For assistance in accessing this document, please contact ghgreporting@epa.gov.



OFFICE OF ATMOSPHERIC PROTECTION

WASHINGTON, D.C. 20460

September 25, 2024

Mr. Brad Rogers Bayswater Operating, LLC 1625 County Road 280 Westbrook, Texas 79565

Re: Monitoring, Reporting and Verification (MRV) Plan for Mongoose Amine Treating Facility

Dear Mr. Rogers:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Mongoose Amine Treating Facility, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Mongoose Amine Treating Facility on August 20, 2024, as the final MRV plan. The MRV Plan Approval Number is 1014747-1. This decision is effective September 30, 2024 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78. In conjunction with this MRV plan approval, we recommend reviewing the Subpart PP regulations to determine whether your facility is required to report data as a supplier of carbon dioxide. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

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

Mis Da L

Julius Banks Supervisor, Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for the Mongoose Amine Treating Facility

September 2024

Contents

1	Overview of Project	L
2	Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA)	2
3	Identification of Potential Surface Leakage Pathways	3
4	Strategy for Detecting and Quantifying Surface Leakage of CO2 and for Establishing Expected Baselines for Monitoring	3
5	Considerations Used to Calculate Site-Specific Variables for the Mass Balance Equation1	3
6	Summary of Findings10	5

Appendices

Appendix A: Final MRV Plan

Appendix B: Submissions and Responses to Requests for Additional Information

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 Bayswater Operating Company, LLC (Bayswater) for the Mongoose Amine Treating Facility (MATF) treated acid gas (TAG) injection project, which injects into the Ellenburger Formation. 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. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

1 Overview of Project

Section 1 of the MRV plan states that the MATF currently has a Class II UIC permit issued by the Texas Railroad Commission (TRRC) to inject TAG for the Mongoose acid gas injection (AGI) No. 1 well, API No. 42-335-36013, UIC No. 000125803. The permit was originally issued in March 2023 under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas). The MATF states that the permit currently authorizes the facility to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO₂) and hydrogen sulfide (H₂S) into the Ellenburger Formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose AGI No. 1 well is a new well located in a rural area of Mitchell County, Texas. The MRV plan also states that the MATF is currently seeking TRRC approval to amend the existing Mongoose AGI No. 1 well permit by increasing the permitted maximum quantity of injected TAG from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. The MATF intends to inject up to 19.5 MMscf/D into this well for approximately 40 years. The primary source of the injected CO₂ is the MATF.

Section 2 of the MRV plan discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the MATF. The MRV plan states that the Mongoose AGI No. 1 well will inject a CO₂ stream containing 41.2% CO₂ and 58.8% H₂S. The target injection interval for the Mongoose AGI No. 1 well, the Ellenburger Formation, is 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the MATF states that the Mongoose AGI No. 1 well and the MATF are designed to protect against leakage out of the injection interval, to protect against contaminating other subsurface formations, and to prevent surface releases.

The MRV plan states that the MATF is located on the Eastern Shelf of the greater Permian Basin of West Texas and New Mexico. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician. During the lower Ordovician period, the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture and irregular mottling patterns, likely indicative of bioturbation structures. These same features were interpreted in the open-hole logs from the Mongoose AGI No. 1 well and the cores from the offset well Buchanan 3111 #1XD. On the Eastern Shelf, the Ellenburger Formation is roughly 900 ft thick and dips west-southwest, towards the Midland Basin. The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. The predominant pore types of this group are ooid grainstone and ooid-peloid packstone-grainstone and reservoirs tend to be of good porosity and moderate permeability. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger Formation underwent significant "karsting" and dolomitization. This dolomitization process has facilitated porosity development within the Ellenburger Formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs.

The MRV plan states that the Devonian Woodford Formation will serve as the upper confining zone. The Ellenburger Group underlies the Woodford Formation on the Eastern Shelf, and the contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition. The Woodford shale was created through a widespread marine transgression. The MRV plan states that the U.S. Geological Survey (USGS) CO₂ Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit. The MATF states that permeability and porosity values from routine core analysis performed on rotary sidewall cores taken from the offset well Buchanan 3111 #1XD approximately 10.4 miles away reflect optimal confining characteristics and validate the USGS's assessment of an appropriate sealing formation for CO₂ storage.

According to the MRV plan, the Precambrian formations will serve as the lower confining zone. The MATF states that in the Permian Basin area, Precambrian formations are not normally specifically named in scientific literature. As a result, the MRV plan states these formations will be referred to as "Precambrian." Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sourced from outcrops in central Texas and the Trans-Pecos region of Texas and central New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section. Ellenburger injector wells were drilled through the Ellenburger section and reached total depths near the Precambrian. The MRV plan states that the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone. The lithologic and petrophysical characteristics of the Ellenburger Formation at the MATF indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity.

The description of the project 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

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 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.

According to the MRV plan, the modeling software used to evaluate this project was Computer Modeling Group's GEM 2023.2 (GEM) simulator. The plume boundary was defined by the weighted average gas saturation in the aquifer, and a weighted average value of 3% gas saturation was used to determine the boundary of the plume. The MATF states that when injection ceases after 40 years, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast. The MRV plan states that the MMA is the stabilized plume boundary after 120 years of density drift with an all-around buffer zone of one-half mile added. The MMA is displayed in Figure 42 of the MRV plan.

The MRV plan states that the initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free- phase CO₂ plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. MATF states that by 2036, a revised MRV plan will be submitted to define a new AMA. Figure 43 of the MRV plan shows the area covered by the AMA.

The delineations of the MMA and AMA are acceptable per the requirements in 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV plan are clearly 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 surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). The MATF identified the following as potential leakage pathways in Section 4 of their MRV plan that required consideration:

- Leakage from surface equipment
- Leakage through existing and future wells within the MMA
- Leakage through faults and fractures

- Leakage through the confining layer
- Leakage from natural or induced seismicity

A summary table of the MATF's evaluation of the likelihood, magnitude, and timing of any potential CO₂ leakage can be found in Table 12 of the MRV plan and is reproduced below.

Potential Leakage Pathway	Likelihood		Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. Two artificial penetrations were drilled into the gross injection interval. These wells were plugged in accordance TRRC requirements.	Low	Low. Vertical migration of CO ₂ would likely enter a shallower hydrocarbon production zone.	During active injection.
Faults and fractures	Unlikely. There are no faults within the modeled area. Bayswater monitors the area for seismic activity.	Low	Low. Vertical migration of CO ₂ would likely enter a shallower hydrocarbon production zone.	During active injection.
Upper confining layer	Unlikely. The lateral continuity of the Woodford Shale blanketing the Ellenburger is recognized as a very competent seal. There is 7,825' of overburden between the Injection Interval and the base of the USDW.	Low	Low. Vertical migration of CO ₂ would likely enter a shallower hydrocarbon production zone.	During active injection.
Natural or induced seismicity	Unlikely. There have been no seismic events of 3.0 magnitude or greater detected. There is over 7,825' of overburden between the Injection Interval and the base of the USDW.	Low	Low. Vertical migration of CO ₂ would likely enter a shallower hydrocarbon production zone.	During active injection.

Magnitude Assessment Description

Low - categorized as little to no impact to safety, health and the environment and the costs to mitigate are minimal.

Medium - potential risks to the USDW and for surface releases does exist, but circumstances can be easily remediated.

High - danger to the USDW and significant surface release may exist, and if occurs this would require significant costs to remediate.

3.1 Leakage from Surface Equipment

Section 4.1 of the MRV plan states that the MATF and the Mongoose AGI No. 1 well are newly designed and constructed facilities for treating and injecting acid gas with the fundamental objective of ensuring maximum safety for the public, the employees, and the environment. The site plan and the Mongoose AGI No. 1 wellbore schematic are depicted in Figures 44 and 45 of the MRV plan, respectively. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H₂S are installed at key locations around the MATF as depicted in the site plan in Appendix B-2 of the MRV plan. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H₂S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the TRRC with the Class II AGI application. OSHA sets the detection or exposure limits at 15 parts per million (ppm) as the High Alarm and the High- High Alarm or Facility Shutdown limit at 40 ppm.

The MATF states that these facilities have been designed and constructed with other safety systems to provide for safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the MATF and Mongoose AGI No. 1 well. The MATF installed a flare stack to safely depressurize piping and equipment if an event occurs. These valves, gas monitors, and the gas flow meter are called out in the detailed site plan in Appendix B-2 of the MRV plan. Data from this flow meter will be used in the calculations of the total mass of CO₂ (in metric tons) in the CO₂ stream injected each year, per 40 CFR §98.444(b).

The MRV plan states that with the level of monitoring implemented at the MATF, a release of CO_2 would be quickly identified, and the safety systems would minimize the release volume. The acid gas stream injected into the Mongoose AGI No. 1 well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the well is from the amine treater in the MATF adjacent to the well. The MATF will increase its future injection volumes from its own gas production and possibly other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release in accordance with 40 CFR §98.448(a)(5). The MATF concludes that the leakage of CO_2 through the surface equipment is unlikely.

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

3.2 Leakage through Existing Wells within the MMA

Section 4.2 of the MRV plan states the Mongoose AGI No. 1 well was designed to prevent migration from the injection interval to the surface through a special casing and cementing design. Mechanical

integrity tests (MIT), required under Statewide Rule (SWR) §3.46 [40 CFR §146.23(b)(3)], will take place every five years to verify that the well and wellhead can contain the appropriate operating pressures. The MRV plan also states that if an MIT were to indicate a leak, the well would be isolated, and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 46 of the MRV plan as well as Appendix C of the MRV plan. According to the MRV plan, two wells penetrate the MMA's gross injection zone. These wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements. There are additional wells that are shallower and do not penetrate the injection zone, but they are isolated by the Woodford Shale. The MRV plan states that the Woodford Shale provides 50 ft or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset artificial penetrations is unlikely. The MRV plan also states that Bayswater is the operator of many of the shallower offset oil and gas wells within the MMA and frequently performs gas analysis on their production volumes.

Future Drilling

The MRV plan states that potential leakage pathways caused by future drilling in the area are not expected to occur. The deeper formations, such as the Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC around the MATF 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. The Ellenburger is among the formations listed for which operators in Mitchell County and district 8 (where the MATF is located) are required to comply with TRRC Rule 13. 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. The MRV plan also states that in this instance, any new well permitted and drilled to the Mongoose AGI No. 1 well's injection zone and located within a one-quarter-mile radius of the well, will be required under TRRC Rule 13 to set steel casing and cement above the MATF's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and 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.

Groundwater Wells

The MRV plan states that a groundwater well search resulted in three groundwater wells found within the MMA, as identified by the Texas Water Development Board. The surface, intermediate, and production casing strings in the Mongoose AGI No. 1 well, as shown in Figure 45 of the MRV plan, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the Groundwater Advisory Unit (GAU) letter issued for this location. The MRV plan also states that the wellbore casings and cements also prevent CO₂ leakage to the surface along the borehole. For these

reasons, the MATF concludes that leakage of the sequestered CO₂ to the groundwater aquifer is unlikely.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through existing wells within the MMA.

3.3 Leakage through Faults and Fractures

Section 4.3 of the MRV plan states that no faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose AGI No. 1 well. This includes areas outside the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

The MRV plan states that in the event of an unmapped fault existing within the plume boundary, any displacement would be below 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing vertical migration.

Porosity development within the injection intervals is primarily attributed to fractures and aerial exposure. However, these fractures are limited and do not extend into the upper confining unit, which helps mitigate the risk of migration through fractures outside of the designated injection interval.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected through faults and fractures.

3.4 Leakage through the Confining Layer

Section 4.4 of the MRV plan states that the overlying Woodford Formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in Section 2 of the MRV plan. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale, which would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

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

3.5 Leakage from Natural or Induced Seismicity

Section 4.5 of the MRV plan states that the Mongoose AGI No. 1 well is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic

Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48 of the MRV plan, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

The MRV plan states all seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, MATF states the risks associated with injectate migration beyond the injection interval are unlikely. Additionally, stringent operating procedures will be programmed into the SCADA and control systems to ensure that operating pressures stay below the fracture gradient of both the injection and confining intervals.

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

Thus, the MRV plan provides an acceptable characterization of potential CO_2 leakage pathways as required by 40 CFR 98.448(a)(2).

4 Strategy for Detecting and Quantifying Surface Leakage of CO₂ 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 CO₂, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring potential CO₂ leakage. Section 5 of the MRV plan discusses the strategy that the MATF will employ for detecting and quantifying surface leakage of CO₂ through the pathways identified in Section 4 of the MRV plan, to meet the requirements of 40 CFR 98.448(a)(3). As the injectate stream contains both H₂S and CO₂, the H₂S will be a proxy for CO₂ leakage and therefore the monitoring systems in place to detect H₂S will also indicate a release of CO₂. Monitoring will occur during the planned 40-year injection period, or otherwise the cessation of operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

A summary table of the MATF's strategies for monitoring and responding to any potential CO₂ leakage can be found in Table 13 of the MRV plan and is reproduced below.

Leakage Pathway	Monitoring Method
	Fixed H_2S monitors throughout the AGI facility

	Visual inspections
Leakage from surface equipment	SCADA continuous monitoring of the AGI facility
	SCADA continuous monitoring of the AGI well
	Monitor CO ₂ levels in Above Zone producing wells
Leakage through existing wells	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Annual soil gas sampling at well locations that penetrate the Upper Confining Zone within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	Compliance with TRRC Rule 13 Regulations
Loakago through faults and fracturos	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO ₂ levels in Above Zone producing wells
Lookage through the confining lover	SCADA continuous monitoring at the AGI well (volumes and pressures)
	Monitor CO ₂ levels in Above Zone producing wells
Loakago from natural or induced coismicity	Monitor CO ₂ levels in Above Zone producing wells
	Monitor existing TexNet station

4.1 Detection of Leakage from Surface Equipment

Section 5.1 of the MRV plan states that as the MATF and Mongoose AGI No. 1 well are designed to reduce the possibility of CO₂ and H₂S escaping, 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 connections are designed to minimize corrosion points. A baseline atmospheric CO₂ concentration will be established during the commissioning of the MATF. Ambient H₂S monitors located at the MATF and near the Mongoose AGI No. 1 well are connected to the SCADA system for continuous monitoring.

The MRV plan states the MATF 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 surface equipment associated with the sequestered CO_2 and inspection of the cathodic protection system. These inspections and the automated systems allow the MATF to respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5) and §98.444(d).

The MRV plan states that pressures and flow rates 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, including pressure, flow rate, size of the leak point opening, and duration of the leak.

Table 13 of the MRV plan provides a detailed characterization of detecting diffuse CO₂ leakage that could be expected from surface equipment. Thus, the MRV plan provides adequate characterization of MATF's approach to detect potential leakage from surface equipment as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through Existing and Future Wells within the MMA

Section 5.2 of the MRV plan states that the MATF continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems for the Mongoose AGI No. 1 well. These data are reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. The Mongoose AGI No. 1 well 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 injection or annular pressure would indicate the presence of a possible leak. In addition, an MIT will be performed every 5 years, as required by the TRRC and UIC regulations. The MIT would also indicate the presence of a leak if a leak were to occur. The MRV plan explains that upon a negative MIT, the well would be isolated, and the leak mitigated.

As discussed previously in the MRV plan, Rule 13 would ensure that new wells in the field will be constructed to prevent migration from the injection interval.

In addition to the fixed monitors described previously, the MRV plan states that the MATF will also establish and operate an in-field soil gas monitoring program to detect CO₂ leakage within the AMA. This would include sample collection and testing for CO₂ and H₂S at the AGI well site and near one of the identified artificial penetrations of the injection interval within the MMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. The MRV plan also states that prior to approval and implementation of the MRV plan and through the post-injection site care period, the MATF will have these monitoring systems in place.

According to the MRV plan, two wells have been identified within the AMA that penetrate the upper confining zone. As both wells have been plugged and abandoned in compliance with TRRC requirements, MATF believes a leak event is unlikely. The MRV plan states MATF will perform soil gas sampling and analysis proximate to the Mongoose and one of the abandoned artificial penetrations by May 20, 2024. Thereafter, soil gas samples will be taken annually and analyzed by a third-party lab, and the results will be included in the annual report.

The MRV plan reiterates that Bayswater is the operator of many oil and gas producing wells with the AMA. These wells will be used as a proxy for an above-zone monitoring well. If any CO₂ migrates uphole, the CO₂ will likely end up in this formation. Since gas analysis is performed on a regular basis on the hydrocarbons produced from this formation, any material variance from historical data would indicate the potential of an issue needing further investigation.

Groundwater Quality Monitoring

The MRV plan states that no groundwater wells were found within the MMA after an extensive search of records. Therefore, there are no groundwater wells to monitor.

Table 13 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through existing and future wells within the MMA. Thus, the MRV plan provides adequate characterization of MATF's approach to detect potential leakage through existing and future wells within the MMA as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage through Faults, Fractures, or Confining Seals

Section 5.3 of the MRV plan states the MATF continuously monitors the operations of the Mongoose AGI No. 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 due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken to shut in the well, if necessary.

The MRV plan also states the MATF will monitor production from their oil and gas wells that do not penetrate the injection zone for any material variance in CO_2 content in the produced gas stream. Since gas analysis is very consistent over time, any material variance in the CO_2 content would be an early indicator of a potential issue. Should the CO_2 migrate vertically, the magnitude risk of this event would be very low, as the reservoir provides an ideal containment given the upper confining zone has successfully held hydrocarbons in place.

Table 13 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected through faults, fractures, or confining seals. Thus, the MRV plan provides adequate characterization of MATF's approach to detect potential leakage through faults, fractures, or confining seals as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage from Natural or Induced Seismicity

The MRV plan states that while the likelihood of a natural or induced seismicity event is extremely low, the MATF plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose AGI No. 1 well. This station is 3.5 miles west-northwest of the well location, as shown in Figure 49 of the MRV plan. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the MATF. The MATF will monitor this station for any seismic activity that occurs near the well. The MRV plan also states if a seismic event of 3.0 magnitude or greater is detected, the MATF will review the injection volumes and pressures of the Mongoose AGI No. 1 well to determine if any significant changes have occurred that would indicate potential leakage.

Table 13 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected from natural or induced seismicity. Thus, the MRV plan provides adequate characterization of

MATF's approach to detect potential leakage from natural or induced seismicity as required by 40 CFR 98.448(a)(3).

4.5 Quantification

Section 7 of the MRV plan states that the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, the MATF believes the most appropriate method to quantify the mass of CO₂ released will be determined on a case-by-case basis. Any mass of CO₂ detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. The MRV plan also states in the unlikely event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline.

4.6 Determination of Baselines

Section 6 of the MRV plan identifies the strategies that the MATF will undertake to establish the expected baselines for CO₂ surface leakage per 40 CFR §98.448(a)(4). The MRV plan states the MATF will use existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of CO₂. The MRV plan identifies the following strategies for determining baselines:

Visual Inspections

The MRV plan states regular inspections will be conducted by field personnel at the MATF and the Mongoose AGI No. 1 well. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken to address such issues.

CO₂/H₂S Detection

The MRV plan states that in addition to the fixed gas monitors at the well site, the MATF will perform an annual soil gas sampling program to detect any CO₂ leakage proximate to select artificial penetrations of the Upper Confining Zone within the AMA. The baseline determination will include atmospheric H₂S measurements at the AGI well and soil gas sampling near the AGI well and one of the abandoned artificial penetrations within the AMA.

These soil gas sample probes will be inserted below the surface and collect samples over a 21-day period. These samples will then be sent to a third-party laboratory to be analyzed for CO₂, H₂S, and trace contaminants typically found in a hydrocarbon gas stream. This initial sample collection is scheduled to be completed by May 20, 2024; a sufficient time period prior to the implementation of the MRV plan and will establish baseline values for future reference.

Operational Data

The MRV plan states that upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO₂.

Continuous Monitoring

The MRV plan states the total mass of CO₂ emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the OSHA Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) limit of 5,000 ppm. Direct leak surveys are hazardous due to the presence of H₂S in the acid gas stream. The mass of the CO₂ released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. According to the MRV plan, this method is consistent with 40 CFR §98.448(a)(5) and §98.444(d), allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a de-pressuring event, the acid gas stream will be diverted to a flare stack to be safely processed and vented. The event will be reported as required for the operation of the well.

Thus, the MRV plan provides an acceptable approach for detecting and quantifying leakage and for establishing expected baselines in accordance with 40 CFR 98.448(a)(3) and 40 CFR 98.448(a)(4).

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

5.1 Determining Mass of CO₂ Received

According to Section 7 of the MRV plan, the CO_2 received for the Mongoose AGI No. 1 well is wholly injected and not mixed with any other supply. Therefore, the MATF states 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.

MATF provides an acceptable approach to calculating the mass of CO_2 received under subpart RR requirements.

5.2 Determining Mass of CO₂ Injected

The MRV plan states since the mass of CO₂ injected will be measured with a volumetric flow meter, the total annual mass of CO₂, in metric tons, will be calculated by multiplying the volumetric flow at standard conditions by the CO₂ concentration in the flow and the density of CO₂ at standard conditions, according to Equation RR-5:

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

Where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

MATF provides an acceptable approach to calculating the mass of CO₂ injected under subpart RR requirements.

5.3 Mass of CO₂ Produced

The MRV plan states the Mongoose AGI No. 1 well is not part of an enhanced oil recovery project; therefore, no CO₂ will be produced.

5.4 Calculation of Mass of CO₂ Emitted by Surface Leakage

The MRV plan states that the mass of CO₂ emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains high concentrations of H₂S. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required, and those emissions sent to a flare stack and reported as a part of the required GHG reporting for the MATF. Any leakage

would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of CO_2 and H_2S . The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

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



Where:

CO_{2E} = Total annual CO₂ 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 also states calculation methods using equations from subpart W will be used to calculate CO₂ emissions due to any surface equipment leakage between the flow meter used to measure injection quantity and the injection wellhead.

MATF provides an acceptable approach for calculating the mass of CO₂ emitted by surface leakage under subpart RR requirements.

5.5 Calculation of Mass of CO₂ Sequestered

The MRV plan states that the mass of CO₂ sequestered in subsurface geologic formations will be calculated based on Equation RR-12 as the Mongoose AGI No. 1 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_{21} = 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 CO₂ mass emitted (metric tons) by surface leakage in the reporting year.

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

The MRV plan states that CO_{2FI} will be calculated in accordance with subpart W reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required, and those emissions are sent to a flare stack and reported as part of the required GHG reporting for the MATF. The MRV plan also states 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.

MATF provides an acceptable approach for calculating the mass of CO₂ sequestered under subpart RR requirements.

6 Summary of Findings

The subpart RR MRV plan for the Mongoose Amine Treating Facility meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the MATF MRV plan.

Subpart RR MRV Plan Requirement	MATF 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. The MMA boundary was established by taking the stabilized plume boundary after 120 years of density drift and adding a one half-mile buffer. The initial AMA boundary was established by superimposing the area based on a one half-mile buffer around the anticipated plume location after 12 years of injection (2036) with the area of the projected free-phase CO ₂ plume at five additional years (2041).

40 CFR 98.448(a)(2): Identification of	Section 4 of the MRV plan identifies and evaluates the
potential surface leakage pathways for CO ₂	potential surface leakage pathways. MATF identifies
in the MMA and the likelihood, magnitude,	the following potential pathways: leakage from surface
and timing, of surface leakage of CO ₂	equipment; leakage through existing wells within the
through these pathways.	MMA; leakage through faults and fractures, leakage
	through the confining layer; and leakage from natural
	or induced seismicity. The MRV plan analyzes the
	likelihood, magnitude, and timing of surface leakage
	through these pathways.
40 CFR 98.448(a)(3): A strategy for	Sections 5 and 7 of the MRV plan describe both
detecting and quantifying any surface	strategies for how the MATF intends to detect CO_2
leakage of CO ₂ .	leakage to the surface and how the leakage would be
	quantified, should leakage occur. The MRV plan states
	that leaks would be detecting using methods such as
	visual inspections, SCADA systems, MITs, soil gas
	sampling, groundwater sampling, TexNet monitoring,
	and in-field as well as personal H ₂ S monitors.
	Continue Confident MDV when the operation that
40 CFR 98.448(a)(4): A strategy for	Section 6 of the MRV plan describes the strategy that
establishing the expected baselines for	the MATE will employ to establish baselines against
monitoring CO ₂ surface leakage.	which monitoring results can be compared to assess
	following strategies viewel increasing U.S.(CO
	following strategies: visual inspections, H ₂ S/CO ₂
	monitoring, monitoring of operational data, and
	continuous monitoring.
40 CFR 98.448(a)(5): A summary of the	Section 7 of the MRV plan describes MATF's approach
considerations you intend to use to	to determining the amount of CO ₂ sequestered using
calculate site-specific variables for the mass	the subpart RR mass balance equation, including as
balance equation.	related to calculation of total annual mass emitted
	from equipment leakage.
	Continue 1 of the MADY when any video the small
40 CFR 98.448(a)(6): For each injection	Section 1 of the MRV plan provides the well
well, report the well identification number	injection numbers for the Mongoose AGI NO. 1
used for the OIC permit (or the permit	Injection well. The MRV plan specifies that the wells
application) and the OIC permit class.	nave been issued a OIC class II permit under TRRC Rule
	9 and Rule 36.
40 CFR 98.448(a)(7): Proposed date to	Section 8 of the MRV plan states that the MATF will
begin collecting data for calculating total	begin collecting data for calculating the total amount of
amount sequestered according to equation	CO ₂ sequestered according to Equation RR-12 of this
RR-11 or RR-12 of this subpart.	subpart upon receiving approval from EPA.

Appendix A: Final MRV Plan



Subpart RR Monitoring, Reporting, and Verification (MRV) Plan Mongoose AGI No. 1

Mitchell County, TX

Prepared for *Bayswater Operating Company LLC* Denver, CO

By

Lonquist Sequestration, LLC Austin, TX

> Version 4.0 August 2024



INTRODUCTION

Bayswater Operating Company LLC (Bayswater) currently has a Class II acid gas injection (AGI) permit, issued by the Texas Railroad Commission (TRRC) for the Mongoose AGI No. 1 well (Mongoose), API No. 42-335-36013. The permit was issued March 10, 2023. This permit authorizes Bayswater to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO₂) and hydrogen sulfide (H₂S) into the Ellenburger formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose is a new well and is associated with the Mongoose Amine Treating Facility (the Plant) located in a rural area of Mitchell County, Texas, as shown in Figure 1.



Figure 1 – Location of Mongoose AGI No. 1 Well

Bayswater is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Bayswater is also seeking TRRC approval to amend the existing Mongoose permit by increasing the permitted maximum quantity of injected treated acid gas (TAG) from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. Bayswater intends to inject into this well for approximately 40 years up to a maximum of 19.5 MMscf/D. The primary source of this injected CO₂ gas is the Mongoose Amine Treating Facility. Table 1 shows the expected composition of the gas stream to be sequestered. Table 2 shows the expected average daily volume of acid gas.

Table 1 – Expected Gas Composition

Component	Mol Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

Table 2 – Expected Sequestered Gas Volumes

Contract Status	Avg. Rate (MMscf/D)
Committed	6.9
Proposed	12.6
Total	19.5

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH ₄	Methane
CMG	Computer Modelling Group Carbon Dioxide (may also refer to other Carbon
CO ₂	- · ·
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H ₂ S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet

MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
Ν	North
NAD	North American Datum
NW	Northwest
OBG	Overburden Gradient
OSHA	Occupational Safety and Health Administration
PG	Pore Gradient
рН	Scale of Acidity
PISC	Post Injection Site Care
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
ТОС	Total Organic Carbon
TRRC	Texas Railroad Commission
UCZ	Upper Confining Zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

TABLE OF CONTENTS

INTRO	DUCTIO	Ν	2
ACRO	NYMS AI	ND ABBREVIATIONS	4
SECTIC	DN 1 – U	IC INFORMATION	10
1.1	Unde	rground Injection Control Permit Class: Class II	10
1.2	UIC V	Vell Identification Number	10
1.3	Repo	rter Number	10
1.4	Facili	ty Address	10
SECTIC) N 2 – P	ROJECT DESCRIPTION	11
2.1	Regiona	l Geology	11
	2.1.1	Regional Faulting	20
2.2	Site C	Characterization	20
	2.2.1	Stratigraphy and Lithologic Characteristics	20
	2.2.2	Upper Confining Zone – Woodford Shale	21
	2.2.3	Injection Interval – Ellenburger	29
	2.2.4	Lower Confining Zone – Precambrian-age formations	38
2.3	Geon	nechanics	40
	2.3.1	Determination of Vertical Stress (S _v) from Density Measurements	40
	2.3.2	Elastic Moduli and Fracture Gradient	40
2.4	Local	Structure	42
2.5	Inject	ion and Confinement Summary	46
2.6	Grou	ndwater Hydrology	46
2.7	Desci	iption of the Injection Process	52
	2.7.1	Current Operations	52
2.8	Rese	voir Characterization Modeling	52
	2.8.1	Simulation Modeling	55
SECTIC	DN 3 – D	ELINEATION OF MONITORING AREA	64
3.1	Maxi	mum Monitoring Area	64
3.2	Activ	e Monitoring Area	65
SECTIC	DN 4 – P	OTENTIAL PATHWAYS FOR LEAKAGE	67
4.1	Leaka	age from Surface Equipment	68
4.2	Leaka	age Through Existing Wells Within the MMA	71
	4.2.1	Future Drilling	74
	4.2.2	Groundwater Wells	74
4.3	Leaka	age Through Faults and Fractures	74
4.4	Leaka	age Through the Confining Layer	75
4.5	Leaka	age from Natural or Induced Seismicity	75
SECTIC	DN 5 – N	1ONITORING FOR LEAKAGE	77
5.1	Leaka	age from Surface Equipment	78
5.2	Leaka	age Through Existing and Future Wells Within the MMA	78
5.3	Leaka	age Through Faults, Fractures, or Confining Seals	80
5.4	Leaka	age Through Natural or Induced Seismicity	80
SECTIC	DN 6 – B	ASELINE DETERMINATIONS	82
6.1	Visua	I Inspections	82

6.2	CO ₂ /H ₂ S Detection	82
6.3	Operational Data	82
6.4	Continuous Monitoring	82
SECTION	7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION	83
7.1	Mass of CO ₂ Received	83
7.2	Mass of CO_2 Injected	83
7.3	Mass of CO ₂ Produced	84
7.4	Mass of CO ₂ Emitted by Surface Leakage	84
7.5	Mass of CO ₂ Sequestered	85
SECTION	8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN	87
SECTION	9 – QUALITY ASSURANCE	88
9.1	Monitoring QA/QC	88
9.2	Missing Data	88
9.3	MRV Plan Revisions	89
SECTION	10 – RECORDS RETENTION	90
SECTION	11 - REFERENCES	91

Figures

Figure 1 – Location of Mongoose AGI No. 1 Well2
Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red
star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, &
Walsh)12
Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)13
Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf14
Figure 5 - Cross section indicating formation truncations when approaching the Eastern Shelf
(Waite, 2021)15
Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger
Group of the Permian Basin, West Texas, 2006)16
Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth17
Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks,
2003)
Figure 9 – Type Log and Disposal Units and Zones from PXD Well No. 1 (Sanchez, Loughry, &
Coringrato, 2019)
Figure 10 – Mongoose AGI No. 1 Type Log20
Figure 11 – Buchanan 3111 #XD location Offset well for Core Data22
Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting
the Woodford and sidewall cores23
Figure 13 – Core Photo of Samples Within the Woodford Formation24
Figure 14 – Routine Core Analysis Within the Woodford Formation25
Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation26
Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation
Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation28

Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)....32 Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells36 Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map......43 Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)......47 Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986)......50 Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011)......51 Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model54 Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)......58 Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)59 Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation) Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection) Figure 40 – North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)......62 Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Figure 43 – Active Monitoring Area66 Figure 45 – Mongoose AGI No. 1 Wellbore Schematic70 Figure 46 – All Oil and Gas Wells Within the MMA.....72 Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA......73 Figure 48 – Seismicity Review (TexNet – 08/04/2023)76

igure 49 – Seismic Events and Monitoring Station81
--

Tables

Table 1 – Expected Gas Composition	3
Table 2 – Expected Sequestered Gas Volumes	3
Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples	38
Table 4 – Calculated Vertical Stresses	40
Table 5 – Fracture Gradient Calculation Inputs and Results	41
Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamk	ourger
Jr., 1967)	47
Table 7 – Gas Composition at the Plant Outlet	52
Table 8 – Modeled Initial Gas Composition	53
Table 9 – GEM Model Layer Package Properties	55
Table 10 – Offset SWD Wells Included in GEM Model	56
Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injection	63
Table 12 – Potential Leakage Pathway Risk Assessment	67
Table 13 – Summary of Leakage Monitoring Methods	77

Appendices

Appendix A – TRRC MONGOOSE AGI No. 1 FORMS

- Appendix A-1 UIC Class II Order
- Appendix A-2 GAU Groundwater Protection Determination
- Appendix A-3 Drilling Permit
- Appendix A-4 Completion Report

Appendix B – Site Safety and Layout

- Appendix B-1 Operating Safety Plan
- Appendix B-2 Mongoose Site Plan

Appendix C – Area of Review

- Appendix C-1 Oil and Gas Wells Within the MMA Map
- Appendix C-2 Oil and Gas Wells Within the MMA List

Appendix D – Section 2 Cross Sections

Appendix D-1 – Figure 28 – Structural Cross Section Depicting the Ellenburger Appendix D-2 – Figure 29 – Stratigraphic Cross Section Flattened on the Ellenburger

SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the UIC Class II program. The TRRC classifies Mongoose AGI No. 1 as a UIC Class II well. A Class II permit was issued to Bayswater on March 10, 2023, under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

1.2 UIC Well Identification Number

Mongoose AGI No. 1, API No. 42-335-36013, UIC No. 000125803

1.3 <u>Reporter Number</u>

- Facility Name: Mongoose Amine Treating Facility
- Greenhouse Gas Reporting Program ID: 586481
 - Currently reporting under Subpart UU
- Operator: Bayswater Operating Company LLC

1.4 Facility Address

Mongoose Amine Treating Facility 1625 County Road 280 Westbrook, Texas 79565

Coordinates in North American Datum of 1983 (NAD 83) for this facility:

Latitude: 32.4225396641 Longitude: -101.1714709142

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Mongoose AGI No. 1 well.

The Mongoose injects both H_2S and CO_2 into Ellenburger formation at a depth of 8,300 ft to 9,000 ft, and approximately 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The Mongoose is located on the Eastern Shelf, as shown in the area map in Figure 2, within the greater Permian Basin of west Texas and New Mexico. The Permian Basin covers more than 86,000 square miles extending across an area approximately 250 miles wide and 300 miles long. The TRRC cites that the greater Permian Basin accounts for close to 40% of all oil production within the United States and nearly 15% of natural gas production. A general cross section of the basin is presented in Figure 3.

The ancestral Tobosa Basin was formed by structural flexure in the Precambrian basement at the southern margin of the North American Craton, or Laurentian Plate, during the Proterozoic (Popova, 2020). The modern form of the Permian Basin was shaped during the Carboniferous period due to the collision between Laurasia and Gondwana forming the supercontinent Pangea. The following uplift of the Central Basin Platform differentiated the greater basin into the Delaware Basin in the west, and the Midland Basin in the east along with its surrounding shelf margins (Popova, 2020).



Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, & Walsh).



Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)

The target injection interval for the Mongoose is the Ellenburger formation. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician (Sanchez, Loughry, & Coringrato, 2019). The Ellenburger is of lower Ordovician age and underlies the Woodford formation on the Eastern Shelf. The contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition (Sanchez, Loughry, & Coringrato, 2019). Many formations that are present within the Midland Basin are eroded and not seen upon reaching the Eastern Shelf. A cross section showing these truncations is displayed in Figure 5.

A generalized stratigraphic column of the Eastern Shelf is shown in Figure 4, with the target-injection formation indicated by the red star and historically productive formations indicated in the green stars. The Ellenburger formation is roughly 900 ft thick on the Eastern Shelf as shown by the isopach thickness map in Figure 6 (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006). On the Eastern Shelf, the Ellenburger formation dips to the west-southwest, towards the Midland Basin, and its subsea depth is roughly 6,000 ft (Sanchez, Loughry, & Coringrato, 2019). Figure 7 displays a structure map of the Ellenburger formation. Being far from any major sources of terrigenous clastic sediment input and at a time of a greenhouse climate leading to warm waters created an ideal setting primed for massive carbonate production during the Ellenburger deposition (Waite, 2021). The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. Predominant pore types of this group determined by Holtz and Kerans are "ooid grainstone; ooid-peloid packstone-grainstone"

and reservoirs tend to be of good porosity and moderate permeability (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006).



Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf


Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf (Waite, 2021).



Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006)



Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth.

The lower Ordovician period on the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture. Within this dolomite, there were irregular mottling patterns, likely indicative of bioturbation structures. Mudstone and peloid-wackestone, although in

Subpart RR MRV Plan – Mongoose AGI No. 1

smaller quantities, were also observed in the area (Kerans, 1990). To visually represent these different depositional environments and their corresponding lithologies, a map is presented in Figure 8. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger formation underwent significant "karsting" and dolomitization. This karsting process resulted in the formation of extensive paleocave systems within the Ellenburger, which later collapsed and led to the creation of widespread brecciated and fractured carbonates. These formations are responsible for the occurrence of many Ellenburger reservoirs, according to Loucks (2006).



Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

In their research on saltwater disposal (SWD) injection into the Ellenburger, Pioneer Natural Resources describes three distinct facies within the formation as noted in the Figure 9 type log. The upper and middle facies are composed of fracture breccia, breccia fabrics, and matrix-supported breccia, which coincide with collapsed paleo cave facies as described by Loucks. The lower unit does not exhibit these characteristics but shows a high volume of small vugs (inch-scale) and large-dissolution features (foot-scale) and represents an area of the Ellenburger with elevated porosity and permeability (Sanchez, Loughry, & Coringrato, 2019).





2.1.1 Regional Faulting

The modeled area near the Mongoose does not show any faults. However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area. This fault trend runs north-south in parallel with the dip. Figure 7 displayed this fault trend, which is the only example of such a trend within the area. Apart from this, the basin area is structurally inactive.

2.2 <u>Site Characterization</u>

The following section discusses site-specific geological characteristics of the Mongoose.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 shows an annotated well log for Mongoose that goes from the surface to the total depth. It indicates the injection and primary upper confining units with regional formation tops.



Figure 10 – Mongoose AGI No. 1 Type Log

2.2.2 Upper Confining Zone – Woodford Shale

The upper confining unit is the Upper Devonian age Woodford formation. The Woodford Shale, a late Devonian-aged organic-rich rock, was created through a widespread marine transgression. The deposition of the Woodford spread across a large area of the Permian Basin, producing a low-relief blanket of shale. The Woodford formation is an organic-rich petroleum source rock comprised of uncharacteristically highly radioactive, dark fissile shale and siltstone (Merril et al., 2015). Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991). As shown in Figure 5, the Wristen Group is a formation that lies directly below the Woodford to the west of the Mongoose location. The Wristen Group pinches out and is not found at the Mongoose location. However, the sealing nature of the Woodford, as described by Comer (1991), also provides confinement for the Ellenburger at this location. The Woodford formation overlies both unconformably and is diachronous to the underlying Ellenburger formation at the Mongoose location. The U.S. Geological Survey (USGS) CO₂ Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit (SAU) (Merril et al., 2015).

Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose. The Buchanan 3111 #1XD is approximately 10.4 mi. from the Mongoose as depicted in Figure 11. Figure 12 is a stratigraphic cross section showing the correlating cored Woodford formation (pink triangles representing cored intervals) in the Buchanan 3111 #1XD and the Mongoose wells. Routine core analysis, rock mechanics, and threshold entry pressure tests were performed on the core samples from the Woodford formation.

Core photos of the samples taken and analyzed within the Woodford are shown in Figure 13. The black shale unit exemplifies a well cemented unit with little to no fracturing. Routine core analysis was performed on these two samples, which includes bulk density, matrix permeability (as received and as under dry and Dean Stark extracted conditions), gas-filled porosity, gas saturation, grain density, porosity, oil saturation, and water saturation. The results are shown in Figure 14, with the footnotes at the base giving details on the testing processes of each value.

Under the dry and Dean Stark extracted conditions, permeability values of 2.2E-07 millidarcy (mD) were observed with even lower values of 4.87E-07 mD in the as-received samples. Porosities within the same sample were 1.3% when dried and .25% when gas-filled. These permeability and porosity values reflect optimal confining characteristics and validate the USGS assessment of an appropriate sealing formation for CO_2 storage.

To ensure these sealant properties would not be compromised by pressure influence of the injected fluid, a threshold entry pressure test was examined on these Woodford core samples. Figure 15 depicts a graph of permeability vs. pressure showing that, even with pressure increases up to 2,000 pounds per square inch (psi), permeability readings are still in the nano-darcy range. These values are shown in table form in Figure 16 against the pressures administered on the core, with the highest pressure being 2,000 psi. Given that permeability values were lowest (4.03E-07 mD) at 2,000 psi, it can be assumed that the threshold entry pressure of the Woodford formation was not met and

would be greater than 2,000 psi. Additionally, a table summary is depicted in Figure 17. These characteristics gathered from the Buchanan core provide a high level of detail into the confining nature of the Woodford Shale and alleviate any concerns of transmissibility through the confining unit.



Figure 11 – Buchanan 3111 #XD location -- Offset well for Core Data



Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Woodford and sidewall cores.



Figure 13 – Core Photo of Samples Within the Woodford Formation



CL File No.: 202105972 Date: February 04, 2022 Analyst(s): MP

Shale Core Analysis (Rotary Sidewall Cores)

As received					Dry & Dean Stark Extracted Conditions (2)					
Sample	Depth (ft)	Bulk Density (g/cc)	Matrix Permeability ⁽¹⁾ (mD)	Gas-filled Porosity (%)	Gas Saturation (%)	Grain Density (g/cc)	Matrix Permeability ⁽⁵⁾ (mD)	Porosity (%)	Oil Saturation ⁽³⁾ (%)	Water Saturation ⁽⁴⁾ (%)
30,31	9076.03 - 9076.26	2.601	4.87E-09	0.25	18.9	2.624	2.22E-07	1.30	3.3	77.8

Footnotes:

Each sample is a composite of several rotary sidewall cores.

(1) Matrix Permeability is an effective Kg determined from pressure decay results on the fresh, crushed, 20/35 mesh size equivalent sample.

(2) Dean Stark extracted sample (20/35 mesh size) dried at 110 °C. Porosity and saturations are relative to total interconnected pore space.

(3) Oil volume computed assuming an oil density of 0.844 g/cc

(4) Water volume corrected assuming a brine concentration of 80000 ppm NaCl with an ambient density of 1.054 g/cc

(5) Matrix Permeability is an absolute Kg determined from pressure decay results on the clean and dry 20/35 mesh size equivalent sample.

Reference: "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs", GRI-95/0496, Gas Research Institute, April 1996

Figure 14 – Routine Core Analysis Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

Company:Bayswater Exploration & ProductionWell:Buchanan 3111 1XDField:SpraberryLocation:Howard County, TexasFile:HOU-2105972



Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation

PETROLEUM SERVICES

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production Well: Buchanan 3111 1XD Field: Spraberry Location: Howard County, Texas

File: HOU-2105972

Sample 30B					
Gas					
Injection	Permeability				
Pressure,	to Brine*,				
psi	mD				
500	1.44E-06				
750	2.20E-06				
1000	1.46E-06				
1200	6.73E-07				
1400	5.77E-07				
1600	6.72E-07				
1800	5.39E-07				
2000	4.03E-07				

Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation

SUMMARY OF THRESHOLD ENTRY PRESSURE RESULTS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company:	Bayswater Exploration & Production
Well:	Buchanan 3111 1XD
Field:	Spraberry
Location:	Howard County, Texas

File: HOU-2105972

				Final	Threshold
				Permeability	Entry
Sample	Depth,	Length,	Diameter,	to Brine*,	Pressure,
Number	feet	cm	cm	millidarcies	psi
30B	9076.03	2.67	2.54	4.03E-07	TEP>2000

* Apparent permeability to brine with humidified nitrogen displacing water

Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation

2.2.3 Injection Interval – Ellenburger

2.2.3.1 Ellenburger

As described in the Regional Geology section, the Ellenburger at the Mongoose location is a widespread lower Ordovician carbonate deposited over the entire Permian area, indicating a relatively uniform depositional condition (Hendricks, 1964). However, post-depositional sequences have highly altered the section. These sequences have a large influence on the development of the reservoir quality within the injection interval and its ability to accept the proposed injectate. Further analysis based on regional and site-specific data was analyzed, as discussed below, to better understand the reservoir conditions at and around the Mongoose well location.

2.2.3.2 Ellenburger Porosity/Permeability Development

Facies in the low-energy, restricted shelf setting exhibit extensive dolomitization and are characterized by significant bioturbation, resulting in mottling patterns (Loucks, 2003). This dolomitization process has facilitated porosity development within the Ellenburger formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs. These same features were interpreted from the openhole logs in the Mongoose well and core from the Buchanan 3111 #1XD well. A total of 23 sidewall cores were taken within the Ellenburger formation in the Buchanan 3111 #1XD well, with 12 of those having routine core analysis performed on them. Figure 18 shows the results of the analysis.

Porosity values were primarily derived from offset openhole porosity logs within the Ellenburger section. Petrophysical analysis was performed on the offset logs to calculate an effective porosity curve, the porosity of a rock that is available to contribute to fluid flow, to better estimate porosity ranges with regards to injection within the Ellenburger. This is done by accounting for clay content and matrix lithology to better understand the varying porosity within the injection interval and how it relates to injection capacity. The ranges of effective porosity within the modeled wells are 0 to 39.4% with the mean being 4.6%. Figure 19 is a histogram depicting these porosity distributions within the seven modeled wells. These values are validated through similar ranges seen in the core results. The logical inference would be that, as the effective porosity increases, the reservoir quality for injection improves and the associated porosity increment leads to a rise in permeability.

A porosity to permeability relationship was created from this data with the outliers and nonapplicable samples redacted. Additional regional data from Loucks (2003) was incorporated into the relationship to assist with the higher permeability ranges, to ensure that overestimates of permeability were not calculated. The data from Loucks (2003) is exemplified in Figure 20. A twofunction porosity-permeability curve was developed from the regional and local core data. Figure 21 shows the equations and relationships where:

> If Effective Porosity (Φ eff) < 6.5%: $K(mD) = 7E - 08e^{3.3028*\Phi}$ eff If Effective Porosity (Φ eff) > 6.5%: $K(mD) = 277.39 \ln(\Phi eff) - 380.58$

These equations were extrapolated to all the wells within the model including the Mongoose. In Figure 22, the cross section of the Mongoose and Buchanan well is depicted. This illustration showcases the Ellenburger formation, with the sidewall cores from the Buchanan well represented by pink triangles. The calculated permeability curves resulting from the equations mentioned earlier are shown in red, while green represents the effective porosity. High permeability and porosity sections can be seen in both wells, most likely reflecting strata that had prolonged subaerial exposure creating the karst and vug features that will be targeted and utilized for injection. Figure 23 is a core photo from the Buchanan well depicting an example of what a vug feature within the Ellenburger can look like. These features will be taking the bulk of the injection and will be modeled within the area based on openhole log analysis.

Permeability ranges within the seven wells utilized in the model vary from 0 mD to 638 mD, with the mean being 40.822 mD. A histogram representing these ranges and distributions within the seven modeled wells is displayed in Figure 24. This range corroborates with Loucks (2003) and data recovered from the Buchanan well, and it can be concluded that the process used to determine the permeability distributions within the injection interval is valid.

Bayswater Exploration & Production Buchanan 3111 1XD Spraberry Howard County, Texas



CL File No.: 202105972 Date: March 31, 2022 Analyst(s): MP

	CMS-300 ROTARY SIDEWALL ANALYSIS												
			Net Confining		Permea	ability				Satu	ration	Grain	
San	nple	Depth	Stress	Porosity	Klinkenberg	Kair	b(air)	Beta	Alpha	Oil	Water	Density	Footnote
Nun	nber	(ft)	(psig)	(%)	(md)	(md)	psi	ft(-1)	(microns)	% Pore	Volume	(g/cm3)	
2	23	9236.98	2960	25.81	.259	.389	11.97	3.27E+09	2.75E+00	0.0	94.7	2.666	
2	21	9257.01	2960	4.77	.002	.009	104.71	2.14E+15	1.48E+04	1.2	66.1	2.746	(1)
1	9	9363.99	2960	5.23	5.17	5.81	2.07	1.75E+12	2.93E+04	4.1	66.9	2.800	(6)
1	5	9485.99	2960	3.41	.005	.016	62.63	3.24E+13	5.63E+02	2.3	64.6	2.838	(6)
1	3	9549.48	Ambient	1.55	N/A	N/A	N/A	N/A	N/A	1.9	44.7	2.829	(5)
1	2	9604.98	2960	1.63	.00006	.001	354.43	2.46E+18	5.38E+05	2.6	54.0	2.842	(1)
1	0	9712.03	Ambient	1.28	N/A	N/A	N/A	N/A	N/A	1.2	74.3	2.758	(5)
	7	9835.05	2960	2.28	.001	.004	155.69	2.03E+16	4.48E+04	1.5	81.1	2.701	
	6	9868.97	2960	3.43	.001	.003	166.37	3.03E+16	5.46E+04	0.9	81.6	2.827	
	5	9892.03	2960	3.46	.001	.005	132.61	8.12E+15	2.84E+04	2.1	91.6	2.809	
	4	9914.00	2960	5.46	659	669	0.18	1.07E+09	2.29E+03	0.7	58.7	2.835	(6)
	3	9969.01	Ambient	11.18	N/A	N/A	N/A	N/A	N/A	1.7	42.9	2.846	(5),(6)

Figure 18 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)



Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells

			Tectonically Fractured
	Karst Modified	Ramp Carbonate	Dolostone
Lithology			
	Dolostone	Dolostone	Dolostone
Depositional			
setting	Inner ramp	Mid- to outer ramp	Inner ramp
		Sub-Middle Ordovician,	
	Extensive sub-	sub-Silurian/Devonian,	
	Middle	sub-Mississippian, sub-	Variable intra-Ellenburger,
Karst facies	Ordovician	Permian/ Pennsylvanian	sub-Middle Ordovician
Fault-related			
fracturing	Subsidiary	Subsidiary	Locally extensive
	Karst-related		
Dominant pore	fractures and	Intercrystalline in	
type	interbreccia	dolomite	Fault-related fractures
		Partial, stratigraphic and	
Dolomitization	Pervasive	fracture-controlled	Pervasive

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

Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)



Porosity vs Permeability

Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Data



Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Ellenburger formation and sidewall cores.



Figure 23 – Core photo of Ellenburger sample displaying vug features.



Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells

2.2.3.3 Formation Fluid

Two wells were identified within approximately 30 miles of the Mongoose through a review of oilfield brine compositions of the Ellenburger formation from the USGS National Produced Waters Geochemical Database (ver. 2.3). The location of these wells is shown in Figure 25. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids (TDS). Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger formation is compatible with the proposed injection fluids.



Figure 25 – Offset wells used for formation fluid characterization.

	Average	Low	High
Total Dissolved Solids (ppm*)	47,427	42,014	52,840
рН	7	7	7
Sodium (ppm)	16,384	15,000	17,767
Chlorides (ppm)	27,590	24,900	30,281

Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples

*ppm – parts per million

2.2.4 Lower Confining Zone – Precambrian-age Formations

In the Permian Basin area, Precambrian-age formations are not normally specifically named in scientific literature. For the purposes of this MRV, these formations will just be referred to as the "Precambrian." Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sourced from outcrops in central Texas and the Trans-Pecos region of Texas and central New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section (Adams & Keller, 1996).

Adams and Keller conducted a geophysical analysis in 1996 to enhance the understanding of Precambrian rock types and their distribution in the Permian Basin. The study incorporated gravity modeling and magnetic and gravity anomalies, as well as rock data from Precambrian outcrops and drills to interpret the upper crustal geology of the area. Figure 26 displays the map resulting from their investigation, revealing that batholiths are likely present in the Precambrian basement rock at the Mongoose well location. Additionally, samples collected from offset wells displayed predominantly felsic rocks, which led to the interpretation of "granitic bodies in the upper crust" (Adams & Keller, 1996).

Offset Ellenburger injector wells were drilled through the Ellenburger section and reached total depths near the Precambrian. Log characteristics of strata near the total depth of the wells display gamma ray responses well above 90 gamma units of the American Petroleum Institute (GAPI), which is indicative of a high radioactive response. Additionally, the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone.



Figure 26 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Geomechanics

2.3.1 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density of the upper and lower confining and injection zones was calculated from log data at the Buchanan 3111 #1XD (API No. 42-227-41307) offset well. The overburden gradient and vertical stress at the top of each zone were calculated by integrating the bulk density from surface to the formation depth in half-foot intervals. Table 4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Formation	ormation Depth Bulk Density (ft) (g/cm^3)		Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Woodford	8,322	2.63	164.1	8,563	1.029
Ellenburger	8,375	2.75	171.2	8,635	1.031
Precambrian	9,500*	2.83	176.7	9,937	1.046

Table 4 – Calculated Vertical Stresses

*Estimated

2.3.2 Elastic Moduli and Fracture Gradient

The 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. The calculation requires Poisson's ratio (v), overburden gradient (OBG), and pore gradient (PG) in order to determine the required pressure to fracture the formation. These variables can be changed to match the site-specific injection zone.

A thorough review of log data, available literature, and industry standards indicate a 0.465 psi/ft pore gradient should be assumed when there are no site-specific numbers available. Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the Buchanan 3111 #1XD. The calculation was performed using the equation below for log data points at half-foot depth intervals. The results were then averaged for the depth range of each zone. This resulted in a Poisson's ratio of 0.261 for the upper confining zone and 0.273 for the injection zone.

$$v = \frac{\frac{1}{2} \left(\frac{v_p}{v_s}\right)^2 - 1}{\left(\frac{v_p}{v_s}\right)^2 - 1}$$

Where:

v = Poisson's Ratio v_p = Compressional Velocity v_s = Shear Velocity

Log data was unavailable for the lower confining zone, therefore the Poisson's ratio for this zone was estimated through a review of available literature. The lower confining zone consists of granite, which has been observed to have a Poisson's ratio ranging from 0.19 to 0.35 with a mean value of 0.28 (Domede, 2017). Based on this research, an average value of 0.28 was assumed. Using these values in the equation below, a fracture gradient of 0.664 psi/ft was calculated for the upper confining zone. A 10% safety factor was applied to this number resulting in a maximum allowed bottomhole pressure of 0.598 psi/ft. This zone had the lowest fracture gradient of the confining and injection zones. It was used to define the maximum allowable pressure to ensure that the injection pressure would not exceed the fracture pressure of any of the three zones. The resulting fracture gradients are displayed in Table 5.

Example Fracture Gradient Calculation for Upper Confining Zone

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

$$FG = \frac{0.261}{1 - 0.261} (1.029 - 0.465) + 0.465 = 0.664 \, psi/ft$$

FG with
$$SF = 0.689 \times 90\% = 0.598 \, psi/ft$$

Table 5 –	Fracture	Gradient	Calculation	Inputs and	Results

Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
8,322	Upper Confining	Woodford	1.029	0.465	0.261	0.664
8,375	Injection	Ellenburger	1.031	0.465	0.273	0.678
9,500*	Lower Confining	Precambrian	1.046	0.465	0.28	0.691

*Estimated

2.4 Local Structure

The area surrounding the Mongoose well is characterized by a monoclinal dip from east to west that is influenced by a shallow westward slope towards the Midland Basin and an upward slope to the east towards the Eastern Shelf. No evidence of structural faulting was found in this specific region that could have affected the geological trend. Figure 27 shows the topography of the Ellenburger formation, with the Mongoose well marked by a black star.

Subsurface interpretations of the Ellenburger formation heavily relied on well data and 3D seismic coverage in the area. The black boundary in Figure 27 represents the extent of the seismic coverage. Within the mapped area, approximately 100 wells have penetrated the Ellenburger formation. However, only seven of these wells fully penetrated the entire Ellenburger section. The remaining 93 wells only reached the top of the Ellenburger formation. These wells are plotted on the map and cover four counties. In addition to the Mongoose well, six other wells located offset of the Mongoose were used for the model build and are indicated by red stars.

Figure 28 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map. The Ellenburger was broken down into eight subsections labeled Ellenburger A through H. Figure 29 is a stratigraphic cross section flattened on the Ellenburger that better illustrates these subtops.

The cross sections reveal the regional unconformity in the area when moving east from the Midland Basin. As we go farther updip and to the east, the Fusselman section gradually erodes. While there is also thinning in the Woodford, the cross section shows that the Woodford is present throughout the modeled area, creating a continuous seal above the plume.

With no major structural or stratigraphic features within the injection interval in the Mongoose area, there is little to no concern of geologic conduits outside of the injection interval. General flow trends will follow dip and optimal reservoir features within the Ellenburger. Large scale versions of Figures 28 and 29 are provided in *Appendix D*.



Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map.



Figure 28 – Structural cross section depicting the Ellenburger.



Figure 29 – Stratigraphic cross section flattened on the Ellenburger.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger formation at the Mongoose location indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity. The Woodford Shale formation at the same well location has low permeability and is of adequate thickness and lateral continuity to act as the upper confining zone. Below the injection interval, the Precambrian formation has low permeability and low porosity, making it unsuitable for fluid migration and serving as the lower confining zone.

A thorough study of the area of review has been conducted to identify any potential subsurface features that could impact the ability of the injection and confinement units to retain the injectate within the desired injection interval. Fortunately, no faults or other hazardous geologic conditions have been identified in the area. Therefore, the conditions in this area are ideal for injection and containment.

2.6 Groundwater Hydrology

The Mongoose is located within Mitchell County, home to a population of approximately 8,400 residents, and is serviced by the Lone Wolf Groundwater Conservation District, which consists solely of Mitchell County. This conservation district has an area of roughly 900 square miles. Much of the county's economy is derived from agriculture and oil production, both water-intensive operations. Groundwater usage within the county is estimated to be 13,391 acre-feet on a yearly basis (Lone Wolf Groundwater Conservation District, 2019).

Surface Water

Mitchell County lies within the Colorado River basin, as the Colorado runs through the county. Drainage from both the east and west flow centrally towards the Colorado River, which splits the county in half. The estimated supply of surface water is 395 acre-feet (Lone Wolf Groundwater Conservation District, 2019).

Groundwater

There are multiple units where groundwater is available within Mitchell County, although only the Dockum Group provides significant amounts of water. Table 6 discusses water-bearing units in the county, and Figure 30 shows a generalized reference to structure and formation relationships.

Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger Jr., 1967)

System	Series	Group	Formation	Approximate thickness (feet)	Lithology	Water-bearing characteristics
Quaternary	Pleistocene and Recent		Alluvium	0-100	Fine to coarse sand, and small to large gravel, with occasional clay and caliche beds.	Above the regional water table east of Colo- rado River, but yields up to 20 gpm of good quality water in southwestern Mitchell County.
Tertiary	Pliocene		Ogallala	0-100	Fine to coarse sand, gravel, caliche, and zones of clay.	Above the water table east of Colorado River, but yields up to 20 gpm of good quality water to wells in northwestern Mitchell County.
		Fredericksburg		0-220	Predominently limestone. 15 to 25 feet of sandy yellow marl at base overlain by chalk and shaly limestone. Very dense, massive, fossiliferous lime- stone in the upper part.	Upper limestones contain in places small to moderate supplies of potable but hard water in solutional openings developed along fracture systems; recharge to the openings occurs through numerous sinks.
Cretaceous	Comanche	Trinity		0-100	White to purplish quartz sand, fine to medium grained, moderately to loosely consolidated, with occasional lenses of quartz gravel at the base.	Yields small to large quantities of potsble but hard water, the amount depends on saturated thickness which ranges from 100 percent under interior limestone areas to a few feet in parts of the outcrop; yields of several hundred gallons per minute are reported.
		Deckury	Chinle	0-640	Predominantly red to marbon and pur- plish clay and shale, interbedded with thin, tight, cross-bedded, yellow-brown to reddish-white sand- atone.	Sandstones contain generally small quantities of moderately to highly mineralized water; used principally for livestock.
Triassic		DOCKOB	Santa Rosa	0-330	Basal conglomerate overlain by brown to gray, micaccous and carbonaccous, cross-bedded sand alternating with beds of red and gray clay.	Sands and gravels contain moderate to large quantities of fresh water east of the Colorado River, with yields up to 1,000 gpm reported; west of Colorado River capa- city of sand is reportedly substantial but water is generally not potable.
Permain	Guadalupe and Ochoa				Fine-grained, red to brown sandstone; dense red silty shale with occasional gypsum or anhydrite beds.	Yield small quantities of moderately to high- ly mineralized water to livestock and domestic wells.



Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)

Permian

Permian age strata underlies much of the area and outcrops in the southeast of Mitchell County and along the Colorado River and its tributaries. These strata consist primarily of "red beds," dense red silty shales. Water wells in the Permian strata are typically less than 100 ft deep, yielding small amounts of moderately to highly mineralized water usable only for livestock (Shamburger Jr., 1967).

Dockum Aquifer

The Triassic Age Dockum group comprised by the Santa Rosa sandstone and the Chinle formation are the main sources of ground water within the county. An overview map of the extent of the Dockum Aquifer is shown in Figure 31, with outcrops depicted in solid color. The Chinle is further divided into the Tecovas formation, the Trujillo sandstone, and the Cooper Canyon formation, although the Tecovas and Cooper Canyon are generally unimportant and yield only small amounts of highly mineralized water.

The Santa Rosa sandstone lies unconformably atop the Permian age strata at the base of the Dockum Group and is one of the major sources of water for Mitchell County. It is comprised of a basal conglomerate overlain by alternating beds of red and gray micaceous shale, sand, and gravel reaching up to 130 ft in thickness (Bradley & Kalaswad, 2001). The Trujillo sandstone overlies the Tecovas, which in turn overlies the Santa Rosa, and is a cross-bedded unit composed of sandstones and conglomerates. The Santa Rosa and Trujillo sandstones are regarded as the main producers of water in the Dockum Group in Mitchell County (Lone Wolf Groundwater Conservation District, 2019). The Dockum Group was likely deposited from sediments into "fluvial, deltaic, and lacustrine environments within a closed continental basin" (Bradley & Kalaswad, 2001). The base of the Santa Rosa is typically considered the lower extent of fresh water in the area. Water levels in wells throughout the county vary between 15 ft and 215 ft below ground level (Shamburger Jr., 1967), and the aquifer is considered confined to partially confined (Bradley & Kalaswad, 2001).

Recharge of the aquifer is provided by rainwater infiltration through outcrops in the county and is estimated to be 18,108 acre-feet per year. Groundwater in the Dockum aquifer system flows towards the central Colorado River. A potentiometric surface map of the Santa Rosa sandstone, the lower Dockum member, is depicted in Figure 32. Although no values of porosity have been determined empirically, a conservative value of 10% is assumed for effective aquifer porosity (Lone Wolf Groundwater Conservation District, 2019).

Groundwater quality is generally considered poor with TDS and other constituents exceeding secondary drinking water standards (Bradley & Kalaswad, 2001). As a typical assumption, water quality west of the Colorado River within the aquifer is poor and unsuitable for municipal use, while east of the river water quality is less mineralized and is of suitable quality for municipal purposes (Lone Wolf Groundwater Conservation District, 2019). For example, a well tested 10 miles northwest of Colorado City contained chloride at 560 milligrams per liter (mg/L), sulfate at 337 mg/L, and TDS at 1,893 mg/L, all of which are above limits set by the Texas Commission on Environmental Quality (TCEQ) for use in municipal water supplies. In contrast, a well 8 miles east of Colorado City contained

chloride at 34 mg/L, sulfate at 73 mg/L, and TDS at 418 mg/L (Lone Wolf Groundwater Conservation District, 2019). A map showing TDS values for the Dockum Aquifer is shown in Figure 33.



Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location (George, Mace, & Petrossian, 2011).



Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986).


Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011).

Ogallala Formation

The Tertiary age Ogallala formation occurs in the northern extents of Mitchell County. In the eastern part of the county, Ogallala sediments are generally above the water table and not a source of groundwater; however, they do provide an effective means of recharge to the underlying Santa Rosa formation. In the western part of the county, the Ogallala is up to 100 ft thick of unconsolidated sand and gravel and provides small quantities of usable water for domestic and livestock wells (Lone Wolf Groundwater Conservation District, 2019).

2.7 <u>Description of the Injection Process</u>

2.7.1 Current Operations

The Mongoose Amine Treating Facility and the associated Mongoose well began operating in August of 2023. The maximum rate during the injection period is expected to be 377.2 MT/yr (19.5MMscf/D). The TAG is 41.2% CO₂, which equates to 155.3 MT/yr of CO₂ each year. The current composition of the TAG stream is:

Table 7 – Gas Composition at the Plant Outlet

Component	Mole Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

The Mongoose Amine Treating Facility is designed to dehydrate, treat, and compress the natural gas produced from the surrounding acreage in Mitchell County. The gas is dehydrated to remove the water content, and treated to remove the CO₂ and H₂S. The compressed rich gas stream is then transported via pipeline to a separate facility for processing to separate the natural gas liquids from the methane. The TAG is then directly routed from the Plant's amine unit to the Mongoose. The Plant is manned 24 hours per day, 7 days per week.

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (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.

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 Ellenberger formation is the target formation for the Mongoose. The Petrel software package was utilized to create the geologic model of the target formation. Within the Petrel platform, the porosity and permeability distributions were established for the model. The geologic structure was then imported into GEM for simulation purposes.

In Petrel, the structure's construction involved the utilization of nine contour tops, which were layered sequentially. These contour tops, identified as "Ellenberger A" through "Ellenberger I," collectively define the structure's configuration, Ellenberger A being the shallowest and Ellenberger I being the deepest structure package. To accurately represent the formation's true structure, true vertical depth subsea was used to account for the differing overburden depths associated with the

wells used in contour delineation. The distinction between true vertical depth (TVD) and true vertical depth subsea (TVDSS) is taken into consideration when inputting pressure and temperature gradients into the GEM model.

Porosity estimates were determined using openhole porosity logs from seven offset wells within the Ellenberger formation. These logs were used within Petrel to distribute porosity and permeability spatially. Permeability was found by using the two-function porosity-permeability curve developed from regional and local core data within the Ellenberger formation.

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 H₂S and CO₂ based on initial estimates from the source, as shown in Table 8. However, the precise gas composition may vary slightly as the Plant is still in its commissioning phase. Initial estimates anticipate the injectate composition to be 58.8% H₂S and 41.2% CO₂. Once a steady-state operating composition is determined, the MRV plan will be updated if there is a material difference. Based on the initial gas samples, the modeled percentages in the injectate for the 40-year injection period of the Mongoose is 58.8% H₂S and 41.2% CO₂.

Table 8 – Modeled Initial Gas Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Hydrogen Sulfide (H ₂ S)	58.8	58.8
Carbon Dioxide (CO ₂)	41.2	41.2

Core data from literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Ellenberger dolomitic carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 10%, an irreducible water saturation of 39.7%, and a maximum residual gas saturation of 30%. The relative permeability curves used for the GEM model are shown in Figure 34.



Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 135 blocks in the x-direction (east-west) and 77 blocks in the y-direction (northsouth), resulting in a total of 10,395 grid blocks per layer. Each grid block spans dimensions of 1,000 ft by 1,000 ft. This configuration yields a grid size measuring 135,000 ft by 77,000 ft, equating to just under 373 square miles in area. The grid cells in the vicinity of the Mongoose, within a radius of 2.5 miles, have been refined to dimensions of 250 ft by 250 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume.

In the model, each layer is characterized by heterogeneous permeability and porosity values. These values are derived from the geostatistical distribution of properties, using porosity logs implemented in Petrel as a basis. The model encompasses a total of 79 layers, each featuring varying thicknesses, with an average of approximately 10 ft per layer. As previously mentioned, the structure of the Ellenberger formation was formed using nine contour packages. The summarized property values for each of these packages are displayed in Table 9.

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Ellenberger A	9	8,369	101	49.1	5.2%
Ellenberger B	9	8,470	76	65.1	6.0%
Ellenberger C	8	8,546	75	38.5	4.2%
Ellenberger D	9	8,621	86	39.2	4.9%
Ellenberger E	15	8,707	153	48	4.8%
Ellenberger F	6	8,860	63	32.5	4.4%
Ellenberger G	4	8,923	39	16.5	3.2%
Ellenberger H	8	8,962	82	76.9	5.5%
Ellenberger I	11	9,044	112	66	3.4%

Table 9 – GEM Model Layer Package Properties

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

- 1. Estimate the maximum areal extent and density drift of the acid gas plume after injection.
- 2. Assess the impact of offset SWD well injection on density drift of the plume.
- 3. Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone.
- 4. 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 47,427 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The acid gas stream is primarily composed of CO₂ and H₂S as stated previously. Core data was used to help generate relative permeability curves. From the literature reviews as previously discussed, cores that most closely represent the vuggy dolomitic carbonate seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975). The initial reservoir pressure is 3,903 psig, which is equivalent to a 0.465 psi/ft pressure gradient and was determined from offset injection well analysis. The fracture gradient of the injection zone was estimated to be 0.664 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.598 psi/ft, which is equivalent to 5,007 psig.

The model considers the injection volumes of offset SWD wells close to the Mongoose. Nine such wells were identified within a 19-mile radius. Historical injection rates of eight of the nine of these wells currently injecting into the Ellenberger were provided by the operators and were input into

the model. All but one of the SWD wells in the model are currently permitted and injecting. The SWD well that has not yet started injection and has no historical injection data is conservatively assumed to inject at its maximum permitted rate for 30 years and to start at the same time as the Mongoose begins injection. Projected injection rates were assumed to be the maximum permitted injection rates and ended after 30 years of life for all nine offset SWDs. This simulation includes the effect of water injection on the density drift of the plume and the bottomhole pressure of the Mongoose. The SWDs included in the model are listed in Table 10.

API Number	Well Name	Well Number
42-227-41332	Fryar 3S	2XD
42-227-41307	Buchanan 3111	1XD
42-227-39064	Pipeline SWD	1
42-335-34319	Wild Bill	1WD
42-227-41775	Sterling	1XD
42-335-36026	Oasis Deep	9XD
42-227-39098	846 SWD	2
42-227-39119	N. Midway SWD	1
42-227-40310	Hull SWD	1

Table 10 – Offset SWD Wells Included in GEM Model

The model runs for a total of 175.33 years, comprising 15.33 years of historical SWD well injection prior to the commencement of acid gas injection. This is followed by 40 years of active acid gas injection through the Mongoose, succeeded by an additional 120 years of density drift. The model begins in September 2008, aligning with the start of historical injection data for the first offset SWD well. The remainder of the SWD wells turn on between then and the start of the acid gas injection, which begins in January 2024. Throughout the entire 40-year injection period, an injection rate of 19.5 MMscf/D is assumed to model the maximum available rate, yielding a more cautious estimate of the plume size. After the 40-year injection period, when the Mongoose ceases injection, all nine offset SWD wells have been shut in—as they began injecting before the Mongoose and were assumed to stop injecting after 30 years.

The maximum plume extent during the 40-year injection period is shown in Figure 35. The final extent after 120 years of density drift after injection ceases is shown in Figure 36. Both figures show the entire grid with the included offset SWD wells. Due to the large nature of the model, a zoomed-in view of the plume extent during the 40-year injection period is shown in Figure 37 and the final extent after 120 years of density drift after injection ceases is shown in Figure 38.



Figure 35 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)



Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

The cross-sectional view of the Mongoose shows the extent of the plume from a side-view angle cutting through the formation at the wellbore. Figure 39 shows the maximum plume extent during the 40-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 40 shows the final extent of the plume after 120 years of migration. At this point in time, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, as it is less dense than the formation brine, until an impermeable layer is reached. Both figures are shown in a north-to-south view.



Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 40 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)

Figure 41 shows the surface injection rate, bottomhole pressures, and surface pressures over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate begins, reaching a maximum pressure of 4,453 psig, then slightly decreases and remains constant. This buildup of 550 psig keeps the bottomhole pressure below the fracture pressure of 5,007 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,008 psig, well below the maximum allowable 2,500 psig per the TRRC UIC permit for this well. At roughly 30 years into injection for the Mongoose, all SWD wells included in the model have ceased injection. Due to the shut-in of offset SWD wells, the pressure effects within the formation are felt by the Mongoose. When this occurs, the bottomhole pressure decreases by 50 psig and surface pressure decreases by 40 psig. Bottomhole and wellhead pressures over time are in Table 11.



Figure 41 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injection
--

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	3,916	-
10	4,389	1,977
20	4,394	1,982
30	4,393	1,980
40	4,343	1,942
50	3,923	-
120	3,919	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO₂ plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

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

Bayswater's expected gas composition was used in the model. The acid gas injectate is estimated at a molar composition of 58.8% H₂S and 41.2% CO₂, with trace amounts of other constituents. Upon the Plant achieving stable operations, a representative injectate sample will be collected and analyzed by a third-party laboratory. If the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be provided. As discussed in *Section 2*, the gas will be injected into the Ellenberger formation. The geomodel was created based on the rock properties of the Ellenberger.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 40, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast.

Figure 42 shows the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA is depicted in this figure by taking the stabilized plume boundary after 120 years of density drift, and adding an all-around buffer zone of one half mile.



Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. This provides Bayswater sufficient time to develop its asset base, achieve steady operations, and evaluate any potential modifications to the MRV plan.

The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free-phase CO₂ plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. By 2036, a revised MRV plan will be submitted to define a new AMA. Figure 43 shows the area covered by the AMA.



Figure 43 – 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. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within the MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from natural or induced seismicity

Table 12 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood		Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. Two artificial penetrations were drilled into the gross injection interval. These wells were plugged in accordancee TRRC requirements.	Low	Low. Vertical migration of CO ₂ would likely enter a shallower hydrocarbon production zone.	During active injection.
Faults and fractures	Unlikely. There are no faults within the modeled area. Bayswater monitors the area for seismic activity.	Low	Low. Vertical migration of CO ₂ would likely enter a shallower hydrocarbon production zone.	During active injection.
Upper confining layer	Unlikely. The lateral continuity of the Woodford Shale blanketing the Ellenburger is recognized as a very competent seal. There is 7,825' of overburden between the Injection Interval and the base of the USDW.	Low	Low. Vertical migration of CO ₂ would likely enter a shallower hydrocarbon production zone.	During active injection.
Natural or induced seismicity	Unlikely. There have been no seismic events of 3.0 magnitude or greater detected. There is over 7,825' of overburden between the Injection Interval and the base of the USDW.	Low	Low. Vertical migration of CO ₂ would likely enter a shallower hydrocarbon production zone.	During active injection.

Magnitude Assessment Description

Low - catergorized as little to no impact to safety, health and the environment and the costs to mitigate are minimal.

Medium - potential risks to the USDW and for surface releases does exist, but circumstances can be easily remediated.

High - danger to the USDW and significant surface release may exist, and if occurs this would require significant costs to remediate.

4.1 Leakage from Surface Equipment

The Plant and Mongoose are newly designed and constructed facilities for treating and injecting acid gas with the fundamental objective of ensuring maximum safety for the public, the employees, and the environment. These are depicted in Figures 44 and 45. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H₂S are installed at key locations around the Plant as depicted on the site plan in Appendix B-2. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H₂S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the TRRC with the Class II AGI application. OSHA sets the detection or exposure limits at 15 ppm as the High Alarm and the High- High Alarm or Facility Shutdown limit at 40 ppm.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant and the Mongoose well. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs. These valves, gas monitors, and the gas flow meter are called out in the detailed site plan in Appendix B-2. Data from this flow meter will be used in the calculations of the total mass of CO₂ (in metric tons) in the CO₂ stream injected each year, per 40 CFR **§98.444(b)**.



Figure 44 – Site Plan



Figure 45 – Mongoose AGI No. 1 Wellbore Schematic

With the level of monitoring implemented at the Plant, a release of CO_2 would be quickly identified, and the safety systems and protocols would minimize the release volume. The acid gas stream injected into the well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the Plant adjacent to the Mongoose. Bayswater will increase its future injection volumes from its own gas production and possibly other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7* in accordance with 40 CFR **§98.448(a)(5)**. Bayswater concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The Mongoose was designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 45. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) §3.46 [40 CFR §146.23 (b)(3)], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 46. The MMA review map and a summary of all wells in the MMA is provided in *Appendix C*. Figure 47 highlights that only two wells penetrate the MMA's gross injection zone. These wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements. Bayswater will perform baseline soil gas sampling prior to the implementation of the MRV plan and subsequent injection records. In addition, annual soil gas samples will be taken in the area adjacent to artificial penetrations and analyzed by a third-party lab. The results, should they indicate an issue with the sequestered CO₂ will be presented in the annual report to the GHGRP.

The summary of all oil and gas wells in *Appendix C* also provides the total depth (TD) of all wells within the MMA. Those wells that are shallower and do not penetrate the injection zone are isolated by the Woodford Shale as discussed in *Section 2.2.2*. The Woodford Shale provides 50 feet or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset artificial penetrations is unlikely.

Bayswater is the operator of many of the shallower offset oil and gas wells within the MMA and frequently performs gas analysis on their production volumes. If a material variance in the quantity of CO_2 produced is indicated, Bayswater would investigate to determine the affected well(s), the root cause of the CO_2 increase to formulate a resolution plan and utilize the gas analysis variance to calculate any adjustments to reported volumes.



Figure 46 – All Oil and Gas Wells Within the MMA



Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC in the area of the Mongoose will include a list of formations for which operators are required to comply with TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC §3.13. The Mongoose drilling permit, provided in Appendix A, serves as an example. The Ellenburger is among the formations listed for which operators in Mitchell County and District 8 (where the Mongoose is located) are required to comply with TRCC Rule 13. The rule requires oil and gas operators to set steel casing and cement either (1) across and above all formations permitted for injection under TRRC Rule 9, or (2) immediately above all formations permitted for injection under Rule 46, for any well proposed within a quarter-mile radius of an injection well. In this instance, any new well permitted and drilled to the injection zone and located within a guarter-mile radius of the Mongoose will be required under TRRC Rule 13 to set steel casing and cement above the well's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and 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 (also provided in the permit in Appendix A).

4.2.2 Groundwater Wells

A groundwater well search results found three wells within the MMA, as identified by the Texas Water Development Board. A field investigation was performed to validate the existence and location of these wells. However, none of the wells listed in the database could be located. An exhaustive search of well records was performed and no completion reports and/or plugging records were found. The result is there are no groundwater wells to monitor as none exist within the MMA.

The surface, intermediate, and production casing strings in the Mongoose, as shown in Figure 45, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations and the GAU letter issued for this location (and included in *Appendix A*). The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Bayswater concludes that leakage of the sequestered CO_2 to the groundwater aquifer is unlikely.

4.3 Leakage Through Faults and Fractures

No faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose. This includes areas well outside of the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

In the event of an unmapped fault existing within the plume boundary, any displacement caused by it would be too small to be detected through 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

Porosity development within the injection intervals is primarily attributed to fractures and aerial exposure. However, these fractures are limited and do not extend into the upper confining unit, which helps mitigate the risk of migration through fractures outside of the designated injection interval.

4.4 Leakage Through the Confining Layer

The overlying Woodford formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in *Section 2*. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale which would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

4.5 Leakage from Natural or Induced Seismicity

The Mongoose is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

All seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

Stringent operating procedures will be programmed into the SCADA and control systems to ensure that operating pressures stay below the fracture gradient of both the injection and confining intervals. Moreover, a combination of continuous well monitoring and monitoring of the TexNet site for activity will promptly identify any irregularities in the operations linked to seismic events.



Figure 48 – Seismicity Review (TexNet – 08/04/2023)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Bayswater 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 H₂S and CO₂, the H₂S will be a proxy for CO₂ leakage and therefore the monitoring systems in place to detect H₂S will also indicate a release of CO₂. Table 13 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 40-year injection period or cessation of injection operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

Leakage Pathway	Monitoring Method		
	Fixed H ₂ S monitors throughout the AGI facility		
Leakage from surface equipment	Visual inspections		
	SCADA continuous monitoring of the AGI facility		
	SCADA continuous monitoring of the AGI well		
	Monitor CO ₂ levels in Above Zone producing wells		
Leakage through existing wells	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years		
	Visual inspections		
	Annual soil gas sampling at well locations that penetrate the Upper Confining Zone within the AMA		
Leakage through groundwater wells	Annual groundwater samples from monitoring wells		
Leakage from future wells	Compliance with TRRC Rule 13 Regulations		
Lookago through foulte and fractures	SCADA continuous monitoring at the AGI well (volumes and pressures)		
Leakage through faults and fractures	Monitor CO ₂ levels in Above Zone producing wells		
Leakage through the confining layer	SCADA continuous monitoring at the AGI well (volumes and pressures)		
	Monitor CO_2 levels in Above Zone producing wells		
Leakage from natural or induced seismicity	Monitor CO ₂ levels in Above Zone producing wells		
	Monitor existing TexNet station		

Table 13 – Summary of Leakage Monitoring Methods

5.1 <u>Leakage from Surface Equipment</u>

The Plant and the Mongoose were designed to operate in a manner that will reduce to the lowest factor the possibility of an escape of CO₂ and H₂S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO₂ concentration will be established during the commissioning of the Plant. Ambient H₂S monitors are located at the Plant and near the Mongoose for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in *Appendix B*. The locations of H₂S detectors and Emergency Shutdowns are identified throughout the facility on the Appendix B-2 Site Plan. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Bayswater to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO₂ released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

5.2 Leakage Through Existing and Future Wells Within the MMA

Bayswater continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the Mongoose. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, an MIT will be performed every 5 years, as required by the TRRC and UIC. A failed MIT would also indicate the potential of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 ensures that new wells in the field would be constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Bayswater will also establish an in-field soil gas monitoring program to detect CO_2 leakage within the AMA. This would include sample collection and testing for CO_2 and H_2S at the AGI well site and near one of the identified artificial penetrations of the injection interval within the AMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. Prior to approval and implementation of

the MRV plan and through the post-injection site care period, Bayswater will have these monitoring systems in place.

There are currently only two wells that have been identified within the AMA that penetrate the Upper Confining Zone. As both wells have been plugged and abandoned in compliance with TRRC requirements, Bayswater believes a leak event is unlikely. Bayswater will perform soil gas sampling and analysis proximate to the Mongoose and one of the abandoned artificial penetrations by May 20, 2024. Thereafter, soil gas samples will be taken annually and analyzed by a third-party lab, and the results will be included in the annual report.

Bayswater is the operator of record for many oil and gas producing wells with the AMA. These wells will be used as a proxy for an above-zone monitoring well. If any CO_2 , migrates up-hole, the CO_2 would likely end up in this formation. Since gas analysis is performed on a regular basis on the hydrocarbons produced from this formation, any material variance from historical data would indicate the potential of an issue needing further investigation. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance. It is not the intent of Bayswater to produce any of the CO_2 in this scenario but to use this as an indication of an event warranting further investigation.

5.2.1.1 <u>Groundwater Quality Monitoring</u>

As explained in *Section 4.2.2,* there are no groundwater wells within the MMA. Therefore, there are no groundwater wells to monitor.

5.3 <u>Leakage Through Faults, Fractures, or Confining Seals</u>

Bayswater continuously monitors the operations of the Mongoose 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 due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Bayswater will also monitor production from their oil and gas wells that do not penetrate the injection zone for any material variance in CO₂ content in the produced gas stream. Since gas analysis is very consistent over time, any material variance in the CO₂ content would be an early indicator of a potential issue. Should the CO₂ migrate vertically, the magnitude risk of this event is very low, as the reservoir provides an ideal containment given the Upper Confining Zone has successfully held hydrocarbons in place. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Bayswater plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose well. This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 49. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Bayswater facility. Bayswater will monitor this station for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected, Bayswater will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.



Figure 49 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

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

6.1 Visual Inspections

Regular inspections will be conducted by field personnel at the Plant and the Mongoose. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken in a prudent and safe manner to address such issues.

6.2 <u>CO₂/H₂S Detection</u>

In addition to the fixed gas monitors at the well site, Bayswater will perform an annual soil gas sampling program to detect any CO₂ leakage proximate to select artificial penetrations of the Upper Confining Zone within the AMA. The baseline determination will include atmospheric H₂S measurements at the AGI well and soil gas sampling near the AGI well and one of the abandoned artificial penetrations within the AMA.

These soil gas sample probes will be inserted below the surface. The probes have special material inserts that collect the gas samples over a 21-day period. These inserts are then removed and sent to a third-party lab to be analyzed for CO_2 , H_2S , and trace contaminants typically found in a hydrocarbon gas stream. This initial sample collection is scheduled to be completed by May 20, 2024; a sufficient time period prior to the implementation of the MRV plan and will establish baseline values for future reference.

6.3 **Operational Data**

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO₂.

6.4 <u>Continuous Monitoring</u>

The total mass of CO₂ emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel due to the presence of H₂S in the gas stream. Continuous monitoring systems will trigger an alarm if there is a release. The mass of the CO₂ released would be calculated based on the operating conditions,

including pressure, flow rate, percentage of CO₂, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a de-pressuring event, the acid gas stream will be diverted to a flare stack to be safely processed and vented. The event will be reported as required for the operation of the well.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO₂ Received

Per 40 CFR **§98.443**, the mass of CO₂ received must be calculated using the specified CO₂ received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4)**." 40 CFR **§98.444(a)(4)** states that "if the CO₂ you receive is wholly injected and is not mixed with any other supply of CO₂, you may report the annual mass of CO₂ injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO₂ received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO₂ received." The CO₂ received for this injection well is wholly injected and not mixed with any other supply; the annual mass of CO₂ injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO₂ 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 volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, 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 CO₂ mass injected (metric tons) as measured by flow meter u

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO₂ Produced

The Mongoose is not part of an enhanced oil recovery project; therefore, no CO₂ will be produced.

7.4 Mass of CO₂ Emitted by Surface Leakage

The mass of CO₂ emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains high concentrations of H₂S. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions sent to a flare stack and reported as a part of the required GHG reporting for the Plant. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of CO₂ and H₂S. The mass of the CO₂ released would be calculated for the operating conditions, including pressure, flow rate, size of the leak-point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO₂ was released because of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

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

Where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

Calculation methods using equations from Subpart W will be used to calculate CO₂ emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Bayswater believes the most appropriate method to quantify the mass of CO₂ released will be determined on a case-by-case basis. Any mass of CO₂ detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. In the unlikely event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events will be kept and stored as stated in *Section 10*.

7.5 Mass of CO₂ Sequestered

The mass of CO₂ sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Since the Mongoose has commenced operations, Bayswater will begin collecting data for reporting under this plan based on the approval of this MRV plan and any applicable stipulations therein. The calculation of sequestered volumes utilizes the following equation as this well will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

 CO_{21} = 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 CO₂ mass emitted (metric tons) by surface leakage in the reporting year

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

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting is expected to occur, the calculations would be based on an unusual event that a blowdown is required and those emissions are sent to a flare stack and reported as part of the required GHG reporting for the Plant.

• Calculation methods from Subpart W will be used to calculate CO₂ 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 Mongoose is a new injection well currently reporting under the TRRC Class II regulations. Bayswater is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

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

9.1 Monitoring QA/QC

CO₂ Injected

- The flow rate of the CO₂ being injected will be measured with a volumetric flow meter, consistent with applicable industry standards. These flow rates will be compiled quarterly.
- The composition of the injectate stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with applicable industry standards.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The gas measurement equipment will be calibrated per the requirements of 40 CFR §98.444(e) and §98.3(i).

CO₂ Emissions from Leaks and Vented Emissions

- Gas monitors within the Mongoose facility will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.
- Calculation methods from Subpart W will be used to calculate CO₂ emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR §98.3(i).
- Flow meters will be operated and maintained in accordance with applicable standards as published by a consensus-based standards organization.

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

9.2 Missing Data

In accordance with 40 CFR **§98.445**, Bayswater 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 CO₂ injected is missing, the amount will be estimated using a representative quantity of CO₂ injected from the nearest previous period at a similar injection pressure.

• Fugitive CO₂ emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR **§98**.

9.3 MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Bayswater will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least 3 years and include the following:

- Quarterly records of the CO₂ injected
 - Volumetric flow at standard conditions
 - Volumetric flow at operating conditions
 - Operating temperature and pressure
 - Concentration of the CO₂ stream
- Annual records of the information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of the information used to calculate CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 11 - REFERENCES

- Adams, D. C., & Keller, G. R. (1996). Precambrian Basement Geology of the Permian Basin Region of West Texas and Eastern New Mexico: A Geophysical Perspective1. *AAPG*.
- Aird, P. (2019). *Deepwater Geology* & *Geoscience*. Retrieved from ScienceDirect: https://www.sciencedirect.com/topics/engineering/overburden-stress
- Bradley, R. G., & Kalaswad, S. (2001). *Chapter 12: Dockum Aquifer in West Texas*. Texas Water Development Board.
- Bennion, B., & Bachu, S. (2010). Drainage and Imbibition CO₂/Brine Relative Permeability Curves at Reservoir Conditions for Carbonate Formations. *SPE Annual Technical Conference and Exhibition*.
- Comer, J. B. (1991). Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas asn Southeatern New Mexico. *BEG*.
- Conselman, F. B. (1954). Preliminary Report on the Geology of the Cambrian Trend of West Central Texas. *Abilene Geologic Society*.
- Domede, P. S. (2017). *Mechanical behaviour of granite. A compilation, analysis and correlation of data from around the world*. Retrieved from https://hal.insa-toulouse.fr/hal-01743870/document
- Dutton, A. R., & Simpkins, W. W. (1986). *Hydrogeochemistry and Water Resources of the Triassic Lower Dockum Group in the Texas Panhandle and Eastern New Mexico*. Austin Tx: Bureau of Economic Geology.
- Fanchi, J. R. (2010). Integrated Reservoir Asset Management.
- Galley, J. (1958). Oil and Geology in the Permian Basin of Texas and New Mexico. *Basin or Areal Analysis or Evaluation*.
- Gunn, R. D. (1982). Desmoinesian Depositonal Systems in the Knox Baylor Trough. *North Texas Geological Society*.
- Hendricks, L. (1964). STRATIGRAPHIC SUMMARY OF THE ELLENBURGER GROUP OF NORTH TEXAS. *Tulsa Geological Society Digest, Volume 32*.
- Hornhach, M. J. (2016). Ellenburger wastwater injection and seismicity in North Texas. *Physics of the Earth and Planetary Interiors*.
- Jesse G. White, P. P. (2014). Reconstruction of Paleoenvironments through Integrative Sedimentology and Ichnology of the Pennsylvanian Strawn Formation. *AAPG Southwest Section Annual Convention, Midland, Texas*.
- Keelan, K., & Pugh, V. (1975). Trapped-Gas Saturations in Carbonate Formations. SPE J. 15: 149–160.
- Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas. *Bureau of Economic Geology*.
- Lone Wolf Groundwater Conservation District. (2019). *Management Plan 2019-2024.* Colorado City, Tx.
- Loucks, R. (2003). REVIEW OF THE LOWER ORDOVICIAN ELLENBURGER GROUP OF THE PERMIAN BASIN, WEST TEXAS. *Bureau of Economic Geology*.
- Loucks, R. (2006). *Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas.* Austin, Tx: Bureau of Economic Geology.
- Mason, C. C. (1961). GROUND-WATER GEOLOGY OF THE HICKORYSANDSTONE MEMBER OF THE RILEY FORMATION. McCULLOCH COUNTY. TEXAS. *TEXAS BOARD OF WATER ENGINEERS*.

- Merrill, M., Slucher, E., Roberts -Ashby, T., Warwick, P., Blondes, M., Freeman, P., . . . Lohr, C. (2015). Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources–Permian and Palo Duro Basins and Bend Arch-Fort Worth Basin. *USGS*.
- Popova, O. (2020). Permian Basin Part 1 Wolfcamp, Bone Spring, Delaware shale plays of the Delaware Basin Geology Review. *USDOE*.
- Powers, R. B. (1989). Petroleum Exploration Plays and Resource Estimates, 1989, On shore United States -- Region 5, West Texas and Eastern New Mexico. USGS.
- Sanchez, T., Loughry, D., & Coringrato, V. (2019). Evaluating the Ellenburger Reservoir for Salt Water Disposal in the Midland Basin: An Assessment of Porosity Distribution Beyond the Scale of Karsts. Unconventional Resources Technology Conference (pp. 1-17). Denver: URTeC. doi:10.15530/urtec-2019-600
- Scanlon, B. R., Reedy, R. C., Male, F., & Walsh, M. (n.d.). *Water Issues Related to Transitioning from Conventional to Unconventional Oil Production in the Permian Basin.* Austin: Bureau of Economic Geology.
- Shamburger Jr., V. M. (1967). *Report 50: Ground-Water Resources of Mitchell and Western Nolan Counties, Texas.* Austin, Tx: Texas Water Development Board.
- Snee, J.-E. L., & Zoback, M. D. (2018). State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity. *The Leading Edge*, 810-819.
- Waite, L. (2021, October 25). Geology of the Permian Basin. UT Dallas Geoscience Permian Basin Research Lab.
- Zerwer, N. Y. (1997). Stress Regimes in the Gulf Coast, Offshore Louisiana:. AAPG Bulletin, 293-307.

APPENDICES

APPENDICES

<u>APPENDIX A – MONGOOSE AGI No. 1 TRRC FORMS</u>

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

APPENDIX A-5: API 42-335-33555 VAN TUYLE PLUGGING RECORDS

APPENDIX A-6: API 42-227-03634 STEWART PLUGGING RECORDS

CHRISTI CRADDICK, CHAIRMAN WAYNE CHRISTIAN, COMMISSIONER JIM WRIGHT, COMMISSIONER



A-1

DANNY SORRELLS DEPUTY EXECUTIVE DIRECTOR DIRECTOR, OIL AND GAS DIVISION PAUL DUBOIS, P.E. 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. 17174

BAYSWATER OPERATING COMPANY LLC 730 17TH STREET SUITE 500 DENVER CO 80202

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 22, 2022, for the permitted interval(s) of the WOODFORD and ELLENBURGER formation(s) and subject to the following terms and special conditions:

MONGOOSE AGI (000000) LEASE SPRABERRY (TREND AREA) FIELD MITCHELL COUNTY DISTRICT 08

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	33536013	000125803	Carbon Dioxide (CO2); Hydrogen Sulfide (H2S)	8300	9000	6900	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
		1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.
		2. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.
1	33536013	3. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.
		4. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.
		5. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.

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.
- Prior to beginning injection and subsequently after any work over, an annulus pressure test must 4. 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 March 10, 2023.

Hilf

For Sean Avitt, Manager Injection-Storage Permits Unit

			A-2				
	GROUNDWATER PROTEC		Form GW-2				
	Groundwater Advisory Unit						
Date Issued:	04 March 2022	GAU Number:	336979				
Attention:	BAYSWATER OPERATING	API Number:	33536013				
	730 17TH STREET SUITE 500	County:	MITCHELL Mongoose AGI				
	DENVER, CO 80202	Lease Number:	Mongoose Aon				
Operator No.:	058827	Well Number:	1				
		Total Vertical	9250				
		Latitude:	32.422884				
		Longitude:	-101.169661				
		Datum:	NAD27				
Purpose:	Injection into Non-producing Zone (W-1	4) ock-29 [.] Townshin-1N [.] Sec	ntion_4				
To protect usable-qu Texas recommends	uality groundwater at this location, the Gro	bundwater Advisory Unit c	of the Railroad Commission of				
The base of usable- well.	quality water-bearing strata is estimated t	o occur at a depth of 350	feet at the site of the referenced				
The BASE OF UND feet at the site of the	ERGROUND SOURCES OF DRINKING	WATER (USDW) is estima	ated to occur at a depth of 475				
This recommendation is applicable to all wells within a radius of 200 feet of this location.							
Note: Unless stated Unless stated other	otherwise, this recommendation is intend wise, this recommendation is for normal d	ed to apply to all wells dri rilling, production, and plu	lled within 200 feet of the subject well. Igging operations only.				
This determination is based on information provided when the application was submitted on 03/02/2022. 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 Advisc	ory Unit, Oil and Gas Division						
Form GW-2 P.C Rev. 02/2014). Box 12967 Austin, Texas 78771-2967	7 512-463-2741 lr	nternet address: www.rrc.texas.				

	RAILROAD COMMISSION OF TEX OIL & GAS DIVISION	AS			
PERMIT TO DRILL, DEEPEN, PLUG	ACK, OR RE-ENTER ON A REGULAR OR A	DMINISTRA	TIVE EXCER	PTION LOCATI	ON
PERMIT NUMBER 876754	DATE PERMIT ISSUED OR AMENDED Feb 10, 2022	DISTRICT	* 0)8	
APINUMBER 42-335-36013	FORM W-1 RECEIVED Feb 03 2022	COUNTY	MITCH	HELL	
TYPE OF OPERATION	WELLBORE PROFILE(S)	ACRES			
NEW DRILL	Vertical		4	0	
OPERATOR BAYSWATER OPERATING 730 17TH STREET SUITE DENVER, CO 80202-0000	This permi revoked if O Dis	NOTI t and any allow payment for f commission is strict Office T (432) 68-	ICE wable assigned ma fee(s) submitted to not honorad. Felephone No: 4-5581	ay b o the	
LEASE NAME MONG	OOSE AGI	WELL NU	MBER	1	
LOCATION 10.4 miles NW direct	ion from WESTBROOK	TOTAL DE	SPTH	10000	
SECTION 4 SURVEY T&P RR CO/MORRIS DISTANCE TO SURVEY LINES	BLOCK 29 T1N ABSTRA	DISTANCE	15 e to neare	ST LEASE LINI	E
551 IL EAST	2164 ft. SOUTH	DISTANCE	TONEARE	T.	EA 6
400 ft. EAST	650 ft. SOUTH	DISTILICE	See FIEI	LD(s) Below	
FIELD NAME LEASE NAME		ACRES NEAREST LE	DEPTH SASE	WELL # NEAREST WE	D
SPRABERRY (TREND AREA)		40.00	10,000	1	-
MONGOOSE AGI				0	
RESTRICTIONS: Do not use this by the Environm	well for injection/disposal/hydrocar ental Services section of the Railroa	bon storage 1 Commissio	e purposes on, Austin,	vithout appro Texas office	ova e.
THE F This well shall be completed and produc well is to be used for brine mining, under salt formations, a permit for that specific drilling, of the well in accordance with St This well must comply to the new SWR is corrosive formation fluids. See approve drilling the well in.	OLLOWING RESTRICTIONS APPLY TO ed in compliance with applicable special field rground storage of liquid hydrocarbons in salt purpose must be obtained from Environment atewide Rules B1, 95, and 97. 3.13 requirements concerning the isolation of d permit for those formations that have been i	ALL FIELD or statewide formations, al Services p any potentia dentified for	DS a spacing an or undergrou prior to const al flow zones the county in	d density rules. und storage of g truction, includir and zones with n which you are	lft gas ng n
Data Validation Time Stamp:	Feb 10, 2022 9:58 AM('As Approved' Version)	Page 3 of 4		



RAILROAD COMMISSION OF TEXAS

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

Tracking No.:

Submitted 09/11/2023 298516

Form W-2

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

UPERALL	
	Operator 059927
Operator 730 17TH STREET SUITE 500 DENVER CO	
WELL	INFORMATION
API 42-335-36013	County: MITCHELL
Well No.: 1	RRC District 08
Lease MONGOOSE AGI	Field SPRABERRY (TREND AREA)
RRC Lease	Field No.: 85280300
Location Section: 4, Block: 29 T1N, Survey: T&P RR CO/MORRIS	SON, W, Abstract: 1545
Latitude 32.423000	Longitud -101.170059
line tion from WEATDDOOK	
which is the nearest town in the	
FILING	INFORMATION
Purpose of Initial Potential	
Type of New Well	
Well Type: Active UIC	Completion or Recompletion 04/28/2023
Type of Permit	Date Permit No.
Permit to Drill, Plug Back, or	02/10/2022 876754
Rule 37 Exception	
Fluid Injection	
O&G Waste Disposal	17174
Other:	
COMPLET	
Spud 10/12/2022	Date of first production after rig 04/28/2023
Date plug back, deepening,	Date plug back, deepening, recompletion,
drilling operation 10/12/2022	drilling operation $04/28/2023$
Number of producing wells on this lease	Distance to nearest well in lease &
Number of producing wells on this lease this field (reservoir) including this 1	Distance to nearest well in lease & reservoir
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00	Distance to nearest well in lease & reservoir Elevation 2252 GL
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-Yes	Distance to nearest well in lease & reservoir Elevation 2252 Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNo	Distance to nearest well in lease & reservoir Elevation 2252 Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W- YesYesRecompletion orNoType(s) of electric or other log(s) Electric Log Other Description:Combo of Indu	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No iction/Neutron/Density/Sonic
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400 400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Inction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and 0 Feet from the South Line of the
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400650	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Inction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W- YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this 1 Total number of acres in 40.00 Total depth TVD 9289 Plug back depth TVD 9036 Was directional survey made other inclination (Form W- Yes Recompletion or No Type(s) of electric or other log(s) Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is 400 FORMER FIELD (WITH RESE	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this 1 Total number of acres in 40.00 Total depth TVD 9289 Plug back depth TVD 9036 Was directional survey made other inclination (Form W- Yes Recompletion or No Type(s) of electric or other log(s) Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is 400 FORMER FIELD (WITH RESE Field & Reservoir	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and 0 Feet from the South Line of the MONGOOSE AGI Lease. RVOIR) & GAS ID OR OIL LEASE NO. Gas ID or Oil Lease Well No. Prior Service Type

W2:	N/A				
FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:					
GAU Ground	dwater Protection Determination	Depth	350.0	Date 03/04/2022	
SWR 13 Exc	eption	Depth			

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION					
Date of		Production			
Number of hours 24		Choke			
Was swab used during this	No	Oil produced prior to			
PRODUCTION DURING TEST PERIOD:					
Oil		Gas			
Gas - Oil 0		Flowing Tubing			
Water					
	CALCULATED	24-HOUR RATE			
Oil		Gas			
Oil Gravity - API - 60.:		Casing			
Water					

	CASING RECORD										
	Type of	Casing Size	Hole Size	Setting Depth	<u>Multi -</u> Stage Tool	<u>Multi -</u> Stage Shoe	Cement Class	Cement Amoun	Slurry Volume	Top of Cemen	t <u>TOC</u> t Determined
<u>Ro</u>	Casing	<u>(in.)</u>							<u>(cu.</u>	<u>(ft.)</u>	Ву
1	Surface	13 3/8	17 1/2	569			С	637	847.0	0	Circulated to Surface
2	Intermediate	9 5/8	12 1/4	5328	3001		С	725	1752.0	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5328			С	610	1175.0	3001	Calculation
4 C	Conventional Production	n 7	8 3/4	8343			C & RESIN	594	1513.0	1800	Calculation

_					LINER RECORD			
<u>Ro</u>	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu. (ft.)	TOC Determined
N/A								

		TUBING RECORD	
Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	8260	8230 / INCONEL
			925

PRODUCING/INJECTION/DISPOSAL INTERVAL					
Ro	Open hole?	From (ft.)	<u>To (ft.)</u>		
1	Yes	L 8343	9036.0		

ACID, FRACTURE, C	EMENT SQUEEZE, CAST IRON BRIDGE PLUG,	RETAINER, ETC.			
Was hydraulic fracturing treatment	No				
Is well equipped with a downhole sleeve? No	If yes, actuation pressure				
Production casing test pressure (PSI	IG) Actual maximum pressur	e (PSIG) during			
hydraulic fracturing	fracturin				
Has the hydraulic fracturing fluid disclosure been No					
Ro Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)			

OPEN HOLE CEMENT PLUG WITH 58 SACKS CLASS H

1

Other

9036 9289

		FORMATION REV	CORD		
Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
SANTA ROSA - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT
YATES - OVERPRESSURED, POSSIBLE FLOWS	Yes	1001.0		Yes	
SEVEN RIVERS	Yes	1137.0		Yes	
SAN ANDRES - HIGH FLOWS, H2 CORROSIVE	S, Yes	2008.0		Yes	
GLORIETA	Yes	2875.0		Yes	
CLEARFORK	Yes	3089.0		Yes	
TUBB	No			No	NOT PRESENT AT LOCATION
WICHITA	No			No	NOT PRESENT AT LOCATION
COLEMAN JUNCTION - POSSIBL LOST CIRCULATION	E No			No	NOT PRESENT AT LOCATION
WOLFCAMP	Yes	5369.0		Yes	
STRAWN	Yes	7918.0		Yes	
ODOM	No			No	NOT PRESENT AT LOCATION.
MISSISSIPPIAN	Yes	8153.0		Yes	
WOODFORD	Yes	8322.0		Yes	
ELLENBURGER	Yes	8374.0		Yes	
CAMBRIAN	Yes	9279.0		Yes	
Do the producing interval of this w	ell produce H	2S with a concer	tration in exc	ess of 100 ppm	No
Is the completion being downhole	commingled	N	0		

REMARKS DIRECTIONAL SURVEY RUN FOR INFORMATION PURPOSES ONLY.

PUBLIC COMMENTS:

RRC REMARKS

CASING RECORD :

SURFACE CASING IS SET AT 543.5' AS MEASURED FROM GROUND LEVEL, WHICH IS WITHIN 200' OF BUQW.

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

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

POTENTIAL TEST DATA:

		OPERATOR'S CERTIF	ICATION	
Printed	James Clark	Title:	Consulting Petroleum Engineer	
Telephone	(512) 415-4191	Date	09/11/2023	

Ð 7 Ð ŋ 7 η ŋ Ŋ 20. Do you have the right to develop the minerals under nny right of way that crosses, or is contiguous to, this innet? If not, and if the well requires a Rule 37 or 38 exception. 25. is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes 23. Is this a pooled unit? Perpendicular surface location from two nearest designated lines:
 trace.Unit <u>1000</u>, FNL & 2500, FEL 11. Distance from proposed location to nearest leave or unit line 2 Address (including city and zip code) Purpose of filing (murk appropriate bodes): · Sunny/Section 1000' FNL & 2500' FEL of Section 15-Operator's Name (exactly as shown on Form P.S. Organization Front) see Instructions for Rule 37. ĩ Krimerka Nulicamp, (Wildcat) File a copy of W-1 and plat in JORC Di Ellenburger (Wildcat) 1800 £ Midland, Texas 3200 West Cuthbert, Bright se zones. One zone per line, ELD NAME: [Exactly as sheem; on RRC privation adult a all estublished and whiles! somes of anticipated repiction. Attach additional Form W-1's as needed to last any firentealo かって 121 Uttach Form P-12 and certified plat. 21 × たりや Company 30 D III 6 Directional Well 5 and \$180.00 fee 79701 Rai Bau **Nation** Suite 2-C trict Office. Deepen (below casing) Sidetrack Application for Permit to Drill, Deepen, Plug Back, or Re-Enter ã 5200-8300' **Gebru** 7800 1000 × 10. Location 3. IURC Operator No. 6. Lease Name (32 spaces maximum) Van Tuyle 093125 'This well is to be located ______ Section . 8 8 Deepen (within casing) Amended Permit (enter permit no. at right & explain fully in Remarks) which is the nearest town in the county of the well site RAILROAD COMMISSION OF TEXAS Oll and Gas Division N 10 (n.) 467-1200 2 467 1200 Specing 467-1200 No 2 Lini 2 15 203091 0CT 1890 If subject to Rule 36, ts Form H 9 Aled? Yes Ę ł I certify that information stated in this application is ince and complete, to the best of my knowledge ĕ 12. Number of configuous acres in lease, pooled unit, or unitized iract **4**0 Density If a directional will show also projected bottom-hole location: pallern Hock 24 Jo liem 17 less that Jiem 18 (substandersberrehe for any field applied for?? 4. FIRC District No. G Lengel Mail Signature Date: Խ 20, 1-1-1 mary Artiling unity for this well OUTLINE 15 Plug Back ALL DE LO 5 4 鍧 _miles in a _north ŝ 9/26/90 1 Smuth. 5. County of Well Site day. Mitchell TEP RR Cor, TWP T-N NO NO a Re-Enter Fine Ungonty - Fine - ----7. RRC Lease/ID No. direction from <u>Latan</u> ٧ Tel: Area Code S. Dawner from NA TRA-NA Inchesed your talavoli. (N.) Cont to nature Read Instructions on Back 915-697-2214 Tracy D. Tenison, Engineer Name and title of operator's representative Enter here, lf assigned: letted wes Z, ۷ "Ennite h 8. Well No. 640 80 V If not filed, explain in Remarks. Number Type and or other Penny 42-33 0 9 0 Rule 37 Case No Abstract No. A. 584 21. Act, of applied for per-mitted, or complete and becattoms that during the this one on bear in the this one on bear in the this reservoir. (1) 5 Form W-1 (OUTLINE ON PLAT.) 9. Total Depth 1 85001 2355 ŝ 5 5 3

A-5



<u>*</u>		<u>इ</u>	26 17 19	25.11	22.11		- 12 M	5 17	s	Ę	() 중용) 11. Pl				λ εi	в 1.0p		Իսդ	¥ ⊒ .≇
		inai ks	you have the right to develop the minerals under y y right of way that crosses, or is configuous to, this tract? y nut, and if the well requires a Rule 37 or 38 exception, r Inviruentions for Rule 37.	his wellwre subject to Statewide Rule 36 (hydrogen aufide are	 Interpretendent of the second s	Sunn Section 1000' FNL & 2500' PEL of Su	pendicular surface location from two neatret designated lines: I.cov/Unit 1000' FNL & 2500' FEL	llenburger (Wildcat)	trawn (Wildcat)	olfcamp (Wildcat)	rpletion. Attach additional Form W-1's as needed to list ae zones. One zone per line.	ELD NAME (Exactly as shown on RBC provation achedule), all established and wildcal zones of anticipated	istance from proposed location to nearest lease or unit line			Hdlynd, Texas 79701	dress linktuding city and zip code)	iright & Company	Directional Well Sidetrack	ne of filing (mark appropriate boxes): X Drill Dreprin (Lelow casing)	 Transver of Trans. Address to: Distant Ossenaria, Driffing Permits P. O. Drever 12007, Capital Station Autin, Trans 79711 Arupy of W-1 and plat to USC District Office.
			×	117 Yes 🔲	No	tet ion-t		8300'	7800'	5200'	Completion depth		1000	wh	• 1	10. Loca	Van	001 093			Rication fo
!				No X	X			467-1200	467-1200	467-1200	Specing pattern (fl.)	15,	\$ }	tch 15 the nearest	is well is to be loc	tion 15	Tuyle	125	mended Permit (c	pen (within casin	NILROAD CO Oll and Permit to Dr
	Date	Sign	I certify the	If subject to	24. IN Her Yea		La	40	40	40	Denalty pattern (acres)	16	12. Number	town in the c	aled5				nter permit n	Ē	indission I Gas Divisio III, Deepen
	1110	ature 9/26/	at Information st	Rule 36. Is Form	n 17 Jesa than It	urvey/Section	nase/Unit	40	40	40	OUTLINE ON PLAT.	17. Number of acres in defiling unit	of contiguous at	ounty of the wel	miles in a	29 7-1-1V		B STIRLING	o. at right & esp	Flug Back	OF TEXAS
• JURC	day y r .	06	ated in this applicati		em 16 (substandard ach Form W-1A)		שט ףנטוברוכם ססווטוח	NO	NO	NO	Inis rectivour If eo, caplein In Remarks,	18. Is the acrosp assigned to an- other well on this lease P in	tres in lesse, pooled u	Isite	north	vy T&P RR Co		Mitchell	lain fully in Remarks	ReEnter	or Re-Enter
Use Only •	Tel: Area Code	Name and till 915-697-3	ion is true and com. Tracy D.	No 0	actrate for any field		Sufficient and	NA	NA	NA	this inser @ tractvoir. (fl.)	19, Distance from proposed loca- lion to nearest applied for, permitted, or	init, or unitized trai		direction from	· · · · · · · · · · · · · · · · · · ·				Eater here, if assigned:	Read Instructi
	Number	e of o pera tor's 22 1 4	plete, to the be Tenison	If not filed.	1 applied forl?			ô	0	0	type well Spe well	OIL gan	π <u>640</u>		atan	·	1		V	► 42- Remit N	ons on Back
 		representative	st of my knowl	explain in Ren	N.			1		-	OIL	21. No. of appl mitted, or ex locations (ii) this one) on this reservoi	IOUTLINE O				8500		2	P	Form V
1				narks							GAS	ited for, per- ompleted ucluding lease in f.	IN PLAT.)			130		7			



JERRY A. DUNN

à.

TEXAS P.L.S. NO. 4735 TEXAS P.L.S. NO. 4839

MIDLA	ND	JOH	IN	WEST	&	ASSO	CIAI	ES	_	TOAS
Scole:	1"=	1000'			Т	Drawn b	y:	N	T	
Dale:		10-2-	90		T	Sheet	1	of	1	aheete
Revision	1 Dol	le:			Т	W.O. No.	: 6	900	63	

13(4) Exception Dated 440		RS DIV	ISION	Mo ())		ii.		W. 10/74
				NO.42-3	35-33555		R R R R	et
WELL IS LOCATED WITHIN T	IRTY D	YS AFT	ER PLU	GGING	GH	4.	RRC Leest	or M.
Wildont	V.	an Tuyl	e /	-0		5.	Wall Number	1
Bright & Company	ős. Origi	and Form W-	-1 Filed in	Name of:	<u></u>	10.	County Mitchel	11
ADDRESS 2911 Turtle Creek Blvd #70 Dallas, TX 75219)() ^{6b.} Any 1	Subsequent	W-l's File	d in Name of	-	11.	Date Drill Permit Jan 10/18/9	01
Location of Well, Relative to Nearest Lease Boundaries	1000	i Zma N	orth 1	ine and 25	OD Foot P	12,	Permit Mus	and the
SECTION BLOCK AND SURVEY	east Li	ne of the	VIII I			- 11	379724	2
ec 15. Blk 29. TIN. T&P/RR Co	Coun	^{ty} 8.	7 milos		Vestbro		Co.72670	0./
i. Type Well (Oll, Gas, Dry) (Oll, Gas, Dry) 8360 [†]	at All Field :	Names and		T Ges ID No	NESCOLOC	LL, 14,	Dute Drilli Completed	AK DO
I Ges, Amt. of Cond. on Hend at time of Plugging					-	15,	Dete Well 12-17-	Planed 90
CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5 1	LUG #6	PLUG #7	PLUG #8
7. Cementing Date	12-17	12-17	12-17	12-17	12-27	\sum		- 2 637.0
D. Size of Hole or Pipe in which Plug Placed (inches)	7-7/8	7-7/8	7-7/8	8-5/8	8-5/8	<u> </u>		
. Depth to Bottom of Tubing or Drill Pipe (ft.)	8250	2700	2350	400	15 .	WY I	1 to	
2. Sacks of Coment Used (each plug)	50	50	180	50	10 \		1./ - y/	
I. Slurry Volume Fulpped (cli. If.)	8076	2526	1792	325	Surf			
Measured Top of Plus (if tassed) (ft.)	0070	2320	1790	525	Sull .	JAK	1.4.100	
5. Sturry Wt. #/Gel.	15.6	15.6	15.6	15.6	15.6	VIT		-
7. Type Cement	Prem.	Prem.	Prem.	Prem.	Prem.	taka.	15 75%	6
8. CASING AND TUBING RECORD AFTER PLUGGING		29, W	an Ceelor)	-Drillable M Left in This	aterial (Othe: Well		Ye.	K No
ZE WT. #/FT. PUT IN WELL(A.) LEFT IN WELL(A.) I	HOLE SIZE	(m_) 29s. If	enswer to a d briefly de	bove is "Ye scribe non-	is" state dep drillable mat	th vio top Hindu - TU	of "Junk"	left in hole Side of
3/3 48 361 361	17-1/2	- P	orm if more	space is nee	eded.)	10 101	12.8	
<u>5/6 32 22/4 22/4 22/4 </u>					1.	1. 4	1.55	(3.13)
		-	1.18.41	-5. 9	12 400	1. 200		an a
LIST ALL OPEN HOLE AND/OR PERFORATED INTE	RYALS	-	5		1	C/1.		
PROM 2274 TO 8360		FR	он	-	T	520	3/	
ROM LAND I IN THE THE TO		PR	OM 1	nsiurs to	1. b. T	0	15/	
PROM TO		FR	OM C	Leel [1]	NT.	66100		
FROM ADD 1 7 1991 TO		TR	оні	RH.O.de	T	00		STATES
PROM		FR	OM The factor	1.1.1	ा	0		
have knowledge that the cementing operations, as reflected	by the inform	nation found	s on this for	m, were per	formed as Ind	icated by	each infor	nauon.
resignates items to be completed by Cementing Company. It	eme not so d	lesignated a	hali be com	pleted by O	perator.			
				iii tean Cann	ulaan in	4- 0-		
- MC - CACUM X/			III IOUT	LUN SEL	vices, B	TR Sb	ring, T	A
nature of Comenter or Authorized Representative		Ma	me of Cene	nting Compo	in y			
I declare under penalties prescribed in Sec. 91.143	, Texas Natu	mi Resourc	es Code, ti	hat I am auth	orland to me	ke this re	port, that t	hla
report was prepared by me or under my supervision a	und direction,	, and that d	ate and fect	is stated the	rein are true,	carrect,	and comple	te, Status
to ris nation with menalanday								
Amonda I Hand		Annat		1/1 + /				
REPRESENTATIVE OF COMPANY		TITLE		RECEDAT	<u>р</u>	hont		NUMBER
			F	R.C OF TET	45	3		
Dr. A That Teletan	.)	÷.						
GNATURE: REPRESENTATIVE OF RAILROAD COMMIS	SION	•	MA	IR 0 5 19	991 <u></u>	8, ÿ	~	
					and it.		コクノ	

истер алоб язта**н .** С

.

34. Tetal Depth 8360	Other Fresh Water TOP	Zones by T.I BOTTO	D.W.R. DM	35. Have all Abandoned Walls on this Leas according to R.R.C. Rules?	se been Plugged	X Y•1
Depth of Deepeat Fresh Water				36. If NO, Zaplain		No
37. Neme and Address Halliburton, F	of Cementing or Server. . O. Box 380;	, Snyder	who min, Texa	ad and pumped coment plugs in this welt as 79549	Date RR notified	C District Office
Ben Van Tuyl	ers of Surface Owner e, 432 Hillds	ale Dr.	and Oper Ann Ai	retors of Offert Producing Leases		
39. Was Notice Given	Before Pipeeine to Ec	sch of the Ab				
Yes				· · · · · · · · · · · · · · · · · · ·		
40. For Dry Holes, this released to a Com	Form must be accom	LY spanled by ei	ther a Dr	ilier's, Electric, Radioactivity or Acoustical	i/Sonic Log or at	ich Log must be
- 	g Attached	Lag releas	sed to _		Date	
122			. ×		Date	
The second second				20		
Type Loga:	lier's	X Elec	tric	Redicectivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (lier's Special Cleanance) Fi	X Elec	tric	Radioactivity	Aco	untical/Sonic
Type Logs: Dri 41. Date FORM P-8 (1 42. Amount of Oli prod	lier's ipecial Cleanance) FL	ied?	tric	Radioactivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (: 42. Amount of Oil prod * Flie FORM P-1 (C	ller's Special Clearance) Fi uced prior to Plugging II Production Report)	Ied?	iric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>BRC USE ONLY</u>	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	Ied?	itric	Badioactivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oli prod Pile FORM P-1 (C RRC USE ONLY Nearest Field	lier's Special Clearance) Fi uced prior to Plugging Still Production Report)	Ied?	itric	Redicectivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>BRC USE ONLY</u> Mearent Field	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Jed?	itric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Mearest Field BMARKS	lier's Special Clearance) Fi aced prior to Plugging 011 Production Report)	Ied?	itric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oil prod • File FORM P-1 (C <u>RRC USE ONLY</u> Hearest Field BMARKS	ller's Special Clearance) Fi uced prior to Plugging III Production Report)	Ied?	itric	Bediosctivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field EMARKS	lier's Special Clearance) F1 uced prior to Plugging 011 Production Report)	Elec Ied?	iric	Bediosctivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fl uced prior to Plugging III Production Report)	Ied?	itric	Redicectivity	Aco	ustics1/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R & C USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	Elec	itric	Redioactivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>BRC USE ONLY</u> Hearest Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Ied?	itric			ustics1/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C RC USE ONLY Nearest Field BMARKS	lier's special Clearance) Fi uced prior to Plugging li Production Report	E	itric	Redioactivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C • RC USE ONLY Nearest Field EMARKS	lier's Special Clearance) FL sced prior to Plugging II Production Report)	Elec	itric	Redioactivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>RRC USE ONLY</u> Nearest Field EMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	E Elec	itric	Redioactivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fl uced prior to Plugging III Production Report)	E	itric	Redicectivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1) 42. Amount of Oll prod • Flie FORM P-1 (C <u>R & C USE ONLY</u> Nearest Field BMARKS	lier's Special Clearance) Fl uced prior to Plugging II Production Report	E Elec	itric	Redicectivity		uetical/Sonic
Type Loge: Dri 41. Date FORM P-8 (1 42. Amount of Oil prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report	Elec	itric	Redioactivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>BRC USE ONLY</u> Hearent Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	E	itric	Redioactivity bbls* produced		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	E Elec	itric	Redioactivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field EMARKS	lier's Special Clearance) Fl uced prior to Plugging II Production Report	E Elec	itric	Redioactivity		ustical/Sonic

en e const la e const la seconda e m la seconda e m

1

.....

419

PLACE FOLS | R1

< 1

Compared and the second largest and the secon	RAILROAD COME Oll and C	2 1 3	(AS	o Wa	Form Cemienti Prv. 48	a W-10 Ing Rep 4/1/03 8-015
1. Operator's Name (As shown on Form P.5, Organiza	tion Report) 2. R	RC Operator No.	3. RRC District No.	4. County	of Well Site	1.04744
Bright & Co.		093125	8	Mitch	el1 👘	10 30
5. Field Name (Wildcat or exactly as shown on RRC re	rords)		5. API No.	7.	Drilling Permit	Na.
Wildcat			42- 335-33	555	379724	1 - 1
8. Lease Name	9.1	Rule 37 Case No.	10. Oil Lease/Gas	ID No. 11.	Well No.	10-14
Van Tuyle	1				1	1220

CASE	IG CEMENTING DATA:	SURFACE CASING	INTER MEDIATE	PRODU	CTION	MULTI- CEMENTIN	STAGE
			CASING	Single String	Multiple Parallel Strings	Tool	- 19 Mar 19
12.0	Brugen bit for 10550						
13. •	Drilled hole size	17-1/2	11		1	an C _{all} _{an} X	
36	Est, % wash or hole enlargement						
14. 5	ter of casing (in. O.D.)	13-3/8	8-5/8	alike datus	5 - 2°	a lign ^{an}	
15. T	op of liner (fr.)	a			2		
16. S	etting depth (ft.)	361	2274	3			
17 N	umber of centralizers used	3	3				
18 H	its, waiting on cement before drill out	12	12				
Â	19. API cement used: No. of socks	390	300-			170 - 1641 - 1816	1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.
4 81	Class	Premium P	111	27 AP reul	aff , Mich ,	WHE Standt	-13 Truch-
a <	Additives	27 Calciu	m Chloride	i dina			101.65
Ŷ	No. of sacks 🕨 🕨						
d Sh	Class 🕨	inener Ken	themes defined	intol at an:	inurtant		
18	Additives	ين ورجاد حققوني فرواني	and to be seen for	A marte data and inco	A PARTY A MARTINE	D. OF TEXAS	
È	No. of sacita	of the advances prope	ter des medications	cristellis wilds	the state of the s	. if fabgeties in	- South RE Suffrage
d Slu	Class	ar island et al.	all and shows	aradina or yunar Aradina ortuguna	a in later owner, ne ge a tracht genter - Na		n in 124 - Dùn 127 Institu Print - Barned Dunret
ñ	Additives 🕨	 Track of State Str Track of Strategy and 	na da da mijaka nji Suldana urbana st		Leff Biro't Husp area a an	CG	a da compañía com e
ti	20., Slurry pumped: Volume (cu. ft.) 🌘		591	intres investion	IA CONTRACTOR		State Water I a
	Height (ft.) 🕨 🕨	Surface	2268	1 B 1 327 2079 (s temp tigdes ansätt va en en en en en	P. Weitzers and and	W 15, in oks
¥	an an an the Volume (cu. ft.) 🍉	- Section of Suppl	- 194 Berlin (1944)	s rians - Frank an	i dina aratisa hire	an a	 Subarrolluni)
64 I	ileight (fs.)	A SAME SALANA A A	 anaparities contractor designed in Lindé (c) 	, Hondrachagasa CHarc sasara	េ មេរ៉ានីវារូក ភូមិ កើនដែរប្រាំការ ភ	unter ünterstandt i Unter unstandere	: Bast received to an
z	Volume (cu. ft.) 🕨	1 N X.		a fé bolt an et ES.	n albig zint fog drav dat. A	e fitter halter («»	and al say within
•		me ante ave		tiere is on these e	institues land	enet belever statte sin	i incaratora fasis religit
1	Volume (cu, ft.) D.	514.1	591	- Hannahan and an early a	o Ladistra Miran	1	
B	an and all each off in the Height (if Lifes in the second se	Surface	110000 000 01 4000	nthyanthijh Lalk	in the provide states of the second states of the s	ert valie de trat	
21. Y	Ves cement circulated to ground surface or bottom of cellar) outside casing?	Toras Yes	n inte Ro	1. Startinger Start	2. Stallier feit		Contraction of the second
22. F	iemarika	41. 23.11		RECEIVED R.R.C. OF TEX	(ΛS	The second second	and the part of the
		1. U.S.	na Angelan ing	MAR 05 1	991		n - Suzidaje Suzidaje Suzidaje

and the second second second

:

OIL & GAS DIV MIDLAND TEXAS

OVER

	FLUG # 1	PLUG * 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	- PLUD *
and the second second	. E	ZET RO V	nesciento:	GERRAL W	76).		00000000	e
State of hale or pipe plugged (in.)								
Dapth to bottom of tubing or drill pipe (ft.)								
	and and	0			Net an An	Harris and a		$\tau(A_{I,2},\gamma_{A_{i}})$
	RALLAU IN	1. it we	the second		•••••	18-18-19-18-19-19-19-19-19-19-19-19-19-19-19-19-19-		
	1.	42		ي. ديورت م وريسيد				16:27
Memoured top of plug, if tagged (ft.)								
	- 30-590 GF24	1993 () () 19	11.2 21/12	1 1 12 N 1 0	stiller Geru		100.000	ज्या व
STATES IN STATES	i Didine i	Static Static		14.4-22			242	
A CONTRACTOR OF THE OWNER		N. Honore Comp.			and the state			- togaine
1/10 · · · · · · · · · · · · · · · · · · ·							by the or weak	
			- internet in the		يب			1 17 5
	Section of				1.	11.00	117 - er itma	1 - 177 - 5
				9	Liles,	11.90		a le segle
			A 2.5	<u>, 9</u>		1 De	۱۱۱۰۰ ^{(۵} ۰۰ ۲۱۱) ۱۹۰۰ (۱۹۰۰)	1 17 S
	Sardor-				1123 713-31716	1.00	1-26-90	ente se la Gastinata Secolaria
OPERATOR'S CERTIFICATE I declary	Eurofer -	prescribed in	A - 34 Sec. 91,143. To	San Najural Re	573-3526 sources Code, (D that I am author	1-26-90 2 dis dif	wie w _e le wie w _e le mid in aa wontere this
OPERATOR'S CERTIFICATE: 1 declary certification, that I have knowledge of the true, correct, and complete, to the best	E under penaltien ne well data and in of my knowledg	prescribed in formation pre- e. This certifie	Sec. 91.143. To control in this rep tition covers all v	915 915 Tel: Amo and that da reli data.	573-3576 Construction of the second s	that I am authorsented on both	1-26-90 Lais dra rized to make idea of this form	a la segle (4.5 - 1.5 (4.5 - 1.5 (4.5 - 1.5 (4.5) (4.5) (4.5) (4.5) (5) (4.5) (5) (4.5) (5) (5) (5) (5) (5) (5) (5) (5) (5) (

Instructions to Form W-15, Cementing Report

State. Zip Code

Tel.: Area Code Number

Date

mo.

day

yr.

