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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

OFFICE OF AIR AND RADIATION

WASHINGTON, D.C. 20460

August 30, 2024

Mr. Jimmy Oxford
Area Manager
Targa Resources Corporation
1934 W NM Highway 128
Jal, New Mexico 88252

Re: Monitoring, Reporting and Verification (MRV) Plan for Red Hills Gas Processing Plant

Dear Mr. Oxford:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Red Hills Gas Processing Plant, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Red Hills Gas Processing Plant on July 23, 2024, as the final MRV plan. The MRV Plan Approval Number is 1011064-2. This decision is effective September 4, 2024 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78. 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 miller.melinda@epa.gov.

Sincerely,

Julius Banks,
Supervisor, Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for the Red Hills Gas Processing Plant

August 2024

Contents

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 Red Hills Gas Processing Plant (RHGPP) for its Acid Gas Injection (AGI) project located in Lea County, New Mexico. Note that this evaluation pertains only to the Subpart RR MRV plan for the RHGPP, 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

The MRV plan states that Targa Northern Delaware, LLC (TND) is currently authorized to inject treated acid gas (TAG) into the Red Hills Acid Gas Injection well (RH AGI #1) (American Petroleum Institute (API) # 30-025-40448) and RH AGI #3 well (API # 30-025-51970) under the New Mexico Oil Conservation Commission (NMOCC) Orders R-13507 – 13507F and Order R-20916H, respectively, at the RHGPP located approximately 20 miles NNW of Jal in Lea County, New Mexico. Both the RH AGI #1 and the RH AGI #3 wells are approved to inject 13 million standard cubic feet per day (MMSCFD) of TAG. However, the MRV plan states that the RH AGI #1 is physically only capable of taking approximately 5 MMSCFD of TAG due to formation and surface pressure limitations.

The MRV plan states that the RH AGI #1 was previously operated by Lucid Energy Delaware, LLC (Lucid). TND acquired Lucid assets in 2022. Lucid received authorization to construct a redundant well, RH AGI #2 (API # 30-025-49474) under NMOCC Order R-20916-H, which is offset 200 feet (ft) to the north of RH AGI #1 and is currently temporarily abandoned in the Bell Canyon Formation. RHGPP states that they recently received approval from NMOCC for its C-108 application to drill, complete and operate a third acid gas injection well (RH AGI #3) in which TND requested an injection volume of up to 13 MMSCFD. The MRV plan states that the RH AGI #3 well was spudded on 9/13/2023, completed on 9/27/2023, and injection commenced on 1/11/2024. The MRV plan states that since the RH AGI #1 does not have complete redundancy, having a greater permitted disposal volume will also increase operational reliability. At the time of its most recent MRV plan submittal, RHGPP is currently drilling the RH AGI #3. The depth of the proposed injection zone for the RH AGI #3 is approximately 5,700 to 7,600 ft in the Bell Canyon and Cherry Canyon Formations. The MRV plan states that analysis of the reservoir characteristics of these units confirms that they act as excellent closed-system reservoirs that will accommodate the future needs of the RHGPP for disposal of TAG. RHGPP states that they intend to inject carbon dioxide (CO_2) for another 30 years.

The MRV plan states that, based on geologic analysis of the subsurface at the RHGPP, the uppermost portion of the Cherry Canyon Formation was chosen for AGI and CO_2 sequestration for the RH AGI #1 and the uppermost Delaware Mountain Group (the Bell Canyon and Cherry Canyon Formations) for the RH AGI #3.

The MRV plan states that for the RH AGI #1, the injection interval includes five high porosity sandstone units and has excellent caps above, below, and between the individual sandstone units. The MRV plan also states that there is no local production in the overlying Delaware Sands Pool of the Bell Canyon Formation. Additionally, the MRV plan states that there are no structural features or faults that would serve as potential vertical conduits. RHGPP believes that the high net porosity of the RH AGI #1 injection zone indicates that the injected hydrogen sulfide (H_2S) and CO_2 will be easily contained close to the injection well.

The MRV plan states that for the RH AGI #3, this interval has been expanded to include the five high porosity zones in the Cherry Canyon sandstone as well as the sandstone horizons in the overlying Bell Canyon Formation. RHGPP believes that there are several potential high porosity sandstones, that if present in the RH AGI #3, would be excellent injection zones. The thickest of these sands is commonly referred to as the Delaware Sand within the Delaware Basin. The MRV plan states that while the Delaware Sand is productive, it is not in the local area surrounding RHGPP. The MRV plan states that most of the sand bodies in the Bell Canyon and Cherry Canyon Formations are surrounded by shales or limestones, forming caps for the injection zones. There are no structural features or faults that would serve as potential vertical conduits, and the overlying Ochoan evaporites form an excellent seal.

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

The MRV plan states that Schlumberger’s Petrel software was used to construct the geological models used for the MRV plan. RHGPP states that the modeling and simulation focused on the Bell Canyon and Cherry Canyon formations as the main injection target zone for acid gas storage. The MRV plan states that in determining the MMA and AMA, the extent of the TAG plume is equal to the superposition of plumes in any layer for any of the model scenarios described in Section 3.8 of the MRV plan.

The MMA and AMA are delineated in Figure 4.1-1. The MRV plan states that the MMA is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The MRV plan states that the MMA is defined by the extent of the TAG plume at year 2059 plus a one-half mile buffer. The MRV plan states that RHGPP intends to define the AMA as the same area as the MMA.

The MRV plan states that the AMA is consistent with the requirements in 40 CFR 98.449 because it is the area projected:

1. To contain the free phase CO_2 plume for the duration of the project (year t, t = 2054), plus an all-around buffer zone of one-half mile

2. To contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2059).

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). In Section 5 of their MRV plan, RHGPP identified the following potential leakage pathways that required consideration:

- Surface Equipment
- Approved, Not Yet Drilled Wells
- Existing Wells
- Confining/Seal System
- Lateral Migration
- Fractures and Faults
- Natural/Induced Seismicity

3.1 Surface Equipment

The MRV plan states that due to the corrosive nature of CO_2 and H_2S, there is a potential for a leakage from surface equipment at sour gas facilities. RHGPP infers that there is a potential for CO_2 leakage via surface equipment. For timing, the MRV plan states that surface component leakage or venting is only a concern during the injection operation phase. Any leaks from surface equipment would result in immediate (timing) emissions of CO_2 to the atmosphere, the magnitude of which would depend on the duration of the leak, the operational conditions at the time of leakage, the location of the leak, and the component's failure mode. For example, the MRV plan states that a rapid break or rupture could release thousands of pounds of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO_2 over several hours or days. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

The MRV plan states that preventative risk mitigation for CO_2 leakage from surface equipment includes adherence to relevant regulatory requirements and industry standards governing the construction, operation, and maintenance of gas plants. Additional operational risk mitigation measures will include a schedule for regular inspection and maintenance of surface equipment.

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

3.2 Approved, Not Yet Drilled Wells

The MRV plan states that the RH AGI #3 well very recently began injecting in January 2024. The only wells within the MMA that are approved but not yet drilled are horizontal wells. The MRV plan states that there are no vertical wells within the MMA with a well status of “permitted.”

Horizontal Wells

Figure 4.1-1 of the MRV plan shows a number of horizontal wells in the area, many of which have approved permits to drill but which are not yet drilled. The MRV plan states if any of these wells are drilled through the Bell Canyon and Cherry Canyon injection zones for RH AGI #3 and the Cherry Canyon injection zone for RH AGI #1, they will be required to take special precautions to prevent leakage of TAG minimizing the likelihood of CO_2 leakage to the surface. This precaution will be made by the New Mexico Oil Conservation Division (NMOCD) in regulating applications for permit to drill (APD) and in ensuring that the operator and driller are aware that they are drilling through an H_2S injection zone in order to access their target production formation. Additionally, the MRV plan states that NMAC 19.15.11 for Hydrogen Sulfide Gas includes standards for personnel and equipment safety and H_2S detection and monitoring during well drilling, completion, well workovers, and well servicing operations all of which apply for wells drilled through the RHGPP TAG plume. The MRV plan states that the likelihood of CO_2 emissions to the surface via these horizontal wells to be highly unlikely.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through approved, not yet drilled wells.

3.3 Existing Wells

The MRV plan states that RHGPP considered all wells completed and approved within the MMA in the National Risk Assessment Partnership (NRAP) risk assessment. Some of these wells penetrate the injection and/or confining zones while others do not. Even though the risk of CO_2 leakage through the wells that did not penetrate confining zones is highly unlikely, RHGPP did not omit any potential source of leakage in the NRAP analysis. If leakage through wellbores happens, the worst-case scenario is predicted using the NRAP tool to quantitatively assess the amount of CO_2 leakage through existing and approved wellbores within the MMA. Thirty-nine existing and approved wells inside MMA were addressed in the NRAP analysis. Through this analysis, RHGPP states that CO_2 leakage to the surface via this potential leakage pathway can be considered improbable.

Wells Completed in the Bell Canyon and Cherry Canyon Formations

The MRV plan states that the only wells completed in the Bell Canyon and Cherry Canyon Formations within the MMA are RH AGI #1, RH AGI #2 (drilling stopped in the Bell Canyon), and RH AGI #3, and the 30-025-08371 well which was completed at a depth of 5,425 ft. This well is within the RHGPP facility boundary and is plugged and abandoned. The MRV plan states that injection of TAG into the RH AGI #1 and #3 occurs through tubing with a permanent production packer set above the injection zone.

The MRV plan states that the RH AGI #2 is located in close proximity to RH AGI #1 and is temporarily abandoned. Drilling of this well stopped at 6,205 ft due to concerns about high pressures by drilling into the Cherry Canyon Formation and therefore, did not penetrate the Cherry Canyon Formation. The MRV plan states that the cement plug was tagged at 5,960 ft which is above the injection zone for RH AGI #1.

The MRV plan states that due to the robust construction of the RH AGI wells, the plugging of the 30-025-08371 well above the Bell Canyon, the plugging of RH AGI #2 above the Cherry Canyon Formation, and considering the NRAP analysis described above, RHGPP considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

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

Wells Completed in the Bone Spring/Wolfcamp Zones

The MRV plan states that several wells are completed in the Bone Spring and Wolfcamp oil and gas production zones. These productive zones lie more than 2,000 ft below the RH AGI well injection zones minimizing the likelihood of communication between the RH AGI well injection zones and the Bone Spring/Wolfcamp production zones. The MRV plan states that due to the construction of these wells, the fact that the modeled TAG plume does not reach the surface hole location (SHL) of these wells and considering the NRAP analysis, RHGPP considers that, while the likelihood of CO_2 emissions to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

Wells Completed in the Siluro-Devonian Zone

The MRV plan states that one well penetrated the Devonian at the boundary of the MMA – EOG Resources, Government Com 001, API # 30-025-25604, TVD = 17,625 ft, 0.87 miles from the RH AGI #3. The MRV plan states that this well was permanently plugged and abandoned on December 30, 2004. The MRV plan also states that the approved plugging provides zonal isolation for the Bell Canyon and

Cherry Canyon injection zones minimizing the likelihood that this well will be a pathway for CO_2 emissions to the surface from either injection zone. Due to the location of this well at the edge of the MMA and considering the NRAP analysis, RHGPP considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

Groundwater Wells

The MRV plan states that 15 water wells are within a 2-mile radius of the RH AGI wells, with two of these wells being within the MMA. The deepest of these wells is 650 ft deep. The evaporite sequence of the Permian Ochoan Salado and Castile Formations provides an excellent seal between these groundwater wells, and the Bell and Cherry Canyon injection zones of the RH AGI #1 and RH AGI #3 according to the MRV plan. Due to the shallow depth of the groundwater wells within the MMA relative to the depth of the RH AGI wells and considering the NRAP analysis described in the introductory paragraph in Section 5, TND considers that, while the likelihood of CO_2 emissions to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

3.4 Confining/Seal System

The MRV plan states that the injection zone for the RH AGI wells is overlain by a thick sequence of Permian Ochoan evaporates, limestone, and siltstones with no evidence of faulting, as described in Sections 3.2.2 and 3.3.1 of the MRV plan. Therefore, RHGPP states that it is unlikely that TAG injected into the Bell Canyon and Cherry Canyon Formations will leak through the confining zone to the surface. The MRV plan states that the injection pressure will also be limited to less than the fracture pressure of the confining zone, further minimizing the likelihood of CO_2 leakage through the confining seal of this reservoir.

The MRV plan states that the worst-case scenario is defined as leakage through the seal happening right above the injection wells, where CO_2 saturation is highest. However, the worst-case scenario of leakage only shows that 0.0017% of total CO_2 injection in 30 years was leaked from the injection zone through the seals. The MRV plan states that the likelihood of such an event will diminish proportionally with the distance from the source. Additionally, if a leakage event does occur, the leak must pass upward through the confining zone, the secondary confining strata that consists of additional low permeability geologic units, and other geologic units. Therefore, RHGPP concludes that the risk of leakage through this pathway is highly unlikely.

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

3.5 Lateral Migration

As described in the MRV plan, the Cherry Canyon Formation is composed of channel turbidite sandstones deposited in submarine fan complexes. Due to the nature of their depositional environment, these sandstones are encased in low porosity and low permeability, fine-grained siliciclastics and mudstones with lateral continuity. The regional consideration of the depositional environment suggests a preferred orientation for fluid and gas flow to be south-to-north along the channel axis. However, the MRV plan states that the local high net porosity of the RH AGI #1 and RH AGI #3 injection zones indicates adequate storage capacity such that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA due to the preferred regional depositional orientation.

Based on the discussion of the channeled sands in the injection zone, RHGPP considers that the likelihood of CO_2 to migrate laterally along the channel axes is possible. However, RHGPP states that the turbidite sands are encased in low porosity and permeability, fine-grained siliciclastics and mudstones with lateral continuity. In addition, the MRV plan states that the injectate is projected to be contained within the injection zone close to the injection wells which minimizes the likelihood that CO_2 will migrate to a potential conduit to the surface.

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

3.6 Fractures and Faults

RHGPP states that prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed to understand the geology as well as identify and understand the distribution of faults and fractures. The MRV plan states that the identified faults are confined to the Paleozoic section below the injection zone for the RH AGI wells and that no faults were identified in the confining zone above the Bell Canyon and Cherry Canyon injection zone for the RH AGI wells.

The MRV plan states that no faults were identified within the MMA which could potentially serve as conduits for surface CO_2 emissions. The closest RHGPP identified fault lies approximately 1.5 miles east of the RHGPP site and has approximately 1,000 ft of down-to-the-west structural relief. The MRV plan states that since this fault is confined to the lower Paleozoic unit well below the injection zone for the RH AGI wells, there is minimal chance it would be a potential leakage pathway. Therefore, RHGPP believes that the CO_2 leakage rate through the fault is zero and that the risk of leakage through this potential leakage pathway is highly improbable.

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

3.7 Natural and Induced Seismicity

RHGPP states that they used the New Mexico Tech Seismological Observatory (NMTSO) to search for seismic activity near the RHGPP. The MRV plan states that a search through the NMTSO database showed that no recent seismic events occurred close to the RHGPP operations. The closest recent seismic events as of September 4, 2023 are:

- 7.5 miles, 2022-09-03, Magnitude 3.0
- 8.0 miles, 2022-09-02, Magnitude 2.23
- 8.6 miles, 2022-10-29, Magnitude 2.1

The MRV plan states that due to the distance between the RH AGI wells and the recent seismic events, the magnitude of these events, and the fact that RHGPP injects at pressures below fracture opening pressure, RHGPP considers the likelihood of CO_2 emissions to the surface caused by seismicity to be improbable.

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

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

Under the provisions of 40 CFR 98.448(a)(3) an MRV plan requires a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Sections 5, 6, and 7 of the MRV plan discuss the strategies RHGPP will employ for monitoring and quantifying surface leakage of CO_2 through the pathways identified in the previous section to meet the requirements of 40 CFR §98.448(a)(4). Section 7 of the MRV plan discusses the strategies that RHGPP will use for establishing expected baselines for CO_2 leakage. Monitoring will occur during the planned 30-year injection period, or otherwise the cessation of operations, plus a proposed 5-year post-injection period. A summary table of RHGPP's detection monitoring strategy for CO_2 leakage or loss can be found in Table 6-1 of the MRV plan and is recreated below.

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors
Existing RH AGI Wells	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors • In-well P/T sensors • Groundwater monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Additional Monitoring	• Groundwater monitoring • Soil flux monitoring

4.1 Detection of Leakage from Surface Equipment

The MRV plan states that RHGPP implements several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S and CO_2 sensors, and continual monitoring of operational parameters. As described in Section 6 of the MRV plan, RHGPP considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S contingency plan to establish baselines for monitoring CO_2 surface leakage.

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

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

4.2 Detection of Leakage from Approved, Not Yet Drilled Wells

RHGPP states in the MRV plan that special precautions will be taken in the drilling of any new wells that will penetrate the injection zones as described in Section 5.2.1 of the MRV plan for RH AGI #3 including more frequent monitoring during drilling operations. These precautions apply to RHGPP and other operators drilling new wells through the RH AGI wells injection zones within the MMA.

Thus, the MRV plan provides adequate characterization of RHGPP's approach to detect potential leakage from approved, not yet drilled wells as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage from Existing Wells

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

To monitor leakage and wellbore integrity, RHGPP deployed two pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) in the RH AGI #1. The MRV plan states that one gauge is designated to monitor the tubing ID (reservoir) pressure and temperature and the second gauge monitors the annular space between the tubing and the long string casing. The MRV plan states that temperature variation could be an indicator of leaks.

The MRV plan states that pressure and temperature gauges as well as DTS were deployed in the RH AGI #3. The MRV plan also states that the temporarily abandoned RH AGI #2 well will be monitored by the fixed in-field gas monitors, handheld H_2S monitors, and CO_2 soil flux monitoring.

The MRV plan states that if operational parameter monitoring and Mechanical Integrity Test (MIT) failures indicate a CO_2 leak has occurred, RHGPP will take actions to quantify the leak based on operating conditions at the time of the detection including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and the estimate of the size of the emission site.

For other existing wells within the MMA, the MRV plan states that well surveillance by other operators of existing wells would provide an indication of CO_2 leakage. Additionally, the MRV plan states that groundwater and soil CO_2 flux monitoring locations throughout the MMA will also produce an indication of CO_2 leakage to the surface.

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

4.4 Detection of Leakage through the Confining/Seal System

As discussed in Section 5 of the MRV plan, RHGPP states that it is very unlikely that CO_2 leakage to the surface will occur through the confining zone. According to the MRV plan, continuous operational monitoring of the RH AGI wells, described in Sections 6.3 and 7.5 of the MRV plan, will provide an indicator if CO_2 leaks out of the injection zone. Furthermore, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface.

The MRV plan states that, if changes in operating parameters or other monitoring listed in Table 6-1 of the MRV plan indicate leakage of CO_2 through the confining/seal system, RHGPP will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, including shutting in the well(s).

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

4.5 Detection of Leakage due to Lateral Migration

The MRV plan states that continuous monitoring of the RH AGI wells during and after the period of injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The CO_2 monitoring network and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone. Furthermore, the MRV plan states that groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface.

The MRV plan states that if monitoring of operational parameters of other monitoring methods listed in Table 6-1 indicates that the CO_2 plume extends beyond the area modeled, RHGPP will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 release to the surface. As this scenario would be considered a material change per 40 CFR 98.448(d)(1), RHGPP states that they would submit a revised MRV plan.

Thus, the MRV plan provides adequate characterization of RHGPP's approach to detect potential leakage due to lateral migration as required by 40 CFR 98.448(a)(3).

4.6 Detection of Leakage from Fractures and Faults

As discussed in the MRV plan, RHGPP claims that it is very unlikely that CO_2 leakage to the surface will occur through faults. However, the MRV plan states that if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, RHGPP will identify which of the pathways listed in the MRV plan are responsible for the leak, including the possibility of heretofore unidentified faults or fractures within the MMA. RHGPP will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the type of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, the MRV plan states that groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface.

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

4.7 Detection of Leakage due to Natural/Induced Seismicity

The MRV plan states that RHGPP will use the established NMTSO seismic network to monitor the influence of natural and/or induced seismicity. The network consists of seismic monitoring stations that detect and locate seismic events. The MRV plan states that continuous monitoring helps differentiate between natural and induced seismicity.

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

4.8 Determination of Baselines

Section 7 of the MRV plan identifies the strategies that RHGPP will use to establish the baselines for monitoring CO_2 surface leakage per §98.448(a)(4). RHGPP will use the existing automatic distributed control system to continuously monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO_2. RHGPP considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S contingency plan to establish baselines for monitoring CO_2 surface leakage.

Visual Inspection

RHGPP state their field personnel conduct frequent periodic inspections of all surface equipment providing opportunities to assess baseline concentrations of H_2S, a proxy for CO_2, at the RHGPP.

Fixed In-Field, Handheld, and Personal H_2S Monitors

The MRV plan that compositional analysis of the gas injectate at the RHGPP indicates an approximate H_2S concentration of 20%, thus requiring RHGPP to develop and maintain an H_2S Contingency Plan according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). This H_2S Contingency Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated RH AGI wells and documents procedures that would be followed in case of such an event.

The MRV plan states that RHGPP utilizes numerous fixed-point monitors, strategically located throughout the plant to detect the presence of H_2S in ambient air. In addition, handheld gas detection monitors are available at strategic locations around the plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The MRV plan states that all personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the plant must wear personal H_2S monitoring devices to assist them in detecting the presence of unsafe levels of H_2S.

CO_2 Detection

The MRV plan states that New Mexico Tech, through a Department of Energy (DOE) research grant, will assist RHGPP in setting up a monitoring network for CO_2 leakage detection in the AMA. The DOE project includes field sampling activities to monitor CO_2/H_2S at the two RH AGI wells. These monitoring activities include periodic well (groundwater and gas) and atmospheric sampling from an area of 10-15 square miles around the injection wells. RHGPP will assume responsibility for the monitoring, recording, and reporting of the data collected once the project network has been set up.

Continuous Parameter Monitoring

The MRV plan states that the DCS of the plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS, and engineering and operations are alerted if the parameter is outside the allowable window. The MRV plan states that if the parameter is outside the allowable window, this will trigger further investigation to determine if the issue poses a leak threat.

Well Surveillance

RHGPP states that they adhere to the requirements of NMOCC Rule 26 governing the construction, operation, and closing of an injection well under the Oil and Gas Act. Rule 26 also includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. The MRV plan states RHGPP's Routine Operations and Maintenance Producers for the RH AGI wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

Seismic (Microseismic) Monitoring Stations

RHGPP states in the MRV plan that they have installed a model TCH120-1 Trillium Compact Horizon Seismometer and a model CTR4-3S Centaur Digital Recorder to monitor for and record for any seismic events at the RHGPP. The MRV plan states that the seismic station meets the requirements of the NMOCC Order No. R-20916-H to "install, operate, and monitor for the life of the [Class II AGI] permit a seismic monitoring station or stations as directed by the manager of the New Mexico Tech Seismological Observatory ("state seismologist") at the New Mexico Bureau of Geology and Mineral Resources."

In addition, the MRV plan also states that data that are recorded by the State of New Mexico deployed seismic network within a 10-mile radius of the Red Hills Gas Plant will be analyzed by the New Mexico Bureau of Geology (NMBGMR) and made publicly available. The MRV plan states that the NMBGMR seismologist will create a report and map showing the magnitudes of recorded events from seismic activity. The data are being continuously recorded. By examining historical data, a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

Groundwater Monitoring

As part of the same DOE research grant described above, New Mexico Tech will monitor groundwater wells for CO_2 leakage within the AMA. The MRV plan states that water samples will be collected and analyzed monthly for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly. The MRV plan will be collected according to EPA methods for groundwater sampling.

Soil CO_2 Flux Monitoring

The MRV plan states that a vital part of the monitoring program is to identify potential leakage of CO_2 and/or brine from the injection horizon into the overlying formations and to the surface. RHGPP states that they will gather and analyze soil CO_2 flux data which serves as a means for assessing potential migration of CO_2 through the soil and its escape to the atmosphere.

The MRV plan states that soil CO_2 flux will be collected monthly for 12 months to establish the baseline and understand seasonal and other variation at the RHGPP. After the baseline is established, data will be collected bi-monthly for one year and then quarterly.

Thus, the RHGPP provides an acceptable approach for establishing expected baselines in accordance with 40 CFR 98.448(a)(4).

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

Section 8 of the MRV plan provides the equations that RHGPP will use to calculate sequestration masses.

5.1 Calculation of Mass of CO_2 Received

The MRV plan states that Equation RR-2 will be used to calculate the mass of CO_2 received from through pipelines and measured through volumetric flow meters. The MRV plan states that receiving flow meter r in the following equations corresponds to meters M1 and M2 in Figure 3.6-2 of the MRV plan.

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

The MRV plan states that the total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3.

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

RHGPP provides an acceptable approach for calculating the mass of CO_2 received under Subpart RR.

5.2 Calculation of Mass of CO_2 Injected

The MRV plan states that RHGPP injects CO_2 into the RH AGI #1 and RH AGI #3. The MRV plan states that the annual mass of CO_2 injected at the RHGPP at each injection well will be calculated with Equation RR-5. The MRV plan states that receiving flow meter r in the following equations corresponds to meters M1 and M2 in Figure 2.6-2 of the MRV plan.

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

The MRV plan states that the total annual mass of CO_2 injected into both wells will be calculated with Equation RR-6:

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

(Equation RR-6)

where:

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

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

u = Flow meter.

RHGPP provides an acceptable approach for calculating the mass of CO_2 injected.

5.3 Calculation of CO_2 Produced/Recycled

RHGPP states that they do not produce oil or gas or any other liquid at its Red Hills Gas Plant so there is no CO_2 produced or recycled.

RHGPP provides an acceptable approach for calculating CO_2 produced/recycled.

5.4 Calculation of CO_2 Lost by Surface Leakage

The MRV plan states that Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 of the MRV plan.

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

RHGPP provides an acceptable approach for calculating the mass of CO_2 lost by surface leakage under Subpart RR.

5.5 Calculation of CO_2 Emitted from Equipment Leaks and Vented Emissions

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

5.6 Calculation of CO_2 Sequestered in Subsurface Geologic Formations

The MRV plan states that Equation RR-12 in 40 CFR 98.443 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations.

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

where:

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

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

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

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

RHGPP provides an acceptable approach for calculating the mass of CO_2 sequestered in subsurface geologic formations.

6 Summary of Findings

The Subpart RR MRV plan for the Red Hills Gas Processing 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 RHGPP's MRV plan.

Subpart RR MRV Plan Requirement	RHGPP MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 4 of the MRV plan delineates and describes the MMA and AMA. The MMA is defined by the most conservative extent of the TAG plume at year 2054 plus a one-half mile buffer. RHGPP states that they intend to define the active monitoring area as the same area as the MMA.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude,	Section 5 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: surface

and timing, of surface leakage of CO_2 through these pathways.	equipment; approved, not yet drilled wells; existing wells; confining/seal system; lateral migration; faults and fractures, and natural/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 detecting and quantifying any surface leakage of CO_2.	Sections 5, 6, and 7 of the MRV plan describe the strategies that RHGPP will use to detect and quantify potential CO_2 leakage to the surface should it occur. The MRV plan states that leakage models including transport, geomechanical, or reactive transport model simulations will be used to quantify CO_2 leakage.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 7 of the MRV plan describes the strategies for establishing baselines against which monitoring results will be compared to assess potential surface leakage. RHGPP will use an existing automatic distributed control system to identify and investigate deviations from expected performance that could indicate CO_2 leakage. RHGPP's approach to collecting information for the determination of baselines includes visual inspection; H_2S monitors; CO_2 detection; continuous parameter monitoring; well surveillance; seismic (micro seismic) monitoring stations; groundwater monitoring, and soil CO_2 flux monitoring.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 8 of the MRV plan describes RHGPP's approach to determining the total amount of CO_2 sequestered using the Subpart RR mass balance equations, including calculation of total annual mass emitted by equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 12 of the MRV plan identifies the injection and monitoring wells used in the RHGPP. The RHGPP has Class II AGI permits under the NMOCD.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 8 of the MRV plan states that it is anticipated that the RHGPP will be implemented as soon as it is approved by EPA. The MRV plan states that baseline

	monitoring have been established and data collected by RHGPP and its predecessor.

Appendix A: Final MRV Plan

MONITORING, REPORTING, AND VERIFICATION PLAN

Red Hills AGI #1 and Red Hills AGI #3

Targa Northern Delaware, LLC (TND)

Version 1.0
July 23, 2024

Table of Contents

1 Introduction

Targa Northern Delaware, LLC (TND) is currently authorized to inject treated acid gas (TAG) into the Red Hills Acid Gas Injection #1 well (RH AGI #1)(American Petroleum Institute (API) 30-025-40448) and the RH AGI #3 well (API # 30-025-51970) under the New Mexico Oil Conservation Commission (NMOCC) Orders R-13507 – 13507F and Order R-20916H, respectively, at the Red Hills Gas Plant located approximately 20 miles NNW of Jal in Lea County, New Mexico (**Figure 1-1**). Each well is approved to inject 13 million standard cubic feet per day (MMSCFD). However, although approved to inject 13 MMSCFD, RH AGI #1 is physically only capable of taking ~5 MMSCFD due to formation and surface pressure limitations.

RH AGI #1 was previously operated by Lucid Energy Delaware, LLC's ("Lucid"). TND acquired Lucid assets in 2022. Lucid received authorization to construct a redundant well, RH AGI #2 (API# 30-025-49474) under NMOCC Order R-20916-H, which is offset 200 ft to the north of RH AGI #1 and is currently temporarily abandoned in the Bell Canyon Formation.

TND recently received approval from NMOCC for its C-108 application to drill, complete and operate a third acid gas injection well (RH AGI #3) for which TND requested an injection volume of up to 13 MMSCFD. RH AGI #3 was spudded on 9/13/2023, completed on 9/27/2023, and injection commenced on 1/11/2024. Because RH AGI #1 does not have complete redundancy, having a greater permitted disposal volume will also increase operational reliability. RH AGI #3 is a vertical well with its surface location at approximately 3,116 ft from the north line (FNL) and 1,159 ft from the east line (FEL) of Section 13. The depth of the injection zone for this well is approximately 5,700 to 7,600 ft in the Bell Canyon and Cherry Canyon Formations (see As-Built schematic in **Figure Appendix 1-2**). Analysis of the reservoir characteristics of these units confirms that they act as excellent closed-system reservoirs that will accommodate the future needs of TND for disposal of treated acid gas (H_2S and CO_2) from the Red Hills Gas Plant.

TND has chosen to submit this Monitoring, Reporting, and Verification (MRV) plan to EPA for approval according to 40CFR98.440(c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. TND intends to inject CO_2 for another 30 years.

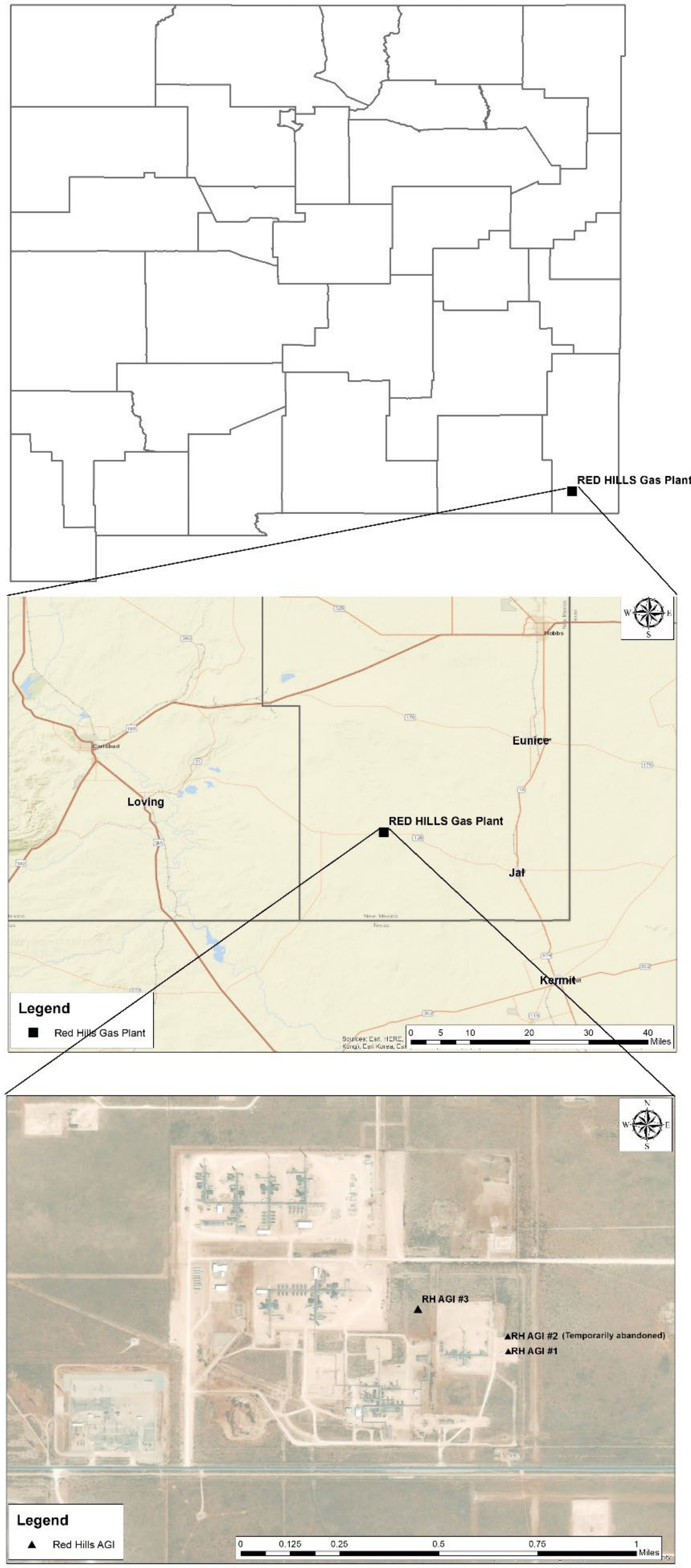


***Figure 1-1**: Location of the Red Hills Gas Plant and Wells – RH AGI #1, RH AGI #2 (temporarily abandoned), and RH AGI #3*

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40CFR98.449, and as required by 40CFR98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40CFR98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage as required by 40CFR98.448(a)(3).

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40CFR98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40CFR98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40CFR98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40CFR98.445.

Section 11 describes the records to be retained according to the requirements of 40CFR98.3(g) of Subpart A of the GHGRP and 40CFR98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan, including information required by 40CFR98.448(a)(6).

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is **553798**

2.2 UIC injection well identification numbers

This MRV plan is for RH AGI #1 and RH AGI #3 (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

For injection wells that are the subject of this MRV plan, the New Mexico Oil Conservation Division (NMOCD) has issued Underground Injection Control (UIC) Class II acid gas injection (AGI) permits under its State Rule 19.15.26 NMAC (see **Appendix 2**). All oil- and gas-related wells around the RH AGI wells, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3 Project Description

The following project description was developed by the Petroleum Recovery Research Center (PRRC) at New Mexico Institute of Mining and Technology (NMT) and the Department of Geosciences at the University of Texas Permian Basin (UTPB).

3.1 General Geologic Setting / Surficial Geology

The TND Red Hills Gas Plant is located in T 24 S R 33 E, Section 13, in Lea County, New Mexico, immediately adjacent to the RH AGI wells. (**Figure 3.1-1**). The plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. The dune sands are locally stabilized with shin oak, mesquite, and some burr-grass. There are no natural surface bodies of water within one mile of the plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

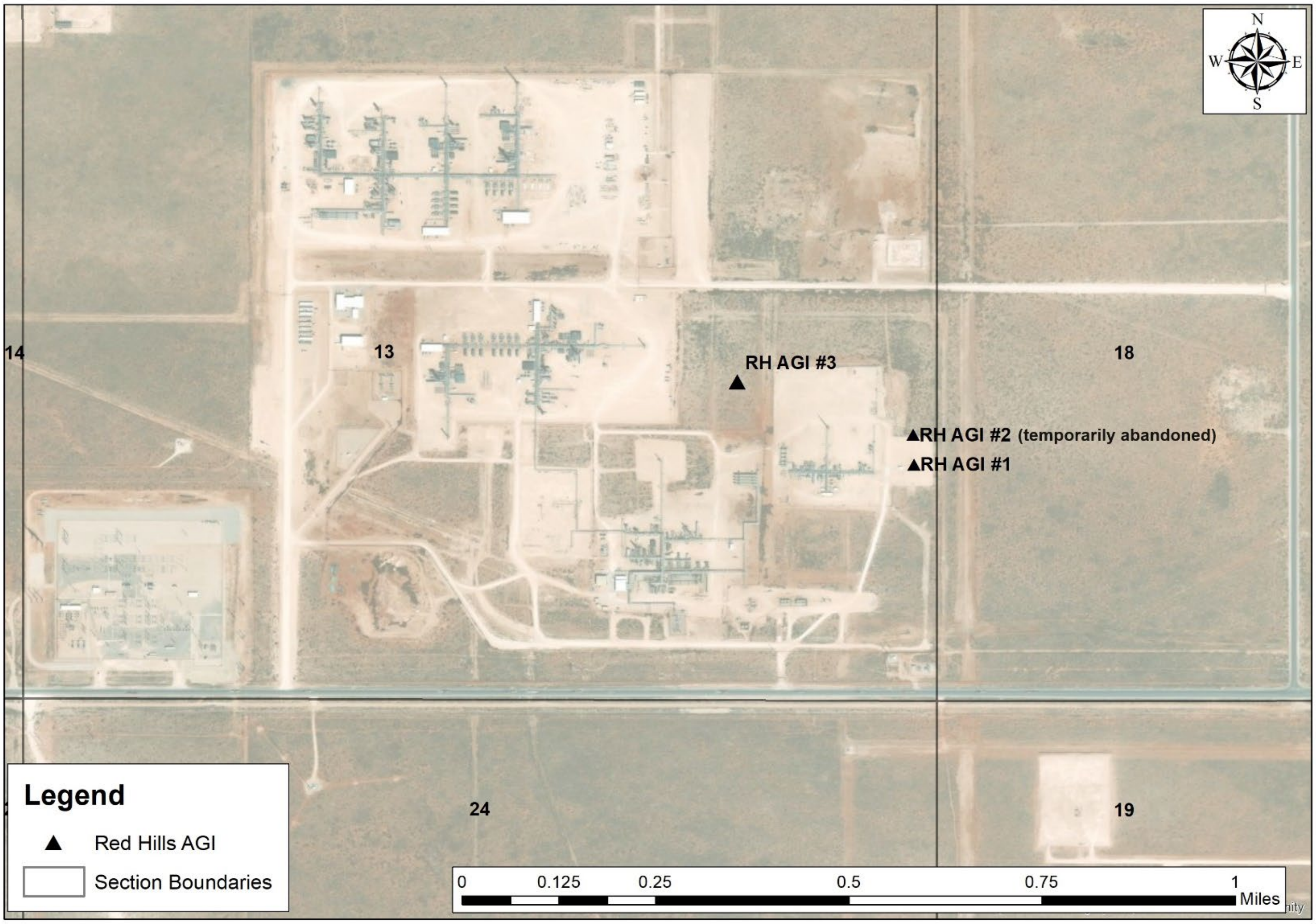


***Figure 3.1-1**: Map showing location of TND Red Hills Gas Plant and RH AGI Wells in Section 13, T 24 S, R 33 E*

3.2 Bedrock Geology

3.2.1 Basin Development

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

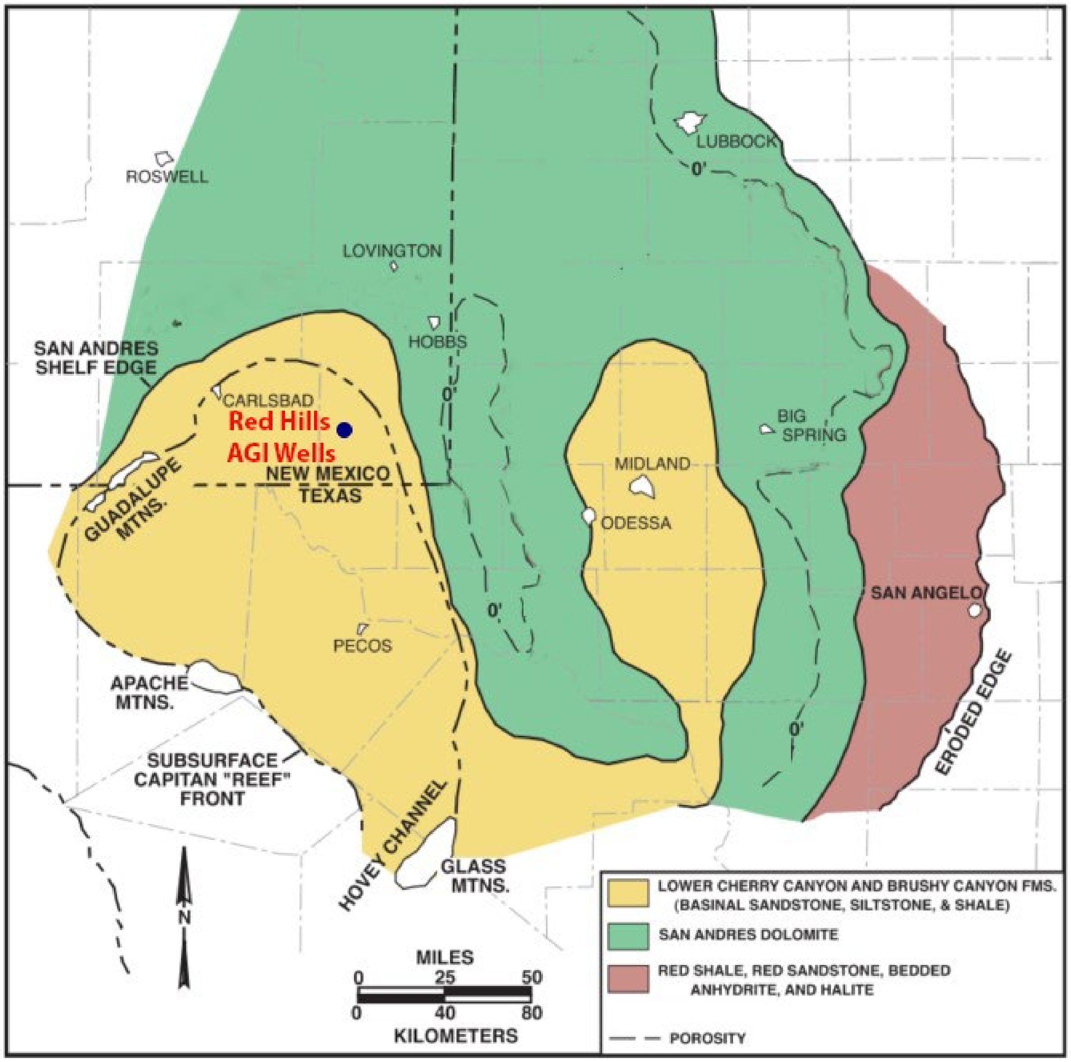


***Figure 3.2-1**: Structural features of the Permian Basin during the Late Permian. Location of the RH AGI wells is shown by the black circle. (Modified from Ward, et al (1986))*

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

The RH AGI wells are located in the Delaware Basin portion of the broader Permian Basin. Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland (**Figure 3.2-3**). With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Ellenburger Formation (0 – 1000 ft) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Throughout this narrative, the numbers after the formations indicate the range in thickness for that unit. Tectonic activity near the end of Ellenburger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit's overall porosity and permeability.

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

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

During Middle to Upper Ordovician time, seas once again covered the area and deposited the carbonates, sandstones and shales of the Simpson Group (0 – 1000 ft) and then the Montoya Formation (0 – 600 ft). This is the period when the Tobosa Basin formed due to the Pedernal uplift and development of the Texas Arch (**Figure 3.2-4**; Harrington, 2019), which shed Precambrian crystalline clasts into the basin. Simpson reservoirs in New Mexico are typically within deposits of shoreline sandstones (Broadhead, 2017). A subaerial exposure and karstification event followed the deposition of the Simpson Group. The Montoya Formation marked a return to dominantly carbonate sedimentation with minor siliciclastic sedimentation within the Tobosa Basin (Broadhead, 2017; Harrington and Loucks, 2019). The Montoya Formation consists of sandstones and dolomites and has also undergone karstification.

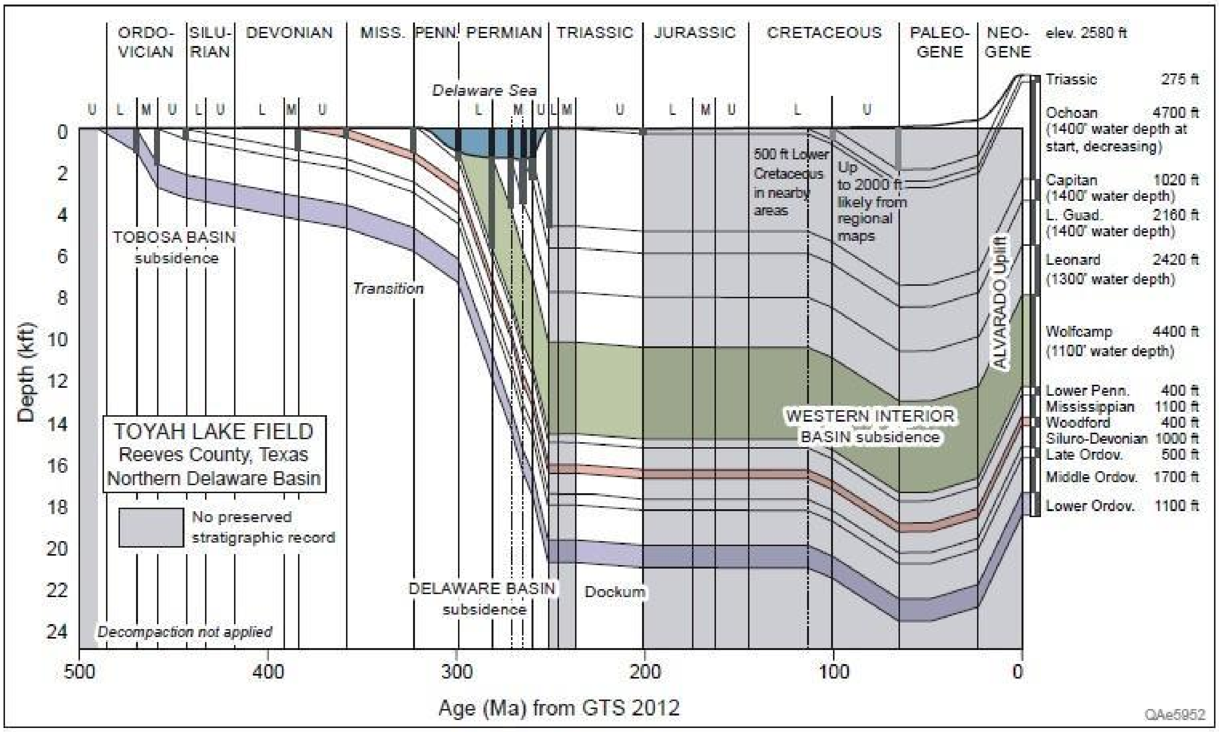


***Figure 3.2-3**: A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)*

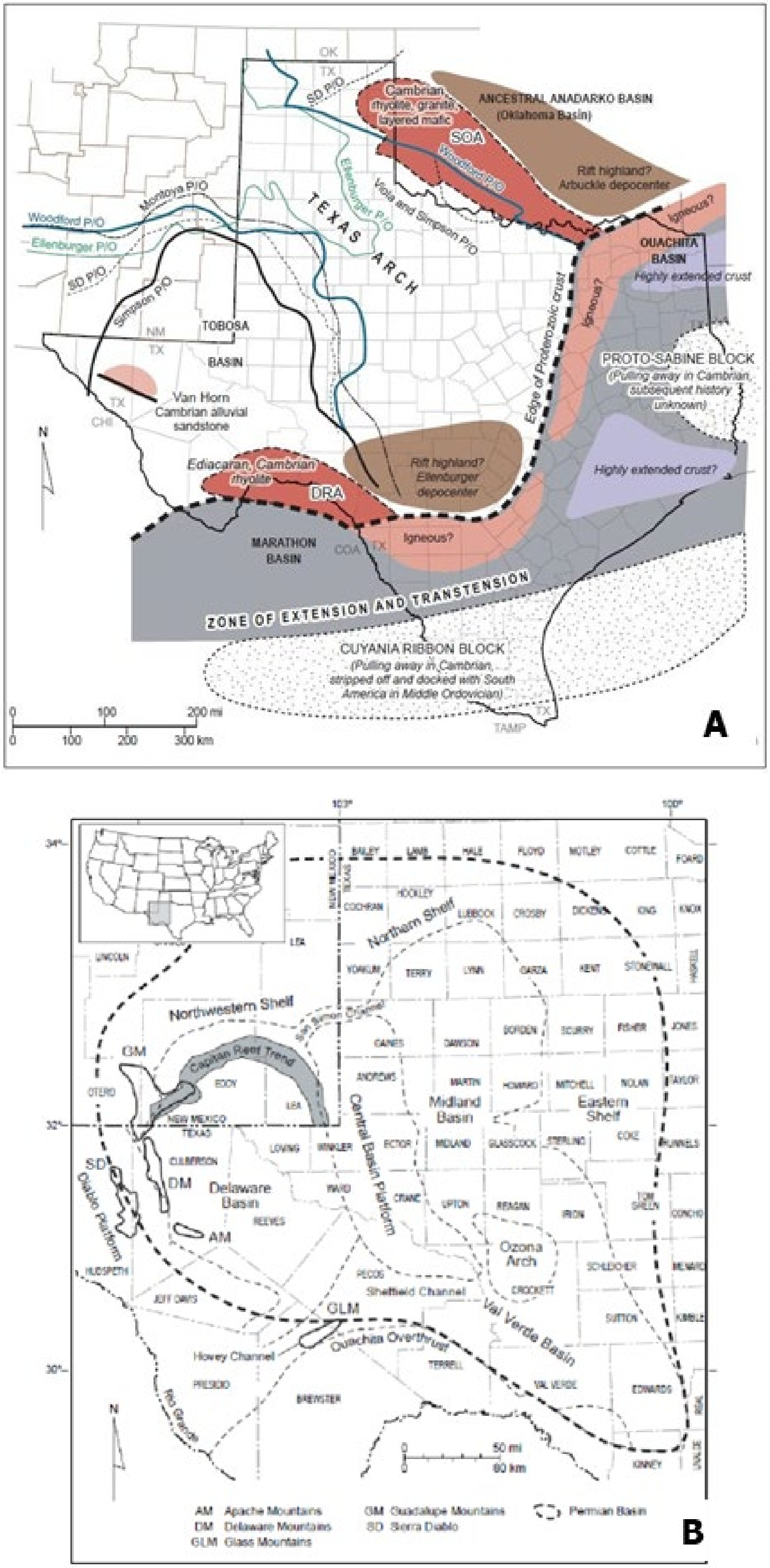


Figure 3.2-4: *Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).*

Siluro-Devonian formations consist of the Upper Ordovician to Lower Silurian Fusselman Formation (0 – 1,500 ft), the Upper Silurian to Lower Devonian Wristen Group (0 – 1,400 ft), and the Lower Devonian Thirtyone Formation (0 – 250 ft). The Fusselman Formation is primarily shallow-marine platform deposits of dolostones and limestones (Broadhead, 2017; Ruppel, 2019b). Subaerial exposure and karstification associated with another unconformity at top of the Fusselman Formation as well as intraformational exposure events created brecciated fabrics, widespread dolomitization, and solution-enlarged pores and fractures (Broadhead, 2017). The overlying Wristen and Thirtyone units appear to be conformable. The Wristen Group consists of tidal to high-energy platform margin carbonate deposits of dolostones, limestones, and cherts with minor siliciclastics (Broadhead, 2017; Ruppel, 2020). The Thirtyone Formation is present in the southeastern corner of New Mexico and appears to be either removed by erosion or not deposited elsewhere in New Mexico (**Figure 3.2-5**). It is shelfal carbonate with varying amounts of chert nodules and represents the last carbonate deposition in the area during Devonian time (Ruppel et al., 2020a).

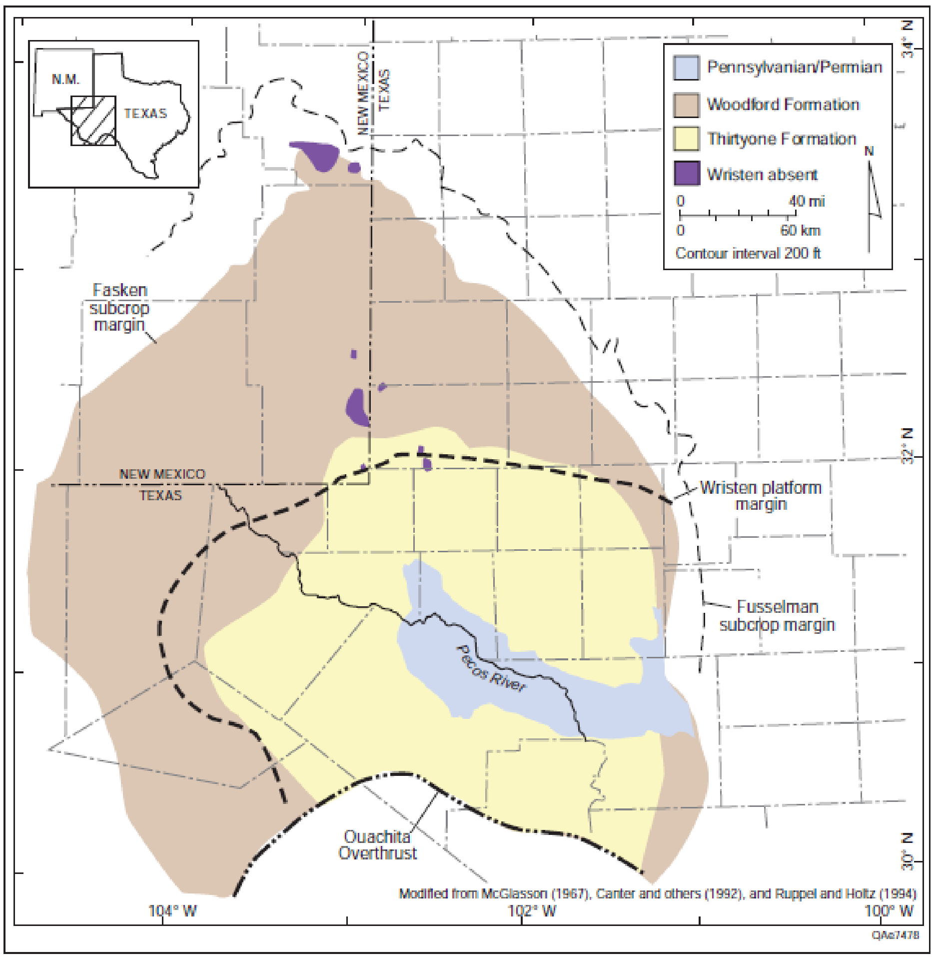


***Figure 3.2-5**: A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there are no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in Section 3.2.2.

The Devonian Woodford Shale, an un-named Mississippian limestone, and the Upper Mississippian Barnett Shale are seals for the underlying Siluro-Devonian strata. While the Mississippian recrystallized limestones have minor porosity and permeability, the Woodford and Barnett shales have extremely low porosity and permeability and would be effective barriers to upward migration of acid gas out of the injection zone. The Woodford Shale (0 – 300 ft) ranges from organic–rich argillaceous mudstones with abundant siliceous microfossils to organic-poor argillaceous mudstones (Ruppel et al., 2020b). The Woodford sediments represent stratified deeper marine basinal deposits with their organic content being a function of the oxygenation within the bottom waters – the more anoxic the waters the higher the organic content.

The Mississippian strata within the Delaware Basin consists of an un-named carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoirs limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise porosity is very low. The Barnett Shale (0 – 400 ft) unconformably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal siliciclastic deposits that make up the Barnett Shale.

Pennsylvanian sedimentation is dominated by glacio-eustatic sea-level cycles that produced shallowing upward cycles of sediments, ranging from deep marine siliciclastic and carbonate deposits to shallow-water limestones and siliciclastics, and capping terrestrial siliciclastic sediments and karsted limestones. Lower Pennsylvanian units consist of the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). The Atoka Formation (0-500 ft) was deposited during another sea-level transgression within the area. Within the area, the Atoka sediments are dominated by siliciclastic sediments, and depositional environments range from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

Middle Pennsylvanian units consist of the Strawn group (an informal name used by industry). Strawn sediments (250 - 1,000 ft) within the area consist of marine sediments that range from ramp carbonates, containing patch reefs, and marine sandstone bars to deeper marine shales (Broadhead, 2017).

Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales.

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

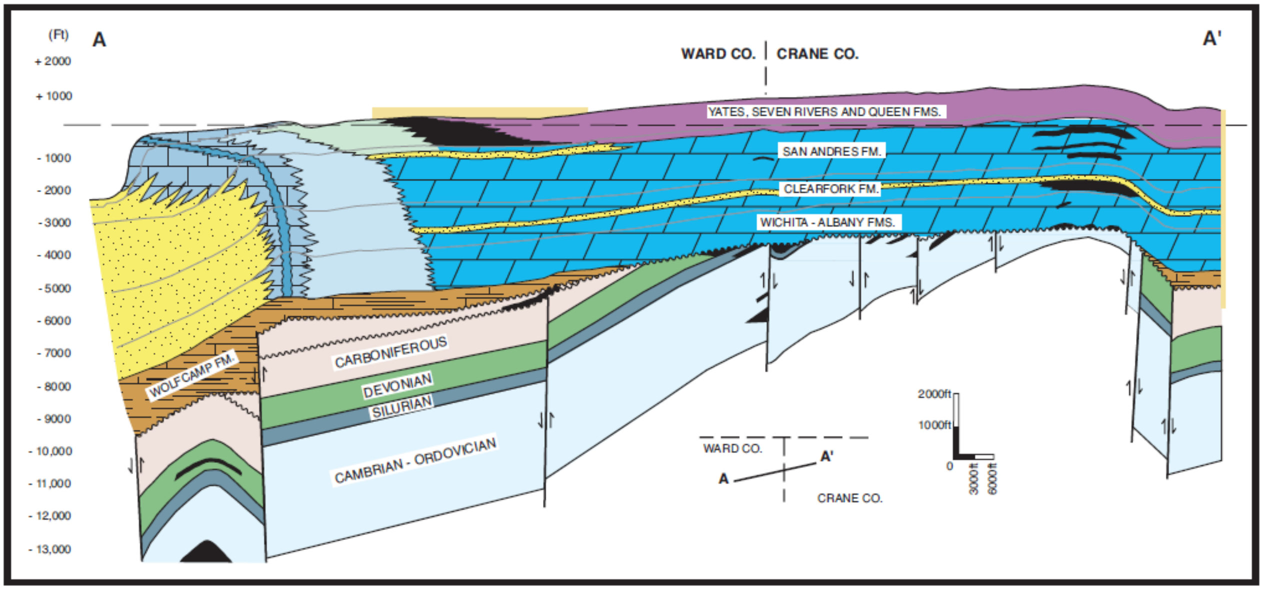


Figure 3.2-6: Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).

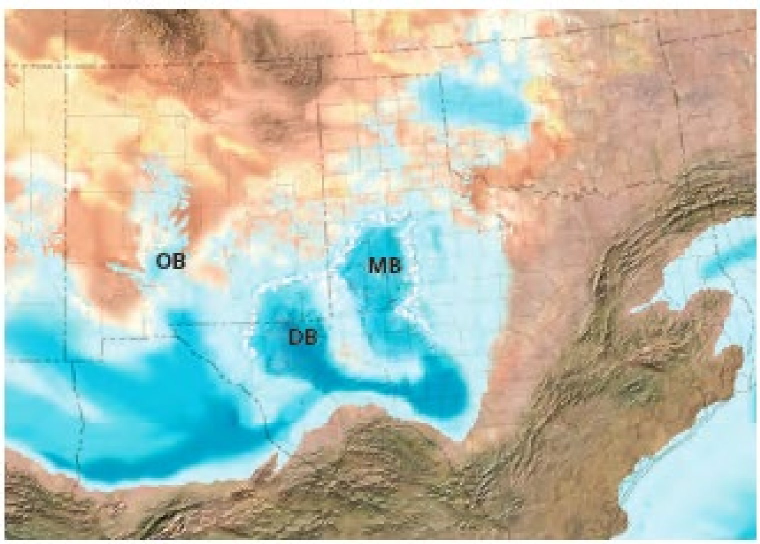


Figure 3.2-7: Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, siliciclastic sediments largely bypassed the shelves and were deposited deeper in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a "carbonate factory" on the shelf and shelf edge. Carbonate debris beds shedding off the shelf margin were transported into the basin (Wilson, 1972; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100s feet to feet).

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along Northwest Shelf margin to shallow-marine, back-reef carbonates behind the shelf margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2019a). Sediments basinward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2019a). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. The Bone Spring Formation is a thick sequence of alternating carbonate and siliciclastic horizons that formed because of changes in sea level; the carbonates during highstands, and siliciclastics during lowstands. Overlying the Yeso, are the clean, white eolian sandstones of the Glorietta Formation, a key marker bed in the region, both on outcrop and in the subsurface. Within the basin, it is equivalent to the lowermost Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have been identified that have resulted in karstification and pervasive dolomitization of the unit. These exposure events/sea-level lowstands are correlated to sandstones/siltstones that moved out over the exposed shelf leaving minor traces of their presence on the shelf but formed thick sections of sandstones and siltstones in the basin. Within the Delaware Basin, the San Andres Formation is equivalent to the Brushy and lower Cherry Canyon Formations.

The Artesia Group (Grayburg, Queen, Seven Rivers, Yates, and Tansill formations, ascending order) is equivalent to Capitan Limestone, the Guadalupian barrier/fringing reef facies. Within the basin, the Artesia Group is equivalent to the upper Cherry and Bell Canyon formations, a series of relatively featureless sandstones and siltstones. The Queen and Yates formations contain more sandstones than the Grayburg, Seven Rivers, and Tansill formations. The Artesia units and the shelf edge equivalent Capitan reef sediments represent the period when the carbonate factory was at its greatest productivity with the shelf margin/Capitan reef prograding nearly 6 miles into the basin (Scholle et al., 2007). The Artesia Group sediments were deposited in back-reef, shallow marine to supratidal/evaporite environments. Like the San Andres Formation, the individual formations were periodically exposed during lowstands.

The final stage of Permian deposition on the Northwest Shelf consists of the Ochoan/Lopingian Salado Formation (<2,800 ft, Nance, 2020). Within the basin, the Castile formation, a thick sequence (total thickness ~1,800 ft, Scholle et al., 2007) of cyclic laminae of deep-water gypsum/anhydrite interbedded with calcite and organics, formed due to the restriction of marine waters flowing into the basin. Gypsum/anhydrite laminae precipitated during evaporative conditions, and the calcite and organic-rich horizons were a result of seasonal “freshening” of the basin waters by both marine and freshwaters. Unlike the Castile Formation, the Salado Formation is a relatively shallow water evaporite deposit. Halite, sylvite, anhydrite, gypsum, and numerous potash minerals were precipitated. The Rustler Formation (500 ft , Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represent the last Permian marine deposits in the Delaware Basin.

The Rustler Formation was followed by terrestrial sabkha red beds of the Dewey Lake Formation (~350', Nance, 2020), ending Permian deposition in the area.

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

3.2.2 Stratigraphy

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent, renamed Lopingian), Guadalupian, Leonardian (renamed Cisuralian), and Wolfcampian (oldest) (**Figure 3.2-2**). This sequence of shallow marine carbonates and thick, basinal siliciclastic deposits contains abundant oil and gas resources and are the main source of oil within New Mexico. In the area around the RH AGI wells, Permian strata are mainly basin deposits consisting of sandstones, siltstones, shales, and lesser amounts of carbonates. Besides production in the Delaware Mountain Group, there is also production, mainly gas, in the basin Bone Spring Formation, a sequence of carbonates and siliciclastics. The injection and confining zones for RH AGI #1 and RH AGI #3 are discussed below.

CONFINING/SEAL ROCKS

Permian Ochoa Series. The youngest of the Permian sediments, the Ochoan- or Lopingian-aged deposits, consists of evaporites, carbonates, and red beds. The Castile Formation is made of cyclic laminae of deep-water gypsum/anhydrite beds interlaminated with calcite and organics. This basin-occurring unit can be up to 1,800 ft thick. The Castile evaporites were followed by the Salado Formation (~1,500 ft thick). The Salado Formation is a shallow water evaporite deposit, when compared to the Castile Formation, and consists of halite, sylvite, anhydrite, gypsum, and numerous potash/bittern minerals. Salado deposits fill the basin and lap onto the older Permian shelf deposits. The Rustler Formation (up to 500 ft, Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin. The Ochoan evaporitic units are superb seals (usually <1% porosity and <0.01 mD permeability) and are the reason that the Permian Basin is such a hydrocarbon-rich region despite its less than promising total organic carbon (TOC) content.

INJECTION ZONE

Permian Guadalupe Series. Sediments in the underlying Delaware Mountain Group (descending, Bell Canyon, Cherry Canyon, and Brushy Canyon formations) are marine units that represent deposition controlled by eustacy and tectonics. Lowstand deposits are associated with submarine canyons that incised the carbonate platform margin surrounding the Delaware basin. Depositional environments consist of turbidite channels, splays, and levee/overbank deposits (**Figure 3.2-8**).

Additionally, debris flows formed by the failure of the carbonate margin and density currents also make up basin sediments. Isolated coarse-grained to boulder-sized carbonate debris flows and grain falls within the lowstand clastic sediments likely resulted from erosion and failure of the shelf margin during sea-level lowstands or slope failure to tectonic activity (earthquakes). Density current deposits resulted from stratified basin waters. The basal waters were likely stratified and so dense that turbidity flows containing sands, silts and clays were unable to displace those bottom waters and instead flowed out over the density interface (**Figure 3.2-9**). Eventually, the entrained sediments would settle out in a constant rain of sediment forming laminated deposits with little evidence of traction (bottom flowing) deposition.

Interbedded with the very thick lowstand sequences are thin, deep-water limestones and mudstones that represent highstand deposition. These deposits are thickest around the edge (toe-of-slope) of the basin and thin to the basin center (**Figure 3.2-10**). The limestones are dark, finely crystalline, radiolarian-rich micrites to biomicrites. These highstand deposits are a combination of suspension and pelagic sediments that also thin towards the basin center. These relatively thin units are time equivalent to the massive highstand carbonate deposits on the shelf.

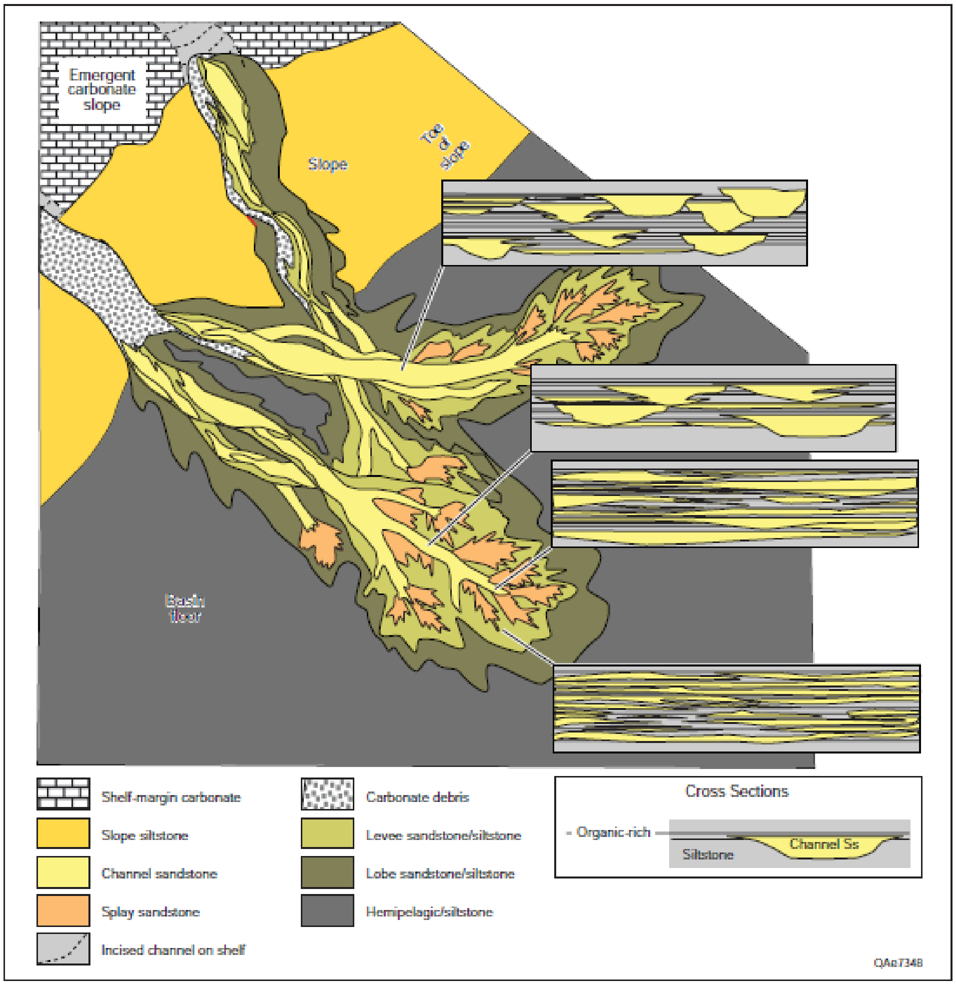


***Figure 3.2-8**: A diagram of typical Delaware Mountain Group basinal siliciclastic deposition patterns (from Nance, 2020). The channel and splay sandstones have the best porosity, but some of the siltstones also have potential as injection zones.*

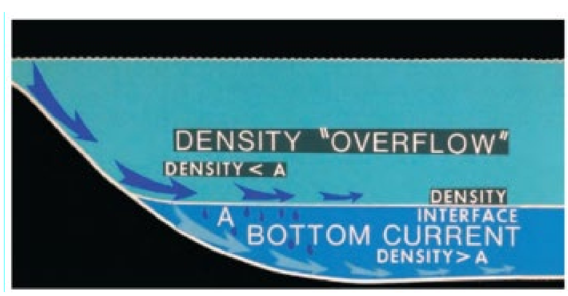


***Figure 3.2-9**: Harms' (1974) density overflow model explains the deposition of laminated siliciclastic sediments in the Delaware Basin. Low density sand-bearing fluids flow over the top of dense, saline brines at the bottom of the basin. The sands gradually drop out as the flow loses velocity creating uniform, finely laminated deposits (from Scholle et al., 2007).*

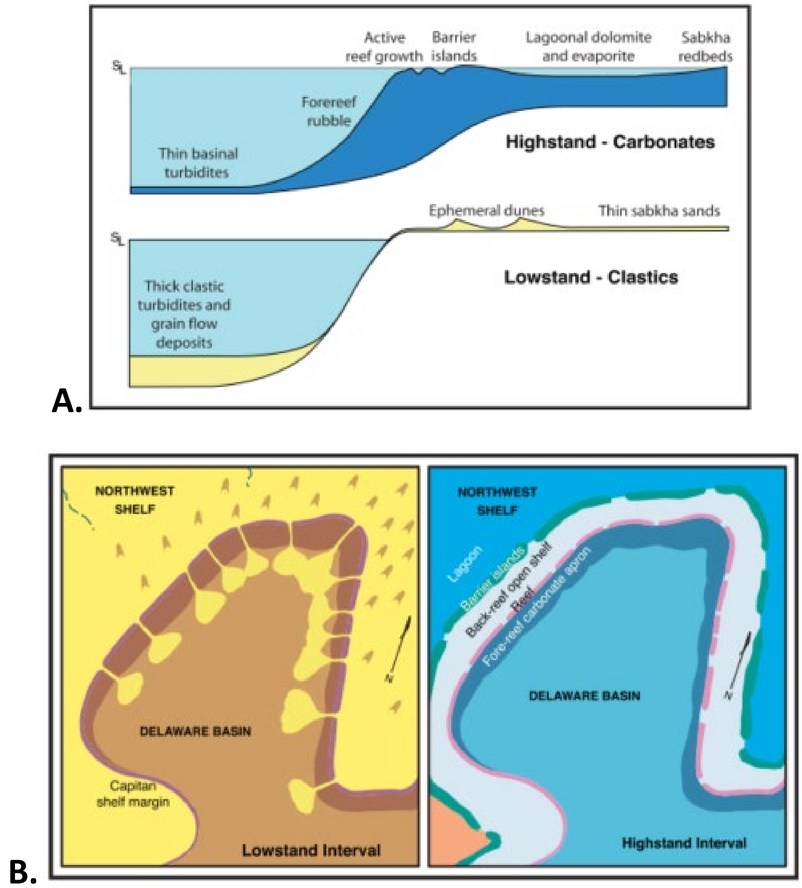


***Figure 3.2-10**: The impact of sea-level fluctuations (also known as reciprocal sedimentation) on the depositional systems within the Delaware Basin. A) A diagrammatic representation of sea-level variations impact on deposition. B) Model showing basin-wide depositional patterns during lowstand and highstand periods (from Scholle et al., 2007).*

The top of the Guadalupian Series is the Lamar Limestone, which is the source of hydrocarbons found in underlying Delaware Sand (an upper member of the Bell Canyon Formation). The Bell Canyon Formation is roughly 1,000 ft thick in the Red Hills area and contains numerous turbidite input points around the basin margin (**Figures 3.2-10, 3.2-11**). During Bell Canyon deposition, the relative importance of discrete sand sources varied (Giesen and Scholle, 1990), creating a network of channel and levee deposits that also varied in their size and position within the basin. Based on well log analyses, the Bell Canyon 2 and 3 had the thickest sand deposits.

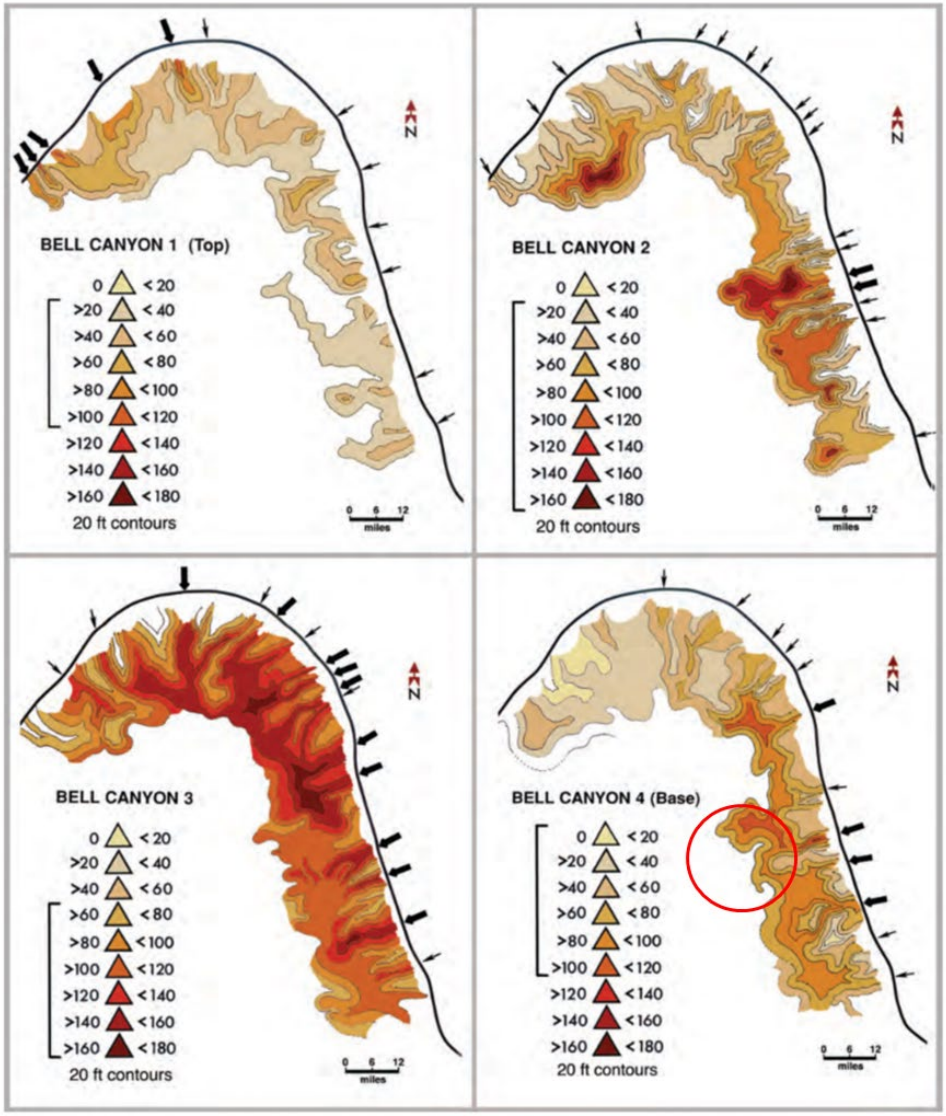


Figure 3.2-11*: These maps of Bell Canyon Formation were created by measuring sandstone thicknesses on well logs in four regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). The red circle on the last map surrounds the Red Hills area.*

Like the Bell Canyon and Brushy Canyon formations, the Cherry Canyon Formation is approximately 1,300 ft thick and contains numerous turbidite source points. Unlike the Bell Canyon and Brushy Canyon deposits, the channel deposits are not as large (Giesen and Scholle, 1990), and the source of the sands appears to be dominantly from the eastern margin (**Figure 3.2-12**). Cherry Canyon 1 and 5 have the best channel development and the thickest sands. Overall, the Cherry Canyon Formation, on outcrop, is less influenced by traction current deposition than the rest of the Delaware Mountain Group deposits and is more influenced by sedimentation by density overflow currents (**Figure 3.2-9**). The Brushy Canyon has notably more discrete channel deposits and coarser sands than the Cherry Canyon and Bell Canyon. The Brushy Canyon Formation is approximately 1,500 ft thick.

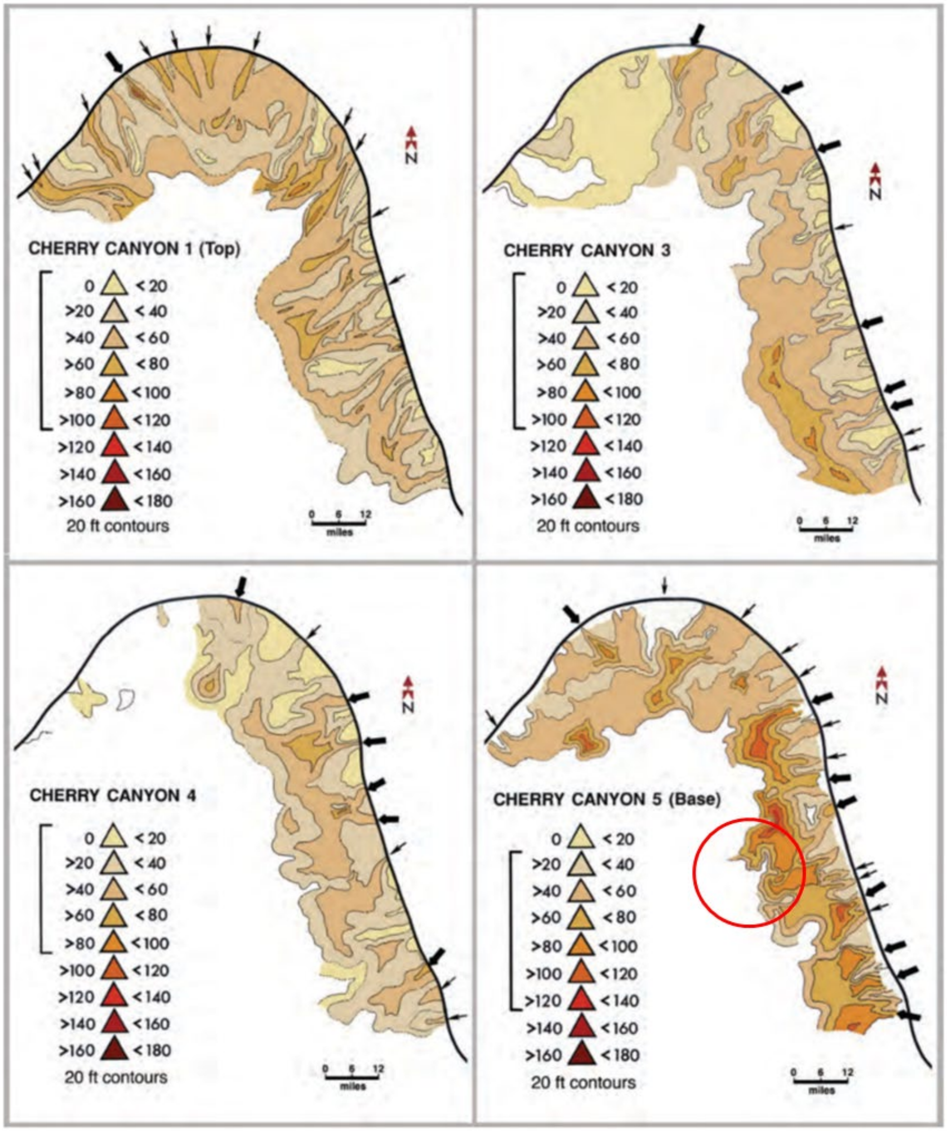


Figure 3.2-12: These maps of Cherry Canyon Formation were created by measuring sandstone thicknesses on well logs in five regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). Unlike the Bell Canyon sandstones, the Cherry Canyon sands are thinner and contain fewer channels. The red circle on the last map surrounds the Red Hills area.

Within the Delaware Mountain Group in the Red Hills area, the Bell Canyon and Cherry Canyon have better porosity (averaging 15 – 25 % within channel/splay sandstones) and permeability (averaging 2-13 mD) than the Brushy Canyon (~14% porosity, an <3 mD; Ge et al, 2022, Smye et al., 2021).

UNDERLYING CONFINING ZONE

Permian Leonard Series. The Leonardian/Cisuralian Series, located beneath the Guadalupian Series sediments, is represented by >3,000 ft of basin-deposited carbonate and siliciclastic sediments of the Bone Spring Formation. The Bone Spring Formation is more carbonate rich than the Delaware Mountain Group deposits, but the sea-level-driven cycles of sedimentation and the associated depositional environments are similar with debris flows, turbidites, and pelagic carbonate sediments. The Bone Spring Formation contains both conventional and unconventional fields within the Delaware Basin in both sandstone-rich and carbonate-rich facies. Most of these plays occur within toe-of-slope carbonate and siliciclastic deposits or the turbidite facies in the deeper sections of the basin (Nance and Hamlin, 2020). The upper most Bone Spring is usually dense carbonate mudstone with limited porosity and low porosity.

3.2.3 Faulting

In this immediate area of the Permian Basin, faulting is primarily confined to the lower Paleozoic section, where seismic data shows major faulting and ancillary fracturing-affected rocks only as high up as the base of the lower Wolfcamp strata (**Figures 3.2-6 and 5.6-1**). Faults that have been identified in the area are normal faults associated with Ouachita related movement along the western margin of the Central Platform to the east of the RH AGI facilities. The closest identified fault lies approximately 1.5 miles east of the Red Hills facilities and has approximately 1,000 ft of down-to-the-west structural relief. Because these faults are confined to the lower Paleozoic unit well below the injection zone for the RH AGI wells, they will not be discussed further (Horne et al., 2021). Within the area of the Red Hills site, no shallow faults within the Delaware Mountain Group have been identified by seismic data interpretation nor as reported by Horne et al., 2022).

3.3 Lithologic and Reservoir Characteristics

Based on the geologic analyses of the subsurface at the Red Hills Gas Plant, the uppermost portion of the Cherry Canyon Formation was chosen for acid gas injection and CO_2 sequestration for RH AGI #1 and the uppermost Delaware Mountain Group (the Bell Canyon and Cherry Canyon Formations) for RH AGI #3.

In the Red Hills area, the thickest sand within the Delaware Mountain Group is a sandstone within the Bell Canyon Formation that is informally and locally referred to as the Delaware Sand. The Delaware sand is productive, but it is not locally.

For RH AGI #1, this injection interval includes five high porosity sandstone units (sometimes referred to as the Manzanita) and has excellent caps above, below and between the individual sandstone units. There is no local production in the overlying Delaware Sands pool and there are no structural features or faults that would serve as potential vertical conduits. The high net porosity of the RH AGI #1 injection zone indicates that the injected H_2S and CO_2 will be easily contained close to the injection well.

For RH AGI #3, the injection interval has been expanded to include high porosity sandstones present within the Bell Canyon Formation in RH AGI #3 as well as the five high porosity zones in the Cherry Canyon Formation. Most of the sand bodies in the Bell Canyon and Cherry Canyon formations are surrounded by shales or limestones, forming caps for the injection zones. There are no structural features or faults that would serve as potential vertical conduits, and the overlying Ochoan evaporites form an excellent overall seal for the system. Even if undetected faulting existed, the evaporites (Castile and Salado) would self-seal and prevent vertical migration out of the Delaware Mountain Group.

3D seismic data, as well as geophysical logs for all wells penetrating the Bell Canyon and Cherry Canyon formations within a three-mile radius of the RH AGI wells were reviewed. There are no faults visible within the Delaware Mountain Group in the Red Hills area. Within the seismic review area, the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales (**Figure 3.2-8**) as well as being encased by them. Based on regional studies (Giesen and Scholle, 1990 and **Figures 3.2-11, 3.2-12**), the preferred orientation of the channels, and hence the preferred fluid migration pathways, are roughly from the east to the west.

Porosity was evaluated using geophysical logs from nearby wells penetrating the Cherry Canyon Formation. **Figure 3.3-1** shows the Resistivity (Res) and Thermal Neutron Porosity (TNPH) logs from 5,050 ft to 6,650 ft and includes the injection interval. Five clean sands (>10% porosity and <60 API gamma units) are targets for injection within the Cherry Canyon formation and potentially another 5 sands with >10% porosity and <60 API gamma units were identified. Ten percent was the minimum cut-off considered for adequate porosity for injection. The sand units are separated by lime mudstone and shale beds with lateral continuity. The high porosity sand units exhibit an average porosity of about 18.9%; taken over the average thickness of the clean sand units within ½ mile of the RH AGI #1. There is an average of 177 ft with an irreducible water (S_{wir}) of 0.54 (see Table 1 of the RH AGI #1 permit application). Many of the sands are very porous (average porosity of > 22%) and it is anticipated that for these more porous sands, the S_{wir} may be too high. The effective porosity (Total Porosity – Clay Bound Water) would therefore also be higher. As a result, the estimated porosity ft (PhiH) of approximately 15.4 porosity-ft should be considered to be a minimum. The overlying Bell Canyon Formation has 900 ft of sands and intervening tight limestones, shales, and calcitic siltstones with porosities as low as 4%, but as mentioned above, there are at least 5 zones with a total thickness of approximately 460 ft and containing 18 to 20% porosity. The injection interval is located more than 2,650 ft above the Bone Spring Formation, which is the next production zone in the area.

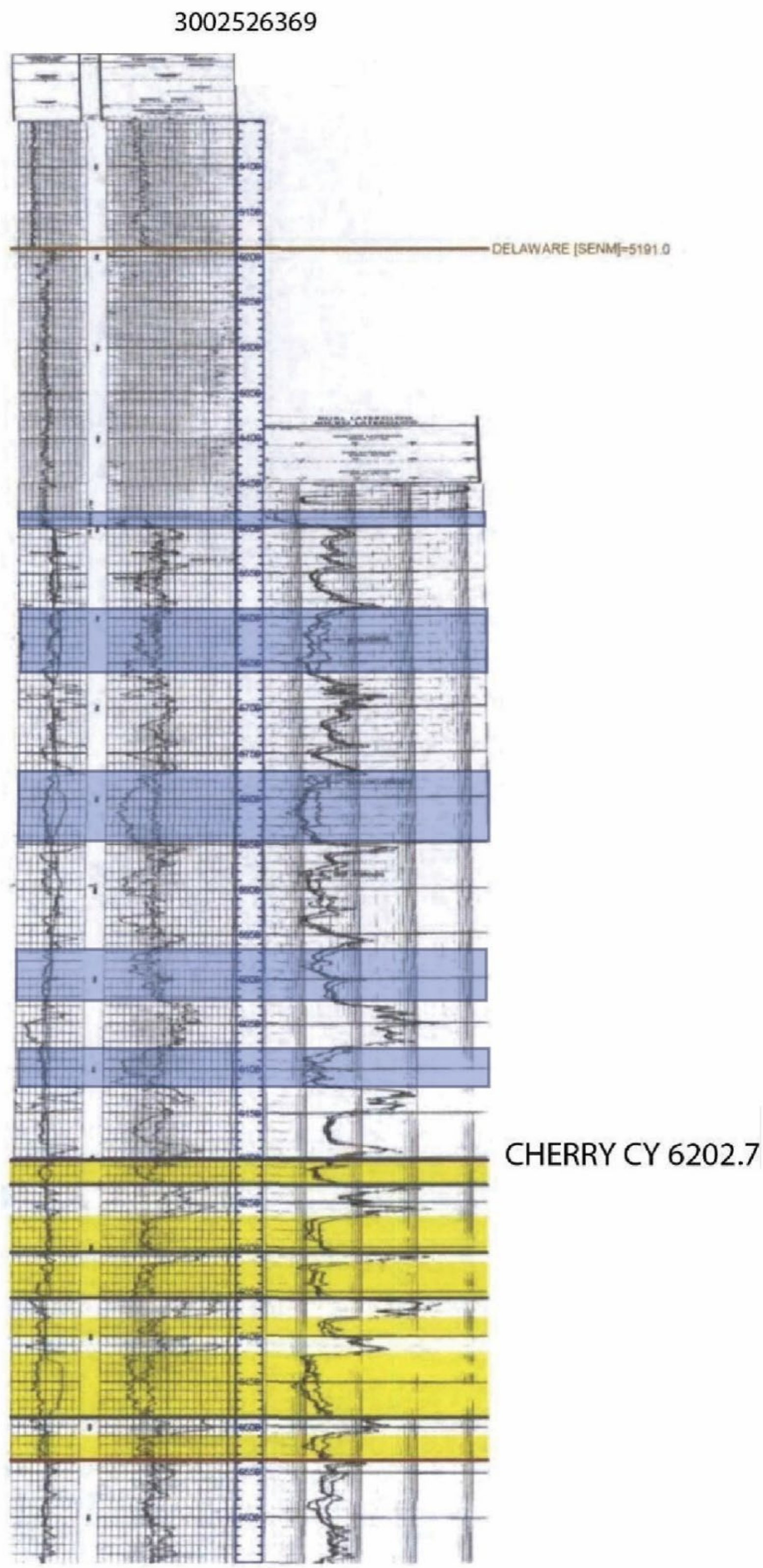


***Figure 3.3-1**: Geophysical logs from the Bell Canyon and the Upper Cherry Canyon from the Government L Com #002 well, located 0.38 miles from the RH AGI #1 Well. The blue intervals are Bell Canyon porosity zones, and the yellow intervals are Cherry Canyon porosity zones.*

3.4 Formation Fluid Chemistry

A chemical analysis (**Table 3.4-1**) of water from Federal 30 Well No. 2 (API 30-025-29069), approximately 3.9 miles away, indicates that the formation waters are highly saline (180,000 ppm NaCl) and compatible with the injection.

***Table 3.4-1**: Formation fluid analysis for Cherry Canyon Formation from Federal 30 Well No. 2*

Sp. Gravity	1.125 @ 74°F	Resistivity	0.07 @ 74°F
pH	7	Sulfate	1,240
Iron	Good/Good	Bicarbonate	2,135
Hardness	45,000	Chloride	110,000
Calcium	12,000	NaCl	180,950
Magnesium	3,654	Sod. & Pot.	52,072

Table extracted from C-108 Application to Inject by Ray Westall Associates with SWD-1067 – API 30-025-24676. Water analysis for formation water from Federal 30 #2 Well (API 30-025-29069), depth 7,335-7,345 ft, located 3.9 miles from RH AGI #1 well.

3.5 Groundwater Hydrology in the Vicinity of the Red Hills Gas Plant

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are 15 freshwater wells located within a two-mile radius of the RH AGI wells, and only 2 water wells within one mile; the closest water well is located 0.31 miles away and has a total depth of 650 ft (**Figure 3.5-1; Appendix 3**). All water wells within the two-mile radius are shallow, collecting water from about 60 to 650 ft depth, in Alluvium and the Triassic redbeds. The shallow freshwater aquifer is protected by the surface and intermediate casings and cements in the RH AGI wells (**Figures Appendix 1-1 and Appendix 1.2**). While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

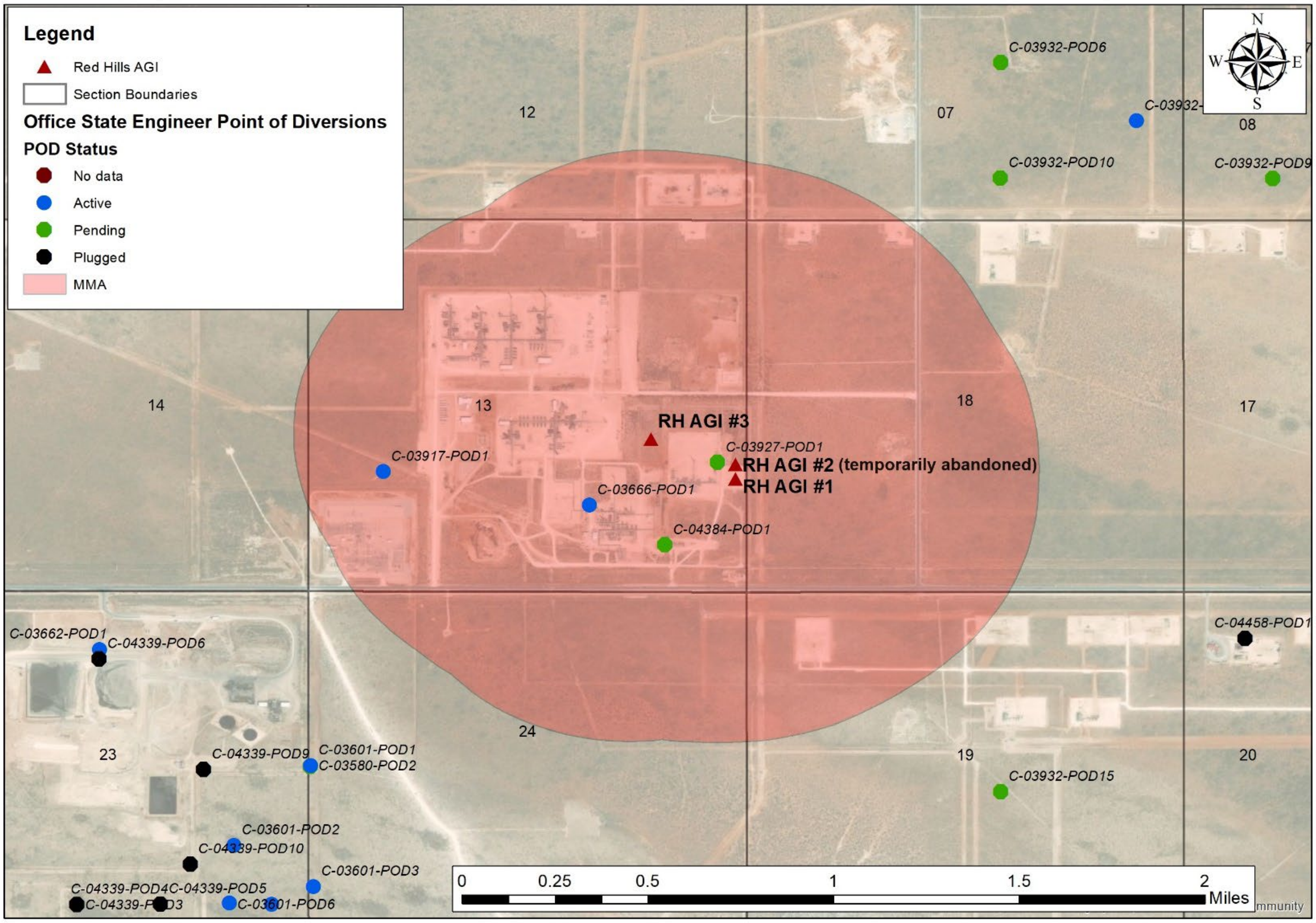


Figure 3.5-1: Reported Water Wells within the MMA for the RH AGI Wells.

3.6 Historical Operations

3.6.1 Red Hills Site

On July 20, 2010, Agave Energy Company (Agave) filed an application with NMOCD to inject treated acid gas into an acid gas injection well. Agave built the Red Hills Gas Processing Plant and drilled RH AGI #1 in 2012-13. However, the well was never completed and never put into service because the plant was processing only sweet gas (no H_2S). Lucid purchased the plant from Agave in 2016 and completed the RH AGI #1 well. TND acquired Lucid's Red Hills assets in 2022. **Figure 3.6-1** shows the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells. **Figure 3.6-2** shows a process block flow diagram.

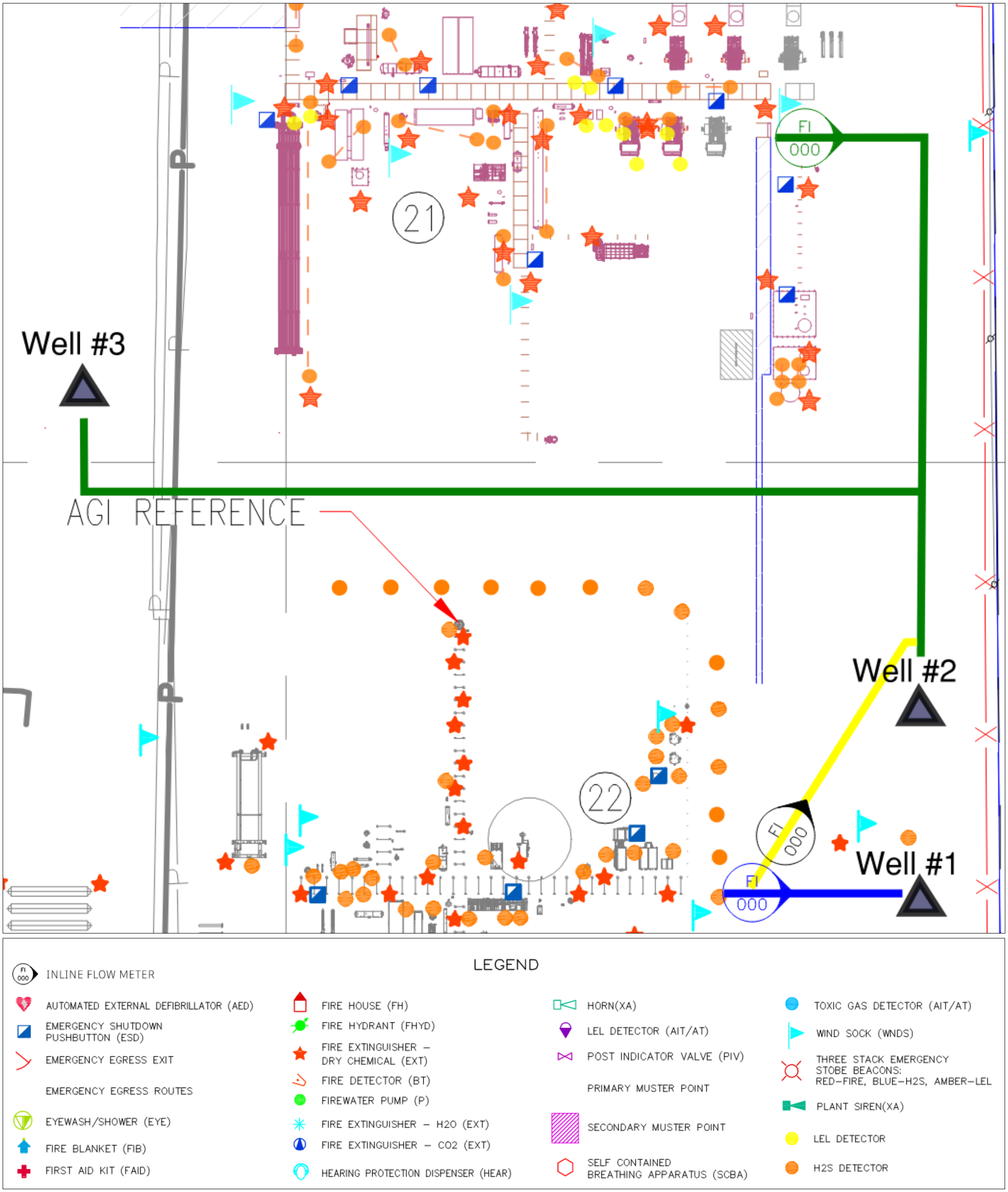


***Figure 3.6-1**: Diagram showing the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells. RH AGI #2 is temporarily abandoned.*

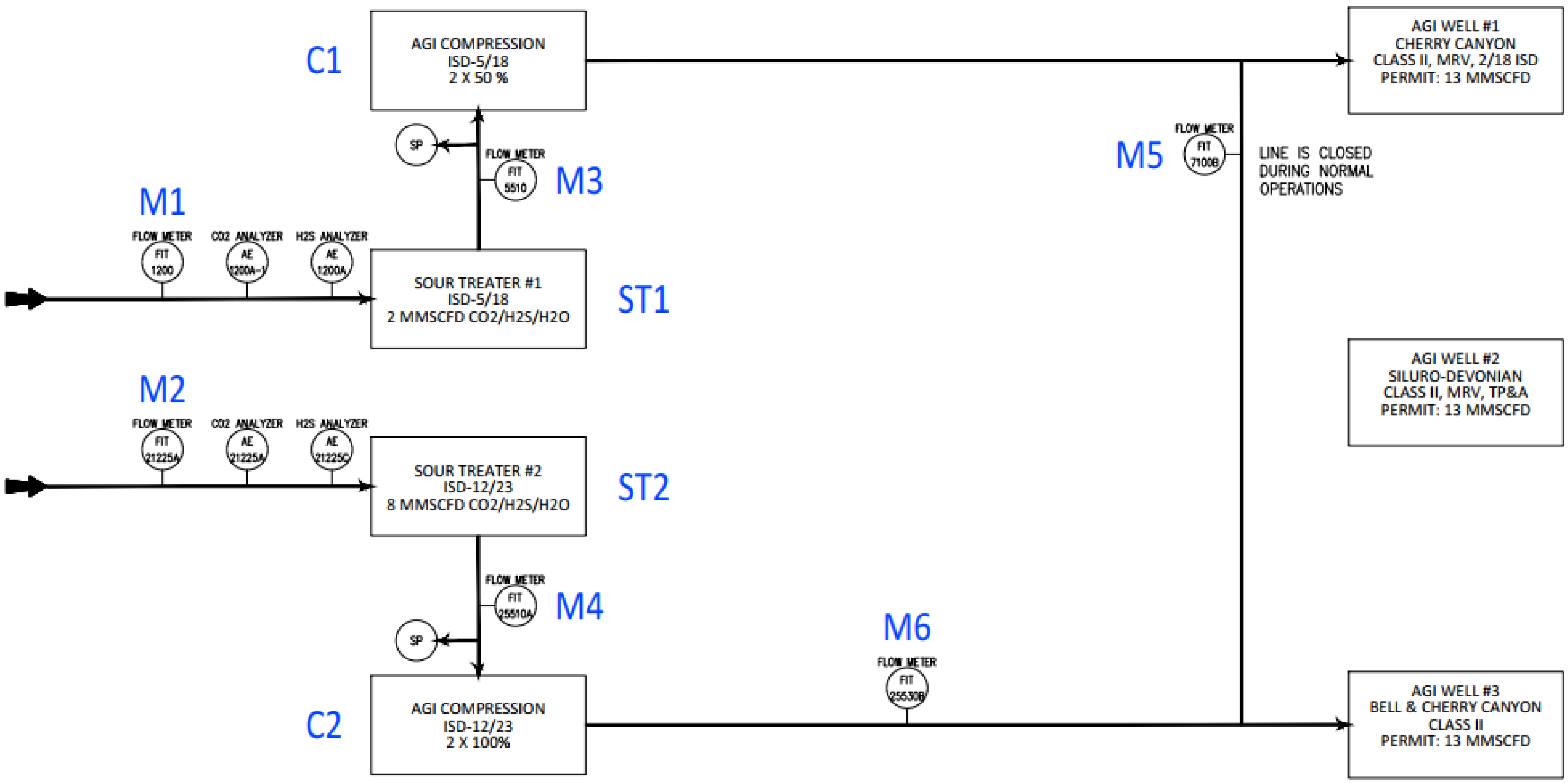


Figure 3.6-2: *Process Block Flow Diagram. RH AGI #2 is temporarily abandoned. M1 – M6: volumetric flow meters; C1 and C2: compressors; ST1 and ST2: sour treaters; and Sample Points (SP) for biweekly collection of data for determining the TAG stream concentration.*

3.6.2 Operations within the MMA for the RH AGI Wells

NMOCD records identify a total of 22 oil- and gas-related wells within the MMA for the RH AGI wells (see **Appendix 4**). **Figure 3.6-3** shows the geometry of producing and injection wells within the MMA for the RH AGI wells. **Appendix 4** summarizes the relevant information for those wells. All active production in this area is targeted for the Bone Spring and Wolfcamp zones, at depths of 8,900 to 11,800 ft, the Strawn (11,800 to 12,100 ft) and the Morrow (12,700 to 13,500 ft). All of these productive zones lie at more than 2,000 ft below the RH AGI #1 and AGI #3 injection zone.

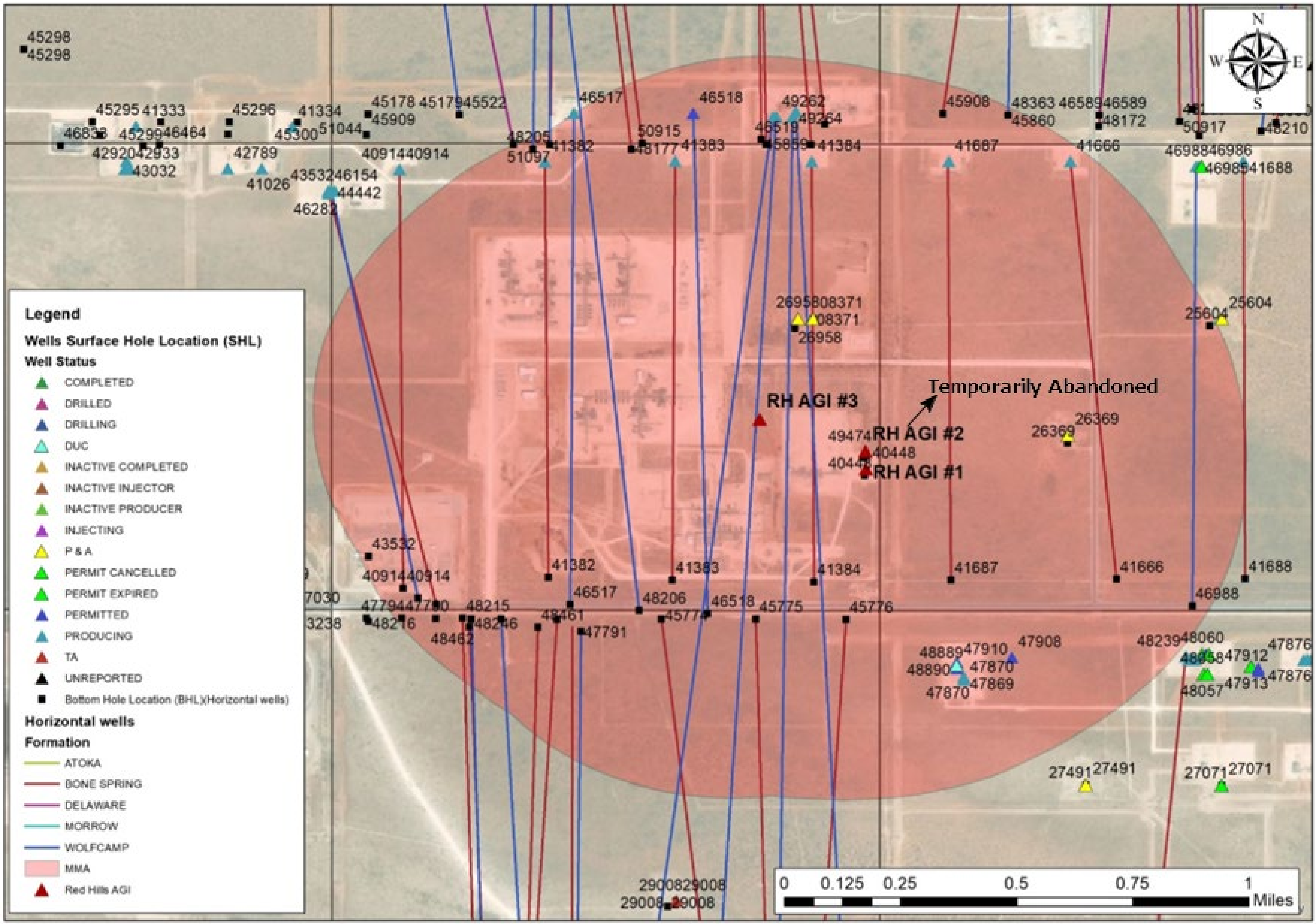


Figure 3.6-3: Location of all oil- and gas-related wells within the MMA for the RH AGI wells. Both the surface hole locations (SHL) and bottom hole locations (BHL) are labeled on the figure. For clarity, only the last five digits of the API numbers are used in labeling the wells.

3.7 Description of Injection Process

The Red Hills Gas Plant, including RH AGI #1 and RH AGI #3, is in operation and staffed 24-hours-a-day, 7-days-a week. The plant operations include gas compression, treating and processing. The plant gathers and processes produced natural gas from Lea and Eddy Counties in New Mexico. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the plant's sweeteners will be routed to a central compressor facility, located west of the well head. Compressed TAG is then routed to the wells via high-pressure rated lines. **Figure 3.7-1** is a schematic of the AGI facilities.

The approximate composition of the TAG stream is: 80% CO_2, 20% H_2S, with trace components of C_1 – C_6 (methane – hexane) and Nitrogen. The anticipated duration of injection is 30 years.

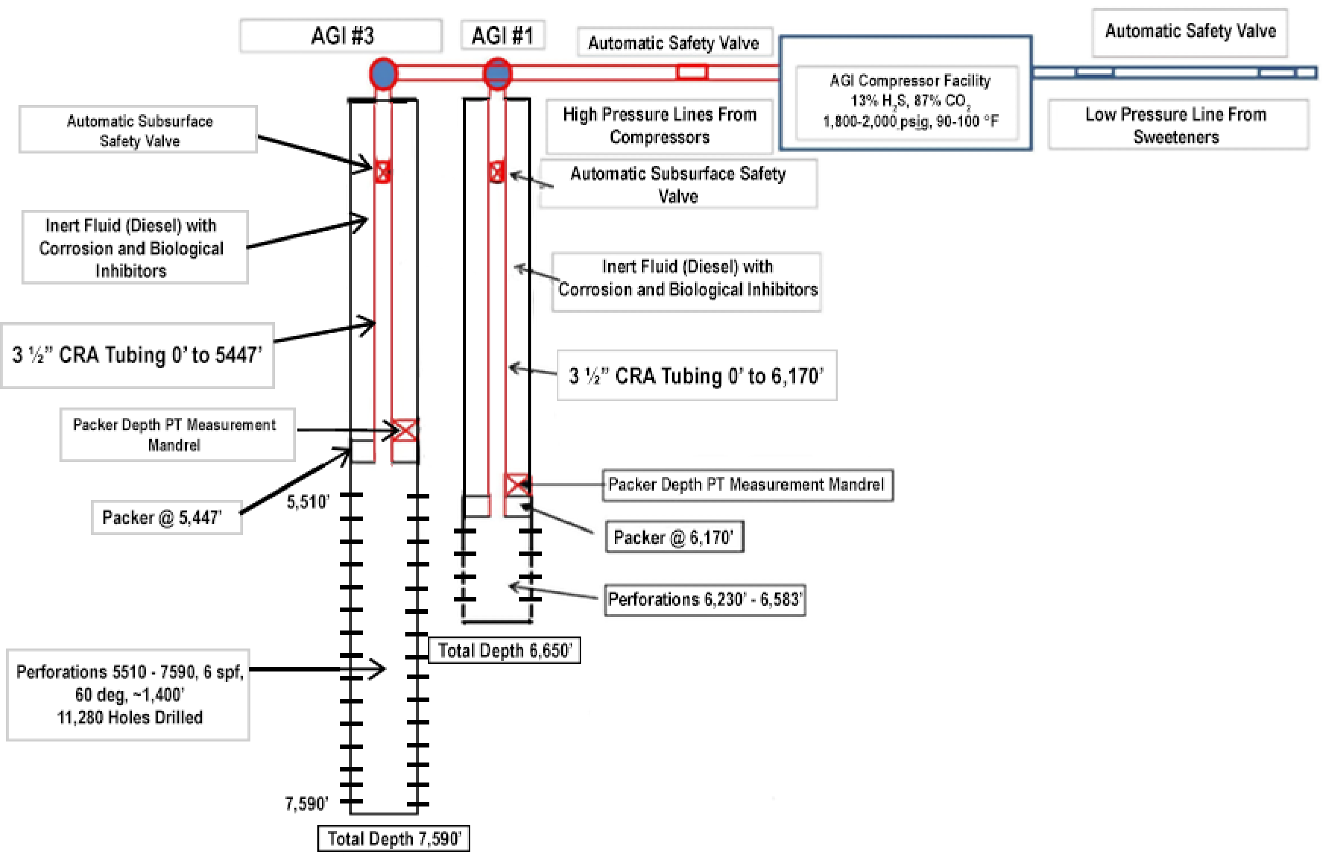


__Figure 3.7-1__: Schematic of surface facilities and RH AGI wells at the Red Hills Gas Processing Plant

3.8 Reservoir Characterization Modeling

The modeling and simulation focused on the Bell Canyon and Cherry Canyon Formations as the main injection target zone for acid gas storage. RH AGI #1 (API 30-025-40448) and RH AGI #3 (API 30-025-51970) are the approved injectors for treated acid gas injection by NMOCD and will serve as the injection wells in the model under the approved disposal timeframe and maximum allowable injection pressure. RH AGI #1 is completed in the Cherry Canyon Formation between 6,230 feet to 6,583 feet (MD). RH AGI #3 is completed in both the Bell Canyon and Cherry Canyon Formations between approximately 5,700 feet to 7,600 feet (MD).

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

The static model is constructed with well tops and licensed 3D seismic data to interpret and delineate the structural surfaces of a layer within the caprock (Lamar Limestone) and its overlaying, underlying formations. The geologic model covers a 3.5-mile by 3.3-mile area. No distinctive geological structures such as faults have been identified within the geologic model boundary. The model is gridded with 182 x 167 x 18, totaling 547,092 cells. The average grid dimension of the active injection area is 100 square feet. **Figure 3.8-1** shows the simulation model in 3D view. The porosity and permeability of the model is populated through existing well logs. The range of the porosity is between 0.01 to 0.31. The initial permeability are interpolated between 0.02 to 155 millidarcy (mD), and the vertical permeability anisotropy was 0.1. **(Figure 3.8-2 and Figure 3.8-3)**. These values are validated and calibrated with the historical injection data of RH AGI #1 since 2018 as shown in **Figures 3.8-4, 3.8-5, and 3.8-6**.

The simulation model is calibrated with the injection history of RH AGI #1 since 2018. Simulation studies were further performed to estimate the reservoir responses when predicting TAG injection for 30 years through both RH AGI #1 (2018 – 2048) and RH AGI #3 (2024 - 2054). RH AGI #2 is temporarily abandoned as of the submission of this document. RH AGI #1 is simulated to inject with the average rate of the last 5 years, 1.2 MMSCF, in the prediction phase. RH AGI #3 is simulated to inject with permitted injection rate, 13 MMSCF, with 1,767 psi maximum surface injection pressure constraint approved by State agency. The simulation terminated in the year 2084, 30 years after the termination of all injection activities, to estimate the maximum impacted area during post injection phase.

During the calibration period (2018 – 2023), the historical injection rates were used as the primary injection control, and the maximum bottom hole pressures (BHP) are imposed on wells as the constraint, calculated based on the approved maximum injection pressure. This restriction is also estimated to be less than 90% of the formation fracture pressure calculated at the shallowest perforation depth of each well to ensure safe injection operations. The reservoir properties are tuned to match the historical injection until it was reasonably matched. **Figure 3.8-4** shows that the historical injection rates from RH AGI #1 in the Cherry Canyon Formation. **Figure 3.8-5** shows the BHP response of RH AGI #1 during the history matching phase.

During the forecasting period, linear cumulative injection behavior indicates that the Cherry Canyon and Bell Canyon Formations received the TAG stream freely. **Figure 3.8-6** shows the cumulative disposed H_2S and CO_2 of each RH AGI injector separately in gas mass. The modeling results indicate that the Cherry Canyon and Bell Canyon Formations are capable of safely storing and containing the gas volume without violating the permitted rate and pressure. **Figure 3.8-7** shows the gas saturation represented TAG plume at the end of 30-year forecasting in 3D view. **Figure 3.8-8** shows the extent of the plume migration in a map view at 4 key time steps. It can be observed that the size of the TAG plume is very limited and mainly stayed within Targa's Red Hills facility boundary at the end of injection. In the year 2084, after 30 years of monitoring, the injected gas remained trapped in the reservoir and there was no significant change in the observed TAG footprint as compared to that at the end of injection.

In summary, after careful reservoir engineering review and numerical simulation study, our analysis shows that the Bell Canyon and Cherry Canyon Formations can receive treated acid gas (TAG) at the injection rate and permitted maximum surface injection pressure permitted by NMOCC. The injection formations will safely contain the injected TAG volume within the injection and post-injection timeframe. The injection wells will allow for sequestration while preventing associated environmental impacts.

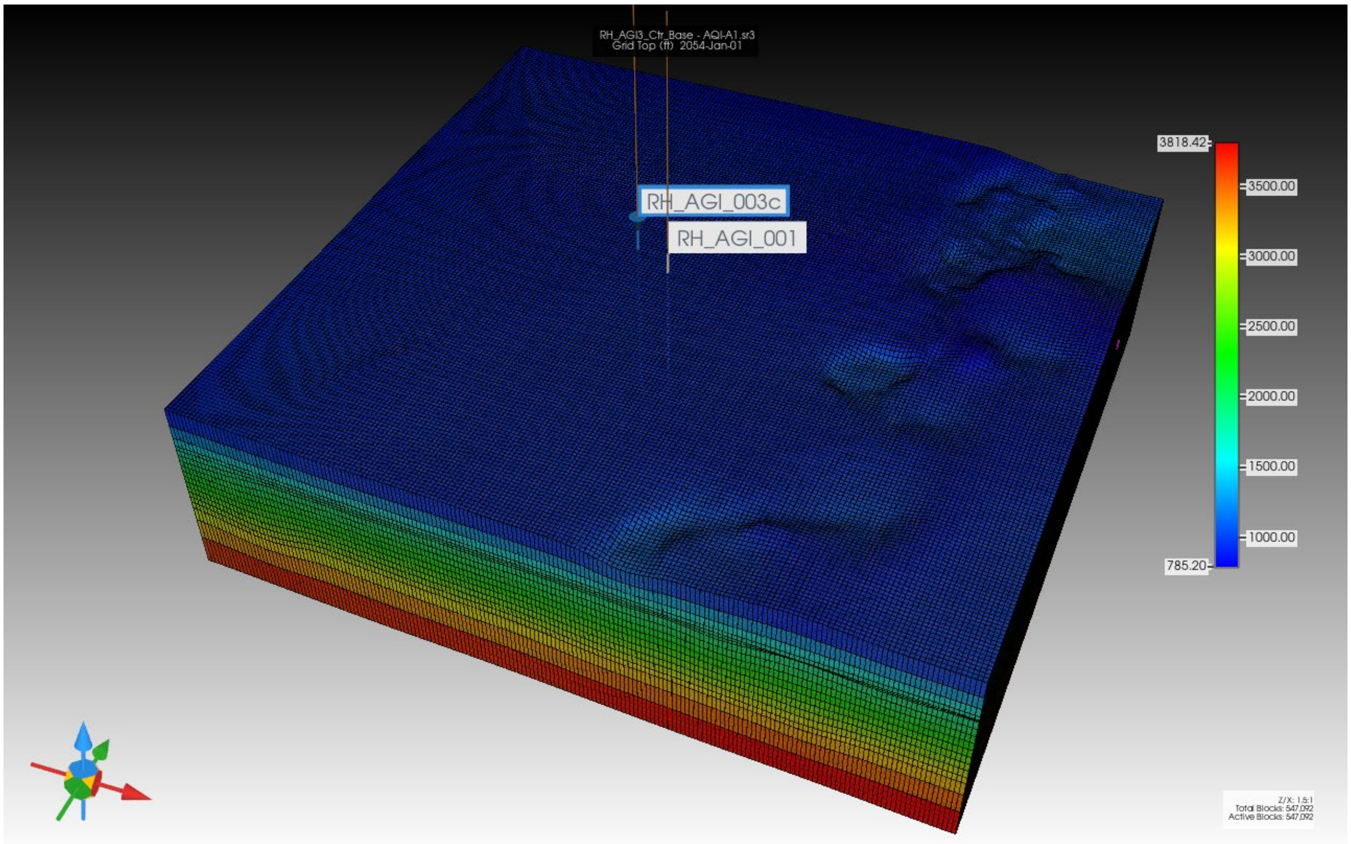


Figure 3.8-1: *3D view of the simulation model of RH AGI #1 and RH AGI #3, containing Salado-Castile Formation, Lamar Limestone, Bell Canyon Formation, and Cherry Canyon Formation. Color legends represents the elevation of layers.*

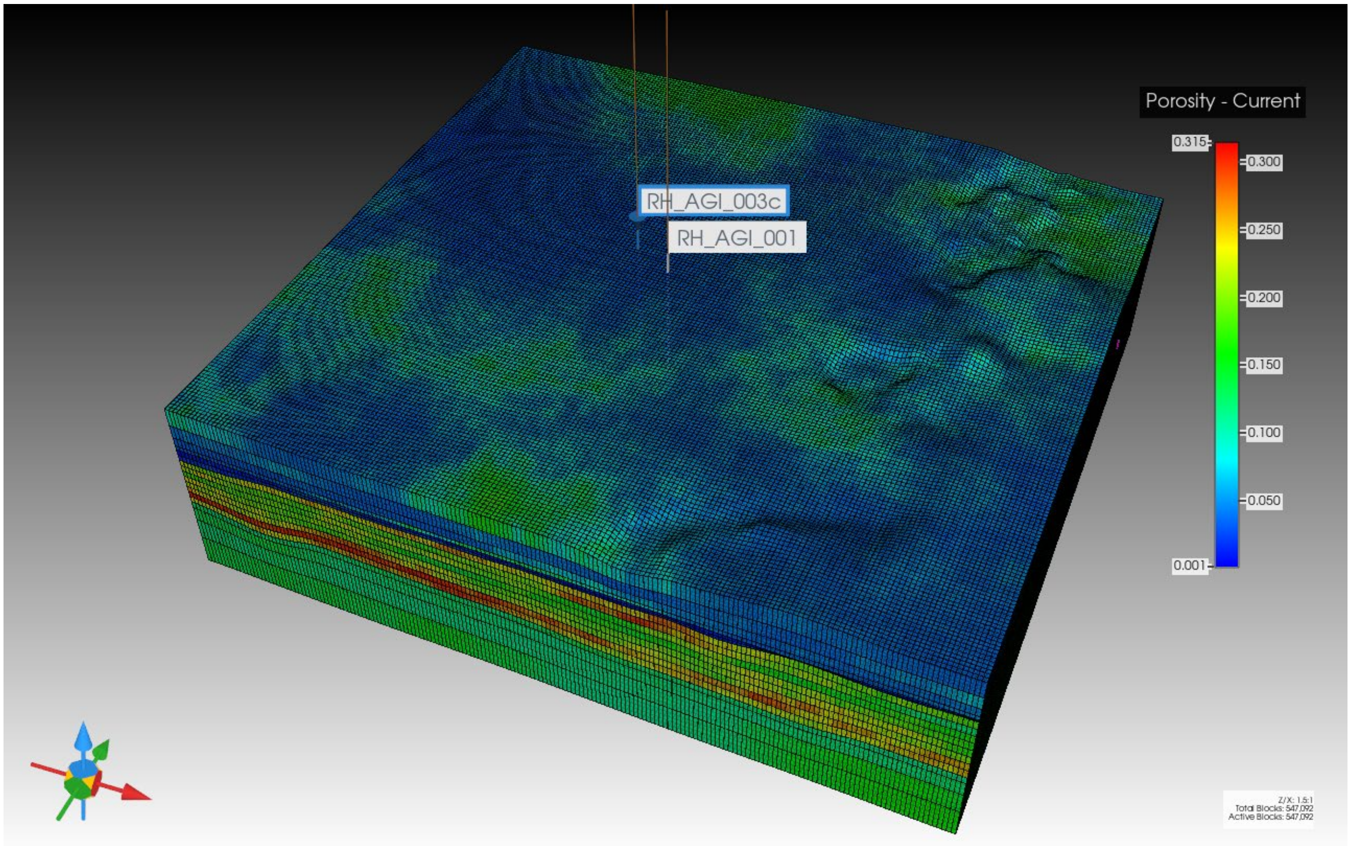


Figure 3.8-2: *Porosity estimation using available well data for the simulation domain.*

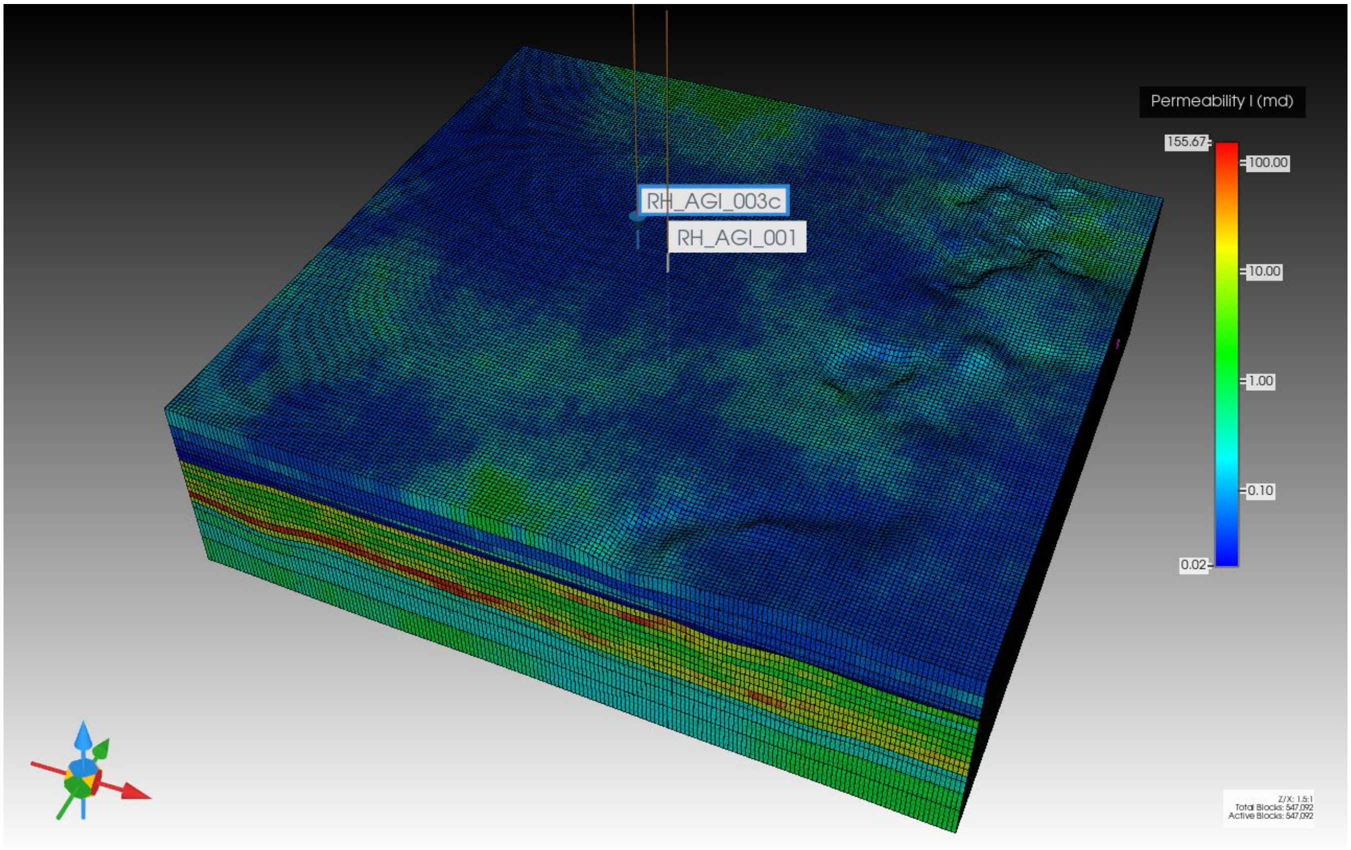


Figure 3.8-3: *Permeability estimation using available well data for simulation domain.*

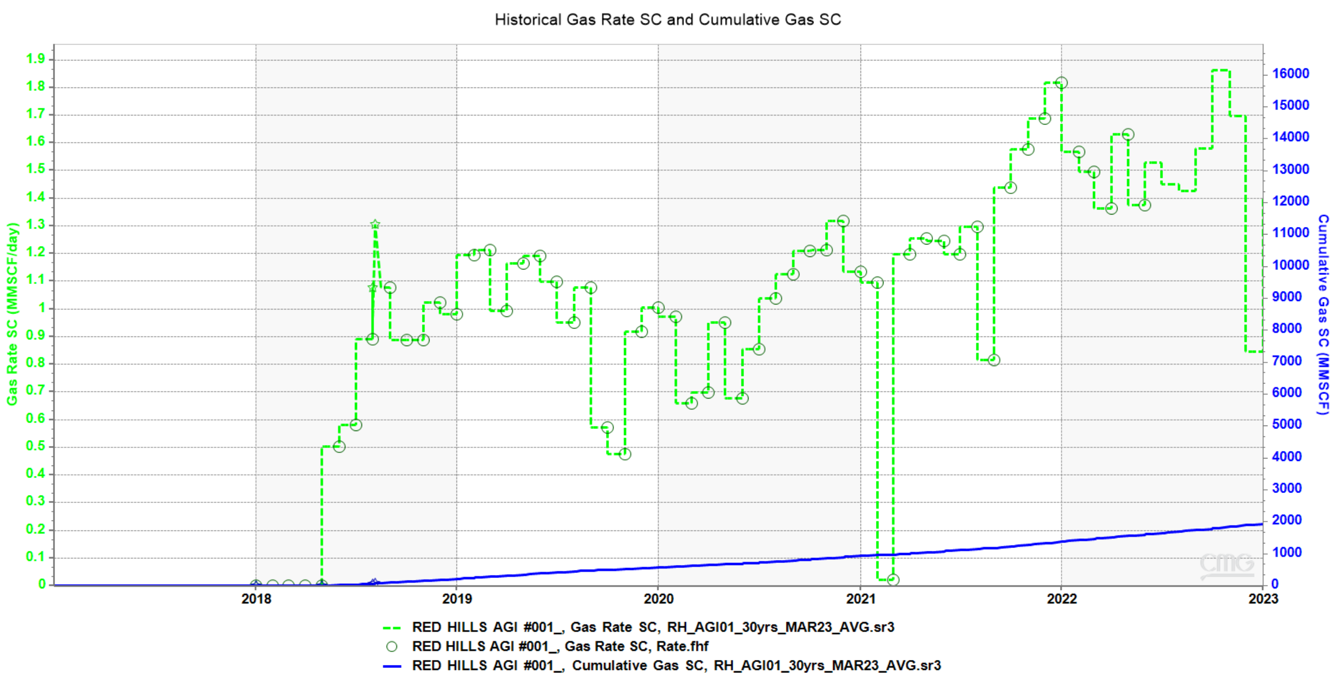


Figure 3.8-4: *The historical injection rate and total gas injected from RH AGI #1 (2018 to 2023).*

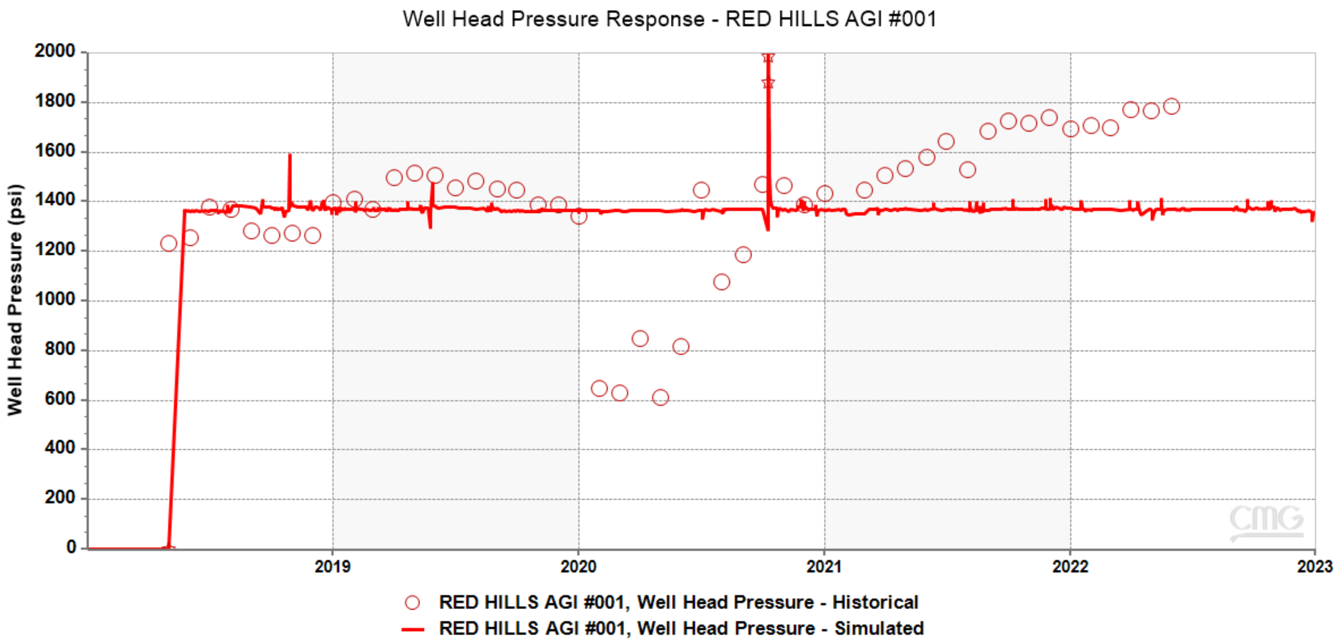


Figure 3.8-5: *The historical bottom hole pressure response from RH AGI #1 (2018 to 2023)*

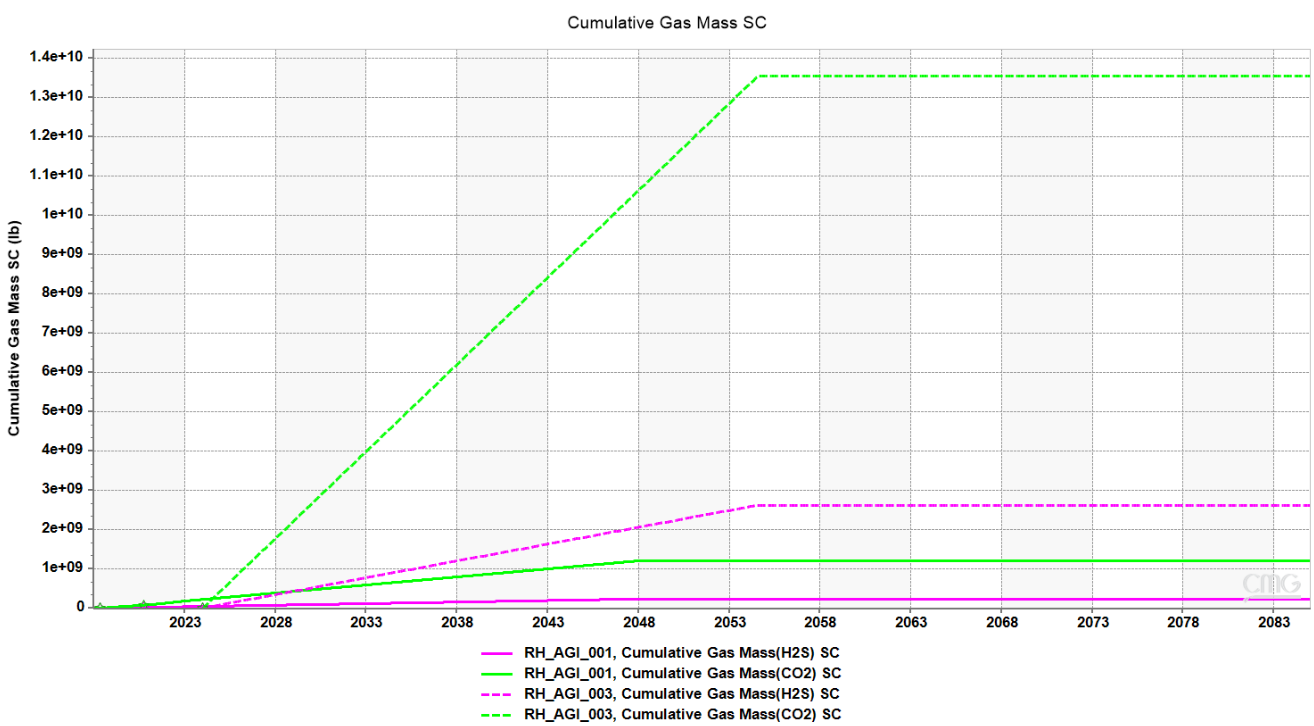


Figure 3.8-6: *Prediction of cumulative mass of injected CO_2 and H_2S for RH AGI #1 and RH AGI #3 (2018 to 2054).*

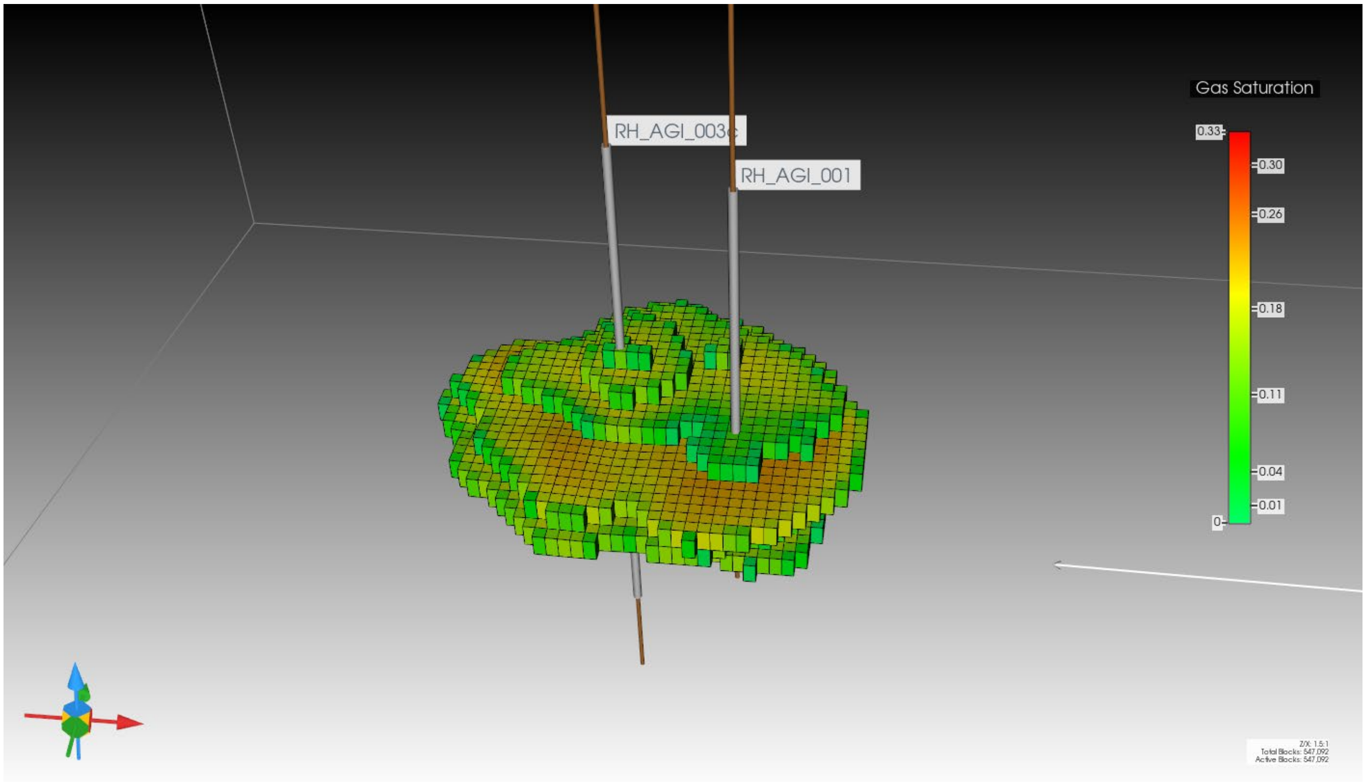


Figure 3.8-7: *Simulation model depicting the free phase TAG (represented by gas saturation) at the end of the 30-year post-injection monitoring period (2054) in 3D view.*

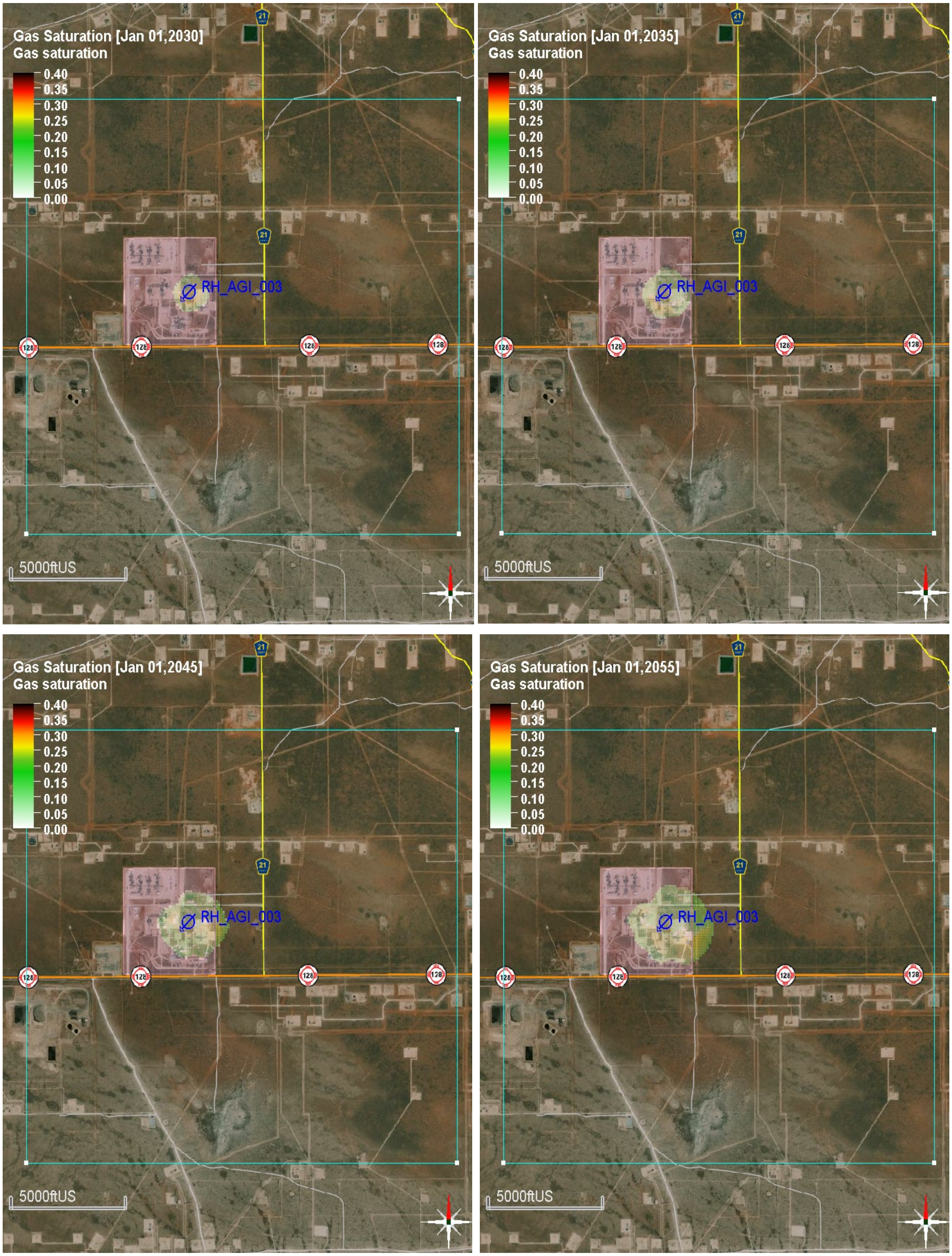


Figure 3.8-8: *Map view depicting the free phase TAG plume at years 2030, 2035, 2045, 2055 (1-year post injection).*

4 Delineation of the Monitoring Areas

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

4.1 MMA – Maximum Monitoring Area

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. **Figures 4.1-1** shows the MMA as defined by the extent of the stabilized TAG plume at year 2059 plus a 1/2-mile buffer.

4.2 AMA – Active Monitoring Area

The Active Monitoring Area (AMA) is shown in **Figure 4.1-1**. The AMA is consistent with the requirements in 40 CFR 98.449 because it is the area projected: (1) to contain the free phase CO_2 plume for the duration of the project (year t, t = 2054), plus an all-around buffer zone of one-half mile. (2) to contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2059). Targa intends to define the active monitoring area (AMA) as the same area as the MMA. The purple cross-hatched polygon in **Figure 4.1-1** is the plume extent at the end of injection. The yellow polygon in **Figure 4.1-1** is the stabilized plume extent 5 years after injection ceases. The AMA/MMA shown as the red-filled polygon contains the CO_2 plume during the duration of the project and at the time the plume has stabilized.

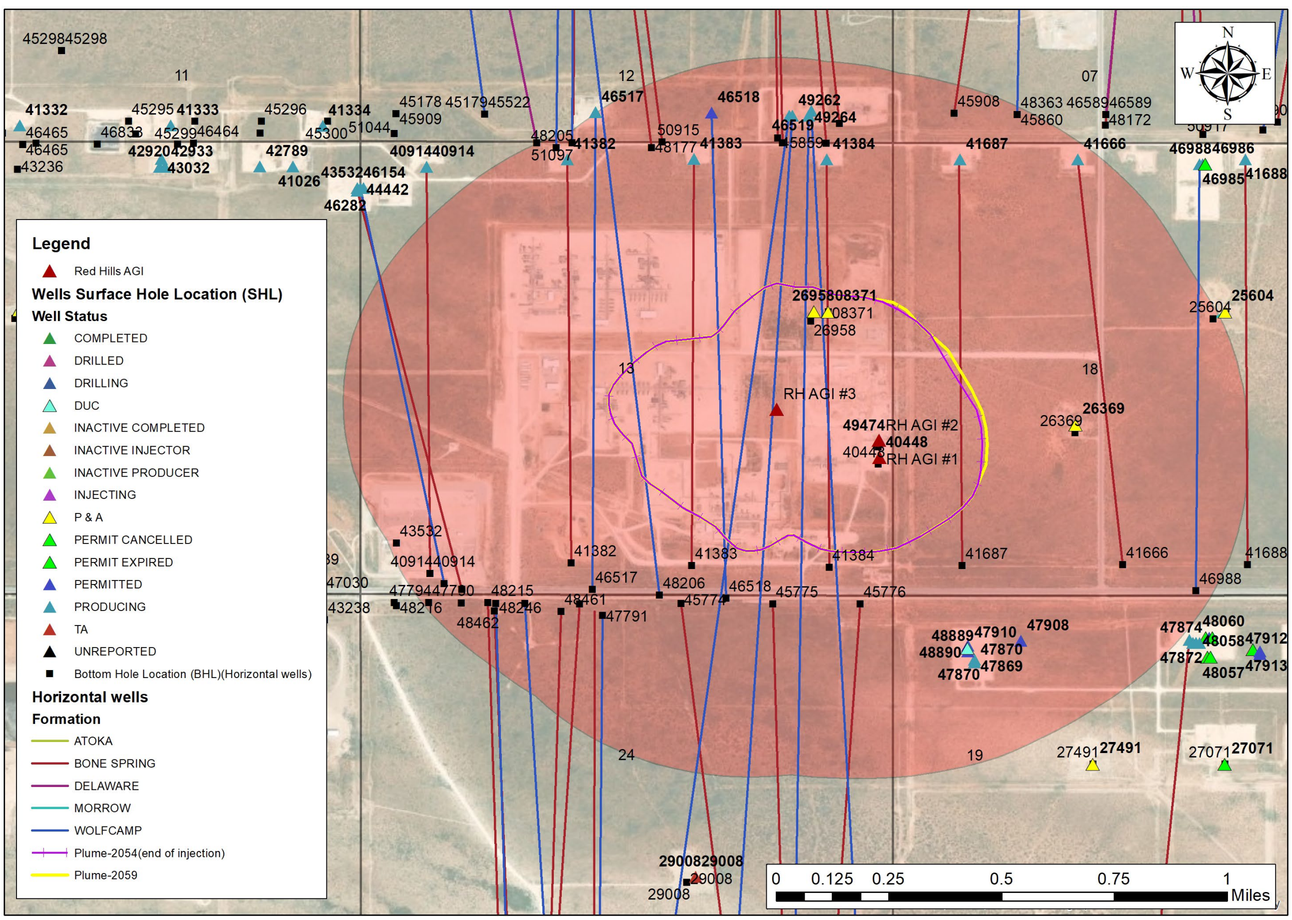


Figure 4.1-1: Active monitoring area (AMA) for RH AGI #1, RH AGI #2 (temporarily abandoned) and RH AGI #3 at the end of injection (2054, purple polygon) and 5 years post-monitoring (2059, yellow polygon). Maximum monitoring area (MMA) is shown in red shaded area.

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

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

Through the site characterization required by the NMOCD C-108 application process for Class II injection wells, the geologic characterization presented in Section 3, and the reservoir modeling described in Section 3.8, TND has identified and evaluated the potential CO_2 leakage pathways to the surface.

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

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas facilities. Preventative risk mitigation includes adherence to relevant regulatory requirements and industry standards governing the construction, operation, and maintenance of gas plants. Specifically, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills."

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

Although mitigative measures are in place to minimize CO_2 emissions from surface equipment, such emissions are possible. Any leaks from surface equipment would result in immediate (timing) emissions of CO_2 to the atmosphere the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak.

The injection wells and the pipeline that carries CO_2 to them are the most likely surface components of the system to allow CO_2 to leak to the surface. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable source of the leakage. Another possible source of leakage is the release of air through relief valves, which are designed to alleviate pipeline overpressure. Leakage can also occur when the surface components are damaged by an accident or natural disaster, which releases CO_2. Therefore, TND infers that there is a potential for leakage via this route. Depending on the component's failure mode, the magnitude of the leak can vary greatly. For example, a rapid break or rupture could release thousands of pounds of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO_2 over several hours or days. Surface component leakage or venting is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

5.2 Potential Leakage from Approved, Not Yet Drilled Wells

The only wells within the MMA that are approved but not yet drilled are horizontal wells. These wells have a Well Status of "permitted" in **Appendix 4**. There are no vertical wells within the MMA with a Well Status of "permitted".

5.2.1 Horizontal Wells

The table in **Appendix 3** and **Figure 4.1-1** shows a number of horizontal wells in the area, many of which have approved permits to drill but which are not yet drilled. If any of these wells are drilled through the Bell Canyon and Cherry Canyon injection zones for RH AGI #3 and RH AGI #1, they will be required to take special precautions to prevent leakage of TAG minimizing the likelihood of CO_2 leakage to the surface. This requirement will be made by NMOCD in regulating applications for permit to drill (APD) and in ensuring that the operator and driller are aware that they are drilling through an H_2S injection zone in order to access their target production formation. NMAC 19.15.11 for Hydrogen Sulfide Gas includes standards for personnel and equipment safety and H_2S detection and monitoring during well drilling, completion, well workovers, and well servicing operations all of which apply for wells drilled through the RH AGI wells TAG plume.

Due to the safeguards described above, the fact there are no proposed wells for which the surface hole location (SHL) lies within the simulated TAG plume and, considering the NRAP risk analysis described here in Section 5, TND considers the likelihood of CO_2 emissions to the surface via these horizontal wells to be highly unlikely.

5.3 Potential Leakage from Existing Wells

Existing oil and gas wells within the MMA as delineated in Section 4 are shown in **Figure 3.6-3** and detailed in **Appendix 4**.

TND considered all wells completed and approved within the MMA in the NRAP risk assessment. Some of these wells penetrate the injection and/or confining zones while others do not. Even though the risk of CO_2 leakage through the wells that did not penetrate confining zones is highly unlikely, TND did not omit any potential source of leakage in the NRAP analysis. If leakage through wellbores happens, the worst-case scenario is predicted using the NRAP tool to quantitatively assess the amount of CO_2 leakage through existing and approved wellbores within the MMA. Thirty-nine existing and approved wells inside MMA were addressed in the NRAP analysis. The reservoir properties, well data, formation stratigraphy, and MMA area were incorporated into the NRAP tool to forecast the rate and mass of CO_2 leakage. The worst scenario is that all of the 39 wells were located right at the source of CO_2 – the injection wells' location. In this case, the maximum leakage rate of one well is approximately 7e-6 kg/s. This value is the maximum amount of CO_2 leakage, 220 kg/year, and occurs in the second year of injection, then gradually reduces to 180 kg at the end of year 30. Comparing the total amount of CO_2 injected (assuming 5 MMSCFD of supercritical CO_2 injected continuously for 30 years), the leakage mass amounts to 0.0054% of the total CO_2 injected. This leakage is considered negligible. Also, this worst-case scenario, where 39 wells are located right at the injection point, is impossible in reality. Therefore, CO_2 leakage to the surface via this potential leakage pathway can be considered improbable.

5.3.1 Wells Completed in the Bell Canyon and Cherry Canyon Formations

The only wells completed in the Bell Canyon and Cherry Canyon Formations within the MMA are RH AGI #1, RH AGI #2 (drilling stopped in the Bell Canyon), and RH AGI #3 and the 30-025-08371 well which was completed at a depth of 5,425 ft. This well is within the Red Hills facility boundary and is plugged and abandoned (see **Appendix 9** for plugging and abandonment (P&A) record).

Appendix 1 includes schematics of the RH AGI #1, RH AGI #2,and RH AGI #3 wells' construction showing multiple strings of casing all cemented to surface. Injection of TAG into RH AGI #1 and RH AGI #3 occurs through tubing with a permanent production packer set above the injection zone.

RH AGI #2 is located in close proximity to RH AGI #1 and is temporarily abandoned. Drilling of this well stopped at 6,205 ft due to concerns about high pressures by drilling into the Cherry Canyon Formation and therefore, did not penetrate the Cherry Canyon Formation. The cement plug was tagged at 5,960 feet which is above the injection zone for RH AGI #1 (see **Figure Appendix 1-3**).

Due to the robust construction of the RH AGI wells, the plugging of the well 30-025-08371 above the Bell Canyon, the plugging of RH AGI #2 above the Cherry Canyon Formation, and considering the NRAP analysis described above, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.2 Wells Completed in the Bone Spring / Wolfcamp Zones

Several wells are completed in the Bone Spring and Wolfcamp oil and gas production zones as described in Section 3.6.2. These productive zones lie more than 2,000 ft below the RH AGI wells injection zone minimizing the likelihood of communication between the RH AGI well injection zones and the Bone Spring / Wolfcamp production zones. Construction of these wells includes surface casing set at 1,375 ft and cemented to surface and intermediate casing set at the top of the Bell Canyon at depths of from 5,100 to 5,200 ft and cemented through the Permian Ochoan evaporites, limestone and siltstone (**Figure 3.2-2**) providing zonal isolation preventing TAG injected into the Bell Canyon and Cherry Canyon formations through the RH AGI wells from leaking upward along the borehole in the event the TAG plume were to reach these wellbores. **Figure 4.1-1** shows that the modeled TAG plume extent after 30 years of injection and 5 years of post-injection stabilization does not extend to well boreholes completed in the Bone Spring / Wolfcamp production zones thereby indicating that these wells are not likely to be pathways for CO_2 leakage to the surface.

Due to the construction of these wells, the fact that the modeled TAG plume does not reach the SHL of these wells and considering the NRAP analysis described in the introductory paragraph of Section 5, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.3 Wells Completed in the Siluro-Devonian Zone

One well penetrated the Devonian at the boundary of the MMA - EOG Resources, Government Com 001, API # 30-025-25604, TVD = 17,625 ft, 0.87 miles from RH AGI #3. This well was drilled to a total depth of 17,625 ft on March 5, 1978, but plugged back to 14,590 ft, just below the Morrow, in May of 1978. Subsequently, this well was permanently plugged and abandoned on December 30, 2004, and approved by NMOCD on January 4, 2005 (see **Appendix 9** for P&A records). The approved plugging provides zonal isolation for the Bell Canyon and Cherry Canyon injection zones minimizing the likelihood that this well will be a pathway for CO_2 emissions to the surface from either injection zone.

Due to the location of this well at the edge of the MMA and considering the NRAP analysis described in the introductory paragraph of Section 5, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.4 Groundwater Wells

The table in Appendix 3 lists 15 water wells within a 2-mile radius of the RH AGI wells, only 2 of which are within a 1-mile radius of and within the MMA for the RH AGI wells (**Figure 3.5-1**). The deepest ground water well is 650 ft deep. The evaporite sequence of the Permian Ochoan Salado and Castile Formations (see

Section 3.2.2) provides an excellent seal between these groundwater wells and the Bell and Cherry Canyon injection zones of RH AGI #1and RH AGI #3. Therefore, it is unlikely that these two groundwater wells are a potential pathway of CO_2 leakage to the surface. Nevertheless, the CO_2 surface monitoring and groundwater monitoring described in Sections 6 and 7 will provide early detection of CO_2 leakage followed by immediate response thereby minimizing the magnitude of CO_2 leakage volume via this potential pathway.

Due to the shallow depth of the groundwater wells within the MMA relative to the depth of the RH AGI wells and considering the NRAP analysis described in the introductory paragraph in Section 5, TND considers that, while the likelihood of CO_2 emissions to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.4 Potential Leakage through the Confining / Seal System

The site characterization for the injection zone of the RH AGI wells described in Sections 3.2.2 and 3.3 indicates a thick sequence of Permian Ochoan evaporites, limestone, and siltstones (**Figure 3.2-2**) above the Bell Canyon and Cherry Canyon Formations and no evidence of faulting. Therefore, it is unlikely that TAG injected into the Bell Canyon and Cherry Canyon Formations will leak through this confining zone to the surface. Limiting the injection pressure to less than the fracture pressure of the confining zone will minimize the likelihood of CO_2 leakage through this potential pathway to the surface.

Leakage through a confining zone happens in low-permeability shale formations containing natural fractures. The injection zone for RH AGI #1 and RH AGI #3 is the Delaware Mountain Group Formation (Bell Canyon and Cherry Canyon), which underlie the very much lower permeability (<0.01 mD) Castile and Salado Formations that provide excellent seals. Still, TND took leakage through confining zones into consideration in the NRAP risk assessment. The worst-case scenario is defined as leakage through the seal happening right above the injection wells, where CO_2 saturation is highest. However, this worst-case scenario of leakage only shows that 0.0017% of total CO_2 injection in 30 years was leaked from the injection zone through the seals. As we go further from the source of CO_2, the likelihood of such an event will diminish proportionally with the distance from the source. Considering that this is the greatest amount of CO_2 leakage in this worst-case scenario, if the event happens, the leak must pass upward through the confining zone, the secondary confining strata that consists of additional low permeability geologic units, and other geologic units, TND concludes that the risk of leakage through this pathway is highly unlikely.

5.5 Potential Leakage due to Lateral Migration

The characterization of the sand layers in the Cherry Canyon Formation described in Section 3.3 states that these sands were deposited by turbidites in channels in submarine fan complexes; each sand is encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity. Regional consideration of their depositional environment suggests a preferred orientation for fluid and gas flow would be south-to-north along the channel axis. However, locally the high net porosity of the RH AGI #1 and RH AGI #3 injection zones indicates adequate storage capacity such that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA due to a preferred regional depositional orientation.

Lateral migration of the injected TAG was addressed in detail in Section 3.3. Therein it states that the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales as well as being encased by them.

Based on the discussion of the channeled sands in the injection zone, TND considers that the likelihood of CO_2 to migrate laterally along the channel axes is possible. However, the facts that the turbidite sands are encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity and that the injectate is projected to be contained within the injection zone close to the injection wells minimizes the likelihood that CO_2 will migrate to a potential conduit to the surface.

5.6 Potential Leakage through Fractures and Faults

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology as well as identify and understand the distribution of faults and fractures. **Figure 5.6-1** shows the fault traces in the vicinity of the Red Hills plant. The faults shown on **Figure 5.6-1** are confined to the Paleozoic section below the injection zone for the RH AGI wells. No faults were identified in the confining zone above the Bell Canyon and Cherry Canyon injection zone for the RH AGI wells.

No faults were identified within the MMA which could potentially serve as conduits for surface CO_2 emission. The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief. Because this fault is confined to the lower Paleozoic unit more than 5,100 feet below the injection zone for the RH AGI wells, there is minimal chance it would be a potential leakage pathway. This inference is supported by the NRAP simulation result. Therefore, TND concludes that the CO_2 leakage rate through this fault is zero and that the risk of leakage through this potential leakage pathway is highly improbable.

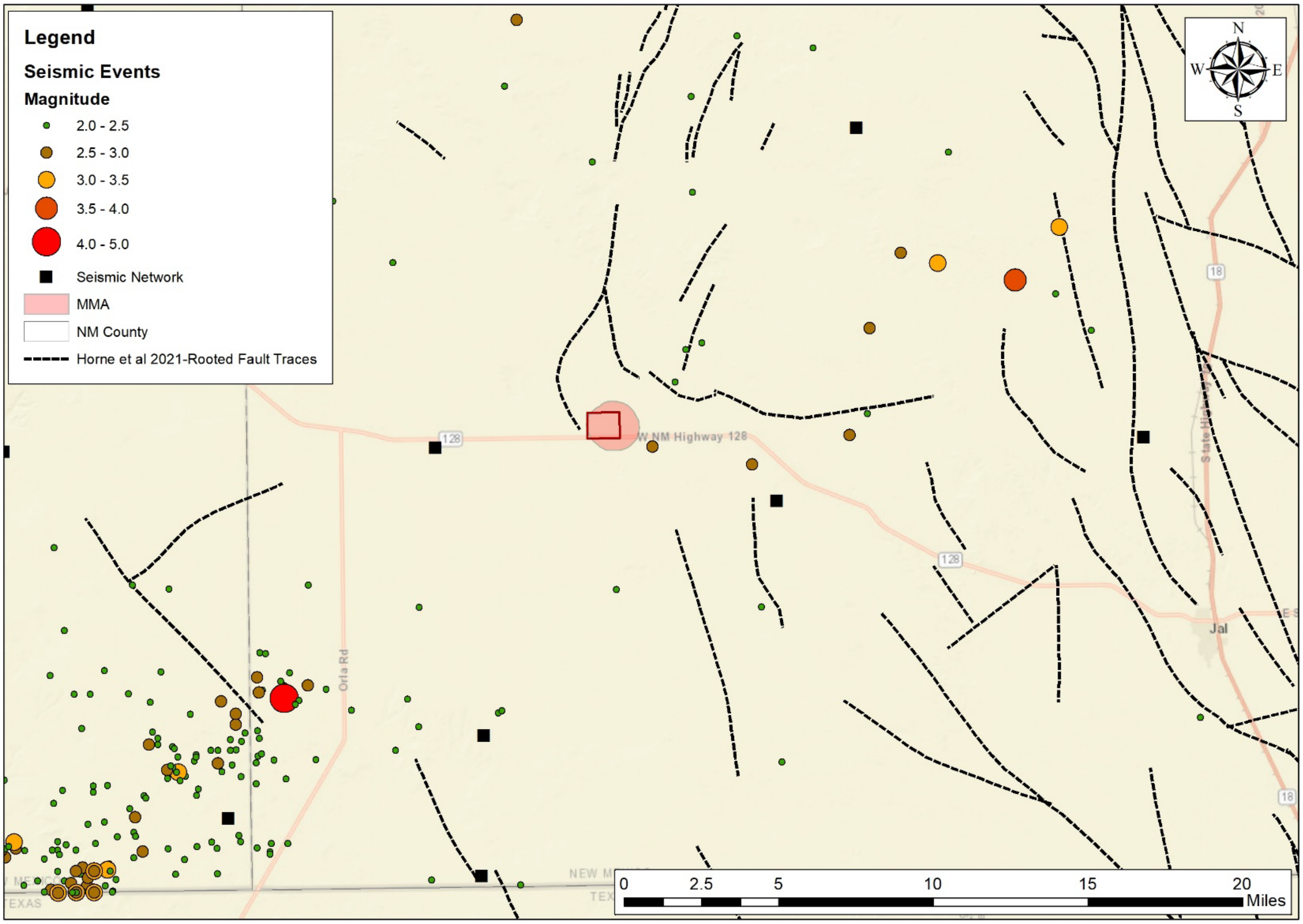


***Figure 5.6-1**: New Mexico Tech Seismological Observatory (NMTSO) seismic network close to the operations, recent seismic events, and fault traces (2022-2023). Note: Fault traces are from Horne et al 2021 for deep seated faults in the lower Paleozoic. The fault traces shown close to the Red Hills facility die out at the base of the Wolfcamp formation at a depth of 12,600 feet, more than 5,100 feet below the bottom of the injection zone at 7,500 feet.*

5.7 Potential Leakage due to Natural / Induced Seismicity

The New Mexico Tech Seismological Observatory (NMTSO) monitors seismic activity in the state of New Mexico. A search of the database shows no recent seismic events close to the Red Hills operations. The closest recent, as of 4 September 2023, seismic events are:

- 7.5 miles, 2022-09-03, Magnitude 3
- 8 miles, 2022-09-02, Magnitude 2.23
- 8.6 miles, 2022-10-29, Magnitude 2.1

Figure 5.6-1 shows the seismic stations and recent seismic events in the area around the Red Hills facility.

Due to the distance between the RH AGI wells and the recent seismic events, the magnitude of these events, and the fact that TND injects at pressures below fracture opening pressure, TND considers the likelihood of CO_2 emissions to the surface caused by seismicity to be improbable.

Monitoring of seismic events in the vicinity of the RH AGI wells is discussed in Section 6.7.

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

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

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

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors
Existing RH AGI Wells	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors • In-well P/T sensors • Groundwater monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Additional Monitoring	• Groundwater monitoring • Soil flux monitoring

6.1 Leakage from Surface Equipment

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

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

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

> "**Fixed Monitors**
> The Red Hills Plant has numerous ambient hydrogen sulfide detectors placed strategically throughout the Plant to detect possible leaks. Upon detection of hydrogen sulfide at 10 ppm at any detector, visible beacons are activated, and an alarm is sounded. Upon detection of hydrogen sulfide at 90 ppm at any detector, an evacuation alarm is sounded throughout the Plant at which time all personnel will proceed immediately to a designated evacuation area. The Plant utilizes fixed-point monitors to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the Distributed Control System (DCS). The monitors are equipped with amber beacons. The beacon is activated at 10 ppm. The plant and the RH AGI well horns are activated with a continuous warbling alarm at 10 ppm and a siren at 90 ppm. All monitoring equipment is Red Line brand. The Control Panel is a 24 Channel Monitor Box, and the fixed point H_2S Sensor Heads are model number RL-101.
>
> The Plant will be able to monitor concentrations of H_2S via H_2S Analyzers in the following locations:
>
> - Inlet gas of the combined stream from Winkler and Limestone
> - Inlet sour liquid downstream of the slug catcher
> - Outlet Sweet Gas to Red Hills 1
> - Outlet Sweet Liquid to Red Hills Condensate Surge
>
> The RH AGI system monitors can also be viewed on the PLC displays located at the Plant. These sensors are all shown on the plot plan (see **Figure 3.6-1**). This requires immediate action for any occurrence or malfunction. All H_2S sensors are calibrated monthly.
>
> **Personal and Handheld H_2S Monitors**
>
> All personnel working at the Plant wear personal H_2S monitors. The personal monitors are set to alarm and vibrate at 10 ppm. Handheld gas detection monitors are available at strategic locations around the Plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and carbon dioxide (CO_2)."

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones including more frequent monitoring during drilling operations (see **Table 6-1**). This applies to TND and other operators drilling new wells through the RH AGI wells injection zones within the MMA.

6.3 Leakage from Existing Wells

6.3.1 RH AGI Wells

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

To monitor leakage and wellbore integrity, two pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) were deployed in RH AGI #1. One gauge is designated to monitor the tubing ID (reservoir) pressure and temperature and the second gauge monitors the annular space between the tubing and the long string casing (**Figure 6.2-1**). A leak is indicated when both gauges start reading the same pressure. DTS is clamped to the tubing, and it monitors the temperature profiles of the annulus from 6,159 ft to surface. DTS can detect variation in the temperature profile events throughout the tubing and or casing. Temperature variation could be an indicator of leaks. Data from temperature and pressure gauges is recorded by an interrogator housed in an onsite control room. DTS (temperature) data is recorded by a separate interrogator that is also housed in the onsite control room. Data from both interrogators are transmitted to a remote location for daily real time or historical analysis.

As is described above for RH AGI #1, pressure and temperature gauges as well as DTS were deployed in RH AGI #3 (see **Figure Appendix 1-2** for location of PT gauges).

The temporarily abandoned RH AGI #2 well will be monitored by the fixed in-field gas monitors, handheld H_2S monitors, and CO_2 soil flux monitoring described in Sections 7.2 and 7.3.

If operational parameter monitoring, MIT failures, or surface gas monitoring indicate a CO_2 leak has occurred, TND will take actions to quantify the leak based on operating conditions at the time of the detection including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site.

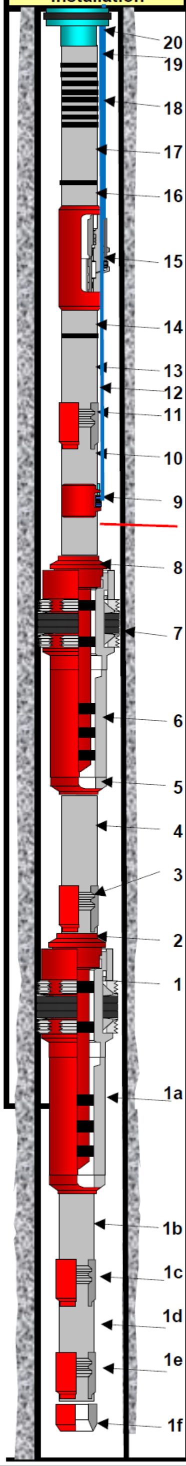
HALLIBURTON

Lucid

Red Hills AGI 1
Lea County New Mexico
2/3/21 - 2/28/21

WSP - Troy Gillen / Michael Forrier
Sales Rep - Lynn Talley (432) 631-4626
Tool Specialists: Carey Lehmann, Jonathan Phillips, Jose Vargas

Installation



Installation	Depth	Length	Jts.	Description	OD	ID
	18.50	18.50		KB		
20	22.90	4.40		20) Hanger Sub 3 1/2" 9.2# CRA VAMTOP x 7.7# VAM Ace Pin	7.000	3.000
19	64.05	41.15	1	19) 3 1/2" 7.7# VAM ACE 125K G3 Tubing (Slick Joint)	3.500	3.035
				Ran Eight Subs 8', 8', 6', 6',4', 4', 2', 2'		
18	103.97	39.92		18) 3 1/2" 7.7# VAM ACE 125K G3 Spaceout Subs	3.500	3.035
17	235.95	131.98	3	17) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.035
16	241.95	6.00		16) 6' x 3 1/2" 7.7# CRA VAM ACE Box x 9.2# VAMTOP Pin	3.540	2.959
15	246.30	4.35		15) 3 1/2" NE HES SSSV Nickel Alloy 925 w/Alloy 825 Control Line 3 1/2" 9.2# VAMTOP Box x Pin	5.300	2.813
14	252.29	5.99		14) 6' x 3 1/2" 9.2# CRA VAMTOP Box x 7.7# VAM ACE Pin	3.540	2.959
13	6,140.23	5,887.94	134	13) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.305
12				12) 3 1/2" 7.7# VAM ACE Box x 9.2# VAMTOP Pin CRA Crossover	3.830	2.959
11				11) 2.813" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925	4.073	2.813
10	6,153.72	13.49		10) 6' x 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy G3 Sub	3.540	2.959
				13.49' Length Includes Line Items 10, 11 & 12		
9	6,159 Tubing	P/T		9) Baker PT Sensor Mandrel 3 1/2" 9.2# VAMTOP Box x Pin	5.200	2.992
	6,162.6 Annular	P/T		6' VAMTOP 9.2# CRA Tubing Sub Above & Below Gauge Mdl		
8	6,161.23	7.51		8) 4.00" BWS Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925	4.470	2.959
				7.51' Length Includes Line Items 8 & 9		
7	6,164.55	3.32		7) 7" 26-32# x 4.00" BWS Packer Nickel Alloy 925 Casing Collar @ 6,160.6' WL Measurement	5.875	4.000
6	6,172.05	7.5		6) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
5	6,172.88	0.83		5) 4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
4	6,181.19	8.31		4) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
3	6,182.52	1.33		3) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925 #102204262	4.073	2.562
2	6,184.29	1.77		2) Straight Slot Locator Seal Assembly Above Top Of Packer	4.450	2.880
1		6,186.06		1) BWD Permanent Packer. WL Measured Depth Previously 6189'	5.875	4.000
1a				1a) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.660	2.965
1b				1b) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1c				1c) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel,	2.920	2.562
1d				1d) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1e				1e) 2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	3.920	2.321
1f				1f) Re-Entry Guide / POP	3.950	3.000

Figure 6.2-1: *Well Schematic for RH AGI #1 showing installation of P/T sensors*

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7.3 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. Additionally, groundwater and soil CO_2 flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through the Confining / Seal System

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

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

6.5 Leakage due to Lateral Migration

Continuous operational monitoring of the RH AGI wells during and after the period of injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The CO_2 monitoring network described in Section 7.3, and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

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

6.6 Leakage from Fractures and Faults

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through faults. However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, TND will identify which of the pathways listed in this section are responsible for the leak, including the possibility of heretofore unidentified faults or fractures within the MMA. TND will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details. See Section 6.8 for additional information on quantification strategies.

6.7 Leakage due to Natural / Induced Seismicity

In order to monitor the influence of natural and/or induced seismicity, TND will use the established NMTSO seismic network. The network consists of seismic monitoring stations that detect and locate seismic events. Continuous monitoring helps differentiate between natural and induced seismicity. The network surrounding the Red Hills Gas Processing Plant has been mapped on **Figure 5.6-1**. The monitoring network records Helicorder data from UTC (coordinated universal time) all day long. The data are plotted daily at

5pm MST (mountain standard time). These plots can be browsed either by station or by day. The data are streamed continuously to the New Mexico Tech campus and archived at the Incorporated Research Institutions for Seismology Data Management Center (IRIS DMC).

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

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

For normal operations, quantification of emissions of CO_2 from surface equipment will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR. Quantification of major leakage events from surface equipment as identified by the detection techniques listed in **Table 6-1** will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified the leakage location will be isolated to prevent additional emissions to the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. TND has standard operating procedures to report and quantify all pipeline leaks in accordance with the NMOCD regulations (New Mexico administrative Code 19.15.28 Natural Gas Gathering Systems). TND will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by TND or third parties. Additionally, TND may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

6.8.2 Subsurface Leakage

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

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

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, or which may be initiated by seismic events and as may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO_2 leaking back to the surface emphasizing the importance of monitoring

network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO_2 flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 6.8.1, or from the subsurface. In the latter case, CO_2 flux monitoring methodologies, as described in Section 7.8, will be employed to quantify the surface leaks.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

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

7.1 Visual Inspection

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

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

Compositional analysis of TND's gas injectate at the Red Hills Gas Plant indicates an approximate H_2S concentration of 20% thus requiring TND to develop and maintain an H_2S Contingency Plan (Plan) according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). TND considers H_2S to be a proxy for CO_2 leaks at the plant. The Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated RH AGI wells and documents procedures that would be followed in case of such an event.

7.2.1 Fixed In-Field H_2S Monitors

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

7.2.2 Handheld and Personal H_2S Monitors

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

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

7.3 CO_2 Detection

In addition to the handheld gas detection monitors described above, New Mexico Tech, through a DOE research grant (DE-FE0031837 – Carbon Utilization and Storage Project of the Western USA (CUSP)), will assist TND in setting up a monitoring network for CO_2 leakage detection in the AMA as defined in Section 4.2. The scope of work for the DOE project includes field sampling activities to monitor CO_2/H_2S at the two RH AGI wells. These activities include periodic well (groundwater and gas) and atmospheric sampling from an area of 10 – 15 square miles around the injection wells. Once the network is set up, TND will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

7.4 Continuous Parameter Monitoring

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

7.5 Well Surveillance

TND adheres to the requirements of NMOCC Rule 26 governing the construction, operation and closing of an injection well under the Oil and Gas Act. Rule 26 also includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, NMOCC includes special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. TND's Routine Operations and Maintenance Procedures for the RH AGI wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic (Microseismic) Monitoring Stations

TND has Installed a model TCH120-1 Trillium Compact Horizon Seismometer and a model CTR4-3S Centaur Digital Recorder to monitor for and record data for any seismic event at the Red Hills Gas Plant (see **Figure 7-1)**. The seismic station meets the requirements of the NMOCC Order No. R-20916-H to "install, operate, and monitor for the life of the [Class II AGI] permit a seismic monitoring station or stations as directed by the Manager of the New Mexico Tech Seismological Observatory ("state seismologist") at the New Mexico Bureau of Geology and Mineral Resources."

