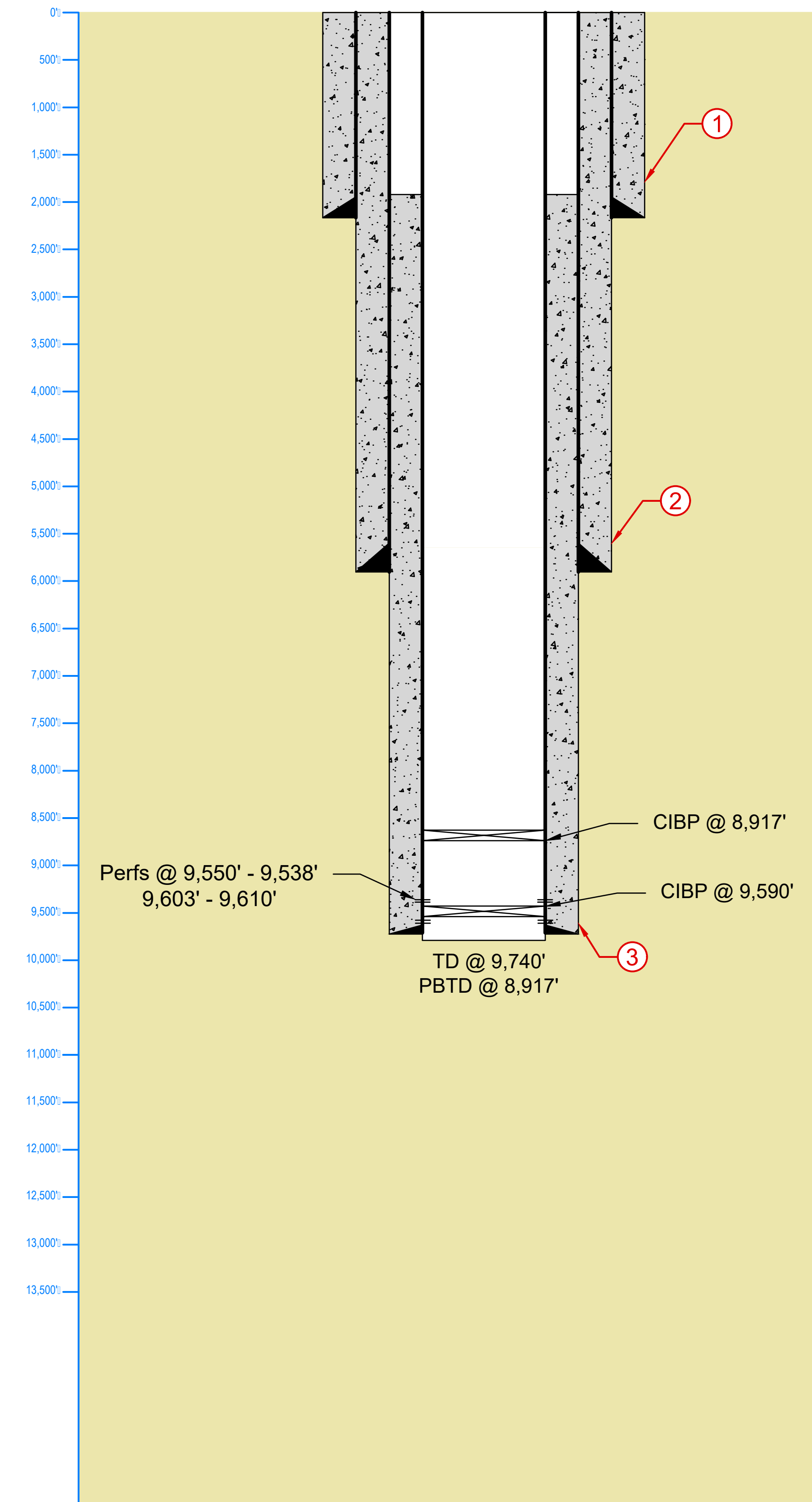
Exxon Corp.	E. Randall No. 42L	
Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 07/01/1995	**Survey:** John H. Gipson
API No: 42-501-34023	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,166'	5,902'	9,735'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	2,000'
Volume	1,530 sks	3,505 sks	967 sks

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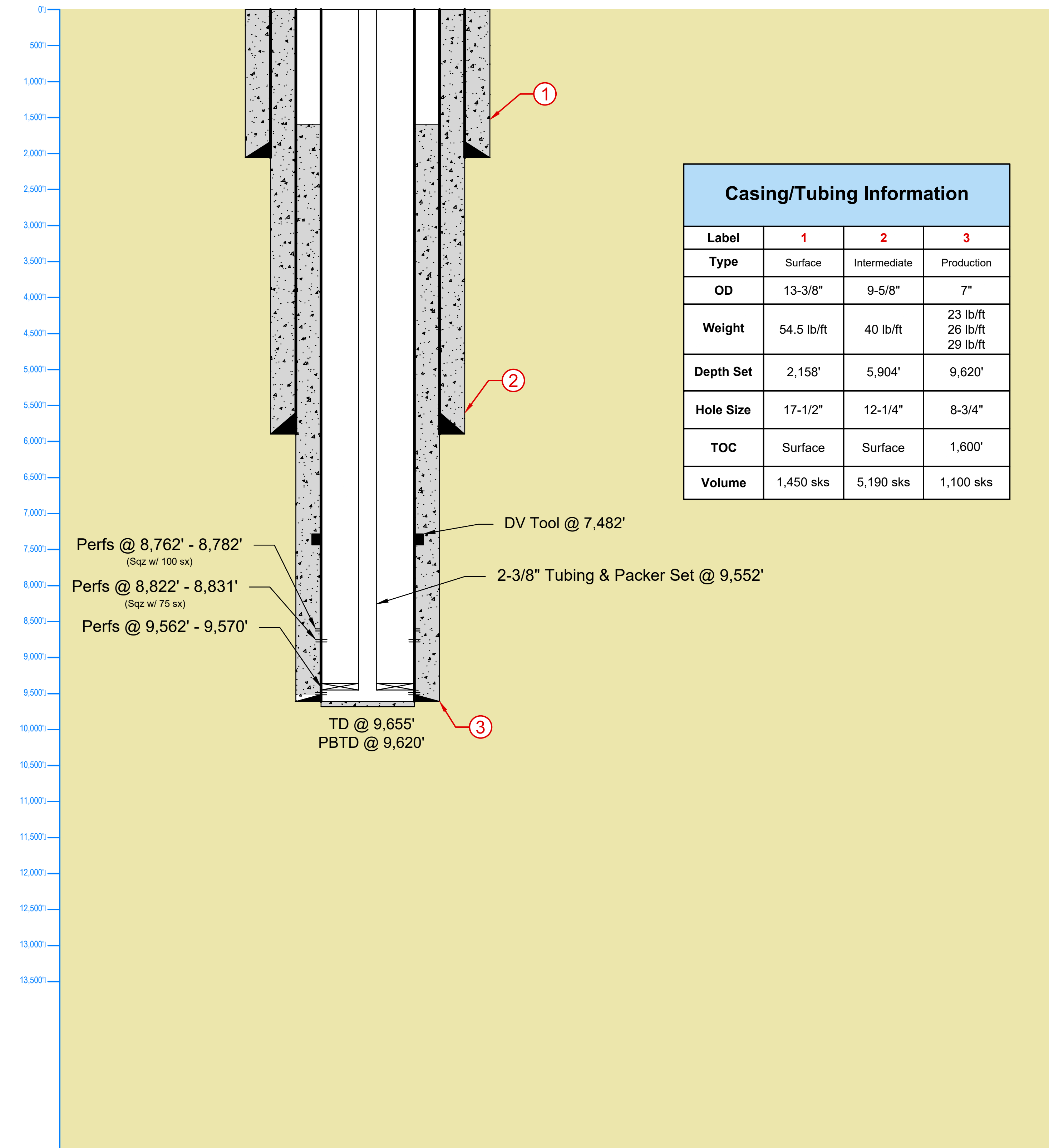
Exxon Corp.

E. Randall No. 43L

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 832, Block D	**Spud Date:** 04/08/1995	**Survey:** John H. Gipson
API No: 42-501-34016	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP

Notes:



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft 29 lb/ft
Depth Set	2,158'	5,904'	9,620'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	1,600'
Volume	1,450 sks	5,190 sks	1,100 sks

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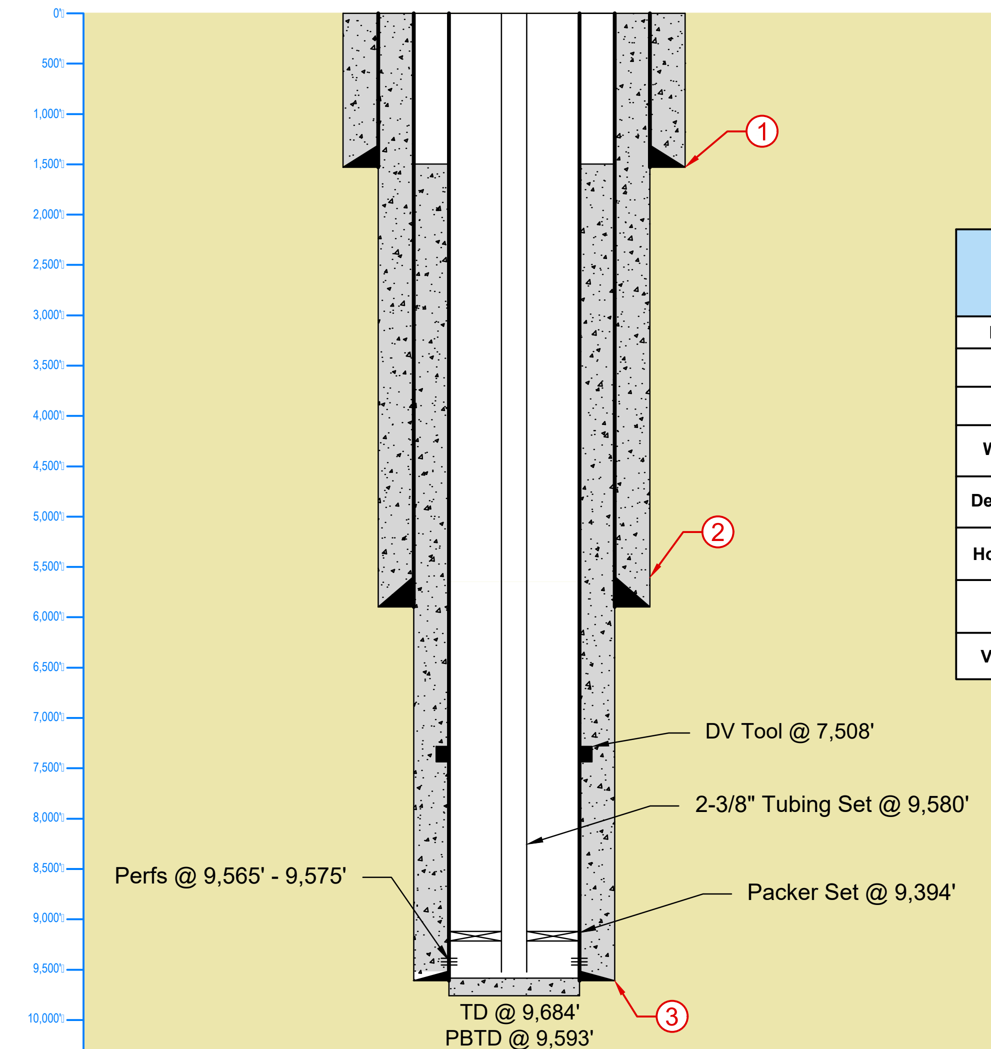
Exxon Corp.

E. Randall No. 44

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 08/09/1995	**Survey:** John H. Gipson
API No: 42-501-34024	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,175'	5,898'	9,615'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	1,500'
Volume	1,530 sks	3,525 sks	1,170 sks

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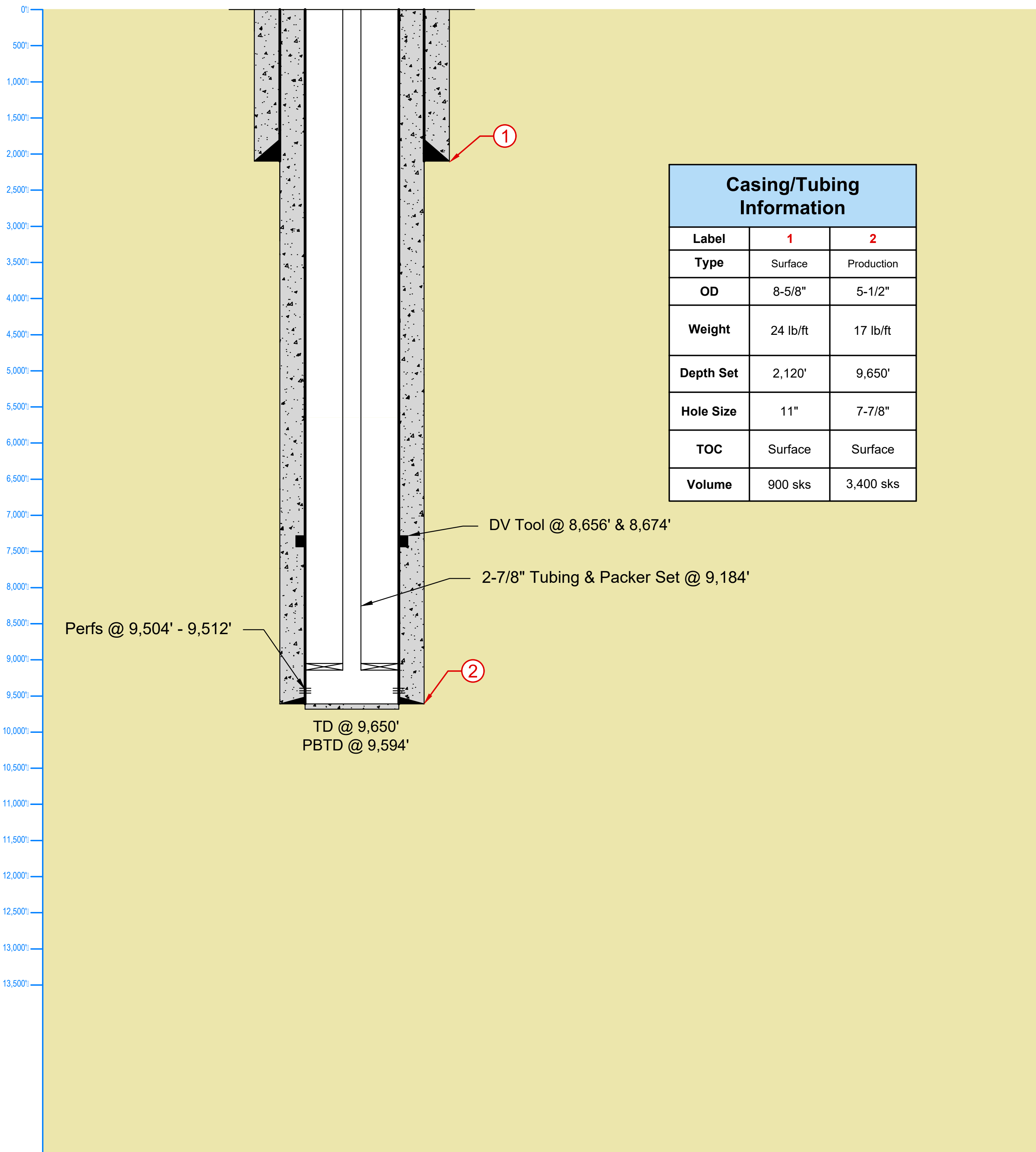
Exxon Corp.

E. Randall No. 45L

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 02/05/1994	**Survey:** John H. Gipson
API No: 42-501-34017	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2
Type	Surface	Production
OD	8-5/8"	5-1/2"
Weight	24 lb/ft	17 lb/ft
Depth Set	2,120'	9,650'
Hole Size	11"	7-7/8"
TOC	Surface	Surface
Volume	900 sks	3,400 sks

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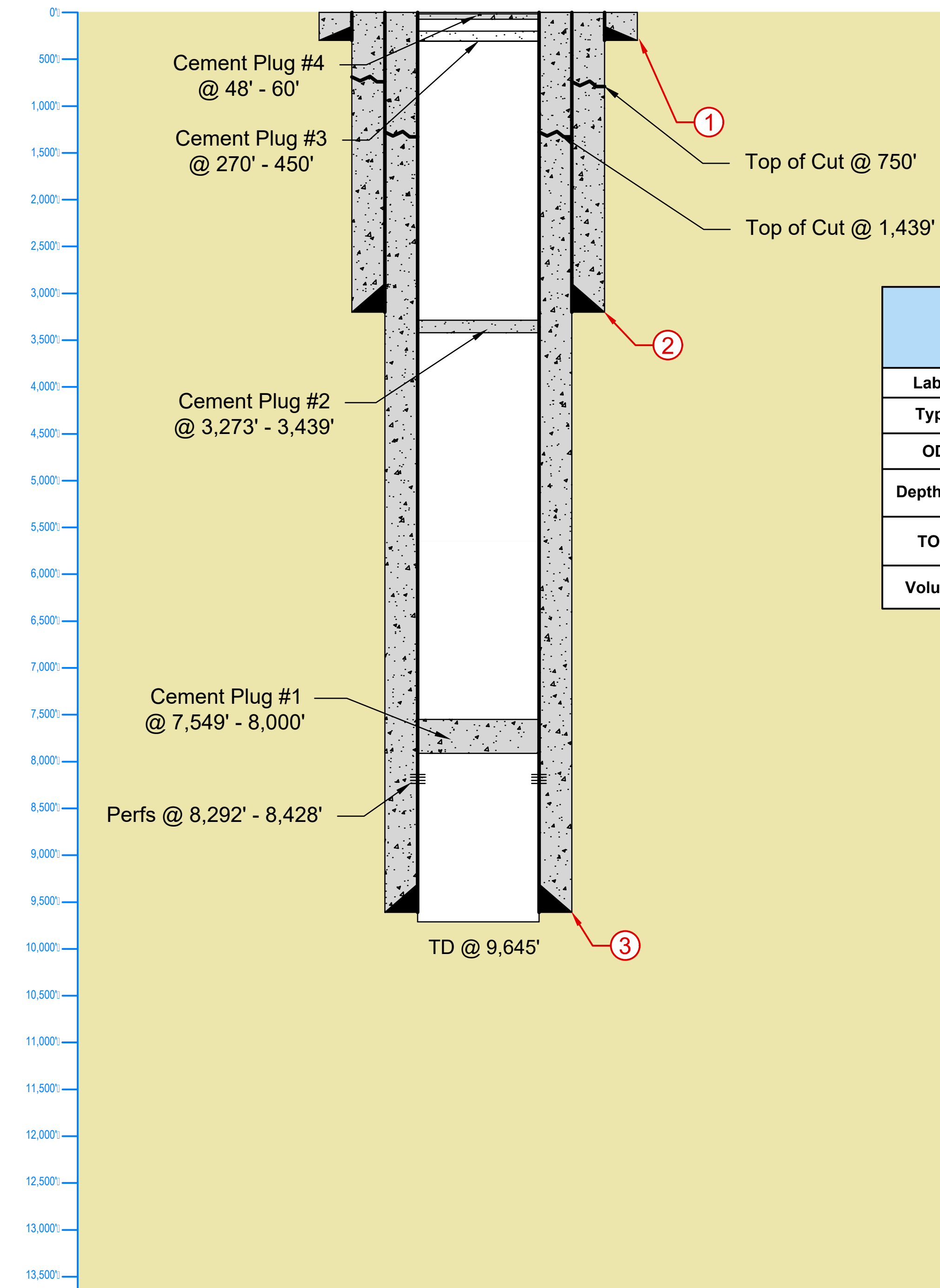
XTO Energy, Inc.	E. Randall No. 46	
Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 05/23/2007	**Survey:** John H. Gipson
API No: 42-501-35418	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	5-1/2"
Depth Set	300'	3,200'	9,610'
TOC	Surface	Surface	Surface
Volume	400 sks	300 sks	425 sks

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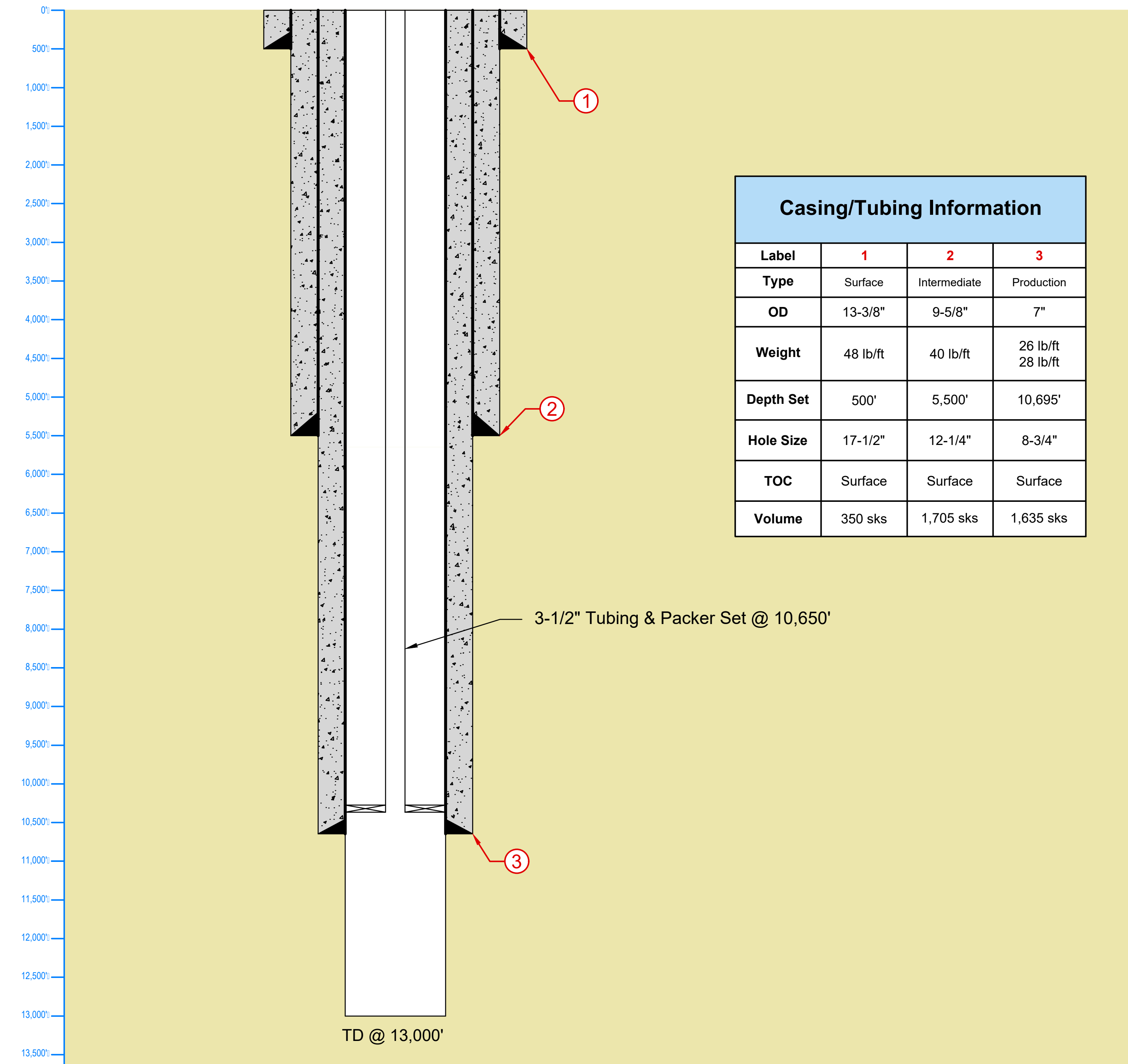
Bonanza Oil Corp.	C.A. Elliott No. 2	
Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 832, Block D	**Spud Date:** 05/10/1965	**Survey:** John H. Gipson
API No: 42-501-10046	**Field:** Wasson (Wichita Albany)	**RRC Lease Number:** 18875
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	48 lb/ft	40 lb/ft	26 lb/ft 28 lb/ft
Depth Set	500'	5,500'	10,695'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	Surface
Volume	350 sks	1,705 sks	1,635 sks

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Amtex Energy, Inc.

Miller SWD No. 7 (Permitted)

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 732, Block D	**Spud Date:** 08/09/1995	**Survey:** John H. Gipson
API No: 42-501-37252	**Field:** Wasson	**Permit Number:** 16637
RRC District No: 7-C	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP

Notes:

Request for Additional Information: 30-30 Gas Plant
July 25, 2022

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	NA	NA	Several map figures in the MRV plan have difficult to read text within the map legends. We recommend increasing the font size where needed. For example, Figures 11, 26, 27, etc.	Larger scale versions of all maps have been included in the Appendices and references to the maps added
2.	INTRO	1	"This AGI well is associated with Stakeholder's 30-30 gas treating and processing plant ("30-30") located in a rural, sparsely populated area of Yoakum County, Texas, approximately seven miles northwest of the town of Plains." Please add a reference for Figure 1.	"as shown in Figure 1." Added to the last sentence in paragraph 1 (pg 1)
3.	INTRO	2	Please define MMSCF/d and other acronyms upon first use.	Added: "16 million standard cubic feet per day ("MMSCF/d")." (pg 2)
4.	2	9	"The Rattlesnake AGI #1 well is located and designed to protect against migration of CO_2 into productive oil and gas formations and freshwater aquifers and to prevent surface releases." This sentence is awkwardly worded. We recommend adjusting to improve clarity.	Sentence modified to "The Rattlesnake AGI #1 well is located and designed to protect against migration of CO2 out of the injection interval and to prevent surface releases."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	2	9	"in the area and 8,593' below the base of the lowest useable quality water table, as **Shown** in Figure 2." Please fix capitalization.	Capitalization fixed (pg 9)
6.	2	13	"The Wristen Group is composed of three formations; Fasken, Frame, and Wink formations." Please consider changing the semicolon to a colon in the above sentence.	Semicolon changed to colon (pg 13)
7.	2	16	"The Woodford is a late Devonian-aged…" Consider changing "aged" to "age"	Changed "aged" to "age" (pg 16)
8.	2	19	Please clarify why the Rattlesnake AGI #1 (42-501-36998) well log is used in Figure 10, but an offset well (45-501-10238) is used in Figure 7.	Added "An offset well log was used to depict the upper confining intervals as electric logs were only run in the Rattlesnake AGI #1 well across the injection zone." to the paragraph discussing Figure 7 (pg 15)
9.	2	20	The pH values in Table 1 are the same as the values used in the Campo Viejo Gas Processing Plant MRV plan. Please confirm whether these values are accurate for the 30-30 Plant.	The pH values are correct for the Rattlesnake area
10.	2	30	"Figure 19 shows the subsurface and outcrop extent of the Ogallala Aquifer." We believe the reference here is to Figure 20. Please address.	Corrected to "Figure 20" (pg 30)

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
11.	2	30	"… by approximately 9,500' of rock…" Section 2 of the MRV plan gives the figure of 8,593 feet. Please clarify.	Corrected to "approximately 8,600' of rock" (pg 30). Also corrected "650' of Salado salt" to "576' of Salado salt"
12.	2	32	Figure 21 is the exact same as the figure used in the Campo Viejo Gas Processing Plant MRV plan. Please clarify whether this figure and values are applicable to the 30-30 Gas Plant.	The ranges provided for H2S/CO2 compositions is applicable, as confirmed in Table 5 – Modeled Initial Gas Composition. However, the high pressure for the injection pumps has been updated to reflect the expected permitted MASIP
13.	2	33	"The grid contains 141 blocks in the x-direction (E-W) and 201 blocks in the y-direction (N-S), totaling 28,341 grid blocks per layer. This results in the grid being 21,150' by 30,150' totaling just over a 23-square mile area (14,640 acres)." The MRV plan does not provide the dimensions of the individual blocks themselves. Please add for clarity.	"The grid blocks are each 150' by 150' by layer thickness as specified in Table 6." added to provide dimensions (pg 33)
14.	3	40	"In this case, the plume boundary in 2041 is within the plume at 2036 plus a half-mile buffer. By 2036 at the latest, a revised MRV will be submitted to define a new AMA. Figure 27 shows the area covered by the AMA." Please add "plan" after "MRV".	"plan" added after MRV (pg 40)
15.	4	44	"A larger scale version of **Figure 27** is provided in Appendix D." Is this supposed to be Figure 28? Please address.	Figure 27 changed to Figure 28 (pg 44)

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
16.	4	44	"… a few wells have produced from the **Wolfcamp The** Wolfcamp is separated from the…" It appears that a punctuation mark is missing. Please address.	Period added after sentence (pg 44)
17.	4	44	"All of the wells which penetrate the injection interval within the MMA were properly cased and cemented to prevent annular leakage of CO_2 to the surface." Please clarify whether this is a determination made by the 30-30 Gas Plant operators or if this is according to TRRC records.	Sentence changed to "A review of the TRRC records for all of the wells which penetrate the injection interval within the MMA, shows the wells were properly cased and cemented to prevent annular leakage of CO2 to the surface." to clarify that the TRRC records show that the wells are properly constructed. (pg 44)
18.	4	48	"In this instance, any new well permitted and drilled to the Rattlesnake AGI #1 well's injection zone located within a one-quarter mile radius of the Rattlesnake AGI #1 well will be required under TRRC Rule 13 to set steel casing and cement above the Rattlesnake AGI #1 well injection zone." This sentence is confusing to read. We recommend adjusting with punctuation or rewording.	Sentence clarified "In this instance, any new well permitted and drilled to the Rattlesnake AGI #1 well's injection zone, and located within a one-quarter mile radius of the Rattlesnake AGI #1 well, will be required under TRRC Rule 13 to set steel casing and cement above the Rattlesnake AGI #1 well injection zone." (pg 48)
19.	4	48	"See GAU letter attached included within Appendix B" Should this read, "See GAU letter attached in Appendix B"?	"Attached" removed from sentence (pg 48)
20.	4	50	In Table 9, owners are referred to both as FRANCIS BARBINI and FRANCIS BARBIDI. Are these two different owners, or is one a misspelling?	Likely "Barbidi" is a misspelling, but listed as per TWDB records

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
21.	4	51	"Leakage from Natural or Induced Seismicity" is discussed primarily from the perspective historical seismicity in the area. Will there be any operational practices implemented to ensure that the risk of induced seismicity is mitigated?	The following: "Pressures will be kept significantly below the fracture gradient of the injection and confining intervals. Additionally, continuous well monitoring combined with seismic monitoring will identify any operational anomalies associated with a seismicity event." was added to this section (pg 51)
22.	5	54	"Table 8 summarizes the monitoring of potential leakage pathways to the surface." Should this refer to Table 10?	Table 8 corrected to Table 10 (pg 54)
23.	5	54	"Monitoring will occur during the planned 25-year injection period, or cessation of injection operations, plus a proposed 5-year post-injection period." Other parts of the MRV plan reference an injection period of 17 years. Please clarify and update the MRV plan as necessary	"25-year" corrected to "17-year" (pg 54)
24.	5	55	"…which are shown in Figure **28above**" It appears there is a space missing. Please address.	Space added (pg 55)
25.	5	55	"The scope of work will include H_2S and CO_2 monitoring at the AGI well site as well as minimum, quarterly atmospheric monitoring near identified penetrations within the AMA." Please describe what atmospheric monitoring will be conducted. E.g., what types of parameters will be measured?	"At the well site, H2S and CO2 concentrations will be monitored continuously with fixed monitors that detect atmospheric concentrations of H2S and CO2. At penetrating well sites, Stakeholder will similarly measure atmospheric concentrations of CO2 and H2S using mobile gas monitors. This data will be recorded at least quarterly." was added to clarify the parameters to be measured (pg 55)

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
26.	5	55	"Stakeholder will monitor the groundwater quality in fluids above the confining interval by sampling the well on the facility property and analyzing the sample with a third-party laboratory on an annual basis." What types of parameters will be measured in the groundwater samples?	"The parameters to be measured will include pH, total dissolved solids, total inorganic and organic carbons, density, temperature and other standard laboratory measurements. Any significant differences in these parameters from the baseline sample will be evaluated to determine if leakage of CO2 to the USDW may have occurred." was added to clarify the parameters to be measured (pg 56)
27.	5	56	"Stakeholder plans to install a seismic monitoring station in the general area of the Rattlesnake AGI #1 well." When is the seismic monitoring station planned to be installed?	"The installation of this station would start upon approval of the MRV plan, with an expected in-service data within six months after the commencement of the installation project." added to this paragraph (pg 56)
28.	7	59	Mass of CO_2 Injected "Per 40 CFR §98.444(b), since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the mass flow by the CO_2 concentration in the flow according to Equation RR-4:" When using a volumetric flow meter, you must use Equation RR-5. Equation RR-4 is used when a mass flow meter is used to measure the injection quantity. Please clarify what type of flow meter will be used and which equation will be used to calculate mass of CO_2 injected.	Corrected to Equation RR-5 (pg 59)
29.	2	31		Corrected depths and thickness to those provided by GAU letter (pg 30)
30.				

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Rattlesnake AGI #1

Yoakum County, Texas

Prepared for *Stakeholder Gas Services, LLC*
San Antonio, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 1
June 2022

INTRODUCTION

Stakeholder Gas Services, LLC ("Stakeholder") currently has a Class II acid gas injection ("AGI") permit, issued by the Texas Railroad Commission ("TRRC") in November 2018, for the Rattlesnake AGI #1 well, API No. 42-501-36998. This permit was originally issued to Santa Fe Midstream Permian, LLC, in 2018 and the asset was subsequently acquired by Stakeholder in December of 2020. This permit currently authorizes Stakeholder to inject up to 4,500 barrels per day ("bbls/d") of treated acid gas ("TAG") into the Devonian formation at a depth of 11,000' to 12,000' with a maximum allowable surface pressure of 2,200 psi. Since being permitted, injection has proceeded without incident. This AGI well is associated with Stakeholder's 30-30 gas treating and processing plant ("30-30") located in a rural, sparsely populated area of Yoakum County, Texas, approximately seven miles northwest of the town of Plains.

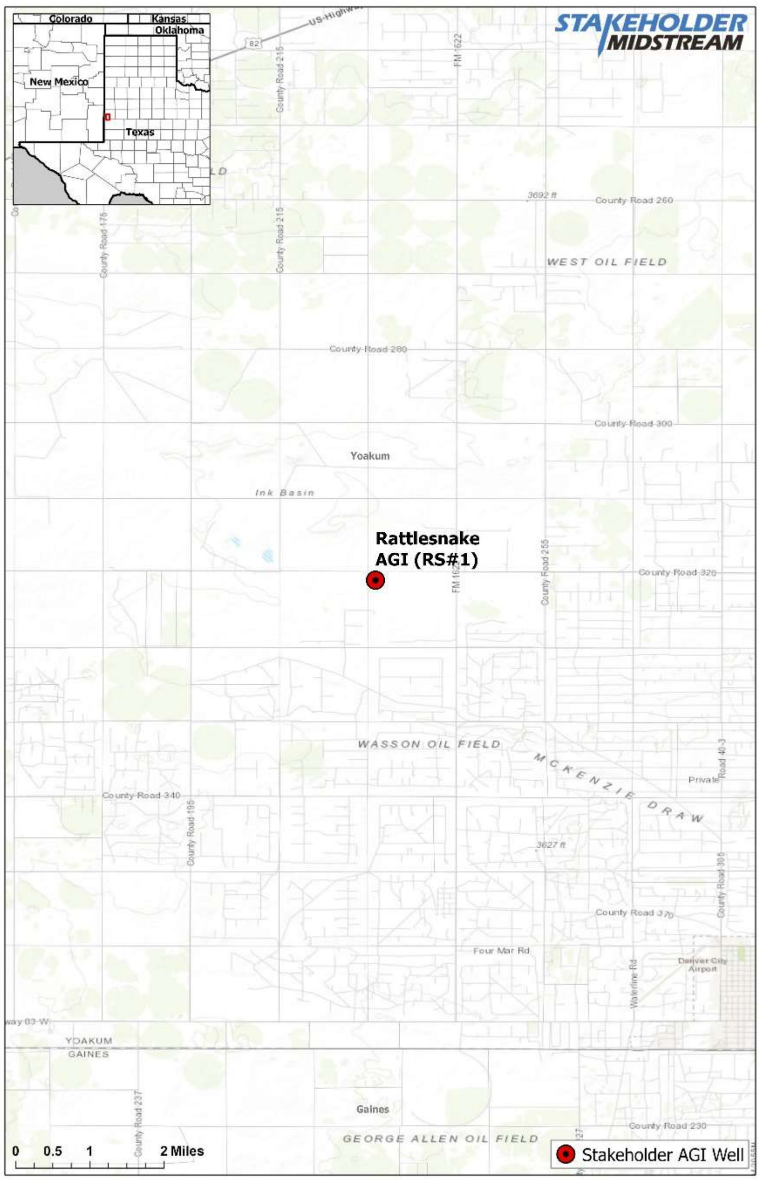

Figure 1 – Location of Rattlesnake AGI #1 Well

Stakeholder is submitting this Monitoring, Reporting, and Verification ("MRV") plan to the EPA for approval under 40 CFR §98.440(a), Subpart RR, of the Greenhouse Gas Reporting Program ("GHGRP"). In addition to submitting this MRV plan to the EPA, Stakeholder is also applying to the TRRC for an amendment to the Rattlesnake AGI #1 well's Class II permit to increase its authorized injection volume and maximum allowable surface injection pressure ("MASIP"). Approval of the permit amendment will allow Stakeholder to increase the capacity of its existing 30-30 Facility, which removes H_2S and CO_2 from natural gas production using amine treating, as well as increase the injection well capacity for a future gas processing facility which is currently under development by Stakeholder. Additionally, expanded capacity allows Stakeholder to potentially provide future disposal in its AGI well for oil and gas waste derived TAG from similar third-party gas processing facilities. Increased disposal capacity will allow for greater gas processing capacity in the region, ultimately helping to reduce flaring and its associated emissions. Throughout this document, both in written reference and in modeling inputs, Stakeholder has used the applied-for expanded permit capacity of 16 MMSCF/d. Stakeholder plans to inject CO_2 for approximately 14 more years.

ACRONYMS AND ABBREVIATIONS

‘	Feet
%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group’s GEM 2020.11
GHGs	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program
H_2S	Hydrogen Sulfide
md	Millidarcy(ies)
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMCF	Million Cubic Feet
MMSCF	Million Standard Cubic Feet

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

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LIST OF FIGURES

LIST OF TABLES

SECTION 1 – FACILITY INFORMATION

This section contains key information regarding the Acid Gas and CO_2 injection facility.

Reporter number:

- Gas Plant Facility Name: 30-30 Gas Plant
- Greenhouse Gas Reporting Program ID: 574501
    - Currently reporting under Subpart UU
- Operator: Stakeholder Gas Services, LLC

Underground Injection Control (UIC) Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control ("UIC") Class II program. TRRC classifies the Rattlesnake AGI #1 well as a UIC Class II well. A Class II permit was issued to Stakeholder under TRRC Rule 9 (entitled "Disposal into Non-Productive Formations") and Rule 36 (entitled "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas").

UIC Well Identification Number:

Rattlesnake AGI #1, API No. 42-501-36998, UIC #000117143.

SECTION 2 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection volumes and process, and the reservoir modeling performed for the Rattlesnake AGI #1 well. The Class II UIC permit was initially applied for and received by Santa Fe Midstream Permian, LLC. The asset was acquired in 2020 by Stakeholder and has been in operation since that time. Since the original application, Lonquist has revised and updated the geology and the plume modeling within the reservoir in preparing this MRV Plan.

The Rattlesnake AGI #1 well is located and designed to protect against migration of CO_2 into productive oil and gas formations and freshwater aquifers and to prevent surface releases. The injection interval for Rattlesnake AGI #1 is located over 4,720' below the primary producing formation, the San Andres, in the area and 8,593' below the base of the lowest useable quality water table, as Shown in Figure 2. This well injects both H_2S and CO_2, therefore the well and the facility are designed to minimize any leakage to the surface.

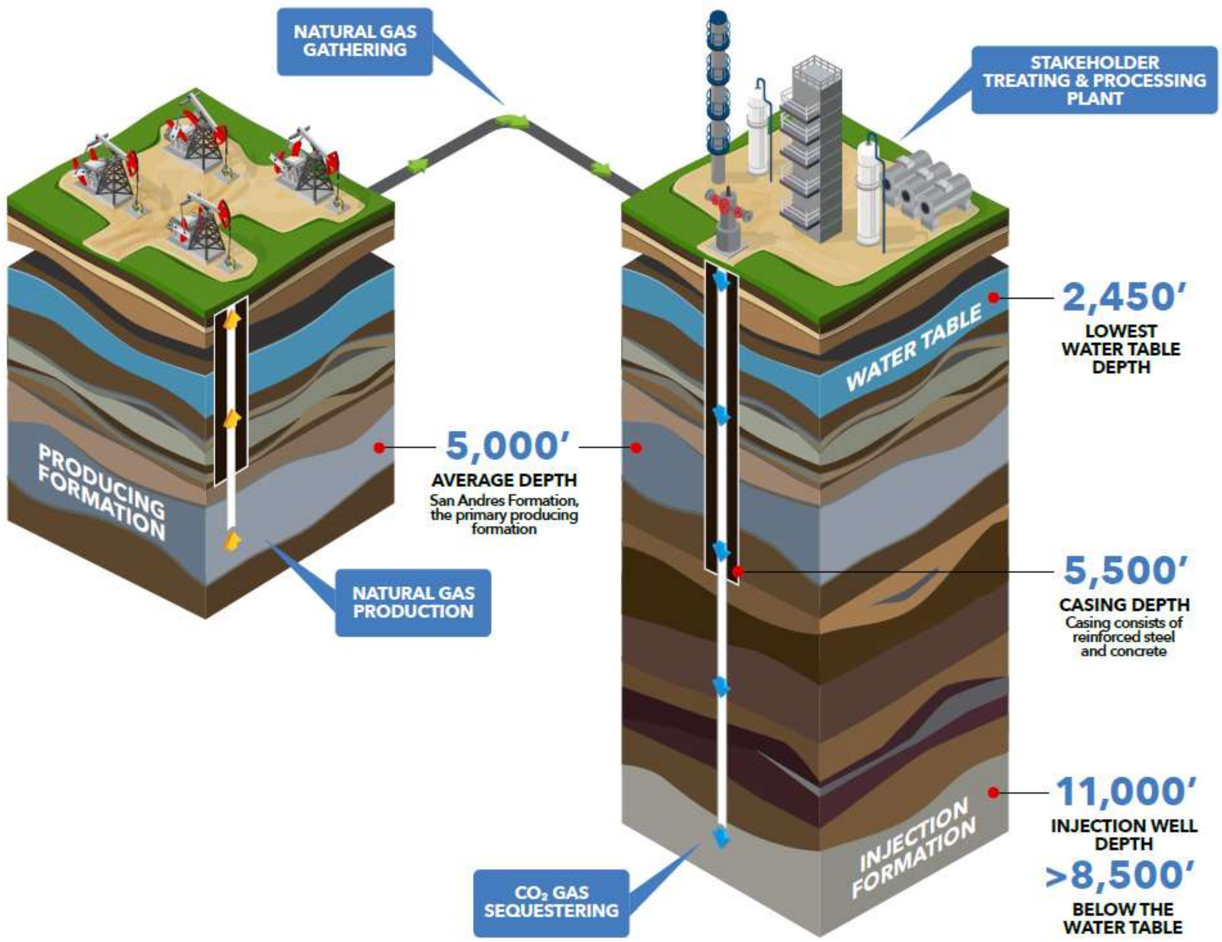


Figure 2 – Illustrative overview of Rattlesnake AGI #1 and 30-30 Facility

Regional Geology

The Rattlesnake AGI #1 well is located on the southern portion of the Northwestern Shelf within the larger Permian Basin as seen in Figure 3. The Northwestern Shelf is a broad marine shelf located in the northern portion of the Permian Basin.

