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OFFICE OF AIR AND RADIATION
WASHINGTON, D.C. 20460

June 10, 2024

Ms. Kaitlyn Lopez
Piñon Midstream
465 W NM Hwy 128
Jal, New Mexico 88252

Re: Monitoring, Reporting and Verification (MRV) Plan for Dark Horse Treating Plant

Dear Ms. Lopez:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Dark Horse Treating 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 Dark Horse Treating Plant on April 18, 2024, as the final MRV plan. The MRV Plan Approval Number is 1014467-1. This decision is effective June 15, 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,
Chief, Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for the Dark Horse Treating Plant

June 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 Piñon Midstream LLC's (Piñon) Dark Horse Treating Plant (Dark Horse) for its acid gas injection (AGI) project in the Delaware Basin, a sub-basin of the Permian Basin, near Jal, New Mexico. Note that this evaluation pertains only to the Subpart RR MRV plan, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

1 Overview of Project

Dark Horse indicates in Section 1 of the MRV plan that they are currently authorized to inject treated acid gas (TAG) at a combined rate of up to 20 million standard cubic feet per day (MMscfd) into their acid gas injection (AGI) wells named Independence AGI #1 and Independence AGI #2 under the New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Commission (NMOCC). The NMOCC regulates oil and gas activities in New Mexico and has primacy to implement the Underground Injection Control Class II program, which both wells are classified under. Dark Horse states that Independence AGI #1 was spudded in December 2020, while Independence AGI #2 commenced drilling in the summer of 2022.

Dark Horse is located approximately six miles west of Jal, New Mexico in Lea County within the northern margin of the Denver Basin. The Denver Basin is a sub-basin of the larger, encompassing Permian Basin. The Permian Basin and its sedimentary fill have been formed and controlled by tectonism of varying degrees and sedimentation events that began in the Precambrian and continued throughout the Cenozoic (Neogene). Early Paleozoic deposition took place in the Late Cambrian as marginal areas of the North American craton began to be flooded by marine seas. These Late Cambrian sediments were comprised of basal siliciclastic sands and muds from areas of exposed Precambrian igneous, metamorphic, and sedimentary rocks and shallow-water carbonates. Parts of the following basin development descriptions in this subsection of the MRV plan have been modified and summarized from Ruppel (2019). Flooding continued across the North American craton throughout the Early Ordovician, establishing a widespread shallow-water carbonate platform.

Section 3 of the MRV plan describes the geologic setting of the Dark Horse facility. Both Independence AGI #1 and Independence AGI #2 are injecting into the Silurian-Devonian Injection Zone. The MRV plan states that Independence AGI #1 is permitted to inject at approximately 16,230 to 17,900 feet into the injection zone, while Independence AGI #2 is permitted to inject at approximately 16,080 to 17,683 feet into the injection zone. The Silurian-Devonian Injection Zone includes the Devonian Thirtyone Formation, Silurian Wristen Group, and Fusselman Formation, collectively referred to as the Silurian-Devonian. These strata commonly include numerous intervals of dolomites and dolomitic limestones with moderate to high primary porosity. Additionally, the Silurian-Devonian Injection Zone includes significant regions of secondary, solution-enlarged porosity produced during periods where strata were subaerially exposed and significant karst features developed. These karst features are frequently developed in the Fusselman Formation and include solution enlarged cavities and fractures. Fracture networks through the Silurian-Devonian section are substantial enough to provide additional permeability that is not readily apparent on geophysical well logs. The porous zones of the Silurian-Devonian are separated by tight limestones and dolomites. The MRV plan also states that the Woodford Shale and Mississippian limestone will act as overlying confining units while the Montoya Formation will form the underlying confining zone.

According to Section 1 of the MRV plan, Dark Horse plans to inject 378,399 metric tons per year (MT/yr) of TAG for 30 years followed by a 5-year rest period, 11,351,970 MT of TAG total. This total is split between both Independence AGI #1 and Independence AGI #2 wells, which is the maximum permitted amount according to the MRV plan. The MRV plan states that the maximum allowable surface pressure for Independence AGI #1 is approximately 4,779 pounds per square inch gauge (psig), while Independence AGI #2's is 5,005 psig. Dark Horse will receive CO_2 through three pipelines: the Hondo High Pressure Sour Gas Pipeline (owned and operated by Piñon), the Franklin Mountain Low Pressure Pipeline (owned and operated by Franklin Mountain Energy), and the Ameredev II Low Pressure Pipeline (owned and operated by Ameredev). The MRV plan also states that for the period of September 2021 through March 2022, the TAG stream at the Dark Horse facility averaged 57.076% CO_2 and 38.703% hydrogen sulfide (H_2S) by volume, with hydrocarbons (C1 – C7) and H_2O comprising the remaining volume.

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

Section 3.9 of the MRV plan states that Schlumberger's simulation software Eclipse Compositional E300 (Version 2020.1) was used in the reservoir simulations presented in the MRV plan with simulation results and visuals provided by Geolex, Inc. An injection forecast model was performed for a period of thirty years with injection and then a five-year post-injection rest period to ascertain fluid movement and pressure evolution. The MRV also states that this model showed that all the injected gas remained in the reservoir and there was no change in the size of the TAG extent compared at the end of injection and five-year post-injection period. The MMA and AMA are show in Figure 4.1-1 of the MRV plan.

As stated in the MRV plan, 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. In general, the western margins of the plume retract to the east following the injection period as gas flows up-dip. In this case, the farthest plume extent and hence the MMA margin is therefore found at year 30 (year t), with the plume extent to the west shrinking by year t+5 and stabilizing. On this side, the MMA is based on the largest plume extent which is at year 30 (t). To the east, fault trapping and the anticline near the injection site generally prevent major movement eastward. Beyond year 30 (t), the plume slowly expands east and northeast, finally stabilizing around year 50 (t+20). In all cases, the plume margin polygon is defined by the maximum extent of any plume in any scenario at any simulation time, with a 0.5-mile buffer extending beyond this polygon defining the margin of the MMA.

As stated in the MRV plan, Dark Horse intends to define the AMA as the same area as the MMA. Per 40 CFR 98.449, AMA is defined as the area that will be monitored over a specific time interval from the first year of the period (n = 2023) to the last year in the period (t = 2053, a 30-year injection period). The MRV plan states that the boundary of the AMA 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, and (2) the area projected to contain the free phase CO_2 plume at the end of year t + 5 (2058, or year 35 of the simulation). However, as the plume has not stabilized by year t+5, the AMA and MMA in these areas are defined by the larger area of the stable plume which occurs at year t+20.

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 duration of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). Dark Horse identified the following as potential leakage pathways in Section 5 of their MRV plan that required consideration:

- Surface Equipment
- Existing Wells
- Fractures and Faults
- Confining/Seal System
- Natural or Induced Seismicity
- Lateral Migration

3.1 Surface Equipment

The MRV plan explains that due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas treating facilities. To minimize this potential for leakage, the construction, operation, and maintenance of Dark Horse's sour gas treating facilities follow industry standards and relevant regulatory requirements. The MRV plan also states that New Mexico Administrative Code (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."

Additionally, to further minimize the likelihood of surface leakage of CO_2 from surface equipment, the MRV plan states that Dark Horse implements a schedule for regular inspection and maintenance of surface equipment. To further minimize the magnitude and duration of detected gas leaks to the surface, Dark Horse implements several methods for detecting gas leaks at the surface, which will be discussed in the next section.

Dark Horse also states that due to the required continuous monitoring of the gas gathering and processing systems, the likelihood of CO_2 leakage is low. This potential leakage remains consistent throughout the project lifetime. Leakage mass is predicted to be less than one tenth of a percent of total injection, which is less than 12,000 metric tons.

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

3.2 Existing Wells

The MRV plan states there are several existing wells within a two-mile radius of the Independence AGI wells. Specifically, there are two third-party wells within two miles of the Independence AGI wells that penetrate the Silurian-Devonian Injection Zone. The first well, West Jal B Deep #1, is an active brine injection well located approximately one mile from the Independence #2 surface hole location (SHL). This well was drilled to a total depth of 18,945 feet and is permitted to inject through perforated intervals of the Strawn through Fusselman strata. Despite being granted approval for injection into the Fusselman (approved June 2014), New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division (NMOCD) records document no reports of work to drill out plugged intervals at 14,200 feet. Additional research indicated that the intent of one operator to drill out these plugs, but no subsequent reports confirming completion of this work have been identified. Additionally, reported injection volumes for this well do not appear to exhibit any significant increase that might indicate this work was completed. The second well penetrating the Silurian-Devonian Injection Zone is the plugged and abandoned West Jal Unit #1, located approximately 0.67 miles from the Independence AGI #2 SHL. Final plugging operations were completed in April 1984 and all relevant plugging reports and documents are included in Appendix 9 of the MRV plan. The well is plugged with multiple cast iron bridge plugs (CIBPs) and cement plugs through the Silurian-Devonian Injection Zone, and it is not anticipated to be negatively affected by the operation of the Independence AGI wells. The MRV plan also states that the remaining wells that are planned to be drilled within the MMA are completed in zones more than 4,000 feet above the Silurian-Devonian Injection Zone.

Dark Horse describes the likelihood of CO_2 leakage as low because NMOCD regulations governing each wellbore within the MMA/AMA, require the respective operators to case the well 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 zone or to the surface around the outside of a casing string. Additionally, the NMOCD requires each respective operator of a wellbore within the MMA/AMA to operate and maintain their assets so that the injected fluids are confined to the approved intervals and prevent surface damage or pollution. The risk of leakage at each wellbore is greatest after CO_2 has reached that location and when pressures are greatest, which occurs towards the end of the injection time period. Leakage mass is predicted to be less than one percent of total injection, which is less than 0.15 million metric tons.

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

3.3 Fractures and Faults

The MRV plan states that the reservoir characterization modeling and the delineation of the monitoring areas show that the TAG plume reaches the faults shown in Figure 3.5-1 of the MRV plan during the thirty-year injection period and the five-year post-injection monitoring period. Vertical permeability may be present parallel to the plane of the fault vertically, especially where the two main faults intersect. A review of available drilling fluid records was conducted to evaluate regional reservoir pressure conditions in the Delaware basin. Above the Silurian-Devonian injection reservoir, mud weights utilized range from 12.1 to 15.1 pounds per gallon, while for the injection reservoir less dense fluids were used (average of 9.0 pounds per gallon). According to the MRV plan, these mud weights support the interpretation that the overlying productive zones in this area are over pressured with respect to the target reservoir, which would produce a downward gradient through any fault-parallel permeability. The MRV plan also states that the pressure differential between the overlying interval and target interval will act as a barrier preventing vertical migration even along localized open conduits.

Dark Horse also states that due to evidence that production zones overlying the Silurian-Devonian Injection Zone are over pressured and that the basement rooted faults in the area are confined to the lower Paleozoic up to the lower Woodford Shale, Dark Horse considers the likelihood of CO_2 leakage to the surface via this potential leakage pathway to be unlikely. The risk of leakage is greatest when pressures are at their highest, which occurs at the end of the injection period. The anticipated magnitude of leakage is negligible.

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

3.4 Confining/Seal System

The MRV plan states that the subsurface lithologic characterization presented in Section 3.2.2 of the MRV plan describes the thick sequence of Mississippian through Permian strata overlying the Silurian-Devonian Injection Zone and reveals the existence of several excellent confining zone layers. Therefore, it is unlikely that TAG injected into the Silurian-Devonian Injection Zone 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.

Dark Horse describes the likelihood of CO_2 leakage to the surface via this potential leakage pathway as unlikely due to the thickness, lateral extent, and low porosity and permeability of the Woodford Shale. The risk of leakage is greatest when pressures are at their highest, which occurs at the end of the injection period. The anticipated magnitude of leakage is negligible.

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

3.5 Natural or Induced Seismicity

The MRV plan states that the faults considered in this assessment do not display significant potential for injection-induced slip, and the Independence AGI #2 is not predicted by the Stanford Center for Induced and Triggered Seismicity's Fault Slip Potential (FSP) model to contribute significantly to the total resultant pressure front. Dark Horse concludes that the likelihood for the creation and/or opening of vertical conduits for CO_2 leakage to the surface due to induced seismicity is low. Nevertheless, the NMOCC Order requires Dark Horse to install, operate, and monitor a seismic monitoring station, or stations, for the life of the project.

The MRV plan also states that according to data obtained from the New Mexico Tech Seismic Observatory (2023), there have been four seismic events within the MMA since January 12, 2017. These seismic events range in magnitude of 1.16-1.88 and occurred between September 2020 and October 2021. Data queries with the United States Geological Survey (USGS) Earthquake Catalog did not show any seismic activity within the MMA.

According to the MRV plan, the results of the fault slip potential model indicate no likelihood of slip on the fault east of the Independence AGI Wells. The maximum FSP was determined to have a value of 0.05 at the injection wells, with AGI injections causing no increase in probability. Any slip would depend on the injection volumes of brine disposal wells (at present there is no brine injection in the target area). Should fault slip occur, the short lengths of the potentially slipping segment likely preclude large earthquakes, and seismicity would be expected to be <2.5 in magnitude. Any earthquakes at or above this value would be carefully evaluated to determine location, depth, and sense of motion.

Darkhorse concludes that the likelihood for the creation of vertical conduits for CO_2 leakage to the surface due to induced and natural seismicity to be unlikely. The risk of leakage due to natural seismicity is not anticipated to change over the life of the project while the risk of leakage due to induced seismicity is greatest when pressures are at their highest, which occurs at the end of the injection period. The anticipated magnitude of leakage is negligible.

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

3.6 Lateral Migration

The MRV plan explains that results from modeling indicate the TAG is unlikely to migrate laterally beyond approximately 2.5 miles within the Silurian-Devonian Injection Zone to encounter any conduits to the surface. The model extended approximately 20 square miles from the injection site and included relevant features such as faults and nearby injection wells. The risk of leakage is greatest when pressures are at their highest, which occurs at the end of the injection period. The anticipated magnitude of leakage is negligible.

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

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

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

40 CFR 98.448(a)(3) requires that an MRV plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Section 6 of the MRV plan discusses the strategy that Dark Horse will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in the previous sections to meet the requirements of 40 CFR §98.448(a)(3). As the injected stream contains both H_2S and CO_2, any observation of H_2S will serve as a preliminary indicator for CO_2 leakage, and therefore the monitoring systems to detect H_2S will also suggest a leak of CO_2. If CO_2 surface emissions are detected, Dark Horse will quantify the mass emitted via approved emission factors, such as those found in 40 CFR Part 98, Subpart W, or use engineering estimates based on the operational conditions present at the time of leakage. This quantification can include leak amounts based on measurements, frequency of inspection, and other factors related to each specific leak identification. Monitoring will occur during the planned 30-year injection period, or otherwise the cessation of operations, plus a proposed two-year post-injection period. A summary table of Dark Horse's monitoring strategies for detecting surface leakage pathways associated with CO_2 injection can be found in Table 6.1 of the MRV plan and copied below.

Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system ("**DCS**") surveillance of facility operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/H_2S and low explosive level ("**LEL**") monitoring network • Personal and hand-held gas monitors
Independence AGI #1 & Independence AGI #2	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests ("**MIT**") • Fixed in-field gas monitors/H_2S and LEL monitoring network • Personal and hand-held gas monitors
Existing Other Operator Active and Abandoned Wells	• Monitoring of well operating parameters • Visual inspections • MITs • Mobile CO_2 detectors
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network • Mobile CO_2 detectors
Confining / Seal System	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network

4.1 Detection of Leakage through Surface Equipment

As described in Section 6.1 of the MRV plan, leaks from surface equipment are detected by Dark Horse using both in-field and personal monitors which detect H_2S. Dark Horse field personnel also follow daily and weekly inspection protocols which include reporting and responding to any detected leakage events. The MRV plan also provides a description of the gas detection equipment based on the H_2S Contingency Plan. To summarize the description of fixed monitors at Dark Horse: Upon detection of H_2S concentrations of 10 parts per million (ppm) at any detector, visible beacons are activated, and an alarm is sounded. Upon detection of H_2S concentrations of 90 ppm at any detector, an evacuation alarm is sounded throughout the Dark Horse facility, at which time all personnel will proceed immediately to a designated evacuation area. While personal and handheld monitors alarm and vibrate upon detection of H_2S concentrations of 10 ppm, handheld gas detection monitors are also available at strategic locations around the Dark Horse facility so that facility personnel can check specific areas and equipment prior to initiating maintenance or other work.

Table 6.1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through surface equipment. Thus, the MRV plan provides adequate characterization of Dark Horse's approach to detect potential leakage through surface equipment as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through Existing Wells

As part of ongoing operations, Dark Horse continuously monitors and collects flow, pressure, temperature, and gas composition data from each Independence AGI well. This data is monitored continuously by qualified technicians who follow response and reporting protocols when the monitoring system delivers alerts that data is not within acceptable limits. Mechanical integrity tests (MIT) are performed on each Independence AGI well annually. Failure of an MIT would indicate a leak in the applicable well and result in immediate action by shutting in the well, assessing the MIT failure, and implementing mitigative steps. If operating parameter monitoring and MIT failures indicate a CO_2 leak has occurred, Dark Horse will take actions to quantify the leak based on operating conditions at the time of the detection.

Dark Horse also states they will annually employ mobile CO_2 detectors, which may include drone mounted sensors, to monitor for any CO_2 emission at the location of the West Jal B Deep Well No. 1 and West Jal Unit #1. If surface CO_2 leakage is correlated with loss through this well, Dark Horse will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, which may include shutting in the Independence AGI well(s).

Dark Horse states that it has been in contact with the oil and natural gas producers that have wells completed and proposed in the Wolfcamp, Bone Spring, and shallower stratigraphic units. Dark Horse will work cooperatively with them to investigate any potential leakage. Similar to other wells, Dark Horse will also employ mobile CO_2 detectors to aid in this. Dark Horse will take actions to quantify the amount of CO_2 released and take mitigative action to stop it.

Table 6.1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through existing wells. Thus, the MRV plan provides adequate characterization of Dark Horse's approach to detect potential leakage through existing wells within the MMA as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage through Fractures and Faults

Section 6.3 of the MRV plan reiterates that it is unlikely that CO_2 leakage to the surface will occur through a fracture or fault. Continuous operational monitoring of the Independence AGI wells will provide an indicator if CO_2 leaks out of the Silurian-Devonian Injection Zone.

The MRV plan states that Dark Horse will assess any changes in operating parameters or data which might indicate surface leakage of CO_2 along fractures or faults. Dark Horse will also employ mobile CO_2 detectors, which may include drone mounted sensors, to monitor for any emission above mapped fractures and faults. If surface CO_2 leakage is detected through a mapped fracture or fault, Dark Horse will (i) take actions, including by working with relevant surface owners, to quantify the mass of CO_2 emitted based on the conditions that existed at the time of 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; and (ii) take mitigative action to stop it, which may include shutting in the Independence AGI well(s).

Table 6.1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through fractures and faults. Thus, the MRV plan provides adequate characterization of Dark Horse's approach to detect potential leakage through fractures and faults as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage through the Confining/Seal System

Section 6.4 of the MRV plan reiterates that it is unlikely that CO_2 leakage to the surface will occur through the confining/seal system. Continuous operational monitoring of the Independence AGI wells will provide an indicator if CO_2 leaks out of the Silurian-Devonian Injection Zone.

The MRV plan states that if changes in operating parameters or data indicate surface leakage of CO_2 through the confining/seal system, Dark Horse will take actions to quantify the amount of CO_2 released based on 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. Dark Horse will also take mitigative action to stop it, which may include shutting in the Independence AGI well(s).

Table 6.1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through confining/seal system. Thus, the MRV plan provides adequate characterization of Dark Horse'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 through Natural or Induced Seismicity

Section 6.5 of the MRV plan states that continuous operational monitoring of the Independence AGI wells coupled with a detection of a seismic event by the seismic stations discussed previously will provide an indicator if CO_2 leaks out of the Silurian-Devonian Injection Zone due to a seismic event.

The MRV plan also states that after a seismic event, Dark Horse will assess any changes in operating parameters and data from the surrounding seismic stations which might indicate leakage of CO_2 along faults or fractures activated by the event. If leakage is correlated with a seismic event, Dark Horse will take actions to quantify the amount of CO_2 released based on 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. Dark

Horse will also take mitigative action to stop it, which may include shutting in the Independence AGI well(s).

Table 6.1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through natural or induced seismicity. Thus, the MRV plan provides adequate characterization of Dark Horse's approach to detect potential leakage through natural or induced seismicity as required by 40 CFR 98.448(a)(3).

4.6 Detection of Leakage through Lateral Migration

Section 6.6 of the MRV plan states that the continuous operational monitoring of the Independence AGI wells during and after the injection period will provide an indication of the movement of the CO_2 plume migration in the Silurian-Devonian Injection Zones. The CO_2 monitoring network and routine well surveillance will provide an indicator if CO_2 leaks out of the Silurian-Devonian Injection Zone.

The MRV plan also states that if monitoring of operational parameters indicates that the CO_2 plume extends beyond the MMA, Dark Horse will reassess the plume migration model for evidence that the plume may have intersected a pathway for CO_2 release to the surface. If it is determined that the plume intersected a pathway for CO_2 release to the surface, this would be considered a material change per 40 CFR 98.448(d)(1), and Dark Horse will submit a revised MRV plan as required by 40 CFR 98.448(d).

Table 6.1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through lateral migration. Thus, the MRV plan provides adequate characterization of Dark Horse's approach to detect potential leakage through lateral migration as required by 40 CFR 98.448(a)(3).

4.7 Determination of Baselines for Monitoring CO_2 Leakage

40 CFR 98.448(a)(3) requires that an MRV plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Section 7 of the MRV plan identifies the strategies that Dark Horse will undertake to establish the expected baselines for monitoring CO_2 surface leakage per §98.448(a)(4). Dark Horse 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 explains that the scope of work will include H_2S monitoring at the AGI well site and atmospheric monitoring near identified penetrations of the Silurian-Devonian Injection Zone within the AMA. Upon approval of the MRV Plan and for the five (5) year post-injection period, Dark Horse will have these monitoring processes and systems in place.

The MRV plan states that Compositional analysis of gas injectate at the Dark Horse facility indicates an approximate H_2S concentration of 38.7%. Dark Horse field personnel equipped with handheld and personal monitors will conduct daily visual inspections of surface equipment located at the Dark Horse

Facility and the Independence AGI Wells. Personal monitoring devices will give an audible alarm and vibrate upon detection of H_2S concentrations of 10 ppm. These inspections will aid with identifying and addressing issues in a timely fashion to minimize the possibility of leakage. The MRV plan states that if any issues are identified, prompt corrective actions would be taken to address such leakage.

The MRV plan states that the Dark Horse facility also uses fixed-point in-field H_2S monitors, strategically placed around the facility, as part of their H_2S Contingency plan. The sensors are connected to the control room alarm panel's programmable logic controllers (PLC), and then to the distributed control system (DCS). The MRV plan also states that upon detection of H_2S concentrations of 10 ppm at any monitor, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of H_2S concentrations of 90 ppm at any monitor, an evacuation alarm is sounded throughout the Dark Horse facility at which time all personnel will proceed immediately to a designated evacuation area.

The MRV plan states that the DCS of the Dark Horse facility 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. The MRV plan also states that if a parameter is outside the allowable window, it will trigger further investigation to determine if the issue poses a leakage threat. Additionally, Dark Horse's Routine Operations and Maintenance Procedures for the Independence AGI wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action. Dark Horse's Routine Operations and Maintenance Procedures for the Independence AGI Wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

The MRV plan states that Dark Horse 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 always maintain mechanical integrity. Furthermore, NMOCC includes special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary.

The MRV plan states that Dark Horse owns a model TCH120-1 Trillium Compact Horizon Seismometer and a model CTR4-3S Centaur Digital Recorder to monitor and record data for any seismic event at the Dark Horse facility. The seismic station will meet the requirements of the NMOCC Order to "install, operate, and monitor for the life of this Order a seismic monitoring station or stations. NMOCD shall be responsible for coordinating with the Manager of the New Mexico Tech Seismological Observatory at the New Mexico Bureau of Geology and Mineral Resources for appropriate specifications for the equipment and the required reporting procedure for the monitoring data."

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

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

Section 8 of the MRV plan provides the equations that Dark Horse will use to calculate the mass of CO_2 sequestered annually.

5.1 Calculation of Mass of CO_2 Received

The MRV plan states that Dark Horse currently receives sour natural gas through three pipelines, the Hondo High Pressure Sour Gas Pipeline (owned and operated by Piñon), the Franklin Mountain Low Pressure Pipeline (owned and operated by Franklin Mountain Energy), and the Ameredev II Low Pressure Pipeline (owned and operated by Ameredev). Dark Horse will use Equation RR-2 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.

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \qquad \text{(Equation RR-2 for Pipelines)}$$

where:

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

$Q_{r,p}$ = Quarterly volumeteric 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 CO2 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.

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \qquad \text{(Equation RR-3 for Pipelines)}$$

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.

The MRV plan also states that if Dark Horse begins to receive CO_2 in containers, they will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. If CO_2 received in containers results in a material change as described in 40 CFR 98.488(d)(1), Dark Horse will submit a revised MRV plan addressing the material change.

Dark Horse 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 Dark Horse injects CO_2 into the existing Independence AGI #1 well and upon its completion, Dark Horse will commence injection of CO_2 into the existing Independence AGI #2. The MRV plan also states that Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the Independence AGI wells and Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the Independence AGI Wells.

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \qquad \text{(Equation RR-5)}$$

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.

$C_{CO2,p,u}$ = 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.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \qquad \text{(Equation RR-6)}$$

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.

Dark Horse provides an acceptable approach for calculating the mass of CO_2 injected under Subpart RR.

5.3 Calculation of Mass of CO_2 Produced

The MRV plan states that Dark Horse does not produce oil, natural gas, or any other liquid at the Dark Horse facility so there is no CO_2 produced or recycled.

Dark Horse provides an acceptable approach for calculating the mass of CO_2 produced under Subpart RR.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

The MRV plan states that surface leakage of CO_2 will not be measured directly, rather it will be determined by employing the CO_2 proxy detection system described in Section 7.2 of the MRV plan. Equation RR-10 will be used to calculate the 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.

Dark Horse provides an acceptable approach for calculating the mass of CO_2 emitted by surface leakage under Subpart RR.

5.5 Calculation of Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

The MRV plan states that Dark Horse 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 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 total will be calculated using procedures provided in Subpart W.

5.6 Calculation of Mass of CO_2 Sequestered

The MRV plan states that since Dark Horse does not actively produce oil, natural gas, or any other fluid at the Dark Horse facility, Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations.

The MRV plan also states that to fulfill the requirements of 98.448(d), Dark Horse will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W.

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

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 CO2 mass emitted (metric tons) from equipment leaks and vented emissions of CO2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of the GHGRP.

Dark Horse provides an acceptable approach for calculating the mass of CO_2 sequestered under Subpart RR.

6 Summary of Findings

The Subpart RR MRV plan for Piñon Midstream LLC's Dark Horse Treating Plant meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the Dark Horse MRV plan.

Subpart RR MRV Plan Requirement	Dark Horse MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA).	Section 4 of the MRV plan delineates and describes the MMA and AMA. Dark Horse used geologic and numerical modeling to simulate AGI injection. The MRV plan explains that the farthest plume extent was found at year 30 (t). The plume stabilizes at around year 50 (t+20). Dark Horse defines the plume margin polygon as the maximum extent of the plume with a 0.5 mile buffer. Dark Horse will use the MMA boundary as the AMA boundary.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 5 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: surface equipment; existing wells; faults and fractures; confining/seal system; natural or induced seismicity; and lateral migration. The MRV plan analyzes the likelihood, magnitude, and duration of surface leakage through these pathways.

40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 6 of the MRV plan describes Dark Horse's strategy for detecting and quantifying potential CO_2 leakage to the surface should it occur, such as personal as well as fixed in-field H_2S monitors, field inspections, DCS surveillance of facility/well operations, and MIT. The MRV plan states that quantification of CO_2 leakage will be calculated based on operating conditions at the time of detection.
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 Dark Horse's strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage. Dark Horse personnel equipped with handheld and personal H_2S monitors will carry out daily visual inspections at the facility and the Independence AGI wells. Fixed-point in-field H_2S monitors are also placed around the facility. Dark Horse monitors operational parameters at the injection wells with high and low points programmed into the DCS. Additionally, Dark Horse will deploy their own seismic monitoring stations.
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 Dark Horse's approach for determining the total amount of CO_2 sequestered using the Subpart RR mass balance equations, including calculation of the total annual mass of CO_2 emitted from equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 1 and 2 of the MRV plan identify the Independence AGI #1 and #2 Well's UIC numbers and permit class. According to the MRV plan, the NMOCD has issued UIC Class II AGI permits for the Independence AGI #1 (API 30-025-48081) and #2 (API 30-025-49974).
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 9 of the MRV plan states that Dark Horse will commence collecting data for calculating total amount of CO_2 sequestered according to the equations outlined in Section 8 of the MRV plan on June 1, 2023, after it is approved by EPA.

Appendix A: Final MRV Plan

MONITORING, REPORTING, AND VERIFICATION PLAN

Independence AGI #1 and #2 Wells

Pinon Midstream, LLC

Version Number: 5.0
Version Date: February, 2024

Contents

1 Introduction

Ameredev II, LLC (together with its affiliates, "**Ameredev**") is an oil and natural gas producer operating in portions of the Delaware Basin located in southeastern New Mexico and western Texas. In 2020 Ameredev began evaluating methods for treating its sour natural gas production in Lea County, New Mexico to remove and permanently sequester large quantities of hydrogen sulfide ("**H_2S**") and carbon dioxide ("**CO_2**") commingled in its produced natural gas stream. On July 10, 2020, Ameredev filed an application with New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division ("**NMOCD**") seeking to drill an acid gas injection ("**AGI**") well approximately six (6) miles west of Jal in Lea County, New Mexico for the injection and permanent sequestration of treated acid gas ("**TAG**"). The application was heard and approved at a New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Commission ("**NMOCC**") hearing held on October 8, 2020. The approved order (Order No. R-21455-A) was subsequently issued at the November 4, 2020 NMOCC hearing and the final, approved, Class II injection permit was issued on November 11, 2020. The Independence AGI #001 vertical well (API 30-025-48081; "**Independence AGI #1**") was spud on December 27, 2020 by Ameredev.

In December of 2020, certain affiliates of Ameredev and other outside investors funded Piñon Midstream, LLC ("**Piñon**") to construct and operate the Dark Horse Sour Gas Treating Facility (the "**Dark Horse Facility**") adjacent to the Independence AGI #1 (Figure 1-1) and Ameredev subsequently contributed and assigned the Independence AGI #1 to Piñon on May 21, 2021. Piñon became the operator of record for the Independence AGI #1 on August 24, 2021. Upon completion in late August 2021, treatment of sour natural gas (using amine to isolate H_2S and CO_2) and the injection of TAG through Independence AGI #1 commenced at the Dark Horse Facility (a full description of the treating and injection process is provided in Section 3.8). On March 31, 2022 the NMOCC authorized the drilling of the Independence AGI #002 deviated well (API 30-025-49974; "**Independence AGI #2**") (together the "**Independence AGI Wells**"), which commenced during the summer of 2022, with initial TAG injection through the well occurring in April 2023.

Independence AGI #1 is permitted to inject into the Devonian Thirtyone and Upper Silurian Wristen and Fusselman Formations from a true vertical depth ("**TVD**") of approximately 16,230 to 17,900 feet (the "**AGI #1 Injection Zone**") and at a maximum surface pressure of approximately 4,779 pounds per square inch gauge ("**psig**"). Independence AGI #2 is permitted to inject into the Devonian Thirtyone Formation and Upper Silurian Wristen and Fusselman Formations from a TVD of approximately 16,080 to 17,683 feet (the "**AGI #2 Injection Zone**", and together with the AGI #1 Injection Zone, the "**Siluro-Devonian Injection Zone**") and at a maximum surface pressure of approximately 5,005 psig. In accordance with NMOCC Order No. R-21455-A (as amended by Order No. R-21455-B, the "**NMOCC Order**"), Piñon is authorized to inject and dispose of TAG, utilizing the Independence AGI Wells, at an aggregate *combined* maximum daily injection rate of up to 20 million standard cubic feet per day ("**MMSCF/D**"), which is the equivalent of approximately 8,200 barrels per day ("**bpd**") or 1,036.7 metric tonnes per day. Gas is injected for 30 years at a rate of 1,036.73 tonnes per day (378,399 tonnes per year or 11,351,970 total tonnes) followed by a 5-year rest period. If Independence AGI #1 is not injecting volumes of TAG, Independence AGI #2 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG. If Independence AGI #2 is not injecting volumes of TAG, Independence AGI #1 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG.

Piñon has chosen to submit this Monitoring, Reporting, and Verification Plan (the "**MRV Plan**") to the United States Environmental Protection Agency (the "**EPA**") for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (the "**GHGRP**") for the purpose of qualifying for the tax credit in Section 45Q of the federal Internal Revenue Code. Piñon intends to utilize the Independence AGI Wells for the injection and disposal of TAG for another approximately thirty (30) years.

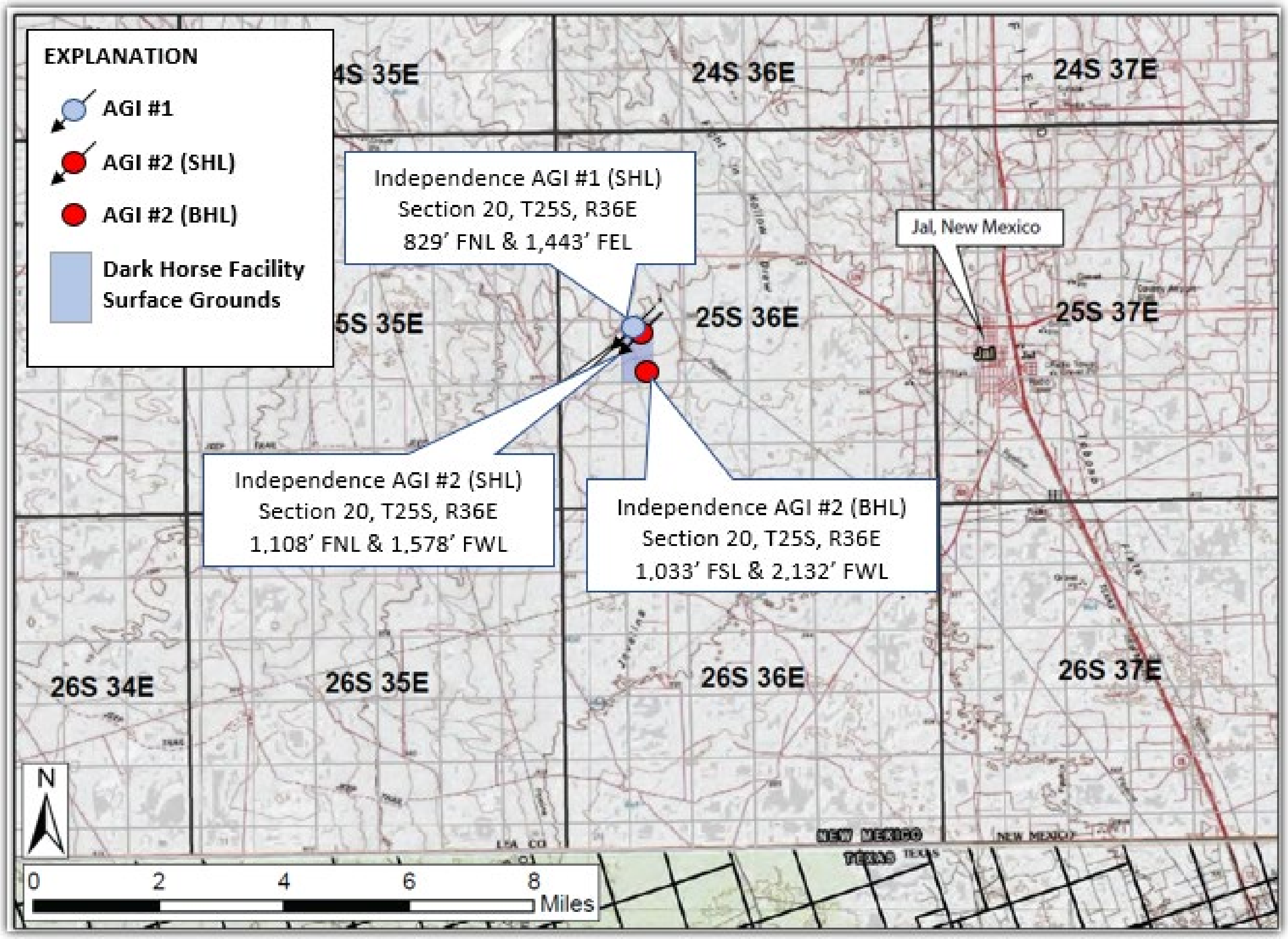

***Figure 1-1**: Location of Dark Horse Facility and the Independence AGI Wells. The approximate surface hole location ("SHL") and the approximate bottom hole location ("BHL") are indicated for both Independence AGI Wells. (Modified from Figure 1 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

This MRV Plan contains twelve (12) sections:

Section 1 is this Introduction.
Section 2 contains facility information.
Section 3 contains the project description.
Section 4 contains the delineation of the maximum monitoring area ("**MMA**") and the active monitoring area ("**AMA**"), both defined in 40 CFR 98.449, and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.
Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and duration of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP.
Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage.
Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.
Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.
Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.
Section 11 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.
Section 12 includes Appendices supporting the narrative of the MRV Plan.

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is 582541. There are no other facilities related to this MRV plan.

2.2 Underground injection control ("UIC") well identification numbers

This MRV Plan is for the Independence AGI Wells (*see* Appendix 1). The details of the injection process are provided in Section 3.8.

2.3 UIC permit class

The NMOCD has issued UIC Class II Acid Gas Injection ("**AGI**") permits for the Independence AGI Wells under its State Rule 19.15.26 NMAC (*see* Appendix 2). All oil- and natural gas-related wells located near the Independence 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

Parts of the following project description have been taken from the Class II permit applications for (i) Independence AGI #1, prepared by Geolex, Inc. for Ameredev, dated July 10, 2020; and (ii) Independence AGI #2, also prepared by Geolex, Inc. for Piñon, dated November 4, 2021.

3.1 General Geologic Setting / Surficial Geology

The Dark Horse Facility is located adjacent to the Independence AGI Wells as shown in Figure 3.1-1. The site lies on the eastern flank of the Pecos River Basin within the Javelina Basin. Referred to as the South Plain by Nicholson & Clepsch (1961), the region exhibits irregular topography without integrated drainage. Surficial sediments commonly consist of unconsolidated alluvium and eolian sands. There are no observed surface bodies of water, or groundwater discharge sites within one (1) mile of the Independence AGI Wells. The Dark Horse Facility overlies Quaternary alluvium overlying the Triassic redbeds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater. The thick sequences of Permian rocks that underlie these deposits are described in Section 3.2.2.

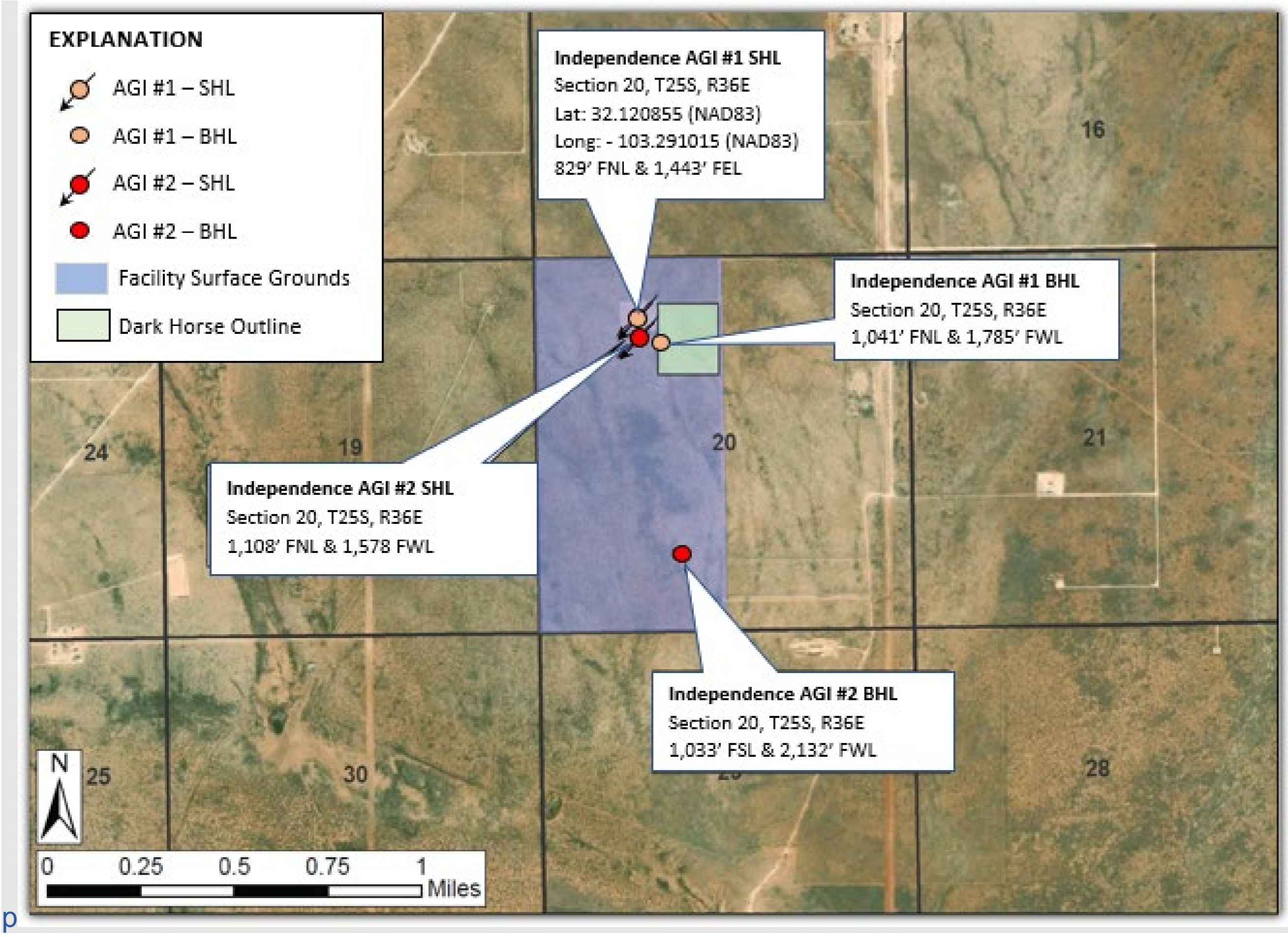

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__Figure 3.1-1__: Map showing location of Dark Horse Facility and the Independence AGI Wells in Section 20, T25S, R36E NMPM. The BHL of the Independence AGI #1 sidetrack is 446' southeast of the SHL. The SHL and the BHL for Independence AGI #2 are shown. (Modified from Figure 2 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.2 Bedrock Geology

3.2.1 Basin Development

The Dark Horse Facility is 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. The Permian Basin and its sedimentary fill have been formed and controlled by tectonism of varying degrees and sedimentation events that began in the Precambrian and throughout the Cenozoic (Neogene). Early Paleozoic deposition took place in the Late Cambrian as marginal areas of the North American craton began to be flooded by marine seas. Late Cambrian sediments comprised of basal siliciclastic sands and muds from areas of exposed Precambrian igneous, metamorphic, and sedimentary rocks and shallow-water carbonates.

Parts of the following basin development descriptions in this subsection have been modified and summarized from Ruppel (2019). Flooding continued across the North American craton throughout the Early Ordovician, establishing a widespread shallow-water carbonate platform. The Ellenburger Formation (Figure 3.2-2) rocks are derived from peritidal and shallow subtidal carbonates. These sediments were exposed during one of the sea-level drops during the Ordovician deposition resulting in karstification and dolomitization. During the Early to Middle Paleozoic time, the Permian Basin region was occupied by a relatively shallow basin called the Tobosa Basin. The first rapid subsidence and formation of the Tobosa Basin began in Simpson time (Middle Ordovician), and subsidence slowly diminished into the Early Devonian (Ewing, 2019). Subsequent tectonic history of the Tobosa and Permian Basins will be discussed throughout this section.

Early Paleozoic deposition is mostly defined by multiple high-frequency sea-level changes, karsting, and erosional events. Large-scale shift in facies and environments indicate tectonic and/or eustatic controls on sediment distribution patterns. Simpson Group (Middle Ordovician) rocks unconformably overlie Ellenburger Formation rocks at a widespread hiatus caused by Early Ordovician to Middle Ordovician relative sea-level fall. Simpson rocks are a cyclic succession of lime mudstones and quartz sandstones and were deposited during the subsequent reflooding of the shelf. Carbonate-dominated Montoya Formation (Late Ordovician) and Fusselman Formation (Latest Ordovician -Early Silurian) rocks overlie the Simpson Group and indicate a shift and deepening of Tobosa Basin. These rocks are indicative of an overall relative sea level rise.

Middle Silurian-Early Devonian Wristen Group and Thirtyone Formation rocks indicate differential subsidence in the area and represented a deepening and expansion of the basin. Wristen Group rocks comprised of carbonate mudstones and wackestones of the Wink Formation, which underlies the shallow-water carbonate platform packstones, grainstones, and reef facies (corals and stromatoporoids) of the Fasken Formation and the deep-water lime mudstones of the Frame Formation. These facies outline the position of a Silurian platform margin and imply a downwarping of the North American craton. Although Wristen and Fusselman show evidence of numerous high-frequency sea-level changes, the larger-scale change in facies and depositional environments indicates tectonic and/or eustatic controls on sediment distribution patterns. The Silurian platform margin is a recurring feature that controls facies distribution through the Late Mississippian, suggesting tectonic and/or basement terrain control. The rocks of the Thirtyone Formation (Early Devonian) consist of platform carbonate grainstones and packstones surrounding calcareous, radiolarian-rich basin facies.

According to Ruppel (2019) and Ruppel and others, (2020a), a major episode of relative sea-level fall in the Middle Devonian is documented by an absence of Late Early Devonian and early Middle Devonian rocks. Late Devonian Woodford rocks overlie eroded and karsted Silurian (Wristen Group), Early Devonian Thirtyone, and older rocks. Local folding of these rocks below the Woodford suggests that the hiatus may have been at least partially driven by tectonic events. Evidence from the distribution of later Mississippian rocks indicates that the tectonic event caused uplift and localized deformation of pre-Middle Devonian rocks and changed subsidence and depositional patterns across the entire region.

Following the Middle Devonian Permian Basin-area uplift and emergence, Late Devonian marine transgression flooded the region with anoxic bottom-water seas and deposited black, organic-rich biosiliceous mudstones of the Woodford Formation (Ruppel, 2019). Sea-level fall-and-rise sequences defined the Early and Late Mississippian and were even more pronounced during the Pennsylvanian. In the Late Mississippian, initial collision occurred between Laurentia and Gondwanaland, and the Marathon-Ouachita orogenic belt first started to form in northeastern North America (Yang and Dorobek, 1995) with tractions propagating toward the southwest, impacting the Permian Basin by the Middle Pennsylvanian Epoch (Desmoinesian, 310 Ma) (Horne, 2021). Mississippian limestones and the Barnett Formation shales were deposited following a marine transgression that resulted in the development of an extensive carbonate platform, surrounded by a deep-water, organic-rich mud basin.

Collision along the western and southwestern margins of Laurentia, combined with tractions from the Marathon-Ouachita thrusting in the southeast, resulted in northwest-southeast-trending uplifts throughout the western United States known as the Ancestral Rocky Mountain orogeny, which began in Early Pennsylvanian time and continued into the Early Permian (Horne, 2021). The Pennsylvanian tectonic setting in the Permian Basin is the product of the combined Ancestral Rocky Mountain and Marathon–Ouachita effects occurring along the southwest and southeast margins of Laurentia. These events contributed to basin evolution and specific structural domains and styles. In the Permian Basin, the Ancestral Rocky Mountain orogeny is responsible for the uplift of the Central Basin Platform and the major structural development of the Midland and Delaware Basins (Horne, 2021).

During Desmoinesian to early Missourian sedimentation, Permian Basin deformation reached its peak. The antecedent Tobosa Basin was tectonically differentiated, formed into the crustal uplifts and sub-basins that now characterize the Central Basin Platform, Midland Basin, and Delaware Basin. Throughout Pennsylvanian and most of Permian sedimentation, tectonics coupled with glacial eustacy played an important role in the development of regional facies. Middle to Late Pennsylvanian saw decreasing tectonic deformation activity, and by the Wolfcampian time (Early Permian), deformation was limited to subsidence within the structures formed by the existing uplifts and basins (e.g., Delaware and Midland Basins, Central Basin Platform). The continual subsidence of the Delaware basin affected sediment infilling, with some areas accumulating as much as 12,000 ft of basin-fill sediment. Marine transgression eventually submerged uplifts and became the location of carbonate sedimentation, while the basins became filled with organic-rich siliceous muds. By the end of the Wolfcampian, the major Permian Basin physiographic features (Central Basin Platform, Delaware and Midland Basins) were fully developed, and controlled sedimentation types and location for the remainder of the Paleozoic.

The Middle Permian (Leonardian and Guadalupian) was punctuated by cyclic sediment deposition during sea-level eustatic events. The Leonardian was a time of gradual global warming from the icehouse climates of the late Carboniferous to warmer and more arid greenhouse climates of the later Permian and Mesozoic (Tabor, 2004). The Leonardian marked the beginning of the last stages of the formation of Pangea, producing greater restriction of open ocean connections to the Permian Basin (Ruppel, 2020b). The abundance of tidal-flat facies, evaporites, and reflux dolomites in Leonardian rocks reflects the development of much more arid conditions compared with those in the earlier Permian (Ruppel, 2020b). In the shelf areas (Central Basin Platform and Northern, Northwestern, and Eastern Shelves) (Figure 3.2-1), sedimentation was characterized by shallow-water carbonate production and deposition during sea-level rise, and by shelf exposure and sand-silt deposition during sea-level fall and subsequent shelf exposure. In the Delaware and Midland basins, sedimentation was characterized by cyclic intervals of detrital carbonate-sediment transport into the basins by sea-level highs, and by sand-silt transport and deposition during sea-level falls. Dolomitization of carbonate-shelf deposits occurred during the more regionally arid climates of the Leonardian and the Guadalupian as a product of the Permian Basin area being situated at the equator and from refluxing brines created during periods of sea-level highstand events. Deposition of evaporites became more common in the shelf areas during this time, likely in response to the increasingly arid environment and/or decreased accommodation. By the end of the Guadalupian, the Midland Basin was largely filled, and peritidal muds and evaporite deposition dominated. Sea-level fall and closure of the Hovey Channel (Figure 3.2-1) cut off the Delaware Basin from its marine supply, resulting in regional exposure and nondeposition and the filling of the basin with evaporites of the Castille Formation (Lopingian “Ochoa” Series) (Ruppel, 2019). Most of the rocks deposited during Lopingian “Ochoan” time were evaporites such as anhydrite, halite, and potash minerals with minor amounts of limestone, mudstone, and siltstone and are subdivided into (ascending) Castile Formation, Salado Formation, Rustler Formation, and Dewey Lake Red Beds. Most of the early Ochoan deposition was confined to the Delaware Basin (Bachman, 1984).

3.2.2 Stratigraphy

Figure 3.2-2 is a generalized stratigraphic column showing the formations that underlie the Dark Horse Facility and the Independence AGI Wells. The sequences of Ordovician through Permian rocks are described below.

Ordovician. Below the Silurian Fusselman Formation lies about 400 feet of Ordovician Montoya Formation cherty carbonates which overlies about 400 feet of Ordovician Simpson Group sandstones, shales, and tight limestones. These formations are underlain by the Lower Ordovician Ellenburger Formation which is a thick, carbonate-dominated sequence composed of dolostones and limestones. It is 0-1,000 feet thick in southeastern New Mexico. The Ellenburger carbonates sit on a veneer of Cambrian to Lower Ordovician Bliss Sandstone and granite wash on the Precambrian basement.

During the Early Ordovician, much of the United States was covered by a shallow sea, and southeast New Mexico was a shallow-water shelf with deep water conditions to the south. Due to sea-level changes and regional tectonic activity, the entire lower Paleozoic interval (Ellenburger through Devonian) was periodically subjected to subaerial exposure and prolonged periods of karst and karst-terrain formation, most especially in the Ellenburger, Fusselman and Devonian strata. The cave systems collapsed with subsequent burial, creating brecciated and fractured carbonate bodies that formed many of the Ellenberger reservoirs and created complex pore networks. The result of these exposure events was the development of numerous horizons of karst-related secondary porosity with solution-enlarged fractures, vugs, and small cavities and caves. Particularly in the Ellenburger and Fusselman strata, solution features from temporally distinct karst events became interconnected with each successive episode, so there could be some degree of vertical continuity in parts of the Fusselman section that could lead to enhanced vertical and horizontal permeability. The Ellenburger is well below the Siluro-Devonian Injection Zone, so it is unlikely to be affected by any proposed activity.

Devonian and Silurian. The Devonian Thirtyone Formation, the Silurian Fusselman Formation, and the Silurian Wristen Group consist of interbedded dolomites and dolomitic limestones and are collectively often referred to as the Siluro-Devonian. In the Middle Devonian, regional marine transgression deposited mostly black, organic-matter-rich siliceous muds of the Woodford Formation (Ruppel, 2019). The Siluro-Devonian Injection Zone does not contain economic hydrocarbons closer than fifteen (15) miles away from the well sites. There have been no commercially significant deposits of oil or natural gas found in the Devonian or Silurian rocks in the vicinity of the Independence AGI Wells and there is no current or foreseeable production at these depths within a two (2) mile radius around the Independence AGI Wells (Figure 3.7-3). Adjacent wells have shown that these formations are primarily water-bearing and are routinely approved as produced-water injection zones in this area.

Mississippian. According to Broadhead (2017), the Mississippian section unconformably overlies the Woodford Formation shales throughout most of southeastern New Mexico and, in places, unconformably overlies the Silurian Fusselman Formation or Ordovician strata in limited areas. These units reach a maximum thickness of 1,400 ft in the Tatum Basin northwest of Hobbs, New Mexico and constitute a major portion of the stratigraphic section. The Mississippian section in southeastern New Mexico is subdivided into the Lower Mississippian limestone (Kinderhookian to Osagean age) and various Upper Mississippian units. The Upper Mississippian section consists of the Barnett Shale in the basinal area to the south and the Meramec and Chester units on the shelf to the north. The Mississippian strata constitute the least developed of the major stratigraphic units in southeastern New Mexico and oil and natural gas production has been from relatively small and widely scattered reservoirs (Broadhead, 2017). The Chester Formation consists of several hundred feet of shales and basinal limestones which are underlain by several hundred feet of Osage limestone.

Pennsylvanian. The Pennsylvanian-age strata is comprised of (ascending) Morrow, Atoka, Strawn, Canyon, and Cisco. Within this entire sequence, the Morrow is a major natural gas producing zone, with smaller contributions from the overlying Atoka and Strawn. The Morrowan strata are dominantly siliciclastic and consist of interbedded shales and lenticular sandstones deposited in multiple regressive sequences and represent basinward migration of nearhore, sand-rich facies tracts from the erosion of exposed Precambrian rocks (Broadhead, 2017). The overlying Atokan strata are also dominantly siliciclastic, with sandstones and shales being deposited in fluvial-deltaic and strandline environments (Broadhead, 2017). The Middle Pennsylvanian (Desmoinesian) Strawn strata is composed of ramp limestones interbedded with marine shales and minor sandstones, and both sandstone and limestone reservoirs are productive (Broadhead, 2017). Although there was past production of oil and natural gas from the Pennsylvanian Strawn pool, there are no active wells in that pool within two (2) miles of the Dark Horse Facility nor are there any natural gas producing wells in any pools. The Upper Pennsylvanian strata are informally referred to as the Canyon (Missourian) and Cisco (Virgilian) groups, and are composed of interbedded carbonates, dark-gray to black shales, and minor sandstones (Broadhead, 2017). These groups contain prolific oil reservoirs in southeastern New Mexico.

Permian. The overlying Permian rocks found in the Delaware Basin are divided into four (4) series, the Lopingian ("Ochoa") (most recent), Guadalupe, Cisuralian ("Leonard"), and Hueco ("Wolfcamp") (oldest) (Figure 3.2-2). Numerous oil pools have been identified in these rocks (*see* Appendix 3, Table 3a). Active oil producing reservoirs within two (2) miles of the Dark Horse Facility include the following Permian pools: Tansil, Yates, Seven Rivers, Delaware, Bone Spring, and Wolfcamp. New oil wells permitted but not yet drilled are primarily targeting the Bone Spring and the Wolfcamp pools. The rock units of the Permian series are discussed in more detail below.

Permian Hueco ("Wolfcamp") Group. The Lower Permian Wolfcampian strata in the Permian Basin record deposition in deepwater basins surrounded by shallow-water carbonate platforms, where the Wolfcampian platform carbonate succession exposed in southeastern New Mexico comprises a complex record of deposition mainly controlled by fluctuations in glacio-eustatic sea level (Fu and others, 2020). The Wolfcamp is extremely variable in lithology in response to changes in the environment of deposition. In the area of the Dark Horse Facility, it is composed of dark skeletal to fine-grained limestone, fine-grained sand to coarse silt, and shale in these basin facies. Horizontal wells are being drilled in the Bone Spring and Wolfcamp; however, most activity is primarily to the west of the Dark Horse Facility.

Permian Leonardian Series. The Cisuralian ("Leonard Series"), sediments in shelf areas (Central Basin Platform, Northwest Shelf, etc.) are characterized by shallow-water carbonate-sediment production and deposition during sea-level rise, and by shelf flooding and quartz-dominated sand-silt deposition during sea-level fall and shelf exposure (Ruppel, 2019). In the Delaware Basin, this pattern of sea-level control on sediment supply resulted in the deposition of cyclic intervals of detrital carbonate-sediment transport to basins during sea-level highs and by quartz sand-silt transport and deposition during sea-level falls (Ruppel, 2019). Overall, the Leonard succession is one of punctuated upward shallowing from deep-water, outer-platform—platform-margin settings to inner-platform, peritidal conditions (Ruppel, 2020b).

The Bone Spring Formation is present only in the Delaware Basin and is stratigraphically equivalent to the Abo and Yeso Formations of the Northwest Shelf and Central Basin Platform, attains a maximum thickness of about 4,000 ft in southern Eddy County, New Mexico, and has been productive from several plays in the basin (Broadhead, 2017). The Bone Spring stratigraphy consists of alternating carbonate and siliciclastic successions that were deposited in marine slope and basin-floor environments, where sandstones and siltstones are widespread on the basin floor, whereas carbonates are thickest in periplatform areas (Nance and Hamiln, 2020; Saller and others, 1989). Most Bone Spring carbonate slope deposits accumulated by transport from shallow-water environments on the shelf during highstands of sea level and the siliciclastic deposits were transported basinwards during lowstands of sea level (Nance and Hamlin, 2020). Most of the carbonates are detrital, composed of bioclasts and lithoclasts derived from surrounding shallow-water platforms, and the siliciclastic members were deposited primarily on the basin floor in widespread submarine-fan complexes (Nance and Hamlin, 2020).

Permian Guadalupe Series. The Upper Permian Guadalupian-age strata are found on both Northwest Shelf and Central Basin Platform, and in the Delaware Basin. The Goat Seep/Capitan Reef system, a profoundly critical component of the Permian Basin Guadalupian paleogeography, prominently divides the shelves of the Central Basin Platform, the Northwestern Shelf, and the Western Shelf from the Delaware Basin (Nance, 2020a). Units on the shelf and platform comprise of (ascending) the San Andres Formation and the Artesia Group (*see* Figure 3.2-2). The five (5) formations of the Artesia Group include (ascending) Grayburg, Queen, Seven Rivers, Yates, and Tansill. The Delaware Basin equivalents of the reef trend include the Delaware Mountain Group: (ascending) Brushy Canyon, Cherry Canyon, and Bell Canyon. The Artesia Group comprises as much as 2,650 ft of stratigraphically cyclic, mixed-siliciclastic/carbonate/evaporite platform strata deposited shelfward of the Guadalupian Capitan Reef system that rims the Delaware Basin (Nance, 2020a). These formations have provided significant oil and natural gas production in southeastern New Mexico, and widespread, reddish-colored evaporitic shales and evaporites provide effective vertical and lateral seals (Broadhead, 2017).

According to Nance (2020a), Artesia facies tracts include, from basin to shelf, immediate-back-reef carbonate grainstone to packstone; shelf-crest pisolite-bearing carbonate shoals; lagoonal wackestone to mudstone and siliciclastic siltstone; algal-laminated, tidal-flat carbonate packstone to wackestone and fine to very fine grained sandstone; beach-ridge fine sandstone; siliciclastic-sabkha anhydrite and halite; brine-pool and evaporitic-lagoon anhydritic dolomite, dolomitic anhydrite, anhydrite, and halite; and eolian to fluvial siliciclastics. During sea-level highstand, siliciclastics are limited to updip areas, whereas eolian-siliciclastic depositional environments migrate downdip during sea-level lowstands. During transgressions, siliciclastics in more basin-proximal positions were reworked by marine and marginal processes. Reservoir quality was impacted mostly by dissolution of feldspar and carbonate allochems and precipitation of authigenic feldspar, clay, and evaporite.
The Delaware Mountain Group of the Delaware Basin comprises up to 4,500 ft of arkosic to subarkosic sandstone, siltstone, and carbonate debrites that were deposited in deep water, mainly during lowstand and early transgressive sea-level stages, and primary depositional processes include density-current flow and suspension settling (Nance, 2020b). The Delaware Mountain Group is restricted to slope-and-basin areas and was sourced from shelf-sediment areas through poorly exposed incised valleys, and interbedded carbonate units thicken shelfward and are typically correlative to "reef"-margin-complex carbonate sources along the shelf margin (Nance, 2020b).

Permian Lopingian ("Ochoa") Series. The youngest of the Permian Basin sediments are referred to as the Lopingian ("Ochoa") Series. The Ochoan series includes the Castile, Salado, Rustler, and Dewey Lake formations. Ochoan units on the shelf include the Salado, Rustler, and Dewey Lake Formations. *Castile Formation* usage is restricted to the deposits within the Delaware Basin only (Figure 3.2-2). The Ochoan in the Permian Basin contains no hydrocarbon reservoirs on the shelf (Nance, 2020a). The basal Salado Formation forms the ultimate top seal for the underlying Guadalupian reservoirs and effectively inhibits hydrocarbon migration into Ochoan units (Nance, 2020a). Lack of a seal above the Ochoan precludes widespread entrapment within the interval of hydrocarbons that may have been generated within the series. Ochoan strata are not hydrocarbon productive in the Permian Basin except for a few very small, isolated reservoirs in the Castile Anhydrite in the northern part of the Delaware Basin (Broadhead, 2017). The Castile is considered to be the top seal for Delaware Basin hydrocarbon reservoirs and is responsible for controlling migration of hydrocarbons from basinal source beds into reservoirs on the surrounding shelves (Hills, 1984). Anhydrite is the dominant rock type in the Castile Formation, along with limestone interlaminated in anhydrite, thin beds of limestone, and minor amounts of dolomite and magnesite, and halite is present as several massive beds in the formation in the subsurface but is much less prominent than the halite in the overlying Salado Formation (Bachman, 1984). The interlaminated anhydrite and limestone are distinctive lithologic features of the Castile Formation and are thought to represent annual cycles of sedimentation (Bachman, 1984).

The regionally extensive Salado Formation includes thick evaporite deposits and records a long-term salinity crisis in the region (Nance, 2020a). The Salado includes halite, minor beds of anhydrite, and commercial deposits of potash minerals (Bachman, 1984). The contact between the Castile and the overlying Salado Formations is sharp and most places and is between massive beds of anhydrite in the Castile and a sequence dominated by halite, potash minerals, and thin beds of anhydrite in the Salado (Bachman, 1984). The Rustler Formation overlies the Salado, and consists of dolomite, evaporites, and siliciclastics and marks the last major migration of marine waters into the Permian Basin (Ruppel, 2019). Red beds of terrigenous sands in the Rustler Formation resulted from eolian sediment transport. These red beds grade downwards into evaporites of the Salado and Castile Formations and are composed of red-orange silts and sandstones with interbeds of gypsum or anhydrite and halite. The Rustler carbonates, evaporites, and siliciclastics mark a relatively abbreviated return of marginal-marine conditions to the region (Nance, 2020a). The Dewey Lake Formation rests conformably on the Rustler Formation and consists mainly of redbeds and minor gypsum, alternating thin, even beds of moderately reddish-brown to moderately reddish-orange siltstone and fine-grained sandstone (Bachman, 1984). The Dewey Lake sediments mark the youngest episode of preserved Permian deposition in the region, after which a significant net-depositional hiatus prevailed until the onset of Late Triassic sediment accumulation (Nance, 2020a).

Beds of Triassic age rest unconformably on, and overlap, the Dewey Lake Formation, and exposures of these rocks in southeastern New Mexico are dark reddish-brown, cross-laminated, poorly sorted conglomerate sandstones with interbeds of dark reddish-brown sandy shale (Bachman, 1984). These Triassic units were deposited in a fluvial—deltaic—lacustrine system and signaled the onset of net deposition during overall wetter conditions after a protracted period of net nondeposition (Nance, 2020a; Bachman, 1984).

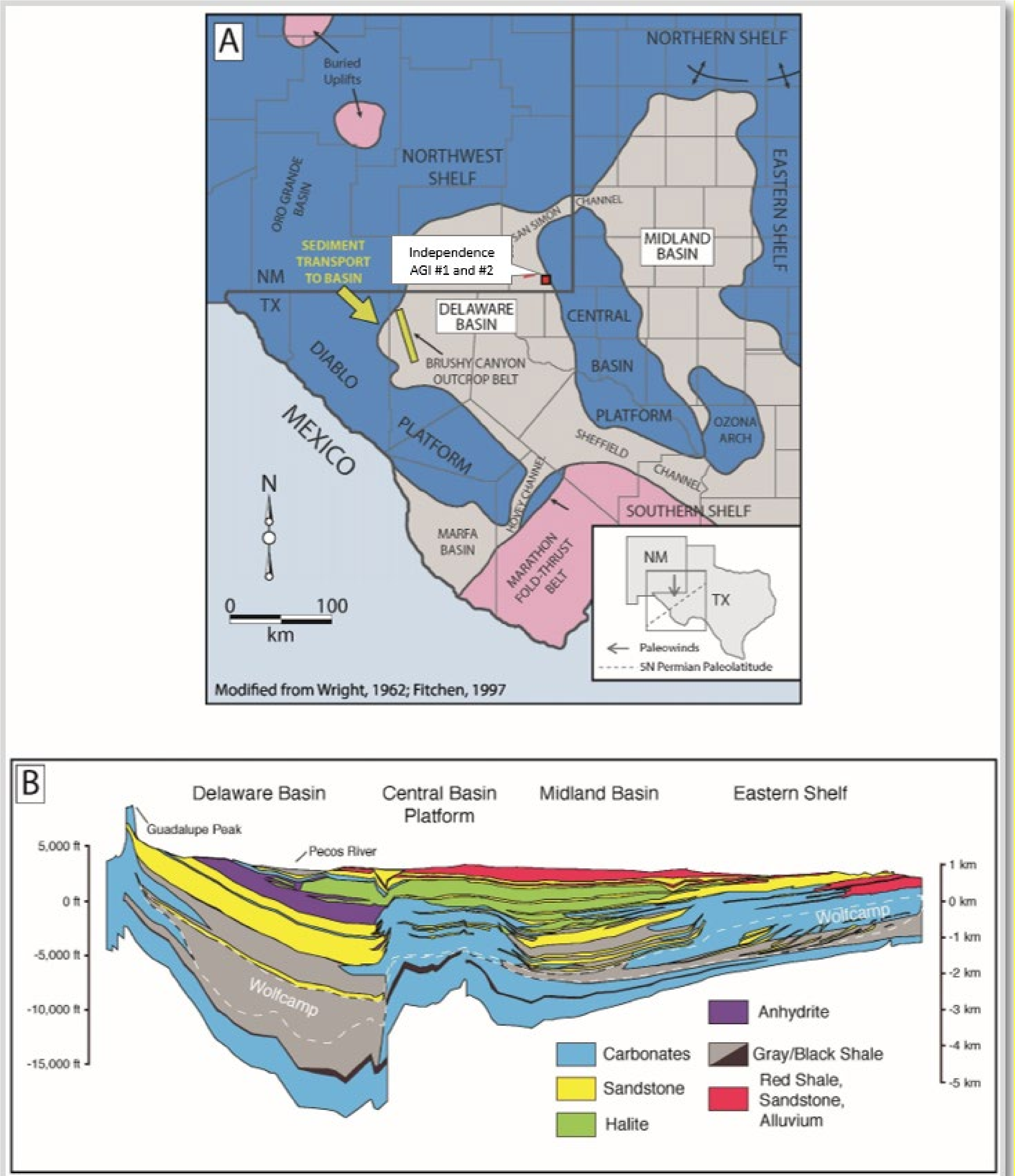


***Figure 3.2-1**: Structural setting (panel A) and general lithologies (panel B) of the Permian Basin. The location of the Independence AGI Wells is shown by the red square. (Modified from Wright, 1962; Fitchen, 1997) (Modified from Figure 12 of Class II permit application for Independence AGI #2, Geolex, Inc.).*

Age		Stratigraphic Units: Northwest Shelf and Central Basin Platform		Stratigraphic Units: Delaware Basin	
Triassic		Chinle		Chinle	
		Santa Rosa		Santa Rosa	
Permian	Lopingian ("Ochoan")	Dewey Lake		Dewey Lake	
		Rustler		Rustler	
		Salado		Salado	
				Castile	
	Guadalupian	Artesia Group	Tansill	Delaware Mountain Group	Bell Canyon
			Yates		
			Seven Rivers		Cherry Canyon
			Queen		
			Grayburg		
		San Andres			Brushy Canyon
	Cisuralian ("Leonardian")	Glorieta			
		Yeso	Paddock	Bone Spring	
			Blinebry		
			Tubb		
			Drinkard		
	Wolfcampian	Abo			
		Hueco ("Wolfcamp")		Hueco ("Wolfcamp")	
Pennsylvanian	Virgilian	Cisco	Bough	Cisco	
	Missourian	Canyon		Canyon	
	Des Moinesian	Strawn		Strawn	
	Atokan	Atoka		Atoka	
	Morrowan	Morrow		Morrow	
Miss.	Upper	Undivided		Barnett	
	Lower			undivided limestone	
Dev.	Upper	Woodford		Woodford	
	Middle				
	Lower	Thirtyone		Thirtyone	
Sil.	Upper	Wristen		Wristen	
	Middle				
	Lower	Fusselman		Fusselman	
Ord.	Upper	Montoya		Montoya	
	Middle	Simpson		Simpson	
	Lower	Ellenburger		Ellenburger	
Cambrian		Bliss		Bliss	
Precambrian		igneous, metamorphics, volcanics		igneous, metamorphics, volcanics	

Figure 3.2-2: Generalized stratigraphic correlation chart for the Permian Basin region (modified from Broadhead, 2017).

3.2.3 Faulting

The Permian Basin region has a complex tectonic history, shaped by several convergent and divergent events from the Proterozoic through the Cenozoic (Neogene). The Delaware Basin is defined by a complex network of basement-rooted faults. Recent regional 3D structural framework and kinematic models by Horne et al. (2021) provides interpretations of basement-rooted faults in the Delaware Basin. This region contains more than 650 basement-rooted fault surfaces, dominated by "primary" north-northwest—south-southeast-striking high-angle reverse faults that bound "secondary" fault orientations west-northwest—east-southeast and west-southwest—east-northeast (Horne et al., 2021). Their kinematic model suggests that the primary structural grain formed first in response to the encroaching Ancestral Rocky Mountain orogenic front, and the secondary fault zones formed under the combined stresses from the Ancestral Rocky Mountain and Marathon-Ouachita convergence fronts, which compartmentalized the Delaware Basin and Central Basin Platform (Horne et al., 2021).

To identify subsurface structures in the area of the Independence AGI Wells, Geolex evaluated and interpreted licensed seismic survey data (WesternGeco South Lea Survey) covering the Lea County area of interest. These findings and interpretations specific to the Dark Horse Facility area are discussed further in Section 3.5.

3.3 Lithologic and Reservoir Characteristics of the Siluro-Devonian Formations

The Siluro-Devonian Injection Zone includes the Devonian Thirtyone Formation, Silurian Wristen Group and Fusselman Formation, collectively referred to as the Siluro-Devonian. These strata commonly include numerous intervals of dolomites and dolomitic limestones with moderate to high primary porosity. Additionally, the Siluro-Devonian Injection Zone includes significant regions of secondary, solution-enlarged porosity produced during periods where strata were subaerially exposed and significant karst features developed. These karst features are frequently developed in the Fusselman Formation and include solution enlarged cavities and fractures. Fracture networks through the Siluro-Devonian section are substantial enough to provide additional permeability that is not readily apparent on geophysical well logs. The porous zones of the Siluro-Devonian are separated by tight limestones and dolomites.

In evaluating the location of the Independence AGI Wells, an in-depth review of licensed seismic survey data (WesternGeco – South Lea Survey) was completed to support the evaluation that the Siluro-Devonian reservoir exhibited sufficient porosity potential to accommodate the needs of the Independence AGI Wells. Seismic inversion data, specifically impedance attributes, were evaluated to identify reservoir targets with significant porosity potential in the Siluro-Devonian reservoir. As a result of this review, the location in Section 20, T25S, R36E was selected as it was observed to overlay an expansive region of porosity in the upper Devonian, Wristen, and Fusselman strata.
Based on the geologic evaluation of the subsurface, AGI was recommended between depths of approximately 16,080 to 17,683 feet TVD (16,477 to 18,080 feet measured depth). Figure 3.3-1 includes a type log of the Siluro-Devonian Injection Zone that includes the formation tops identified at the location of Independence AGI #1 and illustrates the sufficient low-porosity intervals overlying the target injection reservoir. Anticipated formation tops underlying the Independence AGI #2 location are included in the following Table 3.3-1. In the area of the Independence AGI Wells, depth to Devonian strata increases to the southwest and the Independence AGI Wells lie downdip of a structural high to the east (Figure 3.3-2).

Units overlying the Siluro-Devonian Injection Zone provide an excellent caprock to prevent the upward migration of injectate out of the target reservoir. This caprock includes 335 feet of dense Woodford Shale overlain by at least 796 feet of Mississippian limestone (Table 3.3-1). These units will provide a geologic seal above the porous carbonates of the Siluro-Devonian Injection Zone providing protection to shallow groundwater resources and overlying pay intervals.

[Figure 3.3-3](#) includes structural cross section A-A' covering the area of Independence AGI #2 and highlights the lateral extent of available upper Devonian porosity and the regional coverage of overlying caprock in the area. As shown in Figure 3.3-2, there are two (2) faults located approximately one (1) mile east and one (1) mile north from the SHLs of the Independence AGI Wells. These structures were identified through review of licensed 3D seismic survey data and are discussed further in Section 3.5.

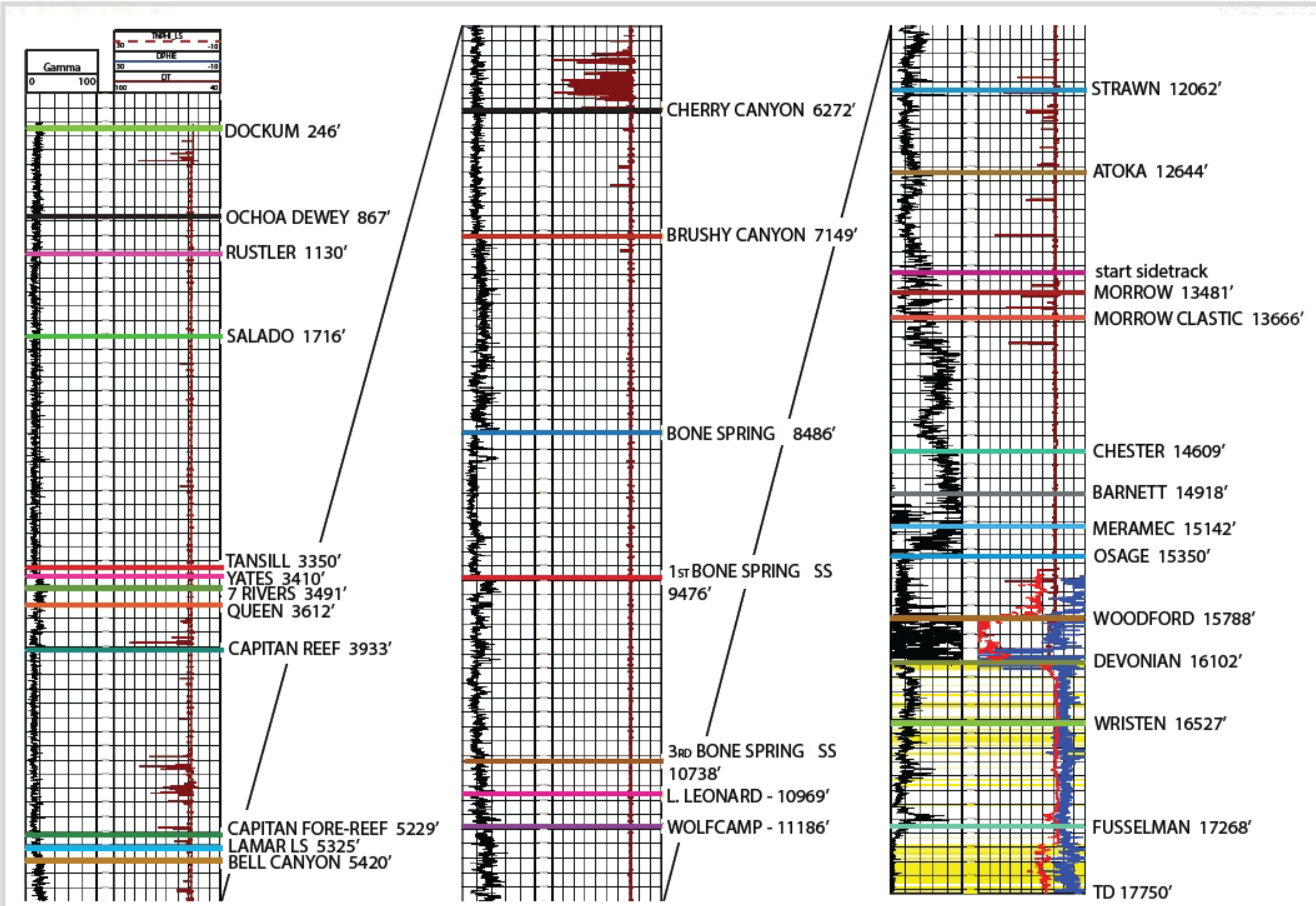


***Figure 3.3-1**: Type log of the Independence AGI #1, illustrating identified formation tops in TVD. Anticipated formation tops for the Independence AGI #2 are included in Table 3.3-1 (Modified from Figure 14 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

***Table 3.3-1**: Anticipated formation tops at the Independence AGI #2 location. (Extracted from Table 6 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

FORMATION	DEPTH (TVD)	DEPTH (MD)	FORMATION	DEPTH (TVD)	DEPTH (MD)
Dockum	485	485	Bone Spring	8,467	8,632
Ochoa-Dewey	747	747	Wolfcamp	11,131	11,387
Rustler	1,130	1,130	Strawn	12,004	12,289
Salado	1,720	1,720	Atoka	12,733	13,044
Tansill	3,401	3,401	Morrow	13,541	13,880
Yates	3,461	3,461	Barnett	14,949	15,336
7 Rivers	3,542	3,542	Osage	15,380	15,703
Queen	3,663	3,663	Woodford	15,745	16,142
Capitan Reef	3,935	3,943	Devonian	16,080	16,477
Bell Canyon	5,425	5,484	Wristen	16,467	16,864
Cherry Canyon	6,277	6,364	Fusselman	17,201	17,598
Brushy Canyon	7,058	7,174	Montoya	17,684	18,081

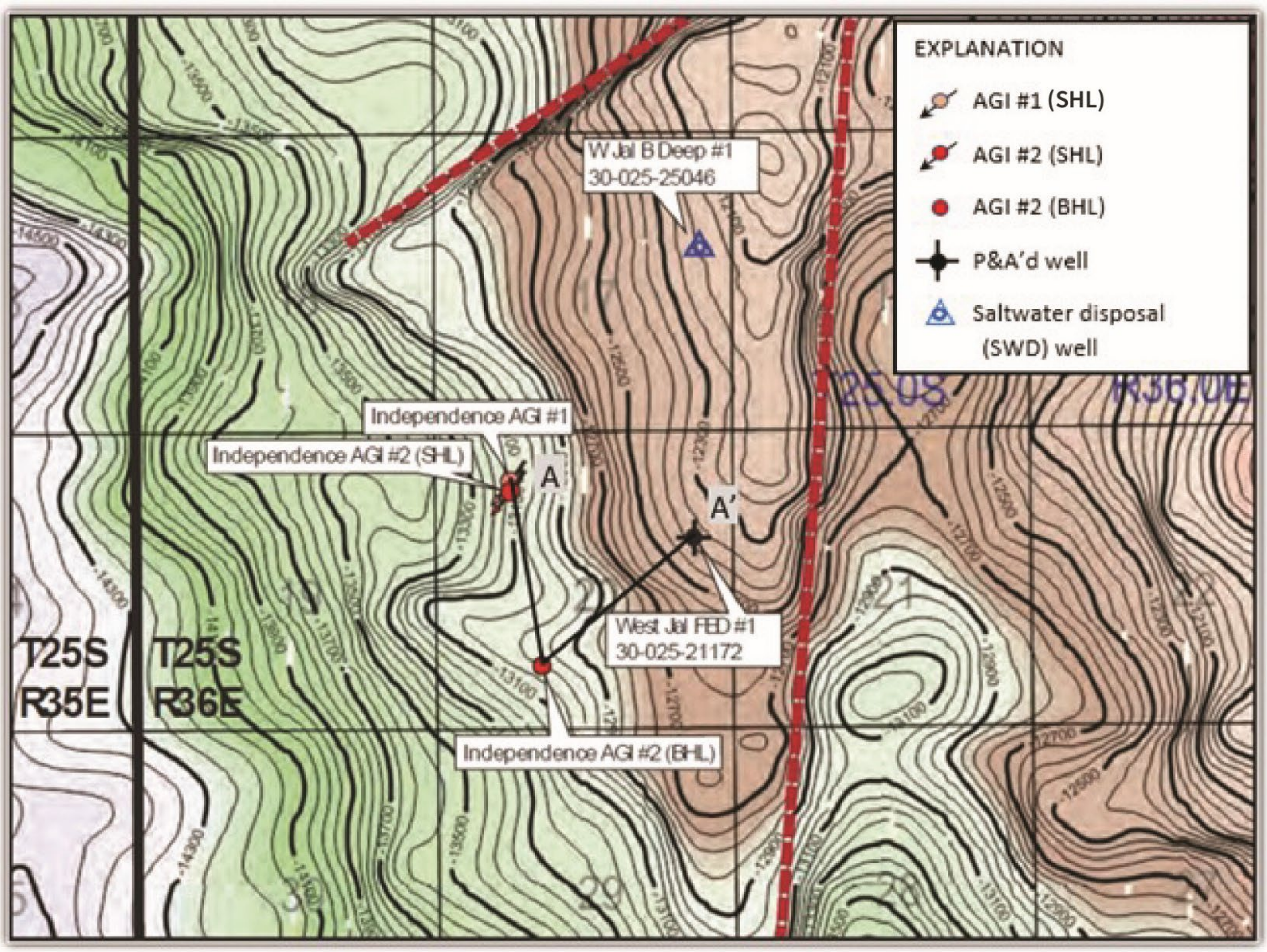
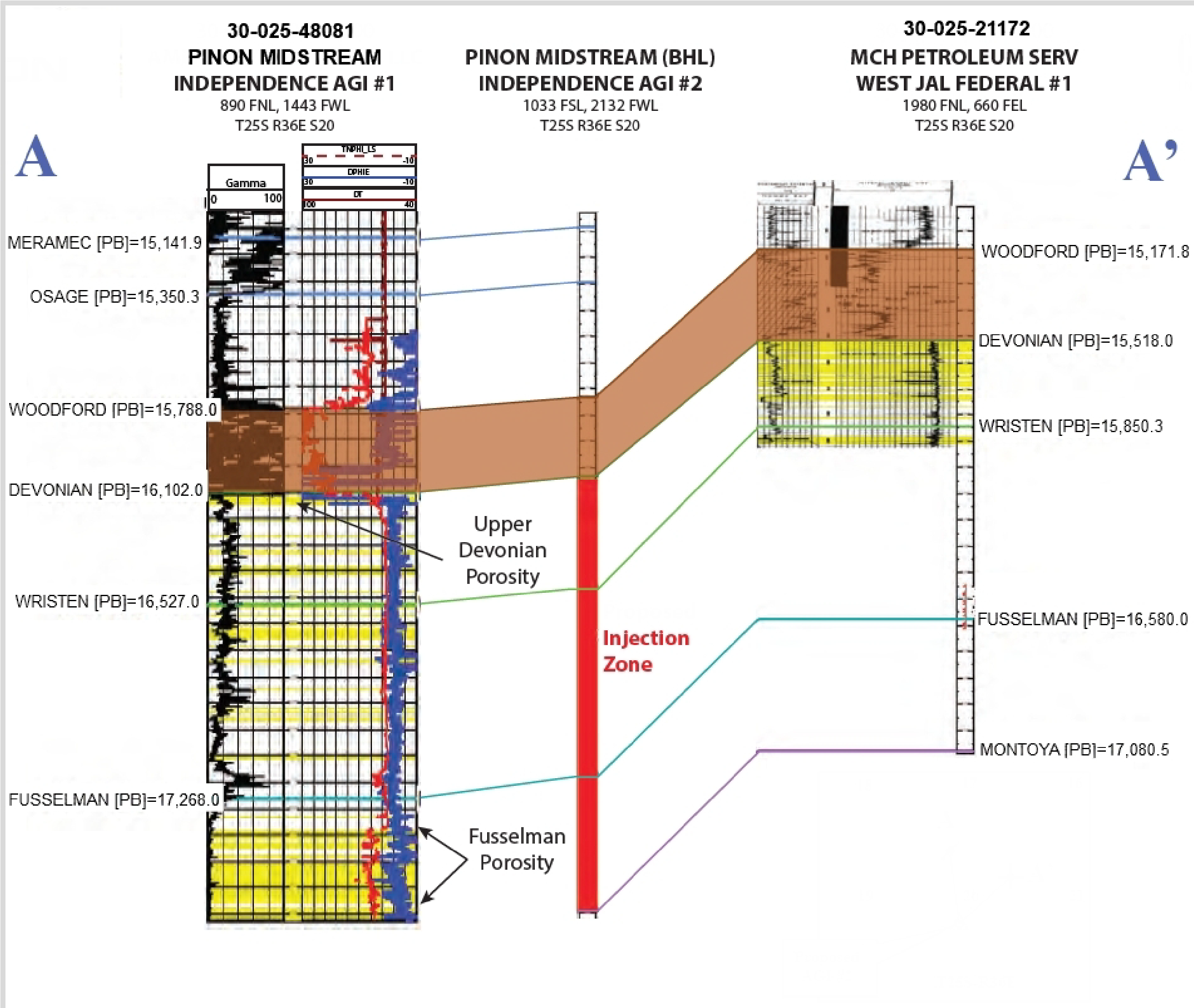


***Figure 3.3-2**: Structure contour map showing the top of the Siluro-Devonian target reservoir. Two (2) faults identified in review of 3D seismic data are shown with red dashes. Also, shown are wells within 1 mile of the Independence AGI Wells that penetrate the Siluro-Devonian target zone. Cross section A – A' is shown in Figure 3.3-3. (Modified from Figure 15 of Class II permit application for Independence AGI*

#2, Geolex, Inc.)** Not shown: The **BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in <u>Figure 3.1-1</u>.



<u>Figure 3.3-3</u>: Structural cross section A-A' showing porosity profile from nearby wells penetrating the Siluro-Devonian Injection Zone and regional extent of overlying Woodford Shale caprock. The Independence AGI #2 Injection Zone is from 16,080 feet TVD to 17,683 feet TVD (red bar). (Modified from Figure 16 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.4 Chemistry of Siluro-Devonian Interval Formation Fluids

A review of formation waters from the U.S. Geological Survey National Produced Waters Geochemical Database v. 2.3 identified twenty-one (21) wells with analyses of fluid samples collected from the Siluro-Devonian interval. These samples were collected from wells within approximately fifteen (15) miles of the Independence AGI Wells. Results of laboratory analysis to determine their composition are summarized in <u>Table 3.4-1</u>. These results have been supplemented with samples collected from Independence AGI #1 on May 31, 2021 which show Total Dissolved Solids ("**TDS**") values ranging from 109,000 to 115,000 parts per million ("**ppm**").

***Table 3.4-1**: Summary of Siluro-Devonian produced water analyses from nearby wells (U.S. Geological Survey National Produced Water Geochemical Database v. 2.3) * (Extracted from Table 7 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

API	WELL NAME	CONCENTRATION (parts per million)							
		TDS	HCO3	Ca	Cl	K + Na	Mg	Na	SO4
3002548081	Ind. AGI 1	110000	342	5600	68000	32559	759	31800	664
3002510945	Hill-federal D 1	112959	288	6264	67390	34340	1912	-	2765
3002510947	EC Hill-federal 1	35639	-	1369	22070		592	11608	-
3002511126	JR Holt A3	116415	154	7501	71110	34680	1767	-	1203
3002511196	S. Mattix Unit 3	68431	990	3180	40960	21690	974	-	637
3002511202	S. Mattix Unit 11	67130	853	5075	40430	16950	2348	-	1474
3002511383	Hodges B 3	81712	722	4320	47500	25400	1030	-	2740
3002511556	Blocker-federal 4	57675	595	2850	34030	18370	619	-	1211
3002511747	Ab Coates FED D2	82794	977	2408	47200	28190	851	-	3168
3002511760	Ida Wimberley 5	63817	360	2774	35870	20750	621	-	3442
3002811763	Ida Wimberley 9	61040	900	2680	35600	19560	800	-	1500
3002511765	Carlson-federal A3	66418	690	3002	37650	20390	1339	-	3347
3002511812	Clyde Lanehart 1	99879	687	4753	60410	32610	828	-	591
3002511818	Copper 1	27506	1089	1384	15270	8144	540	-	1079
3002511863	Arnott Ramsay B3	158761	476	17240	100300	35400	5345	-	-
3002511886	Dabbs 1	101036	540	5393	61630	30380	2183	-	910
3002511890	Sam Dabbs 1	85150	675	5368	50260	25130	1395	-	2322
3002511907	Arnott Ramsay F9	58220	367	1546	32790	-	278	20430	2816
3002511950	Farnsworth FED 6	31931	302	7196	20450	1151	2241	-	591
3002512272	LE Elliott FED H1	58687	761	3004	35460	18980	482	-	-
3002512286	JB McGhee 1	62392	552	2696	34380	20060	702	-	4002
3002521601	North Custer Mt 1	>64,000	1610	2136	36230	21830	403	-	1950

These analyses report TDS in the area of the Independence AGI Wells ranging from 27,506 to 158,761 ppm with an average of 75,981 ppm. The primary constituent in sampled formation waters is the chloride ion, with an average concentration of 45,227 ppm. The closest well, Independence AGI #1, at approximately 3,000 feet away from the Independence AGI #2 BHL, has reservoir fluids with a TDS value of approximately 110,000 ppm, and chloride ions in concentrations of approximately 68,000 ppm. Based on this data, the Siluro-Devonian reservoir fluids are anticipated to be completely compatible with the TAG injectate.

3.5 Potential for Induced Seismicity in the area of the Dark Horse Facility

To evaluate the potential for seismic events in response to injected fluids, Piñon conducted an induced-seismicity risk assessment for the area surrounding the Independence AGI Wells. This estimate (a) models the impact of seven (7) injection wells over a thirty (30) year injection period, and (b) estimates the fault-slip probability associated with the simulated injection scenario(s). This analysis was completed utilizing the Stanford Center for Induced and Triggered Seismicity's Fault Slip Potential ("**FSP**") model developed by Walsh and Zoback, 2016.

To identify subsurface structures in the area of the Independence AGI Wells, Piñon evaluated and interpreted licensed seismic survey data (WesternGeco – South Lea Survey) covering the Lea County area of interest. Based on this review, Piñon identified eight (8) subsurface faults in the area surrounding the Independence AGI Wells (Figure 3.5-1). The closest fault is observed to be located approximately one (1) mile east of the Independence AGI Wells. Major faults in the area (those

exhibiting significant lateral extent) generally strike NNW-SSE with minor faults striking NE-SW and NW to SE.

Due to the location of faults relative to the Independence AGI Wells and the general low density of injection wells in the immediate area of the Independence AGI Wells, it is anticipated that the injection scenario(s) will not pose any elevated risk of injection-induced fault slip. To support the interpretation that these structures would not be affected by operation of the Independence AGI Wells, a fault-slip probability analysis was completed to quantify the risk associated with injection operations in the area surrounding the Independence AGI Wells, and although the risk of induced seismicity is low, a seismic monitoring station was installed at the facility prior to the commencement of injection into Independence AGI #1. The station transmits data to the New Mexico Tech Seismic Network and will aid the state in seismicity interpretations.

To calculate the fault-slip probability for the model simulations, input parameters characterizing the local stress field, reservoir characteristics, subsurface features, and injected fluids are required. Parameters utilized and their sources for the area surrounding the Independence AGI Wells are included in Table 3.5-1. Additionally, Table 3.5-2 details the injection volume characteristics and locations of the injection wells modeled in the injection scenario(s). To ensure the model simulations provide a conservative estimation of induced-seismicity risk, injection wells included in the simulations were modeled utilizing their maximum anticipated daily injection volumes as recorded by NMOCD approved permits. Due to the minimal reported injection volume of the Jal North Ranch SWD #1 (30-025-27085) which is approximately 5.3 miles to the east northeast of the Independence wells, a potential of 10,000 bpd was assumed to account for the potential of increased injection rates due to future needs of the operator or any future workover that may improve the injectivity of this well.

Daily maximum injection volumes utilized in the fault-slip probability model range from 4,265 to 30,000 bpd (Table 3.5-2). In submission of the Class II injection well applications, Piñon requested approval to operate the Independence AGI Wells for a period of at least thirty (30) years, however, the duration of the FSP model simulation was increased to forty (40) years to characterize the reservoir effects of injection wells that are currently operating and have been in operation since 2010. Figure 3.5-2 shows the resultant pressure front and single well radial pressure solutions, as predicted by the FSP model, after thirty (30) years of injection at the maximum injection rates.

For this study, limitations of the FSP model required a conservative approach be taken in determining the fault-slip probability of the injection scenario. Specifically, the FSP model is only capable of considering a single set of fluid characteristics and this study aims to model an injection scenario that includes both brine injection and AGI. To ensure a conservative fault-slip probability estimate, the Independence AGI Wells were simulated utilizing the characteristics of a brine injectate. This approach yields a more conservative model prediction as brine displays greater density, dynamic viscosity, and is significantly less compressible than TAG. For comparison, characteristics of TAG at the anticipated reservoir conditions, as modeled by AQUAlibrium™, are shown in Table 3.5-1.

Generally, faults considered in this assessment are predicted by the FSP model to have very low potential for injection-induced slip and operation of the Independence AGI Wells is not predicted by the model to contribute significantly to the estimate of risk (Table 3.5-3 and Figure 3.5-3). Table 3.5-3 summarizes the predicted pressure change along each fault segment and includes the model-derived pressure change necessary to induce slip for each feature. Fault-slip probability values range from 0.00 to 0.05 with the majority of fault segments predicted to have zero probability of slip (Table 3.5-3). Major faults (faults 4, 7, and 8 in Figure 3.5-1) in the area, which would have the greatest energy release potential upon slip, are predicted to have zero probability for slip in response to the modeled injection scenario.

In summary, no structures included in the modeled simulations are predicted to be at increased risk for injection-induced slip in response to the injection scenario presented. Features estimated to have a non-zero slip potential are generally smaller-scale features and predicted probabilities are very low

(≤ 0.05). Furthermore, subsequent model simulations in which contribution from Independence AGI #2 is excluded illustrate that operation of the Independence AGI #2 will have little impact on conditions near the identified faults in the area due to significantly lower proposed injection volumes in comparison to nearby brine injection wells.

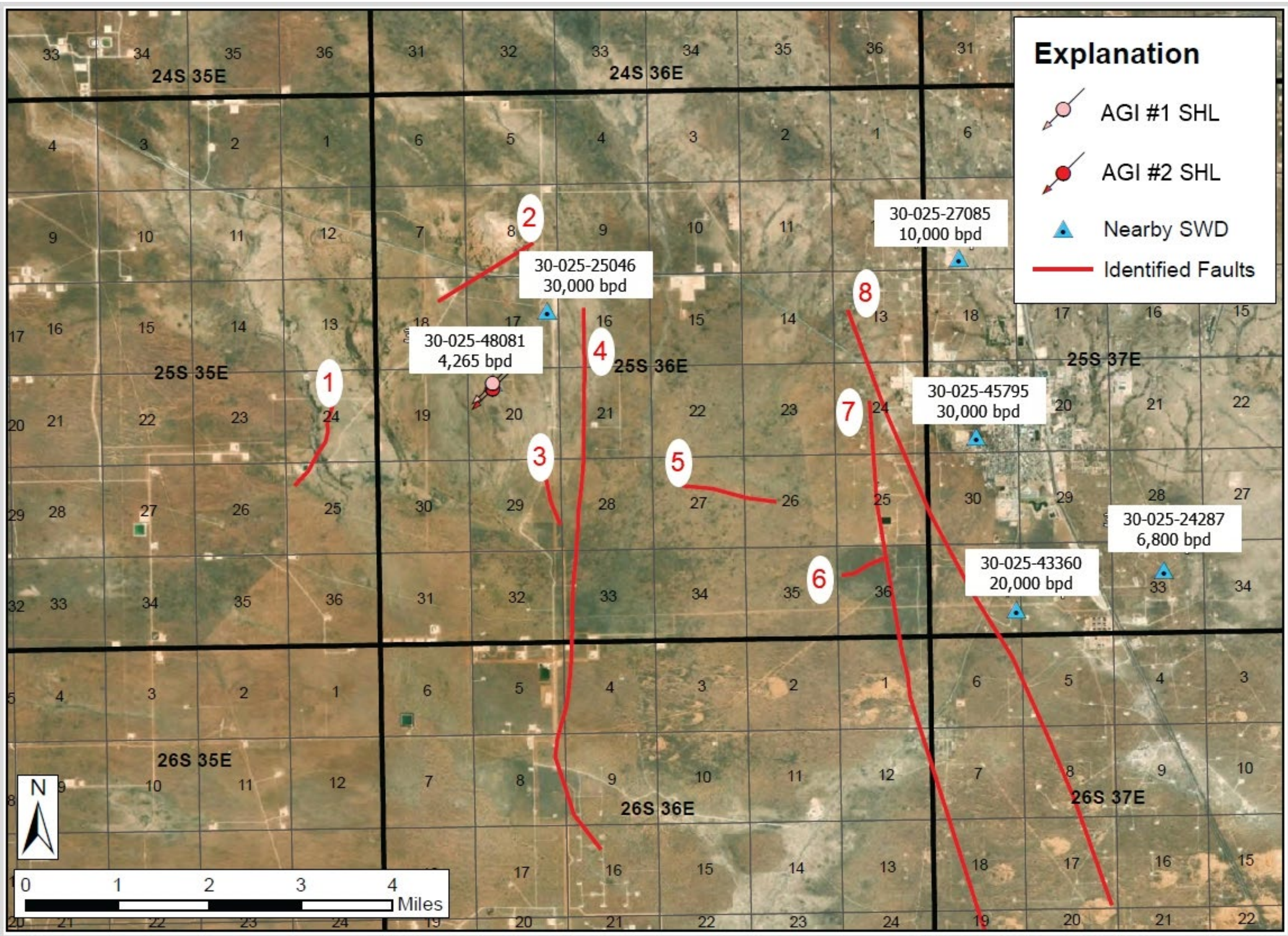


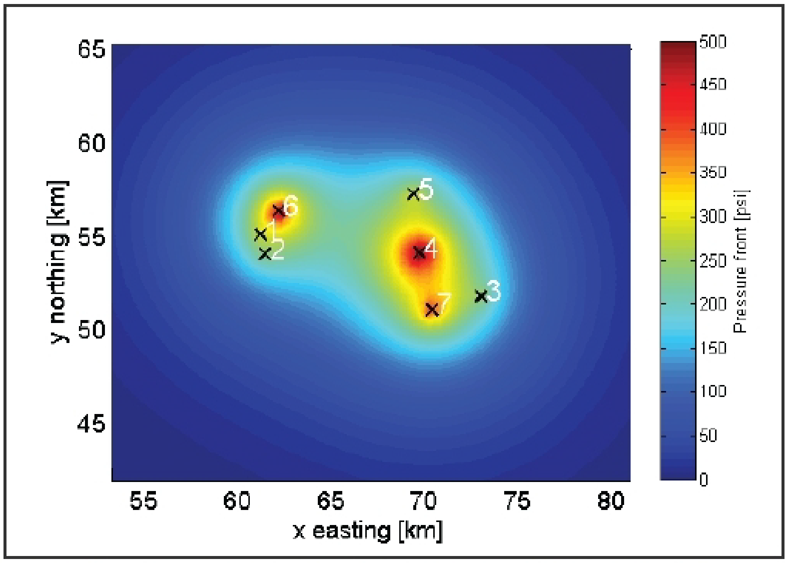
***Figure 3.5-1**: Map showing Siluro-Devonian injection wells and subsurface identified faults in the vicinity of the Independence AGI Wells. (Modified from Figure 18 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

***Table 3.5-1**: Input parameters and source material for FSP model simulations. (Extracted from Table 10 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

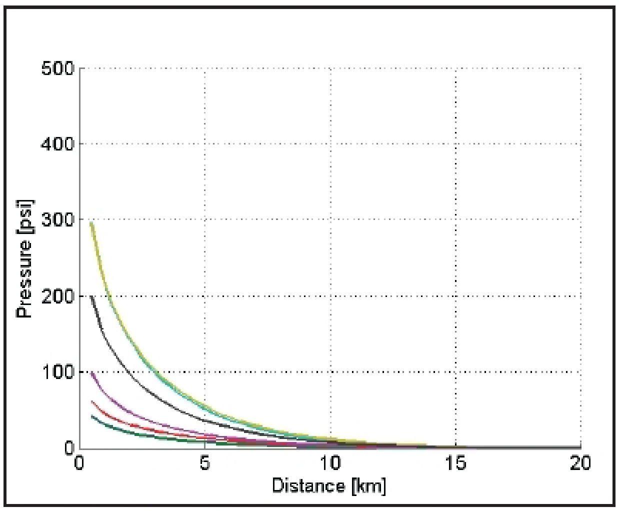
Modeled Parameter	Input Value	Variability (+/-)	UOM	Source
Stress				
Vertical Stress Gradient	1.05	0.105	psig/ft	Nearby well estimate
Max Horizontal Stress Direction	N75E	5	Deg	Lund Snee & Zoback, 2018
Reference Depth	17000		ft	Nearby well evaluation
Initial Res. Pressure Gradient	0.43	0.043	psig/ft	Lund Snee & Zoback, 2018 Nearby well evaluation
A_ϕ Parameter	0.6	0.06	-	Lund Snee & Zoback, 2018
Reference Friction Coefficient (μ)	0.6	0.06	-	Standard value
Hydrologic				
Aquifer Thickness	1500	0	ft	Nearby well evaluation
Porosity	3.5	0.35	%	Nearby well evaluation
Permeability	20	2	mD	Nearby well evaluation
Material Properties				
Density (Water)	1040	40	Kg/m^3	Standard value
Dynamic Viscosity (Water	0.0008	0.0001	Pa.s	Standard value
Fluid Compressibility (Water)	3.6×10^{-10}	0	Pa^{-1}	Standard value
Rock Compressibility	1.08×10^{-9}	0	Pa^{-1}	Standard value
Acid Gas Properties @ 7,370 psig & 228 °F				
Density	821.80	-	kg/m^3	AQUAlibrium™
Dynamic Viscosity	8.067×10^{-5}	-	Pa.s	AQUAlibrium™

***Table 3.5-2**: Location and characteristics of injection wells modeled in the FSP assessment. (Extracted from Table 11 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

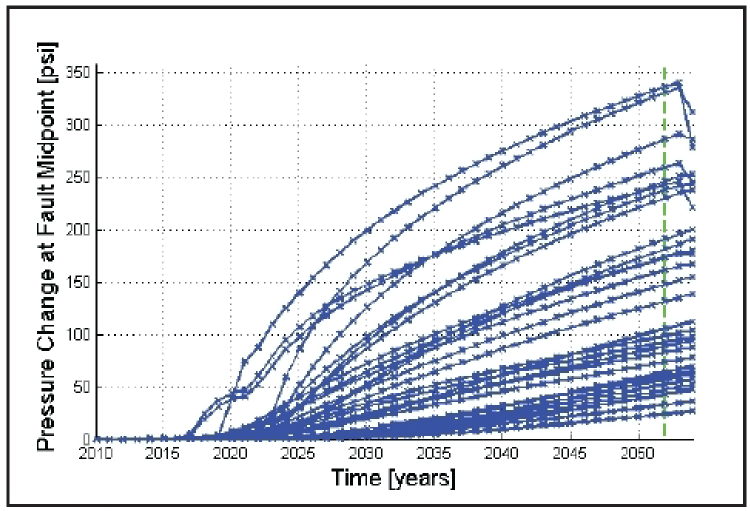
#	API	Well Name	LAT	LONG	Volume (bbls/day)	Start (year)	End (year)
1	3002548081	Independence AGI #1	32.120855	-103.291021	4265	2020	2052
2	-	Independence AGI #2	32.111454	-103.288812	4265	2022	2052
3	3002524287	Crosby Deep #2	32.089508	-103.166733	6800	2010	2052
4	3002545795	Sholes Deep SWD #1	32.110998	-103.201266	30000	2020	2052
5	3002527085	Jal N. Ranch SWD #1	32.139347	-103.203911	10000*	2017	2052
6	3002525046	West Jal B Deep #1	32.132091	-103.280708	30000	2015	2052
7	3002543360	Kimberly SWD #1	32.083537	-103.194274	20000	2019	2052



Panel A. Resultant pressure front after 30 years of injection operations at the maximum anticipated injection rates, as reported in **NMOCD** records



Panel B. Single well radial pressure solutions, as determined by the FSP model

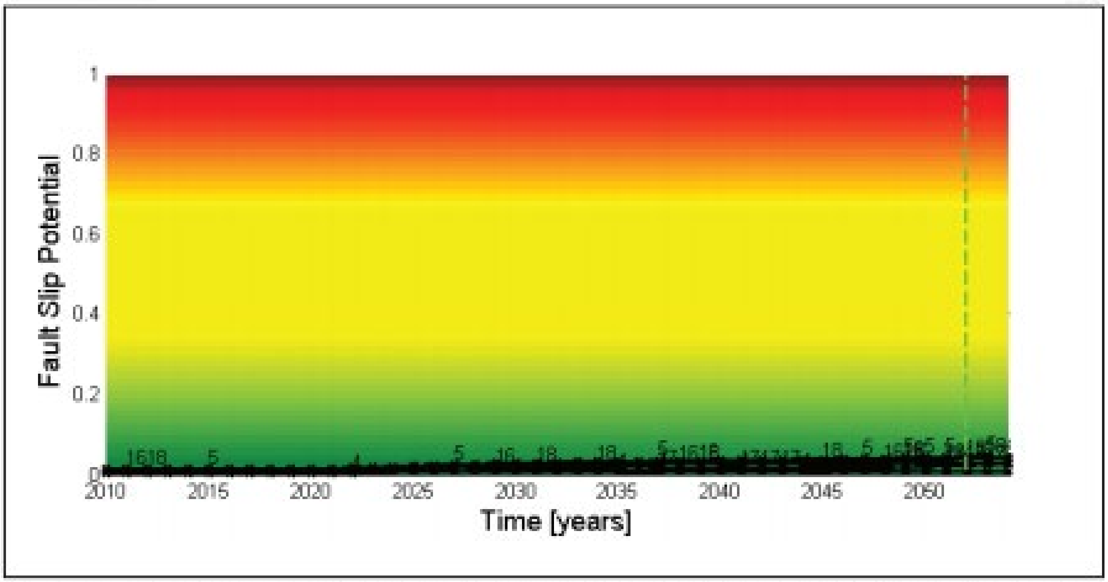


Panel C. Model-predicted pressure change through time at the midpoint of each fault segment included in the simulation

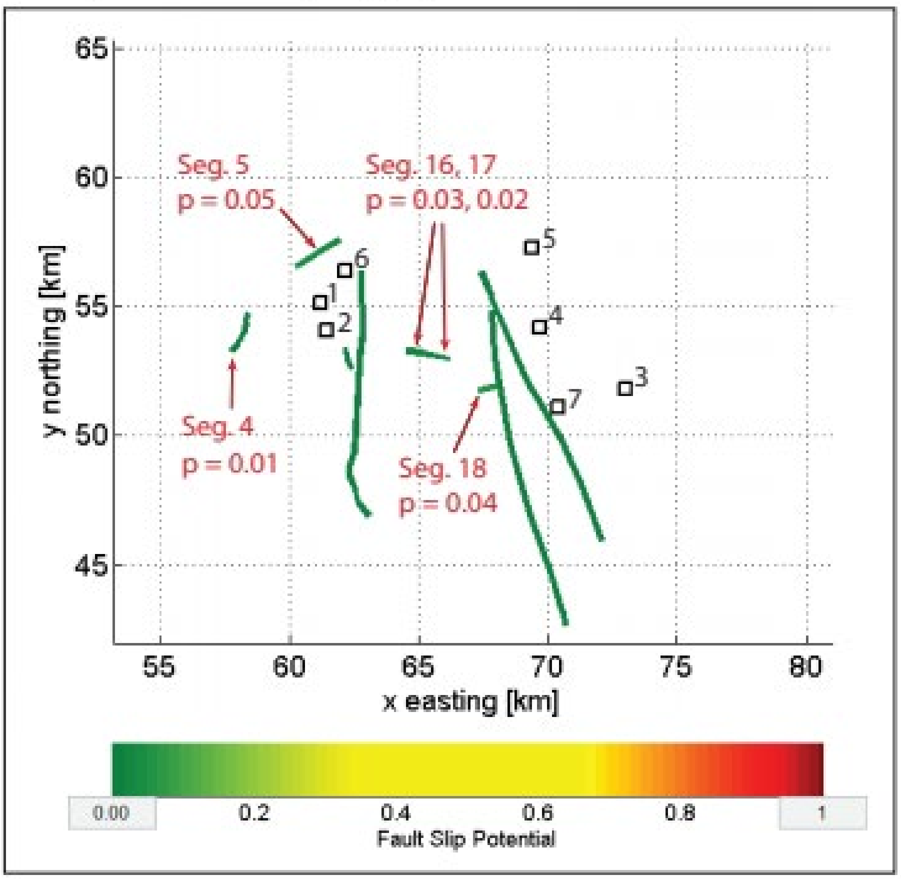
<u>Figure 3.5-2</u>: Summary of model-predicted pressure effects in response to the simulated seven (7) well injection scenario. (Extracted from Figure 19 of Class II permit application for Independence AGI #2, Geolex, Inc.)

***Table 3.5-3**: Summary of model-simulation results showing the required pressure change to induce fault slip, actual change in pressure as predicted by the FSP model, probability of fault slip at the end of the thirty (30) year injection scenario, and fault-slip probability when Independence AGI #2 is excluded from simulation. (Extracted from Table 12 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

Fault #	Segment #	ΔPressure necessary to induce fault slip	Actual ΔPressure at 2052	Fault Slip Potential at 2052	FSP (excluding AGI #2)
1	1	3137	109	0.00	0.00
	2	4357	103	0.00	0.00
	3	1786	93	0.00	0.00
	4	1201	83	0.01	0.01
2	5	1197	253	0.05	0.05
3	6	6869	186	0.00	0.00
	7	6298	168	0.00	0.00
4	8	5645	277	0.00	0.00
	9	4610	194	0.00	0.00
	10	5005	117	0.00	0.00
	11	2709	70	0.00	0.00
	12	5302	63	0.00	0.00
	13	6339	57	0.00	0.00
	14	6899	51	0.00	0.00
	15	4197	46	0.00	0.00
5	16	1101	192	0.03	0.03
	17	1085	199	0.02	0.02
6	18	1554	234	0.04	0.04
7	19	6012	290	0.00	0.00
	20	6680	241	0.00	0.00
	21	6914	133	0.00	0.00
	22	6758	61	0.00	0.00
	23	6931	33	0.00	0.00
	24	6590	25	0.00	0.00
8	25	6508	250	0.00	0.00
	26	6327	334	0.00	0.00
	27	5455	228	0.00	0.00
	28	6305	174	0.00	0.00
	29	6684	89	0.00	0.00



Panel A. Fault-slip probability throughout the entire simulated injection period. FSP model results suggest no significant risk of injection-induced slip along any feature included in the simulation.



Panel B. Map view illustrating the model-estimated slip potential of faults at the end fo the 42-year injection scenario. Any feature estimated to have a non-zero slip potential determination is labeled on the above map.

<u>Figure 3.5-3</u>: Summary of model-determined fault-slip probabilities over the simulated injection period (2010-2052). (Modified from Figure 20 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.6 Groundwater Hydrology in the Vicinity of the Dark Horse Facility

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are fifteen (15) water wells and points-of-diversion located within a two (2) mile radius of the Independence AGI Wells. Of these wells, the closest is located approximately 0.34 miles away and has a total depth of 505 feet (Figure 3.6-1 and Table 3.6-1). The remaining fourteen (14) wells within the two (2) mile radius have depths of approximately 240 to 600 feet deep, collecting water from Alluvium and the Triassic red beds. The shallow freshwater aquifer will be protected as the Independence AGI Wells are designed to isolate shallow zones via a five (5) string casing design including a surface casing interval that extends to 1,230 feet within the Rustler Formation, effectively isolating shallow groundwater resources (Figures A1-1 and A1-2).

The area surrounding the Independence AGI Wells is arid and there are no surface water bodies within a two (2) mile radius.

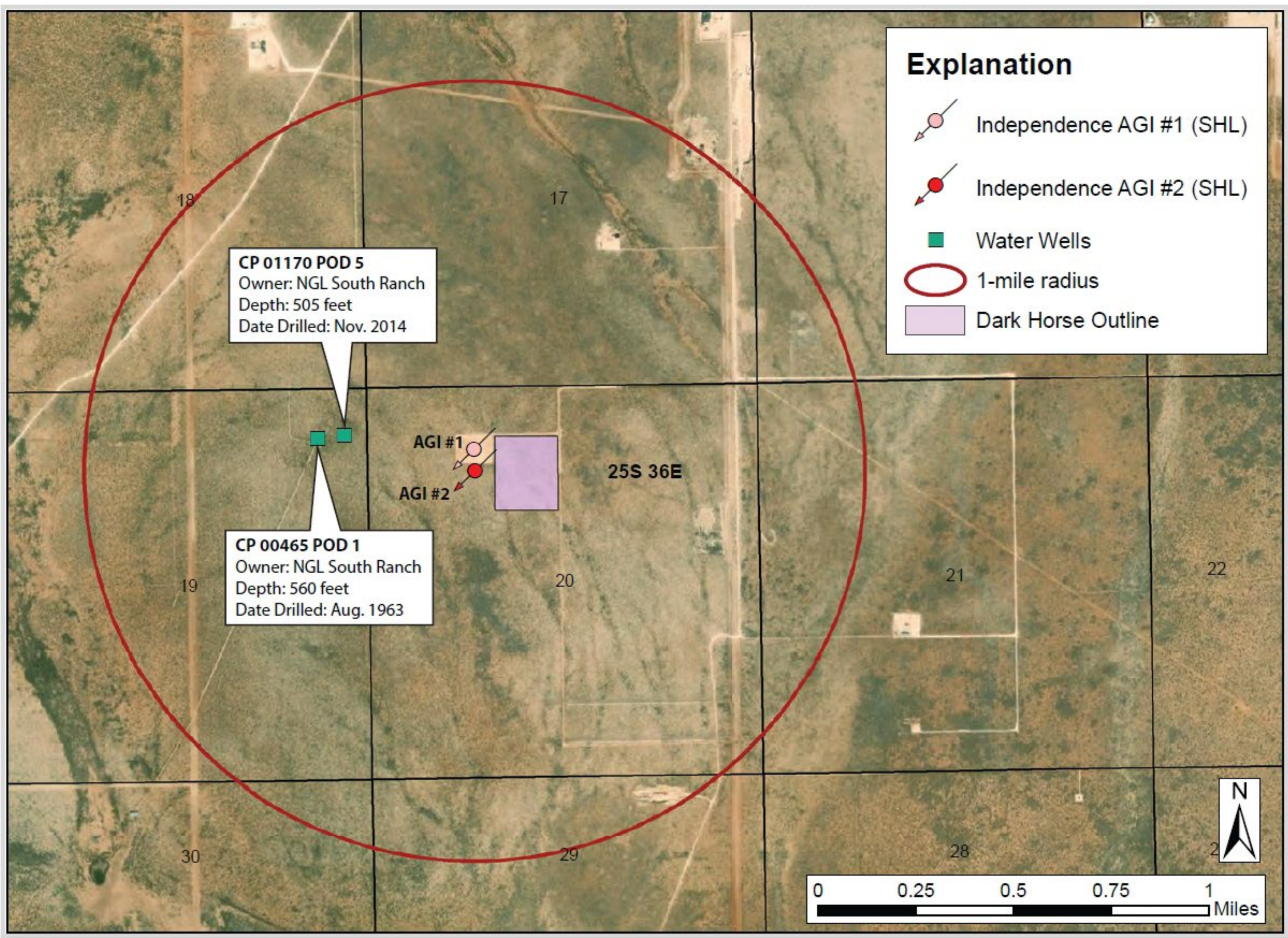


***Figure 3.6-1**: Reported water wells within 1-mile radius of the SHLs of the Independence AGI Wells. The BHLs for AGI #1 and #2 are not shown. (Extracted from Figure 17 of Class II permit application for Independence AGI #2, Geolex, Inc.) Only SHLs shown for the Independence AGI #1 and #2 wells.*

***Table 3.6-1**: Water wells within one (1) mile of the Independence AGI Wells (Retrieved from the New Mexico Office of the State Engineer's Files on October 4, 2021). (Extracted from Table 8 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

POD #	Source	Use	Owner	LAT (NAD83)	LONG (NAD83)	Distance (miles)	Depth (feet)	Date Completed
CP 1170 POD 5	Shallow	Commercial	NGL South Ranch	32.121417	-103.296667	0.34	505	11/2014
CP 465 POD 1	Shallow	Commercial	NGL South Ranch	32.119465	-103.299882	0.53	560	08/1963

According to Order No. 190 of the New Mexico Office of the State Engineer signed March 22, 2021, the Capitan Underground Water Basin, within which the Independence AGI Wells lie, is closed indefinitely to new appropriations of water. Therefore, no new water wells are anticipated to be constructed during the Independence AGI Wells' anticipated thirty (30) year operation period. Due to the shallow completion depths of the few groundwater wells in the area surrounding the Independence AGI Wells, it is highly unlikely that groundwater wells will serve as conduits for CO_2 leakage to the surface.

Geolex conducted a review of Geology and Ground-Water Conditions in Southern Lea County, New Mexico (Nicholson and Clebsch, 1961) to identify published groundwater data representative of nearby water wells in the area surrounding the Independence AGI Wells. Table 3.6-2 summarizes the wells identified in this review and the results of those analyses.

***Table 3.6- 2**: Chemical analysis results of samples collected from water wells in the area surrounding the Independence AGI Wells (Nicholson and Clebsch, 1961 – Geology and Groundwater Conditions in Southern Lea County, New Mexico). (Taken from Table 9 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

Historical Owner	Location (T-R-S)	Location (Qtr-Qtr)	Depth (ft)	Ca (ppm)	Mg (ppm)	Na+K (ppm)	HCO_3 (ppm)	SO_4 (ppm)	Cl (ppm)	NO_3 (ppm)
Sun Oil Co.	25-37-15	NE/4 NE/4	-	307	98	271	145	737	610	9
City of Jal	25-37-19	NE/4 NE/4	500	55	49	170	376	280	71	0.4
City of Jal	25-37-19	SE/4 NE/4	450	34	43	175	264	286	54	0.5
City of Jal	25-37-20	NW/4 SW/4	70	-	-	-	150	145	168	7.6

This analysis confirms that the Independence AGI Wells pose no risk of contaminating groundwater in the area as (a) the well design includes material considerations to protect shallow groundwater resources, and (b) there are no identified conduits that would facilitate migration of injected fluids to freshwater-bearing strata nor to the surface.

3.7 Historical Operations

3.7.1 Dark Horse Facility and Independence AGI Wells

Piñon operates the Dark Horse Facility which treats sour natural gas that is delivered to the facility from gathering systems in the area. These gathering systems are shown in Figure 3.7-1. Figure 3.7-2 shows the major process units and the H_2S and gas detection sensors. The figure in Appendix 10 shows the process block flow diagram for the Dark Horse Facility. The Dark Horse Facility is designed to treat produced natural gas containing H_2S and CO_2 and handles and/or generates sulfur dioxide (SO_2). Ameredev received authorization to inject H_2S and CO_2 from the NMOCD and drilled and completed Independence AGI #1, which is utilized for the injection and permanent sequestration of TAG. Procedures and materials used by Ameredev for well operations and construction are consistent with NMOCD regulations pertaining to "Protection from Hydrogen Sulfide during Drilling,

Completion, Workover and Well Servicing Operations" (NMAC 19.15.11.11). Following drilling and completion of the Independence AGI #1, and after approval by NMOCD, Ameredev contributed and assigned operations of the well to Piñon. Piñon became the operator of record for the Independence AGI #1 on August 24, 2021.

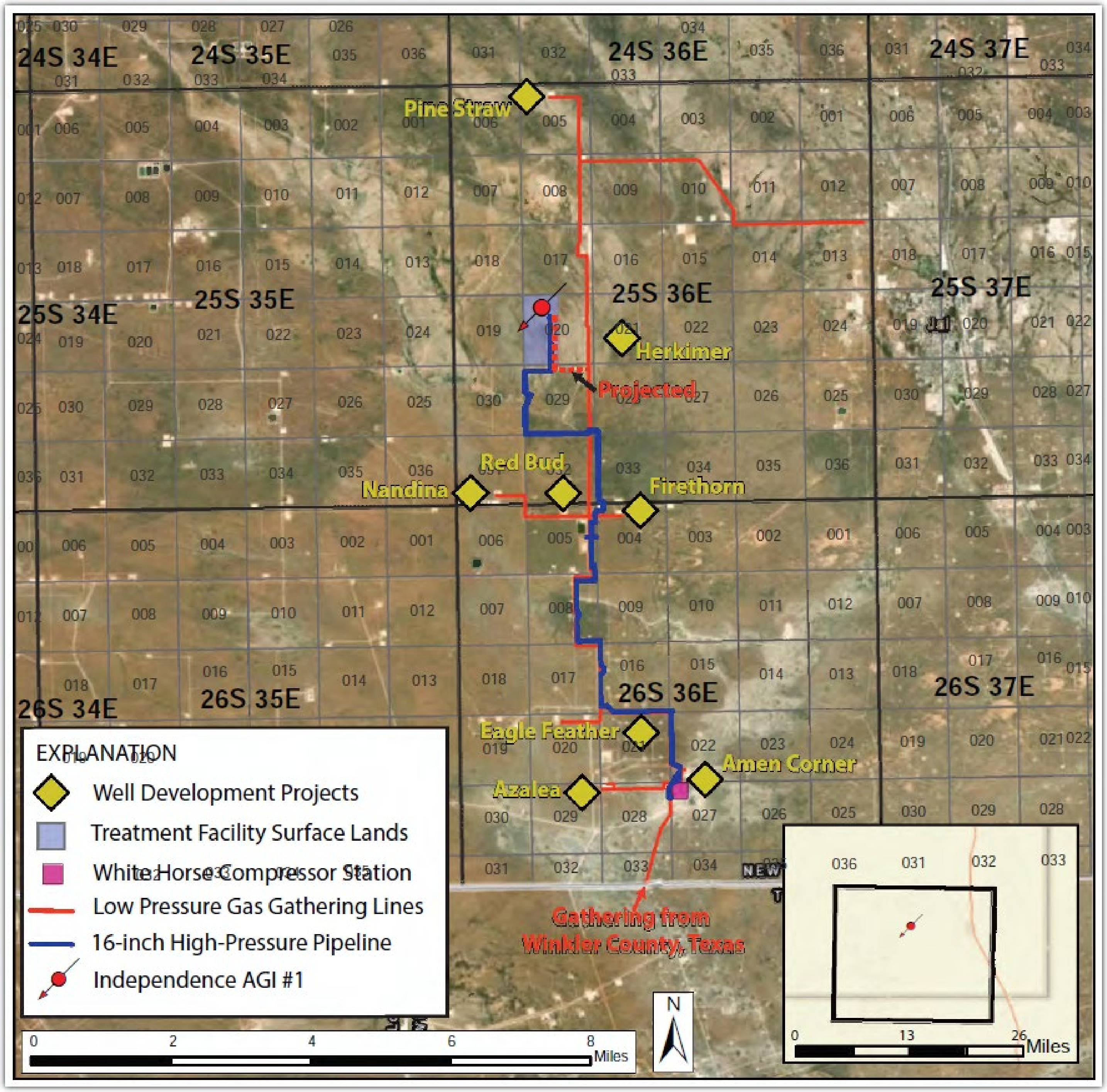


***Figure 3.7-1**: Location of gas gathering lines leading to the Dark Horse Gas Treatment Plant and White Horse Compression station. Low pressure lines either lead to the compressor station or directly to the treatment plant. Gas sent to the compressor station is sent to the treatment plant via a 16-inch high-pressure pipeline.*

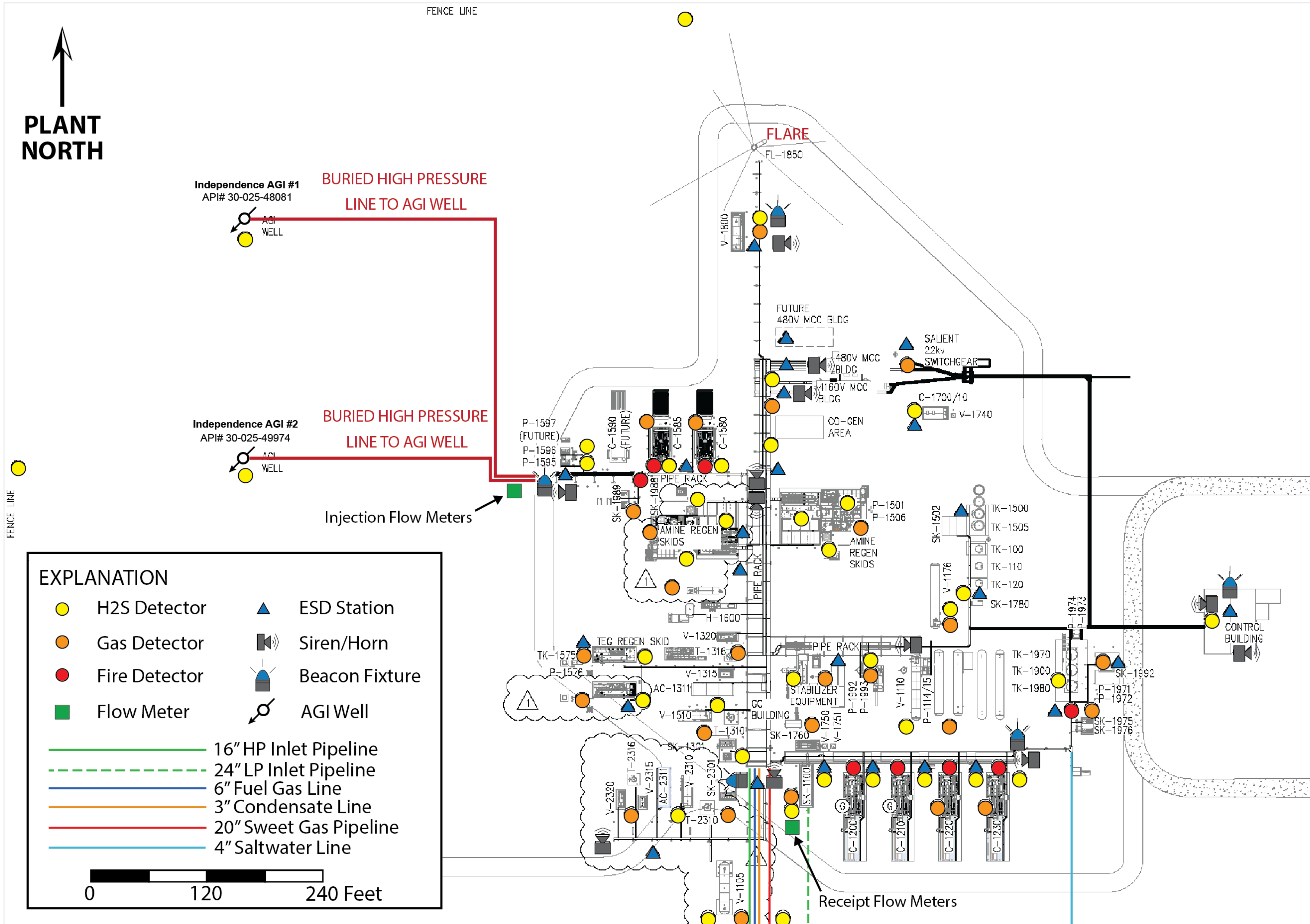
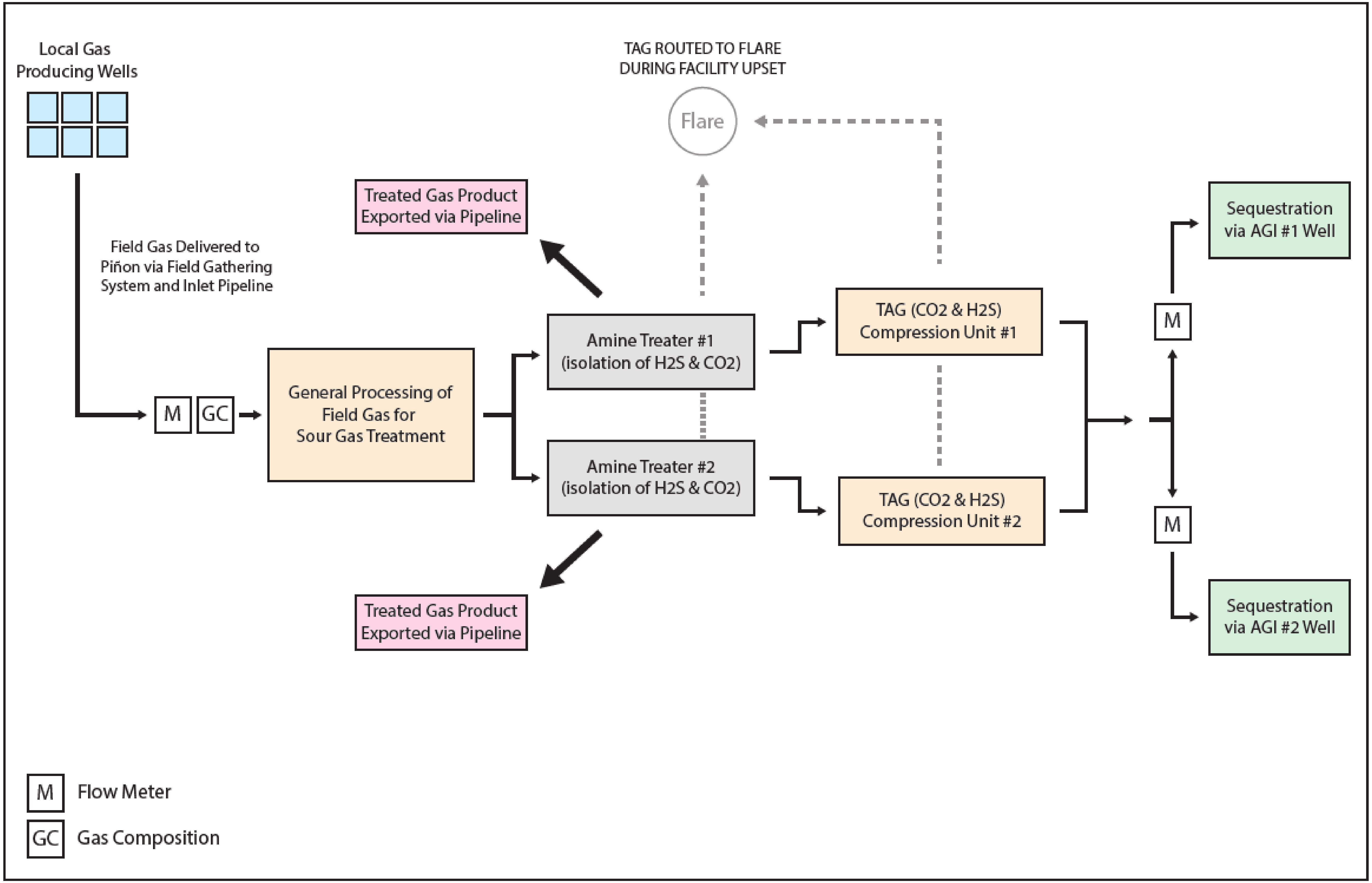


***Figure 3.7-2**: Detailed Dark Horse Facility schematic illustrating the location of major process units, all emergency equipment, H_2S and gas detection sensors, sirens and beacons, and major gas flow lines at the facility. (Taken from Figure 2 of the H_2S Contingency Plan for Dark Horse Gas Treatment Facility, Geolex, Inc.). The yellow circles indicate the location of fixed H_2S sensors.*



<u>Figure 3.7-2.b</u>: Dark Horse Facility General Flow and Measurement Schematic illustrating the location of flow and gas composition meters for the facility related to the calculation of CO_2 for this facility.

3.7.2 Operations within a 2-mile radius of the Independence AGI Wells

Appendix 3 summarizes in detail all NMOCD recorded wells within a two (2) mile radius of the Independence AGI Wells. These wells are shown in Figure 3.7-3 and include active, plugged, and new (permitted but not yet drilled) well locations. In total, there are fifty-four (54) wells within a two (2) mile radius of the Independence AGI Wells. Of these, there are ten (10) active wells, thirty-three (33) permitted wells, and eleven (11) plugged wells.

Active wells in the area include one brine injection well completed across the Strawn through Fusselman formations, and nine (9) active oil and natural gas wells completed in various other strata. There are two (2) third-party wells within two (2) miles of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone (Table 3.7-1).

The first well is an active brine injection well (West Jal B Deep #001) located approximately one (1) mile from the Independence #2 SHL. This well was drilled to a total depth of 18,945 feet and is permitted to inject through perforated intervals of the Strawn through Fusselman strata. A Form C-103- Sundry Notices and Reports on Wells, submitted November 2018 contain a wellbore diagram that shows the locations of two cast iron bridge plugs ("**CIBP**"). The first CIBP is at a measured depth of 14,200 feet (within the lower Atoka Formation), and the second CIBP is at a measured depth of 17, 100 feet (within the Fusselman Formation). Despite BC & D Operating being granted approval for injection into the Fusselman (approved by NMOCD June 2014), NMOCD records document no reports of work to drill out the CIBP at 14,200 feet. The same Form C-103- Sundry Notices and Reports on Wells mentioned above indicates the intent of BC & D Operating to drill out the CIBP, but there have been no identified subsequent reports confirming completion of this work. Additionally, reported injection volumes since the filing of the Form C-103 in November 2018 for this well do not appear to exhibit any significant increase that might indicate this work was completed. Furthermore, according to a search of publicly available data as of June 2023, the West Jal B Deep #001 ceased water injection operations during or after July 2022, and water injected volumes have been reported as "0" since July 2022.

The second well penetrating the Siluro-Devonian Injection Zone is the plugged West Jal Unit #1, located approximately 0.67 miles from the Independence AGI #2 SHL. Final plugging operations were completed in April 1984 and all relevant plugging reports and documents are included in Appendix 9. The well is properly cemented through the Siluro-Devonian Injection Zone, and it is not anticipated to be negatively affected by the operation of the Independence AGI Wells nor is it considered to be a likely pathway for CO_2 leakage to the surface.

Appendix 3 and Figure 3.7-3 also show a number of wells in the area which have approved permits to drill but are not yet drilled. The new oil and natural gas wells are targeting various production zones, more than 4,000 feet above the Siluro-Devonian Injection Zone for the Independence AGI Wells. All new oil and natural gas wells and injection wells are subject to the requirements of regulations governing sealing off strata (NMAC 19.16.16.10) and casing and tubing requirements (NMAC 19.16.16.10) to prevent the contents of production or injection zones from passing into other strata. To minimize the likelihood of leaks from new wells, NMAC 19.15.26.9 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." Therefore, due to the fact that these wells do not penetrate the Siluro-Devonian Injection Zone, and that the wells are more than 4,000 feet above the Siluro-Devonian Injection Zone, Piñon does not consider these new wells to be pathways for CO_2 leakage to the surface. In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage.

<u>Table 3.7-1</u>: Wells located within a two (2) mile radius of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone. (Additional details are provided in <u>Appendix 3</u>)

API	Well Name	Pool	Status	TVD (feet)
30-025-21172	WEST JAL UNIT #1	Strawn	Plugged	17,086
30-025-48081	INDEPENDENCE AGI #1	Devonian - Fusselman	Active	17,750
30-025-49974	INDEPENDENCE AGI #2	Devonian - Fusselman	New	17,683 (proposed)
30-025-25046	WEST JAL B DEEP #001	Mississippian – Fusselman	Active	18,945

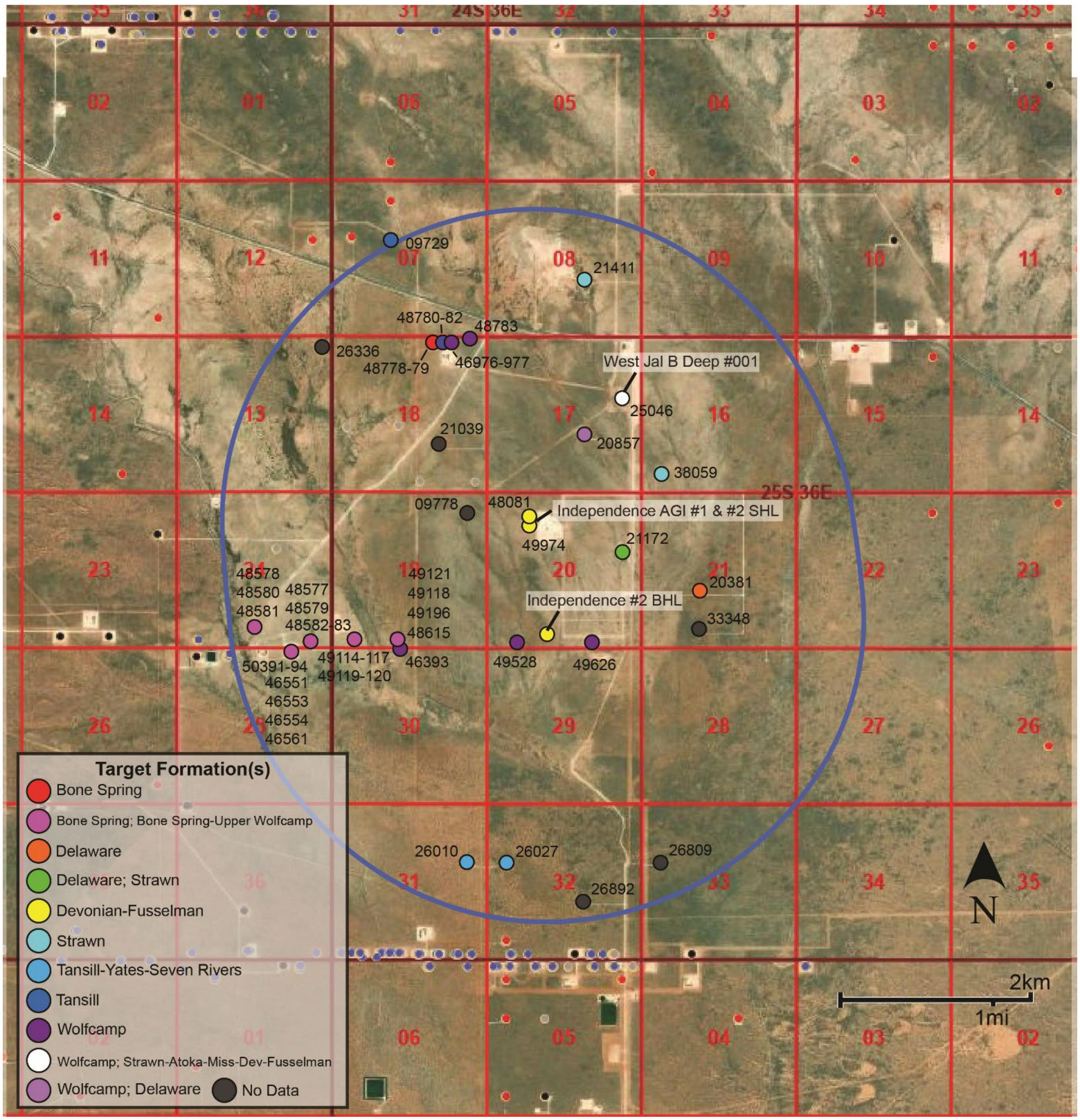


***Figure 3.7-3*: Location of all oil- and natural gas-related wells within a two (2) mile (blue line) of the Independence AGI Wells. Colors indicate the target formation(s) for each well. The oblong shape of the two (2) mile area accounts for the BHL of Independence AGI #2 as shown in *Figure 3.1-1*. Labels denote the last five (5) digits of API #30-025-XXXXX. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in *Figure 3.1-1*.**

3.8 Description of Injection Process

Once delivered to the Dark Horse Facility, sour natural gas is treated using amine to isolate H_2S and CO_2. The amine (which now contains H_2S and CO_2) is then regenerated which creates a TAG waste stream. This TAG waste stream is then routed to on-site compression facilities that compress the TAG waste stream into a dense phase (roughly 1,250 psig). The dense phase stream is then pumped to upwards of 2,500 psig prior to being sent to the Independence AGI Wells, through a National Association of Corrosion Engineers ("**NACE**") rated pipe, for injection. Figure 3.8-1 is a schematic of the surface facilities for the Independence AGI Wells. The sweet natural gas that results from the amine scavenging process is then treated to remove water ("**H_2O**") and subsequently transported offsite, via pipeline, and redelivered to Piñon's customers at various delivery points.

For the period of September 2021 through March 2022, the TAG stream at the Dark Horse Facility averaged 57.076% CO_2 and 38.703% H_2S by volume, with hydrocarbons (C1 – C7) and H_2O comprising the remaining volume.

The anticipated duration of TAG injection into the Independence AGI Wells at the Dark Horse Facility is approximately thirty (30) years.

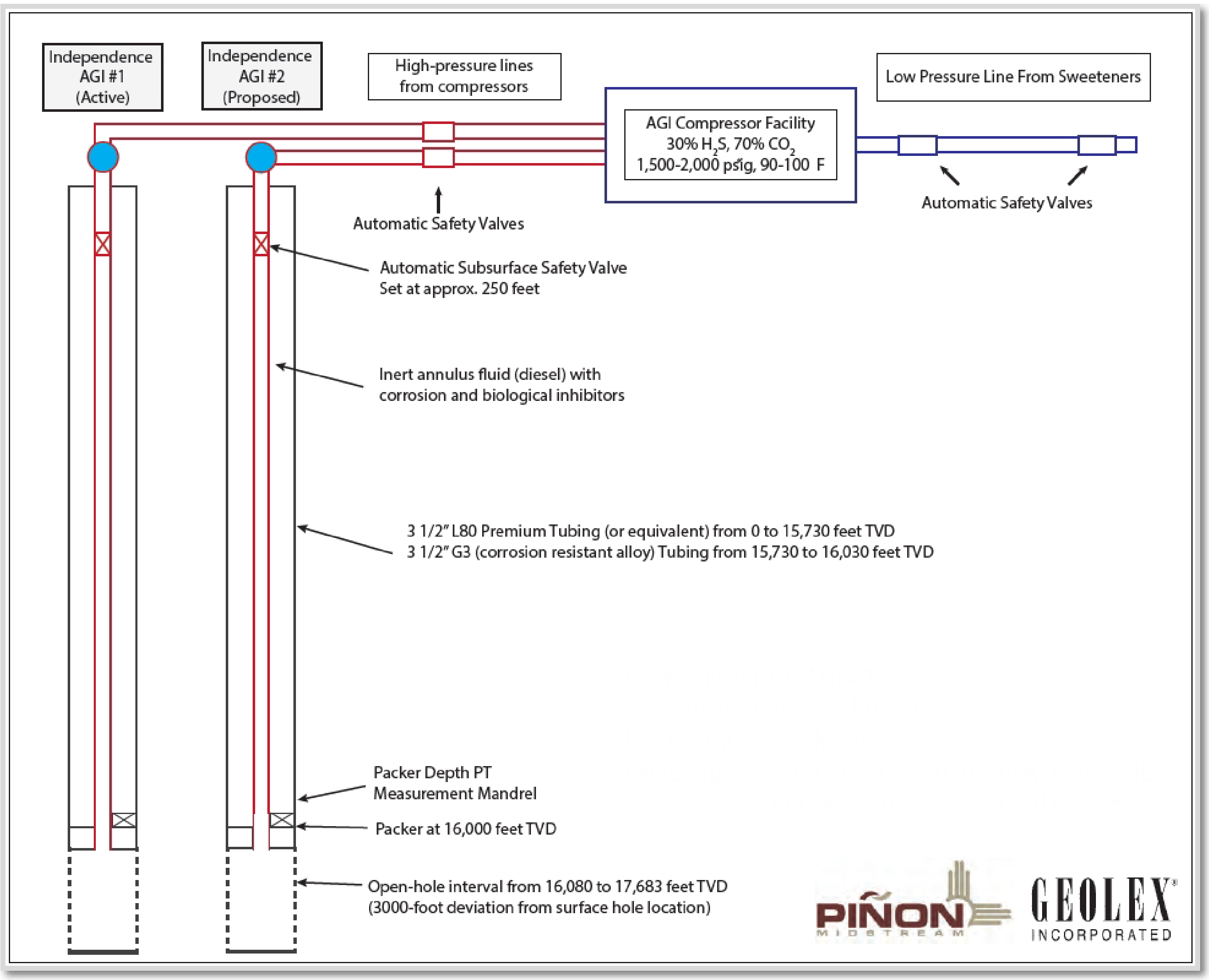


Figure 3.8-1: Schematic of surface facilities at the Dark Horse Facility and the Independence AGI Wells. (Modified from Figure 3 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.9 Reservoir Characterization Modeling

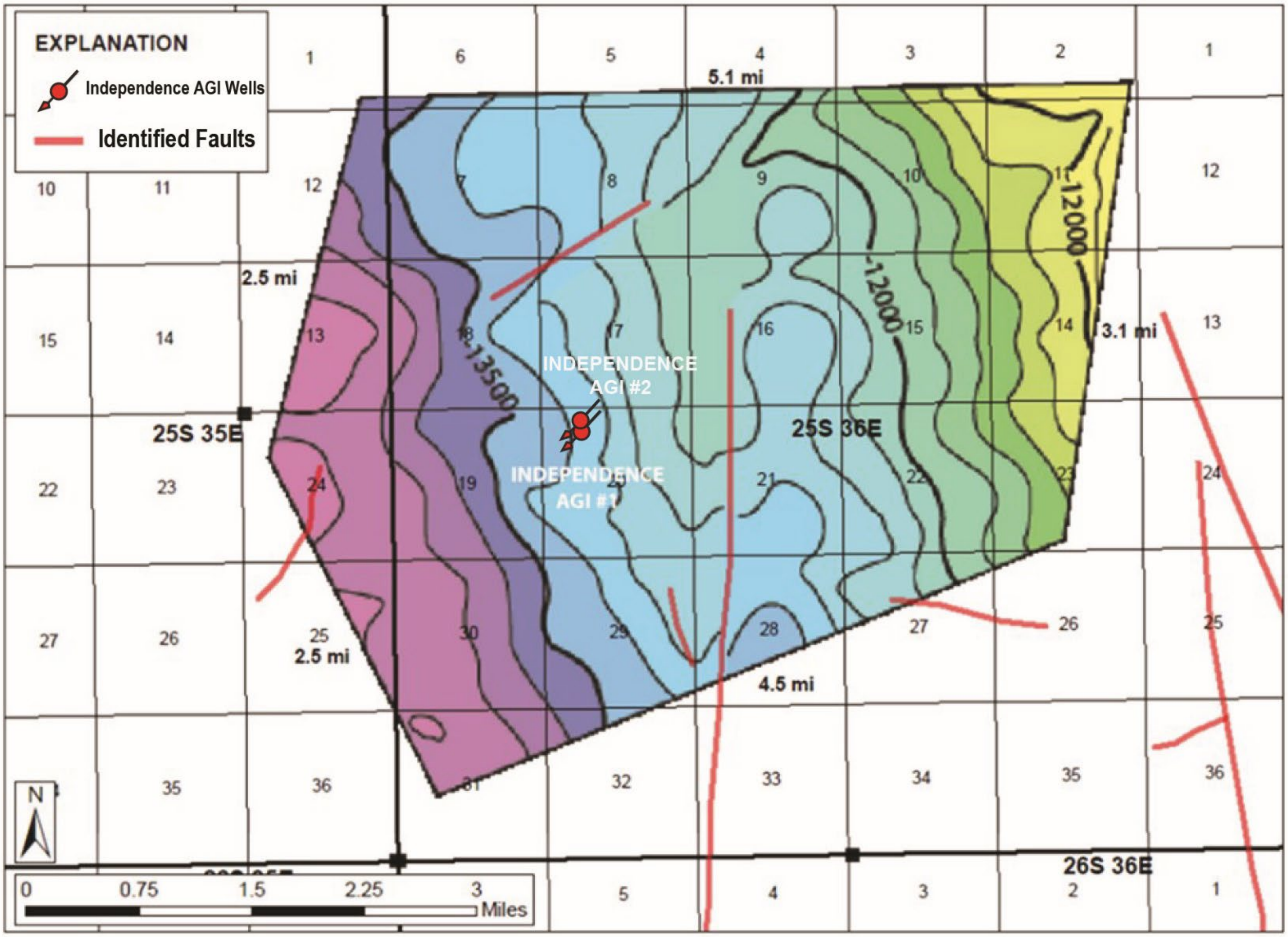
The Independence AGI Wells penetrate the lower Devonian Thirtyone formation and the Silurian Wristen and Fusselman formations and overlie the Ordovician Montoya formation. The upper Devonian Woodford formation serves as the primary containment seal with thick shales having an estimated permeability in the nanodarcy range.

Schlumberger's Petrel (Version 2020.4) software was used to construct the geological models used in this work. Schlumberger's simulation software Eclipse Compositional E300 (Version 2020.1) was used in the reservoir simulations presented in this MRV Plan with simulation results and visuals provided by Geolex Inc. The model simulates solubility trapping of the injected TAG in the formation water and/or the portion of the TAG that can exist in a supercritical phase. The modeling did not consider CO_2 storage attributed to mineral and geomechanical trapping mechanisms. Also, the model did not implicitly model storage attributed to residual trapping because insufficient information was available to develop the hysteresis effects.

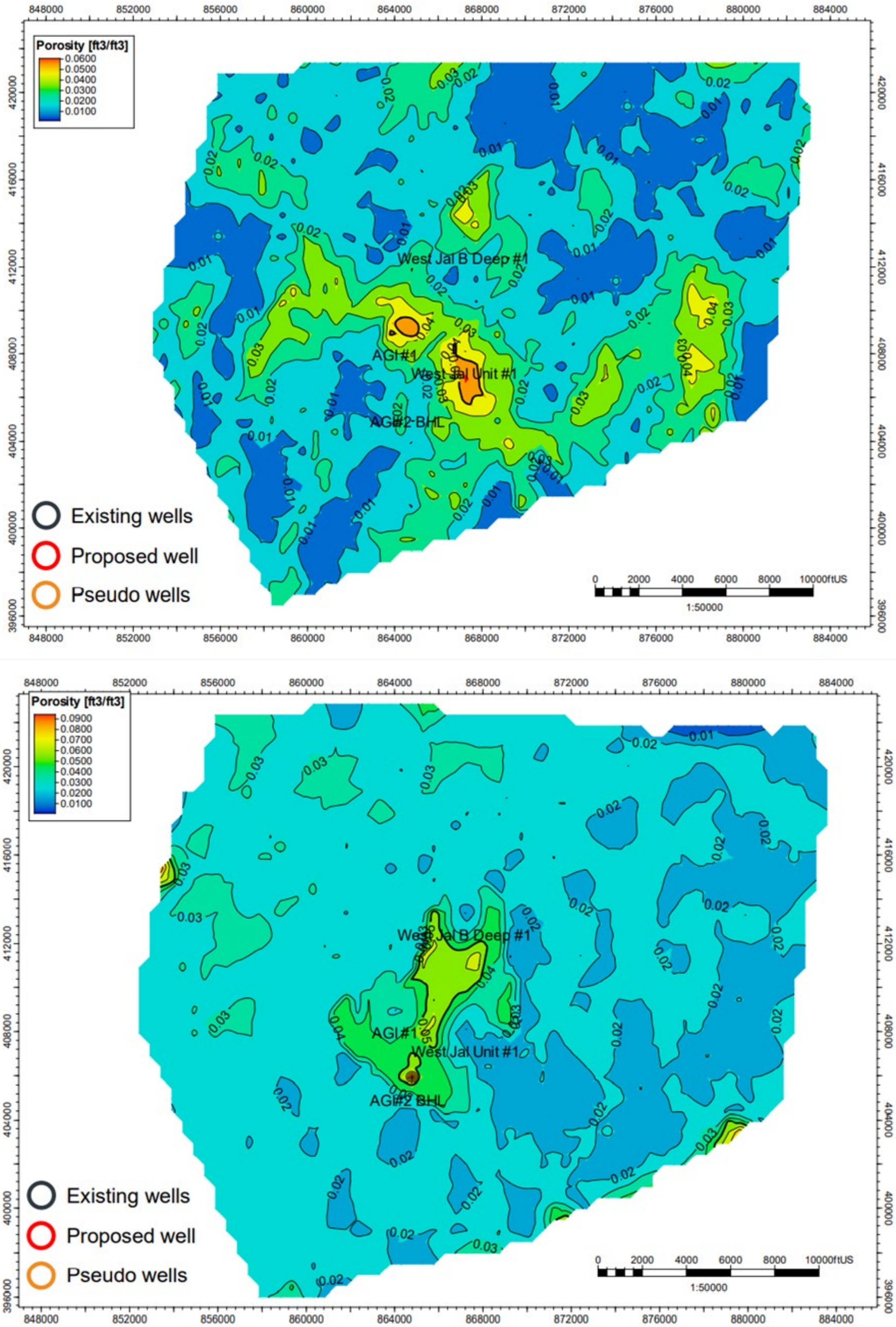
Though the Independence AGI Wells were modeled separately, similar constraints were used for both models. The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. The injection gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Both TAG components are assumed to be soluble into the aqueous phase. An irreducible water saturation of 0.17 is used to generate the relative permeability curves for the gas/water system. The external boundary conditions are specified to be Neumann boundaries and hence no-flow with respect to mass.

3.9.1 AGI Injection Characterization and Modeling

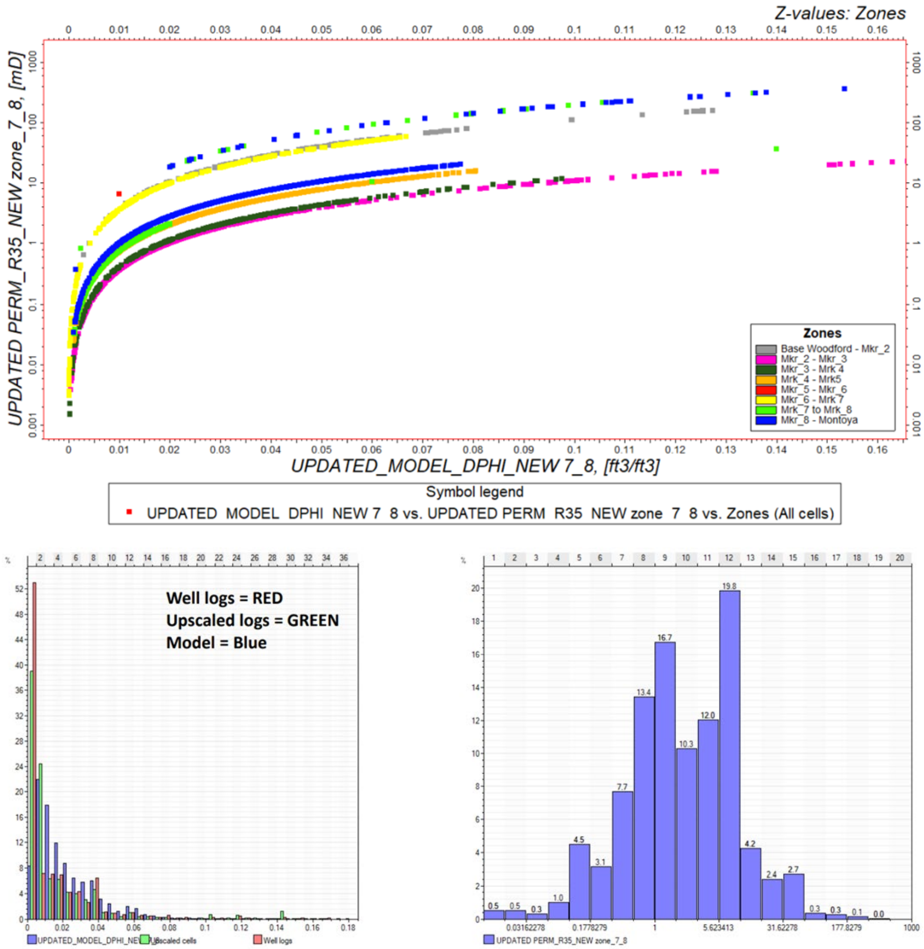
Formation tops were picked from the few well logs available for the area and geophysical measurements and mapped to construct the structural surfaces for the Silurian-Devonian reservoir between the underlying Montoya and capping Woodford formations. The geologic model extends approximately twenty (20) square miles with an irregular polygonal edge (Figure 3.9-1) and includes relevant subsurface features (e.g. faults, folds) and nearby injection wells. The simulation grid is comprised of 292 simulation layers characterizing eight (8) discrete zones. Horizontal spacing is uniform at 500 × 500 feet throughout the model, and the numerical grid overall contains 923,000 grid cells. Figure 3.9-1 shows the structural surface for Layer 1, covering the top of the reservoir immediately below the Woodford cap. Porosity data derived from the Independence AGI #1 well logs augmented by 3D seismic survey impedance data along with drill-stem and injection tests were used to populate the model porosity values (Figure 3.9-2). A porosity-permeability relationship was established to develop a correlation to populate 3D distribution of permeability (Figure 3.9-3). The permeability distribution signifies a fairly tight formation with typical values ranging from 1.0 to 79.0 millidarcies. Figure 3.9-4 shows the permeability distribution in Layer 1 of the model at the top of the Devonian Thirtyone Formation (*see* Section 3.3.1). Separate scenarios were run for non-transmissive faults and for permeability across faults.



<u>Figure 3.9-1</u>: Structural surface for top of Layer 1 (top) of the geological and numerical model. Only SHLs shown for the Independence AGI #1 and #2 wells.



<u>Figure 3.9-2</u>: Model layer porosities for Zone 1 (top) and Zones 7 and 8 (bottom). Porosities are based on 2 wells, 3D seismic impedance surveys, and well stem tests. Only SHLs shown for the Independence AGI #1 and #2 wells.



<u>Figure 3.9-3</u>: Geological zones and ranges of the properties for the Siluro-Devonian geologic model

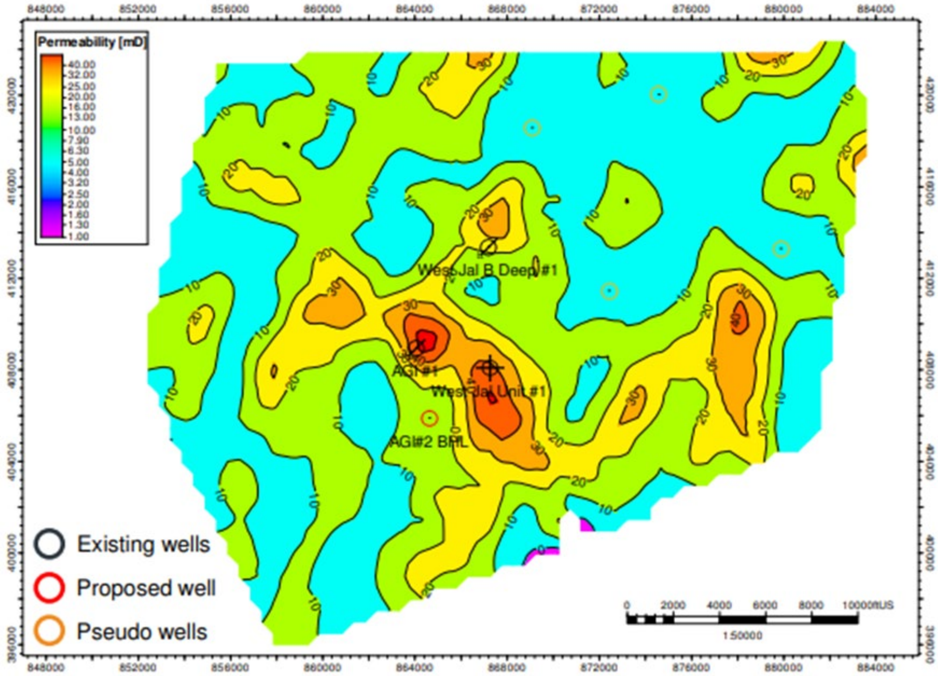


***Figure 3.9-4**: Graphic showing the permeability distribution in Layer 1 of the model representing the Thirtyone formation. Plan view. Only SHLs shown for the Independence AGI #1 and #2 wells.*

3.9.2 Simulation Modeling for the Independence AGI Wells

Once the geological model was established, numerical modeling was performed to:

1. Assess the maximum injection rate with respect to estimated maximum bottomhole pressure ("**BHP**") to ensure safe operation, and
2. Estimate the modeled extent of the injected TAG after thirty (30) year injection period and five (5) year post injection monitoring period.

The reservoir is assumed to be initially saturated with 100% brine and exhibit hydrostatic equilibrium with the initial pressure based on the measured pressure at the top of the reservoir pre-injection. The injection gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Gas is injected for 30 years at a rate of 1,036.73 tonnes per day (378,399 tonnes per year or 11,351,970 total tonnes) followed by a 5-year rest period. Permeability curves for the multiphase gas/water system are defined for three (3) material ranges with a residual liquid saturation between 40% and 65%. An estimated maximum BHP of 9,730 psig, based on the calculated fracture pressure gradient, was imposed on the Independence AGI #1 to ensure safe injection operations. This pressure was important for Independence AGI #1 in the model scenario where all TAG was injected into Independence AGI #1, but otherwise simulations showed pressure at the Independence AGI Wells remaining below this threshold. In all simulations where West Jal Deep B #001 injected 30,000 bpd of brine into the reservoir, the West Jal Deep B #001 would need to decrease injectivity to remain below its permitted threshold pressure. Present modeling work does not indicate sufficient connectivity between the West Jal Deep B #001 and the Independence AGI Wells to impact AGI injectivity under all other modeled scenarios. Figure 3.9-5 shows the calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1. AGI rates are lower than target numbers and limited data are available so a more detailed calibration cannot yet be constructed. An injection forecast model was performed for a period of thirty (30) years with injection and then a five (5) year post-injection rest period to ascertain fluid movement and pressure evolution. Figure 3.9-6 shows the injection profile for the forecasting period which showed that the target injection rate could be hit in all scenarios except Scenario 5. The model showed that all the injected

gas remained in the reservoir and there was no substantive change in the size of the TAG extent compared at the end of injection and five (5) year post injection period.

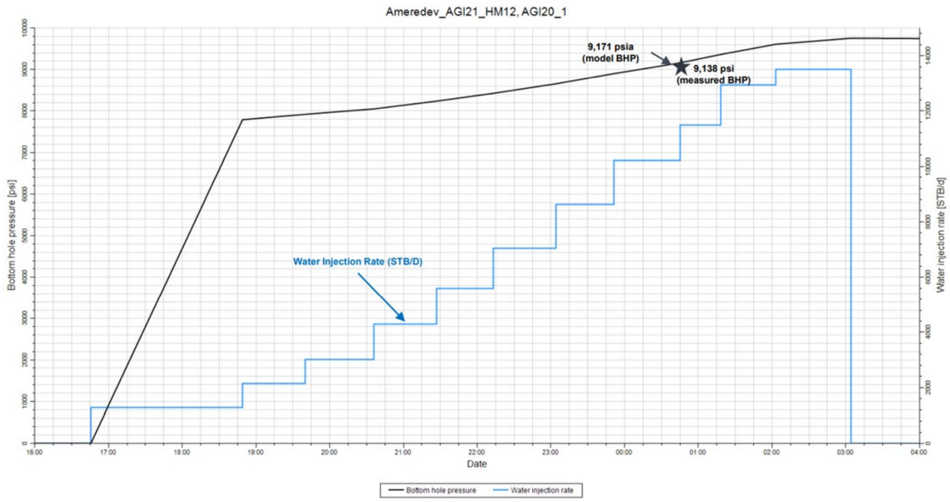


***Figure 3.9-5**: Graph showing calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1.*

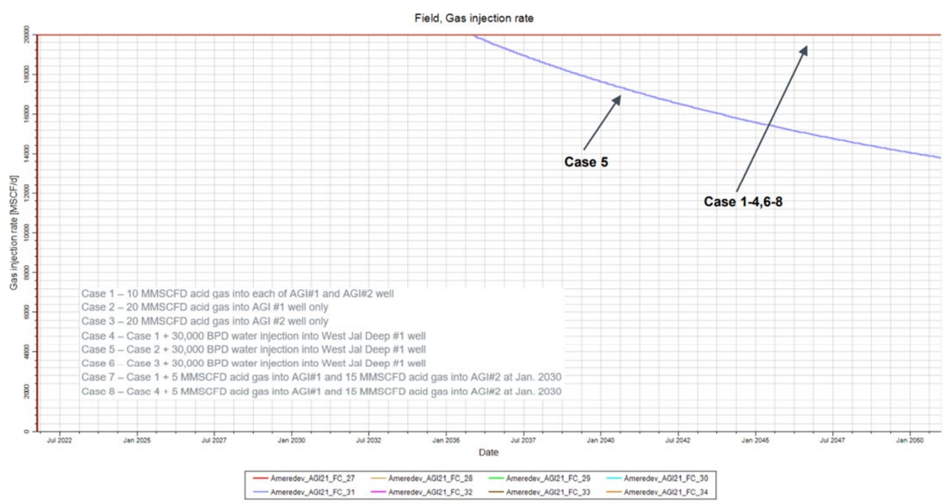


***Figure 3.9-6**: Graph showing the forecast profile for the injection rate and cumulative injection volume over the simulated period*

A considerable source of uncertainty in the plume model relates to the injectivity of the West Jal Deep B #001 well located about one (1) mile northeast of Independence AGI #1. This well is permitted to dispose of up to 30,000 bpd of brine into several reservoirs, including the Siluro-Devonian reservoir used by the Independence AGI Wells, and other shallower reservoirs. It is unclear from publicly available data how this fluid is planned to be partitioned between the various injection layers. As of this application, the wellbore currently has CIBPs at measured depths of 14,200 feet (lower Atoka Formation) and 17,100 feet (Fusselman Formation), restricting injection into the Siluro-Devonian reservoir, and no fluid is currently being injected at the well. However, since this well is permitted for injections, modeling for the present application considered two (2) end-member scenarios: (a) All West Jal Deep B #001 injection is into shallower reservoirs and does not interact with the Siluro-Devonian one (cases 1,2,3), or (b) all West Jal Deep B #001 volumes are injected into the Siluro-Devonian reservoir (cases 4,5,6,7,8). The brine injection at this well is significant for several reasons:

- High volumes of brine injection within the Siluro-Devonian in relatively close proximity of the Independence AGI Wells may raise pressure in the reservoir;

- Pressure from the brine injection pushes against the advancing gas front, directing flow south and west away from the well; and
- The West Jal Deep B #001 wellbore could be a potential leakage pathway if injection ceases and the supercritical fluid plume from the Independence AGI Wells reaches it. Simulations that do not include injections at this well have the TAG plume area including this well.

In all simulations with injection at West Jal Deep B #001, the local pressure at the brine injection well rapidly rises to the breakover point and the injection rate begins dropping within the first two (2) years of that well's operation to maintain pressures below 80% of the breakover threshold and ensure no rock fracturing occurs (Figure 3.9-7). It is unknown how in reality this will translate to well operations within the Siluro-Devonian reservoir. Simulations do not indicate that the pressure increase from this well will adversely affect the Independence AGI Wells due to the early shut down of the brine injection well. Simulations where there is no brine injection result in the plume extending farther northeast beyond the West Jal Deep B #001 well (Figure 3.9-8). If brine is injected, then the plume is repelled towards the south and west, with some TAG flanking the northwest fault and extending northwest (Figure 3.9-9). Simulations suggest a pressure impact on Independence AGI #1 that could result in curtailed injections under a scenario with all TAG injection in Independence AGI #1 and West Jal Deep B #001 active (Case 5, *see* Figure 3.9.6).

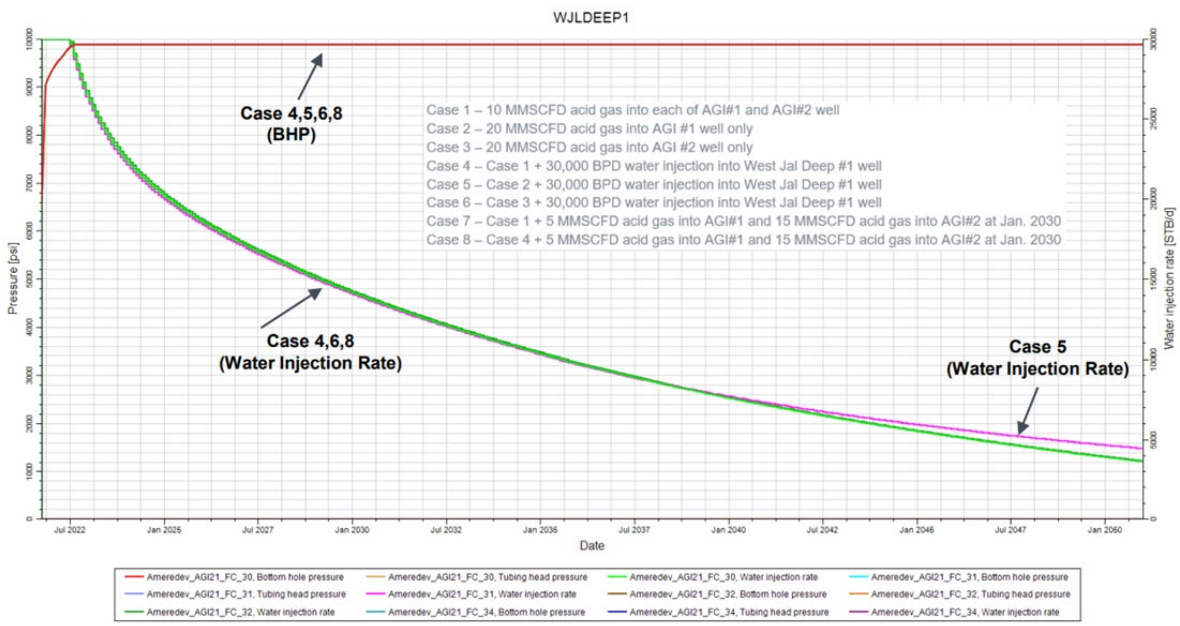


Figure 3.9-7: Graph showing the injection profile of the West Jal Deep B #001 brine injection well under different injection scenarios.

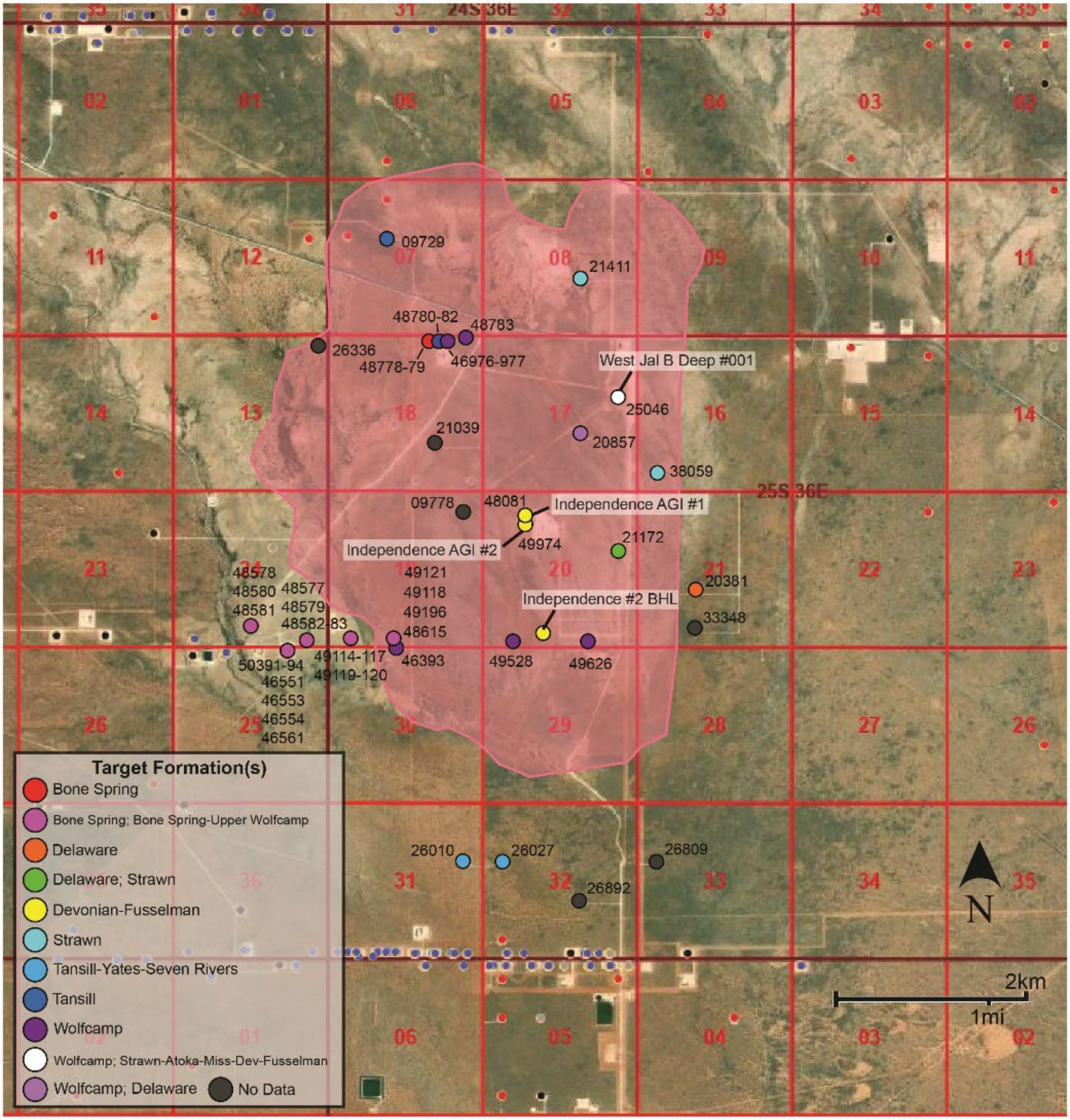


***Figure 3.9-8**: Map showing the largest lateral extent of the TAG when the West Jal Deep B #001 well does not inject into the Siluro-Devonian. Colors indicate target formations for the well. West Jal Deep B #001 is the white dot northeast of the Independence AGI Wells. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.*

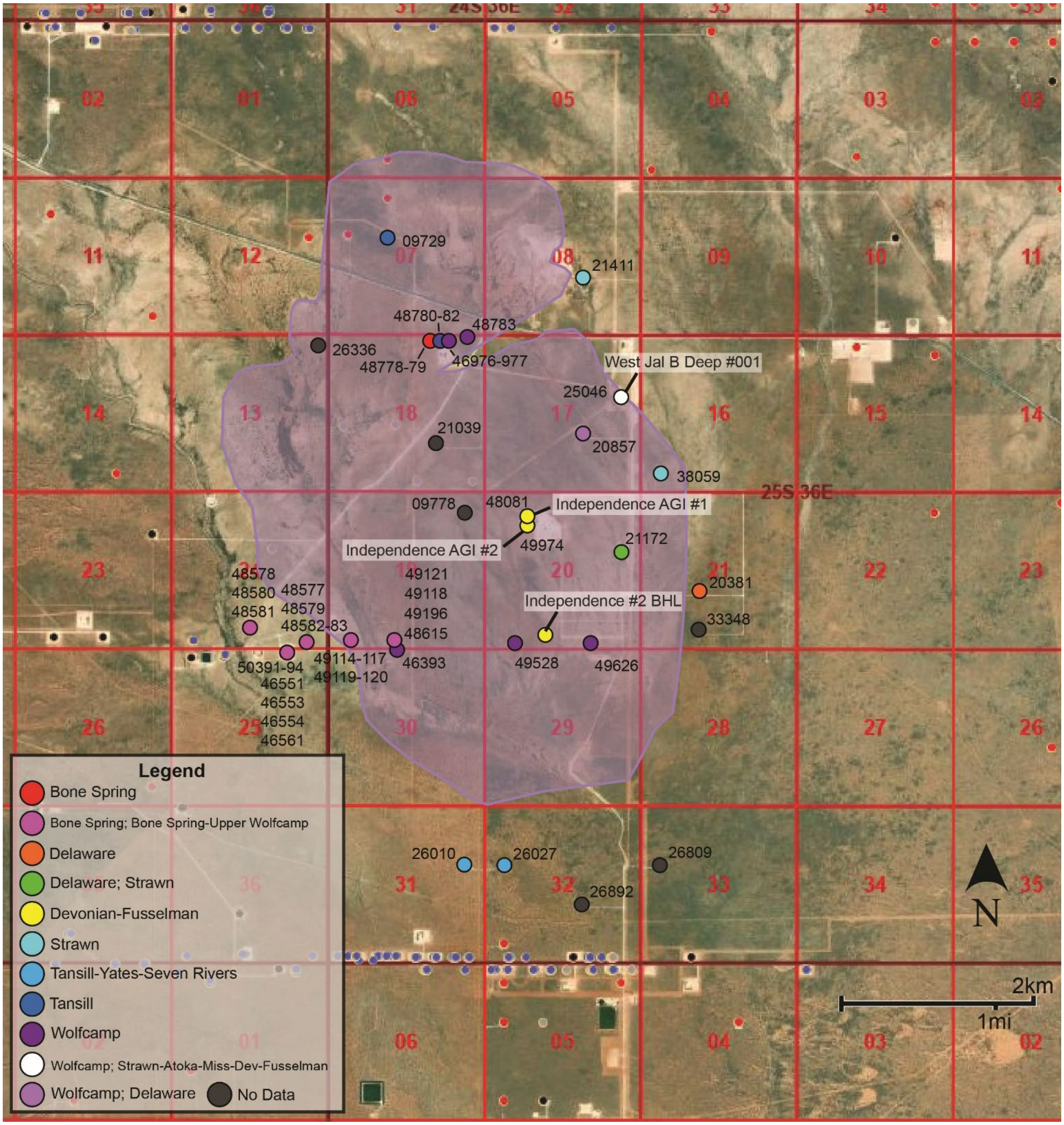


***Figure 3.9-9**: Map showing the largest lateral extent of the TAG when the West Jal Deep B #001 injects an initial rate of 30,000 bpd of brine into the Siluro-Devonian. Colors indicate target formations for the well. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in **Figure 3.1-1**.*

4 Delineation of the Monitoring Areas

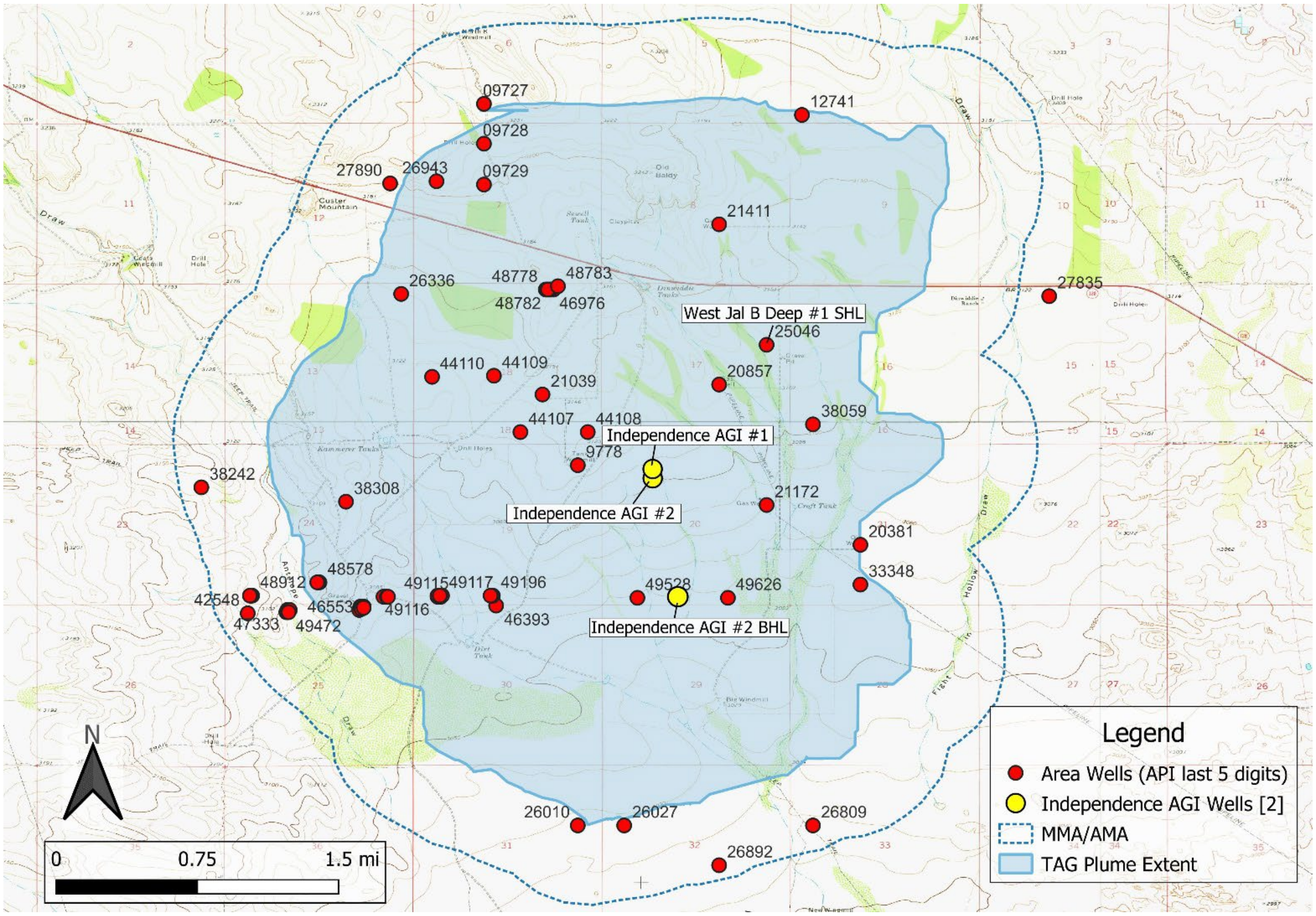
In determining the monitoring areas below, the extent of the TAG plume is equal to the superposition of plumes in any layer for any of the model scenarios described in Section 3.9.

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 (Figure 4.1-1). In general, the western margins of the plume retract to the east following the injection period as gas flows up-dip. In this case, the farthest plume extent and hence the MMA margin is therefore found at year 30 (year t), with the plume extent to the west shrinking by year t+5 and stabilizing. On this side, the MMA is based on the largest plume extent which is at year 30 (t). To the east, fault trapping and the anticline near the injection site generally prevent major movement eastward. Beyond year 30 (t), the plume slowly expands east and northeast, finally stabilizing around year 50 (t+20). In all cases, the plume margin polygon in Figure 4.1-1 is defined by the maximum extent of any plume in any scenario at any simulation time, with a 0.5 mile buffer extending beyond this polygon defining the margin of the MMA.

4.2 AMA – Active Monitoring Area

Piñon intends to define the AMA as the same area as the MMA. Per 40 CFR 98.449, AMA is defined as the area that will be monitored over a specific time interval from the first year of the period (n = 2023) to the last year in the period (t = 2053, a 30-year injection period). The boundary of the AMA 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 (2058, or year 35 of the simulation). However, as the plume has not fully stabilized by year t+5, the AMA and MMA in these areas is defined by the larger area of the stable plume which occurs at year t+20. This definition includes all areas at years t, t+5, and t+20. The zone shown in Figure 4.1-1 has a one-half mile buffer beyond the maximum plume extent of any scenario. Piñon intends to define the AMA as the entirety of the MMA.



<u>Figure 4.1-1</u>: MMA and AMA for the Independence AGI Wells. The plume extents are shown at year 35 (t+= 2058), or 5 years beyond injection time. The plume largely stabilizes by this time, with continued minor migration updip to the northeast which is constrained by faults offsetting permeable layers. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in <u>Figure 3.1-1</u>.

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 duration 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 and the reservoir modeling described in <u>Section 3.9</u>, Piñon 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 treating facilities. To minimize this potential for leakage, the construction, operation, and maintenance of sour gas treating facilities 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, Piñon implements a schedule for regular inspection and maintenance of surface equipment. To further

minimize the magnitude and duration of detected gas leaks to the surface, Piñon implements several methods for detecting gas leaks at the surface. These methods are described in more detail in Sections 6 and 7. Detection is followed up by immediate response.

Likelihood: Due to the required continuous monitoring of the gas gathering and the gas processing systems, Piñon considers the likelihood of CO_2 leakage to the surface via this potential leakage pathway to be low.

Timing: Potential leakage from surface equipment remains consistent over the project lifetime.

Magnitude: Leakage mass will be quantified following the requirements of 40 CFR 98.230-238, noted as Subpart W of EPA's GHGRP. Leakage mass is predicted to be less than one tenth a percent of total injection, less than 12,000 tonnes.

Detection and quantification of any leaks from surface equipment is described in more detail in Section 6.1 below.

5.2 Potential Leakage from Existing Wells

As shown in Figure 3.7-3 and detailed in Appendix 3, there are several existing oil and natural gas-related wells within a two (2) mile radius around the Independence AGI Wells (Figure 4.1-1). The deep wells discussed in Section 3.7.1 (*see* Table 3.7-1) also lie within the MMA/AMA.

Likelihood: The NMOCD regulations governing each wellbore within the MMA/AMA, require the respective operators to case the well 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 zone or to the surface around the outside of a casing string. Additionally, the NMOCD requires each respective operator of a wellbore within the MMA/AMA to operate and maintain their assets so that the injected fluids are confined to the approved intervals and prevent surface damage or pollution. Regulatory citations for these requirements can be found in 19.15.26.9 and 10 NMAC. For these reasons, the likelihood of leaks from existing wells is considered low.