In addition, data that are recorded by the State of New Mexico deployed seismic network within a 10-mile radius of the Red Hills Gas Plant will be analyzed by the New Mexico Bureau of Geology (NMBGMR), see **Figure 5.6-1**, and made publicly available. The NMBGMR seismologist will create a report and map showing the magnitudes of recorded events from seismic activity. The data are being continuously recorded. By examining historical data, a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

7.7 Groundwater Monitoring

New Mexico Tech, through the same DOE research grant described in Section 7.3 above, will monitor groundwater wells for CO_2 leakage which are located within the AMA as defined in Section 4.2. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 7.7-1**. Baseline analyses will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Red Hills Gas Plant. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

Table 7.7-1: *Groundwater Monitoring Parameters*

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

7.8 Soil CO_2 Flux Monitoring

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

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

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

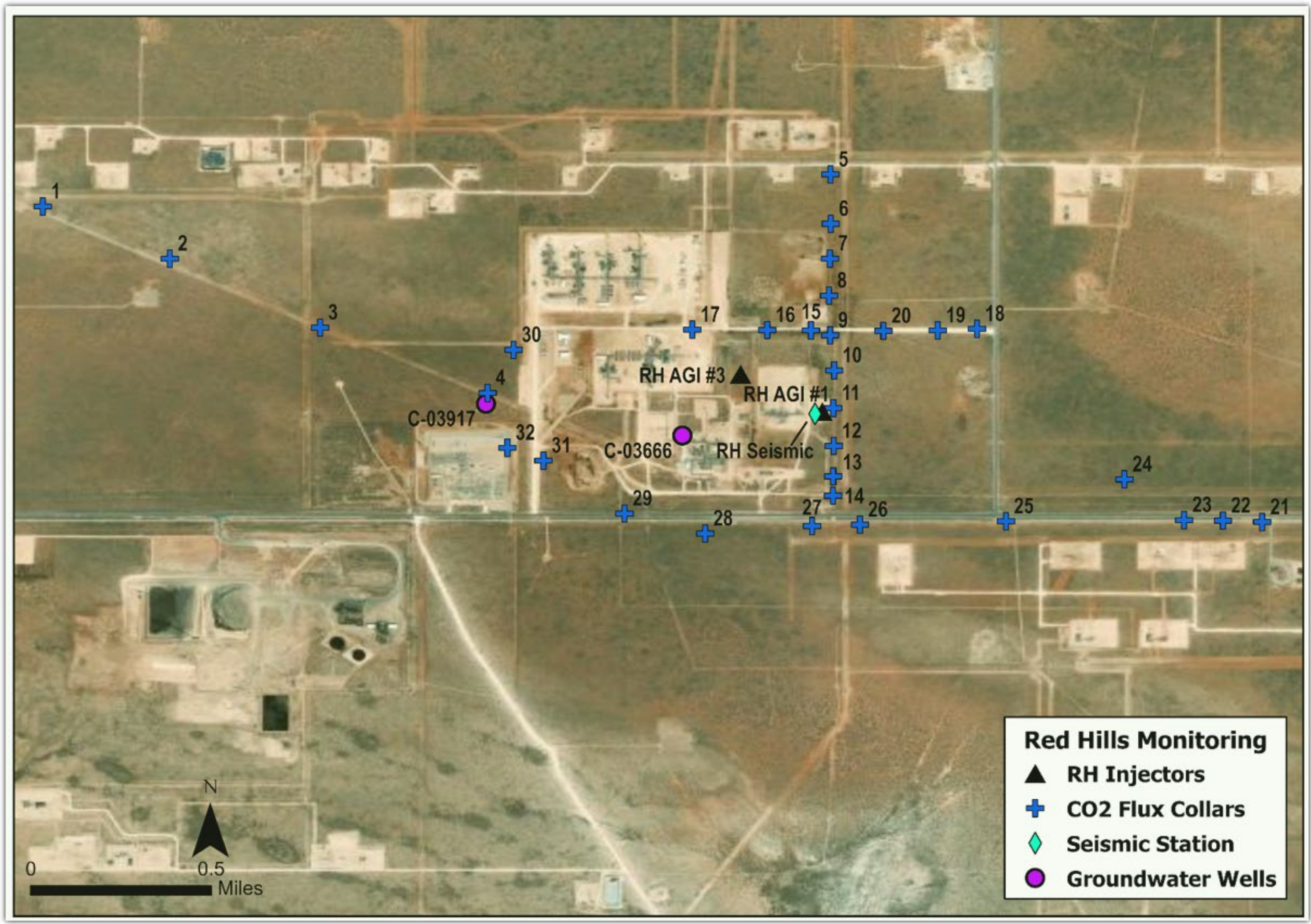


Figure 7-1: *Red Hills monitoring network of 32 CO_2 flux locations, 2 groundwater wells, and a seismic station developed by New Mexico Tech and Targa Resources to detect leakage during injection.*

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve Subpart RR equations used to calculate the mass of CO_2 sequestered annually. **Appendix 8** includes the twelve equations from Subpart RR. Not all of these equations apply to TND's current operations at the Red Hills Gas Plant but are included in the event TND's operations change in such a way that their use is required.

Figure 3.6-2 shows the location of all surface equipment and points of venting listed in 40CFR98.232(d) of Subpart W that will be used in the calculations listed below.

8.1 CO_2 Received

Currently, TND receives gas to its Red Hills Gas Plant through six pipelines: Gut Line, Winkler Discharge, Red Hills 24" Inlet Loop, Greyhound Discharge, Limestone Discharge, and the Plantview Loop. The gas is processed as described in Section 3.8 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection. TND will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3. Receiving flow meter r in the following equations corresponds to meters M1 and M2 in **Figure 3.6-2**.

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

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

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

8.2 CO_2 Injected

TND injects CO_2 into RH AGI #1 and RH AGI #3. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into both wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in

Equation RR-12. Volumetric flow meter u in the following equations corresponds to meters M3 and M6 in **Figure 3.6-2**.

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

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

(Equation RR-6)

where:

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

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

u = Flow meter.

8.3 CO_2 Produced / Recycled

TND does not produce oil or gas or any other liquid at its Red Hills Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.6 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6.8.

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

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

8.6 CO_2 Sequestered

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

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

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

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

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

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

9 Estimated Schedule for Implementation of MRV Plan

The baseline monitoring and leakage detection and quantification strategies described herein have been established and data collected by TND and its predecessor, Lucid, for several years and continues to the present. TND will begin implementing this revised MRV plan as soon as it is approved by EPA.

10 GHG Monitoring and Quality Assurance Program

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

10.1 GHG Monitoring

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

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations

- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

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

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

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.3 CO_2 injected.

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

10.1.4 CO_2 produced.

TND does not produce CO_2 at the Red Hills Gas Plant.

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

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

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

10.1.6 Measurement devices.

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

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

10.2 QA/QC Procedures

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

10.3 Estimating Missing Data

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

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

10.4 Revisions of the MRV Plan

TND will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of New Mexico. If any operational changes constitute a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change.

11 Records Retention

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

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

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

(i) The GHG emissions calculations and methods used

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

(iii) The results of all required analyses

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

(3) The annual GHG reports.

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

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

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

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

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

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

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

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

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

12 Appendices

Appendix 1 TND Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Red Hills AGI #1	30-025-40448	1,600 ft FSL, 150 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	10/23/2013	6,650 ft	6,170 ft
Red Hills AGI #2 (temporarily abandoned)	30-025-49474	150 ft FEL, 1,800 ft FSL Sec. 13, T24S, R33E, NMPM	Lea, NM		6,205 ft	
Red Hill AGI #3	30-025-51970	3,116 ft FNL, 1,159 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	9/13/2023	7,600 ft	5,700 ft

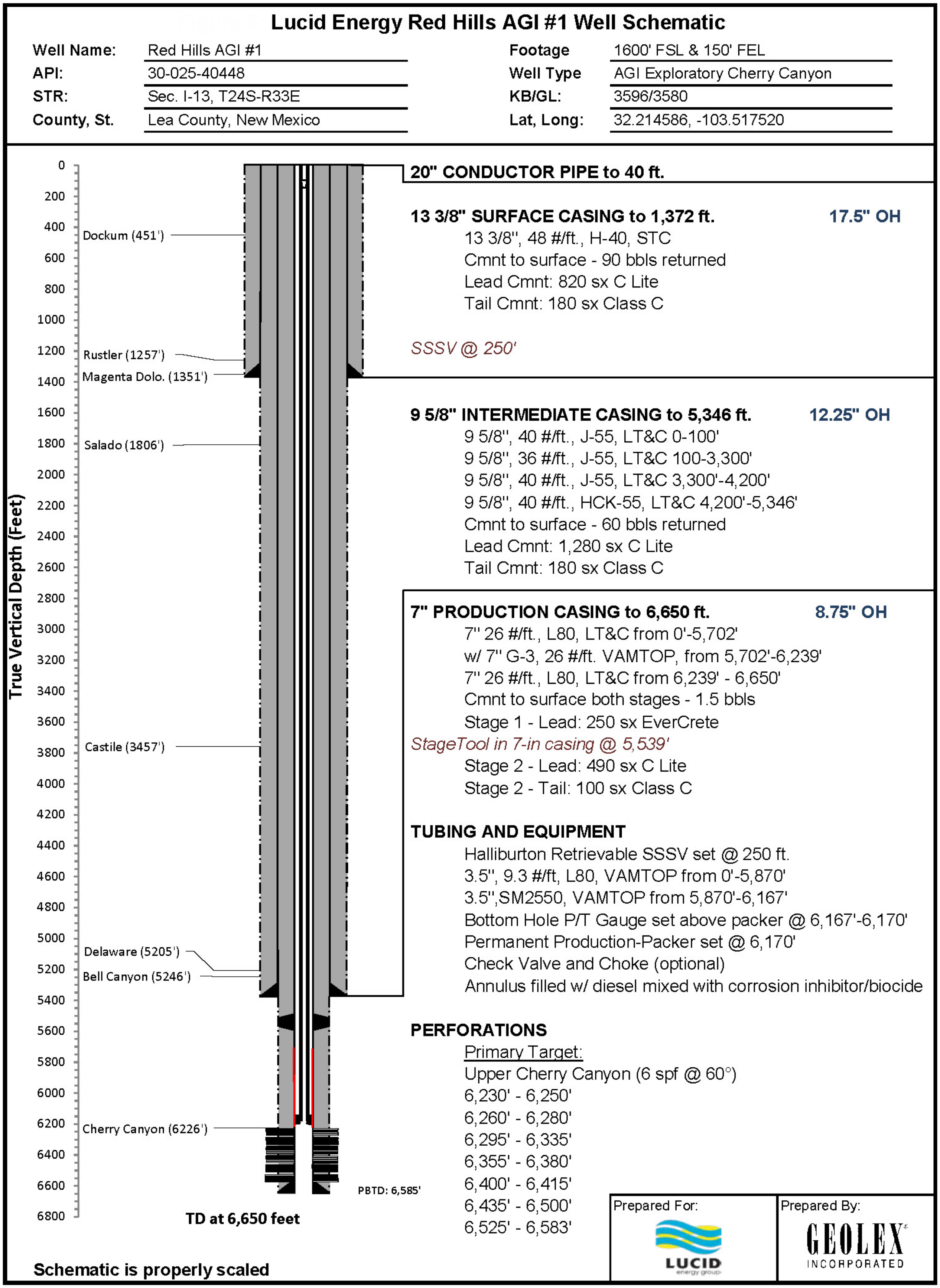


Figure Appendix 1-1: *Schematic of RH AGI #1*

Targa Resources
Red Hills Delaware AGI #3
Location 3116' FNL & 1159' FEL
Sec 13 - T 24S - R 33E
GL 3578', RKB TBD

Surface - (Conventional)

Hole Size:	17.5"
Casing:	13.375" 72# L-80 VAM TOP
Depth Top:	Surface
Depth Btm:	1307'
Cement:	TBD sks - Class C + Additives
Cement Top:	Surface - (Circulate)

Intermediate #1 - (Conventional)

Hole Size:	12.25"
Casing:	9.625" 47# HCL-80 BTC
Depth Top:	Surface
Depth Btm:	5205'
Cement:	TBD - Class C + Additives
Cement Top:	Surface - (Circulate)

Production - (Conventional)

Hole Size:	8.5"
Casing 1:	7" 32# I-80 VAMSTL
Depths:	0' to 5280' & 5580' to 7600'
Casing 2:	7" 32# G3 CRA VAM HDL
Depths:	5280' to 5580'
Cement:	TBD - Class C + Additives, Well Lock resin 5280'-5580'
Cement Top:	Surface - (Circulate)
ECP/DV Tool:	5280' & 5580'

Tubing

Depth:	5700'
Tubing:	3.5" 7.7# G3 CRA VAM ACE
Packer:	7" x 3.5" PermaPak or equivalent (Inconel)
SSSV:	175'
PT Gauges:	5690'

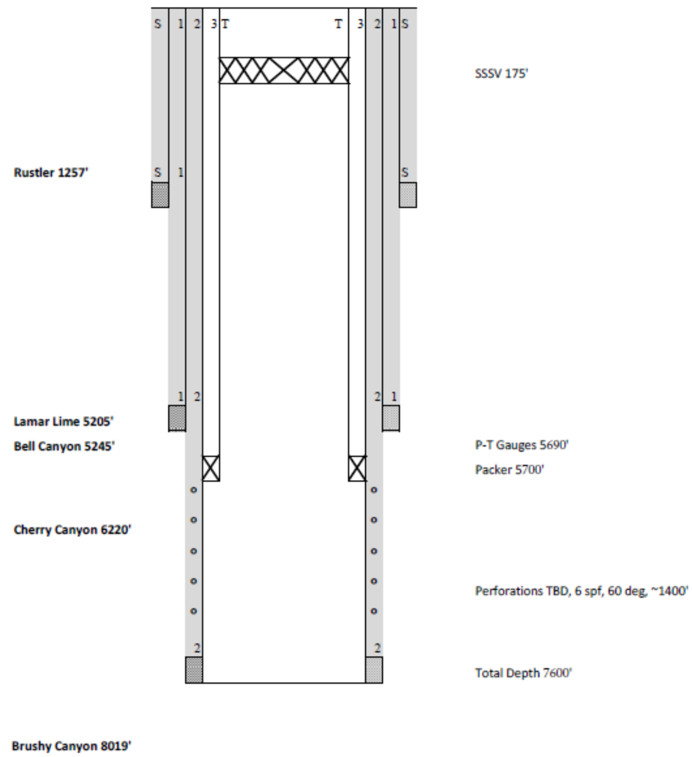


***Figure Appendix 1-2**: As-built wellbore schematic for RH AGI #3*

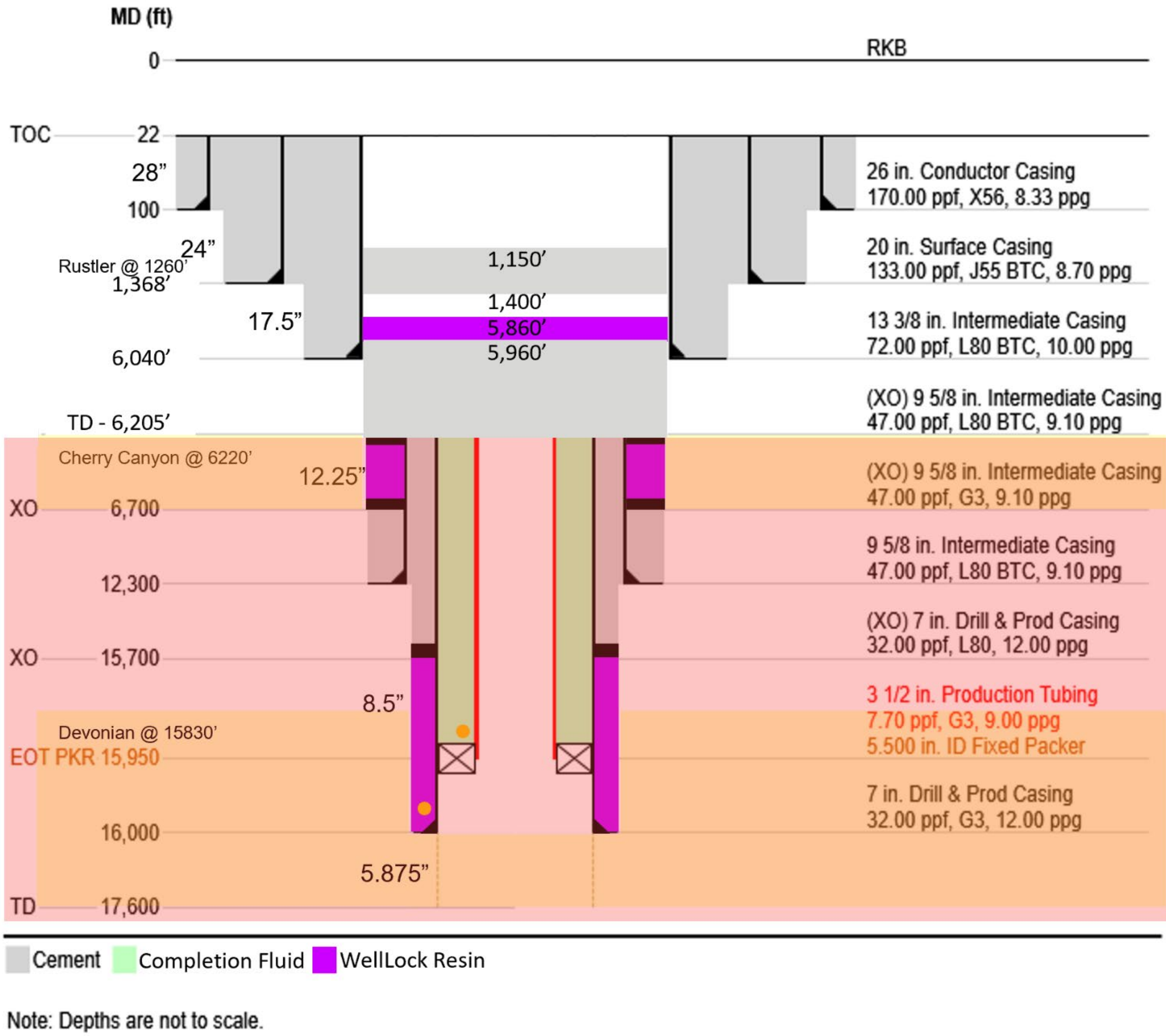


***Figure Appendix 1-3**: As-built wellbore schematic for the RH AGI #2 Well (temporarily abandoned). The colored portion of the schematic below 6,205 ft was not completed.*

Appendix 2 Referenced Regulations

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

New Mexico Administrative Code (NMAC) > Title 19 – Natural resources > Chapter 15 – Oil and Gas

CHAPTER 15 - OIL AND GAS

19.15.1 NMAC	GENERAL PROVISIONS AND DEFINITIONS [REPEALED]
19.15.2 NMAC	GENERAL PROVISIONS FOR OIL AND GAS OPERATIONS
19.15.3 NMAC	RULEMAKING
19.15.4 NMAC	ADJUDICATION
19.15.5 NMAC	ENFORCEMENT AND COMPLIANCE
19.15.6 NMAC	TAX INCENTIVES
19.15.7 NMAC	FORMS AND REPORTS
19.15.8 NMAC	FINANCIAL ASSURANCE
19.15.9 NMAC	WELL OPERATOR PROVISIONS
19.15.10 NMAC	SAFETY
19.15.11 NMAC	HYDROGEN SULFIDE GAS
19.15.12 NMAC	POOLS
19.15.13 NMAC	COMPULSORY POOLING
19.15.14 NMAC	DRILLING PERMITS
19.15.15 NMAC	WELL SPACING AND LOCATION
19.15.16 NMAC	DRILLING AND PRODUCTION
19.15.17 NMAC	PITS, CLOSED-LOOP SYSTEMS, BELOW-GRADE TANKS AND SUMPS
19.15.18 NMAC	PRODUCTION OPERATING PRACTICES
19.15.19 NMAC	NATURAL GAS PRODUCTION OPERATING PRACTICE
19.15.20 NMAC	OIL PRORATION AND ALLOCATION
19.15.21 NMAC	GAS PRORATION AND ALLOCATION
19.15.22 NMAC	HARDSHIP GAS WELLS
19.15.23 NMAC	OFF LEASE TRANSPORT OF CRUDE OIL OR CONTAMINANTS
19.15.24 NMAC	ILLEGAL SALE AND RATABLE TAKE
19.15.25 NMAC	PLUGGING AND ABANDONMENT OF WELLS
19.15.26 NMAC	INJECTION
19.15.27 - 28 NMAC	[RESERVED] PARTS 27 - 28
19.15.29 NMAC	RELEASES

19.15.30 NMAC	REMEDIATION
19.15.31 - 33 NMAC	[RESERVED] PARTS 31 - 33
19.15.34 NMAC	PRODUCED WATER, DRILLING FLUIDS AND LIQUID OIL FIELD WASTE
19.15.35 NMAC	WASTE DISPOSAL
19.15.36 NMAC	SURFACE WASTE MANAGEMENT FACILITIES
19.15.37 NMAC	REFINING
19.15.38 NMAC	[RESERVED]
19.15.39 NMAC	SPECIAL RULES
19.15.40 NMAC	NEW MEXICO LIQUIFIED PETROLEUM GAS STANDARD
19.15.41 - 102 NMAC	[RESERVED] PARTS 41 - 102
19.15.103 NMAC	SPECIFICATIONS, TOLERANCES, AND OTHER TECHNICAL REQUIREMENTS FOR COMMERCIAL WEIGHING AND MEASURING DEVICES
19.15.104 NMAC	STANDARD SPECIFICATIONS/MODIFICATIONS FOR PETROLEUM PRODUCTS
19.15.105 NMAC	LABELING REQUIREMENTS FOR PETROLEUM PRODUCTS
19.15.106 NMAC	OCTANE POSTING REQUIREMENTS
19.15.107 NMAC	APPLYING ADMINISTRATIVE PENALTIES
19.15.108 NMAC	BONDING AND REGISTRATION OF SERVICE TECHNICIANS AND SERVICE ESTABLISHMENTS FOR COMMERCIAL WEIGHING OR MEASURING DEVICES
19.15.109 NMAC	NOT SEALED NOT LEGAL FOR TRADE
19.15.110 NMAC	BIODIESEL FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.111 NMAC	E85 FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.112 NMAC	RETAIL NATURAL GAS (CNG / LNG) REGULATIONS [REPEALED]

Appendix 3 Water Wells

Water wells identified by the New Mexico State Engineer's files within two miles of the RH AGI wells; water wells within one mile are highlighted in yellow.

POD Number	County	Sec	Tws	Rng	UTME	UTMN	Distance (mi)	Depth Well (ft)	Depth Water (ft)	Water Column (ft)
C 03666 POD1	LE	13	24S	33E	639132	3565078	0.31	650	390	260
C 03917 POD1	LE	13	24S	33E	638374	3565212	0.79	600	420	180
C 03601 POD1	LE	23	24S	33E	638124	3563937	1.17			
C 02309	LE	25	24S	33E	639638	3562994	1.29	60	30	30
C 03601 POD3	LE	24	24S	33E	638142	3563413	1.38			
C 03932 POD8	LE	7	24S	34E	641120	3566769	1.40	72		
C 03601 POD2	LE	23	24S	33E	637846	3563588	1.44			
C 03662 POD1	LE	23	24S	33E	637342	3564428	1.48	550	110	440
C 03601 POD5	LE	23	24S	33E	637988	3563334	1.48			
C 03601 POD6	LE	23	24S	33E	637834	3563338	1.55			
C 03601 POD7	LE	23	24S	33E	637946	3563170	1.58			
C 03600 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03602 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03600 POD1	LE	26	24S	33E	637275	3563023	1.94			
C 03600 POD3	LE	26	24S	33E	637784	3562340	2.05			

Appendix 4 Oil and Gas Wells within 2-mile Radius of the RH AGI Well Site

Note – a completion status of "New" indicates that an Application for Permit to Drill has been filed and approved but the well has not yet been completed. Likewise, a spud date of 31-Dec-99 is actually 12-31-9999, a date used by NMOCD databases to indicate work not yet reported.

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-08371	COSSATOT E 002	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	5425	Yes
30-025-25604	GOVERNMENT L COM 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	17625	No
30-025-26369	GOVERNMENT L COM 002	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	14698	Yes
30-025-26958	SIMS 001	BOPCO, L.P.	GAS	DELAWARE VERTICAL	P & A	VERTICAL	15007	Yes
30-025-27491	SMITH FEDERAL 001	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	15120	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-40448	RED HILLS AGI 001	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	INJECTING	VERTICAL	6650	Yes
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL		PRODUCING	VERTICAL	10997	No
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11034	No
30-025-41382	DECKARD FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11067	Yes
30-025-41383	DECKARD FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11162	Yes
30-025-41384	DECKARD FEDERAL COM 004H	COG OPERATING LLC	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11103	Yes
30-025-41666	SEBASTIAN FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10927	Yes
30-025-41687	SEBASTIAN FEDERAL COM 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10944	Yes
30-025-41688	SEBASTIAN FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11055	No
30-025-43532	LEO THORSNESS 13 24 33 211H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12371	No
30-025-44442	STRONG 14 24 33 AR 214H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12500	No
30-025-46154	LEO THORSNESS 13 24 33 221H	MATADOR PRODUCTION COMPANY	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12868	No
30-025-46282	LEO THORSNESS 13 24 33 AR 135H	MATADOR PRODUCTION COMPANY	OIL	3RD BONE SPRING SAND	PRODUCING	HORIZONTAL	12103	No

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-46517	BROADSIDE 13 W FEDERAL COM 001H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12213	No
30-025-46518	BROADSIDE 13 24 FEDERAL COM 002H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-46519	BROADSIDE 13 24 FEDERAL COM 003H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12320	Yes
30-025-46985	SEBASTIAN FEDERAL COM 703H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12123	No
30-025-46988	SEBASTIAN FEDERAL COM 704H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12142	No
30-025-47869	JUPITER 19 FEDERAL COM 501H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11175	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47874	JUPITER 19 FEDERAL COM 506H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10950	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47877	JUPITER 19 FEDERAL COM 509H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11156	No
30-025-47878	JUPITER 19 FEDERAL COM 510H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11102	No
30-025-47908	JUPITER 19 FEDERAL COM 601H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-47910	JUPITER 19 FEDERAL COM 702H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	DUC	HORIZONTAL	0	Yes
30-025-47911	JUPITER 19 FEDERAL COM 705H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12290	No
30-025-47912	JUPITER 19 FEDERAL COM 707H	EOG RESOURCES INC	OIL	WOLFCAMP B UPPER	PERMITTED	HORIZONTAL	12515	No
30-025-47913	JUPITER 19 FEDERAL COM 708H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12477	No
30-025-48239	JUPITER 19 FEDERAL COM 306H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10270	No
30-025-48889	JUPITER 19 FEDERAL COM 701H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-48890	JUPITER 19 FEDERAL COM 703H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-49262	BROADSIDE 13 24 FEDERAL COM 004H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12531	Yes
30-025-49263	BROADSIDE 13 24 FEDERAL COM 015H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B LOWER	PRODUCING	HORIZONTAL	12746	Yes
30-025-49264	BROADSIDE 13 24 FEDERAL COM 025H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11210	Yes
30-025-49474	RED HILLS AGI 002	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	Temporarily Abandoned	VERTICAL	17600	Yes

Appendix 5 References

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Appendix 6 Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
AoR – Area of Review
API – American Petroleum Institute
CFR – Code of Federal Regulations
C1 – methane
C6 – hexane
C7 - heptane
CO_2 – carbon dioxide
DCS – distributed control system
EPA – US Environmental Protection Agency, also USEPA
ft – foot (feet)
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MSCFD– thousand standard cubic feet per day
MMSCFD – million standard cubic feet per day
MMstb – million stock tank barrels
MRRW B – Morrow B
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NIST - National Institute of Standards and Technology
NMOCC – New Mexico Oil Conservation Commission
NMOCD - New Mexico Oil Conservation Division
PPM – Parts Per Million
psia – pounds per square inch absolute
QA/QC – quality assurance/quality control
SCITS - Stanford Center for Induced and Triggered Seismicity
Stb/d – stock tank barrel per day
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TVD – True Vertical Depth
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

Appendix 7 TND Red Hills AGI Wells - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

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

* All measurements must be made in accordance with 40 CFR 98.444 – Monitoring and QA/QC Requirements.

** If you measure the mass of contents of containers summed quarterly using weigh bill, scales, or load cells (40 CFR 98.444(a)(2)(i)), use RR-1 for Containers to calculate CO_2 received in containers for injection.

*** If you determine the volume of contents of containers summed quarterly (40 CFR 98.444(a)(2)(ii)), use RR-2 for Containers to calculate CO_2 received in containers for injection.

Appendix 8 Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

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

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

(Equation RR-1 for Pipelines)

where:

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

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

(Equation RR-1 for Containers)

where:

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

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

(Equation RR-2 for Containers)

where:

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

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

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

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

(Equation RR-4)

where:

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

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

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

p = Quarter of the year.

u = Flow meter.

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

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

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

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

(Equation RR-6)

where:

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

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

u = Flow meter.

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

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

(Equation RR-7)

where:

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-8)

where:

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

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-9)

where:

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

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

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

w = Separator.

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

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

Appendix 9 P&A Records

P&A Record for Government Com 001, API #30-025-25604

New Mexico Oil Conservation Division, District I
1625 N. French Drive
Hobbs, NM 88240

Form 3160-5
(April 2004)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OM B No. 1004-0137
Expires: March 31, 2007

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

5. Lease Serial No. NM-17446

6. If Indian, Allottee or Tribe Name

***SUBMIT IN TRIPLICATE** - Other instructions on reverse side.*

7. If Unit or CA/Agreement, Name and/or No.

1. Type of Well: ☐ Oil Well ☑ Gas Well ☐ Other

8. Well Name and No. Government "L" Com #1

2. Name of Operator: EOG Resources, Inc

9. API Well No. 30-025-~~05010~~ 25604

3a. Address: P.O. Box 2267, Midland, TX, 79702

3b. Phone No. *(include area code)* 432-561-8600

10. Field and Pool, or Exploratory Area: Bell Lake, South Morrow

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*

Unit Letter G, 1980 FNL, 1980 FEL
Section 18, Township 24-S, Range 34-E

11. County or Parish, State: Lea, New Mexico

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
☑ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☐ Other
	☐ Change Plans	☑ Plug and Abandon	☐ Temporarily Abandon	
	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

1. Notified Jim McCormick w/BLM 24 hrs prior to MI and RU.
2. Cut 3 1/2' tbg at 11500, spot 50sx CLass "H" cmt, plug from 11500-11400, WOC Tag at 11389.
3. Circ hole w/MLF.
4. Perf 4 holes at 9050, press up to 2000 PSI, spot 75sx, plug from 9100-8950, WOC Tag @ 8938.
5. Perf 4 holes at 7000, press up to 2000 PSI, spot 75sx, plug from 7050-6900, WOC Tag at 6855.
6. Cut 10 3/4" csg at 5450, L/D csg, spot 150sx, plug from 5500-5350, WOC Tag at 5336.
7. Spot 75sx, plug from 1300-1200 (T-Salt) WOC Tag at 1143.
8. Spot 150sx, plug from 650-450 (20" Shoe) WOC Tag at 423.
9. Spot 20sx, plug from 30-Surf.
10. Clean location. Install dry hole marker 12-30-04.

P&A Complete 12-30-04

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

14. I hereby certify that the foregoing is true and correct
Name *(Printed/Typed)* Jimmy Bagley | Title Consultant

Signature | Date 12/30/2004

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by | Title | Date

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon. | Office

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on page 2)

GWW

P&A Records for API #30-025-26958

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

RECEIVED
AUG 16 2012
HOBBSOCD

Form C-103
Revised August 1, 2011

	WELL API NO. 3002526958
	5. Indicate Type of Lease STATE ☐ FEE ☒
	6. State Oil & Gas Lease No. SCR-389
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name Sims
1. Type of Well: Oil Well ☐ Gas Well ☒ Other	8. Well Number #1
2. Name of Operator: Agave Energy Company	9. OGRID Number 147831
3. Address of Operator 104 S. Fourth St., Artesia NM 88210 (575-748-4528)	10. Pool name or Wildcat Big Sinks Wolfcamp

4. Well Location
Unit Letter K: 1980 feet from the N line and 800 feet from the E line
Section 13 Township 24S Range 33E NMPM Lea County

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
OTHER: ☐		OTHER ☒ Replug to cement off Cherry Canyon per NMOCC R-13507	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion

The remediation of the Sims #1 well pursuant to NMOCC order was completed on August 15, 2011 and all equipment has been demobilized. The plugging was done pursuant to NMOCD requirements and all aspects of the effort were reported to Mark Whitaker and E.L. Gonzales of the OCD District 1 office who approved the specifics of the plugging as shown in the attached plugging diagram. When establishing a rate prior to squeezing the Cherry Canyon, it is clear that the reservoir is an excellent reservoir as it was taking 3bbl/min on vacuum. This indicates that the predicted injection plume for the Red Hills AGI #1 in this reservoir will be smaller than anticipated and the reservoir conditions act to prevent migration of injected acid gas out of the intended and permitted injection zone by any nearby wellbores including the Govt#2, Govt#1 and Smith Federal #1 in addition to the Sims#1. Please see attached wellbore sketch for plugging details of all plugs set and amounts of cement squeezed for each plug.

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE_______________ TITLE_ Consultant to Agave Energy Company _DATE August 16, 2012____

Type or print name ___Alberto A. Gutierrez, RG E-mail address: ___aag@geolex.com______ PHONE: __505-842-8000____

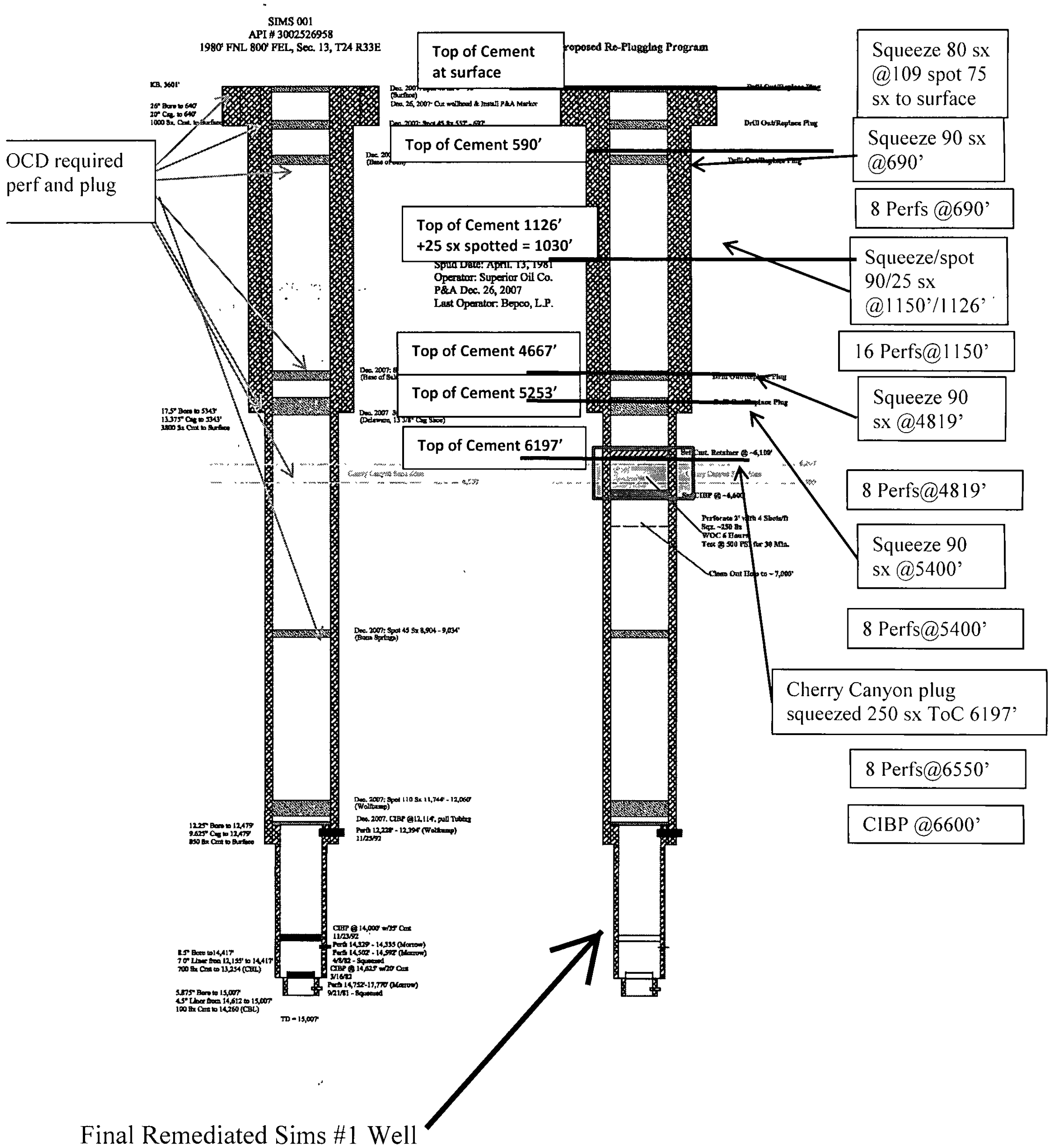
For State Use Only

APPROVED BY: ________ TITLE Dist Mgr DATE 8-16-2012
Conditions of Approval (if any):

AUG 16 2012

GEOLEX
INCORPORATED

8/16/2012



P&A Records for API 30-025-08371

NEW MEXICO OIL CONSERVATION COMMISSION

FORM C-103 (Rev 3-55)

MISCELLANEOUS REPORTS ON WELLS

(Submit to appropriate District Office as per Commission Rule 1106)

Name of Company: Byard Bennett			Address: 207 West Third, Roswell, New Mexico		
Lease: Holland	Well No. 1	Unit Letter H	Section 13	Township 24 South	Range 33 East
Date Work Performed: March 8, 1961	Pool: Wildcat		County: Lea		

THIS IS A REPORT OF: *(Check appropriate block)*

[ ] Beginning Drilling Operations [ ] Casing Test and Cement Job [ ] Other *(Explain)*:

[X] Plugging [ ] Remedial Work

Detailed account of work done, nature and quantity of materials used, and results obtained.

Top of Rustler: 1245', Top of Salt: 1392', Base of Salt: 4930', Top of Dela Ls: 5190'
Top of Delaware Sand: 5210', Total Depth: 5425', Casing 8 5/8 set at 365', Hole size 6 3/4

Cement Plugs set as follows:
5375-5425 with 15 sacks, 5175-5240 with 20 sacks, 1375-1425 with 20 sacks, 340-390 with 20 sacks, 5 sacks and marker pipe set at surface.
Heavy mud (4 cc wtr. loss) between all cement plugs.
Job performed and witnessed by Mr. Pool, Pool Drlg Co.
Prior verbal approval of plugging program from Mr. Engbrecht, New Mexico O C C.

Location will be cleaned and leveled as soon as practical.

Witnessed by	Position	Company
Mr. Fred Pool	Owner	Pool Drlg Co.

FILL IN BELOW FOR REMEDIAL WORK REPORTS *ONLY*

ORIGINAL WELL DATA

D F Elev.	T D	P B T D	Producing Interval	Completion Date

Tubing Diameter	Tubing Depth	Oil String Diameter	Oil String Depth

Perforated Interval(s)

Open Hole Interval | Producing Formation(s)

RESULTS OF WORKOVER

Test	Date of Test	Oil Production BPD	Gas Production MCFPD	Water Production BPD	GOR Cubic feet/Bbl	Gas Well Potential MCFPD
Before Workover						
After Workover						

OIL CONSERVATION COMMISSION

Approved by: Leslie A. Clements

Title

Date

I hereby certify that the information given above is true and complete to the best of my knowledge.

Name: Guy A. Swartz

Position: Agent

Company: Byard Bennett

Temporary Abandonment Record for RH AGI #2

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

	WELL API NO. 30-025-49474
	5. Indicate Type of Lease STATE ☐ FEE ☒
	6. State Oil & Gas Lease No.
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name RED HILLS AGI
1. Type of Well: Oil Well ☐ Gas Well ☒ Other Acid Gas Injection	8. Well Number 002
2. Name of Operator TARGA NORTHERN DELAWARE, LLC	9. OGRID Number 331548
3. Address of Operator 110 W 7TH STREET, SUITE 2300, TULSA OK 74119	10. Pool name or Wildcat

4. Well Location
Unit Letter_I_:_1800____feet from the SOUTH________ line and 150______feet from the EAST___________line
Section 13 Township 24S Range 33E NMPM LEA County

11. Elevation (*Show whether DR, RKB, RT, GR, etc.*)
3575 GR

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
CLOSED-LOOP SYSTEM ☐			
OTHER:	TEMPORARY ABANDON ☒	OTHER:	☐

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

3/08/2023 Drilled out of 13 3/8" with 12 ¼" bit. Drilled to 6161'and lost circulation. Attempt to regain with 3 heavy LCM pills.
3/08-3/10 Regained partial circulation and drilled to 6205'.
3/11 Rig up Halliburton and squeeze zone with 370 sacks of HalCem cement .
3/12 Drilled out cement squeeze and ran FIT test but would only hold 11.5 lb/gal.
3/15 Rig up Halliburton and set 150 sack balanced plug with Hal NEO CEM cement
Tagged plug at 5960' and shut down to wait on orders.
Decision has been made to not attempt to drill into the Cherry Canyon Injection zone due to not being able to maintain mud weight.
Propose to TEMPORARY ABANDON THE WELL BY:
RUN A CEMENT BOND LOG INSIDE THE 13 3/8"
SET A 100' CORROSION RESISTANT PLUG ON TOP OF EXISTING PLUG, SET A CEMENT PLUG INSIDE THE 13 3/8" ACROSS THE CASING SHOE (1350') AND 50' ABOVE THE RUSTLER (1260'). The plug would be from 1200' to 1400'.
PRESSURE TEST THE CASING TO 500 PSI FOR 30 MINUTES
REMOVE THE BOP AND INSTALL A BLIND FLANGE AND NIGHTCAP ON THE WELLHEAD.
RIG DOWN AND MOVE THE RIG OFF.

Spud Date: 02/13/2023 Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE___*Paul Ragsdale*__________ TITLE______ENGINEER____________________DATE______03/17/2023______

Type or print name _PAUL RAGSDALE___________ E-mail address: _pragsdale3727@gmail.com____ PHONE: ___575-626-7903_

For State Use Only

APPROVED BY:______________________________TITLE________________________________DATE__________________
Conditions of Approval (if any):

District I
1625 N. French Dr., Hobbs, NM 88240
Phone:(575) 393-6161 Fax:(575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone:(575) 748-1283 Fax:(575) 748-9720
District III
1000 Rio Brazos Rd., Aztec, NM 87410
Phone:(505) 334-6178 Fax:(505) 334-6170
District IV
1220 S. St Francis Dr., Santa Fe, NM 87505
Phone:(505) 476-3470 Fax:(505) 476-3462

State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

CONDITIONS

Action 198393

CONDITIONS

Operator:	
Targa Northern Delaware, LLC. 110 W. 7th Street, Suite 2300 Tulsa, OK 74119	OGRID: 331548
	Action Number: 198393
	Action Type: [C-103] Sub. General Sundry (C-103Z)

CONDITIONS

Created By	Condition	Condition Date
pkautz	MUST CAP EXISTING PLUG WITH 100' CORROSION RESISTANT CEMENT	3/17/2023
pkautz	AFTER TA MUST PERFORM TA PRESSURE TEST	3/17/2023
pkautz	AFTER TA SUBMIT A WELLBORE SCHEMATIC	3/17/2023

Appendix B: Submissions and Responses to Requests for Additional Information

MONITORING, REPORTING, AND VERIFICATION PLAN

Red Hills AGI #1 and Red Hills AGI #3

Targa Northern Delaware, LLC (TND)

Version 1.0
July 23, 2024

Table of Contents

1 Introduction

Targa Northern Delaware, LLC (TND) is currently authorized to inject treated acid gas (TAG) into the Red Hills Acid Gas Injection #1 well (RH AGI #1)(American Petroleum Institute (API) 30-025-40448) and the RH AGI #3 well (API # 30-025-51970) under the New Mexico Oil Conservation Commission (NMOCC) Orders R-13507 – 13507F and Order R-20916H, respectively, at the Red Hills Gas Plant located approximately 20 miles NNW of Jal in Lea County, New Mexico (**Figure 1-1**). Each well is approved to inject 13 million standard cubic feet per day (MMSCFD). However, although approved to inject 13 MMSCFD, RH AGI #1 is physically only capable of taking ~5 MMSCFD due to formation and surface pressure limitations.

RH AGI #1 was previously operated by Lucid Energy Delaware, LLC's ("Lucid"). TND acquired Lucid assets in 2022. Lucid received authorization to construct a redundant well, RH AGI #2 (API# 30-025-49474) under NMOCC Order R-20916-H, which is offset 200 ft to the north of RH AGI #1 and is currently temporarily abandoned in the Bell Canyon Formation.

TND recently received approval from NMOCC for its C-108 application to drill, complete and operate a third acid gas injection well (RH AGI #3) for which TND requested an injection volume of up to 13 MMSCFD. RH AGI #3 was spudded on 9/13/2023, completed on 9/27/2023, and injection commenced on 1/11/2024. Because RH AGI #1 does not have complete redundancy, having a greater permitted disposal volume will also increase operational reliability. RH AGI #3 is a vertical well with its surface location at approximately 3,116 ft from the north line (FNL) and 1,159 ft from the east line (FEL) of Section 13. The depth of the injection zone for this well is approximately 5,700 to 7,600 ft in the Bell Canyon and Cherry Canyon Formations (see As-Built schematic in **Figure Appendix 1-2**). Analysis of the reservoir characteristics of these units confirms that they act as excellent closed-system reservoirs that will accommodate the future needs of TND for disposal of treated acid gas (H_2S and CO_2) from the Red Hills Gas Plant.

TND has chosen to submit this Monitoring, Reporting, and Verification (MRV) plan to EPA for approval according to 40CFR98.440(c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. TND intends to inject CO_2 for another 30 years.

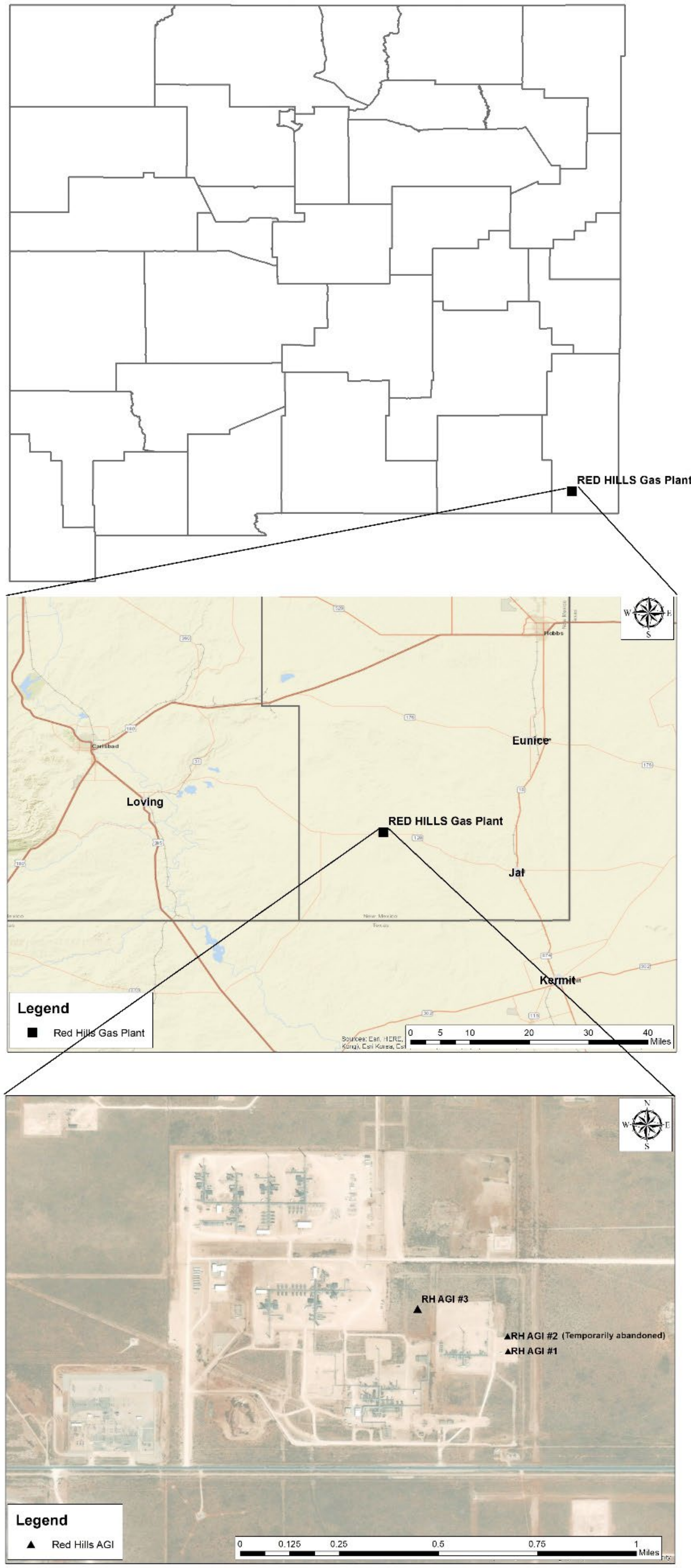


***Figure 1-1**: Location of the Red Hills Gas Plant and Wells – RH AGI #1, RH AGI #2 (temporarily abandoned), and RH AGI #3*

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40CFR98.449, and as required by 40CFR98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40CFR98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage as required by 40CFR98.448(a)(3).

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40CFR98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40CFR98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40CFR98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40CFR98.445.

Section 11 describes the records to be retained according to the requirements of 40CFR98.3(g) of Subpart A of the GHGRP and 40CFR98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan, including information required by 40CFR98.448(a)(6).

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is **553798**

2.2 UIC injection well identification numbers

This MRV plan is for RH AGI #1 and RH AGI #3 (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

For injection wells that are the subject of this MRV plan, the New Mexico Oil Conservation Division (NMOCD) has issued Underground Injection Control (UIC) Class II acid gas injection (AGI) permits under its State Rule 19.15.26 NMAC (see **Appendix 2**). All oil- and gas-related wells around the RH AGI wells, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3 Project Description

The following project description was developed by the Petroleum Recovery Research Center (PRRC) at New Mexico Institute of Mining and Technology (NMT) and the Department of Geosciences at the University of Texas Permian Basin (UTPB).

3.1 General Geologic Setting / Surficial Geology

The TND Red Hills Gas Plant is located in T 24 S R 33 E, Section 13, in Lea County, New Mexico, immediately adjacent to the RH AGI wells. (**Figure 3.1-1**). The plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. The dune sands are locally stabilized with shin oak, mesquite, and some burr-grass. There are no natural surface bodies of water within one mile of the plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

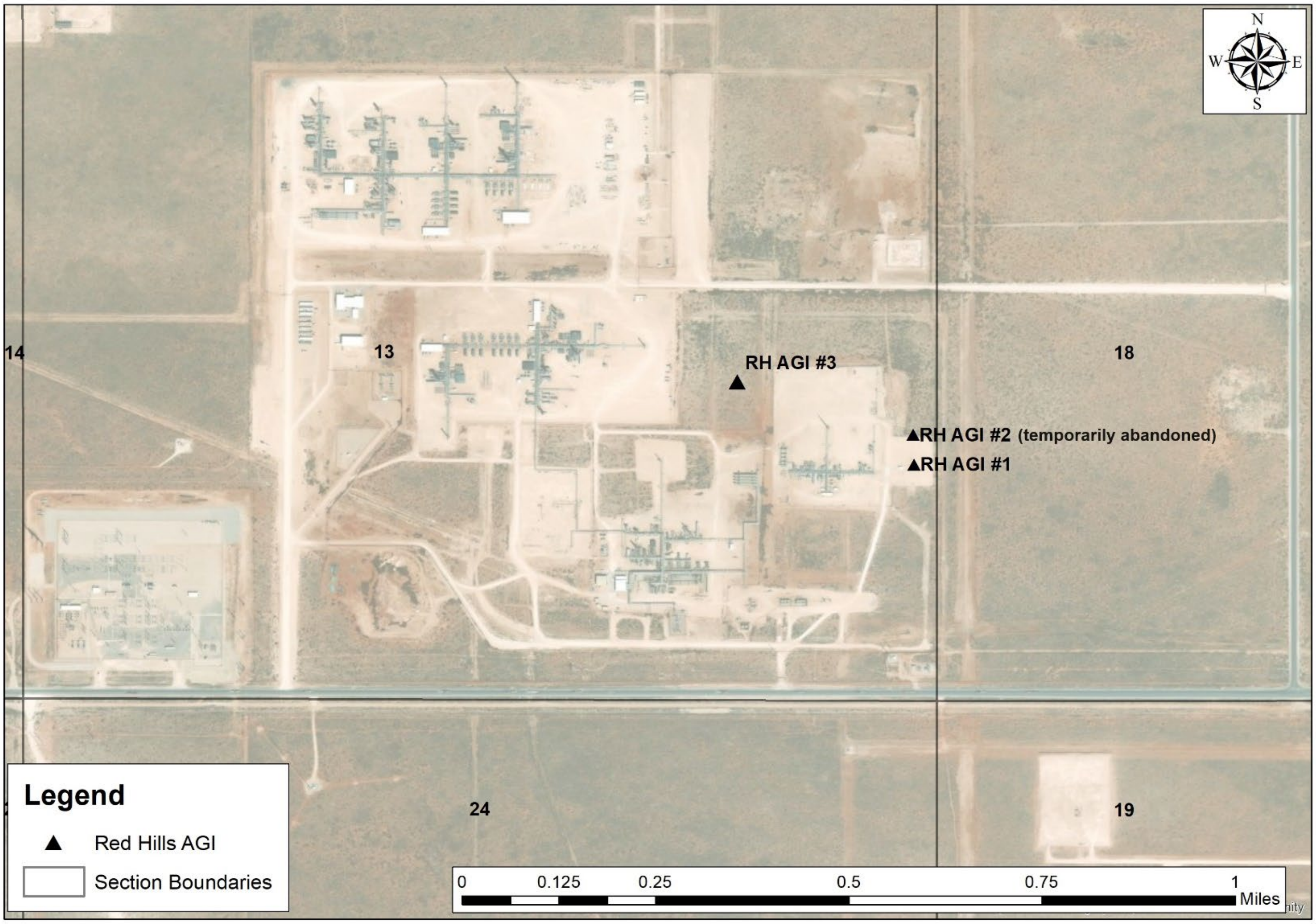


***Figure 3.1-1**: Map showing location of TND Red Hills Gas Plant and RH AGI Wells in Section 13, T 24 S, R 33 E*

3.2 Bedrock Geology

3.2.1 Basin Development

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

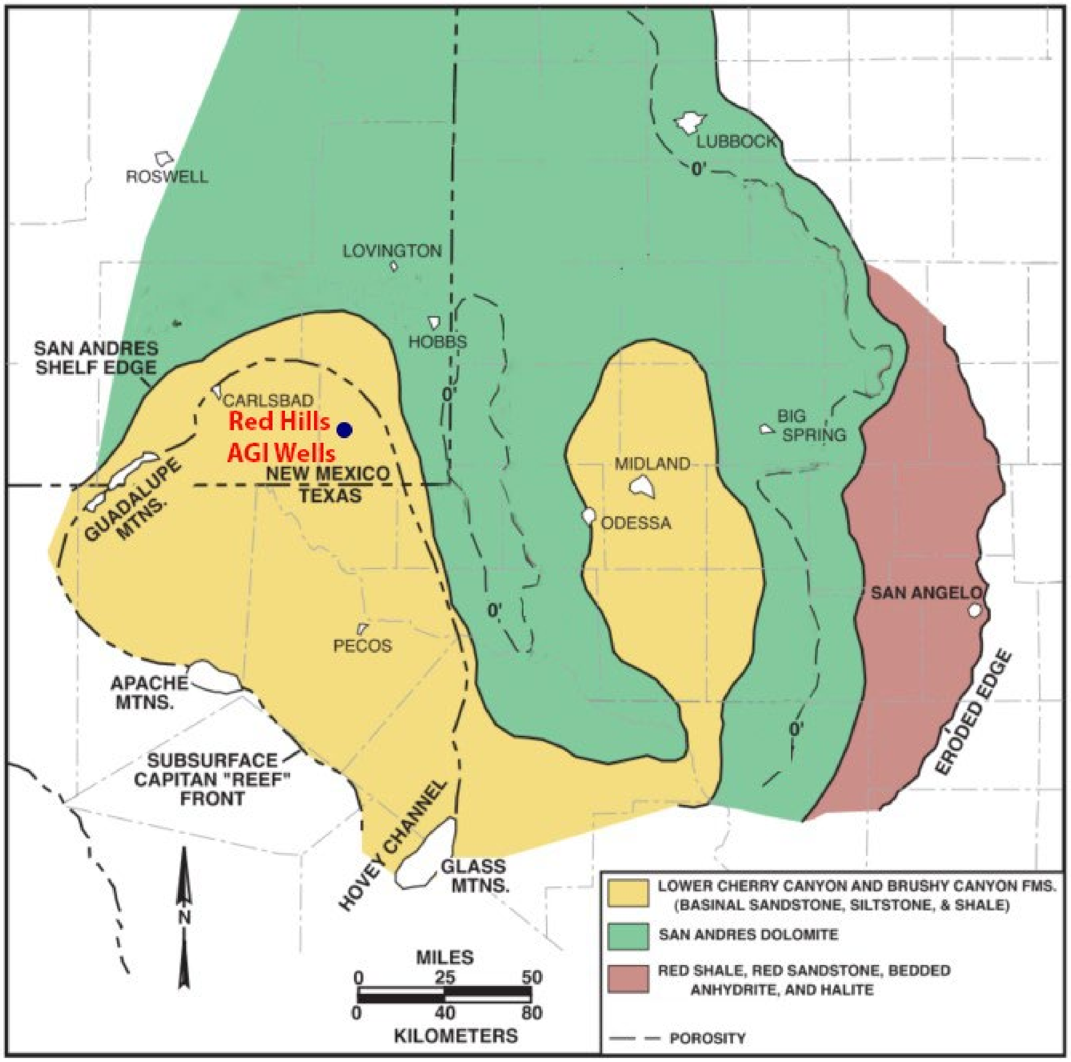


Figure 3.2-1*: Structural features of the Permian Basin during the Late Permian. Location of the RH AGI wells is shown by the black circle. (Modified from Ward, et al (1986))*

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

The RH AGI wells are located in the Delaware Basin portion of the broader Permian Basin. Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland (**Figure 3.2-3**). With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Ellenburger Formation (0 – 1000 ft) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Throughout this narrative, the numbers after the formations indicate the range in thickness for that unit. Tectonic activity near the end of Ellenburger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit's overall porosity and permeability.

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

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

During Middle to Upper Ordovician time, seas once again covered the area and deposited the carbonates, sandstones and shales of the Simpson Group (0 – 1000 ft) and then the Montoya Formation (0 – 600 ft). This is the period when the Tobosa Basin formed due to the Pedernal uplift and development of the Texas Arch (**Figure 3.2-4**; Harrington, 2019), which shed Precambrian crystalline clasts into the basin. Simpson reservoirs in New Mexico are typically within deposits of shoreline sandstones (Broadhead, 2017). A subaerial exposure and karstification event followed the deposition of the Simpson Group. The Montoya Formation marked a return to dominantly carbonate sedimentation with minor siliciclastic sedimentation within the Tobosa Basin (Broadhead, 2017; Harrington and Loucks, 2019). The Montoya Formation consists of sandstones and dolomites and has also undergone karstification.

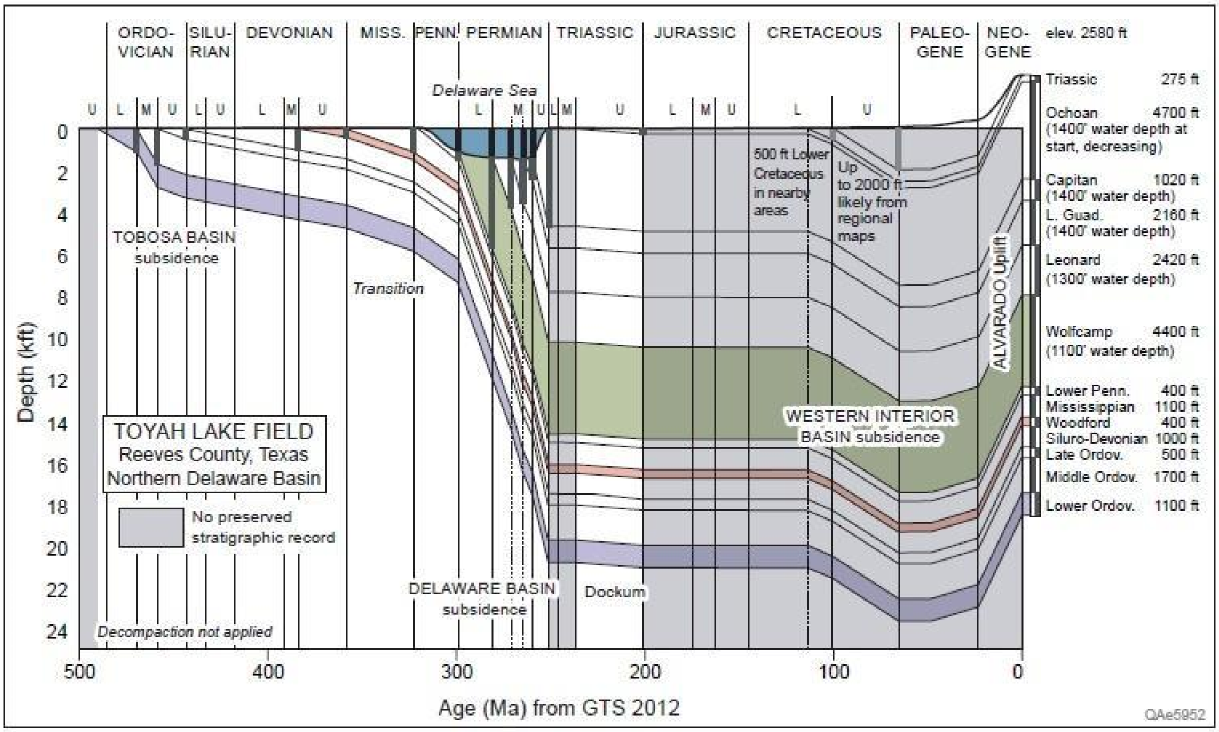


***Figure 3.2-3**: A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)*

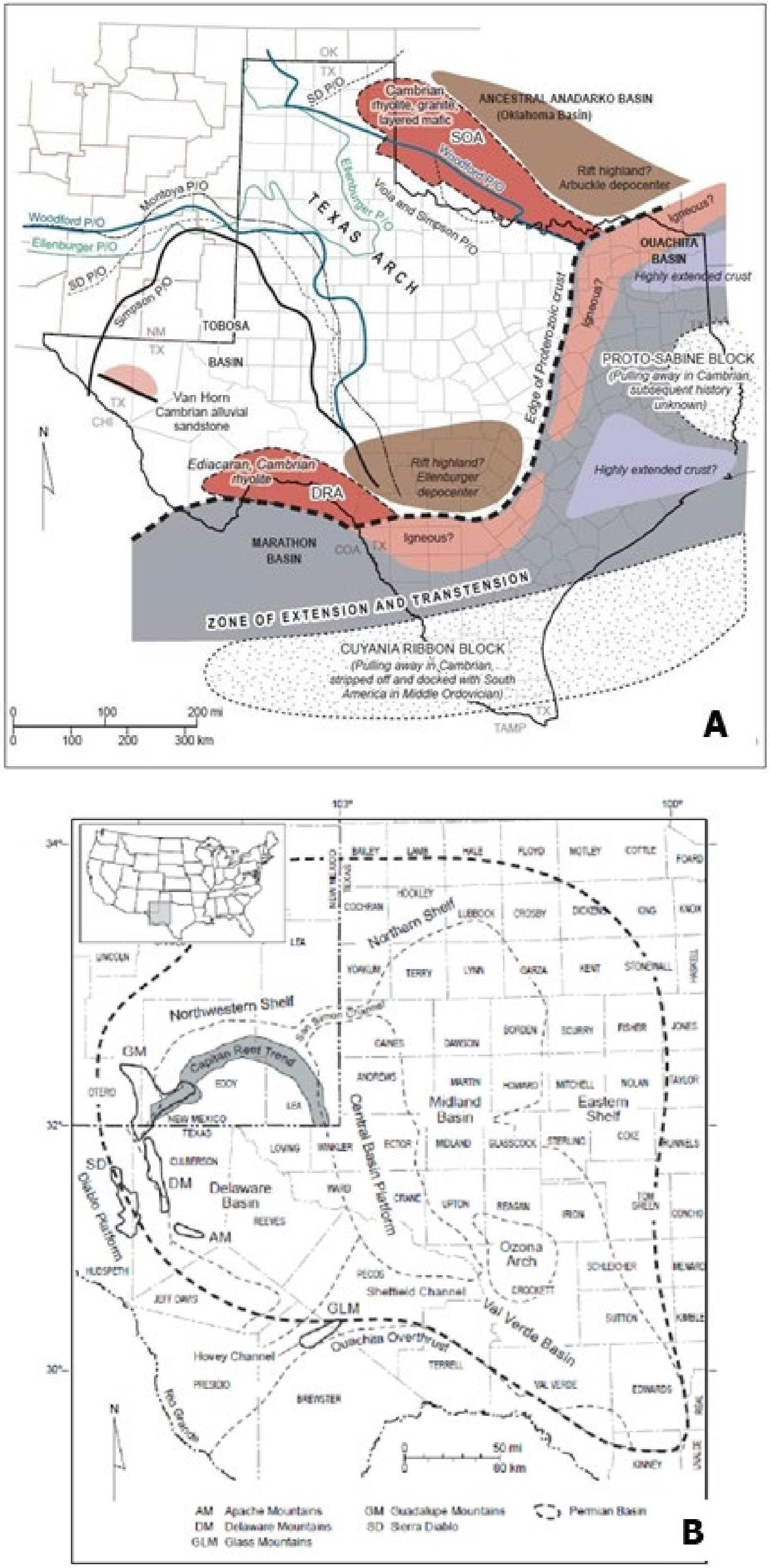


Figure 3.2-4: Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).

Siluro-Devonian formations consist of the Upper Ordovician to Lower Silurian Fusselman Formation (0 – 1,500 ft), the Upper Silurian to Lower Devonian Wristen Group (0 – 1,400 ft), and the Lower Devonian Thirtyone Formation (0 – 250 ft). The Fusselman Formation is primarily shallow-marine platform deposits of dolostones and limestones (Broadhead, 2017; Ruppel, 2019b). Subaerial exposure and karstification associated with another unconformity at top of the Fusselman Formation as well as intraformational exposure events created brecciated fabrics, widespread dolomitization, and solution-enlarged pores and fractures (Broadhead, 2017). The overlying Wristen and Thirtyone units appear to be conformable. The Wristen Group consists of tidal to high-energy platform margin carbonate deposits of dolostones, limestones, and cherts with minor siliciclastics (Broadhead, 2017; Ruppel, 2020). The Thirtyone Formation is present in the southeastern corner of New Mexico and appears to be either removed by erosion or not deposited elsewhere in New Mexico (**Figure 3.2-5**). It is shelfal carbonate with varying amounts of chert nodules and represents the last carbonate deposition in the area during Devonian time (Ruppel et al., 2020a).

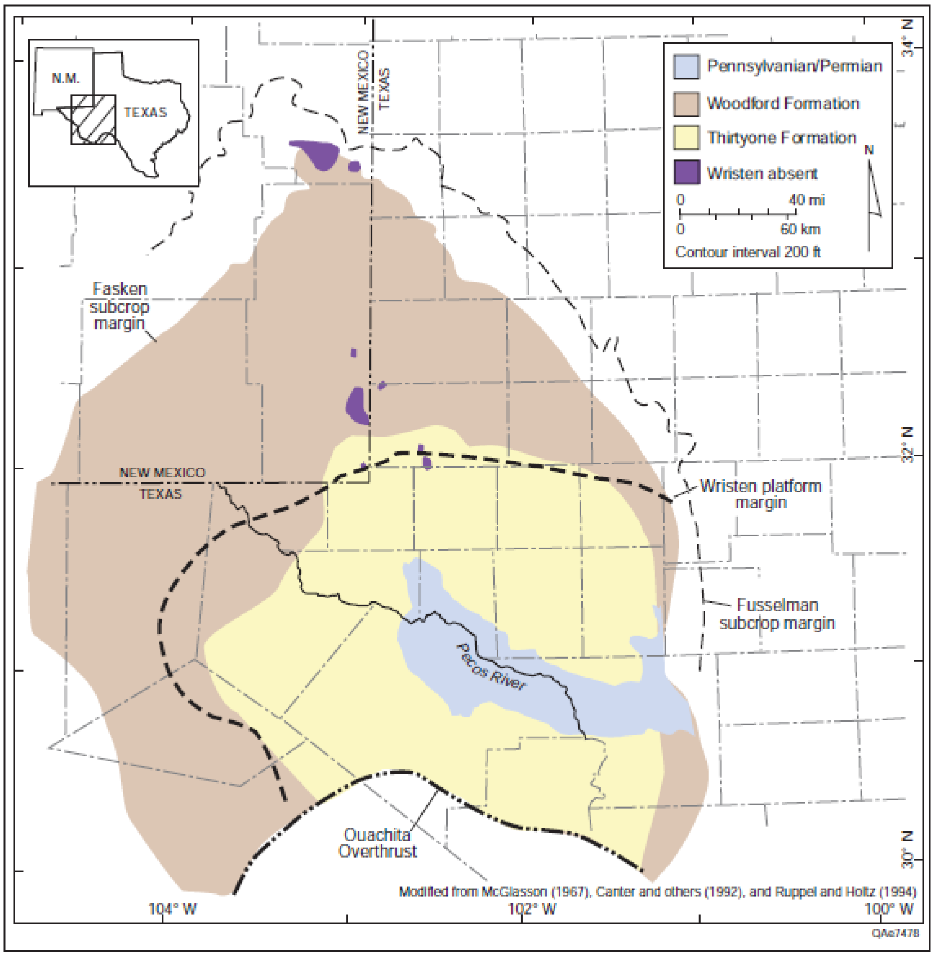


***Figure 3.2-5**: A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there are no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in Section 3.2.2.

The Devonian Woodford Shale, an un-named Mississippian limestone, and the Upper Mississippian Barnett Shale are seals for the underlying Siluro-Devonian strata. While the Mississippian recrystallized limestones have minor porosity and permeability, the Woodford and Barnett shales have extremely low porosity and permeability and would be effective barriers to upward migration of acid gas out of the injection zone. The Woodford Shale (0 – 300 ft) ranges from organic–rich argillaceous mudstones with abundant siliceous microfossils to organic-poor argillaceous mudstones (Ruppel et al., 2020b). The Woodford sediments represent stratified deeper marine basinal deposits with their organic content being a function of the oxygenation within the bottom waters – the more anoxic the waters the higher the organic content.

The Mississippian strata within the Delaware Basin consists of an un-named carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoirs limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise porosity is very low. The Barnett Shale (0 – 400 ft) unconformably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal siliciclastic deposits that make up the Barnett Shale.

Pennsylvanian sedimentation is dominated by glacio-eustatic sea-level cycles that produced shallowing upward cycles of sediments, ranging from deep marine siliciclastic and carbonate deposits to shallow-water limestones and siliciclastics, and capping terrestrial siliciclastic sediments and karsted limestones. Lower Pennsylvanian units consist of the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). The Atoka Formation (0-500 ft) was deposited during another sea-level transgression within the area. Within the area, the Atoka sediments are dominated by siliciclastic sediments, and depositional environments range from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

Middle Pennsylvanian units consist of the Strawn group (an informal name used by industry). Strawn sediments (250 - 1,000 ft) within the area consist of marine sediments that range from ramp carbonates, containing patch reefs, and marine sandstone bars to deeper marine shales (Broadhead, 2017).

Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales.

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

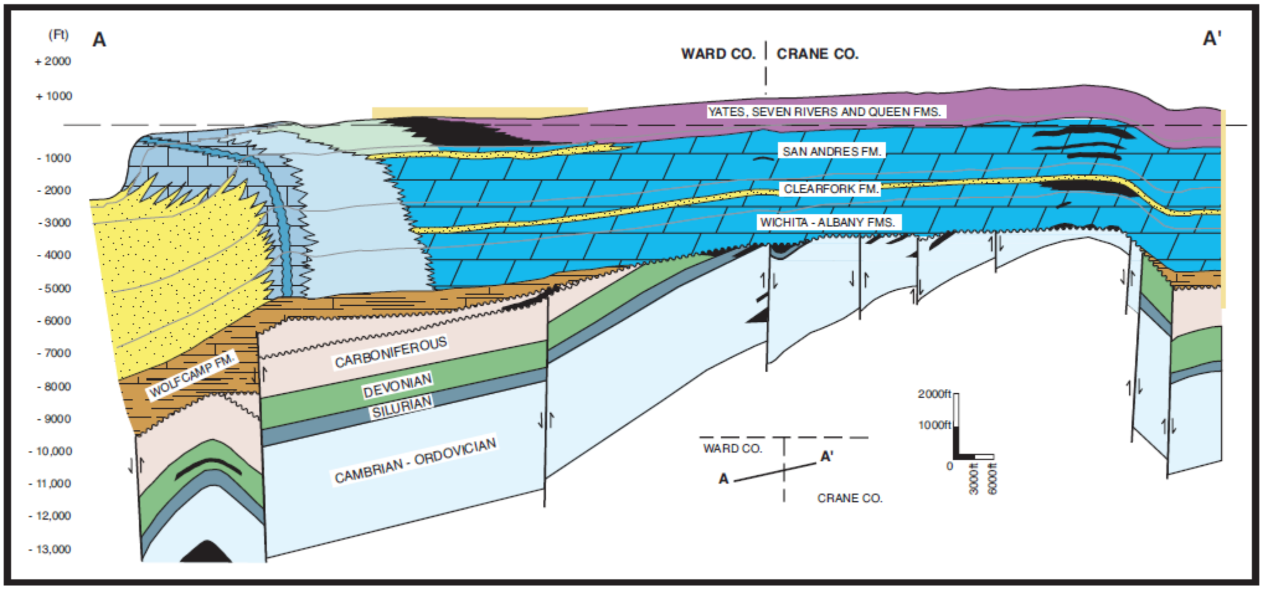


Figure 3.2-6: *Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).*

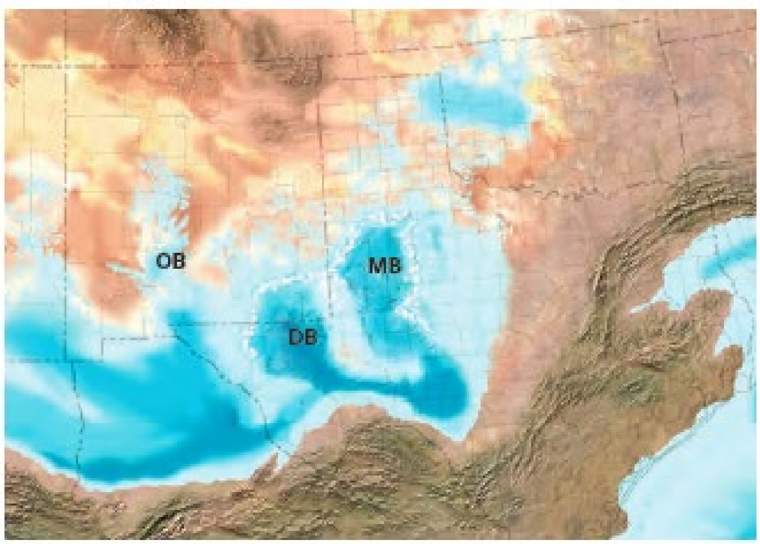


Figure 3.2-7: *Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).*

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, siliciclastic sediments largely bypassed the shelves and were deposited deeper in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a “carbonate factory” on the shelf and shelf edge. Carbonate debris beds shedding off the shelf margin were transported into the basin (Wilson, 1972; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100s feet to feet).

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along Northwest Shelf margin to shallow-marine, back-reef carbonates behind the shelf margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2019a). Sediments basinward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2019a). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. The Bone Spring Formation is a thick sequence of alternating carbonate and siliciclastic horizons that formed because of changes in sea level; the carbonates during highstands, and siliciclastics during lowstands. Overlying the Yeso, are the clean, white eolian sandstones of the Glorietta Formation, a key marker bed in the region, both on outcrop and in the subsurface. Within the basin, it is equivalent to the lowermost Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have been identified that have resulted in karstification and pervasive dolomitization of the unit. These exposure events/sea-level lowstands are correlated to sandstones/siltstones that moved out over the exposed shelf leaving minor traces of their presence on the shelf but formed thick sections of sandstones and siltstones in the basin. Within the Delaware Basin, the San Andres Formation is equivalent to the Brushy and lower Cherry Canyon Formations.

The Artesia Group (Grayburg, Queen, Seven Rivers, Yates, and Tansill formations, ascending order) is equivalent to Capitan Limestone, the Guadalupian barrier/fringing reef facies. Within the basin, the Artesia Group is equivalent to the upper Cherry and Bell Canyon formations, a series of relatively featureless sandstones and siltstones. The Queen and Yates formations contain more sandstones than the Grayburg, Seven Rivers, and Tansill formations. The Artesia units and the shelf edge equivalent Capitan reef sediments represent the period when the carbonate factory was at its greatest productivity with the shelf margin/Capitan reef prograding nearly 6 miles into the basin (Scholle et al., 2007). The Artesia Group sediments were deposited in back-reef, shallow marine to supratidal/evaporite environments. Like the San Andres Formation, the individual formations were periodically exposed during lowstands.

The final stage of Permian deposition on the Northwest Shelf consists of the Ochoan/Lopingian Salado Formation (<2,800 ft, Nance, 2020). Within the basin, the Castile formation, a thick sequence (total thickness ~1,800 ft, Scholle et al., 2007) of cyclic laminae of deep-water gypsum/anhydrite interbedded with calcite and organics, formed due to the restriction of marine waters flowing into the basin. Gypsum/anhydrite laminae precipitated during evaporative conditions, and the calcite and organic-rich horizons were a result of seasonal “freshening” of the basin waters by both marine and freshwaters. Unlike the Castile Formation, the Salado Formation is a relatively shallow water evaporite deposit. Halite, sylvite, anhydrite, gypsum, and numerous potash minerals were precipitated. The Rustler Formation (500 ft , Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represent the last Permian marine deposits in the Delaware Basin.

The Rustler Formation was followed by terrestrial sabkha red beds of the Dewey Lake Formation (~350', Nance, 2020), ending Permian deposition in the area.

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

3.2.2 Stratigraphy

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent, renamed Lopingian), Guadalupian, Leonardian (renamed Cisuralian), and Wolfcampian (oldest) (**Figure 3.2-2**). This sequence of shallow marine carbonates and thick, basinal siliciclastic deposits contains abundant oil and gas resources and are the main source of oil within New Mexico. In the area around the RH AGI wells, Permian strata are mainly basin deposits consisting of sandstones, siltstones, shales, and lesser amounts of carbonates. Besides production in the Delaware Mountain Group, there is also production, mainly gas, in the basin Bone Spring Formation, a sequence of carbonates and siliciclastics. The injection and confining zones for RH AGI #1 and RH AGI #3 are discussed below.

CONFINING/SEAL ROCKS

Permian Ochoa Series. The youngest of the Permian sediments, the Ochoan- or Lopingian-aged deposits, consists of evaporites, carbonates, and red beds. The Castile Formation is made of cyclic laminae of deep-water gypsum/anhydrite beds interlaminated with calcite and organics. This basin-occurring unit can be up to 1,800 ft thick. The Castile evaporites were followed by the Salado Formation (~1,500 ft thick). The Salado Formation is a shallow water evaporite deposit, when compared to the Castile Formation, and consists of halite, sylvite, anhydrite, gypsum, and numerous potash/bittern minerals. Salado deposits fill the basin and lap onto the older Permian shelf deposits. The Rustler Formation (up to 500 ft, Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin. The Ochoan evaporitic units are superb seals (usually <1% porosity and <0.01 mD permeability) and are the reason that the Permian Basin is such a hydrocarbon-rich region despite its less than promising total organic carbon (TOC) content.

INJECTION ZONE

Permian Guadalupe Series. Sediments in the underlying Delaware Mountain Group (descending, Bell Canyon, Cherry Canyon, and Brushy Canyon formations) are marine units that represent deposition controlled by eustacy and tectonics. Lowstand deposits are associated with submarine canyons that incised the carbonate platform margin surrounding the Delaware basin. Depositional environments consist of turbidite channels, splays, and levee/overbank deposits (**Figure 3.2-8**).

Additionally, debris flows formed by the failure of the carbonate margin and density currents also make up basin sediments. Isolated coarse-grained to boulder-sized carbonate debris flows and grain falls within the lowstand clastic sediments likely resulted from erosion and failure of the shelf margin during sea-level lowstands or slope failure to tectonic activity (earthquakes). Density current deposits resulted from stratified basin waters. The basal waters were likely stratified and so dense that turbidity flows containing sands, silts and clays were unable to displace those bottom waters and instead flowed out over the density interface (**Figure 3.2-9**). Eventually, the entrained sediments would settle out in a constant rain of sediment forming laminated deposits with little evidence of traction (bottom flowing) deposition.

Interbedded with the very thick lowstand sequences are thin, deep-water limestones and mudstones that represent highstand deposition. These deposits are thickest around the edge (toe-of-slope) of the basin and thin to the basin center (**Figure 3.2-10**). The limestones are dark, finely crystalline, radiolarian-rich micrites to biomicrites. These highstand deposits are a combination of suspension and pelagic sediments that also thin towards the basin center. These relatively thin units are time equivalent to the massive highstand carbonate deposits on the shelf.

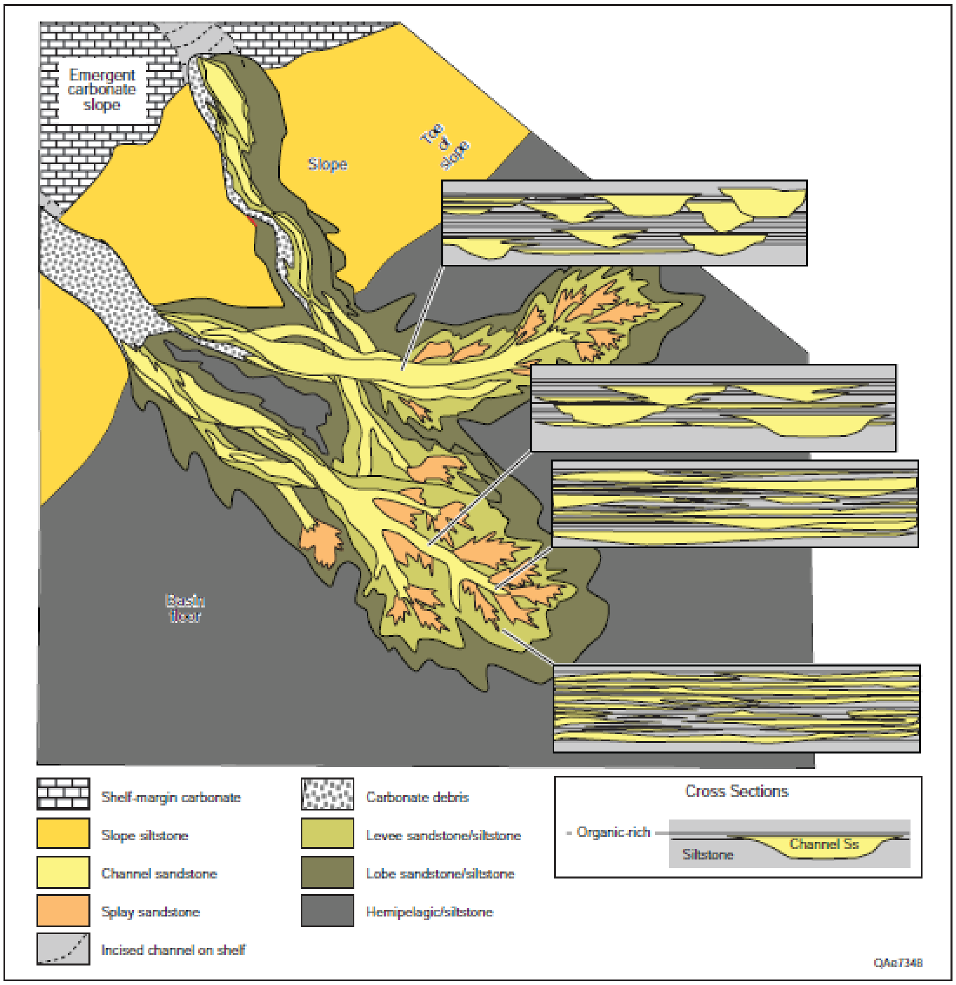


***Figure 3.2-8**: A diagram of typical Delaware Mountain Group basinal siliciclastic deposition patterns (from Nance, 2020). The channel and splay sandstones have the best porosity, but some of the siltstones also have potential as injection zones.*

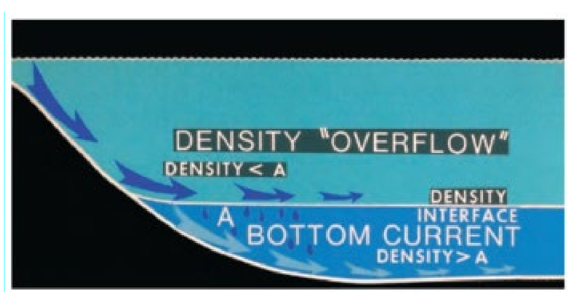


***Figure 3.2-9**: Harms' (1974) density overflow model explains the deposition of laminated siliciclastic sediments in the Delaware Basin. Low density sand-bearing fluids flow over the top of dense, saline brines at the bottom of the basin. The sands gradually drop out as the flow loses velocity creating uniform, finely laminated deposits (from Scholle et al., 2007).*

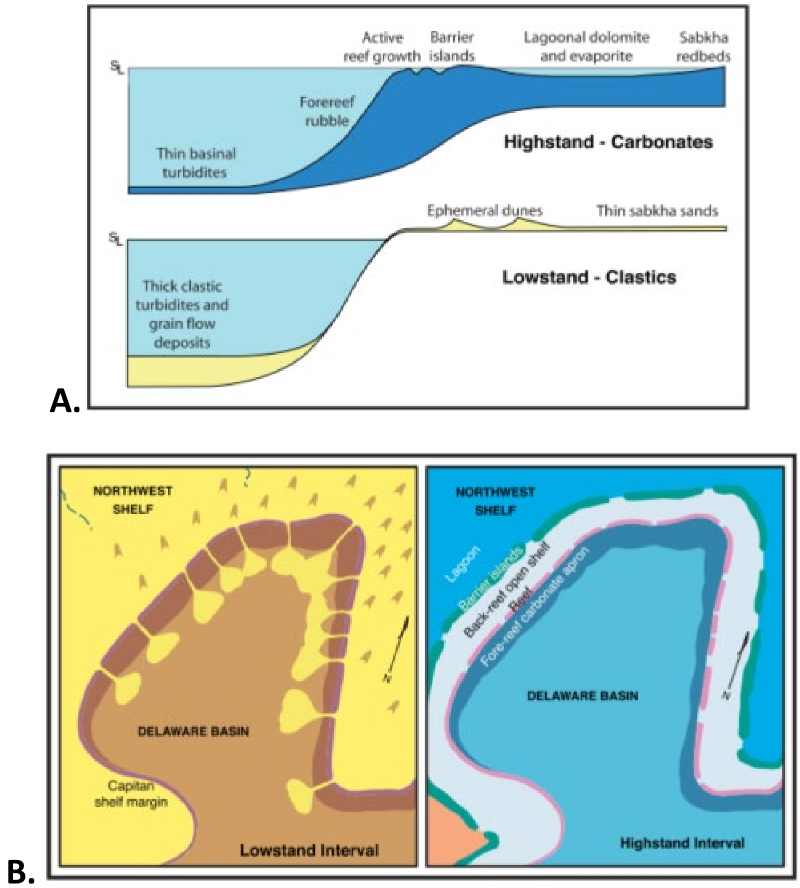


***Figure 3.2-10**: The impact of sea-level fluctuations (also known as reciprocal sedimentation) on the depositional systems within the Delaware Basin. A) A diagrammatic representation of sea-level variations impact on deposition. B) Model showing basin-wide depositional patterns during lowstand and highstand periods (from Scholle et al., 2007).*

The top of the Guadalupian Series is the Lamar Limestone, which is the source of hydrocarbons found in underlying Delaware Sand (an upper member of the Bell Canyon Formation). The Bell Canyon Formation is roughly 1,000 ft thick in the Red Hills area and contains numerous turbidite input points around the basin margin (**Figures 3.2-10, 3.2-11**). During Bell Canyon deposition, the relative importance of discrete sand sources varied (Giesen and Scholle, 1990), creating a network of channel and levee deposits that also varied in their size and position within the basin. Based on well log analyses, the Bell Canyon 2 and 3 had the thickest sand deposits.

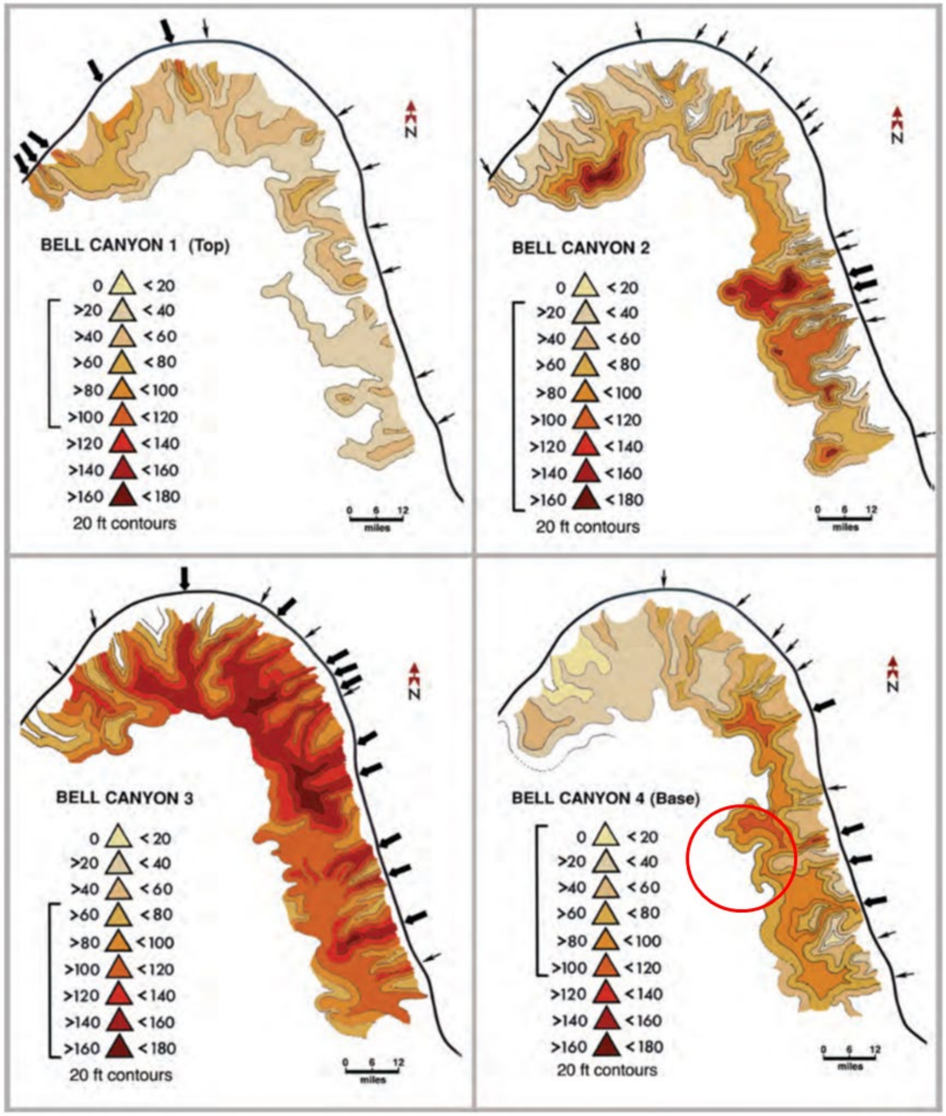


***Figure 3.2-11**: These maps of Bell Canyon Formation were created by measuring sandstone thicknesses on well logs in four regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). The red circle on the last map surrounds the Red Hills area.*

Like the Bell Canyon and Brushy Canyon formations, the Cherry Canyon Formation is approximately 1,300 ft thick and contains numerous turbidite source points. Unlike the Bell Canyon and Brushy Canyon deposits, the channel deposits are not as large (Giesen and Scholle, 1990), and the source of the sands appears to be dominantly from the eastern margin (**Figure 3.2-12**). Cherry Canyon 1 and 5 have the best channel development and the thickest sands. Overall, the Cherry Canyon Formation, on outcrop, is less influenced by traction current deposition than the rest of the Delaware Mountain Group deposits and is more influenced by sedimentation by density overflow currents (**Figure 3.2-9**). The Brushy Canyon has notably more discrete channel deposits and coarser sands than the Cherry Canyon and Bell Canyon. The Brushy Canyon Formation is approximately 1,500 ft thick.

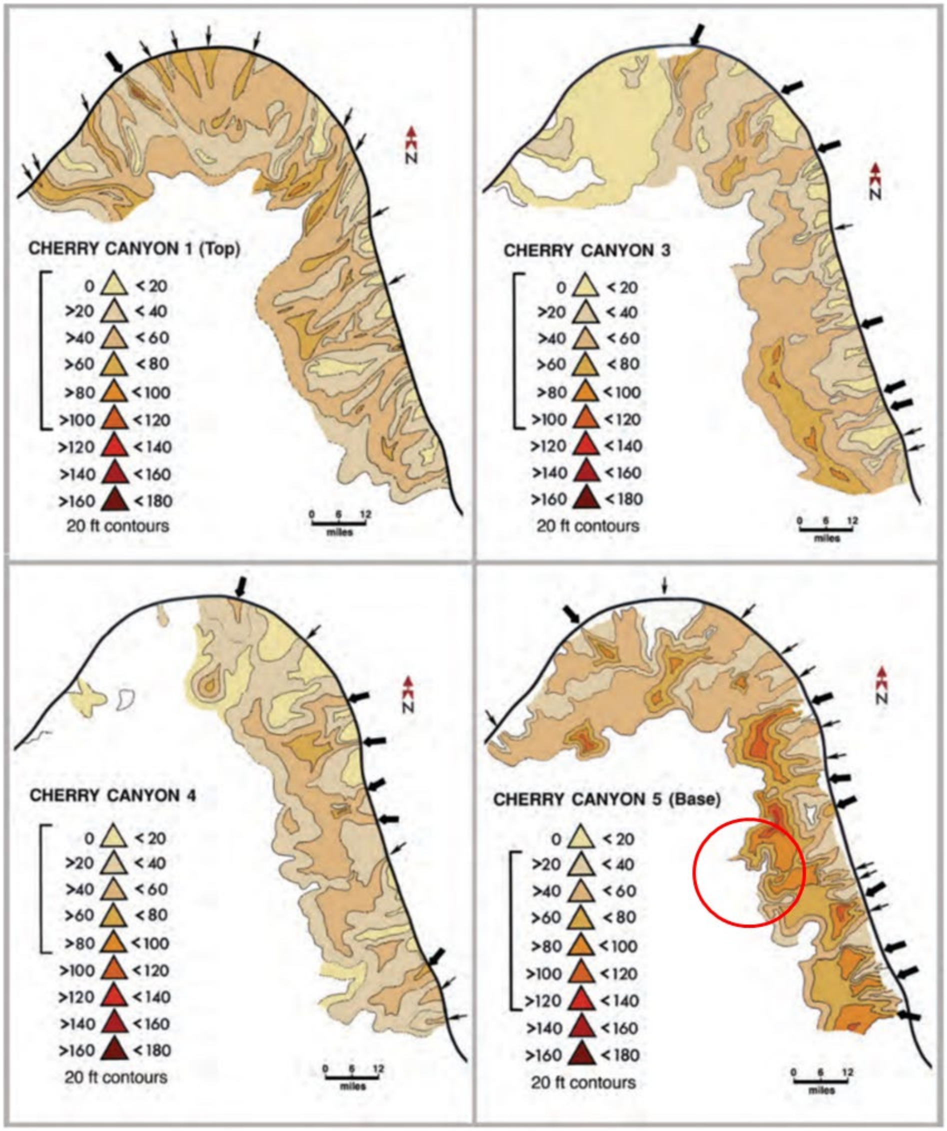


Figure 3.2-12: These maps of Cherry Canyon Formation were created by measuring sandstone thicknesses on well logs in five regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). Unlike the Bell Canyon sandstones, the Cherry Canyon sands are thinner and contain fewer channels. The red circle on the last map surrounds the Red Hills area.

Within the Delaware Mountain Group in the Red Hills area, the Bell Canyon and Cherry Canyon have better porosity (averaging 15 – 25 % within channel/splay sandstones) and permeability (averaging 2-13 mD) than the Brushy Canyon (~14% porosity, an <3 mD; Ge et al, 2022, Smye et al., 2021).

UNDERLYING CONFINING ZONE

Permian Leonard Series. The Leonardian/Cisuralian Series, located beneath the Guadalupian Series sediments, is represented by >3,000 ft of basin-deposited carbonate and siliciclastic sediments of the Bone Spring Formation. The Bone Spring Formation is more carbonate rich than the Delaware Mountain Group deposits, but the sea-level-driven cycles of sedimentation and the associated depositional environments are similar with debris flows, turbidites, and pelagic carbonate sediments. The Bone Spring Formation contains both conventional and unconventional fields within the Delaware Basin in both sandstone-rich and carbonate-rich facies. Most of these plays occur within toe-of-slope carbonate and siliciclastic deposits or the turbidite facies in the deeper sections of the basin (Nance and Hamlin, 2020). The upper most Bone Spring is usually dense carbonate mudstone with limited porosity and low porosity.

3.2.3 Faulting

In this immediate area of the Permian Basin, faulting is primarily confined to the lower Paleozoic section, where seismic data shows major faulting and ancillary fracturing-affected rocks only as high up as the base of the lower Wolfcamp strata (**Figures 3.2-6 and 5.6-1**). Faults that have been identified in the area are normal faults associated with Ouachita related movement along the western margin of the Central Platform to the east of the RH AGI facilities. The closest identified fault lies approximately 1.5 miles east of the Red Hills facilities and has approximately 1,000 ft of down-to-the-west structural relief. Because these faults are confined to the lower Paleozoic unit well below the injection zone for the RH AGI wells, they will not be discussed further (Horne et al., 2021). Within the area of the Red Hills site, no shallow faults within the Delaware Mountain Group have been identified by seismic data interpretation nor as reported by Horne et al., 2022).

3.3 Lithologic and Reservoir Characteristics

Based on the geologic analyses of the subsurface at the Red Hills Gas Plant, the uppermost portion of the Cherry Canyon Formation was chosen for acid gas injection and CO_2 sequestration for RH AGI #1 and the uppermost Delaware Mountain Group (the Bell Canyon and Cherry Canyon Formations) for RH AGI #3.

In the Red Hills area, the thickest sand within the Delaware Mountain Group is a sandstone within the Bell Canyon Formation that is informally and locally referred to as the Delaware Sand. The Delaware sand is productive, but it is not locally.

For RH AGI #1, this injection interval includes five high porosity sandstone units (sometimes referred to as the Manzanita) and has excellent caps above, below and between the individual sandstone units. There is no local production in the overlying Delaware Sands pool and there are no structural features or faults that would serve as potential vertical conduits. The high net porosity of the RH AGI #1 injection zone indicates that the injected H_2S and CO_2 will be easily contained close to the injection well.

For RH AGI #3, the injection interval has been expanded to include high porosity sandstones present within the Bell Canyon Formation in RH AGI #3 as well as the five high porosity zones in the Cherry Canyon Formation. Most of the sand bodies in the Bell Canyon and Cherry Canyon formations are surrounded by shales or limestones, forming caps for the injection zones. There are no structural features or faults that would serve as potential vertical conduits, and the overlying Ochoan evaporites form an excellent overall seal for the system. Even if undetected faulting existed, the evaporites (Castile and Salado) would self-seal and prevent vertical migration out of the Delaware Mountain Group.

3D seismic data, as well as geophysical logs for all wells penetrating the Bell Canyon and Cherry Canyon formations within a three-mile radius of the RH AGI wells were reviewed. There are no faults visible within the Delaware Mountain Group in the Red Hills area. Within the seismic review area, the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales (**Figure 3.2-8**) as well as being encased by them. Based on regional studies (Giesen and Scholle, 1990 and **Figures 3.2-11, 3.2-12**), the preferred orientation of the channels, and hence the preferred fluid migration pathways, are roughly from the east to the west.

Porosity was evaluated using geophysical logs from nearby wells penetrating the Cherry Canyon Formation. **Figure 3.3-1** shows the Resistivity (Res) and Thermal Neutron Porosity (TNPH) logs from 5,050 ft to 6,650 ft and includes the injection interval. Five clean sands (>10% porosity and <60 API gamma units) are targets for injection within the Cherry Canyon formation and potentially another 5 sands with >10% porosity and <60 API gamma units were identified. Ten percent was the minimum cut-off considered for adequate porosity for injection. The sand units are separated by lime mudstone and shale beds with lateral continuity. The high porosity sand units exhibit an average porosity of about 18.9%; taken over the average thickness of the clean sand units within ½ mile of the RH AGI #1. There is an average of 177 ft with an irreducible water (S_{wir}) of 0.54 (see Table 1 of the RH AGI #1 permit application). Many of the sands are very porous (average porosity of > 22%) and it is anticipated that for these more porous sands, the S_{wir} may be too high. The effective porosity (Total Porosity – Clay Bound Water) would therefore also be higher. As a result, the estimated porosity ft (PhiH) of approximately 15.4 porosity-ft should be considered to be a minimum. The overlying Bell Canyon Formation has 900 ft of sands and intervening tight limestones, shales, and calcitic siltstones with porosities as low as 4%, but as mentioned above, there are at least 5 zones with a total thickness of approximately 460 ft and containing 18 to 20% porosity. The injection interval is located more than 2,650 ft above the Bone Spring Formation, which is the next production zone in the area.

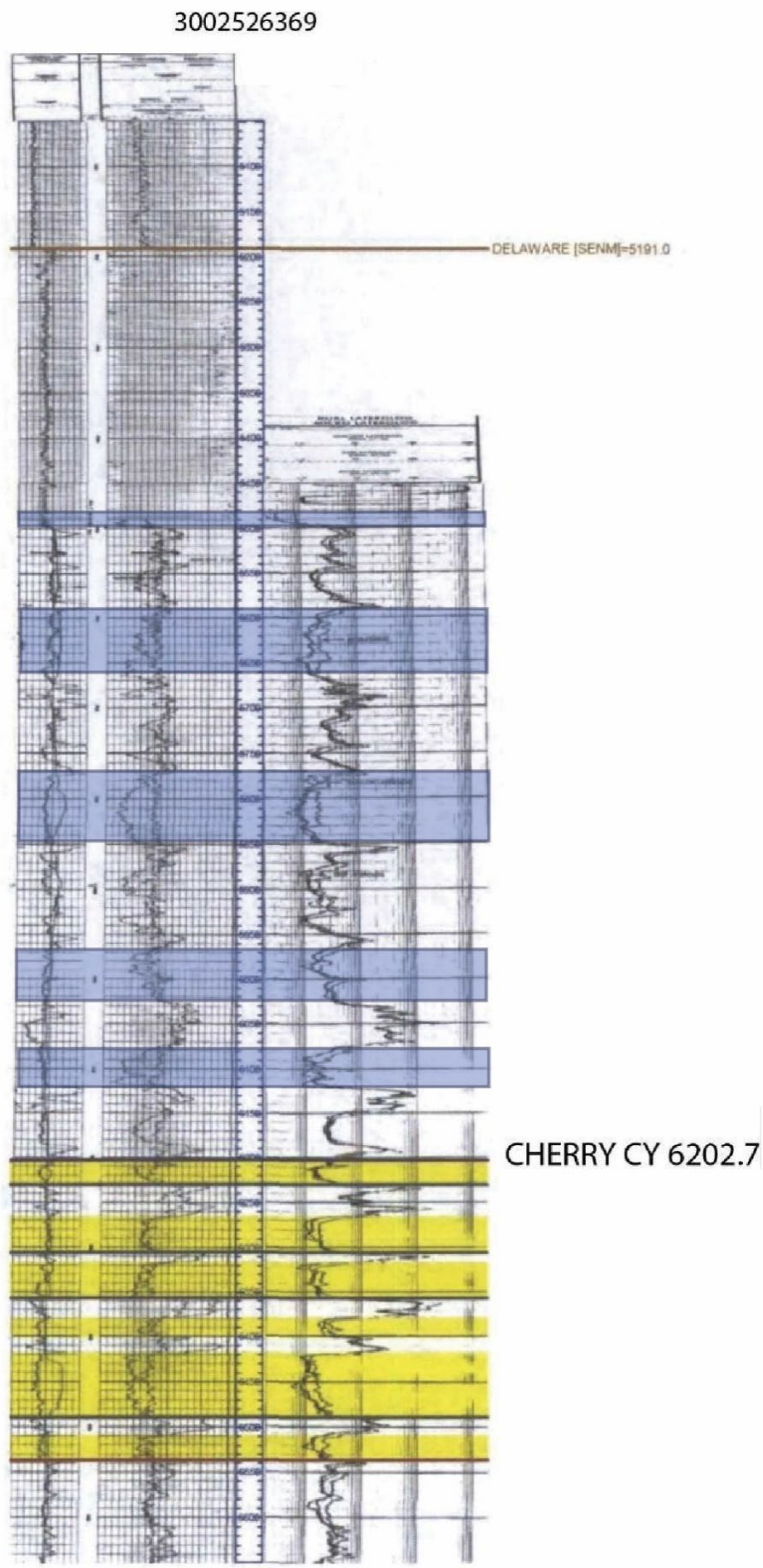


***Figure 3.3-1**: Geophysical logs from the Bell Canyon and the Upper Cherry Canyon from the Government L Com #002 well, located 0.38 miles from the RH AGI #1 Well. The blue intervals are Bell Canyon porosity zones, and the yellow intervals are Cherry Canyon porosity zones.*

3.4 Formation Fluid Chemistry

A chemical analysis (**Table 3.4-1**) of water from Federal 30 Well No. 2 (API 30-025-29069), approximately 3.9 miles away, indicates that the formation waters are highly saline (180,000 ppm NaCl) and compatible with the injection.

***Table 3.4-1**: Formation fluid analysis for Cherry Canyon Formation from Federal 30 Well No. 2*

Sp. Gravity	1.125 @ 74°F	Resistivity	0.07 @ 74°F
pH	7	Sulfate	1,240
Iron	Good/Good	Bicarbonate	2,135
Hardness	45,000	Chloride	110,000
Calcium	12,000	NaCl	180,950
Magnesium	3,654	Sod. & Pot.	52,072

Table extracted from C-108 Application to Inject by Ray Westall Associates with SWD-1067 – API 30-025-24676. Water analysis for formation water from Federal 30 #2 Well (API 30-025-29069), depth 7,335-7,345 ft, located 3.9 miles from RH AGI #1 well.

3.5 Groundwater Hydrology in the Vicinity of the Red Hills Gas Plant

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are 15 freshwater wells located within a two-mile radius of the RH AGI wells, and only 2 water wells within one mile; the closest water well is located 0.31 miles away and has a total depth of 650 ft (**Figure 3.5-1; Appendix 3**). All water wells within the two-mile radius are shallow, collecting water from about 60 to 650 ft depth, in Alluvium and the Triassic redbeds. The shallow freshwater aquifer is protected by the surface and intermediate casings and cements in the RH AGI wells (**Figures Appendix 1-1 and Appendix 1.2**). While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

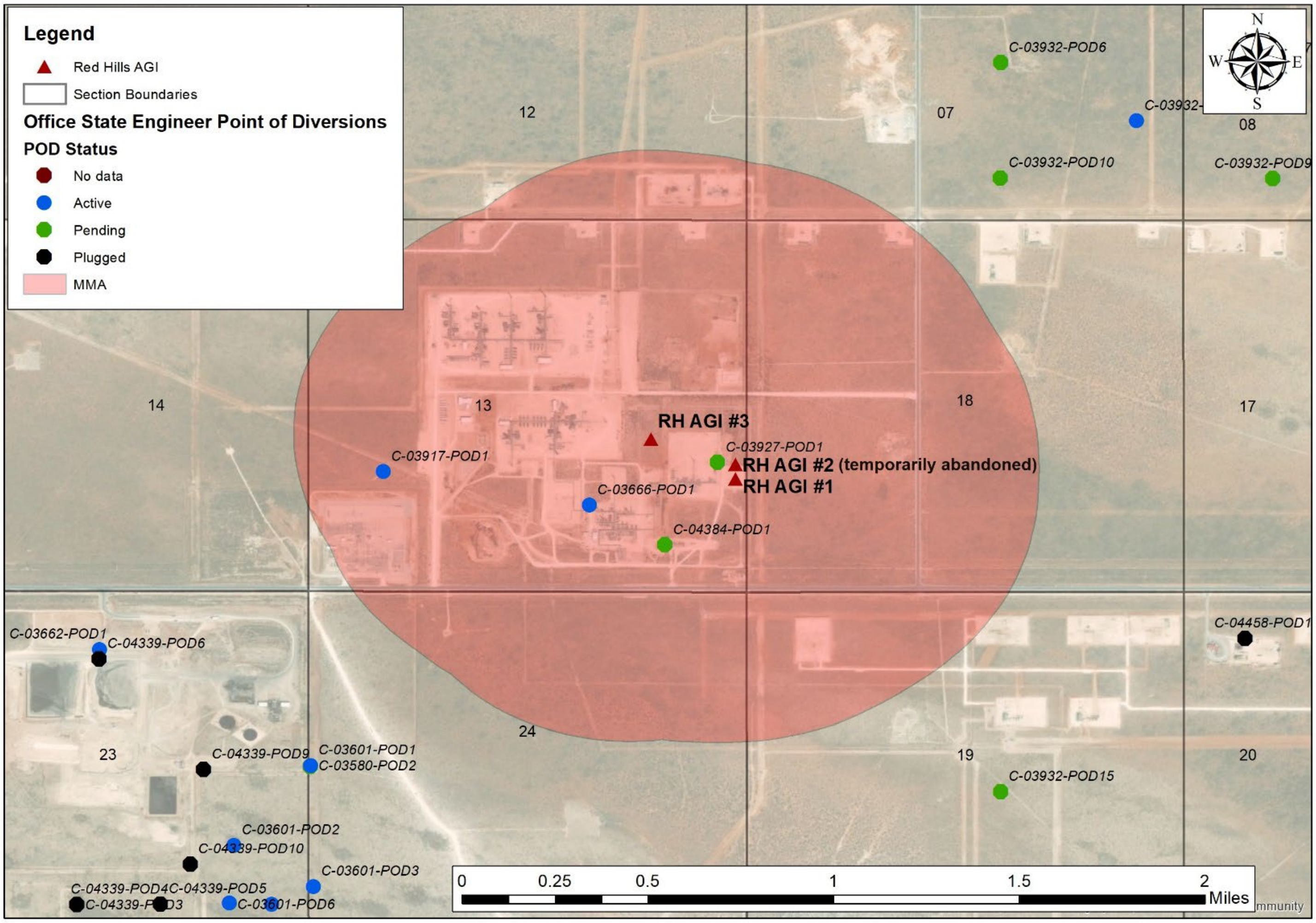


Figure 3.5-1: Reported Water Wells within the MMA for the RH AGI Wells.

3.6 Historical Operations

3.6.1 Red Hills Site

On July 20, 2010, Agave Energy Company (Agave) filed an application with NMOCD to inject treated acid gas into an acid gas injection well. Agave built the Red Hills Gas Processing Plant and drilled RH AGI #1 in 2012-13. However, the well was never completed and never put into service because the plant was processing only sweet gas (no H_2S). Lucid purchased the plant from Agave in 2016 and completed the RH AGI #1 well. TND acquired Lucid's Red Hills assets in 2022. **Figure 3.6-1** shows the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells. **Figure 3.6-2** shows a process block flow diagram.

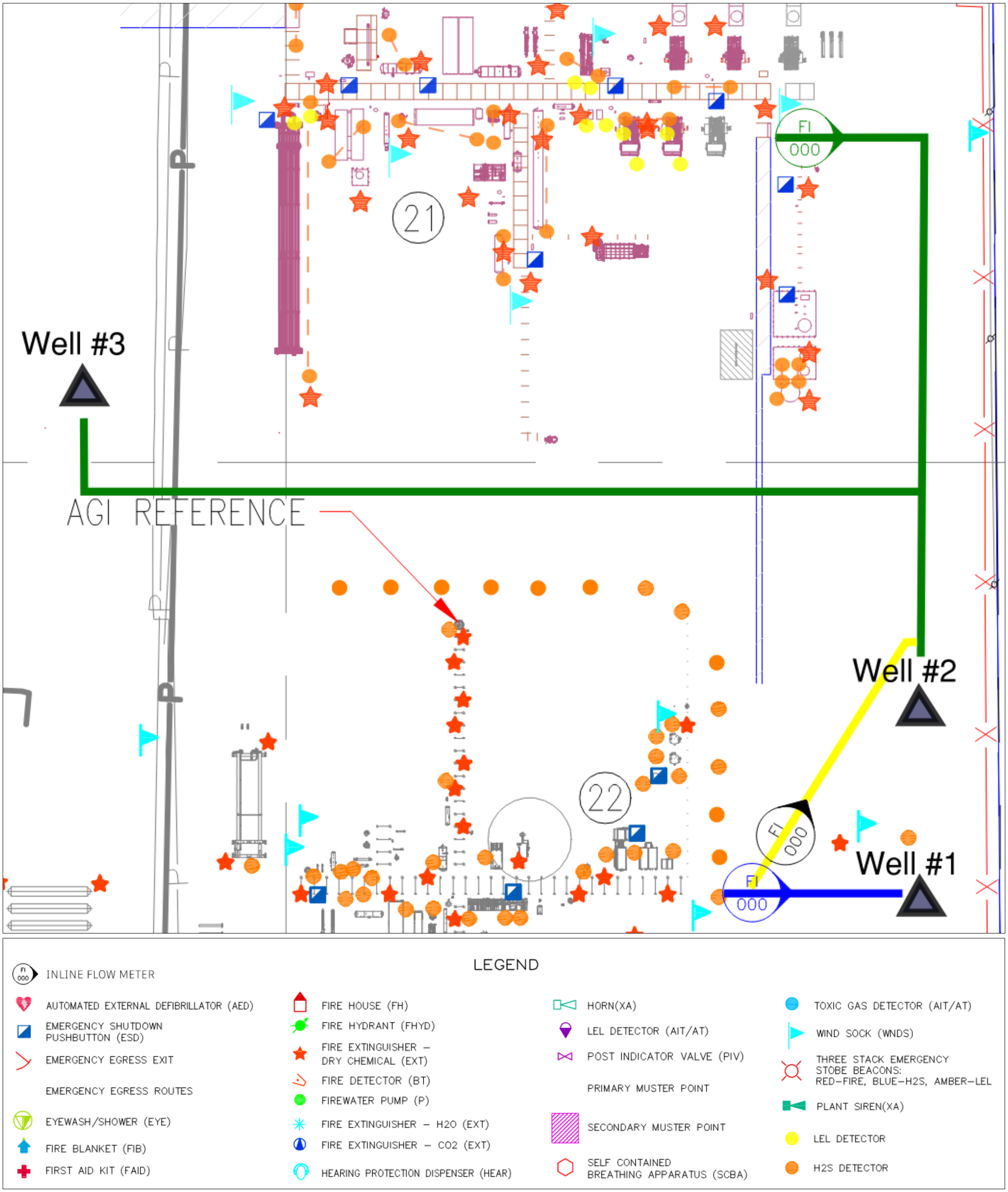


***Figure 3.6-1**: Diagram showing the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells. RH AGI #2 is temporarily abandoned.*

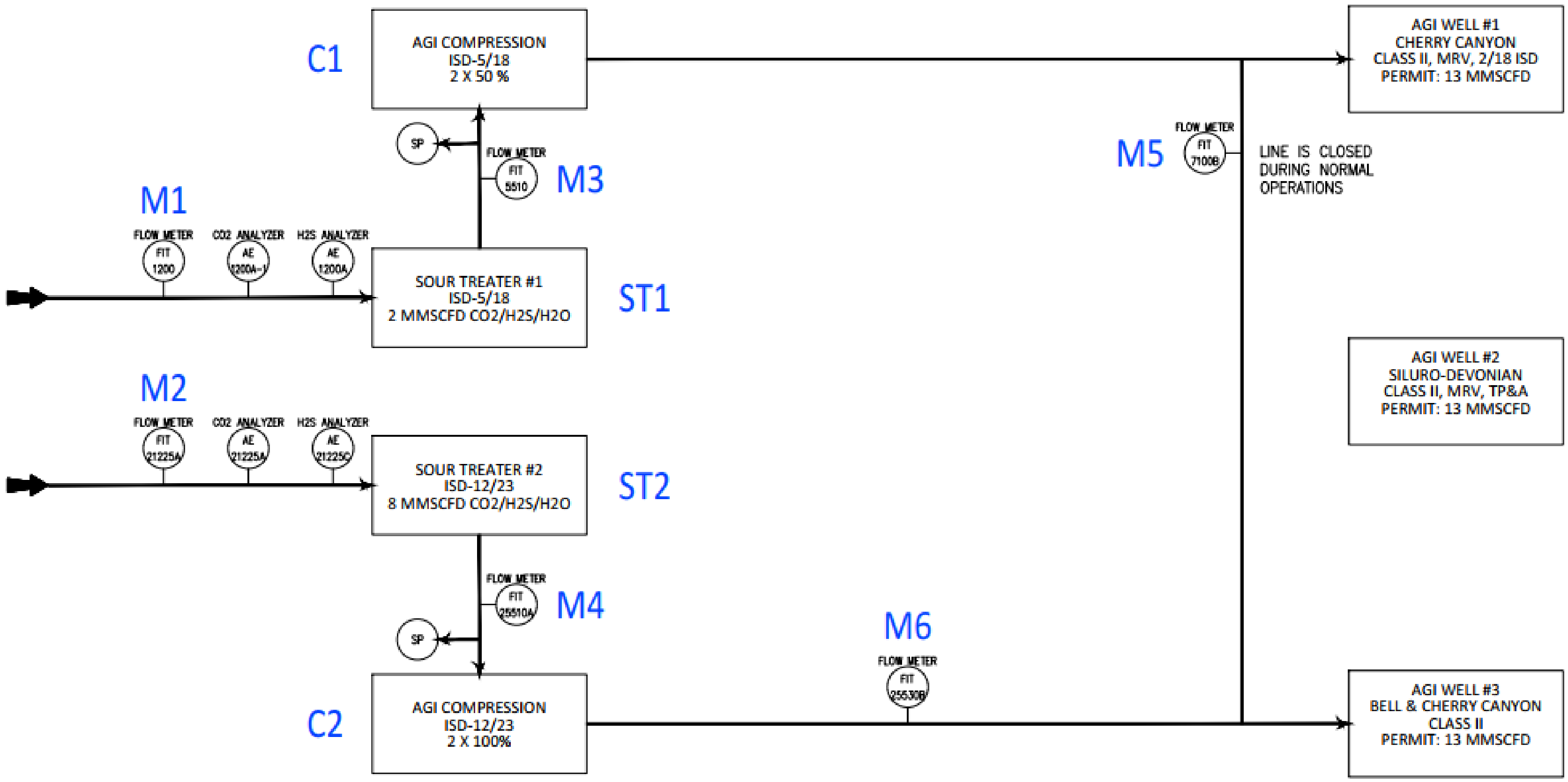


Figure 3.6-2: *Process Block Flow Diagram. RH AGI #2 is temporarily abandoned. M1 – M6: volumetric flow meters; C1 and C2: compressors; ST1 and ST2: sour treaters; and Sample Points (SP) for biweekly collection of data for determining the TAG stream concentration.*

3.6.2 Operations within the MMA for the RH AGI Wells

NMOCD records identify a total of 22 oil- and gas-related wells within the MMA for the RH AGI wells (see **Appendix 4**). **Figure 3.6-3** shows the geometry of producing and injection wells within the MMA for the RH AGI wells. **Appendix 4** summarizes the relevant information for those wells. All active production in this area is targeted for the Bone Spring and Wolfcamp zones, at depths of 8,900 to 11,800 ft, the Strawn (11,800 to 12,100 ft) and the Morrow (12,700 to 13,500 ft). All of these productive zones lie at more than 2,000 ft below the RH AGI #1 and AGI #3 injection zone.

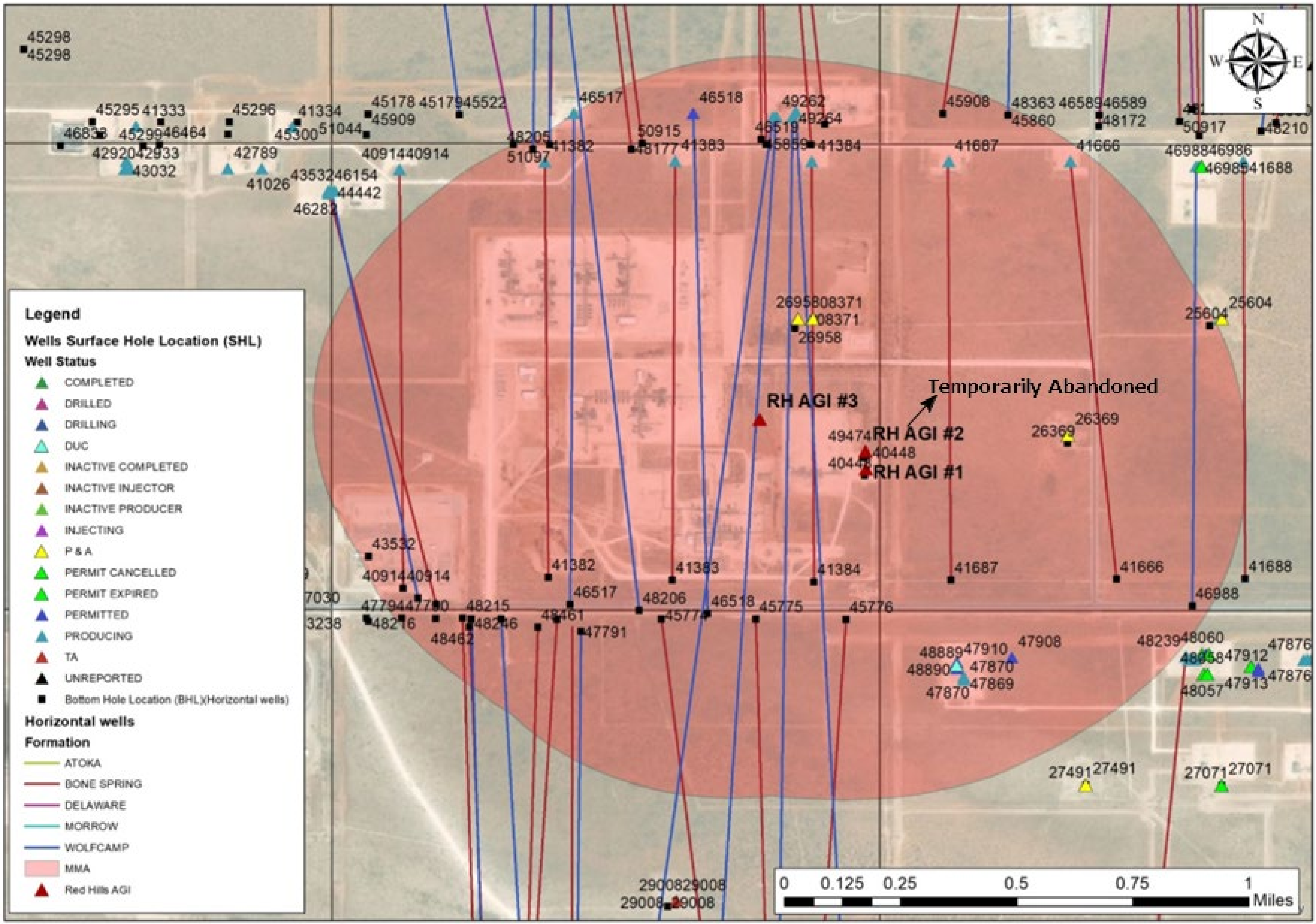


Figure 3.6-3: Location of all oil- and gas-related wells within the MMA for the RH AGI wells. Both the surface hole locations (SHL) and bottom hole locations (BHL) are labeled on the figure. For clarity, only the last five digits of the API numbers are used in labeling the wells.

3.7 Description of Injection Process

The Red Hills Gas Plant, including RH AGI #1 and RH AGI #3, is in operation and staffed 24-hours-a-day, 7-days-a week. The plant operations include gas compression, treating and processing. The plant gathers and processes produced natural gas from Lea and Eddy Counties in New Mexico. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the plant's sweeteners will be routed to a central compressor facility, located west of the well head. Compressed TAG is then routed to the wells via high-pressure rated lines. **Figure 3.7-1** is a schematic of the AGI facilities.

The approximate composition of the TAG stream is: 80% CO_2, 20% H_2S, with trace components of $C_1 – C_6$ (methane – hexane) and Nitrogen. The anticipated duration of injection is 30 years.

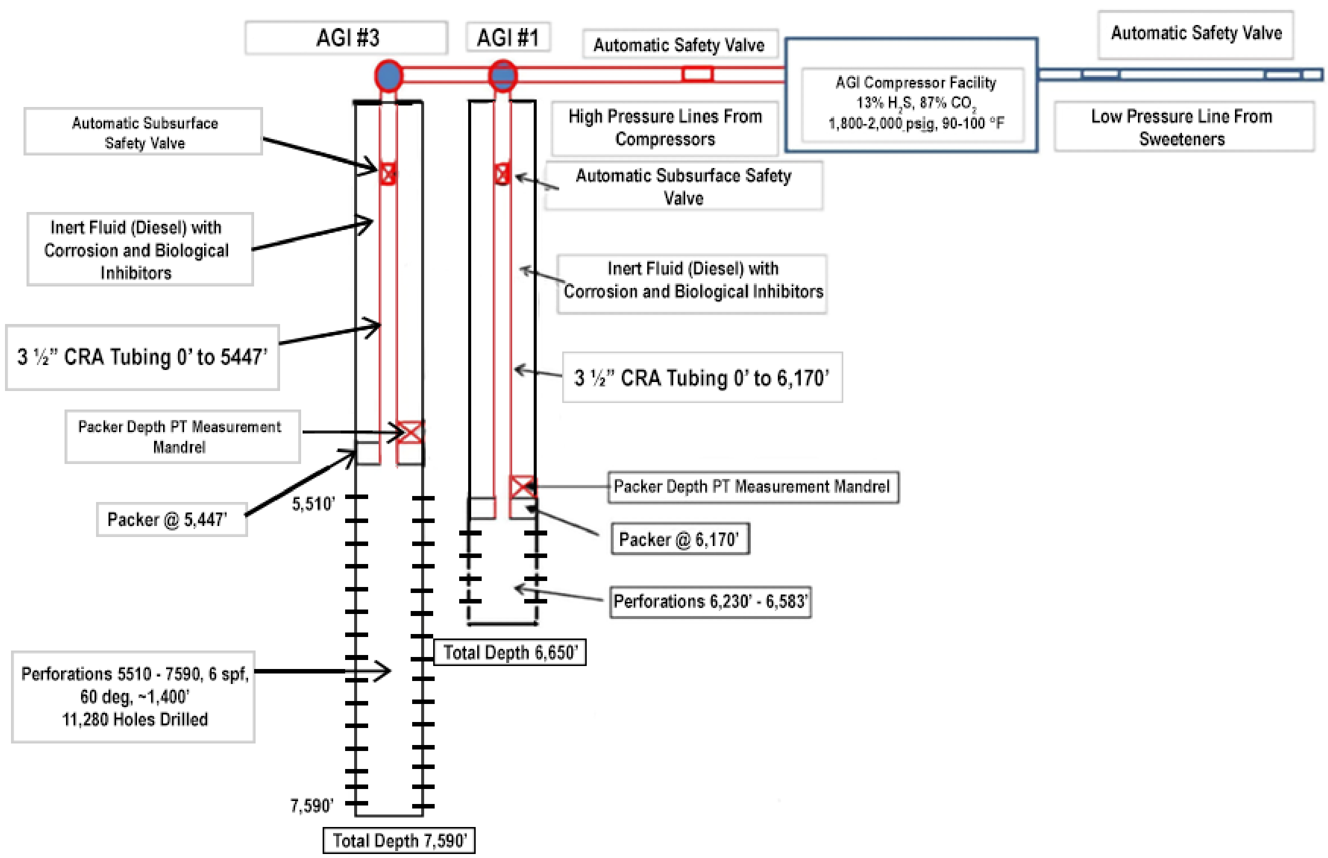


__Figure 3.7-1__: Schematic of surface facilities and RH AGI wells at the Red Hills Gas Processing Plant

3.8 Reservoir Characterization Modeling

The modeling and simulation focused on the Bell Canyon and Cherry Canyon Formations as the main injection target zone for acid gas storage. RH AGI #1 (API 30-025-40448) and RH AGI #3 (API 30-025-51970) are the approved injectors for treated acid gas injection by NMOCD and will serve as the injection wells in the model under the approved disposal timeframe and maximum allowable injection pressure. RH AGI #1 is completed in the Cherry Canyon Formation between 6,230 feet to 6,583 feet (MD). RH AGI #3 is completed in both the Bell Canyon and Cherry Canyon Formations between approximately 5,700 feet to 7,600 feet (MD).

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

The static model is constructed with well tops and licensed 3D seismic data to interpret and delineate the structural surfaces of a layer within the caprock (Lamar Limestone) and its overlaying, underlying formations. The geologic model covers a 3.5-mile by 3.3-mile area. No distinctive geological structures such as faults have been identified within the geologic model boundary. The model is gridded with 182 x 167 x 18, totaling 547,092 cells. The average grid dimension of the active injection area is 100 square feet. **Figure 3.8-1** shows the simulation model in 3D view. The porosity and permeability of the model is populated through existing well logs. The range of the porosity is between 0.01 to 0.31. The initial permeability are interpolated between 0.02 to 155 millidarcy (mD), and the vertical permeability anisotropy was 0.1. **(Figure 3.8-2 and Figure 3.8-3)**. These values are validated and calibrated with the historical injection data of RH AGI #1 since 2018 as shown in **Figures 3.8-4, 3.8-5, and 3.8-6**.

The simulation model is calibrated with the injection history of RH AGI #1 since 2018. Simulation studies were further performed to estimate the reservoir responses when predicting TAG injection for 30 years through both RH AGI #1 (2018 – 2048) and RH AGI #3 (2024 - 2054). RH AGI #2 is temporarily abandoned as of the submission of this document. RH AGI #1 is simulated to inject with the average rate of the last 5 years, 1.2 MMSCF, in the prediction phase. RH AGI #3 is simulated to inject with permitted injection rate, 13 MMSCF, with 1,767 psi maximum surface injection pressure constraint approved by State agency. The simulation terminated in the year 2084, 30 years after the termination of all injection activities, to estimate the maximum impacted area during post injection phase.

During the calibration period (2018 – 2023), the historical injection rates were used as the primary injection control, and the maximum bottom hole pressures (BHP) are imposed on wells as the constraint, calculated based on the approved maximum injection pressure. This restriction is also estimated to be less than 90% of the formation fracture pressure calculated at the shallowest perforation depth of each well to ensure safe injection operations. The reservoir properties are tuned to match the historical injection until it was reasonably matched. **Figure 3.8-4** shows that the historical injection rates from RH AGI #1 in the Cherry Canyon Formation. **Figure 3.8-5** shows the BHP response of RH AGI #1 during the history matching phase.

During the forecasting period, linear cumulative injection behavior indicates that the Cherry Canyon and Bell Canyon Formations received the TAG stream freely. **Figure 3.8-6** shows the cumulative disposed H_2S and CO_2 of each RH AGI injector separately in gas mass. The modeling results indicate that the Cherry Canyon and Bell Canyon Formations are capable of safely storing and containing the gas volume without violating the permitted rate and pressure. **Figure 3.8-7** shows the gas saturation represented TAG plume at the end of 30-year forecasting in 3D view. **Figure 3.8-8** shows the extent of the plume migration in a map view at 4 key time steps. It can be observed that the size of the TAG plume is very limited and mainly stayed within Targa's Red Hills facility boundary at the end of injection. In the year 2084, after 30 years of monitoring, the injected gas remained trapped in the reservoir and there was no significant change in the observed TAG footprint as compared to that at the end of injection.

In summary, after careful reservoir engineering review and numerical simulation study, our analysis shows that the Bell Canyon and Cherry Canyon Formations can receive treated acid gas (TAG) at the injection rate and permitted maximum surface injection pressure permitted by NMOCC. The injection formations will safely contain the injected TAG volume within the injection and post-injection timeframe. The injection wells will allow for sequestration while preventing associated environmental impacts.

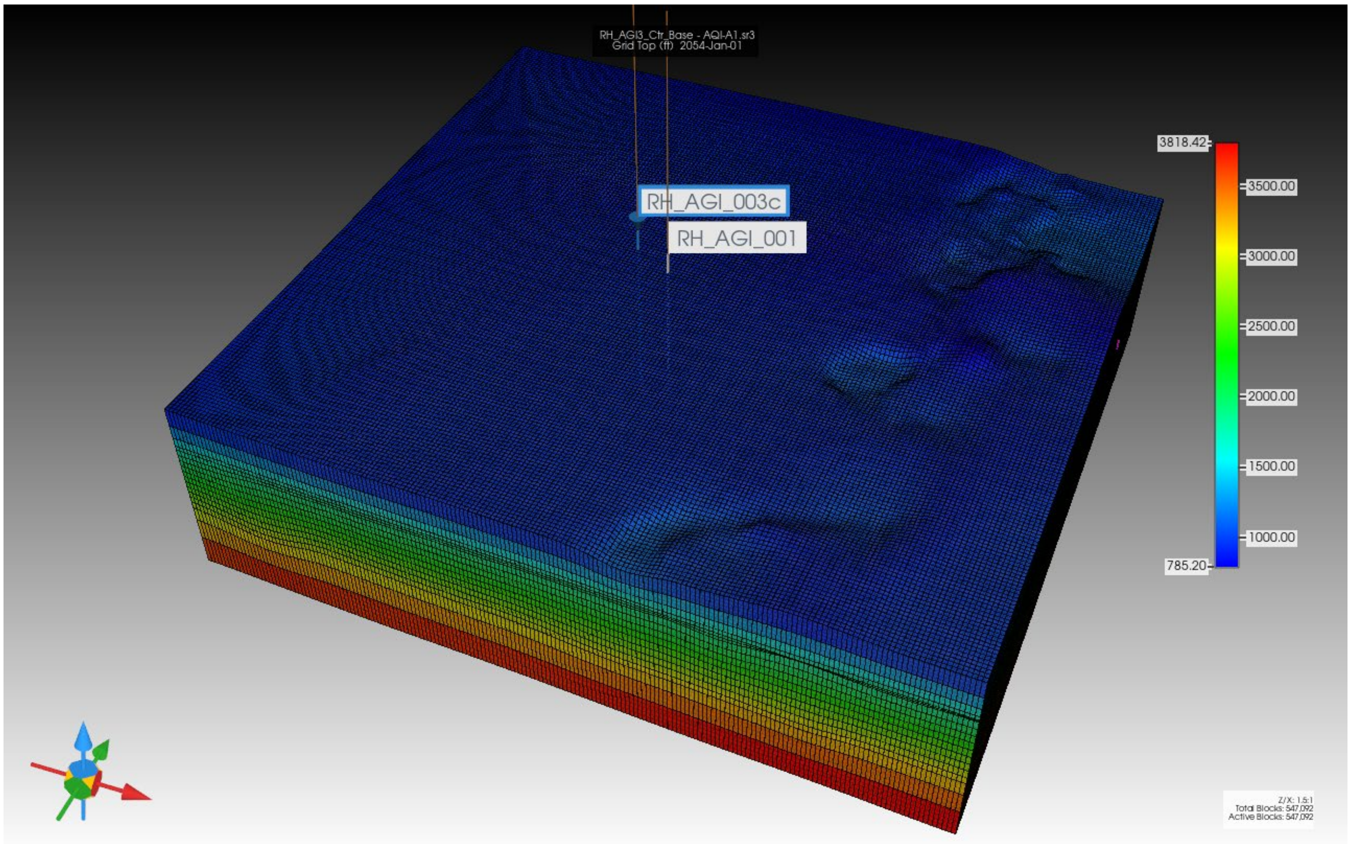


Figure 3.8-1: *3D view of the simulation model of RH AGI #1 and RH AGI #3, containing Salado-Castile Formation, Lamar Limestone, Bell Canyon Formation, and Cherry Canyon Formation. Color legends represents the elevation of layers.*

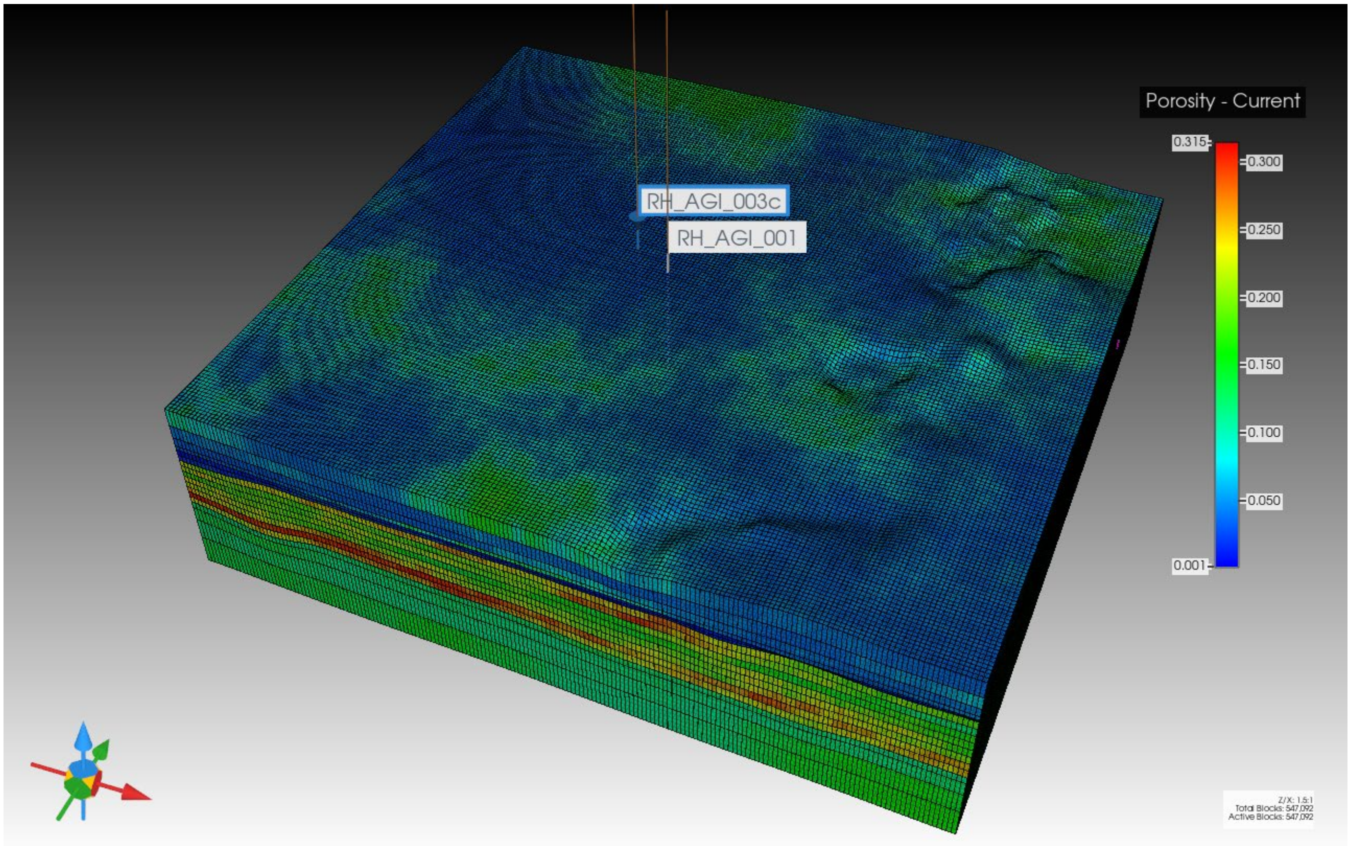


Figure 3.8-2: *Porosity estimation using available well data for the simulation domain.*

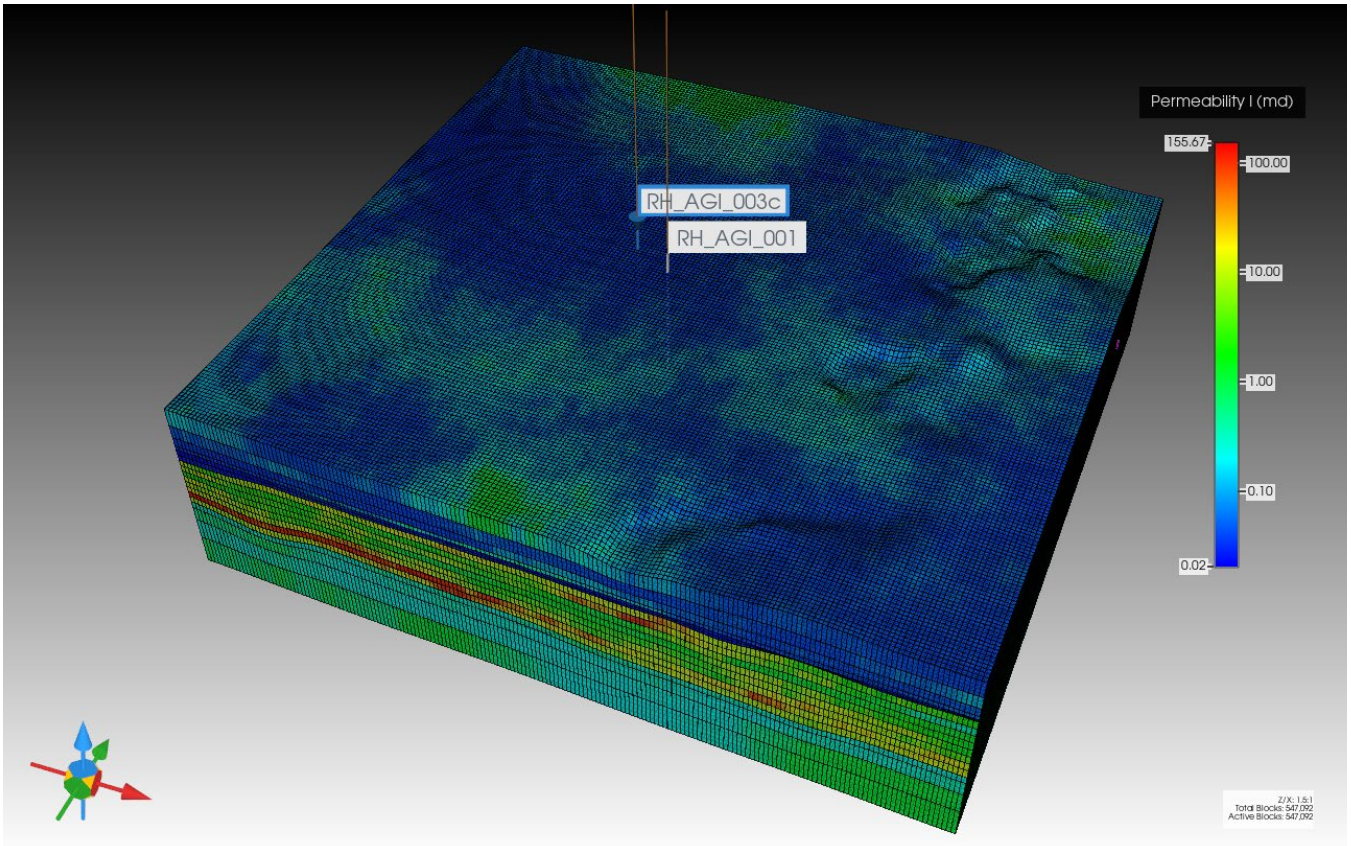


Figure 3.8-3: *Permeability estimation using available well data for simulation domain.*

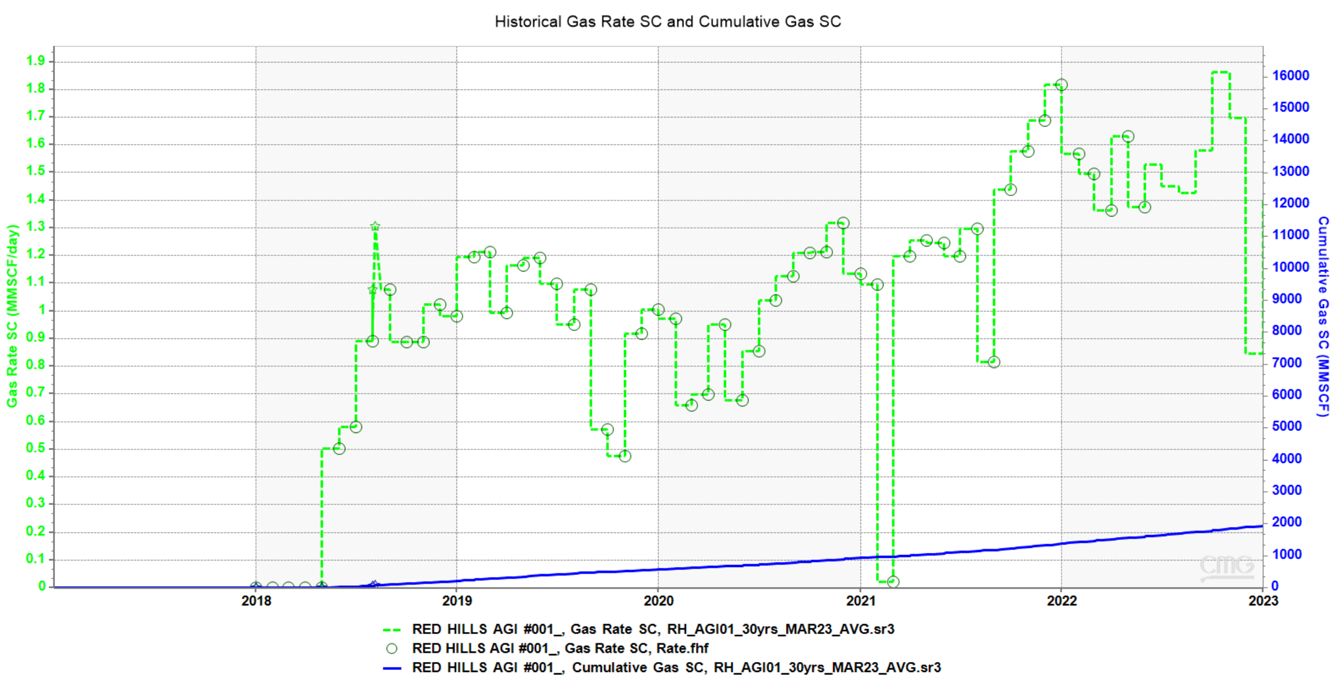


Figure 3.8-4: *The historical injection rate and total gas injected from RH AGI #1 (2018 to 2023).*

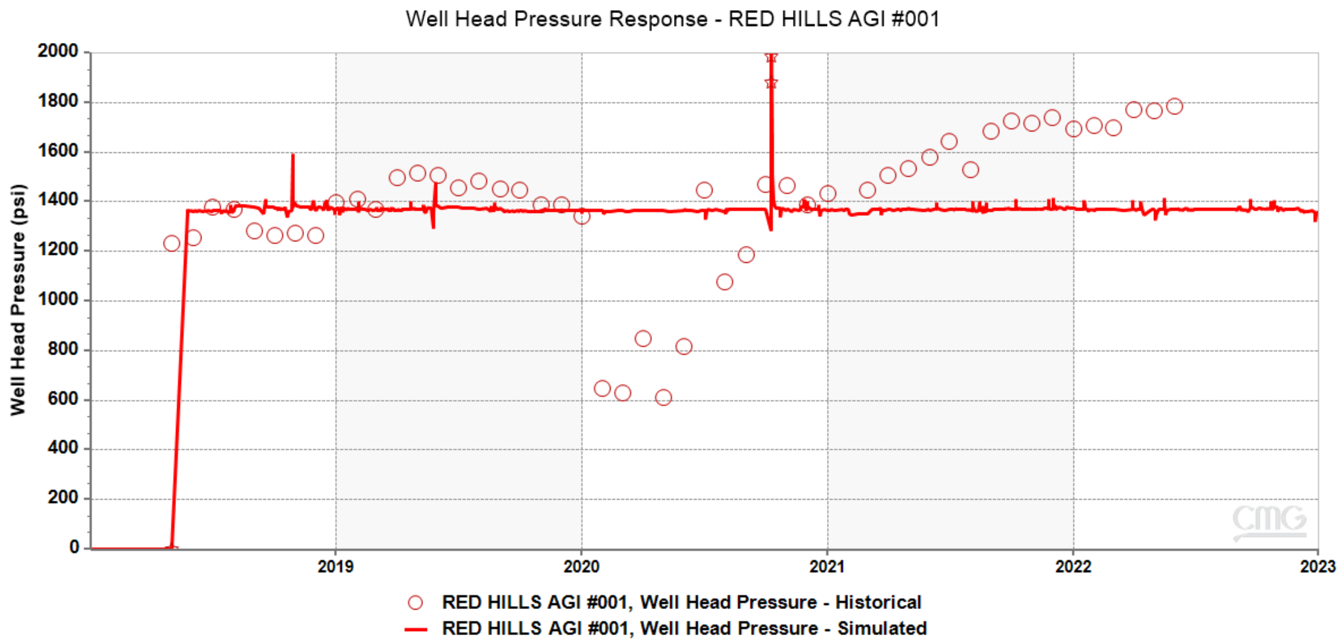


Figure 3.8-5: *The historical bottom hole pressure response from RH AGI #1 (2018 to 2023)*

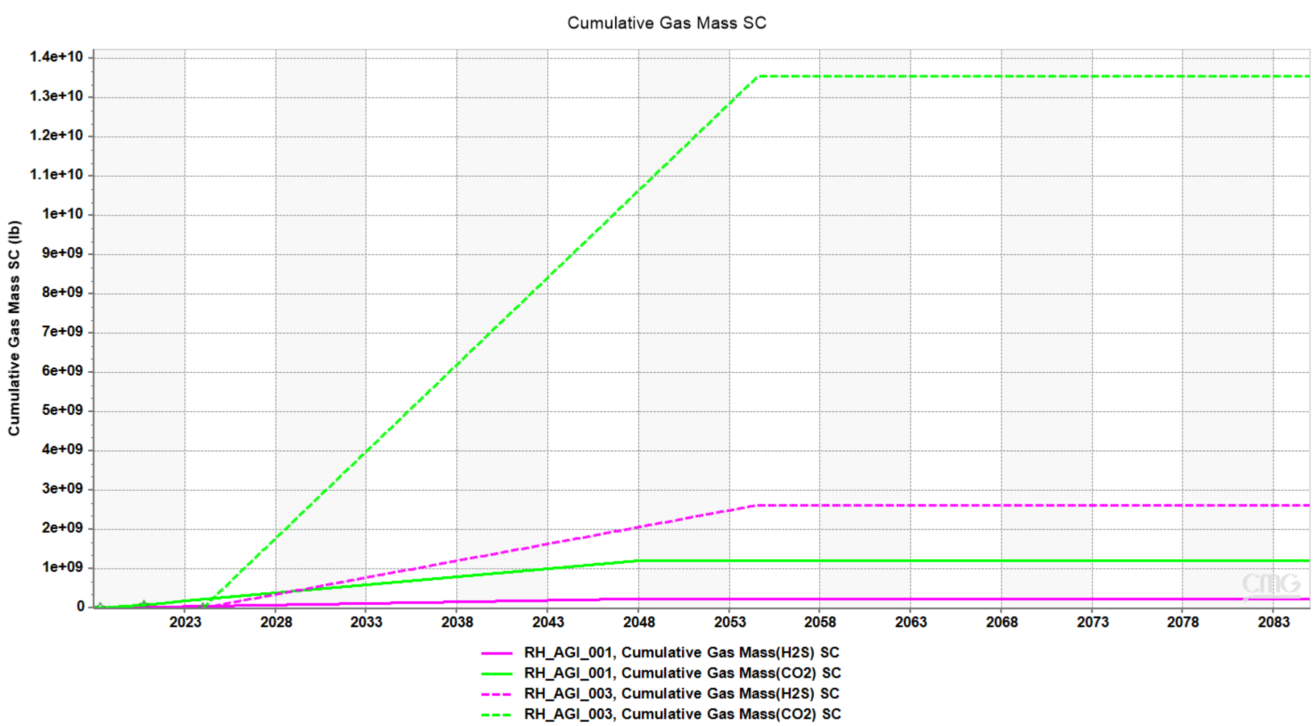


Figure 3.8-6: *Prediction of cumulative mass of injected CO_2 and H_2S for RH AGI #1 and RH AGI #3 (2018 to 2054).*

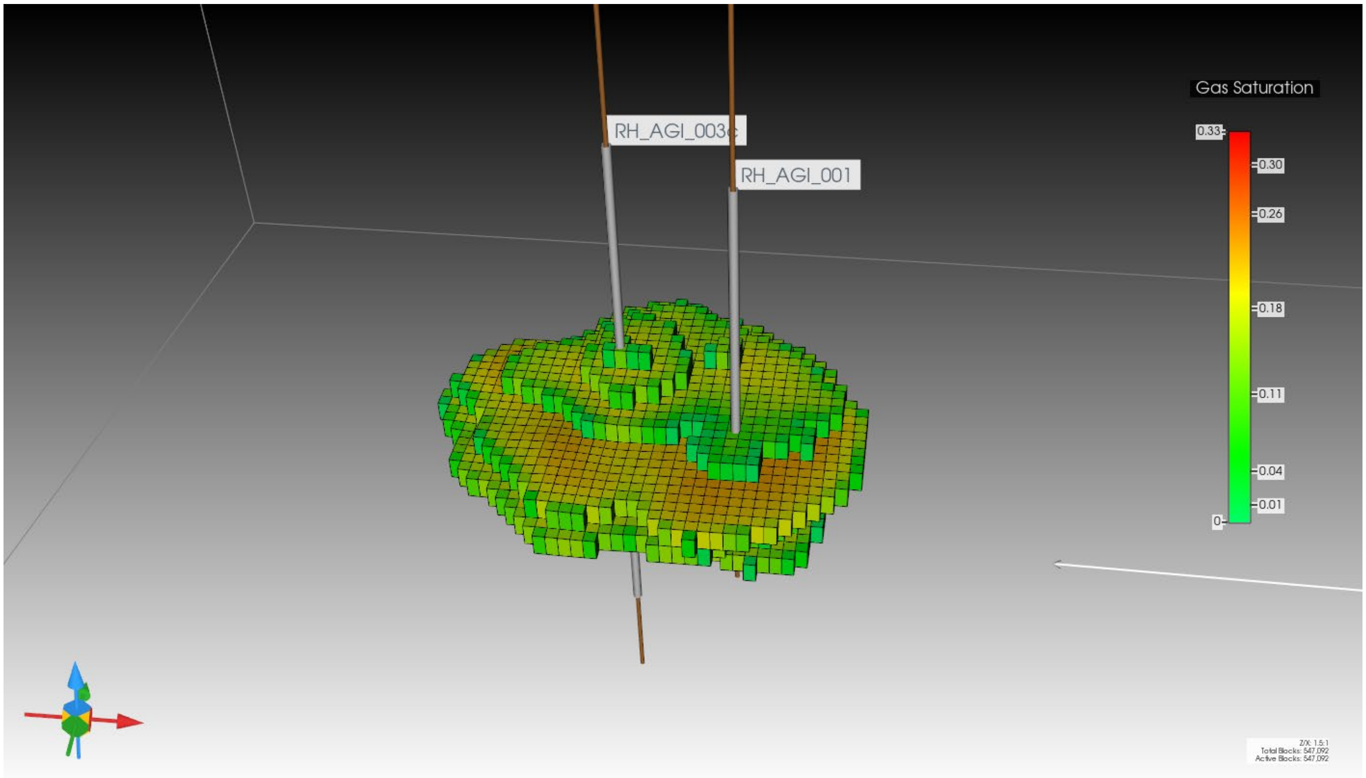


__Figure 3.8-7:__ Simulation model depicting the free phase TAG (represented by gas saturation) at the end of the 30-year post-injection monitoring period (2054) in 3D view.

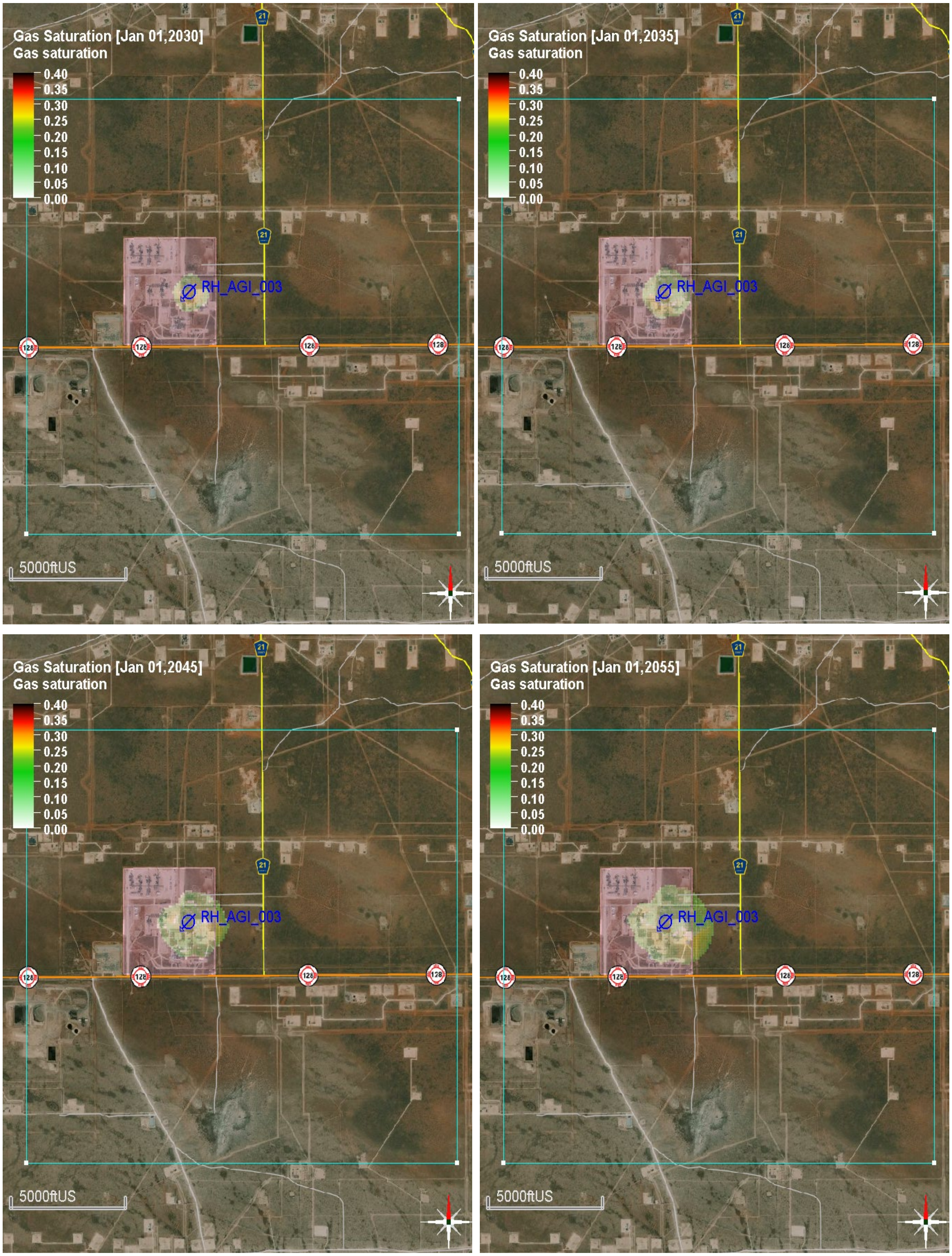


Figure 3.8-8: *Map view depicting the free phase TAG plume at years 2030, 2035, 2045, 2055 (1-year post injection).*

4 Delineation of the Monitoring Areas

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

4.1 MMA – Maximum Monitoring Area

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. **Figures 4.1-1** shows the MMA as defined by the extent of the stabilized TAG plume at year 2059 plus a 1/2-mile buffer.

4.2 AMA – Active Monitoring Area

The Active Monitoring Area (AMA) is shown in **Figure 4.1-1**. The AMA is consistent with the requirements in 40 CFR 98.449 because it is the area projected: (1) to contain the free phase CO_2 plume for the duration of the project (year t, t = 2054), plus an all-around buffer zone of one-half mile. (2) to contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2059). Targa intends to define the active monitoring area (AMA) as the same area as the MMA. The purple cross-hatched polygon in **Figure 4.1-1** is the plume extent at the end of injection. The yellow polygon in **Figure 4.1-1** is the stabilized plume extent 5 years after injection ceases. The AMA/MMA shown as the red-filled polygon contains the CO_2 plume during the duration of the project and at the time the plume has stabilized.

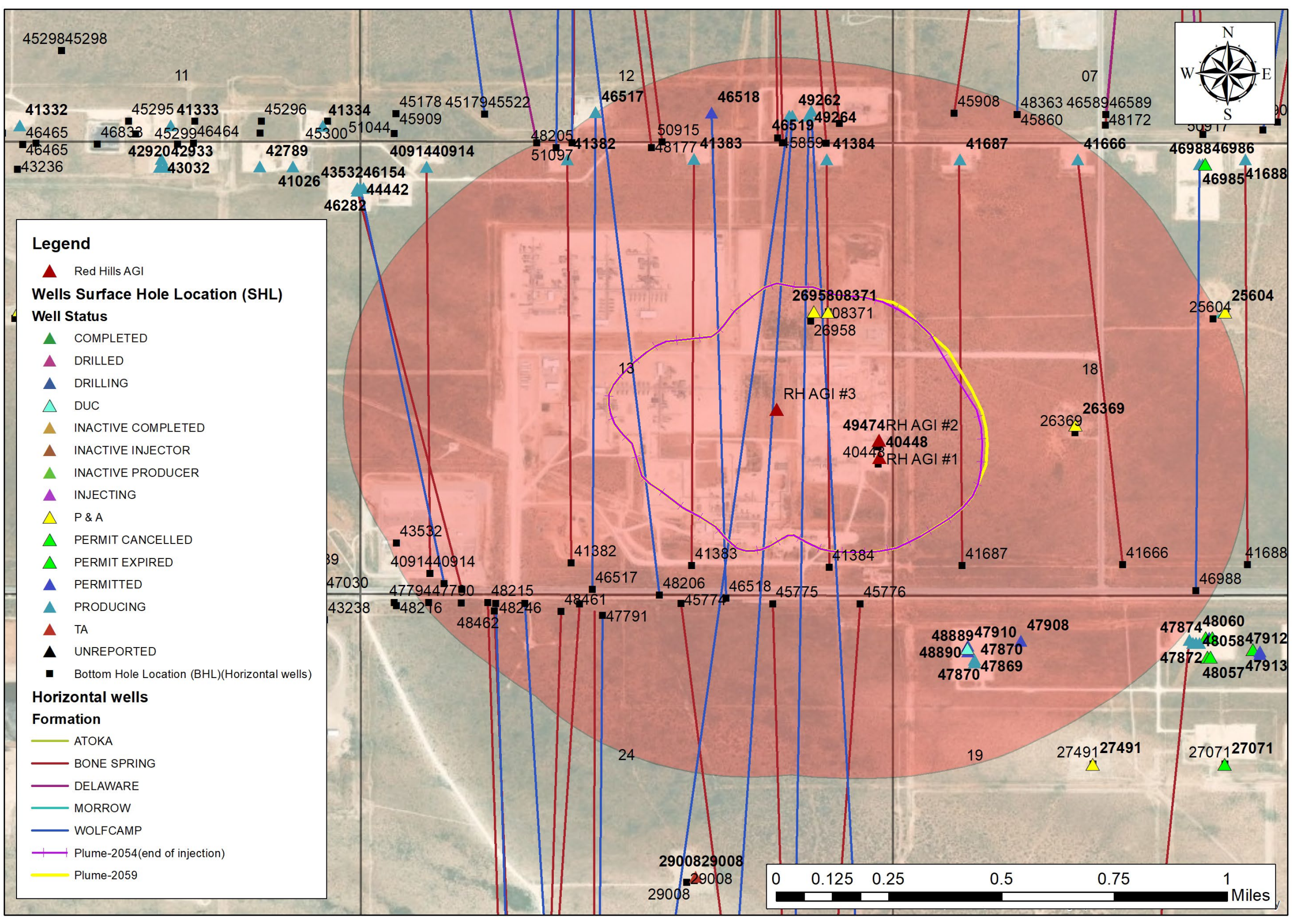


Figure 4.1-1: Active monitoring area (AMA) for RH AGI #1, RH AGI #2 (temporarily abandoned) and RH AGI #3 at the end of injection (2054, purple polygon) and 5 years post-monitoring (2059, yellow polygon). Maximum monitoring area (MMA) is shown in red shaded area.

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

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

Through the site characterization required by the NMOCD C-108 application process for Class II injection wells, the geologic characterization presented in Section 3, and the reservoir modeling described in Section 3.8, TND has identified and evaluated the potential CO_2 leakage pathways to the surface.

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

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas facilities. Preventative risk mitigation includes adherence to relevant regulatory requirements and industry standards governing the construction, operation, and maintenance of gas plants. Specifically, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills."

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

Although mitigative measures are in place to minimize CO_2 emissions from surface equipment, such emissions are possible. Any leaks from surface equipment would result in immediate (timing) emissions of CO_2 to the atmosphere the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak.

The injection wells and the pipeline that carries CO_2 to them are the most likely surface components of the system to allow CO_2 to leak to the surface. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable source of the leakage. Another possible source of leakage is the release of air through relief valves, which are designed to alleviate pipeline overpressure. Leakage can also occur when the surface components are damaged by an accident or natural disaster, which releases CO_2. Therefore, TND infers that there is a potential for leakage via this route. Depending on the component's failure mode, the magnitude of the leak can vary greatly. For example, a rapid break or rupture could release thousands of pounds of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO_2 over several hours or days. Surface component leakage or venting is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

5.2 Potential Leakage from Approved, Not Yet Drilled Wells

The only wells within the MMA that are approved but not yet drilled are horizontal wells. These wells have a Well Status of "permitted" in **Appendix 4**. There are no vertical wells within the MMA with a Well Status of "permitted".

5.2.1 Horizontal Wells

The table in **Appendix 3** and **Figure 4.1-1** shows a number of horizontal wells in the area, many of which have approved permits to drill but which are not yet drilled. If any of these wells are drilled through the Bell Canyon and Cherry Canyon injection zones for RH AGI #3 and RH AGI #1, they will be required to take special precautions to prevent leakage of TAG minimizing the likelihood of CO_2 leakage to the surface. This requirement will be made by NMOCD in regulating applications for permit to drill (APD) and in ensuring that the operator and driller are aware that they are drilling through an H_2S injection zone in order to access their target production formation. NMAC 19.15.11 for Hydrogen Sulfide Gas includes standards for personnel and equipment safety and H_2S detection and monitoring during well drilling, completion, well workovers, and well servicing operations all of which apply for wells drilled through the RH AGI wells TAG plume.

Due to the safeguards described above, the fact there are no proposed wells for which the surface hole location (SHL) lies within the simulated TAG plume and, considering the NRAP risk analysis described here in Section 5, TND considers the likelihood of CO_2 emissions to the surface via these horizontal wells to be highly unlikely.

5.3 Potential Leakage from Existing Wells

Existing oil and gas wells within the MMA as delineated in Section 4 are shown in **Figure 3.6-3** and detailed in **Appendix 4**.

TND considered all wells completed and approved within the MMA in the NRAP risk assessment. Some of these wells penetrate the injection and/or confining zones while others do not. Even though the risk of CO_2 leakage through the wells that did not penetrate confining zones is highly unlikely, TND did not omit any potential source of leakage in the NRAP analysis. If leakage through wellbores happens, the worst-case scenario is predicted using the NRAP tool to quantitatively assess the amount of CO_2 leakage through existing and approved wellbores within the MMA. Thirty-nine existing and approved wells inside MMA were addressed in the NRAP analysis. The reservoir properties, well data, formation stratigraphy, and MMA area were incorporated into the NRAP tool to forecast the rate and mass of CO_2 leakage. The worst scenario is that all of the 39 wells were located right at the source of CO_2 – the injection wells' location. In this case, the maximum leakage rate of one well is approximately 7e-6 kg/s. This value is the maximum amount of CO_2 leakage, 220 kg/year, and occurs in the second year of injection, then gradually reduces to 180 kg at the end of year 30. Comparing the total amount of CO_2 injected (assuming 5 MMSCFD of supercritical CO_2 injected continuously for 30 years), the leakage mass amounts to 0.0054% of the total CO_2 injected. This leakage is considered negligible. Also, this worst-case scenario, where 39 wells are located right at the injection point, is impossible in reality. Therefore, CO_2 leakage to the surface via this potential leakage pathway can be considered improbable.

5.3.1 Wells Completed in the Bell Canyon and Cherry Canyon Formations

The only wells completed in the Bell Canyon and Cherry Canyon Formations within the MMA are RH AGI #1, RH AGI #2 (drilling stopped in the Bell Canyon), and RH AGI #3 and the 30-025-08371 well which was completed at a depth of 5,425 ft. This well is within the Red Hills facility boundary and is plugged and abandoned (see **Appendix 9** for plugging and abandonment (P&A) record).

Appendix 1 includes schematics of the RH AGI #1, RH AGI #2,and RH AGI #3 wells' construction showing multiple strings of casing all cemented to surface. Injection of TAG into RH AGI #1 and RH AGI #3 occurs through tubing with a permanent production packer set above the injection zone.

RH AGI #2 is located in close proximity to RH AGI #1 and is temporarily abandoned. Drilling of this well stopped at 6,205 ft due to concerns about high pressures by drilling into the Cherry Canyon Formation and therefore, did not penetrate the Cherry Canyon Formation. The cement plug was tagged at 5,960 feet which is above the injection zone for RH AGI #1 (see **Figure Appendix 1-3**).

Due to the robust construction of the RH AGI wells, the plugging of the well 30-025-08371 above the Bell Canyon, the plugging of RH AGI #2 above the Cherry Canyon Formation, and considering the NRAP analysis described above, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.2 Wells Completed in the Bone Spring / Wolfcamp Zones

Several wells are completed in the Bone Spring and Wolfcamp oil and gas production zones as described in Section 3.6.2. These productive zones lie more than 2,000 ft below the RH AGI wells injection zone minimizing the likelihood of communication between the RH AGI well injection zones and the Bone Spring / Wolfcamp production zones. Construction of these wells includes surface casing set at 1,375 ft and cemented to surface and intermediate casing set at the top of the Bell Canyon at depths of from 5,100 to 5,200 ft and cemented through the Permian Ochoan evaporites, limestone and siltstone (**Figure 3.2-2**) providing zonal isolation preventing TAG injected into the Bell Canyon and Cherry Canyon formations through the RH AGI wells from leaking upward along the borehole in the event the TAG plume were to reach these wellbores. **Figure 4.1-1** shows that the modeled TAG plume extent after 30 years of injection and 5 years of post-injection stabilization does not extend to well boreholes completed in the Bone Spring / Wolfcamp production zones thereby indicating that these wells are not likely to be pathways for CO_2 leakage to the surface.

Due to the construction of these wells, the fact that the modeled TAG plume does not reach the SHL of these wells and considering the NRAP analysis described in the introductory paragraph of Section 5, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.3 Wells Completed in the Siluro-Devonian Zone

One well penetrated the Devonian at the boundary of the MMA - EOG Resources, Government Com 001, API # 30-025-25604, TVD = 17,625 ft, 0.87 miles from RH AGI #3. This well was drilled to a total depth of 17,625 ft on March 5, 1978, but plugged back to 14,590 ft, just below the Morrow, in May of 1978. Subsequently, this well was permanently plugged and abandoned on December 30, 2004, and approved by NMOCD on January 4, 2005 (see **Appendix 9** for P&A records). The approved plugging provides zonal isolation for the Bell Canyon and Cherry Canyon injection zones minimizing the likelihood that this well will be a pathway for CO_2 emissions to the surface from either injection zone.

Due to the location of this well at the edge of the MMA and considering the NRAP analysis described in the introductory paragraph of Section 5, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.4 Groundwater Wells

The table in Appendix 3 lists 15 water wells within a 2-mile radius of the RH AGI wells, only 2 of which are within a 1-mile radius of and within the MMA for the RH AGI wells (**Figure 3.5-1**). The deepest ground water well is 650 ft deep. The evaporite sequence of the Permian Ochoan Salado and Castile Formations (see

Section 3.2.2) provides an excellent seal between these groundwater wells and the Bell and Cherry Canyon injection zones of RH AGI #1and RH AGI #3. Therefore, it is unlikely that these two groundwater wells are a potential pathway of CO_2 leakage to the surface. Nevertheless, the CO_2 surface monitoring and groundwater monitoring described in Sections 6 and 7 will provide early detection of CO_2 leakage followed by immediate response thereby minimizing the magnitude of CO_2 leakage volume via this potential pathway.

Due to the shallow depth of the groundwater wells within the MMA relative to the depth of the RH AGI wells and considering the NRAP analysis described in the introductory paragraph in Section 5, TND considers that, while the likelihood of CO_2 emissions to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.4 Potential Leakage through the Confining / Seal System

The site characterization for the injection zone of the RH AGI wells described in Sections 3.2.2 and 3.3 indicates a thick sequence of Permian Ochoan evaporites, limestone, and siltstones (**Figure 3.2-2**) above the Bell Canyon and Cherry Canyon Formations and no evidence of faulting. Therefore, it is unlikely that TAG injected into the Bell Canyon and Cherry Canyon Formations will leak through this confining zone to the surface. Limiting the injection pressure to less than the fracture pressure of the confining zone will minimize the likelihood of CO_2 leakage through this potential pathway to the surface.

Leakage through a confining zone happens in low-permeability shale formations containing natural fractures. The injection zone for RH AGI #1 and RH AGI #3 is the Delaware Mountain Group Formation (Bell Canyon and Cherry Canyon), which underlie the very much lower permeability (<0.01 mD) Castile and Salado Formations that provide excellent seals. Still, TND took leakage through confining zones into consideration in the NRAP risk assessment. The worst-case scenario is defined as leakage through the seal happening right above the injection wells, where CO_2 saturation is highest. However, this worst-case scenario of leakage only shows that 0.0017% of total CO_2 injection in 30 years was leaked from the injection zone through the seals. As we go further from the source of CO_2, the likelihood of such an event will diminish proportionally with the distance from the source. Considering that this is the greatest amount of CO_2 leakage in this worst-case scenario, if the event happens, the leak must pass upward through the confining zone, the secondary confining strata that consists of additional low permeability geologic units, and other geologic units, TND concludes that the risk of leakage through this pathway is highly unlikely.

5.5 Potential Leakage due to Lateral Migration

The characterization of the sand layers in the Cherry Canyon Formation described in Section 3.3 states that these sands were deposited by turbidites in channels in submarine fan complexes; each sand is encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity. Regional consideration of their depositional environment suggests a preferred orientation for fluid and gas flow would be south-to-north along the channel axis. However, locally the high net porosity of the RH AGI #1 and RH AGI #3 injection zones indicates adequate storage capacity such that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA due to a preferred regional depositional orientation.

Lateral migration of the injected TAG was addressed in detail in Section 3.3. Therein it states that the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales as well as being encased by them.

Based on the discussion of the channeled sands in the injection zone, TND considers that the likelihood of CO_2 to migrate laterally along the channel axes is possible. However, the facts that the turbidite sands are encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity and that the injectate is projected to be contained within the injection zone close to the injection wells minimizes the likelihood that CO_2 will migrate to a potential conduit to the surface.

5.6 Potential Leakage through Fractures and Faults

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology as well as identify and understand the distribution of faults and fractures. **Figure 5.6-1** shows the fault traces in the vicinity of the Red Hills plant. The faults shown on **Figure 5.6-1** are confined to the Paleozoic section below the injection zone for the RH AGI wells. No faults were identified in the confining zone above the Bell Canyon and Cherry Canyon injection zone for the RH AGI wells.

No faults were identified within the MMA which could potentially serve as conduits for surface CO_2 emission. The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief. Because this fault is confined to the lower Paleozoic unit more than 5,100 feet below the injection zone for the RH AGI wells, there is minimal chance it would be a potential leakage pathway. This inference is supported by the NRAP simulation result. Therefore, TND concludes that the CO_2 leakage rate through this fault is zero and that the risk of leakage through this potential leakage pathway is highly improbable.

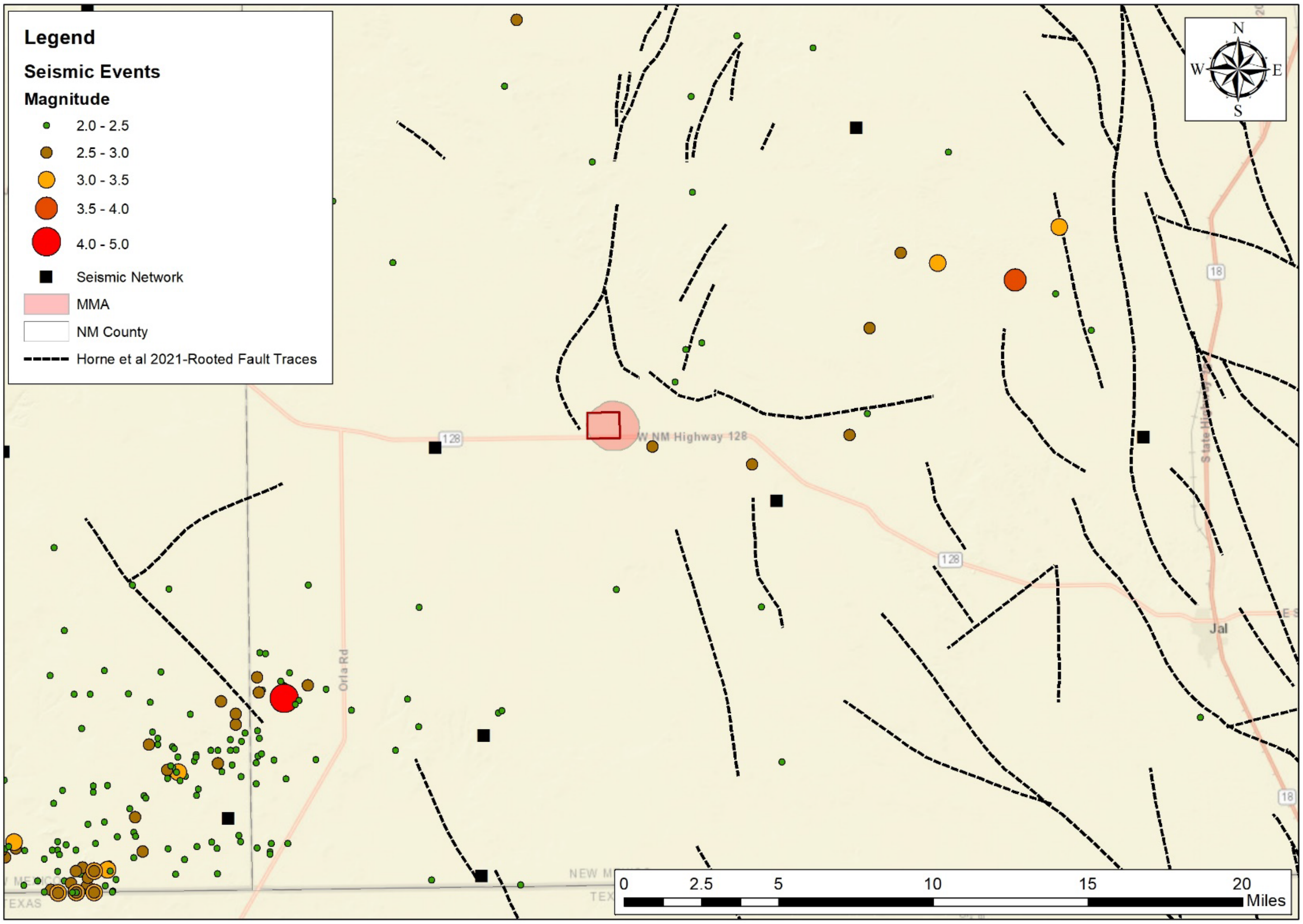


***Figure 5.6-1**: New Mexico Tech Seismological Observatory (NMTSO) seismic network close to the operations, recent seismic events, and fault traces (2022-2023). Note: Fault traces are from Horne et al 2021 for deep seated faults in the lower Paleozoic. The fault traces shown close to the Red Hills facility die out at the base of the Wolfcamp formation at a depth of 12,600 feet, more than 5,100 feet below the bottom of the injection zone at 7,500 feet.*

5.7 Potential Leakage due to Natural / Induced Seismicity

The New Mexico Tech Seismological Observatory (NMTSO) monitors seismic activity in the state of New Mexico. A search of the database shows no recent seismic events close to the Red Hills operations. The closest recent, as of 4 September 2023, seismic events are:

- 7.5 miles, 2022-09-03, Magnitude 3
- 8 miles, 2022-09-02, Magnitude 2.23
- 8.6 miles, 2022-10-29, Magnitude 2.1

Figure 5.6-1 shows the seismic stations and recent seismic events in the area around the Red Hills facility.