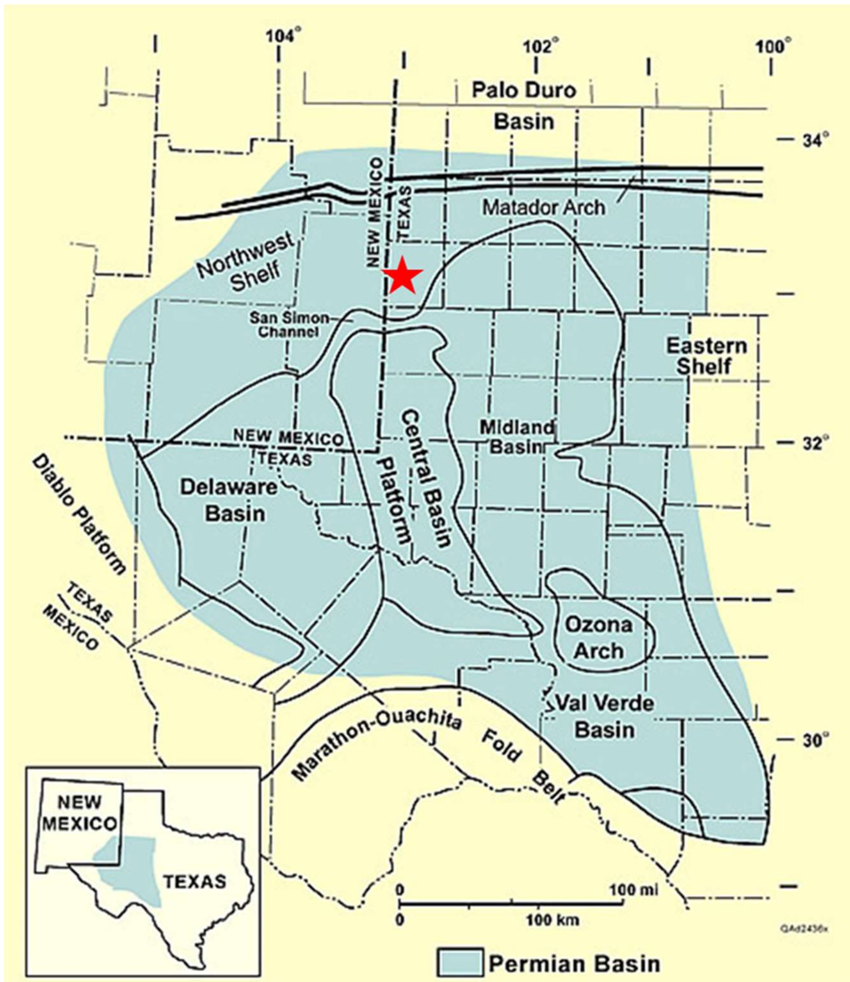


Figure 3 – Regional Map of the Permian Basin. Red Star is approximate location of Rattlesnake AGI #1 well

Figure 4 depicts the stratigraphic column found at the Rattlesnake AGI #1 well location with red stars referencing the injection formation and green stars indicating the productive intervals in the area. The primary injection interval is found within the Wristen group, of Silurian-age, as seen in Figure 5. The TRRC refers to this sequence under the general terms "Devonian", "Silurian-Devonian" or "Siluro-Devonian".

<table>
<tr><th>Period</th><th>Epoch</th><th colspan="2">Formation</th><th>General Lithology</th></tr>
<tr><td rowspan="16">Permian</td><td rowspan="3">Ochoan</td><td colspan="2">Dewey Lake</td><td>Redbeds/Anhydrite</td></tr>
<tr><td colspan="2">Rustler</td><td>Halite</td></tr>
<tr><td colspan="2">Salado</td><td>Halite/Anhydrite</td></tr>
<tr><td rowspan="5">Guadalupian</td><td colspan="2">Tansil</td><td>Anhydrite/Dolomite</td></tr>
<tr><td colspan="2">Yates</td><td>Anhydrite/Dolomite</td></tr>
<tr><td colspan="2">Seven Rivers</td><td>Dolomite/Anhydrite</td></tr>
<tr><td colspan="2">Queen</td><td>Sandy Dolomite/Anhydrite/Sandstone</td></tr>
<tr><td colspan="2">Grayburg</td><td>Dolomite/Anhydrite/Shale/Sandstone</td></tr>
<tr><td rowspan="7">Leonardian</td><td colspan="2">★ San Andres</td><td>Dolomite/Anhydrite</td></tr>
<tr><td colspan="2">Glorieta</td><td>Sandy Dolomite</td></tr>
<tr><td rowspan="4">Yeso</td><td>Paddock</td><td rowspan="4">Dolomite/Anhydrite/Sandstone</td></tr>
<tr><td>Blinebry</td></tr>
<tr><td>Tubb</td></tr>
<tr><td>Drinkard</td></tr>
<tr><td colspan="2">Abo</td><td>Dolomite/Anhydrite/Shale</td></tr>
<tr><td>Wolfcampian</td><td colspan="2">★ Wolfcamp</td><td>Limestone/Dolomite</td></tr>
<tr><td rowspan="5">Pennsylvanian</td><td>Virgilian</td><td colspan="2">Cisco</td><td>Limestone/Dolomite</td></tr>
<tr><td>Missourian</td><td colspan="2">Canyon</td><td>Limestone/Shale</td></tr>
<tr><td>Des Moinesian</td><td colspan="2">Strawn</td><td>Limestone/Sandstone</td></tr>
<tr><td>Atokan</td><td colspan="2">Bend</td><td rowspan="2">Limestone/Sandstone/Shale</td></tr>
<tr><td>Morrowan</td><td colspan="2">Morrow</td></tr>
<tr><td>Mississippian</td><td></td><td colspan="2">Mississippian Lime</td><td>Limestone</td></tr>
<tr><td>Devonian</td><td></td><td colspan="2">Woodford</td><td>Shale</td></tr>
<tr><td rowspan="2">Silurian</td><td></td><td colspan="2">★Wristen Group</td><td>Dolomite/Limestone</td></tr>
<tr><td></td><td colspan="2" rowspan="2">★ Fusselman</td><td rowspan="2">Dolomite/Chert</td></tr>
<tr><td rowspan="4">Ordovician</td><td rowspan="2">Upper</td></tr>
<tr><td colspan="2">Montoya</td><td>Dolomite/Chert</td></tr>
<tr><td>Middle</td><td colspan="2">Simspson Gp</td><td>Limestone/Sandstone/Shale</td></tr>
<tr><td>Lower</td><td colspan="2">Ellenburger</td><td>Dolomite</td></tr>
</table>

Figure 4 – Stratigraphic column of the Northwest Shelf. Red stars indicate injection interval. Green stars indicate productive intervals.

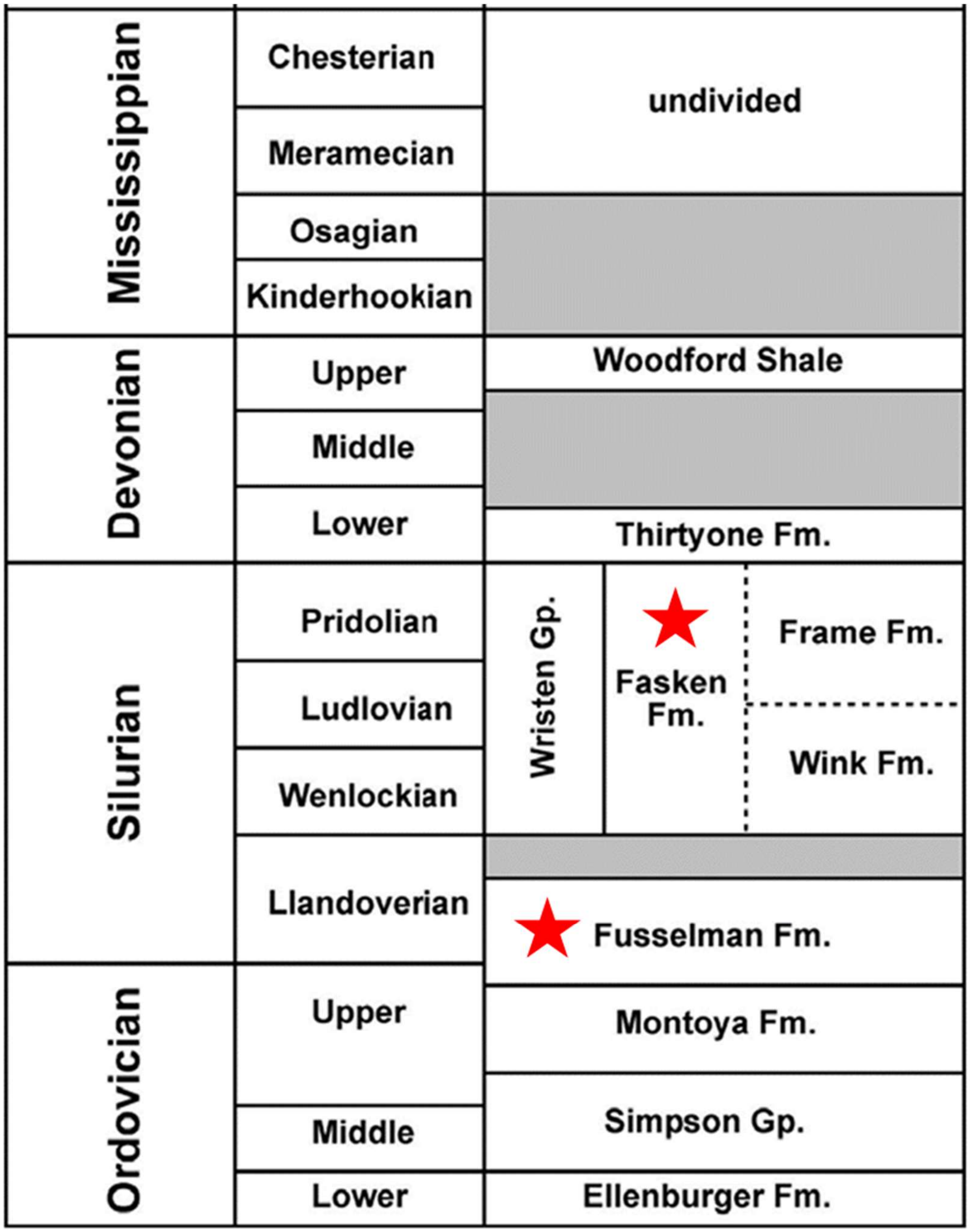


Figure 5 – Stratigraphic column depicting the composition of the Silurian group. Red star indicates injection interval (Broadhead, 2005)

The Wristen group was deposited in a basin platform setting across the northern half of the Permian Basin. The depositional environment over Yoakum County during the Silurian period was a shallow inner platform, the margin of which exists to the south, in southern Andrews County, Texas. The Silurian-age lithology on the inner platform is dominated by grain-rich skeletal carbonates. Carbonate buildups are common within the shallow inner platform, mainly skeletal wackestone, indicating a lower-energy deposition on the inner platform. The carbonate shelf margin to the south acted as a barrier from basin-ward wave energy (Ruppel and Holtz, 1994).

Depositional cycles within the inner platform indicate it was controlled by episodic sea level rise and fall, resulting in sub-areal exposure and diagenesis. The diagenesis of the Silurian-age carbonate rocks initiated

secondary porosity development and increased permeability. Dolomite and solution-related features are the most prominent diagenetic characteristics found within the Silurian. The Wristen Group is composed of three formations; Fasken, Frame, and Wink formations. The Frame and Wink formations are found near the ramp boundary to the south, while the Fasken formation is found predominantly in the inner platform, where the Rattlesnake AGI #1 well is located. The Fasken formation is predominately dolomite grading to limestone, occurring as cycles, down section. This dolomitization is due in part to sub-areal exposure, during which karsts and secondary porosity developed. Additional dolomitization was possible during successive sea level fluctuations via movement of magnesium-rich solution through karsts and vugs, which acted as channels for fluid flow (Ruppel and Holtz, 1994).

Figure 6 shows a regional isopach map of the Silurian (combined Fasken and Fusselman formations) with a red star depicting the Rattlesnake AGI #1 well location. Thickness of the Silurian-age rock is approximately 1,000’ at the Rattlesnake AGI #1 well location.

North of Andrews County there is little differentiation between the Fasken and Fusselman formations which are both carbonate deposits with the potential for sub-areal exposure and porosity development. For purposes of this MRV Plan, the combined Fasken and Fusselman formations are defined as the injection interval, and the underlying Montoya formation serves as the lower confining unit.

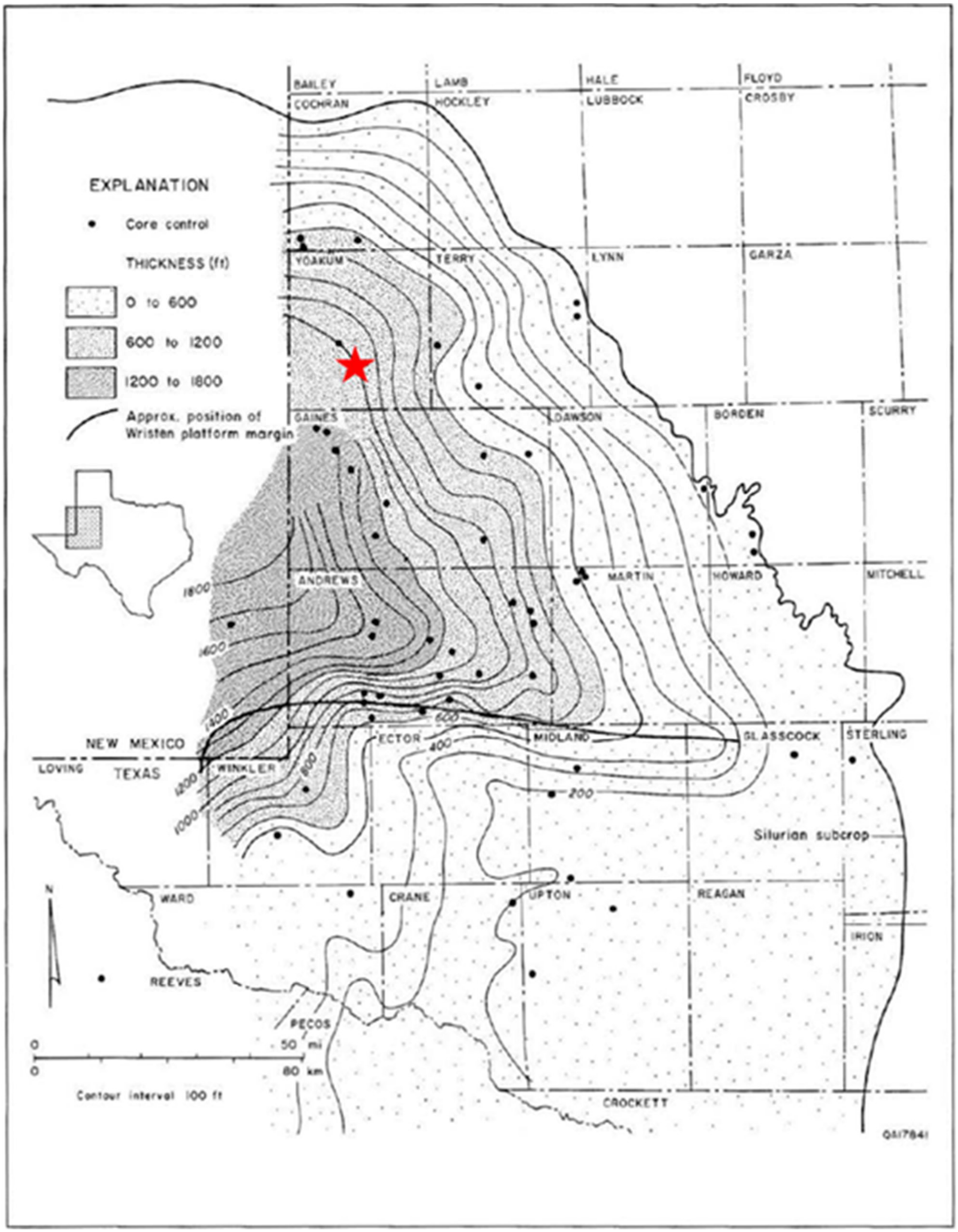


Figure 6 – Thickness map of the Silurian system which composes the Fusselman and Wristen group

Regional Faulting

A major uplift that began during the Pennsylvanian Period to the south, the Central Basin Platform, ceased in the Early Permian (Wolfcampian), which caused a regional unconformity of the underlying formations (Hoak, Sundberg, and Ortoleva). Faulting on the Northwest Shelf can be seen through high angle basement faults that tend to die within the Pennsylvanian strata. These faults predominately represent contractional (thrust) faults that were initiated during the Pennsylvanian as a result of regional tectonics. Hydrocarbon traps within the Wristen group are primarily anticlinal structures dependent upon reservoir development (Broadhead, 2005).

Site Characterization

The Rattlesnake AGI #1 well is located in Section 733, Block D, John H. Gibson Survey, in Yoakum County, Texas. Stakeholder owns the 82.42-acre surface tract where the plant and Rattlesnake AGI #1 well are located. The following discusses the geological character of this site.

Stratigraphy and Lithologic Characteristics

Figure 7 depicts an open hole log from an offset well (API No. 42-501-10238) to the Rattlesnake AGI #1 well indicating the injection and primary upper confining zone. This well is approximately 1.8 miles to the northwest of the Rattlesnake AGI #1 well.

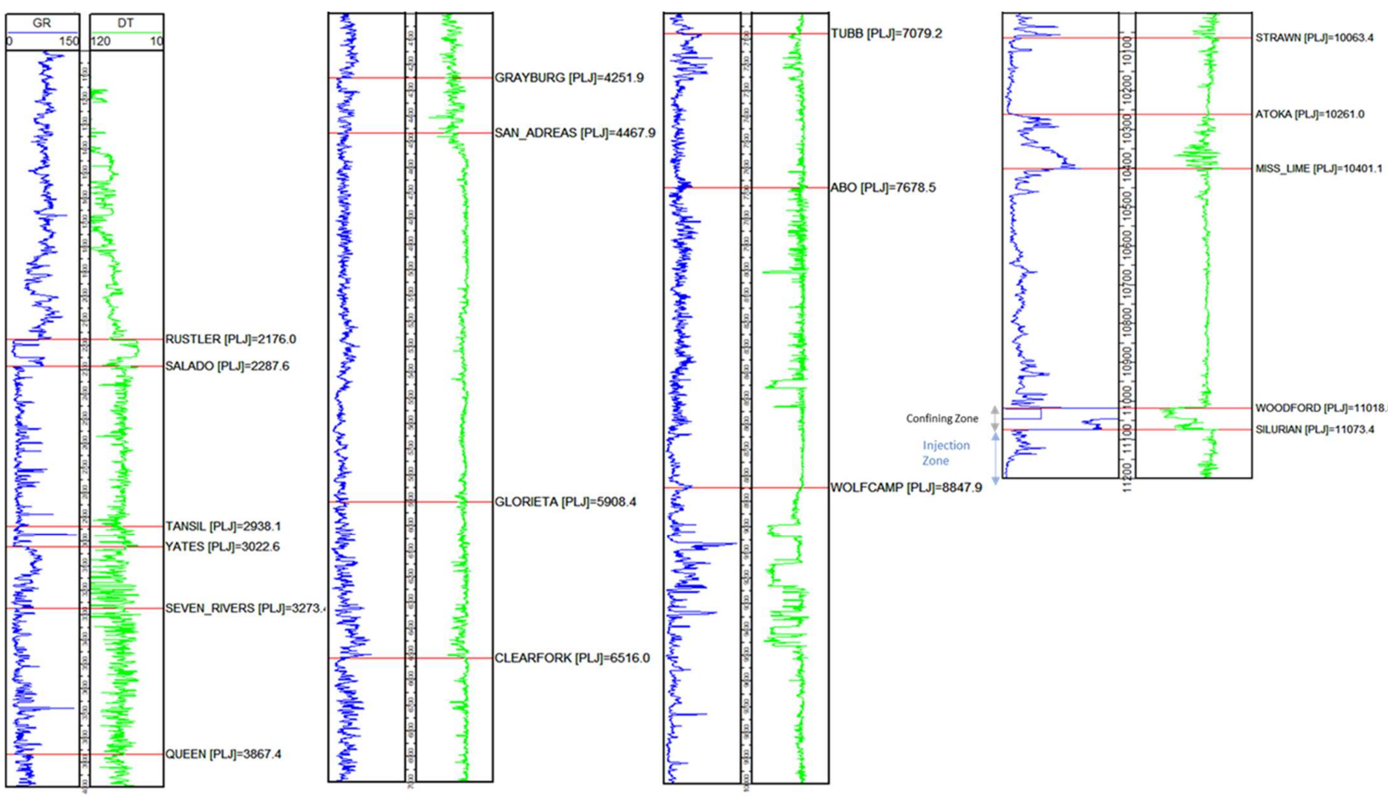


Figure 7 – Type Log (42-501-10238) with tops, confining and injection zones depicted

Upper Confining Interval - Woodford Shale

The Woodford is a late Devonian-aged organic-rich shale deposited as a result of a widespread marine transgression. The flooding event occurred over the majority of the Permian basin, which produced a low-relief blanket-like shale deposit of the Woodford. Two major lithofacies found within the Woodford are black shale and siltstone. Nutrient-rich surface waters promoted the decay of abundant organic matter within the Woodford, resulting in a high total organic carbon ("TOC") percentage. The Woodford shale acts as the primary source and sealant rock for the Wristen Group (Comer, 1991).

Figure 8 is a description of a core sample taken in Lea County, New Mexico just southwest of the Rattlesnake AGI #1 well location. This sample is referenced as C9 in the reference map with the blue star representing the Rattlesnake AGI #1 well. In the core description, black shale with abundant illitic clays is observed in the upper section, and medium gray dolomitic siltstone found in the basal section. The mineralogic and lithologic properties recorded in this description serve as excellent sealant characteristics to prohibit any injected fluids from migrating above the injection interval.

The Woodford at the Rattlesnake AGI #1 well location is encountered at 10,973' and is approximately 63' thick.

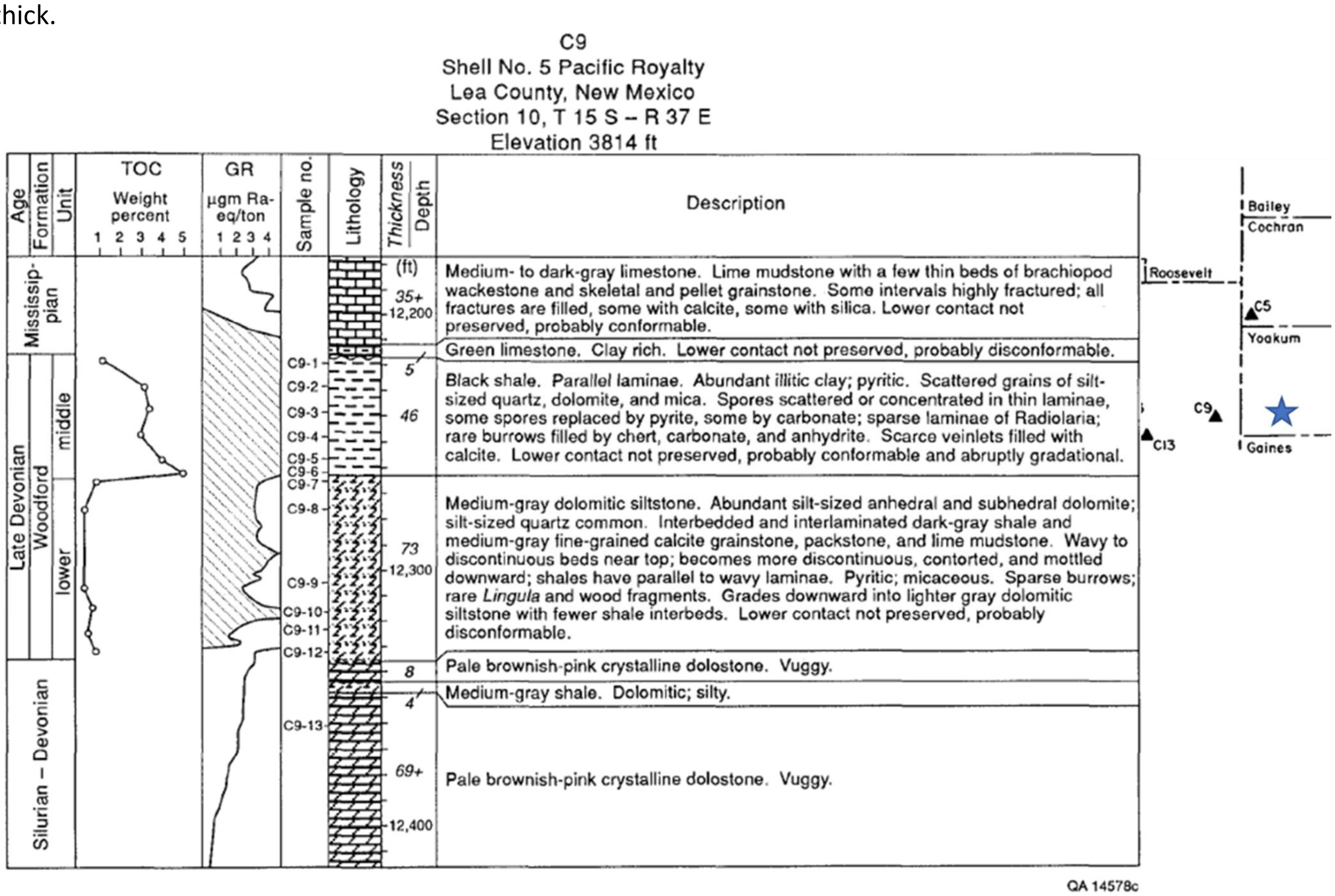


Figure 8 – Core description of the Woodford Shale and Upper Silurian (Ruppel and Holtz, 1994)

Injection Interval – Fasken Formation

The Rattlesnake AGI #1 well reaches total depth in the Fasken/Fusselman formation (Silurian in age), directly below the Woodford formation. Dolomites at the top of the Fasken formation underwent multiple leaching and diagenetic episodes which developed secondary porosity. This is evidenced in offset wells by the practice of only drilling through the top 30' of the Fasken, in anticipation of encountering the best reservoir quality. In Figure 8, the uppermost Silurian section is described as 'vuggy dolostone' in the core description. Beds below the top of the Fasken section may also have similar petrophysical attributes if exposed to multiple diagenetic events. Solution-collapse and karst breccia horizons can be found within inner platform deposits, some occurring as much as 100' below the Fasken top (Ruppel and Holtz, 1994).

<u>Porosity/Permeability Development</u>

Porosity in the Fasken formation at the Rattlesnake AGI #1 well location is typically moldic and intercrystalline associated with leaching of allochem-rich intervals. Porosity is directly related to these leaching events which occurred during and post-deposition, resulting in vugs and karst-like features. Figure 9 provides reservoir information from core data within fields in the Wristen buildup and platform carbonate play. The average porosity of these cores is 7.1% with an average permeability of 45.28 millidarcies (Ruppel and Holtz, 1994). The porosity and permeability described in the offset core data indicate the Fasken formation provides sufficient accessible pore space for the amount of fluid injection proposed.

Using the above values as reference points, the Rattlesnake AGI #1 porosity log (API No. 42-501-36998) was evaluated. Figure 10 is the product of the petrophysical analysis performed on the open hole logs run within the injection interval at the Rattlesnake AGI #1 well. A permeability curve was generated from the effective porosity curve using the table in Figure 9 to establish the porosity-permeability relationship. In Figure 10, the majority of the injection interval's porosity and permeability is found at the top of the Fasken formation, which correlates with the diagenetic processes described above. These curves are extrapolated to the injection site and used to establish reservoir characteristics in the plume model.

	Fusselman Shallow Platform Carbonate play	Wristen Buildups and Platform Carbonate play	Thirtyone Ramp Carbonate play	Thirtyone Deep-Water Chert play
Porosity (%)				
Number of data points	33	30	16	35
Mean	7.93	7.10	6.41	14.85
Minimum	1.00	2.70	3.50	2.00
Maximum	17.70	14.00	9.50	30.00
Standard deviation	4.01	2.67	1.75	6.76
Permeability (md)				
Number of data points	21	24	12	33
Mean	11.61	45.28	1.51	8.56
Minimum	0.60	2.90	0.40	1.00
Maximum	84.80	400.00	30.00	100.00
Standard deviation	22.48	99.17	8.36	22.23
Initial water saturation (%)				
Number of data points	24	28	10	31
Mean	26.96	31.55	24.70	31.46
Minimum	10.00	20.00	16.00	10.00
Maximum	50.00	55.00	40.00	45.00
Standard deviation	9.31	10.45	7.39	8.33
Residual oil saturation (%)				
Number of data points	8	13	5	22
Mean	34.06	30.54	21.30	29.17
Minimum	30.00	20.00	9.00	14.00
Maximum	50.00	35.00	35.00	48.20
Standard deviation	6.99	4.61	11.66	9.76
Oil viscosity (cp)				
Number of data points	11	12	5	21
Mean	0.69	1.16	0.33	0.68
Minimum	0.13	0.32	0.04	0.07
Maximum	1.08	2.00	1.00	1.03
Standard deviation	0.81	0.75	0.40	0.42
Oil formation volume factor				
Number of data points	21	22	6	32
Mean	1.57	1.22	1.65	1.50
Minimum	1.05	1.05	1.31	1.30
Maximum	1.91	1.55	1.66	1.73
Standard deviation	0.28	0.14	0.48	0.16
Bubble-point pressure (psi)				
Number of data points	9	9	5	19
Mean	2,272	1,055	3,750	2,752
Minimum	798	450	2,660	1,755
Maximum	4,050	2,600	4,440	4,656
Standard deviation	1,300	689	756	667

Figure 9 – Table of reservoir properties found within the Wristen buildups and platform plays (Ruppel and Holtz, 1994)

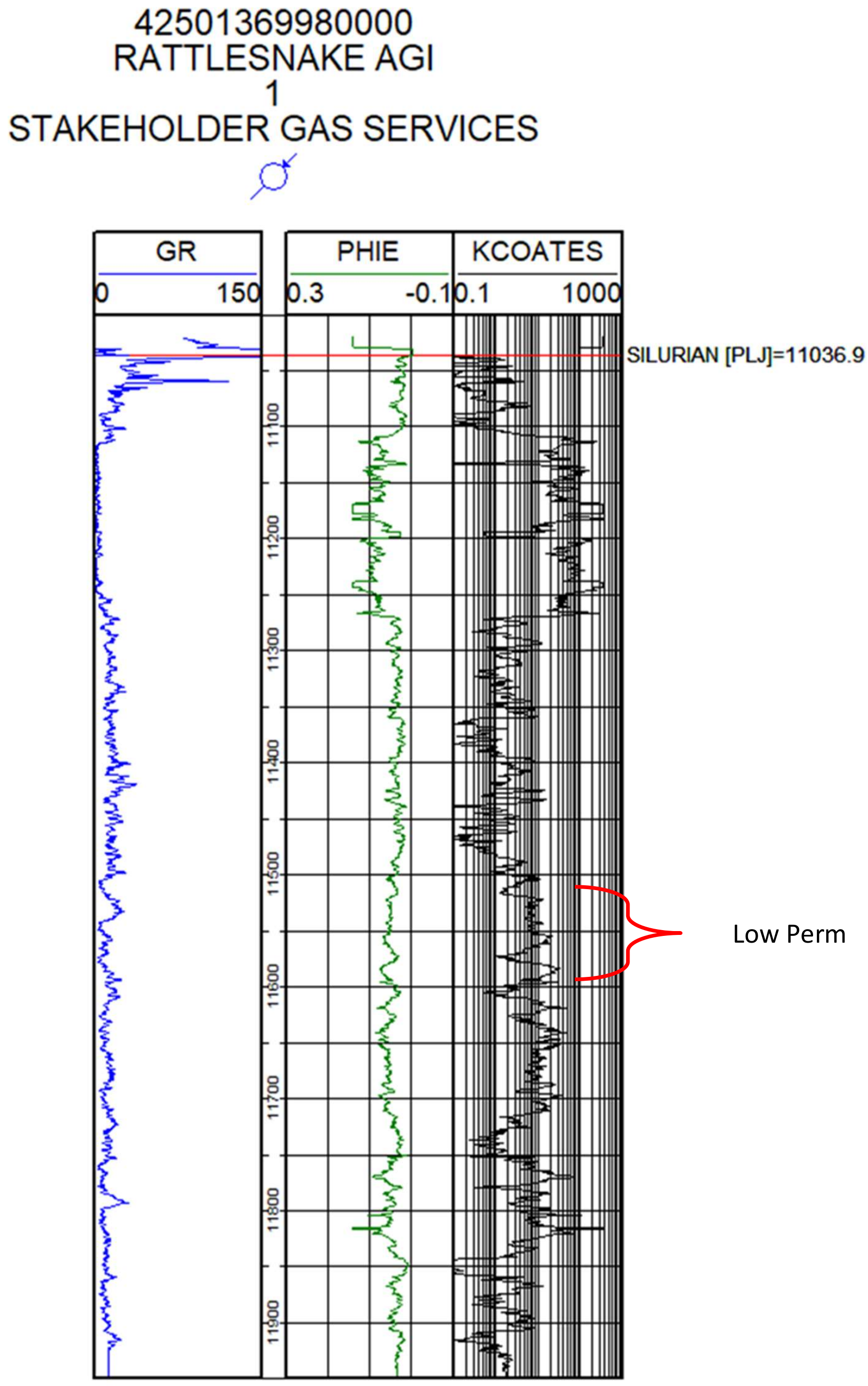


Figure 10 – Rattlesnake AGI #1 open hole log (42-501-36998) with effective porosity (green) and permeability (black)

Formation Fluid

Four wells were identified through a review of chemical analyses of oil-field brines from the U.S. Geological Survey National Produced Waters Geochemical Database v2.1 within the Devonian, Silurian-Devonian, or Fusselman formations within 20 miles of the Rattlesnake AGI #1 well. The location of these wells is shown in Figure 11. Water chemistry analyses conducted on oil-field brines in Gaines County, as reported to the Texas

Water Development Board, provided additional data on Devonian and Silurian reservoir fluids. Results from the synthesis of these two sources are provided in Table 1. The fluids have greater than 20,000 parts per million ("ppm") total dissolved solids, therefore these aquifers are considered saline. These analyses indicate the in-situ reservoir fluid of the Devonian, Silurian, and Fusselman formations are compatible with the proposed injection fluids.

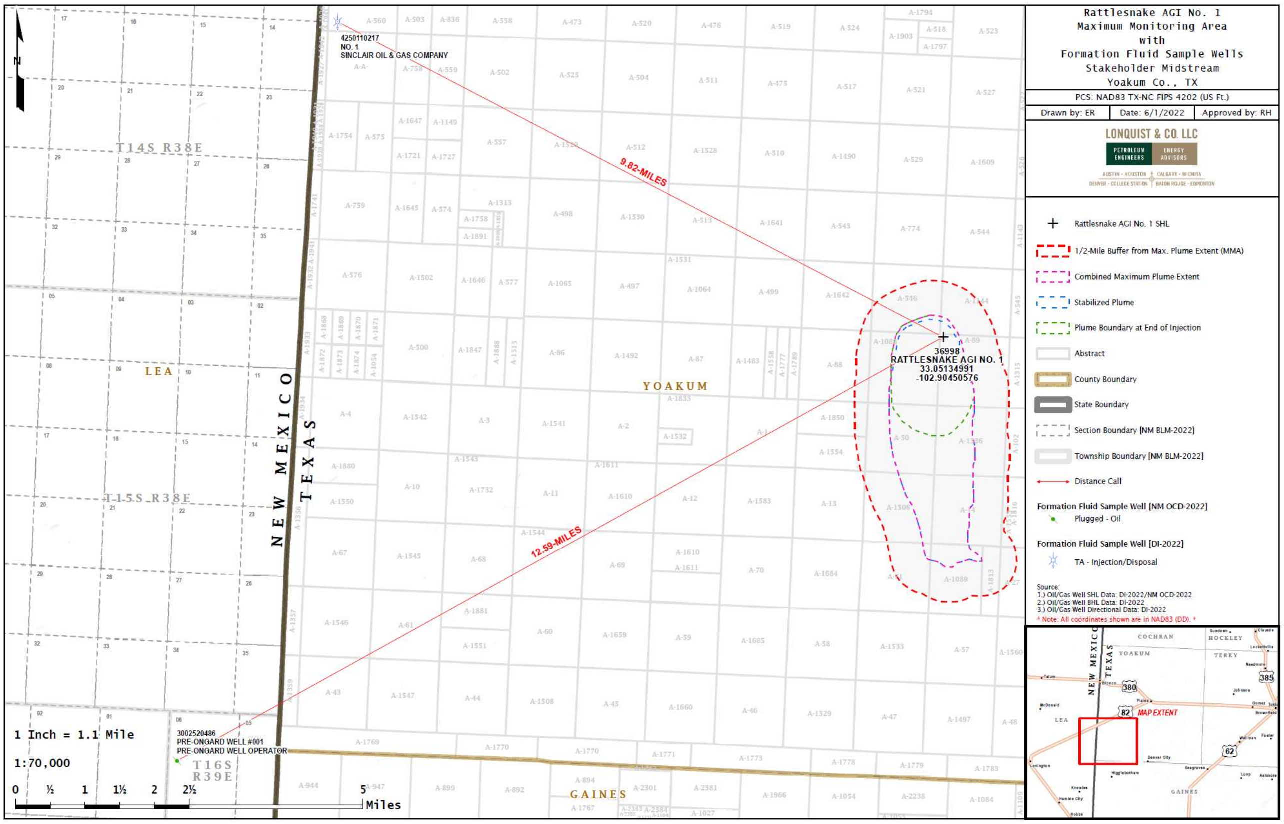


Figure 11 – Offset wells used for Formation Fluid Characterization

Table 1 – Analysis of Silurian-Devonian age formation fluids from nearby oil-field brine samples

	Average	Low	High
Total Dissolved Solids (ppm)	41,428	23,100	55,953
pH	7.2	7.0	7.3
Sodium (ppm)	12,458	7,426	15,948
Calcium (ppm)	1,759	1,010	2,320
Chlorides (ppm)	23,423	12,810	31,930

Fracture Pressure Gradient

Fracture pressure gradient was estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for the determination of fracture gradients. Poisson's ratio ("ν"), overburden gradient ("OBG"), and pore gradient ("PG") are all variables that can be changed to match the site-specific injection zone. Through literature review and industry standards, we are able to determine the expected

fracture gradient. First, 1.05 psi/ft and 0.465 psi/ft were assumed for both the overburden and pore gradients, respectively. These values are considered best practice values when there are no site-specific numbers available. For limestone/dolomite rock, the Poisson's ratio to be assumed to be 0.3 through literature review (Molina, Vilarras, Zeidouni 2016). Using these values in the equation below, a fracture gradient of 0.72 psi/ft was calculated. A 10% safety factor was then applied to this number resulting in maximum allowed bottom hole pressure of 0.64 psi/ft. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

For the upper confining interval, a similar fracture gradient as the limestone was calculated. Shale has an increased chance to vertically fracture if the injection interval is fractured (Molina, Vilarras, Zeidouni 2016), so assuming a Poisson's ratio equal to the injection interval was used as a conservative estimate. The lower confining zone was assumed to be of a similar matrix to that of the injection interval, with the key difference being that the formation is much tighter (lower porosity/permeability). The Poisson's ratio was assumed to be slightly higher in this rock. As seen in Table 2, the fracture gradient is slightly higher than the upper zones.

Table 2 – Fracture Gradient Assumptions

	Injection Interval	Upper Confining	Lower Confining
Overburden Gradient (psi/ft)	1.05	1.05	1.05
Pore Gradient (psi/ft)	0.465	0.465	0.465
Poisson's Ratio	0.30	0.30	0.31
Fracture Gradient psi/ft	0.72	0.72	0.73
FG + 10% Safety Factor (psi/ft)	**0.64**	**0.64**	**0.66**

The following steps were taken to calculate fracture gradient:

$$FG = \frac{\nu}{1-\nu}(OBG - PG) + PG$$

$$FG = \frac{0.3}{1-0.3}(1.05 - 0.465) + 0.465 = 0.72$$

$$FG\ with\ SF = 0.72\ \times (1 - 0.1) = \mathbf{0.64}$$

Lower Confining Zone – Montoya Formation

The low-permeability Montoya Formation is a tight limestone/dolomite that will act as the lower confining unit for the injection interval. Figure 10 shows the decreasing trend in porosity of the limestone rock in the lower section that was not exposed to leaching diagenesis. Porosity in the lower section can range from 2-3% with permeabilities below 1 millidarcy. The Rattlesnake AGI #1 well drilled 6' into the Montoya formation, but the section was not logged. The Montoya is anticipated to be roughly 250' thick. These petrophysical characteristics represent ideal sealing properties to prohibit any migration of injected fluid outside of the injection interval.