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

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

 An initial oil or gas completion report. Form W-2 or G-1, as required by Statewide or special field rules;

• Form W-4. Application for Multiple Completion. If the well is a multiple parallel casing completion; and

Clbr.

 Form W-3, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting dry holes, operators must complete Form W-15, in addition to Form W-3, to show any casing cemented in the hole.

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

のないないではないではないためにていたのですのができ

Address

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

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

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

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

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

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

Please to File No.

11.4.

RAILROAD COMMISSION OF TEXAS OIL AND GAS DIVISION

APPLICATION TO PLUG AND WELL RECORD FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

M.K.C. Malando

Name of Com	any or Oper	stor	he Texas	Compar	ι <u>γ</u>	Address Dor 1720	Fort Worth,
County	loward		SurveyT&	P,RRGo.		29 T-1-1 Sec.	1 exas
Name of Leas	<u>. A. L.</u>	Wasso	n	No. of Acres	1760 W	Il No. 1	2300 (DF)
Located Appr	ox.21	NE	Direction	from.Bi	g Spring,	Texas (Nea	rest P. O. or Town)
Name of Field	in which we	ll is locate	a Wild	cat	*******	99 19- 4 - 4 - 4 - 4 - 4 - 4 - 4 - 4 - 4 - 4	
Form 1, "Noti	e of Intentio	n to Drill,'	" was filed in 1	name of	The Texas	Company	
Drilling Comm	enced 12	-28	****	19. <u>52</u> , D	cilling Completed	3-28	19 52
Has this well	ever produce	a olt No.		******		or Gast	
baracter of	Well (Oil, Ge	s or Dry)	Dry			Total Depth	86701
)ate you wisł	to Plag	3-2	7		19 52	88 - C J. A.	
lame of Party	Plugging W	en Liv	ermore D	rilling	Address 6	10 Lubbock Nat	1 Eank
orrespondence	regarding i	ihis well a	hould be sent	to: Name	The Texa	S Company	dations and an anno 1999. Airtí
lddress Box	1720, 1	Fort W	orth, Te		RECORD	-/	
SIZE	PUT IN	WELL	PULL	ED OUT	1. · / Laure de 1		Ann moto
3 3/81	196	In.	None	, _† In.	196	In. Texas Pa	ttera
5/81	2115		100		201	Hallibur	ton - & S
198 - 1992 M	1301 S. 10		and a state of the second		and the second sec		

ASING WAS CEMENTED GIVE NUMBER OF SACKS USED ON DIFFERENT STRINGS a ser a ser a ser a ser a Sec.

Initial Production	of Oil: Barreis None	WORE 24 nrs. Pressur	None Fill	DLAND, TEXAS
Give notice perore When Plugging co the Deputy Superv	Plugging to all available L suppleted, file final Plugging isor of district in which we	sease Owners, as required by R r Report, duly signed, and swe il is located.	ula (10) ril. to. All more in C	R 10.1952 will be furnished to Commission of Texas
NOTE: If no ing ava formation, water south	india, in state and give all info- , and to may as penably data ve	motion that eac he obtained to us to	tal depth, gades a benerger	OVE DIVIZION .
General Remarks: oil or gas.	This well dril. We therefore	desire to abandon	selvage and plu	g well in the
fcllowing.	manner: (Cut 9 5	/8" casing at 100	and pull same)	and He (Over)
		AND AND AND AVIDAVIT OF		1

ź

- - - A.E.

12

24

Galiche 0 100 At depth 206' emented 13 3/6" Red Reds 100 206 casing at 206' with 250 sacks. Shale & Anhy 206 9.5 Gament circulsted. Anhy & Shele 1254 1409 At depth 2125' camented 9.5/8" Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Shale 1255 2125		TOP	BOTTOM	
Band Reds 100 200 cost of the second sec	Caliche		100	At doubh 2061 computed 12 2 day
Shale # Anhy 206 0.45 Comment circulfied. Anhy 94.5 1254 Anent circulfied. Anhy & Shale 1251 1409 At depth 2125' camented 9.5/8". Anhy & Shale 1250 1437 at 2125' with 600 sacks. Anhy & Shale 1750 1437 at 2125' with 600 sacks. Anhy & Shale 1955 116 116 Anhy & Shale 1252 2200 116 Lime 2125 2200 116 Lime & Shale 2125 2200 116 Lime & Ghert 3612 3820 3979 Lime & Sand 3820 3979 116 Lime & Chert 3612 3820 3979 Lime & Chert 3612 3820 3979 Lime & Sand 4155 4538 116 Lime & Chert 514 5232 6203 Lime & Chert 7953 8670 514 Total Depth 8670 8670 155 Shale 6201-15 sacks 203-2043; 40 sacks 1125'-1 10 sacks 2025'-4975'-7 <	Red Beda	100	206	At depth 200' demented 13 3/8"
Anhy 945 1254 Address Anhy & Shele 1254 1499 At depth 2125' camented 9.5/8" depth 2125' depth 215' camented 9.5/8" depth 215' depth 215	Shale & Anhy	206	0/5	Carsing AL 200 With 250 Sacks.
Auhy & Shale 1254 1409 At depth 2125' camented 9 5/8", Anby & Salt Anby & Salt 1750 1877 Anhy & Lime 1955 2125 Jime 2125 2290 Lime Shale 2290 Lime & Shale 3116 3612 Lime & Chert 3612 3820 Lime & Sand 4155 4538 Lime & Chert 4536 4000 Lime & Chert 5114 5232 Lime & Shale 5222 6203 Shale 514 5232 Lime & Chert 7953 8670 Total Depth 8570 15 All Measurements from Notory Table or 12' above ground. 28 Remarks Cont'd 870 15 Stacks 5400'-550': 15 sacks 7860'-7810': 15 sacks 1125'-1 15 15 sacks 200'-2075': 15 sacks 625'-4975': 15 sack 660'-5610': 15 sacks 1125'-1 15 sacks 210'-275':	Anhy	94.5	1254	
Anhy & Salt. 1/90 1750 at 2125' with 600 ancks. Anhy & Lime 1750 1837 055. Anhy & Lime 1955 2125 1837 Lime 1955 2125 1837 Lime 1252 2290 Lime 2125 2290 Lime & Shale 2290 2322 Lime & Shale 2322: 3116 Lime & Shale 2322: 3116 Lime & Shale 3612 3820 Lime & Chert 3079 Lime & Chert 3070 4155 Lime & Chert 3079 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 753 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd .	Auby & Shele	1254	1400-	At depth 21251 comented Q 5/RH
Anhy 1837 1837 Anhy & Lime 1955 125 Lime 2125 2290 Lime & Shale 2125 2290 Lime & Shale 2322 3116 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3079 4155 Lime & Sand 3820 3979 Lime & Sand 4155 4538 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 8670 State 6203 7953 Lime & Cont'd 8670 15 Sacks 500-5171 15 sacks 5600'-7810': 15 sacks 7260': 15 sacks 1025'-975': 15 sacks 500': 15 sacks 10'-2760': 15 sacks 2093-2043: 20 sacks 1125'-1 Los sacks 102'-2760': 15 sacks 2093-2043: 20 sacks 1125'-1	Anhy & Selt.	1499	1750	at 2125! with 600 spoks
Anhy - 1837 1955 Nime 1955 2125 2290 Lime & Shale 2290 2322 116 Lime & Shale 2290 2322 116 Lime & Shale 3116 3612 3820 Lime & Sand 3820 3979 155 Lime & Sand 4155 4538 1455 Lime & Sand 4155 4538 146 Lime & Chert 5114 5232 6203 Lime & Chert 5114 5232 6203 Shale 6201 7953 6670 Total Depth 8670 8670 No 15 8670 15 All Measurements from Notory Pable or 12' above ground. 15 Remarks Cont'd 8670 15 Scole - 4520': 15 15 8670 15 All Measurements from Notory Pable or 12' above ground. 125 125 Remarks Cont'd 8670 15 8670 15 Scole - 4520': 15 sacks 5430-5580': 15 15 8680'-7810': 15 8680'-7810': 15 <td>Anhy & Shale</td> <td>1750</td> <td>1837</td> <td></td>	Anhy & Shale	1750	1837	
Anhy & Lime 1955 2125 Lime 2125 2290 Lime & Shale 2220 2322 Lime & Shale 2322 3116 Lime & Shale 3612 3820 Lime & Shale 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3620 3979 Lime & Sand 4535 4538 Lime & Chert 4538 4900 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 8670 Take Heavy mud between plugs. spot the following cement plugs. 95 sack 8670'-7810': 15 sacks 7705'-7 15 macks 5000'-5550': 15 sacks 5430-5380': 15 sacks 7860'-7810': 15 sacks 7705'-7 15 macks 5000'-5550': 15 sacks 5430-5380': 15 sacks 2025'-4975': 15 sacks 660'-4630': 15 sacks 8210'-2760': 15 sacks 270': 15 sacks 7705'-7 15 macks 5002'-550': 15 sacks 5730-5380': 15 sacks 2025'-4975': 15 sacks 957 # 1. Phr. failed	Anhy	1837	1955 .	
Hime 2125 2290 Lime & Shale 2122: 3116 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3979 Liss Lime & Chert 3979 Liss Lime & Sand 4515 4538 Lime & Chert 4538 4000 Lime & Chert 5314 522 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 15 Sacks Cont'd 8670 15 Lime & Cont'd 8670 15 Sacks Cont'd 8670 15 Lime & Sold: 500'-550': 15 sacks 7800'-7810': 15 sacks 7705'-7 Lime & Sold: 500'-550': 15 sacks 760'-7810': 15 sacks 7705'-7 Lime & Sold: 500'-550': 15 sacks 2093-2043: £0 sacks 1125'-1 40 Lime & Sold: 500'-550': 15 sacks 1025'-1475'.5 5 5 <td>Anhy & Lime</td> <td>1955</td> <td>2125</td> <td></td>	Anhy & Lime	1955	2125	
Inter & Shale 2290 2322 Linee Shale 3116 Linee & Shale 3116 3612 Linee & Chert 3612 3820 Linee & Sand 4155 4538 Linee & Chert 3979 4155 Linee & Chert 438 4000 Linee & Chert 4538 4500 Linee & Chert 5314 Linee & Chert Linee & Chert 5314 Linee & Chert Linee & Chert 7953 8670 Total Depth 8670 12' All Measurements from Notory Table or 12' above ground. 8670 Remarks Cont'd 8670 12' All Measurements from Notory Table or 12' above ground. 8670'-7810': 15 sacks 7705'- 7 Stacks 5600'-550': 15 sacks 5430-5380': 15 sacks 205'-4975': 15 sack 660'-4630': 15 sacks 2125'-1 Lo sacks 1025'-975': 15 sacks 570': 15 sacks 2025'-2043; 20 sacks 1125'-1 40 sacks 1025'-975': 15 sack Lo sacks 1025'-975': 10 sacks 675': 325': 30 sacks 1125'-1 10 sacks 100': 15 sacks 203'-2260': 10 sacks 1125'-1 Lo sacks 1025'-975': 10 open 1 hr. Recovered 2250' salt water and 225 125'-116' sacks 2500': 10 open 1 1/2 hrs. Recovered 300' dris, mud.	Lime	2125	2290	00.0 · · · · · · · · · · · · · · · · · ·
Lime 2122 1110 Lime & Shale 3116 3612 Lime & Chert 3612 3820 Lime & Sand 3820 3979 Lime & Chert 3612 3820 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4538 4900 Lime & Sand 5232 6203 Shale 5232 6203 Shale 6203 7953 Lime & Ghert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground, Remarks Cont'd 15 sacks 8215-8163, 15 sacks 7860°-7810'; 15 sacks 7705'-7 15 macks 5600'-550'; 15 sacks 5430-5380'; 15 sacks 500'; 15 sacks 7705'-7 15 macks 5600'-550'; 15 sacks 5430-5380'; 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks, 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. DST # 1: Pkr. failed DST # 2: 4805-4200. Tool open 2 hrs. Recovered 2250' salt water and 225 satt water tout with drig, mud. DST # 3: 5100, 5216. Tool open 1 1/2 hrs	Lime & Shale	2290	2322	
Jillo Jol2 Lime & Chert 3612 Jime & Sand 3820 Jame & Sand 3820 Jime & Chert 3079 Lime & Sand 4155 Lime & Sand 4155 Lime & Sand 4538 Lime & Chert 4538 Lime & Chert 4538 Lime & Chert 5114 Jime & Shale 5232 Lime & Shale 5232 Jime & Ghert 7953 Jime & Ghert 7953 Jime & Ghert 7953 Shale 6203 Total Depth 8670 Total Depth 8670 State Heavy mud Datween plugs, spot the following cement plugs, 95 sack 8670-8373':15 sacks 5163. 15 sacks 7860'-7810': 15 sacks 7705'- 7 Jacks 500'-5550':15 sacks 5430-5380': 15 sacks 2093-2043: 40 sacks 1125'-1 460'-4630':15 sacks 810'-2750': 15 sacks 75'-825': 30 sacks in top casing. Drill Stem Tests	Idmo & Shalo	2322 1	3116	· · · · · · · · · · · · · · · · · · ·
Lime & Sand 3820 3979 Lime & Chert 3979 4155 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Shale 5222 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 Total Depth 8670 School & Chert 7953 School & Sch	Line & Chent	2612	1 1012	
Lime & Chert 3070 1155 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4453 4900 Lime & Sand 44900 5114 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Ghert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 660'-7810': 15 sacks 7705'-7 15 marks 560'-5550': 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 5125'-7 4680'-4630': 15 sacks 2810'-2760': 15 sacks 2033-2043; 10 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests	Line & Sand	2620	1 2020	•
Lime & Sand 4155 4538 Lime & Chert 4538 4900 Lime & Chert 4538 4900 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 8670 Stale 8210 12' above ground. Remarks Cont'd 12' above ground. Remarks Cont'd 12' above ground. Remarks 5600'-5500': 15 sacks 5215-8163 15 sacks 7705'-7 15 macks 5600'-5500': 15 sacks 5215-8163 15 sacks 7705'-7 15 macks 5600'-5500': 15 sacks 5215-8163 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks 1025'-975': 40 sacks 875'-825': 30 sacks 1n top. casing. Drill Stam Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 4805-4900, Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 2: 5405-5500 Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 2: 5405-5500 Tool open 1 hr. Recovered 100' drig. mud. DST # 2: 5405-5500 Tool open 1 hr. Recovered 20' drig. mud. DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 4: 740 Tool open 1 hr. Recovered 5' drig. mud & 180' slightly drig	Line & Chert	3070	1.155	Past in Party
Lime & Chert 438 400 Lime & Sand 4900 5114 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd 15 8000 5100': 15 8000 700': 10 8000 800': 1000 800': 1000 700': 1000 700': 1000 700': 1000 700': 1000 700': 1000	Lame & Sand	1155	1.538	
Lime & Sand 4000 5114 Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Shart 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 7 Fathe Heavy mud batween plugs, spot the following cement plugs, 95 sack 8670 - 7810'; 15 sacks 7705'-7 Lime & Solo - 5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 7705'-7 Lime & Solo - 5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 125'-1 Lo sacks 500'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 125'-1 Lo sacks 1025'-975'; 10 sacks 875'-825'; 30 sacks in top casing. Drill Stam Tests Drill Stam Tests DST # 1: Pkr. failed DST # 2: 1405-4900, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 2: 5100-5216, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 5' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 5' drlg, mud. DST # 7: 723 brain the total state of the	Line & Chert	1.538	1,000	•
Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 12 above ground. Remarks Cont'd 15 acks 510 relation of the following cement plugs, 95 sack 5670 relation of the following cement of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 relation of the following cement plugs, 95 relation of the following cement plugs, 95 relation of the following cement p	Lime & Sand	4900	5114	
Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Bains Heavy mud batween plugs, spot the following cement plugs, 95 sack 8670-8373 115 sacks 8215-8163, 15 sacks 7860'-7810': 15 sacks 7705'- 7 15 macks 5600'-5550': 15 sacks 5430-5380': 15 sacks 2025'-4975': 15 sack 6680'-4630': 15 sacks 2810'-2760': 15 sacks 2093-2043: 20 sacks 1125'-1 40 sacks 1025'-975': 40 sacks 875'-825': 30 sacks 1n top casing. Drill Stem Tests Drill Stem Tests Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 mail water cut with drig. mud. DST # 3: 5100-5210, Tool open 1 hr. Recovered 300' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 180' ell. DST # 7: 783 mod. DST	Line & Chert	5114	5232	
Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Taths Heavy mud batween plugs. spot the following cement plugs. 95 sacks 8670-8373':15 sacks 2215-8163. 15 sacks 7860'-7810': 15 sacks 7705'-7 15 macks 5600'-5550': 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 600'-6810': 15 sacks 2093-2043: 40 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 1 1/2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 5400-5485. Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 5400-5485. Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 5: 5002.5600 Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 7: 723 Tool open 1 1/2 hrs. Recovered 20' drig. Mud & 120 DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' dr	Lime & Shale	5232	6203	o alteration and the second state of the second second
Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. All Measurements from Notory Table or 12' above ground. Remarks Cont'd 6670 Saing Heavy mud butween plugs, spot the following cement plugs, 95 sack 8670 - 3731:15 sacks 2215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7 15 macks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 4680'-4630': 15 sacks 2810'-2760'; 15 sacks 2093-2043; 20 sacks 1125'-1 40 sacks 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 4805-4900, Tool open 1 1/2 hrs. Recovered 300' drig, mud. DST # 5: 5002.5000, Tool open 1 1/2 hrs. Recovered 300' drig. mud. DST # 5: 5002.5000, Tool open 1 hr. Recovered 75' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 100' drig. mud. 1700-115 DST # 4: 700 means 1 hr. Recovered 100' drig. mud. 1700-115 DST # 4: 700 means 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. None	Shale	6203	7953	olari mayadar. A sidamedinda yang ang panamaa
Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Baths Heavy mud batteen plugs. spot the following cement plugs. 95 sacks 8670'-8373':15 sacks 8215-8163. 15 sacks 7705'-7 15 macks 560'-5550':15 sacks 5430-5380':15 sacks 5025'-4975':15 sack 660'-4630':15 sacks 2215-8163. 15 sacks 2093-2043: 40 sacks 125'-7 15 macks 560'-5550':15 sacks 5430-5380':15 sacks 5025'-4975':15 sack 660'-4630':15 sacks 2810'-2760':15 sacks 2093-2043: 40 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests Dst # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 3: 5100-5218; Tool open 1 1/2 hrs. Recovered 300' drig, mud. DST # 4: 740-5145; Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 760-5145; Tool open 1 hr. Recovered 100' drig. mud. DST # 4: 760-5145; Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760-5145; Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760-7610; Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760-7620; Tool open 1 hr. Recovered 20' drig. mud. DST # 4: 760-7620; Tool open 1 hr. Recovered 5' drig. mud & 180' slig. DST # 7: 7630-7620; Tool open 1 hr.	Lime & Chert	7953	8670	al a development and set water a set of the
All Measurements from hotory Table or 12' above ground. Remarks Cont'd Hathg Heavy mud between plugs, spot the following cement plugs, 95 sack 8670'-8373':15 sacks 8215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7 15 macks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sac 6680'-4630':15 sacks 2810'-2760'; 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5216 Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 760 fool open 1 hr. Recovered 75' sliphtly gas cut drlg. DST # 4: 760 fool open 1 hr. Recovered 70' drlg. Mud & 120 DST # 4: 760 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 5' drlg. mud. DST # 4: 750 fool open 1 hr. Recovered 5' drlg. Mud & 180' ell sud ebod of samin of task 26 and of task 1 hour fool open 1 hr. None	Total Depth	a state of states and a second	8670	The second seco second second sec
AU sacks, 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 selt water cut with drlg. mud. DST # 3: 5100-5210. Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 4: 5400-5210. Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7400-7470. Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 7400-7470. Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 7400-7470. Tool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 7400-7470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 743. Model of a setting of rate Constant of the set of	I E marke FGOOL FEFO	Plant P. Plant and all	ELOO FO	1000 -1010 ; 1) Backs //0/ - /
Deill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5218. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5440-5485 Tool open 1 hr. Recovered 75' slightly gas cut drly. DST # 4: 780 1000 Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 780 1000 Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 1000 1000 1000 1000 1000 1000 1000 10	15-macks 5600'-5550	1:-15 sack ks 2810'-2	s 5430-53 760': 15	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-10
DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5216, Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5440=5485; Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7805-7870; Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7805-7870; Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 5' drlg. mud & 180' sli show of shapping of relevant Cased of 1 drlg. Mud & 180' sli per cent None	15-macks 56001-5550 46801-46301:15 sec 40 macks 10251-975	1;-15 sack ks 2810'-2 1; 40 sack	8 5430-53 760': 15 8 875'-82	80'; 15 sacks 5025'-4975'; 15 sac aacks 2093-2043; 40 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5210. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5400-5445. Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7800-6470. Tool open 1 hr. Recovered 100' drlg. mud. 1000-010 DST # 4: 7800-6470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 7800-6470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 5' drlg. mud & 180' sli show of shepting of rise 2 ased of the sheet of the sheet off. Ies mount of water th oil NODE (1) per cent None	15-macks 5600'-5550 4680'-4630': 15 sec 40 sacks. 1025'-975	11:-15 sack ks 2810'-2 1: 40 sack	s 5430-53 760': 15 s 875'-82	80': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing.
DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 selt water cut with drlg. mud. DST # 3: 5100-5218, Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 4: 5100-5218; Tool open 1 hr. Recovered 75' slightly gas cut drlg DST # 4: 7800-6000, Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 180' slip DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 180' slip	15-macks 5600'-5550 4680'-4630': 15 sec 40 sacks. 1025'-975 Drill-Stem Tests	1;-15 sack ks 2810'-2 ; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-1 5'; 30 sacks in top casing.
aslt water cut with drlg. mud. DST # 3: 5100-5216. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 1: 5400-5485 Tool open 1 hr. Recovered 75' slightly gas cut drly. DST # 1: 5002-6000 Tool open 1 hr. Recovered 100' drlg. mud. 1200- DST # 1: 7800-7420 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud. 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip mount of water with oil 010 010 / 100 / 1	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill Stem Tests	11;-15 sack ks 2810'-2 1; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 10 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 3. 5100-5216, "Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 54:0-5485; Tool open 1 hr. Recovered 75' slightly gas cut drlg DST # 4. 780 model Tool open 1 1/2 hrs. Recovered 100' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. Sole open 1 hrs. Recovered 5' drlg. Sole open 1 hrs. Sole op	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900	1;-15 sack ks 2810'-2 1; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-10 5'; 30 sacks in top casing.
DST # 4. 780 model open 1 hr. Recovered 75' slightly gas cut drlg DST # 4. 780 model open 1 hr. Recovered 100' drlg. mud. 1000 model 1 hr. Recovered 20' drlg. Mud & 120 DST # 4. 780 model open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 781 Model of the state of the st	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900,	1; 15 sack ks 2810'-2 i; 40 sack i tool open selt wate	s 5430-53 760': 15 s 875'-82 2 hrs. 3	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 20 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 4. 780 creation in the second state of t	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900,	tis 15 sack ks 2810'-2 is 40 sack is 40 sack is 40 sack is 40 sack is 40 sack	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 20 sacks 1125'-10 5'; 30 sacks in top casing.
DST # 4. 780 model DST # 7. 763 model DST #	15 macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 4: 5440=5485	d Tool open Tool open Tool open	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re	ecovered 2250' salt water and 2250 h drlg. mud.
abod of shepting of rates of the second of t	15-macks 5600*-5550 4680*-4630*: 15 sec 40 macks. 1025*-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3-5100-5216 DST # 3-5100-5216 DST # 3-5100-5216	d Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud.
allod of abetting of water a Case(of the apert and a water completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3-5100-5218 DST # 3-5100-5218 DST # 3-5002-6000	tis 15 sack ks 2810'-2 is 40 sack d Tool open selt wate Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. R r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	s. Recovered 300' drlg, mud. covered 100' drlg, mud.
athod of sheeting of water - Cased D it water completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 4- 780 mac20	Colopen Tool open Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re	s. Recovered 20' drlg. Mud & 120'
athod of sherting a vater Cased Of the per completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3- 5100-5218, DST # 4- 7800-5485 IST # 4- 7800-64701	ticel open Tool open Tool open Tool open Tool open	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 1/2 hr gas cut d	s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120'
mount of water with oil	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5218, DST # 4: 7805-4900 DST # 4: 7805-4900	i - 15 sack ks 2810'-2 i 40 sack d Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	ecovered 2250' salt water and 2250' h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120'
mount of water with oll	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 3: 5100-5216, DST # 4: 7805-6000, DST # 4: 7805	i - 15 sack ks 2810'-2 i 40 sack i 40 sach i 4	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 c cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	so': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. 100 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' sl1
	15-macks 5600'-5550 6680'-6630': 15 sec 60 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3: 5100-5216 DST # 3: 5100-5216 DST # 4: 7805-6000 DST # 4: 7805-6000	i 15 sack ks 2810'-2 i 40 sack i 40	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 c cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	sovered 2250' salt water and 2250' h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud.
	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST #	i - 15 sack ks 2810'-2 i 40 sack i fool open fool open fool open fool open fool open fool open fool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 225 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg covered 100' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip ater completely shut off? Yes
	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 3- 5002-5000 DST # 3- 50000 DST # 3- 5000 DST # 3- 50000 DST # 3- 50000 DST # 3- 50000 DST #	Li-15 sack ks 2810'-2 Li-40 sack i Tool open selt wate Tool open fool open f	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud. 180' slip ater completely shut off: Ies cent None
SUEDEN SIL	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 3- 5100-5218 DST # 4- 780 0000 DST # 4- 780 00000 DST # 4- 780 000000 DST # 4- 780 0000000000000000000000000000000000	tol open fool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1799-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip the sad matter berson and that the same bre true ts and matter berson and that the same bre true
Fouriet SILEDEU	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5218, DST # 3: 5100-5218, DST # 4: 780 55485 AST # 7: 780 55485 AS	ticol open Tool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drly covered 100' drlg. mud. 1. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip ater completely shut off? Ies cent None
A contract A cont	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 3: 5100	d flool open selt wate flool open flool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 20 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg, mud. covered 100' drlg. mud. covered 100' drlg. mud. 1000 covered 5' drlg. mud & 180' sl1; ater completely shut off: Ies cent None covered 20' drlg. Tes cent None
ALEOIN Marchell and swere to before me this day of Appell Marchell and swere to be for the swere	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks. 1025'-975 Drill Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900. DST # 3- 5100-5216. DST # 3- 510	d Tool open Tool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 10 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 225 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1000 s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 5' drlg. mud. 180' gl1 ater completely shut off: Yes cent None ts and matter bermany of that the content of the trans- ter completely shut off: Yes cent None

A. L. Wasson, Wildcat, Howard County

DST # 8: 8418-8468, Tool open 1 hr. Recovered 100' drlg. mud.

- DST # 9: 8455-8543, Tool open 2 hrs. Recovered 390' slightly gas cut & sulphur cut drlg. mud.
- DST # 10:8546-8670, Tool open 1 1/2 hrs. Recovered 7230' sulphur water.

RECEIVED MIDLAND, TEXAL

APR 101952

Railroad Commission of Texas OIL'84 GAS DIVISION

File No.	RAILEOAD COMMISSION OF TEXAS	Form 4
8	OIL AND GAS DIVISION	1. union a second
FILE IN DUPLICATE WIT	TH DEPUTY SUPERVISOR OF DISTRICT IN WHICH	H WELL IS LOCATED
Company The Texas Company	Address Box 1720;	Ft. Worth, Texas
Sec. No. 4 Block No. 29	T-I-N Survey. T & P RRCO County.	Howard
Well No. 1 Name of Lease	A. L. Wasson	No. of Acres 1760
Name of Field in which well is located	a Wildcat	327
Form 1 (Notice of Intention to Drill) V	Yns Filed in Name of	ompany
Character of Well at the time of comp	iletion: Oil	
Amount well producing when plugged	: Oil None Ca.	It.; Water Nong
Has this well ever produced oil or gar	17	
Total Depth 8670	Top of each producing sand	
Was the well filled with mud-laden flu	id, according to regulations of the Railroad Commission	Yes
How was mud applied?	drill pipe	
Sported the following 7860-7810 15 sx 7705- 15 sx 2810-2760 15 sx spot 40 sy 1125-1070 - Have all abandoned wells of this leas Manner of confining all oil, yes or weak 9 5/8 confining all oil, yes or weak	plug: 95 sx 8670-8373, 15 sx 82 7655, 15 sx 5600-5550, 15 sx 543 2093-2043, Cut off 9 5/8" ceain 40. ar 1025-975, 40 sx 875-825, 3 is been plugged according to Commissions rule? r to strate: All 13 3/8" ceaing left	13-8163, 15 sx 0-5380, 15 sx ex 4680-4630 g @ 100' and pulled 0 sx in top of casi Yes
or cassed of with come	<u>hole. All strata protected by c</u> nt.	asing left in hole
or caused of with come	hole. All strata protected by c. nt.	fellow:
or caused of with come The manus of edjecent lease, royalty a 11 adjacent property	hole. All strata protected by c nt. Ind landowners with their addresses in each instance as leased by The Taxas Company	Asing left in hole
or caused of with come The memory of adjecent lesse, reyalty a All adjacent property	hole. All strata protected by c. nt. ind landowners with their addresses in each instance as leased by The Taxas Company	Asing left in hole
or caused of with come The names of adjacent losse, royalty a All adjacent property Fas motion given before plugging to a	hole. All strata protected by c. nt. ind landowners with their addresses in each instance as leased by The Taxas Company ll available adjacent lease owners as required by Rule I	Asing left in hole
or caused of with came The names of adjacent losse, royalty a All adjacent property Van melies given before plugging to a	hole. All strata protected by c. nt. ind landowners with their addresses in each instance as leased by The Taxas Company ill available adjacent lease owners as required by Rule.	Asing left in hole
Or CARSAD of with come The manues of adjecent lease, royalty a All adjacent property Van motion given before plugging to a I. T. P. Drew ad the matter herein set forth and th	hole. All strata protected by c nt. ind landowners with their addresses in each instance as leased by The Toxas Company Ill available adjacent lease owners as required by Rule I being first duly aworn on oath, state the at the same are true and correct.	fellowe:
Or CARSAD of with come The manus of adjecent lease, royalty a All adjacent property Yes making given before plugging to a I, T. P. Drew and the matter herein set forth and th	hole. All strata protected by c int. and landowners with their addresses in each instance as leased by The Taxas Company Ill available adjacent lease owners as required by Rule I being first duly avorn on path, state the at the same are true and correct. Name	Asing left in hole fellows: 07. Yes 11 have knowledge of the facts Dist. S
Or CARSAC of with come The manage of adjecent losse, royalty a All adjacent property Was motion given before plugging to a I,	hole. All strata protected by c int. Ind landowners with their addresses in each instance as leased by The Taxas Company Ill available adjacent lease owners as required by Rule 1 being first duly avorn on path, state the at the same are true and correct. Name 15 day of May	asing left in hole fellow: 07 Yes 1 have knowledge of the facts Dist. S 10 52
Or CARSAC of with come The manues of adjecent losse, royalty a All adjacent property Was motion given before plugging to a I. T. P. Drew ad the matter herein set forth and the ubscribed and swern to before me this	hole. All strata protected by c int. and landowners with their addresses in each instance as leased by The Taxas Company all available adjacent lease owners as required by Role 1 at the same are true and correct. Name 15 day of May	asing left in hole fellow: or Yes There knowledge of the facts Dist. S 10 52

i i i v		0) ()	2	2	, /1;	07	7					- 1,78			in the second se	
emanne, <u>Ortginal</u> Plugged av	NO ALLOWARLY WILL HE A In protect all fresh water van ments, it will be necessery excertain the depit to which i	A. LEATE LINE				Wildcat	8/00	Pretto WAMK (Restly as sh Protector Belways includie applicable) If Widdes, so	1 - 2 - 2 - 10.		た 一 の 別 小 切	YES X; NO (Big Spring,	P. D. Box 4	McCannyCoro	Check coli DiDIJLL	см. т. 1659.: нозн 911 (4	ipe mail Mo. 42 second on ("Hit b) an have ble
<u>1 Operator</u> Lease Name nd Abandon	ABSIONED to any we vide. Where Commiss y to contact Texat fresh, water sands mu	660' FWL &				ine 11	100	dem on N. N. C. ng Weservoir If state below.	14. 14.	REFER	er. Br	(bestrucțion (2) on be	TX 79720	48			PPILICA Hus	
. The	M In which dres ion rules do n Water Develo at be protected	1980 1980 1980	deed e See e		23 2 - 0 74	42101	Completion Depth	fansa lun Shi ya k Gila ya k	A 14	TO INSTRI	аі. 1 ¹	ck alde.)	: 17 . 37	1041 4 3 4 6 1 3	50	ow Caning) w Atlanh Sets	.dR_PE	
<u>Vasson</u> 27-52	not have sufficient surficient Board, options Board, d.	ĒŇI, ĒNĻ	2 1 8			None	lf done, State Nore.	All Prior Rule 37.Exe, Case Numbers for	3 13.	UCTIONS O	P		a dina andra andra andra	n uta E Fata Infase Grune	5		In the second	4 1
We LL	face casing re Austin, Tex	e co e constant	900 1907 (1907	112 5	N.	467	Rujes, 5 (a). 667-1 200. (h.)	Applicable Field Rules	16.4	N BACK S	EACH PRO	Notrest	6. This we Directio	Sec.	* (*) 7 (5 4 4 4		0 Tring	OIL AND O
	guire tu tu tu tu tu tu		ري الاركى الم		ander Historie Maria	40	Wules, State Acres)	A pulicable A pulicable Denaity	5. IZ. T	IDE: READ	POSED CO	Post Office o	II Is to be los	4. B1k	Stewart	:::홍 *: [] :: 월	EEPEN-	AS DIVISIO
1 	3.8	n 8.1	K			40	DESIGNATE	Number of Accession Drilling Unit for this Well	- 10.	CAREFULL	MPLETION	r Taina.	Vincent	- 29 - 1	17102 13/112 172 112	G BACK	DIR PLUG	ž
Signature A Title Date Telephone:	I declare und Code, that I by me or un therein are tr					<u></u> れっ	emplein in remarks.)	Taithle acre- ege presently sectaned to another well in seme fired? (Ven	- 19-3 19-3	Y AND FURN		i a i ai i î i str	TX	-1-N, 5	arts Stro Stro Stro], उगभ्रद्ध (क्रु	BACK	
dminist unc 12,	ar penalties p am authorizes der my super- ne, correct, at	25. (a) Is this (b) If subje (If no. (20		т с. 1. К. – У	None	piles for well in same res. an semi lease (h.)	Distanct and Direction from pioposed loca- tion to near-st dulling com- plated of sp-	. 20.	ISH COMPLE		192 1141 23	Southea	& F RH	Bade a an a annas annas	erify) TE-e	64 65 55	- - -
21. 3 rative 1980 915	CERTIF rescribed in S d to make this vision and dim vision and dim	wellbore subj oct to SWR 36, attach explana	Reg ^{ula} r 1	Regular 1	Regular 1	Regular 1 🔀 Rule 37 Z	the appro- priate box.	ls this a i. Regular: or 2. Rule 37 Eze, Locas	21.	TE DATA.:	i e	21 4	i ត្រុ	Go.	tstea Tol	ntry	1	ermit
Assist:	ICATE ec. 91.143, To report, that the tetion, and the p the best of r	ect to SWR 36 has Form II- ition.)	JU	A R R	75	0i1	Type Well (Specify)	011, Gas,	22.	2	66 21	12. Total Dep	11. Distance I to Nearest (fL)	iv. Summer of	P. Helling	8. County	7. NRC Dist	ARC Percit
nt 1-7455	egas Natural 7 his report was it data and fac ny knowledge.	yol-" y been filnd"	N 1 .	12	114D	0	110	Number of Wei Permitted fore this Lease in Reservate for a Permit is Regi	15 N N	11.00	63	4600	1 Property of L	640	<u> </u>	loward	net B	284
TET -	Prepared ors stated	1983 1111	U	6		c	GAS	lla or attons on same thichthis usered?		20		3674	Ease Line	, 1	, 2%) (201	r_{0}	4	547

menag Record	RAIL	NOAD COM OIL AND (MISSION BAS DI	OF TA	EXAS			PO Re	RH W-:
1				- <u>A</u> P	I NO,	42227-	-00000	RRC Distric	16
FILE IN DUPLIC	ATE WITH DIST	RICT OFFIC	CE OF	DISTRICT	IN W	HICH	45 . 	08	1 1 16
WELL IS LO	CATED WITHIN	THIRTY D	AYS AF	rer pll	IGGING	1.	Sec. 1	Hunter	98 X.
2. FIELD NAME (as per RRC Rec	orda)	3. Leas	e Name	<u> </u>		····	5,	Well Number	
WILDCAL		fer Oalat	Stew	art	Maria a fa			1	-1
McCann Corpora	tion	. Mc	Cann	Corpor	ation	23		Howan	
7. ADDRESS		ob. Any	Subsequent	W-1's Pile	d in Name	of:	11.	Date Pritile	E.
P. O. Box 448,	Big Spring	<u>, TX</u>	- 11 - 14 - 14 - 14 - 14 - 14 - 14 - 14	00 ==				8-17-	80
of Lease on which this Well is i	arest Lease Boundaris Located	North	ert From	Stew	Int and 1	980 Feet	From 12	Persuit Num	ide 17 - st
. SECTION, BLOCK, AND SURVI	Y	9b. Dista	ince and D	reution Fra	m Nearest	Town in this	13	Dete Drillin	¢
Sec. 4, Blk. 29,T	-1-N,T&P RR	Col	4 m	iles S	Eof	Vincent		10-10-	80
(Oit, Gam, Dry) DRY	a wontible completion	LINE ALL FIELD	Names and		AS ID or	No.'s	RLL	Dute Drillin Completed	F
8. If Gas, Amt. of Cond. on Hand at time of Plurgian					HENDE -		15,	Date Well'h	ged
							6. a	10-12-	
CEMENTING TO PLUG AND A	BANDON DATA:	PLUG #1	10-13	PLUG #3	PLUG	I PLUG.#5	PLUG #6	PLUG #7	38.0
0. Size of Hole or Pipe in which Plu	ig Places (inches)	9-5/8	9-5/8	13-3	8	2 10 UN FeB	15/1 61		
1. Depth to Bottom of Tubing or Dri	Il Pipe (fr.)	11000	250	Top O	E.	121092 (P	and see	1 + + (+,17	16 20
2. Sucks of Cement Used (each plug	<u>}</u>	50	100	10	ļ	22012 (002)	200303400	e van eesteer	474 A.
4. Calculated Top of Plug (ft.)		990	70	Surf				1 2007	
5. Measured Top of Plug (if tagged)	((1.)		N.						550
G. Slurry Wt. #/Gal.		1.33	1,33	1.33	-				
7. Type Coment 8. CASING AND TUBING RECORD	AFTER PLUGGING		129. W	any Non-	Deillable	Material (Oth	1 er		
ZE WT. #/FT. PUT IN WELL (II.	LEFT IN WELL (in.)	HOLE SIZE(n.) 79a. If	Answer to a	bove is "	Yes" state d	pth to top	of "junk" in	ft in hale
5.8 24# 200	500 .	11	P	ora lí more	space is n	eeded.)	iterial. (O	RE MANALES I	Ide of the
		1		a a - 2	er en elses	••••(***)	· · · · · · · · · · · · · · · · · · ·	Harris H.	
	1								1
. LIST ALL OPEN HOLE AND/O	R PERFORATEO IN	TERVALS					1.5	5 1112 ₁₁₁	
PROM	то		FR	М			10 01		
FROM	<u>10</u>		FR	DM DM	or in the second s		TO		0.4495
FROM	то		PR	DM.		L.	ro		11 (12-52) 14 (12-52)
PROM	70	····	PR	CM			то	4	- 12
profiles of Cementer as Authorized R CERTIFICATE:	epresentative rescribed in Sec. 91.1	43, Tezas Natur n and direction,	DO No al Resource and that do	well I we of Comerce of Comerce of Comerce of Comerce of Code, the ten and fact	pletod by (DIVIS] nting Comp et 1 nm eu e stated th	Deemstor.	Dow C	hemical	L C3.
I declare under penalites p report was prepared by me o to the best of my knowled	x•.	Pr	aller:	<u>t (</u>	Peril	<u>1981</u>	Phone Z	5 26.	7-748

APR 2 0 1981 D.G. MIDLAND, TEXAS

D1-80

et an ar star things of a

Ť

.

mark)

1

÷ ÷,



1676° 4 4 4 4	*		
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1			
		<u> </u>	

10.4 14.2

.

te die segulat	-Lates Flaid,	Yes 32. No. Wa	Circulated	33. Wed Bright B. F. sam
	TOP	N by T.D.W.R.	39. Have all Alambound Weits on this Leave	teen Flugged
			36, If NO, Explain	In the second seco
		20		
S 4	nonting of Service	company who me	in and pupped coment plage in this well	Date BRC District Office
Docell Divis	sion of Do	w Chemic	al Co Colorado City.	TX and I of Firest
Altrests of Altrests of	Buface Owner of T	fell Size and Op-	metors of Ollers Producing Leases	
SDanny Stewar	$rt = P \cdot O$	<u>Box 26.</u>	Sterling City, Tx. 769	<u>b</u>
and a guident and a state	0 e			
	a at			
			V.	
Statute Contra Contra Balare	Plagging to Rock 4	of the Alleve?		
res		200		
Fill an anti-ou pole off	BUST be accompta	ied by either a f	Willer's, Riectric, Radioantivity or Acoustical/	Sonic Log & such Log must be
relation to a Comportial	Log Service.	-	5 K.	
Log Alloc	cheed 📃 🗖 L	og released to		Dele
			10 C	
Driller's		Blectric	The disactivity	Acoustics)/Bonie
t di: Base FCRM P-3 (Special List al	Clearance) Filed?			
48. Amount of Oil produced pr	rior to Plugging	<u> </u>	one bble*	
4. Amount of Oil produced pr	rior to Plugging duction Report) for	fi month this oil v	ONC bbls*	
C. Amount of Oil produced pr - Oile Point P-1 (Oil Prod REC WE OILY	rior to Plugging duction Report) for	nonth this oil a	ONC bbla®	
42. Amount of Dil produced pr 4. Plan FORM P-1 (Oil Prod 8. C. 1986 - Oth Y. Steamon Field	rior to Plugging duction Report) for	l'i month this ail •	ONC bbla*	
42. Amount of Oll produced pr 4 (File FORM P-1 (Oll Pro- REC WIE GULY Stewart Field	rior to Flugging duction Report) for	ri month this oil •	ONC bble [®]	
42. Amount of Oil produced pr 4 Plan Folint P-1 (Oil Proc 5 CC 1998 Oth Y. Stours of Pield	elor to Plugging duction Report) for	Pi month this oil *	one bble*	
C. Amount of Dil produced pr	rior to Plugging duction Report) for	ri month this oil •	one bble*	
42. Amount of Oil produced pr 4. Plan Folint P-1 (Oil Prod 1. C. Will Coll-Y. Steament Pield	elor to Plugging duction Report) for	ri month this oil •	one bble*	
Amount of Dil produced pr Plan Police P-1 (Oil Proc Electronic Proto Storem Proto	rior to Plugging duction Report) for	ri month this oil •	one bble ^s	
42. Amount of Oil produced pr 9 pile Folin P-1 (Oil Proc 9 CC will Oil.Y. Stewart Pield	elor to Plugging duction Report) for	Pi month this oil •	onc bble*	
42. Amount of Dil produced pr plan Poline P-1 (Oil Pro- Elife unit entry Storem Pietod	elor to Plugging duction Report) for	Pi month this oil •	one bble ^e	
42. Amount of Oil produced pr 4 Plan Folint P-1 (Oil Pro- RCC WE COLY. Stewart Pield	rior to Pingging duction Report) for	Pi month this oil •	one bble [®]	
42. Amount of Oil produced pr 940 POINt P-1 (Oil Prot Rife will Golly Steamon Pietld 940 940 940 940 940 940 940 940	rior to Plugging duction Report) for	Pi month this oil •	onc bble*	
42. Amount of Oil produced pr 4 Plan Folin P-1 (Oil Pro- RCC WH ONLY. Stewart Pield	rior to Pingging duction Report) for	Pi month this oil •	onc bble [®]	
42. American of Oil produced pr - Pilo Poline P-1 (Oil Proc - Rice will Goll-Y. - Stources Pield	elor to Plugging duction Report) for	Pi month this oil •	onc bble*	
Amount of Oil produced pr Plan Polint P-1 (Oil Proc Elic unit of Polint P-1 (Oil Proc Second Pietol	elor to Plugging duction Report) for	Pi month this oil •	onc bble [®]	
42. American of Oil produced pr 9 Jan Foling P-1 (Oil Proc Bits Foling P-1 (Oil Proc Bits Foling Pield Pield 0) 11 - 12 - 12 - 12 - 12 - 12 - 12 - 12 -	rior to Pingging duction Report) for	Pi month this oil •	onc bble [®]	
C. Amount of Oil produced pr Plac Folin P-1 (Oil Prod Citic Hill Coll-7. Sieuren Pieted Citic Sieuren Piet	duction Report) for	Month this oil •	onc bble [®]	
42. Amount of Oil produced pr Pile Point P-1 (Oil Prod Rife unit Orly, Steamon Pietd CO State	duction Report) for	Pi month this oil •	onc bble [®]	
42. Amount of Oil produced pr - Plan Poline P1 (Oil Proc - Bill C 1998 - Bill	duction Report) for duction Report for duction Repor	A GA	onc bble [®]	
C. Amount of Oil produced produced produced produce Poils Poils Poil (Coll Produced	duction Report for duction Repor	nonth this oil o	onc bble [®]	

OIL AND GAS DIVISION

Ë.

CEMENTING REPORT

Wildcat				*2. MRC Disider	08	
*1. Operator Mc. Capp. Corporation			Barren - San	4. County	00	
"5. Lease Same(a) and RRC Lease Number(a) or 1. D. Num Stowart	aber(a)			·6. Well Humber,	oward	
*7. Location (Section, Black, and Servey)	PP Co C	-		- 199 - Charles Table	Tool and the	
3ec. 4, bik. 29, 1-1-4, 10r	SUBEACE	MTER.	PROM	ICTION		of the Points A
CASING CEMENTING DATA:	CASING	MEDIATE	Single	inc.	CENTRY	S PROCESS IT
			String	Perellal Strings	Třel	Shee.
8. Cementing Date	99 (N) 1991		310 ₁	P. Sugar	1. 30 Bach	. 1923
*9. (a) Size of Drill Bit (inches)	3040		-			
(D) Estimated 7: Wash or Hole Enlargement Used in Calculations.	8 W	6060 20	4830 (SS 100 10	1. 1. 1.	an se an Santan	
*10. Size of Casing (inches O.D.)			6 53 9	2. x 2.1 - X.	unter?	t Devo
*31. Top of Liner (if liner used) (ft.)	SC 159	185.5 185.5				
*12. Setting Depth of Casing (ft.)		8 C	8		1.54. 6171	11. 11-11
13. Type API Class Coment & Amount of Additives Used: (a) In First (Lead) or Only Slarry [1] additional space				Steen a		14.1070
(b) in Second Sturry	G I					1997 - 19
(c) In Third Sivery		25.		100 100 100 100 100 100 100 100 100 100		1
14. Sacks of Crment Used: (a) In First (Lead) or Only Sluny						() - ()
(b) in Second Siwn						
(c) In Third Siury			2.40.00.4			
(c) Total Sacks of Cement Used			1. 1.1.1	50 CEC 1976		
15. Slurry Volume per Sack of Cement (cu.it./sach); (a) In First (Lead) or Only Slurry					10 million	
(b) In Second Slurry						
(c) in Third Sharry	9. 94	949 80 - 202 - 138			n an	1996 1997
16. Volume of Siurry Pumped; (cu. fl.) (item 14 z fiem 15) (a) In First flendt og Only Siurry		1970	1.000	11 SHO Y		· · ·
(b) In Second Sturry				1997 - 19	11.92	1.1.1.1
(c) in Third Store						11
				N 12	10.00	
(d) Yotal Slurry Volume Pumped (cu.ft.) 17. Celculated Annular Height of Cement Slurry	<u></u>	122	- 24 - 00 	966 - 669	11 1 N 1 1 1	an facilities an
behind Pipe (II.)					e marte a	· · · · · · · · · · · · · · · · · · ·
(or bottom of cellar) outside casing? (Yes or No)				5	1. 24 C	ST Verat
CEMENTING TO PLUG AND ABANDON DATA:	PLUG NO. 1	PLUG NO. 2	PLUG NO. 3	PLUG NO. 4	PLUG NO. 5	PLUG NO. 6
19. Cementing Date	10-12-80	10-13-80	10-13		4. S	
#20. Size of Hote or fips in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8			1 B
*21. Depth to Hotiom of Tubing or Drill Pipe (ft.)	1000	250	Top Oul			. C_ 3
22. Facks of Cement Used (each plug)	50	100	10	-		i
23. Sturry Volume Pumped (cu. ft.)	66	133	13		S 2	21 - T
\$4 . 6 at-utated Fogo of Sting (fr.)	990	70	Sur f ^{#d}	Q. BY, TEXAS		
*25. Measured Top of Flug (If tagged) (It.)	†		AP	R 2 0 1981		M
CENERTING CONDARY AND ODERATOR	MUST PONDIA	/ WITH THU	WETRUCTION		er ouse tir	

-te

(Nev. 14.8)

	• 27. Remarks:	
The sector of the prestice prescribed as Sec. \$1.143. Tesas Natural the the cetification, that the	T declare under penalties prescribed in Sec. 31 143. Resources Cude, that I am authorized to make this cost	Cover Natural
I demonstrag of cooling and/or the placing of content plugs in this work as	have increaledge of the well date and information presents and that data and facts presented on bath sides of the	d in this regard. 6 Earm ant true
servet, and complete, to the best of my knowledge. This certification	covers all well date and information presented herein	
	1 4 6	
In the keldowd	Four ille Cam	
Commere of Contenter or Authorized Depresentative	Bignature of Operator or Authorized Representative	
	Tom McCann - President	
Butter of Person and Title (type ar print)	"Name af Person and Title (type or print)	
Demolt Division of Dow Chemical Co.	McCann Corporation	
Committee Company	*Operator	
Banta 3. Box 178	P. O. Bux 48	
Shiert Address or P.O. Box	•Street Address or P.O. Box	
Colorado City, Tx 79512	Big Spring, Texas	75736
City, Baste Zip Cede	*City, State	Zip Cade
915 728-5291	*Telephone 915 267-7488	
Area Code	Anna Colta	
	Ares Cour	
10-14-80	-1-6-81	21 S 25 S
10-14-80 Date IN L. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting rej to computing requirements in Statewide or Special Rules;	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except	tion is norded
10-14-80 This This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting re- to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl At least an original and one copy of this form shall be filed f	etton. or each cementing company used on a well.	tion is needed
10-14-80 Date IN L. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The computing of different casing strings on a well by one complete C. The computing of different casing strings on a well by one complete C. The computing of different casing strings on a well by one complete C. The computing of different casing strings on a well by one complete C. The computing of different casing strings on a well by one complete C. C. C	etton. or each cementing company used on a well. menting company may be consolidated on one form (to be	tion is norded filed in duplicat
10-14-80 Date IN 1. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companing of different casing strings on a well by one casing 2. Companing Company and Operator shall comply with the applicable (1) Company and Operator shall comply with the applicable	Area Code 	tion is needed filed in duplicat e operations .
10-14-80 This This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting reg- to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companing of different casing strings on a well by one cas Companing Company and Operator shall comply with the applicable Camenting Company and Operator shall comply with Statewide Rules B. We arrive Will L. AMOUNT OF SURFACE CASING:	Avec cost 	tion is need filed in duplicat expensions.
10-14-80 This A. This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a commanding regulation is commanding requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed for C. The commanding of different casing strings on a well by one com- Commaning Company and Operator shall comply with the applicable Commaning Company and Operator shall comply with Statewide Rules B. At least an original company shall comply with the applicable Commaning Company and Operator shall comply with Statewide Rules B. At least an original company and Operator shall comply with Statewide Rules Command Company and Operator shall comply with Statewide Rules B. At least and the company and Operator shall comply with Statewide Rules Command Company and Operator shall comply with Statewide Rules B. At least and the company and Operator shall comply with Statewide Rules Command Company and Operator shall comply with Statewide Rules B. At least and the company and Operator shall comply with Statewide Rules Command Company and Operator shall comply with Statewide Rules B. At least and the complexity of SURFACE CASING A. Depth to protect fresh water determined by:	etton. or such company used on a well. menting company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E).	tion is needed filed in duplicat e operations .
ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companies of different casing strings on a well by one case Companies Company and Operator shall comply with the applicable Companies Company and Operator shall comply with Statewide Rules; (1) Fi Rule A. Depth to protect fresh water determined by: (1) Fi Rule a. Water Development Doard, if op Field Bulk	Area Code - <u>3-6-B1</u> ISTRUCTIONS Office with: port is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. Immenting company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E).	tion is needed
10-14-80 This This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a community reprive community requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed f C. The commaning of different casing strings on a well by one case Commaning Company and Operator shall comply with the applicable Commaning Company and Operator shall comply with Statewide Rules M meeting FULL ANOUNT OF SURFACE CASING A. Depth to protect fresh water determined by: (1) Fi Rule (2) To s Water Development Board, if no Field Rule B. Set surface casing below depth to be protected and command for	Area Cose - <u>abale</u> ISTRUCTIONS Mfice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be to portions of Statewide Rules 8, 13, and 14. For offshore lie 13(E). om casing shoe to ground surface.	tion is need filed in duplicat experations.
IN IN IN IN IN IN IN IN IN IN	Area Code - <u>abale</u> ISTRUCTIONS Mfice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the TALE). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL BE OBTAINE	tion is needed filed in duplicat e operations .
IN I. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companies of different casing strings on a well by one co Companies Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for A. IF SETTING ANYTHING OTHER THAN THE FULL ASIOUNT OF RALEROAD COMMISSION. 5: If setting NO SURFACE CASING (See Item 4 above.):	Area Code 	tion is needed filed in duplicat poperations.
 10-14-80 Date IN A. This form shall be filed by the operator in the RRC District (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing completes and one copy of this form shall be filed for the companies of different casing strings on a well by one cases and the company and Operator shall comply with the applicable Commuting Company and Operator shall comply with Statewide Rules; (2) File Rule (2) Transform and Operator shall comply with Statewide Rules. Facting FULL ANOUNT OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) File Rule (2) Transform to be protected and cement for the Sector State Community Community (2) File Rule (2) Transform Community Community	Area Code 	tion is needed filed in duplicat expensions.
 10-14-80 Content IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation of the computing requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing compiles. At least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicabl Company and Operator shall comply with the applicabl Company and Operator shall comply with Statewide Rules; (1) File Rule Y setting FULL AMOUNT OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) File Rule (2) To a Water Development Board, if no Field Rule E Set surface casing below depth to be protected and cement for RALENDAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: If no multi-stage tool on the next deeper string, cement 	Area Code 	tion is needed filed in duplicat e operations. ED FROM THE face.
IN-14-80 This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a commanding regulation of the second seco	Area Code 	tion is needed filed in duplicat e operations . ID FROM THE face
IN I. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-I or W-2 if a commanding regulation of the company of Form W-3; (2) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed f C. The commanding of different casing strings on a well by one com- Commanding Company and Operator shall comply with the applicable Commanding Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RAL ROAD COMMISSION. I fisetting NO SURFACE CASING (See Item 4 above.): A: If no multi-stage tool is used, the next deeper string, cement If satting SHORT SURFACE CASING (See Item 4 above.): A: Command the multi-stage tool is used, the next deeper string, cement If satting SHORT SURFACE CASING (See Item 4 above.): A: Comment short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper string.	Area Code 	tion is needed filed in duplicat e operations. The FROM THE face.
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a compating register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing completed in the filed of the company and one copy of this form shall be filed of C. The company and Operator shall comply with the applicable Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) The state Development Board, if no Field Rule B. Set surface casing below depth to be protected and cement for (2) The stating NO SURFACE CASING (See Item 4 above.): A: If setting NO SURFACE CASING (See Item 4 above.): A: The multi-stage tool is used, the next deeper string, cement (1) files the multi-stage tool is or is not used on the next for (1) the surface, or (2) a point midway between shoe of surface string and the surface. 	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be to portions of Statewide Rules 8, 13, and 14. For offshore lie 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. trifrom the depth that protects fresh water sands to the sur- face. Compliance will be considered of a temperature sur- from the shue of the surface strong to the surface.	tion is norded filed in duplicat poperations. In FROM THE face.
IN-14-80 Date IN A. This form shell be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commiting re- to comparing requirements in Statewide or Special Rules; (2) Each copy of Form W-3 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicable Comparing Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule B. Set surface casing below depth to be protected and cement for ALLROAD COMMISSION. I If setting NO SURFACE CASING (See Item 4 above.): A.: If no multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool on the next deeper string, cement If setting SHORT SURFACE CASING (See Item 4 above.): A.: Cercent short surface casing from the shot to the surface. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting or is not used on the next face. B. Whether the commuting or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting of the commuting of the distance 7. Soming PRODUCTION STRING of Casing: (Statewide Rules, Spec-	Area Code 	tion is needed filed in duplicat e operations, to FROM THE face. Is water saids to ver shows that
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regularements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple A. At least an original and one copy of this form shall be filed f C. The community of different casing strings on a well by one cas Community of different casing strings on a well by one cas Community of different casing strings on a well by one cas Community and Operator shall comply with the applicable Community and Operator shall comply with Statewide Rule; (1) Fi Rule; (2) To a stater Development Board, if no Field Rule E. Set surface casing below depth to be protected and community of RALEROAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: This multi-stage tool is used, the next deeper string, cement If satting SHORT SURFACE CASING (See Item 4 above.): A: Cement short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper (1) the surface, or (2) a point midway between shoe of surface string and the sut the top of the cement is at least ene-third of the distance 	Area Code 	tion is needed filed in duplicat e operations. ID FROM THE face. In water saids to ver shows that
 ID-14-80 IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form C-1 or W-2 if a commuting requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing comple to comparing of form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed f C. The commuting of different casing strings on a well by one case comple and operator shall comply with the applicable Communing Company and Operator shall comply with Statewide Rules; (2) The company and Operator shall comply with Statewide Rule E setting PULL AMOUNT OF SURFACE CASING A. Depth to protect fresh water determined by: (1) Fi Rule (2) The state Development Board, if no Field Rule (2) The state casing below depth to be protected and comment for RALENOAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A. Concent short surface casing from the shoe to the surface. B. When the multi-stage tool is or is not used on the next deep (1) the surface, or (2) a paint midway between shoe of surface string and the surface. E. Stating PRODUCTION STRING of Casing: (Statewide Filen, Spe A. Comment is at least ene-third of the distance B. When 3,000 feet or more of piperistate. 	Area Code 	tion is norded filed in duplicat roperations. In PROM THE face. In water calls to ver shows that
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commiting requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil A. At least an original and one copy of this form shall be filed file. C. The comenting of different casing strings on a well by one ca Comenting Company and Operator shall comply with the applicable Commiting Company and Operator shall comply with the applicable Commiting Company and Operator shall comply with Statewide Rule. M setting FULL AMOUNT OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) Fi Rule (2) Tr - s Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RALEROAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A.: The multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool on the next deeper string, cement (1) the surface. B. When the multi-stage tool is or is not used on the next face. B. When the support of a string of surface string and the stut the top of the cement is at least one-third of the distance A. Cement to a point at least 600 feet, above the casing shoe. B. When 3,000 feet or more of piperiaraec. So the production or point at least for production or point at least for string or the string shoe. 	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if eccept etton. or each cementing company used on a well. menting company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E). or casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. trifrom the depth that protects fresh water sands to the sur- per casing string, cement from the depth that protects fresh face. Compliance will be considered if a temperature sur- from the shue of the surface string to the surface sur- cial Rules may vary 1 etecting string, a minimum of 30 feet of cement shall temperature.	tion is needed filed in duplicat e operations. EP FROM THE face. Is water satisfies to very shown that
 ID-14-80 Data IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commenting requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed file C. The company and Operator shall comply with the applicable Companies Company and Operator shall comply with Statewide Rules; (1) File Rule (2) Tr. a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RALEROAD COMMISSION. If setting NO SURPACE CASING (See Item 4 above.): A. This multi-stage tool is used, the next deeper casing string on B: If using the multi-stage tool is or is not used on the next deeper for string. If setting SHORT SURFACE CASING (See Item 4 above.): A. Cement short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper for string. (1) the surface, or (2) a point midway between shoe of surface string and the surface. B. Whether the multi-stage tool is or is not used on the next deeper for the string. A. Cement to a point at least 600 feet, above the casing shore. B. When 3,000 feet or more of piperistate. B. When 3,000 feet or more of piperistate. A. Cement plugs shall be placed in the well bore as required by the casing shall be placed in the well bore as required by the top of the tempth and the surface. 	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if eccept etion. or such company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore ite spritons of Statewide Rules 8, 13, and 14. For offshore ite 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OUTAINE hall be comented from the casing shoe to the surface. trifrom the depth that protects fresh water sands to the sur- per casing string, coment from the depth that protects fresh face. Compliance will be considered if a temperature sur- from the shoe of the surface string to the surface. cial Rules may vary 1 etecting string, a minimum of 30 feet of communication plus any addition Rules and Regulations of the Communication plus any addition	tion is needed filed in duplicat e operations, to FROM THE face. di water saids to ver shows that off costs the pro-
 ID-14-60 Data IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a comrating regiments in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compile A. Least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Company and Operator shall comply with Statewide Rules; (2) The company and Operator shall comply with Statewide Rule; (2) The company and Operator shall comply with Statewide Rule; (2) The Rule; (2) The Rule; (3) The Rule; (3) The Rule; (4) File Rule; (5) The State Development Board, if no Field Rule; (5) File Rule; (7) The Rule; (7) The Rule; (8) State Development Board, if no Field Rule; (9) File Rule; (1) File Rule; (2) The State Development Board, if no Field Rule; (1) File Rule; (2) The State Development Board, if no Field Rule; (2) The State Development Board, if no Field Rule; (3) File State Commission. If setting NO SURFACE CASING (See Item 4 above.): A. The multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool is or is not used an the next deep (1) the surface. (9) Subther the multi-stage tool is or is not used an the next deep (1) the surface, or (2) a point midway between shoe of surface string and the sut the top of the cement is at least one-third of the distance; Accement to a point at least 600 feet apove the casing shoe. (9) apoint midway between shoe of surface string shoe. Stheine PRODUCTION STRING of Casing: (Statewide Filen, Special Accement to a point	ISTRUCTIONS Mice with: poort is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. meeting company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore lie 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OUTAINE hall be cemented from the casing shoe to the surface. to from the depth that protects fresh water sands to the sur- face. Compliance will be considered if a temperature sur- from the shue of the surface string to the surface cial Rules may vary b effecting string, a minimum of JD fort of cements shall be Rules and Regulations of the Commission plus any additional all be a slurry volume equal to the amount no enfary to form	tion is needed filed in duplicat e operations. In FROM THE face. Is water satisfies to yes above that of costs the para- tistic calculated

APPENDIX B - SITE SAFETY AND LAYOUT

Bayswater Operating's Mongoose Gas Plant and AGI No. 1 are operated and monitored 24 hours a day, 7 days a week, by on-site personnel utilizing Plant operating and SCADA systems. These systems gather operating data such as pressures, temperatures, flow rates, remote sensors, compressor run data, and control valve positions. The recording and retention of this operating data enables the operator to evaluate trends and use predictive analytics to potentially identify issues before they become an "alarm" event. If an alarm event occurs, the automated control system is programmed to execute pre-programmed protocols to safely manage the event. Operators are specially trained to follow detailed practices to minimize risk to people, the facility, and the environment.

In the event of a leak or system failure, the Plant control system will execute its shutdown protocols as timely as is practicable to isolate the event and minimize the intensity. The Plant operator will investigate the circumstances and oversee an orderly resolution to the situation. Since this facility handles H₂S, Bayswater is required to maintain a Hydrogen Sulfide Contingency Plan to safely manage any planned or unplanned release event. The Plant operating staff are highly trained in safety and emergency response protocols to ensure safety for both plant personnel and the surrounding community and environment.


B	-2

			ITEM	DESCRIPTION
			1	SLUG CATCHER
			2	INLET COMPRESSOR W/ COOLER
	1		2F	INLET COMPRESSOR (FUTURE) W/ COOLER
			3	COMPRESSOR DISCHARGE COALESCER
			4	
	v	V	× 6	
	1	~		
			8	
			9	
			10	AMINE REGENERATOR REBOILER
	1		11	AMINE SURGE TANK
			12	AMINE BOOSTER/REFLUX PUMP SKID
			13	AMINE REGENERATOR REFLUX CONDENSER
			14	LEAN AMINE COOLER
			15	AMINE CHARGE PUMPS
			16	HOT OIL PUMP SKID
			17	HOT OIL HEATER
			18	FLARE K.O. DRUM
	1		19	FLARE
- BARF	RIER		20	COMBUSTOR
			21	SLOP STORAGE TANKS
	+		22	AMINE MAKE UP STORAGE TANK
			23	
			24	
			241	
			25	
			20	
			27	
			20	DI WATER TANK
	·		30	GLYCOL CONTACTOR
			31	GLYCOL SEPARATOR
			32	TEG REGEN
			33	BTEX
			34	GAS GENERATOR SET
			35	AMINE SUMP TANK
			36	NEW LUBE OIL TANKS
			37	CONDENSATE TRANSFER PUMPS
			38	VAPOR RECOVERY UNIT
			39	TANK COMBUSTOR K.O. DRUM
			40	MV TRANSFORMER
			40F	MV TRANSFORMER (FUTURE)
				LEGEND
				FIRE EXTINGUISHER = 9 ea.
				HYDROGEN SULFIDE DETECTOR = 10 ea.
				AUDIBLE ALARM SOUNDER = 4 ea.
				R STROBE LIGHT (RED) — FIRE = 4 ea.
_	- east secu	RITY GATE		SHUTERCENT SHUT PLANT EMERGENCY SHUTDOWN = 6 ea. Down
				FIRST AID & SCBA KIT = 3 ea.
	-*X -	X		EYE WASH STATION = 3 ea.
	й С		E 10(WIND SOCK = 1 ea.
				MUSTER POINT = 3 ea.
r :	RΔ	YSWATER	FXPLOR	ATION & PRODUCTION
CT ·	DA	COUD		
		SUUK	GAS IR	EATING FAUILITY
·		FACILITY	INSTRUN ′SAFET`	IENTATION (LOCATION PLAN
WN	CHECKED	SCALE	DATE	JOB NO. DRAWING NO. SHEET NO.
DC DC	GA	AS NOTED	06/09/22	BAY220316 IN-PLN-0790 1 OF 1

APPENDIX C – AREA OF REVIEW

APPENDIX C-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX C-2: OIL AND GAS WELLS WITHIN THE MMA LIST



Mongoose AGI No. 1

Area of Review: Oil & Gas Wells List										
API	WELL NAME	WELL NO.	CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (FT.)	PERFORATED INTERVAL (FT.)	DATE DRILLED
4222700101	JONES, C.L	1	ARMER L H	1603	32.445815	-101.187399	DRY HOLE	NR	NR	NR
4222703634	STEWART	1	MCCANN CORP	1601	32.423136	-101.1837088	DRY HOLE	8670	NR	10/11/1980
4222732304	CATHEY	1	MCCANN CORP	204	32.42347	-101.1890569	DRY HOLE	4310	NR	10/31/1980
4222734502	STERLING CATTLE COMPANY	3402	MDC TEXAS ENERGY	1603	32.44553	-101.17894	P & A	7795	7764-7795	10/19/1989
4222734688	STERLING FAMILY TRUST	3403	TREND EXPLORATION COMPANY	1603	32.4403185	-101.1792589	P & A	7918	7747-7760	3/5/1992
4222736361	STERLING 38	1	HIGHPEAK ENERGY	1371	32.42744	-101.196842	INACTIVE PRODUCER	8075	5635-7848	4/5/2010
4222741505	KAMIKAZE 5-8	H 3W	BAYSWATER OPERATING COMPANY LLC	204	32.399666	-101.180898	PRODUCING	5433	5911-15810 (MD)	1/9/2022
4222741505	KAMIKAZE 5-8-17-20	ЗW	BAYSWATER OPERATING COMPANY LLC	204	32.426344	-101.191374	PRODUCING	5643.22	5911-15810 (MD)	1/9/2022
4222741939	WINFORD 35-38 B UNIT A	7H	HIGHPEAK ENERGY	745	32.450886	-101.197238	PRODUCING	5785.42	6081-15105 (MD)	9/9/2022
4222741972	PHARAOH 10-15-34-39	H 1W	BAYSWATER OPERATING COMPANY LLC	1602	32.473311	-101.191423	INACTIVE PRODUCER	5847	NR	10/27/2022
4222742086	KAMIKAZE 5-8	H 2WD	BAYSWATER OPERATING COMPANY LLC	204	32.426337	-101.191712	COMPLETED	7821	NR	4/14/2023
4222742087	KAMIKAZE 5-8	H 4WX	BAYSWATER OPERATING COMPANY LLC	204	32.4263090	-101.1918370	COMPLETED	5818	NR	4/5/2023
4222742088	KAMIKAZE 5-8	H 2W	BAYSWATER OPERATING COMPANY LLC	204	32.4262950	-101.1919000	COMPLETED	5669	NR	3/22/2023
4222742089	KAMIKAZE 5-8	H 1WD	BAYSWATER OPERATING COMPANY LLC	204	32.4263230	-101.1917740	COMPLETED	7820	NR	4/8/2023
4222742105	KAMIKAZE 5-8	H 1W	BAYSWATER OPERATING COMPANY LLC	204	32.4262810	-101.1919620	COMPLETED	5816	NR	5/24/2023



Mongoose AGI No. 1

4233500959	MACKEY, P.K.	1	MCDERMOTT-RAY	1344	32.4133665	-101.1552679	DRY HOLE	NR	NR	4/25/1954
4233501046	MACKEY, P.K.	1	MOSS H S	582	32.4215460	-101.1434280	DRY HOLE	NR	NR	12/8/1947
4233501860	JONES, CHESTER L	1	DANSBY, BEN JR.	17	32.4497350	-101.1605990	DRY HOLE	NR	NR	NR
4233533555	VAN TUYLE	1	BRIGHT & COMPANY	584	32.4027340	-101.1529820	P & A	8360	NR	11/26/1990
4233533624	STERLING FAMILY TRUST-A-	3301	MDC OPERATING, INC.	17	32.4438844	-101.1638476	P & A	7850	7756-7760	1/23/1993
4233535973	SI-10.2 CP UNIT	1	ENERGY TRANSFER	1536	32.4233850	-101.1407330	PERMIT EXPIRED	550	NR	-
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.434283	-101.161962	PRODUCING	5543	6052-19217 (MD)	7/7/2022
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.4717700	-101.1619280	PRODUCING	5543	6052-19217 (MD)	7/6/2022
4233536030	JADE PALACE 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1344	32.4049880	-101.1607180	DUC	5491	NR	11/8/2022
4233536031	GOLDEN SAND 10-3	H 1W	BAYSWATER OPERATING COMPANY LLC	1344	32.4050010	-101.1606550	DUC	5606	NR	11/8/2022
4233536041	PEARL RIVER 4-9	H 1W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016760	-101.1745840	PERMITTED	7100	NR	-
4233536042	PEARL RIVER 4-9	H 2W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016620	-101.1745210	PERMITTED	7100	NR	-
4233536045	PEARL RIVER 4-9	H 3W	BAYSWATER OPERATING COMPANY LLC	1634	32.4017660	-101.1748560	PERMITTED	7100	NR	-
4233536046	PEARL RIVER 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016350	-101.1743950	PERMITTED	7100	NR	-
4233536047	JAVA 16-21	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016210	-101.1743330	PERMITTED	7100	NR	-

*Note: Well entries in red penetrate the upper confining layer.



APPENDIX D – SECTION 2 CROSS SECTIONS

APPENDIX D-1: FIGURE 28 – STRUCTURAL CROSS SECTION DEPICTING THE ELLENBURGER

APPENDIX D-2: FIGURE 29 – STRATIGRAPHIC CROSS SECTION FLATTENED ON THE ELLENBURGER



D-1



Appendix B: Submissions and Responses to Requests for Additional Information



Subpart RR Monitoring, Reporting, and Verification (MRV) Plan Mongoose AGI No. 1

Mitchell County, TX

Prepared for *Bayswater Operating Company LLC* Denver, CO

By

Lonquist Sequestration, LLC Austin, TX

> Version 4.0 August 2024



INTRODUCTION

Bayswater Operating Company LLC (Bayswater) currently has a Class II acid gas injection (AGI) permit, issued by the Texas Railroad Commission (TRRC) for the Mongoose AGI No. 1 well (Mongoose), API No. 42-335-36013. The permit was issued March 10, 2023. This permit authorizes Bayswater to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO₂) and hydrogen sulfide (H₂S) into the Ellenburger formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose is a new well and is associated with the Mongoose Amine Treating Facility (the Plant) located in a rural area of Mitchell County, Texas, as shown in Figure 1.



Figure 1 – Location of Mongoose AGI No. 1 Well

Bayswater is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Bayswater is also seeking TRRC approval to amend the existing Mongoose permit by increasing the permitted maximum quantity of injected treated acid gas (TAG) from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. Bayswater intends to inject into this well for approximately 40 years up to a maximum of 19.5 MMscf/D. The primary source of this injected CO₂ gas is the Mongoose Amine Treating Facility. Table 1 shows the expected composition of the gas stream to be sequestered. Table 2 shows the expected average daily volume of acid gas.

Table 1 – Expected Gas Composition

Component	Mol Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

Table 2 – Expected Sequestered Gas Volumes

Contract Status	Avg. Rate (MMscf/D)
Committed	6.9
Proposed	12.6
Total	19.5

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH ₄	Methane
CMG	Computer Modelling Group Carbon Dioxide (may also refer to other Carbon
CO ₂	- · ·
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H ₂ S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet

MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
Ν	North
NAD	North American Datum
NW	Northwest
OBG	Overburden Gradient
OSHA	Occupational Safety and Health Administration
PG	Pore Gradient
рН	Scale of Acidity
PISC	Post Injection Site Care
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
ТОС	Total Organic Carbon
TRRC	Texas Railroad Commission
UCZ	Upper Confining Zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

TABLE OF CONTENTS

INTRO	DUCTIO	Ν	2
ACRO	NYMS AI	ND ABBREVIATIONS	4
SECTIC	DN 1 – U	IC INFORMATION	10
1.1	Unde	rground Injection Control Permit Class: Class II	10
1.2	UIC V	Vell Identification Number	10
1.3	Repo	rter Number	10
1.4	Facili	ty Address	10
SECTIC) N 2 – P	ROJECT DESCRIPTION	11
2.1	Regiona	l Geology	11
	2.1.1	Regional Faulting	20
2.2	Site C	Characterization	20
	2.2.1	Stratigraphy and Lithologic Characteristics	20
	2.2.2	Upper Confining Zone – Woodford Shale	21
	2.2.3	Injection Interval – Ellenburger	29
	2.2.4	Lower Confining Zone – Precambrian-age formations	38
2.3	Geon	nechanics	40
	2.3.1	Determination of Vertical Stress (S _v) from Density Measurements	40
	2.3.2	Elastic Moduli and Fracture Gradient	40
2.4	Local	Structure	42
2.5	Inject	ion and Confinement Summary	46
2.6	Grou	ndwater Hydrology	46
2.7	Desci	iption of the Injection Process	52
	2.7.1	Current Operations	52
2.8	Rese	voir Characterization Modeling	52
	2.8.1	Simulation Modeling	55
SECTIC)N 3 – D	ELINEATION OF MONITORING AREA	64
3.1	Maxi	mum Monitoring Area	64
3.2	Activ	e Monitoring Area	65
SECTIC	DN 4 – P	OTENTIAL PATHWAYS FOR LEAKAGE	67
4.1	Leaka	age from Surface Equipment	68
4.2	Leaka	age Through Existing Wells Within the MMA	71
	4.2.1	Future Drilling	74
	4.2.2	Groundwater Wells	74
4.3	Leaka	age Through Faults and Fractures	74
4.4	Leaka	age Through the Confining Layer	75
4.5	Leaka	age from Natural or Induced Seismicity	75
SECTIC	DN 5 – N	1ONITORING FOR LEAKAGE	77
5.1	Leaka	age from Surface Equipment	78
5.2	Leaka	age Through Existing and Future Wells Within the MMA	78
5.3	Leaka	age Through Faults, Fractures, or Confining Seals	80
5.4	Leaka	age Through Natural or Induced Seismicity	80
SECTIC	DN 6 – B	ASELINE DETERMINATIONS	82
6.1	Visua	I Inspections	82

6.2	CO ₂ /H ₂ S Detection	82
6.3	Operational Data	82
6.4	Continuous Monitoring	82
SECTION	7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION	83
7.1	Mass of CO ₂ Received	83
7.2	Mass of CO_2 Injected	83
7.3	Mass of CO ₂ Produced	84
7.4	Mass of CO ₂ Emitted by Surface Leakage	84
7.5	Mass of CO ₂ Sequestered	85
SECTION	8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN	87
SECTION	9 – QUALITY ASSURANCE	88
9.1	Monitoring QA/QC	88
9.2	Missing Data	88
9.3	MRV Plan Revisions	89
SECTION	10 – RECORDS RETENTION	90
SECTION	11 - REFERENCES	91

Figures

Figure 1 – Location of Mongoose AGI No. 1 Well
Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red
star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, &
Walsh)12
Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)13
Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf14
Figure 5 - Cross section indicating formation truncations when approaching the Eastern Shelf
(Waite, 2021)15
Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger
Group of the Permian Basin, West Texas, 2006)16
Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth17
Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks,
2003)
Figure 9 – Type Log and Disposal Units and Zones from PXD Well No. 1 (Sanchez, Loughry, &
Coringrato, 2019)
Figure 10 – Mongoose AGI No. 1 Type Log
Figure 11 – Buchanan 3111 #XD location Offset well for Core Data22
Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting
the Woodford and sidewall cores23
Figure 13 – Core Photo of Samples Within the Woodford Formation24
Figure 14 – Routine Core Analysis Within the Woodford Formation25
Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation26
Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation
Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation28

Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)....32 Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells36 Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map......43 Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)......47 Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986)......50 Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011)......51 Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model54 Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)......58 Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)59 Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation) Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection) Figure 40 – North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)......62 Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Figure 43 – Active Monitoring Area66 Figure 45 – Mongoose AGI No. 1 Wellbore Schematic70 Figure 46 – All Oil and Gas Wells Within the MMA.....72 Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA......73 Figure 48 – Seismicity Review (TexNet – 08/04/2023)76

Figure 49 – Seismic Events and Monitoring Station8	1
--	---

Tables

Table 2 – Expected Sequestered Gas Volumes3Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples38Table 4 – O be be be a block of the second
Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples
Table 4 – Calculated Vertical Stresses40
Table 5 – Fracture Gradient Calculation Inputs and Results41
Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger
Jr., 1967)47
Table 7 – Gas Composition at the Plant Outlet52
Table 8 – Modeled Initial Gas Composition53
Table 9 – GEM Model Layer Package Properties55
Table 10 – Offset SWD Wells Included in GEM Model56
Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injection63
Table 12 – Potential Leakage Pathway Risk Assessment
Table 13 – Summary of Leakage Monitoring Methods77

Appendices

Appendix A – TRRC MONGOOSE AGI No. 1 FORMS

- Appendix A-1 UIC Class II Order
- Appendix A-2 GAU Groundwater Protection Determination
- Appendix A-3 Drilling Permit
- Appendix A-4 Completion Report

Appendix B – Site Safety and Layout

- Appendix B-1 Operating Safety Plan
- Appendix B-2 Mongoose Site Plan

Appendix C – Area of Review

- Appendix C-1 Oil and Gas Wells Within the MMA Map
- Appendix C-2 Oil and Gas Wells Within the MMA List

Appendix D – Section 2 Cross Sections

Appendix D-1 – Figure 28 – Structural Cross Section Depicting the Ellenburger Appendix D-2 – Figure 29 – Stratigraphic Cross Section Flattened on the Ellenburger

SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the UIC Class II program. The TRRC classifies Mongoose AGI No. 1 as a UIC Class II well. A Class II permit was issued to Bayswater on March 10, 2023, under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

1.2 UIC Well Identification Number

Mongoose AGI No. 1, API No. 42-335-36013, UIC No. 000125803

1.3 <u>Reporter Number</u>

- Facility Name: Mongoose Amine Treating Facility
- Greenhouse Gas Reporting Program ID: 586481
 - Currently reporting under Subpart UU
- Operator: Bayswater Operating Company LLC

1.4 Facility Address

Mongoose Amine Treating Facility 1625 County Road 280 Westbrook, Texas 79565

Coordinates in North American Datum of 1983 (NAD 83) for this facility:

Latitude: 32.4225396641 Longitude: -101.1714709142

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Mongoose AGI No. 1 well.

The Mongoose injects both H_2S and CO_2 into Ellenburger formation at a depth of 8,300 ft to 9,000 ft, and approximately 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The Mongoose is located on the Eastern Shelf, as shown in the area map in Figure 2, within the greater Permian Basin of west Texas and New Mexico. The Permian Basin covers more than 86,000 square miles extending across an area approximately 250 miles wide and 300 miles long. The TRRC cites that the greater Permian Basin accounts for close to 40% of all oil production within the United States and nearly 15% of natural gas production. A general cross section of the basin is presented in Figure 3.

The ancestral Tobosa Basin was formed by structural flexure in the Precambrian basement at the southern margin of the North American Craton, or Laurentian Plate, during the Proterozoic (Popova, 2020). The modern form of the Permian Basin was shaped during the Carboniferous period due to the collision between Laurasia and Gondwana forming the supercontinent Pangea. The following uplift of the Central Basin Platform differentiated the greater basin into the Delaware Basin in the west, and the Midland Basin in the east along with its surrounding shelf margins (Popova, 2020).



Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, & Walsh).



Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)

The target injection interval for the Mongoose is the Ellenburger formation. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician (Sanchez, Loughry, & Coringrato, 2019). The Ellenburger is of lower Ordovician age and underlies the Woodford formation on the Eastern Shelf. The contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition (Sanchez, Loughry, & Coringrato, 2019). Many formations that are present within the Midland Basin are eroded and not seen upon reaching the Eastern Shelf. A cross section showing these truncations is displayed in Figure 5.

A generalized stratigraphic column of the Eastern Shelf is shown in Figure 4, with the target-injection formation indicated by the red star and historically productive formations indicated in the green stars. The Ellenburger formation is roughly 900 ft thick on the Eastern Shelf as shown by the isopach thickness map in Figure 6 (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006). On the Eastern Shelf, the Ellenburger formation dips to the west-southwest, towards the Midland Basin, and its subsea depth is roughly 6,000 ft (Sanchez, Loughry, & Coringrato, 2019). Figure 7 displays a structure map of the Ellenburger formation. Being far from any major sources of terrigenous clastic sediment input and at a time of a greenhouse climate leading to warm waters created an ideal setting primed for massive carbonate production during the Ellenburger deposition (Waite, 2021). The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. Predominant pore types of this group determined by Holtz and Kerans are "ooid grainstone; ooid-peloid packstone-grainstone"

and reservoirs tend to be of good porosity and moderate permeability (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006).



Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf



Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf (Waite, 2021).



Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006)



Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth.

The lower Ordovician period on the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture. Within this dolomite, there were irregular mottling patterns, likely indicative of bioturbation structures. Mudstone and peloid-wackestone, although in

Subpart RR MRV Plan – Mongoose AGI No. 1

smaller quantities, were also observed in the area (Kerans, 1990). To visually represent these different depositional environments and their corresponding lithologies, a map is presented in Figure 8. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger formation underwent significant "karsting" and dolomitization. This karsting process resulted in the formation of extensive paleocave systems within the Ellenburger, which later collapsed and led to the creation of widespread brecciated and fractured carbonates. These formations are responsible for the occurrence of many Ellenburger reservoirs, according to Loucks (2006).



Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

In their research on saltwater disposal (SWD) injection into the Ellenburger, Pioneer Natural Resources describes three distinct facies within the formation as noted in the Figure 9 type log. The upper and middle facies are composed of fracture breccia, breccia fabrics, and matrix-supported breccia, which coincide with collapsed paleo cave facies as described by Loucks. The lower unit does not exhibit these characteristics but shows a high volume of small vugs (inch-scale) and large-dissolution features (foot-scale) and represents an area of the Ellenburger with elevated porosity and permeability (Sanchez, Loughry, & Coringrato, 2019).





2.1.1 Regional Faulting

The modeled area near the Mongoose does not show any faults. However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area. This fault trend runs north-south in parallel with the dip. Figure 7 displayed this fault trend, which is the only example of such a trend within the area. Apart from this, the basin area is structurally inactive.

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the Mongoose.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 shows an annotated well log for Mongoose that goes from the surface to the total depth. It indicates the injection and primary upper confining units with regional formation tops.



Figure 10 – Mongoose AGI No. 1 Type Log

2.2.2 Upper Confining Zone – Woodford Shale

The upper confining unit is the Upper Devonian age Woodford formation. The Woodford Shale, a late Devonian-aged organic-rich rock, was created through a widespread marine transgression. The deposition of the Woodford spread across a large area of the Permian Basin, producing a low-relief blanket of shale. The Woodford formation is an organic-rich petroleum source rock comprised of uncharacteristically highly radioactive, dark fissile shale and siltstone (Merril et al., 2015). Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991). As shown in Figure 5, the Wristen Group is a formation that lies directly below the Woodford to the west of the Mongoose location. The Wristen Group pinches out and is not found at the Mongoose location. However, the sealing nature of the Woodford, as described by Comer (1991), also provides confinement for the Ellenburger at this location. The Woodford formation overlies both unconformably and is diachronous to the underlying Ellenburger formation at the Mongoose location. The U.S. Geological Survey (USGS) CO₂ Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit (SAU) (Merril et al., 2015).

Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose. The Buchanan 3111 #1XD is approximately 10.4 mi. from the Mongoose as depicted in Figure 11. Figure 12 is a stratigraphic cross section showing the correlating cored Woodford formation (pink triangles representing cored intervals) in the Buchanan 3111 #1XD and the Mongoose wells. Routine core analysis, rock mechanics, and threshold entry pressure tests were performed on the core samples from the Woodford formation.

Core photos of the samples taken and analyzed within the Woodford are shown in Figure 13. The black shale unit exemplifies a well cemented unit with little to no fracturing. Routine core analysis was performed on these two samples, which includes bulk density, matrix permeability (as received and as under dry and Dean Stark extracted conditions), gas-filled porosity, gas saturation, grain density, porosity, oil saturation, and water saturation. The results are shown in Figure 14, with the footnotes at the base giving details on the testing processes of each value.

Under the dry and Dean Stark extracted conditions, permeability values of 2.2E-07 millidarcy (mD) were observed with even lower values of 4.87E-07 mD in the as-received samples. Porosities within the same sample were 1.3% when dried and .25% when gas-filled. These permeability and porosity values reflect optimal confining characteristics and validate the USGS assessment of an appropriate sealing formation for CO_2 storage.

To ensure these sealant properties would not be compromised by pressure influence of the injected fluid, a threshold entry pressure test was examined on these Woodford core samples. Figure 15 depicts a graph of permeability vs. pressure showing that, even with pressure increases up to 2,000 pounds per square inch (psi), permeability readings are still in the nano-darcy range. These values are shown in table form in Figure 16 against the pressures administered on the core, with the highest pressure being 2,000 psi. Given that permeability values were lowest (4.03E-07 mD) at 2,000 psi, it can be assumed that the threshold entry pressure of the Woodford formation was not met and

would be greater than 2,000 psi. Additionally, a table summary is depicted in Figure 17. These characteristics gathered from the Buchanan core provide a high level of detail into the confining nature of the Woodford Shale and alleviate any concerns of transmissibility through the confining unit.



Figure 11 – Buchanan 3111 #XD location -- Offset well for Core Data



Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Woodford and sidewall cores.



Figure 13 – Core Photo of Samples Within the Woodford Formation



CL File No.: 202105972 Date: February 04, 2022 Analyst(s): MP

Shale Core Analysis (Rotary Sidewall Cores)

As received					Dry & Dean Stark Extracted Conditions (2)					
Sample	Depth (ft)	Bulk Density (g/cc)	Matrix Permeability ⁽¹⁾ (mD)	Gas-filled Porosity (%)	Gas Saturation (%)	Grain Density (g/cc)	Matrix Permeability ⁽⁵⁾ (mD)	Porosity (%)	Oil Saturation ⁽³⁾ (%)	Water Saturation ⁽⁴⁾ (%)
30,31	9076.03 - 9076.26	2.601	4.87E-09	0.25	18.9	2.624	2.22E-07	1.30	3.3	77.8

Footnotes:

Each sample is a composite of several rotary sidewall cores.

(1) Matrix Permeability is an effective Kg determined from pressure decay results on the fresh, crushed, 20/35 mesh size equivalent sample.

(2) Dean Stark extracted sample (20/35 mesh size) dried at 110 °C. Porosity and saturations are relative to total interconnected pore space.

(3) Oil volume computed assuming an oil density of 0.844 g/cc

(4) Water volume corrected assuming a brine concentration of 80000 ppm NaCl with an ambient density of 1.054 g/cc

(5) Matrix Permeability is an absolute Kg determined from pressure decay results on the clean and dry 20/35 mesh size equivalent sample.

Reference: "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs", GRI-95/0496, Gas Research Institute, April 1996

Figure 14 – Routine Core Analysis Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

Company:Bayswater Exploration & ProductionWell:Buchanan 3111 1XDField:SpraberryLocation:Howard County, TexasFile:HOU-2105972



Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation

PETROLEUM SERVICES

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production Well: Buchanan 3111 1XD Field: Spraberry Location: Howard County, Texas

File: HOU-2105972

Sample 30B				
Gas				
Injection	Permeability			
Pressure,	to Brine*,			
psi	mD			
500	1.44E-06			
750	2.20E-06			
1000	1.46E-06			
1200	6.73E-07			
1400	5.77E-07			
1600	6.72E-07			
1800	5.39E-07			
2000	4.03E-07			

Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation
SUMMARY OF THRESHOLD ENTRY PRESSURE RESULTS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company:	Bayswater Exploration & Production
Well:	Buchanan 3111 1XD
Field:	Spraberry
Location:	Howard County, Texas

File: HOU-2105972

				Final	Threshold
				Permeability	Entry
Sample	Depth,	Length,	Diameter,	to Brine*,	Pressure,
Number	feet	cm	cm	millidarcies	psi
30B	9076.03	2.67	2.54	4.03E-07	TEP>2000

* Apparent permeability to brine with humidified nitrogen displacing water

Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation

2.2.3 Injection Interval – Ellenburger

2.2.3.1 Ellenburger

As described in the Regional Geology section, the Ellenburger at the Mongoose location is a widespread lower Ordovician carbonate deposited over the entire Permian area, indicating a relatively uniform depositional condition (Hendricks, 1964). However, post-depositional sequences have highly altered the section. These sequences have a large influence on the development of the reservoir quality within the injection interval and its ability to accept the proposed injectate. Further analysis based on regional and site-specific data was analyzed, as discussed below, to better understand the reservoir conditions at and around the Mongoose well location.

2.2.3.2 Ellenburger Porosity/Permeability Development

Facies in the low-energy, restricted shelf setting exhibit extensive dolomitization and are characterized by significant bioturbation, resulting in mottling patterns (Loucks, 2003). This dolomitization process has facilitated porosity development within the Ellenburger formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs. These same features were interpreted from the openhole logs in the Mongoose well and core from the Buchanan 3111 #1XD well. A total of 23 sidewall cores were taken within the Ellenburger formation in the Buchanan 3111 #1XD well, with 12 of those having routine core analysis performed on them. Figure 18 shows the results of the analysis.

Porosity values were primarily derived from offset openhole porosity logs within the Ellenburger section. Petrophysical analysis was performed on the offset logs to calculate an effective porosity curve, the porosity of a rock that is available to contribute to fluid flow, to better estimate porosity ranges with regards to injection within the Ellenburger. This is done by accounting for clay content and matrix lithology to better understand the varying porosity within the injection interval and how it relates to injection capacity. The ranges of effective porosity within the modeled wells are 0 to 39.4% with the mean being 4.6%. Figure 19 is a histogram depicting these porosity distributions within the seven modeled wells. These values are validated through similar ranges seen in the core results. The logical inference would be that, as the effective porosity increases, the reservoir quality for injection improves and the associated porosity increment leads to a rise in permeability.

A porosity to permeability relationship was created from this data with the outliers and nonapplicable samples redacted. Additional regional data from Loucks (2003) was incorporated into the relationship to assist with the higher permeability ranges, to ensure that overestimates of permeability were not calculated. The data from Loucks (2003) is exemplified in Figure 20. A twofunction porosity-permeability curve was developed from the regional and local core data. Figure 21 shows the equations and relationships where:

> If Effective Porosity (Φ eff) < 6.5%: $K(mD) = 7E - 08e^{3.3028*\Phi}$ eff If Effective Porosity (Φ eff) > 6.5%: $K(mD) = 277.39 \ln(\Phi eff) - 380.58$

These equations were extrapolated to all the wells within the model including the Mongoose. In Figure 22, the cross section of the Mongoose and Buchanan well is depicted. This illustration showcases the Ellenburger formation, with the sidewall cores from the Buchanan well represented by pink triangles. The calculated permeability curves resulting from the equations mentioned earlier are shown in red, while green represents the effective porosity. High permeability and porosity sections can be seen in both wells, most likely reflecting strata that had prolonged subaerial exposure creating the karst and vug features that will be targeted and utilized for injection. Figure 23 is a core photo from the Buchanan well depicting an example of what a vug feature within the Ellenburger can look like. These features will be taking the bulk of the injection and will be modeled within the area based on openhole log analysis.

Permeability ranges within the seven wells utilized in the model vary from 0 mD to 638 mD, with the mean being 40.822 mD. A histogram representing these ranges and distributions within the seven modeled wells is displayed in Figure 24. This range corroborates with Loucks (2003) and data recovered from the Buchanan well, and it can be concluded that the process used to determine the permeability distributions within the injection interval is valid.

Bayswater Exploration & Production Buchanan 3111 1XD Spraberry Howard County, Texas



CL File No.: 202105972 Date: March 31, 2022 Analyst(s): MP

	CMS-300 ROTARY SIDEWALL ANALYSIS												
			Net Confining		Permea	ability				Satu	ration	Grain	
San	nple	Depth	Stress	Porosity	Klinkenberg	Kair	b(air)	Beta	Alpha	Oil	Water	Density	Footnote
Nun	nber	(ft)	(psig)	(%)	(md)	(md)	psi	ft(-1)	(microns)	% Pore	Volume	(g/cm3)	
2	23	9236.98	2960	25.81	.259	.389	11.97	3.27E+09	2.75E+00	0.0	94.7	2.666	
2	21	9257.01	2960	4.77	.002	.009	104.71	2.14E+15	1.48E+04	1.2	66.1	2.746	(1)
1	9	9363.99	2960	5.23	5.17	5.81	2.07	1.75E+12	2.93E+04	4.1	66.9	2.800	(6)
1	5	9485.99	2960	3.41	.005	.016	62.63	3.24E+13	5.63E+02	2.3	64.6	2.838	(6)
1	3	9549.48	Ambient	1.55	N/A	N/A	N/A	N/A	N/A	1.9	44.7	2.829	(5)
1	2	9604.98	2960	1.63	.00006	.001	354.43	2.46E+18	5.38E+05	2.6	54.0	2.842	(1)
1	0	9712.03	Ambient	1.28	N/A	N/A	N/A	N/A	N/A	1.2	74.3	2.758	(5)
	7	9835.05	2960	2.28	.001	.004	155.69	2.03E+16	4.48E+04	1.5	81.1	2.701	
	6	9868.97	2960	3.43	.001	.003	166.37	3.03E+16	5.46E+04	0.9	81.6	2.827	
	5	9892.03	2960	3.46	.001	.005	132.61	8.12E+15	2.84E+04	2.1	91.6	2.809	
	4	9914.00	2960	5.46	659	669	0.18	1.07E+09	2.29E+03	0.7	58.7	2.835	(6)
	3	9969.01	Ambient	11.18	N/A	N/A	N/A	N/A	N/A	1.7	42.9	2.846	(5),(6)

Figure 18 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)



Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells

			Tectonically Fractured
	Karst Modified	Ramp Carbonate	Dolostone
Lithology			
	Dolostone	Dolostone	Dolostone
Depositional			
setting	Inner ramp	Mid- to outer ramp	Inner ramp
		Sub-Middle Ordovician,	
	Extensive sub-	sub-Silurian/Devonian,	
	Middle	sub-Mississippian, sub-	Variable intra-Ellenburger,
Karst facies	Ordovician	Permian/ Pennsylvanian	sub-Middle Ordovician
Fault-related			
fracturing	Subsidiary	Subsidiary	Locally extensive
	Karst-related		
Dominant pore	fractures and	Intercrystalline in	
type	interbreccia	dolomite	Fault-related fractures
		Partial, stratigraphic and	
Dolomitization	Pervasive	fracture-controlled	Pervasive

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

Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)



Porosity vs Permeability

Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Data



Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Ellenburger formation and sidewall cores.



Figure 23 – Core photo of Ellenburger sample displaying vug features.



Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells

2.2.3.3 Formation Fluid

Two wells were identified within approximately 30 miles of the Mongoose through a review of oilfield brine compositions of the Ellenburger formation from the USGS National Produced Waters Geochemical Database (ver. 2.3). The location of these wells is shown in Figure 25. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids (TDS). Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger formation is compatible with the proposed injection fluids.



Figure 25 – Offset wells used for formation fluid characterization.

	Average	Low	High
Total Dissolved Solids (ppm*)	47,427	42,014	52,840
рН	7	7	7
Sodium (ppm)	16,384	15,000	17,767
Chlorides (ppm)	27,590	24,900	30,281

Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples

*ppm – parts per million

2.2.4 Lower Confining Zone – Precambrian-age Formations

In the Permian Basin area, Precambrian-age formations are not normally specifically named in scientific literature. For the purposes of this MRV, these formations will just be referred to as the "Precambrian." Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sourced from outcrops in central Texas and the Trans-Pecos region of Texas and central New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section (Adams & Keller, 1996).

Adams and Keller conducted a geophysical analysis in 1996 to enhance the understanding of Precambrian rock types and their distribution in the Permian Basin. The study incorporated gravity modeling and magnetic and gravity anomalies, as well as rock data from Precambrian outcrops and drills to interpret the upper crustal geology of the area. Figure 26 displays the map resulting from their investigation, revealing that batholiths are likely present in the Precambrian basement rock at the Mongoose well location. Additionally, samples collected from offset wells displayed predominantly felsic rocks, which led to the interpretation of "granitic bodies in the upper crust" (Adams & Keller, 1996).

Offset Ellenburger injector wells were drilled through the Ellenburger section and reached total depths near the Precambrian. Log characteristics of strata near the total depth of the wells display gamma ray responses well above 90 gamma units of the American Petroleum Institute (GAPI), which is indicative of a high radioactive response. Additionally, the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone.



Figure 26 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Geomechanics

2.3.1 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density of the upper and lower confining and injection zones was calculated from log data at the Buchanan 3111 #1XD (API No. 42-227-41307) offset well. The overburden gradient and vertical stress at the top of each zone were calculated by integrating the bulk density from surface to the formation depth in half-foot intervals. Table 4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Formation	Depth (ft)	Bulk Density (g/cm^3)	Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Woodford	8,322	2.63	164.1	8,563	1.029
Ellenburger	8,375	2.75	171.2	8,635	1.031
Precambrian	9,500*	2.83	176.7	9,937	1.046

Table 4 – Calculated Vertical Stresses

*Estimated

2.3.2 Elastic Moduli and Fracture Gradient

The 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. The calculation requires Poisson's ratio (v), overburden gradient (OBG), and pore gradient (PG) in order to determine the required pressure to fracture the formation. These variables can be changed to match the site-specific injection zone.

A thorough review of log data, available literature, and industry standards indicate a 0.465 psi/ft pore gradient should be assumed when there are no site-specific numbers available. Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the Buchanan 3111 #1XD. The calculation was performed using the equation below for log data points at half-foot depth intervals. The results were then averaged for the depth range of each zone. This resulted in a Poisson's ratio of 0.261 for the upper confining zone and 0.273 for the injection zone.

$$v = \frac{\frac{1}{2} \left(\frac{v_p}{v_s}\right)^2 - 1}{\left(\frac{v_p}{v_s}\right)^2 - 1}$$

Where:

v = Poisson's Ratio v_p = Compressional Velocity v_s = Shear Velocity

Log data was unavailable for the lower confining zone, therefore the Poisson's ratio for this zone was estimated through a review of available literature. The lower confining zone consists of granite, which has been observed to have a Poisson's ratio ranging from 0.19 to 0.35 with a mean value of 0.28 (Domede, 2017). Based on this research, an average value of 0.28 was assumed. Using these values in the equation below, a fracture gradient of 0.664 psi/ft was calculated for the upper confining zone. A 10% safety factor was applied to this number resulting in a maximum allowed bottomhole pressure of 0.598 psi/ft. This zone had the lowest fracture gradient of the confining and injection zones. It was used to define the maximum allowable pressure to ensure that the injection pressure would not exceed the fracture pressure of any of the three zones. The resulting fracture gradients are displayed in Table 5.

Example Fracture Gradient Calculation for Upper Confining Zone

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

$$FG = \frac{0.261}{1 - 0.261} (1.029 - 0.465) + 0.465 = 0.664 \, psi/ft$$

$$FG \text{ with } SF = 0.689 \times 90\% = 0.598 \text{ } psi/ft$$

Table 5 –	Fracture	Gradient	Calculation	Inputs and	Results

Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
8,322	Upper Confining	Woodford	1.029	0.465	0.261	0.664
8,375	Injection	Ellenburger	1.031	0.465	0.273	0.678
9,500*	Lower Confining	Precambrian	1.046	0.465	0.28	0.691

*Estimated

2.4 Local Structure

The area surrounding the Mongoose well is characterized by a monoclinal dip from east to west that is influenced by a shallow westward slope towards the Midland Basin and an upward slope to the east towards the Eastern Shelf. No evidence of structural faulting was found in this specific region that could have affected the geological trend. Figure 27 shows the topography of the Ellenburger formation, with the Mongoose well marked by a black star.

Subsurface interpretations of the Ellenburger formation heavily relied on well data and 3D seismic coverage in the area. The black boundary in Figure 27 represents the extent of the seismic coverage. Within the mapped area, approximately 100 wells have penetrated the Ellenburger formation. However, only seven of these wells fully penetrated the entire Ellenburger section. The remaining 93 wells only reached the top of the Ellenburger formation. These wells are plotted on the map and cover four counties. In addition to the Mongoose well, six other wells located offset of the Mongoose were used for the model build and are indicated by red stars.

Figure 28 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map. The Ellenburger was broken down into eight subsections labeled Ellenburger A through H. Figure 29 is a stratigraphic cross section flattened on the Ellenburger that better illustrates these subtops.

The cross sections reveal the regional unconformity in the area when moving east from the Midland Basin. As we go farther updip and to the east, the Fusselman section gradually erodes. While there is also thinning in the Woodford, the cross section shows that the Woodford is present throughout the modeled area, creating a continuous seal above the plume.

With no major structural or stratigraphic features within the injection interval in the Mongoose area, there is little to no concern of geologic conduits outside of the injection interval. General flow trends will follow dip and optimal reservoir features within the Ellenburger. Large scale versions of Figures 28 and 29 are provided in *Appendix D*.



Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map.



Figure 28 – Structural cross section depicting the Ellenburger.



Figure 29 – Stratigraphic cross section flattened on the Ellenburger.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger formation at the Mongoose location indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity. The Woodford Shale formation at the same well location has low permeability and is of adequate thickness and lateral continuity to act as the upper confining zone. Below the injection interval, the Precambrian formation has low permeability and low porosity, making it unsuitable for fluid migration and serving as the lower confining zone.

A thorough study of the area of review has been conducted to identify any potential subsurface features that could impact the ability of the injection and confinement units to retain the injectate within the desired injection interval. Fortunately, no faults or other hazardous geologic conditions have been identified in the area. Therefore, the conditions in this area are ideal for injection and containment.

2.6 Groundwater Hydrology

The Mongoose is located within Mitchell County, home to a population of approximately 8,400 residents, and is serviced by the Lone Wolf Groundwater Conservation District, which consists solely of Mitchell County. This conservation district has an area of roughly 900 square miles. Much of the county's economy is derived from agriculture and oil production, both water-intensive operations. Groundwater usage within the county is estimated to be 13,391 acre-feet on a yearly basis (Lone Wolf Groundwater Conservation District, 2019).

Surface Water

Mitchell County lies within the Colorado River basin, as the Colorado runs through the county. Drainage from both the east and west flow centrally towards the Colorado River, which splits the county in half. The estimated supply of surface water is 395 acre-feet (Lone Wolf Groundwater Conservation District, 2019).

Groundwater

There are multiple units where groundwater is available within Mitchell County, although only the Dockum Group provides significant amounts of water. Table 6 discusses water-bearing units in the county, and Figure 30 shows a generalized reference to structure and formation relationships.

Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger Jr., 1967)

System	Series	Group	Formation	Approximate thickness (feet)	Lithology	Water-bearing characteristics
Quaternary	Pleistocene and Recent		Alluvium	0-100	Fine to coarse sand, and small to large gravel, with occasional clay and caliche beds.	Above the regional water table east of Colo- rado River, but yields up to 20 gpm of good quality water in southwestern Mitchell County.
Tertiary	Pliocene		Ogallala	0-100	Fine to coarse sand, gravel, caliche, and zones of clay.	Above the water table east of Colorado River, but yields up to 20 gpm of good quality water to wells in northwestern Mitchell County.
		Fredericksburg		0-220	Predominently limestone. 15 to 25 feet of sandy yellow marl at base overlain by chalk and shaly limestone. Very dense, massive, fossiliferous lime- stone in the upper part.	Upper limestones contain in places small to moderate supplies of potable but hard water in solutional openings developed along fracture systems; recharge to the openings occurs through numerous sinks.
Cretaceous	Comanche	Trinity		0-100	White to purplish quartz sand, fine to medium grained, moderately to loosely consolidated, with occasional lenses of quartz gravel at the base.	Yields small to large quantities of potsble but hard water, the amount depends on saturated thickness which ranges from 100 percent under interior limestone areas to a few feet in parts of the outcrop; yields of several hundred gallons per minute are reported.
		Deckury	Chinle	0-640	Predominantly red to marbon and pur- plish clay and shale, interbedded with thin, tight, cross-bedded, yellow-brown to reddish-white sand- atone.	Sandstones contain generally small quantities of moderately to highly mineralized water; used principally for livestock.
Irlassic		Dockum	Santa Rosa	0-330	Basal conglomerate overlain by brown to gray, micaccous and carbonaccous, cross-bedded sand alternating with beds of red and gray clay.	Sands and gravels contain moderate to large quantities of fresh water east of the Colorado River, with yields up to 1,000 gpm reported; west of Colorado River capa- city of sand is reportedly substantial but water is generally not potable.
Permain	Guadalupe and Ochoa				Fine-grained, red to brown sandstone; dense red silty shale with occasional gypsum or anhydrite beds.	Yield small quantities of moderately to high- ly mineralized water to livestock and domestic wells.



Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)

Permian

Permian age strata underlies much of the area and outcrops in the southeast of Mitchell County and along the Colorado River and its tributaries. These strata consist primarily of "red beds," dense red silty shales. Water wells in the Permian strata are typically less than 100 ft deep, yielding small amounts of moderately to highly mineralized water usable only for livestock (Shamburger Jr., 1967).

Dockum Aquifer

The Triassic Age Dockum group comprised by the Santa Rosa sandstone and the Chinle formation are the main sources of ground water within the county. An overview map of the extent of the Dockum Aquifer is shown in Figure 31, with outcrops depicted in solid color. The Chinle is further divided into the Tecovas formation, the Trujillo sandstone, and the Cooper Canyon formation, although the Tecovas and Cooper Canyon are generally unimportant and yield only small amounts of highly mineralized water.

The Santa Rosa sandstone lies unconformably atop the Permian age strata at the base of the Dockum Group and is one of the major sources of water for Mitchell County. It is comprised of a basal conglomerate overlain by alternating beds of red and gray micaceous shale, sand, and gravel reaching up to 130 ft in thickness (Bradley & Kalaswad, 2001). The Trujillo sandstone overlies the Tecovas, which in turn overlies the Santa Rosa, and is a cross-bedded unit composed of sandstones and conglomerates. The Santa Rosa and Trujillo sandstones are regarded as the main producers of water in the Dockum Group in Mitchell County (Lone Wolf Groundwater Conservation District, 2019). The Dockum Group was likely deposited from sediments into "fluvial, deltaic, and lacustrine environments within a closed continental basin" (Bradley & Kalaswad, 2001). The base of the Santa Rosa is typically considered the lower extent of fresh water in the area. Water levels in wells throughout the county vary between 15 ft and 215 ft below ground level (Shamburger Jr., 1967), and the aquifer is considered confined to partially confined (Bradley & Kalaswad, 2001).

Recharge of the aquifer is provided by rainwater infiltration through outcrops in the county and is estimated to be 18,108 acre-feet per year. Groundwater in the Dockum aquifer system flows towards the central Colorado River. A potentiometric surface map of the Santa Rosa sandstone, the lower Dockum member, is depicted in Figure 32. Although no values of porosity have been determined empirically, a conservative value of 10% is assumed for effective aquifer porosity (Lone Wolf Groundwater Conservation District, 2019).

Groundwater quality is generally considered poor with TDS and other constituents exceeding secondary drinking water standards (Bradley & Kalaswad, 2001). As a typical assumption, water quality west of the Colorado River within the aquifer is poor and unsuitable for municipal use, while east of the river water quality is less mineralized and is of suitable quality for municipal purposes (Lone Wolf Groundwater Conservation District, 2019). For example, a well tested 10 miles northwest of Colorado City contained chloride at 560 milligrams per liter (mg/L), sulfate at 337 mg/L, and TDS at 1,893 mg/L, all of which are above limits set by the Texas Commission on Environmental Quality (TCEQ) for use in municipal water supplies. In contrast, a well 8 miles east of Colorado City contained

chloride at 34 mg/L, sulfate at 73 mg/L, and TDS at 418 mg/L (Lone Wolf Groundwater Conservation District, 2019). A map showing TDS values for the Dockum Aquifer is shown in Figure 33.



Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location (George, Mace, & Petrossian, 2011).



Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986).



Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011).

Ogallala Formation

The Tertiary age Ogallala formation occurs in the northern extents of Mitchell County. In the eastern part of the county, Ogallala sediments are generally above the water table and not a source of groundwater; however, they do provide an effective means of recharge to the underlying Santa Rosa formation. In the western part of the county, the Ogallala is up to 100 ft thick of unconsolidated sand and gravel and provides small quantities of usable water for domestic and livestock wells (Lone Wolf Groundwater Conservation District, 2019).

2.7 <u>Description of the Injection Process</u>

2.7.1 Current Operations

The Mongoose Amine Treating Facility and the associated Mongoose well began operating in August of 2023. The maximum rate during the injection period is expected to be 377.2 MT/yr (19.5MMscf/D). The TAG is 41.2% CO₂, which equates to 155.3 MT/yr of CO₂ each year. The current composition of the TAG stream is:

Table 7 – Gas Composition at the Plant Outlet

Component	Mole Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

The Mongoose Amine Treating Facility is designed to dehydrate, treat, and compress the natural gas produced from the surrounding acreage in Mitchell County. The gas is dehydrated to remove the water content, and treated to remove the CO_2 and H_2S . The compressed rich gas stream is then transported via pipeline to a separate facility for processing to separate the natural gas liquids from the methane. The TAG is then directly routed from the Plant's amine unit to the Mongoose. The Plant is manned 24 hours per day, 7 days per week.

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (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.

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 Ellenberger formation is the target formation for the Mongoose. The Petrel software package was utilized to create the geologic model of the target formation. Within the Petrel platform, the porosity and permeability distributions were established for the model. The geologic structure was then imported into GEM for simulation purposes.

In Petrel, the structure's construction involved the utilization of nine contour tops, which were layered sequentially. These contour tops, identified as "Ellenberger A" through "Ellenberger I," collectively define the structure's configuration, Ellenberger A being the shallowest and Ellenberger I being the deepest structure package. To accurately represent the formation's true structure, true vertical depth subsea was used to account for the differing overburden depths associated with the

wells used in contour delineation. The distinction between true vertical depth (TVD) and true vertical depth subsea (TVDSS) is taken into consideration when inputting pressure and temperature gradients into the GEM model.

Porosity estimates were determined using openhole porosity logs from seven offset wells within the Ellenberger formation. These logs were used within Petrel to distribute porosity and permeability spatially. Permeability was found by using the two-function porosity-permeability curve developed from regional and local core data within the Ellenberger formation.

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 H₂S and CO₂ based on initial estimates from the source, as shown in Table 8. However, the precise gas composition may vary slightly as the Plant is still in its commissioning phase. Initial estimates anticipate the injectate composition to be 58.8% H₂S and 41.2% CO₂. Once a steady-state operating composition is determined, the MRV plan will be updated if there is a material difference. Based on the initial gas samples, the modeled percentages in the injectate for the 40-year injection period of the Mongoose is 58.8% H₂S and 41.2% CO₂.

Table 8 – Modeled Initial Gas Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)	
Hydrogen Sulfide (H ₂ S)	58.8	58.8	
Carbon Dioxide (CO ₂)	41.2	41.2	

Core data from literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Ellenberger dolomitic carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 10%, an irreducible water saturation of 39.7%, and a maximum residual gas saturation of 30%. The relative permeability curves used for the GEM model are shown in Figure 34.



Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 135 blocks in the x-direction (east-west) and 77 blocks in the y-direction (northsouth), resulting in a total of 10,395 grid blocks per layer. Each grid block spans dimensions of 1,000 ft by 1,000 ft. This configuration yields a grid size measuring 135,000 ft by 77,000 ft, equating to just under 373 square miles in area. The grid cells in the vicinity of the Mongoose, within a radius of 2.5 miles, have been refined to dimensions of 250 ft by 250 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume.

In the model, each layer is characterized by heterogeneous permeability and porosity values. These values are derived from the geostatistical distribution of properties, using porosity logs implemented in Petrel as a basis. The model encompasses a total of 79 layers, each featuring varying thicknesses, with an average of approximately 10 ft per layer. As previously mentioned, the structure of the Ellenberger formation was formed using nine contour packages. The summarized property values for each of these packages are displayed in Table 9.

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Ellenberger A	9	8,369	101	49.1	5.2%
Ellenberger B	9	8,470	76	65.1	6.0%
Ellenberger C	8	8,546	75	38.5	4.2%
Ellenberger D	9	8,621	86	39.2	4.9%
Ellenberger E	15	8,707	153	48	4.8%
Ellenberger F	6	8,860	63	32.5	4.4%
Ellenberger G	4	8,923	39	16.5	3.2%
Ellenberger H	8	8,962	82	76.9	5.5%
Ellenberger I	11	9,044	112	66	3.4%

Table 9 – GEM Model Layer Package Properties

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

- 1. Estimate the maximum areal extent and density drift of the acid gas plume after injection.
- 2. Assess the impact of offset SWD well injection on density drift of the plume.
- 3. Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone.
- 4. 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 47,427 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The acid gas stream is primarily composed of CO₂ and H₂S as stated previously. Core data was used to help generate relative permeability curves. From the literature reviews as previously discussed, cores that most closely represent the vuggy dolomitic carbonate seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975). The initial reservoir pressure is 3,903 psig, which is equivalent to a 0.465 psi/ft pressure gradient and was determined from offset injection well analysis. The fracture gradient of the injection zone was estimated to be 0.664 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.598 psi/ft, which is equivalent to 5,007 psig.

The model considers the injection volumes of offset SWD wells close to the Mongoose. Nine such wells were identified within a 19-mile radius. Historical injection rates of eight of the nine of these wells currently injecting into the Ellenberger were provided by the operators and were input into

the model. All but one of the SWD wells in the model are currently permitted and injecting. The SWD well that has not yet started injection and has no historical injection data is conservatively assumed to inject at its maximum permitted rate for 30 years and to start at the same time as the Mongoose begins injection. Projected injection rates were assumed to be the maximum permitted injection rates and ended after 30 years of life for all nine offset SWDs. This simulation includes the effect of water injection on the density drift of the plume and the bottomhole pressure of the Mongoose. The SWDs included in the model are listed in Table 10.

API Number	Well Name	Well Number	
42-227-41332	Fryar 3S	2XD	
42-227-41307	Buchanan 3111	1XD	
42-227-39064	Pipeline SWD	1	
42-335-34319	Wild Bill	1WD	
42-227-41775	Sterling	1XD	
42-335-36026	Oasis Deep	9XD	
42-227-39098	846 SWD	2	
42-227-39119	N. Midway SWD	1	
42-227-40310	Hull SWD	1	

Table 10 – Offset SWD Wells Included in GEM Model

The model runs for a total of 175.33 years, comprising 15.33 years of historical SWD well injection prior to the commencement of acid gas injection. This is followed by 40 years of active acid gas injection through the Mongoose, succeeded by an additional 120 years of density drift. The model begins in September 2008, aligning with the start of historical injection data for the first offset SWD well. The remainder of the SWD wells turn on between then and the start of the acid gas injection, which begins in January 2024. Throughout the entire 40-year injection period, an injection rate of 19.5 MMscf/D is assumed to model the maximum available rate, yielding a more cautious estimate of the plume size. After the 40-year injection period, when the Mongoose ceases injection, all nine offset SWD wells have been shut in—as they began injecting before the Mongoose and were assumed to stop injecting after 30 years.

The maximum plume extent during the 40-year injection period is shown in Figure 35. The final extent after 120 years of density drift after injection ceases is shown in Figure 36. Both figures show the entire grid with the included offset SWD wells. Due to the large nature of the model, a zoomed-in view of the plume extent during the 40-year injection period is shown in Figure 37 and the final extent after 120 years of density drift after injection ceases is shown in Figure 38.



Figure 35 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)



Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

The cross-sectional view of the Mongoose shows the extent of the plume from a side-view angle cutting through the formation at the wellbore. Figure 39 shows the maximum plume extent during the 40-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 40 shows the final extent of the plume after 120 years of migration. At this point in time, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, as it is less dense than the formation brine, until an impermeable layer is reached. Both figures are shown in a north-to-south view.



Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 40 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)

Figure 41 shows the surface injection rate, bottomhole pressures, and surface pressures over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate begins, reaching a maximum pressure of 4,453 psig, then slightly decreases and remains constant. This buildup of 550 psig keeps the bottomhole pressure below the fracture pressure of 5,007 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,008 psig, well below the maximum allowable 2,500 psig per the TRRC UIC permit for this well. At roughly 30 years into injection for the Mongoose, all SWD wells included in the model have ceased injection. Due to the shut-in of offset SWD wells, the pressure effects within the formation are felt by the Mongoose. When this occurs, the bottomhole pressure decreases by 50 psig and surface pressure decreases by 40 psig. Bottomhole and wellhead pressures over time are in Table 11.



Figure 41 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injectio	n
---	---

Time from Start of Injection (years)	BHP (psig)	WHP (psig)	
0	3,916	-	
10	4,389	1,977	
20	4,394	1,982	
30	4,393	1,980	
40	4,343	1,942	
50	3,923	-	
120	3,919	-	
SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO₂ plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

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

Bayswater's expected gas composition was used in the model. The acid gas injectate is estimated at a molar composition of 58.8% H₂S and 41.2% CO₂, with trace amounts of other constituents. Upon the Plant achieving stable operations, a representative injectate sample will be collected and analyzed by a third-party laboratory. If the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be provided. As discussed in *Section 2*, the gas will be injected into the Ellenberger formation. The geomodel was created based on the rock properties of the Ellenberger.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 40, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast.

Figure 42 shows the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA is depicted in this figure by taking the stabilized plume boundary after 120 years of density drift, and adding an all-around buffer zone of one half mile.



Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. This provides Bayswater sufficient time to develop its asset base, achieve steady operations, and evaluate any potential modifications to the MRV plan.

The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free-phase CO₂ plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. By 2036, a revised MRV plan will be submitted to define a new AMA. Figure 43 shows the area covered by the AMA.



Figure 43 – 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. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within the MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from natural or induced seismicity

Table 12 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood		Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. Two artificial penetrations were drilled into the gross injection interval. These wells were plugged in accordancee TRRC requirements.	Low	Low. Vertical migration of CO ₂ would likely enter a shallower hydrocarbon production zone.	During active injection.
Faults and fractures	Unlikely. There are no faults within the modeled area. Bayswater monitors the area for seismic activity.	Low	Low. Vertical migration of CO ₂ would likely enter a shallower hydrocarbon production zone.	During active injection.
Upper confining layer	Unlikely. The lateral continuity of the Woodford Shale blanketing the Ellenburger is recognized as a very competent seal. There is 7,825' of overburden between the Injection Interval and the base of the USDW.	Low	Low. Vertical migration of CO ₂ would likely enter a shallower hydrocarbon production zone.	During active injection.
Natural or induced seismicity	Unlikely. There have been no seismic events of 3.0 magnitude or greater detected. There is over 7,825' of overburden between the Injection Interval and the base of the USDW.	Low	Low. Vertical migration of CO ₂ would likely enter a shallower hydrocarbon production zone.	During active injection.

Magnitude Assessment Description

Low - catergorized as little to no impact to safety, health and the environment and the costs to mitigate are minimal.

Medium - potential risks to the USDW and for surface releases does exist, but circumstances can be easily remediated.

High - danger to the USDW and significant surface release may exist, and if occurs this would require significant costs to remediate.

4.1 Leakage from Surface Equipment

The Plant and Mongoose are newly designed and constructed facilities for treating and injecting acid gas with the fundamental objective of ensuring maximum safety for the public, the employees, and the environment. These are depicted in Figures 44 and 45. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H₂S are installed at key locations around the Plant as depicted on the site plan in Appendix B-2. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H₂S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the TRRC with the Class II AGI application. OSHA sets the detection or exposure limits at 15 ppm as the High Alarm and the High- High Alarm or Facility Shutdown limit at 40 ppm.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant and the Mongoose well. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs. These valves, gas monitors, and the gas flow meter are called out in the detailed site plan in Appendix B-2. Data from this flow meter will be used in the calculations of the total mass of CO₂ (in metric tons) in the CO₂ stream injected each year, per 40 CFR **§98.444(b)**.



Figure 44 – Site Plan



Figure 45 – Mongoose AGI No. 1 Wellbore Schematic

With the level of monitoring implemented at the Plant, a release of CO_2 would be quickly identified, and the safety systems and protocols would minimize the release volume. The acid gas stream injected into the well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the Plant adjacent to the Mongoose. Bayswater will increase its future injection volumes from its own gas production and possibly other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7* in accordance with 40 CFR **§98.448(a)(5)**. Bayswater concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The Mongoose was designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 45. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) §3.46 [40 CFR §146.23 (b)(3)], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 46. The MMA review map and a summary of all wells in the MMA is provided in *Appendix C*. Figure 47 highlights that only two wells penetrate the MMA's gross injection zone. These wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements. Bayswater will perform baseline soil gas sampling prior to the implementation of the MRV plan and subsequent injection records. In addition, annual soil gas samples will be taken in the area adjacent to artificial penetrations and analyzed by a third-party lab. The results, should they indicate an issue with the sequestered CO₂ will be presented in the annual report to the GHGRP.

The summary of all oil and gas wells in *Appendix C* also provides the total depth (TD) of all wells within the MMA. Those wells that are shallower and do not penetrate the injection zone are isolated by the Woodford Shale as discussed in *Section 2.2.2*. The Woodford Shale provides 50 feet or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset artificial penetrations is unlikely.

Bayswater is the operator of many of the shallower offset oil and gas wells within the MMA and frequently performs gas analysis on their production volumes. If a material variance in the quantity of CO_2 produced is indicated, Bayswater would investigate to determine the affected well(s), the root cause of the CO_2 increase to formulate a resolution plan and utilize the gas analysis variance to calculate any adjustments to reported volumes.



Figure 46 – All Oil and Gas Wells Within the MMA



Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC in the area of the Mongoose will include a list of formations for which operators are required to comply with TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC §3.13. The Mongoose drilling permit, provided in Appendix A, serves as an example. The Ellenburger is among the formations listed for which operators in Mitchell County and District 8 (where the Mongoose is located) are required to comply with TRCC Rule 13. The rule requires oil and gas operators to set steel casing and cement either (1) across and above all formations permitted for injection under TRRC Rule 9, or (2) immediately above all formations permitted for injection under Rule 46, for any well proposed within a quarter-mile radius of an injection well. In this instance, any new well permitted and drilled to the injection zone and located within a guarter-mile radius of the Mongoose will be required under TRRC Rule 13 to set steel casing and cement above the well's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and 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 (also provided in the permit in Appendix A).

4.2.2 Groundwater Wells

A groundwater well search results found three wells within the MMA, as identified by the Texas Water Development Board. A field investigation was performed to validate the existence and location of these wells. However, none of the wells listed in the database could be located. An exhaustive search of well records was performed and no completion reports and/or plugging records were found. The result is there are no groundwater wells to monitor as none exist within the MMA.

The surface, intermediate, and production casing strings in the Mongoose, as shown in Figure 45, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations and the GAU letter issued for this location (and included in *Appendix A*). The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Bayswater concludes that leakage of the sequestered CO_2 to the groundwater aquifer is unlikely.

4.3 Leakage Through Faults and Fractures

No faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose. This includes areas well outside of the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

In the event of an unmapped fault existing within the plume boundary, any displacement caused by it would be too small to be detected through 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

Porosity development within the injection intervals is primarily attributed to fractures and aerial exposure. However, these fractures are limited and do not extend into the upper confining unit, which helps mitigate the risk of migration through fractures outside of the designated injection interval.

4.4 Leakage Through the Confining Layer

The overlying Woodford formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in *Section 2*. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale which would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

4.5 Leakage from Natural or Induced Seismicity

The Mongoose is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

All seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

Stringent operating procedures will be programmed into the SCADA and control systems to ensure that operating pressures stay below the fracture gradient of both the injection and confining intervals. Moreover, a combination of continuous well monitoring and monitoring of the TexNet site for activity will promptly identify any irregularities in the operations linked to seismic events.