Timing: Risk of leakage at each specific existing wellbore is greatest after CO_2 has reached that location and when pressures are greatest, which is towards the end of the project injection time period discussed in Section 3.8.

Magnitude: Leakage mass is predicted to be less than one percent of total injection, less than 0.15 million tonnes.

Further details regarding the wellbores within the MMA/AMA are discussed below.

5.2.1 Independence AGI Wells

Independence AGI #1 has an open hole interval between 16,122 and 17,709 feet with more than 300 feet of Woodford Shale immediately above (*see* Figure A1-1). Independence AGI #2, which was drilled and completed in October 2022, has an open hole interval between 16,080 and 17,683 feet (*see* Figure A1-2). The combined depth to the Siluro-Devonian Injection Zone, cement program for both wells illustrated in Figures A1-1 and 2, existence of suitable confining layers above the Siluro-Devonian Injection Zone described in Section 3, and continuous monitoring of well operational parameters indicates that leakage of CO_2 to the surface via the Independence AGI Wells themselves is unlikely. Therefore, Piñon considers the likelihood, magnitude, and duration of CO_2 emissions to the surface through the Independence AGI Wells to be minimal. Detection and quantification of any leaks from Independence AGI Wells are described in Section 6.2 below.

5.2.2 West Jal B Deep #001 Well

The West Jal B Deep #001 (API 30-025-25046) brine injection well is located one (1) mile northeast of the surface hole locations of the Independence AGI Wells. Additional details for this well are presented in Section 3.7.1. The wellbore currently has two CIBPs at measured depths of 14,200 feet (lower Atoka Formation) and 17,100 feet (Fusselman Formation). These CIBPs restrict access to any existing reservoirs located below the lower Atoka Formation, including within the Mississippian Lime (14,544 feet), Devonian (15,380 feet), and the Fusselman (16,404 feet), and injections in this wellbore to-date have been up-section of the relevant area. In the event of incomplete plugging of the borehole or leakage through the well casing, the shallower reservoir is at higher pressure than the Siluro-Devonian reservoir, and consequently it is assessed that downward flow of fluid would repel the TAG plume from the AGI wells. Nevertheless, the potential for CO_2 leakage to the surface through this well is considered possible, albeit unlikely, and monitoring for this possibility is described in Section 6.2.2.

5.2.3 West Jal Unit #1 Well

The West Jal Unit #1 well (API 30-025-21172) was plugged and abandoned in April 1984. The plugging documents presented in Appendix 9 indicate that the well is properly plugged to prevent vertical migration of pressure or fluids outside of the storage reservoir with multiple CIPBs and cement plugs, including the Siluro-Devonian Injection Zone. Piñon concludes that the risk of any magnitude for CO_2 leakage to the surface through plugged and abandoned well is unlikely. However unlikely, Piñon will conduct quantification and monitoring for as described in Section 6.

5.2.4 Wells Completed and Proposed to be Completed in the Wolfcamp, Bone Spring, and Shallower Stratigraphic Units

There are several oil and natural gas wells (Appendix 3) completed or proposed to be completed in the Wolfcamp, Bone Spring and shallower stratigraphic units within the MMA. The deepest of these wells is completed in the Upper Wolfcamp (see Figures 3.2-2 and 3.3-1). The nearly 4,000 feet of strata between the top of the Siluro-Devonian Injection Zone and the Wolfcamp production zone includes nearly 300 - 400 feet of low porosity and low permeability Woodford Shale, the primary confining unit/seal for the Independence AGI Wells (see Figure 3.3-3).

Due to the thickness of the strata between the deepest wells completed in the Wolfcamp and the thickness of the Woodford Shale above the Siluro-Devonian Injection Zone, Piñon considers the likelihood, magnitude, and duration of CO_2 leakage to the surface via this potential leakage pathway to be unlikely. Detection and quantification of any leaks through these wells are described in Section 6.2 below.

5.3 Potential Leakage through Fractures and Faults

Faults and fractures were discussed in Section 3.2.3 and the potential for induced seismicity was discussed in Section 3.5. The reservoir characterization modeling (Section 3.9) and the delineation of the monitoring areas (Section 4) show that the TAG plume reaches the faults shown in Figure 3.5-1 during the thirty (30) year injection period and the five (5) year post injection monitoring period. Vertical permeability may be present parallel to the plane of the fault vertically, especially where the two main faults intersect. A review of available drilling fluid records was conducted to evaluate regional reservoir pressure conditions in the Delaware basin. Above the Siluro-Devonian injection reservoir, mud weights utilized range from 12.1 to 15.1 pounds per gallon, while for the injection reservoir less dense fluids were used (average of 9.0 pounds per gallon). These support the interpretation that the overlying productive zones in this area are over pressured with respect to the target reservoir, which would produce a downward gradient through any fault-parallel permeability.

Likelihood: Due to evidence that production zones overlying the Siluro-Devonian Injection Zone are over pressured and that the basement rooted faults in the area are confined to the lower Paleozoic up to the lower Woodford Shale, the likelihood of leakage of CO_2 is considered unlikely.

Timing: Risk of leakage through fractures and faults is greatest when pressures are at their highest, which is at the end of the project injection time period discussed in Section 3.8.

Magnitude: Due to the unlikely potential noted above, anticipated leakage magnitude is negligible.

Detection and quantification of any leaks through these basement rooted faults are described in Section 6.3 below.

5.4 Potential Leakage through the Confining / Seal System

The subsurface lithologic characterization presented in Section 3.2.2 describes the thick sequence of Mississippian through Permian strata overlying the Siluro-Devonian Injection Zone and reveals the existence of several excellent confining zone layers including nearly 300 - 400 feet of low porosity low permeability Woodford Shale.

Likelihood: Due to the thickness, lateral extent, and low porosity and permeability of the Woodford Shale, Piñon considers the likelihood of CO_2 leakage to the surface through the confining zone is unlikely.

Timing: Risk of leakage through the confining / seal system is greatest when pressures are at their highest, which is at the end of the project injection time period discussed in Section 3.8.

Magnitude: Due to the unlikely potential noted above, anticipated leakage magnitude is negligible.

Detection and quantification of any leaks through the confining zone are described in Section 6.4 below.

5.5 Potential Leakage due to Natural / Induced Seismicity

The potential for leaks initiated by induced seismicity was addressed in Section 3.5. It was concluded that generally, faults considered in this assessment do not display significant potential for injection-induced slip and the Independence AGI #2 is not predicted by the FSP model to contribute significantly to the total resultant pressure front.

According to data obtained from the New Mexico Tech Seismic Observatory (2023), there have been four (4) seismic events within the MMA since January 12, 2017 (Figure 5.6-1). These seismic events range in magnitude of 1.16-1.88 and occurred between September 2020 and October 2021 (Table 5.6-1). The New Mexico Tech database applied a model for epicenter location that was not capable of determining focal depth. Revisions to this database are planned for late 2023 but have not been released at the time of this writing. Hence, earthquake depths are unknown, but accounting for the lack of local development in the Devonian strata, and the greater development at shallower depths, it is believed these earthquakes occurred in a shallower reservoir. Data queries with the USGS Earthquake Catalog did not show any seismic activity within the MMA (USGS Earthquake Hazards Program, 2023).

As noted in Section 3.5, the results of the fault slip potential model indicate no likelihood of slip on the fault east of the Independence AGI Wells. The maximum segment slip potential was determined at 0.05 northwest of the injection wells, with AGI injections causing no increase in probability. Any slip would depend on the injection volumes of brine disposal wells (at present there is no brine injection in the target area). Should fault slip occur, the short lengths of the potentially slipping segment likely preclude large earthquakes, and seismicity would be expected to be <2.5 in magnitude. Any earthquakes at or above this value would be carefully evaluated to determine location, depth, and sense of motion. Remote gas observation sweeps will be conducted above or as close to the mobile fault segment as possible at 10, 30, 100, and 365 days following the event to determine if leakage is occurring. The rate of gas leakage will likely depend on the time required to saturate the fracture network created by the seismic event and the timeline of this process is expected to be on order 10 to 100 days after the fracture network is exposed to gas (Hyman et al. 2019).

In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage. Nevertheless, the NMOCC Order requires Piñon to install, operate, and monitor for the life of the project a seismic monitoring station or stations. Seismic monitoring station or stations are described in more detail in Section 7.6.

Likelihood: Piñon concludes that the likelihood for the creation and/or opening of vertical conduits for CO_2 leakage to the surface due to induced and natural seismicity is unlikely.

Timing: Risk of leakage due to natural seismicity is not anticipated to change over the life of the project. Risk of leakage due to induced seismicity is greatest when pressures are at their highest, which is at the end of the project injection time period discussed in Section 3.8.

Magnitude: Due to the unlikely potential noted above, anticipated leakage magnitude is negligible.

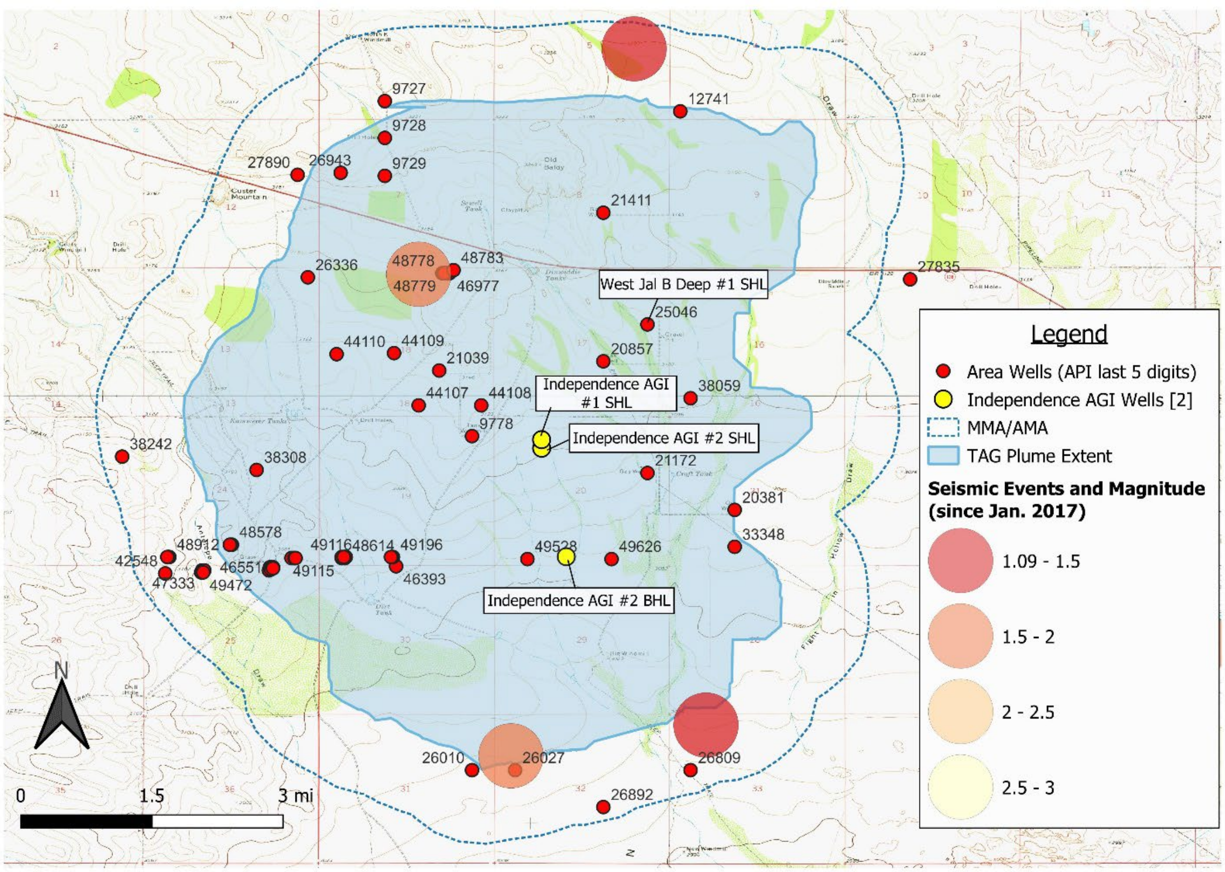


***Figure 5.6-1**: Map showing seismic event locations within the MMA for the Independence AGI wells. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in **Figure 3.1-1**.*

Date+Time(UTC)	Latitude	Longitude	Magnitude
2021-10-30 07:14:26.600	32.093	-103.275	1.16
2021-10-11 12:19:51.300	32.09	-103.294	1.88
2021-09-09 08:23:05.600	32.137	-103.303	1.74
2020-10-03 03:51:12.600	32.159	-103.282	1.47

***Table 5.6-1**: Table showing the locations, dates and times, and magnitudes of seismic events within the MMA for the Independence AGI wells.*

5.6 Potential Leakage due to Lateral Migration

Lateral migration of the injected TAG was addressed in the simulation modeling detailed in Section 3.9. The results of that modeling indicate the TAG is unlikely to migrate laterally beyond approximately 2.5 miles within the Siluro-Devonian Injection Zone to encounter any conduits to the surface.

Likelihood: Leakage to the surface due to lateral migration is unlikely.

Timing: Risk of leakage through lateral migration is greatest when pressures are at their highest, which is at the end of the project injection time period discussed in Section 3.8.

Magnitude: Due to the unlikely potential noted above, anticipated leakage magnitude is negligible.

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. Piñon 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. Piñon considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ 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 five (5) year post-injection period.

If CO_2 surface emissions are detected by any of the monitoring methods listed in Table 6.1, Piñon will quantify the mass of CO_2 emitted via approved emission factors such as those found in 40 CFR Part 98, Subpart W or engineering estimates 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. Quantification can include leak amounts based on measurements, frequency of inspection, and other factors related to each specific identification. Piñon maintains a Greenhouse Gas Monitoring Plan to report and quantify all leaks in accordance with 40 CFR Part 98.

***Table 6.1** – Summary of Leak Detection Monitoring*

Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system ("**DCS**") surveillance of facility operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/H_2S and low explosive level ("**LEL**") monitoring network • Personal and hand-held gas monitors

Leakage Pathway	Detection Monitoring
Independence AGI #1 & Independence AGI #2	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests ("**MIT**") • Fixed in-field gas monitors/H_2S and LEL monitoring network • Personal and hand-held gas monitors
Existing Other Operator Active Wells	• Monitoring of well operating parameters • Visual inspections • MITs • Mobile CO_2 detectors
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network • Mobile CO_2 detectors
Confining / Seal System	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network

6.1 Leakage from Surface Equipment

Piñon 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 Piñon using in-field monitors which detect H_2S. 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. Additionally, Piñon field personnel, wearing personal H_2S monitors, follow daily and weekly inspection protocols which include reporting and responding to any detected leakage events.

Piñon's internal operational documents and protocols detail the steps to be taken to verify leaks of H_2S. The following description of the gas detection equipment at the Dark Horse Facility was summarized from the H_2S Contingency Plan:

Fixed Monitors

The Dark Horse Facility has numerous ambient H_2S detectors placed strategically throughout the facility to detect possible leaks. Upon detection of H_2S concentrations of 10 ppm at any detector, visible beacons are activated and an alarm is sounded. Upon detection of H_2S concentrations of 90 ppm at any detector, an evacuation alarm is sounded throughout the Dark Horse Facility at which time all personnel will proceed immediately to a designated evacuation area. The Dark Horse Facility 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 ("**PLC**"), and then to the DCS. The monitors are equipped with amber beacons. The beacon is activated upon detection of H_2S concentrations of 10 ppm. The Dark Horse Facility horns are activated with a continuous warbling alarm upon detection of H_2S concentrations of 10 ppm and a facility-

wide siren upon detection of H_2S concentrations of 90 ppm. All monitoring equipment is Rosemount brand. The control panel is a twenty-four (24) channel monitor box, and the fixed point H_2S sensor heads are model number ST320A-100-ASSY.
The Dark Horse Facility will monitor the inlet sour natural gas steam and sweet natural gas stream concentrations of H_2S via H_2S analyzers with sample points located on the north/south-oriented pipe rack (Figure 7.2-1). Concentrations of H_2S in the TAG stream will be sampled near the AGI pumps located on the west side of the Dark Horse Facility. All H_2S analyzers are model T224, manufactured by Analytical Systems KECO.
The monitors can also be viewed on the PLC displays located at the Dark Horse Facility and the locations of ambient H_2S sensors are shown on the plot plan (*see* Figure 3.7-2). Immediate action is required for any alarm occurrence or malfunction. All H_2S sensors are calibrated monthly.

Personal and Handheld H_2S Monitors

All personnel working at the Dark Horse Facility wear personal H_2S monitors, which are required to alarm and vibrate upon detection of H_2S concentrations of 10 ppm. Handheld gas detection monitors are available at strategic locations around the Dark Horse Facility so that facility 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.

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 10.1.5. Furthermore, if CO_2 emissions are detected through any of the surveillance methods described above, Piñon 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.

6.2 Leakage from Existing Wells

6.2.1 Independence AGI Wells

As part of ongoing operations, Piñon continuously monitors and collects flow, pressure, temperature, and gas composition data from each Independence AGI Well. This data is monitored continuously by qualified technicians who follow response and reporting protocols when the monitoring system delivers alerts that data is not within acceptable limits. Mechanical integrity tests (MIT) are performed on each Independence AGI Well annually. Failure of an MIT would indicate a leak in the applicable well and result in immediate action by shutting in the well, assessing the MIT failure, and implementing mitigative steps.

If operating parameter monitoring and MIT failures indicate a CO_2 leak has occurred, Piñon will (a) take actions 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.2.2 West Jal B Deep #001 and West Jal Unit #1 Wells

Piñon will annually employ mobile CO_2 detectors, which may include drone mounted sensors, to monitor for any CO_2 emission at the locations of the West Jal B Deep #001 and West Jal Unit #1 wells. If surface CO_2 leakage is correlated with loss through these wells, Piñon will (a) take actions, including by working with the third party operator of the West Jal B Deep #001 and West Jal Unit #1 wells, to quantify the amount of CO_2 emitted based on the operational conditions that existed at the time of 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.2.3 Wells Completed and Proposed to be Completed in the Wolfcamp, Bone Spring, and Shallower Stratigraphic Units

As discussed in Section 5, it is unlikely that the TAG injected through the Independence AGI Wells into the Siluro-Devonian Injection Zone will migrate upward to these shallower production wells and be emitted to the surface through these wells. Due to the natural presence of H_2S and CO_2 in the production streams of oil and natural gas producers in the AMA, Piñon has been in contact with such producers in the AMA regarding Piñon's core business of sour gas (high in H_2S and CO_2) treatment and sequestration. Piñon will continue to work cooperatively with such producers and immediately investigate, including by use of mobile CO_2 detectors, any CO_2 emissions from wells operated by oil and natural gas producers in the AMA which is suspected to arise from Piñon's operations. If surface CO_2 leakage is correlated with loss through these wells, Piñon will (a) take actions, including by working with the third party operator of the well(s), to quantify the amount of CO_2 emitted based on the operational conditions that existed at the time of 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.3 Leakage from Fractures and Faults

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through a fracture or fault. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone.

Piñon will assess any changes in operating parameters or data which indicates surface leakage of CO_2 along faults or fractures. Piñon will employ mobile CO_2 detectors, which may include drone mounted sensors, to monitor for any emission above mapped fractures and faults. If surface CO_2 leakage is correlated with loss through fractures or faults, Piñon will (a) take actions, including by working with relevant surface owners, to quantify the amount of CO_2 emitted based on the conditions that existed at the time of 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.4 Leakage through the Confining / Seal System

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through the confining / seal system. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.2 and 7.5, will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone.

If changes in operating parameters or data indicate surface leakage of CO_2 through the confining / seal system, Piñon will (a) take actions to quantify the amount of CO_2 emitted based on 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI well(s).

6.5 Leakage due to Natural / Induced Seismicity

Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.2 and 7.5 coupled with a detection of a seismic event by the seismic stations described in Section 7.6 will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone due to a seismic event.
After a seismic event, Piñon will assess any changes in operating parameters and data from the surrounding seismic stations which might indicate leakage of CO_2 along faults or fractures activated

by the event. If leakage of CO_2 is correlated with a seismic event, Piñon will (a) take actions to quantify the amount of CO_2 emitted based on 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.6 Leakage due to Lateral Migration

Continuous operational monitoring of the Independence 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 Siluro-Devonian Injection Zone. 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 Siluro-Devonian Injection Zone.

If monitoring of operational parameters indicates that the CO_2 plume extends beyond the area modeled in Section 3.9 and presented in Section 4, Piñon will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 release to the surface. If it is determined that the plume intersected a pathway for CO_2 release to the surface, this would be considered a material change per 40 CFR 98.448(d)(1), and Piñon will submit a revised MRV plan as required by 40 CFR 98.448(d).

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

Subpart RR at 40 CFR 448(a)(4) requires a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. Piñon 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 Piñon's strategy for collecting baseline information.

7.1 Visual Inspection

Piñon field personnel conduct daily visual inspections of surface equipment located at the Dark Horse Facility and the Independence AGI Wells. These visual inspections will aid in identifying and timely addressing potential areas of concern to minimize the possibility of H_2S, a proxy for CO_2, leakage. If any leakage is identified during such visual inspections, Piñon field personnel will take prompt corrective actions to address such leakage.

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

Compositional analysis of gas injectate at the Dark Horse Facility indicates an approximate H_2S concentration of 38.7% thus requiring Piñon to develop and maintain an H_2S Contingency Plan according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). Piñon considers H_2S to be a proxy for CO_2 leaks at the Dark Horse Facility. The H_2S Contingency Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the Dark Horse Facility or the associated Independence 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 Dark Horse Facility utilizes numerous fixed-point monitors, strategically located throughout the facility, to detect the presence of H_2S in ambient air (Figure 3.7-2). The diagram in Appendix 10 shows the location of the Ultrasonic inflow meters and the Coriolis meters to the Independence AGI wells. The sensors are connected to the Control Room alarm panel's PLCs, and then to the DCS. Upon detection of H_2S concentrations of 10 ppm at any monitor, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of H_2S concentrations of 90 ppm at any monitor, an evacuation alarm is sounded throughout the Dark Horse Facility 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 Dark Horse Facility so that facility 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 Oxide ("**CO**").

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the Dark Horse Facility 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 upon detection of H_2S concentrations of 10 ppm.

7.3 CO_2 Detection

Any CO_2 release to the surface would be accompanied by H_2S and therefore the H_2S monitors will serve as a CO_2 release warning system both at the facility and in the field. In addition to the fixed and personal monitors described in Section 7, Piñon will establish and operate a monitoring program to detect H_2S leakages within the AMA. The scope of work will include H_2S monitoring at the AGI well site and atmospheric monitoring near identified penetrations of the Siluro-Devonian Injection Zone within the AMA. Upon approval of the MRV Plan and for the five (5) year post-injection period, Piñon will have these monitoring processes and systems in place.

7.4 Continuous Parameter Monitoring

The DCS of the Dark Horse Facility 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

Piñon 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. Piñon's Routine Operations and Maintenance Procedures for the Independence AGI Wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic Monitoring Stations

Piñon owns 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 Dark Horse Facility. The seismic station will meet the requirements of the NMOCC Order to "install, operate, and monitor for the life of this Order a seismic monitoring station or stations. OCD shall be responsible for coordinating with the Manager of the New Mexico Tech Seismological Observatory at the New Mexico Bureau of Geology and Mineral Resources for appropriate specifications for the equipment and the required reporting procedure for the monitoring data."

Additionally, Figure 7-1 shows the location of other seismic monitoring stations in the vicinity of the Independence AGI Wells.

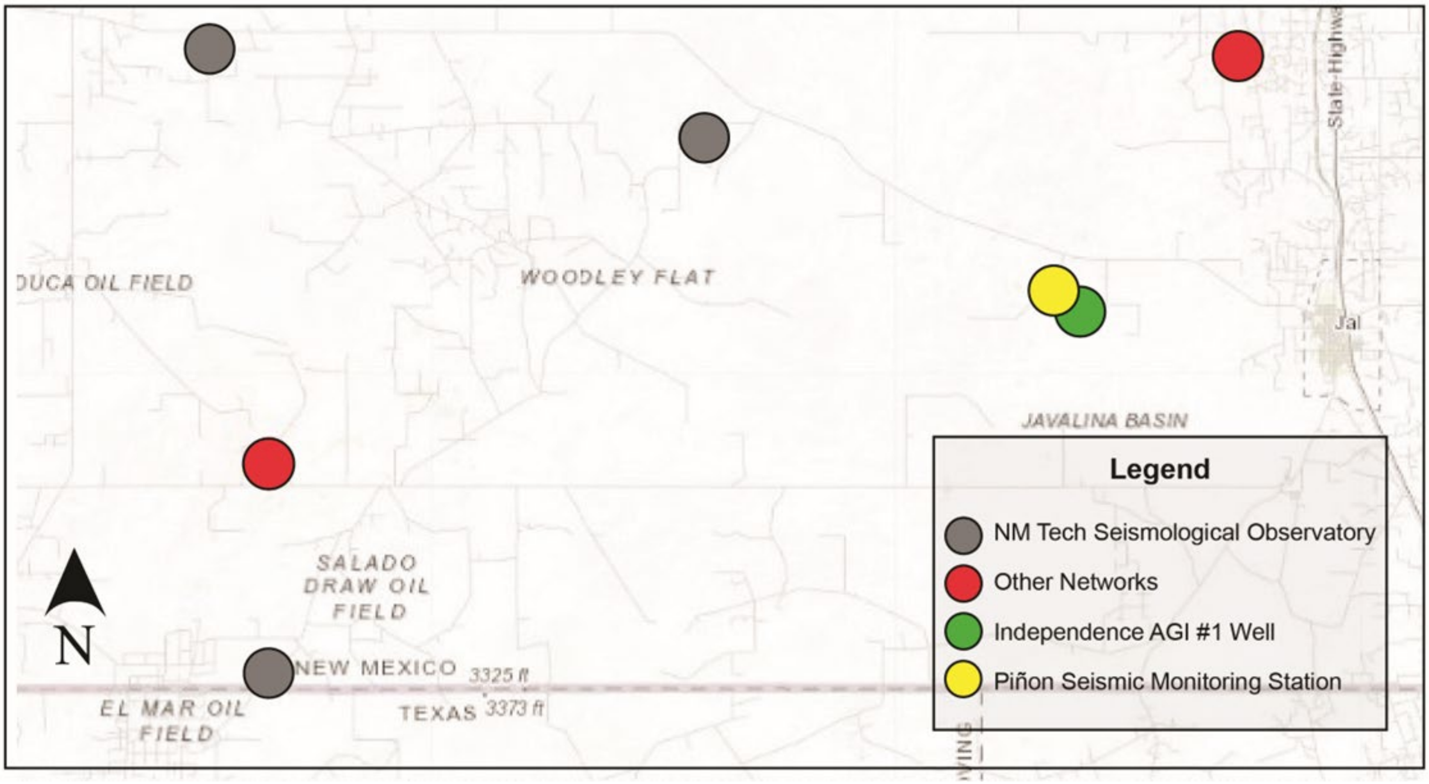


***Figure 7-1**: Location of seismic monitoring stations in the vicinity of the Independence AGI Wells.*

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve (12) Subpart RR equations used to calculate the mass of CO_2 sequestered annually. Appendix 8 includes the twelve (12) equations from Subpart RR. Not all of these equations apply to Piñon's current operations at the Dark Horse Facility but are included in the event Piñon's operations change in such a way that their use is required.

Figure 3.7-2.b shows the location receipt meters and injection meters listed in 40 CFR 98.232(d) of Subpart RR that will be used in the calculations set forth below.

8.1 CO_2 Received

Currently, Piñon receives sour natural gas at the Dark Horse Facility through three (3) pipelines: the Hondo High Pressure Sour Gas Pipeline (owned and operated by Piñon), the Franklin Mountain Low Pressure Pipeline (owned and operated by Franklin Mountain Energy) and the Ameredev II Low Pressure Pipeline (owned and operated by Ameredev). Piñon 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. Receipt meters are shown on Figure 3.7-2.b.

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

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \quad \text{(Equation RR-3 for Pipelines)}$$

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.

Although Piñon does not currently receive CO_2 in containers for injection, they have chosen to include the flexibility in this MRV Plan to do so. If Piñon begins to receive CO_2 in containers, they will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. Piñon will adhere to the requirements in 40 CFR 98.444(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 40 CFR 98.488(d)(1), Piñon will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Piñon injects CO_2 into the existing Independence AGI #1. Upon its completion, Piñon will commence injection of CO_2 into Independence AGI #2. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the Independence AGI Wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the Independence AGI Wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Injection meters are shown on Figure 3.7-2.b.

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \quad \text{(Equation RR-5)}$$

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.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \quad \text{(Equation RR-6)}$$

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

Piñon does not produce oil or natural gas or any other liquid at the Dark Horse Facility 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 (CO_{2E}) from the leakage pathways identified and evaluated in Section 5. 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.

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

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.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

As required by 98.444(d) of Subpart RR, Piñon 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 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 Piñon does not actively produce oil or natural gas or any other fluid at the Dark Horse Facility, 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 the GHGRP.

9 Estimated Schedule for Implementation of MRV Plan

Piñon intends to implement this MRV Plan on June 1, 2023, after it is approved by EPA.

10 GHG Monitoring and Quality Assurance Program

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

10.1 GHG Monitoring

As required by 40 CFR 98.3(g)(5)(i), Piñon'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 greenhouse gas ("**GHG**") calculations; and
- 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 will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association ("**GPA**") standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40 CFR 98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2 and RR-5, of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 15.025 pounds per square inch absolute ("**psia**") (Appendix 6). Piñon utilizes Coriolis metering to measure the dense phase injected TAG stream. Piñon utilizes the following two standards: American Petroleum Institute API 14.1 for measuring barrels and the American Gas Association AGA 7 for million cubic feet ("**MCF**") equivalent calculations.

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 Independence AGI Wells using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.4 CO_2 Produced.

Piñon does not produce CO_2 at the Dark Horse Facility.

10.1.5 CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2.

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

10.1.6 Measurement devices.

As required by 40 CFR 98.444(e), Piñon 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 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute, the AGA, the GPA, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.
- All flow meter calibrations performed are National Institute of Standards and Technology ("**NIST**") traceable.

10.2 QA/QC Procedures

Piñon 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

Piñon will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or using a representative concentration value from the 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

Piñon will revise the MRV Plan as needed to (a) reflect changes in monitoring instrumentation and quality assurance procedures; (b) improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or (c) address additional requirements as directed by the EPA or the State of New Mexico.

11 Records Retention

Piñon will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, Piñon will retain the following documents:

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

(b) 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

(c) The annual GHG reports.

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

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

(f) 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.

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

(h) 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.

(i) 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.

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

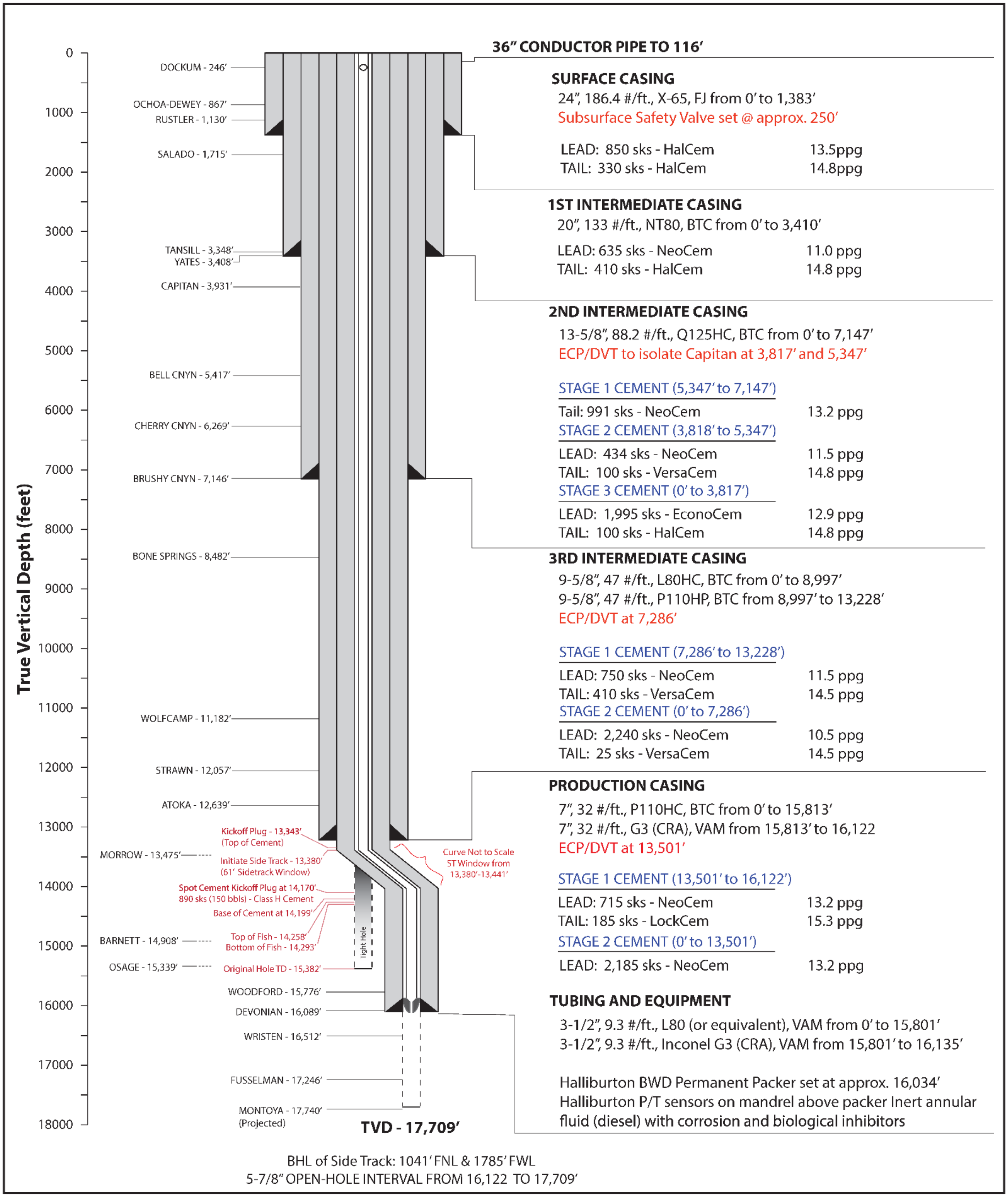
(k) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

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

12 Appendices

Appendix 1 - Independence AGI Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Independence AGI #1	30-025-48081	SHL 829' FNL, 1,443' FEL BHL of Sidetrack: 1041'FNL, 1785'FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120855 and -103.291021	Lea, NM	12/27/2020	17,750'	16,114'
Independence AGI #2	30-025-49974	SHL 1,180' FNL, 1,578' FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120020 and -103.291015 BHL 1,033' FSL, 2,132' FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.111581 and -103.289273	Lea, NM	07/02/2022	17,683' TVD	16,610'



<u>Figure A1-1</u>: Independence AGI #1: As-drilled well schematic consisting of a surface string of casing, three (3) intermediate strings , and a production string with associating tubing/equipment and cement types. Original hole and sidetrack are shown. (Taken from End-of-Well Report for Independence AGI #1, Geolex, Inc.)

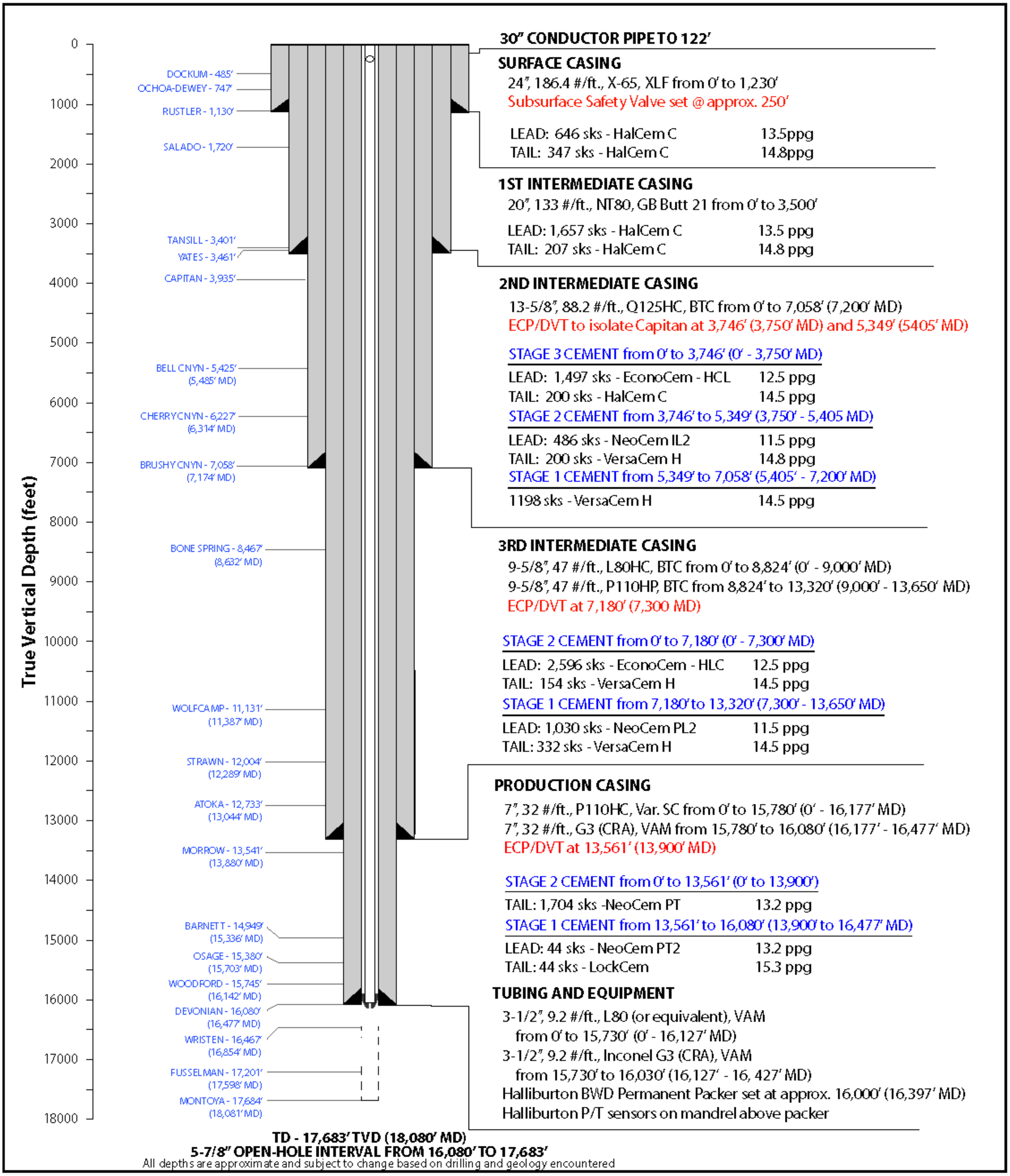


***Figure A1-2**: Independence AGI #2: Well schematic. (Taken from NMOCC Order 3/31/2022)*

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
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
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
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 - Oil and natural gas wells within 2-mile radius of the Independence AGI Wells

The data in the following table was obtained from the NMOCD database and is accurate as of 8/5/2022.

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-09729	PAN AM KELLY 7 FEDER	Oil	Plugged (site released)	JOHN H TRIGG	32.1466	-103.3063		1900	3,540	0	-	1/1/1900	CUSTER, TANSILL
30-025-09778	FEDERAL #1	Oil	Plugged (site released)	EDWARD C. DONAHUE	32.1212	-103.2978	No Data	1900	3,891	0	-	1/1/1900	No Data
30-025-20381	HERKIMER BQF FEDERAL #001H	Oil	Active	AMEREDEV OPERATING, LLC	32.114	-103.2722	H	1963	8,515	10,121	10,100	-	DELAWARE, WEST
30-025-20857	WEST JAL B #001	Brine Injection	New	BC & D OPERATING INC.	32.1285	-103.2850	V	1964	12,275	12,275	6,170	-	WOLFCAMP, WEST; DELAWARE
30-025-21039	WEST JAL 18 #1	Oil	Plugged (site released)	SKELLY OIL CO.	32.1276	-103.3010	No Data	1900	12,950	0	-	1/1/1900	No Data
30-025-21172	WEST JAL UNIT #1	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.1176	-103.2807	V	1961	17,086	17,086	-	4/4/1984	DELAWARE, WEST; JAL, STRAWN, WEST
30-025-21411	C ELLIOTT FEDERAL	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.143	-103.2850	V	1900	12,276	12,276	-	6/26/1993	STRAWN, WEST
30-025-25046	WEST JAL B DEEP #001	Brine Injection	Active	BC & D OPERATING INC.	32.1321	-103.2807	V	1975	18,945	18,945	14,175	-	STRAWN, WEST; WOLFCAMP, WEST; FUSSELMAN, WEST; ST-AT-MISS-DEV-FUS
30-025-26010	SPOTTED TAIL FED. #1	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2978	No Data	1900	3,336	0	-	1/1/1900	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26027	SITTING BULL A #001	Oil	Active	FULFER OIL & CATTLE LLC	32.0886	-103.2936	V	1978	3,368	3,368	-	-	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26336	FEDERAL 13 A #1	OIL	Plugged (site released)	GETTY OIL CO.	32.1367	-103.3138	V	1979	3,686	0	-	-	No Data
30-025-26809	LITTLE HAWK FEDERAL #	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2765	No Data	1900	3,690	0	-	1/1/1900	No Data
30-025-26892	SITTING BULL #2	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.085	-103.2850	No Data	1900	3,746	0	-	1/1/1900	No Data
30-025-33348	TEXACO WEST JAL 21 #001	Oil	Plugged (site released)	ENSERCH EXPLORATION INC.	32.1104	-103.2722	V	1996	7,700	7,700	-	4/25/1996	No Data
30-025-38059	DINWIDDIE STATE COM #001	Gas	Plugged (site released)	COG OPERATING LLC	32.1249	-103.2765	V	2006	12,192	12,192	-	12/12/2008	STRAWN, WEST

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-46393	NANDINA 25 36 31 FEDERAL COM #124H	Oil	New	AMEREDEV OPERATING, LLC	32.1085	-103.3052	H	-	0	23,130	-	-	WOLFCAMP, WEST
30-025-46533	SIOUX 25 36 STATE FEDERAL COM #008H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2019	12,149	22,150	22,117	-	UPPER WOLFCAMP
30-025-46551	SIOUX 25 36 STATE FEDERAL COM #009H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3175	H	2020	11,894	21,945	21,912	-	BONE SPRING
30-025-46553	SIOUX 25 36 STATE FEDERAL COM #012H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3174	H	2020	11,994	22,350	22,319	-	BONE SPRING; UPPER WOLFCAMP
30-025-46554	SIOUX 25 36 STATE FEDERAL COM #013H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2020	11,725	21,962	21,930	-	BONE SPRING; UPPER WOLFCAMP
30-025-46561	SIOUX 25 36 STATE FEDERAL COM #010H	Oil	Active	CAZA OPERATING, LLC	32.1081	-103.3176	H	2020	12,107	22,209	22,175	-	UPPER WOLFCAMP
30-025-46976	BLACK MARLIN FEDERAL COM #204H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3002	H	2020	11,640	21,953	21,895	-	WOLFCAMP, WEST
30-025-46977	BLACK MARLIN FEDERAL COM #214H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3000	H	2020	11,741	22,055	21,994	-	WOLFCAMP, WEST
30-025-48081	INDEPENDENCE AGI #001	AGI	Active	Pinon Midstream, LLC	32.1208	-103.2910	V	2020	17,709	17,900	-	-	DEVONIAN-FUSSELMAN
30-025-48577	SANTA FE FEDERAL COM #603H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3154	H	-	0	21,874	-	-	BONE SPRING
30-025-48578	SANTA FE FEDERAL COM #704H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3212	H	-	0	22,063	-	-	WOLFCAMP, WEST
30-025-48579	SANTA FE FEDERAL COM #705H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3152	H	-	0	22,129	-	-	WOLFCAMP, WEST
30-025-48580	TRINITY FEDERAL #602H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3214	H	-	0	21,938	-	-	BONE SPRING
30-025-48581	TRINITY FEDERAL #703H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3213	H	-	0	22,206	-	-	WOLFCAMP, WEST
30-025-48582	ZIA FEDERAL COM #604H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3151	H	-	0	21,973	-	-	BONE SPRING
30-025-48583	ZIA FEDERAL COM #706H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3150	H	-	0	21,973	-	-	WOLFCAMP, WEST
30-025-48614	BLUE MARLIN STATE #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3102	H	-	0	19,502	-	-	WOLFCAMP, WEST
30-025-48615	BLUE MARLIN STATE #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	-	0	19,350	-	-	WOLFCAMP, WEST
30-025-48778	BLACK MARLIN FEDERAL COM #113H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3007	H	-	0	20,014	-	-	BONE SPRING
30-025-48779	BLACK MARLIN FEDERAL COM #114H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3006	H	-	0	20,056	-	-	BONE SPRING
30-025-48780	BLACK MARLIN FEDERAL COM #203H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3005	H	2021	11,786	21,842	21,879	-	WOLFCAMP, WEST
30-025-48781	BLACK MARLIN FEDERAL COM #206H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3003	H	-	0	21,981	-	-	WOLFCAMP, WEST
30-025-48782	BLACK MARLIN FEDERAL COM #213H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3004	H	2021	0	22,140	22,073	-	WOLFCAMP, WEST
30-025-48783	BLACK MARLIN FEDERAL COM #216H	Oil	New	TAP ROCK OPERATING, LLC	32.1374	-103.2996	H	2021	0	22,258	22,258	-	WOLFCAMP, WEST

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-49115	BLUE MARLIN FEDERAL COM #111H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3105	H	-	0	20,039	0	-	BONE SPRING
30-025-49116	BLUE MARLIN FEDERAL COM #112H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3105	H	-	0	20,217	0	-	BONE SPRING
30-025-49117	BLUE MARLIN FEDERAL COM #201H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3102	H	2021	11,613	21,985	21,923	-	WOLFCAMP, WEST
30-025-49118	BLUE MARLIN FEDERAL COM #202H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	2021	11,539	21,929	21,866	-	WOLFCAMP, WEST
30-025-49119	BLUE MARLIN FEDERAL COM #205H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3101	H	2021	11,533	21,980	21,916	-	WOLFCAMP, WEST
30-025-49120	BLUE MARLIN FEDERAL COM #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3103	H	2021	12,148	22,554	22,495	-	WOLFCAMP, WEST
30-025-49121	BLUE MARLIN FEDERAL COM #215H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3057	H	2021	11,720	22,188	22,120	-	WOLFCAMP, WEST
30-025-49196	BLUE MARLIN FEDERAL COM #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3055	H	2021	12,003	22,422	22,389	-	WOLFCAMP, WEST
30-025-49528	DOGWOOD 25 36 20 FEDERAL COM #112H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2924	H	2021	0	22,356	0	-	WOLFCAMP, WEST
30-025-49626	DOGWOOD 25 36 20 FEDERAL COM #116H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2842	H	-	0	22,080	0	-	WOLFCAMP, WEST
30-025-49974	INDEPENDENCE AGI #002	AGI	New	Pinon Midstream, LLC	32.1201	-103.2910	D	2022	17,683	18,080	0	-	DEVONIAN-FUSSELMAN
30-025-50391	SIOUX 25 36 STATE FEDERAL COM #020H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	22,710	0	-	UPPER WOLFCAMP
30-025-50392	SIOUX 25 36 STATE FEDERAL COM #021H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	20,244	0	-	BONE SPRING
30-025-50393	SIOUX 25 36 STATE FEDERAL COM #022H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	22,539	0	-	UPPER WOLFCAMP
30-025-50394	SIOUX 25 36 STATE FEDERAL COM #023H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	20,120	0	-	BONE SPRING

Appendix 4 - References

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Appendix 5 - Abbreviations and Acronyms

Abbreviations and acronyms not otherwise defined herein:

3D – 3 dimensional
API – American Petroleum Institute
CFR – Code of Federal Regulations
EOS – Equation of State
ft – foot (feet)
m – meter(s)
mg/l – milligrams per liter
MT -- Metric tonne
NG—Natural Gas
QA/QC – quality assurance/quality control
ST – Short Ton

Appendix 6 - Conversion Factors

Piñon reports CO_2 at standard conditions of temperature and pressure as defined in the State of New Mexico - 60°F and 15.025 psia (NMAC 19.15.2.7 (C)(16))

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the NIST. This online database is available at:
http://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner EOS at a wide range of temperatures and pressures. At State of New Mexico standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.0027097 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2204.62\ lbs}$$

Where:

$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$

$Density_{CO2} = 0.0027097$

$MW_{CO2} = 44.0095$

$$Density_{CO2} = 5.4092\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.4092\ x\ 10^{-2}\ \frac{MT}{Mcf}$$

The conversion factor 5.4092 x 10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Appendix 7 - Independence 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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \qquad \text{(Equation RR-1 for Pipelines)}$$

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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \qquad \text{(Equation RR-1 for Containers)}$$

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

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

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \qquad \text{(Equation RR-3 for Pipelines)}$$

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

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \qquad \text{(Equation RR-4)}$$

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

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \qquad \text{(Equation RR-5)}$$

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

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \qquad \text{(Equation RR-6)}$$

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

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

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.

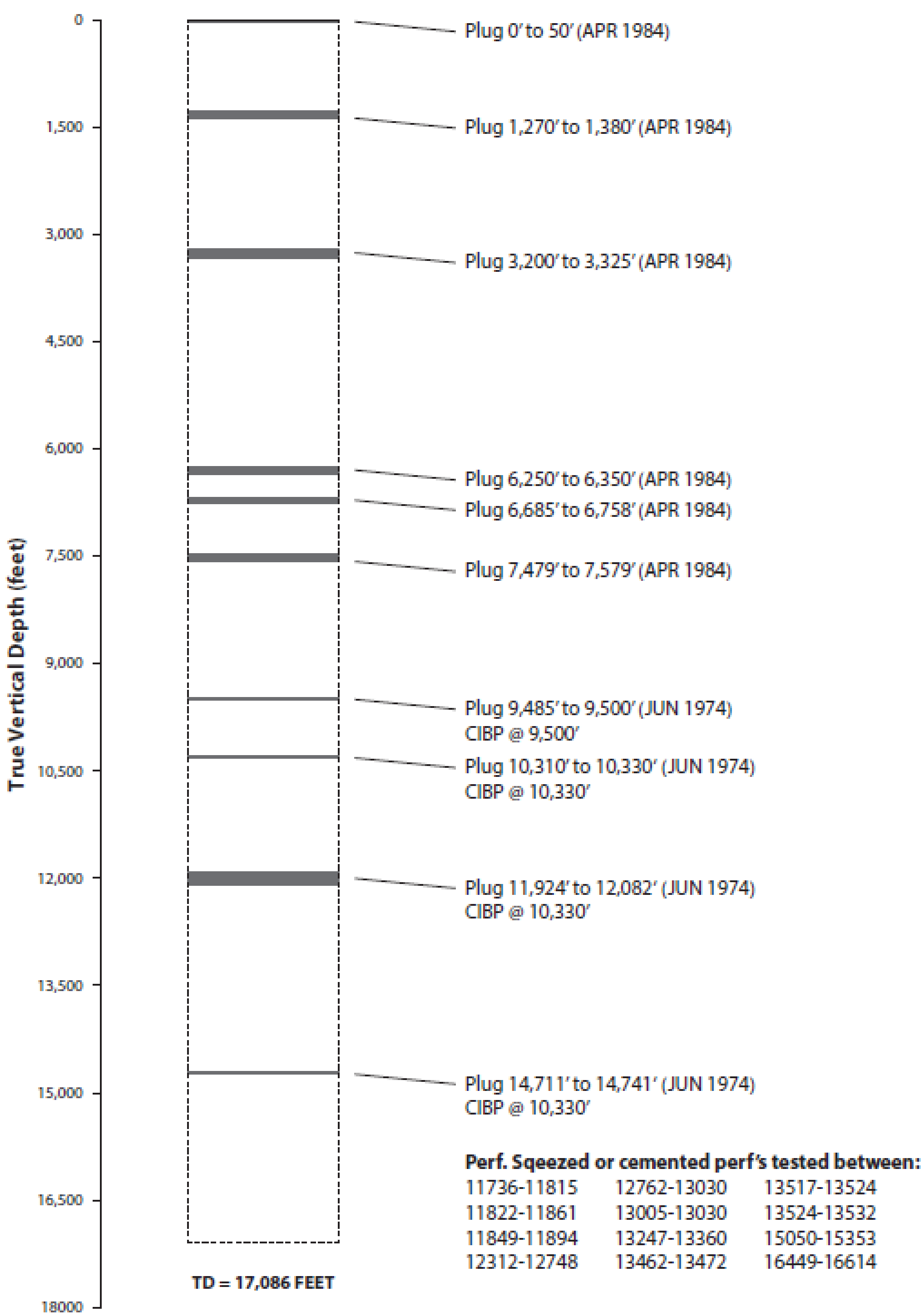
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

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 - Plugging Records for West Jal Unit #1

TEXACO EXPLORATION AND PROD. - WEST JAL UNIT #1 PLUGGING DIAGRAM

Lease Name:	West Jal Unit #1	**Footage:**	1980 FNL and 660 FEL
API:	30-025-21172	**Well Type:**	Oil
Location:	Sec. 20, T25S, R36E	**Total Depth:**	17,086′
County, State:	Lea County, New Mexico	**Coordinates:**	32.117596, -103.280739 (NAD83)



*Schematic is properly scaled

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P. 0. BOX 1980
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UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Buluu No. 1004-0135
Expires: March 31, 1993

5. Lease Designation and Serial No.
NJ

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT-" for such proposals

SUBMIT IN TRIPLICATE

7. If Unit or CA, Agreement Designation

1. Type of Well
[X] Oil Well [ ] Gas Well [X] Other Reentry

8. Well Name and No.
f JA-/t:Jt!JLA-fry

2. Name of Operator
MCH Petroleum Services

9. API Well No.
c30-025-2/112

3. Address and Telephone No.
-:1:)1 W. Pin St: Midland, Tx 79705 915 683 4772

10. Field and Pool, or Exploratory Area
~~Undesignated~~ W.-Sal Delaware

4. Location of Well (footage, Sec., T., R., M., or Survey Description)
/'f4!0 PAt ,o F=G1- -S Z.0, r- zs-s, 11- 'It =
H S£NE .6J•,)1 h\.

11. County or Parish, State
Lea, NM

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

TYPE OF SUBMISSION	TYPE OF ACTION	
[g] Notice of Intent	D Abandonment	0 Change of Plans
	Recompletion	D New Construction
[J Subsequent Report	D Plugging Back	0 Non-Routine Fracturing
	D Casing Repair	[ ] Water Shut-Off
[ ] Final Abandonment Notice	D Altering Casing	D Conversion to Injection
	Other eNtAy	D Dispose Water
		(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abandoned by Texaco in 1983. MCH will drill out cement plugs and cibp@ 7,579' to a total depth of approx. 8,350'(in-s;ide casing). This will leave in place cibp at 9,500' and deeper. We will then test E!Xisting perforations@ 7,807'-7,857' and stimulate as necessary.
Mud Program: Fresh water will be used for the reentry inside casing.
BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO
GENERAL REQUIREMENTS AND
SPECIAL STIPULATIONS
ATTACHED

14. I hereby certify that the foregoing is true and correct
Signed Craig Huber Title Owner Date 4/13/93

(This space for Federal or State office use)
Approved by '" 1ITC &r.n L MAron; Title AR-A MANAG. Date JUN 4 1993
Conditions of approval, if any:

Title 18 U.S.C. Section 1001, makes 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.

*See Instruction on Reverse Side

G 31

Form 3160-3
(December 1990)

SUBMIT IN TRI[illegible]TE*
(Other instructions o.. reverse side)

Form approved.
Budget Bureau No. 1004-0136
Expires: December 31, 1991

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR DEEPEN

5. LEASE DESIGNATION AND SERIAL NO. NM 71792

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME, WELL NO. West JAL Federal #1

9. API WELL NO. 30-025-21172

10. FIELD AND POOL, OR WILDCAT ~~Abandoned~~ W. Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA S-20, T-25S, R36E

12. COUNTY OR PARISH Lea

13. STATE NM

1a. TYPE OF WORK DRILL ☐ DEEPEN ☐

b. TYPE OF WELL OIL WELL ☒ GAS WELL ☐ OTHER Reentry SINGLE ZONE ☒ MULTIPLE ZONE ☐

2. NAME OF OPERATOR MCH Petroleum Services

3. ADDRESS AND TELEPHONE NO. 708 W. Pine St. Midland, Tx 79705 915 683 4772

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*)
At surface 1980' FNL, 660' FEL Sec 20 T-25S, R-36E Lea Co. NM
At proposed prod. zone SAme H SENE

14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE* 6 miles W. Jal, N.M.

15. DISTANCE FROM PROPOSED* LOCATION TO NEAREST PROPERTY OR LEASE LINE, FT. (Also to nearest drlg. unit line, if any) 660'

16. NO. OF ACRES IN LEASE 600

17. NO. OF ACRES ASSIGNED TO THIS WELL 40

18. DISTANCE FROM PROPOSED LOCATION* TO NEAREST WELL, DRILLING, COMPLETED, OR APPLIED FOR, ON THIS LEASE, FT.

19. PROPOSED DEPTH 8350

20. ROTARY OR CABLE TOOLS Pulling unit / Reverse unit

21. ELEVATIONS (Show whether DF, RT, GR, etc.) 3076' GL

22. APPROX. DATE WORK WILL START* ASAP (Prior to 6/1/93 exp.)

23. PROPOSED CASING AND CEMENTING PROGRAM

SIZE OF HOLE	GRADE, SIZE OF CASING	WEIGHT PER FOOT	SETTING DEPTH	QUANTITY OF CEMENT
26	20		869' (In Place)	1630 sx.
17 1/2	13 3/8	72, 68, 64	6300' (In Place)	3606 sx.
12 1/4	9 5/8	53.5, 47, 43.5	11,736 (In Place)	775 sx.
8 3/4	7	26	6735-12213 (Shot off @ 6735)	612 sx
6 1/4	5 1/2 (LNR.)	(unk.)	12,032-15,400	450 sx.
(unk)	3 1/2 (LNR.)	(unk)	14,967-17,084	250 sx.

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abondoned by Texaco in 1983. MCH will drill out cement plugs and cibp @ 7,579' to a total depth of approx. 8,350' (inside casing). This will leave in place cibp at 9,500' and deeper. We will then test existing perforations @ 7,807'-7,857' and stimulate as necessary.

Mud Program: Fresh water will be used for the reentry inside casing.

BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO GENERAL REQUIREMENTS AND SPECIAL STIPULATIONS ATTACHED

IN ABOVE SPACE DESCRIBE PROPOSED PROGRAM: If proposal is to deepen, give data on present productive zone and proposed new productive zone. If proposal is to drill or deepen directionally, give pertinent data on subsurface locations and measured and true vertical depths. Give blowout preventer program, if any.

24. SIGNED Craig Huber TITLE Owner DATE 4/13/93

(This space for Federal or State office use)

PERMIT NO. ______ APPROVAL DATE ______

Application approval 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.
CONDITIONS OF APPROVAL, IF ANY:

APPROVED BY ______ TITLE ______ DATE ______

*See Instructions On Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

Form 3160–5
(November 1983)
(Formerly 9–331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

P. O. BOX 1980
HOBBS, NEW MEXICO 88240

Form approved.
Budget Bureau No. 1004–0135
Expires August 31, 1985

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—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO.: NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

1. OIL WELL [X] GAS WELL [ ] OTHER

7. UNIT AGREEMENT NAME: West Jal Unit

2. NAME OF OPERATOR: Getty Oil Company

8. FARM OR LEASE NAME:

3. ADDRESS OF OPERATOR: P.O. Box 730, Hobbs, NM 88240

9. WELL NO.: 1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

Unit Ltr. H, 1980' FNL & 660' FEL

10. FIELD AND POOL, OR WILDCAT: West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: Sec. 20, T-25S, R-36E

BUREAU OF LAND MANAGEMENT RECEIVED APR ... DIST. 6 N. M. ROSWELL, NEW MEXICO

14. PERMIT NO.:

15. ELEVATIONS (Show whether DF, RT, GR, etc.): 3138' D.F.

12. COUNTY OR PARISH: Lea

13. STATE: NM

16. **Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data**

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	[ ]	PULL OR ALTER CASING	[ ]	WATER SHUT-OFF	[ ]	REPAIRING WELL	[ ]
FRACTURE TREAT	[ ]	MULTIPLE COMPLETE	[ ]	FRACTURE TREATMENT	[ ]	ALTERING CASING	[ ]
SHOOT OR ACIDIZE	[ ]	ABANDON*	[ ]	SHOOTING OR ACIDIZING	[ ]	ABANDONMENT*	[XX]
REPAIR WELL	[ ]	CHANGE PLANS	[ ]	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

3/26/84 Rigged up. Pulled rods and pump. Unseat tbg. anchor and install BOP.
3/28/84 Pulled 2 7/8" buttress & 2 3/8" tbg. anchor. Ran 7" CI plug, set @ 7579'. Ran 2 3/8" to 4290'. By Halliburton, circ. 191 bbls. gel brine, pulled tbg. Perfs 4-0.25" holes @ 6400'. Circ. out 7" between 9 5/8". Ran 2 7/8" to 7554'.
3/29/84 Rigged up csg. puller unit. Pulled tbg. Remove BOP & 7" tbg. spool.
3/30/84 Weld 7" pull nipple. Cut 7" csg. @ 6735'. Pulled 11 jts 7", 26#, P-110 csg. 8 rd.
3/31/84 Layed down total 163 jts (est. 6525') 7", 8rd casing. Nipple down 9 5/8" head.
4/2/84 Weld on 9 5/8" pulled nipple. Attempted to pull slips with 500,000#. Set off primer cord around head, no movement. Left soaking in penetrating oil.
4/3/84 Dug out 13 3/8" csg. unflange head. Move pipe 1" with 600,000#. Cut off. Pulled nipple, installed BOP. Ran tbg to 5216'.
4/4/84 Spot 20 sxs cement on top of CIBP 7579-7479'. Spot 100' plug (45 sxs) at 6758-6685', 6350-6250', 3325-3200', 1380-1270'. Remove csg. head.
4/5/84 Rigged down. Installed 20 sxs. Plugged 0-50'. Installed dry hole marker. P&A.

18. I hereby certify that the foregoing is true and correct

SIGNED Donald J. Steinner TITLE Area Superintendent DATE April 11, 1984

for Dale R. Crockett

(This space for Federal or State office use)

Orig. Sgd. ...

APPROVED BY ... TITLE ... DATE 6 8 8 7

CONDITIONS OF APPROVAL, IF ANY:

0+6-BLM-Roswell 1-Mr. J.A.-Midland
1-File 1-Laura Richardson-Midland
1-Engr Jim 1-BB, 1-JA
1-Foreman CK 1-SH, 1-CP 1-Southland Royalty Company, 1-ARCO

Approved as to plugging of the well bore. Liability under bond is retained until surface restoration is completed.

***See Instructions on Reverse Side**

Title 18 U.S.C. Section 1001, makes 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.

N. M. OIL CONS. COMMISSION
P. O. BOX 1980
HOBBS, NEW MEXICO 88240

O+6 - BLM - P.O. Box 1857, Roswell, 1-File, 1-Engr.JIM, 1-Foreman CK

Form 9-331
Dec. 1973

1 - Laura Richardson-Midland

Form Approved.
Budget Bureau No. 42-R1424

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

BUREAU OF LAND MANAGEMENT
RECEIVED
JUL 25 1983
DIST. 6 N. M.
ROSWELL, NEW MEXICO

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 Form 9-331-C for such proposals.)

1. oil well XX gas well ☐ other

2. NAME OF OPERATOR
Getty Oil Company

3. ADDRESS OF OPERATOR
P.O. Box 730 Hobbs, NM 88240

4. LOCATION OF WELL (REPORT LOCATION CLEARLY. See space 17 below.)
AT SURFACE: Unit ltr. H, 1980' FNL & 660 FEL
AT TOP PROD. INTERVAL:
AT TOTAL DEPTH:

5. LEASE
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME
West Jal Unit

9. WELL NO.
1

10. FIELD OR WILDCAT NAME
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, 25S-36E

12. COUNTY OR PARISH
Lea

13. STATE
NM

14. API NO.

15. ELEVATIONS (SHOW DF, KDB, AND WD)
3138' D.F.

16. CHECK APPROPRIATE BOX TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

	REQUEST FOR APPROVAL TO:	SUBSEQUENT REPORT OF:
TEST WATER SHUT-OFF	☐	☐
FRACTURE TREAT	☐	☐
SHOOT OR ACIDIZE	☐	☐
REPAIR WELL	☐	☐
PULL OR ALTER CASING	☐	☐
MULTIPLE COMPLETE	☐	☐
CHANGE ZONES	☐	☐
ABANDON*	XX	☐
(other) Revised		

(NOTE: Report results of multiple completion or zone change on Form 9-330.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

Revised procedure as per conversation with Mr. Peter Chester 7/18/83:

1. Install B.O.P.
2. Set C.I.B.P. at ±7860 w/35' cement on top.
3. Perforate 2 holes @ 6375' & squeeze with sufficient cement to bring cement to 6225'.
4. Set cement plug 1230-1330' top of salt. (in & behind casings).
5. Set 50' surface plug.
6. Install dry hole marker.
7. Restore location.

Subsurface Safety Valve: Manu. and Type ______ Set @ ______ Ft.

18. I hereby certify that the foregoing is true and correct

SIGNED Dale R. Crockett TITLE Area Superintendent DATE July 22, 1983

APPROVED

(This space for Federal or State office use)

APPROVED BY (Orig. Sgd.) ... M. CHESTER TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

SEP 14 1983

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

5. LEASE DESIGNATION AND SERIAL NO.: NM-03429-A

WELL COMPLETION OR RECOMPLETION REPORT AND LOG *

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: - - - - - -

1a. TYPE OF WELL: OIL WELL [X] GAS WELL [ ] DRY [ ] Other

7. UNIT AGREEMENT NAME: - - - - - -

b. TYPE OF COMPLETION: NEW WELL [ ] WORK OVER [ ] DEEP-EN [ ] PLUG BACK [X] DIFF. RESVR. [X] Other

8. FARM OR LEASE NAME: West Jal Unit

2. NAME OF OPERATOR: Skelly Oil Company

9. WELL NO.: 1

3. ADDRESS OF OPERATOR: P. O. Box 1351, Midland, Texas 79701

10. FIELD AND POOL, OR WILDCAT: UNDESIGNATED Jal Delaware, West

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface: Unit Letter H, 1980' FNL and 660' FEL, Sec. 20-25S-36E
At top prod. interval reported below
At total depth

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec. 20-25S-36E

14. PERMIT NO. | DATE ISSUED

12. COUNTY OR PARISH: Lea
13. STATE: New Mexico

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
- -	- -	5-28-74	3138' DF	- - -

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
17086'	9485' PBTD	- -	→	- -	- -

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*
7807-7857' Delaware

25. WAS DIRECTIONAL SURVEY MADE: - - -

26. TYPE ELECTRIC AND OTHER LOGS RUN: None

27. WAS WELL CORED: - -

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
No Change					

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
-	-	-	-	-
-	-	-	-	-

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-3/8"OD	7941'	- -
2-7/8"OD		- -

31. PERFORATION RECORD (Interval, size and number)
7807-7811', 7816-7818', 7833-7857', total 32 shots, 0.50" diameter, two shots per foot.

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
7807-7857'	750 gallons mud acid 5000 gallons 15% NE acid, 82 ball sealers, 9000# 20-40 sand, 9000 gallons lease oil

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
5-28-74	Pumping	Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
6-19-74	24	-	→	63	1	6	16

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
- -	63#	→	63	1	6	41°

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.): Used for Fuel

TEST WITNESSED BY

35. LIST OF ATTACHMENTS: None

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED (Signed) D. R. Crow D. R. Crow TITLE Lead Clerk DATE 6-20-74

*(See Instructions and Spaces for Additional Data on Reverse Side)

INSTRUCTIONS

General: This form is designed for submitting a complete and correct well completion report and log on all types of lands and leases to either a Federal agency or a State agency, or both, pursuant to applicable Federal and/or State laws and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local, area, or regional procedures and practices, either are shown below or will be issued by, or may be obtained from, the local Federal and/or State office. See instructions on items 22 and 24, and 33, below regarding separate reports for separate completions.

If not filed prior to the time this summary record is submitted, copies of all currently available logs (drillers, geologists, sample and core analysis, all types electric, etc.), formation and pressure tests, and directional surveys, should be attached hereto, to the extent required by applicable Federal and/or State laws and regulations. All attachments should be listed on this form, see item 35.

Item 4: If there are no applicable State requirements, locations on Federal or Indian land should be described in accordance with Federal requirements. Consult local State or Federal office for specific instructions.

Item 18: Indicate which elevation is used as reference (where not otherwise shown) for depth measurements given in other spaces on this form and in any attachments.

Items 22 and 24: If this well is completed for separate production from more than one interval zone (multiple completion), so state in item 22, and in item 24 show the producing interval, or intervals, top(s), bottom(s) and name(s) (if any) for only the interval reported in item 33. Submit a separate report (page) on this form, adequately identified, for each additional interval to be separately produced, showing the additional data pertinent to such interval.

Item 29: "*Sacks Cement*": Attached supplemental records for this well should show the details of any multiple stage cementing and the location of the cementing tool.

Item 33: Submit a separate completion report on this form for each interval to be separately produced. (See instruction for items 22 and 24 above.)

37. SUMMARY OF POROUS ZONES:
SHOW ALL IMPORTANT ZONES OF POROSITY AND CONTENTS THEREOF; CORED INTERVALS; AND ALL DRILL-STEM TESTS, INCLUDING DEPTH INTERVAL TESTED, CUSHION USED, TIME TOOL OPEN, FLOWING AND SHUT-IN PRESSURES, AND RECOVERIES

38. GEOLOGIC MARKERS

FORMATION	TOP	BOTTOM	DESCRIPTION, CONTENTS, ETC.	NAME	TOP: MEAS. DEPTH	TOP: TRUE VERT. DEPTH

1) Squeezed Fusselman perfs. 16,449-16,614' with 100 sacks Class "H" cement, 5/10% CFR-2.
2) Spotted 25 sacks cement 14,711-14,741', 25 sacks 11,924-12,082' and set cast iron bridge plug at 10,330' and spotted 4 sacks cement 10,310-10,330'.
3) Perforated 7" OD casing in First Bone Springs formation with two 0.48 diameter holes per foot at 10,112-10,122' and 10,128-10,132'. (28 shots total)
4) Treated First Bone Springs perfs. 10,112-10,132 with 5500 gallons acid and 68 ball sealers.
5) Swab tested First Bone Springs perfs. 10,112-10,132' May 14, 1974, to May 21, 1974, for no oil, 14 bbls. water and slight show of gas in 5 hours.
6) Set cast iron bridge plug at 9500' and cemented with 3 sacks cement plugging back to 9485'.
7) Perforated 7" OD casing in Delaware formation with two 0.50" diameter holes per foot at 7807-7811', 7816-7824' and 7853-7857'. (32 shots total)
8) Treated Delaware perfs. 7807-7857' with 750 gallons mud acid, 5000 gallons 15% NE acid, 9000 gallons gelled lease oil, 9000# 20-40 sand and 22 ball sealers.
9) Returned well to production status 5-28-74 pumping Delaware perfs. 7807-7857' for 63 bbls. oil, 6 bbls. water and 1 MCFGPD.

U.S. GOVERNMENT PRINTING OFFICE : 1963—O-683636

871-233

8) Flowed 24-1/2 hours through 1" choke, making no oil, 45 bbls. load water, 393 bbls. formation water and gas at rate of 266 MCF per day. FTP 200#, CP 2300#.
9) Ran flow meter, Gradionometer and Temperature Survey to determine water entry.
10) Shut well in seven hours, then ran Base Temperature Log 16,000-17,020'. Water channelling from bottom of well bore to 16,508'.
11) Set cement retainer at 16,250' and squeezed perfs. 16,499-16,614' with 150 sacks Class "H" cement containing 4/10ths of 1% CFR-2 and 1% Halad 9. Squeeze failed. WOC 4 hours.
12) Resqueezed perfs. 16,449-16,614' with 50 sacks Class "H" cement with 1% Halad 9, 4/10ths of 1% CFR-2 and 1/4# Flocele per sack and 150 sacks Class "H" containing 1% Halad 9 and 4/10ths of 1% CFR-2. Squeeze failed.
13) Attempted to pull cement retainer - stuck.
14) Milled and pushed cement retainer from 16,250' to 16,490'. Recovered cement retainer.
15) Drilled and pushed junk to 16,930'.
16) Ran 254 jts. (14,793') of 2-7/8" OD tubing and set packer at 14,810'. Swabbed 9 hours, recovering 60 bbls. load water with good show of gas.
17) Treated perfs. 16,449-16,614' with 500 gals. 15% NE acid with 2 ball sealers. Swabbed 7 hours, recovering 1 bbl. load water, flowing gas at rate of 50 MCF per day.
18) Treated perfs. 16,449-16,614' with 5000 gals. 15% NE acid and 27 ball sealers.
19) Ran Temperature Survey 15,000-16,958'.
20) Tested well. Well flowed at rate of 910 MCF per day on 23/64" choke, no oil, FTP 310#. Pulled tubing and packer.
21) Reran 457 jts. (14,940') of 2-7/8" OD 7.9# DSS-HT Atlas-Bradford Condition "A" tubing and set at 14,967'.
22) Circulated hole with corrosion inhibitor water. Released rig 11-8-72. Flowed and tested well.
23) On Dec. 11, 1972, treated perfs 16,449-16,614' with 12,500 gals. of 1% KCL water with 62# friction reducer, 25 gals. Adofoam and 25 gals. scale inhibitor, 20,000 gals. 20% retarded acid with 100# friction reducer, 40 gals. Adofoam, 160 gals. acid inhibitor, 1000# fluid loss agent and 40 gals. scale inhibitor and 7 ball sealers. All fluid contained 400 S.C.F Nitrogen per barrel.
24) Testing well.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

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—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO.: NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: —

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME: —

2. NAME OF OPERATOR: Skelly Oil Company

8. FARM OR LEASE NAME: West Jal Unit

3. ADDRESS OF OPERATOR: P. O. Box 1351, Midland, TExas 79701

9. WELL NO.: 1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT: Undesignated Fusselman

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: Sec. 20-25S-36E

14. PERMIT NO.:

15. ELEVATIONS (Show whether DF, RT, GR, etc.): 3076' GR

12. COUNTY OR PARISH: Lea

13. STATE: New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Clean out & deepen to 17,086'	x		
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

1) Rigged up rotary tools 7-28-72. Pulled tubing and packer.
2) Set cement retainer at 11,390' and squeezed Strawn 7" OD casing perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 1% CFR-2 and 3# sand per sack. Squeeze failed. WOC 4 hours.
3) Resqueezed perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 5/10% of 1% CFR-2 and 3# sand per sack. Squeezed at 6500#. Reversed out 15 sacks.
4) After WOC 12 hours, drilled cement retainer at 11,390' and cement 11,390-11,755' with 6-1/2" bit.
5) Tested squeeze job to 3000#; held okay.
6) Drilled cement 11,790-11,832' and tested old squeeze job on perfs. 11,736-11,815' to 3000#; held okay.
7) Drilled cement 11,832-11,844'; pushed plus-plug to 11,976'. Drilled plug. Tagged junk at 12,002' and pushed to 12,312'.
8) Cleaned to top of 5-1/2" OD liner at 12,032', set cement retainer at 11,820' and found casing perfs. 11,849-11,894' open.
9) Squeezed 5-1/2" casing perfs. 11,849-11,894' with 50 sacks Class "H" with 1% CFR-2 and 100 sacks Class "H" with 1% CFR-2 and 3# sand per sack.
10) Dumped 20 sacks cement on retainer at 11,820', plugging back to 11,717'. Reversed out 90 sacks cement. WOC 12 hours.

(continued on page 2)

18. I hereby certify that the foregoing is true and correct

SIGNED ______ TITLE Lead Clerk DATE Dec. 18, 1972

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______
CONDITIONS OF APPROVAL, IF ANY:

ACCEPTED FOR RECORD
DEC 20 1972
U. S. GEOLOGICAL SURVEY
HOBBS, NEW MEXICO

*See Instructions on Reverse Side

West Jal Unit
Well No. 1
Lea Co., New Mexico
Page 2

11) Drilled cement 11,708-11,820'; cement retainer 11,820-11,822' and cement 11,822-11,861'. Cleaned out to top of liner at 12,032'.
12) Tested squeeze job to 2500#; held okay.
13) Drilled junk 12,312-12,748.5'; cement 12,748.5-12,760'; junk to 12,762'; cement 12,762-13,030'.
14) Tested old squeezed perfs. 13,005-13,030' to 2500#; held okay.
15) Milled and drilled cast iron bridge plug at 13,174' and pushed to 13,395'.
16) Tested 5-1/2" OD liner perfs. 13,247-13,360' to 2900#; could not pump into perfs.
17) Milled cast iron bridge plug 13,396-13,400'.
18) Tested perfs. 13,462-13,472' to 2700#; could not pump into perfs.
19) Milled and drilled out cement retainer 13,517-13,524'; cement 13,524-13,532'; cement 15,050-15,353'.
20) Milled and drilled cast iron bridge plug 15,340-15,858'. Washed over fish 15,858'; recovered fish. Cleaned out to old TD of 15,958'.
21) Drilled 4-3/4" new hole 15,958-16,498'.
22) Ran Drill Stem Test No. 1 (Silurian) 15,400-16,498'.
23) Drilled 4-3/4" hole 16,498' to total depth of 17,086' at 11 p.m. October 4, 1972.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instruction on reverse side)

Form approved. Budget Bureau No. 42-R1424.

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—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO.: NM - 03429 - A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: - - -

7. UNIT AGREEMENT NAME: - - -

1. OIL WELL ☐ GAS WELL ☒ OTHER

2. NAME OF OPERATOR: Skelly Oil Company

8. FARM OR LEASE NAME: West Jal Unit

3. ADDRESS OF OPERATOR: P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.: 1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Section 20-25S-36E

10. FIELD AND POOL, OR WILDCAT: Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: 20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.): 3102' DF

12. COUNTY OR PARISH: Lea

13. STATE: New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF ☐ PULL OR ALTER CASING ☐
FRACTURE TREAT ☐ MULTIPLE COMPLETE ☐
SHOOT OR ACIDIZE ☐ ABANDON* ☐
REPAIR WELL ☐ CHANGE PLANS ☐
(Other)

SUBSEQUENT REPORT OF:

WATER SHUT-OFF ☐ REPAIRING WELL ☐
FRACTURE TREATMENT ☐ ALTERING CASING ☐
SHOOTING OR ACIDIZING ☐ ABANDONMENT* ☐
(Other) Cement, perforate & treat ☒

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

1) Perforated 2-7/8"OD tubing at 11,696',11,297', 10,574; 9698'; 8892';8707',8403'. Circulated to remove mud from annulus. Work began 1-29-69.
2) Pulled tubing
3) Ran 2-7/8"OD tubing with "RTTS" Packer. Set packer at 11,448'.
4) Squeezed 7"OD casing perforations 11,736-11,894' with 150 sacks class "H" Cement with 1% CFR-2 per sack, maximum pressure 4600#, failed. W.O.C. 4 hours. Broke formation down with 5000#.
5) Squeezed 7"OD casing perforations 11,736-11,894" with 50 sacks Class "H" cement with 1% CFR-2 and 5# No. 3 sand per sack. Displaced 35 sacks into formation. Pulled tubing and packer.
6) WOC 36 hours. Ran tubing with 6-1/8" bit. Top of cement inside 7"OD casing at 11,595'. Washed and circulated cement to 11,620'. Drilled cement 11,620-11,700'. Drilled packer 11,700-705'. Drilled cement 11,705-755'.
7) Tested casing to 3000#, held okay.
8) Spotted 12 bbls. acid 11,755-11,443'.
9) Perforated 7"OD casing with 2 shots per foot as follows:

11,510 - 513'	3'	6 shots
11,517- 527'	10'	20 shots
11,536 - 540'	4'	8 shots
11,550 - 556'	6'	12 shots
11,561 - 567'	6'	12 shots
11,575 - 579'	4'	8 shots
11,660 - 667'	7'	14 shots

18. I hereby certify that the foregoing is true and correct

SIGNED ________ TITLE District Production Manager DATE 3-10-69

(This space for Federal or State office use)

APPROVED BY ________ TITLE (ORIGINAL SIGNED) V. H. Fletcher
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
MAR 11 1969
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
~~73503~~ NM-034291-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
----

7. UNIT AGREEMENT NAME

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

2. NAME OF OPERATOR
Skelly Oil Company

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*
See also space 17 below.)
At surface **1980 from North line and 660 from East line, Section 20**

20-25S-36E

8. FARM OR LEASE NAME
West Jal Unit

9. WELL NO.
1

10. FIELD AND POOL, OR WILDCAT
Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3092' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other)			☐
(Other) **Cement, Perforate & Treat**			☒	(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)			

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

Squeeze present perforated interval 11,736-11,852', below packer set at 11,700', with 125 sacks cement. Drill out to 11,790'. Perforate 11,510-11,783' with 2 shots per foot. Treat perforations 11,510-11,783' with 300 gallons 15% acid with 3 stage treatment using Dowell J-182 as diverting agent. Inject 72 barrels distillate to remove diverting agent. Swab and test.

18. I hereby certify that the foregoing is true and correct

SIGNED (Signed) C. R. DAVIS TITLE **District Operations Manager** DATE **1/24/69**

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
JAN 2_ 1969
J. L. GORDON
ACTING DISTRICT ENGINEER

RT/jc

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- -

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
- -

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*
See also space 17 below.)
At surface

1980' from North line and 660' from East line

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.
- -

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138'

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐
REPAIR WELL	☐	CHANGE PLANS	☐
(Other)			

SUBSEQUENT REPORT OF:

WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
(Other) Eliminate water production			☒

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

(1) Moved in and rigged up workover rig 10-21-68
(2) Set Schlumberger "plus" plug in 7"OD casing at 11,844'.
(3) Dumped 5' cement on top of plug, filling from 11,844' to 11,839'.
(4) Dumped 200 lbs. Hydromite on top of "plus" plug, filling back to 11,832'.
(5) Swabbed well.
(6) Apparent communications still exist between upper and lower perforations behind 7"OD casing. Objective to shut off lower perforations 11,860 - 11,894' and to decrease water production unsuccessful.
(7) Well returned to producing status 10-27-68 flowing 150 MCF gas per day through 7" OD casing perforations 11,736 - 11,894'.

18. I hereby certify that the foregoing is true and correct

SIGNED [signature] TITLE District Production Manager DATE 10-30-68

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ APPROVED
CONDITIONS OF APPROVAL, IF ANY:

NOV 1968
J L GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429 - A

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—" for such proposals.)

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
-----

1. OIL WELL ☐ GAS WELL XX OTHER

7. UNIT AGREEMENT NAME
-----

2. NAME OF OPERATOR
SKELLY OIL COMPANY

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

1980' FNL & 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO.
-----

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Clean, Determine Water Source, Eliminate Water Production			X
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

Moved in and rigged up Workover Rig. Killed well. Ran 1-5/8" drill pipe and fishing tools to top of fish at 9901', pushed to 9991', caught fish, circulated and pulled out of hole. Recovered 2 strings of fishing tools previously left in hole. Reran 1-5/8" drill pipe several times with fishing tools and recovered 1786' in several pieces of 5/16" wire line, and a chemica cutter.

Tagged bottom of 2-7/8"OD tubing at 11,715'. Knocked off one foot of tubing and a bull plug that had been previously cut off. Pushed and drove bull plug to 12,482'. Hit firm fill-up of formation cavings and left one-foot piece of 2-7/8"OD tubing and bull plug in hole at 12,482', leaving tubing open-ended at 11,715' with full 2-7/8" opening. Pulled drill pipe and fishing tools and installed Xmas tree. Ran Gradiomanometer, Continuous Flowmeter and Packer Flowmeter to determine water source. Surveys indicated water source being produced through casing perfora tions 11,883-11,894'.

Set packer at 11,883'. Returned to production status November 19, 1967, producing 38 bbls. oil, 800 bbls. water and 2,000 MCF gas per day from the Strawn Gas Pool through perforations 11736-11894' through 7"OD casing.

18. I hereby certify that the foregoing is true and correct

SIGNED (ORIGINAL SIGNED) V. E. Fletcher TITLE District Superintendent DATE April 25, 1968

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
APR 26 1968
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE*
(See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. LEASE DESIGNATION AND SERIAL NO.: NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: ---

7. UNIT AGREEMENT NAME: ---

8. FARM OR LEASE NAME: West Jal Unit

9. WELL NO.: 1

10. FIELD AND POOL, OR WILDCAT: Undesignated Fusselman

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec. 20-25S-36E

12. COUNTY OR PARISH: Lea

13. STATE: New Mexico

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL ☒ DRY ☐ Other

b. TYPE OF COMPLETION: NEW WELL ☐ WORK OVER ☒ DEEP-EN ☒ PLUG BACK ☐ DIFF. RESVR. ☒ Other

2. NAME OF OPERATOR: Skelly Oil Company

3. ADDRESS OF OPERATOR: P. O. Box 1351, Midland, Texas 79701

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface 1980' FNL and 660' FEL Sec. 20-25S-36E
At top prod. interval reported below
At total depth

14. PERMIT NO.   DATE ISSUED

15. DATE ~~SPUDDED~~ started	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
7-28-72	11-1-72	10-4-72	3076' GR	---

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
17,086'	17,020'	---	→	15,958-17,086'	---

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*
16,449-16,614' (Fusselman)

25. WAS DIRECTIONAL SURVEY MADE: No

26. TYPE ELECTRIC AND OTHER LOGS RUN: BHC Sonic Gamma Ray with Caliper, Dual Laterolog, Continuous Dipmeter, Compensated Neutron & Formation Density

27. WAS WELL CORED: No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
20"	94#	869'	26"	1630 sacks	None
13-3/8"	72,61 & 68#	6300'	17-1/2"	3206 sacks	None
9-5/8"	53.5 & 47#	11,732'	12-1/4"	975 sacks	None

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
		(See attachment)		

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-7/8"	14,967'	None

31. PERFORATION RECORD (Interval, size and number)
16,449-16,614' (Fourteen .33" holes over 165' interval)

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
11,510-11,741'	200 sacks Class "H" Cement
11,849-11,894'	150 sacks Class "H" Cement
16,449-16,614'	350 sacks Class "H" Cement
	(See attachment)

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
11-1-72	Flowing	Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
11-14-72	24	24/64"	→	-0-	5950	216	---

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
1900#	---	→	-0-	5950	216	---

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.): Sold

TEST WITNESSED BY

35. LIST OF ATTACHMENTS: 2 copies each: Borehole Compensated Sonic Log - Gamma Ray, Compensated Neutron-Formation Density, Dual Laterolog, Gammatron

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED C.J. Love TITLE Dist. Prod. Manager DATE Dec. 20, 1972

*(See Instructions and Spaces for Additional Data on Reverse Side)

2MOI1DJ5T2M1

WILL RO. !.

Set Baker Calt Iron Bridge Plug at 13,400'. Spotted 2 aacka c••nt on top of bridge plug traa 13,-00' to 1.3,386'. Perto:rated 5-1/2" OD liner with 4 holea at 13,210' and 1queezed with 85 aacka ot caat. Drill.eel out oeaeat \o 13,386'• Perforated S-1/2" liner with 4 ahota per foot •• followa1 13,247-13,2'10', 13,272-1.3,275', 13,286-13,292', 13,298-13,320', 13,326-13,329', 1.3,343-13,345', 13,)56-13,360' tor a total ot 63• and 252 hol••• Treated tbroqh S-1/2" OD caaing liner pert•• 13,247-13,360' (intenala) with 2500 gallon• Mud Acid. Teated .-.11 Hftr&I houn with -n,lae to aall to meanre. Treated through 5-1/2" OD caeing liner perta. 13,21.7-13,360' (intenala) with 2500 gallons Mud Acid.. t'eelMI •li-'.aeveral hN. with TOIUM to -11 to meaaure. Treated through S-1/2" OD casing liner pert▪• 13,247-IJ,'601 (intenala) with 10,000 galana 1,- llegular Acid. Teated well aenral houri with wl1111e to .all to m•an• Set Baker Caat Iron Model "I" Bridge Plug at 13,180'• Dmlpecl 2 eacka ot cement on top ot plug, wbieh pl11g nll b&ek tra 13,180' to 1.3,166•. Pertorat.ed 5-1/2" OD liner with bole• per toot trcra 13,0051 to 13,030• for a total of 251 and 100 hol••• Treated thrcnlgh 5-1/2" OD liner perte. 13,00S-13,030' with S,000 gallons 15C Regular Acid. Teated well N'Yer&I hove with TOluae \oo ▪-ll to aeanre. We teaJ>l'?'8,ril7 abandoned the teat.inc ot the Morrow Zone at t.hie t.m, Set Halliburton "DC" C... nt Retainer at 12,790' and aqueesed 85 eaeke ot CtllHllt into 5-1/2" OD liner perte. 13,005-13,030•. Plugged back total depth 12,7901• Pertorat.ed 7" OD casing with 4 bolea per toot aa tollowa1 11,736-ll,7U', 11,781-11,787', ll,801-ll,815t, ll,&1+,-11,852', 11,860-U,894' tor a total ot 55t and 220 holea. Set Baker Model "7" Production Packer at 11,700'• Ran 2-7/8" OD 6.1+0# Bllttre•• threat! 1-80 tubing to 11,715' and ....ted in Baker Model"'" Production Packer at 11,700' with pert▪• 11,711-ll,715'. Ot.ia l.allding nipple position No. l at ll,709'. Ot.1• aid• doar ahitt. valft at U,698'. otie landing nipple poaition lo. 2 at 10,700'. otil lending nipple position lo. 3 at 9700'• Opened well up and flowed to pit to clean up. Shut well in tor 89 hove. After 89 houra with dead night T.P. 6218# flowed and teated well 1n the toll.owing anner1

nowed 1-3/4 hour▪ on 10/64" choke, opening TP 6218# (W), FTP 6156pai., gas wltae 2,737 JEPPD and 7.6') 'bbl•• ot 52 degree correeted gra'Yit7 condenaate.
lu.t. two hour▪ tlowd through 12/64• ohoke, ITP 6075 pai. (17W), gas luae 4563 KCfPD .w1i and 6.60 bbla. of condenea.te.
lut two noura fiowd throUgh 14/6'+" choke, FTP 599S pei. (DW), gae wlUM 6025 MCPPD and 1.70 bbl•• or oonden•t••
Rut one and one halt hours tLowed through 16/64" choke, PTP 5915 p▪i• (IM), gas volUM 8009 ICFPD and undetel"llined 8JI0\1llt or oonclen▪ate to pita.
Eatabliahed 24 hour In Maioo Ooneel'"fttion C.-d.eaion AOF Potential ot 310,000 tcFFD.
Completed Ja.,.17 22, 1963, a1 a "Wildcat" CCIIl.J)letion in strawn (Penn117l'Y8Bian) toraation, Total cond.enate ree0Ye17 during 7-1/4 hn. t.eet waa 22,80 bbls. to tank and undetermined aaomt to pita.

Well now ahut in - waiting on ga• connection.

POBMATIOI RECORD

From	To	!!!i		
0	12,058	12,0,s		
12,058	12,152	94		
12,152	12,477	32,	Lime & Shale	- Top Atoka 12,152'
12,477	13,366	889	Sand	- Top Morrow 12,477'
13,366	14,S83	1,217	$ale	- Top Barp,ett Shale lJ,366•
14,583	14,685	102	Lhle	- 'lop Miasiaaippian 14,853'
14,685	1,,138	453	Chert	- Top Che. 14,685'
15,138	15,518	380	Shale	- Top Wood.torcl IS 131
15,518	15,988	440	LIM & Dolaite	- Top • {'5,518'
[illegible]	I5,9SI	Total Depth		
	12,790	Plugged Back Total Depth		

Geological Tops by Schlumberger Gama Ray Sonic log

Appendix 10 - Process Flow Diagram

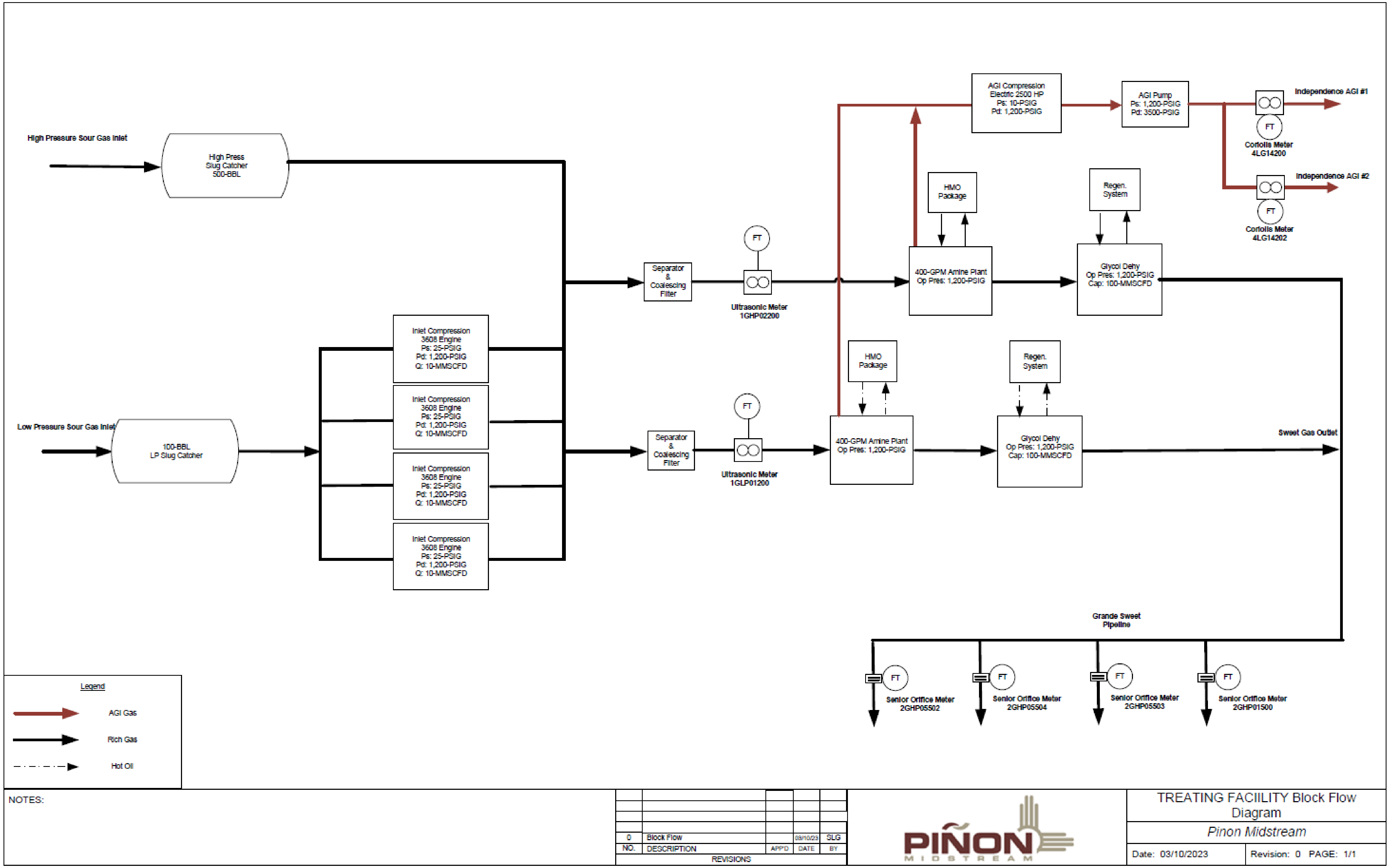


Figure A10-1: Treating Facility Block Flow Diagram

Appendix B: Submissions and Responses to Requests for Additional Information

MONITORING, REPORTING, AND VERIFICATION PLAN

Independence AGI #1 and #2 Wells

Pinon Midstream, LLC

Version Number: 5.0
Version Date: February, 2024

Contents

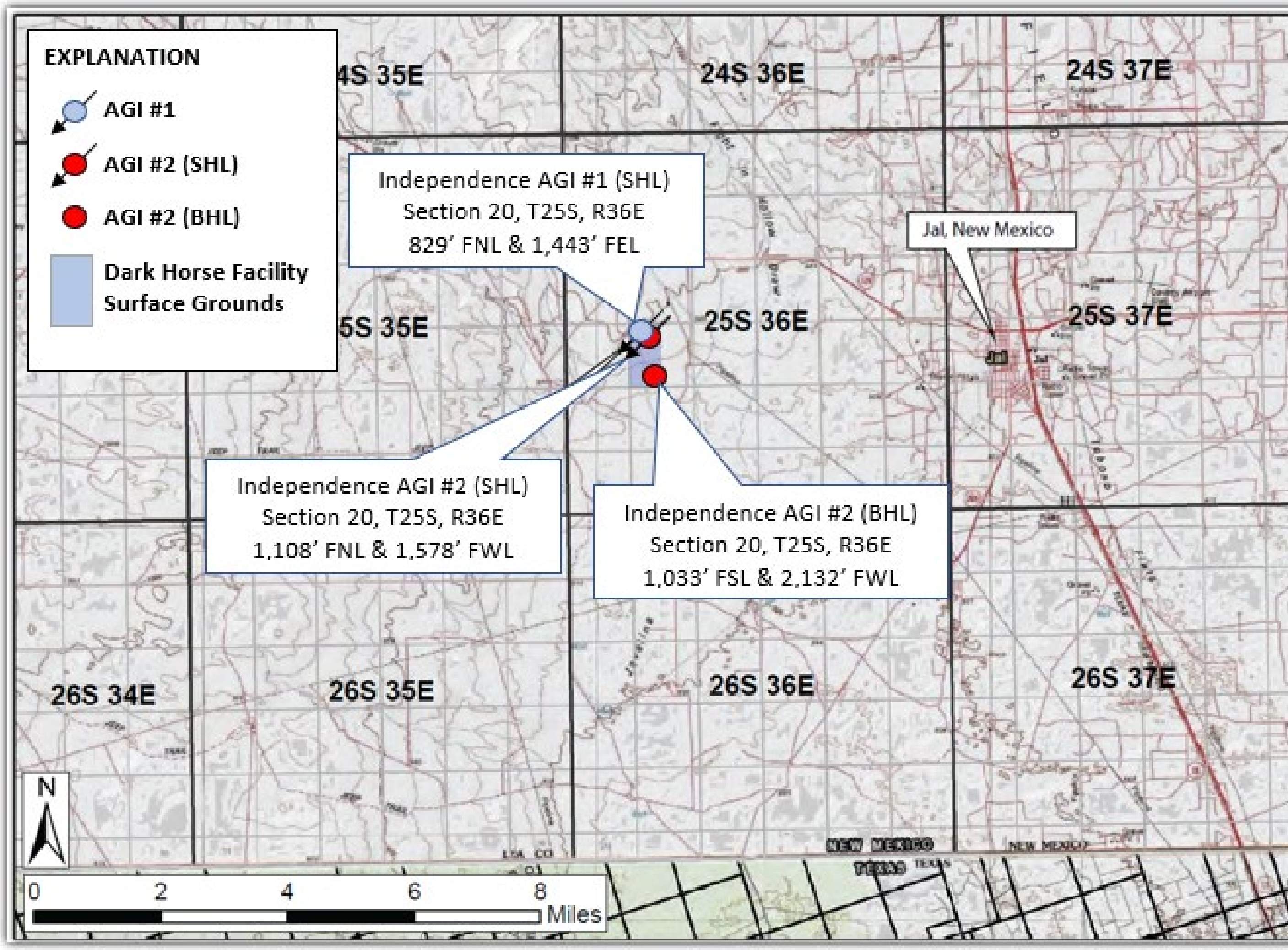
1 Introduction

Ameredev II, LLC (together with its affiliates, "**Ameredev**") is an oil and natural gas producer operating in portions of the Delaware Basin located in southeastern New Mexico and western Texas. In 2020 Ameredev began evaluating methods for treating its sour natural gas production in Lea County, New Mexico to remove and permanently sequester large quantities of hydrogen sulfide ("**H_2S**") and carbon dioxide ("**CO_2**") commingled in its produced natural gas stream. On July 10, 2020, Ameredev filed an application with New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division ("**NMOCD**") seeking to drill an acid gas injection ("**AGI**") well approximately six (6) miles west of Jal in Lea County, New Mexico for the injection and permanent sequestration of treated acid gas ("**TAG**"). The application was heard and approved at a New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Commission ("**NMOCC**") hearing held on October 8, 2020. The approved order (Order No. R-21455-A) was subsequently issued at the November 4, 2020 NMOCC hearing and the final, approved, Class II injection permit was issued on November 11, 2020. The Independence AGI #001 vertical well (API 30-025-48081; "**Independence AGI #1**") was spud on December 27, 2020 by Ameredev.

In December of 2020, certain affiliates of Ameredev and other outside investors funded Piñon Midstream, LLC ("**Piñon**") to construct and operate the Dark Horse Sour Gas Treating Facility (the "**Dark Horse Facility**") adjacent to the Independence AGI #1 (Figure 1-1) and Ameredev subsequently contributed and assigned the Independence AGI #1 to Piñon on May 21, 2021. Piñon became the operator of record for the Independence AGI #1 on August 24, 2021. Upon completion in late August 2021, treatment of sour natural gas (using amine to isolate H_2S and CO_2) and the injection of TAG through Independence AGI #1 commenced at the Dark Horse Facility (a full description of the treating and injection process is provided in Section 3.8). On March 31, 2022 the NMOCC authorized the drilling of the Independence AGI #002 deviated well (API 30-025-49974; "**Independence AGI #2**") (together the "**Independence AGI Wells**"), which commenced during the summer of 2022, with initial TAG injection through the well occurring in April 2023.

Independence AGI #1 is permitted to inject into the Devonian Thirtyone and Upper Silurian Wristen and Fusselman Formations from a true vertical depth ("**TVD**") of approximately 16,230 to 17,900 feet (the "**AGI #1 Injection Zone**") and at a maximum surface pressure of approximately 4,779 pounds per square inch gauge ("**psig**"). Independence AGI #2 is permitted to inject into the Devonian Thirtyone Formation and Upper Silurian Wristen and Fusselman Formations from a TVD of approximately 16,080 to 17,683 feet (the "**AGI #2 Injection Zone**", and together with the AGI #1 Injection Zone, the "**Siluro-Devonian Injection Zone**") and at a maximum surface pressure of approximately 5,005 psig. In accordance with NMOCC Order No. R-21455-A (as amended by Order No. R-21455-B, the "**NMOCC Order**"), Piñon is authorized to inject and dispose of TAG, utilizing the Independence AGI Wells, at an aggregate *combined* maximum daily injection rate of up to 20 million standard cubic feet per day ("**MMSCF/D**"), which is the equivalent of approximately 8,200 barrels per day ("**bpd**") or 1,036.7 metric tonnes per day. Gas is injected for 30 years at a rate of 1,036.73 tonnes per day (378,399 tonnes per year or 11,351,970 total tonnes) followed by a 5-year rest period. If Independence AGI #1 is not injecting volumes of TAG, Independence AGI #2 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG. If Independence AGI #2 is not injecting volumes of TAG, Independence AGI #1 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG.

Piñon has chosen to submit this Monitoring, Reporting, and Verification Plan (the "**MRV Plan**") to the United States Environmental Protection Agency (the "**EPA**") for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (the "**GHGRP**") for the purpose of qualifying for the tax credit in Section 45Q of the federal Internal Revenue Code. Piñon intends to utilize the Independence AGI Wells for the injection and disposal of TAG for another approximately thirty (30) years.



<u>Figure 1-1</u>: Location of Dark Horse Facility and the Independence AGI Wells. The approximate surface hole location ("SHL") and the approximate bottom hole location ("BHL") are indicated for both Independence AGI Wells. (Modified from Figure 1 of Class II permit application for Independence AGI #2, Geolex, Inc.)

This MRV Plan contains twelve (12) sections:

<u>Section 1</u> is this Introduction.
<u>Section 2</u> contains facility information.
<u>Section 3</u> contains the project description.
<u>Section 4</u> contains the delineation of the maximum monitoring area ("**MMA**") and the active monitoring area ("**AMA**"), both defined in 40 CFR 98.449, and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.
<u>Section 5</u> identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and duration of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP.
<u>Section 6</u> describes the detection, verification, and quantification of leakage from the identified potential sources of leakage.
<u>Section 7</u> describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.
<u>Section 8</u> provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.
<u>Section 9</u> provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.
Section 11 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.
Section 12 includes Appendices supporting the narrative of the MRV Plan.

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is 582541. There are no other facilities related to this MRV plan.

2.2 Underground injection control ("UIC") well identification numbers

This MRV Plan is for the Independence AGI Wells (*see* Appendix 1). The details of the injection process are provided in Section 3.8.

2.3 UIC permit class

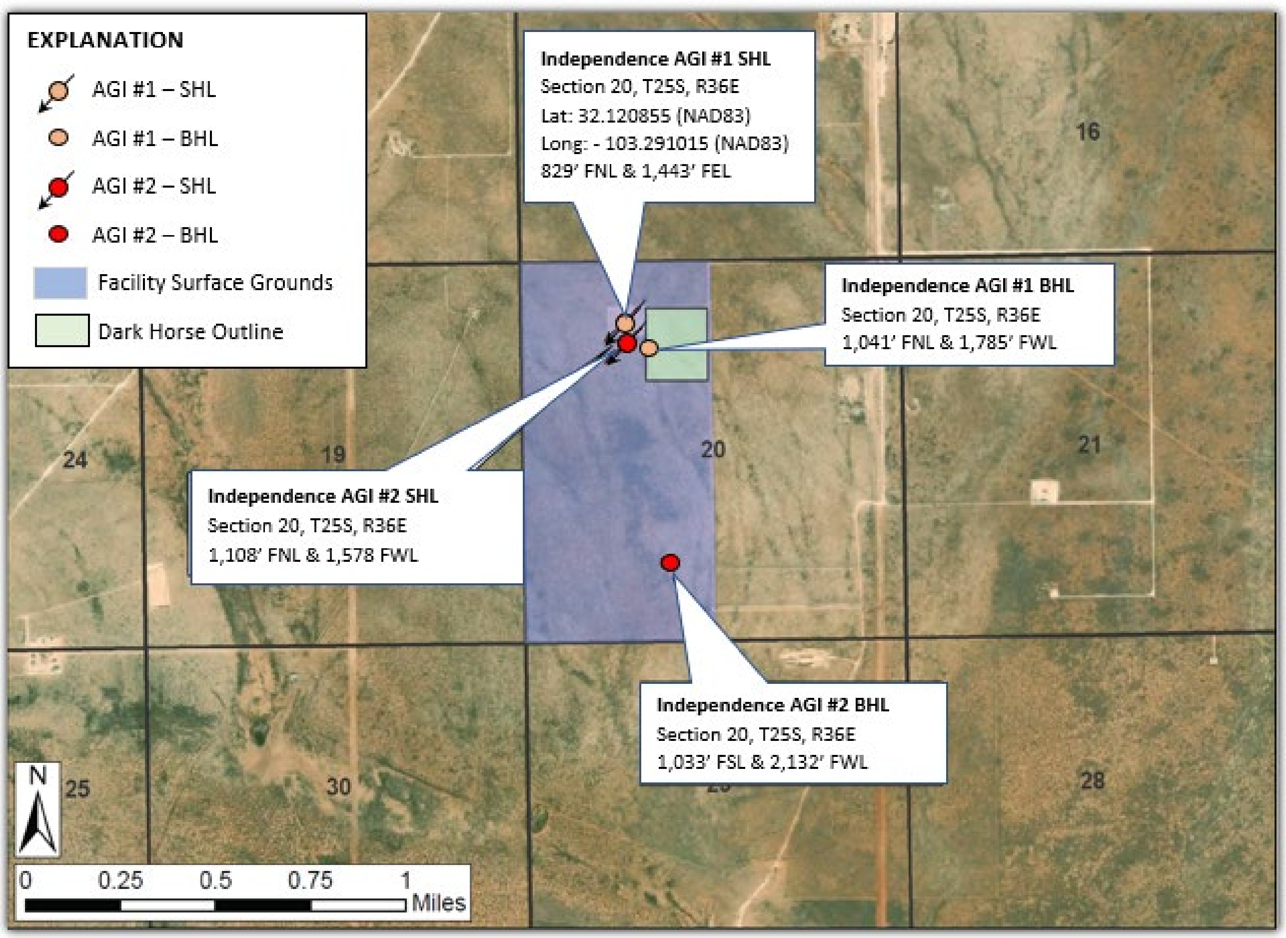
The NMOCD has issued UIC Class II Acid Gas Injection ("**AGI**") permits for the Independence AGI Wells under its State Rule 19.15.26 NMAC (*see* Appendix 2). All oil- and natural gas-related wells located near the Independence AGI Wells, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3 Project Description

Parts of the following project description have been taken from the Class II permit applications for (i) Independence AGI #1, prepared by Geolex, Inc. for Ameredev, dated July 10, 2020; and (ii) Independence AGI #2, also prepared by Geolex, Inc. for Piñon, dated November 4, 2021.

3.1 General Geologic Setting / Surficial Geology

The Dark Horse Facility is located adjacent to the Independence AGI Wells as shown in Figure 3.1-1. The site lies on the eastern flank of the Pecos River Basin within the Javelina Basin. Referred to as the South Plain by Nicholson & Clepsch (1961), the region exhibits irregular topography without integrated drainage. Surficial sediments commonly consist of unconsolidated alluvium and eolian sands. There are no observed surface bodies of water, or groundwater discharge sites within one (1) mile of the Independence AGI Wells. The Dark Horse Facility overlies Quaternary alluvium overlying the Triassic redbeds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater. The thick sequences of Permian rocks that underlie these deposits are described in Section 3.2.2.



p

Figure 3.1-1: Map showing location of Dark Horse Facility and the Independence AGI Wells in Section 20, T25S, R36E NMPM. The BHL of the Independence AGI #1 sidetrack is 446' southeast of the SHL. The SHL and the BHL for Independence AGI #2 are shown. (Modified from Figure 2 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.2 Bedrock Geology

3.2.1 Basin Development

The Dark Horse Facility is 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. The Permian Basin and its sedimentary fill have been formed and controlled by tectonism of varying degrees and sedimentation events that began in the Precambrian and throughout the Cenozoic (Neogene). Early Paleozoic deposition took place in the Late Cambrian as marginal areas of the North American craton began to be flooded by marine seas. Late Cambrian sediments comprised of basal siliciclastic sands and muds from areas of exposed Precambrian igneous, metamorphic, and sedimentary rocks and shallow-water carbonates.

Parts of the following basin development descriptions in this subsection have been modified and summarized from Ruppel (2019). Flooding continued across the North American craton throughout the Early Ordovician, establishing a widespread shallow-water carbonate platform. The Ellenburger Formation (Figure 3.2-2) rocks are derived from peritidal and shallow subtidal carbonates. These sediments were exposed during one of the sea-level drops during the Ordovician deposition resulting in karstification and dolomitization. During the Early to Middle Paleozoic time, the Permian Basin region was occupied by a relatively shallow basin called the Tobosa Basin. The first rapid subsidence and formation of the Tobosa Basin began in Simpson time (Middle Ordovician), and subsidence slowly diminished into the Early Devonian (Ewing, 2019). Subsequent tectonic history of the Tobosa and Permian Basins will be discussed throughout this section.

Early Paleozoic deposition is mostly defined by multiple high-frequency sea-level changes, karsting, and erosional events. Large-scale shift in facies and environments indicate tectonic and/or eustatic controls on sediment distribution patterns. Simpson Group (Middle Ordovician) rocks unconformably overlie Ellenburger Formation rocks at a widespread hiatus caused by Early Ordovician to Middle Ordovician relative sea-level fall. Simpson rocks are a cyclic succession of lime mudstones and quartz sandstones and were deposited during the subsequent reflooding of the shelf. Carbonate-dominated Montoya Formation (Late Ordovician) and Fusselman Formation (Latest Ordovician -Early Silurian) rocks overlie the Simpson Group and indicate a shift and deepening of Tobosa Basin. These rocks are indicative of an overall relative sea level rise.

Middle Silurian-Early Devonian Wristen Group and Thirtyone Formation rocks indicate differential subsidence in the area and represented a deepening and expansion of the basin. Wristen Group rocks comprised of carbonate mudstones and wackestones of the Wink Formation, which underlies the shallow-water carbonate platform packstones, grainstones, and reef facies (corals and stromatoporoids) of the Fasken Formation and the deep-water lime mudstones of the Frame Formation. These facies outline the position of a Silurian platform margin and imply a downwarping of the North American craton. Although Wristen and Fusselman show evidence of numerous high-frequency sea-level changes, the larger-scale change in facies and depositional environments indicates tectonic and/or eustatic controls on sediment distribution patterns. The Silurian platform margin is a recurring feature that controls facies distribution through the Late Mississippian, suggesting tectonic and/or basement terrain control. The rocks of the Thirtyone Formation (Early Devonian) consist of platform carbonate grainstones and packstones surrounding calcareous, radiolarian-rich basin facies.

According to Ruppel (2019) and Ruppel and others, (2020a), a major episode of relative sea-level fall in the Middle Devonian is documented by an absence of Late Early Devonian and early Middle Devonian rocks. Late Devonian Woodford rocks overlie eroded and karsted Silurian (Wristen Group), Early Devonian Thirtyone, and older rocks. Local folding of these rocks below the Woodford suggests that the hiatus may have been at least partially driven by tectonic events. Evidence from the distribution of later Mississippian rocks indicates that the tectonic event caused uplift and localized deformation of pre-Middle Devonian rocks and changed subsidence and depositional patterns across the entire region.

Following the Middle Devonian Permian Basin-area uplift and emergence, Late Devonian marine transgression flooded the region with anoxic bottom-water seas and deposited black, organic-rich biosiliceous mudstones of the Woodford Formation (Ruppel, 2019). Sea-level fall-and-rise sequences defined the Early and Late Mississippian and were even more pronounced during the Pennsylvanian. In the Late Mississippian, initial collision occurred between Laurentia and Gondwanaland, and the Marathon-Ouachita orogenic belt first started to form in northeastern North America (Yang and Dorobek, 1995) with tractions propagating toward the southwest, impacting the Permian Basin by the Middle Pennsylvanian Epoch (Desmoinesian, 310 Ma) (Horne, 2021). Mississippian limestones and the Barnett Formation shales were deposited following a marine transgression that resulted in the development of an extensive carbonate platform, surrounded by a deep-water, organic-rich mud basin.

Collision along the western and southwestern margins of Laurentia, combined with tractions from the Marathon-Ouachita thrusting in the southeast, resulted in northwest-southeast-trending uplifts throughout the western United States known as the Ancestral Rocky Mountain orogeny, which began in Early Pennsylvanian time and continued into the Early Permian (Horne, 2021). The Pennsylvanian tectonic setting in the Permian Basin is the product of the combined Ancestral Rocky Mountain and Marathon–Ouachita effects occurring along the southwest and southeast margins of Laurentia. These events contributed to basin evolution and specific structural domains and styles. In the Permian Basin, the Ancestral Rocky Mountain orogeny is responsible for the uplift of the Central Basin Platform and the major structural development of the Midland and Delaware Basins (Horne, 2021).

During Desmoinesian to early Missourian sedimentation, Permian Basin deformation reached its peak. The antecedent Tobosa Basin was tectonically differentiated, formed into the crustal uplifts and sub-basins that now characterize the Central Basin Platform, Midland Basin, and Delaware Basin. Throughout Pennsylvanian and most of Permian sedimentation, tectonics coupled with glacial eustacy played an important role in the development of regional facies. Middle to Late Pennsylvanian saw decreasing tectonic deformation activity, and by the Wolfcampian time (Early Permian), deformation was limited to subsidence within the structures formed by the existing uplifts and basins (e.g., Delaware and Midland Basins, Central Basin Platform). The continual subsidence of the Delaware basin affected sediment infilling, with some areas accumulating as much as 12,000 ft of basin-fill sediment. Marine transgression eventually submerged uplifts and became the location of carbonate sedimentation, while the basins became filled with organic-rich siliceous muds. By the end of the Wolfcampian, the major Permian Basin physiographic features (Central Basin Platform, Delaware and Midland Basins) were fully developed, and controlled sedimentation types and location for the remainder of the Paleozoic.

The Middle Permian (Leonardian and Guadalupian) was punctuated by cyclic sediment deposition during sea-level eustatic events. The Leonardian was a time of gradual global warming from the icehouse climates of the late Carboniferous to warmer and more arid greenhouse climates of the later Permian and Mesozoic (Tabor, 2004). The Leonardian marked the beginning of the last stages of the formation of Pangea, producing greater restriction of open ocean connections to the Permian Basin (Ruppel, 2020b). The abundance of tidal-flat facies, evaporites, and reflux dolomites in Leonardian rocks reflects the development of much more arid conditions compared with those in the earlier Permian (Ruppel, 2020b). In the shelf areas (Central Basin Platform and Northern, Northwestern, and Eastern Shelves) (Figure 3.2-1), sedimentation was characterized by shallow-water carbonate production and deposition during sea-level rise, and by shelf exposure and sand-silt deposition during sea-level fall and subsequent shelf exposure. In the Delaware and Midland basins, sedimentation was characterized by cyclic intervals of detrital carbonate-sediment transport into the basins by sea-level highs, and by sand-silt transport and deposition during sea-level falls. Dolomitization of carbonate-shelf deposits occurred during the more regionally arid climates of the Leonardian and the Guadalupian as a product of the Permian Basin area being situated at the equator and from refluxing brines created during periods of sea-level highstand events. Deposition of evaporites became more common in the shelf areas during this time, likely in response to the increasingly arid environment and/or decreased accommodation. By the end of the Guadalupian, the Midland Basin was largely filled, and peritidal muds and evaporite deposition dominated. Sea-level fall and closure of the Hovey Channel (Figure 3.2-1) cut off the Delaware Basin from its marine supply, resulting in regional exposure and nondeposition and the filling of the basin with evaporites of the Castille Formation (Lopingian “Ochoa” Series) (Ruppel, 2019). Most of the rocks deposited during Lopingian “Ochoan” time were evaporites such as anhydrite, halite, and potash minerals with minor amounts of limestone, mudstone, and siltstone and are subdivided into (ascending) Castile Formation, Salado Formation, Rustler Formation, and Dewey Lake Red Beds. Most of the early Ochoan deposition was confined to the Delaware Basin (Bachman, 1984).

3.2.2 Stratigraphy

Figure 3.2-2 is a generalized stratigraphic column showing the formations that underlie the Dark Horse Facility and the Independence AGI Wells. The sequences of Ordovician through Permian rocks are described below.

Ordovician. Below the Silurian Fusselman Formation lies about 400 feet of Ordovician Montoya Formation cherty carbonates which overlies about 400 feet of Ordovician Simpson Group sandstones, shales, and tight limestones. These formations are underlain by the Lower Ordovician Ellenburger Formation which is a thick, carbonate-dominated sequence composed of dolostones and limestones. It is 0-1,000 feet thick in southeastern New Mexico. The Ellenburger carbonates sit on a veneer of Cambrian to Lower Ordovician Bliss Sandstone and granite wash on the Precambrian basement.

During the Early Ordovician, much of the United States was covered by a shallow sea, and southeast New Mexico was a shallow-water shelf with deep water conditions to the south. Due to sea-level changes and regional tectonic activity, the entire lower Paleozoic interval (Ellenburger through Devonian) was periodically subjected to subaerial exposure and prolonged periods of karst and karst-terrain formation, most especially in the Ellenburger, Fusselman and Devonian strata. The cave systems collapsed with subsequent burial, creating brecciated and fractured carbonate bodies that formed many of the Ellenberger reservoirs and created complex pore networks. The result of these exposure events was the development of numerous horizons of karst-related secondary porosity with solution-enlarged fractures, vugs, and small cavities and caves. Particularly in the Ellenburger and Fusselman strata, solution features from temporally distinct karst events became interconnected with each successive episode, so there could be some degree of vertical continuity in parts of the Fusselman section that could lead to enhanced vertical and horizontal permeability. The Ellenburger is well below the Siluro-Devonian Injection Zone, so it is unlikely to be affected by any proposed activity.

Devonian and Silurian. The Devonian Thirtyone Formation, the Silurian Fusselman Formation, and the Silurian Wristen Group consist of interbedded dolomites and dolomitic limestones and are collectively often referred to as the Siluro-Devonian. In the Middle Devonian, regional marine transgression deposited mostly black, organic-matter-rich siliceous muds of the Woodford Formation (Ruppel, 2019). The Siluro-Devonian Injection Zone does not contain economic hydrocarbons closer than fifteen (15) miles away from the well sites. There have been no commercially significant deposits of oil or natural gas found in the Devonian or Silurian rocks in the vicinity of the Independence AGI Wells and there is no current or foreseeable production at these depths within a two (2) mile radius around the Independence AGI Wells (Figure 3.7-3). Adjacent wells have shown that these formations are primarily water-bearing and are routinely approved as produced-water injection zones in this area.

Mississippian. According to Broadhead (2017), the Mississippian section unconformably overlies the Woodford Formation shales throughout most of southeastern New Mexico and, in places, unconformably overlies the Silurian Fusselman Formation or Ordovician strata in limited areas. These units reach a maximum thickness of 1,400 ft in the Tatum Basin northwest of Hobbs, New Mexico and constitute a major portion of the stratigraphic section. The Mississippian section in southeastern New Mexico is subdivided into the Lower Mississippian limestone (Kinderhookian to Osagean age) and various Upper Mississippian units. The Upper Mississippian section consists of the Barnett Shale in the basinal area to the south and the Meramec and Chester units on the shelf to the north. The Mississippian strata constitute the least developed of the major stratigraphic units in southeastern New Mexico and oil and natural gas production has been from relatively small and widely scattered reservoirs (Broadhead, 2017). The Chester Formation consists of several hundred feet of shales and basinal limestones which are underlain by several hundred feet of Osage limestone.

Pennsylvanian. The Pennsylvanian-age strata is comprised of (ascending) Morrow, Atoka, Strawn, Canyon, and Cisco. Within this entire sequence, the Morrow is a major natural gas producing zone, with smaller contributions from the overlying Atoka and Strawn. The Morrowan strata are dominantly siliciclastic and consist of interbedded shales and lenticular sandstones deposited in multiple regressive sequences and represent basinward migration of nearhore, sand-rich facies tracts from the erosion of exposed Precambrian rocks (Broadhead, 2017). The overlying Atokan strata are also dominantly siliciclastic, with sandstones and shales being deposited in fluvial-deltaic and strandline environments (Broadhead, 2017). The Middle Pennsylvanian (Desmoinesian) Strawn strata is composed of ramp limestones interbedded with marine shales and minor sandstones, and both sandstone and limestone reservoirs are productive (Broadhead, 2017). Although there was past production of oil and natural gas from the Pennsylvanian Strawn pool, there are no active wells in that pool within two (2) miles of the Dark Horse Facility nor are there any natural gas producing wells in any pools. The Upper Pennsylvanian strata are informally referred to as the Canyon (Missourian) and Cisco (Virgilian) groups, and are composed of interbedded carbonates, dark-gray to black shales, and minor sandstones (Broadhead, 2017). These groups contain prolific oil reservoirs in southeastern New Mexico.

Permian. The overlying Permian rocks found in the Delaware Basin are divided into four (4) series, the Lopingian ("Ochoa") (most recent), Guadalupe, Cisuralian ("Leonard"), and Hueco ("Wolfcamp") (oldest) (Figure 3.2-2). Numerous oil pools have been identified in these rocks (*see* Appendix 3, Table 3a). Active oil producing reservoirs within two (2) miles of the Dark Horse Facility include the following Permian pools: Tansil, Yates, Seven Rivers, Delaware, Bone Spring, and Wolfcamp. New oil wells permitted but not yet drilled are primarily targeting the Bone Spring and the Wolfcamp pools. The rock units of the Permian series are discussed in more detail below.

Permian Hueco ("Wolfcamp") Group. The Lower Permian Wolfcampian strata in the Permian Basin record deposition in deepwater basins surrounded by shallow-water carbonate platforms, where the Wolfcampian platform carbonate succession exposed in southeastern New Mexico comprises a complex record of deposition mainly controlled by fluctuations in glacio-eustatic sea level (Fu and others, 2020). The Wolfcamp is extremely variable in lithology in response to changes in the environment of deposition. In the area of the Dark Horse Facility, it is composed of dark skeletal to fine-grained limestone, fine-grained sand to coarse silt, and shale in these basin facies. Horizontal wells are being drilled in the Bone Spring and Wolfcamp; however, most activity is primarily to the west of the Dark Horse Facility.

Permian Leonardian Series. The Cisuralian ("Leonard Series"), sediments in shelf areas (Central Basin Platform, Northwest Shelf, etc.) are characterized by shallow-water carbonate-sediment production and deposition during sea-level rise, and by shelf flooding and quartz-dominated sand-silt deposition during sea-level fall and shelf exposure (Ruppel, 2019). In the Delaware Basin, this pattern of sea-level control on sediment supply resulted in the deposition of cyclic intervals of detrital carbonate-sediment transport to basins during sea-level highs and by quartz sand-silt transport and deposition during sea-level falls (Ruppel, 2019). Overall, the Leonard succession is one of punctuated upward shallowing from deep-water, outer-platform—platform-margin settings to inner-platform, peritidal conditions (Ruppel, 2020b).

The Bone Spring Formation is present only in the Delaware Basin and is stratigraphically equivalent to the Abo and Yeso Formations of the Northwest Shelf and Central Basin Platform, attains a maximum thickness of about 4,000 ft in southern Eddy County, New Mexico, and has been productive from several plays in the basin (Broadhead, 2017). The Bone Spring stratigraphy consists of alternating carbonate and siliciclastic successions that were deposited in marine slope and basin-floor environments, where sandstones and siltstones are widespread on the basin floor, whereas carbonates are thickest in periplatform areas (Nance and Hamiln, 2020; Saller and others, 1989). Most Bone Spring carbonate slope deposits accumulated by transport from shallow-water environments on the shelf during highstands of sea level and the siliciclastic deposits were transported basinwards during lowstands of sea level (Nance and Hamlin, 2020). Most of the carbonates are detrital, composed of bioclasts and lithoclasts derived from surrounding shallow-water platforms, and the siliciclastic members were deposited primarily on the basin floor in widespread submarine-fan complexes (Nance and Hamlin, 2020).

Permian Guadalupe Series. The Upper Permian Guadalupian-age strata are found on both Northwest Shelf and Central Basin Platform, and in the Delaware Basin. The Goat Seep/Capitan Reef system, a profoundly critical component of the Permian Basin Guadalupian paleogeography, prominently divides the shelves of the Central Basin Platform, the Northwestern Shelf, and the Western Shelf from the Delaware Basin (Nance, 2020a). Units on the shelf and platform comprise of (ascending) the San Andres Formation and the Artesia Group (*see* Figure 3.2-2). The five (5) formations of the Artesia Group include (ascending) Grayburg, Queen, Seven Rivers, Yates, and Tansill. The Delaware Basin equivalents of the reef trend include the Delaware Mountain Group: (ascending) Brushy Canyon, Cherry Canyon, and Bell Canyon. The Artesia Group comprises as much as 2,650 ft of stratigraphically cyclic, mixed-siliciclastic/carbonate/evaporite platform strata deposited shelfward of the Guadalupian Capitan Reef system that rims the Delaware Basin (Nance, 2020a). These formations have provided significant oil and natural gas production in southeastern New Mexico, and widespread, reddish-colored evaporitic shales and evaporites provide effective vertical and lateral seals (Broadhead, 2017).

According to Nance (2020a), Artesia facies tracts include, from basin to shelf, immediate-back-reef carbonate grainstone to packstone; shelf-crest pisolite-bearing carbonate shoals; lagoonal wackestone to mudstone and siliciclastic siltstone; algal-laminated, tidal-flat carbonate packstone to wackestone and fine to very fine grained sandstone; beach-ridge fine sandstone; siliciclastic-sabkha anhydrite and halite; brine-pool and evaporitic-lagoon anhydritic dolomite, dolomitic anhydrite, anhydrite, and halite; and eolian to fluvial siliciclastics. During sea-level highstand, siliciclastics are limited to updip areas, whereas eolian-siliciclastic depositional environments migrate downdip during sea-level lowstands. During transgressions, siliciclastics in more basin-proximal positions were reworked by marine and marginal processes. Reservoir quality was impacted mostly by dissolution of feldspar and carbonate allochems and precipitation of authigenic feldspar, clay, and evaporite.

The Delaware Mountain Group of the Delaware Basin comprises up to 4,500 ft of arkosic to subarkosic sandstone, siltstone, and carbonate debrites that were deposited in deep water, mainly during lowstand and early transgressive sea-level stages, and primary depositional processes include density-current flow and suspension settling (Nance, 2020b). The Delaware Mountain Group is restricted to slope-and-basin areas and was sourced from shelf-sediment areas through poorly exposed incised valleys, and interbedded carbonate units thicken shelfward and are typically correlative to “reef”-margin-complex carbonate sources along the shelf margin (Nance, 2020b).

Permian Lopingian (“Ochoa”) Series. The youngest of the Permian Basin sediments are referred to as the Lopingian (“Ochoa”) Series. The Ochoan series includes the Castile, Salado, Rustler, and Dewey Lake formations. Ochoan units on the shelf include the Salado, Rustler, and Dewey Lake Formations. *Castile Formation* usage is restricted to the deposits within the Delaware Basin only (Figure 3.2-2). The Ochoan in the Permian Basin contains no hydrocarbon reservoirs on the shelf (Nance, 2020a). The basal Salado Formation forms the ultimate top seal for the underlying Guadalupian reservoirs and effectively inhibits hydrocarbon migration into Ochoan units (Nance, 2020a). Lack of a seal above the Ochoan precludes widespread entrapment within the interval of hydrocarbons that may have been generated within the series. Ochoan strata are not hydrocarbon productive in the Permian Basin except for a few very small, isolated reservoirs in the Castile Anhydrite in the northern part of the Delaware Basin (Broadhead, 2017). The Castile is considered to be the top seal for Delaware Basin hydrocarbon reservoirs and is responsible for controlling migration of hydrocarbons from basinal source beds into reservoirs on the surrounding shelves (Hills, 1984). Anhydrite is the dominant rock type in the Castile Formation, along with limestone interlaminated in anhydrite, thin beds of limestone, and minor amounts of dolomite and magnesite, and halite is present as several massive beds in the formation in the subsurface but is much less prominent than the halite in the overlying Salado Formation (Bachman, 1984). The interlaminated anhydrite and limestone are distinctive lithologic features of the Castile Formation and are thought to represent annual cycles of sedimentation (Bachman, 1984).

The regionally extensive Salado Formation includes thick evaporite deposits and records a long-term salinity crisis in the region (Nance, 2020a). The Salado includes halite, minor beds of anhydrite, and commercial deposits of potash minerals (Bachman, 1984). The contact between the Castile and the overlying Salado Formations is sharp and most places and is between massive beds of anhydrite in the Castile and a sequence dominated by halite, potash minerals, and thin beds of anhydrite in the Salado (Bachman, 1984). The Rustler Formation overlies the Salado, and consists of dolomite, evaporites, and siliciclastics and marks the last major migration of marine waters into the Permian Basin (Ruppel, 2019). Red beds of terrigenous sands in the Rustler Formation resulted from eolian sediment transport. These red beds grade downwards into evaporites of the Salado and Castile Formations and are composed of red-orange silts and sandstones with interbeds of gypsum or anhydrite and halite. The Rustler carbonates, evaporites, and siliciclastics mark a relatively abbreviated return of marginal-marine conditions to the region (Nance, 2020a). The Dewey Lake Formation rests conformably on the Rustler Formation and consists mainly of redbeds and minor gypsum, alternating thin, even beds of moderately reddish-brown to moderately reddish-orange siltstone and fine-grained sandstone (Bachman, 1984). The Dewey Lake sediments mark the youngest episode of preserved Permian deposition in the region, after which a significant net-depositional hiatus prevailed until the onset of Late Triassic sediment accumulation (Nance, 2020a).

Beds of Triassic age rest unconformably on, and overlap, the Dewey Lake Formation, and exposures of these rocks in southeastern New Mexico are dark reddish-brown, cross-laminated, poorly sorted conglomerate sandstones with interbeds of dark reddish-brown sandy shale (Bachman, 1984). These Triassic units were deposited in a fluvial—deltaic—lacustrine system and signaled the onset of net deposition during overall wetter conditions after a protracted period of net nondeposition (Nance, 2020a; Bachman, 1984).

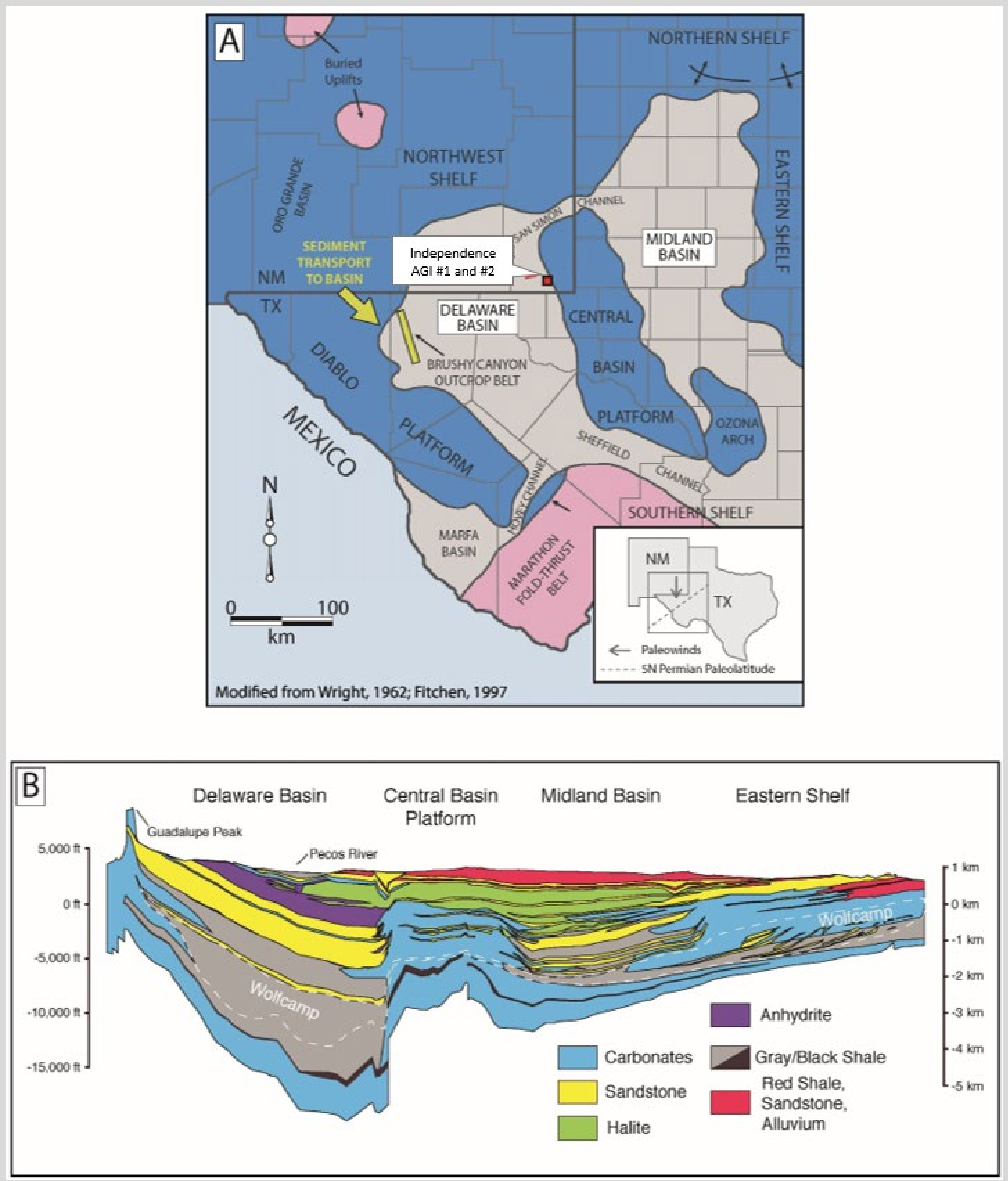


Figure 3.2-1: Structural setting (panel A) and general lithologies (panel B) of the Permian Basin. The location of the Independence AGI Wells is shown by the red square. (Modified from Wright, 1962; Fitchen, 1997) (Modified from Figure 12 of Class II permit application for Independence AGI #2, Geolex, Inc.).

Age		Stratigraphic Units Northwest Shelf and Central Basin Platform	Stratigraphic Units Delaware Basin
Triassic		Chinle	Chinle
		Santa Rosa	Santa Rosa
Permian	Lopingian ("Ochoan")	Dewey Lake	Dewey Lake
		Rustler	Rustler
		Salado	Salado
			Castile
	Guadalupian	Artesia Group: Tansill	Delaware Mountain Group: Bell Canyon
		Artesia Group: Yates	
		Artesia Group: Seven Rivers	Delaware Mountain Group: Cherry Canyon
		Artesia Group: Queen	
		Artesia Group: Grayburg	Delaware Mountain Group: Brushy Canyon
		San Andres	
	Cisuralian ("Leonardian")	Glorieta	
		Yeso: Paddock	Bone Spring
		Yeso: Blinebry	
		Yeso: Tubb	
		Yeso: Drinkard	
	Wolfcampian	Abo	
		Hueco ("Wolfcamp")	Hueco ("Wolfcamp")
Pennsylvanian	Virgilian	Cisco / Bough	Cisco
	Missourian	Canyon	Canyon
	Des Moinesian	Strawn	Strawn
	Atokan	Atoka	Atoka
	Morrowan	Morrow	Morrow
Miss.	Upper	Undivided	Barnett
	Lower		undivided limestone
Dev.	Upper	Woodford	Woodford
	Middle		
	Lower	Thirtyone	Thirtyone
Sil.	Upper	Wristen	Wristen
	Middle		
	Lower	Fusselman	Fusselman
Ord.	Upper	Montoya	Montoya
	Middle	Simpson	Simpson
	Lower	Ellenburger	Ellenburger
Cambrian		Bliss	Bliss
Precambrian		igneous, metamorphics, volcanics	igneous, metamorphics, volcanics

Figure 3.2-2: Generalized stratigraphic correlation chart for the Permian Basin region (modified from Broadhead, 2017).

3.2.3 Faulting

The Permian Basin region has a complex tectonic history, shaped by several convergent and divergent events from the Proterozoic through the Cenozoic (Neogene). The Delaware Basin is defined by a complex network of basement-rooted faults. Recent regional 3D structural framework and kinematic models by Horne et al. (2021) provides interpretations of basement-rooted faults in the Delaware Basin. This region contains more than 650 basement-rooted fault surfaces, dominated by “primary” north-northwest—south-southeast-striking high-angle reverse faults that bound “secondary” fault orientations west-northwest—east-southeast and west-southwest—east-northeast (Horne et al., 2021). Their kinematic model suggests that the primary structural grain formed first in response to the encroaching Ancestral Rocky Mountain orogenic front, and the secondary fault zones formed under the combined stresses from the Ancestral Rocky Mountain and Marathon-Ouachita convergence fronts, which compartmentalized the Delaware Basin and Central Basin Platform (Horne et al., 2021).

To identify subsurface structures in the area of the Independence AGI Wells, Geolex evaluated and interpreted licensed seismic survey data (WesternGeco South Lea Survey) covering the Lea County area of interest. These findings and interpretations specific to the Dark Horse Facility area are discussed further in Section 3.5.

3.3 Lithologic and Reservoir Characteristics of the Siluro-Devonian Formations

The Siluro-Devonian Injection Zone includes the Devonian Thirtyone Formation, Silurian Wristen Group and Fusselman Formation, collectively referred to as the Siluro-Devonian. These strata commonly include numerous intervals of dolomites and dolomitic limestones with moderate to high primary porosity. Additionally, the Siluro-Devonian Injection Zone includes significant regions of secondary, solution-enlarged porosity produced during periods where strata were subaerially exposed and significant karst features developed. These karst features are frequently developed in the Fusselman Formation and include solution enlarged cavities and fractures. Fracture networks through the Siluro-Devonian section are substantial enough to provide additional permeability that is not readily apparent on geophysical well logs. The porous zones of the Siluro-Devonian are separated by tight limestones and dolomites.

In evaluating the location of the Independence AGI Wells, an in-depth review of licensed seismic survey data (WesternGeco – South Lea Survey) was completed to support the evaluation that the Siluro-Devonian reservoir exhibited sufficient porosity potential to accommodate the needs of the Independence AGI Wells. Seismic inversion data, specifically impedance attributes, were evaluated to identify reservoir targets with significant porosity potential in the Siluro-Devonian reservoir. As a result of this review, the location in Section 20, T25S, R36E was selected as it was observed to overlay an expansive region of porosity in the upper Devonian, Wristen, and Fusselman strata.
Based on the geologic evaluation of the subsurface, AGI was recommended between depths of approximately 16,080 to 17,683 feet TVD (16,477 to 18,080 feet measured depth). Figure 3.3-1 includes a type log of the Siluro-Devonian Injection Zone that includes the formation tops identified at the location of Independence AGI #1 and illustrates the sufficient low-porosity intervals overlying the target injection reservoir. Anticipated formation tops underlying the Independence AGI #2 location are included in the following Table 3.3-1. In the area of the Independence AGI Wells, depth to Devonian strata increases to the southwest and the Independence AGI Wells lie downdip of a structural high to the east (Figure 3.3-2).

Units overlying the Siluro-Devonian Injection Zone provide an excellent caprock to prevent the upward migration of injectate out of the target reservoir. This caprock includes 335 feet of dense Woodford Shale overlain by at least 796 feet of Mississippian limestone (Table 3.3-1). These units will provide a geologic seal above the porous carbonates of the Siluro-Devonian Injection Zone providing protection to shallow groundwater resources and overlying pay intervals.

Figure 3.3-3 includes structural cross section A-A' covering the area of Independence AGI #2 and highlights the lateral extent of available upper Devonian porosity and the regional coverage of overlying caprock in the area. As shown in Figure 3.3-2, there are two (2) faults located approximately one (1) mile east and one (1) mile north from the SHLs of the Independence AGI Wells. These structures were identified through review of licensed 3D seismic survey data and are discussed further in Section 3.5.

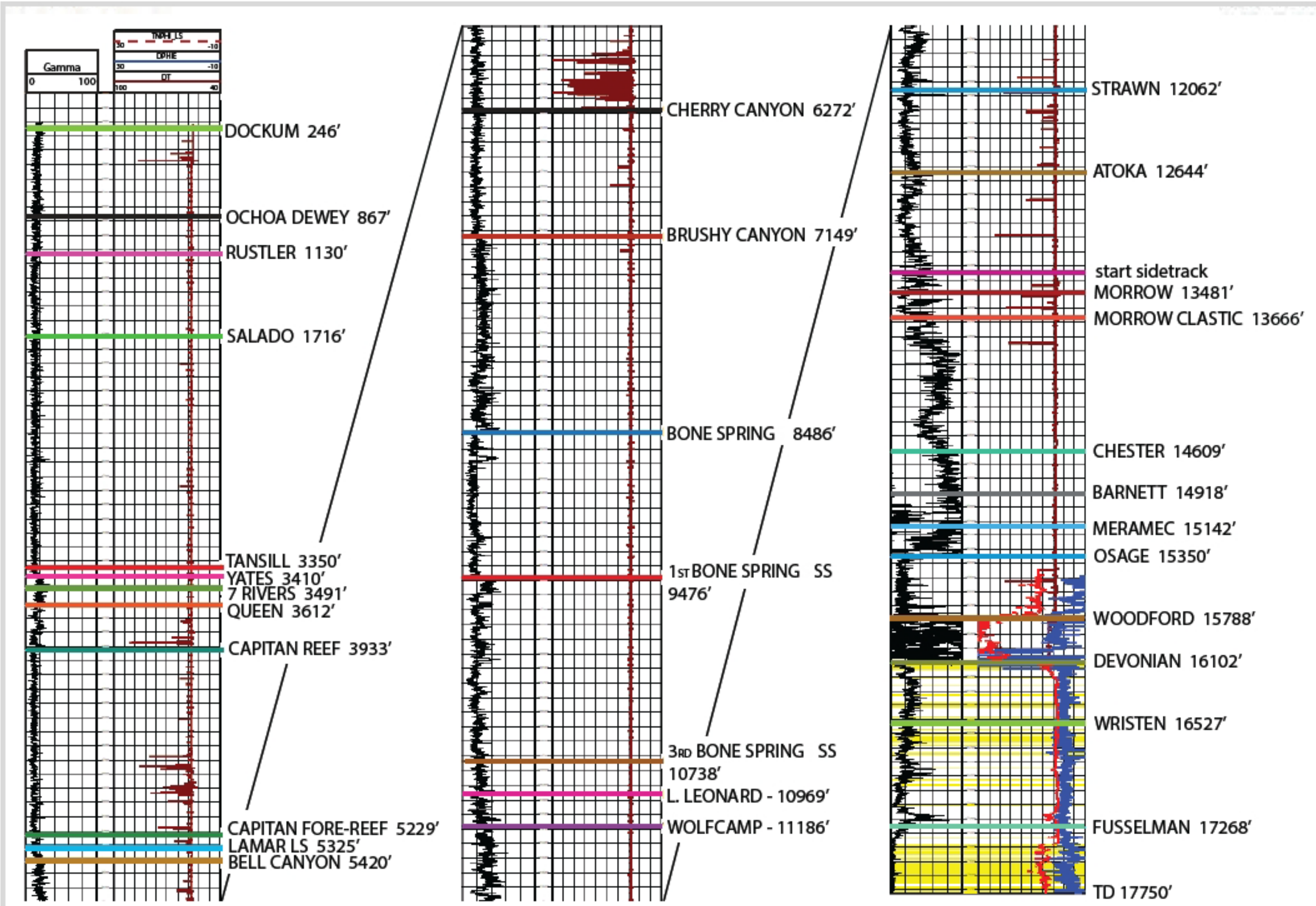


***Figure 3.3-1**: Type log of the Independence AGI #1, illustrating identified formation tops in TVD. Anticipated formation tops for the Independence AGI #2 are included in Table 3.3-1 (Modified from Figure 14 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

***Table 3.3-1**: Anticipated formation tops at the Independence AGI #2 location. (Extracted from Table 6 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

FORMATION	DEPTH (TVD)	DEPTH (MD)	FORMATION	DEPTH (TVD)	DEPTH (MD)
Dockum	485	485	Bone Spring	8,467	8,632
Ochoa-Dewey	747	747	Wolfcamp	11,131	11,387
Rustler	1,130	1,130	Strawn	12,004	12,289
Salado	1,720	1,720	Atoka	12,733	13,044
Tansill	3,401	3,401	Morrow	13,541	13,880
Yates	3,461	3,461	Barnett	14,949	15,336
7 Rivers	3,542	3,542	Osage	15,380	15,703
Queen	3,663	3,663	Woodford	15,745	16,142
Capitan Reef	3,935	3,943	Devonian	16,080	16,477
Bell Canyon	5,425	5,484	Wristen	16,467	16,864
Cherry Canyon	6,277	6,364	Fusselman	17,201	17,598
Brushy Canyon	7,058	7,174	Montoya	17,684	18,081

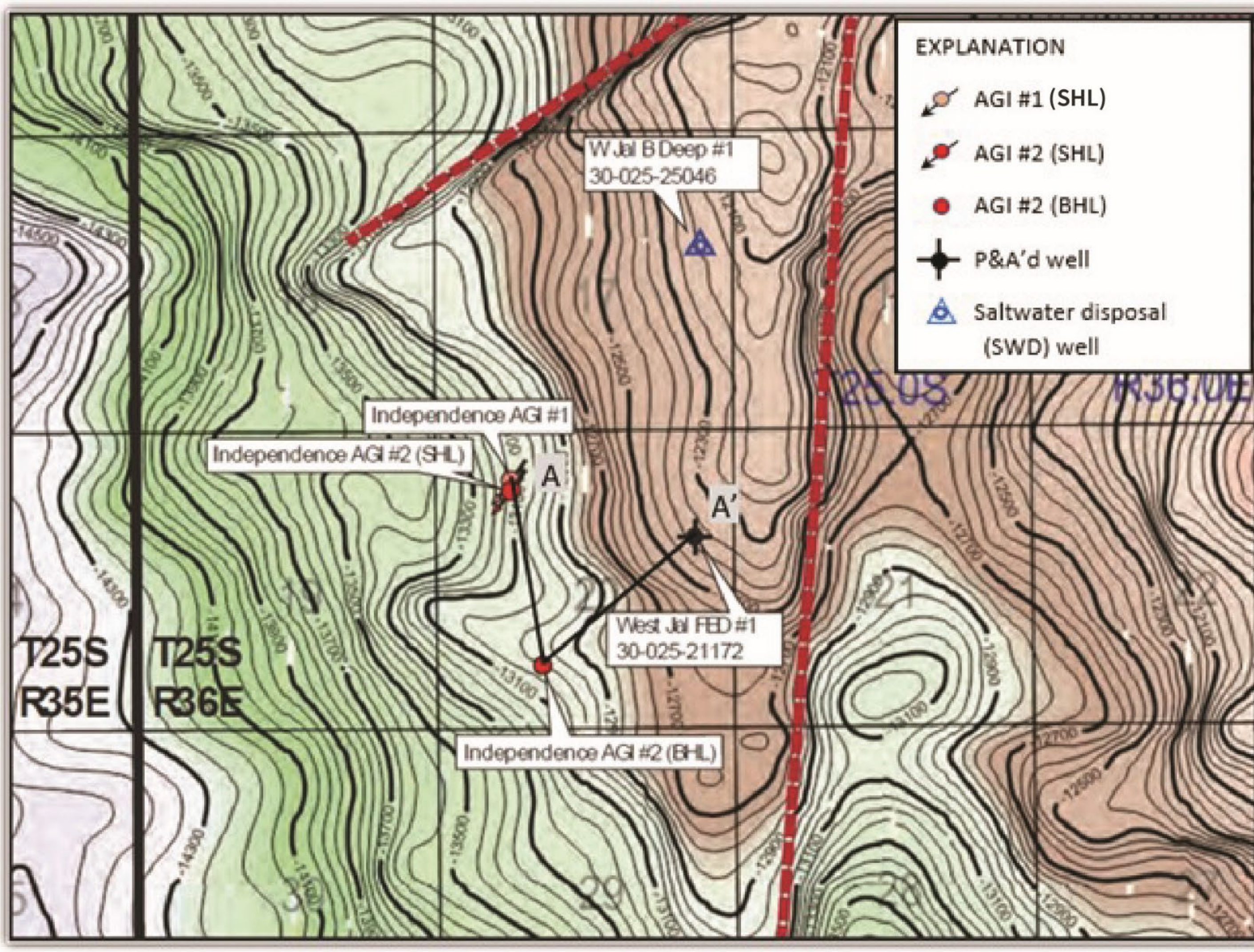
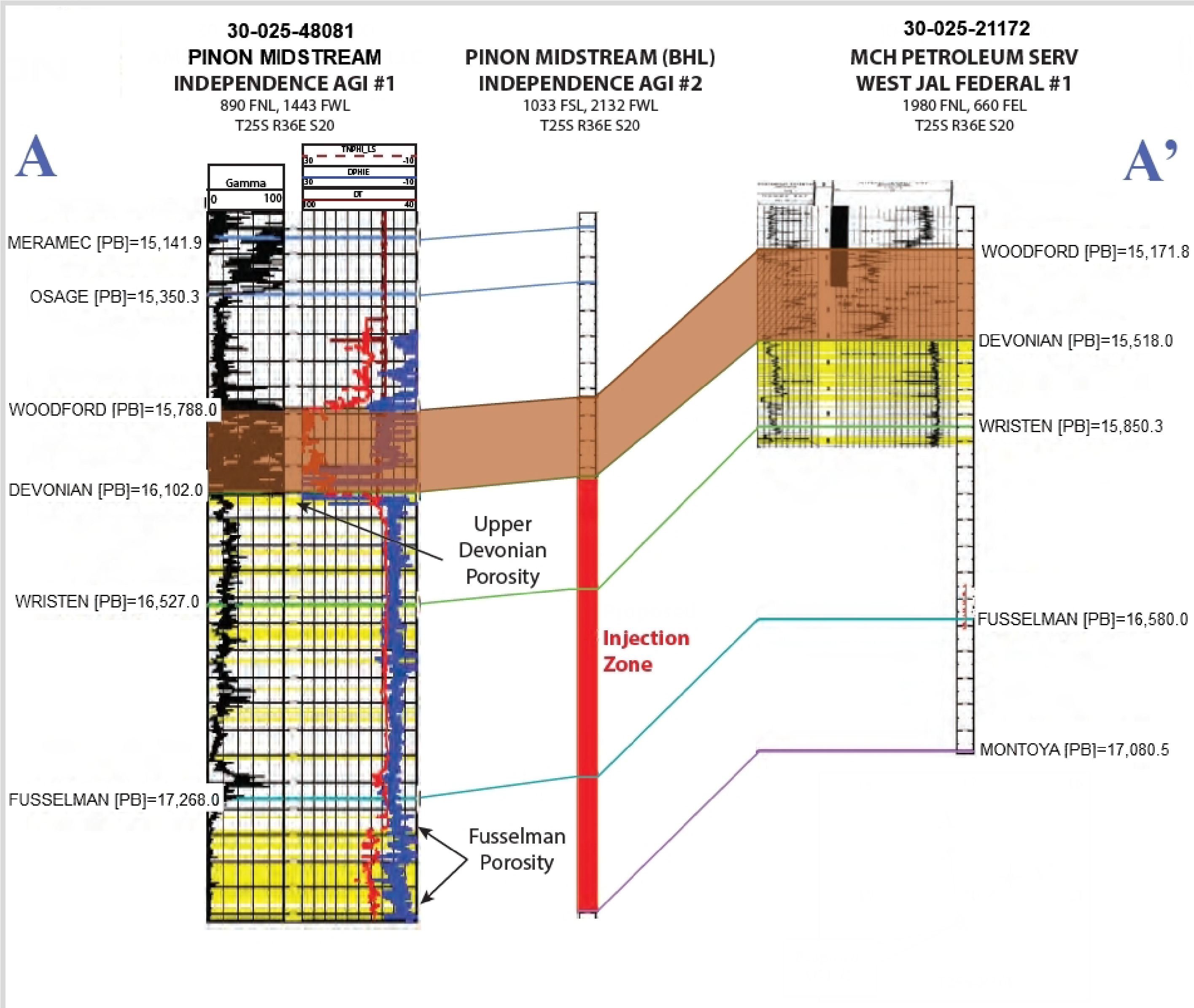


***Figure 3.3-2**: Structure contour map showing the top of the Siluro-Devonian target reservoir. Two (2) faults identified in review of 3D seismic data are shown with red dashes. Also, shown are wells within 1 mile of the Independence AGI Wells that penetrate the Siluro-Devonian target zone. Cross section A – A' is shown in **Figure 3.3-3**. (Modified from Figure 15 of Class II permit application for Independence AGI*

#2, Geolex, Inc.)** Not shown: The **BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in <u>Figure 3.1-1</u>.



<u>Figure 3.3-3</u>: Structural cross section A-A' showing porosity profile from nearby wells penetrating the Siluro-Devonian Injection Zone and regional extent of overlying Woodford Shale caprock. The Independence AGI #2 Injection Zone is from 16,080 feet TVD to 17,683 feet TVD (red bar). (Modified from Figure 16 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.4 Chemistry of Siluro-Devonian Interval Formation Fluids

A review of formation waters from the U.S. Geological Survey National Produced Waters Geochemical Database v. 2.3 identified twenty-one (21) wells with analyses of fluid samples collected from the Siluro-Devonian interval. These samples were collected from wells within approximately fifteen (15) miles of the Independence AGI Wells. Results of laboratory analysis to determine their composition are summarized in <u>Table 3.4-1</u>. These results have been supplemented with samples collected from Independence AGI #1 on May 31, 2021 which show Total Dissolved Solids ("**TDS**") values ranging from 109,000 to 115,000 parts per million ("**ppm**").

***Table 3.4-1**: Summary of Siluro-Devonian produced water analyses from nearby wells (U.S. Geological Survey National Produced Water Geochemical Database v. 2.3) * (Extracted from Table 7 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

API	WELL NAME	CONCENTRATION (parts per million)							
		TDS	HCO3	Ca	Cl	K + Na	Mg	Na	SO4
3002548081	Ind. AGI 1	110000	342	5600	68000	32559	759	31800	664
3002510945	Hill-federal D 1	112959	288	6264	67390	34340	1912	-	2765
3002510947	EC Hill-federal 1	35639	-	1369	22070		592	11608	-
3002511126	JR Holt A3	116415	154	7501	71110	34680	1767	-	1203
3002511196	S. Mattix Unit 3	68431	990	3180	40960	21690	974	-	637
3002511202	S. Mattix Unit 11	67130	853	5075	40430	16950	2348	-	1474
3002511383	Hodges B 3	81712	722	4320	47500	25400	1030	-	2740
3002511556	Blocker-federal 4	57675	595	2850	34030	18370	619	-	1211
3002511747	Ab Coates FED D2	82794	977	2408	47200	28190	851	-	3168
3002511760	Ida Wimberley 5	63817	360	2774	35870	20750	621	-	3442
3002811763	Ida Wimberley 9	61040	900	2680	35600	19560	800	-	1500
3002511765	Carlson-federal A3	66418	690	3002	37650	20390	1339	-	3347
3002511812	Clyde Lanehart 1	99879	687	4753	60410	32610	828	-	591
3002511818	Copper 1	27506	1089	1384	15270	8144	540	-	1079
3002511863	Arnott Ramsay B3	158761	476	17240	100300	35400	5345	-	-
3002511886	Dabbs 1	101036	540	5393	61630	30380	2183	-	910
3002511890	Sam Dabbs 1	85150	675	5368	50260	25130	1395	-	2322
3002511907	Arnott Ramsay F9	58220	367	1546	32790	-	278	20430	2816
3002511950	Farnsworth FED 6	31931	302	7196	20450	1151	2241	-	591
3002512272	LE Elliott FED H1	58687	761	3004	35460	18980	482	-	-
3002512286	JB McGhee 1	62392	552	2696	34380	20060	702	-	4002
3002521601	North Custer Mt 1	>64,000	1610	2136	36230	21830	403	-	1950

These analyses report TDS in the area of the Independence AGI Wells ranging from 27,506 to 158,761 ppm with an average of 75,981 ppm. The primary constituent in sampled formation waters is the chloride ion, with an average concentration of 45,227 ppm. The closest well, Independence AGI #1, at approximately 3,000 feet away from the Independence AGI #2 BHL, has reservoir fluids with a TDS value of approximately 110,000 ppm, and chloride ions in concentrations of approximately 68,000 ppm. Based on this data, the Siluro-Devonian reservoir fluids are anticipated to be completely compatible with the TAG injectate.

3.5 Potential for Induced Seismicity in the area of the Dark Horse Facility

To evaluate the potential for seismic events in response to injected fluids, Piñon conducted an induced-seismicity risk assessment for the area surrounding the Independence AGI Wells. This estimate (a) models the impact of seven (7) injection wells over a thirty (30) year injection period, and (b) estimates the fault-slip probability associated with the simulated injection scenario(s). This analysis was completed utilizing the Stanford Center for Induced and Triggered Seismicity's Fault Slip Potential ("**FSP**") model developed by Walsh and Zoback, 2016.

To identify subsurface structures in the area of the Independence AGI Wells, Piñon evaluated and interpreted licensed seismic survey data (WesternGeco – South Lea Survey) covering the Lea County area of interest. Based on this review, Piñon identified eight (8) subsurface faults in the area surrounding the Independence AGI Wells (Figure 3.5-1). The closest fault is observed to be located approximately one (1) mile east of the Independence AGI Wells. Major faults in the area (those

exhibiting significant lateral extent) generally strike NNW-SSE with minor faults striking NE-SW and NW to SE.

Due to the location of faults relative to the Independence AGI Wells and the general low density of injection wells in the immediate area of the Independence AGI Wells, it is anticipated that the injection scenario(s) will not pose any elevated risk of injection-induced fault slip. To support the interpretation that these structures would not be affected by operation of the Independence AGI Wells, a fault-slip probability analysis was completed to quantify the risk associated with injection operations in the area surrounding the Independence AGI Wells, and although the risk of induced seismicity is low, a seismic monitoring station was installed at the facility prior to the commencement of injection into Independence AGI #1. The station transmits data to the New Mexico Tech Seismic Network and will aid the state in seismicity interpretations.

To calculate the fault-slip probability for the model simulations, input parameters characterizing the local stress field, reservoir characteristics, subsurface features, and injected fluids are required. Parameters utilized and their sources for the area surrounding the Independence AGI Wells are included in Table 3.5-1. Additionally, Table 3.5-2 details the injection volume characteristics and locations of the injection wells modeled in the injection scenario(s). To ensure the model simulations provide a conservative estimation of induced-seismicity risk, injection wells included in the simulations were modeled utilizing their maximum anticipated daily injection volumes as recorded by NMOCD approved permits. Due to the minimal reported injection volume of the Jal North Ranch SWD #1 (30-025-27085) which is approximately 5.3 miles to the east northeast of the Independence wells, a potential of 10,000 bpd was assumed to account for the potential of increased injection rates due to future needs of the operator or any future workover that may improve the injectivity of this well.

Daily maximum injection volumes utilized in the fault-slip probability model range from 4,265 to 30,000 bpd (Table 3.5-2). In submission of the Class II injection well applications, Piñon requested approval to operate the Independence AGI Wells for a period of at least thirty (30) years, however, the duration of the FSP model simulation was increased to forty (40) years to characterize the reservoir effects of injection wells that are currently operating and have been in operation since 2010. Figure 3.5-2 shows the resultant pressure front and single well radial pressure solutions, as predicted by the FSP model, after thirty (30) years of injection at the maximum injection rates.

For this study, limitations of the FSP model required a conservative approach be taken in determining the fault-slip probability of the injection scenario. Specifically, the FSP model is only capable of considering a single set of fluid characteristics and this study aims to model an injection scenario that includes both brine injection and AGI. To ensure a conservative fault-slip probability estimate, the Independence AGI Wells were simulated utilizing the characteristics of a brine injectate. This approach yields a more conservative model prediction as brine displays greater density, dynamic viscosity, and is significantly less compressible than TAG. For comparison, characteristics of TAG at the anticipated reservoir conditions, as modeled by AQUAlibrium™, are shown in Table 3.5-1.

Generally, faults considered in this assessment are predicted by the FSP model to have very low potential for injection-induced slip and operation of the Independence AGI Wells is not predicted by the model to contribute significantly to the estimate of risk (Table 3.5-3 and Figure 3.5-3). Table 3.5-3 summarizes the predicted pressure change along each fault segment and includes the model-derived pressure change necessary to induce slip for each feature. Fault-slip probability values range from 0.00 to 0.05 with the majority of fault segments predicted to have zero probability of slip (Table 3.5-3). Major faults (faults 4, 7, and 8 in Figure 3.5-1) in the area, which would have the greatest energy release potential upon slip, are predicted to have zero probability for slip in response to the modeled injection scenario.

In summary, no structures included in the modeled simulations are predicted to be at increased risk for injection-induced slip in response to the injection scenario presented. Features estimated to have a non-zero slip potential are generally smaller-scale features and predicted probabilities are very low

(≤ 0.05). Furthermore, subsequent model simulations in which contribution from Independence AGI #2 is excluded illustrate that operation of the Independence AGI #2 will have little impact on conditions near the identified faults in the area due to significantly lower proposed injection volumes in comparison to nearby brine injection wells.

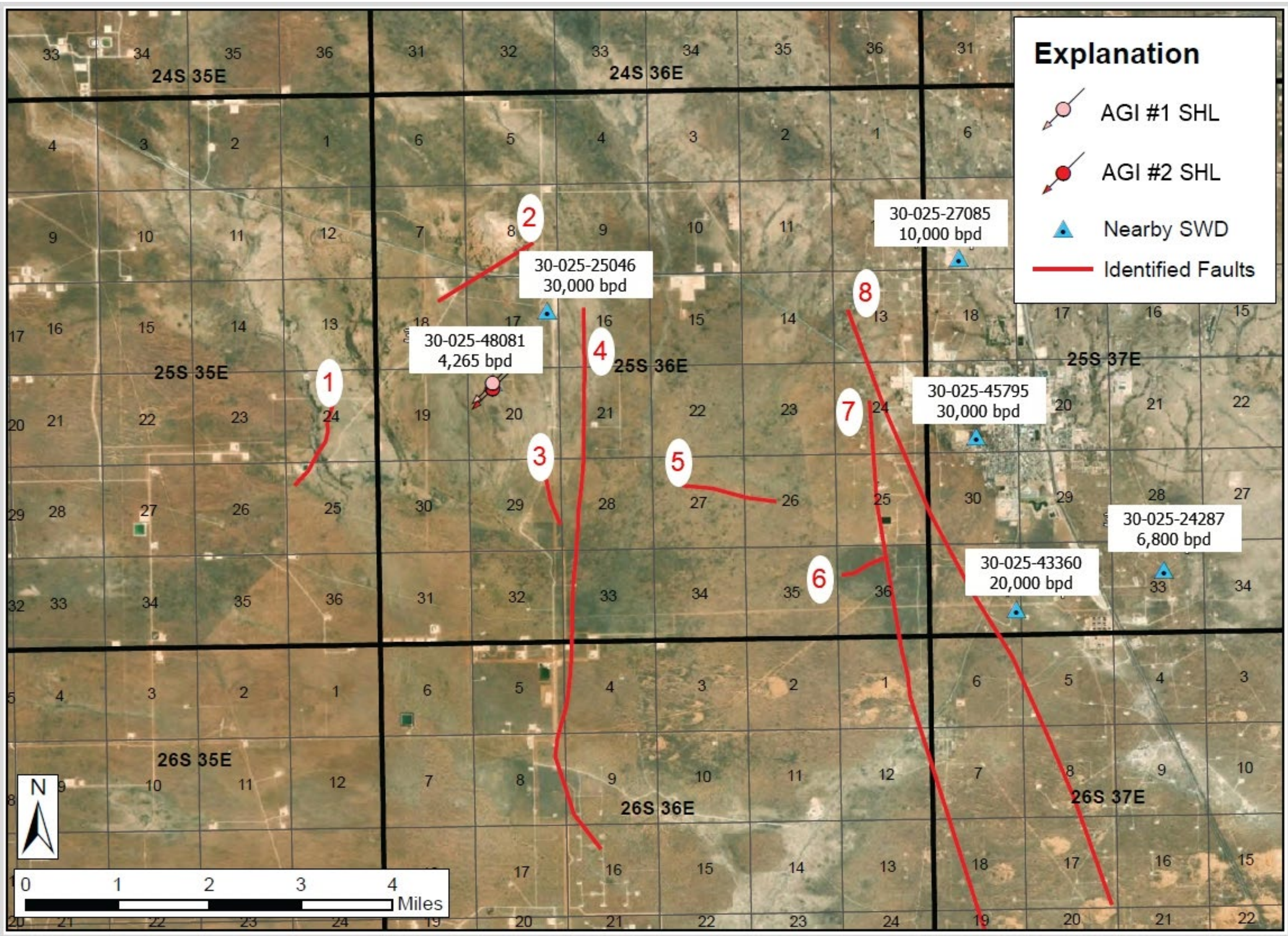


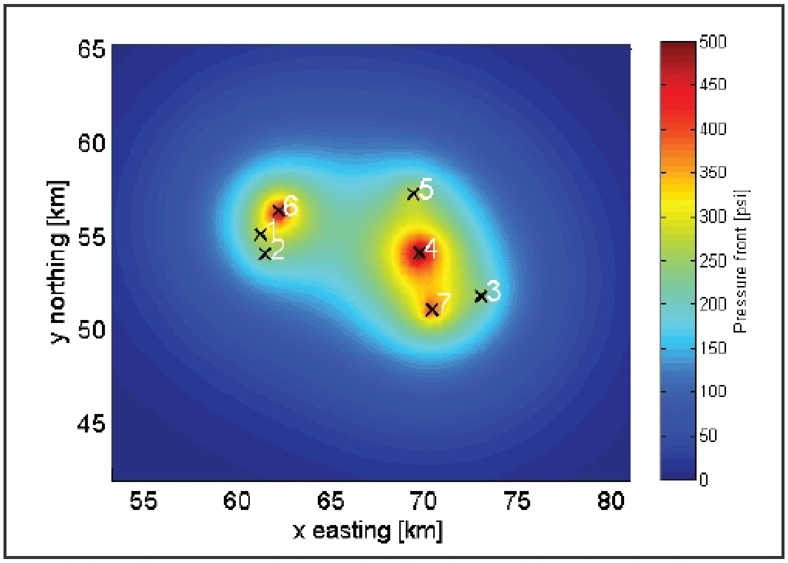
***Figure 3.5-1**: Map showing Siluro-Devonian injection wells and subsurface identified faults in the vicinity of the Independence AGI Wells. (Modified from Figure 18 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

<u>Table 3.5-1</u>: Input parameters and source material for FSP model simulations. (Extracted from Table 10 of Class II permit application for Independence AGI #2, Geolex, Inc.)

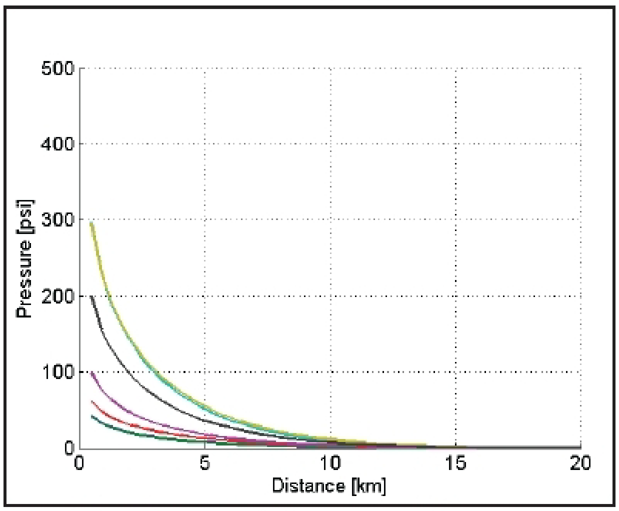
Modeled Parameter	Input Value	Variability (+/-)	UOM	Source
Stress				
Vertical Stress Gradient	1.05	0.105	psig/ft	Nearby well estimate
Max Horizontal Stress Direction	N75E	5	Deg	Lund Snee & Zoback, 2018
Reference Depth	17000		ft	Nearby well evaluation
Initial Res. Pressure Gradient	0.43	0.043	psig/ft	Lund Snee & Zoback, 2018 Nearby well evaluation
A_ϕ Parameter	0.6	0.06	-	Lund Snee & Zoback, 2018
Reference Friction Coefficient (μ)	0.6	0.06	-	Standard value
Hydrologic				
Aquifer Thickness	1500	0	ft	Nearby well evaluation
Porosity	3.5	0.35	%	Nearby well evaluation
Permeability	20	2	mD	Nearby well evaluation
Material Properties				
Density (Water)	1040	40	Kg/m^3	Standard value
Dynamic Viscosity (Water	0.0008	0.0001	Pa.s	Standard value
Fluid Compressibility (Water)	3.6×10^{-10}	0	Pa^{-1}	Standard value
Rock Compressibility	1.08×10^{-9}	0	Pa^{-1}	Standard value
Acid Gas Properties @ 7,370 psig & 228 °F				
Density	821.80	-	kg/m^3	AQUAlibrium™
Dynamic Viscosity	8.067×10^{-5}	-	Pa.s	AQUAlibrium™

<u>Table 3.5-2</u>: Location and characteristics of injection wells modeled in the FSP assessment. (Extracted from Table 11 of Class II permit application for Independence AGI #2, Geolex, Inc.)

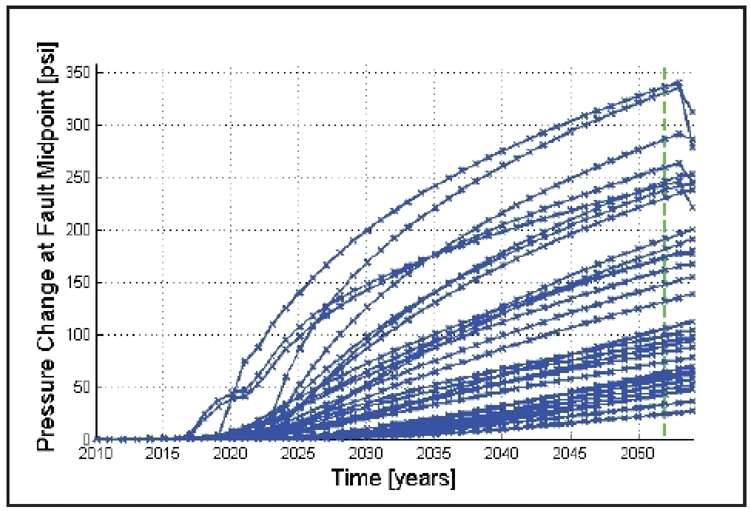
#	API	Well Name	LAT	LONG	Volume (bbls/day)	Start (year)	End (year)
1	3002548081	Independence AGI #1	32.120855	-103.291021	4265	2020	2052
2	-	Independence AGI #2	32.111454	-103.288812	4265	2022	2052
3	3002524287	Crosby Deep #2	32.089508	-103.166733	6800	2010	2052
4	3002545795	Sholes Deep SWD #1	32.110998	-103.201266	30000	2020	2052
5	3002527085	Jal N. Ranch SWD #1	32.139347	-103.203911	10000*	2017	2052
6	3002525046	West Jal B Deep #1	32.132091	-103.280708	30000	2015	2052
7	3002543360	Kimberly SWD #1	32.083537	-103.194274	20000	2019	2052



Panel A. Resultant pressure front after 30 years of injection operations at the maximum anticipated injection rates, as reported in **NMOCD** records



Panel B. Single well radial pressure solutions, as determined by the FSP model

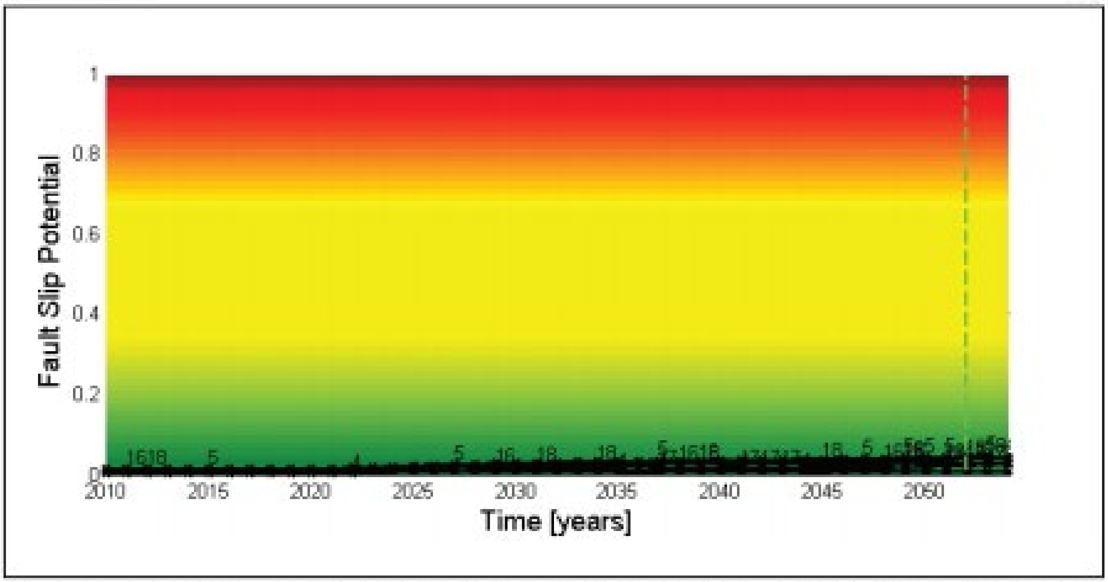


Panel C. Model-predicted pressure change through time at the midpoint of each fault segment included in the simulation

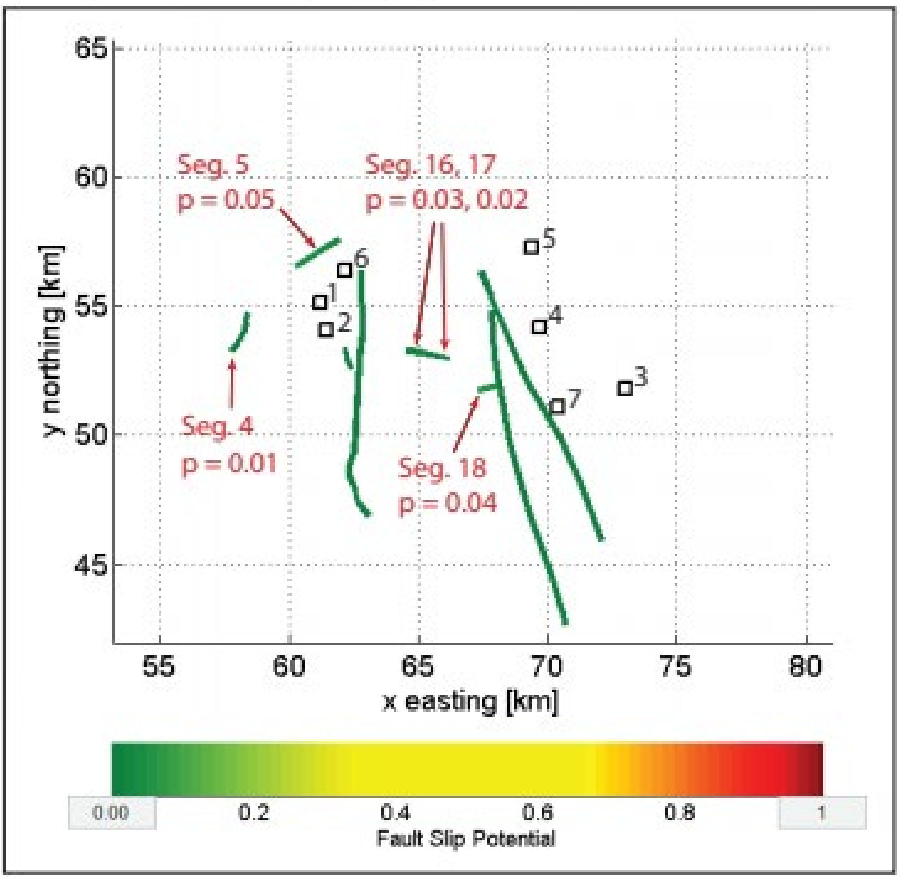
<u>Figure 3.5-2</u>: Summary of model-predicted pressure effects in response to the simulated seven (7) well injection scenario. (Extracted from Figure 19 of Class II permit application for Independence AGI #2, Geolex, Inc.)

***Table 3.5-3**: Summary of model-simulation results showing the required pressure change to induce fault slip, actual change in pressure as predicted by the FSP model, probability of fault slip at the end of the thirty (30) year injection scenario, and fault-slip probability when Independence AGI #2 is excluded from simulation. (Extracted from Table 12 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

Fault #	Segment #	ΔPressure necessary to induce fault slip	Actual ΔPressure at 2052	Fault Slip Potential at 2052	FSP (excluding AGI #2)
1	1	3137	109	0.00	0.00
	2	4357	103	0.00	0.00
	3	1786	93	0.00	0.00
	4	1201	83	0.01	0.01
2	5	1197	253	0.05	0.05
3	6	6869	186	0.00	0.00
	7	6298	168	0.00	0.00
4	8	5645	277	0.00	0.00
	9	4610	194	0.00	0.00
	10	5005	117	0.00	0.00
	11	2709	70	0.00	0.00
	12	5302	63	0.00	0.00
	13	6339	57	0.00	0.00
	14	6899	51	0.00	0.00
	15	4197	46	0.00	0.00
5	16	1101	192	0.03	0.03
	17	1085	199	0.02	0.02
6	18	1554	234	0.04	0.04
7	19	6012	290	0.00	0.00
	20	6680	241	0.00	0.00
	21	6914	133	0.00	0.00
	22	6758	61	0.00	0.00
	23	6931	33	0.00	0.00
	24	6590	25	0.00	0.00
8	25	6508	250	0.00	0.00
	26	6327	334	0.00	0.00
	27	5455	228	0.00	0.00
	28	6305	174	0.00	0.00
	29	6684	89	0.00	0.00



Panel A. Fault-slip probability throughout the entire simulated injection period. FSP model results suggest no significant risk of injection-induced slip along any feature included in the simulation.



Panel B. Map view illustrating the model-estimated slip potential of faults at the end fo the 42-year injection scenario. Any feature estimated to have a non-zero slip potential determination is labeled on the above map.

<u>Figure 3.5-3</u>: Summary of model-determined fault-slip probabilities over the simulated injection period (2010-2052). (Modified from Figure 20 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.6 Groundwater Hydrology in the Vicinity of the Dark Horse Facility

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are fifteen (15) water wells and points-of-diversion located within a two (2) mile radius of the Independence AGI Wells. Of these wells, the closest is located approximately 0.34 miles away and has a total depth of 505 feet (Figure 3.6-1 and Table 3.6-1). The remaining fourteen (14) wells within the two (2) mile radius have depths of approximately 240 to 600 feet deep, collecting water from Alluvium and the Triassic red beds. The shallow freshwater aquifer will be protected as the Independence AGI Wells are designed to isolate shallow zones via a five (5) string casing design including a surface casing interval that extends to 1,230 feet within the Rustler Formation, effectively isolating shallow groundwater resources (Figures A1-1 and A1-2).

The area surrounding the Independence AGI Wells is arid and there are no surface water bodies within a two (2) mile radius.

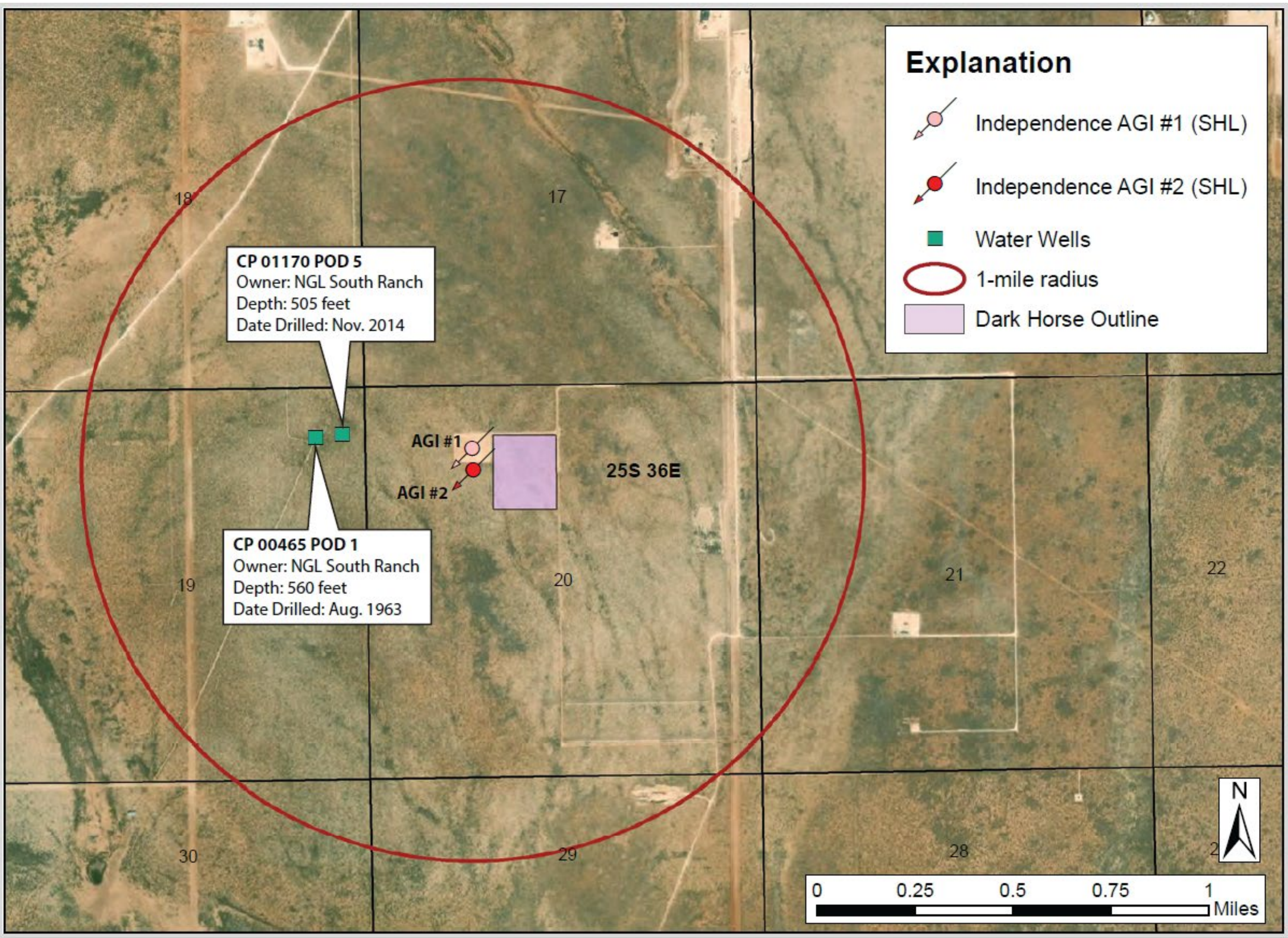


***Figure 3.6-1**: Reported water wells within 1-mile radius of the SHLs of the Independence AGI Wells. The BHLs for AGI #1 and #2 are not shown. (Extracted from Figure 17 of Class II permit application for Independence AGI #2, Geolex, Inc.) Only SHLs shown for the Independence AGI #1 and #2 wells.*

***Table 3.6-1**: Water wells within one (1) mile of the Independence AGI Wells (Retrieved from the New Mexico Office of the State Engineer's Files on October 4, 2021). (Extracted from Table 8 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

POD #	Source	Use	Owner	LAT (NAD83)	LONG (NAD83)	Distance (miles)	Depth (feet)	Date Completed
CP 1170 POD 5	Shallow	Commercial	NGL South Ranch	32.121417	-103.296667	0.34	505	11/2014
CP 465 POD 1	Shallow	Commercial	NGL South Ranch	32.119465	-103.299882	0.53	560	08/1963

According to Order No. 190 of the New Mexico Office of the State Engineer signed March 22, 2021, the Capitan Underground Water Basin, within which the Independence AGI Wells lie, is closed indefinitely to new appropriations of water. Therefore, no new water wells are anticipated to be constructed during the Independence AGI Wells' anticipated thirty (30) year operation period. Due to the shallow completion depths of the few groundwater wells in the area surrounding the Independence AGI Wells, it is highly unlikely that groundwater wells will serve as conduits for CO_2 leakage to the surface.

Geolex conducted a review of Geology and Ground-Water Conditions in Southern Lea County, New Mexico (Nicholson and Clebsch, 1961) to identify published groundwater data representative of nearby water wells in the area surrounding the Independence AGI Wells. Table 3.6-2 summarizes the wells identified in this review and the results of those analyses.