Local Structure

Regional structure in the area of the Rattlesnake AGI #1 well is dictated by carbonate buildups and structural events causing anticlinal to synclinal features throughout the area. The Rattlesnake AGI #1 well is specifically located at the base of a syncline with anticlinal features to the northeast, south, and east. Figure 12 is a

structure map of the Silurian formation of subsea depths with the star representing the location of the Rattlesnake AGI #1 well. The red and blue lines represent the cross-section reference lines.

Faulting can be seen to the south and east of the Rattlesnake AGI #1 well location. These faults were interpreted from roughly 9 square miles of 3D seismic indicated by the purple outline in Figure 12. Many of these faults are minor, with offsets less than 50'. The nearest large fault is found southeast of the Rattlesnake AGI #1 well and has an offset of roughly 120'. None of these faults project above the Wolfcamp formation, rather, they appear to terminate between the Strawn and base of the Wolfcamp formation. Production is associated with a hydrocarbon trap set up by the larger fault to the southeast, indicating the fault is vertically sealing in nature. If, in the unlikely event the faults' sealing properties are compromised post-injection, secondary confinement is provided by the tight limestones found within the overlying Mississippian Lime formation along with shale layers found in the Atoka and Wolfcamp formations. As seen in Figure 14, the largest fault found southeast of the Rattlesnake AGI #1 well terminates within the Atoka formation. Though it crosses the Silurian section, this fault thrusts the Mississippian Lime upward against the Atoka shales. The tight reservoir characteristics of the Mississippian Lime and shaley section of the Atoka create a confining environment vertically and laterally to contain potential upward migration of buoyant fluids. Shales within the Wolfcamp formation provide additional confining beds between overlying USDWs and the fault plane. Figures 13 and 14 are north-south and west-east structural cross sections showing the structural dips. As seen in these figures, the Woodford formation is laterally present above the injection interval, alleviating risk of erosion of the upper sealant formation.

Larger versions of Figures 12, 13 and 14 are provided in Appendix A.

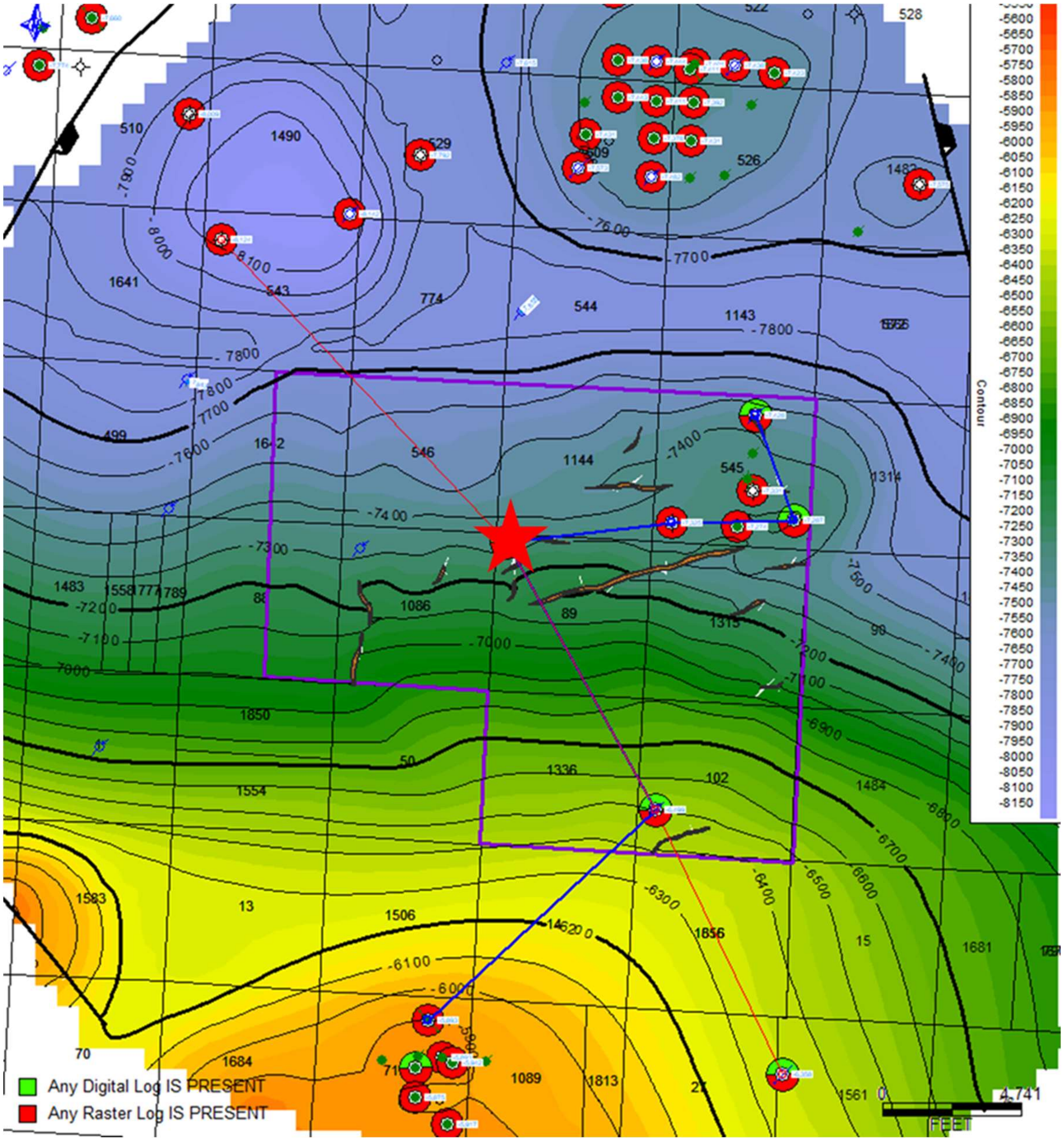


Figure 12 – Silurian Structure Map (subsea depths)

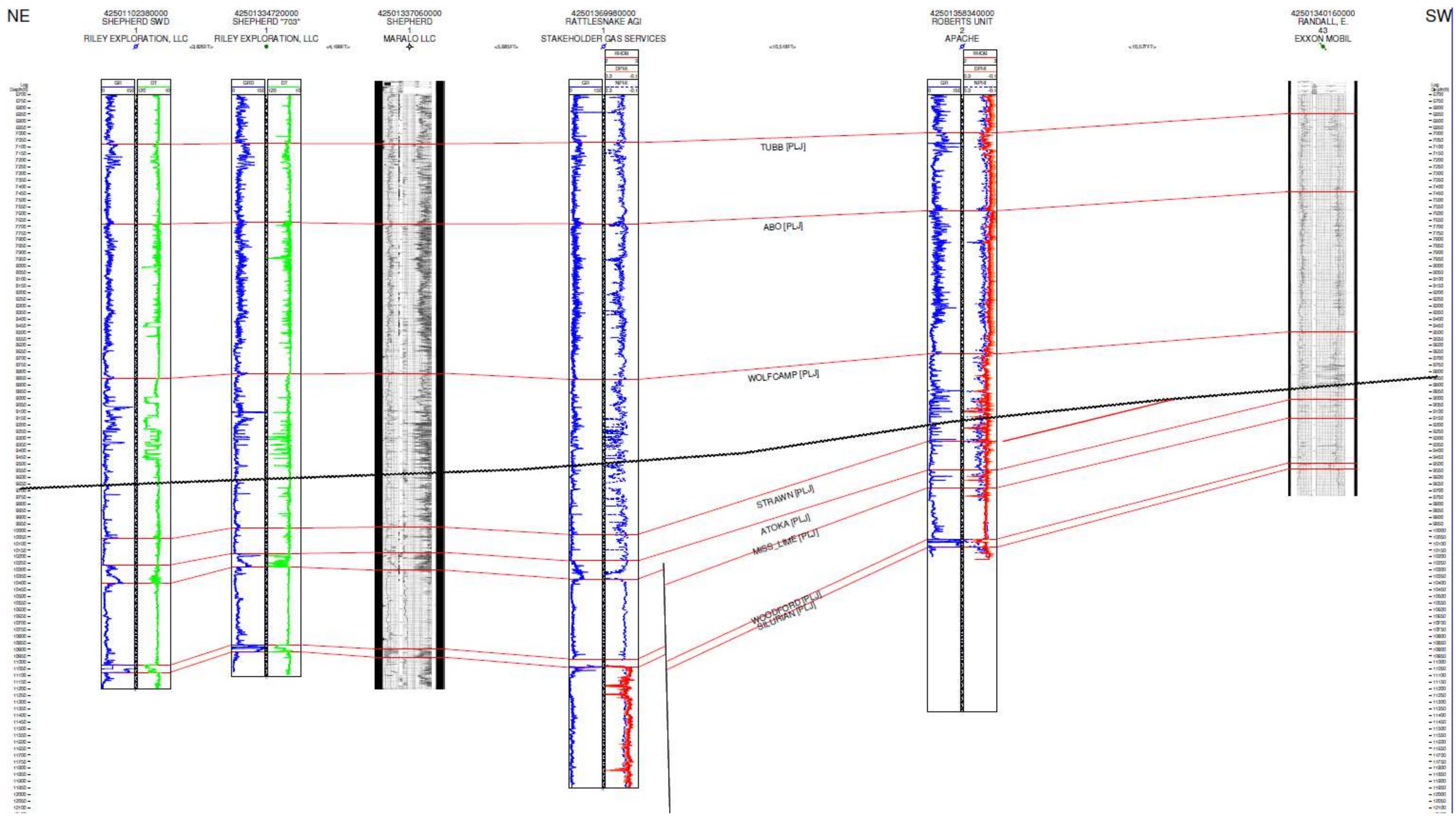
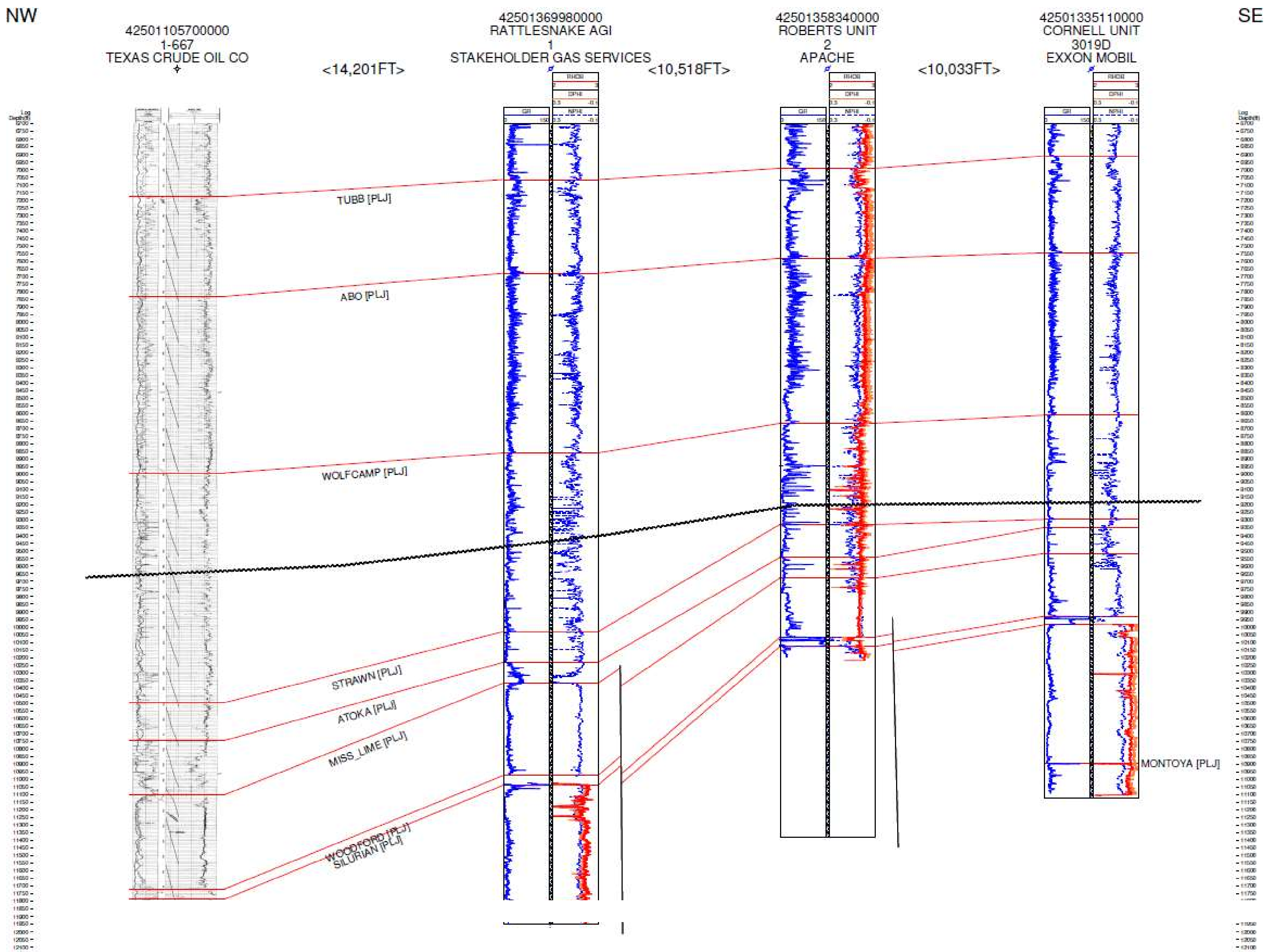


Figure 13 – Structural Northeast-Southwest Cross Section



NW
SE
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EXXON MOBIL
TUBB [PLJ]
ABO [PLJ]
WOLFCAMP [PLJ]
STRAWN [PLJ]
ATOKA [PLJ]
MISS_LIME [PLJ]
WOODFORD [PLJ]
SILURIAN [PLJ]
MONTOYA [PLJ]

Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Fasken and Fusselman formations at the Rattlesnake AGI #1 well location indicate the formations have sufficient thickness, porosity, permeability, and lateral continuity to accept the proposed injection fluids. The Woodford formation shale at the Rattlesnake AGI #1 well has low permeability and is of sufficient thickness and lateral continuity to serve as the upper confining zone. Beneath the injection interval, the low permeability, low porosity Montoya formation is unsuitable for fluid migration and serves as the lower confining zone. Deeper, laterally continuous formations, including the Simpson Group, provide additional confinement.

Groundwater Hydrology

Yoakum County falls within the boundary of the Sandy Land Underground Water Conservation District. Three aquifers are identified by the Texas Water Development Board's *Aquifers of Texas* report in the vicinity of the proposed Rattlesnake AGI #1 well: the Dockum Aquifer, Edwards-Trinity Aquifer, and Ogallala Aquifer (George, Mace and Petrossian, 2011). Table 3 references the aquifers' positions in geologic time and the associated geologic formations. A schematic cross section in Figure 15, near the proposed Rattlesnake AGI #1 well, illustrates the structure and stratigraphy of these water-bearing formations. Groundwater flow direction is the same for the three aquifers, generally from northwest to southeast, Figure 16 (Teeple, et al., 2021).

Table 3 – Geologic and hydrogeologic units with accompanying lithologic descriptions near Gaines, Terry and Yoakum Counties, Texas (Teeple, et al. 2021)

Era	Period	Epoch or series	Geologic unit group or formation	Lithologic descriptions	Hydrogeologic unit
Cenozoic	Tertiary	Pliocene	Ogallala Formation	Gravel, sand, silt, and clay	High Plains aquifer system (Ogallala aquifer)
		Miocene			
Mesozoic	Cretaceous[1]	Comanchean Series	Washita Group[2]	Shale and limestone	Edwards-Trinity (High Plains) aquifer system
			Fredericksburg Group	Clay, shale, and limestone	
			Trinity Group	Sand and gravel	
	Triassic	Upper	Dockum Group	Siltstone, mudstone, shale, and sandstone	Dockum aquifer

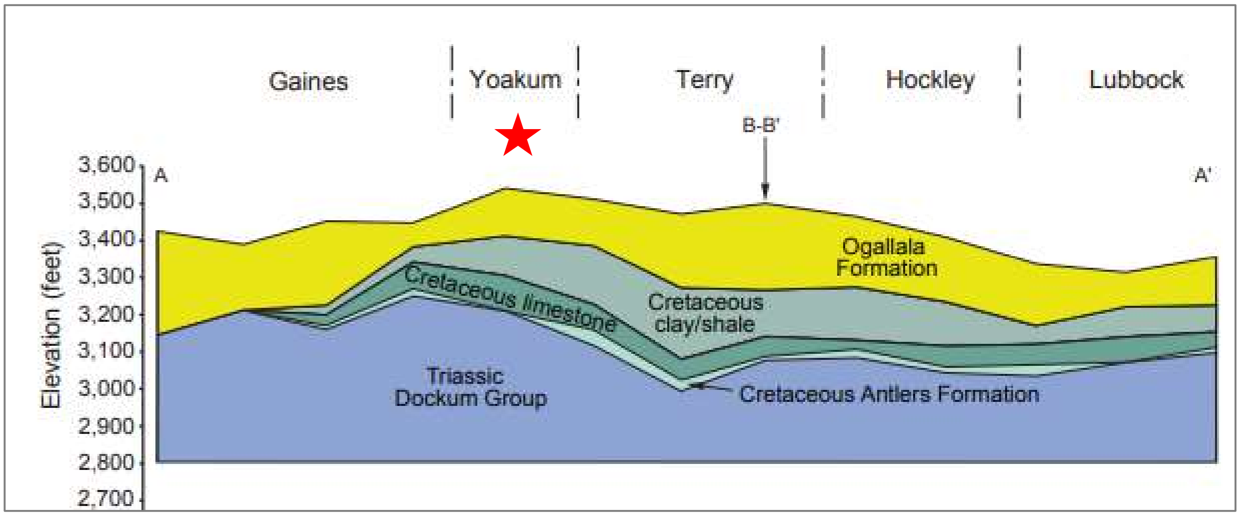


Figure 15 – NW-SE Cross Section of aquifers in the Rattlesnake AGI #1 well area (George, Mac and Petrossian, 2011)

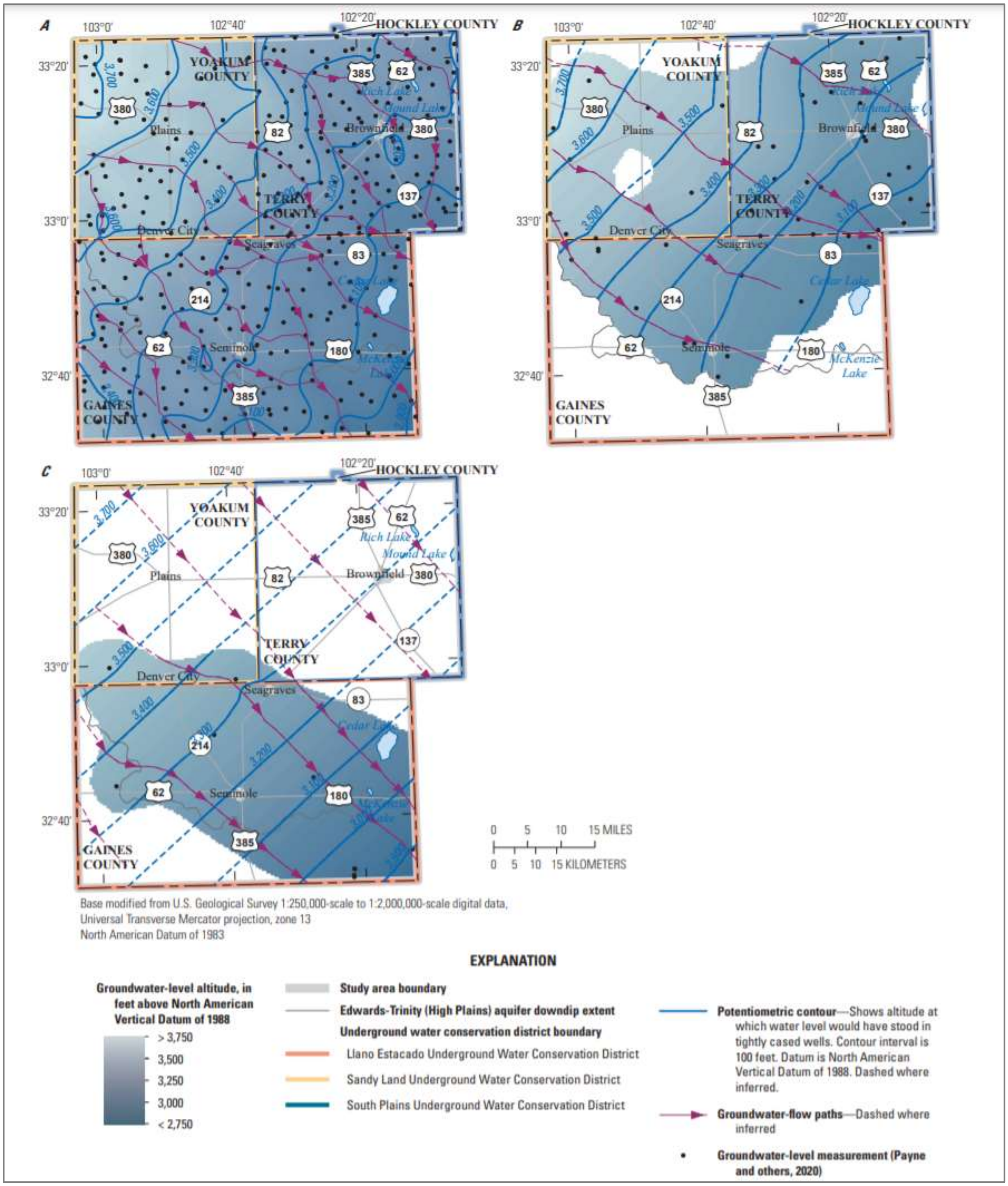


Figure 16 – Potentiometric surfaces from wells completed in A, Ogallala aquifer, B, the Edwards-Trinity aquifer and C, the Dockum aquifer (George, Mace and Petrossian, 2011).

The Dockum Aquifer is the oldest of the three aquifers, formed from Triassic-age Dockum Group sediments, and underlies the Cretaceous Trinity and Fredericksburg Groups (Teeple, et al., 2021). Figure 17 shows the subsurface and outcrop extent of the Dockum Aquifer. As shown in Figure 18, the total dissolved solids in western Yoakum County exceed 5,000 milligrams per liter ("mg/L"), therefore the aquifer is considered brackish.

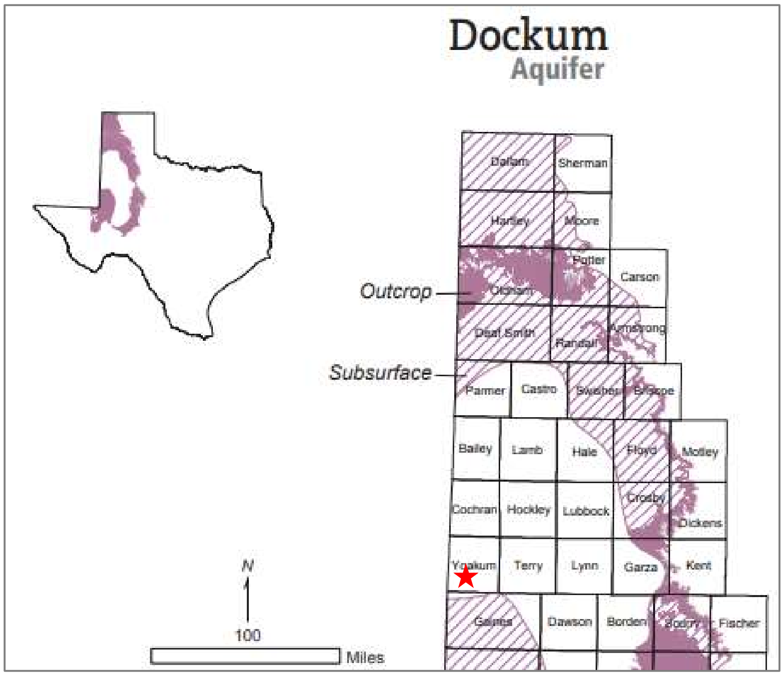


Figure 17 – Regional extent of the Dockum freshwater aquifer (TWDB)

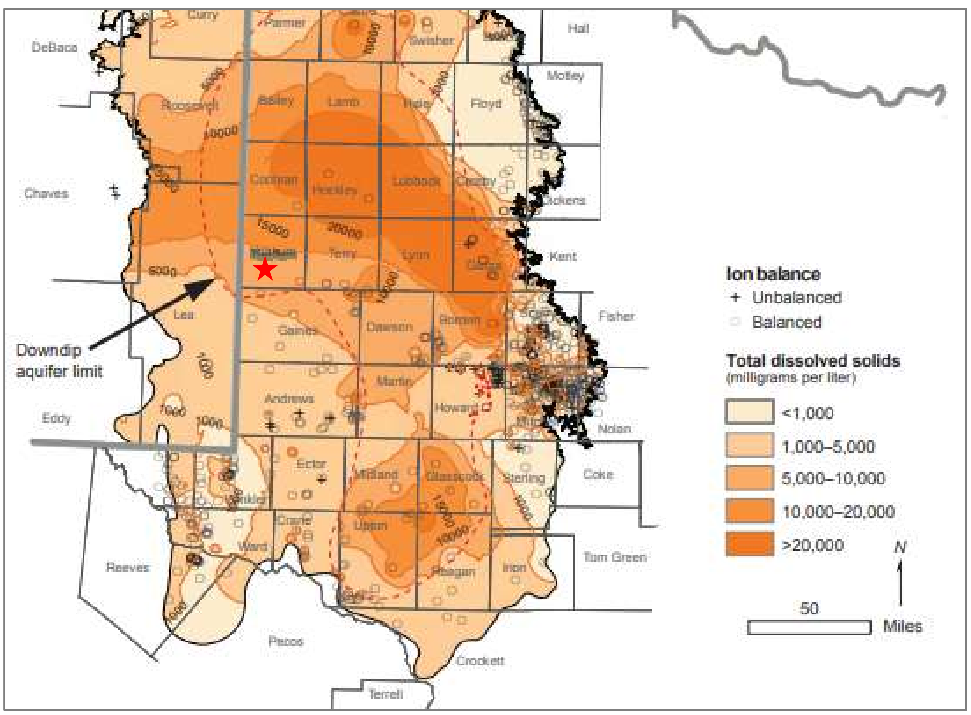


Figure 18 – Total dissolved solids in groundwater from the Dockum Aquifer (Ewing et al, 2008)

The Edwards-Trinity Aquifer is a collection of Cretaceous age sediments – primarily the Trinity Group Antlers formation sandstone and limestones of the Fredericksburg Group, specifically the Comanche Peak and Edwards formations. Figure 19 shows the subsurface and outcrop extent of the Edwards-Trinity Aquifer. Freshwater infiltration to this aquifer is primarily from the overlying Ogallala Aquifer (George, Mace and Petrossian, 2011).

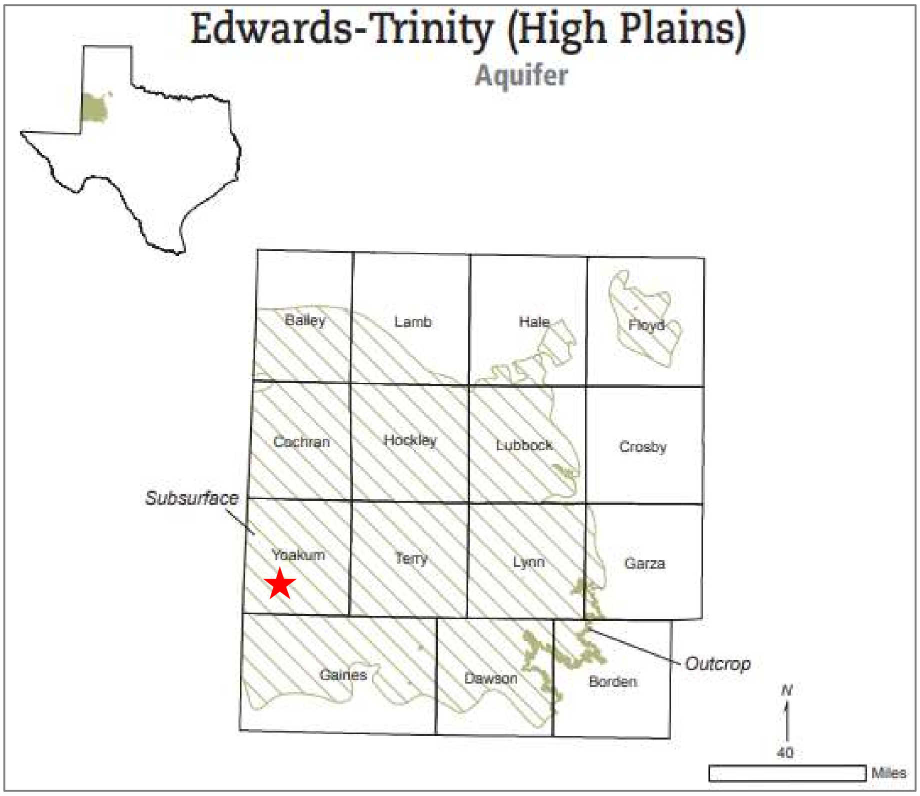


Figure 19 – Regional extent of the Edwards-Trinity freshwater aquifer (George, Mace and Petrossian, 2011)

The Ogallala aquifer consists of sand, gravel, clay and silt sediments (George, Mace and Petrossian, 2011) and produces the majority of the freshwater for Yoakum County. Figure 19 shows the subsurface and outcrop extent of the Ogallala Aquifer.

The base of the deepest aquifer is separated from the injection interval by approximately 9,500' of rock, including 650' of Salado salt. Though unlikely for reasons outlined in the confinement and potential leaks sections, if migration of injected fluid did occur above the Woodford Shale, thousands of feet of tight sandstone, limestone, shale, salt and anhydrite beds occur between the injection interval and the lowest water-bearing aquifer.

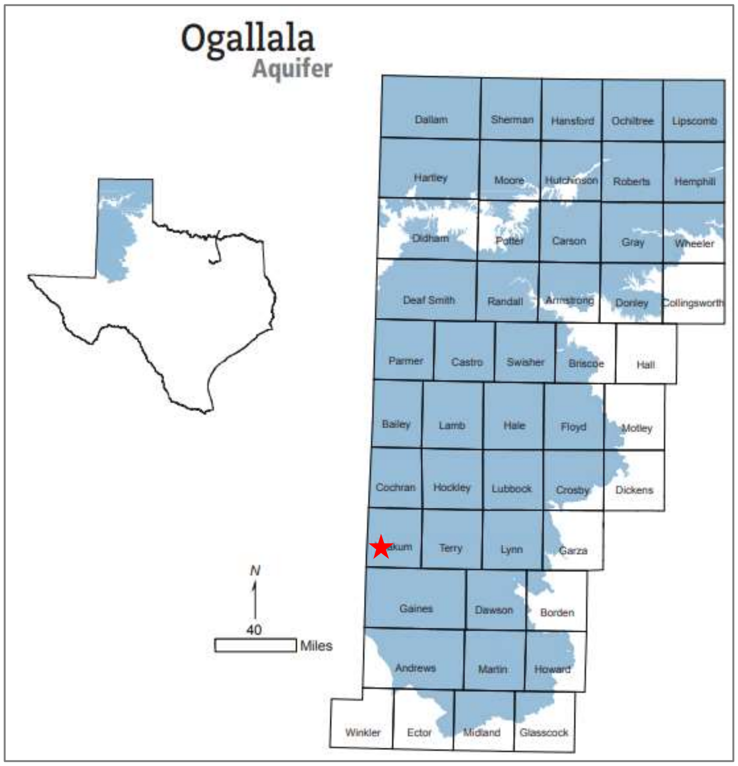


Figure 20 – Regional extent of the Ogallala freshwater aquifer (George, Mace and Petrossian, 2011)

The TRRC's Groundwater Advisory Unit ("GAU") identified the base of Underground Sources of Drinking Water ("USDW") at 2,250' at the location of the Rattlesnake AGI #1 well. Therefore, there is approximately 9,470' separating the base of the USDW and the injection interval. A copy of the GAU's Groundwater Protection Determination letter issued by the TRRC as part of the Class II permitting process for the Rattlesnake AGI #1 well is provided in Appendix B.

Description of the Injection Process

Current Operations

The 30-30 Facility and its associated Rattlesnake AGI #1 well began operating in March of 2019. Since operations began, 258 million cubic feet ("MMCF") of treated acid gas ("TAG") has been injected, which equates to 12,316 metric tons of CO_2. Over the life of the injection period, the average daily injection rate has been 223 MSCF/d. The approximate current composition of the TAG stream is as follows:

Table 4 – Gas Composition of 30-30 Facility outlet

Component	Mol %
	1.12%

The 30-30 Facility is designed to compress, treat, and process natural gas produced from the surrounding counties in Texas and New Mexico. The gas is dehydrated to remove the water content, then processed to separate natural gas liquids which are then sold, along with the pipeline quality natural gas, to various customers. TAG is then directly routed from the plant amine regen system to the Rattlesnake AGI #1 well. The facility is manned 24 hours per day, 7 days per week.

Planned Operations

Stakeholder anticipates increasing the amount of CO_2 injected into Rattlesnake AGI #1 well from the current rate up to 16 MMSCF/d. Additional growth is expected both at Stakeholder facilities and regionally as rising sour gas production and flaring reduction mandates create the need for additional CO_2 and H_2S disposal capacity. Stakeholder plans to inject into this AGI well for another 14 years for a total of 17 years from the start of injection in 2019.

Figure 21 shows a high-level view of the current process flow plus the prospective additional operations over time.

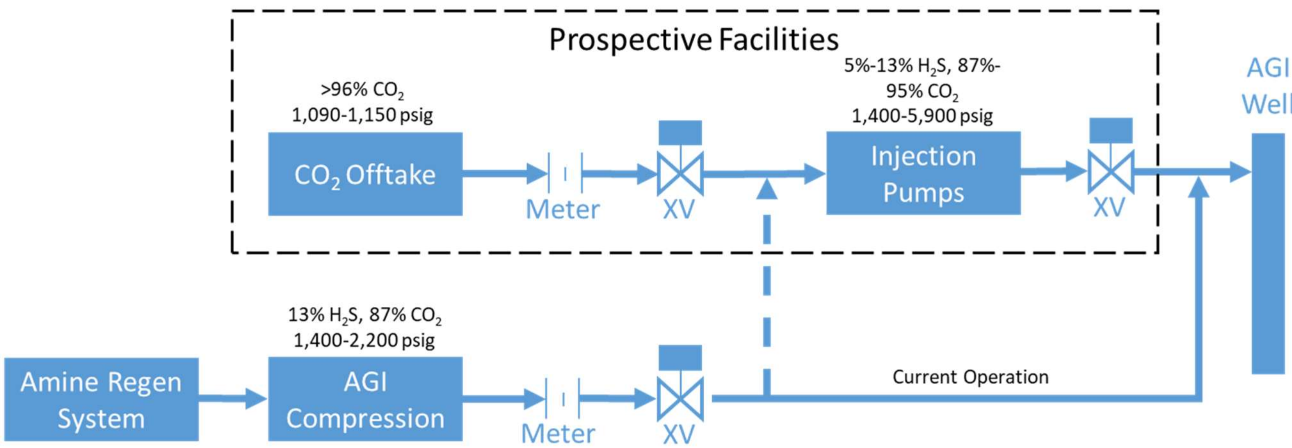


Figure 21 – 30-30 Facility Process Flow Diagram

<u>Reservoir Characterization Modeling</u>

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2020.11 ("GEM") simulator. Computer Modelling Group ("CMG") has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM utilizes equation-of-state ("EOS") algorithms along with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon injection and storage. The GEM model is recognized by the EPA for use in area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Silurian (Fasken/Fusselman) formation is the target formation for Rattlesnake AGI #1 well. The Petra software package was used to create the geologic model of the target formation. The faulting and geologic structure was then imported into GEM and used to create contours for the model grid.

Porosity and permeability estimates were determined using the porosity log from the Rattlesnake AGI #1 well and a petrophysical analysis was performed to correlate porosity values by depth with core porosities as shown in the Holtz paper. The Coates permeability equation was then used to calculate permeability with depth. Both porosity and permeability are assumed to be laterally homogeneous in the reservoir.

The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. An infinite acting reservoir was created to simulate boundary conditions. The gas injectate is composed of H_2S, CO_2, CH_4, and other components as shown in Table 5. Core data from literature review was used to determine residual gas saturation (Ruppel and Holtz, 1994). The modeled composition only takes into consideration the carbon dioxide and hydrogen sulfide as they comprise nearly 99% of total stream. For the initial injection period, these compositions are normalized up to 100%. For the proposed additional injection period, it is expected that a larger portion of the gas added is carbon dioxide, changing the composition to ~93% CO_2 and ~7% H_2S.

Table 5 – Modeled Initial Gas Composition

Component	Measured Current Composition (mol%)	2019-2024 Model Composition (mol%)	2024-2036 Model Composition (mol%)
Carbon Dioxide (CO2)	89.678	90.696	92.921
Hydrogen Sulfide (H2S)	9.200	9.304	7.079
Methane (C1)	0.303	0	0
Ethane (C2)	0.058	0	0
Propane (C3)	0.108	0	0
N-Butane (NC4)	0.025	0	0
Hexane Plus (C6+)	0.628	0	0

Core data from literature review was used to determine relative permeability curves between carbon dioxide and the connate brine within the Silurian-Devonian carbonates (Ruppel and Holtz, 1994). The key inputs used in the model include an irreducible water saturation of 25% and a maximum residual gas saturation of 21%.

The grid contains 141 blocks in the x-direction (E-W) and 201 blocks in the y-direction (N-S), totaling 28,341 grid blocks per layer. This results in the grid being 21,150' by 30,150' totaling just over a 23-square mile area (14,640 acres). Each layer in the model was determined by identifying higher permeability zones as targets for injection from the logs and assigning each high permeability and intermediary low permeability zone its own layer. One zone was identified as being a karst limestone (layers 2-7). Due to the "karsted" nature of this rock, it was determined that most of the injectate would flow into this zone. Therefore, the karst limestone was further split into layers by permeability to provide higher resolution and more accurately simulate which layer will have the greatest gas flows. Figure 22 provides a detailed breakdown of the "karsted" rock.

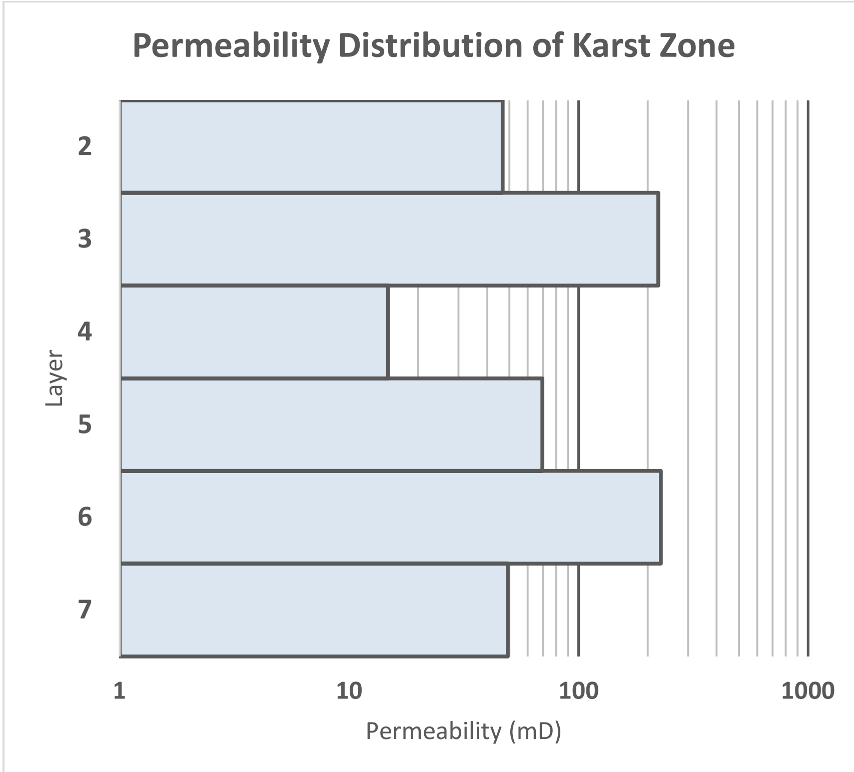


Figure 22 – Permeability Distribution of Karst Limestone

In total, there are sixteen (16) layers in the model, representing ten (10) layers of pay and six (6) layers of intermediary low permeability zones. The properties of each of these layers are summarized in Table 6 below.

Table 6 – CMG Model Layer Properties

Layer #	Top (ft)	Thickness (ft)	Permeability (mD)	Porosity
1	11,037	71	1	2.8%
2	11,108	57	47	8.0%
3	11,165	19	223	11.9%
4	11,184	16	15	6.3%
5	11,200	39	70	9.2%
6	11,238	11	228	12.3%
7	11,249	21	49	8.3%
8	11,270	251	2	3.7%
9	11,520	46	9	5.6%
10	11,566	13	3	4.3%
11	11,579	19	17	6.5%
12	11,597	14	2	3.9%
13	11,611	103	13	6.0%
14	11,714	46	2	3.7%
15	11,759	67	23	6.1%
16	11,826	125	2	3.6%

Simulation Modeling

The primary objectives of the model simulation were to:

1) Estimate the maximum areal extent and density drift of the acid gas plume after injection
2) Assess the impact of offset saltwater disposal ("SWD") well injection on density drift of the plume
3) Assess the impact of offset producing wells on the density drift of the plume
4) Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone
5) Assess the likelihood of the acid gas plume migrating into potential leak pathways

The reservoir is assumed to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 53,000 ppm (Texas Water Development Board, 1972). The acid gas stream is primarily composed of CO_2 and H_2S as stated previously. Core data was used to help generate relative permeability curves. Cores, from the literature reviews previously discussed, that most closely represent the vuggy carbonate seen in this region were identified and the Corey-Brooks equations were used to develop the curves. The lowest residual gas saturation found in the cores was then used for a conservative estimate of plume size. From offset injection well analysis, the initial reservoir pressure was determined to be 5,132 psi which is equivalent to a 0.465 psi/ft pressure gradient. The fracture gradient of the injection zone was estimated to be 0.72 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottom-hole pressure allowed in the model at 0.64 psi/ft which is equivalent to 7,064 psi.