Due to the distance between the RH AGI wells and the recent seismic events, the magnitude of these events, and the fact that TND injects at pressures below fracture opening pressure, TND considers the likelihood of CO_2 emissions to the surface caused by seismicity to be improbable.

Monitoring of seismic events in the vicinity of the RH AGI wells is discussed in Section 6.7.

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

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

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

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors
Existing RH AGI Wells	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors • In-well P/T sensors • Groundwater monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Additional Monitoring	• Groundwater monitoring • Soil flux monitoring

6.1 Leakage from Surface Equipment

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

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

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

> "**Fixed Monitors**
> The Red Hills Plant has numerous ambient hydrogen sulfide detectors placed strategically throughout the Plant to detect possible leaks. Upon detection of hydrogen sulfide at 10 ppm at any detector, visible beacons are activated, and an alarm is sounded. Upon detection of hydrogen sulfide at 90 ppm at any detector, an evacuation alarm is sounded throughout the Plant at which time all personnel will proceed immediately to a designated evacuation area. The Plant utilizes fixed-point monitors to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the Distributed Control System (DCS). The monitors are equipped with amber beacons. The beacon is activated at 10 ppm. The plant and the RH AGI well horns are activated with a continuous warbling alarm at 10 ppm and a siren at 90 ppm. All monitoring equipment is Red Line brand. The Control Panel is a 24 Channel Monitor Box, and the fixed point H_2S Sensor Heads are model number RL-101.
>
> The Plant will be able to monitor concentrations of H_2S via H_2S Analyzers in the following locations:
> - Inlet gas of the combined stream from Winkler and Limestone
> - Inlet sour liquid downstream of the slug catcher
> - Outlet Sweet Gas to Red Hills 1
> - Outlet Sweet Liquid to Red Hills Condensate Surge
>
> The RH AGI system monitors can also be viewed on the PLC displays located at the Plant. These sensors are all shown on the plot plan (see **Figure 3.6-1**). This requires immediate action for any occurrence or malfunction. All H_2S sensors are calibrated monthly.
>
> **Personal and Handheld H_2S Monitors**
>
> All personnel working at the Plant wear personal H_2S monitors. The personal monitors are set to alarm and vibrate at 10 ppm. Handheld gas detection monitors are available at strategic locations around the Plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and carbon dioxide (CO_2)."

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones including more frequent monitoring during drilling operations (see **Table 6-1**). This applies to TND and other operators drilling new wells through the RH AGI wells injection zones within the MMA.

6.3 Leakage from Existing Wells

6.3.1 RH AGI Wells

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

To monitor leakage and wellbore integrity, two pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) were deployed in RH AGI #1. One gauge is designated to monitor the tubing ID (reservoir) pressure and temperature and the second gauge monitors the annular space between the tubing and the long string casing (**Figure 6.2-1**). A leak is indicated when both gauges start reading the same pressure. DTS is clamped to the tubing, and it monitors the temperature profiles of the annulus from 6,159 ft to surface. DTS can detect variation in the temperature profile events throughout the tubing and or casing. Temperature variation could be an indicator of leaks. Data from temperature and pressure gauges is recorded by an interrogator housed in an onsite control room. DTS (temperature) data is recorded by a separate interrogator that is also housed in the onsite control room. Data from both interrogators are transmitted to a remote location for daily real time or historical analysis.

As is described above for RH AGI #1, pressure and temperature gauges as well as DTS were deployed in RH AGI #3 (see **Figure Appendix 1-2** for location of PT gauges).

The temporarily abandoned RH AGI #2 well will be monitored by the fixed in-field gas monitors, handheld H_2S monitors, and CO_2 soil flux monitoring described in Sections 7.2 and 7.3.

If operational parameter monitoring, MIT failures, or surface gas monitoring indicate a CO_2 leak has occurred, TND will take actions to quantify the leak based on operating conditions at the time of the detection including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site.

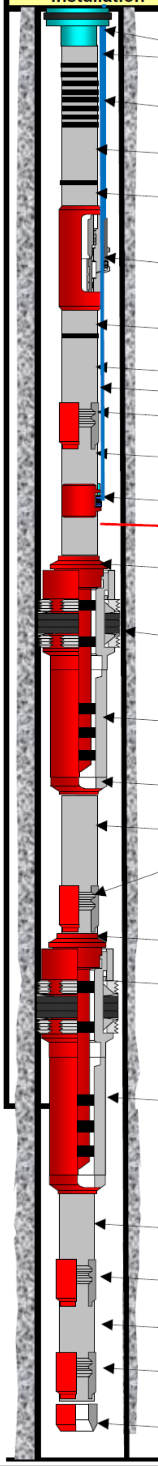
HALLIBURTON

Lucid

Red Hills AGI 1
Lea County New Mexico
2/3/21 - 2/28/21

WSP - Troy Gillen / Michael Forrier
Sales Rep - Lynn Talley (432) 631-4626
Tool Specialists: Carey Lehmann, Jonathan Phillips, Jose Vargas

Installation



Installation	Depth	Length	Jts.	Description	OD	ID
	18.50	18.50		KB		
20	22.90	4.40		20) Hanger Sub 3 1/2" 9.2# CRA VAMTOP x 7.7# VAM Ace Pin	7.000	3.000
19	64.05	41.15	1	19) 3 1/2" 7.7# VAM ACE 125K G3 Tubing (Slick Joint)	3.500	3.035
				Ran Eight Subs 8', 8', 6', 6',4', 4', 2', 2'		
18	103.97	39.92		18) 3 1/2" 7.7# VAM ACE 125K G3 Spaceout Subs	3.500	3.035
17	235.95	131.98	3	17) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.035
16	241.95	6.00		16) 6' x 3 1/2" 7.7# CRA VAM ACE Box x 9.2# VAMTOP Pin	3.540	2.959
15	246.30	4.35		15) 3 1/2" NE HES SSSV Nickel Alloy 925 w/Alloy 825 Control Line 3 1/2" 9.2# VAMTOP Box x Pin	5.300	2.813
14	252.29	5.99		14) 6' x 3 1/2" 9.2# CRA VAMTOP Box x 7.7# VAM ACE Pin	3.540	2.959
13	6,140.23	5,887.94	134	13) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.305
12				12) 3 1/2" 7.7# VAM ACE Box x 9.2# VAMTOP Pin CRA Crossover	3.830	2.959
11				11) 2.813" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925	4.073	2.813
10	6,153.72	13.49		10) 6' x 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy G3 Sub	3.540	2.959
				13.49' Length Includes Line Items 10, 11 & 12		
9	6,159 Tubing	P/T		9) Baker PT Sensor Mandrel 3 1/2" 9.2# VAMTOP Box x Pin	5.200	2.992
	6,162.6 Annular	P/T		6' VAMTOP 9.2# CRA Tubing Sub Above & Below Gauge Mdl		
8	6,161.23	7.51		8) 4.00" BWS Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925	4.470	2.959
				7.51' Length Includes Line Items 8 & 9		
7	6,164.55	3.32		7) 7" 26-32# x 4.00" BWS Packer Nickel Alloy 925 Casing Collar @ 6,160.6' WL Measurement	5.875	4.000
6	6,172.05	7.5		6) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
5	6,172.88	0.83		5) 4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
4	6,181.19	8.31		4) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
3	6,182.52	1.33		3) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925 #102204262	4.073	2.562
2	6,184.29	1.77		2) Straight Slot Locator Seal Assembly Above Top Of Packer	4.450	2.880
1		6,186.06		1) BWD Permanent Packer. WL Measured Depth Previously 6189'	5.875	4.000
1a				1a) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.660	2.965
1b				1b) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1c				1c) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel,	2.920	2.562
1d				1d) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1e				1e) 2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	3.920	2.321
1f				1f) Re-Entry Guide / POP	3.950	3.000

Figure 6.2-1: *Well Schematic for RH AGI #1 showing installation of P/T sensors*

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7.3 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. Additionally, groundwater and soil CO_2 flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through the Confining / Seal System

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

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

6.5 Leakage due to Lateral Migration

Continuous operational monitoring of the RH AGI wells during and after the period of injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The CO_2 monitoring network described in Section 7.3, and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

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

6.6 Leakage from Fractures and Faults

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through faults. However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, TND will identify which of the pathways listed in this section are responsible for the leak, including the possibility of heretofore unidentified faults or fractures within the MMA. TND will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details. See Section 6.8 for additional information on quantification strategies.

6.7 Leakage due to Natural / Induced Seismicity

In order to monitor the influence of natural and/or induced seismicity, TND will use the established NMTSO seismic network. The network consists of seismic monitoring stations that detect and locate seismic events. Continuous monitoring helps differentiate between natural and induced seismicity. The network surrounding the Red Hills Gas Processing Plant has been mapped on **Figure 5.6-1**. The monitoring network records Helicorder data from UTC (coordinated universal time) all day long. The data are plotted daily at

5pm MST (mountain standard time). These plots can be browsed either by station or by day. The data are streamed continuously to the New Mexico Tech campus and archived at the Incorporated Research Institutions for Seismology Data Management Center (IRIS DMC).

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

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

For normal operations, quantification of emissions of CO_2 from surface equipment will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR. Quantification of major leakage events from surface equipment as identified by the detection techniques listed in **Table 6-1** will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified the leakage location will be isolated to prevent additional emissions to the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. TND has standard operating procedures to report and quantify all pipeline leaks in accordance with the NMOCD regulations (New Mexico administrative Code 19.15.28 Natural Gas Gathering Systems). TND will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by TND or third parties. Additionally, TND may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

6.8.2 Subsurface Leakage

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

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

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, or which may be initiated by seismic events and as may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO_2 leaking back to the surface emphasizing the importance of monitoring

network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO_2 flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 6.8.1, or from the subsurface. In the latter case, CO_2 flux monitoring methodologies, as described in Section 7.8, will be employed to quantify the surface leaks.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

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

7.1 Visual Inspection

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

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

Compositional analysis of TND's gas injectate at the Red Hills Gas Plant indicates an approximate H_2S concentration of 20% thus requiring TND to develop and maintain an H_2S Contingency Plan (Plan) according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). TND considers H_2S to be a proxy for CO_2 leaks at the plant. The Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated RH AGI wells and documents procedures that would be followed in case of such an event.

7.2.1 Fixed In-Field H_2S Monitors

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

7.2.2 Handheld and Personal H_2S Monitors

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

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

7.3 CO_2 Detection

In addition to the handheld gas detection monitors described above, New Mexico Tech, through a DOE research grant (DE-FE0031837 – Carbon Utilization and Storage Project of the Western USA (CUSP)), will assist TND in setting up a monitoring network for CO_2 leakage detection in the AMA as defined in Section 4.2. The scope of work for the DOE project includes field sampling activities to monitor CO_2/H_2S at the two RH AGI wells. These activities include periodic well (groundwater and gas) and atmospheric sampling from an area of 10 – 15 square miles around the injection wells. Once the network is set up, TND will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

7.4 Continuous Parameter Monitoring

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

7.5 Well Surveillance

TND adheres to the requirements of NMOCC Rule 26 governing the construction, operation and closing of an injection well under the Oil and Gas Act. Rule 26 also includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, NMOCC includes special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. TND's Routine Operations and Maintenance Procedures for the RH AGI wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic (Microseismic) Monitoring Stations

TND has Installed a model TCH120-1 Trillium Compact Horizon Seismometer and a model CTR4-3S Centaur Digital Recorder to monitor for and record data for any seismic event at the Red Hills Gas Plant (see **Figure 7-1)**. The seismic station meets the requirements of the NMOCC Order No. R-20916-H to "install, operate, and monitor for the life of the [Class II AGI] permit a seismic monitoring station or stations as directed by the Manager of the New Mexico Tech Seismological Observatory ("state seismologist") at the New Mexico Bureau of Geology and Mineral Resources."

In addition, data that are recorded by the State of New Mexico deployed seismic network within a 10-mile radius of the Red Hills Gas Plant will be analyzed by the New Mexico Bureau of Geology (NMBGMR), see **Figure 5.6-1**, and made publicly available. The NMBGMR seismologist will create a report and map showing the magnitudes of recorded events from seismic activity. The data are being continuously recorded. By examining historical data, a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

7.7 Groundwater Monitoring

New Mexico Tech, through the same DOE research grant described in Section 7.3 above, will monitor groundwater wells for CO_2 leakage which are located within the AMA as defined in Section 4.2. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 7.7-1**. Baseline analyses will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Red Hills Gas Plant. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

***Table 7.7-1**: Groundwater Monitoring Parameters*

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

7.8 Soil CO_2 Flux Monitoring

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

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

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

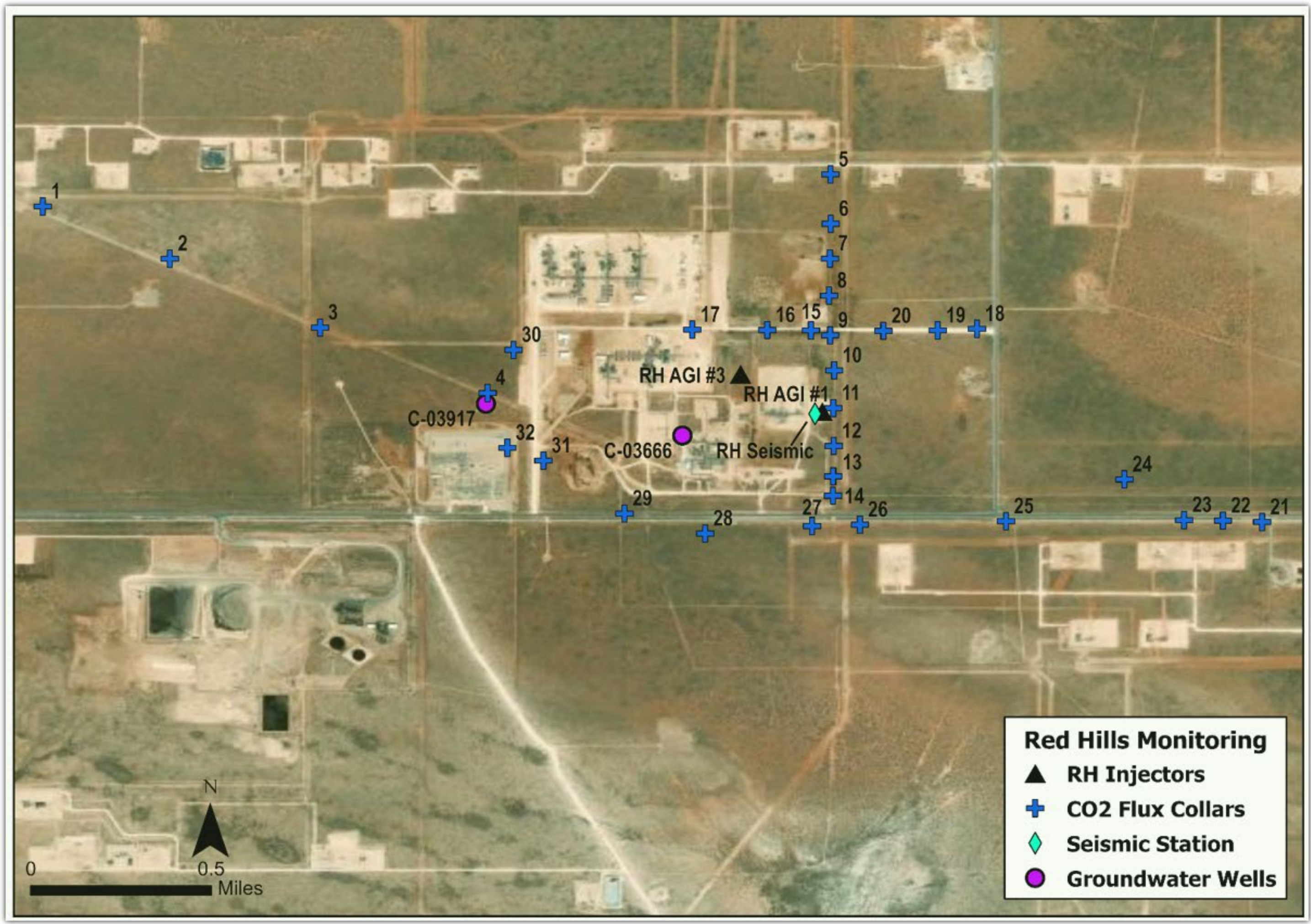


Figure 7-1: *Red Hills monitoring network of 32 CO_2 flux locations, 2 groundwater wells, and a seismic station developed by New Mexico Tech and Targa Resources to detect leakage during injection.*

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve Subpart RR equations used to calculate the mass of CO_2 sequestered annually. **Appendix 8** includes the twelve equations from Subpart RR. Not all of these equations apply to TND's current operations at the Red Hills Gas Plant but are included in the event TND's operations change in such a way that their use is required.

Figure 3.6-2 shows the location of all surface equipment and points of venting listed in 40CFR98.232(d) of Subpart W that will be used in the calculations listed below.

8.1 CO_2 Received

Currently, TND receives gas to its Red Hills Gas Plant through six pipelines: Gut Line, Winkler Discharge, Red Hills 24" Inlet Loop, Greyhound Discharge, Limestone Discharge, and the Plantview Loop. The gas is processed as described in Section 3.8 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection. TND will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3. Receiving flow meter r in the following equations corresponds to meters M1 and M2 in **Figure 3.6-2**.

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

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

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

8.2 CO_2 Injected

TND injects CO_2 into RH AGI #1 and RH AGI #3. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into both wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in

Equation RR-12. Volumetric flow meter u in the following equations corresponds to meters M3 and M6 in **Figure 3.6-2**.

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

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

(Equation RR-6)

where:

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

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

u = Flow meter.

8.3 CO_2 Produced / Recycled

TND does not produce oil or gas or any other liquid at its Red Hills Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.6 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6.8.

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

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

8.6 CO_2 Sequestered

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

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

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

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

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

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

9 Estimated Schedule for Implementation of MRV Plan

The baseline monitoring and leakage detection and quantification strategies described herein have been established and data collected by TND and its predecessor, Lucid, for several years and continues to the present. TND will begin implementing this revised MRV plan as soon as it is approved by EPA.

10 GHG Monitoring and Quality Assurance Program

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

10.1 GHG Monitoring

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

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations

- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

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

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

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.3 CO_2 injected.

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

10.1.4 CO_2 produced.

TND does not produce CO_2 at the Red Hills Gas Plant.

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

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

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

10.1.6 Measurement devices.

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

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

10.2 QA/QC Procedures

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

10.3 Estimating Missing Data

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

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

10.4 Revisions of the MRV Plan

TND will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of New Mexico. If any operational changes constitute a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change.

11 Records Retention

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

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

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

(i) The GHG emissions calculations and methods used

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

(iii) The results of all required analyses

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

(3) The annual GHG reports.

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

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

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

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

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

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

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

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

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

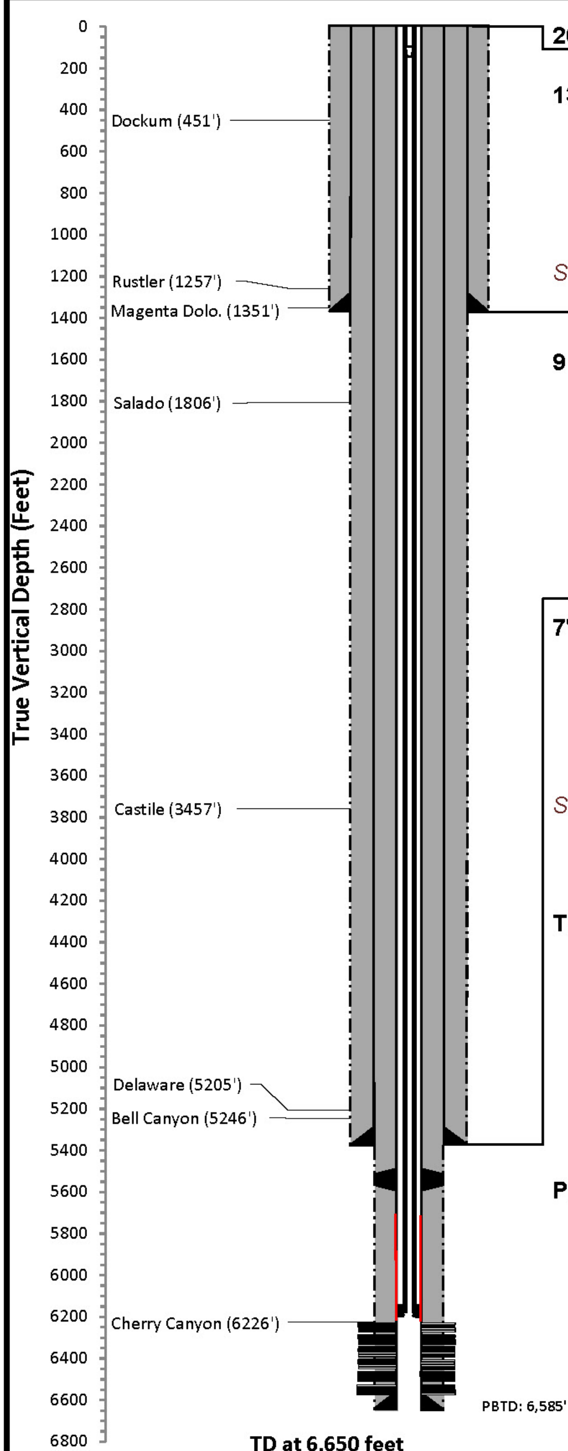
12 Appendices

Appendix 1 TND Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Red Hills AGI #1	30-025-40448	1,600 ft FSL, 150 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	10/23/2013	6,650 ft	6,170 ft
Red Hills AGI #2 (temporarily abandoned)	30-025-49474	150 ft FEL, 1,800 ft FSL Sec. 13, T24S, R33E, NMPM	Lea, NM		6,205 ft	
Red Hill AGI #3	30-025-51970	3,116 ft FNL, 1,159 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	9/13/2023	7,600 ft	5,700 ft

Lucid Energy Red Hills AGI #1 Well Schematic

Well Name:	Red Hills AGI #1	**Footage**	1600' FSL & 150' FEL
API:	30-025-40448	**Well Type**	AGI Exploratory Cherry Canyon
STR:	Sec. I-13, T24S-R33E	**KB/GL:**	3596/3580
County, St.	Lea County, New Mexico	**Lat, Long:**	32.214586, -103.517520



20" CONDUCTOR PIPE to 40 ft.

13 3/8" SURFACE CASING to 1,372 ft. **17.5" OH**

13 3/8", 48 #/ft., H-40, STC
Cmnt to surface - 90 bbls returned
Lead Cmnt: 820 sx C Lite
Tail Cmnt: 180 sx Class C

SSSV @ 250'

9 5/8" INTERMEDIATE CASING to 5,346 ft. **12.25" OH**

9 5/8", 40 #/ft., J-55, LT&C 0-100'
9 5/8", 36 #/ft., J-55, LT&C 100-3,300'
9 5/8", 40 #/ft., J-55, LT&C 3,300'-4,200'
9 5/8", 40 #/ft., HCK-55, LT&C 4,200'-5,346'
Cmnt to surface - 60 bbls returned
Lead Cmnt: 1,280 sx C Lite
Tail Cmnt: 180 sx Class C

7" PRODUCTION CASING to 6,650 ft. **8.75" OH**

7" 26 #/ft., L80, LT&C from 0'-5,702'
w/ 7" G-3, 26 #/ft. VAMTOP, from 5,702'-6,239'
7" 26 #/ft., L80, LT&C from 6,239' - 6,650'
Cmnt to surface both stages - 1.5 bbls
Stage 1 - Lead: 250 sx EverCrete
StageTool in 7-in casing @ 5,539'
Stage 2 - Lead: 490 sx C Lite
Stage 2 - Tail: 100 sx Class C

TUBING AND EQUIPMENT

Halliburton Retrievable SSSV set @ 250 ft.
3.5", 9.3 #/ft, L80, VAMTOP from 0'-5,870'
3.5",SM2550, VAMTOP from 5,870'-6,167'
Bottom Hole P/T Gauge set above packer @ 6,167'-6,170'
Permanent Production-Packer set @ 6,170'
Check Valve and Choke (optional)
Annulus filled w/ diesel mixed with corrosion inhibitor/biocide

PERFORATIONS

Primary Target:
Upper Cherry Canyon (6 spf @ 60°)
6,230' - 6,250'
6,260' - 6,280'
6,295' - 6,335'
6,355' - 6,380'
6,400' - 6,415'
6,435' - 6,500'
6,525' - 6,583'

Prepared For: LUCID energy group
Prepared By: GEOLEX INCORPORATED

Schematic is properly scaled

Figure Appendix 1-1: *Schematic of RH AGI #1*

Targa Resources
Red Hills Delaware AGI #3
Location 3116' FNL & 1159' FEL
Sec 13 - T 24S - R 33E
GL 3578', RKB TBD

Surface - (Conventional)
Hole Size: 17.5"
Casing: 13.375" 72# L-80 VAM TOP
Depth Top: Surface
Depth Btm: 1307'
Cement: TBD sks - Class C + Additives
Cement Top: Surface - (Circulate)

Intermediate #1 - (Conventional)
Hole Size: 12.25"
Casing: 9.625" 47# HCL-80 BTC
Depth Top: Surface
Depth Btm: 5205'
Cement: TBD - Class C + Additives
Cement Top: Surface - (Circulate)

Production - (Conventional)
Hole Size: 8.5"
Casing 1: 7" 32# I-80 VAMSTL
Depths: 0' to 5280' & 5580' to 7600'
Casing 2: 7" 32# G3 CRA VAM HDL
Depths: 5280' to 5580'
Cement: TBD - Class C + Additives, Well Lock resin 5280'-5580'
Cement Top: Surface - (Circulate)
ECP/DV Tool: 5280' & 5580'

Tubing
Depth: 5700'
Tubing: 3.5" 7.7# G3 CRA VAM ACE
Packer: 7" x 3.5" PermaPak or equivalent (Inconel)
SSSV: 175'
PT Gauges: 5690'

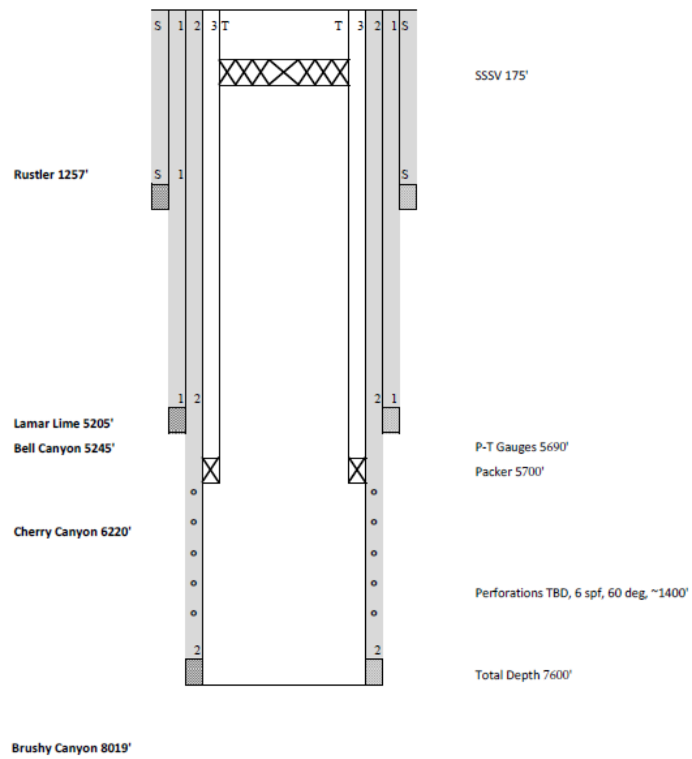


***Figure Appendix 1-2**: As-built wellbore schematic for RH AGI #3*

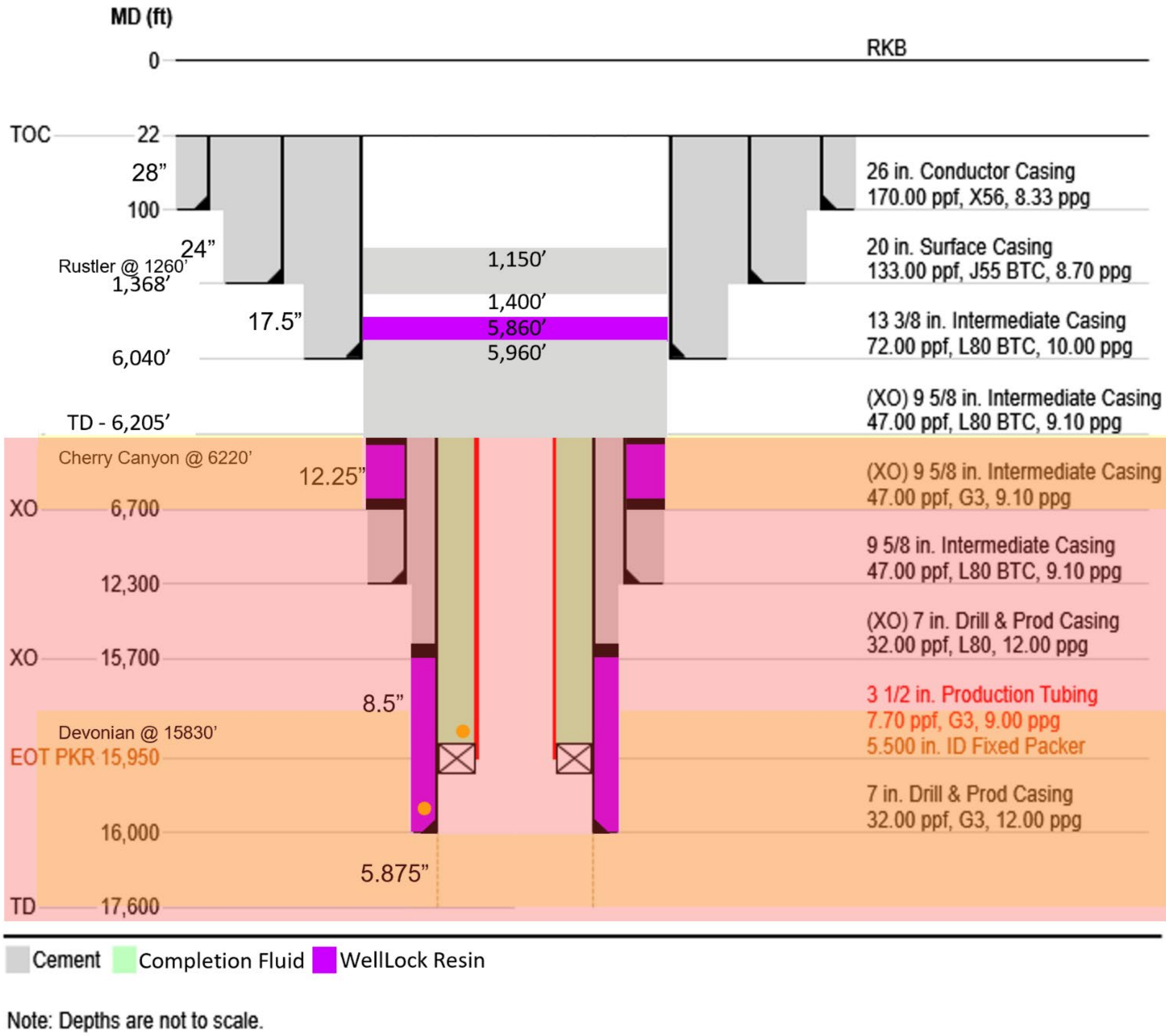


***Figure Appendix 1-3**: As-built wellbore schematic for the RH AGI #2 Well (temporarily abandoned). The colored portion of the schematic below 6,205 ft was not completed.*

Appendix 2 Referenced Regulations

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

New Mexico Administrative Code (NMAC) > Title 19 – Natural resources > Chapter 15 – Oil and Gas

CHAPTER 15 - OIL AND GAS

19.15.1 NMAC	GENERAL PROVISIONS AND DEFINITIONS [REPEALED]
19.15.2 NMAC	GENERAL PROVISIONS FOR OIL AND GAS OPERATIONS
19.15.3 NMAC	RULEMAKING
19.15.4 NMAC	ADJUDICATION
19.15.5 NMAC	ENFORCEMENT AND COMPLIANCE
19.15.6 NMAC	TAX INCENTIVES
19.15.7 NMAC	FORMS AND REPORTS
19.15.8 NMAC	FINANCIAL ASSURANCE
19.15.9 NMAC	WELL OPERATOR PROVISIONS
19.15.10 NMAC	SAFETY
19.15.11 NMAC	HYDROGEN SULFIDE GAS
19.15.12 NMAC	POOLS
19.15.13 NMAC	COMPULSORY POOLING
19.15.14 NMAC	DRILLING PERMITS
19.15.15 NMAC	WELL SPACING AND LOCATION
19.15.16 NMAC	DRILLING AND PRODUCTION
19.15.17 NMAC	PITS, CLOSED-LOOP SYSTEMS, BELOW-GRADE TANKS AND SUMPS
19.15.18 NMAC	PRODUCTION OPERATING PRACTICES
19.15.19 NMAC	NATURAL GAS PRODUCTION OPERATING PRACTICE
19.15.20 NMAC	OIL PRORATION AND ALLOCATION
19.15.21 NMAC	GAS PRORATION AND ALLOCATION
19.15.22 NMAC	HARDSHIP GAS WELLS
19.15.23 NMAC	OFF LEASE TRANSPORT OF CRUDE OIL OR CONTAMINANTS
19.15.24 NMAC	ILLEGAL SALE AND RATABLE TAKE
19.15.25 NMAC	PLUGGING AND ABANDONMENT OF WELLS
19.15.26 NMAC	INJECTION
19.15.27 - 28 NMAC	[RESERVED] PARTS 27 - 28
19.15.29 NMAC	RELEASES

19.15.30 NMAC	REMEDIATION
19.15.31 - 33 NMAC	[RESERVED] PARTS 31 - 33
19.15.34 NMAC	PRODUCED WATER, DRILLING FLUIDS AND LIQUID OIL FIELD WASTE
19.15.35 NMAC	WASTE DISPOSAL
19.15.36 NMAC	SURFACE WASTE MANAGEMENT FACILITIES
19.15.37 NMAC	REFINING
19.15.38 NMAC	[RESERVED]
19.15.39 NMAC	SPECIAL RULES
19.15.40 NMAC	NEW MEXICO LIQUIFIED PETROLEUM GAS STANDARD
19.15.41 - 102 NMAC	[RESERVED] PARTS 41 - 102
19.15.103 NMAC	SPECIFICATIONS, TOLERANCES, AND OTHER TECHNICAL REQUIREMENTS FOR COMMERCIAL WEIGHING AND MEASURING DEVICES
19.15.104 NMAC	STANDARD SPECIFICATIONS/MODIFICATIONS FOR PETROLEUM PRODUCTS
19.15.105 NMAC	LABELING REQUIREMENTS FOR PETROLEUM PRODUCTS
19.15.106 NMAC	OCTANE POSTING REQUIREMENTS
19.15.107 NMAC	APPLYING ADMINISTRATIVE PENALTIES
19.15.108 NMAC	BONDING AND REGISTRATION OF SERVICE TECHNICIANS AND SERVICE ESTABLISHMENTS FOR COMMERCIAL WEIGHING OR MEASURING DEVICES
19.15.109 NMAC	NOT SEALED NOT LEGAL FOR TRADE
19.15.110 NMAC	BIODIESEL FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.111 NMAC	E85 FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.112 NMAC	RETAIL NATURAL GAS (CNG / LNG) REGULATIONS [REPEALED]

Appendix 3 Water Wells

Water wells identified by the New Mexico State Engineer's files within two miles of the RH AGI wells; water wells within one mile are highlighted in yellow.

POD Number	County	Sec	Tws	Rng	UTME	UTMN	Distance (mi)	Depth Well (ft)	Depth Water (ft)	Water Column (ft)
C 03666 POD1	LE	13	24S	33E	639132	3565078	0.31	650	390	260
C 03917 POD1	LE	13	24S	33E	638374	3565212	0.79	600	420	180
C 03601 POD1	LE	23	24S	33E	638124	3563937	1.17			
C 02309	LE	25	24S	33E	639638	3562994	1.29	60	30	30
C 03601 POD3	LE	24	24S	33E	638142	3563413	1.38			
C 03932 POD8	LE	7	24S	34E	641120	3566769	1.40	72		
C 03601 POD2	LE	23	24S	33E	637846	3563588	1.44			
C 03662 POD1	LE	23	24S	33E	637342	3564428	1.48	550	110	440
C 03601 POD5	LE	23	24S	33E	637988	3563334	1.48			
C 03601 POD6	LE	23	24S	33E	637834	3563338	1.55			
C 03601 POD7	LE	23	24S	33E	637946	3563170	1.58			
C 03600 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03602 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03600 POD1	LE	26	24S	33E	637275	3563023	1.94			
C 03600 POD3	LE	26	24S	33E	637784	3562340	2.05			

Appendix 4   Oil and Gas Wells within 2-mile Radius of the RH AGI Well Site

Note – a completion status of "New" indicates that an Application for Permit to Drill has been filed and approved but the well has not yet been completed. Likewise, a spud date of 31-Dec-99 is actually 12-31-9999, a date used by NMOCD databases to indicate work not yet reported.

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-08371	COSSATOT E 002	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	5425	Yes
30-025-25604	GOVERNMENT L COM 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	17625	No
30-025-26369	GOVERNMENT L COM 002	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	14698	Yes
30-025-26958	SIMS 001	BOPCO, L.P.	GAS	DELAWARE VERTICAL	P & A	VERTICAL	15007	Yes
30-025-27491	SMITH FEDERAL 001	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	15120	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-40448	RED HILLS AGI 001	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	INJECTING	VERTICAL	6650	Yes
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL		PRODUCING	VERTICAL	10997	No
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11034	No
30-025-41382	DECKARD FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11067	Yes
30-025-41383	DECKARD FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11162	Yes
30-025-41384	DECKARD FEDERAL COM 004H	COG OPERATING LLC	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11103	Yes
30-025-41666	SEBASTIAN FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10927	Yes
30-025-41687	SEBASTIAN FEDERAL COM 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10944	Yes
30-025-41688	SEBASTIAN FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11055	No
30-025-43532	LEO THORSNESS 13 24 33 211H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12371	No
30-025-44442	STRONG 14 24 33 AR 214H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12500	No
30-025-46154	LEO THORSNESS 13 24 33 221H	MATADOR PRODUCTION COMPANY	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12868	No
30-025-46282	LEO THORSNESS 13 24 33 AR 135H	MATADOR PRODUCTION COMPANY	OIL	3RD BONE SPRING SAND	PRODUCING	HORIZONTAL	12103	No

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-46517	BROADSIDE 13 W FEDERAL COM 001H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12213	No
30-025-46518	BROADSIDE 13 24 FEDERAL COM 002H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-46519	BROADSIDE 13 24 FEDERAL COM 003H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12320	Yes
30-025-46985	SEBASTIAN FEDERAL COM 703H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12123	No
30-025-46988	SEBASTIAN FEDERAL COM 704H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12142	No
30-025-47869	JUPITER 19 FEDERAL COM 501H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11175	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47874	JUPITER 19 FEDERAL COM 506H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10950	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47877	JUPITER 19 FEDERAL COM 509H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11156	No
30-025-47878	JUPITER 19 FEDERAL COM 510H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11102	No
30-025-47908	JUPITER 19 FEDERAL COM 601H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-47910	JUPITER 19 FEDERAL COM 702H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	DUC	HORIZONTAL	0	Yes
30-025-47911	JUPITER 19 FEDERAL COM 705H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12290	No
30-025-47912	JUPITER 19 FEDERAL COM 707H	EOG RESOURCES INC	OIL	WOLFCAMP B UPPER	PERMITTED	HORIZONTAL	12515	No
30-025-47913	JUPITER 19 FEDERAL COM 708H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12477	No
30-025-48239	JUPITER 19 FEDERAL COM 306H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10270	No
30-025-48889	JUPITER 19 FEDERAL COM 701H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-48890	JUPITER 19 FEDERAL COM 703H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-49262	BROADSIDE 13 24 FEDERAL COM 004H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12531	Yes
30-025-49263	BROADSIDE 13 24 FEDERAL COM 015H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B LOWER	PRODUCING	HORIZONTAL	12746	Yes
30-025-49264	BROADSIDE 13 24 FEDERAL COM 025H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11210	Yes
30-025-49474	RED HILLS AGI 002	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	Temporarily Abandoned	VERTICAL	17600	Yes

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Appendix 6 Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
AoR – Area of Review
API – American Petroleum Institute
CFR – Code of Federal Regulations
C1 – methane
C6 – hexane
C7 - heptane
CO_2 – carbon dioxide
DCS – distributed control system
EPA – US Environmental Protection Agency, also USEPA
ft – foot (feet)
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MSCFD– thousand standard cubic feet per day
MMSCFD – million standard cubic feet per day
MMstb – million stock tank barrels
MRRW B – Morrow B
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NIST - National Institute of Standards and Technology
NMOCC – New Mexico Oil Conservation Commission
NMOCD - New Mexico Oil Conservation Division
PPM – Parts Per Million
psia – pounds per square inch absolute
QA/QC – quality assurance/quality control
SCITS - Stanford Center for Induced and Triggered Seismicity
Stb/d – stock tank barrel per day
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TVD – True Vertical Depth
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

Appendix 7 TND Red Hills AGI Wells - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

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

* All measurements must be made in accordance with 40 CFR 98.444 – Monitoring and QA/QC Requirements.

** If you measure the mass of contents of containers summed quarterly using weigh bill, scales, or load cells (40 CFR 98.444(a)(2)(i)), use RR-1 for Containers to calculate CO_2 received in containers for injection.

*** If you determine the volume of contents of containers summed quarterly (40 CFR 98.444(a)(2)(ii)), use RR-2 for Containers to calculate CO_2 received in containers for injection.

Appendix 8 Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

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

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

(Equation RR-1 for Pipelines)

where:

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

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

(Equation RR-1 for Containers)

where:

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

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

(Equation RR-2 for Containers)

where:

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

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

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

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

(Equation RR-4)

where:

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

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

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

p = Quarter of the year.

u = Flow meter.

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

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

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

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

(Equation RR-6)

where:

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

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

u = Flow meter.

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

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

(Equation RR-7)

where:

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-8)

where:

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

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-9)

where:

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

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

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

w = Separator.

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

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

Appendix 9 P&A Records

P&A Record for Government Com 001, API #30-025-25604

New Mexico Oil Conservation Division, District I
1625 N. French Drive
Hobbs, NM 88240

Form 3160-5
(April 2004)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OM B No. 1004-0137
Expires: March 31, 2007

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

***SUBMIT IN TRIPLICATE**- Other instructions on reverse side.*

5. Lease Serial No. NM-17446
6. If Indian, Allottee or Tribe Name
7. If Unit or CA/Agreement, Name and/or No.

1. Type of Well ☐ Oil Well ☑ Gas Well ☐ Other
8. Well Name and No. Government "L" Com #1
2. Name of Operator EOG Resources, Inc
9. API Well No. 30-025-~~0~~ 25604
3a. Address P.O. Box 2267, Midland, TX, 79702
3b. Phone No. *(include area code)* 432-561-8600
10. Field and Pool, or Exploratory Area Bell Lake, South Morrow
4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*
Unit Letter G, 1980 FNL, 1980 FEL
Section 18, Township 24-S, Range 34-E
11. County or Parish, State Lea, New Mexico

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
☑ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☐ Other
	☐ Change Plans	☑ Plug and Abandon	☐ Temporarily Abandon	
	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

1. Notified Jim McCormick w/BLM 24 hrs prior to MI and RU.
2. Cut 3 1/2' tbg at 11500, spot 50sx CLass "H" cmt, plug from 11500-11400, WOC Tag at 11389.
3. Circ hole w/MLF.
4. Perf 4 holes at 9050, press up to 2000 PSI, spot 75sx, plug from 9100-8950, WOC Tag @ 8938.
5. Perf 4 holes at 7000, press up to 2000 PSI, spot 75sx, plug from 7050-6900, WOC Tag at 6855.
6. Cut 10 3/4" csg at 5450, L/D csg, spot 150sx, plug from 5500-5350, WOC Tag at 5336.
7. Spot 75sx, plug from 1300-1200 (T-Salt) WOC Tag at 1143.
8. Spot 150sx, plug from 650-450 (20" Shoe) WOC Tag at 423.
9. Spot 20sx, plug from 30-Surf.
10. Clean location. Install dry hole marker 12-30-04.

P&A Complete 12-30-04

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

14. I hereby certify that the foregoing is true and correct
Name *(Printed/Typed)* Jimmy Bagley
Title Consultant
Signature
Date 12/30/2004

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by ______ Title ______ Date ______

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.
Office

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on page 2)

GWW

P&A Records for API #30-025-26958

Submit 1 Copy To Appropriate District Office District I – (575) 393-6161 1625 N. French Dr., Hobbs, NM 88240 District II – (575) 748-1283 811 S. First St., Artesia, NM 88210 District III – (505) 334-6178 1000 Rio Brazos Rd., Aztec, NM 87410 District IV – (505) 476-3460 1220 S. St. Francis Dr., Santa Fe, NM 87505	State of New Mexico Energy, Minerals and Natural Resources RECEIVED OIL CONSERVATION DIVISION 1220 South St. Francis Dr. AUG 16 2012 Santa Fe, NM 87505 HOBBSOCD	Form C-103 Revised August 1, 2011

	WELL API NO. 3002526958
	5. Indicate Type of Lease STATE ☐ FEE ☒
	6. State Oil & Gas Lease No. SCR-389
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name Sims
1. Type of Well: Oil Well ☐ Gas Well ☒ Other	8. Well Number #1
2. Name of Operator: Agave Energy Company	9. OGRID Number 147831
3. Address of Operator 104 S. Fourth St., Artesia NM 88210 (575-748-4528)	10. Pool name or Wildcat Big Sinks Wolfcamp

4. Well Location

Unit Letter K: 1980 feet from the N line and 800 feet from the E line

Section 13 Township 24S Range 33E NMPM Lea County

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
OTHER: ☐		OTHER ☒ Replug to cement off Cherry Canyon per NMOCC R-13507	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

The remediation of the Sims #1 well pursuant to NMOCC order was completed on August 15, 2011 and all equipment has been demobilized. The plugging was done pursuant to NMOCD requirements and all aspects of the effort were reported to Mark Whitaker and E.L. Gonzales of the OCD District 1 office who approved the specifics of the plugging as shown in the attached plugging diagram. When establishing a rate prior to squeezing the Cherry Canyon, it is clear that the reservoir is an excellent reservoir as it was taking 3bbl/min on vacuum. This indicates that the predicted injection plume for the Red Hills AGI #1 in this reservoir will be smaller than anticipated and the reservoir conditions act to prevent migration of injected acid gas out of the intended and permitted injection zone by any nearby wellbores including the Govt#2, Govt#1 and Smith Federal #1 in addition to the Sims#1. Please see attached wellbore sketch for plugging details of all plugs set and amounts of cement squeezed for each plug.

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE_______________ TITLE_ Consultant to Agave Energy Company _DATE August 16, 2012

Type or print name Alberto A. Gutierrez, RG E-mail address: aag@geolex.com PHONE: 505-842-8000

For State Use Only

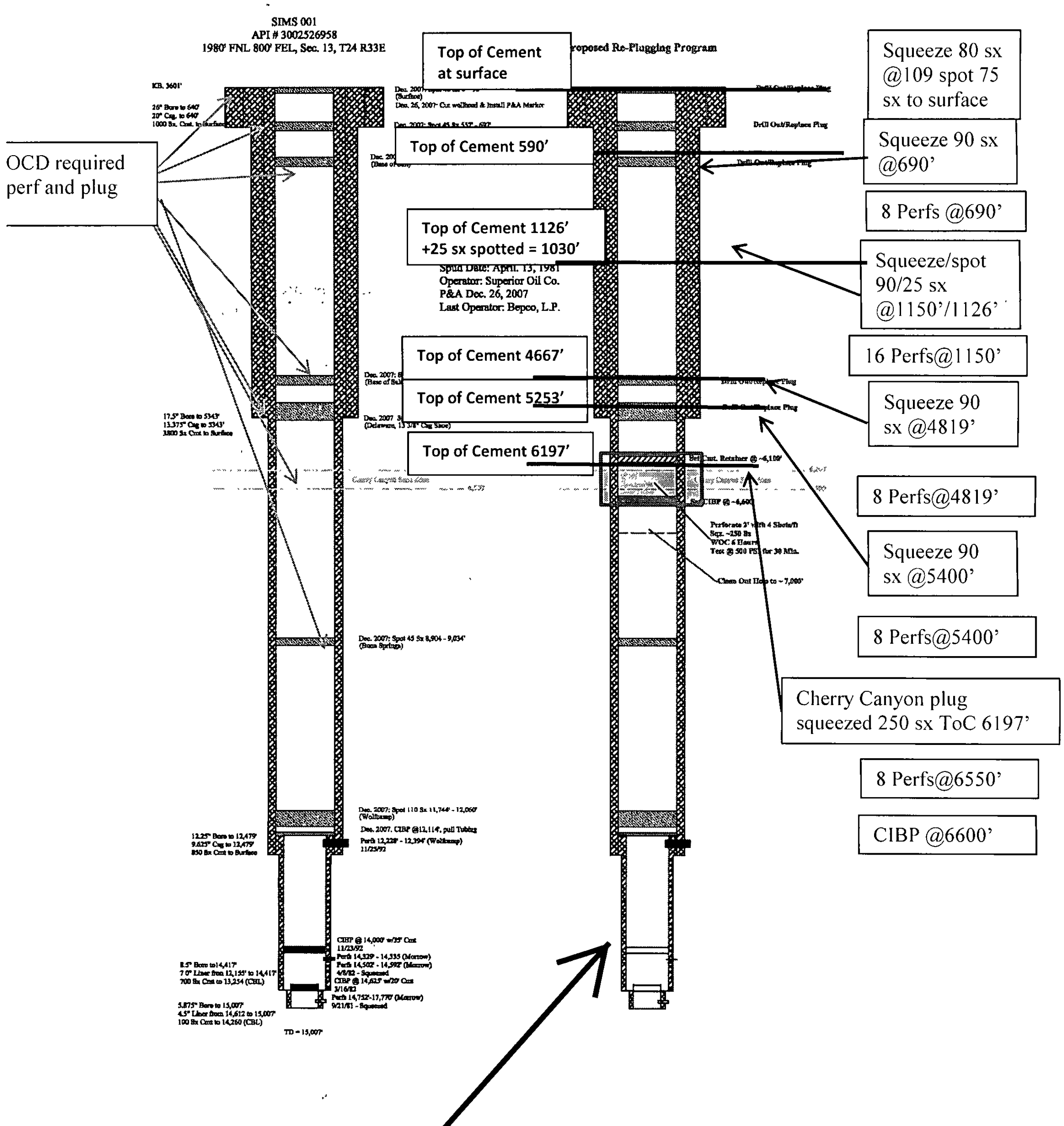
APPROVED BY: ______ TITLE Dist Mgr DATE 8-16-2012

Conditions of Approval (if any):

AUG 16 2012

GEOLEX
INCORPORATED

8/16/2012



Final Remediated Sims #1 Well

P&A Records for API 30-025-08371

NEW MEXICO OIL CONSERVATION COMMISSION

FORM C-103 (Rev 3-55)

MISCELLANEOUS REPORTS ON WELLS

(Submit to appropriate District Office as per Commission Rule 1106)

Name of Company: Byard Bennett				Address: 207 West Third, Roswell, New Mexico	
Lease: Holland	Well No. 1	Unit Letter H	Section 13	Township 24 South	Range 33 East
Date Work Performed: March 8, 1961	Pool: Wildcat			County: Lea	

THIS IS A REPORT OF: *(Check appropriate block)*

[ ] Beginning Drilling Operations [ ] Casing Test and Cement Job [ ] Other *(Explain)*:

[X] Plugging [ ] Remedial Work

Detailed account of work done, nature and quantity of materials used, and results obtained.

Top of Rustler: 1245', Top of Salt: 1392', Base of Salt: 4930', Top of Dela Ls: 5190'
Top of Delaware Sand: 5210', Total Depth: 5425', Casing 8 5/8 set at 365', Hole size 6 3/4

Cement Plugs set as follows:
5375-5425 with 15 sacks, 5175-5240 with 20 sacks, 1375-1425 with 20 sacks, 340-390 with 20 sacks, 5 sacks and marker pipe set at surface.
Heavy mud (4 cc wtr. loss) between all cement plugs.
Job performed and witnessed by Mr. Pool, Pool Drlg Co.
Prior verbal approval of plugging program from Mr. Engbrecht, New Mexico O C C.

Location will be cleaned and leveled as soon as practical.

Witnessed by	Position	Company
Mr. Fred Pool	Owner	Pool Drlg Co.

FILL IN BELOW FOR REMEDIAL WORK REPORTS *ONLY*

ORIGINAL WELL DATA

D F Elev.	T D	P B T D	Producing Interval	Completion Date

Tubing Diameter	Tubing Depth	Oil String Diameter	Oil String Depth

Perforated Interval(s)

Open Hole Interval | Producing Formation(s)

RESULTS OF WORKOVER

Test	Date of Test	Oil Production BPD	Gas Production MCFPD	Water Production BPD	GOR Cubic feet/Bbl	Gas Well Potential MCFPD
Before Workover						
After Workover						

OIL CONSERVATION COMMISSION

Approved by: Leslie A. Clements

Title

Date

I hereby certify that the information given above is true and complete to the best of my knowledge.

Name: Guy A. Swartz

Position: Agent

Company: Byard Bennett

Temporary Abandonment Record for RH AGI #2

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

	WELL API NO. 30-025-49474
	5. Indicate Type of Lease STATE ☐ FEE ☒
	6. State Oil & Gas Lease No.
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name RED HILLS AGI
1. Type of Well: Oil Well ☐ Gas Well ☒ Other Acid Gas Injection	8. Well Number 002
2. Name of Operator TARGA NORTHERN DELAWARE, LLC	9. OGRID Number 331548
3. Address of Operator 110 W 7TH STREET, SUITE 2300, TULSA OK 74119	10. Pool name or Wildcat

4. Well Location
Unit Letter_I_:_1800____feet from the SOUTH________ line and 150______feet from the EAST___________line
Section 13 Township 24S Range 33E NMPM LEA County

11. Elevation (Show whether DR, RKB, RT, GR, etc.)
3575 GR

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
CLOSED-LOOP SYSTEM ☐			
OTHER: TEMPORARY ABANDON ☒		OTHER: ☐	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

3/08/2023 Drilled out of 13 3/8" with 12 ¼" bit. Drilled to 6161'and lost circulation. Attempt to regain with 3 heavy LCM pills.
3/08-3/10 Regained partial circulation and drilled to 6205'.
3/11 Rig up Halliburton and squeeze zone with 370 sacks of HalCem cement .
3/12 Drilled out cement squeeze and ran FIT test but would only hold 11.5 lb/gal.
3/15 Rig up Halliburton and set 150 sack balanced plug with Hal NEO CEM cement
Tagged plug at 5960' and shut down to wait on orders.
Decision has been made to not attempt to drill into the Cherry Canyon Injection zone due to not being able to maintain mud weight.
Propose to TEMPORARY ABANDON THE WELL BY:
RUN A CEMENT BOND LOG INSIDE THE 13 3/8"
SET A 100' CORROSION RESISTANT PLUG ON TOP OF EXISTING PLUG, SET A CEMENT PLUG INSIDE THE 13 3/8" ACROSS THE CASING SHOE (1350') AND 50' ABOVE THE RUSTLER (1260'). The plug would be from 1200' to 1400'.
PRESSURE TEST THE CASING TO 500 PSI FOR 30 MINUTES
REMOVE THE BOP AND INSTALL A BLIND FLANGE AND NIGHTCAP ON THE WELLHEAD.
RIG DOWN AND MOVE THE RIG OFF.

Spud Date: 02/13/2023 Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE___Paul Ragsdale__________ TITLE______ENGINEER____________________DATE______03/17/2023______

Type or print name _PAUL RAGSDALE___________ E-mail address: _pragsdale3727@gmail.com____ PHONE: ___575-626-7903_

For State Use Only

APPROVED BY:_____________________________TITLE_______________________________DATE_________________
Conditions of Approval (if any):

District I
1625 N. French Dr., Hobbs, NM 88240
Phone:(575) 393-6161 Fax:(575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone:(575) 748-1283 Fax:(575) 748-9720
District III
1000 Rio Brazos Rd., Aztec, NM 87410
Phone:(505) 334-6178 Fax:(505) 334-6170
District IV
1220 S. St Francis Dr., Santa Fe, NM 87505
Phone:(505) 476-3470 Fax:(505) 476-3462

State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

CONDITIONS

Action 198393

CONDITIONS

Operator: Targa Northern Delaware, LLC. 110 W. 7th Street, Suite 2300 Tulsa, OK 74119	OGRID: 331548
	Action Number: 198393
	Action Type: [C-103] Sub. General Sundry (C-103Z)

CONDITIONS

Created By	Condition	Condition Date
pkautz	MUST CAP EXISTING PLUG WITH 100' CORROSION RESISTANT CEMENT	3/17/2023
pkautz	AFTER TA MUST PERFORM TA PRESSURE TEST	3/17/2023
pkautz	AFTER TA SUBMIT A WELLBORE SCHEMATIC	3/17/2023

Request for Additional Information: Red Hills Gas Processing Plant
July 19, 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.	N/A	N/A	In the previous RFAI, we asked that you please ensure that the wording describing the status of the RH AGI #3 well is consistent throughout the MRV plan. While clarifying edits were made to certain text in your newest version of the MRV plan to address this issue, there are still instances of inconsistent descriptions regarding the status of RH AGI #3 well. Examples include: - "In the Bell Canyon Formation there are several potential high porosity sandstones, **that if present in the well**, would be excellent, injection zones similar to the depositional environments of the Cherry Canyon sandstones." (Section 3.3, page 22 of the MRV plan) - "Upon completion, TND will commence injection into RH AGI #3." (Section 8.2, page 56 of the MRV plan) Please review the entire MRV plan and ensure that all necessary adjustments have been made to ensure that the status of the RH AGI #3 is consistent throughout the MRV plan.	This issue has been addressed in the revised MRV plan.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
2.	N/A	N/A	In the previous RFAI, we asked that you include a characterization of potential leakage through the RH AGI #2. While details were added to Section 5.3 ("Potential Leakage from Existing Wells") of your most recently submitted MRV plan, Section 6.3 ("Leakage from Existing Wells") was not adjusted to include a strategy for detecting CO_2 leakage through the RH AGI #2. Please ensure that all necessary adjustments have been made to sufficiently describe RH AGI #2 throughout the MRV plan.	This issue has been addressed in the revised MRV plan.

MONITORING, REPORTING, AND VERIFICATION PLAN

Red Hills AGI #1 and AGI #3

Targa Northern Delaware, LLC (TND)

Version 1.0
July 15, 2024

Table of Contents

1 Introduction

Targa Northern Delaware, LLC (TND) is currently authorized to inject treated acid gas (TAG) into the Red Hills Acid Gas Injection #1 well (RH AGI #1)(American Petroleum Institute (API) 30-025-40448) and RH AGI #3 well (API # 30-025-51970) under the New Mexico Oil Conservation Commission (NMOCC) Orders R-13507 – 13507F and Order R-20916H, respectively, at the Red Hills Gas Plant located approximately 20 miles NNW of Jal in Lea County, New Mexico (**Figure 1-1**). Each well is approved to inject 13 million standard cubic feet per day (MMSCFD). However, although approved to inject 13 MMSCFD, RH AGI #1 is physically only capable of taking ~5 MMSCFD due to formation and surface pressure limitations.

The AGI wells were previously operated by Lucid Energy Delaware, LLC's ("Lucid"). TND acquired Lucid assets in 2022. Lucid received authorization to construct a redundant well, RH AGI #2 (API# 30-025-49474) under NMOCC Order R-20916-H, which is offset 200 ft to the north of RH AGI #1 and is currently temporarily abandoned in the Bell Canyon Formation.

TND recently received approval from NMOCC for its C-108 application to drill, complete and operate a third acid gas injection well (RH AGI #3) in which TND requested an injection volume of up to 13 MMSCFD. RH AGI #3 was spudded on 9/13/2023, completed on 9/27/2023, and injection commenced on 1/11/2024. Because RH AGI #1 does not have complete redundancy, having a greater permitted disposal volume will also increase operational reliability. RH AGI #3 is a vertical well with its surface location at approximately 3,116 ft from the north line (FNL) and 1,159 ft from the east line (FEL) of Section 13. The depth of the injection zone for this well is approximately 5,700 to 7,600 ft in the Bell Canyon and Cherry Canyon Formations (see As-Built schematic in **Figure Appendix 1-2**). Analysis of the reservoir characteristics of these units confirms that they act as excellent closed-system reservoirs that will accommodate the future needs of TND for disposal of treated acid gas (H_2S and CO_2) from the Red Hills Gas Plant.

TND has chosen to submit this Monitoring, Reporting, and Verification (MRV) plan to EPA for approval according to 40CFR98.440(c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. TND intends to inject CO_2 for another 30 years.

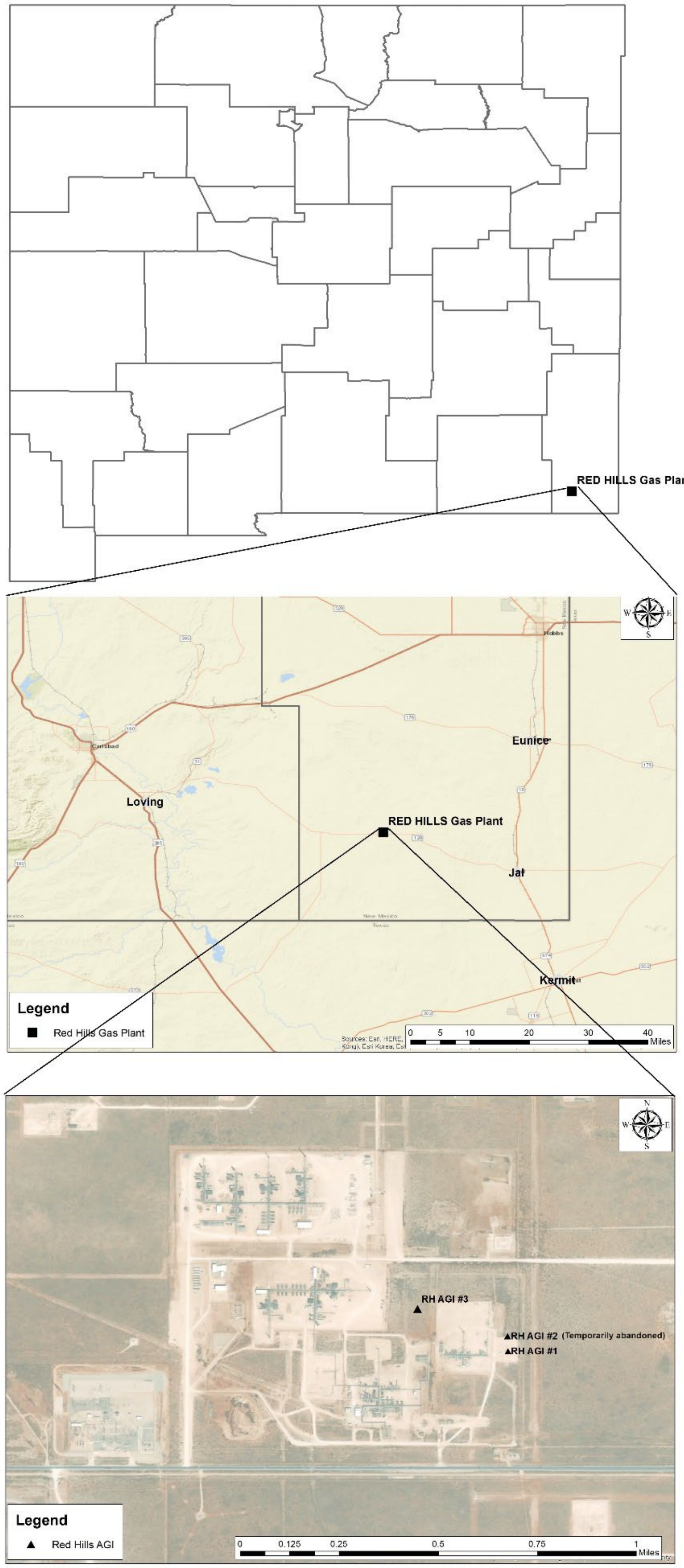


***Figure 1-1**: Location of the Red Hills Gas Plant and Wells – RH AGI #1, RH AGI #2 (temporarily abandoned), and RH AGI #3*

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40CFR98.449, and as required by 40CFR98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40CFR98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage as required by 40CFR98.448(a)(3).

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40CFR98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40CFR98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40CFR98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40CFR98.445.

Section 11 describes the records to be retained according to the requirements of 40CFR98.3(g) of Subpart A of the GHGRP and 40CFR98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan, including information required by 40CFR98.448(a)(6).

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is **553798**

2.2 UIC injection well identification numbers

This MRV plan is for RH AGI #1 and RH AGI #3 (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

For injection wells that are the subject of this MRV plan, the New Mexico Oil Conservation Division (NMOCD) has issued Underground Injection Control (UIC) Class II acid gas injection (AGI) permits under its State Rule 19.15.26 NMAC (see **Appendix 2**). All oil- and gas-related wells around the RH AGI wells, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3 Project Description

The following project description was developed by the Petroleum Recovery Research Center (PRRC) at New Mexico Institute of Mining and Technology (NMT) and the Department of Geosciences at the University of Texas Permian Basin (UTPB).

3.1 General Geologic Setting / Surficial Geology

The TND Red Hills Gas Plant is located in T 24 S R 33 E, Section 13, in Lea County, New Mexico, immediately adjacent to the RH AGI wells. (**Figure 3.1-1**). The plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. The dune sands are locally stabilized with shin oak, mesquite, and some burr-grass. There are no natural surface bodies of water or groundwater discharge sites within one mile of the plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

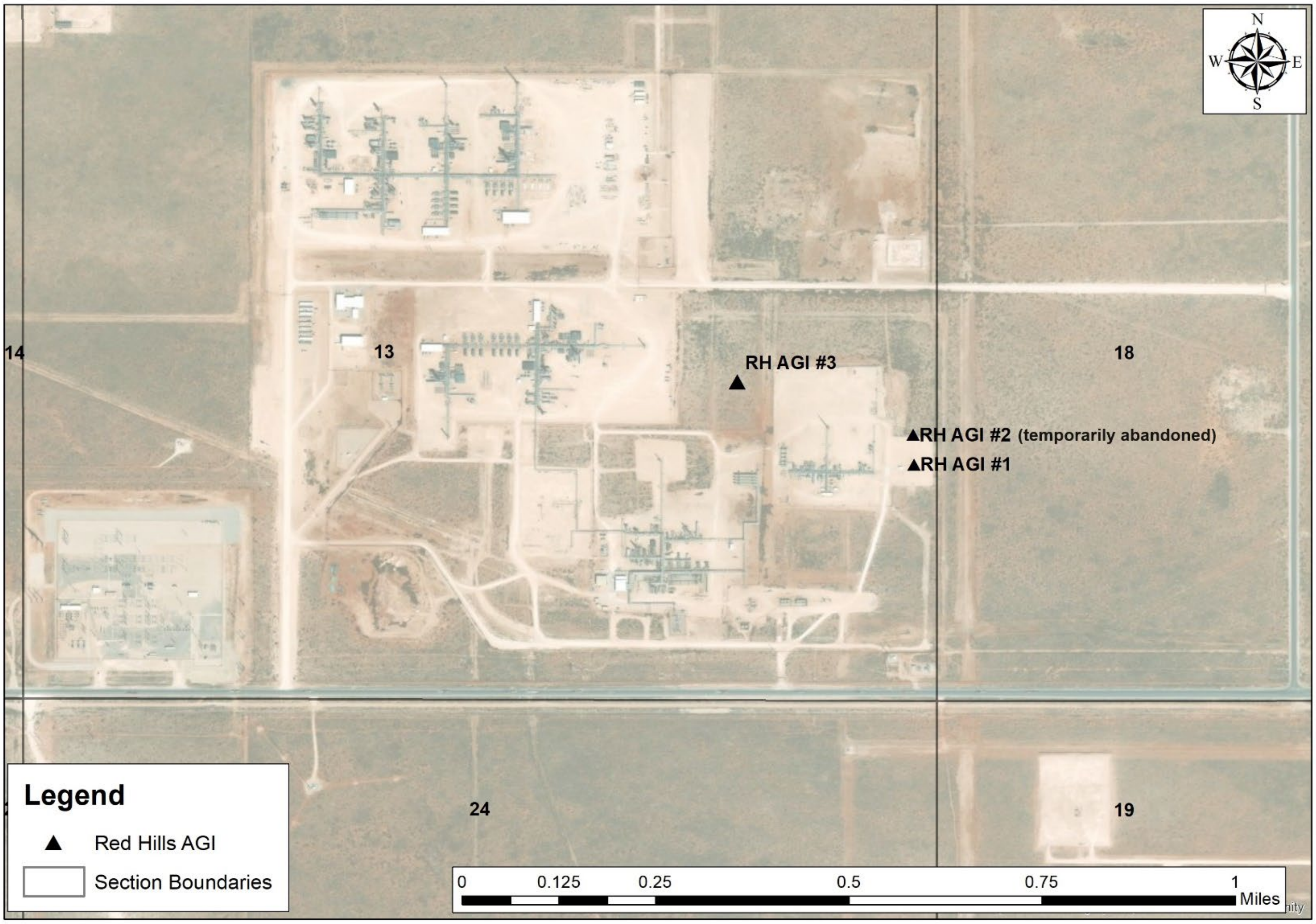


Figure 3.1-1: Map showing location of TND Red Hills Gas Plant and RH AGI Wells in Section 13, T 24 S, R 33 E

3.2 Bedrock Geology

3.2.1 Basin Development

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

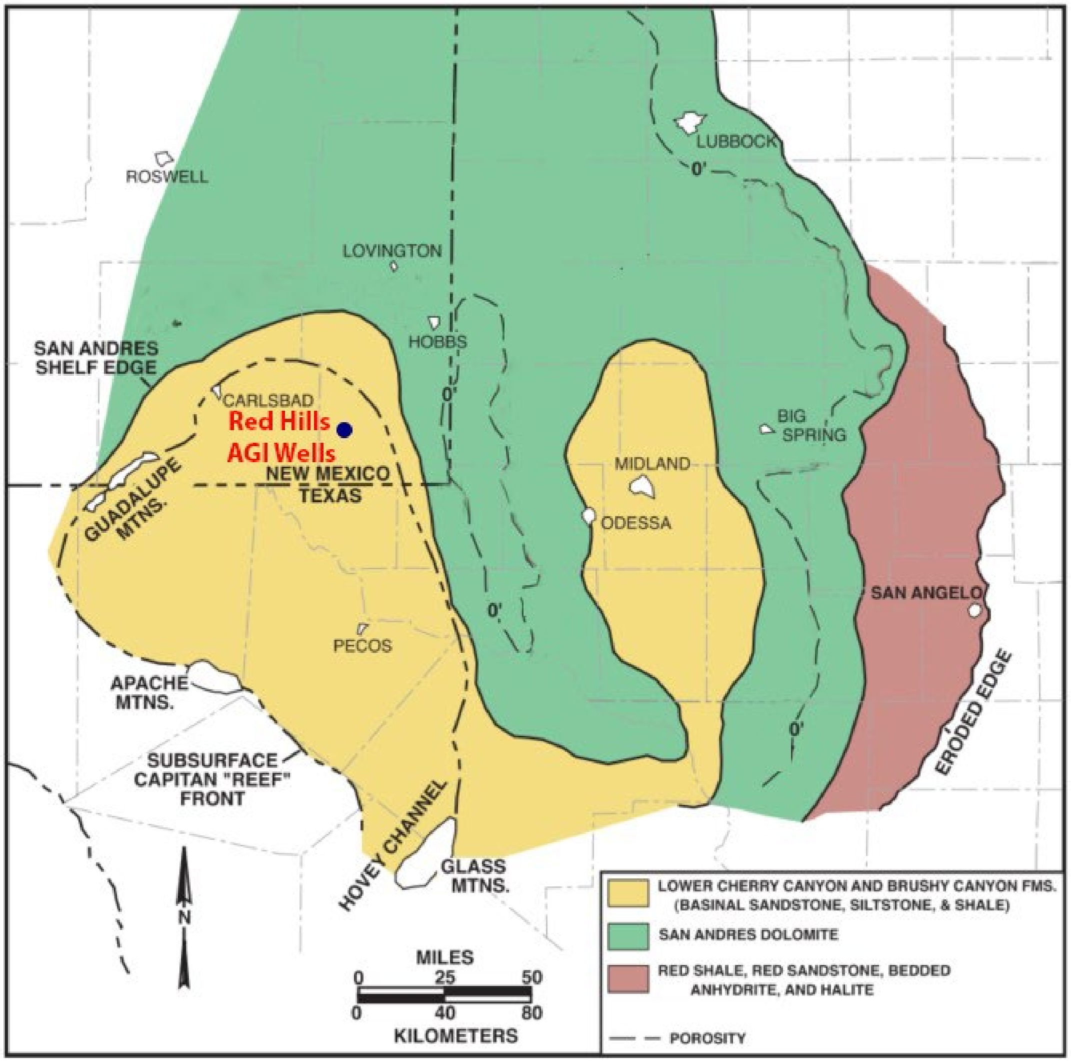


***Figure 3.2-1**: Structural features of the Permian Basin during the Late Permian. Location of the TND RH AGI wells is shown by the black circle. (Modified from Ward, et al (1986))*

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

The RH AGI wells are in the Delaware Basin portion of the broader Permian Basin. Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland (**Figure 3.2-3**). With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Ellenburger Formation (0 – 1000 ft) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Throughout this narrative, the numbers after the formations indicate the range in thickness for that unit. Tectonic activity near the end of Ellenburger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit’s overall porosity and permeability.

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

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

During Middle to Upper Ordovician time, the seas once again covered the area and deposited the carbonates, sandstones and shales of the Simpson Group (0 – 1000 ft) and then the Montoya Formation (0 – 600 ft). This is the period when the Tobosa Basin formed due to the Pedernal uplift and development of the Texas Arch (**Figure 3.2-4**; Harrington, 2019) shedding Precambrian crystalline clasts into the basin. Reservoirs in New Mexico are typically within deposits of shoreline sandstones (Broadhead, 2017). A subaerial exposure and karstification event followed the deposition of the Simpson Group. The Montoya Formation marked a return to dominantly carbonate sedimentation with minor siliciclastic sedimentation within the Tobosa Basin (Broadhead, 2017; Harrington and Loucks, 2019). The Montoya Formation consists of sandstones and dolomites and have also undergone karstification.

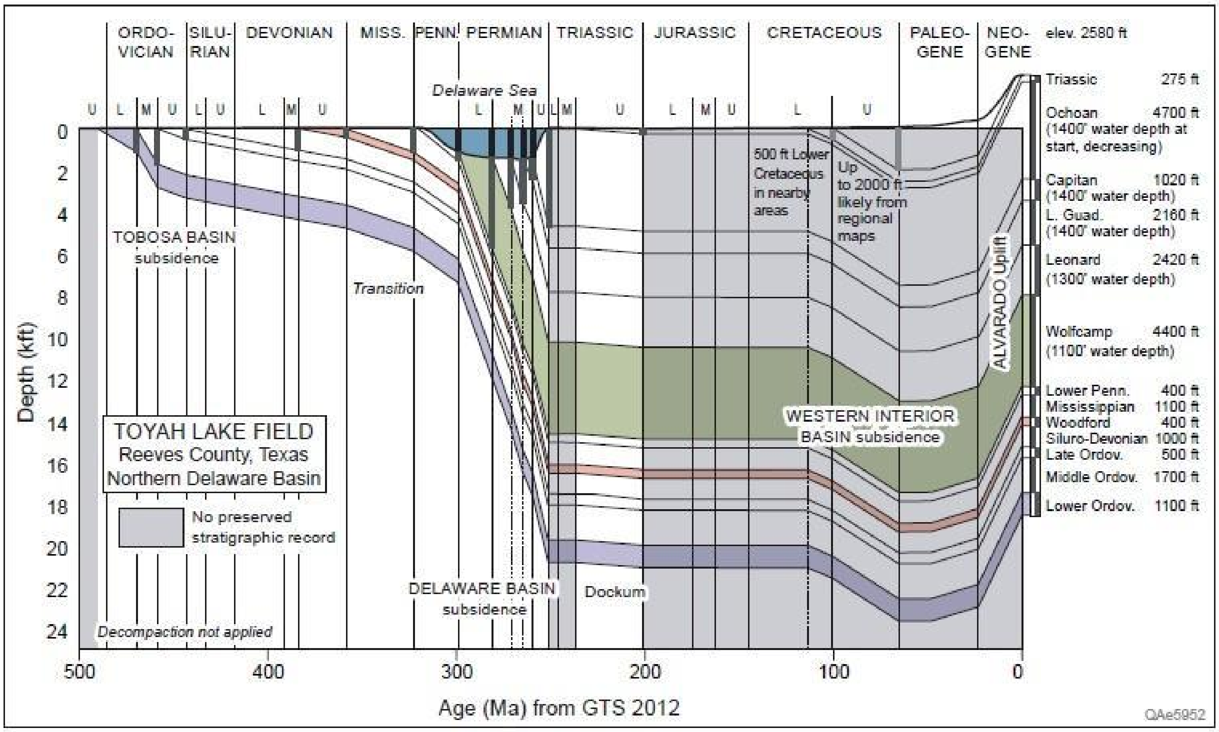


***Figure 3.2-3**: A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)*

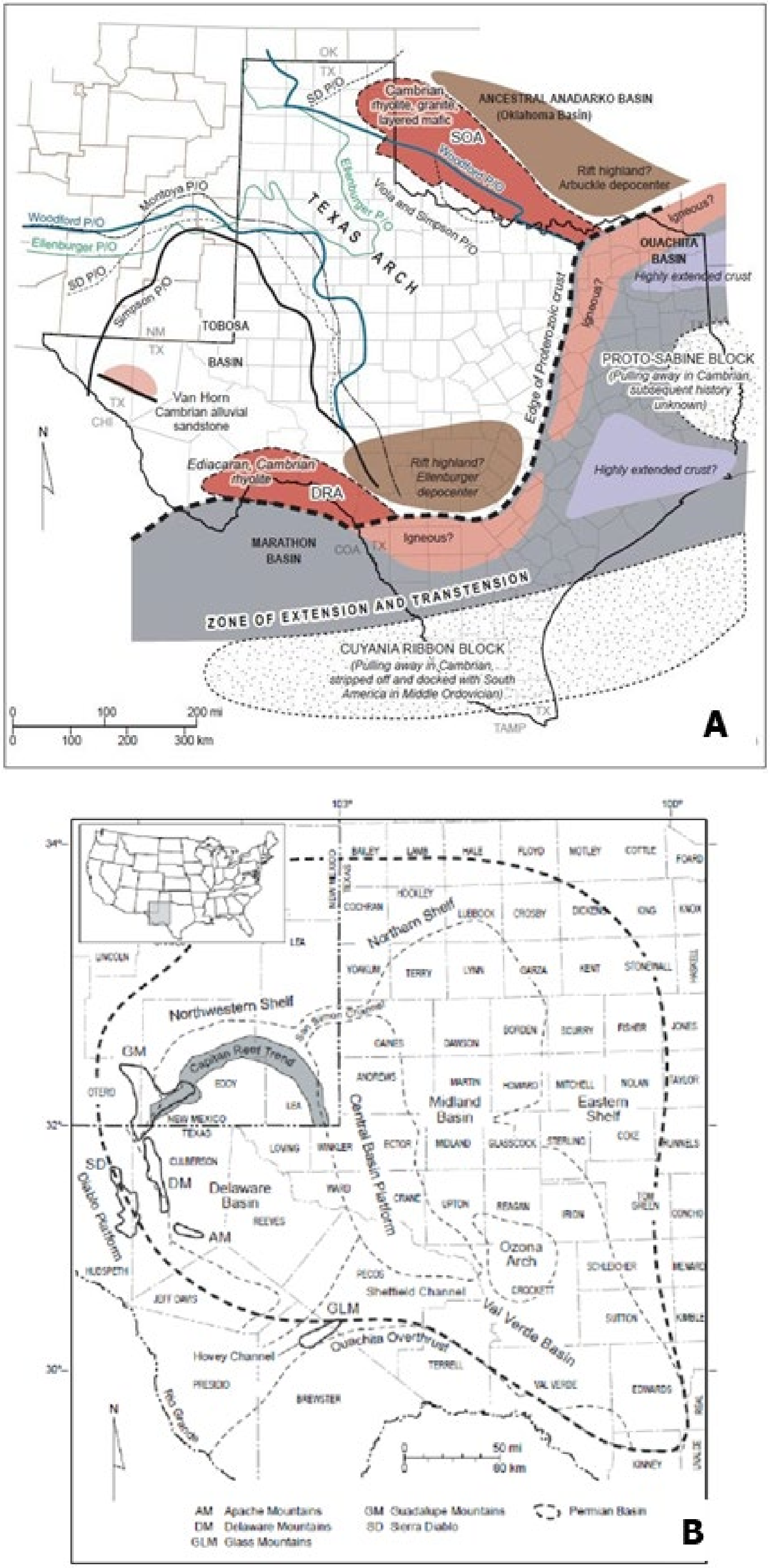


***Figure 3.2-4**: Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).*

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

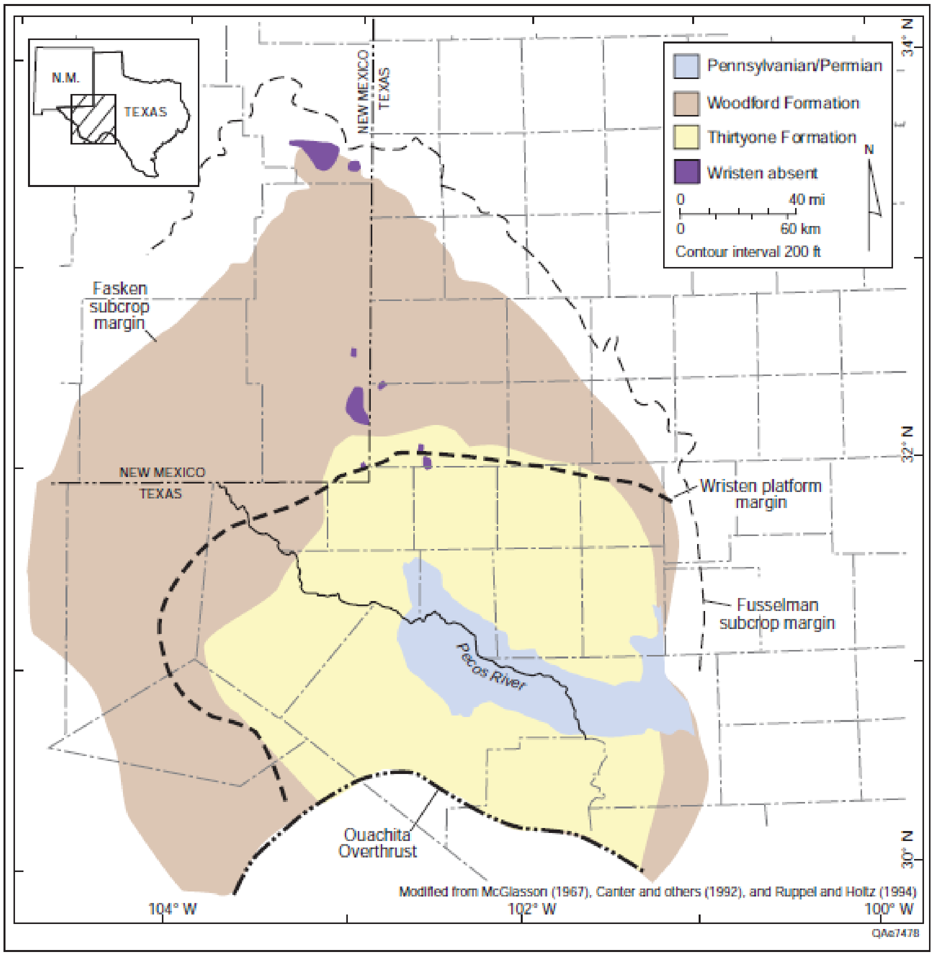


***Figure 3.2-5**: A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there are no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in Section 3.2.2.

The Devonian Woodford Shale, an un-named Mississippian limestone, and the Upper Mississippian Barnett Shale are seals for the underlying Siluro-Devonian strata. While the Mississippian recrystallized limestones have minor porosity and permeability, the Woodford and Barnett shales have extremely low porosity and

permeability and would be effective barriers to upward migration of acid gas out of the injection zone. The Woodford Shale (0 – 300 ft) ranges from organic–rich argillaceous mudstones with abundant siliceous microfossils to organic-poor argillaceous mudstones (Ruppel et al., 2020b). The Woodford sediments represent stratified deeper marine basinal deposits with their organic content being a function of the oxygenation within the bottom waters – the more anoxic the waters the higher the organic content.

The Mississippian strata within the Delaware Basin consists of an un-named carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoirs limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise it is tight. The Barnett Shale (0 – 400 ft) unconformably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal, siliciclastic deposits (the Barnett Shale).

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

Pennsylvanian sedimentation is dominated by glacio-eustatic sea-level cycles that produced shallowing upward cycles of sediments, ranging from deep marine siliciclastic and carbonate deposits to shallow-water limestones and siliciclastics, and capping terrestrial siliciclastic sediments and karsted limestones. Lower Pennsylvanian units consist of the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). The Atoka Formation (0-500 ft) was deposited during another sea-level transgression within the area. Within the area, the Atoka sediments are dominated by siliciclastic sediments, and depositional environments range from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

Middle Pennsylvanian units consist of the Strawn group (an informal name used by industry). Strawn sediments (250 - 1,000 ft) within the area consists of marine sediments that range from ramp carbonates, containing patch reefs, and marine sandstone bars to deeper marine shales (Broadhead, 2017).

Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales.

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

throughout the Permian, the Wolfcampian sediments were truncated in places like the Central Basin Platform (**Figure 3.2-6**).

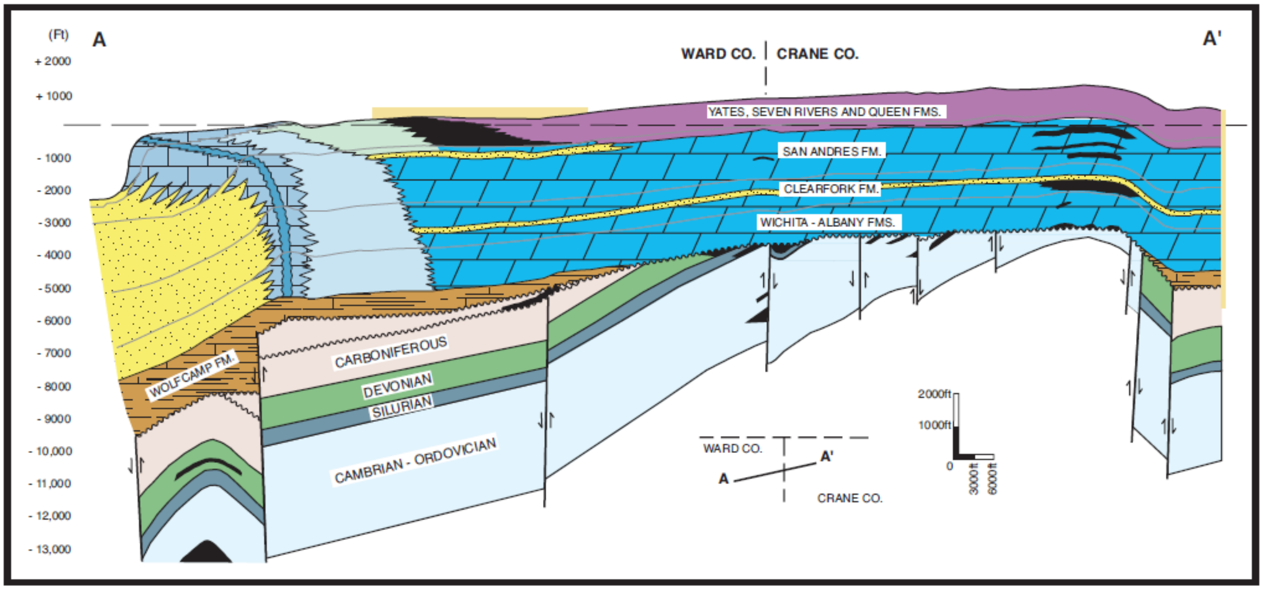


Figure 3.2-6: Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).

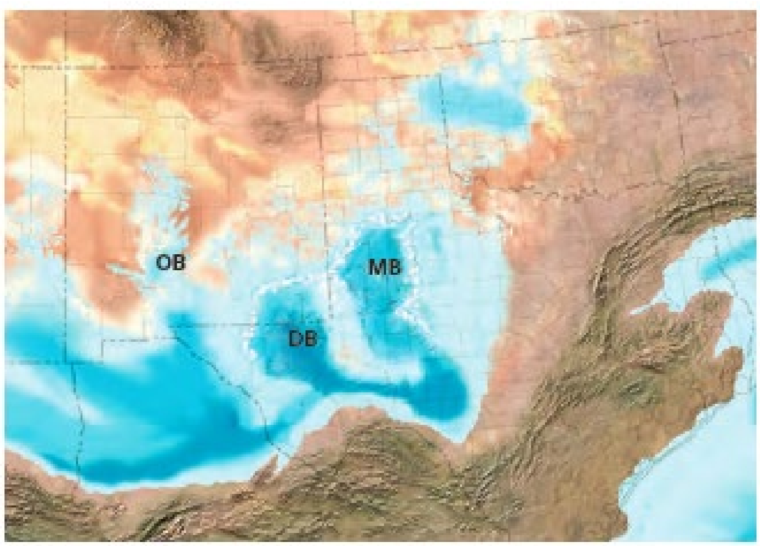


Figure 3.2-7: Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, thousands of feet of siliciclastic sediments bypassed the shelves and were deposited in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a

“carbonate factory” on the shelf and shelf edge. Carbonate debris beds shedding off the shelf margin were transported into the basin (Wilson, 1972; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100s feet to feet).

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along Northwest Shelf margin to shallow-marine, back-reef carbonates behind the shelf margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2019a). Sediments basinward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2019a). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. The Bone Spring Formation is a thick sequence of alternating carbonate and siliciclastic horizons that formed because of changes in sea level; the carbonates during highstands, and siliciclastics during lowstands. Overlying the Yeso, are the clean, white eolian sandstones of the Glorietta Formation. It is a key marker bed in the region, both on outcrop and in the subsurface. Within the basin, it is equivalent to the lowermost Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have been identified that have resulted in karstification and pervasive dolomitization of the unit. These exposure events/sea-level lowstands are correlated to sandstones/siltstones that moved out over the exposed shelf leaving on minor traces of their presence on the shelf but formed thick sections of sandstones and siltstones in the basin. Within the Delaware Basin, the San Andres Formation is equivalent to the Brushy and lower Cherry Canyon Formations.

The Artesia Group (Grayburg, Queen, Seven Rivers, Yates, and Tansill formations, ascending order) is equivalent to Capitan Limestone, the Guadalupian barrier/fringing reef facies. Within the basin, the Artesia Group is equivalent to the upper Cherry and Bell Canyon formations, a series of relatively featureless sandstones and siltones. The Queen and Yates formations contain more sandstones than the Grayburg, Seven Rivers, and Tansill formations. The Artesia units and the shelf edge equivalent Capitan reef sediments represent the period when the carbonate factory was at its greatest productivity with the shelf margin/Capitan reef prograding nearly 6 miles into the basin (Scholle et al., 2007). The Artesia Group sediments were deposited in back-reef, shallow marine to supratidal/evaporite environments. Like the San Andres Formation, the individual formations were periodically exposed during lowstands.

The final stage of Permian deposition on the NW Shelf consists of the Ochoan/Lopingian Salado Formation (<2,800 ft, Nance, 2020). Within the basin, the Castile formation, a thick sequence (total thickness ~1,800 ft, Scholle et al., 2007) of cyclic laminae of deep-water gypsum/anhydrite interbedded with calcite and organics, formed due to the restriction of marine waters flowing into the basin. Gypsum/anhydrite laminae precipitated during evaporative conditions, and the calcite and organic-rich horizons were a result of seasonal “freshening” of the basin waters by both marine and freshwaters. Unlike the Castile Formation, the Salado Formation is a relatively shallow water evaporite deposit. Halite, sylvite, anhydrite, gypsum, and numerous potash minerals were precipitated. The Rustler Formation (500 ft , Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin.

The Rustler Formation was followed by terrestrial sabkha red beds of the Dewey Lake Formation (~350', Nance, 2020), ending Permian deposition in the area.

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

3.2.2 Stratigraphy

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent, renamed Lopingian), Guadalupian, Leonardian (renamed Cisuralian), and Wolfcampian (oldest) (**Figure 3.2-2**). This sequence of shallow marine carbonates and thick, basinal siliciclastic deposits contains abundant oil and gas resources. The Delaware Basin high porosity sands are the main source of oil within New Mexico. In the area around the Red Hills AGI wells, Permian strata are mainly basin deposits consisting of sandstones, siltstones, shales, and lesser amounts of carbonates. Besides production in the Delaware Mountain Group, there is also production, mainly gas, in the basin Bone Spring Formation, a sequence of carbonates and siliciclastics. The injection and confining zones for RH AGI #1 and #3 are discussed below.

CONFINING/SEAL ROCKS

Permian Ochoa Series. The youngest of the Permian sediments, the Ochoan- or Lopingian-aged deposits, consists of evaporites, carbonates, and red beds. The Castile Formation is made of cyclic laminae of deep-water gypsum/anhydrite beds interlaminated with calcite and organics. This basin-occurring unit can be up to 1,800 ft thick. The Castile evaporites were followed by the Salado Formation (~1,500 ft thick). The Salado Formation is a shallow water evaporite deposit, when compared to the Castile Formation, and consists of halite, sylvite, anhydrite, gypsum, and numerous potash/bittern minerals. Salado deposits fill the basin and lap onto the older Permian shelf deposits. The Rustler Formation (up to 500 ft, Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin. The Ochoan evaporitic units are superb seals (usually <1% porosity and <0.01 mD permeability) and are the reason that the Permian Basin is such a hydrocarbon-rich region despite its less than promising total organic carbon (TOC) content.

INJECTION ZONE

Permian Guadalupe Series. Sediments in the underlying Delaware Mountain Group (descending, Bell Canyon, Cherry Canyon, and Brushy Canyon formations) are marine units that represent deposition controlled by eustacy and tectonics. Lowstand deposits are associated with submarine canyons incising the carbonate platform surround most of the Delaware Basin. Depositional environments include submarine fan complexes that encircle the Delaware Basin margin. These deposits are associated with submarine canyons incising the carbonate platform margin and turbidite channels, splays, and levee/overbank deposits (**Figure 3.2-8**). Additionally, debris flows formed by the failure of the carbonate margin and density currents also make up basin sediments. Isolated coarse-grained to boulder-sized carbonate debris flows and grain falls within the lowstand clastic sediments likely resulted from erosion and failure of the shelf margin during sea-level lowstands or slope failure to tectonic activity (earthquakes). Density current deposits resulted from stratified basin waters. The basal waters were likely stratified and so dense, that turbidity flows containing sands, silts and clays were unable to displace those bottom waters and instead flowed out over the density interface (**Figure 3.2-9**). Eventually, the entrained sediments would settle out in a constant rain of sediment forming laminated deposits with little evidence of traction (bottom flowing) deposition. Interbedded with the very thick lowstand sequences are thin, deep-water limestones and mudstones that represent highstand

deposition up on the platform. These deposits are thickest around the edge (toe-of-slope) of the basin and thin to the basin center (**Figure 3.2-10**). The limestones are dark, finely crystalline, radiolarian-rich micrites to biomicrites. These highstand deposits are a combination of suspension and pelagic sediments that also thin towards the basin center. These relatively thin units are time equivalent to the massive highstand carbonate deposits on the shelf.

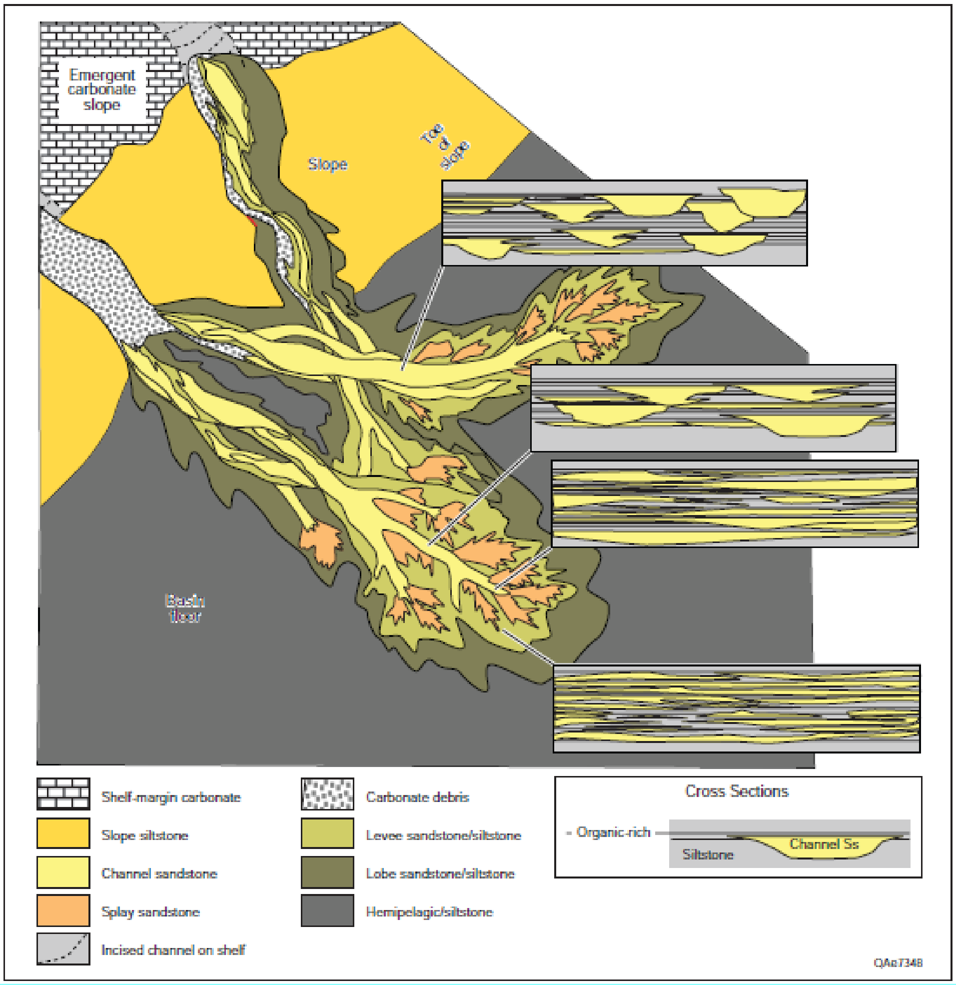


__Figure 3.2-8__: A diagram of typical Delaware Mountain Group basinal siliciclastic deposition patterns (from Nance, 2020). The channel and splay sandstones have the best porosity, but some of the siltstones also have potential as injection zones.

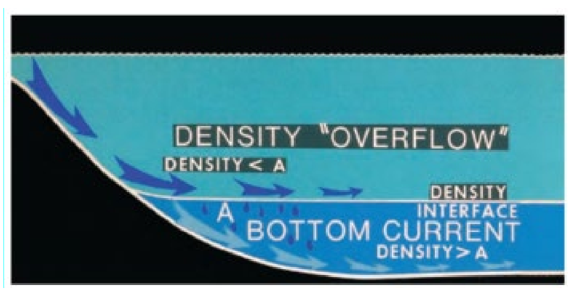


__Figure 3.2-9__: Harms' (1974) density overflow model explains the deposition of laminated siliciclastic sediments in the Delaware Basin. Low density sand-bearing fluids flow over the top of dense, saline brines at the bottom of the basin. The sands gradually drop out as the flow loses velocity creating uniform, finely laminated deposits (from Scholle et al., 2007).

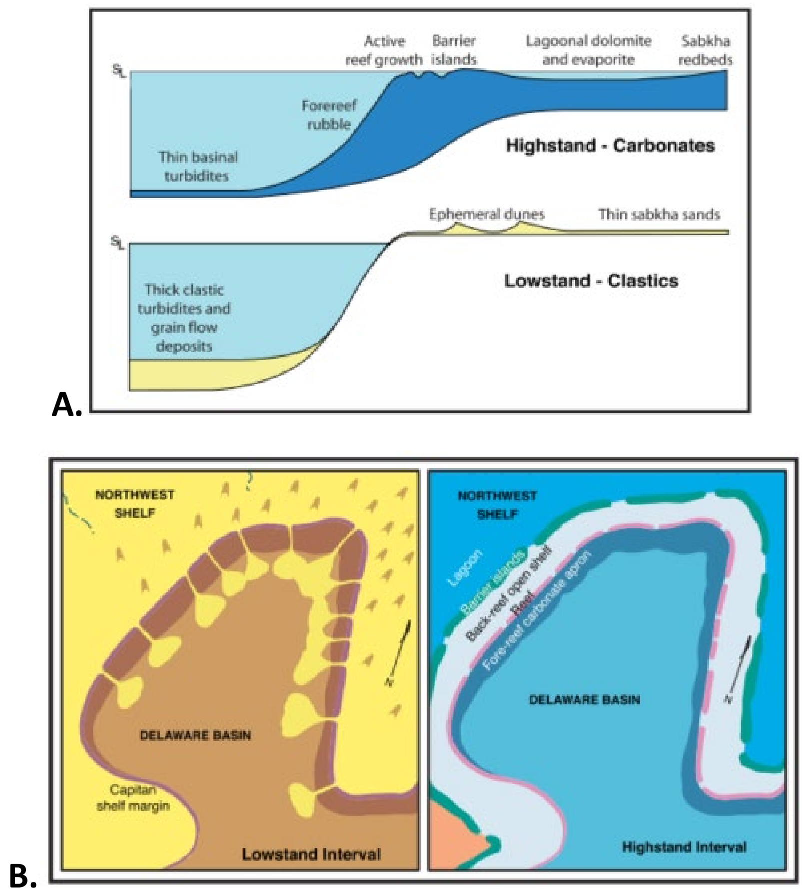


Figure 3.2-10: *The impact of sea-level fluctuations (also known as reciprocal sedimentation) on the depositional systems within the Delaware Basin. A) A diagrammatic representation of sea-level variations impact on deposition. B) Model showing basin-wide depositional patterns during lowstand and highstand periods (from Scholle et al., 2007).*

The top of the Guadalupian Series is the Lamar Limestone, which is the source of hydrocarbons found in underlying Delaware Sand (an upper member of the Bell Canyon Formation). The Bell Canyon Formation is roughly 1,000 ft thick in the Red Hills area and contains numerous turbidite input points around the basin margin (**Figures 3.2-10, 3.2-11**). During Bell Canyon deposition, the relative importance of discrete sand sources varied (Giesen and Scholle, 1990), creating network of channel and levee deposits that also varied in their size and position within the basin. Based on well log analyses, the Bell Canyon 2 and 3 had the thickest sand deposits.

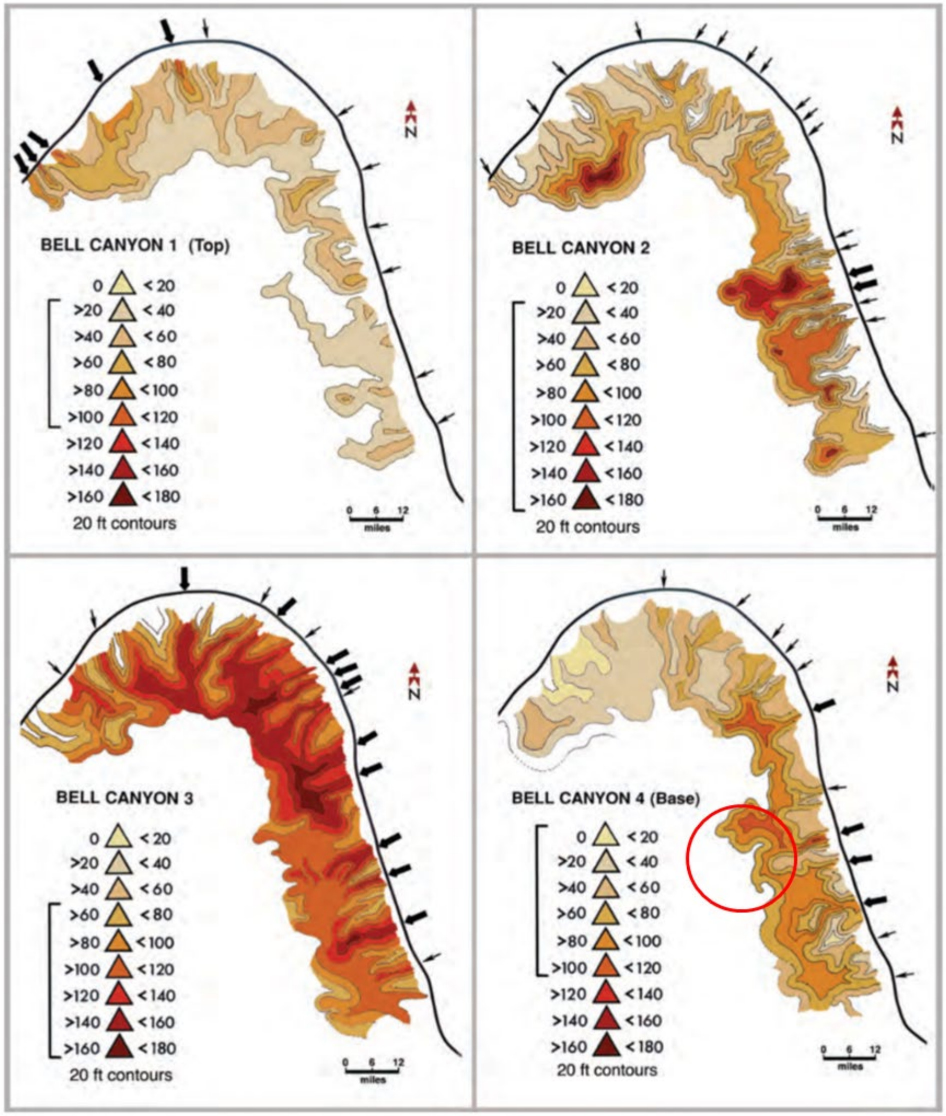


Figure 3.2-11: These maps of Bell Canyon Formation were created by measuring sandstone thicknesses on well logs in four regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). The red circle on the last map surrounds the Red Hills area.

Like the Bell Canyon and Brushy Canyon formations, the Cherry Canyon Formation is approximately 1,300 ft thick and contains numerous turbidite source points. Unlike the Bell Canyon and Brushy Canyon deposits, the channel deposits are not as large (Giesen and Scholle, 1990), and the source of the sands appears to be dominantly from the eastern margin (**Figure 3.2-12**). Cherry Canyon 1 and 5 have the best channel development and the thickest sands. Overall, the Cherry Canyon Formation, on outcrop, is less influenced by traction current deposition than the rest of the Delaware Mountain Group deposits and is more influenced by sedimentation by density overflow currents (**Figure 3.2-9**). The Brushy Canyon has notably more discrete channel deposits and coarser sands than the Cherry Canyon and Bell Canyon. The Brushy Canyon Formation is approximately 1,500 ft thick.

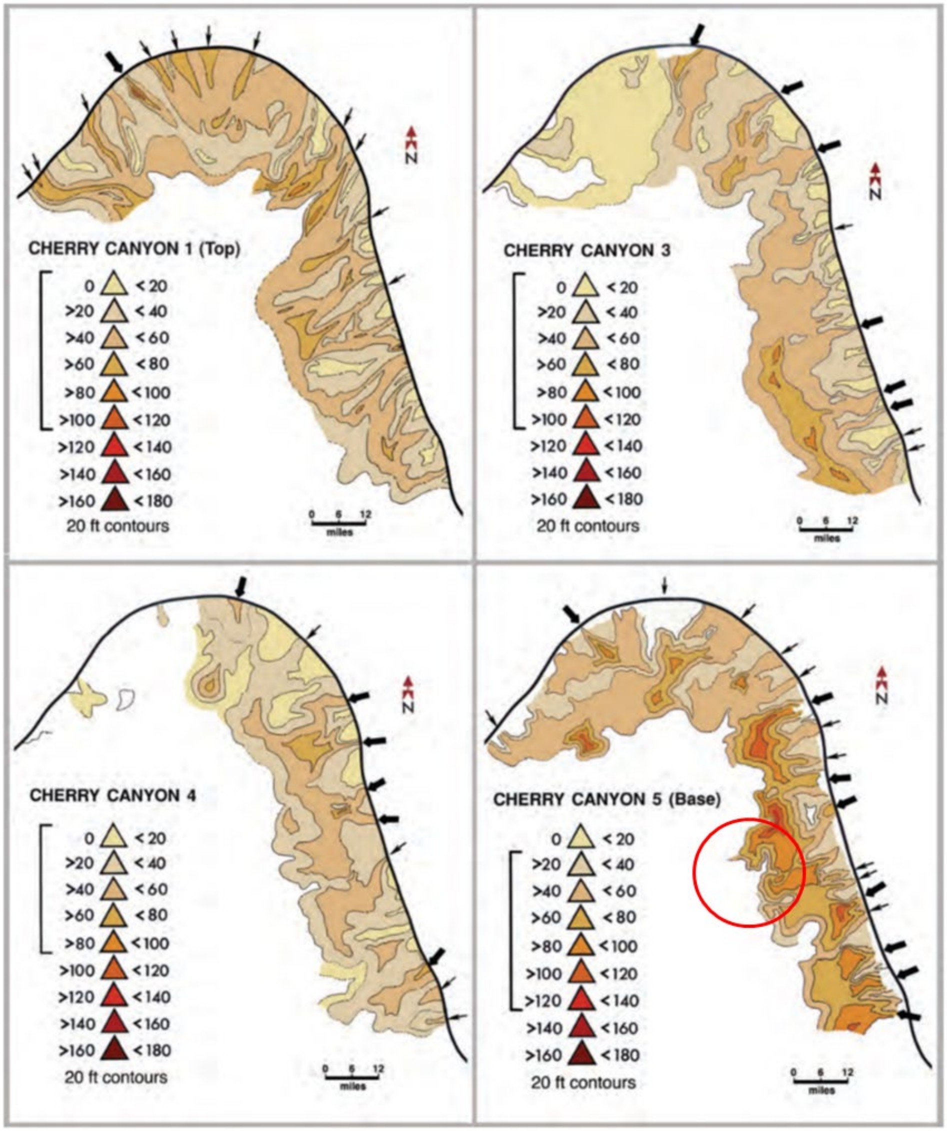


***Figure 3.2-12**: These maps of Cherry Canyon Formation were created by measuring sandstone thicknesses on well logs in five regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). Unlike the Bell Canyon sandstones, the Cherry Canyon sands are thinner and contain fewer channels. The red circle on the last map surrounds the Red Hills area.*

Within the Delaware Mountain Group in the Red Hills area, the Bell Canyon and Cherry Canyon have the best porosity (averaging 15 – 25 % within channel/splay sandstones) and permeability (averaging 2-13 mD) than the Brushy Canyon (~14% porosity, an <3 mD; Ge et al, 2022, Smye et al., 2021).

UNDERLYING CONFINING ZONE

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

3.2.3 Faulting

In this immediate area of the Permian Basin, faulting is primarily confined to the lower Paleozoic section, where seismic data shows major faulting and ancillary fracturing-affected rocks only as high up as the base of the lower Wolfcamp strata (**Figures 3.2-6 and 5.6-1**). Faults that have been identified in the area are normal faults associated with Ouachita related movement along the western margin of the Central Platform to the east of the RH AGI well site. The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief. Because these faults are confined to the lower Paleozoic unit well below the injection zone for the RH AGI wells, they will not be discussed further (Horne et al., 2021). Within the area of the Red Hills site, no shallow faults within the Delaware Mountain Group have been identified by seismic data interpretation nor as reported by Horne et al., 2022).

3.3 Lithologic and Reservoir Characteristics

Based on the geologic analyses of the subsurface at the Red Hills Gas Plant, the uppermost portion of the Cherry Canyon Formation was chosen for acid gas injection and CO_2 sequestration for RH AGI #1 and the uppermost Delaware Mountain Group (the Bell Canyon and Cherry Canyon Formations) for RH AGI #3.

For RH AGI #1, this interval includes five high porosity sandstone units (sometimes referred to as the Manzanita) and has excellent caps above, below and between the individual sandstone units. There is no local production in the overlying Delaware Sands pool of the Bell Canyon Formation. There are no structural features or faults that would serve as potential vertical conduits. The high net porosity of the RH AGI #1 injection zone indicates that the injected H_2S and CO_2 will be easily contained close to the injection well.

For RH AGI #3, this interval has been expanded to include the five porosity zones in the Cherry Canyon sandstone as well as the sandstone horizons in the overlying Bell Canyon Formation. In the Bell Canyon Formation there are several potential high porosity sandstones, that if present in the well, would be excellent , injection zones similar to the depositional environments of the Cherry Canyon sandstones. The thickest sand is commonly referred to as the Delaware Sand within the Delaware Basin. The Delaware sand is productive, but it is not locally. Most of the sand bodies in the Bell Canyon and Cherry Canyon formations are surrounded by shales or limestones, forming caps for the injection zones. There are no structural features or faults that would serve as potential vertical conduits, and the overlying Ochoan evaporites form an excellent overall seal for the system. Even if faulting existed, the evaporites (Castile and Salado) would self-seal and prevent vertical migration out of the Delaware Mountain Group.

The geophysical logs were examined for all wells penetrating the Bell Canyon and Cherry Canyon formations within a three-mile radius of the RH AGI wells as well as 3-D seismic data. There are no faults visible within the Delaware Mountain Group in the Red Hills area. Within the seismic area, the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales (**Figure 3.2-8**) as well as being encased by them. Based on regional studies (Giesen and Scholle, 1990 and **Figures 3.2-11, 3.2-12**), the preferred orientation of the channels, and hence the preferred fluid migration pathways, are roughly from the east to the west.

The porosity was evaluated using geophysical logs from nearby wells penetrating the Cherry Canyon Formation. **Figure 3.3-1** shows the Resistivity (Res) and Thermal Neutron Porosity (TNPH) logs from 5,050 ft to 6,650 ft and includes the injection interval. Five clean sands (>10% porosity and <60 API gamma units) are targets for injection within the Cherry Canyon formation and potentially another 5 sands with >10% porosity and <60 API gamma units were identified. Ten percent was the minimum cut-off considered for adequate

porosity for injection. The sand units are separated by lime mudstone and shale beds with lateral continuity. The high porosity sand units exhibit an average porosity of about 18.9%; taken over the average thickness of the clean sand units within ½ mile of the RH AGI #1. There is an average of 177 ft with an irreducible water (S_{wir}) of 0.54 (see Table 1 of the RH AGI #1 permit application). Many of the sands are very porous (average porosity of > 22%) and it is anticipated that for these more porous sands, the S_{wir} may be too high. The effective porosity (Total Porosity – Clay Bound Water) would therefore also be higher. As a result, the estimated porosity ft (PhiH) of approximately 15.4 porosity-ft should be considered to be a minimum. The overlying Bell Canyon Formation has 900 ft of sands and intervening tight limestones, shales, and calcitic siltstones with porosities as low as 4%, but as mentioned above, there are at least 5 zones with a total thickness of approximately 460 ft and containing 18 to 20% porosity. The injection interval is located more than 2,650 ft above the Bone Spring Formation, which is the next production zone in the area.

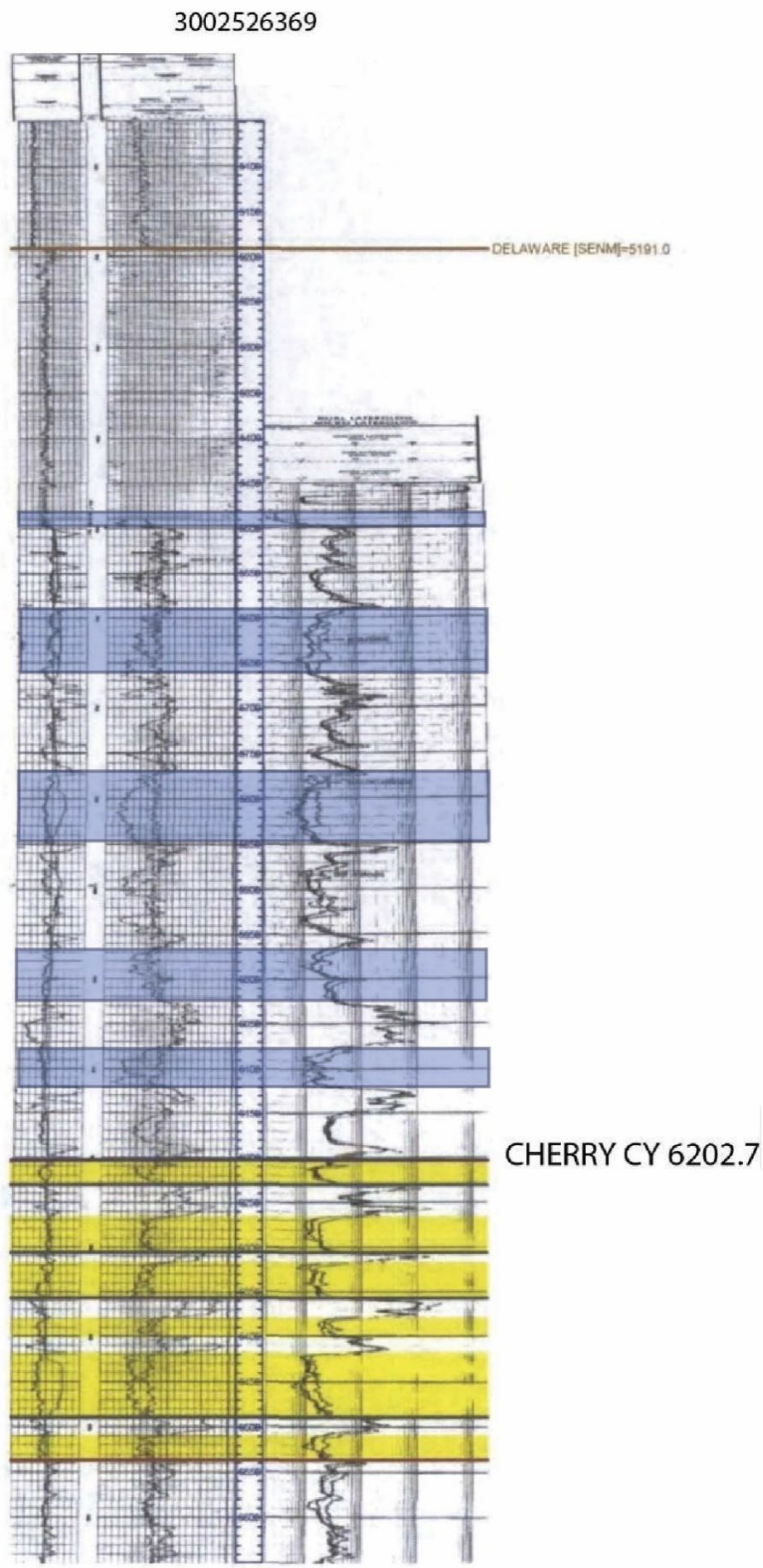


***Figure 3.3-1**: Geophysical logs from the Bell Canyon and the Upper Cherry Canyon from the Government L Com #002 well, located 0.38 miles from the RH AGI #1 Well. The blue intervals are Bell Canyon porosity zones, and the yellow intervals are Cherry Canyon porosity zones.*

3.4 Formation Fluid Chemistry

A chemical analysis (**Table 3.4-1**) of water from Federal 30 Well No. 2 (API 30-025-29069), approximately 3.9 miles away, indicates that the formation waters are highly saline (180,000 ppm NaCl) and compatible with the injection.

***Table 3.4-1**: Formation fluid analysis for Cherry Canyon Formation from Federal 30 Well No. 2*

Sp. Gravity	1.125 @ 74°F	Resistivity	0.07 @ 74°F
pH	7	Sulfate	1,240
Iron	Good/Good	Bicarbonate	2,135
Hardness	45,000	Chloride	110,000
Calcium	12,000	NaCl	180,950
Magnesium	3,654	Sod. & Pot.	52,072

Table extracted from C-108 Application to Inject by Ray Westall Associated with SWD-1067 – API 30-025-24676. Water analysis for formation water from Federal 30 #2 Well (API 30-025-29069), depth 7,335-7,345 ft, located 3.9 miles from RH AGI #1 well.

3.5 Groundwater Hydrology in the Vicinity of the Red Hills Gas Plant

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are 15 freshwater wells located within a two-mile radius of the RH AGI wells, and only 2 water wells within one mile; the closest water well is located 0.31 miles away and has a total depth of 650 ft (**Figure 3.5-1; Appendix 3**). All water wells within the two-mile radius are shallow, collecting water from about 60 to 650 ft depth, in Alluvium and the Triassic redbeds. The shallow freshwater aquifer is protected by the surface and intermediate casings and cements in the RH AGI wells (**Figures Appendix 1-1 and Appendix 1.2**). While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

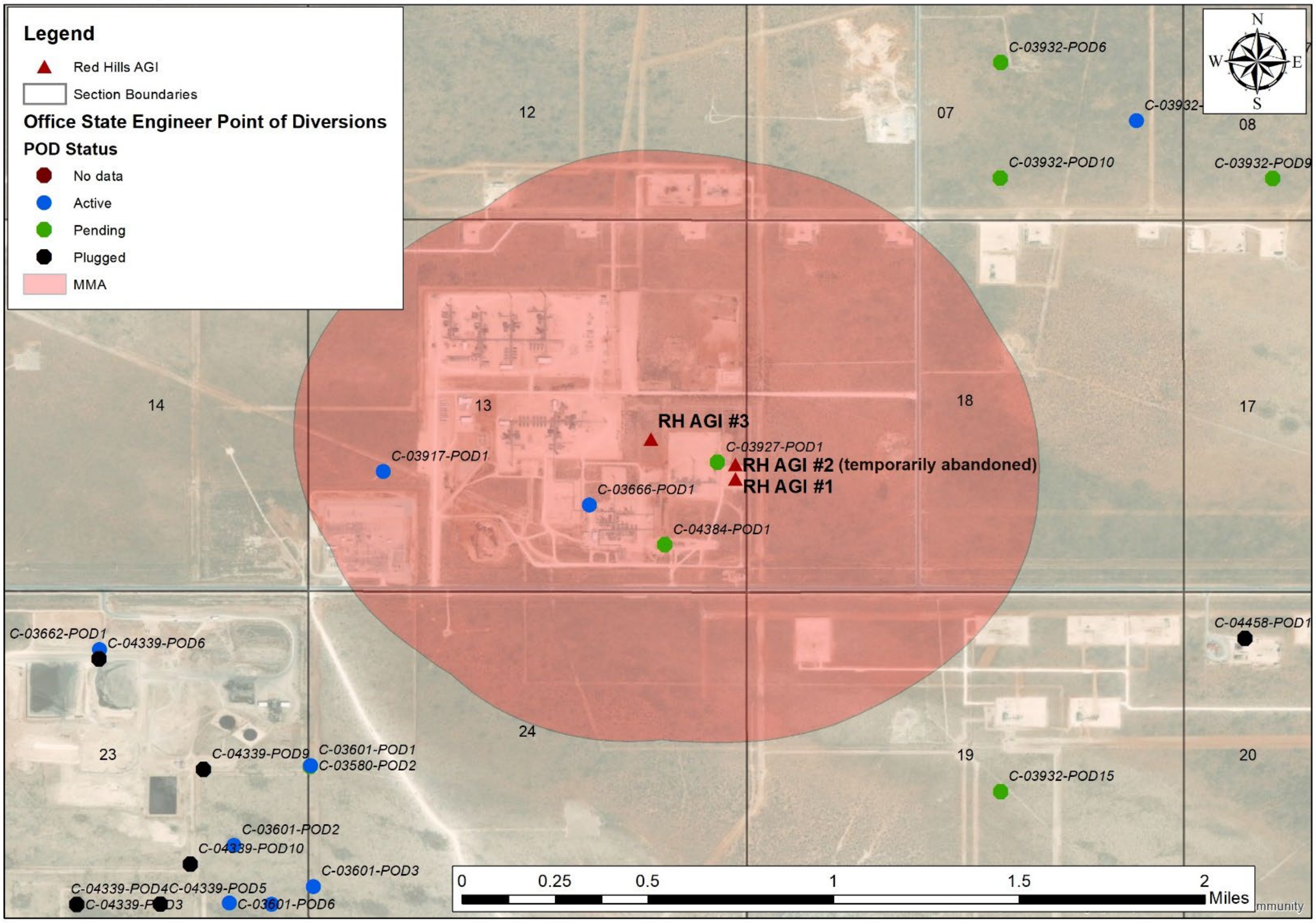


Figure 3.5-1: Reported Water Wells within the MMA for the RH AGI Wells.

3.6 Historical Operations

3.6.1 Red Hills Site

On July 20, 2010, Agave Energy Company (Agave) filed an application with NMOCD to inject treated acid gas into an acid gas injection well. Agave built the Red Hills Gas Processing Plant and drilled RH AGI #1 in 2012-13. However, the well was never completed and never put into service because the plant was processing only sweet gas (no H_2S). Lucid purchased the plant from Agave in 2016 and completed the RH AGI #1 well. TND acquired Lucid's Red Hills assets in 2022. **Figure 3.6-1** shows the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells. **Figure 3.6-2** shows a process block flow diagram.

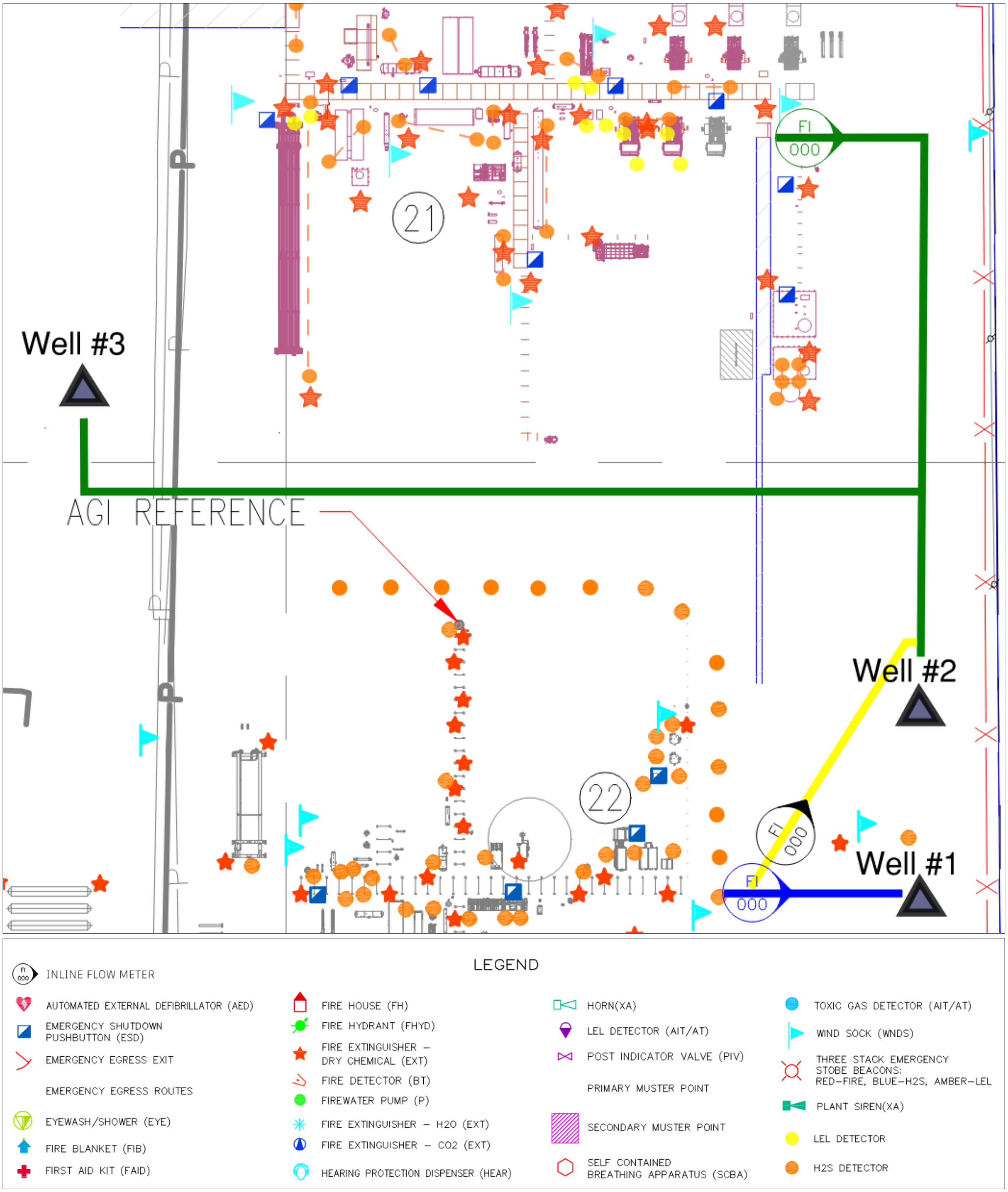


***Figure 3.6-1**: Diagram showing the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells.*

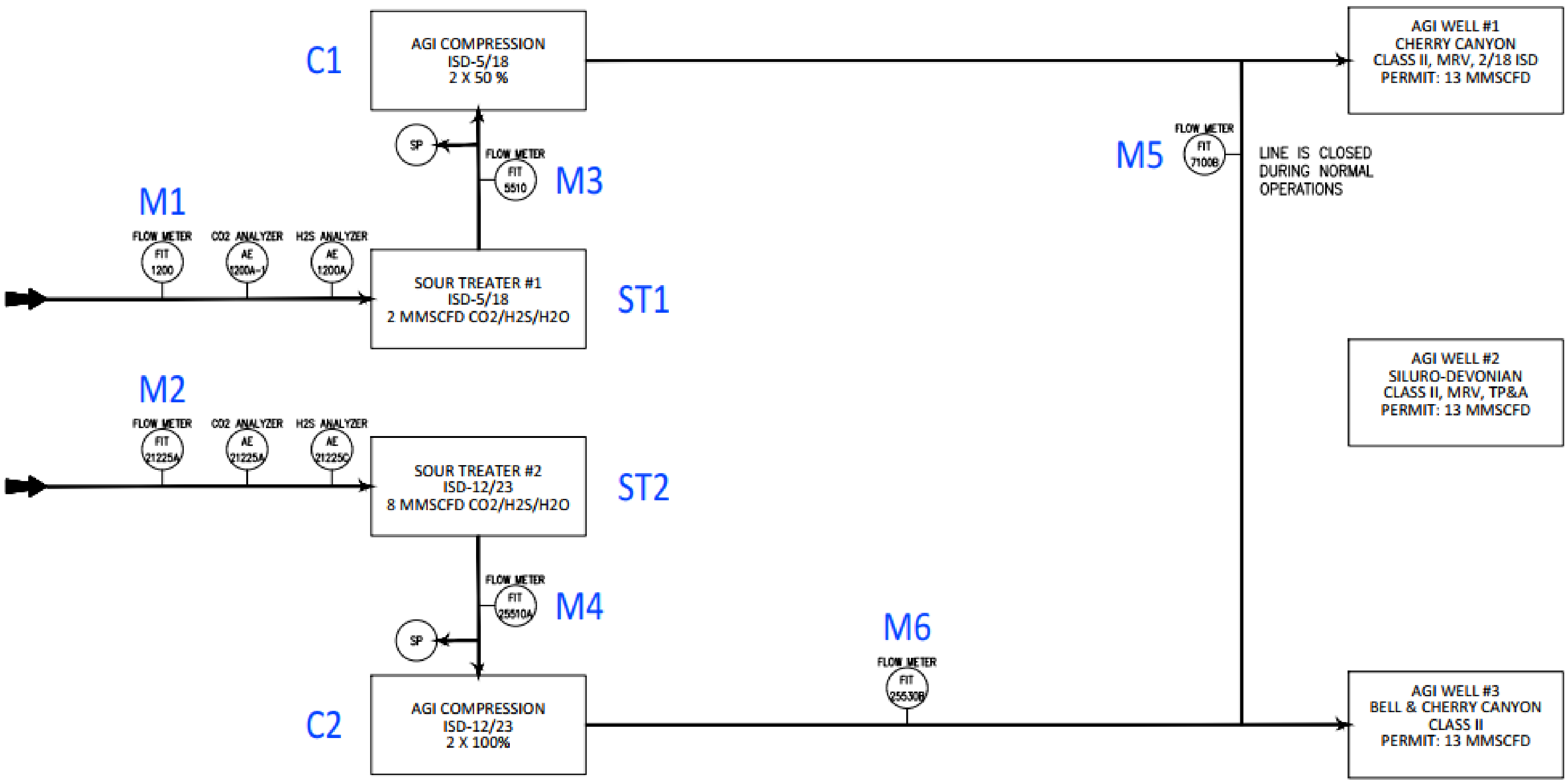


Figure 3.6-2: *Process Block Flow Diagram. RH AGI #2 is temporarily abandoned. M1 – M6: volumetric flow meters; C1 and C2: compressors; ST1 and ST2: sour treaters; and Sample Points (SP) for biweekly collection of data for determining the TAG stream concentration.*

3.6.2 Operations within the MMA for the RH AGI Wells

NMOCD records identify a total of 22 oil- and gas-related wells within the MMA for the RH AGI wells (see **Appendix 4**). **Figure 3.6-3** shows the geometry of producing and injection wells within the MMA for the RH AGI wells. **Appendix 4** summarizes the relevant information for those wells. All active production in this area is targeted for the Bone Spring and Wolfcamp zones, at depths of 8,900 to 11,800 ft, the Strawn (11,800 to 12,100 ft) and the Morrow (12,700 to 13,500 ft). All of these productive zones lie at more than 2,000 ft below the RH AGI #1 and AGI #3 injection zone.

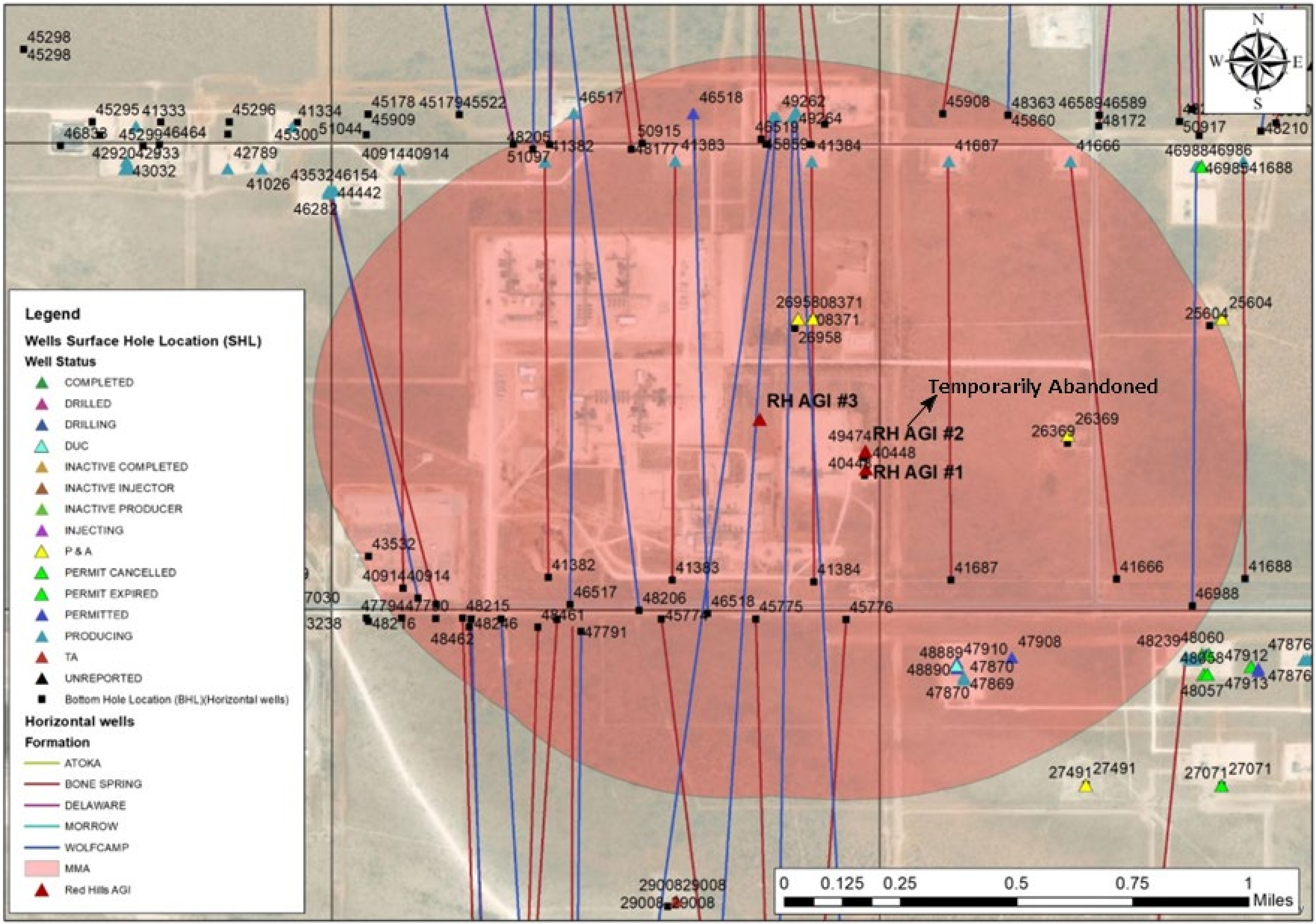


Figure 3.6-3: Location of all oil- and gas-related wells within the MMA for the RH AGI wells. Both the surface hole locations (SHL) and bottom hole locations (BHL) are labeled on the figure. For clarity, only the last four digits of the API numbers are used in labeling the wells.

3.7 Description of Injection Process

The Red Hills Gas Plant, including the existing RH AGI #1 well, is in operation and staffed 24-hours-a-day, 7-days-a week. The plant operations include gas compression, treating and processing. The plant gathers and processes produced natural gas from Lea and Eddy Counties in New Mexico. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the plant's sweeteners will be routed to a central compressor facility, located west of the well head. Compressed TAG is then routed to the wells via high-pressure rated lines. **Figure 3.7-1** is a schematic of the AGI facilities.

The approximate composition of the TAG stream is: 80% CO_2, 20% H_2S, with Trace Components of $C_1 – C_6$ (methane – hexane) and Nitrogen. The anticipated duration of injection is 30 years.

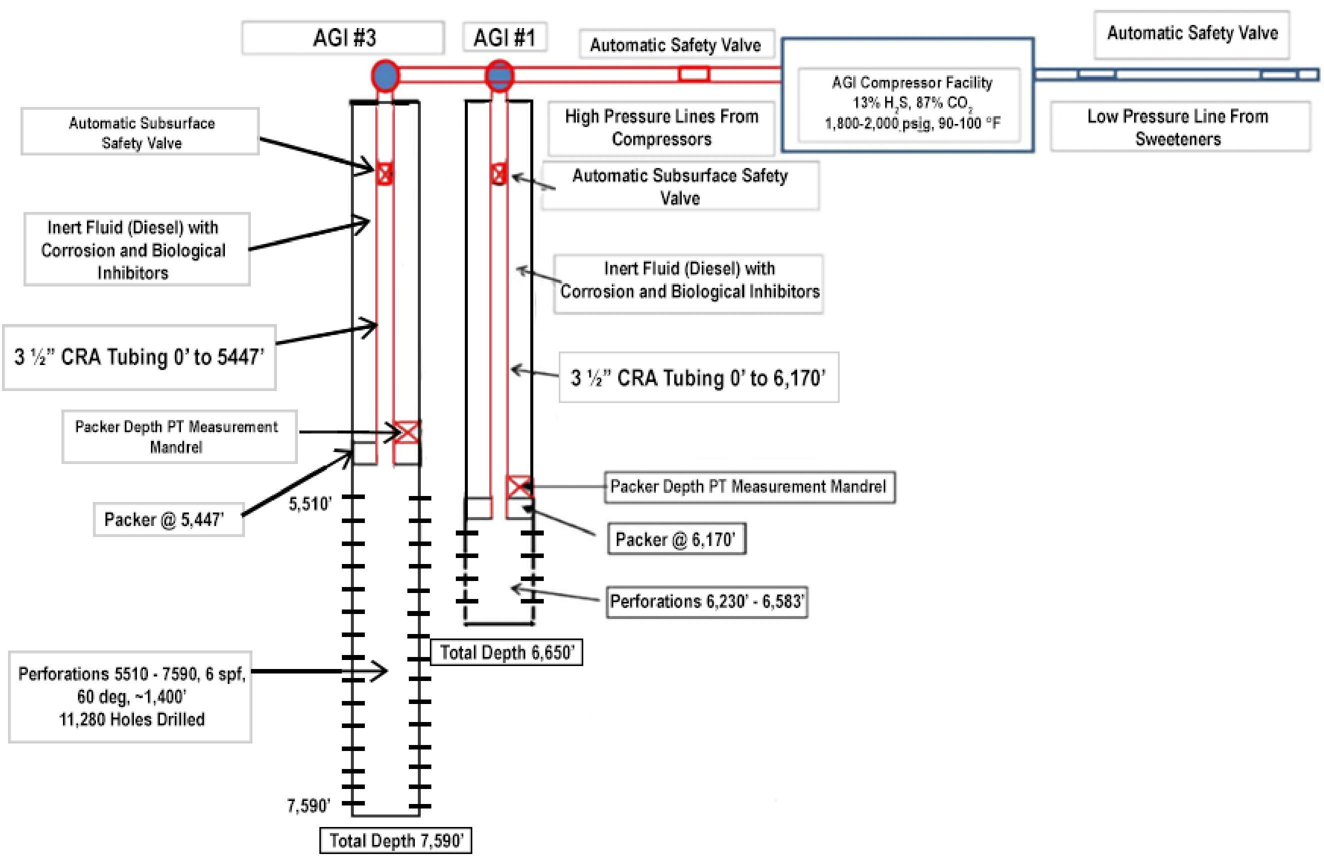


Figure 3.7-1: Schematic of surface facilities and RH AGI wells at the Red Hills Gas Processing Plant

3.8 Reservoir Characterization Modeling

The modeling and simulation focused on the Bell Canyon and Cherry Canyon formations as the main injection target zone for acid gas storage. The RH AGI #1 well (API 30-025-40448) and the RH AGI #3 well (API 30-025-51970) are the approved injectors for treated acid gas injection by NMOCD and will serve as the injection wells in the model under approved disposal timeframe and maximum allowable injection pressure. RH AGI #1 well is completed in the Cherry Canyon formation between 6,230 feet to 6,583 feet (MD). The RH AGI #3 well is completed in both the Bell Canyon and Cherry Canyon formations between approximately 5,700 feet to 7,600 feet (MD).

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

The static model is constructed with well tops and licensed 3D seismic data to interpret and delineate the structural surfaces of a layer within the caprock (Lamar Limestone) and its overlaying, underlying formations. The geologic model covers a 3.5-mile by 3.3-mile area. No distinctive geological structures such as faults are identified within the geologic model boundary. The model is gridded with 182 x 167 x 18, totaling 547,092 cells. The average grid dimension of the active injection area is 100 feet square. **Figure 3.8-1** shows the simulation model in 3D view. The porosity and permeability of the model is populated through existing well logs. The range of the porosity is between 0.01 to 0.31. The initial permeability are interpolated between 0.02 to 155 millidarcy (mD), and the vertical permeability anisotropy was 0.1. **(Figure 3.8-2 and Figure 3.8-3)**. These values are validated and calibrated with the historical injection data of RH AGI #1 well since 2018 as shown in **Figures 3.8-4, 3.8-5, and 3.8-6**.

The simulation model is calibrated with the injection history of RH AGI #1 well since 2018. Simulation studies were further performed to estimate the reservoir responses when predicting TAG injection for 30 years through both RH AGI #1 well (2018 – 2048) and RH AGI #3 (2024 - 2054). RH AGI #2 well is temporarily abandoned as of the submission of this document. RH AGI #1 is simulated to inject with the average rate of the last 5 years, 1.2 MMSCF, in the prediction phase. RH AGI #3 is simulated to inject with permitted injection rate, 13 MMSCF, with 1,767 psi maximum surface injection pressure constraint approved by State agency. The simulation terminated at year 2084, 30 years after the termination of all injection activities, to estimate the maximum impacted area during post injection phase.

During the calibration period (2018 – 2023), the historical injection rates were used as the primary injection control, and the maximum bottom hole pressures (BHP) are imposed on wells as the constraint, calculated based on the approved maximum injection pressure. This restriction is also estimated to be less than 90% of the formation fracture pressure calculated at the shallowest perforation depth of each well to ensure safe injection operations. The reservoir properties are tuned to match the historical injection until it was reasonably matched. **Figure 3.8-4** shows that the historical injection rates from the RH AGI #1 well in the Cherry Canyon Formation. **Figure 3.8-5** shows the BHP response of RH AGI #1 during the history matching phase.

During the forecasting period, linear cumulative injection behavior indicates that the Cherry Canyon and Bell Canyon formations received the TAG stream freely. **Figure 3.8-6** shows the cumulative disposed H_2S and CO_2 of each AGI injectors separately in gas mass. The modeling results indicate that the Cherry Canyon and Bell Canyon formations are capable of safely storing and containing the gas volume without violating the permitted rate and

pressure. **Figure 3.8-7** shows the gas saturation represented TAG plume at the end of 30-year forecasting in 3D view. **Figure 3.8-8** shows the extent of the plume migration in a map view at 4 key time steps. It can be observed that the size of the TAG is very limited and mainly stayed within Targa's Red Hills facility at the end of injection. In the year 2084, after 30 years of monitoring, the injected gas remained trapped in the reservoir and there was no significant migration of TAG footprint observed, compared to that at the end of injection.

In summary, after careful reservoir engineering review and numerical simulation study, our analysis shows that the Bell Canyon and Cherry Canyon formations can receive treated acid gas (TAG) at the injection rate and permitted maximum surface injection pressure permitted by New Mexico Oil Conservation Committee. The formation will safely contain the injected TAG volume within the injection and post-injection timeframe. The injection well will allow for the sequestration while preventing associated environmental impacts.

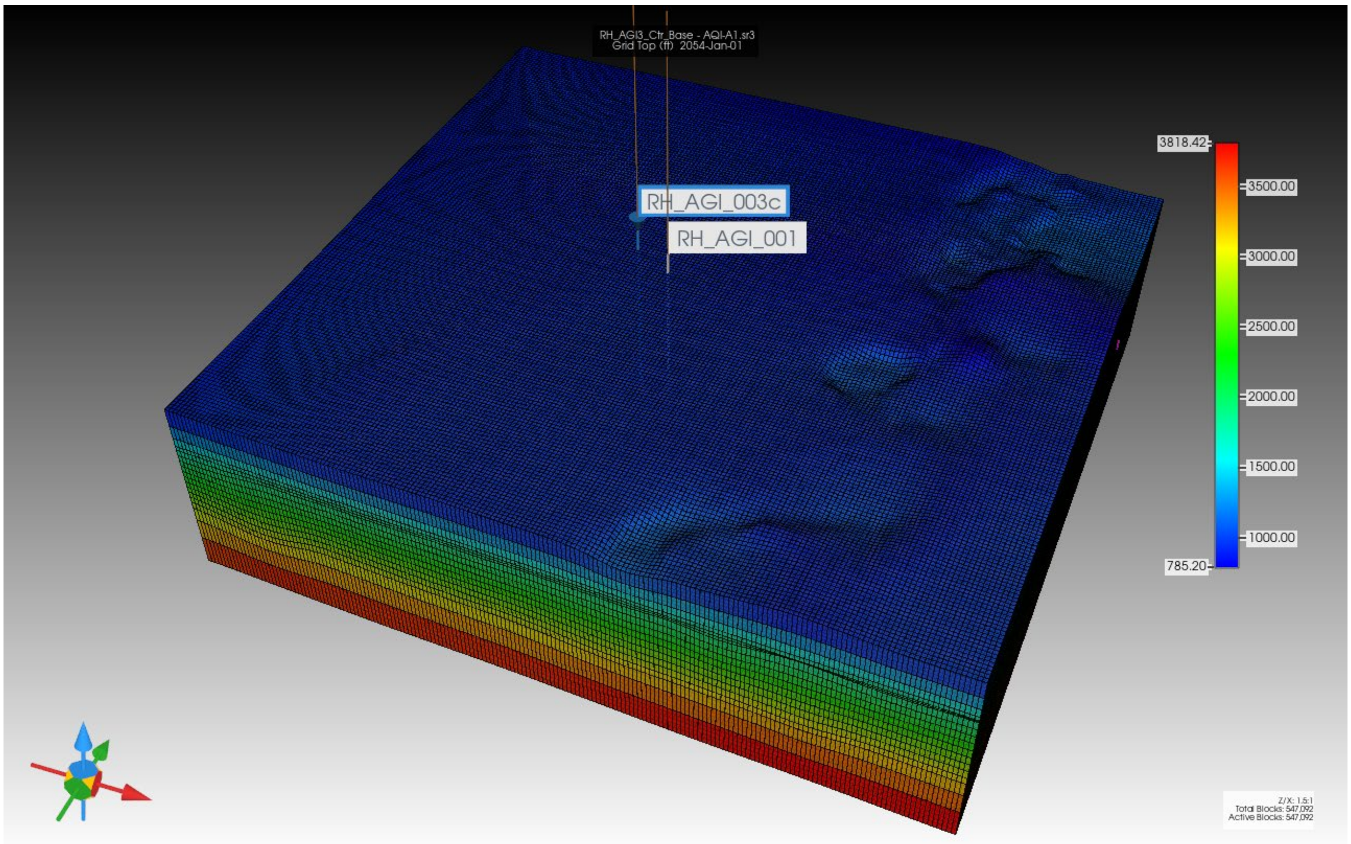


Figure 3.8-1: *3D view of the simulation model of the Red Hills AGI #1 and #3 AGI wells, containing Salado-Castile formation, Lamar limestone, Bell Canyon, and Cherry Canyon formations. Color legends represents the elevation of layers.*

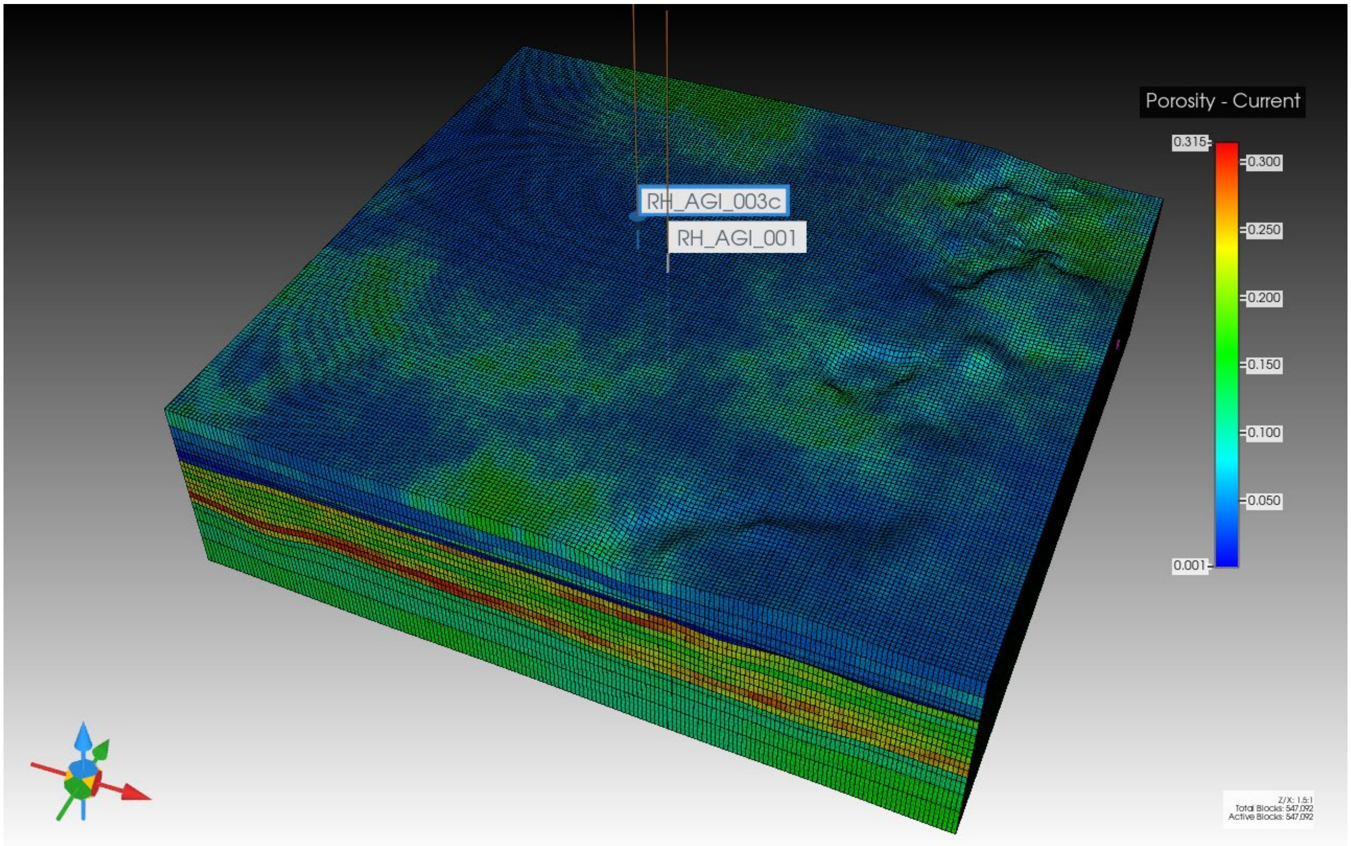


Figure 3.8-2: *Porosity estimation using available well data for the simulation domain.*

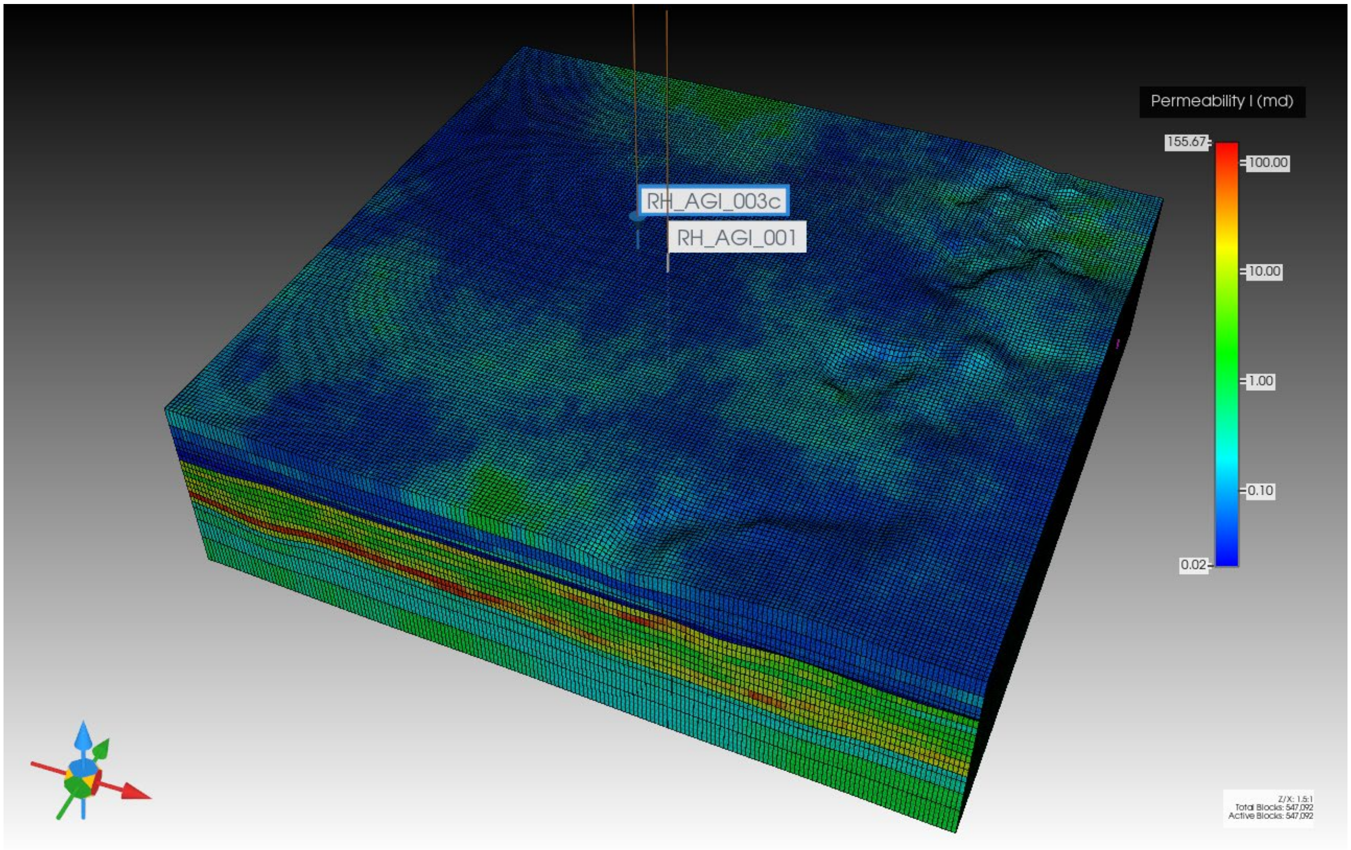


Figure 3.8-3: Permeability estimation using available well data for simulation domain.

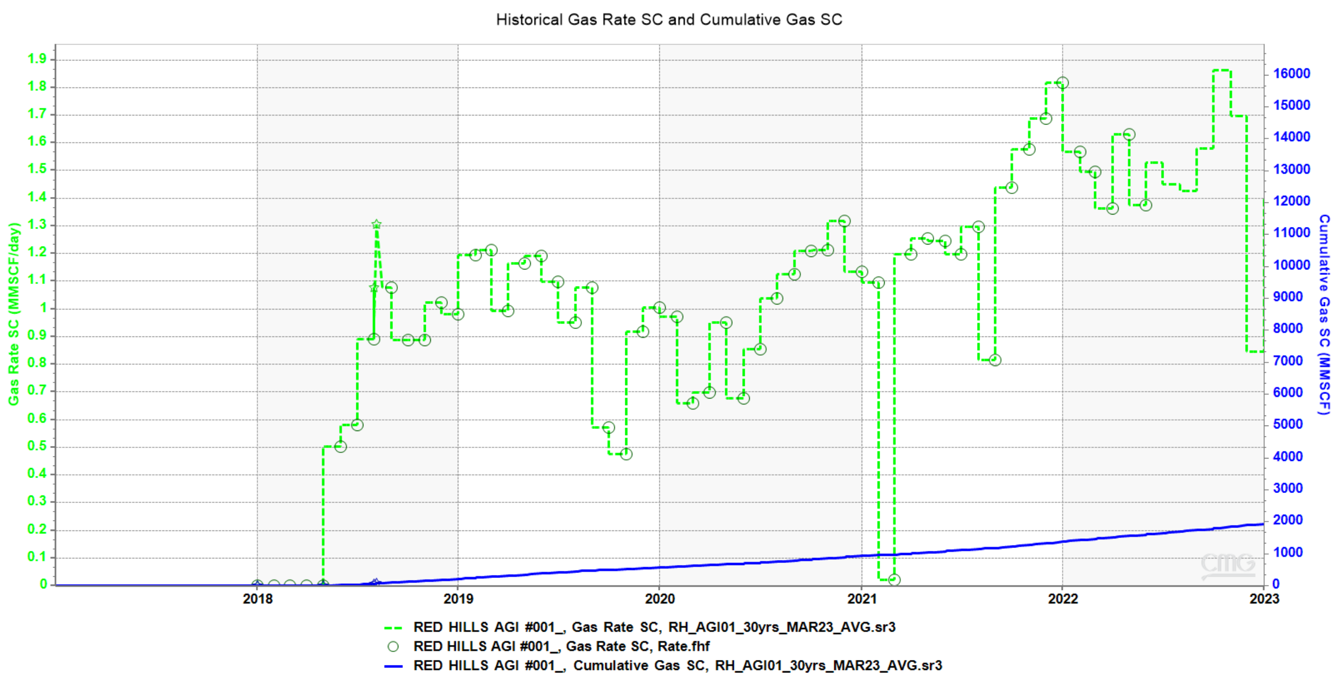


Figure 3.8-4: *shows the historical injection rate and total gas injected from Red Hills AGI #1 well (2018 to 2023)*

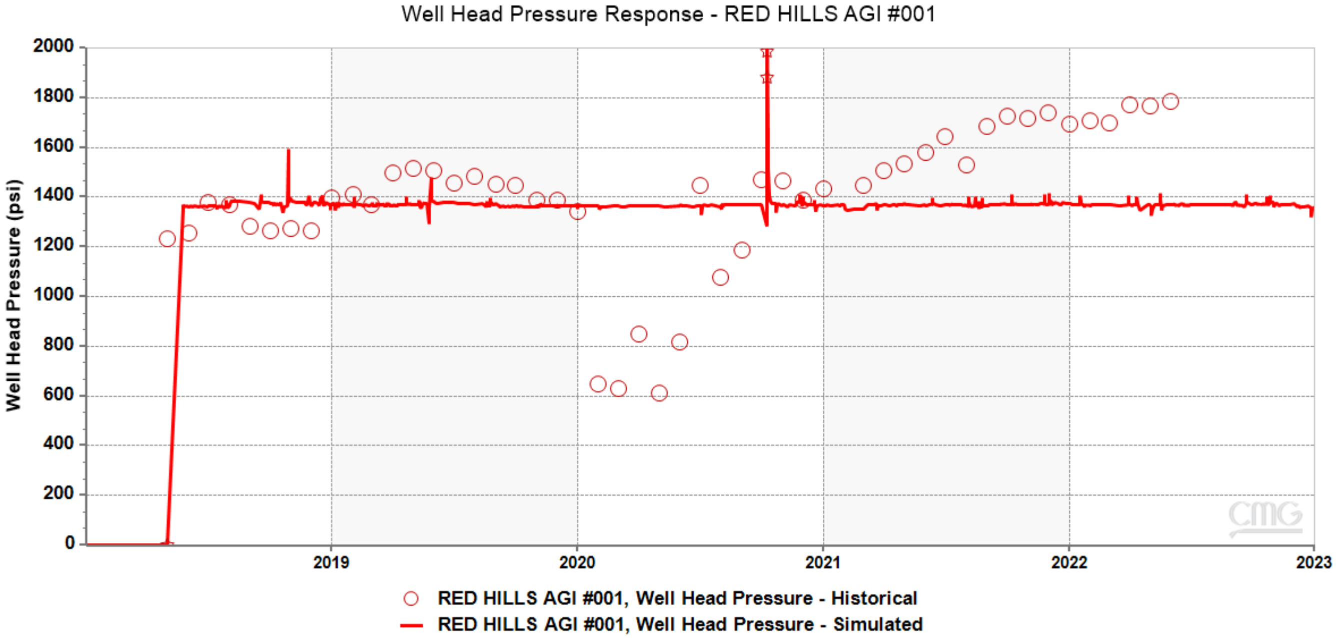


Figure 3.8-5: *shows the historical bottom hole pressure response from Red Hills AGI #1 well (2018 to 2023)*

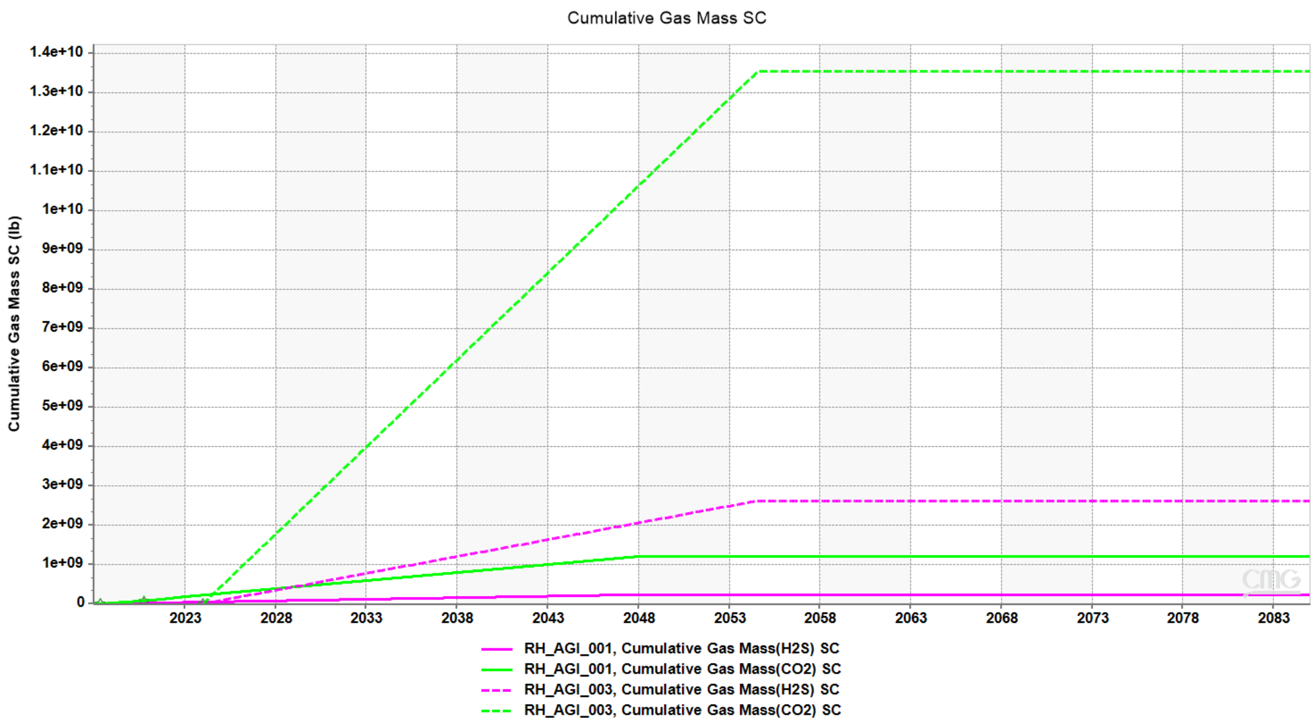


Figure 3.8-6: *shows the prediction of cumulative mass of injected CO_2 and H_2S of Red Hills AGI #1 and #3 wells (2018 to 2054).*

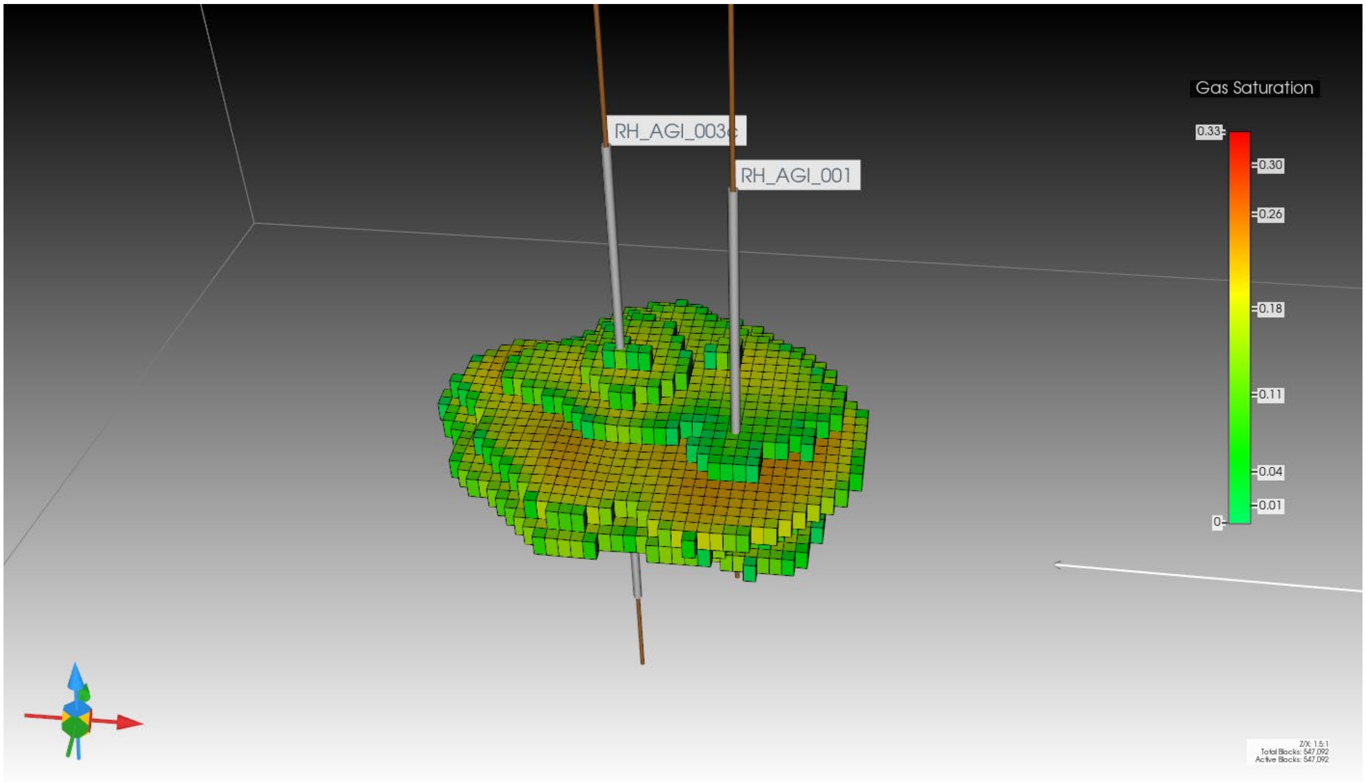


Figure 3.8-7: *shows the free phase TAG (represented by gas saturation) at the end of 30-year post-injection monitoring (2054) in 3D view.*

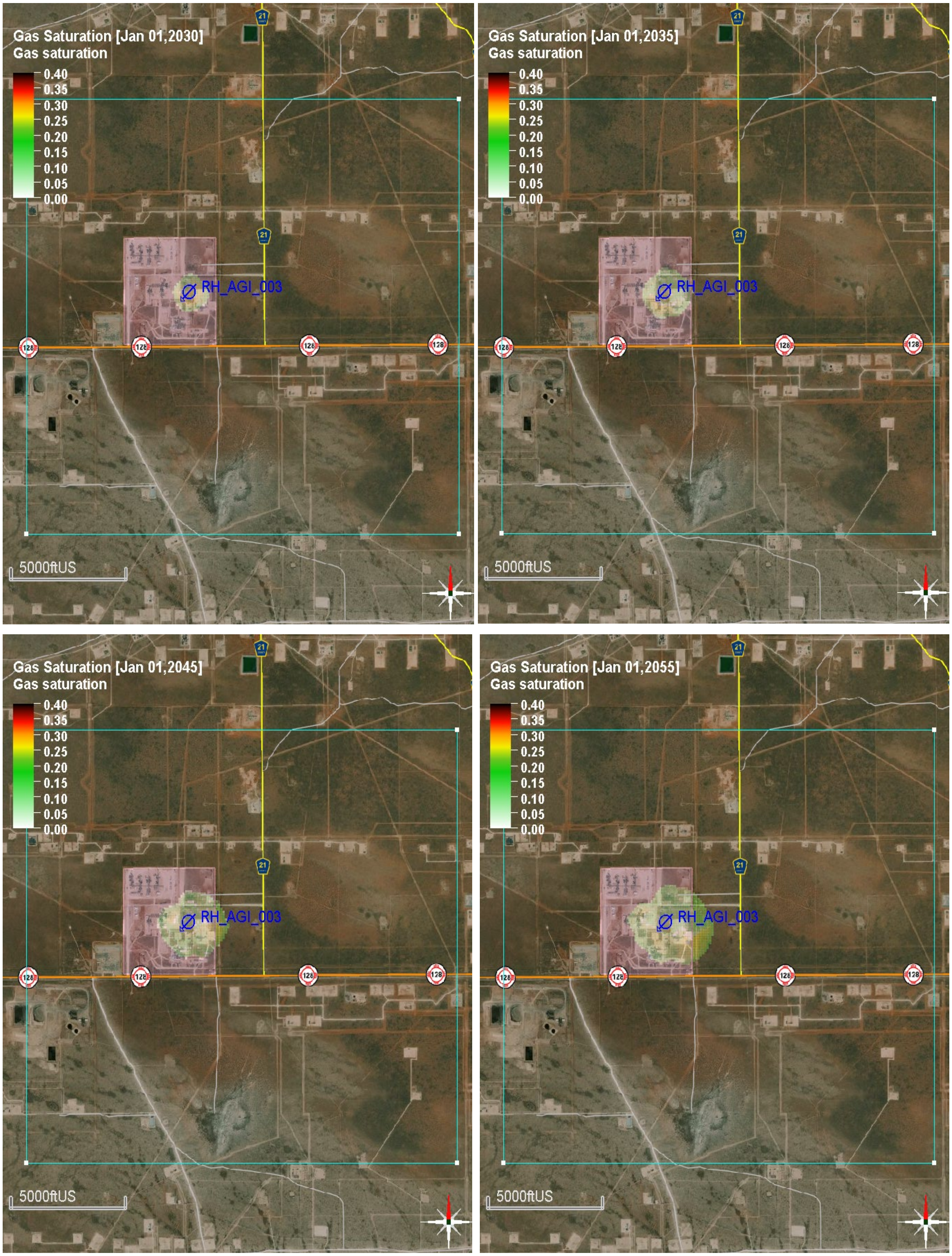


Figure 3.8-8: *shows the free phase TAG plume at year 2030, 2035, 2045, 2055 (1-year end of injection) in a map view.*

4 Delineation of the Monitoring Areas

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

4.1 MMA – Maximum Monitoring Area

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. **Figures 4.1-1** shows the MMA as defined by the extent of the stabilized TAG plume at year 2059 plus a 1/2-mile buffer.

4.2 AMA – Active Monitoring Area

The Active Monitoring Area (AMA) is shown in **Figure 4.1-1**. The AMA is consistent with the requirements in 40 CFR 98.449 because it is the area projected: (1) to contain the free phase CO_2 plume for the duration of the project (year t, t = 2054), plus an all-around buffer zone of one-half mile. (2) to contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2059). Targa intends to define the active monitoring area (AMA) as the same area as the MMA. The purple cross-hatched polygon in **Figure 4.1-1** is the plume extent at the end of injection. The yellow polygon in **Figure 4.1-1** is the stabilized plume extent 5 years after injection ceases. The AMA/MMA shown as the red-filled polygon contains the CO_2 plume during the duration of the project and at the time the plume has stabilized.

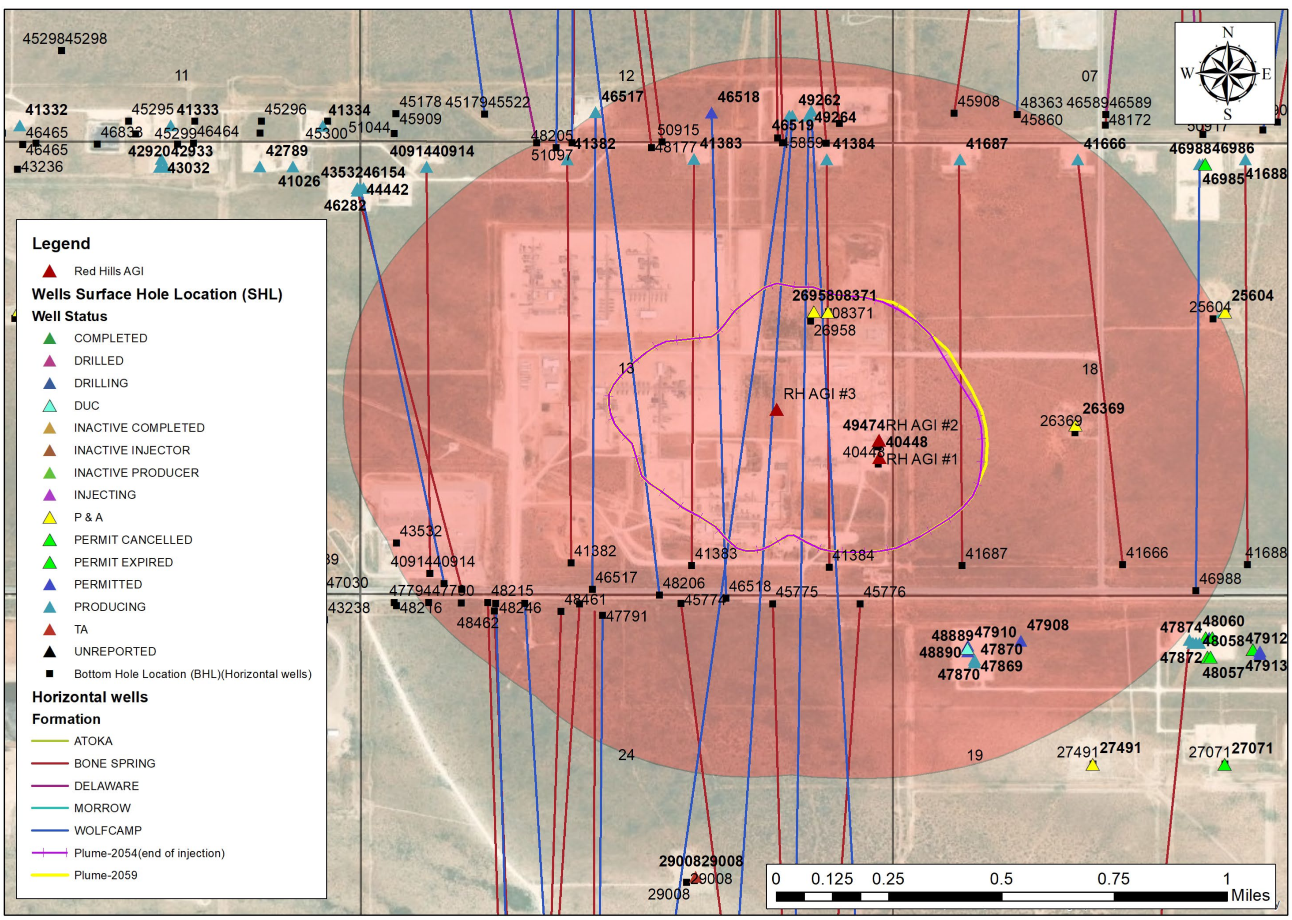


Figure 4.1-1: Active monitoring area (AMA) for TND Red Hills AGI #1, #2 (temporarily abandoned) and #3 wells at the end of injection (2054, purple polygon) and 5 years post-monitoring (2059, yellow polygon). Maximum monitoring area (MMA) is shown in red shaded area.