Figure 48 – Seismicity Review (TexNet – 08/04/2023)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Bayswater 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 H₂S and CO₂, the H₂S will be a proxy for CO₂ leakage and therefore the monitoring systems in place to detect H₂S will also indicate a release of CO₂. Table 13 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 40-year injection period or cessation of injection operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

Leakage Pathway	Monitoring Method		
	Fixed H ₂ S monitors throughout the AGI facility		
Leakage from surface equipment	Visual inspections		
	SCADA continuous monitoring of the AGI facility		
	SCADA continuous monitoring of the AGI well		
	Monitor CO ₂ levels in Above Zone producing wells		
Lookago through existing wells	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years		
	Visual inspections		
	Annual soil gas sampling at well locations that penetrate the Upper Confining Zone within the AMA		
Leakage through groundwater wells	Annual groundwater samples from monitoring wells		
Leakage from future wells	Compliance with TRRC Rule 13 Regulations		
Lookago through foulte and fractures	SCADA continuous monitoring at the AGI well (volumes and pressures)		
	Monitor CO ₂ levels in Above Zone producing wells		
Leckage through the confining lover	SCADA continuous monitoring at the AGI well (volumes and pressures)		
	Monitor CO_2 levels in Above Zone producing wells		
Lookago from patural or induced coismicity	Monitor CO ₂ levels in Above Zone producing wells		
	Monitor existing TexNet station		

Table 13 – Summary of Leakage Monitoring Methods

5.1 <u>Leakage from Surface Equipment</u>

The Plant and the Mongoose were designed to operate in a manner that will reduce to the lowest factor the possibility of an escape of CO₂ and H₂S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO₂ concentration will be established during the commissioning of the Plant. Ambient H₂S monitors are located at the Plant and near the Mongoose for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in *Appendix B*. The locations of H₂S detectors and Emergency Shutdowns are identified throughout the facility on the Appendix B-2 Site Plan. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Bayswater to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO₂ released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

5.2 Leakage Through Existing and Future Wells Within the MMA

Bayswater continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the Mongoose. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, an MIT will be performed every 5 years, as required by the TRRC and UIC. A failed MIT would also indicate the potential of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 ensures that new wells in the field would be constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Bayswater will also establish an in-field soil gas monitoring program to detect CO_2 leakage within the AMA. This would include sample collection and testing for CO_2 and H_2S at the AGI well site and near one of the identified artificial penetrations of the injection interval within the AMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. Prior to approval and implementation of

the MRV plan and through the post-injection site care period, Bayswater will have these monitoring systems in place.

There are currently only two wells that have been identified within the AMA that penetrate the Upper Confining Zone. As both wells have been plugged and abandoned in compliance with TRRC requirements, Bayswater believes a leak event is unlikely. Bayswater will perform soil gas sampling and analysis proximate to the Mongoose and one of the abandoned artificial penetrations by May 20, 2024. Thereafter, soil gas samples will be taken annually and analyzed by a third-party lab, and the results will be included in the annual report.

Bayswater is the operator of record for many oil and gas producing wells with the AMA. These wells will be used as a proxy for an above-zone monitoring well. If any CO_2 , migrates up-hole, the CO_2 would likely end up in this formation. Since gas analysis is performed on a regular basis on the hydrocarbons produced from this formation, any material variance from historical data would indicate the potential of an issue needing further investigation. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance. It is not the intent of Bayswater to produce any of the CO_2 in this scenario but to use this as an indication of an event warranting further investigation.

5.2.1.1 <u>Groundwater Quality Monitoring</u>

As explained in *Section 4.2.2,* there are no groundwater wells within the MMA. Therefore, there are no groundwater wells to monitor.

5.3 <u>Leakage Through Faults, Fractures, or Confining Seals</u>

Bayswater continuously monitors the operations of the Mongoose 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 due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Bayswater will also monitor production from their oil and gas wells that do not penetrate the injection zone for any material variance in CO₂ content in the produced gas stream. Since gas analysis is very consistent over time, any material variance in the CO₂ content would be an early indicator of a potential issue. Should the CO₂ migrate vertically, the magnitude risk of this event is very low, as the reservoir provides an ideal containment given the Upper Confining Zone has successfully held hydrocarbons in place. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Bayswater plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose well. This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 49. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Bayswater facility. Bayswater will monitor this station for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected, Bayswater will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.



Figure 49 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

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

6.1 Visual Inspections

Regular inspections will be conducted by field personnel at the Plant and the Mongoose. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken in a prudent and safe manner to address such issues.

6.2 <u>CO₂/H₂S Detection</u>

In addition to the fixed gas monitors at the well site, Bayswater will perform an annual soil gas sampling program to detect any CO_2 leakage proximate to select artificial penetrations of the Upper Confining Zone within the AMA. The baseline determination will include atmospheric H₂S measurements at the AGI well and soil gas sampling near the AGI well and one of the abandoned artificial penetrations within the AMA.

These soil gas sample probes will be inserted below the surface. The probes have special material inserts that collect the gas samples over a 21-day period. These inserts are then removed and sent to a third-party lab to be analyzed for CO_2 , H_2S , and trace contaminants typically found in a hydrocarbon gas stream. This initial sample collection is scheduled to be completed by May 20, 2024; a sufficient time period prior to the implementation of the MRV plan and will establish baseline values for future reference.

6.3 **Operational Data**

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO₂.

6.4 <u>Continuous Monitoring</u>

The total mass of CO₂ emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel due to the presence of H₂S in the gas stream. Continuous monitoring systems will trigger an alarm if there is a release. The mass of the CO₂ released would be calculated based on the operating conditions,

including pressure, flow rate, percentage of CO₂, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a de-pressuring event, the acid gas stream will be diverted to a flare stack to be safely processed and vented. The event will be reported as required for the operation of the well.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO₂ Received

Per 40 CFR **§98.443**, the mass of CO₂ received must be calculated using the specified CO₂ received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4)**." 40 CFR **§98.444(a)(4)** states that "if the CO₂ you receive is wholly injected and is not mixed with any other supply of CO₂, you may report the annual mass of CO₂ injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO₂ received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO₂ received." The CO₂ received for this injection well is wholly injected and not mixed with any other supply; the annual mass of CO₂ injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO₂ 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 volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, 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 CO₂ mass injected (metric tons) as measured by flow meter u

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO₂ Produced

The Mongoose is not part of an enhanced oil recovery project; therefore, no CO₂ will be produced.

7.4 Mass of CO₂ Emitted by Surface Leakage

The mass of CO₂ emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains high concentrations of H₂S. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions sent to a flare stack and reported as a part of the required GHG reporting for the Plant. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of CO₂ and H₂S. The mass of the CO₂ released would be calculated for the operating conditions, including pressure, flow rate, size of the leak-point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO₂ was released because of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

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

Where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

Calculation methods using equations from Subpart W will be used to calculate CO₂ emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Bayswater believes the most appropriate method to quantify the mass of CO₂ released will be determined on a case-by-case basis. Any mass of CO₂ detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. In the unlikely event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events will be kept and stored as stated in *Section 10*.

7.5 Mass of CO₂ Sequestered

The mass of CO₂ sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Since the Mongoose has commenced operations, Bayswater will begin collecting data for reporting under this plan based on the approval of this MRV plan and any applicable stipulations therein. The calculation of sequestered volumes utilizes the following equation as this well will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

 CO_{21} = 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 CO₂ mass emitted (metric tons) by surface leakage in the reporting year

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

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting is expected to occur, the calculations would be based on an unusual event that a blowdown is required and those emissions are sent to a flare stack and reported as part of the required GHG reporting for the Plant.

• Calculation methods from Subpart W will be used to calculate CO₂ 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 Mongoose is a new injection well currently reporting under the TRRC Class II regulations. Bayswater is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

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

9.1 Monitoring QA/QC

CO₂ Injected

- The flow rate of the CO₂ being injected will be measured with a volumetric flow meter, consistent with applicable industry standards. These flow rates will be compiled quarterly.
- The composition of the injectate stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with applicable industry standards.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The gas measurement equipment will be calibrated per the requirements of 40 CFR §98.444(e) and §98.3(i).

CO₂ Emissions from Leaks and Vented Emissions

- Gas monitors within the Mongoose facility will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.
- Calculation methods from Subpart W will be used to calculate CO₂ emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR §98.3(i).
- Flow meters will be operated and maintained in accordance with applicable standards as published by a consensus-based standards organization.

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

9.2 Missing Data

In accordance with 40 CFR **§98.445**, Bayswater 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 CO₂ injected is missing, the amount will be estimated using a representative quantity of CO₂ injected from the nearest previous period at a similar injection pressure.

• Fugitive CO₂ emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR **§98**.

9.3 MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Bayswater will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least 3 years and include the following:

- Quarterly records of the CO₂ injected
 - Volumetric flow at standard conditions
 - Volumetric flow at operating conditions
 - Operating temperature and pressure
 - Concentration of the CO₂ stream
- Annual records of the information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of the information used to calculate CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 11 - REFERENCES

- Adams, D. C., & Keller, G. R. (1996). Precambrian Basement Geology of the Permian Basin Region of West Texas and Eastern New Mexico: A Geophysical Perspective1. *AAPG*.
- Aird, P. (2019). *Deepwater Geology* & *Geoscience*. Retrieved from ScienceDirect: https://www.sciencedirect.com/topics/engineering/overburden-stress
- Bradley, R. G., & Kalaswad, S. (2001). *Chapter 12: Dockum Aquifer in West Texas*. Texas Water Development Board.
- Bennion, B., & Bachu, S. (2010). Drainage and Imbibition CO₂/Brine Relative Permeability Curves at Reservoir Conditions for Carbonate Formations. *SPE Annual Technical Conference and Exhibition*.
- Comer, J. B. (1991). Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas asn Southeatern New Mexico. *BEG*.
- Conselman, F. B. (1954). Preliminary Report on the Geology of the Cambrian Trend of West Central Texas. *Abilene Geologic Society*.
- Domede, P. S. (2017). *Mechanical behaviour of granite. A compilation, analysis and correlation of data from around the world*. Retrieved from https://hal.insa-toulouse.fr/hal-01743870/document
- Dutton, A. R., & Simpkins, W. W. (1986). *Hydrogeochemistry and Water Resources of the Triassic Lower Dockum Group in the Texas Panhandle and Eastern New Mexico*. Austin Tx: Bureau of Economic Geology.
- Fanchi, J. R. (2010). Integrated Reservoir Asset Management.
- Galley, J. (1958). Oil and Geology in the Permian Basin of Texas and New Mexico. *Basin or Areal Analysis or Evaluation*.
- Gunn, R. D. (1982). Desmoinesian Depositonal Systems in the Knox Baylor Trough. *North Texas Geological Society*.
- Hendricks, L. (1964). STRATIGRAPHIC SUMMARY OF THE ELLENBURGER GROUP OF NORTH TEXAS. *Tulsa Geological Society Digest, Volume 32*.
- Hornhach, M. J. (2016). Ellenburger wastwater injection and seismicity in North Texas. *Physics of the Earth and Planetary Interiors*.
- Jesse G. White, P. P. (2014). Reconstruction of Paleoenvironments through Integrative Sedimentology and Ichnology of the Pennsylvanian Strawn Formation. *AAPG Southwest Section Annual Convention, Midland, Texas*.
- Keelan, K., & Pugh, V. (1975). Trapped-Gas Saturations in Carbonate Formations. SPE J. 15: 149–160.
- Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas. *Bureau of Economic Geology*.
- Lone Wolf Groundwater Conservation District. (2019). *Management Plan 2019-2024.* Colorado City, Tx.
- Loucks, R. (2003). REVIEW OF THE LOWER ORDOVICIAN ELLENBURGER GROUP OF THE PERMIAN BASIN, WEST TEXAS. *Bureau of Economic Geology*.
- Loucks, R. (2006). *Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas.* Austin, Tx: Bureau of Economic Geology.
- Mason, C. C. (1961). GROUND-WATER GEOLOGY OF THE HICKORYSANDSTONE MEMBER OF THE RILEY FORMATION. McCULLOCH COUNTY. TEXAS. *TEXAS BOARD OF WATER ENGINEERS*.

- Merrill, M., Slucher, E., Roberts -Ashby, T., Warwick, P., Blondes, M., Freeman, P., . . . Lohr, C. (2015). Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources–Permian and Palo Duro Basins and Bend Arch-Fort Worth Basin. *USGS*.
- Popova, O. (2020). Permian Basin Part 1 Wolfcamp, Bone Spring, Delaware shale plays of the Delaware Basin Geology Review. *USDOE*.
- Powers, R. B. (1989). Petroleum Exploration Plays and Resource Estimates, 1989, On shore United States -- Region 5, West Texas and Eastern New Mexico. USGS.
- Sanchez, T., Loughry, D., & Coringrato, V. (2019). Evaluating the Ellenburger Reservoir for Salt Water Disposal in the Midland Basin: An Assessment of Porosity Distribution Beyond the Scale of Karsts. Unconventional Resources Technology Conference (pp. 1-17). Denver: URTeC. doi:10.15530/urtec-2019-600
- Scanlon, B. R., Reedy, R. C., Male, F., & Walsh, M. (n.d.). *Water Issues Related to Transitioning from Conventional to Unconventional Oil Production in the Permian Basin.* Austin: Bureau of Economic Geology.
- Shamburger Jr., V. M. (1967). *Report 50: Ground-Water Resources of Mitchell and Western Nolan Counties, Texas.* Austin, Tx: Texas Water Development Board.
- Snee, J.-E. L., & Zoback, M. D. (2018). State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity. *The Leading Edge*, 810-819.
- Waite, L. (2021, October 25). Geology of the Permian Basin. UT Dallas Geoscience Permian Basin Research Lab.
- Zerwer, N. Y. (1997). Stress Regimes in the Gulf Coast, Offshore Louisiana:. AAPG Bulletin, 293-307.

APPENDICES

APPENDICES

<u>APPENDIX A – MONGOOSE AGI No. 1 TRRC FORMS</u>

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

APPENDIX A-5: API 42-335-33555 VAN TUYLE PLUGGING RECORDS

APPENDIX A-6: API 42-227-03634 STEWART PLUGGING RECORDS

CHRISTI CRADDICK, CHAIRMAN WAYNE CHRISTIAN, COMMISSIONER JIM WRIGHT, COMMISSIONER



A-1

DANNY SORRELLS DEPUTY EXECUTIVE DIRECTOR DIRECTOR, OIL AND GAS DIVISION PAUL DUBOIS, P.E. 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. 17174

BAYSWATER OPERATING COMPANY LLC 730 17TH STREET SUITE 500 DENVER CO 80202

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 22, 2022, for the permitted interval(s) of the WOODFORD and ELLENBURGER formation(s) and subject to the following terms and special conditions:

MONGOOSE AGI (000000) LEASE SPRABERRY (TREND AREA) FIELD MITCHELL COUNTY DISTRICT 08

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	33536013	000125803	Carbon Dioxide (CO2); Hydrogen Sulfide (H2S)	8300	9000	6900	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
		1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.
		2. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.
1	33536013	3. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.
		4. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.
		5. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.

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.
- Prior to beginning injection and subsequently after any work over, an annulus pressure test must 4. 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 March 10, 2023.

Hilf

For Sean Avitt, Manager Injection-Storage Permits Unit

			A-2		
	GROUNDWATER PROTEC	TION DETERMINATION	Form GW-2		
	Groundwater A	Advisory Unit			
Date Issued:	04 March 2022	GAU Number:	336979		
Attention:	BAYSWATER OPERATING	API Number:	33536013		
	730 17TH STREET SUITE 500	County:			
	DENVER, CO 80202	Lease Number:			
Operator No.:	058827	Well Number:	1		
		Total Vertical	9250		
		Latitude:	32.422884		
		Longitude:	-101.169661		
		Datum:	NAD27		
2					
Purpose:	Injection into Non-producing Zone (W-1	4) ock-29 [.] Townshin-1N [.] Sec	ntion_4		
To protect usable-qu Texas recommends	uality groundwater at this location, the Gro	bundwater Advisory Unit c	of the Railroad Commission of		
The base of usable- well.	quality water-bearing strata is estimated t	o occur at a depth of 350	feet at the site of the referenced		
The BASE OF UND feet at the site of the	ERGROUND SOURCES OF DRINKING	WATER (USDW) is estima	ated to occur at a depth of 475		
This recommendation is applicable to all wells within a radius of 200 feet of this location.					
Note: Unless stated Unless stated other	otherwise, this recommendation is intend vise, this recommendation is for normal d	ed to apply to all wells dri rilling, production, and plu	lled within 200 feet of the subject well. Igging operations only.		
This determination is based on information provided when the application was submitted on 03/02/2022. 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 Advisc	ory Unit, Oil and Gas Division				
Form GW-2 P.C Rev. 02/2014). Box 12967 Austin, Texas 78771-2967	7 512-463-2741 lr	nternet address: www.rrc.texas.		

	RAILROAD COMMISSION OF TEX OIL & GAS DIVISION	AS			
PERMIT TO DRILL, DEEPEN, PLUG E	ACK, OR RE-ENTER ON A REGULAR OR A	DMINISTR	ATIVE EXCEP	PTION LOCATI	ON
PERMIT NUMBER 876754	DATE PERMIT ISSUED OR AMENDED Feb 10, 2022	DISTRIC	т * 0	18	
APINUMBER 42-335-36013	FORM W-1 RECEIVED Feb 03, 2022	COUNTY	МІТСІ	HELL	
TYPE OF OPERATION	WELLBORE PROFILE(S)	ACRES		•	
NEW DRILL	velucal		4	0	
BAYSWATER OPERATING 730 17TH STREET SUITE DENVER, CO 80202-0000	058827 5 COMPANY LLC 500	This perm revoked I D	NOT it and any allow if payment for f Commission is istrict Office T (432) 684	ICE wable assigned m iee(s) submitted to not honorod. Velephone No: 4-5581	ay bi o the
LEASE NAME MONG	OOSE AGI	WELL N	JMBER.	1	
LOCATION 10.4 miles NW direct	ion from WESTBROOK	TOTALE	EPTH	10000	
SECTION 4 SURVEY T&P RR CO/MORRI DISTANCE TO SURVEY LINES	BLOCK 🕊 29 T1N ABSTR SON, W	DISTANC	45 je to neare	ST LEASE LINE	E
551 ft. EAST	2164 ft. SOUTH			ft.	
DISTANCE TO LEASE LINES 400 ft FAST	650 ft SOUTH	DISTANC	E TO NEARE	ST WELL ON LI	EAS
FIELD NAME LEASE NAME		ACRES NEAREST L	DEPTH EASE	WELL # NEAREST WE	DI
SPRABERRY (TREND AREA)		40.00	10,000	1	(
MONGOOSE AGI				0	
RESTRICTIONS: Do not use this by the Environm	well for injection/disposal/hydrocar ental Services section of the Railroad	bon storag 1 Commissi	e purposes lon, Austin,	without appro Texas office	oval e.
THE F This well shall be completed and product well is to be used for brine mining, under salt formations, a permit for that specific drilling, of the well in accordance with St This well must comply to the new SWR : corrosive formation fluids. See approve drilling the well in.	OLLOWING RESTRICTIONS APPLY TO ed in compliance with applicable special field rground storage of liquid hydrocarbons in salt purpose must be obtained from Environment atewide Rules 81, 95, and 97. 3.13 requirements concerning the isolation of d permit for those formations that have been i	ALL FIEL or statewic formations al Services any potent dentified fo	DS le spacing an , or undergrou prior to const ial flow zones r the county in	d density rules. und storage of g ruction, includir and zones with n which you are	lft gasi ng h
Data Validation Time Stamp:	Feb 10, 2022 9:58 AM('As Approved' Version)	Page 3 of 4		


RAILROAD COMMISSION OF TEXAS

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

Tracking No.:

Submitted 09/11/2023 298516

Form W-2

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

UPERALL	
	Operator 059927
Operator 730 17TH STREET SUITE 500 DENVER CO	
WELL	INFORMATION
API 42-335-36013	County: MITCHELL
Well No.: 1	RRC District 08
Lease MONGOOSE AGI	Field SPRABERRY (TREND AREA)
RRC Lease	Field No.: 85280300
Location Section: 4, Block: 29 T1N, Survey: T&P RR CO/MORRIS	SON, W, Abstract: 1545
Latitude 32.423000	Longitud -101.170059
line tion from WEATDDOOK	
which is the nearest town in the	
FILING	INFORMATION
Purpose of Initial Potential	
Type of New Well	
Well Type: Active UIC	Completion or Recompletion 04/28/2023
Type of Permit	Date Permit No.
Permit to Drill, Plug Back, or	02/10/2022 876754
Rule 37 Exception	
Fluid Injection	
O&G Waste Disposal	17174
Other:	
COMPLET	
Spud 10/12/2022	Date of first production after rig 04/28/2023
Date plug back, deepening,	Date plug back, deepening, recompletion,
drilling operation 10/12/2022	drilling operation $04/28/2023$
Number of producing wells on this lease	Distance to nearest well in lease &
Number of producing wells on this lease this field (reservoir) including this 1	Distance to nearest well in lease & reservoir
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00	Distance to nearest well in lease & reservoir Elevation 2252 GL
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-Yes	Distance to nearest well in lease & reservoir Elevation 2252 Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNo	Distance to nearest well in lease & reservoir Elevation 2252 Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No iction/Neutron/Density/Sonic
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400 400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Inction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and .0 Feet from the South Line of the
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400650	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Inction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W- YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this 1 Total number of acres in 40.00 Total depth TVD 9289 Plug back depth TVD 9036 Was directional survey made other inclination (Form W- Yes Recompletion or No Type(s) of electric or other log(s) Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is 400 650	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this 1 Total number of acres in 40.00 Total depth TVD 9289 Plug back depth TVD 9036 Was directional survey made other inclination (Form W- Yes Recompletion or No Type(s) of electric or other log(s) Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is 400 FORMER FIELD (WITH RESE Field & Reservoir	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and 0 Feet from the South Line of the MONGOOSE AGI Lease. RVOIR) & GAS ID OR OIL LEASE NO. Gas ID or Oil Lease Well No. Prior Service Type

W2:	N/A			
	FOR NEW DRILL OR RE-ENTRY	(, SURFACE CASING	G DEPTH DET	ERMINED BY:
GAU Ground	dwater Protection Determination	Depth	350.0	Date 03/04/2022
SWR 13 Exc	eption	Depth		

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION								
Date of		Production						
Number of hours 24		Choke						
Was swab used during this	No	Oil produced prior to						
PRODUCTION DURING TEST PERIOD:								
Oil		Gas						
Gas - Oil 0		Flowing Tubing						
Water								
	CALCULATED	24-HOUR RATE						
Oil		Gas						
Oil Gravity - API - 60.:		Casing						
Water								

	CASING RECORD										
	Type of	Casing Size	Hole Size	Setting Depth	<u>Multi -</u> Stage Tool	<u>Multi -</u> Stage Shoe	Cement Class	Cement Amoun	Slurry Volume	Top of Cemen	t <u>TOC</u> t Determined
<u>Ro</u>	Casing	<u>(in.)</u>							<u>(cu.</u>	<u>(ft.)</u>	Ву
1	Surface	13 3/8	17 1/2	569			С	637	847.0	0	Circulated to Surface
2	Intermediate	9 5/8	12 1/4	5328	3001		С	725	1752.0	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5328			С	610	1175.0	3001	Calculation
4 C	Conventional Production	n 7	8 3/4	8343			C & RESIN	594	1513.0	1800	Calculation

_					LINER RECORD			
<u>Ro</u>	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu. (ft.)	TOC Determined
N/A								

Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	8260	8230 / INCONEL
			925

	PRODUCING/INJECTION/DISPOSAL INTERVAL										
Ro	Open hole?	From (ft.)	To (ft.)								
1	Yes	L 8343	9036.0								

ACID, FRACTURE, C	EMENT SQUEEZE, CAST IRON BRIDGE PLUG,	RETAINER, ETC.
Was hydraulic fracturing treatment	No	
Is well equipped with a downhole sleeve? No	If yes, actuation pressure	
Production casing test pressure (PSI	IG) Actual maximum pressur	e (PSIG) during
hydraulic fracturing	fracturin	
Has the hydraulic fracturing fluid dis	closure been No	
Ro Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)

OPEN HOLE CEMENT PLUG WITH 58 SACKS CLASS H

1

Other

9036 9289

		FORMATION REV	CORD		
Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
SANTA ROSA - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT
YATES - OVERPRESSURED, POSSIBLE FLOWS	Yes	1001.0		Yes	
SEVEN RIVERS	Yes	1137.0		Yes	
SAN ANDRES - HIGH FLOWS, H2 CORROSIVE	S, Yes	2008.0		Yes	
GLORIETA	Yes	2875.0		Yes	
CLEARFORK	Yes	3089.0		Yes	
TUBB	No			No	NOT PRESENT AT LOCATION
WICHITA	No			No	NOT PRESENT AT LOCATION
COLEMAN JUNCTION - POSSIBL LOST CIRCULATION	E No			No	NOT PRESENT AT LOCATION
WOLFCAMP	Yes	5369.0		Yes	
STRAWN	Yes	7918.0		Yes	
ODOM	No			No	NOT PRESENT AT LOCATION.
MISSISSIPPIAN	Yes	8153.0		Yes	
WOODFORD	Yes	8322.0		Yes	
ELLENBURGER	Yes	8374.0		Yes	
CAMBRIAN	Yes	9279.0		Yes	
Do the producing interval of this w	ell produce H	2S with a concer	tration in exc	ess of 100 ppm	No
Is the completion being downhole	commingled	N	0		

REMARKS DIRECTIONAL SURVEY RUN FOR INFORMATION PURPOSES ONLY.

PUBLIC COMMENTS:

RRC REMARKS

CASING RECORD :

SURFACE CASING IS SET AT 543.5' AS MEASURED FROM GROUND LEVEL, WHICH IS WITHIN 200' OF BUQW.

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

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

POTENTIAL TEST DATA:

OPERATOR'S CERTIFICATION									
Printed	James Clark	Title:	Consulting Petroleum Engineer						
Telephone	(512) 415-4191	Date	09/11/2023						

Ð 7 Ð ŋ 7 η ŋ Ŋ 20. Do you have the right to develop the minerals under nny right of way that crosses, or is contiguous to, this innet? If not, and if the well requires a Rule 37 or 38 exception. 25. is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes 23. Is this a pooled unit? Perpendicular surface location from two nearest designated lines:
 trace.Unit <u>1000</u>, FNL & 2500, FEL 11. Distance from proposed location to nearest leave or unit line 2 Address (including city and zip code) Purpose of filing (murk appropriate bodes): · Sunny/Section 1000' FNL & 2500' FEL of Section 15-Operator's Name (exactly as shown on Form P.S. Organization Front) see Instructions for Rule 37. ĩ Krimerka Nulicamp, (Wildcat) File a copy of W-1 and plat in JORC Di Ellenburger (Wildcat) 1800 £ Midland, Texas 3200 West Cuthbert, Bright se zones. One zone per line, ELD NAME: [Exactly as sheem; on RRC privation adult a all estublished and whiles! somes of anticipated repiction. Attach additional Form W-1's as needed to last any firentealo ふしい 121 Uttach Form P-12 and certified plat. 21 × たりや Company 30 D III 6 Directional Well 5 and \$180.00 fee 79701 Rai Bau **Nation** Suite 2-C trict Office. Deepen (below casing) Sidetrack Application for Permit to Drill, Deepen, Plug Back, or Re-Enter ã 5200-8300' **Gebru** 7800 1000 × 10. Location 3. IURC Operator No. 6. Lease Name (32 spaces maximum) Van Tuyle 093125 'This well is to be located ______ Section . 8 8 Deepen (within casing) Amended Permit (enter permit no. at right & explain fully in Remarks) which is the nearest town in the county of the well site RAILROAD COMMISSION OF TEXAS Oll and Gas Division N 10 (n.) 467-1200 2 467 1200 Specing 467-1200 No 2 Lini 2 15 203091 0CT 1890 If subject to Rule 36, ts Form H 9 Aled? Yes Ę ł I certify that information stated in this application is ince and complete, to the best of my knowledge ĕ 12. Number of configuous acres in lease, pooled unit, or unitized iract **4**0 Density If a directional will show also projected bottom-hole location: pallern Hock 24 Jo liem 17 less that Jiem 18 (substandersberrehe for any field applied for?? 4. FIRC District No. G Lengel Mail Signature Date: Խ 20, 1-1-1 mary Artiling unity for this well OUTLINE 15 Plug Back ALL DE LO 5 4 鍧 _miles in a _north ŝ 9/26/90 1 Smuth. 5. County of Well Site day. Mitchell TEP RR Cor, TWP T-N NO NO a Re-Enter 7. RRC Lease/ID No. direction from <u>Latan</u> ٧ Tel: Area Code S. Dawner from NA TRA-NA Inchesed your talavoli. (N.) Dog to neuro Read Instructions on Back 915-697-2214 Tracy D. Tenison, Engineer Name and title of operator's representative Enter here, lf assigned: letted wes Z, ۷ "Ennite h 8. Well No. 640 80 V If not filed, explain in Remarks. Number Type and or other Penny 42-33 0 9 0 Rule 37 Case No Abstract No. A. 584 21. Act, of applied for per-mitted, or complete and becattoms that during the this one on bear in the this one on bear in the this reservoir. (1) 5 Form W-1 (OUTLINE ON PLAT.) 9. Total Depth 1 85001 2355 ŝ 5 5 3

A-5



<u>*</u>		<u>इ</u>	26 17 19	25.11	22.11		- 12 M	5 17	s	Ę	() 중용) 11. Pl				λ εi	в 1.0p		Իսդ	¥ ⊒ .≇
		inai ks	you have the right to develop the minerals under y y right of way that crosses, or is configuous to, this tract? y nut, and if the well requires a Rule 37 or 38 exception, r Inviruentions for Rule 37.	his wellwre subject to Statewide Rule 36 (hydrogen aufide are	 Interpretendent of the second s	Sunn Section 1000' FNL & 2500' PEL of Su	pendicular surface location from two neatret designated lines: I.cov/Unit 1000' FNL & 2500' FEL	llenburger (Wildcat)	trawn (Wildcat)	olfcamp (Wildcat)	rpletion. Attach additional Form W-1's as needed to list ae zones. One zone per line.	ELD NAME (Exactly as shown on RBC provation achedule), all established and wildcal zones of anticipated	istance from proposed location to nearest lease or unit line			Hdlynd, Texas 79701	dress linktuding city and zip code)	iright & Company	Directional Well Sidetrack	ne of filing (mark appropriate hours): X Drill Dreprin (Lelow casing)	 Transver of Trans. Address to: Distant Ossenaria, Driffing Permits P. O. Drever 12007, Capital Station Autin, Trans 79711 Aropy of W-1 and plat to USC District Office.
			×	117 Yes 🔲	No	tet ion-t		8300'	7800'	5200'	Completion depth		1000	wh	• 1	10. Loca	Van	001 093			Rication fo
!				No X	X			467-1200	467-1200	467-1200	Specing pattern (fl.)	15,	\$ }	tch is the nearest	is well is to be loc	tion 15	Tuyle	125	mended Permit (c	pen (within casin	NILROAD CO Oll and Permit to Dr
	Date	Sign	I certify the	If subject to	24. IN Her Yea		La	40	40	40	Denalty pattern (acres)	16	12. Number	town in the c	aled5				nter permit n	Ē	indission I Gas Divisio III, Deepen
	1110	ature 9/26/	at Information st	Rule 36. Is Form	n 17 Jesa than It	urvey/Section	nase/Unit	40	40	40	OUTLINE ON PLAT.	17. Number of acres in defiling unit	of contiguous at	ounty of the wel	miles in a	29 7-1-1V		B STIRLING	o. at right & esp	Flug Back	OF TEXAS
• JURC	day y r .	06	ated in this applicati		em 16 (substandard ach Form W-1A)		שט ףנטוברוכם ססווטוח	NO	NO	NO	Inis rectivour If eo, caplein In Remarks,	18. Is the acrosp assigned to an- other well on this lease P in	tres in lesse, pooled u	Isite	north	vy T&P RR Co		Mitchell	lain fully in Remarks	ReEnter	or Re-Enter
Use Only •	Tel: Area Code	Name and till 915-697-3	ion is true and com. Tracy D.	No 0	actrate for any field		Sufficient and	NA	NA	NA	this inser @ tractvoir. (fl.)	19, Distance from proposed loca- lion to nearest applied for, permitted, or	init, or unitized trai		direction from	· · · · · · · · · · · · · · · · · · ·				Eater here, if assigned:	Read Instructi
	Number	e of o pera tor's 22 1 4	plete, to the be Tenison	If not filed.	1 applied forl?			ô	0	0	type well Spe well	OIL gan	π <u>640</u>		atan	·	1		V	► 42- Remit N	ons on Back
 		representative	st of my knowl	explain in Ren	N.			1		-	OIL	21. No. of appl mitted, or ex locations (ii) this one) on this reservoi	IOUTLINE O				8500		2	P	Form V
1				narks							GAS	ited for, per- ompleted ucluding lease in f.	IN PLAT.)			130		7			



JERRY A. DUNN

à.

TEXAS P.L.S. NO. 4735 TEXAS P.L.S. NO. 4839

MIDLAND	ЈОНИ /	WEST &	ASSOC	IAT	ES		TOAS
Scole: /"=	1000'		Drawn by:		N	G	
Dale:	10-2-90		Sheet	1	of	1	aheete
Revision Do	te:		W.O. No.:	L 9	007	63	

13(1) Exception Dated 440		RS DIV	ISION	Mo ())		ii.		W. 10/74
				NO.42-3	35-33555		R R R	et
WELL IS LOCATED WITHIN T	IRTY D	YS AFT	ER PLU	GGING	GH	4.	RRC Leest	or M.
Wildont	V.	an Tuyl	e /	-0		5.	Wall Number	1
Bright & Company	ős. Origi	and Form W-	-1 Filed in	Name of:	<u></u>	10.	County Mitchel	11
ADDRESS 2911 Turtle Creek Blvd #70 Dallas, TX 75219)() ^{6b.} Any 1	Subsequent	W-l's File	d in Name of	-	11.	Date Drill Permit Jan 10/18/9	01
Location of Well, Relative to Nearest Lease Boundaries	1000	i Zma N	orth 1	ine and 25	OD Foot P	12,	Permit Mus	and the
SECTION BLOCK AND SURVEY	east Li	ne of the	VIII I			- 11	379724	2
ec 15. Blk 29. TIN. T&P/RR Co	Coun	^{ty} 8.	7 milos		Vestbro		Co.72670	0./
i. Type Well (Oll, Gas, Dry) (Oll, Gas, Dry) 8360 [†]	at All Field :	Names and		T Ges ID No	NESCOLOC OLI-OI WE Gen-GI	LL, 14,	Dute Drilli Completed	AK DO
I Ges, Amt. of Cond. on Hend at time of Plugging					-	15,	Dete Well 12-17-	Planed 90
CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5 1	LUG #6	PLUG #7	PLUG #8
7. Cementing Date	12-17	12-17	12-17	12-17	12-27	\sum		- 2 637.0
D. Size of Hole or Pipe in which Plug Placed (inches)	7-7/8	7-7/8	7-7/8	8-5/8	8-5/8	<u> </u>		
. Depth to Bottom of Tubing or Drill Pipe (ft.)	8250	2700	2350	400	15 .	WY I	1 to	
2. Sacks of Coment Used (each plug)	50	50	180	50	10 \		1./ - y/	
I. Slurry Volume Fulpped (cli. If.)	8076	2526	1792	325	Surf			
Measured Top of Plus (if tassed) (ft.)	0070	2320	1790	525	Sull .	JAK	1.4.100	
5. Sturry Wt. #/Gel.	15.6	15.6	15.6	15.6	15.6	VIT		-
7. Type Cement	Prem.	Prem.	Prem.	Prem.	Prem.	taka.	15 75%	6
8. CASING AND TUBING RECORD AFTER PLUGGING		29, W	an Ceelor)	-Drillable M Left in This	aterial (Othe: Well		Ye.	K No
ZE WT. #/FT. PUT IN WELL(A.) LEFT IN WELL(A.) I	HOLE SIZE	(m_) 29s. If	enswer to a d briefly de	bove is "Ye scribe non-	is" state dep drillable mat	th vio top Hindu - TU	of "Junie"	left in hole Side of
3/3 48 361 361	17-1/2	- P	orm if more	space is nee	eded.)	10 101	12.8	
<u>5/6 32 22/4 22/4 22/4 </u>					1.	1. 4	1.55	(3.13)
		-	1.18.41	-5. 9	12 400	1. 200		an a
LIST ALL OPEN HOLE AND/OR PERFORATED INTE	RYALS	-	5		1	C/1.		
PROM 2274 TO 9360		FR	он	-	T	520	3/	
ROM LAND I IN THE THE TO		PR	OM 1	nsiurs to	1. b. T	0	15/	
PROM TO		FR	OM C	Leel [1]	NT.	661.00		
FROM ADD 1 7 1991 TO		TR	оні	RH.O.de	T	00		STATES
PROM		FR	OM The factor	1.1.1	ा	0		
have knowledge that the cementing operations, as reflected	by the inform	nation found	s on this for	m, were per	formed as Ind	icated by	each infor	nauon.
resignates items to be completed by Cementing Company. It	eme not so d	lesignated a	hali be com	pleted by O	perator.			
				iii tean Cann	ulaan in	4- 0-		
- MC - CACUM X/			III IOUT	LUN SEL	vices, B	TR Sb	ring, T	A
nature of Comenter or Authorized Representative		Ma	me of Cene	nting Compo	in y			
I declare under penalties prescribed in Sec. 91.143	, Texas Natu	mi Resourc	es Code, ti	hat I am auth	orland to me	ke this re	port, that t	hla
report was prepared by me or under my supervision a	und direction,	, and that d	ate and fect	is stated the	rein are true,	carrect,	and comple	te, Status
to ris nation with menalanday								
Amonda I Hand		Annat		1/1 + /				
REPRESENTATIVE OF COMPANY		TITLE		RECEDAT	<u>р</u>	hont		NUMBER
			F	R.C OF TET	45	3		
Dr. A That Teletan	.)	÷.						
GNATURE: REPRESENTATIVE OF RAILROAD COMMIS	SION	•	MA	IR 0 5 19	991 <u></u>	8, ÿ	~	
					and it.		コクノ	

истер алоб язта**н .** С

.

34. Tetal Depth 8360	Other Fresh Water TOP	Zones by T.I BOTTO	D.W.R. DM	35. Have all Abandoned Walls on this Leas according to R.R.C. Rules?	se been Plugged	X Y•1
Depth of Deepeat Fresh Water				36. If NO, Zaplain		No
37. Neme and Address Halliburton, F	of Cementing or Server. . O. Box 380;	, Snyder	who min, Texa	ad and pumped coment plugs in this welt as 79549	Date RR notified	C District Office
Ben Van Tuyl	ers of Surface Owner e, 432 Hillds	ale Dr.	and Oper Ann Ai	retors of Offert Producing Leases		
39. Was Notice Given	Before Pipeeine to Ec	sch of the Ab				
Yes				· · · · · · · · · · · · · · · · · · ·		
40. For Dry Holes, this released to a Com	Form must be accom	LY spanled by ei	ther a Dr	ilier's, Electric, Radioactivity or Acoustical	i/Sonic Log or at	ich Log must be
- 	g Attached	Lag releas	sed to _		Date	
122			. ×		Date	
The second second				20		
Type Loga:	lier's	X Elec	tric	Redicectivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (lier's Special Cleanance) Fi	X Elec	tric	Radioactivity	Aco	untical/Sonic
Type Logs: Dri 41. Date FORM P-8 (1 42. Amount of Oli prod	lier's ipecial Cleanance) FL	ied?	tric	Radioactivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (: 42. Amount of Oil prod * Flie FORM P-1 (C	ller's Special Clearance) Fi uced prior to Plugging II Production Report)	Ied?	iric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>BRC USE ONLY</u>	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	Ied?	itric	Badioactivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oli prod Pile FORM P-1 (C RCC USE ONLY Nearest Field	lier's Special Clearance) Fi uced prior to Plugging Still Production Report)	Ied?	itric	Redicectivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>BRC USE ONLY</u> Mearent Field	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Jed?	itric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Mearest Field EMARKS	lier's Special Clearance) Fi aced prior to Plugging 011 Production Report)	Ied?	itric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oil prod • File FORM P-1 (C <u>RRC USE ONLY</u> Hearest Field BMARKS	ller's Special Clearance) Fi uced prior to Plugging III Production Report)	Ied?	itric	Bediosctivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Mearest Field EMARKS	lier's Special Clearance) F1 uced prior to Plugging 011 Production Report)	Elec Ied?	iric	Bediosctivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fl uced prior to Plugging III Production Report)	Ied?	itric	Redicectivity	Aco	ustics1/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R & C USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	Elec	itric	Redioactivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>BRC USE ONLY</u> Hearest Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Ied?	itric			ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C RC USE ONLY Nearest Field BMARKS	lier's special Clearance) Fi uced prior to Plugging li Production Report	E	itric	Redioactivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C • RC USE ONLY Nearest Field EMARKS	lier's Special Clearance) FL sced prior to Plugging II Production Report)	Elec	itric	Redioactivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>RRC USE ONLY</u> Nearest Field EMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	E Elec	itric	Redioactivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi seed prior to Plugging III Production Report)	E	itric	Redicectivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1) 42. Amount of Oll prod • Flie FORM P-1 (C <u>R & C USE ONLY</u> Nearest Field BMARKS	lier's Special Clearance) Fl uced prior to Plugging II Production Report	E Elec	itric	Redicectivity		uetical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oil prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report	Elec	itric	Redioactivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>BRC USE ONLY</u> Hearent Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	E	itric	Redioactivity bbls* produced		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	E Elec	itric	Redioactivity bbis* sproduced	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field EMARKS	iler's Special Clearance) Fl uced prior to Plugging II Production Report	E Elec	itric	Redioactivity		ustical/Sonic

en e const la e const la seconda e m la seconda e m

1

.....

419

PLACE FOLS | R1

< 1

Compared and the second largest and the secon	RAILROAD COME Oll and C	2 1 3	(AS	o Wa	Form Cemienti Prv. 48	a W-10 Ing Rep 4/1/03 8-015
1. Operator's Name (As shown on Form P.5, Organiza	tion Report) 2. R	RC Operator No.	3. RRC District No.	4. County	of Well Site	1.04744
Bright & Co.		093125	8	Mitch	el1 👘	10 30
5. Field Name (Wildcat or exactly as shown on RRC re	rords)		5. API No.	7.	Drilling Permit	Na.
Wildcat			42- 335-33	555	379724	1 - 1
8. Lease Name	9.1	Rule 37 Case No.	10. Oil Lease/Gas	ID No. 11,	Well No.	10-14
Van Tuyle	1				1	1220

CASE	IG CEMENTING DATA:	SURFACE CASING	INTER MEDIATE	PRODU	CTION	MULTI- CEMENTIN	STAGE
			CASING	Single String	Multiple Parallel Strings	Tool	- 19 Mar 19
12.0	Brugen bit for 10550						
13. •	Drilled hole size	17-1/2	11		192 1	an C _{all} _{an} X	
36	Est, % wash or hole enlargement						
14. 5	ter of casing (in. O.D.)	13-3/8	8-5/8	alike datus	5 - 2°	n lign ^{an}	
15. T	op of liner (fr.)	a			2		
16. S	etting depth (ft.)	361	2274	3			
17 N	umber of centralizers used	3	3				
18 H	its, waiting on cement before drill out	12	12				
Â	19. API cement used: No. of socks	390	300-			170 - 1641 - 1816	1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.
4 81	Class	Premium P	111	27 AP reul	aff , M.C.S.	WHE Standt	-13 Truch-
a <	Additives	27 Calciu	m Chloride	i dina			101.65
Ŷ	No. of sacks 🕨 🕨						
d Sh	Class 🕨	inener Ken	themes defined	intol at an:	inurtant		
18	Additives	ين ورجاد حققوني فرواني	and to be seen for	A marte data and inco	A PARTY A MARTINE	D. OF TEXAS	
È	No. of sacita	of the advances prope	ter des medications	cristellis wilds	the state of the s	. if fabgeties in	- South RE Suffrage
d Slu	Class	ar island et al.	all and show	aradina or yunar Aradina ortuguna	a in later owner, ne ge a tracht genter - Na		n in 124 - Dùn 127 Institu Print - Barned Dunret
ñ	Additives 🕨	 Track of State Str Track of Strategy and 	n en talan dalam yang kang sang kang sang sang sang sang sang sang sang s		Leff Biro't Husp area a an	CG	a da compañía com e
ti	20., Slurry pumped: Volume (cu. ft.) 🌗		591	intres investion	IA CONTRACTOR		State Water I a
	Height (ft.) 🕨 🕨	Surface	2268	1 B 1 327 2079 (s temp tigdes ansätt va en en en en en	P. Weitzers and and	W 15, in oks
¥	an an an the Volume (cu. ft.) 🍉	- Section of Suppl	- 194 Berlin (1944)	s rians - Frank an	i dina aratisa hire	an a	 Subarrolluni)
64 I	ileight (fs.)	A SAME SALANA A A	 anaparities contractor designed in Lindé (c) 	, Hondrachagasa CHarc sasara	េ មេរ៉ានីវារូក ភូមិ កើនដែរប្រាំការ ភ	unter ünterstandt i Unter unstandere	: Bast residentions parts in the other line
z	Volume (cu. ft.) 🕨	1 N X.		a fé li selt an et ES.	n abh ann an Thur Chu	e fitter halter («»	and al say within
•		me ante ave		tiere is on these e	institues land	enet belever statte sin	i incaratora fasis religi
1	Volume (cu, ft.) D.	514.1	591	- Hannahan and an early a	o Ladistra Miran	1	
B	an and all each off in the Height (if Lifes in the second se	Surface	110000 000 01 4000	nthyanthijh Lalk	in the provide states of the s	ert valie de trat	
21. Y	Ves cement circulated to ground surface or bottom of cellar) outside casing?	Toras Yes	n inte Ro	1. Startinger Start	2. Stallier feit		Contraction of the second
22. F	iemarika	41. 3311		RECEIVED R.R.C. OF TEX	(ΛS	The second second	and the part of the
		1. U.S.	na Angelan ing	MAR 05 1	991		n - Suzidaje Suzidaje Suzidaje

and the second second second

:

OIL & GAS DIV MIDLAND TEXAS

OVER

	FLUG # 1	PLUG * 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	- PLUD *
and the second second	. E	ZET RO V	nesciento:	GERRAL W	76) 76)		00000000	e
State of hale or pipe plugged (in.)								
Dapth to bottom of tubing or drill pipe (ft.)								
	and and	0			Net and the second	Harris a		$\tau(A_{I,2},\gamma_{A_{i}})$
	RALLAU IN	1. it we	the second		•••••	18-18-19-18-19-19-19-19-19-19-19-19-19-19-19-19-19-		
	1.	42		ي. ديورت م وريسيده				16:27
Memoured top of plug, if tagged (ft.)								
	- 30-590 GF24	1993 () () 19	11.2 21/12	1 1 12 N 1 0	stiller Geru		100.000	ज्या व
STATES IN STATES	i Didine i	Static Static		14.4-22			242	
A CONTRACTOR OF THE OWNER		N. Honore Comp.			and the state			They are
1/10 · · · · · · · · · · · · · · · · · · ·							by the or weak	
			- internet in the		يب			1 17 5
	Section of				1.	11.00	117 - er itma	1 - 177 - 5
				9	Liles,	11.90		a let segle
			A 2.5	<u>, </u>		1 De	۱۱۱۰۰ ^{(۵} ۰۰ ۲۱۱) ۱۹۰۰ (۱۹۰۰)	1 17 S
	Sardor-				1123 713-31716	1.00	1-26-90	ente se la Gastinata Secolaria
OPERATOR'S CERTIFICATE I declary	Eurofer -	prescribed in	A (-25) Sec. 91,143. Tr	San Najural Re	573-3526 sources Code, (D that I am author	1-26-90 2 dis dif	wie w _e le wie w _e le mid in aa wontere this
OPERATOR'S CERTIFICATE: 1 declary certification, that I have knowledge of the true, correct, and complete, to the best	E under penaltien ne well data and in of my knowledg	prescribed in formation pre- e. This certifie	Sec. 91.143. To control in this rep tition covers all v	915 915 Tel: Amo and that da reli data.	573-3576 Construction of the second s	that I am authorsented on both	1-26-90 Lais dra rized to make idea of this form	a la segle (4.5 - 1.5 (4.5 - 1.5 (4.5 - 1.5 (4.5) (4.5) (4.5) (4.5) (5) (4.5) (5) (4.5) (5) (5) (5) (5) (5) (5) (5) (5) (5) (

Instructions to Form W-15, Cementing Report

State. Zip Code

Tel.: Area Code Number

Date

mo.

day

yr.

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

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

 An initial oil or gas completion report. Form W-2 or G-1, as required by Statewide or special field rules;

• Form W-4. Application for Multiple Completion. If the well is a multiple parallel casing completion; and

Clbr.

 Form W-3, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting dry holes, operators must complete Form W-15, in addition to Form W-3, to show any casing cemented in the hole.

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

のないないではないではないためにていたのですのができ

Address

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

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

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

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

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

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

Please to File No.

11.4.

RAILROAD COMMISSION OF TEXAS OIL AND GAS DIVISION

APPLICATION TO PLUG AND WELL RECORD FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

M.K.C. Malando

Name of Com	any or Oper	stor	he Texas	Compar	ι <u>γ</u>	Address Dor 1720	Fort Worth,
County	loward		SurveyT&	P,RRGo.		29 T-1-1 Sec.	1 exas
Name of Leas	<u>. A. L.</u>	Wasso	n	No. of Acres	1760 W	Il No. 1	2300 (DF)
Located Appr	ox.21	NE	Direction	from.Bi	g Spring,	Texas (Nea	rest P. O. or Town)
Name of Field	in which we	ll is locate	a Wild	cat	*******	99 19- 4 - 4 - 4 - 4 - 4 - 4 - 4 - 4 - 4 - 4	
Form 1, "Noti	e of Intentio	n to Drill,'	" was filed in 1	name of	The Texas	Company	
Drilling Comm	enced 12	-28	****	19. <u>52</u> , D	cilling Completed	3-28	19 52
Has this well	ever produce	a olt No.		******		or Gast	
baracter of	Well (Oil, Ge	s or Dry)	Dry			Total Depth	86701
)ate you wisł	to Plag	3-2	7		19 52	88 - C. P. J. K.	
lame of Party	Plugging W	en Liv	ermore D	rilling	Address 6	10 Lubbock Nat	1 Eank
orrespondence	regarding i	ihis well a	hould be sent	to: Name	The Texa	S Company	dations and an anno 1999. Airtí
lddress Box	1720, 1	Fort W	orth, Te		RECORD	-/	
SIZE	PUT IN	WELL	PULL	ED OUT	1. · / Laure de 1		A ann amoles
3 3/81	196	In.	None	, _† In.	196	In. Texas Pa	ttera
5/81	2115		100		201	Hallibur	ton - & S
198 - 1992 M	13371 S. 16		and a state of the second		and the second sec		

ASING WAS CEMENTED GIVE NUMBER OF SACKS USED ON DIFFERENT STRINGS a ser a ser a ser a ser a Sec.

Initial Production	of Oil: Barreis None	WORE 24 nrs. Pressur	None Fill	DLAND, TEXAS
Give notice perore When Plugging co the Deputy Superv	Plugging to all available L suppleted, file final Plugging isor of district in which we	sease Owners, as required by R r Report, duly signed, and swe il is located.	ula (10) ril. to. All more in C	R 10.1952 will be furnished to Commission of Texas
NOTE: If no ing ava formation, water south	india, in state and give all info- , and to may as penably data ve	motion that eac he obtained to us to	tal depth, gades a beneryot	OVE DIVIZION .
General Remarks: oil or gas.	This well dril. We therefore	desire to abandon	selvage and plu	g well in the
fcllowing.	manner: (Cut 9 5	/8" casing at 100	and pull same)	and He (Over)
		AND AND AND AVIDAVIT OF		1

ź

- - - A.E.

12

24

Galiche 0 100 At depth 206' emented 13 3/6" Red Reds 100 206 casing at 206' with 250 sacks. Shale & Anhy 206 9.5 Gament circulsted. Anhy & Shele 1254 1409 At depth 2125' camented 9.5/8" Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Shale 1255 2280 Lime & Shale 2220 2322 Lime & Shale 2280 2322 Lime & Shale 2322 t 3116 Lime & Shale 3103 3820 3979 Lime & Chert 3612 3820 Lime & Shale 5232 6203 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670		TOP	BOTTOM	
Band Reds 100 200 cost of the second sec	Caliche		100	At doubh 2061 computed 12 2 day
Shale # Anhy 206 0.45 Comment circulfied. Anhy 94.5 1254 Anent circulfied. Anhy & Shale 1251 1409 At depth 2125' camented 9.5/8". Anhy & Shale 1250 1437 at 2125' with 600 sacks. Anhy & Shale 1750 1437 at 2125' with 600 sacks. Anhy & Shale 1750 1437 1457 Anhy & Shale 1955 116 116 Anhy & Shale 1252 2200 116 Lime 2125 2200 116 Lime & Shale 3116 3612 320 Lime & Shale 3200 5114 116 Lime & Chert 3612 3232 116 Lime & Chert 514 5232 6203 Lime & Chert 7953 8670 107 Total Depth 8670 155 sacks 2025'-4975'-715'-715' St	Red Beda	100	206	At depth 200' demented 13 3/8"
Anhy 945 1254 Address Anhy & Shele 1254 1499 At depth 2125' camented 9.5/8" depth 2125' depth 215' camented 9.5/8" depth 215' depth 215	Shale & Anhy	206	0/5	Carsing AL 200 With 250 Sacks.
Auhy & Shale 1254 1409 At depth 2125' camented 9 5/8", Anby & Salt Anby & Salt 1750 1877 Anhy & Lime 1955 2125 Jime 2125 2290 Lime Shale 2290 Lime & Shale 3116 3612 Lime & Chert 3612 3820 Lime & Sand 4155 4538 Lime & Chert 4536 4000 Lime & Chert 5114 5232 Lime & Shale 5222 6203 Shale 514 5232 Lime & Chert 7953 8670 Total Depth 8570 15 All Measurements from Notory Table or 12' above ground. 28 Remarks Cont'd 870 15 Stacks 5400'-550': 15 sacks 7860'-7810': 15 sacks 1125'-1 15 15 sacks 200'-2075': 15 sacks 625'-4975': 15 sack 620'-580': 15 sacks 1125'-1 16 sacks 875'-825':	Anhy	94.5	1254	
Anhy & Salt. 1/90 1750 at 2125' with 600 ancks. Anhy & Lime 1750 1837 055. Anhy & Lime 1955 2125 1837 Lime 1955 2125 1837 Lime 1252 2290 Lime 2125 2290 Lime & Shale 2290 2322 Lime & Shale 2322: 3116 Lime & Shale 2322: 3116 Lime & Shale 3612 3820 Lime & Chert 3079 Lime & Chert 3070 4155 Lime & Chert 3079 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 753 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd .	Auby & Shele	1254	1400-	At depth 21251 comented 0 5/RH
Anhy 1837 1837 Anhy & Lime 1955 125 Lime 2125 2290 Lime & Shale 2125 2290 Lime & Shale 2322 3116 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3079 4155 Lime & Sand 3820 3979 Lime & Sand 4155 4538 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 8670 State 6203 7953 Lime & Cont'd 8670 15 Sacks 500-5171 15 sacks 5600'-7810': 15 sacks 7260': 15 sacks 1025'-975': 15 sacks 500': 15 sacks 10'-2760': 15 sacks 2093-2043: 20 sacks 1125'-1 Los sacks 102'-2760': 15 sacks 2093-2043: 20 sacks 1125'-1	Anhy & Selt.	1499	1750	at 2125! with 600 spoks
Anhy - 1837 1955 Nime 1955 2125 2290 Lime & Shale 2290 2322 116 Lime & Shale 2290 2322 116 Lime & Shale 3116 3612 3820 Lime & Sand 3820 3979 155 Lime & Sand 4155 4538 1455 Lime & Sand 4155 4538 146 Lime & Chert 5114 5232 6203 Lime & Chert 5114 5232 6203 Shale 6201 7953 6670 Total Depth 8670 8670 Notal Depth 8670 15 Actal Depth 8670 15 Scott d 8670 15 8670 Total Depth 8670 15 8670 15 Actal Depth 15 8670 15 8680'-7810'; 15 15 8682'-795'; 15 867'-7810'; 15 868' 10''''''''''''''''''''''''''''''''''''	Anhy & Shale	1750	1837	
Anhy & Lime 1955 2125 Lime 2125 2290 Lime & Shale 2220 2322 Lime & Shale 2322 3116 Lime & Shale 3612 3820 Lime & Shale 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3620 3979 Lime & Sand 4535 4538 Lime & Chert 4538 4900 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 8670 Take Heavy mud between plugs. spot the following cement plugs. 95 sack 8670'-7810': 15 sacks 7705'-7 15 macks 5000'-5550': 15 sacks 5430-5380': 15 sacks 7860'-7810': 15 sacks 7705'-7 15 macks 5002'-550': 15 sacks 5430-25380': 15 sacks 2025'-4975': 15 sacks 660'-4630': 15 sacks 8210'-2760': 15 sacks 270': 15 sacks 7705'-7 15 macks 5002'-550': 15 sacks 5730-2380': 15 sacks 2025'-4975': 15 sacks 957 # 1. Phr. failed	Anhy	1837	1955 .	
Hime 2125 2290 Lime & Shale 2122: 3116 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3979 Liss Lime & Chert 3979 Liss Lime & Sand 4515 4538 Lime & Chert 4538 4000 Lime & Chert 5314 522 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 15 Sacks Cont'd 8670 15 Lime & Cont'd 8670 15 Sacks Cont'd 8670 15 Lime & Sold: 500'-550': 15 sacks 7800'-7810': 15 sacks 7705'-7 Lime & Sold: 500'-550': 15 sacks 760'-7810': 15 sacks 7705'-7 Lime & Sold: 500'-550': 15 sacks 2093-2043: £0 sacks 1125'-1 40 Lime & Sold: 500'-550': 15 sacks 1025'-1475'.5 5 5 <td>Anhy & Lime</td> <td>1955</td> <td>2125</td> <td></td>	Anhy & Lime	1955	2125	
Inter & Shale 2290 2322 Linee Shale 3116 Linee & Shale 3116 3612 Linee & Chert 3612 3820 Linee & Sand 4155 4538 Linee & Chert 3979 4155 Linee & Chert 438 4000 Linee & Chert 4538 4500 Linee & Chert 5314 Linee & Chert Linee & Chert 5314 Linee & Chert Linee & Chert 7953 8670 Total Depth 8670 12' All Measurements from Notory Table or 12' above ground. 8670 State Scottid 8670 12' All Measurements from Notory Table or 12' above ground. 8670'-7810': 15 sacks 7705'- 7 State Scottid 15 sacks 5430-5380': 15 sacks 502'-7810': 15 sacks 7705'- 7 Lines & Chert 1630'-2760': 15 sacks 202'-2043': 10 sacks 1125'-1 Lo sacks.1025'-975': 40 sacks 675'-825': 30 sacks in top casing. 12' Lo sacks.1025'-975': 40 sacks 675'-825': 30 sacks in top casing. 12' Drill Stem Tests 12' 12' DST # 1: Pkr. failed 12' 12'	Lime	2125	2290	00.0 · · · · · · · · · · · · · · · · · ·
Lime 2122 1110 Lime & Shale 3116 3612 Lime & Chert 3612 3820 Lime & Sand 3820 3979 Lime & Chert 3612 3820 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4538 4900 Lime & Sand 5232 6203 Shale 5232 6203 Shale 6203 7953 Lime & Ghert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground, Remarks Cont'd 15 sacks 8215-8163, 15 sacks 7860°-7810'; 15 sacks 7705'-7 15 macks 5600'-550'; 15 sacks 5430-5380'; 15 sacks 500'; 15 sacks 7705'-7 15 macks 5600'-550'; 15 sacks 5430-5380'; 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks, 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. DST # 1: Pkr. failed DST # 2: 4805-4200. Tool open 2 hrs. Recovered 2250' salt water and 225 satt water tout with drig, mud. DST # 3: 5100, 5216. Tool open 1 1/2 hrs	Lime & Shale	2290	2322	
Jillo Jol2 Lime & Chert 3612 Jime & Sand 3820 Jame & Sand 3820 Jime & Chert 3079 Lime & Sand 4155 Lime & Sand 4155 Lime & Sand 4538 Lime & Chert 4538 Lime & Chert 4538 Lime & Chert 5114 Jime & Shale 5232 Lime & Shale 5232 Jime & Ghert 7953 Jime & Ghert 7953 Jime & Ghert 7953 Shale 6203 Total Depth 8670 Total Depth 8670 State Heavy mud Datween plugs, spot the following cement plugs, 95 sack 8670-8373':15 sacks 5163. 15 sacks 7860'-7810': 15 sacks 7705'- 7 Jacks 500'-5550':15 sacks 5430-5380': 15 sacks 2093-2043: 40 sacks 1125'-1 460'-4630':15 sacks 810'-2750': 15 sacks 75'-825': 30 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 75'-825': 30 sacks 1125'-1 40 sacks. <t< td=""><td>Idme & Shale</td><td>2322 1</td><td>3116</td><td>· · · · · · · · · · · · · · · · · · ·</td></t<>	Idme & Shale	2322 1	3116	· · · · · · · · · · · · · · · · · · ·
Lime & Sand 3820 3979 Lime & Chert 3979 4155 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Shale 5222 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 Total Depth 8670 School & Chert 7953 School & Sch	Line & Chent	2612	1 1012	
Lime & Chert 3070 1155 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4453 4900 Lime & Sand 44900 5114 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Ghert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 660'-7810': 15 sacks 7705'-7 15 marks 560'-5550': 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 5125'-7 4680'-4630': 15 sacks 2810'-2760': 15 sacks 2033-2043; 10 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests	Lime & Sand	2620	1 2020	•
Lime & Sand 4155 4538 Lime & Chert 4538 4900 Lime & Chert 4538 4900 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 8670 Stale 8210 12' above ground. Remarks Cont'd 12' above ground. Remarks Cont'd 12' above ground. Remarks 5600'-5500': 15 sacks 5215-8163 15 sacks 7705'-7 15 macks 5600'-5500': 15 sacks 5215-8163 15 sacks 7705'-7 15 macks 5600'-5500': 15 sacks 5215-8163 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks 1025'-975': 40 sacks 875'-825': 30 sacks 1n top. casing. Drill Stam Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 4805-4900, Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 2: 5405-5500 Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 2: 5405-5500 Tool open 1 hr. Recovered 100' drig. mud. DST # 2: 5405-5500 Tool open 1 hr. Recovered 20' drig. mud. DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 4: 740 Tool open 1 hr. Recovered 5' drig. mud & 180' slightly drig	Line & Chert	3070	1.155	Past in Party
Lime & Chert 438 400 Lime & Sand 4900 5114 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd 15 8000 5100': 15 8000 700': 10 8000 800': 1000 800': 1000 700': 1000 700': 1000 700': 1000 700': 1000 700': 1000	Lame & Sand	1155	1.538	
Lime & Sand 4000 5114 Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Shart 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 7 Fathe Heavy mud batween plugs, spot the following cement plugs, 95 sack 8670 - 7810'; 15 sacks 7705'-7 Lime & Solo - 5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 7705'-7 Lime & Solo - 5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 125'-1 Lo sacks 500'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 125'-1 Lo sacks 1025'-975'; 10 sacks 875'-825'; 30 sacks in top casing. Drill Stam Tests Drill Stam Tests DST # 1: Pkr. failed DST # 2: 1405-4900, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 2: 5100-5216, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 5' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 5' drlg, mud. DST # 7: 723 brain the total state of the	Line & Chert	1.538	1,000	•
Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 12 above ground. Remarks Cont'd 15 acks 510 relation of the following cement plugs, 95 sack 5670 relation of the following cement of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 relation of the following cement plugs, 95 relation of the following cement plugs, 95 relation of the following cement p	Lime & Sand	4900	5114	
Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Bains Heavy mud batween plugs, spot the following cement plugs, 95 sack 8670-8373 115 sacks 8215-8163, 15 sacks 7860'-7810': 15 sacks 7705'- 7 15 macks 5600'-5550': 15 sacks 5430-5380': 15 sacks 2025'-4975': 15 sack 6680'-4630': 15 sacks 2810'-2760': 15 sacks 2093-2043: 20 sacks 1125'-1 40 sacks 1025'-975': 40 sacks 875'-825': 30 sacks 1n top casing. Drill Stem Tests Drill Stem Tests Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 mail water cut with drig. mud. DST # 3: 5100-5210, Tool open 1 hr. Recovered 300' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mode DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud & 180' eli DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud & 180' eli DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud & 180' eli DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud & 180' eli DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud & 180' eli DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud & 180' eli DST # 7: 783 mode	Line & Chert	5114	5232	
Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Taths Heavy mud batween plugs. spot the following cement plugs. 95 sacks 8670-8373':15 sacks 2215-8163. 15 sacks 7860'-7810': 15 sacks 7705'-7 15 macks 5600'-5550': 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 600'-6810': 15 sacks 2093-2043: 40 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 1 1/2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 5400-5485. Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 5400-5485. Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 5: 5002.5600 Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 7: 723 Tool open 1 1/2 hrs. Recovered 20' drig. Mud & 120 DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' dr	Lime & Shale	5232	6203	o alteration and the second state and the second
Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. All Measurements from Notory Table or 12' above ground. Remarks Cont'd 6670 Saing Heavy mud butween plugs, spot the following cement plugs, 95 sack 8670 - 3731:15 sacks 2215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7 15 macks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 4680'-4630': 15 sacks 2810'-2760'; 15 sacks 2093-2043; 20 sacks 1125'-1 40 sacks 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 4805-4900, Tool open 1 1/2 hrs. Recovered 300' drig, mud. DST # 5: 5002.5000, Tool open 1 1/2 hrs. Recovered 300' drig. mud. DST # 5: 5002.5000, Tool open 1 hr. Recovered 75' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 100' drig. mud. 1700-115 DST # 4: 700 means 1 hr. Recovered 100' drig. mud. 1700-115 DST # 4: 700 means 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. None	Shale	6203	7953	olari mayadar. Alakimin histori yeni mis yenisaran
Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Baths Heavy mud batteen plugs. spot the following cement plugs. 95 sacks 8670'-8373':15 sacks 8215-8163. 15 sacks 7705'-7 15 macks 560'-5550':15 sacks 5430-5380':15 sacks 5025'-4975':15 sack 660'-4630':15 sacks 2215-8163. 15 sacks 2093-2043: 40 sacks 125'-7 15 macks 560'-5550':15 sacks 5430-5380':15 sacks 5025'-4975':15 sack 660'-4630':15 sacks 2810'-2760':15 sacks 2093-2043: 40 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests Dst # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 3: 5100-5218; Tool open 1 1/2 hrs. Recovered 300' drig, mud. DST # 4: 740-5145; Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 7500-5210. Tool open 1 hr. Recovered 100' drig. mud. DST # 4: 760 field open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760 field open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760 field open 1 hr. Recovered 20' drig. mud. DST # 4: 760 field open 1 hr. Recovered 5' drig. mud & 180' slightly field of height field open 1 hr. Recovered 5' drig. mud & 180' slight field open 1 hr. Recovered 5' drig. mud & 180' sli	Lime & Chert	7953	8670	al a development and sector and a la
All Measurements from hotory Table or 12' above ground. Remarks Cont'd Hathg Heavy mud between plugs, spot the following cement plugs, 95 sack 8670'-8373':15 sacks 8215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7 15 macks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sac 6680'-4630':15 sacks 2810'-2760'; 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5216 Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 760 fool open 1 hr. Recovered 75' sliphtly gas cut drlg. DST # 4: 760 fool open 1 hr. Recovered 70' drlg. Mud & 120 DST # 4: 760 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 5' drlg. mud. DST # 4: 750 fool open 1 hr. Recovered 5' drlg. Mud & 180' ell sud ebod of samin of task 26 and of task 1 hour fool open 1 hr. None	Total Depth	a static static states a	8670	The second seco second second sec
AU sacks, 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 selt water cut with drlg. mud. DST # 3: 5100-5210. Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 4: 5400-5210. Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7400-7470. Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 7400-7470. Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 7400-7470. Tool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 7400-7470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 743. Model of a setting of rate Constant of the set of	I E marke FGOOL FEFO	Plant P. Plant and all	ELOO FO	1000 -1010 ; 1) Backs //0/ - /
Deill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5218. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5440-5485 Tool open 1 hr. Recovered 75' slightly gas cut drly. DST # 4: 780 1000 Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 780 1000 Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 1000 1000 1000 1000 1000 1000 1000 10	15-macks 5600'-5550	1:-15 sack ks 2810'-2	s 5430-53 760': 15	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-10
DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5216, Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5440=5485; Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7805-7870; Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7805-7870; Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 5' drlg. mud & 180' sli show of shapping of relevant Cased of 1 drlg. Mud & 180' sli per cent None	15-macks 56001-5550 46801-46301:15 sec 40 macks 10251-975	1;-15 sack ks 2810'-2 1; 40 sack	8 5430-53 760': 15 8 875'-82	80'; 15 sacks 5025'-4975'; 15 sac aacks 2093-2043; 40 sacks 1125'-1 5'; 30 sacks in top. casing.
DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5210. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5400-5445. Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7800-6470. Tool open 1 hr. Recovered 100' drlg. mud. 1000-010 DST # 4: 7800-6470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 7800-6470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 5' drlg. mud & 180' sli show of shepting of right of the completely shut off: IeB mount of water th oil NODE (put provide the completely shut off: IeB	15-macks 5600'-5550 4680'-4630': 15 sec 40 sacks. 1025'-975	11:-15 sack ks 2810'-2 1: 40 sack	s 5430-53 760': 15 s 875'-82	80': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing.
DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 selt water cut with drlg. mud. DST # 3: 5100-5218, Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 4: 5100-5218; Tool open 1 hr. Recovered 75' slightly gas cut drlg DST # 4: 7800-6000, Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 180' slip DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 180' slip	15-macks 5600'-5550 4680'-4630': 15 sec 40 sacks. 1025'-975 Drill-Stem Tests	1;-15 sack ks 2810'-2 ; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-1 5'; 30 sacks in top casing.
aslt water cut with drlg. mud. DST # 3: 5100-5216. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 1: 5400-5485 Tool open 1 hr. Recovered 75' slightly gas cut drly. DST # 1: 5002-6000 Tool open 1 hr. Recovered 100' drlg. mud. 1200- DST # 1: 7800-7420 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud. 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip mount of water with oil 010 010 / 100 / 1	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill Stem Tests	11;-15 sack ks 2810'-2 1; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 10 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 3. 5100-5216, "Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 54:0-5485; Tool open 1 hr. Recovered 75' slightly gas cut drlg DST # 4. 780 model Tool open 1 1/2 hrs. Recovered 100' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. Sole open 1 hrs. Recovered 5' drlg. Sole open 1 hrs. Sole op	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900	1; -15 sack ks 2810'-2 1; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-10 5'; 30 sacks in top casing.
DST # 4. 780 model open 1 hr. Recovered 75' slightly gas cut drlg DST # 4. 780 model open 1 hr. Recovered 100' drlg. mud. 1000 model 1 hr. Recovered 20' drlg. Mud & 120 DST # 4. 780 model open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 781 Model of the state of the st	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900,	1; 15 sack ks 2810'-2 i; 40 sack i tool open selt wate	s 5430-53 760': 15 s 875'-82 2 hrs. 3	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 20 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 4. 780 creation in the second state of t	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900,	tis 15 sack ks 2810'-2 is 40 sack is 40 sack is 40 sack is 40 sack is 40 sack	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 20 sacks 1125'-10 5'; 30 sacks in top casing.
DST # 4. 780 model DST # 7. 763 model DST #	15 macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 4: 5440=5485	d Tool open Tool open Tool open	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re	so': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-16 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg, mud. covered 75' slightly gas cut drlg.
abod of shepting of rates of the second of t	15-macks 5600*-5550 4680*-4630*: 15 sec 40 macks. 1025*-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3-5100-5216 DST # 3-5100-5216 DST # 3-5100-5216	d Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud.
allod of abetting of water a Case(of the apert and a water completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3-5100-5218 DST # 3-5100-5218 DST # 3-5002-6000	tis 15 sack ks 2810'-2 is 40 sack d Tool open selt wate Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. R r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	s. Recovered 300' drlg, mud. covered 100' drlg, mud.
athod of sheeting of water - Cased D it water completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 4- 780 magai	Colopen Tool open Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re	s. Recovered 20' drlg. Mud & 120'
athod of sherting a vater Cased Of the per completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3- 5100-5218, DST # 4- 7800-5485 IST # 4- 7800-64701	ticel open Tool open Tool open Tool open Tool open	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 1/2 hr gas cut d	s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120'
mount of water with oil	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5218, DST # 4: 7805-4900 DST # 4: 7805-4900	i - 15 sack ks 2810'-2 i 40 sack d Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	ecovered 2250' salt water and 2250' h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120'
mount of water with oll	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 3: 5100-5216, DST # 4: 7805-6000, DST # 4: 7805	i - 15 sack ks 2810'-2 i 40 sack i 40 sach i 4	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 c cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	so': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. 100 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' sl1
	15-macks 5600'-5550 6680'-6630': 15 sec 60 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3: 5100-5216 DST # 3: 5100-5216 DST # 4: 7805-6000 DST # 4: 7805-6000	i 15 sack ks 2810'-2 i 40 sack i 40	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 c cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	sovered 2250' salt water and 2250' h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud.
	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST #	i - 15 sack ks 2810'-2 i 40 sack i tool open fool open fool open fool open fool open fool open fool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 225 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg covered 100' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip ater completely shut off? Yes
	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 3- 5002-5000 DST # 3- 50000 DST # 3- 5000 DST # 3- 50000 DST # 3- 50000 DST # 3- 50000 DST #	Li-15 sack ks 2810'-2 Li-40 sack i Tool open selt wate Tool open fool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud. 180' slip ater completely shut off: Ies cent None
SUEDEN SIL	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 3- 5100-5218 DST # 4- 780 0000 DST # 4- 780 00000 DST # 4- 780 000000 DST # 4- 780 0000000000000000000000000000000000	tol open fool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1799-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip the sad matter berson and that the same bre true ts and matter berson and that the same bre true
Fouriet SILEDEU	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5218, DST # 3: 5100-5218, DST # 4: 780 55485 AST # 7: 780 55485 AS	ticol open Tool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drly. covered 100' drlg. mud. 1. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip ater completely shut off? Ies cent None
A contract A cont	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 3: 5100	d flool open selt wate flool open flool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 20 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg, mud. covered 100' drlg. mud. covered 100' drlg. mud. 1000 covered 100' drlg. mud. 1000 rlg. mud. s. Recovered 20' drlg. Mud & 1200 rlg. mud. Recovered 5' drlg. mud & 180' sl1; ater completely shut off: Ies cent None the and matter bersen and that the set for tra- sector of Company. 0 1052
ALEOIN Marchell and swere to before me this day of Appell Marchell and swere to be for the swere	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks. 1025'-975 Drill Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900. DST # 3- 5100-5216. DST # 3- 510	d Tool open Tool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 10 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 225 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1000 s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 5' drlg. mud. 180' sli ater completely shut off: Yes cent None ts and matter bermany of that the content of the trans- ter completely shut off: Yes cent None

A. L. Wasson, Wildcat, Howard County

DST # 8: 8418-8468, Tool open 1 hr. Recovered 100' drlg. mud.

- DST # 9: 8455-8543, Tool open 2 hrs. Recovered 390' slightly gas cut & sulphur cut drlg. mud.
- DST # 10:8546-8670, Tool open 1 1/2 hrs. Recovered 7230' sulphur water.

RECEIVED MIDLAND, TEXAL

APR 101952

Railroad Commission of Texas OIL'84 GAS DIVISION

File No	ALLEUAD COMMISSION OF TEXAS	Form 4
8	OIL AND GAS DIVISION	1.4 million in the core
FILE IN DUPLICATE	WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH	WELL IS LOCATED
Company The Texas Comp	Address Box 1720 .	Ft. Worth, Texas
Sec. No. 4. Block No. 2	29 T-I-N Survey. T & P RRCO County	Howard
Well No	. A. L. Wasson	No. of Acres 1760
Name of Field in which well is loc	ated Wildcat	
Form 1 (Notice of Intention to Drill	i) Was Filed in Name of	ompany
Character of Well at the time of co	ompletion: Oil	Cu. ft.; Dry
Amount well producing when plug	red: Oil None Dia; Gas None Ca r	L; Water NODS
Has this well over produced oil or	gas?No	
Fotal Depth 8670	eet. Top of each producing sand	
Was the well filled with mud-laden	fluid, according to regulations of the Railroad Commission?	Yes
How was mud applied? Thr	u drill pipe	a an 'n staar 'n staar d
Were plags used? Yes wage used, and depths placed, Also Spotted, the Solicita	If so, show all shoulders left for casing, depth of each, and principal of cement and rock. Was well shot? NO	tise of casing, size and kind of
Were plags used? Yes bage used, and depths placed. Also Spotted the followin 7860-7810 45 ax 770 15 sr 2810-2760 15 Spot 40 sr 1125-1070 Tare all abandened wells of this fanser of confining all oil, may or v 2 5/8" casing left in Dr cassed of with cen	If so, show all shoulders laft for casing, depth of each, and production of comment and rock. Was well shot? NO gr plugs: 95 sx 8670-8373, 15 sx 821 5-7655, 15 sx 5600-5550, 15 sx 5430 increase of the strategy of the state of	ine of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100' and pulled ax in top of casi Yes in hole & 2015: sing left in hole
Were pings used? Yes Many used, and depths placed. Also Spotted the followin 7860-7810, 15 sx 770 15 sx 2810-2760, 15 spot 40 sy 1125-1070 Iave all abandoned wells of this 1 Canser of comfining all oil, yas or w 9 5/8" casing left in or caused of with cent be manage of edjecent base, royalt	If so, show all shoulders laft for casing, depth of each, and presented coment and rock. Was well shot? No B plugs: 95 SX 8670-8373, 15 SX 821 5-7655, 15 SX 5600-5550, 15 SX 5430 memory of the strategy of t	nise of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax A680-A630 @ 100' and puller sx in top of casi Yes in hole & 2015' sing left in hole silere:
Were pings used? Yes bigs used, and depths placed. Also Spotted the followin 7860-7810. 15 ax 770 15 sx 2810-2760. 15 spot 40 sr 1125-1070 lare all abandoned wells of this 1 Canser of confining all oil, yes or v 2.5/8% casing left in or cassed of with cent be manues of edjecent lesse, royalt 11 adjacent property	If so, show all shoulders laft for casing, depth of each, and provintion comment and rock. Was well shot? NO B plugs: 95 SX 8670-8373, 15 SX 821 5-7655, 15 SX 5600-5550, 15 SX 5430 INTERPRETATION FOR STATE STATE SX 2093-2043, Cut off 9 5/8" casing -40° six 1025-975, 40 SX 875-825, 30 lease been plugged according to Commissions rules? Moder to strate: All 13 3/8" casing left n hole. All strata protected by ca ment. ty and landowners with their addresses in each instance as for y leased by The Taxas Company	ise of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100" and puller sx in top of casi Yes in hole & 2015" sing left in hole sllows:
Were pings used? Yes bigs used, and depths placed, Also Spotted the followin 7860-7810, 45 ax 770 Spot 40 sp 1125-1070 fave all abandoned wells on this fanner of confining all oil, pas or v 9.5/8" casing left in or cassed of with cent be memors of adjacent lease, royalt 11 adjacent property	If so, show all shoulders laft for casing, depth of each, and provint of coment and rock. Was well shot? NO B plugs: 95 SX 8670-8373, 15 SX 821 5-7655, 15 SX 5600-5550, 15 SX 5430 INTERACTOR CONTRACTOR 50-25-4975, 15 SX 2093-2043, Cut off 9 5/8" casing -40° six 1025-975, 40 SX 875-825, 30 lease been plugged according to Commissions rules? Water to strate: All 13 3/8" casing left n hole. All strata protected by ca ment. ty and landowners with their addresses in each instance as f y leased by The Taxas Company	ise of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100" and puller sx in top of casi Yes in hole & 2015" sing left in hole silene:
Were pings used? Yes bigs used, and depths placed, Also Spotted the followin 7860-7810, 45 ax 770 Manager 2810-2760, 15 spot 40 sign 1125-1070 fave all abandoned wells on this Manager of confining all oil, gas or y 9 5/8" casing left in or cassed of with cent be memors of adjacent lease, royalt 11 adjacent property Manager before plugging t	If so, show all shoulders laft for casing, depth of each, and provint of coment and rock. Was well shot? NO Plugs: 95 9x 8670-8373, 15 9x 821 5-7655, 15 9x 5600-5550, 15 9x 5430 menazara and an	A consistent of
Were pings used? Yes bigs used, and depths placed, Also Spotted the followin 7860-7810, 45 ax 770 Spot 40 sp 1125-1070 Fave all abandoned wells on this Manner of confining all oil, gas or y 9 5/8" casing left i or cassed of with cent he memors of adjacent lease, royalt 11 adjacent property Manner bios given before plugging t	If so, show all shoulders laft for casing, depth of each, and provint of cement and rock. Was well shot? NO B Digs: 95 SX 8670-8373, 15 SX 821 5-7655, 15 SX 5600-5550, 15 SX 5430 INTERACTION CONTRACTOR STATES SX 2093-2043, Cut off 9 5/8" casing -40 ST 1025-975, 40 SX 875-825, 30 lease been plurged according to Commissions rules? water to strate: All 13 3/8" casing left n hole. All Strata protected by ca ment. ty and landowners with their addresses in each instance as 1 y leased by The Taxas Company to all available adjacent lease owners as required by Rule 10	A consisting and had and a consistence of casing, also and had and consistence of casing loop of casing left in hole and constant of casin
Were plags used? Yes blags used, and depths placed. Also Spotted the followin 7860-7810, 45 ax 770 Management of the followin 15 sx 2810-2760, 15 spot 40 sign 1125-1070 fave all abandoned wells on this Manage of confining all oil, gas or v 9.5/8" casing left i or cassed of with cer be memors of adjacent lease, royalt 11 adjacent property Man metics given before plugging t I. T. P. Drew rd the matter herein set forth and	If so, show all shoulders laft for casing, depth of each, and provintial coment and rock. Was well shot? No E plugs: 95 sx 8670-8373, 15 sx 821 5-7655, 15 sx 5600-5550, 15 sx 5430 in case of the second sec	A set of casing, else and kind of 3-8163, 15 sx -5380, 15 sx sx 4680-4630 @ 100' and pulled sx in top of casi Yes in hole & 2015' sing left in hole slows: Yes
Were plags used ? Yes blage used, and depths placed. Also Spotted the followin 7860-7810 45 sx 770 Spot 40 sy 1125-1070 Hanser of confining all oil, gas or y 9.5/8" casing left i or cassed of with cent The memory of adjecent lease, royalt 11 adjacent property Fas metics given before plugging t I, T. P. Drewf ad the matter herein set forth and	If so, show all shoulders laft for casing, depth of each, and provintial comment and rock. Was well shot? No E plugs: 95 sx 8670-8373, 15 sx 821 5-7655, 15 sx 5600-5550, 15 sx 5430 in case of the commentance of the second seco	size of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ex 4680-4630 @ 100' and pulled ax in top of casi Yes in hole & 2015: sing left in hole sliews: Yes Yes Dist. S
Were plage used ? Yes blage used, and depths placed, Also Spotted the followin 7860-7810 45 ax 770 Minimum Construction and the Spot 40 sy 1125-1070 Spot 40 sy 1125-1070 Far all abandoned wells of this fanser of confining all oil, yas or y 9.5/8° casing left 1 or cassed of with cent the memory of adjecent lease, royalt 11 adjacent property Far metics given before plugging to I, T. P. Drew ad the matter herein set forth and memory and sween to before me	If so, show all shoulders laft for casing, depth of each, and principal comment and rock. Was well shot? No P 1028: 95 SX 8670-8373, 15 SX 821 5-7655, 15 SX 5600-5550, 15 SX 5430 IN CASE OF 15 SX 5600-5550, 15 SX 5430 IN CASE OF 15 SX 5600-5550, 15 SX 5430 IN CASE OF 1025-975, 40 SX 875-825, 30 lease been plugged according to Commissions rules? maker to strate: All 13 3/8" casing left n hole. All strata protected by ca ment. ty and landowners with their addresses in each instance as 2 y leased by The Taxas Company to all available adjacent lease owners as required by Rule 10 to all available adjacent lease owners as required by Rule 10 that the same are true and correct. Name this 15 day of Nav	A set of casing, else and kind of 3-8163, 15 sx -5380, 15 sx sx 4680-4630 @ 100' and pulled sx in top of casi Yes in hole & 2015: sing left in hole slows: Yes Dist. S 10 52
Were plage used ? Yes blage used, and depths placed, Also Spotted the followin 7860-7810 45 ax 770 Manage all contractions and Spot 40 sy 1125-1070 Lanser of confining all oil, yas or y 9.5/8° casing left 1 or cassed of with cent The memory of adjecent lease, royald 11 adjacent property Fas metics given before plugging to I, T. P. Drew I, T. P. Drew I the matter herein set forth and marihad and sween to before me	If so, show all shoulders laft for casing, depth of each, and primipint of coment and rock. Was well shot? No. (C. Plure: 95 9x 8670-8373, 15 9x 821) 5-7655, 15 9x 5600-5550, 15 9x 5430 increase areas an exceedences 50-25-4975, 15 sx 2093-2043, Cut off 9 5/8" ceasing - 40 min 1025-975, 40 9x 875-825, 30 lease been plurged according to Commissions rules? maker to strate: All 13 3/8" casing left n hole. All strata protected by ca ment. ty and landowners with their addresses in each instance as for y leased by The Taxas Company to all available adjacent lease owners as required by Rule 10 , being first duly sworm on oath, state that t that the same are true and correct: Name this 15 day of Nay	A set of casing, else and kind of 3-8163, 15 sx -5380, 15 sx sx 4680-4630 @ 100' and pulled sx in top of casi Yes in hole & 2015: sing left in hole slows: Yes Dist. S 10 52

i i i v		0) () 	2	2		07	7					- 1/3 1				
iewasks: <u>Ortginal</u> Plugged a	NO ALLOWARLY WILL ME A In protect all fresh water and ments. It will be necessary seconder the depth to which i	A. LEATE LINE				Wildcat	R/all	PIELD WANK (Rescily as sh Prostion Releasing furthelis synthesister) If Wildest, so	1 - 2 - 2 - 10		た 一 の 別 化 感		Big Spring,	P D Box 4	McCannyCoro	Check onli DipliLL	(m) () 1632- 1624- 914 (4	ipe mail Mo. 42 second on ("Hit b) an have ble
1 Operator Lease Name nd Abandon	NOTIC NESIONED Io any wai da. Where Commiss y Io contact Texat fresh, water sands mu	710N PROM TWO D1 660' FWL & 660' FWL &				riana 11 12-11	100	olen on R. N. C. ng Weservoir If stary below.	Also - Also	REFER	er. Br	(Instruction (2) on be	TX 79720	40			Pri CAlqua	
: The	M I which dres ion rules do n Water Develo at be protecte	1980 1980 1980	dent K		23 8 - 0 7	42101	Completion Depth	Anna Sir 2011 - Anna 1912 - Anna A	ar 14. "	TO INSTRI	41. 11 ¹	cle alde.)	: 17 	1041 2327 2738	50	or Atlach Sets	.dR PET	
Vasson 27-52	not have suffic optient Board, d.	ĒŇI, ĒNĻ	2 1 8			None	lf done, Btate Nore,	All Prior Rule 37.Exe. Case Numbers for	i 3 13	UCTIONS O	P		a dina andra andra andra	n ute E Fate Infase George	5			4 1
Wc 11	face casing re Austin, Tex	e co e constant	900 1907 (1907	112 5	N.	467	Rujes, Siale 467-1200. (h.)	Applicable Field Rules Pattern, 11no	16	N BACK S	EACH PRO	Nedrest	6. This we Directio	Sec.	* (*) 7 (5 4 4 4	E) (III) TUUM Case	d Tring	OIL AND O
	ay, to		1 () ()			40	Rulen, State Acres)	A palic ble A palic ble P leid Rules Denalty	20 JZ	IDE: READ	POSED CO	Post Office o	ill is to be los	4. Blk	Stewart		EEPENT	a Divisio
1 	2.8	n 8.1	K			40	DESIGNATE	Wumber of Acres in Drilling Unit for this Well	- 10.	CAREFULL	MPLETION	town.	Vincent	59, T	1719 13/11 17	C BACK	DIR PLUG	ž
Signature A Title Date Telephone:	I declare und Code, that I by me or un therein are tr					<u></u> れっ	emplein in remarks.) R	Taithle acre- ere presently assigned to another well in seme field? (Ven	19 ji	Y AND FURN		ul in El any El any Li atra	TX	-1-N, 5	arts Stro Stro Stro	C. OTHER (BP	BACK	
dminist unc 12,	or penalties p am authorizes der my superv Ne, correct, at	25. (a) Is this (b) If subje (If no. (20		т с. 1. К. – У	None	plied for well in same res. on same lease (().)	Distance and Direction from sioposed loca- tion to near-st duiling com- eleved or ap-	. 20.	ISH COMPLE		195 1964 75	Southea	& F RH	bade a an a ana a ana a	•rify) TE-e	64 65 55	- - -
21. 13 rative 1980 915	CERTIF reacribed in S 1 to make this rision and dim rision and dim	wellbore subj oct to SWR 36, attach explana	Reg ^{ula} r 1	Regular 1	Regular 1	Regular 1 🔀 Rule 37 Z	tion? Check the eppro- priate box.	ls this a i. Regular: or 2. Rule 37 Ezc. Locus	21.	TE DATA.:	i e	201 - 4	i ត្រុ	Go.	tstea Tol Tol	ntry	1	ermit
Assist:	ICATE ec. 91.143, To report, that the tetion, and the p the best of a	ect to SWR 36 has Form II- ition.)	JU	A R R	75	0i1	Type Well (Specify)	OII. Car	22.	2	66 21	12. Total Dep	11. Distance I to Nearest (fL)	to. Number of	P. Helling	8. County	7. NRC Dist	ARC Perrils
nt 1-7455	Pegas Natural F his report was at data and fac ny knowledge.	yole" yole"	N	10	LIVED.	0	JIO	Number of Wei Permitted fore this Lease in Roservatriotus Permit is Regi	C 18 8	14.000	63	46001	1 Property of L	640	н.	loward	niet O	284
IT'	Presurces ors stated	1983 1111	U	6		c	GAS	lls of Mons on Michths Michths		20		5674	Ease Line	, 1	, 2%) (201	* 5 * 1 G	4	547

methat Mecord	R	OIL AND G	MISSION (IAS DIVIS	OF TE SION	XAS			PO Re	RH W-
1			12	API	NO, Reliable?	42-227	-000	BRC Distri	16
FILE IN D	JPLICATE WITH D	ISTRICT OFFIC	E OF DIS	TRICT	IN WH	ICH	(4). 191	08	1 1 16
WELL	IS LOCATED WITH	IN THIRTY DA	YS AFTE	k PLU	GGING		2	Hunter	98 X.
2. FIELD NAME (as per R	RC Records)	3. Lease	Name	S _				Well Numbe	
6. OPERATOR		for Coloin	Stewar	t.	Maria de			1	-1
McCann Cor	poration	. Mc	Cann Co	rpor	ition	1	100	Howan	
7. ADDRESS		ób. Any S	ubsequent W-	I's Filed	In Name	of:	11	Date Dritile	E.
P. C. Box	148, Big Spri	ng, TK				100		8-17-	80
of Lease on which this	Felt in Located	iNorth	et From WC	<u>Stew</u>	ne and 11	980 Feet	From	CORA24	ide 17 - st
. SECTION, BLOCK, AND	SURVEY	9b. Dista	nce and Direu	tion Frag	Nearest	Town In this	- 13	Dete Drittin	¢
Sec. 4, Blk.	29, T-1-N, T&P	RR Col	4 mil	es SI	To I	Vincen	t	10-10-	80
(OII, Gas, Dry) DRY	in less a wontble comple	nian wat All Field D	ames and Oll		Gas ID S ID or LEASP #	0.18 011-01 9	RLL	Dute Drillie Completed	F
8. If Gas, Amt. of Cond. on Hand at time of Plurston							2 A I	. Date Woll I	sed
				<u> </u>			1 A A A	10-12-	
9. Cementing Date	AND ABANDON DATA:	10-12-80	10-19 1	10-11	PLUGPA	PLUG.#5	PLUG	PLUG #7	10.00
0. Size of Hole or Pipe in w	hich Plug Places (inches	· 9-5/8	9-5/8	13-37	8	1 1 1 3 1 m	54 6		1.113
1. Depth to Bottom of Tubin	g or Drill Pipe (ft.)	11000	250 T	10 01	E State	11043 0	(1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,	17 - + (+, 17 - ++)	16.20
2. Sacks of Cement Used (e.	sch plug)	50	100	10	· · · · · · · · ·	0.00	22335.40	ere las receiças	100 A
4. Calculated Top of Plug ((1.)	990	70 9	Surf.	ويتكلفوها			1	
5. Messured Top of Plug (if	tagged) (ft.)		N.						295
G. Slurry Wi. #/Gal.		1.33	1.33 1	. <u>33</u>				-	_
a. CASING AND TUBING I	RECORD AFTER PLUG	SING E	129. Wan a	iny Non-	Drillable	Material (Oth	1 IVF	I Van	X Ma
ZE WT. #/FT. PUT IN W	ELL(II.) LEFT IN WELL	(it.) HOLE SIZE(In	.) 79s. If any	wer to ab	ove is ""	es" state d	pth to toy	of "junk" is	ft in hole
5 8 24# 20	200 200		- Porm	Lf more s	pace is n	eded,)			17. 11
	<u> </u>			(* 11) 11)	and shares	*** *** * ** ** **	in a second s	n de Hara Ara Antoire an an an an an Antoire Ara Antoire	1.77 * . 4
			-						
D. LIST ALL OPEN HOLE	AND/OR PERFORATE	1 INTERVALS					÷		
PROM	<u>T0</u>		FROM				TO	QC	
PROM	10 TO		PROM	1	(N N 2	0.2495
FROM	то		FROM			E.	то	1.4.54.542.5	11 M. A.
PROM	70		PRCM	-		······	το	4 + -	- 152
here knowledge that the center of the composition of Commenter as Author CERTIFICATE: I declare under pen report was prepared to the best of my 1	menting operations, as re- leted by Committing Comp arized Representative sites prescribed in Sec. by me or under my superv knowledge.	flected by the informa any. fiems not so def 91.143, Tezas Natura vision and direction, i	tion found on algnated shall DOWE Name of al Resources (and that date of	this form to comp 211 D of Coment Code, the and facts	i, were per letod by C ivisi ling Comp t 1 mm out atoted the	formed as in perstor. Oll Of any horized to m prein are true	Dow (y such inform Themical sport, that this and complete	L C3.
	12	Star 1	1. Mart		In. VC	(Jack	\mathcal{G}	11 71	2 71

APR 2 0 1981 D.G. MIDLAND, TEXAS

D1-80

et an ar star things of a

Ť

.

mart.

1

÷ ÷,



1676° 4 4 4 4	*		
alt for the same			
		<u> </u>	

100 14.2

.

te des seguintiens	adea Flaid, 21	Yes 32. How Wo	Circulated	33. Bed Bright Back and
Colory J	Treah Water Zomes	T.D.V.R.	39, Have all Alambourd Wells on this Los according to BBC Balas?	net teen Plugged
			34, M NO, Explain	
		6.63		
State Transferrer	ation or Service con	pear who mill	d and pupped current pluge in this well	Date BIC District Office
Dovell Divisi	lon of Dow	Chemic	al Co Colorado City	· TA not find of strengton
2. Charter and Addressees of Su	stace Owner of Web	I lite and Open	ators of Olices Producing Leanes	
SDanny Stewart	$t = P \cdot O \cdot$	Box 26.	Sterling City, Tx. 76	<u>.</u>
andre ser for a	0 e			
1. M. C. Stater Chern Befers Pl	legging to Rock of 1	the Alleve?		
ies		31.00		
Col. Ter Dry Maise, this Form to	HOLES ONLY	t by either a Dr	Iller's, Riectric, Radioantivity or Acoustics	al/Soute Log or such Log must be
relation to a Comportial L	og Bervice.	-	5 X.	
Log Alloche	nd 🔄 Log	released to		Dele
			1. C	
Driller's	Į.	Electric	30 Hoactivity	Acoustics)/Bonue
t di: Dite FORM P-3 (Special C	(learance) Filed?			
d. Amount of Dil produced prior	e to Plugging	No	ne bbla*	
C. Amount of Oil produced prior	e to Plugging ction Report) for m	NO mith this oil wa	ne produced	
Amount of Oll produced prior Plic Patric P-1 (Oll Produc Ref C 1998 - 1)	e to Plugging ction Report) for m	No mth this oil wa	nc bbles	
Amount of Oil produced prior Plan Poline P-1 (Oil Produc Ref: VIE Oil, 7 Nouran Field	e to Plugging ction Report) for me	No mit this all we	PRC bbls*	
4. Amount of Oll produced prior 9 Jun Potent P-1 (Oll Produced RAC WE OILY. Rouren Field	e to Plugging clion Report) for me	No mih ihis oli va	nc bbles	
Amount of Oll produced prior Plan Potent P1 (Oll Produc REC VIE ONLY Nouran Field	e to Plugging ction Report) for me	No mih this ail wa	DC bble*	
A. Amount of Oll produced prior plan Polint P-1 (Oll Produced REC WR ONLY Reven Field	e to Plagging ction Report) for mo	No mit the oil we	e produced	
Amount of Oll produced prior Pilo Potes P-1 (Oll Produc REC VIE ONLY Sources Field	e to Plugging clion Report) for me	No mith this oil wa	nc bble*	
Amount of Oli produced prior Pile Point P-1 (Oli Produc RAC WR ONLY Showen Pietd	e to Plagging cliom Report) for me	No mit the oil we	nc bble •	
Amount of Oll produced prior Pilo Potes P-1 (Oll Produc REC util ONLY Sicure Field	e to Plagging ction Report) for me	No mith this oil wa	nc bble*	
Amount of Oil produced prior Plan Police P-1 (Oil Produc Rec vill Oil 7. Steven Field	e to Plagging ction Report) for me	No mth this oil wa	e produced	
Amount of Oil produced prior Pilo Potes P-1 (Oil Produc REC will Oil Produc REC will Oil 7. Ilouren Field	r to Plagging ction Report) for me	No mith this oil wa	nc bble*	
Amount of Oil produced prior Amount of Oil produced prior	e to Plagging ction Report) for me	No mth this oil wa	e produced	
Amount of Oil produced prior Pilo Potes P-1 (Oil Produc REC will Oil 7. Ilouren Field	r to Plagging clion Report) for m	No mit the oil we	nc bble*	
Amount of Oli produced prior Plan Point P1 (Oli Produc Ric vill Ority) Source Pield	e to Plagging ction Report) for me	No mth this oil wa	e produced	
Amount of Oli produced prior Oli produced prior Oli produce P1 (Oli Produc Oli Produc Oli Produce P1 (Oli Produce Oli Produce	e to Plagging clion Report) for me	No mit this oil wa	e produced	
Amount of Oil produced prior Pilo Point P1 (Oil Produc Rec via Oil y Incura Piold	e to Plagging ction Report) for me	No mith this nil wa	PRC bble®	
Amount of Oil produced prior Amount of Oil produced prior Amount of Oil produced prior Amount of Coll 7. Source Field	e to Plagging ction Report) for me	No mth this oil wa	e produced	
Amount of Oil produced prior Pilo Point P1 (Oil Produc Rec via Oil y Incura Piold	C to Plagging ction Report) for me	No mit the oil we	Produced	
Amount of Oli produced prior Amount of Oli produced prior	to Plagging ction Report) for me	No mith this oil wa	e produced	
Amount of Oli produced prior Oli Produc Oli Produc	e to Plagging ction Report) for me dian state dian state HARST AD distance (1901 O S S9	No mit the oil we	e produced	

OIL AND GAS DIVISION

Ë.

CEMENTING REPORT

Wildcat		*2. NRC Displet					
*1. Operator Mc. Cann. Cornoration	ilanın Sar	*4. County Hourand					
"5. Lease Same(a) and RRC Lease Number(a) or 1. D. Num		·6. Well Humber,	oward				
*7. Location (Section, Block, and Survey)	PP Co C	-		- 199 - Charles Table	Tool and the		
Sec. 4, DIK. 29, 1-1-N, 10F	NINEACE	MTER.	PROM	ICTION	e distant dis 1911	1. TO LOUMS W	
CASING CEMENTING DATA:	CASING	MEDIATE	Single	inc.	CENTRY	PROCES	
			String	Perellal Strings	Třel	Shee.	
8. Cementing Date			310 ₁	P. Sugar	1. 30 Bar		
*9. (a) Size of Drill Bit (inches)	384.1		-				
(D) Estimated 75 Wash or Hole Enlargement Used in Calculations.	16	6060 20	4830 (SS 100 10	1. 1. 1.	in an an Stantas		
*10. Size of Casing (inches O.D.)			6 53 9	2. x 2.1 - X.	delato.	1.1.1.200	
*11. Top of Liner (if liner used) (ft.)	20152	No.			1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 -		
*12. Setting Depth of Casing (ft.)		8 C	8		1.54.2671	11.10	
3. Type API Class Cement & Amount of Additives Used: (a) in First (Lead) or Only Starry III additional space				Steen a	. 11-1 175	0.0010	
(b) In Second Sturry	<u></u>						
(c) In Third Sivery		25.		100 100 100 100 100 100 100 100 100 100		1	
14. Sacks of Crment Used: (a) In First (Lead) or Only Sluny						(1) - (1) - (1)	
(b) In Second Siwn							
(c) In Third Siwry	A de						
(c) Total Sacks of Cement Used		21 - M-	£ 50	5 - 212 - 53A	an a		
15. Slurry Volume per Sack of Cement (cu.it./sack): (a) In First (Lead) or Only Slurry					f to the second		
(b) In Second Slurry		276.0					
(c) in Third Slarry	9 54	an 200 000			a national per a composition de la comp	1	
16. Volume of Siurry Pumped: (cu.it.) (item 14 x liem 15) (e) In First (Lead) or Only Siurr			19925				
(b) In Second Sturry				111 2 1.1	10.96	1.	
(c) In Third Sluny						11	
(d) Total fluence to have the set of a b				N 12	21		
17. Celculated Annular Height of Cement Slurry		11.22 15		2002 BOO			
behing Pipe (II.) 18. Was cement circulated to ground surface					$e^{i_{1}} = r^{i_{1}}_{1} \frac{e^{-i_{1}}}{e^{i_{1}}} \frac{e^{-i_{1}}}{e^{-i_{1}}} \frac{e^{-i_{1}}}{e^{-i_{1}}} + \frac{e^{-i_{1}}}{e^{-i_{1}}} + \frac{e^{-i_{1}}}{e^{-i_{1}}} \frac{e^{-i_{1}}}}{e^{-i_{1}}}} \frac{e^{-i_{1}}}}{e^{-i_{1}}} \frac{e^{-i_{1}}}{e^{-i_{1}}}} \frac{e^{-i_{1}}}}{e^{-i_{1}}}} \frac{e^{-i_{1}}}{e^{-i_{1}}} \frac{e^{-i_{1}}}}{e^{-i_{1}}}} \frac{e^{-i_{1}}}}}{e^{-i_{1}}}} \frac{e^{-i_{1}}}}{e^{-i_{1}}}}}$	· · · · · · · · · · · · · · · · · · ·	
(or bottom of cellar) outside casing? (Yes or No)				5	18 2 H S	ST VERS	
CEMENTING TO PLUG AND ABANDON DATA:	PLUG NO. 1	PLUG NO. 2	PLUG NO. 3	PLUG NO. 4	PLUG NO. 5	PLUG NO. 6	
19. Cementing Date	10-12-80	10-13-80	10-13		9. S		
#20. Size of Hote or Sips in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8				
#21. Depth to Hotiom of Tubing or Drill Pipe (ft.)	1000	250	Top Out		1	2°_ 2	
22. Sucks of Cement Used (each plug)	50	100	10	۰	8 ₂₁	1	
23. Sturry Volume Pumped (cu. ft.)	66	133	13		S 8	21 min 7/	
\$4 . 6 at-situted Pop-of 3ting (ft.)	990	70	Surf	Q. BY TEXAS	1		
*25. Messured Top of Flug (M tagged) (It.)			AP	R 2 0 1981	Sec. 14		
(CEMENTING COMPANY AND OPERATOR I	MUST COMPLY	WITH THE	INSTRUCTION	IS CHEREVER	SE SIDE HEI	FORA	

-te

(Nev. 14.8)

	• 27. Remarks:	
		10
	*005504105	
The sector of the sector presties and a fee, \$1.143, Tesan Natural the sector, the Tam authorized to make this certification, that the	T declare under penalties prescribed in Sec. 31 143. Resources Cude, that I am authorized to make this cort	Concern Natural
I demonstrag of cooling and/or the placing of content plugs in this work as	have incovering of the well date and information presents and that data and facts presented on bath sides of this	d in this regard. 6 form and true
servet, and complete, to the best of my knowledge. This certification	covers all well date and information presented herein	
	1 4 6	
In the keldowd	Four ille Cam	
Commere of Contenter or Authorized Depresentative	Bignature of Operator or Authorized Representative	
	Tom McCann - President	
Butter of Person and Title (type ar print)	"Name af Person and Title (type or print)	
Benell Division of Dow Chemical Co.	McCann Corporation	
Committee Company	*Op#retor	
Banta 3. Box 178	P. O. Bux 48	
Shiert Address or P.O. Box	•Street Address or P.O. Box	
Colorado City, Tx 79512	Big Spring, Texas	75736
City, Baste Zip Cede	*City, State	Zip Cade
915 728-5291	*Telephone 915 267-7488	
Area Code	Anna Colta	
	Ares Cour	
10-14-80	- <u>1-6-81</u>	
10-14-80 Date IN L. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting rej to computing requirements in Statewide or Special Rules;	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except	tion is norded
10-14-80 This This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a communing regulation of the transmission of transmission of transmission of the transmission of trans	etion. or such company used on a well.	tion is nurried
10-14-80 Date IN L. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The computing of different casing strings on a well by one co	Area Code <u>Area Code</u> <u>STRUCTIONS</u> Office with: port is required by Statewide or Special Rules, or if eccep etion. or each cementing company used on a well. menting company may be consolidated on one form (to be	tion is needed
10-14-80 Date IN 1. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companing of different casing strings on a well by one co 2. Companing Company and Operator shall comply with the applicable C. The company and Operator shall comply with the applicable	Area Code 	tion is needed filed in duplicat
10-14-80 This This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a communing reg- to company requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed f C. The companies of different casing strings on a well by one cas 2 Companies Company and Operator shall comply with the applicable Companies Company and Operator shall comply with Statewide Rules 2 W applies PULL, AMOUNT OF SURFACE CASING:	Area Code 	tion is needed filed in duplicat poperations.
10-14-80 This A. This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a commanding regulation is commanding requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed for C. The commanding of different casing strings on a well by one com- Commaning Company and Operator shall comply with the applicable Commaning Company and Operator shall comply with Statewide Rules B. At least an original company shall comply with the applicable Commaning Company and Operator shall comply with Statewide Rules B. At least an original company and Operator shall comply with Statewide Rules Command Company and Operator shall comply with Statewide Rules B. At least and the company and Operator shall comply with Statewide Rules Command Company and Operator shall comply with Statewide Rules B. At least and the company and Operator shall comply with Statewide Rules Command Company and Operator shall comply with Statewide Rules B. At least and the company and Operator shall comply with Statewide Rules Command Company and Operator shall comply with Statewide Rules B. At least and the complexity of SURFACE CASING A. Depth to protect fresh water determined by:	Area Code - <u>3Late</u> ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if eccep etion. or each cementing company used on a well. menting company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E).	tion is needed filed in duplicat poperations.
ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companies of different casing strings on a well by one case Companies Company and Operator shall comply with the applicable Companies Company and Operator shall comply with Statewide Rules; (1) Fi Rule A. Depth to protect fresh water determined by: (1) Fi Rule a. Water Development Doard, if op Field Bulk	Area Code - <u>3-6-B1</u> ISTRUCTIONS Office with: port is required by Statewide or Special Rules, or if excep etion. or each cementing company used on a well. ementing company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E).	tion is neerled filed in duplicat poperations.
10-14-80 This This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a community reprive community requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed f C. The commaning of different casing strings on a well by one case Commaning Company and Operator shall comply with the applicable Commaning Company and Operator shall comply with Statewide Rules W setting FULL ANOUNT OF SURFACE CASING A. Depth to protect fresh water determined by: (1) Fi Rule (2) To s Water Development Board, if no Field Rule B. Set surface casing below depth to be protected and command for	Area Code 	tion is needed filed in duplicat experations.
IN IN IN IN IN IN IN IN IN IN	Area Code - <u>abale</u> ISTRUCTIONS Mfice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be is portions of Statewide Rules 8, 13, and 14. For offshore the T3(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE	tion is needed filed in duplicat poperations .
IN I. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companies of different casing strings on a well by one co Companies Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for A. If setting NO SURFACE CASING (See Item 4 above.):	Area Code 	tion is needed filed in duplicat expensions.
 10-14-80 Date IN A. This form shall be filed by the operator in the RRC District (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing completes and one copy of this form shall be filed for the companies of different casing strings on a well by one cases and the company and Operator shall comply with the applicable Commuting Company and Operator shall comply with Statewide Rules; (2) File Rule (2) Transform and Operator shall comply with Statewide Rules. Facting FULL ANOUNT OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) File Rule (2) Transform to be protected and cement for the Sector State Community Community (2) File Rule (2) Transform Community Community	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be to portions of Statewide Rules 8, 13, and 14. For offshore the 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface.	tion is needed filed in duplicat poperations, tp FROM THE
 10-14-80 Content IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation of the computing requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing compiles. At least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicable Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule Y setting FULL AMOUNT OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) File Rule (2) To a Water Development Board, if no Field Rule E Set surface casing below depth to be protected and cement for RALEDAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: If no multi-stage tool on the next deeper string, cement 	Area Code 	tion is needed filed in duplicat poperations.
IN-14-80 This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a commanding regulation of the second seco	Area Code - <u>abale</u> ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be is portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. tifrom the depth that protects fresh water sands to the sur-	tion is needed filed in duplicat poperations, to FROM THE face.
IN I. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-I or W-2 if a commanding regulation of the company of Form W-3; (2) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed f C. The commanding of different casing strings on a well by one com- Commanding Company and Operator shall comply with the applicable Commanding Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RAL ROAD COMMISSION. I fisetting NO SURFACE CASING (See Item 4 above.): A: If no multi-stage tool is used, the next deeper string, cement If satting SHORT SURFACE CASING (See Item 4 above.): A: Command the multi-stage tool is used, the next deeper string, cement If satting SHORT SURFACE CASING (See Item 4 above.): A: Comment short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper string.	Area Code 	tion is needed filed in duplicat s operations . In FROM THE face.
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a compating register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing completed in the filed of the company and one copy of this form shall be filed of C. The company and Operator shall comply with the applicable Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) The state Development Board, if no Field Rule B. Set surface casing below depth to be protected and cement for (2) The stating NO SURFACE CASING (See Item 4 above.): A: If setting NO SURFACE CASING (See Item 4 above.): A: The multi-stage tool is used, the next deeper string, cement (1) files the multi-stage tool is or is not used on the next for (1) the surface, or (2) a point midway between shoe of surface string and the surface. 	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be to portions of Statewide Rules 8, 13, and 14. For offshore lie 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. trifrom the depth that protects fresh water sands to the sur- per casing string, cement from the depth that protects fresh face. Compliance will be considered of a temperature sur- from the shue of the surface string to the surface.	tion is needed filed in duplicat roperations, ip FROM THE face. Is water satisfa to yey shows that
IN-14-80 Date IN A. This form shell be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commiting re- to comparing requirements in Statewide or Special Rules; (2) Each copy of Form W-3 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicable Comparing Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule B. Set surface casing below depth to be protected and cement for ALLROAD COMMISSION. I If setting NO SURFACE CASING (See Item 4 above.): A.: If no multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool on the next deeper string, cement If setting SHORT SURFACE CASING (See Item 4 above.): A.: Cercent short surface casing from the shot to the surface. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting or is not used on the next face. B. Whether the commuting or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting of the commuting of the distance 7. Soming PRODUCTION STRING of Casing: (Statewide Rules, Spec-	Area Code 	tion is needed filed in duplicat poperations. In FROM THE face.
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regularements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple A. At least an original and one copy of this form shall be filed f C. The community of different casing strings on a well by one cas Community of different casing strings on a well by one cas Community of different casing strings on a well by one cas Community and Operator shall comply with the applicable Community and Operator shall comply with Statewide Rule; (1) Fi Rule; (2) To a stater Development Board, if no Field Rule E. Set surface casing below depth to be protected and community of RALEROAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: This multi-stage tool is used, the next deeper string, cement If satting SHORT SURFACE CASING (See Item 4 above.): A: Cement short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper (1) the surface, or (2) a point midway between shoe of surface string and the sut the top of the cement is at least ene-third of the distance 	Area Code 	tion is needed filed in duplicat roperations, in properations, in water satisfies take.
 ID-14-80 IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form C-1 or W-2 if a commuting requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing comple to comparing of form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed f C. The commuting of different casing strings on a well by one case comple and operator shall comply with the applicable Communing Company and Operator shall comply with Statewide Rules; (2) The company and Operator shall comply with Statewide Rule E setting PULL AMOUNT OF SURFACE CASING A. Depth to protect fresh water determined by: (1) Fi Rule (2) The state Development Board, if no Field Rule (2) The state casing below depth to be protected and comment for RALENOAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A. Concent short surface casing from the shoe to the surface. B. When the multi-stage tool is or is not used on the next deep (1) the surface, or (2) a paint midway between shoe of surface string and the surface. E. Stating PRODUCTION STRING of Casing: (Statewide Filen, Spe A. Comment is at least ene-third of the distance B. When 3,000 feet or more of piperistate. 	Area Code 	tion is needed filed in duplicat roperations. ID FROM THE face. Is water calles to ver shows that
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commiting requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil A. At least an original and one copy of this form shall be filed file. C. The comenting of different casing strings on a well by one ca Comenting Company and Operator shall comply with the applicable Commiting Company and Operator shall comply with the applicable Commiting Company and Operator shall comply with Statewide Rule. M setting FULL AMOUNT OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) Fi Rule (2) Tr - s Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RALEROAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A.: The multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool on the next deeper string, cement (1) the surface. B. When the multi-stage tool is or is not used on the next face. B. When the support of a string of surface string and the stut the top of the cement is at least one-third of the distance A. Cement to a point at least 600 feet, above the casing shoe. B. When 3,000 feet or more of piperiaraec. So the production or piperiaraec. 	Area Code 	tion is needed filed in duplicat roperations. In FROM THE face. Is water satisfies to ver about that
 ID-14-80 Data IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commating requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed file C. The company and Operator shall comply with the applicable Companies Company and Operator shall comply with Statewide Rules; (1) File Rule (2) Tr. a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RALEROAD COMMISSION. If setting NO SURPACE CASING (See Item 4 above.): A. This multi-stage tool is used, the next deeper casing string on B: If using the multi-stage tool on the next deeper studie, cement for (1) the surface, or (2) a point midway between shoe of surface string and the surface. B. Whether the multi-stage tool is or is not used on the next deeper for surface. C. Bether the surface casing from the shoe to the surface. E. Whether the multi-stage tool is or is not used on the next deeper for surface. B. Whether the multi-stage tool is or is not used on the next deeper surface. E. Whether the multi-stage tool is or is not used on the next deeper (1) the surface. C. Bether the for the casing from the shoe to the surface. E. Whether the cont is at least one-thurd of the distance the top of the cement is at least one-thurd of the distance. E. Whether to a point at least 600 feet, above the casing shoe. E. Men 3,000 feet or more of piperistate. E. When 3,000 feet or more of piperistate. 	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etton. or such comenting company used on a well. menting company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore ile 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OUTAINE hall be cemented from the casing shoe to the surface. trifrom the depth that protects fresh water sands to the sur- face. Compliance will be considered if a temperature sur- from the shoe of the surface string to the surface. cial Rules may vary 1 effecting string, a minimum of 30 feet of cements and additional Rules and Regulations of the Commission plus any addition	tion is needed filed in duplicat poperations, to FROM THE face. Is water satisfies to yes, shown that if consider the po- orial ploge so the
 ID-14-60 Data IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a comrating regiments in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compile A. Least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) The company and Operator shall comply with Statewide Rules; (2) The company and Operator shall comply with Statewide Rule; (2) The company and Operator shall comply with Statewide Rule; (3) The Rule (4) File Rule (5) The Rule (2) The Rule (3) The Rule (4) File Rule (5) The State Development Board, if no Field Rule E. Set surface casing below depth to be protected and coment for RALERDAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A. The multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool on the next deeper string, coment (1) the surface casing from the shote to the surface. B. Whether the multi-stage tool is or is not used on the next deep (1) the surface, or (2) a point midway between shoe of surface string and the surf the top of the coment is at least one-third of the distance A. Cement to a point at least 600 feet apove the casing shoe. B. When 3,000 feet or more of piperists ecfor the production or production or production or produced of 00 feet of the kole for the filed in each plug shall be placed in the well bore as required by be specified by the RRC District. Director. B. The minimum amount of Efformant is a minich the distance of the surface in the importance of piperists ecfor the casing shoe. 	ISTRUCTIONS Mice with: poort is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. meeting company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the special point of Statewide Rules 8, 13, and 14. For offshore the special point of Statewide Rules 8, 13, and 14. For offshore the 13(E). on casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL THE OUTAINE hall be cemented from the casing shoe to the surface. to from the depth that protects fresh water sands to the sur- per casing string, cement from the depth that protects fresh face. Compliance will be considered if a temperature sur- from the shue of the surface string to the surface cial Rules may vary 1 effecting string, a minimum of 30 feet of cement shall be Rules and Regulations of the Commission plus any additional still be a slurry volume equal to the amount no enfary to find the shue of the surface string to the surface string to find the surface string is a string of the surface string plus any additional string is string and the commission plus any additional string as shall be a slurry volume equal to the amount no enfary to find the surface string to the surface string to find the string to find the surface string to the surface string to find the surface string to find the surface string to the surface string to find the surface string to the surface string to find the surface string to the surface string to find the surface string to the surface string to find the surface string to the surface string to find the surface string to find the surface string to find the surface string to the surface string to find the surface st	tion is needed filed in duplicat poperations, ip FROM THE face. It water satisfies to you above that if costs the po- out place as the if the calculated

APPENDIX B - SITE SAFETY AND LAYOUT

Bayswater Operating's Mongoose Gas Plant and AGI No. 1 are operated and monitored 24 hours a day, 7 days a week, by on-site personnel utilizing Plant operating and SCADA systems. These systems gather operating data such as pressures, temperatures, flow rates, remote sensors, compressor run data, and control valve positions. The recording and retention of this operating data enables the operator to evaluate trends and use predictive analytics to potentially identify issues before they become an "alarm" event. If an alarm event occurs, the automated control system is programmed to execute pre-programmed protocols to safely manage the event. Operators are specially trained to follow detailed practices to minimize risk to people, the facility, and the environment.

In the event of a leak or system failure, the Plant control system will execute its shutdown protocols as timely as is practicable to isolate the event and minimize the intensity. The Plant operator will investigate the circumstances and oversee an orderly resolution to the situation. Since this facility handles H₂S, Bayswater is required to maintain a Hydrogen Sulfide Contingency Plan to safely manage any planned or unplanned release event. The Plant operating staff are highly trained in safety and emergency response protocols to ensure safety for both plant personnel and the surrounding community and environment.



B-	-2

			ITEM	DESCRIPTION
			1	SLUG CATCHER
			2	INLET COMPRESSOR W/ COOLER
	1		2F	INLET COMPRESSOR (FUTURE) W/ COOLER
			3	COMPRESSOR DISCHARGE COALESCER
			4	
	v	V	× 6	
		^	7	
			8	
			9	
			10	AMINE REGENERATOR REBOILER
			11	AMINE SURGE TANK
			12	AMINE BOOSTER/REFLUX PUMP SKID
			13	AMINE REGENERATOR REFLUX CONDENSER
			14	LEAN AMINE COOLER
			15	AMINE CHARGE PUMPS
			16	HOT OIL PUMP SKID
			17	HOT OIL HEATER
			18	FLARE K.O. DRUM
	1		19	FLARE
- BARF	RIER		20	COMBUSTOR
			21	SLOP STORAGE TANKS
	_+		22	AMINE MAKE UP STORAGE TANK
			23	
			24	
			241	
			25	
	1		20	
			27	
			20	DI WATER TANK
	·		30	GLYCOL CONTACTOR
			31	GLYCOL SEPARATOR
			32	TEG REGEN
			33	BTEX
			34	GAS GENERATOR SET
			35	AMINE SUMP TANK
			36	NEW LUBE OIL TANKS
			37	CONDENSATE TRANSFER PUMPS
			38	VAPOR RECOVERY UNIT
			39	TANK COMBUSTOR K.O. DRUM
			40	MV TRANSFORMER
			40F	MV TRANSFORMER (FUTURE)
				LEGEND
				FIRE EXTINGUISHER = 9 ea.
				HYDROGEN SULFIDE DETECTOR = 10 ea.
				AUDIBLE ALARM SOUNDER = 4 ea.
				R STROBE LIGHT (RED) — FIRE = 4 ea.
_	- EAST_SECU	RITY GATE		SHUT PLANT EMERGENCY SHUTDOWN = 6 ea.
				FIRST AID & SCBA KIT = 3 ea.
	-*X -	X		EYE WASH STATION = 3 ea.
	й С		E 10(WIND SOCK = 1 ea.
				MUSTER POINT = 3 ea.
r :	RΔ	YSWATER	FXPLOR	ATION & PRODUCTION
CT ·	DA	COUD		
		SUUK	GAS IR	EATING FAUILITY
·		FACILITY	INSTRUN ′SAFET`	IENTATION (LOCATION PLAN
WN	CHECKED	SCALE	DATE	JOB NO. DRAWING NO. SHEET NO.
DC DC	GA	AS NOTED	06/09/22	BAY220316 IN-PLN-0790 1 OF 1

APPENDIX C – AREA OF REVIEW

APPENDIX C-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX C-2: OIL AND GAS WELLS WITHIN THE MMA LIST



Mongoose AGI No. 1

	Area of Review: Oil & Gas Wells List									
API	WELL NAME	WELL NO.	CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (FT.)	PERFORATED INTERVAL (FT.)	DATE DRILLED
4222700101	JONES, C.L	1	ARMER L H	1603	32.445815	-101.187399	DRY HOLE	NR	NR	NR
4222703634	STEWART	1	MCCANN CORP	1601	32.423136	-101.1837088	DRY HOLE	8670	NR	10/11/1980
4222732304	CATHEY	1	MCCANN CORP	204	32.42347	-101.1890569	DRY HOLE	4310	NR	10/31/1980
4222734502	STERLING CATTLE COMPANY	3402	MDC TEXAS ENERGY	1603	32.44553	-101.17894	P & A	7795	7764-7795	10/19/1989
4222734688	STERLING FAMILY TRUST	3403	TREND EXPLORATION COMPANY	1603	32.4403185	-101.1792589	P & A	7918	7747-7760	3/5/1992
4222736361	STERLING 38	1	HIGHPEAK ENERGY	1371	32.42744	-101.196842	INACTIVE PRODUCER	8075	5635-7848	4/5/2010
4222741505	KAMIKAZE 5-8	H 3W	BAYSWATER OPERATING COMPANY LLC	204	32.399666	-101.180898	PRODUCING	5433	5911-15810 (MD)	1/9/2022
4222741505	KAMIKAZE 5-8-17-20	ЗW	BAYSWATER OPERATING COMPANY LLC	204	32.426344	-101.191374	PRODUCING	5643.22	5911-15810 (MD)	1/9/2022
4222741939	WINFORD 35-38 B UNIT A	7H	HIGHPEAK ENERGY	745	32.450886	-101.197238	PRODUCING	5785.42	6081-15105 (MD)	9/9/2022
4222741972	PHARAOH 10-15-34-39	H 1W	BAYSWATER OPERATING COMPANY LLC	1602	32.473311	-101.191423	INACTIVE PRODUCER	5847	NR	10/27/2022
4222742086	KAMIKAZE 5-8	H 2WD	BAYSWATER OPERATING COMPANY LLC	204	32.426337	-101.191712	COMPLETED	7821	NR	4/14/2023
4222742087	KAMIKAZE 5-8	H 4WX	BAYSWATER OPERATING COMPANY LLC	204	32.4263090	-101.1918370	COMPLETED	5818	NR	4/5/2023
4222742088	KAMIKAZE 5-8	H 2W	BAYSWATER OPERATING COMPANY LLC	204	32.4262950	-101.1919000	COMPLETED	5669	NR	3/22/2023
4222742089	KAMIKAZE 5-8	H 1WD	BAYSWATER OPERATING COMPANY LLC	204	32.4263230	-101.1917740	COMPLETED	7820	NR	4/8/2023
4222742105	KAMIKAZE 5-8	H 1W	BAYSWATER OPERATING COMPANY LLC	204	32.4262810	-101.1919620	COMPLETED	5816	NR	5/24/2023



Mongoose AGI No. 1

4233500959	MACKEY, P.K.	1	MCDERMOTT-RAY	1344	32.4133665	-101.1552679	DRY HOLE	NR	NR	4/25/1954
4233501046	MACKEY, P.K.	1	MOSS H S	582	32.4215460	-101.1434280	DRY HOLE	NR	NR	12/8/1947
4233501860	JONES, CHESTER L	1	DANSBY, BEN JR.	17	32.4497350	-101.1605990	DRY HOLE	NR	NR	NR
4233533555	VAN TUYLE	1	BRIGHT & COMPANY	584	32.4027340	-101.1529820	P & A	8360	NR	11/26/1990
4233533624	STERLING FAMILY TRUST-A-	3301	MDC OPERATING, INC.	17	32.4438844	-101.1638476	P & A	7850	7756-7760	1/23/1993
4233535973	SI-10.2 CP UNIT	1	ENERGY TRANSFER	1536	32.4233850	-101.1407330	PERMIT EXPIRED	550	NR	-
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.434283	-101.161962	PRODUCING	5543	6052-19217 (MD)	7/7/2022
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.4717700	-101.1619280	PRODUCING	5543	6052-19217 (MD)	7/6/2022
4233536030	JADE PALACE 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1344	32.4049880	-101.1607180	DUC	5491	NR	11/8/2022
4233536031	GOLDEN SAND 10-3	H 1W	BAYSWATER OPERATING COMPANY LLC	1344	32.4050010	-101.1606550	DUC	5606	NR	11/8/2022
4233536041	PEARL RIVER 4-9	H 1W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016760	-101.1745840	PERMITTED	7100	NR	-
4233536042	PEARL RIVER 4-9	H 2W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016620	-101.1745210	PERMITTED	7100	NR	-
4233536045	PEARL RIVER 4-9	H 3W	BAYSWATER OPERATING COMPANY LLC	1634	32.4017660	-101.1748560	PERMITTED	7100	NR	-
4233536046	PEARL RIVER 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016350	-101.1743950	PERMITTED	7100	NR	-
4233536047	JAVA 16-21	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016210	-101.1743330	PERMITTED	7100	NR	-

*Note: Well entries in red penetrate the upper confining layer.



APPENDIX D – SECTION 2 CROSS SECTIONS

APPENDIX D-1: FIGURE 28 – STRUCTURAL CROSS SECTION DEPICTING THE ELLENBURGER

APPENDIX D-2: FIGURE 29 – STRATIGRAPHIC CROSS SECTION FLATTENED ON THE ELLENBURGER



D-1



Request for Additional Information: Mongoose Amine Treating Facility August 12, 2024

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.	2.4	42	"Large scale versions of Figures 28 and 29 are provided in Appendix C."	Section 2.4 and the Appendix D have been updated accordingly.
			According to the Appendices submitted with the MRV plan, Appendix D contains the structural and stratigraphic cross sections. Note that these figures are identified as Figures 27 and 28 in the Appendices. Please review the MRV plan to ensure that all references to external documents within the text are correct.	
2.	4.2	71	"The Woodford Shale provides 50 feet or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset APs is unlikely."	Section 4.2 has been updated with the term "artificial penetrations".
			The term "APs" is not defined anywhere in the MRV plan. Please ensure that all acronyms are defined during the first use within the MRV plan.	
3.	4	67	"The lateral continuity of the UCZ is recognized as a very competent seal."	Table 12 has been updated to explain how the confining interval provides a competent seal relative to the leakage pathways.
			This statement appears in Table 12. Please specify how the UCZ being a competent seal relates to the likelihood of leakage for each of these pathways or update the descriptions accordingly.	