***Table 3.6- 2**: Chemical analysis results of samples collected from water wells in the area surrounding the Independence AGI Wells (Nicholson and Clebsch, 1961 – Geology and Groundwater Conditions in Southern Lea County, New Mexico). (Taken from Table 9 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

Historical Owner	Location (T-R-S)	Location (Qtr-Qtr)	Depth (ft)	Ca (ppm)	Mg (ppm)	Na+K (ppm)	HCO_3 (ppm)	SO_4 (ppm)	Cl (ppm)	NO_3 (ppm)
Sun Oil Co.	25-37-15	NE/4 NE/4	-	307	98	271	145	737	610	9
City of Jal	25-37-19	NE/4 NE/4	500	55	49	170	376	280	71	0.4
City of Jal	25-37-19	SE/4 NE/4	450	34	43	175	264	286	54	0.5
City of Jal	25-37-20	NW/4 SW/4	70	-	-	-	150	145	168	7.6

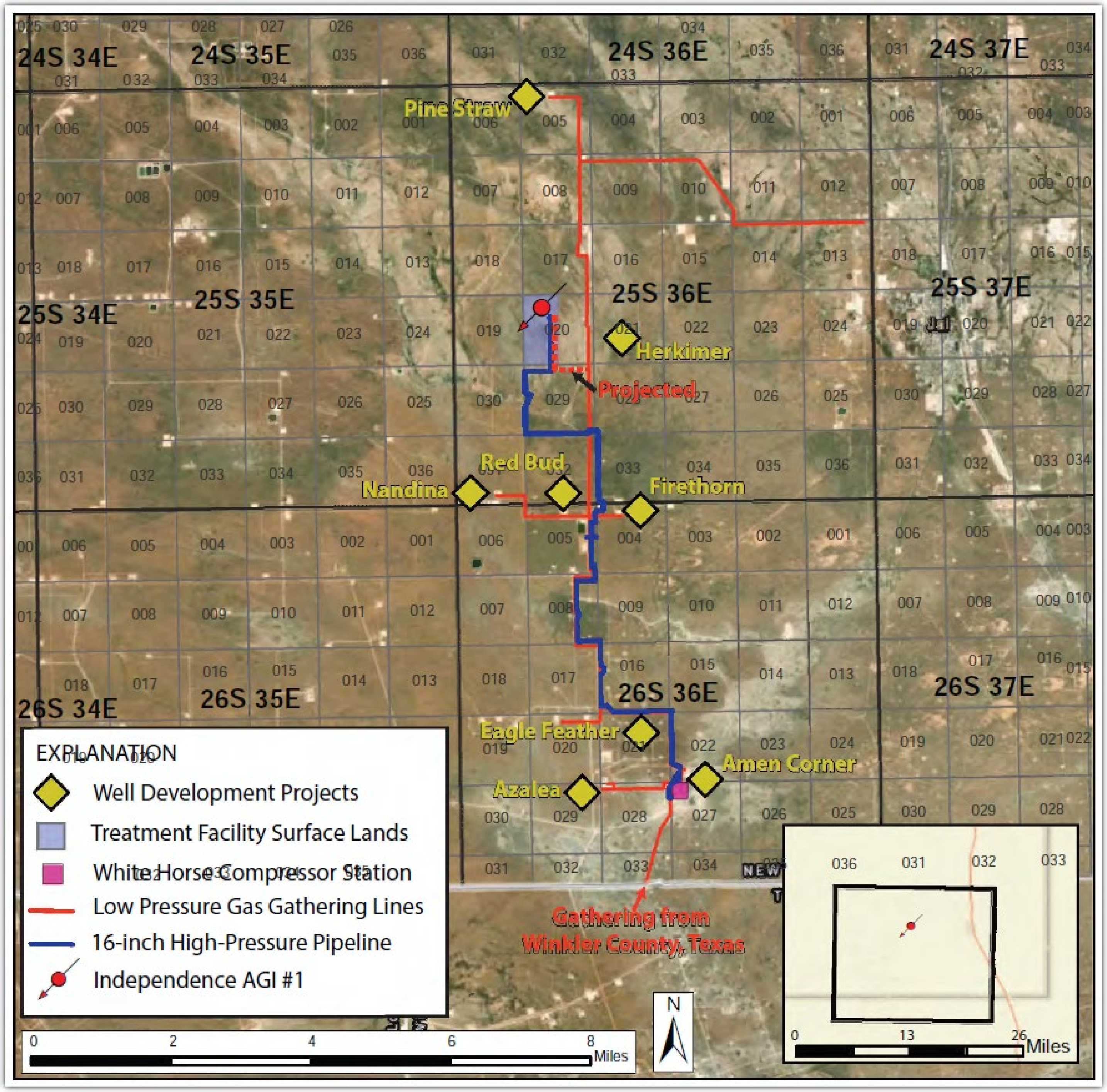
This analysis confirms that the Independence AGI Wells pose no risk of contaminating groundwater in the area as (a) the well design includes material considerations to protect shallow groundwater resources, and (b) there are no identified conduits that would facilitate migration of injected fluids to freshwater-bearing strata nor to the surface.

3.7 Historical Operations

3.7.1 Dark Horse Facility and Independence AGI Wells

Piñon operates the Dark Horse Facility which treats sour natural gas that is delivered to the facility from gathering systems in the area. These gathering systems are shown in Figure 3.7-1. Figure 3.7-2 shows the major process units and the H_2S and gas detection sensors. The figure in Appendix 10 shows the process block flow diagram for the Dark Horse Facility. The Dark Horse Facility is designed to treat produced natural gas containing H_2S and CO_2 and handles and/or generates sulfur dioxide (SO_2). Ameredev received authorization to inject H_2S and CO_2 from the NMOCD and drilled and completed Independence AGI #1, which is utilized for the injection and permanent sequestration of TAG. Procedures and materials used by Ameredev for well operations and construction are consistent with NMOCD regulations pertaining to "Protection from Hydrogen Sulfide during Drilling,

Completion, Workover and Well Servicing Operations" (NMAC 19.15.11.11). Following drilling and completion of the Independence AGI #1, and after approval by NMOCD, Ameredev contributed and assigned operations of the well to Piñon. Piñon became the operator of record for the Independence AGI #1 on August 24, 2021.



<u>Figure 3.7-1</u>: Location of gas gathering lines leading to the Dark Horse Gas Treatment Plant and White Horse Compression station. Low pressure lines either lead to the compressor station or directly to the treatment plant. Gas sent to the compressor station is sent to the treatment plant via a 16-inch high-pressure pipeline.

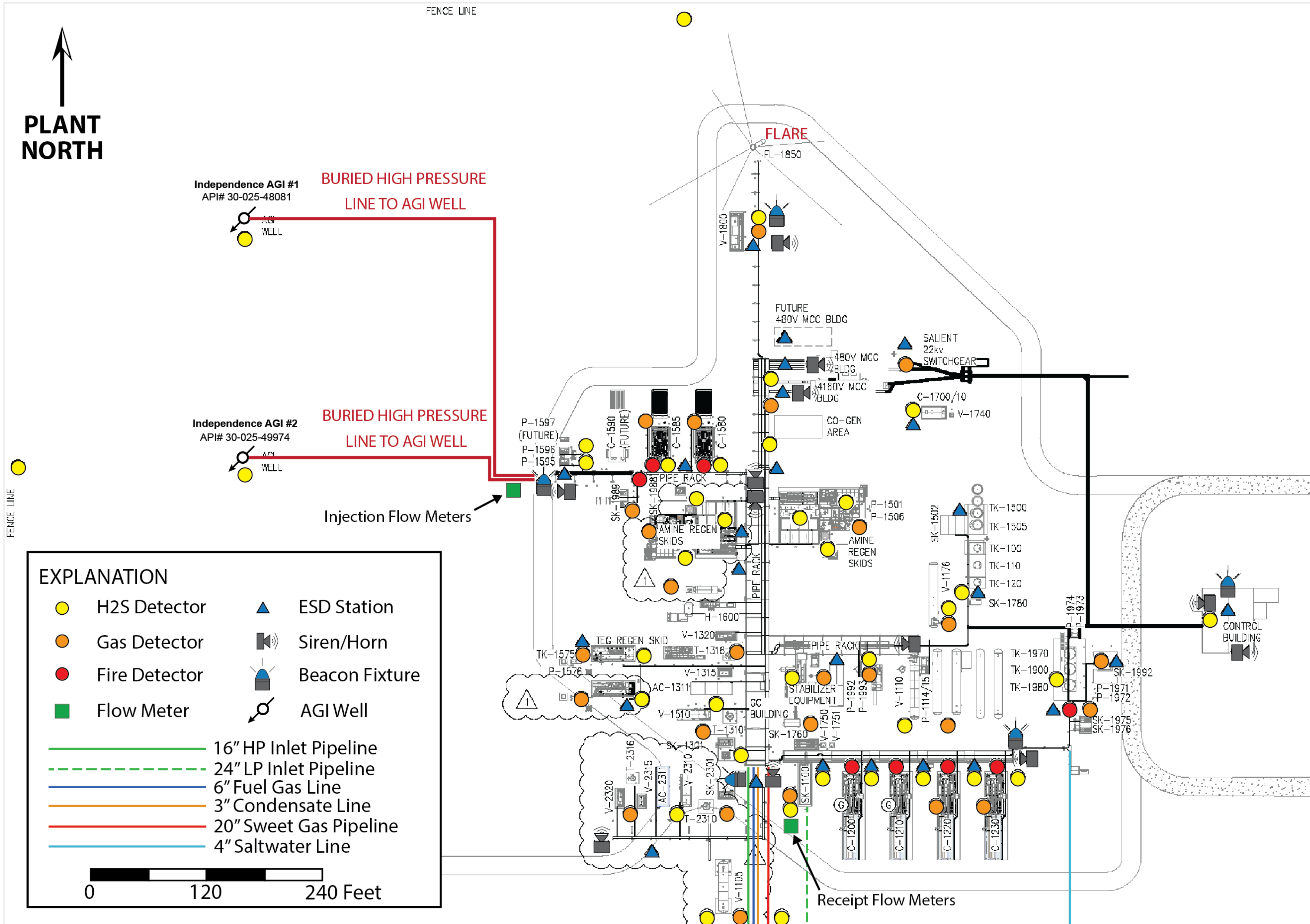


***Figure 3.7-2**: Detailed Dark Horse Facility schematic illustrating the location of major process units, all emergency equipment, H_2S and gas detection sensors, sirens and beacons, and major gas flow lines at the facility. (Taken from Figure 2 of the H_2S Contingency Plan for Dark Horse Gas Treatment Facility, Geolex, Inc.). The yellow circles indicate the location of fixed H_2S sensors.*

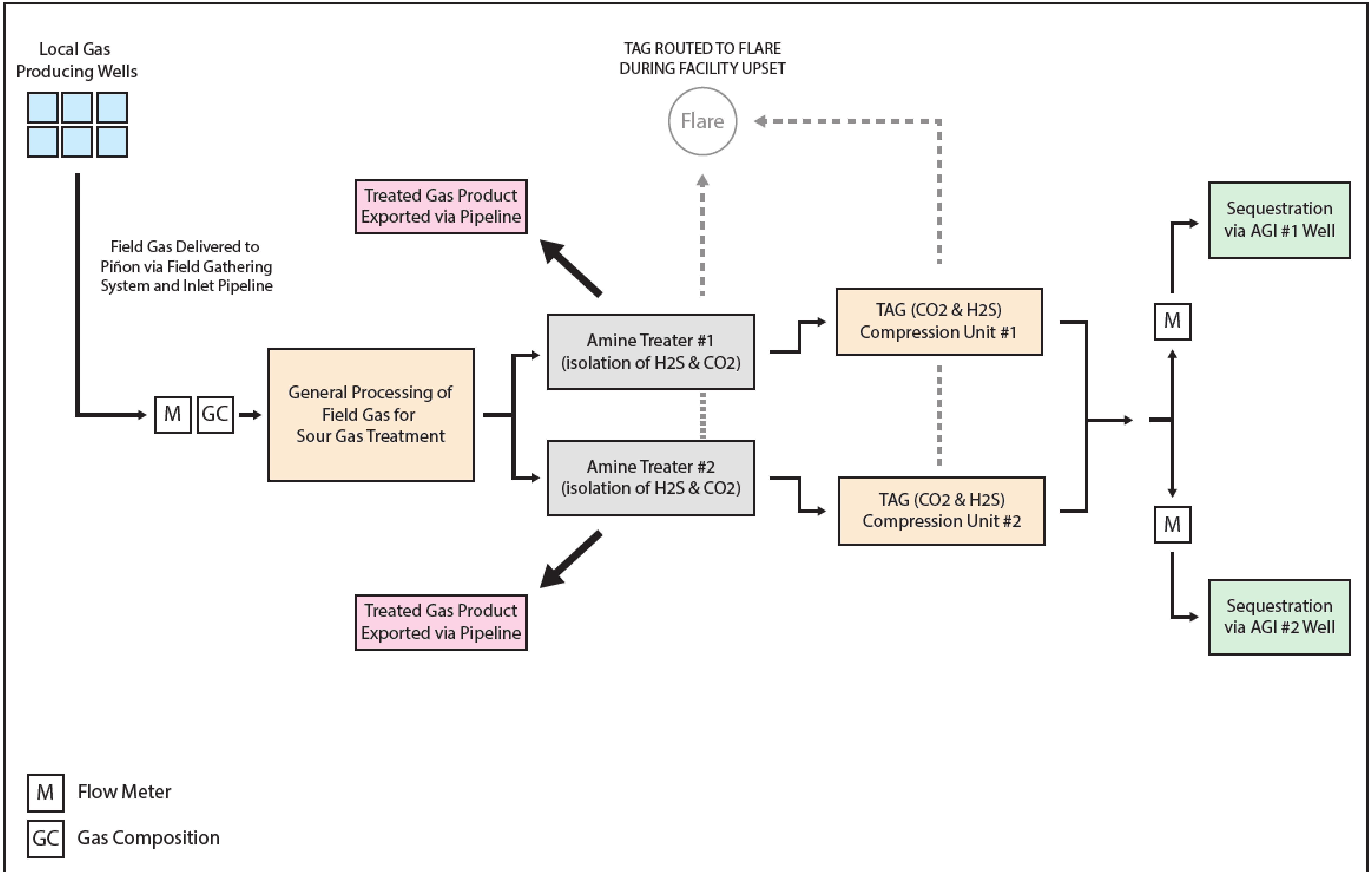


Figure 3.7-2.b: Dark Horse Facility General Flow and Measurement Schematic illustrating the location of flow and gas composition meters for the facility related to the calculation of CO_2 for this facility.

3.7.2 Operations within a 2-mile radius of the Independence AGI Wells

Appendix 3 summarizes in detail all NMOCD recorded wells within a two (2) mile radius of the Independence AGI Wells. These wells are shown in Figure 3.7-3 and include active, plugged, and new (permitted but not yet drilled) well locations. In total, there are fifty-four (54) wells within a two (2) mile radius of the Independence AGI Wells. Of these, there are ten (10) active wells, thirty-three (33) permitted wells, and eleven (11) plugged wells.

Active wells in the area include one brine injection well completed across the Strawn through Fusselman formations, and nine (9) active oil and natural gas wells completed in various other strata. There are two (2) third-party wells within two (2) miles of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone (Table 3.7-1).

The first well is an active brine injection well (West Jal B Deep #001) located approximately one (1) mile from the Independence #2 SHL. This well was drilled to a total depth of 18,945 feet and is permitted to inject through perforated intervals of the Strawn through Fusselman strata. A Form C-103- Sundry Notices and Reports on Wells, submitted November 2018 contain a wellbore diagram that shows the locations of two cast iron bridge plugs ("**CIBP**"). The first CIBP is at a measured depth of 14,200 feet (within the lower Atoka Formation), and the second CIBP is at a measured depth of 17, 100 feet (within the Fusselman Formation). Despite BC & D Operating being granted approval for injection into the Fusselman (approved by NMOCD June 2014), NMOCD records document no reports of work to drill out the CIBP at 14,200 feet. The same Form C-103- Sundry Notices and Reports on Wells mentioned above indicates the intent of BC & D Operating to drill out the CIBP, but there have been no identified subsequent reports confirming completion of this work. Additionally, reported injection volumes since the filing of the Form C-103 in November 2018 for this well do not appear to exhibit any significant increase that might indicate this work was completed. Furthermore, according to a search of publicly available data as of June 2023, the West Jal B Deep #001 ceased water injection operations during or after July 2022, and water injected volumes have been reported as "0" since July 2022.

The second well penetrating the Siluro-Devonian Injection Zone is the plugged West Jal Unit #1, located approximately 0.67 miles from the Independence AGI #2 SHL. Final plugging operations were completed in April 1984 and all relevant plugging reports and documents are included in Appendix 9. The well is properly cemented through the Siluro-Devonian Injection Zone, and it is not anticipated to be negatively affected by the operation of the Independence AGI Wells nor is it considered to be a likely pathway for CO_2 leakage to the surface.

Appendix 3 and Figure 3.7-3 also show a number of wells in the area which have approved permits to drill but are not yet drilled. The new oil and natural gas wells are targeting various production zones, more than 4,000 feet above the Siluro-Devonian Injection Zone for the Independence AGI Wells. All new oil and natural gas wells and injection wells are subject to the requirements of regulations governing sealing off strata (NMAC 19.16.16.10) and casing and tubing requirements (NMAC 19.16.16.10) to prevent the contents of production or injection zones from passing into other strata. To minimize the likelihood of leaks from new wells, NMAC 19.15.26.9 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." Therefore, due to the fact that these wells do not penetrate the Siluro-Devonian Injection Zone, and that the wells are more than 4,000 feet above the Siluro-Devonian Injection Zone, Piñon does not consider these new wells to be pathways for CO_2 leakage to the surface. In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage.

<u>Table 3.7-1</u>: Wells located within a two (2) mile radius of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone. (Additional details are provided in <u>Appendix 3</u>)

API	Well Name	Pool	Status	TVD (feet)
30-025-21172	WEST JAL UNIT #1	Strawn	Plugged	17,086
30-025-48081	INDEPENDENCE AGI #1	Devonian - Fusselman	Active	17,750
30-025-49974	INDEPENDENCE AGI #2	Devonian - Fusselman	New	17,683 (proposed)
30-025-25046	WEST JAL B DEEP #001	Mississippian – Fusselman	Active	18,945

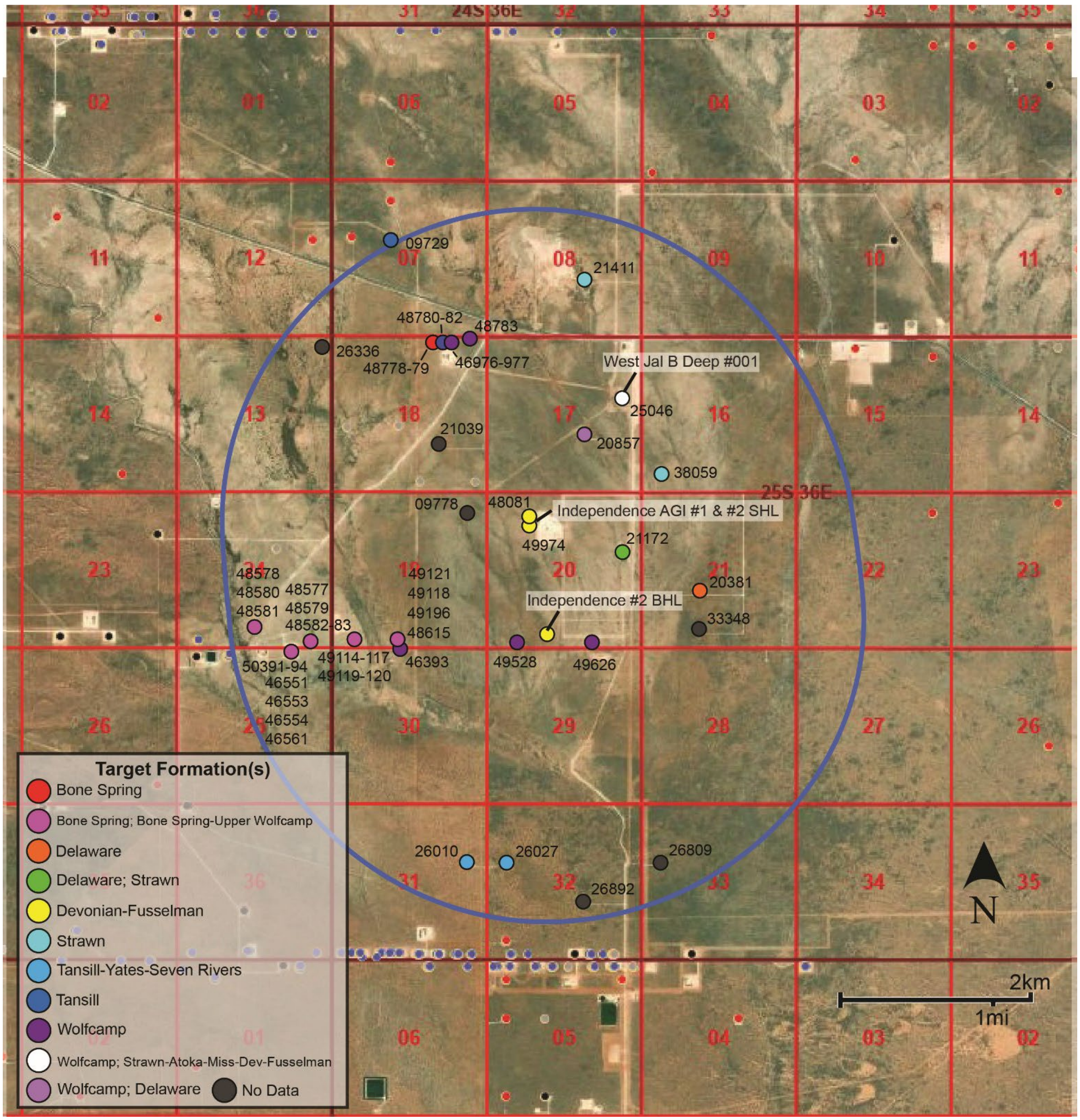


***Figure 3.7-3**: Location of all oil- and natural gas-related wells within a two (2) mile (blue line) of the Independence AGI Wells. Colors indicate the target formation(s) for each well. The oblong shape of the two (2) mile area accounts for the BHL of Independence AGI #2 as shown in Figure 3.1-1. Labels denote the last five (5) digits of API #30-025-XXXXX. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.*

3.8 Description of Injection Process

Once delivered to the Dark Horse Facility, sour natural gas is treated using amine to isolate H_2S and CO_2. The amine (which now contains H_2S and CO_2) is then regenerated which creates a TAG waste stream. This TAG waste stream is then routed to on-site compression facilities that compress the TAG waste stream into a dense phase (roughly 1,250 psig). The dense phase stream is then pumped to upwards of 2,500 psig prior to being sent to the Independence AGI Wells, through a National Association of Corrosion Engineers ("**NACE**") rated pipe, for injection. Figure 3.8-1 is a schematic of the surface facilities for the Independence AGI Wells. The sweet natural gas that results from the amine scavenging process is then treated to remove water ("**H_2O**") and subsequently transported offsite, via pipeline, and redelivered to Piñon's customers at various delivery points.

For the period of September 2021 through March 2022, the TAG stream at the Dark Horse Facility averaged 57.076% CO_2 and 38.703% H_2S by volume, with hydrocarbons (C1 – C7) and H_2O comprising the remaining volume.

The anticipated duration of TAG injection into the Independence AGI Wells at the Dark Horse Facility is approximately thirty (30) years.

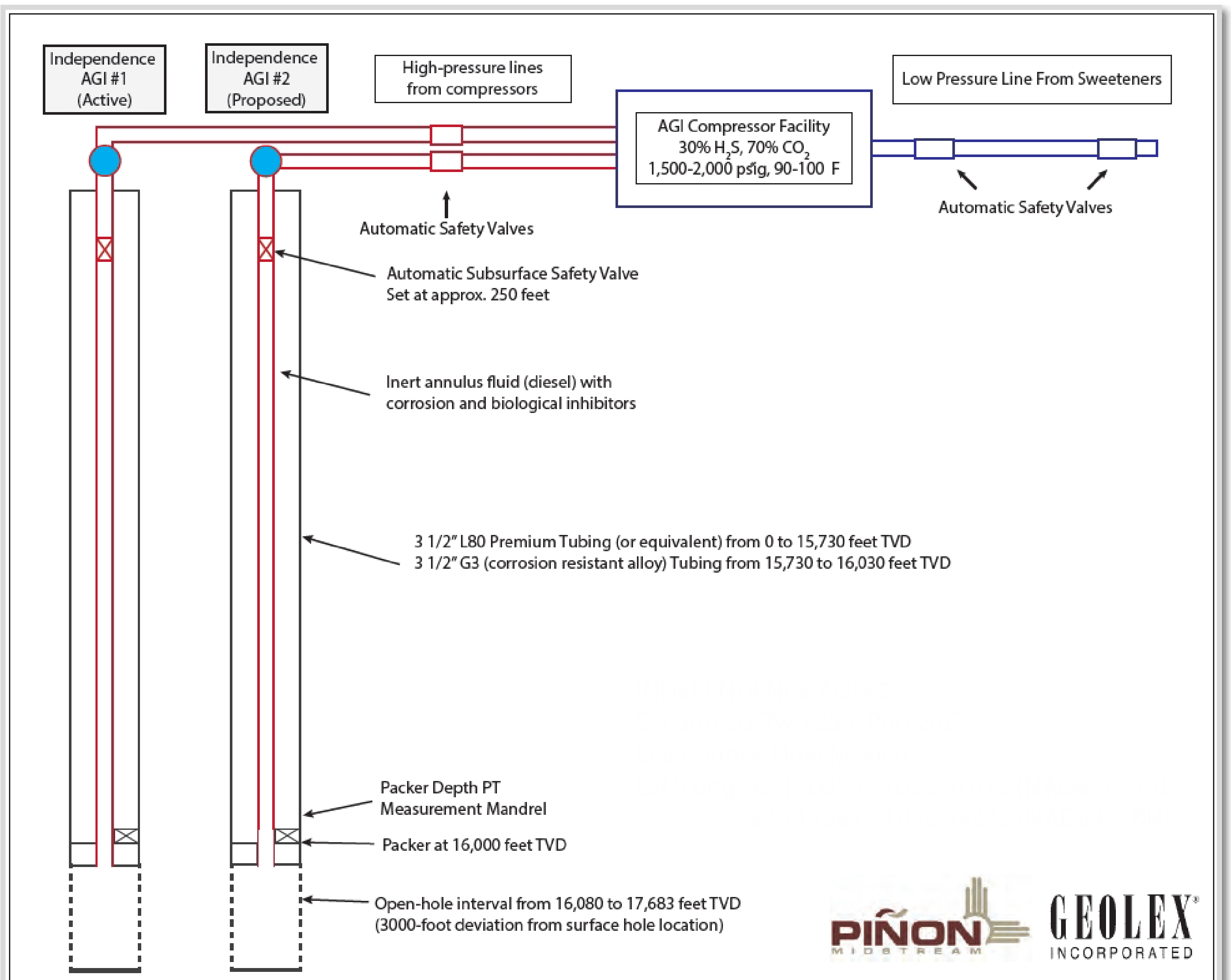


Figure 3.8-1: Schematic of surface facilities at the Dark Horse Facility and the Independence AGI Wells. (Modified from Figure 3 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.9 Reservoir Characterization Modeling

The Independence AGI Wells penetrate the lower Devonian Thirtyone formation and the Silurian Wristen and Fusselman formations and overlie the Ordovician Montoya formation. The upper Devonian Woodford formation serves as the primary containment seal with thick shales having an estimated permeability in the nanodarcy range.

Schlumberger's Petrel (Version 2020.4) software was used to construct the geological models used in this work. Schlumberger's simulation software Eclipse Compositional E300 (Version 2020.1) was used in the reservoir simulations presented in this MRV Plan with simulation results and visuals provided by Geolex Inc. The model simulates solubility trapping of the injected TAG in the formation water and/or the portion of the TAG that can exist in a supercritical phase. The modeling did not consider CO_2 storage attributed to mineral and geomechanical trapping mechanisms. Also, the model did not implicitly model storage attributed to residual trapping because insufficient information was available to develop the hysteresis effects.

Though the Independence AGI Wells were modeled separately, similar constraints were used for both models. The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. The injection gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Both TAG components are assumed to be soluble into the aqueous phase. An irreducible water saturation of 0.17 is used to generate the relative permeability curves for the gas/water system. The external boundary conditions are specified to be Neumann boundaries and hence no-flow with respect to mass.

3.9.1 AGI Injection Characterization and Modeling

Formation tops were picked from the few well logs available for the area and geophysical measurements and mapped to construct the structural surfaces for the Silurian-Devonian reservoir between the underlying Montoya and capping Woodford formations. The geologic model extends approximately twenty (20) square miles with an irregular polygonal edge (Figure 3.9-1) and includes relevant subsurface features (e.g. faults, folds) and nearby injection wells. The simulation grid is comprised of 292 simulation layers characterizing eight (8) discrete zones. Horizontal spacing is uniform at 500 × 500 feet throughout the model, and the numerical grid overall contains 923,000 grid cells. Figure 3.9-1 shows the structural surface for Layer 1, covering the top of the reservoir immediately below the Woodford cap. Porosity data derived from the Independence AGI #1 well logs augmented by 3D seismic survey impedance data along with drill-stem and injection tests were used to populate the model porosity values (Figure 3.9-2). A porosity-permeability relationship was established to develop a correlation to populate 3D distribution of permeability (Figure 3.9-3). The permeability distribution signifies a fairly tight formation with typical values ranging from 1.0 to 79.0 millidarcies. Figure 3.9-4 shows the permeability distribution in Layer 1 of the model at the top of the Devonian Thirtyone Formation (*see* Section 3.3.1). Separate scenarios were run for non-transmissive faults and for permeability across faults.

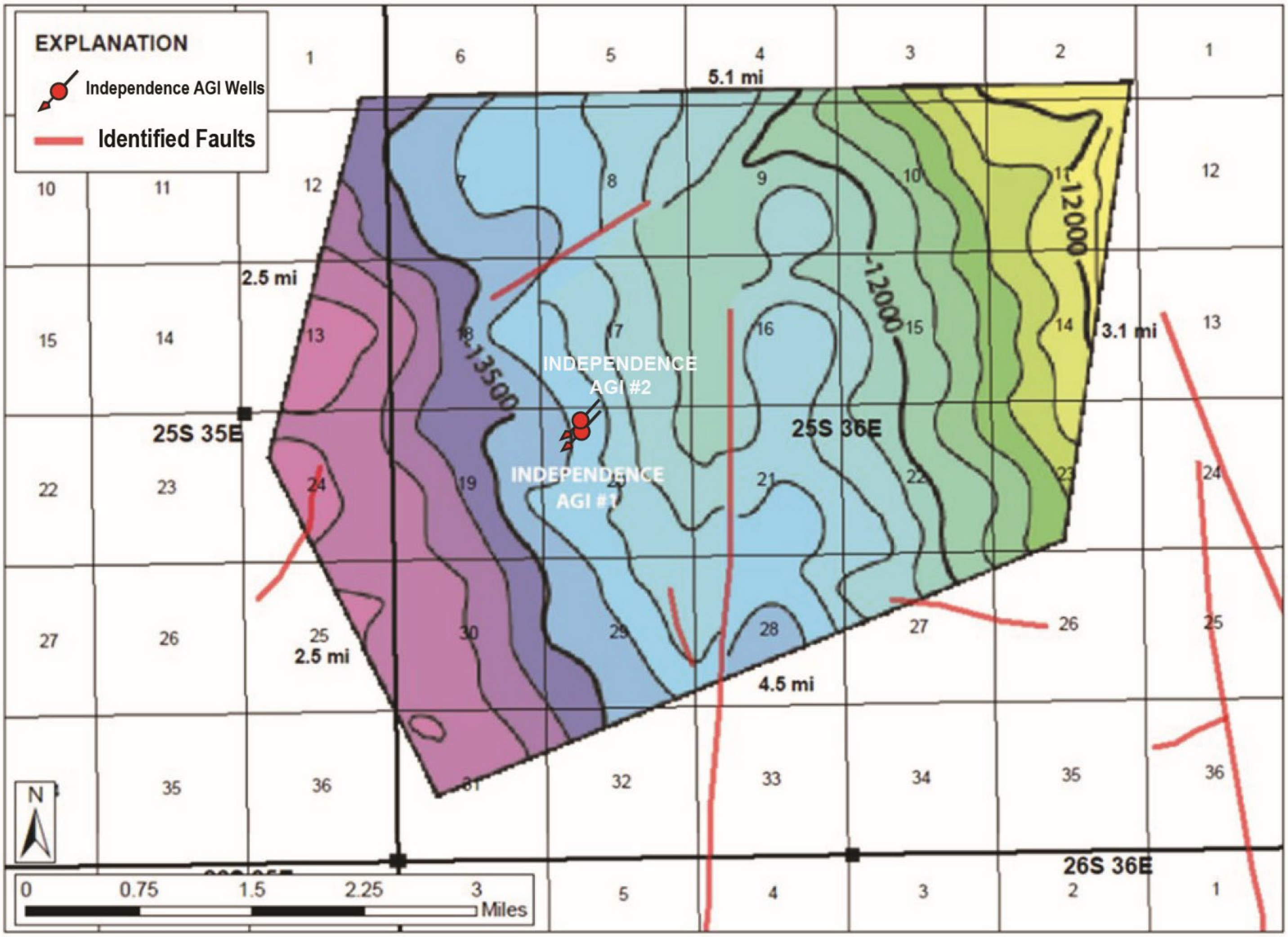
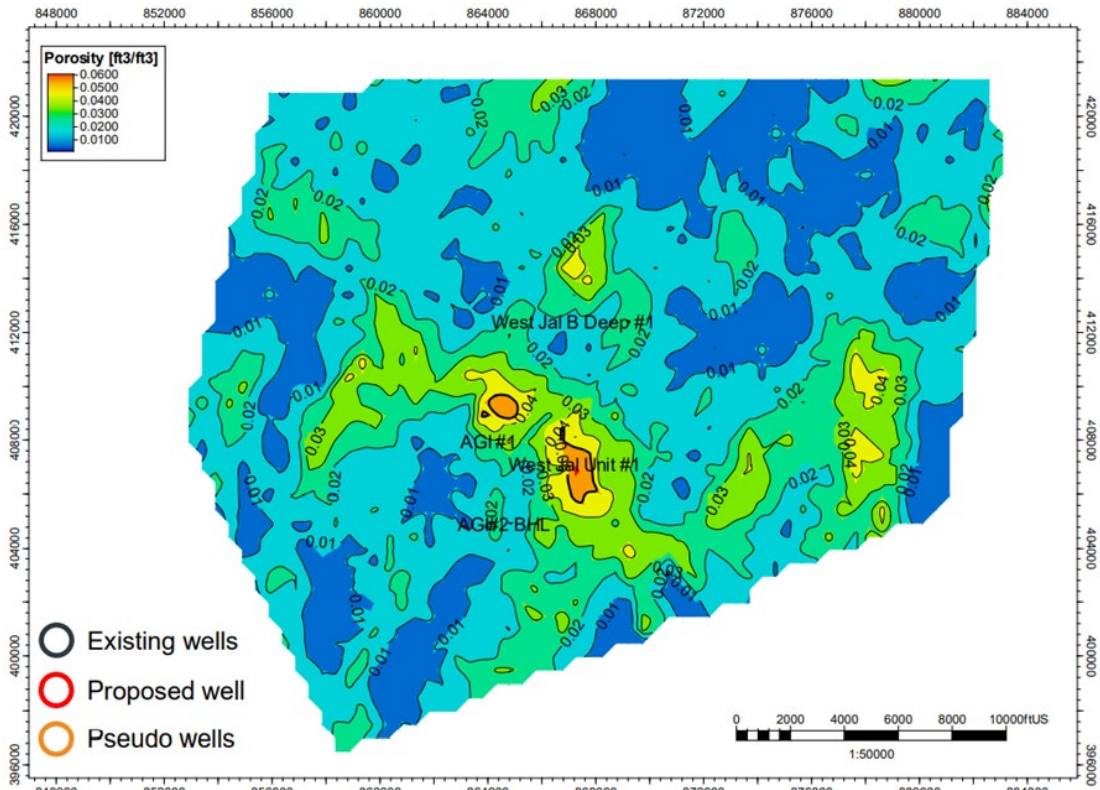
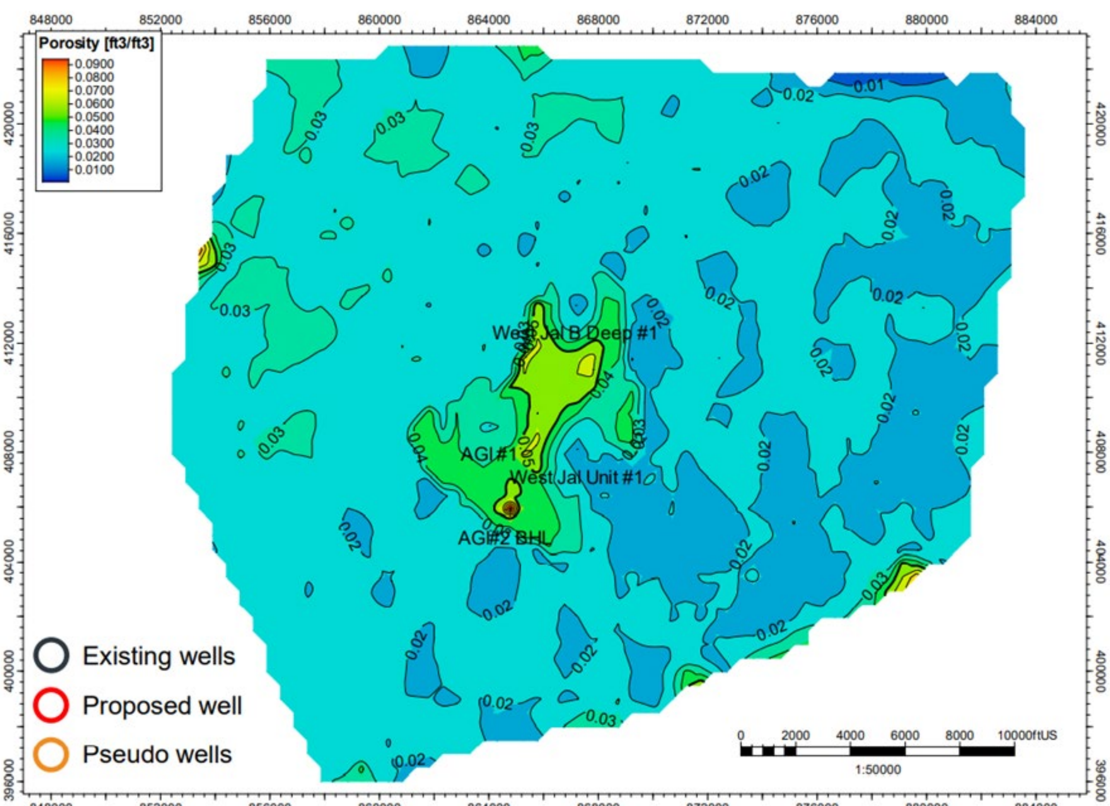


__Figure 3.9-1__: Structural surface for top of Layer 1 (top) of the geological and numerical model. Only SHLs shown for the Independence AGI #1 and #2 wells.





<u>Figure 3.9-2</u>: Model layer porosities for Zone 1 (top) and Zones 7 and 8 (bottom). Porosities are based on 2 wells, 3D seismic impedance surveys, and well stem tests. Only SHLs shown for the Independence AGI #1 and #2 wells.

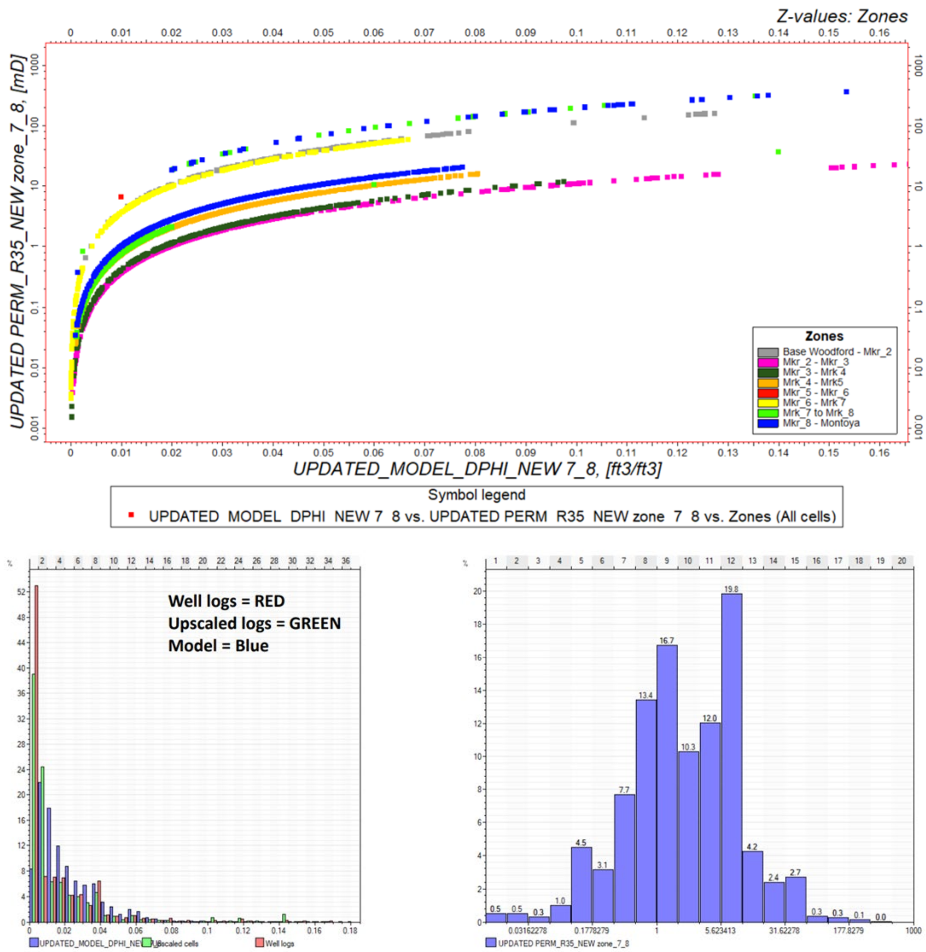
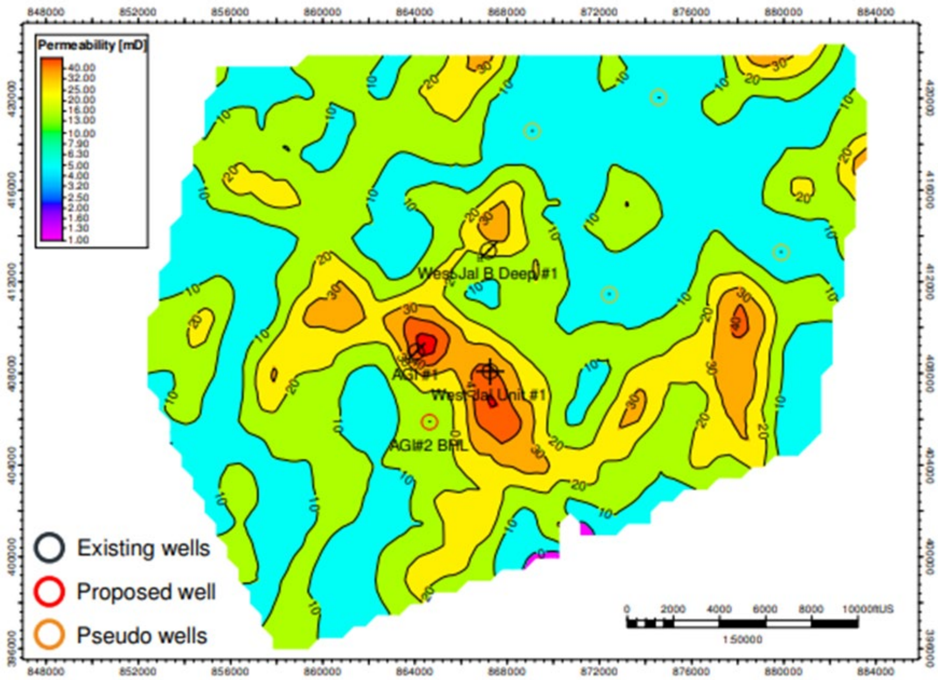


***Figure 3.9-3**: Geological zones and ranges of the properties for the Siluro-Devonian geologic model*



<u>Figure 3.9-4</u>: Graphic showing the permeability distribution in Layer 1 of the model representing the Thirtyone formation. Plan view. Only SHLs shown for the Independence AGI #1 and #2 wells.

3.9.2 Simulation Modeling for the Independence AGI Wells

Once the geological model was established, numerical modeling was performed to:

1. Assess the maximum injection rate with respect to estimated maximum bottomhole pressure ("**BHP**") to ensure safe operation, and
2. Estimate the modeled extent of the injected TAG after thirty (30) year injection period and five (5) year post injection monitoring period.

The reservoir is assumed to be initially saturated with 100% brine and exhibit hydrostatic equilibrium with the initial pressure based on the measured pressure at the top of the reservoir pre-injection. The injection gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Gas is injected for 30 years at a rate of 1,036.73 tonnes per day (378,399 tonnes per year or 11,351,970 total tonnes) followed by a 5-year rest period. Permeability curves for the multiphase gas/water system are defined for three (3) material ranges with a residual liquid saturation between 40% and 65%. An estimated maximum BHP of 9,730 psig, based on the calculated fracture pressure gradient, was imposed on the Independence AGI #1 to ensure safe injection operations. This pressure was important for Independence AGI #1 in the model scenario where all TAG was injected into Independence AGI #1, but otherwise simulations showed pressure at the Independence AGI Wells remaining below this threshold. In all simulations where West Jal Deep B #001 injected 30,000 bpd of brine into the reservoir, the West Jal Deep B #001 would need to decrease injectivity to remain below its permitted threshold pressure. Present modeling work does not indicate sufficient connectivity between the West Jal Deep B #001 and the Independence AGI Wells to impact AGI injectivity under all other modeled scenarios. <u>Figure 3.9-5</u> shows the calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1. AGI rates are lower than target numbers and limited data are available so a more detailed calibration cannot yet be constructed. An injection forecast model was performed for a period of thirty (30) years with injection and then a five (5) year post-injection rest period to ascertain fluid movement and pressure evolution. <u>Figure 3.9-6</u> shows the injection profile for the forecasting period which showed that the target injection rate could be hit in all scenarios except Scenario 5. The model showed that all the injected

gas remained in the reservoir and there was no substantive change in the size of the TAG extent compared at the end of injection and five (5) year post injection period.

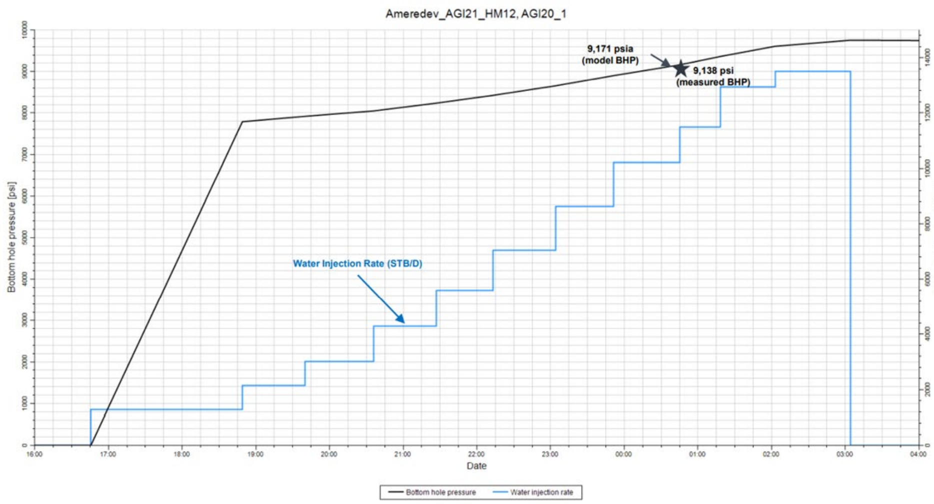


***Figure 3.9-5**: Graph showing calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1.*

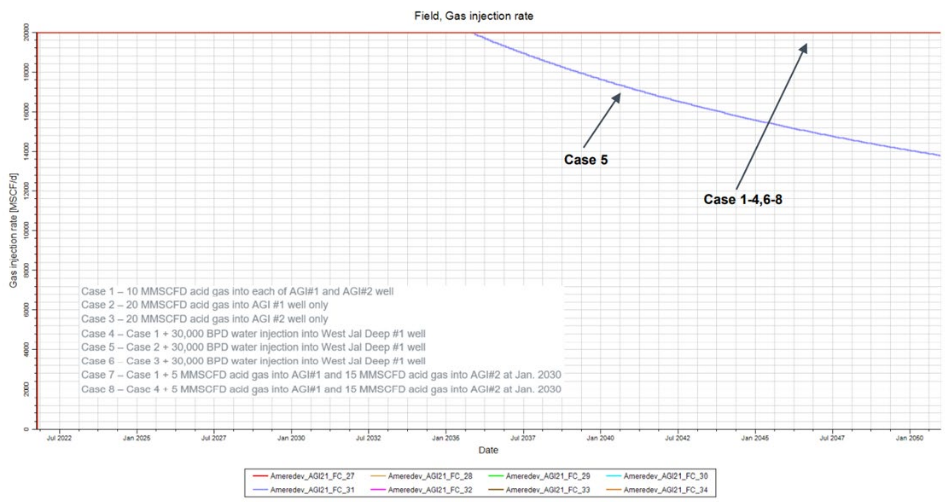


***Figure 3.9-6**: Graph showing the forecast profile for the injection rate and cumulative injection volume over the simulated period*

A considerable source of uncertainty in the plume model relates to the injectivity of the West Jal Deep B #001 well located about one (1) mile northeast of Independence AGI #1. This well is permitted to dispose of up to 30,000 bpd of brine into several reservoirs, including the Siluro-Devonian reservoir used by the Independence AGI Wells, and other shallower reservoirs. It is unclear from publicly available data how this fluid is planned to be partitioned between the various injection layers. As of this application, the wellbore currently has CIBPs at measured depths of 14,200 feet (lower Atoka Formation) and 17,100 feet (Fusselman Formation), restricting injection into the Siluro-Devonian reservoir, and no fluid is currently being injected at the well. However, since this well is permitted for injections, modeling for the present application considered two (2) end-member scenarios: (a) All West Jal Deep B #001 injection is into shallower reservoirs and does not interact with the Siluro-Devonian one (cases 1,2,3), or (b) all West Jal Deep B #001 volumes are injected into the Siluro-Devonian reservoir (cases 4,5,6,7,8). The brine injection at this well is significant for several reasons:

- High volumes of brine injection within the Siluro-Devonian in relatively close proximity of the Independence AGI Wells may raise pressure in the reservoir;

- Pressure from the brine injection pushes against the advancing gas front, directing flow south and west away from the well; and
- The West Jal Deep B #001 wellbore could be a potential leakage pathway if injection ceases and the supercritical fluid plume from the Independence AGI Wells reaches it. Simulations that do not include injections at this well have the TAG plume area including this well.

In all simulations with injection at West Jal Deep B #001, the local pressure at the brine injection well rapidly rises to the breakover point and the injection rate begins dropping within the first two (2) years of that well's operation to maintain pressures below 80% of the breakover threshold and ensure no rock fracturing occurs (Figure 3.9-7). It is unknown how in reality this will translate to well operations within the Siluro-Devonian reservoir. Simulations do not indicate that the pressure increase from this well will adversely affect the Independence AGI Wells due to the early shut down of the brine injection well. Simulations where there is no brine injection result in the plume extending farther northeast beyond the West Jal Deep B #001 well (Figure 3.9-8). If brine is injected, then the plume is repelled towards the south and west, with some TAG flanking the northwest fault and extending northwest (Figure 3.9-9). Simulations suggest a pressure impact on Independence AGI #1 that could result in curtailed injections under a scenario with all TAG injection in Independence AGI #1 and West Jal Deep B #001 active (Case 5, *see* Figure 3.9.6).

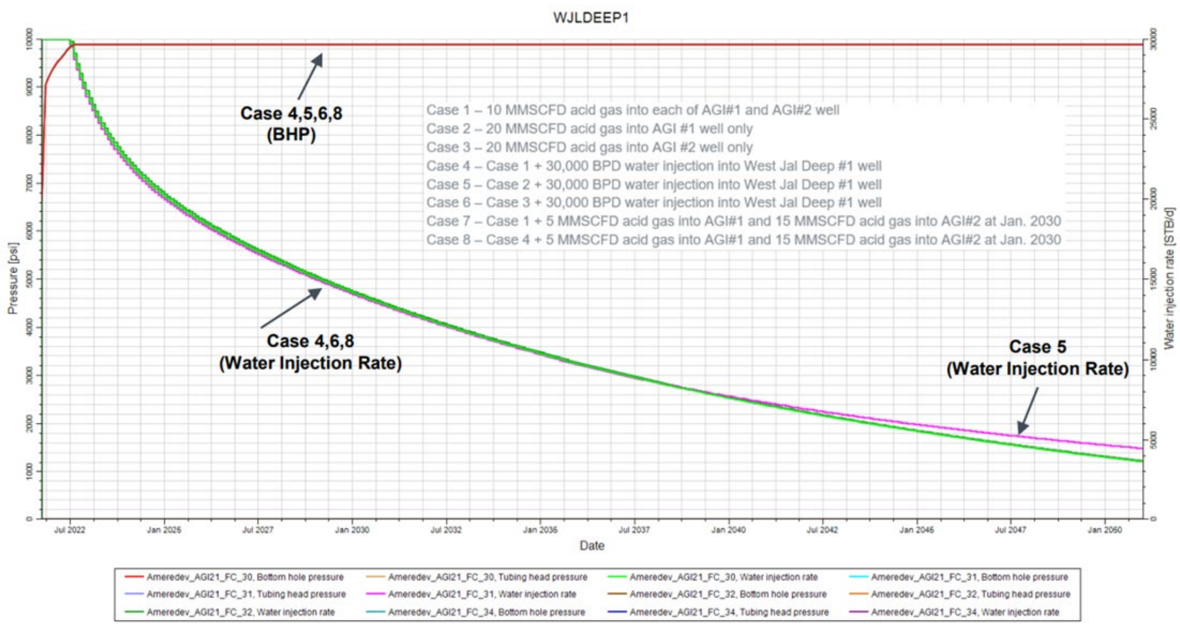


Figure 3.9-7: Graph showing the injection profile of the West Jal Deep B #001 brine injection well under different injection scenarios.

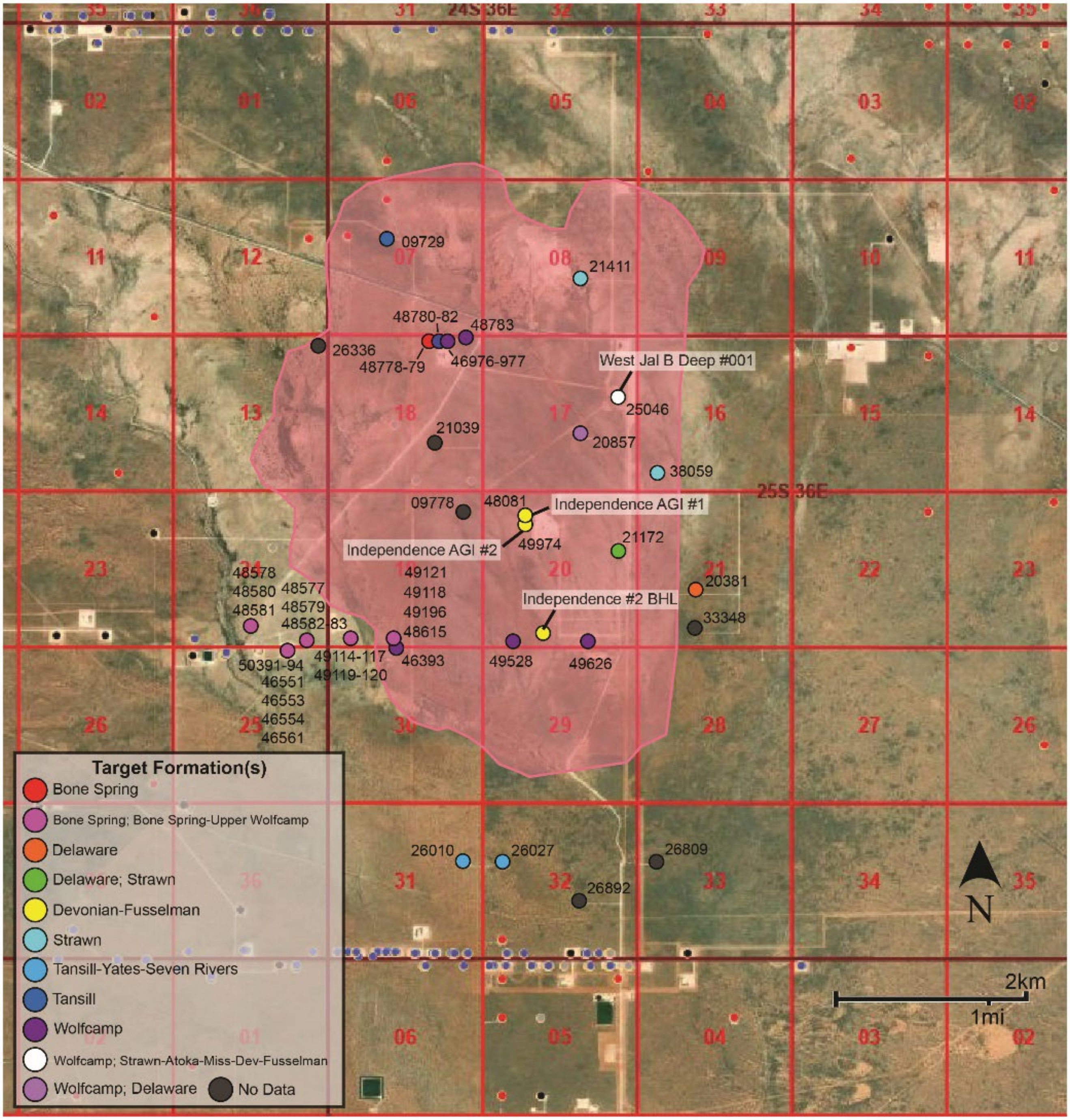
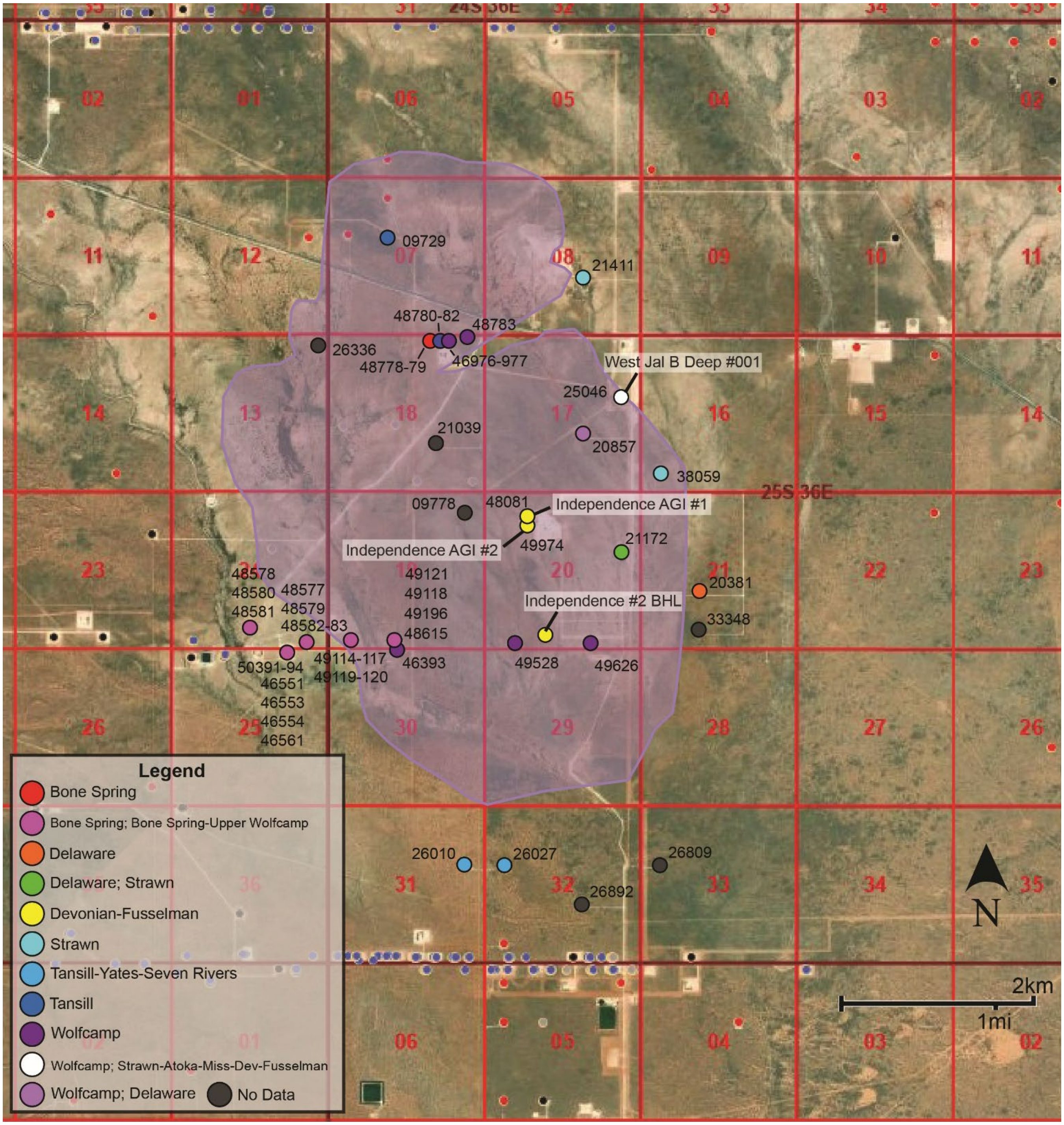


***Figure 3.9-8**: Map showing the largest lateral extent of the TAG when the West Jal Deep B #001 well does not inject into the Siluro-Devonian. Colors indicate target formations for the well. West Jal Deep B #001 is the white dot northeast of the Independence AGI Wells. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.*



<u>Figure 3.9-9</u>: Map showing the largest lateral extent of the TAG when the West Jal Deep B #001 injects an initial rate of 30,000 bpd of brine into the Siluro-Devonian. Colors indicate target formations for the well. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in <u>Figure 3.1-1</u>.

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 3.9.

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 (Figure 4.1-1). In general, the western margins of the plume retract to the east following the injection period as gas flows up-dip. In this case, the farthest plume extent and hence the MMA margin is therefore found at year 30 (year t), with the plume extent to the west shrinking by year t+5 and stabilizing. On this side, the MMA is based on the largest plume extent which is at year 30 (t). To the east, fault trapping and the anticline near the injection site generally prevent major movement eastward. Beyond year 30 (t), the plume slowly expands east and northeast, finally stabilizing around year 50 (t+20). In all cases, the plume margin polygon in Figure 4.1-1 is defined by the maximum extent of any plume in any scenario at any simulation time, with a 0.5 mile buffer extending beyond this polygon defining the margin of the MMA.

4.2 AMA – Active Monitoring Area

Piñon intends to define the AMA as the same area as the MMA. Per 40 CFR 98.449, AMA is defined as the area that will be monitored over a specific time interval from the first year of the period (n = 2023) to the last year in the period (t = 2053, a 30-year injection period). The boundary of the AMA 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 (2058, or year 35 of the simulation). However, as the plume has not fully stabilized by year t+5, the AMA and MMA in these areas is defined by the larger area of the stable plume which occurs at year t+20. This definition includes all areas at years t, t+5, and t+20. The zone shown in Figure 4.1-1 has a one-half mile buffer beyond the maximum plume extent of any scenario. Piñon intends to define the AMA as the entirety of the MMA.

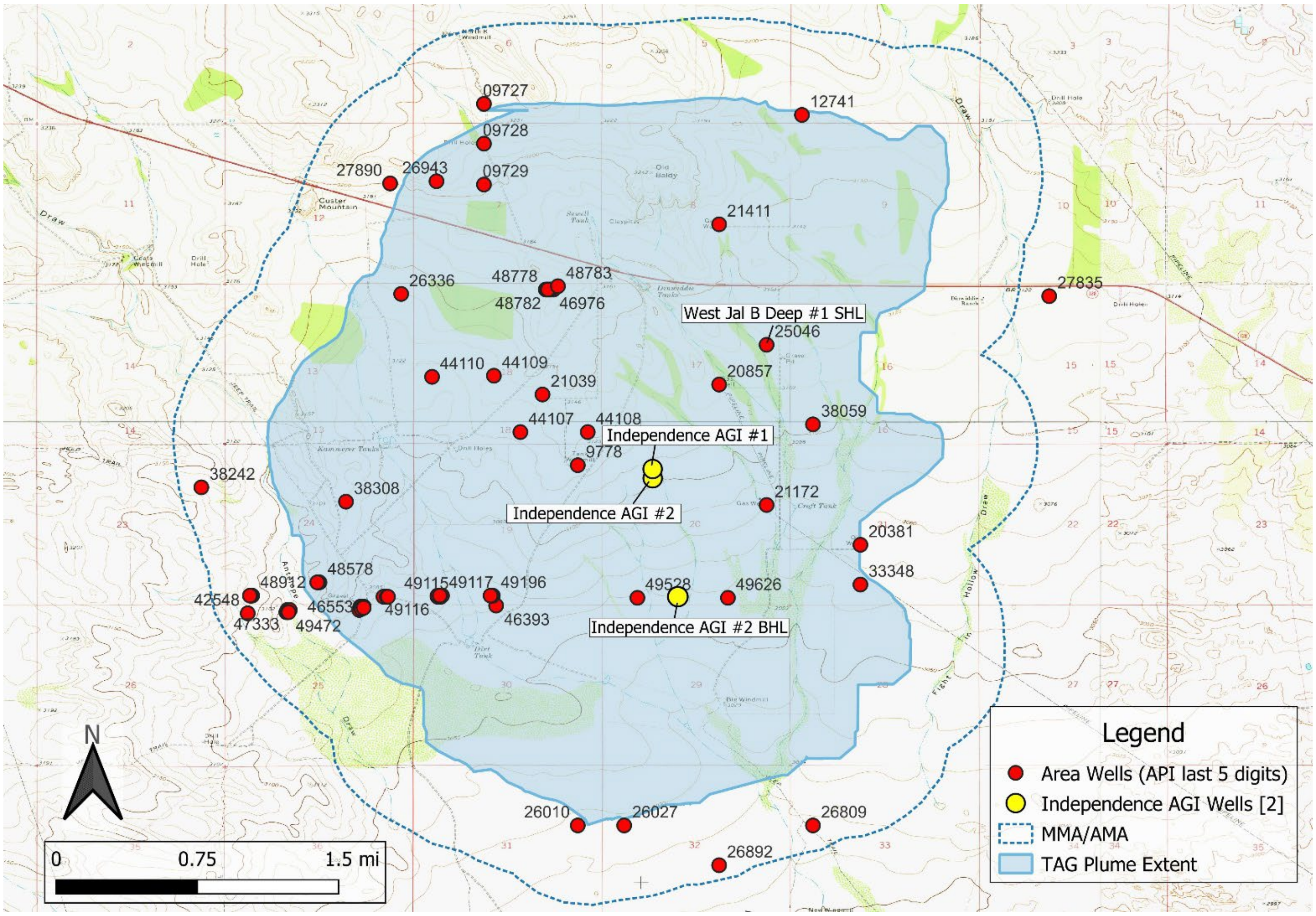


***Figure 4.1-1**: MMA and AMA for the Independence AGI Wells. The plume extents are shown at year 35 (t+= 2058), or 5 years beyond injection time. The plume largely stabilizes by this time, with continued minor migration updip to the northeast which is constrained by faults offsetting permeable layers. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in **Figure 3.1-1**.*

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 duration 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 and the reservoir modeling described in Section 3.9, Piñon 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 treating facilities. To minimize this potential for leakage, the construction, operation, and maintenance of sour gas treating facilities 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, Piñon implements a schedule for regular inspection and maintenance of surface equipment. To further

minimize the magnitude and duration of detected gas leaks to the surface, Piñon implements several methods for detecting gas leaks at the surface. These methods are described in more detail in Sections 6 and 7. Detection is followed up by immediate response.

Likelihood: Due to the required continuous monitoring of the gas gathering and the gas processing systems, Piñon considers the likelihood of CO_2 leakage to the surface via this potential leakage pathway to be low.

Timing: Potential leakage from surface equipment remains consistent over the project lifetime.

Magnitude: Leakage mass will be quantified following the requirements of 40 CFR 98.230-238, noted as Subpart W of EPA's GHGRP. Leakage mass is predicted to be less than one tenth a percent of total injection, less than 12,000 tonnes.

Detection and quantification of any leaks from surface equipment is described in more detail in Section 6.1 below.

5.2 Potential Leakage from Existing Wells

As shown in Figure 3.7-3 and detailed in Appendix 3, there are several existing oil and natural gas-related wells within a two (2) mile radius around the Independence AGI Wells (Figure 4.1-1). The deep wells discussed in Section 3.7.1 (*see* Table 3.7-1) also lie within the MMA/AMA.

Likelihood: The NMOCD regulations governing each wellbore within the MMA/AMA, require the respective operators to case the well 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 zone or to the surface around the outside of a casing string. Additionally, the NMOCD requires each respective operator of a wellbore within the MMA/AMA to operate and maintain their assets so that the injected fluids are confined to the approved intervals and prevent surface damage or pollution. Regulatory citations for these requirements can be found in 19.15.26.9 and 10 NMAC. For these reasons, the likelihood of leaks from existing wells is considered low.

Timing: Risk of leakage at each specific existing wellbore is greatest after CO_2 has reached that location and when pressures are greatest, which is towards the end of the project injection time period discussed in Section 3.8.

Magnitude: Leakage mass is predicted to be less than one percent of total injection, less than 0.15 million tonnes.

Further details regarding the wellbores within the MMA/AMA are discussed below.

5.2.1 Independence AGI Wells

Independence AGI #1 has an open hole interval between 16,122 and 17,709 feet with more than 300 feet of Woodford Shale immediately above (*see* Figure A1-1). Independence AGI #2, which was drilled and completed in October 2022, has an open hole interval between 16,080 and 17,683 feet (*see* Figure A1-2). The combined depth to the Siluro-Devonian Injection Zone, cement program for both wells illustrated in Figures A1-1 and 2, existence of suitable confining layers above the Siluro-Devonian Injection Zone described in Section 3, and continuous monitoring of well operational parameters indicates that leakage of CO_2 to the surface via the Independence AGI Wells themselves is unlikely. Therefore, Piñon considers the likelihood, magnitude, and duration of CO_2 emissions to the surface through the Independence AGI Wells to be minimal. Detection and quantification of any leaks from Independence AGI Wells are described in Section 6.2 below.

5.2.2 West Jal B Deep #001 Well

The West Jal B Deep #001 (API 30-025-25046) brine injection well is located one (1) mile northeast of the surface hole locations of the Independence AGI Wells. Additional details for this well are presented in Section 3.7.1. The wellbore currently has two CIBPs at measured depths of 14,200 feet (lower Atoka Formation) and 17,100 feet (Fusselman Formation). These CIBPs restrict access to any existing reservoirs located below the lower Atoka Formation, including within the Mississippian Lime (14,544 feet), Devonian (15,380 feet), and the Fusselman (16,404 feet), and injections in this wellbore to-date have been up-section of the relevant area. In the event of incomplete plugging of the borehole or leakage through the well casing, the shallower reservoir is at higher pressure than the Siluro-Devonian reservoir, and consequently it is assessed that downward flow of fluid would repel the TAG plume from the AGI wells. Nevertheless, the potential for CO_2 leakage to the surface through this well is considered possible, albeit unlikely, and monitoring for this possibility is described in Section 6.2.2.

5.2.3 West Jal Unit #1 Well

The West Jal Unit #1 well (API 30-025-21172) was plugged and abandoned in April 1984. The plugging documents presented in Appendix 9 indicate that the well is properly plugged to prevent vertical migration of pressure or fluids outside of the storage reservoir with multiple CIPBs and cement plugs, including the Siluro-Devonian Injection Zone. Piñon concludes that the risk of any magnitude for CO_2 leakage to the surface through plugged and abandoned well is unlikely. However unlikely, Piñon will conduct quantification and monitoring for as described in Section 6.

5.2.4 Wells Completed and Proposed to be Completed in the Wolfcamp, Bone Spring, and Shallower Stratigraphic Units

There are several oil and natural gas wells (Appendix 3) completed or proposed to be completed in the Wolfcamp, Bone Spring and shallower stratigraphic units within the MMA. The deepest of these wells is completed in the Upper Wolfcamp (see Figures 3.2-2 and 3.3-1). The nearly 4,000 feet of strata between the top of the Siluro-Devonian Injection Zone and the Wolfcamp production zone includes nearly 300 - 400 feet of low porosity and low permeability Woodford Shale, the primary confining unit/seal for the Independence AGI Wells (see Figure 3.3-3).

Due to the thickness of the strata between the deepest wells completed in the Wolfcamp and the thickness of the Woodford Shale above the Siluro-Devonian Injection Zone, Piñon considers the likelihood, magnitude, and duration of CO_2 leakage to the surface via this potential leakage pathway to be unlikely. Detection and quantification of any leaks through these wells are described in Section 6.2 below.

5.3 Potential Leakage through Fractures and Faults

Faults and fractures were discussed in Section 3.2.3 and the potential for induced seismicity was discussed in Section 3.5. The reservoir characterization modeling (Section 3.9) and the delineation of the monitoring areas (Section 4) show that the TAG plume reaches the faults shown in Figure 3.5-1 during the thirty (30) year injection period and the five (5) year post injection monitoring period. Vertical permeability may be present parallel to the plane of the fault vertically, especially where the two main faults intersect. A review of available drilling fluid records was conducted to evaluate regional reservoir pressure conditions in the Delaware basin. Above the Siluro-Devonian injection reservoir, mud weights utilized range from 12.1 to 15.1 pounds per gallon, while for the injection reservoir less dense fluids were used (average of 9.0 pounds per gallon). These support the interpretation that the overlying productive zones in this area are over pressured with respect to the target reservoir, which would produce a downward gradient through any fault-parallel permeability.

Likelihood: Due to evidence that production zones overlying the Siluro-Devonian Injection Zone are over pressured and that the basement rooted faults in the area are confined to the lower Paleozoic up to the lower Woodford Shale, the likelihood of leakage of CO_2 is considered unlikely.

Timing: Risk of leakage through fractures and faults is greatest when pressures are at their highest, which is at the end of the project injection time period discussed in Section 3.8.

Magnitude: Due to the unlikely potential noted above, anticipated leakage magnitude is negligible.

Detection and quantification of any leaks through these basement rooted faults are described in Section 6.3 below.

5.4 Potential Leakage through the Confining / Seal System

The subsurface lithologic characterization presented in Section 3.2.2 describes the thick sequence of Mississippian through Permian strata overlying the Siluro-Devonian Injection Zone and reveals the existence of several excellent confining zone layers including nearly 300 - 400 feet of low porosity low permeability Woodford Shale.

Likelihood: Due to the thickness, lateral extent, and low porosity and permeability of the Woodford Shale, Piñon considers the likelihood of CO_2 leakage to the surface through the confining zone is unlikely.

Timing: Risk of leakage through the confining / seal system is greatest when pressures are at their highest, which is at the end of the project injection time period discussed in Section 3.8.

Magnitude: Due to the unlikely potential noted above, anticipated leakage magnitude is negligible.

Detection and quantification of any leaks through the confining zone are described in Section 6.4 below.

5.5 Potential Leakage due to Natural / Induced Seismicity

The potential for leaks initiated by induced seismicity was addressed in Section 3.5. It was concluded that generally, faults considered in this assessment do not display significant potential for injection-induced slip and the Independence AGI #2 is not predicted by the FSP model to contribute significantly to the total resultant pressure front.

According to data obtained from the New Mexico Tech Seismic Observatory (2023), there have been four (4) seismic events within the MMA since January 12, 2017 (Figure 5.6-1). These seismic events range in magnitude of 1.16-1.88 and occurred between September 2020 and October 2021 (Table 5.6-1). The New Mexico Tech database applied a model for epicenter location that was not capable of determining focal depth. Revisions to this database are planned for late 2023 but have not been released at the time of this writing. Hence, earthquake depths are unknown, but accounting for the lack of local development in the Devonian strata, and the greater development at shallower depths, it is believed these earthquakes occurred in a shallower reservoir. Data queries with the USGS Earthquake Catalog did not show any seismic activity within the MMA (USGS Earthquake Hazards Program, 2023).

As noted in Section 3.5, the results of the fault slip potential model indicate no likelihood of slip on the fault east of the Independence AGI Wells. The maximum segment slip potential was determined at 0.05 northwest of the injection wells, with AGI injections causing no increase in probability. Any slip would depend on the injection volumes of brine disposal wells (at present there is no brine injection in the target area). Should fault slip occur, the short lengths of the potentially slipping segment likely preclude large earthquakes, and seismicity would be expected to be <2.5 in magnitude. Any earthquakes at or above this value would be carefully evaluated to determine location, depth, and sense of motion. Remote gas observation sweeps will be conducted above or as close to the mobile fault segment as possible at 10, 30, 100, and 365 days following the event to determine if leakage is occurring. The rate of gas leakage will likely depend on the time required to saturate the fracture network created by the seismic event and the timeline of this process is expected to be on order 10 to 100 days after the fracture network is exposed to gas (Hyman et al. 2019).

In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage. Nevertheless, the NMOCC Order requires Piñon to install, operate, and monitor for the life of the project a seismic monitoring station or stations. Seismic monitoring station or stations are described in more detail in Section 7.6.

Likelihood: Piñon concludes that the likelihood for the creation and/or opening of vertical conduits for CO_2 leakage to the surface due to induced and natural seismicity is unlikely.

Timing: Risk of leakage due to natural seismicity is not anticipated to change over the life of the project. Risk of leakage due to induced seismicity is greatest when pressures are at their highest, which is at the end of the project injection time period discussed in Section 3.8.

Magnitude: Due to the unlikely potential noted above, anticipated leakage magnitude is negligible.

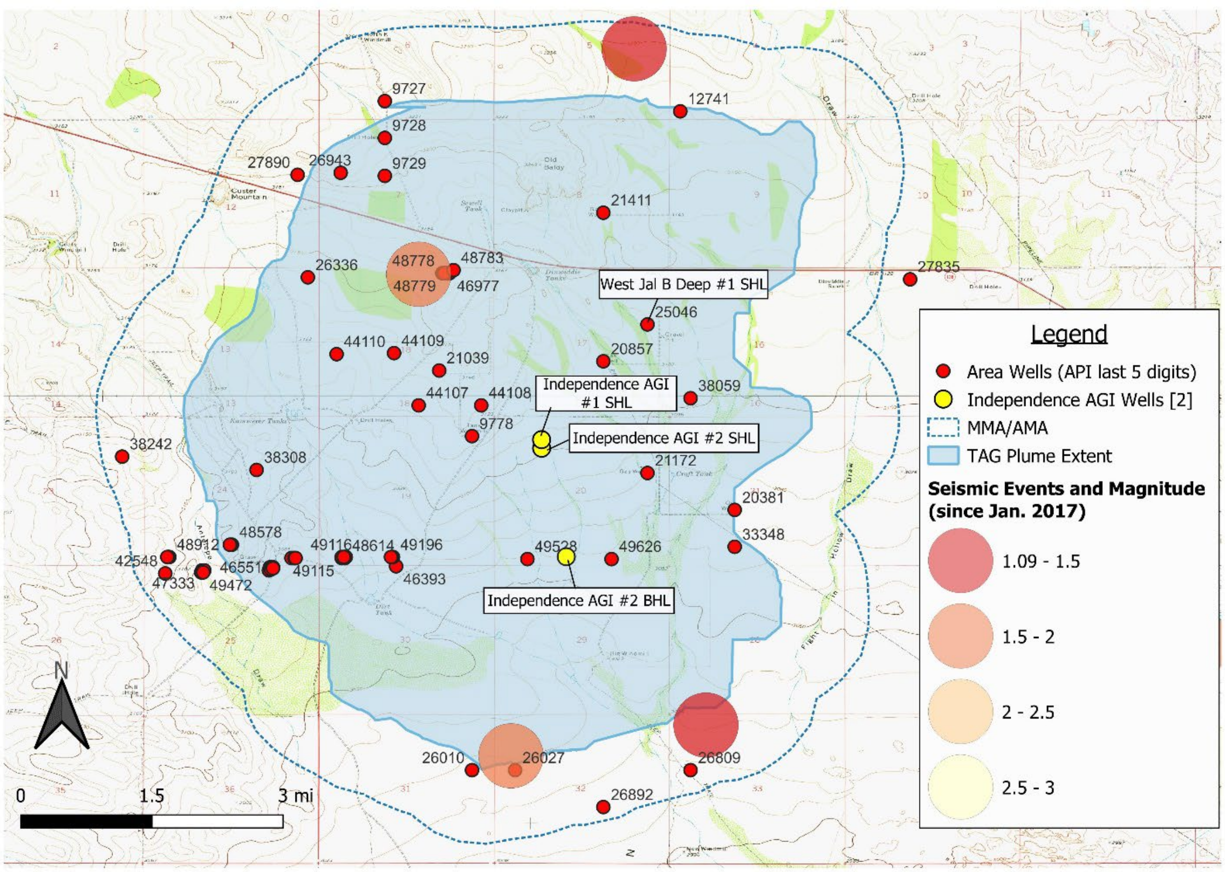


Figure 5.6-1: Map showing seismic event locations within the MMA for the Independence AGI wells. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.

Date+Time(UTC)	Latitude	Longitude	Magnitude
2021-10-30 07:14:26.600	32.093	-103.275	1.16
2021-10-11 12:19:51.300	32.09	-103.294	1.88
2021-09-09 08:23:05.600	32.137	-103.303	1.74
2020-10-03 03:51:12.600	32.159	-103.282	1.47

***Table 5.6-1**: Table showing the locations, dates and times, and magnitudes of seismic events within the MMA for the Independence AGI wells.*

5.6 Potential Leakage due to Lateral Migration

Lateral migration of the injected TAG was addressed in the simulation modeling detailed in Section 3.9. The results of that modeling indicate the TAG is unlikely to migrate laterally beyond approximately 2.5 miles within the Siluro-Devonian Injection Zone to encounter any conduits to the surface.

Likelihood: Leakage to the surface due to lateral migration is unlikely.

Timing: Risk of leakage through lateral migration is greatest when pressures are at their highest, which is at the end of the project injection time period discussed in Section 3.8.

Magnitude: Due to the unlikely potential noted above, anticipated leakage magnitude is negligible.

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. Piñon 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. Piñon considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ 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 five (5) year post-injection period.

If CO_2 surface emissions are detected by any of the monitoring methods listed in Table 6.1, Piñon will quantify the mass of CO_2 emitted via approved emission factors such as those found in 40 CFR Part 98, Subpart W or engineering estimates 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. Quantification can include leak amounts based on measurements, frequency of inspection, and other factors related to each specific identification. Piñon maintains a Greenhouse Gas Monitoring Plan to report and quantify all leaks in accordance with 40 CFR Part 98.

***Table 6.1** – Summary of Leak Detection Monitoring*

Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system ("**DCS**") surveillance of facility operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/H_2S and low explosive level ("**LEL**") monitoring network • Personal and hand-held gas monitors

Leakage Pathway	Detection Monitoring
Independence AGI #1 & Independence AGI #2	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests ("**MIT**") • Fixed in-field gas monitors/H_2S and LEL monitoring network • Personal and hand-held gas monitors
Existing Other Operator Active Wells	• Monitoring of well operating parameters • Visual inspections • MITs • Mobile CO_2 detectors
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network • Mobile CO_2 detectors
Confining / Seal System	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network

6.1 Leakage from Surface Equipment

Piñon 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 Piñon using in-field monitors which detect H_2S. 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. Additionally, Piñon field personnel, wearing personal H_2S monitors, follow daily and weekly inspection protocols which include reporting and responding to any detected leakage events.

Piñon's internal operational documents and protocols detail the steps to be taken to verify leaks of H_2S. The following description of the gas detection equipment at the Dark Horse Facility was summarized from the H_2S Contingency Plan:

Fixed Monitors

The Dark Horse Facility has numerous ambient H_2S detectors placed strategically throughout the facility to detect possible leaks. Upon detection of H_2S concentrations of 10 ppm at any detector, visible beacons are activated and an alarm is sounded. Upon detection of H_2S concentrations of 90 ppm at any detector, an evacuation alarm is sounded throughout the Dark Horse Facility at which time all personnel will proceed immediately to a designated evacuation area. The Dark Horse Facility 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 ("**PLC**"), and then to the DCS. The monitors are equipped with amber beacons. The beacon is activated upon detection of H_2S concentrations of 10 ppm. The Dark Horse Facility horns are activated with a continuous warbling alarm upon detection of H_2S concentrations of 10 ppm and a facility-

wide siren upon detection of H_2S concentrations of 90 ppm. All monitoring equipment is Rosemount brand. The control panel is a twenty-four (24) channel monitor box, and the fixed point H_2S sensor heads are model number ST320A-100-ASSY.
The Dark Horse Facility will monitor the inlet sour natural gas steam and sweet natural gas stream concentrations of H_2S via H_2S analyzers with sample points located on the north/south-oriented pipe rack (Figure 7.2-1). Concentrations of H_2S in the TAG stream will be sampled near the AGI pumps located on the west side of the Dark Horse Facility. All H_2S analyzers are model T224, manufactured by Analytical Systems KECO.
The monitors can also be viewed on the PLC displays located at the Dark Horse Facility and the locations of ambient H_2S sensors are shown on the plot plan (*see* Figure 3.7-2). Immediate action is required for any alarm occurrence or malfunction. All H_2S sensors are calibrated monthly.

Personal and Handheld H_2S Monitors

All personnel working at the Dark Horse Facility wear personal H_2S monitors, which are required to alarm and vibrate upon detection of H_2S concentrations of 10 ppm. Handheld gas detection monitors are available at strategic locations around the Dark Horse Facility so that facility 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.

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 10.1.5. Furthermore, if CO_2 emissions are detected through any of the surveillance methods described above, Piñon 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.

6.2 Leakage from Existing Wells

6.2.1 Independence AGI Wells

As part of ongoing operations, Piñon continuously monitors and collects flow, pressure, temperature, and gas composition data from each Independence AGI Well. This data is monitored continuously by qualified technicians who follow response and reporting protocols when the monitoring system delivers alerts that data is not within acceptable limits. Mechanical integrity tests (MIT) are performed on each Independence AGI Well annually. Failure of an MIT would indicate a leak in the applicable well and result in immediate action by shutting in the well, assessing the MIT failure, and implementing mitigative steps.

If operating parameter monitoring and MIT failures indicate a CO_2 leak has occurred, Piñon will (a) take actions 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.2.2 West Jal B Deep #001 and West Jal Unit #1 Wells

Piñon will annually employ mobile CO_2 detectors, which may include drone mounted sensors, to monitor for any CO_2 emission at the locations of the West Jal B Deep #001 and West Jal Unit #1 wells. If surface CO_2 leakage is correlated with loss through these wells, Piñon will (a) take actions, including by working with the third party operator of the West Jal B Deep #001 and West Jal Unit #1 wells, to quantify the amount of CO_2 emitted based on the operational conditions that existed at the time of 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.2.3 Wells Completed and Proposed to be Completed in the Wolfcamp, Bone Spring, and Shallower Stratigraphic Units

As discussed in Section 5, it is unlikely that the TAG injected through the Independence AGI Wells into the Siluro-Devonian Injection Zone will migrate upward to these shallower production wells and be emitted to the surface through these wells. Due to the natural presence of H_2S and CO_2 in the production streams of oil and natural gas producers in the AMA, Piñon has been in contact with such producers in the AMA regarding Piñon's core business of sour gas (high in H_2S and CO_2) treatment and sequestration. Piñon will continue to work cooperatively with such producers and immediately investigate, including by use of mobile CO_2 detectors, any CO_2 emissions from wells operated by oil and natural gas producers in the AMA which is suspected to arise from Piñon's operations. If surface CO_2 leakage is correlated with loss through these wells, Piñon will (a) take actions, including by working with the third party operator of the well(s), to quantify the amount of CO_2 emitted based on the operational conditions that existed at the time of 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.3 Leakage from Fractures and Faults

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through a fracture or fault. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone.

Piñon will assess any changes in operating parameters or data which indicates surface leakage of CO_2 along faults or fractures. Piñon will employ mobile CO_2 detectors, which may include drone mounted sensors, to monitor for any emission above mapped fractures and faults. If surface CO_2 leakage is correlated with loss through fractures or faults, Piñon will (a) take actions, including by working with relevant surface owners, to quantify the amount of CO_2 emitted based on the conditions that existed at the time of 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.4 Leakage through the Confining / Seal System

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through the confining / seal system. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.2 and 7.5, will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone.

If changes in operating parameters or data indicate surface leakage of CO_2 through the confining / seal system, Piñon will (a) take actions to quantify the amount of CO_2 emitted based on 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI well(s).

6.5 Leakage due to Natural / Induced Seismicity

Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.2 and 7.5 coupled with a detection of a seismic event by the seismic stations described in Section 7.6 will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone due to a seismic event.
After a seismic event, Piñon will assess any changes in operating parameters and data from the surrounding seismic stations which might indicate leakage of CO_2 along faults or fractures activated

by the event. If leakage of CO_2 is correlated with a seismic event, Piñon will (a) take actions to quantify the amount of CO_2 emitted based on 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.6 Leakage due to Lateral Migration

Continuous operational monitoring of the Independence 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 Siluro-Devonian Injection Zone. 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 Siluro-Devonian Injection Zone.

If monitoring of operational parameters indicates that the CO_2 plume extends beyond the area modeled in Section 3.9 and presented in Section 4, Piñon will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 release to the surface. If it is determined that the plume intersected a pathway for CO_2 release to the surface, this would be considered a material change per 40 CFR 98.448(d)(1), and Piñon will submit a revised MRV plan as required by 40 CFR 98.448(d).

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

Subpart RR at 40 CFR 448(a)(4) requires a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. Piñon 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 Piñon's strategy for collecting baseline information.

7.1 Visual Inspection

Piñon field personnel conduct daily visual inspections of surface equipment located at the Dark Horse Facility and the Independence AGI Wells. These visual inspections will aid in identifying and timely addressing potential areas of concern to minimize the possibility of H_2S, a proxy for CO_2, leakage. If any leakage is identified during such visual inspections, Piñon field personnel will take prompt corrective actions to address such leakage.

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

Compositional analysis of gas injectate at the Dark Horse Facility indicates an approximate H_2S concentration of 38.7% thus requiring Piñon to develop and maintain an H_2S Contingency Plan according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). Piñon considers H_2S to be a proxy for CO_2 leaks at the Dark Horse Facility. The H_2S Contingency Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the Dark Horse Facility or the associated Independence 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 Dark Horse Facility utilizes numerous fixed-point monitors, strategically located throughout the facility, to detect the presence of H_2S in ambient air (Figure 3.7-2). The diagram in Appendix 10 shows the location of the Ultrasonic inflow meters and the Coriolis meters to the Independence AGI wells. The sensors are connected to the Control Room alarm panel's PLCs, and then to the DCS. Upon detection of H_2S concentrations of 10 ppm at any monitor, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of H_2S concentrations of 90 ppm at any monitor, an evacuation alarm is sounded throughout the Dark Horse Facility 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 Dark Horse Facility so that facility 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 Oxide ("**CO**").

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the Dark Horse Facility 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 upon detection of H_2S concentrations of 10 ppm.

7.3 CO_2 Detection

Any CO_2 release to the surface would be accompanied by H_2S and therefore the H_2S monitors will serve as a CO_2 release warning system both at the facility and in the field. In addition to the fixed and personal monitors described in Section 7, Piñon will establish and operate a monitoring program to detect H_2S leakages within the AMA. The scope of work will include H_2S monitoring at the AGI well site and atmospheric monitoring near identified penetrations of the Siluro-Devonian Injection Zone within the AMA. Upon approval of the MRV Plan and for the five (5) year post-injection period, Piñon will have these monitoring processes and systems in place.

7.4 Continuous Parameter Monitoring

The DCS of the Dark Horse Facility 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

Piñon 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. Piñon's Routine Operations and Maintenance Procedures for the Independence AGI Wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic Monitoring Stations

Piñon owns 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 Dark Horse Facility. The seismic station will meet the requirements of the NMOCC Order to "install, operate, and monitor for the life of this Order a seismic monitoring station or stations. OCD shall be responsible for coordinating with the Manager of the New Mexico Tech Seismological Observatory at the New Mexico Bureau of Geology and Mineral Resources for appropriate specifications for the equipment and the required reporting procedure for the monitoring data."

Additionally, Figure 7-1 shows the location of other seismic monitoring stations in the vicinity of the Independence AGI Wells.

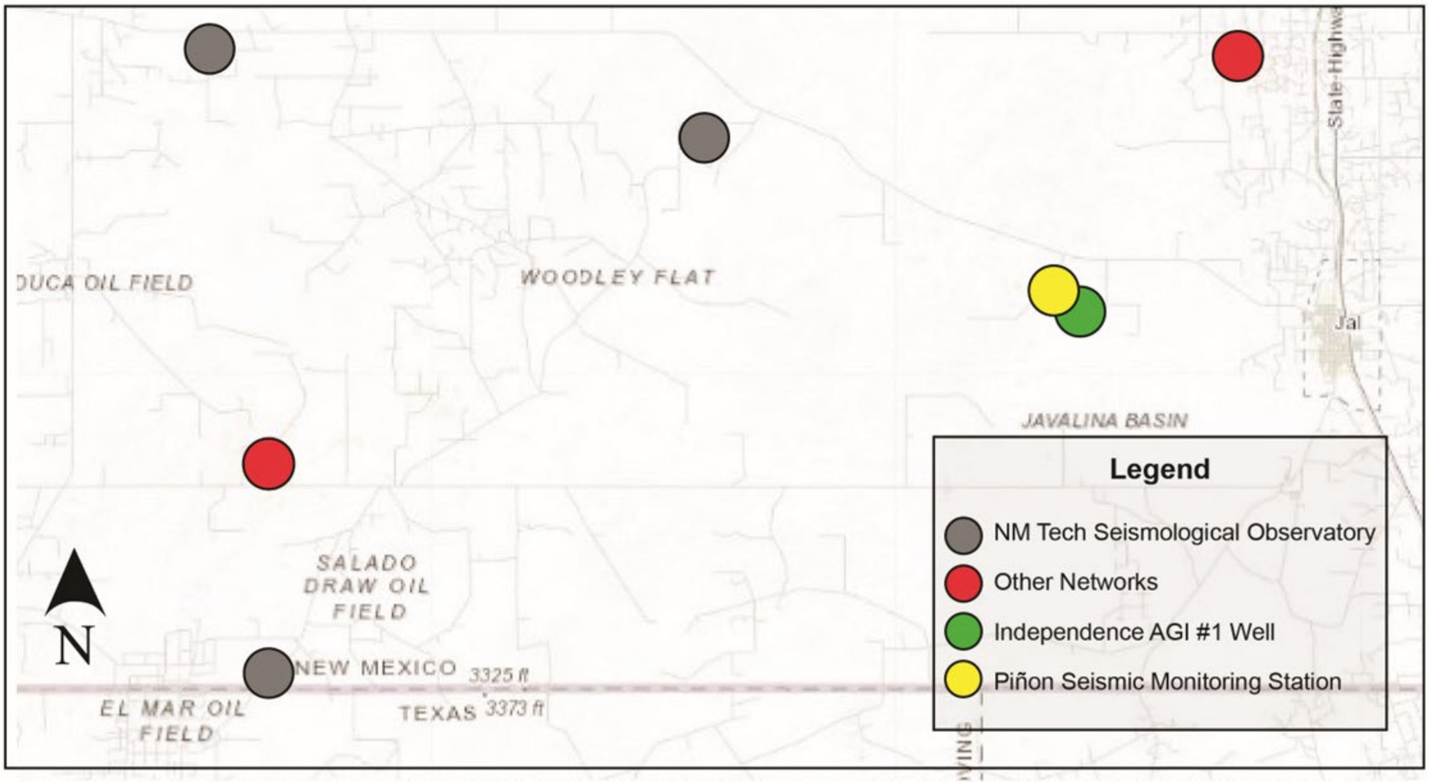


***Figure 7-1*: Location of seismic monitoring stations in the vicinity of the Independence AGI Wells.**

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve (12) Subpart RR equations used to calculate the mass of CO_2 sequestered annually. Appendix 8 includes the twelve (12) equations from Subpart RR. Not all of these equations apply to Piñon's current operations at the Dark Horse Facility but are included in the event Piñon's operations change in such a way that their use is required.

Figure 3.7-2.b shows the location receipt meters and injection meters listed in 40 CFR 98.232(d) of Subpart RR that will be used in the calculations set forth below.

8.1 CO_2 Received

Currently, Piñon receives sour natural gas at the Dark Horse Facility through three (3) pipelines: the Hondo High Pressure Sour Gas Pipeline (owned and operated by Piñon), the Franklin Mountain Low Pressure Pipeline (owned and operated by Franklin Mountain Energy) and the Ameredev II Low Pressure Pipeline (owned and operated by Ameredev). Piñon 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. Receipt meters are shown on Figure 3.7-2.b.

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \quad \text{(Equation RR-2 for Pipelines)}$$

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.

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r}$$ (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 Piñon does not currently receive CO_2 in containers for injection, they have chosen to include the flexibility in this MRV Plan to do so. If Piñon begins to receive CO_2 in containers, they will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. Piñon will adhere to the requirements in 40 CFR 98.444(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 40 CFR 98.488(d)(1), Piñon will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Piñon injects CO_2 into the existing Independence AGI #1. Upon its completion, Piñon will commence injection of CO_2 into Independence AGI #2. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the Independence AGI Wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the Independence AGI Wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Injection meters are shown on <u>Figure 3.7-2.b</u>.

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

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

Piñon does not produce oil or natural gas or any other liquid at the Dark Horse Facility 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 (CO_{2E}) from the leakage pathways identified and evaluated in Section 5. 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.

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

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.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

As required by 98.444(d) of Subpart RR, Piñon 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 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 Piñon does not actively produce oil or natural gas or any other fluid at the Dark Horse Facility, 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 the GHGRP.

9 Estimated Schedule for Implementation of MRV Plan

Piñon intends to implement this MRV Plan on June 1, 2023, after it is approved by EPA.

10 GHG Monitoring and Quality Assurance Program

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

10.1 GHG Monitoring

As required by 40 CFR 98.3(g)(5)(i), Piñon'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 greenhouse gas ("**GHG**") calculations; and
- 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 will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association ("**GPA**") standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40 CFR 98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2 and RR-5, of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 15.025 pounds per square inch absolute ("**psia**") (Appendix 6). Piñon utilizes Coriolis metering to measure the dense phase injected TAG stream. Piñon utilizes the following two standards: American Petroleum Institute API 14.1 for measuring barrels and the American Gas Association AGA 7 for million cubic feet ("**MCF**") equivalent calculations.

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 Independence AGI Wells using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.4 CO_2 Produced.

Piñon does not produce CO_2 at the Dark Horse Facility.

10.1.5 CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2.

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

10.1.6 Measurement devices.

As required by 40 CFR 98.444(e), Piñon 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 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute, the AGA, the GPA, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.
- All flow meter calibrations performed are National Institute of Standards and Technology ("**NIST**") traceable.

10.2 QA/QC Procedures

Piñon 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

Piñon will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or using a representative concentration value from the 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

Piñon will revise the MRV Plan as needed to (a) reflect changes in monitoring instrumentation and quality assurance procedures; (b) improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or (c) address additional requirements as directed by the EPA or the State of New Mexico.

11 Records Retention

Piñon will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, Piñon will retain the following documents:

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

(b) 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

(c) The annual GHG reports.

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

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

(f) 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.

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

(h) 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.

(i) 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.

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

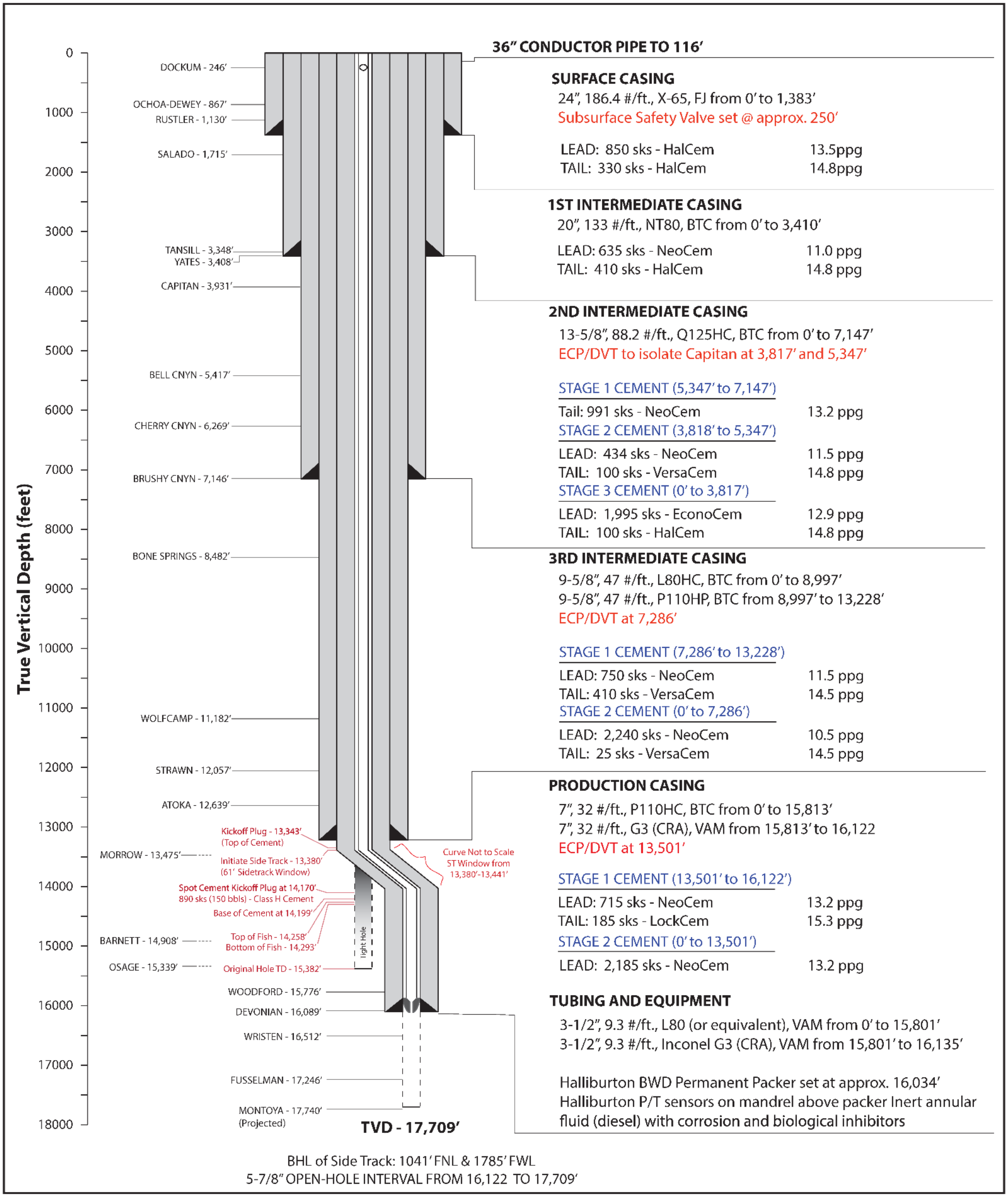
(k) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

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

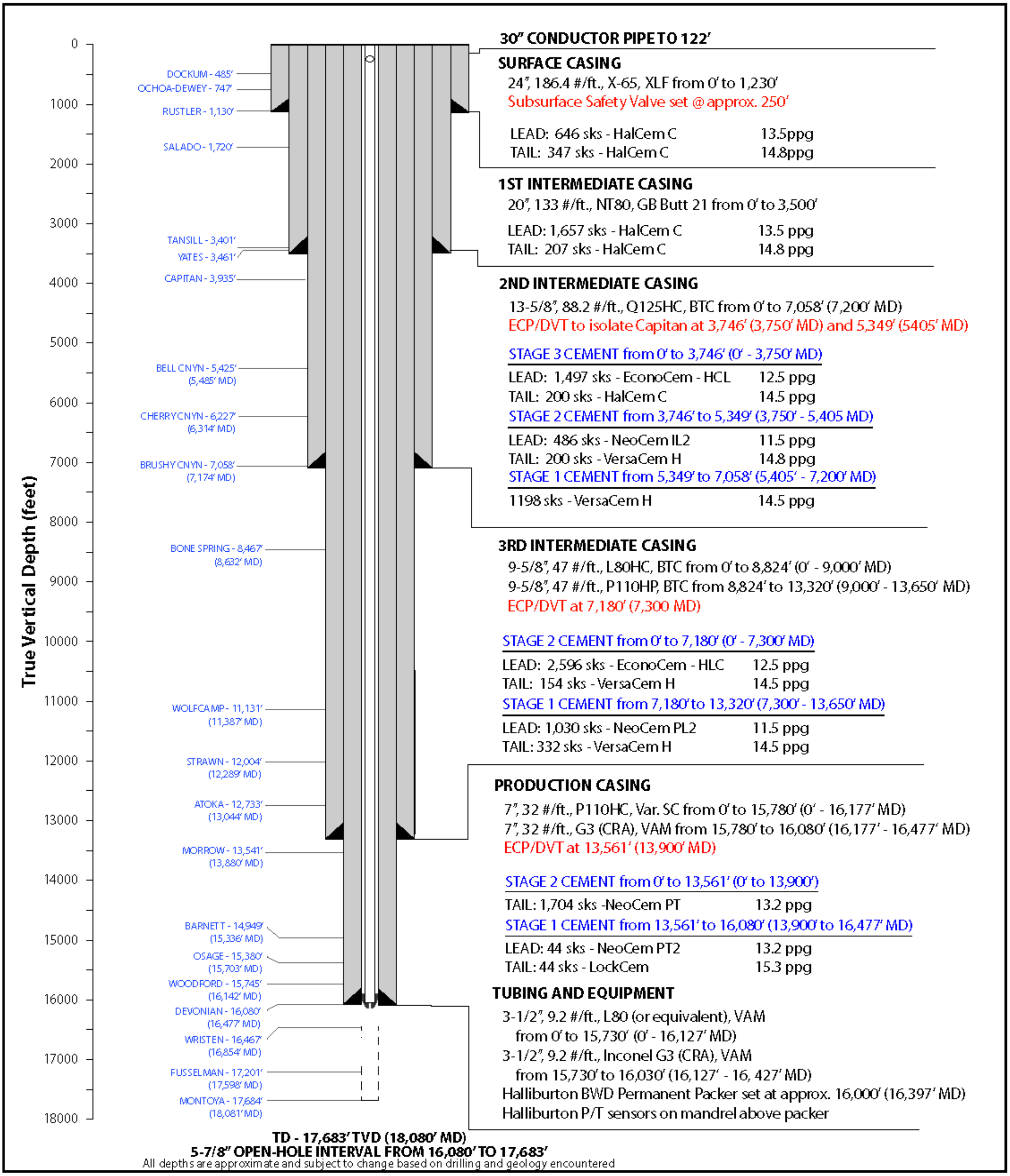
12 Appendices

Appendix 1 - Independence AGI Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Independence AGI #1	30-025-48081	SHL 829' FNL, 1,443' FEL BHL of Sidetrack: 1041'FNL, 1785'FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120855 and -103.291021	Lea, NM	12/27/2020	17,750'	16,114'
Independence AGI #2	30-025-49974	SHL 1,180' FNL, 1,578' FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120020 and -103.291015 BHL 1,033' FSL, 2,132' FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.111581 and -103.289273	Lea, NM	07/02/2022	17,683' TVD	16,610'



<u>Figure A1-1</u>: Independence AGI #1: As-drilled well schematic consisting of a surface string of casing, three (3) intermediate strings , and a production string with associating tubing/equipment and cement types. Original hole and sidetrack are shown. (Taken from End-of-Well Report for Independence AGI #1, Geolex, Inc.)



<u>Figure A1-2</u>: Independence AGI #2: Well schematic. (Taken from NMOCC Order 3/31/2022)

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
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
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
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 - Oil and natural gas wells within 2-mile radius of the Independence AGI Wells

The data in the following table was obtained from the NMOCD database and is accurate as of 8/5/2022.

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-09729	PAN AM KELLY 7 FEDER	Oil	Plugged (site released)	JOHN H TRIGG	32.1466	-103.3063		1900	3,540	0	-	1/1/1900	CUSTER, TANSILL
30-025-09778	FEDERAL #1	Oil	Plugged (site released)	EDWARD C. DONAHUE	32.1212	-103.2978	No Data	1900	3,891	0	-	1/1/1900	No Data
30-025-20381	HERKIMER BQF FEDERAL #001H	Oil	Active	AMEREDEV OPERATING, LLC	32.114	-103.2722	H	1963	8,515	10,121	10,100	-	DELAWARE, WEST
30-025-20857	WEST JAL B #001	Brine Injection	New	BC & D OPERATING INC.	32.1285	-103.2850	V	1964	12,275	12,275	6,170	-	WOLFCAMP, WEST; DELAWARE
30-025-21039	WEST JAL 18 #1	Oil	Plugged (site released)	SKELLY OIL CO.	32.1276	-103.3010	No Data	1900	12,950	0	-	1/1/1900	No Data
30-025-21172	WEST JAL UNIT #1	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.1176	-103.2807	V	1961	17,086	17,086	-	4/4/1984	DELAWARE, WEST; JAL, STRAWN, WEST
30-025-21411	C ELLIOTT FEDERAL	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.143	-103.2850	V	1900	12,276	12,276	-	6/26/1993	STRAWN, WEST
30-025-25046	WEST JAL B DEEP #001	Brine Injection	Active	BC & D OPERATING INC.	32.1321	-103.2807	V	1975	18,945	18,945	14,175	-	STRAWN, WEST; WOLFCAMP, WEST; FUSSELMAN, WEST; ST-AT-MISS-DEV-FUS
30-025-26010	SPOTTED TAIL FED. #1	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2978	No Data	1900	3,336	0	-	1/1/1900	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26027	SITTING BULL A #001	Oil	Active	FULFER OIL & CATTLE LLC	32.0886	-103.2936	V	1978	3,368	3,368	-	-	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26336	FEDERAL 13 A #1	OIL	Plugged (site released)	GETTY OIL CO.	32.1367	-103.3138	V	1979	3,686	0	-	-	No Data
30-025-26809	LITTLE HAWK FEDERAL #	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2765	No Data	1900	3,690	0	-	1/1/1900	No Data
30-025-26892	SITTING BULL #2	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.085	-103.2850	No Data	1900	3,746	0	-	1/1/1900	No Data
30-025-33348	TEXACO WEST JAL 21 #001	Oil	Plugged (site released)	ENSERCH EXPLORATION INC.	32.1104	-103.2722	V	1996	7,700	7,700	-	4/25/1996	No Data
30-025-38059	DINWIDDIE STATE COM #001	Gas	Plugged (site released)	COG OPERATING LLC	32.1249	-103.2765	V	2006	12,192	12,192	-	12/12/2008	STRAWN, WEST

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-46393	NANDINA 25 36 31 FEDERAL COM #124H	Oil	New	AMEREDEV OPERATING, LLC	32.1085	-103.3052	H	-	0	23,130	-	-	WOLFCAMP, WEST
30-025-46533	SIOUX 25 36 STATE FEDERAL COM #008H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2019	12,149	22,150	22,117	-	UPPER WOLFCAMP
30-025-46551	SIOUX 25 36 STATE FEDERAL COM #009H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3175	H	2020	11,894	21,945	21,912	-	BONE SPRING
30-025-46553	SIOUX 25 36 STATE FEDERAL COM #012H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3174	H	2020	11,994	22,350	22,319	-	BONE SPRING; UPPER WOLFCAMP
30-025-46554	SIOUX 25 36 STATE FEDERAL COM #013H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2020	11,725	21,962	21,930	-	BONE SPRING; UPPER WOLFCAMP
30-025-46561	SIOUX 25 36 STATE FEDERAL COM #010H	Oil	Active	CAZA OPERATING, LLC	32.1081	-103.3176	H	2020	12,107	22,209	22,175	-	UPPER WOLFCAMP
30-025-46976	BLACK MARLIN FEDERAL COM #204H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3002	H	2020	11,640	21,953	21,895	-	WOLFCAMP, WEST
30-025-46977	BLACK MARLIN FEDERAL COM #214H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3000	H	2020	11,741	22,055	21,994	-	WOLFCAMP, WEST
30-025-48081	INDEPENDENCE AGI #001	AGI	Active	Pinon Midstream, LLC	32.1208	-103.2910	V	2020	17,709	17,900	-	-	DEVONIAN-FUSSELMAN
30-025-48577	SANTA FE FEDERAL COM #603H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3154	H	-	0	21,874	-	-	BONE SPRING
30-025-48578	SANTA FE FEDERAL COM #704H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3212	H	-	0	22,063	-	-	WOLFCAMP, WEST
30-025-48579	SANTA FE FEDERAL COM #705H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3152	H	-	0	22,129	-	-	WOLFCAMP, WEST
30-025-48580	TRINITY FEDERAL #602H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3214	H	-	0	21,938	-	-	BONE SPRING
30-025-48581	TRINITY FEDERAL #703H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3213	H	-	0	22,206	-	-	WOLFCAMP, WEST
30-025-48582	ZIA FEDERAL COM #604H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3151	H	-	0	21,973	-	-	BONE SPRING
30-025-48583	ZIA FEDERAL COM #706H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3150	H	-	0	21,973	-	-	WOLFCAMP, WEST
30-025-48614	BLUE MARLIN STATE #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3102	H	-	0	19,502	-	-	WOLFCAMP, WEST
30-025-48615	BLUE MARLIN STATE #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	-	0	19,350	-	-	WOLFCAMP, WEST
30-025-48778	BLACK MARLIN FEDERAL COM #113H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3007	H	-	0	20,014	-	-	BONE SPRING
30-025-48779	BLACK MARLIN FEDERAL COM #114H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3006	H	-	0	20,056	-	-	BONE SPRING
30-025-48780	BLACK MARLIN FEDERAL COM #203H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3005	H	2021	11,786	21,842	21,879	-	WOLFCAMP, WEST
30-025-48781	BLACK MARLIN FEDERAL COM #206H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3003	H	-	0	21,981	-	-	WOLFCAMP, WEST
30-025-48782	BLACK MARLIN FEDERAL COM #213H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3004	H	2021	0	22,140	22,073	-	WOLFCAMP, WEST
30-025-48783	BLACK MARLIN FEDERAL COM #216H	Oil	New	TAP ROCK OPERATING, LLC	32.1374	-103.2996	H	2021	0	22,258	22,258	-	WOLFCAMP, WEST

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-49115	BLUE MARLIN FEDERAL COM #111H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3105	H	-	0	20,039	0	-	BONE SPRING
30-025-49116	BLUE MARLIN FEDERAL COM #112H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3105	H	-	0	20,217	0	-	BONE SPRING
30-025-49117	BLUE MARLIN FEDERAL COM #201H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3102	H	2021	11,613	21,985	21,923	-	WOLFCAMP, WEST
30-025-49118	BLUE MARLIN FEDERAL COM #202H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	2021	11,539	21,929	21,866	-	WOLFCAMP, WEST
30-025-49119	BLUE MARLIN FEDERAL COM #205H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3101	H	2021	11,533	21,980	21,916	-	WOLFCAMP, WEST
30-025-49120	BLUE MARLIN FEDERAL COM #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3103	H	2021	12,148	22,554	22,495	-	WOLFCAMP, WEST
30-025-49121	BLUE MARLIN FEDERAL COM #215H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3057	H	2021	11,720	22,188	22,120	-	WOLFCAMP, WEST
30-025-49196	BLUE MARLIN FEDERAL COM #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3055	H	2021	12,003	22,422	22,389	-	WOLFCAMP, WEST
30-025-49528	DOGWOOD 25 36 20 FEDERAL COM #112H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2924	H	2021	0	22,356	0	-	WOLFCAMP, WEST
30-025-49626	DOGWOOD 25 36 20 FEDERAL COM #116H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2842	H	-	0	22,080	0	-	WOLFCAMP, WEST
30-025-49974	INDEPENDENCE AGI #002	AGI	New	Pinon Midstream, LLC	32.1201	-103.2910	D	2022	17,683	18,080	0	-	DEVONIAN-FUSSELMAN
30-025-50391	SIOUX 25 36 STATE FEDERAL COM #020H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	22,710	0	-	UPPER WOLFCAMP
30-025-50392	SIOUX 25 36 STATE FEDERAL COM #021H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	20,244	0	-	BONE SPRING
30-025-50393	SIOUX 25 36 STATE FEDERAL COM #022H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	22,539	0	-	UPPER WOLFCAMP
30-025-50394	SIOUX 25 36 STATE FEDERAL COM #023H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	20,120	0	-	BONE SPRING

Appendix 4 - References

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Appendix 5 - Abbreviations and Acronyms

Abbreviations and acronyms not otherwise defined herein:

3D – 3 dimensional
API – American Petroleum Institute
CFR – Code of Federal Regulations
EOS – Equation of State
ft – foot (feet)
m – meter(s)
mg/l – milligrams per liter
MT -- Metric tonne
NG—Natural Gas
QA/QC – quality assurance/quality control
ST – Short Ton

Appendix 6 - Conversion Factors

Piñon reports CO_2 at standard conditions of temperature and pressure as defined in the State of New Mexico - 60°F and 15.025 psia (NMAC 19.15.2.7 (C)(16))

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the NIST. This online database is available at:
http://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner EOS at a wide range of temperatures and pressures. At State of New Mexico standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.0027097 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb-moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2204.62\ lbs}$$

Where:

$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$
$Density_{CO2} = 0.0027097$
$MW_{CO2} = 44.0095$

$$Density_{CO2} = 5.4092\ x\ 10^{-5} \frac{MT}{ft^3}\ or\ 5.4092\ x\ 10^{-2}\ \frac{MT}{Mcf}$$

The conversion factor 5.4092 x 10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Appendix 7 - Independence 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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \qquad \text{(Equation RR-1 for Pipelines)}$$

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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \qquad \text{(Equation RR-1 for Containers)}$$

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

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \qquad \text{(Equation RR-3 for Pipelines)}$$

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

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \qquad \text{(Equation RR-4)}$$

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

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \qquad \text{(Equation RR-5)}$$

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

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \qquad \text{(Equation RR-6)}$$

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

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

$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP}$ (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.

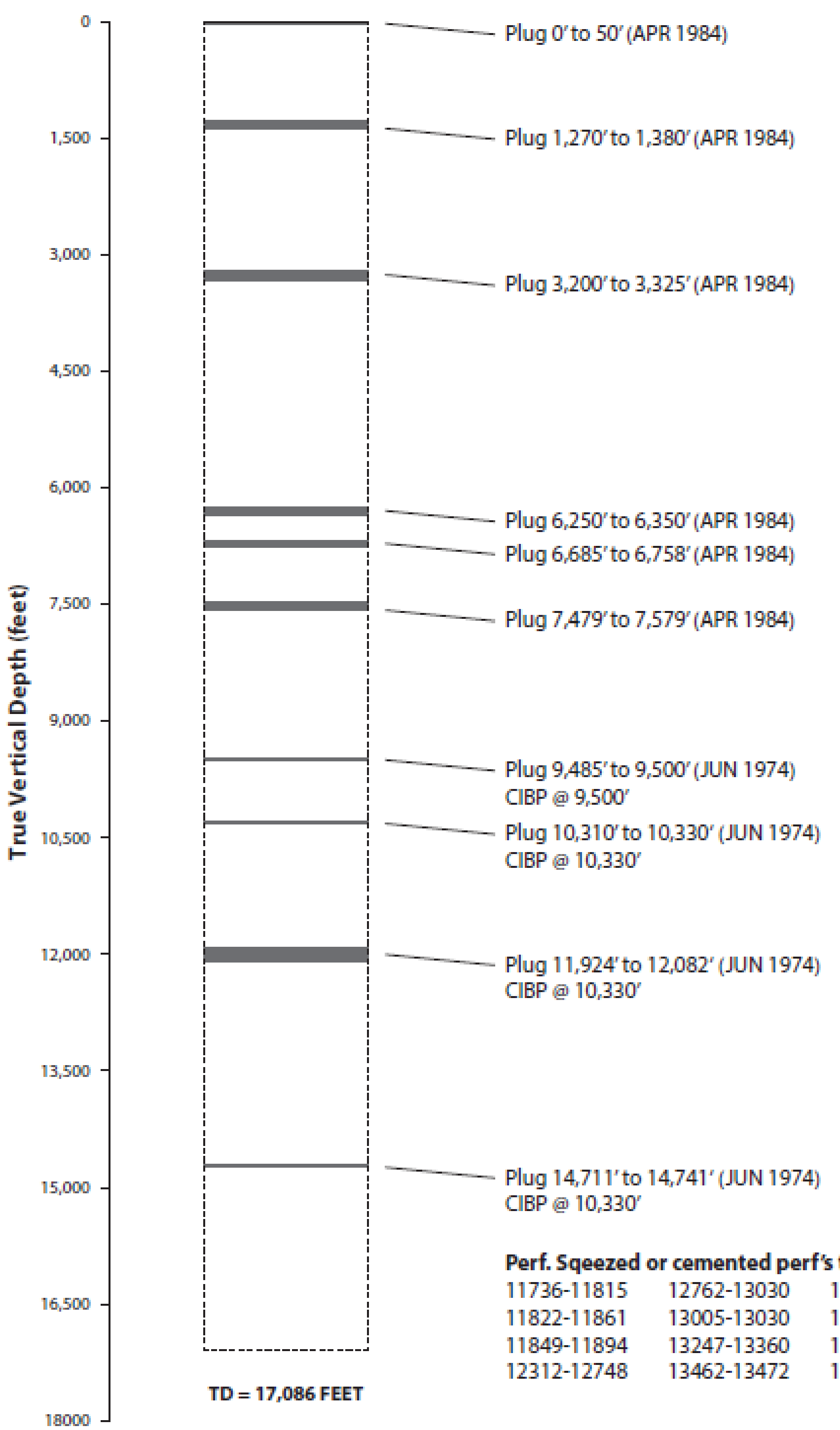
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

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 - Plugging Records for West Jal Unit #1

TEXACO EXPLORATION AND PROD. - WEST JAL UNIT #1 PLUGGING DIAGRAM

Lease Name:	West Jal Unit #1	**Footage:**	1980 FNL and 660 FEL
API:	30-025-21172	**Well Type:**	Oil
Location:	Sec. 20, T25S, R36E	**Total Depth:**	17,086′
County, State:	Lea County, New Mexico	**Coordinates:**	32.117596, -103.280739 (NAD83)



Perf. Sqeezed or cemented perf's tested between:

11736-11815	12762-13030	13517-13524
11822-11861	13005-13030	13524-13532
11849-11894	13247-13360	15050-15353
12312-12748	13462-13472	16449-16614

*Schematic is properly scaled

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P. 0. BOX 1980
HOBBS. NEW MEXICO 88

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UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Buluu No. 1004-0135
Expires: March 31, 1993

5. Lease Designation and Serial No.

N

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT-" for such proposals

SUBMIT IN TRIPLICATE

7. If Unit or CA, Agreement Designation

1. Type of Well
[X] Oil Well [ ] Gas Well [X] Other Reentry

8. Well Name and No.
f JA-/t:Jt!JLA-fry

2. Name of Operator
MCH Petroleum Services

9. API Well No.
30-025-2/112

3. Address and Telephone No.
-:1:)1 W. Pliv St: Midland, Tx 79705 915 683 4772

10. Field and Pool, or Exploratory Area
~~Abandoned~~ W. Sal DeLaware

4. Location of Well (footage, Sec., T., R., M., or Survey Description)
/'f4!o PA1- ,o I=G1- -S Z.0, r- zS-S, 11- 'T'=
H S£NE .6J•,)1 h\.

11. County or Parish, State
Lea, NM

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

TYPE OF SUBMISSION	TYPE OF ACTION	
[g] Notice of Intent	D Abandonment	0 Change of Plans
	Recompletion	D New Construction
[J Subsequent Report	D Plugging Back	0 Non-Routine Fracturing
	D Casing Repair	[ ] Water Shut-Off
[ ] Final Abandonment Notice	D Altering Casing	D Conversion to Injection
	Other eNtAy	D Dispose Water
		(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abandoned by Texaco in 1983. MCH will drill out cement plugs and cibp@ 7,579' to a total depth of approx. 8,350'(inside casing). This will leave in place cibp at 9,500' and deeper. We will then test existing perforations@ 7,807'-7,857' and stimulate as necessary.
Mud Program: Fresh water will be used for the reentry inside casing.
BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO
GENERAL REQUIREMENTS AND
SPECIAL STIPULATIONS
ATTACHED

14. I hereby certify that the foregoing is true and correct

Signed Craig Huber Title Owner Date 4/13/93

(This space for Federal or State office use)
Approved by ''' 1ITC &r.n L MA ron; Title AREA MANAG. Date JUN 4 1993
Conditions of approval, if any:

Title 18 U.S.C. Section 1001, makes 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.

*See Instruction on Reverse Side

G 31

Form 3160-3
(December 1990)

SUBMIT IN TRI[illegible]TE*
(Other instructions o.. reverse side)

Form approved.
Budget Bureau No. 1004-0136
Expires: December 31, 1991

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR DEEPEN

5. LEASE DESIGNATION AND SERIAL NO. NM 71792
6. IF INDIAN, ALLOTTEE OR TRIBE NAME
7. UNIT AGREEMENT NAME
8. FARM OR LEASE NAME, WELL NO. West JAL Federal #1
9. API WELL NO. 30-025-21172
10. FIELD AND POOL, OR WILDCAT ~~[illegible]~~ W. JAL Delaware
11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA S-20, T-25S, R36E
12. COUNTY OR PARISH Lea
13. STATE NM

1a. TYPE OF WORK DRILL ☐ DEEPEN ☐

b. TYPE OF WELL OIL WELL ☒ GAS WELL ☐ OTHER Reentry SINGLE ZONE ☒ MULTIPLE ZONE ☐

2. NAME OF OPERATOR MCH Petroleum Services

3. ADDRESS AND TELEPHONE NO. 708 W. Pine St. Midland, Tx 79705 915 683 4772

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*)
At surface 1980' FNL, 660' FEL Sec 20 T-25S, R-36E Lea Co. NM
At proposed prod. zone SAme H SENE

14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE* 6 miles W. JAL, N.M.

15. DISTANCE FROM PROPOSED* LOCATION TO NEAREST PROPERTY OR LEASE LINE, FT. (Also to nearest drlg. unit line, if any) 660'

16. NO. OF ACRES IN LEASE 600

17. NO. OF ACRES ASSIGNED TO THIS WELL 40

18. DISTANCE FROM PROPOSED LOCATION* TO NEAREST WELL, DRILLING, COMPLETED, OR APPLIED FOR, ON THIS LEASE, FT.

19. PROPOSED DEPTH 8350

20. ROTARY OR CABLE TOOLS Pulling unit/Reverse unit

21. ELEVATIONS (Show whether DF, RT, GR, etc.) 3076' GL

22. APPROX. DATE WORK WILL START* ASAP (Prior to 6/1/93 exp.)

23. PROPOSED CASING AND CEMENTING PROGRAM

SIZE OF HOLE	GRADE, SIZE OF CASING	WEIGHT PER FOOT	SETTING DEPTH	QUANTITY OF CEMENT
26	20		869' (In Place)	1630 sx.
17½	13 3/8	72, 68, 64	6300' (In Place)	3606 sx.
12¼	9 5/8	53.5, 47, 43.5	11,736 (In Place)	775 sx.
8 3/8	7	26	6735-12213 (Shot off @ 6735)	612 sx
6¼	5½ (LNR.)	(unk.)	12,032-15,400	450 sx.
(unk)	3½ (LNR.)	(unk)	14,967-17,084	250 sx.

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abondoned by Texaco in 1983. MCH will drill out cement plugs and cibp @ 7,579' to a total depth of approx. 8,350' (inside casing). This will leave in place cibp at 9,500' and deeper. We will then test existing perforations @ 7,807'-7,857' and stimulate as necessary.
Mud Program: Fresh water will be used for the reentry inside casing.
BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO GENERAL REQUIREMENTS AND SPECIAL STIPULATIONS ATTACHED

IN ABOVE SPACE DESCRIBE PROPOSED PROGRAM: If proposal is to deepen, give data on present productive zone and proposed new productive zone. If proposal is to drill or deepen directionally, give pertinent data on subsurface locations and measured and true vertical depths. Give blowout preventer program, if any.

24.
SIGNED Craig Huben TITLE Owner DATE 4/13/93

(This space for Federal or State office use)

PERMIT NO. ______ APPROVAL DATE ______

Application approval 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.
CONDITIONS OF APPROVAL, IF ANY:

APPROVED BY ______ TITLE ______ DATE ______

*See Instructions On Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

Form 3160-5
(November 1983)
(Formerly 9-331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

P. O. BOX 1980
HOBBS, NEW MEXICO 88240

Form approved.
Budget Bureau No. 1004-0135
Expires August 31, 1985

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

1. OIL WELL [X] GAS WELL [ ] OTHER

7. UNIT AGREEMENT NAME
West Jal Unit

2. NAME OF OPERATOR
Getty Oil Company

8. FARM OR LEASE NAME

3. ADDRESS OF OPERATOR
P.O. Box 730, Hobbs, NM 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
Unit Ltr. H, 1980' FNL & 660' FEL

10. FIELD AND POOL, OR WILDCAT
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, T-25S, R-36E

BUREAU OF LAND MGT.
APR
DIST. 6 N. M.
ROSWELL, NEW MEXICO

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138' D.F.

12. COUNTY OR PARISH
Lea

13. STATE
NM

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	[ ]	PULL OR ALTER CASING	[ ]	WATER SHUT-OFF	[ ]	REPAIRING WELL	[ ]
FRACTURE TREAT	[ ]	MULTIPLE COMPLETE	[ ]	FRACTURE TREATMENT	[ ]	ALTERING CASING	[ ]
SHOOT OR ACIDIZE	[ ]	ABANDON*	[ ]	SHOOTING OR ACIDIZING	[ ]	ABANDONMENT*	XX
REPAIR WELL	[ ]	CHANGE PLANS	[ ]	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

3/26/84 Rigged up. Pulled rods and pump. Unseat tbg. anchor and install BOP.
3/28/84 Pulled 2 7/8" buttress & 2 3/8" tbg. anchor. Ran 7" CI plug, set @ 7579'. Ran 2 3/8" to 4290'. By Halliburton, circ. 191 bbls. gel brine, pulled tbg. Perfs 4-0.25" holes @ 6400'. Circ. out 7" between 9 5/8". Ran 2 7/8" to 7554'.
3/29/84 Rigged up csg. puller unit. Pulled tbg. Remove BOP & 7" tbg. spool.
3/30/84 Weld 7" pull nipple. Cut 7" csg. @ 6735'. Pulled 11 jts 7", 26#, P-110 csg. 8 rd.
3/31/84 Layed down total 163 jts (est. 6525') 7", 8rd casing. Nipple down 9 5/8" head.
4/2/84 Weld on 9 5/8" pulled nipple. Attempted to pull slips with 500,000#. Set off primer cord around head, no movement. Left soaking in penetrating oil.
4/3/84 Dug out 13 3/8" csg. unflange head. Move pipe 1" with 600,000#. Cut off. Pulled nipple, installed BOP. Ran tbg to 5216'.
4/4/84 Spot 20 sxs cement on top of CIBP 7579-7479'. Spot 100' plug (45 sxs) at 6758-6685', 6350-6250', 3325-3200', 1380-1270'. Remove csg. head.
4/5/84 Rigged down. Installed 20 sxs. Plugged 0-50'. Installed dry hole marker. P&A.

18. I hereby certify that the foregoing is true and correct

SIGNED Donald J. Steinner TITLE Area Superintendent DATE April 11, 1984
~~Dale R. Crockett~~

(This space for Federal or State office use)

Orig. Sgd.

APPROVED BY ______ TITLE ______ DATE 6 8 87

CONDITIONS OF APPROVAL, IF ANY:

Approved as to plugging of the well bore. Liability under bond is retained until surface restoration is completed.

0+6-BLM-Roswell 1-Mr. J.A.-Midland
1-File 1-Laura Richardson-Midland
1-Engr Jim 1-BB, 1-JA
1-Foreman CK 1-SH, 1-CP 1-Southland Royalty Company, 1-ARCO

*See Instructions on Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

N. M. OIL CONS. COMMISSION
P. O. BOX 1980
HOBBS, NEW MEXICO 88240

O+6 - BLM - P.O. Box 1857, Roswell, 1-File, 1-Engr.JIM, 1-Foreman CK

Form 9-331
Dec. 1973

1 - Laura Richardson-Midland

Form Approved.
Budget Bureau No. 42-R1424

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

BUREAU OF LAND MANAGEMENT
RECEIVED
JUL 25 1983
DIST. 6 N. M.
ROSWELL, NEW MEXICO

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 Form 9-331-C for such proposals.)

1. oil well XX gas well ☐ other

2. NAME OF OPERATOR
Getty Oil Company

3. ADDRESS OF OPERATOR
P.O. Box 730 Hobbs, NM 88240

4. LOCATION OF WELL (REPORT LOCATION CLEARLY. See space 17 below.)
AT SURFACE: Unit ltr. H, 1980' FNL & 660 FEL
AT TOP PROD. INTERVAL:
AT TOTAL DEPTH:

5. LEASE
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME
West Jal Unit

9. WELL NO.
1

10. FIELD OR WILDCAT NAME
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, 25S-36E

12. COUNTY OR PARISH
Lea

13. STATE
NM

14. API NO.

15. ELEVATIONS (SHOW DF, KDB, AND WD)
3138' D.F.

16. CHECK APPROPRIATE BOX TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

	REQUEST FOR APPROVAL TO:	SUBSEQUENT REPORT OF:
TEST WATER SHUT-OFF	☐	☐
FRACTURE TREAT	☐	☐
SHOOT OR ACIDIZE	☐	☐
REPAIR WELL	☐	☐
PULL OR ALTER CASING	☐	☐
MULTIPLE COMPLETE	☐	☐
CHANGE ZONES	☐	☐
ABANDON*	XX	☐
(other) Revised		

(NOTE: Report results of multiple completion or zone change on Form 9-330.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

Revised procedure as per conversation with Mr. Peter Chester 7/18/83:

1. Install B.O.P.
2. Set C.I.B.P. at ±7860 w/35' cement on top.
3. Perforate 2 holes @ 6375' & squeeze with sufficient cement to bring cement to 6225'.
4. Set cement plug 1230-1330' top of salt. (in & behind casings).
5. Set 50' surface plug.
6. Install dry hole marker.
7. Restore location.

Subsurface Safety Valve: Manu. and Type ______ Set @ ______ Ft.

18. I hereby certify that the foregoing is true and correct

SIGNED Dale R. Crockett TITLE Area Superintendent DATE July 22, 1983

(This space for Federal or State office use)

APPROVED

APPROVED BY (Orig. Sgd.) ... M. CHESTER TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

SEP 14 1983

Jwy

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE*
(See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG *

5. LEASE DESIGNATION AND SERIAL NO.: NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: - - - - - -

1a. TYPE OF WELL: OIL WELL [X] GAS WELL [ ] DRY [ ] Other

7. UNIT AGREEMENT NAME: - - - - - -

b. TYPE OF COMPLETION: NEW WELL [ ] WORK OVER [ ] DEEP-EN [ ] PLUG BACK [X] DIFF. RESVR. [X] Other

8. FARM OR LEASE NAME: West Jal Unit

2. NAME OF OPERATOR: Skelly Oil Company

9. WELL NO.: 1

3. ADDRESS OF OPERATOR: P. O. Box 1351, Midland, Texas 79701

10. FIELD AND POOL, OR WILDCAT: Jal Delaware, West UNDESIGNATED

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*

At surface: Unit Letter H, 1980' FNL and 660' FEL, Sec. 20-25S-36E

At top prod. interval reported below

At total depth

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec. 20-25S-36E

14. PERMIT NO. | DATE ISSUED

12. COUNTY OR PARISH: Lea

13. STATE: New Mexico

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
- -	- -	5-28-74	3138' DF	- - -

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
17086'	9485' PBTD	- -	→	- -	- -

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*

7807-7857' Delaware

25. WAS DIRECTIONAL SURVEY MADE: - - -

26. TYPE ELECTRIC AND OTHER LOGS RUN: None

27. WAS WELL CORED: - -

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
No Change					

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
-	-	-	-	-
-	-	-	-	-

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-3/8"OD	7941'	- -
2-7/8"OD		- -

31. PERFORATION RECORD (Interval, size and number)

7807-7811', 7816-7828', 7853-7857', total 32 shots, 0.50" diameter, two shots per foot.

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
7807-7857'	750 gallons mud acid 5000 gallons 15% NE acid, 82 ball sealers, 9000# 20-40 sand, 9000 gallons lease oil

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
5-28-74	Pumping	Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
6-19-74	24	-	→	63	1	6	16

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
- -	63#	→	63	1	6	41°

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.): Used for Fuel

TEST WITNESSED BY

35. LIST OF ATTACHMENTS: None

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED (Signed) D. R. Crow D. R. Crow TITLE Lead Clerk DATE 6-20-74

*(See Instructions and Spaces for Additional Data on Reverse Side)

INSTRUCTIONS

General: This form is designed for submitting a complete and correct well completion report and log on all types of lands and leases to either a Federal agency or a State agency, or both, pursuant to applicable Federal and/or State laws and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local, area, or regional procedures and practices, either are shown below or will be issued by, or may be obtained from, the local Federal and/or State office. See instructions on items 22 and 24, and 33, below regarding separate reports for separate completions.

If not filed prior to the time this summary record is submitted, copies of all currently available logs (drillers, geologists, sample and core analysis, all types electric, etc.), formation and pressure tests, and directional surveys, should be attached hereto, to the extent required by applicable Federal and/or State laws and regulations. All attachments should be listed on this form, see item 35.

Item 4: If there are no applicable State requirements, locations on Federal or Indian land should be described in accordance with Federal requirements. Consult local State or Federal office for specific instructions.

Item 18: Indicate which elevation is used as reference (where not otherwise shown) for depth measurements given in other spaces on this form and in any attachments.

Items 22 and 24: If this well is completed for separate production from more than one interval zone (multiple completion), so state in item 22, and in item 24 show the producing interval, or intervals, top(s), bottom(s) and name(s) (if any) for only the interval reported in item 33. Submit a separate report (page) on this form, adequately identified, for each additional interval to be separately produced, showing the additional data pertinent to such interval.

Item 29: *"Sacks Cement"*: Attached supplemental records for this well should show the details of any multiple stage cementing and the location of the cementing tool.

Item 33: Submit a separate completion report on this form for each interval to be separately produced. (See instruction for items 22 and 24 above.)

37. SUMMARY OF POROUS ZONES:
SHOW ALL IMPORTANT ZONES OF POROSITY AND CONTENTS THEREOF; CORED INTERVALS; AND ALL DRILL-STEM TESTS, INCLUDING DEPTH INTERVAL TESTED, CUSHION USED, TIME TOOL OPEN, FLOWING AND SHUT-IN PRESSURES, AND RECOVERIES

38. GEOLOGIC MARKERS

FORMATION	TOP	BOTTOM	DESCRIPTION, CONTENTS, ETC.

NAME	TOP: MEAS. DEPTH	TOP: TRUE VERT. DEPTH

1) Squeezed Fusselman perfs. 16,449-16,614' with 100 sacks Class "H" cement, S/10% CFR-2.
2) Spotted 25 sacks cement 14,711-14,741', 25 sacks 11,924-12,082' and set cast iron bridge plug at 10,330' and spotted 4 sacks cement 10,310-10,330'.
3) Perforated 7" OD casing in First Bone Springs formation with two 0.48 diameter holes per foot at 10,112-10,122' and 10,128-10,132'. (28 shots total)
4) Treated First Bone Springs perfs. 10,112-10,132 with 5500 gallons acid and 68 ball sealers.
5) Swab tested First Bone Springs perfs. 10,112-10,132' May 14, 1974, to May 21, 1974, for no oil, 14 bbls. water and slight show of gas in 5 hours.
6) Set cast iron bridge plug at 9500' and cemented with 3 sacks cement plugging back to 9485'.
7) Perforated 7" OD casing in Delaware formation with two 0.50" diameter holes per foot at 7807-7811', 7816-7824' and 7853-7857'. (32 shots total)
8) Treated Delaware perfs. 7807-7857' with 750 gallons mud acid, 5000 gallons 15% HE acid, 9000 gallons gelled lease oil, 9000# 20-40 sand and 22 ball sealers.
9) Returned well to production status 5-28-74 pumping Delaware perfs. 7807-7857' for 63 bbls. oil, 6 bbls. water and 1 MCFGPD.

8) Flowed 24-1/2 hours through 1" choke, making no oil, 45 bbls. load water, 393 bbls. formation water and gas at rate of 266 MCF per day. FTP 200#, CP 2300#.
9) Ran flow meter, Gradionometer and Temperature Survey to determine water entry.
10) Shut well in seven hours, then ran Base Temperature Log 16,000-17,020'. Water channelling from bottom of well bore to 16,508'.
11) Set cement retainer at 16,250' and squeezed perfs. 16,499-16,614' with 150 sacks Class "H" cement containing 4/10ths of 1% CFR-2 and 1% Halad 9. Squeeze failed. WOC 4 hours.
12) Resqueezed perfs. 16,449-16,614' with 50 sacks Class "H" cement with 1% Halad 9, 4/10ths of 1% CFR-2 and 1/4# Flocele per sack and 150 sacks Class "H" containing 1% Halad 9 and 4/10ths of 1% CFR-2. Squeeze failed.
13) Attempted to pull cement retainer - stuck.
14) Milled and pushed cement retainer from 16,250' to 16,490'. Recovered cement retainer.
15) Drilled and pushed junk to 16,930'.
16) Ran 254 jts. (14,793') of 2-7/8" OD tubing and set packer at 14,810'. Swabbed 9 hours, recovering 60 bbls. load water with good show of gas.
17) Treated perfs. 16,449-16,614' with 500 gals. 15% NE acid with 2 ball sealers. Swabbed 7 hours, recovering 1 bbl. load water, flowing gas at rate of 50 MCF per day.
18) Treated perfs. 16,449-16,614' with 5000 gals. 15% NE acid and 27 ball sealers.
19) Ran Temperature Survey 15,000-16,958'.
20) Tested well. Well flowed at rate of 910 MCF per day on 23/64" choke, no oil, FTP 310#. Pulled tubing and packer.
21) Reran 457 jts. (14,940') of 2-7/8" OD 7.9# DSS-HT Atlas-Bradford Condition "A" tubing and set at 14,967'.
22) Circulated hole with corrosion inhibitor water. Released rig 11-8-72. Flowed and tested well.
23) On Dec. 11, 1972, treated perfs 16,449-16,614' with 12,500 gals. of 1% KCL water with 62# friction reducer, 25 gals. Adofoam and 25 gals. scale inhibitor, 20,000 gals. 20% retarded acid with 100# friction reducer, 40 gals. Adofoam, 160 gals. acid inhibitor, 1000# fluid loss agent and 40 gals. scale inhibitor and 7 ball sealers. All fluid contained 400 S.C.F Nitrogen per barrel.
24) Testing well.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

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—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

1. OIL WELL ☐ GAS WELL ☒ OTHER

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 1351, Midland, TExas 79701

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Undesignated Fusselman

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3076' GR

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Clean out & deepen to 17,086'	x		
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

1) Rigged up rotary tools 7-28-72. Pulled tubing and packer.
2) Set cement retainer at 11,390' and squeezed Strawn 7" OD casing perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 1% CFR-2 and 3# sand per sack. Squeeze failed. WOC 4 hours.
3) Resqueezed perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 5/10% of 1% CFR-2 and 3# sand per sack. Squeezed at 6500#. Reversed out 15 sacks.
4) After WOC 12 hours, drilled cement retainer at 11,390' and cement 11,390-11,755' with 6-1/2" bit.
5) Tested squeeze job to 3000#; held okay.
6) Drilled cement 11,790-11,832' and tested old squeeze job on perfs. 11,736-11,815' to 3000#; held okay.
7) Drilled cement 11,832-11,844'; pushed plus-plug to 11,976'. Drilled plug. Tagged junk at 12,002' and pushed to 12,312'.
8) Cleaned to top of 5-1/2" OD liner at 12,032', set cement retainer at 11,820' and found casing perfs. 11,849-11,894' open.
9) Squeezed 5-1/2" casing perfs. 11,849-11,894' with 50 sacks Class "H" with 1% CFR-2 and 100 sacks Class "H" with 1% CFR-2 and 3# sand per sack.
10) Dumped 20 sacks cement on retainer at 11,820', plugging back to 11,717'. Reversed out 90 sacks cement. WOC 12 hours.

(continued on page 2)

18. I hereby certify that the foregoing is true and correct

SIGNED ____________ TITLE Lead Clerk DATE Dec. 18, 1972

(This space for Federal or State office use)

APPROVED BY ____________ TITLE ____________ DATE ____________
CONDITIONS OF APPROVAL, IF ANY:

ACCEPTED FOR RECORD
DEC 20 1972
U. S. GEOLOGICAL SURVEY
HOBBS, NEW MEXICO

*See Instructions on Reverse Side

11) Drilled cement 11,708-11,820'; cement retainer 11,820-11,822' and cement 11,822-11,861'. Cleaned out to top of liner at 12,032'.
12) Tested squeeze job to 2500#; held okay.
13) Drilled junk 12,312-12,748.5'; cement 12,748.5-12,760'; junk to 12,762'; cement 12,762-13,030'.
14) Tested old squeezed perfs. 13,005-13,030' to 2500#; held okay.
15) Milled and drilled cast iron bridge plug at 13,174' and pushed to 13,395'.
16) Tested 5-1/2" OD liner perfs. 13,247-13,360' to 2900#; could not pump into perfs.
17) Milled cast iron bridge plug 13,396-13,400'.
18) Tested perfs. 13,462-13,472' to 2700#; could not pump into perfs.
19) Milled and drilled out cement retainer 13,517-13,524'; cement 13,524-13,532'; cement 15,050-15,353'.
20) Milled and drilled cast iron bridge plug 15,340-15,858'. Washed over fish 15,858'; recovered fish. Cleaned out to old TD of 15,958'.
21) Drilled 4-3/4" new hole 15,958-16,498'.
22) Ran Drill Stem Test No. 1 (Silurian) 15,400-16,498'.
23) Drilled 4-3/4" hole 16,498' to total depth of 17,086' at 11 p.m. October 4, 1972.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instruction on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429 - A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- - -

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
- - -

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Section 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3102' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Cement, perforate & treat			☒
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

1) Perforated 2-7/8"OD tubing at 11,696',11,297', 10,374; 9698'; 8892';8707',8403'. Circulated to remove mud from annulus. Work began 1-29-69.
2) Pulled tubing
3) Ran 2-7/8"OD tubing with "RTTS" Packer. Set packer at 11,448'.
4) Squeezed 7"OD casing perforations 11,736-11,894' with 150 sacks class "H" Cement with 1% CFR-2 per sack, maximum pressure 4600#, failed. W.O.C. 4 hours. Broke formation down with 5000#.
5) Squeezed 7"OD casing perforations 11,736-11,894" with 50 sacks Class "H" cement with 1% CFR-2 and 5# No. 3 sand per sack. Displaced 35 sacks into formation. Pulled tubing and packer.
6) WOC 36 hours. Ran tubing with 6-1/8" bit. Top of cement inside 7"OD casing at 11,595'. Washed and circulated cement to 11,620'. Drilled cement 11,620-11,700'. Drilled packer 11,700-705'. Drilled cement 11,705-755'.
7) Tested casing to 3000#, held okay.
8) Spotted 12 bbls. acid 11,755-11,443'.
9) Perforated 7"OD casing with 2 shots per foot as follows:

11,510 - 513'	3'	6 shots
11,517- 527'	10'	20 shots
11,536 - 540'	4'	8 shots
11,550 - 556'	6'	12 shots
11,561 - 567'	6'	12 shots
11,575 - 579'	4'	8 shots
11,660 - 667'	7'	14 shots

18. I hereby certify that the foregoing is true and correct

SIGNED ______ TITLE District Production Manager DATE 3-10-69

(This space for Federal or State office use)

APPROVED BY ______ TITLE (ORIGINAL SIGNED) V. H. Fletcher

CONDITIONS OF APPROVAL, IF ANY:

APPROVED
MAR 11 1969
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

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—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO.
~~73503~~ NM-034291

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
----

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
----

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*
See also space 17 below.)
At surface **1980 from North line and 660 from East line, Section 20**

20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3092' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other)			
(Other) **Cement, Perforate & Treat**			☒	(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)			

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

Squeeze present perforated interval 11,736-11,852', below packer set at 11,700', with 125 sacks cement. Drill out to 11,790'. Perforate 11,510-11,783' with 2 shots per foot. Treat perforations 11,510-11,783' with 300 gallons 15% acid with 3 stage treatment using Dowell J-182 as diverting agent. Inject 72 barrels distillate to remove diverting agent. Swab and test.

18. I hereby certify that the foregoing is true and correct

SIGNED (signed) C. R. DAVIS TITLE **District Operations Manager** DATE **1/24/69**

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ **APPROVED**
CONDITIONS OF APPROVAL, IF ANY:

JAN 2_ 1969

KT/jc

*See Instructions on Reverse Side

J. L. GORDON
ACTING DISTRICT ENGINEER

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- -

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
- -

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

1980' from North line and 660' from East line

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.
- -

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138'

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Eliminate water production	☒		
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

(1) Moved in and rigged up workover rig 10-21-68
(2) Set Schlumberger "plus" plug in 7"OD casing at 11,844'.
(3) Dumped 5' cement on top of plug, filling from 11,844' to 11,839'.
(4) Dumped 200 lbs. Hydromite on top of "plus" plug, filling back to 11,832'.
(5) Swabbed well.
(6) Apparent communications still exist between upper and lower perforations behind 7"OD casing. Objective to shut off lower perforations 11,860 - 11,894' and to decrease water production unsuccessful.
(7) Well returned to producing status 10-27-68 flowing 150 MCF gas per day through 7" OD casing perforations 11,736 - 11,894'.

18. I hereby certify that the foregoing is true and correct

SIGNED [signature] TITLE District Production Manager DATE 10-30-68

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ APPROVED
CONDITIONS OF APPROVAL, IF ANY:

NOV , 1968
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429 - A

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—" for such proposals.)

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
-----

1. OIL WELL ☐ GAS WELL XX OTHER

7. UNIT AGREEMENT NAME
-----

2. NAME OF OPERATOR
SKELLY OIL COMPANY

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*
See also space 17 below.)
At surface

1980' FNL & 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO.
-----

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Clean, Determine Water Source, Eliminate Water Production			X
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

Moved in and rigged up Workover Rig. Killed well. Ran 1-5/8" drill pipe and fishing tools to top of fish at 9901', pushed to 9991', caught fish, circulated and pulled out of hole. Recovered 2 strings of fishing tools previously left in hole. Reran 1-5/8" drill pipe several times with fishing tools and recovered 1786' in several pieces of 5/16" wire line, and a chemical cutter.

Tagged bottom of 2-7/8"OD tubing at 11,715'. Knocked off one foot of tubing and a bull plug that had been previously cut off. Pushed and drove bull plug to 12,482'. Hit firm fill-up of formation cavings and left one-foot piece of 2-7/8"OD tubing and bull plug in hole at 12,482', leaving tubing open-ended at 11,715' with full 2-7/8" opening. Pulled drill pipe and fishing tools and installed Xmas tree. Ran Gradiomanometer, Continuous Flowmeter and Packer Flowmeter to determine water source. Surveys indicated water source being produced through casing perforations 11,883-11,894'.

Set packer at 11,883'. Returned to production status November 19, 1967, producing 38 bbls. oil, 800 bbls. water and 2,000 MCF gas per day from the Strawn Gas Pool through perforations 11736-11894' through 7"OD casing.

18. I hereby certify that the foregoing is true and correct

SIGNED (ORIGINAL SIGNED) V. E. Fletcher TITLE District Superintendent DATE April 25, 1968

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
APR 26 1968
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE*
(See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

1a. TYPE OF WELL: OIL WELL [ ] GAS WELL [X] DRY [ ] Other

b. TYPE OF COMPLETION: NEW WELL [ ] WORK OVER [X] DEEP-EN [X] PLUG BACK [ ] DIFF. RESVR. [X] Other

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME
West Jal Unit

2. NAME OF OPERATOR
Skelly Oil Company

9. WELL NO.
1

3. ADDRESS OF OPERATOR
P. O. Box 1351, Midland, Texas 79701

10. FIELD AND POOL, OR WILDCAT
Undesignated Fusselman

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface 1980' FNL and 660' FEL Sec. 20-25S-36E
At top prod. interval reported below
At total depth

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO. | DATE ISSUED

12. COUNTY OR PARISH: Lea
13. STATE: New Mexico

15. DATE started	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
7-28-72	11-1-72	10-4-72	3076' GR	

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
17,086'	17,020'	---	→	15,958-17,086'	---

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*
16,449-16,614' (Fusselman)

25. WAS DIRECTIONAL SURVEY MADE: No

26. TYPE ELECTRIC AND OTHER LOGS RUN: BHC Sonic Gamma Ray with Caliper, Dual Laterolog, Continuous Dipmeter, Compensated Neutron & Formation Density

27. WAS WELL CORED: No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
20"	94#	869'	26"	1630 sacks	None
13-3/8"	72,61 & 68#	6300'	17-1/2"	3206 sacks	None
9-5/8"	53.5 & 47#	11,732'	12-1/4"	975 sacks	None

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
		(See attachment)		

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-7/8"	14,967'	None

31. PERFORATION RECORD (Interval, size and number)
16,449-16,614' (Fourteen .33" holes over 165' interval)

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
11,510-11,741'	200 sacks Class "H" Cement
11,849-11,894'	150 sacks Class "H" Cement
16,449-16,614'	350 sacks Class "H" Cement
	(See attachment)

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
11-1-72	Flowing	Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
11-14-72	24	24/64"	→	-0-	5950	216	----

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
1900#	---	→	-0-	5950	216	---

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.): Sold

TEST WITNESSED BY

35. LIST OF ATTACHMENTS: 2 copies each: Borehole Compensated Sonic Log - Gamma Ray, Compensated Neutron-Formation Density, Dual Laterolog, Gammatron

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED C.J. Love TITLE Dist. Prod. Manager DATE Dec. 20, 1972

*(See Instructions and Spaces for Additional Data on Reverse Side)

2MO1T0J3T2M1

WIST JAL UNIT Sheet Ho. 2

WILL RO. !.

Set Baker Calt Iron Bridge Plug at 13,400'. Spotted 2 aacka c••nt on top of bridge plug traa 13,-00' to 1.3,386'. Perto:rated 5--1/2" OD liner with 4 holea at 13,210' and 1queezed with 85 aacka ot caat. Drill.eel out oeaeat \o 13,386'• Perforated S-1/2" liner with 4 ahota per foot •• followa1 13,247-13,2'10', 13,272-1.3,275', 13,286-13,292', 13,298-13,320', 13,326-13,329', 1.3,343-13,345', 13,)56-13,360' tor a total ot 63• and 252 hol••• Treated tbroqh S-1/2" OD caaing liner pert•• 13,247-13,360' (intenala) with 2500 gallon• Mud Acid. Teated .-.11 Hftr&I houn with -n,lae to aall to meanre. Treated through 5-1/2" OD caeing liner perta. 13,21.7-13,360' (intenala) with 2500 gallons Mud Acid.. t'eelMI •li-' aeveral hN. with TOIUM to -11 to meaaure. Treated through S-1/2" OD casing liner pert• 13,247-IJ,'601 (intenala) with 10,000 galana 1,- llegular Acid. Teated well aenral houri with wt1111e to .all to m•an• Set Baker Caat Iron Model "I" Bridge Plug at 13,180'• Dmpecl 2 eacka ot cement on top ot plug, wbieh pl11g nll b&ek tra 13,180' to 1.3,166•. Pertorat.ed 5-1/2" OD liner with bole• per toot troa 13,0051 to 13,030• for a total of 251 and 100 hol••• Treated thrcnlgh 5-1/2" OD liner perte. 13,00S-13,030' with 5,000 gallons 15C Regular Acid. Teated well N'Yer&l hove with TOluae \oo •-ll to aeanre. We teaJ>l'?'8,ril7 abandoned the teat.inc ot the Morrow Zone at t.hie t.m, Set Halliburton "DC" C... nt Retainer at 12,790' and aqueesed 85 eaeke ot CtllHlt into 5-1/2" OD liner perte. 13,005-13,030•. Plugged back total depth 12,7901• Pertorat.ed 7" OD casing with 4 bolea per toot aa tollowa1 11,736-II,7U', 11,781-11,787', II,801-II,815t, II,&1+,-11,852', 11,860-U,894' tor a total ot 55t and 220 holea. Set Baker Model "?" Production Packer at 11,700'• Ran 2-7/8" OD 6.1+0# Blltre•• threat! 1-80 tubing to 11,715' and ....ted in Baker Model"'" Production Packer at 11,700' with pert• 11,711-II,715'. Ot.ia l.allding nipple position No. I at II,709'. Ot.1• aid• doar ahitt. valft at U,698'. otie landing nipple poaition lo. 2 at 10,700'. otil lending nipple position lo. 3 at 9700'• Opened well up and flowed to pit to clean up. Shut well in tor 89 hove. After 89 houra with dead night T.P. 6218# flowed and teated well 1n the toll.owing anner1

nowed 1-3/4 hour• on 10/64" choke, opening TP 6218# (W), FTP 6156pai., gas wltae 2,737 JEPPD and 7.6') 'bbl•• ot 52 degree correeted gra'Yit7 condenaate.
lu.t. two hour• tlowd through 12/64• ohoke, ITP 6075 pai. (17W), gas luae 4563 KCfPD .w1i and 6.60 bbla. of condenea.te.
lut two noura fiowd throUgh 14/6'+" choke, FTP 599S pei. (DW), gae wIUM 6025 MCFPD and 1.70 bbl•• or oonden•t••
Rut one and one halt hours tLowed through 16/64" choke, FTP 5915 p•i• (IM), gas volUM 8009 ICFPD and undetel"llined 8JI0\1llt or oonclen•ate to pita.
Eatabliahed 24 hour In Maioo Ooneel'"fttion C.-d.eaion AOF Potential ot 310,000 tcFFD.
Completed Ja.,.17 22, 1963, a1 a "Wildcat" CCIll.J)letion in strawn (Penn117I'Y8Bian) toraation, Total cond.enate ree0Ye17 during 7-1/4 hn. t.eet waa 22,80 bbls. to tank and undetermined aaomt to pita.

Well now ahut in - waiting on ga• connection.

POBMATIOI RECORD

From	To	!!!i		
0	12,058	12,0,s		
12,058	12,152	94		
12,152	12,477	32,	Lime & Shale	- Top Atoka 12,152'
12,477	13,366	889	Sand	- Top Morrow 12,477'
13,366	14,S83	1,217	$ale	- Top Barp,ett Shale IJ,366•
14,583	14,685	102	Lhle	- 'lop Miasiaaippian 14,853'
14,685	1,,138	453	Chert	- Top Che. 14,685'
15,138	15,518	380	Shale	- Top Woodtorcl IS 131
15,518	15,988	440	L1M & Dolaite	- Top • {'5,518'
15,9??	I5,9SI	Total Depth		
	12,790	Plugged Back Total Depth		

Geological Tops by Schlumberger Gama Ray Sonic log

Appendix 10 - Process Flow Diagram

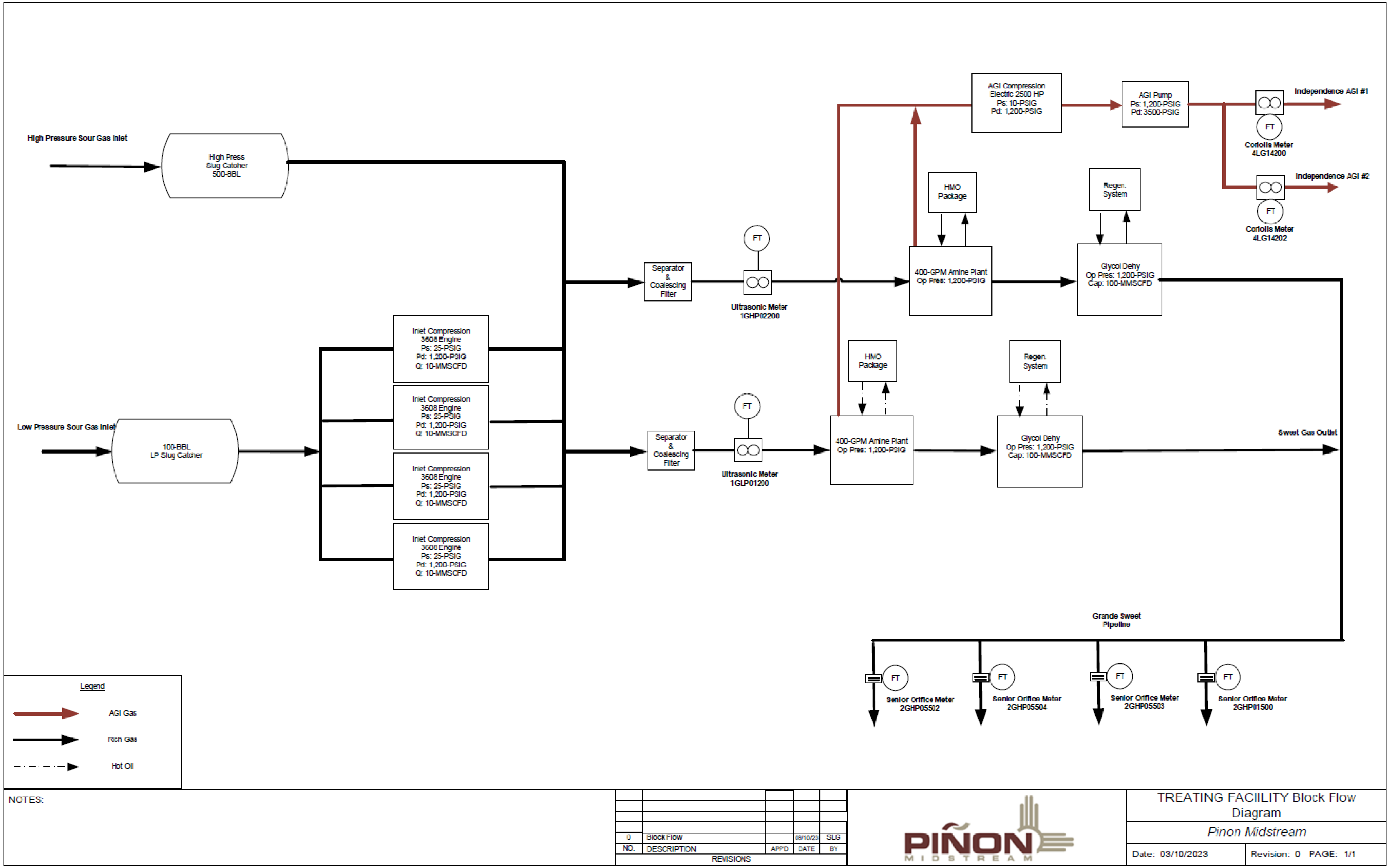


***Figure A10-1**: Treating Facility Block Flow Diagram*

Request for Additional Information: Piñon Midstream, LLC
March 21, 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.	3.7.1	28	While the flow meters intended to measure quantities of CO_2 injected and CO_2 received were added to figure 3.7-2, the specific locations of these meters on facility equipment are still unclear. Please update the figure and/or text to explain where exactly these meters are in relation to other facility components.	An updated figure has been provided. The figure demonstrates the specific locations of the meters in relation to the major equipment associated with the calculation methodologies in Subpart RR.
2.	5	43-47	"Piñon considers the likelihood, magnitude, and duration of CO_2 leakage to the surface via this potential leakage pathway to be minimal." There is no further elaboration of what "minimal" means regarding the likelihood, magnitude, and duration of potential CO_2 leakage in the most recent MRV plan submission. Please provide more detail on the likelihood, magnitude, and timing of leakage through the identified pathways. The discussion can be qualitative, but each leakage pathway should be clearly characterized (e.g., when might leakage be expected in the duration of the project? How much leakage might be expected for each of the different pathways? Is leakage more likely through some of the identified pathways vs. others?).	Additional clarity was provided in Section 5 and has been provided as a part of this update.

MONITORING, REPORTING, AND VERIFICATION PLAN

Independence AGI #1 and #2 Wells

Pinon Midstream, LLC

Version Number: 5.0
Version Date: February, 2024

Contents

1 Introduction

Ameredev II, LLC (together with its affiliates, "**Ameredev**") is an oil and natural gas producer operating in portions of the Delaware Basin located in southeastern New Mexico and western Texas. In 2020 Ameredev began evaluating methods for treating its sour natural gas production in Lea County, New Mexico to remove and permanently sequester large quantities of hydrogen sulfide ("$\mathbf{H_2S}$") and carbon dioxide ("$\mathbf{CO_2}$") commingled in its produced natural gas stream. On July 10, 2020, Ameredev filed an application with New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division ("**NMOCD**") seeking to drill an acid gas injection ("**AGI**") well approximately six (6) miles west of Jal in Lea County, New Mexico for the injection and permanent sequestration of treated acid gas ("**TAG**"). The application was heard and approved at a New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Commission ("**NMOCC**") hearing held on October 8, 2020. The approved order (Order No. R-21455-A) was subsequently issued at the November 4, 2020 NMOCC hearing and the final, approved, Class II injection permit was issued on November 11, 2020. The Independence AGI #001 vertical well (API 30-025-48081; "**Independence AGI #1**") was spud on December 27, 2020 by Ameredev.

In December of 2020, certain affiliates of Ameredev and other outside investors funded Piñon Midstream, LLC ("**Piñon**") to construct and operate the Dark Horse Sour Gas Treating Facility (the "**Dark Horse Facility**") adjacent to the Independence AGI #1 (Figure 1-1) and Ameredev subsequently contributed and assigned the Independence AGI #1 to Piñon on May 21, 2021. Piñon became the operator of record for the Independence AGI #1 on August 24, 2021. Upon completion in late August 2021, treatment of sour natural gas (using amine to isolate H_2S and CO_2) and the injection of TAG through Independence AGI #1 commenced at the Dark Horse Facility (a full description of the treating and injection process is provided in Section 3.8). On March 31, 2022 the NMOCC authorized the drilling of the Independence AGI #002 deviated well (API 30-025-49974; "**Independence AGI #2**") (together the "**Independence AGI Wells**"), which commenced during the summer of 2022, with initial TAG injection through the well occurring in April 2023.

Independence AGI #1 is permitted to inject into the Devonian Thirtyone and Upper Silurian Wristen and Fusselman Formations from a true vertical depth ("**TVD**") of approximately 16,230 to 17,900 feet (the "**AGI #1 Injection Zone**") and at a maximum surface pressure of approximately 4,779 pounds per square inch gauge ("**psig**"). Independence AGI #2 is permitted to inject into the Devonian Thirtyone Formation and Upper Silurian Wristen and Fusselman Formations from a TVD of approximately 16,080 to 17,683 feet (the "**AGI #2 Injection Zone**", and together with the AGI #1 Injection Zone, the "**Siluro-Devonian Injection Zone**") and at a maximum surface pressure of approximately 5,005 psig. In accordance with NMOCC Order No. R-21455-A (as amended by Order No. R-21455-B, the "**NMOCC Order**"), Piñon is authorized to inject and dispose of TAG, utilizing the Independence AGI Wells, at an aggregate *combined* maximum daily injection rate of up to 20 million standard cubic feet per day ("**MMSCF/D**"), which is the equivalent of approximately 8,200 barrels per day ("**bpd**") or 1,036.7 metric tonnes per day. Gas is injected for 30 years at a rate of 1,036.73 tonnes per day (378,399 tonnes per year or 11,351,970 total tonnes) followed by a 5-year rest period. If Independence AGI #1 is not injecting volumes of TAG, Independence AGI #2 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG. If Independence AGI #2 is not injecting volumes of TAG, Independence AGI #1 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG.

Piñon has chosen to submit this Monitoring, Reporting, and Verification Plan (the "**MRV Plan**") to the United States Environmental Protection Agency (the "**EPA**") for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (the "**GHGRP**") for the purpose of qualifying for the tax credit in Section 45Q of the federal Internal Revenue Code. Piñon intends to utilize the Independence AGI Wells for the injection and disposal of TAG for another approximately thirty (30) years.

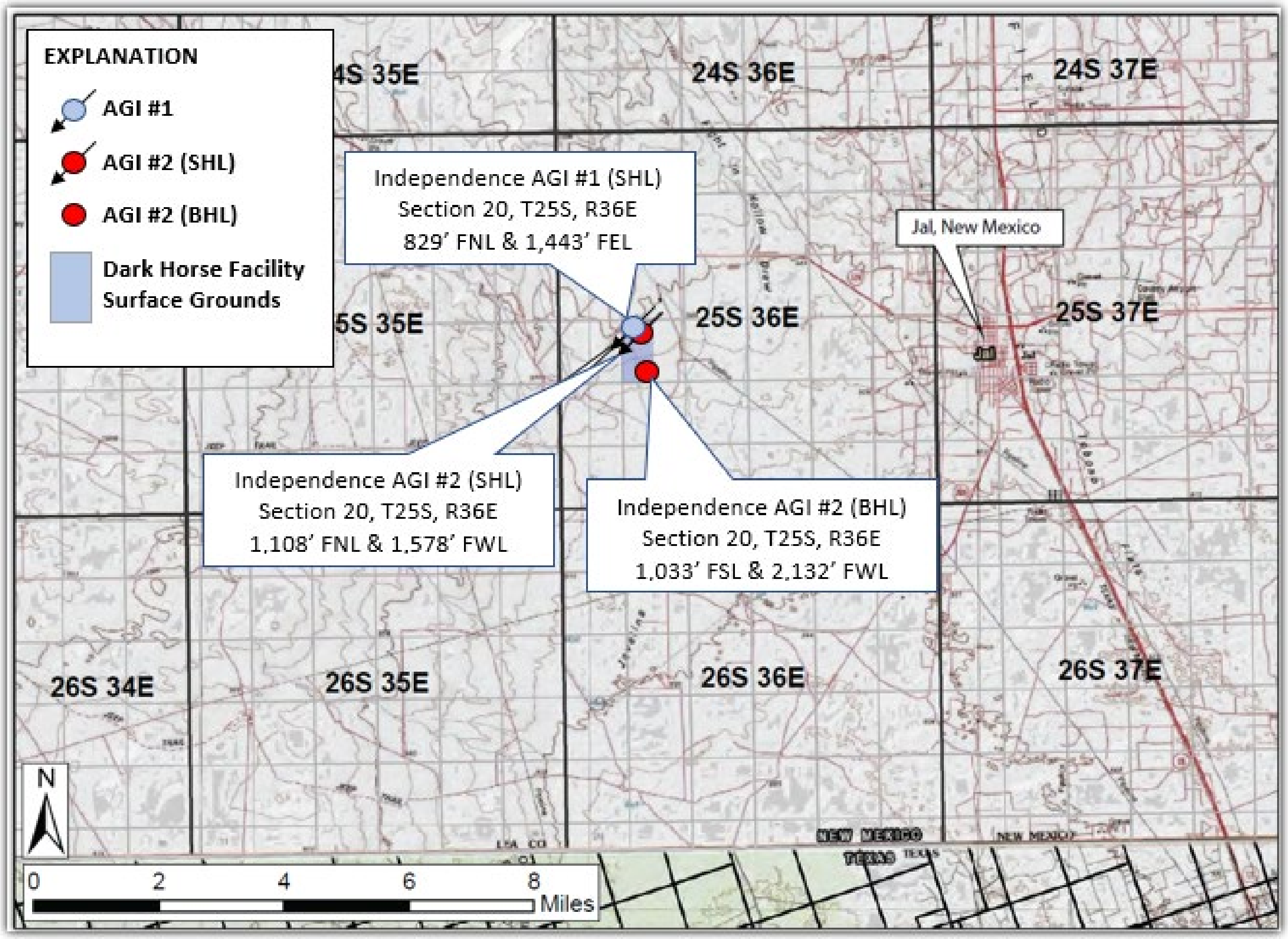


***Figure 1-1**: Location of Dark Horse Facility and the Independence AGI Wells. The approximate surface hole location ("SHL") and the approximate bottom hole location ("BHL") are indicated for both Independence AGI Wells. (Modified from Figure 1 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

This MRV Plan contains twelve (12) sections:

Section 1 is this Introduction.
Section 2 contains facility information.
Section 3 contains the project description.
Section 4 contains the delineation of the maximum monitoring area ("**MMA**") and the active monitoring area ("**AMA**"), both defined in 40 CFR 98.449, and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.
Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and duration of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP.
Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage.
Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.
Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.
Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.
Section 11 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.
Section 12 includes Appendices supporting the narrative of the MRV Plan.

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is 582541. There are no other facilities related to this MRV plan.

2.2 Underground injection control ("UIC") well identification numbers

This MRV Plan is for the Independence AGI Wells (*see* Appendix 1). The details of the injection process are provided in Section 3.8.

2.3 UIC permit class

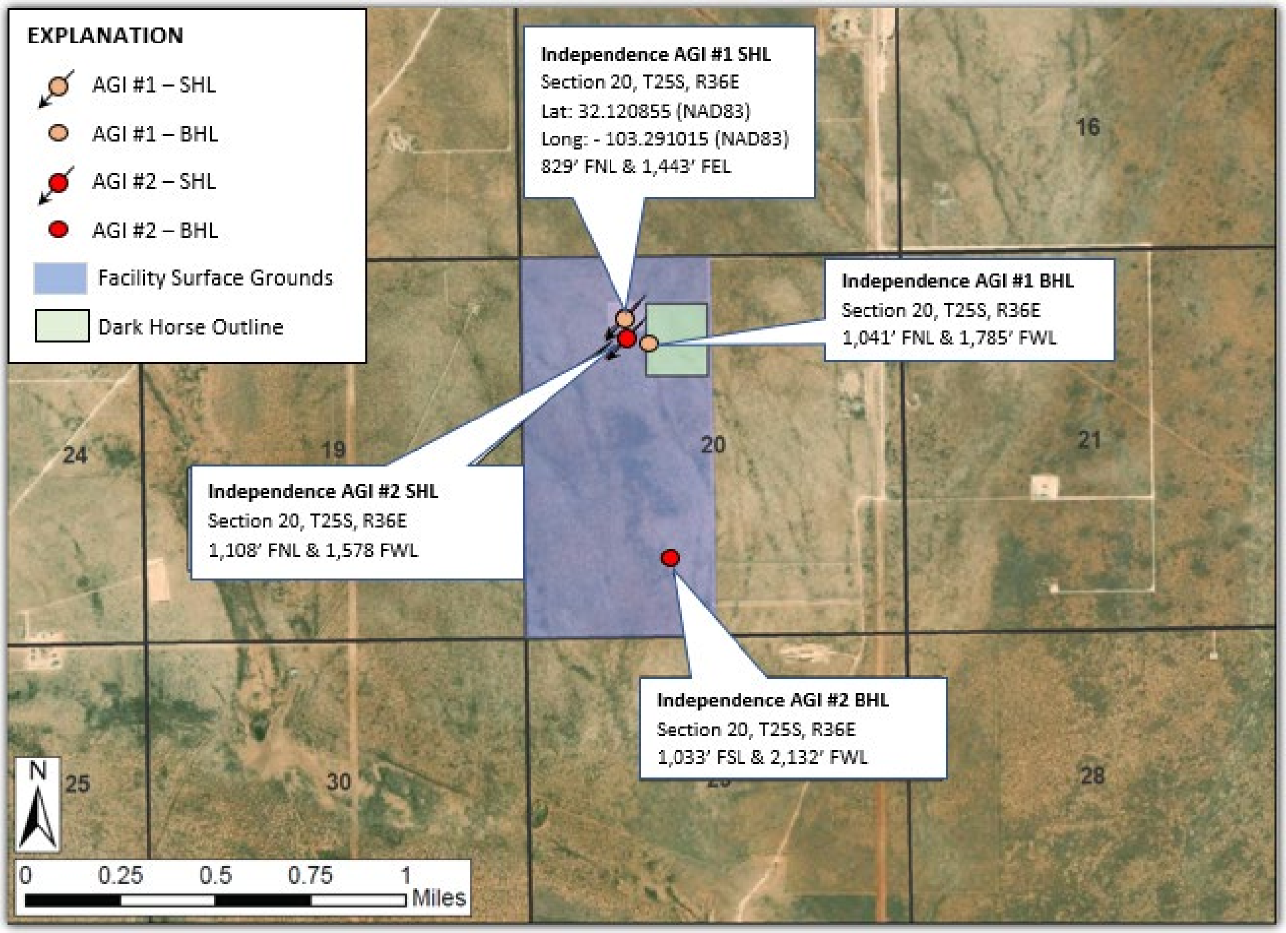
The NMOCD has issued UIC Class II Acid Gas Injection ("**AGI**") permits for the Independence AGI Wells under its State Rule 19.15.26 NMAC (*see* Appendix 2). All oil- and natural gas-related wells located near the Independence AGI Wells, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3 Project Description

Parts of the following project description have been taken from the Class II permit applications for (i) Independence AGI #1, prepared by Geolex, Inc. for Ameredev, dated July 10, 2020; and (ii) Independence AGI #2, also prepared by Geolex, Inc. for Piñon, dated November 4, 2021.

3.1 General Geologic Setting / Surficial Geology

The Dark Horse Facility is located adjacent to the Independence AGI Wells as shown in Figure 3.1-1. The site lies on the eastern flank of the Pecos River Basin within the Javelina Basin. Referred to as the South Plain by Nicholson & Clepsch (1961), the region exhibits irregular topography without integrated drainage. Surficial sediments commonly consist of unconsolidated alluvium and eolian sands. There are no observed surface bodies of water, or groundwater discharge sites within one (1) mile of the Independence AGI Wells. The Dark Horse Facility overlies Quaternary alluvium overlying the Triassic redbeds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater. The thick sequences of Permian rocks that underlie these deposits are described in Section 3.2.2.



p

<u>Figure 3.1-1</u>: Map showing location of Dark Horse Facility and the Independence AGI Wells in Section 20, T25S, R36E NMPM. The BHL of the Independence AGI #1 sidetrack is 446' southeast of the SHL. The SHL and the BHL for Independence AGI #2 are shown. (Modified from Figure 2 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.2 Bedrock Geology

3.2.1 Basin Development

The Dark Horse Facility is located at the northern margin of the Delaware Basin, a sub-basin of the larger, encompassing Permian Basin (<u>Figure 3.2-1</u>), which covers a large area of southeastern New Mexico and west Texas. The Permian Basin and its sedimentary fill have been formed and controlled by tectonism of varying degrees and sedimentation events that began in the Precambrian and throughout the Cenozoic (Neogene). Early Paleozoic deposition took place in the Late Cambrian as marginal areas of the North American craton began to be flooded by marine seas. Late Cambrian sediments comprised of basal siliciclastic sands and muds from areas of exposed Precambrian igneous, metamorphic, and sedimentary rocks and shallow-water carbonates.

Parts of the following basin development descriptions in this subsection have been modified and summarized from Ruppel (2019). Flooding continued across the North American craton throughout the Early Ordovician, establishing a widespread shallow-water carbonate platform. The Ellenburger Formation (<u>Figure 3.2-2</u>) rocks are derived from peritidal and shallow subtidal carbonates. These sediments were exposed during one of the sea-level drops during the Ordovician deposition resulting in karstification and dolomitization. During the Early to Middle Paleozoic time, the Permian Basin region was occupied by a relatively shallow basin called the Tobosa Basin. The first rapid subsidence and formation of the Tobosa Basin began in Simpson time (Middle Ordovician), and subsidence slowly diminished into the Early Devonian (Ewing, 2019). Subsequent tectonic history of the Tobosa and Permian Basins will be discussed throughout this section.

Early Paleozoic deposition is mostly defined by multiple high-frequency sea-level changes, karsting, and erosional events. Large-scale shift in facies and environments indicate tectonic and/or eustatic controls on sediment distribution patterns. Simpson Group (Middle Ordovician) rocks unconformably overlie Ellenburger Formation rocks at a widespread hiatus caused by Early Ordovician to Middle Ordovician relative sea-level fall. Simpson rocks are a cyclic succession of lime mudstones and quartz sandstones and were deposited during the subsequent reflooding of the shelf. Carbonate-dominated Montoya Formation (Late Ordovician) and Fusselman Formation (Latest Ordovician -Early Silurian) rocks overlie the Simpson Group and indicate a shift and deepening of Tobosa Basin. These rocks are indicative of an overall relative sea level rise.

Middle Silurian-Early Devonian Wristen Group and Thirtyone Formation rocks indicate differential subsidence in the area and represented a deepening and expansion of the basin. Wristen Group rocks comprised of carbonate mudstones and wackestones of the Wink Formation, which underlies the shallow-water carbonate platform packstones, grainstones, and reef facies (corals and stromatoporoids) of the Fasken Formation and the deep-water lime mudstones of the Frame Formation. These facies outline the position of a Silurian platform margin and imply a downwarping of the North American craton. Although Wristen and Fusselman show evidence of numerous high-frequency sea-level changes, the larger-scale change in facies and depositional environments indicates tectonic and/or eustatic controls on sediment distribution patterns. The Silurian platform margin is a recurring feature that controls facies distribution through the Late Mississippian, suggesting tectonic and/or basement terrain control. The rocks of the Thirtyone Formation (Early Devonian) consist of platform carbonate grainstones and packstones surrounding calcareous, radiolarian-rich basin facies.

According to Ruppel (2019) and Ruppel and others, (2020a), a major episode of relative sea-level fall in the Middle Devonian is documented by an absence of Late Early Devonian and early Middle Devonian rocks. Late Devonian Woodford rocks overlie eroded and karsted Silurian (Wristen Group), Early Devonian Thirtyone, and older rocks. Local folding of these rocks below the Woodford suggests that the hiatus may have been at least partially driven by tectonic events. Evidence from the distribution of later Mississippian rocks indicates that the tectonic event caused uplift and localized deformation of pre-Middle Devonian rocks and changed subsidence and depositional patterns across the entire region.

Following the Middle Devonian Permian Basin-area uplift and emergence, Late Devonian marine transgression flooded the region with anoxic bottom-water seas and deposited black, organic-rich biosiliceous mudstones of the Woodford Formation (Ruppel, 2019). Sea-level fall-and-rise sequences defined the Early and Late Mississippian and were even more pronounced during the Pennsylvanian. In the Late Mississippian, initial collision occurred between Laurentia and Gondwanaland, and the Marathon-Ouachita orogenic belt first started to form in northeastern North America (Yang and Dorobek, 1995) with tractions propagating toward the southwest, impacting the Permian Basin by the Middle Pennsylvanian Epoch (Desmoinesian, 310 Ma) (Horne, 2021). Mississippian limestones and the Barnett Formation shales were deposited following a marine transgression that resulted in the development of an extensive carbonate platform, surrounded by a deep-water, organic-rich mud basin.

Collision along the western and southwestern margins of Laurentia, combined with tractions from the Marathon-Ouachita thrusting in the southeast, resulted in northwest-southeast-trending uplifts throughout the western United States known as the Ancestral Rocky Mountain orogeny, which began in Early Pennsylvanian time and continued into the Early Permian (Horne, 2021). The Pennsylvanian tectonic setting in the Permian Basin is the product of the combined Ancestral Rocky Mountain and Marathon–Ouachita effects occurring along the southwest and southeast margins of Laurentia. These events contributed to basin evolution and specific structural domains and styles. In the Permian Basin, the Ancestral Rocky Mountain orogeny is responsible for the uplift of the Central Basin Platform and the major structural development of the Midland and Delaware Basins (Horne, 2021).

During Desmoinesian to early Missourian sedimentation, Permian Basin deformation reached its peak. The antecedent Tobosa Basin was tectonically differentiated, formed into the crustal uplifts and sub-basins that now characterize the Central Basin Platform, Midland Basin, and Delaware Basin. Throughout Pennsylvanian and most of Permian sedimentation, tectonics coupled with glacial eustacy played an important role in the development of regional facies. Middle to Late Pennsylvanian saw decreasing tectonic deformation activity, and by the Wolfcampian time (Early Permian), deformation was limited to subsidence within the structures formed by the existing uplifts and basins (e.g., Delaware and Midland Basins, Central Basin Platform). The continual subsidence of the Delaware basin affected sediment infilling, with some areas accumulating as much as 12,000 ft of basin-fill sediment. Marine transgression eventually submerged uplifts and became the location of carbonate sedimentation, while the basins became filled with organic-rich siliceous muds. By the end of the Wolfcampian, the major Permian Basin physiographic features (Central Basin Platform, Delaware and Midland Basins) were fully developed, and controlled sedimentation types and location for the remainder of the Paleozoic.

The Middle Permian (Leonardian and Guadalupian) was punctuated by cyclic sediment deposition during sea-level eustatic events. The Leonardian was a time of gradual global warming from the icehouse climates of the late Carboniferous to warmer and more arid greenhouse climates of the later Permian and Mesozoic (Tabor, 2004). The Leonardian marked the beginning of the last stages of the formation of Pangea, producing greater restriction of open ocean connections to the Permian Basin (Ruppel, 2020b). The abundance of tidal-flat facies, evaporites, and reflux dolomites in Leonardian rocks reflects the development of much more arid conditions compared with those in the earlier Permian (Ruppel, 2020b). In the shelf areas (Central Basin Platform and Northern, Northwestern, and Eastern Shelves) (Figure 3.2-1), sedimentation was characterized by shallow-water carbonate production and deposition during sea-level rise, and by shelf exposure and sand-silt deposition during sea-level fall and subsequent shelf exposure. In the Delaware and Midland basins, sedimentation was characterized by cyclic intervals of detrital carbonate-sediment transport into the basins by sea-level highs, and by sand-silt transport and deposition during sea-level falls. Dolomitization of carbonate-shelf deposits occurred during the more regionally arid climates of the Leonardian and the Guadalupian as a product of the Permian Basin area being situated at the equator and from refluxing brines created during periods of sea-level highstand events. Deposition of evaporites became more common in the shelf areas during this time, likely in response to the increasingly arid environment and/or decreased accommodation. By the end of the Guadalupian, the Midland Basin was largely filled, and peritidal muds and evaporite deposition dominated. Sea-level fall and closure of the Hovey Channel (Figure 3.2-1) cut off the Delaware Basin from its marine supply, resulting in regional exposure and nondeposition and the filling of the basin with evaporites of the Castille Formation (Lopingian “Ochoa” Series) (Ruppel, 2019). Most of the rocks deposited during Lopingian “Ochoan” time were evaporites such as anhydrite, halite, and potash minerals with minor amounts of limestone, mudstone, and siltstone and are subdivided into (ascending) Castile Formation, Salado Formation, Rustler Formation, and Dewey Lake Red Beds. Most of the early Ochoan deposition was confined to the Delaware Basin (Bachman, 1984).