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

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

Through the site characterization required by the NMOCD C-108 application process for Class II injection wells, the geologic characterization presented in Section 3, and the reservoir modeling described in Section 3.8, TND has identified and evaluated the potential CO_2 leakage pathways to the surface.

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

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas facilities. Preventative risk mitigation includes adherence to relevant regulatory requirements and industry standards governing the construction, operation, and maintenance of gas plants. Specifically, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills."

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

Although mitigative measures are in place to minimize CO_2 emissions from surface equipment, such emissions are possible. Any leaks from surface equipment would result in immediate (timing) emissions of CO_2 to the atmosphere the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak.

The injection well and the pipeline that carries CO_2 to it are the most likely surface components of the system to allow CO_2 to leak to the surface. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable source of the leakage. Another possible source of leakage is the release of air through relief valves, which are designed to alleviate pipeline overpressure. Leakage can also occur when the surface components are damaged by an accident or natural disaster, which releases CO_2. Therefore, TND infers that there is a potential for leakage via this route. Depending on the component's failure mode, the magnitude of the leak can vary greatly. For example, a rapid break or rupture could release thousands of pounds of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO_2 over several hours or days. Surface component leakage or venting is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

5.2 Potential Leakage from Approved, Not Yet Drilled Wells

The only wells within the MMA that are approved but not yet drilled are horizontal wells. These wells have a Well Status of "permitted" in **Appendix 4**. There are no vertical wells within the MMA with a Well Status of "permitted".

5.2.1 Horizontal Wells

The table in **Appendix 3** and **Figure 4.1-1** shows a number of horizontal wells in the area, many of which have approved permits to drill but which are not yet drilled. If any of these wells are drilled through the Bell Canyon and Cherry Canyon injection zones for RH AGI #3 and RH AGI #1, they will be required to take special precautions to prevent leakage of TAG minimizing the likelihood of CO_2 leakage to the surface. This requirement will be made by NMOCD in regulating applications for permit to drill (APD) and in ensuring that the operator and driller are aware that they are drilling through an H_2S injection zone in order to access their target production formation. NMAC 19.15.11 for Hydrogen Sulfide Gas includes standards for personnel and equipment safety and H_2S detection and monitoring during well drilling, completion, well workovers, and well servicing operations all of which apply for wells drilled through the RH AGI wells TAG plume.

Due to the safeguards described above, the fact there are no proposed wells for which the surface hole location (SHL) lies within the simulated TAG plume and considering the NRAP risk analysis described here in Section 5, TND considers the likelihood of CO_2 emissions to the surface via these horizontal wells to be highly unlikely.

5.3 Potential Leakage from Existing Wells

Existing oil and gas wells within the MMA as delineated in Section 4 are shown in **Figure 3.6-3** and detailed in **Appendix 4**.

TND considered all wells completed and approved within the MMA in the NRAP risk assessment. Some of these wells penetrate the injection and/or confining zones while others do not. Even though the risk of CO_2 leakage through the wells that did not penetrate confining zones is highly unlikely, TND did not omit any potential source of leakage in the NRAP analysis. If leakage through wellbores happens, the worst-case scenario is predicted using the NRAP tool to quantitatively assess the amount of CO_2 leakage through existing and approved wellbores within the MMA. Thirty-nine existing and approved wells inside MMA were addressed in the NRAP analysis. The reservoir properties, well data, formation stratigraphy, and MMA area were incorporated into the NRAP tool to forecast the rate and mass of CO_2 leakage. The worst scenario is that all of the 39 wells were located right at the source of CO_2 – the injection well's location. In this case, the maximum leakage rate of one well is approximately 7e-6 kg/s. This value is the maximum amount of CO_2 leakage, 220 kg/year, and occurs in the second year of injection, then gradually reduces to 180 kg at the end of year 30. Comparing the total amount of CO_2 injected (assuming 5 MMSCFD of supercritical CO_2 injected continuously for 30 years), the leakage mass amounts to 0.0054% of the total CO_2 injected. This leakage is considered negligible. Also, this worst-case scenario, where 39 wells are located right at the injection point, is impossible in reality. Therefore, CO_2 leakage to the surface via this potential leakage pathway can be considered improbable.

5.3.1 Wells Completed in the Bell Canyon and Cherry Canyon Formations

The only wells completed in the Bell Canyon and Cherry Canyon Formations within the MMA are the RH AGI #1, #2, and #3 wells and the 30-025-08371 well which was completed at a depth of 5,425 ft. This well is within the Red Hills facility boundary and is plugged and abandoned (see **Appendix 9** for plugging and abandonment (P&A) record).

Appendix 1 includes schematics of the RH AGI #1, #2,and #3 wells construction showing multiple strings of casing all cemented to surface. Injection of TAG into RH AGI #1 and #3 occurs through tubing with a permanent production packer set above the injection zone.

RH AGI #2 is located in close proximity to RH AGI #1 and is temporarily abandoned. Drilling of this well stopped at 6,205 ft due to concerns about high pressures by drilling into the Cherry Canyon Formation and therefore, did not penetrate the Cherry Canyon Formation. The cement plug was tagged at 5,960 feet which is above the injection zone for RH AGI #1 (see **Figure Appendix 1-3**).

Due to the robust construction of the RH AGI wells, the plugging of the well 30-025-08371 above the Bell Canyon, the plugging of RH AGI #2 above the Cherry Canyon Formation, and considering the NRAP analysis described above, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.2 Wells Completed in the Bone Spring / Wolfcamp Zones

Several wells are completed in the Bone Spring and Wolfcamp oil and gas production zones as described in Section 3.6.2. These productive zones lie more than 2,000 ft below the RH AGI wells injection zone minimizing the likelihood of communication between the RH AGI well injection zones and the Bone Spring / Wolfcamp production zones. Construction of these wells includes surface casing set at 1,375 ft and cemented to surface and intermediate casing set at the top of the Bell Canyon at depths of from 5,100 to 5,200 ft and cemented through the Permian Ochoan evaporites, limestone and siltstone (**Figure 3.2-2**) providing zonal isolation preventing TAG injected into the Bell Canyon and Cherry Canyon formations through RH AGI wells from leaking upward along the borehole in the event the TAG plume were to reach these wellbores. **Figure 4.1-1** shows that the modeled TAG plume extent after 30 years of injection and 5 years of post-injection stabilization does not extend to well boreholes completed in the Bone Spring / Wolfcamp production zones thereby indicating that these wells are not likely to be pathways for CO_2 leakage to the surface.

Due to the construction of these wells, the fact that the modeled TAG plume does not reach the SHL of these wells and considering the NRAP analysis described in the introductory paragraph of Section 5, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.3 Wells Completed in the Siluro-Devonian Zone

One well penetrated the Devonian at the boundary of the MMA - EOG Resources, Government Com 001, API # 30-025-25604, TVD = 17,625 ft, 0.87 miles from RH AGI #3. This well was drilled to a total depth of 17,625 ft on March 5, 1978, but plugged back to 14,590 ft, just below the Morrow, in May of 1978. Subsequently, this well was permanently plugged and abandoned on December 30, 2004, and approved by NMOCD on January 4, 2005 (see **Appendix 9** for P&A records). The approved plugging provides zonal isolation for the Bell Canyon and Cherry Canyon injection zones minimizing the likelihood that this well will be a pathway for CO_2 emissions to the surface from either injection zone.

Due to the location of this well at the edge of the MMA and considering the NRAP analysis described in the introductory paragraph of Section 5, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.4 Groundwater Wells

The table in Appendix 3 lists 15 water wells within a 2-mile radius of the RH AGI wells, only 2 of which are within a 1-mile radius of and within the MMA for the RH AGI wells (**Figure 3.5-1**). The deepest ground water well is 650 ft deep The evaporite sequence of the Permian Ochoan Salado and Castile Formations (see

Section 3.2.2) provides an excellent seal between these groundwater wells and the Cherry Canyon injection zone of the RH AGI #1 well. Therefore, it is unlikely that these two groundwater wells are a potential pathway of CO_2 leakage to the surface. Nevertheless, the CO_2 surface monitoring and groundwater monitoring described in Sections 6 and 7 will provide early detection of CO_2 leakage followed by immediate response thereby minimizing the magnitude of CO_2 leakage volume via this potential pathway.

Due to the shallow depth of the groundwater wells within the MMA relative to the depth of the RH AGI wells and considering the NRAP analysis described in the introductory paragraph in Section 5, TND considers that, while the likelihood of CO_2 emissions to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.4 Potential Leakage through the Confining / Seal System

The site characterization for the injection zone of the RH AGI wells described in Sections 3.2.2 and 3.3 indicates a thick sequence of Permian Ochoan evaporites, limestone, and siltstones (**Figure 3.2-2**) above the Bell Canyon and Cherry Canyon Formations and no evidence of faulting. Therefore, it is unlikely that TAG injected into the Bell Canyon and Cherry Canyon Formations will leak through this confining zone to the surface. Limiting the injection pressure to less than the fracture pressure of the confining zone will minimize the likelihood of CO_2 leakage through this potential pathway to the surface.

Leakage through a confining zone happens at low-permeability shale formations containing natural fractures. The injection zone for the RH AGI #1 and #3 is the Delaware Group Formation (Bell Canyon and Cherry Canyon), which lies under the Castile and Salado formations with less than 0.01 mD permeability acting as the seals. Therefore, TND took leakage through confining zones into consideration in the NRAP risk assessment. The worst-case scenario is defined as leakage through the seal happening right above the injection wells, where CO_2 saturation is highest. However, this worst-case scenario of leakage only shows that 0.0017% of total CO_2 injection in 30 years was leaked from the injection zone through the seals. As we go further from the source of CO_2, the likelihood of such an event will diminish proportionally with the distance from the source. Considering that this is the greatest amount of CO_2 leakage in this worst-case scenario, if the event happens, the leak must pass upward through the confining zone, the secondary confining strata that consists of additional low permeability geologic units, and other geologic units, TND concludes that the risk of leakage through this pathway is highly unlikely.

5.5 Potential Leakage due to Lateral Migration

The characterization of the sand layers in the Cherry Canyon Formation described in Section 3.3 states that these sands were deposited by turbidites in channels in submarine fan complexes, each sand is encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity. Regional consideration of their depositional environment suggests a preferred orientation for fluid and gas flow would be south-to-north along the channel axis. However, locally the high net porosity of the RH AGI #1 and #3 injection zones indicates adequate storage capacity such that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA due to a preferred regional depositional orientation.

Lateral migration of the injected TAG was addressed in detail in Section 3.3. Therein it states that the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales as well as being encased by them.

Based on the discussion of the channeled sands in the injection zone, TND considers that the likelihood of CO_2 to migrate laterally along the channel axes is possible. However, that the turbidite sands are encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity and that the injectate is projected to be contained within the injection zone close to the injection wells minimizes the likelihood that CO_2 will migrate to a potential conduit to the surface.

5.6 Potential Leakage through Fractures and Faults

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology as well as identify and understand the distribution of faults and fractures. **Figure 5.6-1** shows the fault traces in the vicinity of the Red Hill plant. The faults shown on **Figure 5.6-1** are confined to the Paleozoic section below the injection zone for the RH AGI wells. No faults were identified in the confining zone above the Bell Canyon and Cherry Canyon injection zone for the RH AGI wells.

No faults were identified within the MMA which could potentially serve as conduits for surface CO_2 emission. The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief. Because this fault is confined to the lower Paleozoic unit more than 5,100 feet below the injection zone for the RH AGI wells, there is minimal chance it would be a potential leakage pathway. This inference is supported by the NRAP simulation result. Therefore, TND concludes that the CO_2 leakage rate through this fault is zero and that the risk of leakage through this potential leakage pathway is highly improbable.

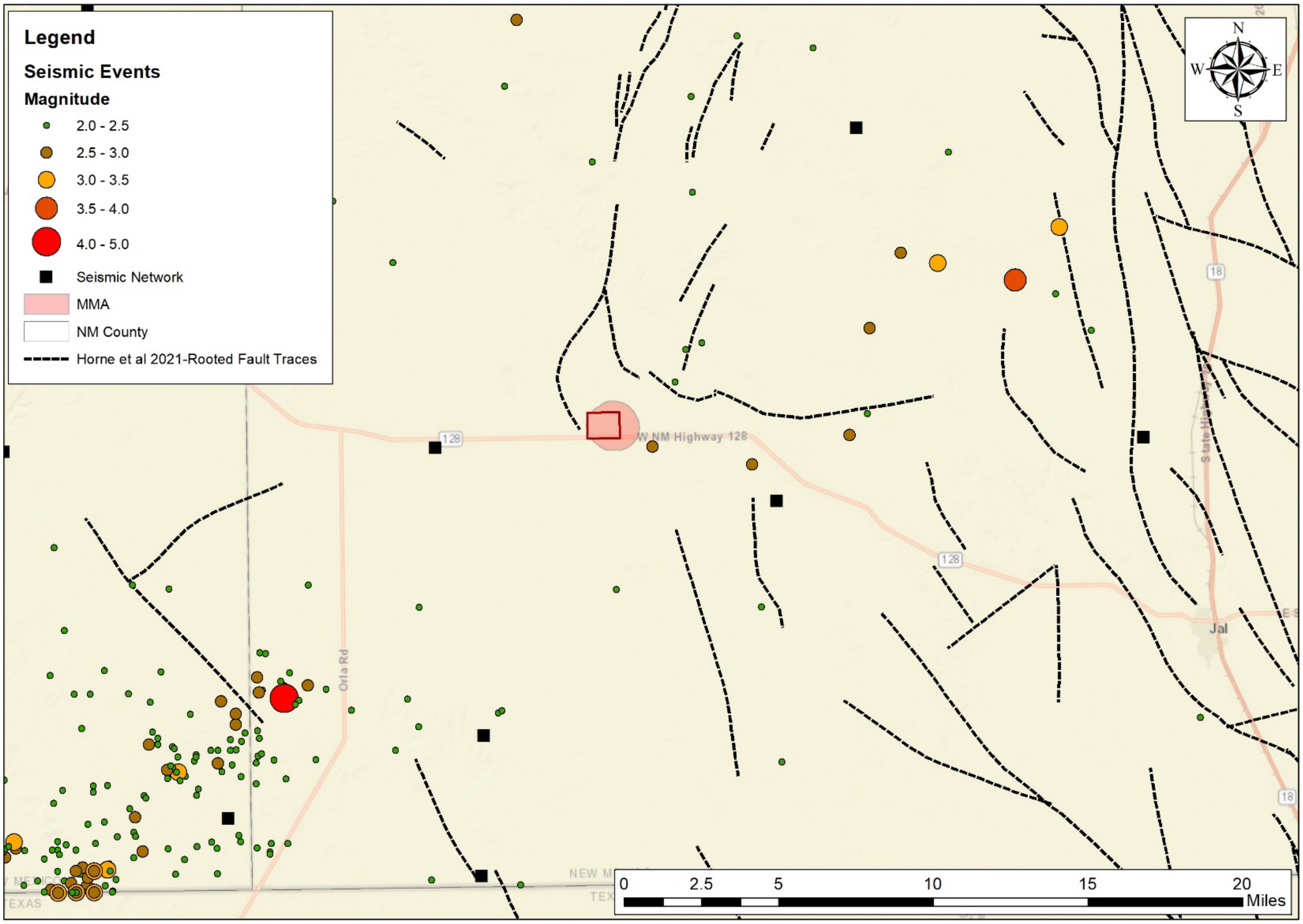


***Figure 5.6-1**: New Mexico Tech Seismological Observatory (NMTSO) seismic network close to the operations, recent seismic events, and fault traces (2022-2023). Note: Fault traces are from Horne et al 2021 for deep seated faults in the lower Paleozoic. The fault traces shown close to the Red Hills facility die out at the base of the Wolfcamp formation at a depth of 12,600 feet, more than 5,100 feet below the bottom of the injection zone at 7,500 feet.*

5.7 Potential Leakage due to Natural / Induced Seismicity

The New Mexico Tech Seismological Observatory (NMTSO) monitors seismic activity in the state of New Mexico. A search of the database shows no recent seismic events close to the Red Hills operations. The closest recent, as of 4 September 2023, seismic events are:

- 7.5 miles, 2022-09-03, Magnitude 3
- 8 miles, 2022-09-02, Magnitude 2.23
- 8.6 miles, 2022-10-29, Magnitude 2.1

Figure 5.6-1 shows the seismic stations and recent seismic events in the area around the Red Hills site.

Due to the distance between the Red Hills AGI wells and the recent seismic events, the magnitude of these events, and the fact that TND injects at pressures below fracture opening pressure, TND considers the likelihood of CO_2 emissions to the surface caused by seismicity to be improbable.

Monitoring of seismic events in the vicinity of the Red Hills AGI wells is discussed in Section 6.7.

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

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

Table 6-1: Summary of Leak Detection Monitoring

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors
Existing RH AGI Wells	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors • In-well P/T sensors • Groundwater monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network

Potential Leakage Pathway	Detection Monitoring
	● Groundwater monitoring
Additional Monitoring	● Groundwater monitoring ● Soil flux monitoring

6.1 Leakage from Surface Equipment

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

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

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

> "**Fixed Monitors**
> The Red Hills Plant has numerous ambient hydrogen sulfide detectors placed strategically throughout the Plant to detect possible leaks. Upon detection of hydrogen sulfide at 10 ppm at any detector, visible beacons are activated, and an alarm is sounded. Upon detection of hydrogen sulfide at 90 ppm at any detector, an evacuation alarm is sounded throughout the Plant at which time all personnel will proceed immediately to a designated evacuation area. The Plant utilizes fixed-point monitors to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the Distributed Control System (DCS). The monitors are equipped with amber beacons. The beacon is activated at 10 ppm. The plant and AGI well horns are activated with a continuous warbling alarm at 10 ppm and a siren at 90 ppm. All monitoring equipment is Red Line brand. The Control Panel is a 24 Channel Monitor Box, and the fixed point H_2S Sensor Heads are model number RL-101.
>
> The Plant will be able to monitor concentrations of H_2S via H_2S Analyzers in the following locations:
> - Inlet gas of the combined stream from Winkler and Limestone
> - Inlet sour liquid downstream of the slug catcher
> - Outlet Sweet Gas to Red Hills 1
> - Outlet Sweet Liquid to Red Hills Condensate Surge
>
> The AGI system monitors can also be viewed on the PLC displays located at the Plant. These sensors are all shown on the plot plan (see **Figure 3.6-1**). This requires immediate action for any occurrence or malfunction. All H_2S sensors are calibrated monthly.

Personal and Handheld H_2S Monitors

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

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones as described in Section 5.2.1 for RH AGI #3 including more frequent monitoring during drilling operations (see **Table 6-1**). This applies to TND and other operators drilling new wells through the RH AGI injection zone within the MMA.

6.3 Leakage from Existing Wells

6.3.1 RH AGI Wells

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

To monitor leakage and wellbore integrity, two pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) were deployed in TND's RH AGI #1 well. One gauge is designated to monitor the tubing ID (reservoir) pressure and temperature and the second gauge monitors the annular space between the tubing and the long string casing (**Figure 6.2-1**). A leak is indicated when both gauges start reading the same pressure. DTS is clamped to the tubing, and it monitors the temperature profiles of the annulus from 6,159 ft to surface. DTS can detect variation in the temperature profile events throughout the tubing and or casing. Temperature variation could be an indicator of leaks. Data from temperature and pressure gauges is recorded by an interrogator housed in an onsite control room. DTS (temperature) data is recorded by a separate interrogator that is also housed in the onsite control room. Data from both interrogators are transmitted to a remote location for daily real time or historical analysis.

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

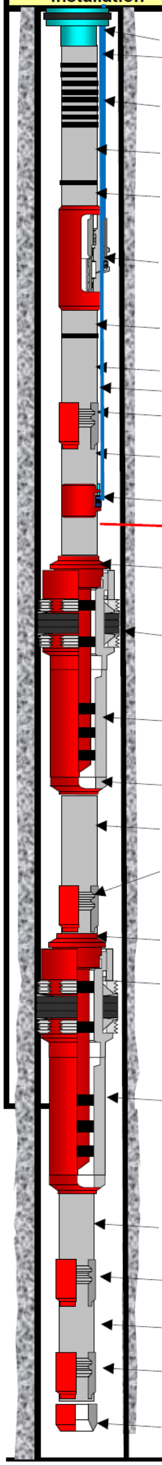
HALLIBURTON

Lucid

Red Hills AGI 1
Lea County New Mexico
2/3/21 - 2/28/21

WSP - Troy Gillen / Michael Forrier
Sales Rep - Lynn Talley (432) 631-4626
Tool Specialists: Carey Lehmann, Jonathan Phillips, Jose Vargas

Installation



Installation	Depth	Length	Jts.	Description	OD	ID
	18.50	18.50		KB		
20	22.90	4.40		20) Hanger Sub 3 1/2" 9.2# CRA VAMTOP x 7.7# VAM Ace Pin	7.000	3.000
19	64.05	41.15	1	19) 3 1/2" 7.7# VAM ACE 125K G3 Tubing (Slick Joint)	3.500	3.035
				Ran Eight Subs 8', 8', 6', 6',4', 4', 2', 2'		
18	103.97	39.92		18) 3 1/2" 7.7# VAM ACE 125K G3 Spaceout Subs	3.500	3.035
17	235.95	131.98	3	17) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.035
16	241.95	6.00		16) 6' x 3 1/2" 7.7# CRA VAM ACE Box x 9.2# VAMTOP Pin	3.540	2.959
15	246.30	4.35		15) 3 1/2" NE HES SSSV Nickel Alloy 925 w/Alloy 825 Control Line 3 1/2" 9.2# VAMTOP Box x Pin	5.300	2.813
14	252.29	5.99		14) 6' x 3 1/2" 9.2# CRA VAMTOP Box x 7.7# VAM ACE Pin	3.540	2.959
13	6,140.23	5,887.94	134	13) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.305
12				12) 3 1/2" 7.7# VAM ACE Box x 9.2# VAMTOP Pin CRA Crossover	3.830	2.959
11				11) 2.813" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925	4.073	2.813
10	6,153.72	13.49		10) 6' x 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy G3 Sub	3.540	2.959
				13.49' Length Includes Line Items 10, 11 & 12		
9	6,159 Tubing	P/T		9) Baker PT Sensor Mandrel 3 1/2" 9.2# VAMTOP Box x Pin	5.200	2.992
	6,162.6 Annular	P/T		6' VAMTOP 9.2# CRA Tubing Sub Above & Below Gauge Mdl		
8	6,161.23	7.51		8) 4.00" BWS Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925	4.470	2.959
				7.51' Length Includes Line Items 8 & 9		
7	6,164.55	3.32		7) 7" 26-32# x 4.00" BWS Packer Nickel Alloy 925 Casing Collar @ 6,160.6' WL Measurement	5.875	4.000
6	6,172.05	7.5		6) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
5	6,172.88	0.83		5) 4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
4	6,181.19	8.31		4) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
3	6,182.52	1.33		3) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925 #102204262	4.073	2.562
2	6,184.29	1.77		2) Straight Slot Locator Seal Assembly Above Top Of Packer	4.450	2.880
1		6,186.06		1) BWD Permanent Packer. WL Measured Depth Previously 6189'	5.875	4.000
1a				1a) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.660	2.965
1b				1b) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1c				1c) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel,	2.920	2.562
1d				1d) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1e				1e) 2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	3.920	2.321
1f				1f) Re-Entry Guide / POP	3.950	3.000

Figure 6.2-1: Well Schematic for RH AGI #1 showing installation of P/T sensors

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7.3 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. Additionally, groundwater and soil CO_2 flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through the Confining / Seal System

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

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

6.5 Leakage due to Lateral Migration

Continuous operational monitoring of the RH AGI wells during and after the period of the injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The CO_2 monitoring network described in Section 7.3, and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

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

6.6 Leakage from Fractures and Faults

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through faults. However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, TND will identify which of the pathways listed in this section are responsible for the leak, including the possibility of heretofore unidentified faults or fractures within the MMA. TND will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details. See Section 6.8 for additional information on quantification strategies.

6.7 Leakage due to Natural / Induced Seismicity

In order to monitor the influence of natural and/or induced seismicity, TND will use the established NMTSO seismic network. The network consists of seismic monitoring stations that detect and locate seismic events. Continuous monitoring helps differentiate between natural and induced seismicity. The network surrounding the Red Hills Gas Processing Plant has been mapped on **Figure 5.6-1**. The monitoring network records Helicorder data from UTC (coordinated universal time) all day long. The data are plotted daily at

5pm MST (mountain standard time). These plots can be browsed either by station or by day. The data are streamed continuously to the New Mexico Tech campus and archived at the Incorporated Research Institutions for Seismology Data Management Center (IRIS DMC).

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

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

For normal operations, quantification of emissions of CO_2 from surface equipment will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR. Quantification of major leakage events from surface equipment as identified by the detection techniques listed in Table 6-1 will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified the leakage location will be isolated to prevent additional emissions to the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. TND has standard operating procedures to report and quantify all pipeline leaks in accordance with the NMOCD regulations (New Mexico administrative Code 19.15.28 Natural Gas Gathering Systems). TND will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by TND or third parties. Additionally, TND may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

6.8.2 Subsurface Leakage

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

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

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, or which may be initiated by seismic events and as may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO_2 leaking back to the surface emphasizing the importance of monitoring

network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO_2 flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 6.8.1, or from the subsurface. In the latter case, CO_2 flux monitoring methodologies, as described in Section 7.8, will be employed to quantify the surface leaks.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

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

7.1 Visual Inspection

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

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

Compositional analysis of TND's gas injectate at the Red Hills Gas Plant indicates an approximate H_2S concentration of 20% thus requiring TND to develop and maintain an H_2S Contingency Plan (Plan) according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). TND considers H_2S to be a proxy for CO_2 leaks at the plant. The Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated RH AGI Wells and documents procedures that would be followed in case of such an event.

7.2.1 Fixed In-Field H_2S Monitors

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

7.2.2 Handheld and Personal H_2S Monitors

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

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

7.3 CO_2 Detection

In addition to the handheld gas detection monitors described above, New Mexico Tech, through a DOE research grant (DE-FE0031837 – Carbon Utilization and Storage Project of the Western USA (CUSP)), will assist TND in setting up a monitoring network for CO_2 leakage detection in the AMA as defined in Section 4.2. The scope of work for the DOE project includes field sampling activities to monitor CO_2/H_2S at the two RH AGI wells. These activities include periodic well (groundwater and gas) and atmospheric sampling from an area of 10 – 15 square miles around the injection wells. Once the network is set up, TND will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

7.4 Continuous Parameter Monitoring

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

7.5 Well Surveillance

TND adheres to the requirements of NMOCC Rule 26 governing the construction, operation and closing of an injection well under the Oil and Gas Act. Rule 26 also includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, NMOCC includes special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. TND's Routine Operations and Maintenance Procedures for the RH AGI wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic (Microseismic) Monitoring Stations

TND has Installed a model TCH120-1 Trillium Compact Horizon Seismometer and a model CTR4-3S Centaur Digital Recorder to monitor for and record data for any seismic event at the Red Hills Gas Plant (see **Figure 7-1)**. The seismic station meets the requirements of the NMOCC Order No. R-20916-H to "install, operate, and monitor for the life of the [Class II AGI] permit a seismic monitoring station or stations as directed by the Manager of the New Mexico Tech Seismological Observatory ("state seismologist") at the New Mexico Bureau of Geology and Mineral Resources."

In addition, data that is recorded by the State of New Mexico deployed seismic network within a 10-mile radius of the Red Hills Gas Plant will be analyzed by the New Mexico Bureau of Geology (NMBGMR), see **Figure 5.6-1**, and made publicly available. The NMBGMR seismologist will create a report and map showing the magnitudes of recorded events from seismic activity. The data is being continuously recorded. By examining historical data, a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

7.7 Groundwater Monitoring

New Mexico Tech, through the same DOE research grant described in Section 7.3 above, will monitor groundwater wells for CO_2 leakage which are located within the AMA as defined in Section 4.2. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 7.7-1**. Baseline analyses will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Red Hills Gas Plant. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

Table 7.7-1: Groundwater Monitoring Parameters

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

7.8 Soil CO_2 Flux Monitoring

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

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

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

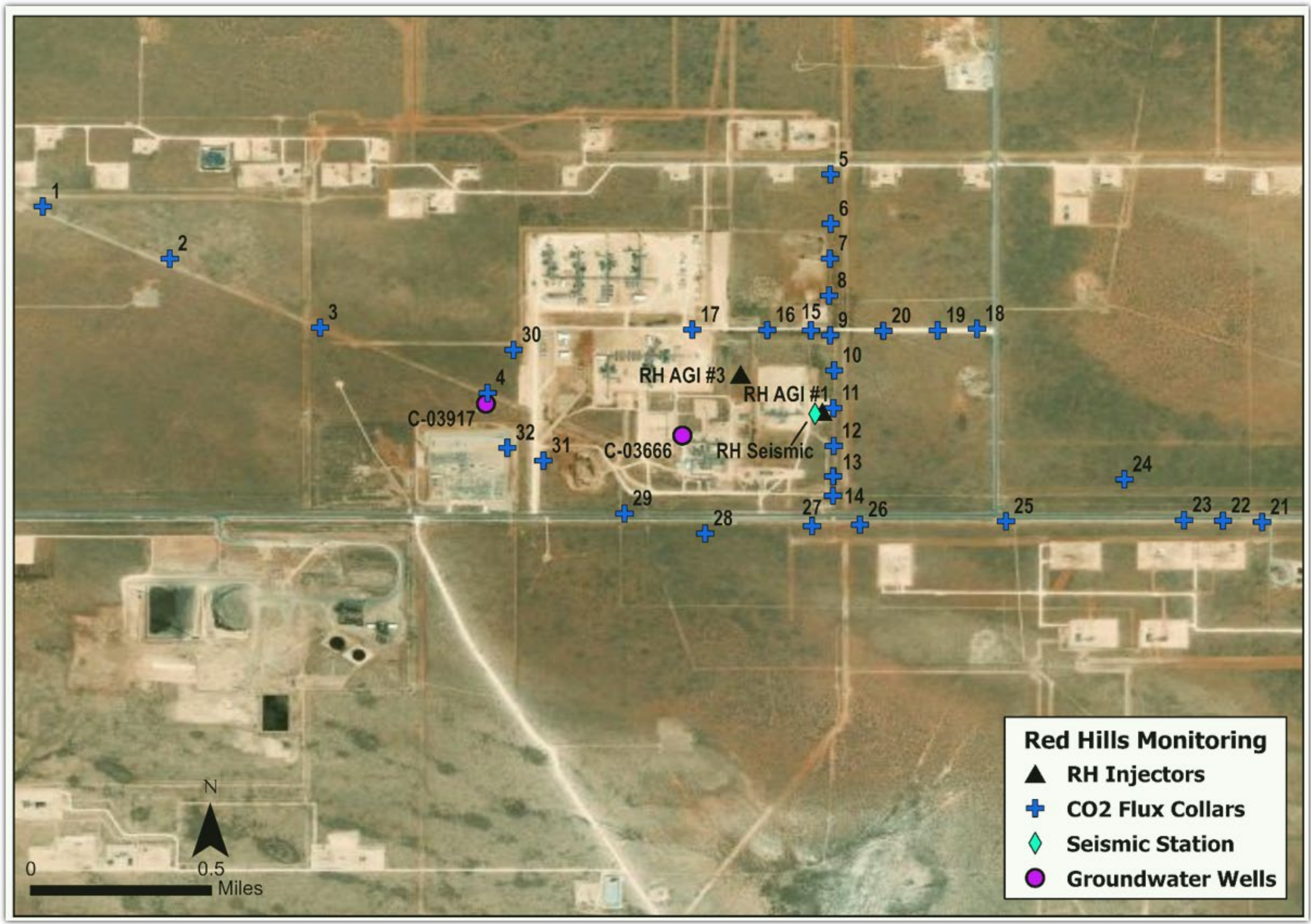


Figure 7-1: *Red Hills monitoring network of 32 CO_2 flux locations, 2 groundwater wells, and a seismic station developed by New Mexico Tech and Targa Resources to detect leakage during injection.*

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve Subpart RR equations used to calculate the mass of CO_2 sequestered annually. **Appendix 8** includes the twelve equations from Subpart RR. Not all of these equations apply to TND's current operations at the Red Hills Gas Plant but are included in the event TND's operations change in such a way that their use is required.

Figure 3.6-2 shows the location of all surface equipment and points of venting listed in 40CFR98.232(d) of Subpart W that will be used in the calculations listed below.

8.1 CO_2 Received

Currently, TND receives gas to its Red Hills Gas Plant through six pipelines: Gut Line, Winkler Discharge, Red Hills 24" Inlet Loop, Greyhound Discharge, Limestone Discharge, and the Plantview Loop. The gas is processed as described in Section 3.8 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection. TND will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3. Receiving flow meter r in the following equations corresponds to meters M1 and M2 in **Figure 3.6-2**.

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

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

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

8.2 CO_2 Injected

TND injects CO_2 into the existing RH AGI #1. Upon completion, TND will commence injection into RH AGI #3. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into both wells. The

calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Volumetric flow meter u in the following equations corresponds to meters M3 and M6 in **Figure 3.6-2**.

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

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

(Equation RR-6)

where:

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

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

u = Flow meter.

8.3 CO_2 Produced / Recycled

TND does not produce oil or gas or any other liquid at its Red Hills Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.6 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6.8.

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

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

8.6 CO_2 Sequestered

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

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

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

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

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

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

9 Estimated Schedule for Implementation of MRV Plan

The baseline monitoring and leakage detection and quantification strategies described herein have been established and data collected by TND and its predecessor, Lucid, for several years and continues to the present. TND will begin implementing this revised MRV plan as soon as it is approved by EPA.

10 GHG Monitoring and Quality Assurance Program

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

10.1 GHG Monitoring

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

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations

- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

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

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

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.3 CO_2 injected.

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

10.1.4 CO_2 produced.

TND does not produce CO_2 at the Red Hills Gas Plant.

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

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

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

10.1.6 Measurement devices.

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

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

10.2 QA/QC Procedures

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

10.3 Estimating Missing Data

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

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

10.4 Revisions of the MRV Plan

TND will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of New Mexico. If any operational changes constitute a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change.

11 Records Retention

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

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

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

(i) The GHG emissions calculations and methods used

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

(iii) The results of all required analyses

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

(3) The annual GHG reports.

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

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

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

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

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

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

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

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

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

12 Appendices

Appendix 1 TND Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Red Hills AGI #1	30-025-40448	1,600 ft FSL, 150 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	10/23/2013	6,650 ft	6,170 ft
Red Hills AGI #2 (temporarily abandoned)	30-025-49474	150 ft FEL, 1,800 ft FSL Sec. 13, T24S, R33E, NMPM	Lea, NM		6,205 ft	
Red Hill AGI #3	30-025-51970	3,116 ft FNL, 1,159 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	9/13/2023	7,600 ft	5,700 ft

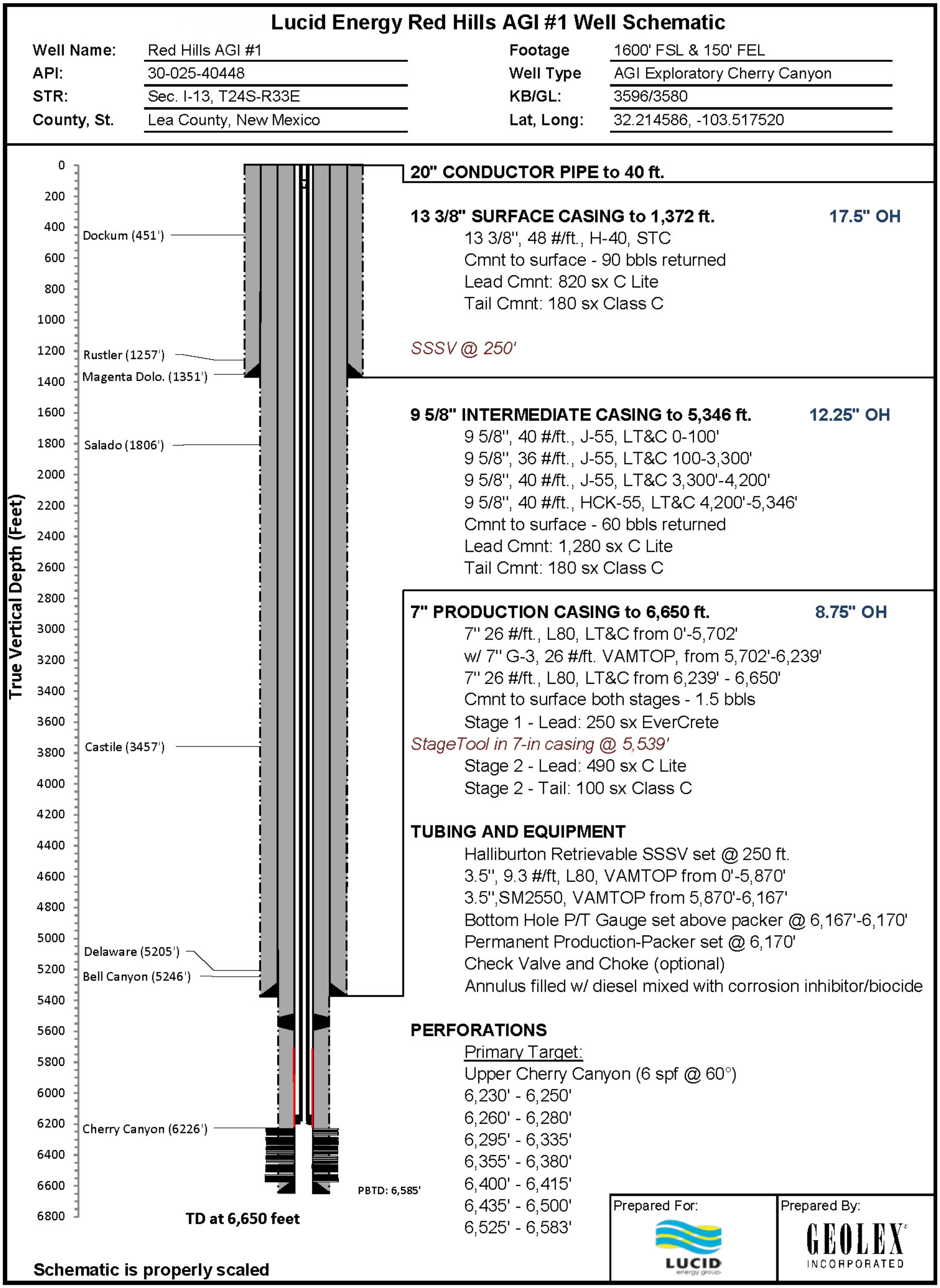


***Figure Appendix 1-1:** Schematic of TND RH AGI #1 Well*

Targa Resources
Red Hills Delaware AGI #3
Location 3116' FNL & 1159' FEL
Sec 13 - T 24S - R 33E
GL 3578', RKB TBD

Surface - (Conventional)
Hole Size: 17.5"
Casing: 13.375" 72# L-80 VAM TOP
Depth Top: Surface
Depth Btm: 1307'
Cement: TBD sks - Class C + Additives
Cement Top: Surface - (Circulate)

Intermediate #1 - (Conventional)
Hole Size: 12.25"
Casing: 9.625" 47# HCL-80 BTC
Depth Top: Surface
Depth Btm: 5205'
Cement: TBD - Class C + Additives
Cement Top: Surface - (Circulate)

Production - (Conventional)
Hole Size: 8.5"
Casing 1: 7" 32# I-80 VAMSTL
Depths: 0' to 5280' & 5580' to 7600'
Casing 2: 7" 32# G3 CRA VAM HDL
Depths: 5280' to 5580'
Cement: TBD - Class C + Additives, Well Lock resin 5280'-5580'
Cement Top: Surface - (Circulate)
ECP/DV Tool: 5280' & 5580'

Tubing
Depth: 5700'
Tubing: 3.5" 7.7# G3 CRA VAM ACE
Packer: 7" x 3.5" PermaPak or equivalent (Inconel)
SSSV: 175'
PT Gauges: 5690'

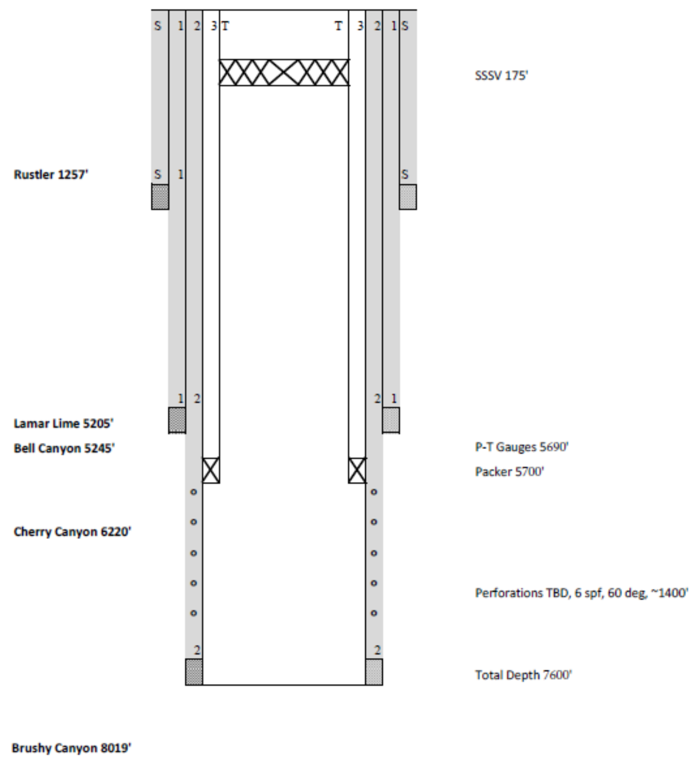


__Figure Appendix 1-2__: As-built wellbore schematic for the TND RH AGI #3 Well

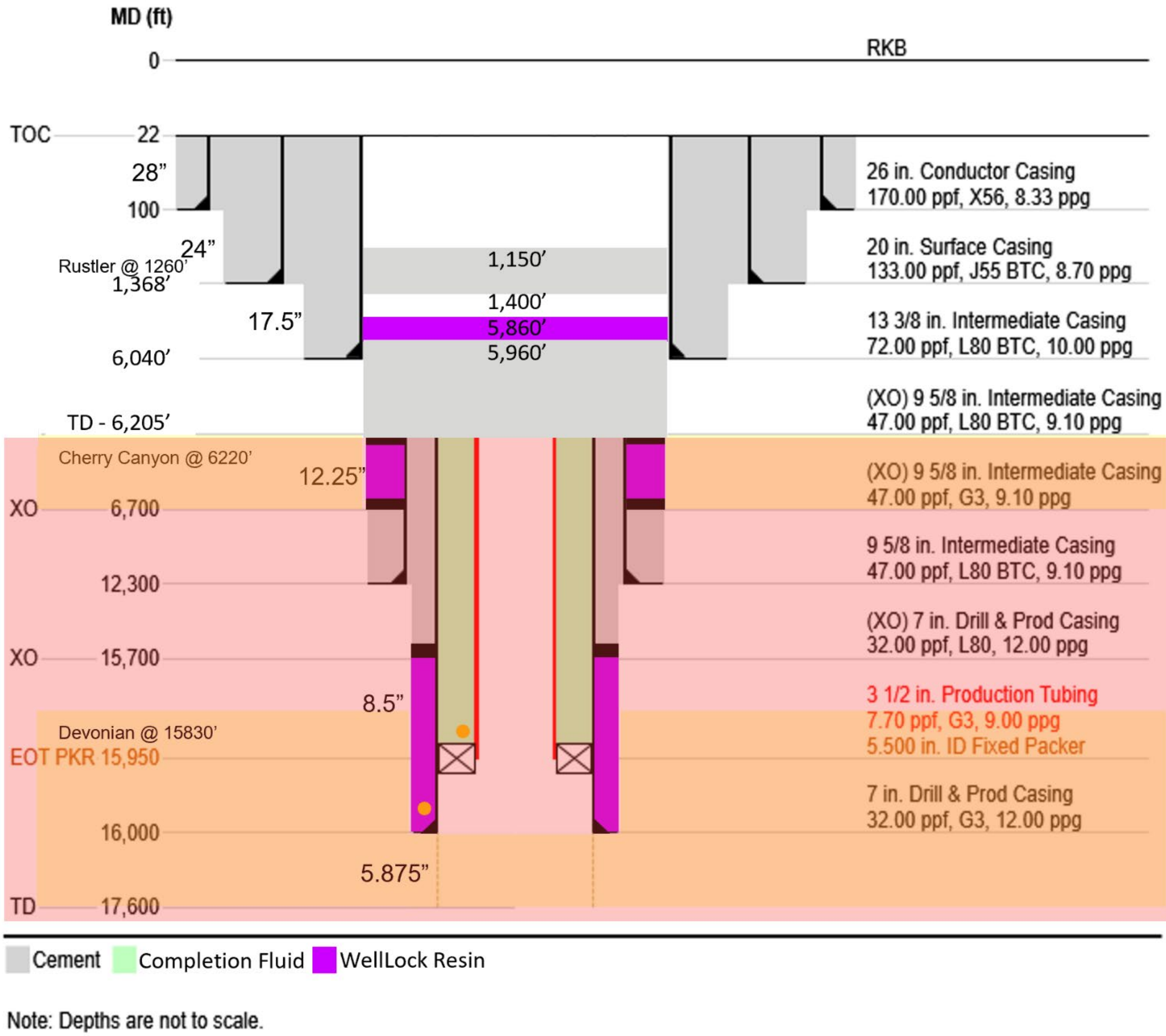


***Figure Appendix 1-3**: As-built wellbore schematic for the TND RH AGI #2 Well (temporarily abandoned). The colored portion of the schematic below 6,205 ft was not completed.*

Appendix 2 Referenced Regulations

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

New Mexico Administrative Code (NMAC) > Title 19 – Natural resources > Chapter 15 – Oil and Gas

CHAPTER 15 - OIL AND GAS

19.15.1 NMAC	GENERAL PROVISIONS AND DEFINITIONS [REPEALED]
19.15.2 NMAC	GENERAL PROVISIONS FOR OIL AND GAS OPERATIONS
19.15.3 NMAC	RULEMAKING
19.15.4 NMAC	ADJUDICATION
19.15.5 NMAC	ENFORCEMENT AND COMPLIANCE
19.15.6 NMAC	TAX INCENTIVES
19.15.7 NMAC	FORMS AND REPORTS
19.15.8 NMAC	FINANCIAL ASSURANCE
19.15.9 NMAC	WELL OPERATOR PROVISIONS
19.15.10 NMAC	SAFETY
19.15.11 NMAC	HYDROGEN SULFIDE GAS
19.15.12 NMAC	POOLS
19.15.13 NMAC	COMPULSORY POOLING
19.15.14 NMAC	DRILLING PERMITS
19.15.15 NMAC	WELL SPACING AND LOCATION
19.15.16 NMAC	DRILLING AND PRODUCTION
19.15.17 NMAC	PITS, CLOSED-LOOP SYSTEMS, BELOW-GRADE TANKS AND SUMPS
19.15.18 NMAC	PRODUCTION OPERATING PRACTICES
19.15.19 NMAC	NATURAL GAS PRODUCTION OPERATING PRACTICE
19.15.20 NMAC	OIL PRORATION AND ALLOCATION
19.15.21 NMAC	GAS PRORATION AND ALLOCATION
19.15.22 NMAC	HARDSHIP GAS WELLS
19.15.23 NMAC	OFF LEASE TRANSPORT OF CRUDE OIL OR CONTAMINANTS
19.15.24 NMAC	ILLEGAL SALE AND RATABLE TAKE
19.15.25 NMAC	PLUGGING AND ABANDONMENT OF WELLS
19.15.26 NMAC	INJECTION
19.15.27 - 28 NMAC	[RESERVED] PARTS 27 - 28
19.15.29 NMAC	RELEASES

19.15.30 NMAC	REMEDIATION
19.15.31 - 33 NMAC	[RESERVED] PARTS 31 - 33
19.15.34 NMAC	PRODUCED WATER, DRILLING FLUIDS AND LIQUID OIL FIELD WASTE
19.15.35 NMAC	WASTE DISPOSAL
19.15.36 NMAC	SURFACE WASTE MANAGEMENT FACILITIES
19.15.37 NMAC	REFINING
19.15.38 NMAC	[RESERVED]
19.15.39 NMAC	SPECIAL RULES
19.15.40 NMAC	NEW MEXICO LIQUIFIED PETROLEUM GAS STANDARD
19.15.41 - 102 NMAC	[RESERVED] PARTS 41 - 102
19.15.103 NMAC	SPECIFICATIONS, TOLERANCES, AND OTHER TECHNICAL REQUIREMENTS FOR COMMERCIAL WEIGHING AND MEASURING DEVICES
19.15.104 NMAC	STANDARD SPECIFICATIONS/MODIFICATIONS FOR PETROLEUM PRODUCTS
19.15.105 NMAC	LABELING REQUIREMENTS FOR PETROLEUM PRODUCTS
19.15.106 NMAC	OCTANE POSTING REQUIREMENTS
19.15.107 NMAC	APPLYING ADMINISTRATIVE PENALTIES
19.15.108 NMAC	BONDING AND REGISTRATION OF SERVICE TECHNICIANS AND SERVICE ESTABLISHMENTS FOR COMMERCIAL WEIGHING OR MEASURING DEVICES
19.15.109 NMAC	NOT SEALED NOT LEGAL FOR TRADE
19.15.110 NMAC	BIODIESEL FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.111 NMAC	E85 FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.112 NMAC	RETAIL NATURAL GAS (CNG / LNG) REGULATIONS [REPEALED]

Appendix 3 Water Wells

Water wells identified by the New Mexico State Engineer's files within two miles of the RH AGI wells; water wells within one mile are highlighted in yellow.

POD Number	County	Sec	Tws	Rng	UTME	UTMN	Distance (mi)	Depth Well (ft)	Depth Water (ft)	Water Column (ft)
C 03666 POD1	LE	13	24S	33E	639132	3565078	0.31	650	390	260
C 03917 POD1	LE	13	24S	33E	638374	3565212	0.79	600	420	180
C 03601 POD1	LE	23	24S	33E	638124	3563937	1.17			
C 02309	LE	25	24S	33E	639638	3562994	1.29	60	30	30
C 03601 POD3	LE	24	24S	33E	638142	3563413	1.38			
C 03932 POD8	LE	7	24S	34E	641120	3566769	1.40	72		
C 03601 POD2	LE	23	24S	33E	637846	3563588	1.44			
C 03662 POD1	LE	23	24S	33E	637342	3564428	1.48	550	110	440
C 03601 POD5	LE	23	24S	33E	637988	3563334	1.48			
C 03601 POD6	LE	23	24S	33E	637834	3563338	1.55			
C 03601 POD7	LE	23	24S	33E	637946	3563170	1.58			
C 03600 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03602 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03600 POD1	LE	26	24S	33E	637275	3563023	1.94			
C 03600 POD3	LE	26	24S	33E	637784	3562340	2.05			

Appendix 4 Oil and Gas Wells within 2-mile Radius of the RH AGI Well Site

Note – a completion status of ”New” indicates that an Application for Permit to Drill has been filed and approved but the well has not yet been completed. Likewise, a spud date of 31-Dec-99 is actually 12-31-9999, a date used by NMOCD databases to indicate work not yet reported.

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-08371	COSSATOT E 002	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	5425	Yes
30-025-25604	GOVERNMENT L COM 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	17625	No
30-025-26369	GOVERNMENT L COM 002	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	14698	Yes
30-025-26958	SIMS 001	BOPCO, L.P.	GAS	DELAWARE VERTICAL	P & A	VERTICAL	15007	Yes
30-025-27491	SMITH FEDERAL 001	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	15120	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-40448	RED HILLS AGI 001	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	INJECTING	VERTICAL	6650	Yes
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL		PRODUCING	VERTICAL	10997	No
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11034	No
30-025-41382	DECKARD FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11067	Yes
30-025-41383	DECKARD FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11162	Yes
30-025-41384	DECKARD FEDERAL COM 004H	COG OPERATING LLC	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11103	Yes
30-025-41666	SEBASTIAN FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10927	Yes
30-025-41687	SEBASTIAN FEDERAL COM 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10944	Yes
30-025-41688	SEBASTIAN FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11055	No
30-025-43532	LEO THORSNESS 13 24 33 211H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12371	No
30-025-44442	STRONG 14 24 33 AR 214H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12500	No
30-025-46154	LEO THORSNESS 13 24 33 221H	MATADOR PRODUCTION COMPANY	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12868	No
30-025-46282	LEO THORSNESS 13 24 33 AR 135H	MATADOR PRODUCTION COMPANY	OIL	3RD BONE SPRING SAND	PRODUCING	HORIZONTAL	12103	No

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-46517	BROADSIDE 13 W FEDERAL COM 001H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12213	No
30-025-46518	BROADSIDE 13 24 FEDERAL COM 002H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-46519	BROADSIDE 13 24 FEDERAL COM 003H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12320	Yes
30-025-46985	SEBASTIAN FEDERAL COM 703H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12123	No
30-025-46988	SEBASTIAN FEDERAL COM 704H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12142	No
30-025-47869	JUPITER 19 FEDERAL COM 501H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11175	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47874	JUPITER 19 FEDERAL COM 506H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10950	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47877	JUPITER 19 FEDERAL COM 509H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11156	No
30-025-47878	JUPITER 19 FEDERAL COM 510H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11102	No
30-025-47908	JUPITER 19 FEDERAL COM 601H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-47910	JUPITER 19 FEDERAL COM 702H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	DUC	HORIZONTAL	0	Yes
30-025-47911	JUPITER 19 FEDERAL COM 705H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12290	No
30-025-47912	JUPITER 19 FEDERAL COM 707H	EOG RESOURCES INC	OIL	WOLFCAMP B UPPER	PERMITTED	HORIZONTAL	12515	No
30-025-47913	JUPITER 19 FEDERAL COM 708H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12477	No
30-025-48239	JUPITER 19 FEDERAL COM 306H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10270	No
30-025-48889	JUPITER 19 FEDERAL COM 701H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-48890	JUPITER 19 FEDERAL COM 703H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-49262	BROADSIDE 13 24 FEDERAL COM 004H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12531	Yes
30-025-49263	BROADSIDE 13 24 FEDERAL COM 015H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B LOWER	PRODUCING	HORIZONTAL	12746	Yes
30-025-49264	BROADSIDE 13 24 FEDERAL COM 025H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11210	Yes
30-025-49474	RED HILLS AGI 002	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	Temporarily Abandoned	VERTICAL	17600	Yes

Appendix 5 References

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Appendix 6 Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
AoR – Area of Review
API – American Petroleum Institute
CFR – Code of Federal Regulations
C1 – methane
C6 – hexane
C7 - heptane
CO_2 – carbon dioxide
DCS – distributed control system
EPA – US Environmental Protection Agency, also USEPA
ft – foot (feet)
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MSCFD– thousand standard cubic feet per day
MMSCFD – million standard cubic feet per day
MMstb – million stock tank barrels
MRRW B – Morrow B
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NIST - National Institute of Standards and Technology
NMOCC – New Mexico Oil Conservation Commission
NMOCD - New Mexico Oil Conservation Division
PPM – Parts Per Million
psia – pounds per square inch absolute
QA/QC – quality assurance/quality control
SCITS - Stanford Center for Induced and Triggered Seismicity
Stb/d – stock tank barrel per day
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TVD – True Vertical Depth
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

Appendix 7 TND Red Hills AGI Wells - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

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

* All measurements must be made in accordance with 40 CFR 98.444 – Monitoring and QA/QC Requirements.

** If you measure the mass of contents of containers summed quarterly using weigh bill, scales, or load cells (40 CFR 98.444(a)(2)(i)), use RR-1 for Containers to calculate CO_2 received in containers for injection.

*** If you determine the volume of contents of containers summed quarterly (40 CFR 98.444(a)(2)(ii)), use RR-2 for Containers to calculate CO_2 received in containers for injection.

Appendix 8 Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

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

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

(Equation RR-1 for Pipelines)

where:

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

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

(Equation RR-1 for Containers)

where:

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

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

(Equation RR-2 for Containers)

where:

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

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

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

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

(Equation RR-4)

where:

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

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

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

p = Quarter of the year.

u = Flow meter.

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

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

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

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

(Equation RR-6)

where:

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

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

u = Flow meter.

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

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

(Equation RR-7)

where:

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-8)

where:

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

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

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

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

p = Quarter of the year.

w = Separator.

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

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

where:

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

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

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

w = Separator.

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

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

where:

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

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

x = Leakage pathway.

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

Appendix 9 P&A Records

P&A Record for Government Com 001, API #30-025-25604

New Mexico Oil Conservation Division, District I
1625 N. French Drive
Hobbs, NM 88240

Form 3160-5
(April 2004)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OM B No. 1004-0137
Expires: March 31, 2007

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

5. Lease Serial No. NM-17446

6. If Indian, Allottee or Tribe Name

***SUBMIT IN TRIPLICATE**- Other instructions on reverse side.*

7. If Unit or CA/Agreement, Name and/or No.

1. Type of Well ☐ Oil Well ☑ Gas Well ☐ Other

8. Well Name and No. Government "L" Com #1

2. Name of Operator EOG Resources, Inc

9. API Well No. 30-025-~~05070~~ 25604

3a. Address P.O. Box 2267, Midland, TX, 79702

3b. Phone No. *(include area code)* 432-561-8600

10. Field and Pool, or Exploratory Area Bell Lake, South Morrow

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*

Unit Letter G, 1980 FNL, 1980 FEL
Section 18, Township 24-S, Range 34-E

11. County or Parish, State Lea, New Mexico

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
☑ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☐ Other
	☐ Change Plans	☑ Plug and Abandon	☐ Temporarily Abandon	
	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

1. **Notified Jim McCormick w/BLM 24 hrs prior to MI and RU.**
2. **Cut 3 1/2' tbg at 11500, spot 50sx CLass "H" cmt, plug from 11500-11400, WOC Tag at 11389.**
3. **Circ hole w/MLF.**
4. **Perf 4 holes at 9050, press up to 2000 PSI, spot 75sx, plug from 9100-8950, WOC Tag @ 8938.**
5. **Perf 4 holes at 7000, press up to 2000 PSI, spot 75sx, plug from 7050-6900, WOC Tag at 6855.**
6. **Cut 10 3/4" csg at 5450, L/D csg, spot 150sx, plug from 5500-5350, WOC Tag at 5336.**
7. **Spot 75sx, plug from 1300-1200 (T-Salt) WOC Tag at 1143.**
8. **Spot 150sx, plug from 650-450 (20" Shoe) WOC Tag at 423.**
9. **Spot 20sx, plug from 30-Surf.**
10. **Clean location. Install dry hole marker 12-30-04.**

P&A Complete 12-30-04

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

14. I hereby certify that the foregoing is true and correct
Name *(Printed/Typed)* Jimmy Bagley — Title Consultant

Signature — Date 12/30/2004

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by ______ Title ______ Date ______

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon. — Office

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on page 2)

GWW

P&A Records for API #30-025-26958

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources
OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

RECEIVED
AUG 16 2012
HOBBSOCD

Form C-103
Revised August 1, 2011

SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.) 1. Type of Well: Oil Well ☐ Gas Well ☒ Other	WELL API NO. 3002526958 5. Indicate Type of Lease STATE ☐ FEE ☒ 6. State Oil & Gas Lease No. SCR-389 7. Lease Name or Unit Agreement Name Sims 8. Well Number #1
2. Name of Operator: Agave Energy Company	9. OGRID Number 147831
3. Address of Operator 104 S. Fourth St., Artesia NM 88210 (575-748-4528)	10. Pool name or Wildcat Big Sinks Wolfcamp

4. Well Location
Unit Letter K: 1980 feet from the N line and 800 feet from the E line
Section 13 Township 24S Range 33E NMPM Lea County

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
OTHER: ☐		OTHER ☒ Replug to cement off Cherry Canyon per NMOCC R-13507	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion

The remediation of the Sims #1 well pursuant to NMOCC order was completed on August 15, 2011 and all equipment has been demobilized. The plugging was done pursuant to NMOCD requirements and all aspects of the effort were reported to Mark Whitaker and E.L. Gonzales of the OCD District 1 office who approved the specifics of the plugging as shown in the attached plugging diagram. When establishing a rate prior to squeezing the Cherry Canyon, it is clear that the reservoir is an excellent reservoir as it was taking 3bbl/min on vacuum. This indicates that the predicted injection plume for the Red Hills AGI #1 in this reservoir will be smaller than anticipated and the reservoir conditions act to prevent migration of injected acid gas out of the intended and permitted injection zone by any nearby wellbores including the Govt#2, Govt#1 and Smith Federal #1 in addition to the Sims#1. Please see attached wellbore sketch for plugging details of all plugs set and amounts of cement squeezed for each plug.

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE_____________ TITLE_ Consultant to Agave Energy Company _DATE August 16, 2012____

Type or print name ___Alberto A. Gutierrez, RG E-mail address: ___aag@geolex.com______ PHONE: __505-842-8000____

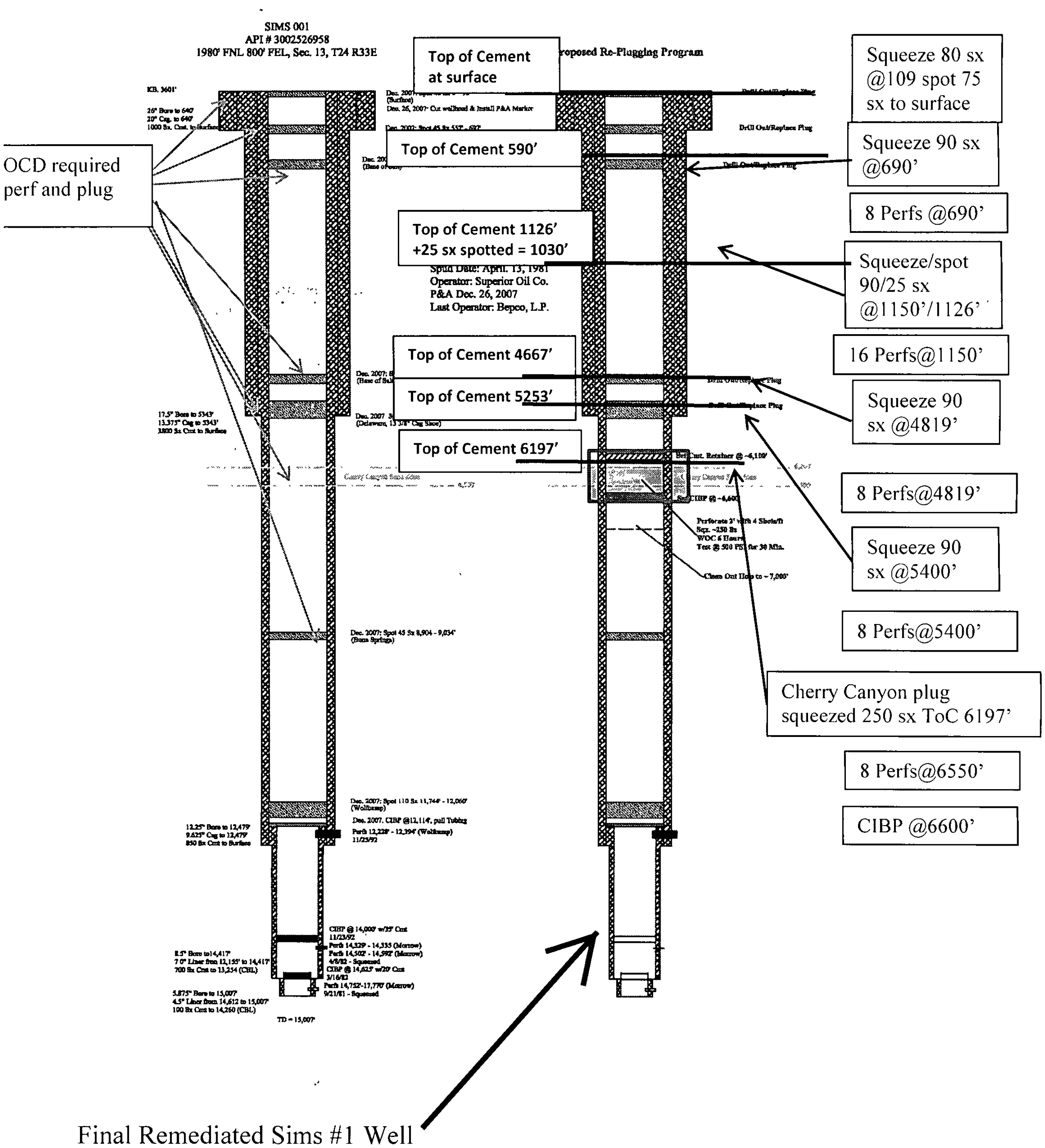
For State Use Only

APPROVED BY: __________ TITLE Dist Mgr DATE 8-16-2012
Conditions of Approval (if any):

AUG 16 2012

GEOLEX
INCORPORATED

8/16/2012



P&A Records for API 30-025-08371

NEW MEXICO OIL CONSERVATION COMMISSION

FORM C-103 (Rev 3-55)

MISCELLANEOUS REPORTS ON WELLS

(Submit to appropriate District Office as per Commission Rule 1106)

Name of Company: Byard Bennett			Address: 207 West Third, Roswell, New Mexico		
Lease: Holland	Well No. 1	Unit Letter H	Section 13	Township 24 South	Range 33 East
Date Work Performed: March 8, 1961	Pool: Wildcat			County: Lea	

THIS IS A REPORT OF: *(Check appropriate block)*

- [ ] Beginning Drilling Operations
- [ ] Casing Test and Cement Job
- [ ] Other *(Explain)*:
- [X] Plugging
- [ ] Remedial Work

Detailed account of work done, nature and quantity of materials used, and results obtained.

Top of Rustler: 1245', Top of Salt: 1392', Base of Salt: 4930', Top of Dela Ls: 5190'
Top of Delaware Sand: 5210', Total Depth: 5425', Casing 8 5/8 set at 365', Hole size 6 3/4

Cement Plugs set as follows:
5375-5425 with 15 sacks, 5175-5240 with 20 sacks, 1375-1425 with 20 sacks,
340-390 with 20 sacks, 5 sacks and marker pipe set at surface.
Heavy mud (4 cc wtr. loss) between all cement plugs.
Job performed and witnessed by Mr. Pool, Pool Drlg Co.
Prior verbal approval of plugging program from Mr. Engbrecht, New Mexico O C C.

Location will be cleaned and leveled as soon as practical.

Witnessed by	Position	Company
Mr. Fred Pool	Owner	Pool Drlg Co.

FILL IN BELOW FOR REMEDIAL WORK REPORTS *ONLY*

ORIGINAL WELL DATA

D F Elev.	T D	P B T D	Producing Interval	Completion Date

Tubing Diameter	Tubing Depth	Oil String Diameter	Oil String Depth

Perforated Interval(s)

Open Hole Interval | Producing Formation(s)

RESULTS OF WORKOVER

Test	Date of Test	Oil Production BPD	Gas Production MCFPD	Water Production BPD	GOR Cubic feet/Bbl	Gas Well Potential MCFPD
Before Workover						
After Workover						

OIL CONSERVATION COMMISSION

Approved by: Leslie A. Clements

Title

Date

I hereby certify that the information given above is true and complete to the best of my knowledge.

Name: Guy A. Swartz

Position: Agent

Company: Byard Bennett

Temporary Abandonment Record for RH AGI #2

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

	WELL API NO. 30-025-49474
	5. Indicate Type of Lease STATE ☐ FEE ☒
	6. State Oil & Gas Lease No.
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name RED HILLS AGI
1. Type of Well: Oil Well ☐ Gas Well ☒ Other Acid Gas Injection	8. Well Number 002
2. Name of Operator TARGA NORTHERN DELAWARE, LLC	9. OGRID Number 331548
3. Address of Operator 110 W 7TH STREET, SUITE 2300, TULSA OK 74119	10. Pool name or Wildcat

4. Well Location
Unit Letter_I_:_1800____feet from the SOUTH________ line and 150______feet from the EAST___________line
Section 13 Township 24S Range 33E NMPM LEA County

11. Elevation (Show whether DR, RKB, RT, GR, etc.)
3575 GR

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
CLOSED-LOOP SYSTEM ☐			
OTHER: TEMPORARY ABANDON ☒		OTHER: ☐	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

3/08/2023 Drilled out of 13 3/8" with 12 ¼" bit. Drilled to 6161'and lost circulation. Attempt to regain with 3 heavy LCM pills.
3/08-3/10 Regained partial circulation and drilled to 6205'.
3/11 Rig up Halliburton and squeeze zone with 370 sacks of HalCem cement .
3/12 Drilled out cement squeeze and ran FIT test but would only hold 11.5 lb/gal.
3/15 Rig up Halliburton and set 150 sack balanced plug with Hal NEO CEM cement
Tagged plug at 5960' and shut down to wait on orders.
Decision has been made to not attempt to drill into the Cherry Canyon Injection zone due to not being able to maintain mud weight.
Propose to TEMPORARY ABANDON THE WELL BY:
RUN A CEMENT BOND LOG INSIDE THE 13 3/8"
SET A 100' CORROSION RESISTANT PLUG ON TOP OF EXISTING PLUG, SET A CEMENT PLUG INSIDE THE 13 3/8" ACROSS THE CASING SHOE (1350') AND 50' ABOVE THE RUSTLER (1260'). The plug would be from 1200' to 1400'.
PRESSURE TEST THE CASING TO 500 PSI FOR 30 MINUTES
REMOVE THE BOP AND INSTALL A BLIND FLANGE AND NIGHTCAP ON THE WELLHEAD.
RIG DOWN AND MOVE THE RIG OFF.

Spud Date: 02/13/2023 Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE___*Paul Ragsdale*__________ TITLE_______ENGINEER_____________________DATE______03/17/2023______

Type or print name _PAUL RAGSDALE___________ E-mail address: _pragsdale3727@gmail.com____ PHONE: ___575-626-7903_

For State Use Only

APPROVED BY:_______________________________TITLE______________________________DATE__________________
Conditions of Approval (if any):

District I
1625 N. French Dr., Hobbs, NM 88240
Phone:(575) 393-6161 Fax:(575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone:(575) 748-1283 Fax:(575) 748-9720
District III
1000 Rio Brazos Rd., Aztec, NM 87410
Phone:(505) 334-6178 Fax:(505) 334-6170
District IV
1220 S. St Francis Dr., Santa Fe, NM 87505
Phone:(505) 476-3470 Fax:(505) 476-3462

State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

CONDITIONS

Action 198393

CONDITIONS

Operator:	
Targa Northern Delaware, LLC. 110 W. 7th Street, Suite 2300 Tulsa, OK 74119	OGRID: 331548
	Action Number: 198393
	Action Type: [C-103] Sub. General Sundry (C-103Z)

CONDITIONS

Created By	Condition	Condition Date
pkautz	MUST CAP EXISTING PLUG WITH 100' CORROSION RESISTANT CEMENT	3/17/2023
pkautz	AFTER TA MUST PERFORM TA PRESSURE TEST	3/17/2023
pkautz	AFTER TA SUBMIT A WELLBORE SCHEMATIC	3/17/2023

Request for Additional Information: Red Hills Gas Processing Plant
July 11, 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.	N/A	N/A	The description of the status of RH AGI #3 is inconsistent in the MRV plan. In some places, the RH AGI #3 is described as already drilled. However, in other places, the RH AGI #3 well is described as not being drilled. For example, page 41 of the MRV states: - "RH AGI #3 very recently began injecting in January 2024." - "TND is began drilling the RH AGI #3 well in September 2023 and began injection in January 2024." - "TND realizes that when they drill the RH AGI #3, they will be drilling into a reservoir…" Please ensure that the wording describing the status of RH AGI #3 is consistent throughout the MRV plan.	The status of RH AGI #3 has been updated in the revised MRV plan. The well was spudded on 9/13/2023, completed on 9/27/2023, and injection commenced on 1/11/2024.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
2.	5.3	42	Page 5 of the MRV plan states, "Lucid received authorization to construct a redundant well, RH AGI #2 (API# 30-025-49474) under NMOCC Order R-20916-H, which is offset 200 ft to the north of RH AGI #1 and is currently temporarily abandoned in the Bell Canyon Formation." However, Section 5.3.1 ("Wells Completed in the Bell Canyon and Cherry Canyon Formations") of the MRV plan does not include a characterization of potential leakage through the RH AGI #2 well. Please update the MRV plan to include this discussion as necessary.	The revised MRV plan has been edited to include a discussion of the potential for leakage through RH AGI #2.

MONITORING, REPORTING, AND VERIFICATION PLAN

Red Hills AGI #1 and AGI #3

Targa Northern Delaware, LLC (TND)

Version 1.0
May 1, 2024

Table of Contents

1 Introduction

Targa Northern Delaware, LLC (TND) is currently authorized to inject treated acid gas (TAG) into the Red Hills Acid Gas Injection #1 well (RH AGI #1)(American Petroleum Institute (API) 30-025-40448) and RH AGI #3 well (API # 30-025-51970) under the New Mexico Oil Conservation Commission (NMOCC) Orders R-13507 – 13507F and Order R-20916H, respectively, at the Red Hills Gas Plant located approximately 20 miles NNW of Jal in Lea County, New Mexico (**Figure 1-1**). Each well is approved to inject 13 million standard cubic feet per day (MMSCFD). However, although approved to inject 13 MMSCFD, RH AGI #1 is physically only capable of taking ~5 MMSCFD due to formation and surface pressure limitations.

The AGI wells were previously operated by Lucid Energy Delaware, LLC's ("Lucid"). TND acquired Lucid assets in 2022. Lucid received authorization to construct a redundant well, RH AGI #2 (API# 30-025-49474) under NMOCC Order R-20916-H, which is offset 200 ft to the north of RH AGI #1 and is currently temporarily abandoned in the Bell Canyon Formation.

TND recently received approval from NMOCC for its C-108 application to drill, complete and operate a third acid gas injection well (RH AGI #3) in which TND requested an injection volume of up to 13 MMSCFD.RH AGI #3 was recently completed and placed into service in January 2024. Because AGI #1 does not have complete redundancy, having a greater permitted disposal volume will also increase operational reliability. The RH AGI #3 well is a vertical well with its surface location at approximately 3,116 ft from the north line (FNL) and 1,159 ft from the east line (FEL) of Section 13. The depth of the injection zone for this well is approximately 5,600 to 7,200 ft in the Bell Canyon and Cherry Canyon Formations. Analysis of the reservoir characteristics of these units confirms that they act as excellent closed-system reservoirs that will accommodate the future needs of TND for disposal of treated acid gas (H_2S and CO_2) from the Red Hills Gas Plant.

TND has chosen to submit this Monitoring, Reporting, and Verification (MRV) plan to EPA for approval according to 40CFR98.440(c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. TND intends to inject CO_2 for another 30 years.

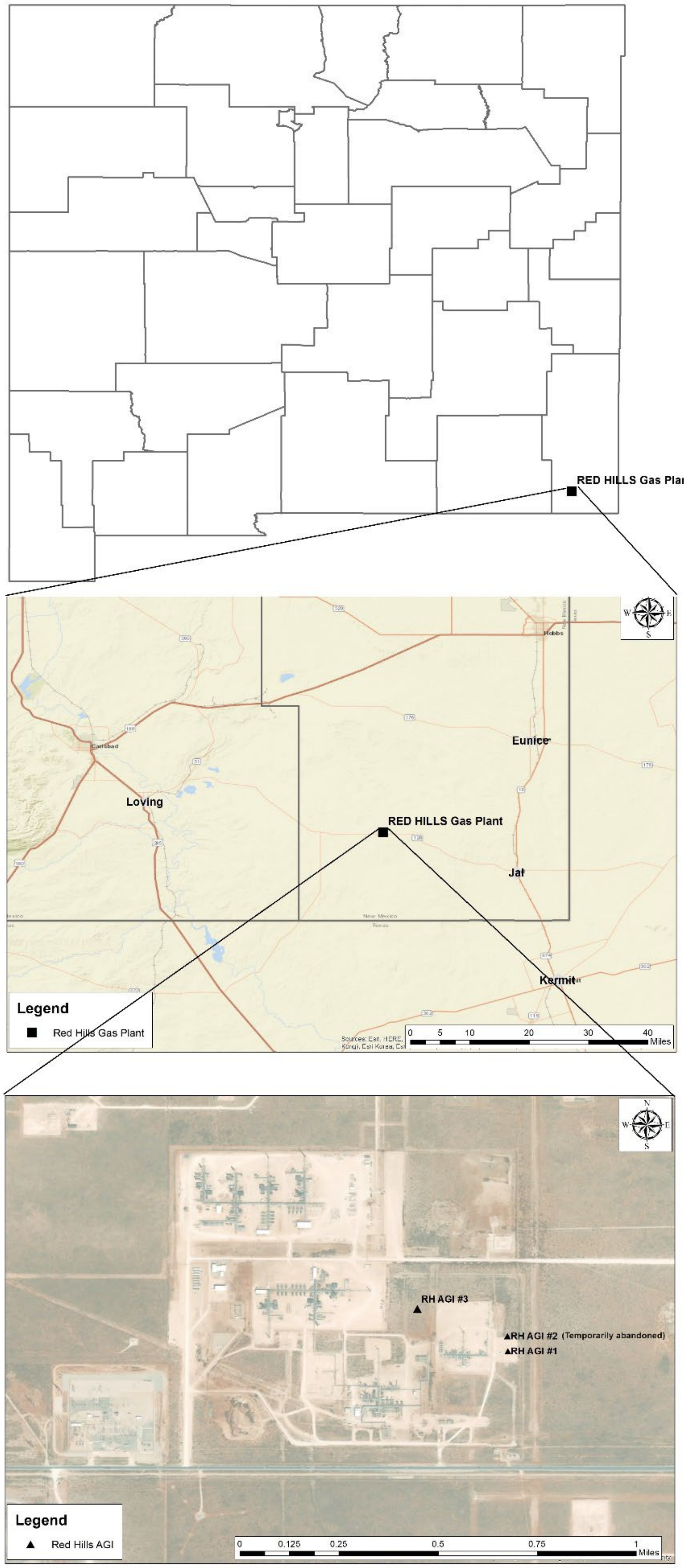


***Figure 1-1**: Location of the Red Hills Gas Plant and Wells – RH AGI #1, RH AGI #2 (temporarily abandoned), and RH AGI #3*

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40CFR98.449, and as required by 40CFR98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40CFR98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage as required by 40CFR98.448(a)(3).

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40CFR98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40CFR98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40CFR98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40CFR98.445.

Section 11 describes the records to be retained according to the requirements of 40CFR98.3(g) of Subpart A of the GHGRP and 40CFR98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan, including information required by 40CFR98.448(a)(6).

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is **553798**

2.2 UIC injection well identification numbers

This MRV plan is for RH AGI #1 and RH AGI #3 (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

For injection wells that are the subject of this MRV plan, the New Mexico Oil Conservation Division (NMOCD) has issued Underground Injection Control (UIC) Class II acid gas injection (AGI) permits under its State Rule 19.15.26 NMAC (see **Appendix 2**). All oil- and gas-related wells around the RH AGI wells, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3 Project Description

The following project description was developed by the Petroleum Recovery Research Center (PRRC) at New Mexico Institute of Mining and Technology (NMT) and the Department of Geosciences at the University of Texas Permian Basin (UTPB).

3.1 General Geologic Setting / Surficial Geology

The TND Red Hills Gas Plant is located in T 24 S R 33 E, Section 13, in Lea County, New Mexico, immediately adjacent to the RH AGI wells. (**Figure 3.1-1**). The plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. The dune sands are locally stabilized with shin oak, mesquite, and some burr-grass. There are no natural surface bodies of water or groundwater discharge sites within one mile of the plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

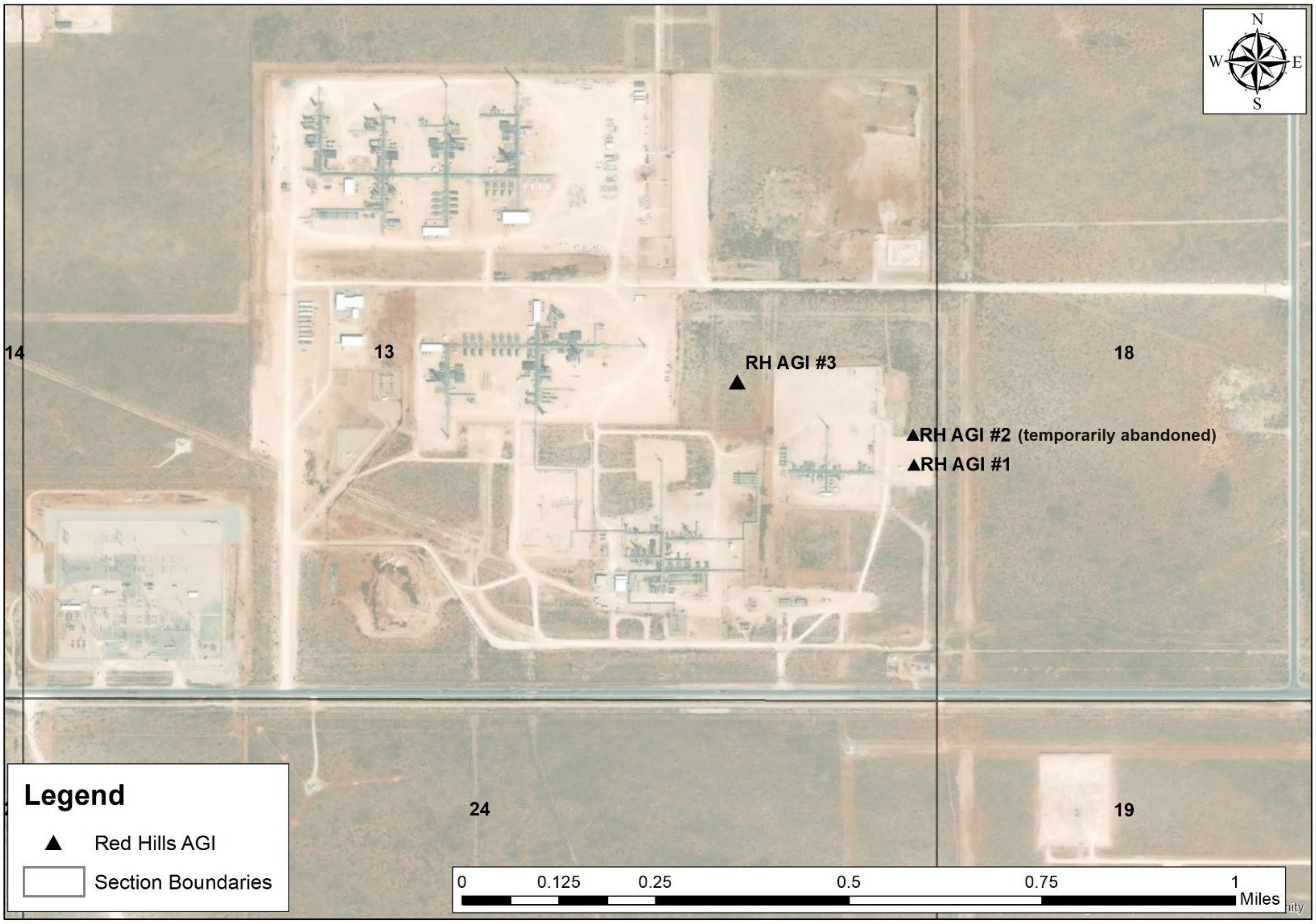


Figure 3.1-1: Map showing location of TND Red Hills Gas Plant and RH AGI Wells in Section 13, T 24 S, R 33 E

3.2 Bedrock Geology

3.2.1 Basin Development

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

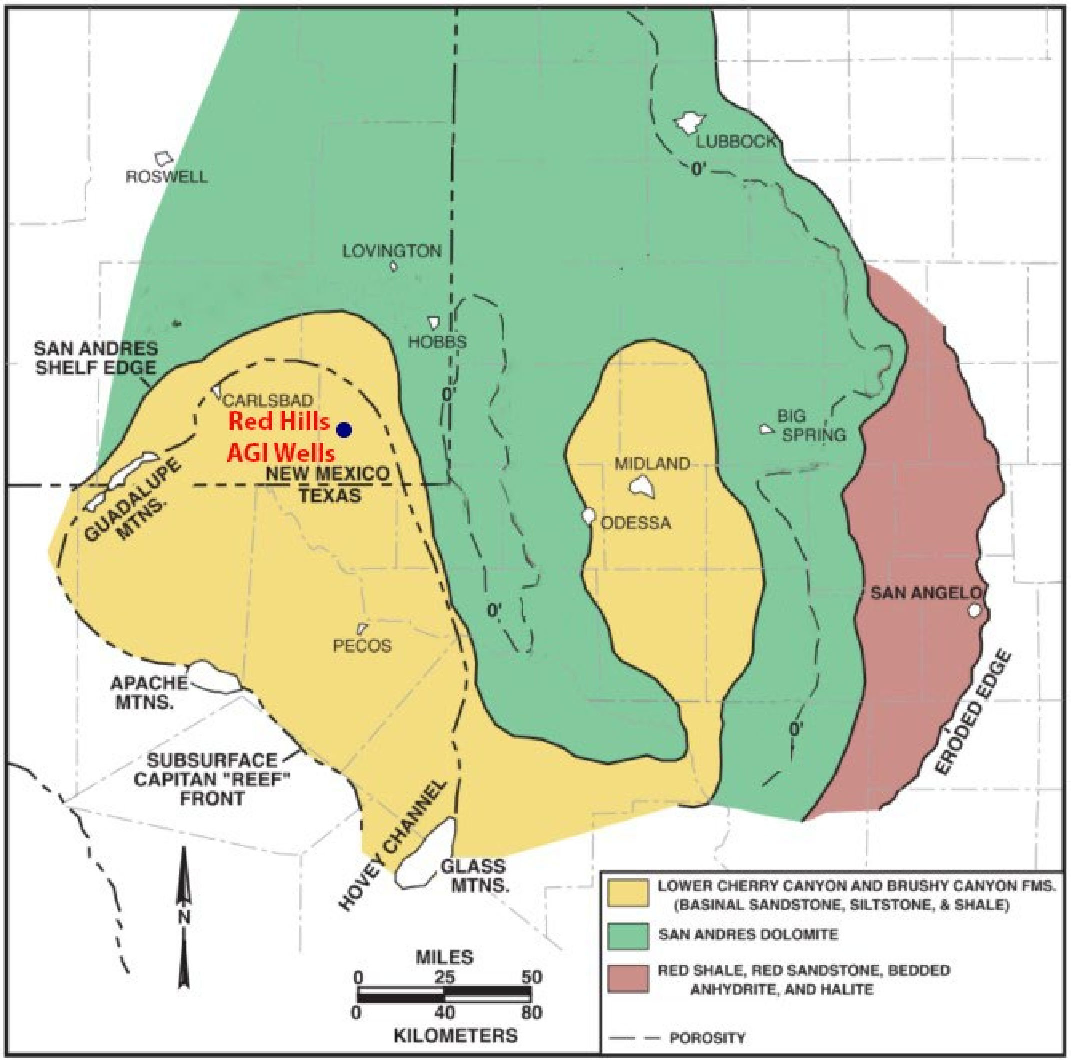


***Figure 3.2-1**: Structural features of the Permian Basin during the Late Permian. Location of the TND RH AGI wells is shown by the black circle. (Modified from Ward, et al (1986))*

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

The RH AGI wells are in the Delaware Basin portion of the broader Permian Basin. Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland (**Figure 3.2-3**). With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Ellenburger Formation (0 – 1000 ft) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Throughout this narrative, the numbers after the formations indicate the range in thickness for that unit. Tectonic activity near the end of Ellenburger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit's overall porosity and permeability.

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

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

During Middle to Upper Ordovician time, the seas once again covered the area and deposited the carbonates, sandstones and shales of the Simpson Group (0 – 1000 ft) and then the Montoya Formation (0 – 600 ft). This is the period when the Tobosa Basin formed due to the Pedernal uplift and development of the Texas Arch (**Figure 3.2-4**; Harrington, 2019) shedding Precambrian crystalline clasts into the basin. Reservoirs in New Mexico are typically within deposits of shoreline sandstones (Broadhead, 2017). A subaerial exposure and karstification event followed the deposition of the Simpson Group. The Montoya Formation marked a return to dominantly carbonate sedimentation with minor siliciclastic sedimentation within the Tobosa Basin (Broadhead, 2017; Harrington and Loucks, 2019). The Montoya Formation consists of sandstones and dolomites and have also undergone karstification.

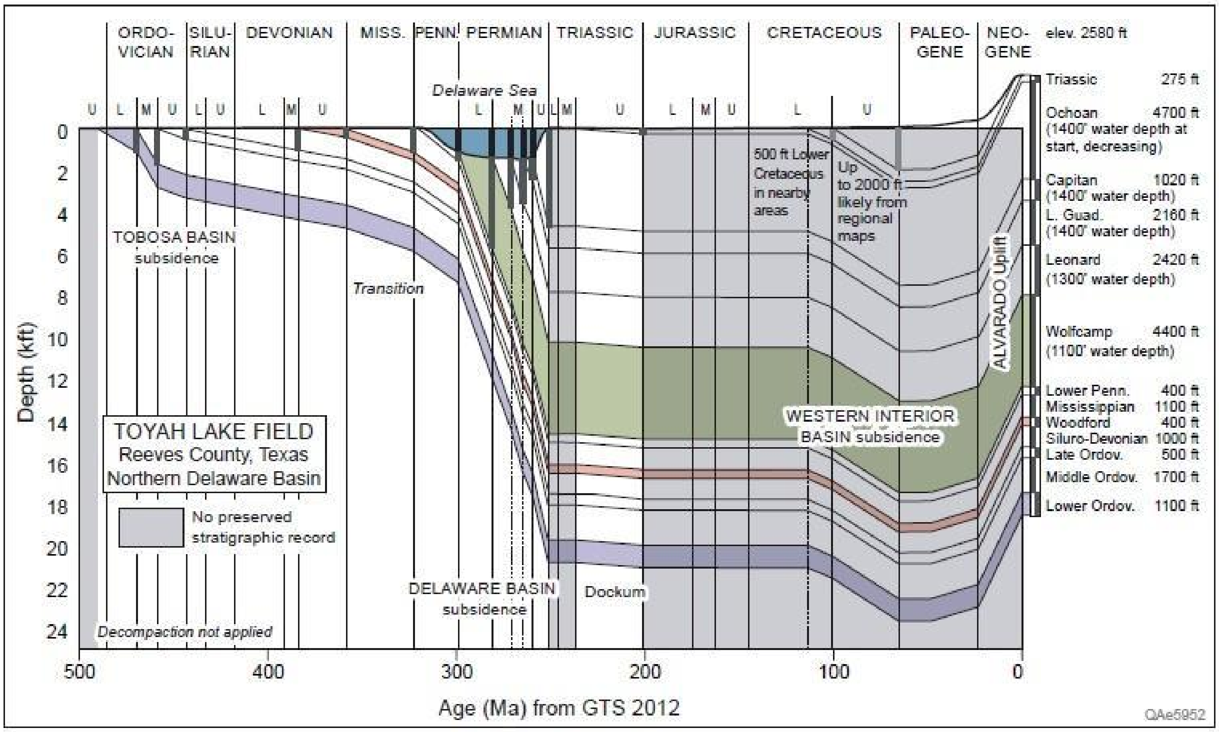


Figure 3.2-3*: A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)*

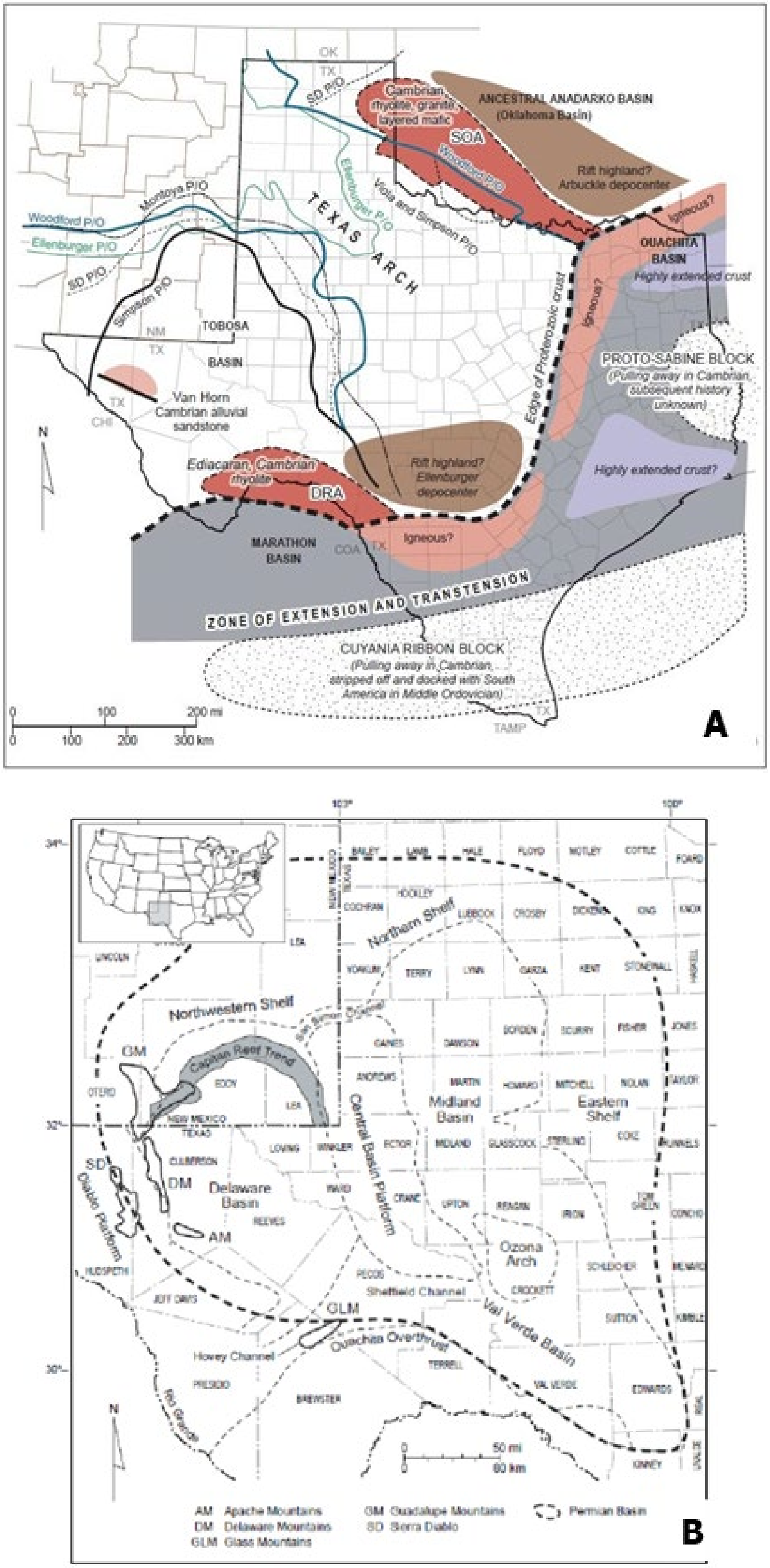


***Figure 3.2-4**: Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).*

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

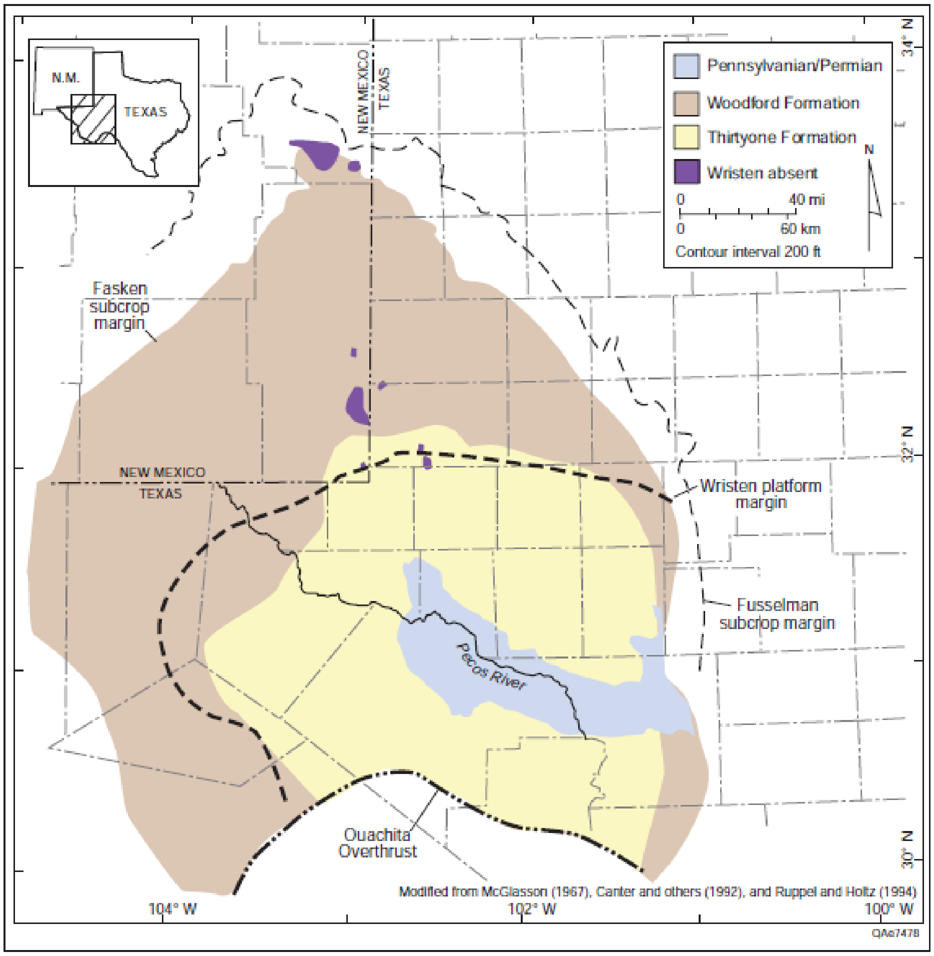


Figure 3.2-5 *-- A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there are no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in Section 3.2.2.

The Devonian Woodford Shale, an un-named Mississippian limestone, and the Upper Mississippian Barnett Shale are seals for the underlying Siluro-Devonian strata. While the Mississippian recrystallized limestones have minor porosity and permeability, the Woodford and Barnett shales have extremely low porosity and

permeability and would be effective barriers to upward migration of acid gas out of the injection zone. The Woodford Shale (0 – 300 ft) ranges from organic–rich argillaceous mudstones with abundant siliceous microfossils to organic-poor argillaceous mudstones (Ruppel et al., 2020b). The Woodford sediments represent stratified deeper marine basinal deposits with their organic content being a function of the oxygenation within the bottom waters – the more anoxic the waters the higher the organic content.

The Mississippian strata within the Delaware Basin consists of an un-named carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoirs limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise it is tight. The Barnett Shale (0 – 400 ft) unconformably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal, siliciclastic deposits (the Barnett Shale).

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

Pennsylvanian sedimentation is dominated by glacio-eustatic sea-level cycles that produced shallowing upward cycles of sediments, ranging from deep marine siliciclastic and carbonate deposits to shallow-water limestones and siliciclastics, and capping terrestrial siliciclastic sediments and karsted limestones. Lower Pennsylvanian units consist of the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). The Atoka Formation (0-500 ft) was deposited during another sea-level transgression within the area. Within the area, the Atoka sediments are dominated by siliciclastic sediments, and depositional environments range from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

Middle Pennsylvanian units consist of the Strawn group (an informal name used by industry). Strawn sediments (250 - 1,000 ft) within the area consists of marine sediments that range from ramp carbonates, containing patch reefs, and marine sandstone bars to deeper marine shales (Broadhead, 2017).

Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales.

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

throughout the Permian, the Wolfcampian sediments were truncated in places like the Central Basin Platform (**Figure 3.2-6**).

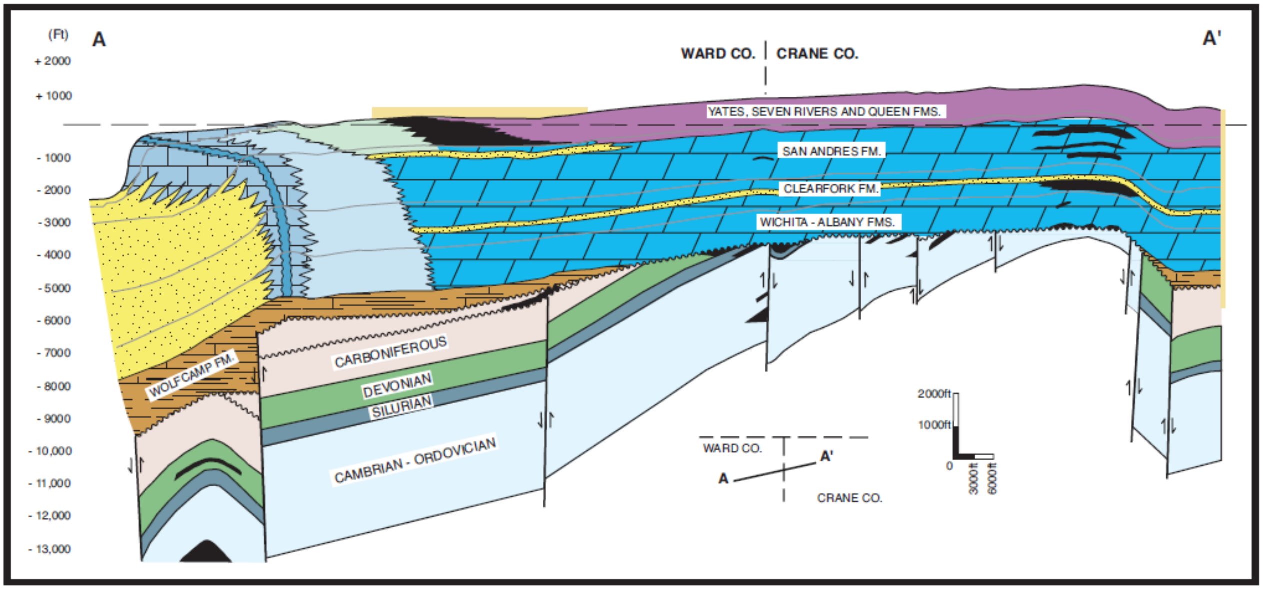


Figure 3.2-6 -- *Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).*

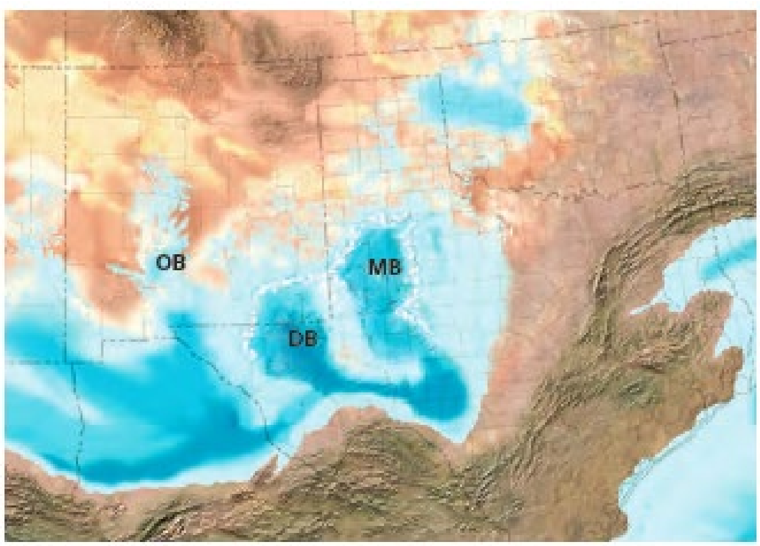


Figure 3.2-7 -- *Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).*

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, thousands of feet of siliciclastic sediments bypassed the shelves and were deposited in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a

“carbonate factory” on the shelf and shelf edge. Carbonate debris beds shedding off the shelf margin were transported into the basin (Wilson, 1972; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100s feet to feet).

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along Northwest Shelf margin to shallow-marine, back-reef carbonates behind the shelf margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2019a). Sediments basinward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2019a). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. The Bone Spring Formation is a thick sequence of alternating carbonate and siliciclastic horizons that formed because of changes in sea level; the carbonates during highstands, and siliciclastics during lowstands. Overlying the Yeso, are the clean, white eolian sandstones of the Glorietta Formation. It is a key marker bed in the region, both on outcrop and in the subsurface. Within the basin, it is equivalent to the lowermost Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have been identified that have resulted in karstification and pervasive dolomitization of the unit. These exposure events/sea-level lowstands are correlated to sandstones/siltstones that moved out over the exposed shelf leaving on minor traces of their presence on the shelf but formed thick sections of sandstones and siltstones in the basin. Within the Delaware Basin, the San Andres Formation is equivalent to the Brushy and lower Cherry Canyon Formations.

The Artesia Group (Grayburg, Queen, Seven Rivers, Yates, and Tansill formations, ascending order) is equivalent to Capitan Limestone, the Guadalupian barrier/fringing reef facies. Within the basin, the Artesia Group is equivalent to the upper Cherry and Bell Canyon formations, a series of relatively featureless sandstones and siltones. The Queen and Yates formations contain more sandstones than the Grayburg, Seven Rivers, and Tansill formations. The Artesia units and the shelf edge equivalent Capitan reef sediments represent the period when the carbonate factory was at its greatest productivity with the shelf margin/Capitan reef prograding nearly 6 miles into the basin (Scholle et al., 2007). The Artesia Group sediments were deposited in back-reef, shallow marine to supratidal/evaporite environments. Like the San Andres Formation, the individual formations were periodically exposed during lowstands.

The final stage of Permian deposition on the NW Shelf consists of the Ochoan/Lopingian Salado Formation (<2,800 ft, Nance, 2020). Within the basin, the Castile formation, a thick sequence (total thickness ~1,800 ft, Scholle et al., 2007) of cyclic laminae of deep-water gypsum/anhydrite interbedded with calcite and organics, formed due to the restriction of marine waters flowing into the basin. Gypsum/anhydrite laminae precipitated during evaporative conditions, and the calcite and organic-rich horizons were a result of seasonal “freshening” of the basin waters by both marine and freshwaters. Unlike the Castile Formation, the Salado Formation is a relatively shallow water evaporite deposit. Halite, sylvite, anhydrite, gypsum, and numerous potash minerals were precipitated. The Rustler Formation (500 ft , Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin.

The Rustler Formation was followed by terrestrial sabkha red beds of the Dewey Lake Formation (~350', Nance, 2020), ending Permian deposition in the area.

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

3.2.2 Stratigraphy

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent, renamed Lopingian), Guadalupian, Leonardian (renamed Cisuralian), and Wolfcampian (oldest) (**Figure 3.2-2**). This sequence of shallow marine carbonates and thick, basinal siliciclastic deposits contains abundant oil and gas resources. The Delaware Basin high porosity sands are the main source of oil within New Mexico. In the area around the Red Hills AGI wells, Permian strata are mainly basin deposits consisting of sandstones, siltstones, shales, and lesser amounts of carbonates. Besides production in the Delaware Mountain Group, there is also production, mainly gas, in the basin Bone Spring Formation, a sequence of carbonates and siliciclastics. The injection and confining zones for RH AGI #1 and #3 are discussed below.

CONFINING/SEAL ROCKS

Permian Ochoa Series. The youngest of the Permian sediments, the Ochoan- or Lopingian-aged deposits, consists of evaporites, carbonates, and red beds. The Castile Formation is made of cyclic laminae of deep-water gypsum/anhydrite beds interlaminated with calcite and organics. This basin-occurring unit can be up to 1,800 ft thick. The Castile evaporites were followed by the Salado Formation (~1,500 ft thick). The Salado Formation is a shallow water evaporite deposit, when compared to the Castile Formation, and consists of halite, sylvite, anhydrite, gypsum, and numerous potash/bittern minerals. Salado deposits fill the basin and lap onto the older Permian shelf deposits. The Rustler Formation (up to 500 ft, Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin. The Ochoan evaporitic units are superb seals (usually <1% porosity and <0.01 mD permeability) and are the reason that the Permian Basin is such a hydrocarbon-rich region despite its less than promising total organic carbon (TOC) content.

INJECTION ZONE

Permian Guadalupe Series. Sediments in the underlying Delaware Mountain Group (descending, Bell Canyon, Cherry Canyon, and Brushy Canyon formations) are marine units that represent deposition controlled by eustacy and tectonics. Lowstand deposits are associated with submarine canyons incising the carbonate platform surround most of the Delaware Basin. Depositional environments include submarine fan complexes that encircle the Delaware Basin margin. These deposits are associated with submarine canyons incising the carbonate platform margin and turbidite channels, splays, and levee/overbank deposits (**Figure 3.2-8**). Additionally, debris flows formed by the failure of the carbonate margin and density currents also make up basin sediments. Isolated coarse-grained to boulder-sized carbonate debris flows and grain falls within the lowstand clastic sediments likely resulted from erosion and failure of the shelf margin during sea-level lowstands or slope failure to tectonic activity (earthquakes). Density current deposits resulted from stratified basin waters. The basal waters were likely stratified and so dense, that turbidity flows containing sands, silts and clays were unable to displace those bottom waters and instead flowed out over the density interface (**Figure 3.2-9**). Eventually, the entrained sediments would settle out in a constant rain of sediment forming laminated deposits with little evidence of traction (bottom flowing) deposition. Interbedded with the very thick lowstand sequences are thin, deep-water limestones and mudstones that represent highstand

deposition up on the platform. These deposits are thickest around the edge (toe-of-slope) of the basin and thin to the basin center (**Figure 3.2-10**). The limestones are dark, finely crystalline, radiolarian-rich micrites to biomicrites. These highstand deposits are a combination of suspension and pelagic sediments that also thin towards the basin center. These relatively thin units are time equivalent to the massive highstand carbonate deposits on the shelf.

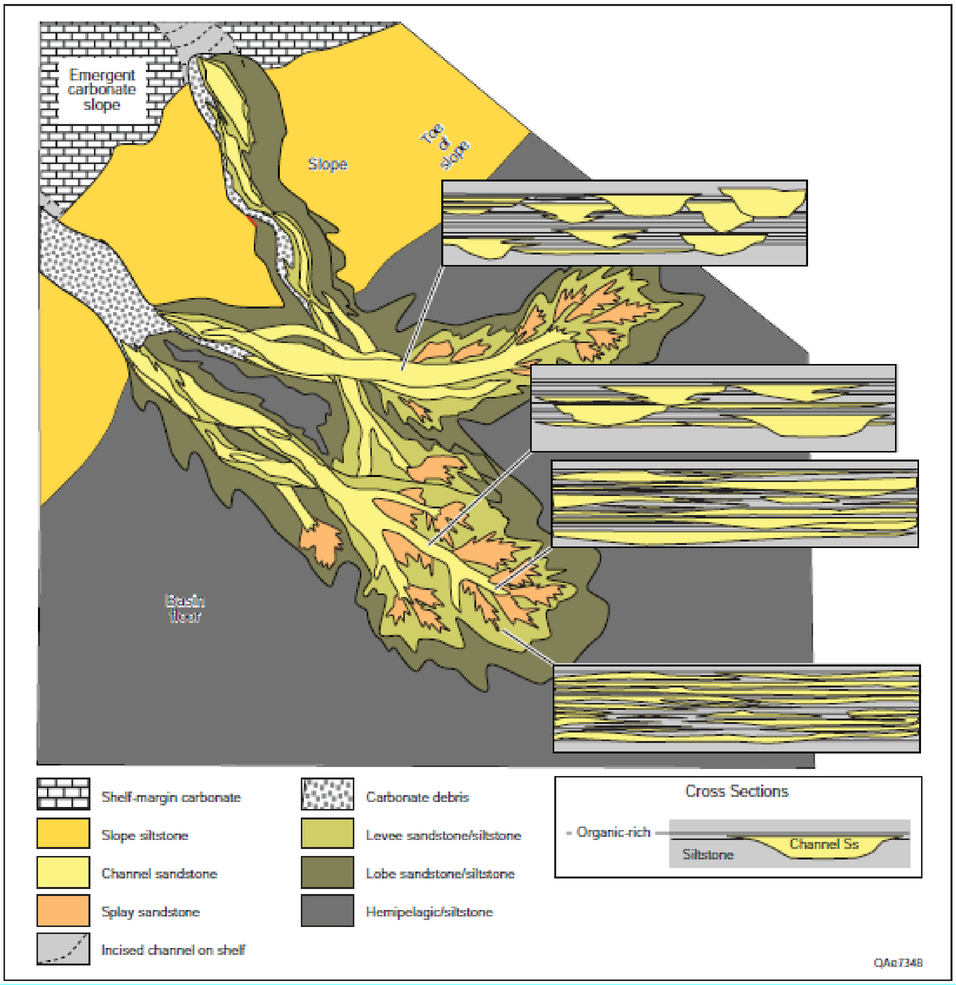


***Figure 3.2-8** – A diagram of typical Delaware Mountain Group basinal siliciclastic deposition patterns (from Nance, 2020). The channel and splay sandstones have the best porosity, but some of the siltstones also have potential as injection zones.*

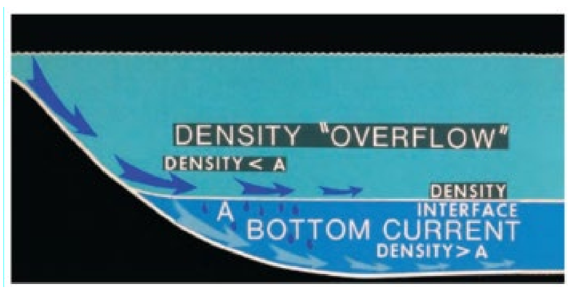


***Figure 3.2-9** – Harms' (1974) density overflow model explains the deposition of laminated siliciclastic sediments in the Delaware Basin. Low density sand-bearing fluids flow over the top of dense, saline brines at the bottom of the basin. The sands gradually drop out as the flow loses velocity creating uniform, finely laminated deposits (from Scholle et al., 2007).*

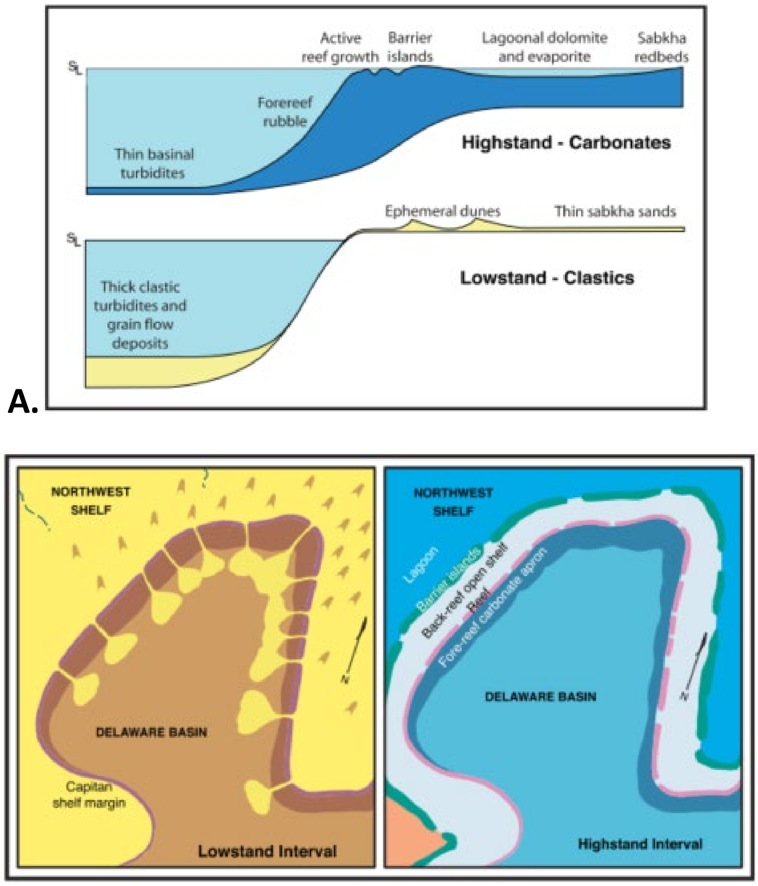


***Figure 3.2-10** – The impact of sea-level fluctuations (also known as reciprocal sedimentation) on the depositional systems within the Delaware Basin. A) A diagrammatic representation of sea-level variations impact on deposition. B) Model showing basin-wide depositional patterns during lowstand and highstand periods (from Scholle et al., 2007).*

The top of the Guadalupian Series is the Lamar Limestone, which is the source of hydrocarbons found in underlying Delaware Sand (an upper member of the Bell Canyon Formation). The Bell Canyon Formation is roughly 1,000 ft thick in the Red Hills area and contains numerous turbidite input points around the basin margin (**Figures 3.2-10, 3.2-11**). During Bell Canyon deposition, the relative importance of discrete sand sources varied (Giesen and Scholle, 1990), creating network of channel and levee deposits that also varied in their size and position within the basin. Based on well log analyses, the Bell Canyon 2 and 3 had the thickest sand deposits.

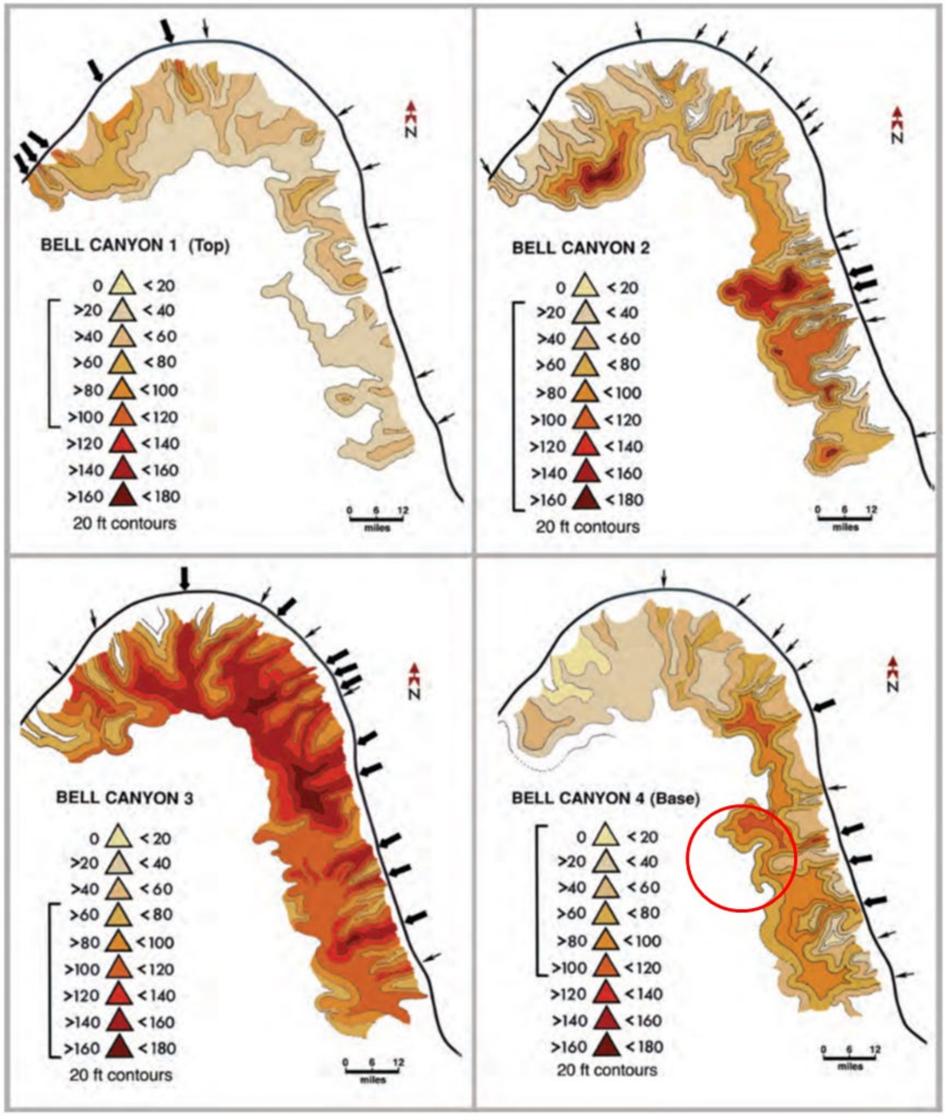


Figure 3.2-11 – These maps of Bell Canyon Formation were created by measuring sandstone thicknesses on well logs in four regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). The red circle on the last map surrounds the Red Hills area.

Like the Bell Canyon and Brushy Canyon formations, the Cherry Canyon Formation is approximately 1,300 ft thick and contains numerous turbidite source points. Unlike the Bell Canyon and Brushy Canyon deposits, the channel deposits are not as large (Giesen and Scholle, 1990), and the source of the sands appears to be dominantly from the eastern margin (**Figure 3.2-12**). Cherry Canyon 1 and 5 have the best channel development and the thickest sands. Overall, the Cherry Canyon Formation, on outcrop, is less influenced by traction current deposition than the rest of the Delaware Mountain Group deposits and is more influenced by sedimentation by density overflow currents (**Figure 3.2-9**). The Brushy Canyon has notably more discrete channel deposits and coarser sands than the Cherry Canyon and Bell Canyon. The Brushy Canyon Formation is approximately 1,500 ft thick.

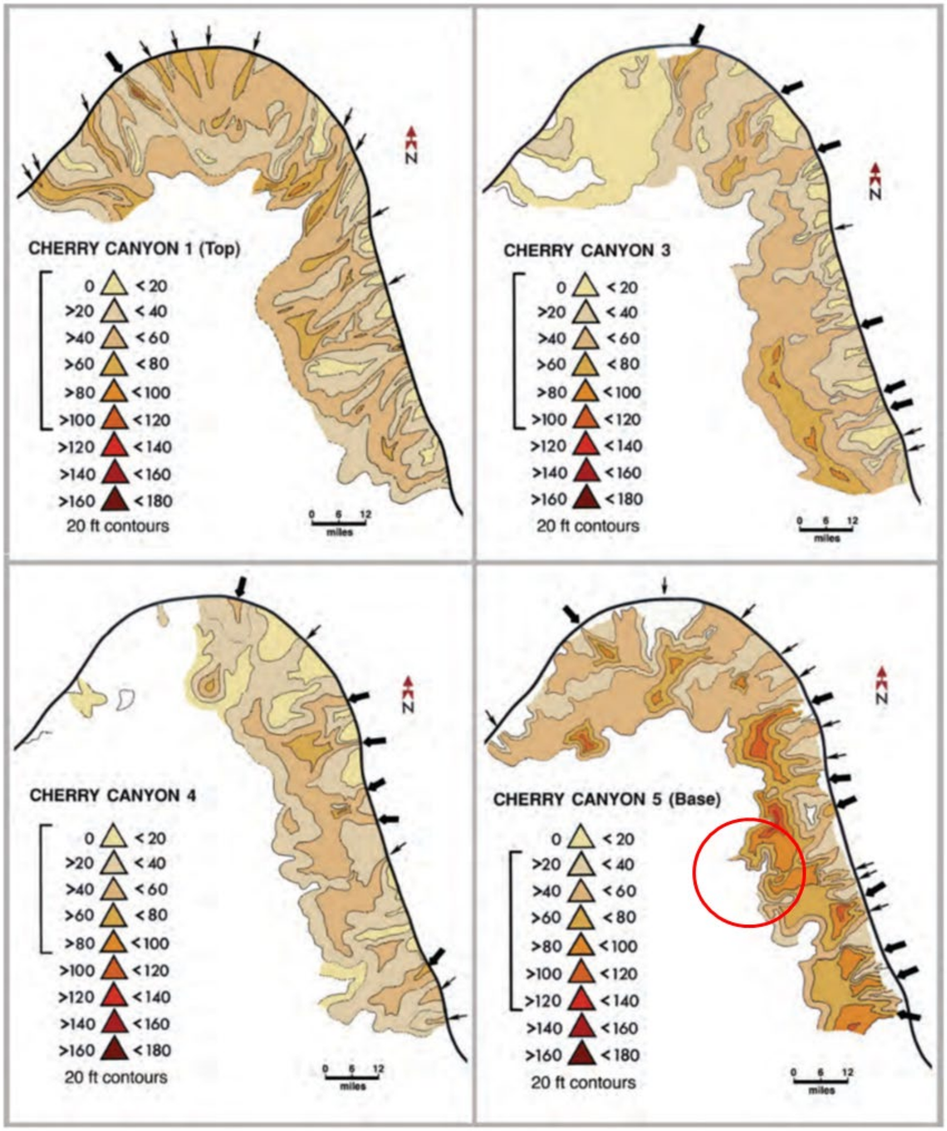


Figure 3.2-12– *These maps of Cherry Canyon Formation were created by measuring sandstone thicknesses on well logs in five regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). Unlike the Bell Canyon sandstones, the Cherry Canyon sands are thinner and contain fewer channels. The red circle on the last map surrounds the Red Hills area.*

Within the Delaware Mountain Group in the Red Hills area, the Bell Canyon and Cherry Canyon have the best porosity (averaging 15 – 25 % within channel/splay sandstones) and permeability (averaging 2-13 mD) than the Brushy Canyon (~14% porosity, an <3 mD; Ge et al, 2022, Smye et al., 2021).

UNDERLYING CONFINING ZONE

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

3.2.3 Faulting

In this immediate area of the Permian Basin, faulting is primarily confined to the lower Paleozoic section, where seismic data shows major faulting and ancillary fracturing-affected rocks only as high up as the base of the lower Wolfcamp strata (**Figures 3.2-6 and 5.6-1**). Faults that have been identified in the area are normal faults associated with Ouachita related movement along the western margin of the Central Platform to the east of the RH AGI well site. The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief. Because these faults are confined to the lower Paleozoic unit well below the injection zone for the RH AGI wells, they will not be discussed further (Horne et al., 2021). Within the area of the Red Hills site, no shallow faults within the Delaware Mountain Group have been identified by seismic data interpretation nor as reported by Horne et al., 2022).

3.3 Lithologic and Reservoir Characteristics

Based on the geologic analyses of the subsurface at the Red Hills Gas Plant, the uppermost portion of the Cherry Canyon Formation was chosen for acid gas injection and CO_2 sequestration for RH AGI #1 and the uppermost Delaware Mountain Group (the Bell Canyon and Cherry Canyon Formations) for RH AGI #3.

For RH AGI #1, this interval includes five high porosity sandstone units (sometimes referred to as the Manzanita) and has excellent caps above, below and between the individual sandstone units. There is no local production in the overlying Delaware Sands pool of the Bell Canyon Formation. There are no structural features or faults that would serve as potential vertical conduits. The high net porosity of the RH AGI #1 injection zone indicates that the injected H_2S and CO_2 will be easily contained close to the injection well.

For RH AGI #3, this interval has been expanded to include the five porosity zones in the Cherry Canyon sandstone as well as the sandstone horizons in the overlying Bell Canyon Formation. In the Bell Canyon Formation there are several potential high porosity sandstones, that if present in the well, would be excellent , injection zones similar to the depositional environments of the Cherry Canyon sandstones. The thickest sand is commonly referred to as the Delaware Sand within the Delaware Basin. The Delaware sand is productive, but it is not locally. Most of the sand bodies in the Bell Canyon and Cherry Canyon formations are surrounded by shales or limestones, forming caps for the injection zones. There are no structural features or faults that would serve as potential vertical conduits, and the overlying Ochoan evaporites form an excellent overall seal for the system. Even if faulting existed, the evaporites (Castile and Salado) would self-seal and prevent vertical migration out of the Delaware Mountain Group.

The geophysical logs were examined for all wells penetrating the Bell Canyon and Cherry Canyon formations within a three-mile radius of the RH AGI wells as well as 3-D seismic data. There are no faults visible within the Delaware Mountain Group in the Red Hills area. Within the seismic area, the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales (**Figure 3.2-8**) as well as being encased by them. Based on regional studies (Giesen and Scholle, 1990 and **Figures 3.2-11, 3.2-12**), the preferred orientation of the channels, and hence the preferred fluid migration pathways, are roughly from the east to the west.

The porosity was evaluated using geophysical logs from nearby wells penetrating the Cherry Canyon Formation. **Figure 3.3-1** shows the Resistivity (Res) and Thermal Neutron Porosity (TNPH) logs from 5,050 ft to 6,650 ft and includes the injection interval. Five clean sands (>10% porosity and <60 API gamma units) are targets for injection within the Cherry Canyon formation and potentially another 5 sands with >10% porosity and <60 API gamma units were identified. Ten percent was the minimum cut-off considered for adequate

porosity for injection. The sand units are separated by lime mudstone and shale beds with lateral continuity. The high porosity sand units exhibit an average porosity of about 18.9%; taken over the average thickness of the clean sand units within ½ mile of the RH AGI #1. There is an average of 177 ft with an irreducible water (S_{wir}) of 0.54 (see Table 1 of the RH AGI #1 permit application). Many of the sands are very porous (average porosity of > 22%) and it is anticipated that for these more porous sands, the S_{wir} may be too high. The effective porosity (Total Porosity – Clay Bound Water) would therefore also be higher. As a result, the estimated porosity ft (PhiH) of approximately 15.4 porosity-ft should be considered to be a minimum. The overlying Bell Canyon Formation has 900 ft of sands and intervening tight limestones, shales, and calcitic siltstones with porosities as low as 4%, but as mentioned above, there are at least 5 zones with a total thickness of approximately 460 ft and containing 18 to 20% porosity. The injection interval is located more than 2,650 ft above the Bone Spring Formation, which is the next production zone in the area.

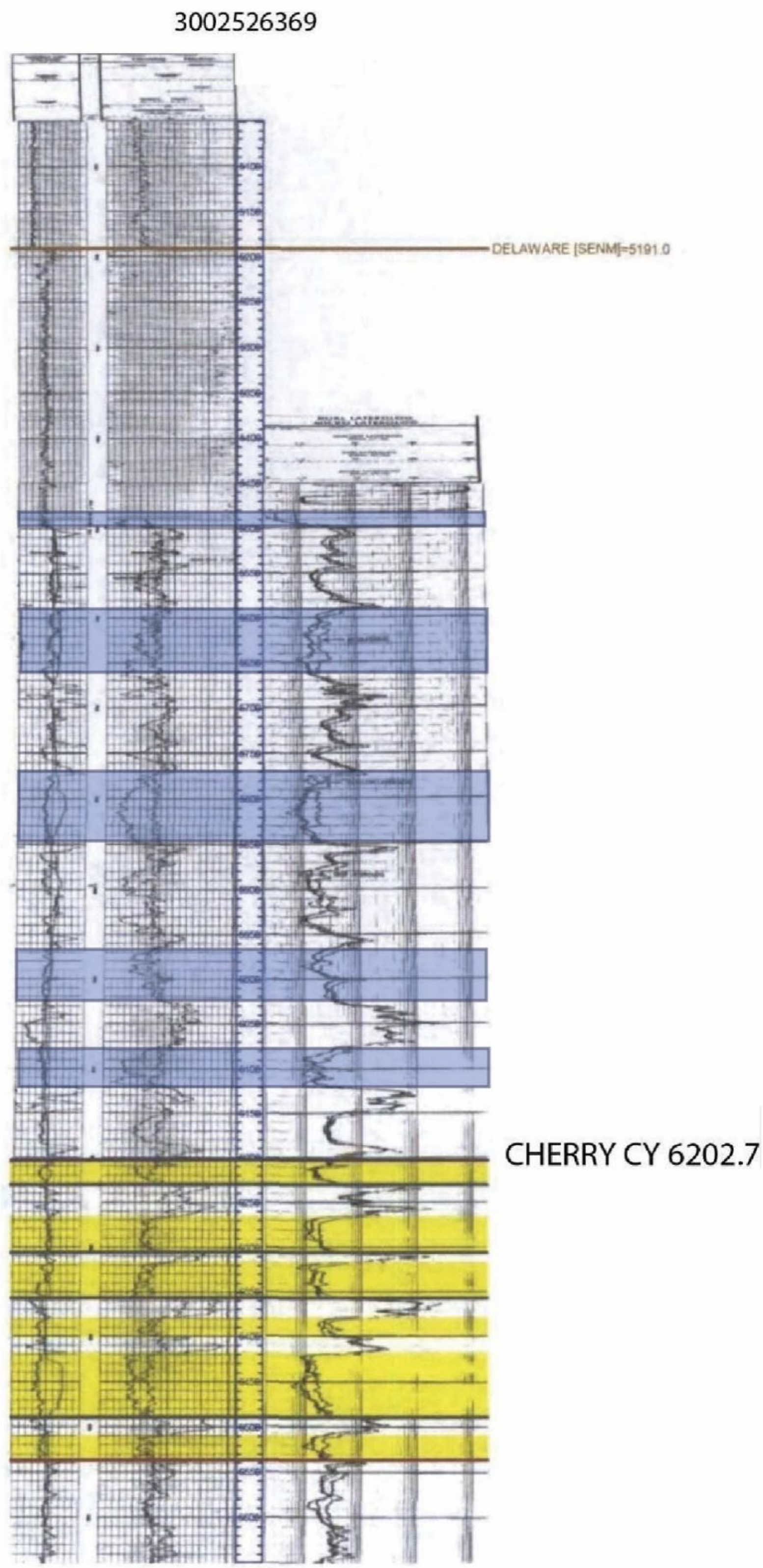


Figure 3.3-1: *Geophysical logs from the Bell Canyon and the Upper Cherry Canyon from the Government L Com #002 well, located 0.38 miles from the RH AGI #1 Well. The blue intervals are Bell Canyon porosity zones, and the yellow intervals are Cherry Canyon porosity zones.*

3.4 Formation Fluid Chemistry

A chemical analysis (**Table 3.4-1**) of water from Federal 30 Well No. 2 (API 30-025-29069), approximately 3.9 miles away, indicates that the formation waters are highly saline (180,000 ppm NaCl) and compatible with the injection.

***Table 3.4-1**: Formation fluid analysis for Cherry Canyon Formation from Federal 30 Well No. 2*

Sp. Gravity	1.125 @ 74°F	Resistivity	0.07 @ 74°F
pH	7	Sulfate	1,240
Iron	Good/Good	Bicarbonate	2,135
Hardness	45,000	Chloride	110,000
Calcium	12,000	NaCl	180,950
Magnesium	3,654	Sod. & Pot.	52,072

Table extracted from C-108 Application to Inject by Ray Westall Associated with SWD-1067 – API 30-025-24676. Water analysis for formation water from Federal 30 #2 Well (API 30-025-29069), depth 7,335-7,345 ft, located 3.9 miles from RH AGI #1 well.

3.5 Groundwater Hydrology in the Vicinity of the Red Hills Gas Plant

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are 15 freshwater wells located within a two-mile radius of the RH AGI wells, and only 2 water wells within one mile; the closest water well is located 0.31 miles away and has a total depth of 650 ft (**Figure 3.5-1; Appendix 3**). All water wells within the two-mile radius are shallow, collecting water from about 60 to 650 ft depth, in Alluvium and the Triassic redbeds. The shallow freshwater aquifer is protected by the surface and intermediate casings and cements in the RH AGI wells (**Figures Appendix 1-1 and Appendix 1.2**). While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

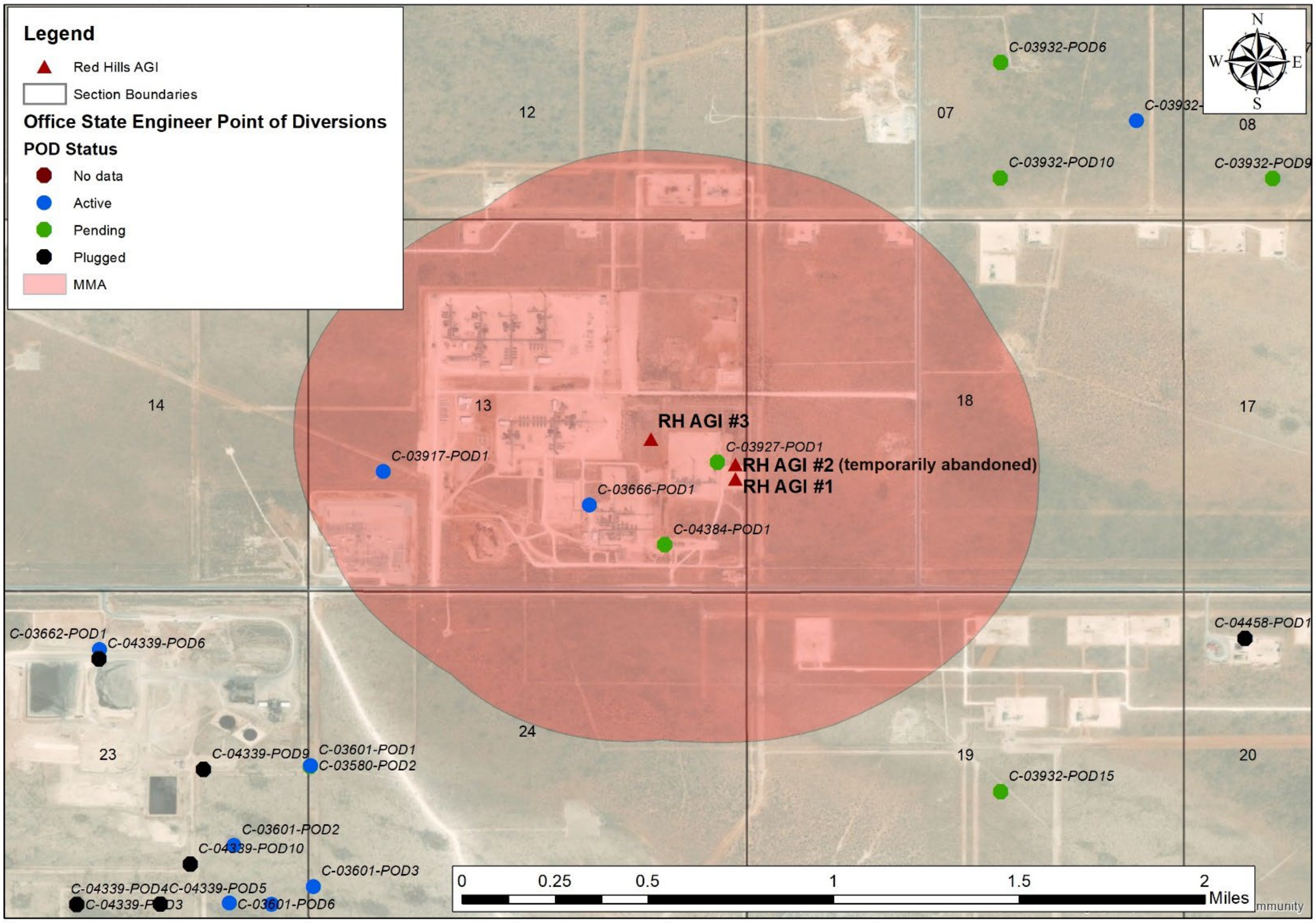


__Figure 3.5-1__: Reported Water Wells within the MMA for the RH AGI Wells.

3.6 Historical Operations

3.6.1 Red Hills Site

On July 20, 2010, Agave Energy Company (Agave) filed an application with NMOCD to inject treated acid gas into an acid gas injection well. Agave built the Red Hills Gas Processing Plant and drilled RH AGI #1 in 2012-13. However, the well was never completed and never put into service because the plant was processing only sweet gas (no H_2S). Lucid purchased the plant from Agave in 2016 and completed the RH AGI #1 well. TND acquired Lucid's Red Hills assets in 2022. **Figure 3.6-1** shows the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells. **Figure 3.6-2** shows a process block flow diagram.

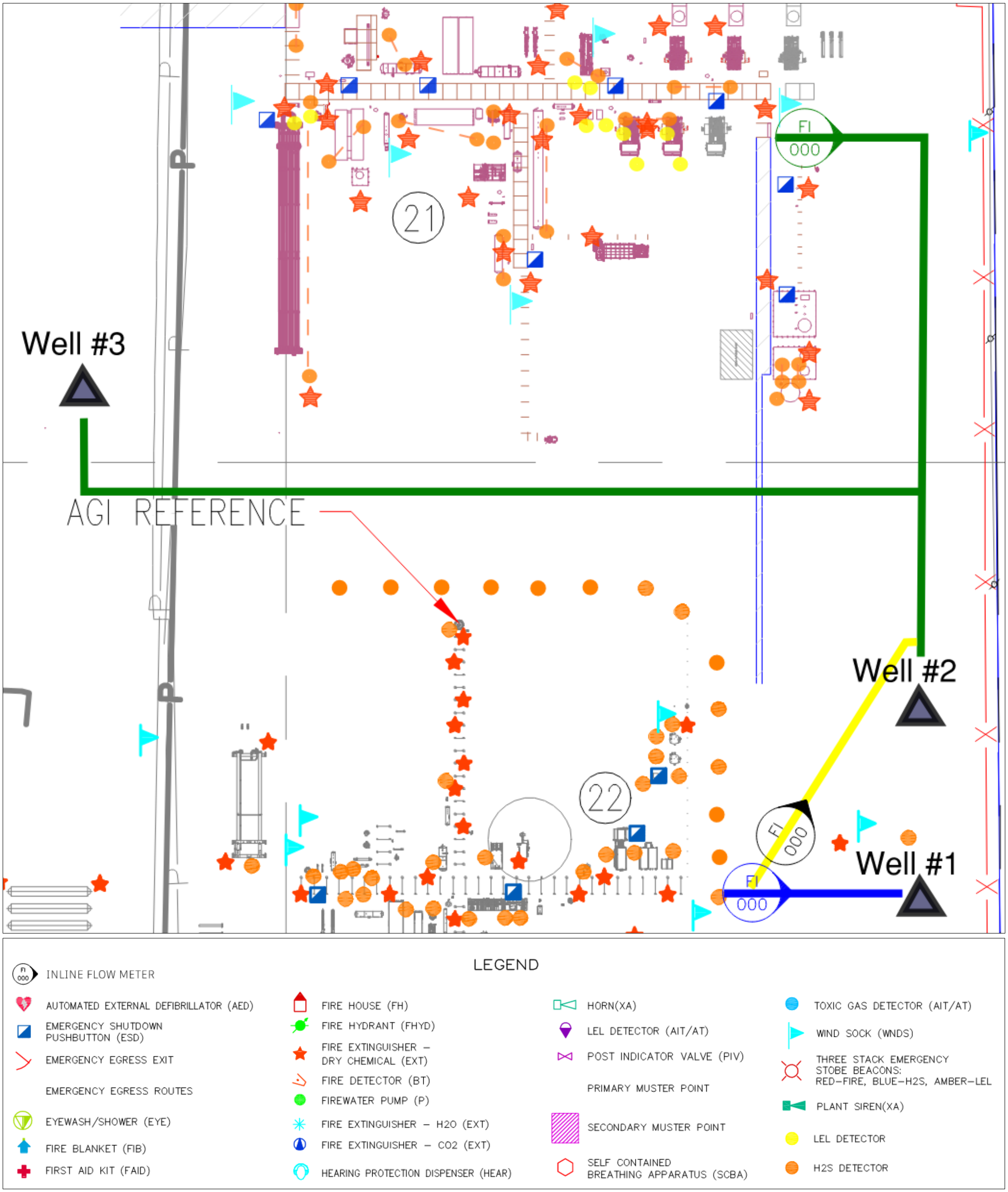


***Figure 3.6-1**: Diagram showing the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells.*

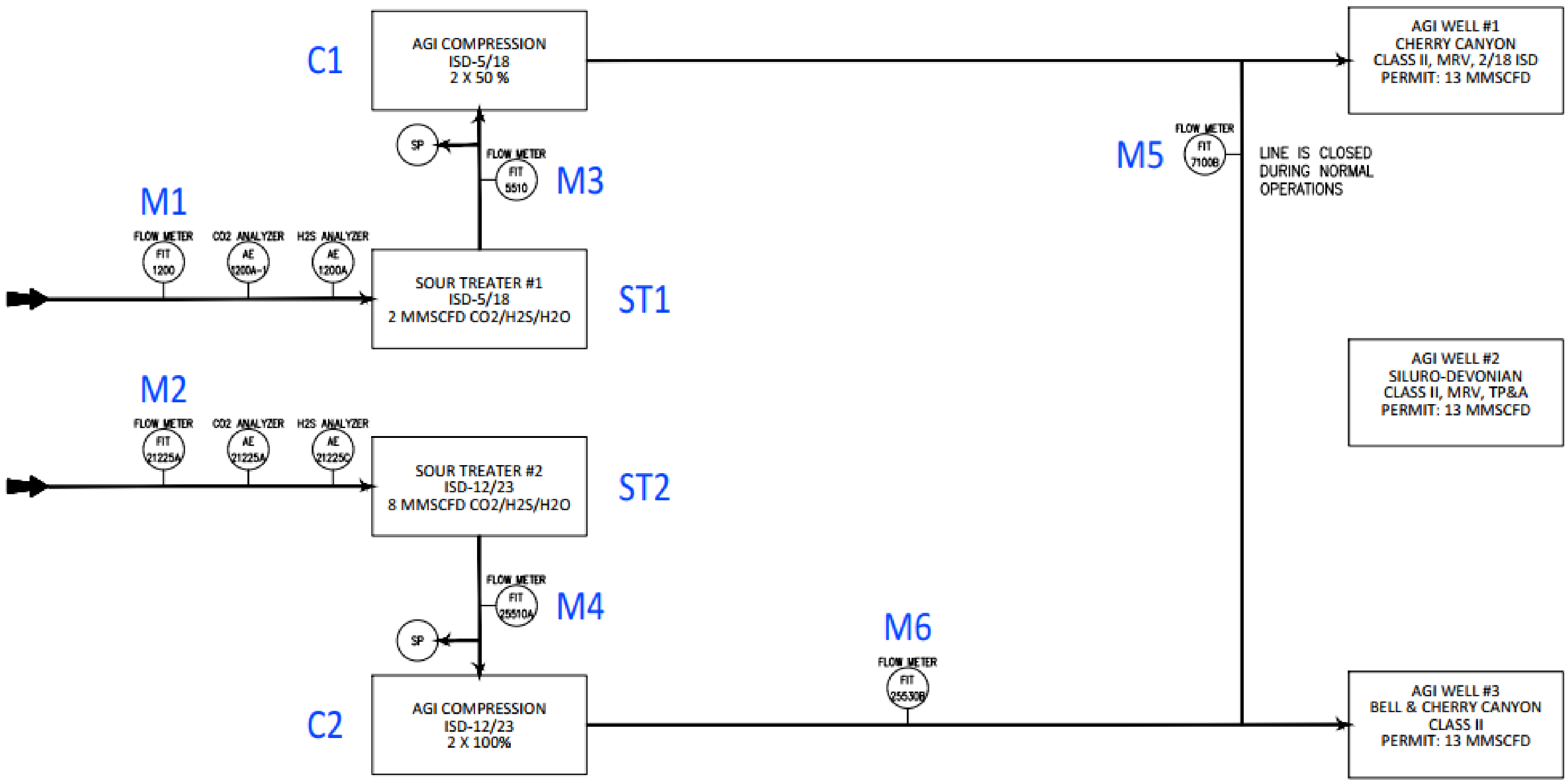


Figure 3.6-2: *Process Block Flow Diagram. RH AGI #2 is temporarily abandoned. M1 – M6: volumetric flow meters; C1 and C2: compressors; ST1 and ST2: sour treaters; and Sample Points (SP) for biweekly collection of data for determining the TAG stream concentration.*

3.6.2 Operations within the MMA for the RH AGI Wells

NMOCD records identify a total of 22 oil- and gas-related wells within the MMA for the RH AGI wells (see **Appendix 4**). **Figure 3.6-3** shows the geometry of producing and injection wells within the MMA for the RH AGI wells. **Appendix 4** summarizes the relevant information for those wells. All active production in this area is targeted for the Bone Spring and Wolfcamp zones, at depths of 8,900 to 11,800 ft, the Strawn (11,800 to 12,100 ft) and the Morrow (12,700 to 13,500 ft). All of these productive zones lie at more than 2,000 ft below the RH AGI #1 and AGI #3 injection zone.

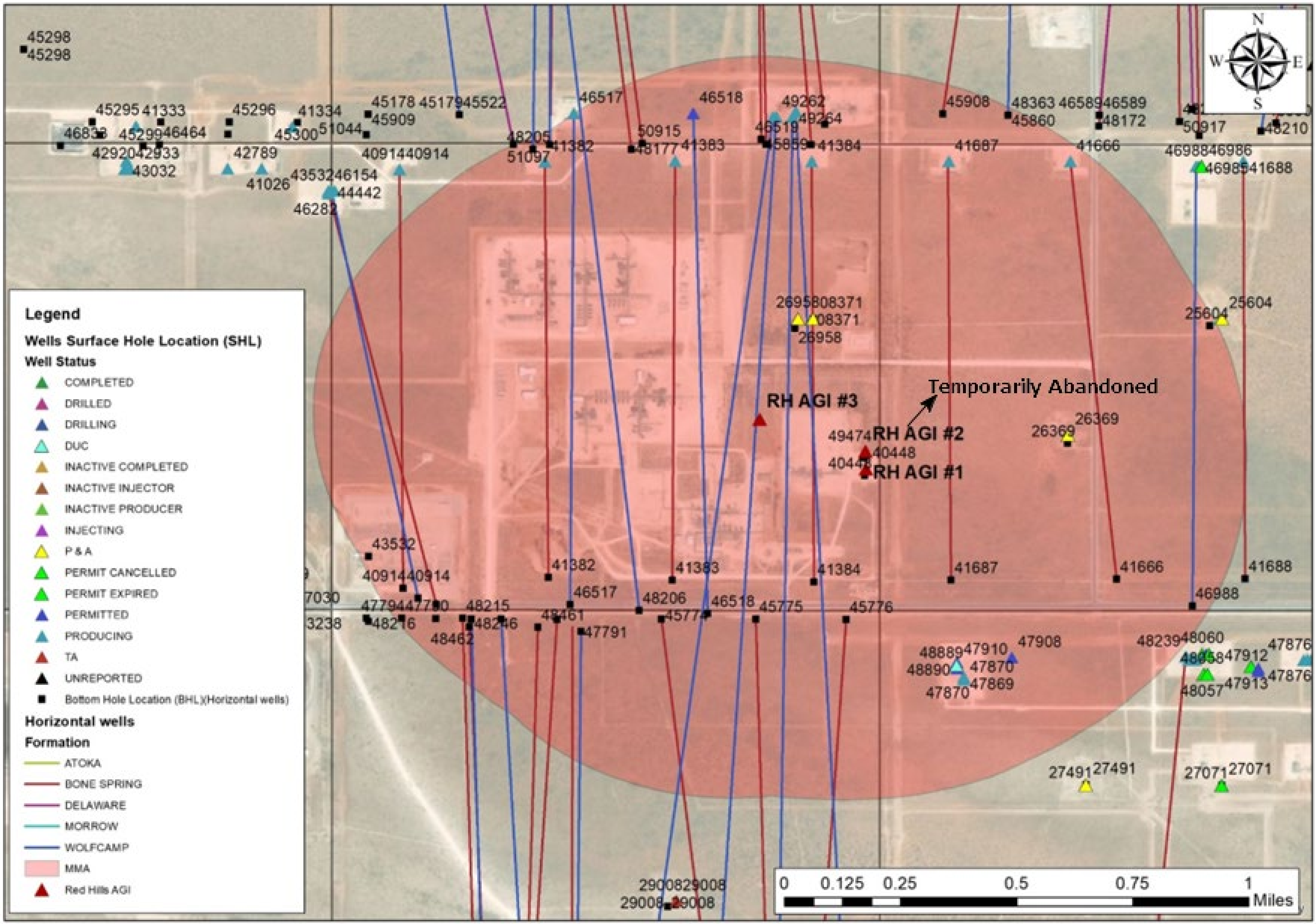


Figure 3.6-3: Location of all oil- and gas-related wells within the MMA for the RH AGI wells. Both the surface hole locations (SHL) and bottom hole locations (BHL) are labeled on the figure. For clarity, only the last four digits of the API numbers are used in labeling the wells.

3.7 Description of Injection Process

The Red Hills Gas Plant, including the existing RH AGI #1 well, is in operation and staffed 24-hours-a-day, 7-days-a week. The plant operations include gas compression, treating and processing. The plant gathers and processes produced natural gas from Lea and Eddy Counties in New Mexico. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the plant's sweeteners will be routed to a central compressor facility, located west of the well head. Compressed TAG is then routed to the wells via high-pressure rated lines. **Figure 3.7-1** is a schematic of the AGI facilities.

The approximate composition of the TAG stream is: 80% CO_2, 20% H_2S, with Trace Components of $C_1 – C_6$ (methane – hexane) and Nitrogen. The anticipated duration of injection is 30 years.

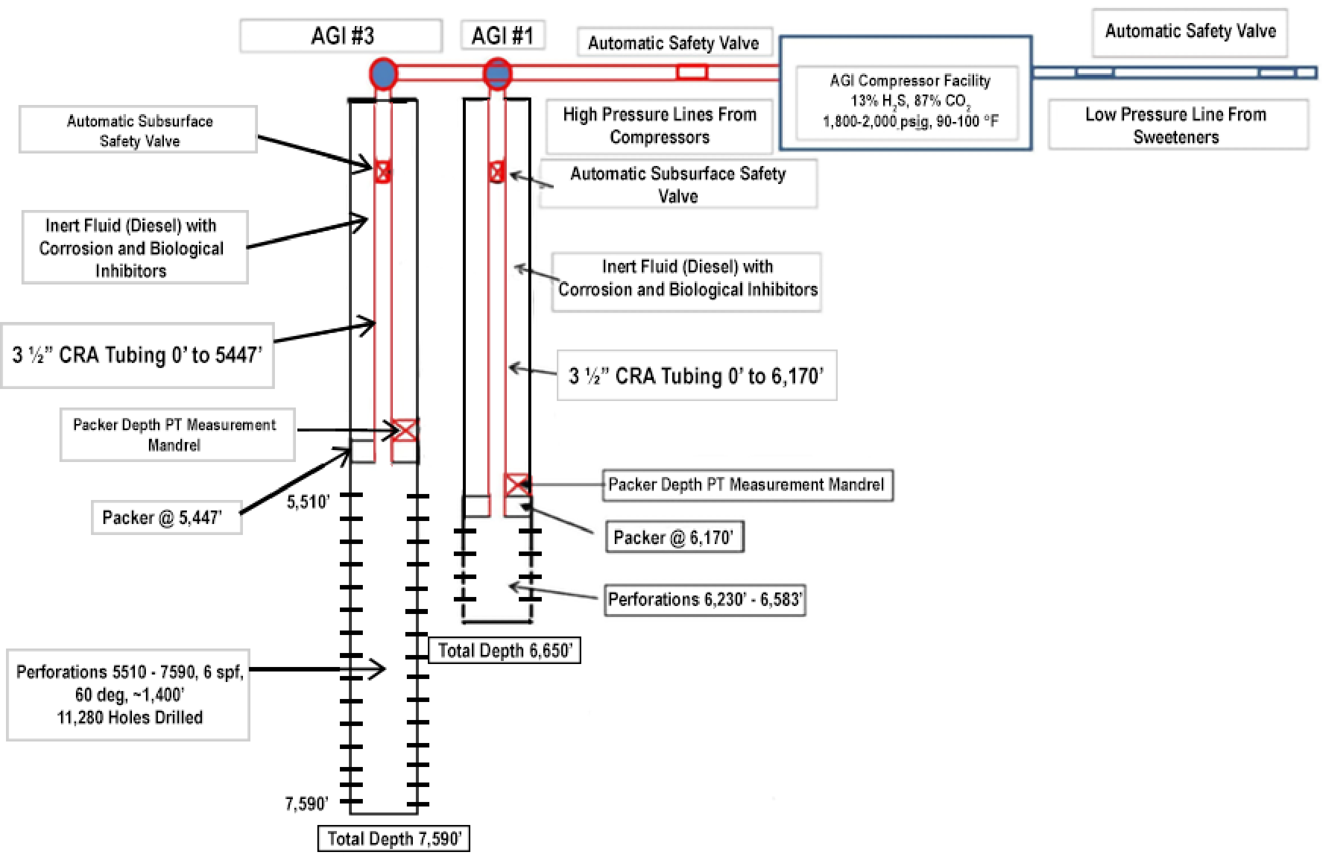


__Figure 3.7-1__: Schematic of surface facilities and RH AGI wells at the Red Hills Gas Processing Plant

3.8 Reservoir Characterization Modeling

The modeling and simulation focused on the Bell Canyon and Cherry Canyon formations as the main injection target zone for acid gas storage. The RH AGI #1 well (API 30-025-40448) and the RH AGI #3 well (API 30-025-51970) are the approved injectors for treated acid gas injection by NMOCD and will serve as the injection wells in the model under approved disposal timeframe and maximum allowable injection pressure. RH AGI #1 well is completed in the Cherry Canyon formation between 6,230 feet to 6,583 feet (MD). The RH AGI #3 well will be completed in both the Bell Canyon and Cherry Canyon formations between approximately 5,245 feet to 6,645 feet (MD).

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

The static model is constructed with well tops and licensed 3D seismic data to interpret and delineate the structural surfaces of a layer within the caprock (Lamar Limestone) and its overlaying, underlying formations. The geologic model covers a 3.5-mile by 3.3-mile area. No distinctive geological structures such as faults are identified within the geologic model boundary. The model is gridded with 182 x 167 x 18, totaling 547,092 cells. The average grid dimension of the active injection area is 100 feet square. **Figure 3.8-1** shows the simulation model in 3D view. The porosity and permeability of the model is populated through existing well logs. The range of the porosity is between 0.01 to 0.31. The initial permeability are interpolated between 0.02 to 155 millidarcy (mD), and the vertical permeability anisotropy was 0.1. **(Figure 3.8-2 and Figure 3.8-3)**. These values are validated and calibrated with the historical injection data of RH AGI #1 well since 2018 as shown in **Figures 3.8-4, 3.8-5, and 3.8-6**.

The simulation model is calibrated with the injection history of RH AGI #1 well since 2018. Simulation studies were further performed to estimate the reservoir responses when predicting TAG injection for 30 years through both RH AGI #1 well (2018 – 2048) and RH AGI #3 (2024 - 2054). RH AGI #2 well is temporarily abandoned as of the submission of this document. RH AGI #1 is simulated to inject with the average rate of the last 5 years, 1.2 MMSCF, in the prediction phase. RH AGI #3 is simulated to inject with permitted injection rate, 13 MMSCF, with 1,767 psi maximum surface injection pressure constraint approved by State agency. The simulation terminated at year 2084, 30 years after the termination of all injection activities, to estimate the maximum impacted area during post injection phase.

During the calibration period (2018 – 2023), the historical injection rates were used as the primary injection control, and the maximum bottom hole pressures (BHP) are imposed on wells as the constraint, calculated based on the approved maximum injection pressure. This restriction is also estimated to be less than 90% of the formation fracture pressure calculated at the shallowest perforation depth of each well to ensure safe injection operations. The reservoir properties are tuned to match the historical injection until it was reasonably matched. **Figure 3.8-4** shows that the historical injection rates from the RH AGI #1 well in the Cherry Canyon Formation. **Figure 3.8-5** shows the BHP response of RH AGI #1 during the history matching phase.

During the forecasting period, linear cumulative injection behavior indicates that the Cherry Canyon and Bell Canyon formations received the TAG stream freely. **Figure 3.8-6** shows the cumulative disposed H_2S and CO_2 of each AGI injectors separately in gas mass. The modeling results indicate that the Cherry Canyon and Bell Canyon formations are capable of safely storing and containing the gas volume without violating the permitted rate and

pressure. **Figure 3.8-7** shows the gas saturation represented TAG plume at the end of 30-year forecasting in 3D view. **Figure 3.8-8** shows the extent of the plume migration in a map view at 4 key time steps. It can be observed that the size of the TAG is very limited and mainly stayed within Targa's Red Hills facility at the end of injection. In the year 2084, after 30 years of monitoring, the injected gas remained trapped in the reservoir and there was no significant migration of TAG footprint observed, compared to that at the end of injection.

In summary, after careful reservoir engineering review and numerical simulation study, our analysis shows that the Bell Canyon and Cherry Canyon formations can receive treated acid gas (TAG) at the injection rate and permitted maximum surface injection pressure permitted by New Mexico Oil Conservation Committee. The formation will safely contain the injected TAG volume within the injection and post-injection timeframe. The injection well will allow for the sequestration while preventing associated environmental impacts.

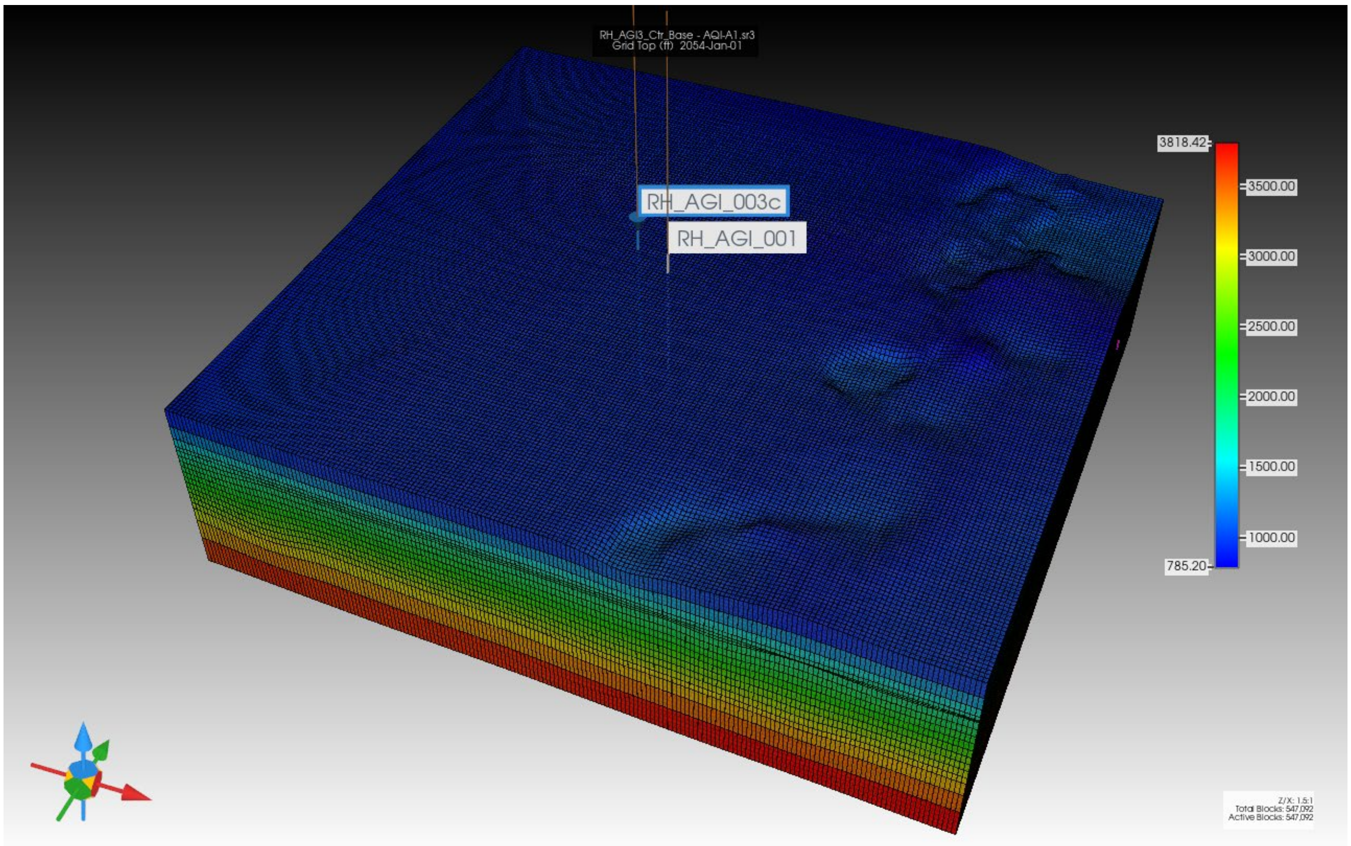


Figure 3.8-1: *3D view of the simulation model of the Red Hills AGI #1 and #3 AGI wells, containing Salado-Castile formation, Lamar limestone, Bell Canyon, and Cherry Canyon formations. Color legends represents the elevation of layers.*

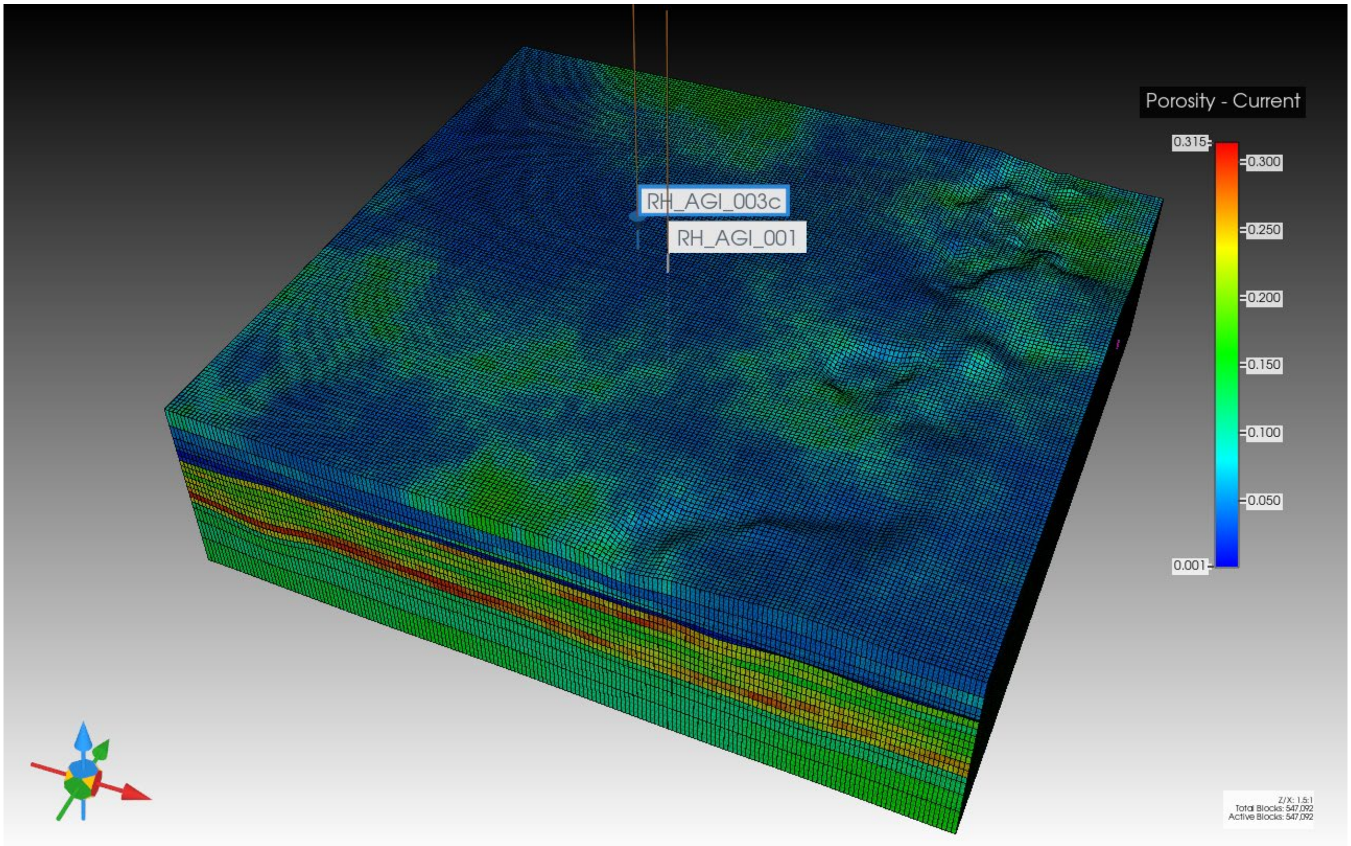


Figure 3.8-2: *Porosity estimation using available well data for the simulation domain.*

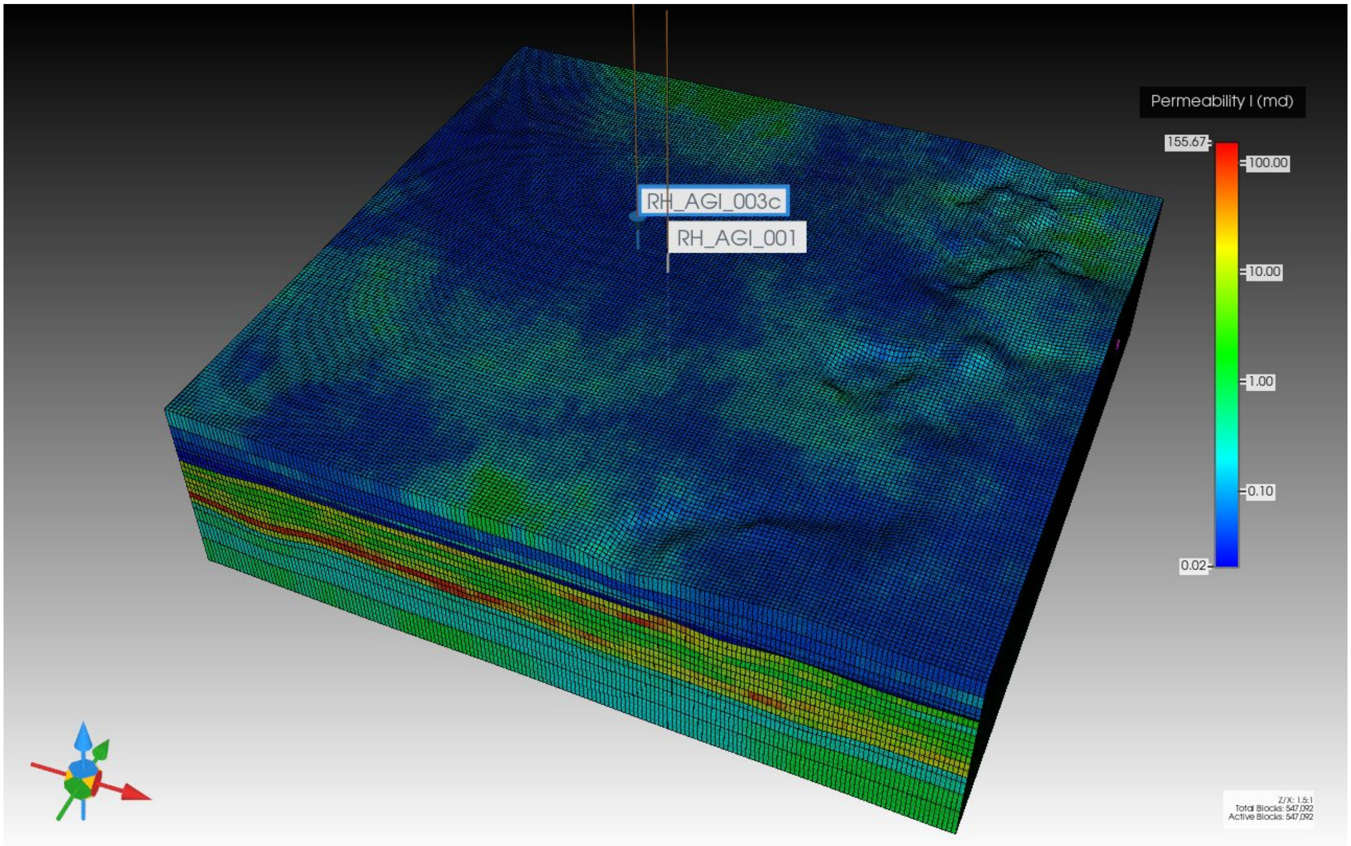


__Figure 3.8-3:__ Permeability estimation using available well data for simulation domain.

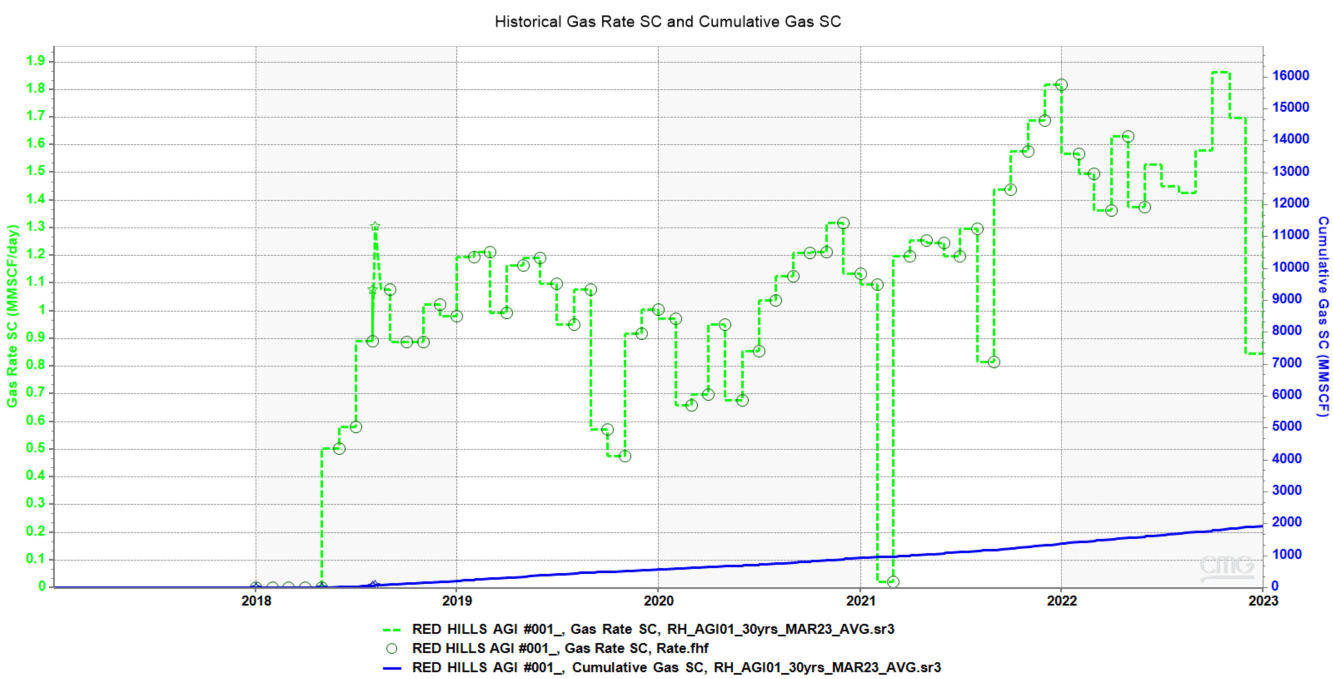


__Figure 3.8-4:__ shows the historical injection rate and total gas injected from Red Hills AGI #1 well (2018 to 2023)

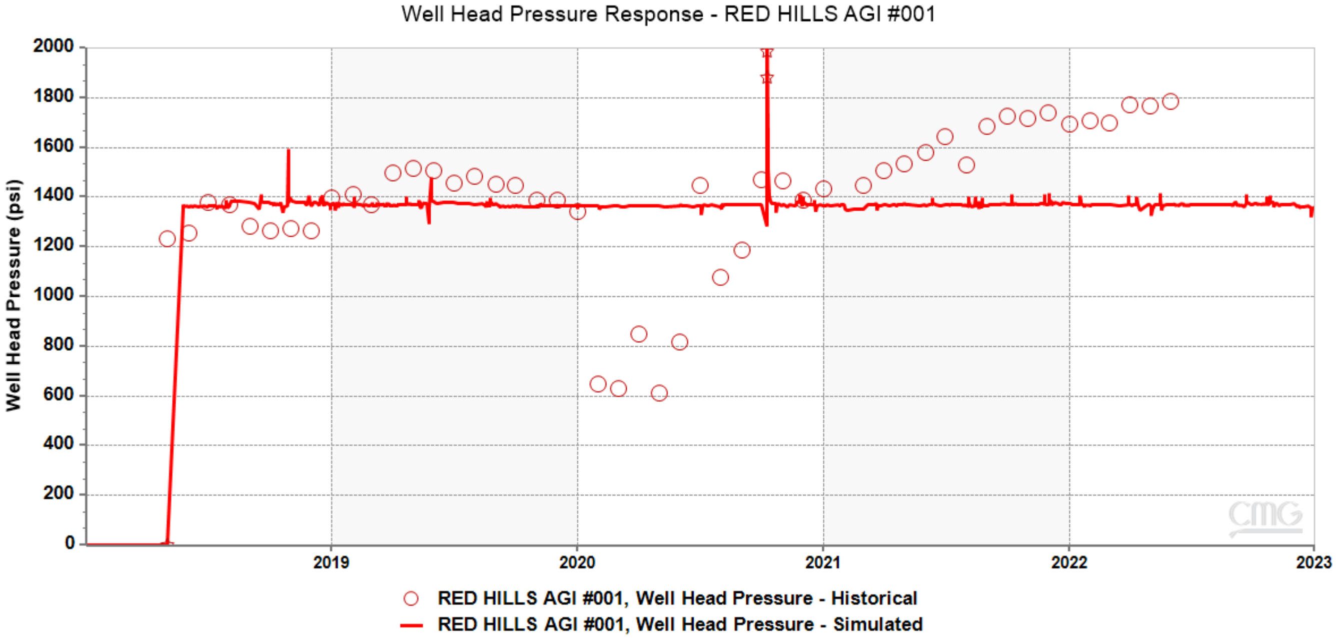


Figure 3.8-5: *shows the historical bottom hole pressure response from Red Hills AGI #1 well (2018 to 2023)*

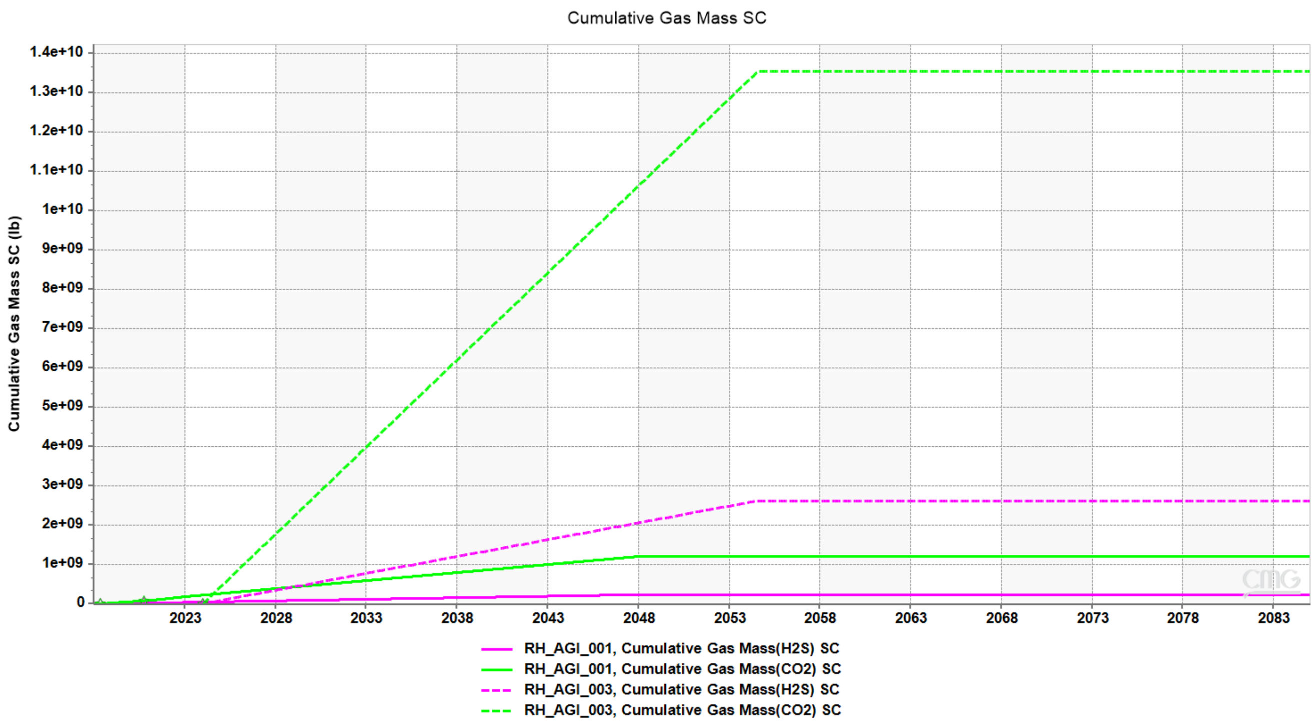


Figure 3.8-6: *shows the prediction of cumulative mass of injected CO_2 and H_2S of Red Hills AGI #1 and #3 wells (2018 to 2054).*

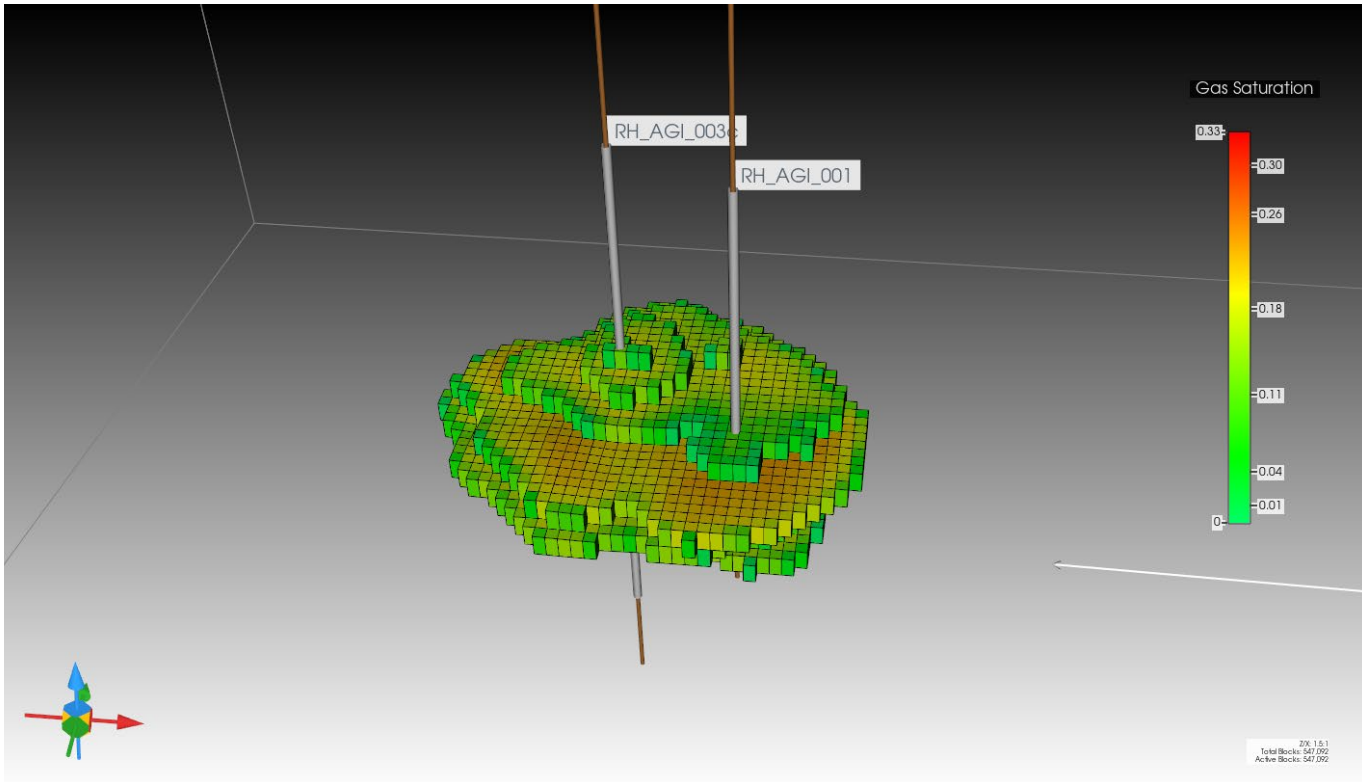


Figure 3.8-7: *shows the free phase TAG (represented by gas saturation) at the end of 30-year post-injection monitoring (2054) in 3D view.*

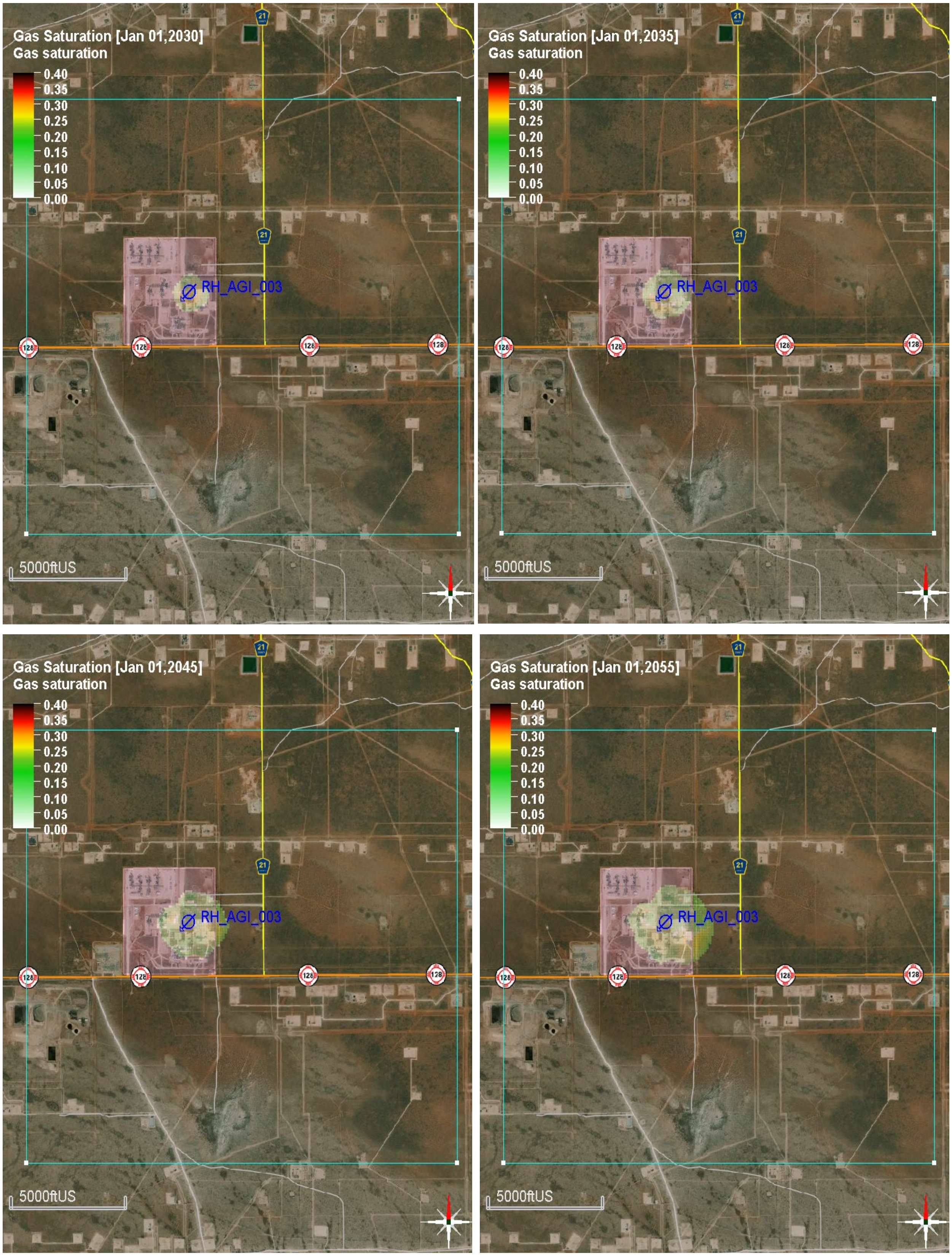


Figure 3.8-8: *shows the free phase TAG plume at year 2030, 2035, 2045, 2055 (1-year end of injection) in a map view.*

4 Delineation of the Monitoring Areas

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

4.1 MMA – Maximum Monitoring Area

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. **Figures 4.1-1** shows the MMA as defined by the extent of the stabilized TAG plume at year 2059 plus a 1/2-mile buffer.