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	7.5	85	"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." Per <u>40 CFR 98.443(f)(2)</u> , this variable should be, "Total annual CO ₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO ₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of this part." Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Equation 7.5 has been updated to include ", for which a calculation procedure is provided in subpart W of this part"



Subpart RR Monitoring, Reporting, and Verification (MRV) Plan Mongoose AGI No. 1

Mitchell County, TX

Prepared for *Bayswater Operating Company LLC* Denver, CO

Ву

Lonquist Sequestration, LLC Austin, TX

> Version 3.0 May 2024



INTRODUCTION

Bayswater Operating Company LLC (Bayswater) currently has a Class II acid gas injection (AGI) permit, issued by the Texas Railroad Commission (TRRC) for the Mongoose AGI No. 1 well (Mongoose), API No. 42-335-36013. The permit was issued March 10, 2023. This permit authorizes Bayswater to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO₂) and hydrogen sulfide (H₂S) into the Ellenburger formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose is a new well and is associated with the Mongoose Amine Treating Facility (the Plant) located in a rural area of Mitchell County, Texas, as shown in Figure 1.



Figure 1 – Location of Mongoose AGI No. 1 Well

Bayswater is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Bayswater is also seeking TRRC approval to amend the existing Mongoose permit by increasing the permitted maximum quantity of injected treated acid gas (TAG) from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. Bayswater intends to inject into this well for approximately 40 years at up to a maximum of 19.5 MMscf/D. The primary source of this injected CO₂ gas is the Mongoose Amine Treating Facility. Table 1 shows the expected composition of the gas stream to be sequestered. Table 2 shows the expected average daily volume of acid gas.

Table 1 – Expected Gas Composition

Component	Mol Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

Table 2 – Expected Sequestered Gas Volumes

Contract Status	Avg. Rate (MMscf/D)
Committed	6.9
Proposed	12.6
Total	19.5
ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH ₄	Methane
CMG	Computer Modelling Group Carbon Dioxide (may also refer to other Carbon
CO ₂	Uxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H ₂ S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet

MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
Ν	North
NW	Northwest
OBG	Overburden Gradient
OSHA	Occupational Safety and Health Administration
PG	Pore Gradient
рН	Scale of Acidity
PISC	Post Injection Site Care
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
ТАС	Texas Administrative Code
TAG	Treated Acid Gas
ТОС	Total Organic Carbon
TRRC	Texas Railroad Commission
UCZ	Upper Confining Zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

TABLE OF CONTENTS

.2
.4
10
10
10
10
10
11
11
20
20
20
21
29
38
40
40
40
42
46
46
52
52
52
55
54
54
65
57
58
71
74
74
74
75
75
77
78
78
30
30
32
32

6.2	CO./H-S Dotoction	00
0.2		
6.3	Operational Data	82
6.4	Continuous Monitoring	82
SECTION	7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION	83
7.1	Mass of CO ₂ Received	83
7.2	Mass of CO ₂ Injected	83
7.3	Mass of CO ₂ Produced	84
7.4	Mass of CO ₂ Emitted by Surface Leakage	84
7.5	Mass of CO ₂ Sequestered	85
SECTION	8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN	87
SECTION	9 – QUALITY ASSURANCE	88
9.1	Monitoring QA/QC	88
9.2	Missing Data	88
9.3	MRV Plan Revisions	89
SECTION	10 – RECORDS RETENTION	90
SECTION	11 - REFERENCES	91

Figures

Figure 1 – Location of Mongoose AGI No. 1 Well
Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red
star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, &
Walsh)12
Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)13
Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf14
Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf
(Waite, 2021)15
Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger
Group of the Permian Basin, West Texas, 2006)16
Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth17
Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks,
2003)
Figure 9 – Type Log and Disposal Units and Zones from PXD Well No. 1 (Sanchez, Loughry, &
Coringrato, 2019)19
Figure 10 – Mongoose AGI No. 1 Type Log20
Figure 11 – Buchanan 3111 #XD location Offset well for Core Data22
Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting
the Woodford and sidewall cores23
Figure 13 – Core Photo of Samples Within the Woodford Formation24
Figure 14 – Routine Core Analysis Within the Woodford Formation25
Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation26
Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation
Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation28

Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)....32 Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells36 Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map......43 Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)......47 Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986)......50 Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011)......51 Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model54 Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)......58 Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)59 Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation) Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection) Figure 40 – North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)......62 Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Figure 43 – Active Monitoring Area66 Figure 45 – Mongoose AGI No. 1 Wellbore Schematic70 Figure 46 – All Oil and Gas Wells Within the MMA.....72 Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA......73 Figure 48 – Seismicity Review (TexNet – 08/04/2023)76

Figure 49 – Seismic Events and I	Monitoring Station81
----------------------------------	----------------------

Tables

3
3
.38
.40
.41
ger
.47
.52
.53
.55
.56
.63
.67
.77

Appendices

Appendix A – TRRC MONGOOSE AGI No. 1 FORMS

- Appendix A-1 UIC Class II Order
- Appendix A-2 GAU Groundwater Protection Determination
- Appendix A-3 Drilling Permit
- Appendix A-4 Completion Report

Appendix B – Site Safety and Layout

- Appendix B-1 Operating Safety Plan
- Appendix B-2 Mongoose Site Plan

Appendix C – Area of Review

- Appendix C-1 Oil and Gas Wells Within the MMA Map
- Appendix C-2 Oil and Gas Wells Within the MMA List

Appendix D – Section 2 Cross Sections

Appendix D-1 – Figure 27 – Structural Cross Section Depicting the Ellenburger Appendix D-2 – Figure 28 – Stratigraphic Cross Section Flattened on the Ellenburger

SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the UIC Class II program. The TRRC classifies Mongoose AGI No. 1 as a UIC Class II well. A Class II permit was issued to Bayswater on March 10, 2023, under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

1.2 UIC Well Identification Number

Mongoose AGI No. 1, API No. 42-335-36013, UIC No. 000125803

1.3 <u>Reporter Number</u>

- Facility Name: Mongoose Amine Treating Facility
- Greenhouse Gas Reporting Program ID: 586481
 - Currently reporting under Subpart UU
- Operator: Bayswater Operating Company LLC

1.4 Facility Address

Mongoose Amine Treating Facility 1625 County Road 280 Westbrook, Texas 79565

Coordinates in NAD83 for this facility:

Latitude: 32.4225396641 Longitude: -101.1714709142

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Mongoose AGI No. 1 well.

The Mongoose injects both H_2S and CO_2 into Ellenburger formation at a depth of 8,300 ft to 9,000 ft, and approximately 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The Mongoose is located on the Eastern Shelf, as shown in the area map in Figure 2, within the greater Permian Basin of west Texas and New Mexico. The Permian Basin covers more than 86,000 square miles extending across an area approximately 250 miles wide and 300 miles long. The TRRC cites that the greater Permian Basin accounts for close to 40% of all oil production within the United States and nearly 15% of natural gas production. A general cross section of the basin is presented in Figure 3.

The ancestral Tobosa Basin was formed by structural flexure in the Precambrian basement at the southern margin of the North American Craton, or Laurentian Plate, during the Proterozoic (Popova, 2020). The modern form of the Permian Basin was shaped during the Carboniferous period due to the collision between Laurasia and Gondwana forming the supercontinent Pangea. The following uplift of the Central Basin Platform differentiated the greater basin into the Delaware Basin in the west, and the Midland Basin in the east along with its surrounding shelf margins (Popova, 2020).



Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, & Walsh).



Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)

The target injection interval for the Mongoose is the Ellenburger formation. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician (Sanchez, Loughry, & Coringrato, 2019). The Ellenburger is of lower Ordovician age and underlies the Woodford formation on the Eastern Shelf. The contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition (Sanchez, Loughry, & Coringrato, 2019). Many formations that are present within the Midland Basin are eroded and not seen upon reaching the Eastern Shelf. A cross section showing these truncations is displayed in Figure 5.

A generalized stratigraphic column of the Eastern Shelf is shown in Figure 4, with the target-injection formation indicated by the red star and historically productive formations indicated in the green stars. The Ellenburger formation is roughly 900 ft thick on the Eastern Shelf as shown by the isopach thickness map in Figure 6 (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006). On the Eastern Shelf, the Ellenburger formation dips to the west-southwest, towards the Midland Basin, and its subsea depth is roughly 6,000 ft (Sanchez, Loughry, & Coringrato, 2019). Figure 7 displays a structure map of the Ellenburger formation. Being far from any major sources of terrigenous clastic sediment input and at a time of a greenhouse climate leading to warm waters created an ideal setting primed for massive carbonate production during the Ellenburger deposition (Waite, 2021). The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. Predominant pore types of this group determined by Holtz and Kerans are "ooid grainstone; ooid-peloid packstone-grainstone"

and reservoirs tend to be of good porosity and moderate permeability (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006).



Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf



Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf (Waite, 2021).



Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006)



Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth.

The lower Ordovician period on the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture. Within this dolomite, there were irregular mottling patterns, likely indicative of bioturbation structures. Mudstone and peloid-wackestone, although in

Subpart RR MRV Plan – Mongoose AGI No. 1

smaller quantities, were also observed in the area (Kerans, 1990). To visually represent these different depositional environments and their corresponding lithologies, a map is presented in Figure 8. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger formation underwent significant "karsting" and dolomitization. This karsting process resulted in the formation of extensive paleocave systems within the Ellenburger, which later collapsed and led to the creation of widespread brecciated and fractured carbonates. These formations are responsible for the occurrence of many Ellenburger reservoirs, according to Loucks (2006).



Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

In their research on saltwater disposal (SWD) injection into the Ellenburger, Pioneer Natural Resources describes three distinct facies within the formation as noted in the Figure 9 type log. The upper and middle facies are composed of fracture breccia, breccia fabrics, and matrix-supported breccia, which coincide with collapsed paleo cave facies as described by Loucks. The lower unit does not exhibit these characteristics but shows a high volume of small vugs (inch-scale) and large-dissolution features (foot-scale) and represents an area of the Ellenburger with elevated porosity and permeability (Sanchez, Loughry, & Coringrato, 2019).





2.1.1 Regional Faulting

The modeled area near the Mongoose does not show any faults. However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area. This fault trend runs north-south in parallel with the dip. Figure 7 displays this fault trend, which is the only example of such a trend within the area. Apart from this, the basin area is structurally inactive.

2.2 <u>Site Characterization</u>

The following section discusses site-specific geological characteristics of the Mongoose.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 shows an annotated well log for Mongoose that goes from the surface to the total depth. It indicates the injection and primary upper confining units with regional formation tops.



Figure 10 – Mongoose AGI No. 1 Type Log

2.2.2 Upper Confining Zone – Woodford Shale

The upper confining unit is the Upper Devonian age Woodford formation. The Woodford Shale, a late Devonian-aged organic-rich rock, was created through a widespread marine transgression. The deposition of the Woodford spread across a large area of the Permian Basin, producing a low-relief blanket of shale. The Woodford formation is an organic-rich petroleum source rock comprised of uncharacteristically highly radioactive, dark fissile shale and siltstone (Merril et al., 2015). Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991). As shown previously in Figure 5, the Wristen Group is a formation that lies directly below the Woodford to the west of the Mongoose location. The Wristen Group pinches out and is not found at the Mongoose location. However, the sealing nature of the Woodford, as described by Comer (1991), also provides confinement for the Ellenburger at this location. The Woodford formation overlies both unconformably and is diachronous to the underlying Ellenburger formation at the Mongoose location. The U.S. Geological Survey (USGS) CO₂ Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit (SAU) (Merril et al., 2015).

Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose. The Buchanan 3111 #1XD is approximately 10.4 mi. from the Mongoose as depicted in Figure 11. Figure 12 is a stratigraphic cross section showing the correlating cored Woodford formation (pink triangles representing cored intervals) in the Buchanan 3111 #1XD and the Mongoose wells. Routine core analysis, rock mechanics, and threshold entry pressure tests were performed on the core samples from the Woodford formation.

Core photos of the samples taken and analyzed within the Woodford are shown in Figure 13. The black shale unit exemplifies a well cemented unit with little to no fracturing. Routine core analysis was performed on these two samples, which includes bulk density, matrix permeability (as received and as under dry and Dean Stark extracted conditions), gas-filled porosity, gas saturation, grain density, porosity, oil saturation, and water saturation. The results are shown in Figure 14, with the footnotes at the base giving details on the testing processes of each value.

Under the dry and Dean Stark extracted conditions, permeability values of 2.2E-07 millidarcy (mD) were observed with even lower values of 4.87E-07 mD in the as-received samples. Porosities within the same sample were 1.3% when dried and .25% when gas-filled. These permeability and porosity values reflect optimal confining characteristics and validate the USGS assessment of an appropriate sealing formation for CO_2 storage.

To ensure these sealant properties would not be compromised by pressure influence of the injected fluid, a threshold entry pressure test was examined on these Woodford core samples. Figure 15 depicts a graph of permeability vs. pressure showing that, even with pressure increases up to 2,000 pounds per square inch (psi), permeability readings are still in the nano-darcy range. These values are shown in table form in Figure 16 against the pressures administered on the core, with the highest pressure being 2,000 psi. Given that permeability values were lowest (4.03E-07 mD) at 2,000 psi, it

can be assumed that the threshold entry pressure of the Woodford formation was not met and would be greater than 2,000 psi. Additionally, a table summary is depicted in Figure 17. These characteristics gathered from the Buchanan core provide a high level of detail into the confining nature of the Woodford Shale and alleviate any concerns of transmissibility through the confining unit.



Figure 11 – Buchanan 3111 #XD location -- Offset well for Core Data



Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Woodford and sidewall cores.



Figure 13 – Core Photo of Samples Within the Woodford Formation



CL File No.: 202105972 Date: February 04, 2022 Analyst(s): MP

Shale Core Analysis (Rotary Sidewall Cores)

As received						Dry & Dean Stark Extracted Conditions (2)					
Sample	Depth (ft)	Bulk Density (g/cc)	Matrix Permeability ⁽¹⁾ (mD)	Gas-filled Porosity (%)	Gas Saturation (%)	Grain Density (g/cc)	Matrix Permeability ⁽⁵⁾ (mD)	Porosity (%)	Oil Saturation ⁽³⁾ (%)	Water Saturation ⁽⁴⁾ (%)	
30,31	9076.03 - 9076.26	2.601	4.87E-09	0.25	18.9	2.624	2.22E-07	1.30	3.3	77.8	

Footnotes:

Each sample is a composite of several rotary sidewall cores.

(1) Matrix Permeability is an effective Kg determined from pressure decay results on the fresh, crushed, 20/35 mesh size equivalent sample.

(2) Dean Stark extracted sample (20/35 mesh size) dried at 110 °C. Porosity and saturations are relative to total interconnected pore space.

(3) Oil volume computed assuming an oil density of 0.844 g/cc

(4) Water volume corrected assuming a brine concentration of 80000 ppm NaCl with an ambient density of 1.054 g/cc

(5) Matrix Permeability is an absolute Kg determined from pressure decay results on the clean and dry 20/35 mesh size equivalent sample.

Reference: "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs", GRI-95/0496, Gas Research Institute, April 1996

Figure 14 – Routine Core Analysis Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

Company:Bayswater Exploration & ProductionWell:Buchanan 3111 1XDField:SpraberryLocation:Howard County, TexasFile:HOU-2105972



Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation

PETROLEUM SERVICES

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production Well: Buchanan 3111 1XD Field: Spraberry Location: Howard County, Texas

File: HOU-2105972

Sample 30B							
Gas							
Injection	Permeability						
Pressure,	to Brine*,						
psi	mD						
500	1.44E-06						
750	2.20E-06						
1000	1.46E-06						
1200	6.73E-07						
1400	5.77E-07						
1600	6.72E-07						
1800	5.39E-07						
2000	4.03E-07						

Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation

SUMMARY OF THRESHOLD ENTRY PRESSURE RESULTS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company:	Bayswater Exploration & Production
Well:	Buchanan 3111 1XD
Field:	Spraberry
Location:	Howard County, Texas

File: HOU-2105972

				Final	Threshold
				Permeability	Entry
Sample	Depth,	Length,	Diameter,	to Brine*,	Pressure,
Number	feet	cm	cm	millidarcies	psi
30B	9076.03	2.67	2.54	4.03E-07	TEP>2000

* Apparent permeability to brine with humidified nitrogen displacing water

Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation

2.2.3 Injection Interval – Ellenburger

2.2.3.1 Ellenburger

As described in the Regional Geology section, the Ellenburger at the Mongoose location is a widespread lower Ordovician carbonate deposited over the entire Permian area, indicating a relatively uniform depositional condition (Hendricks, 1964). However, post-depositional sequences have highly altered the section. These sequences have a large influence on the development of the reservoir quality within the injection interval and its ability to accept the proposed injectate. Further analysis based on regional and site-specific data was analyzed, as discussed below, to better understand the reservoir conditions at and around the Mongoose well location.

2.2.3.2 Ellenburger Porosity/Permeability Development

Facies in the low-energy, restricted shelf setting exhibit extensive dolomitization and are characterized by significant bioturbation, resulting in mottling patterns (Loucks, 2003). This dolomitization process has facilitated porosity development within the Ellenburger formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs. These same features were interpreted from the openhole logs in the Mongoose well and core from the Buchanan 3111 #1XD well. A total of 23 sidewall cores were taken within the Ellenburger formation in the Buchanan 3111 #1XD well, with 12 of those having routine core analysis performed on them. Figure 18 shows the results of the analysis.

Porosity values were primarily derived from offset openhole porosity logs within the Ellenburger section. Petrophysical analysis was performed on the offset logs to calculate an effective porosity curve, the porosity of a rock that is available to contribute to fluid flow, to better estimate porosity ranges with regards to injection within the Ellenburger. This is done by accounting for clay content and matrix lithology to better understand the varying porosity within the injection interval and how it relates to injection capacity. The ranges of effective porosity within the modeled wells are 0 to 39.4% with the mean being 4.6%. Figure 19 is a histogram depicting these porosity distributions within the seven modeled wells. These values are validated through similar ranges seen in the core results. The logical inference would be that, as the effective porosity increases, the reservoir quality for injection improves and the associated porosity increment leads to a rise in permeability.

A porosity to permeability relationship was created from this data with the outliers and nonapplicable samples redacted. Additional regional data from Loucks (2003) was incorporated into the relationship to assist with the higher permeability ranges, to ensure that overestimates of permeability were not calculated. The data from Loucks (2003) is exemplified in Figure 20. A twofunction porosity-permeability curve was developed from the regional and local core data. Figure 21 shows the equations and relationships where:

> If Effective Porosity (Φ eff) < 6.5%: $K(mD) = 7E - 08e^{3.3028*\Phi}$ eff If Effective Porosity (Φ eff) > 6.5%: $K(mD) = 277.39 \ln(\Phi eff) - 380.58$

These equations were extrapolated to all the wells within the model including the Mongoose. In Figure 22, the cross section of the Mongoose and Buchanan well is depicted. This illustration showcases the Ellenburger formation, with the sidewall cores from the Buchanan well represented by pink triangles. The calculated permeability curves resulting from the equations mentioned earlier are shown in red, while green represents the effective porosity. High permeability and porosity sections can be seen in both wells, most likely reflecting strata that had prolonged subaerial exposure creating the karst and vug features that will be targeted and utilized for injection. Figure 23 is a core photo from the Buchanan well depicting an example of what a vug feature within the Ellenburger can look like. These features will be taking the bulk of the injection and will be modeled within the area based on openhole log analysis.

Permeability ranges within the seven wells utilized in the model vary from 0 mD to 638 mD, with the mean being 40.822 mD. A histogram representing these ranges and distributions within the seven modeled wells is displayed in Figure 24. This range corroborates with Loucks (2003) and data recovered from the Buchanan well, and it can be concluded that the process used to determine the permeability distributions within the injection interval is valid.

Bayswater Exploration & Production Buchanan 3111 1XD Spraberry Howard County, Texas



CMS-300 ROTARY SIDEWALL ANALYSIS

CL File No.: 202105972 Date: March 31, 2022 Analyst(s): MP

		Net Confining		Permea	ability			Saturation		ration	Grain	
Sample	Depth	Stress	Porosity	Klinkenberg	Kair	b(air)	Beta	Alpha	Oil	Water	Density	Footnote
Number	(ft)	(psig)	(%)	(md)	(md)	psi	ft(-1)	(microns)	% Pore	Volume	(g/cm3)	
23	9236.98	2960	25.81	.259	.389	11.97	3.27E+09	2.75E+00	0.0	94.7	2.666	
21	9257.01	2960	4.77	.002	.009	104.71	2.14E+15	1.48E+04	1.2	66.1	2.746	(1)
19	9363.99	2960	5.23	5.17	5.81	2.07	1.75E+12	2.93E+04	4.1	66.9	2.800	(6)
15	9485.99	2960	3.41	.005	.016	62.63	3.24E+13	5.63E+02	2.3	64.6	2.838	(6)
13	9549.48	Ambient	1.55	N/A	N/A	N/A	N/A	N/A	1.9	44.7	2.829	(5)
12	9604.98	2960	1.63	.00006	.001	354.43	2.46E+18	5.38E+05	2.6	54.0	2.842	(1)
10	9712.03	Ambient	1.28	N/A	N/A	N/A	N/A	N/A	1.2	74.3	2.758	(5)
7	9835.05	2960	2.28	.001	.004	155.69	2.03E+16	4.48E+04	1.5	81.1	2.701	
6	9868.97	2960	3.43	.001	.003	166.37	3.03E+16	5.46E+04	0.9	81.6	2.827	
5	9892.03	2960	3.46	.001	.005	132.61	8.12E+15	2.84E+04	2.1	91.6	2.809	
4	9914.00	2960	5.46	659	669	0.18	1.07E+09	2.29E+03	0.7	58.7	2.835	(6)
3	9969.01	Ambient	11.18	N/A	N/A	N/A	N/A	N/A	1.7	42.9	2.846	(5),(6)

Figure 18 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)



Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells

			Tectonically Fractured
	Karst Modified	Ramp Carbonate	Dolostone
Lithology			
	Dolostone	Dolostone	Dolostone
Depositional			
setting	Inner ramp	Mid- to outer ramp	Inner ramp
		Sub-Middle Ordovician,	
	Extensive sub-	sub-Silurian/Devonian,	
	Middle	sub-Mississippian, sub-	Variable intra-Ellenburger,
Karst facies	Ordovician	Permian/ Pennsylvanian	sub-Middle Ordovician
Fault-related			
fracturing	Subsidiary	Subsidiary	Locally extensive
	Karst-related		
Dominant pore	fractures and	Intercrystalline in	
type	interbreccia	dolomite	Fault-related fractures
		Partial, stratigraphic and	
Dolomitization	Pervasive	fracture-controlled	Pervasive

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

Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)



Porosity vs Permeability

Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Data



Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Ellenburger formation and sidewall cores.



Figure 23 – Core photo of Ellenburger sample displaying vug features.



Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells

2.2.3.3 Formation Fluid

Two wells were identified within approximately 30 miles of the Mongoose through a review of oilfield brine compositions of the Ellenburger formation from the USGS National Produced Waters Geochemical Database (ver. 2.3). The location of these wells is shown in Figure 25. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids (TDS). Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger formation is compatible with the proposed injection fluids.



Figure 25 – Offset wells used for formation fluid characterization.

	Average	Low	High
Total Dissolved Solids (ppm)	47,427	42,014	52,840
рН	7	7	7
Sodium (ppm)	16,384	15,000	17,767
Chlorides (ppm)	27,590	24,900	30,281

Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples

2.2.4 Lower Confining Zone – Precambrian-age Formations

In the Permian Basin area, Precambrian-age formations are not normally specifically named in scientific literature. For the purposes of this MRV, these formations will just be referred to as the "Precambrian". Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sourced from outcrops in central Texas and the Trans-Pecos region of Texas and central New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section (Adams & Keller, 1996).

Adams and Keller conducted a geophysical analysis in 1996 to enhance the understanding of Precambrian rock types and their distribution in the Permian Basin. The study incorporated gravity modeling and magnetic and gravity anomalies, as well as rock data from Precambrian outcrops and drills to interpret the upper crustal geology of the area. Figure 26 displays the map resulting from their investigation, revealing that batholiths are likely present in the Precambrian basement rock at the Mongoose well location. Additionally, samples collected from offset wells displayed predominantly felsic rocks, which led to the interpretation of "granitic bodies in the upper crust" (Adams & Keller, 1996).

Offset Ellenburger injector wells were drilled through the Ellenburger section and reached total depths near the Precambrian. Log characteristics of strata near the total depth of the wells display gamma ray responses well above 90 gamma units of the American Petroleum Institute (GAPI), which is indicative of a high radioactive response. Additionally, the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone.



Figure 26 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)
2.3 Geomechanics

2.3.1 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density of the upper and lower confining and injection zones was calculated from log data at the Buchanan 3111 #1XD (API No. 42-227-41307) offset well. The overburden gradient and vertical stress at the top of each zone were calculated by integrating the bulk density from surface to the formation depth in half-foot intervals. Table 4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Formation	Depth (ft)	Bulk Density (g/cm^3)	Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Woodford	8,322	2.63	164.1	8,563	1.029
Ellenburger	8,375	2.75	171.2	8,635	1.031
Precambrian	9,500*	2.83	176.7	9,937	1.046

Table 4 – Calculated Vertical Stresses

* Estimated

2.3.2 Elastic Moduli and Fracture Gradient

The 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. The calculation requires Poisson's ratio ("v"), overburden gradient (OBG), and pore gradient (PG) in order to determine the required pressure to fracture the formation. These variables can be changed to match the site-specific injection zone.

A thorough review of log data, available literature, and industry standards indicate a 0.465 psi/ft pore gradient should be assumed when there are no site-specific numbers available. Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the Buchanan 3111 #1XD. The calculation was performed using the equation below for log data points at half-foot depth intervals. The results were then averaged for the depth range of each zone. This resulted in a Poisson's ratio of 0.261 for the upper confining zone and 0.273 for the injection zone.

$$v = \frac{\frac{1}{2} \left(\frac{v_p}{v_s}\right)^2 - 1}{\left(\frac{v_p}{v_s}\right)^2 - 1}$$

Where:

v = Poisson's Ratio v_p = Compressional Velocity v_s = Shear Velocity

Log data was unavailable for the lower confining zone, therefore the Poisson's ratio for this zone was estimated through a review of available literature. The lower confining zone consists of granite, which has been observed to have a Poisson's ratio ranging from 0.19 to 0.35 with a mean value of 0.28 (Domede, 2017). Based on this research, an average value of 0.28 was assumed. Using these values in the equation below, a fracture gradient of 0.664 psi/ft was calculated for the upper confining zone. A 10% safety factor was applied to this number resulting in a maximum allowed bottomhole pressure of 0.598 psi/ft. This zone had the lowest fracture gradient of the confining and injection zones. It was used to define the maximum allowable pressure to ensure that the injection pressure would not exceed the fracture pressure of any of the three zones. The resulting fracture gradients are displayed in Table 5.

Example Fracture Gradient Calculation for Upper Confining Zone

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

$$FG = \frac{0.261}{1 - 0.261} (1.029 - 0.465) + 0.465 = 0.664 \, psi/ft$$

$$FG \text{ with } SF = 0.689 \times 90\% = 0.598 \text{ } psi/ft$$

Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
8,322	Upper Confining	Woodford	1.029	0.465	0.261	0.664
8,375	Injection	Ellenburger	1.031	0.465	0.273	0.678
9,500*	Lower Confining	Precambrian	1.046	0.465	0.28	0.691

*Estimated

2.4 Local Structure

The area surrounding the Mongoose well is characterized by a monoclinal dip from east to west that is influenced by a shallow westward slope towards the Midland Basin and an upward slope to the east towards the Eastern Shelf. No evidence of structural faulting was found in this specific region that could have affected the geological trend. Figure 27 shows the topography of the Ellenburger formation, with the Mongoose well marked by a black star.

Subsurface interpretations of the Ellenburger formation heavily relied on well data and 3D seismic coverage in the area. The black boundary in Figure 27 represents the extent of the seismic coverage. Within the mapped area, approximately 100 wells have penetrated the Ellenburger formation. However, only seven of these wells fully penetrated the entire Ellenburger section. The remaining 93 wells only reached the top of the Ellenburger formation. These wells are plotted on the map and cover four counties. In addition to the Mongoose well, six other wells located offset of the Mongoose were used for the model build and are indicated by red stars.

Figure 28 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map. The Ellenburger was broken down into eight subsections labeled Ellenburger A through H. Figure 29 is a stratigraphic cross section flattened on the Ellenburger that better illustrates these subtops.

The cross sections reveal the regional unconformity in the area when moving east from the Midland Basin. As we go farther updip and to the east, the Fusselman section gradually erodes. While there is also thinning in the Woodford, the cross section shows that the Woodford is present throughout the modeled area, creating a continuous seal above the plume.

With no major structural or stratigraphic features within the injection interval in the Mongoose area, there is little to no concern of geologic conduits outside of the injection interval. General flow trends will follow dip and optimal reservoir features within the Ellenburger. Large scale versions of Figures 28 and 29 are provided in *Appendix C*.



Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map.



Figure 28 – Structural cross section depicting the Ellenburger.



Figure 29 – Stratigraphic cross section flattened on the Ellenburger.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger formation at the Mongoose location indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity. The Woodford Shale formation at the same well location has low permeability and is of adequate thickness and lateral continuity to act as the upper confining zone. Below the injection interval, the Precambrian formation has low permeability and low porosity, making it unsuitable for fluid migration and serving as the lower confining zone.

A thorough study of the area of review has been conducted to identify any potential subsurface features that could impact the ability of the injection and confinement units to retain the injectate within the desired injection interval. Fortunately, no faults or other hazardous geologic conditions have been identified in the area. Therefore, the conditions in this area are ideal for injection and containment.

2.6 Groundwater Hydrology

The Mongoose is located within Mitchell County, home to a population of approximately 8,400 residents, and is serviced by the Lone Wolf Groundwater Conservation District, which consists solely of Mitchell County. This conservation district has an area of roughly 900 square miles. Much of the county's economy is derived from agriculture and oil production, both water-intensive operations. Groundwater usage within the county is estimated to be 13,391 acre-feet on a yearly basis (Lone Wolf Groundwater Conservation District, 2019).

Surface Water

Mitchell County lies within the Colorado River basin, as the Colorado runs through the county. Drainage from both the east and west flow centrally towards the Colorado River, which splits the county in half. The estimated supply of surface water is 395 acre-feet (Lone Wolf Groundwater Conservation District, 2019).

Groundwater

There are multiple units where groundwater is available within Mitchell County, although only the Dockum Group provides significant amounts of water. Table 6 discusses water-bearing units in the county, and Figure 30 shows a generalized reference to structure and formation relationships.

Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger Jr., 1967)

System	Series	Group	Formation	Approximate thickness (feet)	Lithology	Water-bearing characteristics
Quaternary	Pleistocene and Recent		Alluvium	0-100	Fine to coarse sand, and small to large gravel, with occasional clay and caliche beds.	Above the regional water table east of Colo- rado River, but yields up to 20 gpm of good quality water in southwestern Mitchell County.
Tertiary	Pliocene		Ogallala	0-100	Fine to coarse sand, gravel, caliche, and zones of clay.	Above the water table east of Colorado River, but yields up to 20 gpm of good quality water to wells in northwestern Mitchell County.
		Fredericksburg		0-220	Predominantly limestone. 15 to 25 feet of sandy yellow marl at base overlain by chalk and shaly limestone. Very dense, massive, fossiliferous lime- stone in the upper part.	Upper limeatones contain in places small to moderate supplies of potable but hard water in solutional openings developed along fracture systems; recharge to the openings occurs through numerous sinks.
Cretaceous	Comanche	Trinity		0-100	White to purplish quartz sand, fine to medium grained, moderately to loosely consolidated, with occasional lenses of quartz gravel at the base.	Yields small to large quantities of potsble but hard water, the amount depends on saturated thickness which renges from 100 percent under interior limestone areas to a few feet in parts of the outcrop; yields of several hundred gallons per minute are reported.
		Dacker	Chinle	0-640	Predominantly red to marson and pur- plish clay and shale, interbedded with thin, tight, cross-bedded, yellow-brown to reddish-white sand- stone.	Sandstones contain generally small quantities of moderately to highly mineralized water; used principally for livestock.
ITTASSIC		poek dag	Santa Rosa	0-330	Basal conglomerate overlain by brown to gray, micaccous and carbonaccous, cross-bedded sand alternating with beds of red and gray clay.	Sands and gravels contain moderate to large quantities of fresh water east of the Colorado River, with yields up to 1,000 gpm reported; west of Colorado River capa- city of sand is reportedly substantial but water is generally not potable.
Permain	Guadalupe and Ochoa				Fine-grained, red to brown sandstone; dense red silty shale with occasional gypsum or anhydrite beds.	Yield small quantities of moderately to high- ly mineralized water to livestock and domestic wells.



Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)

Permian

Permian age strata underlies much of the area and outcrops in the southeast of Mitchell County and along the Colorado River and its tributaries. These strata consist primarily of "red beds," dense red silty shales. Water wells in the Permian strata are typically less than 100 ft deep, yielding small amounts of moderately to highly mineralized water usable only for livestock (Shamburger Jr., 1967).

Dockum Aquifer

The Triassic Age Dockum group comprised by the Santa Rosa sandstone and the Chinle formation are the main sources of ground water within the county. An overview map of the extent of the Dockum Aquifer is shown in Figure 31, with outcrops depicted in solid color. The Chinle is further divided into the Tecovas formation, the Trujillo sandstone, and the Cooper Canyon formation, although the Tecovas and Cooper Canyon are generally unimportant and yield only small amounts of highly mineralized water.

The Santa Rosa sandstone lies unconformably atop the Permian age strata at the base of the Dockum Group and is one of the major sources of water for Mitchell County. It is comprised of a basal conglomerate overlain by alternating beds of red and gray micaceous shale, sand, and gravel reaching up to 130 ft in thickness (Bradley & Kalaswad, 2001). The Trujillo sandstone overlies the Tecovas, which in turn overlies the Santa Rosa, and is a cross-bedded unit composed of sandstones and conglomerates. The Santa Rosa and Trujillo sandstones are regarded as the main producers of water in the Dockum Group in Mitchell County (Lone Wolf Groundwater Conservation District, 2019). The Dockum Group was likely deposited from sediments into "fluvial, deltaic, and lacustrine environments within a closed continental basin" (Bradley & Kalaswad, 2001). The base of the Santa Rosa is typically considered the lower extent of fresh water in the area. Water levels in wells throughout the county vary between 15 ft and 215 ft below ground level (Shamburger Jr., 1967), and the aquifer is considered confined to partially confined (Bradley & Kalaswad, 2001).

Recharge of the aquifer is provided by rainwater infiltration through outcrops in the county and is estimated to be 18,108 acre-feet per year. Groundwater in the Dockum aquifer system flows towards the central Colorado River. A potentiometric surface map of the Santa Rosa sandstone, the lower Dockum member, is depicted in Figure 32. Although no values of porosity have been determined empirically, a conservative value of 10% is assumed for effective aquifer porosity (Lone Wolf Groundwater Conservation District, 2019).

Groundwater quality is generally considered poor with TDS and other constituents exceeding secondary drinking water standards (Bradley & Kalaswad, 2001). As a typical assumption, water quality west of the Colorado River within the aquifer is poor and unsuitable for municipal use, while east of the river water quality is less mineralized and is of suitable quality for municipal purposes (Lone Wolf Groundwater Conservation District, 2019). For example, a well tested 10 miles northwest of Colorado City contained chloride at 560 milligrams per liter (mg/L), sulfate at 337 mg/L, and TDS at 1,893 mg/L, all of which are above limits set by the Texas Commission on Environmental Quality (TCEQ) for use in municipal water supplies. In contrast, a well 8 miles east of Colorado City contained

chloride at 34 mg/L, sulfate at 73 mg/L, and TDS at 418 mg/L (Lone Wolf Groundwater Conservation District, 2019). A map showing TDS values for the Dockum Aquifer is shown in Figure 33.



Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location (George, Mace, & Petrossian, 2011).



Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986).



Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011).

Ogallala Formation

The Tertiary age Ogallala formation occurs in the northern extents of Mitchell County. In the eastern part of the county, Ogallala sediments are generally above the water table and not a source of groundwater; however, they do provide an effective means of recharge to the underlying Santa Rosa formation. In the western part of the county, the Ogallala is up to 100 ft thick of unconsolidated sand and gravel and provides small quantities of usable water for domestic and livestock wells (Lone Wolf Groundwater Conservation District, 2019).

2.7 <u>Description of the Injection Process</u>

2.7.1 Current Operations

The Mongoose Amine Treating Facility and the associated Mongoose well began operating in August of 2023. The maximum rate during the injection period is expected to be 377.2 MT/yr (19.5MMscf/d). The TAG is 41.2% CO₂, which equates to 155.3 MT/yr of CO₂ each year. The current composition of the TAG stream is:

Component	Mole Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

The Mongoose Amine Treating Facility is designed to dehydrate, treat, and compress the natural gas produced from the surrounding acreage in Mitchell County. The gas is dehydrated to remove the water content, and treated to remove the CO₂ and H₂S. The compressed rich gas stream is then transported via pipeline to a separate facility for processing to separate the natural gas liquids from the methane. The TAG is then directly routed from the Plant's amine unit to the Mongoose. The Plant is manned 24 hours per day, 7 days per week.

2.8 <u>Reservoir Characterization Modeling</u>

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (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 Ellenberger formation is the target formation for the Mongoose. The Petrel software package was utilized to create the geologic model of the target formation. Within the Petrel platform, the porosity and permeability distributions were established for the model. The geologic structure was then imported into GEM for simulation purposes.

In Petrel, the structure's construction involved the utilization of nine contour tops, which were layered sequentially. These contour tops, identified as "Ellenberger A" through "Ellenberger I," collectively define the structure's configuration, Ellenberger A being the shallowest and Ellenberger I being the deepest structure package. To accurately represent the formation's true structure, true vertical depth subsea was used to account for the differing overburden depths associated with the

wells used in contour delineation. The distinction between true vertical depth (TVD) and true vertical depth subsea (TVDSS) is taken into consideration when inputting pressure and temperature gradients into the GEM model.

Porosity estimates were determined using openhole porosity logs from seven offset wells within the Ellenberger formation. These logs were used within Petrel to distribute porosity and permeability spatially. Permeability was found by using the two-function porosity-permeability curve developed from regional and local core data within the Ellenberger formation.

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 H₂S and CO₂ based on initial estimates from the source, as shown in Table 8. However, the precise gas composition may vary slightly as the Plant is still in its commissioning phase. Initial estimates anticipate the injectate composition to be 58.8% H₂S and 41.2% CO₂. Once a steady-state operating composition is determined, the MRV plan will be updated if there is a material difference. Based on the initial gas samples, the modeled percentages in the injectate for the 40-year injection period of the Mongoose is 58.8% H₂S and 41.2% CO₂.

Table 8 – Modeled Initial Gas Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Hydrogen Sulfide (H ₂ S)	58.8	58.8
Carbon Dioxide (CO ₂)	41.2	41.2

Core data from literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Ellenberger dolomitic carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 10%, an irreducible water saturation of 39.7%, and a maximum residual gas saturation of 30%. The relative permeability curves used for the GEM model are shown in Figure 34.



Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 135 blocks in the x-direction (east-west) and 77 blocks in the y-direction (northsouth), resulting in a total of 10,395 grid blocks per layer. Each grid block spans dimensions of 1,000 ft by 1,000 ft. This configuration yields a grid size measuring 135,000 ft by 77,000 ft, equating to just under 373 square miles in area. The grid cells in the vicinity of the Mongoose, within a radius of 2.5 miles, have been refined to dimensions of 250 ft by 250 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume.

In the model, each layer is characterized by heterogeneous permeability and porosity values. These values are derived from the geostatistical distribution of properties, using porosity logs implemented in Petrel as a basis. The model encompasses a total of 79 layers, each featuring varying thicknesses, with an average of approximately 10 ft per layer. As previously mentioned, the structure of the Ellenberger formation was formed using nine contour packages. The summarized property values for each of these packages are displayed in Table 9.

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Ellenberger A	9	8,369	101	49.1	5.2%
Ellenberger B	9	8,470	76	65.1	6.0%
Ellenberger C	8	8,546	75	38.5	4.2%
Ellenberger D	9	8,621	86	39.2	4.9%
Ellenberger E	15	8,707	153	48	4.8%
Ellenberger F	6	8,860	63	32.5	4.4%
Ellenberger G	4	8,923	39	16.5	3.2%
Ellenberger H	8	8,962	82	76.9	5.5%
Ellenberger I	11	9,044	112	66	3.4%

Table 9 – GEM Model Layer Package Properties

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

- 1. Estimate the maximum areal extent and density drift of the acid gas plume after injection.
- 2. Assess the impact of offset SWD well injection on density drift of the plume.
- 3. Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone.
- 4. 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 47,427 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The acid gas stream is primarily composed of CO₂ and H₂S as stated previously. Core data was used to help generate relative permeability curves. From the literature reviews as previously discussed, cores that most closely represent the vuggy dolomitic carbonate seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975). The initial reservoir pressure is 3,903 psig, which is equivalent to a 0.465 psi/ft pressure gradient and was determined from offset injection well analysis. The fracture gradient of the injection zone was estimated to be 0.664 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.598 psi/ft, which is equivalent to 5,007 psig.

The model considers the injection volumes of offset SWD wells close to the Mongoose. Nine such wells were identified within a 19-mile radius. Historical injection rates of eight of the nine of these wells currently injecting into the Ellenberger were provided by the operators and were input into

the model. All but one of the SWD wells in the model are currently permitted and injecting. The SWD well that has not yet started injection and has no historical injection data is conservatively assumed to inject at its maximum permitted rate for 30 years and to start at the same time as the Mongoose begins injection. Projected injection rates were assumed to be the maximum permitted injection rates and ended after 30 years of life for all nine offset SWDs. This simulation includes the effect of water injection on the density drift of the plume and the bottomhole pressure of the Mongoose. The SWDs included in the model are listed in Table 10.

API Number	Well Name	Well Number
42-227-41332	Fryar 3S	2XD
42-227-41307	Buchanan 3111	1XD
42-227-39064	Pipeline SWD 1	
42-335-34319	Wild Bill 1WD	
42-227-41775	Sterling	1XD
42-335-36026	Oasis Deep 9XD	
42-227-39098	846 SWD	2
42-227-39119	N. Midway SWD 1	
42-227-40310	Hull SWD 1	

Table 10 – Offset SWD Wells Included in GEM Model

The model runs for a total of 175.33 years, comprising 15.33 years of historical SWD well injection prior to the commencement of acid gas injection. This is followed by 40 years of active acid gas injection through the Mongoose, succeeded by an additional 120 years of density drift. The model begins in September 2008, aligning with the start of historical injection data for the first offset SWD well. The remainder of the SWD wells turn on between then and the start of the acid gas injection, which begins in January 2024. Throughout the entire 40-year injection period, an injection rate of 19.5 MMscf/D is assumed to model the maximum available rate, yielding a more cautious estimate of the plume size. After the 40-year injection period, when the Mongoose ceases injection, all nine offset SWD wells have been shut in—as they began injecting before the Mongoose and were assumed to stop injecting after 30 years.

The maximum plume extent during the 40-year injection period is shown in Figure 35. The final extent after 120 years of density drift after injection ceases is shown in Figure 36. Both figures show the entire grid with the included offset SWD wells. Due to the large nature of the model, a zoomed-in view of the plume extent during the 40-year injection period is shown in Figure 37 and the final extent after 120 years of density drift after injection ceases is shown in Figure 38.



Figure 35 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)



Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

The cross-sectional view of the Mongoose shows the extent of the plume from a side-view angle cutting through the formation at the wellbore. Figure 39 shows the maximum plume extent during the 40-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 40 shows the final extent of the plume after 120 years of migration. At this point in time, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, as it is less dense than the formation brine, until an impermeable layer is reached. Both figures are shown in a north-to-south view.



Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 40 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)

Figure 41 shows the surface injection rate, bottomhole pressures, and surface pressures over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate begins, reaching a maximum pressure of 4,453 psig, then slightly decreases and remains constant. This buildup of 550 psig keeps the bottomhole pressure below the fracture pressure of 5,007 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,008 psig, well below the maximum allowable 2,500 psig per the TRRC UIC permit for this well. At roughly 30 years into injection for the Mongoose, all SWD wells included in the model have ceased injection. Due to the shut-in of offset SWD wells, the pressure effects within the formation are felt by the Mongoose. When this occurs, the bottomhole pressure decreases by 50 psig and surface pressure decreases by 40 psig. Bottomhole and wellhead pressures over time are in Table 11.



Figure 41 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injection	Table 11 – Bottomhole an	d Wellhead Pressures	Over Time from	Start of Injection
--	--------------------------	----------------------	----------------	--------------------

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	3,916	-
10	4,389	1,977
20	4,394	1,982
30	4,393	1,980
40	4,343	1,942
50	3,923	-
120	3,919	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in 40 CFR **§98.448(a)(1)**.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO₂ plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

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

Bayswater's expected gas composition was used in the model. The acid gas injectate is estimated at a molar composition of 58.8% H₂S and 41.2% CO₂, with trace amounts of other constituents. Upon the Plant achieving stable operations, a representative injectate sample will be collected and analyzed by a third-party laboratory. If the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be provided. As discussed in *Section 2*, the gas will be injected into the Ellenberger formation. The geomodel was created based on the rock properties of the Ellenberger.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 40, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast.

Figure 42 shows the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA is depicted in this figure by taking the stabilized plume boundary after 120 years of density drift, and adding an all-around buffer zone of one half mile.



Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. This provides Bayswater sufficient time to develop its asset base, achieve steady operations, and evaluate any potential modifications to the MRV plan.

The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free-phase CO₂ plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. By 2036, a revised MRV plan will be submitted to define a new AMA. Figure 43 shows the area covered by the AMA.



Figure 43 – 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. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within the MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from natural or induced seismicity

Table 12 – Potential Leakage Pathway Risk Assessment
--

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. The lateral continuity of the UCZ ¹ is recognized as a very competent seal.	Low. Any vertical migration from the Injection Zone would return the CO ₂ to the production zone.	During active injection and Post Injection Site Care ² period.
Faults and fractures	Possible. The lateral continuity of UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO ₂ to the production zone.	During active injection and Post Injection Site Care period.
Upper confining layer	Unlikely. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO ₂ to the production zone.	During active injection and Post Injection Site Care period.
Natural or induced seismicity	Possible. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO ₂ to the production zone.	During active injection and Post Injection Site Care period.

1 - UCZ is defined as the Upper Confining Zone.

2 - Post Injection Site Care is the period of time from the end of injection throught plume stabilization and site closure.

Magnitude Assessment Description

Low - catergorized as little to no impact to safety, health and the environment and the costs to mitigate are minimal.

Medium - potential risks to the USDW and for surface releases does exist, but circumstances can be easily remediated.

High - danger to the USDW and significant surface release may exist, and if occurs this would require significant costs to remediate.

4.1 Leakage from Surface Equipment

The Plant and Mongoose are newly designed and constructed facilities for treating and injecting acid gas with the fundamental objective of ensuring maximum safety for the public, the employees, and the environment. These are depicted in Figures 44 and 45. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H₂S are installed at key locations around the Plant as depicted on the site plan in Appendix B-2. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H₂S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the TRRC with the Class II AGI application. OSHA sets the detection or exposure limits at 15 ppm as the High Alarm and the High- High Alarm or Facility Shutdown limit at 40 ppm.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant and the Mongoose well. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs. These valves, gas monitors, and the gas flow meter are called out in the detailed site plan in Appendix B-2. Data from this flow meter will be used in the calculations of the total mass of CO₂ (in metric tons) in the CO₂ stream injected each year, per 40 CFR **§98.444(b)**.



Figure 44 – Site Plan



Figure 45 – Mongoose AGI No. 1 Wellbore Schematic

With the level of monitoring implemented at the Plant, a release of CO_2 would be quickly identified, and the safety systems and protocols would minimize the release volume. The acid gas stream injected into the well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the Plant adjacent to the Mongoose. Bayswater will increase its future injection volumes from its own gas production and possibly other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7* in accordance with 40 CFR **§98.448(a)(5)**. Bayswater concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The Mongoose was designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 45. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) §3.46 [40 CFR §146.23 (b)(3)], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 46. The MMA review map and a summary of all wells in the MMA is provided in *Appendix C*. Figure 47 highlights that only two wells penetrate the MMA's gross injection zone. These wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements. Bayswater will perform baseline soil gas sampling prior to the implementation of the MRV plan and subsequent injection records. In addition, annual soil gas samples will be taken in the area adjacent to artificial penetrations and analyzed by a third-party lab. The results, should they indicate an issue with the sequestered CO₂ will be presented in the annual report to the GHGRP.

The summary of all oil and gas wells in *Appendix C* also provides the total depth (TD) of all wells within the MMA. Those wells that are shallower and do not penetrate the injection zone are isolated by the Woodford Shale as discussed in Section 2.2.2. The Woodford Shale provides 50 feet or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset APs is unlikely.

Bayswater is the operator of many of the shallower offset oil and gas wells within the MMA and frequently performs gas analysis on their production volumes. If a material variance in the quantity of CO_2 produced is indicated, Bayswater would investigate to determine the affected well(s), the root cause of the CO_2 increase to formulate a resolution plan and utilize the gas analysis variance to calculate any adjustments to reported volumes.



Figure 46 – All Oil and Gas Wells Within the MMA



Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC in the area of the Mongoose will include a list of formations for which operators are required to comply with TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC §3.13. The Mongoose drilling permit, provided in Appendix A, serves as an example. The Ellenburger is among the formations listed for which operators in Mitchell County and District 8 (where the Mongoose is located) are required to comply with TRCC Rule 13. The rule requires oil and gas operators to set steel casing and cement either (1) across and above all formations permitted for injection under TRRC Rule 9, or (2) immediately above all formations permitted for injection under Rule 46, for any well proposed within a quarter-mile radius of an injection well. In this instance, any new well permitted and drilled to the injection zone and located within a guarter-mile radius of the Mongoose will be required under TRRC Rule 13 to set steel casing and cement above the well's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and 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 (also provided in the permit in Appendix A).

4.2.2 Groundwater Wells

A groundwater well search results found three wells within the MMA, as identified by the Texas Water Development Board. A field investigation was performed to validate the existence and location of these wells. However, none of the wells listed in the database could be located. An exhaustive search of well records was performed and no completion reports and/or plugging records were found. The result is there are no groundwater wells to monitor as none exist within the MMA.

The surface, intermediate, and production casing strings in the Mongoose, as shown in Figure 45, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations and the GAU letter issued for this location (and included in *Appendix A*). The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Bayswater concludes that leakage of the sequestered CO_2 to the groundwater aquifer is unlikely.

4.3 Leakage Through Faults and Fractures

No faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose. This includes areas well outside of the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

In the event of an unmapped fault existing within the plume boundary, any displacement caused by it would be too small to be detected through 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

Porosity development within the injection intervals is primarily attributed to fractures and aerial exposure. However, these fractures are limited and do not extend into the upper confining unit, which helps mitigate the risk of migration through fractures outside of the designated injection interval.

4.4 Leakage Through the Confining Layer

The overlying Woodford formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in *Section 2*. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale which would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

4.5 Leakage from Natural or Induced Seismicity

The Mongoose is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

All seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

Stringent operating procedures will be programmed into the SCADA and control systems to ensure that operating pressures stay below the fracture gradient of both the injection and confining intervals. Moreover, a combination of continuous well monitoring and monitoring of the TexNet site for activity will promptly identify any irregularities in the operations linked to seismic events.


Figure 48 – Seismicity Review (TexNet – 08/04/2023)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Bayswater 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 H₂S and CO₂, the H₂S will be a proxy for CO₂ leakage and therefore the monitoring systems in place to detect H₂S will also indicate a release of CO₂. Table 13 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 40-year injection period or cessation of injection operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

Leakage Pathway	Monitoring Method
	Fixed H ₂ S monitors throughout the AGI facility
Leakage from surface equipment	Visual inspections
	SCADA continuous monitoring of the AGI facility
	SCADA continuous monitoring of the AGI well
	Monitor CO ₂ levels in Above Zone producing wells
Leakage through existing wells	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Annual soil gas sampling at well locations that penetrate the Upper Confining Zone within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	Compliance with TRRC Rule 13 Regulations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI well (volumes and pressures)
Leakage through launs and fractures	Monitor CO ₂ levels in Above Zone producing wells
Lookage through the confining lover	SCADA continuous monitoring at the AGI well (volumes and pressures)
Leakage through the contining layer	Monitor CO_2 levels in Above Zone producing wells
Leakage from natural or induced exisminity	Monitor CO ₂ levels in Above Zone producing wells
	Monitor existing TexNet station

Table 13 – Summary of Leakage Monitoring Methods

5.1 <u>Leakage from Surface Equipment</u>

The Plant and the Mongoose were designed to operate in a manner that will reduce to the lowest factor the possibility of an escape of CO₂ and H₂S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO₂ concentration will be established during the commissioning of the Plant. Ambient H₂S monitors are located at the Plant and near the Mongoose for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in *Appendix B*. The locations of H₂S detectors and Emergency Shutdowns are identified throughout the facility on the Appendix B-2 Site Plan. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Bayswater to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO₂ released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

5.2 Leakage Through Existing and Future Wells Within the MMA

Bayswater continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the Mongoose. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, an MIT will be performed every 5 years, as required by the TRRC and UIC. A failed MIT would also indicate the potential of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 ensures that new wells in the field would be constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Bayswater will also establish an in-field soil gas monitoring program to detect CO_2 leakage within the AMA. This would include sample collection and testing for CO_2 and H_2S at the AGI well site and near one of the identified artificial penetrations of the injection interval within the AMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. Prior to approval and implementation of

the MRV plan and through the post-injection site care period, Bayswater will have these monitoring systems in place.

There are currently only two wells that have been identified within the AMA that penetrate the Upper Confining Zone. As both wells have been plugged and abandoned in compliance with TRRC requirements, Bayswater believes a leak event is unlikely. Bayswater will perform soil gas sampling and analysis proximate to the Mongoose and one of the abandoned artificial penetrations by May 20, 2024. Thereafter, soil gas samples will be taken annually and analyzed by a third-party lab, and the results will be included in the annual report.

Bayswater is the operator of record for many oil and gas producing wells with the AMA. These wells will be used as a proxy for an above-zone monitoring well. If any CO_2 , migrates up-hole, the CO_2 would likely end up in this formation. Since gas analysis is performed on a regular basis on the hydrocarbons produced from this formation, any material variance from historical data would indicate the potential of an issue needing further investigation. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance. It is not the intent of Bayswater to produce any of the CO_2 in this scenario but to use this as an indication of an event warranting further investigation.

5.2.1.1 Groundwater Quality Monitoring

As explained in *Section 4.2.2,* there are no groundwater wells within the MMA. Therefore, there are no groundwater wells to monitor.

5.3 <u>Leakage Through Faults, Fractures, or Confining Seals</u>

Bayswater continuously monitors the operations of the Mongoose 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 due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Bayswater will also monitor production from their oil and gas wells that do not penetrate the injection zone for any material variance in CO₂ content in the produced gas stream. Since gas analysis is very consistent over time, any material variance in the CO₂ content would be an early indicator of a potential issue. Should the CO₂ migrate vertically, the magnitude risk of this event is very low, as the reservoir provides an ideal containment given the Upper Confining Zone has successfully held hydrocarbons in place. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Bayswater plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose well. This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 49. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Bayswater facility. Bayswater will monitor this station for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected, Bayswater will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.



Figure 49 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

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

6.1 Visual Inspections

Regular inspections will be conducted by field personnel at the Plant and the Mongoose. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken in a prudent and safe manner to address such issues.

6.2 <u>CO₂/H₂S Detection</u>

In addition to the fixed gas monitors at the well site, Bayswater will perform an annual soil gas sampling program to detect any CO_2 leakage proximate to select artificial penetrations of the Upper Confining Zone within the AMA. The baseline determination will include atmospheric H₂S measurements at the AGI well and soil gas sampling near the AGI well and one of the abandoned artificial penetrations within the AMA.

These soil gas sample probes will be inserted below the surface. The probes have special material inserts that collect the gas samples over a 21-day period. These inserts are then removed and sent to a third-party lab to be analyzed for CO_2 , H_2S , and trace contaminants typically found in a hydrocarbon gas stream. This initial sample collection is scheduled to be completed by May 20, 2024; a sufficient time period prior to the implementation of the MRV plan and will establish baseline values for future reference.

6.3 **Operational Data**

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO₂.

6.4 <u>Continuous Monitoring</u>

The total mass of CO₂ emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel due to the presence of H₂S in the gas stream. Continuous monitoring systems will trigger an alarm if there is a release. The mass of the CO₂ released would be calculated based on the operating conditions,

including pressure, flow rate, percentage of CO₂, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a de-pressuring event, the acid gas stream will be diverted to a flare stack to be safely processed and vented. The event will be reported as required for the operation of the well.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO₂ Received

Per 40 CFR **§98.443**, the mass of CO₂ received must be calculated using the specified CO₂ received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4)**." 40 CFR **§98.444(a)(4)** states that "if the CO₂ you receive is wholly injected and is not mixed with any other supply of CO₂, you may report the annual mass of CO₂ injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO₂ received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO₂ received." The CO₂ received for this injection well is wholly injected and not mixed with any other supply; the annual mass of CO₂ injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO₂ 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 volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, 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 CO₂ mass injected (metric tons) as measured by flow meter u

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO₂ Produced

The Mongoose is not part of an enhanced oil recovery project; therefore, no CO₂ will be produced.

7.4 Mass of CO₂ Emitted by Surface Leakage

The mass of CO₂ emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains high concentrations of H₂S. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions sent to a flare stack and reported as a part of the required GHG reporting for the Plant. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of CO₂ and H₂S. The mass of the CO₂ released would be calculated for the operating conditions, including pressure, flow rate, size of the leak-point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO₂ was released because of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

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

Where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

Calculation methods using equations from Subpart W will be used to calculate CO₂ emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Bayswater believes the most appropriate method to quantify the mass of CO₂ released will be determined on a case-by-case basis. Any mass of CO₂ detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. In the unlikely event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events will be kept and stored as stated in *Section 10*.

7.5 Mass of CO₂ Sequestered

The mass of CO₂ sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Since the Mongoose has commenced operations, Bayswater will begin collecting data for reporting under this plan based on the approval of this MRV plan and any applicable stipulations therein. The calculation of sequestered volumes utilizes the following equation as this well will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

 CO_{21} = 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 CO₂ 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 is expected to occur, the calculations would be based on an unusual event that a blowdown is required and those emissions are sent to a flare stack and reported as part of the required GHG reporting for the Plant.

• Calculation methods from Subpart W will be used to calculate CO₂ 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 Mongoose is a new injection well currently reporting under the TRRC Class II regulations. Bayswater is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

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

9.1 Monitoring QA/QC

CO₂ Injected

- The flow rate of the CO₂ being injected will be measured with a volumetric flow meter, consistent with applicable industry standards. These flow rates will be compiled quarterly.
- The composition of the injectate stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with applicable industry standards.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The gas measurement equipment will be calibrated per the requirements of 40 CFR §98.444(e) and §98.3(i).

CO₂ Emissions from Leaks and Vented Emissions

- Gas monitors within the Mongoose facility will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.
- Calculation methods from Subpart W will be used to calculate CO₂ emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR §98.3(i).
- Flow meters will be operated and maintained in accordance with applicable standards as published by a consensus-based standards organization.

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

9.2 Missing Data

In accordance with 40 CFR **§98.445**, Bayswater 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 CO₂ injected is missing, the amount will be estimated using a representative quantity of CO₂ injected from the nearest previous period at a similar injection pressure.

• Fugitive CO₂ emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR **§98**.

9.3 MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Bayswater will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least 3 years and include the following:

- Quarterly records of the CO₂ injected
 - Volumetric flow at standard conditions
 - Volumetric flow at operating conditions
 - Operating temperature and pressure
 - Concentration of the CO₂ stream
- Annual records of the information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of the information used to calculate CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 11 - REFERENCES

- Adams, D. C., & Keller, G. R. (1996). Precambrian Basement Geology of the Permian Basin Region of West Texas and Eastern New Mexico: A Geophysical Perspective1. *AAPG*.
- Aird, P. (2019). *Deepwater Geology & Geoscience*. Retrieved from ScienceDirect: https://www.sciencedirect.com/topics/engineering/overburden-stress
- Bradley, R. G., & Kalaswad, S. (2001). *Chapter 12: Dockum Aquifer in West Texas*. Texas Water Development Board.
- Bennion, B., & Bachu, S. (2010). Drainage and Imbibition CO₂/Brine Relative Permeability Curves at Reservoir Conditions for Carbonate Formations. *SPE Annual Technical Conference and Exhibition*.
- Comer, J. B. (1991). Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas asn Southeatern New Mexico. *BEG*.
- Conselman, F. B. (1954). Preliminary Report on the Geology of the Cambrian Trend of West Central Texas. *Abilene Geologic Society*.
- Domede, P. S. (2017). *Mechanical behaviour of granite. A compilation, analysis and correlation of data from around the world*. Retrieved from https://hal.insa-toulouse.fr/hal-01743870/document
- Dutton, A. R., & Simpkins, W. W. (1986). *Hydrogeochemistry and Water Resources of the Triassic Lower Dockum Group in the Texas Panhandle and Eastern New Mexico*. Austin Tx: Bureau of Economic Geology.
- Fanchi, J. R. (2010). Integrated Reservoir Asset Management.
- Galley, J. (1958). Oil and Geology in the Permian Basin of Texas and New Mexico. *Basin or Areal Analysis or Evaluation*.
- Gunn, R. D. (1982). Desmoinesian Depositonal Systems in the Knox Baylor Trough. *North Texas Geological Society*.
- Hendricks, L. (1964). STRATIGRAPHIC SUMMARY OF THE ELLENBURGER GROUP OF NORTH TEXAS. *Tulsa Geological Society Digest, Volume 32*.
- Hornhach, M. J. (2016). Ellenburger wastwater injection and seismicity in North Texas. *Physics of the Earth and Planetary Interiors*.
- Jesse G. White, P. P. (2014). Reconstruction of Paleoenvironments through Integrative Sedimentology and Ichnology of the Pennsylvanian Strawn Formation. *AAPG Southwest Section Annual Convention, Midland, Texas.*
- Keelan, K., & Pugh, V. (1975). Trapped-Gas Saturations in Carbonate Formations. SPE J. 15: 149–160.
- Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas. *Bureau of Economic Geology*.
- Lone Wolf Groundwater Conservation District. (2019). *Management Plan 2019-2024.* Colorado City, Tx.
- Loucks, R. (2003). REVIEW OF THE LOWER ORDOVICIAN ELLENBURGER GROUP OF THE PERMIAN BASIN, WEST TEXAS. *Bureau of Economic Geology*.
- Loucks, R. (2006). *Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas.* Austin, Tx: Bureau of Economic Geology.
- Mason, C. C. (1961). GROUND-WATER GEOLOGY OF THE HICKORYSANDSTONE MEMBER OF THE RILEY FORMATION. McCULLOCH COUNTY. TEXAS. *TEXAS BOARD OF WATER ENGINEERS*.

- Merrill, M., Slucher, E., Roberts -Ashby, T., Warwick, P., Blondes, M., Freeman, P., . . . Lohr, C. (2015). Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources–Permian and Palo Duro Basins and Bend Arch-Fort Worth Basin. *USGS*.
- Popova, O. (2020). Permian Basin Part 1 Wolfcamp, Bone Spring, Delaware shale plays of the Delaware Basin Geology Review. *USDOE*.
- Powers, R. B. (1989). Petroleum Exploration Plays and Resource Estimates, 1989, On shore United States -- Region 5, West Texas and Eastern New Mexico. USGS.
- Sanchez, T., Loughry, D., & Coringrato, V. (2019). Evaluating the Ellenburger Reservoir for Salt Water Disposal in the Midland Basin: An Assessment of Porosity Distribution Beyond the Scale of Karsts. Unconventional Resources Technology Conference (pp. 1-17). Denver: URTeC. doi:10.15530/urtec-2019-600
- Scanlon, B. R., Reedy, R. C., Male, F., & Walsh, M. (n.d.). *Water Issues Related to Transitioning from Conventional to Unconventional Oil Production in the Permian Basin.* Austin: Bureau of Economic Geology.
- Shamburger Jr., V. M. (1967). *Report 50: Ground-Water Resources of Mitchell and Western Nolan Counties, Texas.* Austin, Tx: Texas Water Development Board.
- Snee, J.-E. L., & Zoback, M. D. (2018). State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity. *The Leading Edge*, 810-819.
- Waite, L. (2021, October 25). Geology of the Permian Basin. UT Dallas Geoscience Permian Basin Research Lab.
- Zerwer, N. Y. (1997). Stress Regimes in the Gulf Coast, Offshore Louisiana:. AAPG Bulletin, 293-307.



Subpart RR Monitoring, Reporting, and Verification (MRV) Plan Mongoose AGI No. 1

Mitchell County, TX

Prepared for *Bayswater Operating Company LLC* Denver, CO

Ву

Lonquist Sequestration, LLC Austin, TX

> Version 2.0 October 2023



INTRODUCTION

Bayswater Operating Company LLC (Bayswater) currently has a Class II acid gas injection (AGI) permit, issued by the Texas Railroad Commission (TRRC) for the Mongoose AGI No. 1 well (Mongoose), API No. 42-335-36013. The permit was issued March 10, 2023. This permit authorizes Bayswater to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO₂) and hydrogen sulfide (H₂S) into the Ellenburger formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose is a new well and is associated with the Mongoose Amine Treating Facility (the Plant) located in a rural area of Mitchell County, Texas, as shown in Figure 1.



Figure 1 – Location of Mongoose AGI No. 1 Well

Bayswater is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Bayswater is also seeking TRRC approval to amend the existing Mongoose permit by increasing the permitted maximum quantity of injected treated acid gas (TAG) from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. Bayswater intends to inject into this well for approximately 40 years at up to a maximum of 19.5 MMscf/D. The primary source of this injected CO₂ gas is the Mongoose Amine Treating Facility. Table 1 shows the expected composition of the gas stream to be sequestered. Table 2 shows the expected average daily volume of acid gas.

Table 1 – Expected Gas Composition

Component	Mol Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

Table 2 – Expected Sequestered Gas Volumes

Contract Status	Avg. Rate (MMscf/D)
Committed	6.9
Proposed	12.6
Total	19.5

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH ₄	Methane
CMG	Computer Modelling Group Carbon Dioxide (may also refer to other Carbon
CO ₂	- · ·
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H ₂ S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet

MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
Ν	North
NW	Northwest
OBG	Overburden Gradient
OSHA	Occupational Safety and Health Administration
PG	Pore Gradient
рН	Scale of Acidity
PISC	Post Injection Site Care
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
ТАС	Texas Administrative Code
TAG	Treated Acid Gas
ТОС	Total Organic Carbon
TRRC	Texas Railroad Commission
UCZ	Upper Confining Zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

TABLE OF CONTENTS

INTRO	DUCTIO	Ν	2
ACRO	NYMS AN	ID ABBREVIATIONS	4
SECTIO	ON 1 – U	C INFORMATION	<u>1012</u>
1.1	Unde	rground Injection Control Permit Class: Class II	<u>1012</u>
1.2	UIC W	/ell Identification Number	<u>1012</u>
1.3	Repor	ter Number	<u>1012</u>
1.4	Facilit	y Address	<u>1012</u>
SECTIO	DN 2 – PF	ROJECT DESCRIPTION	<u>11</u> 13
2.1	Regional	Geology	<u>11</u> 13
	2.1.1	Regional Faulting	<u>2022</u>
2.2	Site C	haracterization	<u>2022</u>
	2.2.1	Stratigraphy and Lithologic Characteristics	<u>2022</u>
	2.2.2	Upper Confining Zone – Woodford Shale	<u>21</u> 23
	2.2.3	Injection Interval – Ellenburger	<u>29</u> 31
	2.2.4	Lower Confining Zone – Precambrian-age formations	<u>38</u> 40
2.3	Geom	echanics	<u>40</u> 4 2
	2.3.1	Determination of Vertical Stress (Sv) from Density Measurements	<u>40</u> 42
	2.3.2	Elastic Moduli and Fracture Gradient	<u>40</u> 42
2.4	Local	Structure	<u>42</u> 44
2.5	Inject	ion and Confinement Summary	<u>46</u> 48
2.6	Grour	ndwater Hydrology	<u>46</u> 48
2.7	Descr	iption of the Injection Process	<u>52</u> 54
	2.7.1	Current Operations	<u>52</u> 54
2.8	Reser	voir Characterization Modeling	<u>52</u> 54
	2.8.1	Simulation Modeling	<u>55</u> 57
SECTIO	DN 3 – DI	ELINEATION OF MONITORING AREA	<u>64</u> 66
3.1	Maxir	num Monitoring Area	<u>64</u> 66
3.2	Active	e Monitoring Area	<u>65</u> 67
SECTIO	DN 4 – PO	DTENTIAL PATHWAYS FOR LEAKAGE	<u>6769</u>
4.1	Leaka	ge from Surface Equipment	<u>68</u> 70
4.2	Leaka	ge Through Existing Wells Within the MMA	<u>71</u> 73
	4.2.1	Future Drilling	<u>74</u> 76
	4.2.2	Groundwater Wells	<u>74</u> 76
4.3	Leaka	ge Through Faults and Fractures	<u>74</u> 76
4.4	Leaka	ge Through the Confining Layer	<u>75</u> 77
4.5	Leaka	ge from Natural or Induced Seismicity	<u>75</u> 77
SECTIO	DN 5 – M	ONITORING FOR LEAKAGE	<u>77</u> 79
5.1	Leaka	ge trom Surface Equipment	<u>78</u> 80
5.2	Leaka	ge Through Existing and Future Wells Within the MMA	<u>78</u> 80
5.3	Leaka	ge Through Faults, Fractures, or Confining Seals	<u>8082</u>
5.4	Leaka	ge Through Natural or Induced Seismicity	<u>8082</u>
SECTIO	DN 6 – B/	ASELINE DETERMINATIONS	<u>82</u> 84
6.1	Visua	Inspections	<u>82</u> 84

6.2	CO ₂ /H ₂ S Detection	<u>82</u> 84
6.3	Operational Data	<u>82</u> 84
6.4	Continuous Monitoring	<u>82</u> 84
SECTION	7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION	<u>83</u> 85
7.1	Mass of CO ₂ Received	<u>83</u> 85
7.2	Mass of CO ₂ Injected	<u>83</u> 85
7.3	Mass of CO ₂ Produced	84 86
7.4	Mass of CO ₂ Emitted by Surface Leakage	84 86
7.5	Mass of CO ₂ Sequestered	85 87
SECTION	8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN	<u>8789</u>
SECTION 9 – QUALITY ASSURANCE		88 90
9.1	Monitoring QA/QC	88 90
9.2	Missing Data	88 90
9.3	MRV Plan Revisions	89 91
SECTION	I 10 – RECORDS RETENTION	90 92
SECTION	I 11 - REFERENCES	91 93

Figures

Figure 1 – Location of Mongoose AGI No. 1 Well
Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red
star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, &
Walsh)
Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)
Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf
Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf
(Waite. 2021)
Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger
Group of the Permian Basin. West Texas. 2006)
Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth. 1729
Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks.
2003)
Figure 9 – Type Log and Disposal Units and Zones from PXD Well No. 1 (Sanchez, Loughry, &
Coringrato. 2019)
Figure 10 – Mongoose AGI No. 1 Type Log
Figure 11 – Buchanan 3111 #XD location Offset well for Core Data
Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting
the Woodford and sidewall cores
Figure 13 – Core Photo of Samples Within the Woodford Formation
Figure 14 – Routine Core Analysis Within the Woodford Formation 2528
Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation 2629
Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation
2720
Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation <u>2831</u>

Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003) 3235 Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells .3639 Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986)......5053 Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011)......5154 Figure 35 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)......5760 Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation).......5861 Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation) Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection) Figure 40 – North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Figure 45 – Mongoose AGI No. 1 Wellbore Schematic7073 Figure 46 – All Oil and Gas Wells Within the MMA.....7275 Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA......7376

Figure 49 – Seismic Events and Monitoring Station <u>81</u> 8	}4
---	---------------

Tables

3
3
<u>38</u> 42
<u>40</u> 44
<u>41</u> 45
urger
<u>47</u> 51
<u>5256</u>
<u>53</u> 57
<u>5559 59</u>
<u>5660</u>
<u>63</u> 67
<u>6771</u>
<u>77</u> 81

Appendices

Appendix A – TRRC MONGOOSE AGI No. 1 FORMS

- Appendix A-1 UIC Class II Order
- Appendix A-2 GAU Groundwater Protection Determination
- Appendix A-3 Drilling Permit
- Appendix A-4 Completion Report

Appendix B – Site Safety and Layout

- Appendix B-1 Operating Safety Plan
- Appendix B-2 Mongoose Site Plan

Appendix C – Area of Review

- Appendix C-1 Oil and Gas Wells Within the MMA Map
- Appendix C-2 Oil and Gas Wells Within the MMA List

Appendix D – Section 2 Cross Sections

Appendix D-1 – Figure 27 – Structural Cross Section Depicting the Ellenburger Appendix D-2 – Figure 28 – Stratigraphic Cross Section Flattened on the Ellenburger

SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the UIC Class II program. The TRRC classifies Mongoose AGI No. 1 as a UIC Class II well. A Class II permit was issued to Bayswater on March 10, 2023, under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

1.2 UIC Well Identification Number

Mongoose AGI No. 1, API No. 42-335-36013, UIC No. 000125803

1.3 <u>Reporter Number</u>

- Facility Name: Mongoose Amine Treating Facility
- Greenhouse Gas Reporting Program ID: 586481
 - Currently reporting under Subpart UU
- Operator: Bayswater Operating Company LLC

1.4 Facility Address

Mongoose Amine Treating Facility 1625 County Road 280 Westbrook, Texas 79565

Coordinates in NAD83 for this facility:

Latitude: 32.4225396641 Longitude: -101.1714709142

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Mongoose AGI No. 1 well.

The Mongoose injects both H_2S and CO_2 into Ellenburger formation at a depth of 8,300 ft to 9,000 ft, and approximately 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The Mongoose is located on the Eastern Shelf, as shown in the area map in Figure 2, within the greater Permian Basin of west Texas and New Mexico. The Permian Basin covers more than 86,000 square miles extending across an area approximately 250 miles wide and 300 miles long. The TRRC cites that the greater Permian Basin accounts for close to 40% of all oil production within the United States and nearly 15% of natural gas production. A general cross section of the basin is presented in Figure 3.

The ancestral Tobosa Basin was formed by structural flexure in the Precambrian basement at the southern margin of the North American Craton, or Laurentian Plate, during the Proterozoic (Popova, 2020). The modern form of the Permian Basin was shaped during the Carboniferous period due to the collision between Laurasia and Gondwana forming the supercontinent Pangea. The following uplift of the Central Basin Platform differentiated the greater basin into the Delaware Basin in the west, and the Midland Basin in the east along with its surrounding shelf margins (Popova, 2020).



Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, & Walsh).



Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)

The target injection interval for the Mongoose is the Ellenburger formation. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician (Sanchez, Loughry, & Coringrato, 2019). The Ellenburger is of lower Ordovician age and underlies the Woodford formation on the Eastern Shelf. The contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition (Sanchez, Loughry, & Coringrato, 2019). Many formations that are present within the Midland Basin are eroded and not seen upon reaching the Eastern Shelf. A cross section showing these truncations is displayed in Figure 5.

A generalized stratigraphic column of the Eastern Shelf is shown in Figure 4, with the target-injection formation indicated by the red star and historically productive formations indicated in the green stars. The Ellenburger formation is roughly 900 ft thick on the Eastern Shelf as shown by the isopach thickness map in Figure 6 (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006). On the Eastern Shelf, the Ellenburger formation dips to the west-southwest, towards the Midland Basin, and its subsea depth is roughly 6,000 ft (Sanchez, Loughry, & Coringrato, 2019). Figure 7 displays a structure map of the Ellenburger formation. Being far from any major sources of terrigenous clastic sediment input and at a time of a greenhouse climate leading to warm waters created an ideal setting primed for massive carbonate production during the Ellenburger deposition (Waite, 2021). The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. Predominant pore types of this group determined by Holtz and Kerans are "ooid grainstone; ooid-peloid packstone-grainstone"

and reservoirs tend to be of good porosity and moderate permeability (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006).



Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf



Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf (Waite, 2021).



Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006)



Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth.

The lower Ordovician period on the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture. Within this dolomite, there were irregular mottling patterns, likely indicative of bioturbation structures. Mudstone and peloid-wackestone, although in

Subpart RR MRV Plan – Mongoose AGI No. 1

smaller quantities, were also observed in the area (Kerans, 1990). To visually represent these different depositional environments and their corresponding lithologies, a map is presented in Figure 8. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger formation underwent significant "karsting" and dolomitization. This karsting process resulted in the formation of extensive paleocave systems within the Ellenburger, which later collapsed and led to the creation of widespread brecciated and fractured carbonates. These formations are responsible for the occurrence of many Ellenburger reservoirs, according to Loucks (2006).



Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

In their research on saltwater disposal (SWD) injection into the Ellenburger, Pioneer Natural Resources describes three distinct facies within the formation as noted in the Figure 9 type log. The upper and middle facies are composed of fracture breccia, breccia fabrics, and matrix-supported breccia, which coincide with collapsed paleo cave facies as described by Loucks. The lower unit does not exhibit these characteristics but shows a high volume of small vugs (inch-scale) and large-dissolution features (foot-scale) and represents an area of the Ellenburger with elevated porosity and permeability (Sanchez, Loughry, & Coringrato, 2019).




2.1.1 Regional Faulting

The modeled area near the Mongoose does not show any faults. However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area. This fault trend runs north-south in parallel with the dip. Figure 7 displays this fault trend, which is the only example of such a trend within the area. Apart from this, the basin area is structurally inactive.

2.2 <u>Site Characterization</u>

The following section discusses site-specific geological characteristics of the Mongoose.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 shows an annotated well log for Mongoose that goes from the surface to the total depth. It indicates the injection and primary upper confining units with regional formation tops.



Figure 10 – Mongoose AGI No. 1 Type Log

2.2.2 Upper Confining Zone – Woodford Shale

The upper confining unit is the Upper Devonian age Woodford formation. The Woodford Shale, a late Devonian-aged organic-rich rock, was created through a widespread marine transgression. The deposition of the Woodford spread across a large area of the Permian Basin, producing a low-relief blanket of shale. The Woodford formation is an organic-rich petroleum source rock comprised of uncharacteristically highly radioactive, dark fissile shale and siltstone (Merril et al., 2015). Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991). As shown previously in Figure 5, the Wristen Group is a formation that lies directly below the Woodford to the west of the Mongoose location. The Wristen Group pinches out and is not found at the Mongoose location. However, the sealing nature of the Woodford, as described by Comer (1991), also provides confinement for the Ellenburger at this location. The Woodford formation overlies both unconformably and is diachronous to the underlying Ellenburger formation at the Mongoose location. The U.S. Geological Survey (USGS) CO₂ Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit (SAU) (Merril et al., 2015).

Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose. The Buchanan 3111 #1XD is approximately 10.4 mi. from the Mongoose as depicted in Figure 11. Figure 12 is a stratigraphic cross section showing the correlating cored Woodford formation (pink triangles representing cored intervals) in the Buchanan 3111 #1XD and the Mongoose wells. Routine core analysis, rock mechanics, and threshold entry pressure tests were performed on the core samples from the Woodford formation.

Core photos of the samples taken and analyzed within the Woodford are shown in Figure 13. The black shale unit exemplifies a well cemented unit with little to no fracturing. Routine core analysis was performed on these two samples, which includes bulk density, matrix permeability (as received and as under dry and Dean Stark extracted conditions), gas-filled porosity, gas saturation, grain density, porosity, oil saturation, and water saturation. The results are shown in Figure 14, with the footnotes at the base giving details on the testing processes of each value.

Under the dry and Dean Stark extracted conditions, permeability values of 2.2E-07 millidarcy (mD) were observed with even lower values of 4.87E-07 mD in the as-received samples. Porosities within the same sample were 1.3% when dried and .25% when gas-filled. These permeability and porosity values reflect optimal confining characteristics and validate the USGS assessment of an appropriate sealing formation for CO_2 storage.

To ensure these sealant properties would not be compromised by pressure influence of the injected fluid, a threshold entry pressure test was examined on these Woodford core samples. Figure 15 depicts a graph of permeability vs. pressure showing that, even with pressure increases up to 2,000 pounds per square inch (psi), permeability readings are still in the nano-darcy range. These values are shown in table form in Figure 16 against the pressures administered on the core, with the highest pressure being 2,000 psi. Given that permeability values were lowest (4.03E-07 mD) at 2,000 psi, it

can be assumed that the threshold entry pressure of the Woodford formation was not met and would be greater than 2,000 psi. Additionally, a table summary is depicted in Figure 17. These characteristics gathered from the Buchanan core provide a high level of detail into the confining nature of the Woodford Shale and alleviate any concerns of transmissibility through the confining unit.



Figure 11 – Buchanan 3111 #XD location -- Offset well for Core Data



Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Woodford and sidewall cores.



Figure 13 – Core Photo of Samples Within the Woodford Formation



CL File No.: 202105972 Date: February 04, 2022 Analyst(s): MP

Shale Core Analysis (Rotary Sidewall Cores)

As received				Dry & Dean Stark Extracted Conditions (2)						
Sample	Depth (ft)	Bulk Density (g/cc)	Matrix Permeability ⁽¹⁾ (mD)	Gas-filled Porosity (%)	Gas Saturation (%)	Grain Density (g/cc)	Matrix Permeability ⁽⁵⁾ (mD)	Porosity (%)	Oil Saturation ⁽³⁾ (%)	Water Saturation ⁽⁴⁾ (%)
30,31	9076.03 - 9076.26	2.601	4.87E-09	0.25	18.9	2.624	2.22E-07	1.30	3.3	77.8

Footnotes:

Each sample is a composite of several rotary sidewall cores.

(1) Matrix Permeability is an effective Kg determined from pressure decay results on the fresh, crushed, 20/35 mesh size equivalent sample.

(2) Dean Stark extracted sample (20/35 mesh size) dried at 110 °C. Porosity and saturations are relative to total interconnected pore space.

(3) Oil volume computed assuming an oil density of 0.844 g/cc

(4) Water volume corrected assuming a brine concentration of 80000 ppm NaCl with an ambient density of 1.054 g/cc

(5) Matrix Permeability is an absolute Kg determined from pressure decay results on the clean and dry 20/35 mesh size equivalent sample.

Reference: "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs", GRI-95/0496, Gas Research Institute, April 1996

Figure 14 – Routine Core Analysis Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

Company:Bayswater Exploration & ProductionWell:Buchanan 3111 1XDField:SpraberryLocation:Howard County, TexasFile:HOU-2105972



Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation

PETROLEUM SERVICES

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production Well: Buchanan 3111 1XD Field: Spraberry Location: Howard County, Texas

File: HOU-2105972

Sample 30B						
Gas						
Injection	Permeability					
Pressure,	to Brine*,					
psi	mD					
500	1.44E-06					
750	2.20E-06					
1000	1.46E-06					
1200	6.73E-07					
1400	5.77E-07					
1600	6.72E-07					
1800	5.39E-07					
2000	4.03E-07					

Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation

SUMMARY OF THRESHOLD ENTRY PRESSURE RESULTS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company:	Bayswater Exploration & Production
Well:	Buchanan 3111 1XD
Field:	Spraberry
Location:	Howard County, Texas

File: HOU-2105972

				Final	Threshold
				Permeability	Entry
Sample	Depth,	Length,	Diameter,	to Brine*,	Pressure,
Number	feet	cm	cm	millidarcies	psi
30B	9076.03	2.67	2.54	4.03E-07	TEP>2000

* Apparent permeability to brine with humidified nitrogen displacing water

Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation

2.2.3 Injection Interval – Ellenburger

2.2.3.1 Ellenburger

As described in the Regional Geology section, the Ellenburger at the Mongoose location is a widespread lower Ordovician carbonate deposited over the entire Permian area, indicating a relatively uniform depositional condition (Hendricks, 1964). However, post-depositional sequences have highly altered the section. These sequences have a large influence on the development of the reservoir quality within the injection interval and its ability to accept the proposed injectate. Further analysis based on regional and site-specific data was analyzed, as discussed below, to better understand the reservoir conditions at and around the Mongoose well location.

2.2.3.2 Ellenburger Porosity/Permeability Development

Facies in the low-energy, restricted shelf setting exhibit extensive dolomitization and are characterized by significant bioturbation, resulting in mottling patterns (Loucks, 2003). This dolomitization process has facilitated porosity development within the Ellenburger formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs. These same features were interpreted from the openhole logs in the Mongoose well and core from the Buchanan 3111 #1XD well. A total of 23 sidewall cores were taken within the Ellenburger formation in the Buchanan 3111 #1XD well, with 12 of those having routine core analysis performed on them. Figure 18 shows the results of the analysis.

Porosity values were primarily derived from offset openhole porosity logs within the Ellenburger section. Petrophysical analysis was performed on the offset logs to calculate an effective porosity curve, the porosity of a rock that is available to contribute to fluid flow, to better estimate porosity ranges with regards to injection within the Ellenburger. This is done by accounting for clay content and matrix lithology to better understand the varying porosity within the injection interval and how it relates to injection capacity. The ranges of effective porosity within the modeled wells are 0 to 39.4% with the mean being 4.6%. Figure 19 is a histogram depicting these porosity distributions within the seven modeled wells. These values are validated through similar ranges seen in the core results. The logical inference would be that, as the effective porosity increases, the reservoir quality for injection improves and the associated porosity increment leads to a rise in permeability.

A porosity to permeability relationship was created from this data with the outliers and nonapplicable samples redacted. Additional regional data from Loucks (2003) was incorporated into the relationship to assist with the higher permeability ranges, to ensure that overestimates of permeability were not calculated. The data from Loucks (2003) is exemplified in Figure 20. A twofunction porosity-permeability curve was developed from the regional and local core data. Figure 21 shows the equations and relationships where:

> If Effective Porosity (Φ eff) < 6.5%: $K(mD) = 7E - 08e^{3.3028*\Phi}$ eff If Effective Porosity (Φ eff) > 6.5%: $K(mD) = 277.39 \ln(\Phi eff) - 380.58$

These equations were extrapolated to all the wells within the model including the Mongoose. In Figure 22, the cross section of the Mongoose and Buchanan well is depicted. This illustration showcases the Ellenburger formation, with the sidewall cores from the Buchanan well represented by pink triangles. The calculated permeability curves resulting from the equations mentioned earlier are shown in red, while green represents the effective porosity. High permeability and porosity sections can be seen in both wells, most likely reflecting strata that had prolonged subaerial exposure creating the karst and vug features that will be targeted and utilized for injection. Figure 23 is a core photo from the Buchanan well depicting an example of what a vug feature within the Ellenburger can look like. These features will be taking the bulk of the injection and will be modeled within the area based on openhole log analysis.

Permeability ranges within the seven wells utilized in the model vary from 0 mD to 638 mD, with the mean being 40.822 mD. A histogram representing these ranges and distributions within the seven modeled wells is displayed in Figure 24. This range corroborates with Loucks (2003) and data recovered from the Buchanan well, and it can be concluded that the process used to determine the permeability distributions within the injection interval is valid.

Bayswater Exploration & Production Buchanan 3111 1XD Spraberry Howard County, Texas



CL File No.: 202105972 Date: March 31, 2022 Analyst(s): MP

CMS-300 ROTARY SIDEWALL ANALYSIS												
		Net Confining		Permea	ability				Satu	ration	Grain	
Sample	Depth	Stress	Porosity	Klinkenberg	Kair	b(air)	Beta	Alpha	Oil	Water	Density	Footnote
Number	(ft)	(psig)	(%)	(md)	(md)	psi	ft(-1)	(microns)	% Pore	Volume	(g/cm3)	
23	9236.98	2960	25.81	.259	.389	11.97	3.27E+09	2.75E+00	0.0	94.7	2.666	
21	9257.01	2960	4.77	.002	.009	104.71	2.14E+15	1.48E+04	1.2	66.1	2.746	(1)
19	9363.99	2960	5.23	5.17	5.81	2.07	1.75E+12	2.93E+04	4.1	66.9	2.800	(6)
15	9485.99	2960	3.41	.005	.016	62.63	3.24E+13	5.63E+02	2.3	64.6	2.838	(6)
13	9549.48	Ambient	1.55	N/A	N/A	N/A	N/A	N/A	1.9	44.7	2.829	(5)
12	9604.98	2960	1.63	.00006	.001	354.43	2.46E+18	5.38E+05	2.6	54.0	2.842	(1)
10	9712.03	Ambient	1.28	N/A	N/A	N/A	N/A	N/A	1.2	74.3	2.758	(5)
7	9835.05	2960	2.28	.001	.004	155.69	2.03E+16	4.48E+04	1.5	81.1	2.701	
6	9868.97	2960	3.43	.001	.003	166.37	3.03E+16	5.46E+04	0.9	81.6	2.827	
5	9892.03	2960	3.46	.001	.005	132.61	8.12E+15	2.84E+04	2.1	91.6	2.809	
4	9914.00	2960	5.46	659	669	0.18	1.07E+09	2.29E+03	0.7	58.7	2.835	(6)
3	9969.01	Ambient	11.18	N/A	N/A	N/A	N/A	N/A	1.7	42.9	2.846	(5),(6)

Figure 18 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)



Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells

			Tectonically Fractured
	Karst Modified	Ramp Carbonate	Dolostone
Lithology			
	Dolostone	Dolostone	Dolostone
Depositional			
setting	Inner ramp	Mid- to outer ramp	Inner ramp
		Sub-Middle Ordovician,	
	Extensive sub-	sub-Silurian/Devonian,	
	Middle	sub-Mississippian, sub-	Variable intra-Ellenburger,
Karst facies	Ordovician	Permian/ Pennsylvanian	sub-Middle Ordovician
Fault-related			
fracturing	Subsidiary	Subsidiary	Locally extensive
	Karst-related		
Dominant pore	fractures and	Intercrystalline in	
type	interbreccia	dolomite	Fault-related fractures
		Partial, stratigraphic and	
Dolomitization	Pervasive	fracture-controlled	Pervasive

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

Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)



Porosity vs Permeability

Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Data



Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Ellenburger formation and sidewall cores.



Figure 23 – Core photo of Ellenburger sample displaying vug features.



Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells

2.2.3.3 Formation Fluid

Two wells were identified within approximately 30 miles of the Mongoose through a review of oilfield brine compositions of the Ellenburger formation from the USGS National Produced Waters Geochemical Database (ver. 2.3). The location of these wells is shown in Figure 25. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids (TDS). Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger formation is compatible with the proposed injection fluids.



Figure 25 – Offset wells used for formation fluid characterization.

	Average	Low	High
Total Dissolved Solids (ppm)	47,427	42,014	52,840
рН	7	7	7
Sodium (ppm)	16,384	15,000	17,767
Chlorides (ppm)	27,590	24,900	30,281

Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples

2.2.4 Lower Confining Zone – Precambrian-age Formations

In the Permian Basin area, Precambrian-age formations are not normally specifically named in scientific literature. For the purposes of this MRV, these formations will just be referred to as the "Precambrian". Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sourced from outcrops in central Texas and the Trans-Pecos region of Texas and central New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section (Adams & Keller, 1996).

Adams and Keller conducted a geophysical analysis in 1996 to enhance the understanding of Precambrian rock types and their distribution in the Permian Basin. The study incorporated gravity modeling and magnetic and gravity anomalies, as well as rock data from Precambrian outcrops and drills to interpret the upper crustal geology of the area. Figure 26 displays the map resulting from their investigation, revealing that batholiths are likely present in the Precambrian basement rock at the Mongoose well location. Additionally, samples collected from offset wells displayed predominantly felsic rocks, which led to the interpretation of "granitic bodies in the upper crust" (Adams & Keller, 1996).

Offset Ellenburger injector wells were drilled through the Ellenburger section and reached total depths near the Precambrian. Log characteristics of strata near the total depth of the wells display gamma ray responses well above 90 gamma units of the American Petroleum Institute (GAPI), which is indicative of a high radioactive response. Additionally, the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone.



Figure 26 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Geomechanics

2.3.1 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density of the upper and lower confining and injection zones was calculated from log data at the Buchanan 3111 #1XD (API No. 42-227-41307) offset well. The overburden gradient and vertical stress at the top of each zone were calculated by integrating the bulk density from surface to the formation depth in half-foot intervals. Table 4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Formation Depth (ft)		Bulk Density Bulk Dens (g/cm^3) (lb/ft^3		Vertical Stress (psi)	Overburden Gradient (psi/ft)
Woodford	8,322	2.63	164.1	8,563	1.029
Ellenburger	8,375	2.75	171.2	8,635	1.031
Precambrian	9,500*	2.83	176.7	9,937	1.046

Table 4 – Calculated Vertical Stresses

* Estimated

2.3.2 Elastic Moduli and Fracture Gradient

The 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. The calculation requires Poisson's ratio ("v"), overburden gradient (OBG), and pore gradient (PG) in order to determine the required pressure to fracture the formation. These variables can be changed to match the site-specific injection zone.

A thorough review of log data, available literature, and industry standards indicate a 0.465 psi/ft pore gradient should be assumed when there are no site-specific numbers available. Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the Buchanan 3111 #1XD. The calculation was performed using the equation below for log data points at half-foot depth intervals. The results were then averaged for the depth range of each zone. This resulted in a Poisson's ratio of 0.261 for the upper confining zone and 0.273 for the injection zone.

$$v = \frac{\frac{1}{2} \left(\frac{v_p}{v_s}\right)^2 - 1}{\left(\frac{v_p}{v_s}\right)^2 - 1}$$

Where:

v = Poisson's Ratio v_p = Compressional Velocity v_s = Shear Velocity

Log data was unavailable for the lower confining zone, therefore the Poisson's ratio for this zone was estimated through a review of available literature. The lower confining zone consists of granite, which has been observed to have a Poisson's ratio ranging from 0.19 to 0.35 with a mean value of 0.28 (Domede, 2017). Based on this research, an average value of 0.28 was assumed. Using these values in the equation below, a fracture gradient of 0.664 psi/ft was calculated for the upper confining zone. A 10% safety factor was applied to this number resulting in a maximum allowed bottomhole pressure of 0.598 psi/ft. This zone had the lowest fracture gradient of the confining and injection zones. It was used to define the maximum allowable pressure to ensure that the injection pressure would not exceed the fracture pressure of any of the three zones. The resulting fracture gradients are displayed in Table 5.

Example Fracture Gradient Calculation for Upper Confining Zone

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

$$FG = \frac{0.261}{1 - 0.261} (1.029 - 0.465) + 0.465 = 0.664 \, psi/ft$$

$$FG \text{ with } SF = 0.689 \times 90\% = 0.598 \text{ } psi/ft$$

Depth (ft)	Zone	Member	Member Overburden Stress (psi)		Poisson's Ratio	Fracture Gradient (psi/ft)
8,322	Upper Confining	Woodford	1.029	0.465	0.261	0.664
8,375	Injection	Ellenburger	1.031	0.465	0.273	0.678
9,500*	Lower Confining	Precambrian	1.046	0.465	0.28	0.691

*Estimated

2.4 Local Structure

The area surrounding the Mongoose well is characterized by a monoclinal dip from east to west that is influenced by a shallow westward slope towards the Midland Basin and an upward slope to the east towards the Eastern Shelf. No evidence of structural faulting was found in this specific region that could have affected the geological trend. Figure 27 shows the topography of the Ellenburger formation, with the Mongoose well marked by a black star.

Subsurface interpretations of the Ellenburger formation heavily relied on well data and 3D seismic coverage in the area. The black boundary in Figure 27 represents the extent of the seismic coverage. Within the mapped area, approximately 100 wells have penetrated the Ellenburger formation. However, only seven of these wells fully penetrated the entire Ellenburger section. The remaining 93 wells only reached the top of the Ellenburger formation. These wells are plotted on the map and cover four counties. In addition to the Mongoose well, six other wells located offset of the Mongoose were used for the model build and are indicated by red stars.

Figure 28 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map. The Ellenburger was broken down into eight subsections labeled Ellenburger A through H. Figure 29 is a stratigraphic cross section flattened on the Ellenburger that better illustrates these subtops.

The cross sections reveal the regional unconformity in the area when moving east from the Midland Basin. As we go farther updip and to the east, the Fusselman section gradually erodes. While there is also thinning in the Woodford, the cross section shows that the Woodford is present throughout the modeled area, creating a continuous seal above the plume.

With no major structural or stratigraphic features within the injection interval in the Mongoose area, there is little to no concern of geologic conduits outside of the injection interval. General flow trends will follow dip and optimal reservoir features within the Ellenburger. Large scale versions of Figures 28 and 29 are provided in *Appendix C*.



Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map.



Figure 28 – Structural cross section depicting the Ellenburger.



Figure 29 – Stratigraphic cross section flattened on the Ellenburger.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger formation at the Mongoose location indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity. The Woodford Shale formation at the same well location has low permeability and is of adequate thickness and lateral continuity to act as the upper confining zone. Below the injection interval, the Precambrian formation has low permeability and low porosity, making it unsuitable for fluid migration and serving as the lower confining zone.

A thorough study of the area of review has been conducted to identify any potential subsurface features that could impact the ability of the injection and confinement units to retain the injectate within the desired injection interval. Fortunately, no faults or other hazardous geologic conditions have been identified in the area. Therefore, the conditions in this area are ideal for injection and containment.

2.6 Groundwater Hydrology

The Mongoose is located within Mitchell County, home to a population of approximately 8,400 residents, and is serviced by the Lone Wolf Groundwater Conservation District, which consists solely of Mitchell County. This conservation district has an area of roughly 900 square miles. Much of the county's economy is derived from agriculture and oil production, both water-intensive operations. Groundwater usage within the county is estimated to be 13,391 acre-feet on a yearly basis (Lone Wolf Groundwater Conservation District, 2019).

Surface Water

Mitchell County lies within the Colorado River basin, as the Colorado runs through the county. Drainage from both the east and west flow centrally towards the Colorado River, which splits the county in half. The estimated supply of surface water is 395 acre-feet (Lone Wolf Groundwater Conservation District, 2019).

Groundwater

There are multiple units where groundwater is available within Mitchell County, although only the Dockum Group provides significant amounts of water. Table 6 discusses water-bearing units in the county, and Figure 30 shows a generalized reference to structure and formation relationships.

Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger Jr., 1967)

System	Series	Group	Formation	Approximate thickness (feet)	Lithology	Water-bearing characteristics
Quaternary	Pleistocene and Recent		Alluvium	0-100	Fine to coarse sand, and small to large gravel, with occasional clay and caliche beds.	Above the regional water table east of Colo- rado River, but yields up to 20 gpm of good quality water in southwestern Mitchell County.
Tertiary	Pliocene		Ogallala	0-100	Fine to coarse sand, gravel, caliche, and zones of clay.	Above the water table east of Colorado River, but yields up to 20 gpm of good quality water to wells in northwestern Mitchell County.
Cretaceous	Conanche	Fredericksburg		0-220	Predominently limestone. 15 to 25 feet of sandy yellow marl at base overlain by chalk and shaly limestone. Very dense, massive, fossiliferous lime- stone in the upper part.	Upper limestones contain in places small to moderate supplies of potable but hard water in solutional openings developed along fracture systems; recharge to the openings occurs through numerous sinks.
		Comanche	Trinity		0-100	White to purplish quartz sand, fine to medium grained, moderately to loosely consolidated, with occasional lenses of quartz gravel at the base.
Triassic		Chinle	0-640	Predominantly red to marbon and pur- plish clay and shale, interbedded with thin, tight, cross-bedded, yellow-brown to reddish-white sand- atone.	Sandstones contain generally small quantities of moderately to highly mineralized water; used principally for livestock.	
		Dockum	Santa Rosa	0-330	Basal conglomerate overlain by brown to gray, micaccous and carbonaccous, cross-bedded sand alternating with beds of red and gray clay.	Sands and gravels contain moderate to large quantities of fresh water east of the Colorado River, with yields up to 1,000 gpm reported; west of Colorado River capa- city of sand is reportedly substantial but water is generally not potable.
Permain	Guadalupe and Ochoa				Fine-grained, red to brown sandstone; dense red silty shale with occasional gypsum or anhydrite beds.	Yield small quantities of moderately to high- ly mineralized water to livestock and domestic wells.



Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)

Permian

Permian age strata underlies much of the area and outcrops in the southeast of Mitchell County and along the Colorado River and its tributaries. These strata consist primarily of "red beds," dense red silty shales. Water wells in the Permian strata are typically less than 100 ft deep, yielding small amounts of moderately to highly mineralized water usable only for livestock (Shamburger Jr., 1967).

Dockum Aquifer

The Triassic Age Dockum group comprised by the Santa Rosa sandstone and the Chinle formation are the main sources of ground water within the county. An overview map of the extent of the Dockum Aquifer is shown in Figure 31, with outcrops depicted in solid color. The Chinle is further divided into the Tecovas formation, the Trujillo sandstone, and the Cooper Canyon formation, although the Tecovas and Cooper Canyon are generally unimportant and yield only small amounts of highly mineralized water.

The Santa Rosa sandstone lies unconformably atop the Permian age strata at the base of the Dockum Group and is one of the major sources of water for Mitchell County. It is comprised of a basal conglomerate overlain by alternating beds of red and gray micaceous shale, sand, and gravel reaching up to 130 ft in thickness (Bradley & Kalaswad, 2001). The Trujillo sandstone overlies the Tecovas, which in turn overlies the Santa Rosa, and is a cross-bedded unit composed of sandstones and conglomerates. The Santa Rosa and Trujillo sandstones are regarded as the main producers of water in the Dockum Group in Mitchell County (Lone Wolf Groundwater Conservation District, 2019). The Dockum Group was likely deposited from sediments into "fluvial, deltaic, and lacustrine environments within a closed continental basin" (Bradley & Kalaswad, 2001). The base of the Santa Rosa is typically considered the lower extent of fresh water in the area. Water levels in wells throughout the county vary between 15 ft and 215 ft below ground level (Shamburger Jr., 1967), and the aquifer is considered confined to partially confined (Bradley & Kalaswad, 2001).

Recharge of the aquifer is provided by rainwater infiltration through outcrops in the county and is estimated to be 18,108 acre-feet per year. Groundwater in the Dockum aquifer system flows towards the central Colorado River. A potentiometric surface map of the Santa Rosa sandstone, the lower Dockum member, is depicted in Figure 32. Although no values of porosity have been determined empirically, a conservative value of 10% is assumed for effective aquifer porosity (Lone Wolf Groundwater Conservation District, 2019).

Groundwater quality is generally considered poor with TDS and other constituents exceeding secondary drinking water standards (Bradley & Kalaswad, 2001). As a typical assumption, water quality west of the Colorado River within the aquifer is poor and unsuitable for municipal use, while east of the river water quality is less mineralized and is of suitable quality for municipal purposes (Lone Wolf Groundwater Conservation District, 2019). For example, a well tested 10 miles northwest of Colorado City contained chloride at 560 milligrams per liter (mg/L), sulfate at 337 mg/L, and TDS at 1,893 mg/L, all of which are above limits set by the Texas Commission on Environmental Quality (TCEQ) for use in municipal water supplies. In contrast, a well 8 miles east of Colorado City contained

chloride at 34 mg/L, sulfate at 73 mg/L, and TDS at 418 mg/L (Lone Wolf Groundwater Conservation District, 2019). A map showing TDS values for the Dockum Aquifer is shown in Figure 33.



Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location (George, Mace, & Petrossian, 2011).



Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986).



Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011).

Ogallala Formation

The Tertiary age Ogallala formation occurs in the northern extents of Mitchell County. In the eastern part of the county, Ogallala sediments are generally above the water table and not a source of groundwater; however, they do provide an effective means of recharge to the underlying Santa Rosa formation. In the western part of the county, the Ogallala is up to 100 ft thick of unconsolidated sand and gravel and provides small quantities of usable water for domestic and livestock wells (Lone Wolf Groundwater Conservation District, 2019).

2.7 <u>Description of the Injection Process</u>

2.7.1 Current Operations

The Mongoose Amine Treating Facility and the associated Mongoose well began operating in August of 2023. The maximum rate during the injection period is expected to be 377.2 MT/yr (19.5MMscf/d). The TAG is 41.2% CO₂, which equates to 155.3 MT/yr of CO₂ each year. The current composition of the TAG stream is:

Component	Mole Percent		
Carbon Dioxide	41.2%		
Hydrogen Sulfide	58.8%		

The Mongoose Amine Treating Facility is designed to dehydrate, treat, and compress the natural gas produced from the surrounding acreage in Mitchell County. The gas is dehydrated to remove the water content, and treated to remove the CO₂ and H₂S. The compressed rich gas stream is then transported via pipeline to a separate facility for processing to separate the natural gas liquids from the methane. The TAG is then directly routed from the Plant's amine unit to the Mongoose. The Plant is manned 24 hours per day, 7 days per week.

2.8 <u>Reservoir Characterization Modeling</u>

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (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 Ellenberger formation is the target formation for the Mongoose. The Petrel software package was utilized to create the geologic model of the target formation. Within the Petrel platform, the porosity and permeability distributions were established for the model. The geologic structure was then imported into GEM for simulation purposes.

In Petrel, the structure's construction involved the utilization of nine contour tops, which were layered sequentially. These contour tops, identified as "Ellenberger A" through "Ellenberger I," collectively define the structure's configuration, Ellenberger A being the shallowest and Ellenberger I being the deepest structure package. To accurately represent the formation's true structure, true vertical depth subsea was used to account for the differing overburden depths associated with the

wells used in contour delineation. The distinction between true vertical depth (TVD) and true vertical depth subsea (TVDSS) is taken into consideration when inputting pressure and temperature gradients into the GEM model.

Porosity estimates were determined using openhole porosity logs from seven offset wells within the Ellenberger formation. These logs were used within Petrel to distribute porosity and permeability spatially. Permeability was found by using the two-function porosity-permeability curve developed from regional and local core data within the Ellenberger formation.

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 H₂S and CO₂ based on initial estimates from the source, as shown in Table 8. However, the precise gas composition may vary slightly as the Plant is still in its commissioning phase. Initial estimates anticipate the injectate composition to be 58.8% H₂S and 41.2% CO₂. Once a steady-state operating composition is determined, the MRV plan will be updated if there is a material difference. Based on the initial gas samples, the modeled percentages in the injectate for the 40-year injection period of the Mongoose is 58.8% H₂S and 41.2% CO₂.

Table 8 – Modeled Initial Gas Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)	
Hydrogen Sulfide (H ₂ S)	58.8	58.8	
Carbon Dioxide (CO ₂)	41.2	41.2	

Core data from literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Ellenberger dolomitic carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 10%, an irreducible water saturation of 39.7%, and a maximum residual gas saturation of 30%. The relative permeability curves used for the GEM model are shown in Figure 34.



Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 135 blocks in the x-direction (east-west) and 77 blocks in the y-direction (northsouth), resulting in a total of 10,395 grid blocks per layer. Each grid block spans dimensions of 1,000 ft by 1,000 ft. This configuration yields a grid size measuring 135,000 ft by 77,000 ft, equating to just under 373 square miles in area. The grid cells in the vicinity of the Mongoose, within a radius of 2.5 miles, have been refined to dimensions of 250 ft by 250 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume.

In the model, each layer is characterized by heterogeneous permeability and porosity values. These values are derived from the geostatistical distribution of properties, using porosity logs implemented in Petrel as a basis. The model encompasses a total of 79 layers, each featuring varying thicknesses, with an average of approximately 10 ft per layer. As previously mentioned, the structure of the Ellenberger formation was formed using nine contour packages. The summarized property values for each of these packages are displayed in Table 9.

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Ellenberger A	9	8,369	101	49.1	5.2%
Ellenberger B	9	8,470	76	65.1	6.0%
Ellenberger C	8	8,546	75	38.5	4.2%
Ellenberger D	9	8,621	86	39.2	4.9%
Ellenberger E	15	8,707	153	48	4.8%
Ellenberger F	6	8,860	63	32.5	4.4%
Ellenberger G	4	8,923	39	16.5	3.2%
Ellenberger H	8	8,962	82	76.9	5.5%
Ellenberger I	11	9,044	112	66	3.4%

Table 9 – GEM Model Layer Package Properties

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

- 1. Estimate the maximum areal extent and density drift of the acid gas plume after injection.
- 2. Assess the impact of offset SWD well injection on density drift of the plume.
- 3. Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone.
- 4. 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 47,427 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The acid gas stream is primarily composed of CO₂ and H₂S as stated previously. Core data was used to help generate relative permeability curves. From the literature reviews as previously discussed, cores that most closely represent the vuggy dolomitic carbonate seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975). The initial reservoir pressure is 3,903 psig, which is equivalent to a 0.465 psi/ft pressure gradient and was determined from offset injection well analysis. The fracture gradient of the injection zone was estimated to be 0.664 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.598 psi/ft, which is equivalent to 5,007 psig.

The model considers the injection volumes of offset SWD wells close to the Mongoose. Nine such wells were identified within a 19-mile radius. Historical injection rates of eight of the nine of these wells currently injecting into the Ellenberger were provided by the operators and were input into
the model. All but one of the SWD wells in the model are currently permitted and injecting. The SWD well that has not yet started injection and has no historical injection data is conservatively assumed to inject at its maximum permitted rate for 30 years and to start at the same time as the Mongoose begins injection. Projected injection rates were assumed to be the maximum permitted injection rates and ended after 30 years of life for all nine offset SWDs. This simulation includes the effect of water injection on the density drift of the plume and the bottomhole pressure of the Mongoose. The SWDs included in the model are listed in Table 10.

API Number	Well Name	Well Number
42-227-41332	Fryar 3S	2XD
42-227-41307	Buchanan 3111	1XD
42-227-39064	Pipeline SWD	1
42-335-34319	Wild Bill	1WD
42-227-41775	Sterling	1XD
42-335-36026	Oasis Deep	9XD
42-227-39098	846 SWD	2
42-227-39119	N. Midway SWD	1
42-227-40310	Hull SWD	1

Table 10 – Offset SWD Wells Included in GEM Model

The model runs for a total of 175.33 years, comprising 15.33 years of historical SWD well injection prior to the commencement of acid gas injection. This is followed by 40 years of active acid gas injection through the Mongoose, succeeded by an additional 120 years of density drift. The model begins in September 2008, aligning with the start of historical injection data for the first offset SWD well. The remainder of the SWD wells turn on between then and the start of the acid gas injection, which begins in January 2024. Throughout the entire 40-year injection period, an injection rate of 19.5 MMscf/D is assumed to model the maximum available rate, yielding a more cautious estimate of the plume size. After the 40-year injection period, when the Mongoose ceases injection, all nine offset SWD wells have been shut in—as they began injecting before the Mongoose and were assumed to stop injecting after 30 years.

The maximum plume extent during the 40-year injection period is shown in Figure 35. The final extent after 120 years of density drift after injection ceases is shown in Figure 36. Both figures show the entire grid with the included offset SWD wells. Due to the large nature of the model, a zoomed-in view of the plume extent during the 40-year injection period is shown in Figure 37 and the final extent after 120 years of density drift after injection ceases is shown in Figure 38.



Figure 35 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)



Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

The cross-sectional view of the Mongoose shows the extent of the plume from a side-view angle cutting through the formation at the wellbore. Figure 39 shows the maximum plume extent during the 40-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 40 shows the final extent of the plume after 120 years of migration. At this point in time, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, as it is less dense than the formation brine, until an impermeable layer is reached. Both figures are shown in a north-to-south view.



Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 40 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)

Figure 41 shows the surface injection rate, bottomhole pressures, and surface pressures over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate begins, reaching a maximum pressure of 4,453 psig, then slightly decreases and remains constant. This buildup of 550 psig keeps the bottomhole pressure below the fracture pressure of 5,007 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,008 psig, well below the maximum allowable 2,500 psig per the TRRC UIC permit for this well. At roughly 30 years into injection for the Mongoose, all SWD wells included in the model have ceased injection. Due to the shut-in of offset SWD wells, the pressure effects within the formation are felt by the Mongoose. When this occurs, the bottomhole pressure decreases by 50 psig and surface pressure decreases by 40 psig. Bottomhole and wellhead pressures over time are in Table 11.



Figure 41 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 11 – Bottomhole and Wellhead Pressures C	Over Time from Start of Injection
--	-----------------------------------

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	3,916	-
10	4,389	1,977
20	4,394	1,982
30	4,393	1,980
40	4,343	1,942
50	3,923	-
120	3,919	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in 40 CFR **§98.448(a)(1)**.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO₂ plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

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

Bayswater's expected gas composition was used in the model. The acid gas injectate is estimated at a molar composition of 58.8% H₂S and 41.2% CO₂, with trace amounts of other constituents. Upon the Plant achieving stable operations, a representative injectate sample will be collected and analyzed by a third-party laboratory. If the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be provided. As discussed in *Section 2*, the gas will be injected into the Ellenberger formation. The geomodel was created based on the rock properties of the Ellenberger.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 40, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast.

Figure 42 shows the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA is depicted in this figure by taking the stabilized plume boundary after 120 years of density drift, and adding an all-around buffer zone of one half mile.



Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. This provides Bayswater sufficient time to develop its asset base, achieve steady operations, and evaluate any potential modifications to the MRV plan.

The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years 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 in 2036 plus a half-mile buffer. By 2036, a revised MRV plan will be submitted to define a new AMA. Figure 43 shows the area covered by the AMA.



Figure 43 – 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. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within the MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from natural or induced seismicity

Table 12 – Potential Leakage Pathway Risk Assessment
--

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. The lateral continuity of the UCZ ¹ is recognized as a very competent seal.	Low. Any vertical migration from the Injection Zone would return the CO ₂ to the production zone.	During active injection and Post Injection Site Care ² period.
Faults and fractures	Possible. The lateral continuity of UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO ₂ to the production zone.	During active injection and Post Injection Site Care period.
Upper confining layer	Unlikely. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO ₂ to the production zone.	During active injection and Post Injection Site Care period.
Natural or induced seismicity	Possible. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO ₂ to the production zone.	During active injection and Post Injection Site Care period.

1 - UCZ is defined as the Upper Confining Zone.

2 - Post Injection Site Care is the period of time from the end of injection throught plume stabilization and site closure.

Magnitude Assessment Description

Low - catergorized as little to no impact to safety, health and the environment and the costs to mitigate are minimal.

Medium - potential risks to the USDW and for surface releases does exist, but circumstances can be easily remediated.

High - danger to the USDW and significant surface release may exist, and if occurs this would require significant costs to remediate.

4.1 Leakage from Surface Equipment

The Plant and Mongoose are newly designed and constructed facilities for treating and injecting acid gas with the fundamental objective of ensuring maximum safety for the public, the employees, and the environment. These are depicted in Figures 44 and 45. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H₂S are installed at key locations around the Plant as depicted on the site plan in Appendix B-2. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H₂S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the TRRC with the Class II AGI application. OSHA sets the detection or exposure limits at 15 ppm as the High Alarm and the High- High Alarm or Facility Shutdown limit at 40 ppm.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant and the Mongoose well. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs. These valves, gas monitors, and the gas flow meter are called out in the detailed site plan in Appendix B-2. Data from this flow meter will be used in the calculations of the total mass of CO₂ (in metric tons) in the CO₂ stream injected each year, per 40 CFR **§98.444(b)**.



Figure 44 – Site Plan



Figure 45 – Mongoose AGI No. 1 Wellbore Schematic

With the level of monitoring implemented at the Plant, a release of CO_2 would be quickly identified, and the safety systems and protocols would minimize the release volume. The acid gas stream injected into the well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the Plant adjacent to the Mongoose. Bayswater will increase its future injection volumes from its own gas production and possibly other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7* in accordance with 40 CFR **§98.448(a)(5)**. Bayswater concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The Mongoose was designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 45. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) §3.46 [40 CFR §146.23 (b)(3)], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 46. The MMA review map and a summary of all wells in the MMA is provided in *Appendix C*. Figure 47 highlights that only two wells penetrate the MMA's gross injection zone. These wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements. Bayswater will perform baseline soil gas sampling prior to the implementation of the MRV plan and subsequent injection records. In addition, annual soil gas samples will be taken in the area adjacent to artificial penetrations and analyzed by a third-party lab. The results, should they indicate an issue with the sequestered CO₂ will be presented in the annual report to the GHGRP.

The summary of all oil and gas wells in *Appendix C* also provides the total depth (TD) of all wells within the MMA. Those wells that are shallower and do not penetrate the injection zone are isolated by the Woodford Shale as discussed in Section 2.2.2. The Woodford Shale provides 50 feet or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset APs is unlikely.

Bayswater is the operator of many of the shallower offset oil and gas wells within the MMA and frequently performs gas analysis on their production volumes. If a material variance in the quantity of CO₂ produced is indicated, Bayswater would investigate to determine the affected well(s), the root cause of the CO₂ increase to formulate a resolution plan and utilize the gas analysis variance to calculate any adjustments to reported volumes.



Figure 46 – All Oil and Gas Wells Within the MMA



Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC in the area of the Mongoose will include a list of formations for which operators are required to comply with TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC §3.13. The Mongoose drilling permit, provided in Appendix A, serves as an example. The Ellenburger is among the formations listed for which operators in Mitchell County and District 8 (where the Mongoose is located) are required to comply with TRCC Rule 13. The rule requires oil and gas operators to set steel casing and cement either (1) across and above all formations permitted for injection under TRRC Rule 9, or (2) immediately above all formations permitted for injection under Rule 46, for any well proposed within a quarter-mile radius of an injection well. In this instance, any new well permitted and drilled to the injection zone and located within a guarter-mile radius of the Mongoose will be required under TRRC Rule 13 to set steel casing and cement above the well's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and 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 (also provided in the permit in Appendix A).

4.2.2 Groundwater Wells

A groundwater well search results found three wells within the MMA, as identified by the Texas Water Development Board. A field investigation was performed to validate the existence and location of these wells. However, none of the wells listed in the database could be located. An exhaustive search of well records was performed and no completion reports and/or plugging records were found. The result is there are no groundwater wells to monitor as none exist within the MMA.

The surface, intermediate, and production casing strings in the Mongoose, as shown in Figure 45, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations and the GAU letter issued for this location (and included in *Appendix A*). The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Bayswater concludes that leakage of the sequestered CO_2 to the groundwater aquifer is unlikely.

4.3 Leakage Through Faults and Fractures

No faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose. This includes areas well outside of the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

In the event of an unmapped fault existing within the plume boundary, any displacement caused by it would be too small to be detected through 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

Porosity development within the injection intervals is primarily attributed to fractures and aerial exposure. However, these fractures are limited and do not extend into the upper confining unit, which helps mitigate the risk of migration through fractures outside of the designated injection interval.

4.4 Leakage Through the Confining Layer

The overlying Woodford formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in *Section 2*. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale which would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

4.5 Leakage from Natural or Induced Seismicity

The Mongoose is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

All seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

Stringent operating procedures will be programmed into the SCADA and control systems to ensure that operating pressures stay below the fracture gradient of both the injection and confining intervals. Moreover, a combination of continuous well monitoring and monitoring of the TexNet site for activity will promptly identify any irregularities in the operations linked to seismic events.



Figure 48 – Seismicity Review (TexNet – 08/04/2023)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Bayswater 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 H₂S and CO₂, the H₂S will be a proxy for CO₂ leakage and therefore the monitoring systems in place to detect H₂S will also indicate a release of CO₂. Table 13 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 40-year injection period or cessation of injection operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

Leakage Pathway	Monitoring Method	
Leakage from surface equipment	Fixed H ₂ S monitors throughout the AGI facility	
	Visual inspections	
	SCADA continuous monitoring of the AGI facility	
Leakage through existing wells	SCADA continuous monitoring of the AGI well	
	Monitor CO ₂ levels in Above Zone producing wells	
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years	
	Visual inspections	
	Annual soil gas sampling at well locations that penetrate the Upper Confining Zone within the AMA	
Leakage through groundwater wells	Annual groundwater samples from monitoring wells	
Leakage from future wells	Compliance with TRRC Rule 13 Regulations	
Leakage through faults and fractures	SCADA continuous monitoring at the AGI well (volumes and pressures)	
	Monitor CO ₂ levels in Above Zone producing wells	
Leakage through the confining layer	SCADA continuous monitoring at the AGI well (volumes and pressures)	
	Monitor CO_2 levels in Above Zone producing wells	
Leakage from natural or induced seismicity	Monitor CO_2 levels in Above Zone producing wells	
	Monitor existing TexNet station	

Table 13 – Summary of Leakage Monitoring Methods

5.1 <u>Leakage from Surface Equipment</u>

The Plant and the Mongoose were designed to operate in a manner that will reduce to the lowest factor the possibility of an escape of CO₂ and H₂S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO₂ concentration will be established during the commissioning of the Plant. Ambient H₂S monitors are located at the Plant and near the Mongoose for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in *Appendix B*. The locations of H₂S detectors and Emergency Shutdowns are identified throughout the facility on the Appendix B-2 Site Plan. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Bayswater to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO₂ released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

5.2 Leakage Through Existing and Future Wells Within the MMA

Bayswater continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the Mongoose. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, an MIT will be performed every 5 years, as required by the TRRC and UIC. A failed MIT would also indicate the potential of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 ensures that new wells in the field would be constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Bayswater will also establish an in-field soil gas monitoring program to detect CO_2 leakage within the AMA. This would include sample collection and testing for CO_2 and H_2S at the AGI well site and near one of the identified artificial penetrations of the injection interval within the AMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. Prior to approval and implementation of

the MRV plan and through the post-injection site care period, Bayswater will have these monitoring systems in place.

There are currently only two wells that have been identified within the AMA that penetrate the Upper Confining Zone. As both wells have been plugged and abandoned in compliance with TRRC requirements, Bayswater believes a leak event is unlikely. Bayswater will perform soil gas sampling and analysis proximate to the Mongoose and one of the abandoned artificial penetrations by May 20, 2024. Thereafter, soil gas samples will be taken annually and analyzed by a third-party lab, and the results will be included in the annual report.

Bayswater is the operator of record for many oil and gas producing wells with the AMA. These wells will be used as a proxy for an above-zone monitoring well. If any CO_2 , migrates up-hole, the CO_2 would likely end up in this formation. Since gas analysis is performed on a regular basis on the hydrocarbons produced from this formation, any material variance from historical data would indicate the potential of an issue needing further investigation. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance. It is not the intent of Bayswater to produce any of the CO_2 in this scenario but to use this as an indication of an event warranting further investigation.

5.2.1.1 <u>Groundwater Quality Monitoring</u>

As explained in *Section 4.2.2,* there are no groundwater wells within the MMA. Therefore, there are no groundwater wells to monitor.

5.3 <u>Leakage Through Faults, Fractures, or Confining Seals</u>

Bayswater continuously monitors the operations of the Mongoose 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 due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Bayswater will also monitor production from their oil and gas wells that do not penetrate the injection zone for any material variance in CO₂ content in the produced gas stream. Since gas analysis is very consistent over time, any material variance in the CO₂ content would be an early indicator of a potential issue. Should the CO₂ migrate vertically, the magnitude risk of this event is very low, as the reservoir provides an ideal containment given the Upper Confining Zone has successfully held hydrocarbons in place. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Bayswater plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose well. This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 49. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Bayswater facility. Bayswater will monitor this station for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected, Bayswater will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.



Figure 49 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

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

6.1 Visual Inspections

Regular inspections will be conducted by field personnel at the Plant and the Mongoose. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken in a prudent and safe manner to address such issues.

6.2 <u>CO₂/H₂S Detection</u>

In addition to the fixed gas monitors at the well site, Bayswater will perform an annual soil gas sampling program to detect any CO_2 leakage proximate to select artificial penetrations of the Upper Confining Zone within the AMA. The baseline determination will include atmospheric H₂S measurements at the AGI well and soil gas sampling near the AGI well and one of the abandoned artificial penetrations within the AMA.

These soil gas sample probes will be inserted below the surface. The probes have special material inserts that collect the gas samples over a 21-day period. These inserts are then removed and sent to a third-party lab to be analyzed for CO_2 , H_2S , and trace contaminants typically found in a hydrocarbon gas stream. This initial sample collection is scheduled to be completed by May 20, 2024; a sufficient time period prior to the implementation of the MRV plan and will establish baseline values for future reference.

6.3 **Operational Data**

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO₂.

6.4 <u>Continuous Monitoring</u>

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger an alarm if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions,

including pressure, flow rate, percentage of CO₂, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a de-pressuring event, the acid gas stream will be diverted to a flare stack to be safely processed and vented. The event will be reported as required for the operation of the well.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO₂ Received

Per 40 CFR **§98.443**, the mass of CO₂ received must be calculated using the specified CO₂ received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4)**." 40 CFR **§98.444(a)(4)** states that "if the CO₂ you receive is wholly injected and is not mixed with any other supply of CO₂, you may report the annual mass of CO₂ injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO₂ received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO₂ received." The CO₂ received for this injection well is wholly injected and not mixed with any other supply; the annual mass of CO₂ injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO₂ 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 volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, 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 CO₂ mass injected (metric tons) as measured by flow meter u

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO₂ Produced

The Mongoose is not part of an enhanced oil recovery project; therefore, no CO₂ will be produced.

7.4 Mass of CO₂ Emitted by Surface Leakage

The mass of CO₂ emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains high concentrations of H₂S. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions sent to a flare stack and reported as a part of the required GHG reporting for the Plant. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of CO₂ and H₂S. The mass of the CO₂ released would be calculated for the operating conditions, including pressure, flow rate, size of the leak-point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO₂ was released because of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

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

Where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

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

X = Leakage pathway

Calculation methods using equations from Subpart W will be used to calculate CO₂ emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Bayswater believes the most appropriate method to quantify the mass of CO₂ released will be determined on a case-by-case basis. Any mass of CO₂ detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. In the unlikely event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events will be kept and stored as stated in *Section 10*.

7.5 Mass of CO₂ Sequestered

The mass of CO₂ sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Since the Mongoose has commenced operations, Bayswater will begin collecting data for reporting under this plan based on the approval of this MRV plan and any applicable stipulations therein. The calculation of sequestered volumes utilizes the following equation as this well will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

 CO_{21} = 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 CO₂ 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 is expected to occur, the calculations would be based on an unusual event that a blowdown is required and those emissions are sent to a flare stack and reported as part of the required GHG reporting for the Plant.

• Calculation methods from Subpart W will be used to calculate CO₂ 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 Mongoose is a new injection well currently reporting under the TRRC Class II regulations. Bayswater is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

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

9.1 Monitoring QA/QC

CO₂ Injected

- The flow rate of the CO₂ being injected will be measured with a volumetric flow meter, consistent with applicable industry standards. These flow rates will be compiled quarterly.
- The composition of the injectate stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with applicable industry standards.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The gas measurement equipment will be calibrated per the requirements of 40 CFR §98.444(e) and §98.3(i).

CO₂ Emissions from Leaks and Vented Emissions

- Gas monitors within the Mongoose facility will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.
- Calculation methods from Subpart W will be used to calculate CO₂ emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR §98.3(i).
- Flow meters will be operated and maintained in accordance with applicable standards as published by a consensus-based standards organization.

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

9.2 Missing Data

In accordance with 40 CFR **§98.445**, Bayswater 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 CO₂ injected is missing, the amount will be estimated using a representative quantity of CO₂ injected from the nearest previous period at a similar injection pressure.

• Fugitive CO₂ emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR **§98**.