The model also takes into account offset saltwater disposal ("SWD") injection volumes within five (5) miles of the Rattlesnake AGI #1 well. These SWDs create a pressure front that push the plume further up-dip of the formation. A total of twenty (20) offset wells currently injecting into the target formation were identified. Eleven (11) of these offset SWDs were out of the confines of the grid, but were still accounted for in the model. Nine (9) salt-water disposals were modeled within the boundaries of the 23-square-mile grid. Two (2) of these offset injectors are currently only permitted (not drilled) but were assumed to start active injection within the first year of the model. Both permits were simulated at the forecasted injection rate schedule for 30 years. These forecasts were provided by the operators of these wells. Historical injection rates of each of the other existing wells were analyzed and projected into the model. This simulation includes the effect of water injection on the density drift of the plume and bottom hole pressure.

Further review of the area revealed production wells in the Silurian-Devonian formation that could impact the density drift of the plume by creating a "pressure sink". A "pressure sink" is an area of lower pressure caused by the production of formation fluids. To simulate this effect, nine (9) production wells were grouped together and their respective production rates combined into a single well to add more conservatism into the model. These producers were forecasted an additional 15 years to simulate their potential economic lifespan. This simulation includes the effect of fluid production on the density drift of the plume and bottom hole pressure. Overall, the "pressure sink" has little effect on the density drift and, as discussed below, the plume never reaches the producing wells.

The model runs for a total of 814 years, starting in 1965 with the beginning of offset production until the calculated stabilization of the plume in 2779. The injection of TAG from Rattlesnake AGI #1 is modeled from the beginning of injection in 2019 through the planned 14 years of future injection. The model also includes the 57 years of historical plus 15 years of forecasted future oil and gas production.

Additionally, historical monthly injection rates of all nearby SWDs were incorporated into the model to simulate any additional near-wellbore pressure increase that may occur due to offset injection. The

modelling of the saltwater injection begins in 1984 when the first offset SWD well became operational. The SWDs to the North were grouped into four (4) separate groups to simulate their combined effect on the density drift of the plume. All offset injection wells and their groupings are included in Table 7. All offset production wells are listed in Table 8.

Table 7 – All Offset SWDs included in the model

Grouping	API	Well Name	Well #
Group 1	42-501-32511	SAWYER, DESSIE	1
	42-501-02068	WEST, M. M.	2
	42-501-02053	NORTH CENTRAL OIL CO. "A"	1
	42-501-01453	SMITH, ED S. HEIRS "B"	1
	42-501-02059	SMITH, ED "C"	1W
Group 2	42-501-30051	JOHNSON	2
	42-501-30001	JOHNSON	1D
Group 3	42-501-37066	MISS KITTY SWD 669	1W
	42-501-36650	RUSTY CRANE 604	1W
Group 4	42-501-36745	SUNDANCE 642	1
	42-501-33887	WINFREY 602	3WD
Standalone	42-501-37252	Miller SWD	7
	42-501-37367	BLONDIE 704	1W
	42-501-37206	BRUSHY BILL 707	1WD
	42-501-36622	WISHBONE FARMS 710	1W
	42-501-35834	ROBERTS UNIT	2
	42-501-33297	STATE ELMORE	1
	42-501-10238	SHEPHERD SWD	1
	42-501-33511	CORNELL UNIT	3019D
	42-501-32868	WILLARD UNIT	1WD

Table 8 - All Offset Producers included in the model

API	Well Name	Well #
42-501-10046	ELLIOTT, C.A.	2
42-501-10079	RANDALL, E	32
42-501-337932	RANDALL, E	40
42-501-33885	RANDALL, E	41L
42-501-34016	RANDALL, E	43L
42-501-34017	RANDALL, E.	45L
42-501-34023	RANDALL, E	42L
42-501-34024	RANDALL, E	44
42-501-35418	RANDALL, E	46

Rattlesnake AGI #1 came online in 2019 and the model simulated its historical monthly injection rates until 2024. After this initial period, it is conservatively assumed that the injection rate increases to the maximum permitted rate of 16 MMSCF/d for the remainder of the active injection period in 2036. At this point, the

Rattlesnake AGI #1 well stops injection while the offset SWD injectors continue operations for thirty more years. Density drift then occurs until plume stabilizes, which was determined to be 814 years from the start of the model in 1965. Stabilization of the plume is determined to occur when the model shows no further lateral movement horizontally or vertically. The plume boundary is then defined by a weighted average gas saturation in the aquifer of 3%.

The maximum plume extent during the 17-year Rattlesnake injection period is shown in Figure 23. The final extent after 743 years of density drift after injection ceases is shown in Figure 24. The extensive time of the modeled density drift of the plume is driven by the buoyant forces of the gas, the permeability/porosity of the rock, and the residual gas saturation. Initially, the karsted region takes on most of the injection, but due to the buoyant forces, it is slowly pushed up higher into the less permeable layers of the injection interval. These lower permeable layers increase the amount of time it takes for the plume to reach its maximum areal extent. As all the inputs to the model were based on the most conservative approach, the maximum extent of the plume will likely be smaller and the effective impact on reaching potential leakage pathways will be minimal as the amount of CO_2 at those far extents will be small. Throughout the entirety of the density drift period the plume does not intersect any likely leakage pathways.

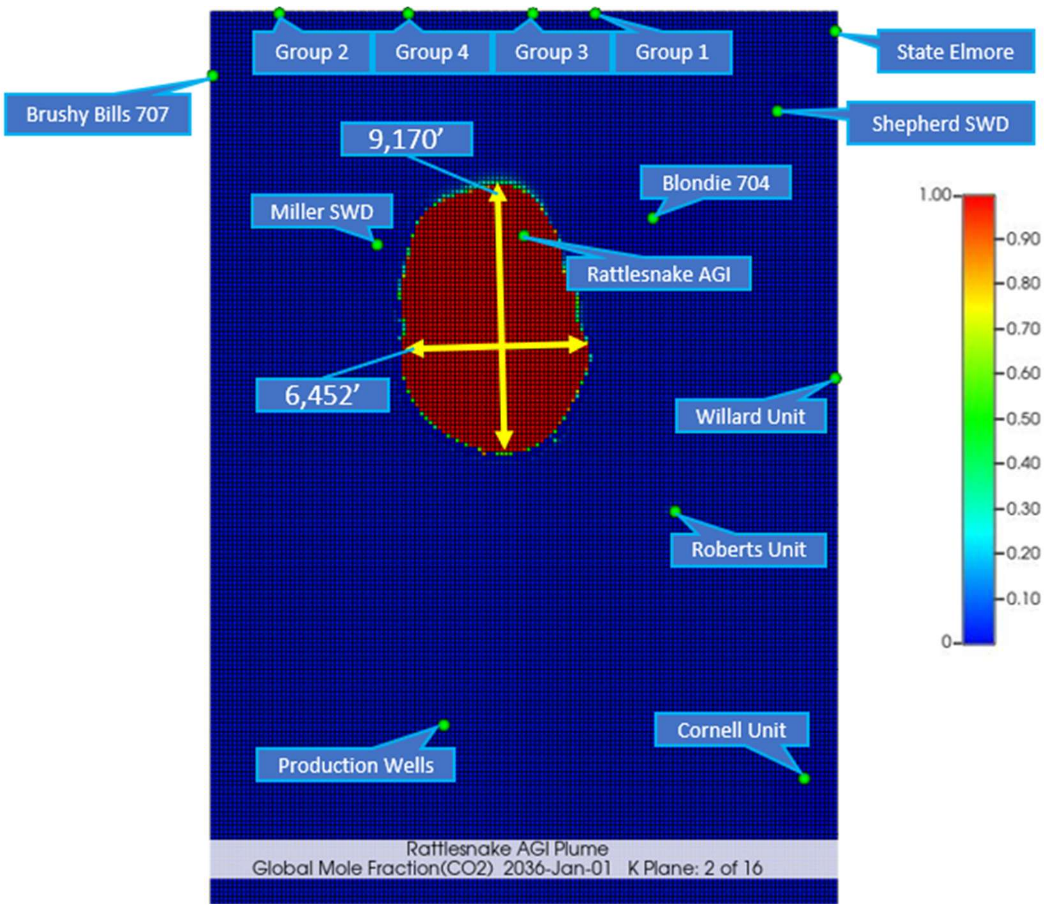


Figure 23 – Areal View Gas Saturation Plume, 2036 (End of Injection)

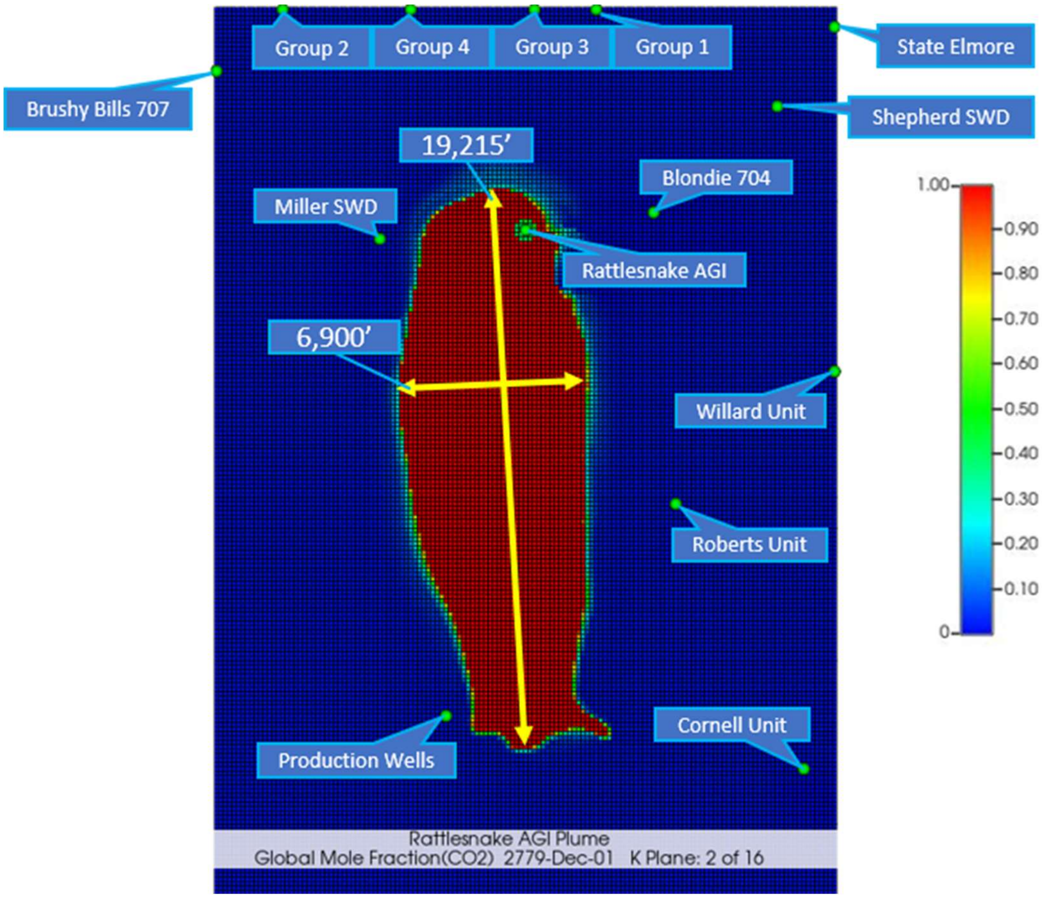


Figure 24 – Areal View Gas Saturation Plume, 2779 (End of Density Drift)

Figure 25 shows the surface injection rate and bottom hole pressure over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate reaches its peak, reaching a maximum pressure of 5,413 psi. This buildup of 280 psi keeps the bottomhole pressure well below the fracture pressure of 7,064 psi. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,494 psi.

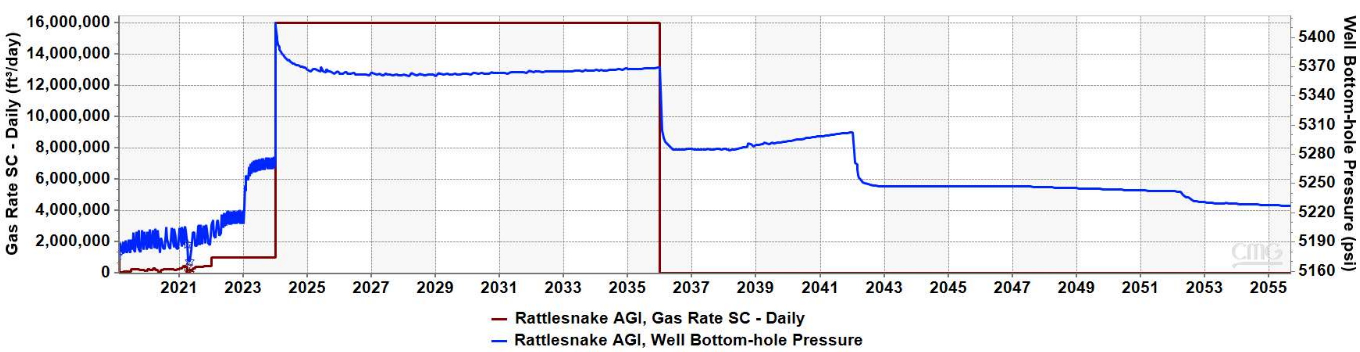


Figure 25 – Well Injection Rate and Bottomhole Pressure over Time

SECTION 3 – DELINATION OF MONITORING AREA

This section discusses the delineation of Maximum Monitoring Area ("MMA") and Active Monitoring Area ("AMA") as described in EPA 40 CFR §98.448(a)(1).

Maximum Monitoring Area

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

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

Acid gas injectate was analyzed by a third-party vendor to determine the initial composition used in the model. The report is provided in Appendix C. The molar composition of the gas is primarily CO_2 with some H_2S and CH_4. The change in molar composition was also incorporated into the model as future predominantly CO_2 streams are added for injection. As discussed in Section 2, the gas was injected into the Silurian formation, specifically, the Fasken/Fusselman formation. The geomodel was created based off the rock properties seen in the Fasken/Fusselman.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in 2036, the areal expanse of the plume will be 1,052 acres. The maximum distance between the wellbore and the edge of the plume is approximately 0.87 miles to the southeast. After 743 additional years of density drift, the areal extent of the plume is 2,177 acres with a maximum distance to the edge of the plume of approximately 1.35 miles to the southeast.

Figure 26 shows the plume boundary at the end of injection, the stabilized plume boundary and the MMA.

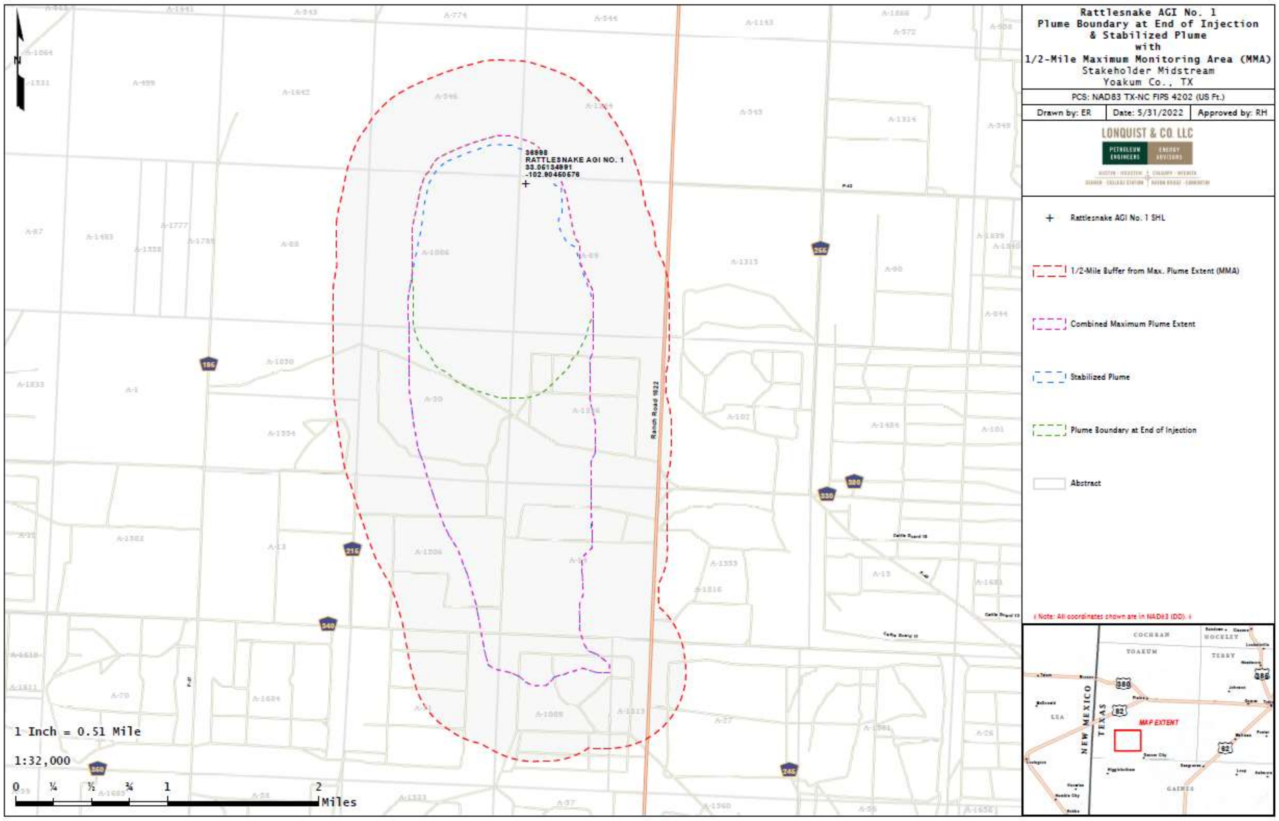


Figure 26 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

Active Monitoring Area

The initial AMA will cover a 14-year monitoring period. This period equates to the time of expected future injection. The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location at the end of injection (2036) with the area of the projected free-phase CO_2 plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume at 2036 plus a half-mile buffer. By 2036 at the latest, a revised MRV will be submitted to define a new AMA. Figure 27 shows the area covered by the AMA.

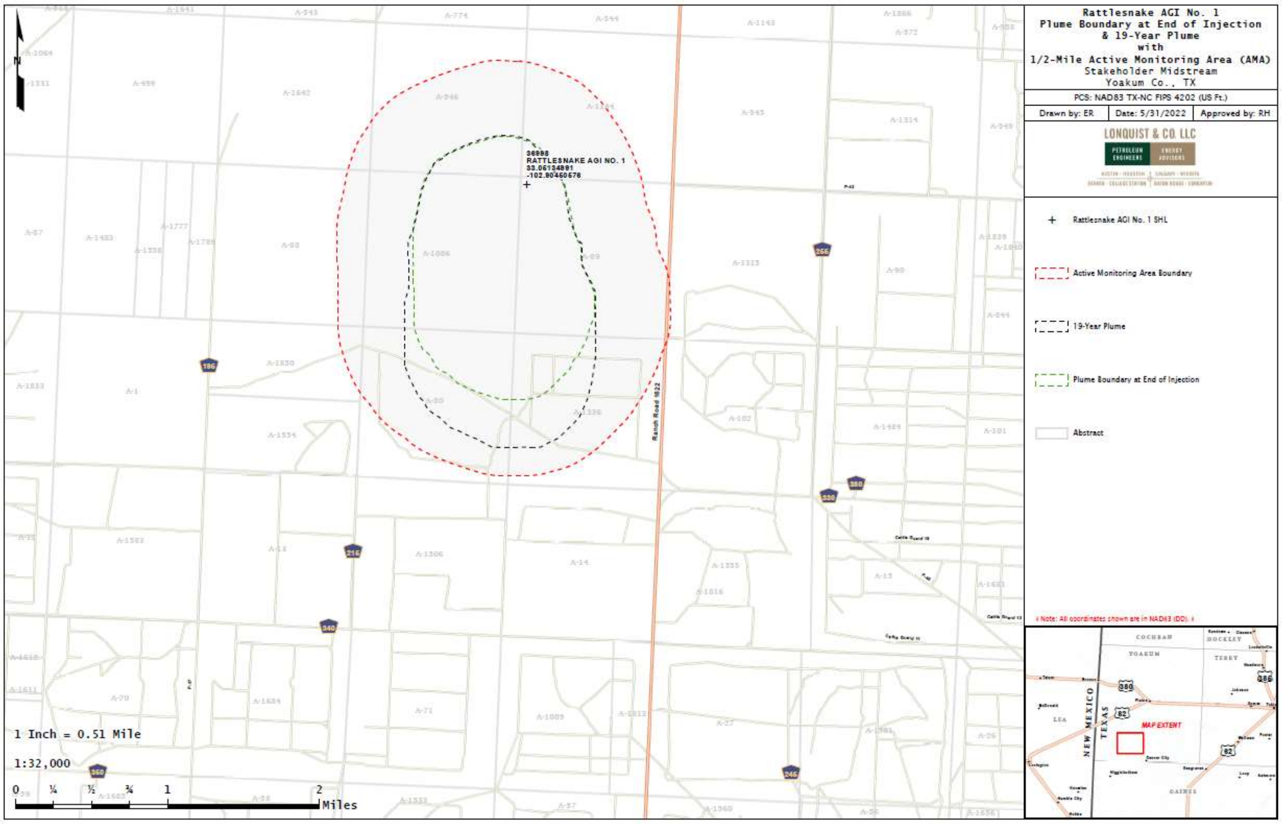


Figure 27 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA and the likelihood, magnitude and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within MMA
- Leakage through faults and fractures
- Natural or Induced Seismicity
- Drilling through the MMA
- Leakage through the confining layer

Leakage from Surface Equipment

The surface facilities at the 30-30 Facility are designed for injecting acid gas containing H_2S, and therefore minimize leakage points such as valves and flanges following industry standards and best practices. H_2S gas detectors are located around the facility and the well site. These gas detectors trigger alarms at 10 parts per million ("ppm"). Additionally, all Stakeholder field personnel are required to wear H_2S monitors which are triggered at 5 ppm of H_2S. A shut-in valve is located at the wellhead and is locally controlled by pressure, with a high pressure and low pressure shut-off.

The facilities have been designed and constructed with additional safety systems to provide for safe operations. These systems include Emergency Shutdown ("ESD") valves to isolate portions of the plant and pipeline, pressure relief valves along the pipeline to prevent over pressurization, and flares to allow piping and equipment to be de-pressured rapidly under safe and controlled operating conditions in the event of a leak. Figures 28 and 29 display the facility safety plot plan, taken from the 30-30 H_2S Contingency Plan, and show the location of the H_2S monitors in the vicinity of the plant and the Rattlesnake AGI #1 well. Should Stakeholder construct additional CO_2 facilities, as indicated in Figure 21, a separate meter will be installed for the additional stream in order to comply with the 40 CFR §98.448(a)(5) measurement. As this meter will be in close proximity to the existing facilities, it will utilize the existing monitoring programs discussed previously. Additionally, CO_2 monitors will be installed near the new meter and tied into the facility monitoring systems.

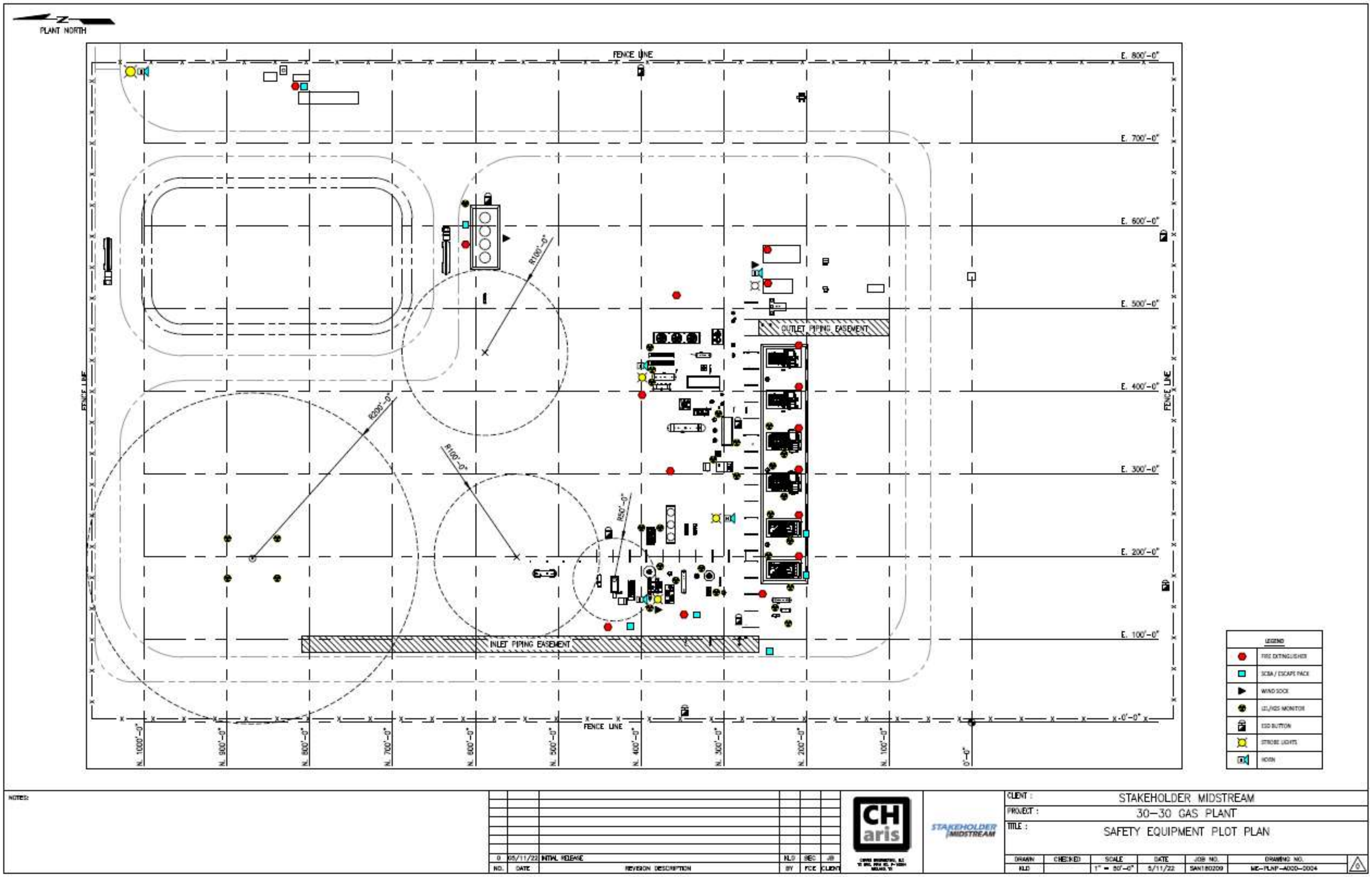


Figure 28 – Site Plan, 30-30 Facility

With the level of monitoring at the 30-30 Facility and the Rattlesnake AGI #1 well, any release of H_2S and CO_2 would be quickly identified, and the safety systems would quickly minimize the volume of the release. The CO_2 injected into the Rattlesnake AGI #1 is injected with H_2S at a concentration of 10% (100,000 ppm). At this high level of H_2S concentration, even a small leakage would trigger personal and facility H_2S monitors set to alarm at 5 ppm and 10 ppm respectively. If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7 in accordance with 40 CFR §98.448(a)(5).

A larger scale version of Figure 27 is provided in Appendix D.

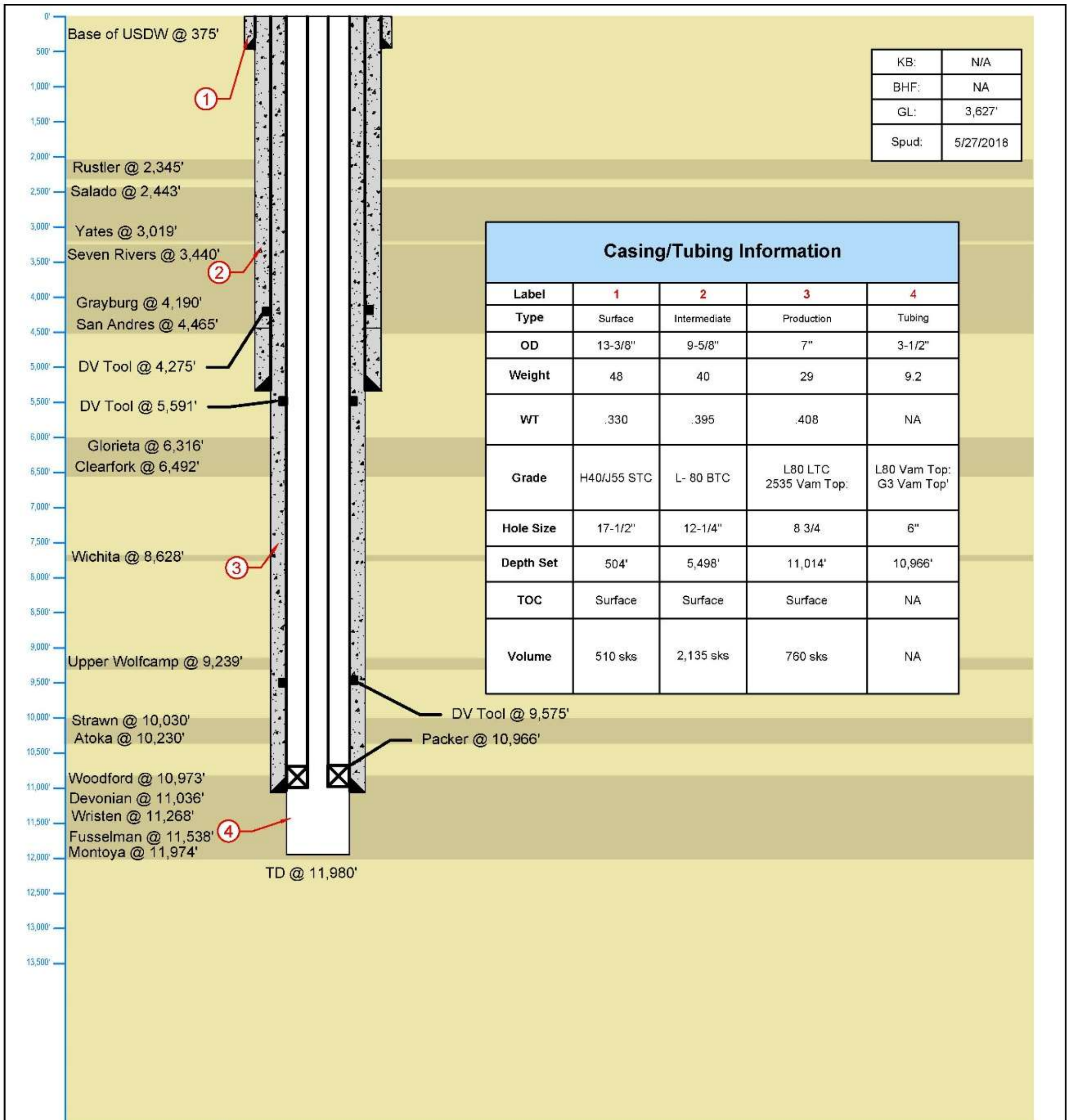
Leakage from Wells in the Monitoring Area

Oil and Gas Operations within Monitoring Area

A significant number of wells have historically been drilled within the area of the Rattlesnake AGI #1 well, however production has primarily been from the shallower San Andres formation in the Wasson Field. The San Andres is separated from the Silurian-Devonian interval by 4,720' in this area. In addition to the primary San Andres production, a few wells have produced from the Wolfcamp The Wolfcamp is separated from the Siluro-Devonian interval by is 1,800'. **Within the projected plume area of the Rattlesnake AGI #1 well, there are no penetrations of the injection interval.** There are ten wells within the MMA that penetrate the injection interval.

All of the wells which penetrate the injection interval within the MMA were properly cased and cemented to prevent annular leakage of CO_2 to the surface. The plugged wells are also adequately protected against migration from the Devonian by the placement of the plugs within the wellbores. Additionally, the Rattlesnake AGI #1 well was designed to prevent migration from the injection interval to the surface through the casing and cement placed in the well, as shown in Figure 29. Mechanical integrity tests ("MIT") required under TRRC rules are run annually to verify the well and wellhead can hold the appropriate amount of pressure. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated quickly to prevent leakage to the atmosphere.

A map of all wells within the MMA is shown in Figure 30. Figure 31 shows only those wells which penetrate the injection interval within the MMA. The MMA review maps, a summary of all the wells in the MMA and detailed wellbore schematics for those wells which penetrate the injection interval are provided in Appendix D.



Casing/Tubing Information

Label	1	2	3	4
Type	Surface	Intermediate	Production	Tubing
OD	13-3/8"	9-5/8"	7"	3-1/2"
Weight	48	40	29	9.2
WT	.330	.395	.408	NA
Grade	H40/J55 STC	L- 80 BTC	L80 LTC 2535 Vam Top:	L80 Vam Top: G3 Vam Top'
Hole Size	17-1/2"	12-1/4"	8 3/4	6"
Depth Set	504'	5,498'	11,014'	10,966'
TOC	Surface	Surface	Surface	NA
Volume	510 sks	2,135 sks	760 sks	NA

LONQUIST & CO. LLC PETROLEUM ENGINEERS / ENERGY ADVISORS HOUSTON | CALGARY AUSTIN | WICHITA | DENVER	Stakeholder Midstream	Rattlesnake No. 1	
	Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
	Location: 33.07884, -103.904514	**Site:**	**Survey:**
	API No: 42-501-36998	**Field:**	**Well Type/Status:** AGI
Texas License F-9147	**RRC District No:**	**Project No:** LS 128	**Date:** 5/27/2022
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** ASG	**Reviewed:** SLP	**Approved:** SLP
	Rev No: 1	**Notes:**	

Figure 29 – Rattlesnake AGI #1 Wellbore Schematic

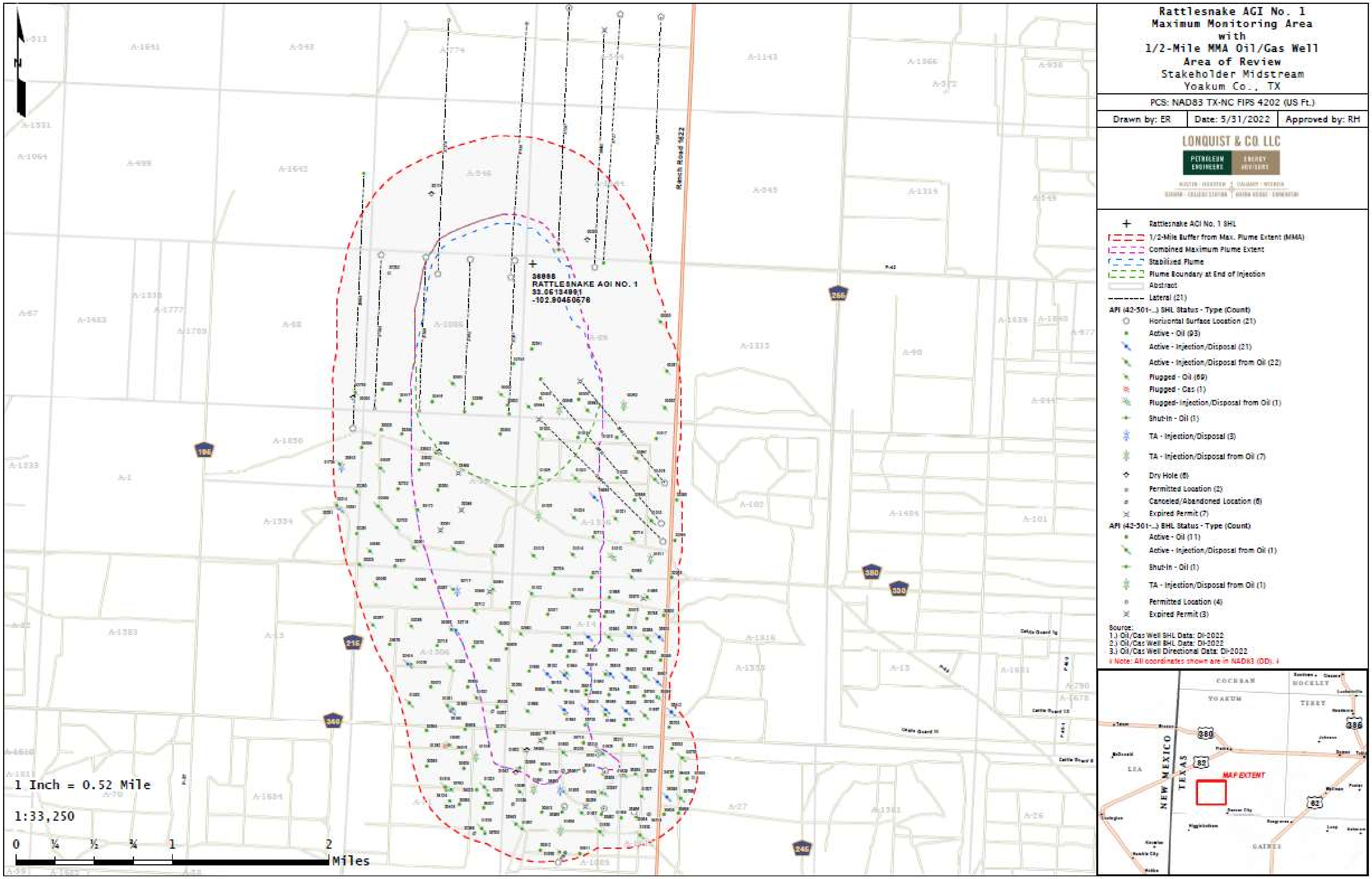


Figure 30 – Oil and Gas Wells within the MMA

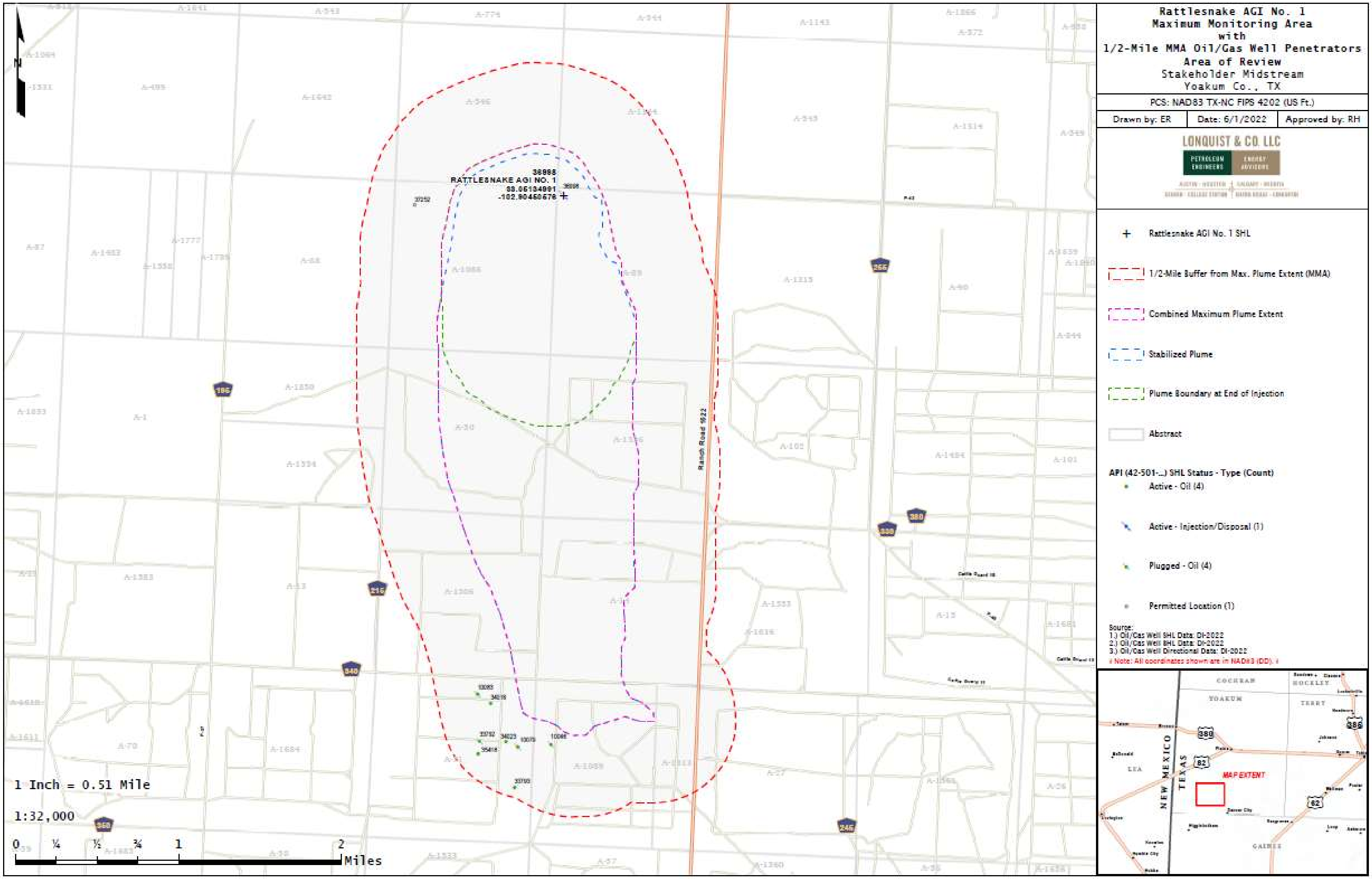


Figure 31 – Penetrating Oil and Gas Wells within the MMA

Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, such as the Devonian, have proven to-date to be less productive or non-productive in this area, which is why the location was selected for injection. Furthermore, any drilling permits issued by the TRRC in the area of the Rattlesnake AGI #1 well include a list of formations for which oil and gas operators are required to comply with TRRC Rule 13 (entitled "Casing, Cementing, Drilling, Well Control, and Completion Requirements"). 16 TAC § 3.13. By way of example, see the Rattlesnake AGI #1 well drilling permit provided in Appendix B. The Devonian is among the formations listed for which operators in Yoakum County (where the Rattlesnake #1 is located) are required to comply with TRCC Rule 13 (Appendix B, pg. 5). TRRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under TRRC Rule 9 or immediately above all formations permitted for injection under Rule 46 for any well proposed within a one-quarter mile radius of an injection well. In this instance, any new well permitted and drilled to the Rattlesnake AGI #1 well's injection zone located within a one-quarter mile radius of the Rattlesnake AGI #1 well will be required under TRRC Rule 13 to set steel casing and cement above the Rattlesnake AGI #1 well injection zone. Additionally, Rule 13 requires operators to case and cement across and above *all* potential flow zones and/or zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued, which is also shown in the above-mentioned permit in Appendix B.