3.2.2 Stratigraphy

Figure 3.2-2 is a generalized stratigraphic column showing the formations that underlie the Dark Horse Facility and the Independence AGI Wells. The sequences of Ordovician through Permian rocks are described below.

Ordovician. Below the Silurian Fusselman Formation lies about 400 feet of Ordovician Montoya Formation cherty carbonates which overlies about 400 feet of Ordovician Simpson Group sandstones, shales, and tight limestones. These formations are underlain by the Lower Ordovician Ellenburger Formation which is a thick, carbonate-dominated sequence composed of dolostones and limestones. It is 0-1,000 feet thick in southeastern New Mexico. The Ellenburger carbonates sit on a veneer of Cambrian to Lower Ordovician Bliss Sandstone and granite wash on the Precambrian basement.

During the Early Ordovician, much of the United States was covered by a shallow sea, and southeast New Mexico was a shallow-water shelf with deep water conditions to the south. Due to sea-level changes and regional tectonic activity, the entire lower Paleozoic interval (Ellenburger through Devonian) was periodically subjected to subaerial exposure and prolonged periods of karst and karst-terrain formation, most especially in the Ellenburger, Fusselman and Devonian strata. The cave systems collapsed with subsequent burial, creating brecciated and fractured carbonate bodies that formed many of the Ellenberger reservoirs and created complex pore networks. The result of these exposure events was the development of numerous horizons of karst-related secondary porosity with solution-enlarged fractures, vugs, and small cavities and caves. Particularly in the Ellenburger and Fusselman strata, solution features from temporally distinct karst events became interconnected with each successive episode, so there could be some degree of vertical continuity in parts of the Fusselman section that could lead to enhanced vertical and horizontal permeability. The Ellenburger is well below the Siluro-Devonian Injection Zone, so it is unlikely to be affected by any proposed activity.

Devonian and Silurian. The Devonian Thirtyone Formation, the Silurian Fusselman Formation, and the Silurian Wristen Group consist of interbedded dolomites and dolomitic limestones and are collectively often referred to as the Siluro-Devonian. In the Middle Devonian, regional marine transgression deposited mostly black, organic-matter-rich siliceous muds of the Woodford Formation (Ruppel, 2019). The Siluro-Devonian Injection Zone does not contain economic hydrocarbons closer than fifteen (15) miles away from the well sites. There have been no commercially significant deposits of oil or natural gas found in the Devonian or Silurian rocks in the vicinity of the Independence AGI Wells and there is no current or foreseeable production at these depths within a two (2) mile radius around the Independence AGI Wells (Figure 3.7-3). Adjacent wells have shown that these formations are primarily water-bearing and are routinely approved as produced-water injection zones in this area.

Mississippian. According to Broadhead (2017), the Mississippian section unconformably overlies the Woodford Formation shales throughout most of southeastern New Mexico and, in places, unconformably overlies the Silurian Fusselman Formation or Ordovician strata in limited areas. These units reach a maximum thickness of 1,400 ft in the Tatum Basin northwest of Hobbs, New Mexico and constitute a major portion of the stratigraphic section. The Mississippian section in southeastern New Mexico is subdivided into the Lower Mississippian limestone (Kinderhookian to Osagean age) and various Upper Mississippian units. The Upper Mississippian section consists of the Barnett Shale in the basinal area to the south and the Meramec and Chester units on the shelf to the north. The Mississippian strata constitute the least developed of the major stratigraphic units in southeastern New Mexico and oil and natural gas production has been from relatively small and widely scattered reservoirs (Broadhead, 2017). The Chester Formation consists of several hundred feet of shales and basinal limestones which are underlain by several hundred feet of Osage limestone.

Pennsylvanian. The Pennsylvanian-age strata is comprised of (ascending) Morrow, Atoka, Strawn, Canyon, and Cisco. Within this entire sequence, the Morrow is a major natural gas producing zone, with smaller contributions from the overlying Atoka and Strawn. The Morrowan strata are dominantly siliciclastic and consist of interbedded shales and lenticular sandstones deposited in multiple regressive sequences and represent basinward migration of nearhore, sand-rich facies tracts from the erosion of exposed Precambrian rocks (Broadhead, 2017). The overlying Atokan strata are also dominantly siliciclastic, with sandstones and shales being deposited in fluvial-deltaic and strandline environments (Broadhead, 2017). The Middle Pennsylvanian (Desmoinesian) Strawn strata is composed of ramp limestones interbedded with marine shales and minor sandstones, and both sandstone and limestone reservoirs are productive (Broadhead, 2017). Although there was past production of oil and natural gas from the Pennsylvanian Strawn pool, there are no active wells in that pool within two (2) miles of the Dark Horse Facility nor are there any natural gas producing wells in any pools. The Upper Pennsylvanian strata are informally referred to as the Canyon (Missourian) and Cisco (Virgilian) groups, and are composed of interbedded carbonates, dark-gray to black shales, and minor sandstones (Broadhead, 2017). These groups contain prolific oil reservoirs in southeastern New Mexico.

Permian. The overlying Permian rocks found in the Delaware Basin are divided into four (4) series, the Lopingian ("Ochoa") (most recent), Guadalupe, Cisuralian ("Leonard"), and Hueco ("Wolfcamp") (oldest) (Figure 3.2-2). Numerous oil pools have been identified in these rocks (*see* Appendix 3, Table 3a). Active oil producing reservoirs within two (2) miles of the Dark Horse Facility include the following Permian pools: Tansil, Yates, Seven Rivers, Delaware, Bone Spring, and Wolfcamp. New oil wells permitted but not yet drilled are primarily targeting the Bone Spring and the Wolfcamp pools. The rock units of the Permian series are discussed in more detail below.

Permian Hueco ("Wolfcamp") Group. The Lower Permian Wolfcampian strata in the Permian Basin record deposition in deepwater basins surrounded by shallow-water carbonate platforms, where the Wolfcampian platform carbonate succession exposed in southeastern New Mexico comprises a complex record of deposition mainly controlled by fluctuations in glacio-eustatic sea level (Fu and others, 2020). The Wolfcamp is extremely variable in lithology in response to changes in the environment of deposition. In the area of the Dark Horse Facility, it is composed of dark skeletal to fine-grained limestone, fine-grained sand to coarse silt, and shale in these basin facies. Horizontal wells are being drilled in the Bone Spring and Wolfcamp; however, most activity is primarily to the west of the Dark Horse Facility.

Permian Leonardian Series. The Cisuralian ("Leonard Series"), sediments in shelf areas (Central Basin Platform, Northwest Shelf, etc.) are characterized by shallow-water carbonate-sediment production and deposition during sea-level rise, and by shelf flooding and quartz-dominated sand-silt deposition during sea-level fall and shelf exposure (Ruppel, 2019). In the Delaware Basin, this pattern of sea-level control on sediment supply resulted in the deposition of cyclic intervals of detrital carbonate-sediment transport to basins during sea-level highs and by quartz sand-silt transport and deposition during sea-level falls (Ruppel, 2019). Overall, the Leonard succession is one of punctuated upward shallowing from deep-water, outer-platform—platform-margin settings to inner-platform, peritidal conditions (Ruppel, 2020b).

The Bone Spring Formation is present only in the Delaware Basin and is stratigraphically equivalent to the Abo and Yeso Formations of the Northwest Shelf and Central Basin Platform, attains a maximum thickness of about 4,000 ft in southern Eddy County, New Mexico, and has been productive from several plays in the basin (Broadhead, 2017). The Bone Spring stratigraphy consists of alternating carbonate and siliciclastic successions that were deposited in marine slope and basin-floor environments, where sandstones and siltstones are widespread on the basin floor, whereas carbonates are thickest in periplatform areas (Nance and Hamiln, 2020; Saller and others, 1989). Most Bone Spring carbonate slope deposits accumulated by transport from shallow-water environments on the shelf during highstands of sea level and the siliciclastic deposits were transported basinwards during lowstands of sea level (Nance and Hamlin, 2020). Most of the carbonates are detrital, composed of bioclasts and lithoclasts derived from surrounding shallow-water platforms, and the siliciclastic members were deposited primarily on the basin floor in widespread submarine-fan complexes (Nance and Hamlin, 2020).

Permian Guadalupe Series. The Upper Permian Guadalupian-age strata are found on both Northwest Shelf and Central Basin Platform, and in the Delaware Basin. The Goat Seep/Capitan Reef system, a profoundly critical component of the Permian Basin Guadalupian paleogeography, prominently divides the shelves of the Central Basin Platform, the Northwestern Shelf, and the Western Shelf from the Delaware Basin (Nance, 2020a). Units on the shelf and platform comprise of (ascending) the San Andres Formation and the Artesia Group (*see* Figure 3.2-2). The five (5) formations of the Artesia Group include (ascending) Grayburg, Queen, Seven Rivers, Yates, and Tansill. The Delaware Basin equivalents of the reef trend include the Delaware Mountain Group: (ascending) Brushy Canyon, Cherry Canyon, and Bell Canyon. The Artesia Group comprises as much as 2,650 ft of stratigraphically cyclic, mixed-siliciclastic/carbonate/evaporite platform strata deposited shelfward of the Guadalupian Capitan Reef system that rims the Delaware Basin (Nance, 2020a). These formations have provided significant oil and natural gas production in southeastern New Mexico, and widespread, reddish-colored evaporitic shales and evaporites provide effective vertical and lateral seals (Broadhead, 2017).

According to Nance (2020a), Artesia facies tracts include, from basin to shelf, immediate-back-reef carbonate grainstone to packstone; shelf-crest pisolite-bearing carbonate shoals; lagoonal wackestone to mudstone and siliciclastic siltstone; algal-laminated, tidal-flat carbonate packstone to wackestone and fine to very fine grained sandstone; beach-ridge fine sandstone; siliciclastic-sabkha anhydrite and halite; brine-pool and evaporitic-lagoon anhydritic dolomite, dolomitic anhydrite, anhydrite, and halite; and eolian to fluvial siliciclastics. During sea-level highstand, siliciclastics are limited to updip areas, whereas eolian-siliciclastic depositional environments migrate downdip during sea-level lowstands. During transgressions, siliciclastics in more basin-proximal positions were reworked by marine and marginal processes. Reservoir quality was impacted mostly by dissolution of feldspar and carbonate allochems and precipitation of authigenic feldspar, clay, and evaporite.
The Delaware Mountain Group of the Delaware Basin comprises up to 4,500 ft of arkosic to subarkosic sandstone, siltstone, and carbonate debrites that were deposited in deep water, mainly during lowstand and early transgressive sea-level stages, and primary depositional processes include density-current flow and suspension settling (Nance, 2020b). The Delaware Mountain Group is restricted to slope-and-basin areas and was sourced from shelf-sediment areas through poorly exposed incised valleys, and interbedded carbonate units thicken shelfward and are typically correlative to “reef”-margin-complex carbonate sources along the shelf margin (Nance, 2020b).

Permian Lopingian (“Ochoa”) Series. The youngest of the Permian Basin sediments are referred to as the Lopingian (“Ochoa”) Series. The Ochoan series includes the Castile, Salado, Rustler, and Dewey Lake formations. Ochoan units on the shelf include the Salado, Rustler, and Dewey Lake Formations. *Castile Formation* usage is restricted to the deposits within the Delaware Basin only (Figure 3.2-2). The Ochoan in the Permian Basin contains no hydrocarbon reservoirs on the shelf (Nance, 2020a). The basal Salado Formation forms the ultimate top seal for the underlying Guadalupian reservoirs and effectively inhibits hydrocarbon migration into Ochoan units (Nance, 2020a). Lack of a seal above the Ochoan precludes widespread entrapment within the interval of hydrocarbons that may have been generated within the series. Ochoan strata are not hydrocarbon productive in the Permian Basin except for a few very small, isolated reservoirs in the Castile Anhydrite in the northern part of the Delaware Basin (Broadhead, 2017). The Castile is considered to be the top seal for Delaware Basin hydrocarbon reservoirs and is responsible for controlling migration of hydrocarbons from basinal source beds into reservoirs on the surrounding shelves (Hills, 1984). Anhydrite is the dominant rock type in the Castile Formation, along with limestone interlaminated in anhydrite, thin beds of limestone, and minor amounts of dolomite and magnesite, and halite is present as several massive beds in the formation in the subsurface but is much less prominent than the halite in the overlying Salado Formation (Bachman, 1984). The interlaminated anhydrite and limestone are distinctive lithologic features of the Castile Formation and are thought to represent annual cycles of sedimentation (Bachman, 1984).

The regionally extensive Salado Formation includes thick evaporite deposits and records a long-term salinity crisis in the region (Nance, 2020a). The Salado includes halite, minor beds of anhydrite, and commercial deposits of potash minerals (Bachman, 1984). The contact between the Castile and the overlying Salado Formations is sharp and most places and is between massive beds of anhydrite in the Castile and a sequence dominated by halite, potash minerals, and thin beds of anhydrite in the Salado (Bachman, 1984). The Rustler Formation overlies the Salado, and consists of dolomite, evaporites, and siliciclastics and marks the last major migration of marine waters into the Permian Basin (Ruppel, 2019). Red beds of terrigenous sands in the Rustler Formation resulted from eolian sediment transport. These red beds grade downwards into evaporites of the Salado and Castile Formations and are composed of red-orange silts and sandstones with interbeds of gypsum or anhydrite and halite. The Rustler carbonates, evaporites, and siliciclastics mark a relatively abbreviated return of marginal-marine conditions to the region (Nance, 2020a). The Dewey Lake Formation rests conformably on the Rustler Formation and consists mainly of redbeds and minor gypsum, alternating thin, even beds of moderately reddish-brown to moderately reddish-orange siltstone and fine-grained sandstone (Bachman, 1984). The Dewey Lake sediments mark the youngest episode of preserved Permian deposition in the region, after which a significant net-depositional hiatus prevailed until the onset of Late Triassic sediment accumulation (Nance, 2020a).

Beds of Triassic age rest unconformably on, and overlap, the Dewey Lake Formation, and exposures of these rocks in southeastern New Mexico are dark reddish-brown, cross-laminated, poorly sorted conglomerate sandstones with interbeds of dark reddish-brown sandy shale (Bachman, 1984). These Triassic units were deposited in a fluvial—deltaic—lacustrine system and signaled the onset of net deposition during overall wetter conditions after a protracted period of net nondeposition (Nance, 2020a; Bachman, 1984).

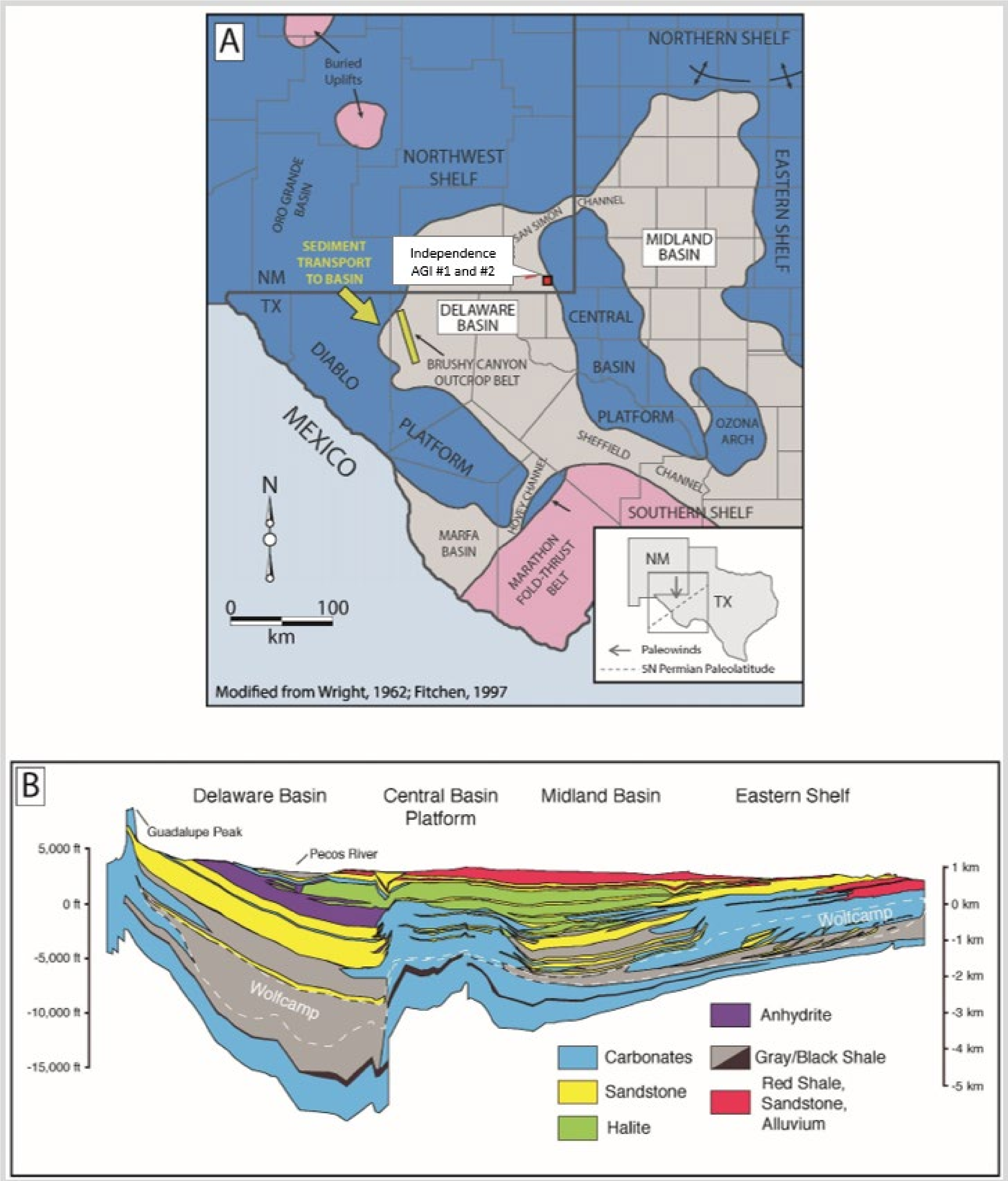


Figure 3.2-1: Structural setting (panel A) and general lithologies (panel B) of the Permian Basin. The location of the Independence AGI Wells is shown by the red square. (Modified from Wright, 1962; Fitchen, 1997) (Modified from Figure 12 of Class II permit application for Independence AGI #2, Geolex, Inc.).

Age		Stratigraphic Units: Northwest Shelf and Central Basin Platform		Stratigraphic Units: Delaware Basin	
Triassic			Chinle		Chinle
			Santa Rosa		Santa Rosa
Permian	Lopingian ("Ochoan")		Dewey Lake		Dewey Lake
			Rustler		Rustler
			Salado		Salado
					Castile
	Guadalupian	Artesia Group	Tansill	Delaware Mountain Group	Bell Canyon
			Yates		
			Seven Rivers		Cherry Canyon
			Queen		
			Grayburg		Brushy Canyon
			San Andres		
	Cisuralian ("Leonardian")		Glorieta		Bone Spring
		Yeso	Paddock		
			Blinebry		
			Tubb		
			Drinkard		
			Abo		
	Wolfcampian		Hueco ("Wolfcamp")		Hueco ("Wolfcamp")
Pennsylvanian	Virgilian		Cisco; Bough		Cisco
	Missourian		Canyon		Canyon
	Des Moinesian		Strawn		Strawn
	Atokan		Atoka		Atoka
	Morrowan		Morrow		Morrow
Miss.	Upper		Undivided		Barnett
	Lower				undivided limestone
Dev.	Upper		Woodford		Woodford
	Middle				
	Lower		Thirtyone		Thirtyone
Sil.	Upper		Wristen		Wristen
	Middle				
	Lower		Fusselman		Fusselman
Ord.	Upper		Montoya		Montoya
	Middle		Simpson		Simpson
	Lower		Ellenburger		Ellenburger
Cambrian			Bliss		Bliss
Precambrian			igneous, metamorphics, volcanics		igneous, metamorphics, volcanics

<u>Figure 3.2-2</u>: Generalized stratigraphic correlation chart for the Permian Basin region (modified from Broadhead, 2017).

3.2.3 Faulting

The Permian Basin region has a complex tectonic history, shaped by several convergent and divergent events from the Proterozoic through the Cenozoic (Neogene). The Delaware Basin is defined by a complex network of basement-rooted faults. Recent regional 3D structural framework and kinematic models by Horne et al. (2021) provides interpretations of basement-rooted faults in the Delaware Basin. This region contains more than 650 basement-rooted fault surfaces, dominated by "primary" north-northwest—south-southeast-striking high-angle reverse faults that bound "secondary" fault orientations west-northwest—east-southeast and west-southwest—east-northeast (Horne et al., 2021). Their kinematic model suggests that the primary structural grain formed first in response to the encroaching Ancestral Rocky Mountain orogenic front, and the secondary fault zones formed under the combined stresses from the Ancestral Rocky Mountain and Marathon-Ouachita convergence fronts, which compartmentalized the Delaware Basin and Central Basin Platform (Horne et al., 2021).

To identify subsurface structures in the area of the Independence AGI Wells, Geolex evaluated and interpreted licensed seismic survey data (WesternGeco South Lea Survey) covering the Lea County area of interest. These findings and interpretations specific to the Dark Horse Facility area are discussed further in Section 3.5.

3.3 Lithologic and Reservoir Characteristics of the Siluro-Devonian Formations

The Siluro-Devonian Injection Zone includes the Devonian Thirtyone Formation, Silurian Wristen Group and Fusselman Formation, collectively referred to as the Siluro-Devonian. These strata commonly include numerous intervals of dolomites and dolomitic limestones with moderate to high primary porosity. Additionally, the Siluro-Devonian Injection Zone includes significant regions of secondary, solution-enlarged porosity produced during periods where strata were subaerially exposed and significant karst features developed. These karst features are frequently developed in the Fusselman Formation and include solution enlarged cavities and fractures. Fracture networks through the Siluro-Devonian section are substantial enough to provide additional permeability that is not readily apparent on geophysical well logs. The porous zones of the Siluro-Devonian are separated by tight limestones and dolomites.

In evaluating the location of the Independence AGI Wells, an in-depth review of licensed seismic survey data (WesternGeco – South Lea Survey) was completed to support the evaluation that the Siluro-Devonian reservoir exhibited sufficient porosity potential to accommodate the needs of the Independence AGI Wells. Seismic inversion data, specifically impedance attributes, were evaluated to identify reservoir targets with significant porosity potential in the Siluro-Devonian reservoir. As a result of this review, the location in Section 20, T25S, R36E was selected as it was observed to overlay an expansive region of porosity in the upper Devonian, Wristen, and Fusselman strata.
Based on the geologic evaluation of the subsurface, AGI was recommended between depths of approximately 16,080 to 17,683 feet TVD (16,477 to 18,080 feet measured depth). Figure 3.3-1 includes a type log of the Siluro-Devonian Injection Zone that includes the formation tops identified at the location of Independence AGI #1 and illustrates the sufficient low-porosity intervals overlying the target injection reservoir. Anticipated formation tops underlying the Independence AGI #2 location are included in the following Table 3.3-1. In the area of the Independence AGI Wells, depth to Devonian strata increases to the southwest and the Independence AGI Wells lie downdip of a structural high to the east (Figure 3.3-2).

Units overlying the Siluro-Devonian Injection Zone provide an excellent caprock to prevent the upward migration of injectate out of the target reservoir. This caprock includes 335 feet of dense Woodford Shale overlain by at least 796 feet of Mississippian limestone (Table 3.3-1). These units will provide a geologic seal above the porous carbonates of the Siluro-Devonian Injection Zone providing protection to shallow groundwater resources and overlying pay intervals.

Figure 3.3-3 includes structural cross section A-A' covering the area of Independence AGI #2 and highlights the lateral extent of available upper Devonian porosity and the regional coverage of overlying caprock in the area. As shown in Figure 3.3-2, there are two (2) faults located approximately one (1) mile east and one (1) mile north from the SHLs of the Independence AGI Wells. These structures were identified through review of licensed 3D seismic survey data and are discussed further in Section 3.5.

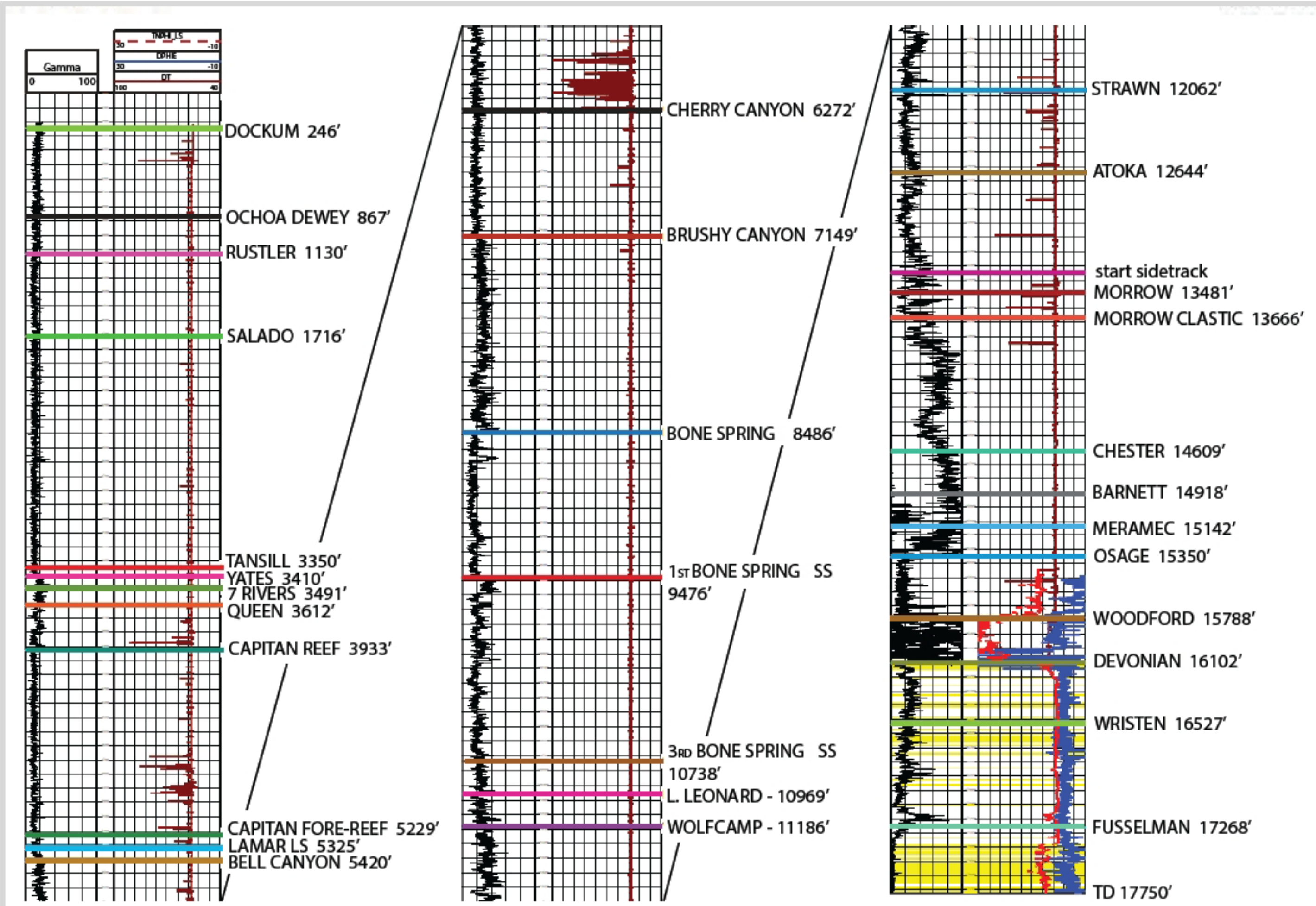


__Figure 3.3-1__: Type log of the Independence AGI #1, illustrating identified formation tops in TVD. Anticipated formation tops for the Independence AGI #2 are included in __Table 3.3-1__ (Modified from Figure 14 of Class II permit application for Independence AGI #2, Geolex, Inc.)

***Table 3.3-1**: Anticipated formation tops at the Independence AGI #2 location. (Extracted from Table 6 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

FORMATION	DEPTH (TVD)	DEPTH (MD)	FORMATION	DEPTH (TVD)	DEPTH (MD)
Dockum	485	485	Bone Spring	8,467	8,632
Ochoa-Dewey	747	747	Wolfcamp	11,131	11,387
Rustler	1,130	1,130	Strawn	12,004	12,289
Salado	1,720	1,720	Atoka	12,733	13,044
Tansill	3,401	3,401	Morrow	13,541	13,880
Yates	3,461	3,461	Barnett	14,949	15,336
7 Rivers	3,542	3,542	Osage	15,380	15,703
Queen	3,663	3,663	Woodford	15,745	16,142
Capitan Reef	3,935	3,943	Devonian	16,080	16,477
Bell Canyon	5,425	5,484	Wristen	16,467	16,864
Cherry Canyon	6,277	6,364	Fusselman	17,201	17,598
Brushy Canyon	7,058	7,174	Montoya	17,684	18,081

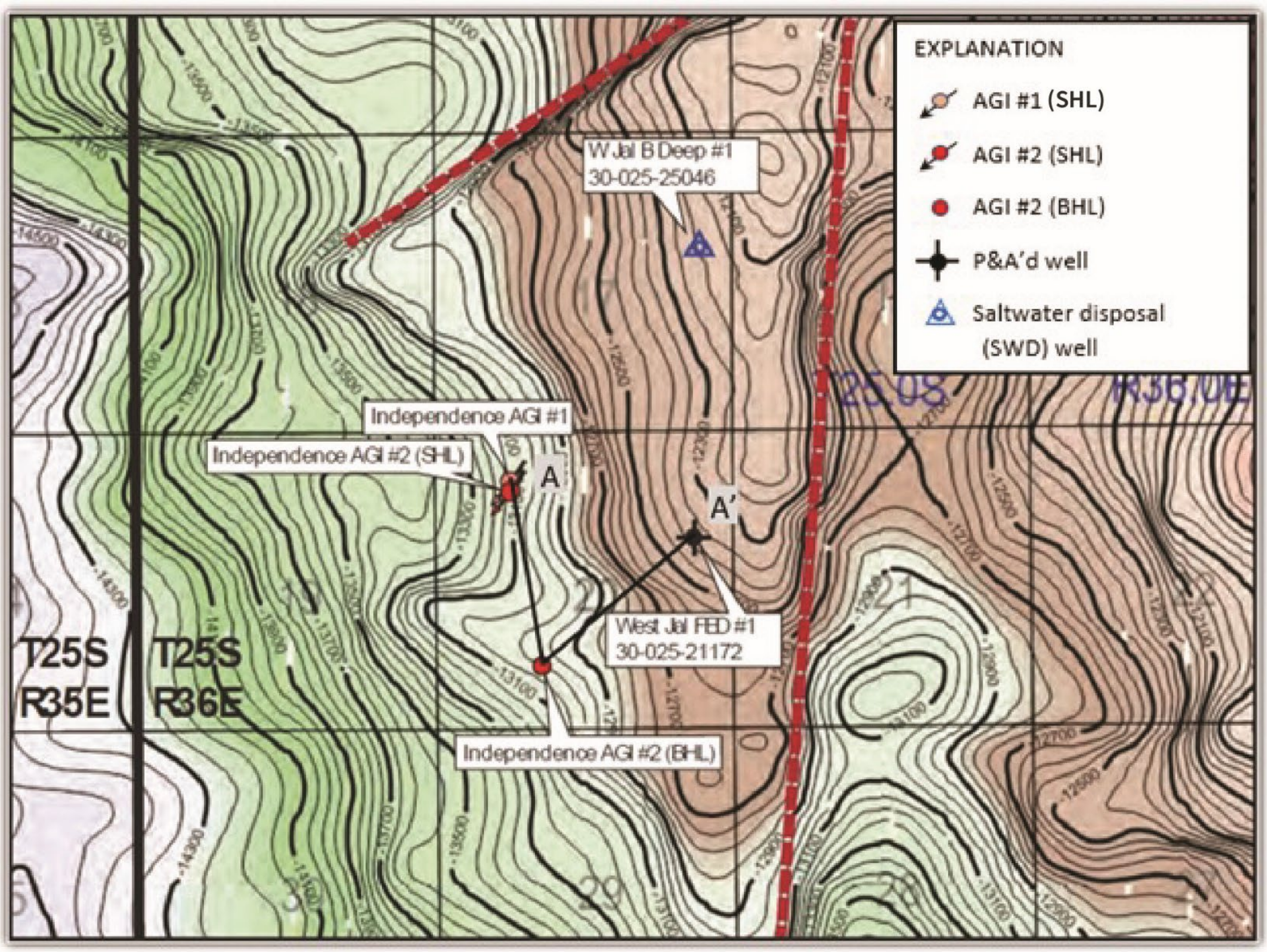
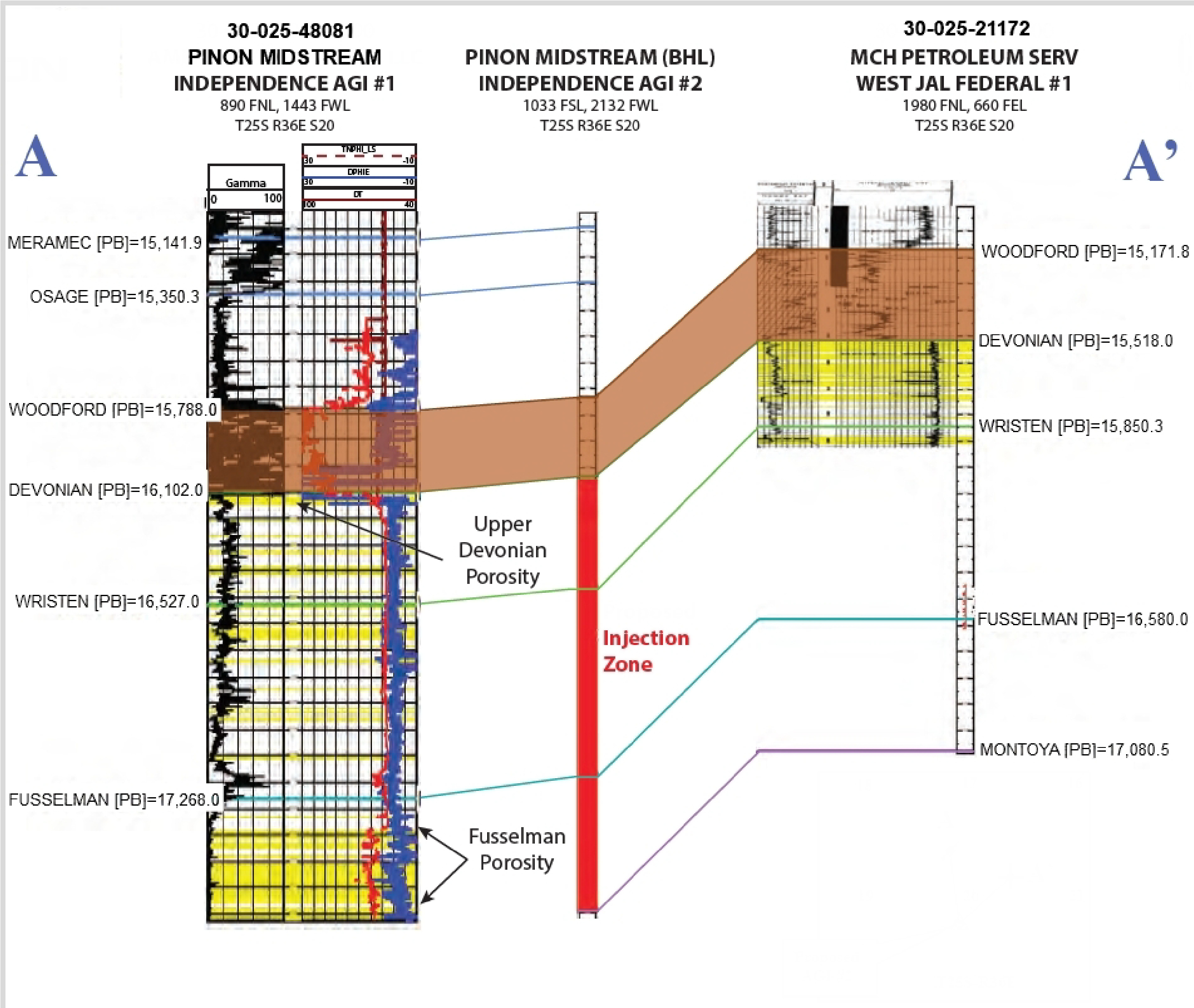


***Figure 3.3-2**: Structure contour map showing the top of the Siluro-Devonian target reservoir. Two (2) faults identified in review of 3D seismic data are shown with red dashes. Also, shown are wells within 1 mile of the Independence AGI Wells that penetrate the Siluro-Devonian target zone. Cross section A – A' is shown in Figure 3.3-3. (Modified from Figure 15 of Class II permit application for Independence AGI*

#2, Geolex, Inc.) Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in <u>Figure 3.1-1</u>.



<u>Figure 3.3-3</u>: Structural cross section A-A' showing porosity profile from nearby wells penetrating the Siluro-Devonian Injection Zone and regional extent of overlying Woodford Shale caprock. The Independence AGI #2 Injection Zone is from 16,080 feet TVD to 17,683 feet TVD (red bar). (Modified from Figure 16 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.4 Chemistry of Siluro-Devonian Interval Formation Fluids

A review of formation waters from the U.S. Geological Survey National Produced Waters Geochemical Database v. 2.3 identified twenty-one (21) wells with analyses of fluid samples collected from the Siluro-Devonian interval. These samples were collected from wells within approximately fifteen (15) miles of the Independence AGI Wells. Results of laboratory analysis to determine their composition are summarized in <u>Table 3.4-1</u>. These results have been supplemented with samples collected from Independence AGI #1 on May 31, 2021 which show Total Dissolved Solids ("**TDS**") values ranging from 109,000 to 115,000 parts per million ("**ppm**").

***Table 3.4-1**: Summary of Siluro-Devonian produced water analyses from nearby wells (U.S. Geological Survey National Produced Water Geochemical Database v. 2.3) * (Extracted from Table 7 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

API	WELL NAME	CONCENTRATION (parts per million)							
		TDS	HCO3	Ca	Cl	K + Na	Mg	Na	SO4
3002548081	Ind. AGI 1	110000	342	5600	68000	32559	759	31800	664
3002510945	Hill-federal D 1	112959	288	6264	67390	34340	1912	-	2765
3002510947	EC Hill-federal 1	35639	-	1369	22070		592	11608	-
3002511126	JR Holt A3	116415	154	7501	71110	34680	1767	-	1203
3002511196	S. Mattix Unit 3	68431	990	3180	40960	21690	974	-	637
3002511202	S. Mattix Unit 11	67130	853	5075	40430	16950	2348	-	1474
3002511383	Hodges B 3	81712	722	4320	47500	25400	1030	-	2740
3002511556	Blocker-federal 4	57675	595	2850	34030	18370	619	-	1211
3002511747	Ab Coates FED D2	82794	977	2408	47200	28190	851	-	3168
3002511760	Ida Wimberley 5	63817	360	2774	35870	20750	621	-	3442
3002811763	Ida Wimberley 9	61040	900	2680	35600	19560	800	-	1500
3002511765	Carlson-federal A3	66418	690	3002	37650	20390	1339	-	3347
3002511812	Clyde Lanehart 1	99879	687	4753	60410	32610	828	-	591
3002511818	Copper 1	27506	1089	1384	15270	8144	540	-	1079
3002511863	Arnott Ramsay B3	158761	476	17240	100300	35400	5345	-	-
3002511886	Dabbs 1	101036	540	5393	61630	30380	2183	-	910
3002511890	Sam Dabbs 1	85150	675	5368	50260	25130	1395	-	2322
3002511907	Arnott Ramsay F9	58220	367	1546	32790	-	278	20430	2816
3002511950	Farnsworth FED 6	31931	302	7196	20450	1151	2241	-	591
3002512272	LE Elliott FED H1	58687	761	3004	35460	18980	482	-	-
3002512286	JB McGhee 1	62392	552	2696	34380	20060	702	-	4002
3002521601	North Custer Mt 1	>64,000	1610	2136	36230	21830	403	-	1950

These analyses report TDS in the area of the Independence AGI Wells ranging from 27,506 to 158,761 ppm with an average of 75,981 ppm. The primary constituent in sampled formation waters is the chloride ion, with an average concentration of 45,227 ppm. The closest well, Independence AGI #1, at approximately 3,000 feet away from the Independence AGI #2 BHL, has reservoir fluids with a TDS value of approximately 110,000 ppm, and chloride ions in concentrations of approximately 68,000 ppm. Based on this data, the Siluro-Devonian reservoir fluids are anticipated to be completely compatible with the TAG injectate.

3.5 Potential for Induced Seismicity in the area of the Dark Horse Facility

To evaluate the potential for seismic events in response to injected fluids, Piñon conducted an induced-seismicity risk assessment for the area surrounding the Independence AGI Wells. This estimate (a) models the impact of seven (7) injection wells over a thirty (30) year injection period, and (b) estimates the fault-slip probability associated with the simulated injection scenario(s). This analysis was completed utilizing the Stanford Center for Induced and Triggered Seismicity's Fault Slip Potential ("**FSP**") model developed by Walsh and Zoback, 2016.

To identify subsurface structures in the area of the Independence AGI Wells, Piñon evaluated and interpreted licensed seismic survey data (WesternGeco – South Lea Survey) covering the Lea County area of interest. Based on this review, Piñon identified eight (8) subsurface faults in the area surrounding the Independence AGI Wells (Figure 3.5-1). The closest fault is observed to be located approximately one (1) mile east of the Independence AGI Wells. Major faults in the area (those

exhibiting significant lateral extent) generally strike NNW-SSE with minor faults striking NE-SW and NW to SE.

Due to the location of faults relative to the Independence AGI Wells and the general low density of injection wells in the immediate area of the Independence AGI Wells, it is anticipated that the injection scenario(s) will not pose any elevated risk of injection-induced fault slip. To support the interpretation that these structures would not be affected by operation of the Independence AGI Wells, a fault-slip probability analysis was completed to quantify the risk associated with injection operations in the area surrounding the Independence AGI Wells, and although the risk of induced seismicity is low, a seismic monitoring station was installed at the facility prior to the commencement of injection into Independence AGI #1. The station transmits data to the New Mexico Tech Seismic Network and will aid the state in seismicity interpretations.

To calculate the fault-slip probability for the model simulations, input parameters characterizing the local stress field, reservoir characteristics, subsurface features, and injected fluids are required. Parameters utilized and their sources for the area surrounding the Independence AGI Wells are included in Table 3.5-1. Additionally, Table 3.5-2 details the injection volume characteristics and locations of the injection wells modeled in the injection scenario(s). To ensure the model simulations provide a conservative estimation of induced-seismicity risk, injection wells included in the simulations were modeled utilizing their maximum anticipated daily injection volumes as recorded by NMOCD approved permits. Due to the minimal reported injection volume of the Jal North Ranch SWD #1 (30-025-27085) which is approximately 5.3 miles to the east northeast of the Independence wells, a potential of 10,000 bpd was assumed to account for the potential of increased injection rates due to future needs of the operator or any future workover that may improve the injectivity of this well.

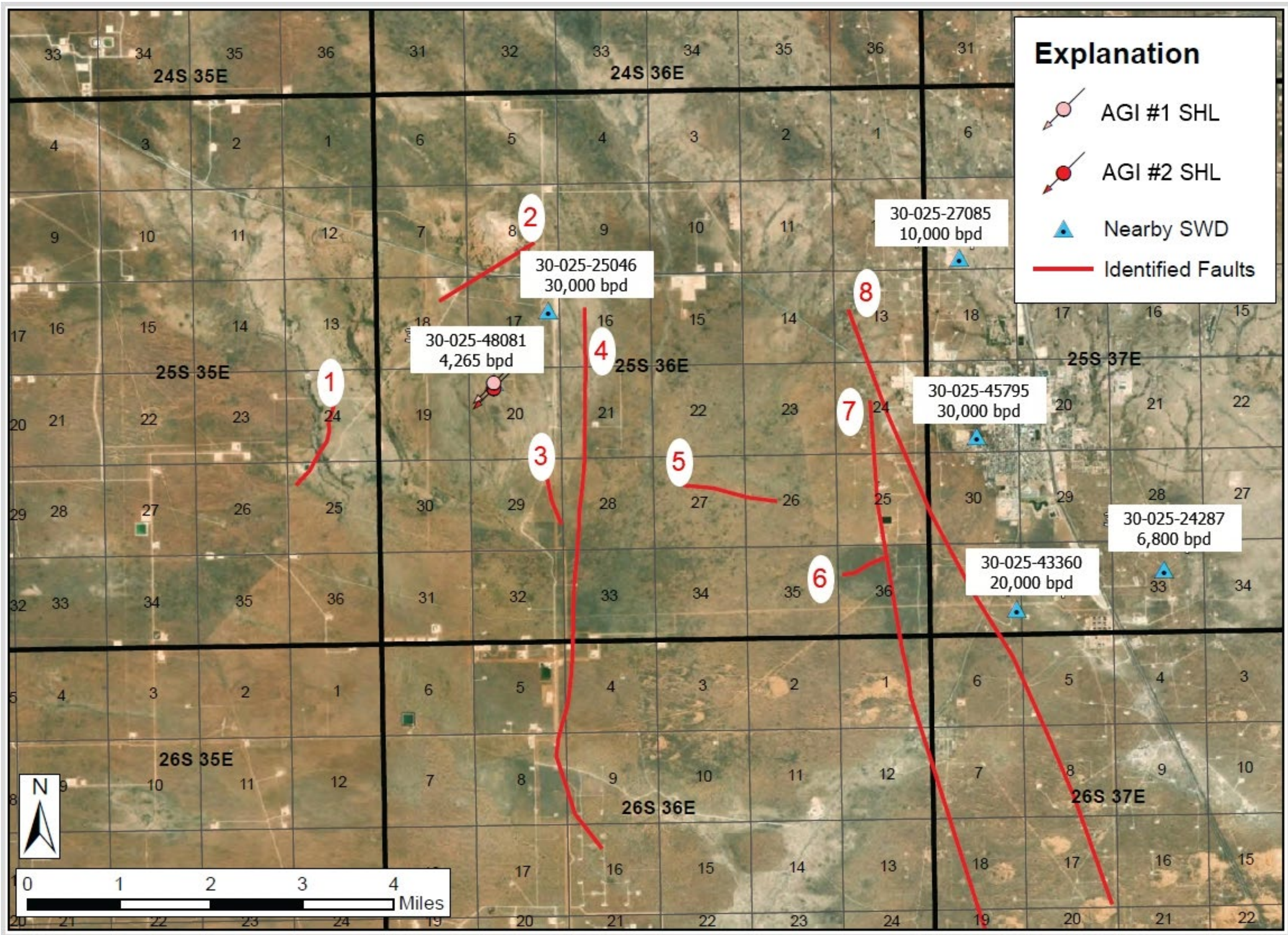
Daily maximum injection volumes utilized in the fault-slip probability model range from 4,265 to 30,000 bpd (Table 3.5-2). In submission of the Class II injection well applications, Piñon requested approval to operate the Independence AGI Wells for a period of at least thirty (30) years, however, the duration of the FSP model simulation was increased to forty (40) years to characterize the reservoir effects of injection wells that are currently operating and have been in operation since 2010. Figure 3.5-2 shows the resultant pressure front and single well radial pressure solutions, as predicted by the FSP model, after thirty (30) years of injection at the maximum injection rates.

For this study, limitations of the FSP model required a conservative approach be taken in determining the fault-slip probability of the injection scenario. Specifically, the FSP model is only capable of considering a single set of fluid characteristics and this study aims to model an injection scenario that includes both brine injection and AGI. To ensure a conservative fault-slip probability estimate, the Independence AGI Wells were simulated utilizing the characteristics of a brine injectate. This approach yields a more conservative model prediction as brine displays greater density, dynamic viscosity, and is significantly less compressible than TAG. For comparison, characteristics of TAG at the anticipated reservoir conditions, as modeled by AQUAlibrium™, are shown in Table 3.5-1.

Generally, faults considered in this assessment are predicted by the FSP model to have very low potential for injection-induced slip and operation of the Independence AGI Wells is not predicted by the model to contribute significantly to the estimate of risk (Table 3.5-3 and Figure 3.5-3). Table 3.5-3 summarizes the predicted pressure change along each fault segment and includes the model-derived pressure change necessary to induce slip for each feature. Fault-slip probability values range from 0.00 to 0.05 with the majority of fault segments predicted to have zero probability of slip (Table 3.5-3). Major faults (faults 4, 7, and 8 in Figure 3.5-1) in the area, which would have the greatest energy release potential upon slip, are predicted to have zero probability for slip in response to the modeled injection scenario.

In summary, no structures included in the modeled simulations are predicted to be at increased risk for injection-induced slip in response to the injection scenario presented. Features estimated to have a non-zero slip potential are generally smaller-scale features and predicted probabilities are very low

(≤ 0.05). Furthermore, subsequent model simulations in which contribution from Independence AGI #2 is excluded illustrate that operation of the Independence AGI #2 will have little impact on conditions near the identified faults in the area due to significantly lower proposed injection volumes in comparison to nearby brine injection wells.



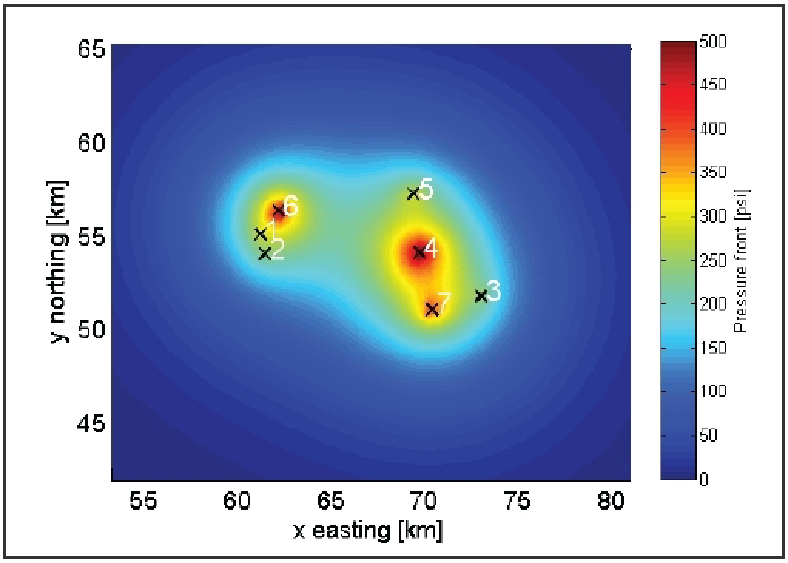
<u>Figure 3.5-1</u>: Map showing Siluro-Devonian injection wells and subsurface identified faults in the vicinity of the Independence AGI Wells. (Modified from Figure 18 of Class II permit application for Independence AGI #2, Geolex, Inc.)

***Table 3.5-1**: Input parameters and source material for FSP model simulations. (Extracted from Table 10 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

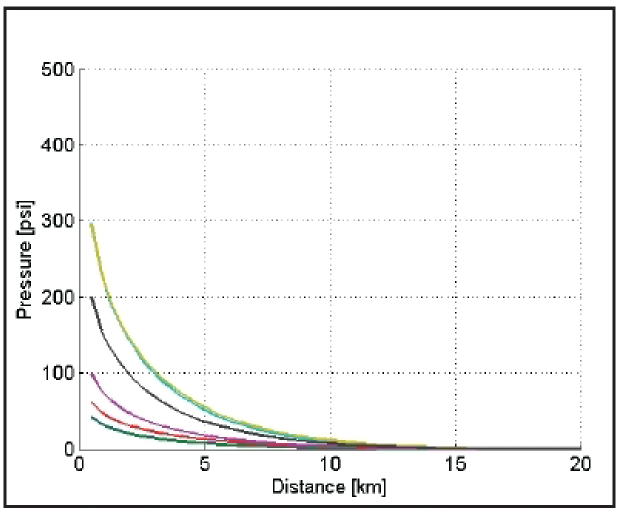
Modeled Parameter	Input Value	Variability (+/-)	UOM	Source
Stress				
Vertical Stress Gradient	1.05	0.105	psig/ft	Nearby well estimate
Max Horizontal Stress Direction	N75E	5	Deg	Lund Snee & Zoback, 2018
Reference Depth	17000		ft	Nearby well evaluation
Initial Res. Pressure Gradient	0.43	0.043	psig/ft	Lund Snee & Zoback, 2018 Nearby well evaluation
A_ϕ Parameter	0.6	0.06	-	Lund Snee & Zoback, 2018
Reference Friction Coefficient (μ)	0.6	0.06	-	Standard value
Hydrologic				
Aquifer Thickness	1500	0	ft	Nearby well evaluation
Porosity	3.5	0.35	%	Nearby well evaluation
Permeability	20	2	mD	Nearby well evaluation
Material Properties				
Density (Water)	1040	40	Kg/m^3	Standard value
Dynamic Viscosity (Water	0.0008	0.0001	Pa.s	Standard value
Fluid Compressibility (Water)	3.6×10^{-10}	0	Pa^{-1}	Standard value
Rock Compressibility	1.08×10^{-9}	0	Pa^{-1}	Standard value
Acid Gas Properties @ 7,370 psig & 228 °F				
Density	821.80	-	kg/m^3	AQUAlibrium™
Dynamic Viscosity	8.067×10^{-5}	-	Pa.s	AQUAlibrium™

***Table 3.5-2**: Location and characteristics of injection wells modeled in the FSP assessment. (Extracted from Table 11 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

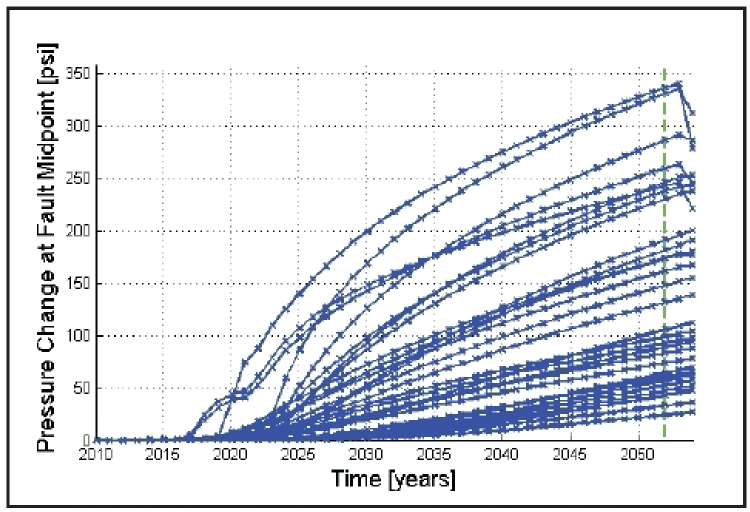
#	API	Well Name	LAT	LONG	Volume (bbls/day)	Start (year)	End (year)
1	3002548081	Independence AGI #1	32.120855	-103.291021	4265	2020	2052
2	-	Independence AGI #2	32.111454	-103.288812	4265	2022	2052
3	3002524287	Crosby Deep #2	32.089508	-103.166733	6800	2010	2052
4	3002545795	Sholes Deep SWD #1	32.110998	-103.201266	30000	2020	2052
5	3002527085	Jal N. Ranch SWD #1	32.139347	-103.203911	10000*	2017	2052
6	3002525046	West Jal B Deep #1	32.132091	-103.280708	30000	2015	2052
7	3002543360	Kimberly SWD #1	32.083537	-103.194274	20000	2019	2052



Panel A. Resultant pressure front after 30 years of injection operations at the maximum anticipated injection rates, as reported in **NMOCD** records



Panel B. Single well radial pressure solutions, as determined by the FSP model

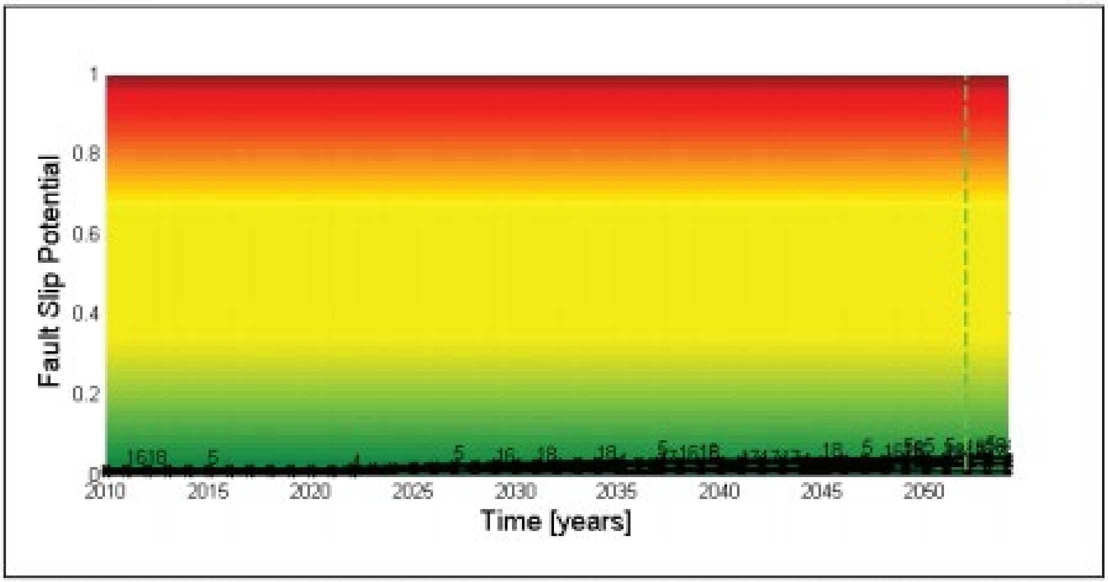


Panel C. Model-predicted pressure change through time at the midpoint of each fault segment included in the simulation

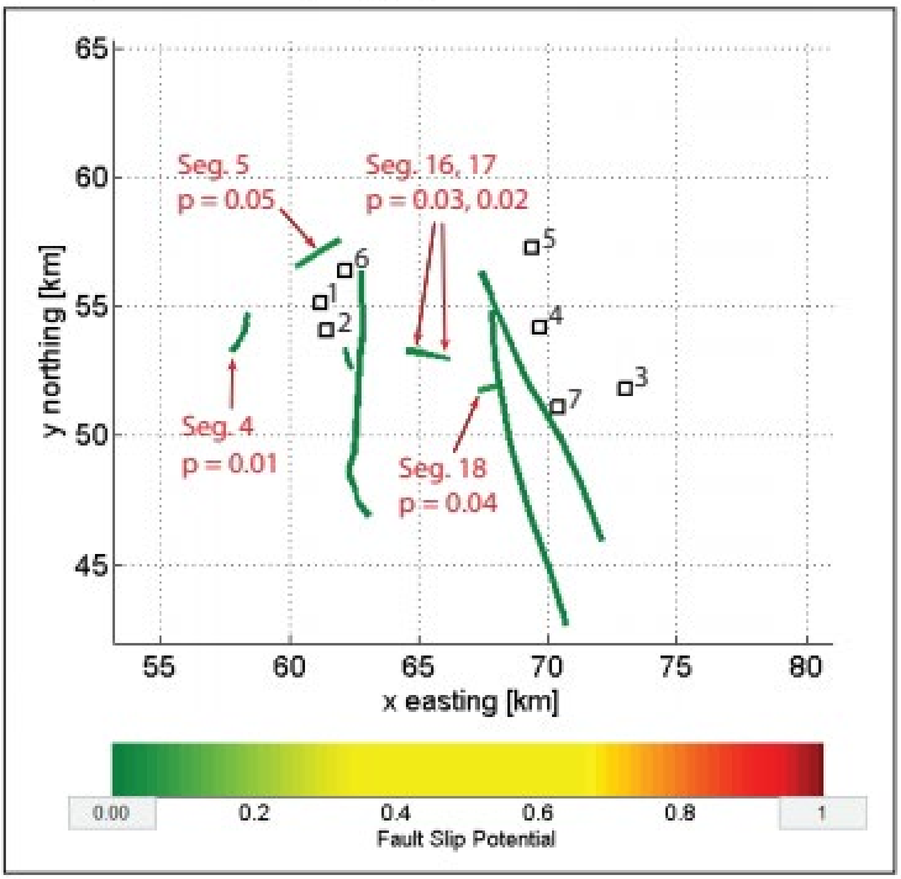
Figure 3.5-2: ***Summary of model-predicted pressure effects in response to the simulated seven (7) well injection scenario. (Extracted from Figure 19 of Class II permit application for Independence AGI #2, Geolex, Inc.)***

***Table 3.5-3**: Summary of model-simulation results showing the required pressure change to induce fault slip, actual change in pressure as predicted by the FSP model, probability of fault slip at the end of the thirty (30) year injection scenario, and fault-slip probability when Independence AGI #2 is excluded from simulation. (Extracted from Table 12 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

Fault #	Segment #	ΔPressure necessary to induce fault slip	Actual ΔPressure at 2052	Fault Slip Potential at 2052	FSP (excluding AGI #2)
1	1	3137	109	0.00	0.00
	2	4357	103	0.00	0.00
	3	1786	93	0.00	0.00
	4	1201	83	0.01	0.01
2	5	1197	253	0.05	0.05
3	6	6869	186	0.00	0.00
	7	6298	168	0.00	0.00
4	8	5645	277	0.00	0.00
	9	4610	194	0.00	0.00
	10	5005	117	0.00	0.00
	11	2709	70	0.00	0.00
	12	5302	63	0.00	0.00
	13	6339	57	0.00	0.00
	14	6899	51	0.00	0.00
	15	4197	46	0.00	0.00
5	16	1101	192	0.03	0.03
	17	1085	199	0.02	0.02
6	18	1554	234	0.04	0.04
7	19	6012	290	0.00	0.00
	20	6680	241	0.00	0.00
	21	6914	133	0.00	0.00
	22	6758	61	0.00	0.00
	23	6931	33	0.00	0.00
	24	6590	25	0.00	0.00
8	25	6508	250	0.00	0.00
	26	6327	334	0.00	0.00
	27	5455	228	0.00	0.00
	28	6305	174	0.00	0.00
	29	6684	89	0.00	0.00



Panel A. Fault-slip probability throughout the entire simulated injection period. FSP model results suggest no significant risk of injection-induced slip along any feature included in the simulation.



Panel B. Map view illustrating the model-estimated slip potential of faults at the end fo the 42-year injection scenario. Any feature estimated to have a non-zero slip potential determination is labeled on the above map.

<u>Figure 3.5-3</u>: Summary of model-determined fault-slip probabilities over the simulated injection period (2010-2052). (Modified from Figure 20 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.6 Groundwater Hydrology in the Vicinity of the Dark Horse Facility

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are fifteen (15) water wells and points-of-diversion located within a two (2) mile radius of the Independence AGI Wells. Of these wells, the closest is located approximately 0.34 miles away and has a total depth of 505 feet (Figure 3.6-1 and Table 3.6-1). The remaining fourteen (14) wells within the two (2) mile radius have depths of approximately 240 to 600 feet deep, collecting water from Alluvium and the Triassic red beds. The shallow freshwater aquifer will be protected as the Independence AGI Wells are designed to isolate shallow zones via a five (5) string casing design including a surface casing interval that extends to 1,230 feet within the Rustler Formation, effectively isolating shallow groundwater resources (Figures A1-1 and A1-2).

The area surrounding the Independence AGI Wells is arid and there are no surface water bodies within a two (2) mile radius.

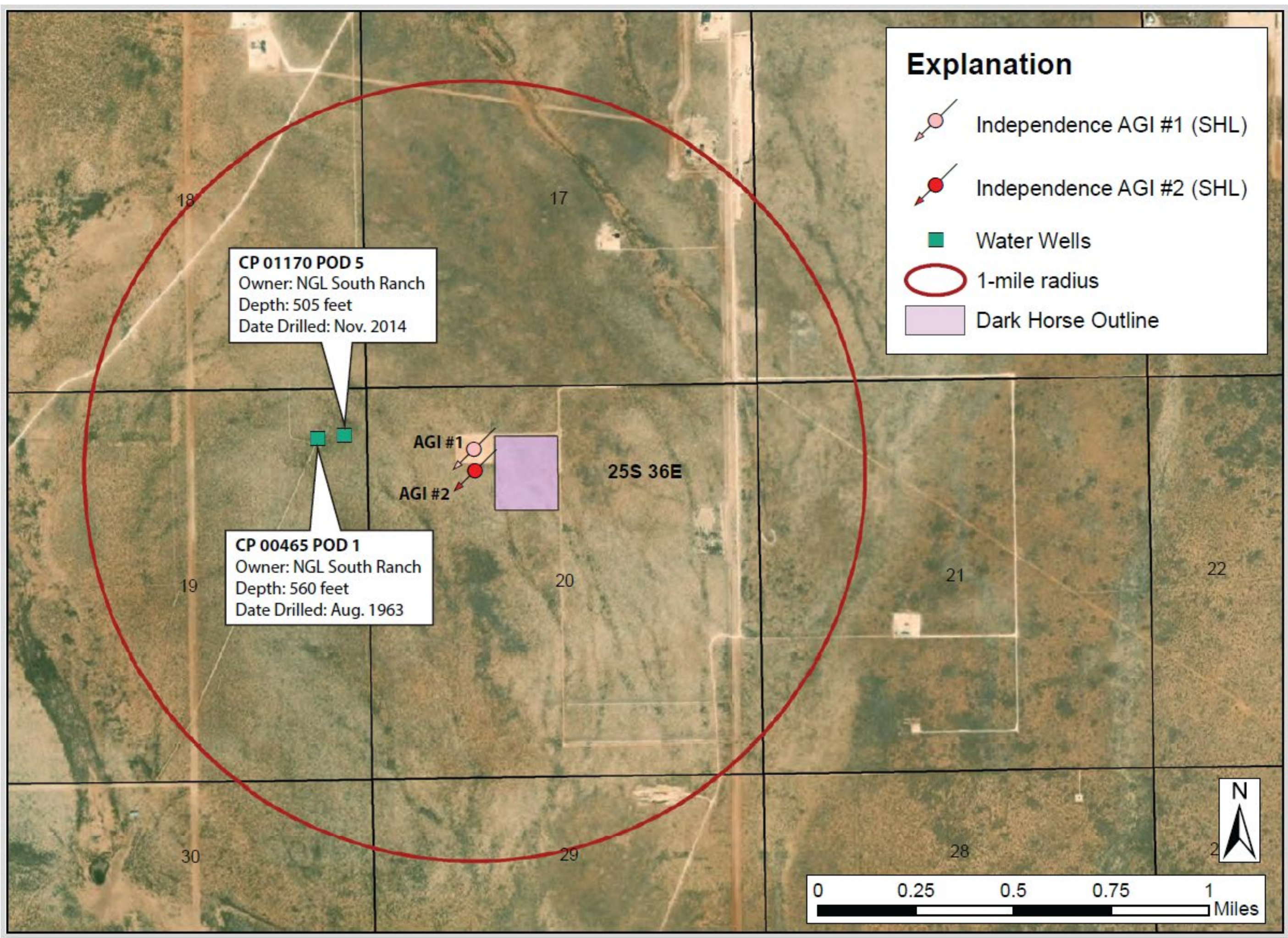


***Figure 3.6-1**: Reported water wells within 1-mile radius of the SHLs of the Independence AGI Wells. The BHLs for AGI #1 and #2 are not shown. (Extracted from Figure 17 of Class II permit application for Independence AGI #2, Geolex, Inc.) Only SHLs shown for the Independence AGI #1 and #2 wells.*

***Table 3.6-1**: Water wells within one (1) mile of the Independence AGI Wells (Retrieved from the New Mexico Office of the State Engineer's Files on October 4, 2021). (Extracted from Table 8 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

POD #	Source	Use	Owner	LAT (NAD83)	LONG (NAD83)	Distance (miles)	Depth (feet)	Date Completed
CP 1170 POD 5	Shallow	Commercial	NGL South Ranch	32.121417	-103.296667	0.34	505	11/2014
CP 465 POD 1	Shallow	Commercial	NGL South Ranch	32.119465	-103.299882	0.53	560	08/1963

According to Order No. 190 of the New Mexico Office of the State Engineer signed March 22, 2021, the Capitan Underground Water Basin, within which the Independence AGI Wells lie, is closed indefinitely to new appropriations of water. Therefore, no new water wells are anticipated to be constructed during the Independence AGI Wells' anticipated thirty (30) year operation period. Due to the shallow completion depths of the few groundwater wells in the area surrounding the Independence AGI Wells, it is highly unlikely that groundwater wells will serve as conduits for CO_2 leakage to the surface.

Geolex conducted a review of Geology and Ground-Water Conditions in Southern Lea County, New Mexico (Nicholson and Clebsch, 1961) to identify published groundwater data representative of nearby water wells in the area surrounding the Independence AGI Wells. Table 3.6-2 summarizes the wells identified in this review and the results of those analyses.

***Table 3.6- 2**: Chemical analysis results of samples collected from water wells in the area surrounding the Independence AGI Wells (Nicholson and Clebsch, 1961 – Geology and Groundwater Conditions in Southern Lea County, New Mexico). (Taken from Table 9 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

Historical Owner	Location (T-R-S)	Location (Qtr-Qtr)	Depth (ft)	Ca (ppm)	Mg (ppm)	Na+K (ppm)	HCO_3 (ppm)	SO_4 (ppm)	Cl (ppm)	NO_3 (ppm)
Sun Oil Co.	25-37-15	NE/4 NE/4	-	307	98	271	145	737	610	9
City of Jal	25-37-19	NE/4 NE/4	500	55	49	170	376	280	71	0.4
City of Jal	25-37-19	SE/4 NE/4	450	34	43	175	264	286	54	0.5
City of Jal	25-37-20	NW/4 SW/4	70	-	-	-	150	145	168	7.6

This analysis confirms that the Independence AGI Wells pose no risk of contaminating groundwater in the area as (a) the well design includes material considerations to protect shallow groundwater resources, and (b) there are no identified conduits that would facilitate migration of injected fluids to freshwater-bearing strata nor to the surface.

3.7 Historical Operations

3.7.1 Dark Horse Facility and Independence AGI Wells

Piñon operates the Dark Horse Facility which treats sour natural gas that is delivered to the facility from gathering systems in the area. These gathering systems are shown in Figure 3.7-1. Figure 3.7-2 shows the major process units and the H_2S and gas detection sensors. The figure in Appendix 10 shows the process block flow diagram for the Dark Horse Facility. The Dark Horse Facility is designed to treat produced natural gas containing H_2S and CO_2 and handles and/or generates sulfur dioxide (SO_2). Ameredev received authorization to inject H_2S and CO_2 from the NMOCD and drilled and completed Independence AGI #1, which is utilized for the injection and permanent sequestration of TAG. Procedures and materials used by Ameredev for well operations and construction are consistent with NMOCD regulations pertaining to "Protection from Hydrogen Sulfide during Drilling,

Completion, Workover and Well Servicing Operations" (NMAC 19.15.11.11). Following drilling and completion of the Independence AGI #1, and after approval by NMOCD, Ameredev contributed and assigned operations of the well to Piñon. Piñon became the operator of record for the Independence AGI #1 on August 24, 2021.

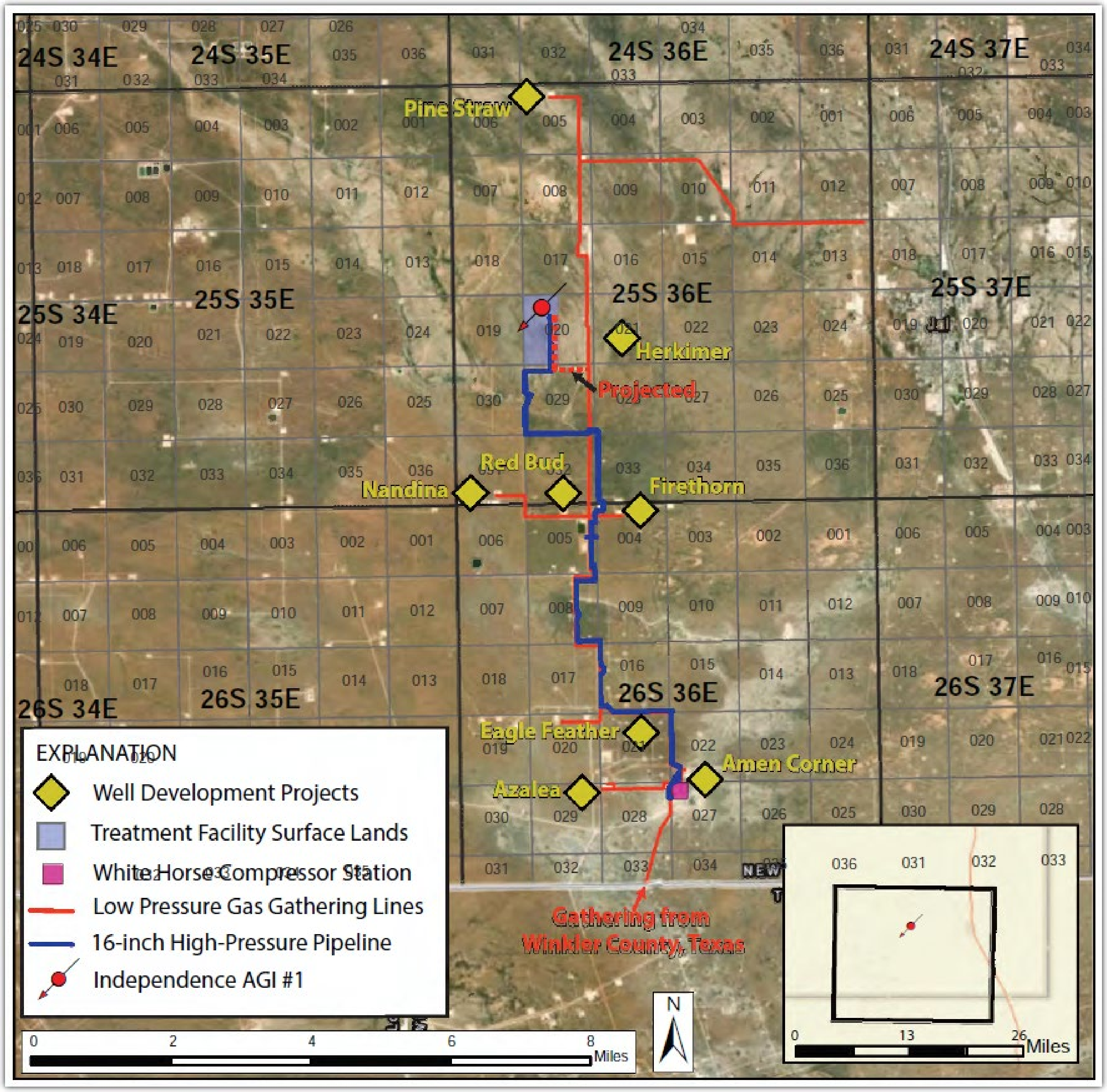


__Figure 3.7-1__: Location of gas gathering lines leading to the Dark Horse Gas Treatment Plant and White Horse Compression station. Low pressure lines either lead to the compressor station or directly to the treatment plant. Gas sent to the compressor station is sent to the treatment plant via a 16-inch high-pressure pipeline.

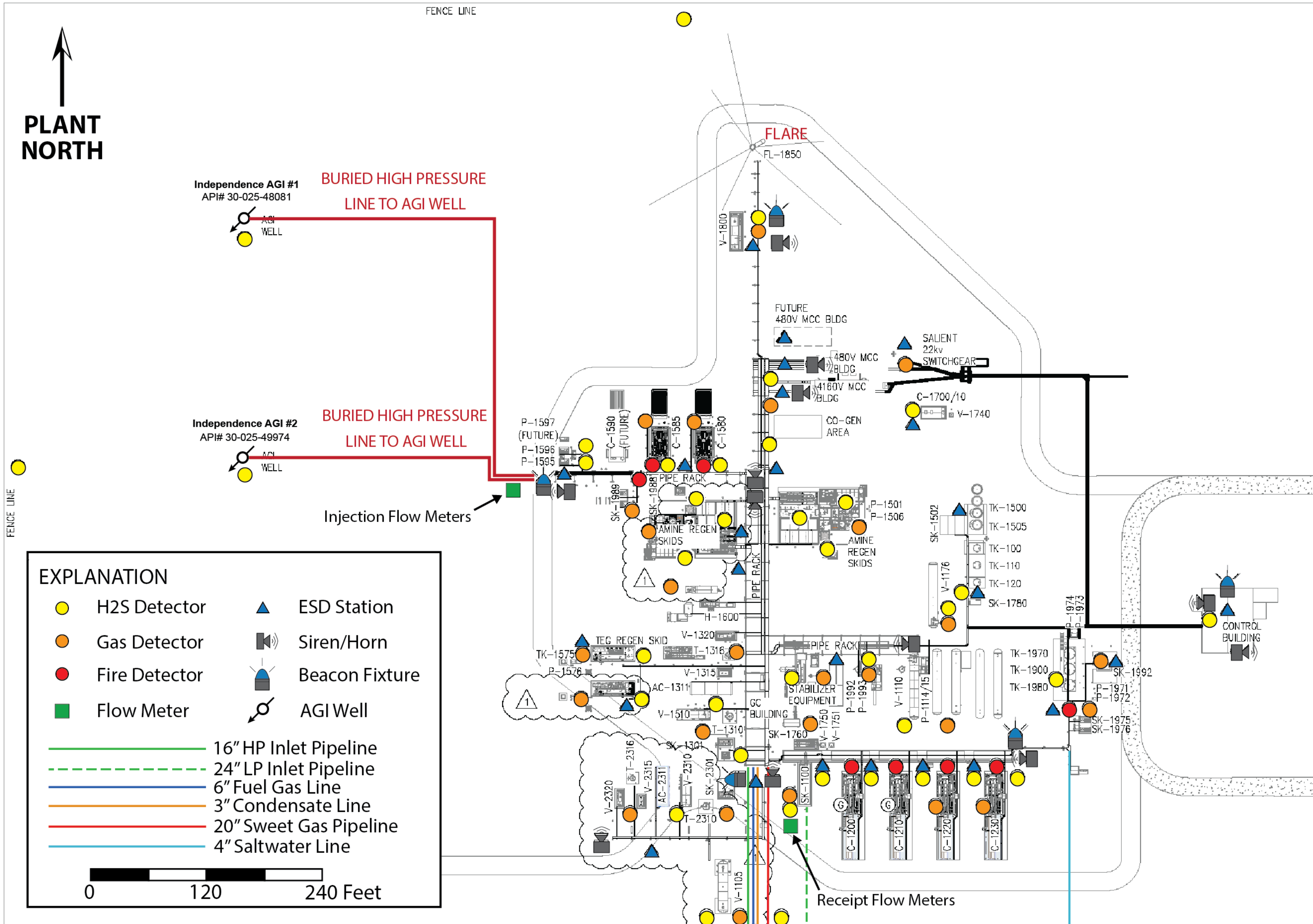


Figure 3.7-2: Detailed Dark Horse Facility schematic illustrating the location of major process units, all emergency equipment, H_2S and gas detection sensors, sirens and beacons, and major gas flow lines at the facility. (Taken from Figure 2 of the H_2S Contingency Plan for Dark Horse Gas Treatment Facility, Geolex, Inc.). The yellow circles indicate the location of fixed H_2S sensors.

3.7.2 Operations within a 2-mile radius of the Independence AGI Wells

Appendix 3 summarizes in detail all NMOCD recorded wells within a two (2) mile radius of the Independence AGI Wells. These wells are shown in Figure 3.7-3 and include active, plugged, and new (permitted but not yet drilled) well locations. In total, there are fifty-four (54) wells within a two (2) mile radius of the Independence AGI Wells. Of these, there are ten (10) active wells, thirty-three (33) permitted wells, and eleven (11) plugged wells.

Active wells in the area include one brine injection well completed across the Strawn through Fusselman formations, and nine (9) active oil and natural gas wells completed in various other strata. There are two (2) third-party wells within two (2) miles of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone (Table 3.7-1).

The first well is an active brine injection well (West Jal B Deep #001) located approximately one (1) mile from the Independence #2 SHL. This well was drilled to a total depth of 18,945 feet and is permitted to inject through perforated intervals of the Strawn through Fusselman strata. A Form C-103- Sundry Notices and Reports on Wells, submitted November 2018 contain a wellbore diagram that shows the locations of two cast iron bridge plugs ("**CIBP**"). The first CIBP is at a measured depth of 14,200 feet (within the lower Atoka Formation), and the second CIBP is at a measured depth of 17, 100 feet (within the Fusselman Formation). Despite BC & D Operating being granted approval for injection into the Fusselman (approved by NMOCD June 2014), NMOCD records document no reports of work to drill out the CIBP at 14,200 feet. The same Form C-103- Sundry Notices and Reports on Wells mentioned above indicates the intent of BC & D Operating to drill out the CIBP, but there have been no identified subsequent reports confirming completion of this work. Additionally, reported injection volumes since the filing of the Form C-103 in November 2018 for this well do not appear to exhibit any significant increase that might indicate this work was completed. Furthermore, according to a search of publicly available data as of June 2023, the West Jal B Deep #001 ceased water injection operations during or after July 2022, and water injected volumes have been reported as "0" since July 2022.

The second well penetrating the Siluro-Devonian Injection Zone is the plugged West Jal Unit #1, located approximately 0.67 miles from the Independence AGI #2 SHL. Final plugging operations were completed in April 1984 and all relevant plugging reports and documents are included in Appendix 9. The well is properly cemented through the Siluro-Devonian Injection Zone, and it is not anticipated to be negatively affected by the operation of the Independence AGI Wells nor is it considered to be a likely pathway for CO_2 leakage to the surface.

Appendix 3 and Figure 3.7-3 also show a number of wells in the area which have approved permits to drill but are not yet drilled. The new oil and natural gas wells are targeting various production zones, more than 4,000 feet above the Siluro-Devonian Injection Zone for the Independence AGI Wells. All new oil and natural gas wells and injection wells are subject to the requirements of regulations governing sealing off strata (NMAC 19.16.16.10) and casing and tubing requirements (NMAC 19.16.16.10) to prevent the contents of production or injection zones from passing into other strata. To minimize the likelihood of leaks from new wells, NMAC 19.15.26.9 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." Therefore, due to the fact that these wells do not penetrate the Siluro-Devonian Injection Zone, and that the wells are more than 4,000 feet above the Siluro-Devonian Injection Zone, Piñon does not consider these new wells to be pathways for CO_2 leakage to the surface. In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage.

***Table 3.7-1*: Wells located within a two (2) mile radius of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone. (Additional details are provided in Appendix 3)**

API	Well Name	Pool	Status	TVD (feet)
30-025-21172	WEST JAL UNIT #1	Strawn	Plugged	17,086
30-025-48081	INDEPENDENCE AGI #1	Devonian - Fusselman	Active	17,750
30-025-49974	INDEPENDENCE AGI #2	Devonian - Fusselman	New	17,683 (proposed)
30-025-25046	WEST JAL B DEEP #001	Mississippian – Fusselman	Active	18,945

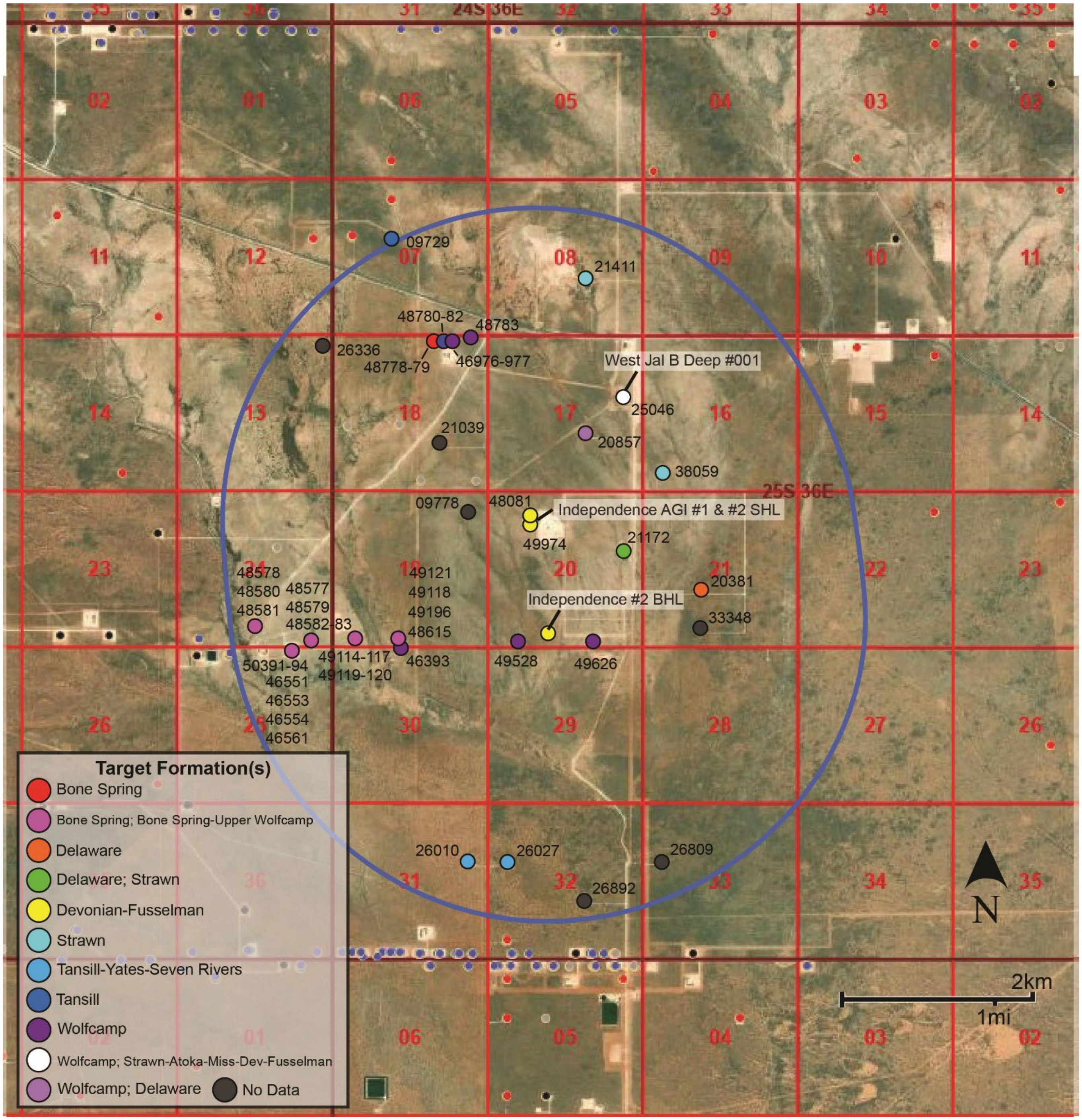


***Figure 3.7-3**: Location of all oil- and natural gas-related wells within a two (2) mile (blue line) of the Independence AGI Wells. Colors indicate the target formation(s) for each well. The oblong shape of the two (2) mile area accounts for the BHL of Independence AGI #2 as shown in Figure 3.1-1. Labels denote the last five (5) digits of API #30-025-XXXXX. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.*

3.8 Description of Injection Process

Once delivered to the Dark Horse Facility, sour natural gas is treated using amine to isolate H_2S and CO_2. The amine (which now contains H_2S and CO_2) is then regenerated which creates a TAG waste stream. This TAG waste stream is then routed to on-site compression facilities that compress the TAG waste stream into a dense phase (roughly 1,250 psig). The dense phase stream is then pumped to upwards of 2,500 psig prior to being sent to the Independence AGI Wells, through a National Association of Corrosion Engineers ("**NACE**") rated pipe, for injection. Figure 3.8-1 is a schematic of the surface facilities for the Independence AGI Wells. The sweet natural gas that results from the amine scavenging process is then treated to remove water ("**H_2O**") and subsequently transported offsite, via pipeline, and redelivered to Piñon's customers at various delivery points.

For the period of September 2021 through March 2022, the TAG stream at the Dark Horse Facility averaged 57.076% CO_2 and 38.703% H_2S by volume, with hydrocarbons (C1 – C7) and H_2O comprising the remaining volume.

The anticipated duration of TAG injection into the Independence AGI Wells at the Dark Horse Facility is approximately thirty (30) years.

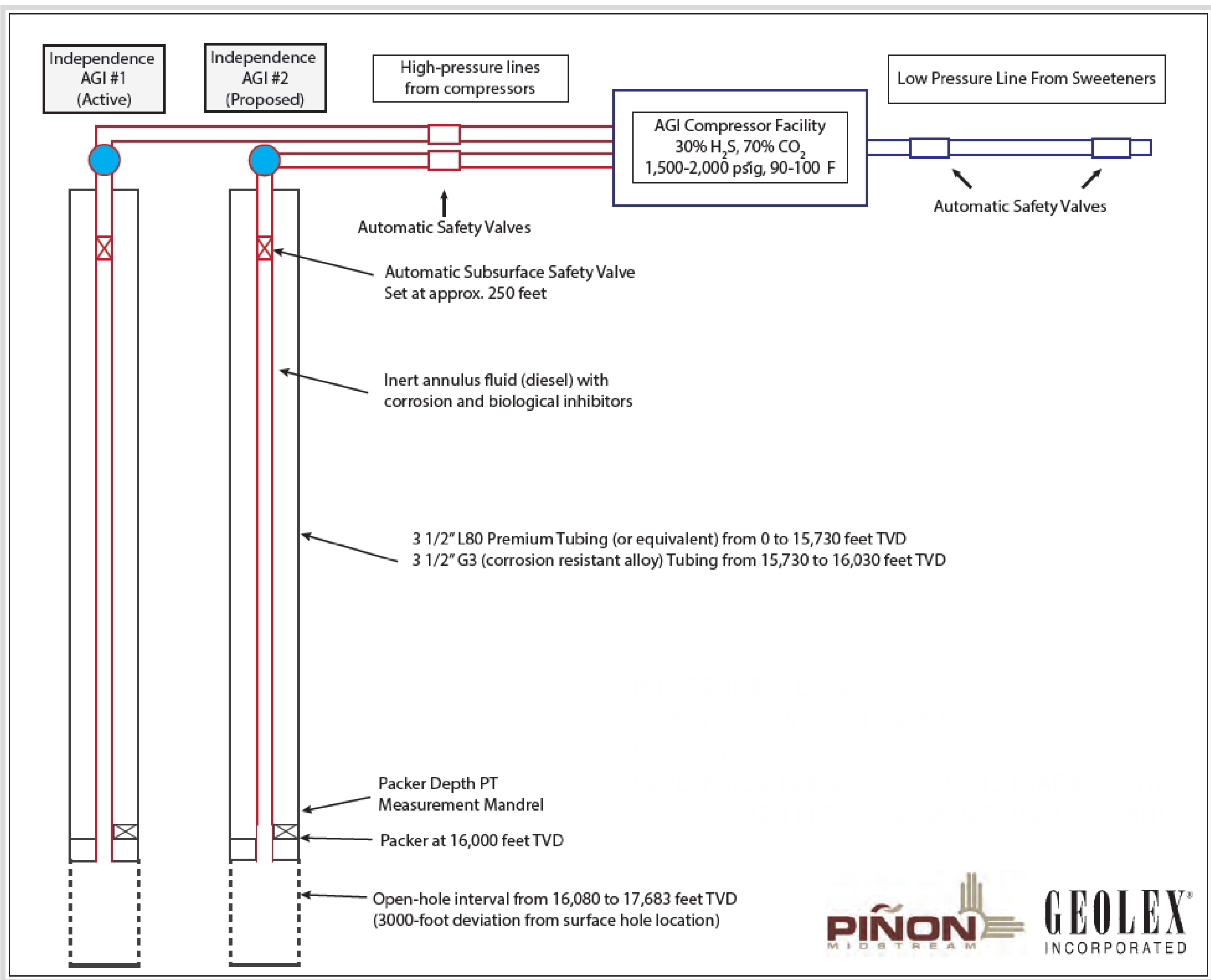


***Figure 3.8-1*: Schematic of surface facilities at the Dark Horse Facility and the Independence AGI Wells. (Modified from Figure 3 of Class II permit application for Independence AGI #2, Geolex, Inc.)**

3.9 Reservoir Characterization Modeling

The Independence AGI Wells penetrate the lower Devonian Thirtyone formation and the Silurian Wristen and Fusselman formations and overlie the Ordovician Montoya formation. The upper Devonian Woodford formation serves as the primary containment seal with thick shales having an estimated permeability in the nanodarcy range.

Schlumberger's Petrel (Version 2020.4) software was used to construct the geological models used in this work. Schlumberger's simulation software Eclipse Compositional E300 (Version 2020.1) was used in the reservoir simulations presented in this MRV Plan with simulation results and visuals provided by Geolex Inc. The model simulates solubility trapping of the injected TAG in the formation water and/or the portion of the TAG that can exist in a supercritical phase. The modeling did not consider CO_2 storage attributed to mineral and geomechanical trapping mechanisms. Also, the model did not implicitly model storage attributed to residual trapping because insufficient information was available to develop the hysteresis effects.

Though the Independence AGI Wells were modeled separately, similar constraints were used for both models. The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. The injection gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Both TAG components are assumed to be soluble into the aqueous phase. An irreducible water saturation of 0.17 is used to generate the relative permeability curves for the gas/water system. The external boundary conditions are specified to be Neumann boundaries and hence no-flow with respect to mass.

3.9.1 AGI Injection Characterization and Modeling

Formation tops were picked from the few well logs available for the area and geophysical measurements and mapped to construct the structural surfaces for the Silurian-Devonian reservoir between the underlying Montoya and capping Woodford formations. The geologic model extends approximately twenty (20) square miles with an irregular polygonal edge (Figure 3.9-1) and includes relevant subsurface features (e.g. faults, folds) and nearby injection wells. The simulation grid is comprised of 292 simulation layers characterizing eight (8) discrete zones. Horizontal spacing is uniform at 500 × 500 feet throughout the model, and the numerical grid overall contains 923,000 grid cells. Figure 3.9-1 shows the structural surface for Layer 1, covering the top of the reservoir immediately below the Woodford cap. Porosity data derived from the Independence AGI #1 well logs augmented by 3D seismic survey impedance data along with drill-stem and injection tests were used to populate the model porosity values (Figure 3.9-2). A porosity-permeability relationship was established to develop a correlation to populate 3D distribution of permeability (Figure 3.9-3). The permeability distribution signifies a fairly tight formation with typical values ranging from 1.0 to 79.0 millidarcies. Figure 3.9-4 shows the permeability distribution in Layer 1 of the model at the top of the Devonian Thirtyone Formation (*see* Section 3.3.1). Separate scenarios were run for non-transmissive faults and for permeability across faults.

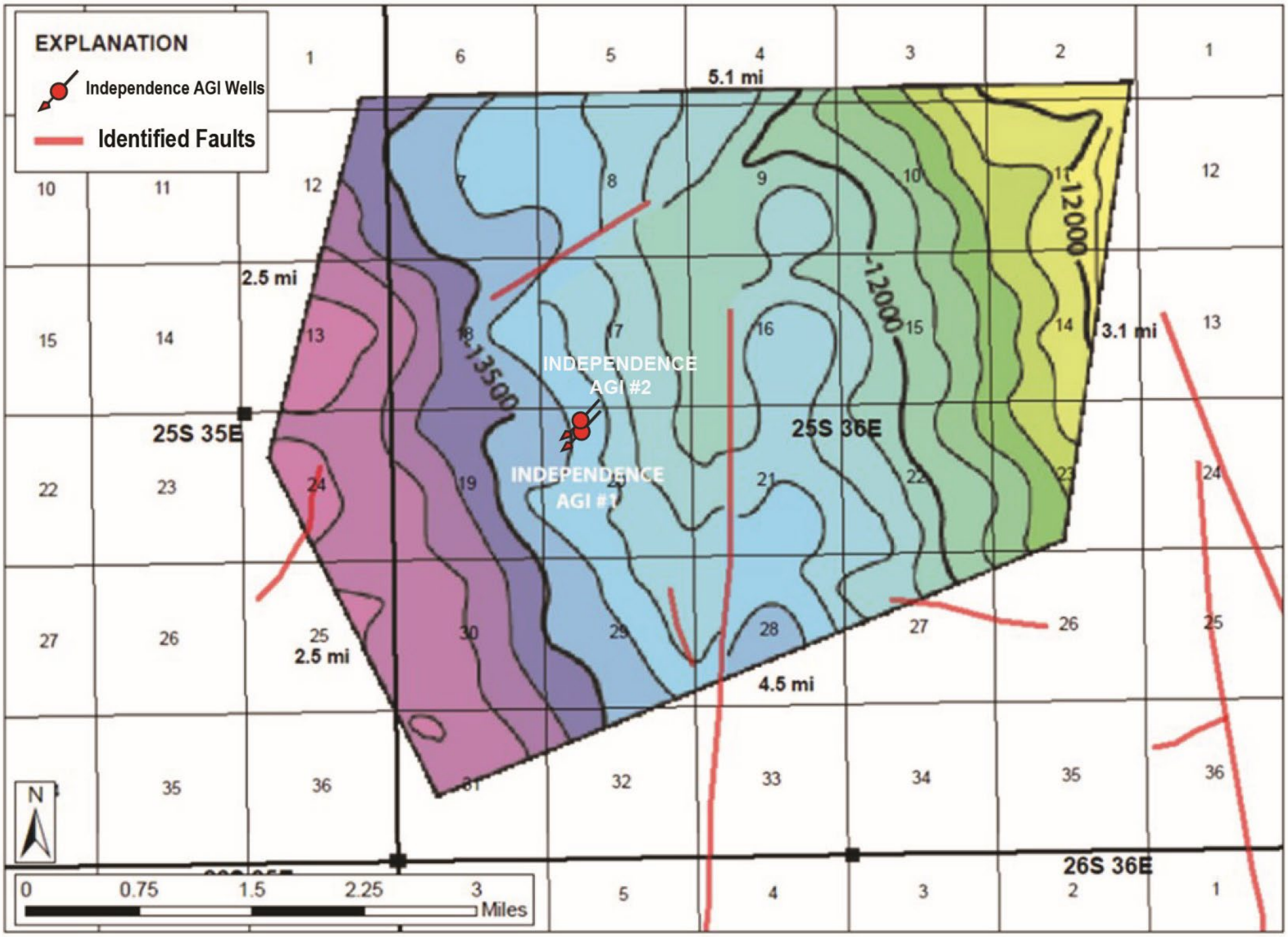
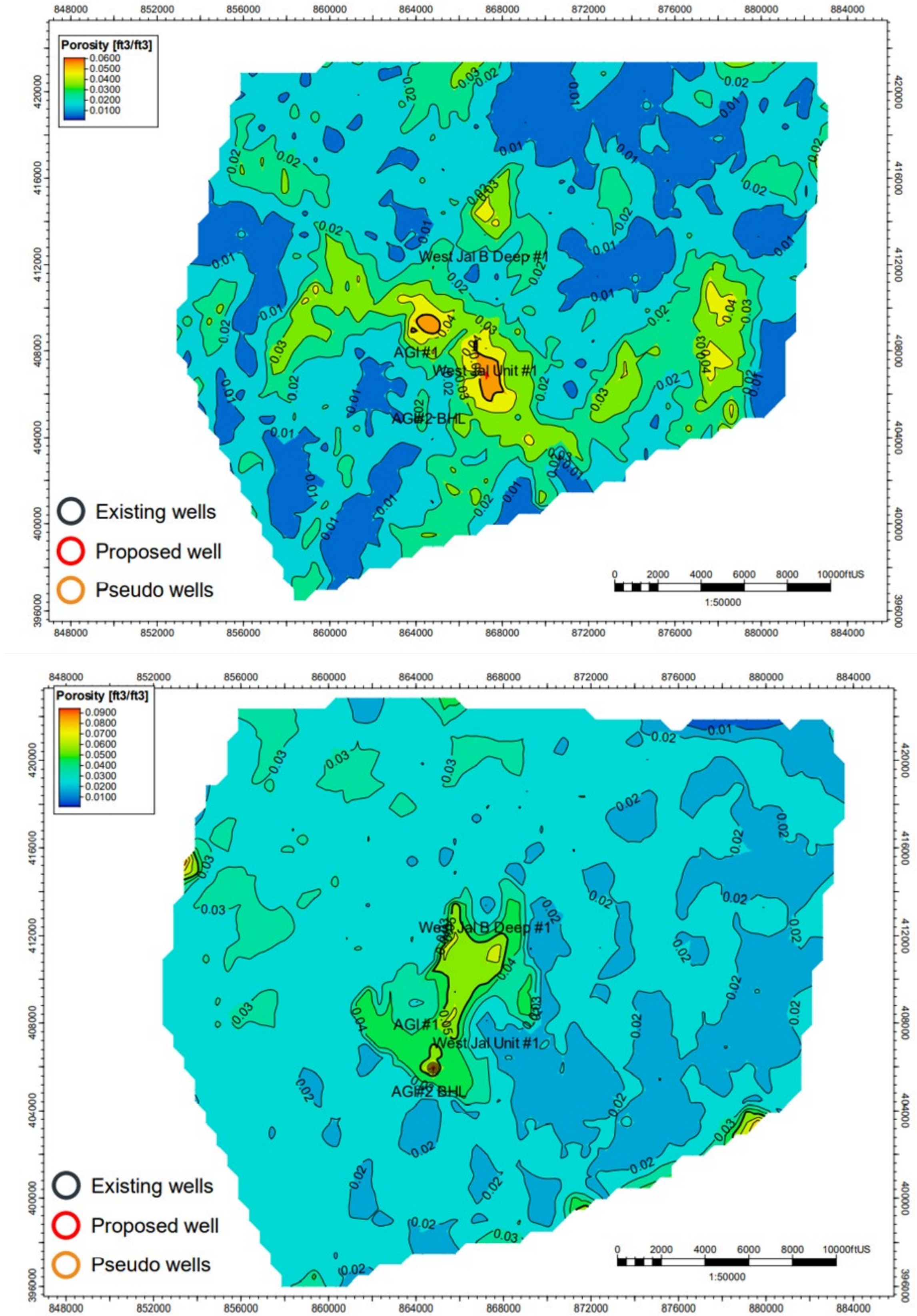


__Figure 3.9-1__: Structural surface for top of Layer 1 (top) of the geological and numerical model. Only SHLs shown for the Independence AGI #1 and #2 wells.



<u>Figure 3.9-2</u>: Model layer porosities for Zone 1 (top) and Zones 7 and 8 (bottom). Porosities are based on 2 wells, 3D seismic impedance surveys, and well stem tests. Only SHLs shown for the Independence AGI #1 and #2 wells.

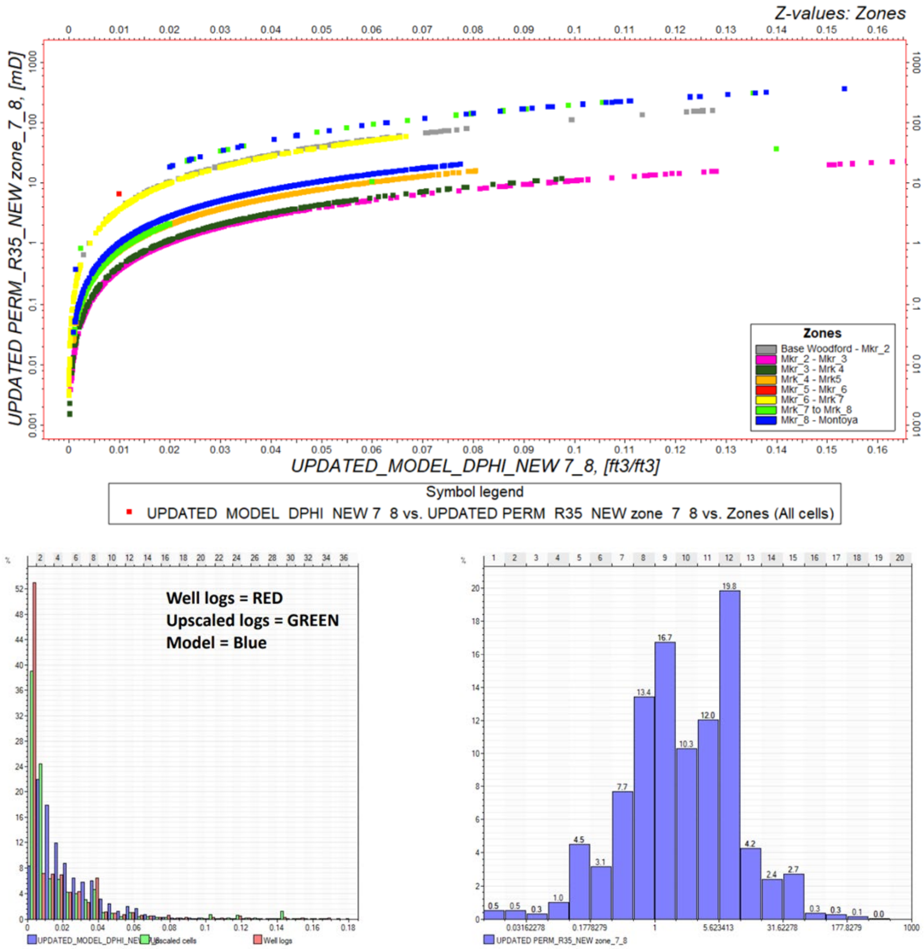


***Figure 3.9-3**: Geological zones and ranges of the properties for the Siluro-Devonian geologic model*

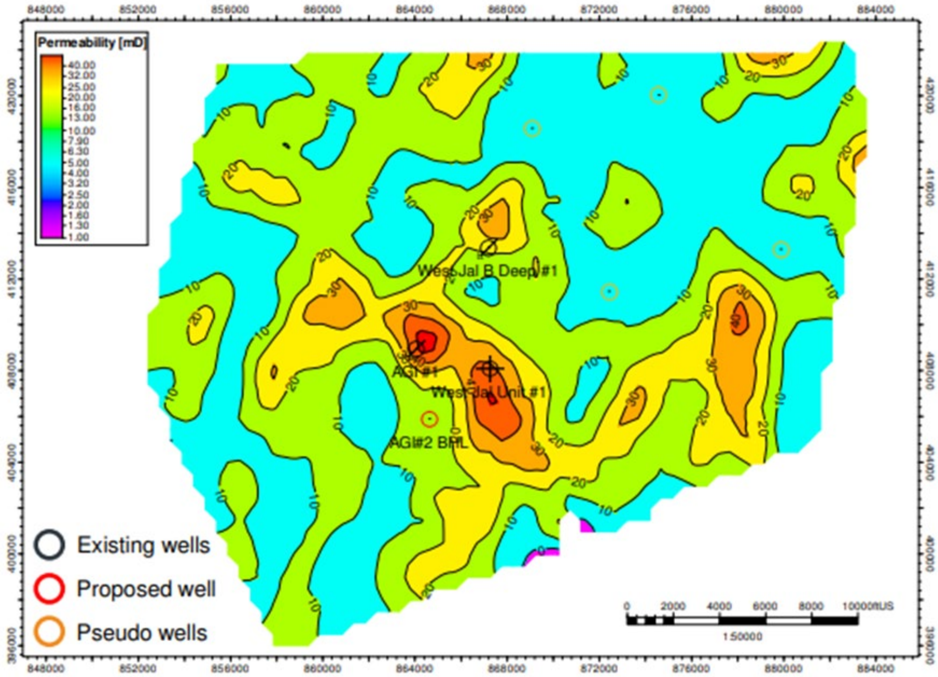


***Figure 3.9-4**: Graphic showing the permeability distribution in Layer 1 of the model representing the Thirtyone formation. Plan view. Only SHLs shown for the Independence AGI #1 and #2 wells.*

3.9.2 Simulation Modeling for the Independence AGI Wells

Once the geological model was established, numerical modeling was performed to:

1. Assess the maximum injection rate with respect to estimated maximum bottomhole pressure ("**BHP**") to ensure safe operation, and
2. Estimate the modeled extent of the injected TAG after thirty (30) year injection period and five (5) year post injection monitoring period.

The reservoir is assumed to be initially saturated with 100% brine and exhibit hydrostatic equilibrium with the initial pressure based on the measured pressure at the top of the reservoir pre-injection. The injection gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Gas is injected for 30 years at a rate of 1,036.73 tonnes per day (378,399 tonnes per year or 11,351,970 total tonnes) followed by a 5-year rest period. Permeability curves for the multiphase gas/water system are defined for three (3) material ranges with a residual liquid saturation between 40% and 65%. An estimated maximum BHP of 9,730 psig, based on the calculated fracture pressure gradient, was imposed on the Independence AGI #1 to ensure safe injection operations. This pressure was important for Independence AGI #1 in the model scenario where all TAG was injected into Independence AGI #1, but otherwise simulations showed pressure at the Independence AGI Wells remaining below this threshold. In all simulations where West Jal Deep B #001 injected 30,000 bpd of brine into the reservoir, the West Jal Deep B #001 would need to decrease injectivity to remain below its permitted threshold pressure. Present modeling work does not indicate sufficient connectivity between the West Jal Deep B #001 and the Independence AGI Wells to impact AGI injectivity under all other modeled scenarios. Figure 3.9-5 shows the calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1. AGI rates are lower than target numbers and limited data are available so a more detailed calibration cannot yet be constructed. An injection forecast model was performed for a period of thirty (30) years with injection and then a five (5) year post-injection rest period to ascertain fluid movement and pressure evolution. Figure 3.9-6 shows the injection profile for the forecasting period which showed that the target injection rate could be hit in all scenarios except Scenario 5. The model showed that all the injected

gas remained in the reservoir and there was no substantive change in the size of the TAG extent compared at the end of injection and five (5) year post injection period.

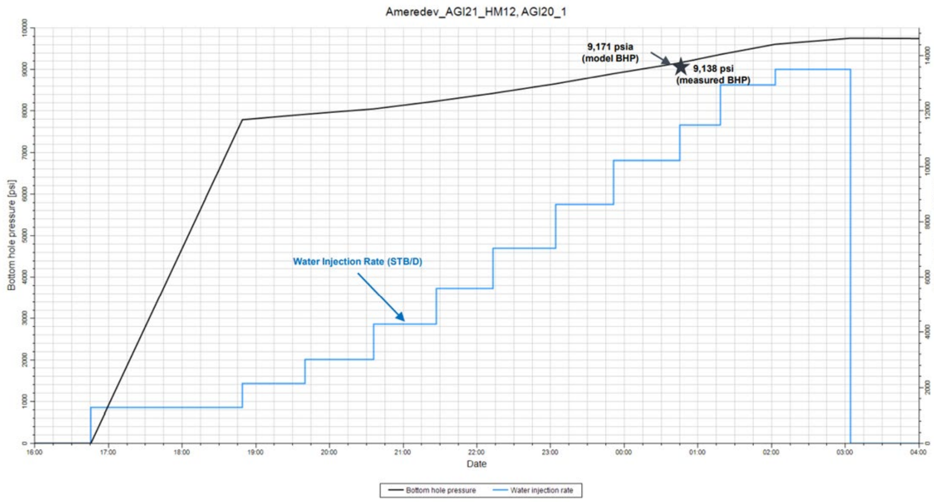


***Figure 3.9-5**: Graph showing calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1.*

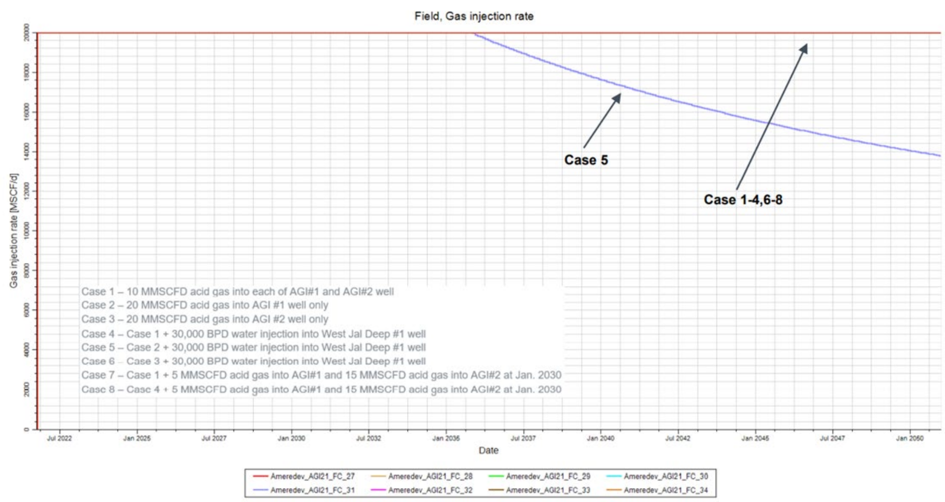


***Figure 3.9-6**: Graph showing the forecast profile for the injection rate and cumulative injection volume over the simulated period*

A considerable source of uncertainty in the plume model relates to the injectivity of the West Jal Deep B #001 well located about one (1) mile northeast of Independence AGI #1. This well is permitted to dispose of up to 30,000 bpd of brine into several reservoirs, including the Siluro-Devonian reservoir used by the Independence AGI Wells, and other shallower reservoirs. It is unclear from publicly available data how this fluid is planned to be partitioned between the various injection layers. As of this application, the wellbore currently has CIBPs at measured depths of 14,200 feet (lower Atoka Formation) and 17,100 feet (Fusselman Formation), restricting injection into the Siluro-Devonian reservoir, and no fluid is currently being injected at the well. However, since this well is permitted for injections, modeling for the present application considered two (2) end-member scenarios: (a) All West Jal Deep B #001 injection is into shallower reservoirs and does not interact with the Siluro-Devonian one (cases 1,2,3), or (b) all West Jal Deep B #001 volumes are injected into the Siluro-Devonian reservoir (cases 4,5,6,7,8). The brine injection at this well is significant for several reasons:

- High volumes of brine injection within the Siluro-Devonian in relatively close proximity of the Independence AGI Wells may raise pressure in the reservoir;

- Pressure from the brine injection pushes against the advancing gas front, directing flow south and west away from the well; and
- The West Jal Deep B #001 wellbore could be a potential leakage pathway if injection ceases and the supercritical fluid plume from the Independence AGI Wells reaches it. Simulations that do not include injections at this well have the TAG plume area including this well.

In all simulations with injection at West Jal Deep B #001, the local pressure at the brine injection well rapidly rises to the breakover point and the injection rate begins dropping within the first two (2) years of that well's operation to maintain pressures below 80% of the breakover threshold and ensure no rock fracturing occurs (Figure 3.9-7). It is unknown how in reality this will translate to well operations within the Siluro-Devonian reservoir. Simulations do not indicate that the pressure increase from this well will adversely affect the Independence AGI Wells due to the early shut down of the brine injection well. Simulations where there is no brine injection result in the plume extending farther northeast beyond the West Jal Deep B #001 well (Figure 3.9-8). If brine is injected, then the plume is repelled towards the south and west, with some TAG flanking the northwest fault and extending northwest (Figure 3.9-9). Simulations suggest a pressure impact on Independence AGI #1 that could result in curtailed injections under a scenario with all TAG injection in Independence AGI #1 and West Jal Deep B #001 active (Case 5, *see* Figure 3.9.6).

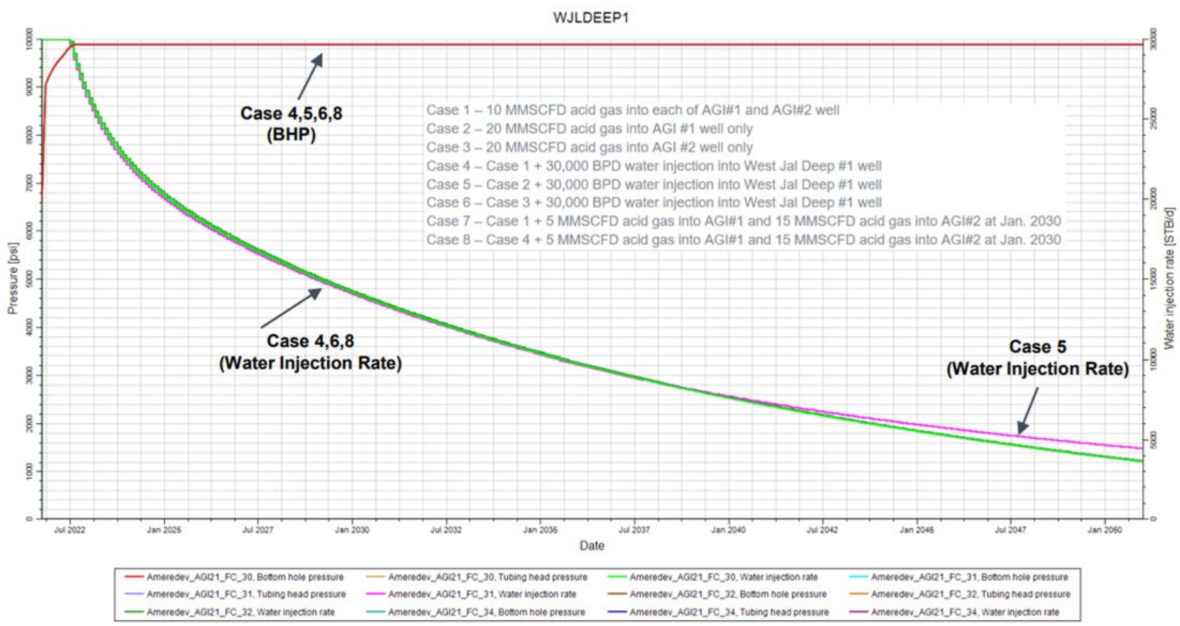
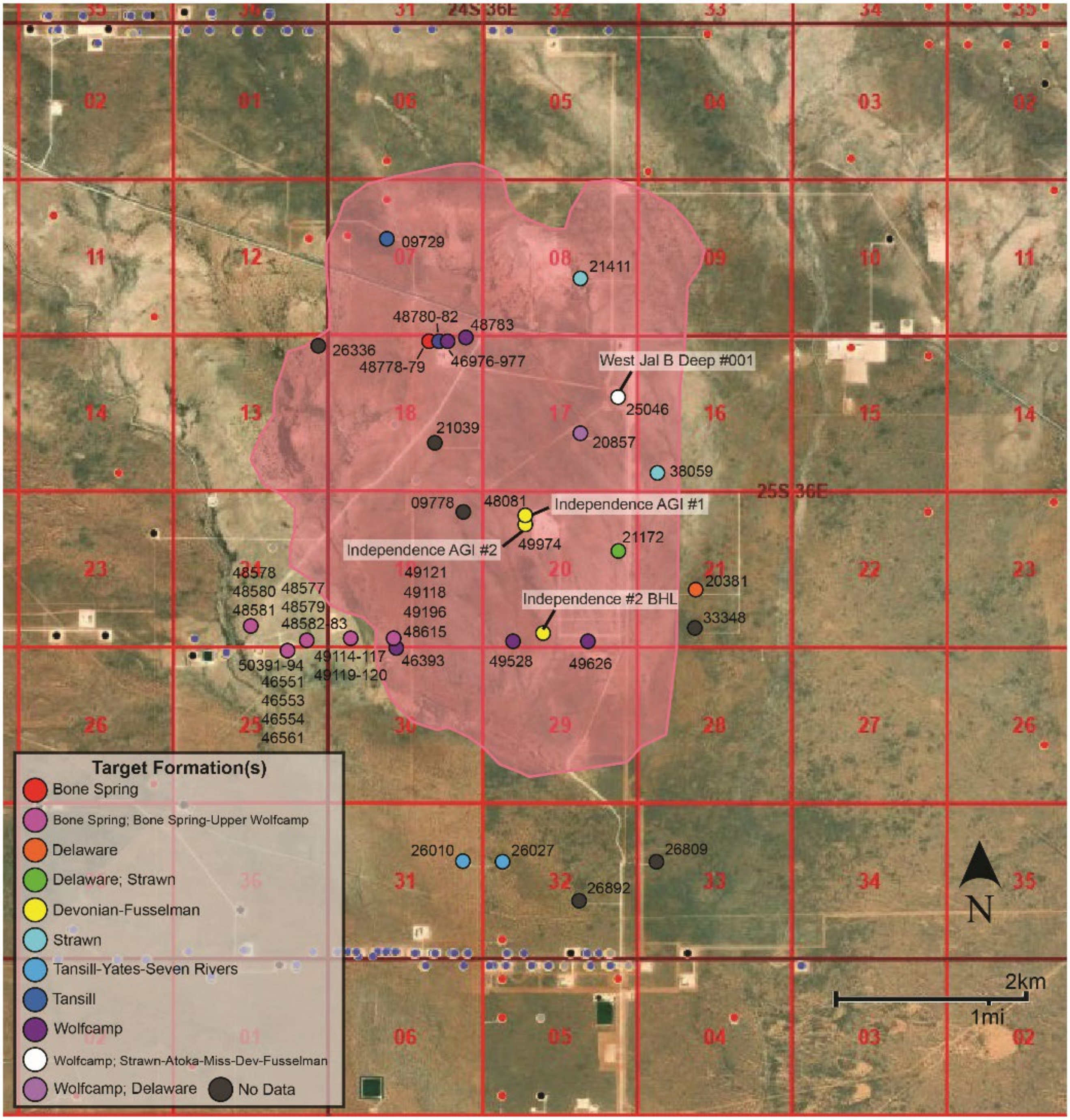


***Figure 3.9-7**: Graph showing the injection profile of the West Jal Deep B #001 brine injection well under different injection scenarios.*



<u>Figure 3.9-8</u>: Map showing the largest lateral extent of the TAG when the West Jal Deep B #001 well does not inject into the Siluro-Devonian. Colors indicate target formations for the well. West Jal Deep B #001 is the white dot northeast of the Independence AGI Wells. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in <u>Figure 3.1-1</u>.

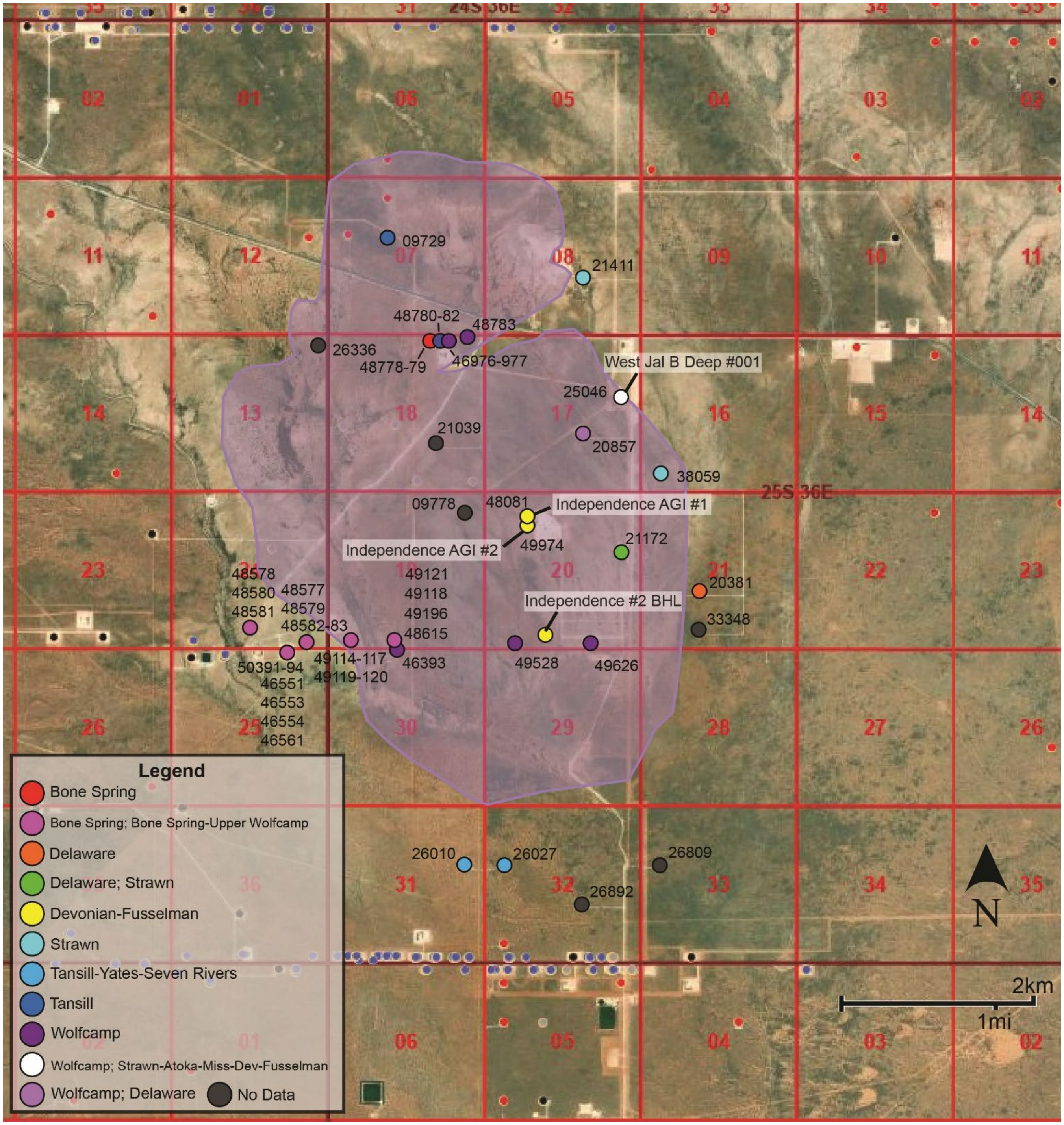


***Figure 3.9-9**: Map showing the largest lateral extent of the TAG when the West Jal Deep B #001 injects an initial rate of 30,000 bpd of brine into the Siluro-Devonian. Colors indicate target formations for the well. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in **Figure 3.1-1**.*

4 Delineation of the Monitoring Areas

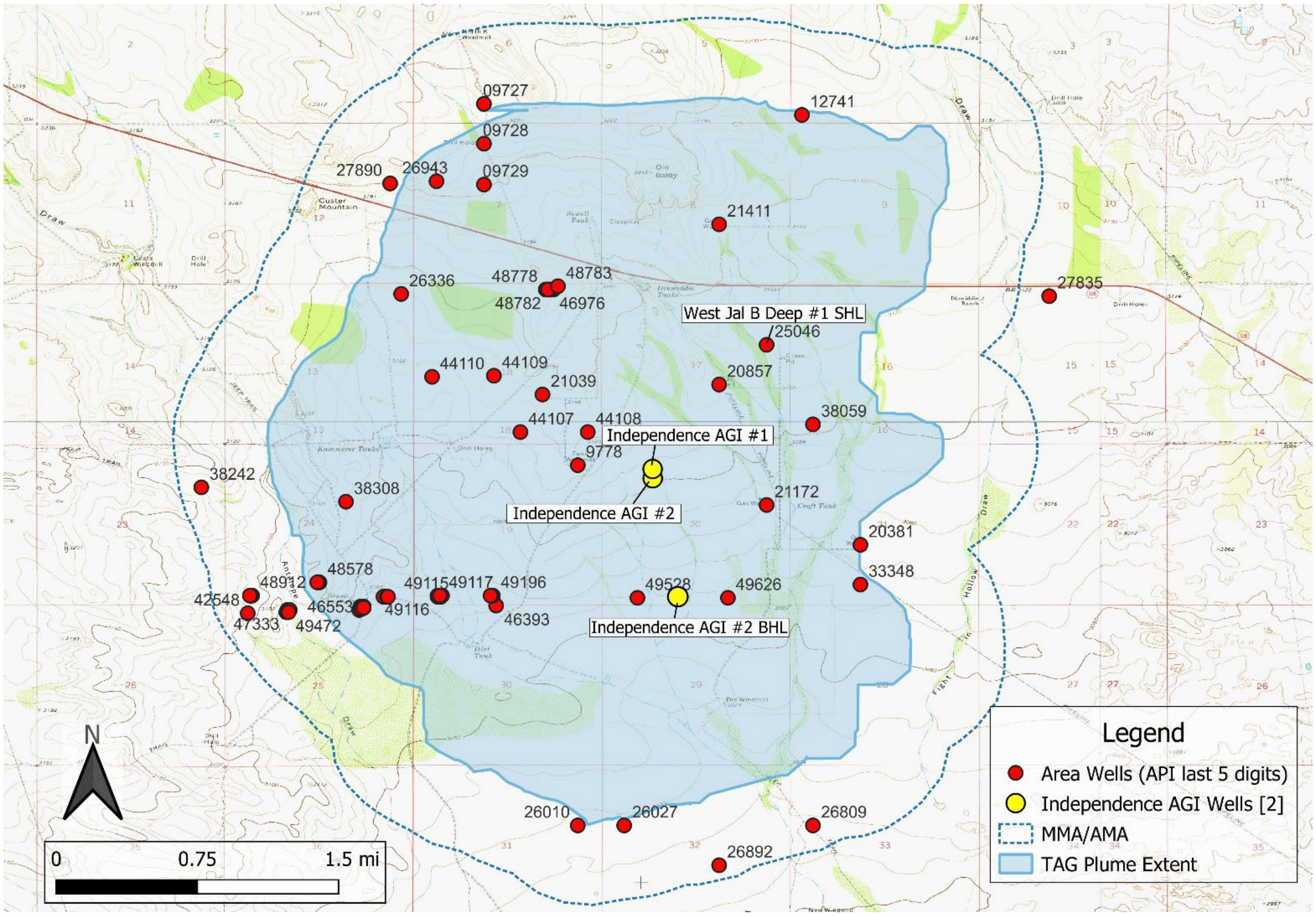
In determining the monitoring areas below, the extent of the TAG plume is equal to the superposition of plumes in any layer for any of the model scenarios described in Section 3.9.

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 (Figure 4.1-1). In general, the western margins of the plume retract to the east following the injection period as gas flows up-dip. In this case, the farthest plume extent and hence the MMA margin is therefore found at year 30 (year t), with the plume extent to the west shrinking by year t+5 and stabilizing. On this side, the MMA is based on the largest plume extent which is at year 30 (t). To the east, fault trapping and the anticline near the injection site generally prevent major movement eastward. Beyond year 30 (t), the plume slowly expands east and northeast, finally stabilizing around year 50 (t+20). In all cases, the plume margin polygon in Figure 4.1-1 is defined by the maximum extent of any plume in any scenario at any simulation time, with a 0.5 mile buffer extending beyond this polygon defining the margin of the MMA.

4.2 AMA – Active Monitoring Area

Piñon intends to define the AMA as the same area as the MMA. Per 40 CFR 98.449, AMA is defined as the area that will be monitored over a specific time interval from the first year of the period (n = 2023) to the last year in the period (t = 2053, a 30-year injection period). The boundary of the AMA 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 (2058, or year 35 of the simulation). However, as the plume has not fully stabilized by year t+5, the AMA and MMA in these areas is defined by the larger area of the stable plume which occurs at year t+20. This definition includes all areas at years t, t+5, and t+20. The zone shown in Figure 4.1-1 has a one-half mile buffer beyond the maximum plume extent of any scenario. Piñon intends to define the AMA as the entirety of the MMA.



<u>Figure 4.1-1</u>: MMA and AMA for the Independence AGI Wells. The plume extents are shown at year 35 (t+= 2058), or 5 years beyond injection time. The plume largely stabilizes by this time, with continued minor migration updip to the northeast which is constrained by faults offsetting permeable layers. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in <u>Figure 3.1-1</u>.

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 duration 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 and the reservoir modeling described in <u>Section 3.9</u>, Piñon 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 treating facilities. To minimize this potential for leakage, the construction, operation, and maintenance of sour gas treating facilities 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, Piñon implements a schedule for regular inspection and maintenance of surface equipment. To further

minimize the magnitude and duration of detected gas leaks to the surface, Piñon implements several methods for detecting gas leaks at the surface. These methods are described in more detail in Sections 6 and 7. Detection is followed up by immediate response.

Due to the required continuous monitoring of the gas gathering and the gas processing systems, Piñon considers the likelihood, magnitude, and duration of CO_2 leakage 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 Existing Wells

As shown in Figure 3.7-3 and detailed in Appendix 3, there are several existing oil and natural gas-related wells within a two (2) mile radius around the Independence AGI Wells (Figure 4.1-1). The deep wells discussed in Section 3.7.1 (*see* Table 3.7-1) also lie within the MMA/AMA. They are discussed below.

5.2.1 Independence AGI Wells

Independence AGI #1 has an open hole interval between 16,122 and 17,709 feet with more than 300 feet of Woodford Shale immediately above (*see* Figure A1-1). Independence AGI #2, which was drilled and completed in October 2022, has an open hole interval between 16,080 and 17,683 feet (*see* Figure A1-2). The combined depth to the Siluro-Devonian Injection Zone, cement program for both wells illustrated in Figures A1-1 and 2, existence of suitable confining layers above the Siluro-Devonian Injection Zone described in Section 3, and continuous monitoring of well operational parameters indicates that leakage of CO_2 to the surface via the Independence AGI Wells themselves is unlikely. Therefore, Piñon considers the likelihood, magnitude, and duration of CO_2 emissions to the surface through the Independence AGI Wells to be minimal. Detection and quantification of any leaks from Independence AGI Wells are described in Section 6.2 below.

5.2.2 West Jal B Deep #001 Well

The West Jal B Deep #001 (API 30-025-25046) brine injection well is located one (1) mile northeast of the surface hole locations of the Independence AGI Wells. Additional details for this well are presented in Section 3.7.1. The wellbore currently has two CIBPs at measured depths of 14,200 feet (lower Atoka Formation) and 17,100 feet (Fusselman Formation). These CIBPs restrict access to any existing reservoirs located below the lower Atoka Formation, including within the Mississippian Lime (14,544 feet), Devonian (15,380 feet), and the Fusselman (16,404 feet), and injections in this wellbore to-date have been up-section of the relevant area. In the event of incomplete plugging of the borehole or leakage through the well casing, the shallower reservoir is at higher pressure than the Siluro-Devonian reservoir, and consequently it is assessed that downward flow of fluid would repel the TAG plume from the AGI wells. Nevertheless, the potential for CO_2 leakage to the surface through this well is considered possible, albeit unlikely, and monitoring for this possibility is described in Section 6.2.2.

5.2.3 West Jal Unit #1 Well

The West Jal Unit #1 well (API 30-025-21172) was plugged and abandoned in April 1984. The plugging documents presented in Appendix 9 indicate that the well is properly plugged to prevent vertical migration of pressure or fluids outside of the storage reservoir with multiple CIPBs and cement plugs, including the Siluro-Devonian Injection Zone. Piñon concludes that the risk of any magnitude for CO_2 leakage to the surface through plugged and abandoned well is unlikely. However unlikely, Piñon will conduct quantification and monitoring for as described in Section 6.

5.2.4 Wells Completed and Proposed to be Completed in the Wolfcamp, Bone Spring, and Shallower Stratigraphic Units

There are several oil and natural gas wells (Appendix 3) completed or proposed to be completed in the Wolfcamp, Bone Spring and shallower stratigraphic units within the MMA. The deepest of these wells is completed in the Upper Wolfcamp (see Figures 3.2-2 and 3.3-1). The nearly 4,000 feet of strata between the top of the Siluro-Devonian Injection Zone and the Wolfcamp production zone includes nearly 300 - 400 feet of low porosity and low permeability Woodford Shale, the primary confining unit/seal for the Independence AGI Wells (see Figure 3.3-3).

Due to the thickness of the strata between the deepest wells completed in the Wolfcamp and the thickness of the Woodford Shale above the Siluro-Devonian Injection Zone, Piñon considers the likelihood, magnitude, and duration of CO_2 leakage to the surface via this potential leakage pathway to be unlikely. Detection and quantification of any leaks through these wells are described in Section 6.2 below.

5.3 Potential Leakage through Fractures and Faults

Faults and fractures were discussed in Section 3.2.3 and the potential for induced seismicity was discussed in Section 3.5. The reservoir characterization modeling (Section 3.9) and the delineation of the monitoring areas (Section 4) show that the TAG plume reaches the faults shown in Figure 3.5-1 during the thirty (30) year injection period and the five (5) year post injection monitoring period. Vertical permeability may be present parallel to the plane of the fault vertically, especially where the two main faults intersect. A review of available drilling fluid records was conducted to evaluate regional reservoir pressure conditions in the Delaware basin. Above the Siluro-Devonian injection reservoir, mud weights utilized range from 12.1 to 15.1 pounds per gallon, while for the injection reservoir less dense fluids were used (average of 9.0 pounds per gallon). These support the interpretation that the overlying productive zones in this area are over pressured with respect to the target reservoir, which would produce a downward gradient through any fault-parallel permeability. The pressure differential between the overlying interval and target interval will act as a barrier preventing vertical migration even along localized open conduits.

Due to evidence that production zones overlying the Siluro-Devonian Injection Zone are over pressured and that the basement rooted faults in the area are confined to the lower Paleozoic up to the lower Woodford Shale, Piñon considers the likelihood, magnitude, and duration of CO_2 leakage to the surface via this potential leakage pathway to be unlikely. Detection and quantification of any leaks through these basement rooted faults are described in Section 6.3 below.

5.4 Potential Leakage through the Confining / Seal System

The subsurface lithologic characterization presented in Section 3.2.2 describes the thick sequence of Mississippian through Permian strata overlying the Siluro-Devonian Injection Zone and reveals the existence of several excellent confining zone layers including nearly 300 - 400 feet of low porosity low permeability Woodford Shale. Due to the thickness, lateral extent, and low porosity and permeability of the Woodford Shale, Piñon considers the likelihood, magnitude, and duration of CO_2 leakage to the surface through the confining zone to be unlikely. Detection and quantification of any leaks through the confining zone are described in Section 6.4 below.

5.5 Potential Leakage due to Natural / Induced Seismicity

The potential for leaks initiated by induced seismicity was addressed in Section 3.5. It was concluded that generally, faults considered in this assessment do not display significant potential for injection-induced slip and the Independence AGI #2 is not predicted by the FSP model to contribute significantly to the total resultant pressure front. Piñon concludes that the likelihood for the creation and/or opening of vertical conduits for CO_2 leakage to the surface due to induced seismicity is low. In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage. Nevertheless, the NMOCC Order requires Piñon to install, operate, and monitor for the life of the project a seismic monitoring station or stations described in more detail in Section 7.6.

According to data obtained from the New Mexico Tech Seismic Observatory (2023), there have been four (4) seismic events within the MMA since January 12, 2017 (Figure 5.6-1). These seismic events range in magnitude of 1.16-1.88 and occurred between September 2020 and October 2021 (Table 5.6-1). The New Mexico Tech database applied a model for epicenter location that was not capable of determining focal depth. Revisions to this database are planned for late 2023 but have not been released at the time of this writing. Hence, earthquake depths are unknown, but accounting for the lack of local development in the Devonian strata, and the greater development at shallower depths, it is believed these earthquakes occurred in a shallower reservoir. Data queries with the USGS Earthquake Catalog did not show any seismic activity within the MMA (USGS Earthquake Hazards Program, 2023).

As noted in Section 3.5, the results of the fault slip potential model indicate no likelihood of slip on the fault east of the Independence AGI Wells. The maximum segment slip potential was determined at 0.05 northwest of the injection wells, with AGI injections causing no increase in probability. Any slip would depend on the injection volumes of brine disposal wells (at present there is no brine injection in the target area). Should fault slip occur, the short lengths of the potentially slipping segment likely preclude large earthquakes, and seismicity would be expected to be <2.5 in magnitude. Any earthquakes at or above this value would be carefully evaluated to determine location, depth, and sense of motion. Remote gas observation sweeps will be conducted above or as close to the mobile fault segment as possible at 10, 30, 100, and 365 days following the event to determine if leakage is occurring. The rate of gas leakage will likely depend on the time required to saturate the fracture network created by the seismic event and the timeline of this process is expected to be on order 10 to 100 days after the fracture network is exposed to gas (Hyman et al. 2019).

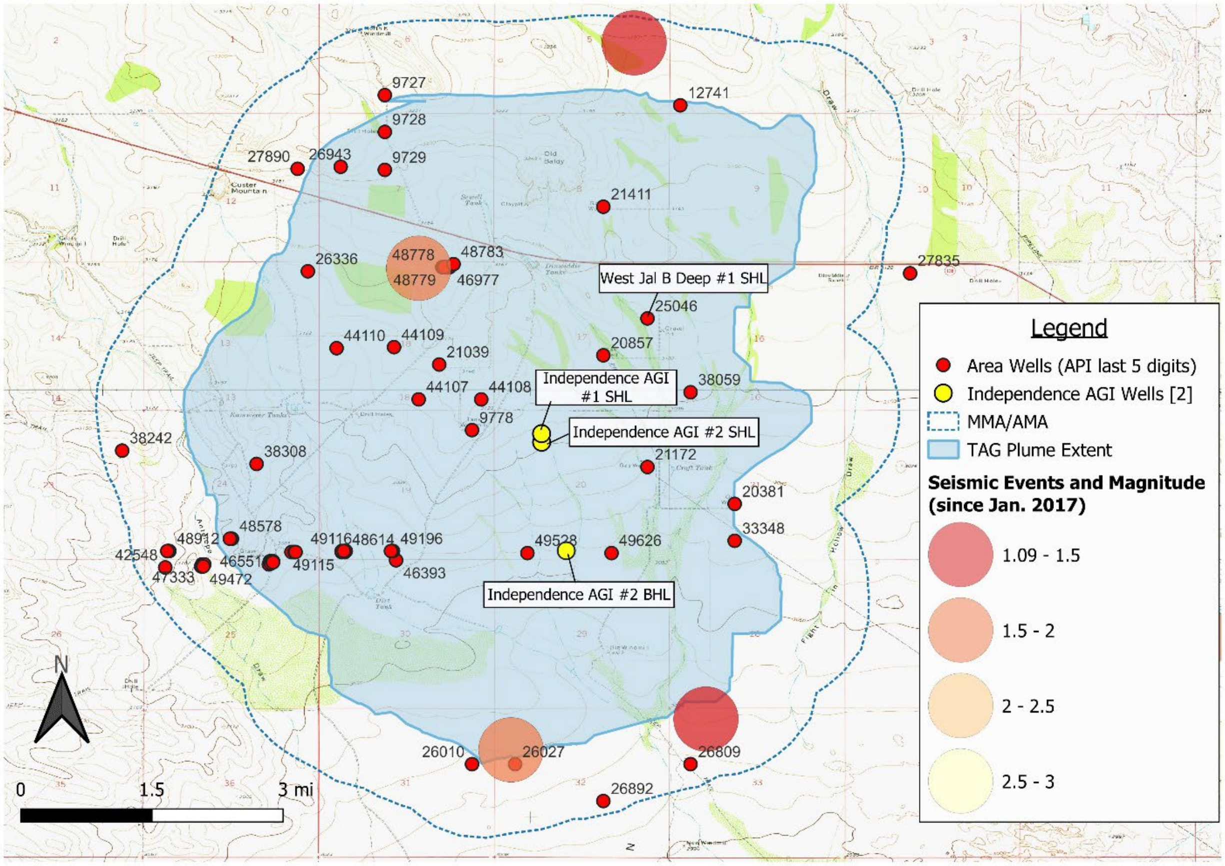


***Figure 5.6-1**: Map showing seismic event locations within the MMA for the Independence AGI wells. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in **Figure 3.1-1**.*

Date+Time(UTC)	Latitude	Longitude	Magnitude
2021-10-30 07:14:26.600	32.093	-103.275	1.16
2021-10-11 12:19:51.300	32.09	-103.294	1.88
2021-09-09 08:23:05.600	32.137	-103.303	1.74
2020-10-03 03:51:12.600	32.159	-103.282	1.47

***Table 5.6-1**: Table showing the locations, dates and times, and magnitudes of seismic events within the MMA for the Independence AGI wells.*

5.6 Potential Leakage due to Lateral Migration

Lateral migration of the injected TAG was addressed in the simulation modeling detailed in Section 3.9. The results of that modeling indicate the TAG is unlikely to migrate laterally beyond approximately 2.5 miles within the Siluro-Devonian Injection Zone to encounter any conduits to the surface.

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. Piñon 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. Piñon considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ 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 five (5) year post-injection period.

If CO_2 surface emissions are detected by any of the monitoring methods listed in Table 6.1, Piñon will quantify the mass of CO_2 emitted via approved emission factors such as those found in 40 CFR Part 98, Subpart W or engineering estimates 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. Quantification can include leak amounts based on measurements, frequency of inspection, and other factors related to each specific identification. Piñon maintains a Greenhouse Gas Monitoring Plan to report and quantify all leaks in accordance with 40 CFR Part 98.

***Table 6.1* – Summary of Leak Detection Monitoring**

Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system ("**DCS**") surveillance of facility operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/H_2S and low explosive level ("**LEL**") monitoring network • Personal and hand-held gas monitors
Independence AGI #1 & Independence AGI #2	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests ("**MIT**") • Fixed in-field gas monitors/H_2S and LEL monitoring network • Personal and hand-held gas monitors
Existing Other Operator Active Wells	• Monitoring of well operating parameters • Visual inspections • MITs • Mobile CO_2 detectors
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network • Mobile CO_2 detectors
Confining / Seal System	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network

6.1 Leakage from Surface Equipment

Piñon 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 Piñon using in-field monitors which detect H_2S. 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. Additionally, Piñon field personnel, wearing personal H_2S monitors, follow daily and weekly inspection protocols which include reporting and responding to any detected leakage events.

Piñon's internal operational documents and protocols detail the steps to be taken to verify leaks of H_2S. The following description of the gas detection equipment at the Dark Horse Facility was summarized from the H_2S Contingency Plan:

Fixed Monitors

The Dark Horse Facility has numerous ambient H_2S detectors placed strategically throughout the facility to detect possible leaks. Upon detection of H_2S concentrations of 10 ppm at any detector, visible beacons are activated and an alarm is sounded. Upon detection of H_2S concentrations of 90 ppm at any detector, an evacuation alarm is sounded throughout the Dark Horse Facility at which time all personnel will proceed immediately to a designated evacuation area. The Dark Horse Facility 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 ("**PLC**"), and then to the DCS. The monitors are equipped with amber beacons. The beacon is activated upon detection of H_2S concentrations of 10 ppm. The Dark Horse Facility horns are activated with a continuous warbling alarm upon detection of H_2S concentrations of 10 ppm and a facility-wide siren upon detection of H_2S concentrations of 90 ppm. All monitoring equipment is Rosemount brand. The control panel is a twenty-four (24) channel monitor box, and the fixed point H_2S sensor heads are model number ST320A-100-ASSY.

The Dark Horse Facility will monitor the inlet sour natural gas steam and sweet natural gas stream concentrations of H_2S via H_2S analyzers with sample points located on the north/south-oriented pipe rack (Figure 7.2-1). Concentrations of H_2S in the TAG stream will be sampled near the AGI pumps located on the west side of the Dark Horse Facility. All H_2S analyzers are model T224, manufactured by Analytical Systems KECO.

The monitors can also be viewed on the PLC displays located at the Dark Horse Facility and the locations of ambient H_2S sensors are shown on the plot plan (*see* Figure 3.7-2). Immediate action is required for any alarm occurrence or malfunction. All H_2S sensors are calibrated monthly.

Personal and Handheld H_2S Monitors

All personnel working at the Dark Horse Facility wear personal H_2S monitors, which are required to alarm and vibrate upon detection of H_2S concentrations of 10 ppm. Handheld gas detection monitors are available at strategic locations around the Dark Horse Facility so that facility 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.

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 10.1.5. Furthermore, if CO_2 emissions are detected through any of the surveillance methods described above, Piñon 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.

6.2 Leakage from Existing Wells

6.2.1 Independence AGI Wells

As part of ongoing operations, Piñon continuously monitors and collects flow, pressure, temperature, and gas composition data from each Independence AGI Well. This data is monitored continuously by qualified technicians who follow response and reporting protocols when the monitoring system delivers alerts that data is not within acceptable limits. Mechanical integrity tests (MIT) are performed on each Independence AGI Well annually. Failure of an MIT would indicate a leak in the applicable well and result in immediate action by shutting in the well, assessing the MIT failure, and implementing mitigative steps.

If operating parameter monitoring and MIT failures indicate a CO_2 leak has occurred, Piñon will (a) take actions 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.2.2 West Jal B Deep #001 and West Jal Unit #1 Wells

Piñon will annually employ mobile CO_2 detectors, which may include drone mounted sensors, to monitor for any CO_2 emission at the locations of the West Jal B Deep #001 and West Jal Unit #1 wells. If surface CO_2 leakage is correlated with loss through these wells, Piñon will (a) take actions, including by working with the third party operator of the West Jal B Deep #001 and West Jal Unit #1 wells, to quantify the amount of CO_2 emitted based on the operational conditions that existed at the time of 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.2.3 Wells Completed and Proposed to be Completed in the Wolfcamp, Bone Spring, and Shallower Stratigraphic Units

As discussed in Section 5, it is unlikely that the TAG injected through the Independence AGI Wells into the Siluro-Devonian Injection Zone will migrate upward to these shallower production wells and be emitted to the surface through these wells. Due to the natural presence of H_2S and CO_2 in the production streams of oil and natural gas producers in the AMA, Piñon has been in contact with such producers in the AMA regarding Piñon's core business of sour gas (high in H_2S and CO_2) treatment and sequestration. Piñon will continue to work cooperatively with such producers and immediately investigate, including by use of mobile CO_2 detectors, any CO_2 emissions from wells operated by oil and natural gas producers in the AMA which is suspected to arise from Piñon's operations. If surface CO_2 leakage is correlated with loss through these wells, Piñon will (a) take actions, including by working with the third party operator of the well(s), to quantify the amount of CO_2 emitted based on the operational conditions that existed at the time of 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.3 Leakage from Fractures and Faults

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through a fracture or fault. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone.

Piñon will assess any changes in operating parameters or data which indicates surface leakage of CO_2 along faults or fractures. Piñon will employ mobile CO_2 detectors, which may include drone mounted sensors, to monitor for any emission above mapped fractures and faults. If surface CO_2 leakage is correlated with loss through fractures or faults, Piñon will (a) take actions, including by working with relevant surface owners, to quantify the amount of CO_2 emitted based on the conditions that existed at the time of 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.4 Leakage through the Confining / Seal System

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through the confining / seal system. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.2 and 7.5, will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone.

If changes in operating parameters or data indicate surface leakage of CO_2 through the confining / seal system, Piñon will (a) take actions to quantify the amount of CO_2 emitted based on 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI well(s).

6.5 Leakage due to Natural / Induced Seismicity

Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.2 and 7.5 coupled with a detection of a seismic event by the seismic stations described in Section 7.6 will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone due to a seismic event. After a seismic event, Piñon will assess any changes in operating parameters and data from the surrounding seismic stations which might indicate leakage of CO_2 along faults or fractures activated by the event. If leakage of CO_2 is correlated with a seismic event, Piñon will (a) take actions to quantify the amount of CO_2 emitted based on 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; and (b) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.6 Leakage due to Lateral Migration

Continuous operational monitoring of the Independence 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 Siluro-Devonian Injection Zone. 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 Siluro-Devonian Injection Zone.

If monitoring of operational parameters indicates that the CO_2 plume extends beyond the area modeled in Section 3.9 and presented in Section 4, Piñon will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 release to the surface. If it is determined that the plume intersected a pathway for CO_2 release to the surface, this would be considered a material change per 40 CFR 98.448(d)(1), and Piñon will submit a revised MRV plan as required by 40 CFR 98.448(d).

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

Subpart RR at 40 CFR 448(a)(4) requires a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. Piñon 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 Piñon's strategy for collecting baseline information.

7.1 Visual Inspection

Piñon field personnel conduct daily visual inspections of surface equipment located at the Dark Horse Facility and the Independence AGI Wells. These visual inspections will aid in identifying and timely addressing potential areas of concern to minimize the possibility of H_2S, a proxy for CO_2, leakage. If any leakage is identified during such visual inspections, Piñon field personnel will take prompt corrective actions to address such leakage.

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

Compositional analysis of gas injectate at the Dark Horse Facility indicates an approximate H_2S concentration of 38.7% thus requiring Piñon to develop and maintain an H_2S Contingency Plan according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). Piñon considers H_2S to be a proxy for CO_2 leaks at the Dark Horse Facility. The H_2S Contingency Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the Dark Horse Facility or the associated Independence 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 Dark Horse Facility utilizes numerous fixed-point monitors, strategically located throughout the facility, to detect the presence of H_2S in ambient air (Figure 3.7-2). The diagram in Appendix 10 shows the location of the Ultrasonic inflow meters and the Coriolis meters to the Independence AGI wells. The sensors are connected to the Control Room alarm panel's PLCs, and then to the DCS. Upon detection of H_2S concentrations of 10 ppm at any monitor, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of H_2S concentrations of 90 ppm at any monitor, an evacuation alarm is sounded throughout the Dark Horse Facility 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 Dark Horse Facility so that facility 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 Oxide ("**CO**").

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the Dark Horse Facility 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 upon detection of H_2S concentrations of 10 ppm.

7.3 CO_2 Detection

Any CO_2 release to the surface would be accompanied by H_2S and therefore the H_2S monitors will serve as a CO_2 release warning system both at the facility and in the field. In addition to the fixed and personal monitors described in Section 7, Piñon will establish and operate a monitoring program to detect H_2S leakages within the AMA. The scope of work will include H_2S monitoring at the AGI well site and atmospheric monitoring near identified penetrations of the Siluro-Devonian Injection Zone within the AMA. Upon approval of the MRV Plan and for the five (5) year post-injection period, Piñon will have these monitoring processes and systems in place.

7.4 Continuous Parameter Monitoring

The DCS of the Dark Horse Facility 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

Piñon 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. Piñon's Routine Operations and Maintenance Procedures for the Independence AGI Wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic Monitoring Stations

Piñon owns 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 Dark Horse Facility. The seismic station will meet the requirements of the NMOCC Order to "install, operate, and monitor for the life of this Order a seismic monitoring station or stations. OCD shall be responsible for coordinating with the Manager of the New Mexico Tech Seismological Observatory at the New Mexico Bureau of Geology and Mineral Resources for appropriate specifications for the equipment and the required reporting procedure for the monitoring data."

Additionally, Figure 7-1 shows the location of other seismic monitoring stations in the vicinity of the Independence AGI Wells.

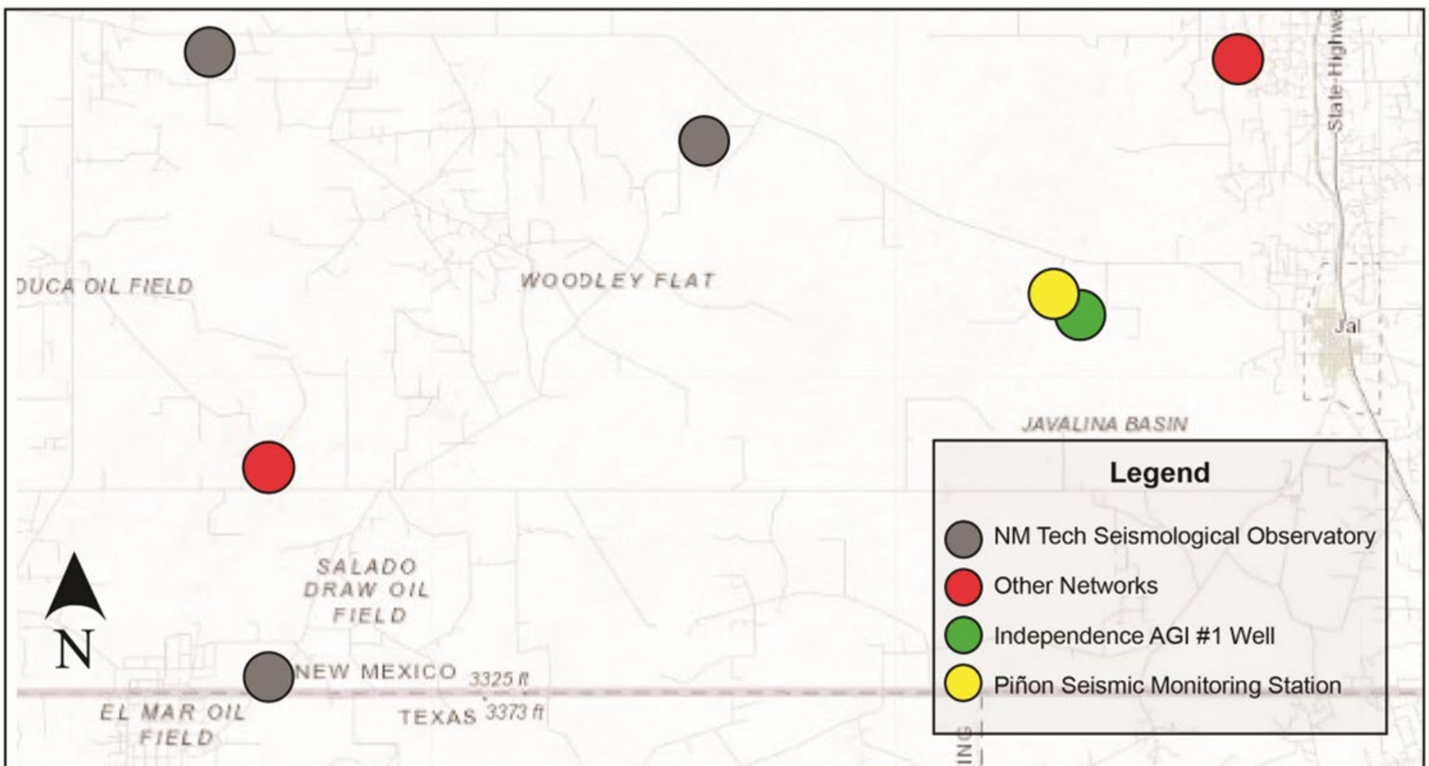


***Figure 7-1**: Location of seismic monitoring stations in the vicinity of the Independence AGI Wells.*

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve (12) Subpart RR equations used to calculate the mass of CO_2 sequestered annually. Appendix 8 includes the twelve (12) equations from Subpart RR. Not all of these equations apply to Piñon's current operations at the Dark Horse Facility but are included in the event Piñon's operations change in such a way that their use is required.

Figure 3.7-2 shows the location receipt meters and injection meters listed in 40 CFR 98.232(d) of Subpart RR that will be used in the calculations set forth below.

8.1 CO_2 Received

Currently, Piñon receives sour natural gas at the Dark Horse Facility through three (3) pipelines: the Hondo High Pressure Sour Gas Pipeline (owned and operated by Piñon), the Franklin Mountain Low Pressure Pipeline (owned and operated by Franklin Mountain Energy) and the Ameredev II Low Pressure Pipeline (owned and operated by Ameredev). Piñon 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. Receipt meters are shown on Figure 3.7-2.

$$CO_{2T,r} = \sum_{p=1}^{4}\left(Q_{r,p} - S_{r,p}\right) * D * C_{CO_{2,p,r}} \qquad \text{(Equation RR-2 for Pipelines)}$$

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.

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \qquad \text{(Equation RR-3 for Pipelines)}$$

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.

Although Piñon does not currently receive CO_2 in containers for injection, they have chosen to include the flexibility in this MRV Plan to do so. If Piñon begins to receive CO_2 in containers, they will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. Piñon will adhere to the requirements in 40 CFR 98.444(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 40 CFR 98.488(d)(1), Piñon will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Piñon injects CO_2 into the existing Independence AGI #1. Upon its completion, Piñon will commence injection of CO_2 into Independence AGI #2. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the Independence AGI Wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the Independence AGI Wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Injection meters are shown on Figure 3.7-2.

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \qquad \text{(Equation RR-5)}$$

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.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \qquad \text{(Equation RR-6)}$$

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.

8.3 CO_2 Produced / Recycled

Piñon does not produce oil or natural gas or any other liquid at the Dark Horse Facility 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 (CO_{2E}) from the leakage pathways identified and evaluated in Section 5. 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.

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

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.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

As required by 98.444(d) of Subpart RR, Piñon 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 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 Piñon does not actively produce oil or natural gas or any other fluid at the Dark Horse Facility, 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

Piñon intends to implement this MRV Plan on June 1, 2023, after it is approved by EPA.

10 GHG Monitoring and Quality Assurance Program

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

10.1 GHG Monitoring

As required by 40 CFR 98.3(g)(5)(i), Piñon'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 greenhouse gas ("**GHG**") calculations; and
- 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 will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association ("**GPA**") standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40 CFR 98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2 and RR-5, of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 15.025 pounds per square inch absolute ("**psia**") (Appendix 6). Piñon utilizes Coriolis metering to measure the dense phase injected TAG stream. Piñon utilizes the following two standards: American Petroleum Institute API 14.1 for measuring barrels and the American Gas Association AGA 7 for million cubic feet ("**MCF**") equivalent calculations.

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 Independence AGI Wells using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.4 CO_2 Produced.

Piñon does not produce CO_2 at the Dark Horse Facility.

10.1.5 CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2.

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

10.1.6 Measurement devices.

As required by 40 CFR 98.444(e), Piñon 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 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute, the AGA, the GPA, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.
- All flow meter calibrations performed are National Institute of Standards and Technology ("**NIST**") traceable.

10.2 QA/QC Procedures

Piñon 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

Piñon will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or using a representative concentration value from the 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

Piñon will revise the MRV Plan as needed to (a) reflect changes in monitoring instrumentation and quality assurance procedures; (b) improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or (c) address additional requirements as directed by the EPA or the State of New Mexico.

11 Records Retention

Piñon will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, Piñon will retain the following documents:

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

(b) 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

(c) The annual GHG reports.

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

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

(f) 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.

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

(h) 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.

(i) 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.

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

(k) 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.

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

12 Appendices

Appendix 1 - Independence AGI Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Independence AGI #1	30-025-48081	SHL 829' FNL, 1,443' FEL BHL of Sidetrack: 1041'FNL, 1785'FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120855 and -103.291021	Lea, NM	12/27/2020	17,750'	16,114'
Independence AGI #2	30-025-49974	SHL 1,180' FNL, 1,578' FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120020 and -103.291015 BHL 1,033' FSL, 2,132' FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.111581 and -103.289273	Lea, NM	07/02/2022	17,683' TVD	16,610'

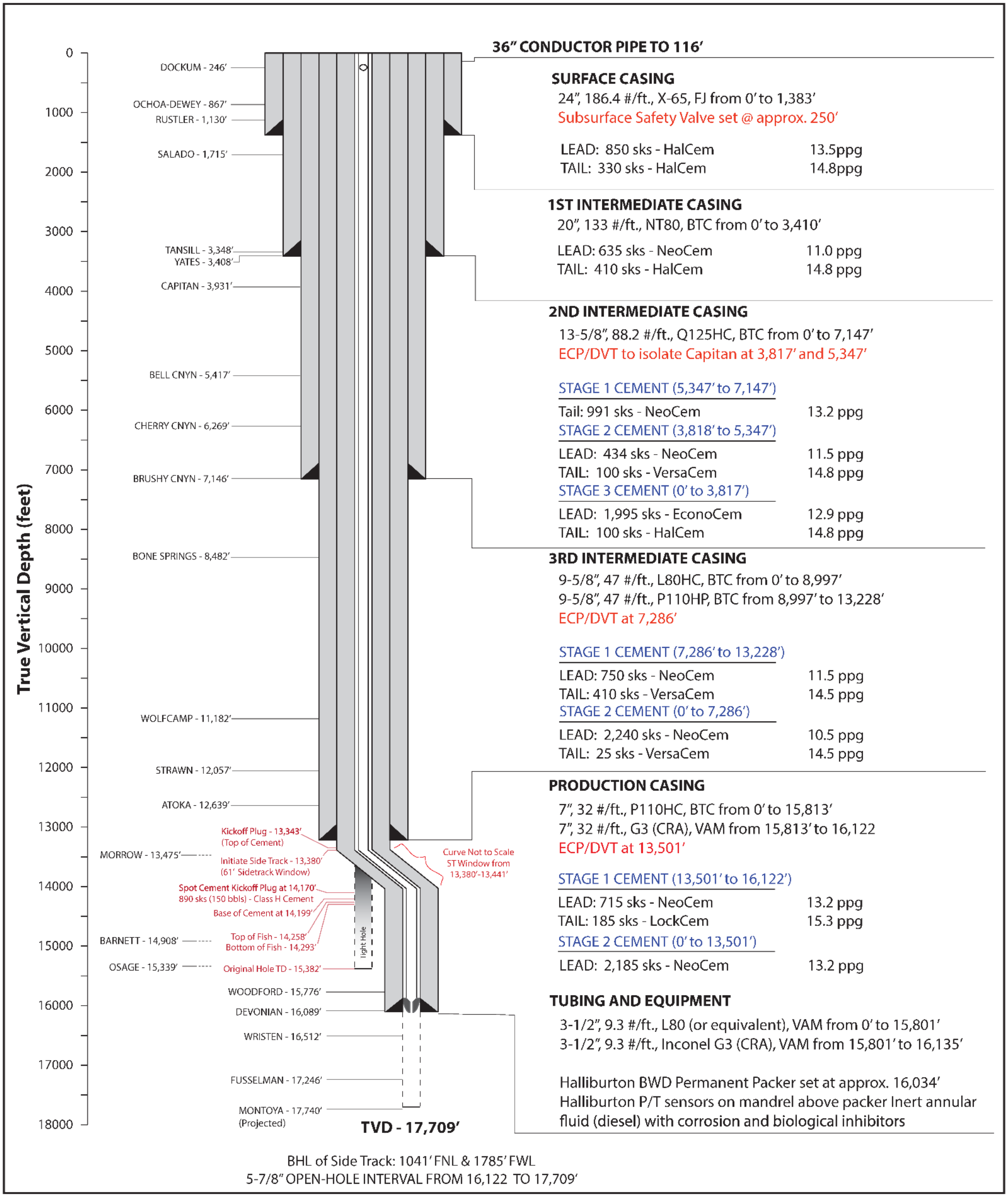


***Figure A1-1**: Independence AGI #1: As-drilled well schematic consisting of a surface string of casing, three (3) intermediate strings , and a production string with associating tubing/equipment and cement types. Original hole and sidetrack are shown. (Taken from End-of-Well Report for Independence AGI #1, Geolex, Inc.)*

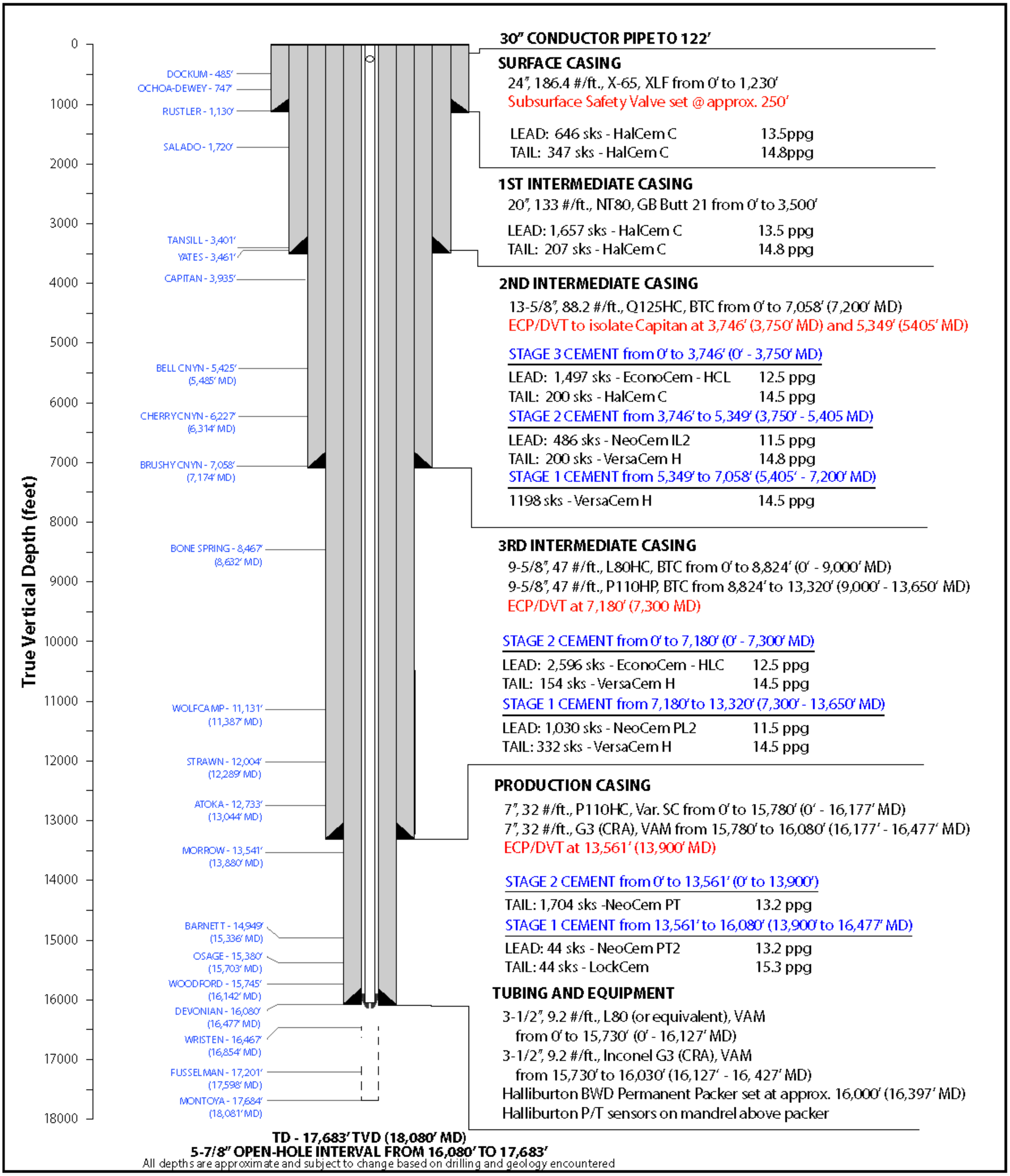


***Figure A1-2**: Independence AGI #2: Well schematic. (Taken from NMOCC Order 3/31/2022)*

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
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
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
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 - Oil and natural gas wells within 2-mile radius of the Independence AGI Wells

The data in the following table was obtained from the NMOCD database and is accurate as of 8/5/2022.

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-09729	PAN AM KELLY 7 FEDER	Oil	Plugged (site released)	JOHN H TRIGG	32.1466	-103.3063		1900	3,540	0	-	1/1/1900	CUSTER, TANSILL
30-025-09778	FEDERAL #1	Oil	Plugged (site released)	EDWARD C. DONAHUE	32.1212	-103.2978	No Data	1900	3,891	0	-	1/1/1900	No Data
30-025-20381	HERKIMER BQF FEDERAL #001H	Oil	Active	AMEREDEV OPERATING, LLC	32.114	-103.2722	H	1963	8,515	10,121	10,100	-	DELAWARE, WEST
30-025-20857	WEST JAL B #001	Brine Injection	New	BC & D OPERATING INC.	32.1285	-103.2850	V	1964	12,275	12,275	6,170	-	WOLFCAMP, WEST; DELAWARE
30-025-21039	WEST JAL 18 #1	Oil	Plugged (site released)	SKELLY OIL CO.	32.1276	-103.3010	No Data	1900	12,950	0	-	1/1/1900	No Data
30-025-21172	WEST JAL UNIT #1	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.1176	-103.2807	V	1961	17,086	17,086	-	4/4/1984	DELAWARE, WEST; JAL, STRAWN, WEST
30-025-21411	C ELLIOTT FEDERAL	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.143	-103.2850	V	1900	12,276	12,276	-	6/26/1993	STRAWN, WEST
30-025-25046	WEST JAL B DEEP #001	Brine Injection	Active	BC & D OPERATING INC.	32.1321	-103.2807	V	1975	18,945	18,945	14,175	-	STRAWN, WEST; WOLFCAMP, WEST; FUSSELMAN, WEST; ST-AT-MISS-DEV-FUS
30-025-26010	SPOTTED TAIL FED. #1	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2978	No Data	1900	3,336	0	-	1/1/1900	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26027	SITTING BULL A #001	Oil	Active	FULFER OIL & CATTLE LLC	32.0886	-103.2936	V	1978	3,368	3,368	-	-	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26336	FEDERAL 13 A #1	OIL	Plugged (site released)	GETTY OIL CO.	32.1367	-103.3138	V	1979	3,686	0	-	-	No Data
30-025-26809	LITTLE HAWK FEDERAL #	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2765	No Data	1900	3,690	0	-	1/1/1900	No Data
30-025-26892	SITTING BULL #2	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.085	-103.2850	No Data	1900	3,746	0	-	1/1/1900	No Data
30-025-33348	TEXACO WEST JAL 21 #001	Oil	Plugged (site released)	ENSERCH EXPLORATION INC.	32.1104	-103.2722	V	1996	7,700	7,700	-	4/25/1996	No Data
30-025-38059	DINWIDDIE STATE COM #001	Gas	Plugged (site released)	COG OPERATING LLC	32.1249	-103.2765	V	2006	12,192	12,192	-	12/12/2008	STRAWN, WEST

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-46393	NANDINA 25 36 31 FEDERAL COM #124H	Oil	New	AMEREDEV OPERATING, LLC	32.1085	-103.3052	H	-	0	23,130	-	-	WOLFCAMP, WEST
30-025-46533	SIOUX 25 36 STATE FEDERAL COM #008H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2019	12,149	22,150	22,117	-	UPPER WOLFCAMP
30-025-46551	SIOUX 25 36 STATE FEDERAL COM #009H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3175	H	2020	11,894	21,945	21,912	-	BONE SPRING
30-025-46553	SIOUX 25 36 STATE FEDERAL COM #012H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3174	H	2020	11,994	22,350	22,319	-	BONE SPRING; UPPER WOLFCAMP
30-025-46554	SIOUX 25 36 STATE FEDERAL COM #013H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2020	11,725	21,962	21,930	-	BONE SPRING; UPPER WOLFCAMP
30-025-46561	SIOUX 25 36 STATE FEDERAL COM #010H	Oil	Active	CAZA OPERATING, LLC	32.1081	-103.3176	H	2020	12,107	22,209	22,175	-	UPPER WOLFCAMP
30-025-46976	BLACK MARLIN FEDERAL COM #204H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3002	H	2020	11,640	21,953	21,895	-	WOLFCAMP, WEST
30-025-46977	BLACK MARLIN FEDERAL COM #214H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3000	H	2020	11,741	22,055	21,994	-	WOLFCAMP, WEST
30-025-48081	INDEPENDENCE AGI #001	AGI	Active	Pinon Midstream, LLC	32.1208	-103.2910	V	2020	17,709	17,900	-	-	DEVONIAN-FUSSELMAN
30-025-48577	SANTA FE FEDERAL COM #603H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3154	H	-	0	21,874	-	-	BONE SPRING
30-025-48578	SANTA FE FEDERAL COM #704H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3212	H	-	0	22,063	-	-	WOLFCAMP, WEST
30-025-48579	SANTA FE FEDERAL COM #705H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3152	H	-	0	22,129	-	-	WOLFCAMP, WEST
30-025-48580	TRINITY FEDERAL #602H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3214	H	-	0	21,938	-	-	BONE SPRING
30-025-48581	TRINITY FEDERAL #703H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3213	H	-	0	22,206	-	-	WOLFCAMP, WEST
30-025-48582	ZIA FEDERAL COM #604H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3151	H	-	0	21,973	-	-	BONE SPRING
30-025-48583	ZIA FEDERAL COM #706H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3150	H	-	0	21,973	-	-	WOLFCAMP, WEST
30-025-48614	BLUE MARLIN STATE #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3102	H	-	0	19,502	-	-	WOLFCAMP, WEST
30-025-48615	BLUE MARLIN STATE #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	-	0	19,350	-	-	WOLFCAMP, WEST
30-025-48778	BLACK MARLIN FEDERAL COM #113H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3007	H	-	0	20,014	-	-	BONE SPRING
30-025-48779	BLACK MARLIN FEDERAL COM #114H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3006	H	-	0	20,056	-	-	BONE SPRING
30-025-48780	BLACK MARLIN FEDERAL COM #203H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3005	H	2021	11,786	21,842	21,879	-	WOLFCAMP, WEST
30-025-48781	BLACK MARLIN FEDERAL COM #206H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3003	H	-	0	21,981	-	-	WOLFCAMP, WEST
30-025-48782	BLACK MARLIN FEDERAL COM #213H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3004	H	2021	0	22,140	22,073	-	WOLFCAMP, WEST
30-025-48783	BLACK MARLIN FEDERAL COM #216H	Oil	New	TAP ROCK OPERATING, LLC	32.1374	-103.2996	H	2021	0	22,258	22,258	-	WOLFCAMP, WEST

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-49115	BLUE MARLIN FEDERAL COM #111H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3105	H	-	0	20,039	0	-	BONE SPRING
30-025-49116	BLUE MARLIN FEDERAL COM #112H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3105	H	-	0	20,217	0	-	BONE SPRING
30-025-49117	BLUE MARLIN FEDERAL COM #201H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3102	H	2021	11,613	21,985	21,923	-	WOLFCAMP, WEST
30-025-49118	BLUE MARLIN FEDERAL COM #202H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	2021	11,539	21,929	21,866	-	WOLFCAMP, WEST
30-025-49119	BLUE MARLIN FEDERAL COM #205H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3101	H	2021	11,533	21,980	21,916	-	WOLFCAMP, WEST
30-025-49120	BLUE MARLIN FEDERAL COM #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3103	H	2021	12,148	22,554	22,495	-	WOLFCAMP, WEST
30-025-49121	BLUE MARLIN FEDERAL COM #215H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3057	H	2021	11,720	22,188	22,120	-	WOLFCAMP, WEST
30-025-49196	BLUE MARLIN FEDERAL COM #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3055	H	2021	12,003	22,422	22,389	-	WOLFCAMP, WEST
30-025-49528	DOGWOOD 25 36 20 FEDERAL COM #112H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2924	H	2021	0	22,356	0	-	WOLFCAMP, WEST
30-025-49626	DOGWOOD 25 36 20 FEDERAL COM #116H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2842	H	-	0	22,080	0	-	WOLFCAMP, WEST
30-025-49974	INDEPENDENCE AGI #002	AGI	New	Pinon Midstream, LLC	32.1201	-103.2910	D	2022	17,683	18,080	0	-	DEVONIAN-FUSSELMAN
30-025-50391	SIOUX 25 36 STATE FEDERAL COM #020H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	22,710	0	-	UPPER WOLFCAMP
30-025-50392	SIOUX 25 36 STATE FEDERAL COM #021H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	20,244	0	-	BONE SPRING
30-025-50393	SIOUX 25 36 STATE FEDERAL COM #022H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	22,539	0	-	UPPER WOLFCAMP
30-025-50394	SIOUX 25 36 STATE FEDERAL COM #023H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	20,120	0	-	BONE SPRING

Appendix 4 - References

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Appendix 5 - Abbreviations and Acronyms

Abbreviations and acronyms not otherwise defined herein:

3D – 3 dimensional
API – American Petroleum Institute
CFR – Code of Federal Regulations
EOS – Equation of State
ft – foot (feet)
m – meter(s)
mg/l – milligrams per liter
MT -- Metric tonne
NG—Natural Gas
QA/QC – quality assurance/quality control
ST – Short Ton

Appendix 6 - Conversion Factors

Piñon reports CO_2 at standard conditions of temperature and pressure as defined in the State of New Mexico - 60°F and 15.025 psia (NMAC 19.15.2.7 (C)(16))

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the NIST. This online database is available at:
http://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner EOS at a wide range of temperatures and pressures. At State of New Mexico standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.0027097 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb-moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2204.62\ lbs}$$

Where:

$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$
$Density_{CO2}\ =\ 0.0027097$
$MW_{CO2}\ =\ 44.0095$

$$Density_{CO2} =\ 5.4092\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.4092\ x\ 10^{-2}\ \frac{MT}{Mcf}$$

The conversion factor 5.4092 x 10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Appendix 7 - Independence 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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \qquad \text{(Equation RR-2 for Pipelines)}$$

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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \qquad \text{(Equation RR-2 for Containers)}$$

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

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \qquad \text{(Equation RR-3 for Pipelines)}$$

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

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \qquad \text{(Equation RR-4)}$$

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

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \qquad \text{(Equation RR-5)}$$

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

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \qquad \text{(Equation RR-6)}$$

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

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

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.

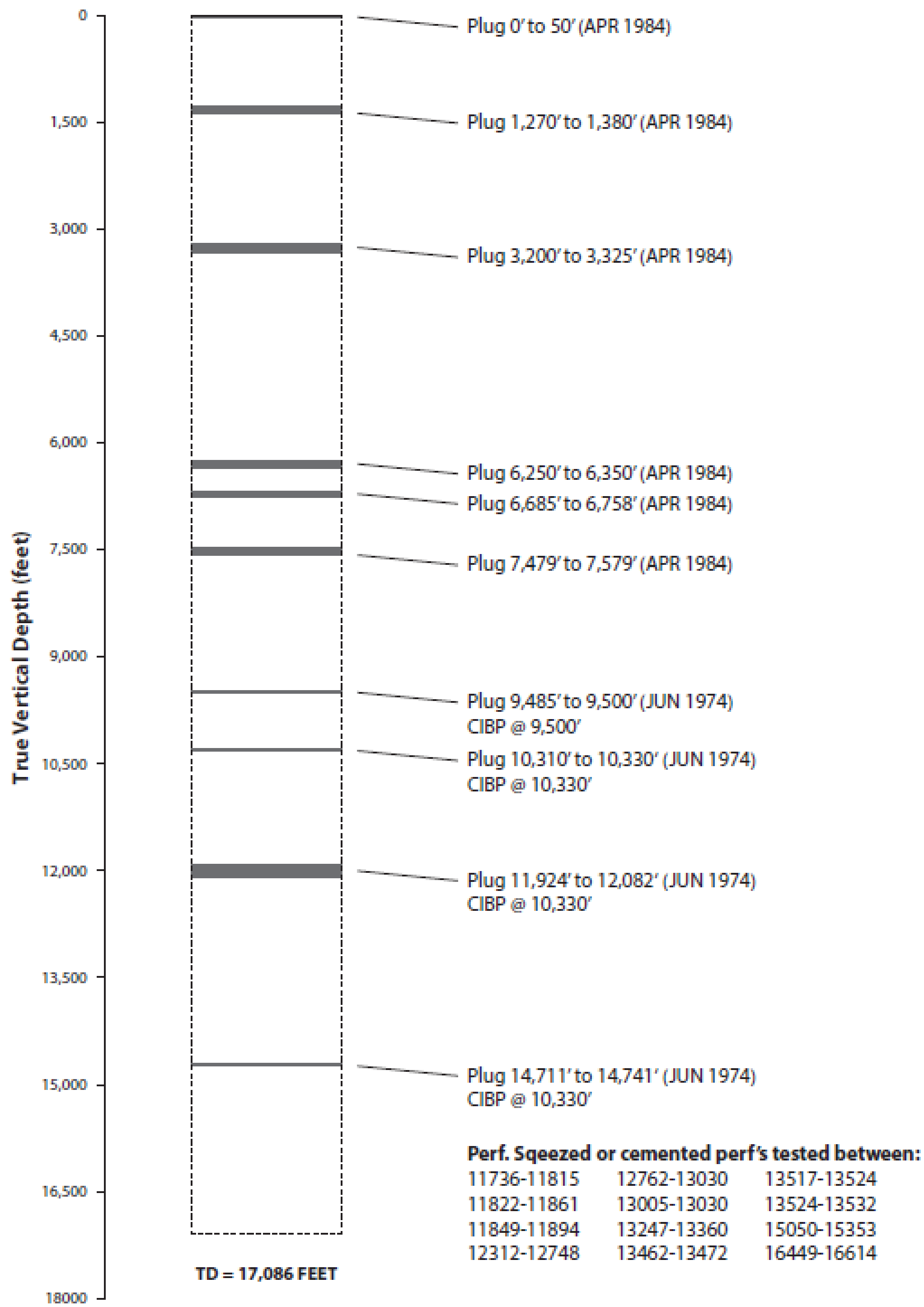
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

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 - Plugging Records for West Jal Unit #1

TEXACO EXPLORATION AND PROD. - WEST JAL UNIT #1 PLUGGING DIAGRAM

Lease Name:	West Jal Unit #1	**Footage:**	1980 FNL and 660 FEL
API:	30-025-21172	**Well Type:**	Oil
Location:	Sec. 20, T25S, R36E	**Total Depth:**	17,086′
County, State:	Lea County, New Mexico	**Coordinates:**	32.117596, -103.280739 (NAD83)



*Schematic is properly scaled

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UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Buluu No. 1004-0135
Expires: March 31, 1993

5. Lease Designation and Serial No.
N

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT-" for such proposals

SUBMIT IN TRIPLICATE

7. If Unit or CA, Agreement Designation

1. Type of Well
[X] Oil Well [ ] Gas Well [X] Other Reentry

8. Well Name and No.
JA-/t:Jt!JLA-fy

2. Name of Operator
MCH Petroleum Services

9. API Well No.
30-025-21112

3. Address and Telephone No.
-:1:)1 W. Pliv St. Midland, Tx 79705 915 683 4772

10. Field and Pool, or Exploratory Area
~~Undesignated~~ W-Jal Delaware

4. Location of Well (footage, Sec., T., R., M., or Survey Description)
1'f4!0 PAt- ,o F=G1- -S Z.0 , r- ZS-S, 11- "L'=
H S£NE 6J•,)1 h\.

11. County or Parish, State
Lea, NM

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

TYPE OF SUBMISSION	TYPE OF ACTION	
[X] Notice of Intent	[ ] Abandonment	[ ] Change of Plans
	Recompletion	[ ] New Construction
[ ] Subsequent Report	[ ] Plugging Back	[ ] Non-Routine Fracturing
	[ ] Casing Repair	[ ] Water Shut-Off
[ ] Final Abandonment Notice	[ ] Altering Casing	[ ] Conversion to Injection
	Other eNEAy	[ ] Dispose Water
		(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abandoned by Texaco in 1983. MCH will drill out cement plugs and cibp@ 7,579' to a total depth of approx. 8,350'(inside casing). This will leave in place cibp at 9,500' and deeper. We will then test existing perforations@ 7,807'-7,857' and stimulate as necessary.
Mud Program: Fresh water will be used for the reentry inside casing.
BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO
GENERAL REQUIREMENTS AND
SPECIAL STIPULATIONS
ATTACHED

14. I hereby certify that the foregoing is true and correct
Signed Craig Huber Title Owner Date 4/13/93

(This space for Federal or State office use)
Approved by: 1ITC &r.n L MAron; Title AREA MANAG. Date JUN 4 1993
Conditions of approval, if any:

Title 18 U.S.C. Section 1001, makes 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.

*See Instruction on Reverse Side

Form 3160-3
(December 1990)

SUBMIT IN TRI[illegible]TE*
(Other instructions o.. reverse side)

Form approved.
Budget Bureau No. 1004-0136
Expires: December 31, 1991

G 31

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR DEEPEN

5. LEASE DESIGNATION AND SERIAL NO.: NM 71792

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

1a. TYPE OF WORK: DRILL ☐ DEEPEN ☐

b. TYPE OF WELL: OIL WELL ☒ GAS WELL ☐ OTHER Reentry SINGLE ZONE ☒ MULTIPLE ZONE ☐

7. UNIT AGREEMENT NAME:

8. FARM OR LEASE NAME, WELL NO.: West JAL Federal #1

2. NAME OF OPERATOR: MCH Petroleum Services

9. API WELL NO.: 30-025-21172

3. ADDRESS AND TELEPHONE NO.: 708 W. Pine St. Midland, Tx 79705 915 683 4772

10. FIELD AND POOL, OR WILDCAT: ~~[illegible]~~ W. JAL Delaware

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*)
At surface 1980' FNL, 660' FEL sec 20 T-25S, R-36E Lea Co. NM
At proposed prod. zone SAme H SE NE

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: S-20, T-25S, R36E

14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE*: 6 miles W. JAL, N.M.