9.3 MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Bayswater will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least 3 years and include the following:

- Quarterly records of the CO₂ injected
 - Volumetric flow at standard conditions
 - Volumetric flow at operating conditions
 - Operating temperature and pressure
 - Concentration of the CO₂ stream
- Annual records of the information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of the information used to calculate CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 11 - REFERENCES

- Adams, D. C., & Keller, G. R. (1996). Precambrian Basement Geology of the Permian Basin Region of West Texas and Eastern New Mexico: A Geophysical Perspective1. *AAPG*.
- Aird, P. (2019). *Deepwater Geology & Geoscience*. Retrieved from ScienceDirect: https://www.sciencedirect.com/topics/engineering/overburden-stress
- Bradley, R. G., & Kalaswad, S. (2001). *Chapter 12: Dockum Aquifer in West Texas*. Texas Water Development Board.
- Bennion, B., & Bachu, S. (2010). Drainage and Imbibition CO₂/Brine Relative Permeability Curves at Reservoir Conditions for Carbonate Formations. *SPE Annual Technical Conference and Exhibition*.
- Comer, J. B. (1991). Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas asn Southeatern New Mexico. *BEG*.
- Conselman, F. B. (1954). Preliminary Report on the Geology of the Cambrian Trend of West Central Texas. *Abilene Geologic Society*.
- Domede, P. S. (2017). *Mechanical behaviour of granite. A compilation, analysis and correlation of data from around the world*. Retrieved from https://hal.insa-toulouse.fr/hal-01743870/document
- Dutton, A. R., & Simpkins, W. W. (1986). *Hydrogeochemistry and Water Resources of the Triassic Lower Dockum Group in the Texas Panhandle and Eastern New Mexico*. Austin Tx: Bureau of Economic Geology.
- Fanchi, J. R. (2010). Integrated Reservoir Asset Management.
- Galley, J. (1958). Oil and Geology in the Permian Basin of Texas and New Mexico. *Basin or Areal Analysis or Evaluation*.
- Gunn, R. D. (1982). Desmoinesian Depositonal Systems in the Knox Baylor Trough. North Texas Geological Society.
- Hendricks, L. (1964). STRATIGRAPHIC SUMMARY OF THE ELLENBURGER GROUP OF NORTH TEXAS. *Tulsa Geological Society Digest, Volume 32*.
- Hornhach, M. J. (2016). Ellenburger wastwater injection and seismicity in North Texas. *Physics of the Earth and Planetary Interiors*.
- Jesse G. White, P. P. (2014). Reconstruction of Paleoenvironments through Integrative Sedimentology and Ichnology of the Pennsylvanian Strawn Formation. *AAPG Southwest Section Annual Convention, Midland, Texas.*
- Keelan, K., & Pugh, V. (1975). Trapped-Gas Saturations in Carbonate Formations. SPE J. 15: 149–160.
- Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas. *Bureau of Economic Geology*.
- Lone Wolf Groundwater Conservation District. (2019). *Management Plan 2019-2024.* Colorado City, Tx.
- Loucks, R. (2003). REVIEW OF THE LOWER ORDOVICIAN ELLENBURGER GROUP OF THE PERMIAN BASIN, WEST TEXAS. *Bureau of Economic Geology*.
- Loucks, R. (2006). *Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas.* Austin, Tx: Bureau of Economic Geology.
- Mason, C. C. (1961). GROUND-WATER GEOLOGY OF THE HICKORYSANDSTONE MEMBER OF THE RILEY FORMATION. McCULLOCH COUNTY. TEXAS. *TEXAS BOARD OF WATER ENGINEERS*.
- Merrill, M., Slucher, E., Roberts -Ashby, T., Warwick, P., Blondes, M., Freeman, P., . . . Lohr, C. (2015). Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources–Permian and Palo Duro Basins and Bend Arch-Fort Worth Basin. *USGS*.
- Popova, O. (2020). Permian Basin Part 1 Wolfcamp, Bone Spring, Delaware shale plays of the Delaware Basin Geology Review. *USDOE*.
- Powers, R. B. (1989). Petroleum Exploration Plays and Resource Estimates, 1989, On shore United States -- Region 5, West Texas and Eastern New Mexico. USGS.
- Sanchez, T., Loughry, D., & Coringrato, V. (2019). Evaluating the Ellenburger Reservoir for Salt Water Disposal in the Midland Basin: An Assessment of Porosity Distribution Beyond the Scale of Karsts. Unconventional Resources Technology Conference (pp. 1-17). Denver: URTeC. doi:10.15530/urtec-2019-600
- Scanlon, B. R., Reedy, R. C., Male, F., & Walsh, M. (n.d.). *Water Issues Related to Transitioning from Conventional to Unconventional Oil Production in the Permian Basin.* Austin: Bureau of Economic Geology.
- Shamburger Jr., V. M. (1967). *Report 50: Ground-Water Resources of Mitchell and Western Nolan Counties, Texas.* Austin, Tx: Texas Water Development Board.
- Snee, J.-E. L., & Zoback, M. D. (2018). State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity. *The Leading Edge*, 810-819.
- Waite, L. (2021, October 25). Geology of the Permian Basin. UT Dallas Geoscience Permian Basin Research Lab.
- Zerwer, N. Y. (1997). Stress Regimes in the Gulf Coast, Offshore Louisiana:. AAPG Bulletin, 293-307.

APPENDICES

APPENDICES

<u>APPENDIX A – MONGOOSE AGI No. 1 TRRC FORMS</u>

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

APPENDIX A-5: API 42-335-33555 VAN TUYLE PLUGGING RECORDS

APPENDIX A-6: API 42-227-03634 STEWART PLUGGING RECORDS

CHRISTI CRADDICK, CHAIRMAN WAYNE CHRISTIAN, COMMISSIONER JIM WRIGHT, COMMISSIONER



A-1

DANNY SORRELLS DEPUTY EXECUTIVE DIRECTOR DIRECTOR, OIL AND GAS DIVISION PAUL DUBOIS, P.E. 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. 17174

BAYSWATER OPERATING COMPANY LLC 730 17TH STREET SUITE 500 DENVER CO 80202

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 22, 2022, for the permitted interval(s) of the WOODFORD and ELLENBURGER formation(s) and subject to the following terms and special conditions:

MONGOOSE AGI (000000) LEASE SPRABERRY (TREND AREA) FIELD MITCHELL COUNTY DISTRICT 08

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	33536013	000125803	Carbon Dioxide (CO2); Hydrogen Sulfide (H2S)	8300	9000	6900	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
		1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.
		2. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.
1	33536013	3. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.
		4. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.
		5. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.

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.
- Prior to beginning injection and subsequently after any work over, an annulus pressure test must 4. 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 March 10, 2023.

Hilf

For Sean Avitt, Manager Injection-Storage Permits Unit

			A-2				
	GROUNDWATER PROTEC		Form GW-2				
	Groundwater Advisory Unit						
Date Issued:	04 March 2022	GAU Number:	336979				
Attention:	BAYSWATER OPERATING	API Number:	33536013				
	730 17TH STREET SUITE 500	County:	MITCHELL Mongoose AGI				
	DENVER, CO 80202	Lease Number:	Mongoose Aon				
Operator No.:	058827	Well Number:	1				
		Total Vertical	9250				
		Latitude:	32.422884				
		Longitude:	-101.169661				
		Datum:	NAD27				
Purpose:	Injection into Non-producing Zone (W-1	4) ock-29 [.] Townshin-1N [.] Sec	ntion_4				
To protect usable-qu Texas recommends	uality groundwater at this location, the Gro	bundwater Advisory Unit c	of the Railroad Commission of				
The base of usable- well.	quality water-bearing strata is estimated t	o occur at a depth of 350	feet at the site of the referenced				
The BASE OF UND feet at the site of the	ERGROUND SOURCES OF DRINKING	WATER (USDW) is estima	ated to occur at a depth of 475				
This recommendation is applicable to all wells within a radius of 200 feet of this location.							
Note: Unless stated Unless stated other	otherwise, this recommendation is intend wise, this recommendation is for normal d	ed to apply to all wells dri rilling, production, and plu	lled within 200 feet of the subject well. Igging operations only.				
This determination is based on information provided when the application was submitted on 03/02/2022. 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 Advisc	ory Unit, Oil and Gas Division						
Form GW-2 P.C Rev. 02/2014). Box 12967 Austin, Texas 78771-2967	7 512-463-2741 lr	nternet address: www.rrc.texas.				

	RAILROAD COMMISSION OF TEX OIL & GAS DIVISION	AS			
PERMIT TO DRILL, DEEPEN, PLUG	ACK, OR RE-ENTER ON A REGULAR OR A	DMINISTRA	TIVE EXCER	PTION LOCATI	ON
PERMIT NUMBER 876754	DATE PERMIT ISSUED OR AMENDED Feb 10, 2022	DISTRICT	* 0)8	
APINUMBER 42-335-36013	FORM W-1 RECEIVED Feb 03 2022	COUNTY	MITCH	HELL	
TYPE OF OPERATION	WELLBORE PROFILE(S)	ACRES			
NEW DRILL	Vertical		4	0	
OPERATOR BAYSWATER OPERATING 730 17TH STREET SUITE DENVER, CO 80202-0000	This permi revoked if O Dis	NOTI t and any allow payment for f commission is strict Office T (432) 68-	ICE wable assigned ma fee(s) submitted to not honorad. Felephone No: 4-5581	ay b o the	
LEASE NAME MONG	OOSE AGI	WELL NU	MBER	1	
LOCATION 10.4 miles NW direct	ion from WESTBROOK	TOTAL DE	SPTH	10000	
SECTION 4 SURVEY T&P RR CO/MORRIS DISTANCE TO SURVEY LINES	BLOCK 29 T1N ABSTRA	DISTANCE	15 e to neare	ST LEASE LINI	E
551 IL EAST	2164 ft. SOUTH	DISTANCE	TONEARE	T.	EA 6
400 ft. EAST	650 ft. SOUTH	DISTILICE	See FIEI	LD(s) Below	
FIELD NAME LEASE NAME		ACRES NEAREST LE	DEPTH SASE	WELL # NEAREST WE	D
SPRABERRY (TREND AREA)		40.00	10,000	1	-
MONGOOSE AGI				0	
RESTRICTIONS: Do not use this by the Environm	well for injection/disposal/hydrocar ental Services section of the Railroa	bon storage 1 Commissio	e purposes on, Austin,	vithout appro Texas office	ova e.
THE F This well shall be completed and produc well is to be used for brine mining, under salt formations, a permit for that specific drilling, of the well in accordance with St This well must comply to the new SWR is corrosive formation fluids. See approve drilling the well in.	OLLOWING RESTRICTIONS APPLY TO ed in compliance with applicable special field rground storage of liquid hydrocarbons in salt purpose must be obtained from Environment atewide Rules B1, 95, and 97. 3.13 requirements concerning the isolation of d permit for those formations that have been i	ALL FIELD or statewide formations, al Services p any potentia dentified for	DS a spacing an or undergrou prior to const al flow zones the county in	d density rules. und storage of g truction, includir and zones with n which you are	lft gas ng n
Data Validation Time Stamp:	Feb 10, 2022 9:58 AM('As Approved' Version)	Page 3 of 4		



RAILROAD COMMISSION OF TEXAS

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

Tracking No.:

Submitted 09/11/2023 298516

Form W-2

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

UPERALL	
	Operator 059927
Operator 730 17TH STREET SUITE 500 DENVER CO	
WELL	INFORMATION
API 42-335-36013	County: MITCHELL
Well No.: 1	RRC District 08
Lease MONGOOSE AGI	Field SPRABERRY (TREND AREA)
RRC Lease	Field No.: 85280300
Location Section: 4, Block: 29 T1N, Survey: T&P RR CO/MORRIS	SON, W, Abstract: 1545
Latitude 32.423000	Longitud -101.170059
line tion from WEATDDOOK	
which is the nearest town in the	
FILING	INFORMATION
Purpose of Initial Potential	
Type of New Well	
Well Type: Active UIC	Completion or Recompletion 04/28/2023
Type of Permit	Date Permit No.
Permit to Drill, Plug Back, or	02/10/2022 876754
Rule 37 Exception	
Fluid Injection	
O&G Waste Disposal	17174
Other:	
COMPLET	
Spud 10/12/2022	Date of first production after rig 04/28/2023
Date plug back, deepening,	Date plug back, deepening, recompletion,
drilling operation 10/12/2022	drilling operation $04/28/2023$
Number of producing wells on this lease	Distance to nearest well in lease &
Number of producing wells on this lease this field (reservoir) including this 1	Distance to nearest well in lease & reservoir
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00	Distance to nearest well in lease & reservoir Elevation 2252 GL
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-Yes	Distance to nearest well in lease & reservoir Elevation 2252 Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNo	Distance to nearest well in lease & reservoir Elevation 2252 Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No iction/Neutron/Density/Sonic
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400 400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Inction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and 0 Feet from the South Line of the
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400650	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Inction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W- YesYesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this 1 Total number of acres in 40.00 Total depth TVD 9289 Plug back depth TVD 9036 Was directional survey made other inclination (Form W- Yes Recompletion or No Type(s) of electric or other log(s) Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is 400 FORMER FIELD (WITH RESE	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this 1 Total number of acres in 40.00 Total depth TVD 9289 Plug back depth TVD 9036 Was directional survey made other inclination (Form W- Yes Recompletion or No Type(s) of electric or other log(s) Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is 400 FORMER FIELD (WITH RESE Field & Reservoir	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and 0 Feet from the South Line of the MONGOOSE AGI Lease. RVOIR) & GAS ID OR OIL LEASE NO. Gas ID or Oil Lease Well No. Prior Service Type

W2:	N/A				
FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:					
GAU Ground	dwater Protection Determination	Depth	350.0	Date 03/04/2022	
SWR 13 Exc	eption	Depth			

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION					
Date of		Production			
Number of hours 24		Choke			
Was swab used during this	No	Oil produced prior to			
PRODUCTION DURING TEST PERIOD:					
Oil		Gas			
Gas - Oil 0		Flowing Tubing			
Water					
	CALCULATED	24-HOUR RATE			
Oil		Gas			
Oil Gravity - API - 60.:		Casing			
Water					

	CASING RECORD										
	Type of	Casing Size	Hole Size	Setting Depth	<u>Multi -</u> Stage Tool	<u>Multi -</u> Stage Shoe	Cement Class	Cement Amoun	Slurry Volume	Top of Cemen	t <u>TOC</u> t Determined
<u>Ro</u>	Casing	<u>(in.)</u>							<u>(cu.</u>	<u>(ft.)</u>	Ву
1	Surface	13 3/8	17 1/2	569			С	637	847.0	0	Circulated to Surface
2	Intermediate	9 5/8	12 1/4	5328	3001		С	725	1752.0	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5328			С	610	1175.0	3001	Calculation
4 C	Conventional Production	n 7	8 3/4	8343			C & RESIN	594	1513.0	1800	Calculation

_					LINER RECORD			
<u>Ro</u>	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu. (ft.)	TOC Determined
N/A								

		TUBING RECORD	
Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	8260	8230 / INCONEL
			925

PRODUCING/INJECTION/DISPOSAL INTERVAL					
Ro	Open hole?	From (ft.)	<u>To (ft.)</u>		
1	Yes	L 8343	9036.0		

ACID, FRACTURE, C	EMENT SQUEEZE, CAST IRON BRIDGE PLUG,	RETAINER, ETC.			
Was hydraulic fracturing treatment	No				
Is well equipped with a downhole sleeve? No	If yes, actuation pressure				
Production casing test pressure (PSI	IG) Actual maximum pressur	e (PSIG) during			
hydraulic fracturing	fracturin				
Has the hydraulic fracturing fluid disclosure been No					
Ro Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)			

OPEN HOLE CEMENT PLUG WITH 58 SACKS CLASS H

1

Other

9036 9289

		FORMATION REV	CORD		
Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
SANTA ROSA - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT
YATES - OVERPRESSURED, POSSIBLE FLOWS	Yes	1001.0		Yes	
SEVEN RIVERS	Yes	1137.0		Yes	
SAN ANDRES - HIGH FLOWS, H2 CORROSIVE	S, Yes	2008.0		Yes	
GLORIETA	Yes	2875.0		Yes	
CLEARFORK	Yes	3089.0		Yes	
TUBB	No			No	NOT PRESENT AT LOCATION
WICHITA	No			No	NOT PRESENT AT LOCATION
COLEMAN JUNCTION - POSSIBL LOST CIRCULATION	E No			No	NOT PRESENT AT LOCATION
WOLFCAMP	Yes	5369.0		Yes	
STRAWN	Yes	7918.0		Yes	
ODOM	No			No	NOT PRESENT AT LOCATION.
MISSISSIPPIAN	Yes	8153.0		Yes	
WOODFORD	Yes	8322.0		Yes	
ELLENBURGER	Yes	8374.0		Yes	
CAMBRIAN	Yes	9279.0		Yes	
Do the producing interval of this w	ell produce H	2S with a concer	tration in exc	ess of 100 ppm	No
Is the completion being downhole	commingled	N	0		

REMARKS DIRECTIONAL SURVEY RUN FOR INFORMATION PURPOSES ONLY.

PUBLIC COMMENTS:

RRC REMARKS

CASING RECORD :

SURFACE CASING IS SET AT 543.5' AS MEASURED FROM GROUND LEVEL, WHICH IS WITHIN 200' OF BUQW.

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

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

POTENTIAL TEST DATA:

		OPERATOR'S CERTIF	ICATION	
Printed	James Clark	Title:	Consulting Petroleum Engineer	
Telephone	(512) 415-4191	Date	09/11/2023	

Ð 7 Ð ŋ 7 η ŋ Ŋ 20. Do you have the right to develop the minerals under nny right of way that crosses, or is contiguous to, this innet? If not, and if the well requires a Rule 37 or 38 exception. 25. is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes 23. Is this a pooled unit? Perpendicular surface location from two nearest designated lines:
 trace.Unit <u>1000</u>, FNL & 2500, FEL 11. Distance from proposed location to nearest leave or unit line 2 Address (including city and zip code) Purpose of filing (murk appropriate bodes): · Sunny/Section 1000' FNL & 2500' FEL of Section 15-Operator's Name (exactly as shown on Form P.S. Organization Front) see Instructions for Rule 37. ĩ Krimerka Nulicamp, (Wildcat) File a copy of W-1 and plat in JORC Di Ellenburger (Wildcat) 1800 £ Midland, Texas 3200 West Cuthbert, Bright se zones. One zone per line, ELD NAME: [Exactly as sheem; on RRC privation added a all extublished and while a zones of anticipated repirtion. Attach additional Form W-1's as needed to list any firencalo ふしい 121 Uttach Form P-12 and certified plat. 21 × たりや Company 30 D III 6 Directional Well S and \$180.00 fee 79701 Rai Bau **Nation** Suite 2-C trict Office. Deepen (below casing) Sidetrack Application for Permit to Drill, Deepen, Plug Back, or Re-Enter ã 5200-8300' **Gebru** 7800 1000 × 10. Location 3. IURC Operator No. 6. Lease Name (32 spaces maximum) Van Tuyle 093125 'This well is to be located ______ Section . 8 8 Deepen (within casing) Amended Permit (enter permit no. at right & explain fully in Remarks) which is the nearest town in the county of the well site RAILROAD COMMISSION OF TEXAS Oll and Gas Division N 10 (n.) 467-1200 2 467 1200 Specing 467-1200 No 2 Lini 2 15 203091 0CT 1890 If subject to Rule 36, ts Form H 9 Aled? Yes Ę ł I certify that information stated in this application is ince and complete, to the best of my knowledge ĕ 12. Number of configuous acres in lease, pooled unit, or unitized iract **4**0 Density If a directional will show also projected bottom-hole location: pallern Hock 24 Jo liem 17 less that Jiem 18 (substandersberrehe for any field applied for?? 4. FIRC District No. G Lengel Mail Signature Date: Խ 20, 1-1-1 mary Artiling unity for this well OUTLINE 15 Plug Back ALL DE LO 5 4 鍧 _miles in a _north ŝ 9/26/90 1 Smuth. 5. County of Well Site day. Mitchell TEP RR Cor, TWP T-N NO NO a Re-Enter 7. RRC Lease/ID No. direction from <u>Latan</u> ٧ Tel: Area Code S. Dawner from NA TRA-NA Inchesed your talavoli. (N.) Dog to neuro Read Instructions on Back 915-697-2214 Tracy D. Tenison, Engineer Name and title of operator's representative Enter here, lf assigned: letted wes Z, ۷ "Ennite h 8. Well No. 640 80 V If not filed, explain in Remarks. Number Type and or other Penny 42-33 0 9 0 Rule 37 Case No Abstract No. A. 584 21. Act, of applied for per-mitted, or complete and becattoms that during the this one on bear in the this one on bear in the this reservoir. (1) 5 Form W-1 (OUTLINE ON PLAT.) 9. Total Depth 1 85001 2355 ŝ 5 5 3

A-5



<u>*</u>		<u>इ</u>	26 17 19	25.11	22.11		- 12 M	5 17	s	Ę	() 중용) 11. Pl				λ εi	в 1.0p		Իսդ	¥ ⊒ .≇
		inai ks	you have the right to develop the minerals under y y right of way that crosses, or is configuous to, this tract? y nut, and if the well requires a Rule 37 or 38 exception, r Inviruentions for Rule 37.	his wellwre subject to Statewide Rule 36 (hydrogen aufide are	 Interpretendent of the second s	Sunn Section 1000' FNL & 2500' PEL of Su	pendicular surface location from two neatret designated lines: I.cov/Unit 1000' FNL & 2500' FEL	llenburger (Wildcat)	trawn (Wildcat)	olfcamp (Wildcat)	rpletion. Attach additional Form W-1's as needed to list ae zones. One zone per line.	ELD NAME (Exactly as shown on RBC provation achedule), all established and wildcal zones of anticipated	istance from proposed location to nearest lease or unit line			Hdlynd, Texas 79701	dress linktuding city and zip code)	iright & Company	Directional Well Sidetrack	ne of filing (mark appropriate hours): X Drill Dreprin (Lelow casing)	 Transver of Trans. Address to: Distant Ossenaria, Driffing Permits P. O. Drever 12007, Capital Station Autin, Trans 79711 Aropy of W-1 and plat to USC District Office.
			×	117 Yes 🔲	No	tet ion-t		8300'	7800'	5200'	Completion depth		1000	wh	• 1	10. Loca	Van	001 093			Rication fo
!				No X	X			467-1200	467-1200	467-1200	Specing pattern (fl.)	15,	\$	tch is the nearest	is well is to be loc	tion 15	Tuyle	125	mended Permit (c	pen (within casin	NILROAD CO Oll and Permit to Dr
	Date	Sign	I certify the	If subject to	24. IN Her Yea		La	40	40	40	Denalty pattern (acres)	16	12. Number	town in the c	aled5				nter permit n	Ē	indission I Gas Divisio III, Deepen
	1110	ature 9/26/	at Information st	Rule 36. Is Form	n 17 Jesa than It	urvey/Section	nase/Unit	40	40	40	OUTLINE ON PLAT.	17. Number of acres in defiling unit	of contiguous at	ounty of the wel	miles in a	29 7-1-1V		B STIRLING	o. at right & esp	Flug Back	OF TEXAS
• JURC	day y r .	06	ated in this applicati		em 16 (substandard ach Form W-1A)		שט ףנטוברוכם ססווטוח	NO	NO	NO	Inis rectivour If eo, caplein In Remarks,	18. Is the acrosp assigned to an- other well on this lease P in	tres in lesse, pooled u	Isite	north	vy T&P RR Co		Mitchell	lain fully in Remarks	ReEnter	or Re-Enter
Use Only •	Tel: Area Code	Name and till 915-697-3	ion is true and com. Tracy D.	No 0	actrate for any field		Sufficient and	NA	NA	NA	this inser @ tractvoir. (fl.)	19, Distance from proposed loca- lion to nearest applied for, permitted, or	init, or unitized trai		direction from	· · · · · · · · · · · · · · · · · · ·				Eater here, if assigned:	Read Instructi
	Number	e of o pera tor's 22 1 4	plete, to the be Tenison	If not filed.	1 applied forl?			ô	0	0	type well Spe well	OIL gan	π <u>640</u>		atan	·	1		V	► 42- Remit N	ons on Back
 		representative	st of my knowl	explain in Ren	N.			1		-	OIL	21. No. of appl mitted, or ex locations (ii) this one) on this reservoi	IOUTLINE O				8500		2	P	Form V
1				narks							GAS	ited for, per- ompleted ucluding lease in f.	IN PLAT.)			130		7			



JERRY A. DUNN

à.

TEXAS P.L.S. NO. 4735 TEXAS P.L.S. NO. 4839

MIDLAND	ЈОНИ /	WEST &	ASSOC	IAT	ES		TOAS
Scole: /"=	1000'		Drawn by:		N	G	
Dale:	10-2-90		Sheet	1	of	1	aheete
Revision Do	te:		W.O. No.:	L 9	007	63	

13(1) Exception Dated 440		RS DIV	ISION	Mo ())		ii.		W. 10/74
				NO.42-3	35-33555		R R R	et
WELL IS LOCATED WITHIN T	IRTY D	YS AFT	ER PLU	GGING	GH	4.	RRC Leest	or M.
Wildont	V.	an Tuyl	e /	-0		5.	Wall Number	1
Bright & Company	ős. Origi	and Form W-	-1 Filed in	Name of:	<u></u>	10.	County Mitchel	11
ADDRESS 2911 Turtle Creek Blvd #70 Dallas, TX 75219)() ^{6b.} Any 1	Subsequent	W-l's File	d in Name of	-	11.	Date Drill Permit Jan 10/18/9	01
Location of Well, Relative to Nearest Lease Boundaries	1000	i Zma N	orth 1	ine and 25	OD Foot P	12,	Permit Mus	and the
SECTION BLOCK AND SURVEY	east Li	ne of the	VIII I			- 11	379724	2
ec 15. Blk 29. TIN. T&P/RR Co	Coun	^{ty} 8.	7 milos		Vestbro		Co.72670	0./
i. Type Well (Oll, Gas, Dry) (Oll, Gas, Dry) 8360 [†]	at All Field :	Names and		T Ges ID No	NESCOLOC	LL, 14,	Dute Drilli Completed	AK DO
I Ges, Amt. of Cond. on Hend at time of Plugging					-	15,	Dete Well 12-17-	Planed 90
CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5 1	LUG #6	PLUG #7	PLUG #8
7. Cementing Date	12-17	12-17	12-17	12-17	12-27	\sum		- 2 637.0
D. Size of Hole or Pipe in which Plug Placed (inches)	7-7/8	7-7/8	7-7/8	8-5/8	8-5/8	<u> </u>		
. Depth to Bottom of Tubing or Drill Pipe (ft.)	8250	2700	2350	400	15 .	WY I	1 to	
2. Sacks of Coment Used (each plug)	50	50	180	50	10 \		1./ - y/	
I. Slurry Volume Fulpped (cli. If.)	8076	2526	1792	325	Surf			
Measured Top of Plus (if tassed) (ft.)	0070	2320	1790	525	Sull .	JAK	1.4.100	
5. Sturry Wt. #/Gel.	15.6	15.6	15.6	15.6	15.6	VIT		-
7. Type Cement	Prem.	Prem.	Prem.	Prem.	Prem.	taka.	15 75%	6
8. CASING AND TUBING RECORD AFTER PLUGGING		29, W	an Ceelor)	-Drillable M Left in This	aterial (Othe: Well		Ye.	K No
ZE WT. #/FT. PUT IN WELL(A.) LEFT IN WELL(A.) I	HOLE SIZE	(m_) 29s. If	enswer to a d briefly de	bove is "Ye scribe non-	is" state dep drillable mat	th vio top Hindu - TU	of "Junk"	left in hole Side of
3/3 48 361 361	17-1/2	- P	orm if more	space is nee	eded.)	10 101	12.8	
<u>5/6 32 22/4 22/4 22/4 </u>					1.	1. 4	1.55	(3.13)
		-	1.18.41	-5. 9	12 400	1. 200		an a
LIST ALL OPEN HOLE AND/OR PERFORATED INTE	RYALS	-	5		1	C/1.		
PROM 2274 TO 8360		FR	ом	-	T	520	3/	
ROM LAND I IN THE THE TO		PR	OM 1	nsiurs to	1. b. T	0	15/	
PROM TO		FR	OM C	Leel [1]	NT.	661.00		
FROM ADD 1 7 1991 TO		TR	оні	RH.O.de	T	00		STATES
PROM		FR	OM The factor	1.1.1	ा	0		
have knowledge that the cementing operations, as reflected	by the inform	nation found	s on this for	m, were per	formed as Ind	icated by	each infor	nauon.
resignates items to be completed by Cementing Company. It	eme not so d	lesignated a	hali be com	pleted by O	perator.			
				iii tean Cann	ulaan in	4- 0-		
- MC - CACUM X/			III IOUT	LUN SEL	vices, B	TR Sb	ring, T	A
nature of Comenter or Authorized Representative		Ma	me of Cene	nting Compo	in y			
I declare under penalties prescribed in Sec. 91.143	, Texas Natu	mi Resourc	es Code, ti	hat I am auth	orland to me	ke this re	port, that t	hla
report was prepared by me or under my supervision a	und direction,	, and that d	ate and fect	is stated the	rein are true,	carrect,	and comple	te, Status
to ris nation with menalanday								
Amonda I Hand		Annat		1/1 + /				
REPRESENTATIVE OF COMPANY		TITLE		RECEDAT	<u>р</u>	hont		NUMBER
			F	R.C OF TET	45	3		
Dr. A That Teletan	.)	÷.						
GNATURE: REPRESENTATIVE OF RAILROAD COMMIS	SION	•	MA	IR 0 5 19	991 <u></u>	8, ÿ	~	
					and it.		コクノ	

истер алоб язта**н .** С

.

34. Tetal Depth 8360	Other Fresh Water TOP	Zones by T.I BOTTO	D.W.R. DM	35. Have all Abandoned Walls on this Leas according to R.R.C. Rules?	se been Plugged	X Y•1
Depth of Deepeat Fresh Water				36. If NO, Zaplain		No
37. Neme and Address Halliburton, F	of Cementing or Server. . O. Box 380;	, Snyder	who min, Texa	ed and pumped coment plugs in this well as 79549	Date RR notified	C District Office
Ben Van Tuyl	ers of Surface Owner e, 432 Hillds	ale Dr.	and Oper Ann Ai	retors of Offert Producing Leases		
39. Was Notice Given	Before Pipeeine to Ec	sch of the Ab				
Yes				· · · · · · · · · · · · · · · · · · ·		
40. For Dry Holes, this released to a Com	Form must be accom	LY spanled by ei	ther a Dr	ilier's, Electric, Radioactivity or Acoustical	i/Sonic Log or at	ich Log must be
- 	g Attached	Lag releas	sed to _		Date	
122			. ×		Date	
The second second				20		
Type Loga:	lier's	X Elec	tric	Redicectivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (lier's Special Cleanance) Fi	X Elec	tric	Radioactivity	Aco	untical/Sonic
Type Logs: Dri 41. Date FORM P-8 (1 42. Amount of Oli prod	lier's ipecial Cleanance) FL	ied?	tric	Radioactivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (: 42. Amount of Oil prod * Flie FORM P-1 (C	ller's Special Clearance) Fi uced prior to Plugging II Production Report)	Ied?	iric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>BRC USE ONLY</u>	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	Ied?	itric	Badioactivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oli prod Pile FORM P-1 (C RCC USE ONLY Nearest Field	lier's Special Clearance) Fi uced prior to Plugging Still Production Report)	Ied?	itric	Redicectivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>BRC USE ONLY</u> Mearent Field	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Jed?	itric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Mearest Field BMARKS	lier's Special Clearance) Fi aced prior to Plugging 011 Production Report)	Ied?	itric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oil prod • File FORM P-1 (C <u>RRC USE ONLY</u> Hearest Field BMARKS	ller's Special Clearance) Fi uced prior to Plugging III Production Report)	Ied?	itric	Bediosctivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Mearest Field EMARKS	lier's Special Clearance) F1 uced prior to Plugging 011 Production Report)	Elec Ied?	iric	Bediosctivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fl uced prior to Plugging III Production Report)	Ied?	itric	Redicectivity	Aco	ustics1/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R & C USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	E Elec	itric	Redioactivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>BRC USE ONLY</u> Hearest Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Ied?	itric			ustics1/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C RC USE ONLY Nearest Field BMARKS	lier's special Clearance) Fi uced prior to Plugging li Production Report	E	itric	Redioactivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field EMARKS	lier's Special Clearance) FL sced prior to Plugging II Production Report)	Elec	itric	Redioactivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>RRC USE ONLY</u> Nearest Field EMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	E Elec	itric	Redioactivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi seed prior to Plugging III Production Report)	E	itric	Redicectivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1) 42. Amount of Oll prod • Flie FORM P-1 (C <u>R & C USE ONLY</u> Nearest Field BMARKS	lier's Special Clearance) Fl uced prior to Plugging II Production Report	E Elec	itric	Redicectivity		uetical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oil prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report	Elec	itric	Redioactivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>BRC USE ONLY</u> Hearent Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	E	itric	Redioactivity bbls* produced		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	E Elec	itric	Redioactivity Bobla* sproduced	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field EMARKS	iler's Special Clearance) Fl uced prior to Plugging II Production Report	E Elec	itric	Redioactivity		ustical/Sonic

en e const la e const la seconda e m la seconda e m

1

.....

419

PLACE FOLS | R1

< 1

Compared and the second largest and the secon	RAILROAD COME Oll and C	Z J 3	(AS	o Wa	Form Cemienti Niv.	a W-10 Ing Rep 4/1/03 8-015
1. Operator's Name (As shown on Form P.5, Organiza	tion Report) 2. R	RC Operator No.	3. RRC District No.	4. County	of Well Site	1.04744
Bright & Co.		093125	8	Mitch	el1 👘	10 30
5. Field Name (Wildcat or exactly as shown on RRC re	rords)		5. API No.	7.	Drilling Permit	Na.
Wildcat			42- 335-33	555	379724	1 - 1
8. Lease Name	9.1	Rule 37 Case No.	10. Oil Lease/Gas	ID No. 11.	Well No.	10-14
Van Tuyle	1				1	1220

CASE	IG CEMENTING DATA:	SURFACE CASING	INTER MEDIATE	PRODU	CTION	MULTI- CEMENTIN	STAGE
			CASING	Single String	Multiple Parallel Strings	Tool	
12.0	Brugen bit for 10550						
13. •	Drilled hole size	17-1/2	11		1	an C _{all} _{an} X	
36	Est, % wash or hole enlargement						
14. 5	ter of casing (in. O.D.)	13-3/8	8-5/8	alike datus	5 - 2°	n lign ^{an}	
15. T	op of liner (fr.)	a			2		
16. S	etting depth (ft.)	361	2274	3			
17 N	umber of centralizers used	3	3				
18 H	its, waiting on cement before drill out	12	12				
Â	19. API cement used: No. of socks	390	300-			170 - 16n1 - 1816	1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.
4 81	Class	Premium P	111	27 AP reul	aff , Mich ,	WHE Standt	-13 Truch-
a <	Additives	27 Calciu	m Chloride	i dina			101.65
Ŷ	No. of sacks 🕨 🕨						
d Sh	Class 🕨	inener Ken	themes defined	intol at an:	inurtant		
18	Additives	ين ورجاد حققوني فرواني	and to be seen for	A marte data and inco	A PARTY A MARTINE	D. OF TEXAS	
È	No. of sacita	of the advances prope	ter des medications	cristellis wilds	the state of the s	. if fabgeties in	South Brind Southern
d Slu	Class	ar island et al.	all and show	aradina or yunar Aradina ortuguna	a in later owner, ne ge a tracht genter - Na		n in 124 - Dùn 127 Institu Print - Barned Dunret
ñ	Additives 🕨	 Track of State Str Track of Strategy and 	n en talan dalam yang kang sang kang sang sang sang sang sang sang sang s		Leff Biro't Husp area a an	CG	a da serrigis con #
ti	20., Slurry pumped: Volume (cu. ft.) 🌘		591	intres investion	IA CONTRACTOR		State Water I a
	Height (ft.) 🕨 🕨	Surface	2268	1 B 1 327 2072 (s temp tigdes ansätt va en en en en en	P. Weitzers and and	W 15, in oks
¥	an an an the Volume (cu. ft.) 🍉	- Section of Suppl	- 194 Berlin (1944)	s rialits - a thug buy	i dina aratisa hire	an a	 Subarrolluni)
64 I	ileight (fs.)	A SAME SALANA A A	 anaparities contractor designed in Lindé (c) 	, Hondrach, 189 1997 - Charles Andreas	េ មេរ៉ានីវារូក ភូមិ កើនដែរប្រាំការ ភ	unter ünterstandt i Unter unstandere	: Bast residentions parts in the other line
z	Volume (cu. ft.) 🕨	1 N X.		a fé li selt an et ES.	n albig zint fog drav dat. A	e fitter halter («»	and al say within
•		me ante ave		tiere is on these e	institues land	enet belever statte sin	i incaratora fasis religi
1	Volume (cu, ft.) D.	514.1	591	- Hannahan and an early a	o Ladistra Miran	1	
B	an and all each off in the Height (if Lifes in the second se	Surface	110000 000 01 4000	nthyanthijh Lalk	in the provide states of the second states of the s	ert valie destrat	
21. Y	Ves cement circulated to ground surface or bottom of cellar) outside casing?	Toras Yes	n inte Ro	1. Startinger Start	2. Stallier feit		Contraction of the second
22. F	iemarika	41. 23.11		RECEIVED R.R.C. OF TEX	(ΛS	A CONTRACTOR	and the part of the
		1. U.S.	na Angelan ing	MAR 05 1	991		n - Suzidaje Suzidaje Suzidaje

and the second second second

:

OIL & GAS DIV MIDLAND TEXAS

OVER

DIO PLUGARO ALMADUR	FLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	TLUD *
And CARDONIA	. E	XHT RO V	Reschind.	nenau.	76) 76)		00000000	e
Size of Jule or pipe plugged (in.)								
Dupth to bottom of tubing or drill pipe (ft.)								
	and a character	0	1917		Net an An	15.000		$\pi(A t_{2}^{-1}, \xi)$
	RALLAS IN	- it we	(Eval) and		· · · · · · · · · · · · · · · · · · ·		· · · • · • · · · ·	
	1.1.27	$\{F_{in}, F_{in}\}\}$			in the second			16 . 24
Homused top of plug, if tagged (ft.)								
		3	2112	N 10	160 e Gera		100.020	ल्या हो। तम
	i Dining i	Static Static		14.452			242	
and the second se		S. House Charge			and the state	1.11.11.11.1		. tomas
					فاستعجزه		Jaking	in terms
Supplier and the		a la		4	1 Lin	Il Qa		
				200	SIZ ZAR	1940's		
		i ana a	1.49362		in state of	<u></u>		
						1	1-26-00	
	网络印刷 人名布里尔		A REAL PROPERTY AND A PARTY OF A REAL PROPERTY.	and some that they want the	of the other state into	and a start as	and die	ing politik
OPERATOR'S CERTIFICATE: I declar certification, that I have knowledge of ()	e under penaltien ne well data and in	prescribed in	Sec. 91.143. Te ented in this rep	zas Natural Report and that day	sources Code, (that I am autho rented on both a	rized to make idea of this form	this Late
OPERATOR'S CERTIFICATE: I decian certification, that I have knowledge of it true, correct, and complete, to the best	e under penaltien te well data and in t of my knowledge	s prescribed in formation pres e. This certifica	Sec. 91.143. Te ented in this rep tion covers all v	xas Natural Re ort, and that da vell data.	sources Code, (ta and facts pres	that I am autho sented on both a	ides of this form	this nare

Instructions to Form W-15, Cementing Report

State. Zip Code

Tel.: Area Code Number

Date

mo.

day

yr.

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

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

 An initial oil or gas completion report. Form W-2 or G-1, as required by Statewide or special field rules;

• Form W-4. Application for Multiple Completion. If the well is a multiple parallel casing completion; and

Clbr.

 Form W-3, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting dry holes, operators must complete Form W-15, in addition to Form W-3, to show any casing cemented in the hole.

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

「日本のではいたけでいたで、これのからのでと

Address

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

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

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

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

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

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

Please to File No.

11.4.

RAILROAD COMMISSION OF TEXAS OIL AND GAS DIVISION

APPLICATION TO PLUG AND WELL RECORD FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

M.K.C. Malando

Name of Com		T. T	he Texas	Compar	IV.	nu Por	1720 50	nt Wonth
neme er ooml	any or open	1007						Texas
ountyH	loward		SurveyT&	P,RRGo.		29T_1_P	Sec4	
iame of Leas	<u>A. I.</u>	Nasso	n	io, of Acres	1760 W	ell No	Elev	2300 (DF)
ocated Appr	ox.21	NE	Direction	from.Bd	g Spring,	Texas	(Nearest P.	O. or Town)
Name of Field	in which we	ll is locate	a Wild	cat	0/400334++444.000/ 1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.		************************	*********
Form 1, "Notic	e of Intentio	n to Drill,'	' was filed in 1	name of	The Texas	Company	*********	
Drilling Comm	enced 12	-28		19. <u>52</u> , 1	cilling Completed	3-28		19.52
las this well	ever produce	d oll the		******		or Gas?	No	ياني تيد
baracter of 1	Well (Oil, Ge	s or Dry)	Dry			Tet	Depth.	16701
) ate you wish	to Plug	3-2	7 ,		-19 52			
lame of Party	Plugging W	en Liv	ermore D	rilling	Address	10 Lubboch	Nat'l Ba	inic
orrespondence	regarding i	this well a	hould be sent	to: Name	The Texa	s Company	Add	Services 11
lddress Box	1720, 1	Fort W	orth, Te	CABING	RECORD	-/-		
SIZE	PUT IN	WELL	PULL	ED OUT	1. : france de	YELL.		
2.0/04	R.	Inc	n.	; i In.	1 /2. 11	ln.		
3 3/81	196		None	1.1.000 5	196	Tex	as Patter	<u>a</u>
5/81	2115		100		201	Hal	liburton -	8 & S
		100		Cert Const	1	1	1.25	

ASING WAS CEMENTED GIVE NUMBER OF SACKS USED ON DIFFERENT STRINGS a ser a ser a ser a ser a Sec.

Initial Production	of Oil: Barreis None	WORE 24 nrs. Pressur	None Fill	DLAND, TEXAS
Give notice perore When Plugging co the Deputy Superv	Plugging to all available L suppleted, file final Plugging isor of district in which we	sease Owners, as required by R r Report, duly signed, and swe il is located.	ula (10) ril. to. All more in C	R 10.1952 will be furnished to Commission of Texas
NOTE: If no ing ava formation, water south	india, in state and give all info- , and to may as penably data ve	motion that eac he obtained to us to	tal depth, gades a beneryot	OVE DIVIZION .
General Remarks: oil or gas.	This well dril. We therefore	desire to abandon	selvage and plu	g well in the
fcllowing.	manner: (Cut 9 5	/8" casing at 100	and pull same)	and He (Over)
		AND AND AND AVIDAVIT OF		1

ź

- - - A.E.

12

24

Galiche 0 100 At depth 206' emented 13 3/6" Red Reds 100 206 casing at 206' with 250 sacks. Shale & Anhy 206 9.5 Gament circulsted. Anhy & Shele 1254 1409 At depth 2125' camented 9.5/8" Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Shale 1255 2125		TOP	BOTTOM	
Band Reds 100 200 cost of the second sec	Caliche		100	At doubh 2061 computed 12 2 day
Shale # Anhy 206 0.45 Comment circulfied. Anhy 94.5 1254 Anent circulfied. Anhy & Shale 1251 1409 At depth 2125' camented 9.5/8". Anhy & Shale 1250 1437 at 2125' with 600 sacks. Anhy & Shale 1750 1437 at 2125' with 600 sacks. Anhy & Shale 1955 116 116 Anhy & Shale 1252 2200 116 Lime 2125 2200 116 Lime & Shale 2125 2200 116 Lime & Ghert 3612 3820 3979 Lime & Sand 3820 3979 116 Lime & Chert 3612 3820 3979 Lime & Chert 3612 3820 3979 Lime & Sand 4155 4538 116 Lime & Chert 514 5232 6203 Lime & Chert 7953 8670 514 Total Depth 8670 8670 155 Shale 6201-15 5001: 15 sacks 2093-2043; 40 sacks 1125'-1 15 sacks 2025'-4975'-7 <t< td=""><td>Red Beda</td><td>100</td><td>206</td><td>At depth 200' demented 13 3/8"</td></t<>	Red Beda	100	206	At depth 200' demented 13 3/8"
Anhy 945 1254 Address Anhy & Shele 1254 1499 At depth 2125' camented 9.5/8" depth 2125' depth 215' camented 9.5/8" depth 215' depth 215	Shale & Anhy	206	0/5	Carsing AL 200 With 250 Sacks.
Auhy & Shale 1254 1409 At depth 2125' camented 9 5/8", Anby & Salt Anby & Salt 1750 1877 Anhy & Lime 1955 2125 Jime 2125 2290 Lime Shale 2290 Lime & Shale 3116 3612 Lime & Chert 3612 3820 Lime & Sand 4155 4538 Lime & Chert 4536 4000 Lime & Chert 5114 5232 Lime & Shale 5222 6203 Shale 514 5232 Lime & Chert 7953 8670 Total Depth 8570 15 All Measurements from Notory Table or 12' above ground. 28 Remarks Cont'd 870 15 Stacks 5400'-550': 15 sacks 7860'-7810': 15 sacks 1125'-1 15 15 sacks 200'-2075': 15 sacks 625'-4975': 15 sack 620'-580': 15 sacks 1125'-1 16 sacks 875'-825':	Anhy	94.5	1254	
Anhy & Salt. 1/90 1750 at 2125' with 600 ancks. Anhy & Lime 1750 1837 055. Anhy & Lime 1955 2125 1837 Lime 1955 2125 1837 Lime 1252 2290 Lime 2125 2290 Lime & Shale 2290 2322 Lime & Shale 2322: 3116 Lime & Shale 2322: 3116 Lime & Shale 3612 3820 Lime & Chert 3079 Lime & Chert 3070 4155 Lime & Chert 3079 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 753 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd .	Auby & Shele	1254	1400-	At depth 21251 comented Q 5/RH
Anhy 1837 1837 Anhy & Lime 1955 125 Lime 2125 2290 Lime & Shale 2125 2290 Lime & Shale 2322 3116 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3079 4155 Lime & Sand 3820 3979 Lime & Sand 4155 4538 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 8670 State 6203 7953 15 sacks 7660°-7810°; 15 sacks 7705°-7 All Measurements from Notory Table or 12° above ground. 8630-630°: 15 sacks 520'-825°-4975°: 15 sacks 500°-7810°; 15 sacks 2093-2043; 20 sacks 1125'-1 All Measurements from Notory Table or 12° sacks 2093-2043; 20 sacks 1125'-7 15 sacks 10°-2760°; 15 sacks 2093-2043; 20 sacks 1125'-7 Ali Measurements from Notory Table or 12° sac	Anhy & Selt.	1499	1750	at 2125! with 600 spoks
Anhy - 1837 1955 Nime 1955 2125 2290 Lime & Shale 2290 2322 116 Lime & Shale 2290 2322 116 Lime & Shale 3116 3612 3820 Lime & Sand 3820 3979 155 Lime & Sand 4155 4538 1455 Lime & Sand 4155 4538 146 Lime & Chert 5114 5232 6203 Lime & Chert 5114 5232 6203 Shale 6201 7953 6670 Total Depth 8670 8670 Notal Depth 8670 15 Actal Depth 8670 15 Scott d 8670 15 8670 Total Depth 8670 15 8670 15 Actal Depth 15 8670 15 8680'-7810'; 15 15 8680'-7810'; 15 8686'//////////////////////////////////	Anhy & Shale	1750	1837	
Anhy & Lime 1955 2125 Lime 2125 2290 Lime & Shale 2220 2322 Lime & Shale 2322 3116 Lime & Shale 3612 3820 Lime & Shale 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3620 3979 Lime & Sand 4535 4538 Lime & Chert 4538 4900 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 8670 Take Heavy mud between plugs. spot the following cement plugs. 95 sack 8670'-7810': 15 sacks 7705'-7 15 macks 5000'-5550': 15 sacks 5430-5380': 15 sacks 7860'-7810': 15 sacks 7705'-7 15 macks 5002'-550': 15 sacks 5430-25380': 15 sacks 2025'-4975': 15 sacks 660'-4630': 15 sacks 8210'-2760': 15 sacks 270': 15 sacks 7705'-7 15 macks 5002'-550': 15 sacks 5730-2380': 15 sacks 2025'-4975': 15 sacks 957 # 1. Phr. failed	Anhy	1837	1955 .	
Hime 2125 2290 Lime & Shale 2122: 3116 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3979 Liss Lime & Chert 3979 Liss Lime & Sand 4515 4538 Lime & Chert 4538 4000 Lime & Chert 5314 522 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 15 Sacks Cont'd 8670 15 Lime & Cont'd 8670 15 Sacks Cont'd 8670 15 Lime & 500'-550': 15 sacks 7800'-7810': 15 Lime & 500'-550': 15 sacks 7025'-7810': 15 sacks 7025'-7810': 15 Lime & Solo'-550': 15 sacks 203-2043: £0 sacks 1125'-1 40 sacks 1125'-1 40 Lime & Solo'-1550': 15 sacks 2093-2043: £0 sacks 1125'-1 5 sacks 1125'-1 5	Anhy & Lime	1955	2125	
Inter & Shale 2290 2322 Linee Shale 3116 Linee & Shale 3116 3612 Linee & Chert 3612 3820 Linee & Sand 4155 4538 Linee & Chert 3979 4155 Linee & Chert 438 4000 Linee & Chert 4538 4500 Linee & Chert 5314 Linee & Chert Linee & Chert 5314 Linee & Chert Linee & Chert 7953 8670 Total Depth 8670 12' All Measurements from Notory Table or 12' above ground. 8670 Remarks Cont'd 8670 12' All Measurements from Notory Table or 12' above ground. 8670'-7810': 15 sacks 7705'- 7 Stacks 5600'-550': 15 sacks 5430-5380': 15 sacks 205'-4975': 15 sack 660'-4630': 15 sacks 2125'-1 Lo sacks 1025'-975': 15 sacks 570': 15 sacks 2025'-2043; 20 sacks 1125'-1 40 sacks 1025'-975': 15 sack Lo sacks 1025'-975': 15 sacks 675'-825': 30 sacks in top casing. 12' Drill Stem Tests 12' 12' DST # 1: Pkr. failed 12' 12' DST # 2: 4805-5435'<	Lime	2125	2290	00.0 · · · · · · · · · · · · · · · · · ·
Lime 2122 1110 Lime & Shale 3116 3612 Lime & Chert 3612 3820 Lime & Sand 3820 3979 Lime & Chert 3612 3820 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4538 4900 Lime & Sand 5232 6203 Shale 5232 6203 Shale 6203 7953 Lime & Ghert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground, Remarks Cont'd 15 sacks 8215-8163, 15 sacks 7860°-7810'; 15 sacks 7705'-7 15 macks 5600'-550'; 15 sacks 5430-5380'; 15 sacks 500'; 15 sacks 7705'-7 15 macks 5600'-550'; 15 sacks 5430-5380'; 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks, 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. DST # 1: Pkr. failed DST # 2: 4805-4200. Tool open 2 hrs. Recovered 2250' salt water and 225 satt water tout with drig, mud. DST # 3: 5100, 5216, Tool open 1 1/2 hrs. Recovered 300	Lime & Shale	2290	2322	
Jillo Jol2 Lime & Chert 3612 Jime & Sand 3820 Jame & Sand 3820 Jime & Chert 3079 Lime & Sand 4155 Lime & Sand 4155 Lime & Sand 4538 Lime & Chert 4538 Lime & Chert 4538 Lime & Chert 5114 Jime & Shale 5232 Lime & Shale 5232 Jime & Ghert 7953 Jime & Ghert 7953 Jime & Ghert 7953 Shale 6203 Total Depth 8670 Total Depth 8670 State Heavy mud Datween plugs, spot the following cement plugs, 95 sack 8670-8373':15 sacks 5163. 15 sacks 7860'-7810': 15 sacks 7705'- 7 Jacks 500'-5550':15 sacks 5430-5380': 15 sacks 2093-2043: 40 sacks 1125'-1 460'-4630':15 sacks 810'-2750': 15 sacks 75'-825': 30 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 75'-825': 30 sacks 1125'-1 40 sacks. <t< td=""><td>Idmo & Shalo</td><td>2322 1</td><td>3116</td><td>· · · · · · · · · · · · · · · · · · ·</td></t<>	Idmo & Shalo	2322 1	3116	· · · · · · · · · · · · · · · · · · ·
Lime & Sand 3820 3979 Lime & Chert 3979 4155 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Shale 5222 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 Total Depth 8670 School & Chert 7953 School & Sch	Line & Chent	2612	1 1012	
Lime & Chert 3070 1155 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4453 4900 Lime & Sand 44900 5114 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Ghert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 660'-5500': 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 5125'-7 15 marks 5600'-5550': 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 5125'-1 4680'-4630': 15 sacks 2810'-2760': 15 sacks 2033-2043': 10 sacks 1125'-1 40 sacks 1025'-975': 40 sacks 37'-825': 30 sacks in top casing. Drill Stem Tests 1001 open' 1 hr. Recovered 2250' salt water and 225 DST # 1: Pkr. failed 12' hrs. Recovered 20' drlg, mud. DST # 2: 54005-545'. Tool open' 1 hr. Recovered 20' drlg, mud. 100'd	Line & Sand	2620	1 2020	•
Lime & Sand 4155 4538 Lime & Chert 4538 4900 Lime & Chert 4538 4900 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 8670 Stale 8210 12' above ground. Remarks Cont'd 12' above ground. Remarks Cont'd 12' above ground. Remarks 5600'-5500': 15 sacks 5215-8163 15 sacks 7705'-7 15 macks 5600'-5500': 15 sacks 5215-8163 15 sacks 7705'-7 15 macks 5600'-5500': 15 sacks 5215-8163 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks 1025'-975': 40 sacks 875'-825': 30 sacks 1n top. casing. Drill Stam Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 4805-4900, Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 2: 5405-5500 Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 2: 5405-5500 Tool open 1 hr. Recovered 100' drig. mud. DST # 2: 5405-5500 Tool open 1 hr. Recovered 20' drig. mud. DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 4: 740 Tool open 1 hr. Recovered 5' drig. mud & 180' slightly drig	Line & Chert	3070	1.155	Past in Party
Lime & Chert 438 400 Lime & Sand 4900 5114 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd 15 8000 5100': 15 8000 700': 10 8000 800': 1000 800': 1000 700': 1000 700': 1000 700': 1000 700': 1000 700': 1000	Lame & Sand	1155	1.538	
Lime & Sand 4000 5114 Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Shart 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 7 Fathe Heavy mud batween plugs, spot the following cement plugs, 95 sack 8670 - 7810'; 15 sacks 7705'-7 Lime & Solo - 5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 7705'-7 Lime & Solo - 5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 125'-1 Lo sacks 500'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 125'-1 Lo sacks 1025'-975'; 10 sacks 875'-825'; 30 sacks in top casing. Drill Stam Tests Drill Stam Tests DST # 1: Pkr. failed DST # 2: 1405-4900, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 2: 5100-5216, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 5' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 5' drlg, mud. DST # 7: 723 brain the second for the formule	Line & Chert	1.538	1,000	•
Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 12 above ground. Remarks Cont'd 15 acks 510 relation of the following cement plugs, 95 sack 5670 relation of the following cement of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 relation of the following cement plugs, 95 relation of the following cement plugs, 95 relation of the following cement p	Lime & Sand	4900	5114	
Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Bains Heavy mud batween plugs, spot the following cement plugs, 95 sack 8670-8373 115 sacks 8215-8163, 15 sacks 7860'-7810': 15 sacks 7705'- 7 15 macks 5600'-5550': 15 sacks 5430-5380': 15 sacks 2025'-4975': 15 sack 6680'-4630': 15 sacks 2810'-2760': 15 sacks 2093-2043: 20 sacks 1125'-1 40 sacks 1025'-975': 40 sacks 875'-825': 30 sacks 1n top casing. Drill Stem Tests Drill Stem Tests Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 mail water cut with drig. mud. DST # 3: 5100-5210, Tool open 1 hr. Recovered 300' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mode DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud & 180' eli DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud & 180' eli DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud & 180' eli DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud & 180' eli DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud & 180' eli DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud & 180' eli DST # 7: 783 mode	Line & Chert	5114	5232	
Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Taths Heavy mud batween plugs. spot the following cement plugs. 95 sacks 8670-8373':15 sacks 2215-8163. 15 sacks 7860'-7810': 15 sacks 7705'-7 15 macks 5600'-5550': 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 600'-6810': 15 sacks 2093-2043: 40 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 1 1/2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 5400-5485. Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 5400-5485. Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 5: 5002.5600 Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 7: 723 Tool open 1 1/2 hrs. Recovered 20' drig. Mud & 120 DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' dr	Lime & Shale	5232	6203	o alteration and the second state and the second
Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. All Measurements from Notory Table or 12' above ground. Remarks Cont'd 6670 Saing Heavy mud butween plugs, spot the following cement plugs, 95 sack 8670 - 3731:15 sacks 2215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7 15 macks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 4680'-4630': 15 sacks 2810'-2760'; 15 sacks 2093-2043; 20 sacks 1125'-1 40 sacks 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 4805-4900, Tool open 1 1/2 hrs. Recovered 300' drig, mud. DST # 5: 5002.5000, Tool open 1 1/2 hrs. Recovered 300' drig. mud. DST # 5: 5002.5000, Tool open 1 hr. Recovered 75' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 100' drig. mud. 1700-115 DST # 4: 700 means 1 hr. Recovered 100' drig. mud. 1700-115 DST # 4: 700 means 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. None	Shale	6203	7953	olari mayadar. Alakimini kutala yang mujukawan
Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Baths Heavy mud batteen plugs. spot the following cement plugs. 95 sacks 8670'-8373':15 sacks 8215-8163. 15 sacks 7705'-7 15 macks 560'-5550':15 sacks 5430-5380':15 sacks 5025'-4975':15 sack 660'-4630':15 sacks 2215-8163. 15 sacks 2093-2043: 40 sacks 125'-7 15 macks 560'-5550':15 sacks 5430-5380':15 sacks 5025'-4975':15 sack 660'-4630':15 sacks 2810'-2760':15 sacks 2093-2043: 40 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests Dst # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 3: 5100-5218; Tool open 1 1/2 hrs. Recovered 300' drig, mud. DST # 4: 740-5145; Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 760-5145; Tool open 1 hr. Recovered 100' drig. mud. DST # 4: 760-5145; Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760-5145; Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760-7610; Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760-7620; Tool open 1 hr. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 7: 763-7620; Tool open 1 hr. Recovered 5' drig. mud & 180' slightly gas cut drig.	Lime & Chert	7953	8670	al a development and sector and a la
All Measurements from hotory Table or 12' above ground. Remarks Cont'd Hathg Heavy mud between plugs, spot the following cement plugs, 95 sack 8670'-8373':15 sacks 8215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7 15 macks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sac 6680'-4630':15 sacks 2810'-2760'; 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5216 Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 760 fool open 1 hr. Recovered 75' sliphtly gas cut drlg. DST # 4: 760 fool open 1 hr. Recovered 70' drlg. Mud & 120 DST # 4: 760 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 5' drlg. mud. DST # 4: 750 fool open 1 hr. Recovered 5' drlg. Mud & 180' ell sud ebod of samin of task 26 and of task 1 hour fool open 1 hr. None	Total Depth	a static static states a	8670	The second seco second second sec
AU sacks, 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 selt water cut with drlg. mud. DST # 3: 5100-5210. Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 4: 5400-5210. Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7400-7470. Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 7400-7470. Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 7400-7470. Tool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 7400-7470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 743. Model of a setting of rate Constant of the set of	I E marke FGOOL FEFO	Plant P. Plant and all	ELOO FO	1000 -1010 ; 1) Backs //0/ - /
Deill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5218. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5440-5485 Tool open 1 hr. Recovered 75' slightly gas cut drly. DST # 4: 780 1000 Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 780 1000 Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 1000 1000 1000 1000 1000 1000 1000 10	15-macks 5600'-5550	1:-15 sack ks 2810'-2	s 5430-53 760': 15	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-10
DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5216, Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5440=5485; Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7805-7870; Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7805-7870; Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 5' drlg. mud & 180' sli show of shapping of relevant Cased of 1 drlg. Mud & 180' sli per cent None	15-macks 56001-5550 46801-46301:15 sec 40 macks 10251-975	1;-15 sack ks 2810'-2 1; 40 sack	8 5430-53 760': 15 8 875'-82	80'; 15 sacks 5025'-4975'; 15 sac aacks 2093-2043; 40 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5210. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5400-5445. Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7800-6470. Tool open 1 hr. Recovered 100' drlg. mud. 1000-010 DST # 4: 7800-6470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 7800-6470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 5' drlg. mud & 180' sli show of shepting of rise 2 ased of the sheet of the sheet off. Ies mount of water th oil NODE (1) per cent None	15-macks 5600'-5550 4680'-4630': 15 sec 40 sacks. 1025'-975	11:-15 sack ks 2810'-2 1: 40 sack	s 5430-53 760': 15 s 875'-82	80': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing.
DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 selt water cut with drlg. mud. DST # 3: 5100-5218, Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 4: 5100-5218; Tool open 1 hr. Recovered 75' slightly gas cut drlg DST # 4: 7800-6000, Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 180' slip DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 180' slip	15-macks 5600'-5550 4680'-4630': 15 sec 40 sacks. 1025'-975 Drill-Stem Tests	1;-15 sack ks 2810'-2 ; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-1 5'; 30 sacks in top casing.
aslt water cut with drlg. mud. DST # 3: 5100-5216. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 1: 5400-5485 Tool open 1 hr. Recovered 75' slightly gas cut drly. DST # 1: 5002-6000 Tool open 1 hr. Recovered 100' drlg. mud. 1200- DST # 1: 7800-7420 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud. 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip mount of water with oil 010 010 / 100 / 1	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill Stem Tests	11;-15 sack ks 2810'-2 1; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 10 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 3. 5100-5216, "Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 54:0-5485; Tool open 1 hr. Recovered 75' slightly gas cut drlg DST # 4. 780 model Tool open 1 1/2 hrs. Recovered 100' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. Sole open 1 hrs. Recovered 5' drlg. Sole open 1 hrs. Sole op	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900	1;-15 sack ks 2810'-2 1; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-10 5'; 30 sacks in top casing.
DST # 4. 780 model open 1 hr. Recovered 75' slightly gas cut drlg DST # 4. 780 model open 1 hr. Recovered 100' drlg. mud. 1000 model 1 hr. Recovered 20' drlg. Mud & 120 DST # 4. 780 model open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 781 Model of the state of the st	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900,	1; 15 sack ks 2810'-2 i; 40 sack i tool open selt wate	s 5430-53 760': 15 s 875'-82 2 hrs. 3	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 20 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 4. 780 creation in the second state of t	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900,	tis 15 sack ks 2810'-2 is 40 sack is 40 sack is 40 sack is 40 sack is 40 sack	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 20 sacks 1125'-10 5'; 30 sacks in top casing.
DST # 4. 780 model DST # 7. 763 model DST #	15 macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 4: 5440=5485	d Tool open Tool open Tool open	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re	ecovered 2250' salt water and 2250 h drlg. mud.
abod of shepting of rates of the second of t	15-macks 5600*-5550 4680*-4630*: 15 sec 40 macks. 1025*-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3-5100-5216 DST # 3-5100-5216 DST # 3-5100-5216	d Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud.
allod of abetting of water a Case(of the apert and a water completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3-5100-5218 DST # 3-5100-5218 DST # 3-5002-6000	tis 15 sack ks 2810'-2 is 40 sack d Tool open selt wate Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. R r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	s. Recovered 300' drlg, mud. covered 100' drlg, mud.
athod of sheeting of water - Cased D it water completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 4- 780 magan	Colopen Tool open Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re	s. Recovered 20' drlg. Mud & 120'
athod of sherting a vater Cased Of the per completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3- 5100-5218, DST # 4- 7800-5485 IST # 4- 7800-64701	ticel open Tool open Tool open Tool open Tool open	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 1/2 hr gas cut d	s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120'
mount of water with oil	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5218, DST # 4: 7805-4900 DST # 4: 7805-4900	i - 15 sack ks 2810'-2 i 40 sack d Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	ecovered 2250' salt water and 2250' h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120'
mount of water with oll	15-macks 5600'-5550 6680'-6630': 15 sec 60 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 3: 5100-5216, DST # 4: 7805-6000, DST # 4: 7805	i - 15 sack ks 2810'-2 i 40 sack i 40 sach i 4	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 c cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	so': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. 100 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' sl1
	15-macks 5600'-5550 6680'-6630': 15 sec 60 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3: 5100-5216 DST # 3: 5100-5216 DST # 4: 7805-6000 DST # 4: 7805-6000	i 15 sack ks 2810'-2 i 40 sack i 40	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 c cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	sovered 2250' salt water and 2250' h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud.
	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST #	i - 15 sack ks 2810'-2 i 40 sack i fool open fool open fool open fool open fool open fool open fool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 225 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg covered 100' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip ater completely shut off? Yes
	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 3- 5002-5000 DST # 3- 50000 DST # 3- 5000 DST # 3- 50000 DST # 3- 50000 DST # 3- 50000 DST #	Li-15 sack ks 2810'-2 Li-40 sack i Tool open selt wate Tool open fool open f	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud. 180' slip ater completely shut off: Ies cent None
SUEDEN SIL	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 3- 5100-5218 DST # 4- 780 0000 DST # 4- 780 00000 DST # 4- 780 000000 DST # 4- 780 0000000000000000000000000000000000	tol open fool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1799-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip the sad matter berson and that the same bre true ts and matter berson and that the same bre true
Fouriet SILEDEU	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5218, DST # 3: 5100-5218, DST # 4: 780 55485 AST # 7: 780 55485 AS	ticol open Tool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drly covered 100' drlg. mud. 1. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip ater completely shut off? Ies cent None
A contract A cont	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 3: 5100	d flool open selt wate flool open flool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 20 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg, mud. covered 100' drlg. mud. covered 100' drlg. mud. 1000 covered 100' drlg. mud. 1000 rlg. mud. s. Recovered 20' drlg. Mud & 1200 rlg. mud. Recovered 5' drlg. mud & 180' sl1; ater completely shut off: Ies cent None the and matter bersen and that the set for tra- sector of Company. 0 1052
ALEOIN Marchell and swere to before me this day of Appell Marchell and swere to before me the swere to before me the swere to be fore me	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks. 1025'-975 Drill Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900. DST # 3- 5100-5216. DST # 3- 510	d Tool open Tool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 10 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 225 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1000 s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 5' drlg. mud. 180' sli ater completely shut off: Yes cent None ts and matter bermany of that the content of the trans- ter completely shut off: Yes cent None

A. L. Wasson, Wildcat, Howard County

DST # 8: 8418-8468, Tool open 1 hr. Recovered 100' drlg. mud.

- DST # 9: 8455-8543, Tool open 2 hrs. Recovered 390' slightly gas cut & sulphur cut drlg. mud.
- DST # 10:8546-8670, Tool open 1 1/2 hrs. Recovered 7230' sulphur water.

RECEIVED MIDLAND, TEXAL

APR 101952

Railroad Commission of Texas OIL'84 GAS DIVISION

File No	RAILEOAD COMMISSION OF TEXAS	Form 4
8	OIL AND GAS DIVISION	1 . ugenig . Hocord
FILE IN DUPLICATE W	VITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH	WELL IS LOCATED
Company The Texas Comp	any Address Box 1720,	Ft. Worth, Texas
Sec. No. 4 Block No. 2	9 T-I-N Survey. T & P RRCO County	Howard
Well No	A. L. Wasson	No. of Acres 1760
Name of Field in which well is loca	ted Wildcat	327
Form 1 (Notice of Intention to Drili)) Was Filed in Name of	ompany
Character of Well at the time of cor	mpletion: Oil	Cu. ft.; Dry
Amount well producing when plugg	red: Oil None ci, i	t.; Water None
Has this well ever produced oil or g	ras?	****
Fotal Depth 8670	et. Top of each producing sand	fort.
Was the well filled with mud-laden (fluid, according to regulations of the Railroad Commission?	Yes
flow was mud applied?	u drill pipe	ar she ta she she a
Were pings used ? Yes I tings used, and depths placed. Also	If so, show all shoulders laft for casing, depth of each, and gine until a coment and rock. Was well shot?	size of casing, size and kind of
Were plags used? Yes 1 have used, and depths placed. Also Spotted the following 7860-7810, 15 sx 770 15 sx 2810-2760, 15 s spot 40 sx 1125-1070, lave all ebandened wells of this is fanner of confining all oil, gas or wi 2 5/6" casing left in or casaed of with com	If so, show all shoulders laft for casing, depth of each, and simplified comment and rock. Was well abot? NO P Dlugs: 95 sx 8670-8373, 15 sx 82 5-7655, 15 sx 5600-5550, 15 sx 5430 in maximum distributions 50-25-4975, 15 six 2093-2043, Cut off 9 5/8" cesing -40 min 1025-975, 40 sx 875-825, 30 mase been plugged according to Commissions rules? mater to strate: All 13 3/8" casing left i hole. All strate protected by: ca ment.	size of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 2 100' and puller sx in top of casi Yes in hole & 2015: using left in hole
Were plags used? Yes 1 bags used, and depths placed. Also Spotted the following 7860-7810. 15 sx 770 15 sx 2810-2760. 15 c Spot 40 sx 1125-1070. Iave all abandoned wells of this is fanner of confining all oil, gas or wi 2.5/8" casing left in or casaed of with com be memore of adjacent lease, royalty	If so, show all shoulders laft for casing, depth of each, and simplified comment and rock. Was well shot? NO Plugs: 95 sx 8670-8373, 15 sx 82 5-7655, 15 sx 5600-5550, 15 sx 5430 measure and the second seco	size of casing, else and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 at 100' and puller at in top of casi Yes in hole & 2015' asing left in hole
Were plags used? Yes 1 by used, and depths placed. Also Spotted the following 7860-7810.15 sx 7705 Spot 40 sr 1125-1070. Iave all abandoned wells of this is fanser of confining all oil, gas or we 2.5/6% casing left in Dr cassed of with com be manual of adjacent lease, royalty 11 adjacent property	If so, show all shoulders laft for casing, depth of each, and invential comment and rock. Was well shot? No plugs: 95 sx 8670-8373, 15 sx 82 5-7655, 15 sx 5600-5550, 15 sx 5430 measure acceleration for 9 5/8" ceaing -40 min 1025-975, 40 sx 875-825, 30 maker to strate: All 13 3/8" casing left i hole. All strata protected by ca nent.	size of casing, else and kind of 3-8163, 15 sx 5-5380, 15 sx ax 4680-4630 ax in top of casi Yes in hole & 2015 sing left in hole
Were plags used? Yes 1 have used, and depths placed. Also Spotted the following 7860-7810, 15 ax 770 15 ax 2810-2760, 15 c spot 40 sy 1125-1070, lave all shandered wells of this le fanner of confining all oil, yes or wi 2.5/6% casing left in br casaed of with cem he memors of adjacent lease, royalty 11 adjacent property	If so, show all shoulders laft for casing, depth of each, and involution comment and rock. Was well shot? NO plug: 95 sx 8670-8373, 15 sx 82 5-7655, 15 sx 5600-5550, 15 sx 5430 in an antipatric sector source for a star 2093-2043, Cut off 9 5/8" casing -40. si 1025-975, 40 sx 875-825, 30 mass been plugged according to Commissions rules? mater to strate: All 13 3/8" casing left 1 hole. All strata protected by ca ment.	size of casing, size and kind of 3-8163, 15 sx 0-5380, 15 sx sx 4680-4630 ax in top of casi Yes in hole & 2015: asing left in hole calore:
Were plags used? Yes 1 have used, and depths placed. Also Spotted the following 7860-7810, 15 ax 770 Market and the following 7860-7810, 15 ax 770 Market and the following 15 ax 28 IO-2760, 15 c spot 40 sy 1125-1070, lave all abandened walls of this is fanner of confising all oil, gas or with 5/6% casing left in br casaad of with com he memore of adjacent lease, royalty 11 ad jacent property 11 ad jacent property	If so, show all shoulders laft for casing, depth of each, and simpunt of coment and rock. Was well shot? NO plug: 95 sx 8670-8373, 15 sx 82 5-7655, 15 sx 5600-5550, 15 sx 5430 in mean framework for a start of the	size of casing, size and kind of 3-8163, 15 sx -5380, 15 sx sx 4680-4630 2 100' and puller sx in top of casi Yes in hole & 2015: using left in hole deleve:
Were plags used? Yes 1 have used, and depths placed. Also Spotted the following 7860-7810, 15 ax 770 Market and the following 7860-7810, 15 ax 770 Market and the following and the following 15 ax 28 IO-2760, 15 c spot 40 sw 1125-1070, lave all abandened walls of this le fanner of confising all oil, gas or with 5/8% casing left in br cassed of with com he menes of adjecent lease, royalty 11 adjacent property 11 adjacent property	If so, show all shoulders laft for casing, depth of each, and simpunt of comment and rock. Was well shot? NO plug: 95 sx 8670-8373, 15 sx 82 5-7655, 15 sx 5600-5550, 15 sx 5430 are manufactorized and 50-25-4.975, 15 ax 2093-2043, Cut off 9 5/8" cpains -40. mi 1025-975, 40 sx 875-825, 30 mase been plugged according to Commissions rules? ater to strate: All 13 3/8" casing left 1 hole. All strata protected by ca ment. y and landowners with their addresses in each instance as 1 leased by The Texas Company	size of casing, size and kind of 3-8163, 15 sx 0-5380, 15 sx ax 4680-4630 ax in top of casi Yes in hole & 2015: using left in hole Nelews:
Were plags used? Yes 1 have used, and depths placed. Also Spotted the following 7860-7810, 15 sx 770 15 sx 2810-2760, 15 s Spot 40 six 1125-1070, lave all abandoned wells on this is fanner of confining all oil, gas or with 5/8" casing left in par cassed of with com The means of adjacent lease, royalty 11 adjacent property 11 adjacent property 11 adjacent property 11 adjacent property 11 adjacent property 12 prevented the matter herein set forth and	If so, show all shoulders laft for casing, depth of each, and invivation consent and rock. Was well shot? No Plugs: 95 sx 8670-8373, 15 sx 82 5-7655, 15 sx 5600-5550, 15 sx 5430 Investor interpretations for 25-4975, 15 sx 2093-2043, Cut off 9 5/8" cesing -40 min 1025-975, 40 sx 875-825, 30 mass been plugged according to Commissions rules? aler to strate: All 13 3/8" casing left 1 hole. All strata protected by ca nent. y and landowners with their addresses in each instance as f leased by The Taxas Company o all available adjacent lease owners as required by Rule 10 being first duly sworn on oath, state that that the same are true and cerrent. Name	size of casing, size and kind of 3-8163, 15 sx 3-5380, 15 sx ax 4680-4630 @ 100' and puller sx in top of casi Yes in hole & 2015! using left in hole calleres:
Were plags used? Yes 1 have used, and depths placed. Also Spotted the following 7860-7810, 15 sx 770 15 sx 2810-2760, 15 s spot 40 sx 1125-1070, lave all ebandened wells on this is fanser of confining all oil, gas or w 9 5/8" casing left in per casaed of with com The meters of adjacent lease, royalty 11 adjacent property Fan meties given before plugging to I, T. P. Drew ad the matter herein set forth and	If so, show all shoulders laft for casing, depth of each, and invitation comment and rock. Was well abot? No Plugs: 95 sx 8670-8373, 15 sx 82 5-7655, 15 sx 5600-5550, 15 sx 5430 invitation of f 9 5/8" casing -40° mix 1025-975, 40 sx 875-825, 30 mass been plugged according to Commissions rules? alter to strate: All 13 3/8" casing left 1 hole. All strata protected by ca nent. y and landowners with their addresses in each instance as 1 leased by The Texas Company being first duly sworn on oath, state that that the same are true and correct. Name Name 15	size of casing, size and kind of 13-8163, 15 sx 0-5380, 15 sx ax A680-A630 @ 100' And puller sx in top of casi Yes in hole & 2015: using left in hole Wellow: Yes Dist. S
Were plags used? Yes 1 have used, and depths placed. Also Spotted the following 7860-7810, 15 sx 770 Maximum base intermediated 15 sx 2810-2760, 15 s Spot 40 six 1125-1070, lave all abandoned wells on this is fanser of confising all oil, gas or w 9 5/8" casing left in or cassed of with com The meties given before plugging to I. T. P. Drew ad the matter herein set forth and marked and swern to before me the	11 so, show all shoulders laft for casing, depth of each, and invitation consent and rock. Was well shot? No Plugs: 95 sx 8670-8373, 15 sx 82 5-7655, 15 sx 5600-5550, 15 sx 5430 invitation provide second states for the state for the strate of the strate for the strate of the strate for the strate of	size of casing, size and kind of 13-8163, 15 sx 1-5380, 15 sx ax 4680-4630 @ 100' and puller sx in top of casi Yes in hole & 2015! using left in hole tellerow: y. Yes Dist. S 10 st. S
Were plags used? Yes 1 have used, and depths placed. Also Spotted the following 7860-7810, 15 sx 770 15 sx 2810-2760, 15 s Spot 40 six 1125-1070, lave all abandoned wells on this is fanser of confining all oil, gas or w 9 5/8" casing left in or cassed of with com The means of adjacent lease, royalty 11 adjacent property 11 adjacent property 11 adjacent before plugging to E. T. P. Drew ad the matter herein set forth and marked and swern to before me the	14 so, show all shoulders laft for casing, depth of each, and similari of censent and rock. Was well shot? NO Plugs: 95 Sx 8670-8373, 15 Sx 82 5-7655, 15 Sx 5600-5550, 15 Sx 5430 In manager and reaction of 9 5/8" casing -40° six 1025-975, 40 sx 875-825, 30 mass been plugged according to Commissions rules? mater to strata: All 13 3/8" casing left 1 hole. All strata protected by ca nent. y and landowners with their addresses in each instance as 1 leased by The Taxas Company being first duly sworm on oath, state that that the same are true and correct: Name his 15 day of May	size of casing, size and kind of 13-8163, 15 sx 1-5380, 15 sx ax 4680-4630 @ 100' and puller sx in top of casi Yes in hole & 2015! using left in hole tellere: y. Yes Dist. S 10 52

i i i v		0) ()	2	2	, /1;	07	7					- 1,78			in the second se	
ewasks: <u>Ortginal</u> Plugged a	NO ALLOWARLY WILL HE A In protect all fresh water van ments, it will be necessery excertain the depit to which i	A. LEATE LINE				Wildcat	8/00	Pretto WAMK (Restly as sh Protector Belways includie applicable) If Widdes, so	1 - 2 - 2 - 10.		た 一 の 別 化 感	YES X; NO (Big Spring,	P. D. Box 4	McCannyCoro	Check coli DiDIJLL	см. т. 1659.: нозн 911 (4	ipe mail Mo. 42 normalise ("Hithights Super also
<u>1 Operator</u> Lease Name nd Abandon	ABSIONED to any we vide. Where Commiss y to contact Texat fresh, water sands mu	660' FWL &				ine 11 14	100	dem on R. N. C. ng Weservoir If state below.	14. 14.	REFER	er. Br	(bestrucțion (2) on be	TX 79720	48			PPILICA Hus	
. The	M In which dres ion rules do n Water Develo at be protected	1980 1980 1980	deed e See e		23 2 - 0 74	42101	Completion Depth	facaa laa ahii ya k ahii ya k	A 14	TO INSTRI	аі. 1 ¹	ck alde.)	: 17 . 37	1041 4 3 4 4 6 1 3	50	ow Caning) w Atlanh Sets	.dR_PE	
<u>Vasson</u> 27-52	not have sufficient surficient Board, options Board, d.	ĒŇI, ĒNĻ	2 1 8			None	lf done, State Nore.	All Prior Rule 37.Exe, Case Numbers for	3 13.	UCTIONS O	P		a dina andra andra andra	n uta E Fata Infase Grune	5		In the second	4 1
Wc L1	face casing re Austin, Tex	e co e constant	900 1907 (1907	112 5	N.	467	Rujes, 5 (a). 667-1 200. (h.)	Applicable Field Rules	16.4	N BACK S	EACH PRO	Nearest	6. This we Directio	Sec.	* (*) 7 (5 4 4 4		0 Tring	OIL AND O
	guire tu tu tu tu tu tu		ري الا		ander Historie Maria	40	Wules, State Acres)	A pulicable A pulicable Denaity	5. IZ. T	IDE: READ	POSED CO	Post Office o	II Is to be los	4. B1k	Stewart	:::홍 *: [] :: 월	EEPEN-	AS DIVISIO
1 	3.8	n 8.1	K			40	DESIGNATE	Number of Accession Drilling Unit for this Well	- 10.	CAREFULL	MPLETION	r Taina.	Vincent	-29, 1	1719 13/11 17	G BACK	DIR PLUG	ž
Signature A Title Date Telephone:	I declare und Code, that I by me or un therein are tr					<u></u> れっ	emplein in remarks.)	Taithle acre- ege presently assumed to asother well in seme fired? (Ven	- 19-3 19-3	Y AND FURN		i a i ai i î i str	TX	-1-N, 5	arts Stro Stro Stro], उगभ्रद्ध (क्रु	BACK	
dminist unc 12,	ar penalties p am authorizes der my super- ne, correct, at	25. (a) Is this (b) If subje (If no. (20		т с. 1. К. – У	None	piles for well in same res. an semi lease (h.)	Distanct and Direction from pioposed loca- tion to near-st dulling com- plated of sp-	. 20.	ISH COMPLE		192 1141 23	Southea	& F RH	bade a an a ana a ana a	erify) TE-e	64 65 55	- - -
21. 3 rative 1980 915	CERTIF rescribed in S d to make this vision and dim vision and dim	wellbore subj oct to SWR 36, attach explana	Reg ^{ula} r 1	Regular 1	Regular 1	Regular 1 🔀 Rule 37 Z	the appro- priate box.	ls this a i. Regular: or 2. Rule 37 Eze, Locas	21.	TE DATA.:	i e	21 4	i ត្រុ	Go.	tstea Tol Tol	ntry	1	ermit
Assist:	ICATE ec. 91.143, To report, that the tetion, and the p the best of r	ect to SWR 36 has Form II- ition.)	JU	A R R	75	0i1	Type Well (Specify)	011, Gas,	22.	2	66 21	12. Total Dep	11. Distance I to Nearest (fL)	iv. Summer of	P. Helling	8. County	7. NRC Dist	ARC Percit
nt 1-7455	egas Natural 7 his report was it data and fac ny knowledge.	yol-" y been filnd"	N 1 .	12	114D	0	110	Number of Wei Permitted fore this Lease in Reservate for a Permit is Regi	15 N N	11.00	63	4600	1 Property of L	640	<u> </u>	loward	net B	284
TET -	Prepared ors stated	1983 1111	U	6		c	GAS	lla or attons on same thichthis usered?		20		3674	Ease Line	, 1	, 2%) (201	r_{0}	4	547

THE PLOY	1-	RAI	LNOAD COM OIL AND (MISSION BAS DI	OF TA	EXAS			PO Re	RM W-	
	1				- AP	PI NO,	42-227	-0000	O REC Distri	1	
FILE	IN DUPLIC	ATE WITH DIS	TRICT OFFIC	CE OF	DISTRICT	r in w	HICH	(b., 141	08	r 1 12	
4	IELL IS LO	CATED WITHI	N THIRTY D	AYS AF	TER PLL	UGGING	1	3 1 4 4 4 1	Tuesday	47 X.	
2. FIELD NAME (a per RRC Reco	orda)	3. Leas	e Name	<u>د</u>				S. Well Number		
6. OPERATOR			6a Oalat	Stew		1					
McCann	Carpora	tion	. Mc	Cann	Corpor	ation	3		Howan	d d	
7. ADDRESS	ob. Any	Subsequent	W-I's Pile	d in Name	r of:	1	1. Date Dritile	E.			
P. O. I	E, TK						- 8-17-	80			
of Lease on whi	ch this Well is 1	erest Lease Bounda located	North	ert From	<u>West </u> Stew	ant ant	980 Fee	From	2. Perult Num		
. SECTION, BLOC	K, AND SURVE	SY	9b. Diata	ince and D	Ireusion Fra	m Nearest	Town in thi		3. Date Drilling	•	
Sec. 4, B	LK. 29,T	-1-N, T&P R	R Col	4 m	iles S	Eof	Vincen	t	10-10-	80	
(O(I, Gas, Dry) DRY		a wontple complet	on clat vit steid :	Names and		AS ID or	No.'	WRLL	4. Dute Drillig Completed	F	
8. If Gas, Amt. of C. Hand at time of P	and, on							I	5. Date Woll 1	ged	
				3		_		61	10-12-		
CEMENTING TO 9. Cementing Date	PLUG AND A	BANDON DATA:	10-12-80	10-13	PLUG #3	PLUG #	4 PLUG.#1	PLUG	6 PLUG #7	38.0	
0. Size of Hole or P	ipe in which Plu	ig Placea (inches)	9-5/8	9-5/8	13-3	8	2 No. 3 Fe	5.5	1. VO - 1. V		
1. Depth to Battom (of Tubing or Dri	Il Pipe (ft.)	11000	250	Top O	E	101090-0		1.12 - + (+,2)	16 20	
2. Sacks of Cement	Used (each plug	<u>}</u>	50	100	10		212.06	22535.44	CHE CHESTON	1	
4. Calculated Top o	f Plug (ft.)		990	70	Surf				1		
5. Messured Top of	Plug (if tagged)	(11.)		N.						2.47	
G. Slurry Wi. #/Gal	•	<u> </u>	1.33	1.33	1.33						
a. CASING AND TU	IBING RECORD	AFTER PLUGGI	KG I	29. W	as any Non-	- Drillable	Material (Ot	hør	i i yan	X Ma	
ZE WT. #/FT. PU	T IN WELL (II.)	LEFT IN WELL	I.) HOLE SIZE(n.) 794. 1f	Answer to a	bove is "	Yes" state (lepth to to	p of "junk" is	ft in hole	
5/8/24#	200	200	<u> </u>	- P	orm If more	space is :	iceded,)			14.16	
	and the set			- 2006	8 0 - X	1			n an Albert Harris Albert Marine an Angel Charles - Albert Albert - Albert	1.77 · · · · · · · · · · · · · · · · · ·	
			<u>*</u>			_) i e		-	
. LIST ALL OPEN	HOLE AND/0	R PERFORATEO	INTERVALS								
PROM	<u>.</u>	<u>T0</u>	······································	FR	NO			TO	2.00		
PROM	· · · · · · · · · · · · · · · · · · ·	то		PR	OM	Ω.		τυ =	S. 5. 3	0.2495	
FROM		то		FR	OM			то			
PROM	·	70		PR	СМ			70	· · · · ·		
have knowledge tha Designates lights to t indice of Cementer CERTIFICA I declare un	t the cementing be completed by ar Autherized R TE: der penalties p	operations, as raile Comming Compan Seresentative rescribed in Sec. 91	cted by the inform y. Rema not so de 	ation found taignated DC No	i on this for hall be com well I me of Comer cen Code, th	m, were p ipleted by DIVIS ning Com	erformed as i Operator. LOII OF pany ithorized to a	DOW (by such inform Chemica	ition. L. C.J.	
report was p to the best	of my knowled	r under my supervis ge.	ion and direction,	and that d	ato and fact	e stated t	1. 1981	ie, carrect	NS 26	7-740	

APR 2 0 1981 D.G. MIDLAND, TEXAS

D1-80

et an ar star things of a

Ť

.

mart.

1

÷ ÷,



1676° 4 4 4 4	*		
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1			
		<u> </u>	

10.4 1.2.2

.

Hilling	te of two 1	Yes 32. Now No	Circulated	33. Bei Bright Bart sinn
The Street Street Convert	Fresh Water Zome	by T.D.C.R.	35, Nove all Ahandound Wells on this L according to ##C Bules?	ease teen Plugged
			36, If NO, Esplain	j De
		20.00	2	
	ating or Service c	ampany who mis	ed and pumped coment plugs in this well	Date BHC District Office
Dowell Divis	ion of Do	w Chemic	al Co Colorado Cit	y. The IV-12-85
2. Super and Addresses of R	stace Owner of Ve	ti Site and Oper	nators of Otters Producing Leases	
Danny Stewart	$t = P_{\bullet} O_{\bullet}$	<u>Box 26.</u>	Sterling City, Tx. 7	.6977
	0 ×			
	1			
101 Min Sinter Chron Bellers P	legging to Rock a	t the Alave?		
Yes		8.03		
	HOLES ONLY	ed by either a D	riller's, Biertric, Beitigartivity or Acoust	cal/South Log or such Log must be
related to a Conserval L	og Service.		8 9.	
Log Alloch	•d 🗌 La	g released to		Dale
The second s	Г		Be linertivity	Acoustics / Barue
	L.			
Col: Bate PORt P-8 (Special C	learance) Filed?			
and files	e to Plancing	No	200	
42. Amount of Oil produced prio	or to Plugging	No. nonth this all w	DIC bble#	
G. Amount of Dil produced prio	or to Plugging action Report) for a	No. nonth this oil wa	one bula*	
C. Amount of Dil produced price C. Amount of Dil produced price C. Pub Potent P-1 (Oil Produ R.C. W.B. Orb. Y. Slowert Pield	or to Plagging incline Report) for a	NC nonth this all w	DDC bble® ne produced	
G. Amount of Dit produced prio G. Amount of Dit produced prio G. Pillo PORNE P-1 (Oil Produ C. C. Will Col.Y. Slower Piold	or to Plugging	No nonth this oil w	bble*	
al. Amount of Oli produced price a. Amount of Oli produced price a. File Found P-1 (Oli Produ RAC WE ONLY. Slower Field	or to Plagging iction Report) for i	Ne month this all wa	DDC bble*	
d. Amount of Dit produced prices d. Amount of Dit produced prices d. Plan Potent P1 (Oil Produced REC. WE. Col.Y. Slowers Pield	or to Plagging iction Report) for i	Ne nonth this all w	bble*	
al. Amount of Oli produced price a. Amount of Oli produced price a. File Found P-1 (Oli Produ RAC WE ONLY. Slower Field	or to Plagging action Report) for a	Ne month this all wa	DIC buls*	
Amount of Oll produced price Amount of Oll produced price Amount of Oll produced price Amount Produced Amount Produced Second Produced	or to Plagging iction Report) for a	Ne nonth this oil w	bbla®	
al. Amount of Dil produced price a. File Point P-1 (Oil Produ RAC WE OILY. Source Pield	or to Plagging action Report) for a	Ne month this all wa	DIC buls*	
al. Amount of Oli produced prices of the point P-1 (Oli Produce P-1) (Oli Produce P-1) (Oli Produce Pield	or to Plugging iction Report) for r	Ne month this oil wa	DIC buls*	
C. Amount of Oll produced price C. Amount of Oll produced price C. Amount of Oll produced price C. Amount Produced C. Amount Produced C. Amount of Oll produced price C. Amount of Oll produced	or to Plagging iction Report) for 1	Ne nonth this oil w	DIC buls*	
al. Amount of Oli produced price al. Amount of Oli produced price all points P-1 (Oli Produced) RAC WELONLY. Source Pield	or to Plugging incline Report) for i	Ne month this oil wa	DIC buls* produced	
C. Amount of Oll produced price C. Amount of Oll produced price C. Allo Polling P-1 (Oll Produced) C. C. C. M. C. C. Y. Source of Pield	or to Plagging incline Report) for a	Ne nonth this oil w	DIC produced	
al. Amount of Oli produced price Pile Point P-1 (Oli Produ RAC MB ONLY. Slower Pield	or to Plagging action Report) for a	Ne month this oil wa	DIC te produced	
al. Amount of Oli produced price al. Amount of Oli produced price al. Place Point P1 (Oli Produ RAC WE ONLY. Source Pield	or to Plugging iction Report) for a	Ne nonth this oil w	buls*	
C. Amount of Oll produced price C. Amount of Oll produced price C. Allo Polling P-1 (Oll Produced Price) C. C. C	or to Plagging	Ne nonth this oil w	DIC buls *	
al. Amount of Oli produced price al. Amount of Oli produced price all points P-1 (Oli Produced) Rac use and price Source Pield	or to Plugging iction Report) for i	Ne month this oil wa	DIC produced	
C. Amount of Oli produced price C. Amount of Oli produced price C. Pale Point P-1 (Oli Produ R. C. M. C. C. Y. Source Pield 	f to Plagging	Ne nonth this oil w	DIC buls*	
C. Amount of Oll produced price Pale Point P-1 (Oll Produced Price) RAC WE COLY. Source Pield C. C. Source Pield C. Source P	C 3 V I 3 J 3 PAK3T AQ dis	Ne nonth this oil wa	DIC produced	
all Amount of Oli produced price all Amount of Oli produced price all points P1 (Oli Produced) all content Pield 	C 3 V 1 3 3 4 HAKST AD CLA	No month this oil wa	DIC bble*	

OIL AND GAS DIVISION

Ë.

CEMENTING REPORT

Wildcat				*2. NRC Disider	08				
*1. Operator Mc. Cann. Cornoration			Barren - San	*4. County Howard					
"5. Lease Same(a) and RRC Lease Number(a) or 1. D. Num Stowart	ber(s)			·6. Well Humber,	oward				
*7. Location (Section, Block, and Survey)	PP Co C	-		- 199 - Charles Tabl	Tool and the				
Sec. 4, DIK. 29, 1-1-N, 10F	NINEACE	MTER.	PROM	ICTION					
CASING CEMENTING DATA:	CASING	MEDIATE	Single	inc.	CENTRY	PROCES			
			String	Perellal Strings	Třel	Shee.			
8. Cementing Date			310 ₁	P. Sugar	1. 30 Bar				
*9. (a) Size of Drill Bit (inches)	384.1		-						
(D) Estimated 75 Wash or Hole Enlargement Used in Calculations.	16	6060 20	4830 (SS 100 10	1. 1. 1.	in an an Stantas				
*10. Size of Casing (inches O.D.)			6 53 9	2. x 2.1 - X.	delato.	1.1.1.200			
*11. Top of Liner (if liner used) (ft.)	20152	No.			1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 - 1999 -				
*12. Setting Depth of Casing (ft.)		8 C	8		1.54.2671	11.10			
3. Type API Class Cement & Amount of Additives Used: (a) in First (Lead) or Only Starry III additional space				Steen a	. 11-1 175	0.0010			
(b) In Second Sturry	<u></u>								
(c) In Third Sivery		25.		100 million (100 million) 100 million (100 million)		1			
14. Sacks of Crment Used: (a) In First (Lead) or Only Sluny						(1) - (1) - (1)			
(b) In Second Siwn									
(c) In Third Siwry	A to the								
(c) Total Sacks of Cement Used		21 - M-	£ 50	5 - 212 - 53A	an a				
15. Slurry Volume per Sack of Cement (cu.it./sack): (a) In First (Lead) or Only Slurry					f to the second				
(b) In Second Slurry		276.0							
(c) in Third Slarry	9 54	an 200 000			a national per a composition de la comp	1			
16. Volume of Siurry Pumped: (cu.it.) (item 14 x liem 15) (e) In First (Lead) or Only Siurr			19925						
(b) In Second Sturry				111 1 1.1	10.96	1.			
(c) In Third Sluny						11			
(d) Total fluence to have the set of a b				N 12	21				
17. Celculated Annular Height of Cement Slurry		11.22 15		2002 BOO					
behing Pipe (II.) 18. Was cement circulated to ground surface					$e^{i_{1}} = r^{i_{1}}_{1} \frac{e^{-i_{1}}}{e^{i_{1}}} \frac{e^{-i_{1}}}{e^{-i_{1}}} \frac{e^{-i_{1}}}{e^{-i_{1}}} + \frac{e^{-i_{1}}}{e^{-i_{1}}} + \frac{e^{-i_{1}}}{e^{-i_{1}}} \frac{e^{-i_{1}}}}{e^{-i_{1}}}} \frac{e^{-i_{1}}}}{e^{-i_{1}}} \frac{e^{-i_{1}}}{e^{-i_{1}}}} \frac{e^{-i_{1}}}}{e^{-i_{1}}}} \frac{e^{-i_{1}}}{e^{-i_{1}}} \frac{e^{-i_{1}}}}{e^{-i_{1}}}} \frac{e^{-i_{1}}}}}{e^{-i_{1}}}} \frac{e^{-i_{1}}}}{e^{-i_{1}}}}}$	· · · · · · · · · · · · · · · · · · ·			
(or bottom of cellar) outside casing? (Yes or No)				5	18 2 H S	ST VERS			
CEMENTING TO PLUG AND ABANDON DATA:	PLUG NO. 1	PLUG NO. 2	PLUG NO. 3	PLUG NO. 4	PLUG NO. 5	PLUG NO. 6			
19. Cementing Date	10-12-80	10-13-80	10-13		9. S				
#20. Size of Hote or Sips in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8						
#21. Depth to Hotiom of Tubing or Drill Pipe (ft.)	1000	250	Top Out		1	2°_ 2			
22. Sucks of Cement Used (each plug)	50	100	10	۲	8 ₂₁	1			
23. Sturry Volume Pumped (cu. ft.)	66	133	13		S 8	21 min 7/			
\$4 . 6 at-situted Pop-of 3ting (ft.)	990	70	Surf	Q. BY TEXAS	1				
*25. Messured Top of Flug (M tagged) (It.)			AP	R 2 0 1981	Sec. 14				
(CEMENTING COMPANY AND OPERATOR I	MUST COMPLY	WITH THE	INSTRUCTION	IS CHEREVER	SE SIDE HEI	FORA			

-te

(Nev. 14.8)

	• 27. Remarks:	
		10
	*005504105	
The sector of the prestice prescribed as Sec. \$1.143. Tesas Natural the the cetification, that the	T declare under penalties prescribed in Sec. 31 143. Resources Cude, that I am authorized to make this cort	Concern Natural
I demonstrag of cooling and/or the placing of content plugs in this work as	have incovering of the well date and information presents and that data and facts presented on bath sides of this	d in this regard. 6 Earm ant true
servet, and complete, to the best of my knowledge. This certification	covers all well date and information presented herein	
	1 4 6	
In the keldowd	Four ille Cam	
Commere of Contenter or Authorized Depresentative	Bignature of Operator or Authorized Representative	
	Tom McCann - President	
Butter of Person and Title (type ar print)	"Name af Person and Title (type or print)	
Demolt Division of Dow Chemical Co.	McCann Corporation	
Committee Company	*Op#retor	
Banta 3. Box 178	P. O. Bux 48	
Shiert Address or P.O. Box	•Street Address or P.O. Box	
Colorado City, Tx 79512	Big Spring, Texas	75736
City, Baste Zip Cede	*City, State	Zip Cade
915 728-5291	*Telephone 915 267-7488	
Area Code	Anna Colta	
	Ares Cour	
10-14-80	- <u>1-6-81</u>	
10-14-80 Date IN L. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting rej to computing requirements in Statewide or Special Rules;	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except	tion is norded
10-14-80 This This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a communing regulation of the transmission of transmission of transmission of the transmission of trans	etion. or such company used on a well.	tion is nurried
10-14-80 Date IN L. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The computing of different casing strings on a well by one co	Area Code <u>Area Code</u> <u>STRUCTIONS</u> Office with: port is required by Statewide or Special Rules, or if eccep etion. or each cementing company used on a well. menting company may be consolidated on one form (to be	tion is needed
10-14-80 Date IN 1. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companing of different casing strings on a well by one co 2. Companing Company and Operator shall comply with the applicable C. The company and Operator shall comply with the applicable	Area Code 	tion is needed filed in duplicat
10-14-80 This This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a communing reg- to comparing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed f C. The companing of different casing strings on a well by one cas 2 Companing Company and Operator shall comply with the applicable Companing Company and Operator shall comply with Statewide Rules; 2 W applies PULL, AMOUNT OF SURFACE CASING:	Area Code 	tion is needed filed in duplicat poperations.
10-14-80 This A. This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a commanding regulation of the company of the second s	Area Code - <u>3Late</u> ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if eccep etion. or each cementing company used on a well. menting company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E).	tion is needed filed in duplicat poperations.
ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companies of different casing strings on a well by one case Companies Company and Operator shall comply with the applicable Companies Company and Operator shall comply with Statewide Rules; (1) Fi Rule A. Depth to protect fresh water determined by: (1) Fi Rule a. Water Development Doard, if op Field Bulk	Area Code - <u>3-6-B1</u> ISTRUCTIONS Office with: port is required by Statewide or Special Rules, or if excep etion. or each cementing company used on a well. ementing company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E).	tion is neerled filed in duplicat poperations.
10-14-80 This This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a community reprive community requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed f C. The commaning of different casing strings on a well by one case Commaning Company and Operator shall comply with the applicable Commaning Company and Operator shall comply with Statewide Rules W setting FULL ANOUNT OF SURFACE CASING A. Depth to protect fresh water determined by: (1) Fi Rule (2) To s Water Development Board, if no Field Rule B. Set surface casing below depth to be protected and command for	Area Code 	tion is needed filed in duplicat expensions.
IN IN IN IN IN IN IN IN IN IN	Area Code - <u>abale</u> ISTRUCTIONS Mfice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be is portions of Statewide Rules 8, 13, and 14. For offshore the T3(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE	tion is needed filed in duplicat poperations .
IN I. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companies of different casing strings on a well by one co Companies Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RAL ROAD COMMISSION. 5: If setting NO SURFACE CASING (See Item 4 above.):	Area Code 	tion is needed filed in duplicat expensions.
 10-14-80 Date IN A. This form shall be filed by the operator in the RRC District (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing completes and one copy of this form shall be filed for the companies of different casing strings on a well by one cases and the company and Operator shall comply with the applicable Commuting Company and Operator shall comply with Statewide Rules; (2) File Rule (2) Transform and Operator shall comply with Statewide Rules. Facting FULL ANOUNT OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) File Rule (2) Transform the substance casing below depth to be protected and cement for the SETTING ANYTHING OTHER THAN THE FULL ANOUNT OF RAIL ROAD COMMISSION. If satting NO SURFACE CASING (See Item 4 above.): A: If so multi-stage tool is used, the next deeper casing string or substantian of the subs	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be to portions of Statewide Rules 8, 13, and 14. For offshore the 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface.	tion is needed filed in duplicat poperations, tp FROM THE
 10-14-80 Content IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation of the computing requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing compiles. At least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicabl Company and Operator shall comply with the applicabl Company and Operator shall comply with Statewide Rules; (1) File Rule Y setting FULL AMOUNT OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) File Rule (2) To a Water Development Board, if no Field Rule E Set surface casing below depth to be protected and cement for RALENDAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: If no multi-stage tool on the next deeper string, cement 	Area Code 	tion is needed filed in duplicat poperations.
IN-14-80 This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a commanding regulation of the second seco	Area Code - <u>abale</u> ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be is portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. tifrom the depth that protects fresh water sands to the sur-	tion is needed filed in duplicat poperations . ID FROM THE
IN I. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-I or W-2 if a commanding regulation of the company of Form W-3; (2) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed f C. The commanding of different casing strings on a well by one com- Commanding Company and Operator shall comply with the applicable Commanding Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RAL ROAD COMMISSION. I fisetting NO SURFACE CASING (See Item 4 above.): A: If no multi-stage tool is used, the next deeper string, cement If satting SHORT SURFACE CASING (See Item 4 above.): A: Cement short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper.	Area Code 	tion is needed filed in duplicat s operations . In FROM THE face.
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a compating register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing completed in the filed of the company and one copy of this form shall be filed of C. The company and Operator shall comply with the applicable Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) The state Development Board, if no Field Rule B. Set surface casing below depth to be protected and cement for (2) The stating NO SURFACE CASING (See Item 4 above.): A: If setting NO SURFACE CASING (See Item 4 above.): A: The multi-stage tool is used, the next deeper string, cement (1) files the multi-stage tool is or is not used on the next for (1) the surface, or (2) a point midway between shoe of surface string and the surface. 	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be to portions of Statewide Rules 8, 13, and 14. For offshore lie 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. trifrom the depth that protects fresh water sands to the sur- per casing string, cement from the depth that protects fresh face. Compliance will be considered of a temperature sur- from the shue of the surface string to the surface.	tion is needed filed in duplicat roperations, ip FROM THE face. Is water satisfa to yey shows that
IN-14-80 Date IN A. This form shell be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commiting re- to comparing requirements in Statewide or Special Rules; (2) Each copy of Form W-3 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicable Comparing Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule B. Set surface casing below depth to be protected and cement for ALLROAD COMMISSION. I If setting NO SURFACE CASING (See Item 4 above.): A.: If no multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool on the next deeper string, cement If setting SHORT SURFACE CASING (See Item 4 above.): A.: Cercent short surface casing from the shot to the surface. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting or is not used on the next face. B. Whether the commuting or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting of the commuting of the distance 7. Soming PRODUCTION STRING of Casing: (Statewide Rules, Spec-	Area Code 	tion is needed filed in duplicat poperations. In FROM THE face.
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regularements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple A. At least an original and one copy of this form shall be filed f C. The community of different casing strings on a well by one cas Community of different casing strings on a well by one cas Community of different casing strings on a well by one cas Community and Operator shall comply with the applicable Community and Operator shall comply with Statewide Rule; (1) Fi Rule; (2) To a stater Development Board, if no Field Rule E. Set surface casing below depth to be protected and community of RALEROAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: This multi-stage tool is used, the next deeper string, cement If satting SHORT SURFACE CASING (See Item 4 above.): A: Cement short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper (1) the surface, or (2) a point midway between shoe of surface string and the sut the top of the cement is at least ene-third of the distance 	Area Code 	tion is needed filed in duplicat roperations, in properations, face. It water satisfies to ver shows that
 ID-14-80 IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form C-1 or W-2 if a commuting requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing comple to comparing of form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed f C. The commuting of different casing strings on a well by one case comple and operator shall comply with the applicable Communing Company and Operator shall comply with Statewide Rules; (2) The company and Operator shall comply with Statewide Rule E setting PULL AMOUNT OF SURFACE CASING A. Depth to protect fresh water determined by: (1) Fi Rule (2) The state Development Board, if no Field Rule (2) The state casing below depth to be protected and comment for RALENOAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A. Concent short surface casing from the shoe to the surface. B. When the multi-stage tool is or is not used on the next deep (1) the surface, or (2) a paint midway between shoe of surface string and the surface. E. Stating PRODUCTION STRING of Casing: (Statewide Filen, Spe A. Comment is at least ene-third of the distance B. When 3,000 feet or more of piperistate. 	Area Code 	tion is needed filed in duplicat roperations. ID FROM THE face. Is water calles to ver shows that
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commiting requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil A. At least an original and one copy of this form shall be filed file. C. The comenting of different casing strings on a well by one ca Comenting Company and Operator shall comply with the applicable Commiting Company and Operator shall comply with the applicable Commiting Company and Operator shall comply with Statewide Rule. M setting FULL AMOUNT OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) Fi Rule (2) Tr - s Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RALEROAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A.: The multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool on the next deeper string, cement (1) the surface. B. When the multi-stage tool is or is not used on the next face. B. When the support of a string of surface string and the stut the top of the cement is at least one-third of the distance A. Cement to a point at least 600 feet, above the casing shoe. B. When 3,000 feet or more of piperiaraec. So the production or point at least for production or point at least for string or the string shoe. 	Area Code 	tion is needed filed in duplicat roperations. In FROM THE face. Is water satisfies to ver about that
 ID-14-80 Data IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commenting requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed file C. The company and Operator shall comply with the applicable Companies Company and Operator shall comply with Statewide Rules; (1) File Rule (2) Tr. a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RALEROAD COMMISSION. If setting NO SURPACE CASING (See Item 4 above.): A. This multi-stage tool is used, the next deeper casing string on B: If using the multi-stage tool is or is not used on the next deeper for string. If setting SHORT SURFACE CASING (See Item 4 above.): A. Cement short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper for string. (1) the surface, or (2) a point midway between shoe of surface string and the surface. B. Whether the multi-stage tool is or is not used on the next deeper for the string. A. Cement to a point at least 600 feet, above the casing shore. B. When 3,000 feet or more of piperistate. B. When 3,000 feet or more of piperistate. A. Cement plugs shall be placed in the well bore as required by the casing shall be placed in the well bore as required by the top of the tempth and the surface. 	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etton. or such company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore ile 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OUTAINE hall be comented from the casing shoe to the surface. trifrom the depth that protects fresh water sands to the sur- per casing string, coment from the depth that protects fresh face. Compliance will be considered if a temperature sur- from the shoe of the surface string to the surface. cial Rules may vary 1 effecting string, a minimum of 30 feet of coments any addition Rules and Regulations of the Commission plus any addition	tion is needed filed in duplicat poperations, to FROM THE face. Is water satisfies to yes, shown that if consider the po- orial ploge so the
 ID-14-60 Data IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a comrating regiments in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compile A. Least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) The company and Operator shall comply with Statewide Rules; (2) The company and Operator shall comply with Statewide Rule; (2) The company and Operator shall comply with Statewide Rule; (3) The Rule (4) File Rule (5) The Rule (2) The Rule (3) The Rule (4) File Rule (5) The State Development Board, if no Field Rule E. Set surface casing below depth to be protected and coment for RALERDAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A. The multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool on the next deeper string, coment (1) the surface casing from the shote to the surface. B. Whether the multi-stage tool is or is not used on the next deep (1) the surface, or (2) a point midway between shoe of surface string and the surf the top of the coment is at least one-third of the distance A. Cement to a point at least 600 feet apove the casing shoe. B. When 3,000 feet or more of piperistate. For the production or production or production or produced of 00 feet of the kole for the file of is a required by the specified by the RRC District. Director. B. The minimum amount of diment in the well bore as required by be specified by the RRC District. Director. 	ISTRUCTIONS Mice with: poort is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. meeting company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL THE OUTAINER hall be cemented from the casing shoe to the surface. tofrom the depth that protects fresh water sands to the sur- per casing string, cement from the depth that protects fresh face. Compliance will be considered if a temperature sur- from the shue of the surface string to the surface cial Rules may vary 1 effecting string, a minimum of J0 feet of cement shall be Rules and Regulations of the Commission plus any additional still be a slurry volume equal to the amount no enfary to find the shue of the surface string to the surface string to find the a slurry volume equal to the amount no enfary to find at the string to the surface string to the surface string to find the a slurry volume equal to the amount no enfary to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to	tion is needed filed in duplicat poperations, ip FROM THE face. It water satisfies to yes above that if costs the po- out ploge sector if the calculated

APPENDIX B - SITE SAFETY AND LAYOUT

Bayswater Operating's Mongoose Gas Plant and AGI No. 1 are operated and monitored 24 hours a day, 7 days a week, by on-site personnel utilizing Plant operating and SCADA systems. These systems gather operating data such as pressures, temperatures, flow rates, remote sensors, compressor run data, and control valve positions. The recording and retention of this operating data enables the operator to evaluate trends and use predictive analytics to potentially identify issues before they become an "alarm" event. If an alarm event occurs, the automated control system is programmed to execute pre-programmed protocols to safely manage the event. Operators are specially trained to follow detailed practices to minimize risk to people, the facility, and the environment.

In the event of a leak or system failure, the Plant control system will execute its shutdown protocols as timely as is practicable to isolate the event and minimize the intensity. The Plant operator will investigate the circumstances and oversee an orderly resolution to the situation. Since this facility handles H₂S, Bayswater is required to maintain a Hydrogen Sulfide Contingency Plan to safely manage any planned or unplanned release event. The Plant operating staff are highly trained in safety and emergency response protocols to ensure safety for both plant personnel and the surrounding community and environment.



B-	-2

			ITEM	DESCRIPTION
			1	SLUG CATCHER
			2	INLET COMPRESSOR W/ COOLER
	1		2F	INLET COMPRESSOR (FUTURE) W/ COOLER
			3	COMPRESSOR DISCHARGE COALESCER
			4	
	v	V	× 6	
		^	7	
			8	
			9	
			10	AMINE REGENERATOR REBOILER
			11	AMINE SURGE TANK
			12	AMINE BOOSTER/REFLUX PUMP SKID
			13	AMINE REGENERATOR REFLUX CONDENSER
			14	LEAN AMINE COOLER
			15	AMINE CHARGE PUMPS
			16	HOT OIL PUMP SKID
			17	HOT OIL HEATER
			18	FLARE K.O. DRUM
	1		19	FLARE
- BARF	RIER		20	COMBUSTOR
			21	SLOP STORAGE TANKS
	_+		22	AMINE MAKE UP STORAGE TANK
			23	
			24	
			241	
			25	
	1		20	
			27	
			20	DI WATER TANK
	·		30	GLYCOL CONTACTOR
			31	GLYCOL SEPARATOR
			32	TEG REGEN
			33	BTEX
			34	GAS GENERATOR SET
			35	AMINE SUMP TANK
			36	NEW LUBE OIL TANKS
			37	CONDENSATE TRANSFER PUMPS
			38	VAPOR RECOVERY UNIT
			39	TANK COMBUSTOR K.O. DRUM
			40	MV TRANSFORMER
			40F	MV TRANSFORMER (FUTURE)
				LEGEND
				FIRE EXTINGUISHER = 9 ea.
				HYDROGEN SULFIDE DETECTOR = 10 ea.
				AUDIBLE ALARM SOUNDER = 4 ea.
				R STROBE LIGHT (RED) — FIRE = 4 ea.
_	- EAST_SECU	RITY GATE		SHUT PLANT EMERGENCY SHUTDOWN = 6 ea.
				FIRST AID & SCBA KIT = 3 ea.
	-*X -	X		EYE WASH STATION = 3 ea.
	й С		E 10(WIND SOCK = 1 ea.
				MUSTER POINT = 3 ea.
r :	RΔ	YSWATER	FXPLOR	ATION & PRODUCTION
CT ·	DA	COUD		
		SUUK	GAS IR	EATING FAUILITY
·		FACILITY	INSTRUN ′SAFET`	IENTATION (LOCATION PLAN
WN	CHECKED	SCALE	DATE	JOB NO. DRAWING NO. SHEET NO.
DC DC	GA	AS NOTED	06/09/22	BAY220316 IN-PLN-0790 1 OF 1

APPENDIX C – AREA OF REVIEW

APPENDIX C-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX C-2: OIL AND GAS WELLS WITHIN THE MMA LIST



Mongoose AGI No. 1

	Area of Review: Oil & Gas Wells List												
API	WELL NAME	WELL NO.	CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (FT.)	PERFORATED INTERVAL (FT.)	DATE DRILLED			
4222700101	JONES, C.L	1	ARMER L H	1603	32.445815	-101.187399	DRY HOLE	NR	NR	NR			
4222703634	STEWART	1	MCCANN CORP	1601	32.423136	-101.1837088	DRY HOLE	8670	NR	10/11/1980			
4222732304	CATHEY	1	MCCANN CORP	204	32.42347	-101.1890569	DRY HOLE	4310	NR	10/31/1980			
4222734502	STERLING CATTLE COMPANY	3402	MDC TEXAS ENERGY	1603	32.44553	-101.17894	P & A	7795	7764-7795	10/19/1989			
4222734688	STERLING FAMILY TRUST	3403	TREND EXPLORATION COMPANY	1603	32.4403185	-101.1792589	P & A	7918	7747-7760	3/5/1992			
4222736361	STERLING 38	1	HIGHPEAK ENERGY	1371	32.42744	-101.196842	INACTIVE PRODUCER	8075	5635-7848	4/5/2010			
4222741505	KAMIKAZE 5-8	H 3W	BAYSWATER OPERATING COMPANY LLC	204	32.399666	-101.180898	PRODUCING	5433	5911-15810 (MD)	1/9/2022			
4222741505	KAMIKAZE 5-8-17-20	3W	BAYSWATER OPERATING COMPANY LLC	204	32.426344	-101.191374	PRODUCING	5643.22	5911-15810 (MD)	1/9/2022			
4222741939	WINFORD 35-38 B UNIT A	7H	HIGHPEAK ENERGY	745	32.450886	-101.197238	PRODUCING	5785.42	6081-15105 (MD)	9/9/2022			
4222741972	PHARAOH 10-15-34-39	H 1W	BAYSWATER OPERATING COMPANY LLC	1602	32.473311	-101.191423	INACTIVE PRODUCER	5847	NR	10/27/2022			
4222742086	KAMIKAZE 5-8	H 2WD	BAYSWATER OPERATING COMPANY LLC	204	32.426337	-101.191712	COMPLETED	7821	NR	4/14/2023			
4222742087	KAMIKAZE 5-8	H 4WX	BAYSWATER OPERATING COMPANY LLC	204	32.4263090	-101.1918370	COMPLETED	5818	NR	4/5/2023			
4222742088	KAMIKAZE 5-8	H 2W	BAYSWATER OPERATING COMPANY LLC	204	32.4262950	-101.1919000	COMPLETED	5669	NR	3/22/2023			
4222742089	KAMIKAZE 5-8	H 1WD	BAYSWATER OPERATING COMPANY LLC	204	32.4263230	-101.1917740	COMPLETED	7820	NR	4/8/2023			
4222742105	KAMIKAZE 5-8	H 1W	BAYSWATER OPERATING COMPANY LLC	204	32.4262810	-101.1919620	COMPLETED	5816	NR	5/24/2023			



Mongoose AGI No. 1

4233500959	MACKEY, P.K.	1	MCDERMOTT-RAY	1344	32.4133665	-101.1552679	DRY HOLE	NR	NR	4/25/1954
4233501046	MACKEY, P.K.	1	MOSS H S	582	32.4215460	-101.1434280	DRY HOLE	NR	NR	12/8/1947
4233501860	JONES, CHESTER L	1	DANSBY, BEN JR.	17	32.4497350	-101.1605990	DRY HOLE	NR	NR	NR
4233533555	VAN TUYLE	1	BRIGHT & COMPANY	584	32.4027340	-101.1529820	P & A	8360	NR	11/26/1990
4233533624	STERLING FAMILY TRUST-A-	3301	MDC OPERATING, INC.	17	32.4438844	-101.1638476	P & A	7850	7756-7760	1/23/1993
4233535973	SI-10.2 CP UNIT	1	ENERGY TRANSFER	1536	32.4233850	-101.1407330	PERMIT EXPIRED	550	NR	-
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.434283	-101.161962	PRODUCING	5543	6052-19217 (MD)	7/7/2022
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.4717700	-101.1619280	PRODUCING	5543	6052-19217 (MD)	7/6/2022
4233536030	JADE PALACE 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1344	32.4049880	-101.1607180	DUC	5491	NR	11/8/2022
4233536031	GOLDEN SAND 10-3	H 1W	BAYSWATER OPERATING COMPANY LLC	1344	32.4050010	-101.1606550	DUC	5606	NR	11/8/2022
4233536041	PEARL RIVER 4-9	H 1W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016760	-101.1745840	PERMITTED	7100	NR	-
4233536042	PEARL RIVER 4-9	H 2W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016620	-101.1745210	PERMITTED	7100	NR	-
4233536045	PEARL RIVER 4-9	H 3W	BAYSWATER OPERATING COMPANY LLC	1634	32.4017660	-101.1748560	PERMITTED	7100	NR	-
4233536046	PEARL RIVER 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016350	-101.1743950	PERMITTED	7100	NR	-
4233536047	JAVA 16-21	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016210	-101.1743330	PERMITTED	7100	NR	-

*Note: Well entries in red penetrate the upper confining layer.


APPENDIX D – SECTION 2 CROSS SECTIONS

APPENDIX D-1: FIGURE 27 – STRUCTURAL CROSS SECTION DEPICTING THE ELLENBURGER

APPENDIX D-2: FIGURE 28 – STRATIGRAPHIC CROSS SECTION FLATTENED ON THE ELLENBURGER



D-1



Request for Additional Information: Mongoose Amine Treating Facility April 23, 2024

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.	2.2	21	"Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991)." The Wristen Group is mentioned in the statement above, but it does not appear in the stratigraphic column or anywhere else in the text. Please clarify its significance as it relates to the MRV plan. Additionally, the Precambrian is time period rather than a formation. Please clarify as necessary.	The following sentence has been added to clarify how the Wristen Group relates to this location: "As shown previously in Figure 5, the Wristen Group is a formation that lies directly below the Woodford to the west of the Mongoose location. The Wristen Group pinches out and is not found at the Mongoose location. However, the sealing nature of the Woodford, as described by Comer (1991), also provides confinement for the Ellenburger at this location." For Precambrian discussions, the following was added in Section 2.2.4: In the Permian Basin area, Precambrian aged formations are not normally specifically named in scientific literature. For the purposes of this MRV, these formations will just be referred to as the "Precambrian".	
2.	4.1	68	"These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant, the Mongoose, and gas monitors and the gas meter are called out in the detailed site plan in Appendix B-2." Please consider revising the statement above for clarity.	The sentence was updated for clarity "These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant and the Mongoose well. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs. These valves, gas monitors, and the gas flow meter are called out in the detailed site plan in Appendix B-2."	

No.	MRV Plan		EPA Questions	Responses	
	Section	Page			
3.	4.1	69	In the previous RFAI, the following was asked: "Figure 43 of the MRV plan shows the Bayswater Amine Facility and provides a description of the surface equipment and monitors. We recommend showing the location of all flow meters relevant to subpart RR calculations in this or a similar figure."	The following sentence was added to describe how the flow meter relates to the monitoring requirement: "Data from this flow meter will be used in the calculations of the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year, per 40 CFR §98.444(b)."	
			The facility diagram in Appendix B-2 identifies a gas meter. However, please update the figure or associated text to clarify where the flow meter is in relation to other facility components and how it relates to the monitoring requirements in <u>40 CFR</u> <u>98.444</u> . E.g., for which subpart RR measurement will this meter be used?		
4.	4.2	71	"A map of all oil and gas wells within the MMA is shown in Figure 46. The MMA review map and a summary of all wells in the MMA is provided in Appendix D." "The summary of all oil and gas wells in Appendix D also provides the total depth (TD) of all wells within the MMA." According to the Appendices submitted with the MRV plan, Appendix D contains the structural and stratigraphic cross sections. Please review the MRV plan to ensure that all references to external documents within the text are correct.	The appendix references have been updated throughout the document. The label for the gas meter on Appendix B-2 has been updated to read "Gas Flow Meter".	
5.	5.1	78	"The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in Appendix E." The statement above references "Appendix E," but the Appendices submitted with the MRV plan do not contain an Appendix E. Please review the MRV plan to ensure that all references to external documents within the text are correct.	The appendix references have been updated throughout the document.	

No.	. MRV Plan		/IRV Plan EPA Questions	Responses
	Section	Page		
6.	7.5	85	"CO ₂₁ = Total annual CO ₂ mass injected (metric tons) in the well covered by this source category in the reporting year." Per <u>40 CFR 98.443(f)(2)</u> , this variable should be, "CO ₂₁ = Total annual CO ₂ mass injected (metric tons) in the well <u>or group of</u> <u>wells</u> covered by this source category in the reporting year." Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	The definitions of variables for the equations in Sections 7.2 and 7.5 have been updated to reflect the precise language used in 40 CFR 98.443.



Subpart RR Monitoring, Reporting, and Verification (MRV) Plan Mongoose AGI No. 1

Mitchell County, TX

Prepared for *Bayswater Operating Company LLC* Denver, CO

Ву

Lonquist Sequestration, LLC Austin, TX

> Version 2.0 October 2023



INTRODUCTION

Bayswater Operating Company LLC (Bayswater) currently has a Class II acid gas injection (AGI) permit, issued by the Texas Railroad Commission (TRRC) for the Mongoose AGI No. 1 well (Mongoose), API No. 42-335-36013. The permit was issued March 10, 2023. This permit authorizes Bayswater to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO₂) and hydrogen sulfide (H₂S) into the Ellenburger formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose is a new well and is associated with the Mongoose Amine Treating Facility (the Plant) located in a rural area of Mitchell County, Texas, as shown in Figure 1.



Figure 1 – Location of Mongoose AGI No. 1 Well

Bayswater is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Bayswater is also seeking TRRC approval to amend the existing Mongoose permit by increasing the permitted maximum quantity of injected treated acid gas (TAG) from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. Bayswater intends to inject into this well for approximately 40 years at up to a maximum of 19.5 MMscf/D. The primary source of this injected CO₂ gas is the Mongoose Amine Treating Facility. Table 1 shows the expected composition of the gas stream to be sequestered. Table 2 shows the expected average daily volume of acid gas.

Table 1 – Expected Gas Composition

Component	Mol Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

Table 2 – Expected Sequestered Gas Volumes

Contract Status	Avg. Rate (MMscf/D)
Committed	6.9
Proposed	12.6
Total	19.5

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH ₄	Methane
CMG	Computer Modelling Group Carbon Dioxide (may also refer to other Carbon
CO ₂	Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H ₂ S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet

MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
Ν	North
NW	Northwest
OBG	Overburden Gradient
OSHA	Occupational Safety and Health Administration
PG	Pore Gradient
рН	Scale of Acidity
PISC	Post Injection Site Care
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
ТАС	Texas Administrative Code
TAG	Treated Acid Gas
тос	Total Organic Carbon
TRRC	Texas Railroad Commission
UCZ	Upper Confining Zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

TABLE OF CONTENTS

INTRO	NTRODUCTION				
ACRO	NYMS AI	ND ABBREVIATIONS	4		
SECTIC	DN 1 – U	IC INFORMATION	10		
1.1	Unde	rground Injection Control Permit Class: Class II	10		
1.2	UIC V	Vell Identification Number	10		
1.3	Repo	rter Number	10		
1.4	Facili	ty Address	10		
SECTIC) N 2 – P	ROJECT DESCRIPTION	11		
2.1	Regiona	l Geology	11		
	2.1.1	Regional Faulting	20		
2.2	Site C	Characterization	20		
	2.2.1	Stratigraphy and Lithologic Characteristics	20		
	2.2.2	Upper Confining Zone – Woodford Shale	21		
	2.2.3	Injection Interval – Ellenburger	29		
	2.2.4	Lower Confining Zone – Precambrian	38		
2.3	Geon	nechanics	40		
	2.3.1	Determination of Vertical Stress (Sv) from Density Measurements	40		
	2.3.2	Elastic Moduli and Fracture Gradient	40		
2.4	Local	Structure	42		
2.5	Inject	ion and Confinement Summary	46		
2.6	Grou	ndwater Hydrology	46		
2.7	Desci	ription of the Injection Process	52		
	2.7.1	Current Operations	52		
2.8	Rese	voir Characterization Modeling	52		
	2.8.1	Simulation Modeling	55		
SECTIC)N 3 – D	ELINEATION OF MONITORING AREA	64		
3.1	Maxi	mum Monitoring Area	64		
3.2	Activ	e Monitoring Area	65		
SECTIC) N 4 – P	OTENTIAL PATHWAYS FOR LEAKAGE	67		
4.1	Leaka	age from Surface Equipment	68		
4.2	Leaka	age Through Existing Wells Within the MMA	71		
	4.2.1	Future Drilling	74		
	4.2.2	Groundwater Wells	74		
4.3	Leaka	age Through Faults and Fractures	74		
4.4	Leaka	age Through the Confining Layer	75		
4.5	Leaka	age from Natural or Induced Seismicity	75		
SECTIC)N 5 – N	1ONITORING FOR LEAKAGE	77		
5.1	Leaka	age from Surface Equipment	78		
5.2	Leaka	age Through Existing and Future Wells Within the MMA	78		
5.3	Leaka	age Through Faults, Fractures, or Confining Seals	80		
5.4	Leaka	age Through Natural or Induced Seismicity	80		
SECTIC	ECTION 6 – BASELINE DETERMINATIONS82				
6.1	Visua	l Inspections	82		

6.2	CO ₂ /H ₂ S Detection	82
6.3	Operational Data	82
6.4	Continuous Monitoring	82
SECTION	7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION	83
7.1	Mass of CO ₂ Received	83
7.2	Mass of CO ₂ Injected	83
7.3	Mass of CO ₂ Produced	84
7.4	Mass of CO ₂ Emitted by Surface Leakage	84
7.5	Mass of CO ₂ Sequestered	85
SECTION	8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN	86
SECTION	9 – QUALITY ASSURANCE	87
9.1	Monitoring QA/QC	87
9.2	Missing Data	87
9.3	MRV Plan Revisions	88
SECTION	10 – RECORDS RETENTION	89
SECTION	11 - REFERENCES	90

Figures

Figure 1 – Location of Mongoose AGI No. 1 Well2
Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red
star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, &
Walsh)12
Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)13
Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf14
Figure 5 - Cross section indicating formation truncations when approaching the Eastern Shelf
(Waite, 2021)15
Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger
Group of the Permian Basin, West Texas, 2006)16
Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth17
Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks,
2003)
Figure 9 – Type Log and Disposal Units and Zones from PXD Well No. 1 (Sanchez, Loughry, &
Coringrato, 2019)
Figure 10 – Mongoose AGI No. 1 Type Log
Figure 11 – Buchanan 3111 #XD location Offset well for Core Data
Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting
the Woodford and sidewall cores23
Figure 13 – Core Photo of Samples Within the Woodford Formation24
Figure 14 – Routine Core Analysis Within the Woodford Formation25
Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation26
Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation
Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation28

Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)....32 Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells36 Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map......43 Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)......47 Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986)......50 Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011)......51 Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model54 Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)......58 Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)59 Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation) Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection) Figure 40 – North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)......62 Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Figure 43 – Active Monitoring Area66 Figure 45 – Mongoose AGI No. 1 Wellbore Schematic70 Figure 46 – All Oil and Gas Wells Within the MMA.....72 Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA......73 Figure 48 – Seismicity Review (TexNet – 08/04/2023)76

Tables

3
3
38
40
41
ırger
47
52
53
55
56
63
67
77

Appendices

Appendix A – TRRC MONGOOSE AGI No. 1 FORMS

- Appendix A-1 UIC Class II Order
- Appendix A-2 GAU Groundwater Protection Determination
- Appendix A-3 Drilling Permit
- Appendix A-4 Completion Report

Appendix B – Site Safety and Layout

- Appendix B-1 Operating Safety Plan
- Appendix B-2 Mongoose Site Plan

Appendix C – Area of Review

- Appendix C-1 Oil and Gas Wells Within the MMA Map
- Appendix C-2 Oil and Gas Wells Within the MMA List

Appendix D – Section 2 Cross Sections

Appendix D-1 – Figure 27 – Structural Cross Section Depicting the Ellenburger Appendix D-2 – Figure 28 – Stratigraphic Cross Section Flattened on the Ellenburger

SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the UIC Class II program. The TRRC classifies Mongoose AGI No. 1 as a UIC Class II well. A Class II permit was issued to Bayswater on March 10, 2023, under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

1.2 UIC Well Identification Number

Mongoose AGI No. 1, API No. 42-335-36013, UIC No. 000125803

1.3 <u>Reporter Number</u>

- Facility Name: Mongoose Amine Treating Facility
- Greenhouse Gas Reporting Program ID: 586481
 - Currently reporting under Subpart UU
- Operator: Bayswater Operating Company LLC

1.4 Facility Address

Mongoose Amine Treating Facility 1625 County Road 280 Westbrook, Texas 79565

Coordinates in NAD83 for this facility:

Latitude: 32.4225396641 Longitude: -101.1714709142

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Mongoose AGI No. 1 well.