4.2 AMA – Active Monitoring Area

The Active Monitoring Area (AMA) is shown in **Figure 4.1-1**. The AMA is consistent with the requirements in 40 CFR 98.449 because it is the area projected: (1) to contain the free phase CO_2 plume for the duration of the project (year t, t = 2054), plus an all-around buffer zone of one-half mile. (2) to contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2059). Targa intends to define the active monitoring area (AMA) as the same area as the MMA. The purple cross-hatched polygon in **Figure 4.1-1** is the plume extent at the end of injection. The yellow polygon in **Figure 4.1-1** is the stabilized plume extent 5 years after injection ceases. The AMA/MMA shown as the red-filled polygon contains the CO_2 plume during the duration of the project and at the time the plume has stabilized.

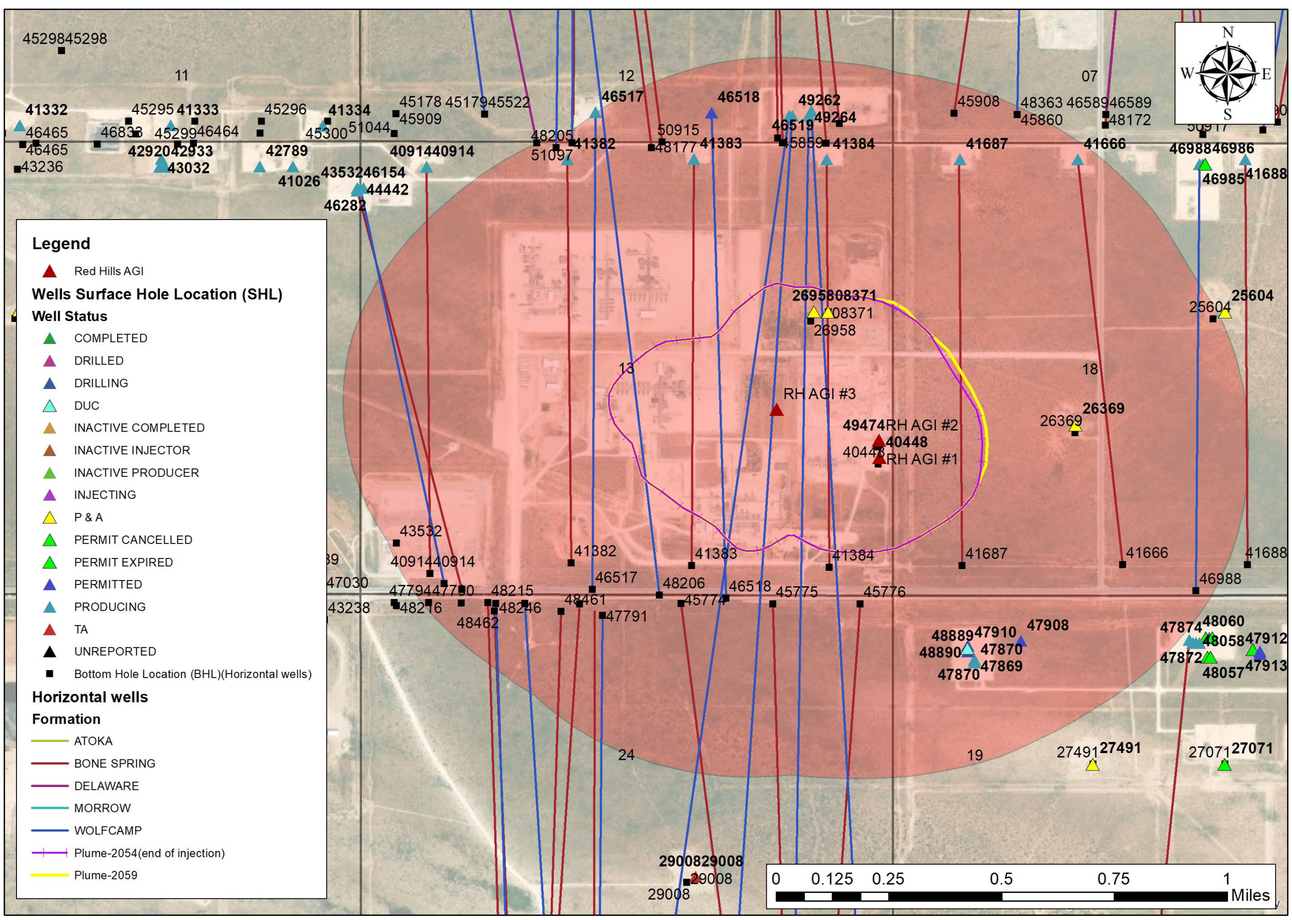


Figure 4.1-1: Active monitoring area (AMA) for TND Red Hills AGI #1, #2 (temporarily abandoned) and #3 wells at the end of injection (2054, purple polygon) and 5 years post-monitoring (2059, yellow polygon). Maximum monitoring area (MMA) is shown in red shaded area.

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

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

Through the site characterization required by the NMOCD C-108 application process for Class II injection wells, the geologic characterization presented in Section 3, and the reservoir modeling described in Section 3.8, TND has identified and evaluated the potential CO_2 leakage pathways to the surface.

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

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas facilities. Preventative risk mitigation includes adherence to relevant regulatory requirements and industry standards governing the construction, operation, and maintenance of gas plants. Specifically, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills."

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

Although mitigative measures are in place to minimize CO_2 emissions from surface equipment, such emissions are possible. Any leaks from surface equipment would result in immediate (timing) emissions of CO_2 to the atmosphere the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak.

The injection well and the pipeline that carries CO_2 to it are the most likely surface components of the system to allow CO_2 to leak to the surface. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable source of the leakage. Another possible source of leakage is the release of air through relief valves, which are designed to alleviate pipeline overpressure. Leakage can also occur when the surface components are damaged by an accident or natural disaster, which releases CO_2. Therefore, TND infers that there is a potential for leakage via this route. Depending on the component's failure mode, the magnitude of the leak can vary greatly. For example, a rapid break or rupture could release thousands of pounds of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO_2 over several hours or days. Surface component leakage or venting is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

5.2 Potential Leakage from RH AGI #3 and Approved, Not Yet Drilled Wells

RH AGI #3 very recently began injecting in January 2024. The only wells within the MMA that are approved but not yet drilled are horizontal wells. These wells have a Well Status of “permitted” in Appendix 4. There are no vertical wells within the MMA with a Well Status of "permitted”.

5.2.1 RH AGI #3

TND is began drilling the RH AGI #3 well in September 2023 and began injection in January 2024. To minimize the likelihood of leaks from new wells, NMAC 19.15.26.9 regarding the casing and cementing of injection wells requires operators to case injection wells “with safe and adequate casing or tubing so as to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluid from the injection zone into another injection zone or to the surface around the outside of the casing string.” To minimize the magnitude and duration (timing) of CO_2 leakage to the surface, NMAC 19.15.16.12 requires the use of “blowout preventers in areas of high pressure at or above the projected depth of the well.” These requirements apply to any other new well drilled within the MMA for this MRV plan.

TND realizes that when they drill the RH AGI #3, they will be drilling into a reservoir in which they have been injecting H_2S and CO_2 for many years. Therefore, for safety purposes, they will be implementing enhanced safety protocols to ensure that no H_2S or CO_2 escapes to the surface during the drilling of RH AGI #3. Enhanced measures include:

- Using managed pressure drilling equipment and techniques thereby minimizing the chance of any gas from entering the wellbore
- Using LCM (loss control material) at a higher-than-normal rate to fill in the pockets of the wellbore thereby minimizing the chance of gas from entering the wellbore while drilling
- Monitoring H_2S at surface at many points to assure operators that we are successfully keeping any possible gas pressures from impacting the drilling operation
- Employing a high level of caution and care while drilling through a known H_2S injection zone, including use of slower drilling processes and more vigilant mud level monitoring in the returns while drilling into the RH AGI #1 injection zone

By drilling through a zone containing pressurized TAG there is a possibility of CO_2 emission to the surface from the pressurized zone. The emission would be nearly immediate. The magnitude of such an emission would be estimated based on field conditions at the time of the detected leak. The safety protocols described above are in place to prevent or minimize the magnitude of such a leak should one occur.

Due to these safeguards and the continuous monitoring of Red Hills well’s operating parameters by the distributed control system (DCS), TND considers that while the likelihood of surface emission of CO_2 is possible, the magnitude of such a leak would be minimal as detection of the leak would be nearly instantaneous followed by immediately shutting in the well and remediation.

5.2.2 Horizontal Wells

The table in **Appendix 3** and **Figure 4.1-1** shows a number of horizontal wells in the area, many of which have approved permits to drill but which are not yet drilled. If any of these wells are drilled through the Bell Canyon injection zone for RH AGI #3 and the Cherry Canyon injection zone for RH AGI #1, they will be required to take special precautions to prevent leakage of TAG minimizing the likelihood of CO_2 leakage to the surface. This requirement will be made by NMOCD in regulating applications for permit to drill (APD) and in ensuring that the operator and driller are aware that they are drilling through an H_2S injection zone in order to access their target production formation. NMAC 19.15.11 for Hydrogen Sulfide Gas includes standards for personnel and equipment safety and H_2S detection and monitoring during well drilling, completion, well workovers, and well servicing operations all of which apply for wells drilled through the RH AGI wells TAG plume.

Due to the safeguards described above, the fact there are no proposed wells for which the surface hole location (SHL) lies within the simulated TAG plume and considering the NRAP risk analysis described here in Section 5, TND considers the likelihood of CO_2 emissions to the surface via these horizontal wells to be highly unlikely.

5.3 Potential Leakage from Existing Wells

Existing oil and gas wells within the MMA as delineated in Section 4 are shown in **Figure 3.6-3** and detailed in **Appendix 4**.

TND considered all wells completed and approved within the MMA in the NRAP risk assessment. Some of these wells penetrate the injection and/or confining zones while others do not. Even though the risk of CO_2 leakage through the wells that did not penetrate confining zones is highly unlikely, TND did not omit any potential source of leakage in the NRAP analysis. If leakage through wellbores happens, the worst-case scenario is predicted using the NRAP tool to quantitatively assess the amount of CO_2 leakage through existing and approved wellbores within the MMA. Thirty-nine existing and approved wells inside MMA were addressed in the NRAP analysis. The reservoir properties, well data, formation stratigraphy, and MMA area were incorporated into the NRAP tool to forecast the rate and mass of CO_2 leakage. The worst scenario is that all of the 39 wells were located right at the source of CO_2 – the injection well's location. In this case, the maximum leakage rate of one well is approximately 7e-6 kg/s. This value is the maximum amount of CO_2 leakage, 220 kg/year, and occurs in the second year of injection, then gradually reduces to 180 kg at the end of year 30. Comparing the total amount of CO_2 injected (assuming 5 MMSCFD of supercritical CO_2 injected continuously for 30 years), the leakage mass amounts to 0.0054% of the total CO_2 injected. This leakage is considered negligible. Also, this worst-case scenario, where 39 wells are located right at the injection point, is impossible in reality. Therefore, CO_2 leakage to the surface via this potential leakage pathway can be considered improbable.

5.3.1 Wells Completed in the Bell Canyon and Cherry Canyon Formations

The only wells completed in the Bell Canyon and Cherry Canyon Formations within the MMA are the RH AGI #1 and #3 wells and the 30-025-08371 well which was completed at a depth of 5,425 ft. This well is within the Red Hills facility boundary and is plugged and abandoned (see **Appendix 9** for plugging and abandonment (P&A) record). **Appendix 1** includes schematics of the RH AGI wells construction showing multiple strings of casing all cemented to surface. Injection of TAG occurs through tubing with a permanent production packer set above the injection zone.

Due to the robust construction of the RH AGI wells, the plugging of the well 30-025-08371 above the Bell Canyon, and considering the NRAP analysis described above, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.2 Wells Completed in the Bone Spring / Wolfcamp Zones

Several wells are completed in the Bone Spring and Wolfcamp oil and gas production zones as described in Section 3.6.2. These productive zones lie more than 2,000 ft below the RH AGI wells injection zone minimizing the likelihood of communication between the RH AGI well injection zones and the Bone Spring / Wolfcamp production zones. Construction of these wells includes surface casing set at 1,375 ft and cemented to surface and intermediate casing set at the top of the Bell Canyon at depths of from 5,100 to 5,200 ft and cemented through the Permian Ochoan evaporites, limestone and siltstone (**Figure 3.2-2**) providing zonal isolation preventing TAG injected into the Bell Canyon and Cherry Canyon formations through RH AGI wells from leaking upward along the borehole in the event the TAG plume were to reach these wellbores. **Figure 4.1-1** shows that the modeled TAG plume extent after 30 years of injection and 5 years of post-injection stabilization does not extend to well boreholes completed in the Bone Spring / Wolfcamp production zones thereby indicating that these wells are not likely to be pathways for CO_2 leakage to the surface.

Due to the construction of these wells, the fact that the modeled TAG plume does not reach the SHL of these wells and considering the NRAP analysis described in the introductory paragraph of Section 5, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.3 Wells Completed in the Siluro-Devonian Zone

One well penetrated the Devonian at the boundary of the MMA - EOG Resources, Government Com 001, API # 30-025-25604, TVD = 17,625 ft, 0.87 miles from RH AGI #3. This well was drilled to a total depth of 17,625 ft on March 5, 1978, but plugged back to 14,590 ft, just below the Morrow, in May of 1978. Subsequently, this well was permanently plugged and abandoned on December 30, 2004, and approved by NMOCD on January 4, 2005 (see **Appendix 9** for P&A records). The approved plugging provides zonal isolation for the Bell Canyon and Cherry Canyon injection zones minimizing the likelihood that this well will be a pathway for CO_2 emissions to the surface from either injection zone.

Due to the location of this well at the edge of the MMA and considering the NRAP analysis described in the introductory paragraph of Section 5, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.4 Groundwater Wells

The table in Appendix 3 lists 15 water wells within a 2-mile radius of the RH AGI wells, only 2 of which are within a 1-mile radius of and within the MMA for the RH AGI wells (**Figure 3.5-1**). The deepest ground water well is 650 ft deep The evaporite sequence of the Permian Ochoan Salado and Castile Formations (see Section 3.2.2) provides an excellent seal between these groundwater wells and the Cherry Canyon injection zone of the RH AGI #1 well. Therefore, it is unlikely that these two groundwater wells are a potential pathway of CO_2 leakage to the surface. Nevertheless, the CO_2 surface monitoring and groundwater monitoring described in Sections 6 and 7 will provide early detection of CO_2 leakage followed by immediate response thereby minimizing the magnitude of CO_2 leakage volume via this potential pathway.

Due to the shallow depth of the groundwater wells within the MMA relative to the depth of the RH AGI wells and considering the NRAP analysis described in the introductory paragraph in Section 5, TND considers that, while the likelihood of CO_2 emissions to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.4 Potential Leakage through the Confining / Seal System

The site characterization for the injection zone of the RH AGI wells described in Sections 3.2.2 and 3.3 indicates a thick sequence of Permian Ochoan evaporites, limestone, and siltstones (**Figure 3.2-2**) above the Bell Canyon and Cherry Canyon Formations and no evidence of faulting. Therefore, it is unlikely that TAG injected into the Bell Canyon and Cherry Canyon Formations will leak through this confining zone to the surface. Limiting the injection pressure to less than the fracture pressure of the confining zone will minimize the likelihood of CO_2 leakage through this potential pathway to the surface.

Leakage through a confining zone happens at low-permeability shale formations containing natural fractures. The injection zone for the RH AGI #1 and #3 is the Delaware Group Formation (Bell Canyon and Cherry Canyon), which lies under the Castile and Salado formations with less than 0.01 mD permeability acting as the seals. Therefore, TND took leakage through confining zones into consideration in the NRAP risk assessment. The worst-case scenario is defined as leakage through the seal happening right above the injection wells, where CO_2 saturation is highest. However, this worst-case scenario of leakage only shows that 0.0017% of total CO_2 injection in 30 years was leaked from the injection zone through the seals. As we go further from the source of CO_2, the likelihood of such an event will diminish proportionally with the distance from the source. Considering that this is the greatest amount of CO_2 leakage in this worst-case scenario, if the event happens, the leak must pass upward through the confining zone, the secondary confining strata that consists of additional low permeability geologic units, and other geologic units, TND concludes that the risk of leakage through this pathway is highly unlikely.

5.5 Potential Leakage due to Lateral Migration

The characterization of the sand layers in the Cherry Canyon Formation described in Section 3.3 states that these sands were deposited by turbidites in channels in submarine fan complexes, each sand is encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity. Regional consideration of their depositional environment suggests a preferred orientation for fluid and gas flow would be south-to-north along the channel axis. However, locally the high net porosity of the RH AGI #1 and #3 injection zones indicates adequate storage capacity such that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA due to a preferred regional depositional orientation.

Lateral migration of the injected TAG was addressed in detail in Section 3.3. Therein it states that the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales as well as being encased by them.

Based on the discussion of the channeled sands in the injection zone, TND considers that the likelihood of CO_2 to migrate laterally along the channel axes is possible. However, that the turbidite sands are encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity and that the injectate is projected to be contained within the injection zone close to the injection wells minimizes the likelihood that CO_2 will migrate to a potential conduit to the surface.

5.6 Potential Leakage through Fractures and Faults

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology as well as identify and understand the distribution of faults and fractures. **Figure 5.6-1** shows the fault traces in the vicinity of the Red Hill plant. The faults shown on **Figure 5.6-1** are confined to the Paleozoic section below the injection zone for the RH AGI wells. No faults were identified in the confining zone above the Bell Canyon and Cherry Canyon injection zone for the RH AGI wells.

No faults were identified within the MMA which could potentially serve as conduits for surface CO_2 emission. The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief. Because this fault is confined to the lower Paleozoic unit more than 5,100 feet below the injection zone for the RH AGI wells, there is minimal chance it would be a potential leakage pathway. This inference is supported by the NRAP simulation result. Therefore, TND concludes that the CO_2 leakage rate through this fault is zero and that the risk of leakage through this potential leakage pathway is highly improbable.

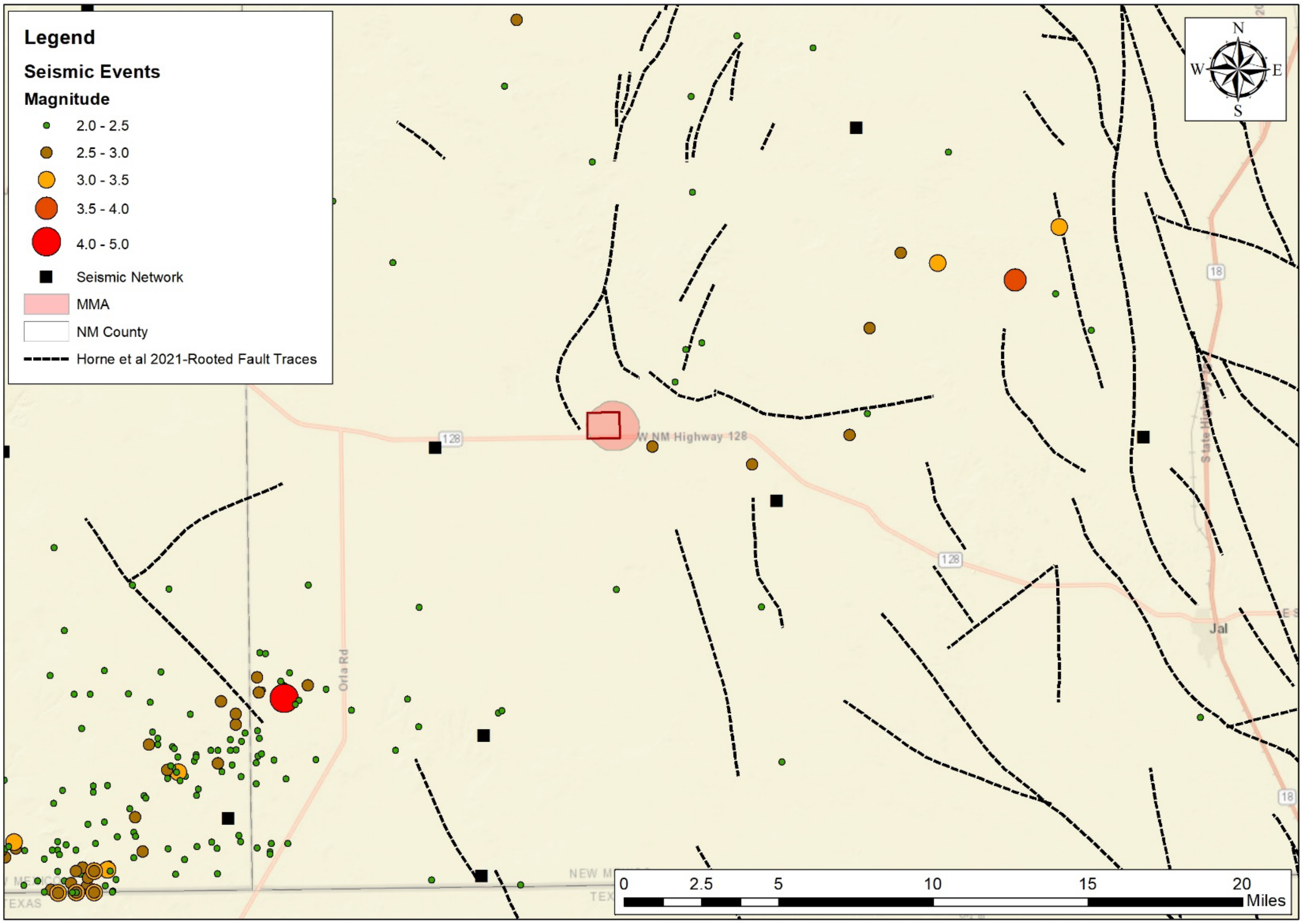


***Figure 5.6-1**: New Mexico Tech Seismological Observatory (NMTSO) seismic network close to the operations, recent seismic events, and fault traces (2022-2023). Note: Fault traces are from Horne et al 2021 for deep seated faults in the lower Paleozoic. The fault traces shown close to the Red Hills facility die out at the base of the Wolfcamp formation at a depth of 12,600 feet, more than 5,100 feet below the bottom of the injection zone at 7,500 feet.*

5.7 Potential Leakage due to Natural / Induced Seismicity

The New Mexico Tech Seismological Observatory (NMTSO) monitors seismic activity in the state of New Mexico. A search of the database shows no recent seismic events close to the Red Hills operations. The closest recent, as of 4 September 2023, seismic events are:

- 7.5 miles, 2022-09-03, Magnitude 3
- 8 miles, 2022-09-02, Magnitude 2.23
- 8.6 miles, 2022-10-29, Magnitude 2.1

Figure 5.6-1 shows the seismic stations and recent seismic events in the area around the Red Hills site.

Due to the distance between the Red Hills AGI wells and the recent seismic events, the magnitude of these events, and the fact that TND injects at pressures below fracture opening pressure, TND considers the likelihood of CO_2 emissions to the surface caused by seismicity to be improbable.

Monitoring of seismic events in the vicinity of the Red Hills AGI wells is discussed in Section 6.7.

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

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

Table 6-1: Summary of Leak Detection Monitoring

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors
Existing RH AGI Wells	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors • In-well P/T sensors • Groundwater monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring

Potential Leakage Pathway	Detection Monitoring
Additional Monitoring	● Groundwater monitoring ● Soil flux monitoring

6.1 Leakage from Surface Equipment

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

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

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

> “**Fixed Monitors**
> The Red Hills Plant has numerous ambient hydrogen sulfide detectors placed strategically throughout the Plant to detect possible leaks. Upon detection of hydrogen sulfide at 10 ppm at any detector, visible beacons are activated, and an alarm is sounded. Upon detection of hydrogen sulfide at 90 ppm at any detector, an evacuation alarm is sounded throughout the Plant at which time all personnel will proceed immediately to a designated evacuation area. The Plant utilizes fixed-point monitors to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel’s Programmable Logic Controllers (PLCs), and then to the Distributed Control System (DCS). The monitors are equipped with amber beacons. The beacon is activated at 10 ppm. The plant and AGI well horns are activated with a continuous warbling alarm at 10 ppm and a siren at 90 ppm. All monitoring equipment is Red Line brand. The Control Panel is a 24 Channel Monitor Box, and the fixed point H_2S Sensor Heads are model number RL-101.
>
> The Plant will be able to monitor concentrations of H_2S via H_2S Analyzers in the following locations:
> - Inlet gas of the combined stream from Winkler and Limestone
> - Inlet sour liquid downstream of the slug catcher
> - Outlet Sweet Gas to Red Hills 1
> - Outlet Sweet Liquid to Red Hills Condensate Surge
>
> The AGI system monitors can also be viewed on the PLC displays located at the Plant. These sensors are all shown on the plot plan (see **Figure 3.6-1**). This requires immediate action for any occurrence or malfunction. All H_2S sensors are calibrated monthly.

Personal and Handheld H_2S Monitors

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

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones as described in Section 5.2.1 for RH AGI #3 including more frequent monitoring during drilling operations (see **Table 6-1**). This applies to TND and other operators drilling new wells through the RH AGI injection zone within the MMA.

6.3 Leakage from Existing Wells

6.3.1 RH AGI Wells

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

To monitor leakage and wellbore integrity, two pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) were deployed in TND's RH AGI #1 well. One gauge is designated to monitor the tubing ID (reservoir) pressure and temperature and the second gauge monitors the annular space between the tubing and the long string casing (**Figure 6.2-1**). A leak is indicated when both gauges start reading the same pressure. DTS is clamped to the tubing, and it monitors the temperature profiles of the annulus from 6,159 ft to surface. DTS can detect variation in the temperature profile events throughout the tubing and or casing. Temperature variation could be an indicator of leaks. Data from temperature and pressure gauges is recorded by an interrogator housed in an onsite control room. DTS (temperature) data is recorded by a separate interrogator that is also housed in the onsite control room. Data from both interrogators are transmitted to a remote location for daily real time or historical analysis.

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

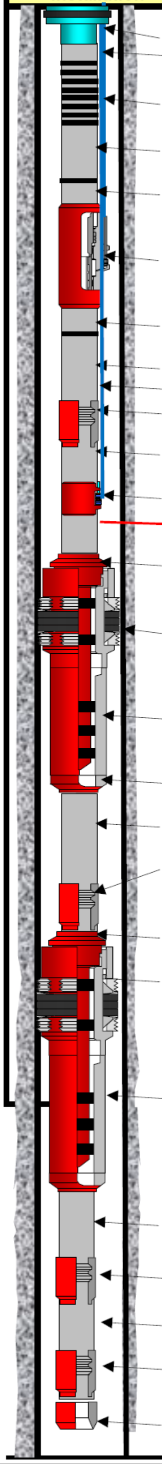
HALLIBURTON

Lucid

Red Hills AGI 1
Lea County New Mexico
2/3/21 - 2/28/21

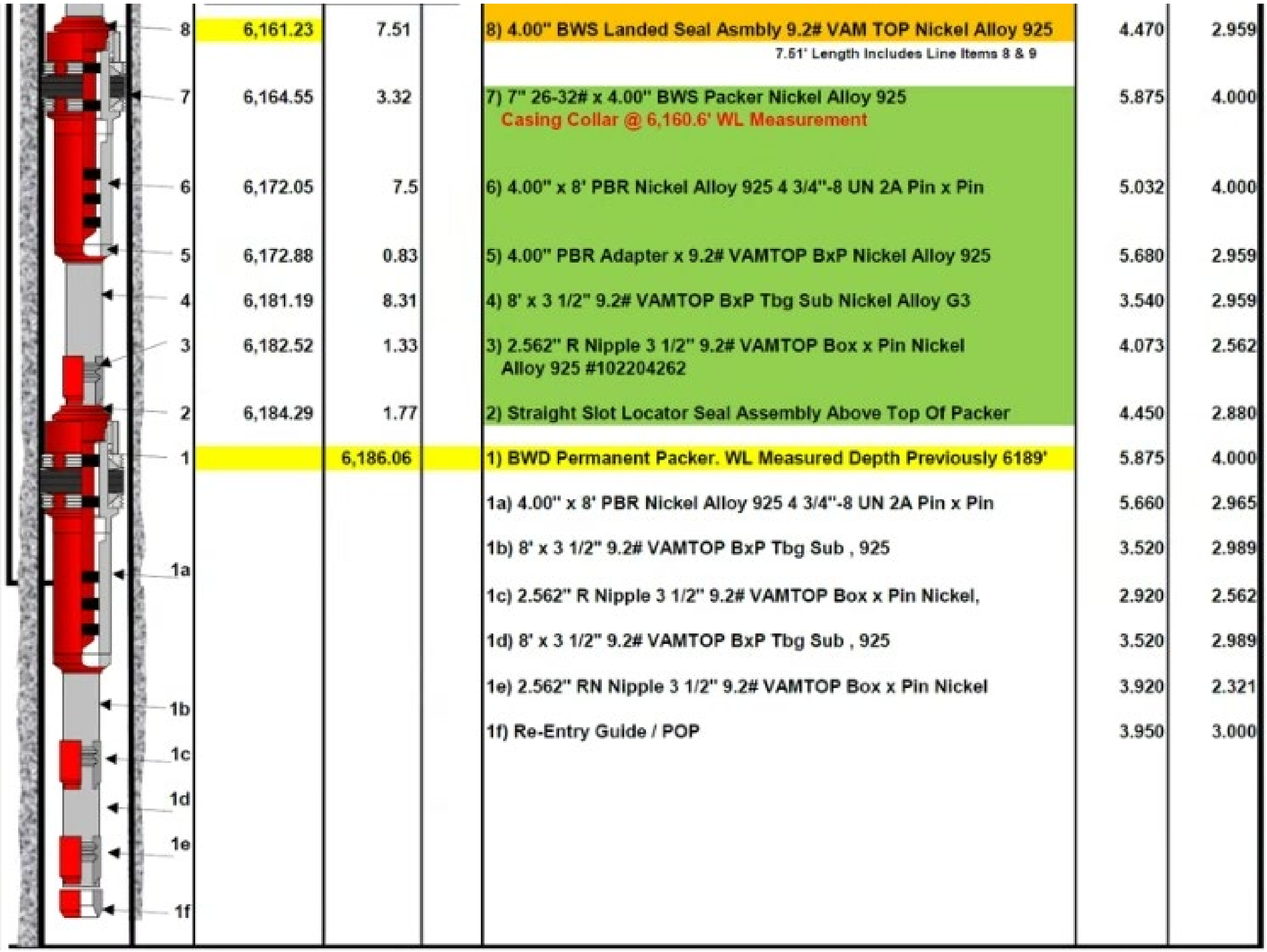
WSP - Troy Gillen / Michael Forrier
Sales Rep - Lynn Talley (432) 631-4626
Tool Specialists: Carey Lehmann, Jonathan Phillips, Jose Vargas

Installation



Installation	Depth	Length	Jts.	Description	OD	ID
	18.50	18.50		KB		
20	22.90	4.40		20) Hanger Sub 3 1/2" 9.2# CRA VAMTOP x 7.7# VAM Ace Pin	7.000	3.000
19	64.05	41.15	1	19) 3 1/2" 7.7# VAM ACE 125K G3 Tubing (Slick Joint)	3.500	3.035
				Ran Eight Subs 8', 8', 6', 6',4', 4', 2', 2'		
18	103.97	39.92		18) 3 1/2" 7.7# VAM ACE 125K G3 Spaceout Subs	3.500	3.035
17	235.95	131.98	3	17) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.035
16	241.95	6.00		16) 6' x 3 1/2" 7.7# CRA VAM ACE Box x 9.2# VAMTOP Pin	3.540	2.959
15	246.30	4.35		15) 3 1/2" NE HES SSSV Nickel Alloy 925 w/Alloy 825 Control Line 3 1/2" 9.2# VAMTOP Box x Pin	5.300	2.813
14	252.29	5.99		14) 6' x 3 1/2" 9.2# CRA VAMTOP Box x 7.7# VAM ACE Pin	3.540	2.959
13	6,140.23	5,887.94	134	13) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.305
12				12) 3 1/2" 7.7# VAM ACE Box x 9.2# VAMTOP Pin CRA Crossover	3.830	2.959
11				11) 2.813" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925	4.073	2.813
10	6,153.72	13.49		10) 6' x 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy G3 Sub	3.540	2.959
				13.49' Length Includes Line Items 10, 11 & 12		
	6,159 Tubing	P/T				
9				9) Baker PT Sensor Mandrel 3 1/2" 9.2# VAMTOP Box x Pin 6' VAMTOP 9.2# CRA Tubing Sub Above & Below Gauge Mdl	5.200	2.992
	6,162.6 Annular	P/T				
8	6,161.23	7.51		8) 4.00" BWS Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925	4.470	2.959
				7.51' Length Includes Line Items 8 & 9		
7	6,164.55	3.32		7) 7" 26-32# x 4.00" BWS Packer Nickel Alloy 925 Casing Collar @ 6,160.6' WL Measurement	5.875	4.000
6	6,172.05	7.5		6) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
5	6,172.88	0.83		5) 4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
4	6,181.19	8.31		4) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
3	6,182.52	1.33		3) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925 #102204262	4.073	2.562
2	6,184.29	1.77		2) Straight Slot Locator Seal Assembly Above Top Of Packer	4.450	2.880
1		6,186.06		1) BWD Permanent Packer. WL Measured Depth Previously 6189'	5.875	4.000
1a				1a) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.660	2.965
1b				1b) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1c				1c) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel,	2.920	2.562
1d				1d) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1e				1e) 2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	3.920	2.321
1f				1f) Re-Entry Guide / POP	3.950	3.000

__Figure 6.2-1:__ Well Schematic for RH AGI #1 showing installation of P/T sensors



8	6,161.23	7.51	8) 4.00" BWS Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925 7.51' Length Includes Line Items 8 & 9	4.470	2.959
7	6,164.55	3.32	7) 7" 26-32# x 4.00" BWS Packer Nickel Alloy 925 Casing Collar @ 6,160.6' WL Measurement	5.875	4.000
6	6,172.05	7.5	6) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
5	6,172.88	0.83	5) 4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
4	6,181.19	8.31	4) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
3	6,182.52	1.33	3) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925 #102204262	4.073	2.562
2	6,184.29	1.77	2) Straight Slot Locator Seal Assembly Above Top Of Packer	4.450	2.880
1		6,186.06	1) BWD Permanent Packer. WL Measured Depth Previously 6189'	5.875	4.000
1a			1a) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.660	2.965
1b			1b) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1c			1c) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel,	2.920	2.562
1d			1d) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1e			1e) 2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	3.920	2.321
1f			1f) Re-Entry Guide / POP	3.950	3.000

***Figure 6.2-2**: Well Schematic for RH AGI #3 showing intended installation of P/T sensors*

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7.3 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. Additionally, groundwater and soil CO_2 flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through the Confining / Seal System

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

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

6.5 Leakage due to Lateral Migration

Continuous operational monitoring of the RH AGI wells during and after the period of the injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The CO_2 monitoring network described in Section 7.3, and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

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

6.6 Leakage from Fractures and Faults

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through faults. However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, TND will identify which of the pathways listed in this section are responsible for the leak, including the possibility of heretofore unidentified faults or fractures within the MMA. TND will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details. See Section 6.8 for additional information on quantification strategies.

6.7 Leakage due to Natural / Induced Seismicity

In order to monitor the influence of natural and/or induced seismicity, TND will use the established NMTSO seismic network. The network consists of seismic monitoring stations that detect and locate seismic events. Continuous monitoring helps differentiate between natural and induced seismicity. The network surrounding the Red Hills Gas Processing Plant has been mapped on **Figure 5.6-1**. The monitoring network records Helicorder data from UTC (coordinated universal time) all day long. The data are plotted daily at 5pm MST (mountain standard time). These plots can be browsed either by station or by day. The data are streamed continuously to the New Mexico Tech campus and archived at the Incorporated Research Institutions for Seismology Data Management Center (IRIS DMC).

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

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

For normal operations, quantification of emissions of CO_2 from surface equipment will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR. Quantification of major leakage events from surface equipment as identified by the detection techniques listed in Table 6-1 will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified the leakage location will be isolated to prevent additional emissions to

the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. TND has standard operating procedures to report and quantify all pipeline leaks in accordance with the NMOCD regulations (New Mexico administrative Code 19.15.28 Natural Gas Gathering Systems). TND will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by TND or third parties. Additionally, TND may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

6.8.2 Subsurface Leakage

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

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

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, or which may be initiated by seismic events and as may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO_2 leaking back to the surface emphasizing the importance of monitoring network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO_2 flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 6.8.1, or from the subsurface. In the latter case, CO_2 flux monitoring methodologies, as described in Section 7.8, will be employed to quantify the surface leaks.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

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

7.1 Visual Inspection

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

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

Compositional analysis of TND's gas injectate at the Red Hills Gas Plant indicates an approximate H_2S concentration of 20% thus requiring TND to develop and maintain an H_2S Contingency Plan (Plan) according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). TND considers H_2S to be a proxy for CO_2 leaks at the plant. The Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated RH AGI Wells and documents procedures that would be followed in case of such an event.

7.2.1 Fixed In-Field H_2S Monitors

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

7.2.2 Handheld and Personal H_2S Monitors

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

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

7.3 CO_2 Detection

In addition to the handheld gas detection monitors described above, New Mexico Tech, through a DOE research grant (DE-FE0031837 – Carbon Utilization and Storage Project of the Western USA (CUSP)), will assist TND in setting up a monitoring network for CO_2 leakage detection in the AMA as defined in Section 4.2. The scope of work for the DOE project includes field sampling activities to monitor CO_2/H_2S at the two RH AGI wells. These activities include periodic well (groundwater and gas) and atmospheric sampling from an area of 10 – 15 square miles around the injection wells. Once the network is set up, TND will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

7.4 Continuous Parameter Monitoring

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

7.5 Well Surveillance

TND adheres to the requirements of NMOCC Rule 26 governing the construction, operation and closing of an injection well under the Oil and Gas Act. Rule 26 also includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, NMOCC includes special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. TND's Routine Operations and Maintenance Procedures for the RH AGI wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic (Microseismic) Monitoring Stations

TND has Installed a model TCH120-1 Trillium Compact Horizon Seismometer and a model CTR4-3S Centaur Digital Recorder to monitor for and record data for any seismic event at the Red Hills Gas Plant (see **Figure 7-1)**. The seismic station meets the requirements of the NMOCC Order No. R-20916-H to "install, operate, and monitor for the life of the [Class II AGI] permit a seismic monitoring station or stations as directed by the Manager of the New Mexico Tech Seismological Observatory ("state seismologist") at the New Mexico Bureau of Geology and Mineral Resources."

In addition, data that is recorded by the State of New Mexico deployed seismic network within a 10-mile radius of the Red Hills Gas Plant will be analyzed by the New Mexico Bureau of Geology (NMBGMR), see **Figure 5.6-1**, and made publicly available. The NMBGMR seismologist will create a report and map showing the magnitudes of recorded events from seismic activity. The data is being continuously recorded. By examining historical data, a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

7.7 Groundwater Monitoring

New Mexico Tech, through the same DOE research grant described in Section 7.3 above, will monitor groundwater wells for CO_2 leakage which are located within the AMA as defined in Section 4.2. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 7.7-1**. Baseline analyses will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Red Hills Gas Plant. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

Table 7.7-1: Groundwater Monitoring Parameters

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

7.8 Soil CO_2 Flux Monitoring

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

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

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

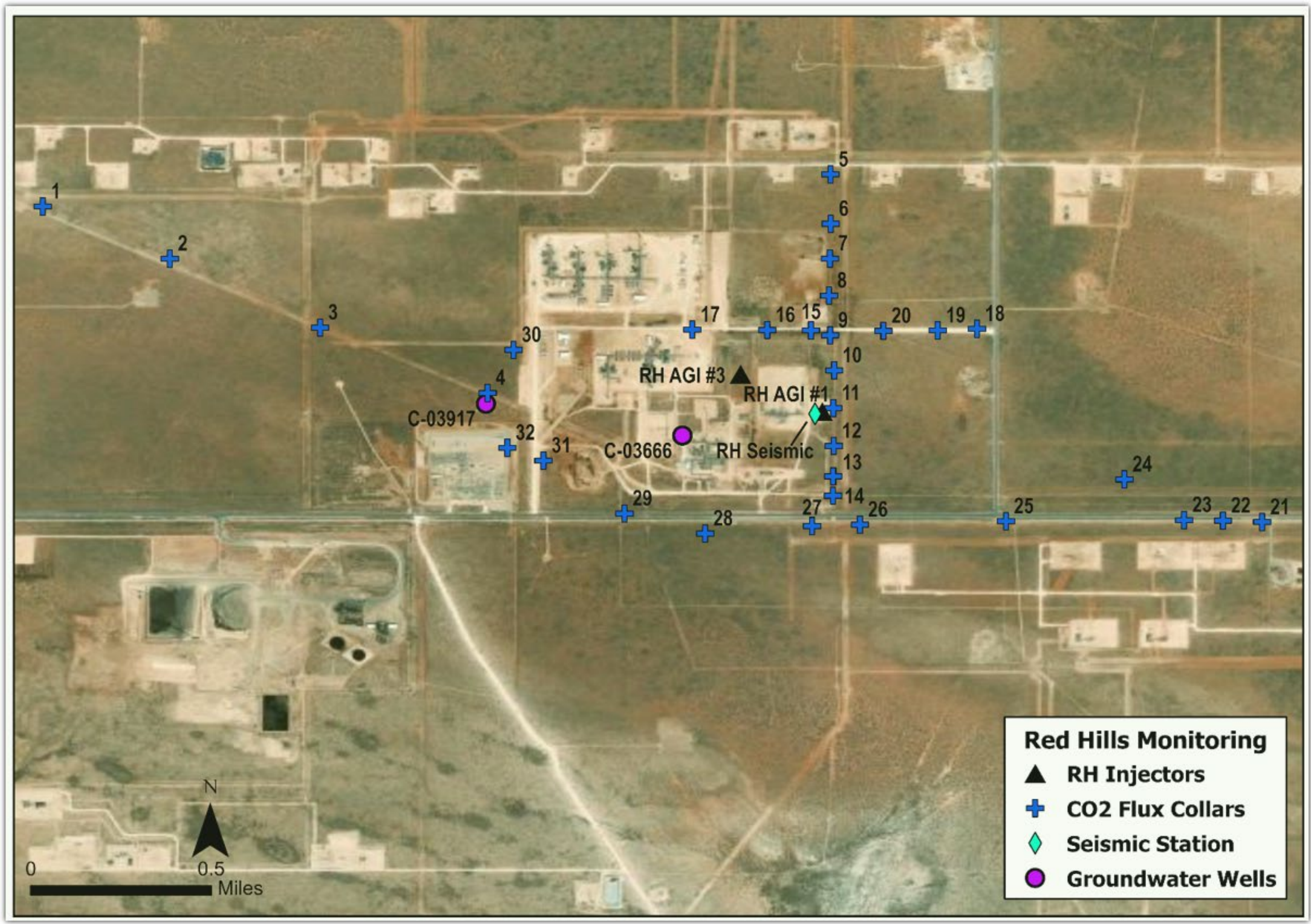


Figure 7-1: *Red Hills monitoring network of 32 CO_2 flux locations, 2 groundwater wells, and a seismic station developed by New Mexico Tech and Targa Resources to detect leakage during injection.*

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve Subpart RR equations used to calculate the mass of CO_2 sequestered annually. **Appendix 8** includes the twelve equations from Subpart RR. Not all of these equations apply to TND's current operations at the Red Hills Gas Plant but are included in the event TND's operations change in such a way that their use is required.

Figure 3.6-2 shows the location of all surface equipment and points of venting listed in 40CFR98.232(d) of Subpart W that will be used in the calculations listed below.

8.1 CO_2 Received

Currently, TND receives gas to its Red Hills Gas Plant through six pipelines: Gut Line, Winkler Discharge, Red Hills 24" Inlet Loop, Greyhound Discharge, Limestone Discharge, and the Plantview Loop. The gas is processed as described in Section 3.8 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection. TND will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3. Receiving flow meter r in the following equations corresponds to meters M1 and M2 in **Figure 3.6-2**.

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

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

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

8.2 CO_2 Injected

TND injects CO_2 into the existing RH AGI #1. Upon completion, TND will commence injection into RH AGI #3. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into both wells. The

calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Volumetric flow meter u in the following equations corresponds to meters M3 and M6 in **Figure 3.6-2**.

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

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

(Equation RR-6)

where:

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

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

u = Flow meter.

8.3 CO_2 Produced / Recycled

TND does not produce oil or gas or any other liquid at its Red Hills Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.6 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6.8.

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

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

8.6 CO_2 Sequestered

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

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

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

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

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

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

9 Estimated Schedule for Implementation of MRV Plan

The baseline monitoring and leakage detection and quantification strategies described herein have been established and data collected by TND and its predecessor, Lucid, for several years and continues to the present. TND will begin implementing this revised MRV plan as soon as it is approved by EPA. After RH AGI #3 is drilled, TND will reevaluate the MRV plan and if any modifications are a material change per 40CFR98.448(d)(1), TND will submit a revised MRV plan as required by 40CFR98.448(d).

10 GHG Monitoring and Quality Assurance Program

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

10.1 GHG Monitoring

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

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data

- Explanation of the processes and methods used to collect the necessary data for the GHG calculations
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

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

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

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.3 CO_2 injected.

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

10.1.4 CO_2 produced.

TND does not produce CO_2 at the Red Hills Gas Plant.

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

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

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

10.1.6 Measurement devices.

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

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

- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.2 QA/QC Procedures

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

10.3 Estimating Missing Data

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

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

10.4 Revisions of the MRV Plan

TND will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of New Mexico. If any operational changes constitute a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change. TND intends to update the MRV plan after RH AGI #3 has been drilled and characterized.

11 Records Retention

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

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

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

(i) The GHG emissions calculations and methods used

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

(iii) The results of all required analyses

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

(3) The annual GHG reports.

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

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

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

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

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

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

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

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

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

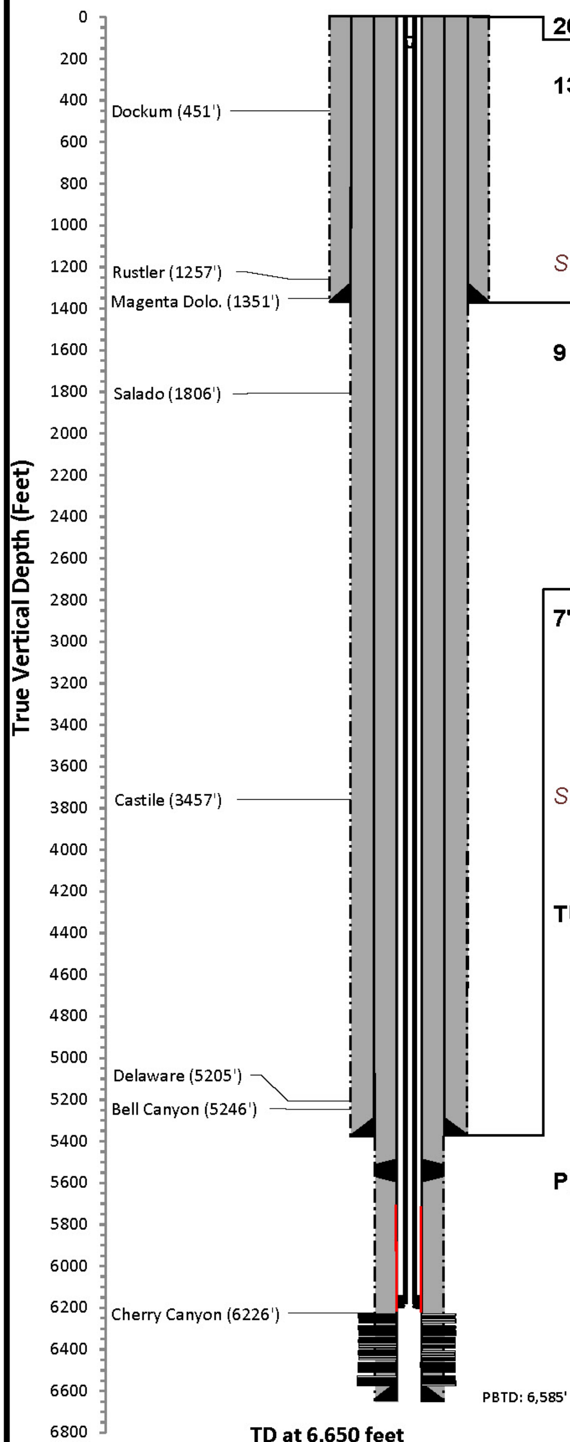
12 Appendices

Appendix 1 TND Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Red Hills AGI #1	30-025-40448	1,600 ft FSL, 150 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	10/23/2013	6,650 ft	6,170 ft
Red Hill AGI #3	30-025-51970	3,116 ft FNL, 1,159 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	9/13/2023	6,650 ft	5,700 ft

Lucid Energy Red Hills AGI #1 Well Schematic

Well Name:	Red Hills AGI #1	**Footage**	1600' FSL & 150' FEL
API:	30-025-40448	**Well Type**	AGI Exploratory Cherry Canyon
STR:	Sec. I-13, T24S-R33E	**KB/GL:**	3596/3580
County, St.	Lea County, New Mexico	**Lat, Long:**	32.214586, -103.517520



20" CONDUCTOR PIPE to 40 ft.

13 3/8" SURFACE CASING to 1,372 ft. **17.5" OH**

13 3/8", 48 #/ft., H-40, STC
Cmnt to surface - 90 bbls returned
Lead Cmnt: 820 sx C Lite
Tail Cmnt: 180 sx Class C

SSSV @ 250'

9 5/8" INTERMEDIATE CASING to 5,346 ft. **12.25" OH**

9 5/8", 40 #/ft., J-55, LT&C 0-100'
9 5/8", 36 #/ft., J-55, LT&C 100-3,300'
9 5/8", 40 #/ft., J-55, LT&C 3,300'-4,200'
9 5/8", 40 #/ft., HCK-55, LT&C 4,200'-5,346'
Cmnt to surface - 60 bbls returned
Lead Cmnt: 1,280 sx C Lite
Tail Cmnt: 180 sx Class C

7" PRODUCTION CASING to 6,650 ft. **8.75" OH**

7" 26 #/ft., L80, LT&C from 0'-5,702'
w/ 7" G-3, 26 #/ft. VAMTOP, from 5,702'-6,239'
7" 26 #/ft., L80, LT&C from 6,239' - 6,650'
Cmnt to surface both stages - 1.5 bbls
Stage 1 - Lead: 250 sx EverCrete
StageTool in 7-in casing @ 5,539'
Stage 2 - Lead: 490 sx C Lite
Stage 2 - Tail: 100 sx Class C

TUBING AND EQUIPMENT

Halliburton Retrievable SSSV set @ 250 ft.
3.5", 9.3 #/ft, L80, VAMTOP from 0'-5,870'
3.5",SM2550, VAMTOP from 5,870'-6,167'
Bottom Hole P/T Gauge set above packer @ 6,167'-6,170'
Permanent Production-Packer set @ 6,170'
Check Valve and Choke (optional)
Annulus filled w/ diesel mixed with corrosion inhibitor/biocide

PERFORATIONS

Primary Target:
Upper Cherry Canyon (6 spf @ 60°)
6,230' - 6,250'
6,260' - 6,280'
6,295' - 6,335'
6,355' - 6,380'
6,400' - 6,415'
6,435' - 6,500'
6,525' - 6,583'

Prepared For: LUCID energy group

Prepared By: GEOLEX INCORPORATED

Schematic is properly scaled

Figure Appendix 1-1: *Schematic of TND RH AGI #1 Well*

Targa Resources
Red Hills Delaware AGI #3
Location 3116' FNL & 1159' FEL
Sec 13 - T 24S - R 33E
GL 3578', RKB TBD

Surface - (Conventional)

Hole Size:	17.5"
Casing:	13.375" 72# L-80 VAM TOP
Depth Top:	Surface
Depth Btm:	1307'
Cement:	TBD sks - Class C + Additives
Cement Top:	Surface - (Circulate)

Intermediate #1 - (Conventional)

Hole Size:	12.25"
Casing:	9.625" 47# HCL-80 BTC
Depth Top:	Surface
Depth Btm:	5205'
Cement:	TBD - Class C + Additives
Cement Top:	Surface - (Circulate)

Production - (Conventional)

Hole Size:	8.5"
Casing 1:	7" 32# I-80 VAMSTL
Depths:	0' to 5280' & 5580' to 7600'
Casing 2:	7" 32# G3 CRA VAM HDL
Depths:	5280' to 5580'
Cement:	TBD - Class C + Additives, Well Lock resin 5280'-5580'
Cement Top:	Surface - (Circulate)
ECP/DV Tool:	5280' & 5580'

Tubing

Depth:	5700'
Tubing:	3.5" 7.7# G3 CRA VAM ACE
Packer:	7" x 3.5" PermaPak or equivalent (Inconel)
SSSV:	175'
PT Gauges:	5690'

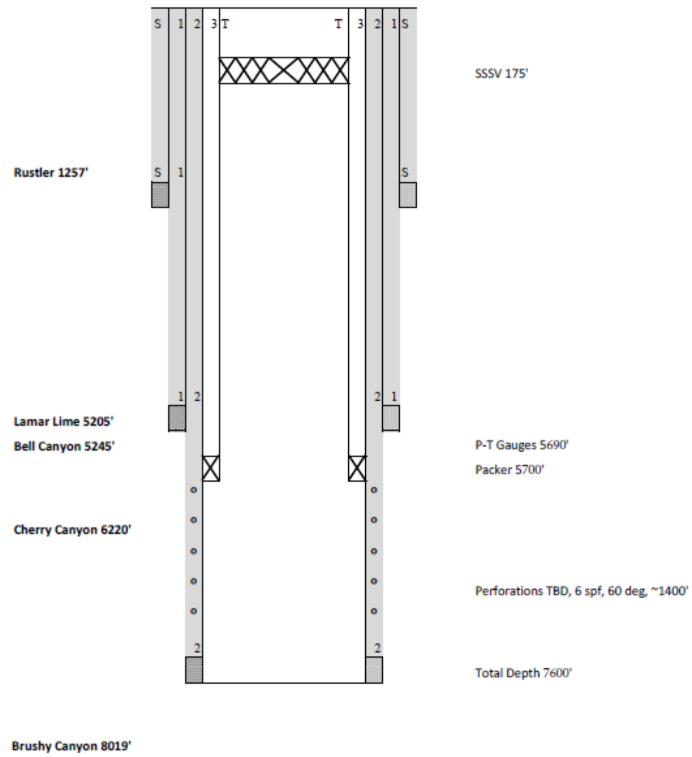


***Figure Appendix 1-2**: As-built wellbore schematic for the TND RH AGI #3 Well*

Appendix 2 Referenced Regulations

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

New Mexico Administrative Code (NMAC) > Title 19 – Natural resources > Chapter 15 – Oil and Gas

CHAPTER 15 - OIL AND GAS

19.15.1 NMAC	GENERAL PROVISIONS AND DEFINITIONS [REPEALED]
19.15.2 NMAC	GENERAL PROVISIONS FOR OIL AND GAS OPERATIONS
19.15.3 NMAC	RULEMAKING
19.15.4 NMAC	ADJUDICATION
19.15.5 NMAC	ENFORCEMENT AND COMPLIANCE
19.15.6 NMAC	TAX INCENTIVES
19.15.7 NMAC	FORMS AND REPORTS
19.15.8 NMAC	FINANCIAL ASSURANCE
19.15.9 NMAC	WELL OPERATOR PROVISIONS
19.15.10 NMAC	SAFETY
19.15.11 NMAC	HYDROGEN SULFIDE GAS
19.15.12 NMAC	POOLS
19.15.13 NMAC	COMPULSORY POOLING
19.15.14 NMAC	DRILLING PERMITS
19.15.15 NMAC	WELL SPACING AND LOCATION
19.15.16 NMAC	DRILLING AND PRODUCTION
19.15.17 NMAC	PITS, CLOSED-LOOP SYSTEMS, BELOW-GRADE TANKS AND SUMPS
19.15.18 NMAC	PRODUCTION OPERATING PRACTICES
19.15.19 NMAC	NATURAL GAS PRODUCTION OPERATING PRACTICE
19.15.20 NMAC	OIL PRORATION AND ALLOCATION
19.15.21 NMAC	GAS PRORATION AND ALLOCATION
19.15.22 NMAC	HARDSHIP GAS WELLS
19.15.23 NMAC	OFF LEASE TRANSPORT OF CRUDE OIL OR CONTAMINANTS
19.15.24 NMAC	ILLEGAL SALE AND RATABLE TAKE
19.15.25 NMAC	PLUGGING AND ABANDONMENT OF WELLS
19.15.26 NMAC	INJECTION
19.15.27 - 28 NMAC	[RESERVED] PARTS 27 - 28
19.15.29 NMAC	RELEASES

19.15.30 NMAC	REMEDIATION
19.15.31 - 33 NMAC	[RESERVED] PARTS 31 - 33
19.15.34 NMAC	PRODUCED WATER, DRILLING FLUIDS AND LIQUID OIL FIELD WASTE
19.15.35 NMAC	WASTE DISPOSAL
19.15.36 NMAC	SURFACE WASTE MANAGEMENT FACILITIES
19.15.37 NMAC	REFINING
19.15.38 NMAC	[RESERVED]
19.15.39 NMAC	SPECIAL RULES
19.15.40 NMAC	NEW MEXICO LIQUIFIED PETROLEUM GAS STANDARD
19.15.41 - 102 NMAC	[RESERVED] PARTS 41 - 102
19.15.103 NMAC	SPECIFICATIONS, TOLERANCES, AND OTHER TECHNICAL REQUIREMENTS FOR COMMERCIAL WEIGHING AND MEASURING DEVICES
19.15.104 NMAC	STANDARD SPECIFICATIONS/MODIFICATIONS FOR PETROLEUM PRODUCTS
19.15.105 NMAC	LABELING REQUIREMENTS FOR PETROLEUM PRODUCTS
19.15.106 NMAC	OCTANE POSTING REQUIREMENTS
19.15.107 NMAC	APPLYING ADMINISTRATIVE PENALTIES
19.15.108 NMAC	BONDING AND REGISTRATION OF SERVICE TECHNICIANS AND SERVICE ESTABLISHMENTS FOR COMMERCIAL WEIGHING OR MEASURING DEVICES
19.15.109 NMAC	NOT SEALED NOT LEGAL FOR TRADE
19.15.110 NMAC	BIODIESEL FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.111 NMAC	E85 FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.112 NMAC	RETAIL NATURAL GAS (CNG / LNG) REGULATIONS [REPEALED]

Appendix 3 Water Wells

Water wells identified by the New Mexico State Engineer's files within two miles of the RH AGI wells; water wells within one mile are highlighted in yellow.

POD Number	County	Sec	Tws	Rng	UTME	UTMN	Distance (mi)	Depth Well (ft)	Depth Water (ft)	Water Column (ft)
C 03666 POD1	LE	13	24S	33E	639132	3565078	0.31	650	390	260
C 03917 POD1	LE	13	24S	33E	638374	3565212	0.79	600	420	180
C 03601 POD1	LE	23	24S	33E	638124	3563937	1.17			
C 02309	LE	25	24S	33E	639638	3562994	1.29	60	30	30
C 03601 POD3	LE	24	24S	33E	638142	3563413	1.38			
C 03932 POD8	LE	7	24S	34E	641120	3566769	1.40	72		
C 03601 POD2	LE	23	24S	33E	637846	3563588	1.44			
C 03662 POD1	LE	23	24S	33E	637342	3564428	1.48	550	110	440
C 03601 POD5	LE	23	24S	33E	637988	3563334	1.48			
C 03601 POD6	LE	23	24S	33E	637834	3563338	1.55			
C 03601 POD7	LE	23	24S	33E	637946	3563170	1.58			
C 03600 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03602 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03600 POD1	LE	26	24S	33E	637275	3563023	1.94			
C 03600 POD3	LE	26	24S	33E	637784	3562340	2.05			

Appendix 4 Oil and Gas Wells within 2-mile Radius of the RH AGI Well Site

Note – a completion status of ”New” indicates that an Application for Permit to Drill has been filed and approved but the well has not yet been completed. Likewise, a spud date of 31-Dec-99 is actually 12-31-9999, a date used by NMOCD databases to indicate work not yet reported.

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-08371	COSSATOT E 002	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	5425	Yes
30-025-25604	GOVERNMENT L COM 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	17625	No
30-025-26369	GOVERNMENT L COM 002	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	14698	Yes
30-025-26958	SIMS 001	BOPCO, L.P.	GAS	DELAWARE VERTICAL	P & A	VERTICAL	15007	Yes
30-025-27491	SMITH FEDERAL 001	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	15120	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-40448	RED HILLS AGI 001	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	INJECTING	VERTICAL	6650	Yes
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL		PRODUCING	VERTICAL	10997	No
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11034	No
30-025-41382	DECKARD FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11067	Yes
30-025-41383	DECKARD FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11162	Yes
30-025-41384	DECKARD FEDERAL COM 004H	COG OPERATING LLC	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11103	Yes
30-025-41666	SEBASTIAN FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10927	Yes
30-025-41687	SEBASTIAN FEDERAL COM 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10944	Yes
30-025-41688	SEBASTIAN FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11055	No
30-025-43532	LEO THORSNESS 13 24 33 211H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12371	No
30-025-44442	STRONG 14 24 33 AR 214H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12500	No
30-025-46154	LEO THORSNESS 13 24 33 221H	MATADOR PRODUCTION COMPANY	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12868	No
30-025-46282	LEO THORSNESS 13 24 33 AR 135H	MATADOR PRODUCTION COMPANY	OIL	3RD BONE SPRING SAND	PRODUCING	HORIZONTAL	12103	No

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-46517	BROADSIDE 13 W FEDERAL COM 001H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12213	No
30-025-46518	BROADSIDE 13 24 FEDERAL COM 002H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-46519	BROADSIDE 13 24 FEDERAL COM 003H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12320	Yes
30-025-46985	SEBASTIAN FEDERAL COM 703H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12123	No
30-025-46988	SEBASTIAN FEDERAL COM 704H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12142	No
30-025-47869	JUPITER 19 FEDERAL COM 501H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11175	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47874	JUPITER 19 FEDERAL COM 506H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10950	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47877	JUPITER 19 FEDERAL COM 509H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11156	No
30-025-47878	JUPITER 19 FEDERAL COM 510H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11102	No
30-025-47908	JUPITER 19 FEDERAL COM 601H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-47910	JUPITER 19 FEDERAL COM 702H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	DUC	HORIZONTAL	0	Yes
30-025-47911	JUPITER 19 FEDERAL COM 705H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12290	No
30-025-47912	JUPITER 19 FEDERAL COM 707H	EOG RESOURCES INC	OIL	WOLFCAMP B UPPER	PERMITTED	HORIZONTAL	12515	No
30-025-47913	JUPITER 19 FEDERAL COM 708H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12477	No
30-025-48239	JUPITER 19 FEDERAL COM 306H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10270	No
30-025-48889	JUPITER 19 FEDERAL COM 701H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-48890	JUPITER 19 FEDERAL COM 703H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-49262	BROADSIDE 13 24 FEDERAL COM 004H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12531	Yes
30-025-49263	BROADSIDE 13 24 FEDERAL COM 015H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B LOWER	PRODUCING	HORIZONTAL	12746	Yes
30-025-49264	BROADSIDE 13 24 FEDERAL COM 025H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11210	Yes
30-025-49474	RED HILLS AGI 002	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	Temporarily Abandoned	VERTICAL	17600	Yes

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Appendix 6 Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
AoR – Area of Review
API – American Petroleum Institute
CFR – Code of Federal Regulations
C1 – methane
C6 – hexane
C7 - heptane
CO_2 – carbon dioxide
DCS – distributed control system
EPA – US Environmental Protection Agency, also USEPA
ft – foot (feet)
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MSCFD– thousand standard cubic feet per day
MMSCFD – million standard cubic feet per day
MMstb – million stock tank barrels
MRRW B – Morrow B
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NIST - National Institute of Standards and Technology
NMOCC – New Mexico Oil Conservation Commission
NMOCD - New Mexico Oil Conservation Division
PPM – Parts Per Million
psia – pounds per square inch absolute
QA/QC – quality assurance/quality control
SCITS - Stanford Center for Induced and Triggered Seismicity
Stb/d – stock tank barrel per day
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TVD – True Vertical Depth
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

Appendix 7 TND Red Hills AGI Wells - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

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

* All measurements must be made in accordance with 40 CFR 98.444 – Monitoring and QA/QC Requirements.

** If you measure the mass of contents of containers summed quarterly using weigh bill, scales, or load cells (40 CFR 98.444(a)(2)(i)), use RR-1 for Containers to calculate CO_2 received in containers for injection.

*** If you determine the volume of contents of containers summed quarterly (40 CFR 98.444(a)(2)(ii)), use RR-2 for Containers to calculate CO_2 received in containers for injection.

Appendix 8 Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

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

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

(Equation RR-1 for Pipelines)

where:

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

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

(Equation RR-1 for Containers)

where:

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

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

(Equation RR-2 for Containers)

where:

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

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

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

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

(Equation RR-4)

where:

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

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

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

p = Quarter of the year.

u = Flow meter.

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

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

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

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

(Equation RR-6)

where:

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

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

u = Flow meter.

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

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

(Equation RR-7)

where:

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-8)

where:

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

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-9)

where:

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

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

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

w = Separator.

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

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

Appendix 9 P&A Records

P&A Record for Government Com 001, API #30-025-25604

New Mexico Oil Conservation Division, District I
1625 N. French Drive
Hobbs, NM 88240

Form 3160-5
(April 2004)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OM B No. 1004-0137
Expires: March 31, 2007

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

5. Lease Serial No. NM-17446

6. If Indian, Allottee or Tribe Name

***SUBMIT IN TRIPLICATE**- Other instructions on reverse side.*

7. If Unit or CA/Agreement, Name and/or No.

1. Type of Well ☐ Oil Well ☑ Gas Well ☐ Other

8. Well Name and No. Government "L" Com #1

2. Name of Operator EOG Resources, Inc

9. API Well No. 30-025-~~05070~~ 25604

3a. Address P.O. Box 2267, Midland, TX, 79702

3b. Phone No. *(include area code)* 432-561-8600

10. Field and Pool, or Exploratory Area Bell Lake, South Morrow

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*

Unit Letter G, 1980 FNL, 1980 FEL
Section 18, Township 24-S, Range 34-E

11. County or Parish, State Lea, New Mexico

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
☑ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☐ Other
	☐ Change Plans	☑ Plug and Abandon	☐ Temporarily Abandon	
	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

1. Notified Jim McCormick w/BLM 24 hrs prior to MI and RU.
2. Cut 3 1/2' tbg at 11500, spot 50sx CLass "H" cmt, plug from 11500-11400, WOC Tag at 11389.
3. Circ hole w/MLF.
4. Perf 4 holes at 9050, press up to 2000 PSI, spot 75sx, plug from 9100-8950, WOC Tag @ 8938.
5. Perf 4 holes at 7000, press up to 2000 PSI, spot 75sx, plug from 7050-6900, WOC Tag at 6855.
6. Cut 10 3/4" csg at 5450, L/D csg, spot 150sx, plug from 5500-5350, WOC Tag at 5336.
7. Spot 75sx, plug from 1300-1200 (T-Salt) WOC Tag at 1143.
8. Spot 150sx, plug from 650-450 (20" Shoe) WOC Tag at 423.
9. Spot 20sx, plug from 30-Surf.
10. Clean location. Install dry hole marker 12-30-04.

P&A Complete 12-30-04

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

14. I hereby certify that the foregoing is true and correct
Name *(Printed/Typed)* Jimmy Bagley

Title Consultant

Signature

Date 12/30/2004

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by Title Date

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.

Office

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on page 2)

GWW

P&A Records for API #30-025-26958

Submit 1 Copy To Appropriate District Office District I – (575) 393-6161 1625 N. French Dr., Hobbs, NM 88240 District II – (575) 748-1283 811 S First St., Artesia, NM 88210 District III – (505) 334-6178 1000 Rio Brazos Rd., Aztec, NM 87410 District IV – (505) 476-3460 1220 S St Francis Dr., Santa Fe, NM 87505	State of New Mexico Energy, Minerals and Natural Resources RECEIVED OIL CONSERVATION DIVISION 1220 South St. Francis Dr. AUG 16 2012 Santa Fe, NM 87505 HOBBSOCD	Form C-103 Revised August 1, 2011 WELL API NO. 3002526958 5. Indicate Type of Lease STATE ☐ FEE ☒ 6. State Oil & Gas Lease No. SCR-389

SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS)	7. Lease Name or Unit Agreement Name Sims
1. Type of Well: Oil Well ☐ Gas Well ☒ Other	8. Well Number #1
2. Name of Operator: Agave Energy Company	9. OGRID Number 147831
3. Address of Operator 104 S. Fourth St., Artesia NM 88210 (575-748-4528)	10. Pool name or Wildcat Big Sinks Wolfcamp

4. Well Location

Unit Letter K: 1980 feet from the N line and 800 feet from the E line

Section 13 Township 24S Range 33E NMPM Lea County

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
OTHER: ☐		OTHER ☒ Replug to cement off Cherry Canyon per NMOCC R-13507	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion

The remediation of the Sims #1 well pursuant to NMOCC order was completed on August 15, 2011 and all equipment has been demobilized. The plugging was done pursuant to NMOCD requirements and all aspects of the effort were reported to Mark Whitaker and E.L. Gonzales of the OCD District 1 office who approved the specifics of the plugging as shown in the attached plugging diagram. When establishing a rate prior to squeezing the Cherry Canyon, it is clear that the reservoir is an excellent reservoir as it was taking 3bbl/min on vacuum. This indicates that the predicted injection plume for the Red Hills AGI #1 in this reservoir will be smaller than anticipated and the reservoir conditions act to prevent migration of injected acid gas out of the intended and permitted injection zone by any nearby wellbores including the Govt#2, Govt#1 and Smith Federal #1 in addition to the Sims#1. Please see attached wellbore sketch for plugging details of all plugs set and amounts of cement squeezed for each plug.

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE_________________ TITLE_ Consultant to Agave Energy Company _DATE August 16, 2012____

Type or print name ___Alberto A. Gutierrez, RG E-mail address: ___aag@geolex.com______ PHONE: __505-842-8000____

For State Use Only

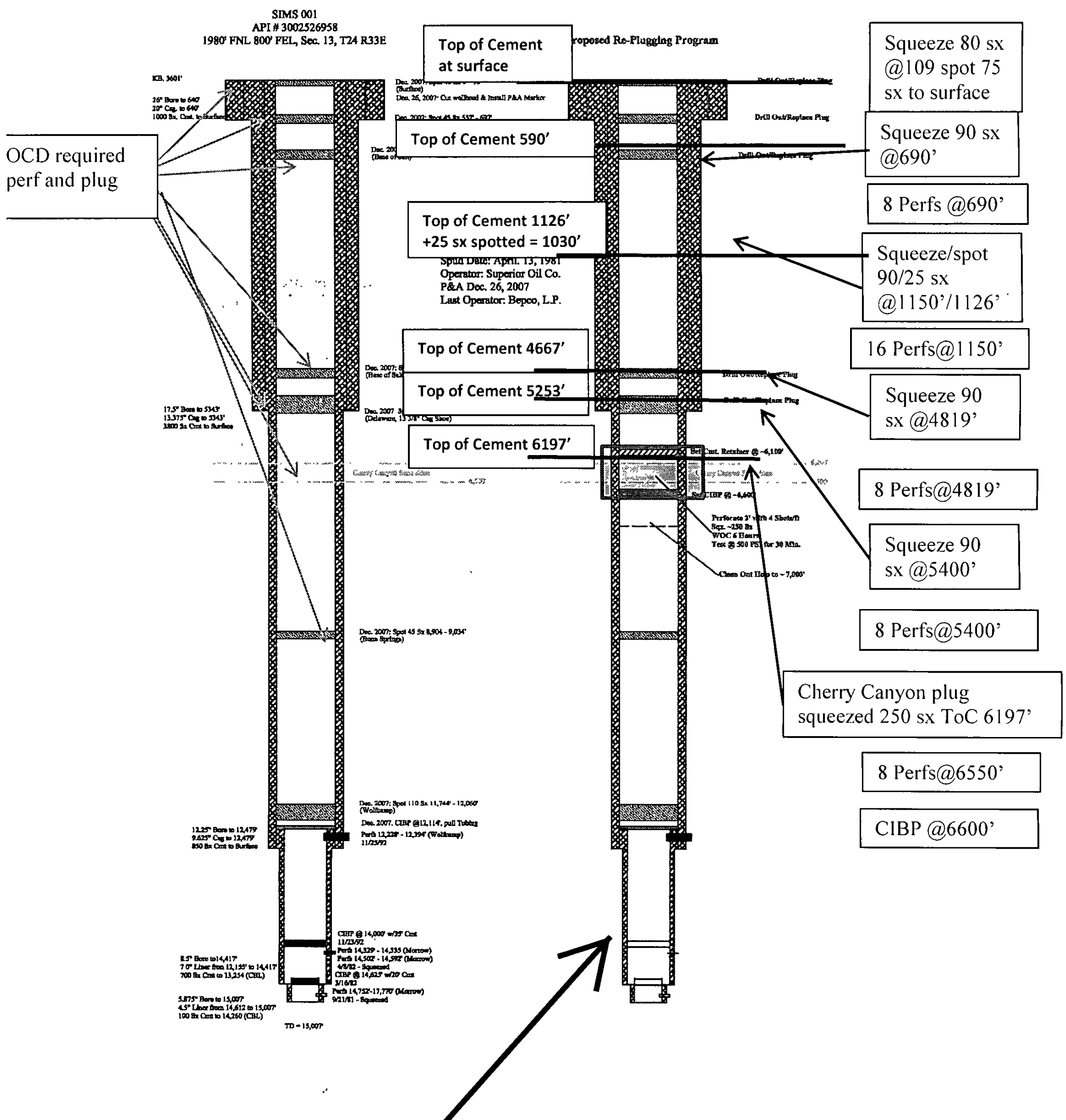
APPROVED BY ____________ TITLE Dist Mgr ____________ DATE 8-16-2012

Conditions of Approval (if any):

AUG 16 2012

GEOLEX
INCORPORATED

8/16/2012



Final Remediated Sims #1 Well

P&A Records for API 30-025-08371

NEW MEXICO OIL CONSERVATION COMMISSION

FORM C-103 (Rev 3-55)

MISCELLANEOUS REPORTS ON WELLS

(Submit to appropriate District Office as per Commission Rule 1106)

Name of Company: Byard Bennett			Address: 207 West Third, Roswell, New Mexico		
Lease: Holland	Well No. 1	Unit Letter H	Section 13	Township 24 South	Range 33 East
Date Work Performed: March 8, 1961	Pool: Wildcat			County: Lea	

THIS IS A REPORT OF: *(Check appropriate block)*

- [ ] Beginning Drilling Operations
- [ ] Casing Test and Cement Job
- [ ] Other *(Explain)*:
- [X] Plugging
- [ ] Remedial Work

Detailed account of work done, nature and quantity of materials used, and results obtained.

Top of Rustler: 1245', Top of Salt: 1392', Base of Salt: 4930', Top of Dela Ls: 5190'
Top of Delaware Sand: 5210', Total Depth: 5425', Casing 8 5/8 set at 365', Hole size 6 3/4

Cement Plugs set as follows:
5375-5425 with 15 sacks, 5175-5240 with 20 sacks, 1375-1425 with 20 sacks,
340-390 with 20 sacks, 5 sacks and marker pipe set at surface.
Heavy mud (4 cc wtr. loss) between all cement plugs.
Job performed and witnessed by Mr. Pool, Pool Drlg Co.
Prior verbal approval of plugging program from Mr. Engbrecht, New Mexico O C C.

Location will be cleaned and leveled as soon as practical.

Witnessed by	Position	Company
Mr. Fred Pool	Owner	Pool Drlg Co.

FILL IN BELOW FOR REMEDIAL WORK REPORTS *ONLY*

ORIGINAL WELL DATA

D F Elev.	T D	PBTD	Producing Interval	Completion Date

Tubing Diameter	Tubing Depth	Oil String Diameter	Oil String Depth

Perforated Interval(s)

Open Hole Interval | Producing Formation(s)

RESULTS OF WORKOVER

Test	Date of Test	Oil Production BPD	Gas Production MCFPD	Water Production BPD	GOR Cubic feet/Bbl	Gas Well Potential MCFPD
Before Workover						
After Workover						

OIL CONSERVATION COMMISSION

Approved by: Leslie A. Clements

Title

Date

I hereby certify that the information given above is true and complete to the best of my knowledge.

Name: Guy A. Swartz

Position: Agent

Company: Byard Bennett

Request for Additional Information: Red Hills Gas Processing Plant
April 22, 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.	5.6	44-45	"No faults were identified within the MMA which could potentially serve as conduits for surface CO_2 emission. The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief." However, Figure 5.6-1 only displays the location of faults with relation to the RH_Plant outline. Figure 5.6-1 displays a fault line within close proximity to the RH_Plant outline that might intersect the MMA/AMA boundary. We recommend including an outline of the MMA/AMA in Figure 5.6-1 to clearly display the relation of this fault to the MMA/AMA or clarifying its proximity in the text.	Figure 5.6-1 of the revised MRV plan has been modified to include the MMA/AMA boundary.
2.	8.1	57	"r = Receiving volumetric flow meter." In Equation RR-2, this variable is "r = receiving flow meter." Equations and variables cannot be modified from the regulations. Please revise this section and **ensure that all equation listed are consistent with the text in 40 CFR 98.443**.	All narrative accompanying the equations in Section 8.1 and in Appendix 8 have been edited in the revised MRV plan to match the text in 40 CFR 98.443.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	8.2	58	u = Volumetric flow meter. In Equation RR-5, this variable is "u = flow meter." Equations and variables cannot be modified from the regulations. Please revise this section and **ensure that all equation listed are consistent with the text in 40 CFR 98.443**.	All narrative accompanying the equations in Section 8.1 and in Appendix 8 have been edited in the revised MRV plan to match the text in 40 CFR 98.443.

4.	8.2	58	For CO_2 injected, 40 CFR 98.444(b) requires that: "(1) You must select a point or points of measurement at which the CO_2 stream(s) is representative of the CO_2 stream(s) being injected. You may use as the point or points of measurement the location(s) of the flow meter(s) used to comply with the flow monitoring and reporting provisions in your Underground Injection Control permit. (2) You must measure flow rate of CO_2 injected with a flow meter and collect the flow rate quarterly. (3) You must sample the injected CO_2 stream at least once per quarter immediately upstream or downstream of the flow meter used to measure flow rate of that CO_2 stream and measure the CO_2 concentration of the sample." The MRV plan states that "TND injects CO_2 into the existing RH AGI #1. Upon completion, TND will commence injection into RH AGI #3. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into both wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Volumetric flow meter u in the following equations corresponds to **meters M5** and M6 in Figure 3.6-2." In Figure 3.6-2, meter M5 is located between the flowlines for RH AGI #1 and RH AGI #3. Based on this process flow diagram, it appears that the volumetric flow from meter M1 into RH AGI #1 would be determined by meter M3 prior to compression, not meter M5. Overall, please revise and/or clarify the text or flow diagram to ensure that all descriptions for metering locations are consistent for the subpart RR regulations.	That is correct. The injection meter to AGI #1 is M3 NOT M5. The revised MRV plan has been modified to reflect this correction. Figure 3.6-2 of the revised MRV plan has been modified to include sampling points between the sour treaters ST1 and ST2 and the corresponding compressors. The CO_2 analyzer and H_2S analyzer between compressor C1 and RH AGI #1 are not currently operational. The flow line where the flow meter M5 is located is only used to divert flow from one AGI well to the other when one of the wells is being worked over. The sampling points are samples bimonthly.

MONITORING, REPORTING, AND VERIFICATION PLAN

Red Hills AGI #1 and AGI #3

Targa Northern Delaware, LLC (TND)

Version 1.0
March 15, 2024

Table of Contents

1 Introduction

Targa Northern Delaware, LLC (TND) is currently authorized to inject treated acid gas (TAG) into the Red Hills Acid Gas Injection #1 well (RH AGI #1)(American Petroleum Institute (API) 30-025-40448) and RH AGI #3 well (API # 30-025-51970) under the New Mexico Oil Conservation Commission (NMOCC) Orders R-13507 – 13507F and Order R-20916H, respectively, at the Red Hills Gas Plant located approximately 20 miles NNW of Jal in Lea County, New Mexico (**Figure 1-1**). Each well is approved to inject 13 million standard cubic feet per day (MMSCFD). However, although approved to inject 13 MMSCFD, RH AGI #1 is physically only capable of taking ~5 MMSCFD due to formation and surface pressure limitations.

The AGI wells were previously operated by Lucid Energy Delaware, LLC's ("Lucid"). TND acquired Lucid assets in 2022. Lucid received authorization to construct a redundant well, RH AGI #2 (API# 30-025-49474) under NMOCC Order R-20916-H, which is offset 200 ft to the north of RH AGI #1 and is currently temporarily abandoned in the Bell Canyon Formation.

TND recently received approval from NMOCC for its C-108 application to drill, complete and operate a third acid gas injection well (RH AGI #3) in which TND requested an injection volume of up to 13 MMSCFD.RH AGI #3 was recently completed and placed into service in January 2024. Because AGI #1 does not have complete redundancy, having a greater permitted disposal volume will also increase operational reliability. The RH AGI #3 well is a vertical well with its surface location at approximately 3,116 ft from the north line (FNL) and 1,159 ft from the east line (FEL) of Section 13. The depth of the injection zone for this well is approximately 5,600 to 7,200 ft in the Bell Canyon and Cherry Canyon Formations. Analysis of the reservoir characteristics of these units confirms that they act as excellent closed-system reservoirs that will accommodate the future needs of TND for disposal of treated acid gas (H_2S and CO_2) from the Red Hills Gas Plant.

TND has chosen to submit this Monitoring, Reporting, and Verification (MRV) plan to EPA for approval according to 40CFR98.440(c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. TND intends to inject CO_2 for another 30 years.

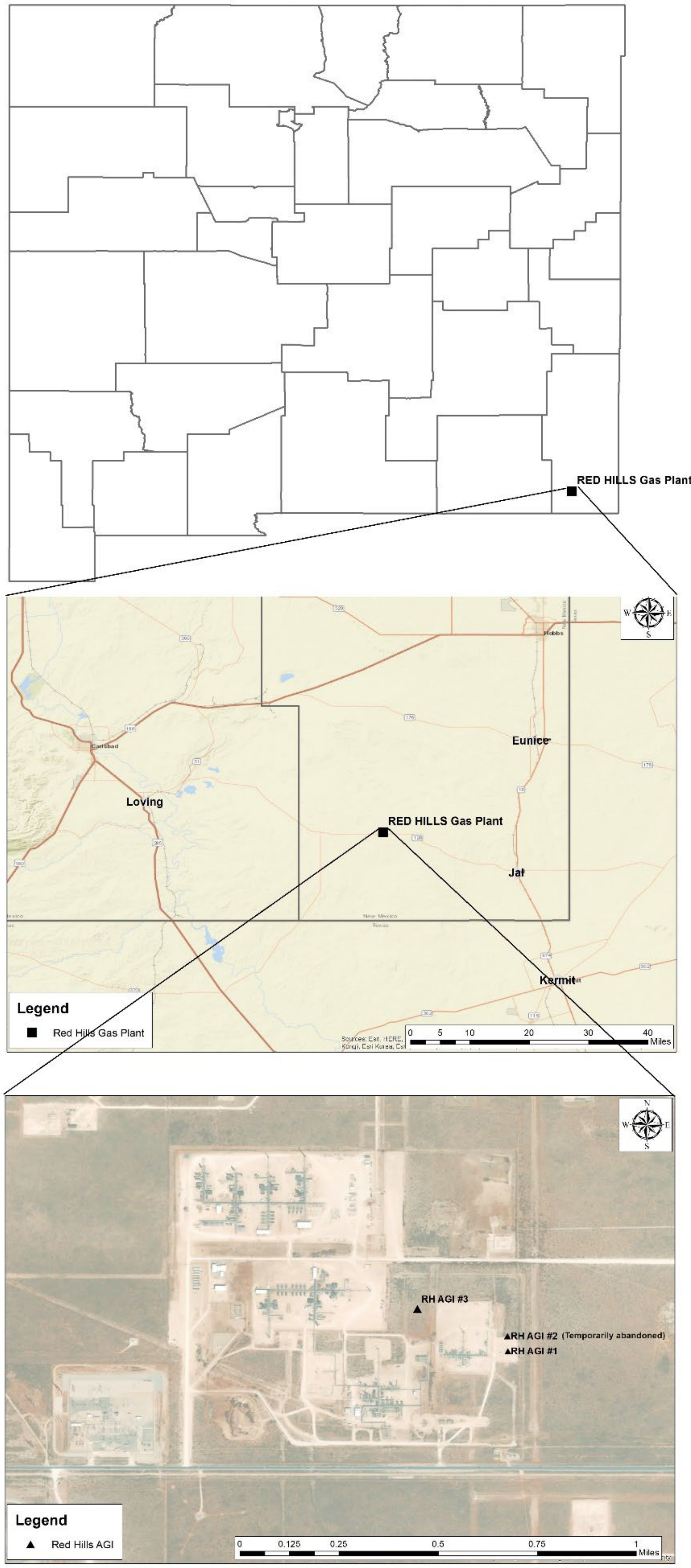


***Figure 1-1**: Location of the Red Hills Gas Plant and Wells – RH AGI #1, RH AGI #2 (temporarily abandoned), and RH AGI #3*

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40CFR98.449, and as required by 40CFR98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40CFR98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage as required by 40CFR98.448(a)(3).

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40CFR98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40CFR98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40CFR98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40CFR98.445.

Section 11 describes the records to be retained according to the requirements of 40CFR98.3(g) of Subpart A of the GHGRP and 40CFR98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan, including information required by 40CFR98.448(a)(6).

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is **553798**

2.2 UIC injection well identification numbers

This MRV plan is for RH AGI #1 and RH AGI #3 (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

For injection wells that are the subject of this MRV plan, the New Mexico Oil Conservation Division (NMOCD) has issued Underground Injection Control (UIC) Class II acid gas injection (AGI) permits under its State Rule 19.15.26 NMAC (see **Appendix 2**). All oil- and gas-related wells around the RH AGI wells, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3 Project Description

The following project description was developed by the Petroleum Recovery Research Center (PRRC) at New Mexico Institute of Mining and Technology (NMT) and the Department of Geosciences at the University of Texas Permian Basin (UTPB).

3.1 General Geologic Setting / Surficial Geology

The TND Red Hills Gas Plant is located in T 24 S R 33 E, Section 13, in Lea County, New Mexico, immediately adjacent to the RH AGI wells. (**Figure 3.1-1**). The plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. The dune sands are locally stabilized with shin oak, mesquite, and some burr-grass. There are no natural surface bodies of water or groundwater discharge sites within one mile of the plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

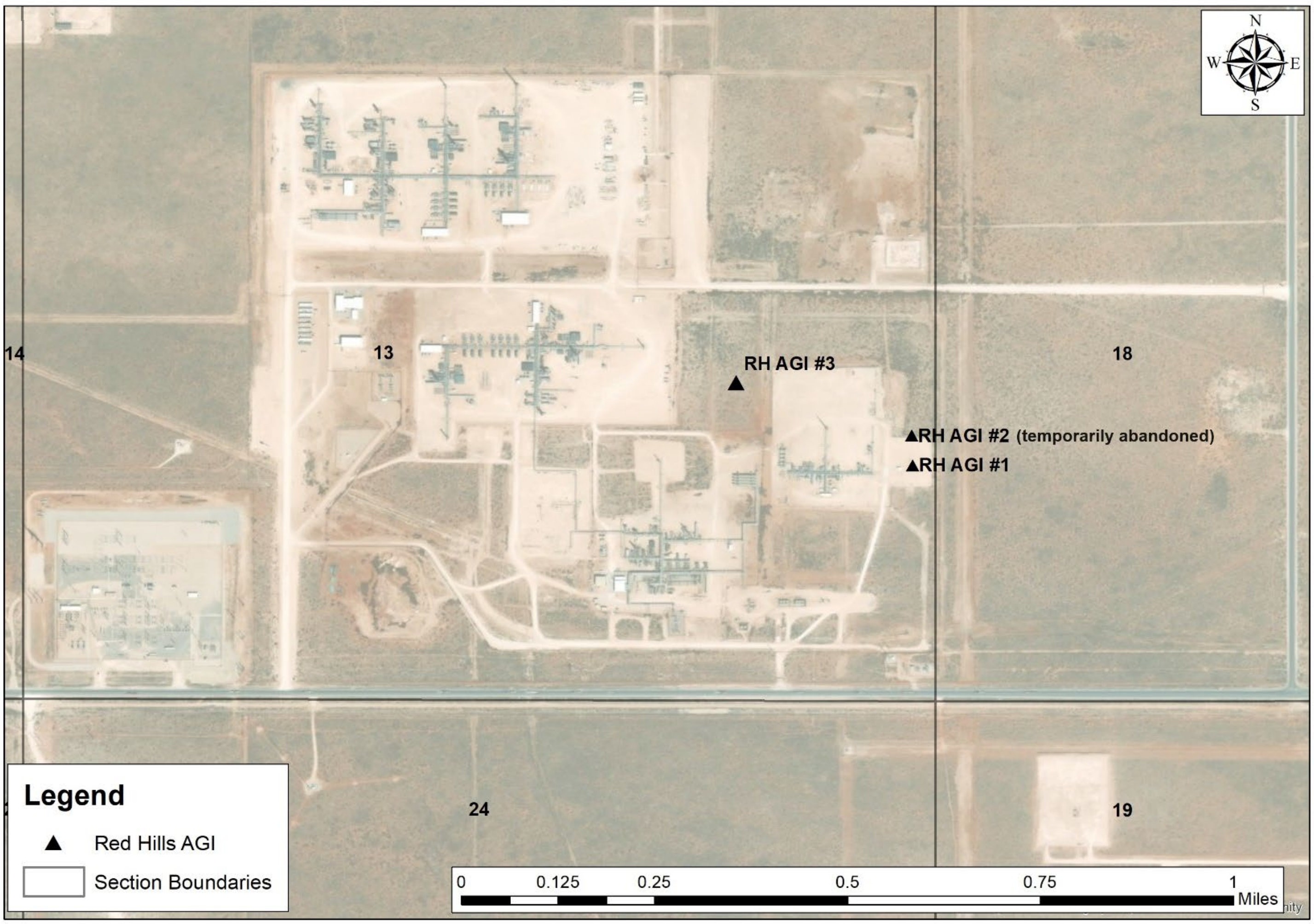


__Figure 3.1-1__: Map showing location of TND Red Hills Gas Plant and RH AGI Wells in Section 13, T 24 S, R 33 E

3.2 Bedrock Geology

3.2.1 Basin Development

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

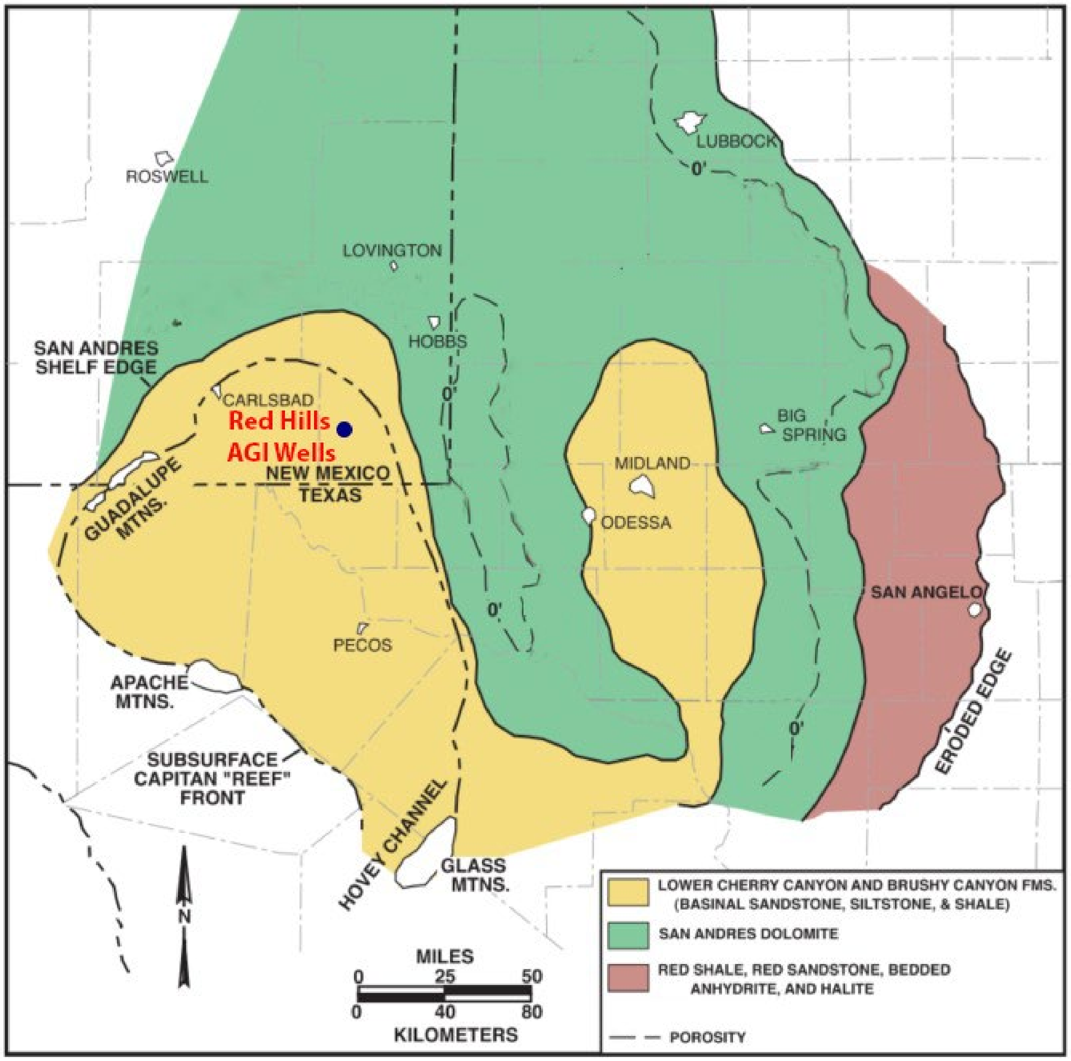


***Figure 3.2-1**: Structural features of the Permian Basin during the Late Permian. Location of the TND RH AGI wells is shown by the black circle. (Modified from Ward, et al (1986))*

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

The RH AGI wells are in the Delaware Basin portion of the broader Permian Basin. Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland (**Figure 3.2-3**). With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Ellenburger Formation (0 – 1000 ft) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Throughout this narrative, the numbers after the formations indicate the range in thickness for that unit. Tectonic activity near the end of Ellenburger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit’s overall porosity and permeability.

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

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

During Middle to Upper Ordovician time, the seas once again covered the area and deposited the carbonates, sandstones and shales of the Simpson Group (0 – 1000 ft) and then the Montoya Formation (0 – 600 ft). This is the period when the Tobosa Basin formed due to the Pedernal uplift and development of the Texas Arch (**Figure 3.2-4**; Harrington, 2019) shedding Precambrian crystalline clasts into the basin. Reservoirs in New Mexico are typically within deposits of shoreline sandstones (Broadhead, 2017). A subaerial exposure and karstification event followed the deposition of the Simpson Group. The Montoya Formation marked a return to dominantly carbonate sedimentation with minor siliciclastic sedimentation within the Tobosa Basin (Broadhead, 2017; Harrington and Loucks, 2019). The Montoya Formation consists of sandstones and dolomites and have also undergone karstification.

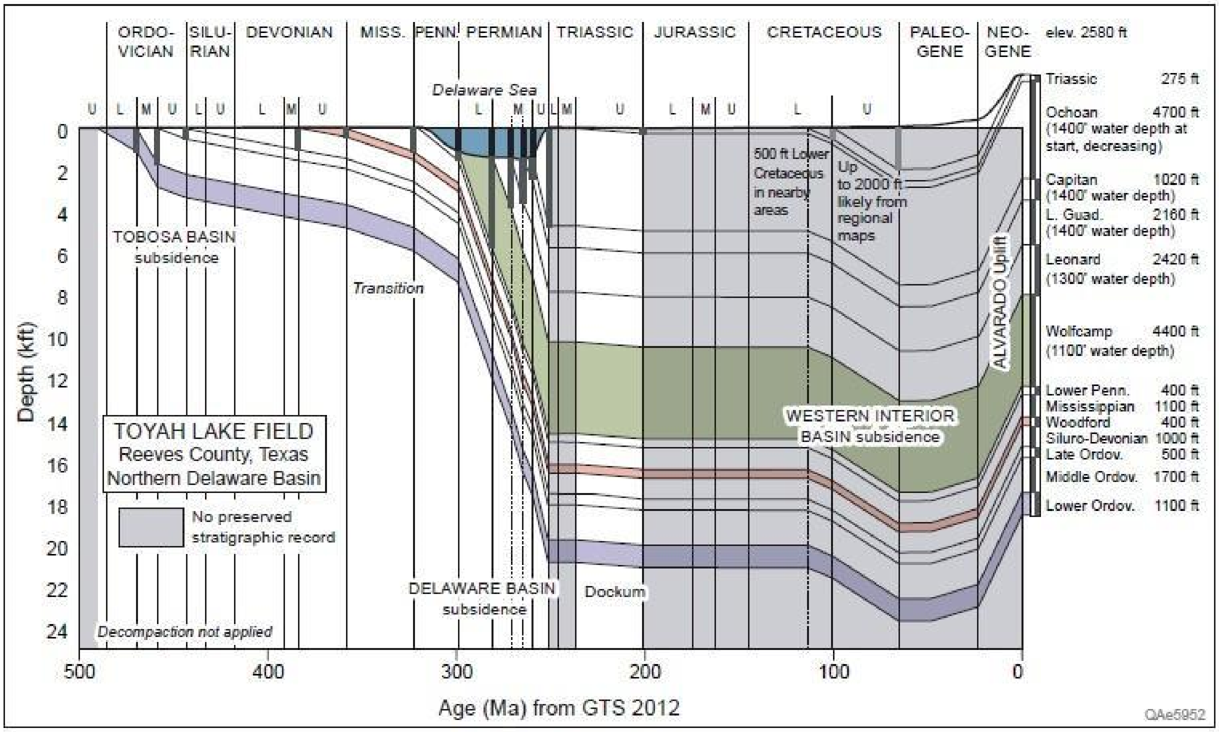


***Figure 3.2-3**: A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)*

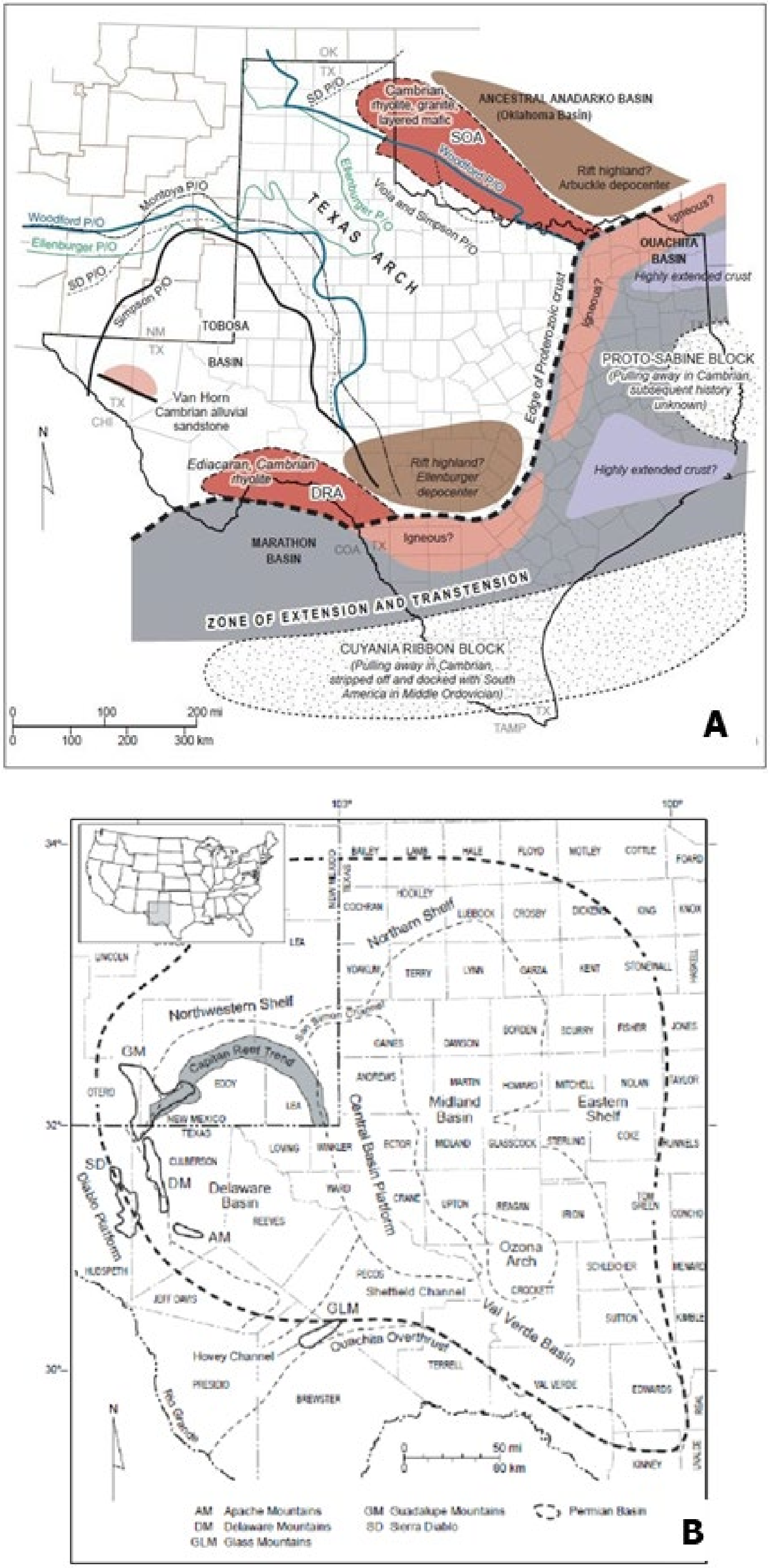


Figure 3.2-4: *Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).*

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

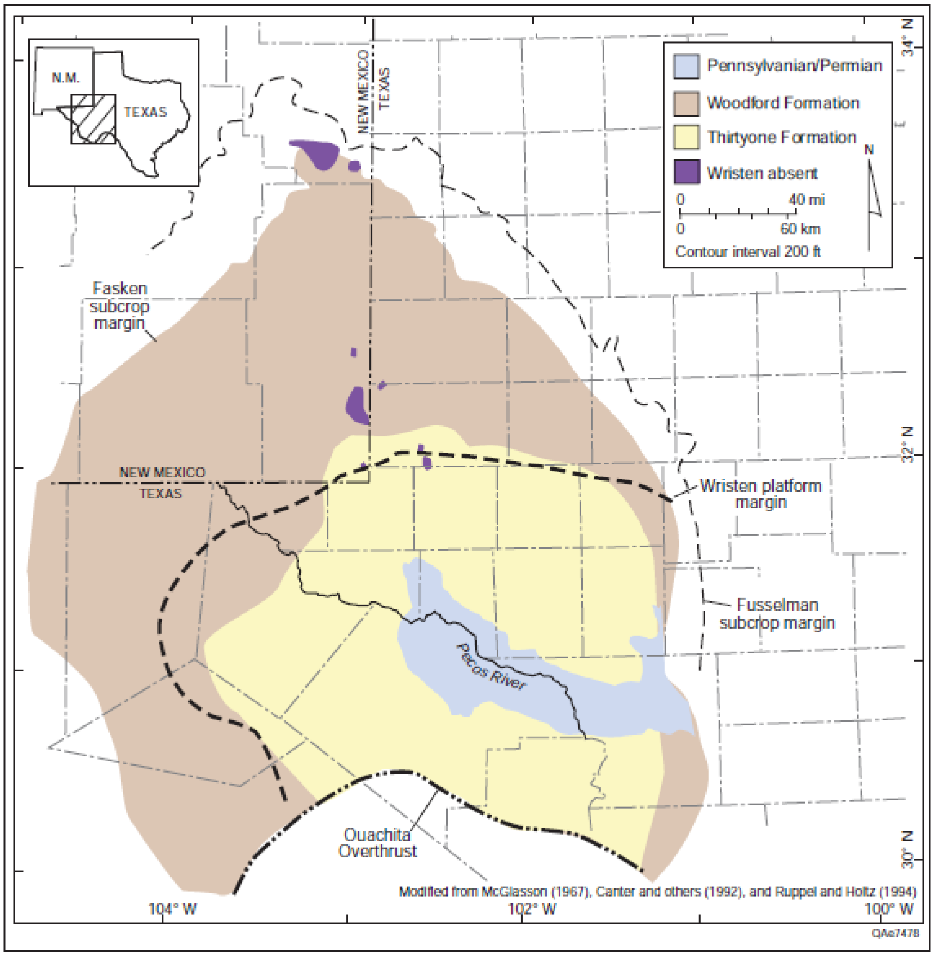


***Figure 3.2-5** -- A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there are no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in Section 3.2.2.

The Devonian Woodford Shale, an un-named Mississippian limestone, and the Upper Mississippian Barnett Shale are seals for the underlying Siluro-Devonian strata. While the Mississippian recrystallized limestones have minor porosity and permeability, the Woodford and Barnett shales have extremely low porosity and

permeability and would be effective barriers to upward migration of acid gas out of the injection zone. The Woodford Shale (0 – 300 ft) ranges from organic–rich argillaceous mudstones with abundant siliceous microfossils to organic-poor argillaceous mudstones (Ruppel et al., 2020b). The Woodford sediments represent stratified deeper marine basinal deposits with their organic content being a function of the oxygenation within the bottom waters – the more anoxic the waters the higher the organic content.

The Mississippian strata within the Delaware Basin consists of an un-named carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoirs limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise it is tight. The Barnett Shale (0 – 400 ft) unconformably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal, siliciclastic deposits (the Barnett Shale).

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

Pennsylvanian sedimentation is dominated by glacio-eustatic sea-level cycles that produced shallowing upward cycles of sediments, ranging from deep marine siliciclastic and carbonate deposits to shallow-water limestones and siliciclastics, and capping terrestrial siliciclastic sediments and karsted limestones. Lower Pennsylvanian units consist of the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). The Atoka Formation (0-500 ft) was deposited during another sea-level transgression within the area. Within the area, the Atoka sediments are dominated by siliciclastic sediments, and depositional environments range from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

Middle Pennsylvanian units consist of the Strawn group (an informal name used by industry). Strawn sediments (250 - 1,000 ft) within the area consists of marine sediments that range from ramp carbonates, containing patch reefs, and marine sandstone bars to deeper marine shales (Broadhead, 2017).

Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales.

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

throughout the Permian, the Wolfcampian sediments were truncated in places like the Central Basin Platform (**Figure 3.2-6**).

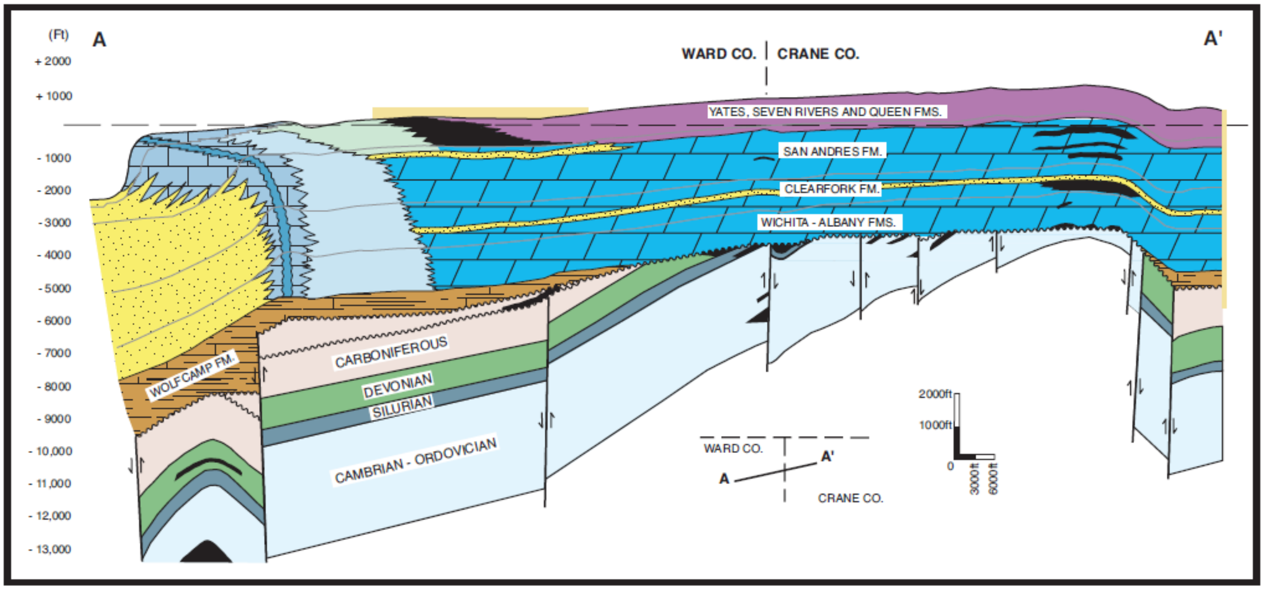


Figure 3.2-6 -- *Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).*

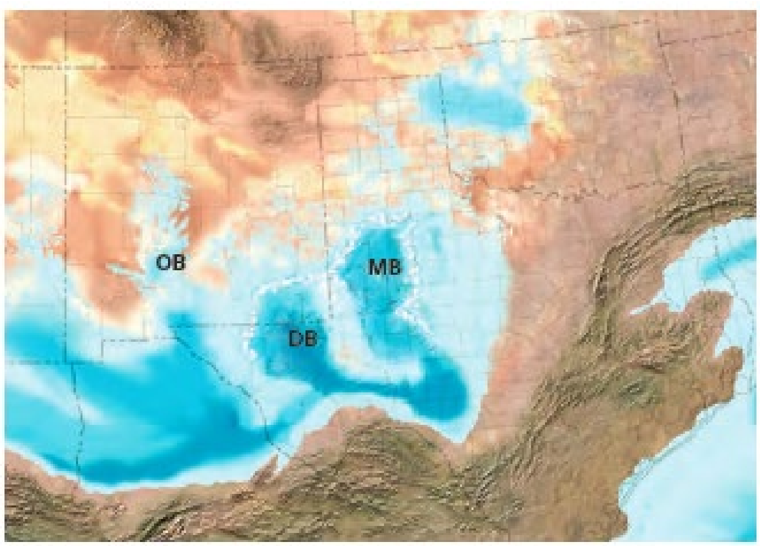


Figure 3.2-7 -- *Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).*

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, thousands of feet of siliciclastic sediments bypassed the shelves and were deposited in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a

"carbonate factory" on the shelf and shelf edge. Carbonate debris beds shedding off the shelf margin were transported into the basin (Wilson, 1972; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100s feet to feet).

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along Northwest Shelf margin to shallow-marine, back-reef carbonates behind the shelf margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2019a). Sediments basinward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2019a). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. The Bone Spring Formation is a thick sequence of alternating carbonate and siliciclastic horizons that formed because of changes in sea level; the carbonates during highstands, and siliciclastics during lowstands. Overlying the Yeso, are the clean, white eolian sandstones of the Glorietta Formation. It is a key marker bed in the region, both on outcrop and in the subsurface. Within the basin, it is equivalent to the lowermost Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have been identified that have resulted in karstification and pervasive dolomitization of the unit. These exposure events/sea-level lowstands are correlated to sandstones/siltstones that moved out over the exposed shelf leaving on minor traces of their presence on the shelf but formed thick sections of sandstones and siltstones in the basin. Within the Delaware Basin, the San Andres Formation is equivalent to the Brushy and lower Cherry Canyon Formations.

The Artesia Group (Grayburg, Queen, Seven Rivers, Yates, and Tansill formations, ascending order) is equivalent to Capitan Limestone, the Guadalupian barrier/fringing reef facies. Within the basin, the Artesia Group is equivalent to the upper Cherry and Bell Canyon formations, a series of relatively featureless sandstones and siltones. The Queen and Yates formations contain more sandstones than the Grayburg, Seven Rivers, and Tansill formations. The Artesia units and the shelf edge equivalent Capitan reef sediments represent the period when the carbonate factory was at its greatest productivity with the shelf margin/Capitan reef prograding nearly 6 miles into the basin (Scholle et al., 2007). The Artesia Group sediments were deposited in back-reef, shallow marine to supratidal/evaporite environments. Like the San Andres Formation, the individual formations were periodically exposed during lowstands.

The final stage of Permian deposition on the NW Shelf consists of the Ochoan/Lopingian Salado Formation (<2,800 ft, Nance, 2020). Within the basin, the Castile formation, a thick sequence (total thickness ~1,800 ft, Scholle et al., 2007) of cyclic laminae of deep-water gypsum/anhydrite interbedded with calcite and organics, formed due to the restriction of marine waters flowing into the basin. Gypsum/anhydrite laminae precipitated during evaporative conditions, and the calcite and organic-rich horizons were a result of seasonal "freshening" of the basin waters by both marine and freshwaters. Unlike the Castile Formation, the Salado Formation is a relatively shallow water evaporite deposit. Halite, sylvite, anhydrite, gypsum, and numerous potash minerals were precipitated. The Rustler Formation (500 ft , Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin.

The Rustler Formation was followed by terrestrial sabkha red beds of the Dewey Lake Formation (~350', Nance, 2020), ending Permian deposition in the area.

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

3.2.2 Stratigraphy

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent, renamed Lopingian), Guadalupian, Leonardian (renamed Cisuralian), and Wolfcampian (oldest) (**Figure 3.2-2**). This sequence of shallow marine carbonates and thick, basinal siliciclastic deposits contains abundant oil and gas resources. The Delaware Basin high porosity sands are the main source of oil within New Mexico. In the area around the Red Hills AGI wells, Permian strata are mainly basin deposits consisting of sandstones, siltstones, shales, and lesser amounts of carbonates. Besides production in the Delaware Mountain Group, there is also production, mainly gas, in the basin Bone Spring Formation, a sequence of carbonates and siliciclastics. The injection and confining zones for RH AGI #1 and #3 are discussed below.

CONFINING/SEAL ROCKS

Permian Ochoa Series. The youngest of the Permian sediments, the Ochoan- or Lopingian-aged deposits, consists of evaporites, carbonates, and red beds. The Castile Formation is made of cyclic laminae of deep-water gypsum/anhydrite beds interlaminated with calcite and organics. This basin-occurring unit can be up to 1,800 ft thick. The Castile evaporites were followed by the Salado Formation (~1,500 ft thick). The Salado Formation is a shallow water evaporite deposit, when compared to the Castile Formation, and consists of halite, sylvite, anhydrite, gypsum, and numerous potash/bittern minerals. Salado deposits fill the basin and lap onto the older Permian shelf deposits. The Rustler Formation (up to 500 ft, Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin. The Ochoan evaporitic units are superb seals (usually <1% porosity and <0.01 mD permeability) and are the reason that the Permian Basin is such a hydrocarbon-rich region despite its less than promising total organic carbon (TOC) content.

INJECTION ZONE

Permian Guadalupe Series. Sediments in the underlying Delaware Mountain Group (descending, Bell Canyon, Cherry Canyon, and Brushy Canyon formations) are marine units that represent deposition controlled by eustacy and tectonics. Lowstand deposits are associated with submarine canyons incising the carbonate platform surround most of the Delaware Basin. Depositional environments include submarine fan complexes that encircle the Delaware Basin margin. These deposits are associated with submarine canyons incising the carbonate platform margin and turbidite channels, splays, and levee/overbank deposits (**Figure 3.2-8**). Additionally, debris flows formed by the failure of the carbonate margin and density currents also make up basin sediments. Isolated coarse-grained to boulder-sized carbonate debris flows and grain falls within the lowstand clastic sediments likely resulted from erosion and failure of the shelf margin during sea-level lowstands or slope failure to tectonic activity (earthquakes). Density current deposits resulted from stratified basin waters. The basal waters were likely stratified and so dense, that turbidity flows containing sands, silts and clays were unable to displace those bottom waters and instead flowed out over the density interface (**Figure 3.2-9**). Eventually, the entrained sediments would settle out in a constant rain of sediment forming laminated deposits with little evidence of traction (bottom flowing) deposition. Interbedded with the very thick lowstand sequences are thin, deep-water limestones and mudstones that represent highstand

deposition up on the platform. These deposits are thickest around the edge (toe-of-slope) of the basin and thin to the basin center (**Figure 3.2-10**). The limestones are dark, finely crystalline, radiolarian-rich micrites to biomicrites. These highstand deposits are a combination of suspension and pelagic sediments that also thin towards the basin center. These relatively thin units are time equivalent to the massive highstand carbonate deposits on the shelf.

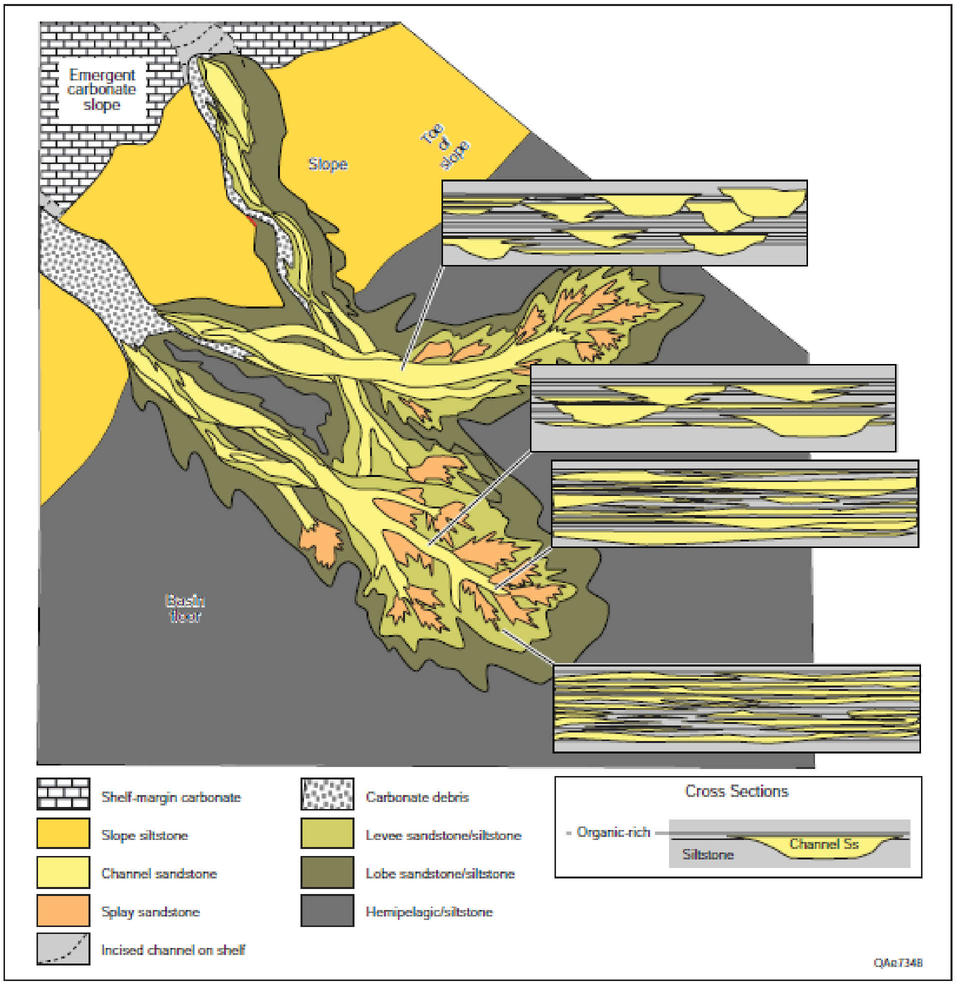


***Figure 3.2-8** – A diagram of typical Delaware Mountain Group basinal siliciclastic deposition patterns (from Nance, 2020). The channel and splay sandstones have the best porosity, but some of the siltstones also have potential as injection zones.*

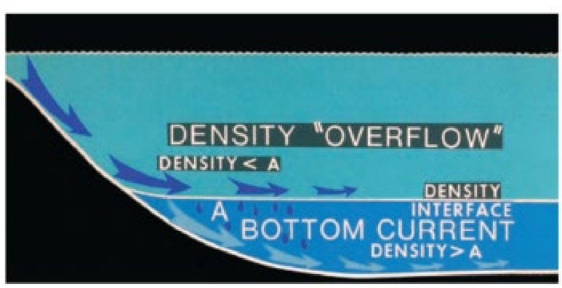


***Figure 3.2-9** – Harms' (1974) density overflow model explains the deposition of laminated siliciclastic sediments in the Delaware Basin. Low density sand-bearing fluids flow over the top of dense, saline brines at the bottom of the basin. The sands gradually drop out as the flow loses velocity creating uniform, finely laminated deposits (from Scholle et al., 2007).*

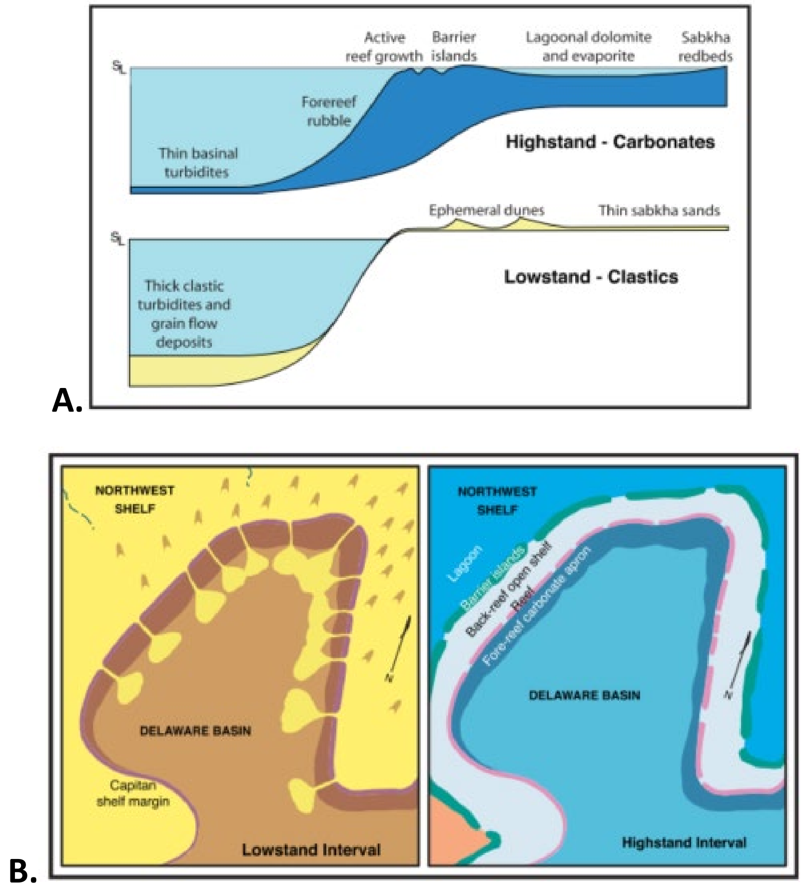


Figure 3.2-10 *– The impact of sea-level fluctuations (also known as reciprocal sedimentation) on the depositional systems within the Delaware Basin. A) A diagrammatic representation of sea-level variations impact on deposition. B) Model showing basin-wide depositional patterns during lowstand and highstand periods (from Scholle et al., 2007).*

The top of the Guadalupian Series is the Lamar Limestone, which is the source of hydrocarbons found in underlying Delaware Sand (an upper member of the Bell Canyon Formation). The Bell Canyon Formation is roughly 1,000 ft thick in the Red Hills area and contains numerous turbidite input points around the basin margin (**Figures 3.2-10, 3.2-11**). During Bell Canyon deposition, the relative importance of discrete sand sources varied (Giesen and Scholle, 1990), creating network of channel and levee deposits that also varied in their size and position within the basin. Based on well log analyses, the Bell Canyon 2 and 3 had the thickest sand deposits.

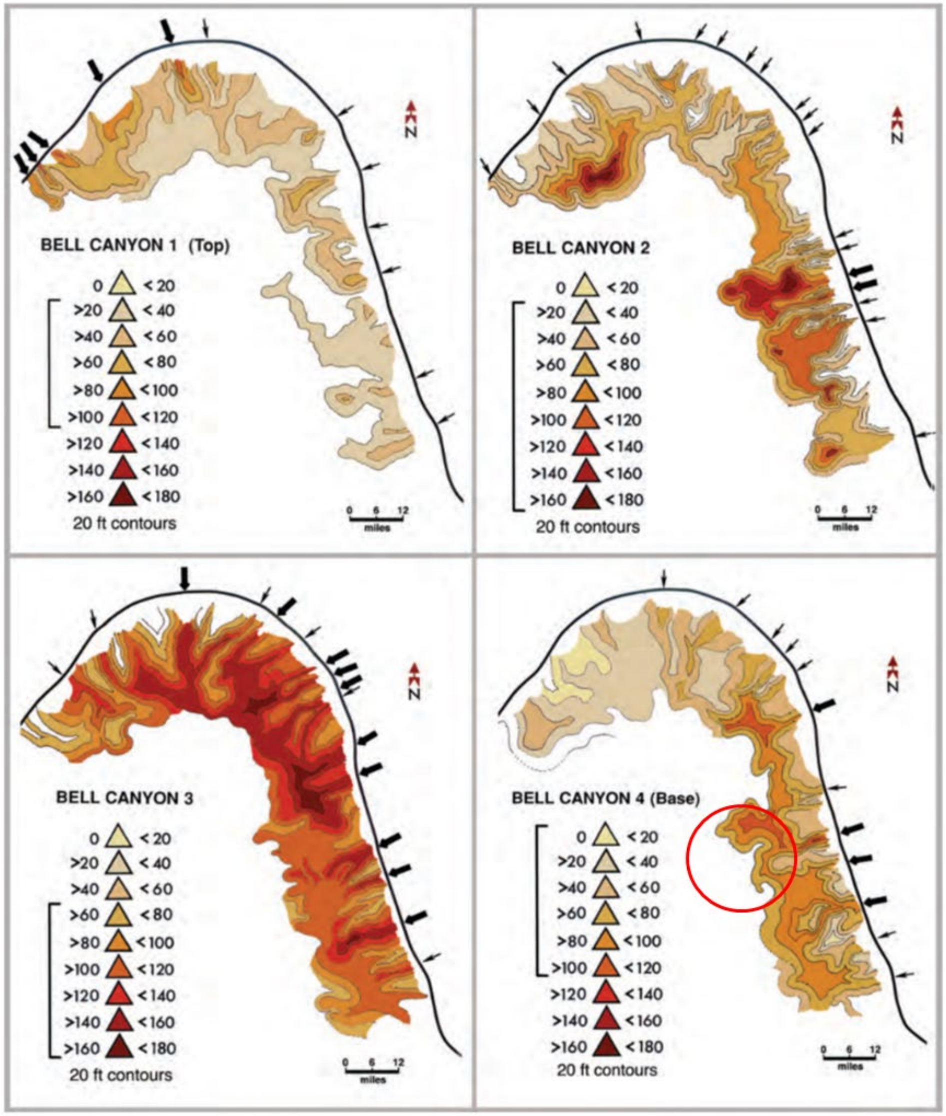


Figure 3.2-11 – These maps of Bell Canyon Formation were created by measuring sandstone thicknesses on well logs in four regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). The red circle on the last map surrounds the Red Hills area.

Like the Bell Canyon and Brushy Canyon formations, the Cherry Canyon Formation is approximately 1,300 ft thick and contains numerous turbidite source points. Unlike the Bell Canyon and Brushy Canyon deposits, the channel deposits are not as large (Giesen and Scholle, 1990), and the source of the sands appears to be dominantly from the eastern margin (**Figure 3.2-12**). Cherry Canyon 1 and 5 have the best channel development and the thickest sands. Overall, the Cherry Canyon Formation, on outcrop, is less influenced by traction current deposition than the rest of the Delaware Mountain Group deposits and is more influenced by sedimentation by density overflow currents (**Figure 3.2-9**). The Brushy Canyon has notably more discrete channel deposits and coarser sands than the Cherry Canyon and Bell Canyon. The Brushy Canyon Formation is approximately 1,500 ft thick.

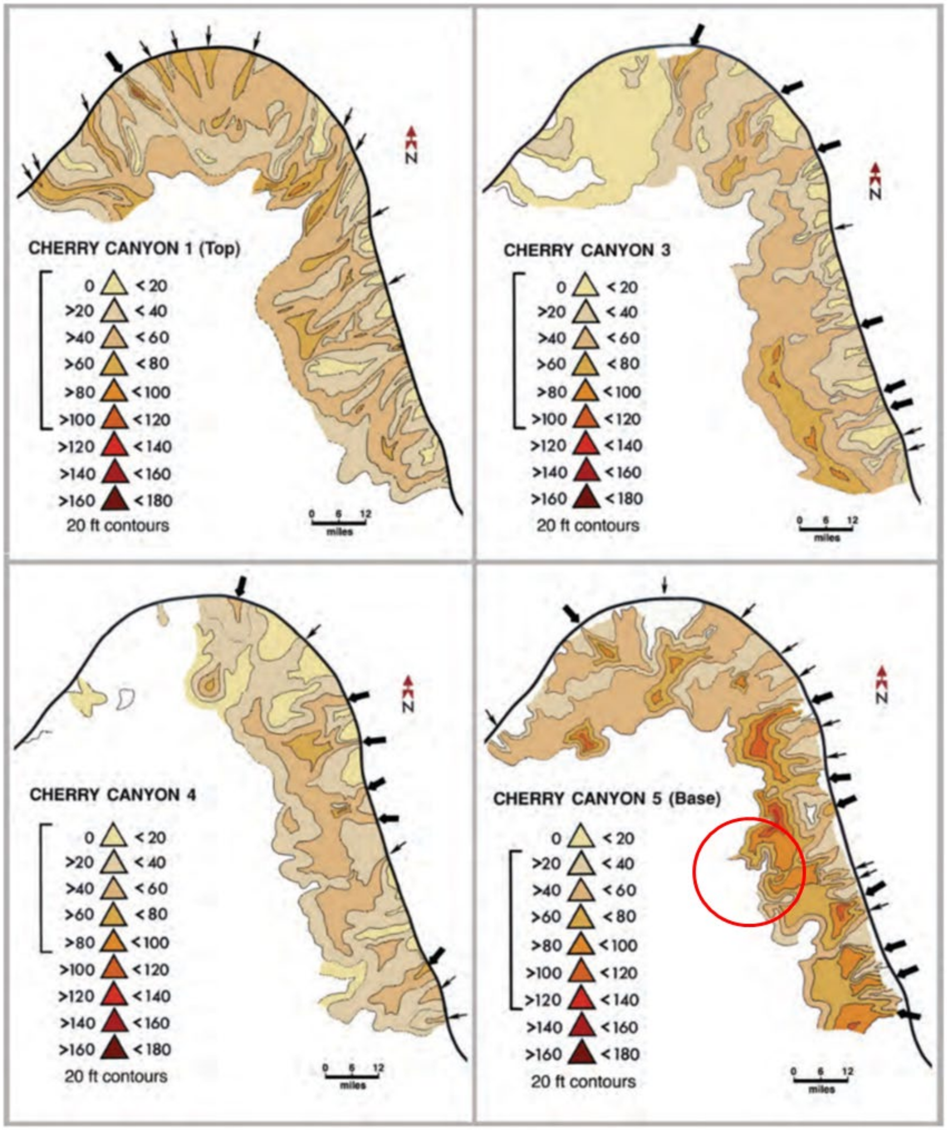


***Figure 3.2-12**– These maps of Cherry Canyon Formation were created by measuring sandstone thicknesses on well logs in five regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). Unlike the Bell Canyon sandstones, the Cherry Canyon sands are thinner and contain fewer channels. The red circle on the last map surrounds the Red Hills area.*

Within the Delaware Mountain Group in the Red Hills area, the Bell Canyon and Cherry Canyon have the best porosity (averaging 15 – 25 % within channel/splay sandstones) and permeability (averaging 2-13 mD) than the Brushy Canyon (~14% porosity, an <3 mD; Ge et al, 2022, Smye et al., 2021).

UNDERLYING CONFINING ZONE

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

3.2.3 Faulting

In this immediate area of the Permian Basin, faulting is primarily confined to the lower Paleozoic section, where seismic data shows major faulting and ancillary fracturing-affected rocks only as high up as the base of the lower Wolfcamp strata (**Figures 3.2-6 and 5.6-1**). Faults that have been identified in the area are normal faults associated with Ouachita related movement along the western margin of the Central Platform to the east of the RH AGI well site. The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief. Because these faults are confined to the lower Paleozoic unit well below the injection zone for the RH AGI wells, they will not be discussed further (Horne et al., 2021). Within the area of the Red Hills site, no shallow faults within the Delaware Mountain Group have been identified by seismic data interpretation nor as reported by Horne et al., 2022).

3.3 Lithologic and Reservoir Characteristics

Based on the geologic analyses of the subsurface at the Red Hills Gas Plant, the uppermost portion of the Cherry Canyon Formation was chosen for acid gas injection and CO_2 sequestration for RH AGI #1 and the uppermost Delaware Mountain Group (the Bell Canyon and Cherry Canyon Formations) for RH AGI #3.

For RH AGI #1, this interval includes five high porosity sandstone units (sometimes referred to as the Manzanita) and has excellent caps above, below and between the individual sandstone units. There is no local production in the overlying Delaware Sands pool of the Bell Canyon Formation. There are no structural features or faults that would serve as potential vertical conduits. The high net porosity of the RH AGI #1 injection zone indicates that the injected H_2S and CO_2 will be easily contained close to the injection well.

For RH AGI #3, this interval has been expanded to include the five porosity zones in the Cherry Canyon sandstone as well as the sandstone horizons in the overlying Bell Canyon Formation. In the Bell Canyon Formation there are several potential high porosity sandstones, that if present in the well, would be excellent , injection zones similar to the depositional environments of the Cherry Canyon sandstones. The thickest sand is commonly referred to as the Delaware Sand within the Delaware Basin. The Delaware sand is productive, but it is not locally. Most of the sand bodies in the Bell Canyon and Cherry Canyon formations are surrounded by shales or limestones, forming caps for the injection zones. There are no structural features or faults that would serve as potential vertical conduits, and the overlying Ochoan evaporites form an excellent overall seal for the system. Even if faulting existed, the evaporites (Castile and Salado) would self-seal and prevent vertical migration out of the Delaware Mountain Group.

The geophysical logs were examined for all wells penetrating the Bell Canyon and Cherry Canyon formations within a three-mile radius of the RH AGI wells as well as 3-D seismic data. There are no faults visible within the Delaware Mountain Group in the Red Hills area. Within the seismic area, the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales (**Figure 3.2-8**) as well as being encased by them. Based on regional studies (Giesen and Scholle, 1990 and **Figures 3.2-11, 3.2-12**), the preferred orientation of the channels, and hence the preferred fluid migration pathways, are roughly from the east to the west.

The porosity was evaluated using geophysical logs from nearby wells penetrating the Cherry Canyon Formation. **Figure 3.3-1** shows the Resistivity (Res) and Thermal Neutron Porosity (TNPH) logs from 5,050 ft to 6,650 ft and includes the injection interval. Five clean sands (>10% porosity and <60 API gamma units) are targets for injection within the Cherry Canyon formation and potentially another 5 sands with >10% porosity and <60 API gamma units were identified. Ten percent was the minimum cut-off considered for adequate

porosity for injection. The sand units are separated by lime mudstone and shale beds with lateral continuity. The high porosity sand units exhibit an average porosity of about 18.9%; taken over the average thickness of the clean sand units within ½ mile of the RH AGI #1. There is an average of 177 ft with an irreducible water (S_{wir}) of 0.54 (see Table 1 of the RH AGI #1 permit application). Many of the sands are very porous (average porosity of > 22%) and it is anticipated that for these more porous sands, the S_{wir} may be too high. The effective porosity (Total Porosity – Clay Bound Water) would therefore also be higher. As a result, the estimated porosity ft (PhiH) of approximately 15.4 porosity-ft should be considered to be a minimum. The overlying Bell Canyon Formation has 900 ft of sands and intervening tight limestones, shales, and calcitic siltstones with porosities as low as 4%, but as mentioned above, there are at least 5 zones with a total thickness of approximately 460 ft and containing 18 to 20% porosity. The injection interval is located more than 2,650 ft above the Bone Spring Formation, which is the next production zone in the area.

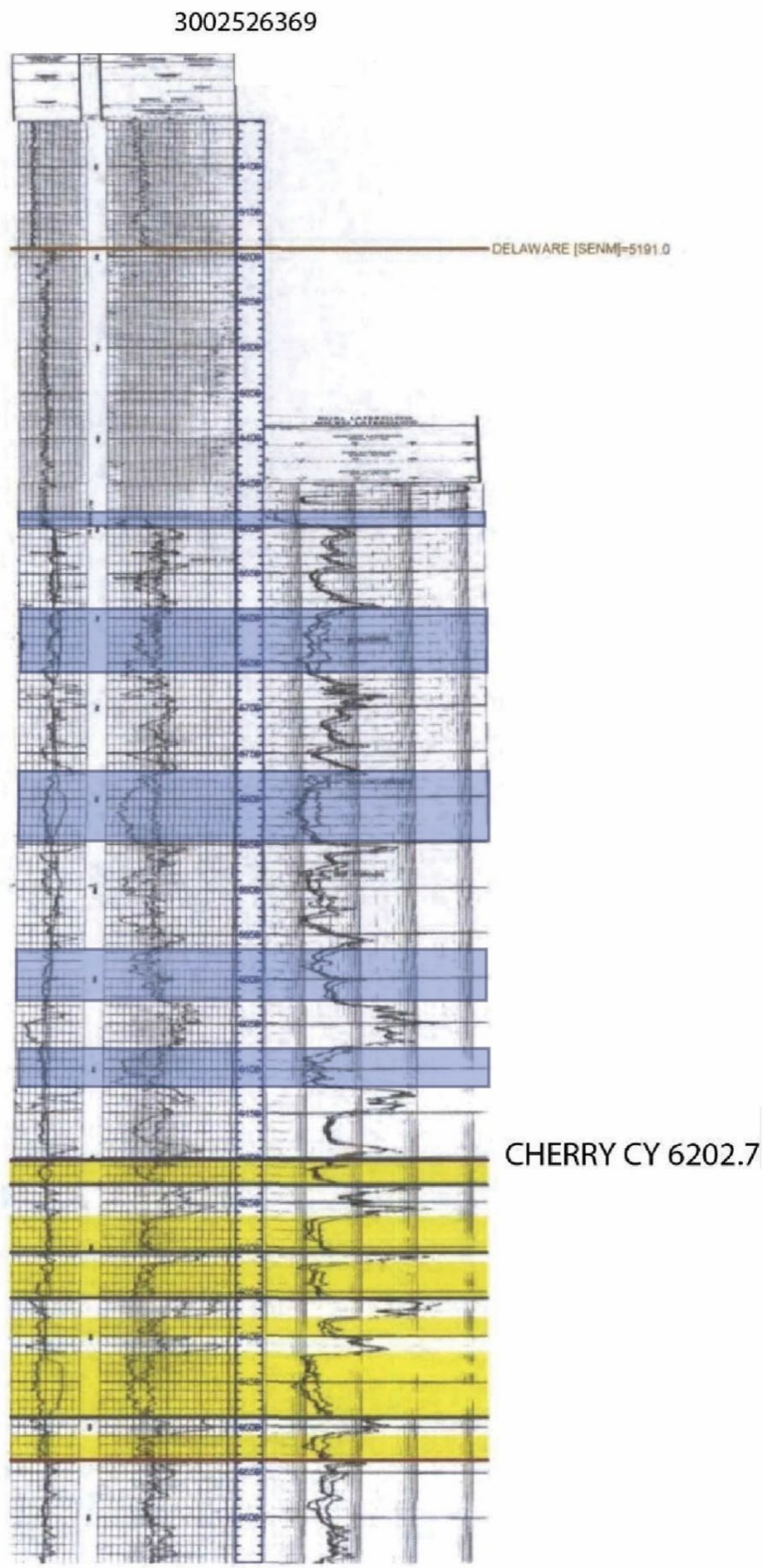


Figure 3.3-1: *Geophysical logs from the Bell Canyon and the Upper Cherry Canyon from the Government L Com #002 well, located 0.38 miles from the RH AGI #1 Well. The blue intervals are Bell Canyon porosity zones, and the yellow intervals are Cherry Canyon porosity zones.*

3.4 Formation Fluid Chemistry

A chemical analysis (**Table 3.4-1**) of water from Federal 30 Well No. 2 (API 30-025-29069), approximately 3.9 miles away, indicates that the formation waters are highly saline (180,000 ppm NaCl) and compatible with the injection.

***Table 3.4-1**: Formation fluid analysis for Cherry Canyon Formation from Federal 30 Well No. 2*

Sp. Gravity	1.125 @ 74°F	Resistivity	0.07 @ 74°F
pH	7	Sulfate	1,240
Iron	Good/Good	Bicarbonate	2,135
Hardness	45,000	Chloride	110,000
Calcium	12,000	NaCl	180,950
Magnesium	3,654	Sod. & Pot.	52,072

Table extracted from C-108 Application to Inject by Ray Westall Associated with SWD-1067 – API 30-025-24676. Water analysis for formation water from Federal 30 #2 Well (API 30-025-29069), depth 7,335-7,345 ft, located 3.9 miles from RH AGI #1 well.

3.5 Groundwater Hydrology in the Vicinity of the Red Hills Gas Plant

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are 15 freshwater wells located within a two-mile radius of the RH AGI wells, and only 2 water wells within one mile; the closest water well is located 0.31 miles away and has a total depth of 650 ft (**Figure 3.5-1; Appendix 3**). All water wells within the two-mile radius are shallow, collecting water from about 60 to 650 ft depth, in Alluvium and the Triassic redbeds. The shallow freshwater aquifer is protected by the surface and intermediate casings and cements in the RH AGI wells (**Figures Appendix 1-1 and Appendix 1.2**). While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

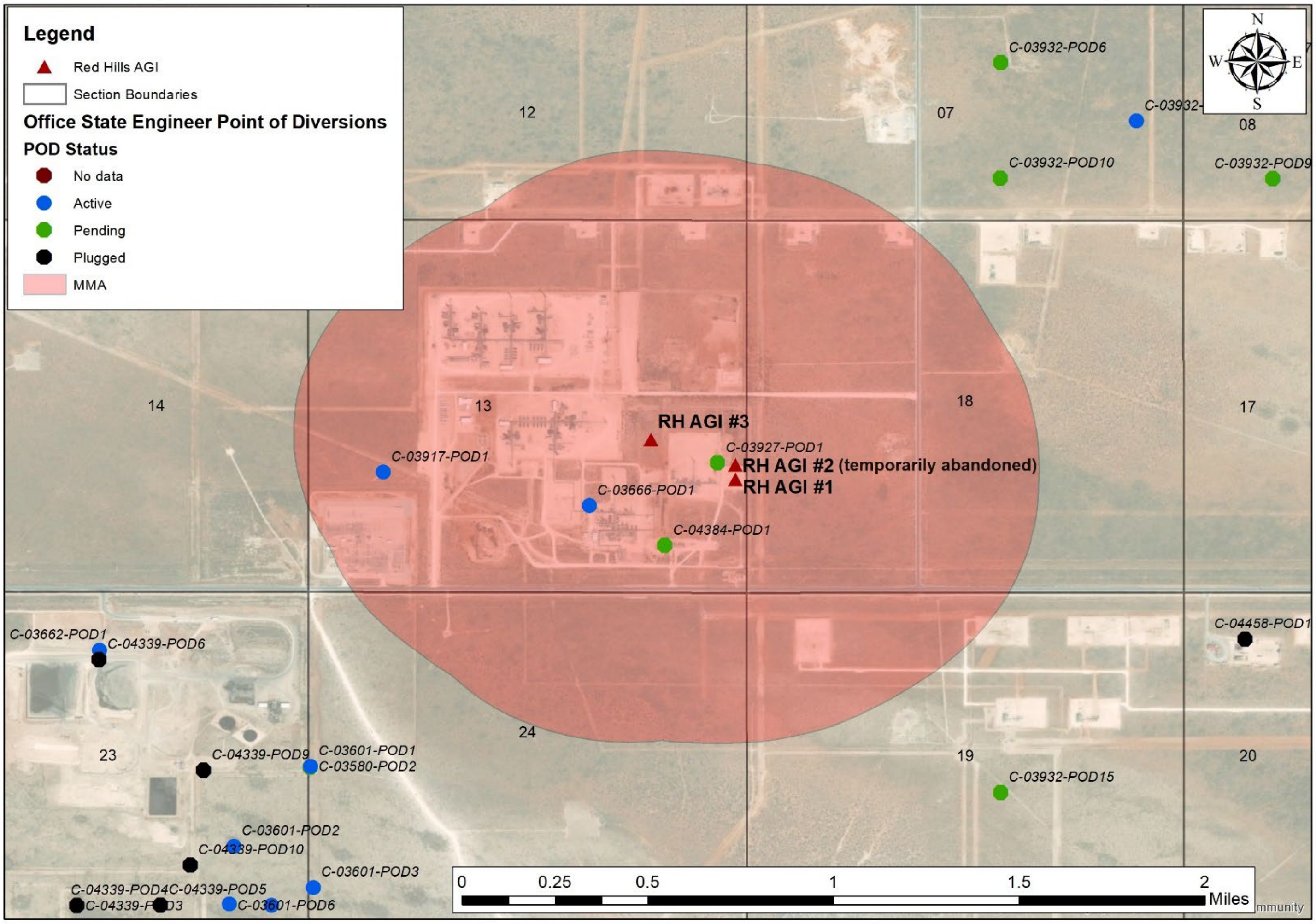


Figure 3.5-1: Reported Water Wells within the MMA for the RH AGI Wells.

3.6 Historical Operations

3.6.1 Red Hills Site

On July 20, 2010, Agave Energy Company (Agave) filed an application with NMOCD to inject treated acid gas into an acid gas injection well. Agave built the Red Hills Gas Processing Plant and drilled RH AGI #1 in 2012-13. However, the well was never completed and never put into service because the plant was processing only sweet gas (no H_2S). Lucid purchased the plant from Agave in 2016 and completed the RH AGI #1 well. TND acquired Lucid's Red Hills assets in 2022. **Figure 3.6-1** shows the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells. **Figure 3.6-2** shows a process block flow diagram.

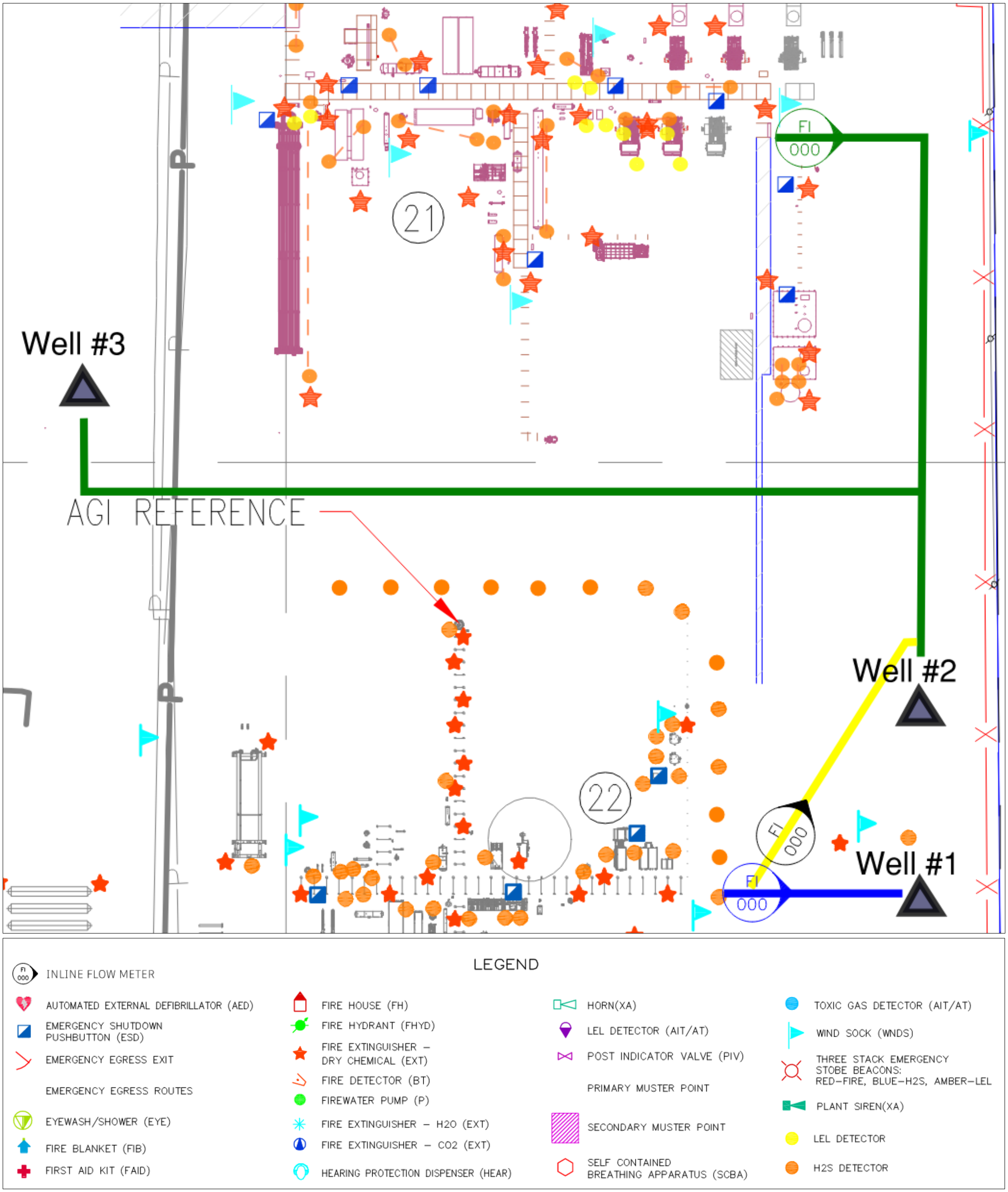


__Figure 3.6-1__: Diagram showing the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells.

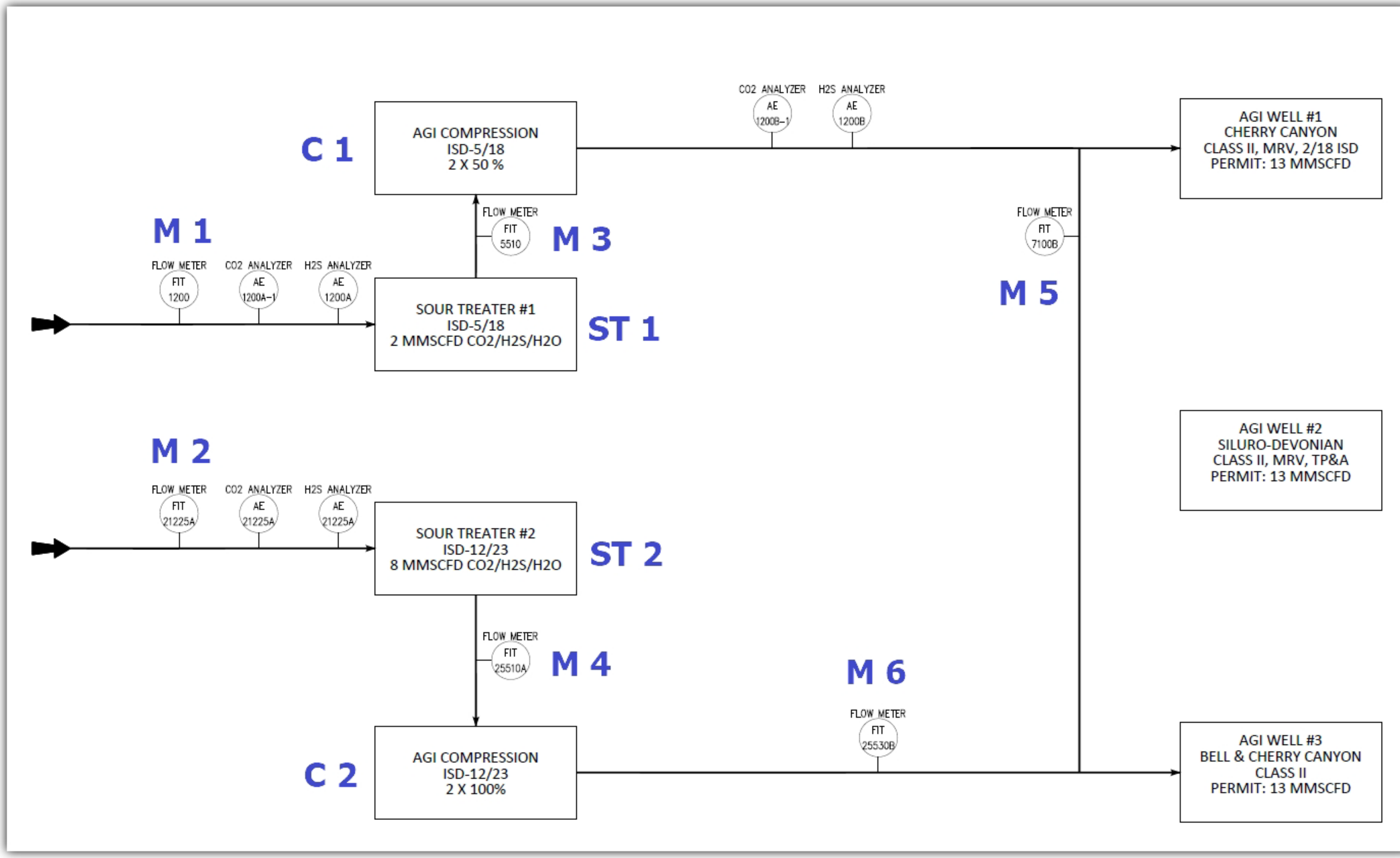


Figure 3.6-2: *Process Block Flow Diagram. RH AGI #2 is temporarily abandoned. M1 – M6: volumetric flow meters; C1 and C2: compressors; ST1 and ST2: sour treaters*

3.6.2 Operations within the MMA for the RH AGI Wells

NMOCD records identify a total of 22 oil- and gas-related wells within the MMA for the RH AGI wells (see **Appendix 4**). **Figure 3.6-3** shows the geometry of producing and injection wells within the MMA for the RH AGI wells. **Appendix 4** summarizes the relevant information for those wells. All active production in this area is targeted for the Bone Spring and Wolfcamp zones, at depths of 8,900 to 11,800 ft, the Strawn (11,800 to 12,100 ft) and the Morrow (12,700 to 13,500 ft). All of these productive zones lie at more than 2,000 ft below the RH AGI #1 and AGI #3 injection zone.

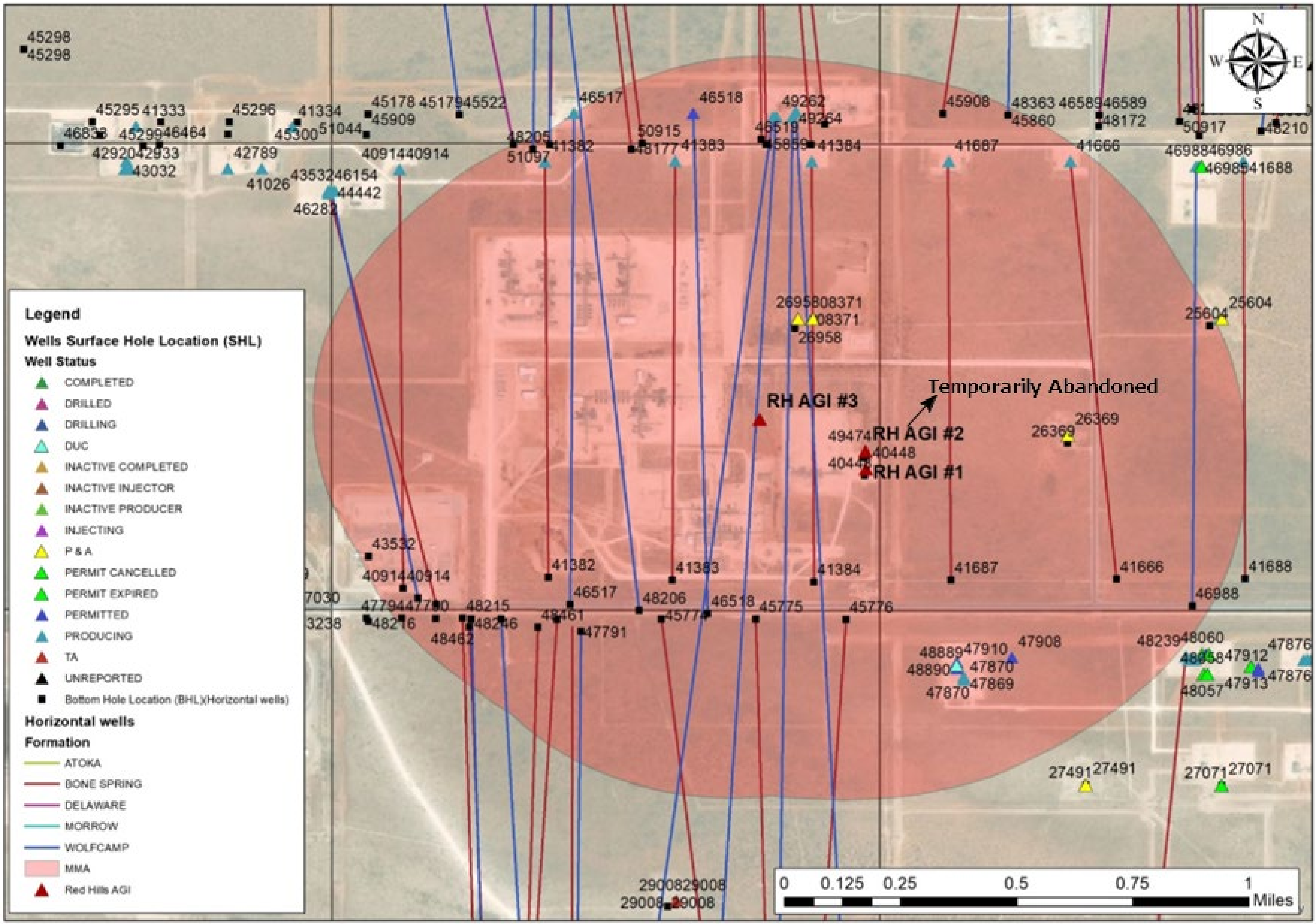


__Figure 3.6-3__: Location of all oil- and gas-related wells within the MMA for the RH AGI wells. Both the surface hole locations (SHL) and bottom hole locations (BHL) are labeled on the figure. For clarity, only the last four digits of the API numbers are used in labeling the wells.

3.7 Description of Injection Process

The Red Hills Gas Plant, including the existing RH AGI #1 well, is in operation and staffed 24-hours-a-day, 7-days-a week. The plant operations include gas compression, treating and processing. The plant gathers and processes produced natural gas from Lea and Eddy Counties in New Mexico. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the plant's sweeteners will be routed to a central compressor facility, located west of the well head. Compressed TAG is then routed to the wells via high-pressure rated lines. **Figure 3.7-1** is a schematic of the AGI facilities.

The approximate composition of the TAG stream is: 80% CO_2, 20% H_2S, with Trace Components of C_1 – C_6 (methane – hexane) and Nitrogen. The anticipated duration of injection is 30 years.

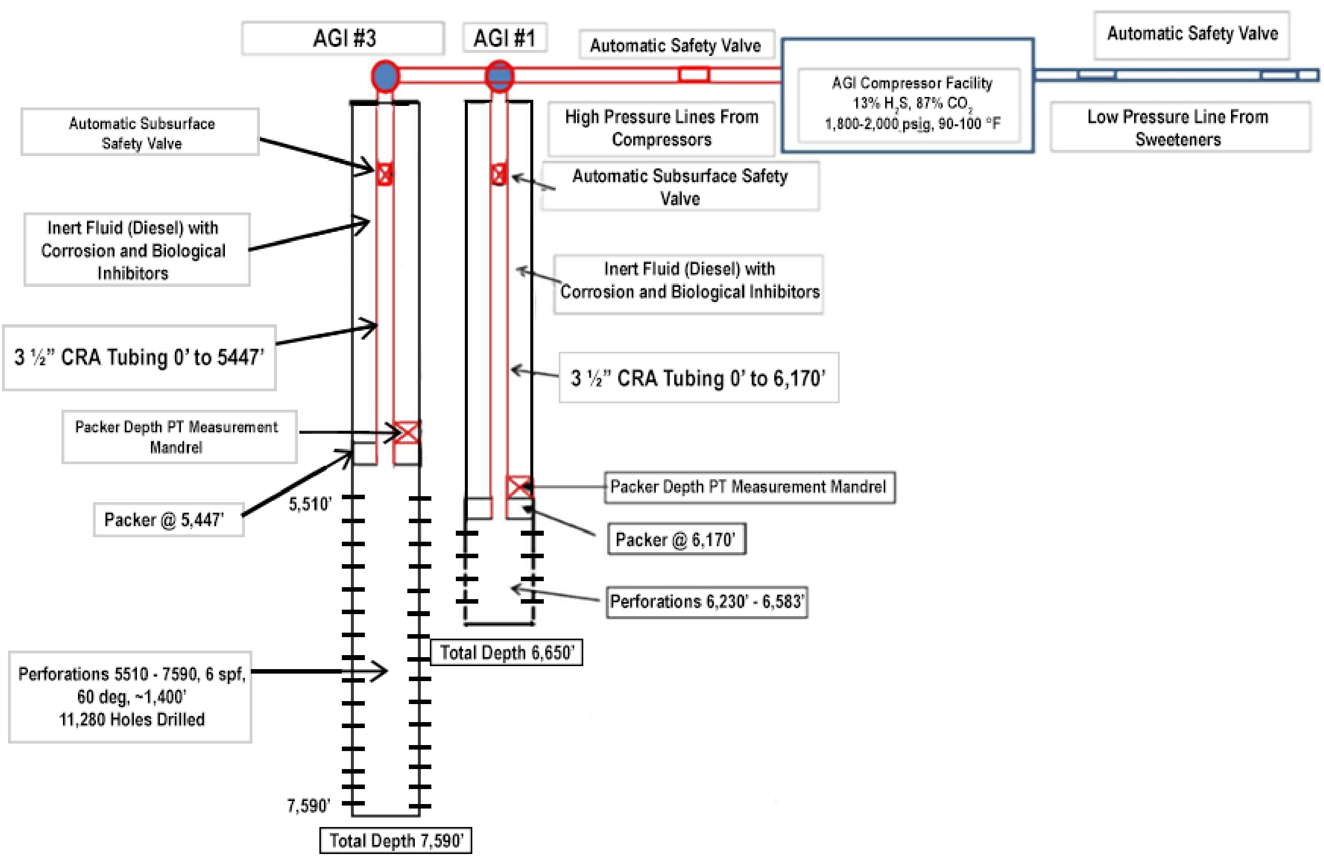


***Figure 3.7-1**: Schematic of surface facilities and RH AGI wells at the Red Hills Gas Processing Plant*

3.8 Reservoir Characterization Modeling

The modeling and simulation focused on the Bell Canyon and Cherry Canyon formations as the main injection target zone for acid gas storage. The RH AGI #1 well (API 30-025-40448) and the RH AGI #3 well (API 30-025-51970) are the approved injectors for treated acid gas injection by NMOCD and will serve as the injection wells in the model under approved disposal timeframe and maximum allowable injection pressure. RH AGI #1 well is completed in the Cherry Canyon formation between 6,230 feet to 6,583 feet (MD). The RH AGI #3 well will be completed in both the Bell Canyon and Cherry Canyon formations between approximately 5,245 feet to 6,645 feet (MD).

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

The static model is constructed with well tops and licensed 3D seismic data to interpret and delineate the structural surfaces of a layer within the caprock (Lamar Limestone) and its overlaying, underlying formations. The geologic model covers a 3.5-mile by 3.3-mile area. No distinctive geological structures such as faults are identified within the geologic model boundary. The model is gridded with 182 x 167 x 18, totaling 547,092 cells. The average grid dimension of the active injection area is 100 feet square. **Figure 3.8-1** shows the simulation model in 3D view. The porosity and permeability of the model is populated through existing well logs. The range of the porosity is between 0.01 to 0.31. The initial permeability are interpolated between 0.02 to 155 millidarcy (mD), and the vertical permeability anisotropy was 0.1. **(Figure 3.8-2 and Figure 3.8-3)**. These values are validated and calibrated with the historical injection data of RH AGI #1 well since 2018 as shown in **Figures 3.8-4, 3.8-5, and 3.8-6**.

The simulation model is calibrated with the injection history of RH AGI #1 well since 2018. Simulation studies were further performed to estimate the reservoir responses when predicting TAG injection for 30 years through both RH AGI #1 well (2018 – 2048) and RH AGI #3 (2024 - 2054). RH AGI #2 well is temporarily abandoned as of the submission of this document. RH AGI #1 is simulated to inject with the average rate of the last 5 years, 1.2 MMSCF, in the prediction phase. RH AGI #3 is simulated to inject with permitted injection rate, 13 MMSCF, with 1,767 psi maximum surface injection pressure constraint approved by State agency. The simulation terminated at year 2084, 30 years after the termination of all injection activities, to estimate the maximum impacted area during post injection phase.

During the calibration period (2018 – 2023), the historical injection rates were used as the primary injection control, and the maximum bottom hole pressures (BHP) are imposed on wells as the constraint, calculated based on the approved maximum injection pressure. This restriction is also estimated to be less than 90% of the formation fracture pressure calculated at the shallowest perforation depth of each well to ensure safe injection operations. The reservoir properties are tuned to match the historical injection until it was reasonably matched. **Figure 3.8-4** shows that the historical injection rates from the RH AGI #1 well in the Cherry Canyon Formation. **Figure 3.8-5** shows the BHP response of RH AGI #1 during the history matching phase.

During the forecasting period, linear cumulative injection behavior indicates that the Cherry Canyon and Bell Canyon formations received the TAG stream freely. **Figure 3.8-6** shows the cumulative disposed H_2S and CO_2 of each AGI injectors separately in gas mass. The modeling results indicate that the Cherry Canyon and Bell Canyon formations are capable of safely storing and containing the gas volume without violating the permitted rate and

pressure. **Figure 3.8-7** shows the gas saturation represented TAG plume at the end of 30-year forecasting in 3D view. **Figure 3.8-8** shows the extent of the plume migration in a map view at 4 key time steps. It can be observed that the size of the TAG is very limited and mainly stayed within Targa's Red Hills facility at the end of injection. In the year 2084, after 30 years of monitoring, the injected gas remained trapped in the reservoir and there was no significant migration of TAG footprint observed, compared to that at the end of injection.

In summary, after careful reservoir engineering review and numerical simulation study, our analysis shows that the Bell Canyon and Cherry Canyon formations can receive treated acid gas (TAG) at the injection rate and permitted maximum surface injection pressure permitted by New Mexico Oil Conservation Committee. The formation will safely contain the injected TAG volume within the injection and post-injection timeframe. The injection well will allow for the sequestration while preventing associated environmental impacts.