12. COUNTY OR PARISH: Lea | 13. STATE: NM

15. DISTANCE FROM PROPOSED* LOCATION TO NEAREST PROPERTY OR LEASE LINE, FT. (Also to nearest drlg. unit line, if any): 660'

16. NO. OF ACRES IN LEASE: 600

17. NO. OF ACRES ASSIGNED TO THIS WELL: 40

18. DISTANCE FROM PROPOSED LOCATION* TO NEAREST WELL, DRILLING, COMPLETED, OR APPLIED FOR, ON THIS LEASE, FT.:

19. PROPOSED DEPTH: 8350

20. ROTARY OR CABLE TOOLS: Pulling unit / Reverse unit

21. ELEVATIONS (Show whether DF, RT, GR, etc.): 3076' GL

22. APPROX. DATE WORK WILL START*: ASAP (Prior to 6/1/93 exp.)

23. PROPOSED CASING AND CEMENTING PROGRAM

SIZE OF HOLE	GRADE, SIZE OF CASING	WEIGHT PER FOOT	SETTING DEPTH	QUANTITY OF CEMENT
26	20		869' (In Place)	1630 sx.
17 1/2	13 3/8	72, 68, 64	6300' (In Place)	3606 sx.
12 1/4	9 5/8	53.5, 47, 43.5	11,736 (In Place)	775 sx.
8 3/8	7	26	6735-12213 (Shot off @ 6735)	612 sx
6 1/4	5 1/2 (LNR.)	(unk.)	12,032-15,400	450 sx.
(unk)	3 1/2 (LNR.)	(unk)	14,967-17,084	250 sx.

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abondoned by Texaco in 1983. MCH will drill out cement plugs and cibp @ 7,579' to a total depth of approx. 8,350' (inside casing). This will leave in place cibp at 9,500' and deeper. We will then test existing perforations @ 7,807'-7,857' and stimulate as necessary.

Mud Program: Fresh water will be used for the reentry inside casing.

BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO GENERAL REQUIREMENTS AND SPECIAL STIPULATIONS ATTACHED

IN ABOVE SPACE DESCRIBE PROPOSED PROGRAM: If proposal is to deepen, give data on present productive zone and proposed new productive zone. If proposal is to drill or deepen directionally, give pertinent data on subsurface locations and measured and true vertical depths. Give blowout preventer program, if any.

24.
SIGNED Craig Huben TITLE Owner DATE 4/13/93

(This space for Federal or State office use)

PERMIT NO. ______ APPROVAL DATE ______

Application approval 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.
CONDITIONS OF APPROVAL, IF ANY:

APPROVED BY ______ TITLE ______ DATE ______

*See Instructions On Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

Form 3160-5
(November 1983)
(Formerly 9-331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

P.O. BOX 1980
HOBBS, NEW MEXICO 88240

Form approved.
Budget Bureau No. 1004-0135
Expires August 31, 1985

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

1. OIL WELL [X] GAS WELL [ ] OTHER

7. UNIT AGREEMENT NAME
West Jal Unit

2. NAME OF OPERATOR
Getty Oil Company

8. FARM OR LEASE NAME

3. ADDRESS OF OPERATOR
P.O. Box 730, Hobbs, NM 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

Unit Ltr. H, 1980' FNL & 660' FEL

10. FIELD AND POOL, OR WILDCAT
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, T-25S, R-36E

BUREAU OF LAND MANAGEMENT
APR ...
DIST. 6 N. M.
ROSWELL, NEW MEXICO

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138' D.F.

12. COUNTY OR PARISH
Lea

13. STATE
NM

16. **Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data**

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	[ ]	PULL OR ALTER CASING	[ ]	WATER SHUT-OFF	[ ]	REPAIRING WELL	[ ]
FRACTURE TREAT	[ ]	MULTIPLE COMPLETE	[ ]	FRACTURE TREATMENT	[ ]	ALTERING CASING	[ ]
SHOOT OR ACIDIZE	[ ]	ABANDON*	[ ]	SHOOTING OR ACIDIZING	[ ]	ABANDONMENT*	[XX]
REPAIR WELL	[ ]	CHANGE PLANS	[ ]	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

3/26/84 Rigged up. Pulled rods and pump. Unseat tbg. anchor and install BOP.
3/28/84 Pulled 2 7/8" buttress & 2 3/8" tbg. anchor. Ran 7" CI plug, set @ 7579'. Ran 2 3/8" to 4290'. By Halliburton, circ. 191 bbls. gel brine, pulled tbg. Perfs 4-0.25" holes @ 6400'. Circ. out 7" between 9 5/8". Ran 2 7/8" to 7554'.
3/29/84 Rigged up csg. puller unit. Pulled tbg. Remove BOP & 7" tbg. spool.
3/30/84 Weld 7" pull nipple. Cut 7" csg. @ 6735'. Pulled 11 jts 7", 26#, P-110 csg. 8 rd.
3/31/84 Layed down total 163 jts (est. 6525') 7", 8rd casing. Nipple down 9 5/8" head.
4/2/84 Weld on 9 5/8" pulled nipple. Attempted to pull slips with 500,000#. Set off primer cord around head, no movement. Left soaking in penetrating oil.
4/3/84 Dug out 13 3/8" csg. unflange head. Move pipe 1" with 600,000#. Cut off. Pulled nipple, installed BOP. Ran tbg to 5216'.
4/4/84 Spot 20 sxs cement on top of CIBP 7579-7479'. Spot 100' plug (45 sxs) at 6758-6685', 6350-6250', 3325-3200', 1380-1270'. Remove csg. head.
4/5/84 Rigged down. Installed 20 sxs. Plugged 0-50'. Installed dry hole marker. P&A.

18. I hereby certify that the foregoing is true and correct

SIGNED Donald J. Steinmerd TITLE Area Superintendent DATE April 11, 1984

for Dale R. Crockett

(This space for Federal or State office use)

Orig. Sgd. ...

APPROVED BY ... TITLE ... DATE 6 8 8 7

CONDITIONS OF APPROVAL, IF ANY:

0+6-BLM-Roswell 1-Mr. J.A.-Midland
1-File 1-Laura Richardson-Midland
1-Engr Jim 1-BB, 1-JA
1-Foreman CK 1-SH, 1-CP 1-Southland Royalty Company, 1-ARCO

Approved as to plugging ... well bore. Liability under bond is retained until surface restoration is completed.

*See Instructions on Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

N. M. OIL CONS. COMMISSION
P. O. BOX 1980
HOBBS, NEW MEXICO 88240

O+6 - BLM - P.O. Box 1857, Roswell, 1-File, 1-Engr.JIM, 1-Foreman CK

Form 9-331
Dec. 1973

1 - Laura Richardson-Midland

Form Approved.
Budget Bureau No. 42-R1424

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

BUREAU OF LAND MANAGEMENT
RECEIVED
JUL 25 1983
DIST. 6 N. M.
ROSWELL, NEW MEXICO

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 Form 9-331-C for such proposals.)

1. oil well XX gas well ☐ other

2. NAME OF OPERATOR
Getty Oil Company

3. ADDRESS OF OPERATOR
P.O. Box 730 Hobbs, NM 88240

4. LOCATION OF WELL (REPORT LOCATION CLEARLY. See space 17 below.)
AT SURFACE: Unit ltr. H, 1980' FNL & 660 FEL
AT TOP PROD. INTERVAL:
AT TOTAL DEPTH:

5. LEASE
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME
West Jal Unit

9. WELL NO.
1

10. FIELD OR WILDCAT NAME
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, 25S-36E

12. COUNTY OR PARISH
Lea

13. STATE
NM

14. API NO.

15. ELEVATIONS (SHOW DF, KDB, AND WD)
3138' D.F.

16. CHECK APPROPRIATE BOX TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

	REQUEST FOR APPROVAL TO:	SUBSEQUENT REPORT OF:
TEST WATER SHUT-OFF	☐	☐
FRACTURE TREAT	☐	☐
SHOOT OR ACIDIZE	☐	☐
REPAIR WELL	☐	☐
PULL OR ALTER CASING	☐	☐
MULTIPLE COMPLETE	☐	☐
CHANGE ZONES	☐	☐
ABANDON*	XX	☐
(other) Revised		

(NOTE: Report results of multiple completion or zone change on Form 9-330.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

Revised procedure as per conversation with Mr. Peter Chester 7/18/83:

1. Install B.O.P.
2. Set C.I.B.P. at +7860 w/35' cement on top.
3. Perforate 2 holes @ 6375' & squeeze with sufficient cement to bring cement to 6225'.
4. Set cement plug 1230-1330' top of salt. (in + behind casings).
5. Set 50' surface plug.
6. Install dry hole marker.
7. Restore location.

Subsurface Safety Valve: Manu. and Type ____ Set @ ____ Ft.

18. I hereby certify that the foregoing is true and correct

SIGNED Dale R. Crockett TITLE Area Superintendent DATE July 22, 1983

(This space for Federal or State office use)

APPROVED

APPROVED BY (Orig. Sgd.) ... M. CHESTER TITLE ____ DATE ____
CONDITIONS OF APPROVAL, IF ANY:

SEP 14 1983

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG *

5. LEASE DESIGNATION AND SERIAL NO.: NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: - - - - - -

1a. TYPE OF WELL: OIL WELL [X] GAS WELL [ ] DRY [ ] Other

7. UNIT AGREEMENT NAME: - - - - - -

b. TYPE OF COMPLETION: NEW WELL [ ] WORK OVER [ ] DEEP-EN [ ] PLUG BACK [X] DIFF. RESVR. [X] Other

8. FARM OR LEASE NAME: West Jal Unit

2. NAME OF OPERATOR: Shelly Oil Company

9. WELL NO.: 1

3. ADDRESS OF OPERATOR: P. O. Box 1351, Midland, Texas 79701

10. FIELD AND POOL, OR WILDCAT: UNDESIGNATED Jal Delaware, West

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface: Unit Letter H, 1980' FNL and 660' FEL, Sec. 20-25S-36E
At top prod. interval reported below
At total depth

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec. 20-25S-36E

14. PERMIT NO. | DATE ISSUED

12. COUNTY OR PARISH: Lea | 13. STATE: New Mexico

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
- -	- -	5-28-74	3138' DF	- - -

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
17086'	9485' PBTD	- -	→	- -	- -

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*: 7807-7857' Delaware

25. WAS DIRECTIONAL SURVEY MADE: - - -

26. TYPE ELECTRIC AND OTHER LOGS RUN: None

27. WAS WELL CORED: - -

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
No Change					

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
-	-	-	-	-
-	-	-	-	-

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-3/8"OD	7941'	- -
2-7/8"OD		- -

31. PERFORATION RECORD (Interval, size and number): 7807-7811', 7816-7824', 7853-7857', total 32 shots, 0.50" diameter, two shots per foot.

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
7807-7857'	750 gallons mud acid 5000 gallons 15% NE acid, 82 ball sealers, 9000# 20-40 sand, 9000 gallons lease oil

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
5-28-74	Pumping	Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
6-19-74	24	-	→	63	1	6	16

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
- -	63#	→	63	1	6	41°

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.): Used for Fuel

TEST WITNESSED BY

35. LIST OF ATTACHMENTS: None

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED (Signed) D. R. Crow D. R. Crow TITLE Lead Clerk DATE 6-20-74

*(See Instructions and Spaces for Additional Data on Reverse Side)

INSTRUCTIONS

General: This form is designed for submitting a complete and correct well completion report and log on all types of lands and leases to either a Federal agency or a State agency, or both, pursuant to applicable Federal and/or State laws and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local, area, or regional procedures and practices, either are shown below or will be issued by, or may be obtained from, the local Federal and/or State office. See instructions on items 22 and 24, and 33, below regarding separate reports for separate completions.

If not filed prior to the time this summary record is submitted, copies of all currently available logs (drillers, geologists, sample and core analysis, all types electric, etc.), formation and pressure tests, and directional surveys, should be attached hereto, to the extent required by applicable Federal and/or State laws and regulations. All attachments should be listed on this form, see item 35.

Item 4: If there are no applicable State requirements, locations on Federal or Indian land should be described in accordance with Federal requirements. Consult local State or Federal office for specific instructions.

Item 18: Indicate which elevation is used as reference (where not otherwise shown) for depth measurements given in other spaces on this form and in any attachments.

Items 22 and 24: If this well is completed for separate production from more than one interval zone (multiple completion), so state in item 22, and in item 24 show the producing interval, or intervals, top(s), bottom(s) and name(s) (if any) for only the interval reported in item 33. Submit a separate report (page) on this form, adequately identified, for each additional interval to be separately produced, showing the additional data pertinent to such interval.

Item 29: "*Sacks Cement*": Attached supplemental records for this well should show the details of any multiple stage cementing and the location of the cementing tool.

Item 33: Submit a separate completion report on this form for each interval to be separately produced. (See instruction for items 22 and 24 above.)

37. SUMMARY OF POROUS ZONES:
SHOW ALL IMPORTANT ZONES OF POROSITY AND CONTENTS THEREOF; CORED INTERVALS; AND ALL DRILL-STEM TESTS, INCLUDING DEPTH INTERVAL TESTED, CUSHION USED, TIME TOOL OPEN, FLOWING AND SHUT-IN PRESSURES, AND RECOVERIES

FORMATION	TOP	BOTTOM	DESCRIPTION, CONTENTS, ETC.

38. GEOLOGIC MARKERS

NAME	TOP	
	MEAS. DEPTH	TRUE VERT. DEPTH

1) Squeezed Fusselman perfs. 16,449-16,614' with 100 sacks Class "H" cement, 5/10% CFR-2.
2) Spotted 25 sacks cement 14,711-14,741', 25 sacks 11,924-12,082' and set cast iron bridge plug at 10,330' and spotted 4 sacks cement 10,310-10,330'.
3) Perforated 7" OD casing in First Bone Springs formation with two 0.48 diameter holes per foot at 10,112-10,122' and 10,128-10,132'. (28 shots total)
4) Treated First Bone Springs perfs. 10,112-10,132 with 5500 gallons acid and 68 ball sealers.
5) Swab tested First Bone Springs perfs. 10,112-10,132' May 14, 1974, to May 21, 1974, for no oil, 14 bbls. water and slight show of gas in 5 hours.
6) Set cast iron bridge plug at 9500' and cemented with 3 sacks cement plugging back to 9485'.
7) Perforated 7" OD casing in Delaware formation with two 0.50" diameter holes per foot at 7807-7811', 7816-7824' and 7853-7857'. (32 shots total)
8) Treated Delaware perfs. 7807-7857' with 750 gallons mud acid, 5000 gallons 15% NE acid, 9000 gallons gelled lease oil, 9000# 20-40 sand and 22 ball sealers.
9) Returned well to production status 5-28-74 pumping Delaware perfs. 7807-7857' for 63 bbls. oil, 6 bbls. water and 1 MCFGPD.

U.S. GOVERNMENT PRINTING OFFICE: 1963—O-683636

8) Flowed 24-1/2 hours through 1" choke, making no oil, 45 bbls. load water, 393 bbls. formation water and gas at rate of 266 MCF per day. FTP 200#, CP 2300#.
9) Ran flow meter, Gradionometer and Temperature Survey to determine water entry.
10) Shut well in seven hours, then ran Base Temperature Log 16,000-17,020'. Water channelling from bottom of well bore to 16,508'.
11) Set cement retainer at 16,250' and squeezed perfs. 16,499-16,614' with 150 sacks Class "H" cement containing 4/10ths of 1% CFR-2 and 1% Halad 9. Squeeze failed. WOC 4 hours.
12) Resqueezed perfs. 16,449-16,614' with 50 sacks Class "H" cement with 1% Halad 9, 4/10ths of 1% CFR-2 and 1/4# Flocele per sack and 150 sacks Class "H" containing 1% Halad 9 and 4/10ths of 1% CFR-2. Squeeze failed.
13) Attempted to pull cement retainer - stuck.
14) Milled and pushed cement retainer from 16,250' to 16,490'. Recovered cement retainer.
15) Drilled and pushed junk to 16,930'.
16) Ran 254 jts. (14,793') of 2-7/8" OD tubing and set packer at 14,810'. Swabbed 9 hours, recovering 60 bbls. load water with good show of gas.
17) Treated perfs. 16,449-16,614' with 500 gals. 15% NE acid with 2 ball sealers. Swabbed 7 hours, recovering 1 bbl. load water, flowing gas at rate of 50 MCF per day.
18) Treated perfs. 16,449-16,614' with 5000 gals. 15% NE acid and 27 ball sealers.
19) Ran Temperature Survey 15,000-16,958'.
20) Tested well. Well flowed at rate of 910 MCF per day on 23/64" choke, no oil, FTP 310#. Pulled tubing and packer.
21) Reran 457 jts. (14,940') of 2-7/8" OD 7.9# DSS-HT Atlas-Bradford Condition "A" tubing and set at 14,967'.
22) Circulated hole with corrosion inhibitor water. Released rig 11-8-72. Flowed and tested well.
23) On Dec. 11, 1972, treated perfs 16,449-16,614' with 12,500 gals. of 1% KCL water with 62# friction reducer, 25 gals. Adofoam and 25 gals. scale inhibitor, 20,000 gals. 20% retarded acid with 100# friction reducer, 40 gals. Adofoam, 160 gals. acid inhibitor, 1000# fluid loss agent and 40 gals. scale inhibitor and 7 ball sealers. All fluid contained 400 S.C.F Nitrogen per barrel.
24) Testing well.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
—

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
—

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 1351, Midland, TExas 79701

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Undesignated Fusselman

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3076' GR

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Clean out & deepen to 17,086'	x		
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

1) Rigged up rotary tools 7-28-72. Pulled tubing and packer.
2) Set cement retainer at 11,390' and squeezed Strawn 7" OD casing perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 1% CFR-2 and 3# sand per sack. Squeeze failed. WOC 4 hours.
3) Resqueezed perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 5/10% of 1% CFR-2 and 3# sand per sack. Squeezed at 6500#. Reversed out 15 sacks.
4) After WOC 12 hours, drilled cement retainer at 11,390' and cement 11,390-11,755' with 6-1/2" bit.
5) Tested squeeze job to 3000#; held okay.
6) Drilled cement 11,790-11,832' and tested old squeeze job on perfs. 11,736-11,815' to 3000#; held okay.
7) Drilled cement 11,832-11,844'; pushed plus-plug to 11,976'. Drilled plug. Tagged junk at 12,002' and pushed to 12,312'.
8) Cleaned to top of 5-1/2" OD liner at 12,032', set cement retainer at 11,820' and found casing perfs. 11,849-11,894' open.
9) Squeezed 5-1/2" casing perfs. 11,849-11,894' with 50 sacks Class "H" with 1% CFR-2 and 100 sacks Class "H" with 1% CFR-2 and 3# sand per sack.
10) Dumped 20 sacks cement on retainer at 11,820', plugging back to 11,717'. Reversed out 90 sacks cement. WOC 12 hours.

(continued on page 2)

18. I hereby certify that the foregoing is true and correct

SIGNED ______ TITLE Lead Clerk DATE Dec. 18, 1972

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______
CONDITIONS OF APPROVAL, IF ANY:

ACCEPTED FOR RECORD
DEC 20 1972
U. S. GEOLOGICAL SURVEY
HOBBS, NEW MEXICO

*See Instructions on Reverse Side

West Jal Unit
Well No. 1
Lea Co., New Mexico
Page 2

11) Drilled cement 11,708-11,820'; cement retainer 11,820-11,822' and cement 11,822-11,861'. Cleaned out to top of liner at 12,032'.
12) Tested squeeze job to 2500#; held okay.
13) Drilled junk 12,312-12,748.5'; cement 12,748.5-12,760'; junk to 12,762'; cement 12,762-13,030'.
14) Tested old squeezed perfs. 13,005-13,030' to 2500#; held okay.
15) Milled and drilled cast iron bridge plug at 13,174' and pushed to 13,395'.
16) Tested 5-1/2" OD liner perfs. 13,247-13,360' to 2900#; could not pump into perfs.
17) Milled cast iron bridge plug 13,396-13,400'.
18) Tested perfs. 13,462-13,472' to 2700#; could not pump into perfs.
19) Milled and drilled out cement retainer 13,517-13,524'; cement 13,524-13,532'; cement 15,050-15,353'.
20) Milled and drilled cast iron bridge plug 15,340-15,858'. Washed over fish 15,858'; recovered fish. Cleaned out to old TD of 15,958'.
21) Drilled 4-3/4" new hole 15,958-16,498'.
22) Ran Drill Stem Test No. 1 (Silurian) 15,400-16,498'.
23) Drilled 4-3/4" hole 16,498' to total depth of 17,086' at 11 p.m. October 4, 1972.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instruction on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429 - A

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—" for such proposals.)

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- - -

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
- - -

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Section 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3102' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Cement, perforate & treat			☒
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

1) Perforated 2-7/8"OD tubing at 11,696',11,297', 10,374; 9698'; 8892';8707',8403'. Circulated to remove mud from annulus. Work began 1-29-69.
2) Pulled tubing
3) Ran 2-7/8"OD tubing with "RTTS" Packer. Set packer at 11,648'.
4) Squeezed 7"OD casing perforations 11,736-11,894' with 150 sacks class "H" Cement with 1% CFR-2 per sack, maximum pressure 4600#, failed. W.O.C. 4 hours. Broke formation down with 5000#.
5) Squeezed 7"OD casing perforations 11,736-11,894" with 50 sacks Class "H" cement with 1% CFR-2 and 5# No. 3 sand per sack. Displaced 35 sacks into formation. Pulled tubing and packer.
6) WOC 36 hours. Ran tubing with 6-1/8" bit. Top of cement inside 7"OD casing at 11,595'. Washed and circulated cement to 11,620'. Drilled cement 11,620-11,700'. Drilled packer 11,700-705'. Drilled cement 11,705-755'.
7) Tested casing to 3000#, held okay.
8) Spotted 12 bbls. acid 11,755-11,443'.
9) Perforated 7"OD casing with 2 shots per foot as follows:

11,510 - 513'	3'	6 shots
11,517- 527'	10'	20 shots
11,536 - 540'	4'	8 shots
11,550 - 556'	6'	12 shots
11,561 - 567'	6'	12 shots
11,575 - 579'	4'	8 shots
11,660 - 667'	7'	14 shots

18. I hereby certify that the foregoing is true and correct

SIGNED ______________ TITLE District Production Manager DATE 3-10-69

(This space for Federal or State office use)

APPROVED BY ______________ TITLE (ORIGINAL SIGNED) V. H. Fletcher
CONDITIONS OF APPROVAL, IF ANY:

APPROVED

MAR 11 1969

J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
~~73503~~ NM-0342911

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
----

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface **1980 from North line and 660 from East line, Section 20**

20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3092' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other)			☐
(Other) **Cement, Perforate & Treat**			☒	(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)			

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

Squeeze present perforated interval 11,736-11,852', below packer set at 11,700', with 125 sacks cement. Drill out to 11,790'. Perforate 11,510-11,783' with 2 shots per foot. Treat perforations 11,510-11,783' with 300 gallons 15% acid with 3 stage treatment using Dowell J-182 as diverting agent. Inject 72 barrels distillate to remove diverting agent. Swab and test.

18. I hereby certify that the foregoing is true and correct

SIGNED (signed) C. R. DAVIS TITLE **District Operations Manager** DATE **1/24/69**

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______

CONDITIONS OF APPROVAL, IF ANY:

APPROVED

JAN 2. 1969

J. L. GORDON
ACTING DISTRICT ENGINEER

KT/jc

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- -

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
- -

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' from North line and 660' from East line

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.
- -

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138'

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Eliminate water production			☒
(Other)			☐				

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

(1) Moved in and rigged up workover rig 10-21-68
(2) Set Schlumberger "plus" plug in 7"OD casing at 11,844'.
(3) Dumped 5' cement on top of plug, filling from 11,844' to 11,839'.
(4) Dumped 200 lbs. Hydromite on top of "plus" plug, filling back to 11,832'.
(5) Swabbed well.
(6) Apparent communications still exist between upper and lower perforations behind 7"OD casing. Objective to shut off lower perforations 11,860 - 11,894' and to decrease water production unsuccessful.
(7) Well returned to producing status 10-27-68 flowing 150 MCF gas per day through 7" OD casing perforations 11,736 - 11,894'.

18. I hereby certify that the foregoing is true and correct

SIGNED [signature] TITLE District Production Manager DATE 10-30-68

(This space for Federal or State office use)

APPROVED BY ________ TITLE ________ DATE

CONDITIONS OF APPROVAL, IF ANY:

APPROVED
NOV 1968
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

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—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO.: NM - 03429 - A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: -----

1. OIL WELL ☐ GAS WELL XX OTHER

7. UNIT AGREEMENT NAME: -----

2. NAME OF OPERATOR: SKELLY OIL COMPANY

8. FARM OR LEASE NAME: West Jal Unit

3. ADDRESS OF OPERATOR: P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.: 1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL & 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT: Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: Sec. 20-25S-36E

14. PERMIT NO.: -----

15. ELEVATIONS (Show whether DF, RT, GR, etc.): 3138' DF

12. COUNTY OR PARISH: Lea

13. STATE: New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Clean, Determine Water Source, Eliminate Water Production			X
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

Moved in and rigged up Workover Rig. Killed well. Ran 1-5/8" drill pipe and fishing tools to top of fish at 9901', pushed to 9991', caught fish, circulated and pulled out of hole. Recovered 2 strings of fishing tools previously left in hole. Reran 1-5/8" drill pipe several times with fishing tools and recovered 1786' in several pieces of 5/16" wire line, and a chemical cutter.

Tagged bottom of 2-7/8"OD tubing at 11,715'. Knocked off one foot of tubing and a bull plug that had been previously cut off. Pushed and drove bull plug to 12,482'. Hit firm fill-up of formation cavings and left one-foot piece of 2-7/8"OD tubing and bull plug in hole at 12,482', leaving tubing open-ended at 11,715' with full 2-7/8" opening. Pulled drill pipe and fishing tools and installed Xmas tree. Ran Gradiomanometer, Continuous Flowmeter and Packer Flowmeter to determine water source. Surveys indicated water source being produced through casing perforations 11,883-11,894'.

Set packer at 11,883'. Returned to production status November 19, 1967, producing 38 bbls. oil, 800 bbls. water and 2,000 MCF gas per day from the Strawn Gas Pool through perforations 11736-11894' through 7"OD casing.

18. I hereby certify that the foregoing is true and correct

SIGNED (ORIGINAL SIGNED) V. E. Fletcher TITLE District Superintendent DATE April 25, 1968

(This space for Federal or State office use)

APPROVED BY ____ TITLE ____ DATE ____
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
APR 26 1968
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE*
(See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. LEASE DESIGNATION AND SERIAL NO. NM-03429-A
6. IF INDIAN, ALLOTTEE OR TRIBE NAME ---------
7. UNIT AGREEMENT NAME ---------
8. FARM OR LEASE NAME West Jal Unit
9. WELL NO. 1
10. FIELD AND POOL, OR WILDCAT Undesignated Fusselman
11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA Sec. 20-25S-36E
12. COUNTY OR PARISH Lea
13. STATE New Mexico

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL ☒ DRY ☐ Other
b. TYPE OF COMPLETION: NEW WELL ☐ WORK OVER ☒ DEEP-EN ☒ PLUG BACK ☐ DIFF. RESVR. ☒ Other

2. NAME OF OPERATOR
Skelly Oil Company

3. ADDRESS OF OPERATOR
P. O. Box 1351, Midland, Texas 79701

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface 1980' FNL and 660' FEL Sec. 20-25S-36E
At top prod. interval reported below
At total depth

14. PERMIT NO. | DATE ISSUED

15. DATE ~~SPUDDED~~ started 7-28-72
16. DATE T.D. REACHED 11-1-72
17. DATE COMPL. (Ready to prod.) 10-4-72
18. ELEVATIONS (DF, RKB, RT, GR, ETC.)* 3076' GR
19. ELEV. CASINGHEAD ---

20. TOTAL DEPTH, MD & TVD 17,086'
21. PLUG, BACK T.D., MD & TVD 17,020'
22. IF MULTIPLE COMPL., HOW MANY* ---
23. INTERVALS DRILLED BY → ROTARY TOOLS 15,958-17,086' CABLE TOOLS ---

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*
16,449-16,614' (Fusselman)
25. WAS DIRECTIONAL SURVEY MADE No

26. TYPE ELECTRIC AND OTHER LOGS RUN BHC Sonic Gamma Ray with Caliper, Dual Laterolog, Continuous Dipmeter, Compensated Neutron & Formation Density
27. WAS WELL CORED No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
20"	94#	869'	26"	1630 sacks	None
13-3/8"	72,61 & 68#	6300'	17-1/2"	3206 sacks	None
9-5/8"	53.5 & 47#	11,732'	12-1/4"	975 sacks	None

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
		(See attachment)		

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-7/8"	14,967'	None

31. PERFORATION RECORD (Interval, size and number)
16,449-16,614' (Fourteen .33" holes over 165' interval)

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
11,510-11,741'	200 sacks Class "H" Cement
11,849-11,894'	150 sacks Class "H" Cement
16,449-16,614'	350 sacks Class "H" Cement
	(See attachment)

33.* PRODUCTION

DATE FIRST PRODUCTION 11-1-72
PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump) Flowing
WELL STATUS (Producing or shut-in) Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
11-14-72	24	24/64"	→	-0-	5950	216	----

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
1900#	---	→	-0-	5950	216	---

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.) Sold
TEST WITNESSED BY

35. LIST OF ATTACHMENTS 2 copies each: Borehole Compensated Sonic Log - Gamma Ray, Compensated Neutron-Formation Density, Dual Laterolog, Gammatron

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED C.J. Love TITLE Dist. Prod. Manager DATE Dec. 20, 1972

*(See Instructions and Spaces for Additional Data on Reverse Side)

2MOITDUЯTƧИI

Set Baker Calt Iron Bridge Plug at 13,400'. Spotted 2 aacka c••nt on top of bridge plug traa 13,-00' to 1.3,386'. Perto:rated 5-1/2" OD liner with 4 holea at 13,210' and 1queezed with 85 aacka ot caat. Drill.eel out oeaeat \o 13,386'• Perforated S-1/2" liner with 4 ahota per foot •• followa1 13,247-13,2'10', 13,272-1.3,275', 13,286-13,292', 13,298-13,320', 13,326-13,329', 1.3,343-13,345', 13,)56-13,360' tor a total ot 63• and 252 hol••• Treated tbroqh S-1/2" OD caaing liner pert•• 13,247-13,360' (intenala) with 2500 gallon• Mud Acid. Teated .-.11 Hftr&I houn with -n,lae to aall to meanre. Treated through 5-1/2" OD caeing liner perta. 13,21.7-13,360' (intenala) with 2500 gallons Mud Acid.. t'eelMI •li-'.aeveral hN. with TOIUM to -11 to meaaure. Treated through S-1/2" OD casing liner pert• 13,247-IJ,'601 (intenala) with 10,000 galana 1,- llegular Acid. Teated well aenral houri with wi111e to .all to m•an• Set Baker Caat Iron Model "I" Bridge Plug at 13,180'• Dmlpecl 2 eacka ot cement on top ot plug, wbieh pl11g nII b&ek tra 13,180' to 1.3,166•. Pertorat.ed 5-1/2" OD liner with bole• per toot tra 13,0051 to 13,030• for a total of 251 and 100 hol••• Treated threnlgh 5-1/2" OD liner perte. 13,00S-13,030' with S,000 gallons 15C Regular Acid. Teated well N'Yer&l hove with TOluae \oo •-II to aeanre. We teaJ>I'?'8,ril7 abandoned the teat.inc ot the Morrow Zone at t.hie t.m, Set Halliburton "DC" C... nt Retainer at 12,790' and aqueesed 85 eaeke ot CtllHlt into 5-1/2" OD liner perte. 13,005-13,030•. Plugged back total depth 12,7901• Pertorat.ed 7" OD casing with 4 bolea per toot aa tollowa1 11,736-II,7U', 11,781-11,787', II,801-II,815t, II,&1+,-11,852', 11,860-U,894' tor a total ot 55t and 220 holea. Set Baker Model "7" Production Packer at 11,700'• Ran 2-7/8" OD 6.1+0# Bllttre•• threat! 1-80 tubing to 11,715' and ....ted in Baker Model"'" Production Packer at 11,700' with pert• 11,711-II,715'. Ot.ia l.allding nipple position No. I at II,709'. Ot1• aid• doar ahitt. valft at U,698'. otie landing nipple poaition lo. 2 at 10,700'. otil lending nipple position lo. 3 at 9700'• Opened well up and flowed to pit to clean up. Shut well in tor 89 hove. After 89 houra with dead night T.P. 6218# fiowed and teated well 1n the toll.owing anner1

nowed 1-3/4 hour on 10/64" choke, opening TP 6218# (W), FTP 6156pai., gas wltae 2,737 JEPPD and 7.6') 'bbl•• ot 52 degree correeted gra'Yit7 condenaate.
lu.t. two hour tlowd through 12/64• ohoke, ITP 6075 pai. (17W), gas luae 4563 KCFPD .w1i and 6.60 bbla. of condenea.te.
lut two noura fiowd throUgh 14/6'+" choke, FTP 599S pei. (DW), gae wIUM 6025 MCFPD and 1.70 bbl•• or oonden•t••
Rut one and one halt hours tLowed through 16/64" choke, FTP 5915 p•i• (IM), gas volUM 8009 ICFPD and undetel"lined 8JI0I1lt or oonclen•ate to pita.
Eatabliahed 24 hour In Maioo Ooneel'"fttion C.-d.eaion AOF Potential ot 310,000 tcFFD. Completed Ja.,.17 22, 1963, a1 a "Wildcat" CCIlI.J)letion in strawn (Penn117I'Y8Bian) toraation, Total cond.enate ree0Ye17 during 7-1/4 hn. t.eet waa 22,80 bbls. to tank and undetermined aaomt to pita.

Well now ahut in - waiting on ga• connection.

POBMATIOI RECORD

From	To	!!!i		
0	12,058	12,0,s		
12,058	12,152	94		
12,152	12,477	32,	Lime & Shale	- Top Atoka 12,152'
12,477	13,366	889	Sand	- Top Morrow 12,477'
13,366	14,583	1,217	$ale	- Top Barp,ett Shale IJ,366•
14,583	14,685	102	Lhle	- 'lop Miasiaaippian 14,853'
14,685	1,,138	453	Chert	- Top Che. 14,685'
15,138	15,518	380	Shale	- Top Woodtorcl IS 131
15,518	15,988	440	L1M & Dolaite	- Top • {'5,518'
15,958	15,9SI	Total Depth		
	12,790	Plugged Back Total Depth		

Geological Tops by Schlumberger Gama Ray Sonic log

Appendix 10 - Process Flow Diagram

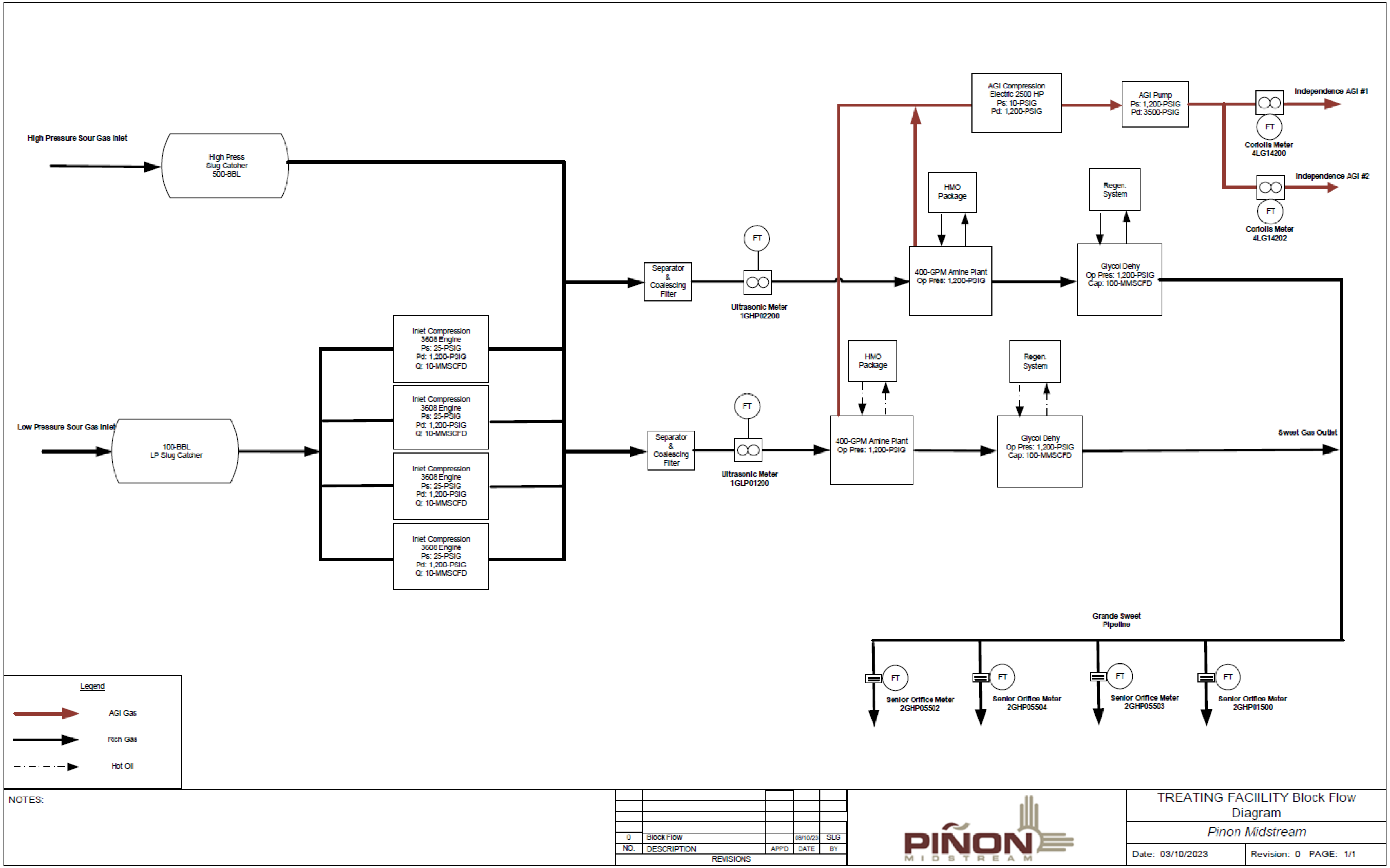


Figure A10-1: Treating Facility Block Flow Diagram

Request for Additional Information: Piñon Midstream, LLC
November 21, 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.	3.7.1	28	Either in a new figure or in Figure 3.7-2, we recommend clearly identifying the locations of flowmeters that are relevant to subpart RR calculations.	Figure 3.7-2 has been updated and uploaded.
2.	5	43-47	"Piñon considers the likelihood, magnitude, and timing of CO2 leakage to the surface via this potential leakage pathway to be minimal." While leakage pathway characterizations can be qualitative, please ensure each identified pathway is clearly and adequately characterized. For example, what is meant by the "timing" of CO2 leakage being "minimal"?	This section has been reviewed, revised, and uploaded.
3.	5.2.3	44	This section does not discuss the magnitude or timing of potential leakage from the West Jal Unit #1 Well. Please provide a clear characterization of the likelihood, magnitude, and timing of potential leakage through the leakage pathway.	This section has been reviewed, revised, and uploaded.
4.	6	47	"If CO_2 surface emissions are **indicted** by any of the monitoring methods listed in Table 6.1, Piñon will quantify the mass of CO_2 emitted based on the conditions that existed at the time of surface emission." We recommend reviewing this sentence and rewording if necessary.	This section has been reviewed, revised, and uploaded.

MONITORING, REPORTING, AND VERIFICATION PLAN

Independence AGI #1 and #2 Wells

Pinon Midstream, LLC

Version Number: 4.0
Version Date: October, 2023

Contents

1 Introduction

Ameredev II, LLC (together with its affiliates, "**Ameredev**") is an oil and natural gas producer operating in portions of the Delaware Basin located in southeastern New Mexico and western Texas. In 2020 Ameredev began evaluating methods for treating its sour natural gas production in Lea County, New Mexico to remove and permanently sequester large quantities of hydrogen sulfide ("**H_2S**") and carbon dioxide ("**CO_2**") commingled in its produced natural gas stream. On July 10, 2020, Ameredev filed an application with New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division ("**NMOCD**") seeking to drill an acid gas injection ("**AGI**") well approximately six (6) miles west of Jal in Lea County, New Mexico for the injection and permanent sequestration of treated acid gas ("**TAG**"). The application was heard and approved at a New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Commission ("**NMOCC**") hearing held on October 8, 2020. The approved order (Order No. R-21455-A) was subsequently issued at the November 4, 2020 NMOCC hearing and the final, approved, Class II injection permit was issued on November 11, 2020. The Independence AGI #001 vertical well (API 30-025-48081; "**Independence AGI #1**") was spud on December 27, 2020 by Ameredev.

In December of 2020, certain affiliates of Ameredev and other outside investors funded Piñon Midstream, LLC ("**Piñon**") to construct and operate the Dark Horse Sour Gas Treating Facility (the "**Dark Horse Facility**") adjacent to the Independence AGI #1 (Figure 1-1) and Ameredev subsequently contributed and assigned the Independence AGI #1 to Piñon on May 21, 2021. Piñon became the operator of record for the Independence AGI #1 on August 24, 2021. Upon completion in late August 2021, treatment of sour natural gas (using amine to isolate H_2S and CO_2) and the injection of TAG through Independence AGI #1 commenced at the Dark Horse Facility (a full description of the treating and injection process is provided in Section 3.8). On March 31, 2022 the NMOCC authorized the drilling of the Independence AGI #002 deviated well (API 30-025-49974; "**Independence AGI #2**") (together the "**Independence AGI Wells**"), which commenced during the summer of 2022, with initial TAG injection through the well occurring in April 2023.

Independence AGI #1 is permitted to inject into the Devonian Thirtyone and Upper Silurian Wristen and Fusselman Formations from a true vertical depth ("**TVD**") of approximately 16,230 to 17,900 feet (the "**AGI #1 Injection Zone**") and at a maximum surface pressure of approximately 4,779 pounds per square inch gauge ("**psig**"). Independence AGI #2 is permitted to inject into the Devonian Thirtyone Formation and Upper Silurian Wristen and Fusselman Formations from a TVD of approximately 16,080 to 17,683 feet (the "**AGI #2 Injection Zone**", and together with the AGI #1 Injection Zone, the "**Siluro-Devonian Injection Zone**") and at a maximum surface pressure of approximately 5,005 psig. In accordance with NMOCC Order No. R-21455-A (as amended by Order No. R-21455-B, the "**NMOCC Order**"), Piñon is authorized to inject and dispose of TAG, utilizing the Independence AGI Wells, at an aggregate *combined* maximum daily injection rate of up to 20 million standard cubic feet per day ("**MMSCF/D**"), which is the equivalent of approximately 8,200 barrels per day ("**bpd**") or 1,036.7 metric tonnes per day. Gas is injected for 30 years at a rate of 1,036.73 tonnes per day (378,399 tonnes per year or 11,351,970 total tonnes) followed by a 5-year rest period. If Independence AGI #1 is not injecting volumes of TAG, Independence AGI #2 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG. If Independence AGI #2 is not injecting volumes of TAG, Independence AGI #1 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG.

Piñon has chosen to submit this Monitoring, Reporting, and Verification Plan (the "**MRV Plan**") to the United States Environmental Protection Agency (the "**EPA**") for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (the "**GHGRP**") for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. Piñon intends to utilize the Independence AGI Wells for the injection and disposal of TAG for another approximately thirty (30) years.

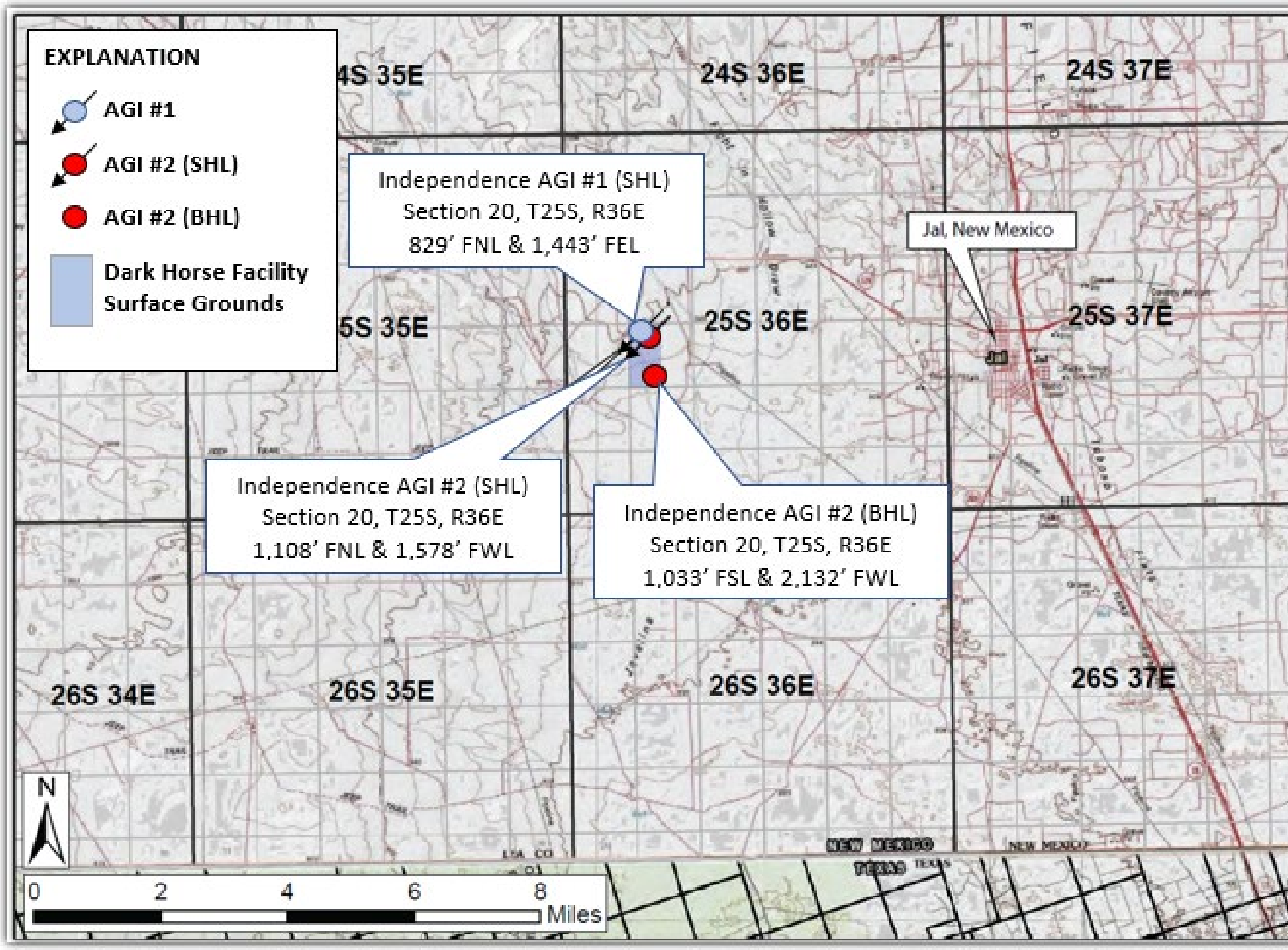


__Figure 1-1__: Location of Dark Horse Facility and the Independence AGI Wells. The approximate surface hole location ("SHL") and the approximate bottom hole location ("BHL") are indicated for both Independence AGI Wells. (Modified from Figure 1 of Class II permit application for Independence AGI #2, Geolex, Inc.)

This MRV Plan contains twelve (12) sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

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

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

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage.

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

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

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

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

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

Section 12 includes Appendices supporting the narrative of the MRV Plan

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is 582541. There are no other facilities related to this MRV plan.

2.2 Underground injection control ("UIC") well identification numbers

This MRV Plan is for the Independence AGI Wells (*see* Appendix 1). The details of the injection process are provided in Section 3.8.

2.3 UIC permit class

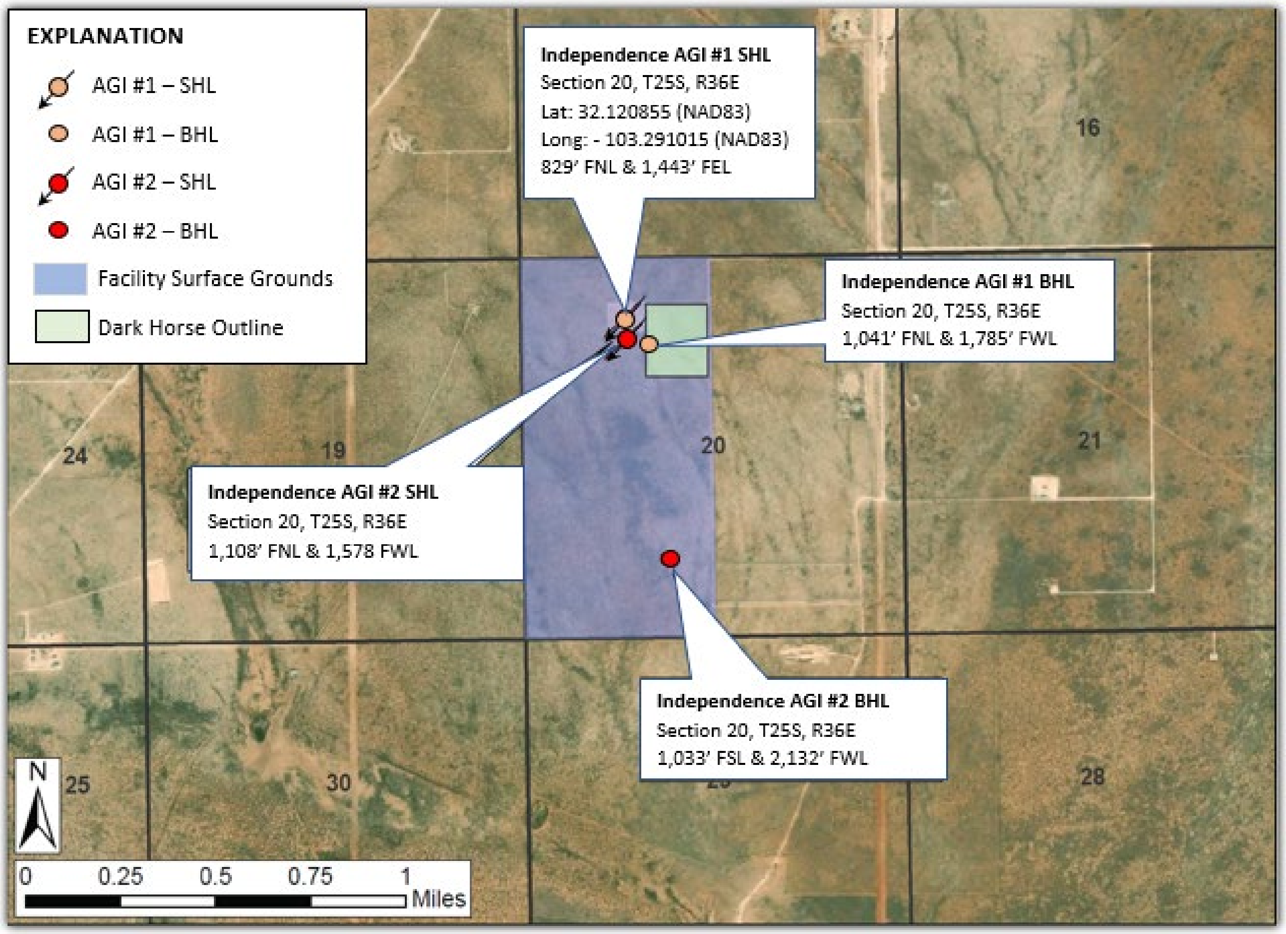
The NMOCD has issued UIC Class II Acid Gas Injection ("**AGI**") permits for the Independence AGI Wells under its State Rule 19.15.26 NMAC (*see* Appendix 2). All oil- and natural gas-related wells located near the Independence AGI Wells, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3 Project Description

Parts of the following project description have been taken from the Class II permit applications for (i) Independence AGI #1, prepared by Geolex, Inc. for Ameredev, dated July 10, 2020; and (ii) Independence AGI #2, also prepared by Geolex, Inc. for Piñon, dated November 4, 2021.

3.1 General Geologic Setting / Surficial Geology

The Dark Horse Facility is located adjacent to the Independence AGI Wells as shown in Figure 3.1-1. The site lies on the eastern flank of the Pecos River Basin within the Javelina Basin. Referred to as the South Plain by Nicholson & Clepsch (1961), the region exhibits irregular topography without integrated drainage. Surficial sediments commonly consist of unconsolidated alluvium and eolian sands. There are no observed surface bodies of water, or groundwater discharge sites within one (1) mile of the Independence AGI Wells. The Dark Horse Facility overlies Quaternary alluvium overlying the Triassic redbeds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater. The thick sequences of Permian rocks that underlie these deposits are described in Section 3.2.2.



p

***Figure 3.1-1**: Map showing location of Dark Horse Facility and the Independence AGI Wells in Section 20, T25S, R36E NMPM. The BHL of the Independence AGI #1 sidetrack is 446' southeast of the SHL. The SHL and the BHL for Independence AGI #2 are shown. (Modified from Figure 2 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

3.2 Bedrock Geology

3.2.1 Basin Development

The Dark Horse Facility is 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. The Permian Basin and its sedimentary fill have been formed and controlled by tectonism of varying degrees and sedimentation events that began in the Precambrian and throughout the Cenozoic (Neogene). Early Paleozoic deposition took place in the Late Cambrian as marginal areas of the North American craton began to be flooded by marine seas. Late Cambrian sediments comprised of basal siliciclastic sands and muds from areas of exposed Precambrian igneous, metamorphic, and sedimentary rocks and shallow-water carbonates.

Parts of the following basin development descriptions in this subsection have been modified and summarized from Ruppel (2019). Flooding continued across the North American craton throughout the Early Ordovician, establishing a widespread shallow-water carbonate platform. The Ellenburger Formation (Figure 3.2-2) rocks are derived from peritidal and shallow subtidal carbonates. These sediments were exposed during one of the sea-level drops during the Ordovician deposition resulting in karstification and dolomitization. During the Early to Middle Paleozoic time, the Permian Basin region was occupied by a relatively shallow basin called the Tobosa Basin. The first rapid subsidence and formation of the Tobosa Basin began in Simpson time (Middle

Ordovician), and subsidence slowly diminished into the Early Devonian (Ewing, 2019). Subsequent tectonic history of the Tobosa and Permian Basins will be discussed throughout this section.

Early Paleozoic deposition is mostly defined by multiple high-frequency sea-level changes, karsting, and erosional events. Large-scale shift in facies and environments indicate tectonic and/or eustatic controls on sediment distribution patterns. Simpson Group (Middle Ordovician) rocks unconformably overlie Ellenburger Formation rocks at a widespread hiatus caused by Early Ordovician to Middle Ordovician relative sea-level fall. Simpson rocks are a cyclic succession of lime mudstones and quartz sandstones and were deposited during the subsequent reflooding of the shelf. Carbonate-dominated Montoya Formation (Late Ordovician) and Fusselman Formation (Latest Ordovician -Early Silurian) rocks overlie the Simpson Group and indicate a shift and deepening of Tobosa Basin. These rocks are indicative of an overall relative sea level rise.

Middle Silurian-Early Devonian Wristen Group and Thirtyone Formation rocks indicate differential subsidence in the area and represented a deepening and expansion of the basin. Wristen Group rocks comprised of carbonate mudstones and wackestones of the Wink Formation, which underlies the shallow-water carbonate platform packstones, grainstones, and reef facies (corals and stromatoporoids) of the Fasken Formation and the deep-water lime mudstones of the Frame Formation. These facies outline the position of a Silurian platform margin and imply a downwarping of the North American craton. Although Wristen and Fusselman show evidence of numerous high-frequency sea-level changes, the larger-scale change in facies and depositional environments indicates tectonic and/or eustatic controls on sediment distribution patterns. The Silurian platform margin is a recurring feature that controls facies distribution through the Late Mississippian, suggesting tectonic and/or basement terrain control. The rocks of the Thirtyone Formation (Early Devonian) consist of platform carbonate grainstones and packstones surrounding calcareous, radiolarian-rich basin facies.

According to Ruppel (2019) and Ruppel and others, (2020a), a major episode of relative sea-level fall in the Middle Devonian is documented by an absence of Late Early Devonian and early Middle Devonian rocks. Late Devonian Woodford rocks overlie eroded and karsted Silurian (Wristen Group), Early Devonian Thirtyone, and older rocks. Local folding of these rocks below the Woodford suggests that the hiatus may have been at least partially driven by tectonic events. Evidence from the distribution of later Mississippian rocks indicates that the tectonic event caused uplift and localized deformation of pre-Middle Devonian rocks and changed subsidence and depositional patterns across the entire region.

Following the Middle Devonian Permian Basin-area uplift and emergence, Late Devonian marine transgression flooded the region with anoxic bottom-water seas and deposited black, organic-rich biosiliceous mudstones of the Woodford Formation (Ruppel, 2019). Sea-level fall-and-rise sequences defined the Early and Late Mississippian and were even more pronounced during the Pennsylvanian. In the Late Mississippian, initial collision occurred between Laurentia and Gondwanaland, and the Marathon-Ouachita orogenic belt first started to form in northeastern North America (Yang and Dorobek, 1995) with tractions propagating toward the southwest, impacting the Permian Basin by the Middle Pennsylvanian Epoch (Desmoinesian, 310 Ma) (Horne, 2021). Mississippian limestones and the Barnett Formation shales were deposited following a marine transgression that resulted in the development of an extensive carbonate platform, surrounded by a deep-water, organic-rich mud basin.

Collision along the western and southwestern margins of Laurentia, combined with tractions from the Marathon-Ouachita thrusting in the southeast, resulted in northwest-southeast-trending uplifts throughout the western United States known as the Ancestral Rocky Mountain orogeny, which began in Early Pennsylvanian time and continued into the Early Permian (Horne, 2021). The Pennsylvanian tectonic setting in the Permian Basin is the product of the combined Ancestral Rocky Mountain and Marathon–Ouachita effects occurring along the southwest and southeast margins of Laurentia. These events contributed to basin evolution and specific structural domains and styles. In the Permian Basin, the Ancestral Rocky Mountain

orogeny is responsible for the uplift of the Central Basin Platform and the major structural development of the Midland and Delaware Basins (Horne, 2021).

During Desmoinesian to early Missourian sedimentation, Permian Basin deformation reached its peak. The antecedent Tobosa Basin was tectonically differentiated, formed into the crustal uplifts and sub-basins that now characterize the Central Basin Platform, Midland Basin, and Delaware Basin. Throughout Pennsylvanian and most of Permian sedimentation, tectonics coupled with glacial eustacy played an important role in the development of regional facies. Middle to Late Pennsylvanian saw decreasing tectonic deformation activity, and by the Wolfcampian time (Early Permian), deformation was limited to subsidence within the structures formed by the existing uplifts and basins (e.g., Delaware and Midland Basins, Central Basin Platform). The continual subsidence of the Delaware basin affected sediment infilling, with some areas accumulating as much as 12,000 ft of basin-fill sediment. Marine transgression eventually submerged uplifts and became the location of carbonate sedimentation, while the basins became filled with organic-rich siliceous muds. By the end of the Wolfcampian, the major Permian Basin physiographic features (Central Basin Platform, Delaware and Midland Basins) were fully developed, and controlled sedimentation types and location for the remainder of the Paleozoic.

The Middle Permian (Leonardian and Guadalupian) was punctuated by cyclic sediment deposition during sea-level eustatic events. The Leonardian was a time of gradual global warming from the icehouse climates of the late Carboniferous to warmer and more arid greenhouse climates of the later Permian and Mesozoic (Tabor, 2004). The Leonardian marked the beginning of the last stages of the formation of Pangea, producing greater restriction of open ocean connections to the Permian Basin (Ruppel, 2020b). The abundance of tidal-flat facies, evaporites, and reflux dolomites in Leonardian rocks reflects the development of much more arid conditions compared with those in the earlier Permian (Ruppel, 2020b). In the shelf areas (Central Basin Platform and Northern, Northwestern, and Eastern Shelves) (Figure 3.2-1), sedimentation was characterized by shallow-water carbonate production and deposition during sea-level rise, and by shelf exposure and sand-silt deposition during sea-level fall and subsequent shelf exposure. In the Delaware and Midland basins, sedimentation was characterized by cyclic intervals of detrital carbonate-sediment transport into the basins by sea-level highs, and by sand-silt transport and deposition during sea-level falls. Dolomitization of carbonate-shelf deposits occurred during the more regionally arid climates of the Leonardian and the Guadalupian as a product of the Permian Basin area being situated at the equator and from refluxing brines created during periods of sea-level highstand events. Deposition of evaporites became more common in the shelf areas during this time, likely in response to the increasingly arid environment and/or decreased accommodation. By the end of the Guadalupian, the Midland Basin was largely filled, and peritidal muds and evaporite deposition dominated. Sea-level fall and closure of the Hovey Channel (Figure 3.2-1) cut off the Delaware Basin from its marine supply, resulting in regional exposure and nondeposition and the filling of the basin with evaporites of the Castille Formation (Lopingian “Ochoa” Series) (Ruppel, 2019). Most of the rocks deposited during Lopingian “Ochoan” time were evaporites such as anhydrite, halite, and potash minerals with minor amounts of limestone, mudstone, and siltstone and are subdivided into (ascending) Castile Formation, Salado Formation, Rustler Formation, and Dewey Lake Red Beds. Most of the early Ochoan deposition was confined to the Delaware Basin (Bachman, 1984).

3.2.2 Stratigraphy

Figure 3.2-2 is a generalized stratigraphic column showing the formations that underlie the Dark Horse Facility and the Independence AGI Wells. The sequences of Ordovician through Permian rocks are described below.

Ordovician. Below the Silurian Fusselman Formation lies about 400 feet of Ordovician Montoya Formation cherty carbonates which overlies about 400 feet of Ordovician Simpson Group sandstones, shales, and tight limestones. These formations are underlain by the Lower Ordovician Ellenburger Formation which is a thick, carbonate-dominated sequence composed of dolostones and limestones. It is 0-1,000 feet thick in

southeastern New Mexico. The Ellenburger carbonates sit on a veneer of Cambrian to Lower Ordovician Bliss Sandstone and granite wash on the Precambrian basement.

During the Early Ordovician, much of the United States was covered by a shallow sea, and southeast New Mexico was a shallow-water shelf with deep water conditions to the south. Due to sea-level changes and regional tectonic activity, the entire lower Paleozoic interval (Ellenburger through Devonian) was periodically subjected to subaerial exposure and prolonged periods of karst and karst-terrain formation, most especially in the Ellenburger, Fusselman and Devonian strata. The cave systems collapsed with subsequent burial, creating brecciated and fractured carbonate bodies that formed many of the Ellenberger reservoirs and created complex pore networks. The result of these exposure events was the development of numerous horizons of karst-related secondary porosity with solution-enlarged fractures, vugs, and small cavities and caves. Particularly in the Ellenburger and Fusselman strata, solution features from temporally distinct karst events became interconnected with each successive episode, so there could be some degree of vertical continuity in parts of the Fusselman section that could lead to enhanced vertical and horizontal permeability. The Ellenburger is well below the Siluro-Devonian Injection Zone, so it is unlikely to be affected by any proposed activity.

Devonian and Silurian. The Devonian Thirtyone Formation, the Silurian Fusselman Formation, and the Silurian Wristen Group consist of interbedded dolomites and dolomitic limestones and are collectively often referred to as the Siluro-Devonian. In the Middle Devonian, regional marine transgression deposited mostly black, organic-matter-rich siliceous muds of the Woodford Formation (Ruppel, 2019). The Siluro-Devonian Injection Zone does not contain economic hydrocarbons closer than fifteen (15) miles away from the well sites. There have been no commercially significant deposits of oil or natural gas found in the Devonian or Silurian rocks in the vicinity of the Independence AGI Wells and there is no current or foreseeable production at these depths within a two (2) mile radius around the Independence AGI Wells (Figure 3.7-3). Adjacent wells have shown that these formations are primarily water-bearing and are routinely approved as produced-water injection zones in this area.

Mississippian. According to Broadhead (2017), the Mississippian section unconformably overlies the Woodford Formation shales throughout most of southeastern New Mexico and, in places, unconformably overlies the Silurian Fusselman Formation or Ordovician strata in limited areas. These units reach a maximum thickness of 1,400 ft in the Tatum Basin northwest of Hobbs, New Mexico and constitute a major portion of the stratigraphic section. The Mississippian section in southeastern New Mexico is subdivided into the Lower Mississippian limestone (Kinderhookian to Osagean age) and various Upper Mississippian units. The Upper Mississippian section consists of the Barnett Shale in the basinal area to the south and the Meramec and Chester units on the shelf to the north. The Mississippian strata constitute the least developed of the major stratigraphic units in southeastern New Mexico and oil and natural gas production has been from relatively small and widely scattered reservoirs (Broadhead, 2017). The Chester Formation consists of several hundred feet of shales and basinal limestones which are underlain by several hundred feet of Osage limestone.

Pennsylvanian. The Pennsylvanian-age strata is comprised of (ascending) Morrow, Atoka, Strawn, Canyon, and Cisco. Within this entire sequence, the Morrow is a major natural gas producing zone, with smaller contributions from the overlying Atoka and Strawn. The Morrowan strata are dominantly siliciclastic and consist of interbedded shales and lenticular sandstones deposited in multiple regressive sequences and represent basinward migration of nearhore, sand-rich facies tracts from the erosion of exposed Precambrian rocks (Broadhead, 2017). The overlying Atokan strata are also dominantly siliciclastic, with sandstones and shales being deposited in fluvial-deltaic and strandline environments (Broadhead, 2017). The Middle Pennsylvanian (Desmoinesian) Strawn strata is composed of ramp limestones interbedded with marine shales and minor sandstones, and both sandstone and limestone reservoirs are productive (Broadhead, 2017). Although there was past production of oil and natural gas from the Pennsylvanian Strawn pool, there are no active wells in that pool within two (2) miles of the Dark Horse Facility nor are there any natural gas producing

wells in any pools. The Upper Pennsylvanian strata are informally referred to as the Canyon (Missourian) and Cisco (Virgilian) groups, and are composed of interbedded carbonates, dark-gray to black shales, and minor sandstones (Broadhead, 2017). These groups contain prolific oil reservoirs in southeastern New Mexico.

Permian. The overlying Permian rocks found in the Delaware Basin are divided into four (4) series, the Lopingian ("Ochoa") (most recent), Guadalupe, Cisuralian ("Leonard"), and Hueco ("Wolfcamp") (oldest) (Figure 3.2-2). Numerous oil pools have been identified in these rocks (*see* Appendix 3, Table 3a). Active oil producing reservoirs within two (2) miles of the Dark Horse Facility include the following Permian pools: Tansil, Yates, Seven Rivers, Delaware, Bone Spring, and Wolfcamp. New oil wells permitted but not yet drilled are primarily targeting the Bone Spring and the Wolfcamp pools. The rock units of the Permian series are discussed in more detail below.

Permian Hueco ("Wolfcamp") Group. The Lower Permian Wolfcampian strata in the Permian Basin record deposition in deepwater basins surrounded by shallow-water carbonate platforms, where the Wolfcampian platform carbonate succession exposed in southeastern New Mexico comprises a complex record of deposition mainly controlled by fluctuations in glacio-eustatic sea level (Fu and others, 2020). The Wolfcamp is extremely variable in lithology in response to changes in the environment of deposition. In the area of the Dark Horse Facility, it is composed of dark skeletal to fine-grained limestone, fine-grained sand to coarse silt, and shale in these basin facies. Horizontal wells are being drilled in the Bone Spring and Wolfcamp; however, most activity is primarily to the west of the Dark Horse Facility.

Permian Leonardian Series. The Cisuralian ("Leonard Series"), sediments in shelf areas (Central Basin Platform, Northwest Shelf, etc.) are characterized by shallow-water carbonate-sediment production and deposition during sea-level rise, and by shelf flooding and quartz-dominated sand-silt deposition during sea-level fall and shelf exposure (Ruppel, 2019). In the Delaware Basin, this pattern of sea-level control on sediment supply resulted in the deposition of cyclic intervals of detrital carbonate-sediment transport to basins during sea-level highs and by quartz sand-silt transport and deposition during sea-level falls (Ruppel, 2019). Overall, the Leonard succession is one of punctuated upward shallowing from deep-water, outer-platform—platform-margin settings to inner-platform, peritidal conditions (Ruppel, 2020b).

The Bone Spring Formation is present only in the Delaware Basin and is stratigraphically equivalent to the Abo and Yeso Formations of the Northwest Shelf and Central Basin Platform, attains a maximum thickness of about 4,000 ft in southern Eddy County, New Mexico, and has been productive from several plays in the basin (Broadhead, 2017). The Bone Spring stratigraphy consists of alternating carbonate and siliciclastic successions that were deposited in marine slope and basin-floor environments, where sandstones and siltstones are widespread on the basin floor, whereas carbonates are thickest in periplatform areas (Nance and Hamiln, 2020; Saller and others, 1989). Most Bone Spring carbonate slope deposits accumulated by transport from shallow-water environments on the shelf during highstands of sea level and the siliciclastic deposits were transported basinwards during lowstands of sea level (Nance and Hamlin, 2020). Most of the carbonates are detrital, composed of bioclasts and lithoclasts derived from surrounding shallow-water platforms, and the siliciclastic members were deposited primarily on the basin floor in widespread submarine-fan complexes (Nance and Hamlin, 2020).

Permian Guadalupe Series. The Upper Permian Guadalupian-age strata are found on both Northwest Shelf and Central Basin Platform, and in the Delaware Basin. The Goat Seep/Capitan Reef system, a profoundly critical component of the Permian Basin Guadalupian paleogeography, prominently divides the shelves of the Central Basin Platform, the Northwestern Shelf, and the Western Shelf from the Delaware Basin (Nance, 2020a). Units on the shelf and platform comprise of (ascending) the San Andres Formation and the Artesia Group (*see* Figure 3.2-2). The five (5) formations of the Artesia Group include (ascending) Grayburg, Queen, Seven Rivers, Yates, and Tansill. The Delaware Basin equivalents of the reef trend include the Delaware Mountain Group: (ascending) Brushy Canyon, Cherry Canyon, and Bell Canyon. The Artesia Group comprises as much as 2,650 ft of stratigraphically cyclic, mixed-siliciclastic/carbonate/evaporite platform strata

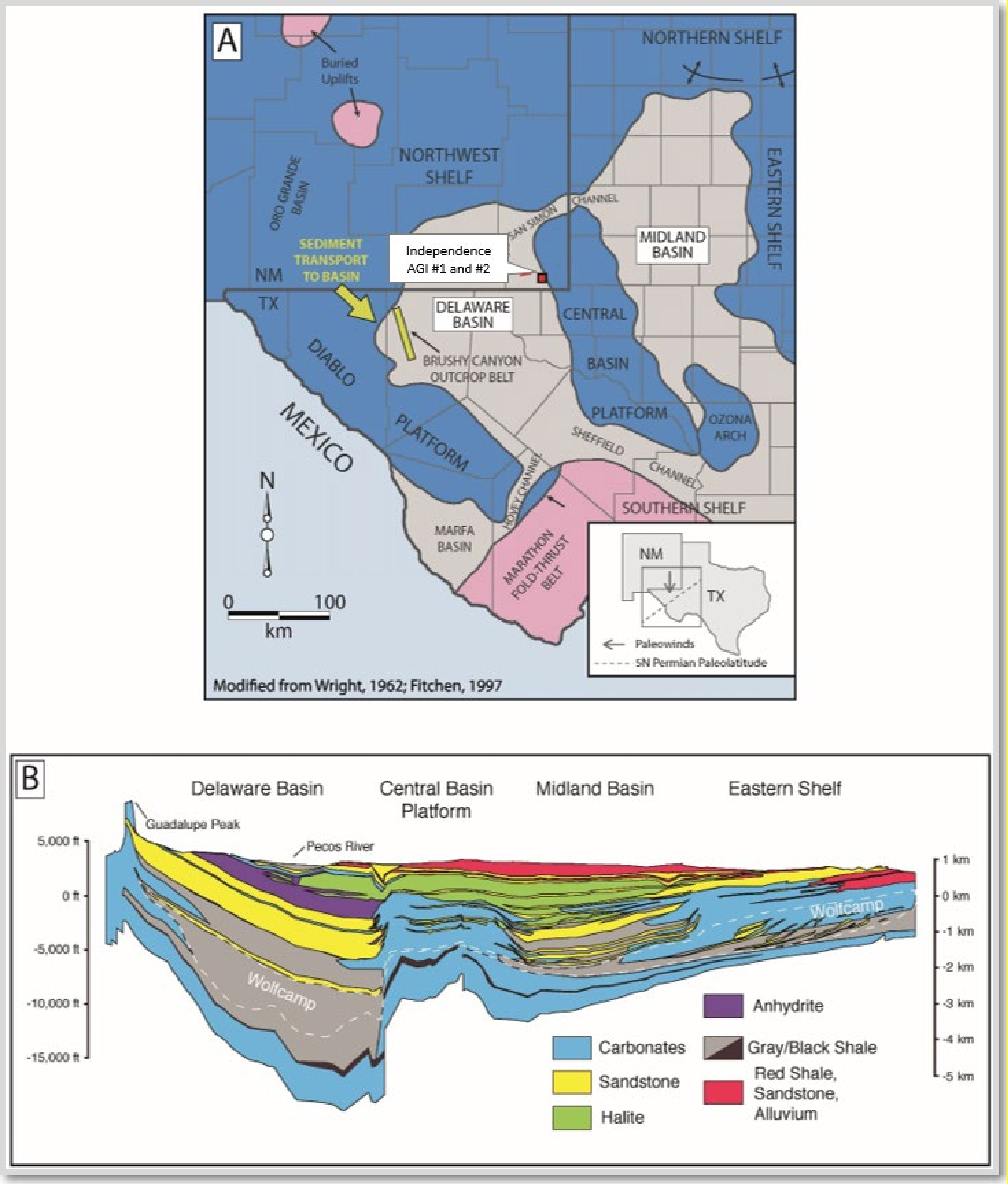
deposited shelfward of the Guadalupian Capitan Reef system that rims the Delaware Basin (Nance, 2020a). These formations have provided significant oil and natural gas production in southeastern New Mexico, and widespread, reddish-colored evaporitic shales and evaporites provide effective vertical and lateral seals (Broadhead, 2017).

According to Nance (2020a), Artesia facies tracts include, from basin to shelf, immediate-back-reef carbonate grainstone to packstone; shelf-crest pisolite-bearing carbonate shoals; lagoonal wackestone to mudstone and siliciclastic siltstone; algal-laminated, tidal-flat carbonate packstone to wackestone and fine to very fine grained sandstone; beach-ridge fine sandstone; siliciclastic-sabkha anhydrite and halite; brine-pool and evaporitic-lagoon anhydritic dolomite, dolomitic anhydrite, anhydrite, and halite; and eolian to fluvial siliciclastics. During sea-level highstand, siliciclastics are limited to updip areas, whereas eolian-siliciclastic depositional environments migrate downdip during sea-level lowstands. During transgressions, siliciclastics in more basin-proximal positions were reworked by marine and marginal processes. Reservoir quality was impacted mostly by dissolution of feldspar and carbonate allochems and precipitation of authigenic feldspar, clay, and evaporite.

The Delaware Mountain Group of the Delaware Basin comprises up to 4,500 ft of arkosic to subarkosic sandstone, siltstone, and carbonate debrites that were deposited in deep water, mainly during lowstand and early transgressive sea-level stages, and primary depositional processes include density-current flow and suspension settling (Nance, 2020b). The Delaware Mountain Group is restricted to slope-and-basin areas and was sourced from shelf-sediment areas through poorly exposed incised valleys, and interbedded carbonate units thicken shelfward and are typically correlative to “reef”-margin-complex carbonate sources along the shelf margin (Nance, 2020b).

Permian Lopingian (“Ochoa”) Series. The youngest of the Permian Basin sediments are referred to as the Lopingian (“Ochoa”) Series. The Ochoan series includes the Castile, Salado, Rustler, and Dewey Lake formations. Ochoan units on the shelf include the Salado, Rustler, and Dewey Lake Formations. *Castile Formation* usage is restricted to the deposits within the Delaware Basin only (Figure 3.2-2). The Ochoan in the Permian Basin contains no hydrocarbon reservoirs on the shelf (Nance, 2020a). The basal Salado Formation forms the ultimate top seal for the underlying Guadalupian reservoirs and effectively inhibits hydrocarbon migration into Ochoan units (Nance, 2020a). Lack of a seal above the Ochoan precludes widespread entrapment within the interval of hydrocarbons that may have been generated within the series. Ochoan strata are not hydrocarbon productive in the Permian Basin except for a few very small, isolated reservoirs in the Castile Anhydrite in the northern part of the Delaware Basin (Broadhead, 2017). The Castile is considered to be the top seal for Delaware Basin hydrocarbon reservoirs and is responsible for controlling migration of hydrocarbons from basinal source beds into reservoirs on the surrounding shelves (Hills, 1984). Anhydrite is the dominant rock type in the Castile Formation, along with limestone interlaminated in anhydrite, thin beds of limestone, and minor amounts of dolomite and magnesite, and halite is present as several massive beds in the formation in the subsurface but is much less prominent than the halite in the overlying Salado Formation (Bachman, 1984). The interlaminated anhydrite and limestone are distinctive lithologic features of the Castile Formation and are thought to represent annual cycles of sedimentation (Bachman, 1984).

The regionally extensive Salado Formation includes thick evaporite deposits and records a long-term salinity crisis in the region (Nance, 2020a). The Salado includes halite, minor beds of anhydrite, and commercial deposits of potash minerals (Bachman, 1984). The contact between the Castile and the overlying Salado Formations is sharp and most places and is between massive beds of anhydrite in the Castile and a sequence dominated by halite, potash minerals, and thin beds of anhydrite in the Salado (Bachman, 1984). The Rustler Formation overlies the Salado, and consists of dolomite, evaporites, and siliciclastics and marks the last major migration of marine waters into the Permian Basin (Ruppel, 2019). Red beds of terrigenous sands in the Rustler Formation resulted from eolian sediment transport. These red beds grade downwards into evaporites of the Salado and Castile Formations and are composed of red-orange silts and sandstones with interbeds of gypsum or anhydrite and halite. The Rustler carbonates, evaporites, and siliciclastics mark a relatively abbreviated return of marginal-marine conditions to the region (Nance, 2020a). The Dewey Lake Formation rests conformably on the Rustler Formation and consists mainly of redbeds and minor gypsum, alternating thin, even beds of moderately reddish-brown to moderately reddish-orange siltstone and fine-grained sandstone (Bachman, 1984). The Dewey Lake sediments mark the youngest episode of preserved Permian deposition in the region, after which a significant net-depositional hiatus prevailed until the onset of Late Triassic sediment accumulation (Nance, 2020a). Beds of Triassic age rest unconformably on, and overlap, the Dewey Lake Formation, and exposures of these rocks in southeastern New Mexico are dark reddish-brown, cross-laminated, poorly sorted conglomerate sandstones with interbeds of dark reddish-brown sandy shale (Bachman, 1984). These Triassic units were deposited in a fluvial—deltaic—lacustrine system and signaled the onset of net deposition during overall wetter conditions after a protracted period of net nondeposition (Nance, 2020a; Bachman, 1984).



<u>Figure 3.2-1</u>: Structural setting (panel A) and general lithologies (panel B) of the Permian Basin. The location of the Independence AGI Wells is shown by the red square. (Modified from Wright, 1962; Fitchen, 1997) (Modified from Figure 12 of Class II permit application for Independence AGI #2, Geolex, Inc.).

Age		Stratigraphic Units: Northwest Shelf and Central Basin Platform	Stratigraphic Units: Delaware Basin
Triassic		Chinle	Chinle
		Santa Rosa	Santa Rosa
Permian	Lopingian ("Ochoan")	Dewey Lake	Dewey Lake
		Rustler	Rustler
		Salado	Salado
			Castile
	Guadalupian	Artesia Group: Tansill	Delaware Mountain Group: Bell Canyon
		Artesia Group: Yates	
		Artesia Group: Seven Rivers	Delaware Mountain Group: Cherry Canyon
		Artesia Group: Queen	
		Artesia Group: Grayburg	
		San Andres	Delaware Mountain Group: Brushy Canyon
	Cisuralian ("Leonardian")	Glorieta	
		Yeso: Paddock	Bone Spring
		Yeso: Blinebry	
		Yeso: Tubb	
		Yeso: Drinkard	
		Abo	
	Wolfcampian	Hueco ("Wolfcamp")	Hueco ("Wolfcamp")
Pennsylvanian	Virgilian	Cisco; Bough	Cisco
	Missourian	Canyon	Canyon
	Des Moinesian	Strawn	Strawn
	Atokan	Atoka	Atoka
	Morrowan	Morrow	Morrow
Miss.	Upper	Undivided	Barnett
	Lower		undivided limestone
Dev.	Upper	Woodford	Woodford
	Middle		
	Lower	Thirtyone	Thirtyone
Sil.	Upper	Wristen	Wristen
	Middle		
	Lower	Fusselman	Fusselman
Ord.	Upper	Montoya	Montoya
	Middle	Simpson	Simpson
	Lower	Ellenburger	Ellenburger
Cambrian		Bliss	Bliss
Precambrian		igneous, metamorphics, volcanics	igneous, metamorphics, volcanics

***Figure 3.2-2**: Generalized stratigraphic correlation chart for the Permian Basin region (modified from Broadhead, 2017).*

3.2.3 Faulting

The Permian Basin region has a complex tectonic history, shaped by several convergent and divergent events from the Proterozoic through the Cenozoic (Neogene). The Delaware Basin is defined by a complex network of basement-rooted faults. Recent regional 3D structural framework and kinematic models by Horne et al. (2021) provides interpretations of basement-rooted faults in the Delaware Basin. This region contains more than 650 basement-rooted fault surfaces, dominated by "primary" north-northwest—south-southeast-striking high-angle reverse faults that bound "secondary" fault orientations west-northwest—east-southeast and west-southwest—east-northeast (Horne et al., 2021). Their kinematic model suggests that the primary structural grain formed first in response to the encroaching Ancestral Rocky Mountain orogenic front, and the secondary fault zones formed under the combined stresses from the Ancestral Rocky Mountain and Marathon-Ouachita convergence fronts, which compartmentalized the Delaware Basin and Central Basin Platform (Horne et al., 2021).

To identify subsurface structures in the area of the Independence AGI Wells, Geolex evaluated and interpreted licensed seismic survey data (WesternGeco South Lea Survey) covering the Lea County area of interest. These findings and interpretations specific to the Dark Horse Facility area are discussed further in Section 3.5.

3.3 Lithologic and Reservoir Characteristics of the Siluro-Devonian Formations

The Siluro-Devonian Injection Zone includes the Devonian Thirtyone Formation, Silurian Wristen Group and Fusselman Formation, collectively referred to as the Siluro-Devonian. These strata commonly include numerous intervals of dolomites and dolomitic limestones with moderate to high primary porosity. Additionally, the Siluro-Devonian Injection Zone includes significant regions of secondary, solution-enlarged porosity produced during periods where strata were subaerially exposed and significant karst features developed. These karst features are frequently developed in the Fusselman Formation and include solution enlarged cavities and fractures. Fracture networks through the Siluro-Devonian section are substantial enough to provide additional permeability that is not readily apparent on geophysical well logs. The porous zones of the Siluro-Devonian are separated by tight limestones and dolomites.

In evaluating the location of the Independence AGI Wells, an in-depth review of licensed seismic survey data (WesternGeco – South Lea Survey) was completed to support the evaluation that the Siluro-Devonian reservoir exhibited sufficient porosity potential to accommodate the needs of the Independence AGI Wells. Seismic inversion data, specifically impedance attributes, were evaluated to identify reservoir targets with significant porosity potential in the Siluro-Devonian reservoir. As a result of this review, the location in Section 20, T25S, R36E was selected as it was observed to overlay an expansive region of porosity in the upper Devonian, Wristen, and Fusselman strata.

Based on the geologic evaluation of the subsurface, AGI was recommended between depths of approximately 16,080 to 17,683 feet TVD (16,477 to 18,080 feet measured depth). Figure 3.3-1 includes a type log of the Siluro-Devonian Injection Zone that includes the formation tops identified at that location and illustrates the sufficient low-porosity intervals overlying the target injection reservoir. Anticipated formation tops underlying the Independence AGI #2 location are included in the following Table 3.3-1. In the area of the Independence AGI Wells, depth to Devonian strata increases to the southwest and the Independence AGI Wells lie downdip of a structural high to the east (Figure 3.3-2).

Units overlying the Siluro-Devonian Injection Zone provide an excellent caprock to prevent the upward migration of injectate out of the target reservoir. This caprock includes 335 feet of dense Woodford Shale overlain by at least 796 feet of Mississippian limestone (Table 3.3-1). These units will provide a geologic seal above the porous carbonates of the Siluro-Devonian Injection Zone providing protection to shallow groundwater resources and overlying pay intervals.

Figure 3.3-3 includes structural cross section A-A' covering the area of Independence AGI #2 and highlights the lateral extent of available upper Devonian porosity and the regional coverage of overlying caprock in the area. As shown in Figure 3.3-2, there are two (2) faults located approximately one (1) mile east and one (1) mile north from the SHLs of the Independence AGI Wells. These structures were identified through review of licensed 3D seismic survey data and are discussed further in Section 3.5.

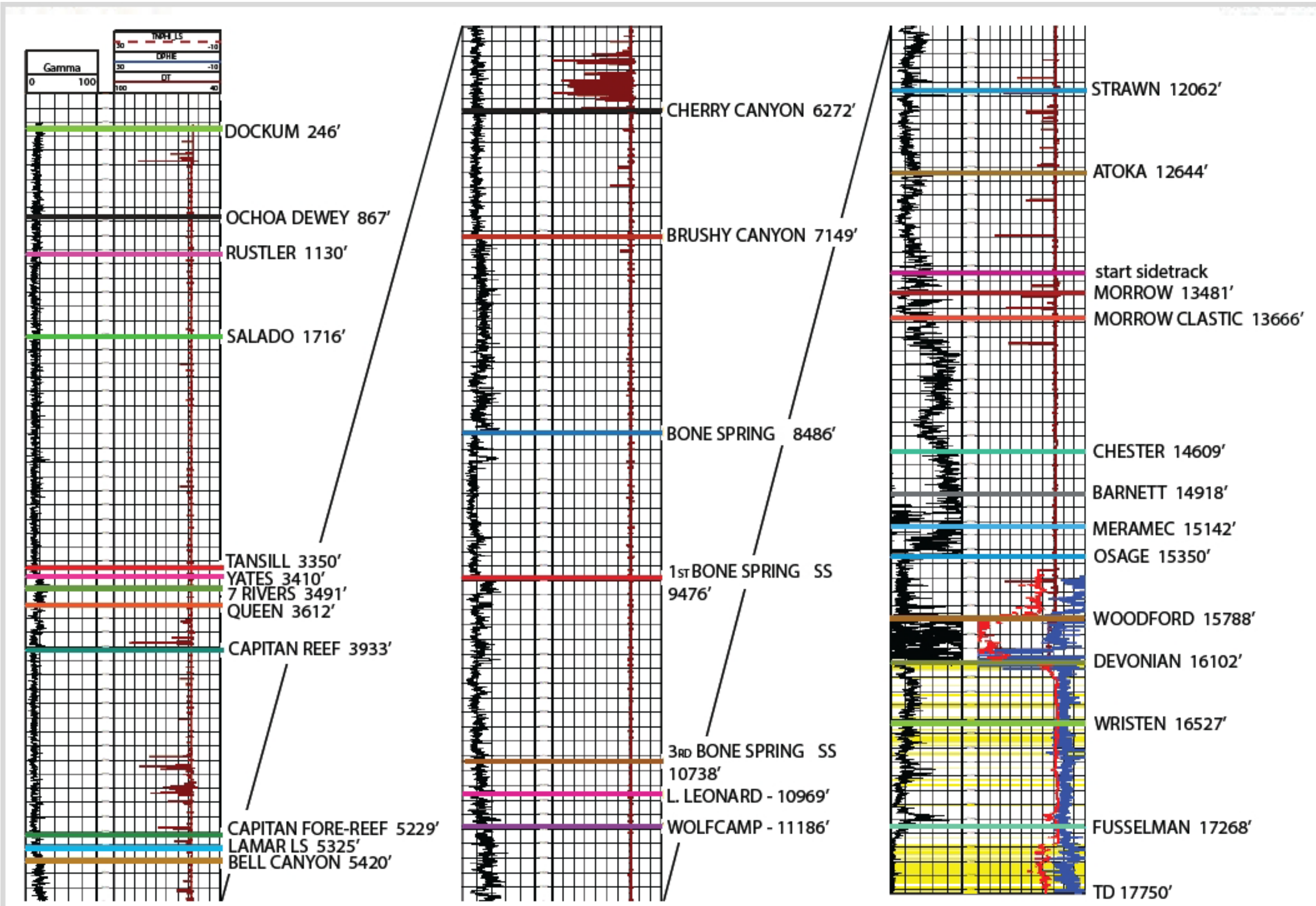
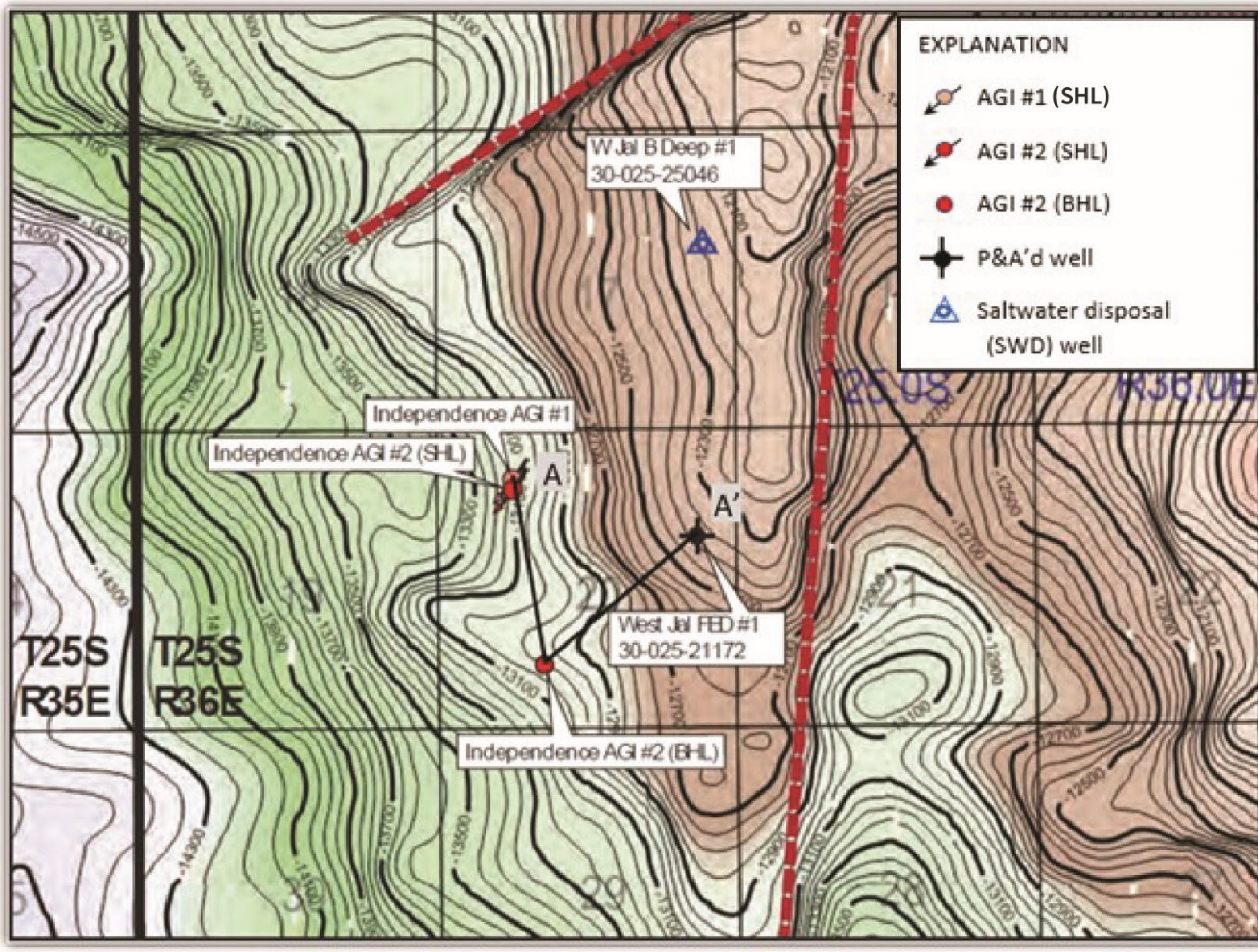


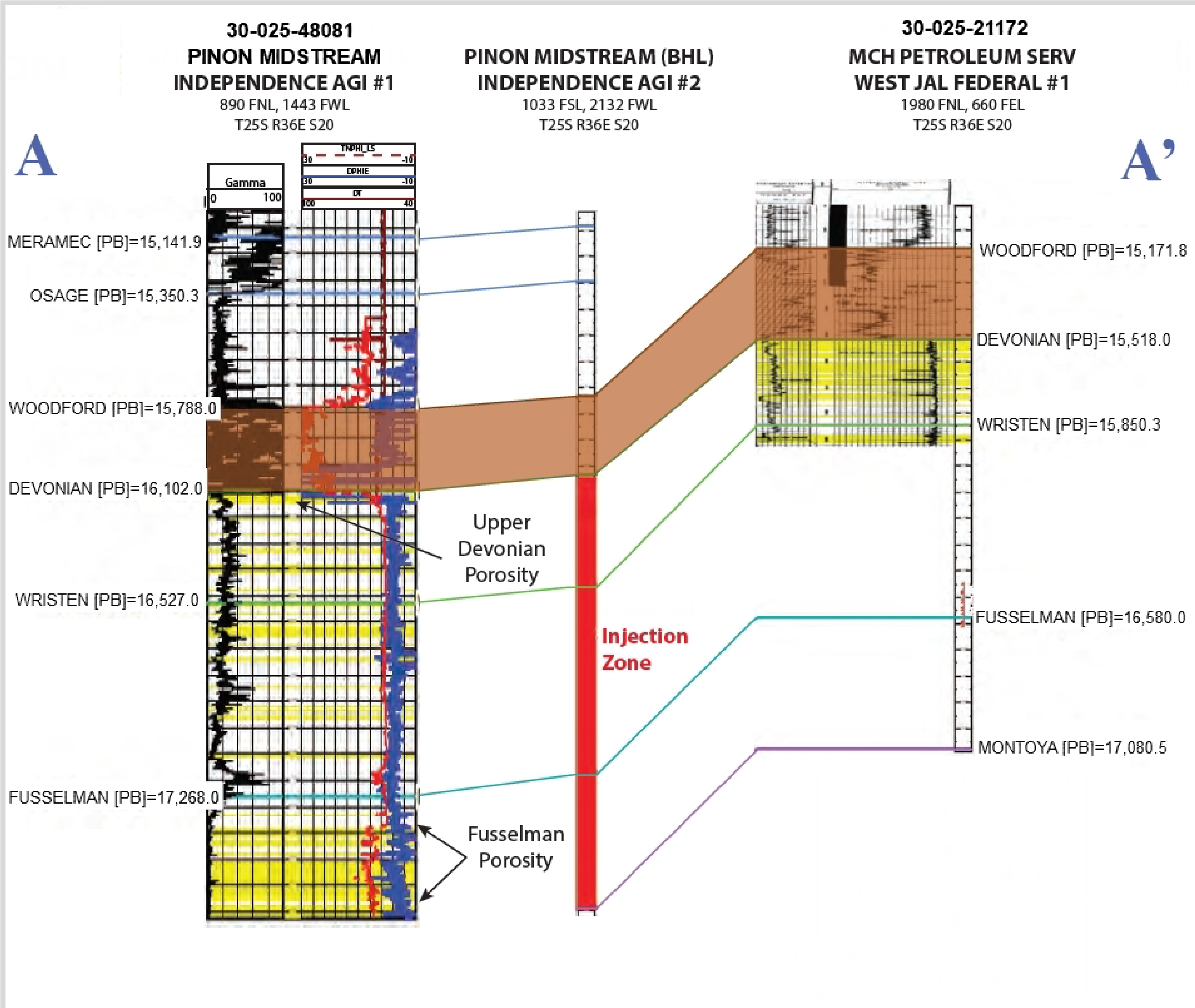
***Figure 3.3-1**: Type log of the Independence AGI #1, illustrating identified formation tops in TVD. Estimated formation tops for the Independence AGI #2 are included in Table 3.3-1 (Modified from Figure 14 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

__Table 3.3-1__: Anticipated formation tops at the Independence AGI #2 location. (Extracted from Table 6 of Class II permit application for Independence AGI #2, Geolex, Inc.)

FORMATION	DEPTH (TVD)	DEPTH (MD)	FORMATION	DEPTH (TVD)	DEPTH (MD)
Dockum	485	485	Bone Spring	8,467	8,632
Ochoa-Dewey	747	747	Wolfcamp	11,131	11,387
Rustler	1,130	1,130	Strawn	12,004	12,289
Salado	1,720	1,720	Atoka	12,733	13,044
Tansill	3,401	3,401	Morrow	13,541	13,880
Yates	3,461	3,461	Barnett	14,949	15,336
7 Rivers	3,542	3,542	Osage	15,380	15,703
Queen	3,663	3,663	Woodford	15,745	16,142
Capitan Reef	3,935	3,943	Devonian	16,080	16,477
Bell Canyon	5,425	5,484	Wristen	16,467	16,864
Cherry Canyon	6,277	6,364	Fusselman	17,201	17,598
Brushy Canyon	7,058	7,174	Montoya	17,684	18,081



<u>Figure 3.3-2</u>: Structure contour map showing the top of the Siluro-Devonian target reservoir. Two (2) faults identified in review of 3D seismic data are shown with red dashes. Also, shown are wells within 1 mile of the Independence AGI Wells that penetrate the Siluro-Devonian target zone. Cross section A – A' is shown in <u>Figure 3.3-3</u>. (Modified from Figure 15 of Class II permit application for Independence AGI #2, Geolex, Inc.) Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.



<u>Figure 3.3-3</u>: Structural cross section A-A' showing porosity profile from nearby wells penetrating the Siluro-Devonian Injection Zone and regional extent of overlying Woodford Shale caprock. The Independence AGI #2 Injection Zone is from 16,080 feet TVD to 17,683 feet TVD (red bar). (Modified from Figure 16 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.4 Chemistry of Siluro-Devonian Interval Formation Fluids

A review of formation waters from the U.S. Geological Survey National Produced Waters Geochemical Database v. 2.3 identified twenty-one (21) wells with analyses of fluid samples collected from the Siluro-Devonian interval. These samples were collected from wells within approximately fifteen (15) miles of the Independence AGI Wells. Results of laboratory analysis to determine their composition are summarized in Table 3.4-1. These results have been supplemented with samples collected from Independence AGI #1 on May 31, 2021 which show Total Dissolved Solids ("**TDS**") values ranging from 109,000 to 115,000 parts per million ("**ppm**").

*__Table 3.4-1__: Summary of Siluro-Devonian produced water analyses from nearby wells (U.S. Geological Survey National Produced Water Geochemical Database v. 2.3) * (Extracted from Table 7 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

API	WELL NAME	CONCENTRATION (parts per million)							
		TDS	HCO3	Ca	Cl	K + Na	Mg	Na	SO4
3002548081	Ind. AGI 1	110000	342	5600	68000	32559	759	31800	664
3002510945	Hill-federal D 1	112959	288	6264	67390	34340	1912	-	2765
3002510947	EC Hill-federal 1	35639	-	1369	22070		592	11608	-
3002511126	JR Holt A3	116415	154	7501	71110	34680	1767	-	1203
3002511196	S. Mattix Unit 3	68431	990	3180	40960	21690	974	-	637
3002511202	S. Mattix Unit 11	67130	853	5075	40430	16950	2348	-	1474
3002511383	Hodges B 3	81712	722	4320	47500	25400	1030	-	2740
3002511556	Blocker-federal 4	57675	595	2850	34030	18370	619	-	1211
3002511747	Ab Coates FED D2	82794	977	2408	47200	28190	851	-	3168
3002511760	Ida Wimberley 5	63817	360	2774	35870	20750	621	-	3442
3002811763	Ida Wimberley 9	61040	900	2680	35600	19560	800	-	1500
3002511765	Carlson-federal A3	66418	690	3002	37650	20390	1339	-	3347
3002511812	Clyde Lanehart 1	99879	687	4753	60410	32610	828	-	591
3002511818	Copper 1	27506	1089	1384	15270	8144	540	-	1079
3002511863	Arnott Ramsay B3	158761	476	17240	100300	35400	5345	-	-
3002511886	Dabbs 1	101036	540	5393	61630	30380	2183	-	910
3002511890	Sam Dabbs 1	85150	675	5368	50260	25130	1395	-	2322
3002511907	Arnott Ramsay F9	58220	367	1546	32790	-	278	20430	2816
3002511950	Farnsworth FED 6	31931	302	7196	20450	1151	2241	-	591
3002512272	LE Elliott FED H1	58687	761	3004	35460	18980	482	-	-
3002512286	JB McGhee 1	62392	552	2696	34380	20060	702	-	4002
3002521601	North Custer Mt 1	>64,000	1610	2136	36230	21830	403	-	1950

These analyses report TDS in the area of the Independence AGI Wells ranging from 27,506 to 158,761 ppm with an average of 75,981 ppm. The primary constituent in sampled formation waters is the chloride ion, with an average concentration of 45,227 ppm. The closest well, Independence AGI #1, at approximately 3,000 feet away from the Independence AGI #2 BHL, has reservoir fluids with a TDS value of approximately 110,000 ppm, and chloride ions in concentrations of approximately 68,000 ppm. Based on this data, the Siluro-Devonian reservoir fluids are anticipated to be completely compatible with the TAG injectate.

3.5 Potential for Induced Seismicity in the area of the Dark Horse Facility

To evaluate the potential for seismic events in response to injected fluids, Piñon conducted an induced-seismicity risk assessment for the area surrounding the Independence AGI Wells. This estimate (a) models the impact of seven (7) injection wells over a thirty (30) year injection period, and (b) estimates the fault-slip probability associated with the simulated injection scenario(s). This analysis was completed utilizing the Stanford Center for Induced and Triggered Seismicity's Fault Slip Potential ("**FSP**") model developed by Walsh and Zoback, 2016.

To identify subsurface structures in the area of the Independence AGI Wells, Piñon evaluated and interpreted licensed seismic survey data (WesternGeco – South Lea Survey) covering the Lea County area of interest. Based on this review, Piñon identified eight (8) subsurface faults in the area surrounding the Independence AGI Wells (Figure 3.5-1). The closest fault is observed to be located approximately one (1) mile east of the

Independence AGI Wells. Major faults in the area (those exhibiting significant lateral extent) generally strike NNW-SSE with minor faults striking NE-SW and NW to SE.

Due to the location of faults relative to the Independence AGI Wells and the general low density of injection wells in the immediate area of the Independence AGI Wells, it is anticipated that the injection scenario(s) will not pose any elevated risk of injection-induced fault slip. To support the interpretation that these structures would not be affected by operation of the Independence AGI Wells, a fault-slip probability analysis was completed to quantify the risk associated with injection operations in the area surrounding the Independence AGI Wells, and although the risk of induced seismicity is low, a seismic monitoring station was installed at the facility prior to the commencement of injection into Independence AGI #1. The station transmits data to the New Mexico Tech Seismic Network and will aid the state in seismicity interpretations.

To calculate the fault-slip probability for the model simulations, input parameters characterizing the local stress field, reservoir characteristics, subsurface features, and injected fluids are required. Parameters utilized and their sources for the area surrounding the Independence AGI Wells are included in Table 3.5-1. Additionally, Table 3.5-2 details the injection volume characteristics and locations of the injection wells modeled in the injection scenario(s). To ensure the model simulations provide a conservative estimation of induced-seismicity risk, injection wells included in the simulations were modeled utilizing their maximum anticipated daily injection volumes as recorded by NMOCD approved permits. Due to the minimal reported injection volume of the Jal North Ranch SWD #1 (30-025-27085) which is approximately 5.3 miles to the east northeast of the Independence wells, a potential of 10,000 bpd was assumed to account for the potential of increased injection rates due to future needs of the operator or any future workover that may improve the injectivity of this well.

Daily maximum injection volumes utilized in the fault-slip probability model range from 4,265 to 30,000 bpd (Table 3.5-2). In submission of the Class II injection well applications, Piñon requested approval to operate the Independence AGI Wells for a period of at least thirty (30) years, however, the duration of the FSP model simulation was increased to forty (40) years to characterize the reservoir effects of injection wells that are currently operating and have been in operation since 2010. Figure 3.5-2 shows the resultant pressure front and single well radial pressure solutions, as predicted by the FSP model, after thirty (30) years of injection at the maximum injection rates.

For this study, limitations of the FSP model required a conservative approach be taken in determining the fault-slip probability of the injection scenario. Specifically, the FSP model is only capable of considering a single set of fluid characteristics and this study aims to model an injection scenario that includes both brine injection and AGI. To ensure a conservative fault-slip probability estimate, the Independence AGI Wells were simulated utilizing the characteristics of a brine injectate. This approach yields a more conservative model prediction as brine displays greater density, dynamic viscosity, and is significantly less compressible than TAG. For comparison, characteristics of TAG at the anticipated reservoir conditions, as modeled by AQUAlibrium™, are shown in Table 3.5-1.

Generally, faults considered in this assessment are predicted by the FSP model to have very low potential for injection-induced slip and operation of the Independence AGI Wells is not predicted by the model to contribute significantly to the estimate of risk (Table 3.5-3 and Figure 3.5-3). Table 3.5-3 summarizes the predicted pressure change along each fault segment and includes the model-derived pressure change necessary to induce slip for each feature. Fault-slip probability values range from 0.00 to 0.05 with the majority of fault segments predicted to have zero probability of slip (Table 3.5-3). Major faults (faults 4, 7, and 8 in Figure 3.5-1) in the area, which would have the greatest energy release potential upon slip, are predicted to have zero probability for slip in response to the modeled injection scenario.

In summary, no structures included in the modeled simulations are predicted to be at increased risk for injection-induced slip in response to the injection scenario presented. Features estimated to have a non-zero slip potential are generally smaller-scale features and predicted probabilities are very low (≤ 0.05). Furthermore, subsequent model simulations in which contribution from Independence AGI #2 is excluded illustrate that operation of the Independence AGI #2 will have little impact on conditions near the identified faults in the area due to significantly lower proposed injection volumes in comparison to nearby brine injection wells.

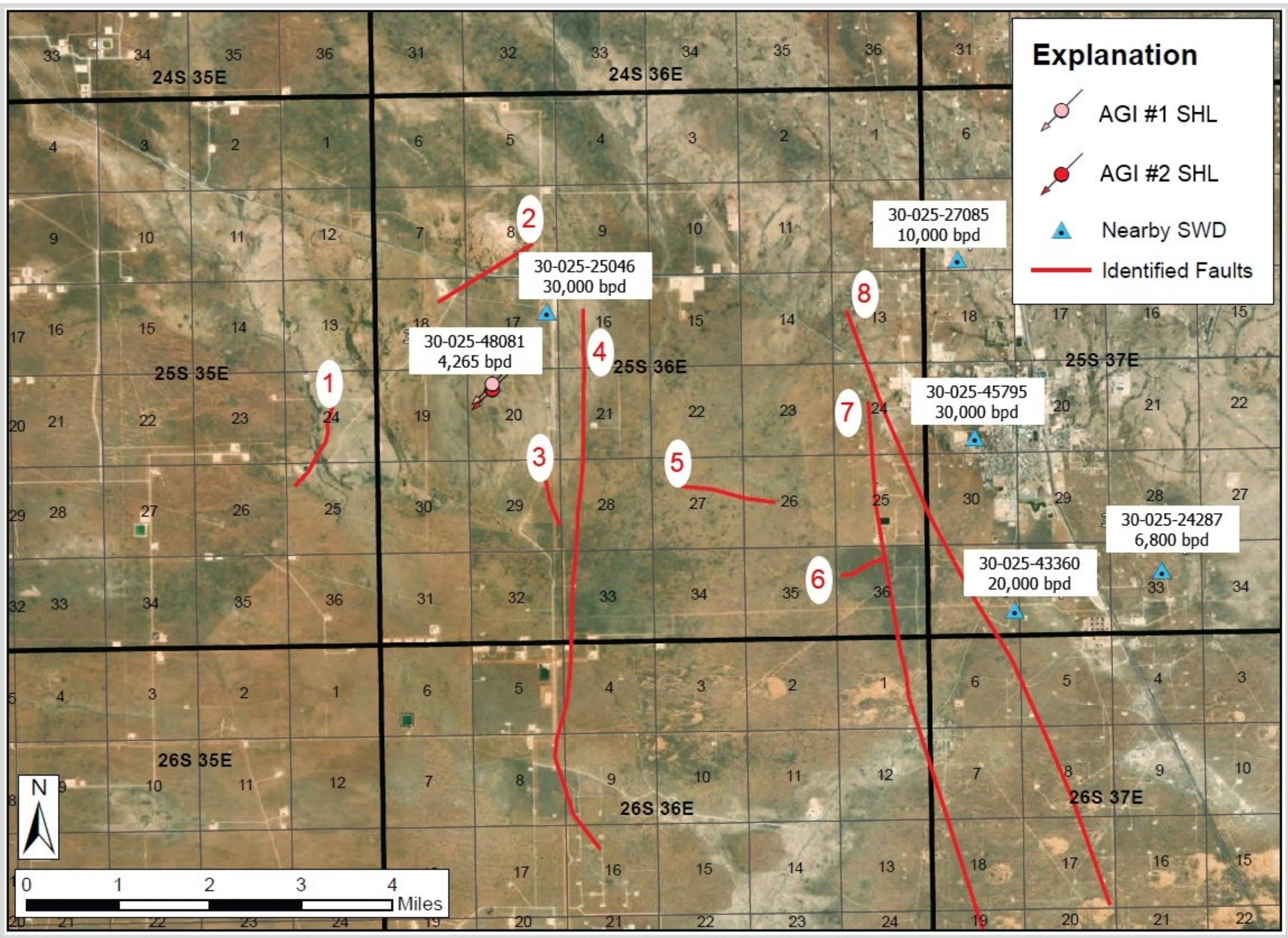


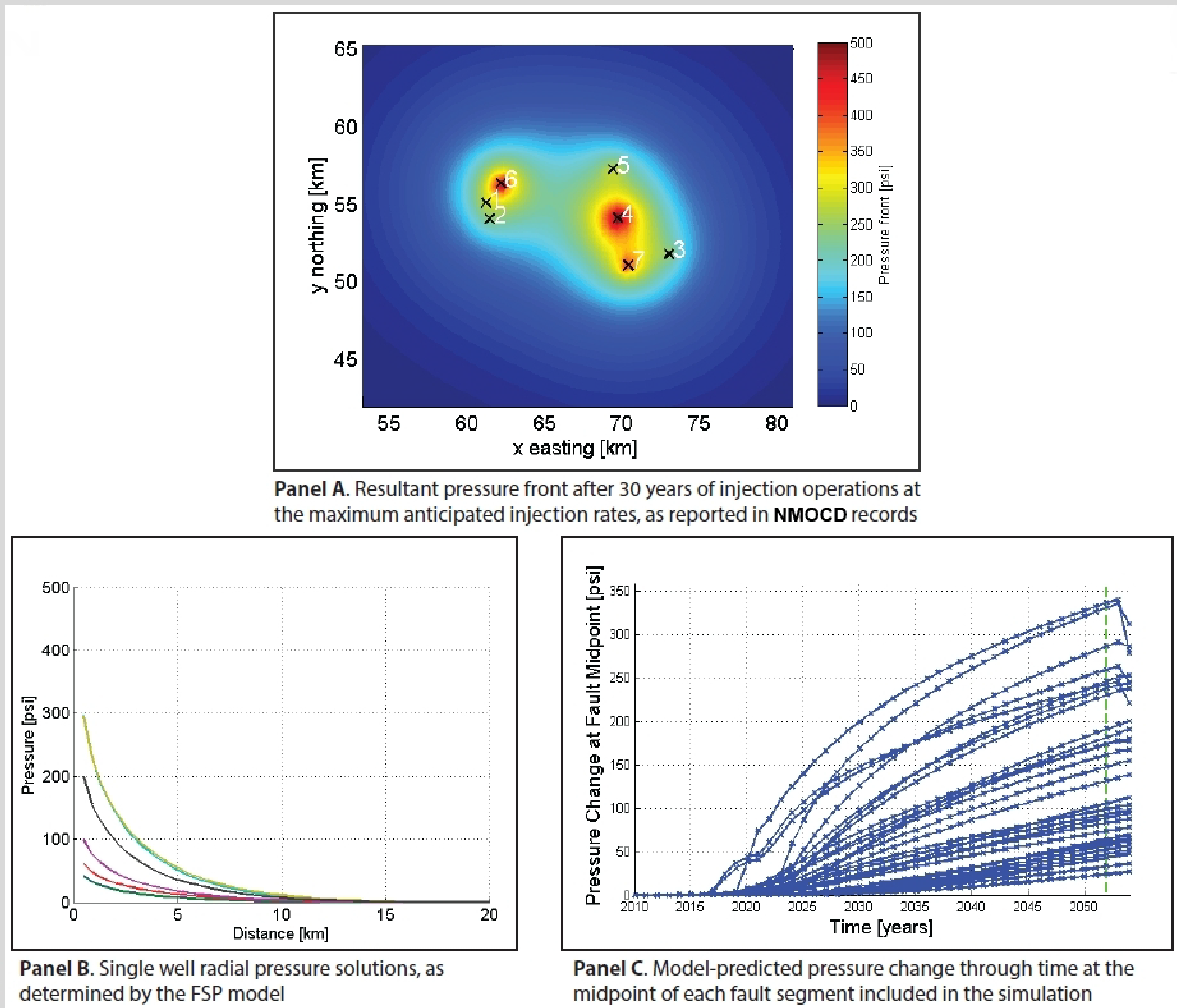
***Figure 3.5-1**: Map showing Siluro-Devonian injection wells and subsurface identified faults in the vicinity of the Independence AGI Wells. (Modified from Figure 18 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

***Table 3.5-1**: Input parameters and source material for FSP model simulations. (Extracted from Table 10 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

Modeled Parameter	Input Value	Variability (+/-)	UOM	Source
Stress				
Vertical Stress Gradient	1.05	0.105	psig/ft	Nearby well estimate
Max Horizontal Stress Direction	N75E	5	Deg	Lund Snee & Zoback, 2018
Reference Depth	17000		ft	Nearby well evaluation
Initial Res. Pressure Gradient	0.43	0.043	psig/ft	Lund Snee & Zoback, 2018 Nearby well evaluation
A_ϕ Parameter	0.6	0.06	-	Lund Snee & Zoback, 2018
Reference Friction Coefficient (μ)	0.6	0.06	-	Standard value
Hydrologic				
Aquifer Thickness	1500	0	ft	Nearby well evaluation
Porosity	3.5	0.35	%	Nearby well evaluation
Permeability	20	2	mD	Nearby well evaluation
Material Properties				
Density (Water)	1040	40	Kg/m^3	Standard value
Dynamic Viscosity (Water	0.0008	0.0001	Pa.s	Standard value
Fluid Compressibility (Water)	3.6×10^{-10}	0	Pa^{-1}	Standard value
Rock Compressibility	1.08×10^{-9}	0	Pa^{-1}	Standard value
Acid Gas Properties @ 7,370 psig & 228 °F				
Density	821.80	-	kg/m^3	AQUAlibrium™
Dynamic Viscosity	8.067×10^{-5}	-	Pa.s	AQUAlibrium™

***Table 3.5-2**: Location and characteristics of injection wells modeled in the FSP assessment. (Extracted from Table 11 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

#	API	Well Name	LAT	LONG	Volume (bbls/day)	Start (year)	End (year)
1	3002548081	Independence AGI #1	32.120855	-103.291021	4265	2020	2052
2	-	Independence AGI #2	32.111454	-103.288812	4265	2022	2052
3	3002524287	Crosby Deep #2	32.089508	-103.166733	6800	2010	2052
4	3002545795	Sholes Deep SWD #1	32.110998	-103.201266	30000	2020	2052
5	3002527085	Jal N. Ranch SWD #1	32.139347	-103.203911	10000*	2017	2052
6	3002525046	West Jal B Deep #1	32.132091	-103.280708	30000	2015	2052
7	3002543360	Kimberly SWD #1	32.083537	-103.194274	20000	2019	2052



Panel A. Resultant pressure front after 30 years of injection operations at the maximum anticipated injection rates, as reported in **NMOCD** records

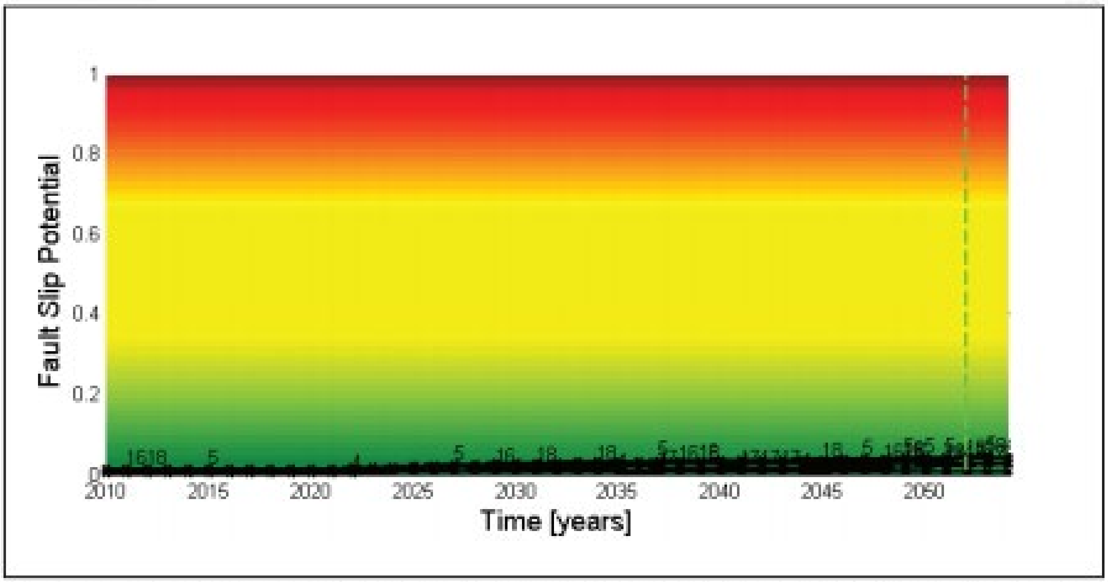
Panel B. Single well radial pressure solutions, as determined by the FSP model

Panel C. Model-predicted pressure change through time at the midpoint of each fault segment included in the simulation

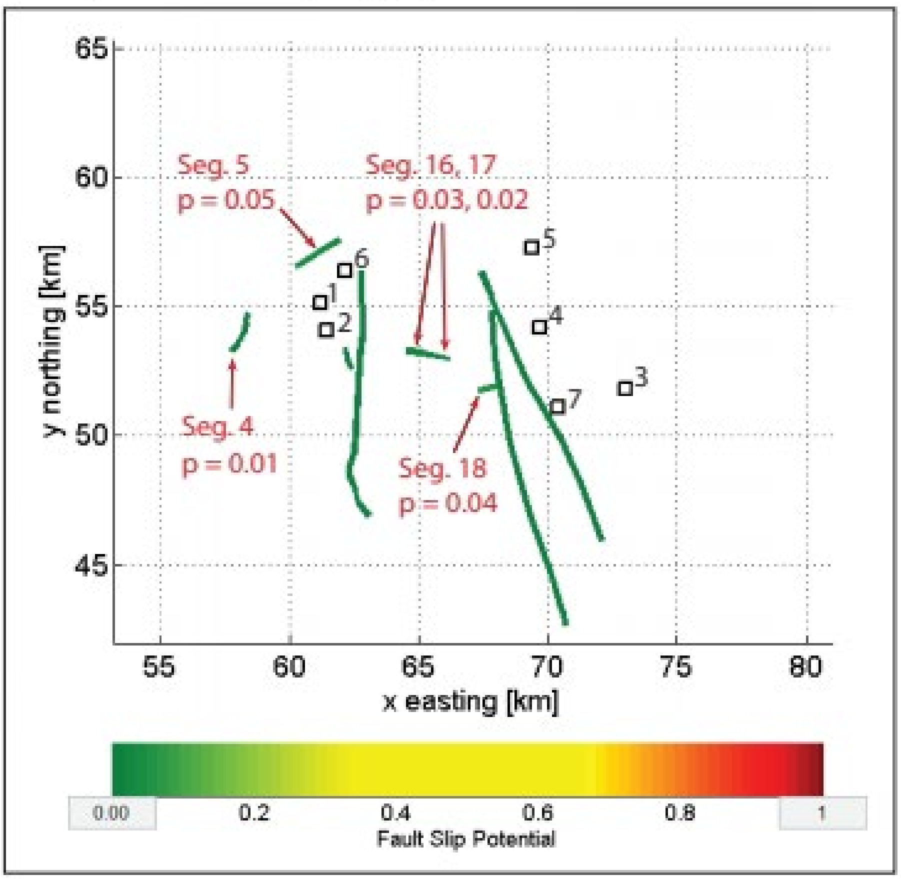
<u>Figure 3.5-2</u>: Summary of model-predicted pressure effects in response to the simulated seven (7) well injection scenario. (Extracted from Figure 19 of Class II permit application for Independence AGI #2, Geolex, Inc.)

Table 3.5-3: Summary of model-simulation results showing the required pressure change to induce fault slip, actual change in pressure as predicted by the FSP model, probability of fault slip at the end of the thirty (30) year injection scenario, and fault-slip probability when Independence AGI #2 is excluded from simulation. (Extracted from Table 12 of Class II permit application for Independence AGI #2, Geolex, Inc.)

Fault #	Segment #	ΔPressure necessary to induce fault slip	Actual ΔPressure at 2052	Fault Slip Potential at 2052	FSP (excluding AGI #2)
1	1	3137	109	0.00	0.00
	2	4357	103	0.00	0.00
	3	1786	93	0.00	0.00
	4	1201	83	0.01	0.01
2	5	1197	253	0.05	0.05
3	6	6869	186	0.00	0.00
	7	6298	168	0.00	0.00
4	8	5645	277	0.00	0.00
	9	4610	194	0.00	0.00
	10	5005	117	0.00	0.00
	11	2709	70	0.00	0.00
	12	5302	63	0.00	0.00
	13	6339	57	0.00	0.00
	14	6899	51	0.00	0.00
	15	4197	46	0.00	0.00
5	16	1101	192	0.03	0.03
	17	1085	199	0.02	0.02
6	18	1554	234	0.04	0.04
7	19	6012	290	0.00	0.00
	20	6680	241	0.00	0.00
	21	6914	133	0.00	0.00
	22	6758	61	0.00	0.00
	23	6931	33	0.00	0.00
	24	6590	25	0.00	0.00
8	25	6508	250	0.00	0.00
	26	6327	334	0.00	0.00
	27	5455	228	0.00	0.00
	28	6305	174	0.00	0.00
	29	6684	89	0.00	0.00



Panel A. Fault-slip probability throughout the entire simulated injection period. FSP model results suggest no significant risk of injection-induced slip along any feature included in the simulation.



Panel B. Map view illustrating the model-estimated slip potential of faults at the end fo the 42-year injection scenario. Any feature estimated to have a non-zero slip potential determination is labeled on the above map.

<u>Figure 3.5-3</u>: Summary of model-determined fault-slip probabilities over the simulated injection period (2010-2052). (Modified from Figure 20 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.6 Groundwater Hydrology in the Vicinity of the Dark Horse Facility

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are fifteen (15) water wells and points-of-diversion located within a two (2) mile radius of the Independence AGI Wells. Of these wells, the closest is located approximately 0.34 miles away and has a total depth of 505 feet (Figure 3.6-1 and Table 3.6-1). The remaining fourteen (14) wells within the two (2) mile radius have depths of approximately 240 to 600 feet deep, collecting water from Alluvium and the Triassic red beds. The shallow freshwater aquifer will be protected as the Independence AGI Wells are designed to isolate shallow zones via a five (5) string casing design including a surface casing interval that extends to 1,230 feet within the Rustler Formation, effectively isolating shallow groundwater resources (Figures A1-1 and A1-2).

The area surrounding the Independence AGI Wells is arid and there are no surface water bodies within a two (2) mile radius.

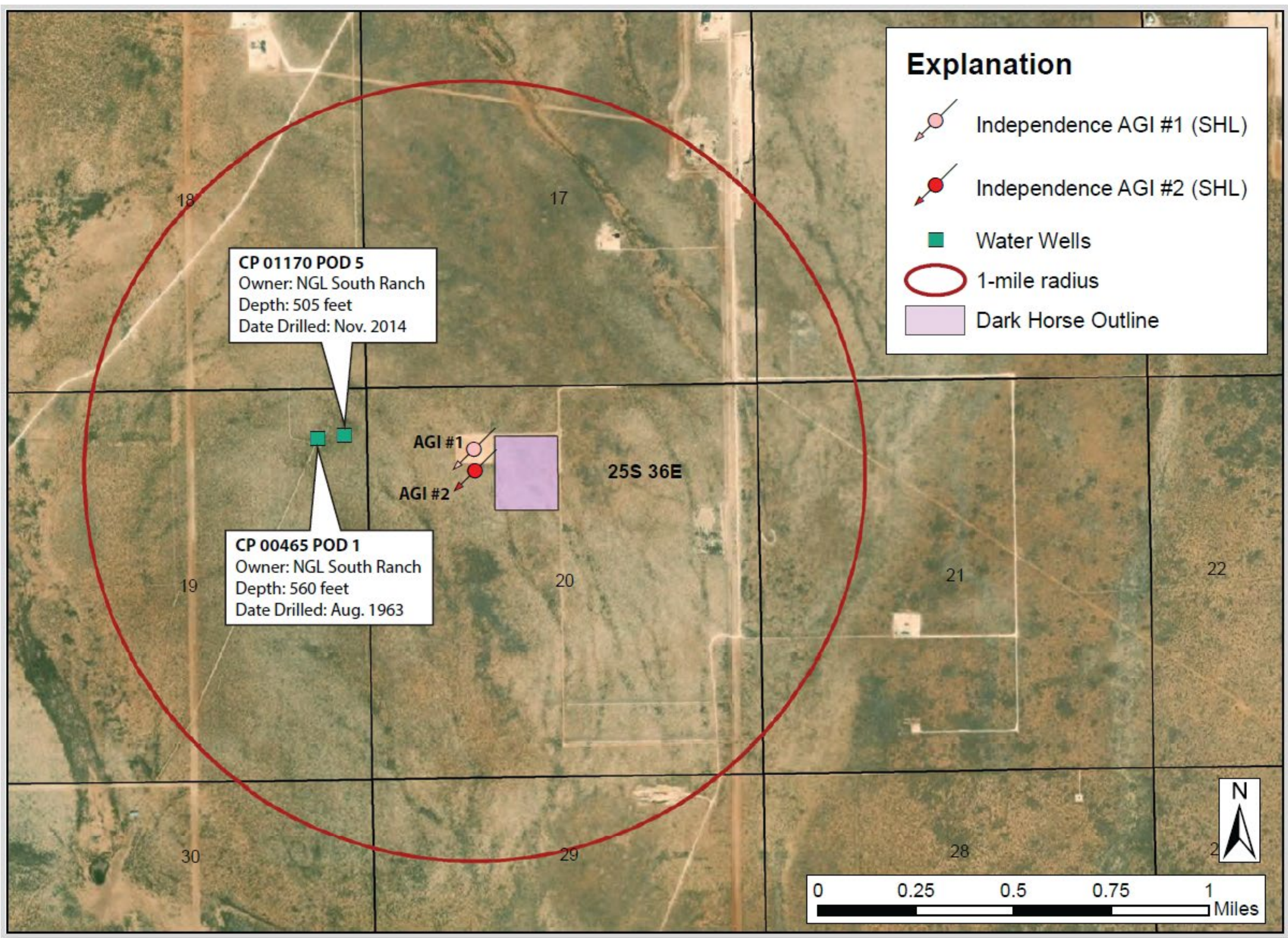


Figure 3.6-1: Reported water wells within 1-mile radius of the SHLs of the Independence AGI Wells. The BHLs for AGI #1 and #2 are not shown. (Extracted from Figure 17 of Class II permit application for Independence AGI #2, Geolex, Inc.) Only SHLs shown for the Independence AGI #1 and #2 wells.

***Table 3.6-1**: Water wells within one (1) mile of the Independence AGI Wells (Retrieved from the New Mexico Office of the State Engineer's Files on October 4, 2021). (Extracted from Table 8 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

POD #	Source	Use	Owner	LAT (NAD83)	LONG (NAD83)	Distance (miles)	Depth (feet)	Date Completed
CP 1170 POD 5	Shallow	Commercial	NGL South Ranch	32.121417	-103.296667	0.34	505	11/2014
CP 465 POD 1	Shallow	Commercial	NGL South Ranch	32.119465	-103.299882	0.53	560	08/1963

According to Order No. 190 of the New Mexico Office of the State Engineer signed March 22, 2021, the Capitan Underground Water Basin, within which the Independence AGI Wells lie, is closed indefinitely to new appropriations of water. Therefore, no new water wells are anticipated to be constructed during the Independence AGI Wells' anticipated thirty (30) year operation period. Due to the shallow completion depths of the few groundwater wells in the area surrounding the Independence AGI Wells, it is highly unlikely that groundwater wells will serve as conduits for CO_2 leakage to the surface.

Geolex conducted a review of Geology and Ground-Water Conditions in Southern Lea County, New Mexico (Nicholson and Clebsch, 1961) to identify published groundwater data representative of nearby water wells in the area surrounding the Independence AGI Wells. Table 3.6-2 summarizes the wells identified in this review and the results of those analyses.

***Table 3.6- 2**: Chemical analysis results of samples collected from water wells in the area surrounding the Independence AGI Wells (Nicholson and Clebsch, 1961 – Geology and Groundwater Conditions in Southern Lea County, New Mexico). (Taken from Table 9 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

Historical Owner	Location (T-R-S)	Location (Qtr-Qtr)	Depth (ft)	Ca (ppm)	Mg (ppm)	Na+K (ppm)	HCO_3 (ppm)	SO_4 (ppm)	Cl (ppm)	NO_3 (ppm)
Sun Oil Co.	25-37-15	NE/4 NE/4	-	307	98	271	145	737	610	9
City of Jal	25-37-19	NE/4 NE/4	500	55	49	170	376	280	71	0.4
City of Jal	25-37-19	SE/4 NE/4	450	34	43	175	264	286	54	0.5
City of Jal	25-37-20	NW/4 SW/4	70	-	-	-	150	145	168	7.6

This analysis confirms that the Independence AGI Wells pose no risk of contaminating groundwater in the area as (a) the well design includes material considerations to protect shallow groundwater resources, and (b) there are no identified conduits that would facilitate migration of injected fluids to freshwater-bearing strata nor to the surface.

3.7 Historical Operations

3.7.1 Dark Horse Facility and Independence AGI Wells

Piñon operates the Dark Horse Facility which treats sour natural gas that is delivered to the facility from gathering systems in the area. These gathering systems are shown in Figure 3.7-1. Figure 3.7-2 shows the major process units and the H_2S and gas detection sensors. The figure in Appendix 10 shows the process block flow diagram for the Dark Horse Facility. The Dark Horse Facility is designed to treat produced natural gas containing H_2S and CO_2 and handles and/or generates sulfur dioxide (SO_2). Ameredev received authorization to inject H_2S and CO_2 from the NMOCD and drilled and completed Independence AGI #1, which is utilized for the injection and permanent sequestration of TAG. Procedures and materials used by Ameredev for well operations and construction are consistent with NMOCD regulations pertaining to "Protection from Hydrogen Sulfide during Drilling, Completion, Workover and Well Servicing Operations" (NMAC 19.15.11.11). Following drilling and completion of the Independence AGI #1, and after approval by NMOCD, Ameredev contributed and assigned operations of the well to Piñon. Piñon became the operator of record for the Independence AGI #1 on August 24, 2021.

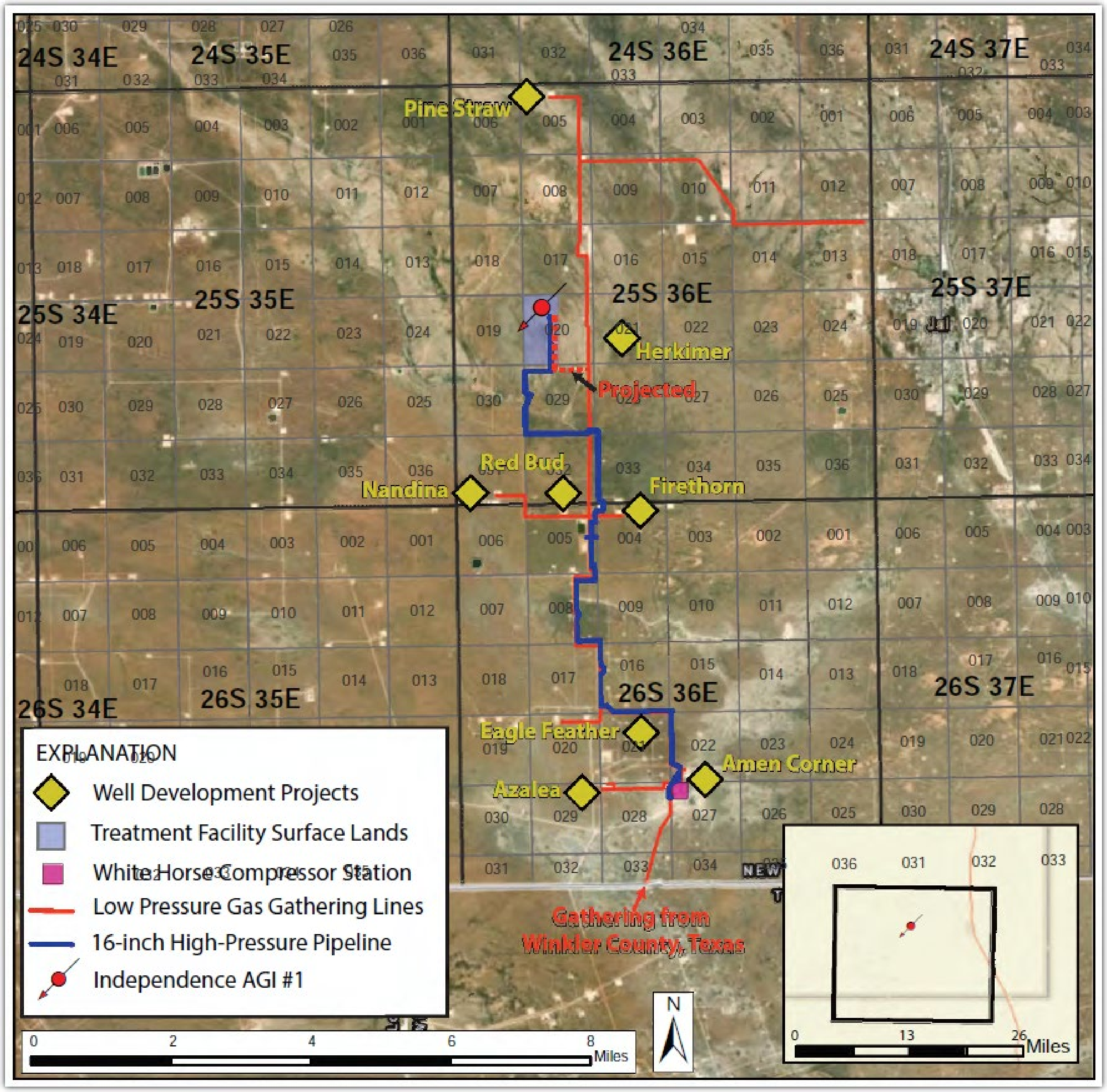


Figure 3.7-1: *Location of gas gathering lines leading to the Dark Horse Gas Treatment Plant and White Horse Compression station. Low pressure lines either lead to the compressor station or directly to the treatment plant. Gas sent to the compressor station is sent to the treatment plant via a 16-inch high-pressure pipeline.*

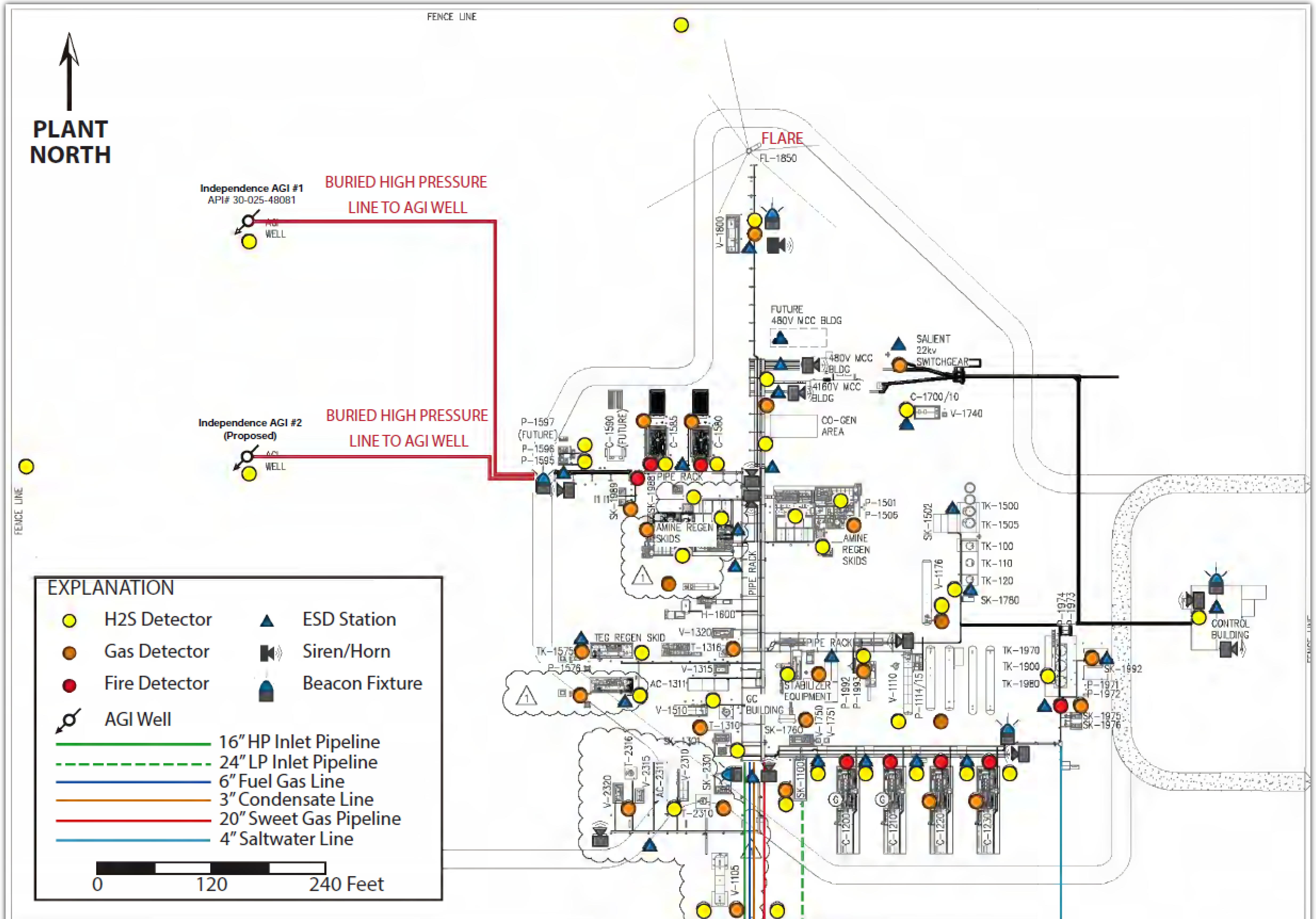


Figure 3.7-2: Detailed Dark Horse Facility schematic illustrating the location of major process units, all emergency equipment, H_2S and gas detection sensors, sirens and beacons, and major gas flow lines at the facility. (Taken from Figure 2 of the H_2S Contingency Plan for Dark Horse Gas Treatment Facility, Geolex, Inc.). The yellow circles indicate the location of fixed H_2S sensors.

3.7.2 Operations within a 2-mile radius of the Independence AGI Wells

Appendix 3 summarizes in detail all NMOCD recorded wells within a two (2) mile radius of the Independence AGI Wells. These wells are shown in Figure 3.7-3 and include active, plugged, and new (permitted but not yet drilled) well locations. In total, there are fifty-four (54) wells within a two (2) mile radius of the Independence AGI Wells. Of these, there are ten (10) active wells, thirty-three (33) permitted wells, and eleven (11) plugged wells.

Active wells in the area include one brine injection well completed across the Strawn through Fusselman formations, and nine (9) active oil and natural gas wells completed in various other strata.

There are two (2) third-party wells within two (2) miles of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone (Table 3.7-1).

The first well is an active brine injection well (West Jal B Deep #001) located approximately one (1) mile from the Independence #2 SHL. This well was drilled to a total depth of 18,945 feet and is permitted to inject through perforated intervals of the Strawn through Fusselman strata. A Form C-103- Sundry Notices and Reports on Wells, submitted November 2018 contain a wellbore diagram that shows the locations of two cast iron bridge plugs ("**CIBP**"). The first CIBP is at a measured depth of 14,200 feet (within the lower Atoka Formation), and the second CIBP is at a measured depth of 17, 100 feet (within the Fusselman Formation). Despite BC & D Operating being granted approval for injection into the Fusselman (approved by NMOCD June 2014), NMOCD records document no reports of work to drill out the CIBP at 14,200 feet. The same Form C-103- Sundry Notices and Reports on Wells mentioned above indicates the intent of BC & D Operating to drill out the CIBP, but there have been no identified subsequent reports confirming completion of this work. Additionally, reported injection volumes since the filing of the Form C-103 in November 2018 for this well do not appear to exhibit any significant increase that might indicate this work was completed. Furthermore, according to a search of publicly available data as of June 2023, the West Jal B Deep #001 ceased water injection operations during or after July 2022, and water injected volumes have been reported as "0" since July 2022.

The second well penetrating the Siluro-Devonian Injection Zone is the plugged West Jal Unit #1, located approximately 0.67 miles from the Independence AGI #2 SHL. Final plugging operations were completed in April 1984 and all relevant plugging reports and documents are included in Appendix 9. The well is properly cemented through the Siluro-Devonian Injection Zone, and it is not anticipated to be negatively affected by the operation of the Independence AGI Wells nor is it considered to be a likely pathway for CO_2 leakage to the surface.

Appendix 3 and Figure 3.7-3 also show a number of wells in the area which have approved permits to drill but are not yet drilled. The new oil and natural gas wells are targeting various production zones, more than 4,000 feet above the Siluro-Devonian Injection Zone for the Independence AGI Wells. All new oil and natural gas wells and injection wells are subject to the requirements of regulations governing sealing off strata (NMAC 19.16.16.10) and casing and tubing requirements (NMAC 19.16.16.10) to prevent the contents of production or injection zones from passing into other strata. To minimize the likelihood of leaks from new wells, NMAC 19.15.26.9 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." Therefore, due to the fact that these wells do not penetrate the Siluro-Devonian Injection Zone, and that the wells are more than 4,000 feet above the Siluro-Devonian Injection Zone, Piñon does not consider these new wells to be pathways for CO_2 leakage to the surface. In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage.

Table 3.7-1: Wells located within a two (2) mile radius of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone. (Additional details are provided in Appendix 3)

API	Well Name	Pool	Status	TVD (feet)
30-025-21172	WEST JAL UNIT #1	Strawn	Plugged	17,086
30-025-48081	INDEPENDENCE AGI #1	Devonian - Fusselman	Active	17,750
30-025-49974	INDEPENDENCE AGI #2	Devonian - Fusselman	New	17,683 (proposed)
30-025-25046	WEST JAL B DEEP #001	Mississippian – Fusselman	Active	18,945

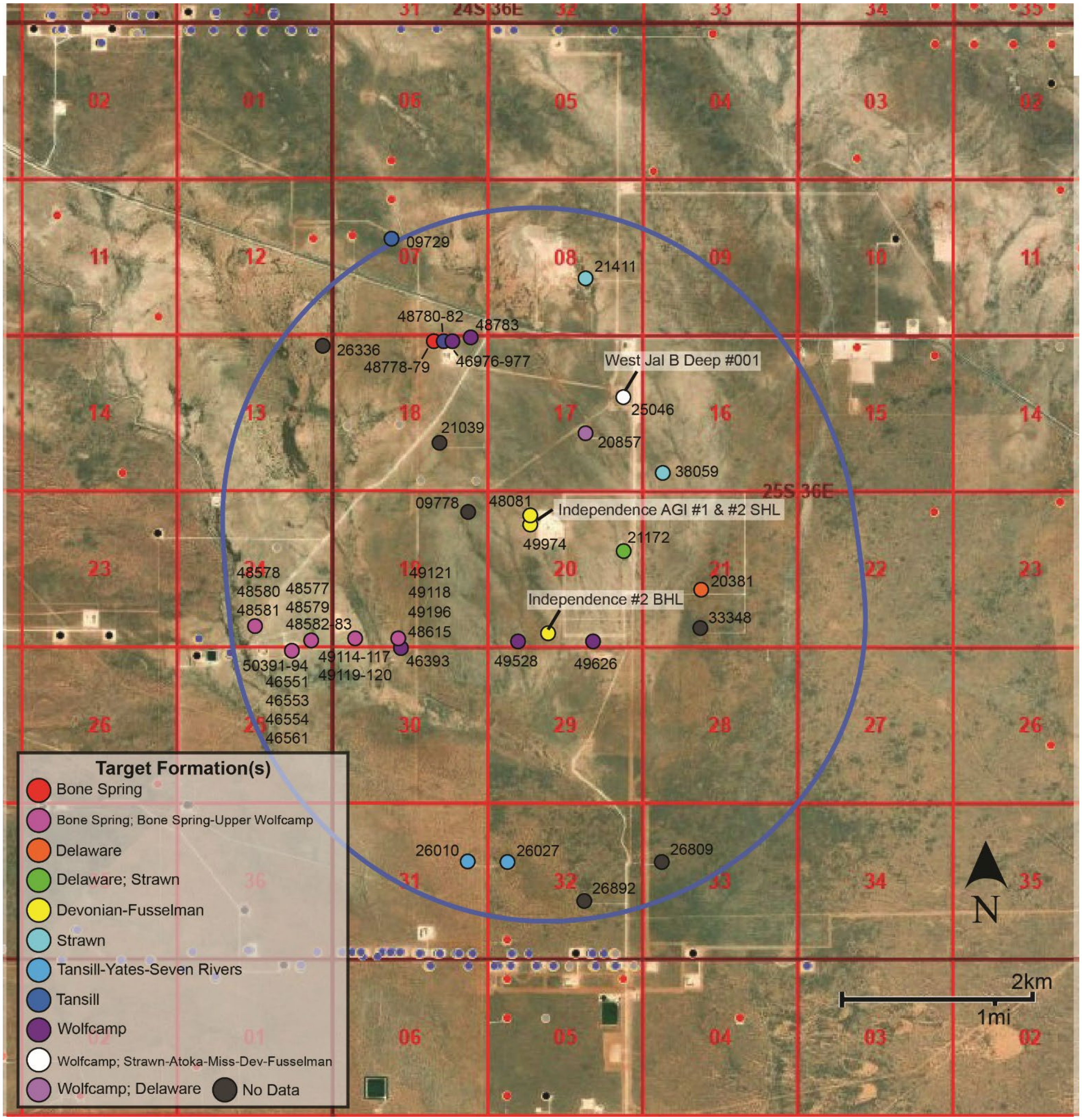


***Figure 3.7-3**: Location of all oil- and natural gas-related wells within a two (2) mile (blue line) of the Independence AGI Wells. Colors indicate the target formation(s) for each well. The oblong shape of the two (2) mile area accounts for the BHL of Independence AGI #2 as shown in Figure 3.1-1. Labels denote the last five (5) digits of API #30-025-XXXXX. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.*

3.8 Description of Injection Process

Once delivered to the Dark Horse Facility, sour natural gas is treated using amine to isolate H_2S and CO_2. The amine (which now contains H_2S and CO_2) is then regenerated which creates a TAG waste stream. This TAG waste stream is then routed to on-site compression facilities that compress the TAG waste stream into a dense phase (roughly 1,250 psig). The dense phase stream is then pumped to upwards of 2,500 psig prior to being sent to the Independence AGI Wells, through a National Association of Corrosion Engineers ("**NACE**") rated pipe, for injection. Figure 3.8-1 is a schematic of the surface facilities for the Independence AGI Wells. The sweet natural gas that results from the amine scavenging process is then treated to remove water ("**H_2O**")and subsequently transported offsite, via pipeline, and redelivered to Piñon's customers at various delivery points.

For the period of September 2021 through March 2022, the TAG stream at the Dark Horse Facility averaged 57.076% CO_2 and 38.703% H_2S by volume, with hydrocarbons (C1 – C7) and H_2O comprising the remaining volume.

The anticipated duration of TAG injection into the Independence AGI Wells at the Dark Horse Facility is approximately thirty (30) years.

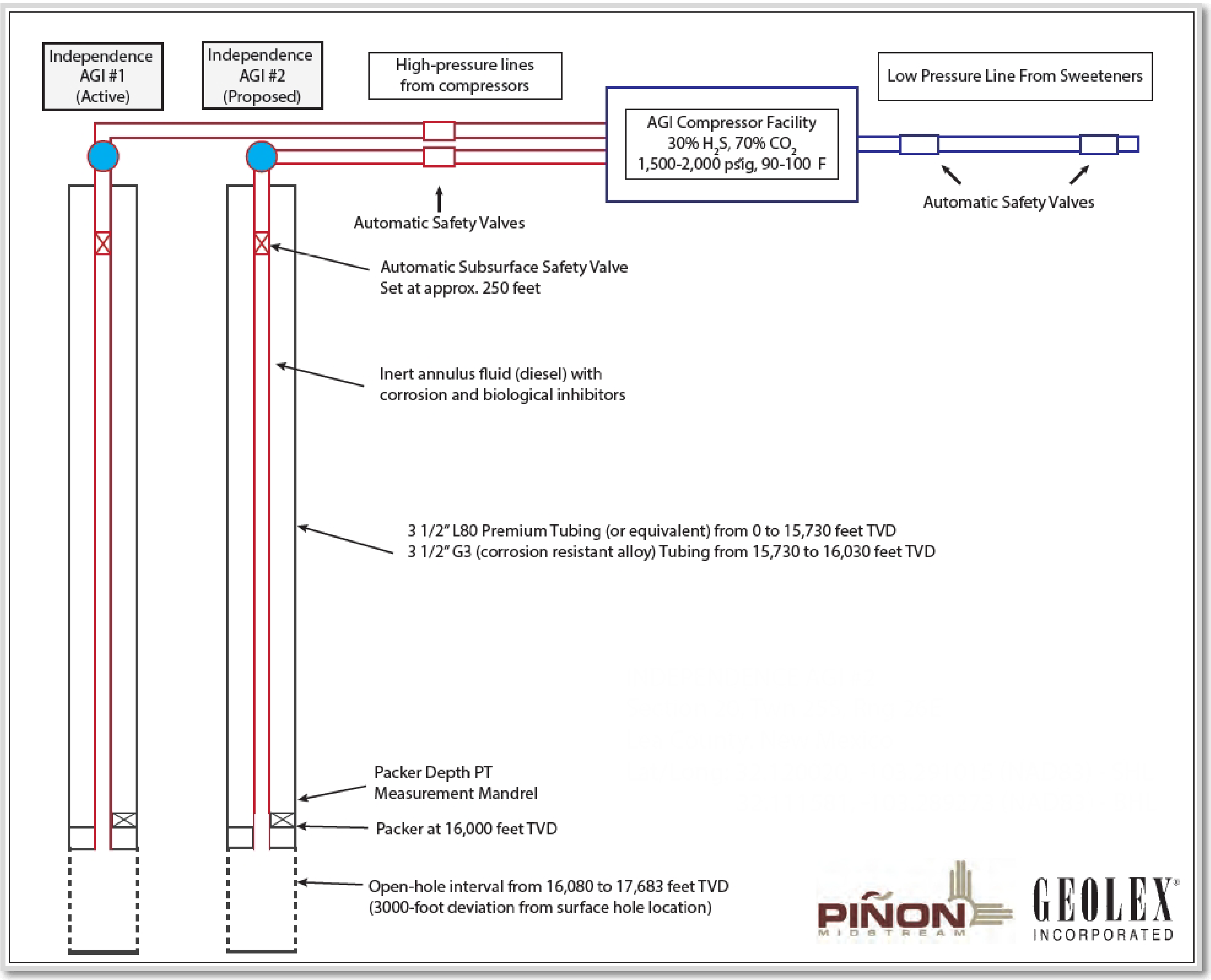


***Figure 3.8-1**: Schematic of surface facilities at the Dark Horse Facility and the Independence AGI Wells. (Modified from Figure 3 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

3.9 Reservoir Characterization Modeling

The Independence AGI Wells penetrate the lower Devonian Thirtyone formation and the Silurian Wristen and Fusselman formations and overlie the Ordovician Montoya formation. The upper Devonian Woodford formation serves as the primary containment seal with thick shales having an estimated permeability in the nanodarcy range.

Schlumberger's Petrel (Version 2020.4) software was used to construct the geological models used in this work. Schlumberger's simulation software Eclipse Compositional E300 (Version 2020.1) was used in the reservoir simulations presented in this MRV Plan with simulation results and visuals provided by Geolex Inc. The model simulates solubility trapping of the injected TAG in the formation water and/or the portion of the TAG that can exist in a supercritical phase. The modeling did not consider CO_2 storage attributed to mineral and geomechanical trapping mechanisms. Also, the model did not implicitly model storage attributed to residual trapping because insufficient information was available to develop the hysteresis effects.

Though the Independence AGI Wells were modeled separately, similar constraints were used for both models. The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. The injection gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Both TAG components are assumed to be soluble into the aqueous phase. An irreducible water saturation of 0.17 is used to generate the relative permeability curves for the gas/water system. The external boundary conditions are specified to be Neumann boundaries and hence no-flow with respect to mass.

3.9.1 AGI Injection Characterization and Modeling

Formation tops were picked from the few well logs available for the area and geophysical measurements and mapped to construct the structural surfaces for the Silurian-Devonian reservoir between the underlying Montoya and capping Woodford formations. The geologic model extends approximately twenty (20) square miles with an irregular polygonal edge (Figure 3.9-1) and includes relevant subsurface features (e.g. faults, folds) and nearby injection wells. The simulation grid is comprised of 292 simulation layers characterizing eight (8) discrete zones. Horizontal spacing is uniform at 500 × 500 feet throughout the model, and the numerical grid overall contains 923,000 grid cells. Figure 3.9-1 shows the structural surface for Layer 1, covering the top of the reservoir immediately below the Woodford cap. Porosity data derived from the Independence AGI #1 well logs augmented by 3D seismic survey impedance data along with drill-stem and injection tests were used to populate the model porosity values (Figure 3.9-2). A porosity-permeability relationship was established to develop a correlation to populate 3D distribution of permeability (Figure 3.9-3). The permeability distribution signifies a fairly tight formation with typical values ranging from 1.0 to 79.0 millidarcies. Figure 3.9-4 shows the permeability distribution in Layer 1 of the model at the top of the Devonian Thirtyone Formation (*see* Section 3.3.1). Separate scenarios were run for non-transmissive faults and for permeability across faults.

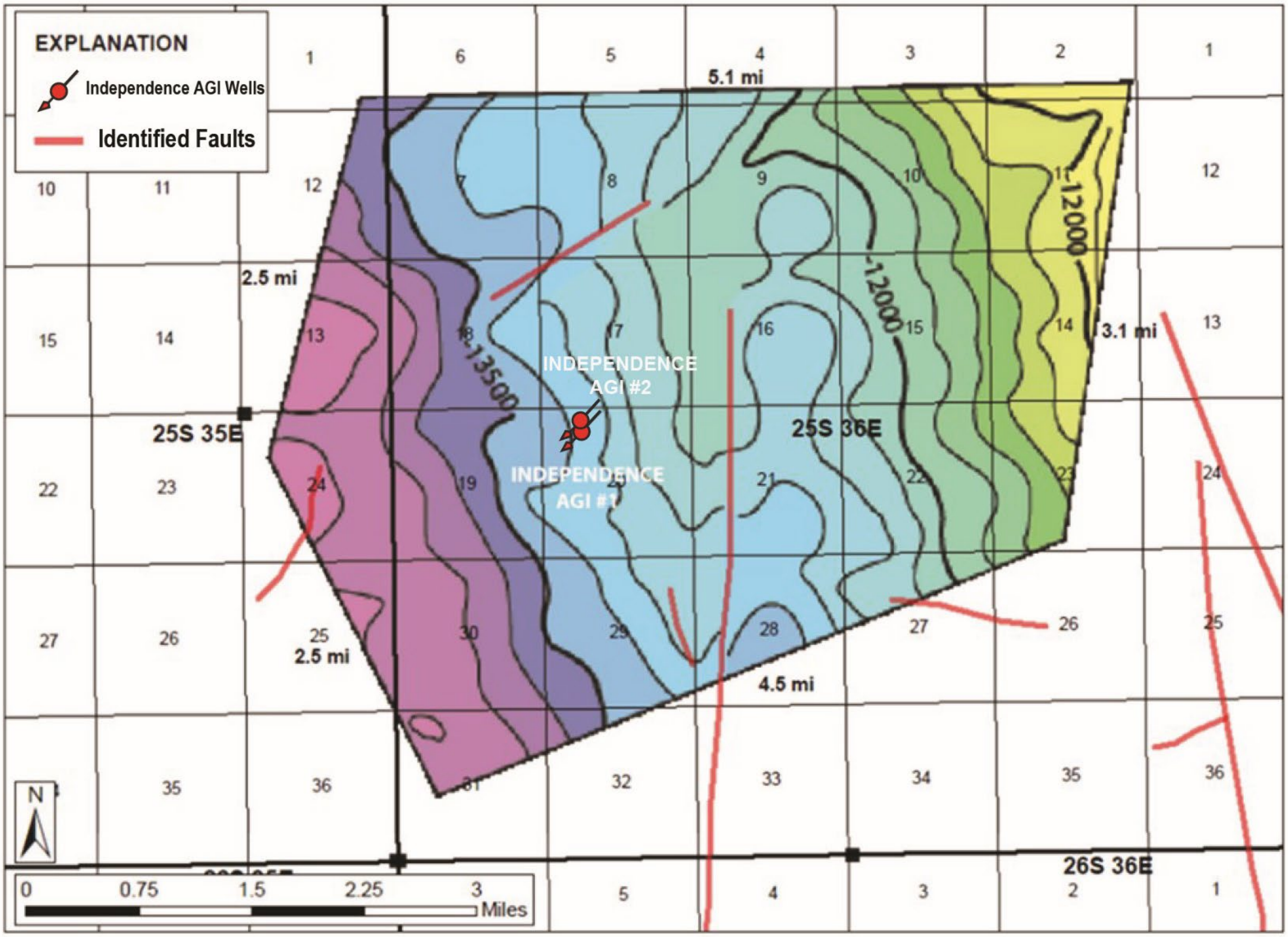
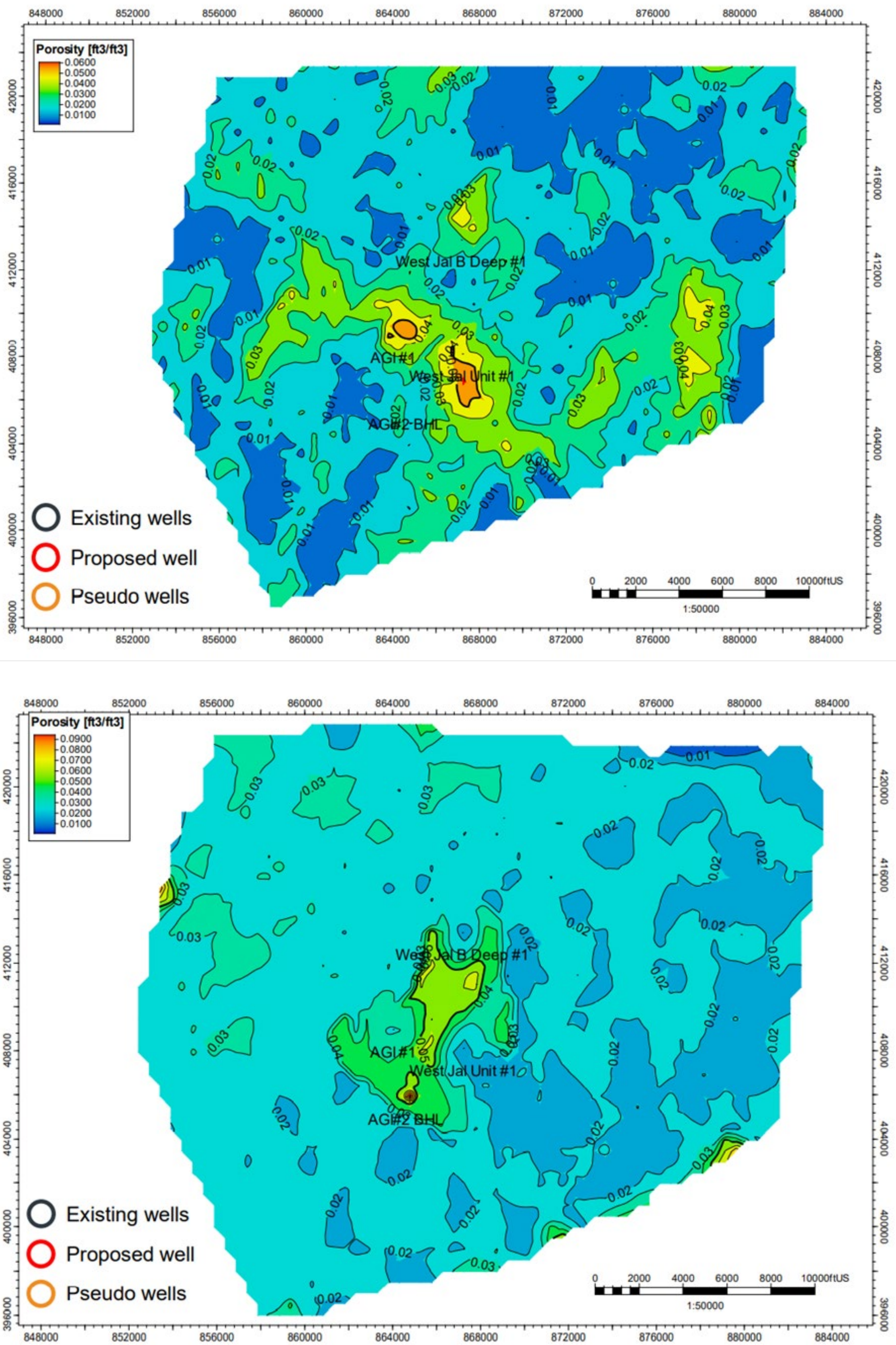


Figure 3.9-1: Structural surface for top of Layer 1 (top) of the geological and numerical model. Only SHLs shown for the Independence AGI #1 and #2 wells.



<u>Figure 3.9-2</u>: Model layer porosities for Zone 1 (top) and Zones 7 and 8 (bottom). Porosities are based on 2 wells, 3D seismic impedance surveys, and well stem tests. Only SHLs shown for the Independence AGI #1 and #2 wells.

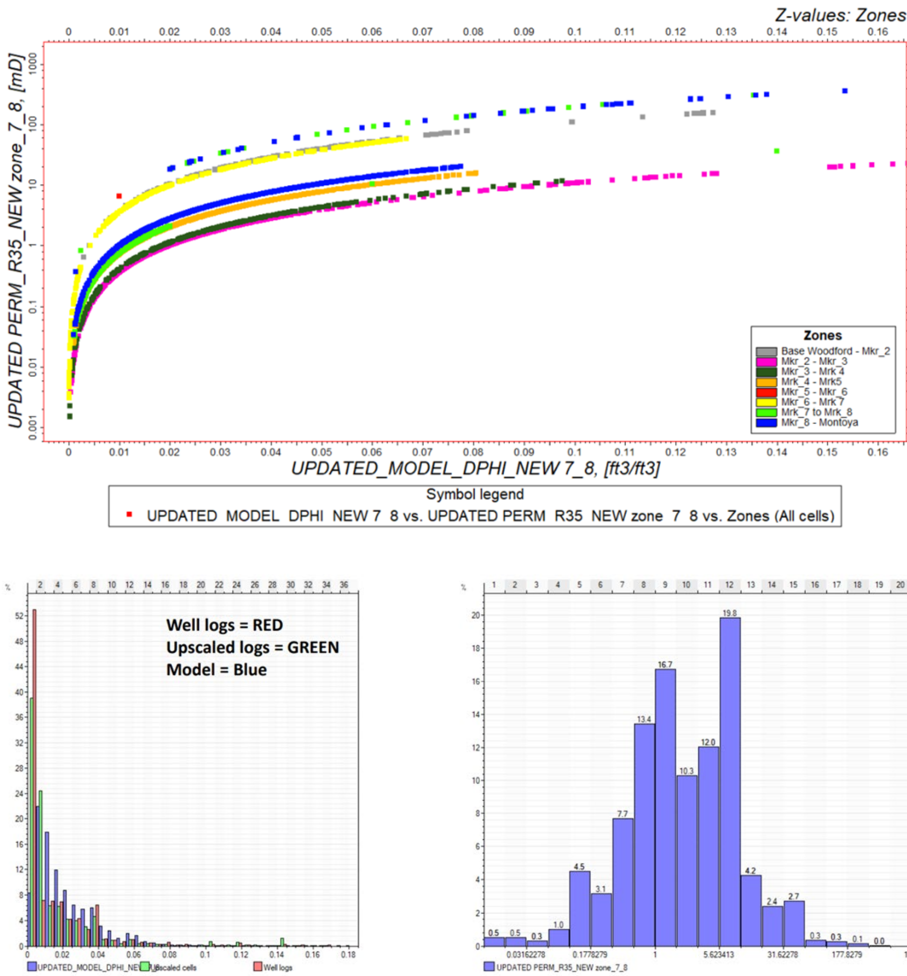


***Figure 3.9-3**: Geological zones and ranges of the properties for the Siluro-Devonian geologic model*

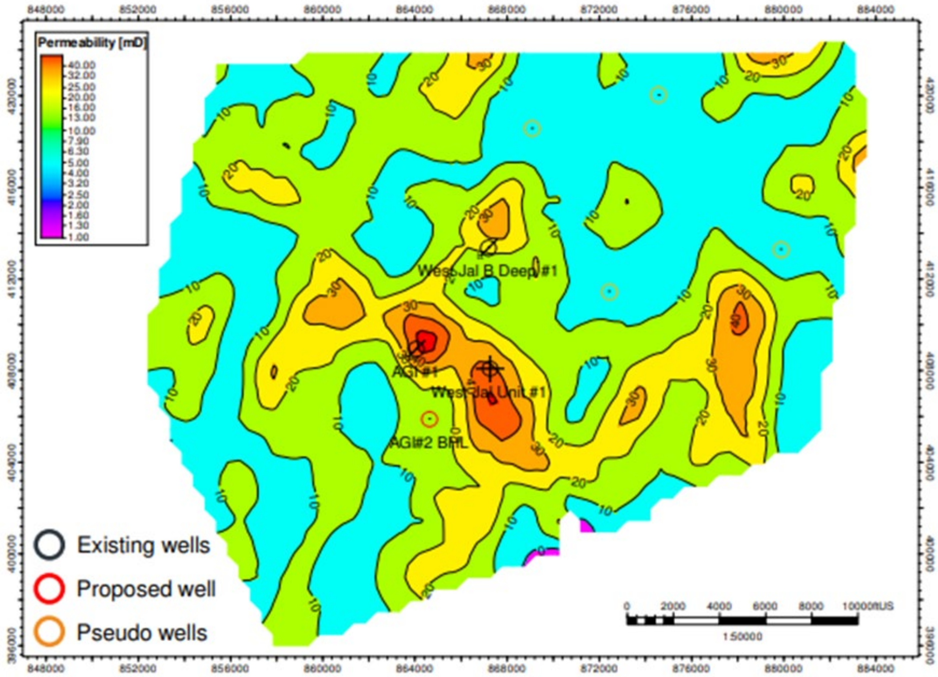


Figure 3.9-4: Graphic showing the permeability distribution in Layer 1 of the model representing the Thirtyone formation. Plan view. Only SHLs shown for the Independence AGI #1 and #2 wells.

3.9.2 Simulation Modeling for the Independence AGI Wells

Once the geological model was established, numerical modeling was performed to:

1. Assess the maximum injection rate with respect to estimated maximum bottomhole pressure ("**BHP**") to ensure safe operation, and
2. Estimate the modeled extent of the injected TAG after thirty (30) year injection period and five (5) year post injection monitoring period.

The reservoir is assumed to be initially saturated with 100% brine and exhibit hydrostatic equilibrium with the initial pressure based on the measured pressure at the top of the reservoir pre-injection. The injection gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Gas is injected for 30 years at a rate of 1,036.73 tonnes per day (378,399 tonnes per year or 11,351,970 total tonnes) followed by a 5-year rest period. Permeability curves for the multiphase gas/water system are defined for three (3) material ranges with a residual liquid saturation between 40% and 65%. An estimated maximum BHP of 9,730 psig, based on the calculated fracture pressure gradient, was imposed on the Independence AGI #1 to ensure safe injection operations. This pressure was important for Independence AGI #1 in the model scenario where all TAG was injected into Independence AGI #1, but otherwise simulations showed pressure at the Independence AGI Wells remaining below this threshold. In all simulations where West Jal Deep B #001 injected 30,000 bpd of brine into the reservoir, the West Jal Deep B #001 would need to decrease injectivity to remain below its permitted threshold pressure. Present modeling work does not indicate sufficient connectivity between the West Jal Deep B #001 and the Independence AGI Wells to impact AGI injectivity under all other modeled scenarios. Figure 3.9-5 shows the calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1. AGI rates are lower than target numbers and limited data are available so a more detailed calibration cannot yet be constructed. An injection forecast model was performed for a period of thirty (30) years with injection and then a five (5) year post-injection rest period to ascertain fluid movement and pressure evolution. Figure 3.9-6 shows the injection profile for the forecasting period which showed that the target injection rate could be hit in all scenarios except Scenario 5. The model showed that all the injected gas remained in the reservoir and there was no substantive change in the size of the TAG extent compared at the end of injection and five (5) year post injection period.

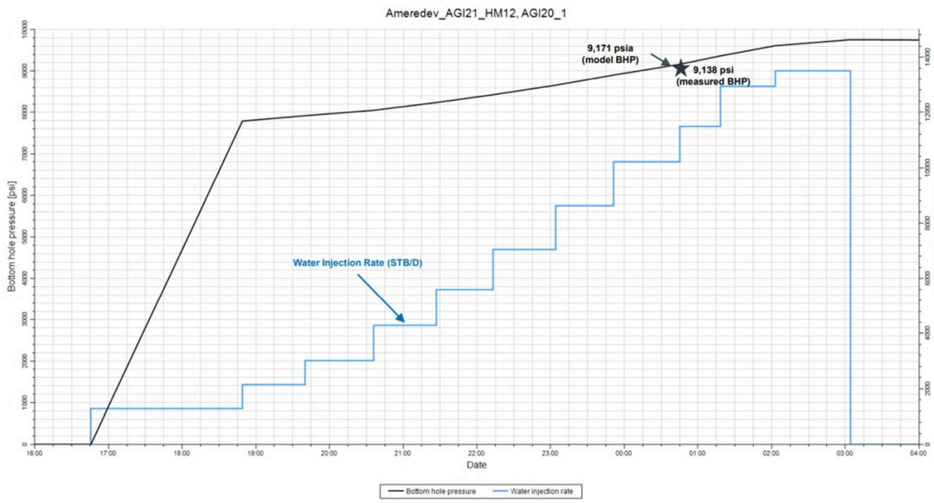


***Figure 3.9-5**: Graph showing calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1.*

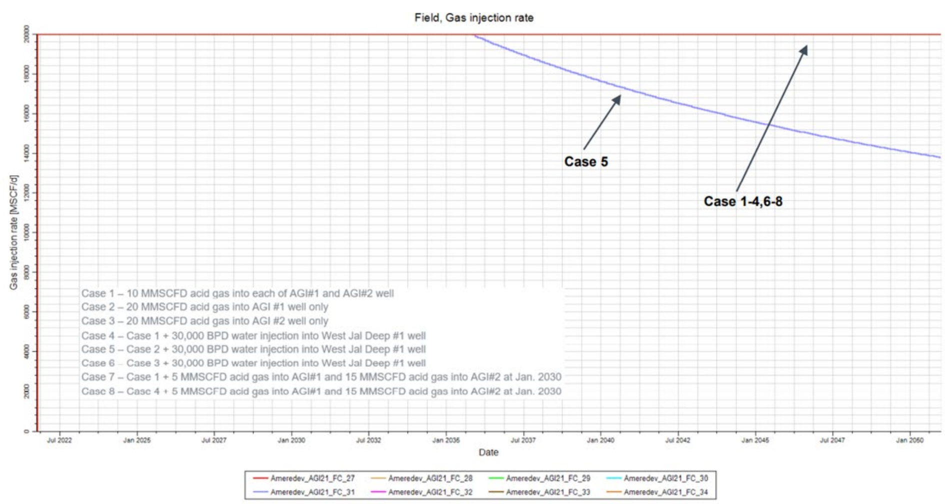


***Figure 3.9-6**: Graph showing the forecast profile for the injection rate and cumulative injection volume over the simulated period*

A considerable source of uncertainty in the plume model relates to the injectivity of the West Jal Deep B #001 well located about one (1) mile northeast of Independence AGI #1. This well is permitted to dispose of up to 30,000 bpd of brine into several reservoirs, including the Siluro-Devonian reservoir used by the Independence AGI Wells, and other shallower reservoirs. It is unclear from publicly available data how this fluid is planned to be partitioned between the various injection layers. As of this application, the wellbore currently has CIBPs at measured depths of 14,200 feet (lower Atoka Formation) and 17,100 feet (Fusselman Formation), restricting injection into the Siluro-Devonian reservoir, and no fluid is currently being injected at the well. However, since this well is permitted for injections, modeling for the present application considered two (2) end-member scenarios: (a) All West Jal Deep B #001 injection is into shallower reservoirs and does not interact with the Siluro-Devonian one (cases 1,2,3), or (b) all West Jal Deep B #001 volumes are injected into the Siluro-Devonian reservoir (cases 4,5,6,7,8). The brine injection at this well is significant for several reasons:

- High volumes of brine injection within the Siluro-Devonian in relatively close proximity of the Independence AGI Wells may raise pressure in the reservoir;
- Pressure from the brine injection pushes against the advancing gas front, directing flow south and west away from the well; and
- The West Jal Deep B #001 wellbore could be a potential leakage pathway if injection ceases and the supercritical fluid plume from the Independence AGI Wells reaches it. Simulations that do not include injections at this well have the TAG plume area including this well.

In all simulations with injection at West Jal Deep B #001, the local pressure at the brine injection well rapidly rises to the breakover point and the injection rate begins dropping within the first two (2) years of that well's operation to maintain pressures below 80% of the breakover threshold and ensure no rock fracturing occurs (Figure 3.9-7). It is unknown how in reality this will translate to well operations within the Siluro-Devonian reservoir. Simulations do not indicate that the pressure increase from this well will adversely affect the Independence AGI Wells due to the early shut down of the brine injection well. Simulations where there is no brine injection result in the plume extending farther northeast beyond the West Jal Deep B #001 well (Figure 3.9-8). If brine is injected, then the plume is repelled towards the south and west, with some TAG flanking the northwest fault and extending northwest (Figure 3.9-9). Simulations suggest a pressure impact on Independence AGI #1 that could result in curtailed injections under a scenario with all TAG injection in Independence AGI #1 and West Jal Deep B #001 active (Case 5, *see* Figure 3.9.6).

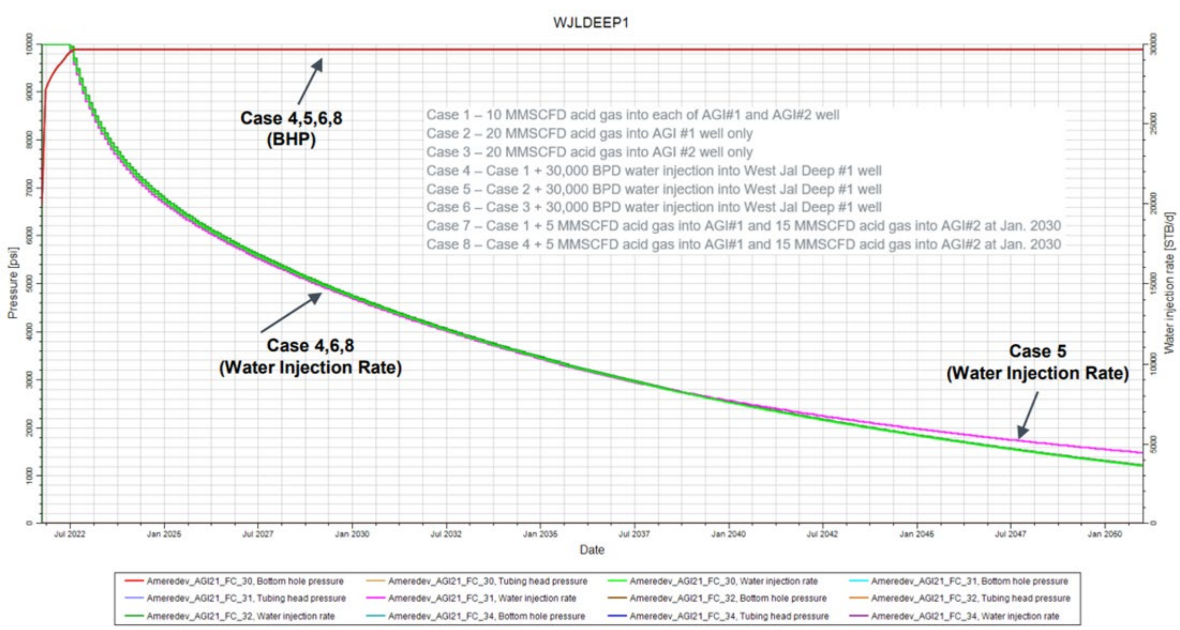


Figure 3.9-7: Graph showing the injection profile of the West Jal Deep B #001 brine injection well under different injection scenarios.

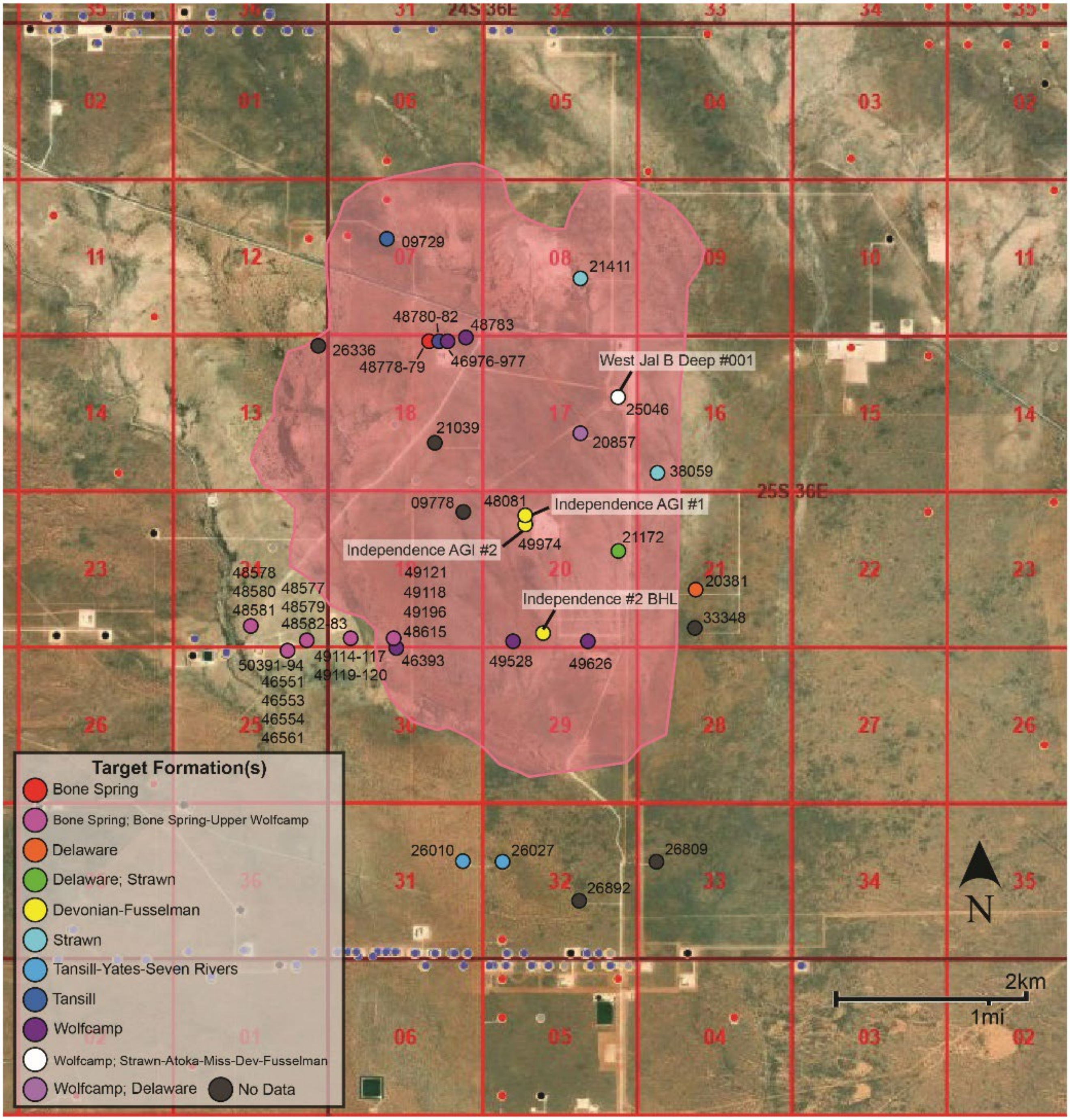
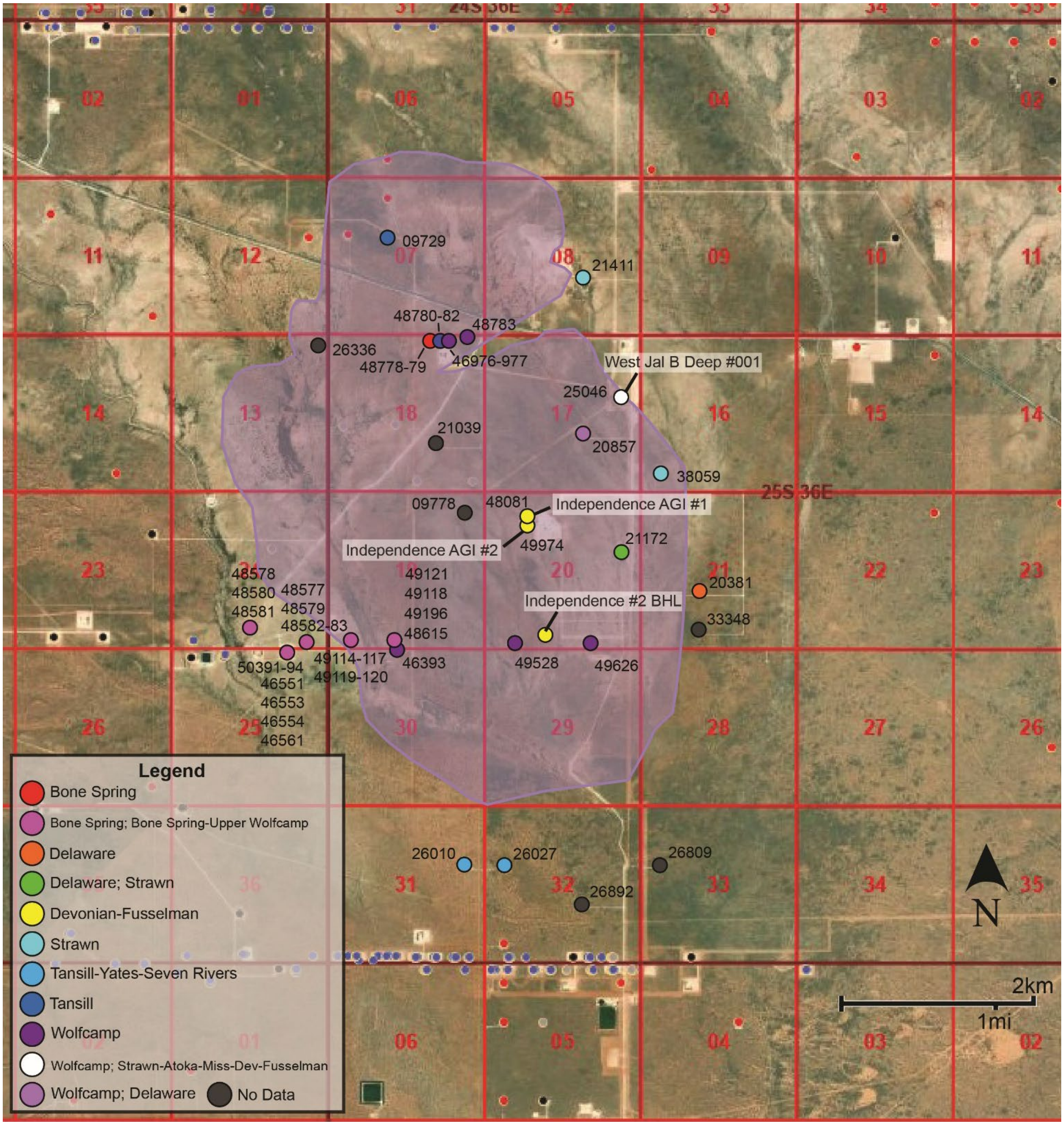


***Figure 3.9-8**: Map showing the largest lateral extent of the TAG when the West Jal Deep B #001 well does not inject into the Siluro-Devonian. Colors indicate target formations for the well. West Jal Deep B #001 is the white dot northeast of the Independence AGI Wells. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.*



<u>Figure 3.9-9</u>: Map showing the largest lateral extent of the TAG when the West Jal Deep B #001 injects an initial rate of 30,000 bpd of brine into the Siluro-Devonian. Colors indicate target formations for the well. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.