If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release.

Groundwater wells

There are seven groundwater wells located within the MMA, as identified by the Texas Water Development Board. All of the identified groundwater wells in the area have total depths less than or equal to 265', as shown in Figure 32 and Table 9. One of the wells is located on the 30-30 facility property with a total depth of 119'and is operated by Stakeholder.

The surface and intermediate casings of the Rattlesnake AGI #1 well, as shown in Figure 29, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the GAU letter issued for this location. See GAU letter attached included within Appendix B. The wellbore casings and cements also serve to prevent CO_2 leakage to the surface along the borehole.

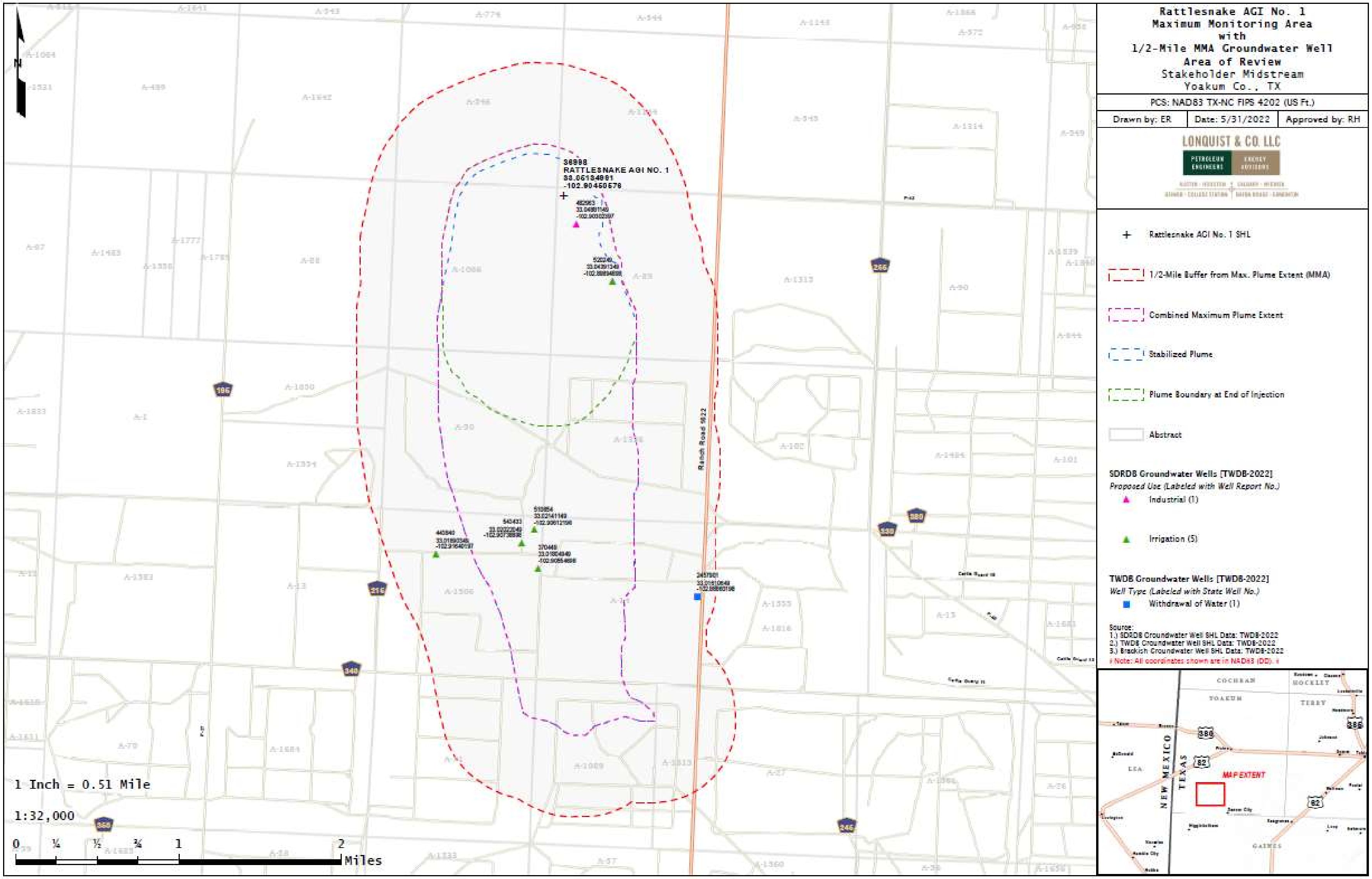


Figure 32 – Groundwater Wells within MMA

Table 9 – Groundwater Well Summary

State Well ID	Owner Name	Primary Use	Well Depth	Data Source
370449	Frances Barbini	Irrigation	237	SDRDB
443840	Frances Jean Barbini	Irrigation	250	SDRDB
482963	Santa Fe Midstream Permian	Industrial	119	SDRDB
510854	FRANCIS BARNINI	Irrigation	255	SDRDB
520249	Thomas Durham	Irrigation	264	SDRDB
543433	FRANCIS BARBIDI	Irrigation	240	SDRDB
84760	TEXACO PRODUCING INC			TWDB_BW

Leakage Through Faults or Fractures

Faults were interpreted from roughly 9 square miles of 3D seismic indicated by the purple outline in Figure 12. Faulting in this region terminates vertically below the Pennsylvanian-age rock. Secondary confining shales within the Wolfcampian and younger strata provide additional, redundant confining layers that would prevent CO_2 from migrating into freshwater aquifers. None of the mapped faults project above the Wolfcamp formation; rather, they appear to terminate between the Strawn and base of the Wolfcamp formation. If in the unlikely event the faults' sealing properties are compromised post-injection, secondary confinement is provided by the tight limestones found within the overlying Mississippianan Lime formation and the shale layers found in the Atoka and Wolfcamp formations. As seen in Figure 14, the largest fault found SE of the Rattlesnake AGI #1 well, terminates within the Atoka formation. Though it crosses the Silurian section, this fault thrusts the Mississippian Lime upward against the Atoka shales. The tight reservoir characteristics of the Mississippian Lime and shaley section of the Atoka create a confining environment vertically and laterally to contain potential upward migration of buoyant fluids. Shales within the Wolfcamp formation provide additional confining beds between overlying USDWs and the fault plane.

Should an unmapped fault exist within the plume boundary, the offset would be below 3D seismic resolution. The offset would be less than the thickness of the Woodford shale, juxtaposing the Woodford against itself, preventing vertical migration.

Fractures and subsequent subaerial exposure are responsible for porosity development within the injection intervals. Open hole logs show little to no porosity development indicating the Woodford or Mississippian Lime were not exposed at this location. Upward migration of injected gas through confining bed fractures is unlikely.

Leakage Through Confining Layers

The Silurian-Devonian injection zones have competent sealing rocks above and below the porous sub-aerially exposed carbonate. The properties of the overlying transgressive Woodford shale (widespread deposition, high illite clay and organic matter composition, and low porosity and permeability) make an excellent sealing rock to the underlying Silurian formation. Tight Mississippian Lime of roughly 660', lay between Atoka and Woodford shale formations, forming an impermeable upper seal to the injection interval. Above this confining unit, correlative shales of the Wolfcamp, Abo and Tubb formations will prevent any upper fluid migration. These impermeable shales are capped by hundreds of feet of the regionally present Salado formation evaporites. The USDW lies above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. The underlying low porosity and permeability Montoya carbonate minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injected gas to the in-situ reservoir fluid makes migration below the lower confining layer unlikely.

Leakage from Natural or Induced Seismicity

The location of Rattlesnake AGI #1 is in an area of the Permian Basin that is inactive from a seismicity perspective, whether induced or natural. A review of historical seismic events on the USGS's Advanced National Seismic System site (from 1971 to present) and the Bureau of Economic Geology's TexNet catalog (from 2017 to present), as shown in Figure 33, indicates the nearest seismic event occurred more than 60 miles away.

A regional analysis of the probabilistic fault slip potential across the Permian Basin (Snee & Zoback 2016), as seen in Figure 34, further demonstrates that the Rattlesnake AGI #1 well is located in a seismically inactive area and confirms that this area has little to no potential for an induced seismicity event.

Therefore, there is no indication that seismic activity poses a risk for loss of CO_2 to the surface within the MMA.

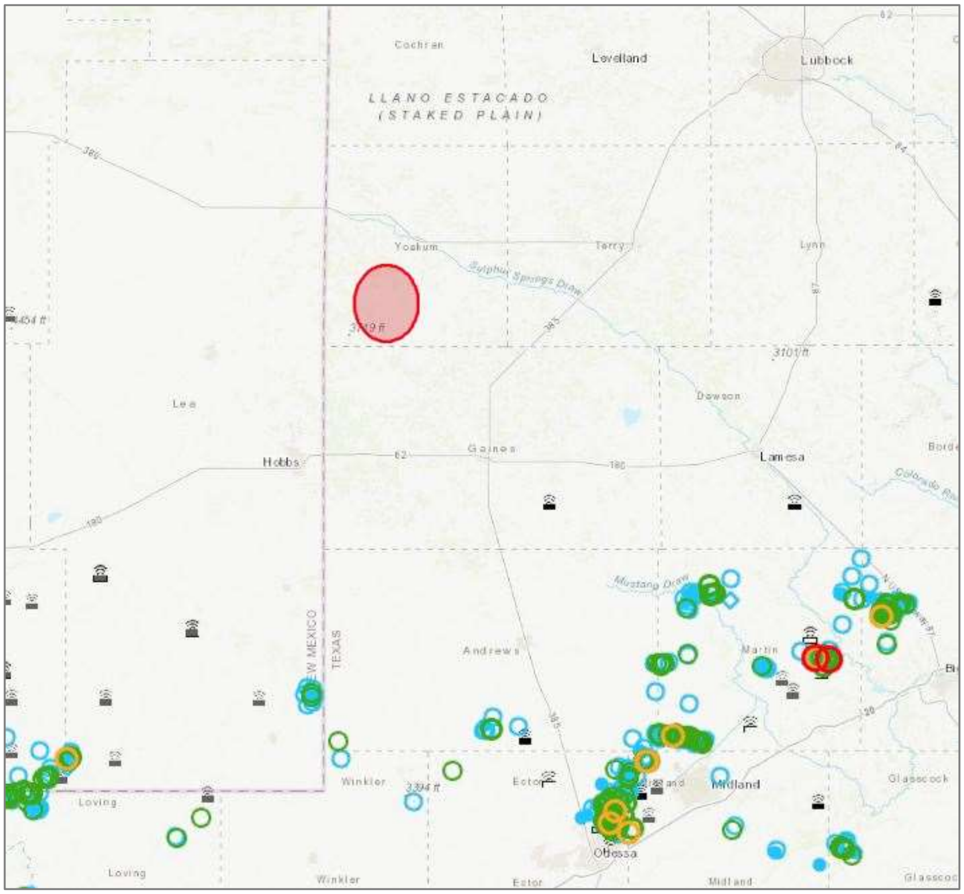


Figure 33 – Seismicity Review (TexNet – 06/01/2022)

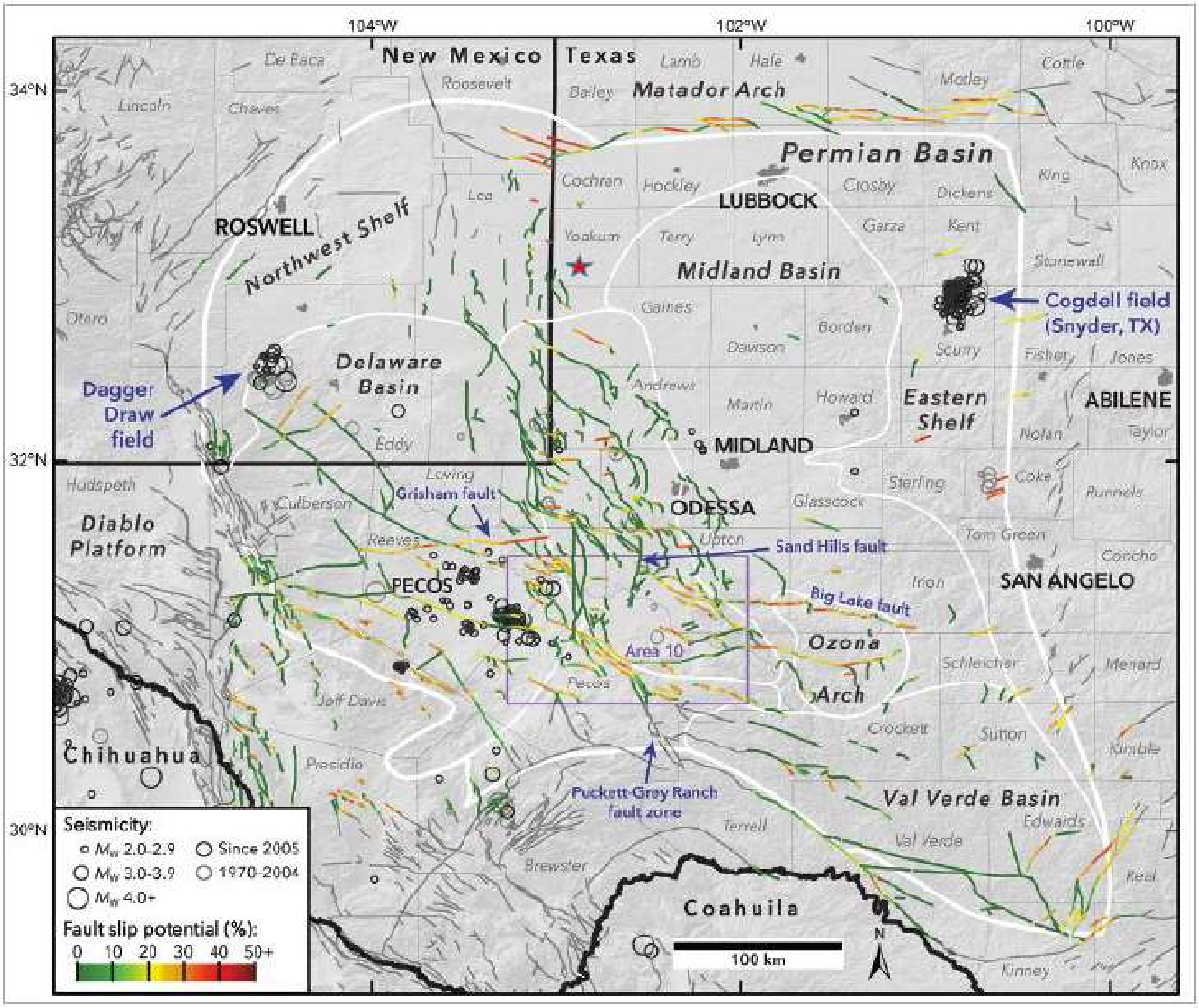


Figure 34 – Probabilistic Fault Slip Potential Analysis with Rattlesnake AGI #1 location (Snee & Zobak 2016)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Stakeholder will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in Section 4 to meet the requirements of 40 CFR §98.448(a)(3). As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 8 summarizes the monitoring of potential leakage pathways to the surface. Monitoring will occur during the planned 25-year injection period, or cessation of injection operations, plus a proposed 5-year post-injection period.

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

Because the acid gas injection stream also contains H_2S, any leakage would be detected by the H_2S alarms located around the facility and would be quickly addressed which would minimize the release of CO_2 into the atmosphere.

Table 10 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed H_2S monitors throughout the AGI facility
	Daily visual inspections
	Personal H_2S monitors
	Distributed Control System Monitoring (Volumes and Pressures)
Leakage through existing wells	Fixed H_2S monitor at the AGI well
	SCADA Continuous Monitoring at the AGI Well
	Annual Mechanical Integrity Tests ("MIT") of the AGI Well
	Visual Inspections
	Quarterly CO_2 Measurements within AMA
Leakage through groundwater wells	Annual Groundwater Samples on Property
Leakage from future wells	H_2S Monitoring during offset drilling operations
Leakage through faults and fractures	SCADA Continuous Monitoring at the AGI Well (volumes and pressures)
	Fixed In-field H_2S monitors
Leakage through confining layer	SCADA Continuous Monitoring at the AGI Well (volumes and pressures)
	Fixed In-field H_2S monitors
Leakage from natural or induced seismicity	Seismic monitoring station to be installed

Leakage from Surface Equipment

As the 30-30 Facility and the Rattlesnake AGI #1 well are designed to handle H_2S, leakage from surface equipment is unlikely to occur and would be quickly detected and addressed. The facility design minimizes leak points through the equipment used and the type of connections are designed to minimize corrosion points. The H_2S in the injectate serves as a proxy for the release of CO_2. The facility and well site contain a number of H_2S alarms, set with a high alarm setpoint of 10 ppm of H_2S, which are shown in Figure 28above. Additionally, all Stakeholder field personnel are required to wear H_2S monitors, which trigger the alarm at 5 ppm H_2S.

The AGI facility is continuously monitored through automated systems. In addition, field personnel conduct daily visual field inspections of gauges, monitors and leak indicators such as vapor plumes. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system, analysis of liquids collected from the line, and inspection of the cathodic protection system. These inspections, in addition to the automated systems, allow Stakeholder to quickly respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5).

Leakage from Existing and Future Wells within Monitoring Area

Stakeholder continuously monitors and collects injection volumes, pressures, temperatures and gas composition data, through their SCADA systems, for the Rattlesnake AGI #1 well. This data is reviewed by qualified personnel and will follow response and reporting procedures when data is outside acceptable performance limits. Rattlesnake AGI #1 has a pressure and temperature gauge placed in the injection stream at its wellhead, and a pressure gauge on the casing annulus. A change of pressure on the annulus would indicate the presence of a possible leak. Mechanical integrity tests ("MITs") performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated and the leak mitigated.

The ten offset penetrating wells within the MMA are adequately cased and cemented to prevent potential leakage of CO_2 from the Rattlesnake AGI #1 well plume. Additionally, the plugged wells were done so in a way to prevent migration of CO_2 as provided in Appendix E. As discussed previously, Rule 13 would ensure that new wells in the field would be constructed in a manner to prevent migration from the injection interval.

In addition to the fixed and personal monitors described previously, Stakeholder will also establish and operate an in-field monitoring program to detect any CO_2 leakage within the AMA. The scope of work will include H_2S and CO_2 monitoring at the AGI well site as well as minimum, quarterly atmospheric monitoring near identified penetrations within the AMA. Upon approval of the MRV and through the post-injection monitoring period, Stakeholder will have these monitoring systems in place. Additional monitoring will be added as the AMA is updated over time.

Groundwater Quality Monitoring

Stakeholder will monitor the groundwater quality in fluids above the confining interval by sampling the well on the facility property and analyzing the sample with a third-party laboratory on an annual basis. Any significant changes to the water analysis would be investigated to determine if such change was a result of leakage from the Rattlesnake AGI #1 well.

Leakage through Faults, Fractures or Confining Seals

Stakeholder continuously monitors the operations of the Rattlesnake AGI #1 well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway such as a fault or breakthrough of the confining seal would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. Field H_2S monitoring systems would alert field personnel for any release of H_2S/CO_2 caused by such leakage.

Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Stakeholder plans to install a seismic monitoring station in the general area of the Rattlesnake AGI #1 well. This monitoring station will be tied in to the Bureau of Economic Geology's TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, Stakeholder will review the injection volumes and pressures at the Rattlesnake AGI #1 well to determine if any significant changes occur that would indicate potential leakage.

SECTION 6 – BASELINE DETERMINATIONS

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

Visual Inspections

Daily inspections will be conducted by field personnel at the 30-30 Facility and the Rattlesnake AGI #1 well. These inspections will aid with identifying and addressing issues timely to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions would be taken to address such issues.

H_2S Detection

H_2S will be initially injected into the AGI well at a concentration of approximately ten (10) percent or 100,000 ppm. The concentration will drop to approximately six (6) percent as additional volumes are added. H_2S gas detectors are located throughout the AGI facility and well site and are set to trigger the alarm at 10 ppm. Additionally, all field personnel are required to wear personal H_2S monitors, which are set to trigger the alarm at 5 ppm. Any alarm would trigger an immediate response to protect personnel and verify that the monitors are working properly. If monitors are working correctly, immediate actions would be taken to secure the facility and mitigate potential leaks.

CO_2 Detection

Any CO_2 release would be accompanied by H_2S and therefore the H_2S monitors at the facility would also serve as a CO_2 release warning system. In addition to the fixed and personal monitors described previously, Stakeholder will also establish and operate an in-field monitoring program to detect any CO_2 leakage within the AMA. The scope of work will include H_2S and CO_2 monitoring at the AGI well site as well as atmospheric monitoring near identified penetrations within the AMA.

Operational Data

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

Continuous Monitoring

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which would be extremely dangerous for personnel to perform a direct leak survey. Any leakage would be detected and managed as per Texas regulations and Stakeholder's TRRC-approved H_2S Contingency Plan. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

No CO_2 emissions will occur from venting because of the high H_2S concentrations. Blowdown emissions are sent to flares and would be reported as part of the required reporting for the gas plant.

Groundwater Monitoring

An initial sample will be taken from the groundwater well on Stakeholder's property, identified as Well # 482963 in Table 9 above, upon approval of Stakeholder's MRV and prior to increasing injection. The sample will be analyzed by a third-party laboratory to establish the baseline properties of the groundwater.

SECTION 7 – SITE SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

Mass of CO_2 Received

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

Mass of CO_2 Injected

Per 40 CFR §98.444(b), since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the mass flow by the CO_2 concentration in the flow according to Equation RR-4:

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

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

Mass of CO_2 Produced

The Rattlesnake AGI #1 well is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

Mass of CO_2 Emitted by Surface Leakage

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which would be extremely dangerous for personnel to perform a direct leak survey. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

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

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

Where:

CO_2 = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year

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

X = Leakage pathway

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

Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based off Equation RR-12, as this well will not actively produce oil or natural gas or any other fluids, as follows:

$$CO_2 = CO_{2\mathrm{I}} - CO_{2\mathrm{E}} - CO_{2\mathrm{F}}$$

Where:

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

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

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting would occur due to the high H_2S concentrations of the injectate stream, the calculations would be based on the blowdown emissions that would be sent to flares and would be reported as part of the required GHG reporting for the gas plant.

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The Rattlesnake AGI #1 well currently reports GHGs under Subpart UU, but Stakeholder has elected to submit an MRV plan under, and otherwise comply with, Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31st of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

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

Monitoring QA/QC

CO_2 *Injected*

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer recommendations.

CO_2 *Emissions from Leaks and Vented Emissions*

- Gas detectors will be operated continuously, except for maintenance and calibration.
- Gas detectors will be calibrated according to manufacturer recommendations and API standards.
- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to the requirements in 40 CFR §98.3(i).
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.
- Flow meter calibrations will be traceable to the National Institute of Standards and Technology (NIST).

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

Missing Data

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

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in subpart W of 40 CFR §98.

MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Stakeholder will retain records as required by 40 CFR §98.3(g). These records will be retained for at least three years and include:

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

References

Broadhead, Ronald E., 2005. Regional Aspects of the Wristen petroleum system, southeastern New Mexico: New Mexico Bureau of Geology and Mineral Resources Open File Report, no. 485.

Comer, John B., 1991. Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas and Southeastern New Mexico: Bureau of Economic Geology Report of Investigations, no. 201.

George, Peter G., Mace, Robert E., and Petrossian, Rima, 2011. Aquifers of Texas: Texas Water Development Board Report, no 380.

Hoak, T., Sundberg, K., and Ortoleva, P. Overview of the Structural Geology and Tectonics of the Central Basin Platform, Delaware Basin, and Midland Basin, West Texas and New Mexico: Department of Energy Open File Report.

Molina, Oscar, Vilarras, Victor, and Zeidouni, Mehdi, 2016. Geologic carbon storage for shale gas recovery: 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18.

Ruppel, Stephen C. and Holtz, Mark H., 1994. Depositional and Diagenetic Facies Patterns and Reservoir Development in Silurian and Devonian Rocks of the Permian Basin: Bureau of Economic Geology Report of Investigations, no. 216.

Snee, Jens-Erik Lund and Zoback, Mark D., 2016. State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity.

Teeple, Andrew P., Ging, Patricia B., Thomas, Jonathan V., Wallace, David S., and Payne, Jason D., 2021. Hydrogeologic Framework, Geochemistry, Groundwater-Flow System, and Aquifer Hydraulic Properties Used in the Development of a Conceptual Model of the Ogallala, Edwards-Trinity (High Plains), and Dockum Aquifers In and Near Gaines, Terry, and Yoakum Counties, Texas: USGS Scientific Investigations Report 2021-5009.

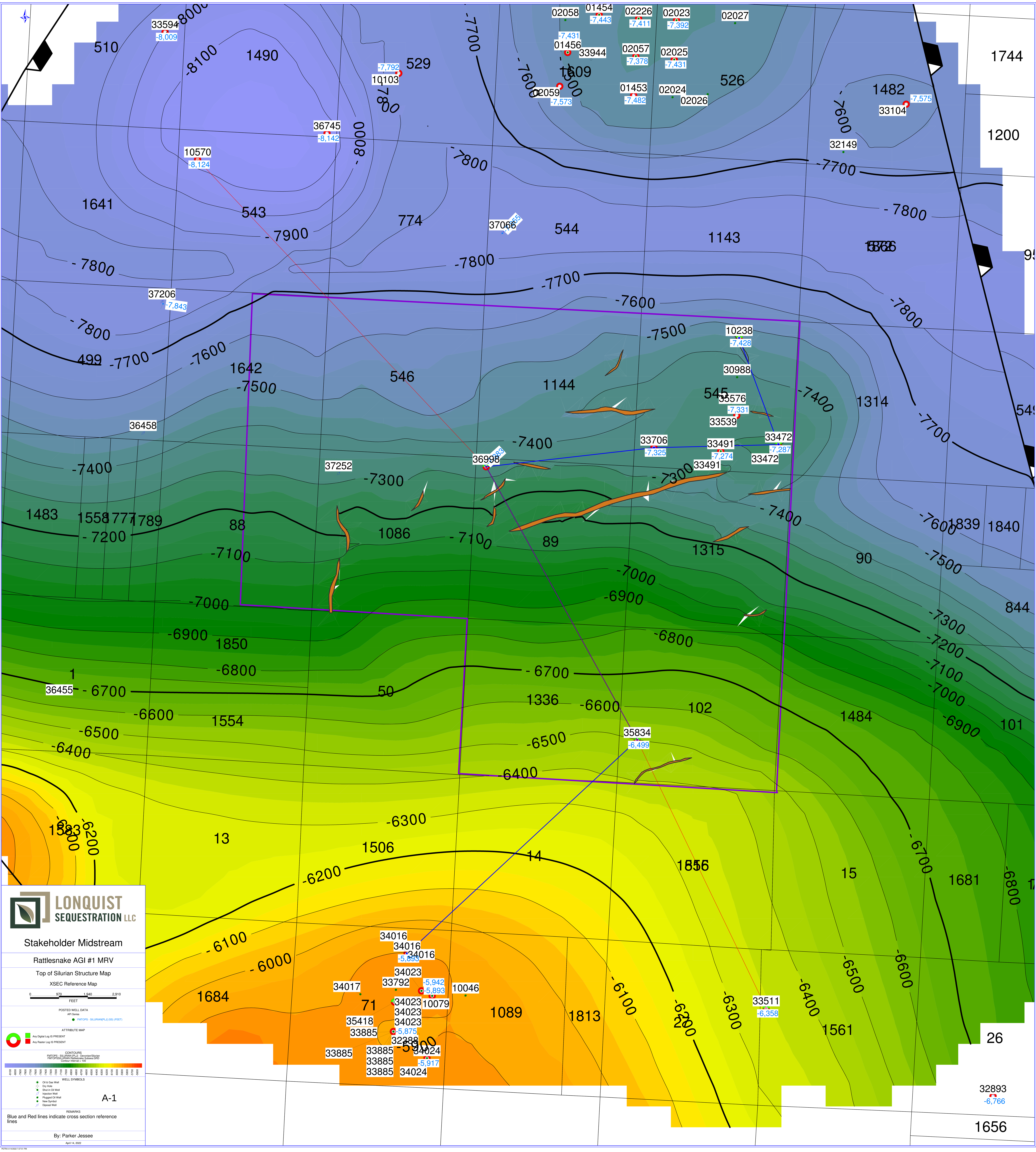
APPENDICES

APPENDIX A – GEOLOGY

APPENDIX A-1: SILURIAN STRUCTURE MAP

APPENDIX A-2: NE-SW CROSS SECTION

APPENDIX A-3: NW-SE CROSS SECTION


LONQUIST SEQUESTRATION LLC
Stakeholder Midstream
Rattlesnake AGI #1 MRV
Top of Silurian Structure Map
XSEC Reference Map
0 970 1,940 2,910
FEET
POSTED WELL DATA
API Series
FMTOPS - SILURIAN[PLJ] (SS) (FEET)
ATTRIBUTE MAP
Any Digital Log IS PRESENT
Any Raster Log IS PRESENT
CONTOURS
FMTOPS - SILURIAN [PLJ] - Devonian/Silurian
FMTOPSSILURIAN Rattlesnake Subsea.GRD
Contour Interval = 100
-8100 -8000 -7900 -7800 -7700 -7600 -7500 -7400 -7300 -7200 -7100 -7000 -6900 -6800 -6700 -6600 -6500 -6400 -6300 -6200 -6100 -6000 -5900 -5800 -5700 -5600
WELL SYMBOLS
Oil & Gas Well
Dry Hole
Shut-in Oil Well
Injection Well
Plugged Oil Well
New Symbol
Diposal Well
A-1
REMARKS
Blue and Red lines indicate cross section reference lines
By: Parker Jessee
April 14, 2022
PETRA 4/14/2022 7:27:51 PM

A-2

LONQUIST SEQUESTRATION LLC

Stakeholder Midstream

Rattlesnake AGI #1 MRV

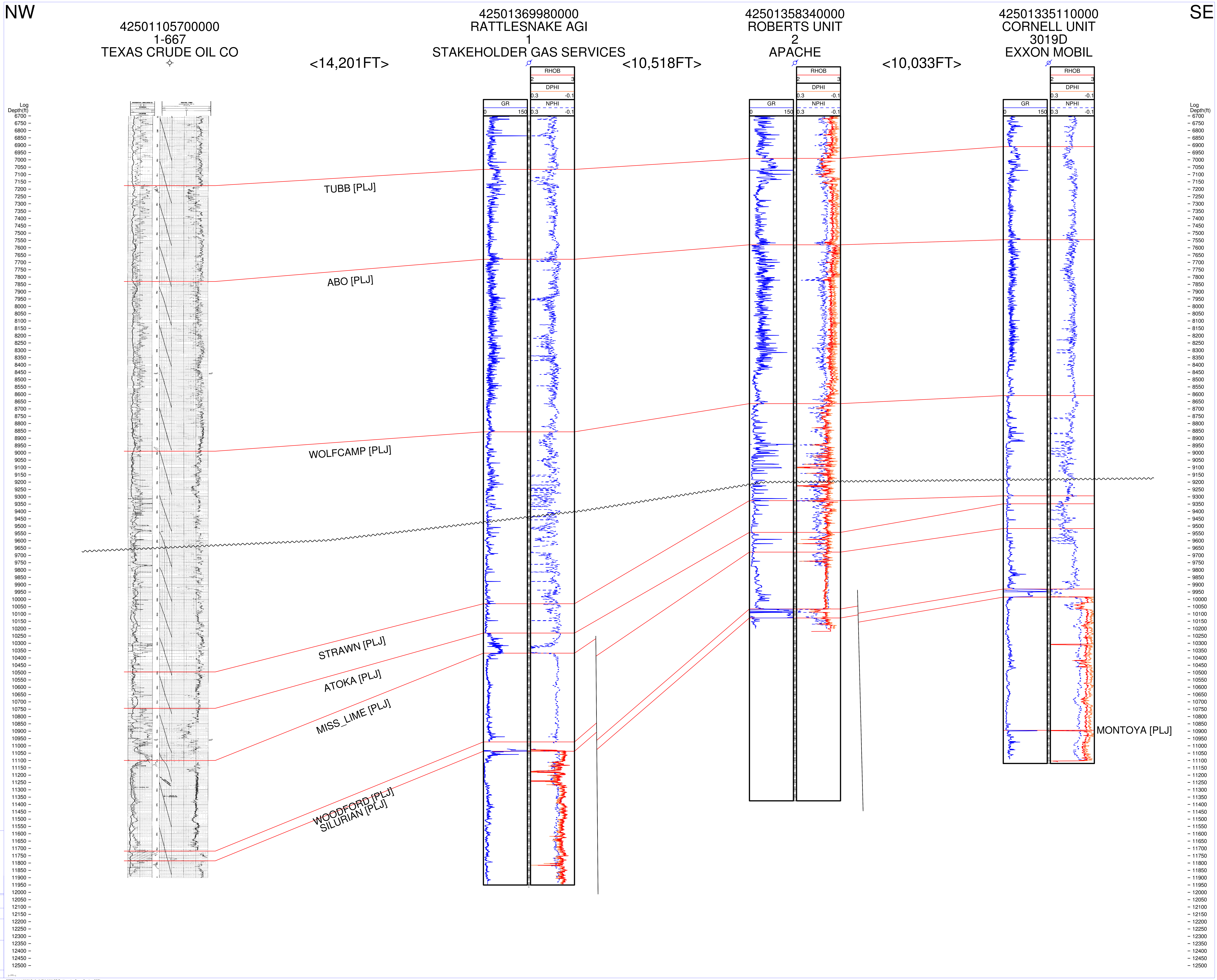
NE-SW Structural Cross Section

Horizontal Scale = 193.4
Vertical Scale = 50.0
Vertical Exaggeration = 3.9x

UWI
Well Name
Well Number
Operator

April 14,2022 7:03 PM

PETRA 4/14/2022 7:03:06 PM



A-3

LONQUIST SEQUESTRATION LLC

Stakeholder Midstream

Rattlesnake agi #1 MRV

NW-SE Structural Cross Section

Horizontal Scale = 289.6
Vertical Scale = 50.0
Vertical Exaggeration = 5.8x

UWI
Well Name
Well Number
Operator

April 14,2022 7:13 PM

APPENDIX B – TRRC FORMS Rattlesnake AGI #1

APPENDIX B-1: UIC CLASS II ORDER

APPENDIX B-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 15848

SANTA FE MIDSTREAM PERMIAN LLC
5830 GRANITE PKWY STE 1025
PLANO, TX 75024

DOCKET NO. 8A-0312019

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated March 12, 2018 for the permitted interval of the DEVONIAN formation and subject to the following terms and special conditions:

RATTLESNAKE AGI (000000) LEASE
WASSON FIELD
YOAKUM COUNTY, DISTRICT 8A

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
1	50136998	000117143	CO_2, and H_2S	11,000	12,000	4,500	N/A	N/A	2,200

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	50136998	**1. Open hole completions shall have a plug back depth no deeper than the bottom of the permitted injection interval.** **2. The operator shall provide to the UIC section an annotated electric log, and a mud log if available, of the subject well with the top(s) and bottom(s) of the permitted formation indicated on the log. Top and bottom of the authorized injection interval may be modified based on electric log or mud log indications of the top and bottom of the permitted formations.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;
   c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON November 14, 2018.

Sean Avitt

Sean Avitt, Manager
Injection-Storage Permits Unit

IN-HOUSE AMENDMENT TO CORRECT THE RATE.

Note: This document will only be distributed electronically.

GROUNDWATER PROTECTION DETERMINATION

Form GW-2

Groundwater Advisory Unit

B-2

Date Issued:	31 August 2017	**GAU Number:**	179154

Attention:	SANTA FE MIDSTREAM	**API Number:**	
	5700 GRANITE PARKWAY	**County:**	YOAKUM
	PLANO, TX 75024	**Lease Name:**	Roberts Unit
Operator No.:	748093	**Lease Number:**	019212
		Well Number:	1
		Total Vertical Depth:	11000
		Latitude:	33.049990
		Longitude:	-102.903464
		Datum:	NAD27

Purpose: New Drill

Location: Survey-Gibson, J H/Poole, J T; Block-D; Section-733

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

The interval from the land surface to a depth of 375 feet must be protected.

Note: Unless stated otherwise, this recommendation is intended to apply only to the subject well and not for area-wide use. This recommendation is for normal drilling, production, and plugging operations only. It does not apply to saltwater disposal operation into a nonproductive zone (RRC Form W-14).

This determination is based on information provided when the application was submitted on 08/30/2017. 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

API No. 42-501-36998

Drilling Permit # 839303

SWR Exception Case/Docket No.

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

APPLICATION FOR PERMIT TO DRILL, RECOMPLETE, OR RE-ENTER

This facsimile W-1 was generated electronically from data submitted to the RRC.
A certification of the automated data is available in the RRC's Austin office.

FORM W-1 07/2004

Permit Status: Approved

B-3

1. RRC Operator No.: 748093
2. Operator's Name (as shown on form P-5, Organization Report): SANTA FE MIDSTREAM PERMIAN LLC
3. Operator Address (include street, city, state, zip): 5830 GRANITE PKWY STE 1025 PLANO, TX 75024-0000
4. Lease Name: RATTLESNAKE AGI
5. Well No.: 1

GENERAL INFORMATION

6. Purpose of filing (mark ALL appropriate boxes): [X] New Drill [ ] Recompletion [ ] Reclass [ ] Field Transfer [ ] Re-Enter [ ] Amended [ ] Amended as Drilled (BHL) (Also File Form W-1D)

7. Wellbore Profile (mark ALL appropriate boxes): [X] Vertical [ ] Horizontal (Also File Form W-1H) [ ] Directional (Also File Form W-1D) [ ] Sidetrack

8. Total Depth: 12000

9. Do you have the right to develop the minerals under any right-of-way ? [X] Yes [ ] No

10. Is this well subject to Statewide Rule 36 (hydrogen sulfide area)? [X] Yes [ ] No

SURFACE LOCATION AND ACREAGE INFORMATION

11. RRC District No.: 8A
12. County: YOAKUM
13. Surface Location: [X] Land [ ] Bay/Estuary [ ] Inland Waterway [ ] Offshore

14. This well is to be located 7.3 miles in a NW direction from DENVER CITY which is the nearest town in the county of the well site.

15. Section: 733
16. Block: D
17. Survey: GIBSON, J H
18. Abstract No.: A-89
19. Distance to nearest lease line: 200 ft.
20. Number of contiguous acres in lease, pooled unit, or unitized tract: 640

21. Lease Perpendiculars: 200 ft from the NORTH line and 200 ft from the WEST line.
22. Survey Perpendiculars: 200 ft from the NORTH line and 200 ft from the WEST line.

23. Is this a pooled unit? [ ] Yes [X] No
24. Unitization Docket No:
25. Are you applying for Substandard Acreage Field? [ ] Yes (attach Form W-1A) [X] No

FIELD INFORMATION List all fields of anticipated completion including Wildcat. List one zone per line.

26. RRC District No.	27. Field No.	28. Field Name (exactly as shown in RRC records)	29. Well Type	30. Completion Depth	31. Distance to Nearest Well in this Reservoir	32. Number of Wells on this lease in this Reservoir
8A	95397001	WASSON	Injection Well	12000	0.00	1
8A	95399400	WASSON, NORTH (SAN ANDRES)	Injection Well	12000	0.00	1

BOTTOMHOLE LOCATION INFORMATION is required for DIRECTIONAL, HORIZONTAL, AND AMENDED AS DRILLED PERMIT APPLICATIONS

Remarks

[FILER Apr 16, 2018 5:16 PM]: Filing for an acid gas injection well.

Certificate:

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

Jessica Risien, Regulatory Compliance Specialist — Name of filer

Apr 25, 2018 — Date submitted

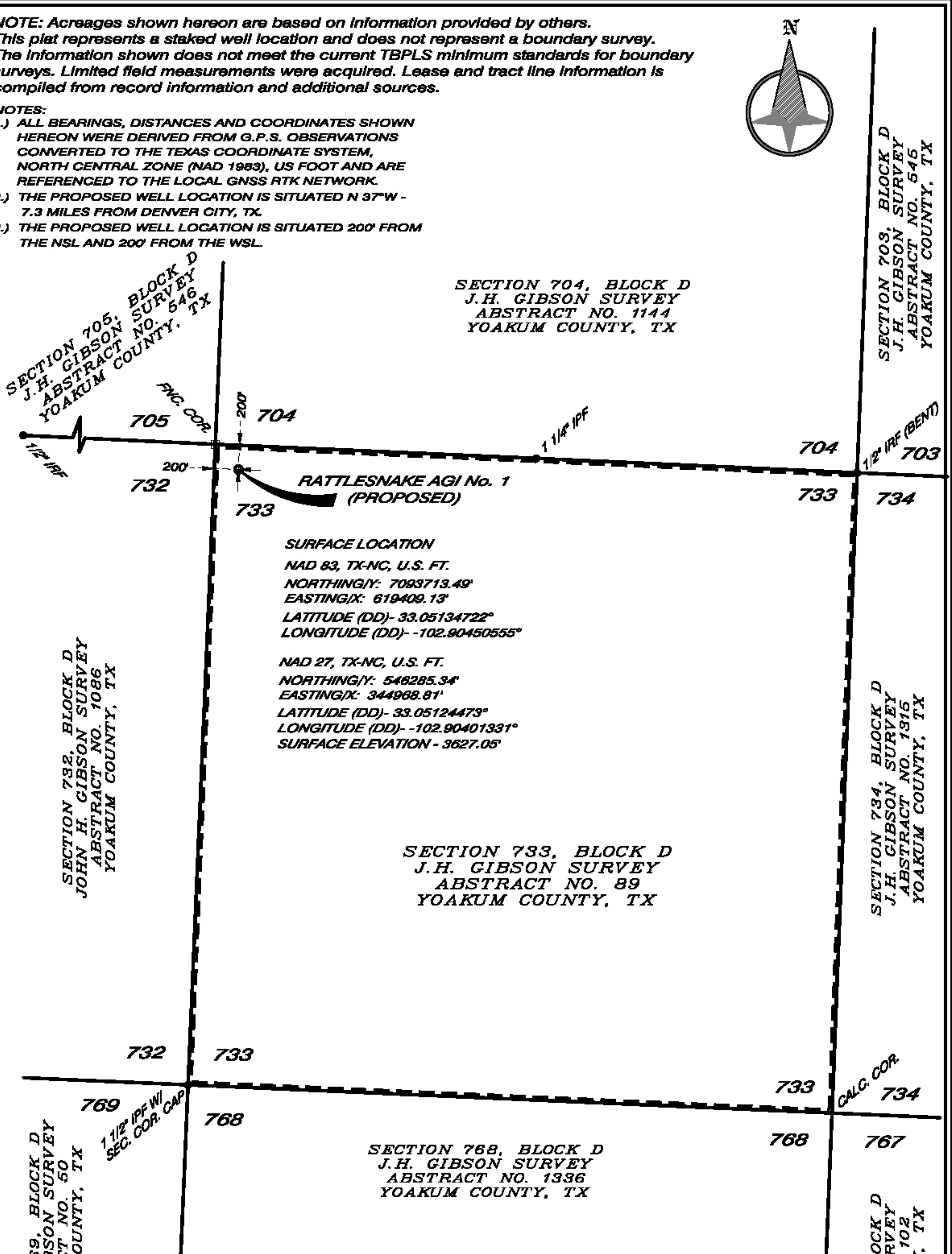
(281)8729300 — Phone

jrisien@ntglobal.com — E-mail Address (OPTIONAL)

RRC Use Only Data Validation Time Stamp: Apr 27, 2018 10:36 AM('As Approved' Version)

NOTE: Acreages shown hereon are based on information provided by others.
This plat represents a staked well location and does not represent a boundary survey.
The information shown does not meet the current TBPLS minimum standards for boundary surveys. Limited field measurements were acquired. Lease and tract line information is compiled from record information and additional sources.