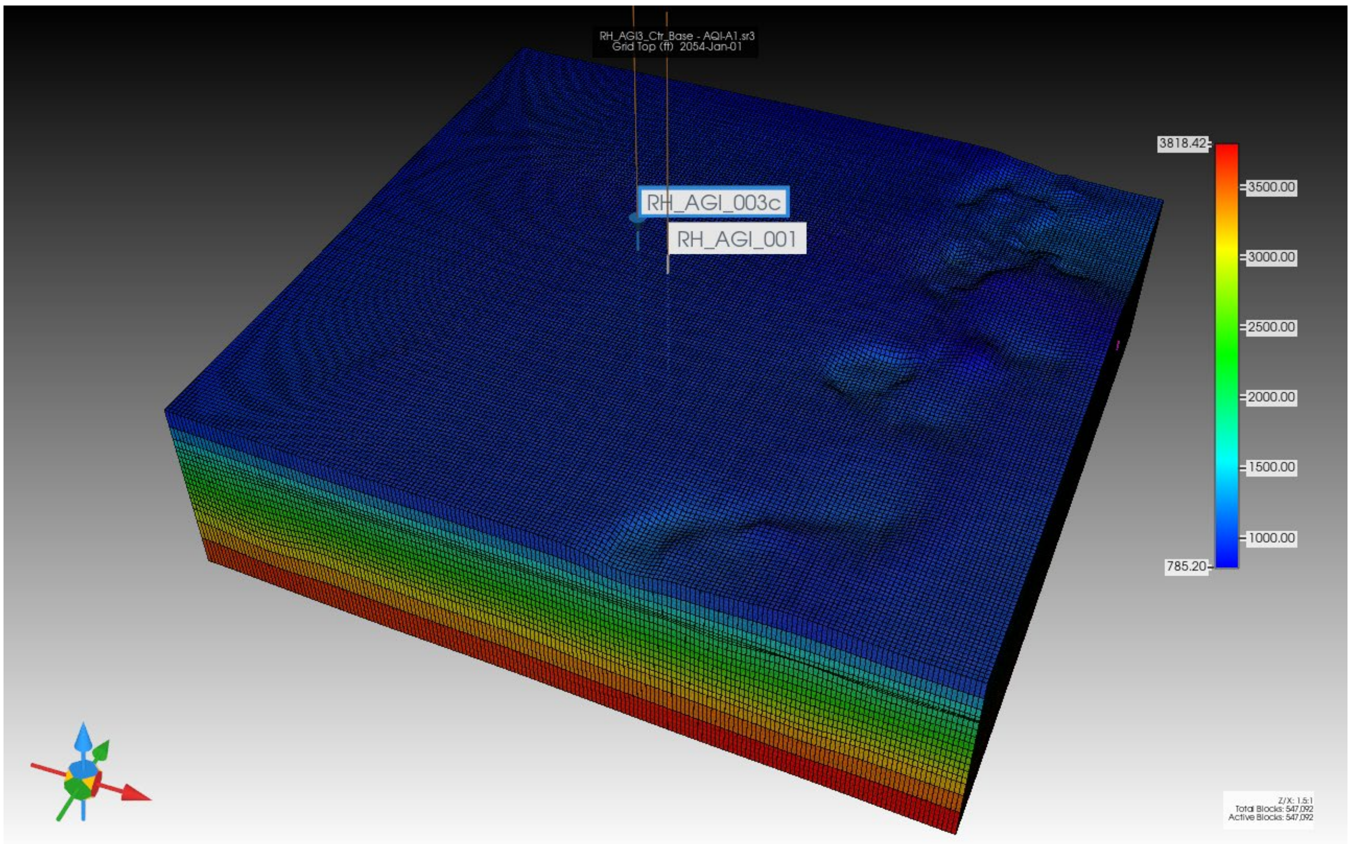


Figure 3.8-1: *3D view of the simulation model of the Red Hills AGI #1 and #3 AGI wells, containing Salado-Castile formation, Lamar limestone, Bell Canyon, and Cherry Canyon formations. Color legends represents the elevation of layers.*

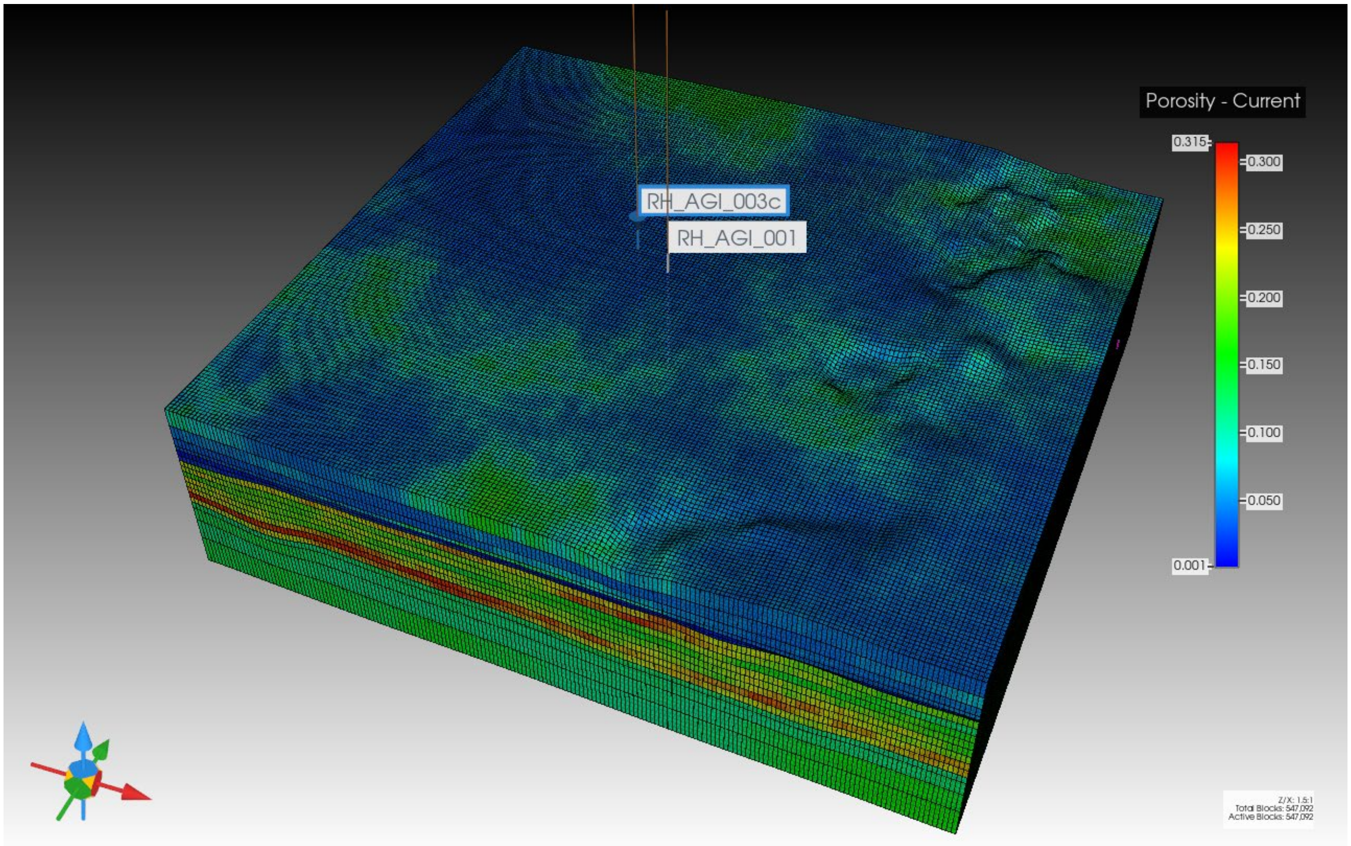


Figure 3.8-2: *Porosity estimation using available well data for the simulation domain.*

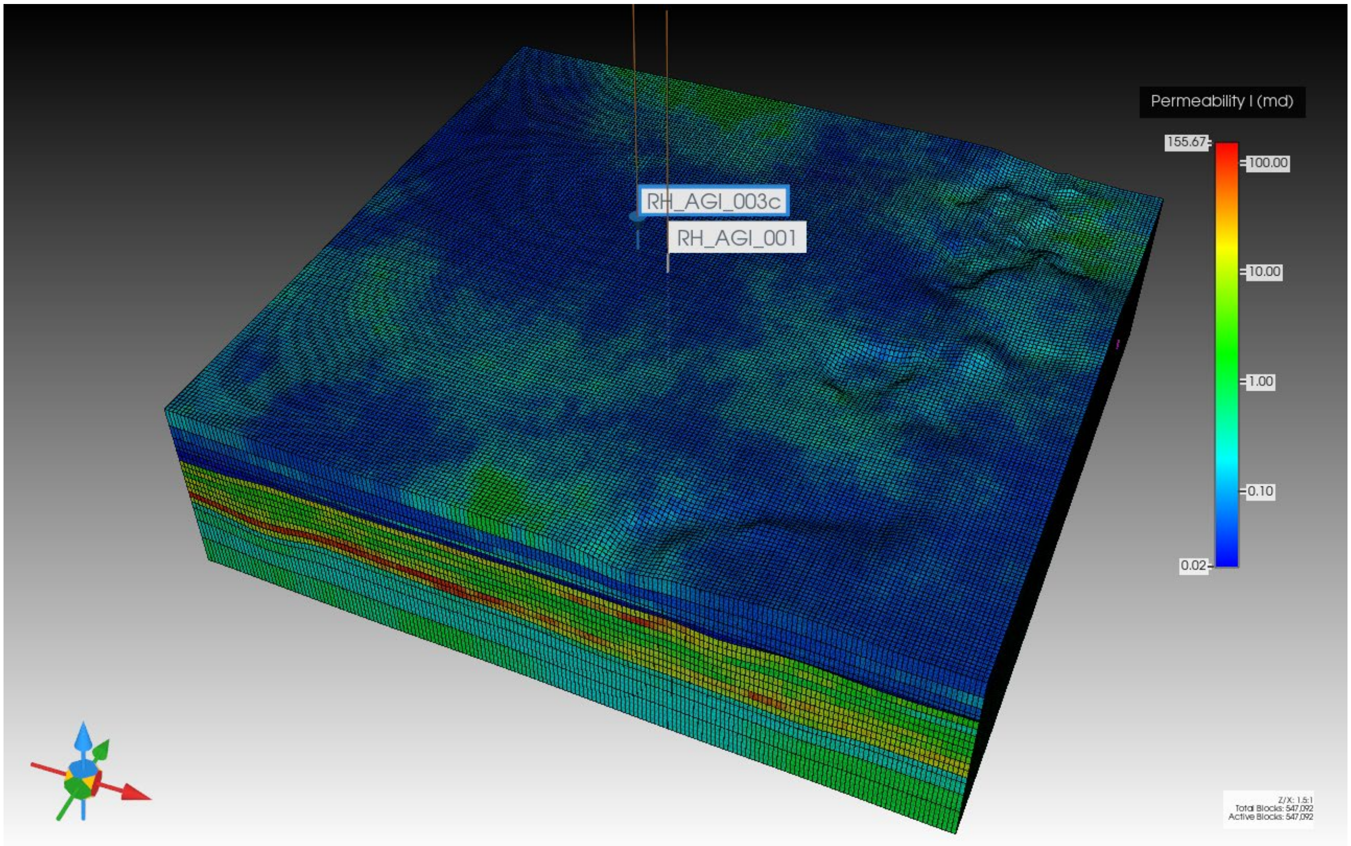


Figure 3.8-3: *Permeability estimation using available well data for simulation domain.*

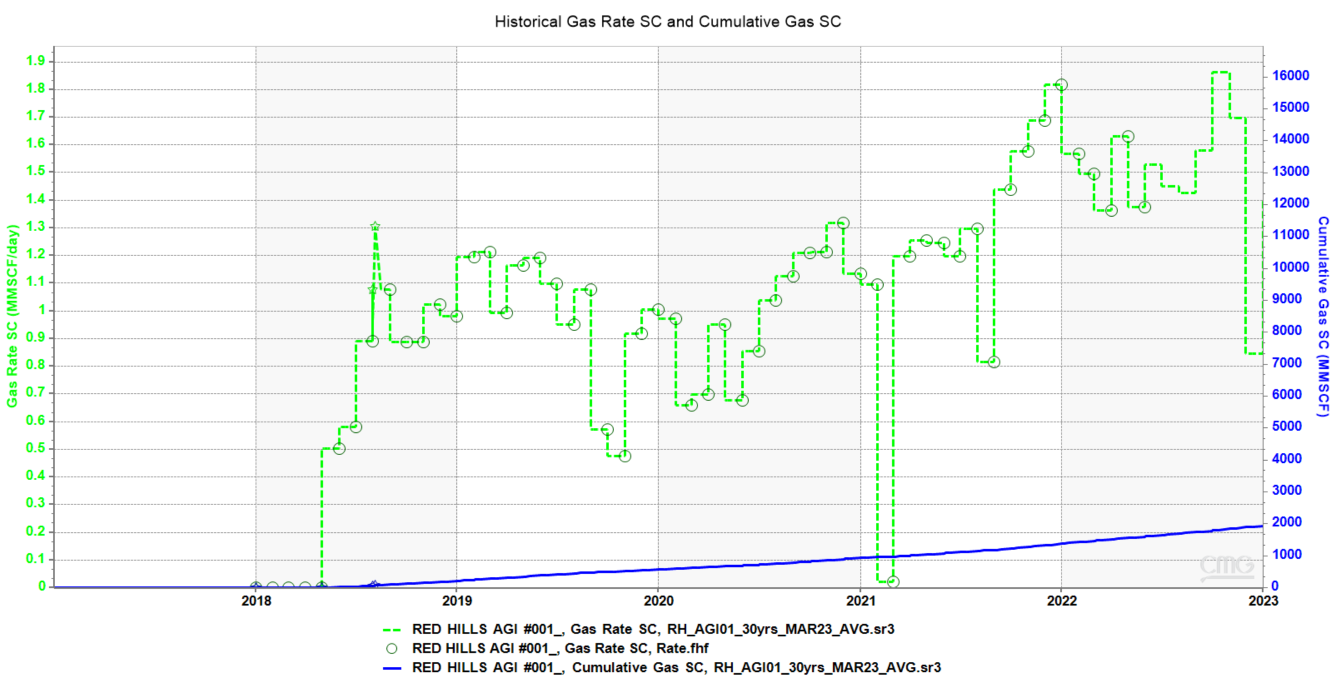


Figure 3.8-4: *shows the historical injection rate and total gas injected from Red Hills AGI #1 well (2018 to 2023)*

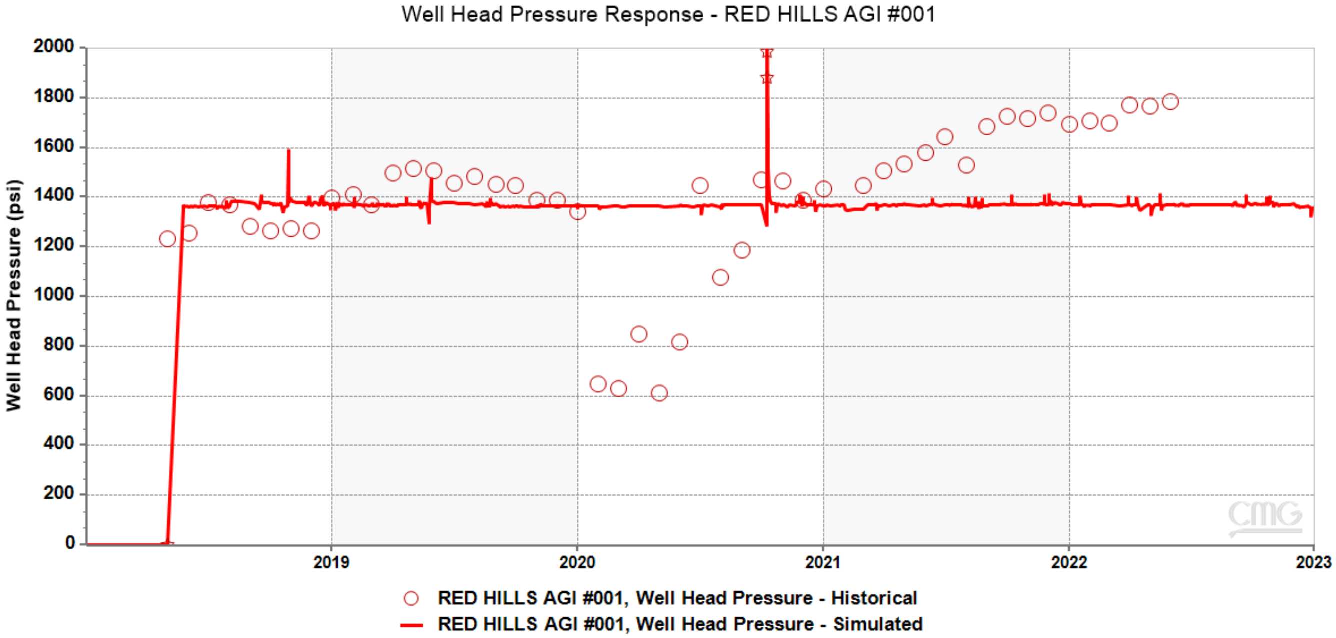


Figure 3.8-5: *shows the historical bottom hole pressure response from Red Hills AGI #1 well (2018 to 2023)*

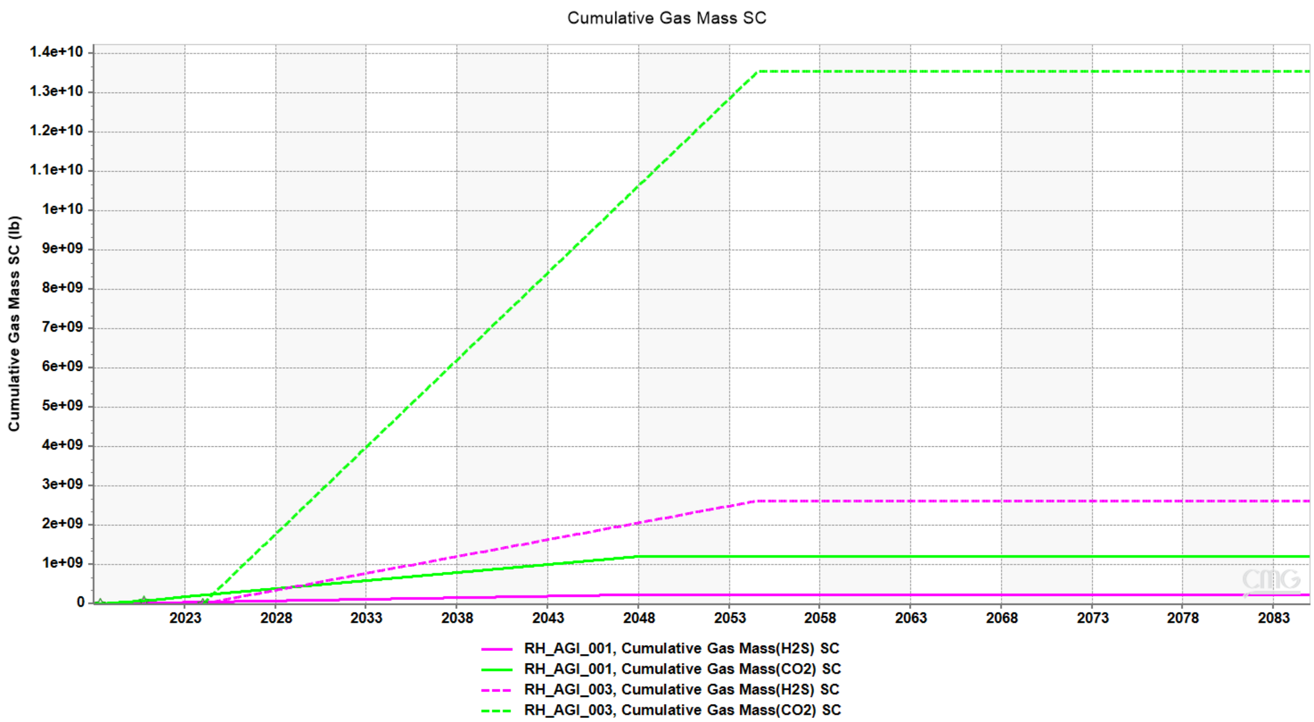


Figure 3.8-6: *shows the prediction of cumulative mass of injected CO_2 and H_2S of Red Hills AGI #1 and #3 wells (2018 to 2054).*

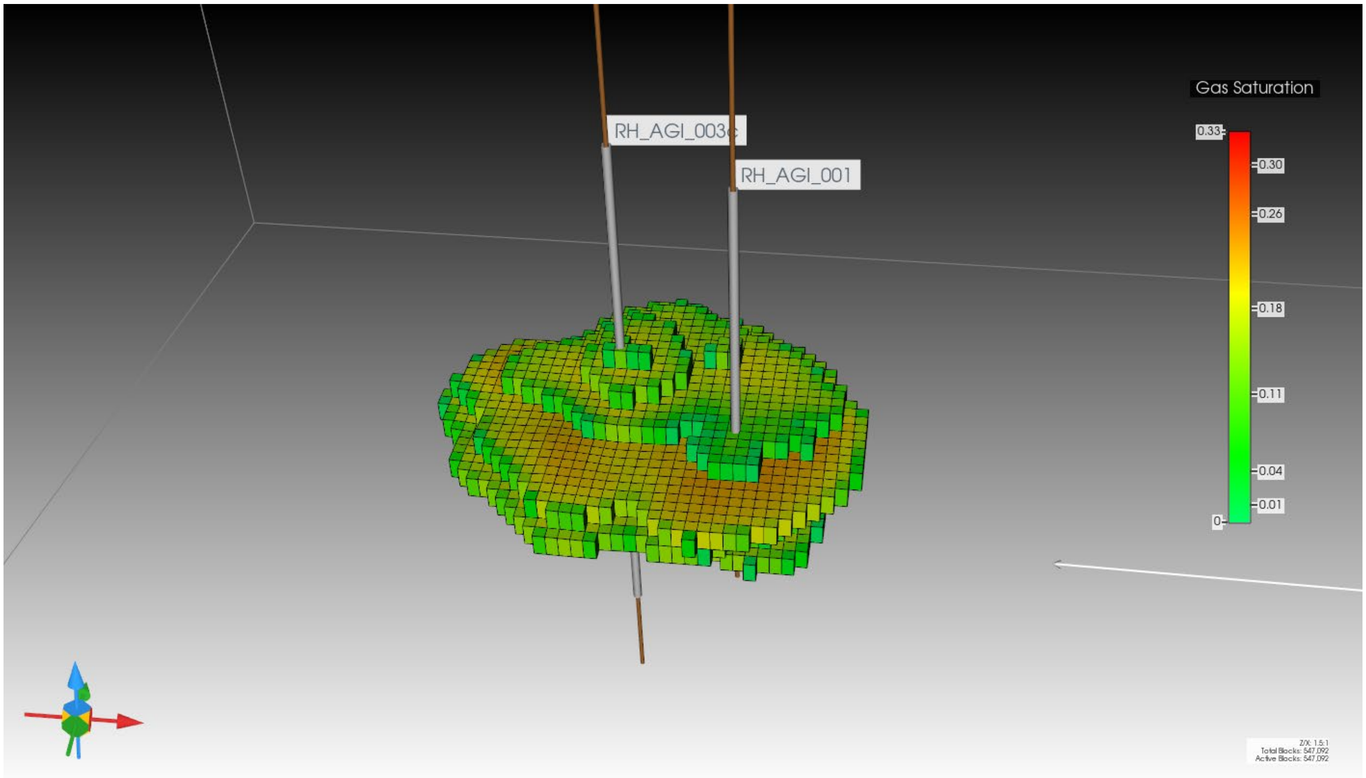


Figure 3.8-7: *shows the free phase TAG (represented by gas saturation) at the end of 30-year post-injection monitoring (2054) in 3D view.*

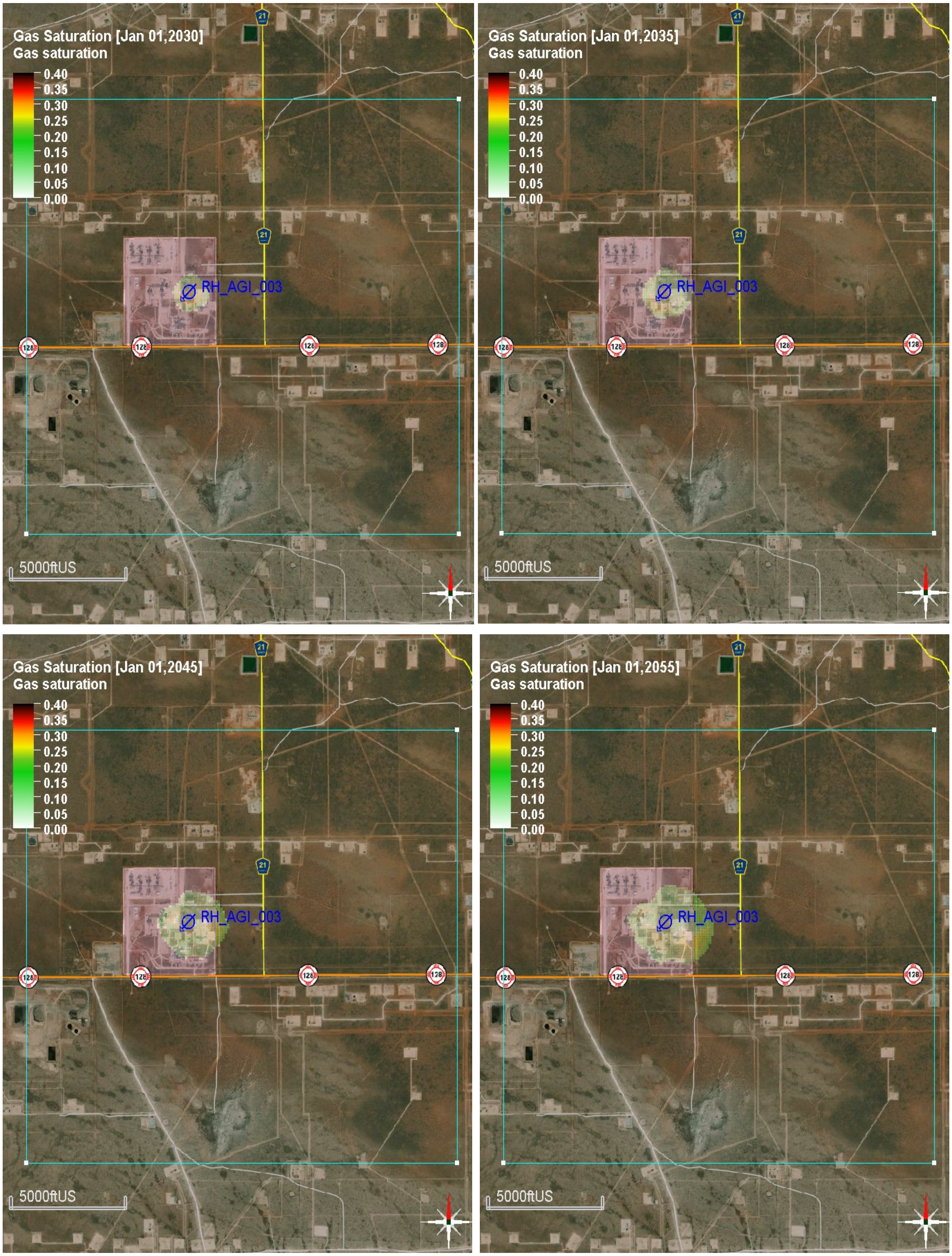


Figure 3.8-8: *shows the free phase TAG plume at year 2030, 2035, 2045, 2055 (1-year end of injection) in a map view.*

4 Delineation of the Monitoring Areas

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

4.1 MMA – Maximum Monitoring Area

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. **Figures 4.1-1** shows the MMA as defined by the extent of the stabilized TAG plume at year 2059 plus a 1/2-mile buffer.

4.2 AMA – Active Monitoring Area

The Active Monitoring Area (AMA) is shown in **Figure 4.1-1**. The AMA is consistent with the requirements in 40 CFR 98.449 because it is the area projected: (1) to contain the free phase CO_2 plume for the duration of the project (year t, t = 2054), plus an all-around buffer zone of one-half mile. (2) to contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2059). Targa intends to define the active monitoring area (AMA) as the same area as the MMA. The purple cross-hatched polygon in **Figure 4.1-1** is the plume extent at the end of injection. The yellow polygon in **Figure 4.1-1** is the stabilized plume extent 5 years after injection ceases. The AMA/MMA shown as the red-filled polygon contains the CO_2 plume during the duration of the project and at the time the plume has stabilized.

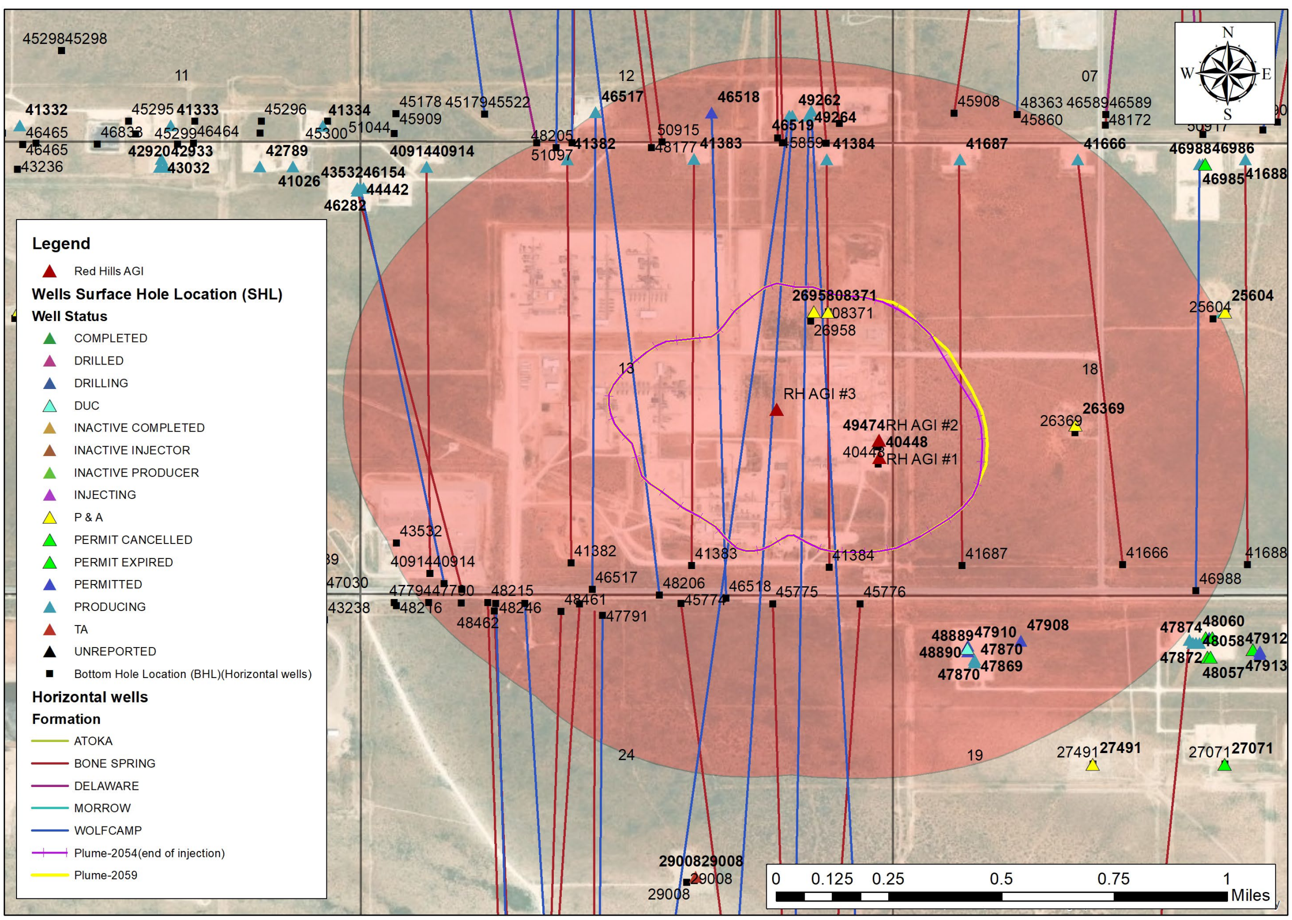


Figure 4.1-1: Active monitoring area (AMA) for TND Red Hills AGI #1, #2 (temporarily abandoned) and #3 wells at the end of injection (2054, purple polygon) and 5 years post-monitoring (2059, yellow polygon). Maximum monitoring area (MMA) is shown in red shaded area.

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

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

Through the site characterization required by the NMOCD C-108 application process for Class II injection wells, the geologic characterization presented in Section 3, and the reservoir modeling described in Section 3.8, TND has identified and evaluated the potential CO_2 leakage pathways to the surface.

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

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas facilities. Preventative risk mitigation includes adherence to relevant regulatory requirements and industry standards governing the construction, operation, and maintenance of gas plants. Specifically, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills."

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

Although mitigative measures are in place to minimize CO_2 emissions from surface equipment, such emissions are possible. Any leaks from surface equipment would result in immediate (timing) emissions of CO_2 to the atmosphere the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak.

The injection well and the pipeline that carries CO_2 to it are the most likely surface components of the system to allow CO_2 to leak to the surface. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable source of the leakage. Another possible source of leakage is the release of air through relief valves, which are designed to alleviate pipeline overpressure. Leakage can also occur when the surface components are damaged by an accident or natural disaster, which releases CO_2. Therefore, TND infers that there is a potential for leakage via this route. Depending on the component's failure mode, the magnitude of the leak can vary greatly. For example, a rapid break or rupture could release thousands of pounds of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO_2 over several hours or days. Surface component leakage or venting is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

5.2 Potential Leakage from RH AGI #3 and Approved, Not Yet Drilled Wells

RH AGI #3 very recently began injecting in January 2024. The only wells within the MMA that are approved but not yet drilled are horizontal wells. These wells have a Well Status of "permitted" in Appendix 4. There are no vertical wells within the MMA with a Well Status of "permitted".

5.2.1 RH AGI #3

TND is began drilling the RH AGI #3 well in September 2023 and began injection in January 2024. To minimize the likelihood of leaks from new wells, NMAC 19.15.26.9 regarding the casing and cementing of injection wells requires operators to case injection wells "with safe and adequate casing or tubing so as to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluid from the injection zone into another injection zone or to the surface around the outside of the casing string." To minimize the magnitude and duration (timing) of CO_2 leakage to the surface, NMAC 19.15.16.12 requires the use of "blowout preventers in areas of high pressure at or above the projected depth of the well." These requirements apply to any other new well drilled within the MMA for this MRV plan.

TND realizes that when they drill the RH AGI #3, they will be drilling into a reservoir in which they have been injecting H_2S and CO_2 for many years. Therefore, for safety purposes, they will be implementing enhanced safety protocols to ensure that no H_2S or CO_2 escapes to the surface during the drilling of RH AGI #3. Enhanced measures include:

- Using managed pressure drilling equipment and techniques thereby minimizing the chance of any gas from entering the wellbore
- Using LCM (loss control material) at a higher-than-normal rate to fill in the pockets of the wellbore thereby minimizing the chance of gas from entering the wellbore while drilling
- Monitoring H_2S at surface at many points to assure operators that we are successfully keeping any possible gas pressures from impacting the drilling operation
- Employing a high level of caution and care while drilling through a known H_2S injection zone, including use of slower drilling processes and more vigilant mud level monitoring in the returns while drilling into the RH AGI #1 injection zone

By drilling through a zone containing pressurized TAG there is a possibility of CO_2 emission to the surface from the pressurized zone. The emission would be nearly immediate. The magnitude of such an emission would be estimated based on field conditions at the time of the detected leak. The safety protocols described above are in place to prevent or minimize the magnitude of such a leak should one occur.

Due to these safeguards and the continuous monitoring of Red Hills well's operating parameters by the distributed control system (DCS), TND considers that while the likelihood of surface emission of CO_2 is possible, the magnitude of such a leak would be minimal as detection of the leak would be nearly instantaneous followed by immediately shutting in the well and remediation.

5.2.2 Horizontal Wells

The table in **Appendix 3** and **Figure 4.1-1** shows a number of horizontal wells in the area, many of which have approved permits to drill but which are not yet drilled. If any of these wells are drilled through the Bell Canyon injection zone for RH AGI #3 and the Cherry Canyon injection zone for RH AGI #1, they will be required to take special precautions to prevent leakage of TAG minimizing the likelihood of CO_2 leakage to the surface. This requirement will be made by NMOCD in regulating applications for permit to drill (APD) and in ensuring that the operator and driller are aware that they are drilling through an H_2S injection zone in order to access their target production formation. NMAC 19.15.11 for Hydrogen Sulfide Gas includes standards for personnel and equipment safety and H_2S detection and monitoring during well drilling, completion, well workovers, and well servicing operations all of which apply for wells drilled through the RH AGI wells TAG plume.

Due to the safeguards described above, the fact there are no proposed wells for which the surface hole location (SHL) lies within the simulated TAG plume and considering the NRAP risk analysis described here in Section 5, TND considers the likelihood of CO_2 emissions to the surface via these horizontal wells to be highly improbable to impossible.

5.3 Potential Leakage from Existing Wells

Existing oil and gas wells within the MMA as delineated in Section 4 are shown in **Figure 3.6-3** and detailed in **Appendix 4**.

TND considered all wells completed and approved within the MMA in the NRAP risk assessment. Some of these wells penetrate the injection and/or confining zones while others do not. Even though the risk of CO_2 leakage through the wells that did not penetrate confining zones is most likely impossible, TND did not omit any potential source of leakage in the NRAP analysis. If leakage through wellbores happens, the worst-case scenario is predicted using the NRAP tool to quantitatively assess the amount of CO_2 leakage through existing and approved wellbores within the MMA. Thirty-nine existing and approved wells inside MMA were addressed in the NRAP analysis. The reservoir properties, well data, formation stratigraphy, and MMA area were incorporated into the NRAP tool to forecast the rate and mass of CO_2 leakage. The worst scenario is that all of the 39 wells were located right at the source of CO_2 – the injection well's location. In this case, the maximum leakage rate of one well is approximately 7e-6 kg/s. This value is the maximum amount of CO_2 leakage, 220 kg/year, and occurs in the second year of injection, then gradually reduces to 180 kg at the end of year 30. Comparing the total amount of CO_2 injected (assuming 5 MMSCFD of supercritical CO_2 injected continuously for 30 years), the leakage mass amounts to 0.0054% of the total CO_2 injected. This leakage can be considered safely negligible. Also, this worst-case scenario, where 39 wells are located right at the injection point, is impossible in reality. Therefore, CO_2 leakage to the surface via this potential leakage pathway can be considered improbable.

5.3.1 Wells Completed in the Bell Canyon and Cherry Canyon Formations

The only wells completed in the Bell Canyon and Cherry Canyon Formations within the MMA are the RH AGI #1 and #3 wells and the 30-025-08371 well which was completed at a depth of 5,425 ft. This well is within the Red Hills facility boundary and is plugged and abandoned (see **Appendix 9** for plugging and abandonment (P&A) record). **Appendix 1** includes schematics of the RH AGI wells construction showing multiple strings of casing all cemented to surface. Injection of TAG occurs through tubing with a permanent production packer set above the injection zone.

Due to the robust construction of the RH AGI wells, the plugging of the well 30-025-08371 above the Bell Canyon, and considering the NRAP analysis described above, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.2 Wells Completed in the Bone Spring / Wolfcamp Zones

Several wells are completed in the Bone Spring and Wolfcamp oil and gas production zones as described in Section 3.6.2. These productive zones lie more than 2,000 ft below the RH AGI wells injection zone minimizing the likelihood of communication between the RH AGI well injection zones and the Bone Spring / Wolfcamp production zones. Construction of these wells includes surface casing set at 1,375 ft and cemented to surface and intermediate casing set at the top of the Bell Canyon at depths of from 5,100 to 5,200 ft and cemented through the Permian Ochoan evaporites, limestone and siltstone (**Figure 3.2-2**) providing zonal isolation preventing TAG injected into the Bell Canyon and Cherry Canyon formations through RH AGI wells from leaking upward along the borehole in the event the TAG plume were to reach these wellbores. **Figure 4.1-1** shows that the modeled TAG plume extent after 30 years of injection and 5 years of post-injection stabilization does not extend to well boreholes completed in the Bone Spring / Wolfcamp production zones thereby indicating that these wells are not likely to be pathways for CO_2 leakage to the surface.

Due to the construction of these wells, the fact that the modeled TAG plume does not reach the SHL of these wells and considering the NRAP analysis described in the introductory paragraph of Section 5, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.3 Wells Completed in the Siluro-Devonian Zone

One well penetrated the Devonian at the boundary of the MMA - EOG Resources, Government Com 001, API # 30-025-25604, TVD = 17,625 ft, 0.87 miles from RH AGI #3. This well was drilled to a total depth of 17,625 ft on March 5, 1978, but plugged back to 14,590 ft, just below the Morrow, in May of 1978. Subsequently, this well was permanently plugged and abandoned on December 30, 2004, and approved by NMOCD on January 4, 2005 (see **Appendix 9** for P&A records). The approved plugging provides zonal isolation for the Bell Canyon and Cherry Canyon injection zones minimizing the likelihood that this well will be a pathway for CO_2 emissions to the surface from either injection zone.

Due to the location of this well at the edge of the MMA and considering the NRAP analysis described in the introductory paragraph of Section 5, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.4 Groundwater Wells

The table in Appendix 3 lists 15 water wells within a 2-mile radius of the RH AGI wells, only 2 of which are within a 1-mile radius of and within the MMA for the RH AGI wells (**Figure 3.5-1**). The deepest ground water well is 650 ft deep The evaporite sequence of the Permian Ochoan Salado and Castile Formations (see Section 3.2.2) provides an excellent seal between these groundwater wells and the Cherry Canyon injection zone of the RH AGI #1 well. Therefore, it is unlikely that these two groundwater wells are a potential pathway of CO_2 leakage to the surface. Nevertheless, the CO_2 surface monitoring and groundwater monitoring described in Sections 6 and 7 will provide early detection of CO_2 leakage followed by immediate response thereby minimizing the magnitude of CO_2 leakage volume via this potential pathway.

Due to the shallow depth of the groundwater wells within the MMA relative to the depth of the RH AGI wells and considering the NRAP analysis described in the introductory paragraph in Section 5, TND considers that, while the likelihood of CO_2 emissions to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.4 Potential Leakage through the Confining / Seal System

The site characterization for the injection zone of the RH AGI wells described in Sections 3.2.2 and 3.3 indicates a thick sequence of Permian Ochoan evaporites, limestone, and siltstones (**Figure 3.2-2**) above the Bell Canyon and Cherry Canyon Formations and no evidence of faulting. Therefore, it is unlikely that TAG injected into the Bell Canyon and Cherry Canyon Formations will leak through this confining zone to the surface. Limiting the injection pressure to less than the fracture pressure of the confining zone will minimize the likelihood of CO_2 leakage through this potential pathway to the surface.

Leakage through a confining zone happens at low-permeability shale formations containing natural fractures. The injection zone for the RH AGI #1 and #3 is the Delaware Group Formation (Bell Canyon and Cherry Canyon), which lies under the Castile and Salado formations with less than 0.01 mD permeability acting as the seals. Therefore, TND took leakage through confining zones into consideration in the NRAP risk assessment. The worst-case scenario is defined as leakage through the seal happening right above the injection wells, where CO_2 saturation is highest. However, this worst-case scenario of leakage only shows that 0.0017% of total CO_2 injection in 30 years was leaked from the injection zone through the seals. As we go further from the source of CO_2, the likelihood of such an event will diminish proportionally with the distance from the source. Considering that this is the greatest amount of CO_2 leakage in this worst-case scenario, if the event happens, the leak must pass upward through the confining zone, the secondary confining strata that consists of additional low permeability geologic units, and other geologic units, TND concludes that the risk of leakage through this pathway is highly improbable to nearly impossible.

5.5 Potential Leakage due to Lateral Migration

The characterization of the sand layers in the Cherry Canyon Formation described in Section 3.3 states that these sands were deposited by turbidites in channels in submarine fan complexes, each sand is encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity. Regional consideration of their depositional environment suggests a preferred orientation for fluid and gas flow would be south-to-north along the channel axis. However, locally the high net porosity of the RH AGI #1 and #3 injection zones indicates adequate storage capacity such that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA due to a preferred regional depositional orientation.

Lateral migration of the injected TAG was addressed in detail in Section 3.3. Therein it states that the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales as well as being encased by them.

Based on the discussion of the channeled sands in the injection zone, TND considers that the likelihood of CO_2 to migrate laterally along the channel axes is possible. However, that the turbidite sands are encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity and that the injectate is projected to be contained within the injection zone close to the injection wells minimizes the likelihood that CO_2 will migrate to a potential conduit to the surface.

5.6 Potential Leakage through Fractures and Faults

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology as well as identify and understand the distribution of faults and fractures. **Figure 5.6-1** shows the fault traces in the vicinity of the Red Hill plant. The faults shown on **Figure 5.6-1** are confined to the Paleozoic section below the injection zone for the RH AGI wells. No faults were identified in the confining zone above the Bell Canyon and Cherry Canyon injection zone for the RH AGI wells.

No faults were identified within the MMA which could potentially serve as conduits for surface CO_2 emission. The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief. Because this fault is confined to the lower Paleozoic unit more than 5,100 feet below the injection zone for the RH AGI wells, there is minimal chance it would be a potential leakage pathway. This inference is supported by the NRAP simulation result. Therefore, TND concludes that the CO_2 leakage rate through this fault is zero and that the risk of leakage through this potential leakage pathway is highly improbable.

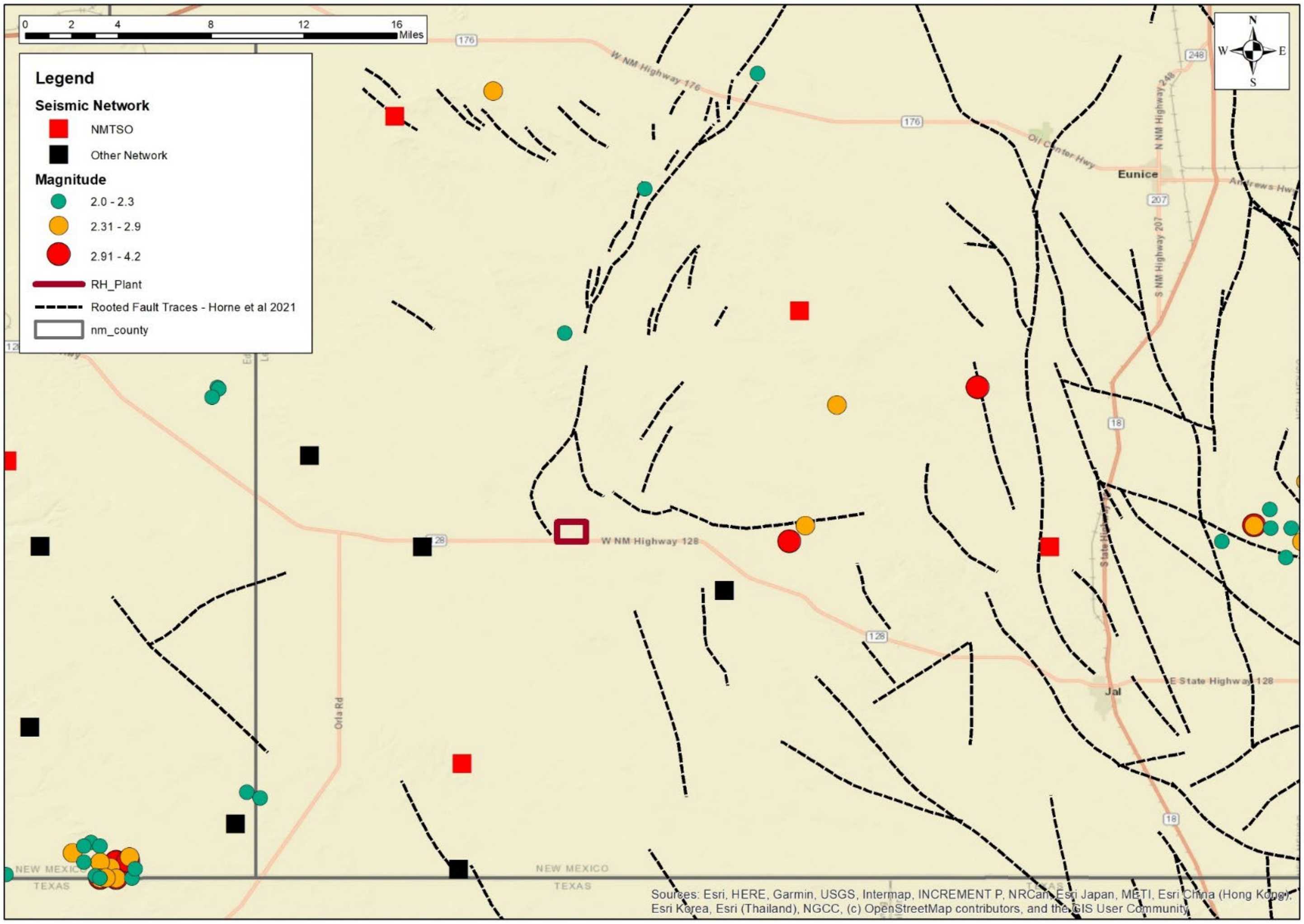


Figure 5.6-1: *New Mexico Tech Seismological Observatory (NMTSO) seismic network close to the operations, recent seismic events, and fault traces (2022-2023). Note: Fault traces are from Horne et al 2021 for deep seated faults in the lower Paleozoic. The fault traces shown close to the Red Hills facility die out at the base of the Wolfcamp formation at a depth of 12,600 feet, more than 5,100 feet below the bottom of the injection zone at 7,500 feet.*

5.7 Potential Leakage due to Natural / Induced Seismicity

The New Mexico Tech Seismological Observatory (NMTSO) monitors seismic activity in the state of New Mexico. A search of the database shows no recent seismic events close to the Red Hills operations. The closest recent, as of 4 September 2023, seismic events are:

- 7.5 miles, 2022-09-03, Magnitude 3
- 8 miles, 2022-09-02, Magnitude 2.23
- 8.6 miles, 2022-10-29, Magnitude 2.1

Figure 5.6-1 shows the seismic stations and recent seismic events in the area around the Red Hills site.

Due to the distance between the Red Hills AGI wells and the recent seismic events, the magnitude of these events, and the fact that TND injects at pressures below fracture opening pressure, TND considers the likelihood of CO_2 emissions to the surface caused by seismicity to be improbable.

Monitoring of seismic events in the vicinity of the Red Hills AGI wells is discussed in Section 6.7.

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

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

Table 6-1: Summary of Leak Detection Monitoring

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors
Existing RH AGI Wells	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors • In-well P/T sensors • Groundwater monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring

Additional Monitoring	● Groundwater monitoring ● Soil flux monitoring

6.1 Leakage from Surface Equipment

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

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

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

> "**Fixed Monitors**
> The Red Hills Plant has numerous ambient hydrogen sulfide detectors placed strategically throughout the Plant to detect possible leaks. Upon detection of hydrogen sulfide at 10 ppm at any detector, visible beacons are activated, and an alarm is sounded. Upon detection of hydrogen sulfide at 90 ppm at any detector, an evacuation alarm is sounded throughout the Plant at which time all personnel will proceed immediately to a designated evacuation area. The Plant utilizes fixed-point monitors to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the Distributed Control System (DCS). The monitors are equipped with amber beacons. The beacon is activated at 10 ppm. The plant and AGI well horns are activated with a continuous warbling alarm at 10 ppm and a siren at 90 ppm. All monitoring equipment is Red Line brand. The Control Panel is a 24 Channel Monitor Box, and the fixed point H_2S Sensor Heads are model number RL-101.
>
> The Plant will be able to monitor concentrations of H_2S via H_2S Analyzers in the following locations:
> - Inlet gas of the combined stream from Winkler and Limestone
> - Inlet sour liquid downstream of the slug catcher
> - Outlet Sweet Gas to Red Hills 1
> - Outlet Sweet Liquid to Red Hills Condensate Surge
>
> The AGI system monitors can also be viewed on the PLC displays located at the Plant. These sensors are all shown on the plot plan (see **Figure 3.6-1**). This requires immediate action for any occurrence or malfunction. All H_2S sensors are calibrated monthly.

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

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones as described in Section 5.2.1 for RH AGI #3 including more frequent monitoring during drilling operations (see **Table 6-1**). This applies to TND and other operators drilling new wells through the RH AGI injection zone within the MMA.

6.3 Leakage from Existing Wells

6.3.1 RH AGI Wells

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

To monitor leakage and wellbore integrity, two pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) were deployed in TND's RH AGI #1 well. One gauge is designated to monitor the tubing ID (reservoir) pressure and temperature and the second gauge monitors the annular space between the tubing and the long string casing (**Figure 6.2-1**). A leak is indicated when both gauges start reading the same pressure. DTS is clamped to the tubing, and it monitors the temperature profiles of the annulus from 6,159 ft to surface. DTS can detect variation in the temperature profile events throughout the tubing and or casing. Temperature variation could be an indicator of leaks. Data from temperature and pressure gauges is recorded by an interrogator housed in an onsite control room. DTS (temperature) data is recorded by a separate interrogator that is also housed in the onsite control room. Data from both interrogators are transmitted to a remote location for daily real time or historical analysis.

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

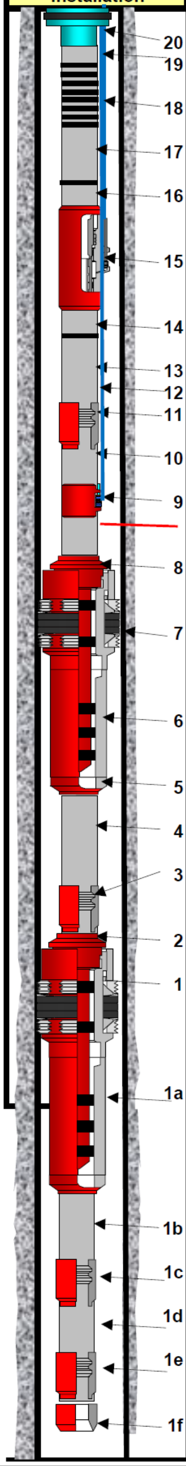
HALLIBURTON

Lucid

Red Hills AGI 1
Lea County New Mexico
2/3/21 - 2/28/21

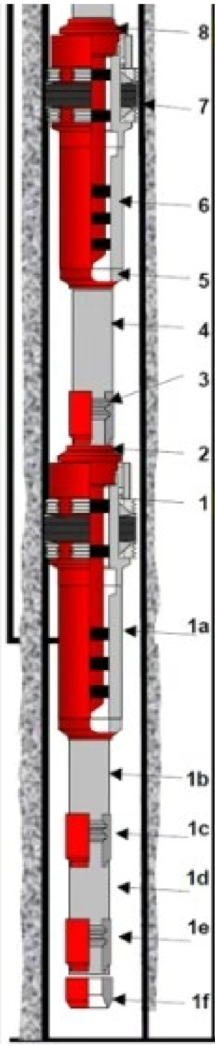
WSP - Troy Gillen / Michael Forrier
Sales Rep - Lynn Talley (432) 631-4626
Tool Specialists: Carey Lehmann, Jonathan Phillips, Jose Vargas

Installation



Installation	Depth	Length	Jts.	Description	OD	ID
	18.50	18.50		KB		
20	22.90	4.40		20) Hanger Sub 3 1/2" 9.2# CRA VAMTOP x 7.7# VAM Ace Pin	7.000	3.000
19	64.05	41.15	1	19) 3 1/2" 7.7# VAM ACE 125K G3 Tubing (Slick Joint)	3.500	3.035
				Ran Eight Subs 8', 8', 6', 6',4', 4', 2', 2'		
18	103.97	39.92		18) 3 1/2" 7.7# VAM ACE 125K G3 Spaceout Subs	3.500	3.035
17	235.95	131.98	3	17) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.035
16	241.95	6.00		16) 6' x 3 1/2" 7.7# CRA VAM ACE Box x 9.2# VAMTOP Pin	3.540	2.959
15	246.30	4.35		15) 3 1/2" NE HES SSSV Nickel Alloy 925 w/Alloy 825 Control Line 3 1/2" 9.2# VAMTOP Box x Pin	5.300	2.813
14	252.29	5.99		14) 6' x 3 1/2" 9.2# CRA VAMTOP Box x 7.7# VAM ACE Pin	3.540	2.959
13	6,140.23	5,887.94	134	13) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.305
12				12) 3 1/2" 7.7# VAM ACE Box x 9.2# VAMTOP Pin CRA Crossover	3.830	2.959
11				11) 2.813" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925	4.073	2.813
10	6,153.72	13.49		10) 6' x 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy G3 Sub	3.540	2.959
				13.49' Length Includes Line Items 10, 11 & 12		
9	6,159 Tubing	P/T		9) Baker PT Sensor Mandrel 3 1/2" 9.2# VAMTOP Box x Pin	5.200	2.992
	6,162.6 Annular	P/T		6' VAMTOP 9.2# CRA Tubing Sub Above & Below Gauge Mdl		
8	6,161.23	7.51		8) 4.00" BWS Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925	4.470	2.959
				7.51' Length Includes Line Items 8 & 9		
7	6,164.55	3.32		7) 7" 26-32# x 4.00" BWS Packer Nickel Alloy 925 Casing Collar @ 6,160.6' WL Measurement	5.875	4.000
6	6,172.05	7.5		6) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
5	6,172.88	0.83		5) 4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
4	6,181.19	8.31		4) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
3	6,182.52	1.33		3) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925 #102204262	4.073	2.562
2	6,184.29	1.77		2) Straight Slot Locator Seal Assembly Above Top Of Packer	4.450	2.880
1		6,186.06		1) BWD Permanent Packer. WL Measured Depth Previously 6189'	5.875	4.000
1a				1a) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.660	2.965
1b				1b) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1c				1c) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel,	2.920	2.562
1d				1d) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1e				1e) 2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	3.920	2.321
1f				1f) Re-Entry Guide / POP	3.950	3.000

Figure 6.2-1: Well Schematic for RH AGI #1 showing installation of P/T sensors



8	6,161.23	7.51	8) 4.00" BWS Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925 7.51' Length Includes Line Items 8 & 9	4.470	2.959
7	6,164.55	3.32	7) 7" 26-32# x 4.00" BWS Packer Nickel Alloy 925 Casing Collar @ 6,160.6' WL Measurement	5.875	4.000
6	6,172.05	7.5	6) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
5	6,172.88	0.83	5) 4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
4	6,181.19	8.31	4) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
3	6,182.52	1.33	3) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925 #102204262	4.073	2.562
2	6,184.29	1.77	2) Straight Slot Locator Seal Assembly Above Top Of Packer	4.450	2.880
1		6,186.06	1) BWD Permanent Packer. WL Measured Depth Previously 6189'	5.875	4.000
1a			1a) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.660	2.965
1b			1b) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1c			1c) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel,	2.920	2.562
1d			1d) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1e			1e) 2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	3.920	2.321
1f			1f) Re-Entry Guide / POP	3.950	3.000

***Figure 6.2-2**: Well Schematic for RH AGI #3 showing intended installation of P/T sensors*

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7.3 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. Additionally, groundwater and soil CO_2 flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through the Confining / Seal System

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

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

6.5 Leakage due to Lateral Migration

Continuous operational monitoring of the RH AGI wells during and after the period of the injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The CO_2 monitoring network described in Section 7.3, and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

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

6.6 Leakage from Fractures and Faults

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through faults. However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, TND will identify which of the pathways listed in this section are responsible for the leak, including the possibility of heretofore unidentified faults or fractures within the MMA. TND will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details. See Section 6.8 for additional information on quantification strategies.

6.7 Leakage due to Natural / Induced Seismicity

In order to monitor the influence of natural and/or induced seismicity, TND will use the established NMTSO seismic network. The network consists of seismic monitoring stations that detect and locate seismic events. Continuous monitoring helps differentiate between natural and induced seismicity. The network surrounding the Red Hills Gas Processing Plant has been mapped on **Figure 5.6-1**. The monitoring network records Helicorder data from UTC (coordinated universal time) all day long. The data are plotted daily at 5pm MST (mountain standard time). These plots can be browsed either by station or by day. The data are streamed continuously to the New Mexico Tech campus and archived at the Incorporated Research Institutions for Seismology Data Management Center (IRIS DMC).

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

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

For normal operations, quantification of emissions of CO_2 from surface equipment will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR. Quantification of major leakage events from surface equipment as identified by the detection techniques listed in Table 6-1 will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified the leakage location will be isolated to prevent additional emissions to

the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. TND has standard operating procedures to report and quantify all pipeline leaks in accordance with the NMOCD regulations (New Mexico administrative Code 19.15.28 Natural Gas Gathering Systems). TND will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by TND or third parties. Additionally, TND may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

6.8.2 Subsurface Leakage

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

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

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, or which may be initiated by seismic events and as may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO_2 leaking back to the surface emphasizing the importance of monitoring network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO_2 flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 6.8.1, or from the subsurface. In the latter case, CO_2 flux monitoring methodologies, as described in Section 7.8, will be employed to quantify the surface leaks.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

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

7.1 Visual Inspection

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

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

Compositional analysis of TND's gas injectate at the Red Hills Gas Plant indicates an approximate H_2S concentration of 20% thus requiring TND to develop and maintain an H_2S Contingency Plan (Plan) according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). TND considers H_2S to be a proxy for CO_2 leaks at the plant. The Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated RH AGI Wells and documents procedures that would be followed in case of such an event.

7.2.1 Fixed In-Field H_2S Monitors

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

7.2.2 Handheld and Personal H_2S Monitors

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

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

7.3 CO_2 Detection

In addition to the handheld gas detection monitors described above, New Mexico Tech, through a DOE research grant (DE-FE0031837 – Carbon Utilization and Storage Project of the Western USA (CUSP)), will assist TND in setting up a monitoring network for CO_2 leakage detection in the AMA as defined in Section 4.2. The scope of work for the DOE project includes field sampling activities to monitor CO_2/H_2S at the two RH AGI wells. These activities include periodic well (groundwater and gas) and atmospheric sampling from an area of 10 – 15 square miles around the injection wells. Once the network is set up, TND will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

7.4 Continuous Parameter Monitoring

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

7.5 Well Surveillance

TND adheres to the requirements of NMOCC Rule 26 governing the construction, operation and closing of an injection well under the Oil and Gas Act. Rule 26 also includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, NMOCC includes special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. TND's Routine Operations and Maintenance Procedures for the RH AGI wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic (Microseismic) Monitoring Stations

TND has Installed a model TCH120-1 Trillium Compact Horizon Seismometer and a model CTR4-3S Centaur Digital Recorder to monitor for and record data for any seismic event at the Red Hills Gas Plant (see **Figure 7-1)**. The seismic station meets the requirements of the NMOCC Order No. R-20916-H to "install, operate, and monitor for the life of the [Class II AGI] permit a seismic monitoring station or stations as directed by the Manager of the New Mexico Tech Seismological Observatory ("state seismologist") at the New Mexico Bureau of Geology and Mineral Resources."

In addition, data that is recorded by the State of New Mexico deployed seismic network within a 10-mile radius of the Red Hills Gas Plant will be analyzed by the New Mexico Bureau of Geology (NMBGMR), see **Figure 5.6-1**, and made publicly available. The NMBGMR seismologist will create a report and map showing the magnitudes of recorded events from seismic activity. The data is being continuously recorded. By examining historical data, a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

7.7 Groundwater Monitoring

New Mexico Tech, through the same DOE research grant described in Section 7.3 above, will monitor groundwater wells for CO_2 leakage which are located within the AMA as defined in Section 4.2. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 7.7-1**. Baseline analyses will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Red Hills Gas Plant. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

Table 7.7-1: Groundwater Monitoring Parameters

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

7.8 Soil CO_2 Flux Monitoring

A vital part of the monitoring program is to identify potential leakage of CO_2 and/or brine from the injection horizon into the overlying formations and to the surface. One method that will be deployed is to gather and analyze soil CO_2 flux data which serves as a means for assessing potential migration of CO_2 through the soil and its escape to the atmosphere. By taking CO_2 soil flux measurements at periodic intervals, TND can continuously characterize the interaction between the subsurface and surface to understand potential leakage pathways. Actionable recommendations can be made based on the collected data.

Soil CO_2 flux will be collected on a monthly basis for 12 months to establish the baseline and understand seasonal and other variation at the Red Hills Gas Plant. After the baseline is established, data will be collected bi-monthly for one year and then quarterly.

Soil CO_2 flux measurements will be taken using a LI-COR LI-8100A flux chamber, or similar instrument, at pre planned locations at the site. PVC soil collars (8cm diameter) will be installed in accordance with the LI-8100A specifications. Measurements will be subsequently made by placing the LI-8100A chamber on the soil collars and using the integrated iOS app to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. The soil collars will be left in place such that each subsequent measurement campaign will use the same locations and collars during data collection.

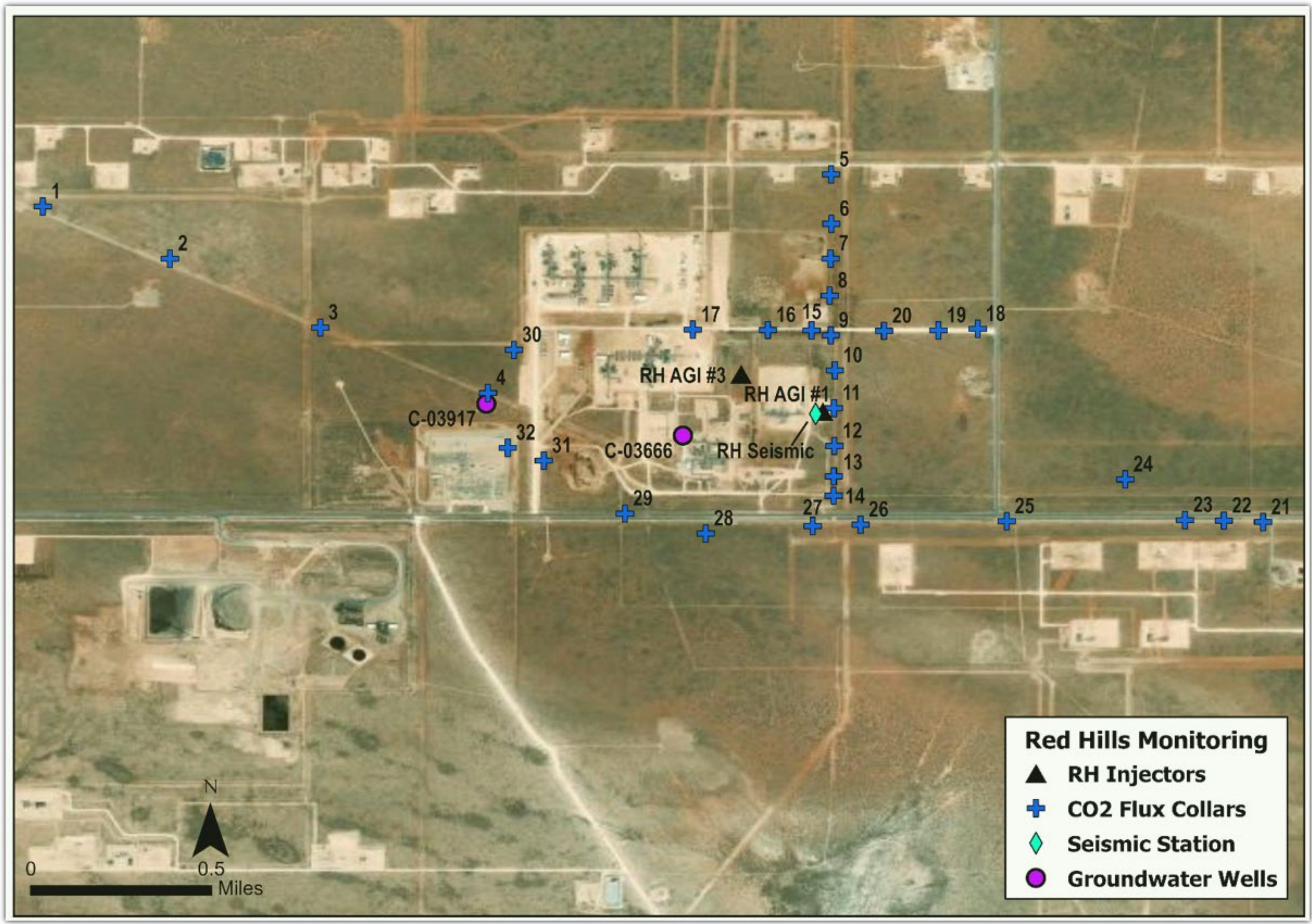


Figure 7-1: *Red Hills monitoring network of 32 CO_2 flux locations, 2 groundwater wells, and a seismic station developed by New Mexico Tech and Targa Resources to detect leakage during injection.*

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve Subpart RR equations used to calculate the mass of CO_2 sequestered annually. **Appendix 8** includes the twelve equations from Subpart RR. Not all of these equations apply to TND's current operations at the Red Hills Gas Plant but are included in the event TND's operations change in such a way that their use is required.

Figure 3.6-2 shows the location of all surface equipment and points of venting listed in 40CFR98.232(d) of Subpart W that will be used in the calculations listed below.

8.1 CO_2 Received

Currently, TND receives gas to its Red Hills Gas Plant through six pipelines: Gut Line, Winkler Discharge, Red Hills 24" Inlet Loop, Greyhound Discharge, Limestone Discharge, and the Plantview Loop. The gas is processed as described in Section 3.8 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection. TND will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3. Receiving flow meter r in the following equations corresponds to meters M1 and M2 in **Figure 3.6-2**.

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}}$$

(Equation RR-2 for Pipelines)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving volumetric flow meter.

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r}$$

(Equation RR-3 for Pipelines)

where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 or RR-2 for flow meter r.

r = Receiving flow meter.

Although TND does not currently receive CO_2 in containers for injection, they wish to include the flexibility in this MRV plan to receive gas from containers. When TND begins to receive CO_2 in containers, TND will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. TND will adhere to the requirements in 40CFR98.444(a)(2) for determining the quarterly mass or volume of CO_2 received in containers.

If CO_2 received in containers results in a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

TND injects CO_2 into the existing RH AGI #1. Upon completion, TND will commence injection into RH AGI #3. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into both wells. The

calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Volumetric flow meter u in the following equations corresponds to meters M5 and M6 in **Figure 3.6-2**.

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

(Equation RR-5)

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO2,p,u}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Volumetric flow meter.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) though all injection wells.

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u. *

u = Flow meter.

*Refer to RR-4 or RR-5 for the calculation of $CO_{2,u}$

8.3 CO_2 Produced / Recycled

TND does not produce oil or gas or any other liquid at its Red Hills Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.6 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6.8.

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$ (Equation RR-10)

where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

As required by 98.444(d) of Subpart RR, TND will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases. Parameter CO_{2FI} in Equation RR-12 is the total annual CO_2 mass emitted or vented from equipment located between the flow meter for measuring injection quantity and the injection wellhead. A calculation procedure is provided in subpart W.

8.6 CO_2 Sequestered

Since TND does not actively produce oil or natural gas or any other fluid at its Red Hills Gas Plant, Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations.

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$ (Equation RR-12)

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of the GHGRP.

9 Estimated Schedule for Implementation of MRV Plan

The baseline monitoring and leakage detection and quantification strategies described herein have been established and data collected by TND and its predecessor, Lucid, for several years and continues to the present. TND will begin implementing this revised MRV plan as soon as it is approved by EPA. After RH AGI #3 is drilled, TND will reevaluate the MRV plan and if any modifications are a material change per 40CFR98.448(d)(1), TND will submit a revised MRV plan as required by 40CFR98.448(d).

10 GHG Monitoring and Quality Assurance Program

TND will meet the monitoring and QA/QC requirements of 40CFR98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 40CFR98.444(d).

10.1 GHG Monitoring

As required by 40CFR98.3(g)(5)(i), TND's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

Measurement of CO_2 Concentration – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GPA) standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40CFR98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2 and RR-5, of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. TND will adhere to the American Gas Association (AGA) Report #3 – Orifice Metering.

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.3 CO_2 injected.

Daily CO_2 injected is recorded by totalizers on the volumetric flow meters on the pipelines to the RH AGI #1 and #3 wells using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.4 CO_2 produced.

TND does not produce CO_2 at the Red Hills Gas Plant.

10.1.5 CO_2 emissions from equipment leaks and vented emissions of CO_2.

As required by 98.444(d), TND will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

As required by 98.444(d) of Subpart RR, TND will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used.

10.1.6 Measurement devices.

As required by 40CFR98.444(e), TND will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40CFR98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards

organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.2 QA/QC Procedures

TND will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

10.3 Estimating Missing Data

TND will estimate any missing data according to the following procedures in 40CFR98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in Subpart RR, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

10.4 Revisions of the MRV Plan

TND will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of New Mexico. If any operational changes constitute a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change. TND intends to update the MRV plan after RH AGI #3 has been drilled and characterized.

11 Records Retention

TND will meet the recordkeeping requirements of paragraph 40CFR98.3(g) of Subpart A of the GHGRP. As required by 40CFR98.3(g) and 40CFR98.447, TND will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:

(i) The GHG emissions calculations and methods used

(ii) Analytical results for the development of site-specific emissions factors, if applicable

(iii) The results of all required analyses

(iv) Any facility operating data or process information used for the GHG emission calculations

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, TND will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) A copy of the most recent revision of this MRV Plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(9) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(10) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(12) Any other records as specified for retention in this EPA-approved MRV plan.

12 Appendices

Appendix 1 TND Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Red Hills AGI #1	30-025-40448	1,600 ft FSL, 150 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	10/23/2013	6,650 ft	6,170 ft
Red Hill AGI #3	30-025-51970	3,116 ft FNL, 1,159 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	9/13/2023	6,650 ft	5,700 ft

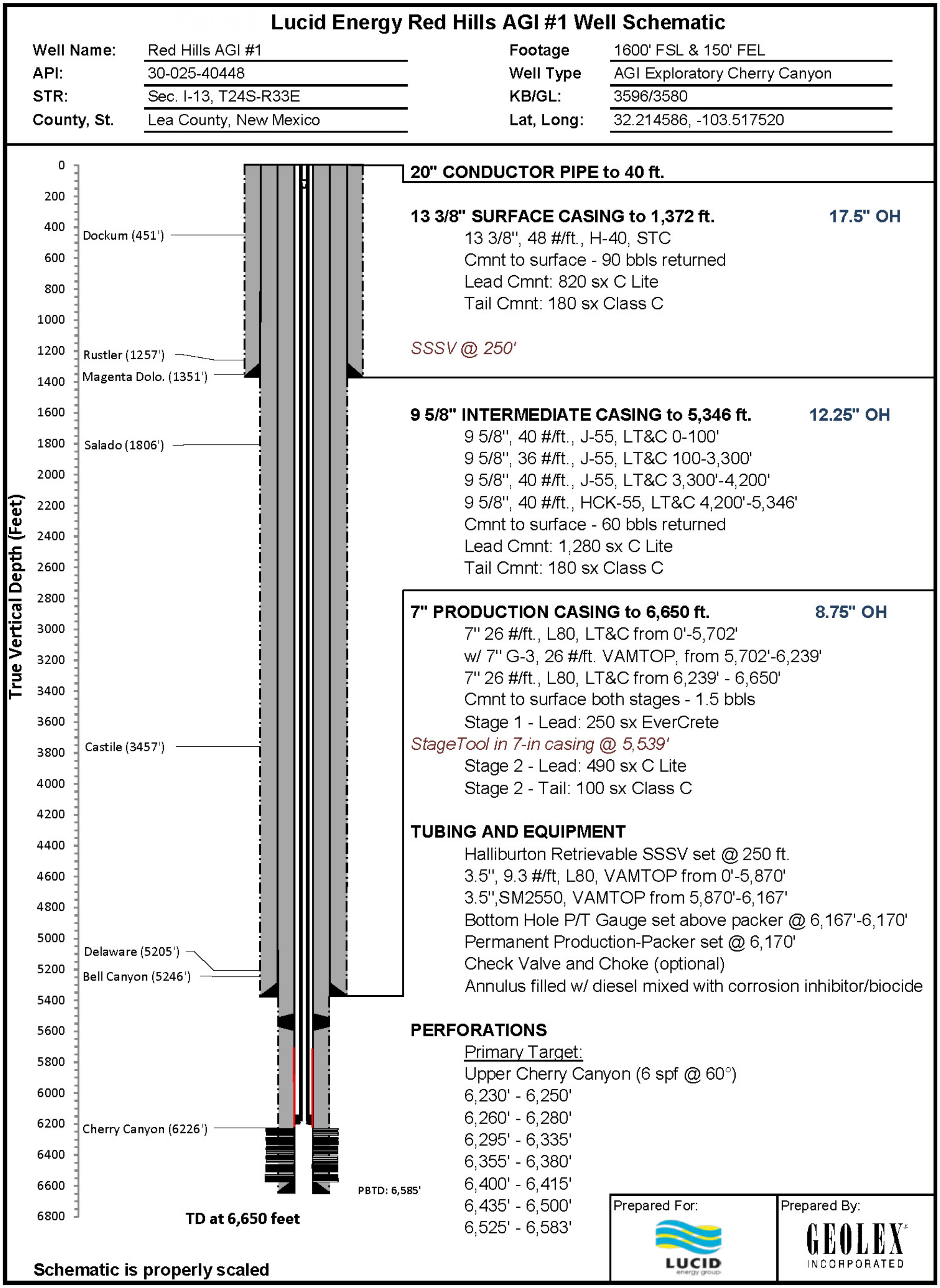
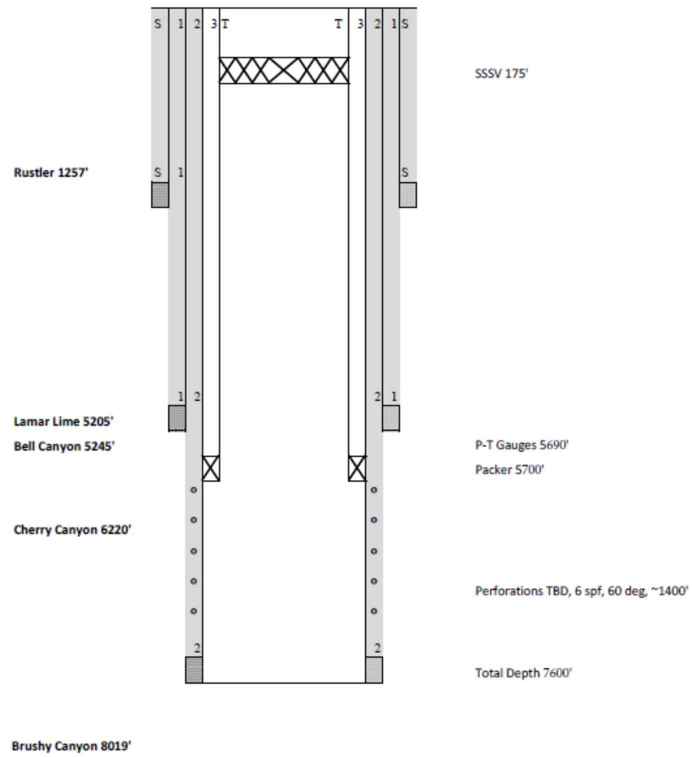


Figure Appendix 1-1: *Schematic of TND RH AGI #1 Well*

Targa Resources
Red Hills Delaware AGI #3
Location 3116' FNL & 1159' FEL
Sec 13 - T 24S - R 33E
GL 3578', RKB TBD



Surface - (Conventional)

Hole Size: 17.5"
Casing: 13.375" 72# L-80 VAM TOP
Depth Top: Surface
Depth Btm: 1307'
Cement: TBD sks - Class C + Additives
Cement Top: Surface - (Circulate)

Intermediate #1 - (Conventional)

Hole Size: 12.25"
Casing: 9.625" 47# HCL-80 BTC
Depth Top: Surface
Depth Btm: 5205'
Cement: TBD - Class C + Additives
Cement Top: Surface - (Circulate)

Production - (Conventional)

Hole Size: 8.5"
Casing 1: 7" 32# I-80 VAMSTL
Depths: 0' to 5280' & 5580' to 7600'
Casing 2: 7" 32# G3 CRA VAM HDL
Depths: 5280' to 5580'

Cement: TBD - Class C + Additives, Well Lock resin 5280'-5580'

Cement Top: Surface - (Circulate)
ECP/DV Tool: 5280' & 5580'

Tubing

Depth: 5700'
Tubing: 3.5" 7.7# G3 CRA VAM ACE
Packer: 7" x 3.5" PermaPak or equivalent (Inconel)
SSSV: 175'
PT Gauges: 5690'

***Figure Appendix 1-2**: As-built wellbore schematic for the TND RH AGI #3 Well*

Appendix 2 Referenced Regulations

U.S. Code > Title 26. INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1. NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits > Section 45Q - Credit for carbon oxide sequestration

New Mexico Administrative Code (NMAC) > Title 19 – Natural resources > Chapter 15 – Oil and Gas

CHAPTER 15 - OIL AND GAS

19.15.1 NMAC	GENERAL PROVISIONS AND DEFINITIONS [REPEALED]
19.15.2 NMAC	GENERAL PROVISIONS FOR OIL AND GAS OPERATIONS
19.15.3 NMAC	RULEMAKING
19.15.4 NMAC	ADJUDICATION
19.15.5 NMAC	ENFORCEMENT AND COMPLIANCE
19.15.6 NMAC	TAX INCENTIVES
19.15.7 NMAC	FORMS AND REPORTS
19.15.8 NMAC	FINANCIAL ASSURANCE
19.15.9 NMAC	WELL OPERATOR PROVISIONS
19.15.10 NMAC	SAFETY
19.15.11 NMAC	HYDROGEN SULFIDE GAS
19.15.12 NMAC	POOLS
19.15.13 NMAC	COMPULSORY POOLING
19.15.14 NMAC	DRILLING PERMITS
19.15.15 NMAC	WELL SPACING AND LOCATION
19.15.16 NMAC	DRILLING AND PRODUCTION
19.15.17 NMAC	PITS, CLOSED-LOOP SYSTEMS, BELOW-GRADE TANKS AND SUMPS
19.15.18 NMAC	PRODUCTION OPERATING PRACTICES
19.15.19 NMAC	NATURAL GAS PRODUCTION OPERATING PRACTICE
19.15.20 NMAC	OIL PRORATION AND ALLOCATION
19.15.21 NMAC	GAS PRORATION AND ALLOCATION
19.15.22 NMAC	HARDSHIP GAS WELLS
19.15.23 NMAC	OFF LEASE TRANSPORT OF CRUDE OIL OR CONTAMINANTS
19.15.24 NMAC	ILLEGAL SALE AND RATABLE TAKE
19.15.25 NMAC	PLUGGING AND ABANDONMENT OF WELLS
19.15.26 NMAC	INJECTION
19.15.27 - 28 NMAC	[RESERVED] PARTS 27 - 28
19.15.29 NMAC	RELEASES

19.15.30 NMAC	REMEDIATION
19.15.31 - 33 NMAC	[RESERVED] PARTS 31 - 33
19.15.34 NMAC	PRODUCED WATER, DRILLING FLUIDS AND LIQUID OIL FIELD WASTE
19.15.35 NMAC	WASTE DISPOSAL
19.15.36 NMAC	SURFACE WASTE MANAGEMENT FACILITIES
19.15.37 NMAC	REFINING
19.15.38 NMAC	[RESERVED]
19.15.39 NMAC	SPECIAL RULES
19.15.40 NMAC	NEW MEXICO LIQUIFIED PETROLEUM GAS STANDARD
19.15.41 - 102 NMAC	[RESERVED] PARTS 41 - 102
19.15.103 NMAC	SPECIFICATIONS, TOLERANCES, AND OTHER TECHNICAL REQUIREMENTS FOR COMMERCIAL WEIGHING AND MEASURING DEVICES
19.15.104 NMAC	STANDARD SPECIFICATIONS/MODIFICATIONS FOR PETROLEUM PRODUCTS
19.15.105 NMAC	LABELING REQUIREMENTS FOR PETROLEUM PRODUCTS
19.15.106 NMAC	OCTANE POSTING REQUIREMENTS
19.15.107 NMAC	APPLYING ADMINISTRATIVE PENALTIES
19.15.108 NMAC	BONDING AND REGISTRATION OF SERVICE TECHNICIANS AND SERVICE ESTABLISHMENTS FOR COMMERCIAL WEIGHING OR MEASURING DEVICES
19.15.109 NMAC	NOT SEALED NOT LEGAL FOR TRADE
19.15.110 NMAC	BIODIESEL FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.111 NMAC	E85 FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.112 NMAC	RETAIL NATURAL GAS (CNG / LNG) REGULATIONS [REPEALED]

Appendix 3 Water Wells

Water wells identified by the New Mexico State Engineer's files within two miles of the RH AGI wells; water wells within one mile are highlighted in yellow.

POD Number	County	Sec	Tws	Rng	UTME	UTMN	Distance (mi)	Depth Well (ft)	Depth Water (ft)	Water Column (ft)
C 03666 POD1	LE	13	24S	33E	639132	3565078	0.31	650	390	260
C 03917 POD1	LE	13	24S	33E	638374	3565212	0.79	600	420	180
C 03601 POD1	LE	23	24S	33E	638124	3563937	1.17			
C 02309	LE	25	24S	33E	639638	3562994	1.29	60	30	30
C 03601 POD3	LE	24	24S	33E	638142	3563413	1.38			
C 03932 POD8	LE	7	24S	34E	641120	3566769	1.40	72		
C 03601 POD2	LE	23	24S	33E	637846	3563588	1.44			
C 03662 POD1	LE	23	24S	33E	637342	3564428	1.48	550	110	440
C 03601 POD5	LE	23	24S	33E	637988	3563334	1.48			
C 03601 POD6	LE	23	24S	33E	637834	3563338	1.55			
C 03601 POD7	LE	23	24S	33E	637946	3563170	1.58			
C 03600 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03602 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03600 POD1	LE	26	24S	33E	637275	3563023	1.94			
C 03600 POD3	LE	26	24S	33E	637784	3562340	2.05			

Appendix 4 Oil and Gas Wells within 2-mile Radius of the RH AGI Well Site

Note – a completion status of "New" indicates that an Application for Permit to Drill has been filed and approved but the well has not yet been completed. Likewise, a spud date of 31-Dec-99 is actually 12-31-9999, a date used by NMOCD databases to indicate work not yet reported.

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-08371	COSSATOT E 002	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	5425	Yes
30-025-25604	GOVERNMENT L COM 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	17625	No
30-025-26369	GOVERNMENT L COM 002	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	14698	Yes
30-025-26958	SIMS 001	BOPCO, L.P.	GAS	DELAWARE VERTICAL	P & A	VERTICAL	15007	Yes
30-025-27491	SMITH FEDERAL 001	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	15120	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-40448	RED HILLS AGI 001	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	INJECTING	VERTICAL	6650	Yes
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL		PRODUCING	VERTICAL	10997	No
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11034	No
30-025-41382	DECKARD FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11067	Yes
30-025-41383	DECKARD FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11162	Yes
30-025-41384	DECKARD FEDERAL COM 004H	COG OPERATING LLC	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11103	Yes
30-025-41666	SEBASTIAN FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10927	Yes
30-025-41687	SEBASTIAN FEDERAL COM 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10944	Yes
30-025-41688	SEBASTIAN FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11055	No
30-025-43532	LEO THORSNESS 13 24 33 211H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12371	No
30-025-44442	STRONG 14 24 33 AR 214H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12500	No
30-025-46154	LEO THORSNESS 13 24 33 221H	MATADOR PRODUCTION COMPANY	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12868	No
30-025-46282	LEO THORSNESS 13 24 33 AR 135H	MATADOR PRODUCTION COMPANY	OIL	3RD BONE SPRING SAND	PRODUCING	HORIZONTAL	12103	No

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-46517	BROADSIDE 13 W FEDERAL COM 001H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12213	No
30-025-46518	BROADSIDE 13 24 FEDERAL COM 002H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-46519	BROADSIDE 13 24 FEDERAL COM 003H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12320	Yes
30-025-46985	SEBASTIAN FEDERAL COM 703H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12123	No
30-025-46988	SEBASTIAN FEDERAL COM 704H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12142	No
30-025-47869	JUPITER 19 FEDERAL COM 501H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11175	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47874	JUPITER 19 FEDERAL COM 506H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10950	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47877	JUPITER 19 FEDERAL COM 509H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11156	No
30-025-47878	JUPITER 19 FEDERAL COM 510H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11102	No
30-025-47908	JUPITER 19 FEDERAL COM 601H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-47910	JUPITER 19 FEDERAL COM 702H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	DUC	HORIZONTAL	0	Yes
30-025-47911	JUPITER 19 FEDERAL COM 705H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12290	No
30-025-47912	JUPITER 19 FEDERAL COM 707H	EOG RESOURCES INC	OIL	WOLFCAMP B UPPER	PERMITTED	HORIZONTAL	12515	No
30-025-47913	JUPITER 19 FEDERAL COM 708H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12477	No
30-025-48239	JUPITER 19 FEDERAL COM 306H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10270	No
30-025-48889	JUPITER 19 FEDERAL COM 701H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-48890	JUPITER 19 FEDERAL COM 703H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-49262	BROADSIDE 13 24 FEDERAL COM 004H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12531	Yes
30-025-49263	BROADSIDE 13 24 FEDERAL COM 015H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B LOWER	PRODUCING	HORIZONTAL	12746	Yes
30-025-49264	BROADSIDE 13 24 FEDERAL COM 025H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11210	Yes
30-025-49474	RED HILLS AGI 002	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	Temporarily Abandoned	VERTICAL	17600	Yes

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Appendix 6 Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
AoR – Area of Review
API – American Petroleum Institute
CFR – Code of Federal Regulations
C1 – methane
C6 – hexane
C7 - heptane
CO_2 – carbon dioxide
DCS – distributed control system
EPA – US Environmental Protection Agency, also USEPA
ft – foot (feet)
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MSCFD– thousand standard cubic feet per day
MMSCFD – million standard cubic feet per day
MMstb – million stock tank barrels
MRRW B – Morrow B
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NIST - National Institute of Standards and Technology
NMOCC – New Mexico Oil Conservation Commission
NMOCD - New Mexico Oil Conservation Division
PPM – Parts Per Million
psia – pounds per square inch absolute
QA/QC – quality assurance/quality control
SCITS - Stanford Center for Induced and Triggered Seismicity
Stb/d – stock tank barrel per day
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TVD – True Vertical Depth
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

Appendix 7 TND Red Hills AGI Wells - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

	Subpart RR Equation	Description of Calculations and Measurements*	Pipeline	Containers	Comments
CO_2 Received	RR-1	calculation of CO_2 received and measurement of CO_2 mass…	through mass flow meter.	in containers. **	
	RR-2	calculation of CO_2 received and measurement of CO_2 volume…	through volumetric flow meter.	in containers. ***	
	RR-3	summation of CO_2 mass received …	through multiple meters.		
CO_2 Injected	RR-4	calculation of CO_2 mass injected, measured through mass flow meters.			
	RR-5	calculation of CO_2 mass injected, measured through volumetric flow meters.			
	RR-6	summation of CO_2 mass injected, as calculated in Equations RR-4 and/or RR-5.			
CO_2 Produced / Recycled	RR-7	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through mass flow meters.			
	RR-8	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through volumetric flow meters.			
	RR-9	summation of CO_2 mass produced / recycled from multiple gas-liquid separators, as calculated in Equations RR-7 and/or RR8.			
CO_2 Lost to Leakage to the Surface	RR-10	calculation of annual CO_2 mass emitted by surface leakage			
CO_2 Sequestered	RR-11	calculation of annual CO_2 mass sequestered for operators ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, produced, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head, and emitted from surface equipment between production well head and production flow meter.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.
	RR-12	calculation of annual CO_2 mass sequestered for operators NOT ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.

* All measurements must be made in accordance with 40 CFR 98.444 – Monitoring and QA/QC Requirements.

** If you measure the mass of contents of containers summed quarterly using weigh bill, scales, or load cells (40 CFR 98.444(a)(2)(i)), use RR-1 for Containers to calculate CO_2 received in containers for injection.

*** If you determine the volume of contents of containers summed quarterly (40 CFR 98.444(a)(2)(ii)), use RR-2 for Containers to calculate CO_2 received in containers for injection.

Appendix 8 Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

RR-1 for Calculating Mass of CO_2 Received through Pipeline Mass Flow Meters

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}}$$

(Equation RR-1 for Pipelines)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving mass flow meter.

RR-1 for Calculating Mass of CO_2 Received in Containers by Measuring Mass in Container

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}}$$

(Equation RR-1 for Containers)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$Q_{r,p}$ = Quarterly mass of contents in containers r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass of contents in containers r redelivered to another facility without being injected into your well in quarter p (metric tons).

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Containers.

RR-2 for Calculating Mass of CO_2 Received through Pipeline Volumetric Flow Meters

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}}$$

(Equation RR-2 for Pipelines)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving volumetric flow meter.

RR-2 for Calculating Mass of CO_2 Received in Containers by Measuring Volume in Container

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}}$$

(Equation RR-2 for Containers)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$Q_{r,p}$ = Quarterly volume of contents in containers r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volume of contents in containers r redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

D = Density of CO_2 received in containers at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Container.

RR-3 for Summation of Mass of CO_2 Received through Multiple Flow Meters for Pipelines

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r}$$

(Equation RR-3 for Pipelines)

where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 or RR-2 for flow meter r.

r = Receiving flow meter.

RR-4 for Calculating Mass of CO_2 Injected through Mass Flow Meters into Injection Well

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}}$$

(Equation RR-4)

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Mass flow meter.

RR-5 for Calculating Mass of CO_2 Injected through Volumetric Flow Meters into Injection Well

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

(Equation RR-5)

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO2,p,u}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Volumetric flow meter.

RR-6 for Summation of Mass of CO_2 Injected into Multiple Wells

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) though all injection wells.

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u. *

u = Flow meter.

*Refer to RR-4 or RR-5 for the calculation of $CO_{2,u}$

RR-7 for Calculating Mass of CO_2 Produced / Recycled from a Gas-Liquid Separator through Mass Flow Meters

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * C_{CO_{2,p,w}}$$

(Equation RR-7)

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Quarterly gas mass flow rate measurement for separator w in quarter p (metric tons).

$C_{CO2,p,w}$ = Quarterly CO_2 concentration measurement in flow for separator w in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Gas / Liquid Separator.

RR-8 for Calculating Mass of CO_2 Produced / Recycled from a Gas-Liquid Separator through Volumetric Flow Meters

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * D * C_{CO_{2,p,w}}$$

(Equation RR-8)

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Quarterly gas volumetric flow rate measurement for separator w in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO2,p,w}$ = Quarterly CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Gas / Liquid Separator.

RR-9 for Summation of Mass of CO_2 Produced / Recycled through Multiple Gas Liquid Separators

$$CO_{2P} = (1+X) * \sum_{w=1}^{W} CO_{2,w}$$

(Equation RR-9)

where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) though all separators in the reporting year.

X = Entrained CO_2 in produced oil or other liquid divided by the CO_2 separated through all separators in the reporting year (wt. percent CO_2 expressed as a decimal fraction).

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year as calculated in Equation RR-7 or RR-8 .

w = Flow meter.

RR-10 for Calculating Annual Mass of CO_2 Emitted by Surface Leakage

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

(Equation RR-10)

where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

RR-11 for Calculating Annual Mass of CO_2 Sequestered for Operators Actively Producing Oil or Natural Gas or Any Other Fluid

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \quad \text{(Equation RR-11)}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells in the reporting year.

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of the GHGRP.

CO_{2FP} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of the GHGRP.

RR-12 for Calculating Annual Mass of CO_2 Sequestered for Operators NOT Actively Producing Oil or Natural Gas or Any Other Fluid

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad \text{(Equation RR-12)}$$

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of the GHGRP.

Appendix 9 P&A Records

P&A Record for Government Com 001, API #30-025-25604

New Mexico Oil Conservation Division, District I
1625 N. French Drive
Hobbs, NM 88240

Form 3160-5
(April 2004)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OM B No. 1004-0137
Expires: March 31, 2007

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

SUBMIT IN TRIPLICATE *- Other instructions on reverse side.*

5. Lease Serial No. **NM-17446**

6. If Indian, Allottee or Tribe Name

7. If Unit or CA/Agreement, Name and/or No.

1. Type of Well ☐ Oil Well ☑ Gas Well ☐ Other

8. Well Name and No. **Government "L" Com #1**

2. Name of Operator **EOG Resources, Inc**

9. API Well No. **30-025-~~05070~~ 25604**

3a. Address **P.O. Box 2267, Midland, TX, 79702**

3b. Phone No. *(include area code)* **432-561-8600**

10. Field and Pool, or Exploratory Area **Bell Lake, South Morrow**

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*

Unit Letter G, 1980 FNL, 1980 FEL
Section 18, Township 24-S, Range 34-E

11. County or Parish, State **Lea, New Mexico**

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
☑ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☐ Other
	☐ Change Plans	☑ Plug and Abandon	☐ Temporarily Abandon	
	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

1. **Notified Jim McCormick w/BLM 24 hrs prior to MI and RU.**
2. **Cut 3 1/2' tbg at 11500, spot 50sx CLass "H" cmt, plug from 11500-11400, WOC Tag at 11389.**
3. **Circ hole w/MLF.**
4. **Perf 4 holes at 9050, press up to 2000 PSI, spot 75sx, plug from 9100-8950, WOC Tag @ 8938.**
5. **Perf 4 holes at 7000, press up to 2000 PSI, spot 75sx, plug from 7050-6900, WOC Tag at 6855.**
6. **Cut 10 3/4" csg at 5450, L/D csg, spot 150sx, plug from 5500-5350, WOC Tag at 5336.**
7. **Spot 75sx, plug from 1300-1200 (T-Salt) WOC Tag at 1143.**
8. **Spot 150sx, plug from 650-450 (20" Shoe) WOC Tag at 423.**
9. **Spot 20sx, plug from 30-Surf.**
10. **Clean location. Install dry hole marker 12-30-04.**

P&A Complete 12-30-04

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

14. I hereby certify that the foregoing is true and correct
Name *(Printed/Typed)* **Jimmy Bagley**   Title **Consultant**

Signature   Date **12/30/2004**

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by ______ Title ______ Date ______

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon. Office

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on page 2)

GWW

P&A Records for API #30-025-26958

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

RECEIVED
AUG 16 2012
HOBBSOCD

Form C-103
Revised August 1, 2011

SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	WELL API NO. 3002526958 5. Indicate Type of Lease: STATE ☐ FEE ☒ 6. State Oil & Gas Lease No. SCR-389 7. Lease Name or Unit Agreement Name: Sims
1. Type of Well: Oil Well ☐ Gas Well ☒ Other	8. Well Number #1
2. Name of Operator: Agave Energy Company	9. OGRID Number 147831
3. Address of Operator: 104 S. Fourth St., Artesia NM 88210 (575-748-4528)	10. Pool name or Wildcat: Big Sinks Wolfcamp

4. Well Location
Unit Letter K: 1980 feet from the N line and 800 feet from the E line
Section 13 Township 24S Range 33E NMPM Lea County

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
OTHER: ☐		OTHER ☒ Replug to cement off Cherry Canyon per NMOCC R-13507	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion

The remediation of the Sims #1 well pursuant to NMOCC order was completed on August 15, 2011 and all equipment has been demobilized. The plugging was done pursuant to NMOCD requirements and all aspects of the effort were reported to Mark Whitaker and E.L. Gonzales of the OCD District 1 office who approved the specifics of the plugging as shown in the attached plugging diagram. When establishing a rate prior to squeezing the Cherry Canyon , it is clear that the reservoir is an excellent reservoir as it was taking 3bbl/min on vacuum. This indicates that the predicted injection plume for the Red Hills AGI #1 in this reservoir will be smaller than anticipated and the reservoir conditions act to prevent migration of injected acid gas out of the intended and permitted injection zone by any nearby wellbores including the Govt#2, Govt#1 and Smith Federal #1 in addition to the Sims#1. Please see attached wellbore sketch for plugging details of all plugs set and amounts of cement squeezed for each plug.

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE_ ______________ TITLE_ Consultant to Agave Energy Company _DATE August 16, 2012____

Type or print name ___Alberto A. Gutierrez, RG E-mail address: ___aag@geolex.com______ PHONE: __505-842-8000____

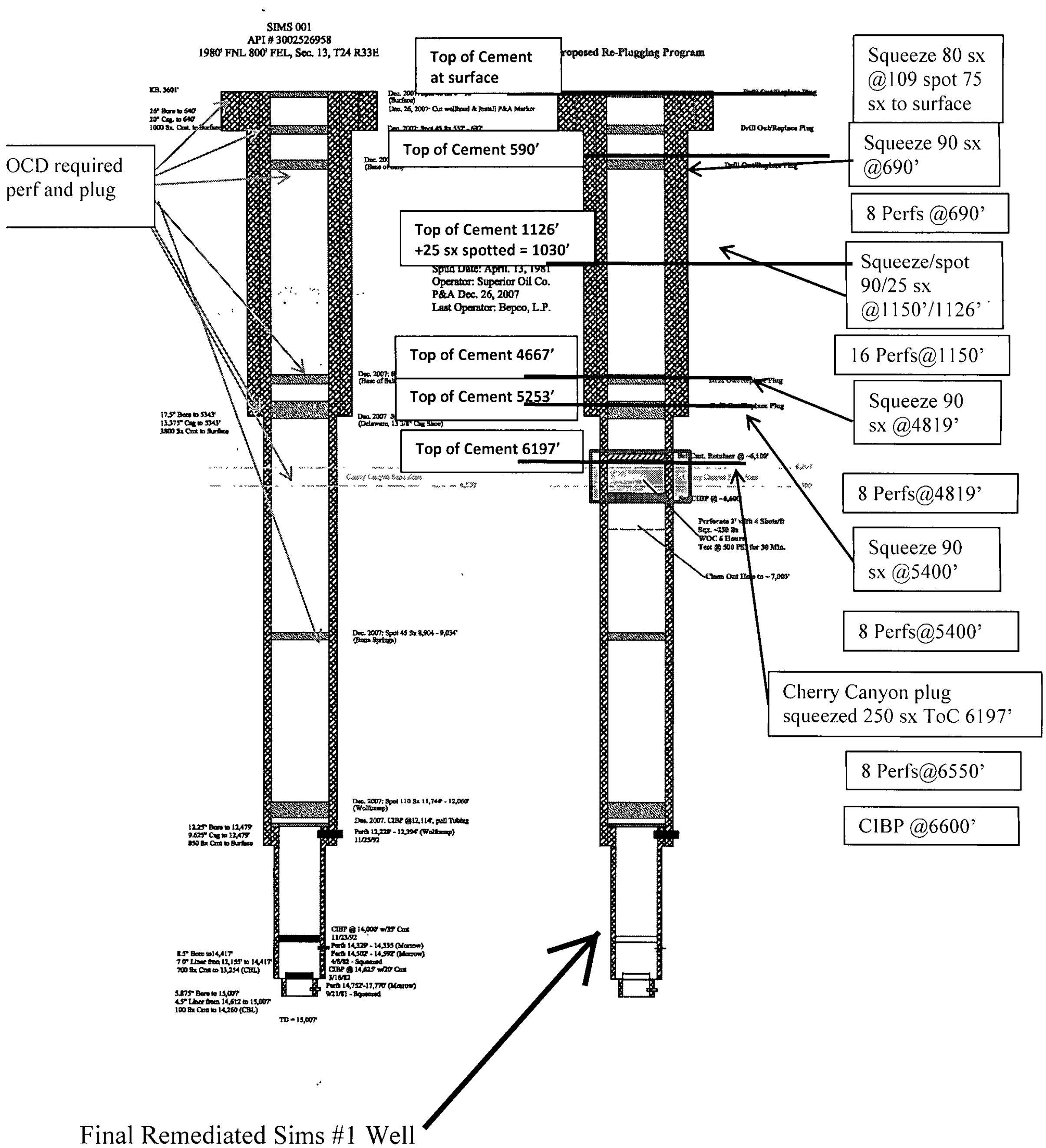
For State Use Only

APPROVED BY: ______________ TITLE Dist Mgr ______________ DATE 8-16-2012
Conditions of Approval (if any):

AUG 16 2012

GEOLEX
INCORPORATED

8/16/2012



P&A Records for API 30-025-08371

NEW MEXICO OIL CONSERVATION COMMISSION

FORM C-103 (Rev 3-55)

MISCELLANEOUS REPORTS ON WELLS

(Submit to appropriate District Office as per Commission Rule 1106)

Name of Company: Byard Bennett			Address: 207 West Third, Roswell, New Mexico		
Lease: Holland	Well No. 1	Unit Letter H	Section 13	Township 24 South	Range 33 East
Date Work Performed: March 8, 1961	Pool: Wildcat		County: Lea		

THIS IS A REPORT OF: *(Check appropriate block)*

[ ] Beginning Drilling Operations [ ] Casing Test and Cement Job [ ] Other *(Explain)*:

[X] Plugging [ ] Remedial Work

Detailed account of work done, nature and quantity of materials used, and results obtained.

Top of Rustler: 1245', Top of Salt: 1392', Base of Salt: 4930', Top of Dela Ls: 5190'
Top of Delaware Sand: 5210', Total Depth: 5425', Casing 8 5/8 set at 365', Hole size 6 3/4

Cement Plugs set as follows:
5375-5425 with 15 sacks, 5175-5240 with 20 sacks, 1375-1425 with 20 sacks,
340-390 with 20 sacks, 5 sacks and marker pipe set at surface.
Heavy mud (4 cc wtr. loss) between all cement plugs.
Job performed and witnessed by Mr. Pool, Pool Drlg Co.
Prior verbal approval of plugging program from Mr. Engbrecht, New Mexico O C C.

Location will be cleaned and leveled as soon as practical.

Witnessed by	Position	Company
Mr. Fred Pool	Owner	Pool Drlg Co.

FILL IN BELOW FOR REMEDIAL WORK REPORTS *ONLY*

ORIGINAL WELL DATA

D F Elev.	T D	P B T D	Producing Interval	Completion Date

Tubing Diameter	Tubing Depth	Oil String Diameter	Oil String Depth

Perforated Interval(s)

Open Hole Interval | Producing Formation(s)

RESULTS OF WORKOVER

Test	Date of Test	Oil Production BPD	Gas Production MCFPD	Water Production BPD	GOR Cubic feet/Bbl	Gas Well Potential MCFPD
Before Workover						
After Workover						

OIL CONSERVATION COMMISSION

Approved by: Leslie A. Clements

Title

Date

I hereby certify that the information given above is true and complete to the best of my knowledge.

Name: Guy A. Swartz

Position: Agent

Company: Byard Bennett

Request for Additional Information: Red Hills Gas Processing Plant
March 4, 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.	N/A	N/A	The previous RFAI asked for clarification regarding the status of RH AGI #2. Please check whether Figure 3.7-1 on page 31 of the MRV plan requires similar updates.	The figures and narrative of the revised MRV plan have been edited to indicate that RH AGI #2 is temporarily abandoned and that RH AGI #3 is actively injecting as of January 2024. Figure 3.7-1 on page 31 has been updated.
2.	N/A	N/A	Please review the figures included in the MRV plan to ensure that all figure numbering is in order and properly referenced within the text. For example, page 14 of the MRV plan references "Figures 3.2-4B", but a corresponding figure is not found within the MRV plan.	Figure 3.2-4 is a two-part figure. The reference to this figure on pages 11 and 14 has been changed in the revised MRV plan to remove the "A" and "B", respectively.
3.	3.6	28	We recommend ensuring that Figure 3.6.1-2 is consistent and accurate with regard to its listed components. For example, M5 has an associated CO_2 analyzer and H_2S analyzer. However, M6 does not have either of these.	Figure 3.6.1-2, which has been renumbered 3.6-2 in the revised MRV plan, is consistent and accurate as drawn.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	4.1	39	"As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Figures 4.1-1 shows the MMA as defined by the most conservative extent of the TAG plume at year 2054 plus a 1/2-mile buffer." Based on Figure 4.1-1, it appears that the plume boundary for the year 2059 is larger than the plume boundary for the year 2054. Please clarify at what point the plume is expected to stabilize and/or update the MMA as necessary.	This statement has been edited in the revised MRV plan as follows: "Figure 4.1-1 shows the MMA as defined by the extent of the stabilized TAG plume at year 2059 plus a ½ mile buffer." The simulation was run for year 2059, 5 years after injection ceased, and for year 2060. The simulation for year 2060 was the same as that for year 2059. Therefore, the plume extent at year 2059 is the stabilized plume extent.
5.	4.2	39	The plan states both of the following: - "The Active Monitoring Area (AMA) is shown in Figure 4.1-1. The AMA is consistent with the requirements in 40 CFR 98.449 because it is the area projected: (1) to contain the free phase CO2 plume for the duration of the project (year t, t = 2054), plus an all-around buffer zone of one-half mile. (2) to contain the free phase CO2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2059)." - "Targa intends to define the active monitoring area (AMA) as the same area as the MMA." Please clarify whether the yellow and purple polygons represent the AMA for this project or if the AMA is equivalent to the MMA. Also note that the definition of AMA includes the area projected "to contain the free phase CO2 plume for the duration of the project (year t, t = 2054), plus an all-around buffer zone of one-half mile". Please clarify whether the identified AMA accounts for this half-mile buffer.	This has been addressed in the revised MRV plan.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
6.	4.2	41	Section 4.2 of the MRV plan discusses "RH AGI #3" and "horizontal wells". Please clarify whether there are other approved, not yet drilled wells such as vertical wells.	Section 5.2, not Section 4.2, of the revised MRV plan has been edited to clearly state that the only wells that are permitted but not yet drilled are horizontal wells. RH AGI #3 was very recently completed and placed into operation. Appendix 4 shows that wells within the MMA with the status of "permitted" are only horizontal wells.
7.	5.3	42	"The wells may or may not penetrate the confining zone and storage reservoir." In the MRV plan, please elaborate what is meant by this statement as it relates to existing wells. Is there not clear information indicating the depth of the existing wells?	This statement has been rewritten in the revised MRV plan to clarify that some of the wells within the MMA penetrate the injection and/or confining zones but others do not. The depths of the wells within the MMA are listed in Appendix 4 and were taken into consideration in the NRAP analysis.
8.	5.6	44	"The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief." Please clarify whether this fault is identified in Figure 5.6-1.	The narrative regarding faulting has been edited in the revised MRV plan to clarify that the faults shown in Figure 5.6-1 are deep seated faults in the lower Paleozoic and die out at depths more than 5,000 feet below the injection zone for the RH AGI wells.
9.	5.6	44	"The CO_2 leakage rate through the aforementioned fault is zero, **which is understandable**." Please clarify what is meant by the above statement and/or update the MRV plan as necessary.	This statement has been edited in the revised MRV plan.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
10.	8	56-59	The equations listed in Section 8 of the MRV plan are difficult to read due to formatting. We recommend ensuring that all equations are legible.	The original MS Word document, from which the pdf was generated, has been modified so that the equations are not corrupted during conversion to pdf. The equations have been edited in the Appendices and Section 8 to address this issue associated with conversion.
11.	8.2	58	"$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as calculated in Equation RR-4 or RR-5 for flow meter u." In Equation RR-6, this variable is "$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u." Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equation listed are consistent with the text in 40 CFR 98.443.	"as calculated in Equation RR-4 or RR-5 for" was added to clarify that the parameter $CO_{2,u}$ is a calculated value using either RR-4 or RR-5. Our intention was not to change the regulatory equation but rather to add clarity for the operator. However, the equation has been edited in the revised MRV plan to be consistent with the equation in 40 CFR 98.443. A foot note has been added in Section 8 and Appendix 8 of the revised MRV plan referencing equations RR - 4 or RR-5.

MONITORING, REPORTING, AND VERIFICATION PLAN

Red Hills AGI #1 and AGI #3

Targa Northern Delaware, LLC (TND)

Version 2.0
January, 2024

Table of Contents

1 Introduction

Targa Northern Delaware, LLC (TND) is currently authorized to inject treated acid gas (TAG) into the Red Hills Acid Gas Injection #1 well (RH AGI #1)(American Petroleum Institute (API) 30-025-40448) and RH AGI #3 well (API # 30-025-51970) under the New Mexico Oil Conservation Commission (NMOCC) Orders R-13507 – 13507F and Order R-20916H, respectively, at the Red Hills Gas Plant located approximately 20 miles NNW of Jal in Lea County, New Mexico (**Figure 1**). Each well is approved to inject 13 million standard cubic feet per day (MMSCFD). However, although approved to inject 13 MMSCFD, RH AGI #1 is physically only capable of taking ~5 MMSCFD due to formation and surface pressure limitations.

The AGI wells were previously operated by Lucid Energy Delaware, LLC's ("Lucid"). TND acquired Lucid assets in 2022. Lucid received authorization to construct a redundant well, RH AGI #2 (API# 30-025-49474) under NMOCC Order R-20916-H, which is offset 200 ft to the north of RH AGI #1 and is currently temporarily abandoned in the Bell Canyon Formation.

TND recently received approval from NMOCC for its C-108 application to drill, complete and operate a third acid gas injection well (RH AGI #3) in which TND requested an injection volume of up to 13 MMSCFD. Because AGI #1 does not have complete redundancy, having a greater permitted disposal volume will also increase operational reliability. The RH AGI #3 well is currently being drilled as a vertical well with its surface location at approximately 3,116 ft from the north line (FNL) and 1,159 ft from the east line (FEL) of Section 13. The depth of the proposed injection zones for this well are approximately 5,600 to 7,200 ft in the Bell Canyon and Cherry Canyon Formations. Analysis of the reservoir characteristics of these units confirms that they act as excellent closed-system reservoirs that will accommodate the future needs of TND for disposal of treated acid gas (H_2S and CO_2) from the Red Hills Gas Plant.

TND has chosen to submit this Monitoring, Reporting, and Verification (MRV) plan to EPA for approval according to 40CFR98.440(c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. TND intends to inject CO_2 for another 30 years.

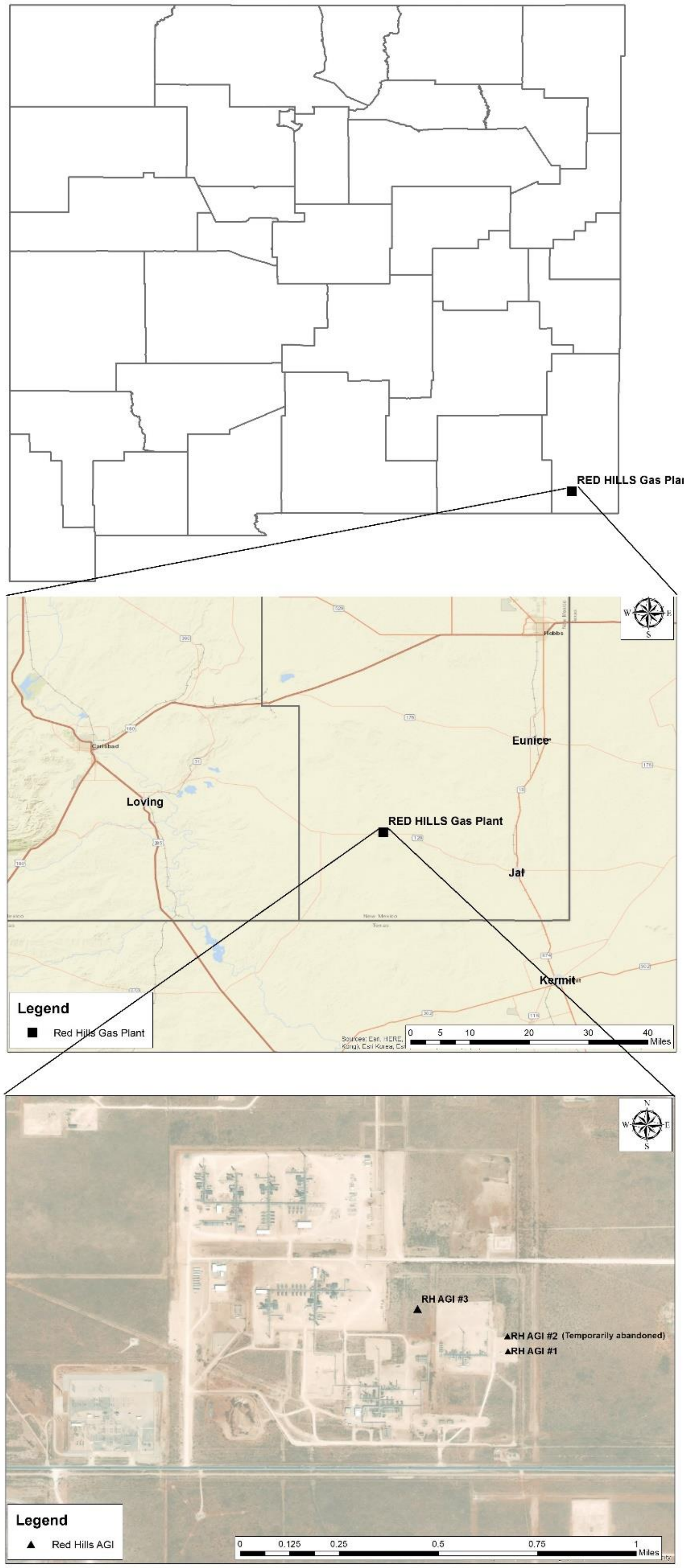


Figure 1: *Location of the Red Hills Gas Plant and Wells – RH AGI #1, RH AGI #2 (temporarily abandoned), and RH AGI #3*

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40CFR98.449, and as required by 40CFR98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40CFR98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage as required by 40CFR98.448(a)(3).

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40CFR98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40CFR98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40CFR98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40CFR98.445.

Section 11 describes the records to be retained according to the requirements of 40CFR98.3(g) of Subpart A of the GHGRP and 40CFR98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan, including information required by 40CFR98.448(a)(6).

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is **553798**

2.2 UIC injection well identification numbers

This MRV plan is for RH AGI #1 and RH AGI #3 (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

For injection wells that are the subject of this MRV plan, the New Mexico Oil Conservation Division (NMOCD) has issued Underground Injection Control (UIC) Class II acid gas injection (AGI) permits under its State Rule 19.15.26 NMAC (see **Appendix 2**). All oil- and gas-related wells around the RH AGI wells, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3 Project Description

The following project description was developed by the Petroleum Recovery Research Center (PRRC) at New Mexico Institute of Mining and Technology (NMT) and the Department of Geosciences at the University of Texas Permian Basin (UTPB).

3.1 General Geologic Setting / Surficial Geology

The TND Red Hills Gas Plant is located in T 24 S R 33 E, Section 13, in Lea County, New Mexico, immediately adjacent to the RH AGI wells. (**Figure 3.1**). The plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. The dune sands are locally stabilized with shin oak, mesquite, and some burr-grass. There are no natural surface bodies of water or groundwater discharge sites within one mile of the plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

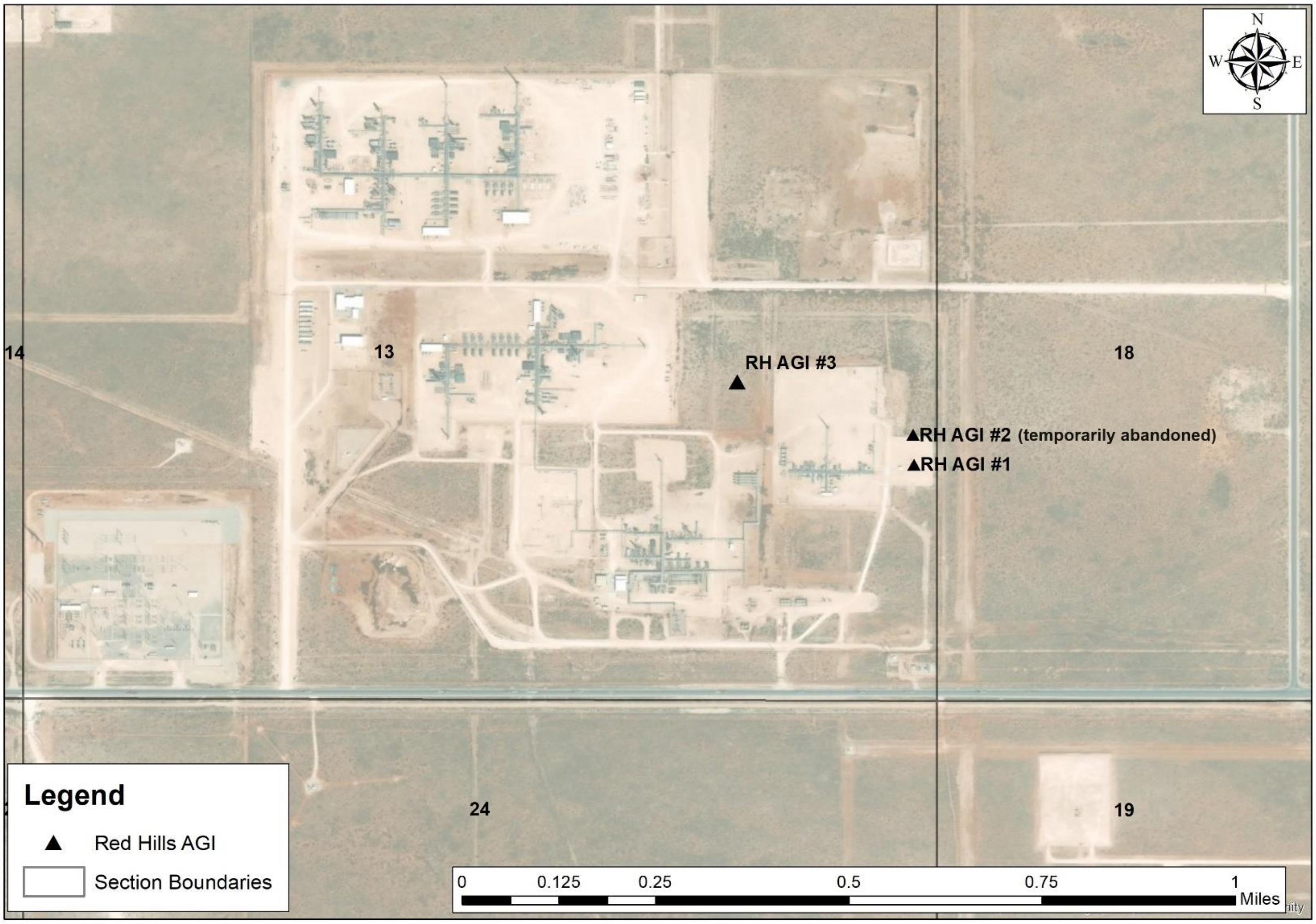


***Figure 3.1**: Map showing location of TND Red Hills Gas Plant and RH AGI Wells in Section 13, T 24 S, R 33 E*

3.2 Bedrock Geology

3.2.1 Basin Development

The Red Hills Gas Plant and the RH AGI wells are located at the northern margin of the Delaware Basin, a sub-basin of the larger, encompassing Permian Basin (**Figure 3.2-1**), which covers a large area of southeastern New Mexico and west Texas.

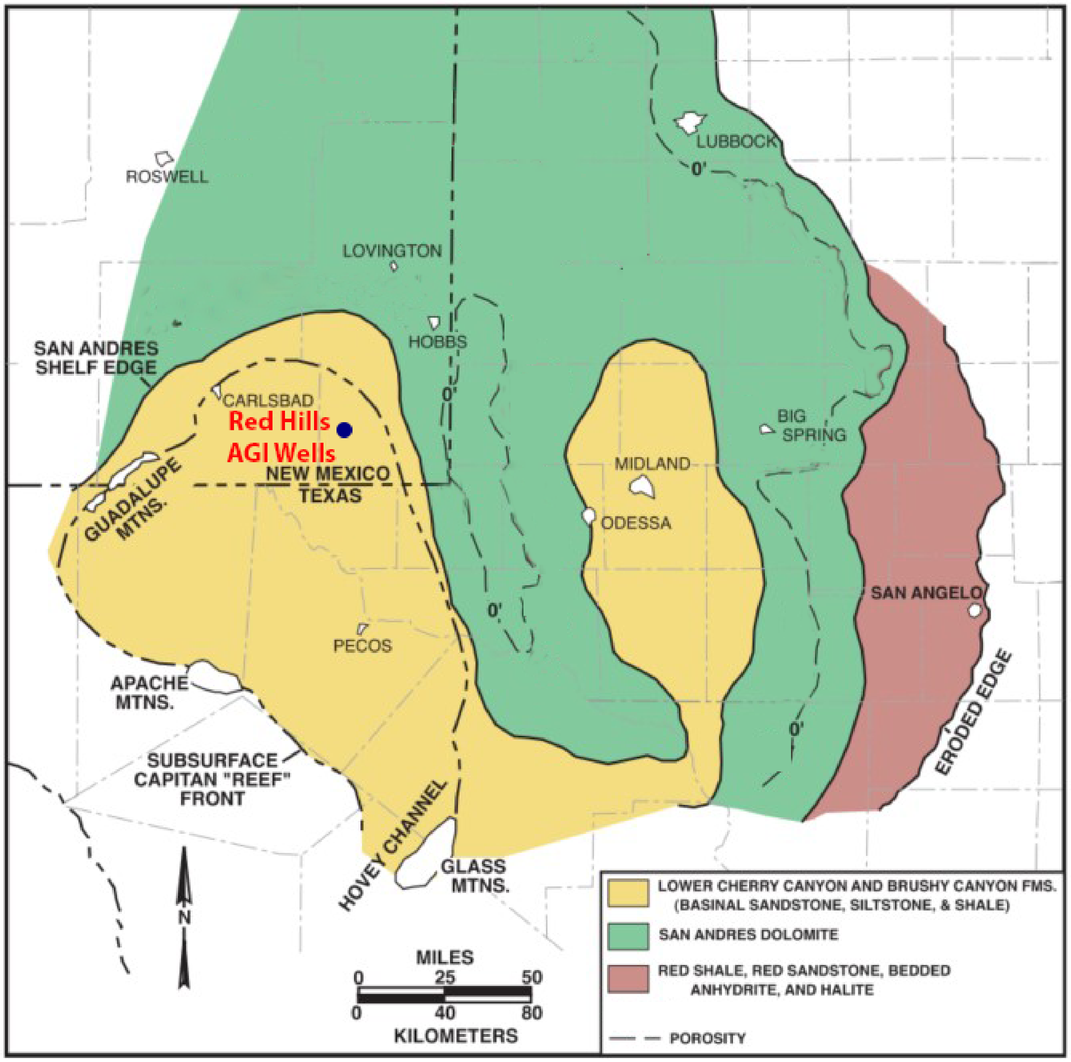


***Figure 3.2-1**: Structural features of the Permian Basin during the Late Permian. Location of the TND RH AGI wells is shown by the black circle. (Modified from Ward, et al (1986))*

Figure 3.2-2 is a generalized stratigraphic column showing the formations that underlie the Red Hills Gas Plant and RH AGI wells site. The thick sequences of Permian through Cambrian rocks are described below. A general description of the stratigraphy of the area is provided in this section. A more detailed discussion of the injection zone and the upper and lower confining zones is presented in Section 3.3 below.

The RH AGI wells are in the Delaware Basin portion of the broader Permian Basin. Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland (**Figure 3.2-3**). With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Ellenburger Formation (0 – 1000 ft) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Throughout this narrative, the numbers after the formations indicate the range in thickness for that unit. Tectonic activity near the end of Ellenburger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit's overall porosity and permeability.

AGE			CENTRAL BASIN PLATFORM-NORTHWEST SHELF		DELAWARE BASIN
Cenozoic			Alluvium		Alluvium
Triassic			Chinle Formation		Chinle Formation
			Santa Rosa Sandstone		Santa Rosa Sandstone
Permian	Lopingian (Ochoan)		Dewey Lake Formation		Dewey Lake Formation
			Rustler Formation		Rustler Formation
			Salado Formation		Salado Formation
					Castile Formation
	Guadalupian	Artesia Group	Tansill Formation	Delaware Mountain Group	Lamar Limestone
			Yates Formation		Bell Canyon Formation
			Seven Rivers Formation		
			Queen Formation		Cherry Canyon Formation
			Grayburg Formation		
			San Andres Formation		Brushy Canyon Formation
	Cisuralian (Leonardian)		Glorieta Formation		
		Yeso	Paddock Mbr.		Bone Spring Formation
			Blinebry Mbr		
			Tubb Sandstone Mbr.		
			Drinkard Mbr.		
	Wolfcampian		Abo Formation		
			Hueco (”Wolfcamp”) Fm.		Hueco (”Wolfcamp”) Fm.
Pennsylvanian	Virgilian		Cisco Formation		Cisco
	Missourian		Canyon Formation		Canyon
	Des Moinesian		Strawn Formation		Strawn
	Atokan		Atoka Formation		Atoka
	Morrowan		Morrow Formation		Morrow
Mississippian	*Upper*		Barnett Shale		Barnett Shale
	Lower		“Mississippian limestone”		“Mississippian limestone”
Devonian	*Upper*		Woodford Shale		Woodford Shale
	Middle				
	Lower		Thirtyone Formation		Thirtyone Formation
Silurian	*Upper*		Wristen Group		Wristen Group
	Middle				
	Lower		Fusselman Formation		Fusselman Formation
Ordovician	*Upper*		Montoya Formation		Montoya Formation
	Middle		Simpson Group		Simpson Group
	Lower		Ellenburger Formation		Ellenburger Formation
Cambrian			Bliss Ss.		Bliss Ss.
Precambrian			Miscellaneous igneous, metamorphic, volcanic rocks		Miscellaneous igneous, metamorphic, volcanic rocks

***Figure 3.2-2**: Stratigraphic column for the Delaware basin, the Northwest Shelf and Central Basin Platform (modified from Broadhead, 2017).*

During Middle to Upper Ordovician time, the seas once again covered the area and deposited the carbonates, sandstones and shales of the Simpson Group (0 – 1000 ft) and then the Montoya Formation (0 – 600 ft). This is the period when the Tobosa Basin formed due to the Pedernal uplift and development of the Texas Arch (**Figure 3.2-4A**; Harrington, 2019) shedding Precambrian crystalline clasts into the basin. Reservoirs in New Mexico are typically within deposits of shoreline sandstones (Broadhead, 2017). A subaerial exposure and karstification event followed the deposition of the Simpson Group. The Montoya Formation marked a return to dominantly carbonate sedimentation with minor siliciclastic sedimentation within the Tobosa Basin (Broadhead, 2017; Harrington and Loucks, 2019). The Montoya Formation consists of sandstones and dolomites and have also undergone karstification.

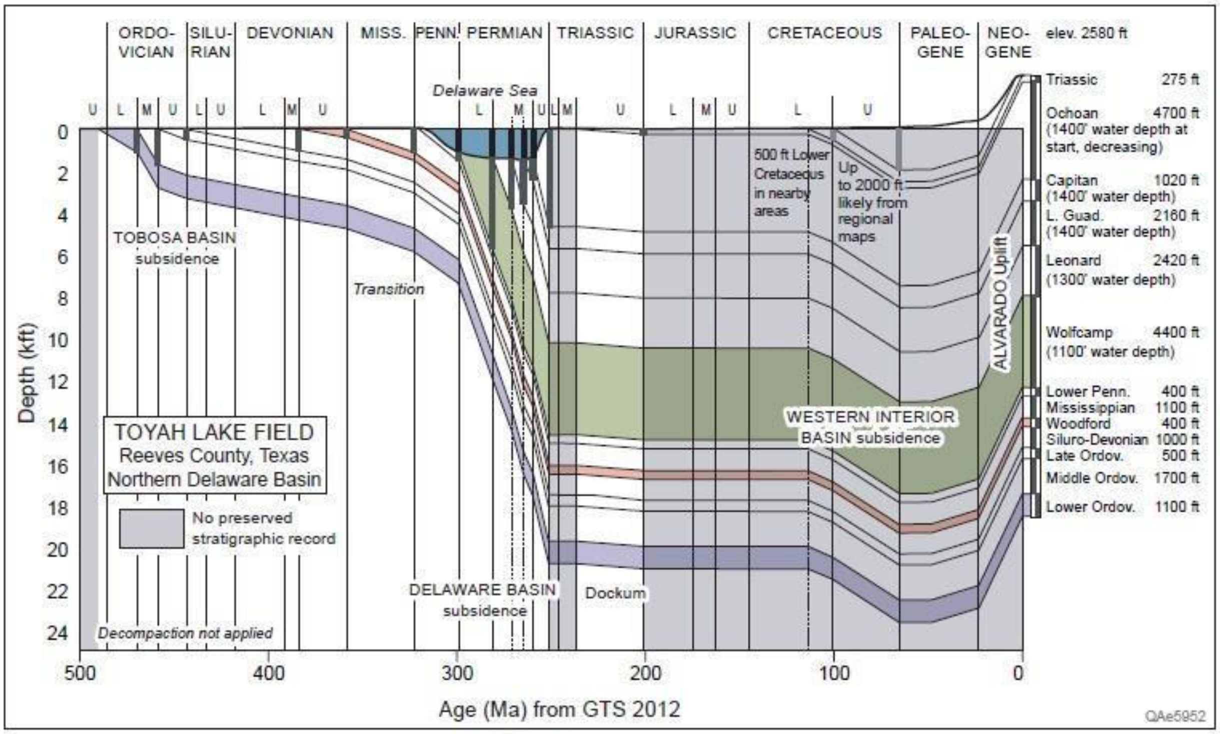


***Figure 3.2-3**: A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)*

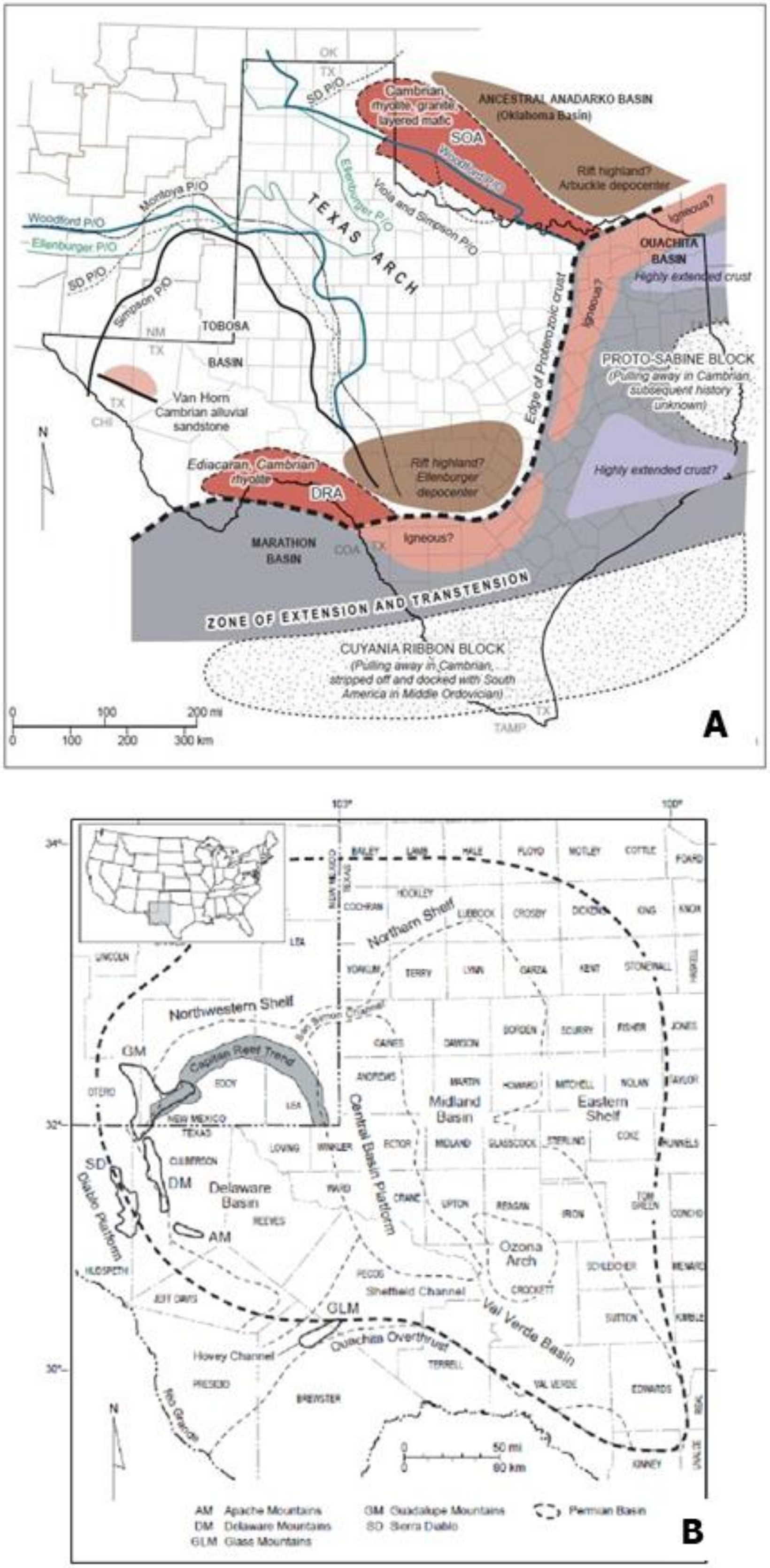


***Figure 3.2-4**: Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).*

Siluro-Devonian formations consist of the Upper Ordovician to Lower Silurian Fusselman Formation (0 – 1,500 ft), the Upper Silurian to Lower Devonian Wristen Group (0 – 1,400 ft), and the Lower Devonian Thirtyone Formation (0 – 250 ft). The Fusselman Formation are shallow-marine platform deposits of dolostones and limestones (Broadhead, 2017; Ruppel, 2019b). Subaerial exposure and karstification associated with another unconformity at top of the Fusselman Formation as well as intraformational exposure events created brecciated fabrics, widespread dolomitization, and solution-enlarged pores and fractures (Broadhead, 2017). The Wristen and Thirtyone units appear to be conformable. The Wristen Group consists of tidal to high-energy platform margin carbonate deposits of dolostones, limestones, and cherts with minor siliciclastics (Broadhead, 2017; Ruppel, 2020a). The Thirtyone Formation is present in the southeastern corner of New Mexico and appears to be either removed by erosion or not deposited elsewhere in New Mexico (**Figure 3.2-5**). It is shelfal carbonate with varying amounts of chert nodules and represents the last carbonate deposition in the area during Devonian time (Ruppel et al., 2020a).

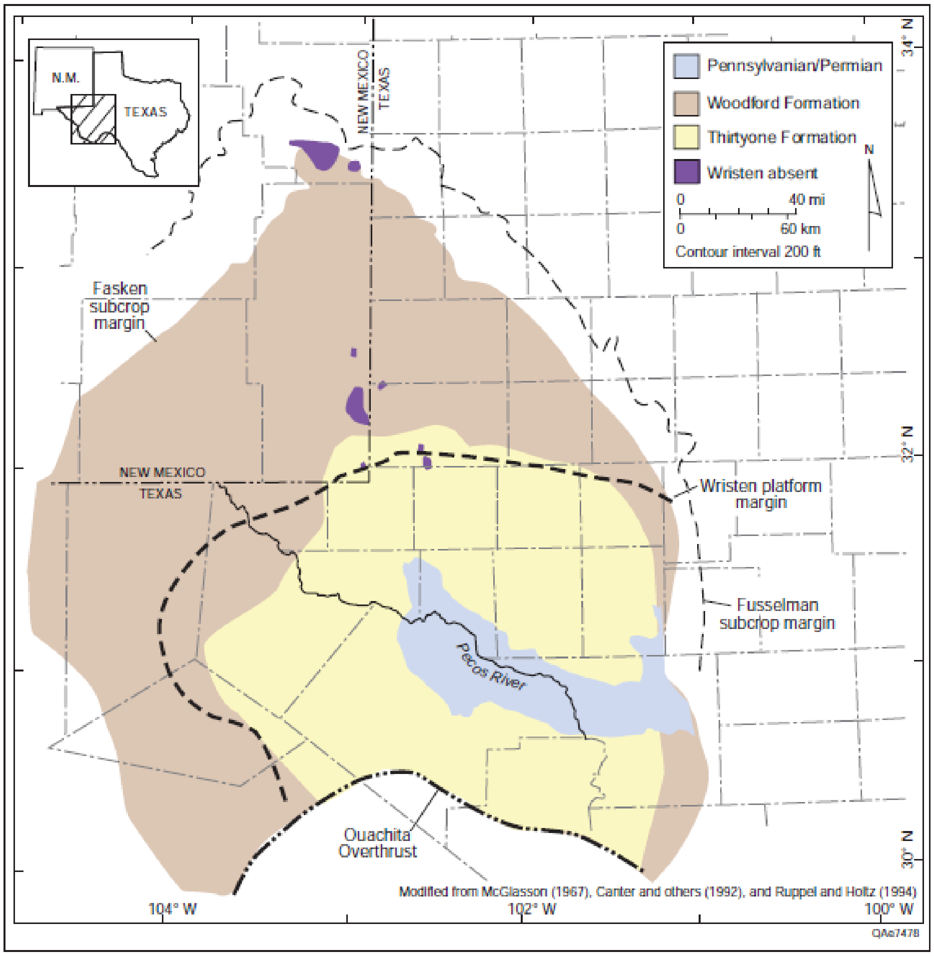


***Figure 3.2-5** -- A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there is no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in Section 3.2.2.

The Devonian Woodford Shale, an un-named Mississippian limestone, and the Upper Mississippian Barnett Shale are seals for the underlying Siluro-Devonian strata. While the Mississippian recrystallized limestones have minor porosity and permeability, the Woodford and Barnett shales have extremely low porosity and

permeability and would be effective barriers to upward migration of acid gas out of the injection zone. The Woodford Shale (0 – 300 ft) ranges from organic–rich argillaceous mudstones with abundant siliceous microfossils to organic-poor argillaceous mudstones (Ruppel et al., 2020c). The Woodford sediments represent stratified deeper marine basinal deposits with their organic content being a function of the oxygenation within the bottom waters – the more anoxic the waters the higher the organic content.

The Mississippian strata within the Delaware Basin consists of an un-named carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoirs limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise it is tight. The Barnett Shale (0 – 400 ft) unconformably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal, siliciclastic deposits (the Barnett Shale).

Pennsylvanian sedimentation in the area is influenced by glacio-eustatic sea-level cycles producing numerous shallowing upward cycles within the rock record; the intensity and number of cycles increase upward in the Pennsylvanian section. The cycles normally start with a sea-level rise that drowns the platform and deposits marine mudstones. As sea-level starts to fall, the platform is shallower and deposition switches to marine carbonates and coastal siliciclastic sediments. Finally, as the seas withdraw from the area, the platform is exposed causing subaerial diagenesis and the deposition terrestrial mudstones, siltstones, and sandstones in alluvial fan to fluvial deposits. This is followed by the next cycle of sea-level rise and drowning of the platform.

Pennsylvanian sedimentation is dominated by glacio-eustatic sea-level cycles that produced shallowing upward cycles of sediments, ranging from deep marine siliciclastic and carbonate deposits to shallow-water limestones and siliciclastics, and capping terrestrial siliciclastic sediments and karsted limestones. Lower Pennsylvanian units consist of the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). The Atoka Formation (0-500 ft) was deposited during another sea-level transgression within the area. Within the area, the Atoka sediments are dominated by siliciclastic sediments, and depositional environments range from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

Middle Pennsylvanian units consist of the Strawn group (an informal name used by industry). Strawn sediments (250 - 1,000 ft) within the area consists of marine sediments that range from ramp carbonates, containing patch reefs, and marine sandstone bars to deeper marine shales (Broadhead, 2017).

Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales.

Deformation, folding and high-angle faulting, associated with the Upper Pennsylvanian/Early Permian Ouachita Orogeny, created the Permian Basin and its two sub-basins, the Midland and Delaware basins (Hills, 1984; King, 1948), the Northwest Shelf (NW Shelf), and the Central Basin Platform (CBP; **Figures 3.2-4B, 3.2-6, 3.2-7**). The Permian "Wolfcamp" or Hueco Formation was deposited after the creation of the Permian Basin. The Wolfcampian sediments were the first sediments to fill in the structural relief (**Figure 3.2-6**). The Wolfcampian Hueco Group (~400 ft on the NW Shelf, >2,000 ft in the Delaware Basin) consists of shelf margin deposits ranging from barrier reefs and fore slope deposits, bioherms, shallow-water carbonate shoals, and basinal carbonate mudstones (Broadhead, 2017; Fu et al., 2020). Since deformation continued

throughout the Permian, the Wolfcampian sediments were truncated in places like the Central Basin Platform (**Figure 3.2-6**).

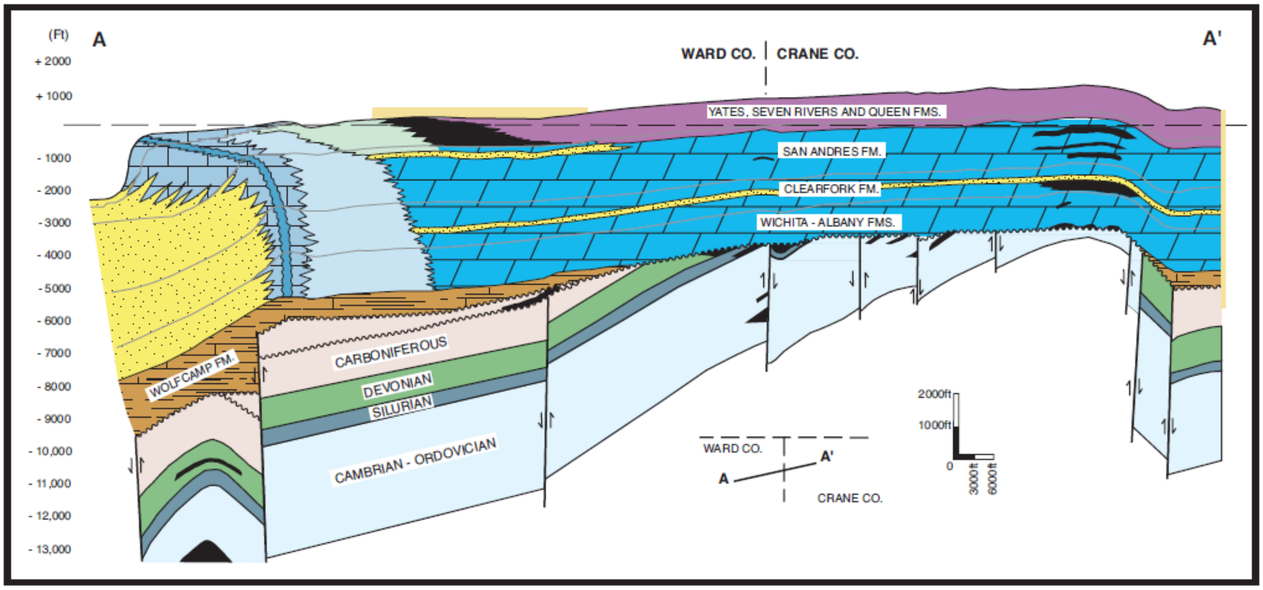


Figure 3.2-6 -- *Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).*

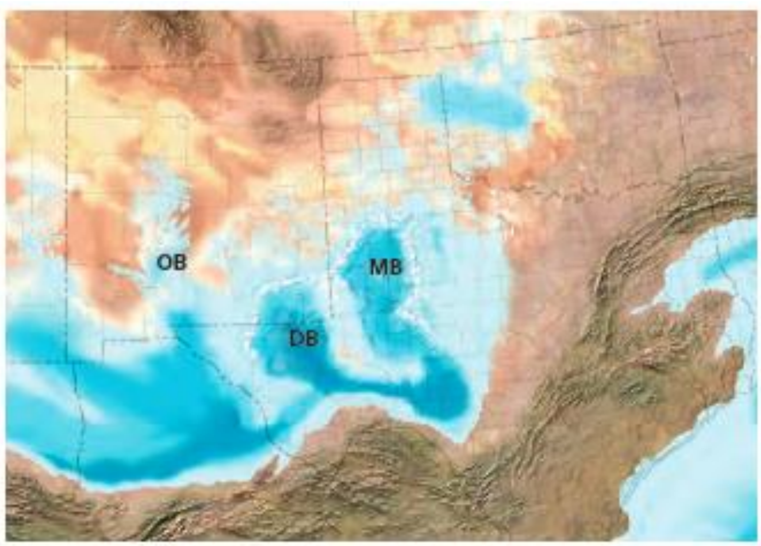


Figure 3.2-7 -- *Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).*

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, thousands of feet of siliciclastic sediments bypassed the shelves and were deposited in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a

“carbonate factory” on the shelf and shelf edge. Carbonate debris beds shedding off the shelf margin were transported into the basin (Wilson, 1977; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100s feet to feet).

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along Northwest Shelf margin to shallow-marine, back-reef carbonates behind the shelf margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2020b). Sediments basinward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2020b). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. The Bone Spring Formation is a thick sequence of alternating carbonate and siliciclastic horizons that formed because of changes in sea level; the carbonates during highstands, and siliciclastics during lowstands. Overlying the Yeso, are the clean, white eolian sandstones of the Glorietta Formation. It is a key marker bed in the region, both on outcrop and in the subsurface. Within the basin, it is equivalent to the lowermost Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have been identified that have resulted in karstification and pervasive dolomitization of the unit. These exposure events/sea-level lowstands are correlated to sandstones/siltstones that moved out over the exposed shelf leaving on minor traces of their presence on the shelf but formed thick sections of sandstones and siltstones in the basin. Within the Delaware Basin, the San Andres Formation is equivalent to the Brushy and lower Cherry Canyon Formations.

The Artesia Group (Grayburg, Queen, Seven Rivers, Yates, and Tansill formations, ascending order) is equivalent to Capitan Limestone, the Guadalupian barrier/fringing reef facies. Within the basin, the Artesia Group is equivalent to the upper Cherry and Bell Canyon formations, a series of relatively featureless sandstones and siltones. The Queen and Yates formations contain more sandstones than the Grayburg, Seven Rivers, and Tansill formations. The Artesia units and the shelf edge equivalent Capitan reef sediments represent the period when the carbonate factory was at its greatest productivity with the shelf margin/Capitan reef prograding nearly 6 miles into the basin (Scholle et al., 2007). The Artesia Group sediments were deposited in back-reef, shallow marine to supratidal/evaporite environments. Like the San Andres Formation, the individual formations were periodically exposed during lowstands.

The final stage of Permian deposition on the NW Shelf consists of the Ochoan/Lopingian Salado Formation (<2,800 ft, Nance, 2020). Within the basin, the Castile formation, a thick sequence (total thickness ~1,800 ft, Scholle et al., 2007) of cyclic laminae of deep-water gypsum/anhydrite interbedded with calcite and organics, formed due to the restriction of marine waters flowing into the basin. Gypsum/anhydrite laminae precipitated during evaporative conditions, and the calcite and organic-rich horizons were a result of seasonal “freshening” of the basin waters by both marine and freshwaters. Unlike the Castile Formation, the Salado Formation is a relatively shallow water evaporite deposit. Halite, sylvite, anhydrite, gypsum, and numerous potash minerals were precipitated. The Rustler Formation (500 ft , Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin.

The Rustler Formation was followed by terrestrial sabkha red beds of the Dewey Lake Formation (~350', Nance, 2020), ending Permian deposition in the area.

Beginning early in the Triassic, uplift and the breakup of Pangea resulted in another regional unconformity and the deposition of non-marine, alluvial Triassic sediments (Santa Rosa Sandstone and Chinle Formation). They are unconformably overlain by Cenozoic alluvium (which is present at the surface). Cenozoic Basin and Range tectonics resulted in the current configuration of the region and reactivated numerous Paleozoic faults.

3.2.2 Stratigraphy

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent, renamed Lopingian), Guadalupian, Leonardian (renamed Cisuralian), and Wolfcampian (oldest) (**Figure 3.2-2**). This sequence of shallow marine carbonates and thick, basinal siliciclastic deposits contains abundant oil and gas resources. The Delaware Basin high porosity sands are the main source of oil within New Mexico. In the area around the Red Hills AGI wells, Permian strata are mainly basin deposits consisting of sandstones, siltstones, shales, and lesser amounts of carbonates. Besides production in the Delaware Mountain Group, there is also production, mainly gas, in the basin Bone Spring Formation, a sequence of carbonates and siliciclastics. The injection and confining zones for RH AGI #1 and #3 are discussed below.

CONFINING/SEAL ROCKS

Permian Ochoa Series. The youngest of the Permian sediments, the Ochoan- or Lopingian-aged deposits, consists of evaporites, carbonates, and red beds. The Castile Formation is made of cyclic laminae of deep-water gypsum/anhydrite beds interlaminated with calcite and organics. This basin-occurring unit can be up to 1,800 ft thick. The Castile evaporites were followed by the Salado Formation (~1,500 ft thick). The Salado Formation is a shallow water evaporite deposit, when compared to the Castile Formation, and consists of halite, sylvite, anhydrite, gypsum, and numerous potash/bittern minerals. Salado deposits fill the basin and lap onto the older Permian shelf deposits. The Rustler Formation (up to 500 ft, Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin. The Ochoan evaporitic units are superb seals (usually <1% porosity and <0.01 mD permeability) and are the reason that the Permian Basin is such a hydrocarbon-rich region despite its less than promising total organic carbon (TOC) content.

INJECTION ZONE

Permian Guadalupe Series. Sediments in the underlying Delaware Mountain Group (descending, Bell Canyon, Cherry Canyon, and Brushy Canyon formations) are marine units that represent deposition controlled by eustacy and tectonics. Lowstand deposits are associated with submarine canyons incising the carbonate platform surround most of the Delaware Basin. Depositional environments include submarine fan complexes that encircle the Delaware Basin margin. These deposits are associated with submarine canyons incising the carbonate platform margin and turbidite channels, splays, and levee/overbank deposits (Figure 3.2.2-1). Additionally, debris flows formed by the failure of the carbonate margin and density currents also make up basin sediments. Isolated coarse-grained to boulder-sized carbonate debris flows and grain falls within the lowstand clastic sediments likely resulted from erosion and failure of the shelf margin during sea-level lowstands or slope failure to tectonic activity (earthquakes). Density current deposits resulted from stratified basin waters. The basal waters were likely stratified and so dense, that turbidity flows containing sands, silts and clays were unable to displace those bottom waters and instead flowed out over the density interface (Figure 3.2.2-2). Eventually, the entrained sediments would settle out in a constant rain of sediment forming laminated deposits with little evidence of traction (bottom flowing) deposition. Interbedded with the very thick lowstand sequences are thin, deep-water limestones and mudstones that represent highstand deposition up on the platform. These deposits are thickest around the edge (toe-of-slope) of the basin and thin to the basin center (Figure 3.2.2-3). The limestones are dark, finely crystalline, radiolarian-rich micrites to biomicrites. These highstand deposits are a combination of suspension and pelagic sediments that also thin towards the basin center. These relatively thin units are time equivalent to the massive highstand carbonate deposits on the shelf.

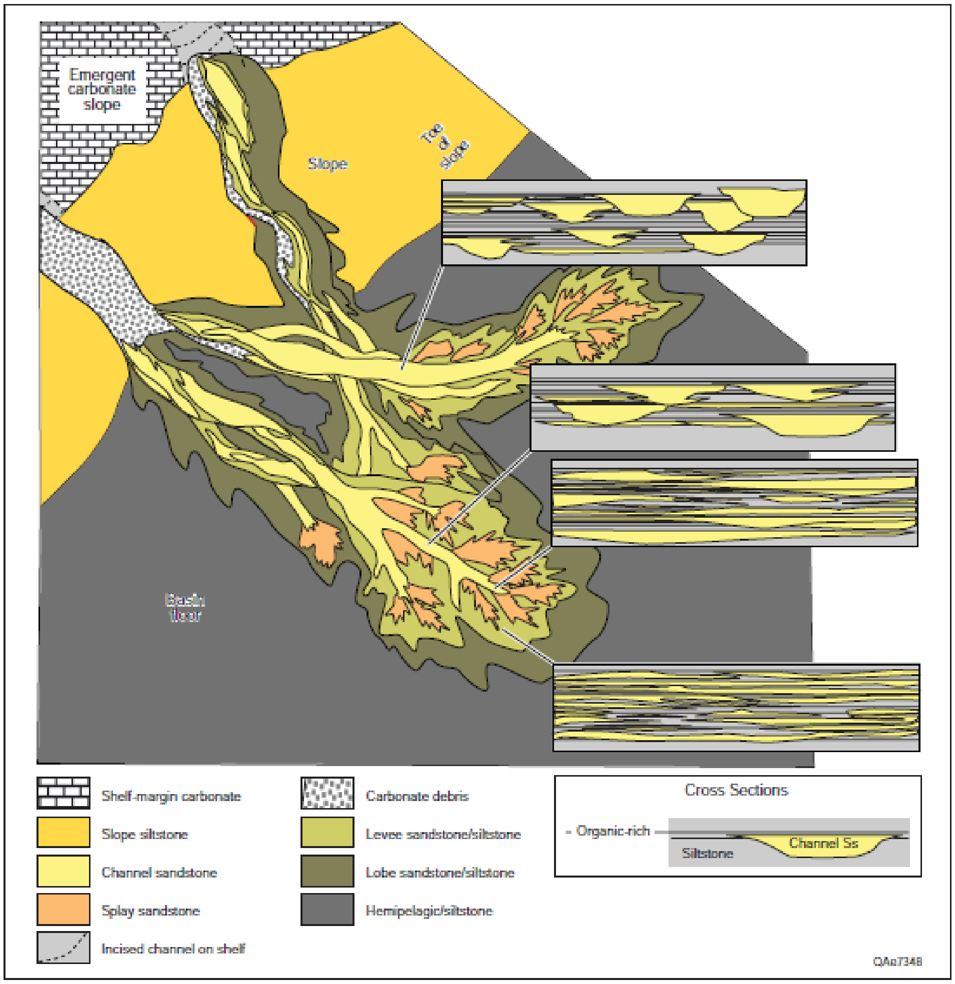


Figure 3.2.2-1 *– A diagram of typical Delaware Mountain Group basinal siliciclastic deposition patterns (from Nance, 2020). The channel and splay sandstones have the best porosity, but some of the siltstones also have potential as injection zones.*

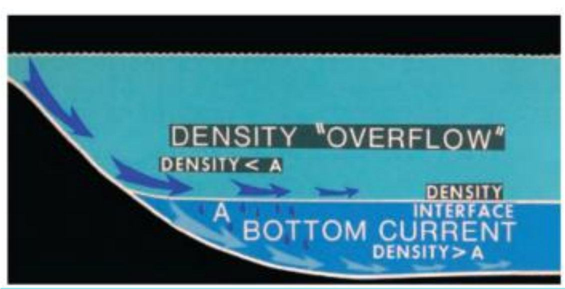
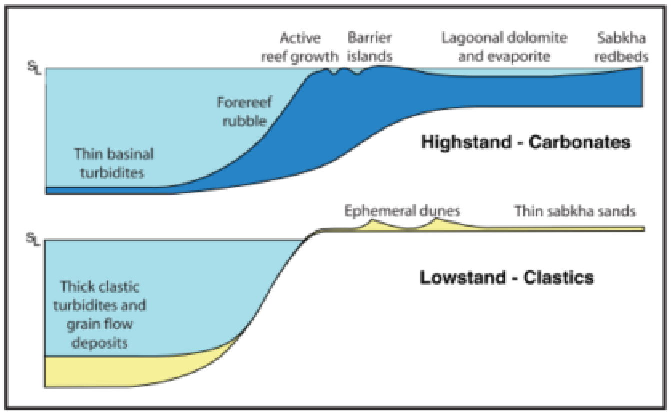
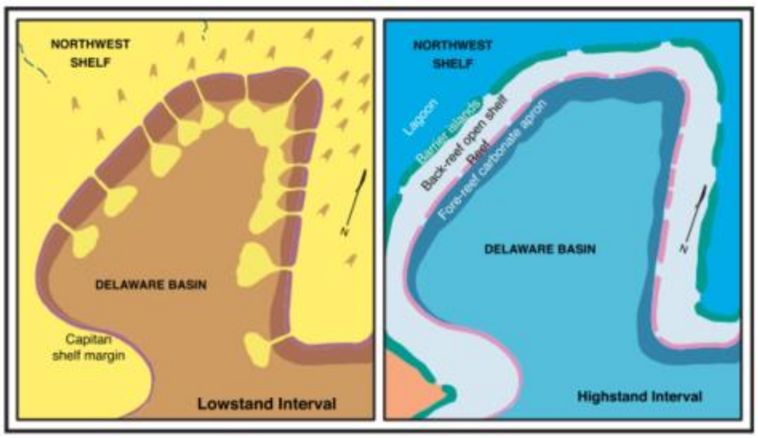


Figure 3.2.2-2 *– Harms' (1974) density overflow model explains the deposition of laminated siliciclastic sediments in the Delaware Basin. Low density sand-bearing fluids flow over the top of dense, saline brines at the bottom of the basin. The sands gradually drop out as the flow loses velocity creating uniform, finely laminated deposits (from Scholle et al., 2007).*



A.



B.

Figure 3.2.2-3 *– The impact of sea-level fluctuations (also known as reciprocal sedimentation) on the depositional systems within the Delaware Basin. A) A diagrammatic representation of sea-level variations impact on deposition. B) Model showing basin-wide depositional patterns during lowstand and highstand periods (from Scholle et al., 2007).*

The top of the Guadalupian Series is the Lamar Limestone, which is the source of hydrocarbons found in underlying Delaware Sand (an upper member of the Bell Canyon Formation). The Bell Canyon Formation is roughly 1,000 ft thick in the Red Hills area and contains numerous turbidite input points around the basin margin (**Figures 3.2.2-3, 3.2.2-4**). During Bell Canyon deposition, the relative importance of discrete sand sources varied (Giesen and Scholle, 1990), creating network of channel and levee deposits that also varied in their size and position within the basin. Based on well log analyses, the Bell Canyon 2 and 3 had the thickest sand deposits.

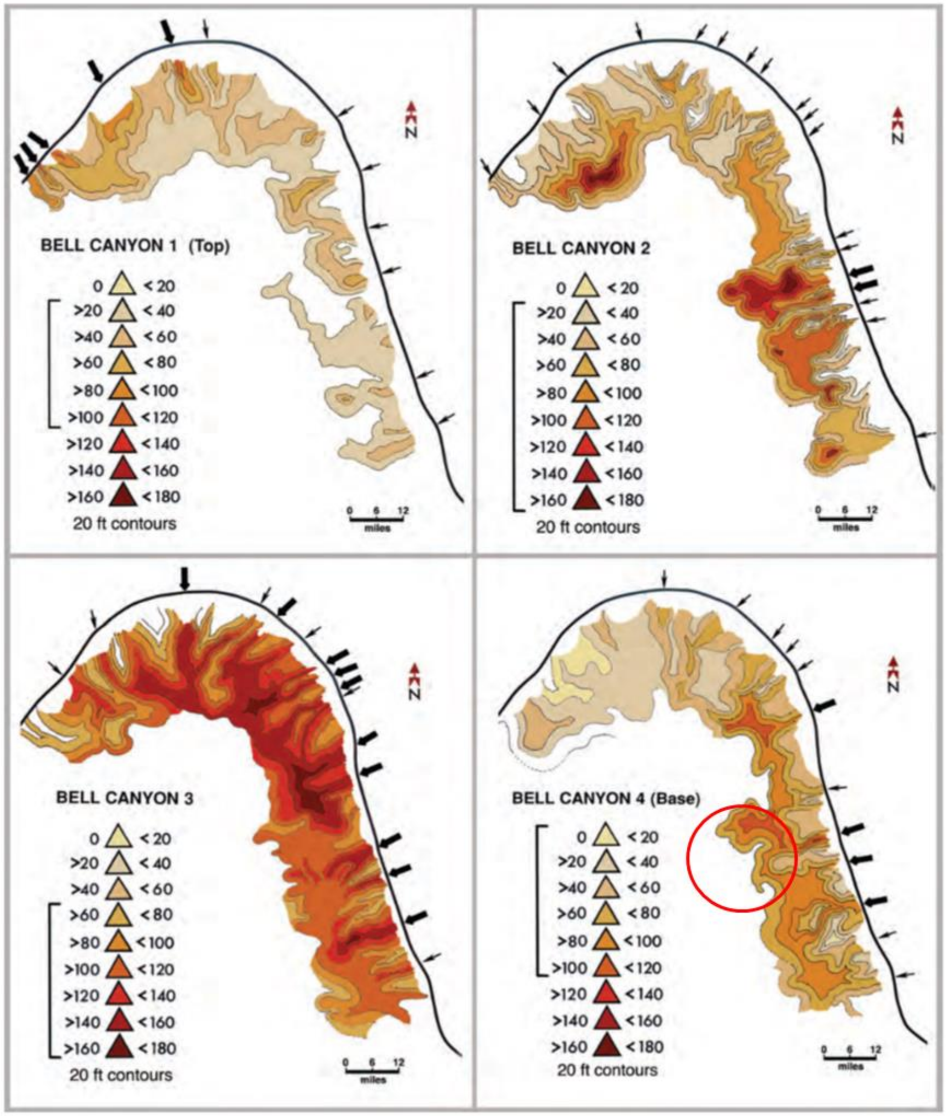


__Figure 3.2.2-4__ – These maps of Bell Canyon Formation were created by measuring sandstone thicknesses on well logs in four regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). The red circle on the last map surrounds the Red Hills area.

Like the Bell Canyon and Brushy Canyon formations, the Cherry Canyon Formation is approximately 1,300 ft thick and contains numerous turbidite source points. Unlike the Bell Canyon and Brushy Canyon deposits, the channel deposits are not as large (Giesen and Scholle, 1990), and the source of the sands appears to be dominantly from the eastern margin (**Figure 3.2.2-5**). Cherry Canyon 1 and 5 have the best channel development and the thickest sands. Overall, the Cherry Canyon Formation, on outcrop, is less influenced by traction current deposition than the rest of the Delaware Mountain Group deposits and is more influenced by sedimentation by density overflow currents (**Figure 3.2.2-2**). The Brushy Canyon has notably more discrete channel deposits (**Figure 3.2.2-6**) and coarser sands than the Cherry Canyon and Bell Canyon. The Brushy Canyon Formation is approximately 1,500 ft thick.

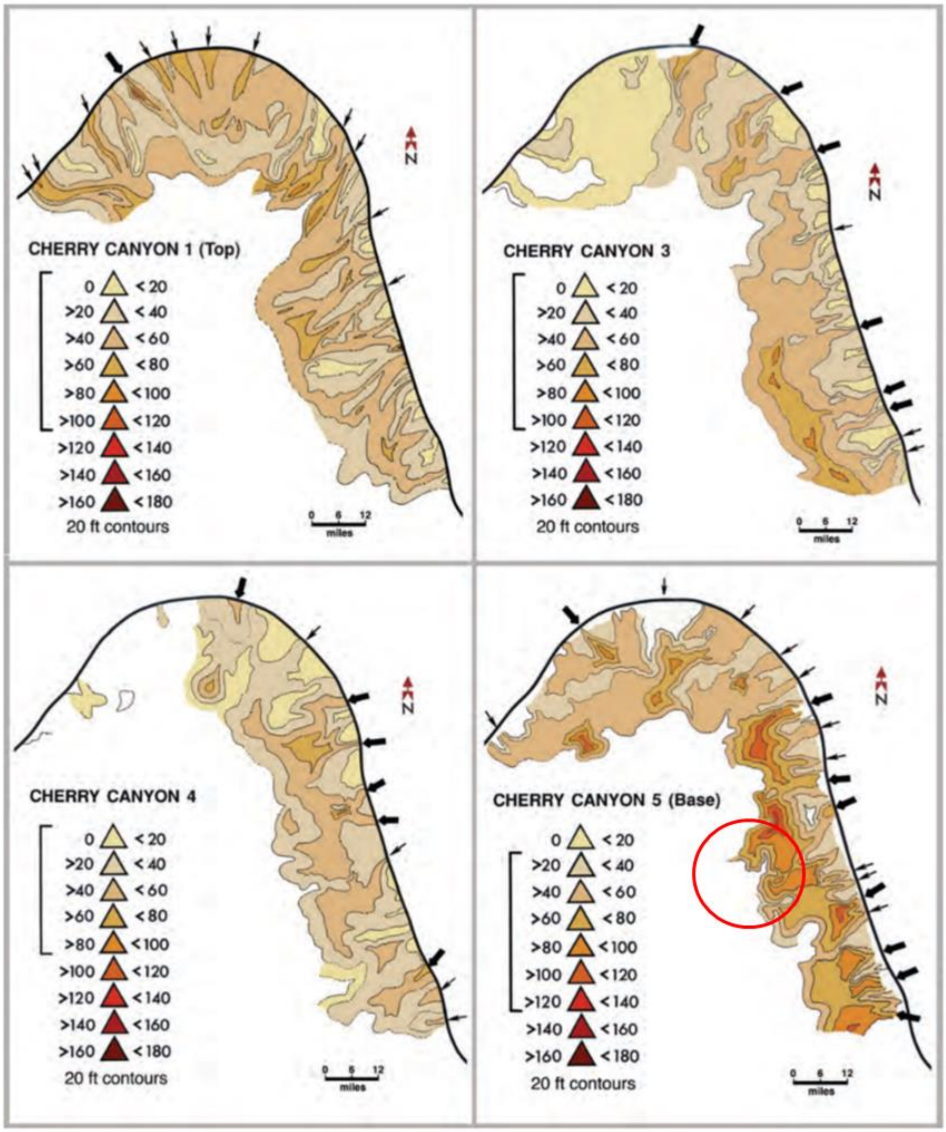


Figure 3.2.2-5– These maps of Cherry Canyon Formation were created by measuring sandstone thicknesses on well logs in five regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). Unlike the Bell Canyon sandstones, the Cherry Canyon sands are thinner and contain fewer channels. The red circle on the last map surrounds the Red Hills area.

Within the Delaware Mountain Group in the Red Hills area, the Bell Canyon and Cherry Canyon have the best porosity (averaging 15 – 25 % within channel/splay sandstones) and permeability (averaging 2-13 mD) than the Brushy Canyon (~14% porosity, an <3 mD).

UNDERLYING CONFINING ZONE

Permian Leonard Series. The Leonardian/Cisuralian Series, located beneath the Guadalupian Series sediments, is characterized by >3,000 ft of basin-deposited carbonate and siliciclastic sediments of the Bone Spring Formation. The Bone Spring Formation is more carbonate rich than the Delaware Mountain Group deposits, but the sea-level-driven cycles of sedimentation and the associated depositional environments are similar with debris flows, turbidites, and pelagic carbonate sediments. The Bone Spring Formation contains both convential and unconventional fields within the Delaware Basin in both the sandstone-rich and carbonate-rich facies. Most of these plays usually occur within toe-of-slope carbonate and siliciclastic deposits or the turbidite facies in the deeper sections of the basin (Nance and Hamlin, 2020). The upper most Bone Spring is usually dense carbonate mudstone with limited porosity and low porosity.

3.2.3 Faulting

In this immediate area of the Permian Basin, faulting is primarily confined to the lower Paleozoic section, where seismic data shows major faulting and ancillary fracturing-affected rocks only as high up as the base of the lower Woodford Shale (**Figures 3.2-4 and 3.2-5**). Faults that have been identified in the area are normal faults associated with Ouachita related movement along the western margin of the Central Platform to the east of the RH AGI well site. The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief. Because these faults are confined to the lower Paleozoic unit well below the injection zone for the RH AGI wells, they will not be discussed further.

3.3 Lithologic and Reservoir Characteristics

Based on the geologic analyses of the subsurface at the Red Hills Gas Plant, the uppermost portion of the Cherry Canyon Formation was chosen for acid gas injection and CO_2 sequestration for RH AGI #1 and the uppermost Delaware Mountain Group (the Bell Canyon and Cherry Canyon Formations) for RH AGI #3.

For RH AGI #1, this interval includes five high porosity sandstone units (sometimes referred to as the Manzanita) and has excellent caps above, below and between the individual sandstone units. There is no local production in the overlying Delaware Sands pool of the Bell Canyon Formation. There are no structural features or faults that would serve as potential vertical conduits. The high net porosity of the RH AGI #1 injection zone indicates that the injected H_2S and CO_2 will be easily contained close to the injection well.

For RH AGI #3, this interval has been expanded to include the five porosity zones in the Cherry Canyon sandstone as well as the sandstone horizons in the overlying Bell Canyon Formation. In the Bell Canyon Formation there are several potential high porosity sandstones, that if present in the well, would be excellent , injection zones similar to the depositional environments of the Cherry Canyon sandstones. The thickest sand is commonly referred to as the Delaware Sand within the Delaware Basin. The Delaware sand is productive, but it is not locally. Most of the sand bodies in the Bell Canyon and Cherry Canyon formations are surrounded by shales or limestones, forming caps for the injection zones. There are no structural features or faults that would serve as potential vertical conduits, and the overlying Ochoan evaporites form an excellent overall seal for the system. Even if faulting existed, the evaporites (Castile and Salado) would self-seal and prevent vertical migration out of the Delaware Mountain Group.

The geophysical logs were examined for all wells penetrating the Bell Canyon and Cherry Canyon formations within a three-mile radius of the RH AGI wells as well as 3-D seismic data. There are no faults visible within the Delaware Mountain Group in the Red Hills area. Within the seismic area, the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales (**Figure 3.2.2-1**) as well as being encased by them. Based on regional studies (Giesen and Scholle, 1990 and **Figures 3.2.2-4, 3.2.2-5**), the preferred orientation of the channels, and hence the preferred fluid migration pathways, are roughly from the east to the west.

The porosity was evaluated using geophysical logs from nearby wells penetrating the Cherry Canyon Formation. **Figure 3.3-1** shows the Resistivity (Res) and Thermal Neutron Porosity (TNPH) logs from 5,050 ft to 6,650 ft and includes the proposed injection interval. Five clean sands (>10% porosity and <60 API gamma units) are targets for injection within the Cherry Canyon formation and potentially another 5 sands with >10% porosity and <60 API gamma units were identified. Ten percent was the minimum cut-off considered for adequate porosity for injection. The sand units are separated by lime mudstone and shale beds with lateral continuity. The high porosity sand units exhibit an average porosity of about 18.9%; taken over the average thickness of the clean sand units within ½ mile of the RH AGI #1. There is an average of 177 ft with an irreducible water (S_{wir}) of 0.54 (see Table 1 of the RH AGI #1 permit application). Many of the sands are very porous (average porosity of > 22%) and it is anticipated that for these more porous sands, the S_{wir} may be too high. The effective porosity (Total Porosity – Clay Bound Water) would therefore also be higher. As a result, the estimated porosity ft (PhiH) of approximately 15.4 porosity-ft should be considered to be a minimum. The overlying Bell Canyon Formation has 900 ft of sands and intervening tight limestones, shales, and calcitic siltstones with porosities as low as 4%, but as mentioned above, there are at least 5 zones with a total thickness of approximately 460 ft and containing 18 to 20% porosity. The proposed injection interval is located more than 2,650 ft above the Bone Spring Formation, which is the next production zone in the area.

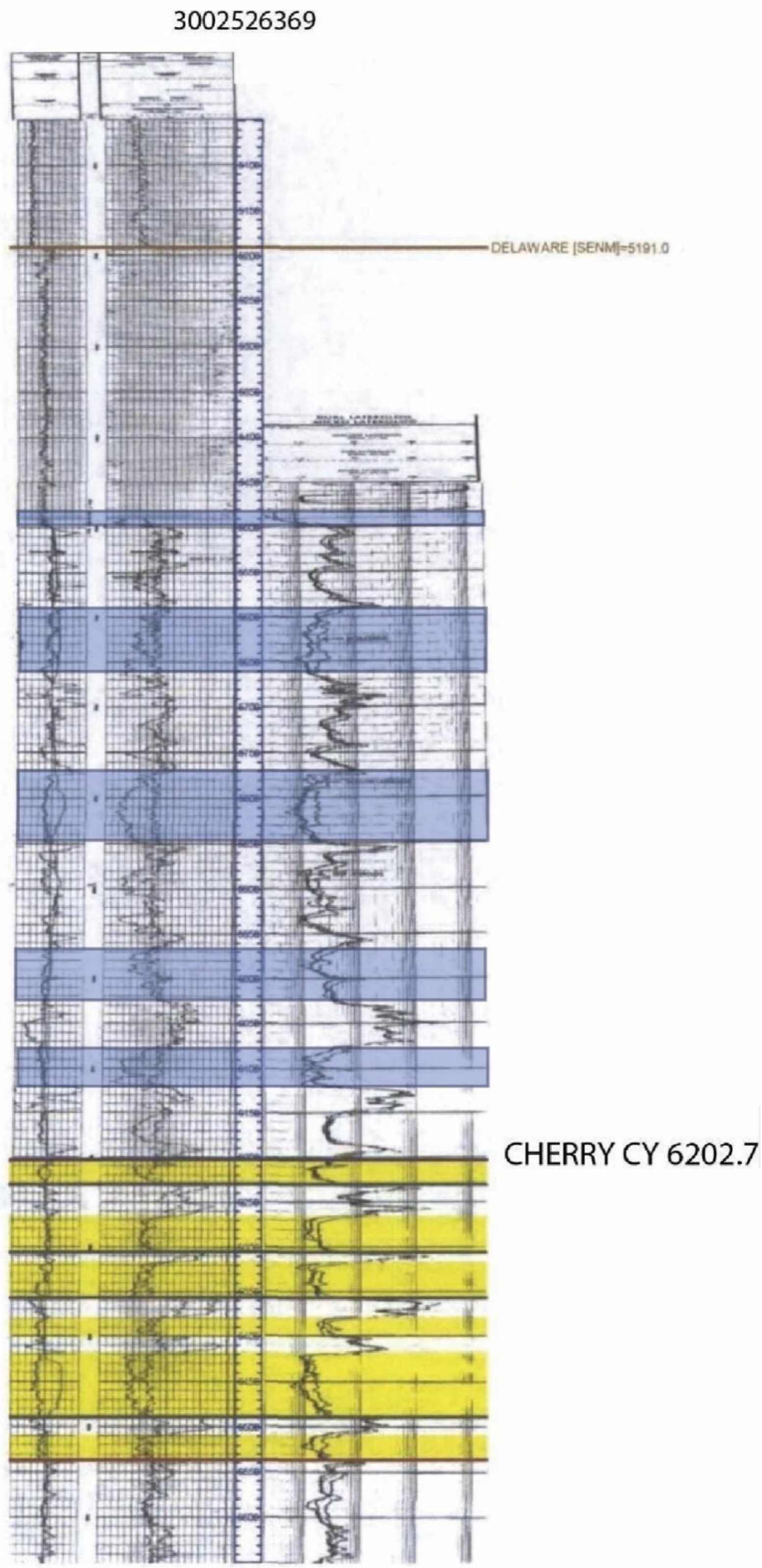


***Figure 3.3-1**: Geophysical logs from the Bell Canyon and the Upper Cherry Canyon from the Government L Com #002 well, located 0.38 miles from the RH AGI #1 Well. The blue intervals are Bell Canyon porosity zones, and the yellow intervals are Cherry Canyon porosity zones.*

3.4 Formation Fluid Chemistry

A chemical analysis (**Table 3.4-1**) of water from Federal 30 Well No. 2 (API 30-025-29069), approximately 3.9 miles away, indicates that the formation waters are highly saline (180,000 ppm NaCl) and compatible with the proposed injection.

***Table 3.4-1**: Formation fluid analysis for Cherry Canyon Formation from Federal 30 Well No. 2*

Sp. Gravity	1.125 @ 74°F	Resistivity	0.07 @ 74°F
pH	7	Sulfate	1,240
Iron	Good/Good	Bicarbonate	2,135
Hardness	45,000	Chloride	110,000
Calcium	12,000	NaCl	180,950
Magnesium	3,654	Sod. & Pot.	52,072

Table extracted from C-108 Application to Inject by Ray Westall Associated with SWD-1067 – API 30-025-24676. Water analysis for formation water from Federal 30 #2 Well (API 30-025-29069), depth 7,335-7,345 ft, located 3.9 miles from RH AGI #1 well.

3.5 Groundwater Hydrology in the Vicinity of the Red Hills Gas Plant

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are 15 freshwater wells located within a two-mile radius of the RH AGI wells, and only 2 water wells within one mile; the closest water well is located 0.31 miles away and has a total depth of 650 ft (**Figure 3.5-1; Appendix 3**). All water wells within the two-mile radius are shallow, collecting water from about 60 to 650 ft depth, in Alluvium and the Triassic redbeds. The shallow freshwater aquifer is protected by the surface and intermediate casings and cements in the RH AGI wells (**Figures Appendix 1-1 and Appendix 1.2**). While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

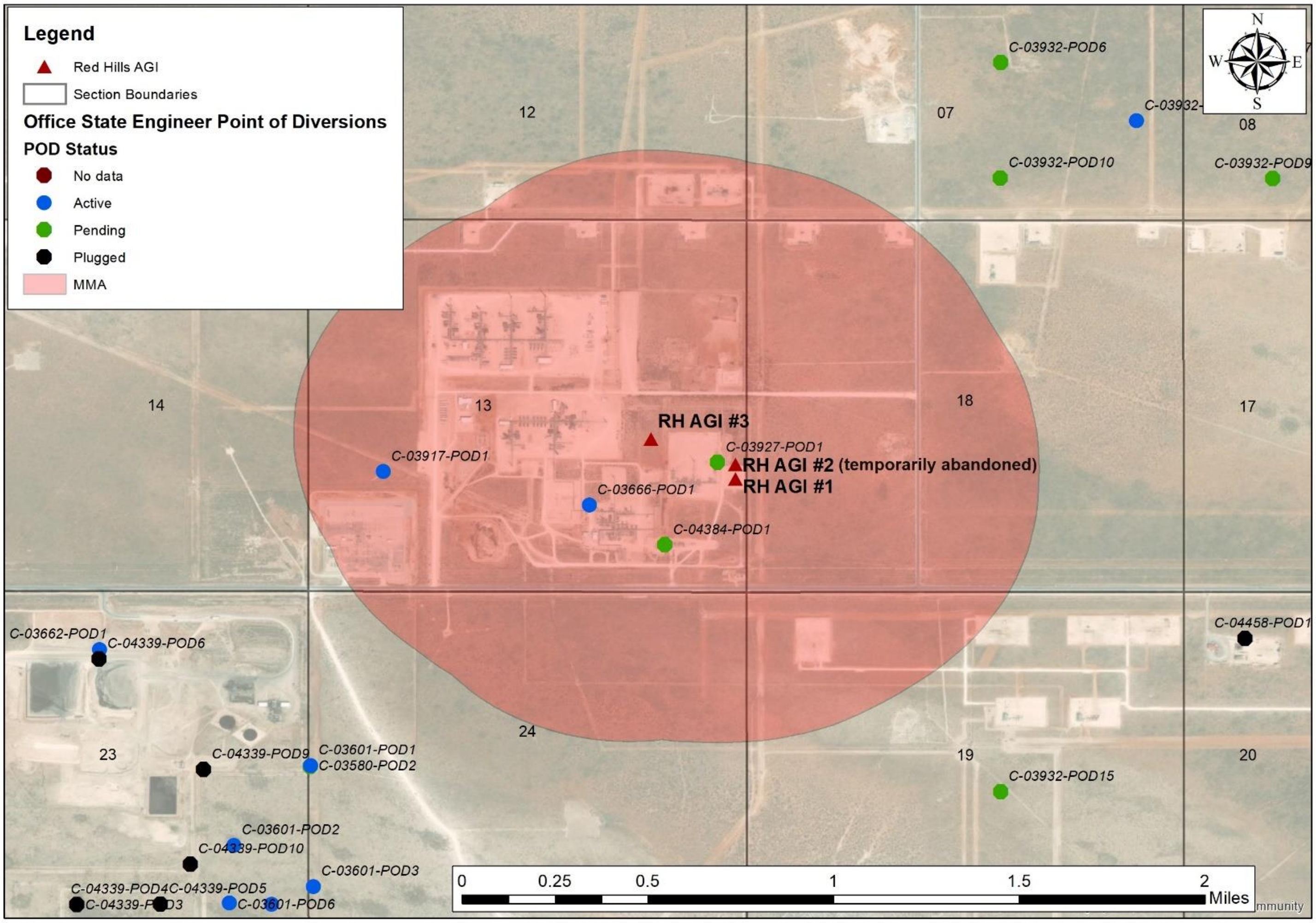


Figure 3.5-1: Reported Water Wells within the MMA for the RH AGI Wells.