4 Delineation of the Monitoring Areas

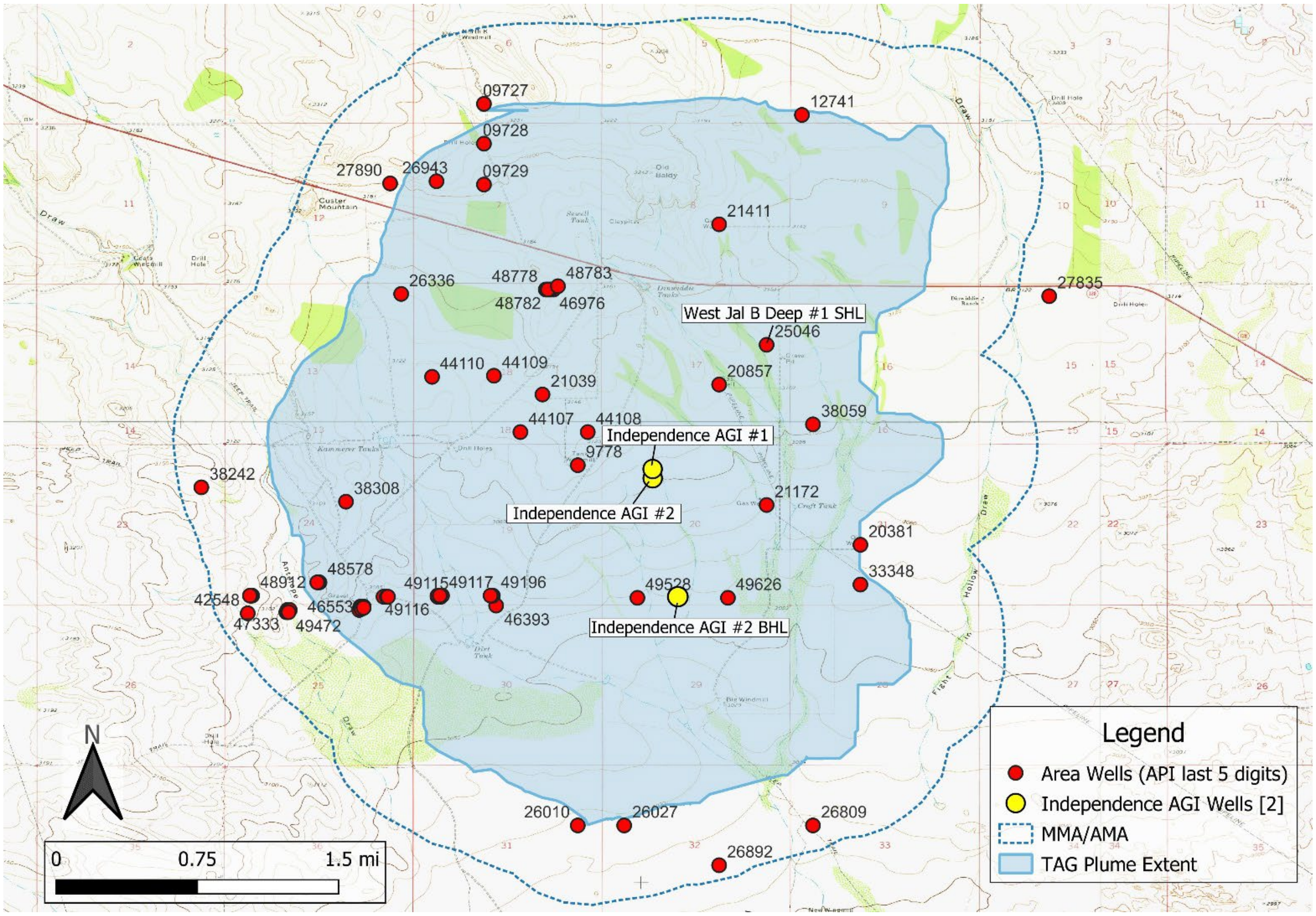
In determining the monitoring areas below, the extent of the TAG plume is equal to the superposition of plumes in any layer for any of the model scenarios described in Section 3.9.

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 (Figure 4.1-1). In general, the western margins of the plume retract to the east following the injection period as gas flows up-dip. In this case, the farthest plume extent and hence the MMA margin is therefore found at year 30 (year t), with the plume extent to the west shrinking by year t+5 and stabilizing. On this side, the MMA is based on the largest plume extent which is at year 30 (t). To the east, fault trapping and the anticline near the injection site generally prevent major movement eastward. Beyond year 30 (t), the plume slowly expands east and northeast, finally stabilizing around year 50 (t+20). In all cases, the plume margin polygon in Figure 4.1-1 is defined by the maximum extent of any plume in any scenario at any simulation time, with a 0.5 mile buffer extending beyond this polygon defining the margin of the MMA.

4.2 AMA – Active Monitoring Area

Piñon intends to define the AMA as the same area as the MMA. Per 40 CFR 98.449, AMA is defined as the area that will be monitored over a specific time interval from the first year of the period (n = 2023) to the last year in the period (t = 2053, a 30-year injection period). The boundary of the AMA 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 (2058, or year 35 of the simulation). However, as the plume has not fully stabilized by year t+5, the AMA and MMA in these areas is defined by the larger area of the stable plume which occurs at year t+20. This definition includes all areas at years t, t+5, and t+20. The zone shown in Figure 4.1-1 has a one-half mile buffer beyond the maximum plume extent of any scenario. Piñon intends to define the AMA as the entirety of the MMA.



<u>Figure 4.1-1</u>: MMA and AMA for the Independence AGI Wells. The plume extents are shown at year 35 (t+= 2058), or 5 years beyond injection time. The plume largely stabilizes by this time, with continued minor migration updip to the northeast which is constrained by faults offsetting permeable layers. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.

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 and the reservoir modeling described in <u>Section 3.9</u>, Piñon 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 treating facilities. To minimize this potential for leakage, the construction, operation, and maintenance of sour gas treating facilities 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, Piñon 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, Piñon implements several methods for detecting gas leaks at the surface. These methods are described in more detail in Sections 6 and 7. Detection is followed up by immediate response.

Due to the required continuous monitoring of the gas gathering and the gas processing systems, Piñon considers the likelihood, magnitude, and timing of CO_2 leakage 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 Existing Wells

As shown in Figure 3.7-3 and detailed in Appendix 3, there are several existing oil and natural gas-related wells within a two (2) mile radius around the Independence AGI Wells (Figure 4.1-1). The deep wells discussed in Section 3.7.1 (*see* Table 3.7-1) also lie within the MMA/AMA. They are discussed below.

5.2.1 Independence AGI Wells

Independence AGI #1 has an open hole interval between 16,122 and 17,709 feet with more than 300 feet of Woodford Shale immediately above (*see* Figure A1-1). Independence AGI #2, which was drilled and completed in October 2022, has an open hole interval between 16,080 and 17,683 feet (*see* Figure A1-2). The combined depth to the Siluro-Devonian Injection Zone, cement program for both wells illustrated in Figures A1-1 and 2, existence of suitable confining layers above the Siluro-Devonian Injection Zone described in Section 3, and continuous monitoring of well operational parameters indicates that leakage of CO_2 to the surface via the Independence AGI Wells themselves is unlikely. Therefore, Piñon considers the likelihood, timing, and magnitude of CO_2 emissions to the surface through the Independence AGI Wells to be minimal. Detection and quantification of any leaks from Independence AGI Wells are described in Section 6.2 below.

5.2.2 West Jal B Deep #001 Well

The West Jal B Deep #001 (API 30-025-25046) brine injection well is located one (1) mile northeast of the surface hole locations of the Independence AGI Wells. Additional details for this well are presented in Section 3.7.1. The wellbore currently has two CIBPs at measured depths of 14,200 feet (lower Atoka Formation) and 17,100 feet (Fusselman Formation). These CIBPs restrict access to any existing reservoirs located below the lower Atoka Formation, including within the Mississippian Lime (14,544 feet), Devonian (15,380 feet), and the Fusselman (16,404 feet), and injections in this wellbore to-date have been up-section of the relevant area. In the event of incomplete plugging of the borehole or leakage through the well casing, the shallower reservoir is at higher pressure than the Siluro-Devonian reservoir, and consequently it is assessed that downward flow of fluid would repel the TAG plume from the AGI wells. Nevertheless, the potential for CO_2 leakage to the surface through this well is considered possible, albeit unlikely, and monitoring for this possibility is described in Section 6.2.2.

5.2.3 West Jal Unit #1 Well

The West Jal Unit #1 well (API 30-025-21172) was plugged and abandoned in April 1984. The plugging documents presented in Appendix 9 indicate that the well is properly plugged through the Siluro-Devonian Injection Zone. Nevertheless, the potential for CO_2 leakage to the surface through this well is considered possible, albeit unlikely, and monitoring for this possibility is described in Section 6.2.2.

5.2.4 Wells Completed and Proposed to be Completed in the Wolfcamp, Bone Spring, and Shallower Stratigraphic Units

There are several oil and natural gas wells (Appendix 3) completed or proposed to be completed in the Wolfcamp, Bone Spring and shallower stratigraphic units within the MMA. The deepest of these wells is completed in the Upper Wolfcamp (see Figures 3.2-2 and 3.3-1). The nearly 4,000 feet of strata between the top of the Siluro-Devonian Injection Zone and the Wolfcamp production zone includes nearly 300 - 400 feet of low porosity and low permeability Woodford Shale, the primary confining unit/seal for the Independence AGI Wells (see Figure 3.3-3)

Due to the thickness of the strata between the deepest wells completed in the Wolfcamp and the thickness of the Woodford Shale above the Siluro-Devonian Injection Zone, Piñon considers the likelihood, magnitude, and timing of CO_2 leakage to the surface via this potential leakage pathway to be unlikely. Detection and quantification of any leaks through these wells are described in Section 6.2 below.

5.3 Potential Leakage through Fractures and Faults

Faults and fractures were discussed in Section 3.2.3 and the potential for induced seismicity was discussed in Section 3.5. The reservoir characterization modeling (Section 3.9) and the delineation of the monitoring areas (Section 4) show that the TAG plume reaches the faults shown in Figure 3.5-1 during the thirty (30) year injection period and the five (5) year post injection monitoring period. Vertical permeability may be present parallel to the plane of the fault vertically, especially where the two main faults intersect. A review of available drilling fluid records was conducted to evaluate regional reservoir pressure conditions in the Delaware basin. Above the Siluro-Devonian injection reservoir, mud weights utilized range from 12.1 to 15.1 pounds per gallon, while for the injection reservoir less dense fluids were used (average of 9.0 pounds per gallon). These support the interpretation that the overlying productive zones in this area are overpressured with respect to the target reservoir, which would produce a downward gradient through any fault-parallel permeability. The pressure differential between the overlying interval and target interval will act as a barrier preventing vertical migration even along localized open conduits.

Due to evidence that production zones overlying the Siluro-Devonian Injection Zone are over pressured and that the basement rooted faults in the area are confined to the lower Paleozoic up to the lower Woodford Shale, Piñon considers the likelihood, magnitude, and timing of CO_2 leakage to the surface via this potential leakage pathway to be unlikely. Detection and quantification of any leaks through these basement rooted faults are described in Section 6.3 below.

5.4 Potential Leakage through the Confining / Seal System

The subsurface lithologic characterization presented in Section 3.2.2 describes the thick sequence of Mississippian through Permian strata overlying the Siluro-Devonian Injection Zone and reveals the existence of several excellent confining zone layers including nearly 300 - 400 feet of low porosity low permeability Woodford Shale. Due to the thickness, lateral extent, and low porosity and permeability of the Woodford Shale, Piñon considers the likelihood, magnitude, and timing of CO_2 leakage to the surface through the confining zone to be unlikely. Detection and quantification of any leaks through the confining zone are described in Section 6.4 below.

5.5 Potential Leakage due to Natural / Induced Seismicity

The potential for leaks initiated by induced seismicity was addressed in Section 3.5. It was concluded that generally, faults considered in this assessment do not display significant potential for injection-induced slip and the Independence AGI #2 is not predicted by the FSP model to contribute significantly to the total resultant pressure front. Piñon concludes that the likelihood for the creation and/or opening of vertical conduits for CO_2 leakage to the surface due to induced seismicity is low. In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage. Nevertheless, the NMOCC Order requires Piñon to install, operate, and monitor for the life of the project a seismic monitoring station or stations described in more detail in Section 7.6.

According to data obtained from the New Mexico Tech Seismic Observatory (2023), there have been four (4) seismic events within the MMA since January 12, 2017 (Figure 5.6-1). These seismic events range in magnitude of 1.16-1.88 and occurred between September 2020 and October 2021 (Table 5.6-1). The New Mexico Tech database applied a model for epicenter location that was not capable of determining focal depth. Revisions to this database are planned for late 2023 but have not been released at the time of this writing. Hence, earthquake depths are unknown, but accounting for the lack of local development in the Devonian strata, and the greater development at shallower depths, it is believed these earthquakes occurred in a shallower reservoir. Data queries with the USGS Earthquake Catalog did not show any seismic activity within the MMA (USGS Earthquake Hazards Program, 2023).

As noted in Section 3.5, the results of the fault slip potential model indicate no likelihood of slip on the fault east of the Independence AGI Wells. The maximum segment slip potential was determined at 0.05 northwest of the injection wells, with AGI injections causing no increase in probability. Any slip would depend on the injection volumes of brine disposal wells (at present there is no brine injection in the target area). Should fault slip occur, the short lengths of the potentially slipping segment likely preclude large earthquakes, and seismicity would be expected to be <2.5 in magnitude. Any earthquakes at or above this value would be carefully evaluated to determine location, depth, and sense of motion. Remote gas observation sweeps will be conducted above or as close to the mobile fault segment as possible at 10, 30, 100, and 365 days following the event to determine if leakage is occurring. The rate of gas leakage will likely depend on the time required to saturate the fracture network created by the seismic event and the timeline of this process is expected to be on order 10 to 100 days after the fracture network is exposed to gas (Hyman et al. 2019).

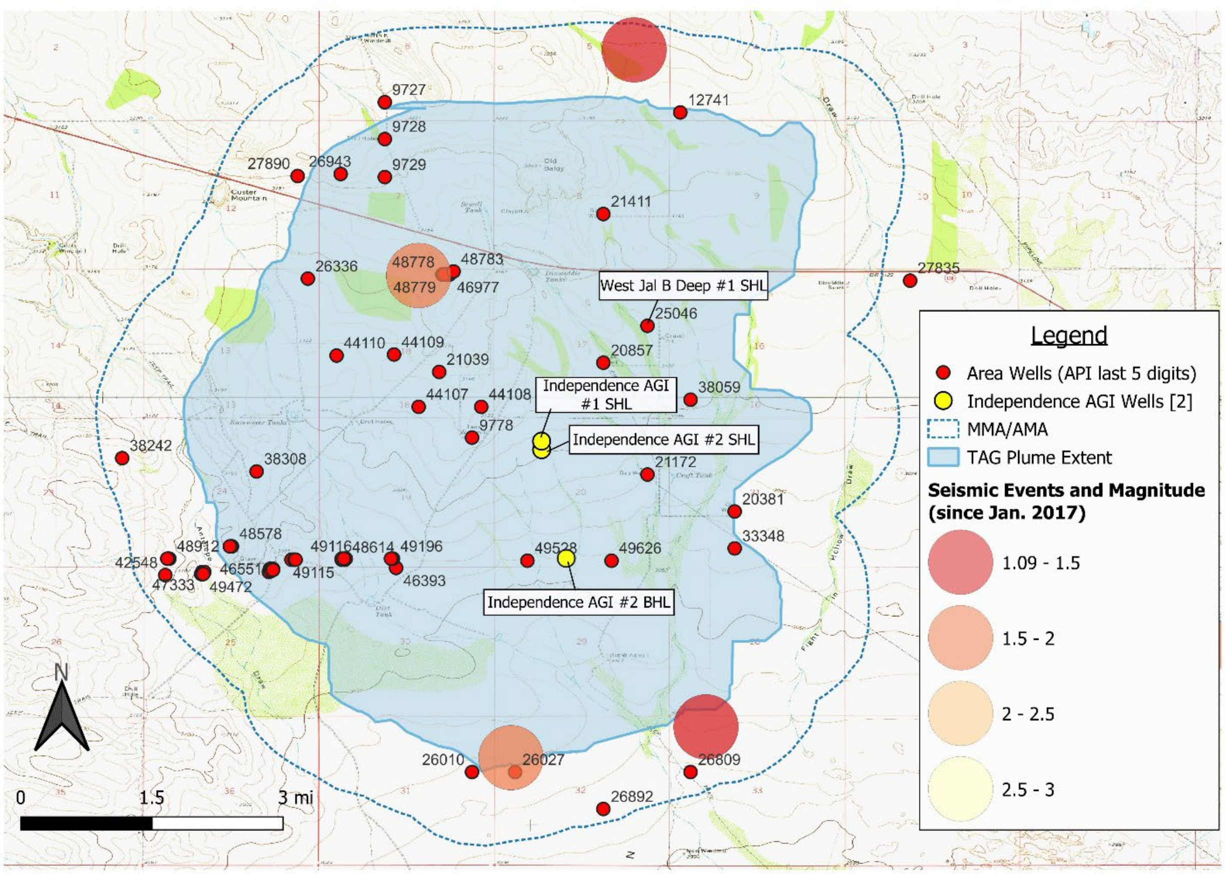


Figure 5.6-1: Map showing seismic event locations within the MMA for the Independence AGI wells. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.

Date+Time(UTC)	Latitude	Longitude	Magnitude
2021-10-30 07:14:26.600	32.093	-103.275	1.16
2021-10-11 12:19:51.300	32.09	-103.294	1.88
2021-09-09 08:23:05.600	32.137	-103.303	1.74
2020-10-03 03:51:12.600	32.159	-103.282	1.47

Table 5.6-1: Table showing the locations, dates and times, and magnitudes of seismic events within the MMA for the Independence AGI wells.

5.6 Potential Leakage due to Lateral Migration

Lateral migration of the injected TAG was addressed in the simulation modeling detailed in Section 3.9. The results of that modeling indicate the TAG is unlikely to migrate laterally beyond approximately 2.5 miles within the Siluro-Devonian Injection Zone to encounter any conduits to the surface.

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. Piñon 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. Piñon considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ 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 five (5) year post-injection period.

If CO_2 surface emissions are indicted by any of the monitoring methods listed in Table 6.1, Piñon will quantify the mass of CO_2 emitted based on the 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.

Table 6.1 – Summary of Leak Detection Monitoring

Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system ("DCS") surveillance of facility operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/H_2S and low explosive level ("LEL") monitoring network • Personal and hand-held gas monitors
Independence AGI #1 & Independence AGI #2	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests ("MIT")

Leakage Pathway	Detection Monitoring
	• Fixed in-field gas monitors/H_2S and LEL monitoring network • Personal and hand-held gas monitors
Existing Other Operator Active Wells	• Monitoring of well operating parameters • Visual inspections • MITs • Mobile CO_2 detectors
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network • Mobile CO_2 detectors
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network

6.1 Leakage from Surface Equipment

Piñon 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 Piñon using in-field monitors which detect H_2S. 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. Additionally, Piñon field personnel, wearing personal H_2S monitors, follow daily and weekly inspection protocols which include reporting and responding to any detected leakage events.

Piñon's internal operational documents and protocols detail the steps to be taken to verify leaks of H_2S. The following description of the gas detection equipment at the Dark Horse Facility was summarized from the H_2S Contingency Plan:

Fixed Monitors

The Dark Horse Facility has numerous ambient H_2S detectors placed strategically throughout the facility to detect possible leaks. Upon detection of H_2S concentrations of 10 ppm at any detector, visible beacons are activated and an alarm is sounded. Upon detection of H_2S concentrations of 90 ppm at any detector, an evacuation alarm is sounded throughout the Dark Horse Facility at which time all personnel will proceed immediately to a designated evacuation area. The Dark Horse Facility 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 ("**PLC**"), and then to the DCS. The monitors are equipped with amber beacons. The beacon is activated upon detection of H_2S concentrations of 10 ppm. The Dark Horse Facility horns are activated with a continuous warbling alarm upon detection of H_2S concentrations of 10 ppm and a facility-wide siren upon detection of H_2S concentrations of 90 ppm. All monitoring equipment is Rosemount brand. The control panel is a twenty-four (24) channel monitor box, and the fixed point H_2S sensor heads are model number ST320A-100-ASSY.

The Dark Horse Facility will monitor the inlet sour natural gas steam and sweet natural gas stream concentrations of H_2S via H_2S analyzers with sample points located on the north/south-oriented pipe rack (Figure 7.2-1). Concentrations of H_2S in the TAG stream will be sampled near the AGI pumps located on the west side of the Dark Horse Facility. All H_2S analyzers are model T224, manufactured by Analytical Systems KECO.

The monitors can also be viewed on the PLC displays located at the Dark Horse Facility and the locations of ambient H_2S sensors are shown on the plot plan (*see* Figure 3.7-2). Immediate action is required for any alarm occurrence or malfunction. All H_2S sensors are calibrated monthly.

Personal and Handheld H_2S Monitors

All personnel working at the Dark Horse Facility wear personal H_2S monitors, which are required to alarm and vibrate upon detection of H_2S concentrations of 10 ppm. Handheld gas detection monitors are available at strategic locations around the Dark Horse Facility so that facility 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.

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 10.1.5. Furthermore, if CO_2 emissions are detected through any of the surveillance methods described above, Piñon 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. Piñon has standard operating procedures to report and quantify emissions from surface equipment in accordance with applicable state (New Mexico) and federal law. Piñon will utilize and modify, if necessary, this procedure to quantify the mass of CO_2 from each leak discovered by Piñon.

6.2 Surface Leakage from Existing Wells

6.2.1 Independence AGI Wells

As part of ongoing operations, Piñon continuously monitors and collects flow, pressure, temperature, and gas composition data. This data is monitored continuously by qualified technicians who follow response and reporting protocols when the monitoring system delivers alerts that data is not within acceptable limits. Mechanical integrity tests (MIT) are performed annually. Failure of an MIT would indicate a leak in the well and result in immediate action by shutting in the well, assessing the MIT failure, and implementing mitigative steps.

If operating parameter monitoring and MIT failures indicate a CO_2 leak has occurred, Piñon will (i) take actions 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; and (ii) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s). Piñon has standard operating procedures to report and quantify emissions from the Independence AGI Wells in accordance with applicable state (New Mexico) and federal law. Piñon will utilize and modify, if necessary, this procedure to quantify the mass of CO_2 from each leak discovered by Piñon.

6.2.2 West Jal B Deep #001 and West Jal Unit #1 Wells

Piñon will annually employ mobile CO_2 detectors, which may include drone mounted sensors, to monitor for any CO_2 emission at the locations of the West Jal B Deep #001 and West Jal Unit #1 wells. If surface CO_2 leakage is correlated with loss through these wells, Piñon will (i) take actions, including by working with the third party operator of the West Jal B Deep #001 and West Jal Unit #1 wells, to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of 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; and (ii) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.2.3 Wells Completed and Proposed to be Completed in the Wolfcamp, Bone Spring, and Shallower Stratigraphic Units

As discussed in Section 5, it is unlikely that the TAG injected through the Independence AGI Wells into the Siluro-Devonian Injection Zone will migrate upward to these shallower production wells and be emitted to the surface through these wells. Due to the natural presence of H_2S and CO_2 in the production streams of oil and natural gas producers in the AMA, Piñon has been in contact with such producers in the AMA regarding Piñon's core business of sour gas (high in H_2S and CO_2) treatment and sequestration. Piñon will continue to work cooperatively with such producers and immediately investigate, including by use of mobile CO_2 detectors, any CO_2 emissions from wells operated by oil and natural gas producers in the AMA which is suspected to arise from Piñon's operations. If surface CO_2 leakage is correlated with loss through these wells, Piñon will (i) take actions, including by working with the third party operator of the well(s), to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of 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; and (ii) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.3 Surface Leakage from Fractures and Faults

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through a fracture/fault. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.3 and 7.5, will provide an indicator of potential or actual CO_2 leaks from the Siluro-Devonian Injection Zone.

Piñon will assess any changes in operating parameters which might indicate surface leakage of CO_2 through any fracture or fault. Piñon will employ mobile CO_2 detectors, which may include drone mounted sensors, to monitor for CO_2 emissions from a mapped fracture/fault. If surface CO_2 leakage is detected through a mapped fracture or fault, Piñon will (i) take actions, including by working with relevant surface owners, to quantify the mass of CO_2 emitted based on the conditions that existed at the time of emission, including flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site; and (ii) take mitigative action to stop it, which may include shutting in the Independence AGI Well(s).

6.4 Leakage through the Confining / Seal System

As discussed in Section 5, it is unlikely that CO_2 leakage will occur through the confining / seal system. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.2 and 7.5, will provide an indicator of potential or actual CO_2 leaks through the confining seal / system.

If changes in operating parameters or data indicate the potential leakage of CO_2 through the confining / seal system, Piñon will reassess the plume migration modeling for evidence that the plume has leaked out of the Siluro-Devonian Injection Zone. If it is determined that the plume has leaked out of the Siluro-Devonian Injection Zone, this would be considered a material change per 40 CFR 98.448(d)(1), and Piñon will submit a revised MRV plan as required by 40 CFR 98.448(d). Any surface leakage associated with a leak through the confining seal system would likely occur through a well, fracture or fault and will be quantified and mitigated in accordance with Section 6.2 or 6.3, as applicable.

6.5 Leakage due to Natural / Induced Seismicity

Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.2 and 7.5, coupled with the detection of seismic events by the seismic stations described in Section 7.6 will provide an indicator of potential or actual CO_2 leakage out of the Siluro-Devonian Injection Zone because of seismic event.

After any seismic event of a 3.0 magnitude or higher, Piñon will assess changes in operating parameters and data from the surrounding seismic stations. If changes in operating parameters or data indicate the potential leakage of CO_2 out of the Siluro-Devonian Injection Zone, Piñon will reassess the plume migration modeling for evidence that the plume has leaked out of the Siluro-Devonian Injection Zone. If it is determined that the plume has leaked out of the Siluro-Devonian Injection Zone, this would be considered a material change per 40 CFR 98.448(d)(1), and Piñon will submit a revised MRV plan as required by 40 CFR 98.448(d). Any surface leakage associated with a seismic event would likely occur through a well, fracture or fault and will be quantified and mitigated in accordance with Section 6.2 or 6.3, as applicable.

6.6 Leakage due to Lateral Migration

Continuous operational monitoring of the Independence 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 Siluro-Devonian Injection Zone. 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 Siluro-Devonian Injection Zone.

If monitoring of operational parameters indicates that the CO_2 plume extends beyond the area modeled in Section 3.9 and presented in Section 4, Piñon will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 release to the surface. If it is determined that the plume intersected a pathway for CO_2 release to the surface, this would be considered a material change per 40 CFR 98.448(d)(1), and Piñon will submit a revised MRV plan as required by 40 CFR 98.448(d).

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

Subpart RR at 40 CFR 448(a)(4) requires a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. Piñon 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 Piñon's strategy for collecting baseline information.

7.1 Visual Inspection

. Piñon field personnel conduct daily visual inspections of surface equipment located at the Dark Horse Facility and the Independence AGI Wells. These visual inspections will aid in identifying and timely addressing potential areas of concern to minimize the possibility of H_2S, a proxy for CO_2, leakage. If any leakage is identified during such visual inspections, Piñon field personnel will take prompt corrective actions to address such leakage.

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

Compositional analysis of gas injectate at the Dark Horse Facility indicates an approximate H_2S concentration of 38.7% thus requiring Piñon to develop and maintain an H_2S Contingency Plan according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). Piñon considers H_2S to be a proxy for CO_2 leaks at the Dark Horse Facility. The H_2S Contingency Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the Dark Horse Facility or the associated Independence 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 Dark Horse Facility utilizes numerous fixed-point monitors, strategically located throughout the facility, to detect the presence of H_2S in ambient air (Figure 3.7-2). The diagram in Appendix 10 shows the location of the Ultrasonic inflow meters and the Coriolis meters to the Independence AGI wells. The sensors are connected to the Control Room alarm panel's PLCs, and then to the DCS. Upon detection of H_2S concentrations of 10 ppm at any monitor, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of H_2S concentrations of 90 ppm at any monitor, an evacuation alarm is sounded throughout the Dark Horse Facility 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 Dark Horse Facility so that facility 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 Oxide ("**CO**").

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the Dark Horse Facility 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 upon detection of H_2S concentrations of 10 ppm.

7.3 CO_2 Detection

Any CO_2 release to the surface would be accompanied by H_2S and therefore the H_2S monitors will serve as a CO_2 release warning system both at the facility and in the field. In addition to the fixed and personal monitors described in Section 7, Piñon will establish and operate a monitoring program to detect H_2S leakages within the AMA. The scope of work will include H_2S monitoring at the AGI well site and atmospheric monitoring near identified penetrations of the Siluro-Devonian Injection Zone within the AMA. Upon approval of the MRV Plan and for the five (5) year post-injection period, Piñon will have these monitoring processes and systems in place.

7.4 Continuous Parameter Monitoring

The DCS of the Dark Horse Facility 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

Piñon 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. Piñon's Routine Operations and Maintenance Procedures for the Independence AGI Wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic Monitoring Stations

Piñon owns 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 Dark Horse Facility. The seismic station will meet the requirements of the NMOCC Order to "install, operate, and monitor for the life of this Order a seismic monitoring station or stations. OCD shall be responsible for coordinating with the Manager of the New Mexico Tech Seismological Observatory at the New Mexico Bureau of Geology and Mineral Resources for appropriate specifications for the equipment and the required reporting procedure for the monitoring data."

Additionally, Figure 7-1 shows the location of other seismic monitoring stations in the vicinity of the Independence AGI Wells.

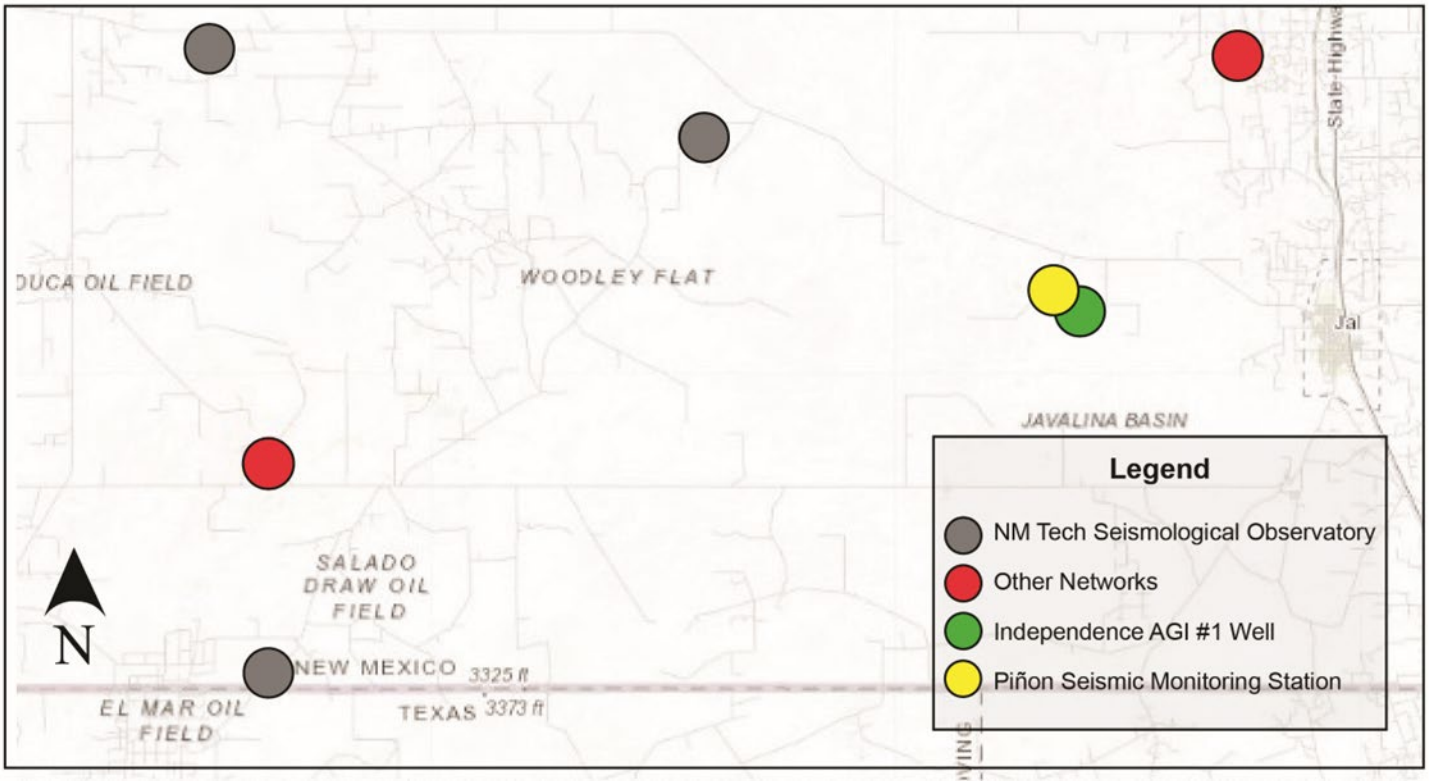


Figure 7-1: Location of seismic monitoring stations in the vicinity of the Independence AGI Wells.

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve (12) Subpart RR equations used to calculate the mass of CO_2 sequestered annually. Appendix 8 includes the twelve (12) equations from Subpart RR. Not all of these equations apply to Piñon's current operations at the Dark Horse Facility but are included in the event Piñon's operations change in such a way that their use is required.

8.1 CO_2 Received

Currently, Piñon receives sour natural gas at the Dark Horse Facility through three (3) pipelines: the Hondo High Pressure Sour Gas Pipeline (owned and operated by Piñon), the Franklin Mountain Low Pressure Pipeline (owned and operated by Franklin Mountain Energy) and the Ameredev II Low Pressure Pipeline (owned and operated by Ameredev). Piñon 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 Piñon does not currently receive CO_2 in containers for injection, they have chosen to include the flexibility in this MRV Plan to do so. If Piñon begins to receive CO_2 in containers, they will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. Piñon will adhere to the requirements in 40 CFR 98.444(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 40 CFR 98.488(d)(1), Piñon will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Piñon injects CO_2 into the existing Independence AGI #1. Upon its completion, Piñon will commence injection of CO_2 into Independence AGI #2. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the Independence AGI Wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the Independence AGI Wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12.

8.3 CO_2 Produced / Recycled

Piñon does not produce oil or natural gas or any other liquid at the Dark Horse Facility so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Surface leakage of CO_2 will not be measured directly, rather it will be determined by employing the CO_2 proxy detection system described in Section 7.3. The monitoring methods described in Section 7 would indicate the occurrence of gas leakage at the surface. The mass of CO_2 emitted would be calculated 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. Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage (CO_{2E}) from the leakage pathways identified and evaluated in Section 5. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.5 below.

8.5 CO_2 Sequestered

Since Piñon does not actively produce oil or natural gas or any other fluid at the Dark Horse Facility, 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, Piñon 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

Piñon intends to implement this MRV Plan on June 1, 2023, after it is approved by EPA.

10 GHG Monitoring and Quality Assurance Program

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

10.1 GHG Monitoring

As required by 40 CFR 98.3(g)(5)(i), Piñon'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 greenhouse gas ("**GHG**") calculations; and
- 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 will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association ("**GPA**") standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40 CFR 98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2 and RR-5, of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 15.025 pounds per square inch absolute ("psia") (Appendix 6). Piñon utilizes Coriolis metering to measure the dense phase injected TAG stream. Piñon utilizes the following two standards: American Petroleum Institute API 14.1 for measuring barrels and the American Gas Association AGA 7 for million cubic feet ("MCF") equivalent calculations.

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 Independence AGI Wells using accepted flow calculations for CO_2 according to the [AGA Report #3].

10.1.4 CO_2 produced.

Piñon does not produce CO_2 at the Dark Horse Facility.

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

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

10.1.6 Measurement devices.

As required by 40 CFR 98.444(e), Piñon 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 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute, the AGA, the GPA, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.
- All flow meter calibrations performed are National Institute of Standards and Technology ("**NIST**") traceable.

10.2 QA/QC Procedures

Piñon 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

Piñon will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or using a representative concentration value from the 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

Piñon will revise the MRV Plan as needed to (a) reflect changes in monitoring instrumentation and quality assurance procedures; (b) improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or (c) address additional requirements as directed by the EPA or the State of New Mexico.

11 Records Retention

Piñon will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, Piñon will retain the following documents:

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

(b) 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

(c) The annual GHG reports.

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

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

(f) 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.

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

(h) 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.

(i) 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.

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

(k) 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.

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

13 Appendices

Appendix 1 - Independence AGI Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Independence AGI #1	30-025-48081	SHL 829’ FNL, 1,443’ FEL BHL of Sidetrack: 1041’FNL, 1785’FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120855 and -103.291021	Lea, NM	12/27/2020	17,750’	16,114’
Independence AGI #2	30-025-49974	SHL 1,180’ FNL, 1,578’ FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120020 and -103.291015 BHL 1,033’ FSL, 2,132’ FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.111581 and -103.289273	Lea, NM	07/02/2022	17,683’ TVD	16,610’

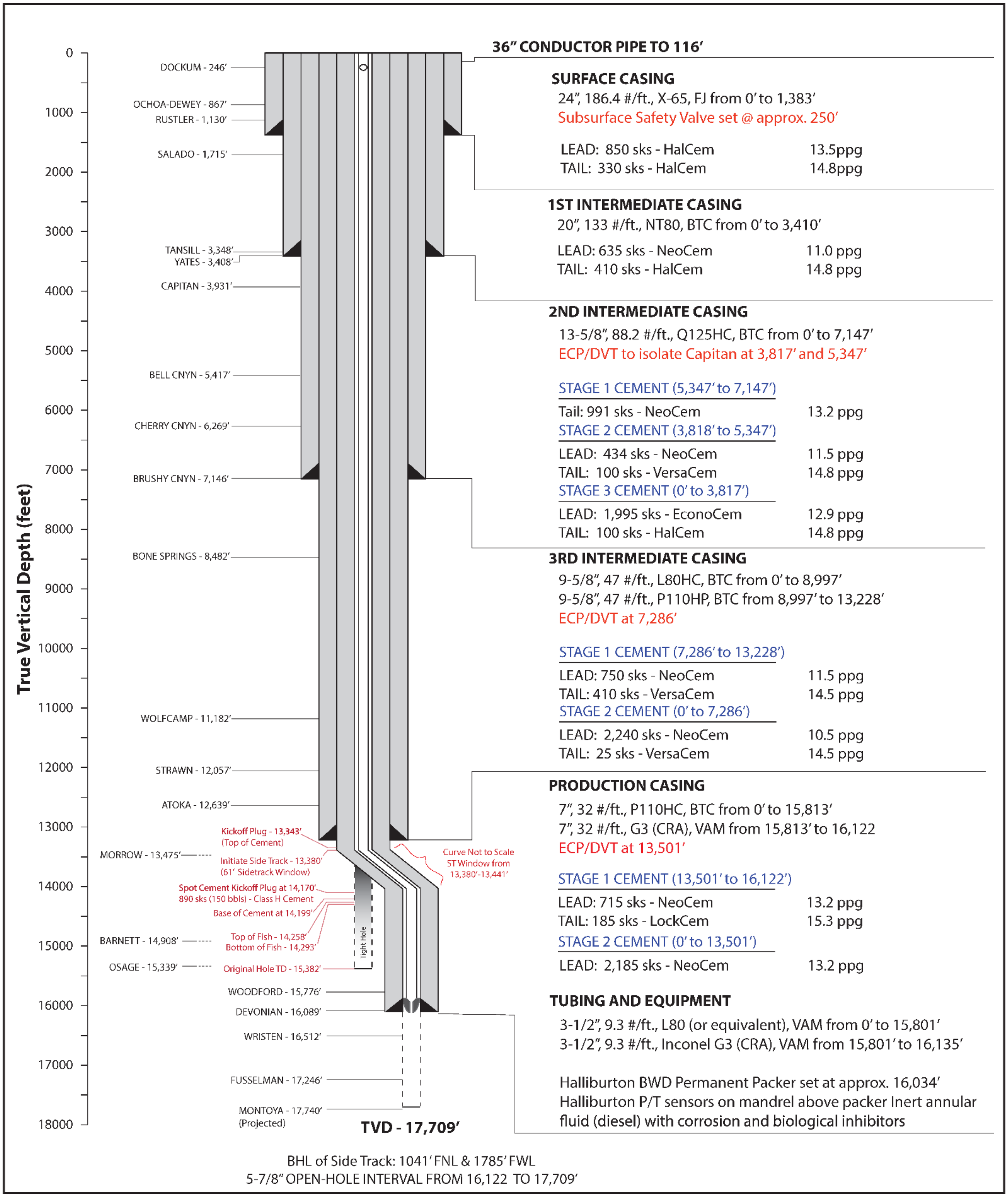
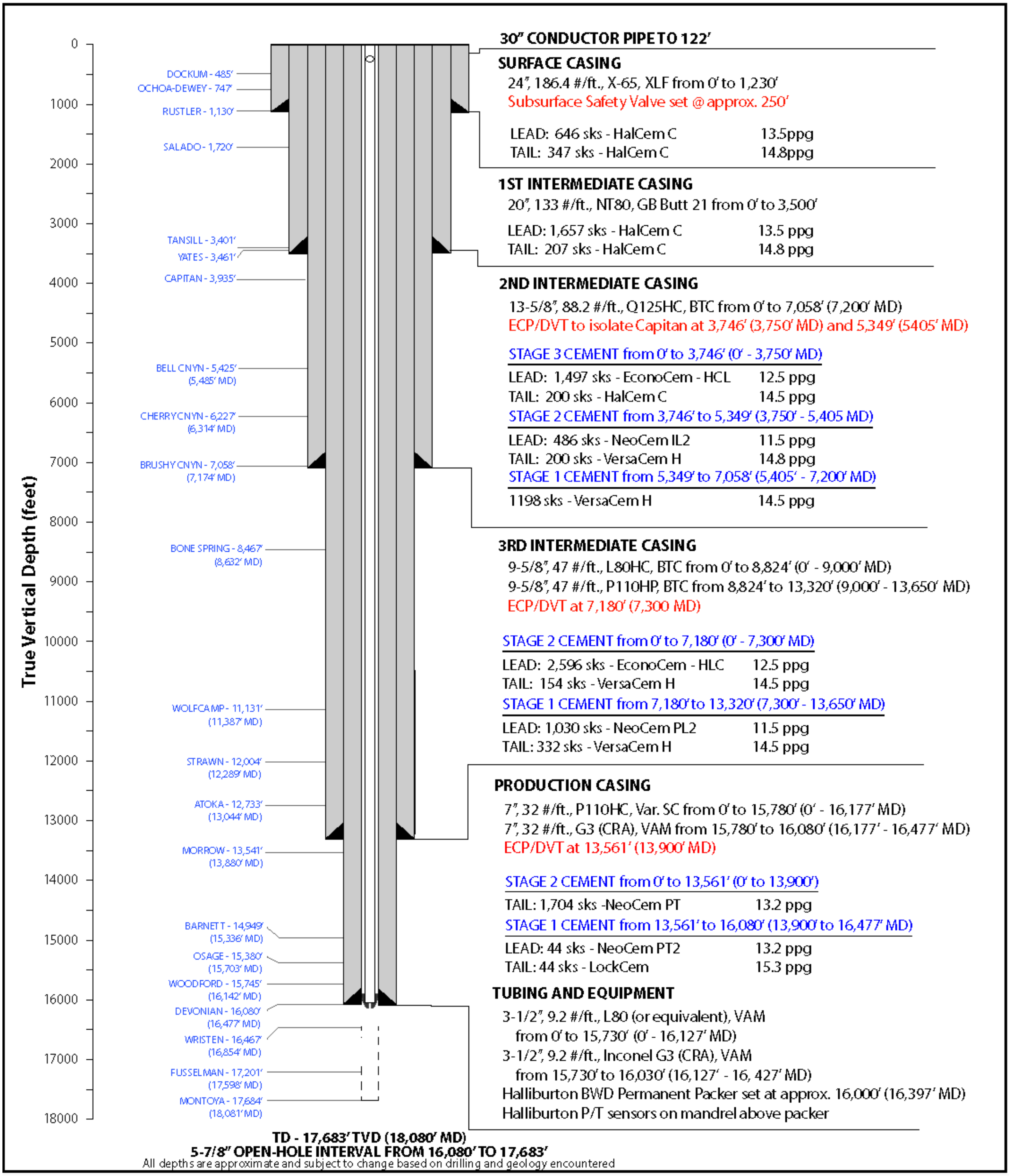


***Figure A1-1**: Independence AGI #1: As-drilled well schematic consisting of a surface string of casing, three (3) intermediate strings , and a production string with associating tubing/equipment and cement types. Original hole and sidetrack are shown. (Taken from End-of-Well Report for Independence AGI #1, Geolex, Inc.)*



<u>Figure A1-2</u>: Independence AGI #2: Well schematic. (Taken from NMOCC Order 3/31/2022)

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
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
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 - Oil and natural gas wells within 2-mile radius of the Independence AGI Wells

The data in the following table was obtained from the NMOCD database and is accurate as of 8/5/2022.

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-09729	PAN AM KELLY 7 FEDER	Oil	Plugged (site released)	JOHN H TRIGG	32.1466	-103.3063		1900	3,540	0	-	1/1/1900	CUSTER, TANSILL
30-025-09778	FEDERAL #1	Oil	Plugged (site released)	EDWARD C. DONAHUE	32.1212	-103.2978	No Data	1900	3,891	0	-	1/1/1900	No Data
30-025-20381	HERKIMER BQF FEDERAL #001H	Oil	Active	AMEREDEV OPERATING, LLC	32.114	-103.2722	H	1963	8,515	10,121	10,100	-	DELAWARE, WEST
30-025-20857	WEST JAL B #001	Brine Injection	New	BC & D OPERATING INC.	32.1285	-103.2850	V	1964	12,275	12,275	6,170	-	WOLFCAMP, WEST; DELAWARE
30-025-21039	WEST JAL 18 #1	Oil	Plugged (site released)	SKELLY OIL CO.	32.1276	-103.3010	No Data	1900	12,950	0	-	1/1/1900	No Data
30-025-21172	WEST JAL UNIT #1	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.1176	-103.2807	V	1961	17,086	17,086	-	4/4/1984	DELAWARE, WEST; JAL, STRAWN, WEST
30-025-21411	C ELLIOTT FEDERAL	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.143	-103.2850	V	1900	12,276	12,276	-	6/26/1993	STRAWN, WEST
30-025-25046	WEST JAL B DEEP #001	Brine Injection	Active	BC & D OPERATING INC.	32.1321	-103.2807	V	1975	18,945	18,945	14,175	-	STRAWN, WEST; WOLFCAMP, WEST; FUSSELMAN, WEST; ST-AT-MISS-DEV-FUS
30-025-26010	SPOTTED TAIL FED. #1	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2978	No Data	1900	3,336	0	-	1/1/1900	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26027	SITTING BULL A #001	Oil	Active	FULFER OIL & CATTLE LLC	32.0886	-103.2936	V	1978	3,368	3,368	-	-	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26336	FEDERAL 13 A #1	OIL	Plugged (site released)	GETTY OIL CO.	32.1367	-103.3138	V	1979	3,686	0	-	-	No Data
30-025-26809	LITTLE HAWK FEDERAL #	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2765	No Data	1900	3,690	0	-	1/1/1900	No Data
30-025-26892	SITTING BULL #2	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.085	-103.2850	No Data	1900	3,746	0	-	1/1/1900	No Data
30-025-33348	TEXACO WEST JAL 21 #001	Oil	Plugged (site released)	ENSERCH EXPLORATION INC.	32.1104	-103.2722	V	1996	7,700	7,700	-	4/25/1996	No Data
30-025-38059	DINWIDDIE STATE COM #001	Gas	Plugged (site released)	COG OPERATING LLC	32.1249	-103.2765	V	2006	12,192	12,192	-	12/12/2008	STRAWN, WEST
30-025-46393	NANDINA 25 36 31 FEDERAL COM #124H	Oil	New	AMEREDEV OPERATING, LLC	32.1085	-103.3052	H	-	0	23,130	-	-	WOLFCAMP, WEST
30-025-46533	SIOUX 25 36 STATE FEDERAL COM #008H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2019	12,149	22,150	22,117	-	UPPER WOLFCAMP
30-025-46551	SIOUX 25 36 STATE FEDERAL COM #009H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3175	H	2020	11,894	21,945	21,912	-	BONE SPRING
30-025-46553	SIOUX 25 36 STATE FEDERAL COM #012H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3174	H	2020	11,994	22,350	22,319	-	BONE SPRING; UPPER WOLFCAMP
30-025-46554	SIOUX 25 36 STATE FEDERAL COM #013H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2020	11,725	21,962	21,930	-	BONE SPRING; UPPER WOLFCAMP
30-025-46561	SIOUX 25 36 STATE FEDERAL COM #010H	Oil	Active	CAZA OPERATING, LLC	32.1081	-103.3176	H	2020	12,107	22,209	22,175	-	UPPER WOLFCAMP
30-025-46976	BLACK MARLIN FEDERAL COM #204H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3002	H	2020	11,640	21,953	21,895	-	WOLFCAMP, WEST
30-025-46977	BLACK MARLIN FEDERAL COM #214H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3000	H	2020	11,741	22,055	21,994	-	WOLFCAMP, WEST
30-025-48081	INDEPENDENCE AGI #001	AGI	Active	Pinon Midstream, LLC	32.1208	-103.2910	V	2020	17,709	17,900	-	-	DEVONIAN-FUSSELMAN
30-025-48577	SANTA FE FEDERAL COM #603H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3154	H	-	0	21,874	-	-	BONE SPRING
30-025-48578	SANTA FE FEDERAL COM #704H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3212	H	-	0	22,063	-	-	WOLFCAMP, WEST
30-025-48579	SANTA FE FEDERAL COM #705H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3152	H	-	0	22,129	-	-	WOLFCAMP, WEST
30-025-48580	TRINITY FEDERAL #602H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3214	H	-	0	21,938	-	-	BONE SPRING
30-025-48581	TRINITY FEDERAL #703H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3213	H	-	0	22,206	-	-	WOLFCAMP, WEST
30-025-48582	ZIA FEDERAL COM #604H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3151	H	-	0	21,973	-	-	BONE SPRING
30-025-48583	ZIA FEDERAL COM #706H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3150	H	-	0	21,973	-	-	WOLFCAMP, WEST
30-025-48614	BLUE MARLIN STATE #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3102	H	-	0	19,502	-	-	WOLFCAMP, WEST
30-025-48615	BLUE MARLIN STATE #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	-	0	19,350	-	-	WOLFCAMP, WEST
30-025-48778	BLACK MARLIN FEDERAL COM #113H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3007	H	-	0	20,014	-	-	BONE SPRING
30-025-48779	BLACK MARLIN FEDERAL COM #114H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3006	H	-	0	20,056	-	-	BONE SPRING
30-025-48780	BLACK MARLIN FEDERAL COM #203H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3005	H	2021	11,786	21,842	21,879	-	WOLFCAMP, WEST
30-025-48781	BLACK MARLIN FEDERAL COM #206H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3003	H	-	0	21,981	-	-	WOLFCAMP, WEST
30-025-48782	BLACK MARLIN FEDERAL COM #213H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3004	H	2021	0	22,140	22,073	-	WOLFCAMP, WEST

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-48783	BLACK MARLIN FEDERAL COM #216H	Oil	New	TAP ROCK OPERATING, LLC	32.1374	-103.2996	H	2021	0	22,258	22,258	-	WOLFCAMP, WEST
30-025-49115	BLUE MARLIN FEDERAL COM #111H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3105	H	-	0	20,039	0	-	BONE SPRING
30-025-49116	BLUE MARLIN FEDERAL COM #112H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3105	H	-	0	20,217	0	-	BONE SPRING
30-025-49117	BLUE MARLIN FEDERAL COM #201H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3102	H	2021	11,613	21,985	21,923	-	WOLFCAMP, WEST
30-025-49118	BLUE MARLIN FEDERAL COM #202H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	2021	11,539	21,929	21,866	-	WOLFCAMP, WEST
30-025-49119	BLUE MARLIN FEDERAL COM #205H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3101	H	2021	11,533	21,980	21,916	-	WOLFCAMP, WEST
30-025-49120	BLUE MARLIN FEDERAL COM #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3103	H	2021	12,148	22,554	22,495	-	WOLFCAMP, WEST
30-025-49121	BLUE MARLIN FEDERAL COM #215H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3057	H	2021	11,720	22,188	22,120	-	WOLFCAMP, WEST
30-025-49196	BLUE MARLIN FEDERAL COM #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3055	H	2021	12,003	22,422	22,389	-	WOLFCAMP, WEST
30-025-49528	DOGWOOD 25 36 20 FEDERAL COM #112H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2924	H	2021	0	22,356	0	-	WOLFCAMP, WEST
30-025-49626	DOGWOOD 25 36 20 FEDERAL COM #116H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2842	H	-	0	22,080	0	-	WOLFCAMP, WEST
30-025-49974	INDEPENDENCE AGI #002	AGI	New	Pinon Midstream, LLC	32.1201	-103.2910	D	2022	17,683	18,080	0	-	DEVONIAN-FUSSELMAN
30-025-50391	SIOUX 25 36 STATE FEDERAL COM #020H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	22,710	0	-	UPPER WOLFCAMP
30-025-50392	SIOUX 25 36 STATE FEDERAL COM #021H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	20,244	0	-	BONE SPRING
30-025-50393	SIOUX 25 36 STATE FEDERAL COM #022H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	22,539	0	-	UPPER WOLFCAMP
30-025-50394	SIOUX 25 36 STATE FEDERAL COM #023H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	20,120	0	-	BONE SPRING

Appendix 4 - References

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Appendix 5 - Abbreviations and Acronyms

Abbreviations and acronyms not otherwise defined herein:

3D – 3 dimensional
API – American Petroleum Institute
CFR – Code of Federal Regulations
EOS – Equation of State
ft – foot (feet)
m – meter(s)
mg/l – milligrams per liter
MT -- Metric tonne
NG—Natural Gas
QA/QC – quality assurance/quality control
ST – Short Ton

Appendix 6 - Conversion Factors

Piñon reports CO_2 at standard conditions of temperature and pressure as defined in the State of New Mexico - 60°F and 15.025 psia (NMAC 19.15.2.7 (C)(16))

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the NIST. This online database is available at:

http://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner EOS at a wide range of temperatures and pressures.

At State of New Mexico standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.0027097 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2}\ =\ 0.0027097$$

$$MW_{CO2}\ =\ 44.0095$$

$$Density_{CO2} =\ 5.4092\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.4092\ x\ 10^{-2}\ \frac{MT}{Mcf}$$

The conversion factor 5.4092 x 10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Appendix 7 - Independence 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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \quad \text{(Equation RR-1 for Pipelines)}$$

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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \quad \text{(Equation RR-1 for Containers)}$$

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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \qquad \text{(Equation RR-2 for Pipelines)}$$

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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \qquad \text{(Equation RR-2 for Containers)}$$

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

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \qquad \text{(Equation RR-3 for Pipelines)}$$

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

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \qquad \text{(Equation RR-4)}$$

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

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \qquad \text{(Equation RR-5)}$$

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

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

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

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

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.

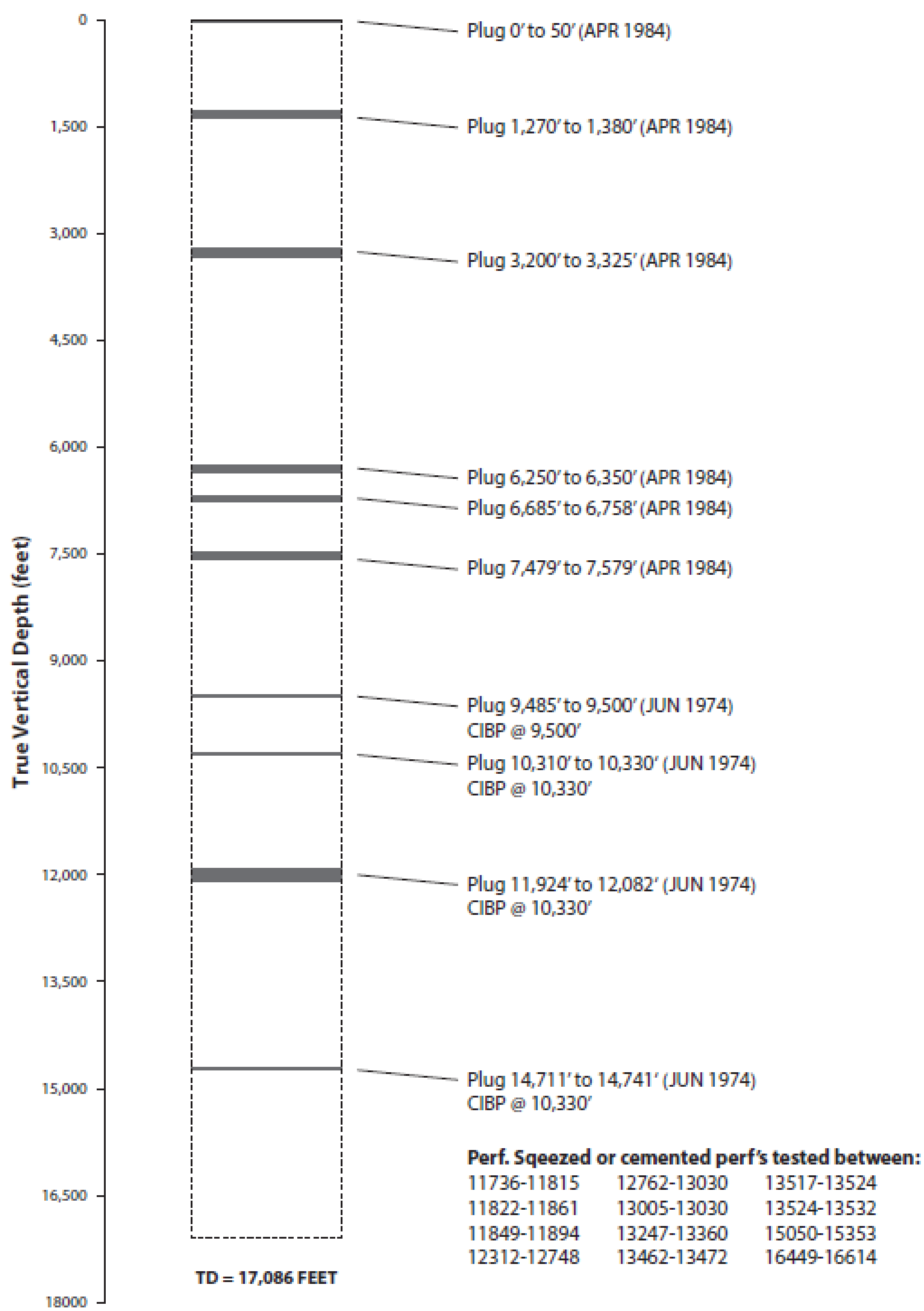
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

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 - Plugging Records for West Jal Unit #1

TEXACO EXPLORATION AND PROD. - WEST JAL UNIT #1 PLUGGING DIAGRAM

Lease Name:	West Jal Unit #1	**Footage:**	1980 FNL and 660 FEL
API:	30-025-21172	**Well Type:**	Oil
Location:	Sec. 20, T25S, R36E	**Total Depth:**	17,086'
County, State:	Lea County, New Mexico	**Coordinates:**	32.117596, -103.280739 (NAD83)



*Schematic is properly scaled

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P. O. BOX 1980
HOBBS. NEW MEXICO 88

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UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Buluu No. 1004-0135
Expires: March 31, 1993

5. Lease Designation and Serial No.
N

6. If Indian, Allottee or Tribe Name

SUNDRY NOTICES AND REPORTS ON WELLS
Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT-" for such proposals

SUBMIT IN TRIPLICATE

7. If Unit or CA, Agreement Designation

1. Type of Well
[X] Oil Well [ ] Gas Well [X] Other Reentry

8. Well Name and No.
f JA-/t:Jt!JLA-Iry

2. Name of Operator
MCH Petroleum Services

9. API Well No.
c30-025-2/112

3. Address and Telephone No.
-:1:)1 W. Pkwy St. Midland, Tx 79705 915 683 4772

10. Field and Pool, or Exploratory Area
~~Abandoned~~ W.-Sal Delaware

4. Location of Well (footage, Sec., T., R., M., or Survey Description)
/'f4!o PAt ,o l=Gl- -S Z.0 , r- zS-S, 11- "I+'=
H S£NE 6J•,)1 h\.

11. County or Parish, State
Lea, NM

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

TYPE OF SUBMISSION	TYPE OF ACTION	
[X] Notice of Intent	[ ] Abandonment	[ ] Change of Plans
	[ ] Recompletion	[ ] New Construction
[ ] Subsequent Report	[ ] Plugging Back	[ ] Non-Routine Fracturing
	[ ] Casing Repair	[ ] Water Shut-Off
[ ] Final Abandonment Notice	[ ] Altering Casing	[ ] Conversion to Injection
	Other Reentry	[ ] Dispose Water
		(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abandoned by Texaco in 1983. MCH will drill out cement plugs and cibp@ 7,579' to a total depth of approx. 8,350'(inside casing). This will leave in place cibp at 9,500' and deeper. We will then test Existing perforations@ 7,807'-7,857' and stimulate as necessary.
Mud Program: Fresh water will be used for the reentry inside casing.
BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO
GENERAL REQUIREMENTS AND
SPECIAL STIPULATIONS
ATTACHED

14. I hereby certify that the foregoing is true and correct

Signed Craig Huber Title Owner Date 4/13/93

(This space for Federal or State office use)

Approved by '" 1ITC &r.n L MAron; Title AREA MANAGER Date JUN 4 1993
Conditions of approval, if any:

Title 18 U.S.C. Section 1001, makes 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.

*See Instruction on Reverse Side

G 31

Form 3160-3
(December 1990)

SUBMIT IN TRI[illegible] TE*
(Other instructions o.. reverse side)

Form approved.
Budget Bureau No. 1004-0136
Expires: December 31, 1991

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR DEEPEN

5. LEASE DESIGNATION AND SERIAL NO. NM 71792

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

1a. TYPE OF WORK: DRILL ☐ DEEPEN ☐

b. TYPE OF WELL: OIL WELL ☒ GAS WELL ☐ OTHER Reentry SINGLE ZONE ☒ MULTIPLE ZONE ☐

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME, WELL NO. West JAL Federal #1

2. NAME OF OPERATOR: MCH Petroleum Services

9. API WELL NO. 30-025-21172

3. ADDRESS AND TELEPHONE NO.: 708 W. Pine St. Midland, Tx 79705 915 683 4772

10. FIELD AND POOL, OR WILDCAT: ~~[illegible]~~ W. Jal Delaware

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*)
At surface 1980' FNL, 660' FEL sec 20 T-25S, R-36E Lea Co. NM
At proposed prod. zone SAme H SENE

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: S-20, T-25S, R36E

14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE*: 6 miles W. JAl, N.M.

12. COUNTY OR PARISH: Lea | 13. STATE: NM

15. DISTANCE FROM PROPOSED* LOCATION TO NEAREST PROPERTY OR LEASE LINE, FT. (Also to nearest drlg. unit line, if any): 660'

16. NO. OF ACRES IN LEASE: 600

17. NO. OF ACRES ASSIGNED TO THIS WELL: 40

18. DISTANCE FROM PROPOSED LOCATION* TO NEAREST WELL, DRILLING, COMPLETED, OR APPLIED FOR, ON THIS LEASE, FT.

19. PROPOSED DEPTH: 8350

20. ROTARY OR CABLE TOOLS: Pulling unit/Reverse unit

21. ELEVATIONS (Show whether DF, RT, GR, etc.): 3076' GL

22. APPROX. DATE WORK WILL START*: ASAP (Prior to 6/1/93 exp.)

23. PROPOSED CASING AND CEMENTING PROGRAM

SIZE OF HOLE	GRADE, SIZE OF CASING	WEIGHT PER FOOT	SETTING DEPTH	QUANTITY OF CEMENT
26	20		869' (In Place)	1630 sx.
17½	13 3/8	72, 68, 64	6300' (In Place)	3606 sx.
12¼	9 5/8	53.5, 47, 43.5	11,736 (In Place)	775 sx.
8 3/8	7	26	6735-12213 (Shot off @ 6735)	612 sx
6¼	5½ (LNR.)	(unk.)	12,032-15,400	450 sx.
(unk)	3½ (LNR.)	(unk)	14,967-17,084	250 sx.

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abondoned by Texaco in 1983. MCH will drill out cement plugs and cibp @ 7,579' to a total depth of approx. 8,350' (inside casing). This will leave in place cibp at 9,500' and deeper. We will then test existing perforations @ 7,807'-7,857' and stimulate as necessary.

Mud Program: Fresh water will be used for the reentry inside casing.

BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO GENERAL REQUIREMENTS AND SPECIAL STIPULATIONS ATTACHED

IN ABOVE SPACE DESCRIBE PROPOSED PROGRAM: If proposal is to deepen, give data on present productive zone and proposed new productive zone. If proposal is to drill or deepen directionally, give pertinent data on subsurface locations and measured and true vertical depths. Give blowout preventer program, if any.

24.

SIGNED Craig Huber TITLE Owner DATE 4/13/93

(This space for Federal or State office use)

PERMIT NO. ______ APPROVAL DATE ______

Application approval 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.
CONDITIONS OF APPROVAL, IF ANY:

APPROVED BY ______ TITLE ______ DATE ______

*See Instructions On Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

Form 3160–5
(November 1983)
(Formerly 9–331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

P. O. BOX 1980
HOBBS, NEW MEXICO 88240

Form approved.
Budget Bureau No. 1004–0135
Expires August 31, 1985

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

1. OIL WELL [X] GAS WELL [ ] OTHER

7. UNIT AGREEMENT NAME
West Jal Unit

2. NAME OF OPERATOR
Getty Oil Company

8. FARM OR LEASE NAME

3. ADDRESS OF OPERATOR
P.O. Box 730, Hobbs, NM 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
Unit Ltr. H, 1980' FNL & 660' FEL

10. FIELD AND POOL, OR WILDCAT
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, T-25S, R-36E

BUREAU OF LAND MGMT. REC'D APR ... DIST. 6 N. M. ROSWELL, NEW MEXICO

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138' D.F.

12. COUNTY OR PARISH
Lea

13. STATE
NM

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	[ ]	PULL OR ALTER CASING	[ ]	WATER SHUT-OFF	[ ]	REPAIRING WELL	[ ]
FRACTURE TREAT	[ ]	MULTIPLE COMPLETE	[ ]	FRACTURE TREATMENT	[ ]	ALTERING CASING	[ ]
SHOOT OR ACIDIZE	[ ]	ABANDON*	[ ]	SHOOTING OR ACIDIZING	[ ]	ABANDONMENT*	[XX]
REPAIR WELL	[ ]	CHANGE PLANS	[ ]	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

3/26/84 Rigged up. Pulled rods and pump. Unseat tbg. anchor and install BOP.
3/28/84 Pulled 2 7/8" buttress & 2 3/8" tbg. anchor. Ran 7" CI plug, set @ 7579'. Ran 2 3/8' to 4290'. By Halliburton, circ. 191 bbls. gel brine, pulled tbg. Perfs 4-0.25" holes @ 6400'. Circ. out 7" between 9 5/8". Ran 2 7/8" to 7554'.
3/29/84 Rigged up csg. puller unit. Pulled tbg. Remove BOP & 7" tbg. spool.
3/30/84 Weld 7" pull nipple. Cut 7" csg. @ 6735'. Pulled 11 jts 7", 26#, P-110 csg. 8 rd.
3/31/84 Layed down total 163 jts (est. 6525') 7", 8rd casing. Nipple down 9 5/8" head.
4/2/84 Weld on 9 5/8" pulled nipple. Attempted to pull slips with 500,000#. Set off primer cord around head, no movement. Left soaking in penetrating oil.
4/3/84 Dug out 13 3/8" csg. unflange head. Move pipe 1" with 600,000#. Cut off. Pulled nipple, installed BOP. Ran tbg to 5216'.
4/4/84 Spot 20 sxs cement on top of CIBP 7579-7479'. Spot 100' plug (45 sxs) at 6758-6685', 6350-6250', 3325-3200', 1380-1270'. Remove csg. head.
4/5/84 Rigged down. Installed 20 sxs. Plugged 0-50'. Installed dry hole marker. P&A.

18. I hereby certify that the foregoing is true and correct

SIGNED Donald J. Steinnerd TITLE Area Superintendent DATE April 11, 1984

(This space for Federal or State office use)
Orig. Sgd. ...

APPROVED BY ... TITLE ... DATE 6 8 8 7

CONDITIONS OF APPROVAL, IF ANY:

Approved as to plugging of the well bore. Liability under bond is retained until surface restoration is completed.

0+6-BLM-Roswell 1-Mr. J.A.-Midland
1-File 1-Laura Richardson-Midland
1-Engr Jim 1-BB, 1-JA
1-Foreman CK 1-SH, 1-CP 1-Southland Royalty Company, 1-ARCO

*See Instructions on Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

N. M. OIL CONS. COMMISSION
P. O. BOX 1980
HOBBS, NEW MEXICO 88240

O+6 - BLM - P.O. Box 1857, Roswell, 1-File, 1-Engr.JIM, 1-Foreman CK

Form 9-331
Dec. 1973

1 - Laura Richardson-Midland

Form Approved.
Budget Bureau No. 42-R1424

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

BUREAU OF LAND MANAGEMENT
RECEIVED
JUL 25 1983
DIST. 6 N. M.
ROSWELL, NEW MEXICO

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 Form 9-331-C for such proposals.)

1. oil well XX gas well ☐ other

2. NAME OF OPERATOR
Getty Oil Company

3. ADDRESS OF OPERATOR
P.O. Box 730 Hobbs, NM 88240

4. LOCATION OF WELL (REPORT LOCATION CLEARLY. See space 17 below.)
AT SURFACE: Unit ltr. H, 1980' FNL & 660 FEL
AT TOP PROD. INTERVAL:
AT TOTAL DEPTH:

5. LEASE
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME
West Jal Unit

9. WELL NO.
1

10. FIELD OR WILDCAT NAME
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, 25S-36E

12. COUNTY OR PARISH
Lea

13. STATE
NM

14. API NO.

15. ELEVATIONS (SHOW DF, KDB, AND WD)
3138' D.F.

16. CHECK APPROPRIATE BOX TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

	REQUEST FOR APPROVAL TO:	SUBSEQUENT REPORT OF:
TEST WATER SHUT-OFF	☐	☐
FRACTURE TREAT	☐	☐
SHOOT OR ACIDIZE	☐	☐
REPAIR WELL	☐	☐
PULL OR ALTER CASING	☐	☐
MULTIPLE COMPLETE	☐	☐
CHANGE ZONES	☐	☐
ABANDON*	XX	☐
(other) Revised		

(NOTE: Report results of multiple completion or zone change on Form 9-330.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

Revised procedure as per conversation with Mr. Peter Chester 7/18/83:

1. Install B.O.P.
2. Set C.I.B.P. at +7860 w/35' cement on top.
3. Perforate 2 holes @ 6375' & squeeze with sufficient cement to bring cement to 6225'.
4. Set cement plug 1230-1330' top of salt. (in & behind casings).
5. Set 50' surface plug.
6. Install dry hole marker.
7. Restore location.

Subsurface Safety Valve: Manu. and Type ______ Set @ ______ Ft.

18. I hereby certify that the foregoing is true and correct

SIGNED Dale R. Crockett TITLE Area Superintendent DATE July 22, 1983

APPROVED

(This space for Federal or State office use)

APPROVED BY (Orig. Sgd.) ... M. CHESTER TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

SEP 14 1983

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429-A

WELL COMPLETION OR RECOMPLETION REPORT AND LOG *

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

1a. TYPE OF WELL: OIL WELL [X] GAS WELL [ ] DRY [ ] Other

7. UNIT AGREEMENT NAME
------

b. TYPE OF COMPLETION: NEW WELL [ ] WORK OVER [ ] DEEP-EN [ ] PLUG BACK [X] DIFF. RESVR. [X] Other

8. FARM OR LEASE NAME
West Jal Unit

2. NAME OF OPERATOR
Skelly Oil Company

9. WELL NO.
1

3. ADDRESS OF OPERATOR
P. O. Box 1351, Midland, Texas 79701

10. FIELD AND POOL, OR WILDCAT
UNDESIGNATED
Jal Delaware, West

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface Unit Letter H, 1980' FNL and 660' FEL, Sec. 20-25S-36E
At top prod. interval reported below
At total depth

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO.
DATE ISSUED

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

15. DATE SPUDDED: --
16. DATE T.D. REACHED: --
17. DATE COMPL. (Ready to prod.): 5-28-74
18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*: 3138' DF
19. ELEV. CASINGHEAD: ---

20. TOTAL DEPTH, MD & TVD: 17086'
21. PLUG, BACK T.D., MD & TVD: 9485' PBTD
22. IF MULTIPLE COMPL., HOW MANY*: --
23. INTERVALS DRILLED BY →
ROTARY TOOLS: --
CABLE TOOLS: --

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*
7807-7857' Delaware

25. WAS DIRECTIONAL SURVEY MADE
---

26. TYPE ELECTRIC AND OTHER LOGS RUN
None

27. WAS WELL CORED
--

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
No Change					

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
-	-	-	-	-
-	-	-	-	-

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-3/8"OD	7941'	--
2-7/8"OD		--

31. PERFORATION RECORD (Interval, size and number)
7807-7811', 7816-7824', 7853-7857', total 32 shots, 0.50" diameter, two shots per foot.

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
7807-7857'	750 gallons mud acid 5000 gallons 15% NE acid, 82 ball sealers, 9000# 20-40 sand, 9000 gallons lease oil

33.* PRODUCTION

DATE FIRST PRODUCTION: 5-28-74
PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump): Pumping
WELL STATUS (Producing or shut-in): Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
6-19-74	24	-	→	63	1	6	16

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
--	63#	→	63	1	6	41°

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.)
Used for Fuel

TEST WITNESSED BY

35. LIST OF ATTACHMENTS
None

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED (Signed) D. R. Crow D. R. Crow TITLE Lead Clerk DATE 6-20-74

*(See Instructions and Spaces for Additional Data on Reverse Side)

INSTRUCTIONS

General: This form is designed for submitting a complete and correct well completion report and log on all types of lands and leases to either a Federal agency or a State agency, or both, pursuant to applicable Federal and/or State laws and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local, area, or regional procedures and practices, either are shown below or will be issued by, or may be obtained from, the local Federal and/or State office. See instructions on items 22 and 24, and 33, below regarding separate reports for separate completions.

If not filed prior to the time this summary record is submitted, copies of all currently available logs (drillers, geologists, sample and core analysis, all types electric, etc.), formation and pressure tests, and directional surveys, should be attached hereto, to the extent required by applicable Federal and/or State laws and regulations. All attachments should be listed on this form, see item 35.

Item 4: If there are no applicable State requirements, locations on Federal or Indian land should be described in accordance with Federal requirements. Consult local State or Federal office for specific instructions.

Item 18: Indicate which elevation is used as reference (where not otherwise shown) for depth measurements given in other spaces on this form and in any attachments.

Items 22 and 24: If this well is completed for separate production from more than one interval zone (multiple completion), so state in item 22, and in item 24 show the producing interval, or intervals, top(s), bottom(s) and name(s) (if any) for only the interval reported in item 33. Submit a separate report (page) on this form, adequately identified, for each additional interval to be separately produced, showing the additional data pertinent to such interval.

Item 29: *"Sacks Cement"*: Attached supplemental records for this well should show the details of any multiple stage cementing and the location of the cementing tool.

Item 33: Submit a separate completion report on this form for each interval to be separately produced. (See instruction for items 22 and 24 above.)

37. SUMMARY OF POROUS ZONES:
SHOW ALL IMPORTANT ZONES OF POROSITY AND CONTENTS THEREOF; CORED INTERVALS; AND ALL DRILL-STEM TESTS, INCLUDING DEPTH INTERVAL TESTED, CUSHION USED, TIME TOOL OPEN, FLOWING AND SHUT-IN PRESSURES, AND RECOVERIES

38. GEOLOGIC MARKERS

FORMATION	TOP	BOTTOM	DESCRIPTION, CONTENTS, ETC.	NAME	TOP MEAS. DEPTH	TOP TRUE VERT. DEPTH

1) Squeezed Fusselman perfs. 16,449-16,614' with 100 sacks Class "H" cement, 5/10% CFR-2.
2) Spotted 25 sacks cement 14,711-14,741', 25 sacks 11,924-12,082' and set cast iron bridge plug at 10,330' and spotted 4 sacks cement 10,310-10,330'.
3) Perforated 7" OD casing in First Bone Springs formation with two 0.48 diameter holes per foot at 10,112-10,122' and 10,128-10,132'. (28 shots total)
4) Treated First Bone Springs perfs. 10,112-10,132 with 5500 gallons acid and 68 ball sealers.
5) Swab tested First Bone Springs perfs. 10,112-10,132' May 14, 1974, to May 21, 1974, for no oil, 14 bbls. water and slight show of gas in 5 hours.
6) Set cast iron bridge plug at 9500' and cemented with 3 sacks cement plugging back to 9485'.
7) Perforated 7" OD casing in Delaware formation with two 0.50" diameter holes per foot at 7807-7811', 7816-7826' and 7853-7857'. (32 shots total)
8) Treated Delaware perfs. 7807-7857' with 750 gallons mud acid, 5000 gallons 15% NE acid, 9000 gallons gelled lease oil, 9000# 20-40 sand and 22 ball sealers.
9) Returned well to production status 5-28-74 pumping Delaware perfs. 7807-7857' for 63 bbls. oil, 6 bbls. water and 1 MCFGPD.

8) Flowed 24-1/2 hours through 1" choke, making no oil, 45 bbls. load water, 393 bbls. formation water and gas at rate of 266 MCF per day. FTP 200#, CP 2300#.
9) Ran flow meter, Gradionometer and Temperature Survey to determine water entry.
10) Shut well in seven hours, then ran Base Temperature Log 16,000-17,020'. Water channelling from bottom of well bore to 16,508'.
11) Set cement retainer at 16,250' and squeezed perfs. 16,499-16,614' with 150 sacks Class "H" cement containing 4/10ths of 1% CFR-2 and 1% Halad 9. Squeeze failed. WOC 4 hours.
12) Resqueezed perfs. 16,449-16,614' with 50 sacks Class "H" cement with 1% Halad 9, 4/10ths of 1% CFR-2 and 1/4# Flocele per sack and 150 sacks Class "H" containing 1% Halad 9 and 4/10ths of 1% CFR-2. Squeeze failed.
13) Attempted to pull cement retainer - stuck.
14) Milled and pushed cement retainer from 16,250' to 16,490'. Recovered cement retainer.
15) Drilled and pushed junk to 16,930'.
16) Ran 254 jts. (14,793') of 2-7/8" OD tubing and set packer at 14,810'. Swabbed 9 hours, recovering 60 bbls. load water with good show of gas.
17) Treated perfs. 16,449-16,614' with 500 gals. 15% NE acid with 2 ball sealers. Swabbed 7 hours, recovering 1 bbl. load water, flowing gas at rate of 50 MCF per day.
18) Treated perfs. 16,449-16,614' with 5000 gals. 15% NE acid and 27 ball sealers.
19) Ran Temperature Survey 15,000-16,958'.
20) Tested well. Well flowed at rate of 910 MCF per day on 23/64" choke, no oil, FTP 310#. Pulled tubing and packer.
21) Reran 457 jts. (14,940') of 2-7/8" OD 7.9# DSS-HT Atlas-Bradford Condition "A" tubing and set at 14,967'.
22) Circulated hole with corrosion inhibitor water. Released rig 11-8-72. Flowed and tested well.
23) On Dec. 11, 1972, treated perfs 16,449-16,614' with 12,500 gals. of 1% KCL water with 62# friction reducer, 25 gals. Adofoam and 25 gals. scale inhibitor, 20,000 gals. 20% retarded acid with 100# friction reducer, 40 gals. Adofoam, 160 gals. acid inhibitor, 1000# fluid loss agent and 40 gals. scale inhibitor and 7 ball sealers. All fluid contained 400 S.C.F Nitrogen per barrel.
24) Testing well.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

7. UNIT AGREEMENT NAME

1. OIL WELL ☐ GAS WELL ☒ OTHER

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 1351, Midland, TExas 79701

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FWL and 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Undesignated Fusselman

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3076' GR

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐
REPAIR WELL	☐	CHANGE PLANS	☐
(Other)			

SUBSEQUENT REPORT OF:			
WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
(Other) Clean out & deepen to 17,086'	x		

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

1) Rigged up rotary tools 7-28-72. Pulled tubing and packer.
2) Set cement retainer at 11,390' and squeezed Strawn 7" OD casing perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 1% CFR-2 and 3# sand per sack. Squeeze failed. WOC 4 hours.
3) Resqueezed perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 5/10% of 1% CFR-2 and 3# sand per sack. Squeezed at 6500#. Reversed out 15 sacks.
4) After WOC 12 hours, drilled cement retainer at 11,390' and cement 11,390-11,755' with 6-1/2" bit.
5) Tested squeeze job to 3000#; held okay.
6) Drilled cement 11,790-11,832' and tested old squeeze job on perfs. 11,736-11,815' to 3000#; held okay.
7) Drilled cement 11,832-11,844'; pushed plus-plug to 11,976'. Drilled plug. Tagged junk at 12,002' and pushed to 12,312'.
8) Cleaned to top of 5-1/2" OD liner at 12,032', set cement retainer at 11,820' and found casing perfs. 11,849-11,894' open.
9) Squeezed 5-1/2" casing perfs. 11,849-11,894' with 50 sacks Class "H" with 1% CFR-2 and 100 sacks Class "H" with 1% CFR-2 and 3# sand per sack.
10) Dumped 20 sacks cement on retainer at 11,820', plugging back to 11,717'. Reversed out 90 sacks cement. WOC 12 hours.

(continued on page 2)

18. I hereby certify that the foregoing is true and correct

SIGNED ______ TITLE Lead Clerk DATE Dec. 18, 1972

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______
CONDITIONS OF APPROVAL, IF ANY:

ACCEPTED FOR RECORD
DEC 20 1972
U. S. GEOLOGICAL SURVEY
HOBBS, NEW MEXICO

*See Instructions on Reverse Side

West Jal Unit
Well No. 1
Lea Co., New Mexico
Page 2

11) Drilled cement 11,708-11,820'; cement retainer 11,820-11,822' and cement 11,822-11,861'. Cleaned out to top of liner at 12,032'.
12) Tested squeeze job to 2500#; held okay.
13) Drilled junk 12,312-12,748.5'; cement 12,748.5-12,760'; junk to 12,762'; cement 12,762-13,030'.
14) Tested old squeezed perfs. 13,005-13,030' to 2500#; held okay.
15) Milled and drilled cast iron bridge plug at 13,174' and pushed to 13,395'.
16) Tested 5-1/2" OD liner perfs. 13,247-13,360' to 2900#; could not pump into perfs.
17) Milled cast iron bridge plug 13,396-13,400'.
18) Tested perfs. 13,462-13,472' to 2700#; could not pump into perfs.
19) Milled and drilled out cement retainer 13,517-13,524'; cement 13,524-13,532'; cement 15,050-15,353'.
20) Milled and drilled cast iron bridge plug 15,340-15,858'. Washed over fish 15,858'; recovered fish. Cleaned out to old TD of 15,958'.
21) Drilled 4-3/4" new hole 15,958-16,498'.
22) Ran Drill Stem Test No. 1 (Silurian) 15,400-16,498'.
23) Drilled 4-3/4" hole 16,498' to total depth of 17,086' at 11 p.m. October 4, 1972.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instruction on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429 - A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- - -

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
- - -

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Section 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3102' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Cement, perforate & treat			☒
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

1) Perforated 2-7/8"OD tubing at 11,696',11,297', 10,574; 9698'; 8892';8707',8403'. Circulated to remove mud from annulus. Work began 1-29-69.
2) Pulled tubing
3) Ran 2-7/8"OD tubing with "RTTS" Packer. Set packer at 11,448'.
4) Squeezed 7"OD casing perforations 11,736-11,894' with 150 sacks class "H" Cement with 1% CFR-2 per sack, maximum pressure 4600#, failed. W.O.C. 4 hours. Broke formation down with 5000#.
5) Squeezed 7"OD casing perforations 11,736-11,894" with 50 sacks Class "H" cement with 1% CFR-2 and 5# No. 3 sand per sack. Displaced 35 sacks into formation. Pulled tubing and packer.
6) WOC 36 hours. Ran tubing with 6-1/8" bit. Top of cement inside 7"OD casing at 11,595'. Washed and circulated cement to 11,620'. Drilled cement 11,620-11,700'. Drilled packer 11,700-705'. Drilled cement 11,705-755'.
7) Tested casing to 3000#, held okay.
8) Spotted 12 bbls. acid 11,755-11,443'.
9) Perforated 7"OD casing with 2 shots per foot as follows:

11,510 - 513'	3'	6 shots
11,517- 527'	10'	20 shots
11,536 - 540'	4'	8 shots
11,550 - 556'	6'	12 shots
11,561 - 567'	6'	12 shots
11,575 - 579'	4'	8 shots
11,660 - 667'	7'	14 shots

18. I hereby certify that the foregoing is true and correct

SIGNED ______ TITLE District Production Manager DATE 3-10-69

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______
CONDITIONS OF APPROVAL, IF ANY:

(ORIGINAL SIGNED) V. H. Fletcher

APPROVED
MAR 11 1969
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
~~73503~~ NM-0342917

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

7. UNIT AGREEMENT NAME
----

1. OIL WELL [ ] GAS WELL [X] OTHER

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface **1980 from North line and 660 from East line, Section 20**

20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3092' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	[ ]	PULL OR ALTER CASING	[ ]	WATER SHUT-OFF	[ ]	REPAIRING WELL	[ ]
FRACTURE TREAT	[ ]	MULTIPLE COMPLETE	[ ]	FRACTURE TREATMENT	[ ]	ALTERING CASING	[ ]
SHOOT OR ACIDIZE	[ ]	ABANDON*	[ ]	SHOOTING OR ACIDIZING	[ ]	ABANDONMENT*	[ ]
REPAIR WELL	[ ]	CHANGE PLANS	[ ]	(Other)			[ ]
(Other) **Cement, Perforate & Treat**			[X]	(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)			

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

Squeeze present perforated interval 11,736-11,852', below packer set at 11,700', with 125 sacks cement. Drill out to 11,790'. Perforate 11,510-11,783' with 2 shots per foot. Treat perforations 11,510-11,783' with 300 gallons 15% acid with 3 stage treatment using Dowell J-182 as diverting agent. Inject 72 barrels distillate to remove diverting agent. Swab and test.

18. I hereby certify that the foregoing is true and correct

SIGNED (signed) C. R. DAVIS TITLE **District Operations Manager** DATE **1/24/69**

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______

CONDITIONS OF APPROVAL, IF ANY:

APPROVED

JAN 2. 1969

J. L. GORDON
ACTING DISTRICT ENGINEER

RT/jc

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- -

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
- -

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' from North line and 660' from East line

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.
- -

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138'

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐
REPAIR WELL	☐	CHANGE PLANS	☐
(Other)			☐

SUBSEQUENT REPORT OF:

WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
(Other) Eliminate water production			☒

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

(1) Moved in and rigged up workover rig 10-21-68
(2) Set Schlumberger "plus" plug in 7"OD casing at 11,844'.
(3) Dumped 5' cement on top of plug, filling from 11,844' to 11,839'.
(4) Dumped 200 lbs. Hydromite on top of "plus" plug, filling back to 11,832'.
(5) Swabbed well.
(6) Apparent communications still exist between upper and lower perforations behind 7"OD casing. Objective to shut off lower perforations 11,860 - 11,894' and to decrease water production unsuccessful.
(7) Well returned to producing status 10-27-68 flowing 150 MCF gas per day through 7" OD casing perforations 11,736 - 11,894'.

18. I hereby certify that the foregoing is true and correct

SIGNED [signature] TITLE District Production Manager DATE 10-30-68

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
NOV , 1968
J L GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429 - A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL XX OTHER

7. UNIT AGREEMENT NAME
-----

2. NAME OF OPERATOR
SKELLY OIL COMPANY

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

1980' FNL & 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO.
-----

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Clean, Determine Water Source, Eliminate Water Production			X
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

Moved in and rigged up Workover Rig. Killed well. Ran 1-5/8" drill pipe and fishing tools to top of fish at 9901', pushed to 9991', caught fish, circulated and pulled out of hole. Recovered 2 strings of fishing tools previously left in hole. Reran 1-5/8" drill pipe several times with fishing tools and recovered 1786' in several pieces of 5/16" wire line, and a chemica cutter.

Tagged bottom of 2-7/8"OD tubing at 11,715'. Knocked off one foot of tubing and a bull plug that had been previously cut off. Pushed and drove bull plug to 12,482'. Hit firm fill-up of formation cavings and left one-foot piece of 2-7/8"OD tubing and bull plug in hole at 12,482', leaving tubing open-ended at 11,715' with full 2-7/8" opening. Pulled drill pipe and fishing tools and installed Xmas tree. Ran Gradiomanometer, Continuous Flowmeter and Packer Flowmeter to determine water source. Surveys indicated water source being produced through casing perfora tions 11,883-11,894'.

Set packer at 11,883'. Returned to production status November 19, 1967, producing 38 bbls. oil, 800 bbls. water and 2,000 MCF gas per day from the Strawn Gas Pool through perforations 11736-11894' through 7"OD casing.

18. I hereby certify that the foregoing is true and correct

SIGNED (ORIGINAL SIGNED) V. E. Fletcher TITLE District Superintendent DATE April 25, 1968

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
APR 26 1968
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE*
(See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
---

7. UNIT AGREEMENT NAME
---

8. FARM OR LEASE NAME
West Jal Unit

9. WELL NO.
1

10. FIELD AND POOL, OR WILDCAT
Undesignated Fusselman

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA
Sec. 20-25S-36E

12. COUNTY OR PARISH: Lea
13. STATE: New Mexico

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL ☒ DRY ☐ Other

b. TYPE OF COMPLETION: NEW WELL ☐ WORK OVER ☒ DEEP-EN ☒ PLUG BACK ☐ DIFF. RESVR. ☒ Other

2. NAME OF OPERATOR
Skelly Oil Company

3. ADDRESS OF OPERATOR
P. O. Box 1351, Midland, Texas 79701

4. LOCATION OF WELL (*Report location clearly and in accordance with any State requirements*)*
At surface 1980' FNL and 660' FEL Sec. 20-25S-36E
At top prod. interval reported below
At total depth

14. PERMIT NO.
DATE ISSUED

15. DATE started	16. DATE T.D. REACHED	17. DATE COMPL. (*Ready to prod.*)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
7-28-72	11-1-72	10-4-72	3076' GR	---

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
17,086'	17,020'	---	→	15,958-17,086'	---

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*
16,449-16,614' (Fusselman)

25. WAS DIRECTIONAL SURVEY MADE: No

26. TYPE ELECTRIC AND OTHER LOGS RUN BHC Sonic Gamma Ray with Caliper, Dual Laterolog, Continuous Dipmeter, Compensated Neutron & Formation Density

27. WAS WELL CORED: No

28. CASING RECORD (*Report all strings set in well*)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
20"	94#	869'	26"	1630 sacks	None
13-3/8"	72,61 & 68#	6300'	17-1/2"	3206 sacks	None
9-5/8"	53.5 & 47#	11,732'	12-1/4"	975 sacks	None

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
		(See attachment)		

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-7/8"	14,967'	None

31. PERFORATION RECORD (*Interval, size and number*)
16,449-16,614' (Fourteen .33" holes over 165' interval)

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
11,510-11,741'	200 sacks Class "H" Cement
11,849-11,894'	150 sacks Class "H" Cement
16,449-16,614'	350 sacks Class "H" Cement
	(See attachment)

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (*Flowing, gas lift, pumping—size and type of pump*)	WELL STATUS (*Producing or shut-in*)
11-1-72	Flowing	Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
11-14-72	24	24/64"	→	-0-	5950	216	----

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
1900#	---	→	-0-	5950	216	---

34. DISPOSITION OF GAS (*Sold, used for fuel, vented, etc.*)
Sold

TEST WITNESSED BY

35. LIST OF ATTACHMENTS 2 copies each: Borehole Compensated Sonic Log - Gamma Ray, Compensated Neutron-Formation Density, Dual Laterolog, Gammatron

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED C.J. Love TITLE Dist. Prod. Manager DATE Dec. 20, 1972

*(See Instructions and Spaces for Additional Data on Reverse Side)

Set Baker Calt Iron Bridge Plug at 13,400'. Spotted 2 aacka c••nt on top of bridge plug traa 13,-00' to 1.3,386'. Perto:rated 5-1/2" OD liner with 4 holea at 13,210' and 1queezed with 85 aacka ot caat. Drill.eel out oeaeat \o 13,386'• Perforated S-1/2" liner with 4 ahota per foot •• followa1 13,247-13,2'10', 13,272-1.3,275', 13,286-13,292', 13,298-13,320', 13,326-13,329', 1.3,343-13,345', 13,)56-13,360' tor a total ot 63• and 252 hol••• Treated tbroqh S-1/2" OD caaing liner pert•• 13,247-13,360' (intenala) with 2500 gallon• Mud Acid. Teated .-.11 Hftr&I houn with -n,lae to aall to meanre. Treated through 5-1/2" OD caeing liner perta. 13,21.7-13,360' (intenala) with 2500 gallons Mud Acid.. t'eelMI •li-'.aeveral hN. with TOIUM to -11 to meaaure. Treated through S-1/2" OD casing liner pert▪• 13,247-IJ,'601 (intenala) with 10,000 galana 1,- llegular Acid. Teated well aenral houri with wl1111e to .all to m•an• Set Baker Caat Iron Model "I" Bridge Plug at 13,180'• Dmlpecl 2 eacka ot cement on top ot plug, wbieh pl11g nll b&ek tra 13,180' to 1.3,166•. Pertorat.ed 5-1/2" OD liner with bole• per toot froa 13,0051 to 13,030• for a total of 251 and 100 hol••• Treated threnlgh 5-1/2" OD liner perte. 13,00S-13,030' with S,000 gallons 15C Regular Acid. Teated well N'Yer&I hove with TOluae \oo ▪-II to aeanre. We teaJ>I'?'8,ril7 abandoned the teat.inc ot the Morrow Zone at t.hie t.m, Set Halliburton "DC" C... nt Retainer at 12,790' and aqueesed 85 eaeke ot CtllHlt into 5-1/2" OD liner perte. 13,005-13,030•. Plugged back total depth 12,7901• Pertorat.ed 7" OD casing with 4 bolea per toot aa tollowa1 11,736-II,7U', 11,781-11,787', II,801-II,815t, II,&1+,-11,852', 11,860-U,894' tor a total ot 55t and 220 holea. Set Baker Model "7" Production Packer at 11,700'• Ran 2-7/8" OD 6.1+0# Bllttre•• threat! 1-80 tubing to 11,715' and ....ted in Baker Model"'" Production Packer at 11,700' with pert▪• 11,711-II,715'. Ot.ia l.allding nipple position No. I at II,709'. Ot.1• aid• doar ahitt. valft at U,698'. otie landing nipple poaition lo. 2 at 10,700'. otil lending nipple position lo. 3 at 9700'• Opened well up and flowed to pit to clean up. Shut well in tor 89 hove. After 89 houra with dead night T.P. 6218# fiowed and teated well 1n the toll.owing anner1

nowed 1-3/4 hour▪ on 10/64" choke, opening TP 6218# (W), FTP 6156pai., gas wltae 2,737 JEPPD and 7.6') 'bbl•• ot 52 degree correeted gra'Yit7 condenaate.
lu.t. two hour▪ tlowd through 12/64• ohoke, ITP 6075 pai. (17W), gas luae 4563 KCFPD .w1i and 6.60 bbla. of condenea.te.
lut two noura fiowd throUgh 14/6'+" choke, FTP 599S pei. (DW), gae wIUM 6025 MCFPD and 1.70 bbl•• or oonden•t••
Rut one and one halt hours tLowed through 16/64" choke, FTP 5915 p▪i• (IM), gas volUM 8009 ICFPD and undetel"llined 8JI0\1llt or oonclen▪ate to pita.
Eatabliahed 24 hour In Maioo Ooneel'"fttion C.-d.eaion AOF Potential ot 310,000 tcFFD. Completed Ja.,.17 22, 1963, a1 a "Wildcat" CCIII.J)letion in strawn (Penn117I'Y8Bian) toraation, Total cond.enate ree0Ye17 during 7-1/4 hn. t.eet waa 22,80 bbls. to tank and undetermined aaomt to pita.

Well now ahut in - waiting on ga• connection.

POBMATIOI RECORD

From	To	!!!i		
0	12,058	12,0,s		
12,058	12,152	94		
12,152	12,477	32,	Lime & Shale	- Top Atoka 12,152'
12,477	13,366	889	Sand	- Top Morrow 12,477'
13,366	14,S83	1,217	$ale	- Top Barp,ett Shale IJ,366•
14,583	14,685	102	Lhle	- 'lop Miasiaaippian 14,853'
14,685	1,,138	453	Chert	- Top Che. 14,685'
15,138	15,518	380	Shale	- Top Woodtorcl IS 131
15,518	15,9S8	440	L1M & Dolaite	- Top • {'5,518'
15,9?8	I5,9SI	Total Depth		
	12,790	Plugged Back Total Depth		

Geological Tops by Schlumberger Gama Ray Sonic log

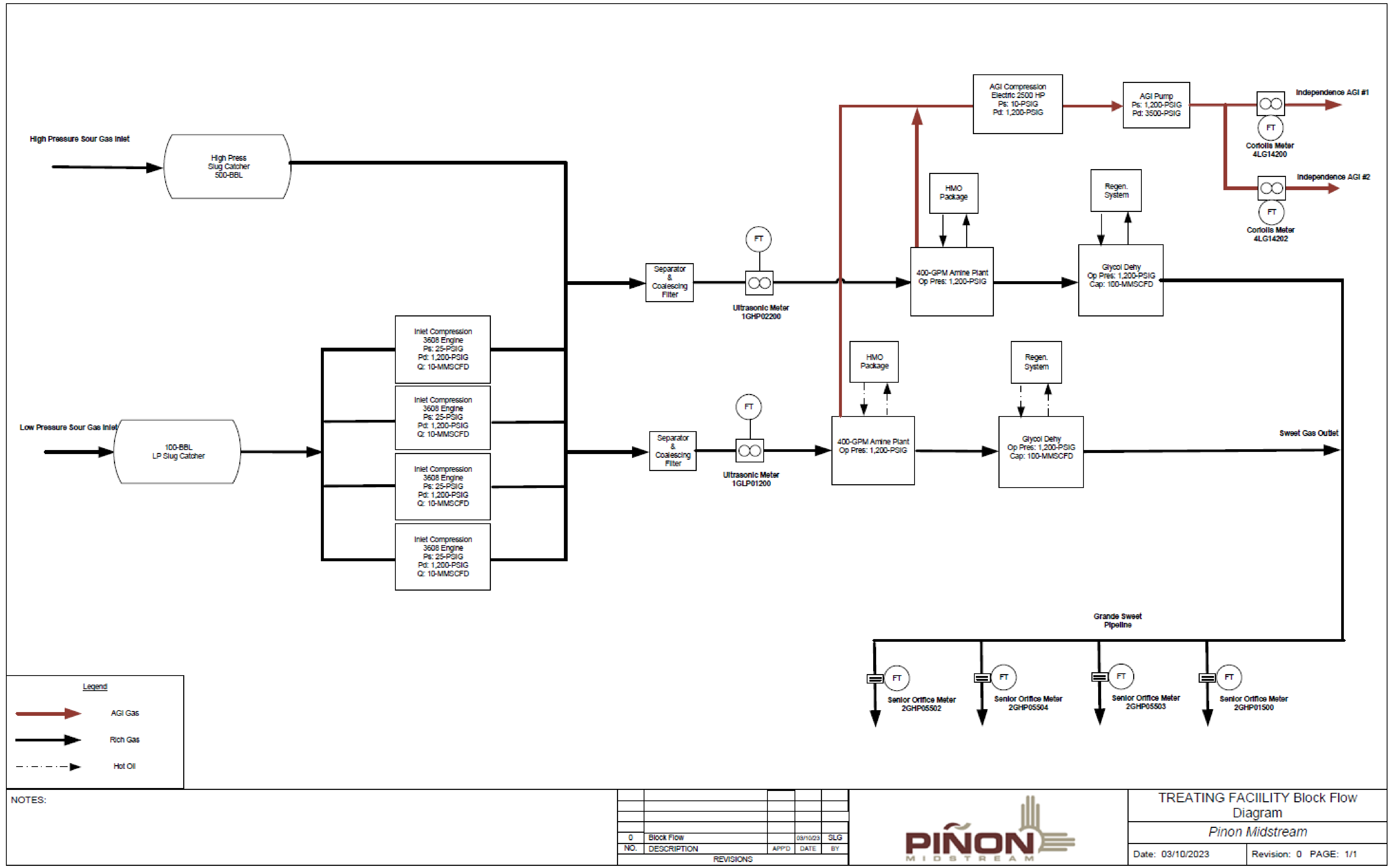


***Figure A10-1*: Treating Facility Block Flow Diagram**

Request for Additional Information: Pinon Midstream, LLC
September 18, 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.	3.5	19	"Due to the minimal reported injection volume of the Jal North Ranch SWD #1, a potential of 10,000 bpd was assumed to account for the potential of increased injection rates due to future needs of the operator or any future workover that may improve the injectivity of this well." This is the only mention of Jal North Ranch SWD #1 in the MRV plan, and it is not listed in Appendix 3. Please clarify the well's significance in the MRV plan.	Section 3.5 was revised to include the well's API number and its distance from the Independence wells. It does not appear in Appendix 3 because it does not fall within a 2-mile radius around the Independence wells and is not mentioned in modeling results because it's location the model domain.
2.	3.7	28	Figure 3.7-1 identifies several wells within the MMA/AMA. While the wells that penetrate the injection zone are discussed as potential leakage pathways in section 5.2 of the MRV plan, there is no discussion regarding wells completed to other injection zones. Please evaluate the potential leakage from these wells in the MRV plan and include monitoring strategies as necessary.	Addressed in Sections 5 and 6 of the revised MRV plan.
3.	3.9.2	37	"As of this application, the well [West Jal Deep B Well] has a stainless-steel plug at the top of the Woodford" Section 5.2 of the MRV plan states "The wellbore currently has two CIBPs at measured depths of 14,200 feet (lower Atoka Formation) and 17,100 feet (Fusselman Formation)." There is no mention of a stainless-steel plug, please add this to the discussion of potential leakage from this well for consistency	Reference to a stainless steel plug was in error and has been corrected in Section 3.9.2. in the revised MRV plan.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	4	40	Section 4.1 of the MRV plan states, "the farthest plume extent and hence the MMA margin is therefore found at year 30 (year t)." Section 4.2 states, "The area projected to contain the free phase CO_2 plume at the end of year t + 5 (2058, or the year 35 of the simulation)." Figure 4.1-1's caption states, "The plume extents are shown at year 35 (t+= 2058), or 5 years beyond injection time." Since Piñon intends to define the AMA as the same area as the MMA, please clarify whether there is any difference between the plume boundaries at year t and year t+5.	Sections 4.1 and 4.2 have been revised to provide additional clarity. There are differences in the plume at year t and t+5, and the plume continues expanding beyond year t+5. Therefore, the MMA/AMA is defined by a polygon encompassing the maximum area of all runs at any time.
5.	4.2	40	Figure 4.1-1's legend has the label "MMA/AMA OLD". Please clarify whether this is intentional.	This is unintentional. "OLD" has been removed from Figure 4.1-1.
6.	5.2	43	While the MRV plan states that West Jal Unit #1 is plugged and abandoned, please discuss the well as a possible leakage pathway and provide a clear characterization of the likelihood, magnitude, and timing of potential leakage. Please also provide any applicable monitoring/detection/quantification strategies.	Addressed in Sections 5 and 6 of the revised MRV plan.
7.	6	45-48	40 CFR 98.448(a)(3) requires that MRV plans include a strategy for detecting and quantifying any surface leakage. Section 6 of the MRV plan describes Piñon's strategy for detecting and quantifying surface leakage of CO_2. There is limited discussion of quantification strategies in the MRV plan. Please provide example quantification strategies that may be applied for the identified leakage pathways.	Addressed in Section 6 of the revised MRV plan.

MONITORING, REPORTING, AND VERIFICATION PLAN

Independence AGI #1 and #2 Wells

Pinon Midstream, LLC

Version Number: 3.0
Version Date: August, 2023

Contents

1 Introduction

Ameredev II, LLC (together with its affiliates, "**Ameredev**") is an oil and natural gas producer operating in portions of the Delaware Basin located in southeastern New Mexico and western Texas. In 2020 Ameredev began evaluating methods for treating its sour natural gas production in Lea County, New Mexico to remove and permanently sequester large quantities of hydrogen sulfide ("**H_2S**") and carbon dioxide ("**CO_2**") commingled in its produced natural gas stream. On July 10, 2020, Ameredev filed an application with New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division ("**NMOCD**") seeking to drill an acid gas injection ("**AGI**") well approximately six (6) miles west of Jal in Lea County, New Mexico for the injection and permanent sequestration of treated acid gas ("**TAG**"). The application was heard and approved at a New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Commission ("**NMOCC**") hearing held on October 8, 2020. The approved order (Order No. R-21455-A) was subsequently issued at the November 4, 2020 NMOCC hearing and the final, approved, Class II injection permit was issued on November 11, 2020. The Independence AGI #001 vertical well (API 30-025-48081; "**Independence AGI #1**") was spud on December 27, 2020 by Ameredev.

In December of 2020, certain affiliates of Ameredev and other outside investors funded Piñon Midstream, LLC ("**Piñon**") to construct and operate the Dark Horse Sour Gas Treating Facility (the "**Dark Horse Facility**") adjacent to the Independence AGI #1 (Figure 1-1) and Ameredev subsequently contributed and assigned the Independence AGI #1 to Piñon on May 21, 2021. Piñon became the operator of record for the Independence AGI #1 on August 24, 2021. Upon completion in late August 2021, treatment of sour natural gas (using amine to isolate H_2S and CO_2) and the injection of TAG into Independence AGI #1 commenced at the Dark Horse Facility (a full description of the treating and injection process is provided in Section 3.8). On March 31, 2022 the NMOCC authorized the drilling of the Independence AGI #002 deviated well (API 30-025-49974; "**Independence AGI #2**") (together the "**Independence AGI Wells**"), which commenced during the summer of 2022.

Independence AGI #1 is permitted to inject into the Devonian Thirtyone and Upper Silurian Wristen and Fusselman Formations from a true vertical depth ("**TVD**") of approximately 16,230 to 17,900 feet (the "**AGI #1 Injection Zone**") and at a maximum surface pressure of approximately 4,779 pounds per square inch gauge ("**psig**"). Independence AGI #2 is permitted to inject into the Devonian Thirtyone Formation and Upper Silurian Wristen and Fusselman Formations from a TVD of approximately 16,080 to 17,683 feet (the "**AGI #2 Injection Zone**", and together with the AGI #1 Injection Zone, the "**Siluro-Devonian Injection Zone**") and at a maximum surface pressure of approximately 5,005 psig. In accordance with NMOCC Order No. R-21455-A (as amended by Order No. R-21455-B, the "**NMOCC Order**"), Piñon is authorized to inject and dispose of TAG, utilizing the Independence AGI Wells, at an aggregate *combined* maximum daily injection rate of up to 20 million standard cubic feet per day ("**MMSCF/D**"), which is the equivalent of approximately 8,200 barrels per day ("**bpd**") or 1,036.7 metric tonnes per day. Gas is injected for 30 years at a rate of 1,036.73 tonnes per day (378,399 tonnes per year or 11,351,970 total tonnes) followed by a 5-year rest period. If Independence AGI #1 is not injecting volumes of TAG, Independence AGI #2 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG. If Independence AGI #2 is not injecting volumes of TAG, Independence AGI #1 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG.

Piñon has chosen to submit this Monitoring, Reporting, and Verification Plan (the "**MRV Plan**") to the United States Environmental Protection Agency (the "**EPA**") for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (the "**GHGRP**") for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. Piñon intends to utilize the Independence AGI Wells for the injection and disposal of TAG for another approximately thirty (30) years.

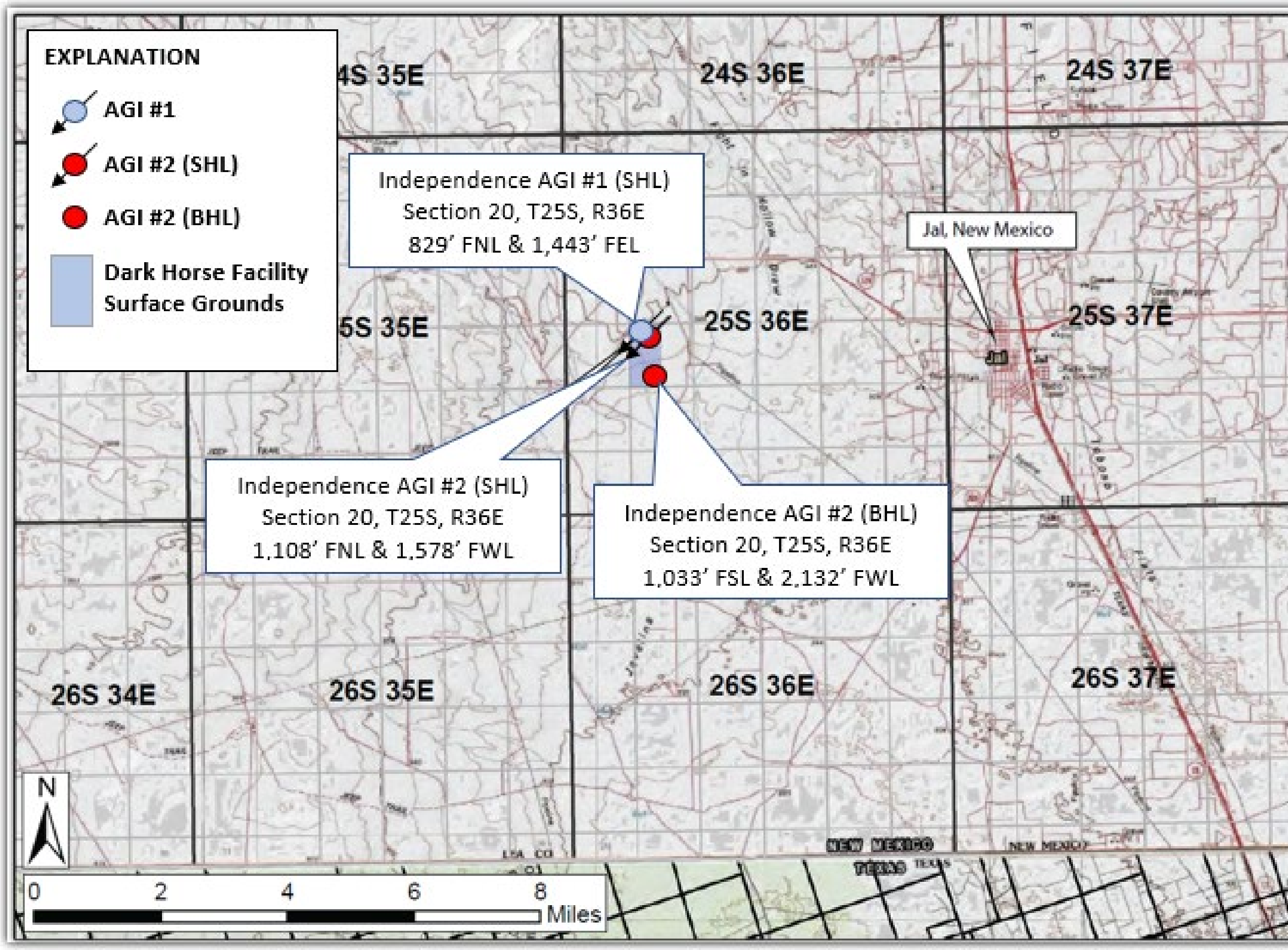


Figure 1-1: Location of Dark Horse Facility and the Independence AGI Wells. The approximate surface hole location ("SHL") and the approximate bottom hole location ("BHL") are indicated for both Independence AGI Wells. (Modified from Figure 1 of Class II permit application for Independence AGI #2, Geolex, Inc.)

This MRV Plan contains twelve (12) sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

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

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

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage.

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

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

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

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

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

Section 12 includes Appendices supporting the narrative of the MRV Plan

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is 582541. There are no other facilities related to this MRV plan.

2.2 Underground injection control ("UIC") well identification numbers

This MRV Plan is for the Independence AGI Wells (*see* Appendix 1). The details of the injection process are provided in Section 3.8.

2.3 UIC permit class

The NMOCD has issued UIC Class II Acid Gas Injection ("**AGI**") permits for the Independence AGI Wells under its State Rule 19.15.26 NMAC (*see* Appendix 2). All oil- and natural gas-related wells located near the Independence 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

Parts of the following project description have been taken from the Class II permit applications for (i) Independence AGI #1, prepared by Geolex, Inc. for Ameredev, dated July 10, 2020; and (ii) Independence AGI #2, also prepared by Geolex, Inc. for Piñon, dated November 4, 2021.

3.1 General Geologic Setting / Surficial Geology

The Dark Horse Facility is located adjacent to the Independence AGI Wells as shown in Figure 3.1-1. The site lies on the eastern flank of the Pecos River Basin within the Javelina Basin. Referred to as the South Plain by Nicholson & Clepsch (1961), the region exhibits irregular topography without integrated drainage. Surficial sediments commonly consist of unconsolidated alluvium and eolian sands. There are no observed surface bodies of water, or groundwater discharge sites within one (1) mile of the Independence AGI Wells. The Dark Horse Facility overlies Quaternary alluvium overlying the Triassic redbeds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater. The thick sequences of Permian rocks that underlie these deposits are described in Section 3.2.2.

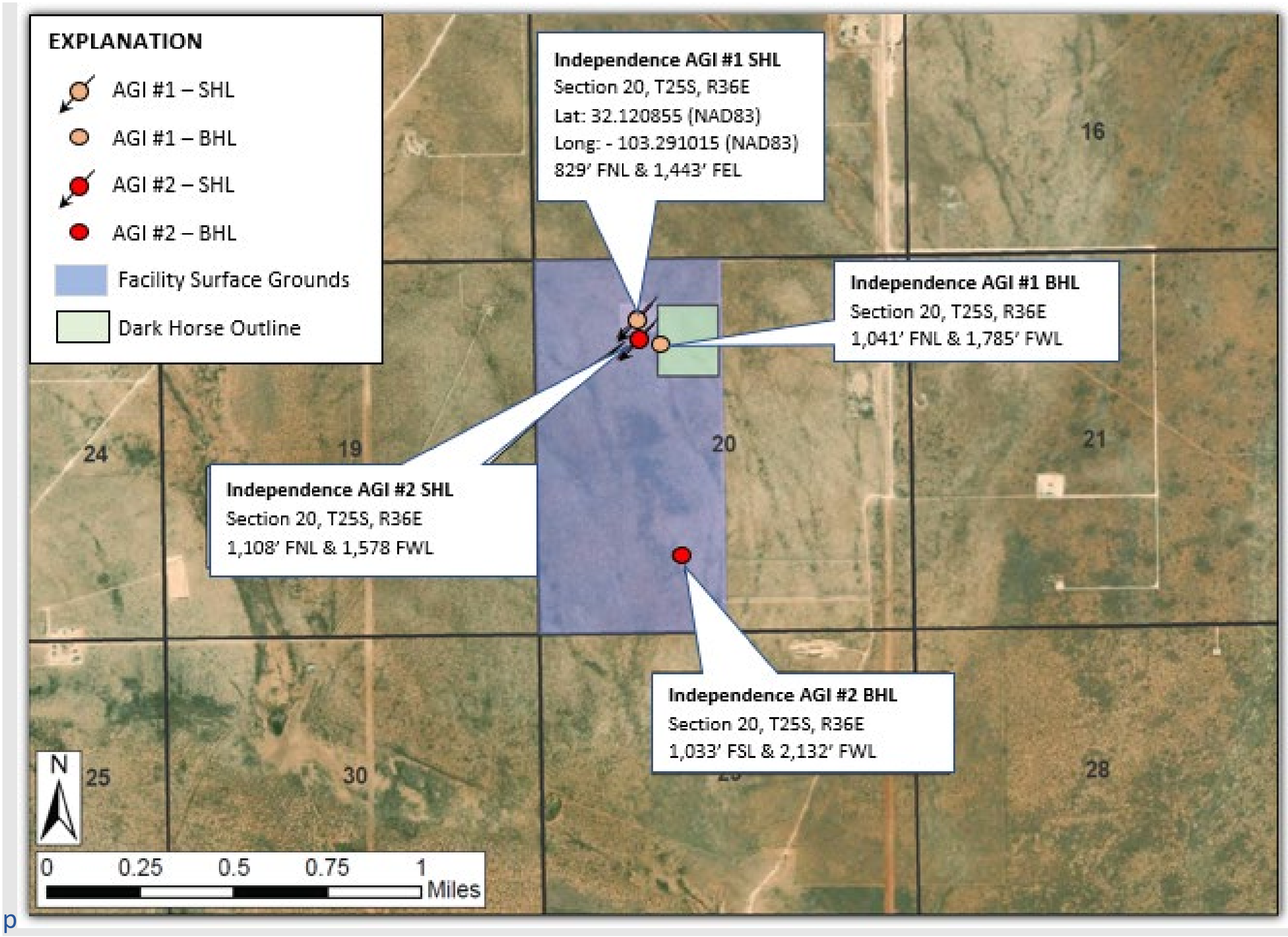


Figure 3.1-1: Map showing location of Dark Horse Facility and the Independence AGI Wells in Section 20, T25S, R36E NMPM. The BHL of the Independence AGI #1 sidetrack is 446' southeast of the SHL. The SHL and the BHL for Independence AGI #2 are shown. (Modified from Figure 2 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.2 Bedrock Geology

3.2.1 Basin Development

The Dark Horse Facility is 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. The Permian Basin and its sedimentary fill have been formed and controlled by tectonism of varying degrees and sedimentation events that began in the Precambrian and throughout the Cenozoic (Neogene). Early Paleozoic deposition took place in the Late Cambrian as marginal areas of the North American craton began to be flooded by marine seas. Late Cambrian sediments comprised of basal siliciclastic sands and muds from areas of exposed Precambrian igneous, metamorphic, and sedimentary rocks and shallow-water carbonates.

Parts of the following basin development descriptions in this subsection have been modified and summarized from Ruppel (2019). Flooding continued across the North American craton throughout the Early Ordovician, establishing a widespread shallow-water carbonate platform. The Ellenburger Formation (Figure 3.2-2) rocks are derived from peritidal and shallow subtidal carbonates. These sediments were exposed during one of the sea-level drops during the Ordovician deposition resulting in karstification and dolomitization. During the Early to Middle Paleozoic time, the Permian Basin region was occupied by a relatively shallow basin called the Tobosa Basin. The first rapid subsidence and formation of the Tobosa Basin began in Simpson time (Middle

Ordovician), and subsidence slowly diminished into the Early Devonian (Ewing, 2019). Subsequent tectonic history of the Tobosa and Permian Basins will be discussed throughout this section.

Early Paleozoic deposition is mostly defined by multiple high-frequency sea-level changes, karsting, and erosional events. Large-scale shift in facies and environments indicate tectonic and/or eustatic controls on sediment distribution patterns. Simpson Group (Middle Ordovician) rocks unconformably overlie Ellenburger Formation rocks at a widespread hiatus caused by Early Ordovician to Middle Ordovician relative sea-level fall. Simpson rocks are a cyclic succession of lime mudstones and quartz sandstones and were deposited during the subsequent reflooding of the shelf. Carbonate-dominated Montoya Formation (Late Ordovician) and Fusselman Formation (Latest Ordovician -Early Silurian) rocks overlie the Simpson Group and indicate a shift and deepening of Tobosa Basin. These rocks are indicative of an overall relative sea level rise.

Middle Silurian-Early Devonian Wristen Group and Thirtyone Formation rocks indicate differential subsidence in the area and represented a deepening and expansion of the basin. Wristen Group rocks comprised of carbonate mudstones and wackestones of the Wink Formation, which underlies the shallow-water carbonate platform packstones, grainstones, and reef facies (corals and stromatoporoids) of the Fasken Formation and the deep-water lime mudstones of the Frame Formation. These facies outline the position of a Silurian platform margin and imply a downwarping of the North American craton. Although Wristen and Fusselman show evidence of numerous high-frequency sea-level changes, the larger-scale change in facies and depositional environments indicates tectonic and/or eustatic controls on sediment distribution patterns. The Silurian platform margin is a recurring feature that controls facies distribution through the Late Mississippian, suggesting tectonic and/or basement terrain control. The rocks of the Thirtyone Formation (Early Devonian) consist of platform carbonate grainstones and packstones surrounding calcareous, radiolarian-rich basin facies.

According to Ruppel (2019) and Ruppel and others, (2020a), a major episode of relative sea-level fall in the Middle Devonian is documented by an absence of Late Early Devonian and early Middle Devonian rocks. Late Devonian Woodford rocks overlie eroded and karsted Silurian (Wristen Group), Early Devonian Thirtyone, and older rocks. Local folding of these rocks below the Woodford suggests that the hiatus may have been at least partially driven by tectonic events. Evidence from the distribution of later Mississippian rocks indicates that the tectonic event caused uplift and localized deformation of pre-Middle Devonian rocks and changed subsidence and depositional patterns across the entire region.

Following the Middle Devonian Permian Basin-area uplift and emergence, Late Devonian marine transgression flooded the region with anoxic bottom-water seas and deposited black, organic-rich biosiliceous mudstones of the Woodford Formation (Ruppel, 2019). Sea-level fall-and-rise sequences defined the Early and Late Mississippian and were even more pronounced during the Pennsylvanian. In the Late Mississippian, initial collision occurred between Laurentia and Gondwanaland, and the Marathon-Ouachita orogenic belt first started to form in northeastern North America (Yang and Dorobek, 1995) with tractions propagating toward the southwest, impacting the Permian Basin by the Middle Pennsylvanian Epoch (Desmoinesian, 310 Ma) (Horne, 2021). Mississippian limestones and the Barnett Formation shales were deposited following a marine transgression that resulted in the development of an extensive carbonate platform, surrounded by a deep-water, organic-rich mud basin.

Collision along the western and southwestern margins of Laurentia, combined with tractions from the Marathon-Ouachita thrusting in the southeast, resulted in northwest-southeast-trending uplifts throughout the western United States known as the Ancestral Rocky Mountain orogeny, which began in Early Pennsylvanian time and continued into the Early Permian (Horne, 2021). The Pennsylvanian tectonic setting in the Permian Basin is the product of the combined Ancestral Rocky Mountain and Marathon–Ouachita effects occurring along the southwest and southeast margins of Laurentia. These events contributed to basin evolution and specific structural domains and styles. In the Permian Basin, the Ancestral Rocky Mountain

orogeny is responsible for the uplift of the Central Basin Platform and the major structural development of the Midland and Delaware Basins (Horne, 2021).

During Desmoinesian to early Missourian sedimentation, Permian Basin deformation reached its peak. The antecedent Tobosa Basin was tectonically differentiated, formed into the crustal uplifts and sub-basins that now characterize the Central Basin Platform, Midland Basin, and Delaware Basin. Throughout Pennsylvanian and most of Permian sedimentation, tectonics coupled with glacial eustacy played an important role in the development of regional facies. Middle to Late Pennsylvanian saw decreasing tectonic deformation activity, and by the Wolfcampian time (Early Permian), deformation was limited to subsidence within the structures formed by the existing uplifts and basins (e.g., Delaware and Midland Basins, Central Basin Platform). The continual subsidence of the Delaware basin affected sediment infilling, with some areas accumulating as much as 12,000 ft of basin-fill sediment. Marine transgression eventually submerged uplifts and became the location of carbonate sedimentation, while the basins became filled with organic-rich siliceous muds. By the end of the Wolfcampian, the major Permian Basin physiographic features (Central Basin Platform, Delaware and Midland Basins) were fully developed, and controlled sedimentation types and location for the remainder of the Paleozoic.

The Middle Permian (Leonardian and Guadalupian) was punctuated by cyclic sediment deposition during sea-level eustatic events. The Leonardian was a time of gradual global warming from the icehouse climates of the late Carboniferous to warmer and more arid greenhouse climates of the later Permian and Mesozoic (Tabor, 2004). The Leonardian marked the beginning of the last stages of the formation of Pangea, producing greater restriction of open ocean connections to the Permian Basin (Ruppel, 2020b). The abundance of tidal-flat facies, evaporites, and reflux dolomites in Leonardian rocks reflects the development of much more arid conditions compared with those in the earlier Permian (Ruppel, 2020b). In the shelf areas (Central Basin Platform and Northern, Northwestern, and Eastern Shelves) (Figure 3.2-1), sedimentation was characterized by shallow-water carbonate production and deposition during sea-level rise, and by shelf exposure and sand-silt deposition during sea-level fall and subsequent shelf exposure. In the Delaware and Midland basins, sedimentation was characterized by cyclic intervals of detrital carbonate-sediment transport into the basins by sea-level highs, and by sand-silt transport and deposition during sea-level falls. Dolomitization of carbonate-shelf deposits occurred during the more regionally arid climates of the Leonardian and the Guadalupian as a product of the Permian Basin area being situated at the equator and from refluxing brines created during periods of sea-level highstand events. Deposition of evaporites became more common in the shelf areas during this time, likely in response to the increasingly arid environment and/or decreased accommodation. By the end of the Guadalupian, the Midland Basin was largely filled, and peritidal muds and evaporite deposition dominated. Sea-level fall and closure of the Hovey Channel (Figure 3.2-1) cut off the Delaware Basin from its marine supply, resulting in regional exposure and nondeposition and the filling of the basin with evaporites of the Castille Formation (Lopingian “Ochoa” Series) (Ruppel, 2019). Most of the rocks deposited during Lopingian “Ochoan” time were evaporites such as anhydrite, halite, and potash minerals with minor amounts of limestone, mudstone, and siltstone and are subdivided into (ascending) Castile Formation, Salado Formation, Rustler Formation, and Dewey Lake Red Beds. Most of the early Ochoan deposition was confined to the Delaware Basin (Bachman, 1984).

3.2.2 Stratigraphy

Figure 3.2-2 is a generalized stratigraphic column showing the formations that underlie the Dark Horse Facility and the Independence AGI Wells. The sequences of Ordovician through Permian rocks are described below.

Ordovician. Below the Silurian Fusselman Formation lies about 400 feet of Ordovician Montoya Formation cherty carbonates which overlies about 400 feet of Ordovician Simpson Group sandstones, shales, and tight limestones. These formations are underlain by the Lower Ordovician Ellenburger Formation which is a thick, carbonate-dominated sequence composed of dolostones and limestones. It is 0-1,000 feet thick in

southeastern New Mexico. The Ellenburger carbonates sit on a veneer of Cambrian to Lower Ordovician Bliss Sandstone and granite wash on the Precambrian basement.

During the Early Ordovician, much of the United States was covered by a shallow sea, and southeast New Mexico was a shallow-water shelf with deep water conditions to the south. Due to sea-level changes and regional tectonic activity, the entire lower Paleozoic interval (Ellenburger through Devonian) was periodically subjected to subaerial exposure and prolonged periods of karst and karst-terrain formation, most especially in the Ellenburger, Fusselman and Devonian strata. The cave systems collapsed with subsequent burial, creating brecciated and fractured carbonate bodies that formed many of the Ellenberger reservoirs and created complex pore networks. The result of these exposure events was the development of numerous horizons of karst-related secondary porosity with solution-enlarged fractures, vugs, and small cavities and caves. Particularly in the Ellenburger and Fusselman strata, solution features from temporally distinct karst events became interconnected with each successive episode, so there could be some degree of vertical continuity in parts of the Fusselman section that could lead to enhanced vertical and horizontal permeability. The Ellenburger is well below the Siluro-Devonian Injection Zone, so it is unlikely to be affected by any proposed activity.

Devonian and Silurian. The Devonian Thirtyone Formation, the Silurian Fusselman Formation, and the Silurian Wristen Group consist of interbedded dolomites and dolomitic limestones and are collectively often referred to as the Siluro-Devonian. In the Middle Devonian, regional marine transgression deposited mostly black, organic-matter-rich siliceous muds of the Woodford Formation (Ruppel, 2019). The Siluro-Devonian Injection Zone does not contain economic hydrocarbons closer than fifteen (15) miles away from the well sites. There have been no commercially significant deposits of oil or natural gas found in the Devonian or Silurian rocks in the vicinity of the Independence AGI Wells and there is no current or foreseeable production at these depths within a two (2) mile radius around the Independence AGI Wells (Figure 3.7-1). Adjacent wells have shown that these formations are primarily water-bearing and are routinely approved as produced-water injection zones in this area.

Mississippian. According to Broadhead (2017), the Mississippian section unconformably overlies the Woodford Formation shales throughout most of southeastern New Mexico and, in places, unconformably overlies the Silurian Fusselman Formation or Ordovician strata in limited areas. These units reach a maximum thickness of 1,400 ft in the Tatum Basin northwest of Hobbs, New Mexico and constitute a major portion of the stratigraphic section. The Mississippian section in southeastern New Mexico is subdivided into the Lower Mississippian limestone (Kinderhookian to Osagean age) and various Upper Mississippian units. The Upper Mississippian section consists of the Barnett Shale in the basinal area to the south and the Meramec and Chester units on the shelf to the north. The Mississippian strata constitute the least developed of the major stratigraphic units in southeastern New Mexico and oil and natural gas production has been from relatively small and widely scattered reservoirs (Broadhead, 2017). The Chester Formation consists of several hundred feet of shales and basinal limestones which are underlain by several hundred feet of Osage limestone.

Pennsylvanian. The Pennsylvanian-age strata is comprised of (ascending) Morrow, Atoka, Strawn, Canyon, and Cisco. Within this entire sequence, the Morrow is a major natural gas producing zone, with smaller contributions from the overlying Atoka and Strawn. The Morrowan strata are dominantly siliciclastic and consist of interbedded shales and lenticular sandstones deposited in multiple regressive sequences and represent basinward migration of nearhore, sand-rich facies tracts from the erosion of exposed Precambrian rocks (Broadhead, 2017). The overlying Atokan strata are also dominantly siliciclastic, with sandstones and shales being deposited in fluvial-deltaic and strandline environments (Broadhead, 2017). The Middle Pennsylvanian (Desmoinesian) Strawn strata is composed of ramp limestones interbedded with marine shales and minor sandstones, and both sandstone and limestone reservoirs are productive (Broadhead, 2017). Although there was past production of oil and natural gas from the Pennsylvanian Strawn pool, there are no active wells in that pool within two (2) miles of the Dark Horse Facility nor are there any natural gas producing

wells in any pools. The Upper Pennsylvanian strata are informally referred to as the Canyon (Missourian) and Cisco (Virgilian) groups, and are composed of interbedded carbonates, dark-gray to black shales, and minor sandstones (Broadhead, 2017). These groups contain prolific oil reservoirs in southeastern New Mexico.

Permian. The overlying Permian rocks found in the Delaware Basin are divided into four (4) series, the Lopingian ("Ochoa") (most recent), Guadalupe, Cisuralian ("Leonard"), and Hueco ("Wolfcamp") (oldest) (Figure 3.2-2). Numerous oil pools have been identified in these rocks (*see* Appendix 3, Table 3a). Active oil producing reservoirs within two (2) miles of the Dark Horse Facility include the following Permian pools: Tansil, Yates, Seven Rivers, Delaware, Bone Spring, and Wolfcamp. New oil wells permitted but not yet drilled are primarily targeting the Bone Spring and the Wolfcamp pools. The rock units of the Permian series are discussed in more detail below.

Permian Hueco ("Wolfcamp") Group. The Lower Permian Wolfcampian strata in the Permian Basin record deposition in deepwater basins surrounded by shallow-water carbonate platforms, where the Wolfcampian platform carbonate succession exposed in southeastern New Mexico comprises a complex record of deposition mainly controlled by fluctuations in glacio-eustatic sea level (Fu and others, 2020). The Wolfcamp is extremely variable in lithology in response to changes in the environment of deposition. In the area of the Dark Horse Facility, it is composed of dark skeletal to fine-grained limestone, fine-grained sand to coarse silt, and shale in these basin facies. Horizontal wells are being drilled in the Bone Spring and Wolfcamp; however, most activity is primarily to the west of the Dark Horse Facility.

Permian Leonardian Series. The Cisuralian ("Leonard Series"), sediments in shelf areas (Central Basin Platform, Northwest Shelf, etc.) are characterized by shallow-water carbonate-sediment production and deposition during sea-level rise, and by shelf flooding and quartz-dominated sand-silt deposition during sea-level fall and shelf exposure (Ruppel, 2019). In the Delaware Basin, this pattern of sea-level control on sediment supply resulted in the deposition of cyclic intervals of detrital carbonate-sediment transport to basins during sea-level highs and by quartz sand-silt transport and deposition during sea-level falls (Ruppel, 2019). Overall, the Leonard succession is one of punctuated upward shallowing from deep-water, outer-platform—platform-margin settings to inner-platform, peritidal conditions (Ruppel, 2020b).

The Bone Spring Formation is present only in the Delaware Basin and is stratigraphically equivalent to the Abo and Yeso Formations of the Northwest Shelf and Central Basin Platform, attains a maximum thickness of about 4,000 ft in southern Eddy County, New Mexico, and has been productive from several plays in the basin (Broadhead, 2017). The Bone Spring stratigraphy consists of alternating carbonate and siliciclastic successions that were deposited in marine slope and basin-floor environments, where sandstones and siltstones are widespread on the basin floor, whereas carbonates are thickest in periplatform areas (Nance and Hamiln, 2020; Saller and others, 1989). Most Bone Spring carbonate slope deposits accumulated by transport from shallow-water environments on the shelf during highstands of sea level and the siliciclastic deposits were transported basinwards during lowstands of sea level (Nance and Hamlin, 2020). Most of the carbonates are detrital, composed of bioclasts and lithoclasts derived from surrounding shallow-water platforms, and the siliciclastic members were deposited primarily on the basin floor in widespread submarine-fan complexes (Nance and Hamlin, 2020).

Permian Guadalupe Series. The Upper Permian Guadalupian-age strata are found on both Northwest Shelf and Central Basin Platform, and in the Delaware Basin. The Goat Seep/Capitan Reef system, a profoundly critical component of the Permian Basin Guadalupian paleogeography, prominently divides the shelves of the Central Basin Platform, the Northwestern Shelf, and the Western Shelf from the Delaware Basin (Nance, 2020a). Units on the shelf and platform comprise of (ascending) the San Andres Formation and the Artesia Group (*see* Figure 3.2-2). The five (5) formations of the Artesia Group include (ascending) Grayburg, Queen, Seven Rivers, Yates, and Tansill. The Delaware Basin equivalents of the reef trend include the Delaware Mountain Group: (ascending) Brushy Canyon, Cherry Canyon, and Bell Canyon. The Artesia Group comprises as much as 2,650 ft of stratigraphically cyclic, mixed-siliciclastic/carbonate/evaporite platform strata

deposited shelfward of the Guadalupian Capitan Reef system that rims the Delaware Basin (Nance, 2020a). These formations have provided significant oil and natural gas production in southeastern New Mexico, and widespread, reddish-colored evaporitic shales and evaporites provide effective vertical and lateral seals (Broadhead, 2017).

According to Nance (2020a), Artesia facies tracts include, from basin to shelf, immediate-back-reef carbonate grainstone to packstone; shelf-crest pisolite-bearing carbonate shoals; lagoonal wackestone to mudstone and siliciclastic siltstone; algal-laminated, tidal-flat carbonate packstone to wackestone and fine to very fine grained sandstone; beach-ridge fine sandstone; siliciclastic-sabkha anhydrite and halite; brine-pool and evaporitic-lagoon anhydritic dolomite, dolomitic anhydrite, anhydrite, and halite; and eolian to fluvial siliciclastics. During sea-level highstand, siliciclastics are limited to updip areas, whereas eolian-siliciclastic depositional environments migrate downdip during sea-level lowstands. During transgressions, siliciclastics in more basin-proximal positions were reworked by marine and marginal processes. Reservoir quality was impacted mostly by dissolution of feldspar and carbonate allochems and precipitation of authigenic feldspar, clay, and evaporite.

The Delaware Mountain Group of the Delaware Basin comprises up to 4,500 ft of arkosic to subarkosic sandstone, siltstone, and carbonate debrites that were deposited in deep water, mainly during lowstand and early transgressive sea-level stages, and primary depositional processes include density-current flow and suspension settling (Nance, 2020b). The Delaware Mountain Group is restricted to slope-and-basin areas and was sourced from shelf-sediment areas through poorly exposed incised valleys, and interbedded carbonate units thicken shelfward and are typically correlative to “reef”-margin-complex carbonate sources along the shelf margin (Nance, 2020b).

Permian Lopingian (“Ochoa”) Series. The youngest of the Permian Basin sediments are referred to as the Lopingian (“Ochoa”) Series. The Ochoan series includes the Castile, Salado, Rustler, and Dewey Lake formations. Ochoan units on the shelf include the Salado, Rustler, and Dewey Lake Formations. *Castile Formation* usage is restricted to the deposits within the Delaware Basin only (Figure 3.2-2). The Ochoan in the Permian Basin contains no hydrocarbon reservoirs on the shelf (Nance, 2020a). The basal Salado Formation forms the ultimate top seal for the underlying Guadalupian reservoirs and effectively inhibits hydrocarbon migration into Ochoan units (Nance, 2020a). Lack of a seal above the Ochoan precludes widespread entrapment within the interval of hydrocarbons that may have been generated within the series. Ochoan strata are not hydrocarbon productive in the Permian Basin except for a few very small, isolated reservoirs in the Castile Anhydrite in the northern part of the Delaware Basin (Broadhead, 2017). The Castile is considered to be the top seal for Delaware Basin hydrocarbon reservoirs and is responsible for controlling migration of hydrocarbons from basinal source beds into reservoirs on the surrounding shelves (Hills, 1984). Anhydrite is the dominant rock type in the Castile Formation, along with limestone interlaminated in anhydrite, thin beds of limestone, and minor amounts of dolomite and magnesite, and halite is present as several massive beds in the formation in the subsurface but is much less prominent than the halite in the overlying Salado Formation (Bachman, 1984). The interlaminated anhydrite and limestone are distinctive lithologic features of the Castile Formation and are thought to represent annual cycles of sedimentation (Bachman, 1984).

The regionally extensive Salado Formation includes thick evaporite deposits and records a long-term salinity crisis in the region (Nance, 2020a). The Salado includes halite, minor beds of anhydrite, and commercial deposits of potash minerals (Bachman, 1984). The contact between the Castile and the overlying Salado Formations is sharp and most places and is between massive beds of anhydrite in the Castile and a sequence dominated by halite, potash minerals, and thin beds of anhydrite in the Salado (Bachman, 1984). The Rustler Formation overlies the Salado, and consists of dolomite, evaporites, and siliciclastics and marks the last major migration of marine waters into the Permian Basin (Ruppel, 2019). Red beds of terrigenous sands in the Rustler Formation resulted from eolian sediment transport. These red beds grade downwards into evaporites

of the Salado and Castile Formations and are composed of red-orange silts and sandstones with interbeds of gypsum or anhydrite and halite. The Rustler carbonates, evaporites, and siliciclastics mark a relatively abbreviated return of marginal-marine conditions to the region (Nance, 2020a). The Dewey Lake Formation rests conformably on the Rustler Formation and consists mainly of redbeds and minor gypsum, alternating thin, even beds of moderately reddish-brown to moderately reddish-orange siltstone and fine-grained sandstone (Bachman, 1984). The Dewey Lake sediments mark the youngest episode of preserved Permian deposition in the region, after which a significant net-depositional hiatus prevailed until the onset of Late Triassic sediment accumulation (Nance, 2020a). Beds of Triassic age rest unconformably on, and overlap, the Dewey Lake Formation, and exposures of these rocks in southeastern New Mexico are dark reddish-brown, cross-laminated, poorly sorted conglomerate sandstones with interbeds of dark reddish-brown sandy shale (Bachman, 1984). These Triassic units were deposited in a fluvial—deltaic—lacustrine system and signaled the onset of net deposition during overall wetter conditions after a protracted period of net nondeposition (Nance, 2020a; Bachman, 1984).

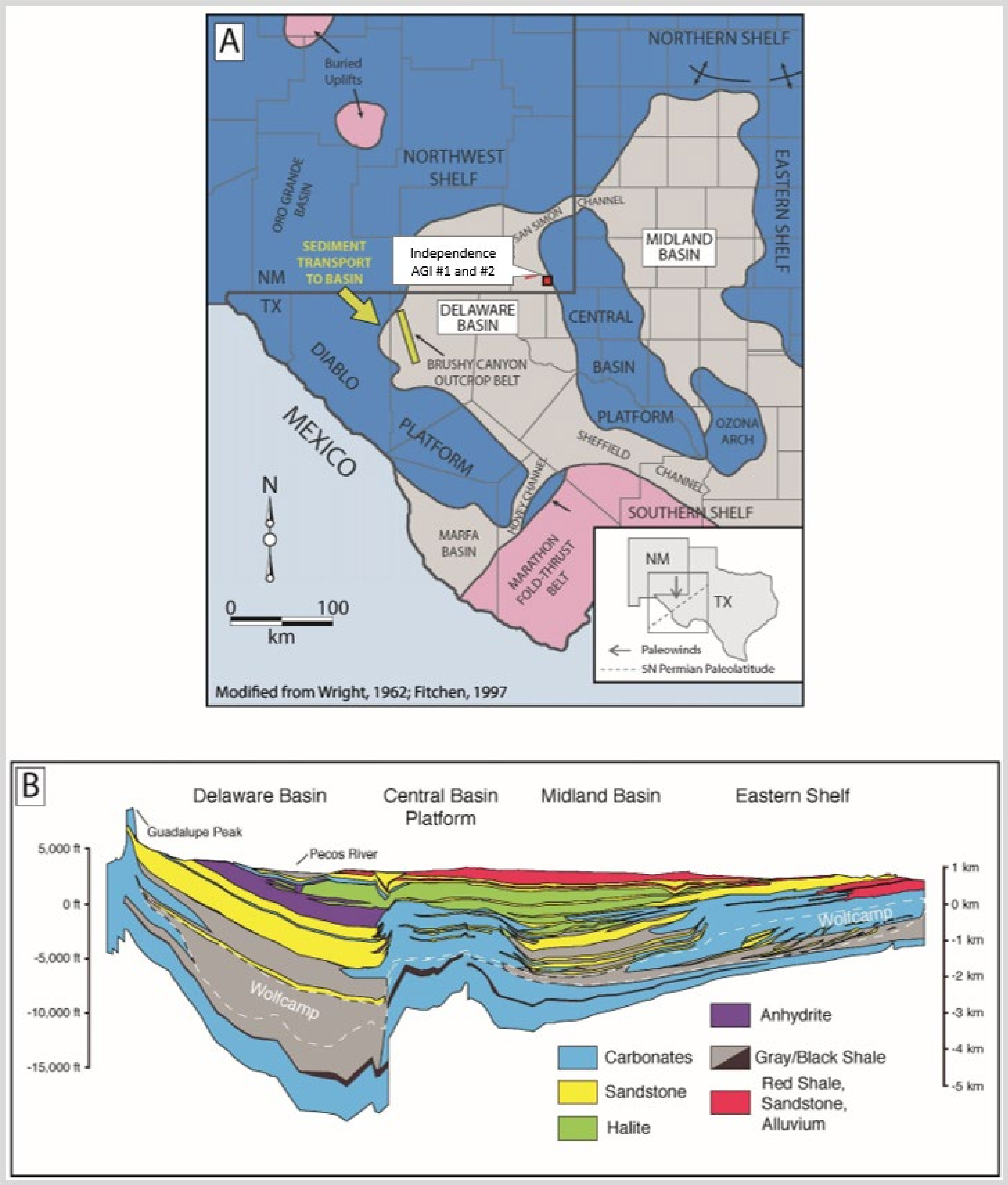


__Figure 3.2-1__: Structural setting (panel A) and general lithologies (panel B) of the Permian Basin. The location of the Independence AGI Wells is shown by the red square. (Modified from Wright, 1962; Fitchen, 1997) (Modified from Figure 12 of Class II permit application for Independence AGI #2, Geolex, Inc.).

Age		Stratigraphic Units: Northwest Shelf and Central Basin Platform	Stratigraphic Units: Delaware Basin
Triassic		Chinle	Chinle
Triassic		Santa Rosa	Santa Rosa
Permian	Lopingian ("Ochoan")	Dewey Lake	Dewey Lake
		Rustler	Rustler
		Salado	Salado
			Castile
	Guadalupian	Artesia Group: Tansill	Delaware Mountain Group: Bell Canyon
		Artesia Group: Yates	
		Artesia Group: Seven Rivers	Delaware Mountain Group: Cherry Canyon
		Artesia Group: Queen	
		Artesia Group: Grayburg	
		San Andres	Delaware Mountain Group: Brushy Canyon
	Cisuralian ("Leonardian")	Glorieta	
		Yeso: Paddock	Bone Spring
		Yeso: Blinebry	
		Yeso: Tubb	
		Yeso: Drinkard	
	Wolfcampian	Abo	
		Hueco ("Wolfcamp")	Hueco ("Wolfcamp")
Pennsylvanian	Virgilian	Cisco; Bough	Cisco
	Missourian	Canyon	Canyon
	Des Moinesian	Strawn	Strawn
	Atokan	Atoka	Atoka
	Morrowan	Morrow	Morrow
Miss.	Upper	Undivided	Barnett
	Lower		undivided limestone
Dev.	Upper	Woodford	Woodford
	Middle		
	Lower	Thirtyone	Thirtyone
Sil.	Upper	Wristen	Wristen
	Middle		
	Lower	Fusselman	Fusselman
Ord.	Upper	Montoya	Montoya
	Middle	Simpson	Simpson
	Lower	Ellenburger	Ellenburger
Cambrian		Bliss	Bliss
Precambrian		igneous, metamorphics, volcanics	igneous, metamorphics, volcanics

<u>Figure 3.2-2</u>: Generalized stratigraphic correlation chart for the Permian Basin region (modified from Broadhead, 2017).

3.2.3 Faulting

The Permian Basin region has a complex tectonic history, shaped by several convergent and divergent events from the Proterozoic through the Cenozoic (Neogene). The Delaware Basin is defined by a complex network of basement-rooted faults. Recent regional 3D structural framework and kinematic models by Horne et al. (2021) provides interpretations of basement-rooted faults in the Delaware Basin. This region contains more than 650 basement-rooted fault surfaces, dominated by "primary" north-northwest—south-southeast-striking high-angle reverse faults that bound "secondary" fault orientations west-northwest—east-southeast and west-southwest—east-northeast (Horne et al., 2021). Their kinematic model suggests that the primary structural grain formed first in response to the encroaching Ancestral Rocky Mountain orogenic front, and the secondary fault zones formed under the combined stresses from the Ancestral Rocky Mountain and Marathon-Ouachita convergence fronts, which compartmentalized the Delaware Basin and Central Basin Platform (Horne et al., 2021).

To identify subsurface structures in the area of the Independence AGI Wells, Geolex evaluated and interpreted licensed seismic survey data (WesternGeco South Lea Survey) covering the Lea County area of interest. These findings and interpretations specific to the Dark Horse Facility area are discussed further in Section 3.5.

3.3 Lithologic and Reservoir Characteristics of the Siluro-Devonian Formations

The Siluro-Devonian Injection Zone includes the Devonian Thirtyone Formation, Silurian Wristen Group and Fusselman Formation, collectively referred to as the Siluro-Devonian. These strata commonly include numerous intervals of dolomites and dolomitic limestones with moderate to high primary porosity. Additionally, the Siluro-Devonian Injection Zone includes significant regions of secondary, solution-enlarged porosity produced during periods where strata were subaerially exposed and significant karst features developed. These karst features are frequently developed in the Fusselman Formation and include solution enlarged cavities and fractures. Fracture networks through the Siluro-Devonian section are substantial enough to provide additional permeability that is not readily apparent on geophysical well logs. The porous zones of the Siluro-Devonian are separated by tight limestones and dolomites.

In evaluating the location of the Independence AGI Wells, an in-depth review of licensed seismic survey data (WesternGeco – South Lea Survey) was completed to support the evaluation that the Siluro-Devonian reservoir exhibited sufficient porosity potential to accommodate the needs of the Independence AGI Wells. Seismic inversion data, specifically impedance attributes, were evaluated to identify reservoir targets with significant porosity potential in the Siluro-Devonian reservoir. As a result of this review, the location in Section 20, T25S, R36E was selected as it was observed to overlay an expansive region of porosity in the upper Devonian, Wristen, and Fusselman strata.

Based on the geologic evaluation of the subsurface, AGI was recommended between depths of approximately 16,080 to 17,683 feet TVD (16,477 to 18,080 feet measured depth). Figure 3.3-1 includes a type log of the Siluro-Devonian Injection Zone that includes the formation tops identified at that location and illustrates the sufficient low-porosity intervals overlying the target injection reservoir. Anticipated formation tops underlying the Independence AGI #2 location are included in the following Table 3.3-1. In the area of the Independence AGI Wells, depth to Devonian strata increases to the southwest and the Independence AGI Wells lie downdip of a structural high to the east (Figure 3.3-2).

Units overlying the Siluro-Devonian Injection Zone provide an excellent caprock to prevent the upward migration of injectate out of the target reservoir. This caprock includes 335 feet of dense Woodford Shale overlain by at least 796 feet of Mississippian limestone (Table 3.3-1). These units will provide a geologic seal above the porous carbonates of the Siluro-Devonian Injection Zone providing protection to shallow groundwater resources and overlying pay intervals.

Figure 3.3-3 includes structural cross section A-A' covering the area of Independence AGI #2 and highlights the lateral extent of available upper Devonian porosity and the regional coverage of overlying caprock in the area. As shown in Figure 3.3-2, there are two (2) faults located approximately one (1) mile east and one (1) mile north from the SHLs of the Independence AGI Wells. These structures were identified through review of licensed 3D seismic survey data and are discussed further in Section 3.5.

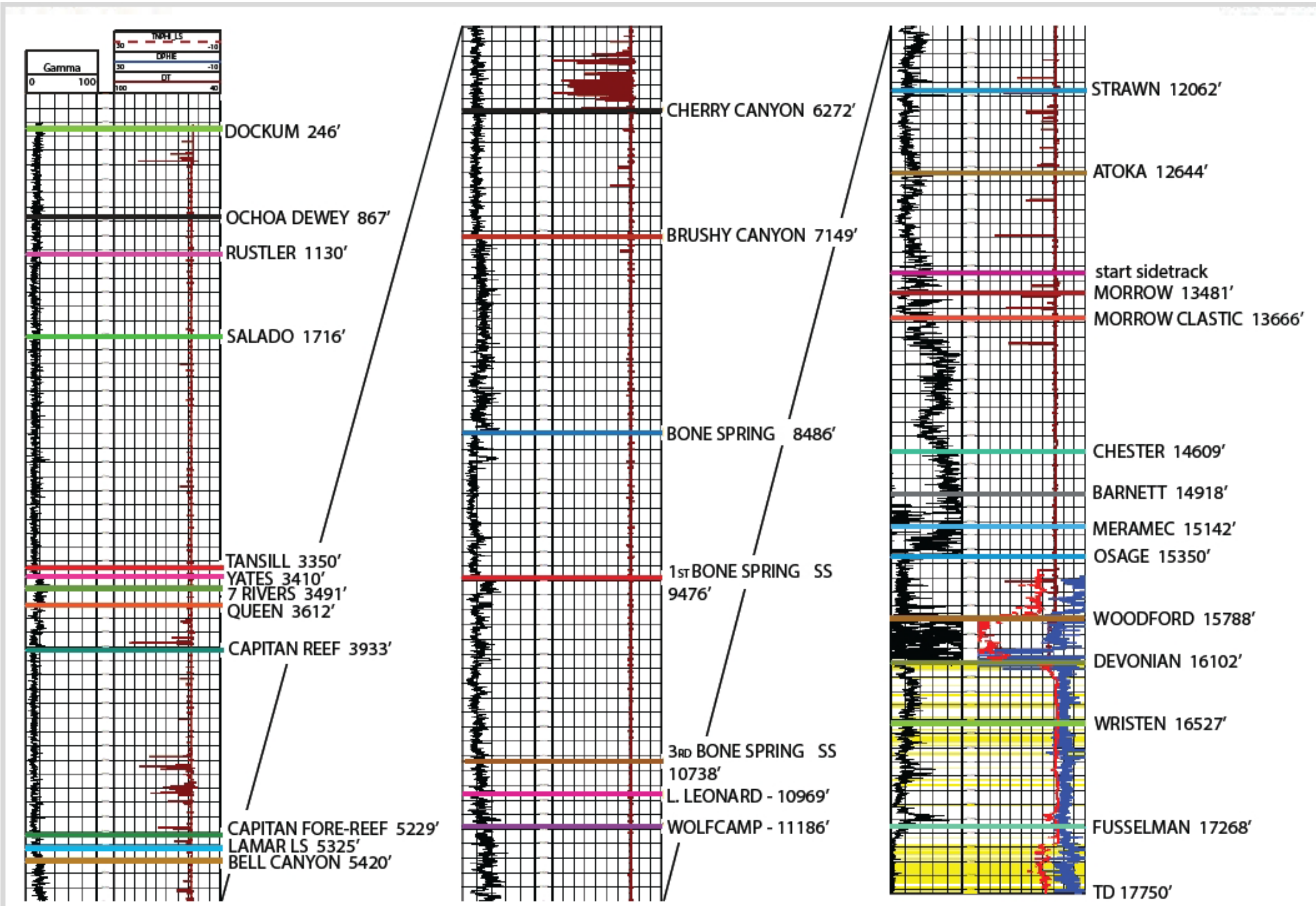
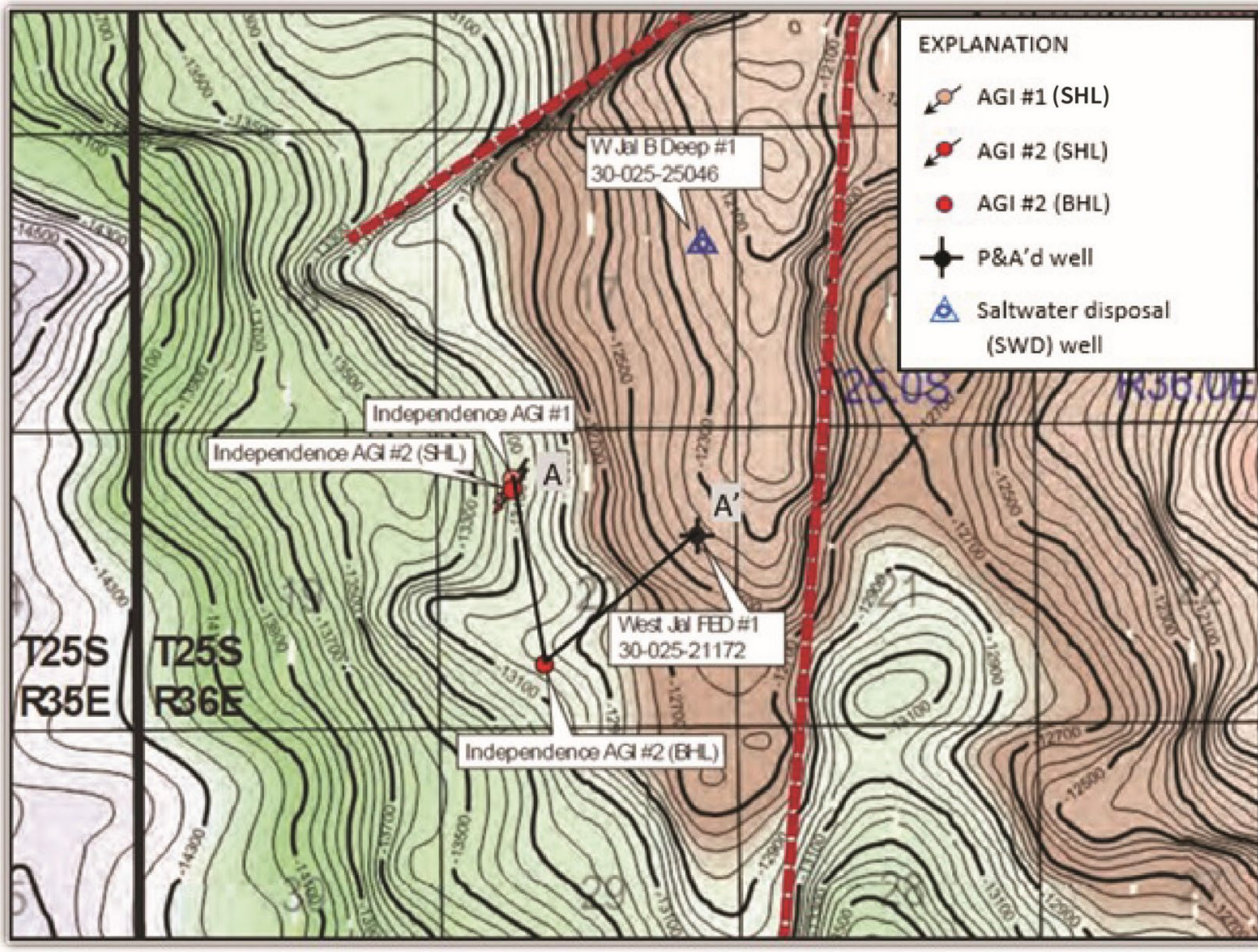


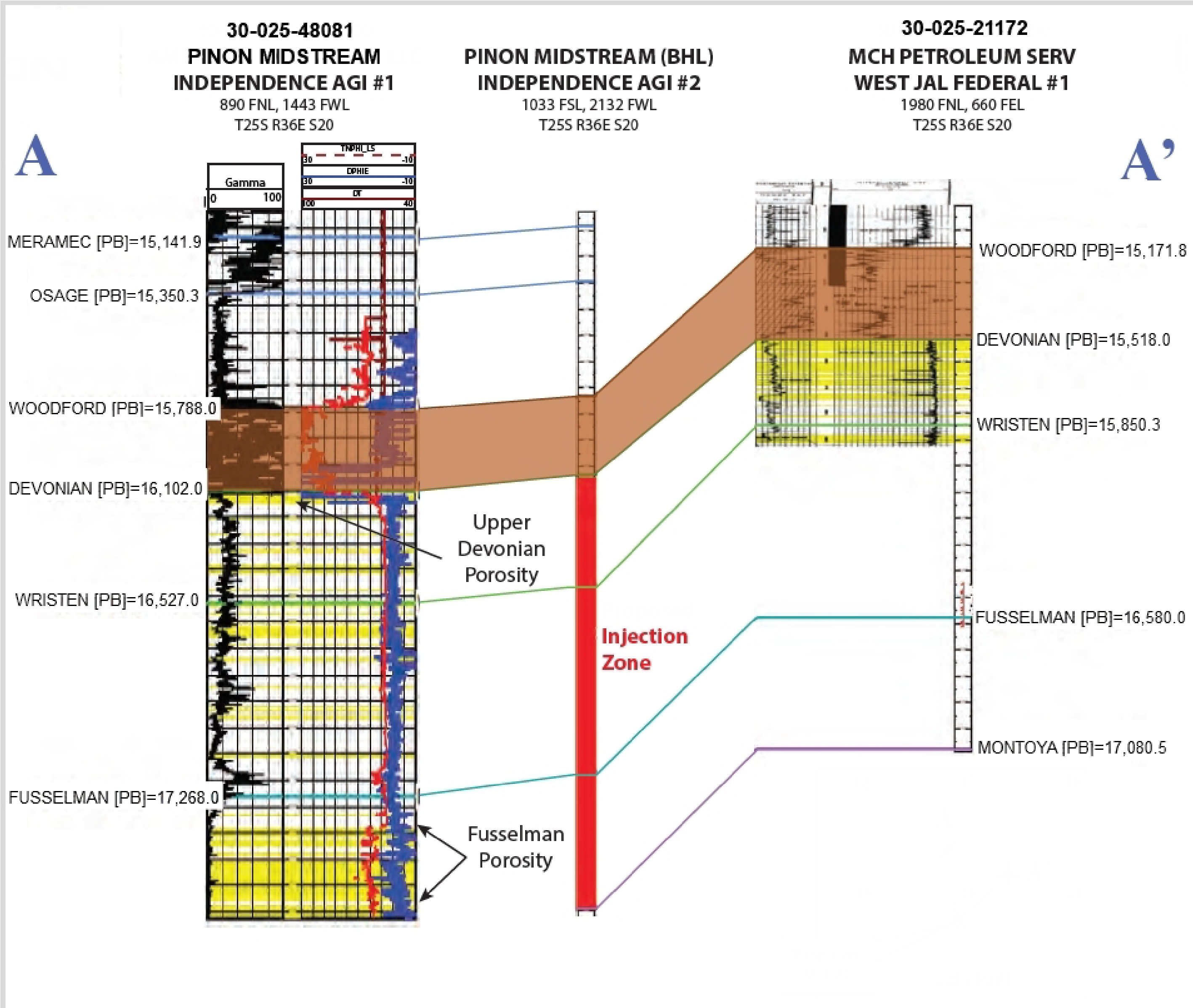
***Figure 3.3-1**: Type log of the Independence AGI #1, illustrating identified formation tops in TVD. Estimated formation tops for the Independence AGI #2 are included in . Table 3.3-1 (Modified from Figure 14 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

__Table 3.3-1__: Anticipated formation tops at the Independence AGI #2 location. (Extracted from Table 6 of Class II permit application for Independence AGI #2, Geolex, Inc.)

FORMATION	DEPTH (TVD)	DEPTH (MD)	FORMATION	DEPTH (TVD)	DEPTH (MD)
Dockum	485	485	Bone Spring	8,467	8,632
Ochoa-Dewey	747	747	Wolfcamp	11,131	11,387
Rustler	1,130	1,130	Strawn	12,004	12,289
Salado	1,720	1,720	Atoka	12,733	13,044
Tansill	3,401	3,401	Morrow	13,541	13,880
Yates	3,461	3,461	Barnett	14,949	15,336
7 Rivers	3,542	3,542	Osage	15,380	15,703
Queen	3,663	3,663	Woodford	15,745	16,142
Capitan Reef	3,935	3,943	Devonian	16,080	16,477
Bell Canyon	5,425	5,484	Wristen	16,467	16,864
Cherry Canyon	6,277	6,364	Fusselman	17,201	17,598
Brushy Canyon	7,058	7,174	Montoya	17,684	18,081



<u>Figure 3.3-</u>**<u>2</u>**: Structure contour map showing the top of the Siluro-Devonian target reservoir. Two (2) faults identified in review of 3D seismic data are shown with red dashes. Also, shown are wells within 1 mile of the Independence AGI Wells that penetrate the Siluro-Devonian target zone. Cross section A – A' is shown in <u>Figure 3.3-3</u>. (Modified from Figure 15 of Class II permit application for Independence AGI #2, Geolex, Inc.) Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.



<u>Figure 3.3-3</u>: Structural cross section A-A' showing porosity profile from nearby wells penetrating the Siluro-Devonian Injection Zone and regional extent of overlying Woodford Shale caprock. The Independence AGI #2 Injection Zone is from 16,080 feet TVD to 17,683 feet TVD (red bar). (Modified from Figure 16 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.4 Chemistry of Siluro-Devonian Interval Formation Fluids

A review of formation waters from the U.S. Geological Survey National Produced Waters Geochemical Database v. 2.3 identified twenty-one (21) wells with analyses of fluid samples collected from the Siluro-Devonian interval. These samples were collected from wells within approximately fifteen (15) miles of the Independence AGI Wells. Results of laboratory analysis to determine their composition are summarized in <u>Table 3.4-1</u>. These results have been supplemented with samples collected from Independence AGI #1 on May 31, 2021 which show Total Dissolved Solids ("**TDS**") values ranging from 109,000 to 115,000 parts per million ("**ppm**").

***Table 3.4-1**: Summary of Siluro-Devonian produced water analyses from nearby wells (U.S. Geological Survey National Produced Water Geochemical Database v. 2.3) * (Extracted from Table 7 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

API	WELL NAME	CONCENTRATION (parts per million)							
		TDS	HCO3	Ca	Cl	K + Na	Mg	Na	SO4
3002548081	Ind. AGI 1	110000	342	5600	68000	32559	759	31800	664
3002510945	Hill-federal D 1	112959	288	6264	67390	34340	1912	-	2765
3002510947	EC Hill-federal 1	35639	-	1369	22070		592	11608	-
3002511126	JR Holt A3	116415	154	7501	71110	34680	1767	-	1203
3002511196	S. Mattix Unit 3	68431	990	3180	40960	21690	974	-	637
3002511202	S. Mattix Unit 11	67130	853	5075	40430	16950	2348	-	1474
3002511383	Hodges B 3	81712	722	4320	47500	25400	1030	-	2740
3002511556	Blocker-federal 4	57675	595	2850	34030	18370	619	-	1211
3002511747	Ab Coates FED D2	82794	977	2408	47200	28190	851	-	3168
3002511760	Ida Wimberley 5	63817	360	2774	35870	20750	621	-	3442
3002811763	Ida Wimberley 9	61040	900	2680	35600	19560	800	-	1500
3002511765	Carlson-federal A3	66418	690	3002	37650	20390	1339	-	3347
3002511812	Clyde Lanehart 1	99879	687	4753	60410	32610	828	-	591
3002511818	Copper 1	27506	1089	1384	15270	8144	540	-	1079
3002511863	Arnott Ramsay B3	158761	476	17240	100300	35400	5345	-	-
3002511886	Dabbs 1	101036	540	5393	61630	30380	2183	-	910
3002511890	Sam Dabbs 1	85150	675	5368	50260	25130	1395	-	2322
3002511907	Arnott Ramsay F9	58220	367	1546	32790	-	278	20430	2816
3002511950	Farnsworth FED 6	31931	302	7196	20450	1151	2241	-	591
3002512272	LE Elliott FED H1	58687	761	3004	35460	18980	482	-	-
3002512286	JB McGhee 1	62392	552	2696	34380	20060	702	-	4002
3002521601	North Custer Mt 1	>64,000	1610	2136	36230	21830	403	-	1950

These analyses report TDS in the area of the Independence AGI Wells ranging from 27,506 to 158,761 ppm with an average of 75,981 ppm. The primary constituent in sampled formation waters is the chloride ion, with an average concentration of 45,227 ppm. The closest well, Independence AGI #1, at approximately 3,000 feet away from the Independence AGI #2 BHL, has reservoir fluids with a TDS value of approximately 110,000 ppm, and chloride ions in concentrations of approximately 68,000 ppm. Based on this data, the Siluro-Devonian reservoir fluids are anticipated to be completely compatible with the TAG injectate.

3.5 Potential for Induced Seismicity in the area of the Dark Horse Facility

To evaluate the potential for seismic events in response to injected fluids, Piñon conducted an induced-seismicity risk assessment for the area surrounding the Independence AGI Wells. This estimate (a) models the impact of seven (7) injection wells over a thirty (30) year injection period, and (b) estimates the fault-slip probability associated with the simulated injection scenario(s). This analysis was completed utilizing the Stanford Center for Induced and Triggered Seismicity's Fault Slip Potential ("**FSP**") model developed by Walsh and Zoback, 2016.

To identify subsurface structures in the area of the Independence AGI Wells, Piñon evaluated and interpreted licensed seismic survey data (WesternGeco – South Lea Survey) covering the Lea County area of interest. Based on this review, Piñon identified eight (8) subsurface faults in the area surrounding the Independence AGI Wells (Figure 3.5-1). The closest fault is observed to be located approximately one (1) mile east of the

Independence AGI Wells. Major faults in the area (those exhibiting significant lateral extent) generally strike NNW-SSE with minor faults striking NE-SW and NW to SE.

Due to the location of faults relative to the Independence AGI Wells and the general low density of injection wells in the immediate area of the Independence AGI Wells, it is anticipated that the injection scenario(s) will not pose any elevated risk of injection-induced fault slip. To support the interpretation that these structures would not be affected by operation of the Independence AGI Wells, a fault-slip probability analysis was completed to quantify the risk associated with injection operations in the area surrounding the Independence AGI Wells, and although the risk of induced seismicity is low, a seismic monitoring station was installed at the facility prior to the commencement of injection into Independence AGI #1. The station transmits data to the New Mexico Tech Seismic Network and will aid the state in seismicity interpretations.

To calculate the fault-slip probability for the model simulations, input parameters characterizing the local stress field, reservoir characteristics, subsurface features, and injected fluids are required. Parameters utilized and their sources for the area surrounding the Independence AGI Wells are included in Table 3.5-1. Additionally, Table 3.5-2 details the injection volume characteristics and locations of the injection wells modeled in the injection scenario(s). To ensure the model simulations provide a conservative estimation of induced-seismicity risk, injection wells included in the simulations were modeled utilizing their maximum anticipated daily injection volumes as recorded by NMOCD approved permits. Due to the minimal reported injection volume of the Jal North Ranch SWD #1, a potential of 10,000 bpd was assumed to account for the potential of increased injection rates due to future needs of the operator or any future workover that may improve the injectivity of this well.

Daily maximum injection volumes utilized in the fault-slip probability model range from 4,265 to 30,000 bpd (Table 3.5-2). In submission of the Class II injection well applications, Piñon requested approval to operate the Independence AGI Wells for a period of at least thirty (30) years, however, the duration of the FSP model simulation was increased to forty (40) years to characterize the reservoir effects of injection wells that are currently operating and have been in operation since 2010. Figure 3.5-2 shows the resultant pressure front and single well radial pressure solutions, as predicted by the FSP model, after thirty (30) years of injection at the maximum injection rates.

For this study, limitations of the FSP model required a conservative approach be taken in determining the fault-slip probability of the injection scenario. Specifically, the FSP model is only capable of considering a single set of fluid characteristics and this study aims to model an injection scenario that includes both brine injection and AGI. To ensure a conservative fault-slip probability estimate, the Independence AGI Wells were simulated utilizing the characteristics of a brine injectate. This approach yields a more conservative model prediction as brine displays greater density, dynamic viscosity, and is significantly less compressible than TAG. For comparison, characteristics of TAG at the anticipated reservoir conditions, as modeled by AQUAlibrium™, are shown in Table 3.5-1.

Generally, faults considered in this assessment are predicted by the FSP model to have very low potential for injection-induced slip and operation of the Independence AGI Wells is not predicted by the model to contribute significantly to the estimate of risk (Table 3.5-3 and Figure 3.5-3). Table 3.5-3 summarizes the predicted pressure change along each fault segment and includes the model-derived pressure change necessary to induce slip for each feature. Fault-slip probability values range from 0.00 to 0.05 with the majority of fault segments predicted to have zero probability of slip (Table 3.5-3). Major faults (faults 4, 7, and 8 in Figure 3.5-1) in the area, which would have the greatest energy release potential upon slip, are predicted to have zero probability for slip in response to the modeled injection scenario.

In summary, no structures included in the modeled simulations are predicted to be at increased risk for injection-induced slip in response to the injection scenario presented. Features estimated to have a non-zero

slip potential are generally smaller-scale features and predicted probabilities are very low (≤ 0.05). Furthermore, subsequent model simulations in which contribution from Independence AGI #2 is excluded illustrate that operation of the Independence AGI #2 will have little impact on conditions near the identified faults in the area due to significantly lower proposed injection volumes in comparison to nearby brine injection wells.

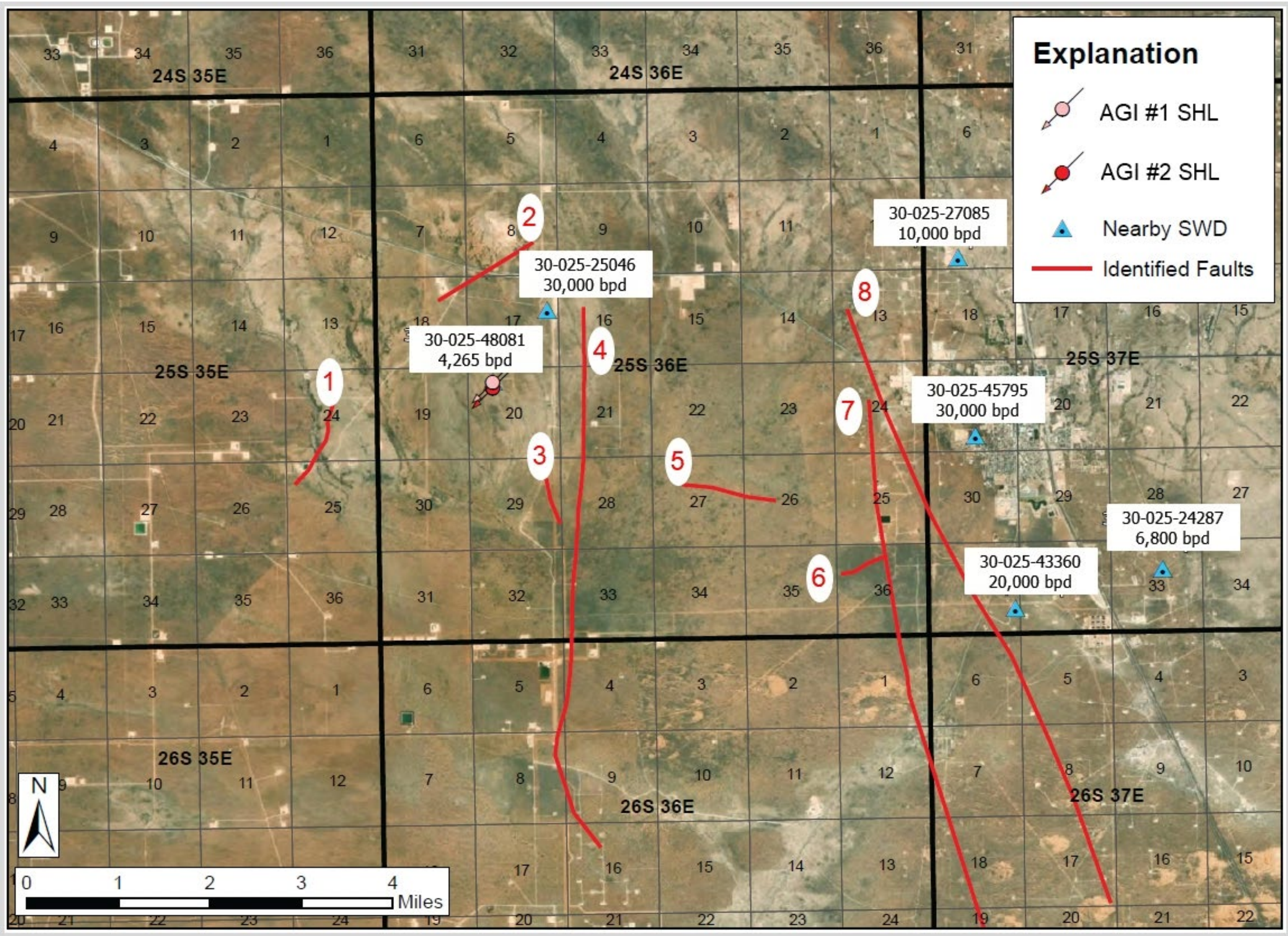


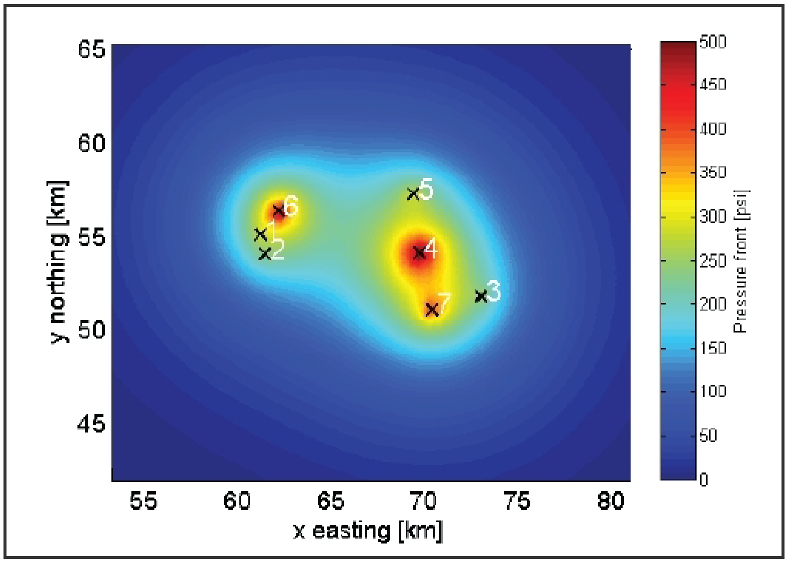
***Figure 3.5-1**: Map showing Siluro-Devonian injection wells and subsurface identified faults in the vicinity of the Independence AGI Wells. (Modified from Figure 18 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

***Table 3.5-1**: Input parameters and source material for FSP model simulations. (Extracted from Table 10 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

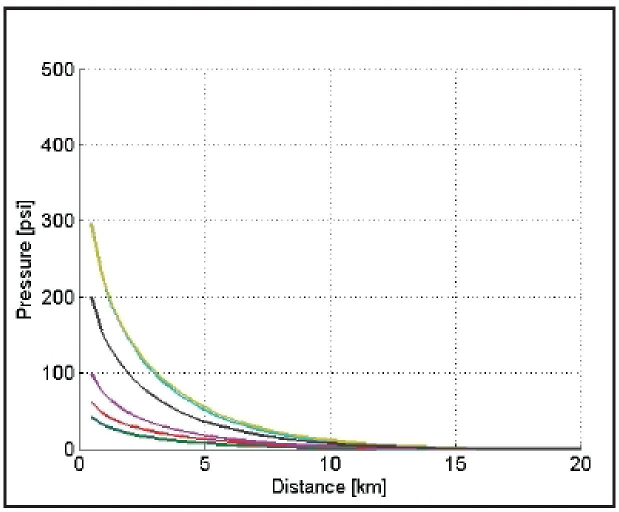
Modeled Parameter	Input Value	Variability (+/-)	UOM	Source
Stress				
Vertical Stress Gradient	1.05	0.105	psig/ft	Nearby well estimate
Max Horizontal Stress Direction	N75E	5	Deg	Lund Snee & Zoback, 2018
Reference Depth	17000		ft	Nearby well evaluation
Initial Res. Pressure Gradient	0.43	0.043	psig/ft	Lund Snee & Zoback, 2018 Nearby well evaluation
A_ϕ Parameter	0.6	0.06	-	Lund Snee & Zoback, 2018
Reference Friction Coefficient (μ)	0.6	0.06	-	Standard value
Hydrologic				
Aquifer Thickness	1500	0	ft	Nearby well evaluation
Porosity	3.5	0.35	%	Nearby well evaluation
Permeability	20	2	mD	Nearby well evaluation
Material Properties				
Density (Water)	1040	40	Kg/m^3	Standard value
Dynamic Viscosity (Water	0.0008	0.0001	Pa.s	Standard value
Fluid Compressibility (Water)	3.6×10^{-10}	0	Pa^{-1}	Standard value
Rock Compressibility	1.08×10^{-9}	0	Pa^{-1}	Standard value
Acid Gas Properties @ 7,370 psig & 228 °F				
Density	821.80	-	kg/m^3	AQUAlibrium™
Dynamic Viscosity	8.067×10^{-5}	-	Pa.s	AQUAlibrium™

***Table 3.5-2**: Location and characteristics of injection wells modeled in the FSP assessment. (Extracted from Table 11 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

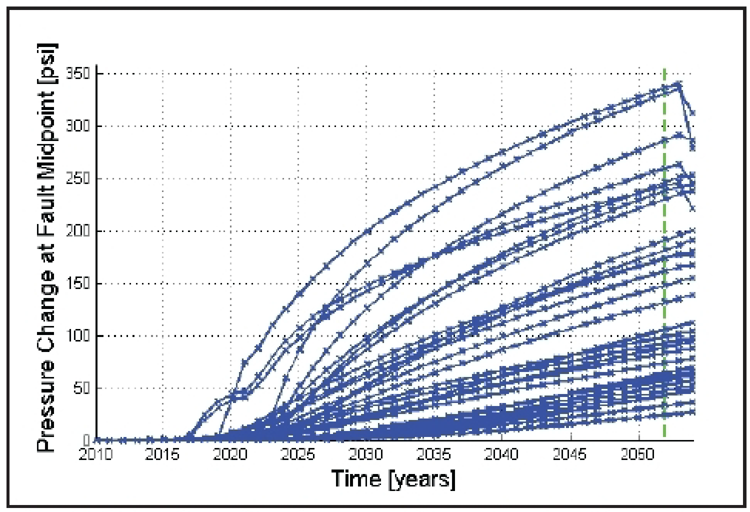
#	API	Well Name	LAT	LONG	Volume (bbls/day)	Start (year)	End (year)
1	3002548081	Independence AGI #1	32.120855	-103.291021	4265	2020	2052
2	-	Independence AGI #2	32.111454	-103.288812	4265	2022	2052
3	3002524287	Crosby Deep #2	32.089508	-103.166733	6800	2010	2052
4	3002545795	Sholes Deep SWD #1	32.110998	-103.201266	30000	2020	2052
5	3002527085	Jal N. Ranch SWD #1	32.139347	-103.203911	10000*	2017	2052
6	3002525046	West Jal B Deep #1	32.132091	-103.280708	30000	2015	2052
7	3002543360	Kimberly SWD #1	32.083537	-103.194274	20000	2019	2052



Panel A. Resultant pressure front after 30 years of injection operations at the maximum anticipated injection rates, as reported in **NMOCD** records



Panel B. Single well radial pressure solutions, as determined by the FSP model

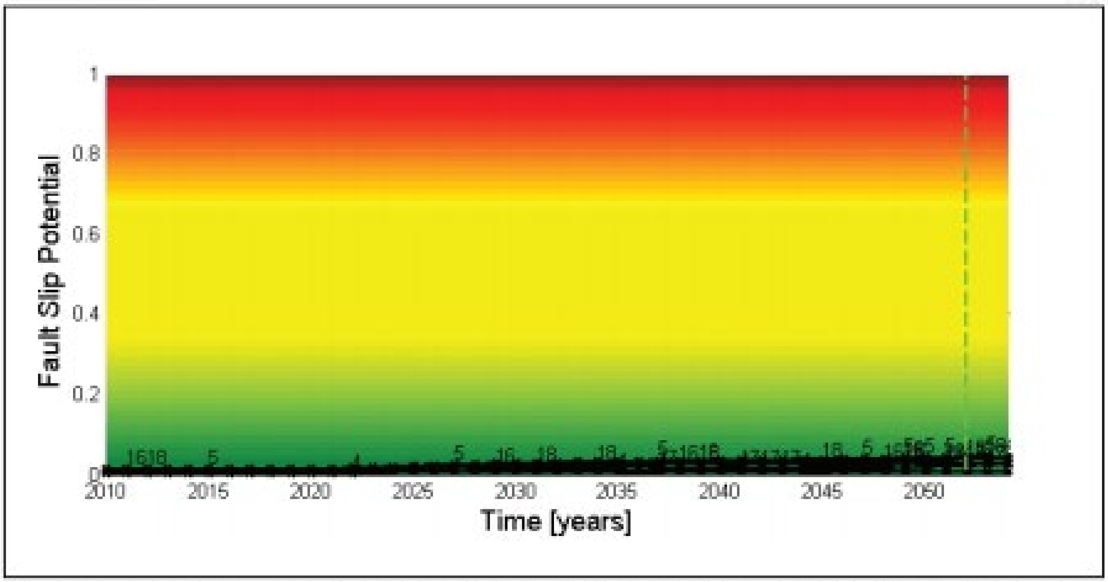


Panel C. Model-predicted pressure change through time at the midpoint of each fault segment included in the simulation

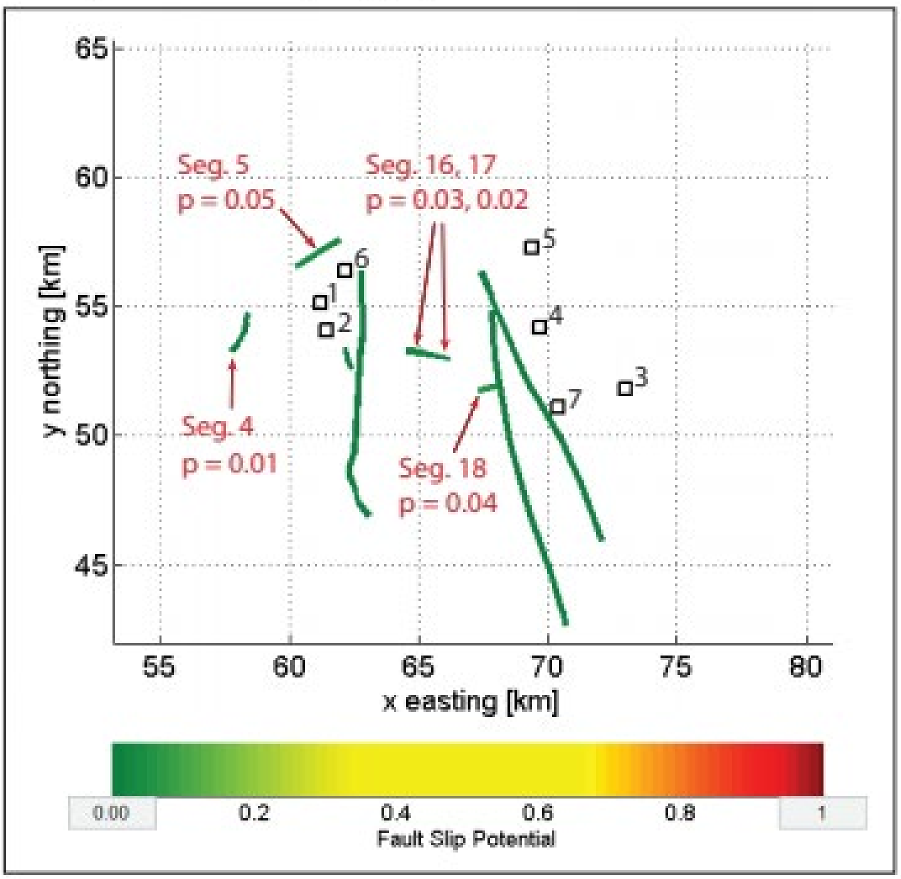
<u>Figure 3.5-2</u>: Summary of model-predicted pressure effects in response to the simulated seven (7) well injection scenario. (Extracted from Figure 19 of Class II permit application for Independence AGI #2, Geolex, Inc.)

***Table 3.5-3**: Summary of model-simulation results showing the required pressure change to induce fault slip, actual change in pressure as predicted by the FSP model, probability of fault slip at the end of the thirty (30) year injection scenario, and fault-slip probability when Independence AGI #2 is excluded from simulation. (Extracted from Table 12 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

Fault #	Segment #	ΔPressure necessary to induce fault slip	Actual ΔPressure at 2052	Fault Slip Potential at 2052	FSP (excluding AGI #2)
1	1	3137	109	0.00	0.00
	2	4357	103	0.00	0.00
	3	1786	93	0.00	0.00
	4	1201	83	0.01	0.01
2	5	1197	253	0.05	0.05
3	6	6869	186	0.00	0.00
	7	6298	168	0.00	0.00
4	8	5645	277	0.00	0.00
	9	4610	194	0.00	0.00
	10	5005	117	0.00	0.00
	11	2709	70	0.00	0.00
	12	5302	63	0.00	0.00
	13	6339	57	0.00	0.00
	14	6899	51	0.00	0.00
	15	4197	46	0.00	0.00
5	16	1101	192	0.03	0.03
	17	1085	199	0.02	0.02
6	18	1554	234	0.04	0.04
7	19	6012	290	0.00	0.00
	20	6680	241	0.00	0.00
	21	6914	133	0.00	0.00
	22	6758	61	0.00	0.00
	23	6931	33	0.00	0.00
	24	6590	25	0.00	0.00
8	25	6508	250	0.00	0.00
	26	6327	334	0.00	0.00
	27	5455	228	0.00	0.00
	28	6305	174	0.00	0.00
	29	6684	89	0.00	0.00



Panel A. Fault-slip probability throughout the entire simulated injection period. FSP model results suggest no significant risk of injection-induced slip along any feature included in the simulation.