The Mongoose injects both H_2S and CO_2 into Ellenburger formation at a depth of 8,300 ft to 9,000 ft, and approximately 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The Mongoose is located on the Eastern Shelf, as shown in the area map in Figure 2, within the greater Permian Basin of west Texas and New Mexico. The Permian Basin covers more than 86,000 square miles extended across an area approximately 250 miles wide and 300 miles long. The TRRC cites that the greater Permian Basin accounts for close to 40% of all oil production within the United States and nearly 15% of natural gas production. A general cross section of the basin is presented in Figure 3.

The ancestral Tobosa Basin was formed by structural flexure in the Precambrian basement at the southern margin of the North American Craton, or Laurentian Plate, during the Proterozoic (Popova, 2020). The modern form of the Permian Basin was shaped during the Carboniferous period due to the collision between Laurasia and Gondwana forming the supercontinent Pangea. The following uplift of the Central Basin Platform differentiated the greater basin into the Delaware Basin in the west, and the Midland Basin in the east along with its surrounding shelf margins (Popova, 2020).



Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, & Walsh).



Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)

The target injection interval for the Mongoose is the Ellenburger formation. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician (Sanchez, Loughry, & Coringrato, 2019). The Ellenburger is of lower Ordovician age and underlies the Woodford formation on the Eastern Shelf. The contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition (Sanchez, Loughry, & Coringrato, 2019). Many formations that are present within the Midland Basin are eroded and not seen upon reaching the Eastern Shelf. A cross section showing these truncations is displayed in Figure 5.

A generalized stratigraphic column of the Eastern Shelf is shown in Figure 4, with the target-injection formation indicated by the red star and historically productive formations indicated in the green stars. The Ellenburger formation is roughly 900 ft thick on the Eastern Shelf as shown by the isopach thickness map in Figure 6 (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006). On the Eastern Shelf, the Ellenburger formation dips to the west-southwest, towards the Midland Basin, and its subsea depth is roughly 6,000 ft (Sanchez, Loughry, & Coringrato, 2019). Figure 7 displays a structure map of the Ellenburger formation. Being far from any major sources of terrigenous clastic sediment input and at a time of a greenhouse climate leading to warm waters created an ideal setting primed for massive carbonate production during the Ellenburger deposition (Waite, 2021). The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. Predominant pore types of this group determined by Holtz and Kerans are "ooid grainstone; ooid-peloid packstone-grainstone"

and reservoirs tend to be of good porosity and moderate permeability (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006).



Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf



Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf (Waite, 2021).



Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006)



Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth.

The lower Ordovician period on the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture. Within this dolomite, there were irregular mottling patterns, likely indicative of bioturbation structures. Mudstone and peloid-wackestone, although in

Subpart RR MRV Plan – Mongoose AGI No. 1

smaller quantities, were also observed in the area (Kerans, 1990). To visually represent these different depositional environments and their corresponding lithologies, a map is presented in Figure 8. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger formation underwent significant "karsting" and dolomitization. This karsting process resulted in the formation of extensive paleocave systems within the Ellenburger, which later collapsed and led to the creation of widespread brecciated and fractured carbonates. These formations are responsible for the occurrence of many Ellenburger reservoirs, according to Loucks (2006).



Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

In their research on saltwater disposal (SWD) injection into the Ellenburger, Pioneer Natural Resources describes three distinct facies within the formation as noted in the Figure 9 type log. The upper and middle facies are composed of fracture breccia, breccia fabrics, and matrix-supported breccia, which coincide with collapsed paleo cave facies as described by Loucks. The lower unit does not exhibit these characteristics but shows a high volume of small vugs (inch-scale) and large-dissolution features (foot-scale) and represents an area of the Ellenburger with elevated porosity and permeability (Sanchez, Loughry, & Coringrato, 2019).





2.1.1 Regional Faulting

The modeled area near the Mongoose does not show any faults. However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area. This fault trend runs north-south in parallel with the dip. Figure 7 displays this fault trend, which is the only example of such a trend within the area. Apart from this, the basin area is structurally inactive.

2.2 <u>Site Characterization</u>

The following section discusses site-specific geological characteristics of the Mongoose.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 shows an annotated well log for Mongoose that goes from the surface to the total depth. It indicates the injection and primary upper confining units with regional formation tops.



Figure 10 – Mongoose AGI No. 1 Type Log

2.2.2 Upper Confining Zone – Woodford Shale

The upper confining unit is the Upper Devonian age Woodford formation. The Woodford Shale, a late Devonian-aged organic-rich rock, was created through a widespread marine transgression. The deposition of the Woodford spread across a large area of the Permian Basin, producing a low-relief blanket of shale. The Woodford formation is an organic-rich petroleum source rock comprised of uncharacteristically highly radioactive, dark fissile shale and siltstone (Merril et al., 2015). Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991). The Woodford formation overlies both unconformably and is diachronous to the underlying Ellenburger formation at the Mongoose location. The U.S. Geological Survey (USGS) CO₂ Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit (SAU) (Merril et al., 2015).

Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose. The Buchanan 3111 #1XD is approximately 10.4 mi. from the Mongoose as depicted in Figure 11. Figure 12 is a stratigraphic cross section showing the correlating cored Woodford formation (pink triangles representing cored intervals) in the Buchanan 3111 #1XD and the Mongoose wells. Routine core analysis, rock mechanics, and threshold entry pressure tests were performed on the core samples from the Woodford formation.

Core photos of the samples taken and analyzed within the Woodford are shown in Figure 13. The black shale unit exemplifies a well cemented unit with little to no fracturing. Routine core analysis was performed on these two samples, which includes bulk density, matrix permeability (as received and as under dry and Dean Stark extracted conditions), gas-filled porosity, gas saturation, grain density, porosity, oil saturation, and water saturation. The results are shown in Figure 14, with the footnotes at the base giving details on the testing processes of each value.

Under the dry and Dean Stark extracted conditions, permeability values of 2.2E-07 millidarcy (mD) were observed with even lower values of 4.87E-07 mD in the as-received samples. Porosities within the same sample were 1.3% when dried and .25% when gas-filled. These permeability and porosity values reflect optimal confining characteristics and validate the USGS assessment of an appropriate sealing formation for CO_2 storage.

To ensure these sealant properties would not be compromised by pressure influence of the injected fluid, a threshold entry pressure test was examined on these Woodford core samples. Figure 15 depicts a graph of permeability vs. pressure showing that, even with pressure increases up to 2,000 pounds per square inch (psi), permeability readings are still in the nano-darcy range. These values are shown in table form in Figure 16 against the pressures administered on the core, with the highest pressure being 2,000 psi. Given that permeability values were lowest (4.03E-07 mD) at 2,000 psi, it can be assumed that the threshold entry pressure of the Woodford formation was not met and would be greater than 2,000 psi. Additionally, a table summary is depicted in Figure 17. These characteristics gathered from the Buchanan core provide a high level of detail into the confining

nature of the Woodford Shale and alleviate any concerns of transmissibility through the confining unit.



Figure 11 – Buchanan 3111 #XD location -- Offset well for Core Data



Figure 12 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Woodford and sidewall cores.



Figure 13 – Core Photo of Samples Within the Woodford Formation



CL File No.: 202105972 Date: February 04, 2022 Analyst(s): MP

Shale Core Analysis (Rotary Sidewall Cores)

		As received				Dry & Dean Stark Extracted Conditions (2)				
Sample	Depth (ft)	Bulk Density (g/cc)	Matrix Permeability ⁽¹⁾ (mD)	Gas-filled Porosity (%)	Gas Saturation (%)	Grain Density (g/cc)	Matrix Permeability ⁽⁵⁾ (mD)	Porosity (%)	Oil Saturation ⁽³⁾ (%)	Water Saturation ⁽⁴⁾ (%)
30,31	9076.03 - 9076.26	2.601	4.87E-09	0.25	18.9	2.624	2.22E-07	1.30	3.3	77.8

Footnotes:

Each sample is a composite of several rotary sidewall cores.

(1) Matrix Permeability is an effective Kg determined from pressure decay results on the fresh, crushed, 20/35 mesh size equivalent sample.

(2) Dean Stark extracted sample (20/35 mesh size) dried at 110 °C. Porosity and saturations are relative to total interconnected pore space.

(3) Oil volume computed assuming an oil density of 0.844 g/cc

(4) Water volume corrected assuming a brine concentration of 80000 ppm NaCl with an ambient density of 1.054 g/cc

(5) Matrix Permeability is an absolute Kg determined from pressure decay results on the clean and dry 20/35 mesh size equivalent sample.

Reference: "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs", GRI-95/0496, Gas Research Institute, April 1996

Figure 14 – Routine Core Analysis Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

Company:Bayswater Exploration & ProductionWell:Buchanan 3111 1XDField:SpraberryLocation:Howard County, TexasFile:HOU-2105972



Figure 15 – Graph of Threshold Entry Pressure Within the Woodford Formation

PETROLEUM SERVICES

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production Well: Buchanan 3111 1XD Field: Spraberry Location: Howard County, Texas

File: HOU-2105972

Sample 30B							
Gas							
Injection	Permeability						
Pressure,	to Brine*,						
psi	mD						
500	1.44E-06						
750	2.20E-06						
1000	1.46E-06						
1200	6.73E-07						
1400	5.77E-07						
1600	6.72E-07						
1800	5.39E-07						
2000	4.03E-07						

Figure 16 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation

SUMMARY OF THRESHOLD ENTRY PRESSURE RESULTS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company:	Bayswater Exploration & Production
Well:	Buchanan 3111 1XD
Field:	Spraberry
Location:	Howard County, Texas

File: HOU-2105972

				Final	Threshold
				Permeability	Entry
Sample	Depth,	Length,	Diameter,	to Brine*,	Pressure,
Number	feet	cm	cm	millidarcies	psi
30B	9076.03	2.67	2.54	4.03E-07	TEP>2000

* Apparent permeability to brine with humidified nitrogen displacing water

Figure 17 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation

2.2.3 Injection Interval – Ellenburger

2.2.3.1 Ellenburger

As described in the Regional Geology section, the Ellenburger at the Mongoose location is a widespread lower Ordovician carbonate deposited over the entire Permian area, indicating a relatively uniform depositional condition (Hendricks, 1964). However, post-depositional sequences have highly altered the section. These sequences have a large influence on the development of the reservoir quality within the injection interval and its ability to accept the proposed injectate. Further analysis based on regional and site-specific data was analyzed, as discussed below, to better understand the reservoir conditions at and around the Mongoose well location.

2.2.3.2 Ellenburger Porosity/Permeability Development

Facies in the low-energy, restricted shelf setting exhibit extensive dolomitization and are characterized by significant bioturbation, resulting in mottling patterns (Loucks, 2003). This dolomitization process has facilitated porosity development within the Ellenburger formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs. These same features were interpreted from the openhole logs in the Mongoose well and core from the Buchanan 3111 #1XD well. A total of 23 sidewall cores were taken within the Ellenburger formation in the Buchanan 3111 #1XD well, with 12 of those having routine core analysis performed on them. Figure 18 shows the results of the analysis.

Porosity values were primarily derived from offset openhole porosity logs within the Ellenburger section. Petrophysical analysis was performed on the offset logs to calculate an effective porosity curve, the porosity of a rock that is available to contribute to fluid flow, to better estimate porosity ranges with regards to injection within the Ellenburger. This is done by accounting for clay content and matrix lithology to better understand the varying porosity within the injection interval and how it relates to injection capacity. The ranges of effective porosity within the modeled wells are 0 to 39.4% with the mean being 4.6%. Figure 19 is a histogram depicting these porosity distributions within the seven modeled wells. These values are validated through similar ranges seen in the core results. The logical inference would be that, as the effective porosity increases, the reservoir quality for injection improves and the associated porosity increment leads to a rise in permeability.

A porosity to permeability relationship was created from this data with the outliers and nonapplicable samples redacted. Additional regional data from Loucks (2003) was incorporated into the relationship to assist with the higher permeability ranges, to ensure that overestimates of permeability were not calculated. The data from Loucks (2003) is exemplified in Figure 20. A twofunction porosity-permeability curve was developed from the regional and local core data. Figure 21 shows the equations and relationships where:

> If Effective Porosity (Φ eff) < 6.5%: $K(mD) = 7E - 08e^{3.3028*\Phi}$ eff If Effective Porosity (Φ eff) > 6.5%: $K(mD) = 277.39 \ln(\Phi eff) - 380.58$

These equations were extrapolated to all the wells within the model including the Mongoose. In Figure 22, the cross section of the Mongoose and Buchanan well is depicted. This illustration showcases the Ellenburger formation, with the sidewall cores from the Buchanan well represented by pink triangles. The calculated permeability curves resulting from the equations mentioned earlier are shown in red, while green represents the effective porosity. High permeability and porosity sections can be seen in both wells, most likely reflecting strata that had prolonged subaerial exposure creating the karst and vug features that will be targeted and utilized for injection. Figure 23 is a core photo from the Buchanan well depicting an example of what a vug feature within the Ellenburger can look like. These features will be taking the bulk of the injection and will be modeled within the area based on openhole log analysis.

Permeability ranges within the seven wells utilized in the model vary from 0 mD to 638 mD, with the mean being 40.822 mD. A histogram representing these ranges and distributions within the seven modeled wells is displayed in Figure 24. This range corroborates with Loucks (2003) and data recovered from the Buchanan well, and it can be concluded that the process used to determine the permeability distributions within the injection interval is valid.

Bayswater Exploration & Production Buchanan 3111 1XD Spraberry Howard County, Texas



CL File No.: 202105972 Date: March 31, 2022 Analyst(s): MP

CMS-300 ROTARY SIDEWALL ANALYSIS													
			Net Confining		Permeability					Saturation		Grain	
San	nple	Depth	Stress	Porosity	Klinkenberg	Kair	b(air)	Beta	Alpha	Oil	Water	Density	Footnote
Nun	nber	(ft)	(psig)	(%)	(md)	(md)	psi	ft(-1)	(microns)	% Pore	Volume	(g/cm3)	
2	23	9236.98	2960	25.81	.259	.389	11.97	3.27E+09	2.75E+00	0.0	94.7	2.666	
2	21	9257.01	2960	4.77	.002	.009	104.71	2.14E+15	1.48E+04	1.2	66.1	2.746	(1)
1	9	9363.99	2960	5.23	5.17	5.81	2.07	1.75E+12	2.93E+04	4.1	66.9	2.800	(6)
1	5	9485.99	2960	3.41	.005	.016	62.63	3.24E+13	5.63E+02	2.3	64.6	2.838	(6)
1	3	9549.48	Ambient	1.55	N/A	N/A	N/A	N/A	N/A	1.9	44.7	2.829	(5)
1	2	9604.98	2960	1.63	.00006	.001	354.43	2.46E+18	5.38E+05	2.6	54.0	2.842	(1)
1	0	9712.03	Ambient	1.28	N/A	N/A	N/A	N/A	N/A	1.2	74.3	2.758	(5)
	7	9835.05	2960	2.28	.001	.004	155.69	2.03E+16	4.48E+04	1.5	81.1	2.701	
	6	9868.97	2960	3.43	.001	.003	166.37	3.03E+16	5.46E+04	0.9	81.6	2.827	
	5	9892.03	2960	3.46	.001	.005	132.61	8.12E+15	2.84E+04	2.1	91.6	2.809	
	4	9914.00	2960	5.46	659	669	0.18	1.07E+09	2.29E+03	0.7	58.7	2.835	(6)
	3	9969.01	Ambient	11.18	N/A	N/A	N/A	N/A	N/A	1.7	42.9	2.846	(5),(6)

Figure 18 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)


Figure 19 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells

			Tectonically Fractured
	Karst Modified	Ramp Carbonate	Dolostone
Lithology			
	Dolostone	Dolostone	Dolostone
Depositional			
setting	Inner ramp	Mid- to outer ramp	Inner ramp
		Sub-Middle Ordovician,	
	Extensive sub-	sub-Silurian/Devonian,	
	Middle	sub-Mississippian, sub-	Variable intra-Ellenburger,
Karst facies	Ordovician	Permian/ Pennsylvanian	sub-Middle Ordovician
Fault-related			
fracturing	Subsidiary	Subsidiary	Locally extensive
	Karst-related		
Dominant pore	fractures and	Intercrystalline in	
type	interbreccia	dolomite	Fault-related fractures
		Partial, stratigraphic and	
Dolomitization	Pervasive	fracture-controlled	Pervasive

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

Figure 20 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)



Porosity vs Permeability

Figure 21 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Data



Figure 22 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Ellenburger formation and sidewall cores.



Figure 23 – Core photo of Ellenburger sample displaying vug features.



Figure 24 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells

2.2.3.3 Formation Fluid

Two wells were identified within approximately 30 miles of the Mongoose through a review of oilfield brine compositions of the Ellenburger formation from the USGS National Produced Waters Geochemical Database (ver. 2.3). The location of these wells is shown in Figure 25. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids (TDS). Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger formation is compatible with the proposed injection fluids.



Figure 25 – Offset wells used for formation fluid characterization.

	Average	Low	High
Total Dissolved Solids (ppm)	47,427	42,014	52,840
рН	7	7	7
Sodium (ppm)	16,384	15,000	17,767
Chlorides (ppm)	27,590	24,900	30,281

Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples

2.2.4 Lower Confining Zone – Precambrian

Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sources from outcrops in central Texas and in the Trans-Pecos region of Texas and centra New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section (Adams & Keller, 1996).

Adams and Keller conducted a geophysical analysis in 1996 to enhance the understanding of Precambrian rock types and their distribution in the Permian Basin. The study incorporated gravity modeling and magnetic and gravity anomalies, as well as rock data from Precambrian outcrops and drills to interpret the upper crustal geology of the area. Figure 26 displays the map resulting from their investigation, revealing that batholiths are likely present in the Precambrian basement rock at the Mongoose well location. Additionally, samples collected from offset wells displayed predominantly felsic rocks, which lead to the interpretation of "granitic bodies in the upper crust" (Adams & Keller, 1996).

Offset Ellenburger injector wells drilled through the Ellenburger section and reached total depths near the Precambrian. Log characteristics of strata near the total depth of the wells display gamma ray responses well above 90 gamma units of the American Petroleum Institute (GAPI), which is indicative of a high radioactive response. Additionally, the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone.



Figure 26 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Geomechanics

2.3.1 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density of the upper and lower confining and injection zones was calculated from log data at the Buchanan 3111 #1XD (API No. 42-227-41307) offset well. The overburden gradient and vertical stress at the top of each zone were calculated by integrating the bulk density from surface to the formation depth in half-foot intervals. Table 4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Formation	Depth (ft)	Bulk Density (g/cm^3)	Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Woodford	8,322	2.63	164.1	8,563	1.029
Ellenburger	8,375	2.75	171.2	8,635	1.031
Precambrian	9,500*	2.83	176.7	9,937	1.046

Table 4 – Calculated Vertical Stresses

* Estimated

2.3.2 Elastic Moduli and Fracture Gradient

The 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. The calculation requires Poisson's ratio ("v"), overburden gradient (OBG), and pore gradient (PG) in order to determine the required pressure to fracture the formation. These variables can be changed to match the site-specific injection zone.

A thorough review of log data, available literature, and industry standards indicate a 0.465 psi/ft pore gradient should be assumed when there are no site-specific numbers available. Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the Buchanan 3111 #1XD. The calculation was performed using the equation below for log data points at half-foot depth intervals. The results were then averaged for the depth range of each zone. This resulted in a Poisson's ratio of 0.261 for the upper confining zone and 0.273 for the injection zone.

$$v = \frac{\frac{1}{2} \left(\frac{v_p}{v_s}\right)^2 - 1}{\left(\frac{v_p}{v_s}\right)^2 - 1}$$

Where:

v = Poisson's Ratio v_p = Compressional Velocity v_s = Shear Velocity

Log data was unavailable for the lower confining zone, therefore the Poisson's ratio for this zone was estimated through a review of available literature. The lower confining zone consists of granite, which has been observed to have a Poisson's ratio ranging from 0.19 to 0.35 with a mean value of 0.28 (Domede, 2017). Based on this research, an average value of 0.28 was assumed. Using these values in the equation below, a fracture gradient of 0.664 psi/ft was calculated for the upper confining zone. A 10% safety factor was applied to this number resulting in a maximum allowed bottomhole pressure of 0.598 psi/ft. This zone had the lowest fracture gradient of the confining and injection zones. It was used to define the maximum allowable pressure to ensure that the injection pressure would not exceed the fracture pressure of any of the three zones. The resulting fracture gradients are displayed in Table 5.

Example Fracture Gradient Calculation for Upper Confining Zone

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

$$FG = \frac{0.261}{1 - 0.261} (1.029 - 0.465) + 0.465 = 0.664 \, psi/ft$$

$$FG \text{ with } SF = 0.689 \times 90\% = 0.598 \text{ } psi/ft$$

Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
8,322	Upper Confining	Woodford	1.029	0.465	0.261	0.664
8,375	Injection	Ellenburger	1.031	0.465	0.273	0.678
9,500*	Lower Confining	Precambrian	1.046	0.465	0.28	0.691

*Estimated

2.4 Local Structure

The area surrounding the Mongoose well is characterized by a monoclinal dip from east to west that is influenced by a shallow westward slope towards the Midland Basin and an upward slope to the east towards the Eastern Shelf. No evidence of structural faulting was found in this specific region that could have affected the geological trend. Figure 27 shows the topography of the Ellenburger formation, with the Mongoose well marked by a black star.

Subsurface interpretations of the Ellenburger formation heavily relied on well data and 3D seismic coverage in the area. The black boundary in Figure 27 represents the extent of the seismic coverage. Within the mapped area, approximately 100 wells have penetrated the Ellenburger formation. However, only seven of these wells fully penetrated the entire Ellenburger section. The remaining 93 wells only reached the top of the Ellenburger formation. These wells are plotted on the map and cover four counties. In addition to the Mongoose well, six other wells located offset of the Mongoose were used for the model build and are indicated by red stars.

Figure 28 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map. The Ellenburger was broken down into eight subsections labeled Ellenburger A through H. Figure 29 is a stratigraphic cross section flattened on the Ellenburger that better illustrates these subtops.

The cross sections reveal the regional unconformity in the area when moving east from the Midland Basin. As we go farther updip and to the east, the Fusselman section gradually erodes. While there is also thinning in the Woodford, the cross section shows that the Woodford is present throughout the modeled area, creating a continuous seal above the plume.

With no major structural or stratigraphic features within the injection interval in the Mongoose area, there is little to no concern of geologic conduits outside of the injection interval. General flow trends will follow dip and optimal reservoir features within the Ellenburger. Large scale versions of Figures 28 and 29 are provided in *Appendix D*.



Figure 27 – Ellenburger structure map in subsea feet. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map.



Figure 28 – Structural cross section depicting the Ellenburger.



Figure 29 – Stratigraphic cross section flattened on the Ellenburger.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger formation at the Mongoose location indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity. The Woodford Shale formation at the same well location has low permeability and is of adequate thickness and lateral continuity to act as the upper confining zone. Below the injection interval, the Precambrian formation has low permeability and low porosity, making it unsuitable for fluid migration and serving as the lower confining zone.

A thorough study of the area of review has been conducted to identify any potential subsurface features that could impact the ability of the injection and confinement units to retain the injectate within the desired injection interval. Fortunately, no faults or other hazardous geologic conditions have been identified in the area. Therefore, the conditions in this area are ideal for injection and containment.

2.6 Groundwater Hydrology

The Mongoose is located within Mitchell County, home to a population of approximately 8,400 residents, and is serviced by the Lone Wolf Groundwater Conservation District, which consists solely of Mitchell County. This conservation district has an area of roughly 900 square miles. Much of the county's economy is derived from agriculture and oil production, both water-intensive operations. Groundwater usage within the county is estimated to be 13,391 acre-feet on a yearly basis (Lone Wolf Groundwater Conservation District, 2019).

Surface Water

Mitchell County lies within the Colorado River basin, as the Colorado runs through the county. Drainage from both the east and west flow centrally towards the Colorado River, which splits the county in half. The estimated supply of surface water is 395 acre-feet (Lone Wolf Groundwater Conservation District, 2019).

Groundwater

There are multiple units where groundwater is available within Mitchell County, although only the Dockum Group provides significant amounts of water. Table 6 discusses water-bearing units in the county, and Figure 30 shows a generalized reference to structure and formation relationships.

Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger Jr., 1967)

System	Series	Group	Formation	Approximate thickness (feet)	Lithology	Water-bearing characteristics
Quaternary	Pleistocene and Recent		Alluvium	0-100	Fine to coarse sand, and small to large gravel, with occasional clay and caliche beds.	Above the regional water table east of Colo- rado River, but yields up to 20 gpm of good quality water in southwestern Mitchell County.
Tertiary	Pliocene		Ogallala	0-100	Fine to coarse sand, gravel, caliche, and zones of clay.	Above the water table east of Colorado River, but yields up to 20 gpm of good quality water to wells in northwestern Mitchell County.
		Fredericksburg		0-220	Predominantly limestone. 15 to 25 feet of sandy yellow marl at base overlain by chalk and shally limestone. Very dense, massive, fossiliferous lime- stone in the upper part.	Upper limestones contain in places small to moderate supplies of potable but hard water in solutional openings developed along fracture systems; recharge to the openings occurs through numerous sinks.
Cretaceous Comanche	Trinity		0-100	White to purplish quartz sand, fine to medium grained, moderately to loosely consolidated, with occasional lenses of quartz gravel at the base.	Yields small to large quantities of potsble but hard water, the amount depends on saturated thickness which ranges from 100 percent under interior limestone areas to a few feet in parts of the outcrop; yields of several hundred gallons per minute are reported.	
		Deckury	Chinle	0-640	Predominantly red to marbon and pur- plish clay and shale, interbedded with thin, tight, cross-bedded, yellow-brown to reddish-white sand- atone.	Sandstones contain generally small quantities of moderately to highly mineralized water; used principally for livestock.
Triassic		Dockum	Santa Rosa	0-330	Basal conglomerate overlain by brown to gray, micaccous and carbonaccous, cross-bedded sand alternating with beds of red and gray clay.	Sands and gravels contain moderate to large quantities of fresh water east of the Colorado River, with yields up to 1,000 gpm reported; west of Colorado River capa- city of sand is reportedly substantial but water is generally not potable.
Permain	Guadalupe and Ochoa				Fine-grained, red to brown sandstone; dense red silty shale with occasional gypsum or anhydrite beds.	Yield small quantities of moderately to high- ly mineralized water to livestock and domestic wells.



Figure 30 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)

Permian

Permian age strata underlies much of the area and outcrops in the southeast of Mitchell County and along the Colorado River and its tributaries. These strata consist primarily of "red beds," dense red silty shales. Water wells in the Permian strata are typically less than 100 ft deep, yielding small amounts of moderately to highly mineralized water usable only for livestock (Shamburger Jr., 1967).

Dockum Aquifer

The Triassic Age Dockum group comprised by the Santa Rosa sandstone and the Chinle formation are the main sources of ground water within the county. An overview map of the extent of the Dockum Aquifer is shown in Figure 31, with outcrops depicted in solid color. The Chinle is further divided into the Tecovas formation, the Trujillo sandstone, and the Cooper Canyon formation, although the Tecovas and Cooper Canyon are generally unimportant and yield only small amounts of highly mineralized water.

The Santa Rosa sandstone lies unconformably atop the Permian age strata at the base of the Dockum Group and is one of the major sources of water for Mitchell County. It is comprised of a basal conglomerate overlain by alternating beds of red and gray micaceous shale, sand, and gravel reaching up to 130 ft in thickness (Bradley & Kalaswad, 2001). The Trujillo sandstone overlies the Tecovas, which in turn overlies the Santa Rosa, and is a cross-bedded unit composed of sandstones and conglomerates. The Santa Rosa and Trujillo sandstones are regarded as the main producers of water in the Dockum Group in Mitchell County (Lone Wolf Groundwater Conservation District, 2019). The Dockum Group was likely deposited from sediments into "fluvial, deltaic, and lacustrine environments within a closed continental basin" (Bradley & Kalaswad, 2001). The base of the Santa Rosa is typically considered the lower extent of fresh water in the area. Water levels in wells throughout the county vary between 15 ft and 215 ft below ground level (Shamburger Jr., 1967), and the aquifer is considered confined to partially confined (Bradley & Kalaswad, 2001).

Recharge of the aquifer is provided by rainwater infiltration through outcrops in the county and is estimated to be 18,108 acre-feet per year. Groundwater in the Dockum aquifer system flows towards the central Colorado River. A potentiometric surface map of the Santa Rosa sandstone, the lower Dockum member, is depicted in Figure 32. Although no values of porosity have been determined empirically, a conservative value of 10% is assumed for effective aquifer porosity (Lone Wolf Groundwater Conservation District, 2019).

Groundwater quality is generally considered poor with TDS and other constituents exceeding secondary drinking water standards (Bradley & Kalaswad, 2001). As a typical assumption, water quality west of the Colorado River within the aquifer is poor and unsuitable for municipal use, while east of the river water quality is less mineralized and is of suitable quality for municipal purposes (Lone Wolf Groundwater Conservation District, 2019). For example, a well tested 10 miles northwest of Colorado City contained chloride at 560 milligrams per liter (mg/L), sulfate at 337 mg/L, and TDS at 1,893 mg/L, all of which are above limits set by the Texas Commission on Environmental Quality (TCEQ) for use in municipal water supplies. In contrast, a well 8 miles east of Colorado City contained

chloride at 34 mg/L, sulfate at 73 mg/L, and TDS at 418 mg/L (Lone Wolf Groundwater Conservation District, 2019). A map showing TDS values for the Dockum Aquifer is shown in Figure 33.



Figure 31 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location (George, Mace, & Petrossian, 2011).



Figure 32 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986).



Figure 33 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011).

Ogallala Formation

The Tertiary age Ogallala formation occurs in the northern extents of Mitchell County. In the eastern part of the county, Ogallala sediments are generally above the water table and not a source of groundwater; however, they do provide an effective means of recharge to the underlying Santa Rosa formation. In the western part of the county, the Ogallala is up to 100 ft thick of unconsolidated sand and gravel and provides small quantities of usable water for domestic and livestock wells (Lone Wolf Groundwater Conservation District, 2019).

2.7 <u>Description of the Injection Process</u>

2.7.1 Current Operations

The Mongoose Amine Treating Facility and the associated Mongoose well began operating in August of 2023. The maximum rate during the injection period is expected to be 377.2 MT/yr (19.5MMscf/d). The TAG is 41.2% CO₂, which equates to 155.3 MT/yr of CO₂ each year. The current composition of the TAG stream is:

Table 7 – Gas Composition at the Plant Outlet

Component	Mole Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

The Mongoose Amine Treating Facility is designed to dehydrate, treat, and compress the natural gas produced from the surrounding acreage in Mitchell County. The gas is dehydrated to remove the water content, and treated to remove the CO₂ and H₂S. The compressed rich gas stream is then transported via pipeline to a separate facility for processing to separate the natural gas liquids from the methane. The TAG is then directly routed from the Plant's amine unit to the Mongoose. The Plant is manned 24 hours per day, 7 days per week.

2.8 <u>Reservoir Characterization Modeling</u>

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (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 Ellenberger formation is the target formation for the Mongoose. The Petrel software package was utilized to create the geologic model of the target formation. Within the Petrel platform, the porosity and permeability distributions were established for the model. The geologic structure was then imported into GEM for simulation purposes.

In Petrel, the structure's construction involved the utilization of nine contour tops, which were layered sequentially. These contour tops, identified as "Ellenberger A" through "Ellenberger I," collectively define the structure's configuration, Ellenberger A being the shallowest and Ellenberger I being the deepest structure package. To accurately represent the formation's true structure, true vertical depth subsea was used to account for the differing overburden depths associated with the

wells used in contour delineation. The distinction of true vertical depth (TVD) and true vertical depth subsea (TVDSS) is taken into consideration when inputting pressure and temperature gradients into the GEM model.

Porosity estimates were determined using openhole porosity logs from seven offset wells within the Ellenberger formation. These logs were used within Petrel to distribute porosity and permeability spatially. Permeability was found by using the two-function porosity-permeability curve developed from regional and local core data within the Ellenberger formation.

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 and CO_2 based on initial estimates from the source, as shown in Table 8. However, the precise gas composition may vary slightly as the Plant is still in its commissioning phase. Initial estimates anticipate the injectate composition to be 58.8% H_2S and 41.2% CO_2 . Once a steady-state operating composition is determined, the MRV plan will be updated if there is a material difference. Based on the initial gas samples, the modeled percentages in the injectate for the 40-year injection period of the Mongoose is 58.8% H_2S and 41.2% CO_2 .

Table 8 – Modeled Initial Gas Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Hydrogen Sulfide (H ₂ S)	58.8	58.8
Carbon Dioxide (CO ₂)	41.2	41.2

Core data from literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Ellenberger dolomitic carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 10%, an irreducible water saturation of 39.7%, and a maximum residual gas saturation of 30%. The relative permeability curves used for the GEM model are shown in Figure 34.



Figure 34 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 135 blocks in the x-direction (east-west) and 77 blocks in the y-direction (northsouth), resulting in a total of 10,395 grid blocks per layer. Each grid block spans dimensions of 1,000 ft by 1,000 ft. This configuration yields a grid size measuring 135,000 ft by 77,000 ft, equating to just under 373 square miles in area. The grid cells in the vicinity of the Mongoose, within a radius of 2.5 miles, have been refined to dimensions of 250 ft by 250 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume.

In the model, each layer is characterized by heterogeneous permeability and porosity values. These values are derived from the geostatistical distribution of properties, using porosity logs implemented in Petrel as a basis. The model encompasses a total of 79 layers, each featuring varying thicknesses, with an average of approximately 10 ft per layer. As previously mentioned, the structure of the Ellenberger formation was formed using nine contour packages. The summarized property values for each of these packages are displayed in Table 9.

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Ellenberger A	9	8,369	101	49.1	5.2%
Ellenberger B	9	8,470	76	65.1	6.0%
Ellenberger C	8	8,546	75	38.5	4.2%
Ellenberger D	9	8,621	86	39.2	4.9%
Ellenberger E	15	8,707	153	48	4.8%
Ellenberger F	6	8,860	63	32.5	4.4%
Ellenberger G	4	8,923	39	16.5	3.2%
Ellenberger H	8	8,962	82	76.9	5.5%
Ellenberger I	11	9,044	112	66	3.4%

Table 9 – GEM Model Layer Package Properties

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

- 1. Estimate the maximum areal extent and density drift of the acid gas plume after injection.
- 2. Assess the impact of offset SWD well injection on density drift of the plume.
- 3. Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone.
- 4. 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 47,427 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The acid gas stream is primarily composed of CO₂ and H₂S as stated previously. Core data was used to help generate relative permeability curves. From the literature reviews as previously discussed, cores that most closely represent the vuggy dolomitic carbonate seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975). The initial reservoir pressure is 3,903 psig, which is equivalent to a 0.465 psi/ft pressure gradient and was determined from offset injection well analysis. The fracture gradient of the injection zone was estimated to be 0.664 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.598 psi/ft, which is equivalent to 5,007 psig.

The model considers the injection volumes of offset SWD wells close to the Mongoose. Nine such wells were identified within a 19-mile radius. Historical injection rates of eight of the nine of these wells currently injecting into the Ellenberger were provided by the operators and were input into

the model. All but one of the SWD wells in the model are currently permitted and injecting. The SWD well that has not yet started injection and has no historical injection data is conservatively assumed to inject at its maximum permitted rate for 30 years and to start at the same time as the Mongoose begins injection. Projected injection rates were assumed to be the maximum permitted injection rates and ended after 30 years of life for all nine offset SWDs. This simulation includes the effect of water injection on the density drift of the plume and the bottomhole pressure of the Mongoose. The SWDs included in the model are listed in Table 10.

API Number	Well Name	Well Number
42-227-41332	Fryar 3S	2XD
42-227-41307	Buchanan 3111	1XD
42-227-39064	Pipeline SWD	1
42-335-34319	Wild Bill	1WD
42-227-41775	Sterling	1XD
42-335-36026	Oasis Deep	9XD
42-227-39098	846 SWD	2
42-227-39119	N. Midway SWD	1
42-227-40310	Hull SWD	1

Table 10 – Offset SWD Wells Included in GEM Model

The model runs for a total of 175.33 years, comprising 15.33 years of historical SWD well injection prior to the commencement of acid gas injection. This is followed by 40 years of active acid gas injection through the Mongoose, succeeded by an additional 120 years of density drift. The model begins in September 2008, aligning with the start of historical injection data for the first offset SWD well. The remainder of the SWD wells turn on between then and the start of the acid gas injection, which begins in January 2024. Throughout the entire 40-year injection period, an injection rate of 19.5 MMscf/D is assumed to model the maximum available rate, yielding a more cautious estimate of the plume size. After the 40-year injection period, when the Mongoose ceases injection, all nine offset SWD wells have been shut in—as they began injecting before the Mongoose and were assumed to stop injecting after 30 years.

The maximum plume extent during the 40-year injection period is shown in Figure 35. The final extent after 120 years of density drift after injection ceases is shown in Figure 36. Both figures show the entire grid with the included offset SWD wells. Due to the large nature of the model, a zoomed-in view of the plume extent during the 40-year injection period is shown in Figure 37 and the final extent after 120 years of density drift after injection ceases is shown in Figure 38.



Figure 35 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 36 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)



Figure 37 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 38 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

The cross-sectional view of the Mongoose shows the extent of the plume from a side-view angle cutting through the formation at the wellbore. Figure 39 shows the maximum plume extent during the 40-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 40 shows the final extent of the plume after 120 years of migration. At this point in time, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, as it is less dense than the formation brine, until an impermeable layer is reached. Both figures are shown in a north-to-south view.



Figure 39 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 40 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)

Figure 41 shows the surface injection rate, bottomhole pressures, and surface pressures over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate begins, reaching a maximum pressure of 4,453 psig, then slightly decreases and remains constant. This buildup of 550 psig keeps the bottomhole pressure below the fracture pressure of 5,007 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,008 psig, well below the maximum allowable 2,500 psig per the TRRC UIC permit for this well. At roughly 30 years into injection for the Mongoose, all SWD wells included in the model have ceased injection. Due to the shut-in of offset SWD wells, the pressure effects within the formation are felt by the Mongoose. When this occurs, the bottomhole pressure decreases by 50 psig and surface pressure decreases by 40 psig. Bottomhole and wellhead pressures over time are in Table 11.



Figure 41 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	3,916	-
10	4,389	1,977
20	4,394	1,982
30	4,393	1,980
40	4,343	1,942
50	3,923	-
120	3,919	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in 40 CFR **§98.448(a)(1)**.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO₂ plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

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

Bayswater's expected gas composition was used in the model. The acid gas injectate is estimated at a molar composition of 58.8% H₂S and 41.2% CO₂, with trace amounts of other constituents. Upon the Plant achieving stable operations, a representative injectate sample will be collected and analyzed by a third-party laboratory. If the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be provided. As discussed in *Section 2*, the gas will be injected into the Ellenberger formation. The geomodel was created based on the rock properties of the Ellenberger.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 40, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast.

Figure 42 shows the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA is depicted in this figure by taking the stabilized plume boundary after 120 years of density drift, and adding an all-around buffer zone of one half mile.



Figure 42 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. This provides Bayswater sufficient time to develop their asset base, achieve steady operations, and evaluate any potential modifications to the MRV plan.

The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free-phase CO₂ plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. By 2036, a revised MRV plan will be submitted to define a new AMA. Figure 43 shows the area covered by the AMA.



Figure 43 – 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. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within the MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from natural or induced seismicity

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. The lateral continuity of the UCZ ¹ is recognized as a very competent seal.	Low. Any vertical migration from the Injection Zone would return the CO ₂ to the production zone.	During active injection and Post Injection Site Care ² period.
Faults and fractures	Possible. The lateral continuity of UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO ₂ to the production zone.	During active injection and Post Injection Site Care period.
Upper confining layer	Unlikely. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO ₂ to the production zone.	During active injection and Post Injection Site Care period.
Natural or induced seismicity	Possible. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO ₂ to the production zone.	During active injection and Post Injection Site Care period.

1 - UCZ is defined as the Upper Confining Zone.

2 - Post Injection Site Care is the period of time from the end of injection throught plume stabilization and site closure.

Magnitude Assessment Description

Low - catergorized as little to no impact to safety, health and the environment and the costs to mitigate are minimal.

Medium - potential risks to the USDW and for surface releases does exist, but circumstances can be easily remediated.

High - danger to the USDW and significant surface release may exist, and if occurs this would require significant costs to remediate.

4.1 Leakage from Surface Equipment

The Plant and Mongoose are newly designed and constructed facilities for treating and injecting acid gas with a fundamental objective to ensure maximum safety to the public, the employees, and the environment. These are depicted in Figures 44 and 45. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H₂S are installed at key locations around the Plant as depicted on the site plan in Appendix B-2. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points based on H₂S exposure limits set by the Occupational Safety and Health Administration (OSHA). These exposure limits are incorporated in the gas dispersion model provided to the TRRC with the Class II AGI application. OSHA sets the detection or exposure limits at 15 ppm as the High Alarm and the High- High Alarm or Facility Shutdown limit at 40 ppm.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant, the Mongoose, and gas monitors and the gas meter are called out in the detailed site plan in Appendix B-2. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs.



Figure 44 – Site Plan



Figure 45 – Mongoose AGI No. 1 Wellbore Schematic

With the level of monitoring implemented at the Plant, a release of CO_2 would be quickly identified, and the safety systems and protocols would minimize the release volume. The acid gas stream injected into the well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the Plant adjacent to the Mongoose. Bayswater will increase its future injection volumes from its own gas production and possible other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. 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)**. Bayswater concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The Mongoose was designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 45. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) §3.46 [40 CFR §146.23 (b)(3)], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 46. The MMA review map and a summary of all wells in the MMA is provided in *Appendix D*. Figure 47 highlights that only two wells penetrate the MMA's gross injection zone. These wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements. Bayswater will perform baseline soil gas sampling prior to implementation of the MRV plan and subsequent injection records. In addition, annual soil gas samples will be taken in the area adjacent to artificial penetrations and analyzed by a third-party lab. The results, should they indicate an issue with the sequestered CO₂ will be presented in the annual report to the GHGRP.

The summary of all oil and gas wells in *Appendix D* also provides the total depth (TD) of all wells within the MMA. Those wells that are shallower and do not penetrate the injection zone are isolated by the Woodford Shale as discussed in Section 2.2.2. The Woodford Shale provides 50 feet or more of contiguous low permeable shale and its presence in offset wells within the MMA indicates lateral continuity, migration of the fluid above the injection zone into shallower offset AP's is unlikely.

Bayswater is the operator of many of the shallower offset oil and gas wells within the MMA and frequently performs gas analysis on their production volumes. If a material variance in the quantity of CO_2 produced is indicated, Bayswater would investigate to determine the effected well(s), the root cause of the CO_2 increase to formulate a resolution plan and utilize the gas analysis variance to calculate any adjustments to reported volumes.



Figure 46 – All Oil and Gas Wells Within the MMA



Figure 47 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC in the area of the Mongoose will include a list of formations for which operators are required to comply with TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC §3.13. The Mongoose drilling permit, provided in Appendix A, serves as an example. The Ellenburger is among the formations listed for which operators in Mitchell County and District 8 (where the Mongoose is located) are required to comply with TRCC Rule 13. The rule requires oil and gas operators to set steel casing and cement either (1) across and above all formations permitted for injection under TRRC Rule 9, or (2) immediately above all formations permitted for injection under Rule 46, for any well proposed within a quarter-mile radius of an injection well. In this instance, any new well permitted and drilled to the injection zone and located within a guarter-mile radius of the Mongoose will be required under TRRC Rule 13 to set steel casing and cement above the well's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and 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 (also provided in the permit in Appendix A).

4.2.2 Groundwater Wells

A groundwater well search results found three wells within the MMA, as identified by the Texas Water Development Board. A field investigation was performed to validate the existence and location of these wells. However, none of the wells listed in the database could be located. An exhaustive search of well records was performed and no completion reports and/or plugging records were found. The result is there are no groundwater wells to monitor as none exist within the MMA.

The surface, intermediate, and production casing strings in the Mongoose, as shown in Figure 45, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations and the GAU letter issued for this location (and included in *Appendix A*). The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Bayswater concludes that leakage of the sequestered CO_2 to the groundwater acquifer is unlikely.

4.3 Leakage Through Faults and Fractures

No faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose. This includes areas well outside of the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

In the event of an unmapped fault existing within the plume boundary, any displacement caused by it would be too small to be detected through 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

Porosity development within the injection intervals is primarily attributed to fractures and aerial exposure. However, these fractures are limited and do not extend into the upper confining unit, which helps mitigate the risk of migration through fractures outside of the designated injection interval.

4.4 Leakage Through the Confining Layer

The overlying Woodford formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in *Section 2*. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale that would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

4.5 Leakage from Natural or Induced Seismicity

The Mongoose is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

All seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

Stringent operating procedures will be programmed into the SCADA and controls systems to ensure that operating pressures stay below the fracture gradient of both the injection and confining intervals. Moreover, a combination of continuous well monitoring and monitoring of the TexNet site for activity will promptly identify any irregularities in the operations linked to seismic events.



Figure 48 – Seismicity Review (TexNet – 08/04/2023)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Bayswater 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 H₂S and CO₂, the H₂S will be a proxy for CO₂ leakage and therefore the monitoring systems in place to detect H₂S will also indicate a release of CO₂. Table 13 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 40-year injection period or cessation of injection operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

Leakage Pathway	Monitoring Method				
	Fixed H ₂ S monitors throughout the AGI facility				
Leakage from surface equipment	Visual inspections				
	SCADA continuous monitoring of the AGI facility				
	SCADA continuous monitoring of the AGI well				
	Monitor CO ₂ levels in Above Zone producing wells				
Leakage through existing wells	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years				
	Visual inspections				
	Annual soil gas sampling at well locations that penetrate the Upper Confining Zone within the AMA				
Leakage through groundwater wells	Annual groundwater samples from monitoring wells				
Leakage from future wells	Compliance with TRRC Rule 13 Regulations				
Lookago through foulte and fractures	SCADA continuous monitoring at the AGI well (volumes and pressures)				
	Monitor CO ₂ levels in Above Zone producing wells				
Leckage through the confining lover	SCADA continuous monitoring at the AGI well (volumes and pressures)				
	Monitor CO_2 levels in Above Zone producing wells				
Leakage from natural or induced sciemicity	Monitor CO ₂ levels in Above Zone producing wells				
	Monitor existing TexNet station				

Table 13 – Summary of Leakage Monitoring Methods

5.1 <u>Leakage from Surface Equipment</u>

The Plant and the Mongoose were designed to operate in a manner that will reduce to the lowest factor the possibility of an escape of CO₂ and H₂S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO₂ concentration will be established during commissioning of the Plant. Ambient H₂S monitors are located at the Plant and near the Mongoose for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in *Appendix E*. The locations of H₂S detectors and Emergency Shutdowns are identified throughout the facility on the Appendix B-2 Site Plan. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Bayswater to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO₂ released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

5.2 Leakage Through Existing and Future Wells Within the MMA

Bayswater continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the Mongoose. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, an MIT will be performed every 5 years, as required by the TRRC and UIC. A failed MIT would also indicate the potential of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 ensures that new wells in the field would be constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Bayswater will also establish an in-field soil gas monitoring program to detect CO_2 leakage within the AMA. This would include sample collection and testing for CO_2 and H_2S at the AGI well site and near one of the identified artificial penetrations of the injection interval within the AMA. The samples will be analyzed by a qualified third party and used to establish a monitoring baseline. Prior to approval and implementation of

the MRV plan and through the post-injection site care period, Bayswater will have these monitoring systems in place.

There are currently only two wells that have been identified within the AMA that penetrate the Upper Confining Zone. As both wells have been plugged and abandoned in compliance with TRRC requirements, Bayswater believes a leak event is unlikely. Bayswater will perform soil gas sampling and analysis proximate to the Mongoose and one of the abandoned artificial penetrations by May 20, 2024. Thereafter, soil gas sample will be taken annually and analyzed by a third-party lab, and the results will be included in the annual report.

Bayswater is the operator of record for many oil and gas producing wells with the AMA. These wells will be used as a proxy for an above zone monitoring well. If any CO_2 , migrates up-hole, the CO_2 would likely end up in this formation. Since gas analysis is performed on a regular basis on the hydrocarbons produced from this formation, any material variance from historical data would indicate the potential of an issue needing further investigation. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance. It is not the intent of Bayswater to produce any of the CO_2 in this scenario, but to use this as an indication of an event warranting further investigation.

5.2.1.1 <u>Groundwater Quality Monitoring</u>

As explained in *Section 4.2.2,* there are no groundwater wells within the MMA. Therefore, there are no groundwater wells to monitor.

5.3 <u>Leakage Through Faults, Fractures, or Confining Seals</u>

Bayswater continuously monitors the operations of the Mongoose 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 due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Bayswater will also monitor production from their oil and gas wells that do not penetrate the injection zone for any material variance in CO₂ content in the produced gas stream. Since gas analysis is very consistent over time, any material variance in the CO₂ content would be an early indicator of a potential issue. Should the CO₂ migrate vertically, the magnitude risk of this event is very low, as the reservoir provides an ideal containment given the Upper Confining Zone has successfully held hydrocarbons in place. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** and **§98.444(d)** based on the actual leakage circumstance.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Bayswater plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose well. This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 49. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Bayswater facility. Bayswater will monitor this station for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected, Bayswater will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.



Figure 49 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

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

6.1 Visual Inspections

Regular inspections will be conducted by field personnel at the Plant and the Mongoose. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken in a prudent and safe manner to address such issues.

6.2 <u>CO₂/H₂S Detection</u>

In addition to the fixed gas monitors at the well site, Bayswater will perform an annual soil gas sampling program to detect any CO_2 leakage proximate to select artificial penetrations of the Upper Confining Zone within the AMA. The baseline determination will include atmospheric H₂S measurements at the AGI well and soil gas sampling near the AGI well and one of the abandoned artificial penetrations within the AMA.

These soil gas sample probes will be inserted below the surface. The probes have special material inserts that collect the gas samples over a 21-day period. These inserts are then removed and sent to a third-party lab to be analyzed for CO_2 , H_2S , and trace contaminants typically found in a hydrocarbon gas stream. This initial sample collection is scheduled to be completed by May 20, 2024; a sufficient time period prior to the implementation of the MRV plan and will establish baseline values for future reference.

6.3 **Operational Data**

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO₂.

6.4 <u>Continuous Monitoring</u>

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger an alarm if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions,

including pressure, flow rate, percentage of CO₂, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a de-pressuring event, the acid gas stream will be diverted to a flare stack to be safely processed and vented. The event will be reported as required for the operation of the well.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO₂ Received

Per 40 CFR **§98.443**, the mass of CO₂ received must be calculated using the specified CO₂ received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4)**." 40 CFR **§98.444(a)(4)** states that "if the CO₂ you receive is wholly injected and is not mixed with any other supply of CO₂, you may report the annual mass of CO₂ injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO₂ received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO₂ received." The CO₂ received for this injection well is wholly injected and not mixed with any other supply; the annual mass of CO₂ injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO₂ 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 CO₂ 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 (standard cubic meters per quarter)

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO₂ Produced

The Mongoose is not part of an enhanced oil recovery project; therefore, no CO₂ will be produced.

7.4 Mass of CO₂ Emitted by Surface Leakage

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 high concentrations of H₂S. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions sent to a flare stack and reported as a part of the required GHG reporting for the Plant. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of CO_2 and H_2S . The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak-point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO₂ was released because of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

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

Where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

Calculation methods using equations from Subpart W will be used to calculate CO₂ emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Bayswater believes the most appropriate method to quantify the mass of CO₂ released will be determined on a case-by-case basis. Any mass of CO₂ detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. In the unlikely event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events will be kept and stored as stated in *Section 10*.

7.5 Mass of CO₂ Sequestered

The mass of CO₂ sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Since the Mongoose has commenced operations, Bayswater will begin collecting data for reporting under this plan based on the approval of this MRV plan and any applicable stipulations therein. The calculation of sequestered volumes utilizes the following equation as this well will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

 CO_{21} = Total annual CO_2 mass injected (metric tons) in the well covered by this source category in the reporting year

CO_{2E} = Total annual CO₂ 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 is expected to occur, the calculations would be based on an unusual event that a blowdown is required and those emissions are sent to a flare stack and reported as part of the required GHG reporting for the Plant.

• Calculation methods from Subpart W will be used to calculate CO₂ 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 Mongoose is a new injection well currently reporting under the TRRC Class II regulations. Bayswater is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

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

9.1 Monitoring QA/QC

CO₂ Injected

- The flow rate of the CO₂ being injected will be measured with a volumetric flow meter, consistent with applicable industry standards. These flow rates will be compiled quarterly.
- The composition of the injectate stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with applicable industry standards.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The gas measurement equipment will be calibrated per the requirements of 40 CFR §98.444(e) and §98.3(i).

CO₂ Emissions from Leaks and Vented Emissions

- Gas monitors within the Mongoose facility will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.
- Calculation methods from Subpart W will be used to calculate CO₂ emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR §98.3(i).
- Flow meters will be operated and maintained in accordance with applicable standards as published by a consensus-based standards organization.

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

9.2 Missing Data

In accordance with 40 CFR **§98.445**, Bayswater 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 CO₂ injected is missing, the amount will be estimated using a representative quantity of CO₂ injected from the nearest previous period at a similar injection pressure.

• Fugitive CO₂ emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR **§98**.

9.3 MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Bayswater will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least 3 years and include the following:

- Quarterly records of the CO₂ injected
 - Volumetric flow at standard conditions
 - Volumetric flow at operating conditions
 - Operating temperature and pressure
 - Concentration of the CO₂ stream
- Annual records of the information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of the information used to calculate CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 11 - REFERENCES

- Adams, D. C., & Keller, G. R. (1996). Precambrian Basement Geology of the Permian Basin Region of West Texas and Eastern New Mexico: A Geophysical Perspective1. *AAPG*.
- Aird, P. (2019). *Deepwater Geology* & *Geoscience*. Retrieved from ScienceDirect: https://www.sciencedirect.com/topics/engineering/overburden-stress
- Bradley, R. G., & Kalaswad, S. (2001). *Chapter 12: Dockum Aquifer in West Texas*. Texas Water Development Board.
- Bennion, B., & Bachu, S. (2010). Drainage and Imbibition CO₂/Brine Relative Permeability Curves at Reservoir Conditions for Carbonate Formations. *SPE Annual Technical Conference and Exhibition*.
- Comer, J. B. (1991). Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas asn Southeatern New Mexico. *BEG*.
- Conselman, F. B. (1954). Preliminary Report on the Geology of the Cambrian Trend of West Central Texas. *Abilene Geologic Society*.
- Domede, P. S. (2017). *Mechanical behaviour of granite. A compilation, analysis and correlation of data from around the world*. Retrieved from https://hal.insa-toulouse.fr/hal-01743870/document
- Dutton, A. R., & Simpkins, W. W. (1986). *Hydrogeochemistry and Water Resources of the Triassic Lower Dockum Group in the Texas Panhandle and Eastern New Mexico*. Austin Tx: Bureau of Economic Geology.
- Fanchi, J. R. (2010). Integrated Reservoir Asset Management.
- Galley, J. (1958). Oil and Geology in the Permian Basin of Texas and New Mexico. *Basin or Areal Analysis or Evaluation*.
- Gunn, R. D. (1982). Desmoinesian Depositonal Systems in the Knox Baylor Trough. *North Texas Geological Society*.
- Hendricks, L. (1964). STRATIGRAPHIC SUMMARY OF THE ELLENBURGER GROUP OF NORTH TEXAS. *Tulsa Geological Society Digest, Volume 32*.
- Hornhach, M. J. (2016). Ellenburger wastwater injection and seismicity in North Texas. *Physics of the Earth and Planetary Interiors*.
- Jesse G. White, P. P. (2014). Reconstruction of Paleoenvironments through Integrative Sedimentology and Ichnology of the Pennsylvanian Strawn Formation. *AAPG Southwest Section Annual Convention, Midland, Texas.*
- Keelan, K., & Pugh, V. (1975). Trapped-Gas Saturations in Carbonate Formations. SPE J. 15: 149–160.
- Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas. *Bureau of Economic Geology*.
- Lone Wolf Groundwater Conservation District. (2019). *Management Plan 2019-2024.* Colorado City, Tx.
- Loucks, R. (2003). REVIEW OF THE LOWER ORDOVICIAN ELLENBURGER GROUP OF THE PERMIAN BASIN, WEST TEXAS. *Bureau of Economic Geology*.
- Loucks, R. (2006). *Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas.* Austin, Tx: Bureau of Economic Geology.
- Mason, C. C. (1961). GROUND-WATER GEOLOGY OF THE HICKORYSANDSTONE MEMBER OF THE RILEY FORMATION. McCULLOCH COUNTY. TEXAS. *TEXAS BOARD OF WATER ENGINEERS*.

- Merrill, M., Slucher, E., Roberts -Ashby, T., Warwick, P., Blondes, M., Freeman, P., . . . Lohr, C. (2015). Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources–Permian and Palo Duro Basins and Bend Arch-Fort Worth Basin. *USGS*.
- Popova, O. (2020). Permian Basin Part 1 Wolfcamp, Bone Spring, Delaware shale plays of the Delaware Basin Geology Review. *USDOE*.
- Powers, R. B. (1989). Petroleum Exploration Plays and Resource Estimates, 1989, On shore United States -- Region 5, West Texas and Eastern New Mexico. USGS.
- Sanchez, T., Loughry, D., & Coringrato, V. (2019). Evaluating the Ellenburger Reservoir for Salt Water Disposal in the Midland Basin: An Assessment of Porosity Distribution Beyond the Scale of Karsts. Unconventional Resources Technology Conference (pp. 1-17). Denver: URTeC. doi:10.15530/urtec-2019-600
- Scanlon, B. R., Reedy, R. C., Male, F., & Walsh, M. (n.d.). *Water Issues Related to Transitioning from Conventional to Unconventional Oil Production in the Permian Basin.* Austin: Bureau of Economic Geology.
- Shamburger Jr., V. M. (1967). *Report 50: Ground-Water Resources of Mitchell and Western Nolan Counties, Texas.* Austin, Tx: Texas Water Development Board.
- Snee, J.-E. L., & Zoback, M. D. (2018). State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity. *The Leading Edge*, 810-819.
- Waite, L. (2021, October 25). Geology of the Permian Basin. UT Dallas Geoscience Permian Basin Research Lab.
- Zerwer, N. Y. (1997). Stress Regimes in the Gulf Coast, Offshore Louisiana:. AAPG Bulletin, 293-307.

APPENDICES

APPENDICES

<u>APPENDIX A – MONGOOSE AGI No. 1 TRRC FORMS</u>

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

APPENDIX A-5: API 42-335-33555 VAN TUYLE PLUGGING RECORDS

APPENDIX A-6: API 42-227-03634 STEWART PLUGGING RECORDS

CHRISTI CRADDICK, CHAIRMAN WAYNE CHRISTIAN, COMMISSIONER JIM WRIGHT, COMMISSIONER



A-1

DANNY SORRELLS DEPUTY EXECUTIVE DIRECTOR DIRECTOR, OIL AND GAS DIVISION PAUL DUBOIS, P.E. 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. 17174

BAYSWATER OPERATING COMPANY LLC 730 17TH STREET SUITE 500 DENVER CO 80202

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 22, 2022, for the permitted interval(s) of the WOODFORD and ELLENBURGER formation(s) and subject to the following terms and special conditions:

MONGOOSE AGI (000000) LEASE SPRABERRY (TREND AREA) FIELD MITCHELL COUNTY DISTRICT 08

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	33536013	000125803	Carbon Dioxide (CO2); Hydrogen Sulfide (H2S)	8300	9000	6900	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
		1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.
		2. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.
1	33536013	3. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.
		4. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.
		5. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.

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.
- Prior to beginning injection and subsequently after any work over, an annulus pressure test must 4. 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 March 10, 2023.

Hilf

For Sean Avitt, Manager Injection-Storage Permits Unit

			A-2						
	GROUNDWATER PROTEC		Form GW-2						
	Groundwater Advisory Unit								
Date Issued:	04 March 2022	GAU Number:	336979						
Attention:	BAYSWATER OPERATING	API Number:	33536013						
	730 17TH STREET SUITE 500	County:	MITCHELL Mongoose AGI						
	DENVER, CO 80202	Lease Number:	Mongoose Aon						
Operator No.:	058827	Well Number:	1						
		Total Vertical	9250						
		Latitude:	32.422884						
		Longitude:	-101.169661						
		Datum:	NAD27						
Purpose:	Injection into Non-producing Zone (W-1	4) ock-29 [.] Townshin-1N [.] Sec	ntion_4						
To protect usable-qu Texas recommends	uality groundwater at this location, the Gro	bundwater Advisory Unit c	of the Railroad Commission of						
The base of usable- well.	quality water-bearing strata is estimated t	o occur at a depth of 350	feet at the site of the referenced						
The BASE OF UND feet at the site of the	ERGROUND SOURCES OF DRINKING	WATER (USDW) is estima	ated to occur at a depth of 475						
This recommendation is applicable to all wells within a radius of 200 feet of this location.									
Note: Unless stated Unless stated other	otherwise, this recommendation is intend wise, this recommendation is for normal d	ed to apply to all wells dri rilling, production, and plu	lled within 200 feet of the subject well. Igging operations only.						
This determination is information has chai If you have question	s based on information provided when the nged, you must contact the Groundwater is, please contact us at 512-463-2741 or g	e application was submitte Advisory Unit, and submit gau@rrc.texas.gov.	d on 03/02/2022. If the location a new application if necessary.						
Groundwater Advisc	ory Unit, Oil and Gas Division								
Form GW-2 P.C Rev. 02/2014). Box 12967 Austin, Texas 78771-2967	7 512-463-2741 lr	nternet address: www.rrc.texas.						

	RAILROAD COMMISSION OF TEX OIL & GAS DIVISION	AS			
PERMIT TO DRILL, DEEPEN, PLUG	ACK, OR RE-ENTER ON A REGULAR OR A	DMINISTRA	TIVE EXCER	PTION LOCATI	ON
PERMIT NUMBER 876754	DATE PERMIT ISSUED OR AMENDED Feb 10, 2022	DISTRICT * 08			
APINUMBER 42-335-36013	FORM W-1 RECEIVED Feb 03 2022	COUNTY	MITCH	HELL	
TYPE OF OPERATION	WELLBORE PROFILE(S)	ACRES			
NEW DRILL	Vertical		4	0	
OPERATOR BAYSWATER OPERATING 730 17TH STREET SUITE DENVER, CO 80202-0000	058827 5 COMPANY LLC 500	This permi revoked if O Dis	NOTI t and any allow payment for f commission is strict Office T (432) 68-	ICE wable assigned ma fee(s) submitted to not honorad. Felephone No: 4-5581	ay b o the
LEASE NAME MONG	OOSE AGI	WELL NU	MBER	1	
LOCATION 10.4 miles NW direct	ion from WESTBROOK	TOTAL DE	SPTH	10000	
SECTION 4 SURVEY T&P RR CO/MORRIS DISTANCE TO SURVEY LINES	BLOCK 29 T1N ABSTRA	DISTANCE	15 e to neare	ST LEASE LINI	E
551 IL EAST	2164 ft. SOUTH	II.			
400 ft. EAST	650 ft. SOUTH	DISTILICE	See FIEI	LD(s) Below	
FIELD NAME LEASE NAME		ACRES NEAREST LE	DEPTH SASE	WELL # NEAREST WE	D
SPRABERRY (TREND AREA)		40.00	10,000	1	-
MONGOOSE AGI				0	
RESTRICTIONS: Do not use this by the Environm	well for injection/disposal/hydrocar ental Services section of the Railroa	bon storage 1 Commissio	e purposes on, Austin,	vithout appro Texas office	ova e.
THE F This well shall be completed and produc well is to be used for brine mining, under salt formations, a permit for that specific drilling, of the well in accordance with St This well must comply to the new SWR is corrosive formation fluids. See approve drilling the well in.	OLLOWING RESTRICTIONS APPLY TO ed in compliance with applicable special field rground storage of liquid hydrocarbons in salt purpose must be obtained from Environment atewide Rules B1, 95, and 97. 3.13 requirements concerning the isolation of d permit for those formations that have been i	ALL FIELD or statewide formations, al Services p any potentia dentified for	DS a spacing an or undergrou prior to const al flow zones the county in	d density rules. und storage of g truction, includir and zones with n which you are	lft gas ng n
Data Validation Time Stamp:	Feb 10, 2022 9:58 AM('As Approved' Version)	Page 3 of 4		



RAILROAD COMMISSION OF TEXAS

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

Tracking No.:

Submitted 09/11/2023 298516

Form W-2

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

UPERALL	
	Operator 059927
Operator 730 17TH STREET SUITE 500 DENVER CO	
WELL	INFORMATION
API 42-335-36013	County: MITCHELL
Well No.: 1	RRC District 08
Lease MONGOOSE AGI	Field SPRABERRY (TREND AREA)
RRC Lease	Field No.: 85280300
Location Section: 4, Block: 29 T1N, Survey: T&P RR CO/MORRIS	SON, W, Abstract: 1545
Latitude 32.423000	Longitud -101.170059
line tion from WEATDDOOK	
which is the nearest town in the	
FILING	INFORMATION
Purpose of Initial Potential	
Type of New Well	
Well Type: Active UIC	Completion or Recompletion 04/28/2023
Type of Permit	Date Permit No.
Permit to Drill, Plug Back, or	02/10/2022 876754
Rule 37 Exception	
Fluid Injection	
O&G Waste Disposal	17174
Other:	
COMPLET	
Spud 10/12/2022	Date of first production after rig 04/28/2023
Date plug back, deepening,	Date plug back, deepening, recompletion,
drilling operation 10/12/2022	drilling operation $04/28/2023$
Number of producing wells on this lease	Distance to nearest well in lease &
Number of producing wells on this lease this field (reservoir) including this 1	Distance to nearest well in lease & reservoir
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00	Distance to nearest well in lease & reservoir Elevation 2252 GL
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-Yes	Distance to nearest well in lease & reservoir Elevation 2252 Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNo	Distance to nearest well in lease & reservoir Elevation 2252 Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W- YesYesRecompletion orNoType(s) of electric or other log(s) Electric Log Other Description:Combo of Indu	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No iction/Neutron/Density/Sonic
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400 400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Inction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and 0 Feet from the South Line of the
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400650	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Inction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W- YesYesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this 1 Total number of acres in 40.00 Total depth TVD 9289 Plug back depth TVD 9036 Was directional survey made other inclination (Form W- Yes Recompletion or No Type(s) of electric or other log(s) Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is 400 FORMER FIELD (WITH RESE	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this 1 Total number of acres in 40.00 Total depth TVD 9289 Plug back depth TVD 9036 Was directional survey made other inclination (Form W- Yes Recompletion or No Type(s) of electric or other log(s) Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is 400 FORMER FIELD (WITH RESE Field & Reservoir	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and 0 Feet from the South Line of the MONGOOSE AGI Lease. RVOIR) & GAS ID OR OIL LEASE NO. Gas ID or Oil Lease Well No. Prior Service Type

W2:	N/A			
	FOR NEW DRILL OR RE-ENTRY	(, SURFACE CASING	G DEPTH DET	ERMINED BY:
GAU Ground	dwater Protection Determination	Depth	350.0	Date 03/04/2022
SWR 13 Exc	eption	Depth		

INITIAL POTE	NTIAL TEST DATA FOR	NEW COMPLETION OR RECOMPLETION
Date of		Production
Number of hours 24		Choke
Was swab used during this	No	Oil produced prior to
	PRODUCTION DU	RING TEST PERIOD:
Oil		Gas
Gas - Oil 0		Flowing Tubing
Water		
	CALCULATED	24-HOUR RATE
Oil		Gas
Oil Gravity - API - 60.:		Casing
Water		

	CASING RECORD										
	Type of	Casing Size	Hole Size	Setting Depth	<u>Multi -</u> Stage Tool	<u>Multi -</u> Stage Shoe	Cement Class	Cement Amoun	Slurry Volume	Top of Cemen	t <u>TOC</u> t Determined
<u>Ro</u>	Casing	<u>(in.)</u>							<u>(cu.</u>	<u>(ft.)</u>	Ву
1	Surface	13 3/8	17 1/2	569			С	637	847.0	0	Circulated to Surface
2	Intermediate	9 5/8	12 1/4	5328	3001		С	725	1752.0	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5328			С	610	1175.0	3001	Calculation
4 C	Conventional Production	n 7	8 3/4	8343			C & RESIN	594	1513.0	1800	Calculation

_					LINER RECORD			
<u>Ro</u>	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu. (ft.)	TOC Determined
N/A								

TUBING RECORD				
Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type	
1	3 1/2	8260	8230 / INCONEL	
			925	

PRODUCING/INJECTION/DISPOSAL INTERVAL				
Ro	Open hole?	From (ft.)	<u>To (ft.)</u>	
1	Yes	L 8343	9036.0	

ACID, FRACTURE, O	CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, I	RETAINER, ETC.				
Was hydraulic fracturing treatment	No					
Is well equipped with a downhole sleeve? No	If yes, actuation pressure					
Production casing test pressure (PS	GIG) Actual maximum pressure	Actual maximum pressure (PSIG) during				
hydraulic fracturing	fracturin	fracturin				
Has the hydraulic fracturing fluid disclosure been No						
Ro Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)				

OPEN HOLE CEMENT PLUG WITH 58 SACKS CLASS H

1

Other

9036 9289

		FORMATION REV	CORD		
Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
SANTA ROSA - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT
YATES - OVERPRESSURED, POSSIBLE FLOWS	Yes	1001.0		Yes	
SEVEN RIVERS	Yes	1137.0		Yes	
SAN ANDRES - HIGH FLOWS, H2 CORROSIVE	S, Yes	2008.0		Yes	
GLORIETA	Yes	2875.0		Yes	
CLEARFORK	Yes	3089.0		Yes	
TUBB	No			No	NOT PRESENT AT LOCATION
WICHITA	No			No	NOT PRESENT AT LOCATION
COLEMAN JUNCTION - POSSIBL LOST CIRCULATION	E No			No	NOT PRESENT AT LOCATION
WOLFCAMP	Yes	5369.0		Yes	
STRAWN	Yes	7918.0		Yes	
ODOM	No			No	NOT PRESENT AT LOCATION.
MISSISSIPPIAN	Yes	8153.0		Yes	
WOODFORD	Yes	8322.0		Yes	
ELLENBURGER	Yes	8374.0		Yes	
CAMBRIAN	Yes	9279.0		Yes	
Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm No					
s the completion being downhole commingled No					

REMARKS DIRECTIONAL SURVEY RUN FOR INFORMATION PURPOSES ONLY.

PUBLIC COMMENTS:

RRC REMARKS

CASING RECORD :

SURFACE CASING IS SET AT 543.5' AS MEASURED FROM GROUND LEVEL, WHICH IS WITHIN 200' OF BUQW.

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

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

POTENTIAL TEST DATA:

OPERATOR'S CERTIFICATION					
Printed	James Clark	Title:	Consulting Petroleum Engineer		
Telephone	(512) 415-4191	Date	09/11/2023		
Ð 7 Ð ŋ 7 η ŋ Ŋ 20. Do you have the right to develop the minerals under nny right of way that crosses, or is contiguous to, this innet? If not, and if the well requires a Rule 37 or 38 exception. 25. is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes 23. Is this a pooled unit? 22. Perpendicular surface location from two nearest designated lines:
 1 proc. Mult. 1000. FNL & 2500. FEL 11. Distance from proposed location to nearest leave or unit line 2 Address (including city and zip code) Purpose of filing (murk appropriate bodes): · Sunny/Section 1000' FNL & 2500' FEL of Section 15-Operator's Name (exactly as shown on Form P.S. Organization Front) see Instructions for Rule 37. ĩ Krimerka Nulicamp, (Wildcat) File a copy of W-1 and plat in JORC Di Ellenburger (Wildcat) 1800 £ Midland, Texas 3200 West Cuthbert, Bright se zones. One zone per line, ELD NAME: [Exactly as sheem; on RRC privation adult a all estublished and whiles! somes of anticipated repiction. Attach additional Form W-1's as needed to last any firentealo ふしい 121 Uttach Form P-12 and certified plat. 21 × たりや Company 30 D III 6 Directional Well 5 and \$180.00 fee 79701 Rai Bau **Nation** Suite 2-C trict Office. Deepen (below casing) Sidetrack Application for Permit to Drill, Deepen, Plug Back, or Re-Enter ã 5200-8300' **Gebru** 7800 1000 × 10. Location 3. IURC Operator No. 6. Lease Name (32 spaces maximum) Van Tuyle 093125 'This well is to be located ______ Section . 8 8 Deepen (within casing) Amended Permit (enter permit no. at right & explain fully in Remarks) which is the nearest town in the county of the well site RAILROAD COMMISSION OF TEXAS Oll and Gas Division N 10 (n.) 467-1200 2 467 1200 Specing 467-1200 No 2 Lini 2 15 203091 0CT 1890 If subject to Rule 36, ts Form H 9 Aled? Yes Ę ł I certify that information stated in this application is ince and complete, to the best of my knowledge ĕ 12. Number of configuous acres in lease, pooled unit, or unitized iract **4**0 Density If a directional will show also projected bottom-hole location: pallern Hock 24 Jo liem 17 less that Jiem 18 (substandersberrehe for any field applied for?? 4. FIRC District No. G Lengel Mail Signature Date: Խ 20, 1-1-1 mary Artiling unity for this well OUTLINE 15 Plug Back ALL DE LO 5 4 鍧 _miles in a _north ŝ 9/26/90 1 Smuth. 5. County of Well Site day. Mitchell TEP RR Cor, TWP T-N NO NO a Re-Enter 7. RRC Lease/ID No. direction from <u>Latan</u> ٧ Tel: Area Code S. Dawner from NA TRA-NA Inchesed your talavoli. (N.) Cont to nature Read Instructions on Back 915-697-2214 Tracy D. Tenison, Engineer Name and title of operator's representative Enter here, lf assigned: letted wes Z, ۷ "Ennite h 8. Well No. 640 80 V If not filed, explain in Remarks. Number Type and or other Penny 42-33 0 9 0 Rule 37 Case No Abstract No. A. 584 21. Act, of applied for per-mitted, or complete and becattoms that during the this one on bear in the this one on bear in the this reservoir. (1) 5 Form W-1 (OUTLINE ON PLAT.) 9. Total Depth 1 85001 2355 ŝ 5 5 3

A-5



<u>*</u>		<u>इ</u>	26 17 19	25.11	22.11		- 12 M	5 17	s	Ę	() 중용) 11. Pl				λ εi	в 1.0p		Իսդ	¥ ⊒ .≇
		inai ks	you have the right to develop the minerals under y y right of way that crosses, or is configuous to, this tract? y nut, and if the well requires a Rule 37 or 38 exception, r Inviruentions for Rule 37.	his wellwre subject to Statewide Rule 36 (hydrogen aufide are	 Interpretendent of the second s	Sunn Section 1000' FNL & 2500' PEL of Su	pendicular surface location from two neatret designated lines: I.cov/Unit 1000' FNL & 2500' FEL	llenburger (Wildcat)	trawn (Wildcat)	olfcamp (Wildcat)	rpletion. Attach additional Form W-1's as needed to list ae zones. One zone per line.	ELD NAME (Exactly as shown on RBC provation achedule), all established and wildcal zones of anticipated	istance from proposed location to nearest lease or unit line			Hdlynd, Texas 79701	dress linktuding city and zip code)	iright & Company	Directional Well Sidetrack	ne of filing (mark appropriate hours): X Drill Dreprin (Lelow casing)	 Transver of Trans. Address to: Distant Osseman, Driffing Permits P. O. Drever 12007, Capital Station Autin, Trans 79711 Arupy of W-1 and plat to USC District Office.
			×	117 Yes 🔲	No	tet ion-t		8300'	7800'	5200'	Completion depth		1000	wh	• 1	10. Loca	Van	001 093			Rication fo
!				No X	X			467-1200	467-1200	467-1200	Specing pattern (fl.)	15,	\$	tch is the nearest	is well is to be loc	tion 15	Tuyle	125	mended Permit (c	pen (within casin	NILROAD CO Oll and Permit to Dr
	Date	Sign	I certify the	If subject to	24. IN Her Yes		La	40	40	40	Denalty pattern (acres)	16	12. Number	town in the c	aled5				nter permit n	Ē	indission I Gas Divisio III, Deepen
	1110	ature 9/26/	at Information st	Rule 36. Is Form	n 17 Jesa than It	urvey/Section	nase/Unit	40	40	40	OUTLINE ON PLAT.	17. Number of acres in defiling unit	of contiguous at	ounty of the wel	miles in a	29 7-1-1V		B STIRLING	o. at right & esp	Flug Back	OF TEXAS
• JURC	day y r .	06	ated in this applicati		em 16 (substandard ach Form W-1A)		שט ףנטוברוכם ססווטוח	NO	NO	NO	Inis rectivour If eo, caplein In Remarks,	18. Is the acrosp assigned to an- other well on this lease P in	tres in lesse, pooled u	Isite	north	vy T&P RR Co		Mitchell	lain fully in Remarks	ReEnter	or Re-Enter
Use Only •	Tel: Area Code	Name and till 915-697-3	ion is true and com. Tracy D.	No 0	actrate for any field		Sufficient and	NA	NA	NA	this inser @ tractvoir. (fl.)	19, Distance from proposed loca- lion to nearest applied for, permitted, or	init, or unitized trai		direction from	· · · · · · · · · · · · · · · · · · ·				Eater here, if assigned:	Read Instructi
	Number	e of o pera tor's 22 1 4	plete, to the be Tenison	If not filed.	1 applied forl?			ô	0	0	type well Spe well	OIL gan	π <u>640</u>		atan	·	1		V	► 42- Remit N	ons on Back
 		representative	st of my knowl	explain in Ren	N.			1		-	OIL	21. No. of appl mitted, or ex locations (ii) this one) on this reservoi	IOUTLINE O				8500		2	P	Form V
1				narks							GAS	ited for, per- ompleted ucluding lease in f.	IN PLAT.)			130		7			



JERRY A. DUNN

à.

TEXAS P.L.S. NO. 4735 TEXAS P.L.S. NO. 4839

MIDLA	ND	JOH	IN	WEST	&	ASSO	CIAI	ES	_	TOAS
Scole:	1"=	1000'			Т	Drawn b	y:	N	T	
Dale:		10-2-	90		T	Sheet	1	of	1	aheete
Revision	1 Dol	le:			Т	W.O. No.	: 6	900	63	

13(1) Exception Dated 440		RS DIV	ISION	Mo ())		ii.		W. 10/74
				NO.42-3	35-33555		R R R	et
WELL IS LOCATED WITHIN T	IRTY D	YS AFT	ER PLU	GGING	GH	4.	RRC Leest	or M.
Wildont	V.	an Tuyl	e /	-0		5.	Wall Number	1
Bright & Company	ős. Origi	and Form W-	-1 Filed in	Name of:	<u></u>	10.	County Mitchel	11
ADDRESS 2911 Turtle Creek Blvd #70 Dallas, TX 75219)() ^{6b.} Any 1	Subsequent	W-l's File	d in Name of	-	11.	Date Drill Permit Jan 10/18/9	01
Location of Well, Relative to Nearest Lease Boundaries	1000	i Zma N	orth 1	ine and 25	OD Foot P	12,	Permit Mus	and the
SECTION BLOCK AND SURVEY	east Li	ne of the	VIII I			- 11	379724	2
ec 15. Blk 29. TIN. T&P/RR Co	Coun	^{ty} 8.	7 milos		Vestbro		Co.72670	0./
i. Type Well (Oll, Gas, Dry) (Oll, Gas, Dry) 8360 [†]	at All Field :	Names and		T Ges ID No	NESCOLOC OLI-OI WE Gen-GI	LL, 14,	Dute Drilli Completed	AK DO
I Ges, Amt. of Cond. on Hend at time of Plugging					-	15,	Dete Well 12-17-	Planed 90
CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5 1	LUG #6	PLUG #7	PLUG #8
7. Cementing Date	12-17	12-17	12-17	12-17	12-27	\sum		- 2 637.0
D. Size of Hole or Pipe in which Plug Placed (inches)	7-7/8	7-7/8	7-7/8	8-5/8	8-5/8	<u> </u>		
. Depth to Bottom of Tubing or Drill Pipe (ft.)	8250	2700	2350	400	15 .	WY I	1 to	
2. Sacks of Coment Used (each plug)	50	50	180	50	10 \		1./ - y/	
I. Slurry Volume Fulpped (cli. If.)	8076	2526	1792	325	Surf			
Measured Top of Plus (if tassed) (ft.)	0070	2320	1790	525	Sull .	JAK	1.4.100	
5. Sturry Wt. #/Gel.	15.6	15.6	15.6	15.6	15.6	VIT		-
7. Type Cement	Prem.	Prem.	Prem.	Prem.	Prem.	take.	15 75%	6
8. CASING AND TUBING RECORD AFTER PLUGGING		29, W	an Ceelor)	-Drillable M Left in This	aterial (Othe: Well		Ye.	K No
ZE WT. #/FT. PUT IN WELL(A.) LEFT IN WELL(A.) I	HOLE SIZE	(m_) 29s. If	enswer to a d briefly de	bove is "Ye scribe non-	is" state dep drillable mat	th vio top Hindu - TU	of "Junie"	left in hole Side of
3/3 48 361 361	17-1/2	- P	orm if more	space is nee	eded.)	10 101	12.8	
<u>5/6 32 22/4 22/4 22/4 </u>					1.	1. 4	1.55	(3.13)
		-	1.18.41	-5. 9	12 400	1. 200		an a
LIST ALL OPEN HOLE AND/OR PERFORATED INTE	RYALS	-	5		1	C/1.		
PROM 2274 TO 9360		FR	он	-	T	520	3/	
ROM LAND I HE STATISTIC		PR	OM 1	nsiurs to	1. b. T	0	15/	
PROM TO		FR	OM C	Leel [1]	NT.	661.00		
FROM ADD 1 7 1991 TO		TR	оні	RH.O.de	T	00		STATES
PROM		FR	OM The factor	1.1.1	ा	0		
have knowledge that the cementing operations, as reflected	by the inform	nation found	s on this for	m, were per	formed as Ind	icated by	each infor	nauon.
resignates items to be completed by Cementing Company. It	eme not so d	lesignated a	hali be com	pleted by O	perator.			
				iii tean Cann	ulaan in	4- 0-		
- MC - CACUM X/			III IOUT	LUN SEL	vices, B	TR Sb	ring, T	A
nature of Comenter or Authorized Representative		Ma	me of Cene	nting Compo	in y			
I declare under penalties prescribed in Sec. 91.143	, Texas Natu	mi Resourc	es Code, ti	hat I am auth	orland to me	ke this re	port, that t	hla
report was prepared by me or under my supervision a	und direction,	, and that d	ate and fect	is stated the	rein are true,	carrect,	and comple	te, Status
to ris nation with menalanday								
Amonda I Hand		Annat		1/1 + /				
REPRESENTATIVE OF COMPANY		ARCHT TITLE		RECEDAT	<u>р</u>	hont		NUMBER
			F	R.C OF TET	45	3		
Dr. A That Teletan	.)	÷.						
GNATURE: REPRESENTATIVE OF RAILROAD COMMIS	SION	•	MA	IR 0 5 19	991 <u></u>	8, ÿ	~	
					and it.		コクノ	

истер алоб язта**н .** С

.

34. Tetal Depth 8360	Other Fresh Water TOP	Zones by T.I BOTTO	D.W.R. DM	35. Have all Abandoned Walls on this Leas according to R.R.C. Rules?	se been Plugged	X Y•1
Depth of Deepeat Fresh Water				36. If NO, Zaplain		No
37. Neme and Address Halliburton, F	of Cementing or Server. . O. Box 380;	, Snyder	who min, Texa	ad and pumped coment plugs in this welt as 79549	Date RR notified	C District Office
Ben Van Tuyl	ers of Surface Owner e, 432 Hillds	ale Dr.	and Oper Ann Ai	retors of Offert Producing Leases		
39. Was Notice Given	Before Pipeeine to Ec	sch of the Ab				
Yes				· · · · · · · · · · · · · · · · · · ·		
40. For Dry Holes, this released to a Com	Form must be accom	LY spanled by ei	ther a Dr	ilier's, Electric, Radioactivity or Acoustical	i/Sonic Log or at	ich Log must be
- 	g Attached	Lag releas	sed to _		Date	
122			. ×		Date	
The second second				20		
Type Loga:	lier's	X Elec	tric	Redicectivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (lier's Special Cleanance) Fi	X Elec	tric	Radioactivity	Aco	untical/Sonic
Type Logs: Dri 41. Date FORM P-8 (1 42. Amount of Oli prod	lier's ipecial Cleanance) FL	ied?	tric	Radioactivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (: 42. Amount of Oil prod * Flie FORM P-1 (C	ller's Special Clearance) Fi uced prior to Plugging II Production Report)	Ied?	iric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oli prod • Flie FORM P-1 (C <u>BRC USE ONLY</u>	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	Ied?	itric	Badioactivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oli prod Pile FORM P-1 (C RRC USE ONLY Nearest Field	lier's Special Clearance) Fi uced prior to Plugging Still Production Report)	Ied?	itric	Redicectivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>BRC USE ONLY</u> Mearent Field	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Jed?	itric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Mearest Field BMARKS	lier's Special Clearance) Fi aced prior to Plugging 011 Production Report)	Ied?	itric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oil prod • File FORM P-1 (C <u>RRC USE ONLY</u> Hearest Field BMARKS	ller's Special Clearance) Fi uced prior to Plugging III Production Report)	Ied?	itric	Bediosctivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Mearest Field EMARKS	lier's Special Clearance) F1 uced prior to Plugging 011 Production Report)	Elec Ied?	iric	Bediosctivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fl uced prior to Plugging III Production Report)	Ied?	itric	Redicectivity	Aco	ustics1/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R & C USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	Elec	itric	Redioactivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>BRC USE ONLY</u> Hearest Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Ied?	itric			ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C RC USE ONLY Nearest Field BMARKS	lier's special Clearance) Fi uced prior to Plugging li Production Report	E	itric	Redioactivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field EMARKS	lier's Special Clearance) FL sced prior to Plugging II Production Report)	Elec	itric	Redioactivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>RRC USE ONLY</u> Nearest Field EMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Ied?	itric	Redioactivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi seed prior to Plugging III Production Report)	E	itric	Redicectivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1) 42. Amount of Oll prod • Flie FORM P-1 (C <u>R & C USE ONLY</u> Nearest Field BMARKS	lier's Special Clearance) Fl uced prior to Plugging II Production Report	E Elec	itric	Redicectivity		uetical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oil prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report	Elec	itric	Redioactivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>BRC USE ONLY</u> Hearent Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	E	itric	Redioactivity bbls* produced		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	E Elec	itric	Redioactivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field EMARKS	lier's Special Clearance) Fl uced prior to Plugging II Production Report	E Elec	itric	Redioactivity		ustical/Sonic

en e const la e const la seconda e m la seconda e m

1

.....

419

PLACE FOLS | R1

< 1

Compared and the second large to the second la	RAILROAD COME Oll and C	2 1 3	(AS	o Wa	Form Cemienti Prv. 48	a W-10 Ing Rep 4/1/03 8-015
1. Operator's Name (As shown on Form P.5, Organiza	tion Report) 2. R	RC Operator No.	3. RRC District No.	4. County	of Well Site	1.04744
Bright & Co.		093125	8	Mitch	el1 👘	10 30
5. Field Name (Wildcat or exactly as shown on RRC re	rords)		5. API No.	7.	Drilling Permit	Na.
Wildcat			42- 335-33	555	379724	1 - 1
8. Lease Name	9.1	Rule 37 Case No.	10. Oil Lease/Gas	ID No. 11,	Well No.	10-14
Van Tuyle	1				1	1220

CASE	IG CEMENTING DATA:	SURFACE CASING	INTER MEDIATE	PRODU	CTION	MULTI- CEMENTIN	STAGE
			CASING	Single String	Multiple Parallel Strings	Tool	- 19 Mar 19
12.0	Brugen bit for 10550						
13. •	Drilled hole size	17-1/2	11		1	an C _{all} _{an} X	
36	Est, % wash or hole enlargement						
14. 5	ter of casing (in. O.D.)	13-3/8	8-5/8	alike datus	5 - 2°	a lign ^{an}	
15. T	op of liner (fr.)	a			2		
16. S	etting depth (ft.)	361	2274	3			
17 N	umber of centralizers used	3	3				
16 H	its, waiting on cement before drill out	12	12				
Â	19. API cement used: No. of socks	390	300-			170 - 1641 - 1816	1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.
4 81	Class	Premium P	111	27 AP reul	aff , M.C.S.	WHE Standt	-13 Truch-
a <	Additives	27 Calciu	m Chloride	i dina			101.65
Ŷ	No. of sacks 🕨 🕨						
d Sh	Class 🕨	inener Ken	themes defined	intol at an:	inurtant		
18	Additives	ين ورجاد حققوني فرواني	and to be seen for	A marte data and inco	A PARTY A MARTINE	D. OF TEXAS	
È	No. of sacita	of the advances prope	ter des medications	cristellis wilds	and the second	. if fabgeties in	South Barran States
d Slu	Class	ar island et al.	all and shows	aradina or yunar Aradina ortuguna	a in later owner, ne ge a fractis pinter - Na		n in 124 - Dùn 127 Institu Print - Barned Dunret
ñ	Additives 🕨	 Track of State Str Track of Strategy and 	na da da mijaka nji Baldana tati kao at		Leff Biro't Husp area a an	CG	a da serrigis con #
ti	20., Slurry pumped: Volume (cu. ft.) 🌗		591	intres investion	IA CONTRACTOR		State Water I a
	Height (ft.) 🕨 🕨	Surface	2268	1 B 1 327 2072 (s temp tigdes ansätt va en en en en en	P. Weitzers and and	W 15, in oks
¥	an an an the Volume (cu. ft.) 🍉	- Section of Suppl	- 194 Berlin (1944)	s rialits - a thug buy	i dina aratisa hire	an a	 Subarrolluni)
64 I	ileight (fs.)	A SAME SALANA A A	 anaparities contractor designed in Lindé (c) 	, Hondrach, 189 1997 - Charles Andreas	េ មេរ៉ានីវារូក ភូមិ កើនដែរប្រាំការ ភ	unter ünterstandt i Unter unstandere	: Bast received to an
z	Volume (cu. ft.) 🕨	1 N X.		a fé li selt an et ES.	n albig zint fog drav dat. A	e fitter halter («»	and al say within
•		15 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1		tiere is on these e	institues land	enet belever statte sin	i incaratora fasis religit
1	Volume (cu, ft.) D.	514.1	591	- Hannahan and an early a	o Ladistra Miran	1	
B	an and all each off in the Height (if Lifes in the second se	Surface	110000 000 01 4000	nthyanthijh Lalk	in the provide states of the second states of the s	ert valie de trat	
21. Y	Ves cement circulated to ground surface or bottom of cellar) outside casing?	Toras Yes	n inte Ro	1. Startinger Start	2. Stallier feit		Contraction of the second
22. F	iemarika	41. 23.11		RECEIVED R.R.C. OF TEX	(ΛS	The second second	and the part of the
		1. U.S.	na Angelan ing	MAR 05 1	991		n - Standage Standage Standage

and the second second second

:

OIL & GAS DIV MIDLAND TEXAS

OVER

	FLUG # 1	PLUG * 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	- PLUD *
and the second second	. E	ZET RO V	nesciento:	GERRAL W	76).		00000000	e
State of hale or pipe plugged (in.)								
Dapth to bottom of tubing or drill pipe (ft.)								
	and and	0			Net and the second	Harris and a		$\tau(A_{I,2},\gamma_{A_{i}})$
	RALLAU IN	1. it we	the second		•••••	18-18-19-18-19-19-19-19-19-19-19-19-19-19-19-19-19-		
	1.	42		ي. ديورت م وريسيده				16:27
Memoured top of plug, if tagged (ft.)								
	- 30-590 GF24	1993 () () 19	11.2 21/12	41 N - 10 O	stiller Geru		100.000	ज्या व
STATES IN STATES	i Didine i	Static Static		14.4-22			242	
A CONTRACTOR OF THE OWNER		N. Honore Comp.			and the state			They are
1/10 · · · · · · · · · · · · · · · · · · ·							by the or weak	
					يب			1 17 5
	Section of				1.	11.00	117 - er itma	1 - 177 - 5
				9	Liles,	11.90		a let segle
			A 2.5	<u>, </u>		1 De	۱۱۱۰۰ ^{(۵} ۰۰ ۲۱۱) ۱۹۰۰ (۱۹۰۰)	1 17 S
	Sardor-				1123 713-31716	1.00	1-26-90	ente se la Gastinata Secolaria
OPERATOR'S CERTIFICATE I declary	Eurofer -	prescribed in	A (-25) Sec. 91,143. Tr	San Najural Re	573-3526 sources Code, (D that I am author	1-26-90 2 dis dif	wie w _e le wie w _e le mid in aa wontree this
OPERATOR'S CERTIFICATE: 1 declary certification, that I have knowledge of the true, correct, and complete, to the best	E under penaltien ne well data and in of my knowledg	prescribed in formation pre- e. This certifie	Sec. 91.143. To control in this rep tition covers all v	915 915 Tel: Amo and that da reli data.	573-3576 Construction of the second s	that I am authorsented on both	1-26-90 Lais dra rized to make idea of this form	a la segle (4.5 - 1.5 (4.5 - 1.5 (4.5 - 1.5 (4.5) (4.5) (4.5) (4.5) (5) (4.5) (5) (4.5) (5) (5) (5) (5) (5) (5) (5) (5) (5) (

Instructions to Form W-15, Cementing Report

State. Zip Code

Tel.: Area Code Number

Date

mo.

day

yr.

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

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

 An initial oil or gas completion report. Form W-2 or G-1, as required by Statewide or special field rules;

• Form W-4. Application for Multiple Completion. If the well is a multiple parallel casing completion; and

Clbr.

 Form W-3, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting dry holes, operators must complete Form W-15, in addition to Form W-3, to show any casing cemented in the hole.

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

のないないではないではないためにていたのですのができ

Address

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

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

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

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

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

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

Please to File No.

11.4.

RAILROAD COMMISSION OF TEXAS OIL AND GAS DIVISION

APPLICATION TO PLUG AND WELL RECORD FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

M.K.C. Malando

Name of Com	any or Oper	stor	he Texas	Compar	ι <u>γ</u>	Address Dor 1720	Fort Worth,
County	loward		SurveyT&	P,RRGo.		29 T-1-1 Sec.	1 exas
Name of Leas	<u>. A. L.</u>	Wasso	n	No. of Acres	1760 W	Il No. 2	2300 (DF)
Located Appr	ox.21	NE	Direction	from.Bi	g Spring,	Texas (Nea	rest P. O. or Town)
Name of Field	in which we	ll is locate	a Wild	cat	*******	99 19- 4 - 4 - 4 - 4 - 4 - 4 - 4 - 4 - 4 - 4	
Form 1, "Noti	e of Intentio	n to Drill,'	" was filed in 1	name of	The Texas	Company	
Drilling Comm	enced 12	-28	****	19. <u>52</u> , D	cilling Completed	3-28	19 52
Has this well	ever produce	a olt No.		******		or Gast	
baracter of	Well (Oil, Ge	s or Dry)	Dry			Total Depth	86701
)ate you wisł	to Plag	3-2	7		19 52	88 - C J. A.	
lame of Party	Plugging W	en Liv	ermore D	rilling	Address 6	10 Lubbock Nat	1 Eank
orrespondence	regarding i	ihis well a	hould be sent	to: Name	The Texa	S Company	dations and an anno 1999. Airtí
lddress Box	1720, 1	Fort W	orth, Te		RECORD	-/	
SIZE	PUT IN	WELL	PULL	ED OUT	1. · / Laure de 1		A ann amoles
3 3/81	196	In.	None	, _† In.	196	In. Texas Pa	ttera
5/81	2115		100		201	Hallibur	ton - & S
198 - 1992 M	13371 S. C.		and a state of the second		and the second sec		

ASING WAS CEMENTED GIVE NUMBER OF SACKS USED ON DIFFERENT STRINGS a ser a ser a ser a ser a Sec.

Initial Production	of Oil: Barreis None	WORE 24 nrs. Pressur	None Fill	DLAND, TEXAS
Give notice perore When Plugging co the Deputy Superv	Plugging to all available L suppleted, file final Plugging isor of district in which we	sease Owners, as required by R r Report, duly signed, and swe il is located.	ula (10) ril. to. All more in C	R 10.1952 will be furnished to Commission of Texas
NOTE: If no ing ava formation, water south	india, in state and give all info- , and to may as penably data ve	motion that eac he obtained to us to	tal depth, gades a benerger	OVE DIVIZION .
General Remarks: oil or gas.	This well dril. We therefore	desire to abandon	selvage and plu	g well in the
fcllowing.	manner: (Cut 9 5	/8" casing at 100	and pull same)	and He (Over)
		AND AND AND AVIDAVIT OF		1

ź

- - - A.E.

12

24

Galiche 0 100 At depth 206' emented 13 3/6" Red Reds 100 206 casing at 206' with 250 sacks. Shale & Anhy 206 9.5 Gament circulsted. Anhy & Shele 1254 1409 At depth 2125' camented 9.5/8" Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Shale 1255 2125		TOP	BOTTOM	
Band Reds 100 200 cost of the second sec	Caliche		100	At doubh 2061 computed 12 2 day
Shale # Anhy 206 0.45 Comment circulfied. Anhy 94.5 1254 Anent circulfied. Anhy & Shale 1251 1409 At depth 2125' camented 9.5/8". Anhy & Shale 1250 1437 at 2125' with 600 sacks. Anhy & Shale 1750 1437 at 2125' with 600 sacks. Anhy & Shale 1955 116 116 Anhy & Shale 1252 2200 116 Lime 2125 2200 116 Lime & Shale 2125 2200 116 Lime & Ghert 3612 3820 3979 Lime & Sand 3820 3979 116 Lime & Chert 3612 3820 3979 Lime & Chert 3612 3820 3979 Lime & Sand 4155 4538 116 Lime & Chert 514 5232 6203 Lime & Chert 7953 8670 514 Total Depth 8670 8670 155 Shale 6201-15 sacks 203-2043; 40 sacks 1125'-1 10 sacks 2025'-4975'-7 <	Red Beda	100	206	At depth 200' demented 13 3/8"
Anhy 945 1254 Address Anhy & Shele 1254 1499 At depth 2125' camented 9.5/8" depth 2125' depth 215' camented 9.5/8" depth 215' depth 215	Shale & Anhy	206	0/5	Carsing AL 200' WIGH 250 SACKS.
Auhy & Shale 1254 1409 At depth 2125' camented 9 5/8", Anby & Salt Anby & Salt 1750 1877 Anhy & Lime 1955 2125 Jime 2125 2290 Lime Shale 2290 Lime & Shale 3116 3612 Lime & Chert 3612 3820 Lime & Sand 4155 4538 Lime & Chert 4536 4000 Lime & Chert 5114 5232 Lime & Shale 5222 6203 Shale 514 5232 Lime & Chert 7953 8670 Total Depth 8570 15 All Measurements from Notory Table or 12' above ground. 28 Remarks Cont'd 870 15 Stacks 5400'-550': 15 sacks 7860'-7810': 15 sacks 1125'-1 15 15 sacks 200'-2075': 15 sacks 625'-4975': 15 sack 620'-580': 15 sacks 1125'-1 16 sacks 875'-825':	Anhy	94.5	1254	
Anhy & Salt. 1/90 1750 at 2125' with 600 ancks. Anhy & Lime 1750 1837 055. Anhy & Lime 1955 2125 1837 Lime 1955 2125 1837 Lime 1252 2290 Lime 2125 2290 Lime & Shale 2290 2322 Lime & Shale 2322: 3116 Lime & Shale 2322: 3116 Lime & Shale 3612 3820 Lime & Chert 3079 Lime & Chert 3070 4155 Lime & Chert 3079 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 753 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd .	Auby & Shele	1254	1400-	At depth 21251 comented Q 5/RH
Anhy 1837 1837 Anhy & Lime 1955 125 Lime 2125 2290 Lime & Shale 2125 2290 Lime & Shale 2322 3116 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3079 4155 Lime & Sand 3820 3979 Lime & Sand 4155 4538 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 8670 State 6203 7953 15 sacks 7660°-7810°; 15 sacks 7705°-7 All Measurements from Notory Table or 12° above ground. 8630-630°: 15 sacks 520'-827°: 15 sacks 2093-2043; 20 sacks 1705'-7 All Measurements from Notory Table or 12° above ground. 8630'-2760': 15 sacks 2093-2043; 20 sacks 1125'-1 All Measurements from Notory Table or 12° above ground. 8630'-2760': 15 sacks 200'-7	Anhy & Selt.	1499	1750	at 2125! with 600 spoks
Anhy - 1837 1955 Nime 1955 2125 2290 Lime & Shale 2290 2322 116 Lime & Shale 2290 2322 116 Lime & Shale 3116 3612 3820 Lime & Sand 3820 3979 155 Lime & Sand 4155 4538 1455 Lime & Sand 4155 4538 146 Lime & Chert 5114 5232 6203 Lime & Chert 5114 5232 6203 Shale 6201 7953 6670 Total Depth 8670 8670 No 15 8670 15 All Measurements from Notory Pable or 12' above ground. 15 Remarks Cont'd 8670 15 Scole - 4520': 15 15 8670 15 All Measurements from Notory Pable or 12' above ground. 125 125 Remarks Cont'd 8670 15 8670 15 Scole - 4520': 15 sacks 5430-5580': 15 15 8680'-7810': 15 8680'-7810': 15 <td>Anhy & Shale</td> <td>1750</td> <td>1837</td> <td></td>	Anhy & Shale	1750	1837	
Anhy & Lime 1955 2125 Lime 2125 2290 Lime & Shale 2220 2322 Lime & Shale 2322 3116 Lime & Shale 3612 3820 Lime & Shale 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3620 3979 Lime & Sand 4535 4538 Lime & Chert 4538 4900 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 8670 Take Heavy mud between plugs. spot the following cement plugs. 95 sack 8670'-7810': 15 sacks 7705'-7 15 macks 5000'-5550': 15 sacks 5430-5380': 15 sacks 7860'-7810': 15 sacks 7705'-7 15 macks 5002'-550': 15 sacks 5430-25380': 15 sacks 2025'-4975': 15 sacks 660'-4630': 15 sacks 8210'-2760': 15 sacks 270': 15 sacks 7705'-7 15 macks 5002'-550': 15 sacks 5730-2380': 15 sacks 2025'-4975': 15 sacks 957 # 1. Phr. failed	Anhy	1837	1955 .	
Hime 2125 2290 Lime & Shale 2122: 3116 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3979 Liss Lime & Chert 3979 Liss Lime & Sand 4515 4538 Lime & Chert 4538 4000 Lime & Chert 5314 522 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 15 Sacks Cont'd 8670 15 Lime & Cont'd 8670 15 Sacks Cont'd 8670 15 Lime & 500'-550': 15 sacks 7800'-7810': 15 Lime & 500'-550': 15 sacks 7025'-7810': 15 sacks 7025'-7810': 15 Lime & Solo'-550': 15 sacks 203-2043: £0 sacks 1125'-1 40 sacks 1125'-1 40 Lime & Solo'-1550': 15 sacks 2093-2043: £0 sacks 1125'-1 5 sacks 1125'-1 5	Anhy & Lime	1955	2125	
Inter & Shale 2290 2322 Linee Shale 3116 Linee & Shale 3116 3612 Linee & Chert 3612 3820 Linee & Sand 4155 4538 Linee & Chert 3979 4155 Linee & Chert 438 4000 Linee & Chert 4538 4500 Linee & Chert 5314 Linee & Chert Linee & Chert 5314 Linee & Chert Linee & Chert 7953 8670 Total Depth 8670 12' All Measurements from Notory Table or 12' above ground. 8670 Remarks Cont'd 8670 12' All Measurements from Notory Table or 12' above ground. 8670'-7810': 15 sacks 7705'- 7 Stacks 5600'-550': 15 sacks 5430-5380': 15 sacks 205'-4975': 15 sack 660'-4630': 15 sacks 2125'-1 Lo sacks 1025'-975': 15 sacks 570': 15 sacks 2025'-2043; 20 sacks 1125'-1 40 sacks 1025'-975': 15 sack Lo sacks 1025'-975': 10 sacks 675': 325': 30 sacks 1125'-1 10 sacks 100': 15 sacks 203'-2260': 10 sacks 1125'-1 Lo sacks 1025'-975': 10 open 1 hr. Recovered 2250' salt water and 225 125'-12' Drill Stem Tests <td< td=""><td>Lime</td><td>2125</td><td>2290</td><td>00.0 · · · · · · · · · · · · · · · · · ·</td></td<>	Lime	2125	2290	00.0 · · · · · · · · · · · · · · · · · ·
Lime 2122 1110 Lime & Shale 3116 3612 Lime & Chert 3612 3820 Lime & Sand 3820 3979 Lime & Chert 3612 3820 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4538 4900 Lime & Sand 5232 6203 Shale 5232 6203 Shale 6203 7953 Lime & Ghert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground, Remarks Cont'd 15 sacks 8215-8163, 15 sacks 7860°-7810'; 15 sacks 7705'-7 15 macks 5600'-550'; 15 sacks 5430-5380'; 15 sacks 500'; 15 sacks 7705'-7 15 macks 5600'-550'; 15 sacks 5430-5380'; 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks, 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. DST # 1: Pkr. failed DST # 2: 4805-4200. Tool open 2 hrs. Recovered 2250' salt water and 225 satt water tout with drig, mud. DST # 3: 5100, 5216. Tool open 1 1/2 hrs	Lime & Shale	2290	2322	
Jillo Jol2 Lime & Chert 3612 Jime & Sand 3820 Jame & Sand 3820 Jime & Chert 3079 Lime & Sand 4155 Lime & Sand 4155 Lime & Sand 4538 Lime & Chert 4538 Lime & Chert 4538 Lime & Chert 5114 Jime & Shale 5232 Lime & Shale 5232 Jime & Ghert 7953 Jime & Ghert 7953 Jime & Ghert 7953 Shale 6203 Total Depth 8670 Total Depth 8670 State Heavy mud Datween plugs, spot the following cement plugs, 95 sack 8670-8373':15 sacks 5163. 15 sacks 7860'-7810': 15 sacks 7705'- 7 Jacks 500'-5550':15 sacks 5430-5380': 15 sacks 2093-2043: 40 sacks 1125'-1 460'-4630':15 sacks 810'-2750': 15 sacks 75'-825': 30 sacks in top casing. Drill Stem Tests	Idmo & Shalo	2322 1	3116	· · · · · · · · · · · · · · · · · · ·
Lime & Sand 3820 3979 Lime & Chert 3979 4155 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Shale 5222 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 Total Depth 8670 School & Chert 7953 School & Sch	Line & Chent	2612	1 1012	
Lime & Chert 3070 1155 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4453 4900 Lime & Sand 44900 5114 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Ghert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 660'-7810': 15 sacks 7705'-7 15 marks 560'-5550': 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 5125'-7 4680'-4630': 15 sacks 2810'-2760': 15 sacks 2033-2043; 10 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests	Line & Sand	2620	1 2020	•
Lime & Sand 4155 4538 Lime & Chert 4538 4900 Lime & Chert 4538 4900 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 8670 Stale 8210 12' above ground. Remarks Cont'd 12' above ground. Remarks Cont'd 12' above ground. Remarks 5600'-5550': 15 sacks 5215-8163 15 sacks 7705'-7 15 macks 5600'-5550': 15 sacks 5215-8163 15 sacks 2060'-7810': 15 sacks 7705'-7 15 macks 5600'-5550': 15 sacks 5215-8163 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks 1025'-975': 40 sacks 875'-825': 30 sacks 1n top. casing. Drill Stam Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 4805-4900, Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 2: 5405-5565; Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 2: 5405-5565; Tool open 1 hr. Recovered 100' drig. mud. DST # 5: 5002.6000 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 failed 100 for 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 failed 100 for 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 failed 100 for 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 failed 100 for 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 failed 100 for 1 hr. Recovered 20' drig. Mud & 120 DST # 74 743 failed 100 for 1 hr. Recovered 20' drig. Mud & 120 DST # 74 743 failed 100 for 1 hr. Recovered 20' drig. Mud & 120 DST # 74 743 failed 100 for 1 hr. Recovered 20' drig. Mud & 120 DST # 74 743 failed 100 for 1 hr. Recovered 5' drig. mud & 120 DST # 74 743 failed 100 for 1 hr. Recovered 5' drig. mud & 120 DST # 74 743 failed 100 for 1 hr. Recovered 5' drig. mud & 120 DST # 74 743 failed 100 for 1 hr. Recovered 5' drig. mud & 120 DST # 74 743 failed 100 for 1 hr. Recovered 5' drig. mud & 120 DST # 74 743 failed 100 for 1 failed 100 for 1 hr. Recovered 5' drig. mud & 100 for 1 hr. Recovered 5' drig. mud & 100 for 1 hr. Recovered	Line & Chert	3070	1.155	Past and the state
Lime & Chert 438 400 Lime & Sand 4900 5114 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd 15 8000 5100': 15 8000 700': 1	Lame & Sand	1155	1.538	
Lime & Sand 4000 5114 Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Shart 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 7 Fathe Heavy mud batween plugs, spot the following cement plugs, 95 sack 8670 - 7810'; 15 sacks 7705'-7 Lime & Solo - 5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 7705'-7 Lime & Solo - 5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 125'-1 Lo sacks 500'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 125'-1 Lo sacks 1025'-975'; 10 sacks 875'-825'; 30 sacks in top casing. Drill Stam Tests Drill Stam Tests DST # 1: Pkr. failed DST # 2: 1405-4900, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 2: 5100-5216, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 5' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 5' drlg, mud. DST # 7: 723 brain the second for the formule	Line & Chert	1.538	1,000	•
Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 12 above ground. Remarks Cont'd 15 acks 510 relation of the following cement plugs, 95 sack 5670 relation of the following cement of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 relation of the following cement plugs, 95 relation of the following cement plugs, 95 relation of the following cement p	Lime & Sand	4900	5114	
Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Bains Heavy mud batween plugs, spot the following cement plugs, 95 sack 8670-8373 115 sacks 8215-8163, 15 sacks 7860'-7810': 15 sacks 7705'- 7 15 macks 5600'-5550': 15 sacks 5430-5380': 15 sacks 2025'-4975': 15 sack 6680'-4630': 15 sacks 2810'-2760': 15 sacks 2093-2043: 20 sacks 1125'-1 40 sacks 1025'-975': 40 sacks 875'-825': 30 sacks 1n top casing. Drill Stem Tests Drill Stem Tests Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 mail water cut with drig. mud. DST # 3: 5100-5210, Tool open 1 hr. Recovered 300' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 7: 783	Line & Chert	5114	5232	
Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Taths Heavy mud batween plugs. spot the following cement plugs. 95 sacks 8670-8373':15 sacks 2215-8163. 15 sacks 7860'-7810': 15 sacks 7705'-7 15 macks 5600'-5550': 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 600'-6810': 15 sacks 2093-2043: 40 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 1 1/2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 5400-5485. Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 5400-5485. Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 5: 5002.5600 Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 7: 723 Tool open 1 1/2 hrs. Recovered 20' drig. Mud & 120 DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' dr	Lime & Shale	5232	6203	o alteration and the second statement of the second
Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. All Measurements from Notory Table or 12' above ground. Remarks Cont'd 6670 Saing Heavy mud butween plugs, spot the following cement plugs, 95 sack 8670 - 3731:15 sacks 2215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7 15 macks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 4680'-4630': 15 sacks 2810'-2760'; 15 sacks 2093-2043; 20 sacks 1125'-1 40 sacks 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 4805-4900, Tool open 1 1/2 hrs. Recovered 300' drig, mud. DST # 5: 5002.5000, Tool open 1 1/2 hrs. Recovered 300' drig. mud. DST # 5: 5002.5000, Tool open 1 hr. Recovered 75' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 100' drig. mud. 1700-115 DST # 4: 700 means 1 hr. Recovered 100' drig. mud. 1700-115 DST # 4: 700 means 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. None	Shale	6203	7953	olari mayadar. A sidan sinda yana ang panamaa
Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Baths Heavy mud batteen plugs. spot the following cement plugs. 95 sacks 8670'-8373':15 sacks 8215-8163. 15 sacks 7705'-7 15 macks 560'-5550':15 sacks 5430-5380':15 sacks 5025'-4975':15 sack 660'-4630':15 sacks 2215-8163. 15 sacks 2093-2043: 40 sacks 125'-7 15 macks 560'-5550':15 sacks 5430-5380':15 sacks 5025'-4975':15 sack 660'-4630':15 sacks 2810'-2760':15 sacks 2093-2043: 40 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests Dst # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 3: 5100-5218; Tool open 1 1/2 hrs. Recovered 300' drig, mud. DST # 4: 740-5145; Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 7500-5210. Tool open 1 hr. Recovered 100' drig. mud. DST # 4: 760 field open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760 field open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760 field open 1 hr. Recovered 20' drig. mud. DST # 4: 760 field open 1 hr. Recovered 5' drig. mud & 180' slightly field of height field open 1 hr. Recovered 5' drig. mud & 180' slight field open 1 hr. Recovered 5' drig. mud & 180' sli	Lime & Chert	7953	8670	al a development and set water a set of the
All Measurements from hotory Table or 12' above ground. Remarks Cont'd Hathg Heavy mud between plugs, spot the following cement plugs, 95 sack 8670'-8373':15 sacks 8215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7 15 macks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sac 6680'-4630':15 sacks 2810'-2760'; 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5216 Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 760 fool open 1 hr. Recovered 75' sliphtly gas cut drlg. DST # 4: 760 fool open 1 hr. Recovered 70' drlg. Mud & 120 DST # 4: 760 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 5' drlg. mud. DST # 4: 750 fool open 1 hr. Recovered 5' drlg. Mud & 180' ell sud ebod of samin of task 26 and of task 1 hour fool open 1 hr. None	Total Depth	a state of states and a second	8670	The second seco second second sec
AU sacks, 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 selt water cut with drlg. mud. DST # 3: 5100-5210. Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 4: 5400-5210. Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7400-7470. Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 7400-7470. Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 7400-7470. Tool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 7400-7470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 743. Model of a setting of rate Constant of the set of	I E marke FGOOL FEFO	Plant P. Plant and all	ELOO FO	1000 -1010 ; 1) Backs //0/ - /
Deill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5218. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5440-5485 Tool open 1 hr. Recovered 75' slightly gas cut drly. DST # 4: 780 1000 Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 780 1000 Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 1000 1000 1000 1000 1000 1000 1000 10	15-macks 5600'-5550	1:-15 sack ks 2810'-2	s 5430-53 760': 15	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-10
DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5216, Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5440=5485; Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7805-7870; Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7805-7870; Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 5' drlg. mud & 180' sli show of shapping of relevant Cased of 1 drlg. Mud & 180' sli per cent None	15-macks 56001-5550 46801-46301:15 sec 40 macks 10251-975	1;-15 sack ks 2810'-2 1; 40 sack	8 5430-53 760': 15 8 875'-82	80'; 15 sacks 5025'-4975'; 15 sac aacks 2093-2043; 40 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5210. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5400-5445. Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7800-6470. Tool open 1 hr. Recovered 100' drlg. mud. 1000-010 DST # 4: 7800-6470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 7800-6470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 5' drlg. mud & 180' sli show of shepting of rise 2 ased of the sheet of the sheet off. Ies mount of water th oil NODE (1) per cent None	15-macks 5600'-5550 4680'-4630': 15 sec 40 sacks. 1025'-975	11:-15 sack ks 2810'-2 1: 40 sack	s 5430-53 760': 15 s 875'-82	80': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing.
DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 selt water cut with drlg. mud. DST # 3: 5100-5218, Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 4: 5100-5218; Tool open 1 hr. Recovered 75' slightly gas cut drlg DST # 4: 7800-6000, Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 180' slip DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 180' slip	15-macks 5600'-5550 4680'-4630': 15 sec 40 sacks. 1025'-975 Drill-Stem Tests	1;-15 sack ks 2810'-2 ; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-1 5'; 30 sacks in top casing.
aslt water cut with drlg. mud. DST # 3: 5100-5216. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 1: 5400-5485 Tool open 1 hr. Recovered 75' slightly gas cut drly. DST # 1: 5002-6000 Tool open 1 hr. Recovered 100' drlg. mud. 1200- DST # 1: 7800-7420 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud. 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip mount of water with oil 010 010 / 100 / 1	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests	11;-15 sack ks 2810'-2 1; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 10 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 3. 5100-5216, "Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 54:0-5485; Tool open 1 hr. Recovered 75' slightly gas cut drlg DST # 4. 780 model Tool open 1 1/2 hrs. Recovered 100' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. Sole open 1 hrs. Recovered 5' drlg. Sole open 1 hrs. Sole op	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900	1;-15 sack ks 2810'-2 1; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-10 5'; 30 sacks in top casing.
DST # 4. 780 model open 1 hr. Recovered 75' slightly gas cut drlg DST # 4. 780 model open 1 hr. Recovered 100' drlg. mud. 1000 model 1 hr. Recovered 20' drlg. Mud & 120 DST # 4. 780 model open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 781 Model of the state of the st	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900,	1; 15 sack ks 2810'-2 i; 40 sack i tool open selt wate	s 5430-53 760': 15 s 875'-82 2 hrs. 3	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 20 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 4. 780 creation in the second state of t	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900,	tis 15 sack ks 2810'-2 is 40 sack is 40 sack is 40 sack is 40 sack is 40 sack	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 20 sacks 1125'-10 5'; 30 sacks in top casing.
DST # 4. 780 model DST # 7. 763 model DST #	15 macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 4: 5440=5485	d Tool open Tool open Tool open	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re	ecovered 2250' salt water and 2250 h drlg. mud.
abod of shepting of rates of the second of t	15-macks 5600*-5550 4680*-4630*: 15 sec 40 macks. 1025*-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3-5100-5216 DST # 3-5100-5216 DST # 3-5100-5216	d Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud.
allod of abetting of water a Case(of the apert and a water completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3-5100-5218 DST # 3-5100-5218 DST # 3-5002-6000	tis 15 sack ks 2810'-2 is 40 sack d Tool open selt wate Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	s. Recovered 300' drlg, mud. covered 100' drlg, mud.
athod of sheeting of water - Cased D it water completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 4- 780 mac20	Colopen Tool open Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re	s. Recovered 20' drlg. Mud & 120'
athod of sherting a vater Cased Of the per completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3- 5100-5218, DST # 4- 7800-5485 IST # 4- 7800-64701	ticel open Tool open Tool open Tool open Tool open	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 1/2 hr gas cut d	s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120'
mount of water with oil	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5218, DST # 4: 7805-4900 DST # 4: 7805-4900	i - 15 sack ks 2810'-2 i 40 sack d Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	ecovered 2250' salt water and 2250' h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120'
mount of water with oll	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 3: 5100-5216, DST # 4: 7805-6000, DST # 4: 7805	i - 15 sack ks 2810'-2 i 40 sack i 40 sach i 4	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 c cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	so': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. 1000 s. Recovered 20' drlg. Mud & 1200 rlg. mud. Recovered 5' drlg. mud & 180' sl1
	15-macks 5600'-5550 6680'-6630': 15 sec 60 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3: 5100-5216 DST # 3: 5100-5216 DST # 4: 7805-6000 DST # 4: 7805-6000	i 15 sack ks 2810'-2 i 40 sack i 40	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 c cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	sovered 2250' salt water and 2250' h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud.
	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST #	i - 15 sack ks 2810'-2 i 40 sack i fool open fool open fool open fool open fool open fool open fool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 225 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg covered 100' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip ater completely shut off? Yes
	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 3- 5002-5000 DST # 3- 50000 DST # 3- 5000 DST # 3- 50000 DST # 3- 50000 DST # 3- 50000 DST #	Li-15 sack ks 2810'-2 Li-40 sack i Tool open selt wate Tool open fool open f	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud. 180' slip ater completely shut off: Ies cent None
SUEDEN SIL	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 3- 5100-5218 DST # 4- 780 0000 DST # 4- 780 00000 DST # 4- 780 000000 DST # 4- 780 0000000000000000000000000000000000	tol open fool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1799-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip the sad matter berson and that the same bre true ts and matter berson and that the same bre true
Fouriet SILEDEU	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5218, DST # 3: 5100-5218, DST # 4: 780 55485 AST # 7: 780 55485 AS	ticol open Tool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drly. covered 100' drlg. mud. 1. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip ater completely shut off? Ies cent None
A contract A cont	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 3: 5100	d flool open selt wate flool open flool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 20 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg, mud. covered 100' drlg. mud. covered 100' drlg. mud. 1000 covered 100' drlg. mud. 1000 rlg. mud. s. Recovered 20' drlg. Mud & 1200 rlg. mud. Recovered 5' drlg. mud & 180' sl1; ater completely shut off: Ies cent None the and matter bersen and that the set for tra- sector of Company. 0 1052
ALEOIN Marchell and swere to before me this day of Appell Marchell and swere to be for the swere	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks. 1025'-975 Drill Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900. DST # 3- 5100-5216. DST # 3- 510	d Tool open Tool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 10 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 225 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1000 s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 5' drlg. mud. 180' sli ater completely shut off: Yes cent None ts and matter bermany of that the content of the second for the second fo

A. L. Wasson, Wildcat, Howard County

DST # 8: 8418-8468, Tool open 1 hr. Recovered 100' drlg. mud.

- DST # 9: 8455-8543, Tool open 2 hrs. Recovered 390' slightly gas cut & sulphur cut drlg. mud.
- DST # 10:8546-8670, Tool open 1 1/2 hrs. Recovered 7230' sulphur water.