NOTES:
1.) ALL BEARINGS, DISTANCES AND COORDINATES SHOWN HEREON WERE DERIVED FROM G.P.S. OBSERVATIONS CONVERTED TO THE TEXAS COORDINATE SYSTEM, NORTH CENTRAL ZONE (NAD 1983), US FOOT AND ARE REFERENCED TO THE LOCAL GNSS RTK NETWORK.
2.) THE PROPOSED WELL LOCATION IS SITUATED N 37°W - 7.3 MILES FROM DENVER CITY, TX.
3.) THE PROPOSED WELL LOCATION IS SITUATED 200' FROM THE NSL AND 200' FROM THE WSL.



WELL LOCATION PLAT

SHOWING

SANTA FE MIDSTREAM PERMIAN LLC

RATTLESNAKE AGI No. 1

J.H. GIBSON SURVEY, A-89

SECTION 733, BLOCK D

YOAKUM COUNTY, TEXAS

I, THE UNDERSIGNED, REGISTERED PROFESSIONAL LAND SURVEYOR, DO HEREBY CERTIFY THAT THE PLAT SHOWN REPRESENTS AN ACTUAL SURVEY MADE ON THE GROUND AND IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

BY: ________________________

ANDREW STOUT 03/20/2018
REGISTERED PROFESSIONAL LAND SURVEYOR
STATE OF TEXAS NO. 5970

STATE OF TEXAS REGISTERED ANDREW STOUT 5970 PROFESSIONAL LAND SURVEYOR

SCALE: 1" = 1000'

1000 500 0 1000

SCALE FEET

INTEGRITY POSITIONS, LLC

14296 FM 314 N.
BROWNSBORO, TX 75756
(903) 595-9395
Firm No. 10194095

Railroad Commission of Texas

PERMIT TO DRILL, RE-COMPLETE, OR RE-ENTER ON REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

CONDITIONS AND INSTRUCTIONS

Permit Invalidation. It is the operator's responsibility to make sure that the permitted location complies with Commission density and spacing rules in effect on the spud date. The permit becomes invalid automatically if, because of a field rule change or the drilling of another well, the stated location is not in compliance with Commission field rules on the spud date. If this occurs, application for an exception to Statewide Rules 37 and 38 must be made and a special permit granted prior to spudding. Failure to do so may result in an allowable not being assigned and/or enforcement procedures being initiated.

Notice Requirements. Per H.B 630, signed May 8, 2007, the operator is required to provide notice to the surface owner no later than the 15th business day after the Commission issues a permit to drill. Please refer to subchapter Q Sec. 91.751-91.755 of the Texas Natural Resources Code for applicability.

Permit expiration. This permit expires two (2) years from the date of issuance shown on the original permit. The permit period will not be extended.

Drilling Permit Number. The drilling permit number shown on the permit MUST be given as a reference with any notification to the district (see below), correspondence, or application concerning this permit.

Rule 37 Exception Permits. This Statewide Rule 37 exception permit is granted under either provision Rule 37 (h)(2)(A) or 37(h)(2)(B). Be advised that a permit granted under Rule 37(h)(2)(A), notice of application, is subject to the General Rules of Practice and Procedures and if a protest is received under Section 1.3, "Filing of Documents," and/or Section 1.4, "Computation of Time," the permit may be deemed invalid.

Before Drilling

Fresh Water Sand Protection. The operator must set and cement sufficient surface casing to protect all usable-quality water, as defined by the Railroad Commission of Texas (RRC) Groundwater Advisory Unit (GWAU). Before drilling a well, the operator must obtain a letter from the Railroad Commission of Texas stating the depth to which water needs protection, Write: Railroad Commission of Texas, Groundwater Advisory Unit (GWAU), P.O. Box 12967, Austin, TX 78711-3087. File a copy of the letter with the appropriate district office.

Accessing the Well Site. If an OPERATOR, well equipment TRANSPORTER or WELL service provider must access the well site from a roadway on the state highway system (Interstate, U.S. Highway, State Highway, Farm-to-Market Road, Ranch-to-Market Road, etc.), an access permit is required from TxDOT. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

Water Transport to Well Site. If an operator intends to transport water to the well site through a temporary pipeline laid above ground on the state's right-of-way, an additional TxDOT permit is required. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

*NOTIFICATION

The operator is **REQUIRED** to notify the district office when setting surface casing, intermediate casing, and production casing, or when plugging a dry hole. The district office MUST also be notified if the operator intends to re-enter a plugged well or re-complete a well into a different regulatory field. Time requirements are given below. The drilling permit number MUST be given with such notifications.

During Drilling

Permit at Drilling Site : A copy of the Form W-1 Drilling Permit Application, the location plat, a copy of Statewide Rule 13 alternate surface casing setting depth approval from the district office, if applicable, and this drilling permit must be kept at the permitted well site throughout drilling operations.

***Notification of Setting Casing :** The operator MUST call in notification to the appropriate district office (phone number shown the on permit) a minimum of eight (8) hours prior to the setting of surface casing, intermediate casing, AND production casing. The individual giving notification MUST be able to advise the district office of the drilling permit number.

***Notification of Re-completion/Re-entry :** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of eight (8) hours prior to the initiation of drilling or re-completion operations. The individual giving notification MUST be able to advise the district office of the drilling permit number.

Completion and Plugging Reports

Hydraulic Fracture Stimulation using Diesel Fuel: Most operators in Texas do not use diesel fuel in hydraulic fracturing fluids. Section 322 of the Energy Policy Act of 2005 amended the Underground Injection Control (UIC) portion of the federal Safe Drinking Water Act (42 USC 300h(d)) to define "underground Injection" to *EXCLUDE* " ...the underground injection of fluids or propping agents *(other than diesel fluels)* pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities." (italic and underlining added.) Therefore, hydraulic fracturing may be subject to regulation under the federal UIC regulations if diesel fuel is injected or used as a propping agent. EPA defined "diesel fuel" using the following five (5) Chemical Abstract Service numbers: 68334-30-5 Primary Name: Fuels, diesel; 68476-34-6 Primary Name: Fuels, diesel, No. 2; 68476-30-2 Primary Name: Fuel oil No. 2; 68476-31-3 Primary Nmae: Fuel oil, No. 4; and 8008-20-6 Primary Name: Kerosene. As a result, an injection well permit would be required before performing hydraulic fracture stimulation using diesel fuel as defined by EPA on any well in Texas. Hydraulic fracture stimulation using diesel fuel as defined by EPA on a well in Texas without an injection well permit could result in enforcement action.

Producing Well : Statewide Rule 16 states that the operator of a well shall file with the Commission the appropriate completion report within thirty (30) days after completion of the well or within ninety (90) days after the date on which the drilling operation is completed, whichever is earlier. Completion of the well in a field authorized by this permit voids the permit for all other fields included in the permit unless the operator indicates on the initial completion report that the well is to be a dual or multiple completion and promptly submits an application for multiple completion. All zones are required to be completed before the expiration date on the existing permit. Statewide Rule 40(d) requires that upon successful completion of a well in the same reservoir as any other well previously assigned the same acreage, proration plats and P-15s (if required) must be submitted with no double assignment of acreage.

Dry or Noncommercial Hole : Statewide Rule 14(b)(2) prohibits suspension of operations on each dry or non-commercial well without plugging unless the hole is cased and the casing is cemented in compliance with Commission rules. If properly cased, Statewide Rule 14(b)(2) requires that plugging operations must begin within a period of one (1) year after drilling or operations have ceased. Plugging operations must proceed with due diligence until completed. An extension to the one-year plugging requirement may be granted under the provisions stated in Statewide Rule 14(b)(2).

Intention to Plug : The operator must file a Form W-3A (Notice of Intention to Plug and Abandon) with the district office at least five (5) days prior to beginning plugging operations. If, however, a drilling rig is already at work on location and ready to begin plugging operations, the district director or the director's delegate may waive this requirement upon request, and verbally approve the proposed plugging procedures.

***Notification of Plugging a Dry Hole :** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of four (4) hours prior to beginning plugging operations. The individual giving the notification MUST be able to advise the district office of the drilling permit number and all water protection depths for that location as stated in the Texas Commission on Environmental Quality letter.

DIRECT INQUIRIES TO: DRILLING PERMIT SECTION, OIL AND GAS DIVISION

PHONE
(512) 463-6751

MAIL:
PO Box 12967
Austin, Texas, 78711-2967

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER	DATE PERMIT ISSUED OR AMENDED	DISTRICT
839303	04/27/2018	8A
API NUMBER 42-501-36998	FORM W-1 RECEIVED 04/25/2018	COUNTY YOAKUM
TYPE OF OPERATION New Drill	WELLBORE PROFILE(S) Vertical	ACRES 640.0

OPERATOR 748093 SANTA FE MIDSTREAM PERMIAN LLC 5830 GRANITE PKWY STE 1025 PLANO, TX 75024-0000	NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. District Office Telephone No: (806) 698-6509
LEASE NAME RATTLESNAKE AGI	WELL NUMBER 1
LOCATION 7.3 miles NW direction from DENVER CITY	TOTAL DEPTH 12000

Section, Block and/or
SECTION 733 BLOCK D ABSTRACT 89
SURVEY GIBSON, J H

DISTANCE TO SURVEY LINES 200.0 ft NORTH 200.0 ft WEST	DISTANCE TO NEAREST LEASE LINE 200.0
DISTANCE TO LEASE LINES 200.0 ft NORTH 200.0 ft WEST	DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL# NEAREST WELL	DIST
WASSON RATTLESNAKE AGI	640.0 200.0	12000	1 0.0	8A

This is a hydrogen sulfide field. This well shall be drilled in accordance with SWR 36.

Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

WASSON, NORTH (SAN ANDRES) RATTLESNAKE AGI	640.0 200.0	12000	1 0.0	8A

This is a hydrogen sulfide field. This well shall be drilled in accordance with SWR 36.

Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

This well must comply to the new SWR 3.13 requirements concerning the isolation of any potential flow zones and zones with corrosive formation fluids. See approved permit for those formations that have been identified for the county in which you are drilling the well in.

Railroad Commission of Texas
Oil and Gas Division
SWR #13 Formation Data
YOAKUM (501) COUNTY

Formation	Remarks	Geological Order	Effective Date
RED BED-SANTA ROSA		1	01/01/2014
YATES		2	01/01/2014
SAN ANDRES	high flows, H2S, corrosive	3	01/01/2014
GLORIETA		4	01/01/2014
CLEARFORK	Active CO2 Flood	5	01/01/2014
WICHITA		6	01/01/2014
LEONARD		7	01/01/2014
WOLFCAMP		8	01/01/2014
PENNSYLVANIAN		9	01/01/2014
STRAWN		10	01/01/2014
MISSISSIPPIAN		11	01/01/2014
DEVONIAN		12	01/01/2014
DEVONIAN-SILURIAN		13	01/01/2014

The above list may not be all inclusive, and may also include formations that do not intersect all wellbores. The listing order of the Formation information reflects the general stratigraphic order and relative geologic age. This is a dynamic list subject to updates and revisions. It is the operator's responsibility to make sure that at the time of spudding the well the most current list is being referenced. Refer to the RRC website at the following address for the most recent information. http://www.rrc.texas.gov/oil-gas/compliance-enforcement/rule-13-geologic-formation-info

RAILROAD COMMISSION OF TEXAS

Form G-1

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Approved
Date: 07/25/2019
Tracking No.: 205926

GAS WELL BACK PRESSURE TEST, COMPLETION OR RECOMPLETION REPORT, AND LOG

OPERATOR INFORMATION

Operator Name: SANTA FE MIDSTREAM PERMIAN LLC **Operator No.:** 748093
Operator Address: 5830 GRANITE PKWY STE 1025 PLANO, TX 75024-0000

WELL INFORMATION

API No.: 42-501-36998
County: YOAKUM
Well No.: 1
RRC District No.: 8A
Lease Name: RATTLESNAKE AGI
Field Name: WASSON
RRC Gas ID No.: 286838
Field No.: 95397001
Location: Section: 733, Block: D, Survey: GIBSON, J H, Abstract: 89

Latitude:
Longitude:

This well is located 7.3 **miles in a** NW
direction from DENVER CITY,
which is the nearest town in the county.

FILING INFORMATION

Purpose of filing: Well Record Only
Type of completion: New Well
Well Type: Active UIC
Completion or Recompletion Date: 08/31/2018

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or Deepen	04/27/2018	839303
Rule 37 Exception		
Fluid Injection Permit		
O&G Waste Disposal Permit	11/14/2018	15848
Other:		

COMPLETION INFORMATION

Spud date: 07/16/2018
Date of first production after rig released: 08/31/2018
Date plug back, deepening, recompletion, or drilling operation commenced: 07/16/2018
Date plug back, deepening, recompletion, or drilling operation ended: 08/31/2018
Number of producing wells on this lease in this field (reservoir) including this well: 1
Distance to nearest well in lease & reservoir (ft.): 0.0
Total number of acres in lease: 640.00
Elevation (ft.): 3627 GR
Total depth TVD (ft.): 11980
Total depth MD (ft.):
Plug back depth TVD (ft.): 11980
Plug back depth MD (ft.):
Was directional survey made other than inclination (Form W-12)? Yes
Rotation time within surface casing (hours): 72.0
Is Cementing Affidavit (Form W-15) attached? Yes
Recompletion or reclass? No
Multiple completion? No
Type(s) of electric or other log(s) run: Combo of Induction/Neutron/Density/Sonic
Electric Log Other Description:
Location of well, relative to nearest lease boundaries of lease on which this well is located:
Off Lease: No
200.0 **Feet from the** North **Line and**
200.0 **Feet from the** West **Line of the**
RATTLESNAKE AGI **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

Field & Reservoir	Gas ID or Oil Lease No.	Well No.	Prior Service Type

G1: N/A

PACKET: N/A

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination **Depth (ft.):** 2025.0 **Date:** 01/12/2018

SWR 13 Exception **Depth (ft.):**

GAS MEASUREMENT DATA

Date of test:

Gas measurement method(s):

Gas production during test (MCF):

Was the well preflowed for 48 hours? No

Run No.	Line size	Orif. or Choke Size (in.)	24 hr. Coeff. Orif. Or Choke (in.)	Static Pm or Choke (in.)	Diff (hw)	Flow Temp (°F)	Temp. (Ftf)	Gravity (Fg)	Compress (Fpv)	Volume (MCF/day)

N/A

FIELD DATA AND PRESSURE CALCULATIONS

Gravity (dry gas):

Gravity (liquid hydrocarbons) (Deg. API):

Gas-Liquid Hydro Ratio (CF/Bbl):

Gravity (mixture): Gmix=

Avg. shut in temp. (°F):

Bottom hole temp. and depth: °F@ FT

Run No.	Time of Run (Min.)	Choke Size (in.)	Wellhead Pressure (PSIA)	Wellhead Flow Temp (°F)

N/A

CASING RECORD

Row	Type of Casing	Casing Size (in.)	Hole Size (in.)	Setting Depth (ft.)	Multi - Stage Tool Depth (ft.)	Multi - Stage Shoe Depth (ft.)	Cement Class	Cement Amount (sacks)	Slurry Volume (cu. ft.)	Top of Cement (ft.)	TOC Determined By
1	Surface	13 3/8	17 1/2	504			C	510	687.5	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5498		5498	C	485	797.0	4275	Circulated to Surface
2	Intermediate	13 3/8	17 1/2	5498	4275		C	1650	3045.0	0	Circulated to Surface
6	Conventional Production	7	8 3/4	11023			WELL LOCK	60	337.0	9575	Calculation
5	Conventional Production	7	8 3/4	11023	5591		PREM PLUS	380	906.5	0	Circulated to Surface
4	Conventional Production	7	8 3/4	11023	9575		PREM PLUS	380	906.5	5591	Calculation

LINER RECORD

Row	Liner Size (in.)	Hole Size (in.)	Liner Top (ft.)	Liner Bottom (ft.)	Cement Class	Cement Amount (sacks)	Slurry Volume (cu. ft.)	Top of Cement (ft.)	TOC Determined By

N/A

TUBING RECORD

Row	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	10966	10966 / HALLIBURTON BWD

PRODUCING/INJECTION/DISPOSAL INTERVAL

Row	Open hole?	From (ft.)	To (ft.)
1	Yes	L 11025	11980

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment performed? No

Is well equipped with a downhole actuation sleeve? No

If yes, actuation pressure (PSIG):

Production casing test pressure (PSIG) prior to hydraulic fracturing treatment:

Actual maximum pressure (PSIG) during hydraulic fracturing:

Has the hydraulic fracturing fluid disclosure been reported to FracFocus disclosure registry (SWR29)? No

Row	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)

N/A

FORMATION RECORD

Formations	Encountered	Depth TVD (ft.)	Depth MD (ft.)	Is formation isolated?	Remarks
YATES	Yes	3019.0		Yes	
SAN ANDRES - HIGH FLOWS, H2S, CORROSIVE	Yes	4465.0		Yes	
GLORIETA	Yes	6316.0		Yes	
CLEARFORK - ACTIVE CO2 FLOOD	Yes	6492.0		Yes	
WICHITA	Yes	8628.0		Yes	
UPPER WOLFCAMP	Yes	9239.0		Yes	
STRAWN	Yes	10030.0		Yes	
ATOKA	Yes	10230.0		Yes	
WOODFORD	Yes	10973.0		Yes	
DEVONIAN	Yes	11036.0		No	DISPOSAL
WRISTEN	Yes	11268.0		No	DISPOSAL
FUSSELMAN	Yes	11538.0		No	DISPOSAL
MONTOYA	Yes	11974.0		No	DISPOSAL
RED BED-SANTA ROSA	No			No	NOT IN AREA
LEONARD	No			No	NOT IN AREA
WOLFCAMP	No			No	NOT IN AREA
PENNSYLVANIAN	No			No	NOT IN AREA
STRAWN	No			No	NOT IN AREA
MISSISSIPPIAN	No			No	NOT IN AREA

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm (SWR 36)? No

Is the completion being downhole commingled (SWR 10)? No

REMARKS

NEW WELL PUTTING ON SCHEDULE.

OPERATOR'S CERTIFICATION

Printed Name:	Karen Zornes	**Title:**	
Telephone No.:	(281) 872-9300	**Date Certified:**	06/25/2019

APPENDIX C – GAS COMPOSITION

C-1

www.permianls.com
575.397.3713 2609 W Marland Hobbs NM 88240

C6+ Gas Analysis Report

Sample Point Code	Sample Point Name	Sample Point Location
11093G	30/30 Acid Gas	30/30 Acid Gas

Source Laboratory	Lab File No	Container Identity	Sampler
Laboratory Services	2021048523	1781	E Benavides - Spot

District	Area Name	Field Name	Facility Name
USA	USA	USA	Texas

Date Sampled	Date Effective	Date Received	Date Reported
Nov 16, 2021	Nov 16, 2021	Nov 19, 2021 09:59	Nov 19, 2021

Ambient Temp (°F)	Flow Rate (Mcf)	Analyst	Press PSI @ Temp °F Source Conditions
		System Administrator	21 @ 129

Operator	Lab Source Description
Stakeholder Midstream	30/30

Component	Normalized Mol %	Un-Normalized Mol %	GPM
H2S (H2S)	9.2000	9.2	
Nitrogen (N2)	0.0000	0	
CO2 (CO2)	89.6780	98.775	
Methane (C1)	0.3030	0.331	
Ethane (C2)	0.0580	0.063	0.0150
Propane (C3)	0.1080	0.118	0.0300
I-Butane (IC4)	0.0000	0	0.0000
N-Butane (NC4)	0.0250	0.027	0.0080
I-Pentane (IC5)	0.0000	0	0.0000
N-Pentane (NC5)	0.0000	0	0.0000
Hexanes Plus (C6+)	0.6280	0.686	0.2710
TOTAL	100.0000	109.2000	0.3240

Method(s): Gas C6+ - GPA 2261, Extended Gas - GPA 2286, Calculations - GPA 2172

Analyzer Information

Device Type:	Gas Chromatograph	Device Make:	Shimadzu
Device Model:	GC-2014	Last Cal Date:	Nov 14, 2021

Gross Heating Values (Real, BTU/ft³)

14.696 PSI @ 60.00 Â°F Dry	14.696 PSI @ 60.00 Â°F Saturated	14.65 PSI @ 60.00 Â°F Dry	14.65 PSI @ 60.00 Â°F Saturated
98.7	98.00	98.4	97.7

Calculated Total Sample Properties

GPA2145-16 *Calculated at Contract Conditions

Relative Density Real	Relative Density Ideal
1.5042	1.4956

Molecular Weight
43.3157

C6+ Group Properties

Assumed Composition

C6 - 60.000% C7 - 30.000% C8 - 10.000%

Field H2S
92000 PPM

PROTREND STATUS:
Passed By Validator on Nov 21, 2021

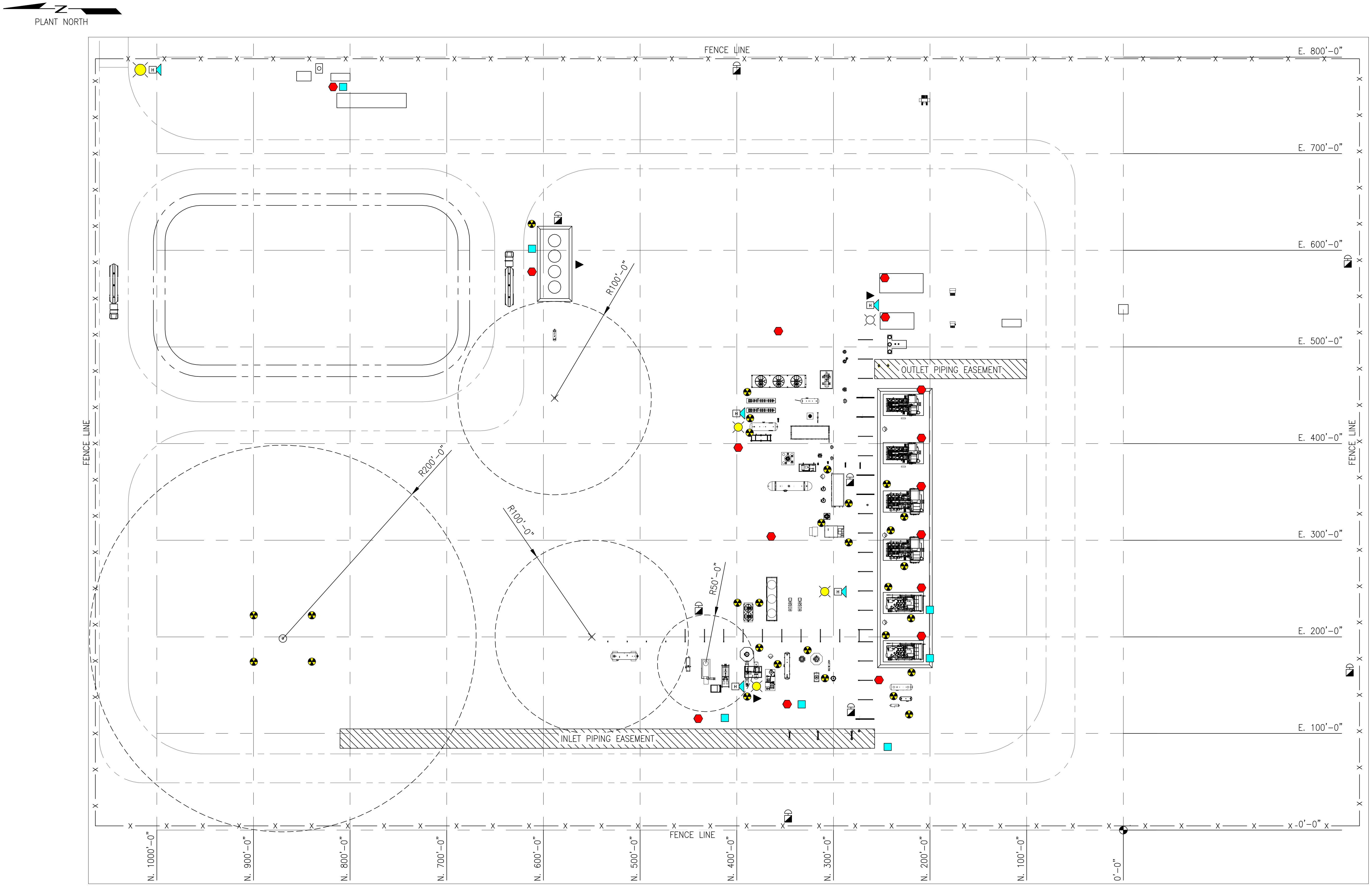
DATA SOURCE:
Imported

PASSED BY VALIDATOR REASON:
Close enough to be considered reasonable.

VALIDATOR:
Dustin Armstrong

VALIDATOR COMMENTS:
OK

APPENDIX D – FACILITY SAFETY PLOT PLANS



LEGEND

(red octagon)	FIRE EXTINGUISHER
(cyan square)	SCBA / ESCAPE PACK
(black triangle)	WIND SOCK
(radiation symbol)	LEL/H2S MONITOR
(ESD symbol)	ESD BUTTON
(yellow circle)	STROBE LIGHTS
H	HORN

NOTES:

D-1

PRELIMINARY FOR REVIEW

NO.	DATE	REVISION DESCRIPTION	BY	FCE	CLIENT
0	05/11/22	INITIAL RELEASE	KLD	BEC	JB

CH aris

CHARIS ENGINEERING, LLC
TX ENG. FIRM NO. F-18864
MIDLAND, TX

STAKEHOLDER MIDSTREAM

CLIENT : STAKEHOLDER MIDSTREAM

PROJECT : 30-30 GAS PLANT

TITLE : SAFETY EQUIPMENT PLOT PLAN

DRAWN	CHECKED	SCALE	DATE	JOB NO.	DRAWING NO.	
KLD		1" = 50'-0"	5/11/22	SAN180209	ME-PLNP-A000-0004	0

APPENDIX E – MMA/AMA REVIEW MAPS

APPENDIX E-1: PLUME BOUNDARY AT END OF INJECTION, STABILIZED PLUME BOUNDARY AND MAXIMUM MONITORING AREA MAP

APPENDIX E-2: ACTIVE MONITORING AREA MAP

APPENDIX E-3: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX E-4: OIL AND GAS WELLS WITHIN THE MMA LIST

APPENDIX E-5: INJECTION INTERVAL PENETRATING WELLS WITHIN THE MMA MAP

APPENDIX E-6: GROUNDWATER WELLS WITHIN THE MMA

APPENDIX E-7: WELLBORE SCHEMATICS FOR INJECTION INTERVAL PENETRATING WELLS

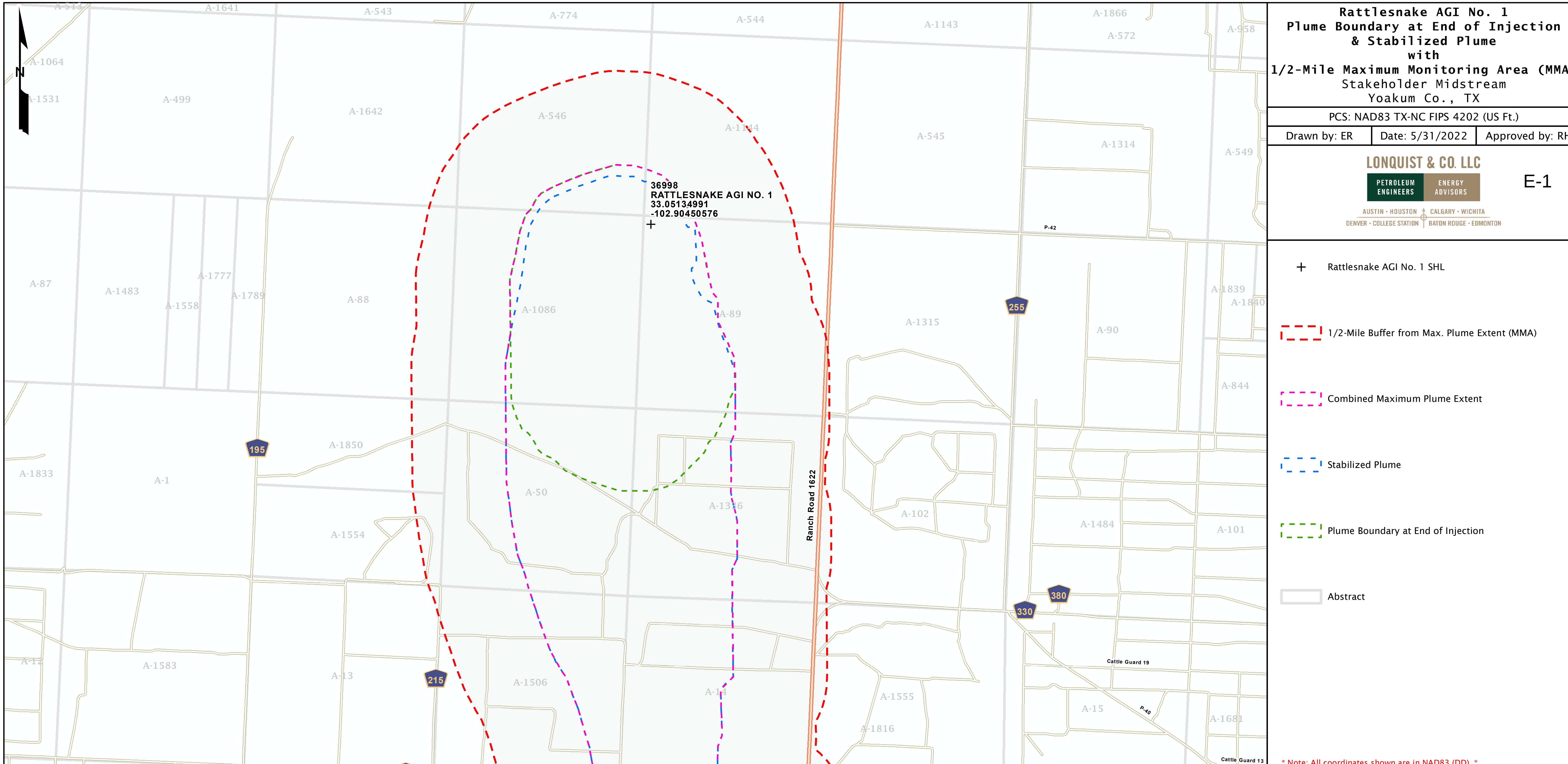
Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& Stabilized Plume
with
1/2-Mile Maximum Monitoring Area (MMA)
Stakeholder Midstream
Yoakum Co., TX

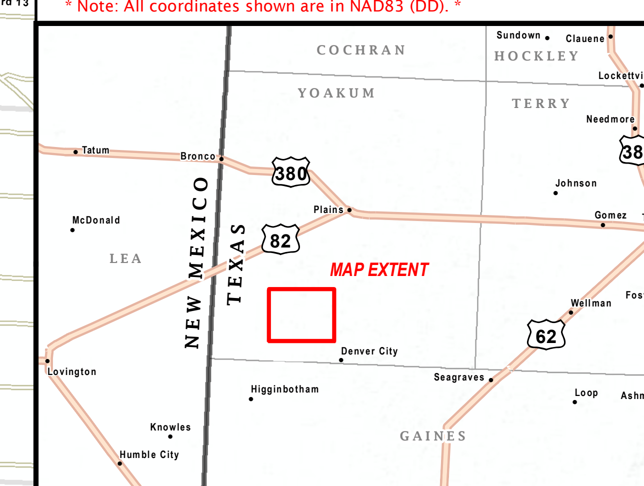
PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

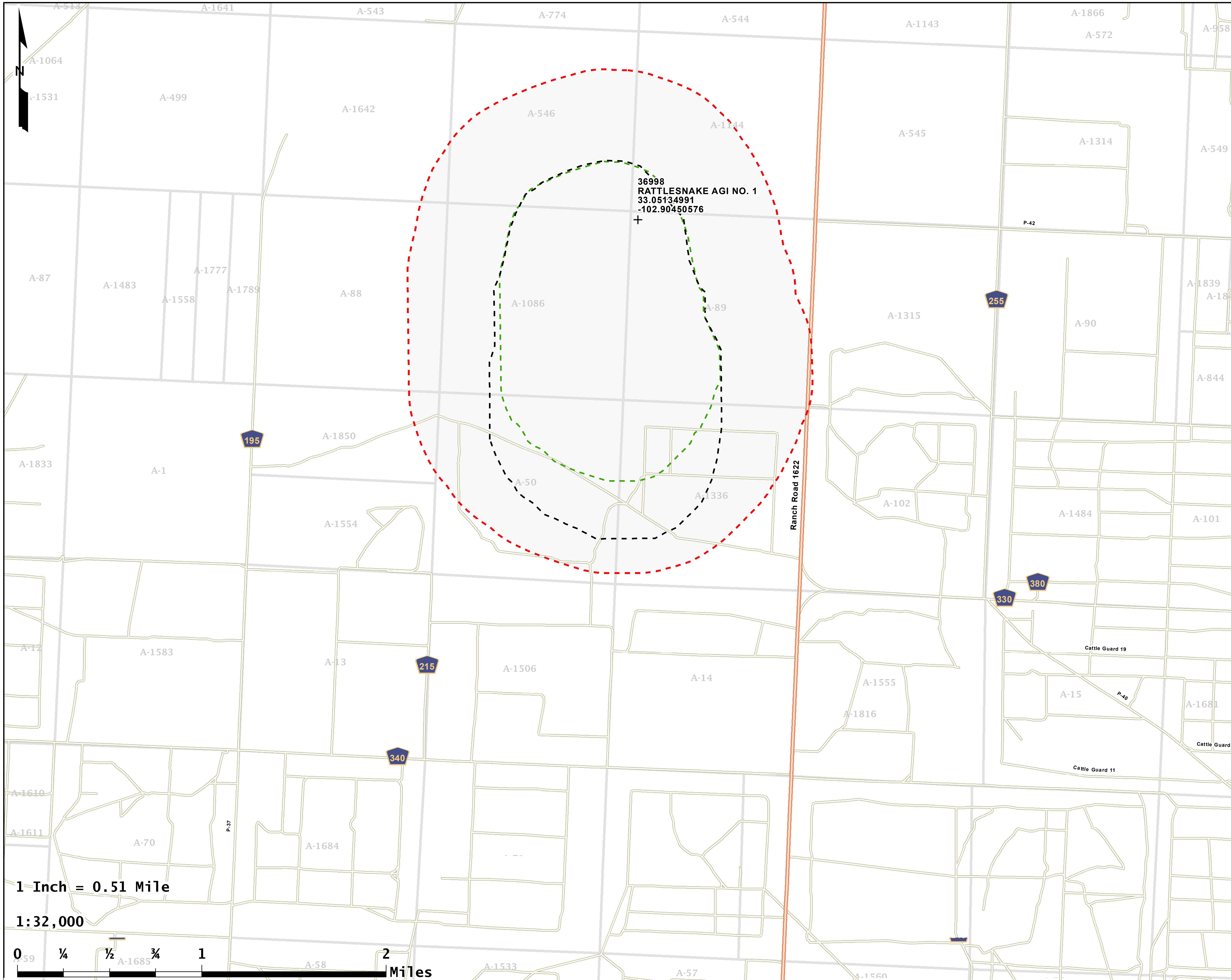
Drawn by: ER	Date: 5/31/2022	Approved by: RH

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS
AUSTIN • HOUSTON • CALGARY • WICHITA
DENVER • COLLEGE STATION • BATON ROUGE • EDMONTON

E-1







Rattlesnake AGI No. 1
Plume Boundary at End of Injection
& 19-Year Plume
with
1/2-Mile Active Monitoring Area (AMA)
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

LONQUIST & CO. LLC
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AUSTIN • HOUSTON • CALGARY • WICHITA
DENVER • COLLEGE STATION • BATON ROUGE • EDMONTON

E-2

+ Rattlesnake AGI No. 1 SHL

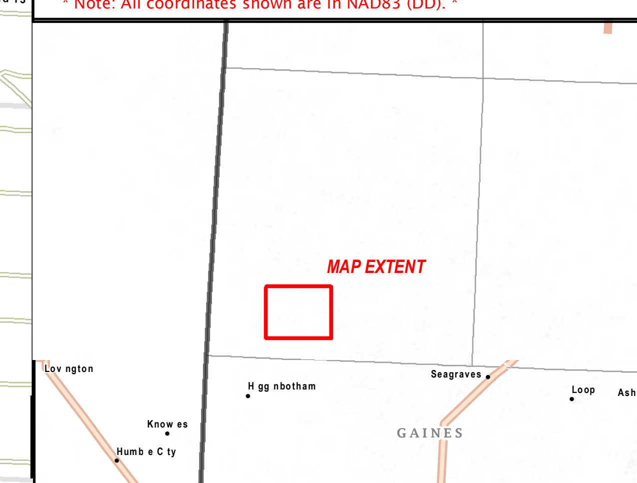
Active Monitoring Area Boundary

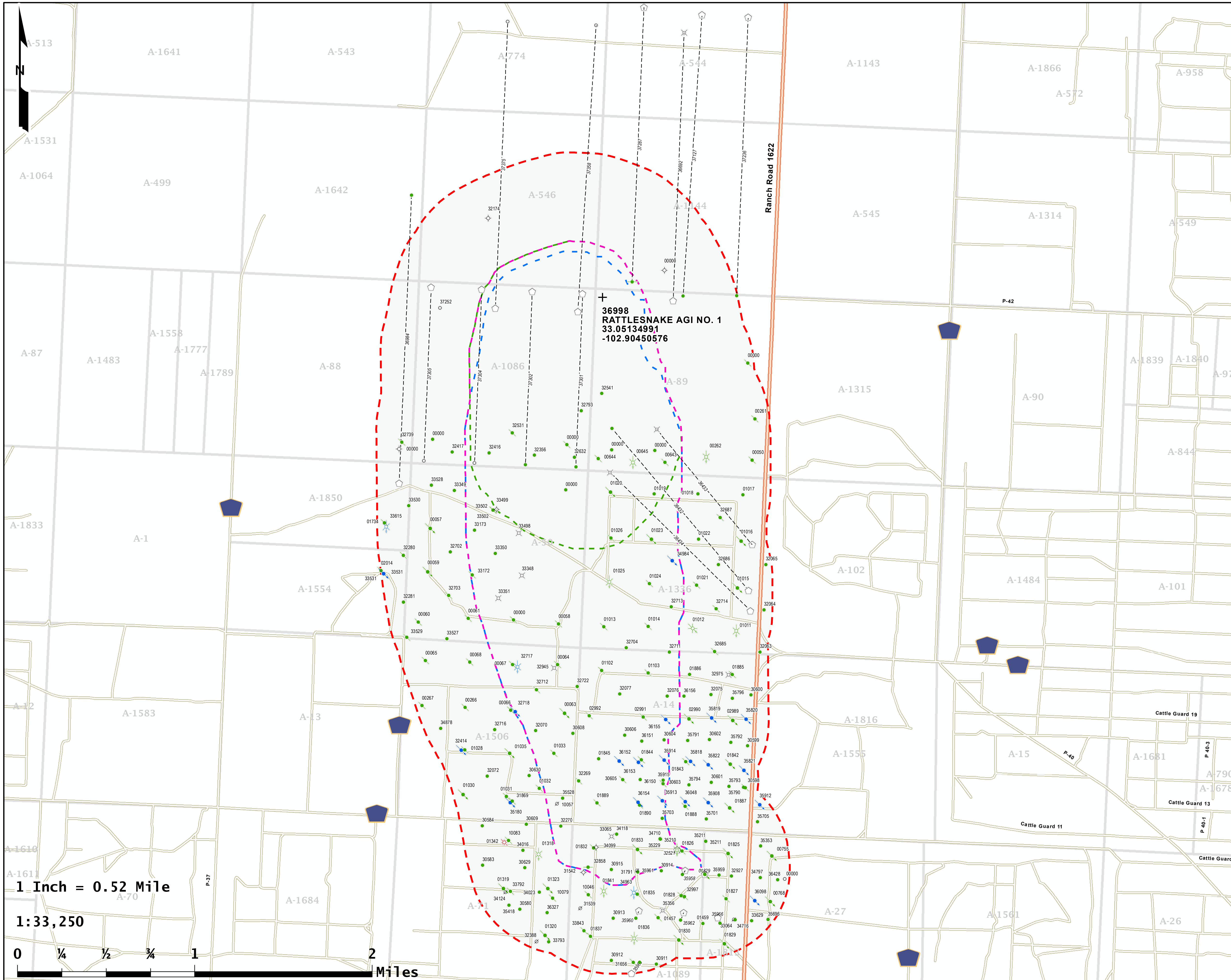
19-Year Plume

Plume Boundary at End of Injection

Abstract

* Note: All coordinates shown are in NAD83 (DD). *





Rattlesnake AGI No. 1
Maximum Monitoring Area with 1/2-Mile MMA Oil/Gas Well Area of Review

Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

LONQUIST & CO. LLC
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DENVER · COLLEGE STATION · BATON ROUGE · EDMONTON

E-3

- Rattlesnake AGI No. 1 SHL
- 1/2-Mile Buffer from Max. Plume Extent (MMA)
- Combined Maximum Plume Extent
- Stabilized Plume
- Plume Boundary at End of Injection
- Abstract
- Lateral (21)

API (42-501-...) SHL Status - Type (Count)

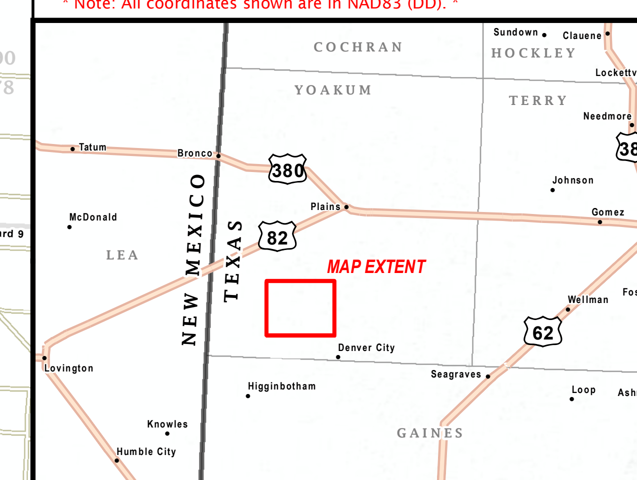
- Horizontal Surface Location (21)
- Active - Oil (93)
- Active - Injection/Disposal (21)
- Active - Injection/Disposal from Oil (22)
- Plugged - Oil (69)
- Plugged - Gas (1)
- Plugged- Injection/Disposal from Oil (1)
- Shut-In - Oil (1)
- TA - Injection/Disposal (3)
- TA - Injection/Disposal from Oil (7)
- Dry Hole (6)
- Permitted Location (2)
- Canceled/Abandoned Location (6)
- Expired Permit (7)

API (42-501-...) BHL Status - Type (Count)

- Active - Oil (11)
- Active - Injection/Disposal from Oil (1)
- Shut-In - Oil (1)
- TA - Injection/Disposal from Oil (1)
- Permitted Location (4)
- Expired Permit (3)

Source:
1.) Oil/Gas Well SHL Data: DI-2022
2.) Oil/Gas Well BHL Data: DI-2022
3.) Oil/Gas Well Directional Data: DI-2022

* Note: All coordinates shown are in NAD83 (DD). *



Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250101829	DENVER UNIT	2215W	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5300	5300	2215W
4250101835	DENVER UNIT	2207	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5185	5185	2207
4250130914	DENVER UNIT	2222	OCCIDENTAL PERMIAN LTD.	Active - Oil			2222
4250101832	DENVER UNIT	2201W	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5190	5190	2201W
4250101826	DENVER UNIT	2203	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5250	5250	2203
4250101319	ROBERTS UNIT	4532W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5200	5200	4532W
4250130629	ROBERTS UNIT	4535	APACHE CORPORATION	Active - Oil	5280	5280	4535
4250130583	ROBERTS UNIT	4525	APACHE CORPORATION	Active - Oil	5286	5286	4525
4250101318	ROBERTS UNIT	4541	APACHE CORPORATION	TA - Injection/Disposal from Oil	5240	5240	4541
4250101889	ROBERTS UNIT	3614	APACHE CORPORATION	Plugged - Oil	5180	5180	3614
4250130598	Roberts Unit	3647	APACHE CORPORATION	Plugged - Oil	5281	5281	3647
4250130603	ROBERTS UNIT	3626	APACHE CORPORATION	Plugged - Oil	5289	5289	3626
4250102992	ROBERTS UNIT	3612W	APACHE CORPORATION	Plugged - Oil	5226	5226	3612W
4250100066	ROBERTS UNIT	3532	APACHE CORPORATION	Plugged - Oil	5231	5231	3532
4250101886	ROBERTS UNIT	3631	APACHE CORPORATION	Plugged - Oil			3631
4250101885	ROBERTS UNIT	3641	APACHE CORPORATION	Plugged - Oil	5212	5212	3641
4250100068	ROBERTS UNIT	3521	APACHE CORPORATION	Plugged - Oil	5225	5225	3521
4250100064	ROBERTS UNIT	3541	APACHE CORPORATION	Plugged - Oil	5264	5264	3541
4250102014	ROBERTS UNIT	2443	APACHE CORPORATION	Plugged - Oil	5226	5226	2443
4250100050	ROBERTS UNIT	1654	APACHE CORPORATION	Plugged - Oil	5198	5198	1654
4250133531	ROBERTS UNIT	2443A		Active - Injection/Disposal	5325	5325	2443A
4250133502	ROBERTS UNIT	2527A		Plugged - Oil	5308	5308	2527A
4250100000	C. A. ELLIOTT	6	AMERICAN LIBERTY OIL CO	Plugged - Oil	5229	5229	6
4250100000	C. A. ELLIOTT	7	AMERICAN LIBERTY AND ATLANTIC	Active - Oil	5182	5182	7
4250100000	GEO CLEVELAND	1	DELFERN OIL CO	Dry Hole	5071	5071	1
4250100000	JAMES H. LYNN	1614	AMERICAN LIBERTY	Active - Oil	5169	5169	1614
4250100000	J. H. LYNN	1634	AMERICAN LIBERTY	Active - Oil	5160	5160	1634
4250100000	A. T. MORRIS	1	ATLANTIC	Active - Oil	5235	5235	1
4250100000	A. T. MORRIS	2	AMERICAN LIBERTY OIL CO	Plugged - Oil	5179	5179	2
4250100000	W. J. CARPENTER	1642	AMERICAN LIBERTY OIL COMPANY	Plugged - Oil	5183	5183	1642
4250100000	E.S. SMITH	1	CREAT WESTERN FROD	Dry Hole	5216	5216	1
4250130607	ROBERTS UNIT	3546		Active - Oil			3546
4250135958	DENVER UNIT	2247	OCCIDENTAL PERMIAN LTD.	Active - Oil	2333	2333	2247
4250131542	DENVER UNIT	2229	SHELL OIL COMPANY	Dry Hole	2409	2409	2229
4250101320	ROBERTS UNIT	4543	APACHE CORPORATION	Active - Injection/Disposal from Oil	5120	5120	4543
4250137301	MILLER	8H	AMTEX ENERGY, INC.	Active - Oil	5157	5157	8H
4250137304	MILLER 732 C	10H	AMTEX ENERGY, INC.	Permitted Location	5157	5157	10H
4250137305	MILLER 732 D	11H	AMTEX ENERGY, INC.	Permitted Location	5157	5157	11H
4250101888	ROBERTS UNIT	3634W	APACHE CORPORATION	Plugged - Oil	5160	5160	3634W

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250101031	ROBERTS UNIT	3534W	APACHE CORPORATION	Plugged - Oil	5164	5164	3534W
4250101828	DENVER UNIT	2208	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5170	5170	2208
4250101032	ROBERTS UNIT	3544	APACHE CORPORATION	Plugged - Oil	5170	5170	3544
4250101841	DENVER UNIT	2206	OCCIDENTAL PERMIAN LTD.	TA - Injection/Disposal from Oil	5177	5177	2206
4250101842	ROBERTS UNIT	3643W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5180	5180	3643W
4250101035	ROBERTS UNIT	3533W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5180	5180	3533W
4250132704	ROBERTS UNIT	2615	APACHE CORPORATION	Active - Oil	5180	5180	2615
4250100261	ROBERTS UNIT	1643W	APACHE CORPORATION	Plugged - Oil	5180	5180	1643W
4250101323	ROBERTS UNIT	4542W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5182	5182	4542W
4250102989	ROBERTS UNIT	3642W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5182	5182	3642W
4250102991	ROBERTS UNIT	3622W	APACHE CORPORATION	Plugged - Oil	5185	5185	3622W
4250132417	MILLER	3	AMTEX ENERGY, INC.	Active - Oil	5186	5186	3
4250101025	ROBERTS UNIT	2613W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5188	5188	2613W
4250101887	ROBERTS UNIT	3644	APACHE CORPORATION	Active - Injection/Disposal from Oil	5189	5189	3644
4250101830	DENVER UNIT	2214WC	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5190	5190	2214WC
4250101103	ROBERTS UNIT	3621	APACHE CORPORATION	Plugged - Oil	5190	5190	3621
4250101024	ROBERTS UNIT	2623	APACHE CORPORATION	Plugged - Oil	5190	5190	2623
4250101023	ROBERTS UNIT	2622W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5190	5190	2622W
4250101022	ROBERTS UNIT	2632	APACHE CORPORATION	Active - Oil	5190	5190	2632
4250101019	ROBERTS UNIT	2621	APACHE CORPORATION	Active - Oil	5190	5190	2621
4250101030	ROBERTS UNIT	3524W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5193	5193	3524W
4250101829	DENVER UNIT	2205	OCCIDENTAL PERMIAN LTD.	TA - Injection/Disposal from Oil	5195	5195	2205
4250101836	DENVER UNIT	2213WC	OCCIDENTAL PERMIAN LTD.	TA - Injection/Disposal from Oil	5200	5200	2213WC
4250101833	DENVER UNIT	2202WC	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5200	5200	2202WC
4250134099	DENVER UNIT	2239WC	OCCIDENTAL PERMIAN LTD.	Dry Hole	5200	5200	2239WC
4250132717	ROBERTS UNIT	3531A	APACHE CORPORATION	TA - Injection/Disposal	5200	5200	3531A
4250101014	ROBERTS UNIT	2624W	APACHE CORPORATION	Plugged - Oil	5200	5200	2624W
4250101028	ROBERTS UNIT	3523	APACHE CORPORATION	Plugged - Oil	5205	5205	3523
4250101102	ROBERTS UNIT	3611	APACHE CORPORATION	Plugged - Oil	5206	5206	3611
4250101827	DENVER UNIT	2209W	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5210	5210	2209W
4250101015		2643	TEXACO INCORPORATED	Active - Injection/Disposal from Oil	5210	5210	2643
4250100266	ROBERTS UNIT	3522W	APACHE CORPORATION	Plugged - Oil	5211	5211	3522W
4250132632	MILLER	5	AMTEX ENERGY, INC.	Active - Oil	5213	5213	5
4250100057	ROBERTS UNIT	2512W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5213	5213	2512W
4250101890	ROBERTS UNIT	3624W	APACHE CORPORATION	Plugged - Oil	5214	5214	3624W
4250101033	ROBERTS UNIT	3543W	APACHE CORPORATION	Plugged - Oil	5215	5215	3543W
4250101012	ROBERTS UNIT	2634W	APACHE CORPORATION	Plugged- Injection/Disposal from Oil	5215	5215	2634W
4250101734	ROBERTS UNIT	2442	APACHE CORPORATION	Plugged - Oil	5215	5215	2442
4250101020	ROBERTS UNIT	2611W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5215	5215	2611W

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250100067	ROBERTS UNIT	3531	APACHE CORPORATION	Plugged - Oil	5216	5216	3531
4250101013	ROBERTS UNIT	2614W	APACHE CORPORATION	Plugged - Oil	5216	5216	2614W
4250101844	ROBERTS UNIT	3623W	APACHE CORPORATION	Plugged - Oil	5217	5217	3623W
4250131869	ROBERTS UNIT	A3534W	APACHE CORPORATION	Plugged - Oil	5220	5220	A3534W
4250102990	ROBERTS UNIT	3632W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5220	5220	3632W
4250100262	ROBERTS UNIT	1644W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5220	5220	1644W
4250132858	DENVER UNIT	2235	OCCIDENTAL PERMIAN LTD.	Shut-In - Oil	5225	5225	2235
4250100058	ROBERTS UNIT	2544W	APACHE CORPORATION	Plugged - Oil	5225	5225	2544W
4250130584	ROBERTS UNIT	4520	APACHE CORPORATION	Active - Oil	5230	5230	4520
4250130630	ROBERTS UNIT	3535	APACHE CORPORATION	Active - Oil	5230	5230	3535
4250100063	ROBERTS UNIT	3542W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5230	5230	3542W
4250132076	ROBERTS UNIT	3627	APACHE CORPORATION	Active - Oil	5230	5230	3627
4250100267	ROBERTS UNIT	3512W	APACHE CORPORATION	Plugged - Oil	5233	5233	3512W
4250101016	ROBERTS UNIT	2642W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5234	5234	2642W
4250134716	DENVER UNIT	2242	OCCIDENTAL PERMIAN LTD.	Active - Oil	5236	5236	2242
4250100061	ROBERTS UNIT	2524W	APACHE CORPORATION	Plugged - Oil	5238	5238	2524W
4250101021	ROBERTS UNIT	2633	APACHE CORPORATION	Plugged - Oil	5240	5240	2633
4250101011	ROBERTS UNIT	2644W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5241	5241	2644W
4250132541	FUTCH	1	AMTEX ENERGY, INC.	Active - Oil	5244	5244	1
4250101026	ROBERTS UNIT	2612W	APACHE CORPORATION	Plugged - Oil	5245	5245	2612W
4250100059	ROBERTS UNIT	2513W	APACHE CORPORATION	Active - Injection/Disposal from Oil	5246	5246	2513W
4250132531	MILLER	4	AMTEX ENERGY, INC.	Plugged - Oil	5248	5248	4
4250132687	ROBERTS UNIT	2635	APACHE CORPORATION	Plugged - Oil	5248	5248	2635
4250131656	DENVER UNIT	2232WC	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5250	5250	2232WC
4250131791	DENVER UNIT	2231	SHELL OIL COMPANY	Canceled/Abandoned Location	5250	5250	2231
4250134118	DENVER UNIT	2238	OCCIDENTAL PERMIAN LTD.	Active - Oil	5250	5250	2238
4250101342	ROBERTS UNIT		APACHE CORPORATION	Plugged - Gas	5250	5250	
4250132269	ROBERTS UNIT	3601	APACHE CORPORATION	Plugged - Oil	5250	5250	3601
4250101843	ROBERTS UNIT	3633W	APACHE CORPORATION	Plugged - Oil	5250	5250	3633W
4250130608	ROBERTS UNIT	3545	APACHE CORPORATION	Active - Oil	5250	5250	3545
4250132077	ROBERTS UNIT	3617	APACHE CORPORATION	Active - Oil	5250	5250	3617
4250134963	DENVER UNIT	2244WC	OCCIDENTAL PERMIAN LTD.	TA- Injection/Disposal	5251	5251	2244WC
4250100060	ROBERTS UNIT	2514	APACHE CORPORATION	Plugged - Oil	5251	5251	2514
4250101459	DENVER UNIT	2211	OCCIDENTAL PERMIAN LTD.	Active - Oil	5252	5252	2211
4250132521	DENVER UNIT	2233W	OCCIDENTAL PERMIAN LTD.	TA- Injection/Disposal from Oil	5253	5253	2233W
4250135211	DENVER UNIT	2241	OCCIDENTAL PERMIAN LTD.	Active - Oil	5253	5253	2241
4250101837	DENVER UNIT	2212W	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5255	5255	2212W
4250132793	MILLER	6	AMTEX ENERGY, INC.	Active - Oil	5258	5258	6
4250132356	MILLER	1	AMTEX ENERGY, INC.	Active - Oil	5260	5260	1

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250101017	ROBERTS UNIT	2641	APACHE CORPORATION	Active - Oil	5260	5260	2641
4250101825	DENVER UNIT	2204W	OCCIDENTAL PERMIAN LTD.	Active - Injection/Disposal from Oil	5264	5264	2204W
4250132416	MILLER	2	AMTEX ENERGY, INC.	Active - Oil	5269	5269	2
4250100065	ROBERTS UNIT	3511W	APACHE CORPORATION	Plugged - Oil	5270	5270	3511W
4250101018	ROBERTS UNIT	2631	APACHE CORPORATION	Active - Oil	5270	5270	2631
4250130600	ROBERTS UNIT	3645	APACHE CORPORATION	Active - Oil	5273	5273	3645
4250130580	ROBERTS UNIT	4536	APACHE CORPORATION	Active - Oil	5279	5279	4536
4250130599	ROBERTS UNIT	3646	APACHE CORPORATION	Active - Oil	5279	5279	3646
4250130602	ROBERTS UNIT	3635	APACHE CORPORATION	Active - Oil	5283	5283	3635
4250132997	DENVER UNIT	2208WC	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5284	5284	2208WC
4250130601	ROBERTS UNIT	3636	APACHE CORPORATION	Active - Oil	5286	5286	3636
4250132174	SHEPHERD	1	YOUNG, MARSHALL R., OIL CO.	Dry Hole	5286	5286	1
4250130604	ROBERTS UNIT	3625	APACHE CORPORATION	Active - Oil	5287	5287	3625
4250130912	DENVER UNIT	2224	OCCIDENTAL PERMIAN LTD.	Active - Oil	5288	5288	2224
4250130911	DENVER UNIT	2225	OCCIDENTAL PERMIAN LTD.	Active - Oil	5290	5290	2225
4250130609	ROBERTS UNIT	4530	APACHE CORPORATION	Active - Oil	5291	5291	4530
4250130605	ROBERTS UNIT	3616	APACHE CORPORATION	Plugged - Oil	5291	5291	3616
4250130606	ROBERTS UNIT	3615	APACHE CORPORATION	Active - Oil	5293	5293	3615
4250133172	ROBERTS UNIT	2523	CONOCOPHILLIPS COMPANY	Plugged - Oil	5295	5295	2523
4250132739	CLEVELAND	1	HIGHLAND PRODUCTION COMPANY	Plugged - Oil	5300	5300	1
4250133064	DENVER UNIT	2238	SHELL WESTERN E&P INC.	Canceled/Abandoned Location	5300	5300	2238
4250132927	DENVER UNIT	2236	OCCIDENTAL PERMIAN LTD.	Active - Oil	5300	5300	2236
4250133065	DENVER UNIT	2237	SHELL WESTERN E&P INC.	Expired Permit	5300	5300	2237
4250132270	ROBERTS UNIT	4540	APACHE CORPORATION	Active - Oil	5300	5300	4540
4250132414	ROBERTS UNIT	3523A	APACHE CORPORATION	Active - Injection/Disposal	5300	5300	3523A
4250132712	ROBERTS UNIT	3537	APACHE CORPORATION	Plugged - Oil	5300	5300	3537
4250132722	ROBERTS UNIT	3547	APACHE CORPORATION	Active - Oil	5300	5300	3547
4250132945	ROBERTS UNIT	3541A	TEXACO PRODUCING INC.	Expired Permit	5300	5300	3541A
4250132975	ROBERTS UNIT	3641A	TEXACO PRODUCING INC.	Expired Permit	5300	5300	3641A
4250132711	ROBERTS UNIT	3620	APACHE CORPORATION	Active - Oil	5300	5300	3620
4250133527	ROBERTS UNIT	2518	APACHE CORPORATION	Active - Oil	5300	5300	2518
4250132714	ROBERTS UNIT	2637	APACHE CORPORATION	Plugged - Oil	5300	5300	2637
4250133351	ROBERTS UNIT	2526	TEXACO PRODUCING INC.	Expired Permit	5300	5300	2526
4250132703	ROBERTS UNIT	2516	APACHE CORPORATION	Plugged - Oil	5300	5300	2516
4250133348	ROBERTS UNIT	2533	TEXACO PRODUCING INC.	Expired Permit	5300	5300	2533
4250132702	ROBERTS UNIT	2515	APACHE CORPORATION	Active - Oil	5300	5300	2515
4250133350	ROBERTS UNIT	2525	APACHE CORPORATION	Active - Oil	5300	5300	2525
4250133498	ROBERTS UNIT	2532	TEXACO PRODUCING INC.	Expired Permit	5300	5300	2532
4250133173	ROBERTS UNIT	2522	APACHE CORPORATION	Active - Oil	5300	5300	2522

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250133499	ROBERTS UNIT	2527	TEXACO PRODUCING INC.	Dry Hole	5300	5300	2527
4250133530	ROBERTS UNIT	2507	APACHE CORPORATION	Active - Oil	5300	5300	2507
4250132685	ROBERTS UNIT	2638	APACHE CORPORATION	Plugged - Oil	5302	5302	2638
4250133349	ROBERTS UNIT	2517	APACHE CORPORATION	Active - Oil	5302	5302	2517
4250132718	ROBERTS UNIT	3532A	APACHE CORPORATION	Active - Injection/Disposal	5304	5304	3532A
4250132713	ROBERTS UNIT	2625	APACHE CORPORATION	Active - Oil	5308	5308	2625
4250133502	ROBERTS UNIT	2527A	APACHE CORPORATION	Plugged - Oil	5308	5308	2527A
4250132716	ROBERTS UNIT	3526	APACHE CORPORATION	Active - Oil	5309	5309	3526
4250100645	ROBERTS UNIT	1624W	APACHE CORPORATION	TA - Injection/Disposal from Oil	5309	5309	1624W
4250130913	DENVER UNIT	2223	OCCIDENTAL PERMIAN LTD.	Active - Oil	5310	5310	2223
4250132686	ROBERTS UNIT	2636	APACHE CORPORATION	Active - Oil	5310	5310	2636
4250101457	DENVER UNIT	2210	OCCIDENTAL PERMIAN LTD.	Plugged - Oil	5325	5325	2210
4250133529	ROBERTS UNIT	2508	APACHE CORPORATION	Plugged - Oil	5325	5325	2508
4250133531	ROBERTS UNIT	2443A	APACHE CORPORATION	Active - Injection/Disposal	5325	5325	2443A
4250133528	ROBERTS UNIT	2511	APACHE CORPORATION	Active - Oil	5325	5325	2511
4250135912	ROBERTS UNIT	3771W	APACHE CORPORATION	Active - Injection/Disposal	5330	5330	3771W
4250132075	ROBERTS UNIT	3637	APACHE CORPORATION	Active - Oil	5330	5330	3637
4250132063	ROBERTS UNIT	2705	APACHE CORPORATION	Active - Oil	5330	5330	2705
4250135793	ROBERTS UNIT	3672	APACHE CORPORATION	Active - Oil	5334	5334	3672
4250135819	ROBERTS UNIT	3674W	APACHE CORPORATION	Active - Injection/Disposal	5336	5336	3674W
4250135792	ROBERTS UNIT	3671	APACHE CORPORATION	Active - Oil	5339	5339	3671
4250135820	ROBERTS UNIT	3675W	APACHE CORPORATION	Active - Injection/Disposal	5341	5341	3675W
4250135818	ROBERTS UNIT	3633RW	APACHE CORPORATION	Active - Injection/Disposal	5344	5344	3633RW
4250135790	ROBERTS UNIT	3647R	APACHE CORPORATION	Active - Oil	5345	5345	3647R
4250100768	CORNELL UNIT	3107W	XTO ENERGY INC.	Active - Injection/Disposal from Oil	5350	5350	3107W
4250130915	DENVER UNIT	2221	OCCIDENTAL PERMIAN LTD.	Active - Oil	5350	5350	2221
4250136048	ROBERTS UNIT	3634RW	APACHE CORPORATION	Active - Injection/Disposal	5350	5350	3634RW
4250135908	ROBERTS UNIT	3678W	APACHE CORPORATION	Active - Injection/Disposal	5350	5350	3678W
4250132072	ROBERTS UNIT	3525	APACHE CORPORATION	Active - Oil	5350	5350	3525
4250135915	ROBERTS UNIT	3626R	APACHE CORPORATION	Active - Oil	5350	5350	3626R
4250132281	ROBERTS UNIT	2446	APACHE CORPORATION	Active - Oil	5350	5350	2446
4250132064	ROBERTS UNIT	2704	APACHE CORPORATION	Active - Oil	5350	5350	2704
4250132280	ROBERTS UNIT	2445	APACHE CORPORATION	Plugged - Oil	5350	5350	2445
4250135791	ROBERTS UNIT	3670	APACHE CORPORATION	Active - Oil	5351	5351	3670
4250135794	ROBERTS UNIT	3673	APACHE CORPORATION	Active - Oil	5352	5352	3673
4250135821	ROBERTS UNIT	3676W	APACHE CORPORATION	Active - Injection/Disposal	5352	5352	3676W
4250135914	ROBERTS UNIT	3681W	APACHE CORPORATION	Active - Injection/Disposal	5352	5352	3681W
4250100643	ROBERTS UNIT	1634W	APACHE CORPORATION	Plugged - Oil	5353	5353	1634W
4250135796	ROBERTS UNIT	3669	APACHE CORPORATION	Active - Oil	5356	5356	3669

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250100644	ROBERTS UNIT	1614	APACHE CORPORATION	Plugged - Oil	5356	5356	1614
4250135913	ROBERTS UNIT	3680W	APACHE CORPORATION	Active - Injection/Disposal	5357	5357	3680W
4250135705	ROBERTS UNIT	3752	APACHE CORPORATION	Active - Oil	5360	5360	3752
4250135822	ROBERTS UNIT	3677W	APACHE CORPORATION	Active - Injection/Disposal	5362	5362	3677W
4250134984	ROBERTS UNIT	2626W	APACHE CORPORATION	Active - Injection/Disposal	5364	5364	2626W
4250135701	ROBERTS UNIT	3667	APACHE CORPORATION	Active - Oil	5365	5365	3667
4250132070	ROBERTS UNIT	3536	APACHE CORPORATION	Active - Oil	5370	5370	3536
4250132065	ROBERTS UNIT	2703	APACHE CORPORATION	Active - Oil	5370	5370	2703
4250100755	CORNELL UNIT	3101W	XTO ENERGY INC.	Active - Injection/Disposal from Oil	5373	5373	3101W
4250135703	ROBERTS UNIT	3668	APACHE CORPORATION	Active - Oil	5380	5380	3668
4250135229	DENVER UNIT	2240	OCCIDENTAL PERMIAN LTD.	Active - Oil	5388	5388	2240
4250136152	ROBERTS UNIT	3682W	APACHE CORPORATION	Active - Injection/Disposal	5397	5397	3682W
4250131539	DENVER UNIT	2230	SHELL OIL COMPANY	Canceled/Abandoned Location	5400	5400	2230
4250136327	ROBERTS UNIT	4547	APACHE CORPORATION	Active - Oil	5400	5400	4547
4250136154	ROBERTS UNIT	3624RW	APACHE CORPORATION	Active - Injection/Disposal	5400	5400	3624RW
4250136155	ROBERTS UNIT	3683W	APACHE CORPORATION	Active - Injection/Disposal	5402	5402	3683W
4250136156	ROBERTS UNIT	3686	APACHE CORPORATION	Active - Oil	5404	5404	3686
4250134797	CORNELL UNIT	3194	XTO ENERGY INC.	Active - Oil	5405	5405	3194
4250135696	CORNELL UNIT	113	XTO ENERGY INC.	Active - Oil	5406	5406	113
4250136150	ROBERTS UNIT	3684	APACHE CORPORATION	Active - Oil	5421	5421	3684
4250133629	CORNELL UNIT	3156	XTO ENERGY INC.	Active - Oil	5425	5425	3156
4250135961	DENVER UNIT	2246	OCCIDENTAL PERMIAN LTD.	Active - Oil	5425	5425	2246
4250135960	DENVER UNIT	2249	OCCIDENTAL PERMIAN LTD.	Active - Oil	5431	5431	2249
4250136153	ROBERTS UNIT	3623RW	APACHE CORPORATION	Active - Injection/Disposal	5439	5439	3623RW
4250135353	CORNELL UNIT	107	XTO ENERGY INC.	Active - Oil	5450	5450	107
4250135528	ROBERTS UNIT	3549	APACHE CORPORATION	Active - Oil	5452	5452	3549
4250136151	ROBERTS UNIT	3685	APACHE CORPORATION	Active - Oil	5463	5463	3685
4250135963	DENVER UNIT	2252	OCCIDENTAL PERMIAN LTD.	Active - Oil	5476	5476	2252
4250136434	ROBERTS UNIT	263H	APACHE CORPORATION	Expired Permit	5500	5500	263H
4250136433	ROBERTS UNIT	262H	APACHE CORPORATION	Expired Permit	5500	5500	262H
4250136098	CORNELL UNIT	110	XTO ENERGY INC.	Active - Injection/Disposal	5510	5510	110
4250133615	ROBERTS UNIT	2442A	APACHE CORPORATION	TA - Injection/Disposal	5516	5516	2442A
4250135180	ROBERTS UNIT	3534B	APACHE CORPORATION	Active - Injection/Disposal	5517	5517	3534B
4250136428	CORNELL UNIT	124	XTO ENERGY INC.	Active - Oil	5532	5532	124
4250134878	ROBERTS UNIT	3548	APACHE CORPORATION	Active - Oil	5550	5550	3548
4250135966	DENVER UNIT	2251	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2251
4250135962	DENVER UNIT	2250	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2250
4250135356	DENVER UNIT	2246	OCCIDENTAL PERMIAN LTD.	Expired Permit	5600	5600	2246
4250135959	DENVER UNIT	2248	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2248

Rattlesnake AGI No. 1
Oil and Gas Wells within MMA

API	WELL NAME	WELL NO	OPERATOR	RRCStatus	TVD	TD	wellNo
4250135210	DENVER UNIT	2240	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2240
4250135211		2241	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2241
4250134710		2240	OCCIDENTAL PERMIAN LTD.	Active - Oil	5600	5600	2240
4250101845	ROBERTS UNIT	3613	APACHE CORPORATION	Active - Oil	7000	7000	3613
4250110083	RANDALL, E.	36	EXXON CORP.	Plugged - Oil	8595	8595	36
4250110046	ELLIOTT, C.A.	2	MCCLURE OIL COMPANY, INC.	Plugged - Oil	9000	9000	2
4250136692	MISS KITTY 704-669	3XH	RILEY EXPLORATION OPG CO, LLC	Expired Permit	9000	9000	3XH
4250133793	RANDALL, E.	39	XTO ENERGY INC.	Active - Oil	9000	9000	39
4250137375	RIP WHEELER 705-668	5XH	RILEY PERMIAN OPERATING CO, LLC	Permitted Location	9000	9000	5XH
4250137358	RIP WHEELER 705-668	1XH	RILEY PERMIAN OPERATING CO, LLC	Permitted Location	9000	9000	1XH
4250133843	ELLIOTT	1	DELTA C02, LLC	Plugged - Oil	9050	9050	1
4250134124	RANDALL, E	46	EXXON CORP.	Canceled/Abandoned Location	9100	9100	46
4250133792	RANDALL, E.	40	XTO ENERGY INC.	Plugged - Oil	9591	9591	40
4250110079	RANDALL, E.	32	EXXON CORP.	Plugged - Oil	9615	9615	32
4250135418	RANDALL, E.	46	XTO ENERGY INC.	Active - Oil	9650	9650	46
4250134023	RANDALL, E.	42	XTO ENERGY INC.	Active - Oil	9660	9660	42
4250134016	RANDALL, E.	43	XTO ENERGY INC.	Active - Oil	9740	9740	43
4250132388	RANDALL, E.	38	EXXON CORP.	Canceled/Abandoned Location	10300	10300	38
4250137302	MILLER 732 B	9H	AMTEX ENERGY, INC.	Active - Oil	5183	10662	9H
4250136432	ROBERTS UNIT	261 H	APACHE CORPORATION	Active - Oil	5151	11117	261 H
4250136998	RATTLESNAKE AGI	1	SANTA FE MIDSTREAM PERMIAN LLC	Active - Injection/Disposal	11980	11980	1
4250137252	MILLER SWD	7	AMTEX ENERGY, INC.	Permitted Location	13000	13000	7
4250136984	MADCAP 731-706	1XH	RILEY PERMIAN OPERATING CO, LLC	Active - Oil	5261	13274	1XH
4250137127	MISS KITTY A 669-704	25XH	RILEY PERMIAN OPERATING CO, LLC	Active - Oil	5321	13428	25XH
4250137287	MISS KITTY A 669-704	4XH	RILEY PERMIAN OPERATING CO, LLC	Shut-In - Oil	5340	13452	4XH
4250137236	MISS KITTY 669-704	2XH	RILEY PERMIAN OPERATING CO, LLC	Active - Oil	5317	13622	2XH

Rattlesnake AGI No. 1
Maximum Monitoring Area
with
1/2-Mile MMA Oil/Gas Well Penetrators
Area of Review
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 6/1/2022	Approved by: RH

LONQUIST & CO. LLC
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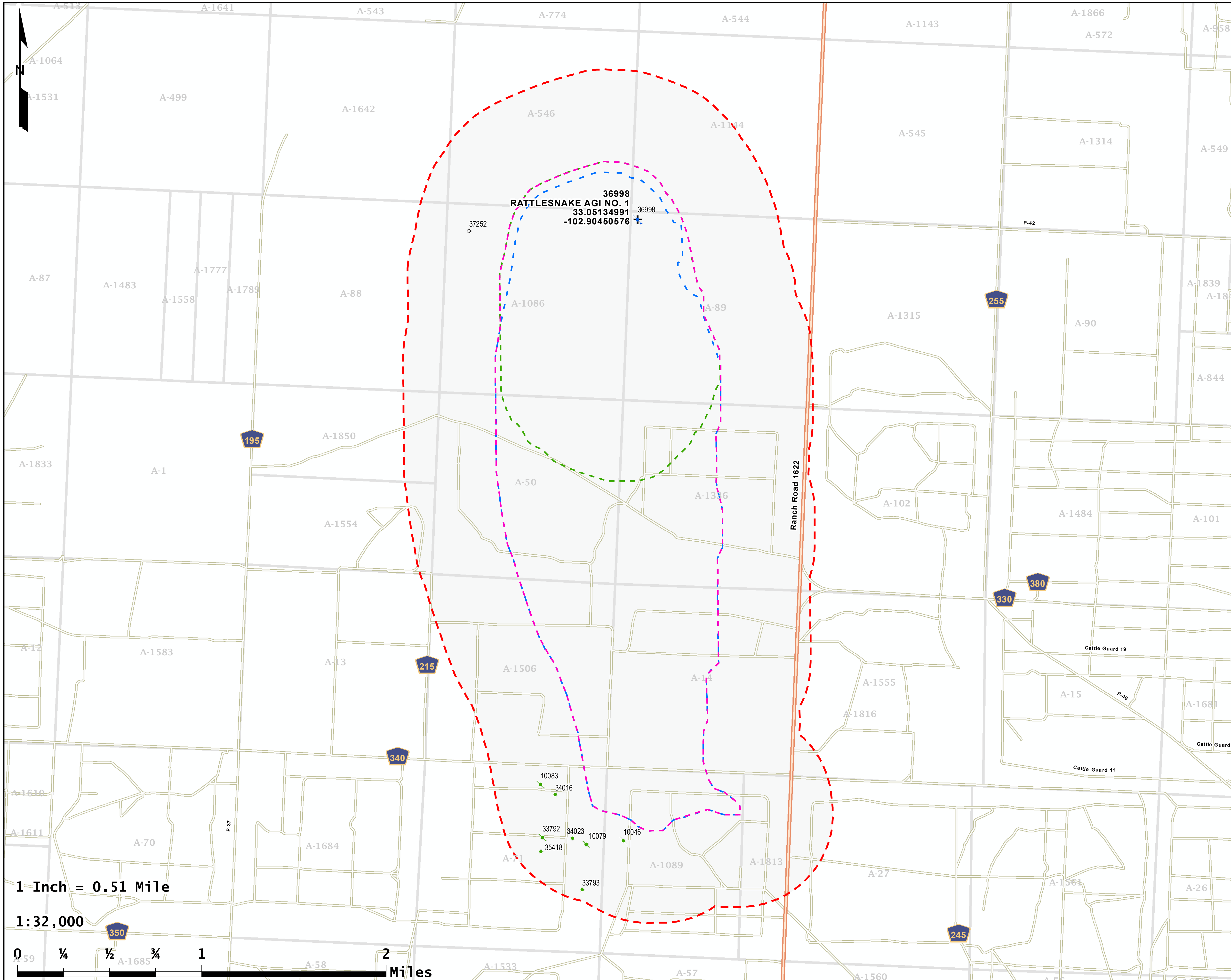
E-5



+ Rattlesnake AGI No. 1 SHL

1/2-Mile Buffer from Max. Plume Extent (MMA)

Combined Maximum Plume Extent

Stabilized Plume

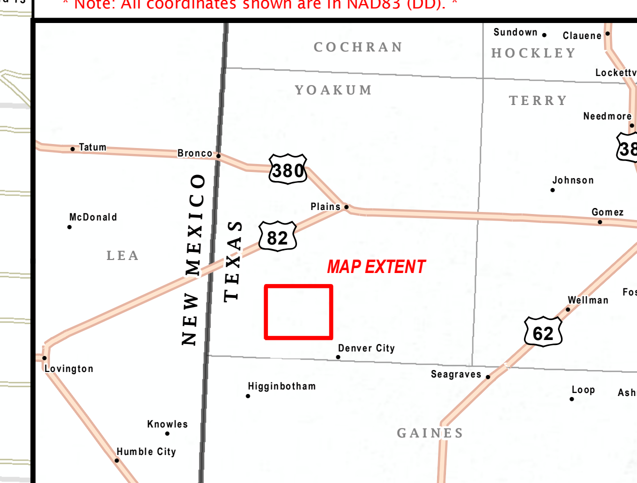
Plume Boundary at End of Injection

Abstract

API (42-501-...) SHL Status - Type (Count)

- Active - Oil (4)
- Active - Injection/Disposal (1)
- Plugged - Oil (4)
- Permitted Location (1)

Source:
1.) Oil/Gas Well SHL Data: DI-2022
2.) Oil/Gas Well BHL Data: DI-2022
3.) Oil/Gas Well Directional Data: DI-2022
* Note: All coordinates shown are in NAD83 (DD). *



Rattlesnake AGI No. 1
Maximum Monitoring Area
with
1/2-Mile MMA Groundwater Well
Area of Review
Stakeholder Midstream
Yoakum Co., TX

PCS: NAD83 TX-NC FIPS 4202 (US Ft.)