Panel B. Map view illustrating the model-estimated slip potential of faults at the end fo the 42-year injection scenario. Any feature estimated to have a non-zero slip potential determination is labeled on the above map.

<u>Figure 3.5-3</u>: Summary of model-determined fault-slip probabilities over the simulated injection period (2010-2052). (Modified from Figure 20 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.6 Groundwater Hydrology in the Vicinity of the Dark Horse Facility

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are fifteen (15) water wells and points-of-diversion located within a two (2) mile radius of the Independence AGI Wells. Of these wells, the closest is located approximately 0.34 miles away and has a total depth of 505 feet (Figure 3.6-1 and Table 3.6-1). The remaining fourteen (14) wells within the two (2) mile radius have depths of approximately 240 to 600 feet deep, collecting water from Alluvium and the Triassic red beds. The shallow freshwater aquifer will be protected as the Independence AGI Wells are designed to isolate shallow zones via a five (5) string casing design including a surface casing interval that extends to 1,230 feet within the Rustler Formation, effectively isolating shallow groundwater resources (Figures A1-1 and A1-2).

The area surrounding the Independence AGI Wells is arid and there are no surface water bodies within a two (2) mile radius.

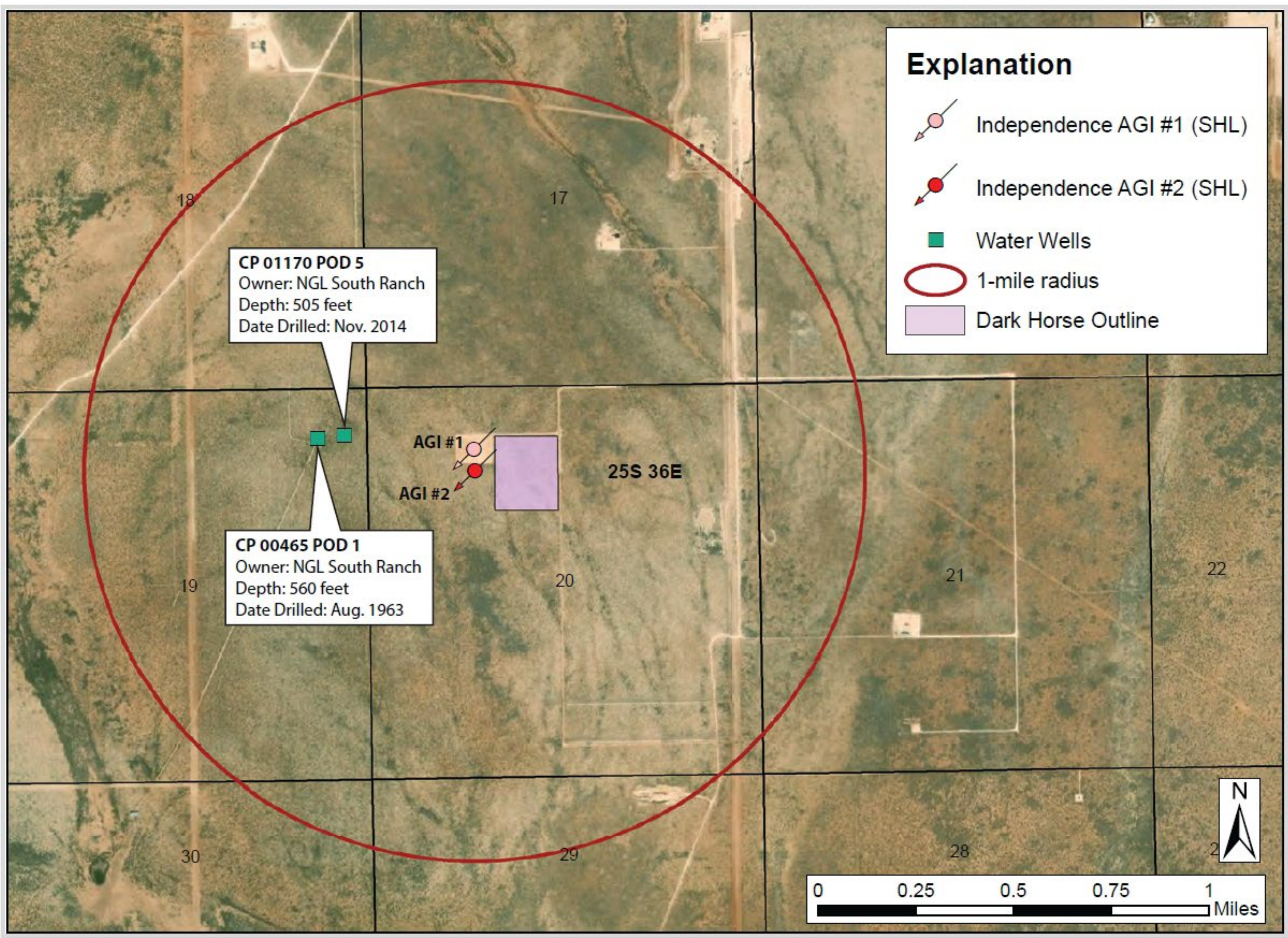


Figure 3.6-1: Reported water wells within 1-mile radius of the SHLs of the Independence AGI Wells. The BHLs for AGI #1 and #2 are not shown. (Extracted from Figure 17 of Class II permit application for Independence AGI #2, Geolex, Inc.) Only SHLs shown for the Independence AGI #1 and #2 wells.

Table 3.6-1: Water wells within one (1) mile of the Independence AGI Wells (Retrieved from the New Mexico Office of the State Engineer's Files on October 4, 2021). (Extracted from Table 8 of Class II permit application for Independence AGI #2, Geolex, Inc.)

POD #	Source	Use	Owner	LAT (NAD83)	LONG (NAD83)	Distance (miles)	Depth (feet)	Date Completed
CP 1170 POD 5	Shallow	Commercial	NGL South Ranch	32.121417	-103.296667	0.34	505	11/2014
CP 465 POD 1	Shallow	Commercial	NGL South Ranch	32.119465	-103.299882	0.53	560	08/1963

According to Order No. 190 of the New Mexico Office of the State Engineer signed March 22, 2021, the Capitan Underground Water Basin, within which the Independence AGI Wells lie, is closed indefinitely to new appropriations of water. Therefore, no new water wells are anticipated to be constructed during the Independence AGI Wells' anticipated thirty (30) year operation period. Due to the shallow completion depths of the few groundwater wells in the area surrounding the Independence AGI Wells, it is highly unlikely that groundwater wells will serve as conduits for CO_2 leakage to the surface.

Geolex conducted a review of Geology and Ground-Water Conditions in Southern Lea County, New Mexico (Nicholson and Clebsch, 1961) to identify published groundwater data representative of nearby water wells in the area surrounding the Independence AGI Wells. Table 3.6-2 summarizes the wells identified in this review and the results of those analyses.

Table 3.6- 2: Chemical analysis results of samples collected from water wells in the area surrounding the Independence AGI Wells (Nicholson and Clebsch, 1961 – Geology and Groundwater Conditions in Southern Lea County, New Mexico). (Taken from Table 9 of Class II permit application for Independence AGI #2, Geolex, Inc.)

Historical Owner	Location (T-R-S)	Location (Qtr-Qtr)	Depth (ft)	Ca (ppm)	Mg (ppm)	Na+K (ppm)	HCO_3 (ppm)	SO_4 (ppm)	Cl (ppm)	NO_3 (ppm)
Sun Oil Co.	25-37-15	NE/4 NE/4	-	307	98	271	145	737	610	9
City of Jal	25-37-19	NE/4 NE/4	500	55	49	170	376	280	71	0.4
City of Jal	25-37-19	SE/4 NE/4	450	34	43	175	264	286	54	0.5
City of Jal	25-37-20	NW/4 SW/4	70	-	-	-	150	145	168	7.6

This analysis confirms that the Independence AGI Wells pose no risk of contaminating groundwater in the area as (a) the well design includes material considerations to protect shallow groundwater resources, and (b) there are no identified conduits that would facilitate migration of injected fluids to freshwater-bearing strata nor to the surface.

3.7 Historical Operations

3.7.1 Operations within a 2-mile radius of the Independence AGI Wells

Appendix 3 summarizes in detail all NMOCD recorded wells within a two (2) mile radius of the Independence AGI Wells. These wells are shown in Figure 3.7-1 and include active, plugged, and new (permitted but not yet drilled) well locations. In total, there are fifty-four (54) wells within a two (2) mile radius of the Independence AGI Wells. Of these, there are ten (10) active wells, thirty-three (33) permitted wells, and eleven (11) plugged wells.

Active wells in the area include one brine injection well completed across the Strawn through Fusselman formations, and nine (9) active oil and natural gas wells completed in various other strata.

There are two (2) third-party wells within two (2) miles of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone (Table 3.7-1).

The first well is an active brine injection well (West Jal B Deep #1) located approximately one (1) mile from the Independence #2 SHL. This well was drilled to a total depth of 18,945 feet and is permitted to inject through perforated intervals of the Strawn through Fusselman strata. A Form C-103- Sundry Notices and Reports on Wells, submitted November 2018 contain a wellbore diagram that shows the locations of two cast iron bridge plugs ("**CIBP**"). The first CIBP is at a measured depth of 14,200 feet (within the lower Atoka Formation), and the second CIBP is at a measured depth of 17, 100 feet (within the Fusselman Formation). Despite BC & D Operating being granted approval for injection into the Fusselman (approved by NMOCD June 2014), NMOCD records document no reports of work to drill out the CIBP at 14,200 feet. The same Form C-103- Sundry Notices and Reports on Wells mentioned above indicates the intent of BC & D Operating to drill out the CIBP, but there have been no identified subsequent reports confirming completion of this work. Additionally, reported injection volumes since the filing of the Form C-103 in November 2018 for this well do not appear to exhibit any significant increase that might indicate this work was completed. Furthermore, according to a search of publicly available data as of June 2023, the West Jal B Deep #1 well ceased water injection operations during or after July 2022, and water injected volumes have been reported as "0" since July 2022.

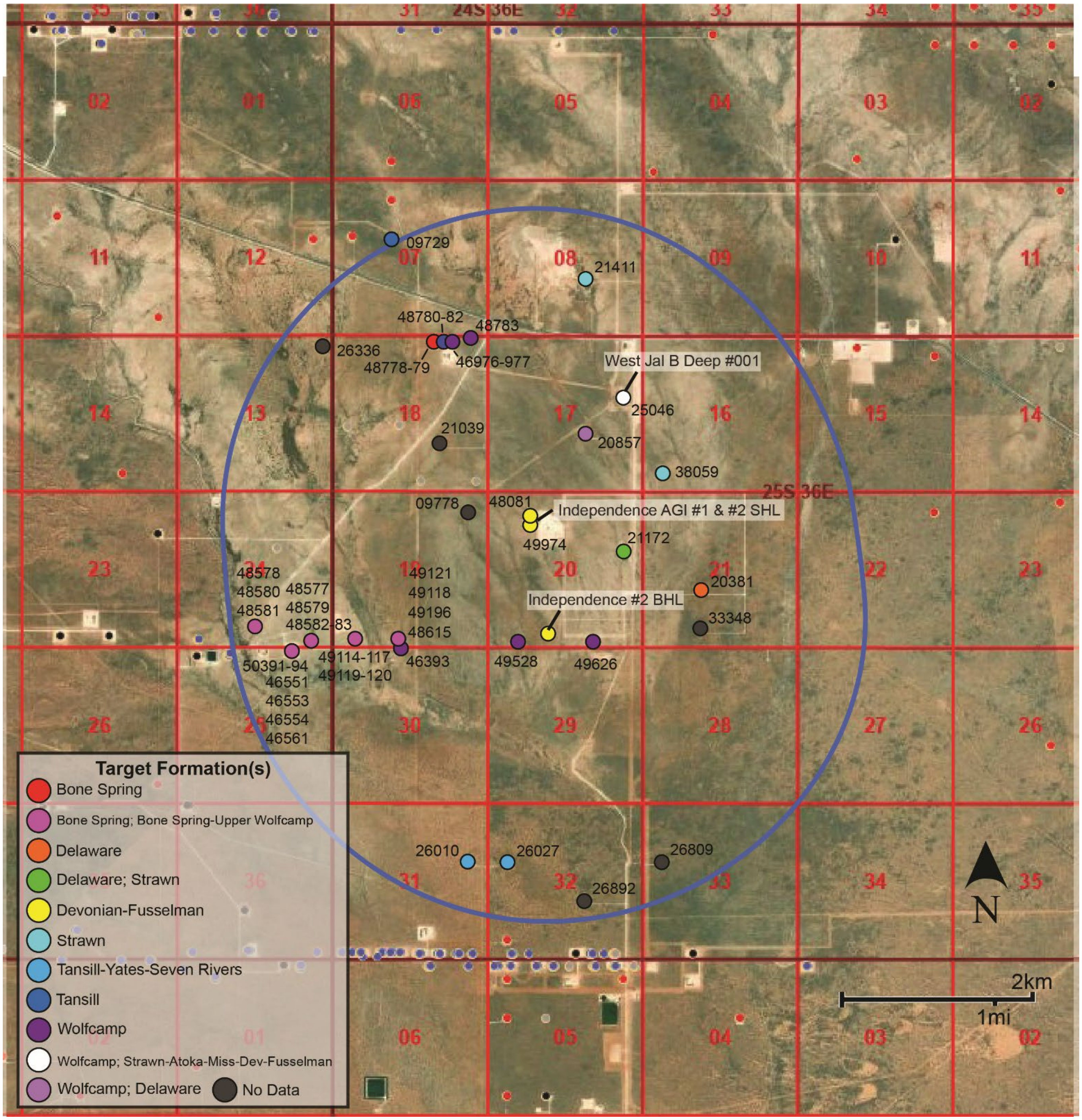
The second well penetrating the Siluro-Devonian Injection Zone is the plugged West Jal Unit #1, located approximately 0.67 miles from the Independence AGI #2 SHL. Final plugging operations were completed in April 1984 and all relevant plugging reports and documents are included in Appendix 9. The well is properly cemented through the Siluro-Devonian Injection Zone, and it is not anticipated to be negatively affected by the operation of the Independence AGI Wells nor is it considered to be a pathway for CO_2 leakage to the surface.

Appendix 3 and Figure 3.7-1 also show a number of wells in the area which have approved permits to drill but are not yet drilled. The new oil and natural gas wells are targeting various production zones, more than 4,000 feet above the Siluro-Devonian Injection Zone for the Independence AGI Wells. All new oil and natural gas wells and injection wells are subject to the requirements of regulations governing sealing off strata (19.16.16.10) and casing and tubing requirements (19.16.16.10) to prevent the contents of production or injection zones from passing into other strata. To minimize the likelihood of leaks from new wells, NMAC 19.15.26.9 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." Therefore, due to the fact that these wells do not penetrate the Siluro-Devonian Injection Zone, and that the wells are more than 4,000 feet above the Siluro-Devonian Injection Zone, Piñon does not consider these new wells to be pathways for CO_2 leakage to the surface. In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage.

***Table 3.7-1*: Wells located within a two (2) mile radius of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone. (Additional details are provided in Appendix 3)**

API	Well Name	Pool	Status	TVD
30-025-21172	WEST JAL UNIT #1	Strawn	Plugged	17,086
30-025-48081	INDEPENDENCE AGI #1	Devonian - Fusselman	Active	17,750

30-025-49974	INDEPENDENCE AGI #2	Devonian - Fusselman	New	17,683 (proposed)
30-025-25046	WEST JAL B DEEP #001	Mississippian – Fusselman	Active	18,945



<u>Figure 3.7-1</u>: Location of all oil- and natural gas-related wells within a two (2) mile (blue line) of the Independence AGI Wells. Colors indicate the target formation(s) for each well. The oblong shape of the two

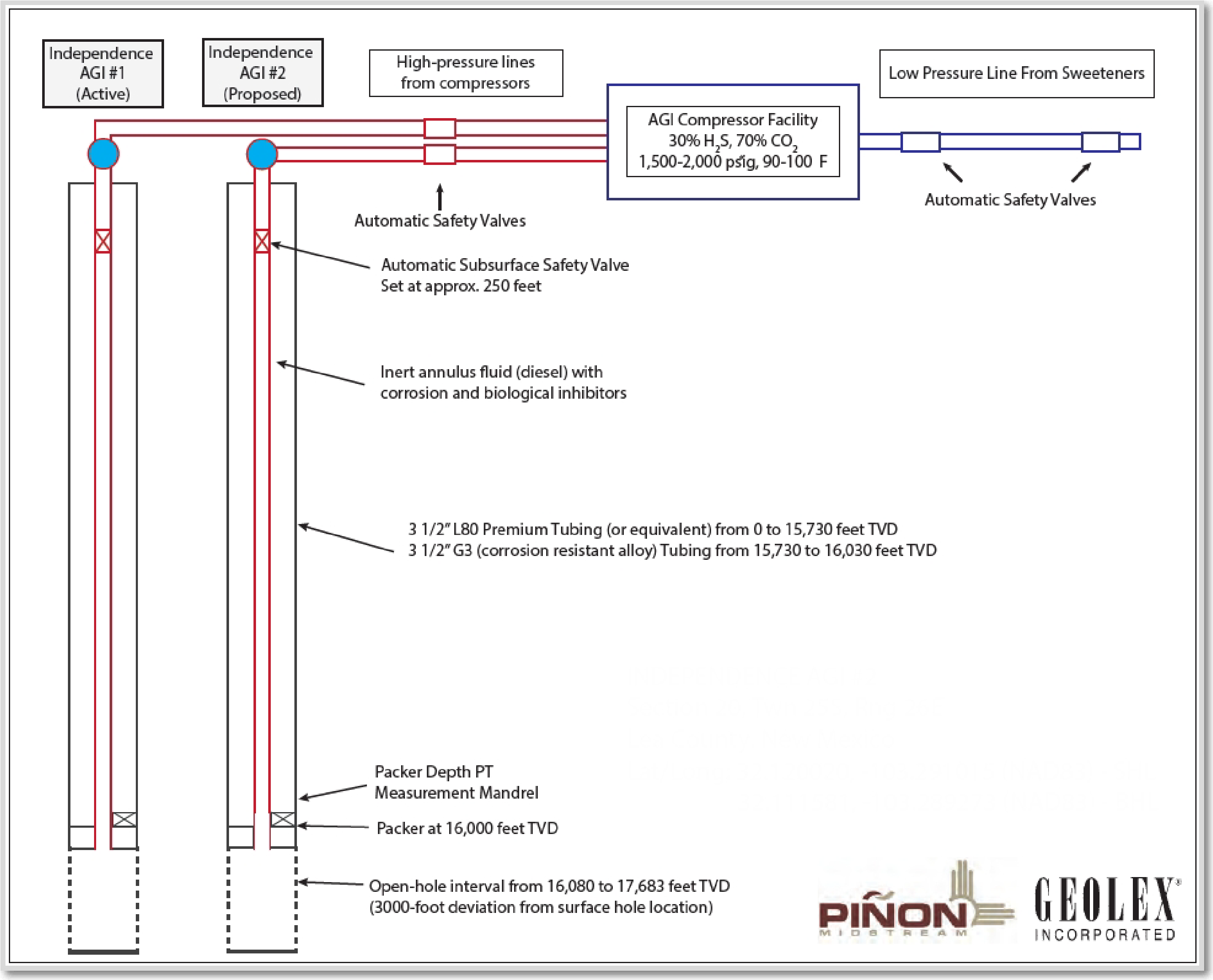
(2) mile area accounts for the BHL of Independence AGI #2 as shown in <u>Figure 3.1-1</u>. Labels denote the last five (5) digits of API #30-025-XXXXX. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.

3.8 Description of Injection Process

Once delivered to the Dark Horse Facility, sour natural gas is treated using amine to isolate H_2S and CO_2. The amine (which now contains H_2S and CO_2) is then regenerated which creates a TAG waste stream. This TAG waste stream is then routed to on-site compression facilities that compress the TAG waste stream into a dense phase (roughly 1,250 psig). The dense phase stream is then pumped to upwards of 2,500 psig prior to being sent to Independence AGI #1 (and when complete, Independence AGI #2), through a National Association of Corrosion Engineers ("**NACE**") rated pipe, for injection. Figure 3.8-1 is a schematic of the surface facilities for the Independence AGI Wells. The sweet natural gas that results from the amine scavenging process is then treated to remove water ("**H_2O**")and subsequently transported offsite, via pipeline, and redelivered to Piñon's customers at various delivery points.

For the period of September 2021 through March 2022, the TAG stream at the Dark Horse Facility averaged 57.076% CO_2 and 38.703% H_2S by volume, with hydrocarbons (C1 – C7) and H_2O comprising the remaining volume.

The anticipated duration of TAG injection into the Independence AGI Wells at the Dark Horse Facility is approximately thirty (30) years.



<u>Figure 3.8-1</u>: Schematic of surface facilities at the Dark Horse Facility and the Independence AGI Wells. (Modified from Figure 3 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.9 Reservoir Characterization Modeling

The Independence AGI Wells penetrate the lower Devonian Thirtyone formation and the Silurian Wristen and Fusselman formations and overlie the Ordovician Montoya formation. The upper Devonian Woodford formation serves as the primary containment seal with thick shales having an estimated permeability in the nanodarcy range.

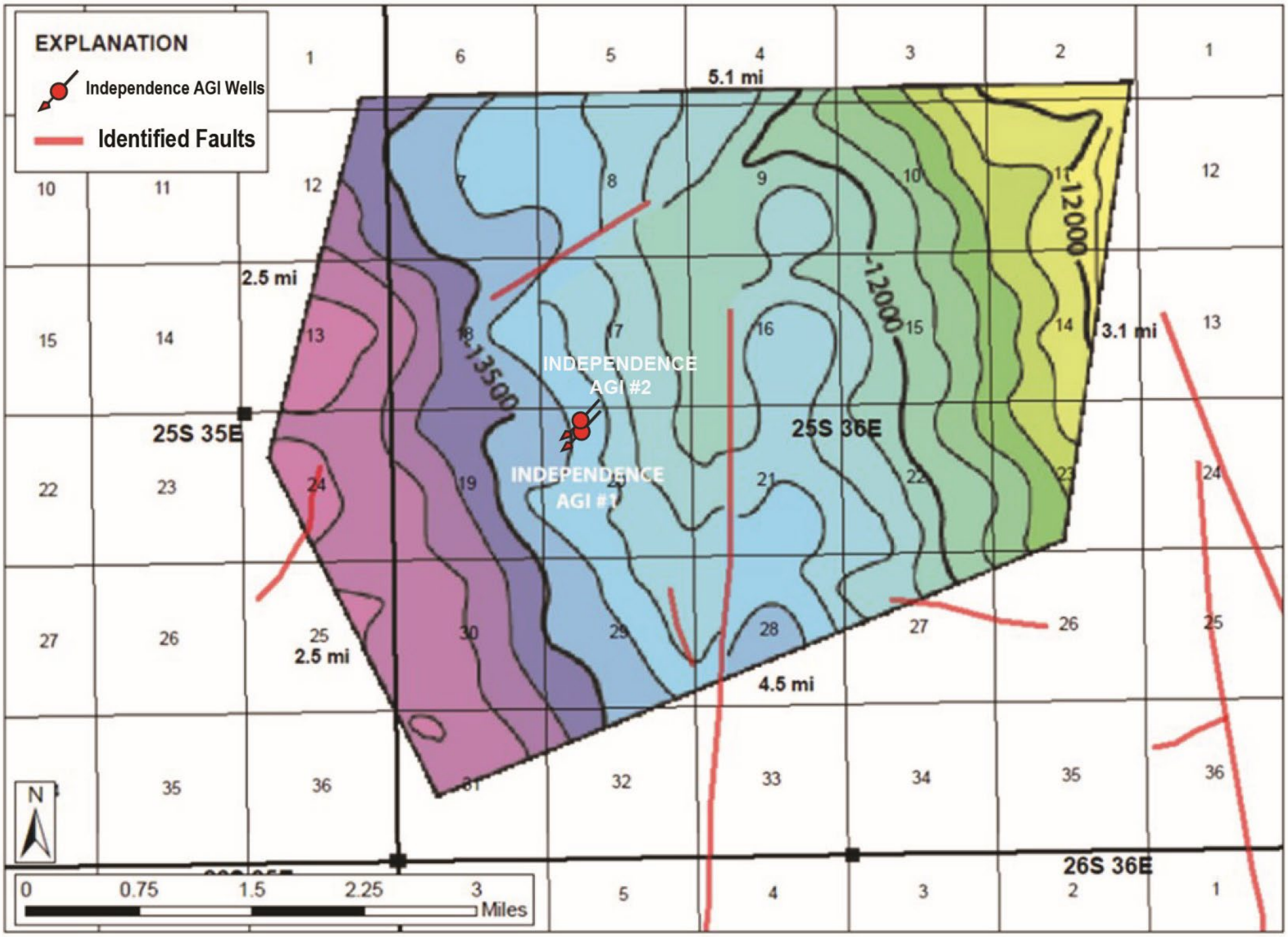
Schlumberger's Petrel (Version 2020.4) software was used to construct the geological models used in this work. Schlumberger's simulation software Eclipse Compositional E300 (Version 2020.1) was used in the reservoir simulations presented in this MRV Plan with simulation results and visuals provided by Geolex Inc. The model simulates solubility trapping of the injected TAG in the formation water and/or the portion of the TAG that can exist in a supercritical phase. The modeling did not consider CO_2 storage attributed to mineral and geomechanical trapping mechanisms. Also, the model did not implicitly model storage attributed to residual trapping because insufficient information was available to develop the hysteresis effects.

Though the Independence AGI Wells were modeled separately, similar constraints were used for both models. The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. The injection

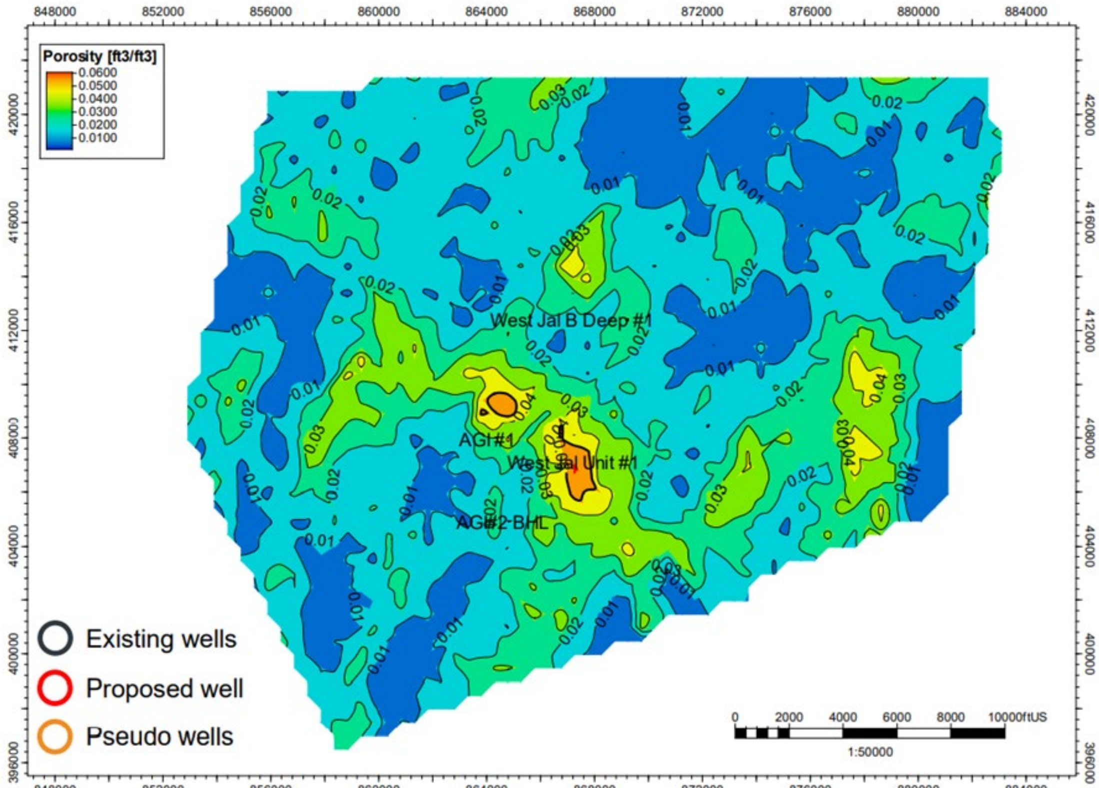
gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Both TAG components are assumed to be soluble into the aqueous phase. An irreducible water saturation of 0.17 is used to generate the relative permeability curves for the gas/water system. The external boundary conditions are specified to be Neumann boundaries and hence no-flow with respect to mass.

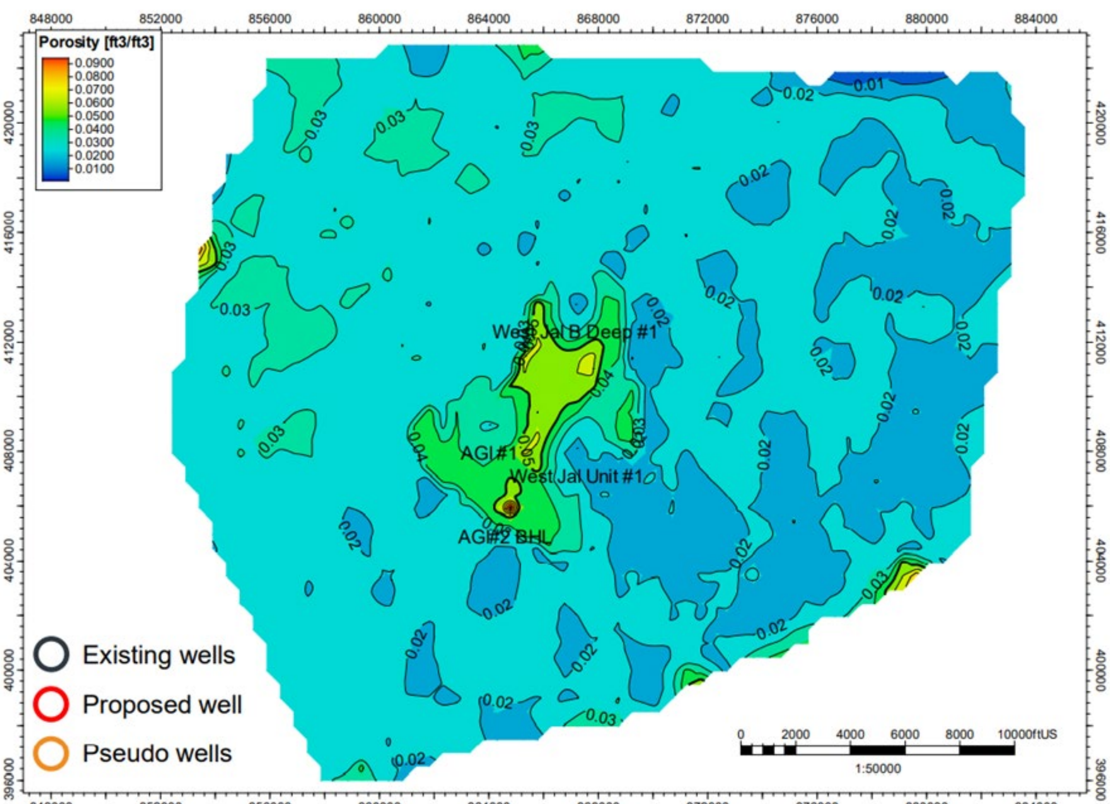
3.9.1 AGI Injection Characterization and Modeling

Formation tops were picked from the few well logs available for the area and geophysical measurements and mapped to construct the structural surfaces for the Silurian-Devonian reservoir between the underlying Montoya and capping Woodford formations. The geologic model extends approximately twenty (20) square miles with an irregular polygonal edge (Figure 3.9-1) and includes relevant subsurface features (e.g. faults, folds) and nearby injection wells. The simulation grid is comprised of 292 simulation layers characterizing eight (8) discrete zones. Horizontal spacing is uniform at 500 × 500 feet throughout the model, and the numerical grid overall contains 923,000 grid cells. Figure 3.9-1 shows the structural surface for Layer 1, covering the top of the reservoir immediately below the Woodford cap. Porosity data derived from the Independence AGI #1 well logs augmented by 3D seismic survey impedance data along with drill-stem and injection tests were used to populate the model porosity values (Figure 3.9-2). A porosity-permeability relationship was established to develop a correlation to populate 3D distribution of permeability (Figure 3.9-3). The permeability distribution signifies a fairly tight formation with typical values ranging from 1.0 to 79.0 millidarcies. Figure 3.9-4 shows the permeability distribution in Layer 1 of the model at the top of the Devonian Thirtyone Formation (*see* Section 3.3.1). Separate scenarios were run for non-transmissive faults and for permeability across faults.

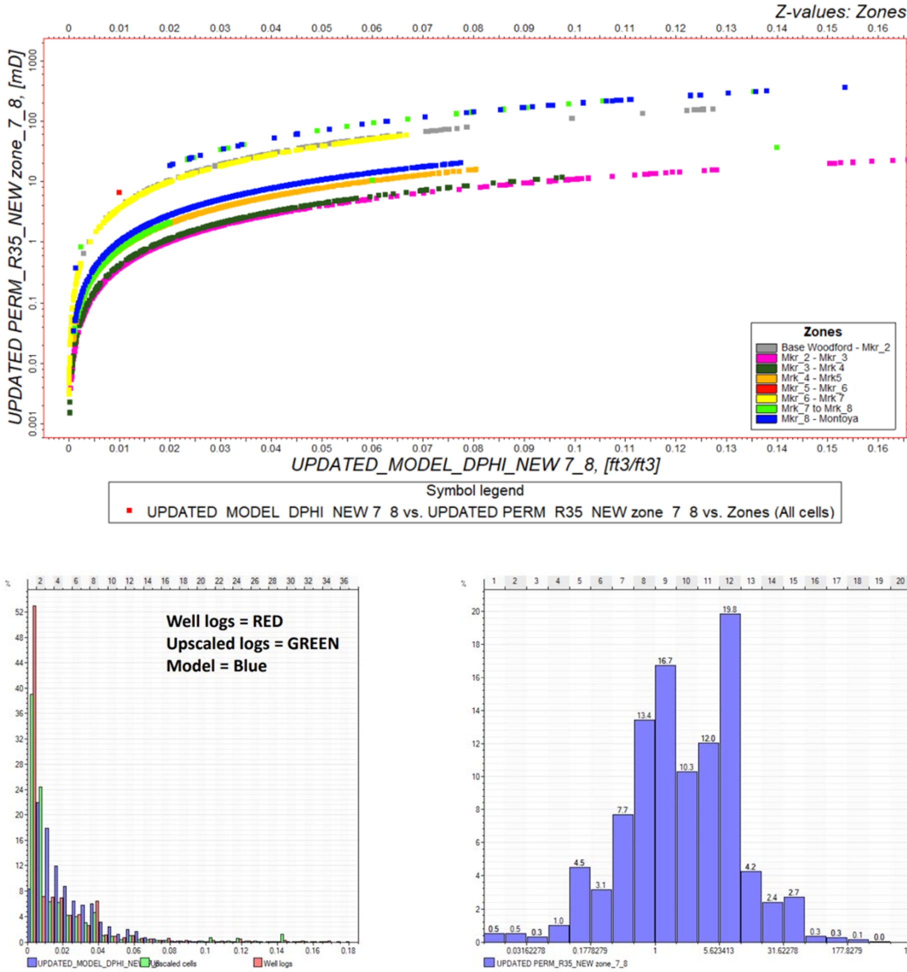


<u>Figure 3.9-1</u>: Structural surface for top of Layer 1 (top) of the geological and numerical model. Only SHLs shown for the Independence AGI #1 and #2 wells.





<u>Figure 3.9-2</u>: Model layer porosities for Zone 1 (top) and Zones 7 and 8 (bottom). Porosities are based on 2 wells, 3D seismic impedance surveys, and well stem tests. Only SHLs shown for the Independence AGI #1 and #2 wells.



<u>Figure 3.9-3</u>: Geological zones and ranges of the properties for the Siluro-Devonian geologic model

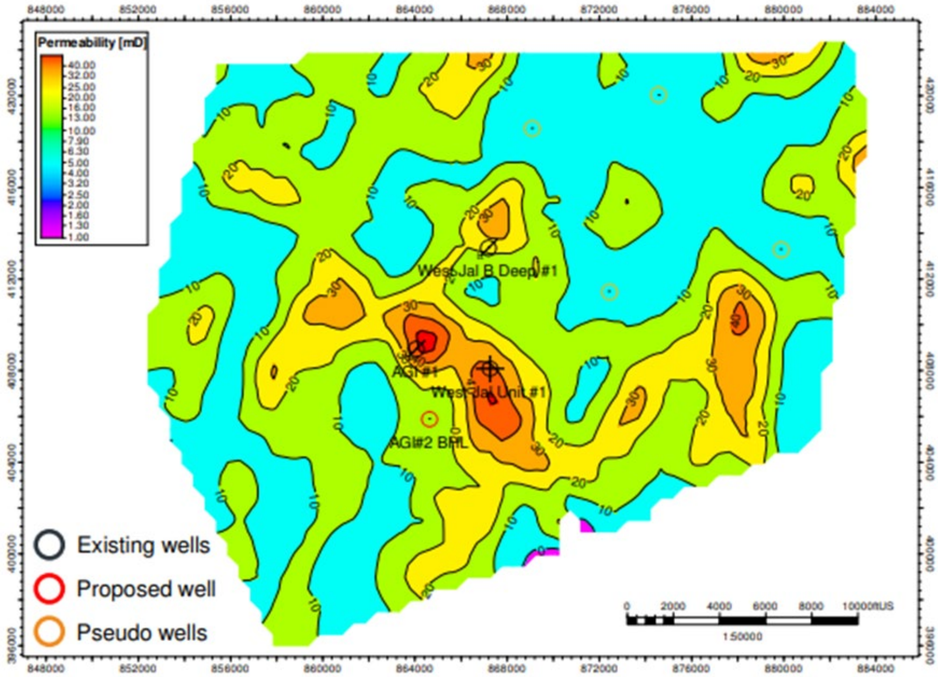


Figure 3.9-4: Graphic showing the permeability distribution in Layer 1 of the model representing the Thirtyone formation. Plan view. Only SHLs shown for the Independence AGI #1 and #2 wells.

3.9.2 Simulation Modeling for the Independence AGI Wells

Once the geological model was established, numerical modeling was performed to:

1. Assess the maximum injection rate with respect to estimated maximum bottomhole pressure ("**BHP**") to ensure safe operation, and

2. Estimate the modeled extent of the injected TAG after thirty (30) year injection period and five (5) year post injection monitoring period.

The reservoir is assumed to be initially saturated with 100% brine and exhibit hydrostatic equilibrium with the initial pressure based on the measured pressure at the top of the reservoir pre-injection. The injection gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Gas is injected for 30 years at a rate of 1,036.73 tonnes per day (378,399 tonnes per year or 11,351,970 total tonnes) followed by a 5-year rest period. Permeability curves for the multiphase gas/water system are defined for three (3) material ranges with a residual liquid saturation between 40% and 65%. An estimated maximum BHP of 9,730 psig, based on the calculated fracture pressure gradient, was imposed on the Independence AGI #1 to ensure safe injection operations. This pressure was important for Independence AGI #1 in the model scenario where all TAG was injected into Independence AGI #1, but otherwise simulations showed pressure at the Independence AGI Wells remaining below this threshold. In all simulations where West Jal Deep B injected 30,000 bpd of brine into the reservoir, the West Jal Deep B would need to decrease injectivity to remain below its permitted threshold pressure. Present modeling work does not indicate sufficient connectivity between the West Jal Deep B and the Independence AGI Wells to impact AGI injectivity under all other modeled scenarios. Figure 3.9-5 shows the calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1. AGI rates are lower than target numbers and limited data are available so a more detailed calibration cannot yet be constructed. An injection forecast model was performed for a period of thirty (30) years with injection and then a five (5) year post-injection rest period to ascertain fluid movement and pressure evolution. Figure 3.9-6 shows the injection profile for the forecasting period which showed that the target injection rate could be hit in all scenarios except Scenario 5. The model showed that all the injected gas remained in the reservoir and there was no substantive change in the size of the TAG extent compared at the end of injection and five (5) year post injection period.

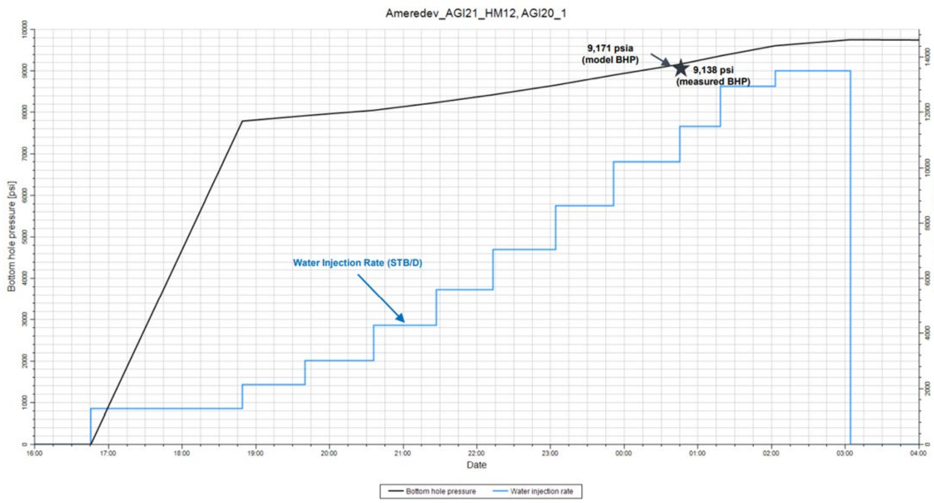


Figure 3.9-5: Graph showing calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1.

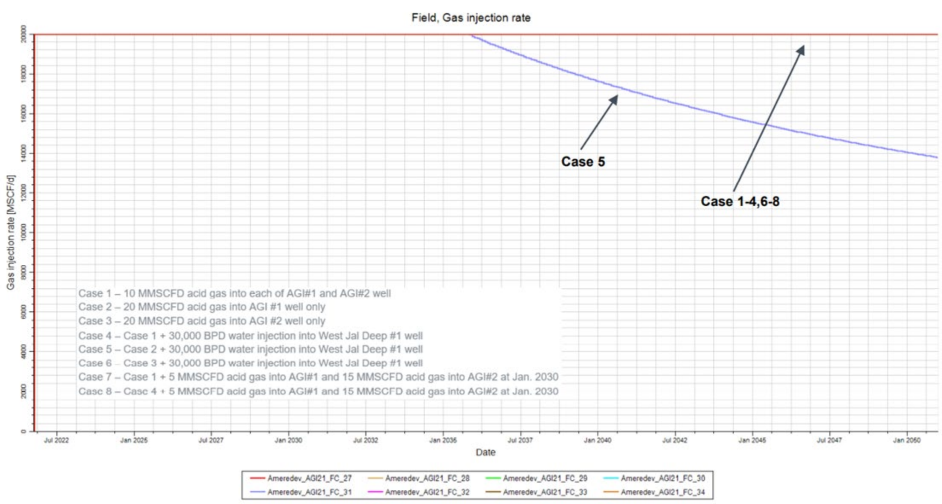


Figure 3.9-6: Graph showing the forecast profile for the injection rate and cumulative injection volume over the simulated period

A considerable source of uncertainty in the plume model relates to the injectivity of the West Jal Deep B well located about one (1) mile northeast of Independence AGI #1. This well is permitted to dispose of up to 30,000 bpd of brine into several reservoirs, including the Siluro-Devonian reservoir used by the Independence AGI Wells, and other shallower reservoirs. It is unclear from publicly available data how this fluid is planned to be partitioned between the various injection layers. As of this application, the well has a stainless steel plug at the top of the Woodford, restricting injection into the Siluro-Devonian reservoir, and no fluid is currently being injected at the well. However, since this well is permitted for injections, modeling for the present application considered two (2) end-member scenarios: (a) All West Jal Deep B injection is into shallower reservoirs and does not interact with the Siluro-Devonian one (cases 1,2,3), or (b) all West Jal Deep B volumes are injected into the Siluro-Devonian reservoir (cases 4,5,6,7,8). The brine injection at this well is significant for several reasons:

- High volumes of brine injection within the Siluro-Devonian in relatively close proximity of the Independence AGI Wells may raise pressure in the reservoir;
- Pressure from the brine injection pushes against the advancing gas front, directing flow south and west away from the well; and
- The West Jal Deep B wellbore could be a potential leakage pathway if injection ceases and the supercritical fluid plume from the Independence AGI Wells reaches it. Simulations that do not include injections at this well have the TAG plume area including this well.

In all simulations with injection at West Jal Deep B, the local pressure at the brine injection well rapidly rises to the breakover point and the injection rate begins dropping within the first two (2) years of that well's operation to maintain pressures below 80% of the breakover threshold and ensure no rock fracturing occurs (Figure 3.9-7). It is unknown how in reality this will translate to well operations within the Siluro-Devonian reservoir. Simulations do not indicate that the pressure increase from this well will adversely affect the Independence AGI Wells due to the early shut down of the brine injection well. Simulations where there is no brine injection result in the plume extending farther northeast beyond the West Jal Deep B well (Figure 3.9-8). If brine is injected, then the plume is repelled towards the south and west, with some TAG flanking the northwest fault and extending northwest (Figure 3.9-9). Simulations suggest a pressure impact on Independence AGI #1 that could result in curtailed injections under a scenario with all TAG injection in Independence AGI #1 and West Jal Deep B active (Case 5, *see* Figure 3.9.6).

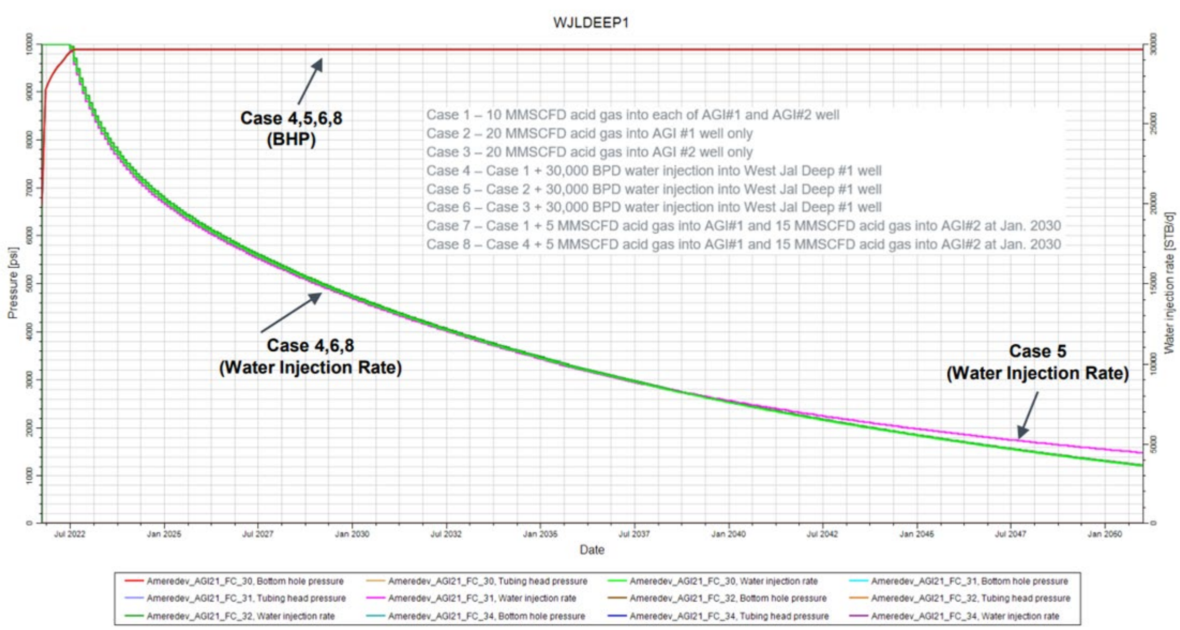
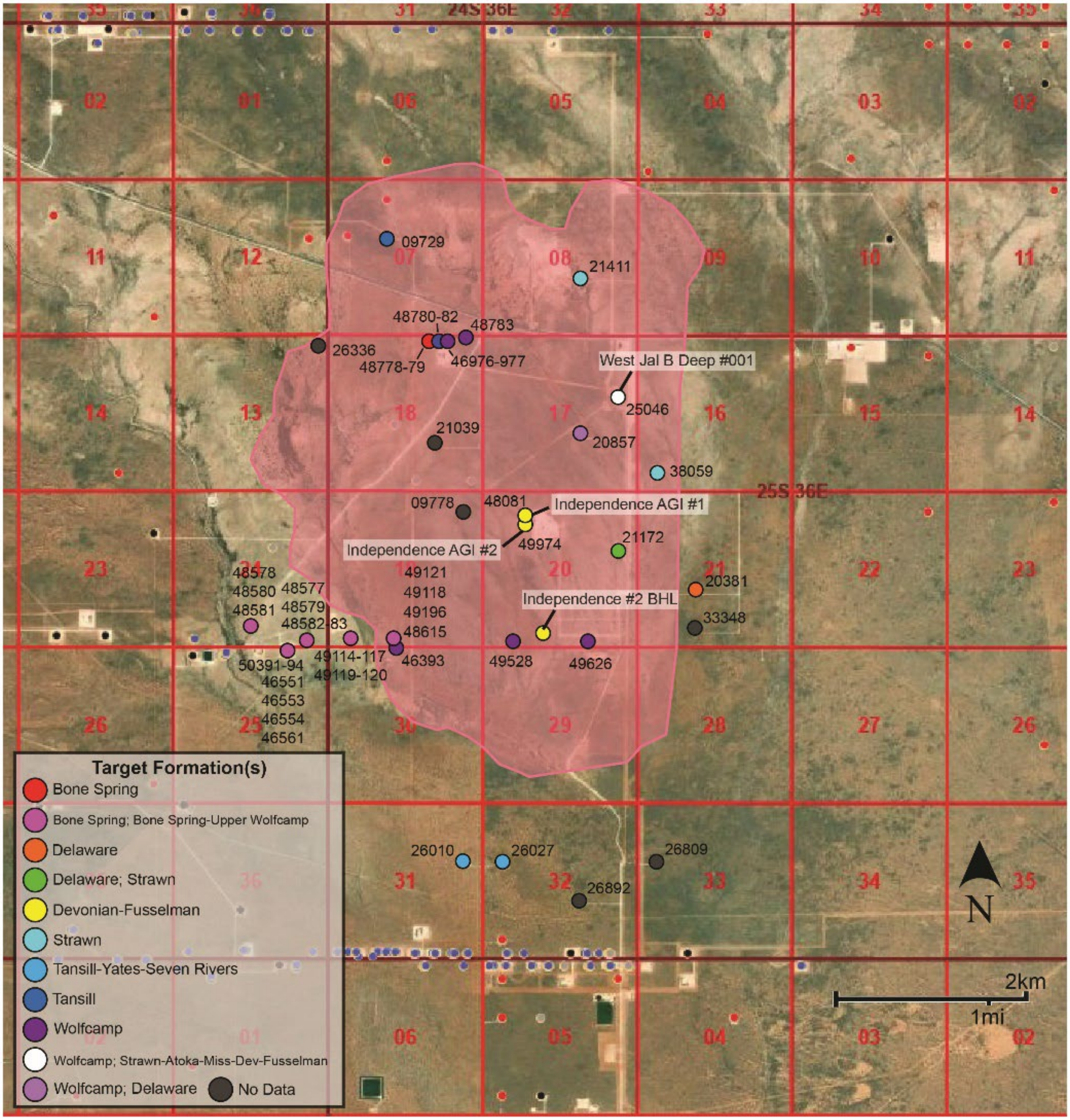
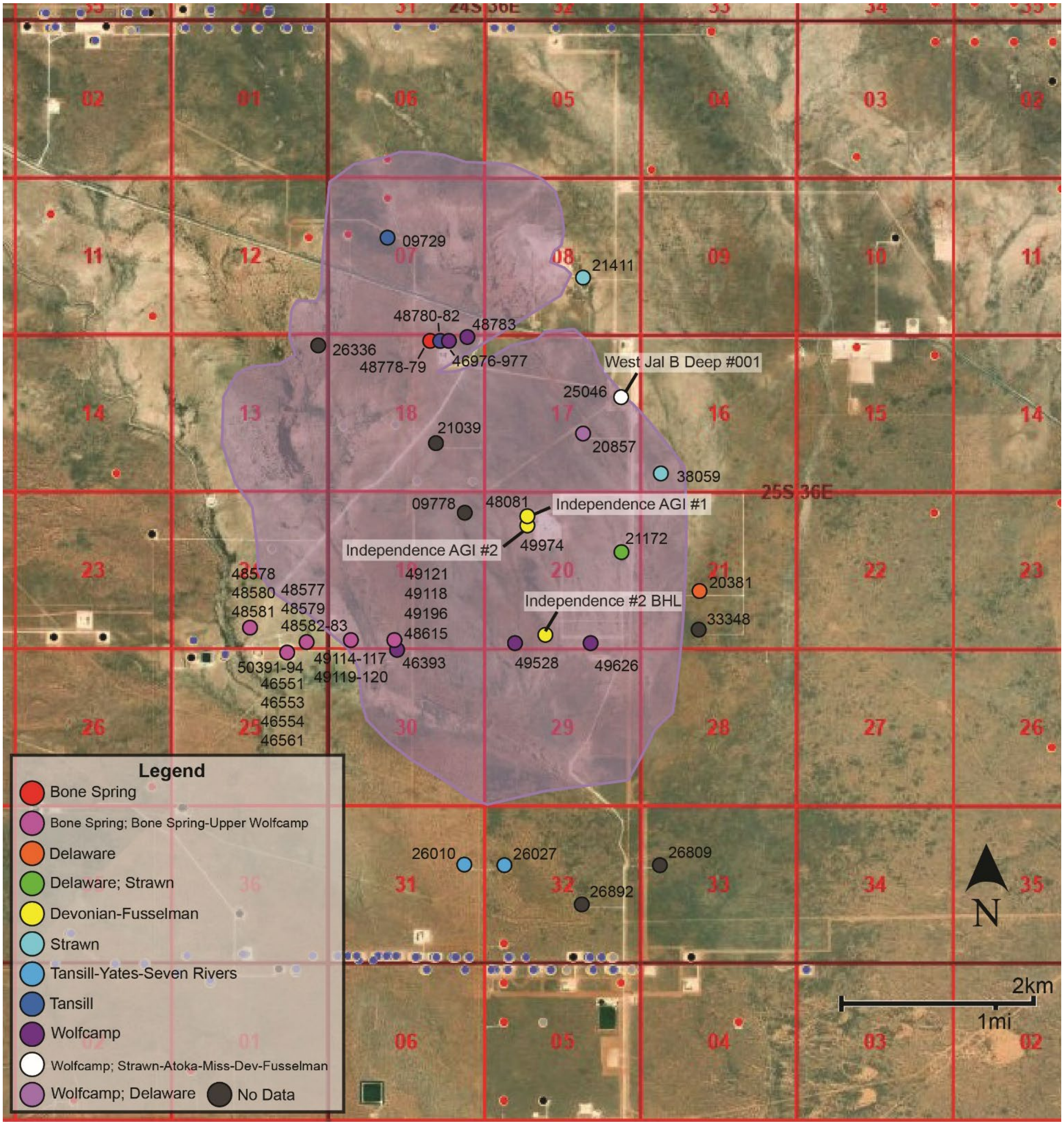


***Figure 3.9-7**: Graph showing the injection profile of the West Jal Deep B brine injection well under different injection scenarios.*



<u>Figure 3.9-8</u>: Map showing the largest lateral extent of the TAG when the West Jal Deep B well does not inject into the Siluro-Devonian. Colors indicate target formations for the well. West Jal Deep B is the white dot northeast of the Independence AGI Wells. *Not shown: The* ***BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.***



<u>Figure 3.9-9</u>: Map showing the largest lateral extent of the TAG when the West Jal Deep B well injects an initial rate of 30,000 bpd of brine into the Siluro-Devonian. Colors indicate target formations for the well. *Not shown: The* ***BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.***

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 3.9.

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 (Figure 4.1-1). In general, the western margins of the plume retract to the east following the injection period as gas flows up-dip. In this case, the farthest plume extent and hence the MMA margin is therefore found at year 30 (year t). To the east, fault trapping and the anticline near the injection site generally prevent major movement eastward. In all cases, the plume margin polygon in Figure 4.1-1 is defined by the maximum extent of any plume in any scenario at any simulation time, with a 0.5 mile buffer extending beyond this polygon defining the margin of the MMA.

4.2 AMA – Active Monitoring Area

Piñon intends to define the AMA as the same area as the MMA. Per 40 CFR 98.449, AMA is defined as the area that will be monitored over a specific time interval from the first year of the period (n = 2023) to the last year in the period (t = 2053, a 30-year injection period). The boundary of the AMA 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 (2058, or year 35 of the simulation). The zone shown in Figure 4.1-1 has a one-half mile buffer beyond the maximum plume extent of any scenario. Piñon intends to define the AMA as the entirety of the MMA.

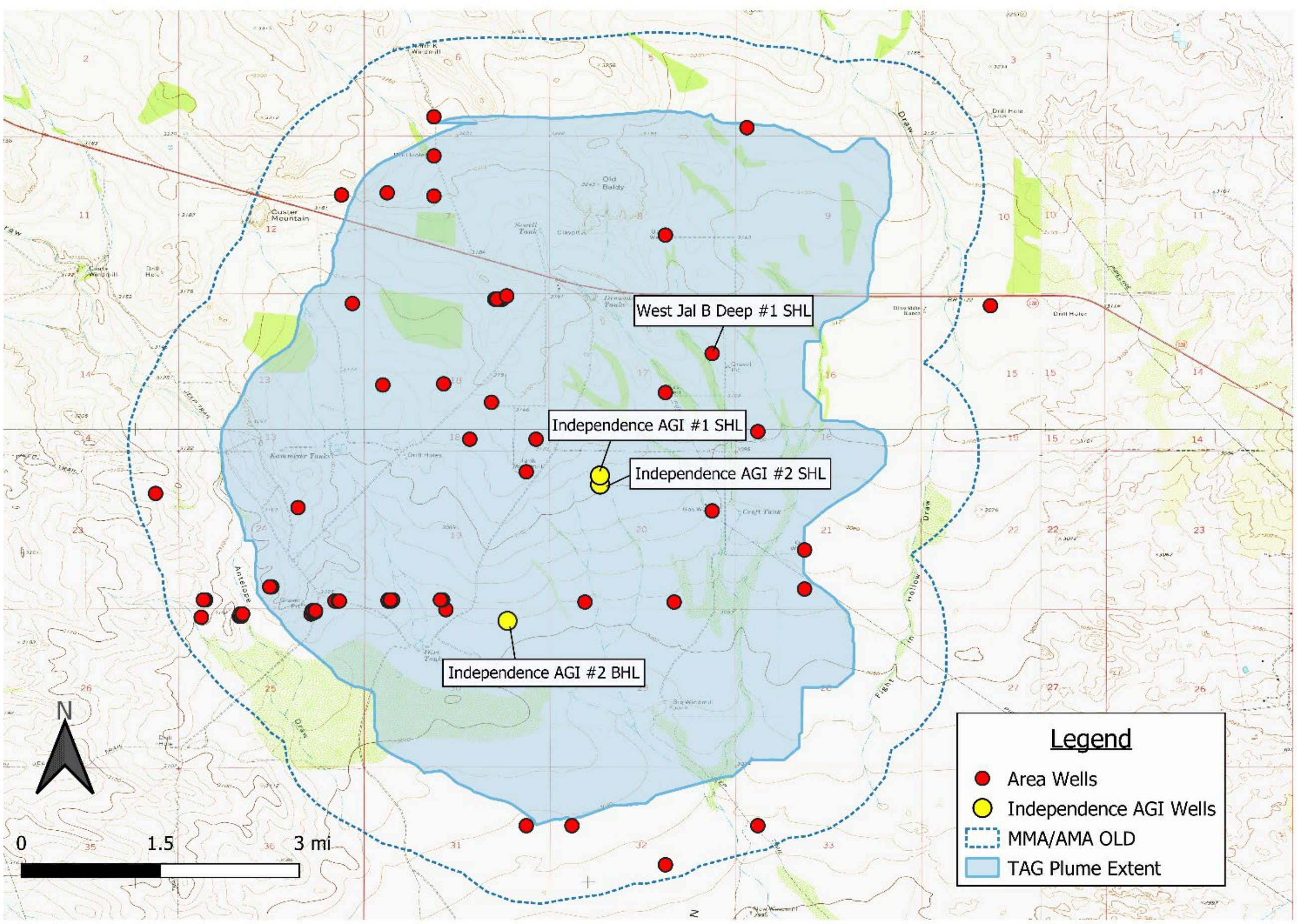


Figure 4.1-1: MMA and AMA for the Independence AGI Wells. The plume extents are shown at year 35 (t+= 2058), or 5 years beyond injection time. The plume largely stabilizes by this time, with continued minor migration updip to the northeast which is constrained by faults offsetting permeable layers. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.

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 and the reservoir modeling described in Section 3.9, Piñon 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 treating facilities. To minimize this potential for leakage, the construction, operation, and maintenance of sour gas treating facilities 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, Piñon 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, Piñon implements several methods for detecting gas leaks at the surface. These methods are described in more detail in Sections 6 and 7. Detection is followed up by immediate response.

5.2 Potential Leakage from Existing Wells

As shown in Figure 3.7-1 and detailed in Appendix 3, there are several existing oil and natural gas-related wells within a two (2) mile radius around the Independence AGI Wells (Figure 4.1-1). The deep wells discussed in Section 3.7.1 (*see* Table 3.7-1) also lie within the MMA/AMA. They are discussed below.

Independence AGI #1 has an open hole interval between 16,122 and 17,709 feet with more than 300 feet of Woodford Shale immediately above (*see* Figure A1-1). Independence AGI #2, which has recently been drilled, has a proposed open hole interval between 16,080 and 17,683 feet (*see* Figure A1-2). The combined depth to the Siluro-Devonian Injection Zone, cement program for both wells illustrated in Figures A1-1 and 2, existence of suitable confining layers above the Siluro-Devonian Injection Zone described in Section 3, and continuous monitoring of well operational parameters indicates that leakage of CO_2 to the surface via the Independence AGI Wells themselves is unlikely.

The West Jal B Deep Well No. 1 (API 30-025-25046) brine injection well is located one (1) mile northeast of the surface hole locations of the Independence AGI Wells. Additional details for this well are presented in Section 3.7.1. The wellbore currently has two CIBPs at measured depths of 14,200 feet (lower Atoka Formation) and 17,100 feet (Fusselman Formation). These CIBPs restrict access to any existing reservoirs located below the lower Atoka Formation, including within the Mississippian Lime (14,544 feet), Devonian (15,380 feet), and the Fusselman (16,404 feet), and injections in this wellbore to-date have been up-section of the relevant area. In the event of incomplete plugging of the borehole or leakage through the well casing, the shallower reservoir is at higher pressure than the Siluro-Devonian reservoir, and consequently it is assessed that downward flow of fluid would repel the TAG plume from the AGI wells. Nevertheless, the potential for CO2 leakage to the surface through this well is considered possible, albeit unlikely, and monitoring for this possibility is described in Section 6.2.2.

The West Jal Unit #1 well (API 30-025-21172) was plugged and abandoned in April 1984. The plugging documents presented in Appendix 9 indicate that the well is properly plugged through the Siluro-Devonian Injection Zone. Therefore, Piñon has concluded that this well is not a potential leakage pathway for CO_2 leakage to the surface.

5.3 Potential Leakage through Fractures and Faults

Faults and fractures were discussed in Section 3.2.3 and the potential for induced seismicity was discussed in Section 3.5. The reservoir characterization modeling (Section 3.9) and the delineation of the monitoring areas (Section 4) show that the TAG plume reaches the faults shown in Figure 3.5-1 during the thirty (30) year injection period and the five (5) year post injection monitoring period. Vertical permeability may be present parallel to the plane of the fault vertically, especially where the two main faults intersect. A review of available drilling fluid records was conducted to evaluate regional reservoir pressure conditions in the Delaware basin. Above the Siluro-Devonian injection reservoir, mud weights utilized range from 12.1 to 15.1 pounds per gallon, while for the injection reservoir less dense fluids were used (average of 9.0 pounds per gallon). These support the interpretation that the overlying productive zones in this area are overpressured with respect to the target reservoir, which would produce a downward gradient through any fault-parallel permeability. The pressure differential between the overlying interval and target interval will act as a barrier preventing vertical migration even along localized open conduits. Therefore, Piñon concludes that the potential for CO_2 leakage to the surface through this potential leakage path is unlikely.

5.4 Potential Leakage through the Confining / Seal System

The subsurface lithologic characterization presented in Section 3.2.2 describes the thick sequence of Mississippian through Permian strata overlying the Siluro-Devonian Injection Zone and reveals the existence of several excellent confining zone layers.

Therefore, it is unlikely that TAG injected into the Siluro-Devonian Injection Zone 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. Section 6.3 describes operational monitoring in place to prevent CO_2 leakage from the Independence AGI Wells.

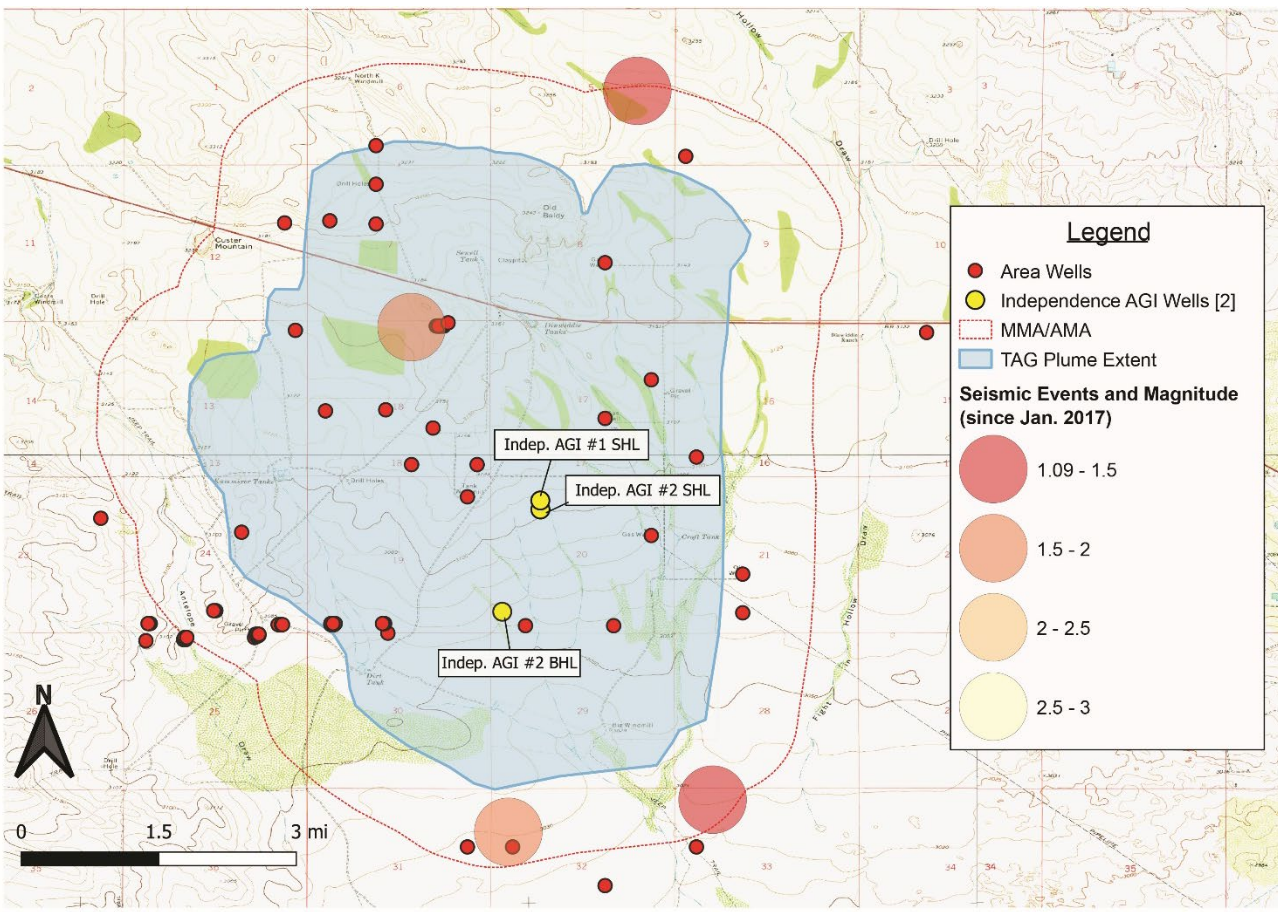
5.5 Potential Leakage due to Natural / Induced Seismicity

The potential for leaks initiated by induced seismicity was addressed in Section 3.5. It was concluded that generally, faults considered in this assessment do not display significant potential for injection-induced slip and the Independence AGI #2 is not predicted by the FSP model to contribute significantly to the total resultant pressure front. Piñon concludes that the likelihood for the creation and/or opening of vertical conduits for CO_2 leakage to the surface due to induced seismicity is low. In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage. Nevertheless, the NMOCC Order requires Piñon to install, operate, and monitor for the life of the project a seismic monitoring station or stations described in more detail in Section 7.6.

According to data obtained from the New Mexico Tech Seismic Observatory (2023), there have been four (4) seismic events within the MMA since January 12, 2017 (Figure 5.6-1). These seismic events range in magnitude of 1.16-1.88 and occurred between September 2020 and October 2021 (Table 5.6-1). The New

Mexico Tech database applied a model for epicenter location that was not capable of determining focal depth. Revisions to this database are planned for late 2023 but have not been released at the time of this writing. Hence, earthquake depths are unknown, but accounting for the lack of local development in the Devonian strata, and the greater development at shallower depths, it is believed these earthquakes occurred in a shallower reservoir. Data queries with the USGS Earthquake Catalog did not show any seismic activity within the MMA (USGS Earthquake Hazards Program, 2023).

As noted in Section 3.5, the results of the fault slip potential model indicate no likelihood of slip on the fault east of the Independence AGI Wells. The maximum segment slip potential was determined at 0.05 northwest of the injection wells, with AGI injections causing no increase in probability. Any slip would depend on the injection volumes of brine disposal wells (at present there is no brine injection in the target area). Should fault slip occur, the short lengths of the potentially slipping segment likely preclude large earthquakes, and seismicity would be expected to be <2.5 in magnitude. Any earthquakes at or above this value would be carefully evaluated to determine location, depth, and sense of motion. Remote gas observation sweeps will be conducted above or as close to the mobile fault segment as possible at 10, 30, 100, and 365 days following the event to determine if leakage is occurring. The rate of gas leakage will likely depend on the time required to saturate the fracture network created by the seismic event and the timeline of this process is expected to be on order 10 to 100 days after the fracture network is exposed to gas (Hyman et al. 2019).



<u>Figure 5.6-1</u>: Map showing seismic event locations within the MMA for the Independence AGI wells. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.

Date+Time(UTC)	Latitude	Longitude	Magnitude
2021-10-30 07:14:26.600	32.093	-103.275	1.16
2021-10-11 12:19:51.300	32.09	-103.294	1.88
2021-09-09 08:23:05.600	32.137	-103.303	1.74
2020-10-03 03:51:12.600	32.159	-103.282	1.47

***Table 5.6-1*: Table showing the locations, dates and times, and magnitudes of seismic events within the MMA for the Independence AGI wells.**

5.6 Potential Leakage due to Lateral Migration

Lateral migration of the injected TAG was addressed in the simulation modeling detailed in Section 3.9. The results of that modeling indicate the TAG is unlikely to migrate laterally beyond approximately 2.5 miles within the Siluro-Devonian Injection Zone to encounter any conduits to the surface.

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. Piñon 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. Piñon considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ 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 five (5) year post-injection period.

If CO_2 surface emissions are indicted by any of the monitoring methods listed in Table 6.1, Piñon 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.

***Table 6.1* – Summary of Leak Detection Monitoring**

Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system ("DCS") surveillance of facility operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/H_2S and low explosive level ("LEL") monitoring network • Personal and hand-held gas monitors
Independence AGI #1 & Independence AGI #2	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests ("MIT") • Fixed in-field gas monitors/H_2S and LEL monitoring network • Personal and hand-held gas monitors
Existing Other Operator Active Wells	• Monitoring of well operating parameters • Visual inspections • MITs • Mobile CO_2 detectors

Leakage Pathway	Detection Monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network • Mobile CO_2 detectors
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network

6.1 Leakage from Surface Equipment

Piñon 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 Piñon using in-field monitors which detect H_2S. 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. Additionally, Piñon field personnel, wearing personal H_2S monitors, follow daily and weekly inspection protocols which include reporting and responding to any detected leakage events.

Piñon's internal operational documents and protocols detail the steps to be taken to verify leaks of H_2S. The following description of the gas detection equipment at the Dark Horse Facility was summarized from the H_2S Contingency Plan:

Fixed Monitors

The Dark Horse Facility has numerous ambient H_2S detectors placed strategically throughout the facility to detect possible leaks. Upon detection of H_2S concentrations of 10 ppm at any detector, visible beacons are activated and an alarm is sounded. Upon detection of H_2S concentrations of 90 ppm at any detector, an evacuation alarm is sounded throughout the Dark Horse Facility at which time all personnel will proceed immediately to a designated evacuation area. The Dark Horse Facility 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 ("**PLC**"), and then to the DCS. The monitors are equipped with amber beacons. The beacon is activated upon detection of H_2S concentrations of 10 ppm. The Dark Horse Facility horns are activated with a continuous warbling alarm upon detection of H_2S concentrations of 10 ppm and a facility-wide siren upon detection of H_2S concentrations of 90 ppm. All monitoring equipment is Rosemount brand. The control panel is a twenty-four (24) channel monitor box, and the fixed point H_2S sensor heads are model number ST320A-100-ASSY.

The Dark Horse Facility will monitor the inlet sour natural gas steam and sweet natural gas stream concentrations of H_2S via H_2S analyzers with sample points located on the north/south-oriented pipe rack (Figure 7.2-1). Concentrations of H_2S in the TAG stream will be sampled near the AGI pumps located on the west side of the Dark Horse Facility. All H_2S analyzers are model T224, manufactured by Analytical Systems KECO.

The monitors can also be viewed on the PLC displays located at the Dark Horse Facility and the locations of ambient H_2S sensors are shown on the plot plan (*see* Figure 7.2-1). Immediate action is required for any alarm occurrence or malfunction. All H_2S sensors are calibrated monthly.

Personal and Handheld H_2S Monitors
All personnel working at the Dark Horse Facility wear personal H_2S monitors, which are required to alarm and vibrate upon detection of H_2S concentrations of 10 ppm. Handheld gas detection monitors are available at strategic locations around the Dark Horse Facility so that facility 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.

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 10.1.5. Furthermore, if CO_2 emissions are detected through any of the surveillance methods described above, Piñon will quantify the amount of CO_2 released based on operating conditions at the time of detection.

6.2 Leakage from Existing Wells

6.2.1 Independence AGI #1

As part of ongoing operations, Piñon continuously monitors and collects flow, pressure, temperature, and gas composition data. This data is monitored continuously by qualified technicians who follow response and reporting protocols when the monitoring system delivers alerts that data is not within acceptable limits. Mechanical integrity tests (MIT) are performed annually. Failure of an MIT would indicate a leak in the well and result in immediate action by shutting in the well, assessing the MIT failure, and implementing mitigative steps.

If operating parameter monitoring and MIT failures indicate a CO_2 leak has occurred, Piñon will take actions to quantify the leak based on operating conditions at the time of the detection.

6.2.2 West Jal B Deep Well No. 1

Piñon will annually employ mobile CO_2 detectors, which may include drone mounted sensors, to monitor for any CO_2 emission at the location of the West Jal B Deep Well No. 1. If surface CO_2 leakage is correlated with loss through this well, Piñon will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, which may include shutting in the Independence AGI well(s).

6.3 Leakage from Fractures and Faults

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through faults. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone.

Piñon will assess any changes in operating parameters which might indicate surface leakage of CO_2 along faults or fractures. Piñon will employ mobile CO_2 detectors, which may include drone mounted sensors, to monitor for any emission above mapped fractures and faults. If surface leakage is correlated with loss through fractures or faults, Piñon will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, which may include shutting in the well(s).

6.4 Leakage through the Confining / Seal System

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.2 and 7.5, will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone.

If changes in operating parameters indicate surface leakage of CO_2 through the confining / seal system, Piñon will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, which may include shutting in the Independence AGI well(s).

6.5 Leakage due to Natural / Induced Seismicity

Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.2 and 7.5 coupled with a detection of a seismic event by the seismic stations described in Section 7.6 will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone due to a seismic event.

After a seismic event, Piñon will assess any changes in operating parameters and data from the surrounding seismic stations which might indicate leakage of CO_2 along faults or fractures activated by the event. If leakage is correlated with a seismic event, Piñon will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, which may include shutting in the well(s).

6.6 Leakage due to Lateral Migration

Continuous operational monitoring of the Independence 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 Siluro-Devonian 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 Siluro-Devonian Injection Zone.

If monitoring of operational parameters indicates that the CO_2 plume extends beyond the area modeled in Section 3.9 and presented in Section 4, Piñon will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 release to the surface. If it is determined that the plume intersected a pathway for CO_2 release to the surface, this would be considered a material change per 40 CFR 98.448(d)(1), and Piñon will submit a revised MRV plan as required by 40 CFR 98.448(d).

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

Subpart RR at 40 CFR 448(a)(4) requires a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. Piñon 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 Piñon's strategy for collecting baseline information.

7.1 Visual Inspection

. Piñon field personnel conduct daily visual inspections of surface equipment located at the Dark Horse Facility and the Independence AGI Wells. These visual inspections will aid in identifying and timely addressing potential areas of concern to minimize the possibility of H_2S, a proxy for CO_2, leakage. If any leakage is identified during such visual inspections, Piñon field personnel will take prompt corrective actions to address such leakage.

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

Compositional analysis of gas injectate at the Dark Horse Facility indicates an approximate H_2S concentration of 38.7% thus requiring Piñon to develop and maintain an H_2S Contingency Plan according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). Piñon considers H_2S to be a proxy for CO_2 leaks at the Dark Horse Facility. The H_2S Contingency Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the Dark Horse Facility or the associated Independence AGI Wells and documents procedures that would be followed in case of such an event.

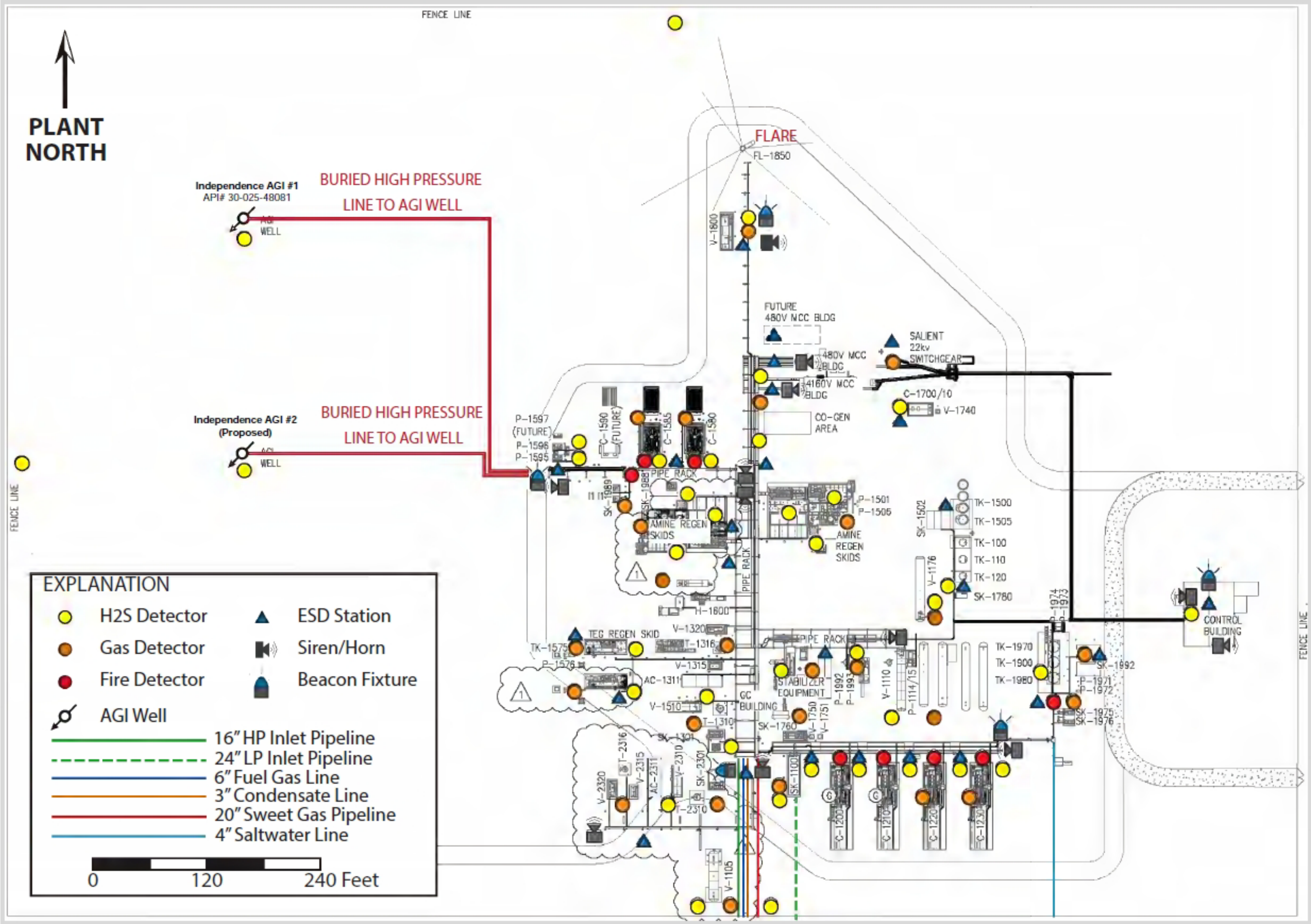
7.2.1 Fixed In-Field H_2S Monitors

The Dark Horse Facility utilizes numerous fixed-point monitors, strategically located throughout the facility, to detect the presence of H_2S in ambient air (Figure 7.2-1). The diagram in Appendix 10 shows the location of the Ultrasonic inflow meters and the Coriolis meters to the Independence AGI wells. The sensors are connected to the Control Room alarm panel's PLCs, and then to the DCS. Upon detection of H_2S concentrations of 10 ppm at any monitor, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of H_2S concentrations of 90 ppm at any monitor, an evacuation alarm is sounded throughout the Dark Horse Facility 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 Dark Horse Facility so that facility 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 Oxide ("**CO**").

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the Dark Horse Facility 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 upon detection of H_2S concentrations of 10 ppm.



<u>Figure 7.2-1</u>: Detailed Dark Horse Facility schematic illustrating the location of major process units, all emergency equipment, H_2S and gas detection sensors, sirens and beacons, and major gas flow lines at the facility (Taken from Figure 2 of the H_2S Contingency Plan for Dark Horse Gas Treatment Facility, Geolex, Inc.). The yellow circles indicate the location of fixed H_2S sensors.

7.3 CO_2 Detection

Any CO_2 release to the surface would be accompanied by H_2S and therefore the H_2S monitors will serve as a CO_2 release warning system both at the facility and in the field. In addition to the fixed and personal monitors described in Section 7, Piñon will establish and operate a monitoring program to detect H_2S leakages within the AMA. The scope of work will include H_2S monitoring at the AGI well site and atmospheric monitoring near identified penetrations of the Siluro-Devonian Injection Zone within the AMA. Upon approval of the MRV Plan and for the five (5) year post-injection period, Piñon will have these monitoring processes and systems in place.

7.4 Continuous Parameter Monitoring

The DCS of the Dark Horse Facility 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

Piñon 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. Piñon's Routine Operations and Maintenance Procedures for the Independence AGI Wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic Monitoring Stations

Piñon owns 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 Dark Horse Facility. The seismic station will meet the requirements of the NMOCC Order to "install, operate, and monitor for the life of this Order a seismic monitoring station or stations. OCD shall be responsible for coordinating with the Manager of the New Mexico Tech Seismological Observatory at the New Mexico Bureau of Geology and Mineral Resources for appropriate specifications for the equipment and the required reporting procedure for the monitoring data."

Additionally, Figure 7-1 shows the location of other seismic monitoring stations in the vicinity of the Independence AGI Wells.

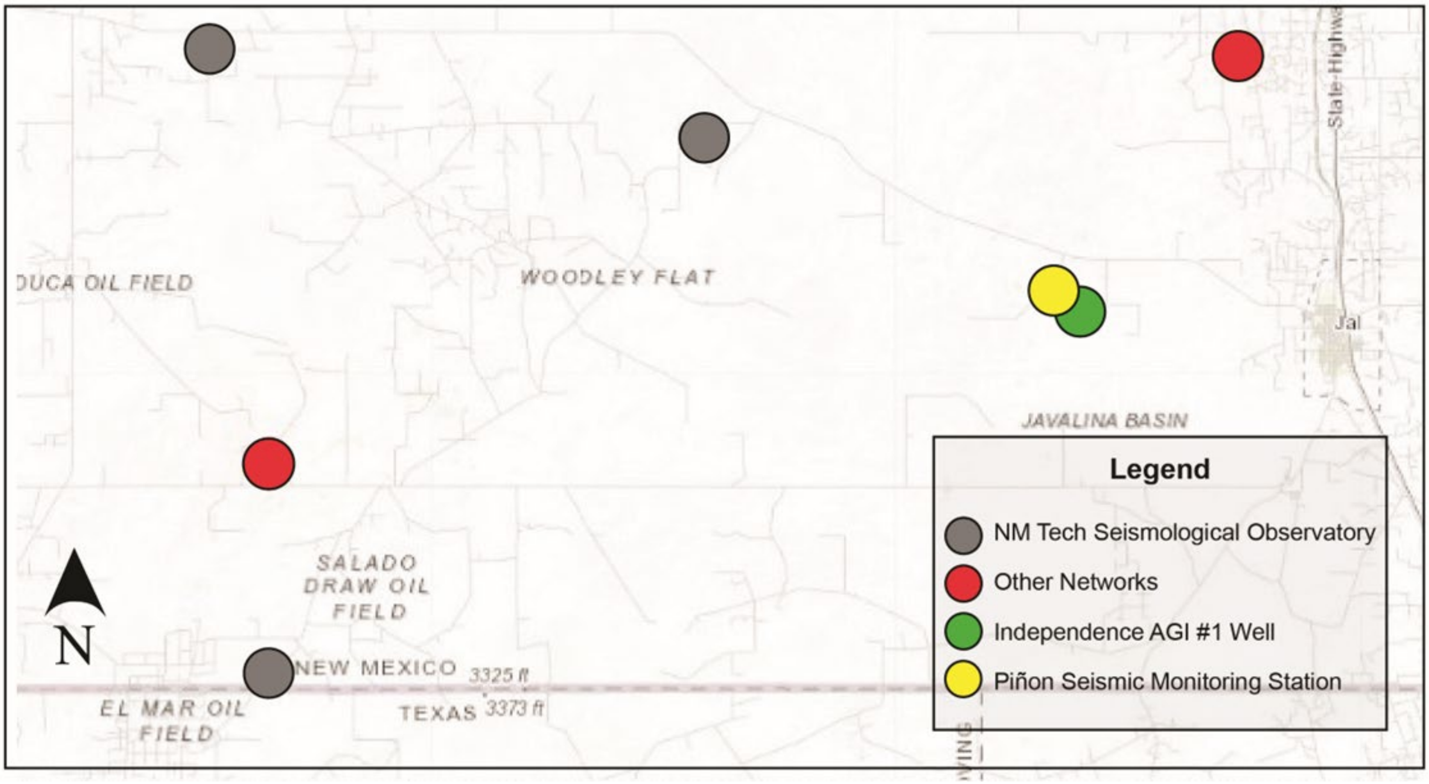


***Figure 7-1**: Location of seismic monitoring stations in the vicinity of the Independence AGI Wells.*

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve (12) Subpart RR equations used to calculate the mass of CO_2 sequestered annually. Appendix 8 includes the twelve (12) equations from Subpart RR. Not all of these equations apply to Piñon's current operations at the Dark Horse Facility but are included in the event Piñon's operations change in such a way that their use is required.

8.1 CO_2 Received

Currently, Piñon receives sour natural gas at the Dark Horse Facility through three (3) pipelines: the Hondo High Pressure Sour Gas Pipeline (owned and operated by Piñon), the Franklin Mountain Low Pressure Pipeline (owned and operated by Franklin Mountain Energy) and the Ameredev II Low Pressure Pipeline (owned and operated by Ameredev). Piñon 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 Piñon does not currently receive CO_2 in containers for injection, they have chosen to include the flexibility in this MRV Plan to do so. If Piñon begins to receive CO_2 in containers, they will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. Piñon will adhere to the requirements in 40 CFR 98.444(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 40 CFR 98.488(d)(1), Piñon will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Piñon injects CO_2 into the existing Independence AGI #1. Upon its completion, Piñon will commence injection of CO_2 into Independence AGI #2. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the Independence AGI Wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the Independence AGI Wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12.

8.3 CO_2 Produced / Recycled

Piñon does not produce oil or natural gas or any other liquid at the Dark Horse Facility so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Surface leakage of CO_2 will not be measured directly, rather it will be determined by employing the CO_2 proxy detection system described in Section 7.3. The monitoring methods described in Section 7 would indicate the occurrence of gas leakage at the surface. The mass of CO_2 emitted would be calculated 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. Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage (CO_{2E}) from the leakage pathways identified and evaluated in Section 5. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.5 below.

8.5 CO_2 Sequestered

Since Piñon does not actively produce oil or natural gas or any other fluid at the Dark Horse Facility, 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, Piñon 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

Piñon intends to implement this MRV Plan on June 1, 2023, after it is approved by EPA.

10 GHG Monitoring and Quality Assurance Program

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

10.1 GHG Monitoring

As required by 40 CFR 98.3(g)(5)(i), Piñon'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 greenhouse gas ("**GHG**") calculations; and
- 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

<u>Measurement of CO_2 Concentration</u> – All measurements of CO_2 concentrations will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association ("**GPA**") standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40 CFR 98.444(a)(3).

<u>Measurement of CO_2 Volume</u> – 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 15.025 pounds per square inch absolute ("psia") (<u>Appendix 6).</u> Piñon utilizes Coriolis metering to measure the dense phase injected TAG stream. Piñon utilizes the following two standards: American Petroleum Institute API 14.1 for measuring barrels and the American Gas Association AGA 7 for million cubic feet ("MCF") equivalent calculations.

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 <u>Section 8</u> 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 Independence AGI Wells using accepted flow calculations for CO_2 according to the [AGA Report #3].

10.1.4 CO_2 produced.

Piñon does not produce CO_2 at the Dark Horse Facility.

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

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

10.1.6 Measurement devices.

As required by 40 CFR 98.444(e), Piñon 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 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute, the AGA, the GPA, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.
- All flow meter calibrations performed are National Institute of Standards and Technology ("**NIST**") traceable.

10.2 QA/QC Procedures

Piñon 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

Piñon will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or using a representative concentration value from the 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

Piñon will revise the MRV Plan as needed to (a) reflect changes in monitoring instrumentation and quality assurance procedures; (b) improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or (c) address additional requirements as directed by the EPA or the State of New Mexico.

11 Records Retention

Piñon will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, Piñon will retain the following documents:

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

(b) 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

(c) The annual GHG reports.

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

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

(f) 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.

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

(h) 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.

(i) 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.

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

(k) 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.

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

13 Appendices

Appendix 1 - Independence AGI Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Independence AGI #1	30-025-48081	SHL 829' FNL, 1,443' FEL BHL of Sidetrack: 1041'FNL, 1785'FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120855 and -103.291021	Lea, NM	12/27/2020	17,750'	16,114'
Independence AGI #2	30-025-49974	SHL 1,180' FNL, 1,578' FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120020 and -103.291015 BHL 1,033' FSL, 2,132' FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.111581 and -103.289273	Lea, NM	Not Drilled Yet	17,683' TVD	approx. 16,000'

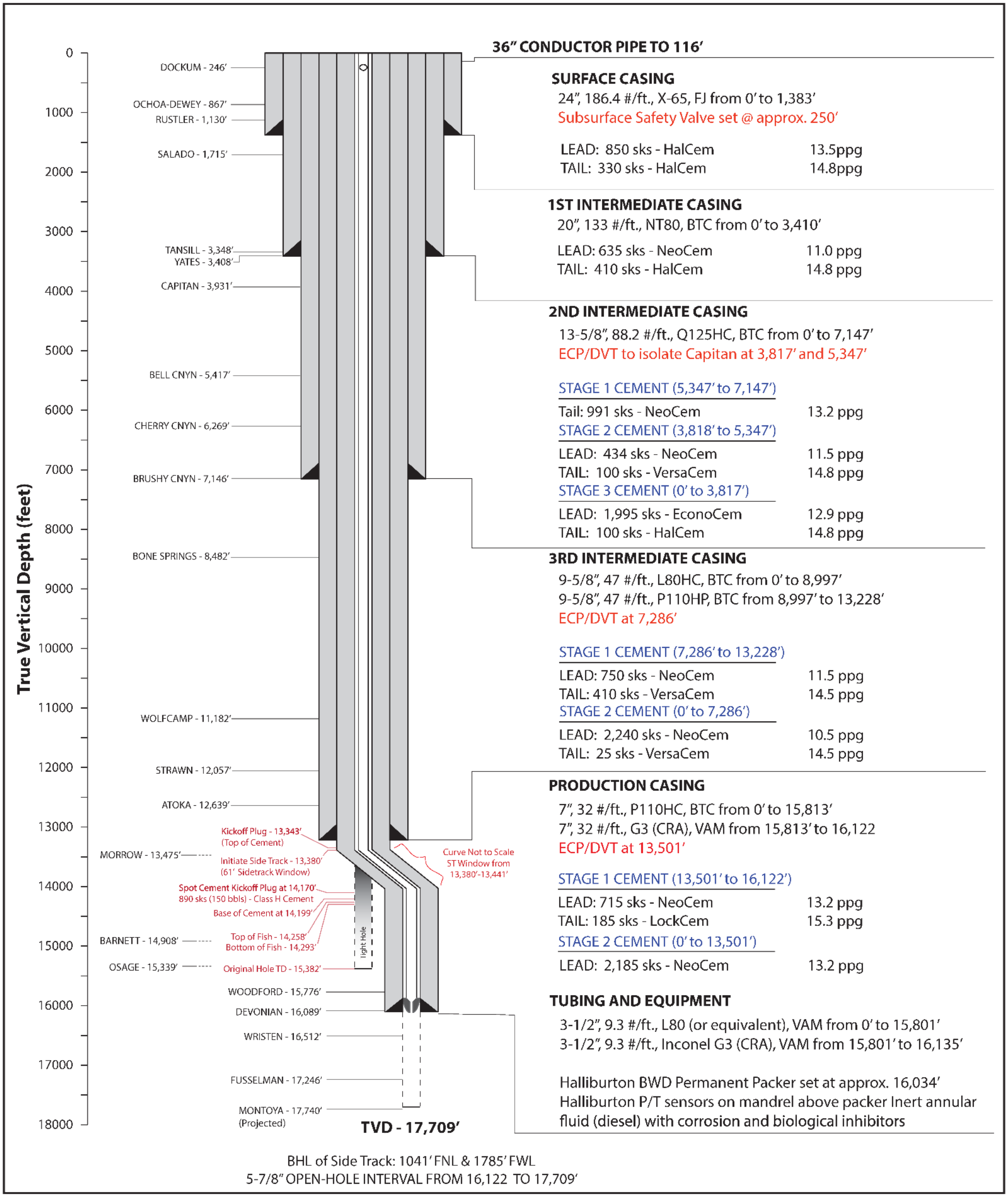


***Figure A1-1**: Independence AGI #1: As-drilled well schematic consisting of a surface string of casing, three (3) intermediate strings , and a production string with associating tubing/equipment and cement types. Original hole and sidetrack are shown. (Taken from End-of-Well Report for Independence AGI #1, Geolex, Inc.)*

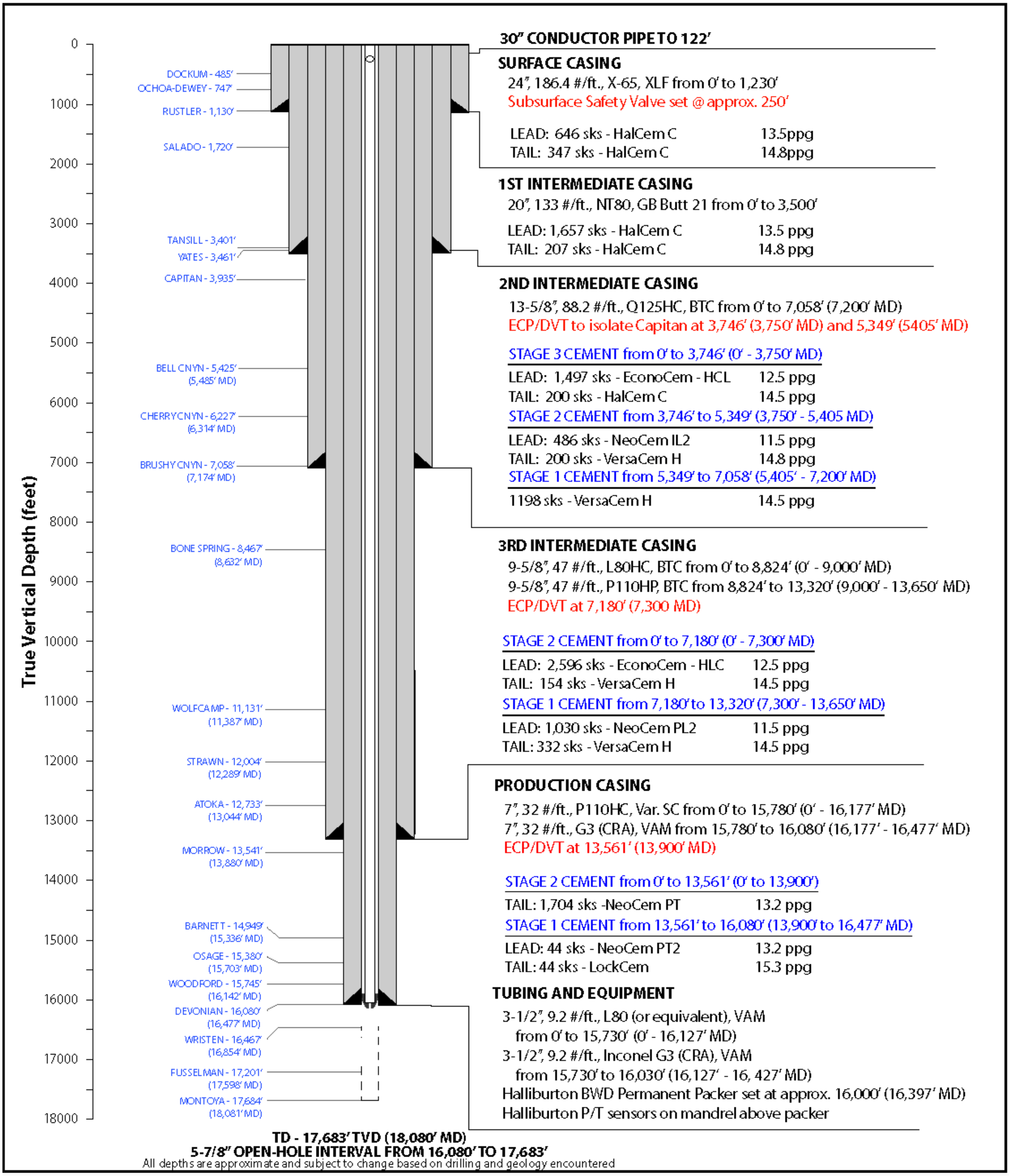


***Figure A1-2**: Independence AGI #2: Well schematic. (Taken from NMOCC Order 3/31/2022)*

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 - Oil and natural gas wells within 2-mile radius of the Independence AGI Wells

The data in the following table was obtained from the NMOCD database and is accurate as of 8/5/2022.

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-09729	PAN AM KELLY 7 FEDER	Oil	Plugged (site released)	JOHN H TRIGG	32.1466	-103.3063		1900	3,540	0	-	1/1/1900	CUSTER, TANSILL
30-025-09778	FEDERAL #1	Oil	Plugged (site released)	EDWARD C. DONAHUE	32.1212	-103.2978	No Data	1900	3,891	0	-	1/1/1900	No Data
30-025-20381	HERKIMER BQF FEDERAL #001H	Oil	Active	AMEREDEV OPERATING, LLC	32.114	-103.2722	H	1963	8,515	10,121	10,100	-	DELAWARE, WEST
30-025-20857	WEST JAL B #001	Brine Injection	New	BC & D OPERATING INC.	32.1285	-103.2850	V	1964	12,275	12,275	6,170	-	WOLFCAMP, WEST; DELAWARE
30-025-21039	WEST JAL 18 #1	Oil	Plugged (site released)	SKELLY OIL CO.	32.1276	-103.3010	No Data	1900	12,950	0	-	1/1/1900	No Data
30-025-21172	WEST JAL UNIT #1	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.1176	-103.2807	V	1961	17,086	17,086	-	4/4/1984	DELAWARE, WEST; JAL, STRAWN, WEST
30-025-21411	C ELLIOTT FEDERAL	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.143	-103.2850	V	1900	12,276	12,276	-	6/26/1993	STRAWN, WEST
30-025-25046	WEST JAL B DEEP #001	Brine Injection	Active	BC & D OPERATING INC.	32.1321	-103.2807	V	1975	18,945	18,945	14,175	-	STRAWN, WEST; WOLFCAMP, WEST; FUSSELMAN, WEST; ST-AT-MISS-DEV-FUS
30-025-26010	SPOTTED TAIL FED. #1	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2978	No Data	1900	3,336	0	-	1/1/1900	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26027	SITTING BULL A #001	Oil	Active	FULFER OIL & CATTLE LLC	32.0886	-103.2936	V	1978	3,368	3,368	-	-	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26336	FEDERAL 13 A #1	OIL	Plugged (site released)	GETTY OIL CO.	32.1367	-103.3138	V	1979	3,686	0	-	-	No Data
30-025-26809	LITTLE HAWK FEDERAL #	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2765	No Data	1900	3,690	0	-	1/1/1900	No Data
30-025-26892	SITTING BULL #2	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.085	-103.2850	No Data	1900	3,746	0	-	1/1/1900	No Data
30-025-33348	TEXACO WEST JAL 21 #001	Oil	Plugged (site released)	ENSERCH EXPLORATION INC.	32.1104	-103.2722	V	1996	7,700	7,700	-	4/25/1996	No Data
30-025-38059	DINWIDDIE STATE COM #001	Gas	Plugged (site released)	COG OPERATING LLC	32.1249	-103.2765	V	2006	12,192	12,192	-	12/12/2008	STRAWN, WEST
30-025-46393	NANDINA 25 36 31 FEDERAL COM #124H	Oil	New	AMEREDEV OPERATING, LLC	32.1085	-103.3052	H	-	0	23,130	-	-	WOLFCAMP, WEST
30-025-46533	SIOUX 25 36 STATE FEDERAL COM #008H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2019	12,149	22,150	22,117	-	UPPER WOLFCAMP
30-025-46551	SIOUX 25 36 STATE FEDERAL COM #009H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3175	H	2020	11,894	21,945	21,912	-	BONE SPRING
30-025-46553	SIOUX 25 36 STATE FEDERAL COM #012H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3174	H	2020	11,994	22,350	22,319	-	BONE SPRING; UPPER WOLFCAMP
30-025-46554	SIOUX 25 36 STATE FEDERAL COM #013H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2020	11,725	21,962	21,930	-	BONE SPRING; UPPER WOLFCAMP
30-025-46561	SIOUX 25 36 STATE FEDERAL COM #010H	Oil	Active	CAZA OPERATING, LLC	32.1081	-103.3176	H	2020	12,107	22,209	22,175	-	UPPER WOLFCAMP
30-025-46976	BLACK MARLIN FEDERAL COM #204H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3002	H	2020	11,640	21,953	21,895	-	WOLFCAMP, WEST
30-025-46977	BLACK MARLIN FEDERAL COM #214H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3000	H	2020	11,741	22,055	21,994	-	WOLFCAMP, WEST
30-025-48081	INDEPENDENCE AGI #001	AGI	Active	Piñon Midstream, LLC	32.1208	-103.2910	V	2020	17,709	17,900	-	-	DEVONIAN-FUSSELMAN
30-025-48577	SANTA FE FEDERAL COM #603H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3154	H	-	0	21,874	-	-	BONE SPRING
30-025-48578	SANTA FE FEDERAL COM #704H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3212	H	-	0	22,063	-	-	WOLFCAMP, WEST
30-025-48579	SANTA FE FEDERAL COM #705H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3152	H	-	0	22,129	-	-	WOLFCAMP, WEST
30-025-48580	TRINITY FEDERAL #602H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3214	H	-	0	21,938	-	-	BONE SPRING
30-025-48581	TRINITY FEDERAL #703H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3213	H	-	0	22,206	-	-	WOLFCAMP, WEST
30-025-48582	ZIA FEDERAL COM #604H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3151	H	-	0	21,973	-	-	BONE SPRING
30-025-48583	ZIA FEDERAL COM #706H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3150	H	-	0	21,973	-	-	WOLFCAMP, WEST
30-025-48614	BLUE MARLIN STATE #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3102	H	-	0	19,502	-	-	WOLFCAMP, WEST
30-025-48615	BLUE MARLIN STATE #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	-	0	19,350	-	-	WOLFCAMP, WEST
30-025-48778	BLACK MARLIN FEDERAL COM #113H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3007	H	-	0	20,014	-	-	BONE SPRING
30-025-48779	BLACK MARLIN FEDERAL COM #114H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3006	H	-	0	20,056	-	-	BONE SPRING
30-025-48780	BLACK MARLIN FEDERAL COM #203H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3005	H	2021	11,786	21,842	21,879	-	WOLFCAMP, WEST
30-025-48781	BLACK MARLIN FEDERAL COM #206H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3003	H	-	0	21,981	-	-	WOLFCAMP, WEST
30-025-48782	BLACK MARLIN FEDERAL COM #213H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3004	H	2021	0	22,140	22,073	-	WOLFCAMP, WEST

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-48783	BLACK MARLIN FEDERAL COM #216H	Oil	New	TAP ROCK OPERATING, LLC	32.1374	-103.2996	H	2021	0	22,258	22,258	-	WOLFCAMP, WEST
30-025-49115	BLUE MARLIN FEDERAL COM #111H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3105	H	-	0	20,039	0	-	BONE SPRING
30-025-49116	BLUE MARLIN FEDERAL COM #112H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3105	H	-	0	20,217	0	-	BONE SPRING
30-025-49117	BLUE MARLIN FEDERAL COM #201H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3102	H	2021	11,613	21,985	21,923	-	WOLFCAMP, WEST
30-025-49118	BLUE MARLIN FEDERAL COM #202H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	2021	11,539	21,929	21,866	-	WOLFCAMP, WEST
30-025-49119	BLUE MARLIN FEDERAL COM #205H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3101	H	2021	11,533	21,980	21,916	-	WOLFCAMP, WEST
30-025-49120	BLUE MARLIN FEDERAL COM #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3103	H	2021	12,148	22,554	22,495	-	WOLFCAMP, WEST
30-025-49121	BLUE MARLIN FEDERAL COM #215H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3057	H	2021	11,720	22,188	22,120	-	WOLFCAMP, WEST
30-025-49196	BLUE MARLIN FEDERAL COM #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3055	H	2021	12,003	22,422	22,389	-	WOLFCAMP, WEST
30-025-49528	DOGWOOD 25 36 20 FEDERAL COM #112H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2924	H	2021	0	22,356	0	-	WOLFCAMP, WEST
30-025-49626	DOGWOOD 25 36 20 FEDERAL COM #116H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2842	H	-	0	22,080	0	-	WOLFCAMP, WEST
30-025-49974	INDEPENDENCE AGI #002	AGI	New	Pinon Midstream, LLC	32.1201	-103.2910	D	2022	17,683	18,080	0	-	DEVONIAN-FUSSELMAN
30-025-50391	SIOUX 25 36 STATE FEDERAL COM #020H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	22,710	0	-	UPPER WOLFCAMP
30-025-50392	SIOUX 25 36 STATE FEDERAL COM #021H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	20,244	0	-	BONE SPRING
30-025-50393	SIOUX 25 36 STATE FEDERAL COM #022H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	22,539	0	-	UPPER WOLFCAMP
30-025-50394	SIOUX 25 36 STATE FEDERAL COM #023H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	20,120	0	-	BONE SPRING

Appendix 4 - References

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Appendix 5 - Abbreviations and Acronyms

Abbreviations and acronyms not otherwise defined herein:

3D – 3 dimensional
API – American Petroleum Institute
CFR – Code of Federal Regulations
EOS – Equation of State
ft – foot (feet)
m – meter(s)
mg/l – milligrams per liter
MT -- Metric tonne
NG—Natural Gas
QA/QC – quality assurance/quality control
ST – Short Ton

Appendix 6 - Conversion Factors

Piñon reports CO_2 at standard conditions of temperature and pressure as defined in the State of New Mexico - 60°F and 15.025 psia (NMAC 19.15.2.7 (C)(16))

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the NIST. This online database is available at:

http://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner EOS at a wide range of temperatures and pressures.

At State of New Mexico standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.0027097 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb-moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2} = 0.0027097$$

$$MW_{CO2} = 44.0095$$

$$Density_{CO2} = 5.4092\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.4092\ x\ 10^{-2}\ \frac{MT}{Mcf}$$

The conversion factor 5.4092 x 10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Appendix 7 - Independence 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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \qquad \text{(Equation RR-2 for Pipelines)}$$

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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \qquad \text{(Equation RR-2 for Containers)}$$

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

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \qquad \text{(Equation RR-3 for Pipelines)}$$

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

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \qquad \text{(Equation RR-4)}$$

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

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \qquad \text{(Equation RR-5)}$$

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

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \qquad \text{(Equation RR-6)}$$

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

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

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.

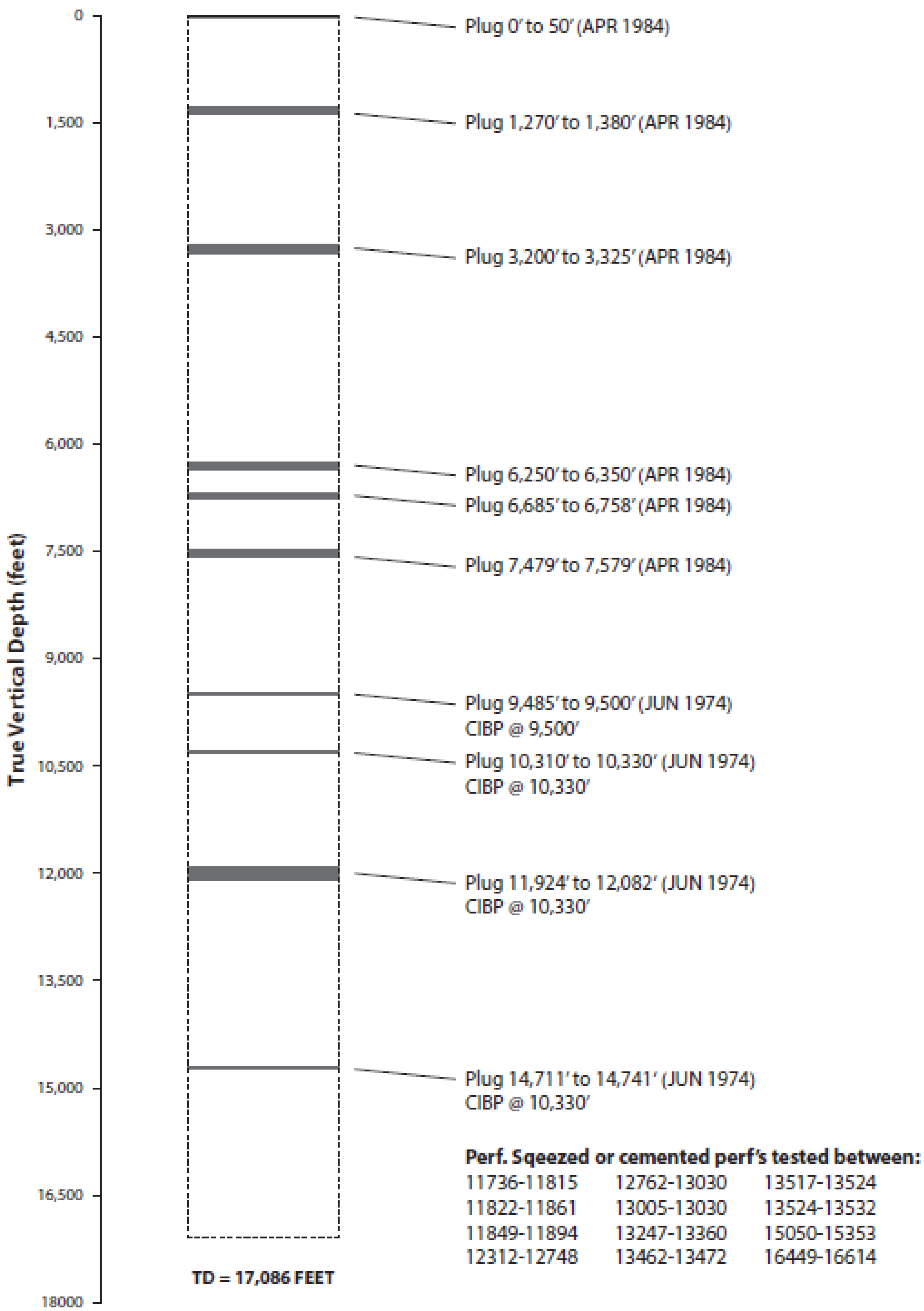
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

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 - Plugging Records for West Jal Unit #1

TEXACO EXPLORATION AND PROD. - WEST JAL UNIT #1 PLUGGING DIAGRAM

Lease Name:	West Jal Unit #1	**Footage:**	1980 FNL and 660 FEL
API:	30-025-21172	**Well Type:**	Oil
Location:	Sec. 20, T25S, R36E	**Total Depth:**	17,086′
County, State:	Lea County, New Mexico	**Coordinates:**	32.117596, -103.280739 (NAD83)



*Schematic is properly scaled

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P. 0. BOX 1980
HOBBS. NEW MEXICO 88

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dune f'kJOI

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Buluu No. 1004-0135
Expires: March 31, 1993

5. Lease Designation and Serial No.
NM

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT-" for such proposals

SUBMIT IN TRIPLICATE

7. If Unit or CA, Agreement Designation

1. Type of Well
[X] Oil Well [ ] Gas Well [X] Other Reentry

8. Well Name and No.
JA-/t:Jt!JLA-fry

2. Name of Operator
MCH Petroleum Services

9. API Well No.
30-025-21112

3. Address and Telephone No.
-:1:)1 W. Pliv St. Midland, Tx 79705 915 683 4772

10. Field and Pool, or Exploratory Area
~~Undesignated~~ W-Sal Delaware

4. Location of Well (footage, Sec., T., R., M., or Survey Description)
/'f4!o PA/- ,o F=GI- -S Z.0, r- ZS-S, 11- "1+'=
H S£NE .6J•1)1 h\.

11. County or Parish, State
Lea, NM

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

TYPE OF SUBMISSION	TYPE OF ACTION	
[g] Notice of Intent	D Abandonment	O Change of Plans
	Recompletion	D New Construction
[J Subsequent Report	D Plugging Back	O Non-Routine Fracturing
	D Casing Repair	[ ] Water Shut-Off
[ ] Final Abandonment Notice	D Altering Casing	D Conversion to Injection
	Other eNtAy	D Dispose Water
		(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abandoned by Texaco in 1983. MCH will drill out cement plugs and cibp@ 7,579' to a total depth of approx. 8,350'(in-s;ide casing). This will leave in place cibp at 9,500' and deeper. We will then test E!Xisting perforations@ 7,807'-7,857' and stimulate as necessary.
Mud Program: Fresh water will be used for the reentry inside casing.
BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO
GENERAL REQUIREMENTS AND
SPECIAL STIPULATIONS
ATTACHED

14. I hereby certify that the foregoing is true and correct

Signed Craig Huber Title Owner Date 4/13/93

(This space for Federal or State office use)

Approved by "' 1ITC &r.n L MA ron; Title AR-A MANAG. Date JUN 4 1993
Conditions of approval, if any:

Title 18 U.S.C. Section 1001, makes 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.

*See Instruction on Reverse Side

G 31

Form 3160-3
(December 1990)

SUBMIT IN TRI[illegible]TE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 1004–0136
Expires: December 31, 1991

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR DEEPEN

1a. TYPE OF WORK: DRILL ☐ DEEPEN ☐

b. TYPE OF WELL: OIL WELL ☒ GAS WELL ☐ OTHER Reentry SINGLE ZONE ☒ MULTIPLE ZONE ☐

2. NAME OF OPERATOR: MCH Petroleum Services

3. ADDRESS AND TELEPHONE NO.: 708 W. Pine St, Midland, Tx 79705 915 683 4772

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*)
At surface: 1980' FNL, 660' FEL Sec 20 T-25S, R-36E Lea Co. NM
At proposed prod. zone: SAme

14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE*: 6 miles W. JAl, N.M.

15. DISTANCE FROM PROPOSED* LOCATION TO NEAREST PROPERTY OR LEASE LINE, FT. (Also to nearest drlg. unit line, if any): 660'

16. NO. OF ACRES IN LEASE: 600

17. NO. OF ACRES ASSIGNED TO THIS WELL: 40

18. DISTANCE FROM PROPOSED LOCATION* TO NEAREST WELL, DRILLING, COMPLETED, OR APPLIED FOR, ON THIS LEASE, FT.:

19. PROPOSED DEPTH: 8350

20. ROTARY OR CABLE TOOLS: Pulling unit/Reverse unit

21. ELEVATIONS (Show whether DF, RT, GR, etc.): 3076' GL

22. APPROX. DATE WORK WILL START*: ASAP (Prior to 6/1/93 exp.)

5. LEASE DESIGNATION AND SERIAL NO.: NM 71792

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

7. UNIT AGREEMENT NAME:

8. FARM OR LEASE NAME, WELL NO.: West JAl Federal #1

9. API WELL NO.: 30-025-21172

10. FIELD AND POOL, OR WILDCAT: ~~[illegible]~~ W. Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: H SENE S-20, T-25S, R36E

12. COUNTY OR PARISH: Lea

13. STATE: NM

23. PROPOSED CASING AND CEMENTING PROGRAM

SIZE OF HOLE	GRADE, SIZE OF CASING	WEIGHT PER FOOT	SETTING DEPTH	QUANTITY OF CEMENT
26	20		869' (In Place)	1630 sx.
17½	13 3/8	72, 68, 64	6300' (In Place)	3606 sx.
12¼	9 5/8	53.5, 47, 43.5	11,736 (in place)	775 sx.
8¾	7	26	6735-12213 (Shot off @ 6735)	612 sx
6¼	5½ (LNR.)	(unk.)	12,032-15,400	450 sx.
(unk)	3½ (LNR.)	(unk)	14,967-17,084	250 sx.

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abondoned by Texaco in 1983. MCH will drill out cement plugs and cibp @ 7,579' to a total depth of approx. 8,350' (inside casing). This will leave in place cibp at 9,500' and deeper. We will then test existing perforations @ 7,807'-7,857' and stimulate as necessary.

Mud Program: Fresh water will be used for the reentry inside casing.

BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO GENERAL REQUIREMENTS AND SPECIAL STIPULATIONS ATTACHED

IN ABOVE SPACE DESCRIBE PROPOSED PROGRAM: If proposal is to deepen, give data on present productive zone and proposed new productive zone. If proposal is to drill or deepen directionally, give pertinent data on subsurface locations and measured and true vertical depths. Give blowout preventer program, if any.

24.

SIGNED Craig Huben TITLE Owner DATE 4/13/93

(This space for Federal or State office use)

PERMIT NO. ______ APPROVAL DATE ______

Application approval 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.
CONDITIONS OF APPROVAL, IF ANY:

APPROVED BY ______ TITLE ______ DATE ______

*See Instructions On Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

Form 3160-5
(November 1983)
(Formerly 9-331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

P. O. BOX 1980
HOBBS, NEW MEXICO 88240

Form approved.
Budget Bureau No. 1004-0135
Expires August 31, 1985

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

1. OIL WELL [X] GAS WELL [ ] OTHER

7. UNIT AGREEMENT NAME
West Jal Unit

2. NAME OF OPERATOR
Getty Oil Company

8. FARM OR LEASE NAME

3. ADDRESS OF OPERATOR
P.O. Box 730, Hobbs, NM 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
Unit Ltr. H, 1980' FNL & 660' FEL

10. FIELD AND POOL, OR WILDCAT
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, T-25S, R-36E

BUREAU OF LAND ... APR ... DIST. 6 N. M. ROSWELL, NEW MEXICO

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138' D.F.

12. COUNTY OR PARISH
Lea

13. STATE
NM

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	[ ]	PULL OR ALTER CASING	[ ]	WATER SHUT-OFF	[ ]	REPAIRING WELL	[ ]
FRACTURE TREAT	[ ]	MULTIPLE COMPLETE	[ ]	FRACTURE TREATMENT	[ ]	ALTERING CASING	[ ]
SHOOT OR ACIDIZE	[ ]	ABANDON*	[ ]	SHOOTING OR ACIDIZING	[ ]	ABANDONMENT*	XX
REPAIR WELL	[ ]	CHANGE PLANS	[ ]	(Other)			[ ]
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

3/26/84	Rigged up. Pulled rods and pump. Unseat tbg. anchor and install BOP.
3/28/84	Pulled 2 7/8" buttress & 2 3/8" tbg. anchor. Ran 7" CI plug, set @ 7579'. Ran 2 3/8' to 4290'. By Halliburton, circ. 191 bbls. gel brine, pulled tbg. Perfs 4-0.25" holes @ 6400'. Circ. out 7" between 9 5/8". Ran 2 7/8" to 7554'.
3/29/84	Rigged up csg. puller unit. Pulled tbg. Remove BOP & 7" tbg. spool.
3/30/84	Weld 7" pull nipple. Cut 7" csg. @ 6735'. Pulled 11 jts 7", 26#, P-110 csg. 8 rd.
3/31/84	Layed down total 163 jts (est. 6525') 7", 8rd casing. Nipple down 9 5/8" head.
4/2/84	Weld on 9 5/8" pulled nipple. Attempted to pull slips with 500,000#. Set off primer cord around head, no movement. Left soaking in penetrating oil.
4/3/84	Dug out 13 3/8" csg. unflange head. Move pipe 1" with 600,000#. Cut off. Pulled nipple, installed BOP. Ran tbg to 5216'.
4/4/84	Spot 20 sxs cement on top of CIBP 7579-7479'. Spot 100' plug (45 sxs) at 6758-6685', 6350-6250', 3325-3200', 1380-1270'. Remove csg. head.
4/5/84	Rigged down. Installed 20 sxs. Plugged 0-50'. Installed dry hole marker. P&A.

18. I hereby certify that the foregoing is true and correct

SIGNED Donald J. Steinmer TITLE Area Superintendent DATE April 11, 1984

for Dale R. Crockett

(This space for Federal or State office use)

Orig. Sgd. ...

APPROVED BY ... TITLE ... DATE 6/8/87

CONDITIONS OF APPROVAL, IF ANY:

0+6-BLM-Roswell — 1-Mr. J.A.-Midland
1-File — 1-Laura Richardson-Midland
1-Engr Jim — 1-BB, 1-JA
1-Foreman CK — 1-SH, 1-CP 1-Southland Royalty Company, 1-ARCO

Approved as to plugging of the well bore. Liability under bond is retained until surface restoration is completed.

*See Instructions on Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

N. M. OIL CONS. COMMISSION
P. O. BOX 1980
HOBBS, NEW MEXICO 88240

O+6 - BLM - P.O. Box 1857, Roswell, 1-File, 1-Engr.JIM, 1-Foreman CK

Form 9-331
Dec. 1973

1 - Laura Richardson-Midland

Form Approved.
Budget Bureau No. 42-R1424

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

BUREAU OF LAND MANAGEMENT
RECEIVED
JUL 25 1983
ROSWELL, NEW MEXICO

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 Form 9-331-C for such proposals.)

1. oil well XX gas well ☐ other

DIST. 6 N. M.

2. NAME OF OPERATOR
Getty Oil Company

3. ADDRESS OF OPERATOR
P.O. Box 730 Hobbs, NM 88240

4. LOCATION OF WELL (REPORT LOCATION CLEARLY. See space 17 below.)
AT SURFACE: Unit ltr. H, 1980' FNL & 660 FEL
AT TOP PROD. INTERVAL:
AT TOTAL DEPTH:

5. LEASE
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME
West Jal Unit

9. WELL NO.
1

10. FIELD OR WILDCAT NAME
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, 25S-36E

12. COUNTY OR PARISH
Lea

13. STATE
NM

14. API NO.

15. ELEVATIONS (SHOW DF, KDB, AND WD)
3138' D.F.

16. CHECK APPROPRIATE BOX TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

	REQUEST FOR APPROVAL TO:	SUBSEQUENT REPORT OF:
TEST WATER SHUT-OFF	☐	☐
FRACTURE TREAT	☐	☐
SHOOT OR ACIDIZE	☐	☐
REPAIR WELL	☐	☐
PULL OR ALTER CASING	☐	☐
MULTIPLE COMPLETE	☐	☐
CHANGE ZONES	☐	☐
ABANDON*	XX	☐
(other) Revised		

(NOTE: Report results of multiple completion or zone change on Form 9-330.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

Revised procedure as per conversation with Mr. Peter Chester 7/18/83:

1. Install B.O.P.
2. Set C.I.B.P. at +7860 w/35' cement on top.
3. Perforate 2 holes @ 6375' & squeeze with sufficient cement to bring cement to 6225'.
4. Set cement plug 1230-1330' top of salt. (in & behind casings).
5. Set 50' surface plug.
6. Install dry hole marker.
7. Restore location.

Subsurface Safety Valve: Manu. and Type ______ Set @ ______ Ft.

18. I hereby certify that the foregoing is true and correct

SIGNED Dale R. Crockett TITLE Area Superintendent DATE July 22, 1983

(This space for Federal or State office use)

APPROVED

APPROVED BY (Orig. Sgd.) ... M. CHESTER TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

SEP 14 1983

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG *

1a. TYPE OF WELL: OIL WELL [X] GAS WELL [ ] DRY [ ] Other

b. TYPE OF COMPLETION: NEW WELL [ ] WORK OVER [ ] DEEP-EN [ ] PLUG BACK [X] DIFF. RESVR. [X] Other

2. NAME OF OPERATOR
Skelly Oil Company

3. ADDRESS OF OPERATOR
P. O. Box 1351, Midland, Texas 79701

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface Unit Letter H, 1980' FNL and 660' FEL, Sec. 20-25S-36E
At top prod. interval reported below
At total depth

14. PERMIT NO. | DATE ISSUED

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- - - - - -

7. UNIT AGREEMENT NAME
- - - - - -

8. FARM OR LEASE NAME
West Jal Unit

9. WELL NO.
1

10. FIELD AND POOL, OR WILDCAT
UNDESIGNATED
Jal Delaware, West

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA
Sec. 20-25S-36E

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
- -	- -	5-28-74	3138' DF	- - -

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
17086'	9485' PBTD	- -	→	- -	- -

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*
7807-7857' Delaware

25. WAS DIRECTIONAL SURVEY MADE
- - -

26. TYPE ELECTRIC AND OTHER LOGS RUN
None

27. WAS WELL CORED
- -

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
No Change					

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
-	-	-	-	-
-	-	-	-	-

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-3/8"OD	7941'	- -
2-7/8"OD		- -

31. PERFORATION RECORD (Interval, size and number)
7807-7811', 7816-7824', 7853-7857', total 32 shots, 0.50" diameter, two shots per foot.

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
7807-7857'	750 gallons mud acid 5000 gallons 15% NE acid, 82 ball sealers, 9000# 20-40 sand, 9000 gallons lease oil

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
5-28-74	Pumping	Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
6-19-74	24	-	→	63	1	6	16

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
- -	63#	→	63	1	6	41°

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.)
Used for Fuel

TEST WITNESSED BY

35. LIST OF ATTACHMENTS
None

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED (Signed) D. R. Crow D. R. Crow TITLE Lead Clerk DATE 6-20-74

*(See Instructions and Spaces for Additional Data on Reverse Side)

INSTRUCTIONS

General: This form is designed for submitting a complete and correct well completion report and log on all types of lands and leases to either a Federal agency or a State agency, or both, pursuant to applicable Federal and/or State laws and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local, area, or regional procedures and practices, either are shown below or will be issued by, or may be obtained from, the local Federal and/or State office. See instructions on items 22 and 24, and 33, below regarding separate reports for separate completions.

If not filed prior to the time this summary record is submitted, copies of all currently available logs (drillers, geologists, sample and core analysis, all types electric, etc.), formation and pressure tests, and directional surveys, should be attached hereto, to the extent required by applicable Federal and/or State laws and regulations. All attachments should be listed on this form, see item 35.

Item 4: If there are no applicable State requirements, locations on Federal or Indian land should be described in accordance with Federal requirements. Consult local State or Federal office for specific instructions.

Item 18: Indicate which elevation is used as reference (where not otherwise shown) for depth measurements given in other spaces on this form and in any attachments.

Items 22 and 24: If this well is completed for separate production from more than one interval zone (multiple completion), so state in item 22, and in item 24 show the producing interval, or intervals, top(s), bottom(s) and name(s) (if any) for only the interval reported in item 33. Submit a separate report (page) on this form, adequately identified, for each additional interval to be separately produced, showing the additional data pertinent to such interval.

Item 29: *"Sacks Cement"*: Attached supplemental records for this well should show the details of any multiple stage cementing and the location of the cementing tool.

Item 33: Submit a separate completion report on this form for each interval to be separately produced. (See instruction for items 22 and 24 above.)

37. SUMMARY OF POROUS ZONES:
SHOW ALL IMPORTANT ZONES OF POROSITY AND CONTENTS THEREOF; CORED INTERVALS; AND ALL DRILL-STEM TESTS, INCLUDING DEPTH INTERVAL TESTED, CUSHION USED, TIME TOOL OPEN, FLOWING AND SHUT-IN PRESSURES, AND RECOVERIES

38. GEOLOGIC MARKERS

FORMATION	TOP	BOTTOM	DESCRIPTION, CONTENTS, ETC.

NAME	TOP MEAS. DEPTH	TOP TRUE VERT. DEPTH

1) Squeezed Fusselman perfs. 16,449-16,614' with 100 sacks Class "H" cement, 5/10% CFR-2.
2) Spotted 25 sacks cement 14,711-14,741', 25 sacks 11,924-12,082' and set cast iron bridge plug at 10,330' and spotted 4 sacks cement 10,310-10,330'.
3) Perforated 7" OD casing in First Bone Springs formation with two 0.48 diameter holes per foot at 10,112-10,122' and 10,128-10,132'. (28 shots total)
4) Treated First Bone Springs perfs. 10,112-10,132 with 5500 gallons acid and 68 ball sealers.
5) Swab tested First Bone Springs perfs. 10,112-10,132' May 14, 1974, to May 21, 1974, for no oil, 14 bbls. water and slight show of gas in 5 hours.
6) Set cast iron bridge plug at 9500' and cemented with 3 sacks cement plugging back to 9485'.
7) Perforated 7" OD casing in Delaware formation with two 0.50" diameter holes per foot at 7807-7811', 7816-7824' and 7853-7857'. (32 shots total)
8) Treated Delaware perfs. 7807-7857' with 750 gallons mud acid, 5000 gallons 15% NE acid, 9000 gallons gelled lease oil, 9000# 20-40 sand and 22 ball sealers.
9) Returned well to production status 5-28-74 pumping Delaware perfs. 7807-7857' for 63 bbls. oil, 6 bbls. water and 1 MCFGPD.

West Jal Unit
Well No. 1
Lea Co., New Mexico

8) Flowed 24-1/2 hours through 1" choke, making no oil, 45 bbls. load water, 393 bbls. formation water and gas at rate of 266 MCF per day. FTP 200#, CP 2300#.
9) Ran flow meter, Gradionometer and Temperature Survey to determine water entry.
10) Shut well in seven hours, then ran Base Temperature Log 16,000-17,020'. Water channelling from bottom of well bore to 16,508'.
11) Set cement retainer at 16,250' and squeezed perfs. 16,499-16,614' with 150 sacks Class "H" cement containing 4/10ths of 1% CFR-2 and 1% Halad 9. Squeeze failed. WOC 4 hours.
12) Resqueezed perfs. 16,449-16,614' with 50 sacks Class "H" cement with 1% Halad 9, 4/10ths of 1% CFR-2 and 1/4# Flocele per sack and 150 sacks Class "H" containing 1% Halad 9 and 4/10ths of 1% CFR-2. Squeeze failed.
13) Attempted to pull cement retainer - stuck.
14) Milled and pushed cement retainer from 16,250' to 16,490'. Recovered cement retainer.
15) Drilled and pushed junk to 16,930'.
16) Ran 254 jts. (14,793') of 2-7/8" OD tubing and set packer at 14,810'. Swabbed 9 hours, recovering 60 bbls. load water with good show of gas.
17) Treated perfs. 16,449-16,614' with 500 gals. 15% NE acid with 2 ball sealers. Swabbed 7 hours, recovering 1 bbl. load water, flowing gas at rate of 50 MCF per day.
18) Treated perfs. 16,449-16,614' with 5000 gals. 15% NE acid and 27 ball sealers.
19) Ran Temperature Survey 15,000-16,958'.
20) Tested well. Well flowed at rate of 910 MCF per day on 23/64" choke, no oil, FTP 310#. Pulled tubing and packer.
21) Reran 457 jts. (14,940') of 2-7/8" OD 7.9# DSS-HT Atlas-Bradford Condition "A" tubing and set at 14,967'.
22) Circulated hole with corrosion inhibitor water. Released rig 11-8-72. Flowed and tested well.
23) On Dec. 11, 1972, treated perfs 16,449-16,614' with 12,500 gals. of 1% KCL water with 62# friction reducer, 25 gals. Adofoam and 25 gals. scale inhibitor, 20,000 gals. 20% retarded acid with 100# friction reducer, 40 gals. Adofoam, 160 gals. acid inhibitor, 1000# fluid loss agent and 40 gals. scale inhibitor and 7 ball sealers. All fluid contained 400 S.C.F Nitrogen per barrel.
24) Testing well.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 1351, Midland, TExas 79701

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Undesignated Fusselman

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3076' GR

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Clean out & deepen to 17,086'	x		
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

1) Rigged up rotary tools 7-28-72. Pulled tubing and packer.
2) Set cement retainer at 11,390' and squeezed Strawn 7" OD casing perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 1% CFR-2 and 3# sand per sack. Squeeze failed. WOC 4 hours.
3) Resqueezed perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 5/10% of 1% CFR-2 and 3# sand per sack. Squeezed at 6500#. Reversed out 15 sacks.
4) After WOC 12 hours, drilled cement retainer at 11,390' and cement 11,390-11,755' with 6-1/2" bit.
5) Tested squeeze job to 3000#; held okay.
6) Drilled cement 11,790-11,832' and tested old squeeze job on perfs. 11,736-11,815' to 3000#; held okay.
7) Drilled cement 11,832-11,844'; pushed plus-plug to 11,976'. Drilled plug. Tagged junk at 12,002' and pushed to 12,312'.
8) Cleaned to top of 5-1/2" OD liner at 12,032', set cement retainer at 11,820' and found casing perfs. 11,849-11,894' open.
9) Squeezed 5-1/2" casing perfs. 11,849-11,894' with 50 sacks Class "H" with 1% CFR-2 and 100 sacks Class "H" with 1% CFR-2 and 3# sand per sack.
10) Dumped 20 sacks cement on retainer at 11,820', plugging back to 11,717'. Reversed out 90 sacks cement. WOC 12 hours.

(continued on page 2)

18. I hereby certify that the foregoing is true and correct

SIGNED ______ TITLE Lead Clerk DATE Dec. 18, 1972

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______
CONDITIONS OF APPROVAL, IF ANY:

ACCEPTED FOR RECORD
DEC 20 1972
U. S. GEOLOGICAL SURVEY
HOBBS, NEW MEXICO

*See Instructions on Reverse Side

11) Drilled cement 11,708-11,820'; cement retainer 11,820-11,822' and cement 11,822-11,861'. Cleaned out to top of liner at 12,032'.
12) Tested squeeze job to 2500#; held okay.
13) Drilled junk 12,312-12,748.5'; cement 12,748.5-12,760'; junk to 12,762'; cement 12,762-13,030'.
14) Tested old squeezed perfs. 13,005-13,030' to 2500#; held okay.
15) Milled and drilled cast iron bridge plug at 13,174' and pushed to 13,395'.
16) Tested 5-1/2" OD liner perfs. 13,247-13,360' to 2900#; could not pump into perfs.
17) Milled cast iron bridge plug 13,396-13,400'.
18) Tested perfs. 13,462-13,472' to 2700#; could not pump into perfs.
19) Milled and drilled out cement retainer 13,517-13,524'; cement 13,524-13,532'; cement 15,050-15,353'.
20) Milled and drilled cast iron bridge plug 15,340-15,858'. Washed over fish 15,858'; recovered fish. Cleaned out to old TD of 15,958'.
21) Drilled 4-3/4" new hole 15,958-16,498'.
22) Ran Drill Stem Test No. 1 (Silurian) 15,400-16,498'.
23) Drilled 4-3/4" hole 16,498' to total depth of 17,086' at 11 p.m. October 4, 1972.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instruction on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429 - A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- - -

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
- - -

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Section 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3102' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐
REPAIR WELL	☐	CHANGE PLANS	☐
(Other)			

SUBSEQUENT REPORT OF:

WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
(Other) Cement, perforate & treat			☒

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

1) Perforated 2-7/8"OD tubing at 11,696',11,297', 10,374; 9698'; 8892';8707',8403'. Circulated to remove mud from annulus. Work began 1-29-69.
2) Pulled tubing
3) Ran 2-7/8"OD tubing with "RTTS" Packer. Set packer at 11,448'.
4) Squeezed 7"OD casing perforations 11,736-11,894' with 150 sacks class "H" Cement with 1% CFR-2 per sack, maximum pressure 4600#, failed. W.O.C. 4 hours. Broke formation down with 5000#.
5) Squeezed 7"OD casing perforations 11,736-11,894" with 50 sacks Class "H" cement with 1% CFR-2 and 5# No. 3 sand per sack. Displaced 35 sacks into formation. Pulled tubing and packer.
6) WOC 36 hours. Ran tubing with 6-1/8" bit. Top of cement inside 7"OD casing at 11,595'. Washed and circulated cement to 11,620'. Drilled cement 11,620-11,700'. Drilled packer 11,700-705'. Drilled cement 11,705-755'.
7) Tested casing to 3000#, held okay.
8) Spotted 12 bbls. acid 11,755-11,443'.
9) Perforated 7"OD casing with 2 shots per foot as follows:

11,510 - 513'	3'	6 shots
11,517- 527'	10'	20 shots
11,536 - 540'	4'	8 shots
11,550 - 556'	6'	12 shots
11,561 - 567'	6'	12 shots
11,575 - 579'	4'	8 shots
11,660 - 667'	7'	14 shots

18. I hereby certify that the foregoing is true and correct

SIGNED ______ TITLE District Production Manager DATE 3-10-69

(This space for Federal or State office use)

APPROVED BY ______ TITLE (ORIGINAL SIGNED) V. H. Fletcher

CONDITIONS OF APPROVAL, IF ANY:

APPROVED

MAR 11 1969

J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

2. NAME OF OPERATOR
Skelly Oil Company

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface **1980 from North line and 660 from East line, Section 20**

20-25S-36E

5. LEASE DESIGNATION AND SERIAL NO.
~~73503~~ NM-0342918

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
----

7. UNIT AGREEMENT NAME
----

8. FARM OR LEASE NAME
West Jal Unit

9. WELL NO.
1

10. FIELD AND POOL, OR WILDCAT
Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3092' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other)			☐
(Other) **Cement, Perforate & Treat**			☒	(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)			

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

Squeeze present perforated interval 11,736-11,852', below packer set at 11,700', with 125 sacks cement. Drill out to 11,790'. Perforate 11,510-11,783' with 2 shots per foot. Treat perforations 11,510-11,783' with 300 gallons 15% acid with 3 stage treatment using Dowell J-182 as diverting agent. Inject 72 barrels distillate to remove diverting agent. Swab and test.

18. I hereby certify that the foregoing is true and correct

SIGNED (signed) C. R. DAVIS TITLE **District Operations Manager** DATE **1/24/69**

(This space for Federal or State office use)

APPROVED BY ____________ TITLE ____________ DATE ____________
CONDITIONS OF APPROVAL, IF ANY:

APPROVED

JAN 2. 1969

J. L. GORDON
ACTING DISTRICT ENGINEER

KT/jc

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- -

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
- -

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*
See also space 17 below.)
At surface

1980' from North line and 660' from East line

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.
- -

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138'

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Eliminate water production			X
(Other)			☐				

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

(1) Moved in and rigged up workover rig 10-21-68
(2) Set Schlumberger "plus" plug in 7"OD casing at 11,844'.
(3) Dumped 5' cement on top of plug, filling from 11,844' to 11,839'.
(4) Dumped 200 lbs. Hydromite on top of "plus" plug, filling back to 11,832'.
(5) Swabbed well.
(6) Apparent communications still exist between upper and lower perforations behind 7"OD casing. Objective to shut off lower perforations 11,860 - 11,894' and to decrease water production unsuccessful.
(7) Well returned to producing status 10-27-68 flowing 150 MCF gas per day through 7" OD casing perforations 11,736 - 11,894'.

18. I hereby certify that the foregoing is true and correct

SIGNED [signature] TITLE District Production Manager DATE 10-30-68

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
NOV 1968
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429 - A

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—" for such proposals.)

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
-----

1. OIL WELL ☐ GAS WELL XX OTHER

7. UNIT AGREEMENT NAME
-----

2. NAME OF OPERATOR
SKELLY OIL COMPANY

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

1980' FNL & 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO.	15. ELEVATIONS (Show whether DF, RT, GR, etc.)	12. COUNTY OR PARISH	13. STATE
-----	3138' DF	Lea	New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Clean, Determine Water Source, Eliminate Water Production	X		
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

Moved in and rigged up Workover Rig. Killed well. Ran 1-5/8" drill pipe and fishing tools to top of fish at 9901', pushed to 9991', caught fish, circulated and pulled out of hole. Recovered 2 strings of fishing tools previously left in hole. Reran 1-5/8" drill pipe several times with fishing tools and recovered 1786' in several pieces of 5/16" wire line, and a chemical cutter.

Tagged bottom of 2-7/8"OD tubing at 11,715'. Knocked off one foot of tubing and a bull plug that had been previously cut off. Pushed and drove bull plug to 12,482'. Hit firm fill-up of formation cavings and left one-foot piece of 2-7/8"OD tubing and bull plug in hole at 12,482', leaving tubing open-ended at 11,715' with full 2-7/8" opening. Pulled drill pipe and fishing tools and installed Xmas tree. Ran Gradiomanometer, Continuous Flowmeter and Packer Flowmeter to determine water source. Surveys indicated water source being produced through casing perforations 11,883-11,894'.

Set packer at 11,883'. Returned to production status November 19, 1967, producing 38 bbls. oil, 800 bbls. water and 2,000 MCF gas per day from the Strawn Gas Pool through perforations 11736-11894' through 7"OD casing.

18. I hereby certify that the foregoing is true and correct

SIGNED (ORIGINAL SIGNED) V. E. Fletcher TITLE District Superintendent DATE April 25, 1968

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
APR 26 1968
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE*
(See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME
West Jal Unit

9. WELL NO.
1

10. FIELD AND POOL, OR WILDCAT
Undesignated Fusselman

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA
Sec. 20-25S-36E

12. COUNTY OR PARISH: Lea
13. STATE: New Mexico

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

1a. TYPE OF WELL: OIL WELL [ ] GAS WELL [X] DRY [ ] Other

b. TYPE OF COMPLETION: NEW WELL [ ] WORK OVER [X] DEEP-EN [X] PLUG BACK [ ] DIFF. RESVR. [X] Other

2. NAME OF OPERATOR
Skelly Oil Company

3. ADDRESS OF OPERATOR
P. O. Box 1351, Midland, Texas 79701

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface 1980' FNL and 660' FEL Sec. 20-25S-36E
At top prod. interval reported below
At total depth

14. PERMIT NO. | DATE ISSUED

15. DATE ~~SPUDDED~~ started 7-28-72
16. DATE T.D. REACHED 11-1-72
17. DATE COMPL. (Ready to prod.) 10-4-72
18. ELEVATIONS (DF, RKB, RT, GR, ETC.)* 3076' GR
19. ELEV. CASINGHEAD

20. TOTAL DEPTH, MD & TVD 17,086'
21. PLUG, BACK T.D., MD & TVD 17,020'
22. IF MULTIPLE COMPL., HOW MANY* ---
23. INTERVALS DRILLED BY → ROTARY TOOLS 15,958-17,086' CABLE TOOLS ---

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*
16,449-16,614' (Fusselman)

25. WAS DIRECTIONAL SURVEY MADE No

26. TYPE ELECTRIC AND OTHER LOGS RUN BHC Sonic Gamma Ray with Caliper, Dual Laterolog, Continuous Dipmeter, Compensated Neutron & Formation Density

27. WAS WELL CORED No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
20"	94#	869'	26"	1630 sacks	None
13-3/8"	72,61 & 68#	6300'	17-1/2"	3206 sacks	None
9-5/8"	53.5 & 47#	11,732'	12-1/4"	975 sacks	None

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
		(See attachment)		

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-7/8"	14,967'	None

31. PERFORATION RECORD (Interval, size and number)
16,449-16,614' (Fourteen .33" holes over 165' interval)

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
11,510-11,741'	200 sacks Class "H" Cement
11,849-11,894'	150 sacks Class "H" Cement
16,449-16,614'	350 sacks Class "H" Cement
	(See attachment)

33.* PRODUCTION

DATE FIRST PRODUCTION: 11-1-72
PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump): Flowing
WELL STATUS (Producing or shut-in): Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
11-14-72	24	24/64"	→	-0-	5950	216	---

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
1900#	---	→	-0-	5950	216	---

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.)
Sold

TEST WITNESSED BY

35. LIST OF ATTACHMENTS 2 copies each: Borehole Compensated Sonic Log - Gamma Ray, Compensated Neutron-Formation Density, Dual Laterolog, Gammatron

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED C.J. Love TITLE Dist. Prod. Manager DATE Dec. 20, 1972

*(See Instructions and Spaces for Additional Data on Reverse Side)

2MO1OJ3152M1

WIST JAL UNIT Sheet Ho. 2

WILL RO. !.

Set Baker Calt Iron Bridge Plug at 13,400'. Spotted 2 aacka c••nt on top of bridge plug traa 13,-00' to 1.3,386'. Perto:rated 5--1/2" OD liner with 4 holea at 13,210' and 1queezed with 85 aacka ot caat. Drill.eel out oeaeat \o 13,386'• Perforated S-1/2" liner with 4 ahota per toot •• followa1 13,247-13,2'10', 13,272-1.3,275', 13,286-13,292', 13,298-13,320', 13,326-13,329', 1.3,343-13,345', 13,)56-13,360' tor a total ot 63• and 252 hol••• Treated tbroqh S-1/2" OD caaing liner pert•• 13,247-13,360' (intenala) with 2500 gallon• Mud Acid. Teated .-.11 Hftr&I houn with -n,lae to aall to meanre. Treated through 5-1/2" OD caeing liner perta. 13,21.7-13,360' (intenala) with 2500 gallons Mud Acid.. t'eelMI •li-'.aeveral hN. with TOIUM to -11 to meaaure. Treated through S-1/2" OD casing liner pert▪• 13,247-IJ,'601 (intenala) with 10,000 galana 1,- llegular Acid. Teated well aenral houri with wl1111e to .all to m•an• Set Baker Caat Iron Model "I" Bridge Plug at 13,180'• Dmlpecl 2 eacka ot cement on top ot plug, wbieh pl11g nll b&ek tra 13,180' to 1.3,166•. Pertorat.ed 5-1/2" OD liner with bole• per toot trcxa 13,0051 to 13,030• for a total of 251 and 100 hol••• Treated thrcnlgh 5-1/2" OD liner perte. 13,00S-13,030' with S,000 gallons 15C Regular Acid. Teated well N'Yer&I hove with TOluae \oo ▪-II to aeanre. We teaJ>I'?'8,ril7 abandoned the teat.inc ot the Morrow Zone at t.hie t.m, Set Halliburton "DC" C... nt Retainer at 12,790' and aqueesed 85 eaeke ot CtlIHlt into 5-1/2" OD liner perte. 13,005-13,030•. Plugged back total depth 12,7901• Pertorat.ed 7" OD casing with 4 bolea per toot aa tollowa1 11,736-II,7U', 11,781-11,787', II,801-II,815t, II,&1+,-11,852', 11,860-U,894' tor a total ot 55t and 220 holea. Set Baker Model "?" Production Packer at 11,700'• Ran 2-7/8" OD 6.1+0# Blltre•• threat! 1-80 tubing to 11,715' and ....ted in Baker Model"'" Production Packer at 11,700' with pert▪• 11,711-II,715'. Ot.ia l.allding nipple position No. I at II,709'. Ot.1• aid• doar ahitt. valft at U,698'. otie landing nipple poaition lo. 2 at 10,700'. otil lending nipple position lo. 3 at 9700'• Opened well up and flowed to pit to clean up. Shut well in tor 89 hove. After 89 houra with dead night T.P. 6218# flowed and teated well 1n the toll.owing anner1

nowed 1-3/4 hour▪ on 10/64" choke, opening TP 6218# (W), FTP 6156pai., gas wltae 2,737 JEPPD and 7.6') 'bbl•• ot 52 degree correeted gra'Yit7 condenaate.
lu.t. two hour▪ tlowd through 12/64• ohoke, ITP 6075 pai. (17w), gas luae 4563 KCFPD .w1i and 6.60 bbla. of condenea.te.
Iut two noura fiowd throUgh 14/6'+" choke, FTP 599S pei. (DW), gae wIUM 6025 MCFPD and 1.70 bbl•• or oonden•t••
Rut one and one halt hours tLowed through 16/64" choke, PTP 5915 p▪i• (IM), gas volUM 8009 ICFPD and undetel"llined 8JI0\1llt or oonclen▪ate to pita.
Eatabliahed 24 hour In Maioo Ooneel"fttion C.-d.eaion AOF Potential ot 310,000 tcFFD. Completed Ja.,.17 22, 1963, a1 a "Wildcat" CCIIl.J)letion in strawn (Penn117I'Y8Bian) toraation, Total cond.enate ree0Ye17 during 7-1/4 hn. t.eet waa 22,80 bbls. to tank and undetermined aaomt to pita.

Well now ahut in - waiting on ga• connection.

POBMATIOI RECORD

From	To	!!!i		
0	12,058	12,0,s		
12,058	12,152	94		
12,152	12,477	32,	Lime & Shale	- Top Atoka 12,152'
12,477	13,366	889	Sand	- Top Morrow 12,477'
13,366	14,S83	1,217	$ale	- Top Barp,ett Shale IJ,366•
14,583	14,685	102	Lhle	- 'lop Miasiaaippian 14,853'
14,685	1,,138	453	Chert	- Top Che. 14)685'
15,138	15,518	380	Shale	- Top Wood.torcl IS 131
15,518	15,9S8	440	L1M & Dolaite	- Top • {'5,518'
15,9?8	I5,9SI	Total Depth		
	12,790	Plugged Back Total Depth		

Geological Tops by Schlumberger Gama Ray Sonic log

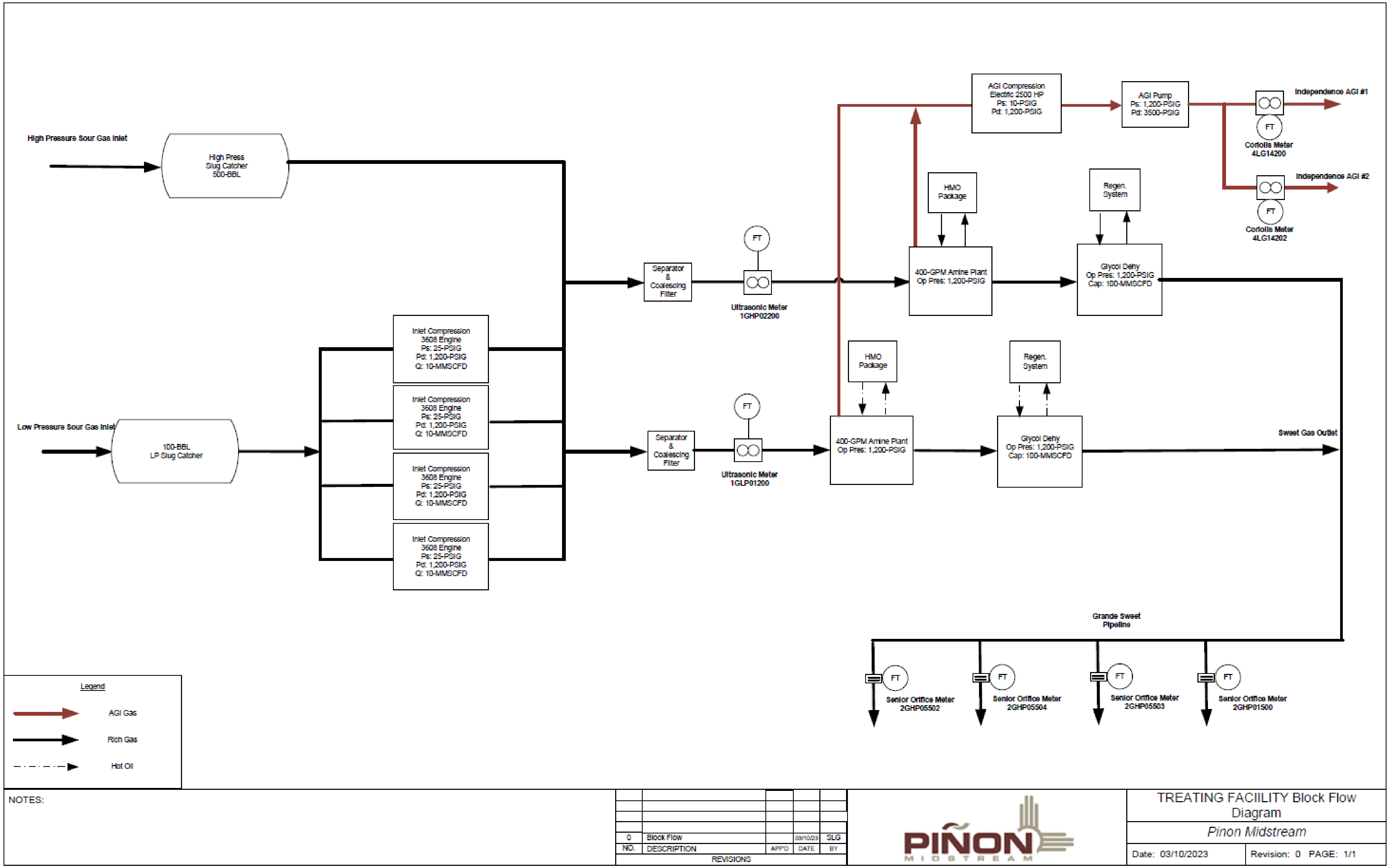

***Figure A10-1*: Treating Facility Block Flow Diagram**

Request for Additional Information: Pinon Midstream, LLC
May 8, 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.	N/A	N/A	It appears a second "Pinon Midstream, LLC" facility was created in e-GGRT in March of this year. Please clarify the relationship between these two facilities.	The MRV and your GHG reports are filed through the same system (e-GGRT) but are in other ways separate. Regarding the multiple Pinon Midstream, LLC facilities, there are two "facility entities", one for the plant and one for the other midstream assets separate from the Plant. The plant reports on its own and the remaining midstream assets report as a basin. This midstream basin entity is a separate "facility" in e-GGRT as required by the EPA. We do not believe we should be required to modify our e-GGRTs set up at this time.
2.	4	40	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.	The text and AMA figure have been updated to show the simulation results for 30 years of injection and another 5 years post-injection. The plume margins to the west (downdip) are greatest at the end of the injection period, and the plume migrates slightly updip from there. In all cases, the MMA is defined by the farthest point reached by the plumes at any time in the simulation with a 0.5 mile buffer. The AMA is defined the same way, and is therefore a conservative AMA. Additional scenarios have been included allowing for some transmissivity across faults.

			The MMA is defined 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. You have presented the definition of the MMA from 40 CFR 98.449 and provided a figure with the proposed MMA shown, but you have not described in the text of Section 4.1 how the MMA in this MRV plan meets the requirements for delineation of the MMA. Please expand the discussion accordingly." Additionally, please elaborate on the expected plume boundaries at different times and how these were used to determine the AMA/MMA. E.g., did modeling indicate that the free phase plume at the end of year t +5 is equal to the stabilized free phase plume, or are these different? What is the expected plume boundary at the end of year t?	
3.	5.3	41	"The West Jal B Deep Well No. 1 (API 30-025-25046) brine injection well is located one (1) mile northeast of the surface hole locations of the Independence AGI Wells. Additional details for this well are presented in Section 3.7.1. Therefore, Piñon concludes that the potential for CO_2 leakage to the surface through this potential leakage pathway is unlikely." Please provide more specific information to explain why Piñon concludes that the West Jal B Deep Well No. 1 presents a low risk of CO_2 leakage rather than just referring to Section 3.7.1.	Updated the text of Section 5.2 (renumbered) to explain this in greater detail: "The West Jal B Deep Well No. 1 (API 30-025-25046) brine injection well is located one (1) mile northeast of the surface hole locations of the Independence AGI Wells. Additional details for this well are presented in Section 3.7.1. The wellbore currently has two CIBPs at measured depths of 14,200 feet (lower Atoka Formation) and 17,100 feet (Fusselman Formation). These CIBPs restrict access to any existing reservoirs located below the lower Atoka Formation, including within the Mississippian Lime (14,544 feet), Devonian (15,380 feet), and the Fusselman (16,404 feet), and injections in this wellbore to-date have been up-section of the relevant area. In the event of incomplete plugging of the borehole or leakage through the well casing, the shallower reservoir is at higher pressure than the Siluro-Devonian

				reservoir, and consequently it is assessed that downward flow of fluid would repel the TAG plume from the AGI wells. Nevertheless, the potential for CO2 leakage to the surface through this well is considered possible, albeit unlikely, and monitoring for this possibility is described in Section 6.2.2."
4.	5.6	42	"According to data obtained from the New Mexico Tech Seismic Observatory (2023), there have been four (4) seismic events within the MMA since January 12, 2017 (Figure 5.6-1). These seismic events range in magnitude of 1.16-1.88 and occurred between September 2020 and October 2021 (Table 5.6-1). Data queries with the USGS Earthquake Catalog did not show any seismic activity within the MMA (USGS Earthquake Hazards Program, 2023)." Please provide a characterization of the likelihood magnitude, and timing of leakage from seismicity.	Updated the text of 5.5 (renumbered): The depths of the four earthquakes are undeterminable from current information, as NMT system does not contain that information. The likelihood of seismicity is reported in discussion of fault slip potential which is now expanded in this section. Magnitude is uncertain but likely small on the relevant fault segments because of relatively short length of segments at risk of slip. Leakage is not expected due to overpressured shallow reservoir. In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage.

5.	6	44-46	"If operating parameter monitoring and MIT failures indicate a CO2 leak has occurred, Piñon will take actions to quantify the leak based on operating conditions at the time of the detection." Section 6 appears to focus on strategies for detecting CO_2 leakage but does not explain how leaks would be quantified. Do you have examples of the actions Pinon would take to quantify CO2 leakage from the identified pathways?	Section 6 of the revised MRV plan has been edited to include the following statement: "If CO_2 surface emissions are indicted by any of the monitoring methods listed in Table 6.1, Piñon 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."
6.	6.2	45	"Aside from Independence AGI #2, other approved but not yet drilled wells target zones more than 4,000 feet above the Siluro-Devonian Injection Zone. Therefore, no additional monitoring is required for these wells over and above what is already required by NMOCC rules and orders. Piñon does not intend to quantify CO_2 leakage to the surface through the approved wells whose target zones are more than 4,000 feet above the injection zone for the Independence AGI wells. Any leakage of CO_2 originating from the injection of TAG into the Independence AGI wells would be detected and quantified through operating parameter monitoring and mitigated long before any leaked CO2 migrated upward toward these wells". Please clarify what monitoring you will perform for other approved but not yet drilled wells. Please note that even if CO2 leakage is unlikely through this pathway, Pinon would need to quantify any CO2 leakage that does occur. Please revise this section accordingly.	Section 6.2 – Leakage from Approved Not Yet Drilled Wells – has been removed from the revised MRV plan. Discussion of wells approved but not yet drilled has been moved to Section 3.7 of the revised MRV plan including an explanation of why Piñon does not consider these wells as potential pathways for CO_2 emission to the surface. In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage.

8.	6.3	46	Strategies for detection and quantification for Independence AGI #1 are discussed in Section 6.3 of the MRV plan, but strategies for the West Jal B Deep Well No. 1 and West Jal Unit Well #1 (mentioned in Section 5.3 of the MRV plan) are not. Please expand Section 6.3 accordingly.	This section has been renumbered in the revised MRV plan to Section 6.2. A new subsection has been added to explain how Piñon will detect and quantify leaks from the West Jal B Deep Well No. 1. Discussion of West Jal Unit Well #1 is included in Section 3.7 including an explanation of why Piñon does not consider this well as a potential pathway for CO_2 emission to the surface. In the unlikely event of leakage via this pathway, Piñon will utilize mobile monitoring to assess and quantify the leakage.
9.	8.4	51	"The calculated total annual CO2 mass emitted by surface leakage is the parameter CO2E in Equation RR-12 addressed in Section 8.5 below." Section 8.5 appears to discuss surface equipment leakage (CO_{2FI}), not surface leakage (CO_{2E}). Please note that surface leakage is different from equipment leakage, and please clarify this section accordingly. For reference, surface leakage is calculated using equation RR-10 at 40 CFR 98.443(e). Strategies for calculating leakage from the identified surface leakage pathways should be identified in the MRV plan.	Section 8.4 has been edited in the revised MRV plan to include the following statement: "The monitoring methods described in Section 7 would indicate the occurrence of gas leakage at the surface. The mass of CO_2 emitted would be calculated 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." Section 8.5 of the MRV plan states that Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations. Section 8.5 has been edited to clarify that the relevant sections of Subpart W will be used to calculate the parameter CO_{2FI} in Equation RR-12. The Table in Appendix 7 has been edited to clarify this point as well.

PIÑON MIDSTREAM

MONITORING, REPORTING, AND VERIFICATION PLAN

Independence AGI #1 and #2 Wells

Pinon Midstream, LLC

Version Number: 2.0
Version Date: February, 2023

Contents

1 Introduction

Ameredev II, LLC (together with its affiliates, "**Ameredev**") is an oil and natural gas producer operating in portions of the Delaware Basin located in southeastern New Mexico and western Texas. In 2020 Ameredev began evaluating methods for treating its sour natural gas production in Lea County, New Mexico to remove and permanently sequester large quantities of hydrogen sulfide ("**H_2S**") and carbon dioxide ("**CO_2**") commingled in its produced natural gas stream. On July 10, 2020, Ameredev filed an application with New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division ("**NMOCD**") seeking to drill an acid gas injection ("**AGI**") well approximately six (6) miles west of Jal in Lea County, New Mexico for the injection and permanent sequestration of treated acid gas ("**TAG**"). The application was heard and approved at a New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Commission ("**NMOCC**") hearing held on October 8, 2020. The approved order (Order No. R-21455-A) was subsequently issued at the November 4, 2020 NMOCC hearing and the final, approved, Class II injection permit was issued on November 11, 2020. The Independence AGI #001 vertical well (API 30-025-48081; "**Independence AGI #1**") was spud on December 27, 2020 by Ameredev.

In December of 2020, certain affiliates of Ameredev and other outside investors funded Piñon Midstream, LLC ("**Piñon**") to construct and operate the Dark Horse Sour Gas Treating Facility (the "**Dark Horse Facility**") adjacent to the Independence AGI #1 (Figure 1-1) and Ameredev subsequently contributed and assigned the Independence AGI #1 to Piñon on May 21, 2021. Piñon became the operator of record for the Independence AGI #1 on August 24, 2021. Upon completion in late August 2021, treatment of sour natural gas (using amine to isolate H_2S and CO_2) and the injection of TAG into Independence AGI #1 commenced at the Dark Horse Facility (a full description of the treating and injection process is provided in Section 3.8). On March 31, 2022 the NMOCC authorized the drilling of the Independence AGI #002 deviated well (API 30-025-49974; "**Independence AGI #2**") (together the "**Independence AGI Wells**"), which commenced during the summer of 2022.

Independence AGI #1 is permitted to inject into the Devonian Thirtyone and Upper Silurian Wristen and Fusselman Formations from a true vertical depth ("**TVD**") of approximately 16,230 to 17,900 feet (the "**AGI #1 Injection Zone**") and at a maximum surface pressure of approximately 4,779 pounds per square inch gauge ("**psig**"). Independence AGI #2 is permitted to inject into the Devonian Thirtyone Formation and Upper Silurian Wristen and Fusselman Formations from a TVD of approximately 16,080 to 17,683 feet (the "**AGI #2 Injection Zone**", and together with the AGI #1 Injection Zone, the "**Siluro-Devonian Injection Zone**") and at a maximum surface pressure of approximately 5,005 psig. In accordance with NMOCC Order No. R-21455-A (as amended by Order No. R-21455-B, the "**NMOCC Order**"), Piñon is authorized to inject and dispose of TAG, utilizing the Independence AGI Wells, at an aggregate *combined* maximum daily injection rate of up to 20 million standard cubic feet per day ("**MMSCF/D**"), which is the equivalent of approximately 8,200 barrels per day ("**bpd**") or 1,036.7 metric tonnes per day. Gas is injected for 30 years at a rate of 1,036.73 tonnes per day (378,399 tonnes per year or 11,351,970 total tonnes) followed by a 5-year rest period. If Independence AGI #1 is not injecting volumes of TAG, Independence AGI #2 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG. If Independence AGI #2 is not injecting volumes of TAG, Independence AGI #1 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG.

Piñon has chosen to submit this Monitoring, Reporting, and Verification Plan (the "**MRV Plan**") to the United States Environmental Protection Agency (the "**EPA**") for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (the "**GHGRP**") for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. Piñon intends to utilize the Independence AGI Wells for the injection and disposal of TAG for another approximately thirty (30) years.

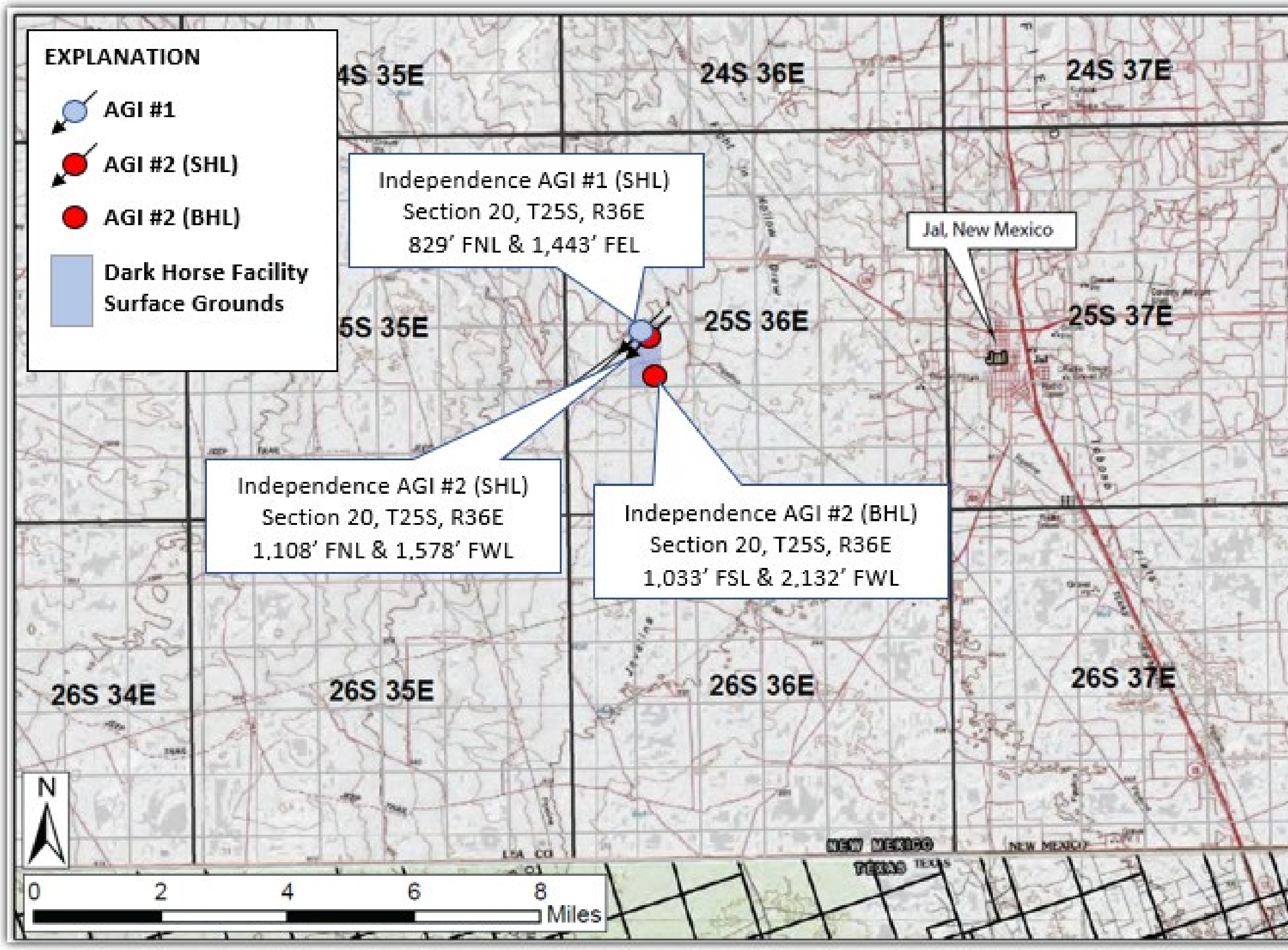

***Figure 1-1**: Location of Dark Horse Facility and the Independence AGI Wells. The approximate surface hole location ("SHL") and the approximate bottom hole location ("BHL") are indicated for both Independence AGI Wells. (Modified from Figure 1 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

This MRV Plan contains twelve (12) sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

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

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

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage.

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

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

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

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

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

Section 12 includes Appendices supporting the narrative of the MRV Plan

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is 582541. There are no other facilities related to this MRV plan.

2.2 Underground injection control ("UIC") well identification numbers

This MRV Plan is for the Independence AGI Wells (*see* Appendix 1). The details of the injection process are provided in Section 3.8.

2.3 UIC permit class

The NMOCD has issued UIC Class II Acid Gas Injection ("**AGI**") permits for the Independence AGI Wells under its State Rule 19.15.26 NMAC (*see* Appendix 2). All oil- and natural gas-related wells located near the Independence 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

Parts of the following project description have been taken from the Class II permit applications for (i) Independence AGI #1, prepared by Geolex, Inc. for Ameredev, dated July 10, 2020; and (ii) Independence AGI #2, also prepared by Geolex, Inc. for Piñon, dated November 4, 2021.

3.1 General Geologic Setting / Surficial Geology

The Dark Horse Facility is located adjacent to the Independence AGI Wells as shown in Figure 3.1-1. The site lies on the eastern flank of the Pecos River Basin within the Javelina Basin. Referred to as the South Plain by Nicholson & Clepsch (1961), the region exhibits irregular topography without integrated drainage. Surficial sediments commonly consist of unconsolidated alluvium and eolian sands. There are no observed surface bodies of water, or groundwater discharge sites within one (1) mile of the Independence AGI Wells. The Dark Horse Facility overlies Quaternary alluvium overlying the Triassic redbeds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater. The thick sequences of Permian rocks that underlie these deposits are described in Section 3.2.2.

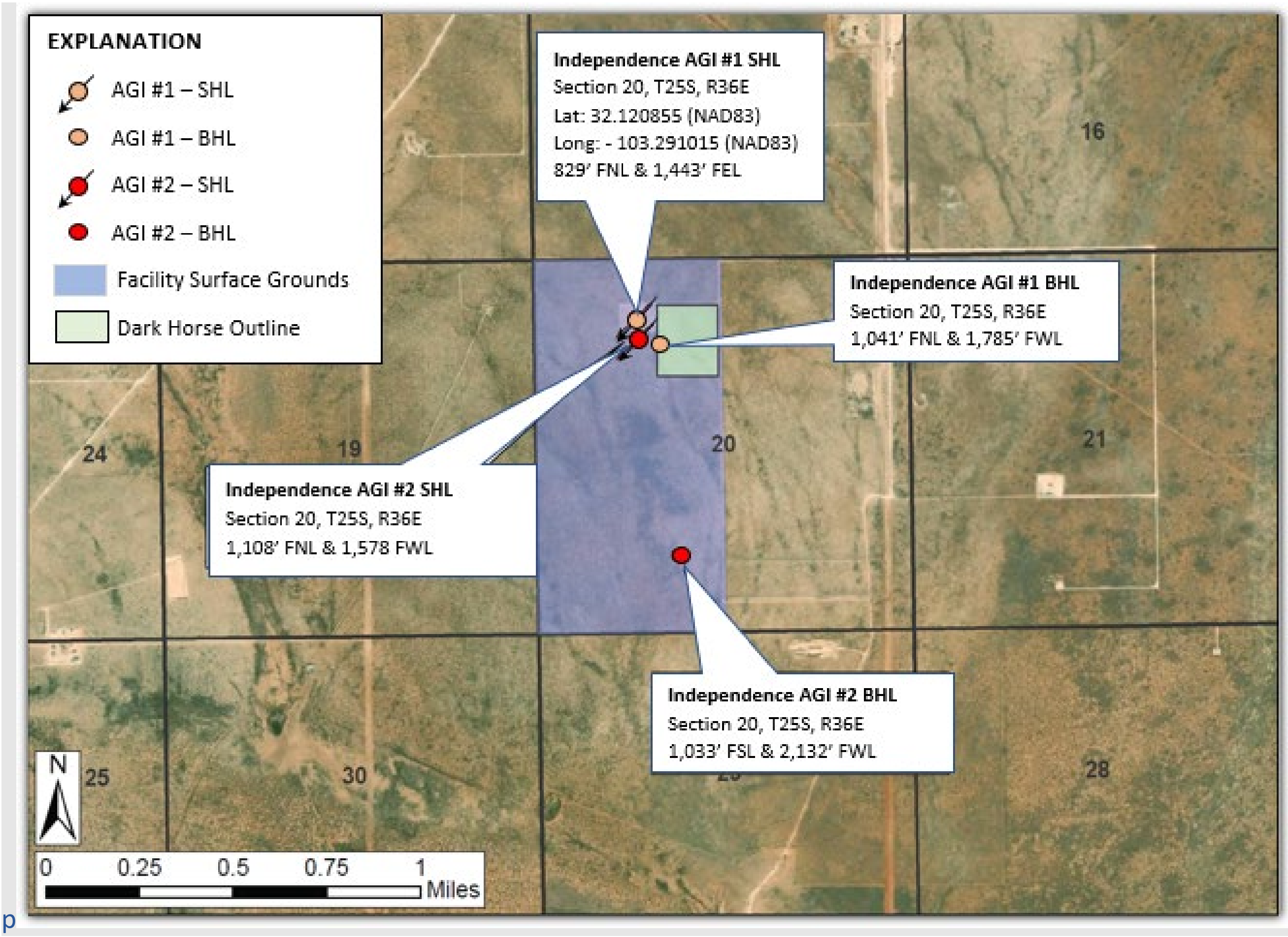

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***Figure 3.1-1**: Map showing location of Dark Horse Facility and the Independence AGI Wells in Section 20, T25S, R36E NMPM. The BHL of the Independence AGI #1 sidetrack is 446' southeast of the SHL. The SHL and the BHL for Independence AGI #2 are shown. (Modified from Figure 2 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

3.2 Bedrock Geology

3.2.1 Basin Development

The Dark Horse Facility is 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. The Permian Basin and its sedimentary fill have been formed and controlled by tectonism of varying degrees and sedimentation events that began in the Precambrian and throughout the Cenozoic (Neogene). Early Paleozoic deposition took place in the Late Cambrian as marginal areas of the North American craton began to be flooded by marine seas. Late Cambrian sediments comprised of basal siliciclastic sands and muds from areas of exposed Precambrian igneous, metamorphic, and sedimentary rocks and shallow-water carbonates.

Parts of the following basin development descriptions in this subsection have been modified and summarized from Ruppel (2019). Flooding continued across the North American craton throughout the Early Ordovician, establishing a widespread shallow-water carbonate platform. The Ellenburger Formation (Figure 3.2-2) rocks are derived from peritidal and shallow subtidal carbonates. These sediments were exposed during one of the sea-level drops during the Ordovician deposition resulting in karstification and dolomitization. During the Early to Middle Paleozoic time, the Permian Basin region was occupied by a relatively shallow basin called the Tobosa Basin. The first rapid subsidence and formation of the Tobosa Basin began in Simpson time (Middle

Ordovician), and subsidence slowly diminished into the Early Devonian (Ewing, 2019). Subsequent tectonic history of the Tobosa and Permian Basins will be discussed throughout this section.

Early Paleozoic deposition is mostly defined by multiple high-frequency sea-level changes, karsting, and erosional events. Large-scale shift in facies and environments indicate tectonic and/or eustatic controls on sediment distribution patterns. Simpson Group (Middle Ordovician) rocks unconformably overlie Ellenburger Formation rocks at a widespread hiatus caused by Early Ordovician to Middle Ordovician relative sea-level fall. Simpson rocks are a cyclic succession of lime mudstones and quartz sandstones and were deposited during the subsequent reflooding of the shelf. Carbonate-dominated Montoya Formation (Late Ordovician) and Fusselman Formation (Latest Ordovician -Early Silurian) rocks overlie the Simpson Group and indicate a shift and deepening of Tobosa Basin. These rocks are indicative of an overall relative sea level rise.

Middle Silurian-Early Devonian Wristen Group and Thirtyone Formation rocks indicate differential subsidence in the area and represented a deepening and expansion of the basin. Wristen Group rocks comprised of carbonate mudstones and wackestones of the Wink Formation, which underlies the shallow-water carbonate platform packstones, grainstones, and reef facies (corals and stromatoporoids) of the Fasken Formation and the deep-water lime mudstones of the Frame Formation. These facies outline the position of a Silurian platform margin and imply a downwarping of the North American craton. Although Wristen and Fusselman show evidence of numerous high-frequency sea-level changes, the larger-scale change in facies and depositional environments indicates tectonic and/or eustatic controls on sediment distribution patterns. The Silurian platform margin is a recurring feature that controls facies distribution through the Late Mississippian, suggesting tectonic and/or basement terrain control. The rocks of the Thirtyone Formation (Early Devonian) consist of platform carbonate grainstones and packstones surrounding calcareous, radiolarian-rich basin facies.

According to Ruppel (2019) and Ruppel and others, (2020a), a major episode of relative sea-level fall in the Middle Devonian is documented by an absence of Late Early Devonian and early Middle Devonian rocks. Late Devonian Woodford rocks overlie eroded and karsted Silurian (Wristen Group), Early Devonian Thirtyone, and older rocks. Local folding of these rocks below the Woodford suggests that the hiatus may have been at least partially driven by tectonic events. Evidence from the distribution of later Mississippian rocks indicates that the tectonic event caused uplift and localized deformation of pre-Middle Devonian rocks and changed subsidence and depositional patterns across the entire region.

Following the Middle Devonian Permian Basin-area uplift and emergence, Late Devonian marine transgression flooded the region with anoxic bottom-water seas and deposited black, organic-rich biosiliceous mudstones of the Woodford Formation (Ruppel, 2019). Sea-level fall-and-rise sequences defined the Early and Late Mississippian and were even more pronounced during the Pennsylvanian. In the Late Mississippian, initial collision occurred between Laurentia and Gondwanaland, and the Marathon-Ouachita orogenic belt first started to form in northeastern North America (Yang and Dorobek, 1995) with tractions propagating toward the southwest, impacting the Permian Basin by the Middle Pennsylvanian Epoch (Desmoinesian, 310 Ma) (Horne, 2021). Mississippian limestones and the Barnett Formation shales were deposited following a marine transgression that resulted in the development of an extensive carbonate platform, surrounded by a deep-water, organic-rich mud basin.

Collision along the western and southwestern margins of Laurentia, combined with tractions from the Marathon-Ouachita thrusting in the southeast, resulted in northwest-southeast-trending uplifts throughout the western United States known as the Ancestral Rocky Mountain orogeny, which began in Early Pennsylvanian time and continued into the Early Permian (Horne, 2021). The Pennsylvanian tectonic setting in the Permian Basin is the product of the combined Ancestral Rocky Mountain and Marathon–Ouachita effects occurring along the southwest and southeast margins of Laurentia. These events contributed to basin evolution and specific structural domains and styles. In the Permian Basin, the Ancestral Rocky Mountain

orogeny is responsible for the uplift of the Central Basin Platform and the major structural development of the Midland and Delaware Basins (Horne, 2021).

During Desmoinesian to early Missourian sedimentation, Permian Basin deformation reached its peak. The antecedent Tobosa Basin was tectonically differentiated, formed into the crustal uplifts and sub-basins that now characterize the Central Basin Platform, Midland Basin, and Delaware Basin. Throughout Pennsylvanian and most of Permian sedimentation, tectonics coupled with glacial eustacy played an important role in the development of regional facies. Middle to Late Pennsylvanian saw decreasing tectonic deformation activity, and by the Wolfcampian time (Early Permian), deformation was limited to subsidence within the structures formed by the existing uplifts and basins (e.g., Delaware and Midland Basins, Central Basin Platform). The continual subsidence of the Delaware basin affected sediment infilling, with some areas accumulating as much as 12,000 ft of basin-fill sediment. Marine transgression eventually submerged uplifts and became the location of carbonate sedimentation, while the basins became filled with organic-rich siliceous muds. By the end of the Wolfcampian, the major Permian Basin physiographic features (Central Basin Platform, Delaware and Midland Basins) were fully developed, and controlled sedimentation types and location for the remainder of the Paleozoic.

The Middle Permian (Leonardian and Guadalupian) was punctuated by cyclic sediment deposition during sea-level eustatic events. The Leonardian was a time of gradual global warming from the icehouse climates of the late Carboniferous to warmer and more arid greenhouse climates of the later Permian and Mesozoic (Tabor, 2004). The Leonardian marked the beginning of the last stages of the formation of Pangea, producing greater restriction of open ocean connections to the Permian Basin (Ruppel, 2020b). The abundance of tidal-flat facies, evaporites, and reflux dolomites in Leonardian rocks reflects the development of much more arid conditions compared with those in the earlier Permian (Ruppel, 2020b). In the shelf areas (Central Basin Platform and Northern, Northwestern, and Eastern Shelves) (Figure 3.2-1), sedimentation was characterized by shallow-water carbonate production and deposition during sea-level rise, and by shelf exposure and sand-silt deposition during sea-level fall and subsequent shelf exposure. In the Delaware and Midland basins, sedimentation was characterized by cyclic intervals of detrital carbonate-sediment transport into the basins by sea-level highs, and by sand-silt transport and deposition during sea-level falls. Dolomitization of carbonate-shelf deposits occurred during the more regionally arid climates of the Leonardian and the Guadalupian as a product of the Permian Basin area being situated at the equator and from refluxing brines created during periods of sea-level highstand events. Deposition of evaporites became more common in the shelf areas during this time, likely in response to the increasingly arid environment and/or decreased accommodation. By the end of the Guadalupian, the Midland Basin was largely filled, and peritidal muds and evaporite deposition dominated. Sea-level fall and closure of the Hovey Channel (Figure 3.2-1) cut off the Delaware Basin from its marine supply, resulting in regional exposure and nondeposition and the filling of the basin with evaporites of the Castille Formation (Lopingian “Ochoa” Series) (Ruppel, 2019). Most of the rocks deposited during Lopingian “Ochoan” time were evaporites such as anhydrite, halite, and potash minerals with minor amounts of limestone, mudstone, and siltstone and are subdivided into (ascending) Castile Formation, Salado Formation, Rustler Formation, and Dewey Lake Red Beds. Most of the early Ochoan deposition was confined to the Delaware Basin (Bachman, 1984).

3.2.2 Stratigraphy

Figure 3.2-2 is a generalized stratigraphic column showing the formations that underlie the Dark Horse Facility and the Independence AGI Wells. The sequences of Ordovician through Permian rocks are described below.

Ordovician. Below the Silurian Fusselman Formation lies about 400 feet of Ordovician Montoya Formation cherty carbonates which overlies about 400 feet of Ordovician Simpson Group sandstones, shales, and tight limestones. These formations are underlain by the Lower Ordovician Ellenburger Formation which is a thick, carbonate-dominated sequence composed of dolostones and limestones. It is 0-1,000 feet thick in

southeastern New Mexico. The Ellenburger carbonates sit on a veneer of Cambrian to Lower Ordovician Bliss Sandstone and granite wash on the Precambrian basement.

During the Early Ordovician, much of the United States was covered by a shallow sea, and southeast New Mexico was a shallow-water shelf with deep water conditions to the south. Due to sea-level changes and regional tectonic activity, the entire lower Paleozoic interval (Ellenburger through Devonian) was periodically subjected to subaerial exposure and prolonged periods of karst and karst-terrain formation, most especially in the Ellenburger, Fusselman and Devonian strata. The cave systems collapsed with subsequent burial, creating brecciated and fractured carbonate bodies that formed many of the Ellenberger reservoirs and created complex pore networks. The result of these exposure events was the development of numerous horizons of karst-related secondary porosity with solution-enlarged fractures, vugs, and small cavities and caves. Particularly in the Ellenburger and Fusselman strata, solution features from temporally distinct karst events became interconnected with each successive episode, so there could be some degree of vertical continuity in parts of the Fusselman section that could lead to enhanced vertical and horizontal permeability. The Ellenburger is well below the Siluro-Devonian Injection Zone, so it is unlikely to be affected by any proposed activity.

Devonian and Silurian. The Devonian Thirtyone Formation, the Silurian Fusselman Formation, and the Silurian Wristen Group consist of interbedded dolomites and dolomitic limestones and are collectively often referred to as the Siluro-Devonian. In the Middle Devonian, regional marine transgression deposited mostly black, organic-matter-rich siliceous muds of the Woodford Formation (Ruppel, 2019). The Siluro-Devonian Injection Zone does not contain economic hydrocarbons closer than fifteen (15) miles away from the well sites. There have been no commercially significant deposits of oil or natural gas found in the Devonian or Silurian rocks in the vicinity of the Independence AGI Wells and there is no current or foreseeable production at these depths within a two (2) mile radius around the Independence AGI Wells (Figure 3.7-1). Adjacent wells have shown that these formations are primarily water-bearing and are routinely approved as produced-water injection zones in this area.