RECEIVED MIDLAND, TEXAL

APR 101952

Railroad Commission of Texas OIL'84 GAS DIVISION

File No	ALLEUAD COMMISSION OF TEXAS	Form 4
8	OIL AND GAS DIVISION	1.4 million in the core
FILE IN DUPLICATE	WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH	WELL IS LOCATED
Company The Texas Comp	Address Box 1720 .	Ft. Worth, Texas
Sec. No. 4. Block No. 2	29 T-I-N Survey. T & P RRCO County	Howard
Well No	. A. L. Wasson	No. of Acres 1760
Name of Field in which well is loc	ated Wildcat	
Form 1 (Notice of Intention to Drill	i) Was Filed in Name of	ompany
Character of Well at the time of co	ompletion: Oil	Cu. ft.; Dry
Amount well producing when plug	red: Oil None Dia; Gas None Ca r	L; Water NODS
Has this well over produced oil or	gas?No	
Fotal Depth 8670	eet. Top of each producing sand	
Was the well filled with mud-laden	fluid, according to regulations of the Railroad Commission?	Yes
How was mud applied? Thr	u drill pipe	a an 'n staar 'n staar d
Were plags used? Yes wage used, and depths placed, Also Spotted, the Solicitation	If so, show all shoulders left for casing, depth of each, and principal of cement and rock. Was well shot? NO	tise of casing, size and kind of
Were plags used? Yes bage used, and depths placed. Also Spotted the followin 7860-7810 45 ax 770 15 sr 2810-2760 15 Spot 40 sr 1125-1070 Tare all abandened wells of this fanser of confining all oil, may or v 2 5/8" casing left in Dr cassed of with cen	If so, show all shoulders laft for casing, depth of each, and production of comment and rock. Was well shot? NO gr plugs: 95 sx 8670-8373, 15 sx 821 5-7655, 15 sx 5600-5550, 15 sx 5430 increase of the strategy of the state of	ine of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100' and pulled ax in top of casi Yes in hole & 2015: sing left in hole
Were pings used? Yes Many used, and depths placed. Also Spotted the followin 7860-7810, 15 sx 770 15 sx 2810-2760, 15 spot 40 sy 1125-1070 Iave all abandoned wells of this 1 Canser of comfining all oil, yas or w 9 5/8" casing left in or caused of with cent be manage of edjecent base, royalt	If so, show all shoulders laft for casing, depth of each, and presented coment and rock. Was well shot? No B plugs: 95 SX 8670-8373, 15 SX 821 5-7655, 15 SX 5600-5550, 15 SX 5430 memory of the strategy of t	nise of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax A680-A630 @ 100' and puller sx in top of casi Yes in hole & 2015' sing left in hole silere:
Were pings used? Yes bigs used, and depths placed. Also Spotted the followin 7860-7810, 45 ax 770 15 sx 2810-2760, 15 spot 40 sx 1125-1070 lare all abandoned wells of this 1 Canser of confining all oil, yas or v 2.5/8% casing left in or cassed of with cent be manues of edjecent lesse, royalt 11 adjacent property	If so, show all shoulders laft for casing, depth of each, and provintion comment and rock. Was well shot? NO B plugs: 95 SX 8670-8373, 15 SX 821 5-7655, 15 SX 5600-5550, 15 SX 5430 INTERPRETATION FOR STATE STATE SX 2093-2043, Cut off 9 5/8" casing -40° six 1025-975, 40 SX 875-825, 30 lease been plugged according to Commissions rules? Moder to strate: All 13 3/8" casing left n hole. All strata protected by ca ment. ty and landowners with their addresses in each instance as for y leased by The Taxas Company	ise of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100" and puller sx in top of casi Yes in hole & 2015" sing left in hole sllows:
Were pings used? Yes bigs used, and depths placed, Also Spotted the followin 7860-7810, 45 ax 770 Spot 40 sp 1125-1070 fave all abandoned wells on this fanner of confining all oil, pas or v 9.5/8" casing left in or cassed of with cent be memors of adjacent lease, royalt 11 adjacent property	If so, show all shoulders laft for casing, depth of each, and provint of cement and rock. Was well shot? NO B plugs: 95 SX 8670-8373, 15 SX 821 5-7655, 15 SX 5600-5550, 15 SX 5430 INTERACTOR CONTRACTOR 50-25-4975, 15 SX 2093-2043, Cut off 9 5/8" casing -40° six 1025-975, 40 SX 875-825, 30 lease been plugged according to Commissions rules? Water to strate: All 13 3/8" casing left n hole. All strata protected by ca ment. ty and landowners with their addresses in each instance as f y leased by The Taxas Company	ise of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100" and puller sx in top of casi Yes in hole & 2015" sing left in hole silene:
Were pings used? Yes bigs used, and depths placed, Also Spotted the followin 7860-7810, 45 ax 770 Manager 2810-2760, 15 spot 40 sign 1125-1070 fave all abandoned wells on this Manager of confining all oil, gas or y 9 5/8" casing left in or cassed of with cent be memors of adjacent lease, royalt 11 adjacent property Manager before plugging t	If so, show all shoulders laft for casing, depth of each, and provint of coment and rock. Was well shot? NO Plugs: 95 9x 8670-8373, 15 9x 821 5-7655, 15 9x 5600-5550, 15 9x 5430 Interactive company 50-25-4975, 15 3x 2093-2043, Cut off 9 5/8" casing -40 min 1025-975, 40 9x 875-825, 30 lease been plugsed according to Commissions rules? water to strate: All 13 3/8" casing left n hole. All strata protected by ca ment. ty and landowners with their addresses in each instance as f y leased by The Taxas Company	A consistent of
Were pings used? Yes bigs used, and depths placed, Also Spotted the followin 7860-7810, 45 ax 770 Spot 40 sp 1125-1070 Fave all abandoned wells on this Manner of confining all oil, gas or y 9 5/8" casing left i or cassed of with cent he memors of adjecent lease, royalt 11 adjacent property Manner bios given before plugging t	If so, show all shoulders laft for casing, depth of each, and provint of cement and rock. Was well shot? NO B Digs: 95 SX 8670-8373, 15 SX 821 5-7655, 15 SX 5600-5550, 15 SX 5430 INTERACTION CONTRACTOR STATES SX 2093-2043, Cut off 9 5/8" casing -40 ST 1025-975, 40 SX 875-825, 30 lease been plurged according to Commissions rules? water to strate: All 13 3/8" casing left n hole. All Strata protected by ca ment. ty and landowners with their addresses in each instance as 1 y leased by The Taxas Company to all available adjacent lease owners as required by Rule 10	A consistent of casing, size and kind of 3-8163, 15 sx -5380, 15 sx sx 4680-4630 @ 100' and pulled sx in top of casi Yes in hole & 2015' sing left in hole silene:
Were plags used? Yes blags used, and depths placed. Also Spotted the followin 7860-7810, 45 ax 770 Management of the followin 15 sx 2810-2760, 15 spot 40 sign 1125-1070 fave all abandoned wells on this Manage of confining all oil, gas or v 9.5/8" casing left i or cassed of with cer be memors of adjacent lease, royalt 11 adjacent property Man metics given before plugging t I. T. P. Drew rd the matter herein set forth and	If so, show all shoulders laft for casing, depth of each, and provintial coment and rock. Was well shot? No E plugs: 95 sx 8670-8373, 15 sx 821 5-7655, 15 sx 5600-5550, 15 sx 5430 in case of the second sec	A set of casing, else and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100' and pulled sx in top of casi Yes in hole & 2015' sing left in hole slows: Yes
Were plags used? Yes blage used, and depths placed. Also Spotted the followin 7860-7810 45 sx 770 Manage all abandoned wells of this Spot 40 sy 1125-1070 Hanser of confining all oil, gas or v 9.5/8" casing left i or cassed of with cent The memory of adjecent lease, royalt 11 adjacent property Fas metics given before plugging t I, T. P. Drewf ad the matter herein set forth and	If so, show all shoulders laft for casing, depth of each, and provintial comment and rock. Was well shot? No E plugs: 95 sx 8670-8373, 15 sx 821 5-7655, 15 sx 5600-5550, 15 sx 5430 in case of the commentance of the second seco	size of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ex 4680-4630 @ 100' and pulled ax in top of casi Yes in hole & 2015: sing left in hole sliews: Yes Yes Dist. S
Were plage used ? Yes blage used, and depths placed, Also Spotted the followin 7860-7810 45 ax 770 Minimum Construction and the Spot 40 sy 1125-1070 Spot 40 sy 1125-1070 Far all abandoned wells of this fanser of confining all oil, yas or y 9.5/8° casing left 1 or cassed of with cent the memory of adjecent lease, royald 11 adjacent property Far metics given before plugging to I, T. P. Drew nd the matter herein set forth and shorthed and sween to before me	If so, show all shoulders laft for casing, depth of each, and principal comment and rock. Was well shot? No P 1028: 95 SX 8670-8373, 15 SX 821 5-7655, 15 SX 5600-5550, 15 SX 5430 IN CASE OF 15 SX 5600-5550, 15 SX 5430 IN CASE OF 15 SX 5600-5550, 15 SX 5430 IN CASE OF 1025-975, 40 SX 875-825, 30 lease been plugged according to Commissions rules? maker to strate: All 13 3/8" casing left n hole. All strata protected by ca ment. ty and landowners with their addresses in each instance as 2 y leased by The Taxas Company to all available adjacent lease owners as required by Rule 10 to all available adjacent lease owners as required by Rule 10 that the same are true and correct. Name this 15 day of Nav	A set of casing, else and kind of 3-8163, 15 sx -5380, 15 sx sx 4680-4630 @ 100' and pulled sx in top of casi Yes in hole & 2015: sing left in hole slows: Yes Dist. S 10 52
Were plage used ? Yes blage used, and depths placed, Also Spotted the followin 7860-7810 45 ax 770 Minimum Construction and the Spot 40 sy 1125-1070 Hanser of confining all oil, yas or y 9.5/8° casing left 1 or cassed of with cent The memory of adjecent lease, royald 11 adjacent property Fas metics given before plugging to I, T. P. Drew I, T. P. Drew I the matter herein set forth and marihad and swarn to before me	If so, show all shoulders laft for casing, depth of each, and primipint of coment and rock. Was well shot? No. (C. Plure: 95 9x 8670-8373, 15 9x 821) 5-7655, 15 9x 5600-5550, 15 9x 5430 increase areas an exceedences 50-25-4975, 15 sx 2093-2043, Cut off 9 5/8" ceasing - 40 min 1025-975, 40 9x 875-825, 30 lease been plurged according to Commissions rules? maker to strate: All 13 3/8" casing left n hole. All strata protected by ca ment. ty and landowners with their addresses in each instance as for y leased by The Taxas Company to all available adjacent lease owners as required by Rule 10 , being first duly sworm on oath, state that t that the same are true and correct: Name this 15 day of Nay	A set of casing, else and kind of 3-8163, 15 sx -5380, 15 sx sx 4680-4630 @ 100' and pulled sx in top of casi Yes in hole & 2015: sing left in hole slows: Yes Dist. S 10 52

i i i v		0) ()	2	2		07	7					- 1/3 1				
iewaska: <u>Original</u> Plugged a	NO ALLOWARLY WILL ME A In protect all fresh water and ments. It will be necessary seconder the depth to which i	A. LEATE LINE				Wildcat	R/all	PIELD WANK (Rescily as sh Prostion Releasing furthelis synthesister) If Wildest, so	1 - 2 - 2 - 10		た 一 の 別 化 感		Big Spring,	P D Box 4	McCannyCoro	Check onli DipliLL	(m) () 1632- 1624- 914 (4	ipe mail Mo. 42 second on ("Hit b) an have bla
1 Operator Lease Name nd Abandon	NOTIC NESIONED Io any wai da. Where Commiss of Connect Texat fresh, water sands mu	710N PROM TWO D1 660' FWL & 660' FWL &				riana 11 12-11	100	olen on R. N. C. ng Weservoir If stary below.	Also - Also	REFER	er. Br	(Instruction (2) on be	TX 79720	40			Pri CAlqua	
: The	M I which dres ion rules do n Water Develo at be protecte	1980 1980 1980	dent K		23 8 - 2 7	42101	Completion Depth	Anna Sir 2011 - Anna 1912 - Anna A	ar 14. "	TO INSTRI	41. 11 ¹	cle alde.)	: 17 	1041 2327 2738	50	or Atlach Sets	.dR PET	
Vasson 27-52	not have suffic optient Board, d.	ĒŇI, ĒNĻ	2 1 8			None	lf done, Btate Nore,	All Prior Rule 37.Exe. Case Numbers for	i 3 13	UCTIONS O	P		a dina andra andra andra	n ute E Fate Infase George	5			4 1
Wc 11	face casing re Austin, Tex	e co e constant	900 1907 (1907	112 5	N.	467	Rujes, Siale 467-1200. (h.)	Applicable Field Rules Pattern, 11no	16	N BACK S	EACH PRO	Nedrest	6. This we Directio	Sec.	* (*) 7 (5 4 4 4	E) (III) TUUM Case	d Tring	OIL AND O
	ay, to		1 () ()			40	Rulen, State Acres)	A palic ble A palic ble P leid Rules Denalty	20 JZ	IDE: READ	POSED CO	Post Office o	ill is to be los	4. Blk	Stewart		EEPENT	a Divisio
1 	2.8	n 8.1	K			40	DESIGNATE	Wumber of Acres in Drilling Unit for this Well	- 10.	CAREFULL	MPLETION	town.	Vincent	59, T	1719 13/11 17	C BACK	DIR PLUG	ž
Signature A Title Date Telephone:	I declare und Code, that I by me or un therein are tr					<u></u> れっ	emplein in remarks.) R	Taithle acre- ere presently assigned to another well in seme field? (Ven	19 ji	Y AND FURN		ul in El any El any Li atra	TX	-1-N, 5	arts Stro Stro Stro	C. OTHER (BP	BACK	
dminist unc 12,	or penalties p am authorizes der my superv Ne, correct, at	25. (a) Is this (b) If subje (If no. (20		т с. 1. К. – У	None	plied for well in same res. on same lease (().)	Distance and Direction from simposed loca- tion to near-st duiling com- eleted or ap-	. 20.	ISH COMPLE		195 1964 75	Southea	& F RH	bade a an a ana a ana a	•rify) TE-e	64 65 55	- - -
21. 13 rative 1980 915	CERTIF reacribed in S 1 to make this rision and dim rision and dim	wellbore subj oct to SWR 36, attach explana	Reg ^{ula} r 1	Regular 1	Regular 1	Regular 1 🔀 Rule 37 Z	tion? Check the eppro- priate box.	ls this a i. Regular: or 2. Rule 37 Ezc. Locus	21.	TE DATA.:	i e	201 - 0	i ត្រុ	Go.	tstea Tol Tol	ntry	1	ermit
Assist:	ICATE ec. 91.143, To report, that the tetion, and the p the best of a	ect to SWR 36 has Form II- ition.)	JU	A R R	75	0i1	Type Well (Specify)	OII. Car	22.	2	66 21	12. Total Dep	11. Distance I to Nearest (fL)	to. Number of	P. Helling	8. County	7. NRC Dist	ARC Perrils
int 1-7455	Pegas Natural F his report was at data and fac ny knowledge.	yole" yole"	N	10	LIVED.	0	JIO	Number of Wei Permitted fore this Lease in Roservatriotus Permit is Regi	C 18 8	14.000	63	46001	1 Property of L	640	н.	loward	niet O	284
IT'	Presurces ors stated	1983 1111	U	6		c	GAS	lls of Mons on Michths Michths		20		5674	Ease Line	, 1	, 2%) (201	* 5 * 1 G	4	547

methos Mecord	R	OIL AND G	MISSION (IAS DIVIS	OF TE SION	XAS			PO Re	RH W-
1			12	API	NO, Reliable?	42-227	-000	BRC Distri	16
FILE IN D	JPLICATE WITH D	ISTRICT OFFIC	E OF DIS	TRICT	IN WH	ICH	(4). 191	08	1 1 16
WELL	IS LOCATED WITH	IN THIRTY DA	YS AFTE	k PLU	GGING		2	Hunter	98 X.
2. FIELD NAME (as per R	RC Records)	3. Lease	Name	S _				Well Numbe	
6. OPERATOR		for Coloin	Stewar	t.	Maria de			1	-1
McCann Cor	poration	. Mc	Cann Co	rpor	ition	1	100	Howan	
7. ADDRESS		ób. Any S	ubsequent W-	I's Filed	In Name	of:	11	Date Dritile	E.
P. C. Box	148, Big Spri	ng, TK				100		8-17-	80
of Lease on which this	Felt in Located	iNorth	et From WC	<u>Stew</u>	ne and 11	980 Feet	From	CORA24	ide 17 - st
. SECTION, BLOCK, AND	SURVEY	9b. Dista	nce and Direu	tion Frag	Nearest	Town In this	- 13	Dete Drittin	¢
Sec. 4, Blk.	29, T-1-N, T&P	RR Col	4 mil	es SI	To I	Vincen	t	10-10-	80
(OII, Gas, Dry) DRY	in less a wontble comple	nian wat All Field D	ames and Oll		Gas ID S ID or LEASP #	0.18 011-01 9	RLL	Dute Drillie Completed	F
8. If Gas, Amt. of Cond. on Hand at time of Plurston							2 A I	. Date Woll I	sed
				<u> </u>			1 A A A	10-12-	
9. Cementing Date	AND ABANDON DATA:	10-12-80	10-19 1	10-11	PLUGPA	PLUG.#5	PLUG	PLUG #7	10.01
0. Size of Hole or Pipe in w	hich Plug Places (inches	· 9-5/8	9-5/8	13-37	8	1 1 1 3 1 m	54 6		1.113
1. Depth to Bottom of Tubin	g or Drill Pipe (ft.)	11000	250 T	10 01	E.S.	11043 0	(1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,	17 - + (+, 17 - ++)	16.20
2. Sacks of Cement Used (e.	sch plug)	50	100	10	· · · · · · · · ·	0.00	22335.40	ere las receiças	100 A
4. Calculated Top of Plug ((1.)	990	70 9	Surf.	ويتكلفوها			1	
5. Messured Top of Plug (if	tagged) (ft.)		N.						295
G. Slurry Wi. #/Gal.		1.33	1.33 1	. <u>33</u>				-	_
a. CASING AND TUBING I	RECORD AFTER PLUG	SING E	129. Wan a	iny Non-	Drillable	Material (Oth	1 IVF	I Van	X Ma
ZE WT. #/FT. PUT IN W	ELL(II.) LEFT IN WELL	(it.) HOLE SIZE(In	.) 79s. If any	wer to ab	ove is ""	es" state d	pth to toy	of "junk" is	ft in hole
5 8 24# 20	200 200		- Porm	Lf more s	pace is n	eded,)			17. 11
	<u> </u>			(* 11) 11)		*** *** * ** ** **	in a second s	n de Hara Ara Alexandra Alexandra de Alexandra	1.77 * . 4
			-						
D. LIST ALL OPEN HOLE	AND/OR PERFORATE	1 INTERVALS					÷		
PROM	<u>T0</u>		FROM				TO	QC	
PROM	10 TO		PROM	1	(N N 2	0.2495
FROM	то		FROM			Ε.	то	1.4.54.542.5	11 M. A.
PROM	70		PRCM	-		······	το	4 + -	- 152
here knowledge that the center of the composition of Commenter as Author CERTIFICATE: I declare under pen report was prepared to the best of my 1	menting operations, as re- leted by Committing Comp asized Representative sites prescribed in Sec. by me or under my superv knowledge.	flected by the informa any. fiems not so def 91.143, Tezas Natura vision and direction, i	tion found on algnated shall DOWE Name of al Resources (and that date of	this form to comp 211 D of Coment Code, the and facts	i, were per letod by C ivisi ling Comp t 1 mm out atoted the	formed as in perstor. Oll Of any horized to m prein are true	Dow (y such inform Themical sport, that this and complete	L C3.
	12	Star 1	1. Mart		In. VC	(Jack	\mathcal{G}	11 71	2 71

APR 2 0 1981 D.G. MIDLAND, TEXAS

D1-80

et an ar star things of a

Ť

.

mart.

1

÷ ÷,



1676° 4 4 4 4	*		
alt for the same			
		<u> </u>	

10.4 14.2

.

	of tree 1	en 32. Now w	Circulated	33. Bud Bright Bart sin
Cherr 7	rah Water Zones by	T.D.W.R.	25. Have all Abandound Wells on this Le according to BBC Bales?	ees teen Flugged
	·		14, If NO, Explain	
		<u> </u>		
State Transferrer	tine or Service come	in the second	and pumped cement place in this well	Date BIC District Office
Dowell Divisi	on of Dow	Chemica	1 Co Colorado City	y. The state of stranger
2. Carper and Addressees of Surf	lace Owner of Well 3	lite and Operat	ore of Ottom Producing Loanes	
Danny Stewart	<u>– P. O. B</u>	<u>ox 26.</u>	Sterling City, Tx. 76	<u> </u>
en e	0.0			
La La Canton Chara Balars Pie	oging to Ruch of the	e Alleve?		
Yes		31 (F)		
PLL & CLOT FOR BAY IN	OLES COLY at he accompanied h	y either a Dril	er's, Electric, Railioartivity or Acoustic	al/Soute Log or such Log must be
related to a Connectal Log	Bervice,	-		
Log Atlached	i 🔄 Log i	elaward to		Dale
E Deiller's		Electric	Be Reactivity	Acoustics)/Bonie
di: Bate POINT P-8 (Special Cie	ramace) Filed?			
The state of the second s				
G. Amount of Dil produced price	to Plugging	Nor	IC bbla*	
C. Amount of Dil produced prior	to Plugging tion Report) for mon	Nor th this all was	lC produced	
41. Amount of Oil produced prior . File Point P-1 (Oil Product . C.C. MIL Coll.Y.	to Plagging tion Report) for man	Nor th this oil was	lC bbla® produced	
4. Amount of OII produced prior 4. Amount of OII produced prior 4. Plan Polint 9-1 (OII Product 5. C. VIII COILY. Slower Pield	to Plugging tion Report for mon	Nor th this all was	IC bbls®	
41. Amount of Oll produced prior • File Point 9-1 (Oll Product • Calc. unit. Ceth.Y. Slower Pietd	to Plugging tion Report) for mon	Nor th this oil was	lC bbla® produced	
4. Amount of OII produced prior 4. June Potter P-1 (OII Product EEC USE COLY. Slower Pield	to Plageing tion Report) for mon	Nor th this oil was	lC bbls" produced	
Amount of Oil produced prior Plan Point P-1 (Oil Product Sice will Geth.) Sicere m Pietd	to Flagging tion Report) for mon	Nor th this oil was	lC bbla® produced	
4. Amount of OII produced prior • Plan Potent P-1 (OII Product • C. USE Col.7. Slower Pield	to Plagging lion Report) for mon	Nor th this oil was	lC bbls " produced	
C. Amount of OII produced prior Pillo POIIN P-1 (OII Product C.C.C. Will COILY. Stours on Pield	to Plugging tion Report) for mon	Nor th this oil was	IC bbla® produced	
4. Amount of OII produced prior Pilo Potter P-1 (OII Product C.C. USE Col.7. Source Pield	to Plagging lion Report) for mon	Nor th this oil was	lC bbls " produced	
Amount of Oil produced prior Pilo Poilit P-1 (Oil Product Stoure m Pield	to Plugging tion Report) for mon	Nor th this oil was	IC bbls" produced	
All Amount of Oil produced prior Othe Potent P-1 (Oil Product Rin C will Corth Y. Slower m Pield	to Plagging lion Report) for mon	Nor th this oil was	IC bbls " produced	
Amount of Dil produced prior Amount of Dil produced prior Allo Polint P-1 (Oil Product Ref C will Coll.Y. Slower or Piold	to Plagging lion Report for mon	Nor th this oil was	IC bbls* produced	
All Amount of Oil produced prior Othe Potent P-1 (Oil Product Rin C will Corth Y. Skowern Pield	to Flagging tion Report) for mon	Nor th this oil was	IC bbls *	
Amount of OII produced prior Pilo Polint P-1 (OII Product REC VIII COLY. Slower Pield	to Plagging lion Report for mon	Nor th this oil was	IC bbls* produced	
Amount of OII produced prior Pilo Polint P-1 (OII Product REC VIE COLY. Slowern Pield	to Plagging lion Report) for mon	Nor th this oil was	IC bbls* produced	
4. Amount of OII produced prior • Pilo Potint P-1 (OII Product EAC: USE Coll-Y. Signature Pield	to Flagging	Nor th this oil was	IC bbls ^e produced	
Alexant of Dil produced prior Pilo Potent P-1 (Oil Product Ricc will Coll.Y. Slower Pield	to Plagging lion Report for mon	Nor th this oil was	IC bbls* produced	
Amount of Dil produced prior Pito Potent P-1 (Oil Product Rick will GetLy, Stown on Pield	to Flagging tion Report) for mon	Nor th this oil was	IC bbls *	
4. Amount of OII produced prior Pile Polint P-1 (OII Product REC. Hill Coll.Y. Slower Pield CO Slower Pield CO Sl	to Plagging tion Report for mon	Nor th this oil was	IC bbls* produced	
Amount of OII produced prior Pilo Polint P-1 (OII Product Rec vill Coll.y. Slowern Pield Coll 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	C 3 V 1 3 13 28 M RAKST AD ALMAN	Nor th this oil was	IC bbls* produced	

OIL AND GAS DIVISION

Ë.

CEMENTING REPORT

Wildcat		*2. MRC Disulet OB				
*1. Operator Mc. Cann. Cornoration	Barren - San	4. County				
"5. Lease Same(a) and RRC Lease Number(a) or 1. D. Num		•4. Well Humber,	oward			
 A Discrimination and Survey) 47. Location (Section, Block, and Survey) 47. Discrimination and Survey) 47. Discrimination and Survey) 	PP Co C	-			To Street Car	
Sec. 4, DIK. 29, 1-1-N, 10F	NINEACE	MTER.	PROM	ICTIOK		1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1
CASING CEMENTING DATA:	CASING	MEDIATE	Single	ing L Multipla	CENTRY	PROCESS
			String	Perellal Strings	Třel	Shee
8. Cementing Date			310 ₁	P. Burch	1. 3.3 Ca	
*9. (a) Size of Drill Bit (inches)	384.1		-			
(D) Estimated 5 Sash or Hole Enlargement Used in Calculations.	16 N	0000 10	-80, 85, 88, 88, 88,	1. 1. 65	an se an Sintan	
*10. Size of Casing (inches O.D.)		16	6 63 9	2 . 1 gar 5.	untria.	tt Electro
*31. Top of Liner (if liner used) (ft.)	937.55	Sec.				
*12. Setting Depth of Casing (ft.)		8 C	8		1.3-4 - 24 - 21	11 11-11-
3. Type API Class Cement & Amount of Additives Used: (a) in First (Lead) or Only Starry III additional space				199.00		1.4.2070
(b) In Second Sturry	0		<u></u>			1
(c) In Third Sturry		505.		22 22		2
14. Sacks of Cement Used: (a) In First (Lead) or Only Slumy						10-1-1-0
(b) in Second Siury						
(c) In Third Siwry						
(c) Total Sacks of Cement Used		21 - M-	£ 50	5 - 25 - 5 m	an a	
15. Slurry Volume per Sack of Cement (cu.it./sack): (a) In First (Lead) or Only Slurry					1000	
(b) In Second Siurry		276.0				
(c) in Third Slarry	9 54	an 200 000			and the second of the	
16. Volume of Siurry Pumped: (cu.it.) (item 14 x liem 15) (e) In First (Lead) or Only Siurr			19925			in the second
(b) in Second Sturry				11 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	1999 B.	1.
(c) in Third Siury					1000	11. 11. X 11.11.
(d) Total fluence to have the set of a b				N 52	27 S. A.	
17. Celculated Annular Height of Cement Slurry		11.22 15		100 BOR	1000 C 1000 C 1000	
behind Pipe (II.) 18. Was cement circulated to ground surface					a renter a	· · · · · · · · · · · · · · · · · · ·
(or bottom of celler) outside casing? (Yes or No)				5 S	a PHONE	ST Veral
CEMENTING TO PLUG AND ABANDON DATA:	PLUG NO. 1	PLUG NO. 2	PLUG NO. 3	PLUG NO. 4	PLUG NO. 5	PLUG NO. 6
19. Cementing Date	10-12-80	10-13-80	10-13		Acres 2	
#20. Size of Hote or Sips in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8			
•21. Depth to Hottom of Tubing or Drill Pipe (ft.)	1000	250	Top Out		13. 13.	2 ⁶ - 2
22. Facks of Coment Land (each plug)	50	100	10	ас <u>—</u>	N	i
23. Slurry Volume Pumped (cu. ft.)	66	133	13		S 8	er olin V
\$4 . 6 at-situted Pop-of 3ting (ft.)	990	70	Surf	Q. U. TEXAS		
*25. Messured Top of Flug (M tagged) (It.)			AP	R 2 0 1981	Sing M	
(CEMENTING COMPARY AND OPERATOR I	MUST COMPLY	WITH THE	INSTRUCTION	A CHILDEVED	SP SIDE HEI	PEOP 1

-te

(Nev. 14.8)

	• 27. Remarks;	
		1
	*00554 TO 5	
The sector of the prestice prescribed as Sec. \$1.143. Tesas Natural the the cetification, that the	T declare unter penalties prescribed in Sec. 31 143. Resources Code, that I am authorized to make this cost.	feres Natural
I demonstrag of cooling and/or the placing of content plugs in this work as	have incovering of the well date and information presents, and that data and facts presented on both sides of this	d ps that regist. Core and true
servet, and complete, to the best of my knowledge. This certification	covers all well data and information presented herein	
	1 4 6	
In the keldowd	For Me Cam	
Commere of Contenter or Authorized Depresentative	Bignature of Operator or Authorized Representative	
	Tom McCann - President	
Butter of Person and Title (type ar print)	"Name of Person and Title (type or print)	
Benell Division of Dow Chemical Co.	McCann Corporation	
Committee Company	*Op#retor	
Banta 3. Box 178	P. O. BUX 448	
Shiert Address or P.O. Box	*Street Address or P.O. Box	
Colorado City, Tx 79512	Big Spring, Texas	75736
City, Baste Zip Cede	*City, State	Lip Cade
915 728-5291	•Telephane 915 267-7488	
Area Code	Arma Coda	
10-14-80	- <u>61-6-81</u>	212 S 252 S
10-14-80 Date IN L. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting rej to computing requirements in Statewide or Special Rules;	STRUCTIONS Mice with: port is required by Statewide or Special Rules, or if eccept	tion is normed
10-14-80 This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a communing regulation of the transmission of transmission of the transmission of	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etion. or each cementing company used on a well.	tion is needed
10-14-80 Date IN L. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation is computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The computing of different casing strings on a well by one co	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be a	tion is needed
10-14-80 Date IN 1. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a community re- to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companing of different casing strings on a well by one co 2. Companing Company and Operator shall comply with the applicable C. The company and Operator shall comply with the applicable	A-G-BL STRUCTIONS Mfice with: port is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be a the portions of Statewide Rules 8, 13, and 14. For offshore the 13 (5)	tion is needed filed in duplicat
10-14-80 This This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a community reprive to community requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed f C. The commaning of different casing strings on a well by one cas 2 Communing Company and Operator shall comply with the applicable Communing Company and Operator shall comply with Statewide Rules 2 W anther Will L. AMOUNT OF SURFACE CASING:	A-G-HL STRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etion. or each cementing company used on a well. menting company may be consolidated on one form (to be a lise portions of Statewide Rules 8, 13, and 14. For offshore all [3(E).	tion is needed filed in duplicat r operations .
IN 10-14-80 Date IN 1. A. This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a commanding regularements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed f C. The commanding of different casing strings on a well by one com- 2. Commaning Company and Operator shall comply with the applicable Commaning Company and Operator shall comply with Statewide Ru- B. At least an UP operator shall comply with Statewide Ru- 2. Commaning Company and Operator shall comply with Statewide Ru- 3. Beeting FULL AMOUNT OF SURFACE CASING- A. Depth to protect fresh water determined by:	A-6-Bl STRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be in the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E).	tion is needed filed in duplicat poperations .
ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a communing register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companies of different casing strings on a well by one case Companies Company and Operator shall comply with the applicable Companies Company and Operator shall comply with Statewide Rules; (1) Fi Rule A. Depth to protect fresh water determined by: (1) Fi Rule a. Water Development Doard, if op Field Bulk	A-G-BL STRUCTIONS Mfice with: port is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be a the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E).	tion is needed filed in duplicat poperations.
ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a communing re- to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The company and operator shall comply with the applicable Companing Company and Operator shall comply with Statewide Rules; (3) Each approximation of SURFACE CASING: A. Depth to protect frash water determined by: (1) Fi Rule (2) To a Water Development Board, if no Field Rule E Set surface casing below depth to be protected and comment for	A-G-HL STRUCTIONS Mfice with: port is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be a le portione of Statewide Rules 8, 13, and 14. For offahore le I3(E). om casing shoe to ground surface.	tion is needed filed in duplicat poperations .
IN A. This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a commanding regulation of the special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed f C. The commanding of different casing strings on a well by one col Commanding Company and Operator shall comply with the applicable Commaning Company and Operator shall comply with Statewide Rules; (1) Fi Rule (2) To swater Development Board, if no Field Rule B. Set surface casing below depth to be protected and cement for ALEDAD COMMISSION.	A-G-BL STRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etion. or each cementing company used on a well. menting company may be consolidated on one form (to be a la portions of Statewide Rules 8, 13, and 14. For offshore the 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE	tion is needed filed in duplicat poperations . IP FROM THE
ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companies of different casing strings on a well by one co Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) Fi Rule (2) To a Water Development Board, if no Field Rule B. Set surface casing below depth to be protected and cement for A. Depth to protect fresh water the protected and cement for A. Set surface casing below depth to be protected and cement for A. If SETTING ANYTHING OTHER THAN THE FULL ANOUNT OF RAL ROAD COMMISSION. 5: If setting NO SURFACE CASING (See Item 4 above.):	A-6-HL ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be in the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE	tion is needed filed in duplicat operations.
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation of the computing requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing complements in Statewide or Special Rules; (3) Each copy of Form W-4 if a multiple parallel casing complements in Statewide or Special Rules; (3) Each copy of Form W-4 if a multiple parallel casing complements in Statewide or Special Rules; (3) Each copy of Form W-4 if a multiple parallel casing complements in Statewide or Special Rules; (3) Each copy of Form W-4 if a multiple parallel casing complements in Statewide or Special Rules; (4) Each copy of Form W-4 if a multiple parallel casing complement for the community of this form shall be filed for the community of the special casing being of different casing strings on a well by one casing betting FULL ANOUNT OF SURFACE CASING; A. Depth to protect fresh water determined by: (1) File Rule (2) Tile Swater Development Board, if no Field Rule B. Set surface casing below depth to be protected and cement for RAL ROAD COMMISSION. If satting NO SURFACE CASING (See Item 4 above.): A: If so multi-stage tool is used, the next deeper casing string or string or string or string or string string or string string or string string	AL-G-HL STRUCTIONS Mfice with: port is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be in the portions of Statewide Rules 8, 13, and 14. For offshore lie 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface.	tion is needed filed in duplicat poperations.
 10-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation of the computing requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed f C. The command of different casing strings on a well by one cold Commuting Company and Operator shall comply with the applicable Commuting Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for Rall ROAD COMMISSION. If setting NO SURPACE CASING (See Item 4 above.): A: If no multi-stage tool on the next deeper string, cement 	A-G-BL STRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etion. or each cementing company used on a well. menting company may be consolidated on one form (to be a le portione of Statewide Rules 8, 13, and 14. For offshore ile I3(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. tifrom the depth that protects fresh water sands to the surface.	tion is needed filed in duplicat poperations.
ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commanding regulation of the second secon	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be in the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. to from the depth that protects fresh water sands to the surface.	tion is needed filed in duplicat r operations . IP FROM THE
IN I. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting register is computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicabl Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RAL ROAD COMMISSION. I fisetting NO SURFACE CASING (See Item 4 above.): A: If no multi-stage tool is used, the next deeper string, cement If satting SHORT SURFACE CASING (See Item 4 above.): A: Cement short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper.	A-6-BL STRUCTIONS Mice with: poort is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be in the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E). on casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL THE OBTAINE hall be cemented from the casing shoe to the surface. to from the depth that protects fresh water sands to the surface. Per casing string, cement from the depth that protects fresh	tion is needed filed in duplicat roperations. In FROM THE face.
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District (1) Each copy of an initial Form G-1 or W-2 if a commuting registerments in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing complete comparing of different casing strings on a well by one case. Comparing Company and Operator shall comply with the applicable Commuting Company and Operator shall comply with Statewide Rules; (1) File Rule (2) Tries a Water Development Board, if no Field Rule E Set surface casing below depth to be protected and cement for RAL ROAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: This multi-stage tool is used, the next deeper string, cement If satting SHORT SURFACE CASING (See Item 4 above.): A: Cement short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper (1) the surface, or (2) a point midway between shoe of surface string and the surface string of the string of the surface of the surface string and the surface string and the surface string and the surface string and the surface string of the surface string and string and the surface st	ISTRUCTIONS Mice with: poort is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be in the portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its 13(E). or casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL THE OBTAINE hall be cemented from the casing shoe to the surface. trifrom the depth that protects fresh water sands to the surface. per casing string, cement from the depth that protects fresh face. Compliance will be considered if a temperature sur- from the shue of the surface string to the surface.	tion is needed filed in duplicat roperations, operations, in provide the face.
IN 14. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting re- to compating requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl At least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicable Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and coment for RAILROAD COMMISSION: 5. If setting NO SURFACE CASING (See Item 4 above.): A.: The omalti-stage tool is used, the next deeper casing string o B: If using the multi-stage tool on the next deeper string, common (1) stating SHORT SURFACE CASING (See Item 4 above.): A.: Corecent short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next for (1) the surface, or (2) a point midway between shoe of surface string and the sur- the top of the coment is at least one-third of the distance 5. Sontag PRODUCTION STRING of Casing: (Statewide Rules, Specific String) of the surface Rules, Specific String of String of the surface Rules, Specific Rules, Specific Rules, Specific Rules, Specific Rules, Specific Rules, String String of String of the surface, or (2) a point midway between shoe of surface string and the sur- the top of the coment is at least one-third of the distance	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be in the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E). on casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL THE OBTAINE hall be cemented from the casing shoe to the surface. to from the depth that protects fresh water sands to the surface face. Compliance will be considered if a temperature surface from the shue of the surface string to the surface cial Rules may vary b	tion is needed filed in duplicat r operations, ip FROM THE face. Is water satisfies to yee, shown that
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commating regularements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple A. At least an original and one copy of this form shall be filed f C. The command of different casing strings on a well by one cas Commany and Operator shall comply with the applicable Commany and Operator shall comply with Statewide Rules; (1) File Rule (2) To a state Development Board, if no Field Rule B. Set surface casing below depth to be protected and comman for RALENDAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: This multi-stage tool is used, the next deeper string, command If setting SHORT SURFACE CASING (See Item 4 above.): A: Commant surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper (1) the surface, or (2) a point midway between shoe of surface string and the surface. E. Statement is at least ene-third of the distance 	A-6-BL STRUCTIONS Mice with: poort is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be in the portions of Statewide Rules 8, 13, and 14. For offshore the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E). or casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL THE OBTAINE hall be cemented from the casing shoe to the surface. to from the depth that protects fresh water sands to the surface. The casing string, cement from the depth that protects fresh face. Compliance will be considered if a temperature sur- from the shue of the surface string to the surface cial Hules mey vary 1	tion is needed filed in duplicat roperations, operations, operations, is provided to the face.
 ID-14-80 This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form C-1 or W-2 if a commiting requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed f C. The cementing of different casing strings on a well by one cell Comenting Company and Operator shall comply with the applicable Comenting Company and Operator shall comply with Statewide Rules; (2) The cementing of different casing strings on a well by one cell Comenting Company and Operator shall comply with Statewide Rules; (3) Each copy of Porm W-4; if a multiple parallel casing complete the casing company and Operator shall comply with Statewide Rules; Commenting FULL AMOUNT OF SURFACE CASING; A. Depth to protect fresh water determined by: (1) Fi Rule (2) Tr s Water Development Board, if no Field Rule B. Set surface casing below depth to be protected and cement from RALENDAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: The multi-stage tool is used, the next deeper casing string to B; If using the multi-stage tool on the next deeper string, cement If setting SHORT SURFACE CASING (See Item 4 above.): A: Cement short surface casing from the shot to the surface. B. Whether the multi-stage tool is or is not used on the next deeper (1) the surface, or (2) a point midway between shoe of surface string and the sut the top of the cement is at least ene-third of the distance Senting PRODUCTION STRING of Casing: (Statewide Film, Spe A. Cement to a point at least 600 feet above the casing shoe. B. When 3,090 feet or more of piperlistate. 	ISTRUCTIONS Mice with: poort is required by Statewide or Special Rules, or if except etion. or each cementing company used on a well. menting company may be consolidated on one form (to be a lise portions of Statewide Rules 8, 13, and 14. For offshore he 13(E). or casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. to from the depth that protects fresh water sands to the surface face. Compliance will be considered if a temperature surface from the shoe of the surface string to the surface cial Rules may vary b electing string, a minimum of 30 feet of cempt shall temperature.	tion is needed filed in duplicat roperations, operations, operations, for PROM THE face.
 ID-14-80 Data IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commating requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing compil A. At least an original and one copy of this form shall be filed file. C. The company and Operator shall comply with the applicable Company and Operator shall comply with the applicable Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (2) The company and Operator shall comply with Statewide Rules; (3) Encloared Company and Operator shall comply with Statewide Rules; (4) File Rule (5) The state of the state determined by: (1) File Rule (2) The state casing below depth to be protected and cement for the SETTING ANYTHING OTHER THAN THE FULL AMOUNT OF RALEROAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A.: The summative casing from the shot to the surface. B. The states, or (3) a point midway between shoe of surface string and the state the top of the cement is at least one-thurd of the distance. B. When 3,000 feet or more of piperlarae. FLUGGING and ABANDONING: 	ISTRUCTIONS Mice with: poort is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. meenting company may be consolidated on one form (to be in the portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its form the state to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. triftom the depth that protects fresh water sands to the surface. triftom the depth that protects fresh water sands to the surface face. Compliance will be considered if a temperature surface from the shue of the surface string to the surface cial Rules may vary 1 etecting string, a minimum of J0 feet of cements shall be appeared of the shue of the surface string to the surface strin	tion is needed filed in duplicat roperations. In FROM THE face. Is water satisfies to very shown that
 ID-14-80 IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a community requirements in Statewide or Special Rules; (2) Each copy of Form W-3 if a multiple parallel casing compling. At least an original and one copy of this form shall be filed file. The comenting of different casing strings on a well by one can company and Operator shall comply with the applicable Community Company and Operator shall comply with Statewide Rules; (1) File Rule Matter Public Amount OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) File Rule (2) Tr. a Water Development Board, if no Field Rule B. Set surface casing below depth to be protected and cement for RALEROAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: The surface tool is used, the next deeper casing string to B: If using the multi-stage tool is used, the next deeper casing string to B: If using SHORT SURFACE CASING (See Item 4 above.): A: Cement short surface casing from the shoe to the surface. B: Whether the multi-stage tool is or is not used on the next deep (1) the surface, or (2) a point midway between shoe of surface string and the surface. Cement to a point at least 600 feet, above the casing shoe. B. When 3,000 feet or more of piperistate. Matter Production STRING of Casing: (Statewide Rulen, Special A: Cement to a point at least 600 feet, above the casing shoe. Matter Production STRING of Casing: (Statewide Rulen, Special defined of the distance Matter Production STRING of Casing: (Statewide Rulen, Special defined production or production or production or production or production or production of Disperiatate. 	ISTRUCTIONS Mice with: poort is required by Statewide or Special Rules, or if except etton. or each cementing company used on a well. menting company may be consolidated on one form (to be in the portions of Statewide Rules 8, 13, and 14. For offshore lie Bortions of Statewide Rules 8, 13, and 14. For offshore lie I3(E). or casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. to from the depth that protects fresh water sands to the surface. per casing string, cement from the depth that protects fresh face. Compliance will be considered of a temperature sur- from the shue of the surface string to the surface cial Rules may vary 1 extercting string, a minimum of di) feet of cement shall be a Rules and Regulations of the Commission plus any addition	tion is needed filed in duplicat r operations, ip FROM THE face. Is water called to ver shows that if course the pro-
 ID-14-60 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a comrating registements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compile A. Least an original and one copy of this form shall be filed filed file companies of different casing strings on a well by one ca Companies Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) Tile a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for a Water Rule State Rules; (2) Tile Rule (2) Tile Rule (2) Tile Rule (3) File Rule (4) File Rule (5) File Rule (6) File Rule (7) File Rule (8) Set surface casing below depth to be protected and cement for RALERDAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A. The multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool is or is not used an the next deep (1) the surface. B. Whether the multi-stage tool is or is not used an the next deep (1) the surface, or (2) a point midway between shoe of surface string and the suit the top of the cement is at least one-third of the distance A. Cement to a point at least 600 feet upoy the casing shoe. B. When 3,000 feet or more of piperistate. For the distance A. Cement plugs shall be placed in the well bore as required by be specified by the RRC District. Director. B. The minimum amount of diment in the dist in each plug shall be placed in the well bore is a required by be specified by the RRC District. Director. 	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etion. or each cementing company used on a well. menting company may be consolidated on one form (to be a lise portions of Statewide Rules 8, 13, and 14. For offshore rile 13(E). on casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. there are and a to the surface state water sands to the surface from the depth that protects fresh water sands to the surface. (from the depth that protects fresh water sands to the surface face. Compliance will be considered if a temperature surface from the shoe of the surface string to the surface cial Rules may vary () effecting string, a minimum of 30 feet of cempt shall be a Rules and Regulations of the Commission plus any additional sill be a slurry volume equal to the amount no enfort to fill	tion is needed filed in duplicat roperations. In pressions. Is water satisfies face. Is water satisfies to you shows that of costs of the pro- sing ploge on the it the calculated

APPENDIX B - SITE SAFETY AND LAYOUT

Bayswater Operating's Mongoose Gas Plant and AGI No. 1 are operated and monitored 24 hours a day, 7 days a week, by on-site personnel utilizing Plant operating and SCADA systems. These systems gather operating data such as pressures, temperatures, flow rates, remote sensors, compressor run data, and control valve positions. The recording and retention of this operating data enables the operator to evaluate trends and use predictive analytics to potentially identify issues before they become an "alarm" event. If an alarm event occurs, the automated control system is programmed to execute pre-programmed protocols to safely manage the event. Operators are specially trained to follow detailed practices to minimize risk to people, the facility, and the environment.

In the event of a leak or system failure, the Plant control system will execute its shutdown protocols as timely as is practicable to isolate the event and minimize the intensity. The Plant operator will investigate the circumstances and oversee an orderly resolution to the situation. Since this facility handles H₂S, Bayswater is required to maintain a Hydrogen Sulfide Contingency Plan to safely manage any planned or unplanned release event. The Plant operating staff are highly trained in safety and emergency response protocols to ensure safety for both plant personnel and the surrounding community and environment.



B	-2

			ITEM	DESCRIPTION
			1	SLUG CATCHER
			2	INLET COMPRESSOR W/ COOLER
	1		2F	INLET COMPRESSOR (FUTURE) W/ COOLER
			3	COMPRESSOR DISCHARGE COALESCER
			4	
	v	V	× 6	
	1	~		
			8	
			9	
			10	AMINE REGENERATOR REBOILER
	1		11	AMINE SURGE TANK
			12	AMINE BOOSTER/REFLUX PUMP SKID
			13	AMINE REGENERATOR REFLUX CONDENSER
			14	LEAN AMINE COOLER
			15	AMINE CHARGE PUMPS
			16	HOT OIL PUMP SKID
			17	HOT OIL HEATER
			18	FLARE K.O. DRUM
	1		19	FLARE
- BARF	RIER		20	COMBUSTOR
			21	SLOP STORAGE TANKS
	+		22	AMINE MAKE UP STORAGE TANK
			23	
			24	
			241	
			25	
	1		20	
			27	
			20	DI WATER TANK
	·		30	GLYCOL CONTACTOR
			31	GLYCOL SEPARATOR
			32	TEG REGEN
			33	BTEX
			34	GAS GENERATOR SET
			35	AMINE SUMP TANK
			36	NEW LUBE OIL TANKS
			37	CONDENSATE TRANSFER PUMPS
			38	VAPOR RECOVERY UNIT
			39	TANK COMBUSTOR K.O. DRUM
			40	MV TRANSFORMER
			40F	MV TRANSFORMER (FUTURE)
				LEGEND
				FIRE EXTINGUISHER = 9 ea.
				HYDROGEN SULFIDE DETECTOR = 10 ea.
				AUDIBLE ALARM SOUNDER = 4 ea.
				R STROBE LIGHT (RED) — FIRE = 4 ea.
_	- EAST_SECU	RITY GATE		SHUT PLANT EMERGENCY SHUTDOWN = 6 ea.
				FIRST AID & SCBA KIT = 3 ea.
	-*X -	X		EYE WASH STATION = 3 ea.
	й С		E 10(WIND SOCK = 1 ea.
				MUSTER POINT = 3 ea.
r :	RΔ	YSWATER	FXPLOR	ATION & PRODUCTION
CT ·	DA	COUD		
		SUUK	GAS IR	EATING FAUILITY
·		FACILITY	INSTRUN ′SAFET`	IENTATION (LOCATION PLAN
WN	CHECKED	SCALE	DATE	JOB NO. DRAWING NO. SHEET NO.
DC DC	GA	AS NOTED	06/09/22	BAY220316 IN-PLN-0790 1 OF 1

APPENDIX C – AREA OF REVIEW

APPENDIX C-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX C-2: OIL AND GAS WELLS WITHIN THE MMA LIST



Mongoose AGI No. 1

	Area of Review: Oil & Gas Wells List												
API	WELL NAME WELL NO.		CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (FT.)	PERFORATED INTERVAL (FT.)	DATE DRILLED			
4222700101	22700101 JONES, C.L 1 ARMER L H 1603		1603	32.445815	-101.187399	DRY HOLE	NR	NR	NR				
4222703634	STEWART 1 MCCANN CORP		1601	32.423136	-101.1837088	DRY HOLE	8670	NR	10/11/1980				
4222732304	CATHEY	1	MCCANN CORP	204	32.42347	-101.1890569	DRY HOLE	4310	NR	10/31/1980			
4222734502	STERLING CATTLE COMPANY	3402	MDC TEXAS ENERGY	1603	32.44553	-101.17894	P & A	7795	7764-7795	10/19/1989			
4222734688	STERLING FAMILY TRUST	3403	TREND EXPLORATION COMPANY	1603	32.4403185	-101.1792589	P & A	7918	7747-7760	3/5/1992			
4222736361	STERLING 38	1	HIGHPEAK ENERGY	1371	32.42744	-101.196842	INACTIVE PRODUCER	8075	5635-7848	4/5/2010			
4222741505	KAMIKAZE 5-8	H 3W	BAYSWATER OPERATING COMPANY LLC	204	32.399666	-101.180898	PRODUCING	5433	5911-15810 (MD)	1/9/2022			
4222741505	KAMIKAZE 5-8-17-20	ЗW	BAYSWATER OPERATING COMPANY LLC	204	32.426344	-101.191374	PRODUCING	5643.22	5911-15810 (MD)	1/9/2022			
4222741939	WINFORD 35-38 B UNIT A	7H	HIGHPEAK ENERGY	745	32.450886	-101.197238	PRODUCING	5785.42	6081-15105 (MD)	9/9/2022			
4222741972	PHARAOH 10-15-34-39	H 1W	BAYSWATER OPERATING COMPANY LLC	1602	32.473311	-101.191423	INACTIVE PRODUCER	5847	NR	10/27/2022			
4222742086	KAMIKAZE 5-8	H 2WD	BAYSWATER OPERATING COMPANY LLC	204	32.426337	-101.191712	COMPLETED	7821	NR	4/14/2023			
4222742087	KAMIKAZE 5-8	H 4WX	BAYSWATER OPERATING COMPANY LLC	204	32.4263090	-101.1918370	COMPLETED	5818	NR	4/5/2023			
4222742088	KAMIKAZE 5-8	H 2W	BAYSWATER OPERATING COMPANY LLC	204	32.4262950	-101.1919000	COMPLETED	5669	NR	3/22/2023			
4222742089	KAMIKAZE 5-8	H 1WD	BAYSWATER OPERATING COMPANY LLC	204	32.4263230	-101.1917740	COMPLETED	7820	NR	4/8/2023			
4222742105	KAMIKAZE 5-8	H 1W	BAYSWATER OPERATING COMPANY LLC	204	32.4262810	-101.1919620	COMPLETED	5816	NR	5/24/2023			



Mongoose AGI No. 1

4233500959	59 MACKEY, P.K.		MCDERMOTT-RAY	1344	32.4133665	-101.1552679	DRY HOLE	NR	NR	4/25/1954
4233501046	MACKEY, P.K.	1	MOSS H S	582	32.4215460	-101.1434280	DRY HOLE	NR	NR	12/8/1947
4233501860	JONES, CHESTER L	1	DANSBY, BEN JR.	17	32.4497350	-101.1605990	DRY HOLE	NR	NR	NR
4233533555	VAN TUYLE	1	BRIGHT & COMPANY	584	32.4027340	-101.1529820	P & A	8360	NR	11/26/1990
4233533624	STERLING FAMILY TRUST-A-	3301	MDC OPERATING, INC.	17	32.4438844	-101.1638476	P & A	7850	7756-7760	1/23/1993
4233535973	SI-10.2 CP UNIT	1	ENERGY TRANSFER	1536	32.4233850	-101.1407330	PERMIT EXPIRED	550	NR	-
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.434283	-101.161962	PRODUCING	5543	6052-19217 (MD)	7/7/2022
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.4717700	-101.1619280	PRODUCING	5543	6052-19217 (MD)	7/6/2022
4233536030	JADE PALACE 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1344	32.4049880	-101.1607180	DUC	5491	NR	11/8/2022
4233536031	GOLDEN SAND 10-3	H 1W	BAYSWATER OPERATING COMPANY LLC	1344	32.4050010	-101.1606550	DUC	5606	NR	11/8/2022
4233536041	PEARL RIVER 4-9	H 1W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016760	-101.1745840	PERMITTED	7100	NR	-
4233536042	PEARL RIVER 4-9	H 2W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016620	-101.1745210	PERMITTED	7100	NR	-
4233536045	PEARL RIVER 4-9	H 3W	BAYSWATER OPERATING COMPANY LLC	1634	32.4017660	-101.1748560	PERMITTED	7100	NR	-
4233536046	PEARL RIVER 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016350	-101.1743950	PERMITTED	7100	NR	-
4233536047	JAVA 16-21	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016210	-101.1743330	PERMITTED	7100	NR	-

*Note: Well entries in red penetrate the upper confining layer.



APPENDIX D – SECTION 2 CROSS SECTIONS

APPENDIX D-1: FIGURE 27 – STRUCTURAL CROSS SECTION DEPICTING THE ELLENBURGER

APPENDIX D-2: FIGURE 28 – STRATIGRAPHIC CROSS SECTION FLATTENED ON THE ELLENBURGER



D-1



Request for Additional Information: Mongoose Amine Treating Facility December 6, 2023

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/Responsible Person
	Section	Page		
1.	N/A	N/A	The MRV plan mentions the Mongoose Amine Treating Facility, the Bayswater Amine Facility, and the Mongoose Gas Plant when referencing the facility's name, however, the facility is listed as the "Mongoose Amine Treating Facility" on e-GGRT. For clarity, we recommend reviewing the MRV plan to ensure that all references to the facility and CO_2 supplier are consistent. Does the Bayswater Amine Facility report any GHG data?	All facility naming references have been edited for consistency to Mongoose Amine Treating Facility, the Mongoose, and the Plant as appropriate. As provided in Section 1.3 Bayswater is currently reporting to the GHGRP under ID: 586481
2.	2.1	17	"However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area." We recommend clearly labeling the fault mentioned above in Figure 7 of the MRV plan.	Figure 7 has been updated to identify the nearest fault.
3.	2.2	21	"Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose." Please clarify the distance between the Mongoose AGI No. 1 well and the offset Buchanan 3111 #1XD well. Additionally, we recommend showing the proximity of the offset well relative to the Mongoose AGI No. 1 well.	Section 2.2.2 (pg. 21) was edited to specify the offset well distance of 10.4 mi. and Figure 11 (pg. 22) was added for reference.
4.	2.3	39	"Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the subject well ." Please clarify what is meant by "subject well".	Sec. 2.3 was edited to specify the subject well as the Buchanan 3111 #1XD.

No.	. MRV Plan		EPA Questions	Responses/Responsible Person	
	Section	Page			
5.	2.4	41	"Figure 26 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map."	References to figures have been corrected/updated.	
			The statement above references Figure 26, but the description matches the label for Figure 27. Please review the MRV plan to ensure that all references to figures and tables within the text are correct.		
6.	2.4	42	We recommend adding units to Figure 26.	Units are noted in 'subsea feet' in the figure caption.	
7.	2.8	52	"The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 0.1, an irreducible water saturation of 0.397, and a maximum residual gas saturation of 30%." We recommend that saturations be consistently expressed as either decimals or percents to the extent possible.	Edited as appropriate to present saturation numbers in percent. 0.10 changed to 10% 0.397 changed to 39.7%	
8.	3.1	63	Per 40 CFR 98.449, maximum monitoring area 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. While the MRV plan identifies the MMA, please state in the plan whether the MMA in Figure 41 includes a ½ mile buffer as described above.	Section 3.1 is edited to define the MMA as inclusive of a one half mile all-around buffer as depicted in Figure 41.	
9.	4	66	Please provide a clear characterization of the likelihood, magnitude, and timing of leakage for each identified potential leakage pathway.	Table 12 was added on pg. 67	
10.	4.1	66	"Monitors for H_2S are installed at key locations around the Plant."	OSHA exposure limits have been added to Sec. 4.1, pg 67.	
			Please clarify the detection limit of the H_2S monitors and at what point they would trigger.		

No.	. MRV Plan		EPA Questions	Responses/Responsible Person
	Section	Page		
11.	4.0	67	Figure 43 of the MRV plan shows the Bayswater Amine Facility and provides a description of the surface equipment and monitors. We recommend showing the location of all flow meters relevant to subpart RR calculations in this or a similar figure.	A detailed site Plan is provided in Appendix B-2.
12.	4.2	69	"Figure 46 highlights that only two wells penetrate the MMA's gross injection zone, and these wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements." While Section 4.2 of the MRV plan states that these wells are plugged and abandoned, please provide a clear characterization of the likelihood, magnitude, and timing of potential leakage from this pathway. Please also provide any applicable monitoring/detection/quantification strategies as necessary.	Table 12, page 67 has been added. Also, penetrations of the gross injection interval within the MMA will be monitored by taking annual soil gas samples adjacent to the APs. These will be analyzed by a third- party lab and any results indicating the presence of sequestered CO ₂ will be provided in the annual report.
13.	4.0	70	There are two figures labeled "Figure 45" in the MRV plan. Please address this and revise the table of contents accordingly.	Figure labels and the Table of Contents have been updated.
14.	4.0	70	Figure 45 of the MRV plan identifies several wells within the MMA/AMA. While the wells that penetrate the injection zone are discussed in Section 4.2, there is no discussion regarding wells completed to other formations. Please evaluate the possibility of leakage from these wells in the MRV plan and include any applicable monitoring/detection/quantification strategies as necessary.	Section 4.2 has been edited with commentary regarding wells completed above the Upper Confining Zone.
15.	5.4	79	"This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 50." The MRV plan does not contain a "Figure 50." Please address this and revise the table of contents accordingly.	Figure reference has been updated (pg. 80)

No.	MRV Plan		EPA Questions	Responses/Responsible Person
	Section	Page		
16.	7.4	82	"those emissions sent to a flare stack and reported as a part of the required GHGG reporting for the Plant." Please define GHGG or revise this sentence as necessary.	Edits have been made for consistent reference of GHGRP and GHG.
17.	7.4	82	" CO₂ = Total annual CO ₂ mass emitted by surface leakage (metric tons) in the reporting year." According to 40 CFR 98.443, the correct variable for Equation RR-10 is CO _{2e} . Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443. See <u>https://www.ecfr.gov/current/title-40/chapter-l/subchapter-C/part-98/subpart-RR/section-98.443</u> for reference.	The equation has been corrected to read CO_{2E}
18.	NA	NA	40 CFR 98.448(a)(7) requires a "Proposed date to begin collecting data for calculating total amount sequestered according to equation RR–11 or RR–12 of this subpart. This date must be after expected baselines as required by paragraph (a)(4) of this section are established and the leakage detection and quantification strategy as required by paragraph (a)(3) of this section is implemented in the initial AMA." Please clarify whether such a date is specified in the MRV plan.	By May 20, 2024, Bayswater shall perform the necessary air gas and soil gas sampling and analysis to establish a CO ₂ baseline for the Mongoose MRV Plan. Bayswater shall begin collecting data for calculation of the sequestered volumes upon the first date that both of the following have occurred: 1) Approval of this MRV plan by the GHGRP, and 2) Completion of the baseline sampling program as provided in the MRV plan.
19.	NA	NA		There are numerous edits made to the MRV plan 1) in response to this RAI; 2) in grammatical edits subsequent to the RAI responses for better clarification; and 3) deletions of material no longer relevant based on these edits.



Subpart RR Monitoring, Reporting, and Verification (MRV) Plan Mongoose AGI No. 1

Mitchell County, TX

Prepared for *Bayswater Operating Company LLC* Denver, CO

Ву

Lonquist Sequestration, LLC Austin, TX

> Version 1.0 October 2023



INTRODUCTION

Bayswater Operating Company LLC (Bayswater) currently has a Class II acid gas injection (AGI) permit, issued by the Texas Railroad Commission (TRRC) for the Mongoose AGI No. 1 well (Mongoose), API No. 42-335-36013. The permit was issued March 10, 2023. This permit authorizes Bayswater to inject up to 6.9 million standard cubic feet per day (MMscf/D) of carbon dioxide (CO₂) and hydrogen sulfide (H₂S) into the Ellenburger formation at a depth of 8,300 feet (ft) to 9,000 ft with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). The Mongoose is a new well and is associated with the Bayswater Amine Facility (the Plant) located in a rural area of Mitchell County, Texas, as shown in Figure 1.



Figure 1 – Location of Mongoose AGI No. 1 Well

Bayswater is submitting this Monitoring, Reporting, and Verification (MRV) Plan to the Environmental Protection Agency (EPA) for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Bayswater is also seeking TRRC approval to amend the existing Mongoose permit by increasing the permitted maximum quantity of injected treated acid gas (TAG) from 6.9 MMscf/D to 19.5 MMscf/D. Bayswater is planning to construct additional plant capacity coinciding with future production growth. Bayswater intends to inject into this well for approximately 40 years at up to a maximum of 19.5 MMscf/D. The primary source of this injected CO₂ gas is the Bayswater Amine Facility. Table 1 shows the expected composition of the gas stream to be sequestered. Table 2 shows the expected average daily volume of acid gas.

Table 1 – Expected Gas Composition

Component	Mol Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

Table 2 – Expected Sequestered Gas Volumes

Contract Status	Avg. Rate (MMscf/D)
Committed	6.9
Proposed	12.6
Total	19.5

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH ₄	Methane
CMG	Computer Modelling Group Carbon Dioxide (may also refer to other Carbon
CO ₂	
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H ₂ S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet

MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
Ν	North
NW	Northwest
OBG	Overburden Gradient
PG	Pore Gradient
рН	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
ТАС	Texas Administrative Code
TAG	Treated Acid Gas
тос	Total Organic Carbon
TRRC	Texas Railroad Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West
TABLE OF CONTENTS

INTRO	DUCTIO	Ν	2
ACRO	NYMS AI	ND ABBREVIATIONS	4
SECTIC	DN 1 – U	IC INFORMATION	10
1.1	Unde	rground Injection Control Permit Class: Class II	10
1.2	UIC V	Vell Identification Number	10
1.3	Repo	rter Number	10
1.4	Facili	ty Address	10
SECTIC	DN 2 – P	ROJECT DESCRIPTION	11
2.1	Regiona	l Geology	11
	2.1.1	Regional Faulting	20
2.2	Site C	Characterization	20
	2.2.1	Stratigraphy and Lithologic Characteristics	20
	2.2.2	Upper Confining Zone – Woodford Shale	21
	2.2.3	Injection Interval – Ellenburger	28
	2.2.4	Lower Confining Zone – Precambrian	37
2.3	Geon	nechanics	39
	2.3.1	Determination of Vertical Stress (S _v) from Density Measurements	39
	2.3.2	Elastic Moduli and Fracture Gradient	39
2.4	Local	Structure	41
2.5	Inject	tion and Confinement Summary	45
2.6	Grou	ndwater Hydrology	45
2.7	Desc	ription of the Injection Process	51
	2.7.1	Current Operations	51
2.8	Rese	rvoir Characterization Modeling	51
	2.8.1	Simulation Modeling	54
SECTIC)N 3 – D	ELINEATION OF MONITORING AREA	63
3.1	Maxi	mum Monitoring Area	63
3.2	Activ	e Monitoring Area	64
SECTIC	DN 4 – P	OTENTIAL PATHWAYS FOR LEAKAGE	66
4.1	Leaka	age from Surface Equipment	66
4.2	Leaka	age Through Existing Wells Within the MMA	69
	4.2.1	Future Drilling	72
	4.2.2	Groundwater Wells	72
4.3	Leaka	age Through Faults and Fractures	74
4.4	Leaka	age Through the Confining Layer	74
4.5	Leaka	age from Natural or Induced Seismicity	74
SECTIC)N 5 – N	1ONITORING FOR LEAKAGE	76
5.1	Leaka	age from Surface Equipment	77
5.2	Leaka	age Through Existing and Future Wells Within the MMA	77
5.3	Leaka	age Through Faults, Fractures, or Confining Seals	79
5.4	Leaka	age Through Natural or Induced Seismicity	79
SECTIC	DN 6 – B	ASELINE DETERMINATIONS	80
6.1	Visua	l Inspections	80
Sı	ıbpart RI	R MRV Plan – Mongoose AGI No. 1	Page 6 of 89

6.2	CO ₂ /H ₂ S Detection	80
6.3	Operational Data	80
6.4	Continuous Monitoring	80
SECTION	7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION	81
7.1	Mass of CO ₂ Received	81
7.2	Mass of CO ₂ Injected	81
7.3	Mass of CO ₂ Produced	82
7.4	Mass of CO ₂ Emitted by Surface Leakage	82
7.5	Mass of CO ₂ Sequestered	83
SECTION	8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN	84
SECTION	9 – QUALITY ASSURANCE	85
9.1	Monitoring QA/QC	85
9.2	Missing Data	85
9.3	MRV Plan Revisions	86
SECTION	10 – RECORDS RETENTION	87
SECTION	11 - REFERENCES	

Figures

Figure 1 – Location of Mongoose AGI No. 1 Well	2
Figure 2 – Overview map of the Permian Basin including subregion names and counties. The	e red
star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Mal	e, &
Walsh)	12
Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)	13
Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf	14
Figure 5 – Cross section indicating formation truncations when approaching the Eastern S	Shelf
(Waite, 2021)	15
Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenbu	irger
Group of the Permian Basin, West Texas, 2006)	16
Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth	17
Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Lou	ucks,
2003)	18
Figure 9 – Type Log and Disposal Units and Zones from PXD Well No. 1 (Sanchez, Loughr	y, &
Coringrato, 2019)	19
Figure 10 – Mongoose AGI No. 1 Type Log	20
Figure 11 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depic	cting
the Woodford and sidewall cores.	22
Figure 12 – Core Photo of Samples Within the Woodford Formation	23
Figure 13 – Routine Core Analysis Within the Woodford Formation	24
Figure 14 – Graph of Threshold Entry Pressure Within the Woodford Formation	25
Figure 15 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Forma	ation
~ , , , ,	26
Figure 16 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation	27
Figure 17 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)	29

Figure 18 – Histogram of the Effective Porosity Distributions with the Seven Modeled Off	set Wells
	30
Figure 19 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 20)03)31
Figure 20 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Region Data	onal Core
Figure 21 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD	depicting
the Ellenburger formation and sidewall cores.	
Figure 22 – Core photo of Ellenburger sample displaying vug features	34
Figure 22 – Histogram of the Permeability Distributions with the Seven Modeled Offset W	مالد عم
Figure $24 - Offset$ wells used for formation fluid characterization	36
Figure 25 – Dre-Cambrian Distribution Man	
Figure $26 - $ Ellophurger structure man in subseq. The black star represents the Mongoos	
1 well location and red stars represent the remaining six wells used in the model. The	e AGI NO.
indicates the cross section reference man	
Figure 27 Structural cross section depicting the Ellephyraer	42
Figure 27 – Structural cross section depicting the Ellenburger.	
Figure 28 – Stratigraphic cross section nationed on the Elienburger.	
Figure 29 – General Geologic Structure and Formation Relationships in Mitchell and Wester	
Counties (Snamburger Jr., 1967)	
Figure 30 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the sul	rface, the
natched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1	. location
(George, Mace, & Petrossian, 2011).	
Figure 31 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Grou	ndwater.
The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986)	
Figure 32 – Total Dissolved Solids in the Dockum Aquiter. The red star shows the Mongoos	e AGI NO.
1 location (George, Mace, and Petrossian, 2011).	50
Figure 33 – Two-Phase Relative Permeability Curves Used in the GEM Model	53
Figure 34 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)	
Figure 35 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation).	57
Figure 36 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)	
Figure 37 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Sin	mulation) 59
Figure 38 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of	Injection)
-	60
Figure 39 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After	er Shut-in
(End of Simulation)	61
Figure 40 – Well Injection Rate and Bottomhole and Surface Pressures Over Time	62
Figure 41 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and M	Maximum
Monitoring Area	64
Figure 42 – Active Monitoring Area	65
Figure 43 – Site Plan	67
Figure 44 – Mongoose AGI No. 1 Wellbore Schematic	68
Figure 45 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA	71
Figure 46 – Groundwater Wells Within the MMA	
Figure 47 – Seismicity Review (TexNet – 08/04/2023)	
Figure 48 – Groundwater Monitoring Wells	

Figure 49 – Seismic Events and Monitoring Static	n79
--	-----

Tables

Table 1 – Expected Gas Composition	3
Table 2 – Expected Sequestered Gas Volumes	3
Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samp	les37
Table 4 – Calculated Vertical Stresses	39
Table 5 – Fracture Gradient Calculation Inputs and Results	40
Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (S	Shamburger
Jr., 1967)	46
Table 7 – Gas Composition at Mongoose Plant Outlet	51
Table 8 – Modeled Initial Gas Composition	52
Table 9 – GEM Model Layer Package Properties	54
Table 10 – Offset SWD Wells Included in GEM Model	55
Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injection	62
Table 12 – Summary of Leakage Monitoring Methods	76

Appendices

Appendix A – TRRC MONGOOSE AGI No. 1 FORMS

- Appendix A-1 UIC Class II Order
- Appendix A-2 GAU Groundwater Protection Determination
- Appendix A-3 Drilling Permit
- Appendix A-4 Completion Report

Appendix B – Site Safety and Layout

- Appendix B-1 Operating Safety Plan
- Appendix B-2 Mongoose Site Plan

Appendix C – Area of Review

- Appendix C-1 Oil and Gas Wells Within the MMA Map
- Appendix C-2 Oil and Gas Wells Within the MMA List
- Appendix C-3 Water Wells Within the MMA Map

Appendix D – Section 2 Cross Sections

- Appendix D-1 Figure 27 Structural Cross Section Depicting the Ellenburger
- Appendix D-2 Figure 28 Stratigraphic Cross Section Flattened on the Ellenburger

SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the UIC Class II program. The TRRC classifies Mongoose AGI No. 1 as a UIC Class II well. A Class II permit was issued to Bayswater on March 10, 2023, under TRRC Rule 9 (Disposal into Non-Productive Formations) and Rule 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

1.2 UIC Well Identification Number

Mongoose AGI No. 1, API No. 42-335-36013, UIC No. 000125803

1.3 <u>Reporter Number</u>

- Gas Plant Facility Name: Bayswater Amine Facility
- Greenhouse Gas Reporting Program ID: 586481

 Currently reporting under Subpart UU
- Operator: Bayswater Operating Company LLC
- Operator: Bayswater Operating Company L

1.4 Facility Address

Bayswater Gas Plant 1625 County Road 280 Westbrook, Texas 79565

Coordinates in NAD83 for this facility:

Latitude: 32.4225396641 Longitude: -101.1714709142

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the Mongoose AGI No. 1 well.

The Mongoose injects both H_2S and CO_2 into Ellenburger formation at a depth of 8,300 ft to 9,000 ft, and approximately 7,825 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The Mongoose is located on the Eastern Shelf, as shown in the area map in Figure 2, within the greater Permian Basin of west Texas and New Mexico. The Permian Basin covers more than 86,000 square miles extended across an area approximately 250 miles wide and 300 miles long. The TRRC cites that the greater Permian Basin accounts for close to 40% of all oil production within the United States and nearly 15% of natural gas production. A general cross section of the basin is presented in Figure 3.

The ancestral Tobosa Basin was formed by structural flexure in the Precambrian basement at the southern margin of the North American Craton, or Laurentian Plate, during the Proterozoic (Popova, 2020). The modern form of the Permian Basin was shaped during the Carboniferous period due to the collision between Laurasia and Gondwana forming the supercontinent Pangea. The following uplift of the Central Basin Platform differentiated the greater basin into the Delaware Basin in the west, and the Midland Basin in the east along with its surrounding shelf margins (Popova, 2020).



Figure 2 – Overview map of the Permian Basin including subregion names and counties. The red star represents the approximate location of the Mongoose AGI No. 1 (Scanlon, Reedy, Male, & Walsh).



Figure 3 – Permian Basin East—West Cross Section (Scanlon, Reedy, Male, & Walsh)

The target injection interval for the Mongoose is the Ellenburger formation. The Ellenburger Group is part of an extensive shallow water carbonate platform known as the Great American Carbonate Bank, which covered much of the Laurentian landmass during the lower Ordovician (Sanchez, Loughry, & Coringrato, 2019). The Ellenburger is of lower Ordovician age and underlies the Woodford formation on the Eastern Shelf. The contact between the Ellenburger and Woodford represents an angular unconformity separated by roughly 110 million years of erosion and halted deposition (Sanchez, Loughry, & Coringrato, 2019). Many formations that are present within the Midland Basin are eroded and not seen upon reaching the Eastern Shelf. A cross section showing these truncations is displayed in Figure 5.

A generalized stratigraphic column of the Eastern Shelf is shown in Figure 4, with the target-injection formation indicated by the red star and historically productive formations indicated in the green stars. The Ellenburger formation is roughly 900 ft thick on the Eastern Shelf as shown by the isopach thickness map in Figure 6 (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006). On the Eastern Shelf, the Ellenburger formation dips to the west-southwest, towards the Midland Basin, and its subsea depth is roughly 6,000 ft (Sanchez, Loughry, & Coringrato, 2019). Figure 7 displays a structure map of the Ellenburger formation. Being far from any major sources of terrigenous clastic sediment input and at a time of a greenhouse climate leading to warm waters created an ideal setting primed for massive carbonate production during the Ellenburger deposition (Waite, 2021). The depositional facies associated with the Ellenburger on the Eastern Shelf is primarily within the restricted shelf depositional setting. Predominant pore types of this group determined by Holtz and Kerans are "ooid grainstone; ooid-peloid packstone-grainstone"

and reservoirs tend to be of good porosity and moderate permeability (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006).



Figure 4 – Generalized Stratigraphic Column of the Eastern Shelf



Figure 5 – Cross section indicating formation truncations when approaching the Eastern Shelf (Waite, 2021).



Figure 6 – Ellenburger Group Isopach Map (Loucks, Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas, 2006)



Figure 7 – Structure map referencing the top of the Ellenburger formation at subsea depth.

The lower Ordovician period on the Eastern Shelf was characterized by a restricted and low-energy shelf environment. The shelf was composed of a consistent sequence of gray to dark-gray dolomite, which had a fine to medium crystalline texture. Within this dolomite, there were irregular mottling patterns, likely indicative of bioturbation structures. Mudstone and peloid-wackestone, although in

smaller quantities, were also observed in the area (Kerans, 1990). To visually represent these different depositional environments and their corresponding lithologies, a map is presented in Figure 8. Due to a decrease in sea levels and subsequent exposure to air, a large portion of the Ellenburger formation underwent significant "karsting" and dolomitization. This karsting process resulted in the formation of extensive paleocave systems within the Ellenburger, which later collapsed and led to the creation of widespread brecciated and fractured carbonates. These formations are responsible for the occurrence of many Ellenburger reservoirs, according to Loucks (2006).



Figure 8 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

In their research on saltwater disposal (SWD) injection into the Ellenburger, Pioneer Natural Resources describes three distinct facies within the formation as noted in the Figure 9 type log. The upper and middle facies are composed of fracture breccia, breccia fabrics, and matrix-supported breccia, which coincide with collapsed paleo cave facies as described by Loucks. The lower unit does not exhibit these characteristics but shows a high volume of small vugs (inch-scale) and large-dissolution features (foot-scale) and represents an area of the Ellenburger with elevated porosity and permeability (Sanchez, Loughry, & Coringrato, 2019).





2.1.1 Regional Faulting

The modeled area near the Mongoose does not show any faults. However, there is one fault interpreted northeast of the Mongoose location that lies outside the modeled area. This fault trend runs north-south in parallel with the dip. Figure 7 displays this fault trend, which is the only example of such a trend within the area. Apart from this, the basin area is structurally inactive.

2.2 <u>Site Characterization</u>

The following section discusses site-specific geological characteristics of the Mongoose.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 shows an annotated well log for Mongoose that goes from the surface to the total depth. It indicates the injection and primary upper confining units with regional formation tops.



Figure 10 – Mongoose AGI No. 1 Type Log

2.2.2 Upper Confining Zone – Woodford Shale

The upper confining unit is the Upper Devonian age Woodford formation. The Woodford Shale, a late Devonian-aged organic-rich rock, was created through a widespread marine transgression. The deposition of the Woodford spread across a large area of the Permian Basin, producing a low-relief blanket of shale. The Woodford formation is an organic-rich petroleum source rock comprised of uncharacteristically highly radioactive, dark fissile shale and siltstone (Merril et al., 2015). Not only is the Woodford Shale a source of oil and gas, but it also acts as the primary source and sealant for the Wristen Group (Comer, 1991). The Woodford formation overlies both unconformably and is diachronous to the underlying Ellenburger formation at the Mongoose location. The U.S. Geological Survey (USGS) CO₂ Storage Assessment defines the Woodford Shale as an appropriate seal due to its composition and regional extent for the Lower Paleozoic composite storage assessment unit (SAU) (Merril et al., 2015).

Rotary sidewall cores were taken from the offset well Buchanan 3111 #1XD (42-227-41307) in support of the acid-gas injection operations within the Mongoose. Figure 11 is a stratigraphic cross section showing the correlating cored Woodford formation (pink triangles representing cored intervals) in the Buchanan 3111 #1XD and the Mongoose wells. Routine core analysis, rock mechanics, and threshold entry pressure tests were performed on the core samples from the Woodford formation.

Core photos of the samples taken and analyzed within the Woodford are shown in Figure 12. The black shale unit exemplifies a well cemented unit with little to no fracturing. Routine core analysis was performed on these two samples, which includes bulk density, matrix permeability (as received and as under dry and Dean Stark extracted conditions), gas-filled porosity, gas saturation, grain density, porosity, oil saturation, and water saturation. The results are shown in Figure 13, with the footnotes at the base giving details on the testing processes of each value.

Under the dry and Dean Stark extracted conditions, permeability values of 2.2E-07 millidarcy (mD) were observed with even lower values of 4.87E-07 mD in the as-received samples. Porosities within the same sample were 1.3% when dried and .25% when gas-filled. These permeability and porosity values reflect optimal confining characteristics and validate the USGS assessment of an appropriate sealing formation for CO_2 storage.

To ensure these sealant properties would not be compromised by pressure influence of the injected fluid, a threshold entry pressure test was examined on these Woodford core samples. Figure 14 depicts a graph of permeability vs. pressure showing that, even with pressure increases up to 2,000 pounds per square inch (psi), permeability readings are still in the nano-darcy range. These values are shown in table form in Figure 15 against the pressures administered on the core, with the highest pressure being 2,000 psi. Given that permeability values were lowest (4.03E-07 mD) at 2,000 psi, it can be assumed that the threshold entry pressure of the Woodford formation was not met and would be greater than 2,000 psi. Additionally, a table summary is depicted in Figure 16. These characteristics gathered from the Buchanan core provide a high level of detail into the confining nature of the Woodford Shale and alleviate any concerns of transmissibility through the confining unit.



Figure 11 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Woodford and sidewall cores.



Figure 12 – Core Photo of Samples Within the Woodford Formation



CL File No.: 202105972 Date: February 04, 2022 Analyst(s): MP

Shale Core Analysis (Rotary Sidewall Cores)

As received					Dry & Dean Stark Extracted Conditions ⁽²⁾					
Sample	Depth (ft)	Bulk Density (g/cc)	Matrix Permeability ⁽¹⁾ (mD)	Gas-filled Porosity (%)	Gas Saturation (%)	Grain Density (g/cc)	Matrix Permeability ⁽⁵⁾ (mD)	Porosity (%)	Oil Saturation ⁽³⁾ (%)	Water Saturation ⁽⁴⁾ (%)
30,31	9076.03 - 9076.26	2.601	4.87E-09	0.25	18.9	2.624	2.22E-07	1.30	3.3	77.8

Footnotes:

Each sample is a composite of several rotary sidewall cores.

(1) Matrix Permeability is an effective Kg determined from pressure decay results on the fresh, crushed, 20/35 mesh size equivalent sample.

(2) Dean Stark extracted sample (20/35 mesh size) dried at 110 °C. Porosity and saturations are relative to total interconnected pore space.

(3) Oil volume computed assuming an oil density of 0.844 g/cc

(4) Water volume corrected assuming a brine concentration of 80000 ppm NaCl with an ambient density of 1.054 g/cc

(5) Matrix Permeability is an absolute Kg determined from pressure decay results on the clean and dry 20/35 mesh size equivalent sample.

Reference: "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs", GRI-95/0496, Gas Research Institute, April 1996

Figure 13 – Routine Core Analysis Within the Woodford Formation

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

Company:Bayswater Exploration & ProductionWell:Buchanan 3111 1XDField:SpraberryLocation:Howard County, TexasFile:HOU-2105972



Figure 14 – Graph of Threshold Entry Pressure Within the Woodford Formation

PETROLEUM SERVICES

THRESHOLD ENTRY PRESSURE ANALYSIS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company: Bayswater Exploration & Production Well: Buchanan 3111 1XD Field: Spraberry Location: Howard County, Texas

File: HOU-2105972

Sample 30B							
Gas							
Injection	Permeability						
Pressure,	to Brine*,						
psi	mD						
500	1.44E-06						
750	2.20E-06						
1000	1.46E-06						
1200	6.73E-07						
1400	5.77E-07						
1600	6.72E-07						
1800	5.39E-07						
2000	4.03E-07						

Figure 15 – Tabular Data of the Threshold Entry Pressure Analysis Within the Woodford Formation

SUMMARY OF THRESHOLD ENTRY PRESSURE RESULTS

Net Confining Stress: 2960 psi Temperature: 68°F Fluid: 80,000 ppm NaCl

PETROLEUM SERVICES

Company:	Bayswater Exploration & Production
Well:	Buchanan 3111 1XD
Field:	Spraberry
Location:	Howard County, Texas

File: HOU-2105972

				Final	Threshold
				Permeability	Entry
Sample	Depth,	Length,	Diameter,	to Brine*,	Pressure,
Number	feet	cm	cm	millidarcies	psi
30B	9076.03	2.67	2.54	4.03E-07	TEP>2000

* Apparent permeability to brine with humidified nitrogen displacing water

Figure 16 – Summary of Threshold Entry Pressure Analysis Within the Woodford Formation

2.2.3 Injection Interval – Ellenburger

2.2.3.1 Ellenburger

As described in the Regional Geology section, the Ellenburger at the Mongoose location is a widespread lower Ordovician carbonate deposited over the entire Permian area, indicating a relatively uniform depositional condition (Hendricks, 1964). However, post-depositional sequences have highly altered the section. These sequences have a large influence on the development of the reservoir quality within the injection interval and its ability to accept the proposed injectate. Further analysis based on regional and site-specific data was analyzed, as discussed below, to better understand the reservoir conditions at and around the Mongoose well location.

2.2.3.2 Ellenburger Porosity/Permeability Development

Facies in the low-energy, restricted shelf setting exhibit extensive dolomitization and are characterized by significant bioturbation, resulting in mottling patterns (Loucks, 2003). This dolomitization process has facilitated porosity development within the Ellenburger formation, accompanied by diagenetic leaching processes and the formation of secondary porosity features, including karsts and vugs. These same features were interpreted from the openhole logs in the Mongoose well and core from the Buchanan 3111 #1XD well. A total of 23 sidewall cores were taken within the Ellenburger formation in the Buchanan 3111 #1XD well, with 12 of those having routine core analysis performed on them. Figure 17 shows the results of the analysis.

Porosity values were primarily derived from offset openhole porosity logs within the Ellenburger section. Petrophysical analysis was performed on the offset logs to calculate an effective porosity curve, the porosity of a rock that is available to contribute to fluid flow, to better estimate porosity ranges with regards to injection within the Ellenburger. This is done by accounting for clay content and matrix lithology to better understand the varying porosity within the injection interval and how it relates to injection capacity. The ranges of effective porosity within the modeled wells are 0 to 39.4% with the mean being 4.6%. Figure 18 is a histogram depicting these porosity distributions within the seven modeled wells. These values are validated through similar ranges seen in the core results. The logical inference would be that, as the effective porosity increases, the reservoir quality for injection improves and the associated porosity increment leads to a rise in permeability.

A porosity to permeability relationship was created from this data with the outliers and nonapplicable samples redacted. Additional regional data from Loucks (2003) was incorporated into the relationship to assist with the higher permeability ranges, to ensure that overestimates of permeability were not calculated. The data from Loucks (2003) is exemplified in Figure 19. A twofunction porosity-permeability curve was developed from the regional and local core data. Figure 20 shows the equations and relationships where:

> If Effective Porosity (Φ eff) < 6.5%: $K(mD) = 7E - 08e^{3.3028*\Phi}$ eff If Effective Porosity (Φ eff) > 6.5%: $K(mD) = 277.39 \ln(\Phi eff) - 380.58$

These equations were extrapolated to all the wells within the model including the Mongoose. In Figure 21, the cross section of the Mongoose and Buchanan well is depicted. This illustration showcases the Ellenburger formation, with the sidewall cores from the Buchanan well represented by pink triangles. The calculated permeability curves resulting from the equations mentioned earlier are shown in red, while green represents the effective porosity. High permeability and porosity sections can be seen in both wells, most likely reflecting strata that had prolonged subaerial exposure creating the karst and vug features that will be targeted and utilized for injection. Figure 22 is a core photo from the Buchanan well depicting an example of what a vug feature within the Ellenburger can look like. These features will be taking the bulk of the injection and will be modeled within the area based on openhole log analysis.

Permeability ranges within the seven wells utilized in the model vary from 0 mD to 638 mD, with the mean being 40.822 mD. A histogram representing these ranges and distributions within the seven modeled wells is displayed in Figure 23. This range corroborates with Loucks (2003) and data recovered from the Buchanan well, and it can be concluded that the process used to determine the permeability distributions within the injection interval is valid.

Bayswater Exploration & Production Buchanan 3111 1XD Spraberry Howard County, Texas



CMS-300 ROTARY SIDEWALL ANALYSIS

CL File No.: 202105972 Date: March 31, 2022 Analyst(s): MP

		Net Confining		Permea	bility				Satu	ration	Grain	
Sample	Depth	Stress	Porosity	Klinkenberg	Kair	b(air)	Beta	Alpha	Oil	Water	Density	Footnote
Number	(ft)	(psig)	(%)	(md)	(md)	psi	ft(-1)	(microns)	% Pore	Volume	(g/cm3)	
23	9236.98	2960	25.81	.259	.389	11.97	3.27E+09	2.75E+00	0.0	94.7	2.666	
21	9257.01	2960	4.77	.002	.009	104.71	2.14E+15	1.48E+04	1.2	66.1	2.746	(1)
19	9363.99	2960	5.23	5.17	5.81	2.07	1.75E+12	2.93E+04	4.1	66.9	2.800	(6)
15	9485.99	2960	3.41	.005	.016	62.63	3.24E+13	5.63E+02	2.3	64.6	2.838	(6)
13	9549.48	Ambient	1.55	N/A	N/A	N/A	N/A	N/A	1.9	44.7	2.829	(5)
12	9604.98	2960	1.63	.00006	.001	354.43	2.46E+18	5.38E+05	2.6	54.0	2.842	(1)
10	9712.03	Ambient	1.28	N/A	N/A	N/A	N/A	N/A	1.2	74.3	2.758	(5)
7	9835.05	2960	2.28	.001	.004	155.69	2.03E+16	4.48E+04	1.5	81.1	2.701	
6	9868.97	2960	3.43	.001	.003	166.37	3.03E+16	5.46E+04	0.9	81.6	2.827	
5	9892.03	2960	3.46	.001	.005	132.61	8.12E+15	2.84E+04	2.1	91.6	2.809	
4	9914.00	2960	5.46	659	669	0.18	1.07E+09	2.29E+03	0.7	58.7	2.835	(6)
3	9969.01	Ambient	11.18	N/A	N/A	N/A	N/A	N/A	1.7	42.9	2.846	(5),(6)

Figure 17 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)



Figure 18 – Histogram of the Effective Porosity Distributions with the Seven Modeled Offset Wells

			Tectonically Fractured
	Karst Modified	Ramp Carbonate	Dolostone
Lithology			
	Dolostone	Dolostone	Dolostone
Depositional			
setting	Inner ramp	Mid- to outer ramp	Inner ramp
		Sub-Middle Ordovician,	
	Extensive sub-	sub-Silurian/Devonian,	
	Middle	sub-Mississippian, sub-	Variable intra-Ellenburger,
Karst facies	Ordovician	Permian/ Pennsylvanian	sub-Middle Ordovician
Fault-related			
fracturing	Subsidiary	Subsidiary	Locally extensive
	Karst-related		
Dominant pore	fractures and	Intercrystalline in	
type	interbreccia	dolomite	Fault-related fractures
		Partial, stratigraphic and	
Dolomitization	Pervasive	fracture-controlled	Pervasive

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

Figure 19 – Regional Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)



Porosity vs Permeability

Figure 20 – Two-Function Porosity vs. Permeability Relationship Utilizing Local and Regional Core Data



Figure 21 – Stratigraphic cross section of Mongoose AGI No. 1 and Buchanan 3111 #1XD depicting the Ellenburger formation and sidewall cores.



Figure 22 – Core photo of Ellenburger sample displaying vug features.



Figure 23 – Histogram of the Permeability Distributions with the Seven Modeled Offset Wells

2.2.3.3 Formation Fluid

Two wells were identified within approximately 30 miles of the Mongoose through a review of oilfield brine compositions of the Ellenburger formation from the USGS National Produced Waters Geochemical Database (ver. 2.3). The location of these wells is shown in Figure 24. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids (TDS). Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger formation is compatible with the proposed injection fluids.



Figure 24 – Offset wells used for formation fluid characterization.

	Average	Low	High
Total Dissolved Solids (ppm)	47,427	42,014	52,840
рН	7	7	7
Sodium (ppm)	16,384	15,000	17,767
Chlorides (ppm)	27,590	24,900	30,281

Table 3 – Analysis of Ordovician Age Formation Fluids from Nearby Oil-Field Brine Samples

2.2.4 Lower Confining Zone – Precambrian

Due to the lack of well penetrations and samples within the Precambrian, most compositions and interpretations of the Precambrian are sources from outcrops in central Texas and in the Trans-Pecos region of Texas and centra New Mexico. Penetrations within the Precambrian are minimal and, when present, only penetrate a few feet into the section (Adams & Keller, 1996).

Adams and Keller conducted a geophysical analysis in 1996 to enhance the understanding of Precambrian rock types and their distribution in the Permian Basin. The study incorporated gravity modeling and magnetic and gravity anomalies, as well as rock data from Precambrian outcrops and drills to interpret the upper crustal geology of the area. Figure 25 displays the map resulting from their investigation, revealing that batholiths are likely present in the Precambrian basement rock at the Mongoose well location. Additionally, samples collected from offset wells displayed predominantly felsic rocks, which lead to the interpretation of "granitic bodies in the upper crust" (Adams & Keller, 1996).

Offset Ellenburger injector wells drilled through the Ellenburger section and reached total depths near the Precambrian. Log characteristics of strata near the total depth of the wells display gamma ray responses well above 90 gamma units of the American Petroleum Institute (GAPI), which is indicative of a high radioactive response. Additionally, the effective porosity curve near the base of the log shows little to no porosity, which represents a tight granitic rock that would act as an ideal lower confining zone. Due to the buoyancy of the injected gas in relation to the connate fluid within the Ellenburger, it is unlikely that the injectate will ever encounter the lower confining zone.



Figure 25 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Geomechanics

2.3.1 Determination of Vertical Stress (S_v) from Density Measurements

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density of the upper and lower confining and injection zones was calculated from log data at the Buchanan 3111 #1XD (API No. 42-227-41307) offset well. The overburden gradient and vertical stress at the top of each zone were calculated by integrating the bulk density from surface to the formation depth in half-foot intervals. Table 4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Formation	Depth (ft)	Bulk Density (g/cm^3)	Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Woodford	8,322	2.63	164.1	8,563	1.029
Ellenburger	8,375	2.75	171.2	8,635	1.031
Precambrian	9,500*	2.83	176.7	9,937	1.046

Table 4 – Calculated Vertical Stresses

* Estimated

2.3.2 Elastic Moduli and Fracture Gradient

The 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. The calculation requires Poisson's ratio ("v"), overburden gradient (OBG), and pore gradient (PG) in order to determine the required pressure to fracture the formation. These variables can be changed to match the site-specific injection zone.

A thorough review of log data, available literature, and industry standards indicate a 0.465 psi/ft pore gradient should be assumed when there are no site-specific numbers available. Poisson's ratio was calculated for the upper confining and injection zones using a sonic log that was run at the subject well. The calculation was performed using the equation below for log data points at half-foot depth intervals. The results were then averaged for the depth range of each zone. This resulted in a Poisson's ratio of 0.261 for the upper confining zone and 0.273 for the injection zone.

$$v = \frac{\frac{1}{2} \left(\frac{v_p}{v_s}\right)^2 - 1}{\left(\frac{v_p}{v_s}\right)^2 - 1}$$

Where:

v = Poisson's Ratio v_p = Compressional Velocity v_s = Shear Velocity

Log data was unavailable for the lower confining zone, therefore the Poisson's ratio for this zone was estimated through a review of available literature. The lower confining zone consists of granite, which has been observed to have a Poisson's ratio ranging from 0.19 to 0.35 with a mean value of 0.28 (Domede, 2017). Based on this research, an average value of 0.28 was assumed. Using these values in the equation below, a fracture gradient of 0.664 psi/ft was calculated for the upper confining zone. A 10% safety factor was applied to this number resulting in a maximum allowed bottomhole pressure of 0.598 psi/ft. This zone had the lowest fracture gradient of the confining and injection zones. It was used to define the maximum allowable pressure to ensure that the injection pressure would not exceed the fracture pressure of any of the three zones. The resulting fracture gradients are displayed in Table 5.

Example Fracture Gradient Calculation for Upper Confining Zone

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

$$FG = \frac{0.261}{1 - 0.261} (1.029 - 0.465) + 0.465 = 0.664 \, psi/ft$$

$$FG$$
 with $SF = 0.689 \times 90\% = 0.598 \, psi/ft$

Depth (ft)	Zone	Member	Overburden Stress (psi)	Pore Pressure (psi)	Poisson's Ratio	Fracture Gradient (psi/ft)
8,322	Upper Confining	Woodford	1.029	0.465	0.261	0.664
8,375	Injection	Ellenburger	1.031	0.465	0.273	0.678
9,500*	Lower Confining	Precambrian	1.046	0.465	0.28	0.691

*Estimated

2.4 Local Structure

The area surrounding the Mongoose well is characterized by a monoclinal dip from east to west that is influenced by a shallow westward slope towards the Midland Basin and an upward slope to the east towards the Eastern Shelf. No evidence of structural faulting was found in this specific region that could have affected the geological trend. Figure 26 shows the topography of the Ellenburger formation, with the Mongoose well marked by a black star.

Subsurface interpretations of the Ellenburger formation heavily relied on well data and 3D seismic coverage in the area. The black boundary in Figure 27 represents the extent of the seismic coverage. Within the mapped area, approximately 100 wells have penetrated the Ellenburger formation. However, only seven of these wells fully penetrated the entire Ellenburger section. The remaining 93 wells only reached the top of the Ellenburger formation. These wells are plotted on the map and cover four counties. In addition to the Mongoose well, six other wells located offset of the Mongoose were used for the model build and are indicated by red stars.

Figure 26 is a structural cross section through the seven wells, modeled as depicted by the blue line on the Ellenburger structure map. The Ellenburger was broken down into eight subsections labeled Ellenburger A through H. Figure 28 is a stratigraphic cross section flattened on the Ellenburger that better illustrates these subtops.

The cross sections reveal the regional unconformity in the area when moving east from the Midland Basin. As we go farther updip and to the east, the Fusselman section gradually erodes. While there is also thinning in the Woodford, the cross section shows that the Woodford is present throughout the modeled area, creating a continuous seal above the plume.

With no major structural or stratigraphic features within the injection interval in the Mongoose area, there is little to no concern of geologic conduits outside of the injection interval. General flow trends will follow dip and optimal reservoir features within the Ellenburger. Large scale versions of Figures 27 and 28 are provided in *Appendix D*.


Figure 26 – Ellenburger structure map in subsea. The black star represents the Mongoose AGI No. 1 location and red stars represent the remaining six wells used in the model. The blue line indicates the cross-section reference map.



Figure 27 – Structural cross section depicting the Ellenburger.



Figure 28 – Stratigraphic cross section flattened on the Ellenburger.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger formation at the Mongoose location indicate that it has the necessary qualities to accept the proposed injection fluids, including sufficient thickness, porosity, permeability, and lateral continuity. The Woodford Shale formation at the same well location has low permeability and is of adequate thickness and lateral continuity to act as the upper confining zone. Below the injection interval, the Precambrian formation has low permeability and low porosity, making it unsuitable for fluid migration and serving as the lower confining zone.

A thorough study of the area of review has been conducted to identify any potential subsurface features that could impact the ability of the injection and confinement units to retain the injectate within the desired injection interval. Fortunately, no faults or other hazardous geologic conditions have been identified in the area. Therefore, the conditions in this area are ideal for injection and containment.

2.6 Groundwater Hydrology

The Mongoose is located within Mitchell County, home to a population of approximately 8,400 residents, and is serviced by the Lone Wolf Groundwater Conservation District, which consists solely of Mitchell County. This conservation district has an area of roughly 900 square miles. Much of the county's economy is derived from agriculture and oil production, both water-intensive operations. Groundwater usage within the county is estimated to be 13,391 acre-feet on a yearly basis (Lone Wolf Groundwater Conservation District, 2019).

Surface Water

Mitchell County lies within the Colorado River basin, as the Colorado runs through the county. Drainage from both the east and west flow centrally towards the Colorado River, which splits the county in half. The estimated supply of surface water is 395 acre-feet (Lone Wolf Groundwater Conservation District, 2019).

Groundwater

There are multiple units where groundwater is available within Mitchell County, although only the Dockum Group provides significant amounts of water. Table 6 discusses water-bearing units in the county, and Figure 29 shows a generalized reference to structure and formation relationships.

Table 6 – Geologic Units and Their Water-Bearing Characteristics in Mitchell County (Shamburger Jr., 1967)

System	Series	Group	Formation	Approximate thickness (feet)	Lithology	Water-bearing characteristics
Quaternary	Pleistocene and Recent		Alluvium	0-100	Fine to coarse sand, and small to large gravel, with occasional clay and caliche beds.	Above the regional water table east of Colo- rado River, but yields up to 20 gpm of good quality water in southwestern Mitchell County.
Tertiary	Pliocene		Ogallala	0-100	Fine to coarse sand, gravel, caliche, and zones of clay.	Above the water table east of Colorado River, but yields up to 20 gpm of good quality water to wells in northwestern Mitchell County.
CretaceOus	Cosanche	Fredericksburg		0-220	Predominantly limestone. 15 to 25 feet of sandy yellow marl at base overlain by chalk and shaly limestone. Very dense, massive, fossiliferous lime- stone in the upper part.	Upper limestones contain in places small to moderate supplies of potable but hard water in solutional openings developed along fracture systems; recharge to the openings occurs through numerous sinks.
		Trinity		0-100	White to purplish quartz sand, fine to medium grained, moderately to loosely consolidated, with occasional lenses of quartz gravel at the base.	Yields small to large quantities of potsble but hard water, the amount depends on saturated thickness which ranges from 100 percent under interior limestone areas to a few feet in parts of the outcrop; yields of several hundred gallons per minute are reported.
Triassic		Dacker	Chinle	0-640	Predominantly red to marson and pur- plish clay and shale, interbedded with thin, tight, cross-bedded, yellow-brown to reddish-white sand- stone.	Sandstones contain generally small quantities of moderately to highly mineralized water; used principally for livestock.
			Santa Rosa	0-330	Basal conglomerate overlain by brown to gray, micaccous and carbonaccous, cross-bedded sand alternating with beds of red and gray clay.	Sands and gravels contain moderate to large quantities of fresh water east of the Colorado River, with yields up to 1,000 gpm reported; west of Colorado River capa- city of sand is reportedly substantial but water is generally not potable.
Permain	Guadalupe and Ochoa				Fine-grained, red to brown sandstone; dense red silty shale with occasional gypsum or anhydrite beds.	Yield small quantities of moderately to high- ly mineralized water to livestock and domestic wells.



Figure 29 – General Geologic Structure and Formation Relationships in Mitchell and Western Nolan Counties (Shamburger Jr., 1967)

Permian

Permian age strata underlies much of the area and outcrops in the southeast of Mitchell County and along the Colorado River and its tributaries. These strata consist primarily of "red beds," dense red silty shales. Water wells in the Permian strata are typically less than 100 ft deep, yielding small amounts of moderately to highly mineralized water usable only for livestock (Shamburger Jr., 1967).

Dockum Aquifer

The Triassic Age Dockum group comprised by the Santa Rosa sandstone and the Chinle formation are the main sources of ground water within the county. An overview map of the extent of the Dockum Aquifer is shown in Figure 30, with outcrops depicted in solid color. The Chinle is further divided into the Tecovas formation, the Trujillo sandstone, and the Cooper Canyon formation, although the Tecovas and Cooper Canyon are generally unimportant and yield only small amounts of highly mineralized water.

The Santa Rosa sandstone lies unconformably atop the Permian age strata at the base of the Dockum Group and is one of the major sources of water for Mitchell County. It is comprised of a basal conglomerate overlain by alternating beds of red and gray micaceous shale, sand, and gravel reaching up to 130 ft in thickness (Bradley & Kalaswad, 2001). The Trujillo sandstone overlies the Tecovas, which in turn overlies the Santa Rosa, and is a cross-bedded unit composed of sandstones and conglomerates. The Santa Rosa and Trujillo sandstones are regarded as the main producers of water in the Dockum Group in Mitchell County (Lone Wolf Groundwater Conservation District, 2019). The Dockum Group was likely deposited from sediments into "fluvial, deltaic, and lacustrine environments within a closed continental basin" (Bradley & Kalaswad, 2001). The base of the Santa Rosa is typically considered the lower extent of fresh water in the area. Water levels in wells throughout the county vary between 15 ft and 215 ft below ground level (Shamburger Jr., 1967), and the aquifer is considered confined to partially confined (Bradley & Kalaswad, 2001).

Recharge of the aquifer is provided by rainwater infiltration through outcrops in the county and is estimated to be 18,108 acre-feet per year. Groundwater in the Dockum aquifer system flows towards the central Colorado River. A potentiometric surface map of the Santa Rosa sandstone, the lower Dockum member, is depicted in Figure 31. Although no values of porosity have been determined empirically, a conservative value of 10% is assumed for effective aquifer porosity (Lone Wolf Groundwater Conservation District, 2019).

Groundwater quality is generally considered poor with TDS and other constituents exceeding secondary drinking water standards (Bradley & Kalaswad, 2001). As a typical assumption, water quality west of the Colorado River within the aquifer is poor and unsuitable for municipal use, while east of the river water quality is less mineralized and is of suitable quality for municipal purposes (Lone Wolf Groundwater Conservation District, 2019). For example, a well tested 10 miles northwest of Colorado City contained chloride at 560 milligrams per liter (mg/L), sulfate at 337 mg/L, and TDS at 1,893 mg/L, all of which are above limits set by the Texas Commission on Environmental Quality (TCEQ) for use in municipal water supplies. In contrast, a well 8 miles east of Colorado City contained

chloride at 34 mg/L, sulfate at 73 mg/L, and TDS at 418 mg/L (Lone Wolf Groundwater Conservation District, 2019). A map showing TDS values for the Dockum Aquifer is shown in Figure 32.



Figure 30 – Location of the Dockum Aquifer. The solid shading signifies outcrops at the surface, the hatched signifies confined subcrops, and the red star signifies the Mongoose AGI No. 1 location (George, Mace, & Petrossian, 2011).



Figure 31 – Potentiometric Surface Map of the Lower Dockum (Santa Rosa) Group Groundwater. The red star shows the Mongoose AGI No. 1 location (Dutton & Simpkins, 1986).



Figure 32 – Total Dissolved Solids in the Dockum Aquifer. The red star shows the Mongoose AGI No. 1 location (George, Mace, and Petrossian, 2011).

Ogallala Formation

The Tertiary age Ogallala formation occurs in the northern extents of Mitchell County. In the eastern part of the county, Ogallala sediments are generally above the water table and not a source of groundwater; however, they do provide an effective means of recharge to the underlying Santa Rosa formation. In the western part of the county, the Ogallala is up to 100 ft thick of unconsolidated sand and gravel and provides small quantities of usable water for domestic and livestock wells (Lone Wolf Groundwater Conservation District, 2019).

2.7 <u>Description of the Injection Process</u>

2.7.1 Current Operations

The Mongoose Gas Plant and the associated Mongoose well began operating in August of 2023. The maximum rate during the injection period is expected to be 377.2 MT/yr (19.5MMscf/d). The TAG is 41.2% CO₂, which equates to 155.3 MT/yr of CO₂ each year. The current composition of the TAG stream is:

Table 7 – Gas Composition at the Mongoose Plant Outlet

Component	Mole Percent
Carbon Dioxide	41.2%
Hydrogen Sulfide	58.8%

The Mongoose Gas Plant is designed to dehydrate, treat, and compress the natural gas produced from the surrounding acreage in Mitchell County. The gas is dehydrated to remove the water content, and treated to remove the CO_2 and H_2S . The compressed rich gas stream is then transported via pipeline to a separate facility for processing to separate the natural gas liquids from the methane. The TAG is then directly routed from the Plant's amine unit to the Mongoose. The Plant is manned 24 hours per day, 7 days per week.

2.8 <u>Reservoir Characterization Modeling</u>

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (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 Ellenberger formation is the target formation for the Mongoose. The Petrel software package was utilized to create the geologic model of the target formation. Within the Petrel platform, the porosity and permeability distributions were established for the model. The geologic structure was then imported into GEM for simulation purposes.

In Petrel, the structure's construction involved the utilization of nine contour tops, which were layered sequentially. These contour tops, identified as "Ellenberger A" through "Ellenberger I," collectively define the structure's configuration, Ellenberger A being the shallowest and Ellenberger I being the deepest structure package. To accurately represent the formation's true structure, true vertical depth subsea was used to account for the differing overburden depths associated with the

wells used in contour delineation. The distinction of true vertical depth (TVD) and true vertical depth subsea (TVDSS) is taken into consideration when inputting pressure and temperature gradients into the GEM model.

Porosity estimates were determined using openhole porosity logs from seven offset wells within the Ellenberger formation. These logs were used within Petrel to distribute porosity and permeability spatially. Permeability was found by using the two-function porosity-permeability curve developed from regional and local core data within the Ellenberger formation.

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 H₂S and CO₂ based on initial estimates from the source, as shown in Table 8. However, the precise gas composition may vary slightly as the Plant is still in its commissioning phase. Initial estimates anticipate the injectate composition to be 58.8% H₂S and 41.2% CO₂. Once a steady-state operating composition is determined, the MRV plan will be updated if there is a material difference. Based on the initial gas samples, the modeled percentages in the injectate for the 40-year injection period of the Mongoose is 58.8% H₂S and 41.2% CO₂.

Table 8 – Modeled Initial Gas Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)	
Hydrogen Sulfide (H ₂ S)	58.8	58.8	
Carbon Dioxide (CO ₂)	41.2	41.2	

Core data from literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Ellenberger dolomitic carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 2.27, a Corey exponent for gas of 2.56, gas permeability at irreducible brine saturation of 0.1, an irreducible water saturation of 0.397, and a maximum residual gas saturation of 30%. The relative permeability curves used for the GEM model are shown in Figure 33.



Figure 33 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 135 blocks in the x-direction (east-west) and 77 blocks in the y-direction (northsouth), resulting in a total of 10,395 grid blocks per layer. Each grid block spans dimensions of 1,000 ft by 1,000 ft. This configuration yields a grid size measuring 135,000 ft by 77,000 ft, equating to just under 373 square miles in area. The grid cells in the vicinity of the Mongoose, within a radius of 2.5 miles, have been refined to dimensions of 250 ft by 250 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume.

In the model, each layer is characterized by heterogeneous permeability and porosity values. These values are derived from the geostatistical distribution of properties, using porosity logs implemented in Petrel as a basis. The model encompasses a total of 79 layers, each featuring varying thicknesses, with an average of approximately 10 ft per layer. As previously mentioned, the structure of the Ellenberger formation was formed using nine contour packages. The summarized property values for each of these packages are displayed in Table 9.

Contour Package	No. of Layers	Top (TVD ft)	Thickness (ft)	Perm. (mD)	Porosity
Ellenberger A	9	8,369	101	49.1	5.2%
Ellenberger B	9	8,470	76	65.1	6.0%
Ellenberger C	8	8,546	75	38.5	4.2%
Ellenberger D	9	8,621	86	39.2	4.9%
Ellenberger E	15	8,707	153	48	4.8%
Ellenberger F	6	8,860	63	32.5	4.4%
Ellenberger G	4	8,923	39	16.5	3.2%
Ellenberger H	8	8,962	82	76.9	5.5%
Ellenberger I	11	9,044	112	66	3.4%

Table 9 – GEM Model Layer Package Properties

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

- 1. Estimate the maximum areal extent and density drift of the acid gas plume after injection.
- 2. Assess the impact of offset SWD well injection on density drift of the plume.
- 3. Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone.
- 4. 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 47,427 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The acid gas stream is primarily composed of CO₂ and H₂S as stated previously. Core data was used to help generate relative permeability curves. From the literature reviews as previously discussed, cores that most closely represent the vuggy dolomitic carbonate seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low and conservative residual gas saturation based on the cores from literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975). The initial reservoir pressure is 3,903 psig, which is equivalent to a 0.465 psi/ft pressure gradient and was determined from offset injection well analysis. The fracture gradient of the injection zone was estimated to be 0.664 psi/ft, which was determined using Eaton's equation. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.598 psi/ft, which is equivalent to 5,007 psig.

The model considers the injection volumes of offset SWD wells close to the Mongoose. Nine such wells were identified within a 19-mile radius. Historical injection rates of eight of the nine of these wells currently injecting into the Ellenberger were provided by the operators and were input into

the model. All but one of the SWD wells in the model are currently permitted and injecting. The SWD well that has not yet started injection and has no historical injection data is conservatively assumed to inject at its maximum permitted rate for 30 years and to start at the same time as the Mongoose begins injection. Projected injection rates were assumed to be the maximum permitted injection rates and ended after 30 years of life for all nine offset SWDs. This simulation includes the effect of water injection on the density drift of the plume and the bottomhole pressure of the Mongoose. The SWDs included in the model are listed in Table 10.

API Number	Well Name	Well Number
42-227-41332	Fryar 3S	2XD
42-227-41307	Buchanan 3111	1XD
42-227-39064	Pipeline SWD	1
42-335-34319	Wild Bill	1WD
42-227-41775	Sterling	1XD
42-335-36026	Oasis Deep	9XD
42-227-39098	846 SWD	2
42-227-39119	N. Midway SWD	1
42-227-40310	Hull SWD	1

Table 10 – Offset SWD Wells Included in GEM Model

The model runs for a total of 175.33 years, comprising 15.33 years of historical SWD well injection prior to the commencement of acid gas injection. This is followed by 40 years of active acid gas injection through the Mongoose, succeeded by an additional 120 years of density drift. The model begins in September 2008, aligning with the start of historical injection data for the first offset SWD well. The remainder of the SWD wells turn on between then and the start of the acid gas injection, which begins in January 2024. Throughout the entire 40-year injection period, an injection rate of 19.5 MMscf/D is assumed to model the maximum available rate, yielding a more cautious estimate of the plume size. After the 40-year injection period, when the Mongoose ceases injection, all nine offset SWD wells have been shut in—as they began injecting before the Mongoose and were assumed to stop injecting after 30 years.

The maximum plume extent during the 40-year injection period is shown in Figure 34. The final extent after 120 years of density drift after injection ceases is shown in Figure 35. Both figures show the entire grid with the included offset SWD wells. Due to the large nature of the model, a zoomed-in view of the plume extent during the 40-year injection period is shown in Figure 36 and the final extent after 120 years of density drift after injection ceases is shown in Figure 37.



Figure 34 – Areal View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 35 – Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)



Figure 36 – Zoomed-In Areal View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 37 – Zoomed Areal View of Saturation Plume at 120 Years After Shut-in (End of Simulation)

The cross-sectional view of the Mongoose shows the extent of the plume from a side-view angle cutting through the formation at the wellbore. Figure 38 shows the maximum plume extent during the 40-year injection period. During this time, gas is injected into the permeable layers of the formation and travels predominantly laterally. Figure 39 shows the final extent of the plume after 120 years of migration. At this point in time, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 30% of injected gas that travels into each grid cell is trapped as the gas travels mostly vertically, as it is less dense than the formation brine, until an impermeable layer is reached. Both figures are shown in a north-to-south view.



Figure 38 – North-South Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)



Figure 39 –North-South Cross-Sectional View of Gas Saturation Plume at 120 Years After Shut-in (End of Simulation)

Figure 40 shows the surface injection rate, bottomhole pressures, and surface pressures over the injection period and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate begins, reaching a maximum pressure of 4,453 psig, then slightly decreases and remains constant. This buildup of 550 psig keeps the bottomhole pressure below the fracture pressure of 5,007 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 2,008 psig, well below the maximum allowable 2,500 psig per the TRRC UIC permit for this well. At roughly 30 years into injection for the Mongoose, all SWD wells included in the model have ceased injection. Due to the shut-in of offset SWD wells, the pressure effects within the formation are felt by the Mongoose. When this occurs, the bottomhole pressure decreases by 50 psig and surface pressure decreases by 40 psig. Bottomhole and wellhead pressures over time are in Table 11.



Figure 40 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	3,916	-
10	4,389	1,977
20	4,394	1,982
30	4,393	1,980
40	4,343	1,942
50	3,923	-
120	3,919	-

Table 11 – Bottomhole and Wellhead Pressures Over Time from Start of Injection

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in 40 CFR **§98.448(a)(1)**.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO₂ plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

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

Bayswater's expected gas composition was used in the model. The acid gas injectate is estimated at a molar composition of 58.8% H₂S and 41.2% CO₂, with trace amounts of other constituents. Upon the Plant achieving stable operations, a representative injectate sample will be collected and analyzed by a third-party laboratory. If the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be provided. As discussed in *Section 2*, the gas will be injected into the Ellenberger formation. The geomodel was created based on the rock properties of the Ellenberger.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 40, the areal expanse of the plume will be 2,192 acres. The maximum distance between the wellbore and the edge of the plume is approximately 1.25 miles to the southeast. After 120 additional years of density drift, the areal extent of the plume is 3,280 acres with a maximum distance to the edge of the plume of approximately 1.5 miles to the southeast.

Figure 41 shows the plume boundary at the end of injection, the stabilized plume boundary, and the MMA.



Figure 41 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The initial AMA will cover a 12-year period, which equates to almost one third of the expected injection lifecycle. This provides Bayswater sufficient time to develop their asset base, achieve steady operations, and evaluate any potential modifications to the MRV plan.

The AMA will be established by superimposing the area based on a half-mile buffer around the anticipated plume location after 12 years of injection (2036), with the area of the projected free-phase CO₂ plume at five additional years (2041). In this case, the plume boundary in 2041 is within the plume in 2036 plus a half-mile buffer. By 2036, a revised MRV plan will be submitted to define a new AMA. Figure 42 shows the area covered by the AMA.



Figure 42 – 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. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within the MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from natural or induced seismicity

4.1 Leakage from Surface Equipment

The Plant and Mongoose are newly designed and constructed facilities for treating and injecting acid gas with a fundamental objective to ensure maximum safety to the public, the employees, and the environment. These are depicted in Figures 43 and 44. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and best practices. Monitors for H₂S are installed at key locations around the Plant. These devices are continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points derived from the baseline study of the ambient air quality and supported by a gas dispersion model.

The facilities have been designed and constructed with important safety systems to provide safe operations. These systems include emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant, the Mongoose, and other components of the facility. Bayswater has installed a flare stack to safely depressure piping and equipment if an event occurs.



Figure 43 – Site Plan



Figure 44 – Mongoose AGI No. 1 Wellbore Schematic

With the level of monitoring implemented at the Plant, a release of CO_2 would be quickly identified, and the safety systems and protocols would minimize the release volume. The acid gas stream injected into the well could include trace amounts of methane, nitrogen, and other compounds. The CO_2 injected into the AGI well is from the amine treater in the Plant adjacent to the Mongoose. Bayswater will increase its future injection volumes from its own production and possible other sources. However, the gas composition is not expected to materially change due to the consistency of the surrounding production. 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)**. Bayswater concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The Mongoose was designed to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 44. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) §3.46 [40 CFR §146.23 (b)(3)], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 45. The MMA review map and a summary of all the wells in the MMA are provided in *Appendix D*. Figure 46 highlights that only two wells penetrate the MMA's gross injection zone, and these wells were non-productive and have been plugged and abandoned in accordance with TRRC requirements.



Figure 45 – All Oil and Gas Wells Within the MMA



Figure 45 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, Cambrian, have proven to date to be nonproductive in this area. Furthermore, any drilling permits issued by the TRRC in the area of the Mongoose will include a list of formations for which operators are required to comply with TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC §3.13. The Mongoose drilling permit, provided in Appendix A, serves as an example. The Ellenburger is among the formations listed for which operators in Mitchell County and District 8 (where the Mongoose is located) are required to comply with TRCC Rule 13. The rule requires oil and gas operators to set steel casing and cement either (1) across and above all formations permitted for injection under TRRC Rule 9, or (2) immediately above all formations permitted for injection under Rule 46, for any well proposed within a quarter-mile radius of an injection well. In this instance, any new well permitted and drilled to the injection zone and located within a guarter-mile radius of the Mongoose will be required under TRRC Rule 13 to set steel casing and cement above the well's injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and 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 (also provided in the permit in Appendix A).

4.2.2 Groundwater Wells

A groundwater well search results found three wells within the MMA, as identified by the Texas Water Development Board and shown in Figure 47.



Figure 46 – Groundwater Wells Within the MMA

The surface, intermediate, and production casing strings in the Mongoose, as shown in Figure 44, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations and the GAU letter issued for this location (and included in *Appendix A*). The wellbore casings and specialty cements also prevent CO_2 leakage to the surface along the borehole. Bayswater concludes that leakage of the sequestered CO_2 to the groundwater wells is unlikely.

4.3 Leakage Through Faults and Fractures

No faults were interpreted at the Ellenburger level within the 3D seismic coverage in the area of the Mongoose. This includes areas well outside of the simulated plume boundary. Therefore, there is little to no risk of injectate leakage through faults in the region.

In the event of an unmapped fault existing within the plume boundary, any displacement caused by it would be too small to be detected through 3D seismic resolution. This displacement would be even smaller than the thickness of the Woodford Shale, effectively keeping it juxtaposed and preventing any vertical migration.

Porosity development within the injection intervals is primarily attributed to fractures and aerial exposure. However, these fractures are limited and do not extend into the upper confining unit, which helps mitigate the risk of migration through fractures outside of the designated injection interval.

4.4 Leakage Through the Confining Layer

The overlying Woodford formation acts as a competent sealing formation for the proposed Ellenburger injection interval. The Woodford contains ideal properties that will allow it to maintain sealing properties through the injection process. This is validated through the permeability and threshold entry pressure tests performed through the core analysis detailed in *Section 2*. If, in the most unlikely circumstance, the Woodford seal is compromised, additional tight Mississippian lime of roughly 168 ft lies above the Woodford Shale that would also act as an additional sealing interval. Additional confining strata that include salt, shale, and tight carbonates are present between the Mississippian lime and USDW, which would alleviate any threat of migration of the injection into the USDW.

4.5 Leakage from Natural or Induced Seismicity

The Mongoose is situated within the Eastern Shelf region, an area that has experienced a few minor seismic events along the edges of the 9.08-kilometer (km) radius recommended by the TRRC. Analyzing historical seismic data available on the USGS's Advanced National Seismic System website (spanning from 1971 until now) and the Bureau of Economic Geology's TexNet catalog (ranging from 2017 forward), as depicted in Figure 48, reveals that the closest seismic occurrence (unspecified whether natural or induced) took place just within the 9.08 km radius.

All seismic events depicted on the map were recorded at depths exceeding 20,000 ft, indicating their occurrence within the Precambrian basement rock. Additionally, none of the events had a

magnitude of 3.0 or greater. Notably, the 3D seismic assessment did not indicate the presence of any faults or fracture zones. This absence suggests that any deep-seated seismic activities are unlikely to compromise the integrity of the upper confining unit. Consequently, the risks associated with injectate migration beyond the injection interval are unlikely.

Stringent operating procedures will be programmed into the SCADA and controls systems to ensure that operating pressures stay below the fracture gradient of both the injection and confining intervals. Moreover, a combination of continuous well monitoring and monitoring of the TexNet site for activity will promptly identify any irregularities in the operations linked to seismic events.



Figure 47 – Seismicity Review (TexNet – 08/04/2023)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Bayswater 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 H₂S and CO₂, the H₂S will be a proxy for CO₂ leakage and therefore the monitoring systems in place to detect H₂S will also indicate a release of CO₂. Table 12 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 40-year injection period or cessation of injection operations, plus a proposed 120-year post-injection period until the plume has stabilized.

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

Leakage Pathway	Monitoring Method		
	Fixed H ₂ S monitors throughout the AGI facility		
Leakage from surface equipment	Visual inspections		
	Remote operated control room 24 hours per day, 7 days per week, 52 weeks per year		
	Fixed H ₂ S monitor at the AGI well		
	Continuous monitoring of the AGI well from remote operated control room		
Leakage through existing wells	Mechanical Integrity Tests (MIT) of the AGI well every 5 years		
	Visual inspections		
	Annual soil gas sampling at well locations the penetrate the Upper Confining Layer within the AMA		
Leakage through groundwater wells	Annual groundwater samples from existing water wells		
Leakage from future wells	CO ₂ monitoring during offset drilling operations		
Leakage through faults and fractures	Remote, continuous monitoring of the AGI well (volumes and pressures)		
	Annual report from in-field soil gas sampling		
Leakage through the confining layer	Remote, continuous monitoring of the AGI well (volumes and pressures)		
	Annual report from in-field soil gas sampling		
Leakage from natural or induced seismicity	Monitor existing TexNet seismic station for activity		

Table 12 – Summary of Leakage Monitoring Methods

5.1 Leakage from Surface Equipment

The Plant and the Mongoose were designed to operate in a manner that will reduce to the lowest factor the possibility of an escape of CO_2 and H_2S . Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established. Ambient H_2S monitors are located at the Plant and near the Mongoose for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant is continuously monitored through automated systems. Details surrounding these systems can be found in *Appendix E*. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Bayswater to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO₂ released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)**.

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

5.2 Leakage Through Existing and Future Wells Within the MMA

Bayswater continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the Mongoose. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, MITs performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 ensures that new wells in the field would be constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Bayswater will also establish and operate an in-field monitoring program to detect CO₂ leakage within the AMA. This would include H₂S monitoring, a proxy for CO₂, at the AGI well site and annual soil gas samples taken near any wells identified that penetrate the injection interval within the AMA. The samples will be analyzed by a qualified third party. Upon approval of the MRV plan and through the post-injection monitoring period, Bayswater will have these monitoring systems in place.
There are currently only two wells that have been identified within the AMA that penetrate the Upper Confining Layer. As both wells have been plugged and abandoned in compliance with TRRC requirements, Bayswater believes a leak event is unlikely. However, a soil gas sample will be taken annually and analyzed by a third-party lab. Additional monitoring will be added as the AMA is updated over time. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.

5.2.1.1 Groundwater Quality Monitoring

Bayswater will monitor the groundwater quality above the confining interval by sampling from groundwater wells near the facility and analyzing the sample with a third-party laboratory on an annual basis. In the case of the Mongoose, three existing groundwater wells have been identified within the AMA (Figure 49).



Figure 48 – Groundwater Monitoring Wells

5.3 Leakage Through Faults, Fractures, or Confining Seals

Bayswater continuously monitors the operations of the Mongoose 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 due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Bayswater plans to use the nearest TexNet seismic monitoring station to monitor the area of the Mongoose well. This station is approximately 3.5 miles west-northwest of the well location, as shown in Figure 50. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Bayswater facility. Bayswater will monitor this station for any seismic activity that occurs in the area. If a seismic event of 3.0 magnitude or greater is detected, Bayswater will review the injection volumes and pressures of the AGI well to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Bayswater will quantify the leak per the strategies discussed in *Section 7*.



Figure 49 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

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

6.1 Visual Inspections

Regular inspections will be conducted by field personnel at the Mongoose facility. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken in a prudent and safe manner to address such issues.

6.2 <u>CO₂/H₂S Detection</u>

In addition to the fixed monitors at the well site described previously, Bayswater will establish and operate an in-field monitoring program to detect any CO_2 leakage within the AMA. The scope of baseline determination will include atmospheric H₂S measurements at the AGI well and soil gas sampling for CO_2 near the two identified abandoned wells within the AMA. Initial readings will be taken to establish baseline values for CO_2 .

6.3 **Operational Data**

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of acid gas and the corresponding component of CO₂.

6.4 Continuous Monitoring

The total mass of CO₂ emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is well beyond the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel due to the presence of H₂S in the gas stream. Continuous monitoring systems will trigger an alarm if there is a release. The mass of the CO₂ released would be calculated based on the operating conditions, including pressure, flow rate, percentage of CO₂, size of the leak-point opening, and duration. 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 case of a de-pressuring event, the acid gas will be sent to a flare stack to safely process and vent the gas stream and will be reported as required for the operation of the well.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO₂ Received

Per 40 CFR **§98.443**, the mass of CO₂ received must be calculated using the specified CO₂ received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4)**." 40 CFR **§98.444(a)(4)** states that "if the CO₂ you receive is wholly injected and is not mixed with any other supply of CO₂, you may report the annual mass of CO₂ injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO₂ received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO₂ received." The CO₂ received for this injection well is wholly injected and not mixed with any other supply; the annual mass of CO₂ injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO₂ Injected

Per 40 CFR **§98.444(b)**, since the flow rate of CO₂ injected will be measured with a volumetric flow meter, the total annual mass of CO₂, in metric tons, will be calculated by multiplying the mass flow by the CO₂ 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 CO₂ 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 (standard cubic meters per quarter)

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO₂ Produced

The Mongoose is not part of an enhanced oil recovery project; therefore, no CO₂ will be produced.

7.4 Mass of CO₂ Emitted by Surface Leakage

The mass of CO₂ emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains high concentrations of H₂S. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions sent to a flare stack and reported as a part of the required GHGG reporting for the Plant. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of CO₂ and H₂S. The mass of the CO₂ released would be calculated for the operating conditions, including pressure, flow rate, size of the leak-point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

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

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

Where:

CO₂ = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

Calculation methods using equations from Subpart W will be used to calculate CO₂ emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Bayswater believes the most appropriate method to quantify the mass of CO₂ released will be determined on a case-by-case basis. Any mass of CO₂ detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. In the unlikely

event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events will be kept and stored as stated in *Section 10*.

7.5 Mass of CO₂ Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Since the Mongoose is in operation, the date Bayswater will begin collecting data for calculating the total amount of CO_2 will be the date the MRV Plan is approved. The calculation of sequestered volumes utilizes the following equation as this well will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

 CO_{21} = Total annual CO_2 mass injected (metric tons) in the well covered by this source category in the reporting year

CO_{2E} = Total annual CO₂ 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 is expected to occur, the calculations would be based on an unusual event that a blowdown is required and those emissions are sent to a flare stack and reported as part of the required GHGG reporting for the Plant.

• Calculation methods from Subpart W will be used to calculate CO₂ 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 Mongoose is a new injection well currently reporting under the TRRC Class II regulations. Bayswater is submitting this MRV application to the GHGG to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

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

9.1 Monitoring QA/QC

CO₂ Injected

- The flow rate of the CO₂ being injected will be measured with a volumetric flow meter, consistent with applicable industry standards. These flow rates will be compiled quarterly.
- The composition of the injectate stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with applicable industry standards.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The gas measurement equipment will be calibrated per the requirements of 40 CFR **§98.444(e)** and **§98.3(i)** of the GHGRP.

CO₂ Emissions from Leaks and Vented Emissions

- Gas monitors within the Mongoose facility will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR **§98.444(e)** and **§98.3(i)** of the GHGG.
- Calculation methods from Subpart W will be used to calculate CO₂ emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR §98.3(i) requirements.
- Flow meters will be operated and maintained in accordance with applicable standards as published by a consensus-based standards organization.

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

9.2 Missing Data

In accordance with 40 CFR **§98.445**, Bayswater 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 CO₂ injected is missing, the amount will be estimated using a representative quantity of CO₂ injected from the nearest previous period at a similar injection pressure.