Drawn by: ER	Date: 5/31/2022	Approved by: RH

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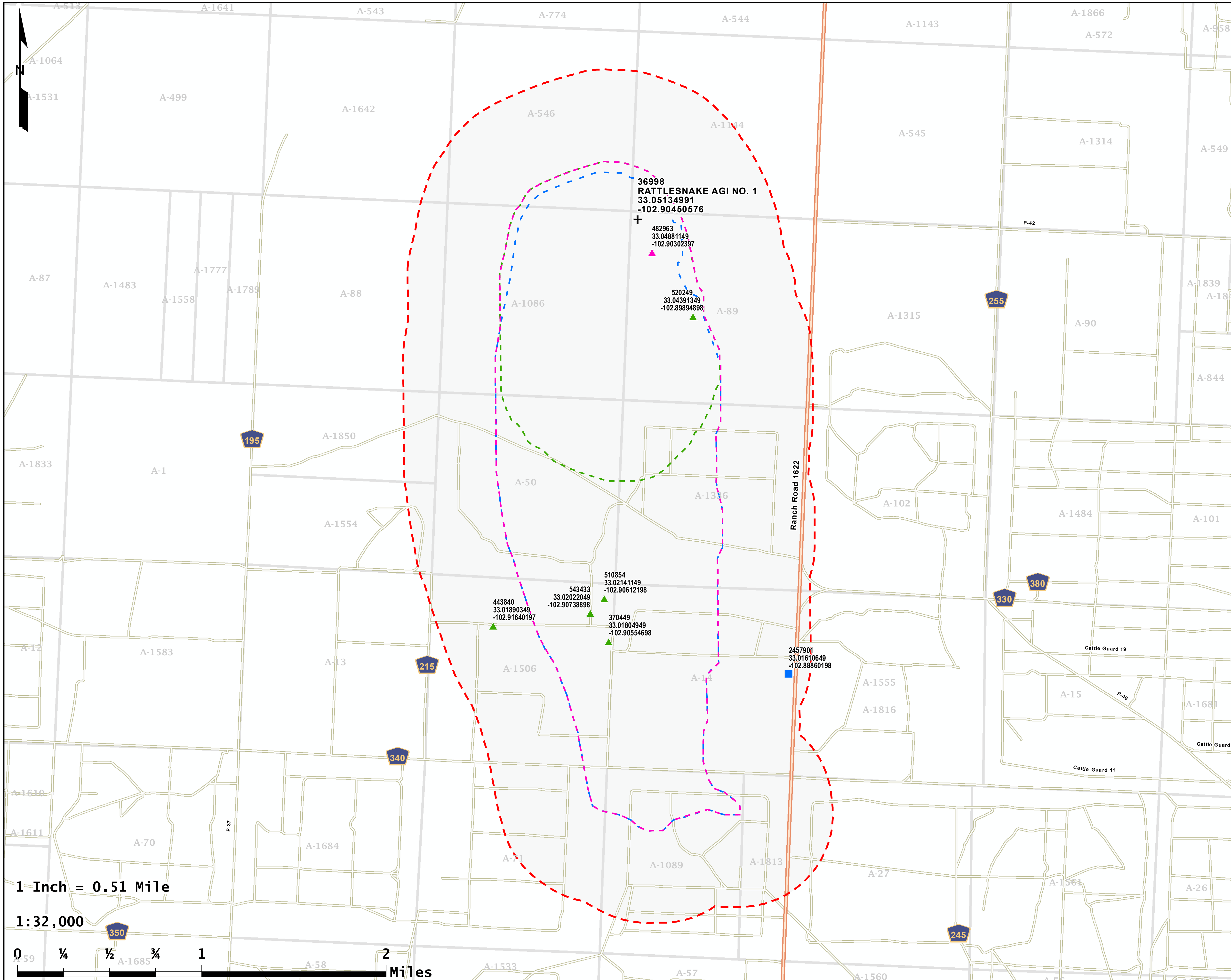
E-6

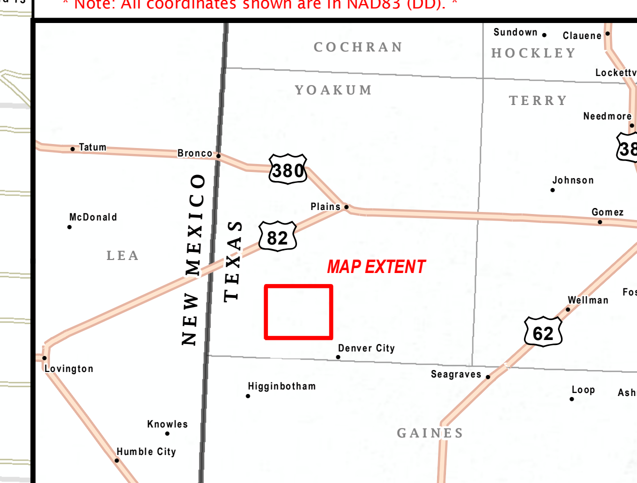


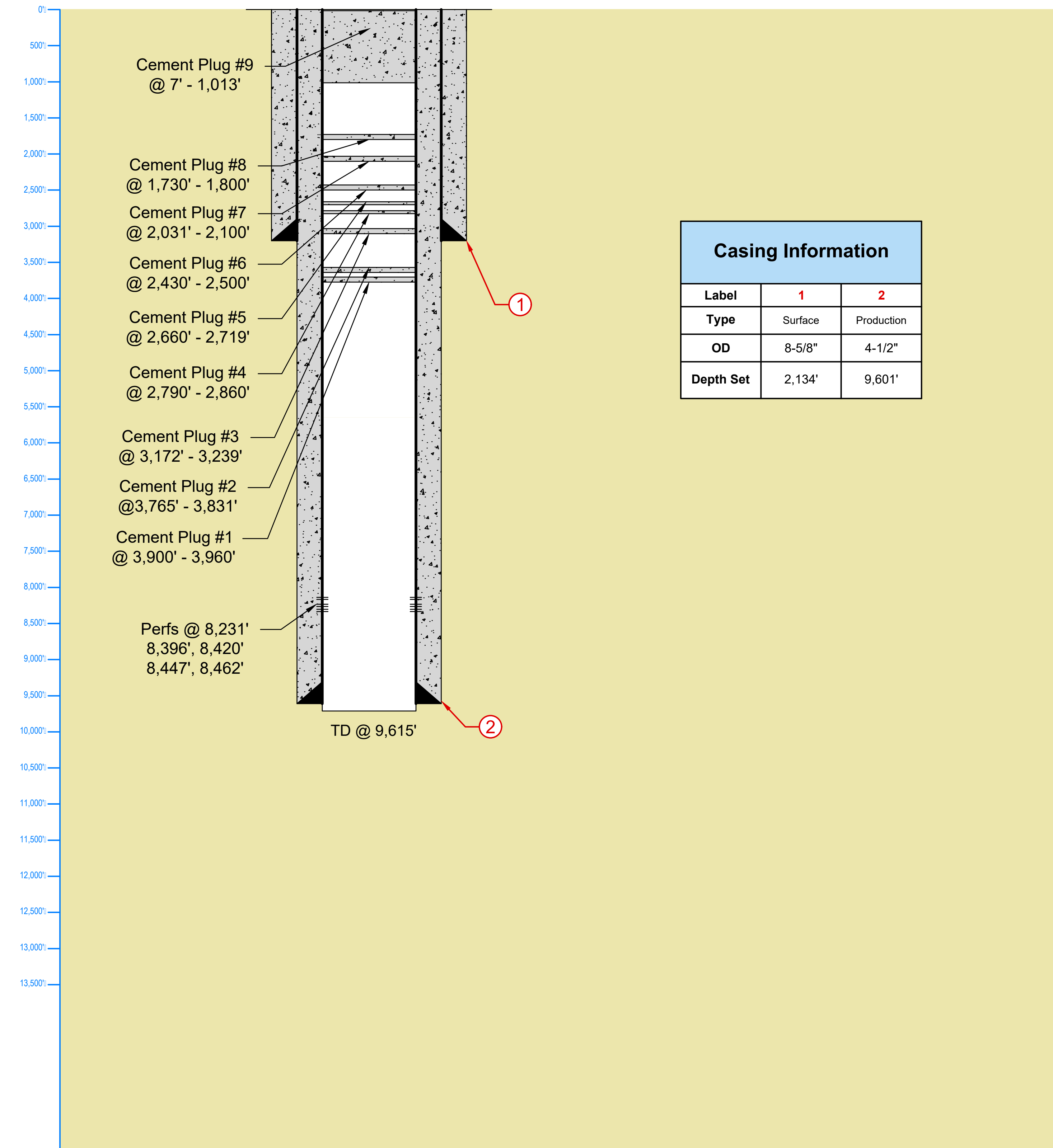
- Rattlesnake AGI No. 1 SHL
- 1/2-Mile Buffer from Max. Plume Extent (MMA)
- Combined Maximum Plume Extent
- Stabilized Plume
- Plume Boundary at End of Injection
- Abstract

SDRDB Groundwater Wells [TWDB-2022]
Proposed Use (Labeled with Well Report No.)
- Industrial (1)
- Irrigation (5)

TWDB Groundwater Wells [TWDB-2022]
Well Type (Labeled with State Well No.)
- Withdrawal of Water (1)

Source:
1.) SDRDB Groundwater Well SHL Data: TWDB-2022
2.) TWDB Groundwater Well SHL Data: TWDB-2022
3.) Brackish Groundwater Well SHL Data: TWDB-2022
* Note: All coordinates shown are in NAD83 (DD). *





Casing Information

Label	1	2
Type	Surface	Production
OD	8-5/8"	4-1/2"
Depth Set	2,134'	9,601'

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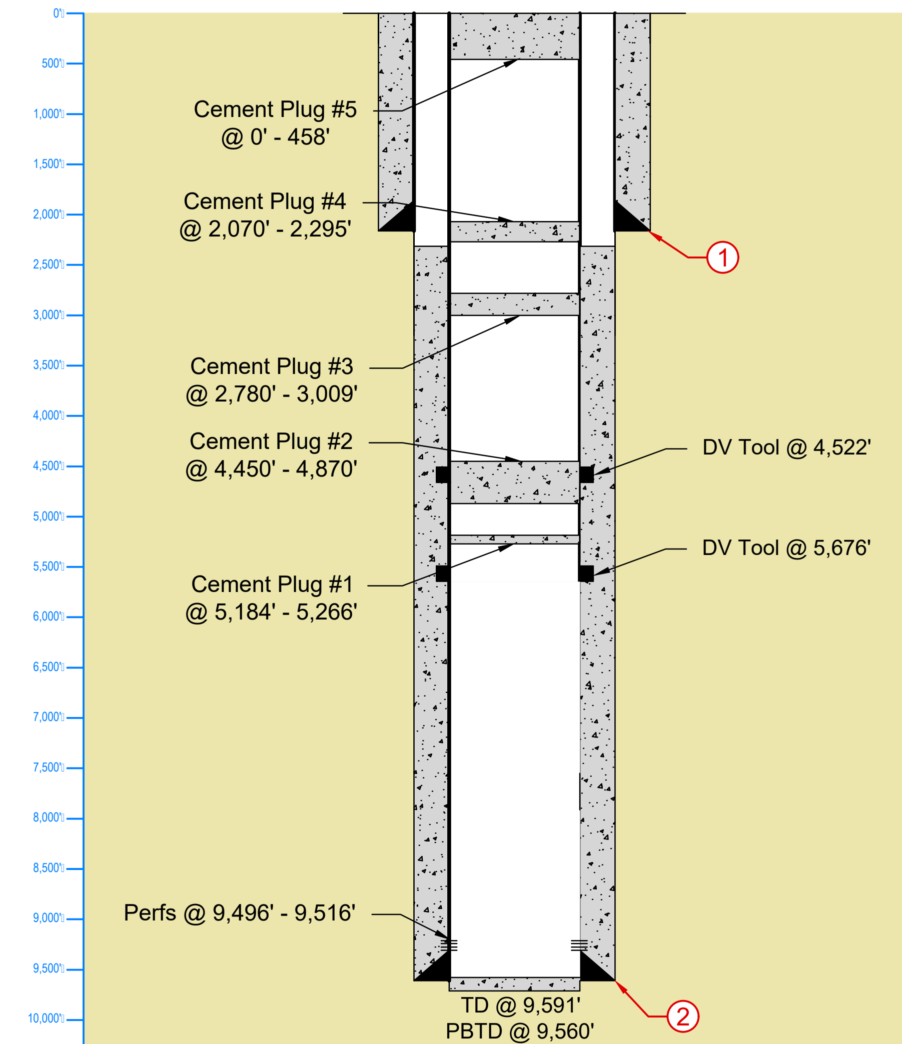
Exxon Corp.

E. Randall No. 32

E-7A

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 05/10/1965	**Survey:** John H. Gipson
API No: 42-501-10079	**Field:** Wasson (Wichita Albany)	**RRC Lease Number:** 18231
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing Information

Label	1	3
Type	Surface	Production
OD	9-5/8"	5-1/2"
Weight	36 lb/ft	UNK
Depth Set	2,162'	9,569'
Hole Size	12-1/4"	7-7/8"
TOC	Surface	2,350'
Volume	880 sks	5,450 sks

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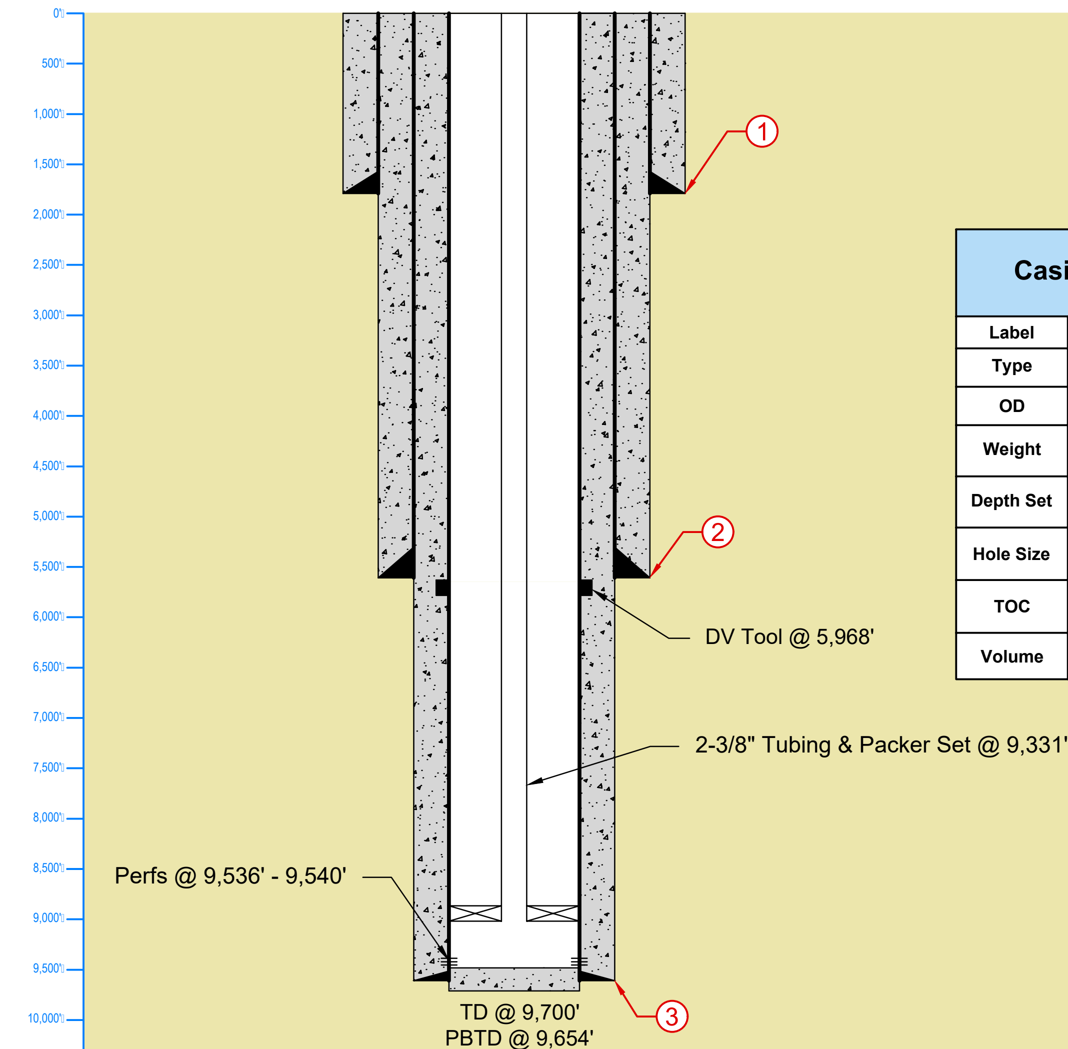
XTO Energy Inc.

E. Randall No. 40

E-7B

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 12/04/1992	**Survey:** John H. Gipson
API No: 42-501-337932	**Field:** Wasson (Wichita Albany)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP

Notes:



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54 lb/ft	36 lb/ft 40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,129'	5,606'	9,699'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	Surface
Volume	1,790 sks	2,910 sks	1,590 sks

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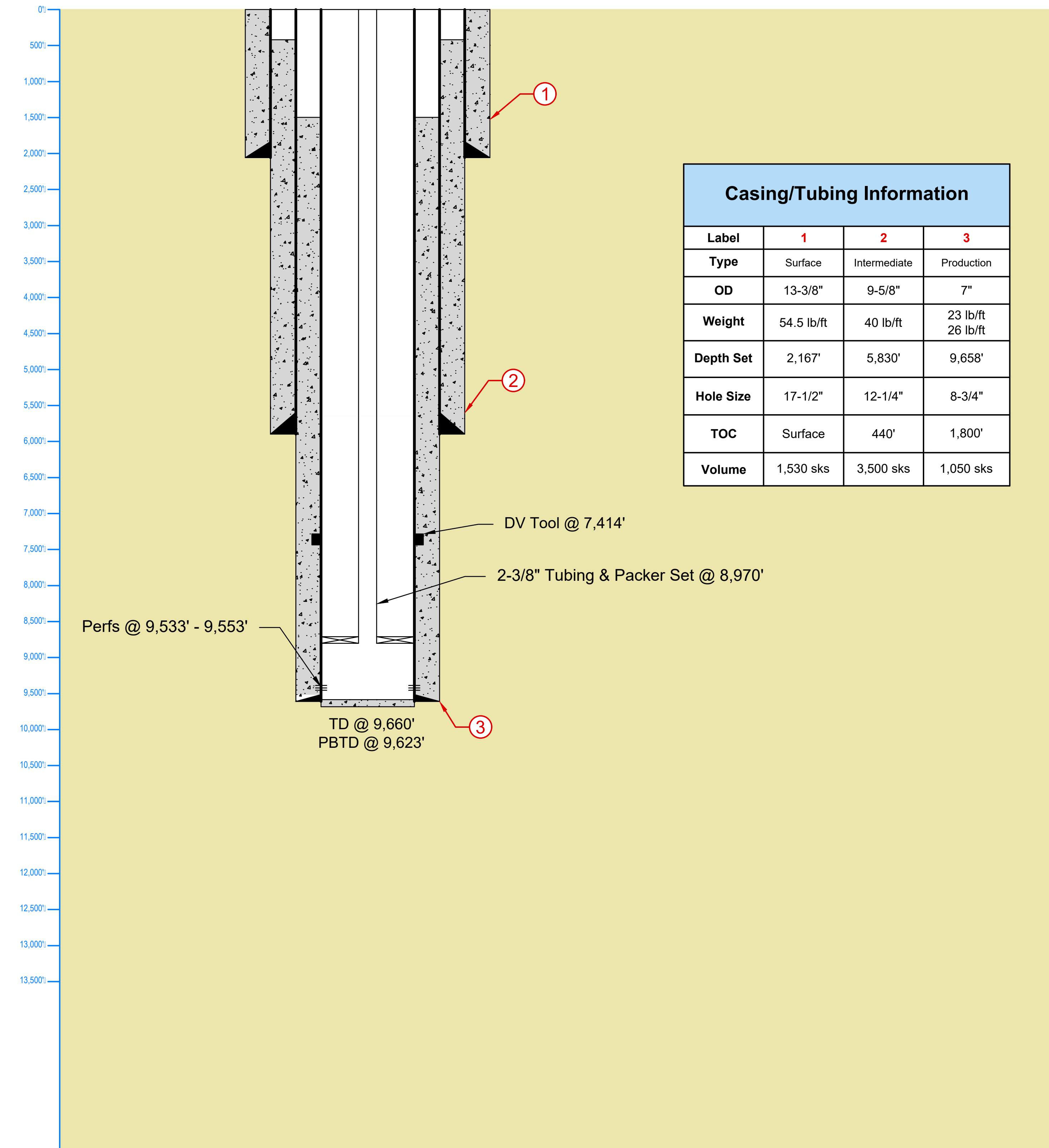
Exxon Corp.

E. Randall No. 41L E-7C

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 832, Block D	**Spud Date:** 02/05/1994	**Survey:** John H. Gipson
API No: 42-501-33885	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP

Notes:



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,167'	5,830'	9,658'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	440'	1,800'
Volume	1,530 sks	3,500 sks	1,050 sks

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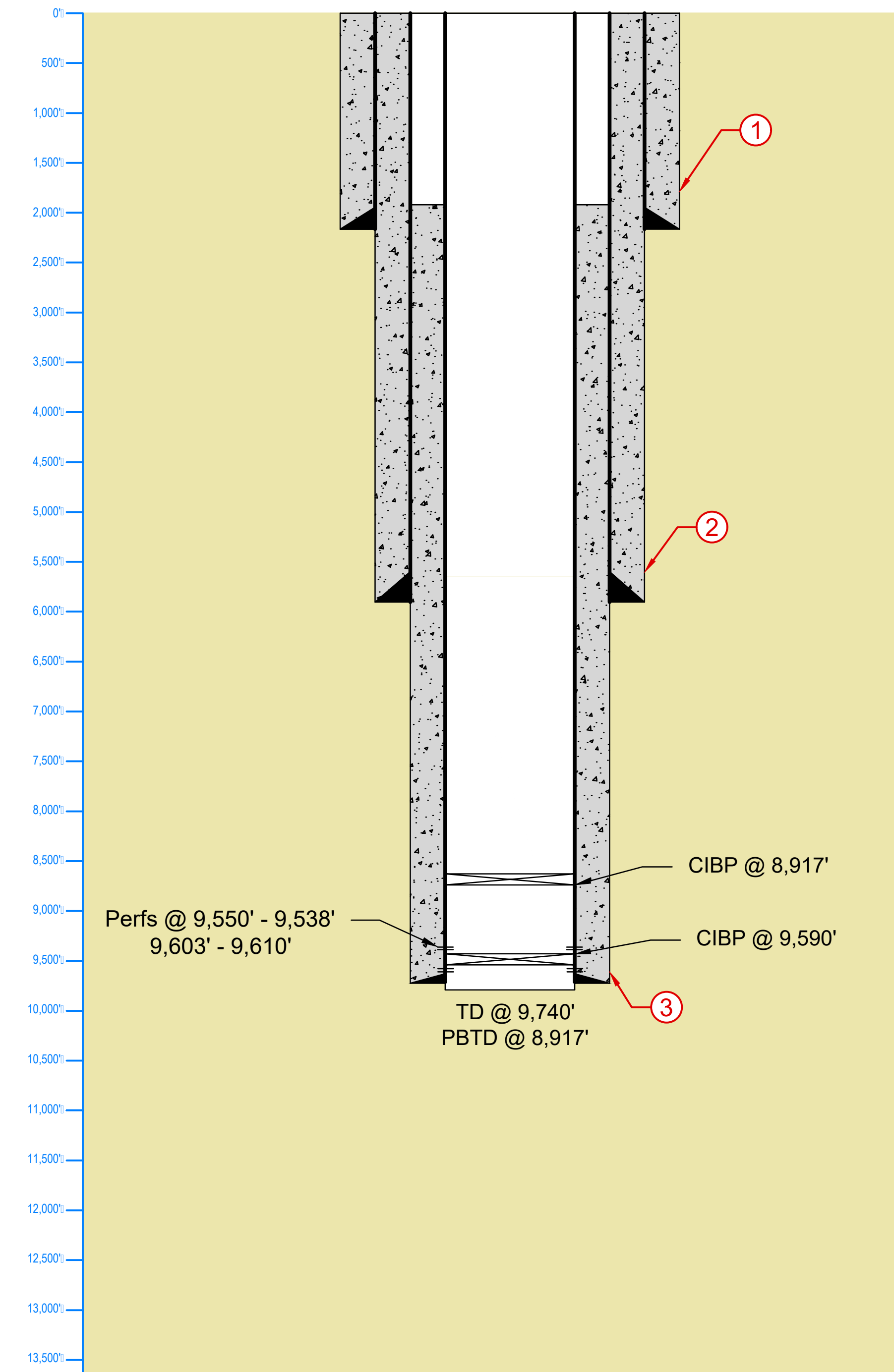
Exxon Corp.	E. Randall No. 42L	E-7D
Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 07/01/1995	**Survey:** John H. Gipson
API No: 42-501-34023	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,166'	5,902'	9,735'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	2,000'
Volume	1,530 sks	3,505 sks	967 sks

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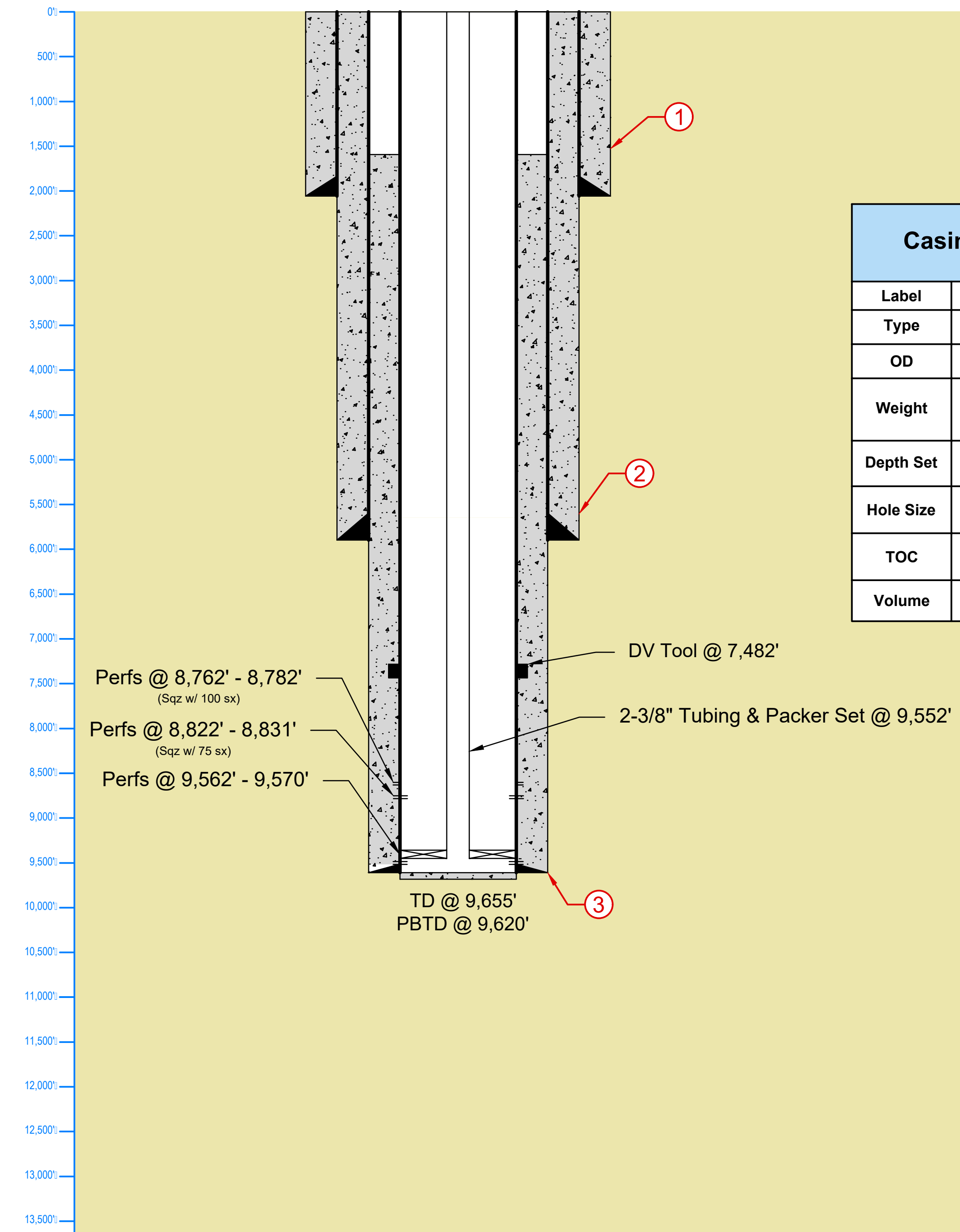
Exxon Corp.	E. Randall No. 43L	E-7E
Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 832, Block D	**Spud Date:** 04/08/1995	**Survey:** John H. Gipson
API No: 42-501-34016	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
	Notes:	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft 29 lb/ft
Depth Set	2,158'	5,904'	9,620'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	1,600'
Volume	1,450 sks	5,190 sks	1,100 sks

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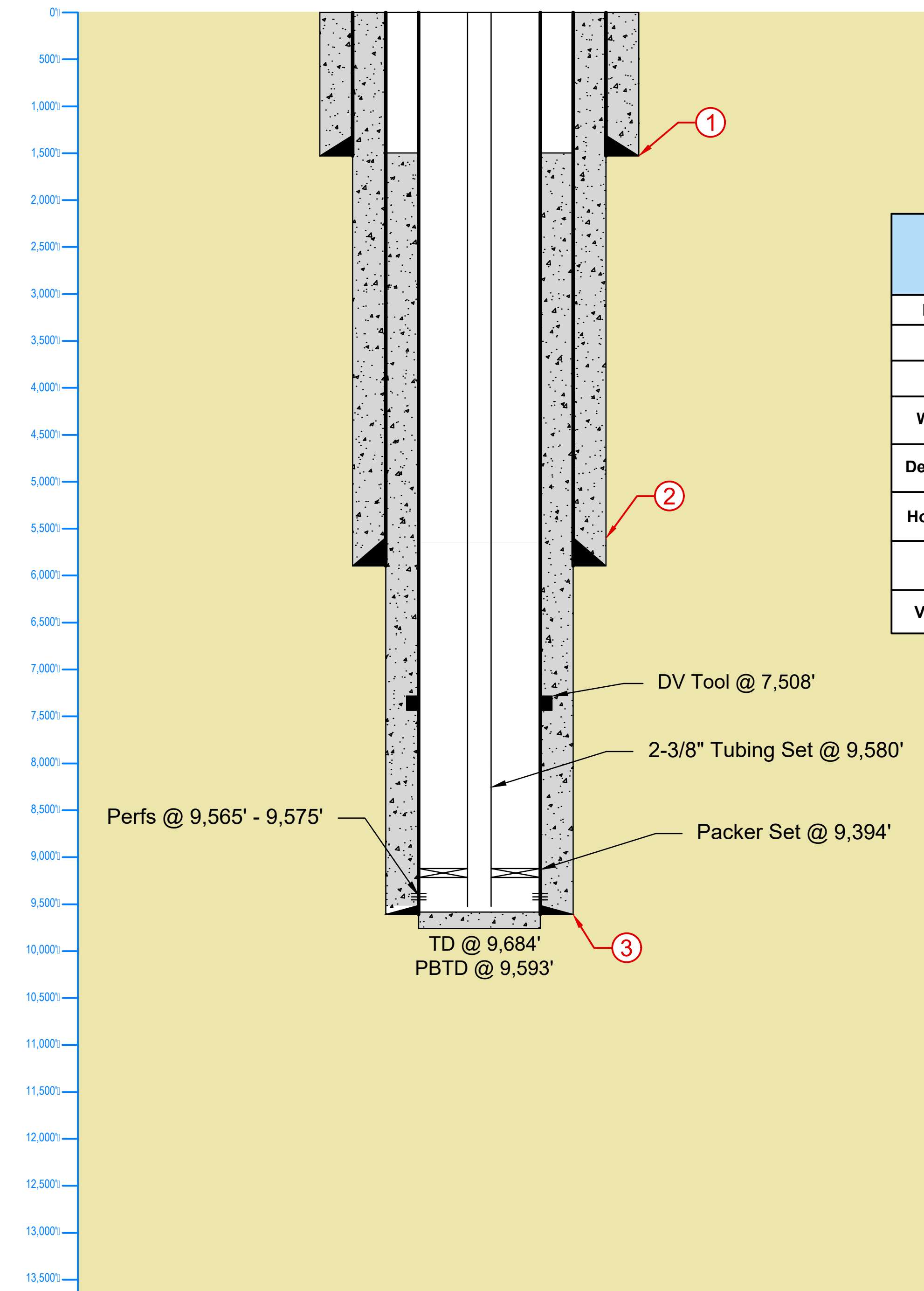
Exxon Corp.

E. Randall No. 44

E-7F

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 08/09/1995	**Survey:** John H. Gipson
API No: 42-501-34024	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP

Notes:



Casing/Tubing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	7"
Weight	54.5 lb/ft	40 lb/ft	23 lb/ft 26 lb/ft
Depth Set	2,175'	5,898'	9,615'
Hole Size	17-1/2"	12-1/4"	8-3/4"
TOC	Surface	Surface	1,500'
Volume	1,530 sks	3,525 sks	1,170 sks

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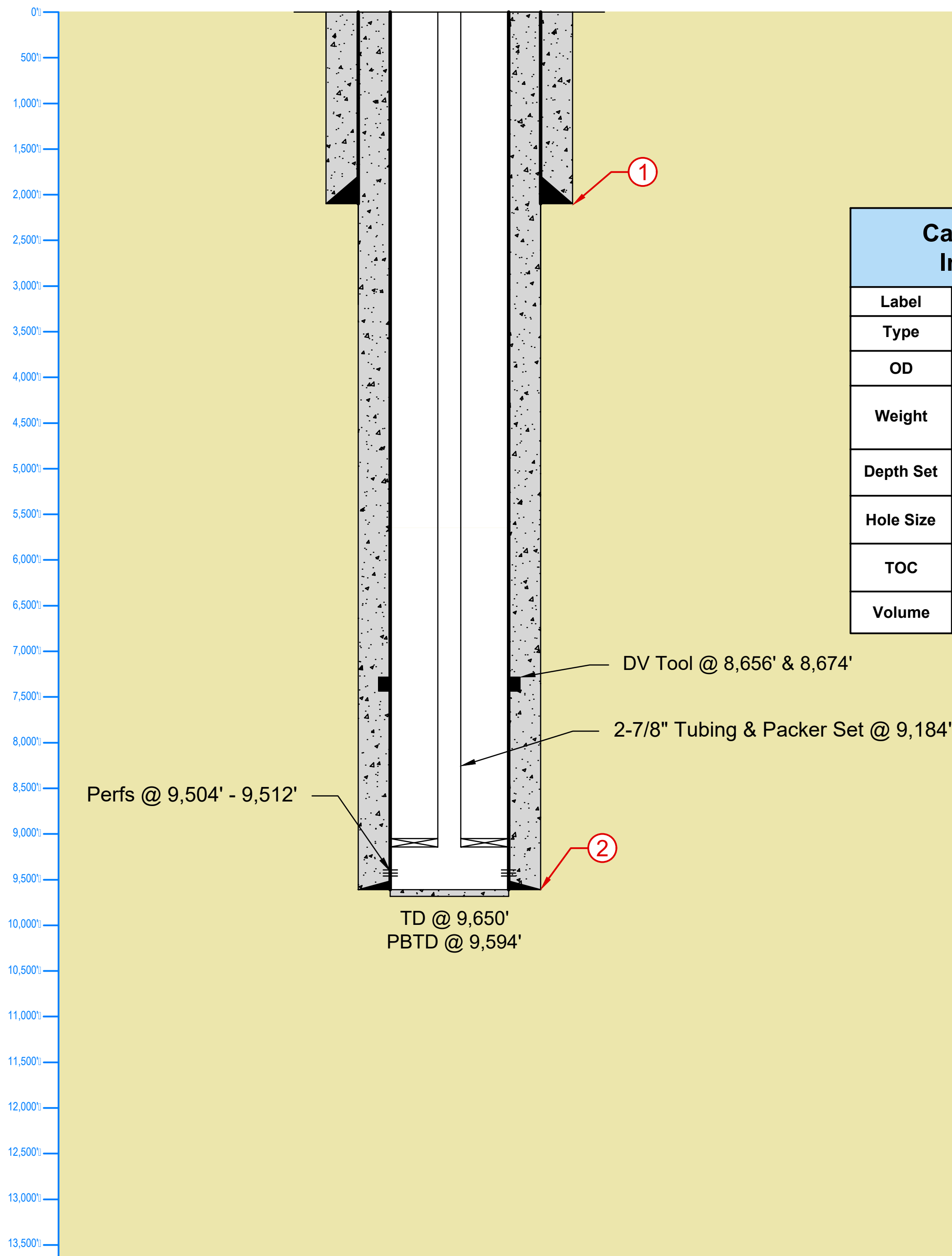
Texas License F-9147	**Country:** USA	**State/Province:** Texas	**County/Parish:** Yoakum
	Location: Section 833, Block D	**Spud Date:** 02/05/1994	**Survey:** John H. Gipson
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**API No:** 42-501-34017	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
	RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
	Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
		Notes:	



Casing/Tubing Information

Label	1	2
Type	Surface	Production
OD	8-5/8"	5-1/2"
Weight	24 lb/ft	17 lb/ft
Depth Set	2,120'	9,650'
Hole Size	11"	7-7/8"
TOC	Surface	Surface
Volume	900 sks	3,400 sks

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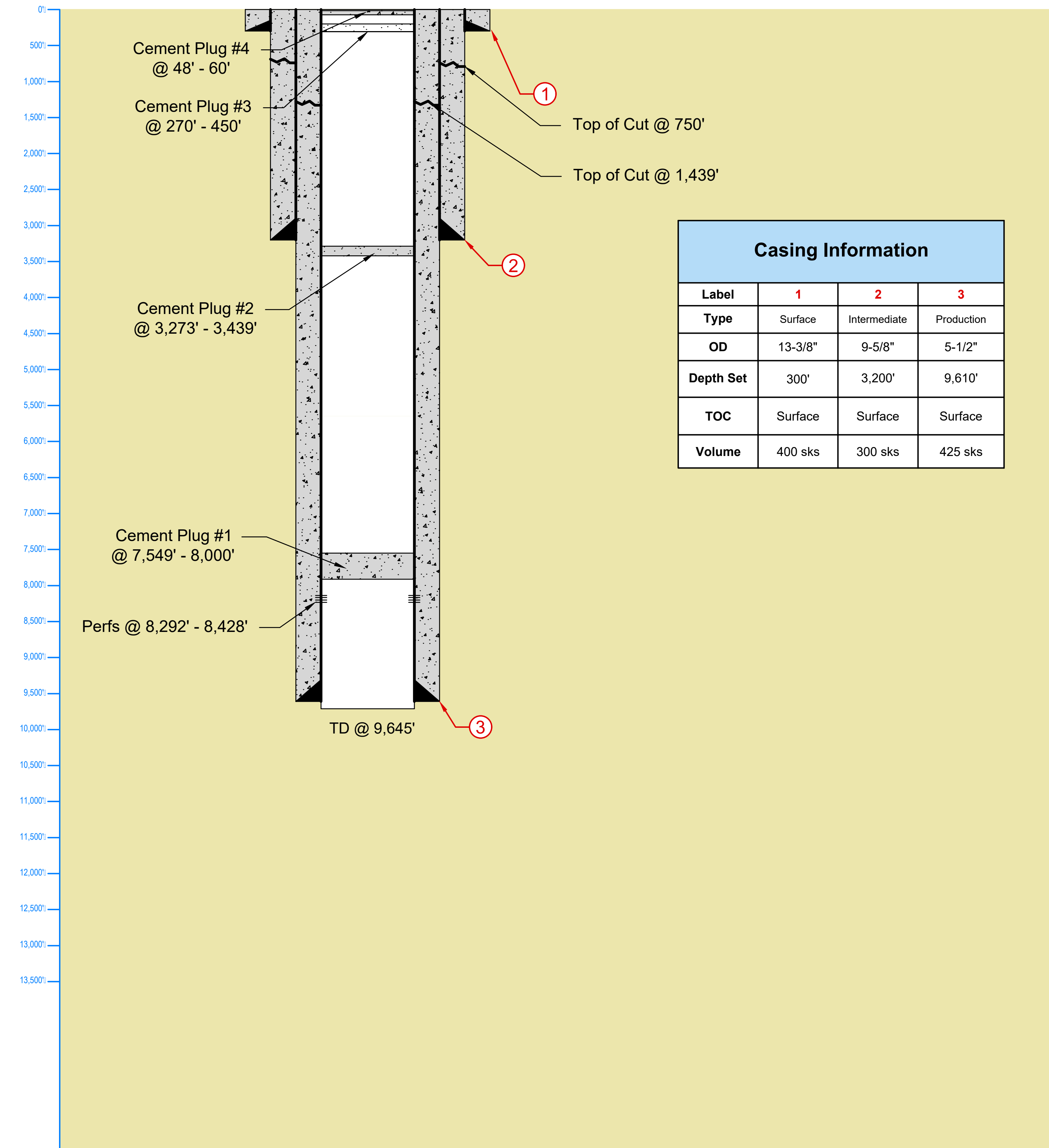
XTO Energy, Inc.

E. Randall No. 46 E-7H

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 833, Block D	**Spud Date:** 05/23/2007	**Survey:** John H. Gipson
API No: 42-501-35418	**Field:** Bruce (Silurian)	**RRC Lease Number:** 66970
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP

Notes:



Casing Information

Label	1	2	3
Type	Surface	Intermediate	Production
OD	13-3/8"	9-5/8"	5-1/2"
Depth Set	300'	3,200'	9,610'
TOC	Surface	Surface	Surface
Volume	400 sks	300 sks	425 sks

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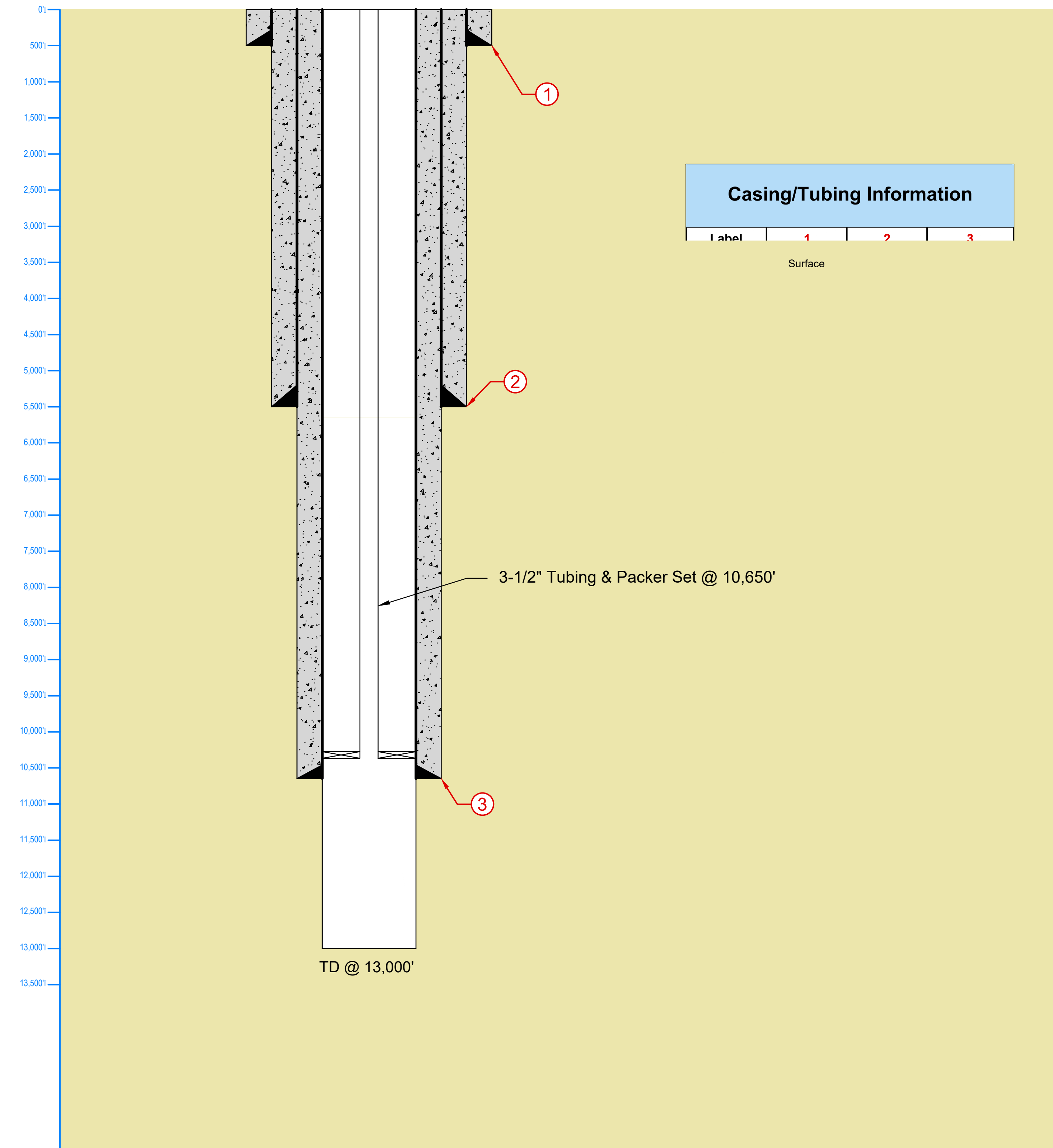
Bonanza Oil Corp.

C.A. Elliott No. 2 E-7I

Country: USA	**State/Province:** Texas	**County/Parish:** Yoakum
Location: Section 832, Block D	**Spud Date:** 05/10/1965	**Survey:** John H. Gipson
API No: 42-501-10046	**Field:** Wasson (Wichita Albany)	**RRC Lease Number:** 18875
RRC District No: 8-A	**Project No:** LS 128	**Date:** 05/31/2022
Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP

Notes:



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Texas License F-9147	**Country:** USA	**State/Province:** Texas	**County/Parish:** Yoakum
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Location:** Section 732, Block D	**Spud Date:** 08/09/1995	**Survey:** John H. Gipson
	API No: 42-501-37252	**Field:** Wasson	**Permit Number:** 16637
	RRC District No: 7-C	**Project No:** LS 128	**Date:** 05/31/2022
	Drawn: KAS	**Reviewed:** RKH	**Approved:** SLP
		Notes:	