3.6 Historical Operations

3.6.1 Red Hills Site

On July 20, 2010, Agave Energy Company (Agave) filed an application with NMOCD to inject treated acid gas into an acid gas injection well. Agave built the Red Hills Gas Processing Plant and drilled RH AGI #1 in 2012-13. However, the well was never completed and never put into service because the plant was processing only sweet gas (no H_2S). Lucid purchased the plant from Agave in 2016 and completed the RH AGI #1 well. TND acquired Lucid's Red Hills assets in 2022. **Figure 3.6.1-1** shows the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells. **Figure 3.6.1-2** shows a process block flow diagram.

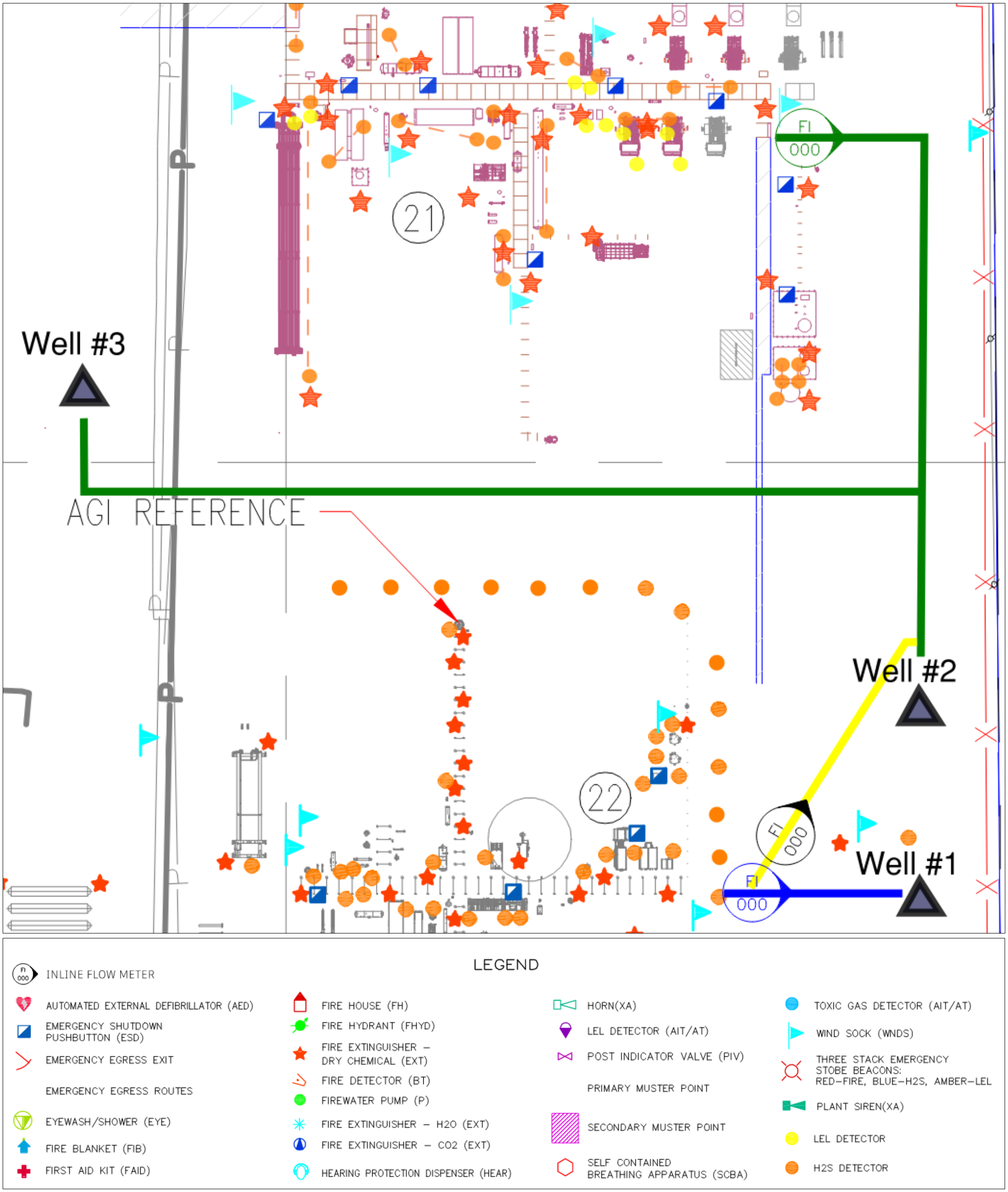


***Figure 3.6.1-1**: Diagram showing the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells.*

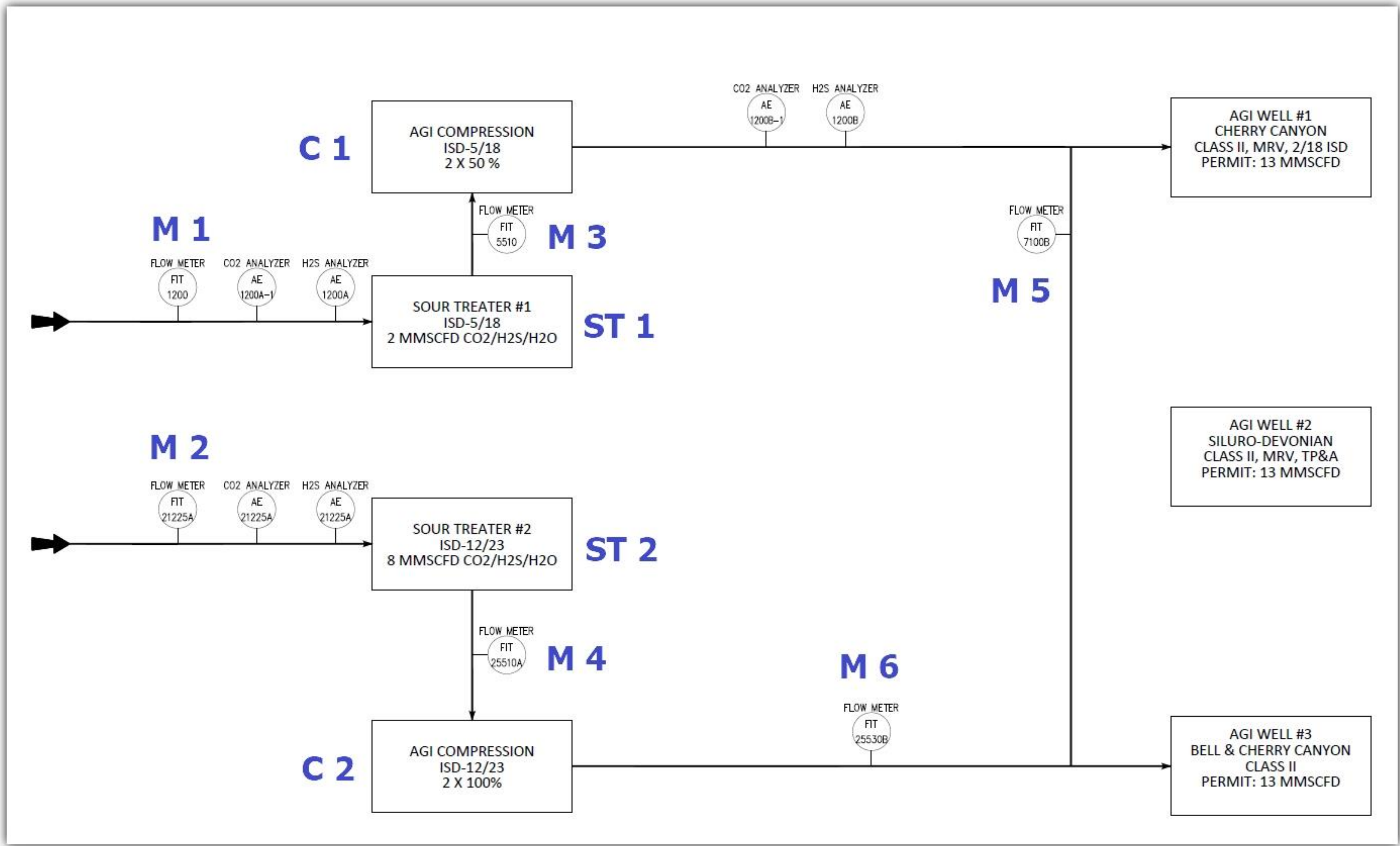


Figure 3.6.1-2: *Process Block Flow Diagram. RH AGI #2 is temporarily abandoned. M1 – M6: volumetric flow meters; C1 and C2: compressors; ST1 and ST2: sour treaters*

3.6.2 Operations within the MMA for the RH AGI Wells

NMOCD records identify a total of 22 oil- and gas-related wells within the MMA for the RH AGI wells (see **Appendix 4**). **Figure 3.6.2-1** shows the geometry of producing and injection wells within the MMA for the RH AGI wells. **Appendix 4** summarizes the relevant information for those wells. All active production in this area is targeted for the Bone Spring and Wolfcamp zones, at depths of 8,900 to 11,800 ft, the Strawn (11,800 to 12,100 ft) and the Morrow (12,700 to 13,500 ft). All of these productive zones lie at more than 2,000 ft below the RH AGI #1 and AGI #3 injection zone.

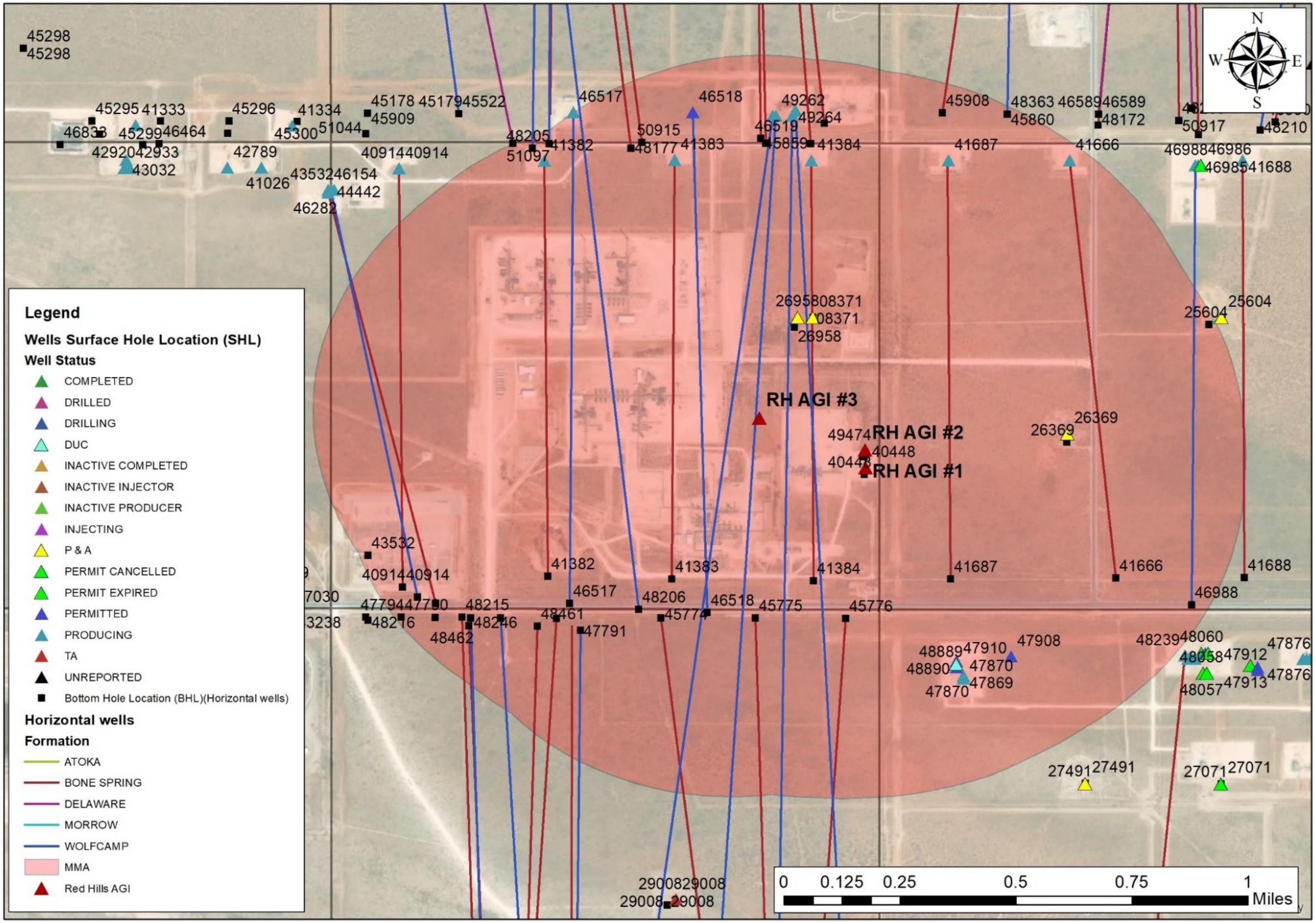


Figure 3.6.2-1*: Location of all oil- and gas-related wells within the MMA for the RH AGI wells. Both the surface hole locations (SHL) and bottom hole locations (BHL) are labeled on the figure. For clarity, only the last four digits of the API numbers are used in labeling the wells.*

3.7 Description of Injection Process

The Red Hills Gas Plant, including the existing RH AGI #1 well, is in operation and staffed 24-hours-a-day, 7-days-a week. The plant operations include gas compression, treating and processing. The plant gathers and processes produced natural gas from Lea and Eddy Counties in New Mexico. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the plant's sweeteners will be routed to a central compressor facility, located west of the well head. Compressed TAG is then routed to the wells via high-pressure rated lines. **Figure 3.7-1** is a schematic of the AGI facilities.

The approximate composition of the TAG stream is: 80% CO_2, 20% H_2S, with Trace Components of C_1 – C_6 (methane – hexane) and Nitrogen. The anticipated duration of injection is 30 years.

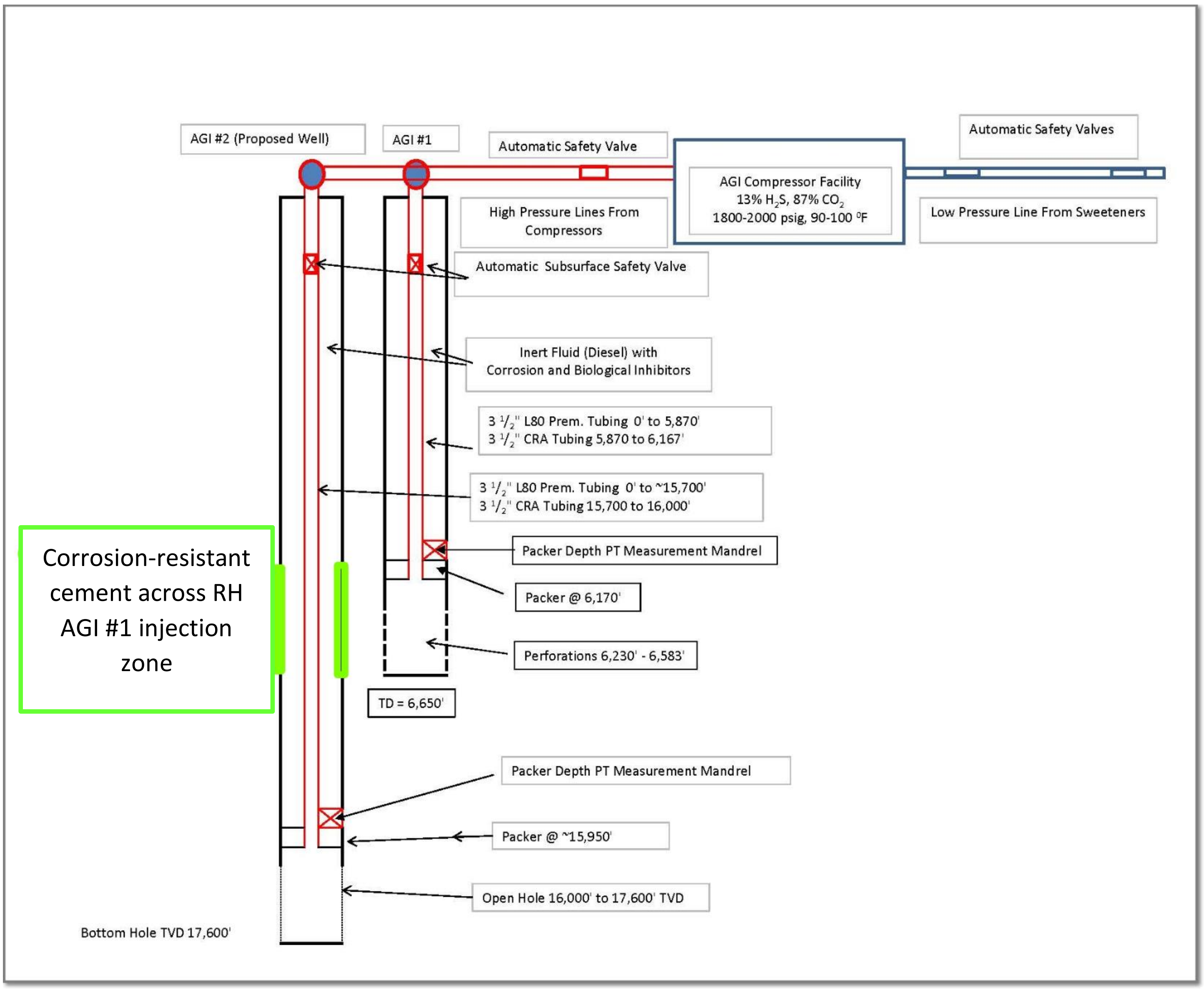


***Figure 3.7-1**: Schematic of surface facilities and RH AGI wells at the Red Hills Gas Processing Plant*

3.8 Reservoir Characterization Modeling

The modeling and simulation focused on the Bell Canyon and Cherry Canyon formations as the main injection target zone for acid gas storage. The RH AGI #1 well (API 30-025-40448) and the RH AGI #3 well (API 30-025-51970) are the approved injectors for treated acid gas injection by NMOCD and will serve as the injection wells in the model under approved disposal timeframe and maximum allowable injection pressure. RH AGI #1 well is completed in the Cherry Canyon formation between 6,230 feet to 6,583 feet (MD). The RH AGI #3 well will be completed in both the Bell Canyon and Cherry Canyon formations between approximately 5,245 feet to 6,645 feet (MD).

Schlumberger's Petrel® (Version 2023.1) software was used to construct the geological models used in this work. Computer Modeling Group (CMG)'s CMG-GEM® (Version 2023.10) was used in the reservoir simulations presented in this MRV plan. CMG-WINPROP® (Version 2023.10) was used to perform PVT calculation through Equation of States and properties interactions among various compositions to feed the hydrodynamic modeling performed by CMG-GEM®. The hydrodynamical model considered aqueous, gaseous, and supercritical phases, and simulates the storage mechanisms including structural trapping, residual gas trapping, and solubility trapping. Injected TAG may exist in the aqueous phase as dissolved state and the gaseous phase as supercritical state. The model was validated through matching the historical injection data of RH AGI #1 well and will be reevaluated periodically as required by the State permitting agency.

The static model is constructed with well tops and licensed 3D seismic data to interpret and delineate the structural surfaces of a layer within the caprock (Lamar Limestone) and its overlaying, underlying formations. The geologic model covers a 3.5-mile by 3.3-mile area. No distinctive geological structures such as faults are identified within the geologic model boundary. The model is gridded with 182 x 167 x 18, totaling 547,092 cells. The average grid dimension of the active injection area is 100 feet square. **Figure 3.8-1** shows the simulation model in 3D view. The porosity and permeability of the model is populated through existing well logs. The range of the porosity is between 0.01 to 0.31. The initial permeability are interpolated between 0.02 to 155 millidarcy (mD), and the vertical permeability anisotropy was 0.1. **(Figure 3.8-2 and Figure 3.8-3)**. These values are validated and calibrated with the historical injection data of RH AGI #1 well since 2018 as shown in **Figures 3.8-4, 3.8-5, and 3.8-6**.

The simulation model is calibrated with the injection history of RH AGI #1 well since 2018. Simulation studies were further performed to estimate the reservoir responses when predicting TAG injection for 30 years through both RH AGI #1 well (2018 – 2048) and RH AGI #3 (2024 - 2054). RH AGI #2 well is temporarily abandoned as of the submission of this document. RH AGI #1 is simulated to inject with the average rate of the last 5 years, 1.2 MMSCF, in the prediction phase. RH AGI #3 is simulated to inject with permitted injection rate, 13 MMSCF, with 1,767 psi maximum surface injection pressure constraint approved by State agency. The simulation terminated at year 2084, 30 years after the termination of all injection activities, to estimate the maximum impacted area during post injection phase.

During the calibration period (2018 – 2023), the historical injection rates were used as the primary injection control, and the maximum bottom hole pressures (BHP) are imposed on wells as the constraint, calculated based on the approved maximum injection pressure. This restriction is also estimated to be less than 90% of the formation fracture pressure calculated at the shallowest perforation depth of each well to ensure safe injection operations. The reservoir properties are tuned to match the historical injection until it was reasonably matched. **Figure 3.8-4** shows that the historical injection rates from the RH AGI #1 well in the Cherry Canyon Formation. **Figure 3.8-5** shows the BHP response of RH AGI #1 during the history matching phase.

During the forecasting period, linear cumulative injection behavior indicates that the Cherry Canyon and Bell Canyon formations received the TAG stream freely. **Figure 3.8-6** shows the cumulative disposed H_2S and CO_2 of each AGI injectors separately in gas mass. The modeling results indicate that the Cherry Canyon and Bell Canyon formations are capable of safely storing and containing the proposed gas volume without violating the permitted rate and pressure. **Figure 3.8-7** shows the gas saturation represented TAG plume at the end of 30-year forecasting in 3D view. **Figure 3.8-8** shows the extent of the plume migration in a map view at 4 key time steps. It can be observed that the size of the TAG is very limited and mainly stayed within Targa's Red Hills facility at the end of injection. In the year 2084, after 30 years of monitoring, the injected gas remained trapped in the reservoir and there was no significant migration of TAG footprint observed, compared to that at the end of injection.

In summary, after careful reservoir engineering review and numerical simulation study, our analysis shows that the Bell Canyon and Cherry Canyon formations can receive treated acid gas (TAG) at the proposed injection rate and permitted maximum surface injection pressure permitted by New Mexico Oil Conservation Committee. The formation will safely contain the injected TAG volume within the proposed injection and post-injection timeframe. The proposed injection well will allow for the sequestration while preventing associated environmental impacts.

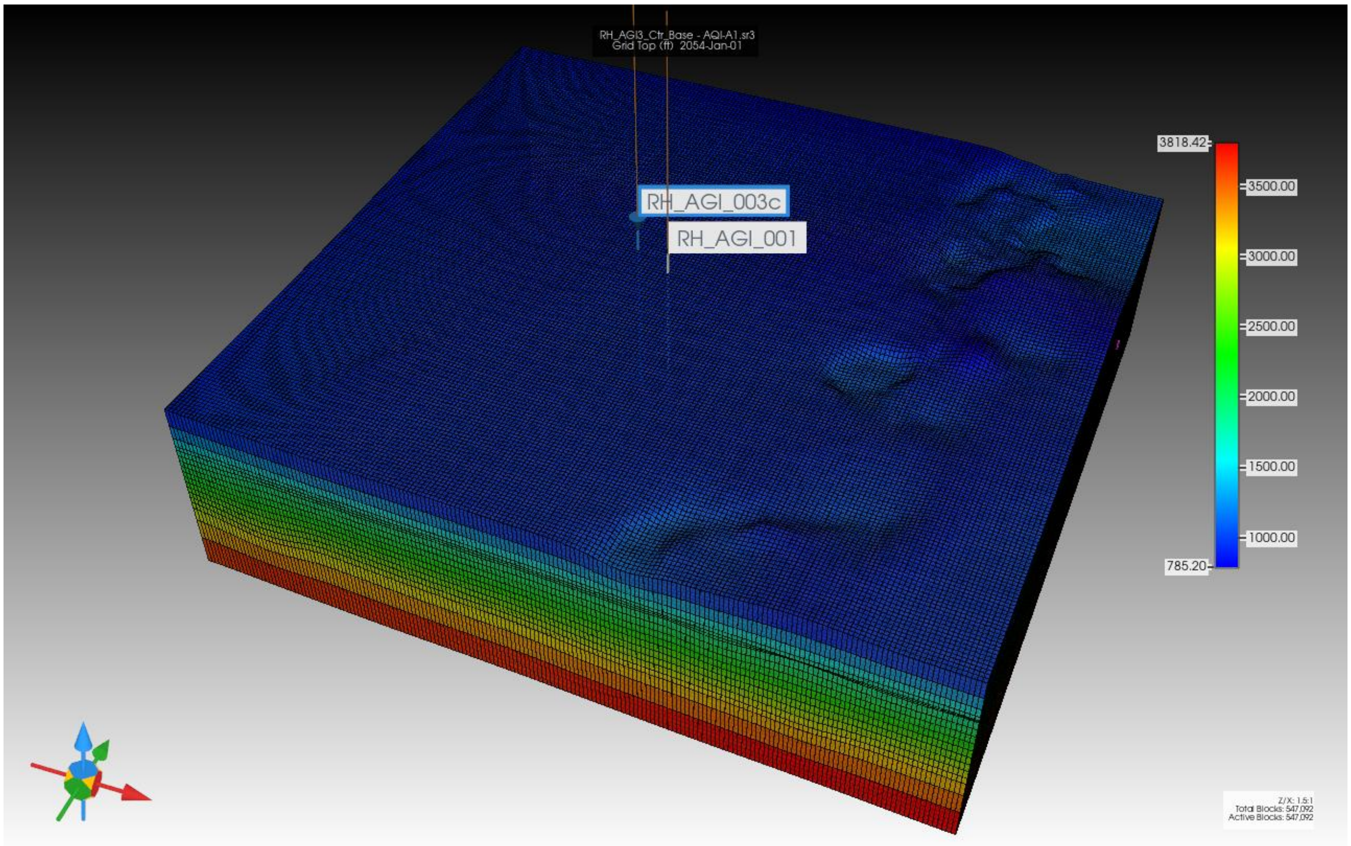


Figure 3.8-1: *3D view of the simulation model of the Red Hills AGI #1 and #3 AGI wells, containing Salado-Castile formation, Lamar limestone, Bell Canyon, and Cherry Canyon formations. Color legends represents the elevation of layers.*

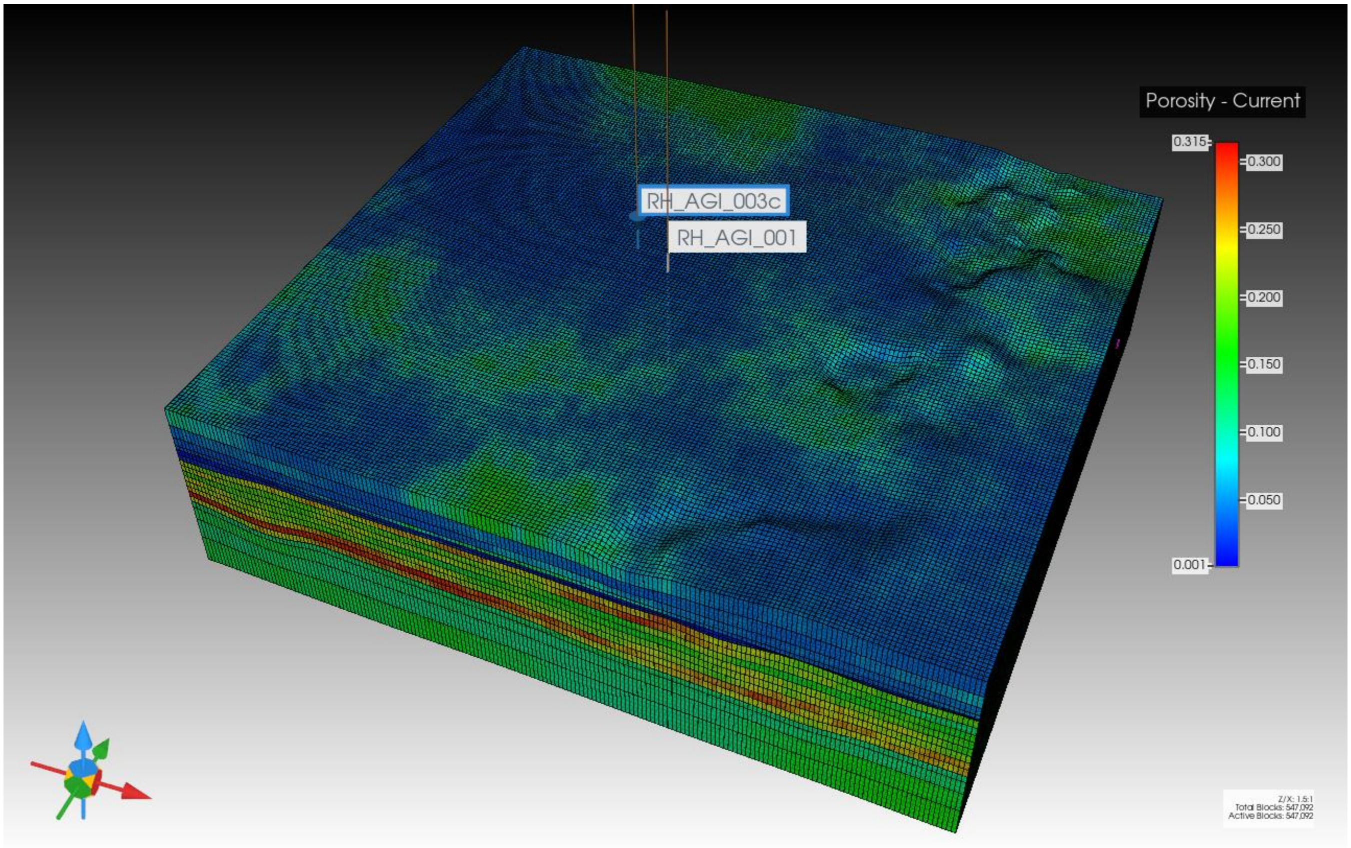


Figure 3.8-2: *Porosity estimation using available well data for the simulation domain.*

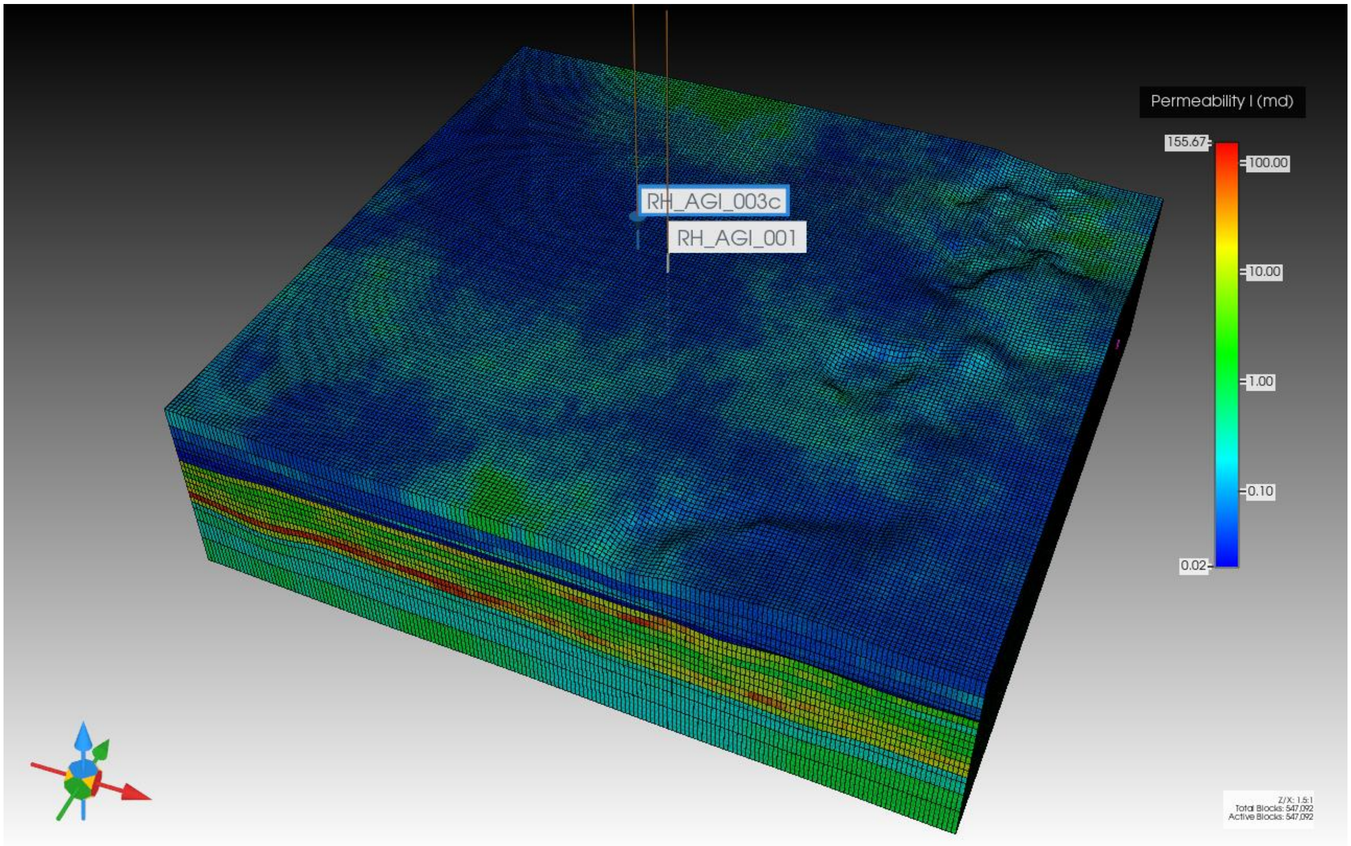


__Figure 3.8-3:__ Permeability estimation using available well data for simulation domain.

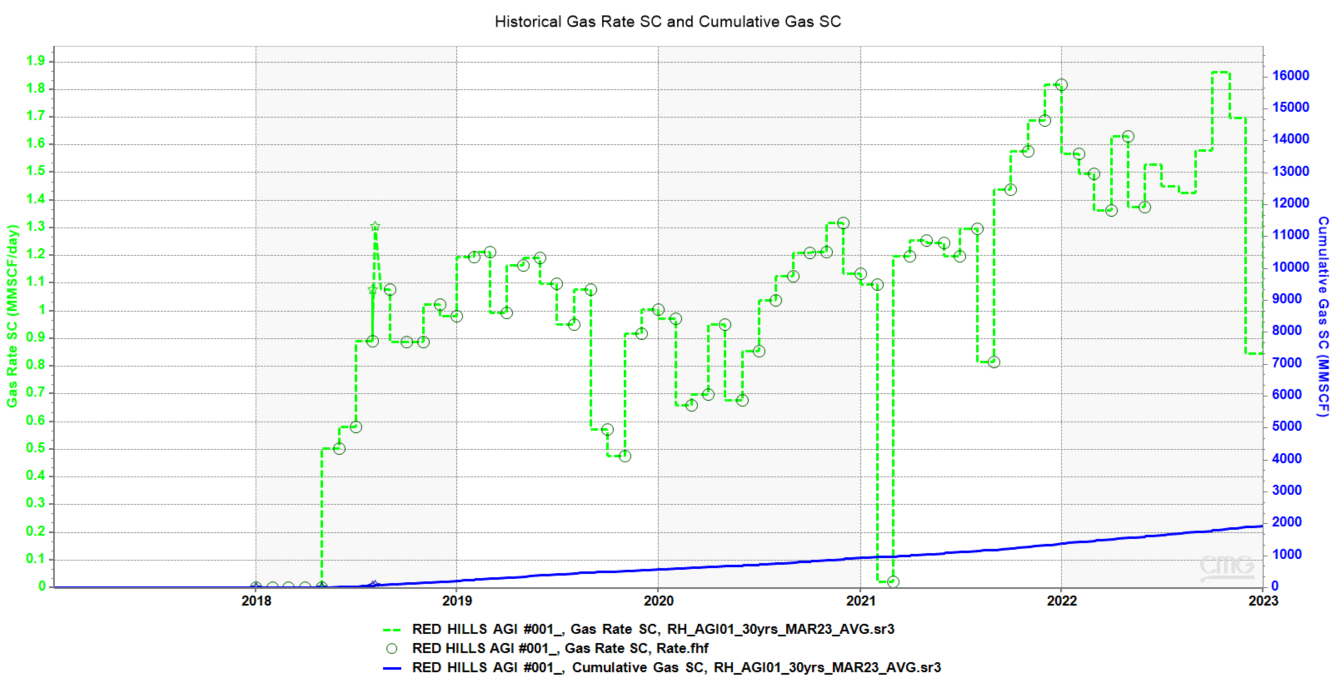


__Figure 3.8-4:__ shows the historical injection rate and total gas injected from Red Hills AGI #1 well (2018 to 2023)

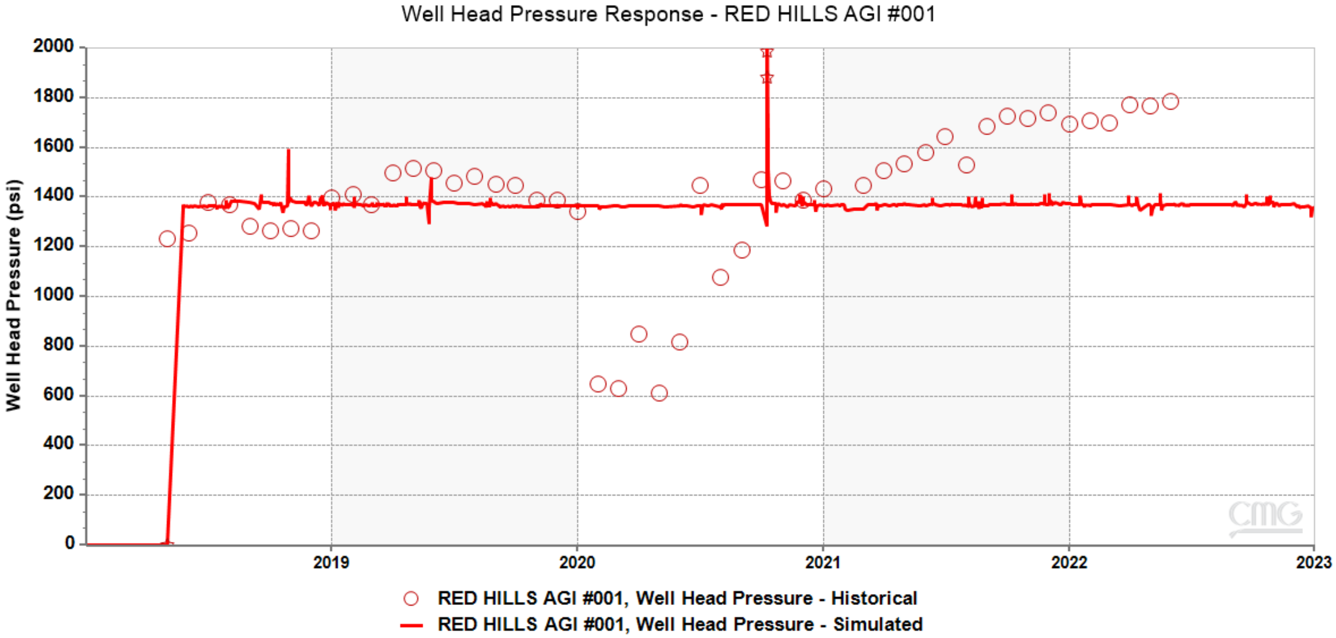


Figure 3.8-5: *shows the historical bottom hole pressure response from Red Hills AGI #1 well (2018 to 2023)*

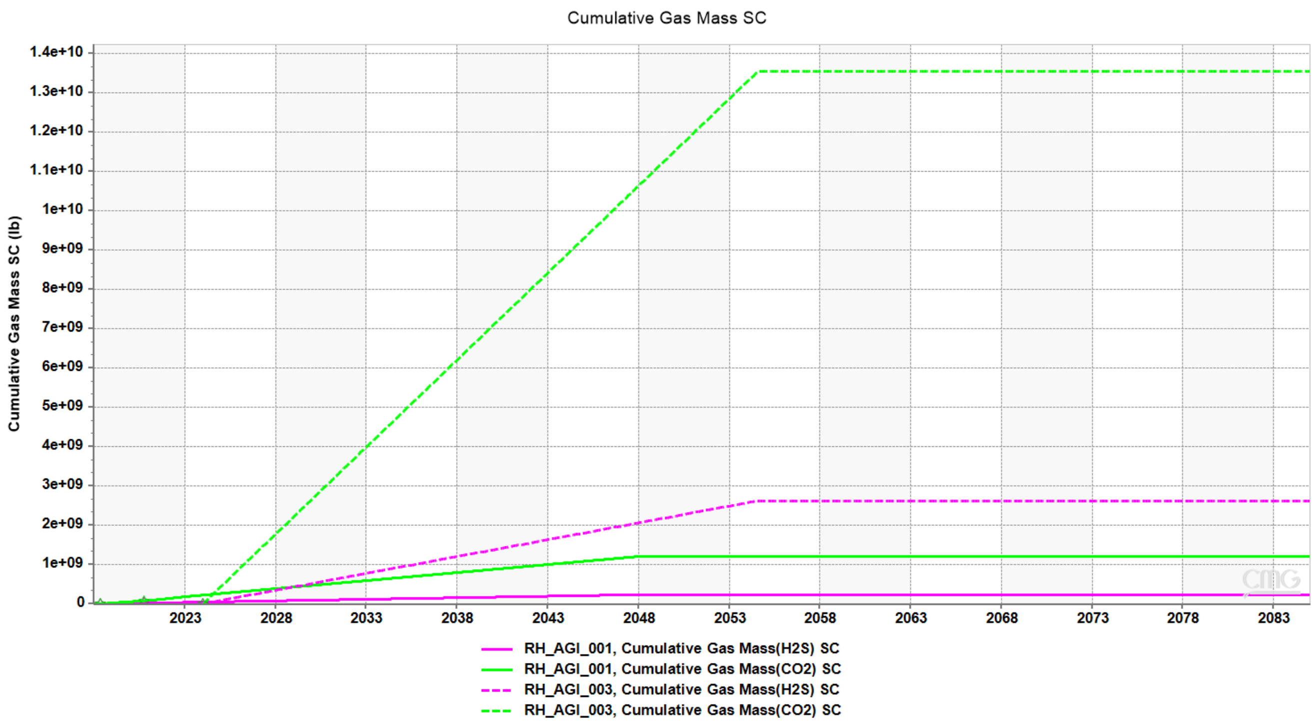


Figure 3.8-6: *shows the prediction of cumulative mass of injected CO_2 and H_2S of Red Hills AGI #1 and #3 wells (2018 to 2054).*

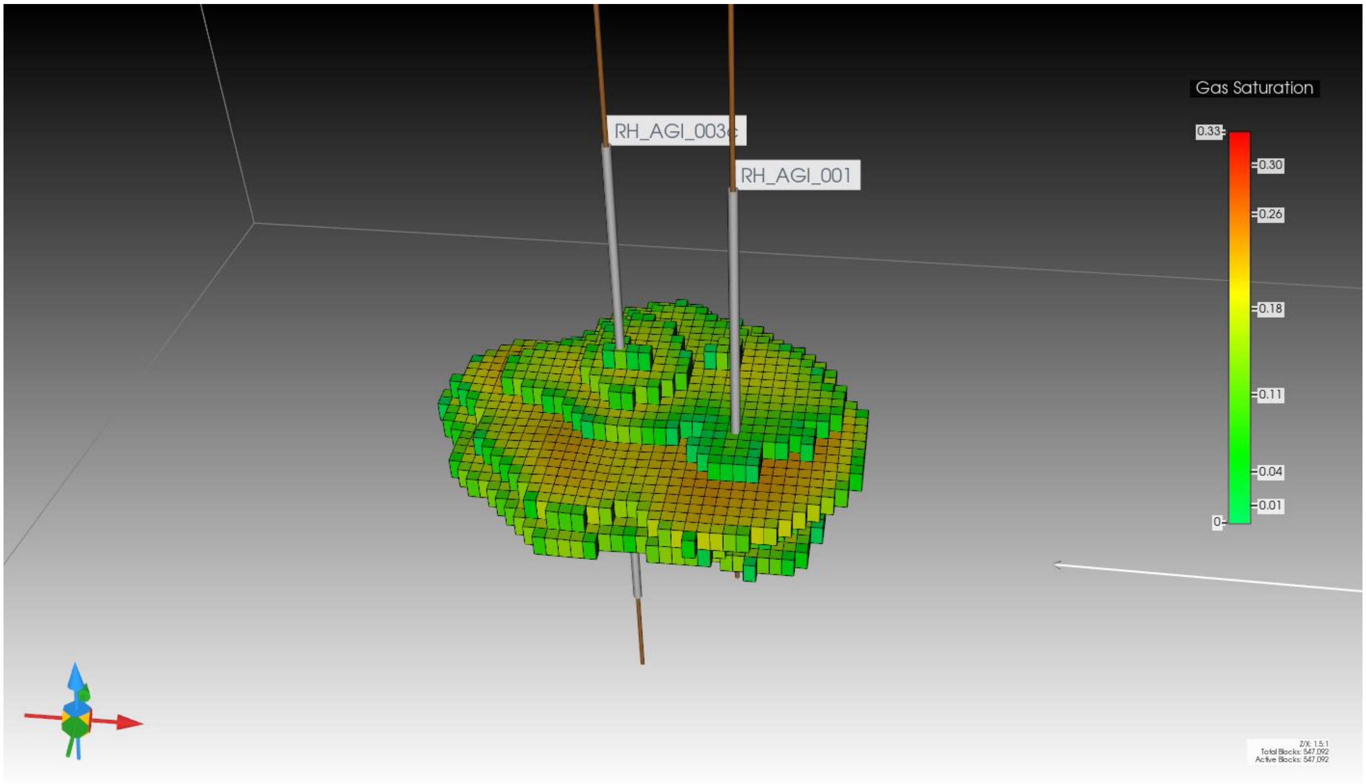


Figure 3.8-7: *shows the free phase TAG (represented by gas saturation) at the end of 30-year post-injection monitoring (2054) in 3D view.*

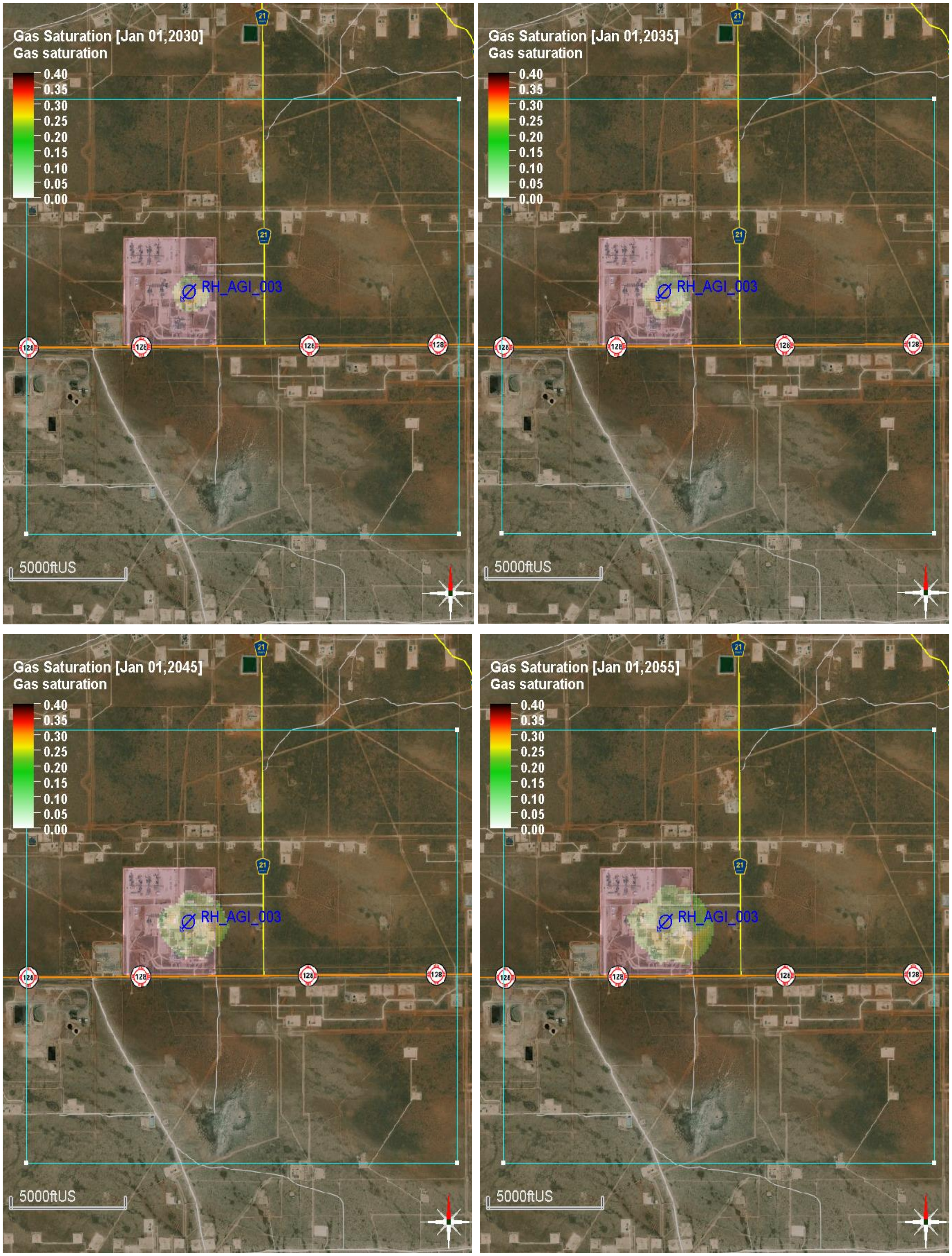


Figure 3.8-8: *shows the free phase TAG plume at year 2030, 2035, 2045, 2055 (1-year end of injection) in a map view.*

4 Delineation of the Monitoring Areas

In determining the monitoring areas below, the extent of the TAG plume is equal to the superposition of plumes in any layer for any of the model scenarios described in Section 3.8.

4.1 MMA – Maximum Monitoring Area

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. **Figures 4.1-1** shows the MMA as defined by the most conservative extent of the TAG plume at year 2054 plus a 1/2-mile buffer.

Targa intends to define the active monitoring area (AMA) as the same area as the MMA.

4.2 AMA – Active Monitoring Area

The Active Monitoring Area (AMA) is shown in **Figure 4.1-1**. The AMA is consistent with the requirements in 40 CFR 98.449 because it is the area projected: (1) to contain the free phase CO_2 plume for the duration of the project (year t, t = 2054), plus an all-around buffer zone of one-half mile. (2) to contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2059).

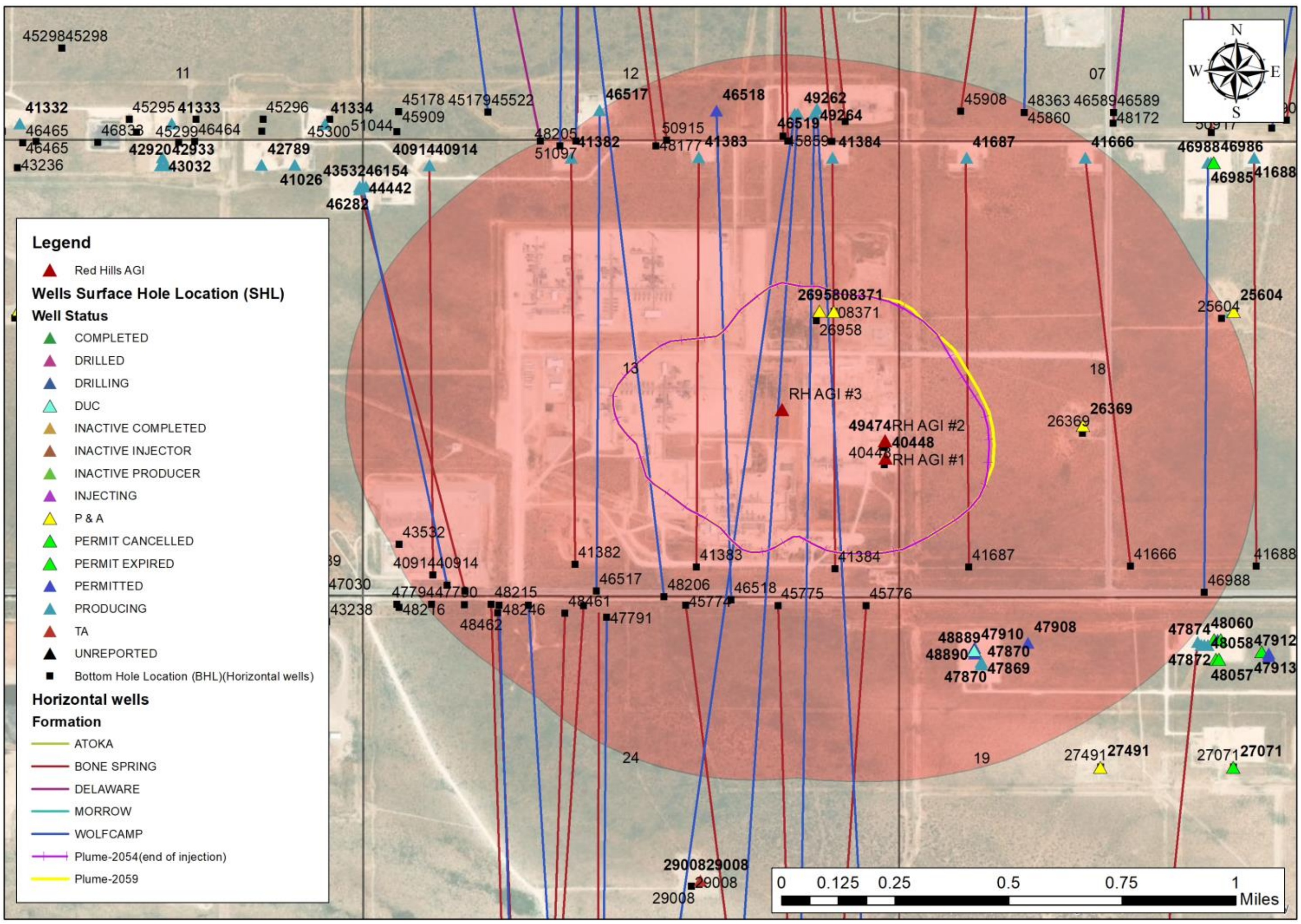


Figure 4.1-1: Active monitoring area (AMA) for TND Red Hills AGI #1, #2 (temporarily abandoned) and #3 wells at the end of injection (2054, purple polygon) and 5 years post-monitoring (2059, yellow polygon). Maximum monitoring area (MMA) is shown in red shaded area.

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

Subpart RR at 40 CFR 448(a)(2) requires the identification of potential surface leakage pathways for CO_2 in the MMA and the evaluation of the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways.

Through the site characterization required by the NMOCD C-108 application process for Class II injection wells, the geologic characterization presented in Section 3, and the reservoir modeling described in Section 3.8, TND has identified and evaluated the potential CO_2 leakage pathways to the surface.

A qualitative evaluation of each of the potential leakage pathways is described in the following paragraphs. Risk estimates were made utilizing the National Risk Assessment Partnership (NRAP) tool, developed by five national laboratories: NETL, Los Alamos National Laboratory (LANL), Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), and Pacific Northwest National Laboratory (PNNL). The NRAP collaborative research effort leveraged broad technical capabilities across the Department of Energy (DOE) to develop the integrated science base, computational tools, and protocols required to assess and manage environmental risks at geologic carbon storage sites. Utilizing the NRAP tool, TND conducted a risk assessment of CO_2 leakage through various potential pathways including surface equipment, existing and approved wellbores within MMA, faults and fractures, and confining zone formations.

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas facilities. Preventative risk mitigation includes adherence to relevant regulatory requirements and industry standards governing the construction, operation, and maintenance of gas plants. Specifically, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills."

Operational risk mitigation measures relevant to potential CO_2 emissions from surface equipment include a schedule for regular inspection and maintenance of surface equipment. Additionally, TND implements several methods for detecting gas leaks at the surface. Detection is followed up by immediate response. These methods are described in more detail in sections 6 and 7.

Although mitigative measures are in place to minimize CO_2 emissions from surface equipment, such emissions are possible. Any leaks from surface equipment would result in immediate (timing) emissions of CO_2 to the atmosphere the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak.

The injection well and the pipeline that carries CO_2 to it are the most likely surface components of the system to allow CO_2 to leak to the surface. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable source of the leakage. Another possible source of leakage is the release of air through relief valves, which are designed to alleviate pipeline overpressure. Leakage can also occur when the surface components are damaged by an accident or natural disaster, which releases CO_2. Therefore, TND infers that there is a potential for leakage via this route. Depending on the component's failure mode, the magnitude of the leak can vary greatly. For example, a rapid break or rupture could release thousands of pounds of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO_2 over several hours or days. Surface component leakage or venting is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

5.2 Potential Leakage from Approved, Not Yet Drilled Wells

5.2.1 RH AGI #3

TND is currently drilling the RH AGI #3 well within the MMA. To minimize the likelihood of leaks from new wells, NMAC 19.15.26.9 regarding the casing and cementing of injection wells requires operators to case injection wells "with safe and adequate casing or tubing so as to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluid from the injection zone into another injection zone or to the surface around the outside of the casing string." To minimize the magnitude and duration (timing) of CO_2 leakage to the surface, NMAC 19.15.16.12 requires the use of "blowout preventers in areas of high pressure at or above the projected depth of the well." These requirements apply to any other new well drilled within the MMA for this MRV plan.

TND realizes that when they drill the RH AGI #3, they will be drilling into a reservoir in which they have been injecting H_2S and CO_2 for many years. Therefore, for safety purposes, they will be implementing enhanced safety protocols to ensure that no H_2S or CO_2 escapes to the surface during the drilling of RH AGI #3. Enhanced measures include:

- Using managed pressure drilling equipment and techniques thereby minimizing the chance of any gas from entering the wellbore
- Using LCM (loss control material) at a higher-than-normal rate to fill in the pockets of the wellbore thereby minimizing the chance of gas from entering the wellbore while drilling
- Monitoring H_2S at surface at many points to assure operators that we are successfully keeping any possible gas pressures from impacting the drilling operation
- Employing a high level of caution and care while drilling through a known H_2S injection zone, including use of slower drilling processes and more vigilant mud level monitoring in the returns while drilling into the RH AGI #1 injection zone

By drilling through a zone containing pressurized TAG there is a possibility of CO_2 emission to the surface from the pressurized zone. The emission would be nearly immediate. The magnitude of such an emission would be estimated based on field conditions at the time of the detected leak. The safety protocols described above are in place to prevent or minimize the magnitude of such a leak should one occur.

Due to these safeguards and the continuous monitoring of Red Hills well's operating parameters by the distributed control system (DCS), TND considers that while the likelihood of surface emission of CO_2 is possible, the magnitude of such a leak would be minimal as detection of the leak would be nearly instantaneous followed by immediately shutting in the well and remediation.

5.2.2 Horizontal Wells

The table in **Appendix 3** and **Figure 4.1-1** shows a number of horizontal wells in the area, many of which have approved permits to drill but which are not yet drilled. If any of these wells are drilled through the Bell Canyon injection zone for RH AGI #3 and the Cherry Canyon injection zone for RH AGI #1, they will be required to take special precautions to prevent leakage of TAG minimizing the likelihood of CO_2 leakage to the surface. This requirement will be made by NMOCD in regulating applications for permit to drill (APD) and in ensuring that the operator and driller are aware that they are drilling through an H_2S injection zone in order to access their target production formation. NMAC 19.15.11 for Hydrogen Sulfide Gas includes standards for personnel and equipment safety and H_2S detection and monitoring during well drilling, completion, well workovers, and well servicing operations all of which apply for wells drilled through the RH AGI wells TAG plume.

Due to the safeguards described above, the fact there are no proposed wells for which the surface hole location (SHL) lies within the simulated TAG plume and considering the NRAP risk analysis described here in

Section 5, TND considers the likelihood of CO_2 emissions to the surface via these horizontal wells to be highly improbable to impossible.

5.3 Potential Leakage from Existing Wells

Existing oil and gas wells within the MMA as delineated in Section 4 are shown in **Figure 3.6.2-1** and detailed in **Appendix 4**.

TND considered all wells completed and approved within the MMA in the NRAP risk assessment. The wells may or may not penetrate the confining zone and storage reservoir. Even though the risk of CO_2 leakage through the wells that did not penetrate confining zones is most likely impossible, TND did not omit any potential source of leakage in the NRAP analysis. If leakage through wellbores happens, the worst-case scenario is predicted using the NRAP tool to quantitatively assess the amount of CO_2 leakage through existing and approved wellbores inside the MMA. Thirty-nine existing and approved wells inside MMA were identified and located in the model. The reservoir properties, well data, formation stratigraphy, and MMA area were incorporated into the NRAP tool to forecast the rate and mass of CO_2 leakage. The worst scenario is that all of the 39 wells were located right at the source of CO_2 – the injection well's location. In this case, the maximum leakage rate of one well is approximately 7e-6 kg/s. This value is the maximum amount of CO_2 leakage, 220 kg/year, and occurs in the second year of injection, then gradually reduces to 180 kg at the end of year 30. Comparing the total amount of CO_2 injected (assuming 5 MMSCFD of supercritical CO_2 injected continuously for 30 years), the leakage mass amounts to 0.0054% of the total CO_2 injected. This leakage can be considered safely negligible. Also, this worst-case scenario, where 39 wells are located right at the injection point, is impossible in reality. Therefore, this leakage pathway can be considered improbable.

5.3.1 Wells Completed in the Bell Canyon and Cherry Canyon Formations

The only wells completed in the Bell Canyon and Cherry Canyon Formations within the MMA are the RH AGI #1 and #3 wells and the 30-025-08371 well which was completed at a depth of 5,425 ft. This well is within the Red Hills facility boundary and is plugged and abandoned (see **Appendix 9** for plugging and abandonment (P&A) record). **Appendix 1** includes schematics of the RH AGI wells construction showing multiple strings of casing all cemented to surface. Injection of TAG occurs through tubing with a permanent production packer set above the injection zone.

Due to the robust construction of the RH AGI wells, the plugging of the well 30-025-08371 above the Bell Canyon, and considering the NRAP analysis described above, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.2 Wells Completed in the Bone Spring / Wolfcamp Zones

Several wells are completed in the Bone Spring and Wolfcamp oil and gas production zones as described in Section 3.6.2. These productive zones lie more than 2,000 ft below the RH AGI wells injection zone minimizing the likelihood of communication between the RH AGI well injection zones and the Bone Spring / Wolfcamp production zones. Construction of these wells includes surface casing set at 1,375 ft and cemented to surface and intermediate casing set at the top of the Bell Canyon at depths of from 5,100 to 5,200 ft and cemented through the Permian Ochoan evaporites, limestone and siltstone (**Figure 3.2-2**) providing zonal isolation preventing TAG injected into the Bell Canyon and Cherry Canyon formations through RH AGI wells from leaking upward along the borehole in the event the TAG plume were to reach these wellbores. **Figure 4.1-1** shows that the modeled TAG plume extent after 30 years of injection and 5 years of post-injection stabilization does not extend to well boreholes completed in the Bone Spring / Wolfcamp production zones thereby indicating that these wells are not likely to be pathways for CO_2 leakage to the surface.

Due to the construction of these wells, the fact that the modeled TAG plume does not reach the SHL of these wells and considering the NRAP analysis described in the introductory paragraph of Section 5, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.3 Wells Completed in the Siluro-Devonian Zone

One well penetrated the Devonian at the boundary of the MMA - EOG Resources, Government Com 001, API # 30-025-25604, TVD = 17,625 ft, 0.87 miles from RH AGI #3. This well was drilled to a total depth of 17,625 ft on March 5, 1978, but plugged back to 14,590 ft, just below the Morrow, in May of 1978. Subsequently, this well was permanently plugged and abandoned on December 30, 2004, and approved by NMOCD on January 4, 2005 (see **Appendix 9** for P&A records). The approved plugging provides zonal isolation for the Bell Canyon and Cherry Canyon injection zones minimizing the likelihood that this well will be a pathway for CO_2 emissions to the surface from either injection zone.

Due to the location of this well at the edge of the MMA and considering the NRAP analysis described in the introductory paragraph of Section 5, TND considers that, while the likelihood of CO_2 emission to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.3.4 Groundwater Wells

The table in Appendix 3 lists 15 water wells within a 2-mile radius of the RH AGI wells, only 2 of which are within a 1-mile radius of and within the MMA for the RH AGI wells (**Figure 3.5-1**). The deepest ground water well is 650 ft deep The evaporite sequence of the Permian Ochoan Salado and Castile Formations (see Section 3.2.2) provides an excellent seal between these groundwater wells and the Cherry Canyon injection zone of the RH AGI #1 well. Therefore, it is unlikely that these two groundwater wells are a potential pathway of CO_2 leakage to the surface. Nevertheless, the CO_2 surface monitoring and groundwater monitoring described in Sections 6 and 7 will provide early detection of CO_2 leakage followed by immediate response thereby minimizing the magnitude of CO_2 leakage volume via this potential pathway.

Due to the shallow depth of the groundwater wells within the MMA relative to the depth of the RH AGI wells and considering the NRAP analysis described in the introductory paragraph in Section 5, TND considers that, while the likelihood of CO_2 emissions to the surface via this potential leakage pathway is possible to improbable, the magnitude of such a leak to be minimal.

5.4 Potential Leakage through the Confining / Seal System

The site characterization for the injection zone of the RH AGI wells described in Sections 3.2.2 and 3.3 indicates a thick sequence of Permian Ochoan evaporites, limestone, and siltstones (**Figure 3.2-2**) above the Bell Canyon and Cherry Canyon Formations and no evidence of faulting. Therefore, it is unlikely that TAG injected into the Bell Canyon and Cherry Canyon Formations will leak through this confining zone to the surface. Limiting the injection pressure to less than the fracture pressure of the confining zone will minimize the likelihood of CO_2 leakage through this potential pathway to the surface.

Leakage through a confining zone happens at low-permeability shale formations containing natural fractures. The injection zone for the RH AGI #1 and #3 is the Delaware Group Formation (Bell Canyon and Cherry Canyon), which lies under the Castile and Salado formations with less than 0.01 mD permeability acting as the seals. Therefore, TND took leakage through confining zones into consideration in the NRAP risk assessment. The worst-case scenario is defined as leakage through the seal happening right above the injection wells, where CO_2 saturation is highest. However, this worst-case scenario of leakage only shows that 0.0017% of total CO_2 injection in 30 years was leaked from the injection zone through the seals. As we go further from the source of CO_2, the likelihood of such an event will diminish proportionally with the distance from the source. Considering that this is the greatest amount of CO_2 leakage in this worst-case scenario, if the event happens, the leak must pass upward through the confining zone, the secondary confining strata that consists of additional low permeability geologic units, and other geologic units, TND concludes that the risk of leakage through this pathway is highly improbable to nearly impossible.

5.5 Potential Leakage due to Lateral Migration

The characterization of the sand layers in the Cherry Canyon Formation described in Section 3.3 states that these sands were deposited by turbidites in channels in submarine fan complexes, each sand is encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity. Regional consideration of their depositional environment suggests a preferred orientation for fluid and gas flow would be south-to-north along the channel axis. However, locally the high net porosity of the RH AGI #1 and #3 injection zones indicates adequate storage capacity such that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA due to a preferred regional depositional orientation.

Lateral migration of the injected TAG was addressed in detail in Section 3.3. Therein it states that the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales as well as being encased by them.

Based on the discussion of the channeled sands in the injection zone, TND considers that the likelihood of CO_2 to migrate laterally along the channel axes is possible. However, that the turbidite sands are encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity and that the injectate is projected to be contained within the injection zone close to the injection wells minimizes the likelihood that CO_2 will migrate to a potential conduit to the surface.

5.6 Potential Leakage through Fractures and Faults

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology as well as identify and understand the distribution of faults and fractures. **Figure 5.6-1** shows the fault traces in the vicinity of the Red Hill plant. The faults shown on **Figure 5.6-1** are confined to the Paleozoic section below the injection zone for the RH AGI wells. No faults were identified in the confining zone above the Bell Canyon and Cherry Canyon injection zone for the RH AGI wells.

No faults were identified within the MMA which could potentially serve as conduits for surface CO_2 emission. The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief. Because this fault is confined to the lower Paleozoic unit well below the injection zone for the RH AGI wells, there is minimal chance it would be a potential leakage pathway. This inference is supported by the NRAP simulation result. The CO_2 leakage rate through the aforementioned fault is zero, which is understandable. Therefore, TND concludes that the risk of leakage through this pathway is highly improbable.

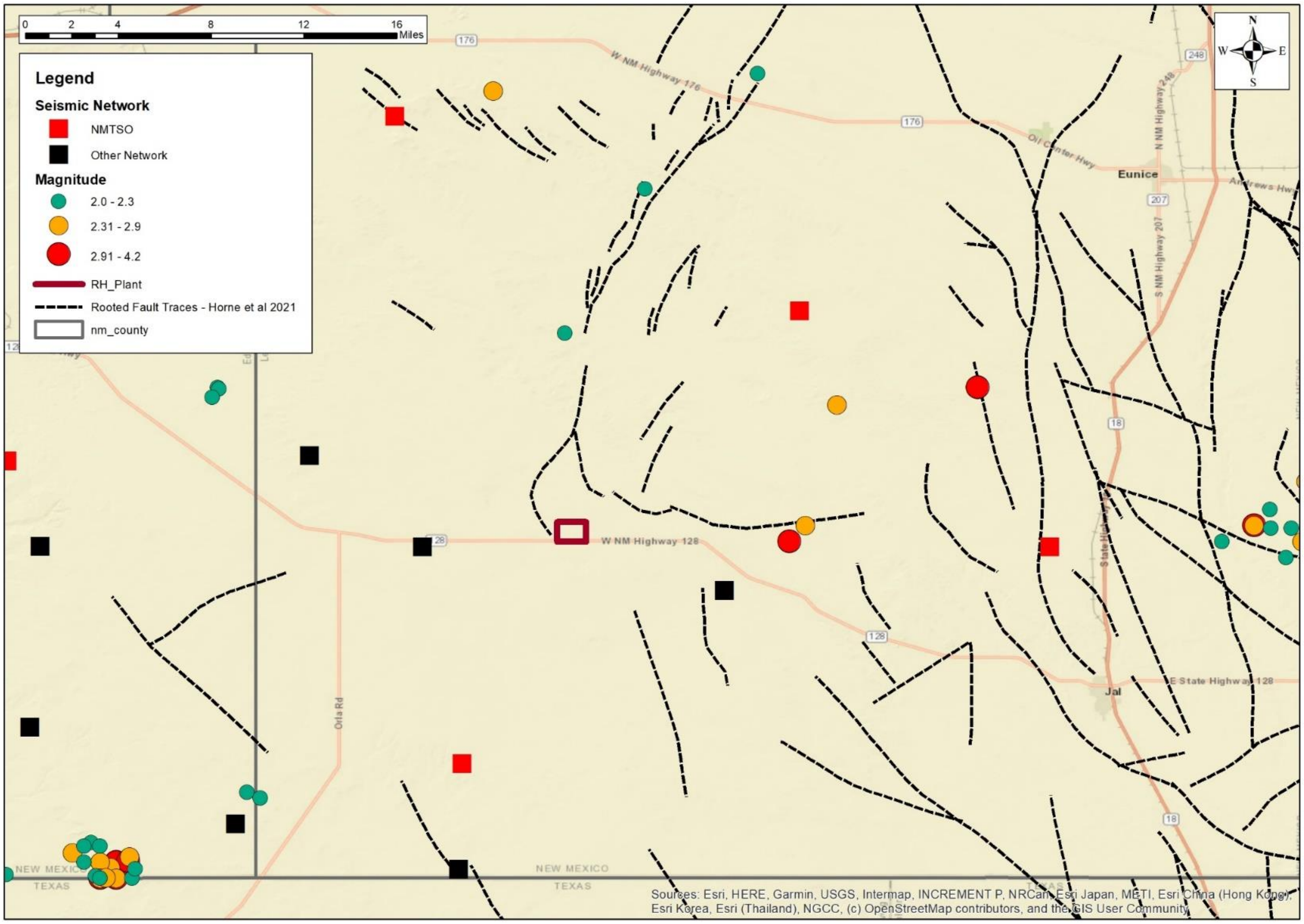


***Figure 5.6-1**: New Mexico Tech Seismological Observatory (NMTSO) seismic network close to the operations, recent seismic events, and fault traces (2022-2023). Note: Fault traces are from Horne et al 2021 for faults in the Paleozoic.*

5.7 Potential Leakage due to Natural / Induced Seismicity

The New Mexico Tech Seismological Observatory (NMTSO) monitors seismic activity in the state of New Mexico. A search of the database shows no recent seismic events close to the Red Hills operations. The closest recent, as of 4 September 2023, seismic events are:

- 7.5 miles, 2022-09-03, Magnitude 3
- 8 miles, 2022-09-02, Magnitude 2.23
- 8.6 miles, 2022-10-29, Magnitude 2.1

Figure 5.6-1 shows the seismic stations and recent seismic events in the area around the Red Hills site.

Due to the distance between the Red Hills AGI wells and the recent seismic events, the magnitude of these events, and the fact that TND injects at pressures below fracture opening pressure, TND considers the likelihood of CO_2 emissions to the surface caused by seismicity to be improbable.

Monitoring of seismic events in the vicinity of the Red Hills AGI wells is discussed in Section 6.7.

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

Subpart RR at 40 CFR 448(a)(3) requires a strategy for detecting and quantifying surface leakage of CO_2. TND will employ the following strategy for detecting, verifying, and quantifying CO_2 leakage to the surface through the potential pathways for CO_2 surface leakage identified in Section 5. TND considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to detect, verify, and quantify CO_2 surface leakage. **Table 6-1** summarizes the leakage monitoring of the identified leakage pathways. Monitoring will occur for the duration of injection and the 5-year post-injection period.

Table 6-1: Summary of Leak Detection Monitoring

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	● Distributed control system (DCS) surveillance of plant operations ● Visual inspections ● Inline inspections ● Fixed in-field gas monitors/CO_2 flux monitoring network ● Personal and hand-held gas monitors
Drilling of new RH AGI #3 well	● Vigilant monitoring of fluid returns during drilling ● Multiple gas monitoring points around drilling operations – personal and hand-held gas monitors
Existing RH AGI Well	● DCS surveillance of well operating parameters ● Visual inspections ● Mechanical integrity tests (MIT) ● Fixed in-field gas monitors/CO_2 flux monitoring network ● Personal and hand-held gas monitors ● In-well P/T sensors ● Groundwater monitoring
Fractures and Faults	● DCS surveillance of well operating parameters ● Fixed in-field gas monitors/CO_2 flux monitoring network ● Groundwater monitoring
Confining Zone / Seal	● DCS surveillance of well operating parameters ● Fixed in-field gas monitors/CO_2 flux monitoring network ● Groundwater monitoring
Natural / Induced Seismicity	● DCS surveillance of well operating parameters ● Seismic monitoring

Lateral Migration	● DCS surveillance of well operating parameters ● Fixed in-field gas monitors/CO_2 flux monitoring network ● Groundwater monitoring
Additional Monitoring	● Groundwater monitoring ● Soil flux monitoring

6.1 Leakage from Surface Equipment

TND implements several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S sensors, and continual monitoring of operational parameters.

Leaks from surface equipment are detected by TND field personnel, wearing personal H_2S monitors, following daily and weekly inspection protocols which include reporting and responding to any detected leakage events. TND also maintains in-field gas monitors to detect H_2S and CO_2. The in-field gas monitors are connected to the DCS housed in the onsite control room. If one of the gas detectors sets off an alarm, it would trigger an immediate response to address and characterize the situation.

The following description of the gas detection equipment at the Red Hills Gas Processing Plant was extracted from the H_2S Contingency Plan:

> "**Fixed Monitors**
> The Red Hills Plant has numerous ambient hydrogen sulfide detectors placed strategically throughout the Plant to detect possible leaks. Upon detection of hydrogen sulfide at 10 ppm at any detector, visible beacons are activated, and an alarm is sounded. Upon detection of hydrogen sulfide at 90 ppm at any detector, an evacuation alarm is sounded throughout the Plant at which time all personnel will proceed immediately to a designated evacuation area. The Plant utilizes fixed-point monitors to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the Distributed Control System (DCS). The monitors are equipped with amber beacons. The beacon is activated at 10 ppm. The plant and AGI well horns are activated with a continuous warbling alarm at 10 ppm and a siren at 90 ppm. All monitoring equipment is Red Line brand. The Control Panel is a 24 Channel Monitor Box, and the fixed point H_2S Sensor Heads are model number RL-101.
>
> The Plant will be able to monitor concentrations of H_2S via H_2S Analyzers in the following locations:
> - Inlet gas of the combined stream from Winkler and Limestone
> - Inlet sour liquid downstream of the slug catcher
> - Outlet Sweet Gas to Red Hills 1
> - Outlet Sweet Liquid to Red Hills Condensate Surge
>
> The AGI system monitors can also be viewed on the PLC displays located at the Plant. These sensors are all shown on the plot plan (see **Figure 5.1-1**). This requires immediate action for any occurrence or malfunction. All H_2S sensors are calibrated monthly.

Personal and Handheld H_2S Monitors

All personnel working at the Plant wear personal H_2S monitors. The personal monitors are set to alarm and vibrate at 10 ppm. Handheld gas detection monitors are available at strategic locations around the Plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and carbon dioxide (CO_2)."

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones as described in Section 5.2.1 for RH AGI #3 including more frequent monitoring during drilling operations (see **Table 6-1**). This applies to TND and other operators drilling new wells through the RH AGI injection zone within the MMA.

6.3 Leakage from Existing Wells

6.3.1 RH AGI Wells

As part of ongoing operations, TND continuously monitors and collects flow, pressure, temperature, and gas composition data in the data collection system. These data are monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits.

To monitor leakage and wellbore integrity, two pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) were deployed in TND's RH AGI #1 well. One gauge is designated to monitor the tubing ID (reservoir) pressure and temperature and the second gauge monitors the annular space between the tubing and the long string casing (**Figure 6.2-1**). A leak is indicated when both gauges start reading the same pressure. DTS is clamped to the tubing, and it monitors the temperature profiles of the annulus from 6,159 ft to surface. DTS can detect variation in the temperature profile events throughout the tubing and or casing. Temperature variation could be an indicator of leaks. Data from temperature and pressure gauges is recorded by an interrogator housed in an onsite control room. DTS (temperature) data is recorded by a separate interrogator that is also housed in the onsite control room. Data from both interrogators are transmitted to a remote location for daily real time or historical analysis.

If operational parameter monitoring and MIT failures indicate a CO_2 leak has occurred, TND will take actions to quantify the leak based on operating conditions at the time of the detection including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site.

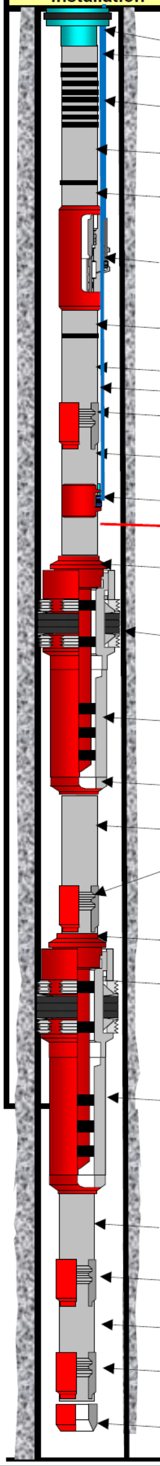
HALLIBURTON

Installation

Lucid

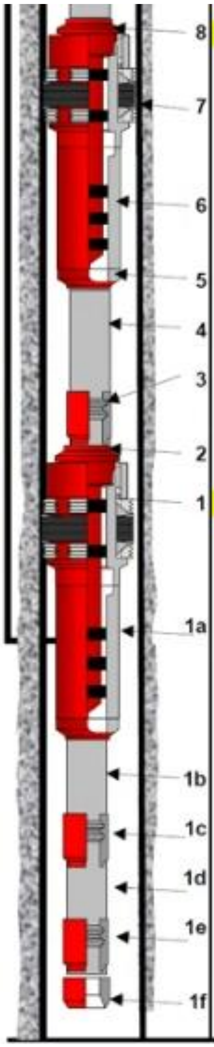
Red Hills AGI 1
Lea County New Mexico
2/3/21 - 2/28/21

WSP - Troy Gillen / Michael Forrier
Sales Rep - Lynn Talley (432) 631-4626
Tool Specialists: Carey Lehmann, Jonathan Phillips, Jose Vargas



Installation	Depth	Length	Jts.	Description	OD	ID
	18.50	18.50		KB		
20	22.90	4.40		20) Hanger Sub 3 1/2" 9.2# CRA VAMTOP x 7.7# VAM Ace Pin	7.000	3.000
19	64.05	41.15	1	19) 3 1/2" 7.7# VAM ACE 125K G3 Tubing (Slick Joint)	3.500	3.035
				Ran Eight Subs 8', 8', 6', 6',4', 4', 2', 2'		
18	103.97	39.92		18) 3 1/2" 7.7# VAM ACE 125K G3 Spaceout Subs	3.500	3.035
17	235.95	131.98	3	17) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.035
16	241.95	6.00		16) 6' x 3 1/2" 7.7# CRA VAM ACE Box x 9.2# VAMTOP Pin	3.540	2.959
15	246.30	4.35		15) 3 1/2" NE HES SSSV Nickel Alloy 925 w/Alloy 825 Control Line 3 1/2" 9.2# VAMTOP Box x Pin	5.300	2.813
14	252.29	5.99		14) 6' x 3 1/2" 9.2# CRA VAMTOP Box x 7.7# VAM ACE Pin	3.540	2.959
13	6,140.23	5,887.94	134	13) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.305
12				12) 3 1/2" 7.7# VAM ACE Box x 9.2# VAMTOP Pin CRA Crossover	3.830	2.959
11				11) 2.813" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925	4.073	2.813
10	6,153.72	13.49		10) 6' x 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy G3 Sub	3.540	2.959
				13.49' Length Includes Line Items 10, 11 & 12		
9	6,159 Tubing	P/T		9) Baker PT Sensor Mandrel 3 1/2" 9.2# VAMTOP Box x Pin 6' VAMTOP 9.2# CRA Tubing Sub Above & Below Gauge Mdl	5.200	2.992
	6,162.6 Annular	P/T				
8	6,161.23	7.51		8) 4.00" BWS Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925	4.470	2.959
				7.51' Length Includes Line Items 8 & 9		
7	6,164.55	3.32		7) 7" 26-32# x 4.00" BWS Packer Nickel Alloy 925 Casing Collar @ 6,160.6' WL Measurement	5.875	4.000
6	6,172.05	7.5		6) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
5	6,172.88	0.83		5) 4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
4	6,181.19	8.31		4) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
3	6,182.52	1.33		3) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925 #102204262	4.073	2.562
2	6,184.29	1.77		2) Straight Slot Locator Seal Assembly Above Top Of Packer	4.450	2.880
1		6,186.06		1) BWD Permanent Packer. WL Measured Depth Previously 6189'	5.875	4.000
1a				1a) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.660	2.965
1b				1b) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1c				1c) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel,	2.920	2.562
1d				1d) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1e				1e) 2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	3.920	2.321
1f				1f) Re-Entry Guide / POP	3.950	3.000

Figure 6.2-1: Well Schematic for RH AGI #1 showing installation of P/T sensors



8	6,161.23	7.51		8) 4.00" BWS Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925 7.51' Length Includes Line Items 8 & 9	4.470	2.959
7	6,164.55	3.32		7) 7" 26-32# x 4.00" BWS Packer Nickel Alloy 925 Casing Collar @ 6,160.6' WL Measurement	5.875	4.000
6	6,172.05	7.5		6) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
5	6,172.88	0.83		5) 4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
4	6,181.19	8.31		4) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
3	6,182.52	1.33		3) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925 #102204262	4.073	2.562
2	6,184.29	1.77		2) Straight Slot Locator Seal Assembly Above Top Of Packer	4.450	2.880
1		6,186.06		1) BWD Permanent Packer. WL Measured Depth Previously 6189'	5.875	4.000
1a				1a) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.660	2.965
1b				1b) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1c				1c) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel,	2.920	2.562
1d				1d) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1e				1e) 2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	3.920	2.321
1f				1f) Re-Entry Guide / POP	3.950	3.000

***Figure 6.2-2**: Well Schematic for RH AGI #3 showing intended installation of P/T sensors*

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7.3 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. Additionally, groundwater and soil CO_2 flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through the Confining / Seal System

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the RH AGI wells, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If changes in operating parameters or other monitoring listed in **Table 6-1** indicate leakage of CO_2 through the confining / seal system, TND will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, including shutting in the well(s) (see Section 6.8).

6.5 Leakage due to Lateral Migration

Continuous operational monitoring of the RH AGI wells during and after the period of the injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The CO_2 monitoring network described in Section 7.3, and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If monitoring of operational parameters or other monitoring methods listed in Table 6-1 indicates that the CO_2 plume extends beyond the area modeled in Section 3.8 and presented in Section 4, TND will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 release to the surface. As this scenario would be considered a material change per 40CFR98.448(d)(1), TND will submit a revised MRV plan as required by 40CFR98.448(d). See Section 6.8 for additional information on quantification strategies.

6.6 Leakage from Fractures and Faults

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through faults. However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, TND will identify which of the pathways listed in this section are responsible for the leak, including the possibility of heretofore unidentified faults or fractures within the MMA. TND will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details. See Section 6.8 for additional information on quantification strategies.

6.7 Leakage due to Natural / Induced Seismicity

In order to monitor the influence of natural and/or induced seismicity, TND will use the established NMTSO seismic network. The network consists of seismic monitoring stations that detect and locate seismic events. Continuous monitoring helps differentiate between natural and induced seismicity. The network surrounding the Red Hills Gas Processing Plant has been mapped on **Figure 5.6-1**. The monitoring network records Helicorder data from UTC (coordinated universal time) all day long. The data are plotted daily at 5pm MST (mountain standard time). These plots can be browsed either by station or by day. The data are streamed continuously to the New Mexico Tech campus and archived at the Incorporated Research Institutions for Seismology Data Management Center (IRIS DMC).

If monitoring of the NMTSO seismic monitoring stations, the operational parameters and the fixed infield gas monitors indicates surface leakage of CO_2 linked to seismic events, TND will assess whether the CO_2 originated from the RH AGI wells and, if so, take measures to quantify the mass of CO_2 emitted to the surface based on operational conditions at the time the leak was detected. See Section 7.6 for details regarding seismic monitoring and analysis. See Section 6.8 for additional information on quantification strategies.

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

For normal operations, quantification of emissions of CO_2 from surface equipment will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR. Quantification of major leakage events from surface equipment as identified by the detection techniques listed in Table 6-1 will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified the leakage location will be isolated to prevent additional emissions to

the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. TND has standard operating procedures to report and quantify all pipeline leaks in accordance with the NMOCD regulations (New Mexico administrative Code 19.15.28 Natural Gas Gathering Systems). TND will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by TND or third parties. Additionally, TND may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

6.8.2 Subsurface Leakage

Selection of a quantification strategy for leaks that occur in the subsurface will be based on the leak detection method (Table 6-1) that identifies the leak. Leaks associated with the point sources, such as the injection wells, and identified by failed MITs, variations of operational parameters outside acceptable ranges, and in-well P/T sensors can be addressed immediately after the injection well has been shut in. Quantification of the mass of CO_2 emitted during the leak will depend on characterization of the subsurface leak, operational conditions at the time of the leak, and knowledge of the geology and hydrogeology at the leakage site. Conservative estimates of the mass of CO_2 emitted to the surface will be made assuming that all CO_2 released during the leak will reach the surface. TND may choose to estimate the emissions to the surface more accurately by employing transport, geochemical, or reactive transport model simulations.

Other wells within the MMA will be monitored with the atmospheric and CO_2 flux monitoring network placed strategically in their vicinity.

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, or which may be initiated by seismic events and as may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO_2 leaking back to the surface emphasizing the importance of monitoring network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO_2 flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 6.8.1, or from the subsurface. In the latter case, CO_2 flux monitoring methodologies, as described in Section 7.8, will be employed to quantify the surface leaks.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

TND uses the existing automatic distributed control system to continuously monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO_2. TND considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to establish baselines for monitoring CO_2 surface leakage. The following describes TND's strategy for collecting baseline information.

7.1 Visual Inspection

TND field personnel conduct frequent periodic inspections of all surface equipment providing opportunities to assess baseline concentrations of H_2S, a proxy for CO_2, at the Red Hills Gas Plant.

7.2 Fixed In-Field, Handheld, and Personal H_2S Monitors

Compositional analysis of TND's gas injectate at the Red Hills Gas Plant indicates an approximate H_2S concentration of 20% thus requiring TND to develop and maintain an H_2S Contingency Plan (Plan) according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). TND considers H_2S to be a proxy for CO_2 leaks at the plant. The Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated RH AGI Wells and documents procedures that would be followed in case of such an event.

7.2.1 Fixed In-Field H_2S Monitors

The Red Hills Gas Plant utilizes numerous fixed-point monitors, strategically located throughout the plant, to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the DCS. Upon detection of H_2S at 10 ppm at any detector, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of hydrogen sulfide at 90 ppm at any monitor, an evacuation alarm is sounded throughout the plant at which time all personnel will proceed immediately to a designated evacuation area.

7.2.2 Handheld and Personal H_2S Monitors

Handheld gas detection monitors are available at strategic locations around the plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and CO_2.

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the plant must wear personal H_2S monitoring devices to assist them in detecting the presence of unsafe levels of H_2S. Personal monitoring devices will give an audible alarm and vibrate at 10 ppm.

7.3 CO_2 Detection

In addition to the handheld gas detection monitors described above, New Mexico Tech, through a DOE research grant (DE-FE0031837 – Carbon Utilization and Storage Project of the Western USA (CUSP)), will assist TND in setting up a monitoring network for CO_2 leakage detection in the AMA as defined in Section 4.2. The scope of work for the DOE project includes field sampling activities to monitor CO_2/H_2S at the two RH AGI wells. These activities include periodic well (groundwater and gas) and atmospheric sampling from an area of 10 – 15 square miles around the injection wells. Once the network is set up, TND will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

7.4 Continuous Parameter Monitoring

The DCS of the plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS, and engineering and operations are alerted if a parameter is outside the allowable window. If a parameter is outside the allowable window, this will trigger further investigation to determine if the issue poses a leak threat. Also, see Section 6.2 for continuous monitoring of P/T in the well.

7.5 Well Surveillance

TND adheres to the requirements of NMOCC Rule 26 governing the construction, operation and closing of an injection well under the Oil and Gas Act. Rule 26 also includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, NMOCC includes special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. TND's Routine Operations and Maintenance Procedures for the RH AGI wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic (Microseismic) Monitoring Stations

TND has Installed a model TCH120-1 Trillium Compact Horizon Seismometer and a model CTR4-3S Centaur Digital Recorder to monitor for and record data for any seismic event at the Red Hills Gas Plant (see **Figure 7-1)**. The seismic station meets the requirements of the NMOCC Order No. R-20916-H to "install, operate, and monitor for the life of the [Class II AGI] permit a seismic monitoring station or stations as directed by the Manager of the New Mexico Tech Seismological Observatory ("state seismologist") at the New Mexico Bureau of Geology and Mineral Resources."

In addition, data that is recorded by the State of New Mexico deployed seismic network within a 10-mile radius of the Red Hills Gas Plant will be analyzed by the New Mexico Bureau of Geology (NMBGMR), see **Figure 5.6-1**, and made publicly available. The NMBGMR seismologist will create a report and map showing the magnitudes of recorded events from seismic activity. The data is being continuously recorded. By examining historical data, a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

7.7 Groundwater Monitoring

New Mexico Tech, through the same DOE research grant described in Section 7.3 above, will monitor groundwater wells for CO_2 leakage which are located within the AMA as defined in Section 4.2. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 7.7-1**. Baseline analyses will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Red Hills Gas Plant. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

***Table 7.7-1**: Groundwater Monitoring Parameters*

Parameters
pH
Alkalinity as HCO3- (mg/L)
Chloride (mg/L)
Fluoride (F-) (mg/L)
Bromide (mg/L)
Nitrate (NO3-) (mg/L)
Phosphate (mg/L)
Sulfate (SO42-) (mg/L)
Lithium (Li) (mg/L)
Sodium (Na) (mg/L)
Potassium (K) (mg/L)
Magnesium (Mg) (mg/L)
Calcium (Ca) (mg/L)
TDS Calculation (mg/L)
Total cations (meq/L)

Total anions (meq/L)
Percent difference (%)
ORP (mV)
IC (ppm)
NPOC (ppm)

7.8 Soil CO_2 Flux Monitoring

A vital part of the monitoring program is to identify potential leakage of CO_2 and/or brine from the injection horizon into the overlying formations and to the surface. One method that will be deployed is to gather and analyze soil CO_2 flux data which serves as a means for assessing potential migration of CO_2 through the soil and its escape to the atmosphere. By taking CO_2 soil flux measurements at periodic intervals, TND can continuously characterize the interaction between the subsurface and surface to understand potential leakage pathways. Actionable recommendations can be made based on the collected data.

Soil CO_2 flux will be collected on a monthly basis for 12 months to establish the baseline and understand seasonal and other variation at the Red Hills Gas Plant. After the baseline is established, data will be collected bi-monthly for one year and then quarterly.

Soil CO_2 flux measurements will be taken using a LI-COR LI-8100A flux chamber, or similar instrument, at pre planned locations at the site. PVC soil collars (8cm diameter) will be installed in accordance with the LI-8100A specifications. Measurements will be subsequently made by placing the LI-8100A chamber on the soil collars and using the integrated iOS app to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. The soil collars will be left in place such that each subsequent measurement campaign will use the same locations and collars during data collection.

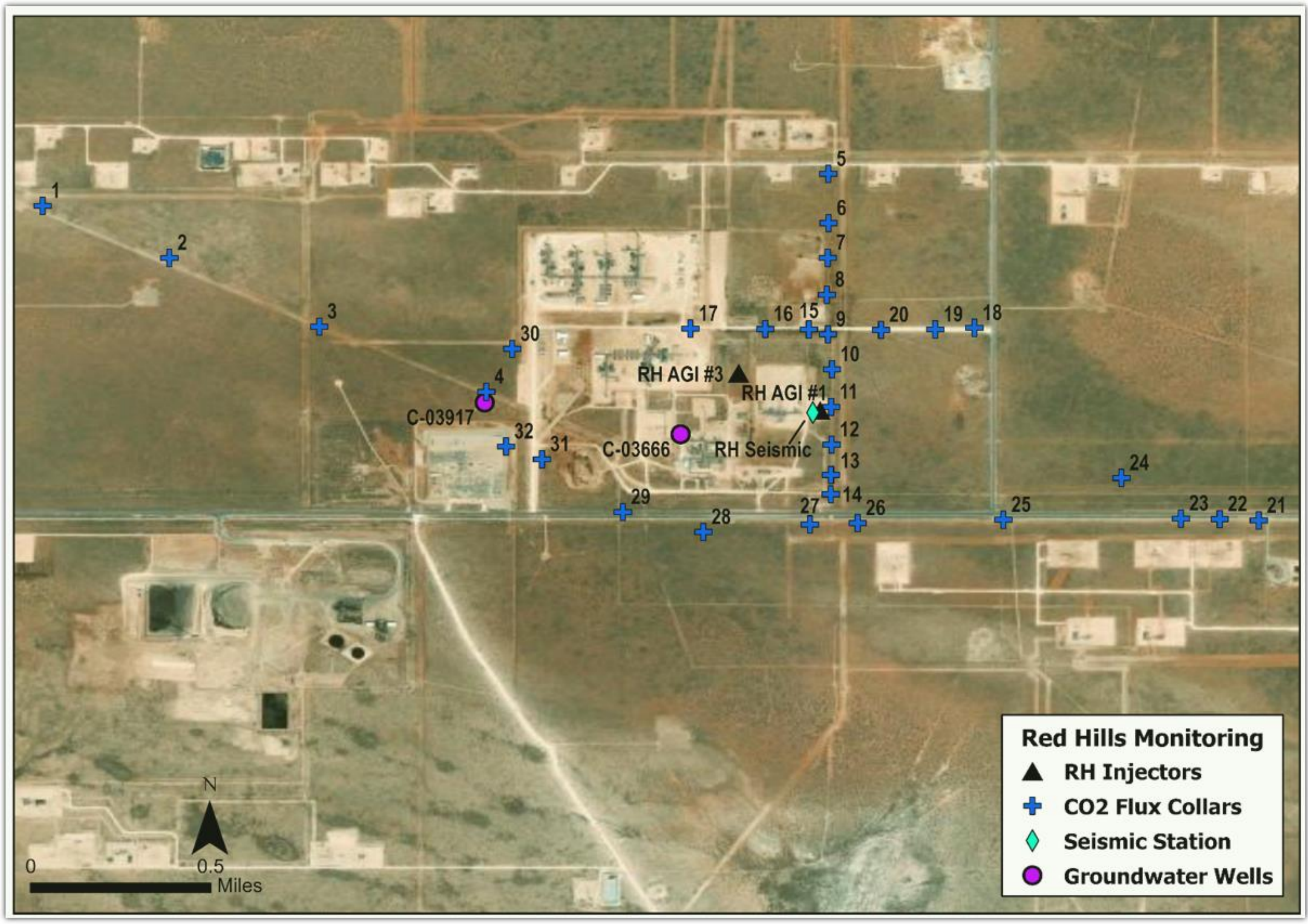


Figure 7-1: *Red Hills monitoring network of 32 CO_2 flux locations, 2 groundwater wells, and a seismic station developed by New Mexico Tech and Targa Resources to detect leakage during injection.*

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve Subpart RR equations used to calculate the mass of CO_2 sequestered annually. **Appendix 8** includes the twelve equations from Subpart RR. Not all of these equations apply to TND's current operations at the Red Hills Gas Plant but are included in the event TND's operations change in such a way that their use is required.

Figure 3.6.1-2 shows the location of all surface equipment and points of venting listed in 40CFR98.232(d) of Subpart W that will be used in the calculations listed below.

8.1 CO_2 Received

Currently, TND receives gas to its Red Hills Gas Plant through six pipelines: Gut Line, Winkler Discharge, Red Hills 24" Inlet Loop, Greyhound Discharge, Limestone Discharge, and the Plantview Loop. The gas is processed as described in Section 3.8 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection. TND will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3. Receiving flow meter r in the following equations corresponds to meters M1 and M2 in **Figure 3.6.1-2**.

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}}$$ (Equation RR-2 for Pipelines)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving volumetric flow meter.

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r}$$ (Equation RR-3 for Pipelines)

where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2,T.r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 or RR-2 for flow meter r.

r = Receiving flow meter.

Although TND does not currently receive CO_2 in containers for injection, they wish to include the flexibility in this MRV plan to receive gas from containers. When TND begins to receive CO_2 in containers, TND will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. TND will adhere to the requirements in 40CFR98.444(a)(2) for determining the quarterly mass or volume of CO_2 received in containers.

If CO_2 received in containers results in a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

TND injects CO_2 into the existing RH AGI #1. Upon completion, TND will commence injection into RH AGI #3. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into both wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Volumetric flow meter u in the following equations corresponds to meters M5 and M6 in **Figure 3.6.1-2**.

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$ (Equation RR-5)

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_2,p,u}$ = 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 = Volumetric flow meter.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \quad \text{(Equation RR-6)}$$

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) though all injection wells.

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as calculated in Equation RR-4 or RR-5 for flow meter u.

u = Flow meter.

8.3 CO_2 Produced / Recycled

TND does not produce oil or gas or any other liquid at its Red Hills Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.6 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6.8.

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \quad \text{(Equation RR-10)}$$

where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

As required by 98.444(d) of Subpart RR, TND will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases. Parameter CO_{2FI} in Equation RR-12 is the total annual CO_2 mass emitted or vented from equipment located between the flow meter for measuring injection quantity and the injection wellhead. A calculation procedure is provided in subpart W.

8.6 CO_2 Sequestered

Since TND does not actively produce oil or natural gas or any other fluid at its Red Hills Gas Plant, Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations.

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad \text{(Equation RR-12)}$$

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of the GHGRP.

9 Estimated Schedule for Implementation of MRV Plan

The baseline monitoring and leakage detection and quantification strategies described herein have been established and data collected by TND and its predecessor, Lucid, for several years and continues to the present. TND will begin implementing this revised MRV plan as soon as it is approved by EPA. After RH AGI #3 is drilled, TND will reevaluate the MRV plan and if any modifications are a material change per 40CFR98.448(d)(1), TND will submit a revised MRV plan as required by 40CFR98.448(d).

10 GHG Monitoring and Quality Assurance Program

TND will meet the monitoring and QA/QC requirements of 40CFR98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 40CFR98.444(d).

10.1 GHG Monitoring

As required by 40CFR98.3(g)(5)(i), TND's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

Measurement of CO_2 Concentration – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GPA) standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40CFR98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2 and RR-5, of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. TND will adhere to the American Gas Association (AGA) Report #3 – Orifice Metering.

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.3 CO_2 injected.

Daily CO_2 injected is recorded by totalizers on the volumetric flow meters on the pipelines to the RH AGI #1 and #3 wells using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.4 CO_2 produced.

TND does not produce CO_2 at the Red Hills Gas Plant.

10.1.5 CO_2 emissions from equipment leaks and vented emissions of CO_2.

As required by 98.444(d), TND will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

As required by 98.444(d) of Subpart RR, TND will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used.

10.1.6 Measurement devices.

As required by 40CFR98.444(e), TND will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40CFR98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.2 QA/QC Procedures

TND will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

10.3 Estimating Missing Data

TND will estimate any missing data according to the following procedures in 40CFR98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in Subpart RR, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

10.4 Revisions of the MRV Plan

TND will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of New Mexico. If any operational changes constitute a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change. TND intends to update the MRV plan after RH AGI #3 has been drilled and characterized.

11 Records Retention

TND will meet the recordkeeping requirements of paragraph 40CFR98.3(g) of Subpart A of the GHGRP. As required by 40CFR98.3(g) and 40CFR98.447, TND will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:

(i) The GHG emissions calculations and methods used

(ii) Analytical results for the development of site-specific emissions factors, if applicable

(iii) The results of all required analyses

(iv) Any facility operating data or process information used for the GHG emission calculations

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, TND will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) A copy of the most recent revision of this MRV Plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(9) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(10) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(12) Any other records as specified for retention in this EPA-approved MRV plan.

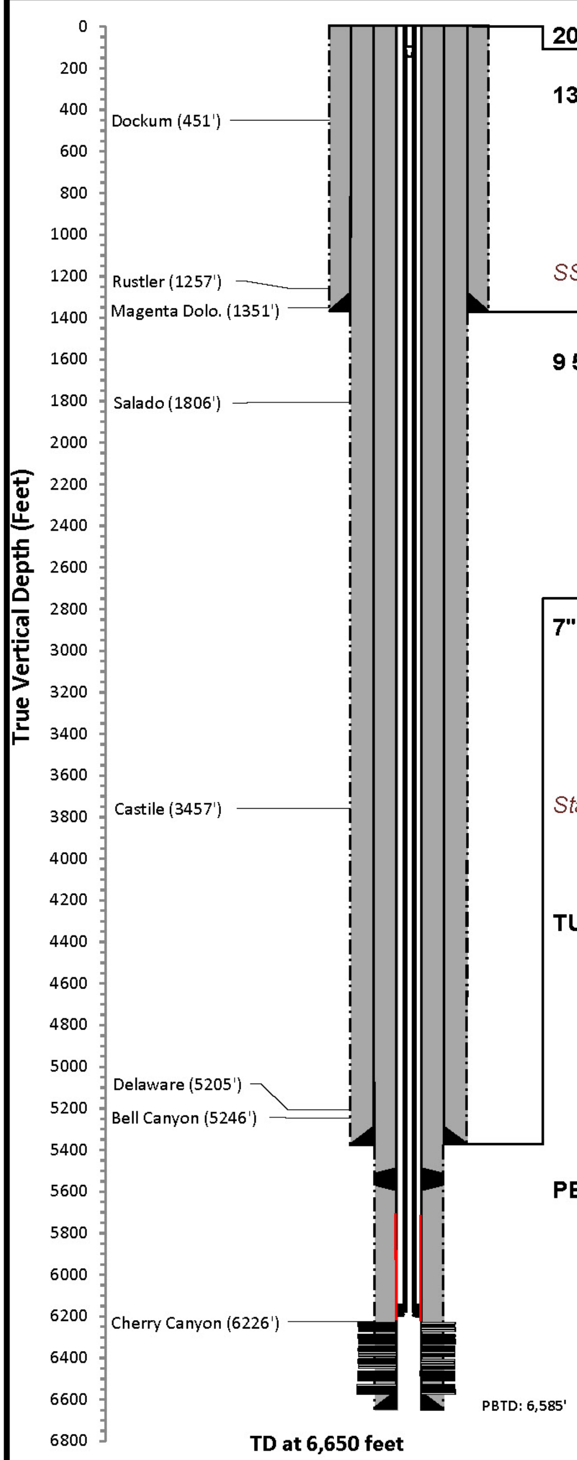
12 Appendices

Appendix 1 TND Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Red Hills AGI #1	30-025-40448	1,600 ft FSL, 150 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	10/23/2013	6,650 ft	6,170 ft
Red Hill AGI #3	30-025-51970	3,116 ft FNL, 1,159 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	9/13/2023	6,650 ft	5,700 ft

Lucid Energy Red Hills AGI #1 Well Schematic

Well Name:	Red Hills AGI #1	**Footage**	1600' FSL & 150' FEL
API:	30-025-40448	**Well Type**	AGI Exploratory Cherry Canyon
STR:	Sec. I-13, T24S-R33E	**KB/GL:**	3596/3580
County, St.	Lea County, New Mexico	**Lat, Long:**	32.214586, -103.517520



20" CONDUCTOR PIPE to 40 ft.

13 3/8" SURFACE CASING to 1,372 ft. **17.5" OH**

13 3/8", 48 #/ft., H-40, STC
Cmnt to surface - 90 bbls returned
Lead Cmnt: 820 sx C Lite
Tail Cmnt: 180 sx Class C

SSSV @ 250'

9 5/8" INTERMEDIATE CASING to 5,346 ft. **12.25" OH**

9 5/8", 40 #/ft., J-55, LT&C 0-100'
9 5/8", 36 #/ft., J-55, LT&C 100-3,300'
9 5/8", 40 #/ft., J-55, LT&C 3,300'-4,200'
9 5/8", 40 #/ft., HCK-55, LT&C 4,200'-5,346'
Cmnt to surface - 60 bbls returned
Lead Cmnt: 1,280 sx C Lite
Tail Cmnt: 180 sx Class C

7" PRODUCTION CASING to 6,650 ft. **8.75" OH**

7" 26 #/ft., L80, LT&C from 0'-5,702'
w/ 7" G-3, 26 #/ft. VAMTOP, from 5,702'-6,239'
7" 26 #/ft., L80, LT&C from 6,239' - 6,650'
Cmnt to surface both stages - 1.5 bbls
Stage 1 - Lead: 250 sx EverCrete
StageTool in 7-in casing @ 5,539'
Stage 2 - Lead: 490 sx C Lite
Stage 2 - Tail: 100 sx Class C

TUBING AND EQUIPMENT

Halliburton Retrievable SSSV set @ 250 ft.
3.5", 9.3 #/ft, L80, VAMTOP from 0'-5,870'
3.5",SM2550, VAMTOP from 5,870'-6,167'
Bottom Hole P/T Gauge set above packer @ 6,167'-6,170'
Permanent Production-Packer set @ 6,170'
Check Valve and Choke (optional)
Annulus filled w/ diesel mixed with corrosion inhibitor/biocide

PERFORATIONS

Primary Target:
Upper Cherry Canyon (6 spf @ 60°)
6,230' - 6,250'
6,260' - 6,280'
6,295' - 6,335'
6,355' - 6,380'
6,400' - 6,415'
6,435' - 6,500'
6,525' - 6,583'

Prepared For: LUCID energy group

Prepared By: GEOLEX INCORPORATED

Schematic is properly scaled

Figure Appendix 1-1: *Schematic of TND RH AGI #1 Well*

Targa Resources
Red Hills Delaware AGI #3
Location 3116' FNL & 1159' FEL
Sec 13 - T 24S - R 33E
GL 3578', RKB TBD

Surface - (Conventional)

Hole Size:	17.5"
Casing:	13.375" 72# L-80 VAM TOP
Depth Top:	Surface
Depth Btm:	1307'
Cement:	TBD sks - Class C + Additives
Cement Top:	Surface - (Circulate)

Intermediate #1 - (Conventional)

Hole Size:	12.25"
Casing:	9.625" 47# HCL-80 BTC
Depth Top:	Surface
Depth Btm:	5205'
Cement:	TBD - Class C + Additives
Cement Top:	Surface - (Circulate)

Production - (Conventional)

Hole Size:	8.5"
Casing 1:	7" 32# I-80 VAMSTL
Depths:	0' to 5280' & 5580' to 7600'
Casing 2:	7" 32# G3 CRA VAM HDL
Depths:	5280' to 5580'
Cement:	TBD - Class C + Additives, Well Lock resin 5280'-5580'
Cement Top:	Surface - (Circulate)
ECP/DV Tool:	5280' & 5580'

Tubing

Depth:	5700'
Tubing:	3.5" 7.7# G3 CRA VAM ACE
Packer:	7" x 3.5" PermaPak or equivalent (Inconel)
SSSV:	175'
PT Gauges:	5690'

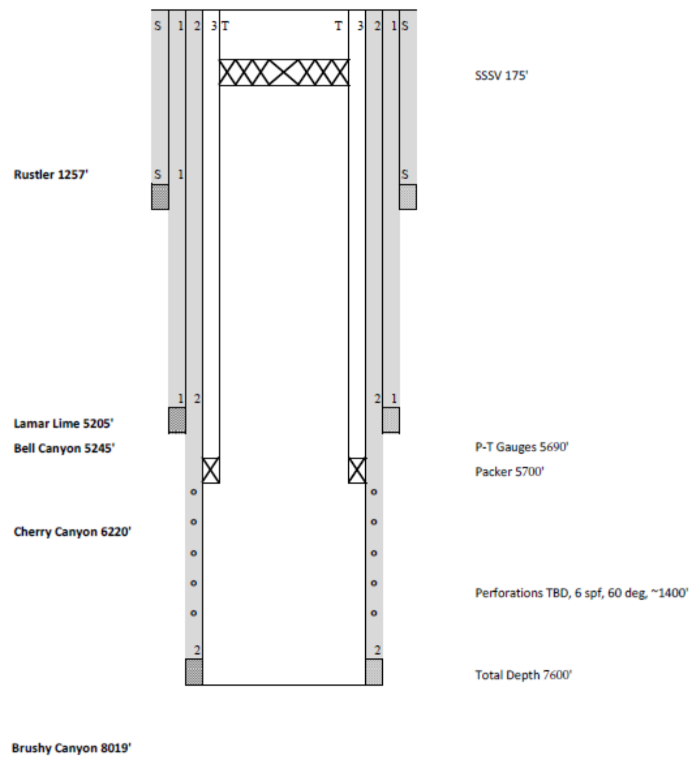


***Figure Appendix 1-2**: Proposed wellbore schematic for the TND RH AGI #3 Well*

Appendix 2 Referenced Regulations

U.S. Code > Title 26. INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1. NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits > Section 45Q - Credit for carbon oxide sequestration

New Mexico Administrative Code (NMAC) > Title 19 – Natural resources > Chapter 15 – Oil and Gas

CHAPTER 15 - OIL AND GAS

19.15.1 NMAC	GENERAL PROVISIONS AND DEFINITIONS [REPEALED]
19.15.2 NMAC	GENERAL PROVISIONS FOR OIL AND GAS OPERATIONS
19.15.3 NMAC	RULEMAKING
19.15.4 NMAC	ADJUDICATION
19.15.5 NMAC	ENFORCEMENT AND COMPLIANCE
19.15.6 NMAC	TAX INCENTIVES
19.15.7 NMAC	FORMS AND REPORTS
19.15.8 NMAC	FINANCIAL ASSURANCE
19.15.9 NMAC	WELL OPERATOR PROVISIONS
19.15.10 NMAC	SAFETY
19.15.11 NMAC	HYDROGEN SULFIDE GAS
19.15.12 NMAC	POOLS
19.15.13 NMAC	COMPULSORY POOLING
19.15.14 NMAC	DRILLING PERMITS
19.15.15 NMAC	WELL SPACING AND LOCATION
19.15.16 NMAC	DRILLING AND PRODUCTION
19.15.17 NMAC	PITS, CLOSED-LOOP SYSTEMS, BELOW-GRADE TANKS AND SUMPS
19.15.18 NMAC	PRODUCTION OPERATING PRACTICES
19.15.19 NMAC	NATURAL GAS PRODUCTION OPERATING PRACTICE
19.15.20 NMAC	OIL PRORATION AND ALLOCATION
19.15.21 NMAC	GAS PRORATION AND ALLOCATION
19.15.22 NMAC	HARDSHIP GAS WELLS
19.15.23 NMAC	OFF LEASE TRANSPORT OF CRUDE OIL OR CONTAMINANTS
19.15.24 NMAC	ILLEGAL SALE AND RATABLE TAKE
19.15.25 NMAC	PLUGGING AND ABANDONMENT OF WELLS
19.15.26 NMAC	INJECTION
19.15.27 - 28 NMAC	[RESERVED] PARTS 27 - 28
19.15.29 NMAC	RELEASES

19.15.30 NMAC	REMEDIATION
19.15.31 - 33 NMAC	[RESERVED] PARTS 31 - 33
19.15.34 NMAC	PRODUCED WATER, DRILLING FLUIDS AND LIQUID OIL FIELD WASTE
19.15.35 NMAC	WASTE DISPOSAL
19.15.36 NMAC	SURFACE WASTE MANAGEMENT FACILITIES
19.15.37 NMAC	REFINING
19.15.38 NMAC	[RESERVED]
19.15.39 NMAC	SPECIAL RULES
19.15.40 NMAC	NEW MEXICO LIQUIFIED PETROLEUM GAS STANDARD
19.15.41 - 102 NMAC	[RESERVED] PARTS 41 - 102
19.15.103 NMAC	SPECIFICATIONS, TOLERANCES, AND OTHER TECHNICAL REQUIREMENTS FOR COMMERCIAL WEIGHING AND MEASURING DEVICES
19.15.104 NMAC	STANDARD SPECIFICATIONS/MODIFICATIONS FOR PETROLEUM PRODUCTS
19.15.105 NMAC	LABELING REQUIREMENTS FOR PETROLEUM PRODUCTS
19.15.106 NMAC	OCTANE POSTING REQUIREMENTS
19.15.107 NMAC	APPLYING ADMINISTRATIVE PENALTIES
19.15.108 NMAC	BONDING AND REGISTRATION OF SERVICE TECHNICIANS AND SERVICE ESTABLISHMENTS FOR COMMERCIAL WEIGHING OR MEASURING DEVICES
19.15.109 NMAC	NOT SEALED NOT LEGAL FOR TRADE
19.15.110 NMAC	BIODIESEL FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.111 NMAC	E85 FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.112 NMAC	RETAIL NATURAL GAS (CNG / LNG) REGULATIONS [REPEALED]

Appendix 3 Water Wells

Water wells identified by the New Mexico State Engineer's files within two miles of the RH AGI wells; water wells within one mile are highlighted in yellow.

POD Number	County	Sec	Tws	Rng	UTME	UTMN	Distance (mi)	Depth Well (ft)	Depth Water (ft)	Water Column (ft)
C 03666 POD1	LE	13	24S	33E	639132	3565078	0.31	650	390	260
C 03917 POD1	LE	13	24S	33E	638374	3565212	0.79	600	420	180
C 03601 POD1	LE	23	24S	33E	638124	3563937	1.17			
C 02309	LE	25	24S	33E	639638	3562994	1.29	60	30	30
C 03601 POD3	LE	24	24S	33E	638142	3563413	1.38			
C 03932 POD8	LE	7	24S	34E	641120	3566769	1.40	72		
C 03601 POD2	LE	23	24S	33E	637846	3563588	1.44			
C 03662 POD1	LE	23	24S	33E	637342	3564428	1.48	550	110	440
C 03601 POD5	LE	23	24S	33E	637988	3563334	1.48			
C 03601 POD6	LE	23	24S	33E	637834	3563338	1.55			
C 03601 POD7	LE	23	24S	33E	637946	3563170	1.58			
C 03600 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03602 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03600 POD1	LE	26	24S	33E	637275	3563023	1.94			
C 03600 POD3	LE	26	24S	33E	637784	3562340	2.05			

Appendix 4 Oil and Gas Wells within 2-mile Radius of the RH AGI Well Site

Note – a completion status of "New" indicates that an Application for Permit to Drill has been filed and approved but the well has not yet been completed. Likewise, a spud date of 31-Dec-99 is actually 12-31-9999, a date used by NMOCD databases to indicate work not yet reported.

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-08371	COSSATOT E 002	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	5425	Yes
30-025-25604	GOVERNMENT L COM 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	17625	No
30-025-26369	GOVERNMENT L COM 002	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	14698	Yes
30-025-26958	SIMS 001	BOPCO, L.P.	GAS	DELAWARE VERTICAL	P & A	VERTICAL	15007	Yes
30-025-27491	SMITH FEDERAL 001	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	15120	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-40448	RED HILLS AGI 001	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	INJECTING	VERTICAL	6650	Yes
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL		PRODUCING	VERTICAL	10997	No
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11034	No
30-025-41382	DECKARD FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11067	Yes
30-025-41383	DECKARD FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11162	Yes
30-025-41384	DECKARD FEDERAL COM 004H	COG OPERATING LLC	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11103	Yes
30-025-41666	SEBASTIAN FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10927	Yes
30-025-41687	SEBASTIAN FEDERAL COM 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10944	Yes
30-025-41688	SEBASTIAN FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11055	No
30-025-43532	LEO THORSNESS 13 24 33 211H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12371	No
30-025-44442	STRONG 14 24 33 AR 214H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12500	No
30-025-46154	LEO THORSNESS 13 24 33 221H	MATADOR PRODUCTION COMPANY	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12868	No
30-025-46282	LEO THORSNESS 13 24 33 AR 135H	MATADOR PRODUCTION COMPANY	OIL	3RD BONE SPRING SAND	PRODUCING	HORIZONTAL	12103	No

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-46517	BROADSIDE 13 W FEDERAL COM 001H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12213	No
30-025-46518	BROADSIDE 13 24 FEDERAL COM 002H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-46519	BROADSIDE 13 24 FEDERAL COM 003H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12320	Yes
30-025-46985	SEBASTIAN FEDERAL COM 703H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12123	No
30-025-46988	SEBASTIAN FEDERAL COM 704H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12142	No
30-025-47869	JUPITER 19 FEDERAL COM 501H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11175	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47874	JUPITER 19 FEDERAL COM 506H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10950	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47877	JUPITER 19 FEDERAL COM 509H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11156	No
30-025-47878	JUPITER 19 FEDERAL COM 510H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11102	No
30-025-47908	JUPITER 19 FEDERAL COM 601H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-47910	JUPITER 19 FEDERAL COM 702H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	DUC	HORIZONTAL	0	Yes
30-025-47911	JUPITER 19 FEDERAL COM 705H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12290	No
30-025-47912	JUPITER 19 FEDERAL COM 707H	EOG RESOURCES INC	OIL	WOLFCAMP B UPPER	PERMITTED	HORIZONTAL	12515	No
30-025-47913	JUPITER 19 FEDERAL COM 708H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12477	No
30-025-48239	JUPITER 19 FEDERAL COM 306H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10270	No
30-025-48889	JUPITER 19 FEDERAL COM 701H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-48890	JUPITER 19 FEDERAL COM 703H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-49262	BROADSIDE 13 24 FEDERAL COM 004H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12531	Yes
30-025-49263	BROADSIDE 13 24 FEDERAL COM 015H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B LOWER	PRODUCING	HORIZONTAL	12746	Yes
30-025-49264	BROADSIDE 13 24 FEDERAL COM 025H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11210	Yes
30-025-49474	RED HILLS AGI 002	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	Temporarily Abandoned	VERTICAL	17600	Yes

Appendix 5 References

Application for Authorization to Inject via Proposed Red Hills AGI #1 Well, Agave Energy Red Hills Gas Plant, Lea County, New Mexico; July 20, 2011; prepared by Geolex, Inc. for Agave Energy Company

Application for a Redundant Class II AGI Well, Lucid Energy Delaware, LLC; Red Hills AGI #2; August 8, 2019, prepared by Geolex, Inc. for Lucid Energy Delaware, LLC

Case No. 20779, Notice Regarding Hearing Exhibits, Application of Lucid Energy Delaware, LLC for Authorization to Inject, Lea County, New Mexico

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Appendix 6 Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
AoR – Area of Review
API – American Petroleum Institute
CFR – Code of Federal Regulations
C1 – methane
C6 – hexane
C7 - heptane
CO_2 – carbon dioxide
DCS – distributed control system
EPA – US Environmental Protection Agency, also USEPA
ft – foot (feet)
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MSCFD– thousand standard cubic feet per day
MMSCFD – million standard cubic feet per day
MMstb – million stock tank barrels
MRRW B – Morrow B
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NIST - National Institute of Standards and Technology
NMOCC – New Mexico Oil Conservation Commission
NMOCD - New Mexico Oil Conservation Division
PPM – Parts Per Million
psia – pounds per square inch absolute
QA/QC – quality assurance/quality control
SCITS - Stanford Center for Induced and Triggered Seismicity
Stb/d – stock tank barrel per day
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TVD – True Vertical Depth
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

Appendix 7 TND Red Hills AGI Wells - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

	Subpart RR Equation	Description of Calculations and Measurements*	Pipeline	Containers	Comments
CO_2 Received	RR-1	calculation of CO_2 received and measurement of CO_2 mass…	through mass flow meter.	in containers. **	
	RR-2	calculation of CO_2 received and measurement of CO_2 volume…	through volumetric flow meter.	in containers. ***	
	RR-3	summation of CO_2 mass received …	through multiple meters.		
CO_2 Injected	RR-4	calculation of CO_2 mass injected, measured through mass flow meters.			
	RR-5	calculation of CO_2 mass injected, measured through volumetric flow meters.			
	RR-6	summation of CO_2 mass injected, as calculated in Equations RR-4 and/or RR-5.			
CO_2 Produced / Recycled	RR-7	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through mass flow meters.			
	RR-8	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through volumetric flow meters.			
	RR-9	summation of CO_2 mass produced / recycled from multiple gas-liquid separators, as calculated in Equations RR-7 and/or RR8.			
CO_2 Lost to Leakage to the Surface	RR-10	calculation of annual CO_2 mass emitted by surface leakage			
CO_2 Sequestered	RR-11	calculation of annual CO_2 mass sequestered for operators ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, produced, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head, and emitted from surface equipment between production well head and production flow meter.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.
	RR-12	calculation of annual CO_2 mass sequestered for operators NOT ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.

* All measurements must be made in accordance with 40 CFR 98.444 – Monitoring and QA/QC Requirements.

** If you measure the mass of contents of containers summed quarterly using weigh bill, scales, or load cells (40 CFR 98.444(a)(2)(i)), use RR-1 for Containers to calculate CO_2 received in containers for injection.

*** If you determine the volume of contents of containers summed quarterly (40 CFR 98.444(a)(2)(ii)), use RR-2 for Containers to calculate CO_2 received in containers for injection.

Appendix 8 Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

RR-1 for Calculating Mass of CO_2 Received through Pipeline Mass Flow Meters

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_2,p,r}$$ (Equation RR-1 for Pipelines)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).

$C_{CO_2,p,r}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving mass flow meter.

RR-1 for Calculating Mass of CO_2 Received in Containers by Measuring Mass in Container

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_2,p,r}$$ (Equation RR-1 for Containers)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$Q_{r,p}$ = Quarterly mass of contents in containers r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass of contents in containers r redelivered to another facility without being injected into your well in quarter p (metric tons).

$C_{CO_2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Containers.

RR-2 for Calculating Mass of CO_2 Received through Pipeline Volumetric Flow Meters

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}}$$ (Equation RR-2 for Pipelines)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving volumetric flow meter.

RR-2 for Calculating Mass of CO_2 Received in Containers by Measuring Volume in Container

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}}$$ (Equation RR-2 for Containers)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$Q_{r,p}$ = Quarterly volume of contents in containers r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volume of contents in containers r redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

D = Density of CO_2 received in containers at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Container.

RR-3 for Summation of Mass of CO_2 Received through Multiple Flow Meters for Pipelines

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r}$$ (Equation RR-3 for Pipelines)

where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2,T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 or RR-2 for flow meter r.

r = Receiving flow meter.

RR-4 for Calculating Mass of CO_2 Injected through Mass Flow Meters into Injection Well

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}}$$ (Equation RR-4)

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

$C_{CO_{2,p,u}}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Mass flow meter.

RR-5 for Calculating Mass of CO_2 Injected through Volumetric Flow Meters into Injection Well

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$ (Equation RR-5)

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = 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 = Volumetric flow meter.

RR-6 for Summation of Mass of CO_2 Injected into Multiple Wells

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \qquad \text{(Equation RR-6)}$$

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) though all injection wells.

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as calculated in Equation RR-4 or RR-5 for flow meter u.

u = Flow meter.

RR-7 for Calculating Mass of CO_2 Produced / Recycled from a Gas-Liquid Separator through Mass Flow Meters

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * C_{CO_{2,p,w}} \qquad \text{(Equation RR-7)}$$

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Quarterly gas mass flow rate measurement for separator w in quarter p (metric tons).

$C_{CO_{2,p,w}}$ = Quarterly CO_2 concentration measurement in flow for separator w in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Gas / Liquid Separator.

RR-8 for Calculating Mass of CO_2 Produced / Recycled from a Gas-Liquid Separator through Volumetric Flow Meters

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * D * C_{CO_{2,p,w}} \qquad \text{(Equation RR-8)}$$

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Quarterly gas volumetric flow rate measurement for separator w in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,w}}$ = Quarterly CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Gas / Liquid Separator.

RR-9 for Summation of Mass of CO_2 Produced / Recycled through Multiple Gas Liquid Separators

$$CO_{2P} = (1 + X) * \sum_{w=1}^{W} CO_{2,w} \qquad \text{(Equation RR-9)}$$

where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) though all separators in the reporting year.

X = Entrained CO_2 in produced oil or other liquid divided by the CO_2 separated through all separators in the reporting year (wt. percent CO_2 expressed as a decimal fraction).

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year as calculated in Equation RR-7 or RR-8 .

w = Flow meter.

RR-10 for Calculating Annual Mass of CO_2 Emitted by Surface Leakage

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{(Equation RR-10)}$$

where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

RR-11 for Calculating Annual Mass of CO_2 Sequestered for Operators Actively Producing Oil or Natural Gas or Any Other Fluid

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \quad \text{(Equation RR-11)}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells in the reporting year.

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of the GHGRP.

CO_{2FP} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of the GHGRP.

RR-12 for Calculating Annual Mass of CO_2 Sequestered for Operators NOT Actively Producing Oil or Natural Gas or Any Other Fluid

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad \text{(Equation RR-12)}$$

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of the GHGRP.

Appendix 9 P&A Records

P&A Record for Government Com 001, API #30-025-25604

New Mexico Oil Conservation Division, District I
1625 N. French Drive
Hobbs, NM 88240

Form 3160-5
(April 2004)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OM B No. 1004-0137
Expires: March 31, 2007

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

5. Lease Serial No. **NM-17446**

6. If Indian, Allottee or Tribe Name

SUBMIT IN TRIPLICATE*- Other instructions on reverse side.*

7. If Unit or CA/Agreement, Name and/or No.

1. Type of Well ☐ Oil Well ☑ Gas Well ☐ Other

8. Well Name and No. **Government "L" Com #1**

2. Name of Operator **EOG Resources, Inc**

9. API Well No. **30-025-~~0~~ 25604**

3a. Address **P.O. Box 2267, Midland, TX, 79702**

3b. Phone No. *(include area code)* **432-561-8600**

10. Field and Pool, or Exploratory Area **Bell Lake, South Morrow**

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*

Unit Letter G, 1980 FNL, 1980 FEL
Section 18, Township 24-S, Range 34-E

11. County or Parish, State **Lea, New Mexico**

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
☑ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☐ Other
	☐ Change Plans	☑ Plug and Abandon	☐ Temporarily Abandon	
	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

1. **Notified Jim McCormick w/BLM 24 hrs prior to MI and RU.**
2. **Cut 3 1/2' tbg at 11500, spot 50sx CLass "H" cmt, plug from 11500-11400, WOC Tag at 11389.**
3. **Circ hole w/MLF.**
4. **Perf 4 holes at 9050, press up to 2000 PSI, spot 75sx, plug from 9100-8950, WOC Tag @ 8938.**
5. **Perf 4 holes at 7000, press up to 2000 PSI, spot 75sx, plug from 7050-6900, WOC Tag at 6855.**
6. **Cut 10 3/4" csg at 5450, L/D csg, spot 150sx, plug from 5500-5350, WOC Tag at 5336.**
7. **Spot 75sx, plug from 1300-1200 (T-Salt) WOC Tag at 1143.**
8. **Spot 150sx, plug from 650-450 (20" Shoe) WOC Tag at 423.**
9. **Spot 20sx, plug from 30-Surf.**
10. **Clean location. Install dry hole marker 12-30-04.**

P&A Complete 12-30-04

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

14. I hereby certify that the foregoing is true and correct
Name *(Printed/Typed)* **Jimmy Bagley**   Title **Consultant**

Signature   Date **12/30/2004**

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by   Title   Date

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.   Office

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on page 2)

GWW

P&A Records for API #30-025-26958

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr, Hobbs, NM 88240
District II – (575) 748-1283
811 S First St, Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd, Aztec, NM 87410
District IV – (505) 476-3460
1220 S St Francis Dr, Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources
OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

RECEIVED
AUG 16 2012
HOBBSOCD

Form C-103
Revised August 1, 2011

SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS) 1. Type of Well: Oil Well ☐ Gas Well ☒ Other	WELL API NO. 3002526958 5. Indicate Type of Lease STATE ☐ FEE ☒ 6. State Oil & Gas Lease No. SCR-389 7. Lease Name or Unit Agreement Name Sims 8. Well Number #1
2. Name of Operator: Agave Energy Company	9. OGRID Number 147831
3. Address of Operator 104 S. Fourth St., Artesia NM 88210 (575-748-4528)	10. Pool name or Wildcat Big Sinks Wolfcamp

4. Well Location
Unit Letter K: 1980 feet from the N line and 800 feet from the E line
Section 13 Township 24S Range 33E NMPM Lea County

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
OTHER: ☐		OTHER ☒ Replug to cement off Cherry Canyon per NMOCC R-13507	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion

The remediation of the Sims #1 well pursuant to NMOCC order was completed on August 15, 2011 and all equipment has been demobilized. The plugging was done pursuant to NMOCD requirements and all aspects of the effort were reported to Mark Whitaker and E.L. Gonzales of the OCD District 1 office who approved the specifics of the plugging as shown in the attached plugging diagram. When establishing a rate prior to squeezing the Cherry Canyon, it is clear that the reservoir is an excellent reservoir as it was taking 3bbl/min on vacuum. This indicates that the predicted injection plume for the Red Hills AGI #1 in this reservoir will be smaller than anticipated and the reservoir conditions act to prevent migration of injected acid gas out of the intended and permitted injection zone by any nearby wellbores including the Govt#2, Govt#1 and Smith Federal #1 in addition to the Sims#1. Please see attached wellbore sketch for plugging details of all plugs set and amounts of cement squeezed for each plug.

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE_______________ TITLE_ Consultant to Agave Energy Company _DATE August 16, 2012___

Type or print name ___Alberto A. Gutierrez, RG E-mail address: ___aag@geolex.com_____ PHONE: __505-842-8000___

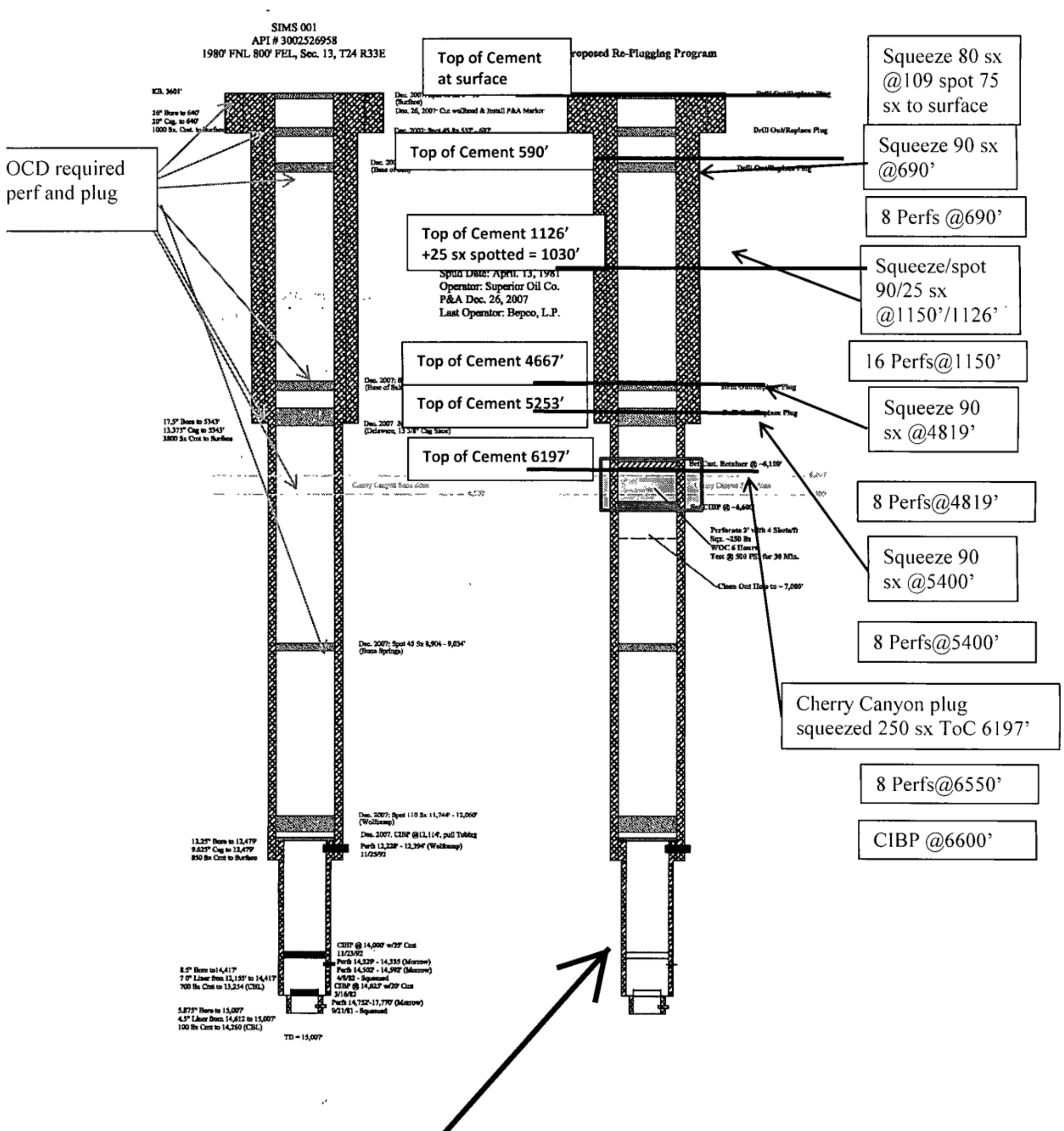
For State Use Only

APPROVED BY: _______________ TITLE Dist Mgr _______________ DATE 8-16-2012
Conditions of Approval (if any):

AUG 16 2012

GEOLEX
INCORPORATED

8/16/2012



Final Remediated Sims #1 Well

P&A Records for API 30-025-08371

NEW MEXICO OIL CONSERVATION COMMISSION

FORM C-103
(Rev 3-55)

MISCELLANEOUS REPORTS ON WELLS

(Submit to appropriate District Office as per Commission Rule 1106)

Name of Company: Byard Bennett			Address: 207 West Third, Roswell, New Mexico			
Lease: Holland	Well No. 1	Unit Letter H	Section 13	Township 24 South	Range 33 East	
Date Work Performed: March 8, 1961	Pool: Wildcat			County: Lea		

THIS IS A REPORT OF: *(Check appropriate block)*

- [ ] Beginning Drilling Operations
- [ ] Casing Test and Cement Job
- [ ] Other *(Explain)*:
- [X] Plugging
- [ ] Remedial Work

Detailed account of work done, nature and quantity of materials used, and results obtained.

Top of Rustler: 1245', Top of Salt: 1392', Base of Salt: 4930', Top of Dela Ls: 5190'
Top of Delaware Sand: 5210', Total Depth: 5425', Casing 8 5/8 set at 365', Hole size 6 3/4

Cement Plugs set as follows:
5375-5425 with 15 sacks, 5175-5240 with 20 sacks, 1375-1425 with 20 sacks,
340-390 with 20 sacks, 5 sacks and marker pipe set at surface.
Heavy mud (4 cc wtr. loss) between all cement plugs.
Job performed and witnessed by Mr. Pool, Pool Drlg Co.
Prior verbal approval of plugging program from Mr. Engbrecht, New Mexico O C C.

Location will be cleaned and leveled as soon as practical.

Witnessed by	Position	Company
Mr. Fred Pool	Owner	Pool Drlg Co.

FILL IN BELOW FOR REMEDIAL WORK REPORTS *ONLY*

ORIGINAL WELL DATA

D F Elev.	T D	P B T D	Producing Interval	Completion Date

Tubing Diameter	Tubing Depth	Oil String Diameter	Oil String Depth

Perforated Interval(s)

Open Hole Interval | Producing Formation(s)

RESULTS OF WORKOVER

Test	Date of Test	Oil Production BPD	Gas Production MCFPD	Water Production BPD	GOR Cubic feet/Bbl	Gas Well Potential MCFPD
Before Workover						
After Workover						

OIL CONSERVATION COMMISSION

Approved by: Leslie A. Clements

Title

Date

I hereby certify that the information given above is true and complete to the best of my knowledge.

Name: Guy A. Swartz

Position: Agent

Company: Byard Bennett

Request for Additional Information: Red Hills Gas Processing Plant
November 16, 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
	Section	Page		
1.	Multiple	Multiple	The submitted plan states: - "This MRV plan is for RH AGI #1 and RH AGI #3…" - "RH AGI #2 is authorized to inject TAG…" - "RH AGI #2 well is temporarily abandoned as of the submission of this document…" - "Upon completion, TND will commence injection into RH AGI #2 and #3…" - "Daily CO2 injected is recorded by totalizers on the volumetric flow meters on the pipelines to the RH AGI #1 and #2 wells…" Please clarify the status of RH AGI #2 throughout the MRV plan. E.g., do the MMA and AMA account for CO2 that may be injected through RH AGI #2? Is RH AGI #2 discussed as a potential leakage pathway in section 5? Why is meant by the statement, "This MRV plan is for RH AGI #1 and RH AGI #3…"?	The introduction of the revised MRV plan has been edited to state that RH AGI #2 is currently temporarily abandoned. Other references to RH AGI #2 have been edited to indicate clearly that it is temporarily abandoned or the references have been removed.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
2.	1	4	"Targa Northern Delaware, LLC (TND) is currently authorized to inject a total of up to 13 million standard cubic feet per day (MMSCFD) of treated acid gas (TAG) in the Red Hills Acid Gas Injection #1 well (RH AGI #1) (American Petroleum Institute (API) 30-025-40448) and RH AGI #3 well (API # 30-025-51970) under the New Mexico Oil Conservation Commission (NMOCC)…" Please clarify how the permitted injection volume is split between the RH AGI #1 and the RH AGI #3. Is this the combined volume, or the volume for each?	The revised MRV plan has been edited to clarify that each well is authorized to inject 13 MMSCFD.
3.	3.5	24	"…the closest water well is located 0.31 miles away and has a total depth of 650 ft (**Figure 3.6-1; Appendix 3**)." Please confirm whether this reference is directed towards the correct figure. We recommend confirming that all figure numbers and references are consistent throughout the MRV plan.	Figure numbers and references have been checked and corrected as necessary in the revised MRV plan.
4.	3.6	27	We recommend expanding and clarifying the process flow diagram by including metering locations as relevant to subpart RR.	The process flow diagram, Figure 3.6.1-2, has been expanded and labeled to show flow meters and other surface equipment. Section 8 has been rewritten to clarify which surface components will be used in Subpart RR equations.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	4.1	37	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 provide further explanation of whether the MMA meets the definitions in 40 CFR 98.449. For example, please specify whether the area is expected to contain the free phase CO_2 plume once it has stabilized as required in the above definitions. When is the plume expected to stabilize?	This section of the revised MRV plan has been rewritten to address this.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
6.	4.2	37	Per 40 CFR 98.449, active monitoring area is defined 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. While the MRV plan identifies the AMA, please provide further explanation of whether the AMA meets the definitions in 40 CFR 98.449. For example, please specify whether CO_2 will remain in the unit boundaries at year t and year t+5 as required in the above definitions. Additionally, please ensure that any figures related to the AMA clearly identify the AMA.	This section of the revised MRV plan has been rewritten to address this.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
7.	5.1	38	"To further minimize the likelihood of **surface leakage of CO_2 from surface equipment**, TND implements a schedule for regular inspection and maintenance of surface equipment." Please note that CO_2 leakage through surface equipment (CO2FI) in subpart RR is different from surface leakage (CO2E) and the two are calculated separately. In the MRV plan, please clarify that equipment leakage is not synonymous with "surface leakage" as defined under 40 CFR 98.449. For further guidance, please also reference 98.442 and 98.444(d). Please ensure that this issue is addressed throughout the MRV plan (we recommend checking Sections 5, 7 and 8).	Section 5.1 has been rewritten in the revised MRV plan to focus on the risk mitigation measures in place to minimize CO_2 emissions from surface equipment. Additionally, Section 8 has been rewritten to clearly show the distinction between the calculation of CO_2 emitted by surface leakage (CO_{2E} in Equation RR-12) and CO_2 emitted from equipment leaks and vented emissions (CO_{2FI} in Equation RR-12).
8.	5.1	38	"…TND considers the likelihood, magnitude, and timing of CO_2 emission to the surface via this potential leakage pathway to be minimal." In addition to listing the possible leakage pathways and their monitoring strategies, please provide a clear characterization of the likelihood, magnitude, and timing of leakage specific to each potential leakage pathway. E.g., what is meant be the "timing" of leakage being "minimal"?	Each of the subsections of Section 5 has been rewritten in the revised MRV plan to provide a clear characterization of the likelihood, magnitude, and time of leakage specific to each identified leakage pathway. The National Risk Assessment Partnership (NRAP) tool was used to analyze the likelihood, magnitude and timing of leakage. Narrative from the NRAP analysis was included in various subsections of Section 5.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
9.	5.3	39	"As shown in **Figure 3.7-1** and detailed in **Appendix 4**, there are **several** existing oil- and gas-related wells within the MMA as delineated in Section 4." Please ensure that the reference to Figure 3.7-1 is correct. We recommend ensuring that all figure numbers and references are consistent throughout the MRV plan. Additionally, please ensure that the description of the wells within the MMA is consistent. Figure 3.6-1 implies that there could be more than "several" wells are within the MMA.	This sentence has been rewritten in the revised MRV plan and the figure reference has been corrected. Figure 3.6.2-1 (newly numbered) and Figure 4.1-1 have been updated in the revised MRV plan to show the same vertical and horizontal wells with their trajectories within the MMA.
10.	5.3	39	While the MRV plan addresses wells completed below and within the injection zone, please include a discussion of wells completed above the injection zone that could present potential pathways should CO_2 migration through the seal occur (even if the likelihood of leakage through this pathway is determined to be low).	All wells within the MMA have been addressed in the revised MRV plan.
11.	5.3	39	Please clarify whether all plugged and abandoned wells within the MMA have been evaluated in these sections.	All wells within the MMA have been addressed in subsection 5.3 and the corresponding NRAP analysis.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
12.	5.3.2	39	"**Figure 4.1-1** shows that the modeled TAG plume extent after 30 years of injection and 5 years of post-injection stabilization does not extend to these well boreholes thereby indicating that **these** wells are not likely to be pathways for CO_2 leakage to the surface." Please clarify which wells are being referred to in this text. In the preceding text, several groups of wells are described based on depth. Figure 4.1-1 does not include many of these wells. Please ensure that the text is consistent with all figures shown throughout the MRV plan.	The MRV plan has been revised for clarity. Figure 4.1-1 is being revised to show the same wells in Figure 3.6.2-1
13.	5.7	42	Please elaborate on the risk of induced seismicity in this section. Will the facility take steps to ensure that seismicity is not induced?	Section 5.7 in the revised MRV plan has been rewritten to state that TND operates its injection wells at pressures below fracture opening pressures.
14.	6	43	While the MRV plan mentions that the facility intends to quantify potential surface leakage, please provide example quantification strategies that may be applied for the surface leakage pathways identified in the plan.	Subsection 6.8 – Strategy for Quantifying CO_2 Leakage and Response – has been added to Section 6 – Strategy for Detecting and Quantifying Surface Leakage of CO_2 to provide examples of quantification strategies.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
15.	8.4	53	"Surface leakage of CO_2 will be determined by employing the CO_2 detection system described in **Section 7.3**." Per the regulations stated in 40 CFR 98.443 (https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-RR/section-98.443), quantification of surface leakage for use in Equation RR-12 must include any leakage detected and quantified by all methodologies in Section 7 of the MRV plan, not just Section 7.3 of the MRV plan. Please revise this section and ensure that all references to equations are consistent with the text in 40 CFR 98.443	Section 8.4 has been rewritten in the revised MRV plan to address this issue.
16.	8.5	53	"As required by 98.448(d) of Subpart RR, TND will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W" 98.448(d) of Subpart RR appears to be the incorrect citation. Please ensure all references to regulatory text are properly cited.	The regulatory reference has been corrected in the revised MRV plan. The reference should be 98.444(d) not 98.448(d).

MONITORING, REPORTING, AND VERIFICATION PLAN

Red Hills AGI #1 and AGI #3

Targa Northern Delaware, LLC (TND)

Version 1.0
October 6, 2023

Table of Contents

1 Introduction

Targa Northern Delaware, LLC (TND) is currently authorized to inject a total of up to 13 million standard cubic feet per day (MMSCFD) of treated acid gas (TAG) in the Red Hills Acid Gas Injection #1 well (RH AGI #1)(American Petroleum Institute (API) 30-025-40448) and RH AGI #3 well (API # 30-025-51970) under the New Mexico Oil Conservation Commission (NMOCC) Orders R-13507 – 13507F and Order R-20916H, respectively, at the Red Hills Gas Plant located approximately 20 miles NNW of Jal in Lea County, New Mexico (**Figure 1-1**). Although approved at 13 MMSCFD, RH AGI #1 is physically only capable of taking ~5 MMSCFD due to formation and surface pressure limitations.

The AGI wells were previously operated by Lucid Energy Delaware, LLC's ("Lucid"). TND acquired Lucid assets in 2022. Lucid received authorization to construct a redundant well, RH AGI #2 (API# 30-025-49474) under NMOCC Order R-20916-H, which is offset 200 ft to the north of RH AGI #1 and is temporarily abandoned in the Bell Canyon Formation. RH AGI #2 is authorized to inject TAG at a maximum daily injection rate of 13 MMSCFD into the Devonian and Upper Silurian Wristen and Fusselman Formations at depths of approximately 16,000 to 17,500 ft with a maximum surface injection pressure of approximately 4,838 pounds per square inch gauge (psig).

TND recently received approval from NMOCC for its C-108 application to drill, complete and operate a third acid gas injection well (RH AGI #3) in which TND requested an injection volume of up to 13 MMSCFD. Because AGI #1 does not have complete redundancy, having a greater permitted disposal volume will also increase operational reliability. The RH AGI #3 well is currently being drilled as a vertical well with its surface location at approximately 3,116 ft from the north line (FNL) and 1,159 ft from the east line (FEL) of Section 13. The depth of the proposed injection zones for this well are approximately 5,600 to 7,200 ft in the Bell Canyon and Cherry Canyon Formations. Analysis of the reservoir characteristics of these units confirms that they act as excellent closed-system reservoirs that will accommodate the future needs of TND for disposal of treated acid gas (H_2S and CO_2) from the Red Hills Gas Plant.

TND has chosen to submit this Monitoring, Reporting, and Verification (MRV) plan to EPA for approval according to 40CFR98.440(c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. TND intends to inject CO_2 for another 30 years.

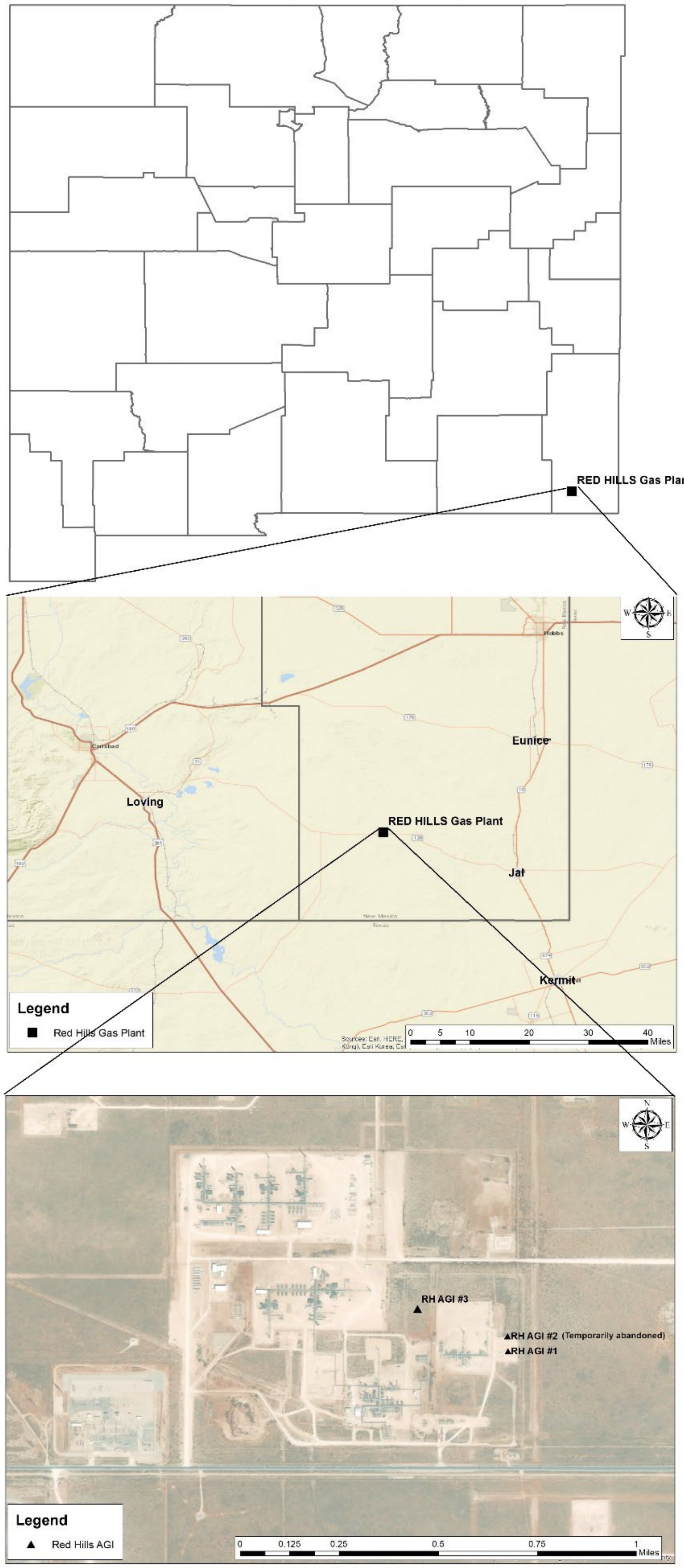


***Figure 1-1**: Location of the Red Hills Gas Plant and Wells – RH AGI #1, RH AGI #2 (temporarily abandoned), and RH AGI #3*

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40CFR98.449, and as required by 40CFR98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40CFR98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage as required by 40CFR98.448(a)(3).

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40CFR98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40CFR98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40CFR98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40CFR98.445.

Section 11 describes the records to be retained according to the requirements of 40CFR98.3(g) of Subpart A of the GHGRP and 40CFR98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan, including information required by 40CFR98.448(a)(6).

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is **553798**

2.2 UIC injection well identification numbers

This MRV plan is for RH AGI #1 and RH AGI #3 (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

For injection wells that are the subject of this MRV plan, the New Mexico Oil Conservation Division (NMOCD) has issued Underground Injection Control (UIC) Class II acid gas injection (AGI) permits under its State Rule 19.15.26 NMAC (see **Appendix 2**). All oil- and gas-related wells around the RH AGI wells, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3 Project Description

The following project description was developed by the Petroleum Recovery Research Center (PRRC) at New Mexico Institute of Mining and Technology (NMT) and the Department of Geosciences at the University of Texas Permian Basin (UTPB).

3.1 General Geologic Setting / Surficial Geology

The TND Red Hills Gas Plant is located in T 24 S R 33 E, Section 13, in Lea County, New Mexico, immediately adjacent to the RH AGI wells. (**Figure 3.1-1**). The plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. The dune sands are locally stabilized with shin oak, mesquite, and some burr-grass. There are no natural surface bodies of water or groundwater discharge sites within one mile of the plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

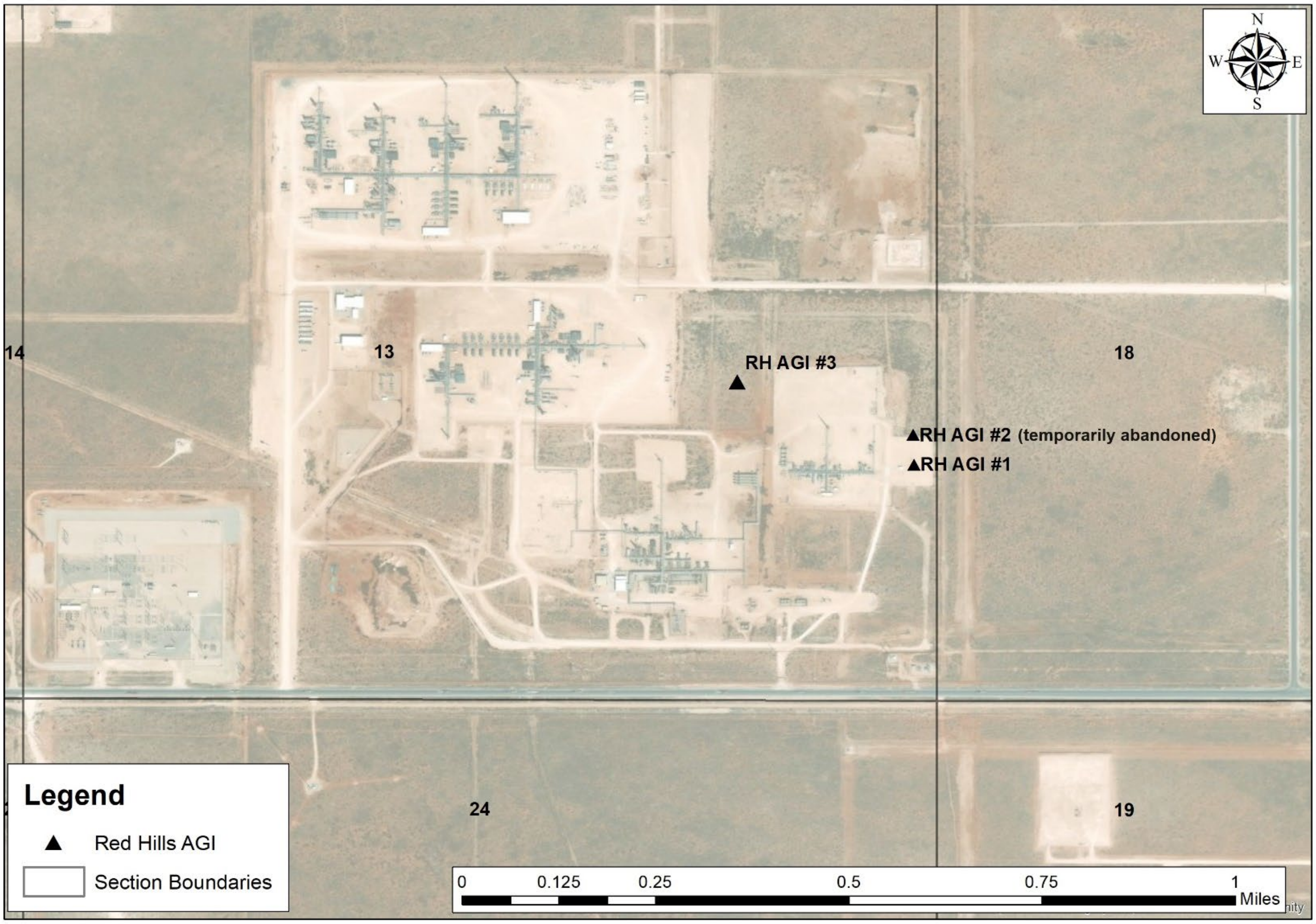


***Figure 3.1-1**: Map showing location of TND Red Hills Gas Plant and RH AGI Wells in Section 13, T 24 S, R 33 E*

3.2 Bedrock Geology

3.2.1 Basin Development

The Red Hills Gas Plant and the RH AGI wells are located at the northern margin of the Delaware Basin, a sub-basin of the larger, encompassing Permian Basin (**Figure 3.2-1**), which covers a large area of southeastern New Mexico and west Texas.

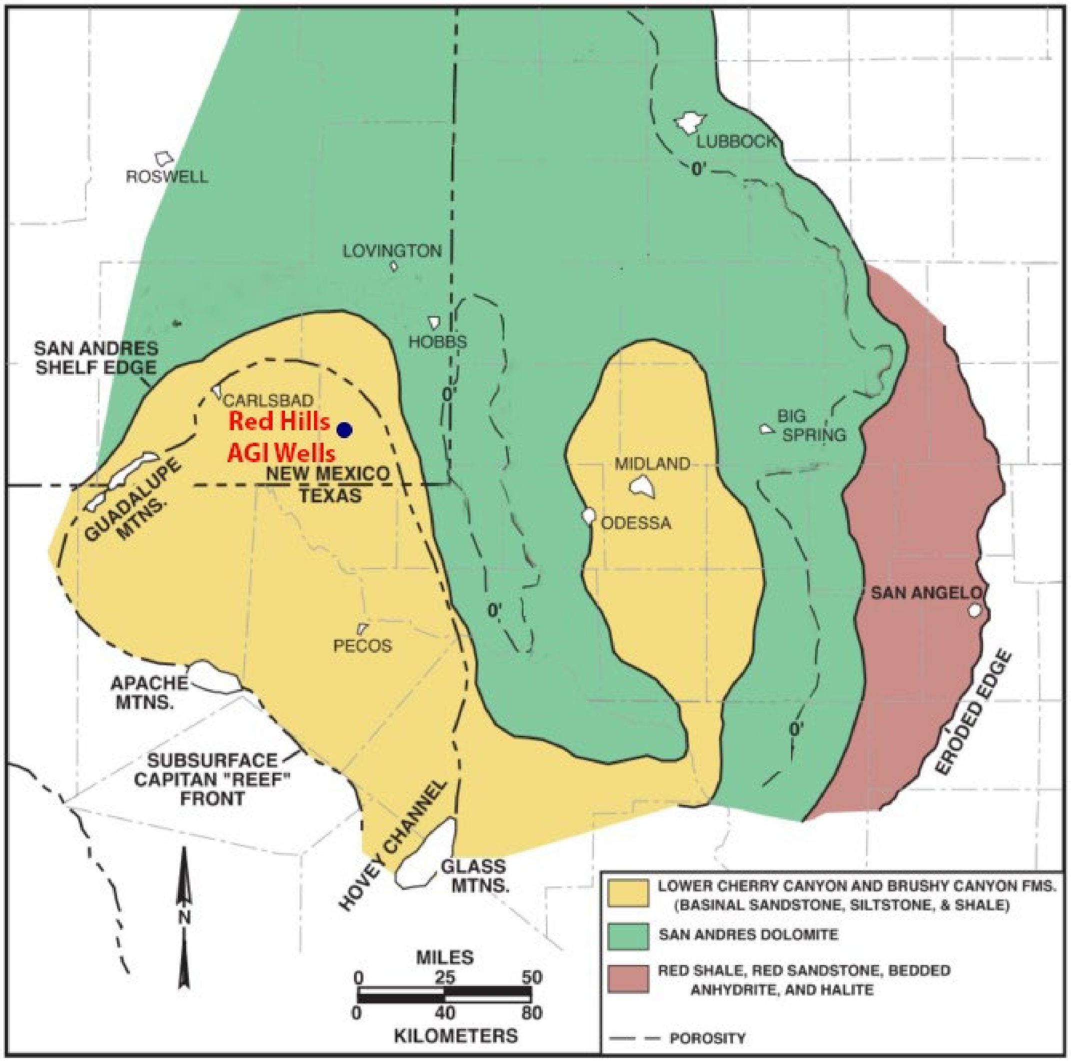


***Figure 3.2-1**: Structural features of the Permian Basin during the Late Permian. Location of the TND RH AGI wells is shown by the black circle. (Modified from Ward, et al (1986))*

Figure 3.2-2 is a generalized stratigraphic column showing the formations that underlie the Red Hills Gas Plant and RH AGI wells site. The thick sequences of Permian through Cambrian rocks are described below. A general description of the stratigraphy of the area is provided in this section. A more detailed discussion of the injection zone and the upper and lower confining zones is presented in Section 3.3 below.

The RH AGI wells are in the Delaware Basin portion of the broader Permian Basin. Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland (**Figure 3.2-3**). With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Ellenburger Formation (0 – 1000 ft) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Throughout this narrative, the numbers after the formations indicate the range in thickness for that unit. Tectonic activity near the end of Ellenburger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit's overall porosity and permeability.

AGE		CENTRAL BASIN PLATFORM-NORTHWEST SHELF		DELAWARE BASIN	
Cenozoic			Alluvium		Alluvium
Triassic			Chinle Formation		Chinle Formation
			Santa Rosa Sandstone		Santa Rosa Sandstone
Permian	Lopingian (Ochoan)		Dewey Lake Formation		Dewey Lake Formation
			Rustler Formation		Rustler Formation
			Salado Formation		Salado Formation
					Castile Formation
	Guadalupian	Artesia Group	Tansill Formation	Delaware Mountain Group	Lamar Limestone
			Yates Formation		Bell Canyon Formation
			Seven Rivers Formation		
			Queen Formation		Cherry Canyon Formation
			Grayburg Formation		
			San Andres Formation		Brushy Canyon Formation
	Cisuralian (Leonardian)		Glorieta Formation		
		Yeso	Paddock Mbr.		Bone Spring Formation
			Blinebry Mbr		
			Tubb Sandstone Mbr.		
			Drinkard Mbr.		
	Wolfcampian		Abo Formation		
			Hueco ("Wolfcamp") Fm.		Hueco ("Wolfcamp") Fm.
Pennsylvanian	Virgilian		Cisco Formation		Cisco
	Missourian		Canyon Formation		Canyon
	Des Moinesian		Strawn Formation		Strawn
	Atokan		Atoka Formation		Atoka
	Morrowan		Morrow Formation		Morrow
Mississippian	*Upper*		Barnett Shale		Barnett Shale
	Lower		"Mississippian limestone"		"Mississippian limestone"
Devonian	*Upper*		Woodford Shale		Woodford Shale
	Middle				
	Lower		Thirtyone Formation		Thirtyone Formation
Silurian	*Upper*		Wristen Group		Wristen Group
	Middle				
	Lower		Fusselman Formation		Fusselman Formation
Ordovician	*Upper*		Montoya Formation		Montoya Formation
	Middle		Simpson Group		Simpson Group
	Lower		Ellenburger Formation		Ellenburger Formation
Cambrian			Bliss Ss.		Bliss Ss.
Precambrian			Miscellaneous igneous, metamorphic, volcanic rocks		Miscellaneous igneous, metamorphic, volcanic rocks

***Figure 3.2-2**: Stratigraphic column for the Delaware basin, the Northwest Shelf and Central Basin Platform (modified from Broadhead, 2017).*

During Middle to Upper Ordovician time, the seas once again covered the area and deposited the carbonates, sandstones and shales of the Simpson Group (0 – 1000 ft) and then the Montoya Formation (0 – 600 ft). This is the period when the Tobosa Basin formed due to the Pedernal uplift and development of the Texas Arch (**Figure 3.2-4A**; Harrington, 2019) shedding Precambrian crystalline clasts into the basin. Reservoirs in New Mexico are typically within deposits of shoreline sandstones (Broadhead, 2017). A subaerial exposure and karstification event followed the deposition of the Simpson Group. The Montoya Formation marked a return to dominantly carbonate sedimentation with minor siliciclastic sedimentation within the Tobosa Basin (Broadhead, 2017; Harrington and Loucks, 2019). The Montoya Formation consists of sandstones and dolomites and have also undergone karstification.

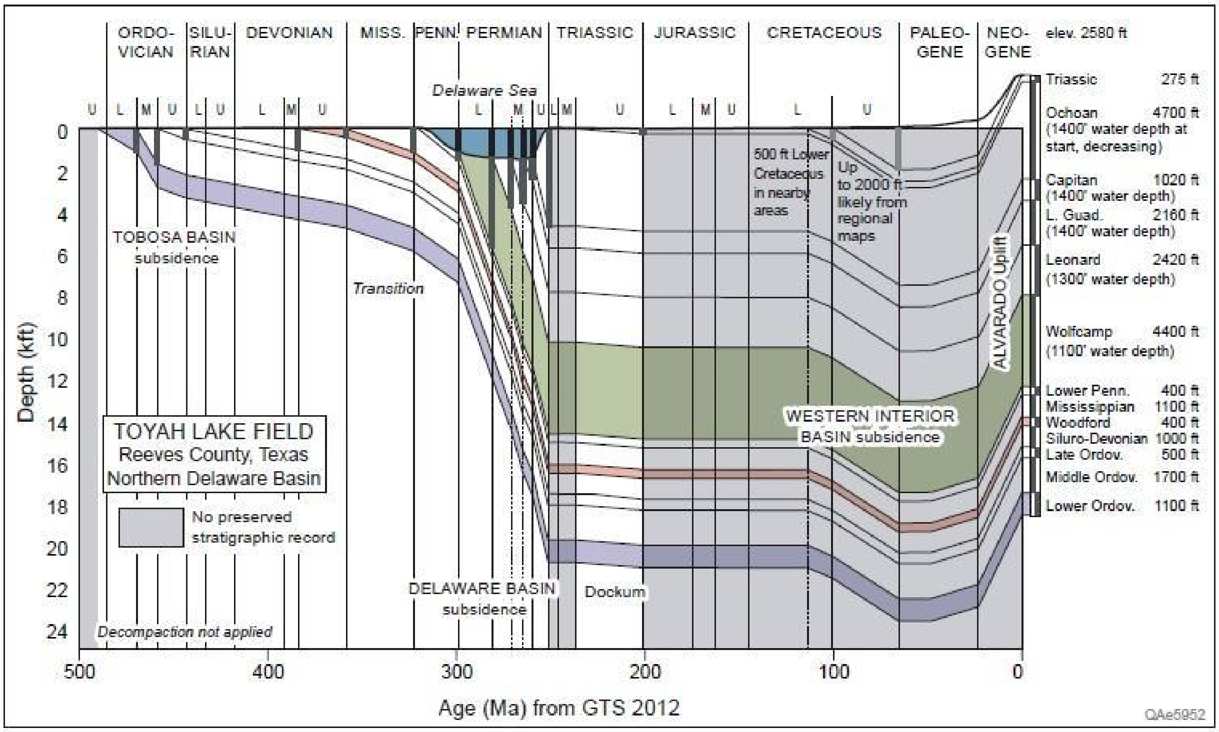


***Figure 3.2-3**: A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)*

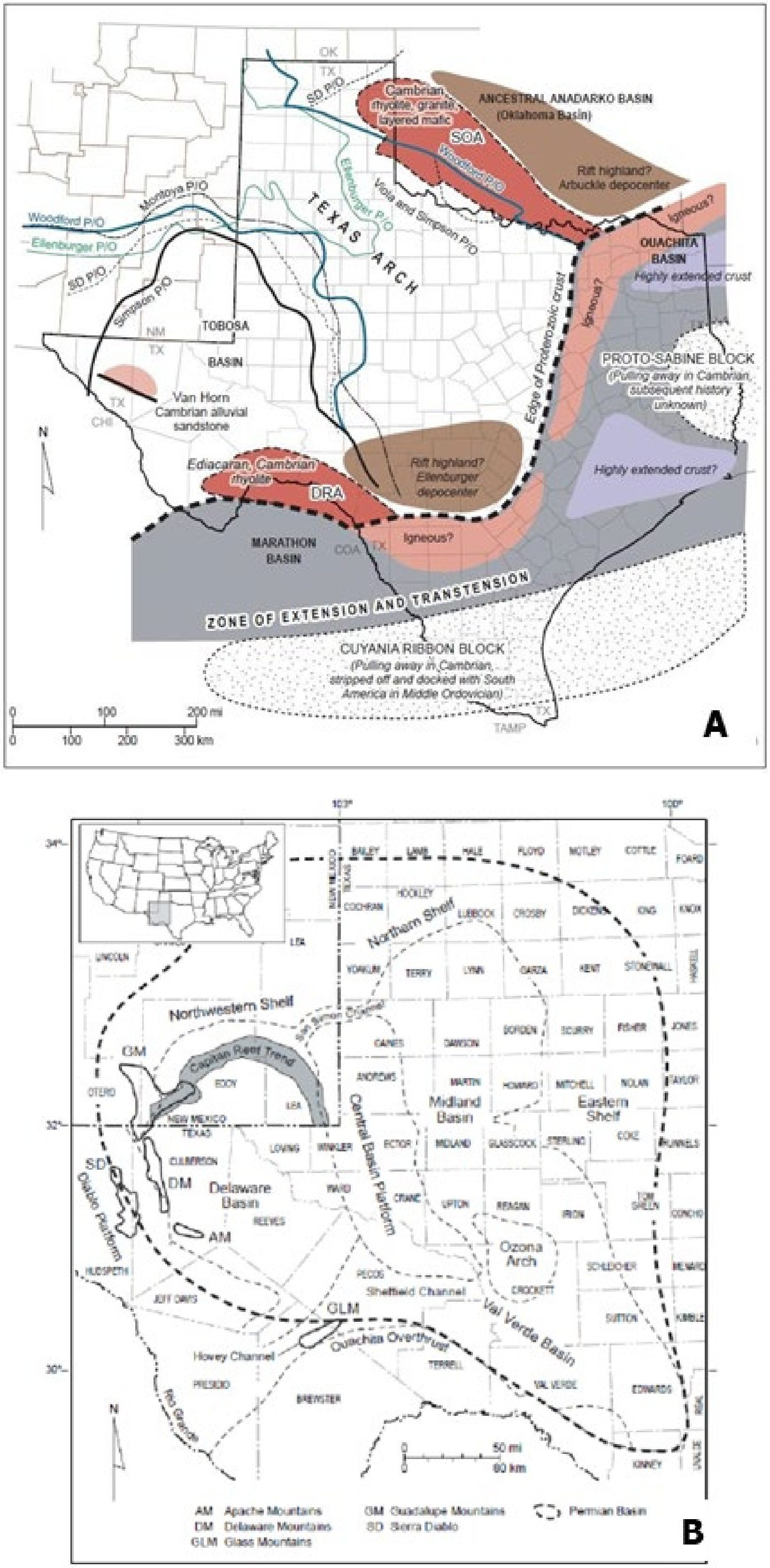


Figure 3.2-4*: Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).*

Siluro-Devonian formations consist of the Upper Ordovician to Lower Silurian Fusselman Formation (0 – 1,500 ft), the Upper Silurian to Lower Devonian Wristen Group (0 – 1,400 ft), and the Lower Devonian Thirtyone Formation (0 – 250 ft). The Fusselman Formation are shallow-marine platform deposits of dolostones and limestones (Broadhead, 2017; Ruppel, 2019b). Subaerial exposure and karstification associated with another unconformity at top of the Fusselman Formation as well as intraformational exposure events created brecciated fabrics, widespread dolomitization, and solution-enlarged pores and fractures (Broadhead, 2017). The Wristen and Thirtyone units appear to be conformable. The Wristen Group consists of tidal to high-energy platform margin carbonate deposits of dolostones, limestones, and cherts with minor siliciclastics (Broadhead, 2017; Ruppel, 2020a). The Thirtyone Formation is present in the southeastern corner of New Mexico and appears to be either removed by erosion or not deposited elsewhere in New Mexico (**Figure 3.2-5**). It is shelfal carbonate with varying amounts of chert nodules and represents the last carbonate deposition in the area during Devonian time (Ruppel et al., 2020a).

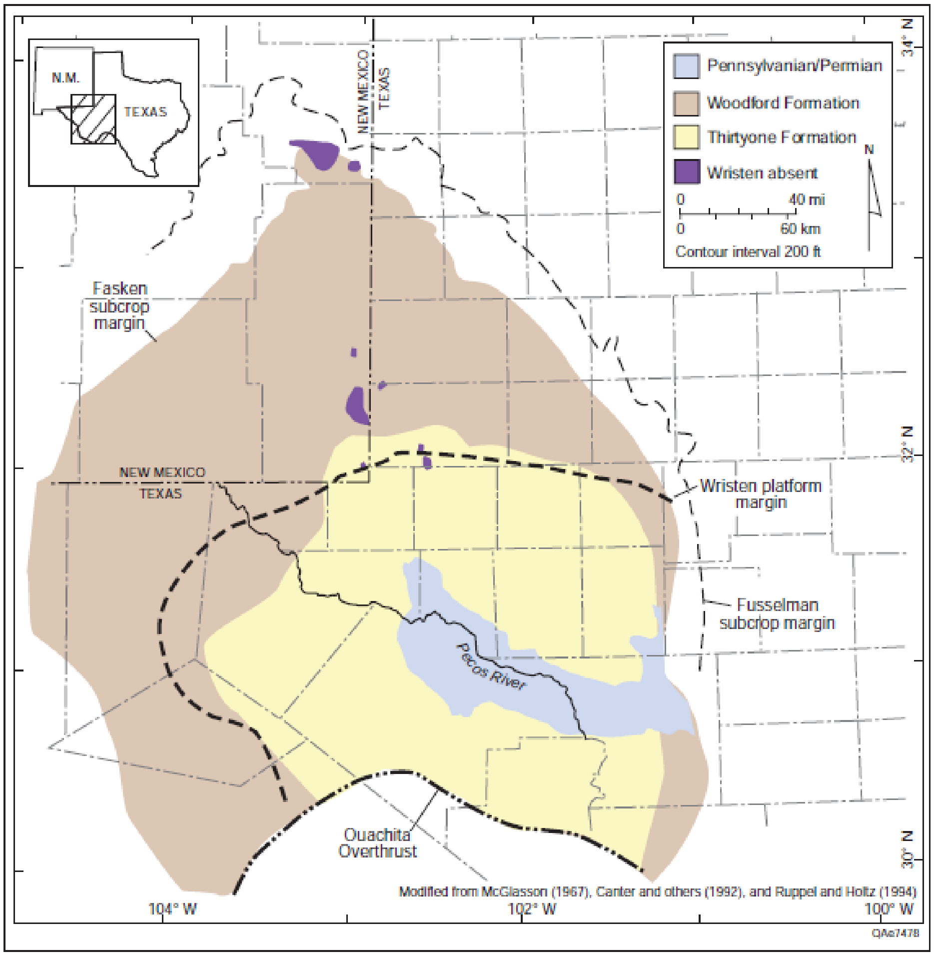


Figure 3.2-5 *-- A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there is no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in **Section 3.2.2**.

The Devonian Woodford Shale, an un-named Mississippian limestone, and the Upper Mississippian Barnett Shale are seals for the underlying Siluro-Devonian strata. While the Mississippian recrystallized limestones have minor porosity and permeability, the Woodford and Barnett shales have extremely low porosity and

permeability and would be effective barriers to upward migration of acid gas out of the injection zone. The Woodford Shale (0 – 300 ft) ranges from organic–rich argillaceous mudstones with abundant siliceous microfossils to organic-poor argillaceous mudstones (Ruppel et al., 2020c). The Woodford sediments represent stratified deeper marine basinal deposits with their organic content being a function of the oxygenation within the bottom waters – the more anoxic the waters the higher the organic content.

The Mississippian strata within the Delaware Basin consists of an un-named carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoirs limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise it is tight. The Barnett Shale (0 – 400 ft) unconformably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal, siliciclastic deposits (the Barnett Shale).

Pennsylvanian sedimentation in the area is influenced by glacio-eustatic sea-level cycles producing numerous shallowing upward cycles within the rock record; the intensity and number of cycles increase upward in the Pennsylvanian section. The cycles normally start with a sea-level rise that drowns the platform and deposits marine mudstones. As sea-level starts to fall, the platform is shallower and deposition switches to marine carbonates and coastal siliciclastic sediments. Finally, as the seas withdraw from the area, the platform is exposed causing subaerial diagenesis and the deposition terrestrial mudstones, siltstones, and sandstones in alluvial fan to fluvial deposits. This is followed by the next cycle of sea-level rise and drowning of the platform.

Pennsylvanian sedimentation is dominated by glacio-eustatic sea-level cycles that produced shallowing upward cycles of sediments, ranging from deep marine siliciclastic and carbonate deposits to shallow-water limestones and siliciclastics, and capping terrestrial siliciclastic sediments and karsted limestones. Lower Pennsylvanian units consist of the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). The Atoka Formation (0-500 ft) was deposited during another sea-level transgression within the area. Within the area, the Atoka sediments are dominated by siliciclastic sediments, and depositional environments range from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

Middle Pennsylvanian units consist of the Strawn group (an informal name used by industry). Strawn sediments (250 - 1,000 ft) within the area consists of marine sediments that range from ramp carbonates, containing patch reefs, and marine sandstone bars to deeper marine shales (Broadhead, 2017).

Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales.

Deformation, folding and high-angle faulting, associated with the Upper Pennsylvanian/Early Permian Ouachita Orogeny, created the Permian Basin and its two sub-basins, the Midland and Delaware basins (Hills, 1984; King, 1948), the Northwest Shelf (NW Shelf), and the Central Basin Platform (CBP; **Figures 3.2-4B, 3.2-6, 3.2-7**). The Permian "Wolfcamp" or Hueco Formation was deposited after the creation of the Permian Basin. The Wolfcampian sediments were the first sediments to fill in the structural relief (**Figure 3.2-6**). The Wolfcampian Hueco Group (~400 ft on the NW Shelf, >2,000 ft in the Delaware Basin) consists of shelf margin deposits ranging from barrier reefs and fore slope deposits, bioherms, shallow-water carbonate shoals, and basinal carbonate mudstones (Broadhead, 2017; Fu et al., 2020). Since deformation continued

throughout the Permian, the Wolfcampian sediments were truncated in places like the Central Basin Platform (**Figure 3.2-6**).

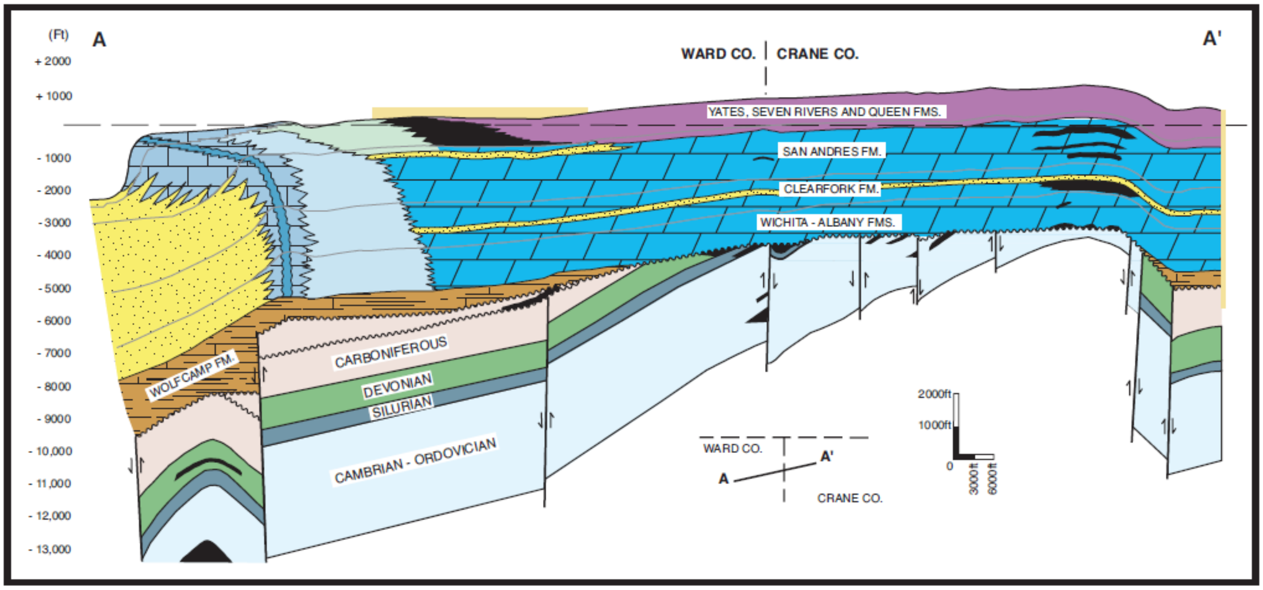


Figure 3.2-6 -- *Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).*

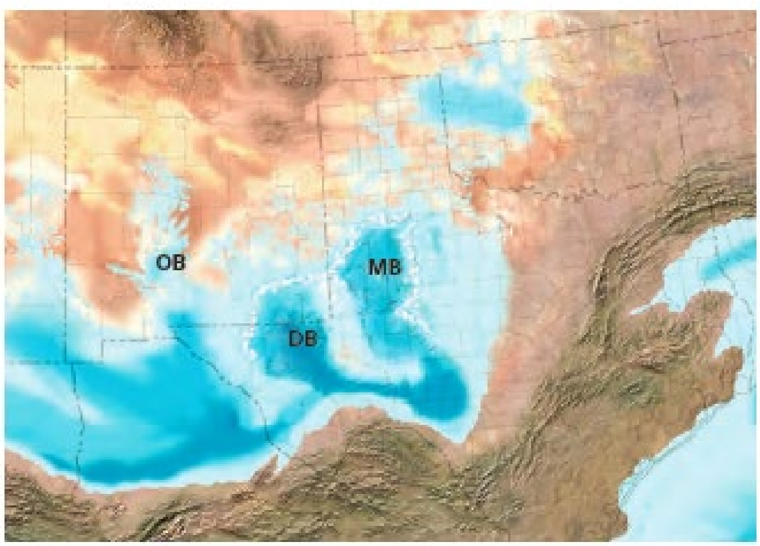


Figure 3.2-7 -- *Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).*

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, thousands of feet of siliciclastic sediments bypassed the shelves and were deposited in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a

"carbonate factory" on the shelf and shelf edge. Carbonate debris beds shedding off the shelf margin were transported into the basin (Wilson, 1977; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100s feet to feet).

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along Northwest Shelf margin to shallow-marine, back-reef carbonates behind the shelf margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2020b). Sediments basinward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2020b). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. The Bone Spring Formation is a thick sequence of alternating carbonate and siliciclastic horizons that formed because of changes in sea level; the carbonates during highstands, and siliciclastics during lowstands. Overlying the Yeso, are the clean, white eolian sandstones of the Glorietta Formation. It is a key marker bed in the region, both on outcrop and in the subsurface. Within the basin, it is equivalent to the lowermost Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have been identified that have resulted in karstification and pervasive dolomitization of the unit. These exposure events/sea-level lowstands are correlated to sandstones/siltstones that moved out over the exposed shelf leaving on minor traces of their presence on the shelf but formed thick sections of sandstones and siltstones in the basin. Within the Delaware Basin, the San Andres Formation is equivalent to the Brushy and lower Cherry Canyon Formations.

The Artesia Group (Grayburg, Queen, Seven Rivers, Yates, and Tansill formations, ascending order) is equivalent to Capitan Limestone, the Guadalupian barrier/fringing reef facies. Within the basin, the Artesia Group is equivalent to the upper Cherry and Bell Canyon formations, a series of relatively featureless sandstones and siltones. The Queen and Yates formations contain more sandstones than the Grayburg, Seven Rivers, and Tansill formations. The Artesia units and the shelf edge equivalent Capitan reef sediments represent the period when the carbonate factory was at its greatest productivity with the shelf margin/Capitan reef prograding nearly 6 miles into the basin (Scholle et al., 2007). The Artesia Group sediments were deposited in back-reef, shallow marine to supratidal/evaporite environments. Like the San Andres Formation, the individual formations were periodically exposed during lowstands.

The final stage of Permian deposition on the NW Shelf consists of the Ochoan/Lopingian Salado Formation (<2,800 ft, Nance, 2020). Within the basin, the Castile formation, a thick sequence (total thickness ~1,800 ft, Scholle et al., 2007) of cyclic laminae of deep-water gypsum/anhydrite interbedded with calcite and organics, formed due to the restriction of marine waters flowing into the basin. Gypsum/anhydrite laminae precipitated during evaporative conditions, and the calcite and organic-rich horizons were a result of seasonal "freshening" of the basin waters by both marine and freshwaters. Unlike the Castile Formation, the Salado Formation is a relatively shallow water evaporite deposit. Halite, sylvite, anhydrite, gypsum, and numerous potash minerals were precipitated. The Rustler Formation (500 ft , Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin.

The Rustler Formation was followed by terrestrial sabkha red beds of the Dewey Lake Formation (~350', Nance, 2020), ending Permian deposition in the area.

Beginning early in the Triassic, uplift and the breakup of Pangea resulted in another regional unconformity and the deposition of non-marine, alluvial Triassic sediments (Santa Rosa Sandstone and Chinle Formation). They are unconformably overlain by Cenozoic alluvium (which is present at the surface). Cenozoic Basin and Range tectonics resulted in the current configuration of the region and reactivated numerous Paleozoic faults.

3.2.2 Stratigraphy

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent, renamed Lopingian), Guadalupian, Leonardian (renamed Cisuralian), and Wolfcampian (oldest) (**Figure 3.2-2**). This sequence of shallow marine carbonates and thick, basinal siliciclastic deposits contains abundant oil and gas resources. The Delaware Basin high porosity sands are the main source of oil within New Mexico. In the area around the Red Hills AGI wells, Permian strata are mainly basin deposits consisting of sandstones, siltstones, shales, and lesser amounts of carbonates. Besides production in the Delaware Mountain Group, there is also production, mainly gas, in the basin Bone Spring Formation, a sequence of carbonates and siliciclastics. The injection and confining zones for RH AGI #1 and #3 are discussed below.

CONFINING/SEAL ROCKS

Permian Ochoa Series. The youngest of the Permian sediments, the Ochoan- or Lopingian-aged deposits, consists of evaporites, carbonates, and red beds. The Castile Formation is made of cyclic laminae of deep-water gypsum/anhydrite beds interlaminated with calcite and organics. This basin-occurring unit can be up to 1,800 ft thick. The Castile evaporites were followed by the Salado Formation (~1,500 ft thick). The Salado Formation is a shallow water evaporite deposit, when compared to the Castile Formation, and consists of halite, sylvite, anhydrite, gypsum, and numerous potash/bittern minerals. Salado deposits fill the basin and lap onto the older Permian shelf deposits. The Rustler Formation (up to 500 ft, Nance, 2020) consists of gypsum/anhydrite, a few magnesitic and dolomitic limestone horizons, and red beds. These are mostly shallow marginal marine deposits and represents the last Permian marine deposits in the Delaware Basin. The Ochoan evaporitic units are superb seals (usually <1% porosity and <0.01 mD permeability) and are the reason that the Permian Basin is such a hydrocarbon-rich region despite its less than promising total organic carbon (TOC) content.

INJECTION ZONE

Permian Guadalupe Series. Sediments in the underlying Delaware Mountain Group (descending, Bell Canyon, Cherry Canyon, and Brushy Canyon formations) are marine units that were deposited within the basin at depths that varied due to numerous changes in sea-level due to eustacy and tectonics. Most of the Delaware Mountain Group is dominated by siliciclastic sediments. The quartz-rich sands are fine grained to silt sized and poorly cemented. Deposition occurred within submarine fan complexes encircling the Delaware Basin margin. These deposits are associated with submarine canyons incising the carbonate platform and turbidite channels, splays, and levee/overbank deposits (**Figure 3.2.2-1**), as well as debris flows formed by the failure of the carbonate margin and density currents. Isolated coarse-grained to boulder-sized carbonate debris flows and grain falls within the lowstand clastic sediments likely resulted from erosion and failure of the shelf margin during sea-level lowstands or slope failure to tectonic activity (earthquakes). Density current deposits formed by the basin waters being stratified. The basal waters were likely stratified and so dense, that turbidity flows containing sands, silts and clays were unable to displace those bottom waters and instead flowed out over the density interface (**Figure 3.2.2-2**). Eventually, the entrained sediments would settle out in a constant rain of sediment forming laminated deposits with little evidence of traction (bottom flowing) deposition. These siliciclastic deposits represent sea-level lowstand deposits.

Interbedded with the very thick lowstand sequences are thin, deep-water limestones and mudstones that are thickest around the edge (toe-of-slope) of the basin and thin to the basin center (**Figure 3.2.2-3**). The limestones are dark, finely crystalline, radiolarian-rich micrites to biomicrites. These highstand deposits are a combination of suspension and pelagic sediments that also thin towards the basin center. These relatively thin units are time equivalent to the massive highstand carbonate deposits on the shelf.

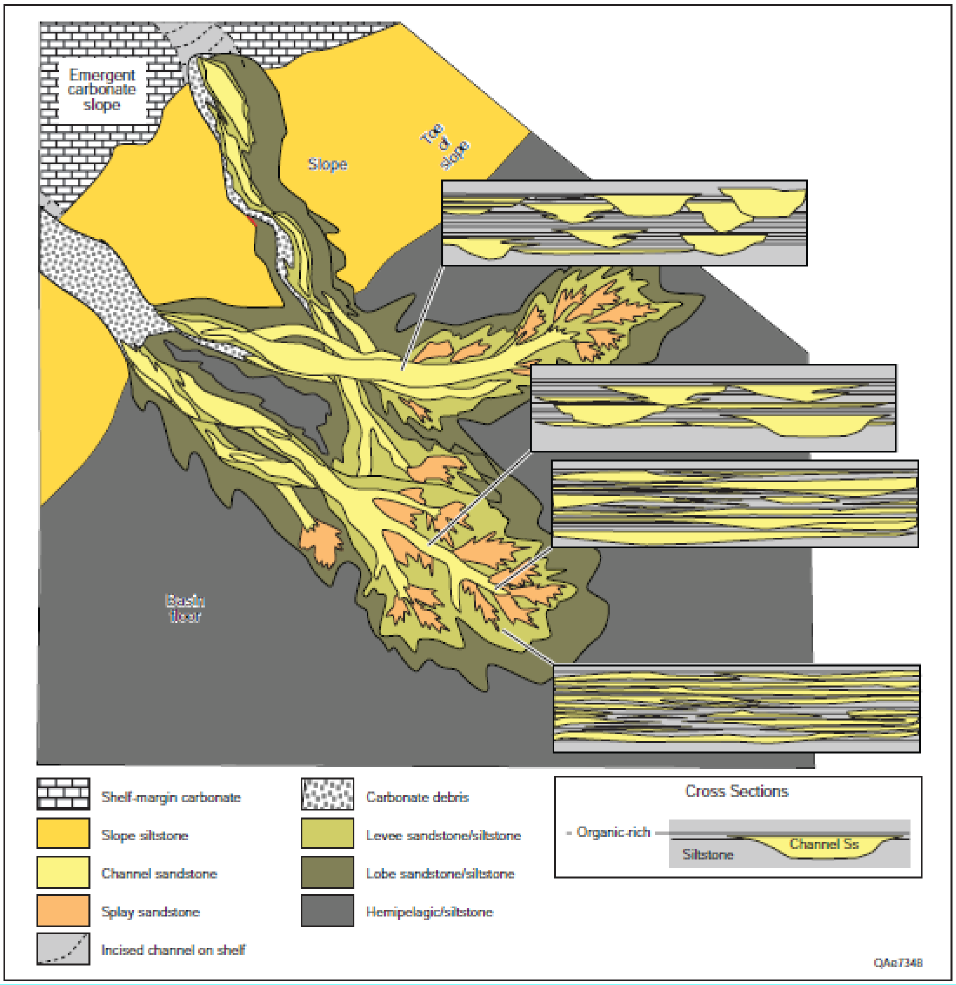


***Figure 3.2.2-1** – A diagram of typical Delaware Mountain Group basinal siliciclastic deposition patterns (from Nance, 2020). The channel and splay sandstones have the best porosity, but some of the siltstones also have potential as injection zones.*

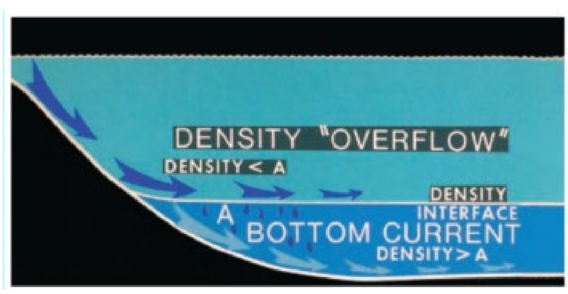


***Figure 3.2.2-2** – Harms' (1974) density overflow model explains the deposition of laminated siliciclastic sediments in the Delaware Basin. Low density sand-bearing fluids flow over the top of dense, saline brines at the bottom of the basin. The sands gradually drop out as the flow loses velocity creating uniform, finely laminated deposits (from Scholle et al., 2007).*

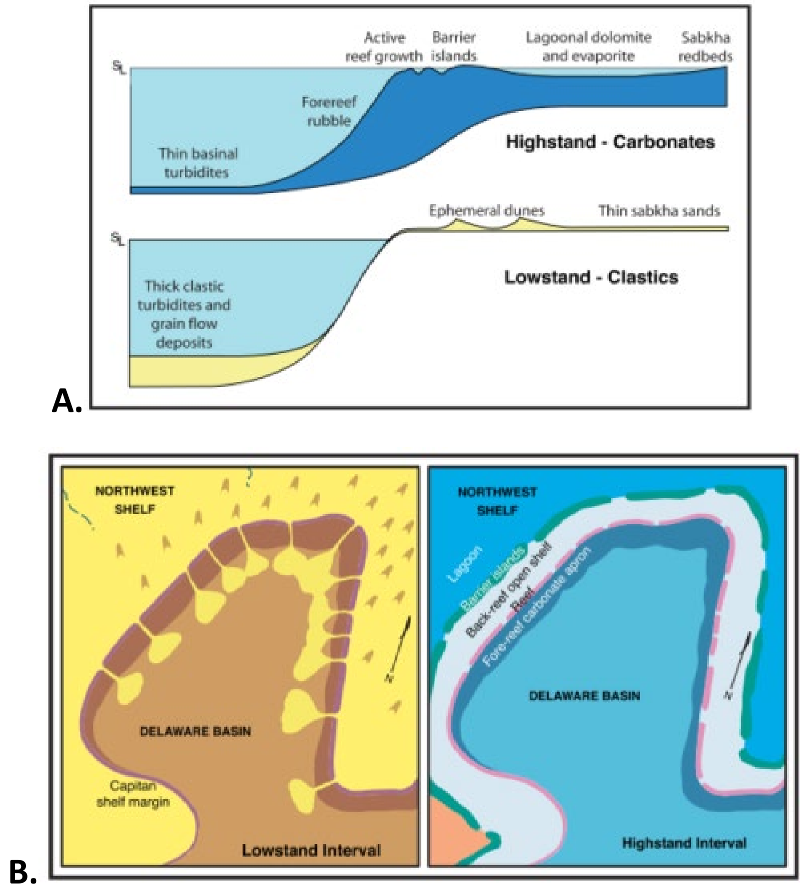


***Figure 3.2.2-3** – The impact of sea-level fluctuations (also known as reciprocal sedimentation) on the depositional systems within the Delaware Basin. A) A diagrammatic representation of sea-level variations impact on deposition. B) Model showing basin-wide depositional patterns during lowstand and highstand periods (from Scholle et al., 2007).*

The top of the Guadalupian Series is the Lamar Limestone, which is the source of hydrocarbons found in underlying Delaware Sand (an upper member of the Bell Canyon Formation). The Bell Canyon Formation is roughly 1,000 ft thick in the Red Hills area and contains numerous turbidite input points around the basin margin (**Figures 3.2.2-3, 3.2.2-4**). During Bell Canyon deposition, the relative importance of discrete sand sources varied (Giesen and Scholle, 1990), creating network of channel and levee deposits that also varied in their size and position within the basin. Based on well log analyses, the Bell Canyon 2 and 3 had the thickest sand deposits.

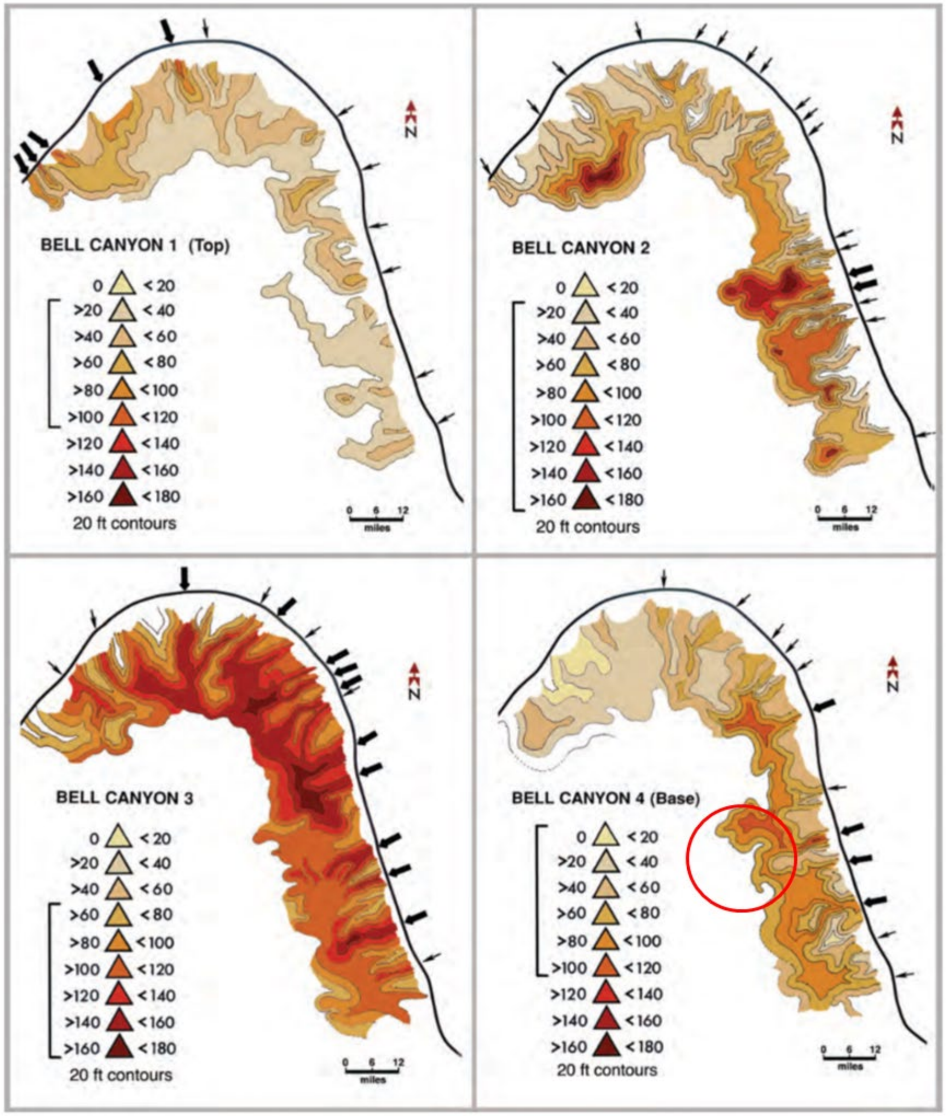


Figure 3.2.2-4 – These maps of Bell Canyon Formation were created by measuring sandstone thicknesses on well logs in four regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). The red circle on the last map surrounds the Red Hills area.

Like the Bell Canyon and Brushy Canyon formations, the Cherry Canyon Formation is approximately 1,300 ft thick and contains numerous turbidite source points. Unlike the Bell Canyon and Brushy Canyon deposits, the channel deposits are not as large (Giesen and Scholle, 1990), and the source of the sands appears to be dominantly from the eastern margin (**Figure 3.2.2-5**). Cherry Canyon 1 and 5 have the best channel development and the thickest sands. Overall, the Cherry Canyon Formation, on outcrop, is less influenced by traction current deposition than the rest of the Delaware Mountain Group deposits and is more influenced by sedimentation by density overflow currents (**Figure 3.2.2-2**). The Brushy Canyon has notably more discrete channel deposits (**Figure 3.2.2-6**) and coarser sands than the Cherry Canyon and Bell Canyon. The Brushy Canyon Formation is approximately 1,500 ft thick.

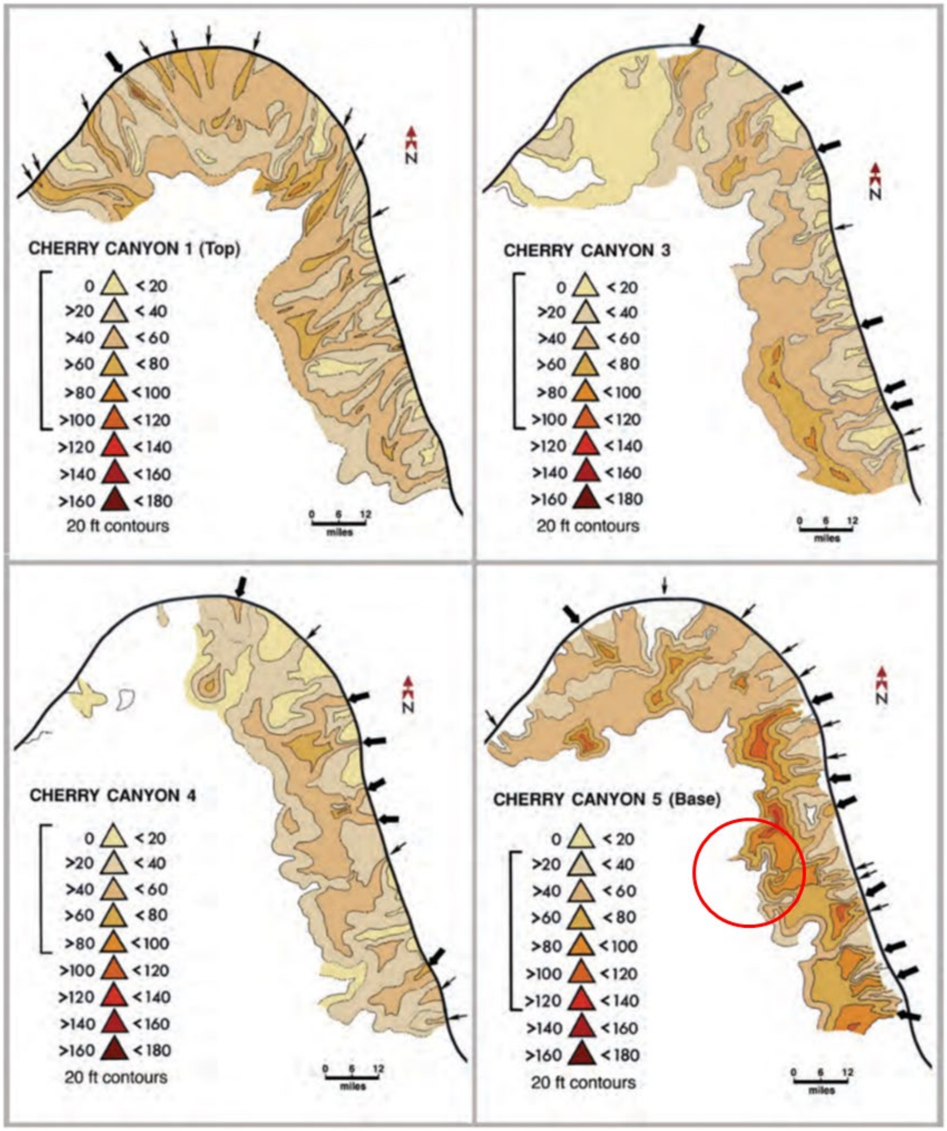


Figure 3.2.2-5*– These maps of Cherry Canyon Formation were created by measuring sandstone thicknesses on well logs in five regionally correlatable intervals (from Giesen and Scholle, 1990 and unpublished thesis research). Unlike the Bell Canyon sandstones, the Cherry Canyon sands are thinner and contain fewer channels. The red circle on the last map surrounds the Red Hills area.*

Within the Delaware Mountain Group in the Red Hills area, the Bell Canyon and Cherry Canyon have the best porosity (averaging 15 – 25 % within channel/splay sandstones) and permeability (averaging 2-13 mD) than the Brushy Canyon (~14% porosity, an <3 mD).

UNDERLYING CONFINING ZONE

Permian Leonard Series. The Leonardian/Cisuralian Series, located beneath the Guadalupian Series sediments, is characterized by >3,000 ft of basin-deposited carbonate and siliciclastic sediments of the Bone Spring Formation. The Bone Spring Formation is more carbonate rich than the Delaware Mountain Group deposits, but the sea-level-driven cycles of sedimentation and the associated depositional environments are similar with debris flows, turbidites, and pelagic carbonate sediments. The Bone Spring Formation contains both convential and unconventional fields within the Delaware Basin in both the sandstone-rich and carbonate-rich facies. Most of these plays usually occur within toe-of-slope carbonate and siliciclastic deposits or the turbidite facies in the deeper sections of the basin (Nance and Hamlin, 2020). The upper most Bone Spring is usually dense carbonate mudstone with limited porosity and low porosity.

3.2.3 Faulting

In this immediate area of the Permian Basin, faulting is primarily confined to the lower Paleozoic section, where seismic data shows major faulting and ancillary fracturing-affected rocks only as high up as the base of the lower Woodford Shale (**Figures 3.2-4 and 3.2-5**). Faults that have been identified in the area are normal faults associated with Ouachita related movement along the western margin of the Central Platform to the east of the RH AGI well site. The closest identified fault lies approximately 1.5 miles east of the Red Hills site and has approximately 1,000 ft of down-to-the-west structural relief. Because these faults are confined to the lower Paleozoic unit well below the injection zone for the RH AGI wells, they will not be discussed further.

3.3 Lithologic and Reservoir Characteristics

Based on the geologic analyses of the subsurface at the Red Hills Gas Plant, the uppermost portion of the Cherry Canyon Formation was chosen for acid gas injection and CO_2 sequestration for RH AGI #1 and the uppermost Delaware Mountain Group (the Bell Canyon and Cherry Canyon Formations) for RH AGI #3.

For RH AGI #1, this interval includes five high porosity sandstone units (sometimes referred to as the Manzanita) and has excellent caps above, below and between the individual sandstone units. There is no local production in the overlying Delaware Sands pool of the Bell Canyon Formation. There are no structural features or faults that would serve as potential vertical conduits. The high net porosity of the RH AGI #1 injection zone indicates that the injected H_2S and CO_2 will be easily contained close to the injection well.

For RH AGI #3, this interval has been expanded to include the five porosity zones in the Cherry Canyon sandstone as well as the sandstone horizons in the overlying Bell Canyon Formation. In the Bell Canyon Formation there are several potential high porosity sandstones, that if present in the well, would be excellent , injection zones similar to the depositional environments of the Cherry Canyon sandstones. The thickest sand is commonly referred to as the Delaware Sand within the Delaware Basin. The Delaware sand is productive, but it is not locally. Most of the sand bodies in the Bell Canyon and Cherry Canyon formations are surrounded by shales or limestones, forming caps for the injection zones. There are no structural features or faults that would serve as potential vertical conduits, and the overlying Ochoan evaporites form an excellent overall seal for the system. Even if faulting existed, the evaporites (Castile and Salado) would self-seal and prevent vertical migration out of the Delaware Mountain Group.

The geophysical logs were examined for all wells penetrating the Bell Canyon and Cherry Canyon formations within a three-mile radius of the RH AGI wells as well as 3-D seismic data. There are no faults visible within the Delaware Mountain Group in the Red Hills area. Within the seismic area, the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales (**Figure 3.2.2-1**) as well as being encased by them. Based on regional studies (Giesen and Scholle, 1990 and **Figures 3.2.2-4, 3.2.2-5**), the preferred orientation of the channels, and hence the preferred fluid migration pathways, are roughly from the east to the west.

The porosity was evaluated using geophysical logs from nearby wells penetrating the Cherry Canyon Formation. **Figure 3.3-1** shows the Resistivity (Res) and Thermal Neutron Porosity (TNPH) logs from 5,050 ft to 6,650 ft and includes the proposed injection interval. Five clean sands (>10% porosity and <60 API gamma units) are targets for injection within the Cherry Canyon formation and potentially another 5 sands with >10% porosity and <60 API gamma units were identified. Ten percent was the minimum cut-off considered for adequate porosity for injection. The sand units are separated by lime mudstone and shale beds with lateral continuity. The high porosity sand units exhibit an average porosity of about 18.9%; taken over the average thickness of the clean sand units within ½ mile of the RH AGI #1. There is an average of 177 ft with an irreducible water (S_{wir}) of 0.54 (see Table 1 of the RH AGI #1 permit application). Many of the sands are very porous (average porosity of > 22%) and it is anticipated that for these more porous sands, the S_{wir} may be too high. The effective porosity (Total Porosity – Clay Bound Water) would therefore also be higher. As a result, the estimated porosity ft (PhiH) of approximately 15.4 porosity-ft should be considered to be a minimum. The overlying Bell Canyon Formation has 900 ft of sands and intervening tight limestones, shales, and calcitic siltstones with porosities as low as 4%, but as mentioned above, there are at least 5 zones with a total thickness of approximately 460 ft and containing 18 to 20% porosity. The proposed injection interval is located more than 2,650 ft above the Bone Spring Formation, which is the next production zone in the area.

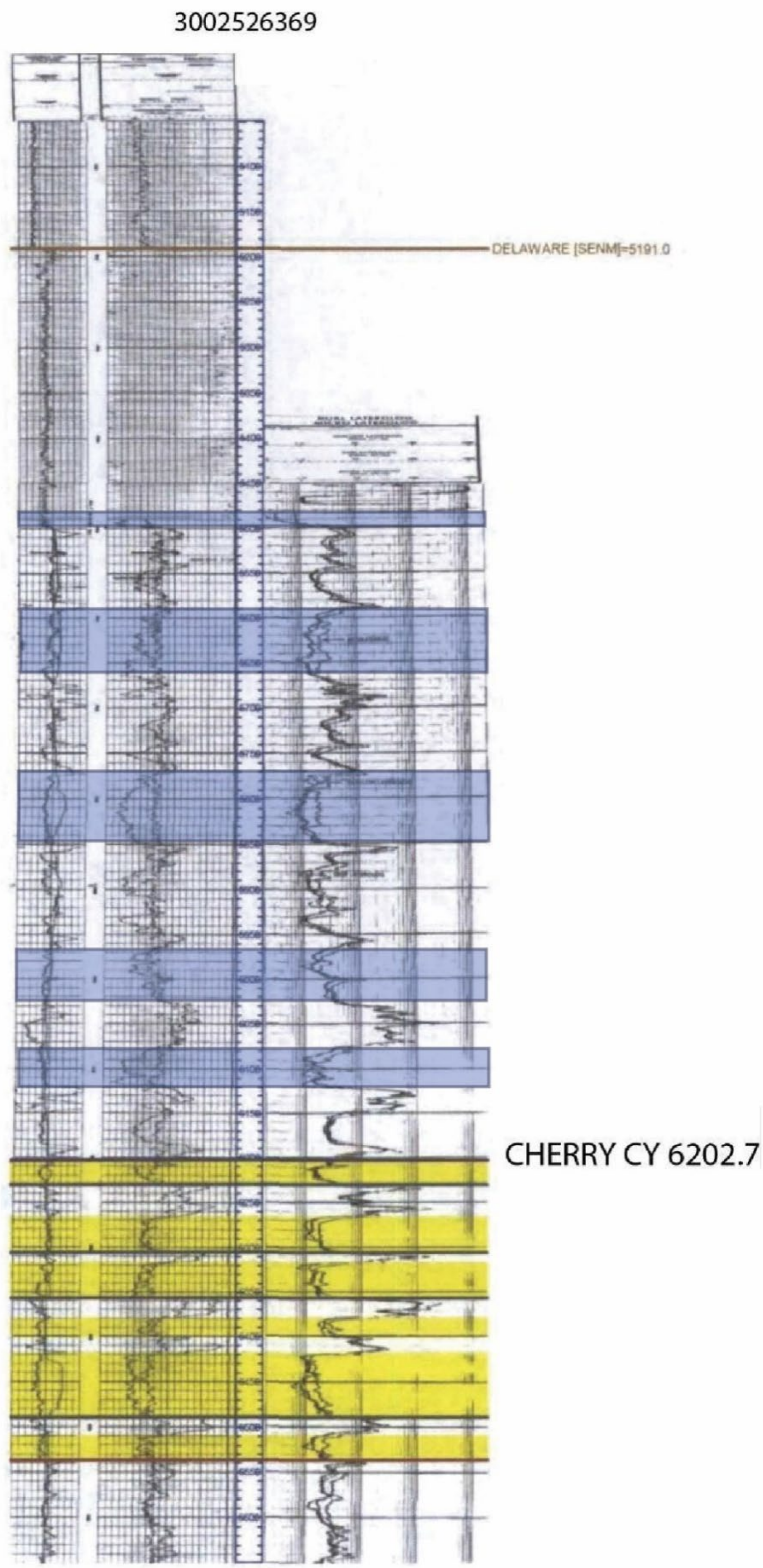


***Figure 3.3-1**: Geophysical logs from the Bell Canyon and the Upper Cherry Canyon from the Government L Com #002 well, located 0.38 miles from the RH AGI #1 Well. The blue intervals are Bell Canyon porosity zones, and the yellow intervals are Cherry Canyon porosity zones.*

3.4 Formation Fluid Chemistry

A chemical analysis (**Table 3.4-1**) of water from Federal 30 Well No. 2 (API 30-025-29069), approximately 3.9 miles away, indicates that the formation waters are highly saline (180,000 ppm NaCl) and compatible with the proposed injection.

***Table 3.4-1**: Formation fluid analysis for Cherry Canyon Formation from Federal 30 Well No. 2*

Sp. Gravity	1.125 @ 74°F	Resistivity	0.07 @ 74°F
pH	7	Sulfate	1,240
Iron	Good/Good	Bicarbonate	2,135
Hardness	45,000	Chloride	110,000
Calcium	12,000	NaCl	180,950
Magnesium	3,654	Sod. & Pot.	52,072

Table extracted from C-108 Application to Inject by Ray Westall Associated with SWD-1067 – API 30-025-24676. Water analysis for formation water from Federal 30 #2 Well (API 30-025-29069), depth 7,335-7,345 ft, located 3.9 miles from RH AGI #1 well.

3.5 Groundwater Hydrology in the Vicinity of the Red Hills Gas Plant

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are 15 freshwater wells located within a two-mile radius of the RH AGI wells, and only 2 water wells within one mile; the closest water well is located 0.31 miles away and has a total depth of 650 ft (**Figure 3.6-1; Appendix 3**). All water wells within the two-mile radius are shallow, collecting water from about 60 to 650 ft depth, in Alluvium and the Triassic redbeds. The shallow freshwater aquifer is protected by the surface and intermediate casings and cements in the RH AGI wells (**Figures Appendix 1-1 and Appendix 1.2**). While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

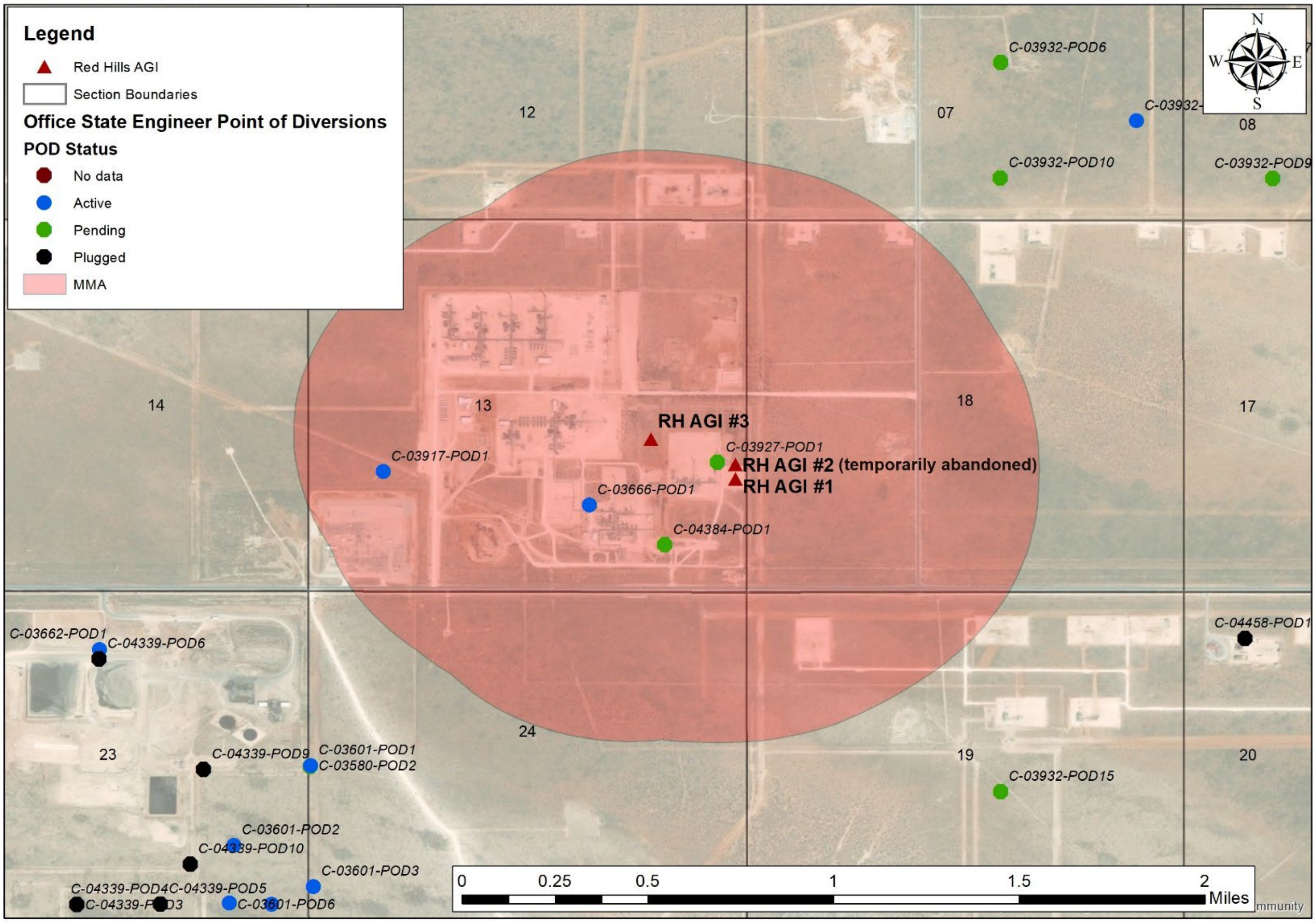


Figure 3.5-1: Reported Water Wells within the MMA for the RH AGI Wells.

3.6 Historical Operations

3.6.1 Red Hills Site

On July 20, 2010, Agave Energy Company (Agave) filed an application with NMOCD to inject treated acid gas into an acid gas injection well. Agave built the Red Hills Gas Processing Plant and drilled RH AGI #1 in 2012-13. However, the well was never completed and never put into service because the plant was processing only sweet gas (no H_2S). Lucid purchased the plant from Agave in 2016 and completed the RH AGI #1 well. TND acquired Lucid's Red Hills assets in 2022. **Figure 3.6.1-1** shows the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells. **Figure 3.6.1-2** shows a process block flow diagram.

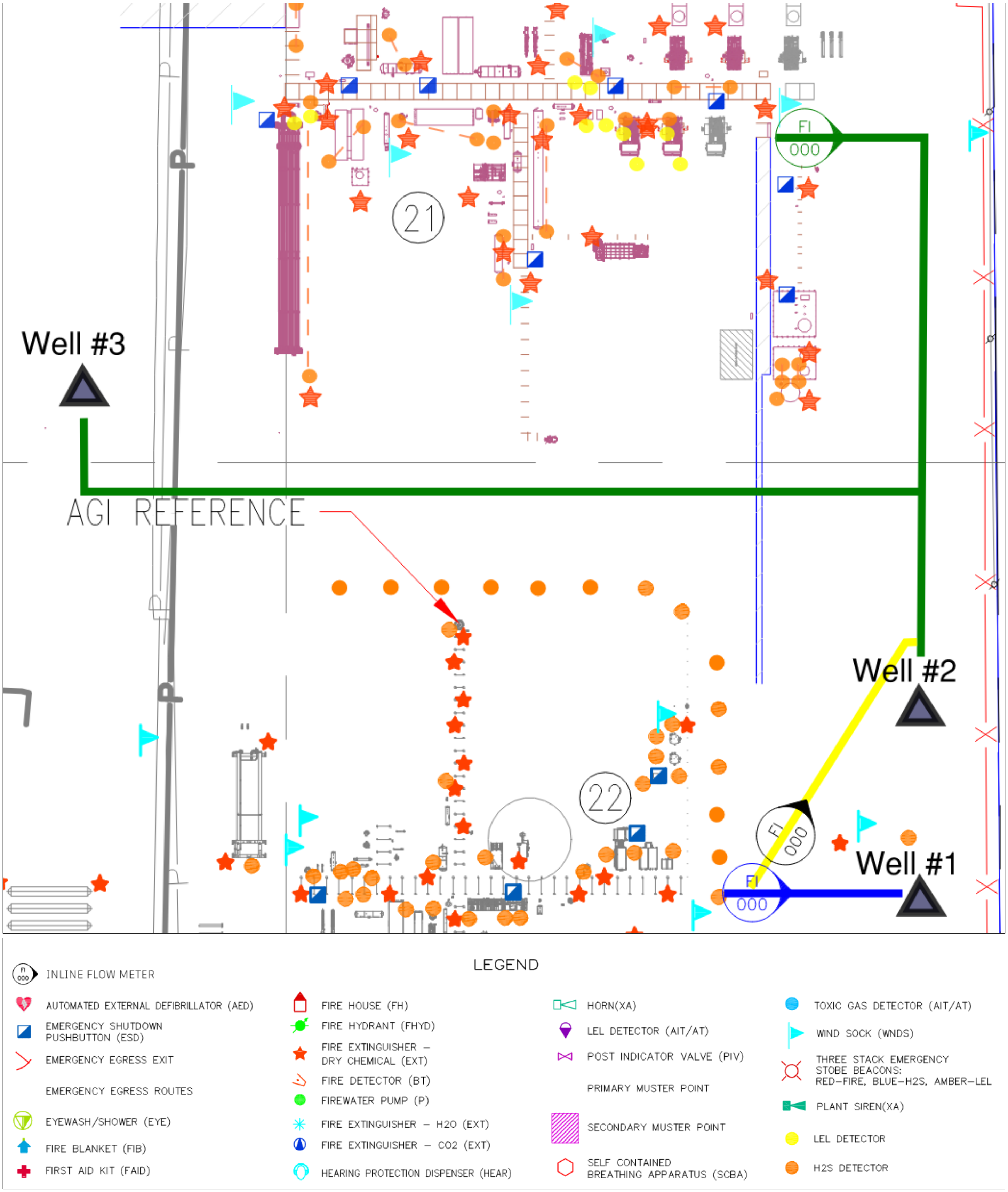


***Figure 3.6.1-1**: Diagram showing the location of fixed H_2S and lower explosive limit (LEL) detectors in the immediate vicinity of the RH AGI wells.*

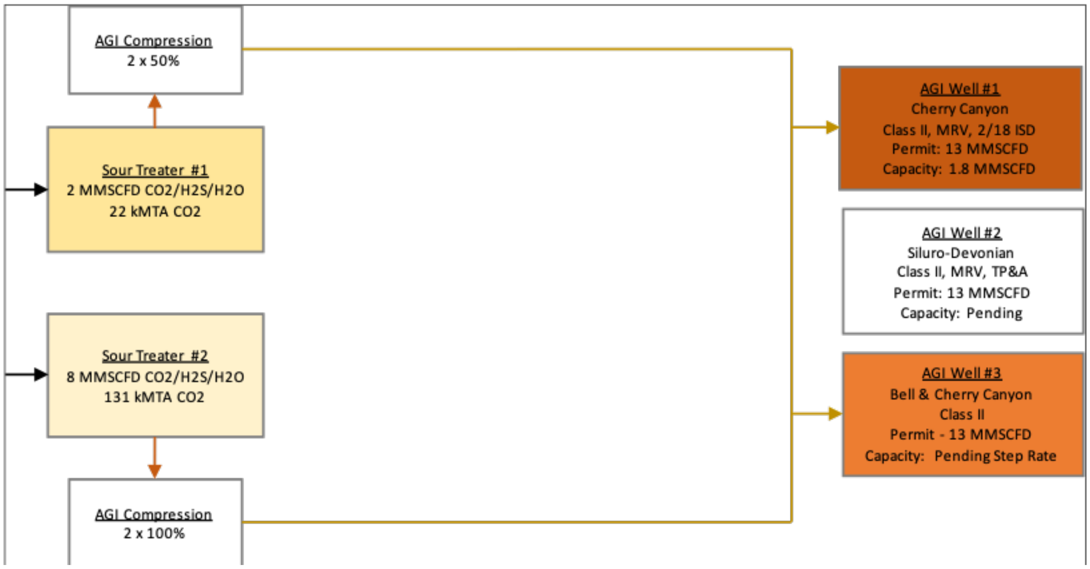


Figure 3.6.1-2: *Process Block Flow diagram showing components from sour treaters to AGI wells.*

3.6.2 Operations within the MMA for the RH AGI Wells

NMOCD records identify a total of 39 oil- and gas-related well records within the MMA for the RH AGI wells (see **Appendix 4**). **Figure 3.6-1** shows the geometry of producing and injection wells within the MMA for the RH AGI wells. **Appendix 4** summarizes the relevant information for those wells. All active production in this area is targeted for the Bone Spring and Wolfcamp zones, at depths of 8,900 to 11,800 ft, the Strawn (11,800 to 12,100 ft) and the Morrow (12,700 to 13,500 ft). All of these productive zones lie at more than 2,000 ft below the RH AGI #1 and AGI #3 injection zone.

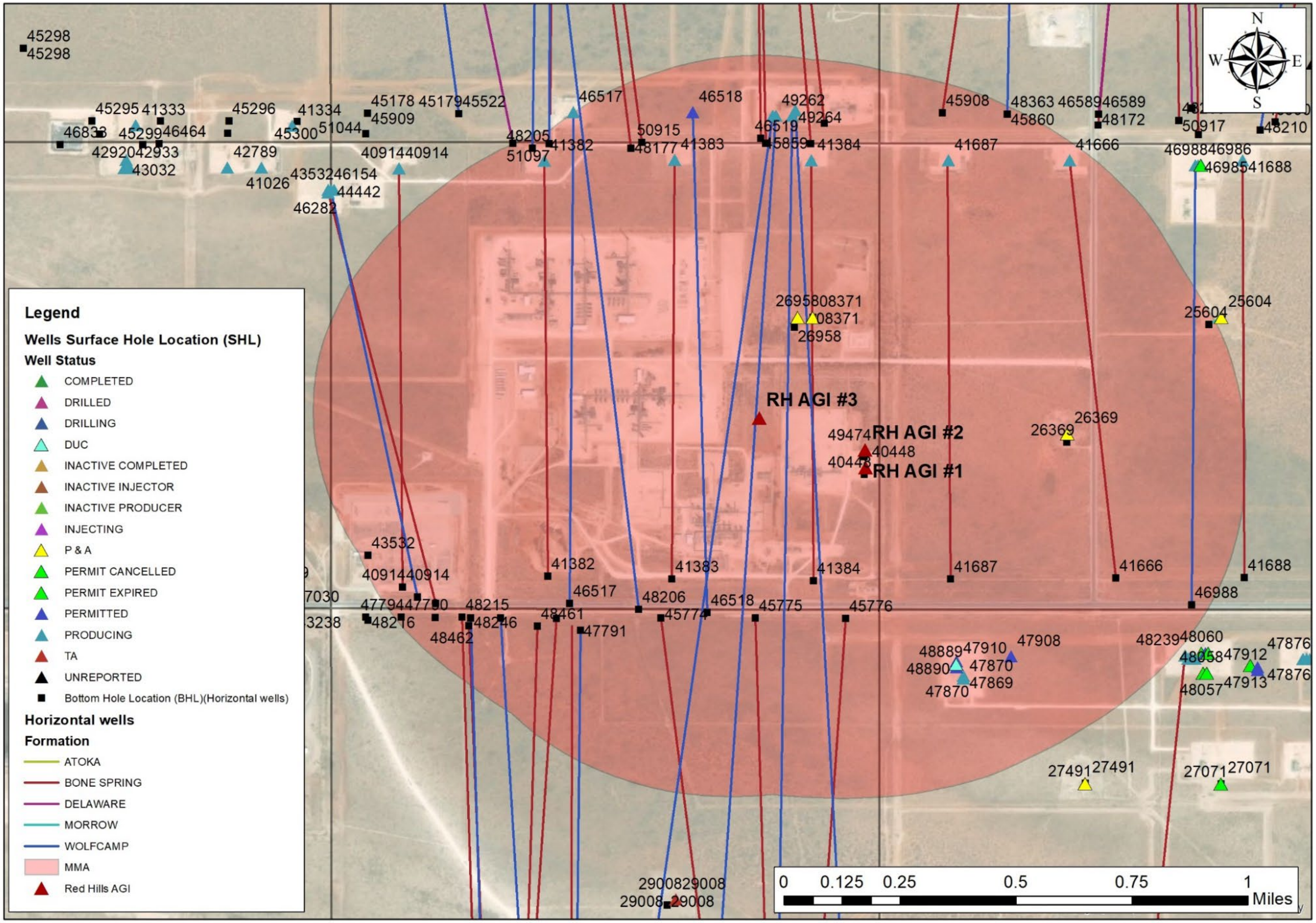


Figure 3.6-1: Location of all oil- and gas-related wells within the MMA for the RH AGI wells. Both the surface hole locations (SHL) and bottom hole locations (BHL) are labeled on the figure.

3.7 Description of Injection Process

The Red Hills Gas Plant, including the existing RH AGI #1 well, is in operation and staffed 24-hours-a-day, 7-days-a week. The plant operations include gas compression, treating and processing. The plant gathers and processes produced natural gas from Lea and Eddy Counties in New Mexico. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the plant's sweeteners will be routed to a central compressor facility, located west of the well head. Compressed TAG is then routed to the wells via high-pressure rated lines. **Figure 3.7-1** is a schematic of the AGI facilities.

The approximate composition of the TAG stream is: 80% CO_2, 20% H_2S, with Trace Components of C_1 – C_6 (methane – hexane) and Nitrogen. The anticipated duration of injection is 30 years.

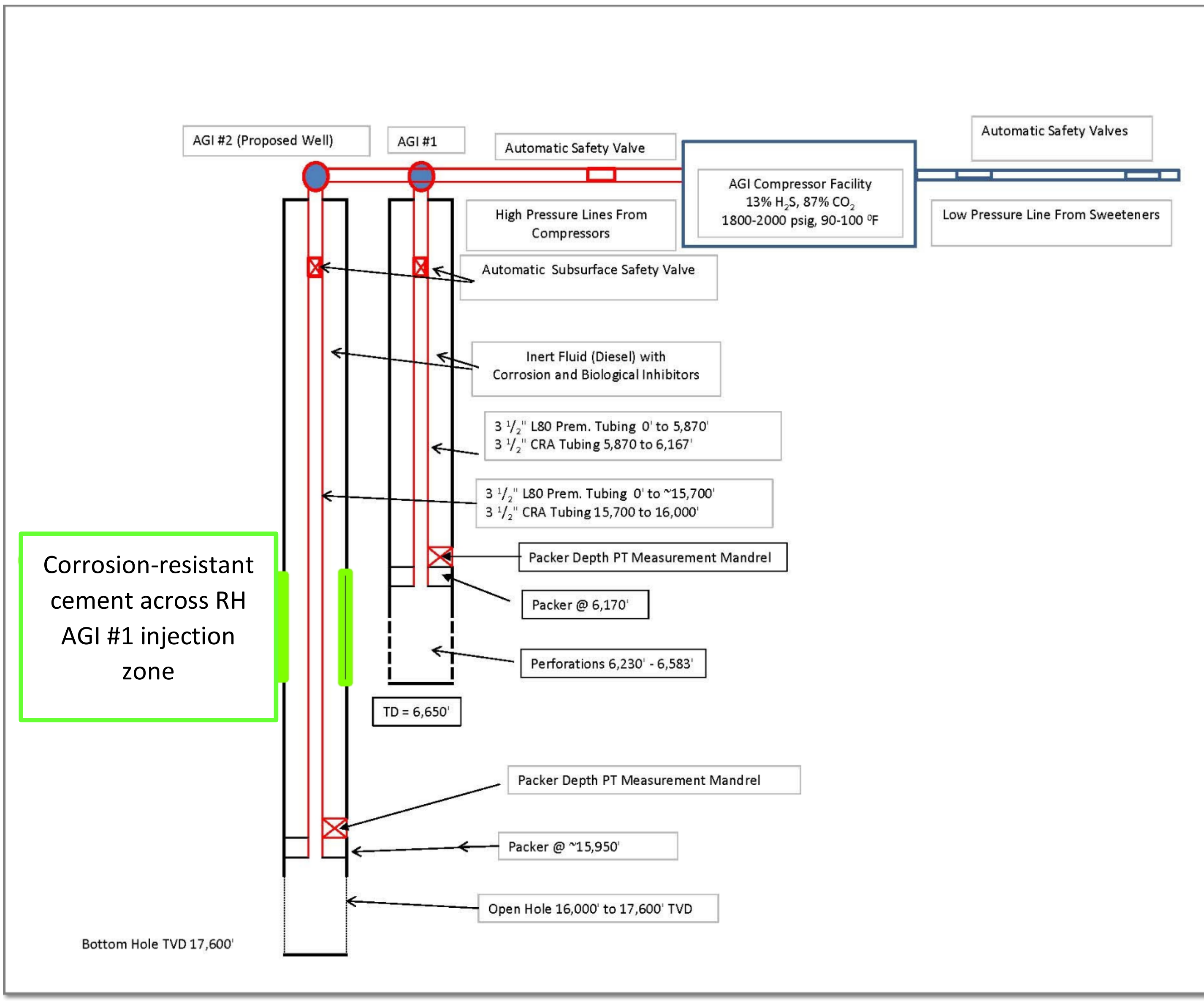


***Figure 3.7-1**: Schematic of surface facilities and RH AGI wells at the Red Hills Gas Processing Plant*

3.8 Reservoir Characterization Modeling

The modeling and simulation focused on the Bell Canyon and Cherry Canyon formations as the main injection target zone for acid gas storage. The RH AGI #1 well (API 30-025-40448) and the RH AGI #3 well (API 30-025-51970) are the approved injectors for treated acid gas injection by NMOCD and will serve as the injection wells in the model under approved disposal timeframe and maximum allowable injection pressure. RH AGI #1 well is completed in the Cherry Canyon formation between 6,230 feet to 6,583 feet (MD). The RH AGI #3 well will be completed in both the Bell Canyon and Cherry Canyon formations between approximately 5,245 feet to 6,645 feet (MD).

Schlumberger's Petrel® (Version 2023.1) software was used to construct the geological models used in this work. Computer Modeling Group (CMG)'s CMG-GEM® (Version 2023.10) was used in the reservoir simulations presented in this MRV plan. CMG-WINPROP® (Version 2023.10) was used to perform PVT calculation through Equation of States and properties interactions among various compositions to feed the hydrodynamic modeling performed by CMG-GEM®. The hydrodynamical model considered aqueous, gaseous, and supercritical phases, and simulates the storage mechanisms including structural trapping, residual gas trapping, and solubility trapping. Injected TAG may exist in the aqueous phase as dissolved state and the gaseous phase as supercritical state. The model was validated through matching the historical injection data of RH AGI #1 well and will be reevaluated periodically as required by the State permitting agency.

The static model is constructed with well tops and licensed 3D seismic data to interpret and delineate the structural surfaces of a layer within the caprock (Lamar Limestone) and its overlaying, underlying formations. The geologic model covers a 3.5-mile by 3.3-mile area. No distinctive geological structures such as faults are identified within the geologic model boundary. The model is gridded with 182 x 167 x 18, totaling 547,092 cells. The average grid dimension of the active injection area is 100 feet square. **Figure 3.8-1** shows the simulation model in 3D view. The porosity and permeability of the model is populated through existing well logs. The range of the porosity is between 0.01 to 0.31. The initial permeability are interpolated between 0.02 to 155 millidarcy (mD), and the vertical permeability anisotropy was 0.1. **(Figure 3.8-2 and Figure 3.8-3)**. These values are validated and calibrated with the historical injection data of RH AGI #1 well since 2018 as shown in **Figures 3.8-4, 3.8-5, and 3.8-6**.

The simulation model is calibrated with the injection history of RH AGI #1 well since 2018. Simulation studies were further performed to estimate the reservoir responses when predicting TAG injection for 30 years through both RH AGI #1 well (2018 – 2048) and RH AGI #3 (2024 - 2054). RH AGI #2 well is temporarily abandoned as of the submission of this document. RH AGI #1 is simulated to inject with the average rate of the last 5 years, 1.2 MMSCF, in the prediction phase. RH AGI #3 is simulated to inject with permitted injection rate, 13 MMSCF, with 1,767 psi maximum surface injection pressure constraint approved by State agency. The simulation terminated at year 2084, 30 years after the termination of all injection activities, to estimate the maximum impacted area during post injection phase.

During the calibration period (2018 – 2023), the historical injection rates were used as the primary injection control, and the maximum bottom hole pressures (BHP) are imposed on wells as the constraint, calculated based on the approved maximum injection pressure. This restriction is also estimated to be less than 90% of the formation fracture pressure calculated at the shallowest perforation depth of each well to ensure safe injection operations. The reservoir properties are tuned to match the historical injection until it was reasonably matched. **Figure 3.8-4** shows that the historical injection rates from the RH AGI #1 well in the Cherry Canyon Formation. **Figure 3.8-5** shows the BHP response of RH AGI #1 during the history matching phase.

During the forecasting period, linear cumulative injection behavior indicates that the Cherry Canyon and Bell Canyon formations received the TAG stream freely. **Figure 3.8-6** shows the cumulative disposed H_2S and CO_2 of each AGI injectors separately in gas mass. The modeling results indicate that the Cherry Canyon and Bell Canyon formations are capable of safely storing and containing the proposed gas volume without violating the permitted rate and pressure. **Figure 3.8-7** shows the gas saturation represented TAG plume at the end of 30-year forecasting in 3D view. **Figure 3.8-8** shows the extent of the plume migration in a map view at 4 key time steps. It can be observed that the size of the TAG is very limited and mainly stayed within Targa's Red Hills facility at the end of injection. In the year 2084, after 30 years of monitoring, the injected gas remained trapped in the reservoir and there was no significant migration of TAG footprint observed, compared to that at the end of injection.

In summary, after careful reservoir engineering review and numerical simulation study, our analysis shows that the Bell Canyon and Cherry Canyon formations can receive treated acid gas (TAG) at the proposed injection rate and permitted maximum surface injection pressure permitted by New Mexico Oil Conservation Committee. The formation will safely contain the injected TAG volume within the proposed injection and post-injection timeframe. The proposed injection well will allow for the sequestration while preventing associated environmental impacts.

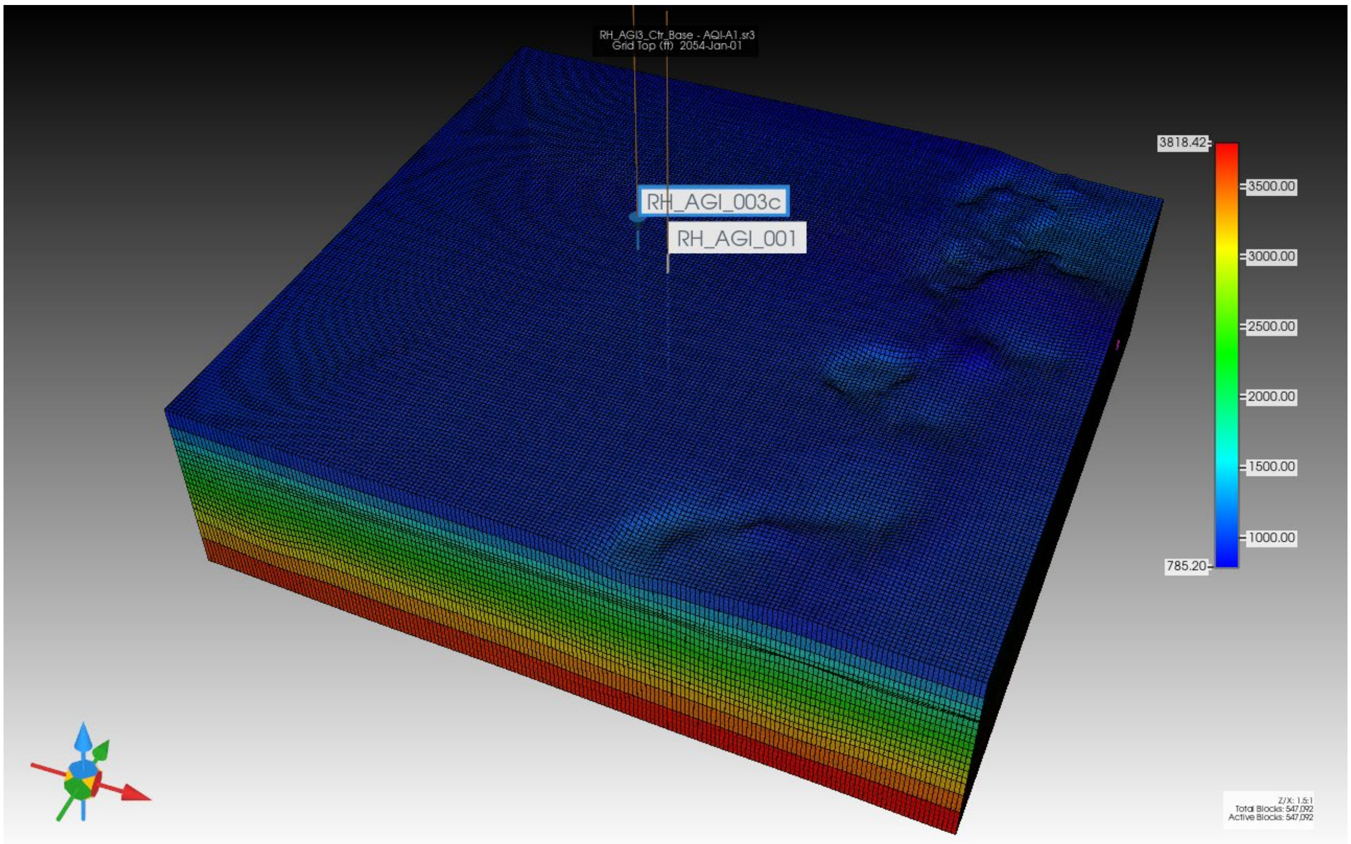


Figure 3.8-1: *3D view of the simulation model of the Red Hills AGI #1 and #3 AGI wells, containing Salado-Castile formation, Lamar limestone, Bell Canyon, and Cherry Canyon formations. Color legends represents the elevation of layers.*

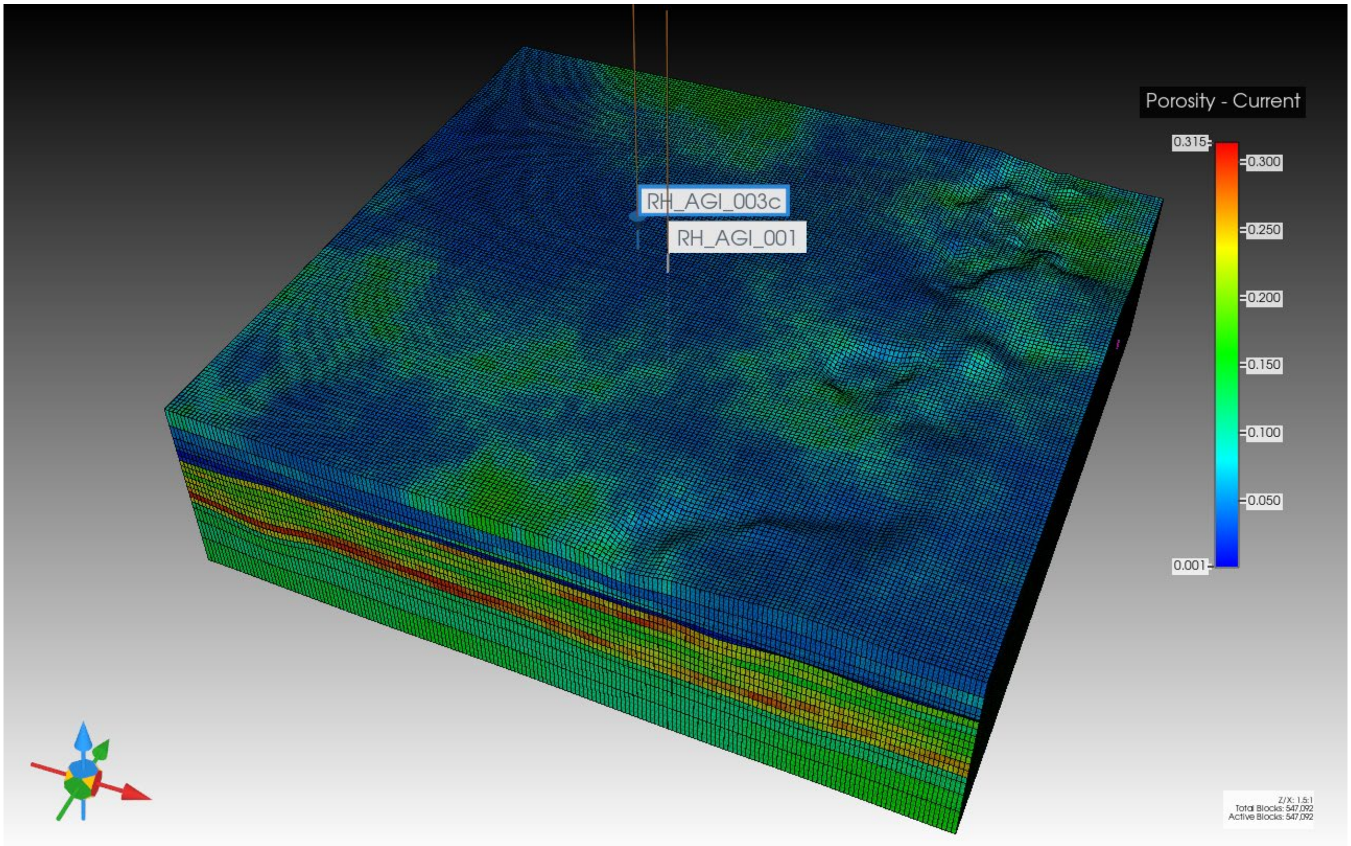


__Figure 3.8-2:__ Porosity estimation using available well data for the simulation domain.

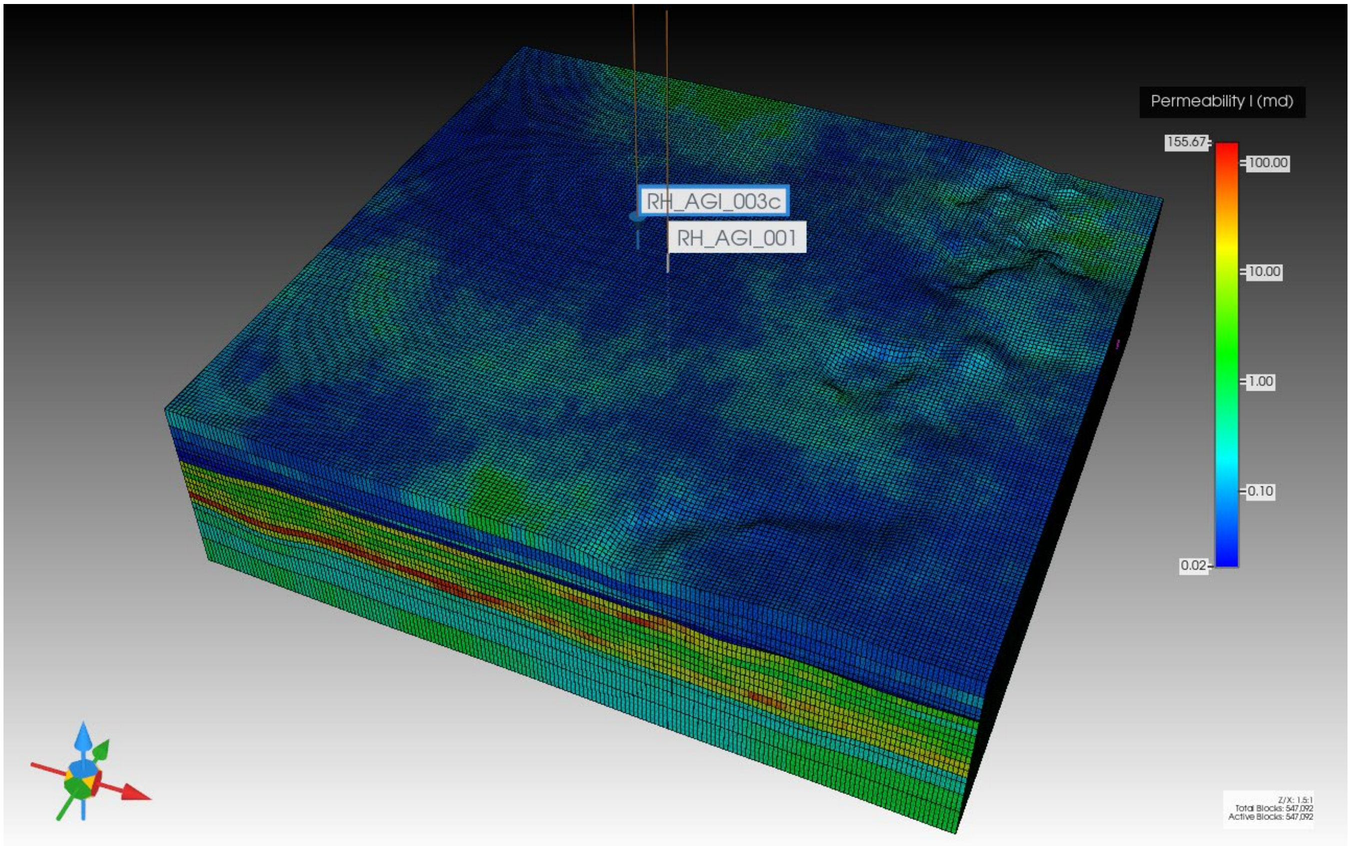


Figure 3.8-3: *Permeability estimation using available well data for simulation domain.*

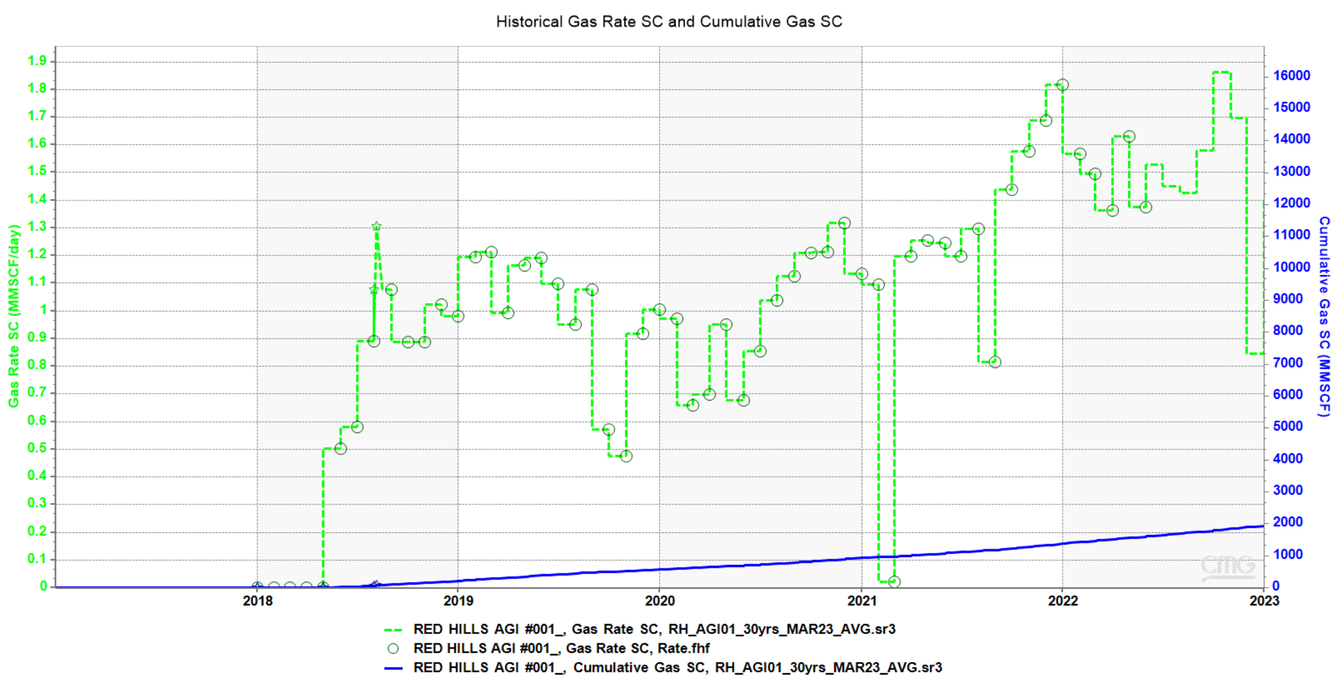


Figure 3.8-4: *shows the historical injection rate and total gas injected from Red Hills AGI #1 well (2018 to 2023)*

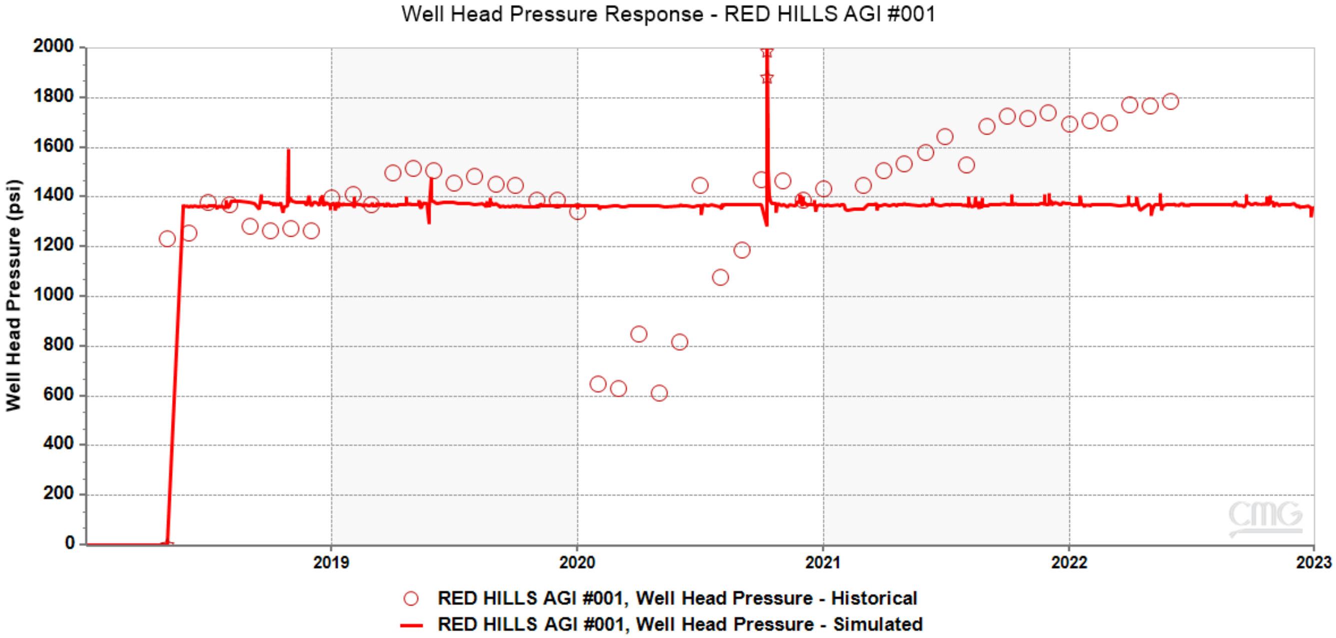


Figure 3.8-5: *shows the historical bottom hole pressure response from Red Hills AGI #1 well (2018 to 2023)*

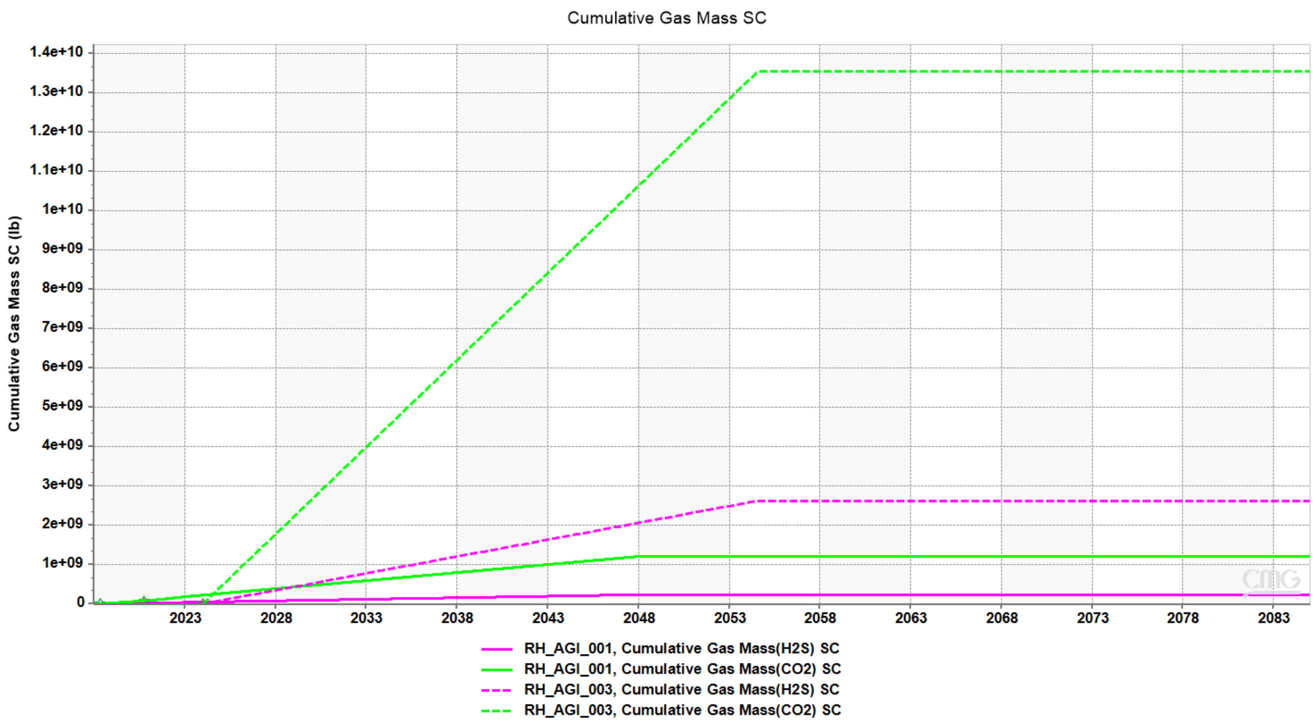


Figure 3.8-6: *shows the prediction of cumulative mass of injected CO_2 and H_2S of Red Hills AGI #1 and #3 wells (2018 to 2054).*

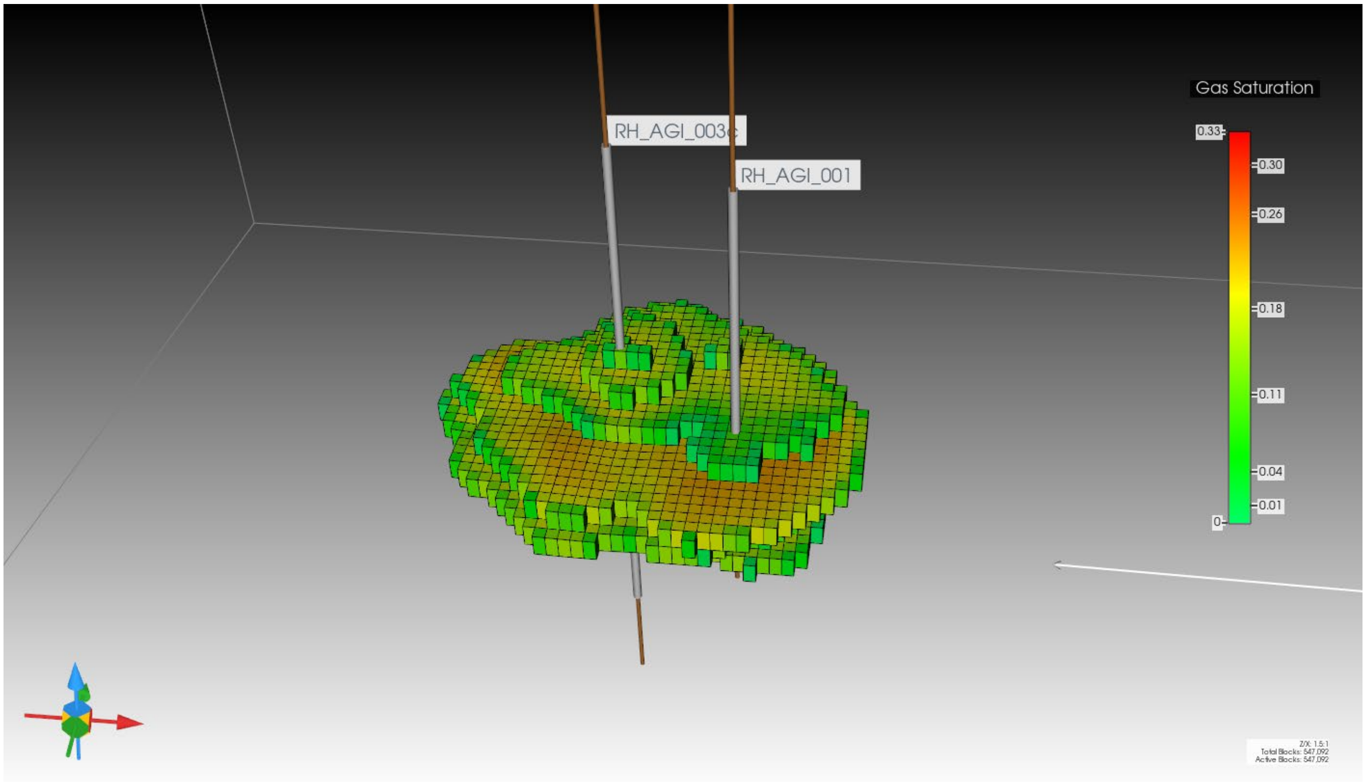


Figure 3.8-7: *shows the free phase TAG (represented by gas saturation) at the end of 30-year post-injection monitoring (2054) in 3D view.*

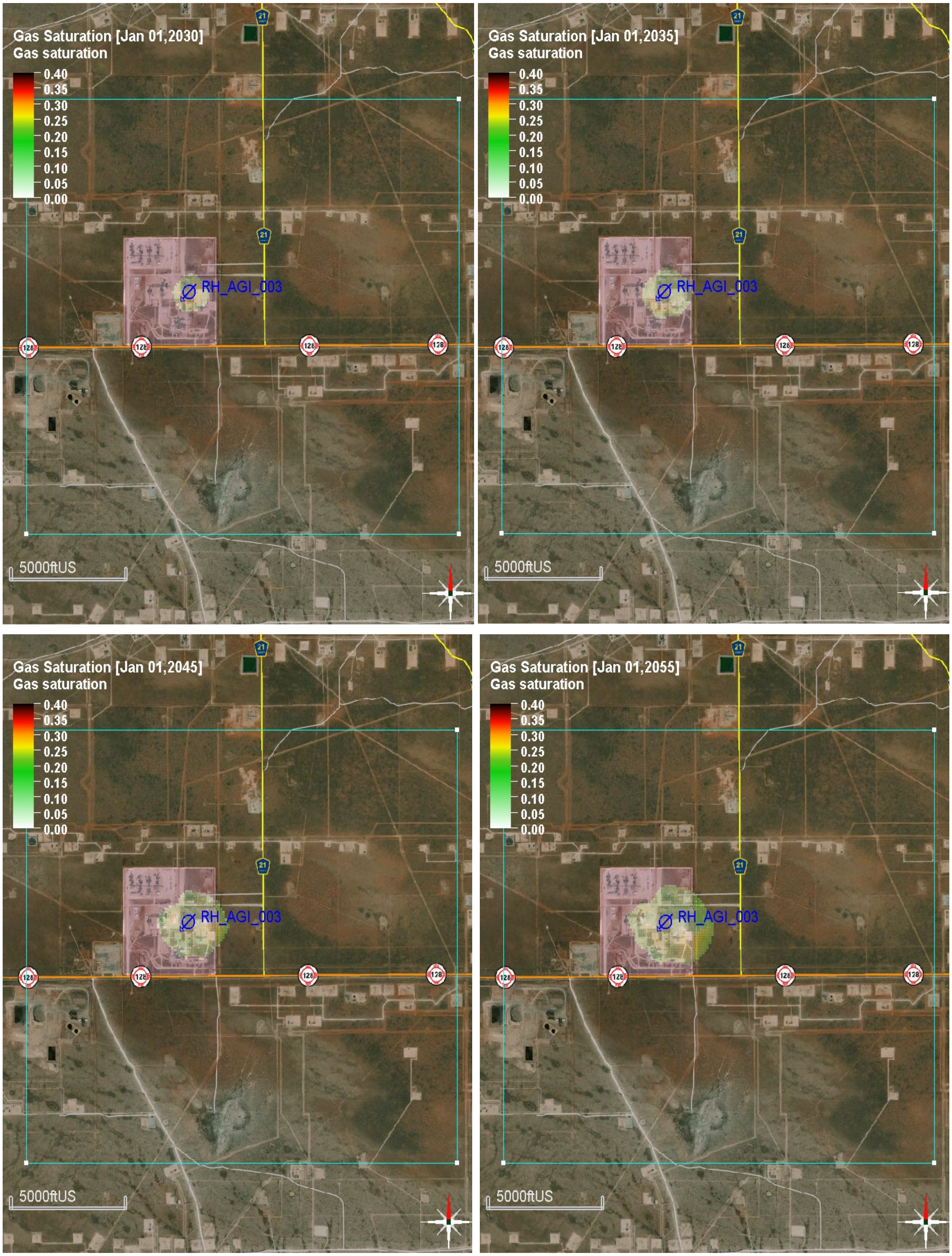


Figure 3.8-8: *shows the free phase TAG plume at year 2030, 2035, 2045, 2055 (1-year end of injection) in a map view.*

4 Delineation of the Monitoring Areas

In determining the monitoring areas below, the extent of the TAG plume is equal to the superposition of plumes in any layer for any of the model scenarios described in Section 3.8.

4.1 MMA – Maximum Monitoring Area

As defined in Subpart RR, the MMA is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. **Figures 4.1-1** shows the MMA as defined by the most conservative extent of the TAG plume at year 2054 plus a 1/2-mile buffer.

4.2 AMA – Active Monitoring Area

TND intends to define the AMA as the same area as the MMA.

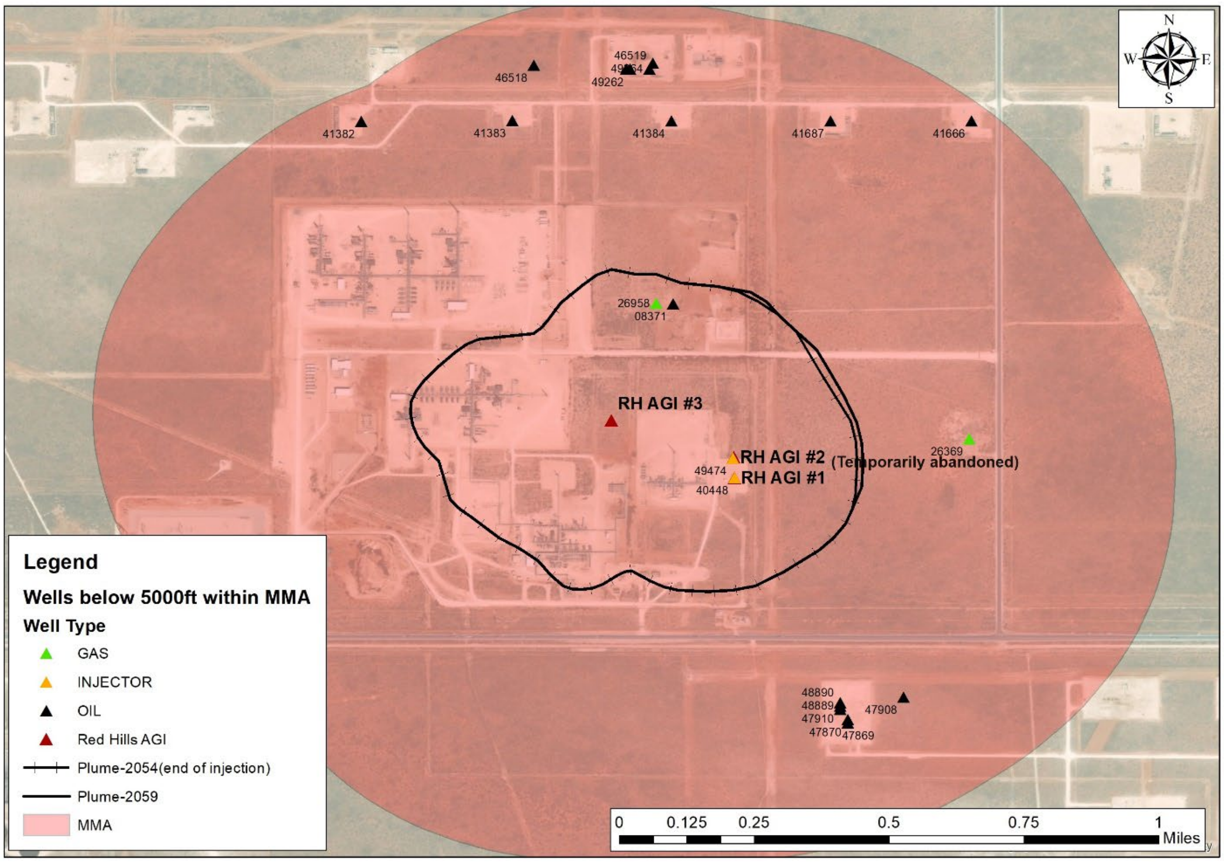


Figure 4.1-1: *Active monitoring area (AMA) for TND Red Hills AGI #1, #2 (temporarily abandoned) and #3 wells at the end of injection (2054, purple polygon) and 5 years post-monitoring (2059, maroon polygon). Maximum monitoring area (MMA) is shown in red shaded area.*

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

Subpart RR at 40 CFR 448(a)(2) requires the identification of potential surface leakage pathways for CO_2 in the MMA and the evaluation of the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways.

Through the site characterization required by the NMOCD C-108 application process for Class II injection wells, the geologic characterization presented in Section 3, and the reservoir modeling described in Section 3.9, TND has identified and evaluated the following potential CO_2 leakage pathways to the surface.

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas facilities. To minimize this potential for leakage, the construction, operation, and maintenance of gas plants follows industry standards and relevant regulatory requirements. Additionally, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills."

To further minimize the likelihood of surface leakage of CO_2 from surface equipment, TND implements a schedule for regular inspection and maintenance of surface equipment. To further minimize the magnitude and duration (timing) of detected gas leaks to the surface, TND implements several methods for detecting gas leaks at the surface. Detection is followed up by immediate response. These methods are described in more detail in sections 6 and 7.

Figure 3.6.1-1 is a schematic (taken from the Red Hills H_2S Contingency Plan) of the surface equipment at the Red Hills Gas Plant showing the location of the fixed H_2S monitors the number of which is greater in the vicinity of the sour gas plant, the sour gas pipeline, and the RH AGI wells.

Due to the required continuous monitoring of the gas processing systems, TND considers the likelihood, magnitude, and timing of CO_2 emission to the surface via this potential leakage pathway to be minimal. Detection and quantification of any leaks from surface equipment is described in Section 6.1 below.

5.2 Potential Leakage from Approved, Not Yet Drilled Wells

5.2.1 RH AGI #3

TND is currently drilling the RH AGI #3 well within the MMA. To minimize the likelihood of leaks from new wells, NMAC 19.15.26.9 regarding the casing and cementing of injection wells requires operators to case injection wells "with safe and adequate casing or tubing so as to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluid from the injection zone into another injection zone or to the surface around the outside of the casing string." To minimize the magnitude and duration (timing) of CO_2 leakage to the surface, NMAC 19.15.16.12 requires the use of "blowout preventers in areas of high pressure at or above the projected depth of the well." These requirements apply to any other new well drilled within the MMA for this MRV plan.

TND realizes that when they drill the RH AGI #3, they will be drilling into a reservoir in which they have been injecting H_2S and CO_2 for many years. Therefore, for safety purposes, they will be implementing enhanced safety protocols to ensure that no H_2S or CO_2 escapes to the surface during the drilling of RH AGI #3. Enhanced measures include:

- Using managed pressure drilling equipment and techniques thereby minimizing the chance of any gas from entering the wellbore
- Using LCM (loss control material) at a higher-than-normal rate to fill in the pockets of the wellbore thereby minimizing the chance of gas from entering the wellbore while drilling
- Monitoring H_2S at surface at many points to assure operators that we are successfully keeping any possible gas pressures from impacting the drilling operation
- Employing a high level of caution and care while drilling through a known H_2S injection zone, including use of slower drilling processes and more vigilant mud level monitoring in the returns while drilling into the RH AGI #1 injection zone

Due to these safeguards and the continuous monitoring of Red Hills wells operating parameters by the distributed control system (DCS), TND considers the likelihood, magnitude, and timing of CO_2 emissions to the surface via this potential leakage pathway to be minimal. Detection and quantification of any emissions from the Red Hills AGI wells are described in Section 6.3.1 below.

5.2.2 Horizontal Wells

The table in **Appendix 3** and **Figure 4.1-1** shows a number of horizontal wells in the area, many of which have approved permits to drill but which are not yet drilled. If any of these wells are drilled through the Bell Canyon injection zone for RH AGI #3 and the Cherry Canyon injection zone for RH AGI #1, they will be required to take special precautions to prevent leakage of TAG minimizing the likelihood of CO_2 leakage to the surface. This requirement will be made by NMOCD in regulating applications for permit to drill (APD) and in ensuring that the operator and driller are aware that they are drilling through an H_2S injection zone in order to access their target production formation. NMAC 19.15.11 for Hydrogen Sulfide Gas includes standards for personnel and equipment safety and H_2S detection and monitoring during well drilling, completion, well workovers, and well servicing operations all of which apply for wells drilled through the RH AGI wells TAG plume.

Due to the safeguards described above and the fact there are no proposed wells for which the surface hole location (SHL) lies within the simulated TAG plume, TND considers the likelihood, magnitude, and timing of CO_2 emissions to the surface via these horizontal wells to be minimal. Detection and quantification of any leaks from the proposed horizontal wells are described in Section 6.3.2 below.

5.3 Potential Leakage from Existing Wells

As shown in **Figure 3.7-1** and detailed in **Appendix 4**, there are several existing oil- and gas-related wells within the MMA as delineated in Section 4.

5.3.1 Well Completed in the Bell Canyon and Cherry Canyon Formations

The only wells completed in the Bell Canyon and Cherry Canyon Formations within the MMA are the RH AGI #1 and #3 wells and the COSSATOT E 002 well (API # 30-025-08371) which was completed at a depth of 5,425 ft. This well is within the Red Hills facility boundary and is plugged and abandoned (see **Appendix 9** for plugging and abandonment (P&A) record). **Appendix 1** includes schematics of the RH AGI wells construction showing multiple strings of casing all cemented to surface. Injection of TAG occurs through tubing with a permanent production packer set above the injection zone.

Due to the robust construction of the RH AGI wells and the plugging of the well 30-025-08371 above the Bell Canyon, TND considers the likelihood, magnitude, and timing of CO_2 emission to the surface via this potential leakage pathway to be minimal. Detection and quantification of any leaks from RH AGI wells and well 30-025-08371 are described in Section 6.3 below.

5.3.2 Wells Completed in the Bone Spring / Wolfcamp Zones

Several wells are completed in the Bone Spring and Wolfcamp production zones as described in Section 3.6.2. These productive zones lie more than 2,000 ft below the RH AGI wells injection zone minimizing the likelihood of communication between the RH AGI well injection zones and the Bone Spring / Wolfcamp production zones. Construction of these wells includes surface casing set at 1,375 ft and cemented to surface and intermediate casing set at the top of the Bell Canyon at depths of from 5,100 to 5,200 ft and cemented through the Permian Ochoan evaporites, limestone and siltstone (**Figure 3.2-2**) providing zonal isolation preventing TAG injected into the Bell Canyon and Cherry Canyon formations through RH AGI wells from leaking upward along the borehole in the event the TAG plume were to reach these wellbores. **Figure 4.1-1** shows that the modeled TAG plume extent after 30 years of injection and 5 years of post-injection stabilization does not extend to these well boreholes thereby indicating that these wells are not likely to be pathways for CO_2 leakage to the surface.

Due to the construction of these wells and the fact that the modeled TAG plume does not reach the SHL of these wells, TND considers the likelihood, magnitude, and timing of CO_2 emissions to the surface via this potential leakage pathway to be minimal. Detection and quantification of any leaks from these wells are described in Section 6.3 below.

5.3.3 Wells Completed in the Siluro-Devonian Zone

One well penetrated the Devonian at the boundary of the MMA - EOG Resources, Government Com 001, API # 30-025-25604, TVD = 17,625 ft, 0.87 miles from RH AGI #3. This well was drilled to a total depth of 17,625 ft on March 5, 1978, but plugged back to 14,590 ft, just below the Morrow, in May of 1978. Subsequently, this well was permanently plugged and abandoned on December 30, 2004, and approved by NMOCD on January 4, 2005 (see **Appendix 9** for P&A records). The approved plugging provides zonal isolation for the Bell Canyon and Cherry Canyon injection zones minimizing the likelihood that this well will be a pathway for CO_2 emissions to the surface from either injection zone.

Due to the location of this well at the edge of the MMA, TND considers the likelihood, magnitude, and timing of CO_2 emissions to the surface via this potential leakage pathway to be minimal. Detection and quantification of any leaks attributed to this well are described in Section 6.3 below.

5.3.4 Groundwater Wells

Figure 3.6-1 shows 15 water wells within a 2-mile radius of the RH AGI wells, only 2 of which are within a 1-mile radius of and within the MMA for the RH AGI wells. The deepest ground water well is 650 ft deep (**Table 3.6-1**). The evaporite sequence of the Permian Ochoan Salado and Castile Formations (see Section 3.2.2) provides an excellent seal between these groundwater wells and the Cherry Canyon injection zone of the RH AGI #1 well. Therefore, it is unlikely that these two groundwater wells are a potential pathway of CO_2 leakage to the surface. Nevertheless, the CO_2 surface monitoring and groundwater monitoring described in Sections 6 and 7 will provide early detection of CO_2 leakage followed by immediate response thereby minimizing the magnitude of CO_2 leakage volume via this potential pathway.

Due to the shallow depth of the groundwater wells within the MMA relative to the depth of the RH AGI wells, TND considers the likelihood, magnitude, and timing of CO_2 emissions to the surface via this potential leakage pathway to be minimal. Detection and quantification of CO_2 in groundwater is described in the groundwater monitoring in Section 7.7 below.

5.4 Potential Leakage through the Confining / Seal System

The site characterization for the injection zone of the RH AGI wells described in Sections 3.2.2 and 3.3 indicates a thick sequence of Permian Ochoan evaporites, limestone, and siltstones (**Figure 3.2-2**) above the Bell Canyon and Cherry Canyon Formations and no evidence of faulting. Therefore, it is unlikely that TAG injected into the Bell Canyon and Cherry Canyon Formations will leak through this confining zone to the surface. Limiting the injection pressure to less than the fracture pressure of the confining zone will minimize the likelihood of CO_2 leakage through this potential pathway to the surface.

Due to the thick sequence of Permian Ochoan evaporites overlying the injection zone for the RH AGI wells, TND considers the likelihood, magnitude, and timing of CO_2 emissions to the surface via this potential leakage pathway to be minimal. Detection and quantification of any surface emissions attributed to leakage through the confining zone are described in Section 6.4 below.

5.5 Potential Leakage due to Lateral Migration

The characterization of the sand layers in the Cherry Canyon Formation described in Section 3.3 states that these sands were deposited by turbidites in channels in submarine fan complexes, each sand is encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity. Regional consideration of their depositional environment suggests a preferred orientation for fluid and gas flow would be south-to-north along the channel axis. However, locally the high net porosity of the RH AGI #1 and

#2 injection zones indicates adequate storage capacity such that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA due to a preferred regional depositional orientation.

Lateral migration of the injected TAG was addressed in detail in Section 3.3. Therein it states that the units dip gently to the southeast with approximately 200 ft of relief across the area. Heterogeneities within both the Bell Canyon and Cherry Canyon sandstones, such as turbidite and debris flow channels, will exert a significant control over the porosity and permeability within the two units and fluid migration within those sandstones. In addition, these channels are frequently separated by low porosity and permeability siltstones and shales as well as being encased by them. Based on regional studies, the preferred orientation of the channels, and hence the preferred fluid migration pathways, are roughly from the east to the west.

Based on the discussion of the channeled sands in the injection zone TND considers the likelihood, magnitude, and timing of CO_2 emissions to the surface via this potential leakage pathway to be possible. Detection and quantification of any emissions attributed to lateral migration to a surface leakage pathway are described in Section 6.5 below.

5.6 Potential Leakage through Fractures and Faults

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology as well as identify and understand the distribution of faults and fractures. **Figure 5.6-1** shows the fault traces in the vicinity of the Red Hill plant. The faults shown on **Figure 5.6-1** are confined to the Paleozoic section below the injection zone for the RH AGI wells. No faults were identified in the confining zone above the Bell Canyon and Cherry Canyon injection zone for the RH AGI wells.

Due to the lack of evidence of faults above the confining zone for the RH AGI wells, TND considers the likelihood, magnitude, and timing of CO_2 emissions to the surface via this potential leakage pathway to be minimal. Detection and quantification of any leaks attributed to any heretofore unidentified faults or fractures are described in Section 6.6 below.

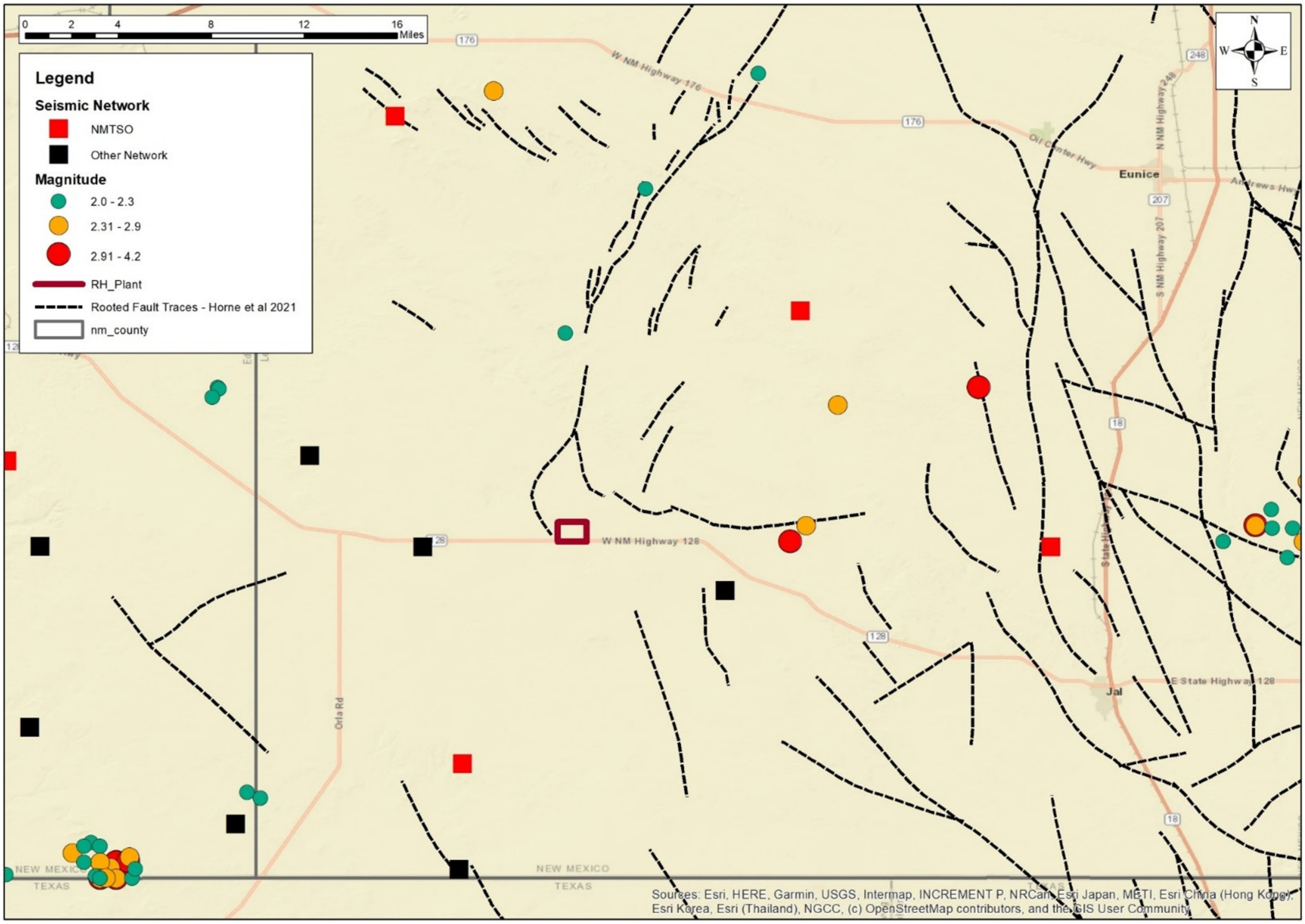


Figure 5.6-1: New Mexico Tech Seismological Observatory (NMTSO) seismic network close to the operations, recent seismic events, and fault traces (2022-2023). Note: Fault traces are from Horne et al 2021 for faults in the Paleozoic.

5.7 Potential Leakage due to Natural / Induced Seismicity

The New Mexico Tech Seismological Observatory (NMTSO) monitors seismic activity in the state of New Mexico. A search of the database shows no recent seismic events close to the Red Hills operations. The closest recent, as of 4 September 2023, seismic events are:

- 7.5 miles, 2022-09-03, Magnitude 3
- 8 miles, 2022-09-02, Magnitude 2.23
- 8.6 miles, 2022-10-29, Magnitude 2.1

Figure 5.6-1 shows the seismic stations and recent seismic events in the area around the Red Hills site.

Due to the distance between the Red Hills AGI wells and the recent seismic events and the magnitude of the events, TND considers the likelihood, magnitude, and timing of CO_2 emissions to the surface via this potential leakage pathway to be minimal. Monitoring of seismic events in the vicinity of the Red Hills AGI wells is discussed in Section 6.7.

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

Subpart RR at 40 CFR 448(a)(3) requires a strategy for detecting and quantifying surface leakage of CO_2. TND will employ the following strategy for detecting, verifying, and quantifying CO_2 leakage to the surface through the potential pathways for CO_2 surface leakage identified in Section 5. TND considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to detect, verify, and quantify CO_2 surface leakage. **Table 6-1** summarizes the leakage monitoring of the identified leakage pathways. Monitoring will occur for the duration of injection and the 5-year post-injection period.

Table 6.1: Summary of Leak Detection Monitoring

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/CO_2 monitoring network • Personal and hand-held gas monitors
New RH AGI Well	• Vigilant monitoring of fluid returns during drilling • Multiple gas monitoring points around drilling operations – personal and hand-held gas monitors
Existing RH AGI Well	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors • In-well P/T sensors • Groundwater monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Confining Zone / Seal	• DCS surveillance of well operating parameters

Potential Leakage Pathway	Detection Monitoring
	● Fixed in-field gas monitors/CO_2 flux monitoring network ● Groundwater monitoring
Natural / Induced Seismicity	● DCS surveillance of well operating parameters ● Seismic monitoring
Lateral Migration	● DCS surveillance of well operating parameters ● Fixed in-field gas monitors/CO_2 flux monitoring network ● Groundwater monitoring
Additional Monitoring	● Groundwater monitoring ● Soil flux monitoring

6.1 Leakage from Surface Equipment

TND implements several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S sensors, and continual monitoring of operational parameters.

Leaks from surface equipment are detected by TND field personnel, wearing personal H_2S monitors, following daily and weekly inspection protocols which include reporting and responding to any detected leakage events. TND also maintains in-field gas monitors to detect H_2S and CO_2. The in-field gas monitors are connected to the DCS housed in the onsite control room. If one of the gas detectors sets off an alarm, it would trigger an immediate response to address and characterize the situation.

The following description of the gas detection equipment at the Red Hills Gas Processing Plant was extracted from the H_2S Contingency Plan:

"**Fixed Monitors**
The Red Hills Plant has numerous ambient hydrogen sulfide detectors placed strategically throughout the Plant to detect possible leaks. Upon detection of hydrogen sulfide at 10 ppm at any detector, visible beacons are activated, and an alarm is sounded. Upon detection of hydrogen sulfide at 90 ppm at any detector, an evacuation alarm is sounded throughout the Plant at which time all personnel will proceed immediately to a designated evacuation area. The Plant utilizes fixed-point monitors to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the Distributed Control System (DCS). The monitors are equipped with amber beacons. The beacon is activated at 10 ppm. The plant and AGI well horns are activated with a continuous warbling alarm at 10 ppm and a siren at 90 ppm. All monitoring equipment is Red Line brand. The Control Panel is a 24 Channel Monitor Box, and the fixed point H_2S Sensor Heads are model number RL-101.

The Plant will be able to monitor concentrations of H_2S via H_2S Analyzers in the following locations:

- Inlet gas of the combined stream from Winkler and Limestone
- Inlet sour liquid downstream of the slug catcher
- Outlet Sweet Gas to Red Hills 1

• Outlet Sweet Liquid to Red Hills Condensate Surge

The AGI system monitors can also be viewed on the PLC displays located at the Plant. These sensors are all shown on the plot plan (see **Figure 5.1-1**). This requires immediate action for any occurrence or malfunction. All H_2S sensors are calibrated monthly.

Personal and Handheld H2S Monitors

All personnel working at the Plant wear personal H_2S monitors. The personal monitors are set to alarm and vibrate at 10 ppm. Handheld gas detection monitors are available at strategic locations around the Plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and carbon dioxide (CO_2)."

TND's internal operational documents and protocols detail the steps to be taken to verify leaks of H_2S.

Quantification of CO_2 emissions from surface equipment and components will be estimated according to the requirements of 98.444(d) of Subpart RR as discussed in Sections 8.4 and 10.4. Furthermore, if CO_2 surface emissions are indicated by any of the monitoring methods listed in Table 6.1, TND will quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. TND has standard operating procedures to report and quantify all pipeline leaks in accordance with the NMOCD regulations (New Mexico administrative Code 19.15.28 Natural Gas Gathering Systems). TND will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by TND or third parties.

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones as described in Section 5.2.1 for RH AGI #3 including more frequent monitoring during drilling operations. This applies to TND and other operators drilling new wells through the RH AGI injection zones.

6.3 Leakage from Existing Wells

6.3.1 RH AGI Wells

As part of ongoing operations, TND continuously monitors and collects flow, pressure, temperature, and gas composition data in the data collection system. These data are monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits.

To monitor leakage and wellbore integrity, two pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) were deployed in TND's RH AGI #1 well. One gauge is designated to monitor the tubing ID (reservoir) pressure and temperature and the second gauge monitors the annular space between the tubing and the long string casing (**Figure 6.2-1**). A leak is indicated when both gauges start reading the same pressure. DTS is clamped to the tubing, and it monitors the temperature profiles of the annulus from 6,159 ft to surface. DTS can detect variation in the temperature profile events throughout the tubing and or casing. Temperature variation could be an indicator of leaks. Data from temperature and pressure gauges is recorded by an interrogator housed in an onsite control room. DTS (temperature) data is recorded by a separate interrogator that is also housed in the onsite control room. Data from both interrogators are transmitted to a remote location for daily real time or historical analysis.

If operational parameter monitoring and MIT failures indicate a CO_2 leak has occurred, TND will take actions to quantify the leak based on operating conditions at the time of the detection including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site.

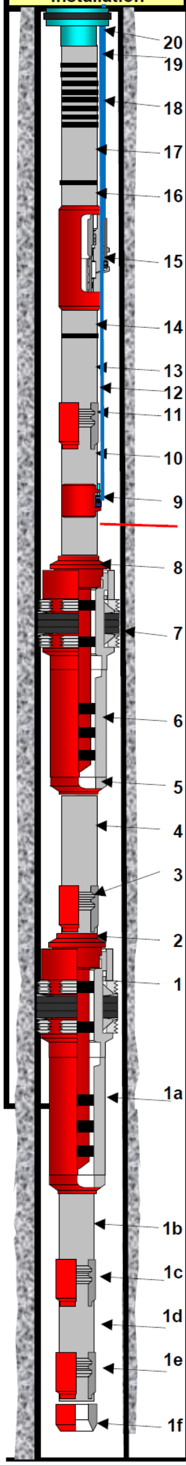
HALLIBURTON

Installation

Lucid

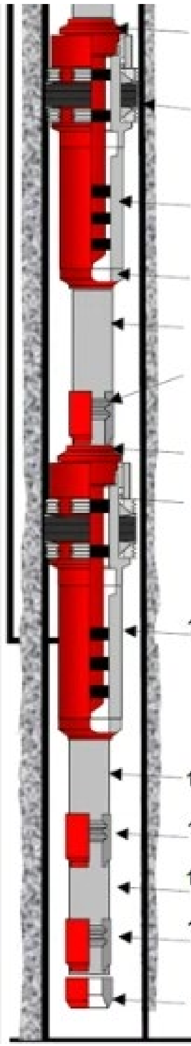
Red Hills AGI 1
Lea County New Mexico
2/3/21 - 2/28/21

WSP - Troy Gillen / Michael Forrier
Sales Rep - Lynn Talley (432) 631-4626
Tool Specialists: Carey Lehmann, Jonathan Phillips, Jose Vargas



Installation	Depth	Length	Jts.	Description	OD	ID
	18.50	18.50		KB		
20	22.90	4.40		20) Hanger Sub 3 1/2" 9.2# CRA VAMTOP x 7.7# VAM Ace Pin	7.000	3.000
19	64.05	41.15	1	19) 3 1/2" 7.7# VAM ACE 125K G3 Tubing (Slick Joint)	3.500	3.035
				Ran Eight Subs 8', 8', 6', 6',4', 4', 2', 2'		
18	103.97	39.92		18) 3 1/2" 7.7# VAM ACE 125K G3 Spaceout Subs	3.500	3.035
17	235.95	131.98	3	17) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.035
16	241.95	6.00		16) 6' x 3 1/2" 7.7# CRA VAM ACE Box x 9.2# VAMTOP Pin	3.540	2.959
15	246.30	4.35		15) 3 1/2" NE HES SSSV Nickel Alloy 925 w/Alloy 825 Control Line 3 1/2" 9.2# VAMTOP Box x Pin	5.300	2.813
14	252.29	5.99		14) 6' x 3 1/2" 9.2# CRA VAMTOP Box x 7.7# VAM ACE Pin	3.540	2.959
13	6,140.23	5,887.94	134	13) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.305
12				12) 3 1/2" 7.7# VAM ACE Box x 9.2# VAMTOP Pin CRA Crossover	3.830	2.959
11				11) 2.813" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925	4.073	2.813
10	6,153.72	13.49		10) 6' x 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy G3 Sub	3.540	2.959
				13.49' Length Includes Line Items 10, 11 & 12		
	6,159 Tubing	P/T				
9				9) Baker PT Sensor Mandrel 3 1/2" 9.2# VAMTOP Box x Pin 6' VAMTOP 9.2# CRA Tubing Sub Above & Below Gauge Mdl	5.200	2.992
	6,162.6 Annular	P/T				
8	6,161.23	7.51		8) 4.00" BWS Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925	4.470	2.959
				7.51' Length Includes Line Items 8 & 9		
7	6,164.55	3.32		7) 7" 26-32# x 4.00" BWS Packer Nickel Alloy 925 Casing Collar @ 6,160.6' WL Measurement	5.875	4.000
6	6,172.05	7.5		6) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
5	6,172.88	0.83		5) 4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
4	6,181.19	8.31		4) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
3	6,182.52	1.33		3) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925 #102204262	4.073	2.562
2	6,184.29	1.77		2) Straight Slot Locator Seal Assembly Above Top Of Packer	4.450	2.880
1		6,186.06		1) BWD Permanent Packer. WL Measured Depth Previously 6189'	5.875	4.000
				1a) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.660	2.965
1a				1b) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
				1c) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel,	2.920	2.562
				1d) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
				1e) 2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	3.920	2.321
1b				1f) Re-Entry Guide / POP	3.950	3.000
1c						
1d						
1e						
1f						

__Figure 6.2-1:__ Well Schematic for RH AGI #1 showing installation of P/T sensors



8	6,161.23	7.51	8) 4.00" BWS Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925 7.51' Length Includes Line Items 8 & 9	4.470	2.959
7	6,164.55	3.32	7) 7" 26-32# x 4.00" BWS Packer Nickel Alloy 925 Casing Collar @ 6,160.6' WL Measurement	5.875	4.000
6	6,172.05	7.5	6) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
5	6,172.88	0.83	5) 4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
4	6,181.19	8.31	4) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
3	6,182.52	1.33	3) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925 #102204262	4.073	2.562
2	6,184.29	1.77	2) Straight Slot Locator Seal Assembly Above Top Of Packer	4.450	2.880
1		6,186.06	1) BWD Permanent Packer. WL Measured Depth Previously 6189'	5.875	4.000
1a			1a) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.660	2.965
1b			1b) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1c			1c) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel,	2.920	2.562
1d			1d) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1e			1e) 2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	3.920	2.321
1f			1f) Re-Entry Guide / POP	3.950	3.000

***Figure 6.2-2**: Well Schematic for RH AGI #3 showing intended installation of P/T sensors*

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7.3 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through the Confining / Seal System

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the RH AGI wells, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If changes in operating parameters or other monitoring listed in Table 6.1 indicate leakage of CO_2 through the confining / seal system, TND will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, including shutting in the well(s).

6.5 Leakage due to Lateral Migration

Continuous operational monitoring of the RH AGI wells during and after the period of the injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The CO_2 monitoring network described in Section 7.3, and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If monitoring of operational parameters or other monitoring methods listed in Table 6.1 indicates that the CO_2 plume extends beyond the area modeled in Section 3.8 and presented in Section 4, TND will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 release to the surface. As this scenario would be considered a material change per 40CFR98.448(d)(1), TND will submit a revised MRV plan as required by 40CFR98.448(d).

6.6 Leakage from Fractures and Faults

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through faults. However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, TND will identify which of the pathways listed in this section are responsible for the leak, including the possibility of heretofore unidentified faults or fractures within the MMA. TND will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.7 Leakage due to Natural / Induced Seismicity

In order to monitor the influence of natural and/or induced seismicity, TND will use the established NMTSO seismic network. The network consists of seismic monitoring stations that detect and locate seismic events. Continuous monitoring helps differentiate between natural and induced seismicity. The network surrounding the Red Hills Gas Processing Plant has been mapped on **Figure 5.6-1**. The monitoring network records Helicorder data from UTC (coordinated universal time) all day long. The data are plotted daily at 5pm MST (mountain standard time). These plots can be browsed either by station or by day. The data are streamed continuously to the New Mexico Tech campus and archived at the Incorporated Research Institutions for Seismology Data Management Center (IRIS DMC).

If monitoring of the NMTSO seismic monitoring stations, the operational parameters and the fixed infield gas monitors indicates surface leakage of CO_2 linked to seismic events, TND will assess whether the CO_2 originated from the RH AGI wells and, if so, take measures to quantify the mass of CO_2 emitted to the surface based on operational conditions at the time the leak was detected. See Section 7.6 for details regarding seismic monitoring and analysis.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

TND uses the existing automatic distributed control system to continuously monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO_2. TND considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to establish baselines for monitoring CO_2 surface leakage. The following describes TND's strategy for collecting baseline information.

7.1 Visual Inspection

TND field personnel conduct frequent periodic inspections of all surface equipment providing opportunities to assess baseline concentrations of H_2S, a proxy for CO_2, at the Red Hills Gas Plant.

7.2 Fixed In-Field, Handheld, and Personal H_2S Monitors

Compositional analysis of TND's gas injectate at the Red Hills Gas Plant indicates an approximate H_2S concentration of 12% thus requiring TND to develop and maintain an H_2S Contingency Plan (Plan) according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). TND considers H_2S to be a proxy for CO_2 leaks at the plant. The Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated RH AGI Wells and documents procedures that would be followed in case of such an event.

7.2.1 Fixed In-Field H_2S Monitors

The Red Hills Gas Plant utilizes numerous fixed-point monitors, strategically located throughout the plant, to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the DCS. Upon detection of H_2S at 10 ppm at any detector, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of hydrogen sulfide at 90 ppm at any monitor, an evacuation alarm is sounded throughout the plant at which time all personnel will proceed immediately to a designated evacuation area.

7.2.2 Handheld and Personal H_2S Monitors

Handheld gas detection monitors are available at strategic locations around the plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and CO_2.

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the plant must wear personal H_2S monitoring devices to assist them in detecting the presence of unsafe levels of H_2S. Personal monitoring devices will give an audible alarm and vibrate at 10 ppm.

7.3 CO_2 Detection

In addition to the handheld gas detection monitors described above, New Mexico Tech, through a DOE research grant (DE-FE0031837 – Carbon Utilization and Storage Project of the Western USA (CUSP)), will assist TND in setting up a monitoring network for CO_2 leakage detection in the AMA as defined in Section 4.2. The scope of work for the DOE project includes field sampling activities to monitor CO_2/H_2S at the two RH AGI wells. These activities include periodic well (groundwater and gas) and atmospheric sampling from an area of 10 – 15 square miles around the injection wells. Once the network is set up, TND will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

7.4 Continuous Parameter Monitoring

The DCS of the plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS, and engineering and operations are alerted if a parameter is outside the allowable window. If a parameter is outside the allowable window, this will trigger further investigation to determine if the issue poses a leak threat. Also, see Section 6.2 for continuous monitoring of P/T in the well.

7.5 Well Surveillance

TND adheres to the requirements of NMOCC Rule 26 governing the construction, operation and closing of an injection well under the Oil and Gas Act. Rule 26 also includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, NMOCC includes special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. TND's Routine Operations and Maintenance Procedures for the RH AGI wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic (Microseismic) Monitoring Stations

TND has Installed a model TCH120-1 Trillium Compact Horizon Seismometer and a model CTR4-3S Centaur Digital Recorder to monitor for and record data for any seismic event at the Red Hills Gas Plant (see **Figure 7-1)**. The seismic station meets the requirements of the NMOCC Order No. R-20916-H to "install, operate, and monitor for the life of the [Class II AGI] permit a seismic monitoring station or stations as directed by the Manager of the New Mexico Tech Seismological Observatory ("state seismologist") at the New Mexico Bureau of Geology and Mineral Resources."

In addition, data that is recorded by the State of New Mexico deployed seismic network within a 10-mile radius of the Red Hills Gas Plant will be analyzed by the New Mexico Bureau of Geology (NMBGMR), see **Figure 5.6-1**, and made publicly available. The NMBGMR seismologist will create a report and map showing the magnitudes of recorded events from seismic activity. The data is being continuously recorded. By examining historical data, a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

7.7 Groundwater Monitoring

New Mexico Tech, through the same DOE research grant described in Section 7.3 above, will monitor groundwater wells for CO_2 leakage which are located within the AMA as defined in Section 4.2. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 7.7-1**. Baseline analyses will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Red Hills Gas Plant. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within expected variation will be further investigated to determine if leakage has occurred from the injection horizon.

***Table 7.7-1**: Groundwater Monitoring Parameters*

Parameters
pH
Alkalinity as HCO3- (mg/L)
Chloride (mg/L)
Fluoride (F-) (mg/L)
Bromide (mg/L)
Nitrate (NO3-) (mg/L)
Phosphate (mg/L)
Sulfate (SO42-) (mg/L)
Lithium (Li) (mg/L)
Sodium (Na) (mg/L)
Potassium (K) (mg/L)
Magnesium (Mg) (mg/L)

Calcium (Ca) (mg/L)
TDS Calculation (mg/L)
Total cations (meq/L)
Total anions (meq/L)
Percent difference (%)
ORP (mV)
IC (ppm)
NPOC (ppm)

7.8 Soil CO_2 Flux Monitoring

A vital part of the monitoring program is to identify potential leakage of CO_2 and/or brine from the injection horizon into the overlying formations and to the surface. One method that will be deployed is to gather and analyze soil CO_2 flux data which serves as a means for assessing potential migration of CO_2 through the soil and its escape to the atmosphere. By taking CO_2 soil flux measurements at periodic intervals, TND can continuously characterize the interaction between the subsurface and surface to understand potential leakage pathways. Actionable recommendations can be made based on the collected data.

CO_2 soil flux will be collected on a monthly basis for 12 months to establish the baseline and understand seasonal and other variation at the Red Hills Gas Plant. After the baseline is established, data will be collected bi-monthly for one year and then quarterly.

CO_2 soil flux measurements will be taken using a LI-COR LI-8100A flux chamber, or similar instrument, at pre planned locations at the site. PVC soil collars (8cm diameter) will be installed in accordance with the LI-8100A specifications. Measurements will be subsequently made by placing the LI-8100A chamber on the soil collars and using the integrated iOS app to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. The soil collars will be left in place such that each subsequent measurement campaign will use the same locations and collars during data collection.

US EPA, O., 2015, Procedures for Groundwater Sampling in the Laboratory Services and Applied Science Division: https://www.epa.gov/quality/procedures-groundwater-sampling-laboratory-services-and-applied-science-division (accessed September 2023).

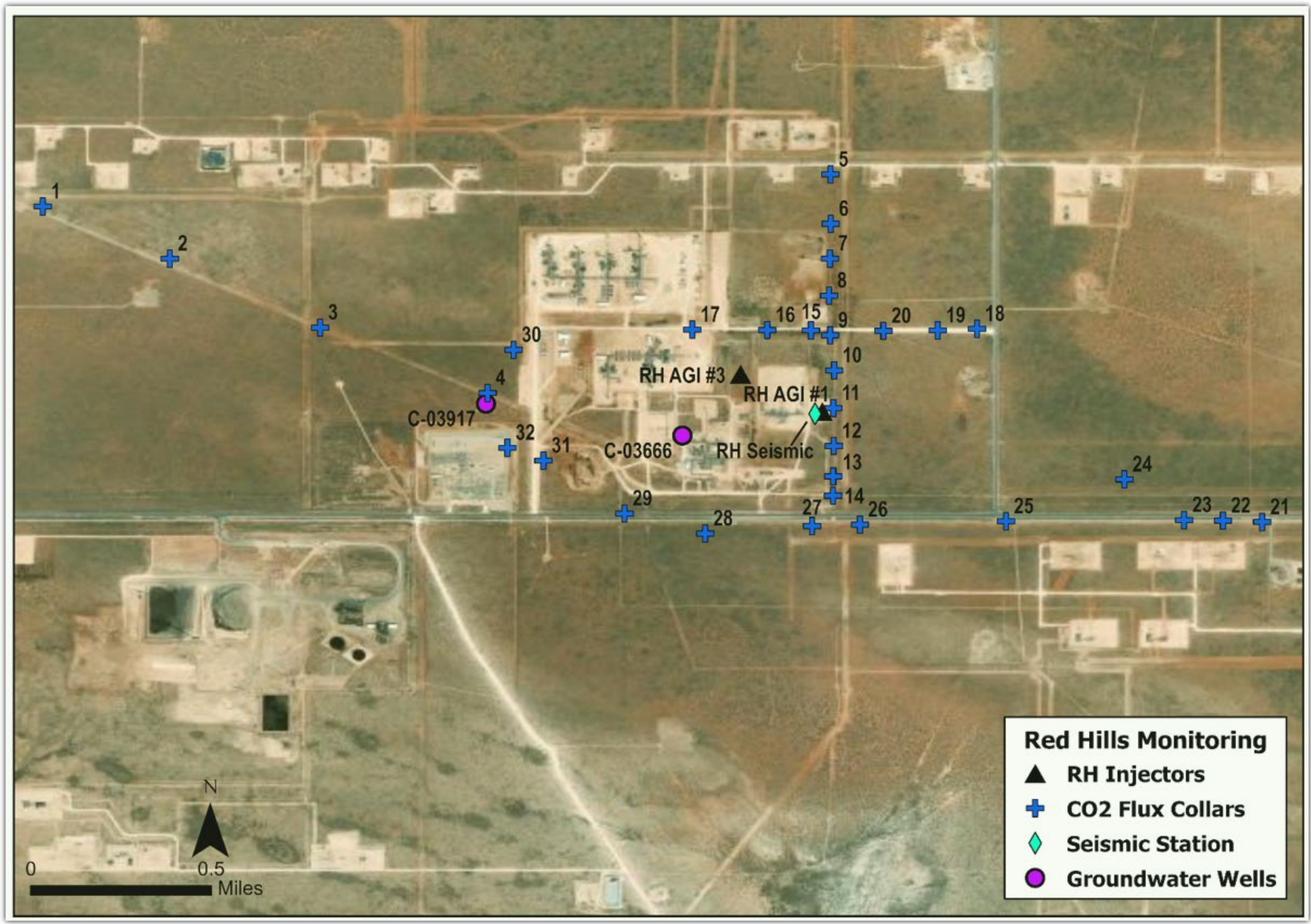


Figure 7-1: *Red Hills monitoring network of 32 CO_2 flux locations, 2 groundwater wells, and a seismic station developed by New Mexico Tech and Targa Resources to detect leakage during injection.*

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve Subpart RR equations used to calculate the mass of CO_2 sequestered annually. **Appendix 8** includes the twelve equations from Subpart RR. Not all of these equations apply to TND's current operations at the Red Hills Gas Plant but are included in the event TND's operations change in such a way that their use is required.

8.1 CO_2 Received

Currently, TND receives gas to its Red Hills Gas Plant through six pipelines: Gut Line, Winkler Discharge, Red Hills 24" Inlet Loop, Greyhound Discharge, Limestone Discharge, and the Plantview Loop. The gas is processed as described in Section 3.8 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection. TND will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3.

Although TND does not currently receive CO_2 in containers for injection, they wish to include the flexibility in this MRV plan to receive gas from containers. When TND begins to receive CO_2 in containers, TND will use Equations

RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. TND will adhere to the requirements in 40CFR98.444(a)(2) for determining the quarterly mass or volume of CO_2 received in containers.

If CO_2 received in containers results in a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

TND injects CO_2 into the existing RH AGI #1. Upon completion, TND will commence injection into RH AGI #2 and #3. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into both wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12.

8.3 CO_2 Produced / Recycled

TND does not produce oil or gas or any other liquid at its Red Hills Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Surface leakage of CO_2 will be determined by employing the CO_2 detection system described in Section 7.3. Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12.

8.5 CO_2 Sequestered

Since TND does not actively produce oil or natural gas or any other fluid at its Red Hills Gas Plant, Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations.

As required by 98.448(d) of Subpart RR, TND will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate the parameter CO_{2FI} in Equation RR-12, the total annual CO_2 mass emitted or vented from equipment located between the flow meter for measuring injection quantity and the injection wellhead.

9 Estimated Schedule for Implementation of MRV Plan

The baseline monitoring and leakage detection and quantification strategies described herein have been established and data collected by TND and its predecessor, Lucid, for several years and continues to the present. TND will begin implementing this revised MRV plan as soon as it is approved by EPA. After RH AGI #3 is drilled, TND will reevaluate the MRV plan and if any modifications are a material change per 40CFR98.448(d)(1), TND will submit a revised MRV plan as required by 40CFR98.448(d).

10 GHG Monitoring and Quality Assurance Program

TND will meet the monitoring and QA/QC requirements of 40CFR98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 40CFR98.444(d).

10.1 GHG Monitoring

As required by 40CFR98.3(g)(5)(i), TND's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations

- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

Measurement of CO_2 Concentration – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GPA) standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40CFR98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2 and RR-5, of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. TND will adhere to the American Gas Association (AGA) Report #3 – Orifice Metering.

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.3 CO_2 injected.

Daily CO_2 injected is recorded by totalizers on the volumetric flow meters on the pipelines to the RH AGI #1 and #2 wells using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.4 CO_2 produced.

TND does not produce CO_2 at the Red Hills Gas Plant.

10.1.5 CO_2 emissions from equipment leaks and vented emissions of CO_2.

As required by 98.444(d), TND will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

As required by 98.444(d) of Subpart RR, TND will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used.

10.1.6 Measurement devices.

As required by 40CFR98.444(e), TND will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40CFR98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.2 QA/QC Procedures

TND will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

10.3 Estimating Missing Data

TND will estimate any missing data according to the following procedures in 40CFR98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in Subpart RR, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

10.4 Revisions of the MRV Plan

TND will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of New Mexico. If any operational changes constitute a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change. TND intends to update the MRV plan after RH AGI #3 has been drilled and characterized.

11 Records Retention

TND will meet the recordkeeping requirements of paragraph 40CFR98.3(g) of Subpart A of the GHGRP. As required by 40CFR98.3(g) and 40CFR98.447, TND will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:

(i) The GHG emissions calculations and methods used

(ii) Analytical results for the development of site-specific emissions factors, if applicable

(iii) The results of all required analyses

(iv) Any facility operating data or process information used for the GHG emission calculations

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, TND will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) A copy of the most recent revision of this MRV Plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(9) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(10) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(12) Any other records as specified for retention in this EPA-approved MRV plan.

12 Appendices

Appendix 1 TND Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Red Hills AGI #1	30-025-40448	1,600 ft FSL, 150 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	10/23/2013	6,650 ft	6,170 ft
Red Hill AGI #3	30-025-51970	3,116 ft FNL, 1,159 ft FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	9/13/2023	6,650 ft	5,700 ft

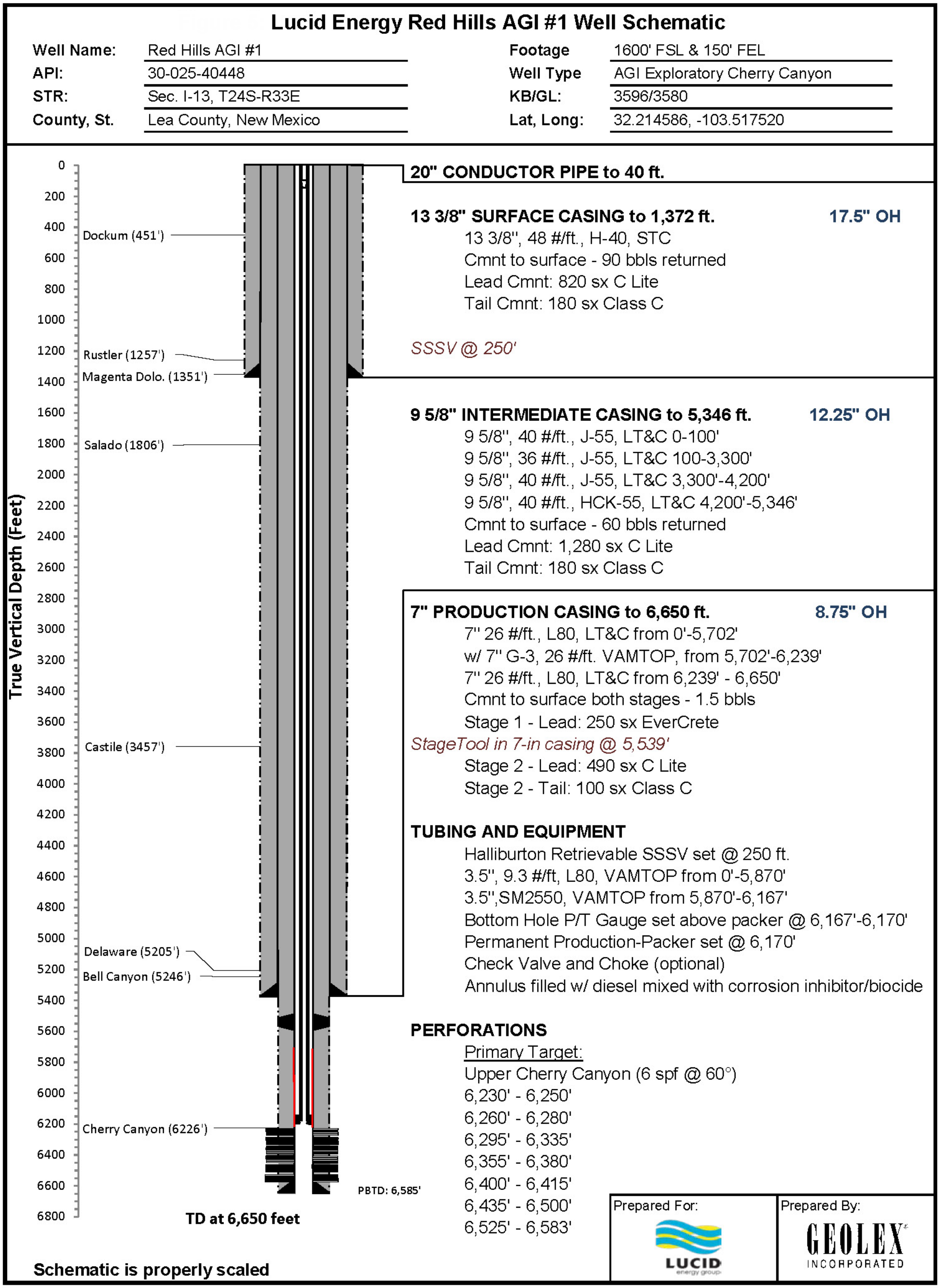


Figure Appendix 1-1: *Schematic of TND RH AGI #1 Well*

Targa Resources
Red Hills Delaware AGI #3
Location 3116' FNL & 1159' FEL
Sec 13 - T 24S - R 33E
GL 3578', RKB TBD

Surface - (Conventional)

Hole Size:	17.5"
Casing:	13.375" 72# L-80 VAM TOP
Depth Top:	Surface
Depth Btm:	1307'
Cement:	TBD sks - Class C + Additives
Cement Top:	Surface - (Circulate)

Intermediate #1 - (Conventional)

Hole Size:	12.25"
Casing:	9.625" 47# HCL-80 BTC
Depth Top:	Surface
Depth Btm:	5205'
Cement:	TBD - Class C + Additives
Cement Top:	Surface - (Circulate)

Production - (Conventional)

Hole Size:	8.5"
Casing 1:	7" 32# I-80 VAMSTL
Depths:	0' to 5280' & 5580' to 7600'
Casing 2:	7" 32# G3 CRA VAM HDL
Depths:	5280' to 5580'
Cement:	TBD - Class C + Additives, Well Lock resin 5280'-5580'
Cement Top:	Surface - (Circulate)
ECP/DV Tool:	5280' & 5580'

Tubing

Depth:	5700'
Tubing:	3.5" 7.7# G3 CRA VAM ACE
Packer:	7" x 3.5" PermaPak or equivalent (Inconel)
SSSV:	175'
PT Gauges:	5690'

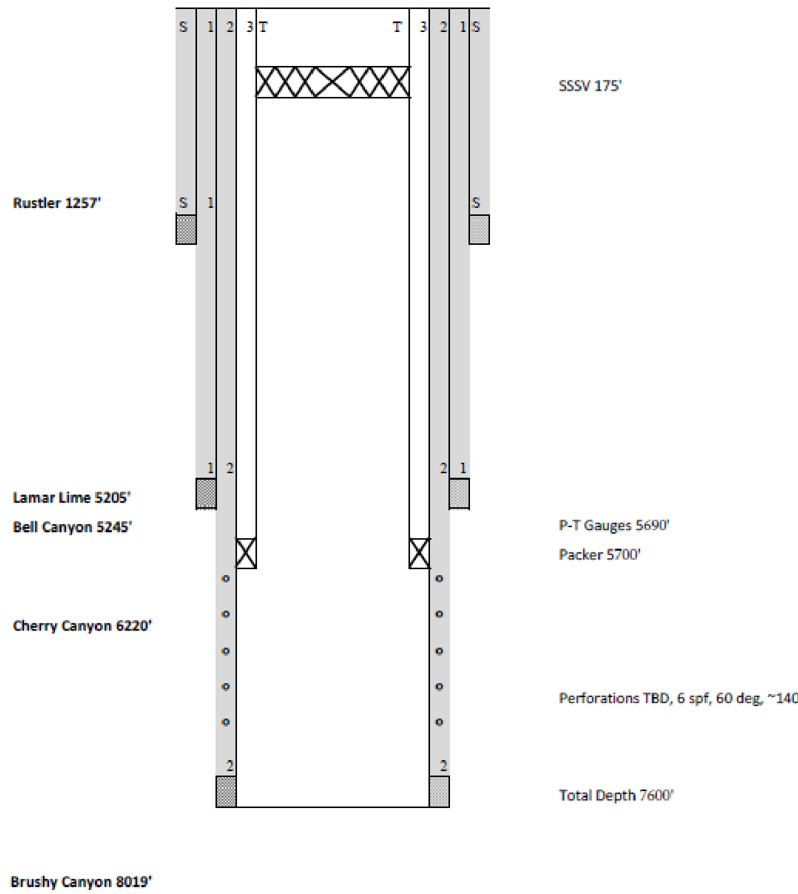


Figure Appendix 1-2: Proposed wellbore schematic for the TND RH AGI #3 Well

Appendix 2 Referenced Regulations

U.S. Code > Title 26. INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1. NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits > Section 45Q - Credit for carbon oxide sequestration

New Mexico Administrative Code (NMAC) > Title 19 – Natural resources > Chapter 15 – Oil and Gas

CHAPTER 15 - OIL AND GAS

19.15.1 NMAC	GENERAL PROVISIONS AND DEFINITIONS [REPEALED]
19.15.2 NMAC	GENERAL PROVISIONS FOR OIL AND GAS OPERATIONS
19.15.3 NMAC	RULEMAKING
19.15.4 NMAC	ADJUDICATION
19.15.5 NMAC	ENFORCEMENT AND COMPLIANCE
19.15.6 NMAC	TAX INCENTIVES
19.15.7 NMAC	FORMS AND REPORTS
19.15.8 NMAC	FINANCIAL ASSURANCE
19.15.9 NMAC	WELL OPERATOR PROVISIONS
19.15.10 NMAC	SAFETY
19.15.11 NMAC	HYDROGEN SULFIDE GAS
19.15.12 NMAC	POOLS
19.15.13 NMAC	COMPULSORY POOLING
19.15.14 NMAC	DRILLING PERMITS
19.15.15 NMAC	WELL SPACING AND LOCATION
19.15.16 NMAC	DRILLING AND PRODUCTION
19.15.17 NMAC	PITS, CLOSED-LOOP SYSTEMS, BELOW-GRADE TANKS AND SUMPS
19.15.18 NMAC	PRODUCTION OPERATING PRACTICES
19.15.19 NMAC	NATURAL GAS PRODUCTION OPERATING PRACTICE
19.15.20 NMAC	OIL PRORATION AND ALLOCATION
19.15.21 NMAC	GAS PRORATION AND ALLOCATION
19.15.22 NMAC	HARDSHIP GAS WELLS
19.15.23 NMAC	OFF LEASE TRANSPORT OF CRUDE OIL OR CONTAMINANTS
19.15.24 NMAC	ILLEGAL SALE AND RATABLE TAKE
19.15.25 NMAC	PLUGGING AND ABANDONMENT OF WELLS
19.15.26 NMAC	INJECTION
19.15.27 - 28 NMAC	[RESERVED] PARTS 27 - 28
19.15.29 NMAC	RELEASES

19.15.30 NMAC	REMEDIATION
19.15.31 - 33 NMAC	[RESERVED] PARTS 31 - 33
19.15.34 NMAC	PRODUCED WATER, DRILLING FLUIDS AND LIQUID OIL FIELD WASTE
19.15.35 NMAC	WASTE DISPOSAL
19.15.36 NMAC	SURFACE WASTE MANAGEMENT FACILITIES
19.15.37 NMAC	REFINING
19.15.38 NMAC	[RESERVED]
19.15.39 NMAC	SPECIAL RULES
19.15.40 NMAC	NEW MEXICO LIQUIFIED PETROLEUM GAS STANDARD
19.15.41 - 102 NMAC	[RESERVED] PARTS 41 - 102
19.15.103 NMAC	SPECIFICATIONS, TOLERANCES, AND OTHER TECHNICAL REQUIREMENTS FOR COMMERCIAL WEIGHING AND MEASURING DEVICES
19.15.104 NMAC	STANDARD SPECIFICATIONS/MODIFICATIONS FOR PETROLEUM PRODUCTS
19.15.105 NMAC	LABELING REQUIREMENTS FOR PETROLEUM PRODUCTS
19.15.106 NMAC	OCTANE POSTING REQUIREMENTS
19.15.107 NMAC	APPLYING ADMINISTRATIVE PENALTIES
19.15.108 NMAC	BONDING AND REGISTRATION OF SERVICE TECHNICIANS AND SERVICE ESTABLISHMENTS FOR COMMERCIAL WEIGHING OR MEASURING DEVICES
19.15.109 NMAC	NOT SEALED NOT LEGAL FOR TRADE
19.15.110 NMAC	BIODIESEL FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.111 NMAC	E85 FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.112 NMAC	RETAIL NATURAL GAS (CNG / LNG) REGULATIONS [REPEALED]

Appendix 3 Water Wells

Water wells identified by the New Mexico State Engineer's files within two miles of the RH AGI wells; water wells within one mile are highlighted in yellow.

POD Number	County	Sec	Tws	Rng	UTME	UTMN	Distance (mi)	Depth Well (ft)	Depth Water (ft)	Water Column (ft)
C 03666 POD1	LE	13	24S	33E	639132	3565078	0.31	650	390	260
C 03917 POD1	LE	13	24S	33E	638374	3565212	0.79	600	420	180
C 03601 POD1	LE	23	24S	33E	638124	3563937	1.17			
C 02309	LE	25	24S	33E	639638	3562994	1.29	60	30	30
C 03601 POD3	LE	24	24S	33E	638142	3563413	1.38			
C 03932 POD8	LE	7	24S	34E	641120	3566769	1.40	72		
C 03601 POD2	LE	23	24S	33E	637846	3563588	1.44			
C 03662 POD1	LE	23	24S	33E	637342	3564428	1.48	550	110	440
C 03601 POD5	LE	23	24S	33E	637988	3563334	1.48			
C 03601 POD6	LE	23	24S	33E	637834	3563338	1.55			
C 03601 POD7	LE	23	24S	33E	637946	3563170	1.58			
C 03600 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03602 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03600 POD1	LE	26	24S	33E	637275	3563023	1.94			
C 03600 POD3	LE	26	24S	33E	637784	3562340	2.05			

Appendix 4 Oil and Gas Wells within 2-mile Radius of the RH AGI Well Site

Note – a completion status of "New" indicates that an Application for Permit to Drill has been filed and approved but the well has not yet been completed. Likewise, a spud date of 31-Dec-99 is actually 12-31-9999, a date used by NMOCD databases to indicate work not yet reported.

API	Well Name	Operator	Well Type	Reported Formation	Well Status	Trajectory	TVD (ft)	Within MMA
30-025-08371	COSSATOT E 002	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	5425	Yes
30-025-25604	GOVERNMENT L COM 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	17625	No
30-025-26369	GOVERNMENT L COM 002	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	P & A	VERTICAL	14698	Yes
30-025-26958	SIMS 001	BOPCO, L.P.	GAS	DELAWARE VERTICAL	P & A	VERTICAL	15007	Yes
30-025-27071	PRE-ONGARD WELL 001	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	PERMIT CANCELLED	VERTICAL	0	No
30-025-27491	SMITH FEDERAL 001	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	P & A	VERTICAL	15120	No
30-025-28869	PRE-ONGARD WELL 001	PRE-ONGARD WELL OPERATOR	OIL	DELAWARE VERTICAL	PERMIT CANCELLED	VERTICAL	0	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-29008	MADERA RIDGE 24 001	EOG RESOURCES INC	GAS	DELAWARE VERTICAL	TA	VERTICAL	15600	No
30-025-40448	RED HILLS AGI 001	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	INJECTING	VERTICAL	6650	Yes
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL		PRODUCING	VERTICAL	10997	No
30-025-40914	DECKARD FEE 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11034	No
30-025-41382	DECKARD FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11067	Yes
30-025-41383	DECKARD FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11162	Yes
30-025-41384	DECKARD FEDERAL COM 004H	COG OPERATING LLC	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11103	Yes
30-025-41666	SEBASTIAN FEDERAL COM 002H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10927	Yes
30-025-41687	SEBASTIAN FEDERAL COM 001H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10944	Yes
30-025-41688	SEBASTIAN FEDERAL COM 003H	COG OPERATING LLC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11055	No
30-025-43532	LEO THORSNESS 13 24 33 211H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12371	No
30-025-44442	STRONG 14 24 33 AR 214H	MATADOR PRODUCTION COMPANY	GAS	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12500	No
30-025-46154	LEO THORSNESS 13 24 33 221H	MATADOR PRODUCTION COMPANY	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12868	No

30-025-46282	LEO THORSNESS 13 24 33 AR 135H	MATADOR PRODUCTION COMPANY	OIL	3RD BONE SPRING SAND	PRODUCING	HORIZONTAL	12103	No
30-025-46517	BROADSIDE 13 W FEDERAL COM 001H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12213	No
30-025-46518	BROADSIDE 13 24 FEDERAL COM 002H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-46519	BROADSIDE 13 24 FEDERAL COM 003H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP A LOWER	PRODUCING	HORIZONTAL	12320	Yes
30-025-46985	SEBASTIAN FEDERAL COM 703H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12123	No
30-025-46986	SEBASTIAN FEDERAL COM 602H	COG OPERATING LLC	OIL	3RD BONE SPRING	PERMIT EXPIRED	HORIZONTAL	11661	No
30-025-46988	SEBASTIAN FEDERAL COM 704H	COG OPERATING LLC	OIL	WOLFCAMP A UPPER	PRODUCING	HORIZONTAL	12142	No
30-025-47476	NED PEPPER 18 TB FEDERAL COM 001H	MARATHON OIL PERMIAN LLC	OIL		PERMIT EXPIRED	HORIZONTAL	0	Yes
30-025-47477	NED PEPPER 18 TB FEDERAL COM 004H	MARATHON OIL PERMIAN LLC	OIL		PERMIT EXPIRED	HORIZONTAL	0	Yes
30-025-47478	NED PEPPER 18 WA FEDERAL COM 002H	MARATHON OIL PERMIAN LLC	OIL	WOLFCAMP B UPPER	PERMIT EXPIRED	HORIZONTAL	12641	Yes
30-025-47479	NED PEPPER 18 WA FEDERAL COM 009H	MARATHON OIL PERMIAN LLC	OIL	WOLFCAMP B UPPER	PERMIT EXPIRED	HORIZONTAL	12552	Yes
30-025-47480	NED PEPPER 18 WXY FEDERAL COM 006H	MARATHON OIL PERMIAN LLC	OIL	WOLFCAMP A LOWER	PERMIT EXPIRED	HORIZONTAL	12485	Yes
30-025-47869	JUPITER 19 FEDERAL COM 501H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11175	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47870	JUPITER 19 FEDERAL COM 502H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11141	Yes
30-025-47871	JUPITER 19 FEDERAL COM 503H	EOG RESOURCES INC	OIL	3RD BONE SPRING	PERMIT EXPIRED	HORIZONTAL	11368	Yes
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47872	JUPITER 19 FEDERAL COM 403H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PRODUCING	HORIZONTAL	10584	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47873	JUPITER 19 FEDERAL COM 309H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10250	No
30-025-47874	JUPITER 19 FEDERAL COM 506H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	10950	No

30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47875	JUPITER 19 FEDERAL COM 507H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11150	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47876	JUPITER 19 FEDERAL COM 508H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11143	No
30-025-47877	JUPITER 19 FEDERAL COM 509H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11156	No
30-025-47878	JUPITER 19 FEDERAL COM 510H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PRODUCING	HORIZONTAL	11102	No
30-025-47908	JUPITER 19 FEDERAL COM 601H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-47910	JUPITER 19 FEDERAL COM 702H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	DUC	HORIZONTAL	0	Yes
30-025-47911	JUPITER 19 FEDERAL COM 705H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12290	No
30-025-47912	JUPITER 19 FEDERAL COM 707H	EOG RESOURCES INC	OIL	WOLFCAMP B UPPER	PERMITTED	HORIZONTAL	12515	No
30-025-47913	JUPITER 19 FEDERAL COM 708H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMITTED	HORIZONTAL	12477	No
30-025-48056	JUPITER 19 FEDERAL COM 602H	EOG RESOURCES INC	OIL		PERMIT EXPIRED	HORIZONTAL	0	Yes
30-025-48057	JUPITER 19 FEDERAL COM 603H	EOG RESOURCES INC	OIL		PERMIT EXPIRED	HORIZONTAL	0	No
30-025-48058	JUPITER 19 FEDERAL COM 604H	EOG RESOURCES INC	OIL		PERMIT EXPIRED	HORIZONTAL	0	No
30-025-48059	JUPITER 19 FEDERAL COM 704H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMIT EXPIRED	HORIZONTAL	12310	No
30-025-48060	JUPITER 19 FEDERAL COM 706H	EOG RESOURCES INC	OIL	WOLFCAMP A LOWER	PERMIT EXPIRED	HORIZONTAL	12308	No
30-025-48224	JUPITER 19 FEDERAL COM 201H	EOG RESOURCES INC	OIL	LOWER AVALON	PERMIT EXPIRED	HORIZONTAL	9982	Yes
30-025-48225	JUPITER 19 FEDERAL COM 202H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PERMIT EXPIRED	HORIZONTAL	10762	Yes
30-025-48226	JUPITER 19 FEDERAL COM 203H	EOG RESOURCES INC	OIL	LOWER AVALON	PERMIT EXPIRED	HORIZONTAL	10079	Yes
30-025-48227	JUPITER 19 FEDERAL COM 204H	EOG RESOURCES INC	OIL	LOWER AVALON	PERMIT EXPIRED	HORIZONTAL	9984	Yes
30-025-48228	JUPITER 19 FEDERAL COM 205H	EOG RESOURCES INC	OIL	LOWER AVALON	PERMIT EXPIRED	HORIZONTAL	10023	Yes

30-025-48229	JUPITER 19 FEDERAL COM 206H	EOG RESOURCES INC	OIL	LOWER AVALON	PERMIT EXPIRED	HORIZONTAL	10100	Yes
30-025-48230	JUPITER 19 FEDERAL COM 207H	EOG RESOURCES INC	OIL	LOWER AVALON	PERMIT EXPIRED	HORIZONTAL	9949	No
30-025-48231	JUPITER 19 FEDERAL COM 208H	EOG RESOURCES INC	OIL	MIDDLE AVALON	PERMIT EXPIRED	HORIZONTAL	9882	No
30-025-48232	JUPITER 19 FEDERAL COM 209H	EOG RESOURCES INC	OIL	MIDDLE AVALON	PERMIT EXPIRED	HORIZONTAL	9881	No
30-025-48233	JUPITER 19 FEDERAL COM 210H	EOG RESOURCES INC	OIL	MIDDLE AVALON	PERMIT EXPIRED	HORIZONTAL	9886	No
30-025-48234	JUPITER 19 FEDERAL COM 301H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PERMIT EXPIRED	HORIZONTAL	10675	Yes
30-025-48235	JUPITER 19 FEDERAL COM 302H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PERMIT EXPIRED	HORIZONTAL	10724	Yes
30-025-48236	JUPITER 19 FEDERAL COM 303H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PERMIT EXPIRED	HORIZONTAL	10675	Yes
30-025-48237	JUPITER 19 FEDERAL COM 304H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PERMIT EXPIRED	HORIZONTAL	10716	Yes
30-025-48238	JUPITER 19 FEDERAL COM 305H	EOG RESOURCES INC	OIL	2ND BONE SPRING	PERMIT EXPIRED	HORIZONTAL	10582	No
30-025-48239	JUPITER 19 FEDERAL COM 306H	EOG RESOURCES INC	OIL	1ST BONE SPRING	PRODUCING	HORIZONTAL	10270	No
30-025-48889	JUPITER 19 FEDERAL COM 701H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-48890	JUPITER 19 FEDERAL COM 703H	EOG RESOURCES INC	OIL	2ND BONE SPRING SAND	PERMITTED	HORIZONTAL	0	Yes
30-025-49262	BROADSIDE 13 24 FEDERAL COM 004H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B UPPER	PRODUCING	HORIZONTAL	12531	Yes
30-025-49263	BROADSIDE 13 24 FEDERAL COM 015H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	WOLFCAMP B LOWER	PRODUCING	HORIZONTAL	12746	Yes
30-025-49264	BROADSIDE 13 24 FEDERAL COM 025H	DEVON ENERGY PRODUCTION COMPANY, LP	OIL	3RD BONE SPRING	PRODUCING	HORIZONTAL	11210	Yes
30-025-49474	RED HILLS AGI 002	TARGA NORTHERN DELAWARE, LLC.	INJECTOR	DELAWARE VERTICAL	Temporarily Abandoned	VERTICAL	17600	Yes

Appendix 5 References

Application for Authorization to Inject via Proposed Red Hills AGI #1 Well, Agave Energy Red Hills Gas Plant, Lea County, New Mexico; July 20, 2011; prepared by Geolex, Inc. for Agave Energy Company

Application for a Redundant Class II AGI Well, Lucid Energy Delaware, LLC; Red Hills AGI #2; August 8, 2019, prepared by Geolex, Inc. for Lucid Energy Delaware, LLC

Case No. 20779, Notice Regarding Hearing Exhibits, Application of Lucid Energy Delaware, LLC for Authorization to Inject, Lea County, New Mexico

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Appendix 6 Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
AoR – Area of Review
API – American Petroleum Institute
CFR – Code of Federal Regulations
C1 – methane
C6 – hexane
C7 - heptane
CO_2 – carbon dioxide
DCS – distributed control system
EPA – US Environmental Protection Agency, also USEPA
ft – foot (feet)
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MSCFD– thousand standard cubic feet per day
MMSCFD – million standard cubic feet per day
MMstb – million stock tank barrels
MRRW B – Morrow B
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NIST - National Institute of Standards and Technology
NMOCC – New Mexico Oil Conservation Commission
NMOCD - New Mexico Oil Conservation Division
PPM – Parts Per Million
psia – pounds per square inch absolute
QA/QC – quality assurance/quality control
SCITS - Stanford Center for Induced and Triggered Seismicity
Stb/d – stock tank barrel per day
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TVD – True Vertical Depth
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

Appendix 7 TND Red Hills AGI Wells - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

	Subpart RR Equation	Description of Calculations and Measurements*	Pipeline	Containers	Comments
CO_2 Received	RR-1	calculation of CO_2 received and measurement of CO_2 mass…	through mass flow meter.	in containers. **	
	RR-2	calculation of CO_2 received and measurement of CO_2 volume…	through volumetric flow meter.	in containers. ***	
	RR-3	summation of CO_2 mass received …	through multiple meters.		
CO_2 Injected	RR-4	calculation of CO_2 mass injected, measured through mass flow meters.			
	RR-5	calculation of CO_2 mass injected, measured through volumetric flow meters.			
	RR-6	summation of CO_2 mass injected, as calculated in Equations RR-4 and/or RR-5.			
CO_2 Produced / Recycled	RR-7	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through mass flow meters.			
	RR-8	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through volumetric flow meters.			
	RR-9	summation of CO_2 mass produced / recycled from multiple gas-liquid separators, as calculated in Equations RR-7 and/or RR8.			
CO_2 Lost to Leakage to the Surface	RR-10	calculation of annual CO_2 mass emitted by surface leakage			
CO_2 Sequestered	RR-11	calculation of annual CO_2 mass sequestered for operators ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, produced, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head, and emitted from surface equipment between production well head and production flow meter.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.
	RR-12	calculation of annual CO_2 mass sequestered for operators NOT ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.

* All measurements must be made in accordance with 40 CFR 98.444 – Monitoring and QA/QC Requirements.

** If you measure the mass of contents of containers summed quarterly using weigh bill, scales, or load cells (40 CFR 98.444(a)(2)(i)), use RR-1 for Containers to calculate CO_2 received in containers for injection.

*** If you determine the volume of contents of containers summed quarterly (40 CFR 98.444(a)(2)(ii)), use RR-2 for Containers to calculate CO_2 received in containers for injection.

Appendix 8 Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

RR-1 for Calculating Mass of CO_2 Received through Pipeline Mass Flow Meters

$$CO_{2T,r} = \sum_{p=1}^{4}\left(Q_{r,p} - S_{r,p}\right) * C_{CO_{2,p,r}} \qquad \text{(Equation RR-1 for Pipelines)}$$

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving mass flow meter.

RR-1 for Calculating Mass of CO_2 Received in Containers by Measuring Mass in Container

$$CO_{2T,r} = \sum_{p=1}^{4}\left(Q_{r,p} - S_{r,p}\right) * C_{CO_{2,p,r}} \qquad \text{(Equation RR-1 for Containers)}$$

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$Q_{r,p}$ = Quarterly mass of contents in containers r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass of contents in containers r redelivered to another facility without being injected into your well in quarter p (metric tons).

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Containers.

RR-2 for Calculating Mass of CO_2 Received through Pipeline Volumetric Flow Meters

$$CO_{2T,r} = \sum_{p=1}^{4}\left(Q_{r,p} - S_{r,p}\right) * D * C_{CO_{2,p,r}} \qquad \text{(Equation RR-2 for Pipelines)}$$

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving volumetric flow meter.

RR-2 for Calculating Mass of CO_2 Received in Containers by Measuring Volume in Container

$$CO_{2T,r} = \sum_{p=1}^{4}\left(Q_{r,p} - S_{r,p}\right) * D * C_{CO_{2,p,r}} \qquad \text{(Equation RR-2 for Containers)}$$

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$Q_{r,p}$ = Quarterly volume of contents in containers r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volume of contents in containers r redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

D = Density of CO_2 received in containers at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Container.

RR-3 for Summation of Mass of CO_2 Received through Multiple Flow Meters for Pipelines

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \quad \text{(Equation RR-3 for Pipelines)}$$

where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2,T.r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 or RR-2 for flow meter r.

r = Receiving flow meter.

RR-4 for Calculating Mass of CO_2 Injected through Mass Flow Meters into Injection Well

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \quad \text{(Equation RR-4)}$$

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

$C_{CO_{2,p,u}}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Mass flow meter.

RR-5 for Calculating Mass of CO_2 Injected through Volumetric Flow Meters into Injection Well

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \quad \text{(Equation RR-5)}$$

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = 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 = Volumetric flow meter.

RR-6 for Summation of Mass of CO_2 Injected into Multiple Wells

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \quad \text{(Equation RR-6)}$$

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) though all injection wells.

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as calculated in Equation RR-4 or RR-5 for flow meter u.

u = Flow meter.

RR-7 for Calculating Mass of CO_2 Produced / Recycled from a Gas-Liquid Separator through Mass Flow Meters

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * C_{CO_{2,p,w}} \quad \text{(Equation RR-7)}$$

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Quarterly gas mass flow rate measurement for separator w in quarter p (metric tons).

$C_{CO_{2,p,w}}$ = Quarterly CO_2 concentration measurement in flow for separator w in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Gas / Liquid Separator.

RR-8 for Calculating Mass of CO_2 Produced / Recycled from a Gas-Liquid Separator through Volumetric Flow Meters

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * D * C_{CO_{2,p,w}} \quad \text{(Equation RR-8)}$$

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Quarterly gas volumetric flow rate measurement for separator w in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,w}}$ = Quarterly CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Gas / Liquid Separator.

RR-9 for Summation of Mass of CO_2 Produced / Recycled through Multiple Gas Liquid Separators

$$CO_{2P} = (1 + X) * \sum_{w=1}^{W} CO_{2,w}$$ (Equation RR-9)

where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) though all separators in the reporting year.

X = Entrained CO_2 in produced oil or other liquid divided by the CO_2 separated through all separators in the reporting year (wt. percent CO_2 expressed as a decimal fraction).

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year as calculated in Equation RR-7 or RR-8 .

w = Flow meter.

RR-10 for Calculating Annual Mass of CO_2 Emitted by Surface Leakage

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$ (Equation RR-10)

where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

RR-11 for Calculating Annual Mass of CO_2 Sequestered for Operators Actively Producing Oil or Natural Gas or Any Other Fluid

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \quad \text{(Equation RR-11)}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells in the reporting year.

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of the GHGRP.

CO_{2FP} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of the GHGRP.

RR-12 for Calculating Annual Mass of CO_2 Sequestered for Operators NOT Actively Producing Oil or Natural Gas or Any Other Fluid

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad \text{(Equation RR-12)}$$

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of the GHGRP.

Appendix 9 P&A Records

P&A Record for Government Com 001, API #30-025-25604

New Mexico Oil Conservation Division, District I
1625 N. French Drive
Hobbs, NM 88240

Form 3160-5
(April 2004)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OM B No. 1004-0137
Expires: March 31, 2007

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

***SUBMIT IN TRIPLICATE**- Other instructions on reverse side.*

5. Lease Serial No. **NM-17446**

6. If Indian, Allottee or Tribe Name

7. If Unit or CA/Agreement, Name and/or No.

1. Type of Well ☐ Oil Well ☑ Gas Well ☐ Other

8. Well Name and No. **Government "L" Com #1**

2. Name of Operator **EOG Resources, Inc**

9. API Well No. 30-025-~~06040~~ 25604

3a. Address **P.O. Box 2267, Midland, TX, 79702**

3b. Phone No. *(include area code)* **432-561-8600**

10. Field and Pool, or Exploratory Area **Bell Lake, South Morrow**

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*

Unit Letter G, 1980 FNL, 1980 FEL
Section 18, Township 24-S, Range 34-E

11. County or Parish, State **Lea, New Mexico**

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
☑ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☐ Other
	☐ Change Plans	☑ Plug and Abandon	☐ Temporarily Abandon	
	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

1. **Notified Jim McCormick w/BLM 24 hrs prior to MI and RU.**
2. **Cut 3 1/2' tbg at 11500, spot 50sx CLass "H" cmt, plug from 11500-11400, WOC Tag at 11389.**
3. **Circ hole w/MLF.**
4. **Perf 4 holes at 9050, press up to 2000 PSI, spot 75sx, plug from 9100-8950, WOC Tag @ 8938.**
5. **Perf 4 holes at 7000, press up to 2000 PSI, spot 75sx, plug from 7050-6900, WOC Tag at 6855.**
6. **Cut 10 3/4" csg at 5450, L/D csg, spot 150sx, plug from 5500-5350, WOC Tag at 5336.**
7. **Spot 75sx, plug from 1300-1200 (T-Salt) WOC Tag at 1143.**
8. **Spot 150sx, plug from 650-450 (20" Shoe) WOC Tag at 423.**
9. **Spot 20sx, plug from 30-Surf.**
10. **Clean location. Install dry hole marker 12-30-04.**

P&A Complete 12-30-04

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

14. I hereby certify that the foregoing is true and correct
Name *(Printed/Typed)* **Jimmy Bagley** Title **Consultant**

Signature Date **12/30/2004**

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by Title Date

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon. Office

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on page 2)

GWW

P&A Records for API #30-025-26958

Submit 1 Copy To Appropriate District Office District I – (575) 393-6161 1625 N. French Dr., Hobbs, NM 88240 District II – (575) 748-1283 811 S. First St., Artesia, NM 88210 District III – (505) 334-6178 1000 Rio Brazos Rd., Aztec, NM 87410 District IV – (505) 476-3460 1220 S. St. Francis Dr., Santa Fe, NM 87505	State of New Mexico Energy, Minerals and Natural Resources RECEIVED OIL CONSERVATION DIVISION 1220 South St. Francis Dr. AUG 16 2012 Santa Fe, NM 87505 HOBBSOCD	Form C-103 Revised August 1, 2011

	WELL API NO. 3002526958
	5. Indicate Type of Lease STATE ☐ FEE ☒
	6. State Oil & Gas Lease No. SCR-389
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name Sims
1. Type of Well: Oil Well ☐ Gas Well ☒ Other	8. Well Number #1
2. Name of Operator: Agave Energy Company	9. OGRID Number 147831
3. Address of Operator 104 S. Fourth St., Artesia NM 88210 (575-748-4528)	10. Pool name or Wildcat Big Sinks Wolfcamp

4. Well Location

Unit Letter___K:___1980__feet from the ___N___ line and ___800___feet from the ___E___line

Section 13 Township 24S Range 33E NMPM Lea County

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS.☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
OTHER: ☐		OTHER ☒ Replug to cement off Cherry Canyon per NMOCC R-13507	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion

The remediation of the Sims #1 well pursuant to NMOCC order was completed on August 15, 2011 and all equipment has been demobilized. The plugging was done pursuant to NMOCD requirements and all aspects of the effort were reported to Mark Whitaker and E.L. Gonzales of the OCD District 1 office who approved the specifics of the plugging as shown in the attached plugging diagram. When establishing a rate prior to squeezing the Cherry Canyon, it is clear that the reservoir is an excellent reservoir as it was taking 3bbl/min on vacuum. This indicates that the predicted injection plume for the Red Hills AGI #1 in this reservoir will be smaller than anticipated and the reservoir conditions act to prevent migration of injected acid gas out of the intended and permitted injection zone by any nearby wellbores including the Govt#2, Govt#1 and Smith Federal #1 in addition to the Sims#1. Please see attached wellbore sketch for plugging details of all plugs set and amounts of cement squeezed for each plug.

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE________________ TITLE_ Consultant to Agave Energy Company _DATE August 16, 2012____

Type or print name ___Alberto A. Gutierrez, RG E-mail address: __aag@geolex.com_____ PHONE: _505-842-8000____

For State Use Only

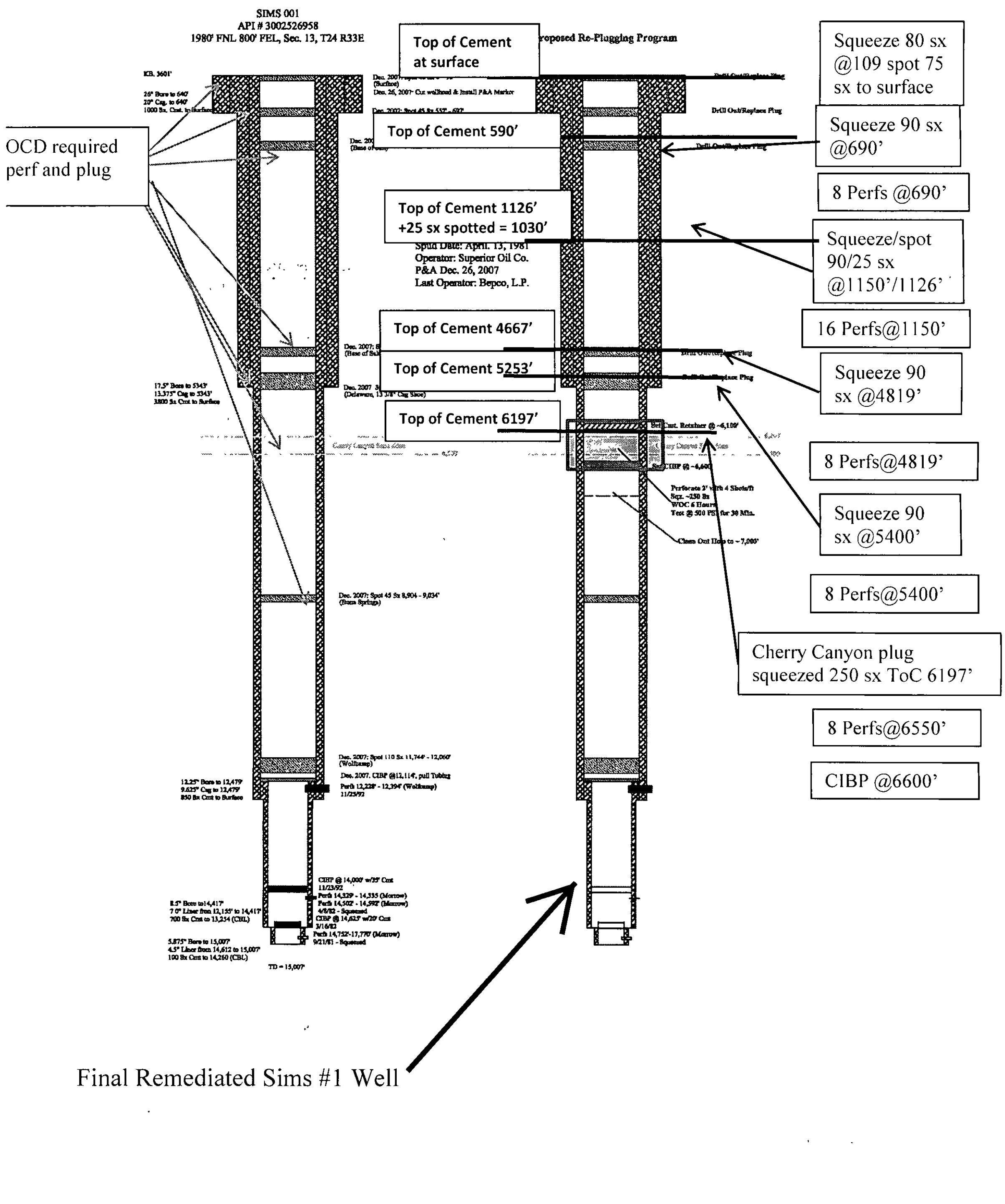
APPROVED BY________________ TITLE Dist Mgr DATE 8-16-2012

Conditions of Approval (if any):

AUG 16 2012

GEOLEX
INCORPORATED

8/16/2012



Final Remediated Sims #1 Well

P&A Records for API 30-025-08371

NEW MEXICO OIL CONSERVATION COMMISSION FORM C-103 (Rev 3-55)

MISCELLANEOUS REPORTS ON WELLS

(Submit to appropriate District Office as per Commission Rule 1106)

Name of Company	Address
Byard Bennett	207 West Third, Roswell, New Mexico

Lease	Well No.	Unit Letter	Section	Township	Range
Holland	1	H	13	24 South	33 East

Date Work Performed	Pool	County
March 8, 1961	Wildcat	Lea

THIS IS A REPORT OF: *(Check appropriate block)*

[ ] Beginning Drilling Operations [ ] Casing Test and Cement Job [ ] Other *(Explain)*:
[X] Plugging [ ] Remedial Work

Detailed account of work done, nature and quantity of materials used, and results obtained.

Top of Rustler: 1245', Top of Salt: 1392', Base of Salt: 4930', Top of Dela Ls: 5190'
Top of Delaware Sand: 5210', Total Depth: 5425', Casing 8 5/8 set at 365', Hole size 6 3/4

Cement Plugs set as follows:
5375-5425 with 15 sacks, 5175-5240 with 20 sacks, 1375-1425 with 20 sacks, 340-390 with 20 sacks, 5 sacks and marker pipe set at surface.
Heavy mud (4 cc wtr. loss) between all cement plugs.
Job performed and witnessed by Mr. Pool, Pool Drlg Co.
Prior verbal approval of plugging program from Mr. Engbrecht, New Mexico O C C.

Location will be cleaned and leveled as soon as practical.

Witnessed by	Position	Company
Mr. Fred Pool	Owner	Pool Drlg Co.

FILL IN BELOW FOR REMEDIAL WORK REPORTS *ONLY*

ORIGINAL WELL DATA

D F Elev.	T D	P B T D	Producing Interval	Completion Date

Tubing Diameter	Tubing Depth	Oil String Diameter	Oil String Depth

Perforated Interval(s)

Open Hole Interval	Producing Formation(s)

RESULTS OF WORKOVER

Test	Date of Test	Oil Production BPD	Gas Production MCFPD	Water Production BPD	GOR Cubic feet/Bbl	Gas Well Potential MCFPD
Before Workover						
After Workover						

OIL CONSERVATION COMMISSION

Approved by Leslie A. Clements
Title
Date

I hereby certify that the information given above is true and complete to the best of my knowledge.

Name Guy A. Swartz
Position Agent
Company Byard Bennett