• Fugitive CO₂ emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR **§98**.

9.3 MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Bayswater will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least 3 years and include the following:

- Quarterly records of the CO₂ injected
 - Volumetric flow at standard conditions
 - Volumetric flow at operating conditions
 - Operating temperature and pressure
 - Concentration of the CO₂ stream
- Annual records of the information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of the information used to calculate CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 11 - REFERENCES

- Adams, D. C., & Keller, G. R. (1996). Precambrian Basement Geology of the Permian Basin Region of West Texas and Eastern New Mexico: A Geophysical Perspective1. *AAPG*.
- Aird, P. (2019). *Deepwater Geology & Geoscience*. Retrieved from ScienceDirect: https://www.sciencedirect.com/topics/engineering/overburden-stress
- Bradley, R. G., & Kalaswad, S. (2001). *Chapter 12: Dockum Aquifer in West Texas.* Texas Water Development Board.
- Comer, J. B. (1991). Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas asn Southeatern New Mexico. *BEG*.
- Conselman, F. B. (1954). Preliminary Report on the Geology of the Cambrian Trend of West Central Texas. *Abilene Geologic Society*.
- Domede, P. S. (2017). *Mechanical behaviour of granite. A compilation, analysis and correlation of data from around the world*. Retrieved from https://hal.insa-toulouse.fr/hal-01743870/document
- Dutton, A. R., & Simpkins, W. W. (1986). *Hydrogeochemistry and Water Resources of the Triassic Lower Dockum Group in the Texas Panhandle and Eastern New Mexico*. Austin Tx: Bureau of Economic Geology.
- Fanchi, J. R. (2010). Integrated Reservoir Asset Management.
- Galley, J. (1958). Oil and Geology in the Permian Basin of Texas and New Mexico. *Basin or Areal Analysis or Evaluation*.
- Gunn, R. D. (1982). Desmoinesian Depositonal Systems in the Knox Baylor Trough. *North Texas Geological Society*.
- Hendricks, L. (1964). STRATIGRAPHIC SUMMARY OF THE ELLENBURGER GROUP OF NORTH TEXAS. *Tulsa Geological Society Digest, Volume 32*.
- Hornhach, M. J. (2016). Ellenburger wastwater injection and seismicity in North Texas. *Physics of the Earth and Planetary Interiors*.
- Jesse G. White, P. P. (2014). Reconstruction of Paleoenvironments through Integrative Sedimentology and Ichnology of the Pennsylvanian Strawn Formation. *AAPG Southwest Section Annual Convention, Midland, Texas.*
- Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas. *Bureau of Economic Geology*.
- Lone Wolf Groundwater Conservation District. (2019). *Management Plan 2019-2024.* Colorado City, Tx.
- Loucks, R. (2003). REVIEW OF THE LOWER ORDOVICIAN ELLENBURGER GROUP OF THE PERMIAN BASIN, WEST TEXAS. *Bureau of Economic Geology*.
- Loucks, R. (2006). *Review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas.* Austin, Tx: Bureau of Economic Geology.
- Mason, C. C. (1961). GROUND-WATER GEOLOGY OF THE HICKORYSANDSTONE MEMBER OF THE RILEY FORMATION. McCULLOCH COUNTY. TEXAS. *TEXAS BOARD OF WATER ENGINEERS*.
- Merrill, M., Slucher, E., Roberts -Ashby, T., Warwick, P., Blondes, M., Freeman, P., . . . Lohr, C. (2015). Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources–Permian and Palo Duro Basins and Bend Arch-Fort Worth Basin. *USGS*.
- Popova, O. (2020). Permian Basin Part 1 Wolfcamp, Bone Spring, Delaware shale plays of the Delaware Basin Geology Review. *USDOE*.

- Powers, R. B. (1989). Petroleum Exploration Plays and Resource Estimates, 1989, On shore United States -- Region 5, West Texas and Eastern New Mexico. USGS.
- Sanchez, T., Loughry, D., & Coringrato, V. (2019). Evaluating the Ellenburger Reservoir for Salt Water Disposal in the Midland Basin: An Assessment of Porosity Distribution Beyond the Scale of Karsts. Unconventional Resources Technology Conference (pp. 1-17). Denver: URTeC. doi:10.15530/urtec-2019-600
- Scanlon, B. R., Reedy, R. C., Male, F., & Walsh, M. (n.d.). *Water Issues Related to Transitioning from Conventional to Unconventional Oil Production in the Permian Basin.* Austin: Bureau of Economic Geology.
- Shamburger Jr., V. M. (1967). *Report 50: Ground-Water Resources of Mitchell and Western Nolan Counties, Texas.* Austin, Tx: Texas Water Development Board.
- Snee, J.-E. L., & Zoback, M. D. (2018). State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity. *The Leading Edge*, 810-819.
- Waite, L. (2021, October 25). Geology of the Permian Basin. UT Dallas Geoscience Permian Basin Research Lab.
- Zerwer, N. Y. (1997). Stress Regimes in the Gulf Coast, Offshore Louisiana:. AAPG Bulletin, 293-307.

APPENDICES

APPENDICES

<u>APPENDIX A – MONGOOSE AGI No. 1 TRRC FORMS</u>

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

APPENDIX A-5: API 42-335-33555 VAN TUYLE PLUGGING RECORDS

APPENDIX A-6: API 42-227-03634 STEWART PLUGGING RECORDS

CHRISTI CRADDICK, CHAIRMAN WAYNE CHRISTIAN, COMMISSIONER JIM WRIGHT, COMMISSIONER



A-1

DANNY SORRELLS DEPUTY EXECUTIVE DIRECTOR DIRECTOR, OIL AND GAS DIVISION PAUL DUBOIS, P.E. 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. 17174

BAYSWATER OPERATING COMPANY LLC 730 17TH STREET SUITE 500 DENVER CO 80202

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 22, 2022, for the permitted interval(s) of the WOODFORD and ELLENBURGER formation(s) and subject to the following terms and special conditions:

MONGOOSE AGI (000000) LEASE SPRABERRY (TREND AREA) FIELD MITCHELL COUNTY DISTRICT 08

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	33536013	000125803	Carbon Dioxide (CO2); Hydrogen Sulfide (H2S)	8300	9000	6900	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
		1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.
		2. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.
1	33536013	3. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.
		4. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.
		5. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.

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.
- Prior to beginning injection and subsequently after any work over, an annulus pressure test must 4. 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 March 10, 2023.

Hilf

For Sean Avitt, Manager Injection-Storage Permits Unit

			A-2				
	GROUNDWATER PROTEC		Form GW-2				
	Groundwater Advisory Unit						
Date Issued:	04 March 2022	GAU Number:	336979				
Attention:	BAYSWATER OPERATING	API Number:	33536013				
	730 17TH STREET SUITE 500	County:	MITCHELL Mongoose AGI				
	DENVER, CO 80202	Lease Number:	Mongoode Act				
Operator No.:	058827	Well Number:	1				
		Total Vertical	9250				
		Latitude:	32.422884				
		Longitude:	-101.169661				
		Datum:	NAD27				
Purpose:	Injection into Non-producing Zone (W-1	4) ock-29 [.] Townshin-1N [.] Sec	ntion_4				
To protect usable-qu Texas recommends	uality groundwater at this location, the Gro	bundwater Advisory Unit c	of the Railroad Commission of				
The base of usable- well.	quality water-bearing strata is estimated t	o occur at a depth of 350	feet at the site of the referenced				
The BASE OF UND feet at the site of the	ERGROUND SOURCES OF DRINKING	WATER (USDW) is estima	ated to occur at a depth of 475				
This recommendation is applicable to all wells within a radius of 200 feet of this location.							
Note: Unless stated Unless stated other	otherwise, this recommendation is intend wise, this recommendation is for normal d	ed to apply to all wells dri rilling, production, and plu	lled within 200 feet of the subject well. Igging operations only.				
This determination is based on information provided when the application was submitted on 03/02/2022. 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 Advisc	ory Unit, Oil and Gas Division						
Form GW-2 P.C Rev. 02/2014). Box 12967 Austin, Texas 78771-2967	7 512-463-2741 lr	nternet address: www.rrc.texas.				

	RAILROAD COMMISSION OF TEX OIL & GAS DIVISION	AS			
PERMIT TO DRILL, DEEPEN, PLUG	ACK, OR RE-ENTER ON A REGULAR OR A	DMINISTRA	TIVE EXCER	PTION LOCATI	ON
PERMIT NUMBER 876754	DATE PERMIT ISSUED OR AMENDED Feb 10, 2022	DISTRICT	* 0)8	
APINUMBER 42-335-36013	FORM W-1 RECEIVED Feb 03 2022	COUNTY	MITCH	HELL	
TYPE OF OPERATION	WELLBORE PROFILE(S)	ACRES			
NEW DRILL	Vertical		4	0	
OPERATOR BAYSWATER OPERATING 730 17TH STREET SUITE DENVER, CO 80202-0000	This permi revoked if O Dis	NOTI t and any allow payment for f commission is strict Office T (432) 68-	ICE wable assigned ma fee(s) submitted to not honorad. Felephone No: 4-5581	ay b o the	
LEASE NAME MONG	OOSE AGI	WELL NU	MBER	1	
LOCATION 10.4 miles NW direct	ion from WESTBROOK	TOTAL DE	SPTH	10000	
SECTION 4 SURVEY T&P RR CO/MORRIS DISTANCE TO SURVEY LINES	BLOCK 29 T1N ABSTRA	DISTANCE	15 e to neare	ST LEASE LINI	E
551 IL EAST	2164 ft. SOUTH	DISTANCE	TONEARE	T.	EA 6
400 ft. EAST	650 ft. SOUTH	DISTILICE	See FIEI	LD(s) Below	
FIELD NAME LEASE NAME		ACRES NEAREST LE	DEPTH SASE	WELL # NEAREST WE	D
SPRABERRY (TREND AREA)		40.00	10,000	1	-
MONGOOSE AGI				0	
RESTRICTIONS: Do not use this by the Environm	well for injection/disposal/hydrocar ental Services section of the Railroa	bon storage 1 Commissio	e purposes on, Austin,	vithout appro Texas office	ova e.
THE F This well shall be completed and produc well is to be used for brine mining, under salt formations, a permit for that specific drilling, of the well in accordance with St This well must comply to the new SWR is corrosive formation fluids. See approve drilling the well in.	OLLOWING RESTRICTIONS APPLY TO ed in compliance with applicable special field rground storage of liquid hydrocarbons in salt purpose must be obtained from Environment atewide Rules B1, 95, and 97. 3.13 requirements concerning the isolation of d permit for those formations that have been i	ALL FIELD or statewide formations, al Services p any potentia dentified for	DS a spacing an or undergrou prior to const al flow zones the county in	d density rules. und storage of g truction, includir and zones with n which you are	lft gas ng n
Data Validation Time Stamp:	Feb 10, 2022 9:58 AM('As Approved' Version)	Page 3 of 4		



RAILROAD COMMISSION OF TEXAS

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

Tracking No.:

Submitted 09/11/2023 298516

Form W-2

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

UPERALL	
	Operator 059927
Operator 730 17TH STREET SUITE 500 DENVER CO	
WELL	INFORMATION
API 42-335-36013	County: MITCHELL
Well No.: 1	RRC District 08
Lease MONGOOSE AGI	Field SPRABERRY (TREND AREA)
RRC Lease	Field No.: 85280300
Location Section: 4, Block: 29 T1N, Survey: T&P RR CO/MORRIS	SON, W, Abstract: 1545
Latitude 32.423000	Longitud -101.170059
line tion from WEATDDOOK	
which is the nearest town in the	
FILING	INFORMATION
Purpose of Initial Potential	
Type of New Well	
Well Type: Active UIC	Completion or Recompletion 04/28/2023
Type of Permit	Date Permit No.
Permit to Drill, Plug Back, or	02/10/2022 876754
Rule 37 Exception	
Fluid Injection	
O&G Waste Disposal	17174
Other:	
COMPLET	
Spud 10/12/2022	Date of first production after rig 04/28/2023
Date plug back, deepening,	Date plug back, deepening, recompletion,
drilling operation 10/12/2022	drilling operation $04/28/2023$
Number of producing wells on this lease	Distance to nearest well in lease &
Number of producing wells on this lease this field (reservoir) including this 1	Distance to nearest well in lease & reservoir
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00	Distance to nearest well in lease & reservoir Elevation 2252 GL
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-Yes	Distance to nearest well in lease & reservoir Elevation 2252 Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes
Number of producing wells on this leasethis field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNo	Distance to nearest well in lease & reservoir Elevation 2252 Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W- YesYesRecompletion orNoType(s) of electric or other log(s) Electric Log Other Description:Combo of Indu	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No iction/Neutron/Density/Sonic
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400 400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Inction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and 0 Feet from the South Line of the
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W-YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description:Location of well, relative to nearest lease of lease on which this well is400650	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Inction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this1Total number of acres in40.00Total depth TVD9289Plug back depth TVD9036Was directional survey made other inclination (Form W- YesRecompletion orNoType(s) of electric or other log(s)Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is400	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this 1 Total number of acres in 40.00 Total depth TVD 9289 Plug back depth TVD 9036 Was directional survey made other inclination (Form W- Yes Recompletion or No Type(s) of electric or other log(s) Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is 400 FORMER FIELD (WITH RESE	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No .0 Feet from the East Line and .0 Feet from the South Line of the MONGOOSE AGI Lease.
Number of producing wells on this lease this field (reservoir) including this 1 Total number of acres in 40.00 Total depth TVD 9289 Plug back depth TVD 9036 Was directional survey made other inclination (Form W- Yes Recompletion or No Type(s) of electric or other log(s) Combo of Indu Electric Log Other Description: Location of well, relative to nearest lease of lease on which this well is 400 FORMER FIELD (WITH RESE Field & Reservoir	Distance to nearest well in lease & reservoir Elevation 2252 GL Total depth MD Plug back depth MD Rotation time within surface casing 41.0 Is Cementing Affidavit (Form W-15) Yes Multiple No Iction/Neutron/Density/Sonic Off Lease : No 0 Feet from the East Line and 0 Feet from the South Line of the MONGOOSE AGI Lease. RVOIR) & GAS ID OR OIL LEASE NO. Gas ID or Oil Lease Well No. Prior Service Type

W2:	N/A				
FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:					
GAU Ground	dwater Protection Determination	Depth	350.0	Date 03/04/2022	
SWR 13 Exc	eption	Depth			

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION					
Date of		Production			
Number of hours 24		Choke			
Was swab used during this	No	Oil produced prior to			
PRODUCTION DURING TEST PERIOD:					
Oil		Gas			
Gas - Oil 0		Flowing Tubing			
Water					
	CALCULATED	24-HOUR RATE			
Oil		Gas			
Oil Gravity - API - 60.:		Casing			
Water					

	CASING RECORD										
	Type of	Casing Size	Hole Size	Setting Depth	<u>Multi -</u> Stage Tool	<u>Multi -</u> Stage Shoe	Cement Class	Cement Amoun	Slurry Volume	Top of Cemen	t <u>TOC</u> t Determined
<u>Ro</u>	Casing	<u>(in.)</u>							<u>(cu.</u>	<u>(ft.)</u>	Ву
1	Surface	13 3/8	17 1/2	569			С	637	847.0	0	Circulated to Surface
2	Intermediate	9 5/8	12 1/4	5328	3001		С	725	1752.0	0	Circulated to Surface
3	Intermediate	9 5/8	12 1/4	5328			С	610	1175.0	3001	Calculation
4 C	Conventional Production	n 7	8 3/4	8343			C & RESIN	594	1513.0	1800	Calculation

_					LINER RECORD			
<u>Ro</u>	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu. (ft.)	TOC Determined
N/A								

		TUBING RECORD	
Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	3 1/2	8260	8230 / INCONEL
			925

PRODUCING/INJECTION/DISPOSAL INTERVAL					
Ro	Open hole?	From (ft.)	<u>To (ft.)</u>		
1	Yes	L 8343	9036.0		

ACID, FRACTURE, C	EMENT SQUEEZE, CAST IRON BRIDGE PLUG,	RETAINER, ETC.			
Was hydraulic fracturing treatment	No				
Is well equipped with a downhole sleeve? No	If yes, actuation pressure				
Production casing test pressure (PSI	IG) Actual maximum pressur	e (PSIG) during			
hydraulic fracturing	fracturin				
Has the hydraulic fracturing fluid disclosure been No					
Ro Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)			

OPEN HOLE CEMENT PLUG WITH 58 SACKS CLASS H

1

Other

9036 9289

		FORMATION REV	CORD		
Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
SANTA ROSA - POSSIBLE LOST CIRCULATION	No			No	NOT PRESENT AT
YATES - OVERPRESSURED, POSSIBLE FLOWS	Yes	1001.0		Yes	
SEVEN RIVERS	Yes	1137.0		Yes	
SAN ANDRES - HIGH FLOWS, H2 CORROSIVE	S, Yes	2008.0		Yes	
GLORIETA	Yes	2875.0		Yes	
CLEARFORK	Yes	3089.0		Yes	
TUBB	No			No	NOT PRESENT AT LOCATION
WICHITA	No			No	NOT PRESENT AT LOCATION
COLEMAN JUNCTION - POSSIBL LOST CIRCULATION	E No			No	NOT PRESENT AT LOCATION
WOLFCAMP	Yes	5369.0		Yes	
STRAWN	Yes	7918.0		Yes	
ODOM	No			No	NOT PRESENT AT LOCATION.
MISSISSIPPIAN	Yes	8153.0		Yes	
WOODFORD	Yes	8322.0		Yes	
ELLENBURGER	Yes	8374.0		Yes	
CAMBRIAN	Yes	9279.0		Yes	
Do the producing interval of this w	ell produce H	2S with a concer	tration in exc	ess of 100 ppm	No
Is the completion being downhole	commingled	N	0		

REMARKS DIRECTIONAL SURVEY RUN FOR INFORMATION PURPOSES ONLY.

PUBLIC COMMENTS:

RRC REMARKS

CASING RECORD :

SURFACE CASING IS SET AT 543.5' AS MEASURED FROM GROUND LEVEL, WHICH IS WITHIN 200' OF BUQW.

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

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

POTENTIAL TEST DATA:

		OPERATOR'S CERTIF	ICATION	
Printed	James Clark	Title:	Consulting Petroleum Engineer	
Telephone	(512) 415-4191	Date	09/11/2023	

Ð 7 Ð ŋ 7 η ŋ Ŋ 20. Do you have the right to develop the minerals under nny right of way that crosses, or is contiguous to, this innet? If not, and if the well requires a Rule 37 or 38 exception. 25. is this wellbore subject to Statewide Rule 36 (hydrogen sulfide area)? Yes 23. Is this a pooled unit? Perpendicular surface location from two nearest designated lines:
 trace.Unit <u>1000</u>, FNL & 2500, FEL 11. Distance from proposed location to nearest leave or unit line 2 Address (including city and zip code) Purpose of filing (murk appropriate bodes): · Sunny/Section 1000' FNL & 2500' FEL of Section 15-Operator's Name (exactly as shown on Form P.S. Organization Front) see Instructions for Rule 37. ĩ Krimerka Nulicamp, (Wildcat) File a copy of W-1 and plat in JORC Di Ellenburger (Wildcat) 1800 £ Midland, Texas 3200 West Cuthbert, Bright se zones. One zone per line, ELD NAME: [Exactly as sheem; on RRC privation adult a all estublished and whiles! somes of anticipated repiction. Attach additional Form W-1's as needed to last any firentealo かって 121 Uttach Form P-12 and certified plat. 21 × たりや Company 30 D III 6 Directional Well 5 and \$180.00 fee 79701 Rai Bau **NAME** Suite 2-C trict Office. Deepen (below casing) Sidetrack Application for Permit to Drill, Deepen, Plug Back, or Re-Enter ã 5200-8300' **Gebru** 7800 1000 × 10. Location 3. IURC Operator No. 6. Lease Name (32 spaces maximum) Van Tuyle 093125 'This well is to be located ______ Section . 8 8 Deepen (within casing) Amended Permit (enter permit no. at right & explain fully in Remarks) which is the nearest town in the county of the well site RAILROAD COMMISSION OF TEXAS Oll and Gas Division N 10 (n.) 467-1200 2 467 1200 Specing 467-1200 No 2 Lini 2 15 203091 0CT 1890 If subject to Rule 36, ts Form H 9 Aled? Yes Ę ł I certify that information stated in this application is ince and complete, to the best of my knowledge ĕ 12. Number of configuous acres in lease, pooled unit, or unitized iract **4**0 Density If a directional will show also projected bottom-hole location: pallern Hock 24 Jo liem 17 less that Jiem 18 (substandersberrehe for any field applied for?? 4. FIRC District No. G Lengel Mail Signature Date: Խ 20, 1-1-1 mary Artiling unity for this well OUTLINE 15 Plug Back ALL DE LO 5 4 鍧 _miles in a _north ŝ 9/26/90 1 Smuth. 5. County of Well Site day. Mitchell TEP RR Cor, TWP T-N NO NO a Re-Enter Fine Ungonty - Fine - ----7. RRC Lease/ID No. direction from <u>Latan</u> ٧ Tel: Area Code S. Dawner from NA TRA-NA Inchesed your talavoli. (N.) Dog to neuro Read Instructions on Back 915-697-2214 Tracy D. Tenison, Engineer Name and title of operator's representative Enter here, lf assigned: letted wes Z, ۷ "Ennite h 8. Well No. 640 80 V If not filed, explain in Remarks. Number Type and or other Penny 42-33 0 9 0 Rule 37 Case No Abstract No. A. 584 21. Act, of applied for per-mitted, or complete and becattoms that during the this one on bear in the this one on bear in the this reservoir. (1) 5 Form W-1 (OUTLINE ON PLAT.) 9. Total Depth 1 85001 2355 ŝ 5 5 3

A-5



<u>*</u>		<u>इ</u>	26 17 19	25.11	22.11		- 12 M	5 17	s	Ę	() 중용) 11. Pl				λ εi	в 1.0p		Իսդ	¥ ⊒ .≇
		inai ks	you have the right to develop the minerals under y y right of way that crosses, or is configuous to, this tract? y nut, and if the well requires a Rule 37 or 38 exception, r Inviruentions for Rule 37.	his wellwre subject to Statewide Rule 36 (hydrogen aufide are	 Interpretendent of the second s	Sunn Section 1000' FNL & 2500' PEL of Su	pendicular surface location from two neatret designated lines: I.cov/Unit 1000' FNL & 2500' FEL	llenburger (Wildcat)	trawn (Wildcat)	olfcamp (Wildcat)	rpletion. Attach additional Form W-1's as needed to list ae zones. One zone per line.	ELD NAME (Exactly as shown on RBC provation achedule), all established and wildcal zones of anticipated	istance from proposed location to nearest lease or unit line			Hdlynd, Texas 79701	dress linktuding city and zip code)	iright & Company	Directional Well Sidetrack	ne of filing (mark appropriate hours): X Drill Dreprin (Lelow casing)	 Transver of Trans. Address to: Distant Ossenaria, Driffing Permits P. O. Drever 12007, Capital Station Autin, Trans 79711 Aropy of W-1 and plat to USC District Office.
			×	117 Yes 🔲	No	tet ion-t		8300'	7800'	5200'	Completion depth		1000	wh	• 1	10. Loca	Van	001 093			Nication fo
!				No X	X			467-1200	467-1200	467-1200	Specing pattern (fl.)	15,	\$	tch is the nearest	is well is to be loc	tion 15	Tuyle	125	mended Permit (c	pen (within casin	NILROAD CO Oll and Permit to Dr
	Date	Sign	I certify the	If subject to	24. IN Her Yea		La	40	40	40	Denalty pattern (acres)	16	12. Number	town in the c	aled5				nter permit n	Ē	indission I Gas Divisio III, Deepen
	1110	ature 9/26/	at Information st	Rule 36. Is Form	n 17 Jesa than It	urvey/Section	nase/Unit	40	40	40	OUTLINE ON PLAT.	17. Number of acres in defiling unit	of contiguous at	ounty of the wel	miles in a	29 7-1-1V		B STIRLING	o. at right & esp	Flug Back	OF TEXAS
• JURC	day y r .	06	ated in this applicati		em 16 (substandard ach Form W-1A)		שט ףנטוברוכם ססווטוח	NO	NO	NO	Inis rectivour If eo, caplein In Remarks,	18. Is the acrosp assigned to an- other well on this lease P in	tres in lesse, pooled u	Isite	north	vy T&P RR Co		Mitchell	lain fully in Remarks	ReEnter	or Re-Enter
Use Only •	Tel: Area Code	Name and till 915-697-3	ion is true and com. Tracy D.	No 0	actrate for any field		Sufficient and	NA	NA	NA	this inser @ tractvoir. (fl.)	19, Distance from proposed loca- lion to nearest applied for, permitted, or	init, or unitized trai		direction from	· · · · · · · · · · · · · · · · · · ·				Eater here, if assigned:	Read Instructi
	Number	e of o pera tor's 22 1 4	plete, to the be Tenison	If not filed.	1 applied forl?			ô	0	0	type well Spe well	OIL gan	π <u>640</u>		atan	·	1		V	► 42- Remit N	ons on Back
 		representative	st of my knowl	explain in Ren	N.			1		-	OIL	21. No. of appl mitted, or ex locations (ii) this one) on this reservoi	IOUTLINE O				8500		2	P	Form V
1				narks							GAS	ited for, per- ompleted ucluding lease in f.	IN PLAT.)			130		7			



JERRY A. DUNN

à.

TEXAS P.L.S. NO. 4735 TEXAS P.L.S. NO. 4839

MIDLAND	ЈОНИ /	WEST &	ASSOC	IAT	ES		TOAS
Scole: /"=	1000'		Drawn by:		N	G	
Dale:	10-2-90		Sheet	1	of	1	aheete
Revision Do	te:		W.O. No.:	L 9	007	63	

13(4) Exception Dated 440		RS DIV	ISION	Mo ())		ii.		W. 10/74
				NO.42-3	35-33555		R R R	et
WELL IS LOCATED WITHIN T	IRTY D	YS AFT	ER PLU	GGING	GH	4.	RRC Leest	or M.
Wildont	V.	an Tuyl	e /	-0		5.	Wall Number	1
Bright & Company	ős. Origi	and Form W-	-1 Filed in	Name of:	<u></u>	10.	County Mitchel	11
ADDRESS 2911 Turtle Creek Blvd #70 Dallas, TX 75219)() ^{6b.} Any 1	Subsequent	W-l's File	d in Name of	-	11.	Date Drill Permit Jan 10/18/9	01
Location of Well, Relative to Nearest Lease Boundaries	1000	i Zma N	orth 1	ine and 25	OD Foot P	12,	Permit Mus	and the
SECTION BLOCK AND SURVEY	east Li	ne of the	VIII I			- 11	379724	2
ec 15. Blk 29. TIN. T&P/RR Co	Coun	^{ty} 8.	7 milos		Vestbro		Co.72670	0./
i. Type Well (Oll, Gas, Dry) (Oll, Gas, Dry) 8360 [†]	at All Field :	Names and		T Ges ID No	NESCOLOC	LL, 14,	Dute Drilli Completed	AK DO
I Ges, Amt. of Cond. on Hend at time of Plugging					-	15,	Dete Well 12-17-	Planed 90
CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5 1	LUG #6	PLUG #7	PLUG #8
7. Cementing Date	12-17	12-17	12-17	12-17	12-27	\sum		- 2 637.0
D. Size of Hole or Pipe in which Plug Placed (inches)	7-7/8	7-7/8	7-7/8	8-5/8	8-5/8	<u> </u>		
. Depth to Bottom of Tubing or Drill Pipe (ft.)	8250	2700	2350	400	15 .	WY I	1 to	
2. Sacks of Coment Used (each plug)	50	50	180	50	10 \		1./ - y/	
I. Slurry Volume Fulpped (cli. If.)	8076	2526	1792	325	Surf			
Measured Top of Plus (if tassed) (ft.)	0070	2320	1790	525	Sull .	JAK	1.4.100	
5. Sturry Wt. #/Gel.	15.6	15.6	15.6	15.6	15.6	VIT		-
7. Type Cement	Prem.	Prem.	Prem.	Prem.	Prem.	taka.	15 75%	6
8. CASING AND TUBING RECORD AFTER PLUGGING		29, W	an Ceelor)	-Drillable M Left in This	aterial (Othe: Well		Ye.	K No
ZE WT. #/FT. PUT IN WELL(A.) LEFT IN WELL(A.) I	HOLE SIZE	(m_) 29s. If	enswer to a d briefly de	bove is "Ye scribe non-	is" state dep drillable mat	th vio top Hindu - TU	of "Junie"	left in hole Side of
3/3 48 361 361	17-1/2	- P	orm if more	space is nee	eded.)	10 101	12.8	
<u>5/6 32 22/4 22/4 22/4 </u>					1.	1. 4	1.55	(3.13)
		-	1.18.41	-5. 9	12 400	1. 200		an a
LIST ALL OPEN HOLE AND/OR PERFORATED INTE	RYALS	-	5		1	C/1.		
PROM 2274 TO 9360		FR	он	-	T	520	3/	
ROM LAND I IN THE THE TO		PR	OM 1	nsiurs to	1. b. T	0	15/	
PROM TO		FR	OM C	Leel [1]	NT.	66100		
FROM ADD 1 7 1991 TO		TR	оні	RH.O.de	T	00		STATES
PROM		FR	OM The factor	1.1.1	ा	0		
have knowledge that the cementing operations, as reflected	by the inform	nation found	s on this for	m, were per	formed as Ind	icated by	each infor	nauon.
resignates items to be completed by Cementing Company. It	eme not so d	lesignated a	hali be com	pleted by O	perator.			
				iii tean Cann	ulaan in	4- 0-		
- MC - CACUM X/			III IOUT	LUN SEL	vices, B	TR Sb	ring, T	A
nature of Comenter or Authorized Representative		Ma	me of Cene	nting Compo	in y			
I declare under penalties prescribed in Sec. 91.143	, Texas Natu	mi Resourc	es Code, ti	hat I am auth	orland to me	ke this re	port, that t	hla
report was prepared by me or under my supervision a	und direction,	, and that d	ate and fect	is stated the	rein are true,	carrect,	and comple	te, Status
to ris nation with menalanday								
Amonda I Hand		Annat		1/1 + /				
REPRESENTATIVE OF COMPANY		ARCHT TITLE		RECEDAT	<u>р</u>	hont		NUMBER
			F	R.C OF TET	45	3		
Dr. A That Teletan	.)	÷.						
GNATURE: REPRESENTATIVE OF RAILROAD COMMIS	SION	•	MA	IR 0 5 19	991 <u></u>	8, ÿ	~	
					and it.		コクノ	

истер олгор язтам .

.

34. Tetal Depth 8360	Other Fresh Water TOP	Zones by T.I BOTTO	D.W.R. DM	35. Have all Abandoned Walls on this Leas according to R.R.C. Rules?	se been Plugged	X Y•1
Depth of Deepeat Fresh Water				36. If NO, Zaplain		No
37. Neme and Address Halliburton, F	of Cementing or Server. . O. Box 380;	, Snyder	who min, Texa	ad and pumped coment plugs in this welt as 79549	Date RR notified	C District Office
Ben Van Tuyl	ers of Surface Owner e, 432 Hillds	ale Dr.	and Oper Ann Ai	retors of Offert Producing Leases		
39. Was Notice Given	Before Pipeeine to Ec	sch of the Ab				
Yes				· · · · · · · · · · · · · · · · · · ·		
40. For Dry Holes, this released to a Com	Form must be accom	LY spanled by ei	ther a Dr	ilier's, Electric, Radioactivity or Acoustical	i/Sonic Log or at	ich Log must be
- 	g Attached	Lag releas	sed to _		Date	
122			. ×		Date	
The second second				20		
Type Loga:	lier's	X Elec	tric	Redicectivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (lier's Special Cleanance) Fi	X Elec	tric	Radioactivity	Aco	untical/Sonic
Type Logs: Dri 41. Date FORM P-8 (1 42. Amount of Oli prod	lier's ipecial Cleanance) FL	ied?	tric	Radioactivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (: 42. Amount of Oil prod * Flie FORM P-1 (C	ller's Special Clearance) Fi uced prior to Plugging II Production Report)	Ied?	iric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oli prod • Flie FORM P-1 (C <u>BRC USE ONLY</u>	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	Ied?	itric	Badioactivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oli prod Pile FORM P-1 (C RRC USE ONLY Nearest Field	lier's Special Clearance) Fi uced prior to Plugging Still Production Report?	Ied?	itric	Redicectivity	Aco	ustical/Sonic
Type Logs: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>BRC USE ONLY</u> Mearent Field	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Jed?	itric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Mearest Field BMARKS	lier's Special Clearance) Fi aced prior to Plugging 011 Production Report)	Ied?	itric	Redicectivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oil prod • File FORM P-1 (C <u>RRC USE ONLY</u> Hearest Field BMARKS	ller's Special Clearance) Fi uced prior to Plugging III Production Report)	Ied?	itric	Bediosctivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Mearest Field EMARKS	lier's Special Clearance) F1 uced prior to Plugging 011 Production Report)	Elec Ied?	iric	Bediosctivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Ied?	itric	Redicectivity	Aco	ustics1/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R & C USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	Elec	itric	Redioactivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>BRC USE ONLY</u> Hearest Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Ied?	itric			ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C RC USE ONLY Nearest Field BMARKS	lier's special Clearance) Fi uced prior to Plugging li Production Report	E	itric	Redioactivity		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field EMARKS	lier's Special Clearance) FL sced prior to Plugging II Production Report)	Elec	itric	Redioactivity	Aco	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>RRC USE ONLY</u> Nearest Field EMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	Ied?	itric	Redioactivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi seed prior to Plugging III Production Report)	E	itric	Redicectivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1) 42. Amount of Oll prod • Flie FORM P-1 (C <u>R & C USE ONLY</u> Nearest Field BMARKS	lier's Special Clearance) Fl uced prior to Plugging II Production Report	E Elec	itric	Redicectivity		uetical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oil prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report	Elec	itric	Redioactivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Flie FORM P-1 (C <u>BRC USE ONLY</u> Hearent Field BMARKS	lier's Special Clearance) Fl sced prior to Plugging III Production Report)	E	itric	Redioactivity bbls* produced		ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod * Plie FORM P-1 (C <u>BRC USE ONLY</u> Nearest Field MARKS	lier's Special Clearance) Fi uced prior to Plugging III Production Report)	E Elec	itric	Redioactivity	Aro	ustical/Sonic
Type Loga: Dri 41. Date FORM P-8 (1 42. Amount of Oll prod • Flie FORM P-1 (C <u>R RC USE ONLY</u> Nearest Field EMARKS	iler's Special Clearance) Fl uced prior to Plugging II Production Report	E Elec	itric	Redioactivity		ustical/Sonic

en e const la e const la seconda e m la seconda e m

1

.....

419

PLACE FOLS | R1

< 1

Compared and the second largest and the secon	RAILROAD COME Oll and C	Z J 3	(AS	o Wa	Form Cemienti Niv.	a W-10 Ing Rep 4/1/03 8-015
1. Operator's Name (As shown on Form P.5, Organiza	tion Report) 2. R	RC Operator No.	3. RRC District No.	4. County	of Well Site	1.04744
Bright & Co.		093125	8	Mitch	el1 👘	10 30
5. Field Name (Wildcat or exactly as shown on RRC re	rords)		5. API No.	7.	Drilling Permit	Na.
Wildcat			42- 335-33	555	379724	1 - 1
8. Lease Name	9.1	Rule 37 Case No.	10. Oil Lease/Gas	ID No. 11.	Well No.	10-14
Van Tuyle	1				1	1220

CASE	IG CEMENTING DATA:	SURFACE CASING	INTER MEDIATE	PRODU	CTION	MULTI- CEMENTIN	STAGE
			CASING	Single String	Multiple Parallel Strings	Tool	- 19 Mar 19
12.0	Brugen bit for 10550						
13. •	Drilled hole size	17-1/2	11		1	an C _{all} _{an} X	
36	Est, % wash or hole enlargement						
14. 5	ter of casing (in. O.D.)	13-3/8	8-5/8	alike datus	5 - 2°	a lign ^{an}	
15. T	op of liner (fr.)	a			2		
16. S	etting depth (ft.)	361	2274	3			
17 N	umber of centralizers used	3	3				
18 H	its, waiting on cement before drill out	12	12				
Â	19. API cement used: No. of socks	390	300-			170 - 1641 - 1816	1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.
4 81	Class	Premium P	111	27 AP reul	aff , Mich ,	WHE Standt	-13 Truch-
a <	Additives	27 Calciu	m Chloride	i dina			101.65
Ŷ	No. of sacks 🕨 🕨						
d Sh	Class 🕨	inener Ken	themes defined	intol at an:	inurtant		
18	Additives	ين ورجاد حققوني فرواني	and to be seen for	A marte data and inco	A PARTY A MARTINE	D. OF TEXAS	
È	No. of sacita	of the advances prope	ter des medications	cristellis wilds	the state of the s	. if fabgeties in	South Brind Southern
d Slu	Class	ar island et al.	all and show	aradina or yunar Aradina ortuguna	a in later owner, ne ge a tracht genter - Na		n in 124 - Dùn 127 Institu Print - Barned Dunret
ñ	Additives 🕨	 Track of State Str Track of Strategy and 	n en talan dalam yang kang sang kang sang sang sang sang sang sang sang s		Leff Biro't Husp area a an	CG	a da compañía com e
ti	20., Slurry pumped: Volume (cu. ft.) 🍉		591	intres investion	IA CONTRACTOR		State Water I a
	Height (ft.) 🕨 🕨	Surface	2268	1 B 1 327 2072 (s temp tigdes ansätt va en en en en en	P. Weitzers and and	W 15, in oks
¥	an an an the Volume (cu. ft.) 🍉	- Section of Suppl	- 194 Berlin (1944)	s rians - Frank an	i dina aratisa hire	an a	 Subarrolluni)
64 I	ileight (fs.)	A SAME SALANA A A	 anaparities contractor designed in Lindé (c) 	, Hondrachagasa CHarc sasara	េ មេរ៉ានីវារូក ភូមិ កើនដែរប្រាំការ ភ	unter ünterstandt i Unter unstandere	: Bast residentions parts in the other line
z	Volume (cu. ft.) 🕨	1 N X.		a fi bolt an it ES.	n albig zint fog drav dat. A	e fitter halter («»	and al say within
•		me ante ave		tiere is on these e	institues land	enet belever statte sin	i incaratora fasis religi
1	Volume (cu, ft.) D.	514.1	591	- Hannahan and an early a	o Ladistra Miran	1	
B	an and all each off in the Height (if Lifes in the second se	Surface	110000 000 01 4000	nthyanthijh Lalk	in the provide states of the second states of the s	ert valie de trat	
21. Y	Ves cement circulated to ground surface or bottom of cellar) outside casing?	Toras Yes	n inte Ro	1. Startinger Start	2. Stallier feit		Contraction of the second
22. F	iemarika	41. 23.11		RECEIVED R.R.C. OF TEX	(ΛS	The second second	and the part of the
		1. U.S.	na Angelan ing	MAR 05 1	991		n - Suzidaje Suzidaje Suzidaje

and the second second second

:

OIL & GAS DIV MIDLAND TEXAS

OVER

DIO PLUGARO ALMADUR	FLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4	PLUG # 5	PLUG # 6	PLUG # 7	TLUD *
And CARDONA And And And And And And And And And And	. E	XHT RO V	Reschind.	nene.	76).		00000000	e
Size of Jule or pipe plugged (in.)								
Dupth to bottom of tubing or drill pipe (ft.)								
	and a character	0	1917		Net an An	15.000		$\pi(A t_{2}^{-1}, \xi)$
	RALLAS IN	- it we	(Eval) and		· · · · · · · · · · · · · · · · · · ·		· · · • · • · · · ·	
	1.1.27	$\{F_{in}, F_{in}\}\}$			in the second			16 . 24
Homused top of plug, if tagged (ft.)								
		3	2112	N 10	160 e Gera		100.020	ल्या हो। तम
	i Dining i	Static Static		14.452			242	
and the second se		S. House Charge			and the state	a from the		. tomas
					فاستعجزه		Jaking	in terms
Supplier and the		a la		4	1 Lin	Il Qa		
	11111			200	SIZ ZAR	100-		
		i ana a	1.49362		in state of	<u></u>		
						1	1-26-00	
	TRANS STATES		A REAL PROPERTY AND A PARTY OF A REAL PROPERTY.	and some that they want the	of the other state into	and a start as	and die	ing politik
OPERATOR'S CERTIFICATE: I declar certification, that I have knowledge of ()	e under penaltien ne well data and in	prescribed in	Sec. 91.143. Te ented in this rep	zas Natural Report and that day	sources Code, (that I am autho rented on both a	rized to make idea of this form	this Late
OPERATOR'S CERTIFICATE: I decian certification, that I have knowledge of it true, correct, and complete, to the best	e under penaltien te well data and in t of my knowledge	prescribed in formation pres e. This certifica	Sec. 91.143. Te ented in this rep tion covers all v	xas Natural Re ort, and that da vell data.	sources Code, (ta and facts pres	that I am autho sented on both a	ides of this form	this nare

Instructions to Form W-15, Cementing Report

State. Zip Code

Tel.: Area Code Number

Date

mo.

day

yr.

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

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

 An initial oil or gas completion report. Form W-2 or G-1, as required by Statewide or special field rules;

• Form W-4. Application for Multiple Completion. If the well is a multiple parallel casing completion; and

Clbr.

 Form W-3, Plugging Record, unless the W-3 is signed by the cementing company representative. When reporting dry holes, operators must complete Form W-15, in addition to Form W-3, to show any casing cemented in the hole.

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

「日本のではいたけでいたで、これのからのでと

Address

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

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

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

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

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

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

Please to File No.

11.4.

RAILROAD COMMISSION OF TEXAS OIL AND GAS DIVISION

APPLICATION TO PLUG AND WELL RECORD FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED FIVE FULL DAYS PRIOR TO PLUGGING

M.K.C. Malando

Name of Com		T. T	he Texas	Compar	IV.	nu Por	1720 50	nt Wonth
neme er ooml	any or open	1007						Texas
ountyH	loward		SurveyT&	P,RRGo.		29T_1_P	Sec4	
iame of Leas	<u>A. I.</u>	Nasso	n	io, of Acres	1760 W	ell No	Elev	2300 (DF)
ocated Appr	ox.21	NE	Direction	from.Bd	g Spring,	Texas	(Nearest P.	O. or Town)
Name of Field	in which we	ll is locate	a Wild	cat	0/400334++444.000/ 1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.		************************	*********
Form 1, "Notic	e of Intentio	n to Drill,'	' was filed in 1	name of	The Texas	Company	*********	
Drilling Comm	enced 12	-28		19. <u>52</u> , 1	cilling Completed	3-28		19.52
las this well	ever produce	d oll the		******		or Gas?	No	ياني تيد
baracter of 1	Well (Oil, Ge	s or Dry)	Dry			Tet	Depth.	16701
) ate you wish	to Plug	3-2	7 ,		-10 52			
lame of Party	Plugging W	en Liv	ermore D	rilling	Address	10 Lubboch	Nat'l Ba	inic
orrespondence	regarding i	this well a	hould be sent	to: Name	The Texa	s Company	Add	Services 11
lddress Box	1720, 1	Fort W	orth, Te	CABING	RECORD	-/-		
SIZE	PUT IN	WELL	PULL	ED OUT	1. : france de	YELL.		
2.2/04	R.	Inc	n.	; i In.	1 /2. 11	ln.		
3 3/81	196		None	1.1.000 5	196	Tex	as Patter	<u>a</u>
5/81	2115		100		201	Hal	liburton -	8 & S
		100		Cert Const	1	1	1.25	

ASING WAS CEMENTED GIVE NUMBER OF SACKS USED ON DIFFERENT STRINGS a ser a ser a ser a ser a Sec.

Initial Production	of Oil: Barreis None	WORE 24 nrs. Pressur	None Fill	DLAND, TEXAS
Give notice perore When Plugging co the Deputy Superv	Plugging to all available L suppleted, file final Plugging isor of district in which we	r Report, duly signed, and swe il is located.	ula (10) ril. to. All more in C	R 10.1952 will be furnished to Commission of Texas
NOTE: If no ing ava formation, water south	india, in state and give all info- , and to may as penably data ve	motion that eac he obtained to us to	tal depth, gades a benerger	OVE DIVIZION .
General Remarks: oil or gas.	This well dril. We therefore	desire to abandon	selvage and plu	g well in the
fcllowing.	manner: (Cut 9 5	/8" casing at 100	and pull same)	and He (Over)
		AND AND AND AVIDAVIT OF		1

ź

- - - A.E.

12

24

Galiche 0 100 At depth 206' emented 13 3/6" Red Reds 100 206 casing at 206' with 250 sacks. Shale & Anhy 206 9.5 Gament circulsted. Anhy & Shele 1254 1409 At depth 2125' camented 9.5/8" Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Salt. 1409 1750 at 2125' with 600 sacks. Anhy & Shale 1255 2125		TOP	BOTTOM	
Band Reds 100 200 cost of the second sec	Caliche		100	At doubh 2061 computed 12 2 day
Shale # Anhy 206 0.45 Comment circulfied. Anhy 94.5 1254 Anent circulfied. Anhy & Shale 1251 1409 At depth 2125' camented 9.5/8". Anhy & Shale 1250 1437 at 2125' with 600 sacks. Anhy & Shale 1750 1437 at 2125' with 600 sacks. Anhy & Shale 1955 116 116 Anhy & Shale 1252 2200 116 Lime 2125 2200 116 Lime & Shale 2125 2200 116 Lime & Ghert 3612 3820 3979 Lime & Sand 3820 3979 116 Lime & Chert 3612 3820 3979 Lime & Chert 3612 3820 3979 Lime & Sand 4155 4538 116 Lime & Chert 514 5232 6203 Lime & Chert 7953 8670 514 Total Depth 8670 8670 155 Shale 6201-15 sacks 203-2043; 40 sacks 1125'-1 10 sacks 2025'-4975'-7 <	Red Beda	100	206	At depth 200' demented 13 3/8"
Anhy 945 1254 Address Anhy & Shele 1254 1499 At depth 2125' camented 9.5/8" depth 2125' depth 215' camented 9.5/8" depth 215' depth 215	Shale & Anhy	206	0/5	Carsing AL 200' WIGH 250 SACKS.
Auhy & Shale 1254 1409 At depth 2125' camented 9 5/8", Anby & Salt Anby & Salt 1750 1877 Anhy & Lime 1955 2125 Jime 2125 2290 Lime Shale 2290 Lime & Shale 3116 3612 Lime & Chert 3612 3820 Lime & Sand 4155 4538 Lime & Chert 4536 4000 Lime & Chert 5114 5232 Lime & Shale 5222 6203 Shale 514 5232 Lime & Chert 7953 8670 Total Depth 8570 15 All Measurements from Notory Table or 12' above ground. 28 Remarks Cont'd 870 15 Stacks 5400'-550': 15 sacks 7860'-7810': 15 sacks 1125'-1 15 15 sacks 200'-2075': 15 sacks 625'-4975': 15 sack 660'-5610': 15 sacks 1125'-1 15 sacks 210'-275':	Anhy	94.5	1254	
Anhy & Salt. 1/90 1750 at 2125' with 600 ancks. Anhy & Lime 1750 1837 055. Anhy & Lime 1955 2125 1837 Lime 1955 2125 1837 Lime 1252 2290 Lime 2125 2290 Lime & Shale 2290 2322 Lime & Shale 2322: 3116 Lime & Shale 2322: 3116 Lime & Shale 3612 3820 Lime & Chert 3079 Lime & Chert 3070 4155 Lime & Chert 3079 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 753 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd .	Auby & Shele	1254	1400-	At depth 21251 comented Q 5/RH
Anhy 1837 1837 Anhy & Lime 1955 125 Lime 2125 2290 Lime & Shale 2125 2290 Lime & Shale 2322 3116 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3079 4155 Lime & Sand 3820 3979 Lime & Sand 4155 4538 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 8670 State 6203 7953 Lime & Cont'd 8670 15 Sacks 500-5171 15 sacks 5600'-7810': 15 sacks 7260': 15 sacks 1025'-975': 15 sacks 500': 15 sacks 10'-2760': 15 sacks 2093-2043: 20 sacks 1125'-1 Los sacks 102'-2760': 15 sacks 2093-2043: 20 sacks 1125'-1	Anhy & Selt.	1499	1750	at 2125! with 600 spoks
Anhy - 1837 1955 Nime 1955 2125 2290 Lime & Shale 2290 2322 116 Lime & Shale 2290 2322 116 Lime & Shale 3116 3612 3820 Lime & Sand 3820 3979 155 Lime & Sand 4155 4538 1455 Lime & Sand 4155 4538 146 Lime & Chert 5114 5232 6203 Lime & Chert 5114 5232 6203 Shale 6201 7953 6670 Total Depth 8670 8670 No 15 8670 15 All Measurements from Notory Pable or 12' above ground. 15 Remarks Cont'd 8670 15 Scole - 4520': 15 15 8670 15 All Measurements from Notory Pable or 12' above ground. 125 125 Remarks Cont'd 8670 15 8670 15 Scole - 4520': 15 sacks 5430-5580': 15 15 8680'-7810': 15 8680'-7810': 15 <td>Anhy & Shale</td> <td>1750</td> <td>1837</td> <td></td>	Anhy & Shale	1750	1837	
Anhy & Lime 1955 2125 Lime 2125 2290 Lime & Shale 2220 2322 Lime & Shale 2322 3116 Lime & Shale 3612 3820 Lime & Shale 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3620 3979 Lime & Sand 4535 4538 Lime & Chert 4538 4900 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 8670 Take Heavy mud between plugs. spot the following cement plugs. 95 sack 8670'-7810': 15 sacks 7705'-7 15 macks 5000'-5550': 15 sacks 5430-5380': 15 sacks 7860'-7810': 15 sacks 7705'-7 15 macks 5000'-5550': 15 sacks 5430-5380': 15 sacks 2025'-4975': 15 sacks 660'-4630': 15 sacks 8210'-2760': 15 sacks 270': 15 sacks 7705'-7 15 macks 5002'-550': 15 sacks 5730-5380': 15 sacks 2025'-4975': 15 sacks 957 # 1. Phr. failed	Anhy	1837	1955 .	
Hime 2125 2290 Lime & Shale 2122: 3116 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3612 3820 Lime & Chert 3979 Liss Lime & Chert 3979 Liss Lime & Sand 4515 4538 Lime & Chert 4538 4000 Lime & Chert 5314 522 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 15 Sacks Cont'd 8670 15 Lime & Cont'd 8670 15 Sacks Cont'd 8670 15 Lime & Sold: 500'-550': 15 sacks 7800'-7810': 15 sacks 7705'-7 Lime & Sold: 500'-550': 15 sacks 760'-7810': 15 sacks 7705'-7 Lime & Sold: 500'-550': 15 sacks 2093-2043: £0 sacks 1125'-1 40 Lime & Sold: 500'-550': 15 sacks 1025'-1475'.5 5 5 <td>Anhy & Lime</td> <td>1955</td> <td>2125</td> <td></td>	Anhy & Lime	1955	2125	
Inter & Shale 2290 2322 Linee Shale 3116 Linee & Shale 3116 3612 Linee & Chert 3612 3820 Linee & Sand 4155 4538 Linee & Chert 3979 4155 Linee & Chert 438 4000 Linee & Chert 4538 4500 Linee & Chert 5314 Linee & Chert Linee & Chert 5314 Linee & Chert Linee & Chert 7953 8670 Total Depth 8670 12' All Measurements from Notory Table or 12' above ground. 8670 Remarks Cont'd 8670 12' All Measurements from Notory Table or 12' above ground. 8670'-7810': 15 sacks 7705'- 7 Stacks 5600'-550': 15 sacks 5430-5380': 15 sacks 205'-4975': 15 sack 660'-4630': 15 sacks 2125'-1 Lo sacks 1025'-975': 15 sacks 570': 15 sacks 2025'-2043; 20 sacks 1125'-1 40 sacks 1025'-975': 15 sack Lo sacks 1025'-975': 10 sacks 675': 325': 30 sacks 1125'-1 10 sacks 100': 15 sacks 203'-2260': 10 sacks 1125'-1 Lo sacks 1025'-975': 10 open 1 hr. Recovered 2250' salt water and 225 125'-116' sacks 2500': 10 open 1 1/2 hrs. Recovered 300' dris, mud.	Lime	2125	2290	00.0 · · · · · · · · · · · · · · · · · ·
Lime 2122 1110 Lime & Shale 3116 3612 Lime & Chert 3612 3820 Lime & Sand 3820 3979 Lime & Chert 3612 3820 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4538 4900 Lime & Sand 5232 6203 Shale 5232 6203 Shale 6203 7953 Lime & Ghert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground, Remarks Cont'd 15 sacks 8215-8163, 15 sacks 7860°-7810'; 15 sacks 7705'-7 15 macks 5600'-550'; 15 sacks 5430-5380'; 15 sacks 500'; 15 sacks 7705'-7 15 macks 5600'-550'; 15 sacks 5430-5380'; 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks, 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. DST # 1: Pkr. failed DST # 2: 4805-4200. Tool open 2 hrs. Recovered 2250' salt water and 225 satt water tout with drig, mud. DST # 3: 5100, 5216. Tool open 1 1/2 hrs	Lime & Shale	2290	2322	
Jillo Jol2 Lime & Chert 3612 Jime & Sand 3820 Jame & Sand 3820 Jime & Chert 3079 Lime & Sand 4155 Lime & Sand 4155 Lime & Sand 4538 Lime & Chert 4538 Lime & Chert 4538 Lime & Chert 5114 Jime & Shale 5232 Lime & Shale 5232 Jime & Ghert 7953 Jime & Ghert 7953 Jime & Ghert 7953 Shale 6203 Total Depth 8670 Total Depth 8670 State Heavy mud Datween plugs, spot the following cement plugs, 95 sack 8670-8373':15 sacks 5163. 15 sacks 7860'-7810': 15 sacks 7705'- 7 Jacks 500'-5550':15 sacks 5430-5380': 15 sacks 2093-2043: 40 sacks 1125'-1 460'-4630':15 sacks 810'-2750': 15 sacks 75'-825': 30 sacks in top casing. Drill Stem Tests	Idmo & Shalo	2322 1	3116	· · · · · · · · · · · · · · · · · · ·
Lime & Sand 3820 3979 Lime & Chert 3979 4155 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Shale 5222 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 Total Depth 8670 School & Chert 7953 School & Sch	Line & Chent	2612	1 1012	
Lime & Chert 3070 1155 Lime & Sand 4155 4538 Lime & Sand 4155 4538 Lime & Sand 4453 4900 Lime & Sand 44900 5114 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Sand 4900 5114 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Ghert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 660'-7810': 15 sacks 7705'-7 15 marks 560'-5550': 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 5125'-7 4680'-4630': 15 sacks 2810'-2760': 15 sacks 2033-2043; 10 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests	Line & Sand	2620	1 2020	•
Lime & Sand 4155 4538 Lime & Chert 4538 4900 Lime & Chert 4538 4900 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 8670 Stale 8210 12' above ground. Remarks Cont'd 12' above ground. Remarks Cont'd 12' above ground. Remarks 5600'-5500': 15 sacks 5215-8163 15 sacks 7705'-7 15 macks 5600'-5500': 15 sacks 5215-8163 15 sacks 7705'-7 15 macks 5600'-5500': 15 sacks 5215-8163 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks 1025'-975': 40 sacks 875'-825': 30 sacks 1n top. casing. Drill Stam Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 4805-4900, Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 2: 5405-5500 Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 2: 5405-5500 Tool open 1 hr. Recovered 100' drig. mud. DST # 2: 5405-5500 Tool open 1 hr. Recovered 20' drig. mud. DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 740 Tool open 1 hr. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 4: 740 Tool open 1 hr. Recovered 5' drig. mud & 180' slightly drig	Line & Chert	3070	1.155	Past and the state
Lime & Chert 438 400 Lime & Sand 4900 5114 Lime & Chert 5114 5232 Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd 15 8000 5100': 15 8000 700': 10 8000 800': 1000 800': 1000 700': 1000 700': 1000 700': 1000 700': 1000 700': 1000	Lame & Sand	1155	1.538	
Lime & Sand 4000 5114 Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Shart 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 7 Fathe Heavy mud batween plugs, spot the following cement plugs, 95 sack 8670 - 7810'; 15 sacks 7705'-7 Lime & Solo - 5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 7705'-7 Lime & Solo - 5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 125'-1 Lo sacks 500'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 125'-1 Lo sacks 1025'-975'; 10 sacks 875'-825'; 30 sacks in top casing. Drill Stam Tests Drill Stam Tests DST # 1: Pkr. failed DST # 2: 1405-4900, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 2: 5100-5216, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 300' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 4: 7405-5485, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 20' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 5' drlg, mud. DST # 5: 5902-5000, Tool open 1 1/2 brs. Recovered 5' drlg, mud. DST # 7: 723 brain the total state of the	Line & Chert	1.538	1,000	•
Lime & Chert 5114 5232 Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Fable or 12' above ground. Remarks Cont'd 12 above ground. Remarks Cont'd 15 acks 510 relation of the following cement plugs, 95 sack 5670 relation of the following cement of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 sack 570 relation of the following cement plugs, 95 relation of the following cement plugs, 95 relation of the following cement plugs, 95 relation of the following cement p	Lime & Sand	4900	5114	
Lime & Shale 5232 6203 Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Bains Heavy mud batween plugs, spot the following cement plugs, 95 sack 8670-8373 115 sacks 8215-8163, 15 sacks 7860'-7810': 15 sacks 7705'- 7 15 macks 5600'-5550': 15 sacks 5430-5380': 15 sacks 2025'-4975': 15 sack 6680'-4630': 15 sacks 2810'-2760': 15 sacks 2093-2043: 20 sacks 1125'-1 40 sacks 1025'-975': 40 sacks 875'-825': 30 sacks 1n top casing. Drill Stem Tests Drill Stem Tests Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 mail water cut with drig. mud. DST # 3: 5100-5210, Tool open 1 hr. Recovered 300' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 120 mod. DST # 4: 7800 mdcol open 1 hr. Recovered 5' drig. mud. 180' ell. DST # 7: 783 mod. DST	Line & Chert	5114	5232	
Shale 6203 7953 Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Taths Heavy mud batween plugs. spot the following cement plugs. 95 sacks 8670-8373':15 sacks 2215-8163. 15 sacks 7860'-7810': 15 sacks 7705'-7 15 macks 5600'-5550': 15 sacks 5430-5380': 15 sacks 5025'-4975': 15 sacks 600'-6810': 15 sacks 2093-2043: 40 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 1 1/2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 5400-5485. Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 5400-5485. Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 5: 5002.5600 Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 7: 723 Tool open 1 1/2 hrs. Recovered 20' drig. Mud & 120 DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' drig. mud & 180' slightly gas cut drig. DST # 7: 723 Tool open 1 1/2 hrs. Recovered 5' dr	Lime & Shale	5232	6203	o alteration and the second state and the second
Lime & Chert 7953 8670 Total Depth 8670 All Measurements from Notory Table or 12' above ground. All Measurements from Notory Table or 12' above ground. Remarks Cont'd 6670 Saing Heavy mud butween plugs, spot the following cement plugs, 95 sack 8670 - 3731:15 sacks 2215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7 15 macks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sack 4680'-4630': 15 sacks 2810'-2760'; 15 sacks 2093-2043; 20 sacks 1125'-1 40 sacks 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 2: 4805-4900, Tool open 1 1/2 hrs. Recovered 300' drig, mud. DST # 5: 5002.5000, Tool open 1 1/2 hrs. Recovered 300' drig. mud. DST # 5: 5002.5000, Tool open 1 hr. Recovered 75' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 100' drig. mud. 1700-115 DST # 4: 700 means 1 hr. Recovered 100' drig. mud. 1700-115 DST # 4: 700 means 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. DST # 4: 700 means 1 hr. Recovered 5' drig. mud & 130' sliphtly gas cut drig. None	Shale	6203	7953	olari mayadar. Alakimin histori yeni mis yenisaran
Total Depth 8670 All Measurements from Notory Table or 12' above ground. Remarks Cont'd Baths Heavy mud batteen plugs. spot the following cement plugs. 95 sacks 8670'-8373':15 sacks 8215-8163. 15 sacks 7705'-7 15 macks 560'-5550':15 sacks 5430-5380':15 sacks 5025'-4975':15 sack 660'-4630':15 sacks 2215-8163. 15 sacks 2093-2043: 40 sacks 125'-7 15 macks 560'-5550':15 sacks 5430-5380':15 sacks 5025'-4975':15 sack 660'-4630':15 sacks 2810'-2760':15 sacks 2093-2043: 40 sacks 1125'-1 40 sacks. 1025'-975': 40 sacks 875'-825': 30 sacks in top casing. Drill Stem Tests Dst # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drig. mud. DST # 3: 5100-5218; Tool open 1 1/2 hrs. Recovered 300' drig, mud. DST # 4: 740-5145; Tool open 1 hr. Recovered 75' slightly gas cut drig. DST # 4: 760-5145; Tool open 1 hr. Recovered 100' drig. mud. DST # 4: 760-5145; Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760-5145; Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760-7610; Tool open 1 hr. Recovered 20' drig. Mud & 120 DST # 4: 760-7620; Tool open 1 hr. Recovered 20' drig. mud. DST # 4: 760-7620; Tool open 1 hr. Recovered 5' drig. mud & 180' slig. DST # 7: 7630-7620; Tool open 1 hr.	Lime & Chert	7953	8670	al a development and sector and a la
All Measurements from hotory Table or 12' above ground. Remarks Cont'd Hathg Heavy mud between plugs, spot the following cement plugs, 95 sack 8670'-8373':15 sacks 8215-8163, 15 sacks 7860'-7810'; 15 sacks 7705'- 7 15 macks 5600'-5550'; 15 sacks 5430-5380'; 15 sacks 5025'-4975'; 15 sac 6680'-4630':15 sacks 2810'-2760'; 15 sacks 2093-2043; 40 sacks 1125'-1 40 sacks 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5216 Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 760 fool open 1 hr. Recovered 75' sliphtly gas cut drlg. DST # 4: 760 fool open 1 hr. Recovered 70' drlg. Mud & 120 DST # 4: 760 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 750 fool open 1 hr. Recovered 5' drlg. mud. DST # 4: 750 fool open 1 hr. Recovered 5' drlg. Mud & 180' ell sud ebod of samin of task 26 and of task 1 hour fool open 1 hr. None	Total Depth	a state of states and a second	8670	The second se second second s second second se
AU sacks, 1025'-975'; 40 sacks 875'-825'; 30 sacks in top casing. Drill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 selt water cut with drlg. mud. DST # 3: 5100-5210. Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 4: 5400-5210. Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7400-7470. Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 7400-7470. Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 7400-7470. Tool open 1 hr. Recovered 20' drlg. Mud & 120 DST # 4: 7400-7470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 743. Model of a setting of rate Constant of the set of	I E marke FGOOL FEFO	Plant P. Plant and all	ELOO FO	1000 -1010 ; 1) Backs //0/ - /
Deill Stem Tests DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5218. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5440-5485 Tool open 1 hr. Recovered 75' slightly gas cut drly. DST # 4: 780 1000 Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 780 1000 Tool open 1 hr. Recovered 100' drlg. mud. DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 780 1000 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 1000 1000 1000 1000 1000 1000 1000 10	15-macks 5600'-5550	1:-15 sack ks 2810'-2	s 5430-53 760': 15	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-10
DST # 1: Pkr. failed DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5216, Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5440=5485; Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7805-7870; Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7805-7870; Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7: 7805-7870; Tool open 1 1/2 hrs. Recovered 5' drlg. mud & 180' sli show of shapping of relevant Cased of 1 drlg. Mud & 180' sli per cent None	15-macks 56001-5550 46801-46301:15 sec 40 macks 10251-975	1;-15 sack ks 2810'-2 1; 40 sack	8 5430-53 760': 15 8 875'-82	80'; 15 sacks 5025'-4975'; 15 sac aacks 2093-2043; 40 sacks 1125'-1 5'; 30 sacks in top. casing.
DST # 1: Pkr. failed DST # 2: 4805-4900. Tool open 2 hrs. Recovered 2250' salt water and 225 salt water cut with drlg. mud. DST # 3: 5100-5210. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 4: 5400-5445. Tool open 1 hr. Recovered 75' slightly gas cut drlg. DST # 4: 7800-6470. Tool open 1 hr. Recovered 100' drlg. mud. 1000-010 DST # 4: 7800-6470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 4: 7800-6470. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7: 783 - 5000. Tool open 1 1/2 hrs. Recovered 5' drlg. mud & 180' sli show of shepting of rise 2 ased of the sheet of the sheet off. Ies mount of water th oil NODE (1) per cent None	15-macks 5600'-5550 4680'-4630': 15 sec 40 sacks. 1025'-975	11:-15 sack ks 2810'-2 1: 40 sack	s 5430-53 760': 15 s 875'-82	80': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing.
DST # 2: 4805-4900, Tool open 2 hrs. Recovered 2250' salt water and 225 selt water cut with drlg. mud. DST # 3: 5100-5218, Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 4: 5100-5218; Tool open 1 hr. Recovered 75' slightly gas cut drlg DST # 4: 7800-6000, Tool open 1 hr. Recovered 100' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 4: 7800-6000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 20' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 1000 DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 180' slip DST # 7: 763 5000, Tool open 1 1/2 hrs. Recovered 5' drlg. mud. 180' slip	15-macks 5600'-5550 4680'-4630': 15 sec 40 sacks. 1025'-975 Drill-Stem Tests	1;-15 sack ks 2810'-2 ; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-1 5'; 30 sacks in top casing.
aslt water cut with drlg. mud. DST # 3: 5100-5216. Tool open 1 1/2 hrs. Recovered 300' drlg. mud. DST # 1: 5400-5485 Tool open 1 hr. Recovered 75' slightly gas cut drly. DST # 1: 5002-6000 Tool open 1 hr. Recovered 100' drlg. mud. 1200- DST # 1: 7800-7420 Tool open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 20' drlg. Mud & 120 DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud. 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip DST # 7: 7620 Dollar to 11 /2 hrs. Recovered 5' drlg. mud & 180' slip mount of water with oil 010 010 / 100 / 1	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill Stem Tests	11;-15 sack ks 2810'-2 1; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 10 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 3. 5100-5216, "Tool open 1 1/2 hrs. Recovered 300' drlg, mud. DST # 54:0-5485; Tool open 1 hr. Recovered 75' slightly gas cut drlg DST # 4. 780 model Tool open 1 1/2 hrs. Recovered 100' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. DST # 7. 7820 Sole open 1 1/2 hrs. Recovered 5' drlg. mud. Sole open 1 hrs. Recovered 5' drlg. Sole open 1 hrs. Sole op	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900	1;-15 sack ks 2810'-2 1; 40 sack	s 5430-53 760': 15 s 875'-82	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 40 sacks 1125'-10 5'; 30 sacks in top casing.
DST # 4. 780 model open 1 hr. Recovered 75' slightly gas cut drlg DST # 4. 780 model open 1 hr. Recovered 100' drlg. mud. 1000 model 1 hr. Recovered 20' drlg. Mud & 120 DST # 4. 780 model open 1 1/2 hrs. Recovered 20' drlg. Mud & 120 DST # 7. 781 Model of the state of the st	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900,	1; 15 sack ks 2810'-2 i; 40 sack i; 40 sack Tool open	s 5430-53 760': 15 s 875'-82 2 hrs. 3	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 20 sacks 1125'-1 5'; 30 sacks in top casing.
DST # 4. 780 creation in the second state of t	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900,	tis 15 sack ks 2810'-2 is 40 sack is 40 sack is 40 sack is 40 sack is 40 sack	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr	80'; 15 sacks 5025'-4975'; 15 sac sacks 2093-2043; 20 sacks 1125'-10 5'; 30 sacks in top casing.
DST # 4. 780 model DST # 7. 763 model DST #	15 macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 4: 5440=5485	d Tool open Tool open Tool open	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re	ecovered 2250' salt water and 2250 h drlg. mud.
abod of shepting of rates of the second of t	15-macks 5600*-5550 4680*-4630*: 15 sec 40 macks. 1025*-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3-5100-5216 DST # 3-5100-5216 DST # 3-5100-5216	d Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud.
allod of abetting of water a Case(of the apert and a water completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks. 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3-5100-5218 DST # 3-5100-5218 DST # 3-5002-6000	tis 15 sack ks 2810'-2 is 40 sack d Tool open selt wate Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. R r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	s. Recovered 300' drlg, mud. covered 100' drlg, mud.
athod of sheeting of water - Cased D it water completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 4- 780 magai	Colopen Tool open Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re	s. Recovered 20' drlg. Mud & 120'
athod of sherting a vater Cased Of the per completely shut off	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3- 5100-5218, DST # 4- 7800-5485 IST # 4- 7800-64701	ticel open Tool open Tool open Tool open Tool open	s 5430-53 760': 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 1/2 hr gas cut d	s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120'
mount of water with oil	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5218, DST # 4: 7805-4900 DST # 4: 7805-4900	i - 15 sack ks 2810'-2 i 40 sack d Tool open Tool open Tool open Tool open Tool open	s 5430-53 760'; 15 s 875'-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	ecovered 2250' salt water and 2250' h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. s. Recovered 20' drlg. Mud & 120' s. Recovered 20' drlg. Mud & 120'
mount of water with oll	15-macks 5600'-5550 4680'-4630': 15 sec 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 3: 5100-5216, DST # 4: 7805-6000, DST # 4: 7805	i - 15 sack ks 2810'-2 i 40 sack i 40 sach i 4	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 c cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	so': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. 1000 s. Recovered 20' drlg. Mud & 1200 rlg. mud. Recovered 5' drlg. mud & 180' sl1
	15-macks 5600'-5550 6680'-6630': 15 sec 60 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3: 5100-5216 DST # 3: 5100-5216 DST # 4: 7805-6000 DST # 4: 7805-6000	i 15 sack ks 2810'-2 i 40 sack i 40	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 c cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	sovered 2250' salt water and 2250' h drlg. mud. s. Recovered 300' drlg. mud. covered 100' drlg. mud. covered 100' drlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud.
	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST #	i - 15 sack ks 2810'-2 i 40 sack i fool open fool open fool open fool open fool open fool open fool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 225 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg covered 100' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip ater completely shut off? Yes
	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 3- 5002-5000 DST # 3- 50000 DST # 3- 5000 DST # 3- 50000 DST # 3- 50000 DST # 3- 50000 DST #	Li-15 sack ks 2810'-2 Li-40 sack i Tool open selt wate Tool open fool open f	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1792-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud. 180' slip ater completely shut off: Ies cent None
SUEDEN SIL	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900 DST # 3- 5100-5218 DST # 3- 5100-5218 DST # 4- 780 0000 DST # 4- 780 00000 DST # 4- 780 000000 DST # 4- 780 0000000000000000000000000000000000	tol open fool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1799-115 s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip the sad matter berson and that the same bre true ts and matter berson and that the same bre true
Fouriet SILEDEU	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5218, DST # 3: 5100-5218, DST # 4: 780 55485 AST # 7: 780 55485 AS	ticol open Tool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 40 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drly covered 100' drlg. mud. 1. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. Recovered 5' drlg. mud & 180' slip ater completely shut off? Ies cent None
A contract A cont	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks 1025'-975 Drill-Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900, DST # 3: 5100-5216, DST # 3: 5100	d flool open selt wate flool open flool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Re	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043; 20 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 2250 h drlg. mud. s. Recovered 300' drlg, mud. covered 100' drlg. mud. covered 100' drlg. mud. 1000 covered 100' drlg. mud. 1000 rlg. mud. s. Recovered 20' drlg. Mud & 1200 rlg. mud. Recovered 5' drlg. mud & 180' sl1; ater completely shut off: Ies cent None the and matter bersen and that the set for tra- sector of Company. 0 1052
ALEOIN Marchell and swere to before me this day of Appell Marchell and swere to be for the swere	15-macks 5600'-5550 4680'-4630': 15 sac 40 macks. 1025'-975 Drill Stem Tests DST # 1: Pkr. faile DST # 2: 4805-4900. DST # 3- 5100-5216. DST # 3- 510	d Tool open selt wate Tool open Tool open	s 5430-53 7601; 15 s 8751-82 2 hrs. 3 r cut wit 1 1/2 hr 1 hr. Re 1 hr. Aud 1 w per lete of the fac	BO': 15 sacks 5025'-4975': 15 sac sacks 2093-2043: 10 sacks 1125'-1 5': 30 sacks in top casing. ecovered 2250' salt water and 225 h drlg. mud. s. Recovered 300' drlg. mud. covered 75' slightly gas cut drlg. covered 100' drlg. mud. 1000 s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 20' drlg. Mud & 120 rlg. mud. s. Recovered 5' drlg. mud. 180' sli ater completely shut off: Yes cent None ts and matter bermany of that the content of the trans- ter completely shut off: Yes cent None

A. L. Wasson, Wildcat, Howard County

DST # 8: 8418-8468, Tool open 1 hr. Recovered 100' drlg. mud.

- DST # 9: 8455-8543, Tool open 2 hrs. Recovered 390' slightly gas cut & sulphur cut drlg. mud.
- DST # 10:8546-8670, Tool open 1 1/2 hrs. Recovered 7230' sulphur water.

RECEIVED MIDLAND, TEXAL

APR 101952

Railroad Commission of Texas OIL'84 GAS DIVISION

File No.	RAILEOAD COMMISSION OF TEXAS	Form 4
8	OIL AND GAS DIVISION	1. Marting Hoscord
FILE IN DUPLICATE	WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH	WELL IS LOCATED
Company The Texas Com	Address Box 1720 .	Ft. Worth, Texas
Sec. NoBlock No.	29 T-I-N Survey T & P RRCO County	Howard
Well No. 1 Name of Les	A. L. Wasson	No. of Acres 1760
Name of Field in which well is lo	ocated Wildcat Date well was plugged	327- 19.5
Form 1 (Notice of Intention to Dr	ill) Was Filed in Name of	ompany
Character of Well at the time of	completion: Oil	
Amount well producing when plu	innel: Oil	L; Water None
Has this well ever produced oil as	r gas?	
Total Depth 8070	feet. Top of each producing sand	
Was the well filled with mud-lade	en fluid, according to regulations of the Railroad Commission?	Yes
How was mud applied?	ru drill pipe	state the fit parts
plage used, and depths placed, Ale	If so, show all shoulders left for casing, depth of each, and so fine unt of cement and rock. Was well shot?	size of casing, size and kind of
Spotted the followi 7860-7810 15 sx 77 15 sx 2810-2760 15 spot 40 sy 1125-107 Have all abandened wells of this Manner of confining all oil, yas or 9 5/6" casing left or cased of with co	If so, show all shoulders left for casing, depth of each, and so invinit of cement and rock. Was well shot? No <u>ng plugs: 95 sx 8670-8373, 15 sx 821</u> 05-7655, 15 sx 5600-5550, 15 sx 5430 receiver and receiver and the second state of the second state of 9 5/8" ceasing 0, -40 sr 1025-975, 40 sx 875-825, 30 lease been pluged according to Commissions rules? water to strate: All 13 3/8" casing left in hole. All strate protected by ca ement.	ine of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100" and puller sx in top of casi Yes in hole & 2015" sing left in hole
All addiscent inace, royn	If so, show all shoulders left for casing, depth of each, and so invite of cement and rock. Was well shot? No ng plugg: 95 sx 8670-8373, 15 sx 821 05-7655, 15 sx 5600-5550, 15 sx 5430 concentration of 9 5/8" casing 0,-40 six 1025-975, 40 sx 875-825, 30 s lesse been plugged according to Commissions rules? water to strata: All 13 3/8" casing left in hole. All strata protected by ca ement.	also of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax A680-A630 @ 100' and puller sx in top of casi Yes in hole & 2015' sing left in hole ellows:
All adjacent propert	If so, show all shoulders left for casing, depth of each, and so invite of cement and rock. Was well shot? No ng plugg: 95 sx 8670-8373, 15 sx 821 05-7655, 15 sx 5600-5550, 15 sx 5430 concentration of 9 5/8" casing 0,-40 min 1025-975, 40 sx 875-825, 30 s lesse been plurged according to Commissions rules? water to strata: All 13 3/8" casing left in hole. All strata protected by ca ement.	aise of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax A680-A630 @ 100' and puller sx in top of casi Yes in hole & 2015' sing left in hole ellow:
All adjacent base, roya	If so, show all shoulders left for casing, depth of each, and so inspirit of cement and rock. Was well shot? No ng plugg: 95 sx 8670-8373, 15 sx 821 05-7655, 15 sx 5600-5550, 15 sx 5430 contained and an another state of 9 state of 9 state of 9 state of 9 state of 9 state of 9 state of 9 state (1025-975, 40 sx 875-825, 30 s lesse been plurged according to Commissions rules). Water to strate: All 13 3/8" casing left in hole. All strata protected by ca ement.	the of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax A680-A630 @ 100' and puller sx in top of casi Yes in hole & 2015' sing left in hole ellow:
Name week, and depths placed, Ala Spotted the followi 7860-7810, 15 Sx 77 15 Sx 2810-2760, 15 Spot 40 Sx 1125-107 Have all abandened wells of this Manner of confining all oil, yes or 9 5/8" casing left or cassed of with co The memors of adjecent lease, roya All adjacent propert	If so, show all shoulders left for casing, depth of each, and so invite of cement and rock. Was well shot? No ng plugg: 95 sx 8670-8373, 15 sx 821 05-7655, 15 sx 5600-5550, 15 sx 5430 contained and an another state of 9 state of 9 state of 9 state of 9 state of 9 state of 9 state of 9 state (1025-975, 40 sx 875-825, 30 s lesse been plurged according to Commissions rules? water to strate: All 13 3/8" casing left in hole. All strata protected by ca ement: alty and landowners with their addresses in each instance as f ty leased by The Texas Company to all available adjacent lesse owners as required by Rule 10	the of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax A680-A630 @ 100' and puller sx in top of casi Yes in hole & 2015' sing left in hole ellows:
Name week, and depths placed, Ala Spotted the followi 7860-7810. 15 Sx 77 15 Sx 2810-2760. 15 Spot 40 Sx 1125-107 Have all abandened wells of this Manner of confining all oil, yes or 9.5/8" casing left or cassed of with co The mannes of adjacent bease, roya All adjacent proper Was wells given before plugging	If so, show all shoulders left for casing, depth of each, and so inspirit of cement and rock. Was well shot? No ng plugg: 95 sx 8670-8373, 15 sx 821 05-7655, 15 sx 5600-5550, 15 sx 5430 contained and an another state of the st	All of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax A680-A630 @ 100' and puller sx in top of casi Yes in hole & 2015' sing left in hole ellow:
Name week, and depths placed. All Spotted the follow! 7860-7810.: 45 ax 77 15 ax 2810-2760.: 15 spot 40 sy 1125-107 Have all abandened wells of this Manner of confining all oil, may or 9 5/8% casing left or cassad of with co The memors of adjecent lease, roys All adjacent propert Was wellse given before plugging I, T. P. Drew and the matter herein set forth ar	If so, show all shoulders left for casing, depth of each, and so invaluation comment and rock. Was well shot? NO <u>RE Plugs: 95 sx 8670-8373, 15 sx 821</u> 05-7655, 15 sx 5600-5550, 15 sx 5430 increase of the product sector of 15 sx 875-825, 30 s lease been plugged according to Commissions rules? water to strata: All 13 3/8" casing left in hole. All strata protected by ca ement. Sty leased by The Texas Company to all available adjacent lease owners as required by Rule 10 to all available adjacent lease owners as required by Rule 10 being first duly sworn on path, state that and that the same are true and correct.	A set of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100" and puller sx in top of casi Yes in hole & 2015" sing left in hole silene: Yes Yes
Name wood, and depths placed. All Spotted the follow! 7860-7810. 15 ax 77 15 sr 2810-2760. 15 spot 40 sr 1125-107 Have all abandered wells of this Manner of confining all oil, gas or 9.5/8% casing left or cassed of with co The memors of adjacent lease, roya 11 adjacent propert Van motion given before plugging I, T. P. Drew ad the matter herein set forth ar	If so, show all shoulders left for casing, depth of each, and so inspirit of cement and rock. Was well shot? No ng plugg: 95 sx 8670-8373, 15 sx 821 05-7655, 15 sx 5600-5550, 15 sx 5430 conservation of 9 states and the state ing 0, -40 mix (1025-975, 40 sx 875-825, 30 s lease been plugged according to Commissions rules? water to strate: All 13 3/8" casing left in hole. All strata protected by ca ement. sty leased by The Texas Company to all available adjacent lease owners as required by Rule 10 to all available adjacent lease owners as required by Rule 10 to all available adjacent lease owners as required by Rule 10 being first duly aworn on path, state that nd that the same are true and correct. Name	A casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100" and puller sx in top of casi Yes in hole & 2015" sing left in hole ellows: Yes Dist. S
Name and and depths placed. All Spotted the follow! 7860-7810. 15 ax 77 15 ax 2810-2760. 15 spot 40 sy 1125-107 Have all abandened walls on this Manner of confining all oil, gas or 9 5/8" casing left or cassed of with co The memors of adjecent lease, roys All adjacent propert Was motion given before plugging I. T. P. Drew and the matter herein set forth ar	If so, show all shoulders left for casing, depth of each, and so invaluation comment and rock. Was well shot? NO <u>RE Plugs: 95 Sx 8670-8373, 15 Sx 821</u> 05-7655, 15 Sx 5600-5550, 15 Sx 5430 Increase of the product sector of 1.9 5/8" casing 0,-40 min 1025-975, 40 Sx 875-825, 30 s lease been plugged according to Commissions rules? water to strata: All 13 3/8" casing left in hole. All strata protected by ca ement. Sty leased by The Texas Company to all available adjacent lease owners as required by Rule 10 to all available adjacent lease owners as required by Rule 10 being first duly sworn on path, state that he that the same are true and correct. Name this 15 day of May	A set of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100" and puller sx in top of casi Yes in hole & 2015" sing left in hole silene: Yes Dist. S Dist. S
Name wood, and depths placed. All Spotted the follow! 7860-7810. 15 ax 77 15 ax 2810-2760. 15 spot 40 sy 1125-107 Have all abandened walls on this Manner of confining all oil, gas or 9 5/8% casing left or cassad of with co The memors of adjecent lease, roya 11 adjacent propert I adjacent propert I adjacent before plugging I, T. P. Drew ad the matter herein set forth ar	If so, show all shoulders laft for casing, depth of each, and so dimpinit of cement and rock. Was well shot? No mg plug: 95 sx 8670-8373, 15 sx 821 05-7655, 15 sx 5600-5550, 15 sx 5430 concentration of the state of the second plug of the second plug of the state of the second plug of the second pl	A state of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100" and puller sx in top of casi Yes in hole & 2015" sing left in hole silene: Yes
Ange weed, and depths placed. All Spotted the follow! 7860-7810. 15 ax 77 15 ax 2810-2760. 15 spot 40 sy 1125-107 lave all abandened wells of this fanner of confining all oil, gas or 2.5/8% casing left or cassad of with co The memory of adjecent lease, roya 11 adjacent propert I adjacent propert I adjacent before plugging I. T. P. Drew ad the matter herein set forth ar shouthed and sworn to before me	If so, show all shoulders laft for casing, depth of each, and so dimbunt of cement and rock. Was well shot? No ng plugs: 95 Sx 8670-8373, 15 Sx 821 05-7655, 15 Sx 5600-5550, 15 Sx 5430 For the second and the second seco	A state of casing, size and kind of 3-8163, 15 sx -5380, 15 sx ax 4680-4630 @ 100" and puller sx in top of casi Yes in hole & 2015" sing left in hole silene: Yes

i i i v		0) ()	2	2	, /1;	07	7					- 1,78			in the second se	
iewasks: <u>Ortginal</u> Plugged a	NO ALLOWARLY WILL ME A In protect all fresh water and ments. It will be necessary seconder the depth to which i	A. LEATE LINE				Wildcat	8/00	PIELD WANK (Rescily as sh Prostion Releasing include synthesister) If Wildest, so	1 - 2 - 2 - 10		た 一 の 別 小 切		Big Spring,	P D Box 4	Net and Corro	Check coli DiDIJLL	си) 1 1634. Нозн 914 (4	ipe mail Mo. 42 normalise ("Hithights Super also
1 Operator Lease Name nd Abandon	NOTIC NESIONED Io any wai da. Where Commiss y Io contact Texat fresh, water sands mu	710N PROM TWO D1 660' FWL & 660' FWL &				riana 11 12-11	100	olen on R. N. C. ng Weservoir If stary below.	Also - Also	REFER	er. Br	(Instruction (2) on be	TX 79720	48		DERPENI (Be	Pri CAlqua	
: The	M I which dres ion rules do n Water Develo at be protecte	1980 1980 1980	dent K		23 8 - 2 7	42101	Completion Depth	Anna Sir 2011 - Anna 1912 - Anna A	ar 14. "	TO INSTRI	41. 11 ¹	cle alde.)	: 17 	10-43 7-5-1 (1-15	50	low Casing) w Atlanh Sets		
Vasson 27-52	not have suffic optient Board, d.	ĒŇI, ĒNĻ	2 1 8			None	lf done, State Nore.	All Prior Rule 37.Exe. Case Numbers for	i 3 13	UCTIONS O	P		a dina andra andra andra	n para Patria Patrias Patrias	5			4 1
Wc 11	face casing re Austin, Tex	e co e constant	900 1907 (1907	112 5	N.	467	Rujes, 5 (a). 667-1 200. (h.)	Applicable Field Rules Pattern, 11no	16	N BACK S	EACH PRO	Nedrest	6. This we Directio	Sec.	* Ci F (5 		0 Tring	OIL AND O
	guirn Tuguirn Tuguirn		ري الا		ander Historie Maria	40	Wules, State Acres)	A pulcable A pulcable Pid Rules Denaity	20 JZ	IDE: READ	POSED CO	Post Office o	II Is to be los	4. Blk	Stewart	:::홍 *: [] :: 월	EEPEN-	AS DIVISIO
1 	2.8	n 8.1	K			40	DESIGNATE	Wumber of Acres in Drilling Unit for this Well	- 10.	CAREFULL	MPLETION	town.	Vincent	59, 1	3/22 3/22 79	G BACK	DIR PLUG	ž
Signature A Title Date Telephone:	I declare und Code, that I by me or un therein are tr					<u></u> れっ	emplein in remarks.)	Taithle acre- ere presently assigned to another well in seme field? (Ven	19 ji	Y AND FURN		ul in El any El any Li atra	TX	-1-N, 5], उगभ्रद्ध (क्रु	BACK	
dminist unc 12,	or penalties p am authorizes der my superv Ne, correct, at	25. (a) Is this (b) If subje (If no. (20		т с. 1. К. – У	None	piles for well in same res. an semi lease (h.)	Distance and Direction from simposed loca- tion to near-st duiling com- eleved or ap-	. 20.	ISH COMPLE		195 1964 75	Southea	& F RH	bad a at it iterat	erify) TE-e	64 65 55	- - -
21. 3 rative 1980 915	CERTIF reacribed in S 1 to make this rision and dim rision and dim	wellbore subj oct to SWR 36, attach explana	Reg ^{ula} r 1	Regular 1	Regular 1	Regular 1 🔀 Rule 37 Z	the appro- priate box.	ls this a i. Regular: or 2. Rule 37 Ezc. Locus	21.	TE DATA.:	i e	201 - 4	i ត្រុ	Co.	fates Tol	ntry	1	ermit
Assist:	ICATE ec. 91.143, To report, that the tetion, and the p the best of a	ect to SWR 36 has Form II- ition.)	JU	A R R	75	0i1	Type Well (Specify)	011. С.	22.	2	66 21	12. Total Dep	11. Distance I to Nearest (fL)	to. Number of	P. Tell	8. County	7. NRC Dist	ARC Percit
int 1-7455	Pegas Natural F his report was at data and fac ny knowledge.	yole" yole"	N	10	LIVED.	0	110	Number of Wei Permitted fore this Lease in Roservatriotus Permit is Regi	C 18 8	14.000	63	46001	1 Property of L 660 1	640	¥	loward	ner Co	284
IT'	Presurces ors stated	1983 1111	U	6		c	GAS	lls of Mons on Michths Michths		20		5674	Ease Line	, 2	(2)) (20	r_{0}	4	547
THE PLOY	1-	RAI	LINDAD COM OIL AND (MISSION BAS DI	VISION	EXAS			PO Re	RM W-								
---	---	---	--	--------------------------------------	---	--	---	-------------	--	--								
	1				- AP	PI NO,	42-227	-0000	O REC Distri	1								
FILE	IN DUPLIC	ATE WITH DIS	TRICT OFFIC	CE OF	DISTRICT	r in w	HICH	(b., 141	08	r i ji								
4	IELL IS LO	CATED WITHI	N THIRTY D/	AYS AF	TER PLL	UGGING	1	3 1 4 4 4 1	Tuesday	47 X.								
2. FIELD NAME (a per RRC Reco	orda)	3. Leas	e Name	<u>د</u>				S. Well Numbe									
6. OPERATOR			6a Oalat	Stew	art	- Manager - 4			1									
McCann	Carpora	tion	. Mc	Cann	Corpor	ation	3		Howan	d d								
7. ADDRESS	22		6b. Any	Subsequent	W-I's Pile	d in Name	r of:	1	1. Date Dritile	E.								
P. O. I	30x 448,	<u>Big Sprin</u>	E, TK						- 8-17-	80								
of Lease on whi	ch this Well is 1	erest Lease Bounda located	North	ert From	<u>West</u> Stew	ant ant	980 Fee	From	2. Perult Num									
. SECTION, BLOC	K, AND SURVE	SY	9b. Diata	ince and D	Ireusion Fra	m Nearest	Town in thi		3. Date Drilling	•								
Sec. 4, B	LK. 29,T	-1-N, T&P R	R Col	4 m	iles S	Eof	Vincen	t	10-10-	80								
(O(I, Gas, Dry) DRY		a wontple complet	on clat vit steid :	Names and		AS ID or	No.'	WRLL	4. Dute Drillig Completed	F								
8. If Gas, Amt. of C. Hand at time of P	and, on							I	5. Date Woll 1	ged								
				3		_		61	10-12-									
CEMENTING TO 9. Cementing Date	PLUG AND A	BANDON DATA:	10-12-80	10-13	PLUG #3	PLUG #	4 PLUG.#1	PLUG	6 PLUG #7	38.0								
0. Size of Hole or P	ipe in which Plu	ig Placea (inches)	9-5/8	9-5/8	13-3	8	2 No. 3 Fe	5.5	1. VO - 1. V									
1. Depth to Battom (of Tubing or Dri	Il Pipe (ft.)	11000	250	Top O	E	101090-0		1.12 - + (+,2)	16 20								
2. Sacks of Cement	Used (each plug	<u>}</u>	50	100	10		212.06	22535.44	CHE CHESTON	1								
4. Calculated Top o	f Plug (ft.)		990	70	Surf				1									
5. Messured Top of	Plug (if tagged)	(11.)		,						2.47								
G. Slurry Wi. #/Gal	•	<u> </u>	1.33	1.33	1.33													
a. CASING AND TU	IBING RECORD	AFTER PLUGGI	KG I	29. W	as any Non-	- Drillable	Material (Ot	hør	i i yan	X Ma								
ZE WT. #/FT. PU	T IN WELL (II.)	LEFT IN WELL	I.) HOLE SIZE(n.) 794. 1f	Answer to a	bove is "	Yes" state (lepth to to	p of "junk" is	ft in hole								
5/8/24#	200	200	<u> </u>	- P	orm If more	space is :	iceded,)			14.16								
	and the set			- 2006	8 0 - X	1			n an Albert Harris Albert Marine an Angel Charles - Albert Albert - Albert	1.77 · · · · · · · · · · · · · · · · · ·								
			<u>*</u>			_) i e		-								
. LIST ALL OPEN	HOLE AND/0	R PERFORATEO	INTERVALS															
PROM	<u>.</u>	<u>T0</u>	······································	FR	NO			TO	2.00									
PROM	· · · · · · · · · · · · · · · · · · ·	то		PR	OM	Ω.		τυ =	S. 5. 3	0.2495								
FROM		то		FR	OM			то										
PROM	·	70		PR	СМ			<u></u>	· · · · ·									
have knowledge tha Designates lights to t indice of Cementer CERTIFICA I declare un	t the cementing be completed by ar Autherized R TE: der pensities p	operations, as raile Comming Compan Seresentative rescribed in Sec. 91	cted by the inform y. Items not so de 	ation found taignated DC No	i on this for hall be com well I me of Comer cen Code, th	m, were p ipleted by DIVIS ning Com	erformed as i Operator. LOII OF pany ithorized to a	DOW (by such inform Chemica	ition. L. C.J.								
report was p to the best	of my knowled	r under my supervis ge.	ion and direction,	and that d	ato and fact	e stated t	ierein ere in 7, 1981	ie, carrect	NS 26	7-740								

APR 2 0 1981 D.G. MIDLAND, TEXAS

D1-80

et an ar star things of a

Ť

.

mart.

1

÷ ÷,



1676° 4 4 4 4	*		
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1			
		<u> </u>	

100 1.2.2

.

Hilling	te of two 1	Yes 32. Now No	Circulated	33. Bei Bright Bart sinn
The Street Street Convert	Fresh Water Zome	by T.D.C.R.	35, Nove all Ahandound Wells on this L according to ##C Bules?	ease teen Plugged
			36, If NO, Esplain	j De
		20.00	2	
	ating or Service c	ampany who mis	ed and pumped coment plugs in this well	Date BHC District Office
Dowell Divis	ion of Do	w Chemic	al Co Colorado Cit	y. The IV-12-85
2. Super and Addresses of R	stace Owner of Ve	ti Site and Oper	nators of Otters Producing Leases	
Danny Stewart	$t = P_{\bullet} O_{\bullet}$	<u>Box 26.</u>	Sterling City, Tx. 7	.6977
	0 ×			
	1			
101 Min Sinter Chron Bellers P	legging to Rock a	t the Alave?		
Yes		8.03		
	HOLES ONLY	ed by either a D	riller's, Biertric, Beitigartivity or Acoust	cal/South Log or such Log must be
related to a Connectal L	og Service.		8 9.	
Log Alloch	•d 🗌 La	g released to		Dale
The second s	Г		Be linertivity	Acoustics / Barue
	L.			
Col: Bate PORt P-8 (Special C	learance) Filed?			
and files	e to Plancing	No	200	
42. Amount of Oil produced prio	or to Plugging	No. nonth this all w	DIC bble#	
G. Amount of Dil produced prio	or to Plugging action Report) for a	No. nonth this oil wa	one bula*	
C. Amount of Oll produced price C. Amount of Oll produced price C. Pale Poller P-1 (Oll Produced C. C. W. C. C. Y. Slowert Pield	or to Plagging incline Report) for a	NC nonth this all w	DDC bble® ne produced	
G. Amount of Dit produced prio G. Amount of Dit produced prio G. Pillo PORNE P-1 (Oil Produ C. C. W.C. Col.Y. Slower Piold	or to Plugging	NC nonth this oil w	bble*	
al. Amount of Oli produced price a. Amount of Oli produced price a. File Found P-1 (Oli Produ RAC WE ONLY. Slower Field	or to Plagging iction Report) for i	Ne month this all wa	DDC bble*	
d. Amount of Dil produced prices d. Amount of Dil produced prices d. Plan Potent P1 (Oil Produced REC. WE. Col.Y. Slowers Pield	or to Plagging iction Report) for i	Ne nonth this all w	bble*	
al. Amount of Oli produced price a. Amount of Oli produced price a. File Found P-1 (Oli Produ RAC WE ONLY. Slower Field	or to Plagging action Report) for a	Ne month this all wa	DIC buls*	
Amount of Oll produced price Amount of Oll produced price Amount of Oll produced price Amount Produced Amount Produced Amount Produced	or to Plagging iction Report) for a	Ne nonth this oil w	bbla®	
al. Amount of Dil produced price a. File Point P-1 (Oil Produ RAC WE OILY. Source Pield	or to Plagging action Report) for a	Ne month this all wa	DIC buls*	
al. Amount of Oli produced prices of the point P-1 (Oli Produce P-1) (Oli Produce P-1) (Oli Produce Pield	or to Plugging iction Report) for r	Ne month this oil wa	DIC buls*	
C. Amount of Oll produced price C. Amount of Oll produced price	or to Plagging iction Report) for 1	Ne nonth this oil w	DIC buls*	
al. Amount of Oli produced price al. Amount of Oli produced price all points P-1 (Oli Produced) RAC WELONLY. Source Pield	or to Plugging incline Report) for i	Ne month this oil wa	DIC buls* produced	
C. Amount of Oll produced price C. Amount of Oll produced price C. Allo Polling P-1 (Oll Produced) C. C. C. M. C. C. Y. Source of Pield	or to Plagging incline Report) for a	Ne nonth this oil w	DIC produced	
al. Amount of Oli produced price Pile Point P-1 (Oli Produ RAC MB ONLY. Slower Pield	or to Plagging action Report) for a	Ne month this oil wa	DIC to produced	
al. Amount of Oli produced price al. Amount of Oli produced price al. Place point P1 (Oli Produ RAC WE ONLY. Source Pield	or to Plugging iction Report) for a	Ne nonth this oil w	buls*	
C. Amount of Oll produced price C. Amount of Oll produced price C. Allo Polling P-1 (Oll Produced Price) C. C. C	or to Plagging	Ne nonth this oil w	DIC buls *	
al. Amount of Oli produced price al. Amount of Oli produced price al. Place Point P-1 (Oli Produ RAC WELONLY. Source Pield	or to Plugging inclion Report) for i	Ne month this oil wa	DIC produced	
C. Amount of Oli produced price C. Amount of Oli produced price C. Pale Point P-1 (Oli Produ R. C. M. C. C. Y. Source Pield 	f to Plagging	Ne nonth this oil w	DIC buls*	
C. Amount of Oll produced price Pale Point P-1 (Oll Produced Price) RAC WE COLY. Source Pield C. C. Source Pield C. Source P	C 3 V 1 3 2 3 PAK3T AQ dis	Ne nonth this oil wa	DIC produced	
all Amount of Oli produced price all Amount of Oli produced price all points P1 (Oli Produced) all content Pield 	C 3 V I 3 3 V HAKST AD CLA	No month this oil wa	DIC bble*	

OIL AND GAS DIVISION

Ë.

CEMENTING REPORT

Wildcat		*2. ARC Displet						
*1. Operator Mc. Cann. Cornoration	ilanın Sar	*4. County Hours ad						
"5. Lease Same(a) and RRC Lease Number(a) or 1. D. Num Stowart	ber(s)			·6. Well Humber,	oward			
*7. Location (Section, Block, and Survey)	PP Co C	-		- 199 - Charles Table	Tool and the			
Sec. 4, DIK. 29, 1-1-N, 10F	RR CO. Survey			ICTION	and the state of graves			
CASING CEMENTING DATA:	CASING	MEDIATE	Single	inc.	CENTRY	S PROCESS		
			String	Perellal Strings	Třel	Shee.		
8. Cementing Date			310 ₁	P. Sugar	1. 30 Bar			
*9. (a) Size of Drill Bit (inches)	384.1		-					
(D) Estimated 75 Wash or Hole Enlargement Used in Calculations.	16	6060 20	4830 (SS 100 10	1. 1. 1.	in an an Stantas			
*10. Size of Casing (inches O.D.)			6 53 9	2. x 2.1 - X.	delato.	1 11 030		
*11. Top of Liner (if liner used) (ft.)	20152	No.			1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 - 1997 -			
*12. Setting Depth of Casing (ft.)		8 C	8		1.54.2671	1997 - 1998 1997 - 1998 1997 - 1998		
3. Type API Class Cement & Amount of Additives Used: (a) in First (Lead) or Only Starry III additional space				Steen a	. 11-1 175	64.0070		
(b) In Second Sturry	<u></u>							
(c) In Third Sivery		25.		100 million (100 million) 100 million (100 million)		1		
14. Sacks of Crment Used: (a) In First (Lead) or Only Sluny						(1) - (1) - (1)		
(b) In Second Siwn								
(c) In Third Siwry	A de							
(c) Total Sacks of Cement Used		21 - M-	£ 50	5 - 212 - 53A	an a			
15. Slurry Volume per Sack of Cement (cu.it./sack): (a) In First (Lead) or Only Slurry					f to the second			
(b) In Second Slurry		276.0						
(c) in Third Slarry	9 54	an 200 000			a national per a composition de la comp	1		
16. Volume of Siurry Pumped: (cu.it.) (item 14 x liem 15) (e) In First (Lead) or Only Siurr			19925					
(b) In Second Sturry				111 2 1.1	10.96	1.		
(c) In Third Sluny						11		
(d) Total fluence to have the set of a b				N 12	21			
17. Celculated Annular Height of Cement Slurry		11.22 15		2002 BOO				
behing Pipe (II.) 18. Was cement circulated to ground surface					$e^{i_{1}} = r^{i_{1}}_{1} \frac{e^{-i_{1}}}{e^{i_{1}}} \frac{e^{-i_{1}}}{e^{-i_{1}}} \frac{e^{-i_{1}}}{e^{-i_{1}}} + e^{-i_{1}}$	· · · · · · · · · · · · · · · · · · ·		
(or bottom of cellar) outside casing? (Yes or No)				5	18 2 H S	ST VERS		
CEMENTING TO PLUG AND ABANDON DATA:	PLUG NO. 1	PLUG NO. 2	PLUG NO. 3	PLUG NO. 4	PLUG NO. 5	PLUG NO. 6		
19. Cementing Date	10-12-80	10-13-80	10-13		9. S			
#20. Size of Hote or Sips in which Plug Placed (inches)	9-5/8	9-5/8	13-3/8					
#21. Depth to Hotiom of Tubing or Drill Pipe (ft.)	1000	250	Top Out		1	2°_ 2		
22. Sucks of Cement Used (each plug)	50	100	10	۰	8 ₂₁	1		
23. Sturry Volume Pumped (cu. ft.)	66	133	13		S 8	21 min 7/		
\$4 . 6 at-situted Pop-of 3ting (ft.)	990	70	Surf	Q. BY TEXAS	1			
*25. Messured Top of Flug (M tagged) (It.)			AP	R 2 0 1981	Sec. 1			
(CEMENTING COMPANY AND OPERATOR I	MUST COMPLY	WITH THE	INSTRUCTION	IS CHEREVER	SE SIDE HEI	FORA		

-te

(Nev. 14.8)

	• 27. Remarks:	
		10
	*005504105	
The sector of the sector presties and a fee, \$1.143, Tesan Natural the sector, the Tam authorized to make this certification, that the	T declare under penalties prescribed in Sec. 31 143. Resources Cude, that I am authorized to make this cort	Concern Natural
I demonstrag of cooling and/or the placing of content plugs in this work as	have incovering of the well date and information presents and that data and facts presented on bath sides of this	d in this regard. 6 form and true
servet, and complete, to the best of my knowledge. This certification	covers all well date and information presented herein	
	1 4 6	
In the keldowd	Four ille Cam	
Commere of Contenter or Authorized Depresentative	Bignature of Operator or Authorized Representative	
	Tom McCann - President	
Butter of Person and Title (type ar print)	"Name af Person and Title (type or print)	
Demolt Division of Dow Chemical Co.	McCann Corporation	
Committee Company	*Op#retor	
Banta 3. Box 178	P. O. Bux 48	
Shiert Address or P.O. Box	•Street Address or P.O. Box	
Colorado City, Tx 79512	Big Spring, Texas	75736
City, Baste Zip Cede	*City, State	Zip Cade
915 728-5291	*Telephone 915 267-7488	
Area Code	Anna Colta	
	Ares Cour	
10-14-80	- <u>1-6-81</u>	
10-14-80 Date IN L. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting rej to computing requirements in Statewide or Special Rules;	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except	tion is norded
10-14-80 This This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a communing regulation of the transmission of transmission of transmission of the transmission of trans	etion. or such company used on a well.	tion is nurried
10-14-80 Date IN L. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The computing of different casing strings on a well by one co	Area Code <u>Area Code</u> <u>STRUCTIONS</u> Office with: port is required by Statewide or Special Rules, or if eccep etion. or each cementing company used on a well. menting company may be consolidated on one form (to be	tion is norded
10-14-80 Date IN 1. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companing of different casing strings on a well by one co 2. Companing Company and Operator shall comply with the applicable C. The company and Operator shall comply with the applicable	Area Code 	tion is needed filed in duplicat
10-14-80 This This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a communing reg- to comparing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed f C. The companing of different casing strings on a well by one cas 2 Companing Company and Operator shall comply with the applicable Companing Company and Operator shall comply with Statewide Rules; 2 W applies PULL, AMOUNT OF SURFACE CASING:	Area Code 	tion is needed filed in duplicat poperations.
10-14-80 This A. This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a commanding regulation of the second se	Area Code - <u>3Late</u> ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if eccep etion. or each cementing company used on a well. menting company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E).	tion is needed filed in duplicat poperations.
ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companies of different casing strings on a well by one case Companies Company and Operator shall comply with the applicable Companies Company and Operator shall comply with Statewide Rules; (1) Fi Rule A. Depth to protect fresh water determined by: (1) Fi Rule a. Water Development Doard, if op Field Bulk	Area Code - <u>3-6-B1</u> ISTRUCTIONS Office with: port is required by Statewide or Special Rules, or if excep etion. or each cementing company used on a well. ementing company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E).	tion is neerled filed in duplicat poperations.
10-14-80 This This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a community reprive community requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed f C. The commaning of different casing strings on a well by one case Commaning Company and Operator shall comply with the applicable Commaning Company and Operator shall comply with Statewide Rules W setting FULL ANOUNT OF SURFACE CASING A. Depth to protect fresh water determined by: (1) Fi Rule (2) To s Water Development Board, if no Field Rule B. Set surface casing below depth to be protected and command for	Area Code 	tion is needed filed in duplicat experations.
IN IN IN IN IN IN IN IN IN IN	Area Code - <u>abale</u> ISTRUCTIONS Mfice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be is portions of Statewide Rules 8, 13, and 14. For offshore the T3(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE	tion is needed filed in duplicat poperations .
IN I. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The companies of different casing strings on a well by one co Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for A. IF SETTING ANYTHING OTHER THAN THE FULL ASIOUNT OF RALEROAD COMMISSION. 5: If setting NO SURFACE CASING (See Item 4 above.):	Area Code 	tion is needed filed in duplicat expensions.
 10-14-80 Date IN A. This form shall be filed by the operator in the RRC District (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing completes and one copy of this form shall be filed for the companies of different casing strings on a well by one cases and the company and Operator shall comply with the applicable Commuting Company and Operator shall comply with Statewide Rules; (2) File Rule (2) Transform and Operator shall comply with Statewide Rules. Facting FULL ANOUNT OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) File Rule (2) Transform the substance casing below depth to be protected and cement for the SETTING ANYTHING OTHER THAN THE FULL ANOUNT OF RAIL ROAD COMMISSION. If satting NO SURFACE CASING (See Item 4 above.): A: If so multi-stage tool is used, the next deeper casing string or substantian of the subs	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be to portions of Statewide Rules 8, 13, and 14. For offshore the 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface.	tion is needed filed in duplicat poperations, tp FROM THE
 10-14-80 Content IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regulation of the computing requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing compiles. At least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicabl Company and Operator shall comply with the applicabl Company and Operator shall comply with Statewide Rules; (1) File Rule Y setting FULL AMOUNT OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) File Rule (2) To a Water Development Board, if no Field Rule E Set surface casing below depth to be protected and cement for RALENDAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: If no multi-stage tool on the next deeper string, cement 	Area Code 	tion is needed filed in duplicat poperations.
IN-14-80 This form shall be filed by the operator in the RRC District ((1) Each copy of an initial Form G-1 or W-2 if a commanding regulation of the second seco	Area Code - <u>abale</u> ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be is portions of Statewide Rules 8, 13, and 14. For offshore its portions of Statewide Rules 8, 13, and 14. For offshore its 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. tifrom the depth that protects fresh water sands to the sur-	tion is needed filed in duplicat poperations, to FROM THE face.
IN I. A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-I or W-2 if a commanding regulation of the company of Form W-3; (2) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed f C. The commanding of different casing strings on a well by one com- Commanding Company and Operator shall comply with the applicable Commanding Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RAL ROAD COMMISSION. I fisetting NO SURFACE CASING (See Item 4 above.): A: If no multi-stage tool is used, the next deeper string, cement If satting SHORT SURFACE CASING (See Item 4 above.): A: Cement short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper.	Area Code 	tion is needed filed in duplicat s operations . In FROM THE face.
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting register to computing requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing completed in the filed of the commuting of different casing strings on a well by one case. Commuting Company and Operator shall comply with the applicable Commuting Company and Operator shall comply with Statewide Rules; (2) File case of the case of the comply with the applicable Commuting Company and Operator shall comply with Statewide Rules; (3) File Rule (3) Tr is Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RAL BOAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: This multi-stage tool is used, the next deeper casing string on B: If using the multi-stage tool on the next deeper string, cement. If satting SHORT SURFACE CASING (See Item 4 above.): A: Cement short surface casing from the shoe to the surface. Whether the multi-stage tool is or is not used on the next form (1) the surface, or (2) a point midway between shoe of surface string and the surface to of the commuting and the surface string and the surface string of the distance. 	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. menting company may be consolidated on one form (to be to portions of Statewide Rules 8, 13, and 14. For offshore lie 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OBTAINE hall be cemented from the casing shoe to the surface. trifrom the depth that protects fresh water sands to the sur- per casing string, cement from the depth that protects fresh face. Compliance will be considered of a temperature sur- from the shue of the surface string to the surface.	tion is needed filed in duplicat roperations, ip FROM THE face. Is water satisfa to yey shows that
IN-14-80 Date IN A. This form shell be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commiting re- to comparing requirements in Statewide or Special Rules; (2) Each copy of Form W-3 if a multiple parallel casing compl B. At least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicable Comparing Company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) To a Water Development Board, if no Field Rule B. Set surface casing below depth to be protected and cement for ALLROAD COMMISSION. I If setting NO SURFACE CASING (See Item 4 above.): A.: If no multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool on the next deeper string, cement If setting SHORT SURFACE CASING (See Item 4 above.): A.: Cercent short surface casing from the shot to the surface. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the multi-stage tool is or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting or is not used on the next face. B. Whether the commuting or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting of is or is not used on the next face. B. Whether the commuting of the commuting of the distance 7. Soming PRODUCTION STRING of Casing: (Statewide Rules, Spec-	Area Code 	tion is needed filed in duplicat poperations. In FROM THE face.
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commuting regularements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple A. At least an original and one copy of this form shall be filed f C. The community of different casing strings on a well by one cas Community of different casing strings on a well by one cas Community of different casing strings on a well by one cas Community and Operator shall comply with the applicable Community and Operator shall comply with Statewide Rule; (1) Fi Rule; (2) To a stater Development Board, if no Field Rule E. Set surface casing below depth to be protected and community of RALEROAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A: This multi-stage tool is used, the next deeper string, cement If satting SHORT SURFACE CASING (See Item 4 above.): A: Cement short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper (1) the surface, or (2) a point midway between shoe of surface string and the sut the top of the cement is at least ene-third of the distance 	Area Code 	tion is needed filed in duplicat roperations, to FROM THE face. It water satisfies to ver shows that
 ID-14-80 IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form C-1 or W-2 if a commuting requirements in Statewide or Special Rules; (2) Each copy of Form W-4 if a multiple parallel casing comple to comparing of form W-3; (3) Each copy of Form W-4 if a multiple parallel casing comple B. At least an original and one copy of this form shall be filed f C. The commuting of different casing strings on a well by one case comple and operator shall comply with the applicable Communing Company and Operator shall comply with Statewide Rules; (2) The company and Operator shall comply with Statewide Rule E setting PULL AMOUNT OF SURFACE CASING A. Depth to protect fresh water determined by: (1) Fi Rule (2) The state Development Board, if no Field Rule (2) The state casing below depth to be protected and comment for RALEROAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A. Concent short surface casing from the shoe to the surface. B. When the multi-stage tool is or is not used on the next deep (1) the surface, or (2) a paint midway between shoe of surface string and the surface. E. Stating PRODUCTION STRING of Casing: (Statewide Filen, Spe A. Comment is at least ene-third of the distance B. When 3,090 feet or more of piperlistate. 	Area Code 	tion is needed filed in duplicat roperations. ID FROM THE face. Is water calles to ver shows that
 ID-14-80 Date IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commiting requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil A. At least an original and one copy of this form shall be filed file. C. The comenting of different casing strings on a well by one ca Comenting Company and Operator shall comply with the applicable Commiting Company and Operator shall comply with the applicable Commiting Company and Operator shall comply with Statewide Rule. M setting FULL AMOUNT OF SURFACE CASING: A. Depth to protect fresh water determined by: (1) Fi Rule (2) Tr - s Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RALEROAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A.: The multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool on the next deeper string, cement (1) the surface. B. When the multi-stage tool is or is not used on the next face. B. When the support of a string of surface string and the stut the top of the cement is at least one-third of the distance A. Cement to a point at least 600 feet, above the casing shoe. B. When 3,000 feet or more of piperiaraec. So the production or point at least for production or point at least for string or the string shoe. 	Area Code 	tion is needed filed in duplicat roperations. In FROM THE face. Is water satisfies to ver about that
 ID-14-80 Data IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a commenting requirements in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compil B. At least an original and one copy of this form shall be filed file C. The company and Operator shall comply with the applicable Companies Company and Operator shall comply with Statewide Rules; (1) File Rule (2) Tr. a Water Development Board, if no Field Rule E. Set surface casing below depth to be protected and cement for RALEROAD COMMISSION. If setting NO SURPACE CASING (See Item 4 above.): A. This multi-stage tool is used, the next deeper casing string on B: If using the multi-stage tool is or is not used on the next deeper for string. If setting SHORT SURFACE CASING (See Item 4 above.): A. Cement short surface casing from the shoe to the surface. B. Whether the multi-stage tool is or is not used on the next deeper for string. (1) the surface, or (2) a point midway between shoe of surface string and the surface. B. Whether the multi-stage tool is or is not used on the next deeper for the string. A. Cement to a point at least 600 feet, above the casing shore. B. When 3,000 feet or more of piperistate. B. When 3,000 feet or more of piperistate. A. Cement plugs shall be placed in the well bore as required by the casing shall be placed in the well bore as required by the top of the tempth and the surface. 	ISTRUCTIONS Mice with: port is required by Statewide or Special Rules, or if except etton. or such company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore ile 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL DE OUTAINE hall be comented from the casing shoe to the surface. trifrom the depth that protects fresh water sands to the sur- per casing string, coment from the depth that protects fresh face. Compliance will be considered if a temperature sur- from the shoe of the surface string to the surface. cial Rules may vary 1 effecting string, a minimum of 30 feet of coments any addition Rules and Regulations of the Commission plus any addition	tion is needed filed in duplicat poperations, to FROM THE face. Is water satisfies to yes, shown that if consider the po- orial ploge so the
 ID-14-60 Data IN A. This form shall be filed by the operator in the RRC District C (1) Each copy of an initial Form G-1 or W-2 if a comrating regiments in Statewide or Special Rules; (2) Each copy of Form W-3; (3) Each copy of Form W-4 if a multiple parallel casing compile A. Least an original and one copy of this form shall be filed f C. The company and Operator shall comply with the applicable Company and Operator shall comply with Statewide Rules; (1) File Rule (2) The company and Operator shall comply with Statewide Rules; (2) The company and Operator shall comply with Statewide Rule; (2) The company and Operator shall comply with Statewide Rule; (3) The Rule (4) File Rule (5) The Rule (2) The Rule (3) The Rule (4) File Rule (5) The State Development Board, if no Field Rule E. Set surface casing below depth to be protected and coment for RALERDAD COMMISSION. If setting NO SURFACE CASING (See Item 4 above.): A. The multi-stage tool is used, the next deeper casing string to B: If using the multi-stage tool on the next deeper string, coment (1) the surface casing from the shote to the surface. B. Whether the multi-stage tool is or is not used on the next deep (1) the surface, or (2) a point midway between shoe of surface string and the surf the top of the coment is at least one-third of the distance A. Cement to a point at least 600 feet apove the casing shoe. B. When 3,000 feet or more of piperistate. For the production or production or production or produced of 00 feet of the kole for the file of is a required by the specified by the RRC District. Director. B. The minimum amount of diment in the well bore as required by be specified by the RRC District. Director. 	ISTRUCTIONS Mice with: poort is required by Statewide or Special Rules, or if excep etton. or each cementing company used on a well. meeting company may be consolidated on one form (to be the portions of Statewide Rules 8, 13, and 14. For offshore the portions of Statewide Rules 8, 13, and 14. For offshore the 13(E). om casing shoe to ground surface. F SURFACE CASING, PERMISSION SHALL THE OUTAINER hall be cemented from the casing shoe to the surface. tofrom the depth that protects fresh water sands to the sur- per casing string, cement from the depth that protects fresh face. Compliance will be considered if a temperature sur- from the shue of the surface string to the surface cial Rules may vary 1 effecting string, a minimum of J0 feet of cement shall be Rules and Regulations of the Commission plus any additional still be a slurry volume equal to the amount no enfary to find the shue of the surface string to the surface string to find the a slurry volume equal to the amount no enfary to find at the string to the surface string to the surface string to find the a slurry volume equal to the amount no enfary to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to the surface string to find the slure volume equal to	tion is needed filed in duplicat poperations, ip FROM THE face. It water satisfies to you above that if costs the po- out place as the if the calculated

APPENDIX B - SITE SAFETY AND LAYOUT

Bayswater Operating's Mongoose Gas Plant and AGI No. 1 are operated and monitored 24 hours a day, 7 days a week, by on-site personnel utilizing Plant operating and SCADA systems. These systems gather operating data such as pressures, temperatures, flow rates, remote sensors, compressor run data, and control valve positions. The recording and retention of this operating data enables the operator to evaluate trends and use predictive analytics to potentially identify issues before they become an "alarm" event. If an alarm event occurs, the automated control system is programmed to execute pre-programmed protocols to safely manage the event. Operators are specially trained to follow detailed practices to minimize risk to people, the facility, and the environment.

In the event of a leak or system failure, the Plant control system will execute its shutdown protocols as timely as is practicable to isolate the event and minimize the intensity. The Plant operator will investigate the circumstances and oversee an orderly resolution to the situation. Since this facility handles H₂S, Bayswater is required to maintain a Hydrogen Sulfide Contingency Plan to safely manage any planned or unplanned release event. The Plant operating staff are highly trained in safety and emergency response protocols to ensure safety for both plant personnel and the surrounding community and environment.



B-	-2

			ITEM	DESCRIPTION
			1	SLUG CATCHER
			2	INLET COMPRESSOR W/ COOLER
	1		2F	INLET COMPRESSOR (FUTURE) W/ COOLER
			3	COMPRESSOR DISCHARGE COALESCER
			4	
	v	V	× 6	
		^	7	
			8	
			9	
			10	AMINE REGENERATOR REBOILER
			11	AMINE SURGE TANK
			12	AMINE BOOSTER/REFLUX PUMP SKID
			13	AMINE REGENERATOR REFLUX CONDENSER
			14	LEAN AMINE COOLER
			15	AMINE CHARGE PUMPS
			16	HOT OIL PUMP SKID
			17	HOT OIL HEATER
			18	FLARE K.O. DRUM
	1		19	FLARE
- BARF	RIER		20	COMBUSTOR
			21	SLOP STORAGE TANKS
	_+		22	AMINE MAKE UP STORAGE TANK
			23	
			24	
			241	
			25	
	1		20	
			27	
			20	DI WATER TANK
	·		30	GLYCOL CONTACTOR
			31	GLYCOL SEPARATOR
			32	TEG REGEN
			33	BTEX
			34	GAS GENERATOR SET
			35	AMINE SUMP TANK
			36	NEW LUBE OIL TANKS
			37	CONDENSATE TRANSFER PUMPS
			38	VAPOR RECOVERY UNIT
			39	TANK COMBUSTOR K.O. DRUM
			40	MV TRANSFORMER
			40F	MV TRANSFORMER (FUTURE)
				LEGEND
				FIRE EXTINGUISHER = 9 ea.
				HYDROGEN SULFIDE DETECTOR = 10 ea.
				AUDIBLE ALARM SOUNDER = 4 ea.
				R STROBE LIGHT (RED) — FIRE = 4 ea.
_	- EAST_SECU	RITY GATE		SHUT PLANT EMERGENCY SHUTDOWN = 6 ea.
				FIRST AID & SCBA KIT = 3 ea.
	-*X -	X		EYE WASH STATION = 3 ea.
	й С		E 10(WIND SOCK = 1 ea.
				MUSTER POINT = 3 ea.
r :	RΔ	YSWATER	FXPLOR	ATION & PRODUCTION
CT ·	DA	COUD		
		SUUK	GAS IR	EATING FAUILITY
·		FACILITY	INSTRUN ′SAFET`	IENTATION (LOCATION PLAN
WN	CHECKED	SCALE	DATE	JOB NO. DRAWING NO. SHEET NO.
DC DC	GA	AS NOTED	06/09/22	BAY220316 IN-PLN-0790 1 OF 1

APPENDIX C – AREA OF REVIEW

APPENDIX C-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX C-2: OIL AND GAS WELLS WITHIN THE MMA LIST

APPENDIX C-3: WATER WELLS WITHIN THE MMA MAP

APPENDIX C-1: WATER WELLS WITHIN THE MMA LIST



Mongoose AGI No. 1

	Area of Review: Oil & Gas Wells List										
API	WELL NAME	WELL NO.	CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (FT.)	PERFORATED INTERVAL (FT.)	DATE DRILLED	
4222700101	JONES, C.L	1	ARMER L H	1603	32.445815	-101.187399	DRY HOLE	NR	NR	NR	
4222703634	STEWART	1	MCCANN CORP	1601	32.423136	-101.1837088	DRY HOLE	8670	NR	10/11/1980	
4222732304	CATHEY	1	MCCANN CORP	204	32.42347	-101.1890569	DRY HOLE	4310	NR	10/31/1980	
4222734502	STERLING CATTLE COMPANY	3402	MDC TEXAS ENERGY	1603	32.44553	-101.17894	P & A	7795	7764-7795	10/19/1989	
4222734688	STERLING FAMILY TRUST	3403	TREND EXPLORATION COMPANY	1603	32.4403185	-101.1792589	P & A	7918	7747-7760	3/5/1992	
4222736361	STERLING 38	1	HIGHPEAK ENERGY	1371	32.42744	-101.196842	INACTIVE PRODUCER	8075	5635-7848	4/5/2010	
4222741505	KAMIKAZE 5-8	H 3W	BAYSWATER OPERATING COMPANY LLC	204	32.399666	-101.180898	PRODUCING	5433	5911-15810 (MD)	1/9/2022	
4222741505	KAMIKAZE 5-8-17-20	3W	BAYSWATER OPERATING COMPANY LLC	204	32.426344	-101.191374	PRODUCING	5643.22	5911-15810 (MD)	1/9/2022	
4222741939	WINFORD 35-38 B UNIT A	7H	HIGHPEAK ENERGY	745	32.450886	-101.197238	PRODUCING	5785.42	6081-15105 (MD)	9/9/2022	
4222741972	PHARAOH 10-15-34-39	H 1W	BAYSWATER OPERATING COMPANY LLC	1602	32.473311	-101.191423	INACTIVE PRODUCER	5847	NR	10/27/2022	
4222742086	KAMIKAZE 5-8	H 2WD	BAYSWATER OPERATING COMPANY LLC	204	32.426337	-101.191712	COMPLETED	7821	NR	4/14/2023	
4222742087	KAMIKAZE 5-8	H 4WX	BAYSWATER OPERATING COMPANY LLC	204	32.4263090	-101.1918370	COMPLETED	5818	NR	4/5/2023	
4222742088	KAMIKAZE 5-8	H 2W	BAYSWATER OPERATING COMPANY LLC	204	32.4262950	-101.1919000	COMPLETED	5669	NR	3/22/2023	
4222742089	KAMIKAZE 5-8	H 1WD	BAYSWATER OPERATING COMPANY LLC	204	32.4263230	-101.1917740	COMPLETED	7820	NR	4/8/2023	
4222742105	KAMIKAZE 5-8	H 1W	BAYSWATER OPERATING COMPANY LLC	204	32.4262810	-101.1919620	COMPLETED	5816	NR	5/24/2023	



Mongoose AGI No. 1

4233500959	MACKEY, P.K.	1	MCDERMOTT-RAY	1344	32.4133665	-101.1552679	DRY HOLE	NR	NR	4/25/1954
4233501046	MACKEY, P.K.	1	MOSS H S	582	32.4215460	-101.1434280	DRY HOLE	NR	NR	12/8/1947
4233501860	JONES, CHESTER L	1	DANSBY, BEN JR.	17	32.4497350	-101.1605990	DRY HOLE	NR	NR	NR
4233533555	VAN TUYLE	1	BRIGHT & COMPANY	584	32.4027340	-101.1529820	P & A	8360	NR	11/26/1990
4233533624	STERLING FAMILY TRUST-A-	3301	MDC OPERATING, INC.	17	32.4438844	-101.1638476	P & A	7850	7756-7760	1/23/1993
4233535973	SI-10.2 CP UNIT	1	ENERGY TRANSFER	1536	32.4233850	-101.1407330	PERMIT EXPIRED	550	NR	-
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.434283	-101.161962	PRODUCING	5543	6052-19217 (MD)	7/7/2022
4233536022	OASIS 9-16-33-40	H 4W	BAYSWATER OPERATING COMPANY LLC	5	32.4717700	-101.1619280	PRODUCING	5543	6052-19217 (MD)	7/6/2022
4233536030	JADE PALACE 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1344	32.4049880	-101.1607180	DUC	5491	NR	11/8/2022
4233536031	GOLDEN SAND 10-3	H 1W	BAYSWATER OPERATING COMPANY LLC	1344	32.4050010	-101.1606550	DUC	5606	NR	11/8/2022
4233536041	PEARL RIVER 4-9	H 1W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016760	-101.1745840	PERMITTED	7100	NR	-
4233536042	PEARL RIVER 4-9	H 2W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016620	-101.1745210	PERMITTED	7100	NR	-
4233536045	PEARL RIVER 4-9	H 3W	BAYSWATER OPERATING COMPANY LLC	1634	32.4017660	-101.1748560	PERMITTED	7100	NR	-
4233536046	PEARL RIVER 4-9	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016350	-101.1743950	PERMITTED	7100	NR	-
4233536047	JAVA 16-21	H 4W	BAYSWATER OPERATING COMPANY LLC	1634	32.4016210	-101.1743330	PERMITTED	7100	NR	-

*Note: Well entries in red penetrate the upper confining layer.





Mongoose AGI No. 1

	Area of Review: Freshwater Wells List											
WELL REPORT/ID NO.	OWNER'S NAME	OWNER ADDRESS	CITY/STATE/ZIP	LAT. WGS 84	LONG. WGS 84	WELL USE	WATER LEVEL (FT.)	TOTAL DEPTH (FT.)	DATE DRILLED			
2839802	TOM JACKSON	-	-	32.413889	-101.168333	PLUGGED OR DESTROYED	-	215	11/1/1967			
287994	BENNARD LAZY H RANCH	5933 LAZY RIVER RD	HOUSTON, TX 77057	32.426667	-101.151945	PLUGGED	DRY	200	9/2/2011			
287998	BENNARD LAZY H RANCH	5933 LAZY RIVER RD	HOUSTON, TX 77057	32.421667	-101.143056	PLUGGED	DRY	220	9/1/2011			



APPENDIX D – SECTION 2 CROSS SECTIONS

APPENDIX D-1: FIGURE 27 – STRUCTURAL CROSS SECTION DEPICTING THE ELLENBURGER

APPENDIX D-2: FIGURE 28 – STRATIGRAPHIC CROSS SECTION FLATTENED ON THE ELLENBURGER



D-1