Mississippian. According to Broadhead (2017), the Mississippian section unconformably overlies the Woodford Formation shales throughout most of southeastern New Mexico and, in places, unconformably overlies the Silurian Fusselman Formation or Ordovician strata in limited areas. These units reach a maximum thickness of 1,400 ft in the Tatum Basin northwest of Hobbs, New Mexico and constitute a major portion of the stratigraphic section. The Mississippian section in southeastern New Mexico is subdivided into the Lower Mississippian limestone (Kinderhookian to Osagean age) and various Upper Mississippian units. The Upper Mississippian section consists of the Barnett Shale in the basinal area to the south and the Meramec and Chester units on the shelf to the north. The Mississippian strata constitute the least developed of the major stratigraphic units in southeastern New Mexico and oil and natural gas production has been from relatively small and widely scattered reservoirs (Broadhead, 2017). The Chester Formation consists of several hundred feet of shales and basinal limestones which are underlain by several hundred feet of Osage limestone.

Pennsylvanian. The Pennsylvanian-age strata is comprised of (ascending) Morrow, Atoka, Strawn, Canyon, and Cisco. Within this entire sequence, the Morrow is a major natural gas producing zone, with smaller contributions from the overlying Atoka and Strawn. The Morrowan strata are dominantly siliciclastic and consist of interbedded shales and lenticular sandstones deposited in multiple regressive sequences and represent basinward migration of nearhore, sand-rich facies tracts from the erosion of exposed Precambrian rocks (Broadhead, 2017). The overlying Atokan strata are also dominantly siliciclastic, with sandstones and shales being deposited in fluvial-deltaic and strandline environments (Broadhead, 2017). The Middle Pennsylvanian (Desmoinesian) Strawn strata is composed of ramp limestones interbedded with marine shales and minor sandstones, and both sandstone and limestone reservoirs are productive (Broadhead, 2017). Although there was past production of oil and natural gas from the Pennsylvanian Strawn pool, there are no active wells in that pool within two (2) miles of the Dark Horse Facility nor are there any natural gas producing

wells in any pools. The Upper Pennsylvanian strata are informally referred to as the Canyon (Missourian) and Cisco (Virgilian) groups, and are composed of interbedded carbonates, dark-gray to black shales, and minor sandstones (Broadhead, 2017). These groups contain prolific oil reservoirs in southeastern New Mexico.

Permian. The overlying Permian rocks found in the Delaware Basin are divided into four (4) series, the Lopingian ("Ochoa") (most recent), Guadalupe, Cisuralian ("Leonard"), and Hueco ("Wolfcamp") (oldest) (Figure 3.2-2). Numerous oil pools have been identified in these rocks (*see* Appendix 3, Table 3a). Active oil producing reservoirs within two (2) miles of the Dark Horse Facility include the following Permian pools: Tansil, Yates, Seven Rivers, Delaware, Bone Spring, and Wolfcamp. New oil wells permitted but not yet drilled are primarily targeting the Bone Spring and the Wolfcamp pools. The rock units of the Permian series are discussed in more detail below.

Permian Hueco ("Wolfcamp") Group. The Lower Permian Wolfcampian strata in the Permian Basin record deposition in deepwater basins surrounded by shallow-water carbonate platforms, where the Wolfcampian platform carbonate succession exposed in southeastern New Mexico comprises a complex record of deposition mainly controlled by fluctuations in glacio-eustatic sea level (Fu and others, 2020). The Wolfcamp is extremely variable in lithology in response to changes in the environment of deposition. In the area of the Dark Horse Facility, it is composed of dark skeletal to fine-grained limestone, fine-grained sand to coarse silt, and shale in these basin facies. Horizontal wells are being drilled in the Bone Spring and Wolfcamp; however, most activity is primarily to the west of the Dark Horse Facility.

Permian Leonardian Series. The Cisuralian ("Leonard Series"), sediments in shelf areas (Central Basin Platform, Northwest Shelf, etc.) are characterized by shallow-water carbonate-sediment production and deposition during sea-level rise, and by shelf flooding and quartz-dominated sand-silt deposition during sea-level fall and shelf exposure (Ruppel, 2019). In the Delaware Basin, this pattern of sea-level control on sediment supply resulted in the deposition of cyclic intervals of detrital carbonate-sediment transport to basins during sea-level highs and by quartz sand-silt transport and deposition during sea-level falls (Ruppel, 2019). Overall, the Leonard succession is one of punctuated upward shallowing from deep-water, outer-platform—platform-margin settings to inner-platform, peritidal conditions (Ruppel, 2020b).

The Bone Spring Formation is present only in the Delaware Basin and is stratigraphically equivalent to the Abo and Yeso Formations of the Northwest Shelf and Central Basin Platform, attains a maximum thickness of about 4,000 ft in southern Eddy County, New Mexico, and has been productive from several plays in the basin (Broadhead, 2017). The Bone Spring stratigraphy consists of alternating carbonate and siliciclastic successions that were deposited in marine slope and basin-floor environments, where sandstones and siltstones are widespread on the basin floor, whereas carbonates are thickest in periplatform areas (Nance and Hamiln, 2020; Saller and others, 1989). Most Bone Spring carbonate slope deposits accumulated by transport from shallow-water environments on the shelf during highstands of sea level and the siliciclastic deposits were transported basinwards during lowstands of sea level (Nance and Hamlin, 2020). Most of the carbonates are detrital, composed of bioclasts and lithoclasts derived from surrounding shallow-water platforms, and the siliciclastic members were deposited primarily on the basin floor in widespread submarine-fan complexes (Nance and Hamlin, 2020).

Permian Guadalupe Series. The Upper Permian Guadalupian-age strata are found on both Northwest Shelf and Central Basin Platform, and in the Delaware Basin. The Goat Seep/Capitan Reef system, a profoundly critical component of the Permian Basin Guadalupian paleogeography, prominently divides the shelves of the Central Basin Platform, the Northwestern Shelf, and the Western Shelf from the Delaware Basin (Nance, 2020a). Units on the shelf and platform comprise of (ascending) the San Andres Formation and the Artesia Group (*see* Figure 3.2-2). The five (5) formations of the Artesia Group include (ascending) Grayburg, Queen, Seven Rivers, Yates, and Tansill. The Delaware Basin equivalents of the reef trend include the Delaware Mountain Group: (ascending) Brushy Canyon, Cherry Canyon, and Bell Canyon. The Artesia Group comprises as much as 2,650 ft of stratigraphically cyclic, mixed-siliciclastic/carbonate/evaporite platform strata

deposited shelfward of the Guadalupian Capitan Reef system that rims the Delaware Basin (Nance, 2020a). These formations have provided significant oil and natural gas production in southeastern New Mexico, and widespread, reddish-colored evaporitic shales and evaporites provide effective vertical and lateral seals (Broadhead, 2017).

According to Nance (2020a), Artesia facies tracts include, from basin to shelf, immediate-back-reef carbonate grainstone to packstone; shelf-crest pisolite-bearing carbonate shoals; lagoonal wackestone to mudstone and siliciclastic siltstone; algal-laminated, tidal-flat carbonate packstone to wackestone and fine to very fine grained sandstone; beach-ridge fine sandstone; siliciclastic-sabkha anhydrite and halite; brine-pool and evaporitic-lagoon anhydritic dolomite, dolomitic anhydrite, anhydrite, and halite; and eolian to fluvial siliciclastics. During sea-level highstand, siliciclastics are limited to updip areas, whereas eolian-siliciclastic depositional environments migrate downdip during sea-level lowstands. During transgressions, siliciclastics in more basin-proximal positions were reworked by marine and marginal processes. Reservoir quality was impacted mostly by dissolution of feldspar and carbonate allochems and precipitation of authigenic feldspar, clay, and evaporite.

The Delaware Mountain Group of the Delaware Basin comprises up to 4,500 ft of arkosic to subarkosic sandstone, siltstone, and carbonate debrites that were deposited in deep water, mainly during lowstand and early transgressive sea-level stages, and primary depositional processes include density-current flow and suspension settling (Nance, 2020b). The Delaware Mountain Group is restricted to slope-and-basin areas and was sourced from shelf-sediment areas through poorly exposed incised valleys, and interbedded carbonate units thicken shelfward and are typically correlative to “reef”-margin-complex carbonate sources along the shelf margin (Nance, 2020b).

Permian Lopingian (“Ochoa”) Series. The youngest of the Permian Basin sediments are referred to as the Lopingian (“Ochoa”) Series. The Ochoan series includes the Castile, Salado, Rustler, and Dewey Lake formations. Ochoan units on the shelf include the Salado, Rustler, and Dewey Lake Formations. *Castile Formation* usage is restricted to the deposits within the Delaware Basin only (Figure 3.2-2). The Ochoan in the Permian Basin contains no hydrocarbon reservoirs on the shelf (Nance, 2020a). The basal Salado Formation forms the ultimate top seal for the underlying Guadalupian reservoirs and effectively inhibits hydrocarbon migration into Ochoan units (Nance, 2020a). Lack of a seal above the Ochoan precludes widespread entrapment within the interval of hydrocarbons that may have been generated within the series. Ochoan strata are not hydrocarbon productive in the Permian Basin except for a few very small, isolated reservoirs in the Castile Anhydrite in the northern part of the Delaware Basin (Broadhead, 2017). The Castile is considered to be the top seal for Delaware Basin hydrocarbon reservoirs and is responsible for controlling migration of hydrocarbons from basinal source beds into reservoirs on the surrounding shelves (Hills, 1984). Anhydrite is the dominant rock type in the Castile Formation, along with limestone interlaminated in anhydrite, thin beds of limestone, and minor amounts of dolomite and magnesite, and halite is present as several massive beds in the formation in the subsurface but is much less prominent than the halite in the overlying Salado Formation (Bachman, 1984). The interlaminated anhydrite and limestone are distinctive lithologic features of the Castile Formation and are thought to represent annual cycles of sedimentation (Bachman, 1984).

The regionally extensive Salado Formation includes thick evaporite deposits and records a long-term salinity crisis in the region (Nance, 2020a). The Salado includes halite, minor beds of anhydrite, and commercial deposits of potash minerals (Bachman, 1984). The contact between the Castile and the overlying Salado Formations is sharp and most places and is between massive beds of anhydrite in the Castile and a sequence dominated by halite, potash minerals, and thin beds of anhydrite in the Salado (Bachman, 1984). The Rustler Formation overlies the Salado, and consists of dolomite, evaporites, and siliciclastics and marks the last major migration of marine waters into the Permian Basin (Ruppel, 2019). Red beds of terrigenous sands in the Rustler Formation resulted from eolian sediment transport. These red beds grade downwards into evaporites

of the Salado and Castile Formations and are composed of red-orange silts and sandstones with interbeds of gypsum or anhydrite and halite. The Rustler carbonates, evaporites, and siliciclastics mark a relatively abbreviated return of marginal-marine conditions to the region (Nance, 2020a). The Dewey Lake Formation rests conformably on the Rustler Formation and consists mainly of redbeds and minor gypsum, alternating thin, even beds of moderately reddish-brown to moderately reddish-orange siltstone and fine-grained sandstone (Bachman, 1984). The Dewey Lake sediments mark the youngest episode of preserved Permian deposition in the region, after which a significant net-depositional hiatus prevailed until the onset of Late Triassic sediment accumulation (Nance, 2020a). Beds of Triassic age rest unconformably on, and overlap, the Dewey Lake Formation, and exposures of these rocks in southeastern New Mexico are dark reddish-brown, cross-laminated, poorly sorted conglomerate sandstones with interbeds of dark reddish-brown sandy shale (Bachman, 1984). These Triassic units were deposited in a fluvial—deltaic—lacustrine system and signaled the onset of net deposition during overall wetter conditions after a protracted period of net nondeposition (Nance, 2020a; Bachman, 1984).

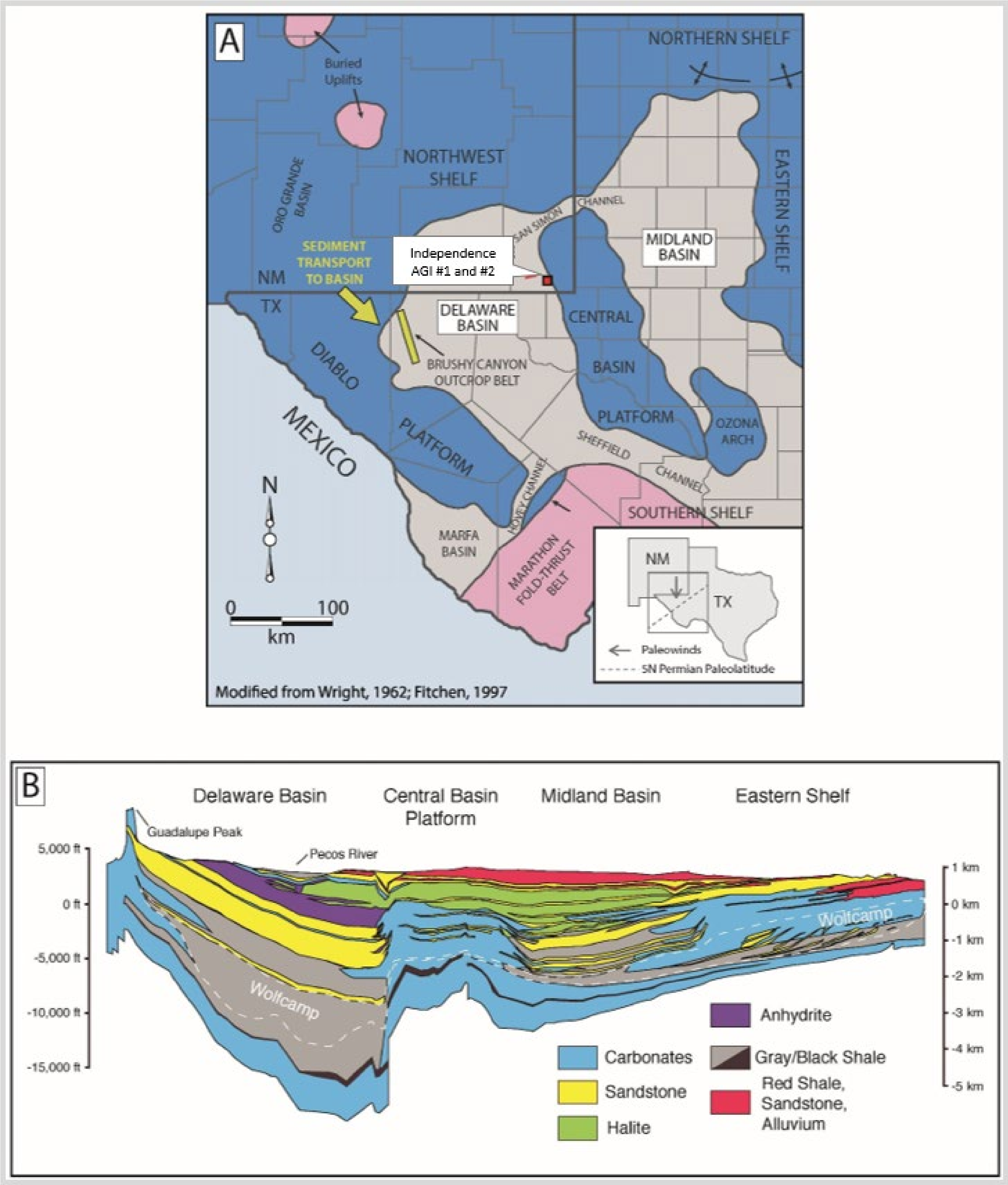
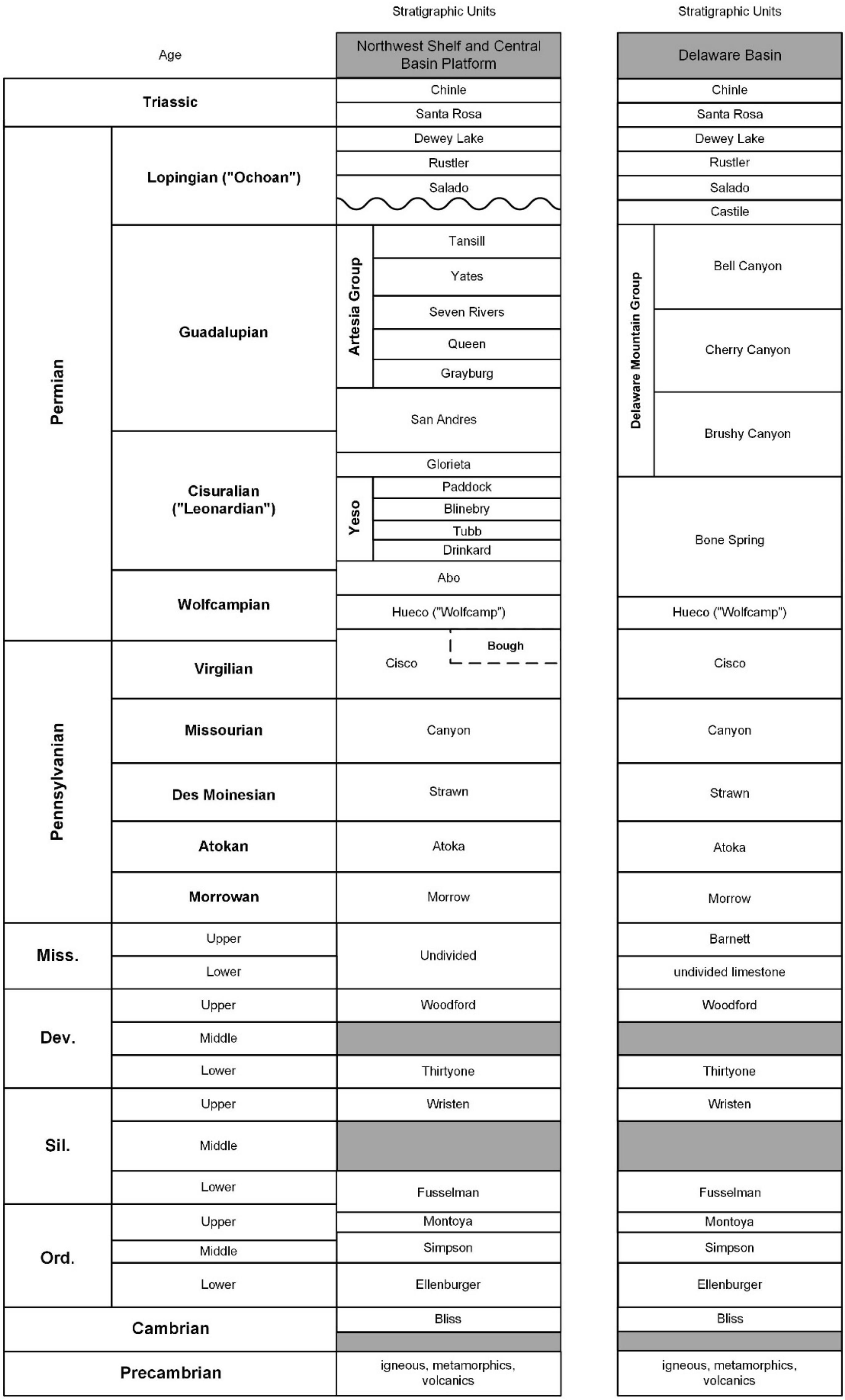


__Figure 3.2-1__: Structural setting (panel A) and general lithologies (panel B) of the Permian Basin. The location of the Independence AGI Wells is shown by the red square. (Modified from Wright, 1962; Fitchen, 1997) (Modified from Figure 12 of Class II permit application for Independence AGI #2, Geolex, Inc.).



<u>Figure 3.2-2</u>: Generalized stratigraphic correlation chart for the Permian Basin region (modified from Broadhead, 2017).

3.2.3 Faulting

The Permian Basin region has a complex tectonic history, shaped by several convergent and divergent events from the Proterozoic through the Cenozoic (Neogene). The Delaware Basin is defined by a complex network of basement-rooted faults. Recent regional 3D structural framework and kinematic models by Horne et al. (2021) provides interpretations of basement-rooted faults in the Delaware Basin. This region contains more than 650 basement-rooted fault surfaces, dominated by "primary" north-northwest—south-southeast-striking high-angle reverse faults that bound "secondary" fault orientations west-northwest—east-southeast and west-southwest—east-northeast (Horne et al., 2021). Their kinematic model suggests that the primary structural grain formed first in response to the encroaching Ancestral Rocky Mountain orogenic front, and the secondary fault zones formed under the combined stresses from the Ancestral Rocky Mountain and Marathon-Ouachita convergence fronts, which compartmentalized the Delaware Basin and Central Basin Platform (Horne et al., 2021).

To identify subsurface structures in the area of the Independence AGI Wells, Geolex evaluated and interpreted licensed seismic survey data (WesternGeco South Lea Survey) covering the Lea County area of interest. These findings and interpretations specific to the Dark Horse Facility area are discussed further in Section 3.5.

3.3 Lithologic and Reservoir Characteristics of the Siluro-Devonian Formations

The Siluro-Devonian Injection Zone includes the Devonian Thirtyone Formation, Silurian Wristen Group and Fusselman Formation, collectively referred to as the Siluro-Devonian. These strata commonly include numerous intervals of dolomites and dolomitic limestones with moderate to high primary porosity. Additionally, the Siluro-Devonian Injection Zone includes significant regions of secondary, solution-enlarged porosity produced during periods where strata were subaerially exposed and significant karst features developed. These karst features are frequently developed in the Fusselman Formation and include solution enlarged cavities and fractures. Fracture networks through the Siluro-Devonian section are substantial enough to provide additional permeability that is not readily apparent on geophysical well logs. The porous zones of the Siluro-Devonian are separated by tight limestones and dolomites.

In evaluating the location of the Independence AGI Wells, an in-depth review of licensed seismic survey data (WesternGeco – South Lea Survey) was completed to support the evaluation that the Siluro-Devonian reservoir exhibited sufficient porosity potential to accommodate the needs of the Independence AGI Wells. Seismic inversion data, specifically impedance attributes, were evaluated to identify reservoir targets with significant porosity potential in the Siluro-Devonian reservoir. As a result of this review, the location in Section 20, T25S, R36E was selected as it was observed to overlay an expansive region of porosity in the upper Devonian, Wristen, and Fusselman strata.

Based on the geologic evaluation of the subsurface, AGI was recommended between depths of approximately 16,080 to 17,683 feet TVD (16,477 to 18,080 feet measured depth). Figure 3.3-1 includes a type log of the Siluro-Devonian Injection Zone that includes the formation tops identified at that location and illustrates the sufficient low-porosity intervals overlying the target injection reservoir. Anticipated formation tops underlying the Independence AGI #2 location are included in the following Table 3.3-1. In the area of the Independence AGI Wells, depth to Devonian strata increases to the southwest and the Independence AGI Wells lie downdip of a structural high to the east (Figure 3.3-2).

Units overlying the Siluro-Devonian Injection Zone provide an excellent caprock to prevent the upward migration of injectate out of the target reservoir. This caprock includes 335 feet of dense Woodford Shale overlain by at least 796 feet of Mississippian limestone (Table 3.3-1). These units will provide a geologic seal above the porous carbonates of the Siluro-Devonian Injection Zone providing protection to shallow groundwater resources and overlying pay intervals.

Figure 3.3-3 includes structural cross section A-A' covering the area of Independence AGI #2 and highlights the lateral extent of available upper Devonian porosity and the regional coverage of overlying caprock in the area. As shown in Figure 3.3-2, there are two (2) faults located approximately one (1) mile east and one (1) mile north from the SHLs of the Independence AGI Wells. These structures were identified through review of licensed 3D seismic survey data and are discussed further in Section 3.5.

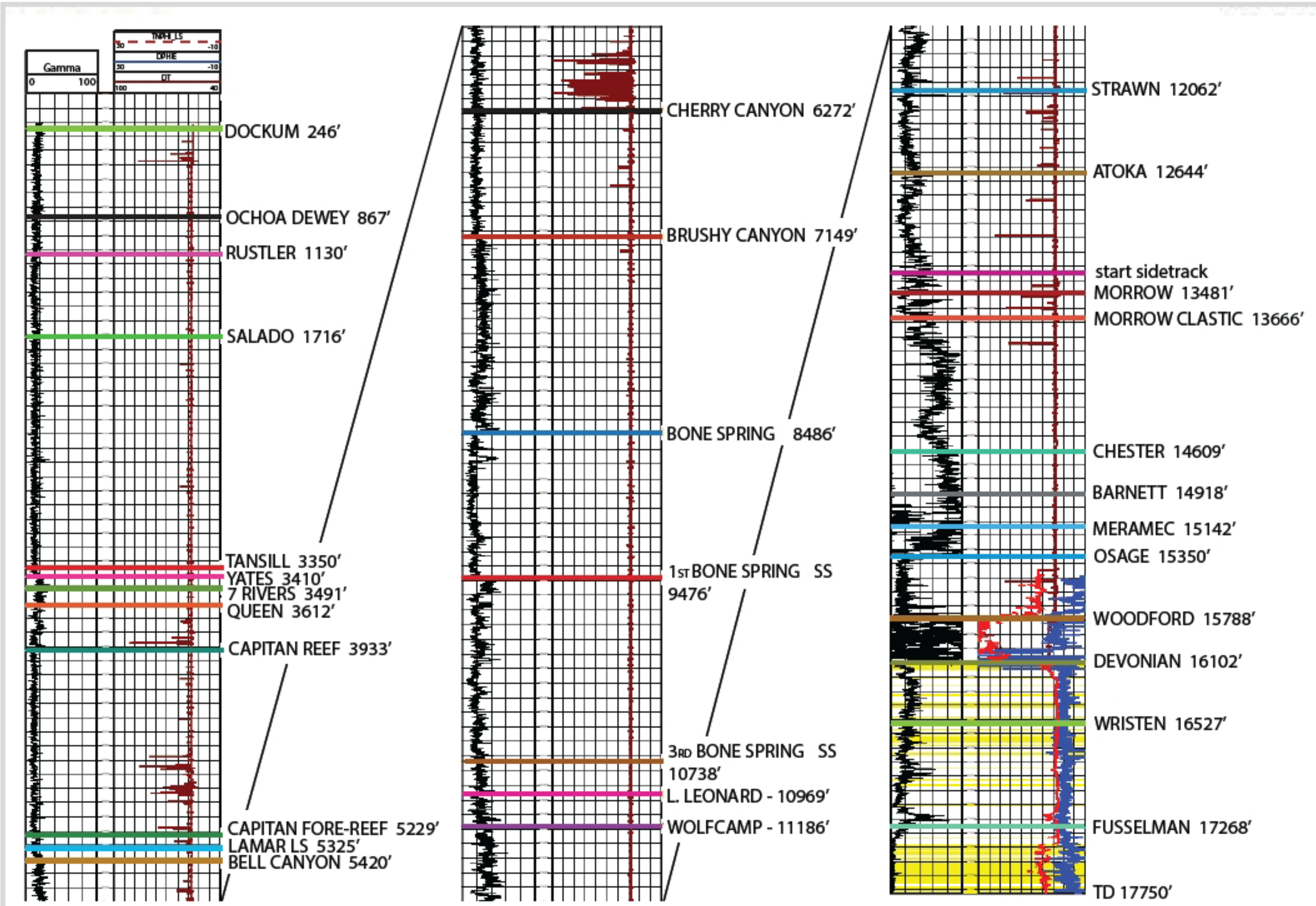
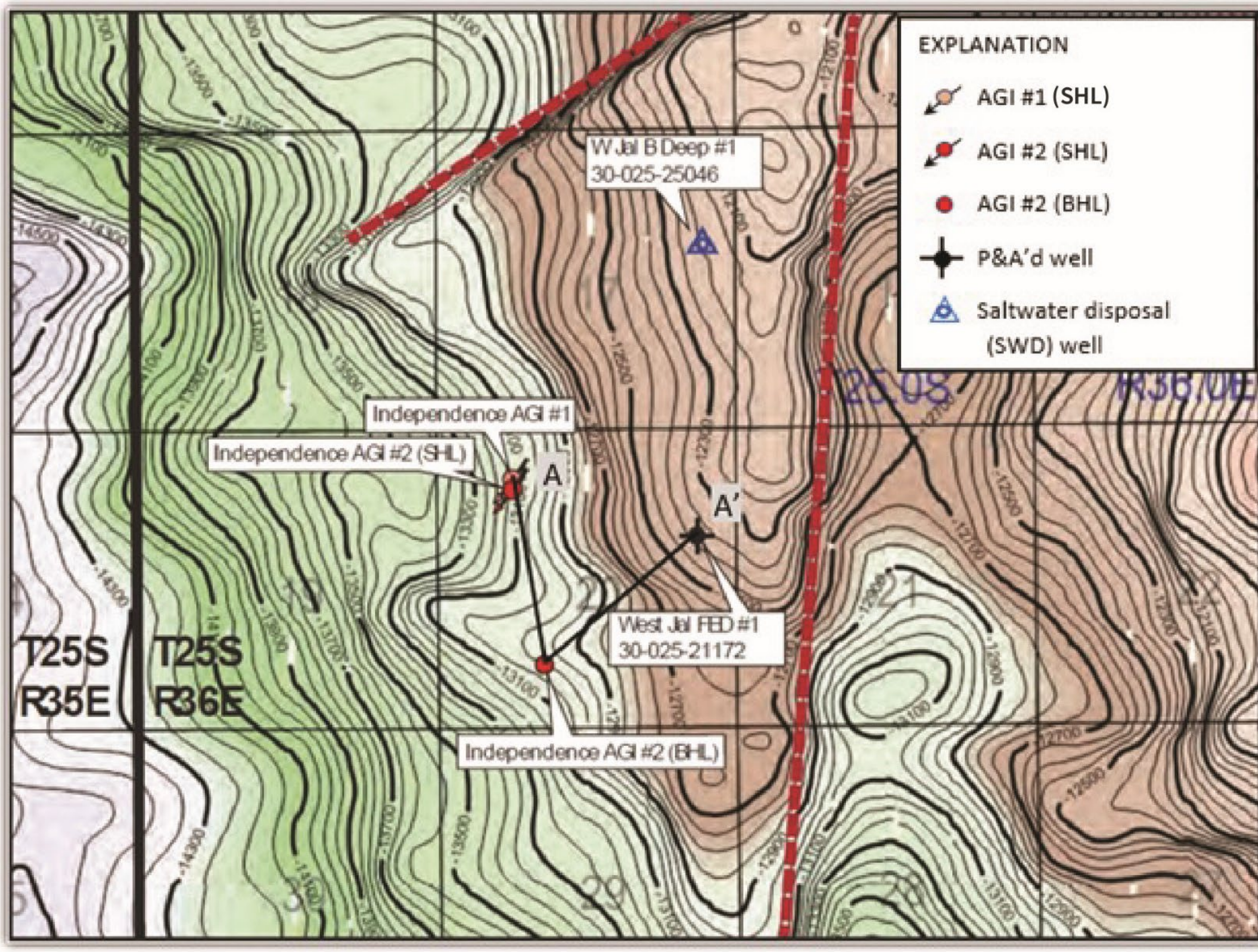


Figure 3.3-1: Type log of the Independence AGI #1, illustrating identified formation tops in TVD. Estimated formation tops for the Independence AGI #2 are included in . Table 3.3-1 (Modified from Figure 14 of Class II permit application for Independence AGI #2, Geolex, Inc.)

<u>Table 3.3-1</u>: Anticipated formation tops at the Independence AGI #2 location. (Extracted from Table 6 of Class II permit application for Independence AGI #2, Geolex, Inc.)

FORMATION	DEPTH (TVD)	DEPTH (MD)	FORMATION	DEPTH (TVD)	DEPTH (MD)
Dockum	485	485	Bone Spring	8,467	8,632
Ochoa-Dewey	747	747	Wolfcamp	11,131	11,387
Rustler	1,130	1,130	Strawn	12,004	12,289
Salado	1,720	1,720	Atoka	12,733	13,044
Tansill	3,401	3,401	Morrow	13,541	13,880
Yates	3,461	3,461	Barnett	14,949	15,336
7 Rivers	3,542	3,542	Osage	15,380	15,703
Queen	3,663	3,663	Woodford	15,745	16,142
Capitan Reef	3,935	3,943	Devonian	16,080	16,477
Bell Canyon	5,425	5,484	Wristen	16,467	16,864
Cherry Canyon	6,277	6,364	Fusselman	17,201	17,598
Brushy Canyon	7,058	7,174	Montoya	17,684	18,081



<u>Figure 3.3-</u>2: Structure contour map showing the top of the Siluro-Devonian target reservoir. Two (2) faults identified in review of 3D seismic data are shown with red dashes. Also, shown are wells within 1 mile of the Independence AGI Wells that penetrate the Siluro-Devonian target zone. Cross section A – A' is shown in <u>Figure 3.3-3</u>. (Modified from Figure 15 of Class II permit application for Independence AGI #2, Geolex, Inc.) Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.

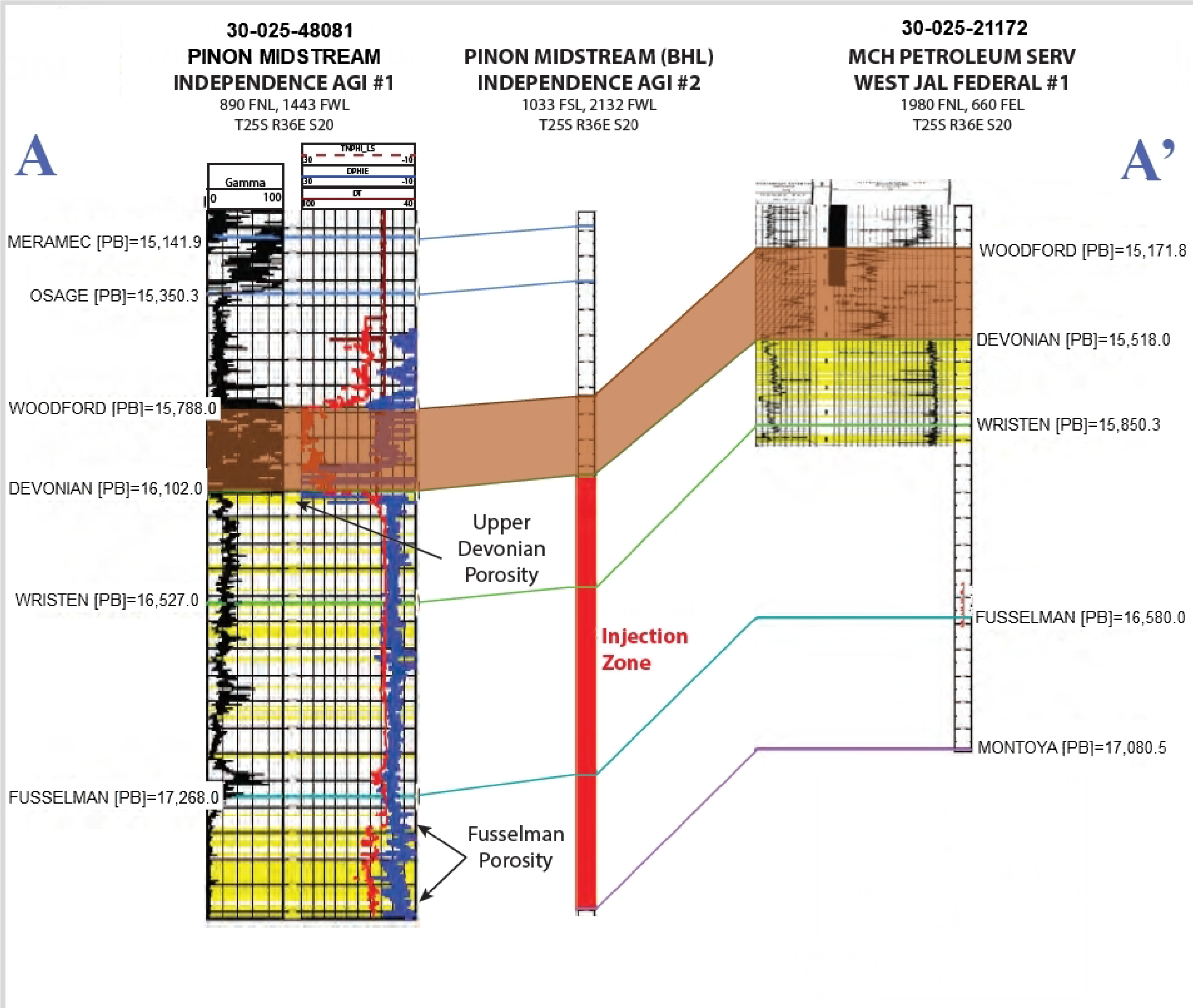


***Figure 3.3-3**: Structural cross section A-A' showing porosity profile from nearby wells penetrating the Siluro-Devonian Injection Zone and regional extent of overlying Woodford Shale caprock. The Independence AGI #2 Injection Zone is from 16,080 feet TVD to 17,683 feet TVD (red bar). (Modified from Figure 16 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

3.4 Chemistry of Siluro-Devonian Interval Formation Fluids

A review of formation waters from the U.S. Geological Survey National Produced Waters Geochemical Database v. 2.3 identified twenty-one (21) wells with analyses of fluid samples collected from the Siluro-Devonian interval. These samples were collected from wells within approximately fifteen (15) miles of the Independence AGI Wells. Results of laboratory analysis to determine their composition are summarized in Table 3.4-1. These results have been supplemented with samples collected from Independence AGI #1 on May 31, 2021 which show Total Dissolved Solids ("**TDS**") values ranging from 109,000 to 115,000 parts per million ("**ppm**").

*Table 3.4-1: Summary of Siluro-Devonian produced water analyses from nearby wells (U.S. Geological Survey National Produced Water Geochemical Database v. 2.3) * (Extracted from Table 7 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

API	WELL NAME	CONCENTRATION (parts per million)							
		TDS	HCO3	Ca	Cl	K + Na	Mg	Na	SO4
3002548081	Ind. AGI 1	110000	342	5600	68000	32559	759	31800	664
3002510945	Hill-federal D 1	112959	288	6264	67390	34340	1912	-	2765
3002510947	EC Hill-federal 1	35639	-	1369	22070		592	11608	-
3002511126	JR Holt A3	116415	154	7501	71110	34680	1767	-	1203
3002511196	S. Mattix Unit 3	68431	990	3180	40960	21690	974	-	637
3002511202	S. Mattix Unit 11	67130	853	5075	40430	16950	2348	-	1474
3002511383	Hodges B 3	81712	722	4320	47500	25400	1030	-	2740
3002511556	Blocker-federal 4	57675	595	2850	34030	18370	619	-	1211
3002511747	Ab Coates FED D2	82794	977	2408	47200	28190	851	-	3168
3002511760	Ida Wimberley 5	63817	360	2774	35870	20750	621	-	3442
3002811763	Ida Wimberley 9	61040	900	2680	35600	19560	800	-	1500
3002511765	Carlson-federal A3	66418	690	3002	37650	20390	1339	-	3347
3002511812	Clyde Lanehart 1	99879	687	4753	60410	32610	828	-	591
3002511818	Copper 1	27506	1089	1384	15270	8144	540	-	1079
3002511863	Arnott Ramsay B3	158761	476	17240	100300	35400	5345	-	-
3002511886	Dabbs 1	101036	540	5393	61630	30380	2183	-	910
3002511890	Sam Dabbs 1	85150	675	5368	50260	25130	1395	-	2322
3002511907	Arnott Ramsay F9	58220	367	1546	32790	-	278	20430	2816
3002511950	Farnsworth FED 6	31931	302	7196	20450	1151	2241	-	591
3002512272	LE Elliott FED H1	58687	761	3004	35460	18980	482	-	-
3002512286	JB McGhee 1	62392	552	2696	34380	20060	702	-	4002
3002521601	North Custer Mt 1	>64,000	1610	2136	36230	21830	403	-	1950

These analyses report TDS in the area of the Independence AGI Wells ranging from 27,506 to 158,761 ppm with an average of 75,981 ppm. The primary constituent in sampled formation waters is the chloride ion, with an average concentration of 45,227 ppm. The closest well, Independence AGI #1, at approximately 3,000 feet away from the Independence AGI #2 BHL, has reservoir fluids with a TDS value of approximately 110,000 ppm, and chloride ions in concentrations of approximately 68,000 ppm. Based on this data, the Siluro-Devonian reservoir fluids are anticipated to be completely compatible with the TAG injectate.

3.5 Potential for Induced Seismicity in the area of the Dark Horse Facility

To evaluate the potential for seismic events in response to injected fluids, Piñon conducted an induced-seismicity risk assessment for the area surrounding the Independence AGI Wells. This estimate (a) models the impact of seven (7) injection wells over a thirty (30) year injection period, and (b) estimates the fault-slip probability associated with the simulated injection scenario(s). This analysis was completed utilizing the Stanford Center for Induced and Triggered Seismicity's Fault Slip Potential ("**FSP**") model developed by Walsh and Zoback, 2016.

To identify subsurface structures in the area of the Independence AGI Wells, Piñon evaluated and interpreted licensed seismic survey data (WesternGeco – South Lea Survey) covering the Lea County area of interest. Based on this review, Piñon identified eight (8) subsurface faults in the area surrounding the Independence AGI Wells (Figure 3.5-1). The closest fault is observed to be located approximately one (1) mile east of the

Independence AGI Wells. Major faults in the area (those exhibiting significant lateral extent) generally strike NNW-SSE with minor faults striking NE-SW and NW to SE.

Due to the location of faults relative to the Independence AGI Wells and the general low density of injection wells in the immediate area of the Independence AGI Wells, it is anticipated that the injection scenario(s) will not pose any elevated risk of injection-induced fault slip. To support the interpretation that these structures would not be affected by operation of the Independence AGI Wells, a fault-slip probability analysis was completed to quantify the risk associated with injection operations in the area surrounding the Independence AGI Wells, and although the risk of induced seismicity is low, a seismic monitoring station was installed at the facility prior to the commencement of injection into Independence AGI #1. The station transmits data to the New Mexico Tech Seismic Network and will aid the state in seismicity interpretations.

To calculate the fault-slip probability for the model simulations, input parameters characterizing the local stress field, reservoir characteristics, subsurface features, and injected fluids are required. Parameters utilized and their sources for the area surrounding the Independence AGI Wells are included in Table 3.5-1. Additionally, Table 3.5-2 details the injection volume characteristics and locations of the injection wells modeled in the injection scenario(s). To ensure the model simulations provide a conservative estimation of induced-seismicity risk, injection wells included in the simulations were modeled utilizing their maximum anticipated daily injection volumes as recorded by NMOCD approved permits. Due to the minimal reported injection volume of the Jal North Ranch SWD #1, a potential of 10,000 bpd was assumed to account for the potential of increased injection rates due to future needs of the operator or any future workover that may improve the injectivity of this well.

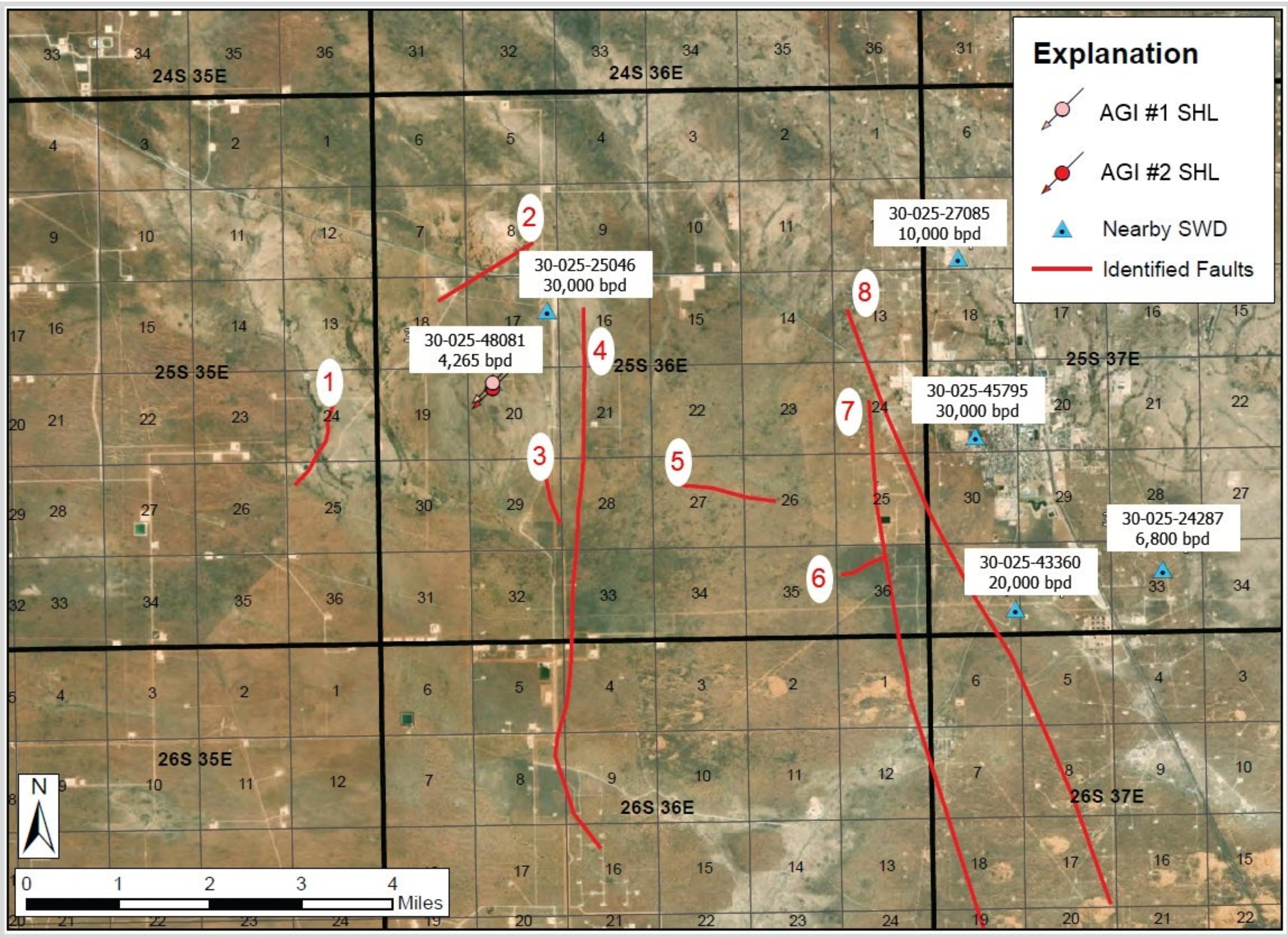
Daily maximum injection volumes utilized in the fault-slip probability model range from 4,265 to 30,000 bpd (Table 3.5-2). In submission of the Class II injection well applications, Piñon requested approval to operate the Independence AGI Wells for a period of at least thirty (30) years, however, the duration of the FSP model simulation was increased to forty (40) years to characterize the reservoir effects of injection wells that are currently operating and have been in operation since 2010. Figure 3.5-2 shows the resultant pressure front and single well radial pressure solutions, as predicted by the FSP model, after thirty (30) years of injection at the maximum injection rates.

For this study, limitations of the FSP model required a conservative approach be taken in determining the fault-slip probability of the injection scenario. Specifically, the FSP model is only capable of considering a single set of fluid characteristics and this study aims to model an injection scenario that includes both brine injection and AGI. To ensure a conservative fault-slip probability estimate, the Independence AGI Wells were simulated utilizing the characteristics of a brine injectate. This approach yields a more conservative model prediction as brine displays greater density, dynamic viscosity, and is significantly less compressible than TAG. For comparison, characteristics of TAG at the anticipated reservoir conditions, as modeled by AQUAlibrium™, are shown in Table 3.5-1.

Generally, faults considered in this assessment are predicted by the FSP model to have very low potential for injection-induced slip and operation of the Independence AGI Wells is not predicted by the model to contribute significantly to the estimate of risk (Table 3.5-3 and Figure 3.5-3). Table 3.5-3 summarizes the predicted pressure change along each fault segment and includes the model-derived pressure change necessary to induce slip for each feature. Fault-slip probability values range from 0.00 to 0.05 with the majority of fault segments predicted to have zero probability of slip (Table 3.5-3). Major faults (faults 4, 7, and 8 in Figure 3.5-1) in the area, which would have the greatest energy release potential upon slip, are predicted to have zero probability for slip in response to the modeled injection scenario.

In summary, no structures included in the modeled simulations are predicted to be at increased risk for injection-induced slip in response to the injection scenario presented. Features estimated to have a non-zero

slip potential are generally smaller-scale features and predicted probabilities are very low (≤ 0.05). Furthermore, subsequent model simulations in which contribution from Independence AGI #2 is excluded illustrate that operation of the Independence AGI #2 will have little impact on conditions near the identified faults in the area due to significantly lower proposed injection volumes in comparison to nearby brine injection wells.



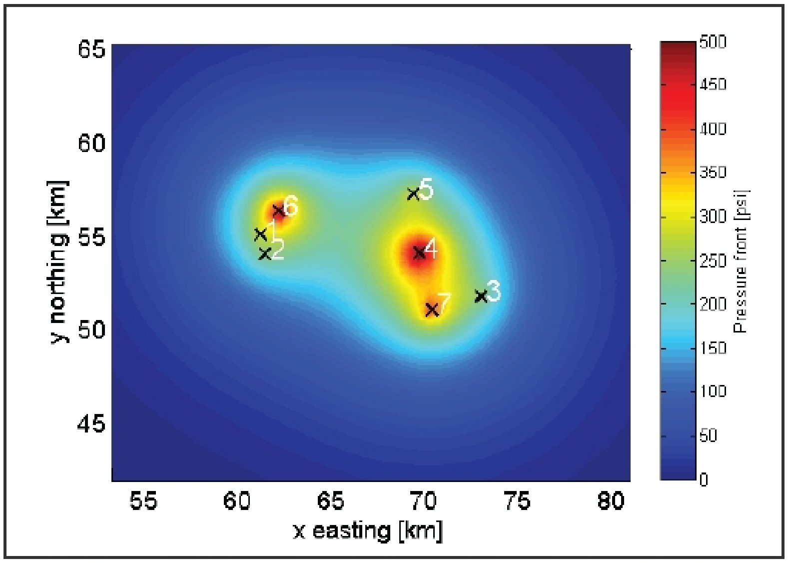
<u>Figure 3.5-1</u>: Map showing Siluro-Devonian injection wells and subsurface identified faults in the vicinity of the Independence AGI Wells. (Modified from Figure 18 of Class II permit application for Independence AGI #2, Geolex, Inc.)

***Table 3.5-1**: Input parameters and source material for FSP model simulations. (Extracted from Table 10 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

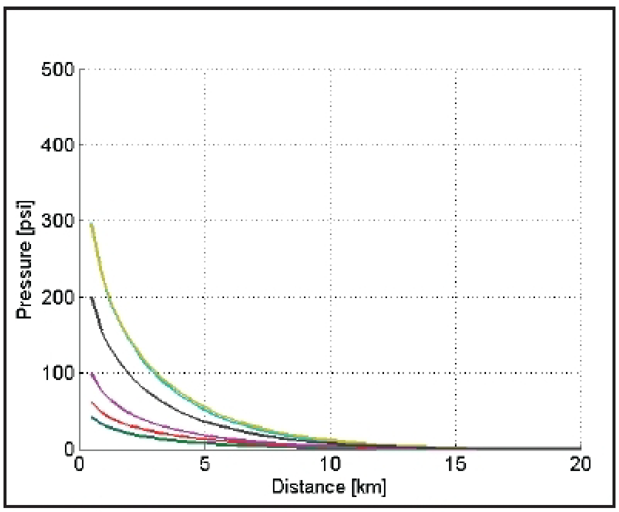
Modeled Parameter	Input Value	Variability (+/-)	UOM	Source
Stress				
Vertical Stress Gradient	1.05	0.105	psig/ft	Nearby well estimate
Max Horizontal Stress Direction	N75E	5	Deg	Lund Snee & Zoback, 2018
Reference Depth	17000		ft	Nearby well evaluation
Initial Res. Pressure Gradient	0.43	0.043	psig/ft	Lund Snee & Zoback, 2018 Nearby well evaluation
A_ϕ Parameter	0.6	0.06	-	Lund Snee & Zoback, 2018
Reference Friction Coefficient (μ)	0.6	0.06	-	Standard value
Hydrologic				
Aquifer Thickness	1500	0	ft	Nearby well evaluation
Porosity	3.5	0.35	%	Nearby well evaluation
Permeability	20	2	mD	Nearby well evaluation
Material Properties				
Density (Water)	1040	40	Kg/m^3	Standard value
Dynamic Viscosity (Water	0.0008	0.0001	Pa.s	Standard value
Fluid Compressibility (Water)	3.6×10^{-10}	0	Pa^{-1}	Standard value
Rock Compressibility	1.08×10^{-9}	0	Pa^{-1}	Standard value
Acid Gas Properties @ 7,370 psig & 228 °F				
Density	821.80	-	kg/m^3	AQUAlibrium™
Dynamic Viscosity	8.067×10^{-5}	-	Pa.s	AQUAlibrium™

***Table 3.5-2**: Location and characteristics of injection wells modeled in the FSP assessment. (Extracted from Table 11 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

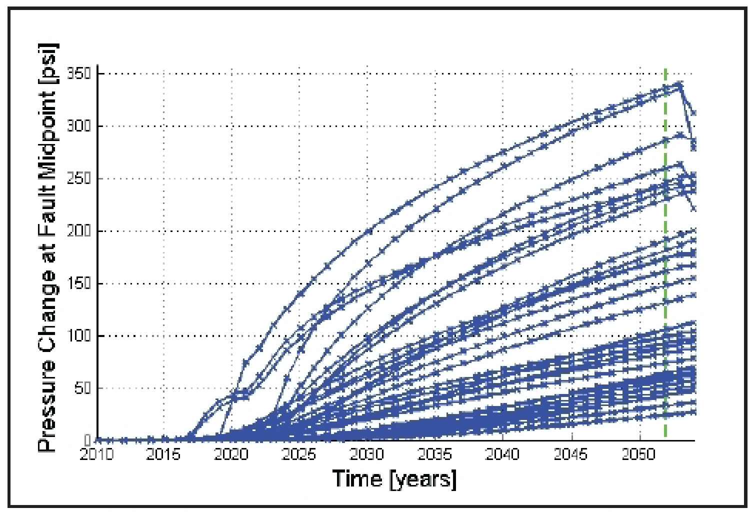
#	API	Well Name	LAT	LONG	Volume (bbls/day)	Start (year)	End (year)
1	3002548081	Independence AGI #1	32.120855	-103.291021	4265	2020	2052
2	-	Independence AGI #2	32.111454	-103.288812	4265	2022	2052
3	3002524287	Crosby Deep #2	32.089508	-103.166733	6800	2010	2052
4	3002545795	Sholes Deep SWD #1	32.110998	-103.201266	30000	2020	2052
5	3002527085	Jal N. Ranch SWD #1	32.139347	-103.203911	10000*	2017	2052
6	3002525046	West Jal B Deep #1	32.132091	-103.280708	30000	2015	2052
7	3002543360	Kimberly SWD #1	32.083537	-103.194274	20000	2019	2052



Panel A. Resultant pressure front after 30 years of injection operations at the maximum anticipated injection rates, as reported in **NMOCD** records



Panel B. Single well radial pressure solutions, as determined by the FSP model

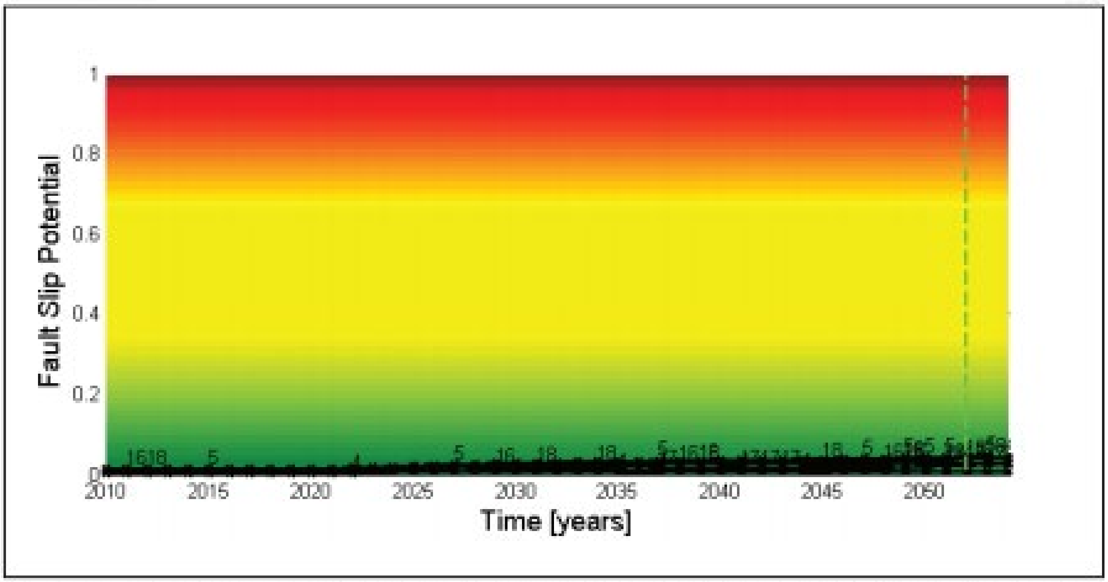


Panel C. Model-predicted pressure change through time at the midpoint of each fault segment included in the simulation

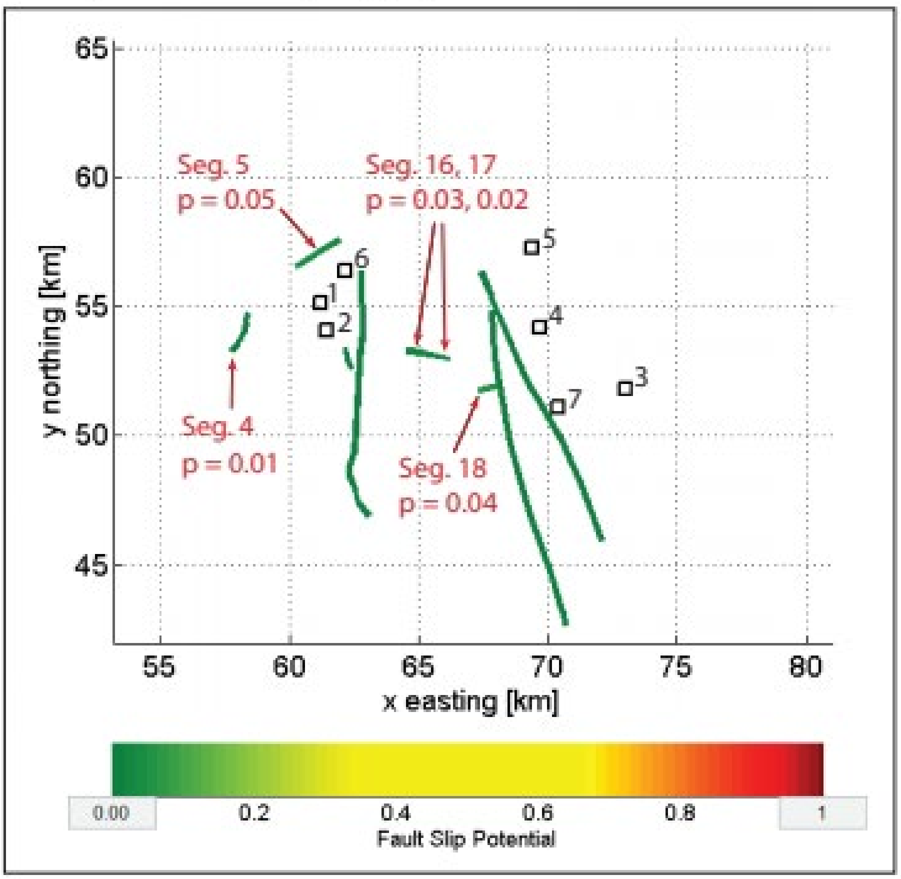
<u>Figure 3.5-2</u>: Summary of model-predicted pressure effects in response to the simulated seven (7) well injection scenario. (Extracted from Figure 19 of Class II permit application for Independence AGI #2, Geolex, Inc.)

<u>Table 3.5-3</u>: Summary of model-simulation results showing the required pressure change to induce fault slip, actual change in pressure as predicted by the FSP model, probability of fault slip at the end of the thirty (30) year injection scenario, and fault-slip probability when Independence AGI #2 is excluded from simulation. (Extracted from Table 12 of Class II permit application for Independence AGI #2, Geolex, Inc.)

Fault #	Segment #	ΔPressure necessary to induce fault slip	Actual ΔPressure at 2052	Fault Slip Potential at 2052	FSP (excluding AGI #2)
1	1	3137	109	0.00	0.00
	2	4357	103	0.00	0.00
	3	1786	93	0.00	0.00
	4	1201	83	0.01	0.01
2	5	1197	253	0.05	0.05
3	6	6869	186	0.00	0.00
	7	6298	168	0.00	0.00
4	8	5645	277	0.00	0.00
	9	4610	194	0.00	0.00
	10	5005	117	0.00	0.00
	11	2709	70	0.00	0.00
	12	5302	63	0.00	0.00
	13	6339	57	0.00	0.00
	14	6899	51	0.00	0.00
	15	4197	46	0.00	0.00
5	16	1101	192	0.03	0.03
	17	1085	199	0.02	0.02
6	18	1554	234	0.04	0.04
7	19	6012	290	0.00	0.00
	20	6680	241	0.00	0.00
	21	6914	133	0.00	0.00
	22	6758	61	0.00	0.00
	23	6931	33	0.00	0.00
	24	6590	25	0.00	0.00
8	25	6508	250	0.00	0.00
	26	6327	334	0.00	0.00
	27	5455	228	0.00	0.00
	28	6305	174	0.00	0.00
	29	6684	89	0.00	0.00



Panel A. Fault-slip probability throughout the entire simulated injection period. FSP model results suggest no significant risk of injection-induced slip along any feature included in the simulation.



Panel B. Map view illustrating the model-estimated slip potential of faults at the end fo the 42-year injection scenario. Any feature estimated to have a non-zero slip potential determination is labeled on the above map.

<u>Figure 3.5-3</u>: Summary of model-determined fault-slip probabilities over the simulated injection period (2010-2052). (Modified from Figure 20 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.6 Groundwater Hydrology in the Vicinity of the Dark Horse Facility

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are fifteen (15) water wells and points-of-diversion located within a two (2) mile radius of the Independence AGI Wells. Of these wells, the closest is located approximately 0.34 miles away and has a total depth of 505 feet (Figure 3.6-1 and Table 3.6-1). The remaining fourteen (14) wells within the two (2) mile radius have depths of approximately 240 to 600 feet deep, collecting water from Alluvium and the Triassic red beds. The shallow freshwater aquifer will be protected as the Independence AGI Wells are designed to isolate shallow zones via a five (5) string casing design including a surface casing interval that extends to 1,230 feet within the Rustler Formation, effectively isolating shallow groundwater resources (Figures A1-1 and A1-2).

The area surrounding the Independence AGI Wells is arid and there are no surface water bodies within a two (2) mile radius.

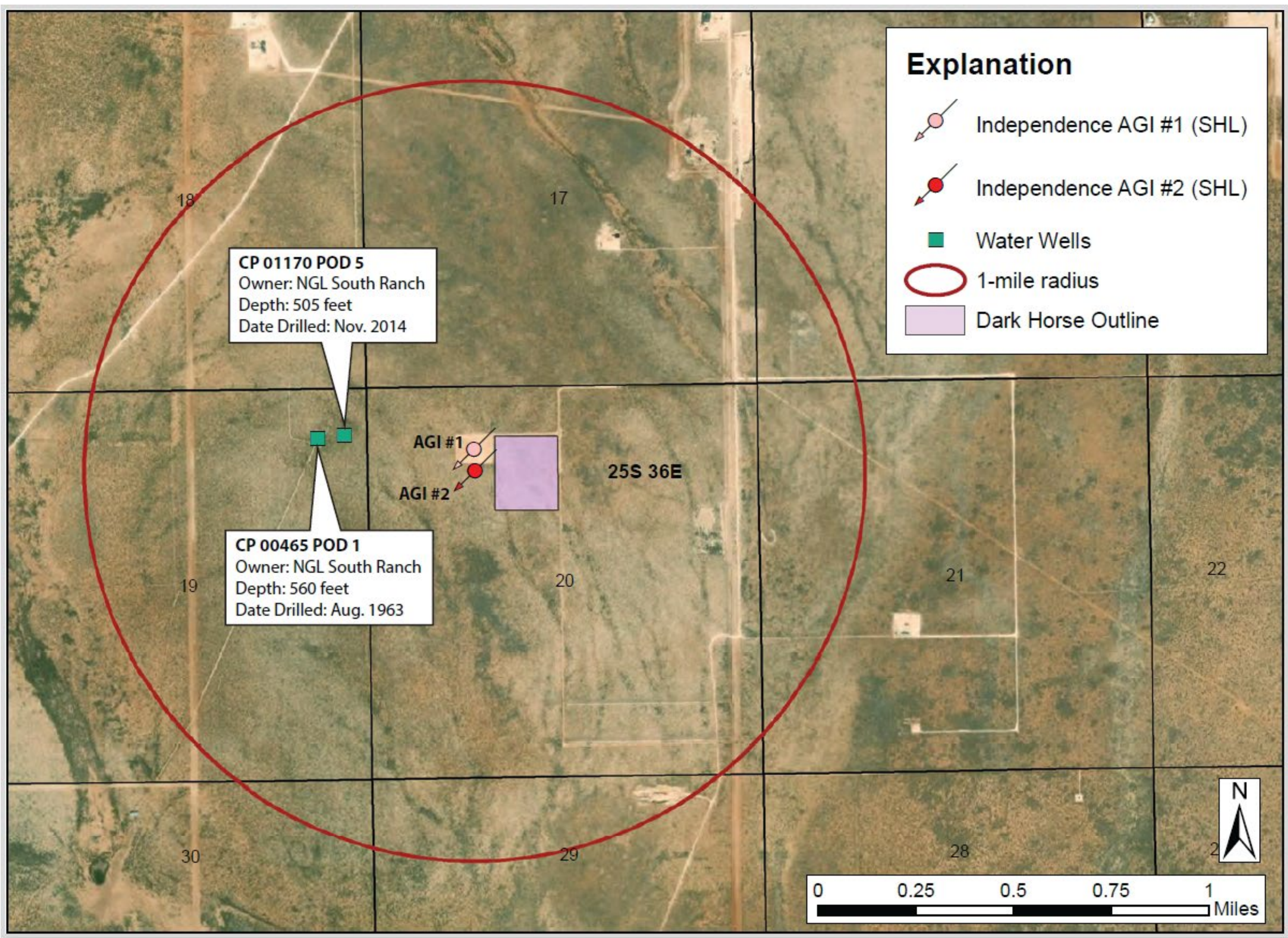


Figure 3.6-1: Reported water wells within 1-mile radius of the SHLs of the Independence AGI Wells. The BHLs for AGI #1 and #2 are not shown. (Extracted from Figure 17 of Class II permit application for Independence AGI #2, Geolex, Inc.) Only SHLs shown for the Independence AGI #1 and #2 wells.

***Table 3.6-1**: Water wells within one (1) mile of the Independence AGI Wells (Retrieved from the New Mexico Office of the State Engineer's Files on October 4, 2021). (Extracted from Table 8 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

POD #	Source	Use	Owner	LAT (NAD83)	LONG (NAD83)	Distance (miles)	Depth (feet)	Date Completed
CP 1170 POD 5	Shallow	Commercial	NGL South Ranch	32.121417	-103.296667	0.34	505	11/2014
CP 465 POD 1	Shallow	Commercial	NGL South Ranch	32.119465	-103.299882	0.53	560	08/1963

According to Order No. 190 of the New Mexico Office of the State Engineer signed March 22, 2021, the Capitan Underground Water Basin, within which the Independence AGI Wells lie, is closed indefinitely to new appropriations of water. Therefore, no new water wells are anticipated to be constructed during the Independence AGI Wells' anticipated thirty (30) year operation period. Due to the shallow completion depths of the few groundwater wells in the area surrounding the Independence AGI Wells, it is highly unlikely that groundwater wells will serve as conduits for CO_2 leakage to the surface.

Geolex conducted a review of Geology and Ground-Water Conditions in Southern Lea County, New Mexico (Nicholson and Clebsch, 1961) to identify published groundwater data representative of nearby water wells in the area surrounding the Independence AGI Wells. Table 3.6-2 summarizes the wells identified in this review and the results of those analyses.

***Table 3.6- 2**: Chemical analysis results of samples collected from water wells in the area surrounding the Independence AGI Wells (Nicholson and Clebsch, 1961 – Geology and Groundwater Conditions in Southern Lea County, New Mexico). (Taken from Table 9 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

Historical Owner	Location (T-R-S)	Location (Qtr-Qtr)	Depth (ft)	Ca (ppm)	Mg (ppm)	Na+K (ppm)	HCO_3 (ppm)	SO_4 (ppm)	Cl (ppm)	NO_3 (ppm)
Sun Oil Co.	25-37-15	NE/4 NE/4	-	307	98	271	145	737	610	9
City of Jal	25-37-19	NE/4 NE/4	500	55	49	170	376	280	71	0.4
City of Jal	25-37-19	SE/4 NE/4	450	34	43	175	264	286	54	0.5
City of Jal	25-37-20	NW/4 SW/4	70	-	-	-	150	145	168	7.6

This analysis confirms that the Independence AGI Wells pose no risk of contaminating groundwater in the area as (a) the well design includes material considerations to protect shallow groundwater resources, and (b) there are no identified conduits that would facilitate migration of injected fluids to freshwater-bearing strata nor to the surface.

3.7 Historical Operations

3.7.1 Operations within a 2-mile radius of the Independence AGI Wells

Appendix 3 summarizes in detail all NMOCD recorded wells within a two (2) mile radius of the Independence AGI Wells. These wells are shown in Figure 3.7-1 and include active, plugged, and new (permitted but not yet drilled) well locations. In total, there are fifty-four (54) wells within a two (2) mile radius of the Independence AGI Wells. Of these, there are ten (10) active wells, thirty-three (33) permitted wells, and eleven (11) plugged wells. Active wells in the area include one brine injection well completed across the Strawn through Fusselman formations, and nine (9) active oil and natural gas wells completed in various other strata.

There are two (2) third-party wells within two (2) miles of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone (Table 3.7-1). The first well is an active brine injection well (West Jal B Deep #1) located approximately one (1) mile from the Independence #2 SHL. This well was drilled to a total depth of 18,945 feet and is permitted to inject through perforated intervals of the Strawn through Fusselman strata. Despite being granted approval for injection into the Fusselman (approved June 2014), NMOCD records document no reports of work to drill out plugged intervals at 14,200 feet. There is a Form C-103- Sundry Notices and Reports on Wells - (submitted November 2018) that indicates the intent of BC&D Operating to drill out these intervals, but no subsequent reports confirming completion of this work have been identified. Additionally, reported injection volumes for this well do not appear to exhibit any significant increase that might indicate this work was completed. The second well penetrating the Siluro-Devonian Injection Zone is the plugged West Jal Unit #1, located approximately 0.67 miles from the Independence AGI #2 SHL. Final plugging operations were completed in April 1984 and all relevant plugging reports and documents are included in Appendix 9. The well is properly cemented through the Siluro-Devonian Injection Zone, and it is not anticipated to be negatively affected by the operation of the Independence AGI Wells.

***Table 3.7-1*: Wells located within a two (2) mile radius of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone. (Additional details are provided in Appendix 3)**

API	Well Name	Pool	Status	TVD
30-025-21172	WEST JAL UNIT #1	Strawn	Plugged	17,086
30-025-48081	INDEPENDENCE AGI #1	Devonian - Fusselman	Active	17,750
30-025-49974	INDEPENDENCE AGI #2	Devonian - Fusselman	New	17,683 (proposed)
30-025-25046	WEST JAL B DEEP #001	Mississippian – Fusselman	Active	18,945

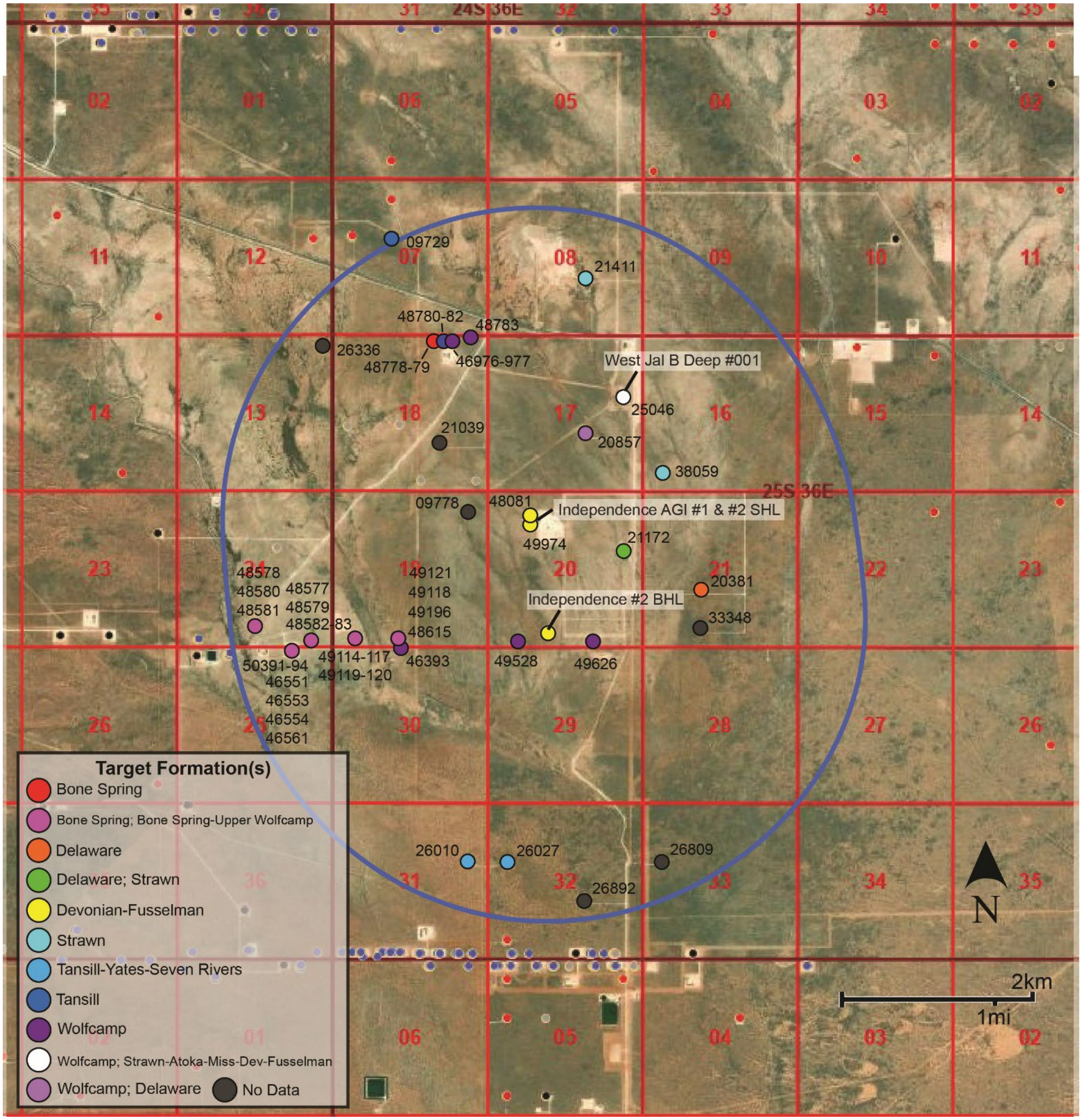


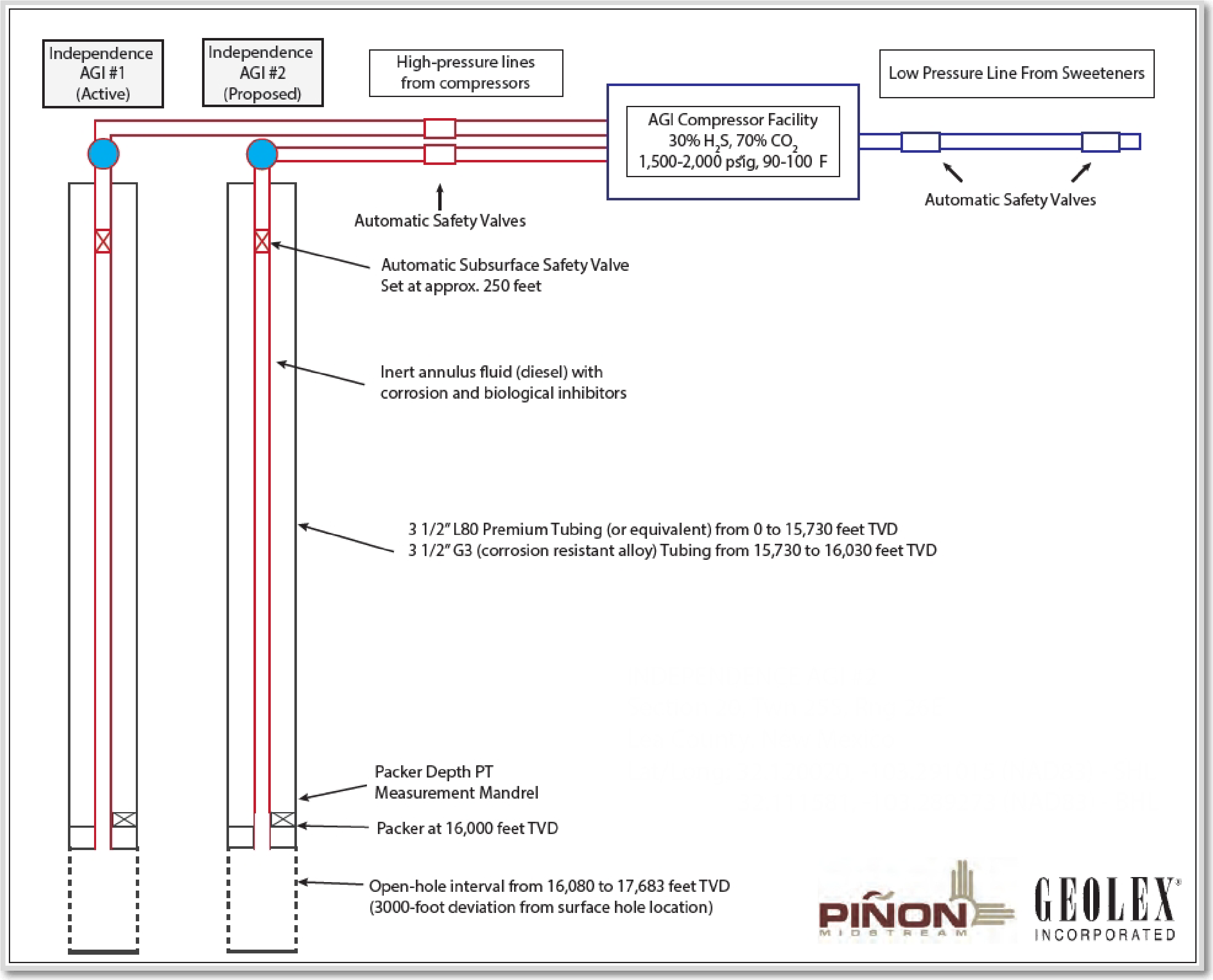
***Figure 3.7-1**: Location of all oil- and natural gas-related wells within a two (2) mile (blue line) of the Independence AGI Wells. Colors indicate the target formation(s) for each well. The oblong shape of the two (2) mile area accounts for the BHL of Independence AGI #2 as shown in Figure 3.1-1. Labels denote the last five (5) digits of API #30-025-XXXXX. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.*

3.8 Description of Injection Process

Once delivered to the Dark Horse Facility, sour natural gas is treated using amine to isolate H_2S and CO_2. The amine (which now contains H_2S and CO_2) is then regenerated which creates a TAG waste stream. This TAG waste stream is then routed to on-site compression facilities that compress the TAG waste stream into a dense phase (roughly 1,250 psig). The dense phase stream is then pumped to upwards of 2,500 psig prior to being sent to Independence AGI #1 (and when complete, Independence AGI #2), through a National Association of Corrosion Engineers ("**NACE**") rated pipe, for injection. Figure 3.8-1 is a schematic of the surface facilities for the Independence AGI Wells. The sweet natural gas that results from the amine scavenging process is then treated to remove water ("**H_2O**")and subsequently transported offsite, via pipeline, and redelivered to Piñon's customers at various delivery points.

For the period of September 2021 through March 2022, the TAG stream at the Dark Horse Facility averaged 57.076% CO_2 and 38.703% H_2S by volume, with hydrocarbons (C1 – C7) and H_2O comprising the remaining volume.

The anticipated duration of TAG injection into the Independence AGI Wells at the Dark Horse Facility is approximately thirty (30) years.



<u>Figure 3.8-1</u>: Schematic of surface facilities at the Dark Horse Facility and the Independence AGI Wells. (Modified from Figure 3 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.9 Reservoir Characterization Modeling

The Independence AGI Wells penetrate the lower Devonian Thirtyone formation and the Silurian Wristen and Fusselman formations and overlies the Ordovician Montoya formation. The upper Devonian Woodford formation serves as the primary containment seal with thick shales having an estimated permeability in the nanodarcy range.

Schlumberger's Petrel (Version 2020.4) software was used to construct the geological models used in this work. Schlumberger's simulation software Eclipse Compositional E300 (Version 2020.1) was used in the reservoir simulations presented in this MRV Plan with simulation results and visuals provided by Geolex Inc. The model simulates solubility trapping of the injected TAG in the formation water and/or the portion of the TAG that can exist in a supercritical phase. The modeling did not consider CO_2 storage attributed to mineral and geomechanical trapping mechanisms. Also, the model did not implicitly model storage attributed to residual trapping because insufficient information was available to develop the hysteresis effects.

Though the Independence AGI Wells were modeled separately, similar constraints were used for both models. The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. The injection

gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Both TAG components are assumed to be soluble into the aqueous phase. An irreducible water saturation of 0.17 is used to generate the relative permeability curves for the gas/water system. The external boundary conditions are specified to be Neumann boundaries and hence no-flow with respect to mass.

3.9.1 AGI Injection Characterization and Modeling

Formation tops were picked from the few well logs available for the area and geophysical measurements and mapped to construct the structural surfaces for the Silurian-Devonian reservoir between the underlying Montoya and capping Woodford formations. The geologic model extends approximately twenty (20) square miles with an irregular polygonal edge (Figure 3.9-1) and includes relevant subsurface features (e.g. faults, folds) and nearby injection wells. The simulation grid is comprised of 292 simulation layers characterizing eight (8) discrete zones. Horizontal spacing is uniform at 500 × 500 feet throughout the model, and the numerical grid overall contains 923,000 grid cells. Figure 3.9-1 shows the structural surface for Layer 1, covering the top of the reservoir immediately below the Woodford cap. Porosity data derived from the Independence AGI #1 well logs augmented by 3D seismic survey impedance data along with drill-stem and injection tests were used to populate the model porosity values (Figure 3.9-2). A porosity-permeability relationship was established to develop a correlation to populate 3D distribution of permeability (Figure 3.9-3). The permeability distribution signifies a fairly tight formation with typical values ranging from 1.0 to 79.0 millidarcies. Figure 3.9-4 shows the permeability distribution in Layer 1 of the model at the top of the Devonian Thirtyone Formation (*see* Section 3.3.1).

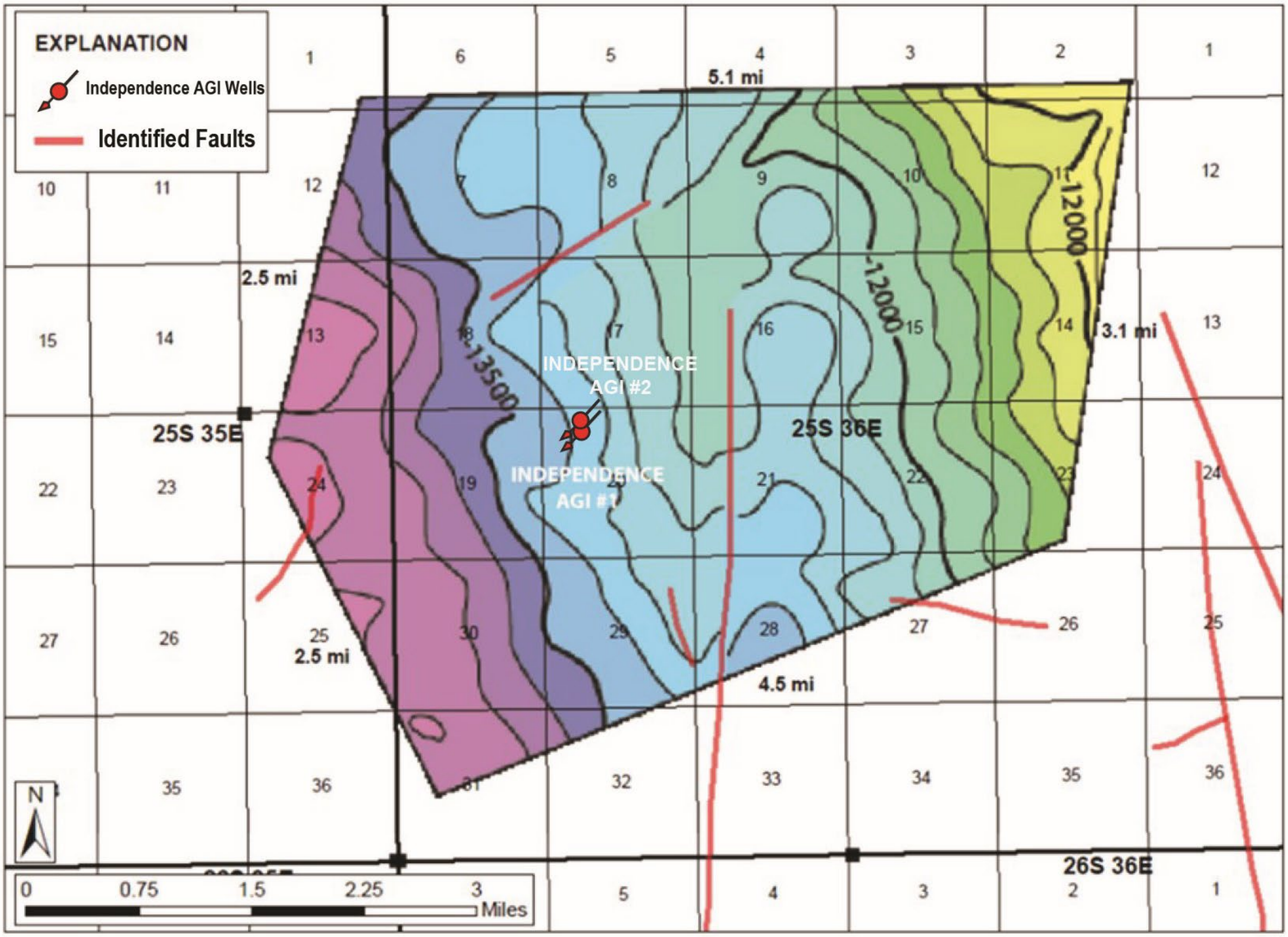
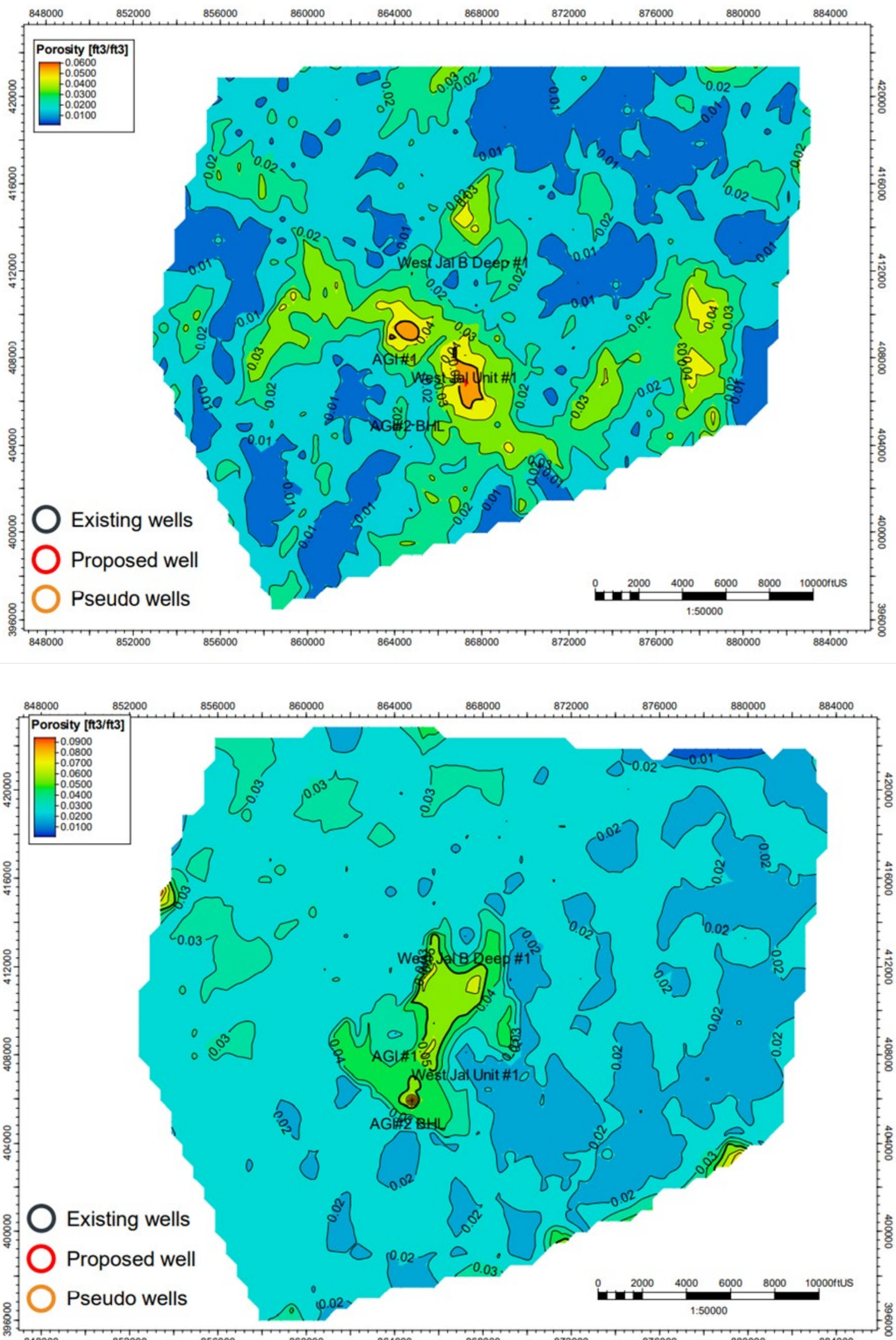
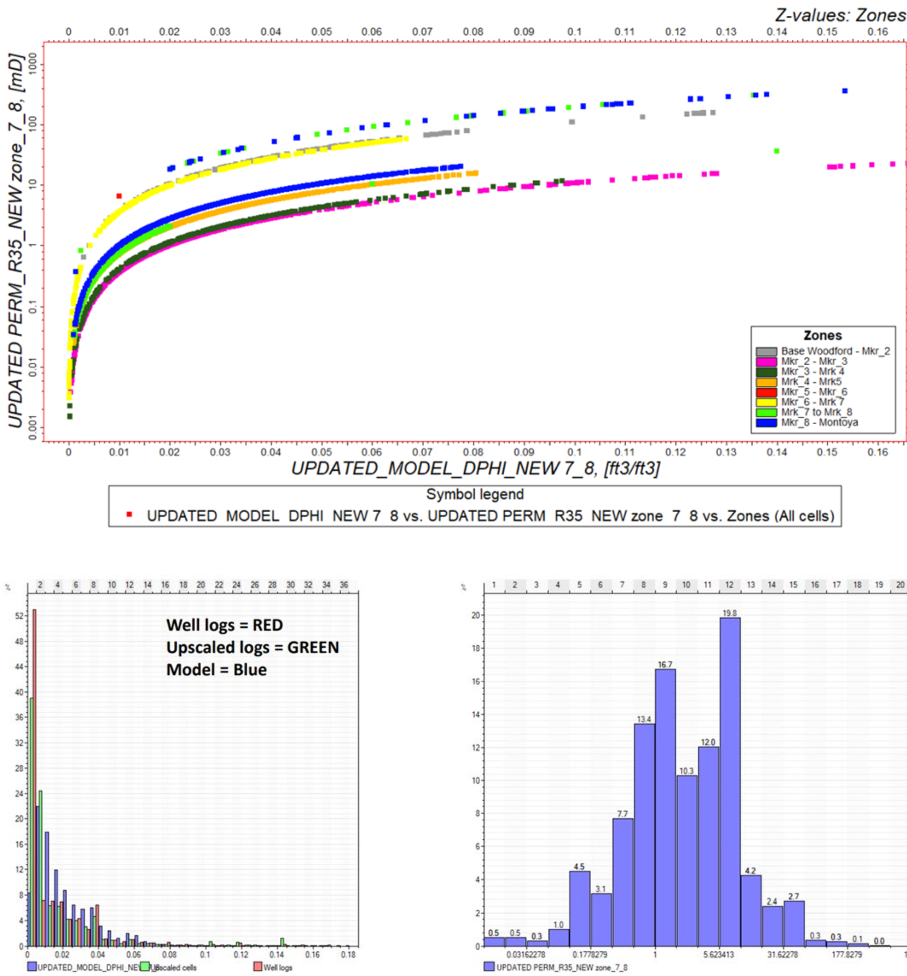


Figure 3.9-1: Structural surface for top of Layer 1 (top) of the geological and numerical model. Only SHLs shown for the Independence AGI #1 and #2 wells.



<u>Figure 3.9-2</u>: Model layer porosities for Zone 1 (top) and Zones 7 and 8 (bottom). Porosities are based on 2 wells, 3D seismic impedance surveys, and well stem tests. Only SHLs shown for the Independence AGI #1 and #2 wells.



<u>Figure 3.9-3</u>: Geological zones and ranges of the properties for the Siluro-Devonian geologic model

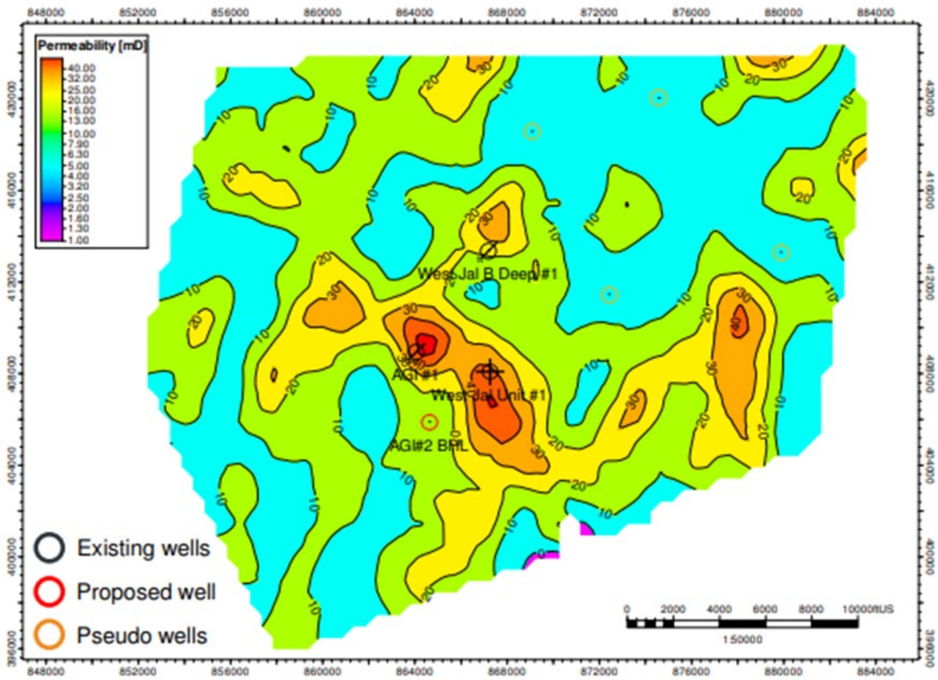


***Figure 3.9-4**: Graphic showing the permeability distribution in Layer 1 of the model representing the Thirtyone formation. Plan view. Only SHLs shown for the Independence AGI #1 and #2 wells.*

3.9.2 Simulation Modeling for the Independence AGI Wells

Once the geological model was established, numerical modeling was performed to:

1. Assess the maximum injection rate with respect to estimated maximum bottomhole pressure ("**BHP**") to ensure safe operation, and
2. Estimate the modeled extent of the injected TAG after thirty (30) year injection period and five (5) year post injection monitoring period.

The reservoir is assumed to be initially saturated with 100% brine and exhibit hydrostatic equilibrium with the initial pressure based on the measured pressure at the top of the reservoir pre-injection. The injection gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Gas is injected for 30 years at a rate of 1,036.73 tonnes per day (378,399 tonnes per year or 11,351,970 total tonnes) followed by a 5-year rest period. Permeability curves for the multiphase gas/water system are defined for three (3) material ranges with a residual liquid saturation between 40% and 65%. An estimated maximum BHP of 9,730 psig, based on the calculated fracture pressure gradient, was imposed on the Independence AGI #1 to ensure safe injection operations. This pressure was important for Independence AGI #1 in the model scenario where all TAG was injected into Independence AGI #1, but otherwise simulations showed pressure at the Independence AGI Wells remaining below this threshold. In all simulations where West Jal Deep B injected 30,000 bpd of brine into the reservoir, the West Jal Deep B would need to decrease injectivity to remain below its permitted threshold pressure. Present modeling work does not indicate sufficient connectivity between the West Jal Deep B and the Independence AGI Wells to impact AGI injectivity under all other modeled scenarios. Figure 3.9-5 shows the calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1. AGI rates are lower than target numbers and limited data are available so a more detailed calibration cannot yet be constructed. An injection forecast model was performed for a period of thirty (30) years with injection and then a five (5) year post-injection rest period to ascertain fluid movement and pressure evolution. Figure 3.9-6 shows the injection profile for the forecasting period which showed that the target injection rate could be hit in all scenarios except Scenario 5. The model showed that all the injected gas remained in the reservoir and there was no change in the size of the TAG extent compared at the end of injection and five (5) year post injection period.

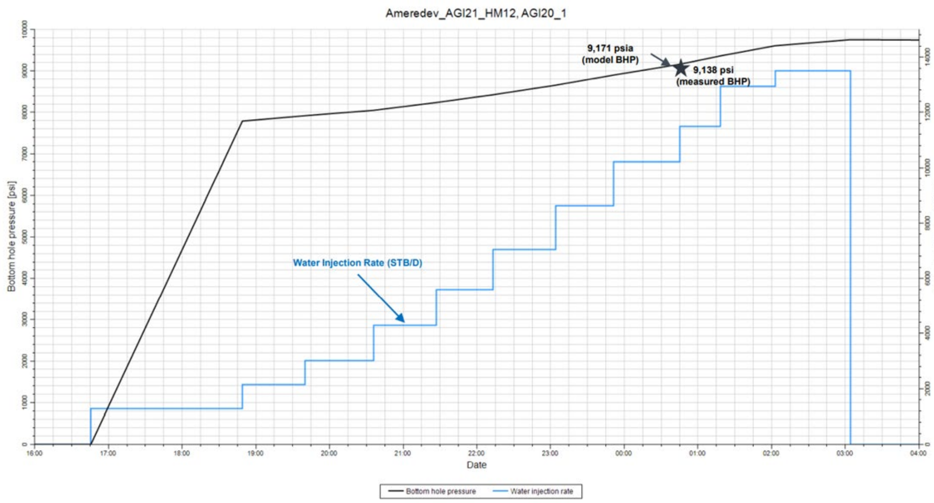


***Figure 3.9-5**: Graph showing calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1.*

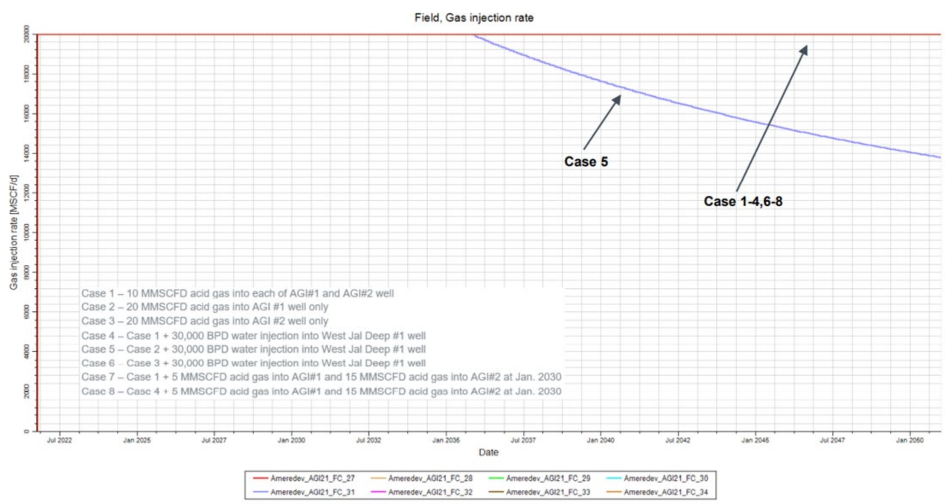


***Figure 3.9-6**: Graph showing the forecast profile for the injection rate and cumulative injection volume over the simulated period*

A considerable source of uncertainty in the plume model relates to the injectivity of the West Jal Deep B well located about one (1) mile northeast of Independence AGI #1. This well is permitted to dispose of up to 30,000 bpd of brine into several reservoirs, including the Siluro-Devonian reservoir used by the Independence AGI Wells, and other shallower reservoirs. It is unclear from publicly available data how this fluid is planned to be partitioned between the various injection layers. Modeling for the present application considered two (2) end-member scenarios: (a) All West Jal Deep B injection is into shallower reservoirs and does not interact with the Siluro-Devonian one (cases 1,2,3), or (b) all West Jal Deep B volumes are injected into the Siluro-Devonian reservoir (cases 4,5,6,7,8). The brine injection at this well is significant for several reasons:

- High volumes of brine injection within the Siluro-Devonian in relatively close proximity of the Independence AGI Wells may raise pressure in the reservoir;
- Pressure from the brine injection pushes against the advancing gas front, directing flow south and west away from the well; and
- The West Jal Deep B wellbore could be a potential leakage pathway if injection ceases and the supercritical fluid plume from the Independence AGI Wells reaches it. Simulations that do not include injections at this well have the TAG plume area including this well.

In all simulations with injection at West Jal Deep B, the local pressure at the brine injection well rapidly rises to the breakover point and the injection rate begins dropping within the first two (2) years of that well's operation to maintain pressures below 80% of the breakover threshold and ensure no rock fracturing occurs (Figure 3.9-7). It is unknown how in reality this will translate to well operations within the Siluro-Devonian reservoir. Simulations do not indicate that the pressure increase from this well will adversely affect the Independence AGI Wells due to the early shut down of the brine injection well. Simulations where there is no brine injection result in the plume extending farther northeast beyond the West Jal Deep B well (Figure 3.9-8). If brine is injected, then the plume is repelled towards the south and west, with some TAG flanking the northwest fault and extending northwest (Figure 3.9-9). Simulations suggest a pressure impact on Independence AGI #1 that could result in curtailed injections under a scenario with all TAG injection in Independence AGI #1 and West Jal Deep B active (Case 5, *see* Figure 3.9.6).

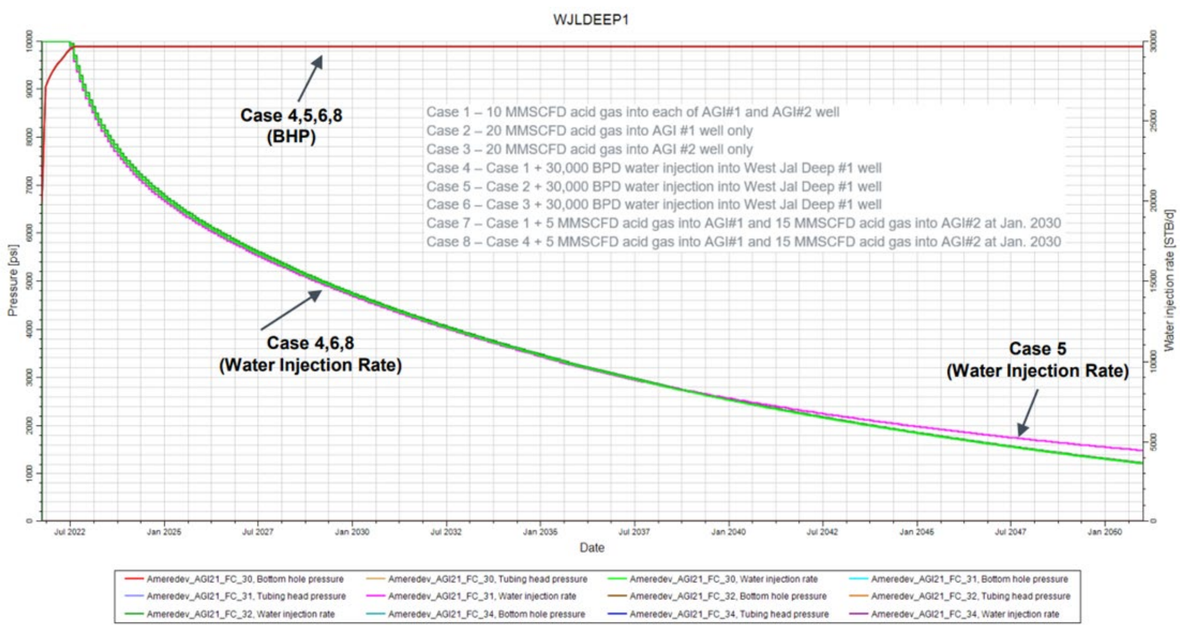
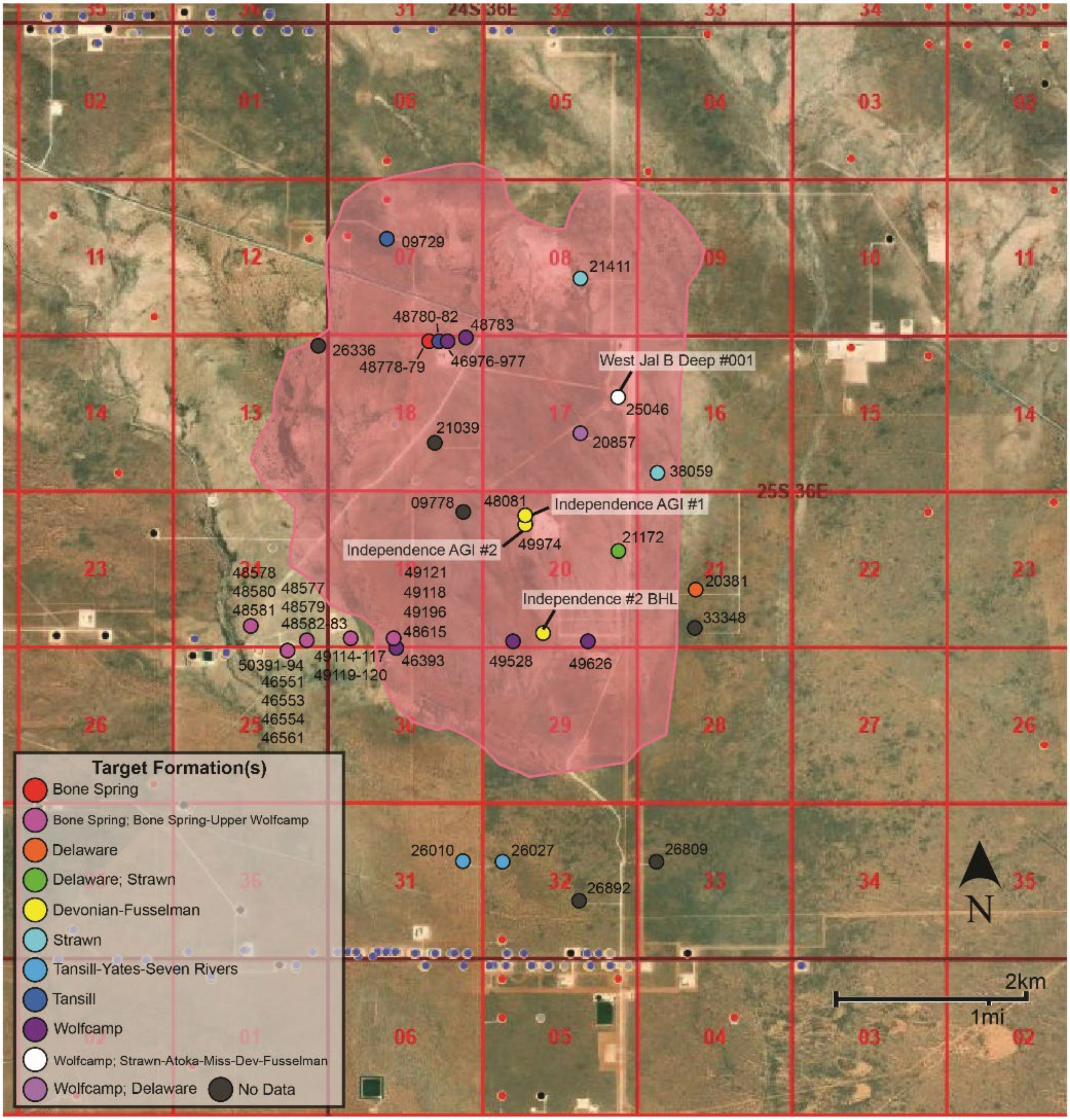


***Figure 3.9-7**: Graph showing the injection profile of the West Jal Deep B brine injection well under different injection scenarios.*



<u>Figure 3.9-8</u>: Map showing the largest lateral extent of the TAG when the West Jal Deep B well does not inject into the Siluro-Devonian. Colors indicate target formations for the well. West Jal Deep B is the white dot northeast of the Independence AGI Wells. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.

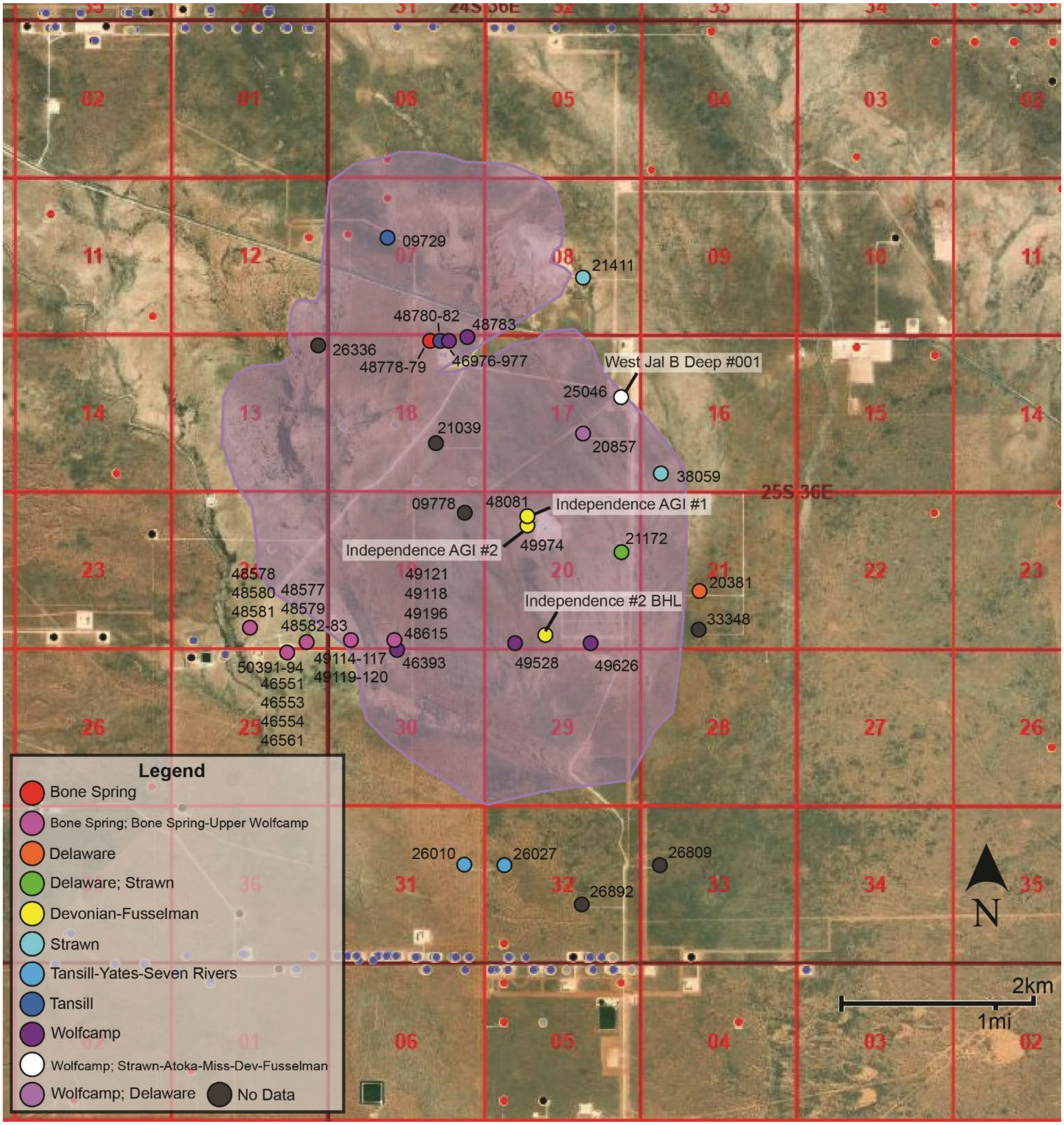


Figure 3.9-9**: Map showing the largest lateral extent of the TAG when the West Jal Deep B well injects an initial rate of 30,000 bpd of brine into the Siluro-Devonian. Colors indicate target formations for the well.* *Not shown: The* ***BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.

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 3.9.

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 (Figure 4.1-1).

4.2 AMA – Active Monitoring Area

Piñon intends to define the AMA as the same area as the MMA. Per 40 CFR 98.449, AMA is defined as the area that will be monitored over a specific time interval from the first year of the period (n = 2023) to the last year in the period (t = 2053, a 30-year injection period). The boundary of the AMA 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 (2058, or year 35 of the simulation). The zone shown in Figure 4.1-1 has a one-half mile buffer beyond the stable plume size at year t+5. Piñon intends to define the AMA as the entirety of the MMA. .

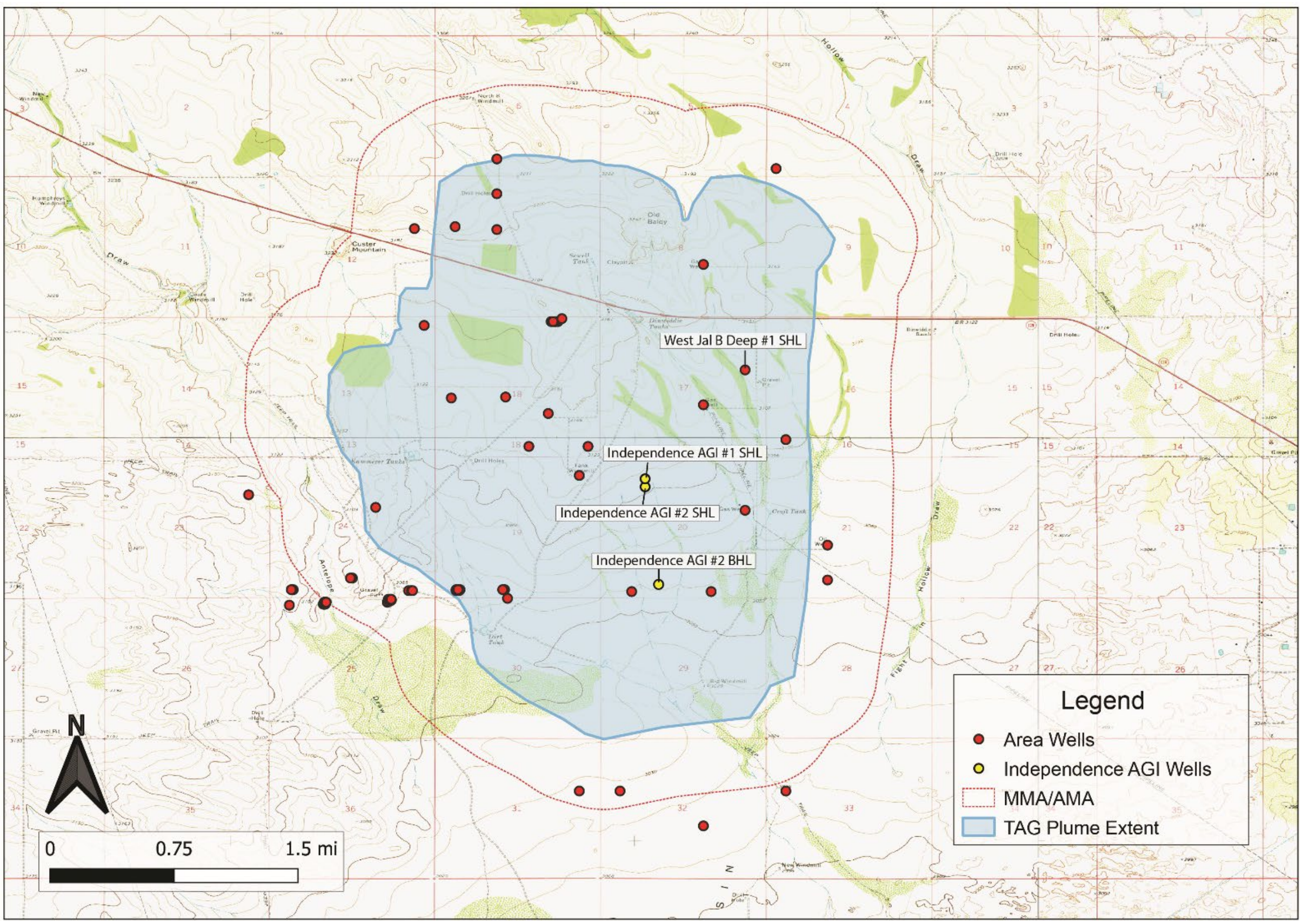


***Figure 4.1-1*: MMA and AMA for the Independence AGI Wells. The plume extents are shown at year 35 (t+5 = 2058), or 5 years beyond injection time. Not shown: The BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.**

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 and the reservoir modeling described in Section 3.9, Piñon 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 treating facilities. To minimize this potential for leakage, the construction, operation, and maintenance of sour gas treating facilities 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, Piñon 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, Piñon implements several methods for detecting gas leaks at the surface. These methods are described in more detail in Sections 6 and 7. Detection is followed up by immediate response.

5.2 Potential Leakage from Approved, Not Yet Drilled Wells

Appendix 3 and Figure 3.7-1 show a number of wells in the area, many of which have approved permits to drill but are not yet drilled. The new oil and natural gas wells are targeting various production zones, more than 4,000 feet above the Siluro-Devonian Injection Zone for the Independence AGI Wells. All new oil and natural gas wells and injection wells are subject to the requirements of regulations governing sealing off strata (19.16.16.10) and casing and tubing requirements (19.16.16.10) to prevent the contents of production or injection zones from passing into other strata. To minimize the likelihood of leaks from new wells, NMAC 19.15.26.9 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."

5.3 Potential Leakage from Existing Wells

As shown in Figure 3.7-1 and detailed in Appendix 3, there are several existing oil- and natural gas-related wells within a two (2) mile radius around the Independence AGI Wells (Figure 4.1-1). The deep wells discussed in Section 3.7.1 (*see* Table 3.7-1) also lie within the MMA/AMA. They are discussed below.

Independence AGI #1 has an open hole interval between 16,122 and 17,709 feet with more than 300 feet of Woodford Shale immediately above (*see* Figure A1-1). Independence AGI #2, which has recently been drilled, has a proposed open hole interval between 16,080 and 17,683 feet (*see* Figure A1-2). The combined depth to the Siluro-Devonian Injection Zone, cement program for both wells illustrated in Figures A1-1 and 2, existence of suitable confining layers above the Siluro-Devonian Injection Zone described in Section 3, and continuous monitoring of well operational parameters indicates that leakage of CO_2 to the surface via the Independence AGI Wells themselves is unlikely.

The West Jal B Deep Well No. 1 (API 30-025-25046) brine injection well is located one (1) mile northeast of the surface hole locations of the Independence AGI Wells. Additional details for this well are presented in

Section 3.7.1. Therefore, Piñon concludes that the potential for CO_2 leakage to the surface through this potential leakage pathway is unlikely.

The West Jal Unit #1 well (API 30-025-21172) was plugged and abandoned in April 1984. The plugging documents presented in Appendix 9 indicate that the well is properly plugged through the Siluro-Devonian Injection Zone. Therefore, Piñon concludes that the potential for CO_2 leakage to the surface through this potential leakage pathway is unlikely.

The remaining wells within the MMA are completed in zones more than 4,000 feet above the Siluro-Devonian Injection Zone. Therefore, Piñon concludes that the potential for CO_2 leakage to the surface through this potential leakage pathway is unlikely.

5.4 Potential Leakage through Fractures and Faults

Faults and fractures were discussed in Section 3.2.3 and the potential for induced seismicity was discussed in Section 3.5. The reservoir characterization modeling (Section 3.9) and the delineation of the monitoring areas (Section 4) show that the TAG plume reaches the faults shown in Figure 3.5-1 during the thirty (30) year injection period and the five (5) year post injection monitoring period. Vertical permeability may be present parallel to the plane of the fault vertically, especially where the two main faults intersect. A review of available drilling fluid records was conducted to evaluate regional reservoir pressure conditions in the Delaware basin. Above the Siluro-Devonian injection reservoir, mud weights utilized range from 12.1 to 15.1 pounds per gallon, while for the injection reservoir less dense fluids were used (average of 9.0 pounds per gallon). These support the interpretation that the overlying productive zones in this area are overpressured with respect to the target reservoir, which would produce a downward gradient through any fault-parallel permeability. The pressure differential between the overlying interval and target interval will act as a barrier preventing vertical migration even along localized open conduits. Therefore, Piñon concludes that the potential for CO_2 leakage to the surface through this potential leakage path is unlikely.

5.5 Potential Leakage through the Confining / Seal System

The subsurface lithologic characterization presented in Section 3.2.2 describes the thick sequence of Mississippian through Permian strata overlying the Siluro-Devonian Injection Zone and reveals the existence of several excellent confining zone layers.

Therefore, it is unlikely that TAG injected into the Siluro-Devonian Injection Zone 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. Section 6.3 describes operational monitoring in place to prevent CO_2 leakage from the Independence AGI Wells.

5.6 Potential Leakage due to Natural / Induced Seismicity

The potential for leaks initiated by induced seismicity was addressed in Section 3.5. It was concluded that generally, faults considered in this assessment do not display significant potential for injection-induced slip and the Independence AGI #2 is not predicted by the FSP model to contribute significantly to the total resultant pressure front. Piñon concludes that the likelihood for the creation and/or opening of vertical conduits for CO_2 leakage to the surface due to induced seismicity is low. Nevertheless, the NMOCC Order requires Piñon to install, operate, and monitor for the life of the project a seismic monitoring station or stations described in more detail in Section 7.6.

According to data obtained from the New Mexico Tech Seismic Observatory (2023), there have been four (4) seismic events within the MMA since January 12, 2017 (Figure 5.6-1). These seismic events range in magnitude of 1.16-1.88 and occurred between September 2020 and October 2021 (Table 5.6-1). Data queries with the USGS Earthquake Catalog did not show any seismic activity within the MMA (USGS Earthquake Hazards Program, 2023).

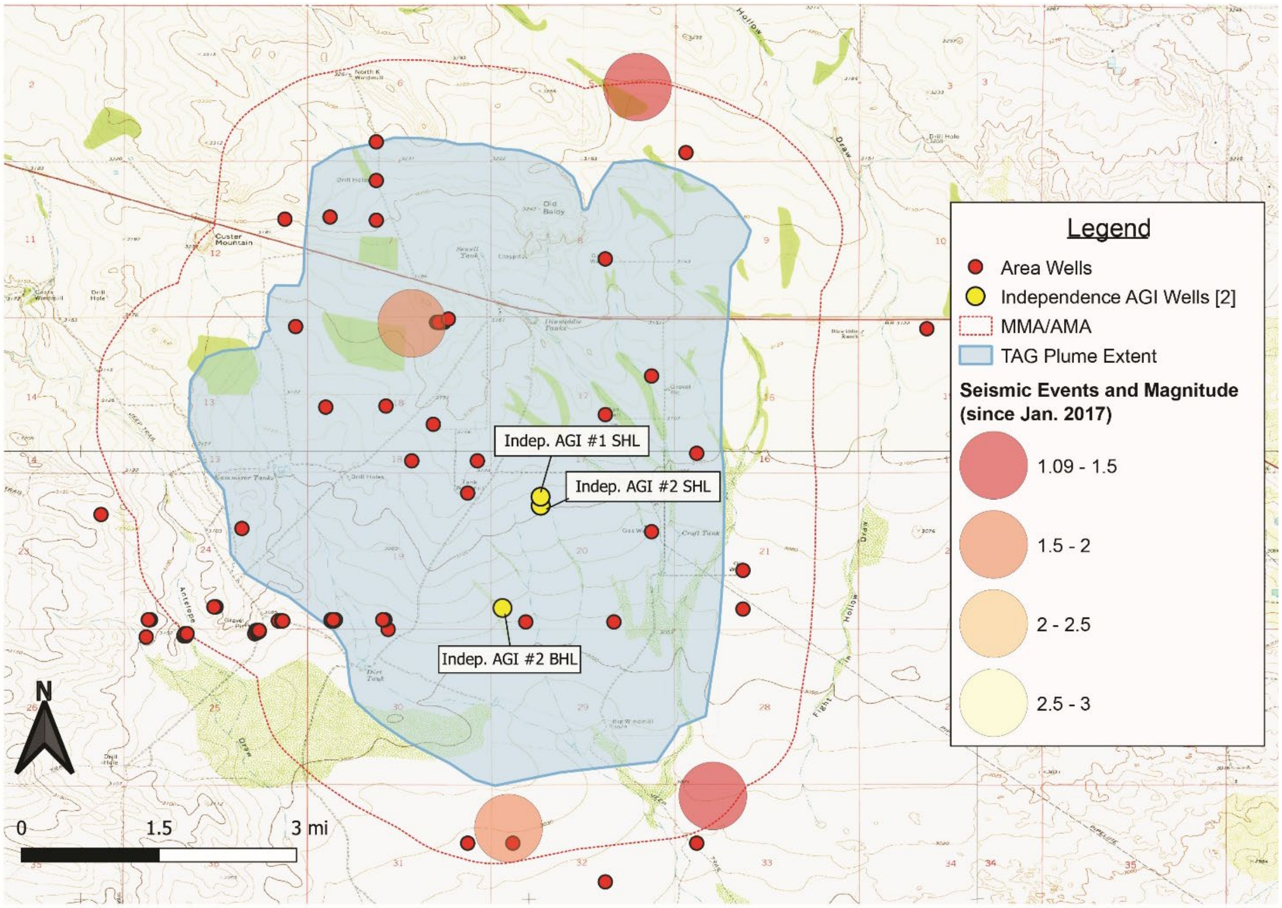


Figure 5.6-1: Map showing seismic event locations within the MMA for the Independence AGI wells.** Not shown: The **BHL of the Independence AGI #1. The BHL deviates 446' southeast of the SHL, as seen in Figure 3.1-1.

Date+Time(UTC)	Latitude	Longitude	Magnitude
2021-10-30 07:14:26.600	32.093	-103.275	1.16
2021-10-11 12:19:51.300	32.09	-103.294	1.88
2021-09-09 08:23:05.600	32.137	-103.303	1.74
2020-10-03 03:51:12.600	32.159	-103.282	1.47

Table 5.6-1: Table showing the locations, dates and times, and magnitudes of seismic events within the MMA for the Independence AGI wells.

5.7 Potential Leakage due to Lateral Migration

Lateral migration of the injected TAG was addressed in the simulation modeling detailed in Section 3.9. The results of that modeling indicate the TAG is unlikely to migrate laterally beyond approximately 2.5 miles within the Siluro-Devonian Injection Zone to encounter any conduits to the surface.

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. Piñon 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. Piñon considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ 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 five (5) year post-injection period.

***Table 6.1** – Summary of Leak Detection Monitoring*

Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system ("DCS") surveillance of facility operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/H_2S and low explosive level ("LEL") monitoring network • Personal and hand-held gas monitors
Independence AGI #1	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests ("MIT") • Fixed in-field gas monitors/H_2S and LEL monitoring network • Personal and hand-held gas monitors
Existing Other Operator Active Wells	• Monitoring of well operating parameters • Visual inspections • MITs
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network

6.1 Leakage from Surface Equipment

Piñon 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 Piñon using in-field monitors which detect H_2S. 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. Additionally, Piñon field personnel, wearing personal H_2S monitors, follow daily and weekly inspection protocols which include reporting and responding to any detected leakage events.

Piñon's internal operational documents and protocols detail the steps to be taken to verify leaks of H_2S. The following description of the gas detection equipment at the Dark Horse Facility was summarized from the H_2S Contingency Plan:

Fixed Monitors
The Dark Horse Facility has numerous ambient H_2S detectors placed strategically throughout the facility to detect possible leaks. Upon detection of H_2S concentrations of 10 ppm at any detector, visible beacons are activated and an alarm is sounded. Upon detection of H_2S concentrations of 90 ppm at any detector, an evacuation alarm is sounded throughout the Dark Horse Facility at which time all personnel will proceed immediately to a designated evacuation area. The Dark Horse Facility 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 ("**PLC**"), and then to the DCS. The monitors are equipped with amber beacons. The beacon is activated upon detection of H_2S concentrations of 10 ppm. The Dark Horse Facility horns are activated with a continuous warbling alarm upon detection of H_2S concentrations of 10 ppm and a facility-wide siren upon detection of H_2S concentrations of 90 ppm. All monitoring equipment is Rosemount brand. The control panel is a twenty-four (24) channel monitor box, and the fixed point H_2S sensor heads are model number ST320A-100-ASSY.

The Dark Horse Facility will monitor the inlet sour natural gas steam and sweet natural gas stream concentrations of H_2S via H_2S analyzers with sample points located on the north/south-oriented pipe rack (Figure 7.2-1). Concentrations of H_2S in the TAG stream will be sampled near the AGI pumps located on the west side of the Dark Horse Facility. All H_2S analyzers are model T224, manufactured by Analytical Systems KECO.

The monitors can also be viewed on the PLC displays located at the Dark Horse Facility and the locations of ambient H_2S sensors are shown on the plot plan (*see* Figure 7.2-1). Immediate action is required for any alarm occurrence or malfunction. All H_2S sensors are calibrated monthly.

Personal and Handheld H_2S Monitors
All personnel working at the Dark Horse Facility wear personal H_2S monitors, which are required to alarm and vibrate upon detection of H_2S concentrations of 10 ppm. Handheld gas detection monitors are available at strategic locations around the Dark Horse Facility so that facility 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.

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 10.1.5. Furthermore, if CO_2 emissions are detected through any of the surveillance methods described above, Piñon will quantify the amount of CO_2 released based on operating conditions at the time of detection.

6.2 Leakage from Approved Not Yet Drilled Wells

Aside from Independence AGI #2, other approved but not yet drilled wells target zones more than 4,000 feet above the Siluro-Devonian Injection Zone. Therefore, no additional monitoring is required for these wells over and above what is already required by NMOCC rules and orders.

Piñon does not intend to quantify CO_2 leakage to the surface through the approved wells whose target zones are more than 4,000 feet above the injection zone for the Independence AGI wells. Any leakage of CO_2 originating from the injection of TAG into the Independence AGI wells would be detected and quantified through operating parameter monitoring and mitigated long before any leaked CO_2 migrated upward toward these wells.

6.3 Leakage from Existing Wells

6.3.1 Independence AGI #1

As part of ongoing operations, Piñon continuously monitors and collects flow, pressure, temperature, and gas composition data. This data is monitored continuously by qualified technicians who follow response and reporting protocols when the monitoring system delivers alerts that data is not within acceptable limits. Mechanical integrity tests (MIT) are performed annually. Failure of an MIT would indicate a leak in the well and result in immediate action by shutting in the well, accessing the MIT failure, and implementing mitigative steps.

If operating parameter monitoring and MIT failures indicate a CO_2 leak has occurred, Piñon will take actions to quantify the leak based on operating conditions at the time of the detection.

6.4 Leakage from Fractures and Faults

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through faults. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone.

Piñon will assess any changes in operating parameters which might indicate surface leakage of CO_2 along faults or fractures. If surface leakage is correlated with loss through fractures or faults, Piñon will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, which may include shutting in the well(s).

6.5 Leakage through the Confining / Seal System

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone.

If changes in operating parameters indicate surface leakage of CO_2 through the confining / seal system, Piñon will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, which may include shutting in the well(s).

6.6 Leakage due to Natural / Induced Seismicity

Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.3 and 7.5 coupled with a detection of a seismic event by the seismic stations described in Section 7.6 will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone due to a seismic event.

After a seismic event, Piñon will assess any changes in operating parameters and data from the surrounding seismic stations which might indicate leakage of CO_2 along faults or fractures activated by the event. If leakage is correlated with a seismic event, Piñon will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, which may include shutting in the well(s).

6.7 Leakage due to Lateral Migration

Continuous operational monitoring of the Independence 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 Siluro-Devonian 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 Siluro-Devonian Injection Zone.

If monitoring of operational parameters indicates that the CO_2 plume extends beyond the area modeled in Section 3.9 and presented in Section 4, Piñon will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 release to the surface. If it is determined that the plume intersected a pathway for CO_2 release to the surface, this would be considered a material change per 40 CFR 98.448(d)(1), and Piñon will submit a revised MRV plan as required by 40 CFR 98.448(d).

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

Subpart RR at 40 CFR 448(a)(4) requires a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. Piñon 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 Piñon's strategy for collecting baseline information.

7.1 Visual Inspection

. Piñon field personnel conduct daily visual inspections of surface equipment located at the Dark Horse Facility and the Independence AGI Wells. These visual inspections will aid in identifying and timely addressing potential areas of concern to minimize the possibility of H_2S, a proxy for CO_2, leakage. If any leakage is identified during such visual inspections, Piñon field personnel will take prompt corrective actions to address such leakage.

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

Compositional analysis of gas injectate at the Dark Horse Facility indicates an approximate H_2S concentration of 38.7% thus requiring Piñon to develop and maintain an H_2S Contingency Plan according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). Piñon considers H_2S to be a proxy for CO_2 leaks at the Dark Horse Facility. The H_2S Contingency Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the Dark Horse Facility or the associated Independence 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 Dark Horse Facility utilizes numerous fixed-point monitors, strategically located throughout the facility, to detect the presence of H_2S in ambient air (Figure 7.2-1). The diagram in Appendix 10 shows the location of the Ultrasonic inflow meters and the Coriolis meters to the Independence AGI wells. The sensors are connected to the Control Room alarm panel's PLCs, and then to the DCS. Upon detection of H_2S concentrations of 10 ppm at any monitor, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of H_2S concentrations of 90 ppm at any monitor, an evacuation alarm is sounded throughout the Dark Horse Facility 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 Dark Horse Facility so that facility 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 Oxide ("**CO**").

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the Dark Horse Facility 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 upon detection of H_2S concentrations of 10 ppm.

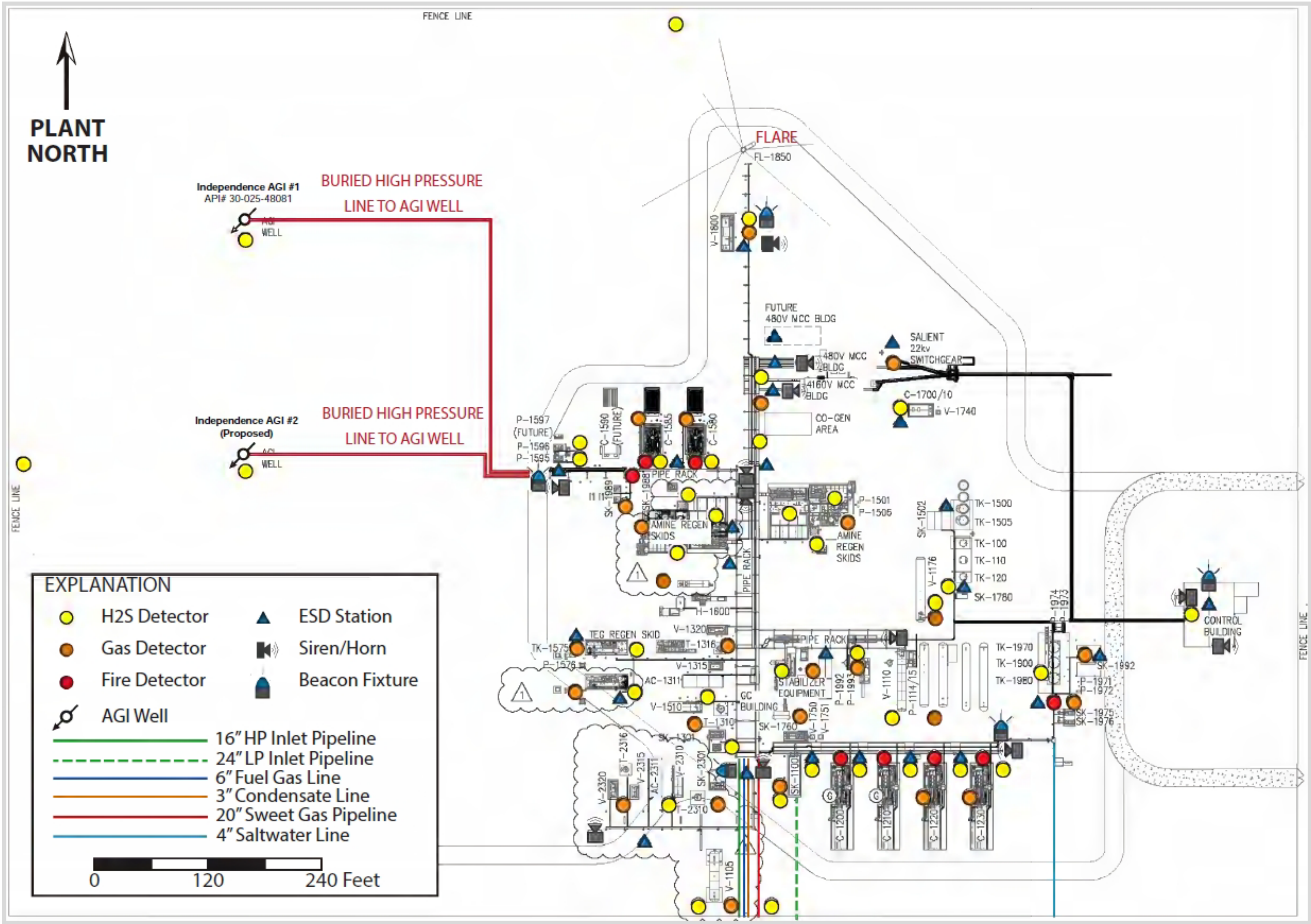


***Figure 7.2-1*: Detailed Dark Horse Facility schematic illustrating the location of major process units, all emergency equipment, H_2S and gas detection sensors, sirens and beacons, and major gas flow lines at the facility (Taken from Figure 2 of the H_2S Contingency Plan for Dark Horse Gas Treatment Facility, Geolex, Inc.). The yellow circles indicate the location of fixed H_2S sensors.**

7.3 CO_2 Detection

Any CO_2 release to the surface would be accompanied by H_2S and therefore the H_2S monitors will serve as a CO_2 release warning system both at the facility and in the field. In addition to the fixed and personal monitors described in Section 7, Piñon will establish and operate a monitoring program to detect H_2S leakages within the AMA. The scope of work will include H_2S monitoring at the AGI well site and atmospheric monitoring near identified penetrations of the Siluro-Devonian Injection Zone within the AMA. Upon approval of the MRV Plan and for the five (5) year post-injection period, Piñon will have these monitoring processes and systems in place.

7.4 Continuous Parameter Monitoring

The DCS of the Dark Horse Facility 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

Piñon 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. Piñon's Routine Operations and Maintenance Procedures for the Independence AGI Wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic Monitoring Stations

Piñon owns 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 Dark Horse Facility. The seismic station will meet the requirements of the NMOCC Order to "install, operate, and monitor for the life of this Order a seismic monitoring station or stations. OCD shall be responsible for coordinating with the Manager of the New Mexico Tech Seismological Observatory at the New Mexico Bureau of Geology and Mineral Resources for appropriate specifications for the equipment and the required reporting procedure for the monitoring data."

Additionally, Figure 7-1 shows the location of other seismic monitoring stations in the vicinity of the Independence AGI Wells.

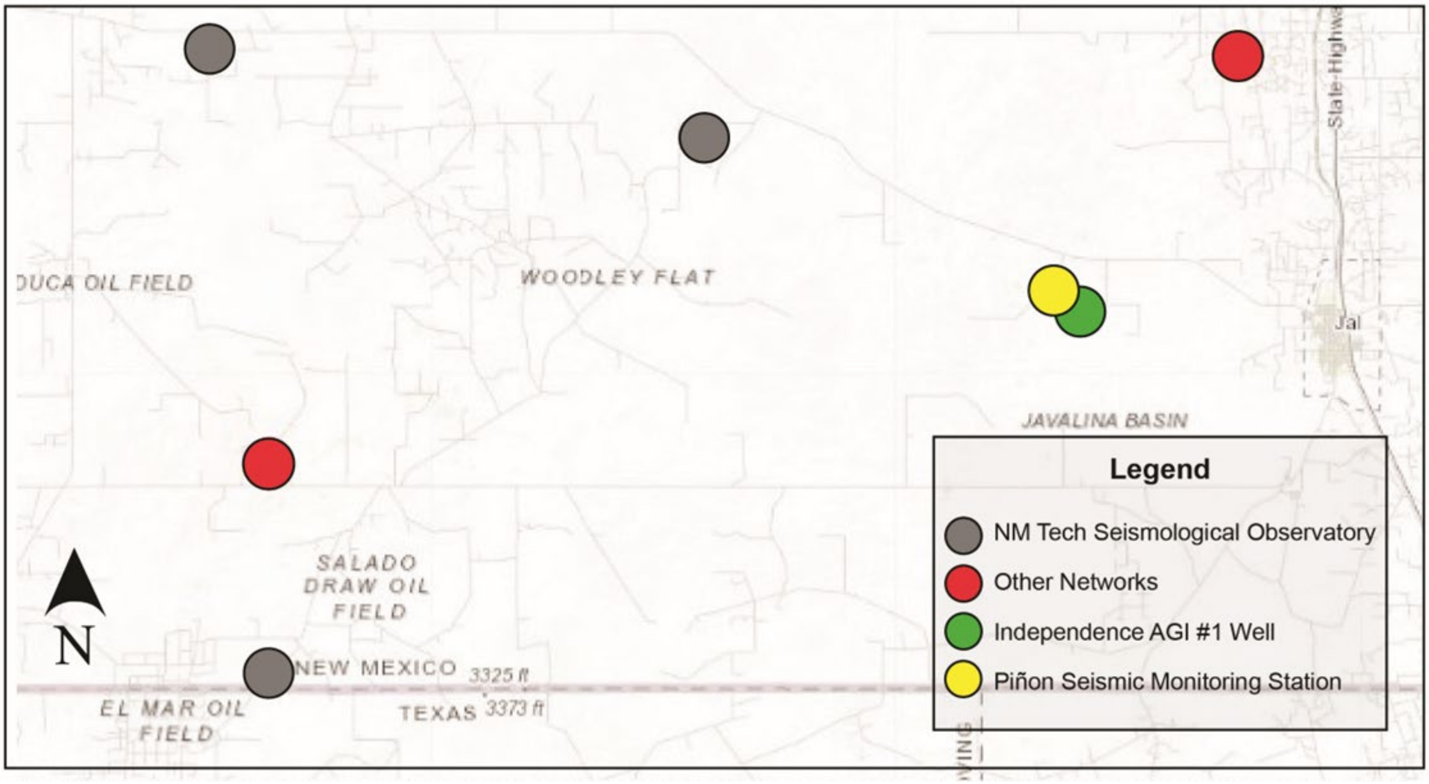


***Figure 7-1*: Location of seismic monitoring stations in the vicinity of the Independence AGI Wells.**

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve (12) Subpart RR equations used to calculate the mass of CO_2 sequestered annually. Appendix 8 includes the twelve (12) equations from Subpart RR. Not all of these equations apply to Piñon's current operations at the Dark Horse Facility but are included in the event Piñon's operations change in such a way that their use is required.

8.1 CO_2 Received

Currently, Piñon receives sour natural gas at the Dark Horse Facility through three (3) pipelines: the Hondo High Pressure Sour Gas Pipeline (owned and operated by Piñon), the Franklin Mountain Low Pressure Pipeline (owned and operated by Franklin Mountain Energy) and the Ameredev II Low Pressure Pipeline (owned and operated by Ameredev). Piñon 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 Piñon does not currently receive CO_2 in containers for injection, they have chosen to include the flexibility in this MRV Plan to do so. If Piñon begins to receive CO_2 in containers, they will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. Piñon will adhere to the requirements in 40 CFR 98.444(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 40 CFR 98.488(d)(1), Piñon will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Piñon injects CO_2 into the existing Independence AGI #1. Upon its completion, Piñon will commence injection of CO_2 into Independence AGI #2. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the Independence AGI Wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the Independence AGI Wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12.

8.3 CO_2 Produced / Recycled

Piñon does not produce oil or natural gas or any other liquid at the Dark Horse Facility so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Surface leakage of CO_2 will not be measured directly, rather it will be determined by employing the CO_2 proxy 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. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.5 below.

8.5 CO_2 Sequestered

Since Piñon does not actively produce oil or natural gas or any other fluid at the Dark Horse Facility, 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, Piñon 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.

9 Estimated Schedule for Implementation of MRV Plan

Piñon intends to implement this MRV Plan on June 1, 2023, after it is approved by EPA.

10 GHG Monitoring and Quality Assurance Program

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

10.1 GHG Monitoring

As required by 40 CFR 98.3(g)(5)(i), Piñon'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 greenhouse gas ("**GHG**") calculations; and
- 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 will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association ("**GPA**") standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40 CFR 98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2 and RR-5, of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 15.025 pounds per square inch absolute ("psia") (Appendix 6). Piñon utilizes Coriolis metering to measure the dense phase injected TAG stream. Piñon utilizes the following two standards: American Petroleum Institute API 14.1 for measuring barrels and the American Gas Association AGA 7 for million cubic feet ("MCF") equivalent calculations.

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 Independence AGI Wells using accepted flow calculations for CO_2 according to the [AGA Report #3].

10.1.4 CO_2 produced.

Piñon does not produce CO_2 at the Dark Horse Facility.

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

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

10.1.6 Measurement devices.

As required by 40 CFR 98.444(e), Piñon 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 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute, the AGA, the GPA, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.
- All flow meter calibrations performed are National Institute of Standards and Technology ("**NIST**") traceable.

10.2 QA/QC Procedures

Piñon 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

Piñon will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or using a representative concentration value from the 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

Piñon will revise the MRV Plan as needed to (a) reflect changes in monitoring instrumentation and quality assurance procedures; (b) improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or (c) address additional requirements as directed by the EPA or the State of New Mexico.

11 Records Retention

Piñon will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, Piñon will retain the following documents:

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

(b) 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

(c) The annual GHG reports.

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

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

(f) 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.

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

(h) 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.

(i) 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.

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

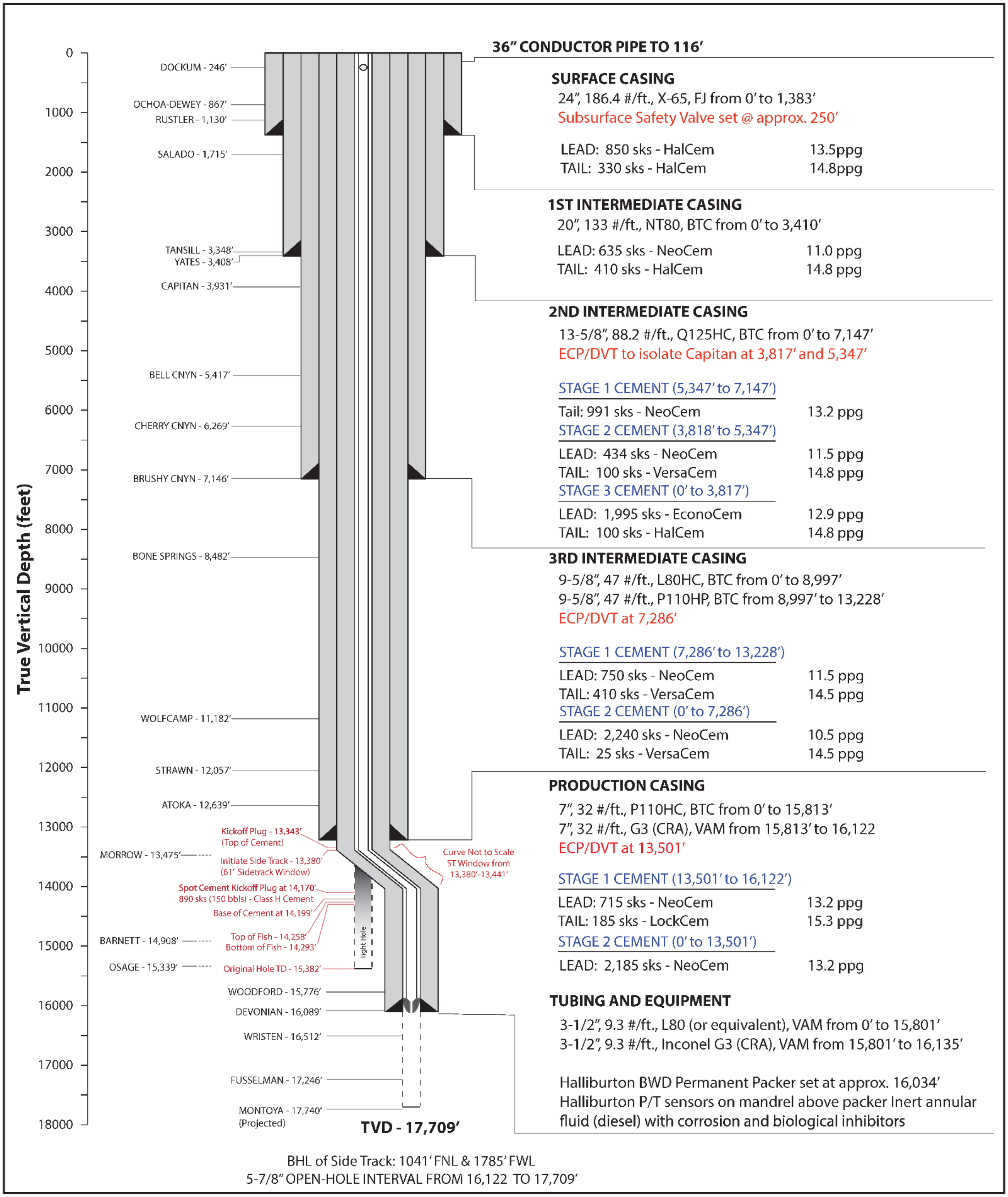
(k) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

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

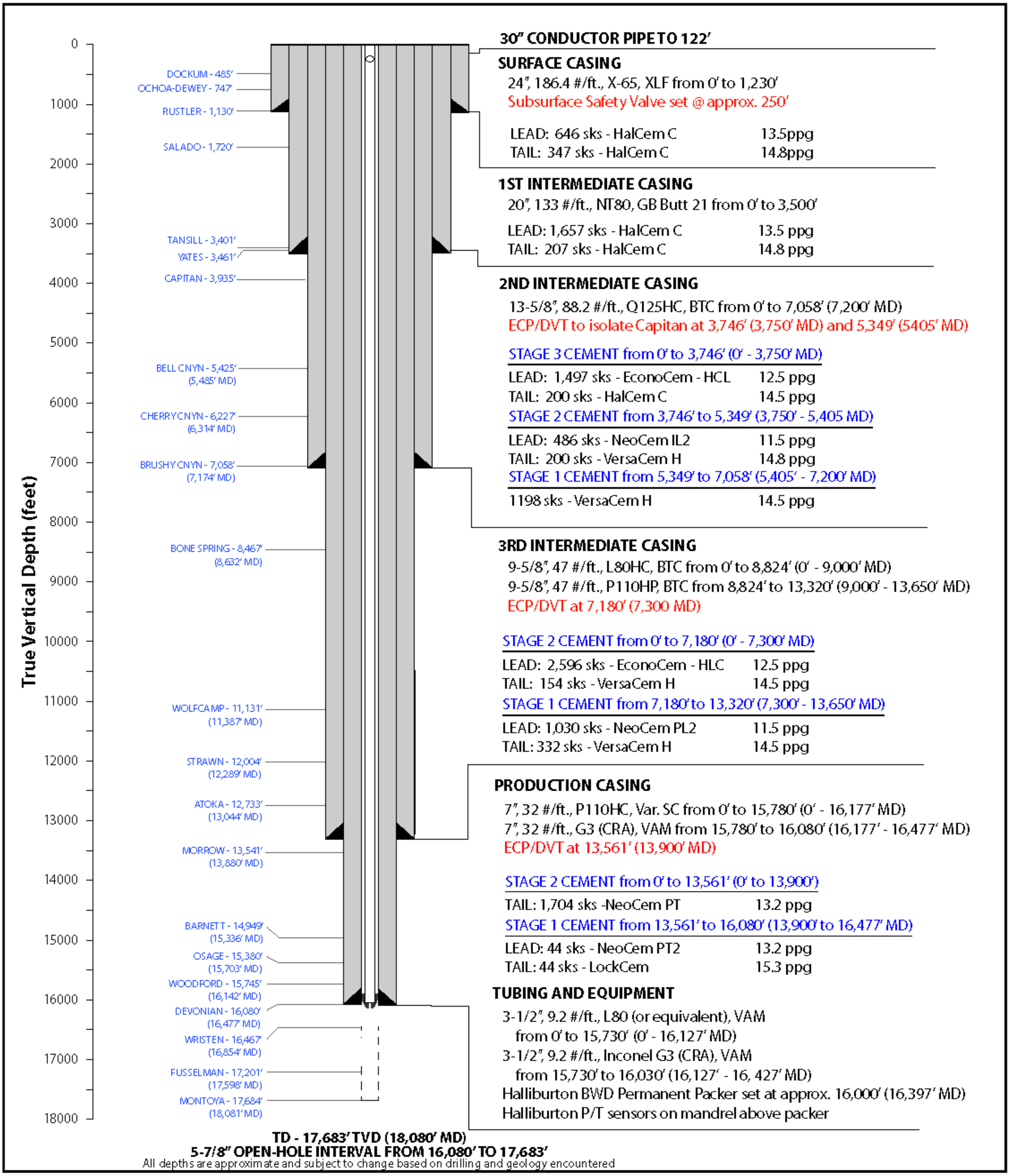
13 Appendices

Appendix 1 - Independence AGI Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Independence AGI #1	30-025-48081	SHL 829’ FNL, 1,443’ FEL BHL of Sidetrack: 1041’FNL, 1785’FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120855 and -103.291021	Lea, NM	12/27/2020	17,750’	16,114’
Independence AGI #2	30-025-49974	SHL 1,180’ FNL, 1,578’ FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120020 and -103.291015 BHL 1,033’ FSL, 2,132’ FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.111581 and -103.289273	Lea, NM	Not Drilled Yet	17,683’ TVD	approx. 16,000’



<u>Figure A1-1</u>: Independence AGI #1: As-drilled well schematic consisting of a surface string of casing, three (3) intermediate strings , and a production string with associating tubing/equipment and cement types. Original hole and sidetrack are shown. (Taken from End-of-Well Report for Independence AGI #1, Geolex, Inc.)



<u>Figure A1-2</u>: Independence AGI #2: Well schematic. (Taken from NMOCC Order 3/31/2022)

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 - Oil and natural gas wells within 2-mile radius of the Independence AGI Wells

The data in the following table was obtained from the NMOCD database and is accurate as of 8/5/2022.

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-09729	PAN AM KELLY 7 FEDER	Oil	Plugged (site released)	JOHN H TRIGG	32.1466	-103.3063		1900	3,540	0	-	1/1/1900	CUSTER, TANSILL
30-025-09778	FEDERAL #1	Oil	Plugged (site released)	EDWARD C. DONAHUE	32.1212	-103.2978	No Data	1900	3,891	0	-	1/1/1900	No Data
30-025-20381	HERKIMER BQF FEDERAL #001H	Oil	Active	AMEREDEV OPERATING, LLC	32.114	-103.2722	H	1963	8,515	10,121	10,100	-	DELAWARE, WEST
30-025-20857	WEST JAL B #001	Brine Injection	New	BC & D OPERATING INC.	32.1285	-103.2850	V	1964	12,275	12,275	6,170	-	WOLFCAMP, WEST; DELAWARE
30-025-21039	WEST JAL 18 #1	Oil	Plugged (site released)	SKELLY OIL CO.	32.1276	-103.3010	No Data	1900	12,950	0	-	1/1/1900	No Data
30-025-21172	WEST JAL UNIT #1	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.1176	-103.2807	V	1961	17,086	17,086	-	4/4/1984	DELAWARE, WEST; JAL, STRAWN, WEST
30-025-21411	C ELLIOTT FEDERAL	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.143	-103.2850	V	1900	12,276	12,276	-	6/26/1993	STRAWN, WEST
30-025-25046	WEST JAL B DEEP #001	Brine Injection	Active	BC & D OPERATING INC.	32.1321	-103.2807	V	1975	18,945	18,945	14,175	-	STRAWN, WEST; WOLFCAMP, WEST; FUSSELMAN, WEST; ST-AT-MISS-DEV-FUS
30-025-26010	SPOTTED TAIL FED. #1	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2978	No Data	1900	3,336	0	-	1/1/1900	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26027	SITTING BULL A #001	Oil	Active	FULFER OIL & CATTLE LLC	32.0886	-103.2936	V	1978	3,368	3,368	-	-	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26336	FEDERAL 13 A #1	OIL	Plugged (site released)	GETTY OIL CO.	32.1367	-103.3138	V	1979	3,686	0	-	-	No Data
30-025-26809	LITTLE HAWK FEDERAL #	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2765	No Data	1900	3,690	0	-	1/1/1900	No Data
30-025-26892	SITTING BULL #2	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.085	-103.2850	No Data	1900	3,746	0	-	1/1/1900	No Data
30-025-33348	TEXACO WEST JAL 21 #001	Oil	Plugged (site released)	ENSERCH EXPLORATION INC.	32.1104	-103.2722	V	1996	7,700	7,700	-	4/25/1996	No Data
30-025-38059	DINWIDDIE STATE COM #001	Gas	Plugged (site released)	COG OPERATING LLC	32.1249	-103.2765	V	2006	12,192	12,192	-	12/12/2008	STRAWN, WEST
30-025-46393	NANDINA 25 36 31 FEDERAL COM #124H	Oil	New	AMEREDEV OPERATING, LLC	32.1085	-103.3052	H	-	0	23,130	-	-	WOLFCAMP, WEST
30-025-46533	SIOUX 25 36 STATE FEDERAL COM #008H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2019	12,149	22,150	22,117	-	UPPER WOLFCAMP
30-025-46551	SIOUX 25 36 STATE FEDERAL COM #009H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3175	H	2020	11,894	21,945	21,912	-	BONE SPRING
30-025-46553	SIOUX 25 36 STATE FEDERAL COM #012H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3174	H	2020	11,994	22,350	22,319	-	BONE SPRING; UPPER WOLFCAMP
30-025-46554	SIOUX 25 36 STATE FEDERAL COM #013H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2020	11,725	21,962	21,930	-	BONE SPRING; UPPER WOLFCAMP
30-025-46561	SIOUX 25 36 STATE FEDERAL COM #010H	Oil	Active	CAZA OPERATING, LLC	32.1081	-103.3176	H	2020	12,107	22,209	22,175	-	UPPER WOLFCAMP
30-025-46976	BLACK MARLIN FEDERAL COM #204H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3002	H	2020	11,640	21,953	21,895	-	WOLFCAMP, WEST
30-025-46977	BLACK MARLIN FEDERAL COM #214H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3000	H	2020	11,741	22,055	21,994	-	WOLFCAMP, WEST
30-025-48081	INDEPENDENCE AGI #001	AGI	Active	Piñon Midstream, LLC	32.1208	-103.2910	V	2020	17,709	17,900	-	-	DEVONIAN-FUSSELMAN
30-025-48577	SANTA FE FEDERAL COM #603H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3154	H	-	0	21,874	-	-	BONE SPRING
30-025-48578	SANTA FE FEDERAL COM #704H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3212	H	-	0	22,063	-	-	WOLFCAMP, WEST
30-025-48579	SANTA FE FEDERAL COM #705H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3152	H	-	0	22,129	-	-	WOLFCAMP, WEST
30-025-48580	TRINITY FEDERAL #602H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3214	H	-	0	21,938	-	-	BONE SPRING
30-025-48581	TRINITY FEDERAL #703H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3213	H	-	0	22,206	-	-	WOLFCAMP, WEST
30-025-48582	ZIA FEDERAL COM #604H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3151	H	-	0	21,973	-	-	BONE SPRING
30-025-48583	ZIA FEDERAL COM #706H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3150	H	-	0	21,973	-	-	WOLFCAMP, WEST
30-025-48614	BLUE MARLIN STATE #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3102	H	-	0	19,502	-	-	WOLFCAMP, WEST
30-025-48615	BLUE MARLIN STATE #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	-	0	19,350	-	-	WOLFCAMP, WEST
30-025-48778	BLACK MARLIN FEDERAL COM #113H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3007	H	-	0	20,014	-	-	BONE SPRING
30-025-48779	BLACK MARLIN FEDERAL COM #114H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3006	H	-	0	20,056	-	-	BONE SPRING
30-025-48780	BLACK MARLIN FEDERAL COM #203H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3005	H	2021	11,786	21,842	21,879	-	WOLFCAMP, WEST
30-025-48781	BLACK MARLIN FEDERAL COM #206H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3003	H	-	0	21,981	-	-	WOLFCAMP, WEST
30-025-48782	BLACK MARLIN FEDERAL COM #213H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3004	H	2021	0	22,140	22,073	-	WOLFCAMP, WEST

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-48783	BLACK MARLIN FEDERAL COM #216H	Oil	New	TAP ROCK OPERATING, LLC	32.1374	-103.2996	H	2021	0	22,258	22,258	-	WOLFCAMP, WEST
30-025-49115	BLUE MARLIN FEDERAL COM #111H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3105	H	-	0	20,039	0	-	BONE SPRING
30-025-49116	BLUE MARLIN FEDERAL COM #112H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3105	H	-	0	20,217	0	-	BONE SPRING
30-025-49117	BLUE MARLIN FEDERAL COM #201H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3102	H	2021	11,613	21,985	21,923	-	WOLFCAMP, WEST
30-025-49118	BLUE MARLIN FEDERAL COM #202H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	2021	11,539	21,929	21,866	-	WOLFCAMP, WEST
30-025-49119	BLUE MARLIN FEDERAL COM #205H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3101	H	2021	11,533	21,980	21,916	-	WOLFCAMP, WEST
30-025-49120	BLUE MARLIN FEDERAL COM #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3103	H	2021	12,148	22,554	22,495	-	WOLFCAMP, WEST
30-025-49121	BLUE MARLIN FEDERAL COM #215H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3057	H	2021	11,720	22,188	22,120	-	WOLFCAMP, WEST
30-025-49196	BLUE MARLIN FEDERAL COM #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3055	H	2021	12,003	22,422	22,389	-	WOLFCAMP, WEST
30-025-49528	DOGWOOD 25 36 20 FEDERAL COM #112H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2924	H	2021	0	22,356	0	-	WOLFCAMP, WEST
30-025-49626	DOGWOOD 25 36 20 FEDERAL COM #116H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2842	H	-	0	22,080	0	-	WOLFCAMP, WEST
30-025-49974	INDEPENDENCE AGI #002	AGI	New	Pinon Midstream, LLC	32.1201	-103.2910	D	2022	17,683	18,080	0	-	DEVONIAN-FUSSELMAN
30-025-50391	SIOUX 25 36 STATE FEDERAL COM #020H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	22,710	0	-	UPPER WOLFCAMP
30-025-50392	SIOUX 25 36 STATE FEDERAL COM #021H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	20,244	0	-	BONE SPRING
30-025-50393	SIOUX 25 36 STATE FEDERAL COM #022H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	22,539	0	-	UPPER WOLFCAMP
30-025-50394	SIOUX 25 36 STATE FEDERAL COM #023H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	20,120	0	-	BONE SPRING

Appendix 4 - References

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Appendix 5 - Abbreviations and Acronyms

Abbreviations and acronyms not otherwise defined herein:

3D – 3 dimensional
API – American Petroleum Institute
CFR – Code of Federal Regulations
EOS – Equation of State
ft – foot (feet)
m – meter(s)
mg/l – milligrams per liter
MT -- Metric tonne
NG—Natural Gas
QA/QC – quality assurance/quality control
ST – Short Ton

Appendix 6 - Conversion Factors

Piñon reports CO_2 at standard conditions of temperature and pressure as defined in the State of New Mexico - 60°F and 15.025 psia (NMAC 19.15.2.7 (C)(16))

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the NIST. This online database is available at:

http://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner EOS at a wide range of temperatures and pressures.

At State of New Mexico standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.0027097 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2} = 0.0027097$$

$$MW_{CO2} = 44.0095$$

$$Density_{CO2} = 5.4092\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.4092\ x\ 10^{-2}\ \frac{MT}{Mcf}$$

The conversion factor 5.4092 x 10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Appendix 7 - Independence AGI Wells - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

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

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

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

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

Appendix 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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \qquad \text{(Equation RR-2 for Pipelines)}$$

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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \qquad \text{(Equation RR-2 for Containers)}$$

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

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

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

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

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

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

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.

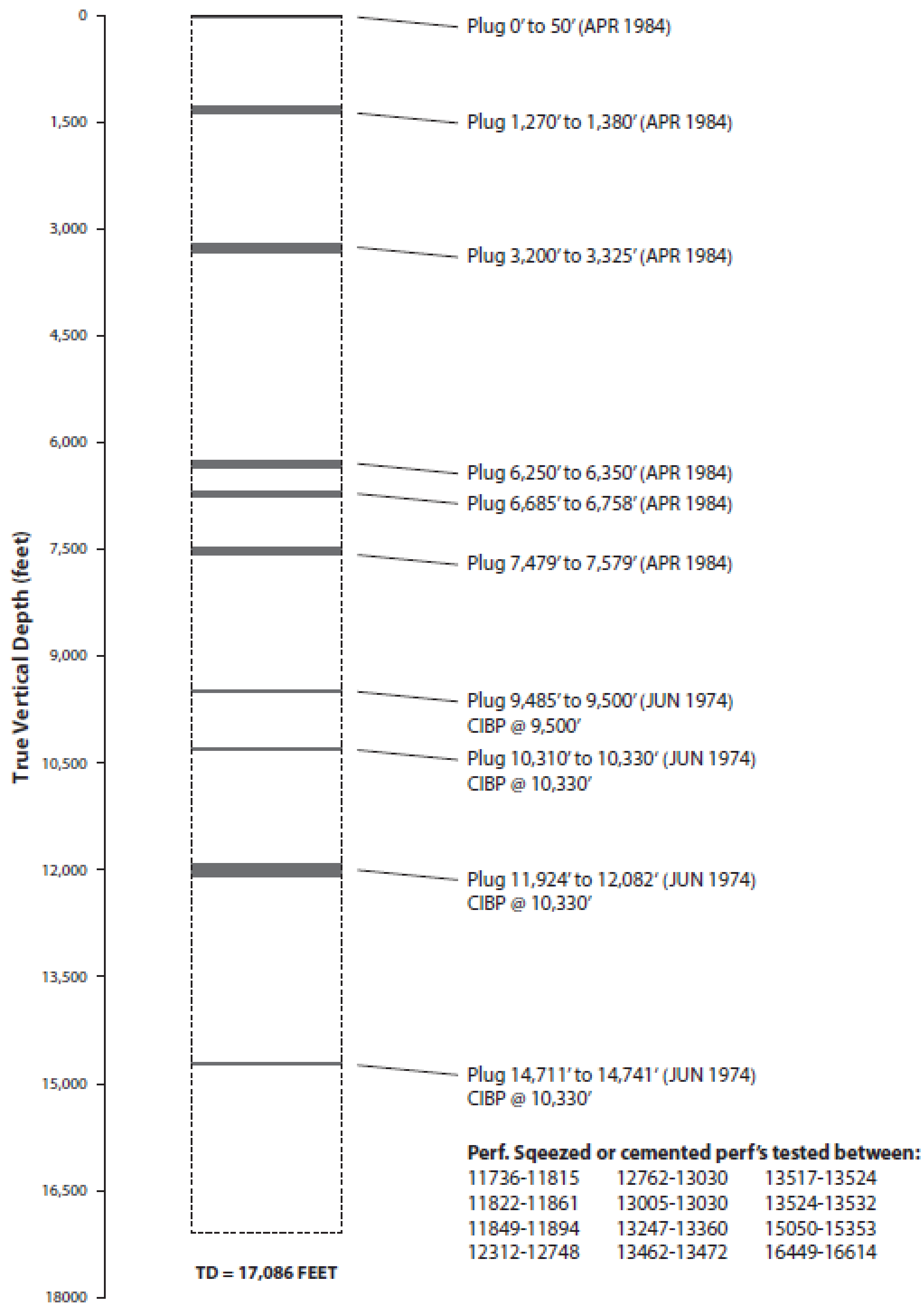
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

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 the GHGRP.

Appendix 9 - Plugging Records for West Jal Unit #1

TEXACO EXPLORATION AND PROD. - WEST JAL UNIT #1 PLUGGING DIAGRAM

Lease Name:	West Jal Unit #1	**Footage:**	1980 FNL and 660 FEL
API:	30-025-21172	**Well Type:**	Oil
Location:	Sec. 20, T25S, R36E	**Total Depth:**	17,086′
County, State:	Lea County, New Mexico	**Coordinates:**	32.117596, -103.280739 (NAD83)



*Schematic is properly scaled

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UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Buluu No. 1004-0135
Expires: March 31, 1993

5. Lease Designation and Serial No.
NJ

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT-" for such proposals

SUBMIT IN TRIPLICATE

7. If Unit or CA, Agreement Designation

1. Type of Well
[X] Oil Well [ ] Gas Well [X] Other Reentry

8. Well Name and No.
JA-/t:Jt!JLA-Iry

2. Name of Operator
MCH Petroleum Services

9. API Well No.
30-025-2/112

3. Address and Telephone No.
-:1:)1 W. Pliv St: Midland, Tx 79705 915 683 4772

10. Field and Pool, or Exploratory Area
~~Undesignated~~ W-Sal Delaware

4. Location of Well (Footage, Sec., T., R., M., or Survey Description)
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11. County or Parish, State
Lea, NM

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

TYPE OF SUBMISSION	TYPE OF ACTION	
[X] Notice of Intent	[ ] Abandonment	[ ] Change of Plans
	[ ] Recompletion	[ ] New Construction
[ ] Subsequent Report	[ ] Plugging Back	[ ] Non-Routine Fracturing
	[ ] Casing Repair	[ ] Water Shut-Off
[ ] Final Abandonment Notice	[ ] Altering Casing	[ ] Conversion to Injection
	Other Reentry	[ ] Dispose Water
		(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abandoned by Texaco in 1983. MCH will drill out cement plugs and cibp@ 7,579' to a total depth of approx. 8,350'(inside casing). This will leave in place cibp at 9,500' and deeper. We will then test Existing perforations@ 7,807'-7,857' and stimulate as necessary.
Mud Program: Fresh water will be used for the reentry inside casing.
BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO
GENERAL REQUIREMENTS AND
SPECIAL STIPULATIONS
ATTACHED

14. I hereby certify that the foregoing is true and correct

Signed Craig Huber Title Owner Date 4/13/93

(This space for Federal or State office use)

Approved by ... 1ITC &r.n L MAron; Title AREA MANAGER Date JUN 4 1993
Conditions of approval, if any:

Title 18 U.S.C. Section 1001, makes 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.

*See Instruction on Reverse Side

G 31

Form 3160-3
(December 1990)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRI[illegible]TE*
(Other instructions o[illegible] reverse side)

Form approved.
Budget Bureau No. 1004–0136
Expires: December 31, 1991

APPLICATION FOR PERMIT TO DRILL OR DEEPEN

1a. TYPE OF WORK
DRILL ☐ DEEPEN ☐

b. TYPE OF WELL
OIL WELL ☒ GAS WELL ☐ OTHER Reentry SINGLE ZONE ☒ MULTIPLE ZONE ☐

2. NAME OF OPERATOR
MCH Petroleum Services

3. ADDRESS AND TELEPHONE NO.
708 W. Pine St, Midland, Tx 79705 915 683 4772

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*)
At surface 1980' FNL, 660' FEL sec 20 T-25S, R-36E
Lea Co. NM
At proposed prod. zone
SAme H SE NE

5. LEASE DESIGNATION AND SERIAL NO.
NM 71792

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME, WELL NO.
West JAl Federal #1

9. API WELL NO.
30-025-21172

10. FIELD AND POOL, OR WILDCAT
~~[illegible]~~ W. JAl Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
S-20, T-25S, R 36E

14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE*
6 miles W. JAl, N.M.

12. COUNTY OR PARISH
Lea

13. STATE
NM

15. DISTANCE FROM PROPOSED* LOCATION TO NEAREST PROPERTY OR LEASE LINE, FT. (Also to nearest drlg. unit line, if any)
660'

16. NO. OF ACRES IN LEASE
600

17. NO. OF ACRES ASSIGNED TO THIS WELL
40

18. DISTANCE FROM PROPOSED LOCATION* TO NEAREST WELL, DRILLING, COMPLETED, OR APPLIED FOR, ON THIS LEASE, FT.

19. PROPOSED DEPTH
8350

20. ROTARY OR CABLE TOOLS
Pulling unit / Reverse unit

21. ELEVATIONS (Show whether DF, RT, GR, etc.)
3076' GL

22. APPROX. DATE WORK WILL START*
ASAP (Prior to 6/1/93 exp.)

23.

PROPOSED CASING AND CEMENTING PROGRAM

SIZE OF HOLE	GRADE, SIZE OF CASING	WEIGHT PER FOOT	SETTING DEPTH	QUANTITY OF CEMENT
26	20		869' (In Place)	1630 sx.
17½	13 3/8	72, 68, 64	6300' (In Place)	3606 sx.
12¼	9 5/8	53.5, 47, 43.5	11,736 (In Place)	775 sx.
8¾	7	26	6735-12213 (Shot off @ 6735)	612 sx
6¼	5½ (LNR.)	(unk.)	12,032-15,400	450 sx.
(unk)	3½ (LNR.)	(unk)	14,967-17,084	250 sx.

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abondoned by Texaco in 1983. MCH will drill out cement plugs and cibp @ 7,579' to a total depth of approx. 8,350' (inside casing). This will leave in place cibp at 9,500' and deeper. We will then test existing perforations @ 7,807'-7,857' and stimulate as necessary.

Mud Program: Fresh water will be used for the reentry inside casing.

BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO GENERAL REQUIREMENTS AND SPECIAL STIPULATIONS ATTACHED

IN ABOVE SPACE DESCRIBE PROPOSED PROGRAM: If proposal is to deepen, give data on present productive zone and proposed new productive zone. If proposal is to drill or deepen directionally, give pertinent data on subsurface locations and measured and true vertical depths. Give blowout preventer program, if any.

24.

SIGNED Craig Huben TITLE Owner DATE 4/13/93

(This space for Federal or State office use)

PERMIT NO. ______ APPROVAL DATE ______

Application approval 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.

CONDITIONS OF APPROVAL, IF ANY:

APPROVED BY ______ TITLE ______ DATE ______

*See Instructions On Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

Form 3160-5
(November 1983)
(Formerly 9-331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

P. O. BOX 1980
HOBBS, NEW MEXICO 88240

Form approved.
Budget Bureau No. 1004-0135
Expires August 31, 1985

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

1. OIL WELL [X] GAS WELL [ ] OTHER

7. UNIT AGREEMENT NAME
West Jal Unit

2. NAME OF OPERATOR
Getty Oil Company

8. FARM OR LEASE NAME

3. ADDRESS OF OPERATOR
P.O. Box 730, Hobbs, NM 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
Unit Ltr. H, 1980' FNL & 660' FEL

BUREAU OF LAND MANAGEMENT RECEIVED APR ... DIST. 6 N. M. ROSWELL, NEW MEXICO

10. FIELD AND POOL, OR WILDCAT
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, T-25S, R-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138' D.F.

12. COUNTY OR PARISH
Lea

13. STATE
NM

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	[ ]	PULL OR ALTER CASING	[ ]	WATER SHUT-OFF	[ ]	REPAIRING WELL	[ ]
FRACTURE TREAT	[ ]	MULTIPLE COMPLETE	[ ]	FRACTURE TREATMENT	[ ]	ALTERING CASING	[ ]
SHOOT OR ACIDIZE	[ ]	ABANDON*	[ ]	SHOOTING OR ACIDIZING	[ ]	ABANDONMENT*	[XX]
REPAIR WELL	[ ]	CHANGE PLANS	[ ]	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

3/26/84 Rigged up. Pulled rods and pump. Unseat tbg. anchor and install BOP.
3/28/84 Pulled 2 7/8" buttress & 2 3/8" tbg. anchor. Ran 7" CI plug, set @ 7579'. Ran 2 3/8' to 4290'. By Halliburton, circ. 191 bbls. gel brine, pulled tbg. Perfs 4-0.25" holes @ 6400'. Circ. out 7" between 9 5/8". Ran 2 7/8" to 7554'.
3/29/84 Rigged up csg. puller unit. Pulled tbg. Remove BOP & 7" tbg. spool.
3/30/84 Weld 7" pull nipple. Cut 7" csg. @ 6735'. Pulled 11 jts 7", 26#, P-110 csg. 8 rd.
3/31/84 Layed down total 163 jts (est. 6525') 7", 8rd casing. Nipple down 9 5/8" head.
4/2/84 Weld on 9 5/8" pulled nipple. Attempted to pull slips with 500,000#. Set off primer cord around head, no movement. Left soaking in penetrating oil.
4/3/84 Dug out 13 3/8" csg. unflange head. Move pipe 1" with 600,000#. Cut off. Pulled nipple, installed BOP. Ran tbg to 5216'.
4/4/84 Spot 20 sxs cement on top of CIBP 7579-7479'. Spot 100' plug (45 sxs) at 6758-6685', 6350-6250', 3325-3200', 1380-1270'. Remove csg. head.
4/5/84 Rigged down. Installed 20 sxs. Plugged 0-50'. Installed dry hole marker. P&A.

18. I hereby certify that the foregoing is true and correct

SIGNED Donald J. Steinnerd TITLE Area Superintendent DATE April 11, 1984

Dale R. Crockett

(This space for Federal or State office use)

Orig. Sgd. ...

APPROVED BY ______ TITLE ______ DATE 6 8 8 7

CONDITIONS OF APPROVAL, IF ANY:

0+6-BLM-Roswell 1-Mr. J.A.-Midland
1-File 1-Laura Richardson-Midland
1-Engr Jim 1-BB, 1-JA
1-Foreman CK 1-SH, 1-CP 1-Southland Royalty Company, 1-ARCO

Approved as to plugging ... Liability under bond is retained until surface restoration is completed.

*See Instructions on Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

N. M. OIL CONS. COMMISSION
P. O. BOX 1980
HOBBS, NEW MEXICO 88240

O+6 - BLM - P.O. Box 1857, Roswell, 1-File, 1-Engr.JIM, 1-Foreman CK

Form 9-331
Dec. 1973

1 - Laura Richardson-Midland

Form Approved.
Budget Bureau No. 42-R1424

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

BUREAU OF LAND MANAGEMENT
RECEIVED
JUL 25 1983
DIST. 6 N. M.
ROSWELL, NEW MEXICO

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 Form 9-331-C for such proposals.)

1. oil well XX gas well ☐ other

2. NAME OF OPERATOR
Getty Oil Company

3. ADDRESS OF OPERATOR
P.O. Box 730 Hobbs, NM 88240

4. LOCATION OF WELL (REPORT LOCATION CLEARLY. See space 17 below.)
AT SURFACE: Unit ltr. H, 1980' FNL & 660 FEL
AT TOP PROD. INTERVAL:
AT TOTAL DEPTH:

5. LEASE
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME
West Jal Unit

9. WELL NO.
1

10. FIELD OR WILDCAT NAME
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, 25S-36E

12. COUNTY OR PARISH
Lea

13. STATE
NM

14. API NO.

15. ELEVATIONS (SHOW DF, KDB, AND WD)
3138' D.F.

16. CHECK APPROPRIATE BOX TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

	REQUEST FOR APPROVAL TO:	SUBSEQUENT REPORT OF:
TEST WATER SHUT-OFF	☐	☐
FRACTURE TREAT	☐	☐
SHOOT OR ACIDIZE	☐	☐
REPAIR WELL	☐	☐
PULL OR ALTER CASING	☐	☐
MULTIPLE COMPLETE	☐	☐
CHANGE ZONES	☐	☐
ABANDON*	XX	☐
(other) Revised		

(NOTE: Report results of multiple completion or zone change on Form 9-330.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

Revised procedure as per conversation with Mr. Peter Chester 7/18/83:

1. Install B.O.P.
2. Set C.I.B.P. at +7860 w/35' cement on top.
3. Perforate 2 holes @ 6375' & squeeze with sufficient cement to bring cement to 6225'.
4. Set cement plug 1230-1330' top of salt. (in & behind casings).
5. Set 50' surface plug.
6. Install dry hole marker.
7. Restore location.

Subsurface Safety Valve: Manu. and Type ______ Set @ ______ Ft.

18. I hereby certify that the foregoing is true and correct

SIGNED Dale R. Crockett TITLE Area Superintendent DATE July 22, 1983

APPROVED

(This space for Federal or State office use)

APPROVED BY (Orig. Sgd.) ... M. CHESTER TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

SEP 14 1983

Jiy

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG *

5. LEASE DESIGNATION AND SERIAL NO.: NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: - - - - - -

7. UNIT AGREEMENT NAME: - - - - - -

8. FARM OR LEASE NAME: West Jal Unit

9. WELL NO.: 1

10. FIELD AND POOL, OR WILDCAT: Jal Delaware, West UNDESIGNATED

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec. 20-25S-36E

12. COUNTY OR PARISH: Lea

13. STATE: New Mexico

1a. TYPE OF WELL: OIL WELL [X] GAS WELL [ ] DRY [ ] Other

b. TYPE OF COMPLETION: NEW WELL [ ] WORK OVER [ ] DEEP-EN [ ] PLUG BACK [X] DIFF. RESVR. [X] Other

2. NAME OF OPERATOR: Skelly Oil Company

3. ADDRESS OF OPERATOR: P. O. Box 1351, Midland, Texas 79701

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*

At surface: Unit Letter H, 1980' FNL and 660' FEL, Sec. 20-25S-36E

At top prod. interval reported below

At total depth

14. PERMIT NO. | DATE ISSUED

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
- -	- -	5-28-74	3138' DF	- - -

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
17086'	9485' PBTD	- -	→	- -	- -

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*: 7807-7857' Delaware

25. WAS DIRECTIONAL SURVEY MADE: - - -

26. TYPE ELECTRIC AND OTHER LOGS RUN: None

27. WAS WELL CORED: - -

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
No Change					

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
-	-	-	-	-
-	-	-	-	-

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-3/8"OD	7941'	- -
2-7/8"OD		- -

31. PERFORATION RECORD (Interval, size and number): 7807-7811', 7816-7828', 7853-7857', total 32 shots, 0.50" diameter, two shots per foot.

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
7807-7857'	750 gallons mud acid 5000 gallons 15% NE acid, 82 ball sealers, 9000# 20-40 sand, 9000 gallons lease oil

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
5-28-74	Pumping	Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
6-19-74	24	-	→	63	1	6	16

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
- -	63#	→	63	1	6	41°

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.): Used for Fuel

TEST WITNESSED BY

35. LIST OF ATTACHMENTS: None

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED (Signed) D. R. Crow D. R. Crow TITLE Lead Clerk DATE 6-20-74

*(See Instructions and Spaces for Additional Data on Reverse Side)

INSTRUCTIONS

General: This form is designed for submitting a complete and correct well completion report and log on all types of lands and leases to either a Federal agency or a State agency, or both, pursuant to applicable Federal and/or State laws and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local, area, or regional procedures and practices, either are shown below or will be issued by, or may be obtained from, the local Federal and/or State office. See instructions on items 22 and 24, and 33, below regarding separate reports for separate completions.

If not filed prior to the time this summary record is submitted, copies of all currently available logs (drillers, geologists, sample and core analysis, all types electric, etc.), formation and pressure tests, and directional surveys, should be attached hereto, to the extent required by applicable Federal and/or State laws and regulations. All attachments should be listed on this form, see item 35.

Item 4: If there are no applicable State requirements, locations on Federal or Indian land should be described in accordance with Federal requirements. Consult local State or Federal office for specific instructions.

Item 18: Indicate which elevation is used as reference (where not otherwise shown) for depth measurements given in other spaces on this form and in any attachments.

Items 22 and 24: If this well is completed for separate production from more than one interval zone (multiple completion), so state in item 22, and in item 24 show the producing interval, or intervals, top(s), bottom(s) and name(s) (if any) for only the interval reported in item 33. Submit a separate report (page) on this form, adequately identified, for each additional interval to be separately produced, showing the additional data pertinent to such interval.

Item 29: *"Sacks Cement"*: Attached supplemental records for this well should show the details of any multiple stage cementing and the location of the cementing tool.

Item 33: Submit a separate completion report on this form for each interval to be separately produced. (See instruction for items 22 and 24 above.)

37. SUMMARY OF POROUS ZONES:
SHOW ALL IMPORTANT ZONES OF POROSITY AND CONTENTS THEREOF; CORED INTERVALS; AND ALL DRILL-STEM TESTS, INCLUDING DEPTH INTERVAL TESTED, CUSHION USED, TIME TOOL OPEN, FLOWING AND SHUT-IN PRESSURES, AND RECOVERIES

38. GEOLOGIC MARKERS

FORMATION	TOP	BOTTOM	DESCRIPTION, CONTENTS, ETC.	NAME	TOP MEAS. DEPTH	TOP TRUE VERT. DEPTH

1) Squeezed Fusselman perfs. 16,449-16,614' with 100 sacks Class "H" cement, 5/10% CFR-2.
2) Spotted 25 sacks cement 14,711-14,741', 25 sacks 11,924-12,082' and set cast iron bridge plug at 10,330' and spotted 4 sacks cement 10,310-10,330'.
3) Perforated 7" OD casing in First Bone Springs formation with two 0.48 diameter holes per foot at 10,112-10,122' and 10,128-10,132'. (28 shots total)
4) Treated First Bone Springs perfs. 10,112-10,132 with 5500 gallons acid and 68 ball sealers.
5) Swab tested First Bone Springs perfs. 10,112-10,132' May 14, 1974, to May 21, 1974, for no oil, 14 bbls. water and slight show of gas in 5 hours.
6) Set cast iron bridge plug at 9500' and cemented with 3 sacks cement plugging back to 9485'.
7) Perforated 7" OD casing in Delaware formation with two 0.50" diameter holes per foot at 7807-7811', 7816-7826' and 7853-7857'. (32 shots total)
8) Treated Delaware perfs. 7807-7857' with 750 gallons mud acid, 5000 gallons 15% HE acid, 9000 gallons gelled lease oil, 9000# 20-40 sand and 22 ball sealers.
9) Returned well to production status 5-28-74 pumping Delaware perfs. 7807-7857' for 63 bbls. oil, 6 bbls. water and 1 MCFGPD.

U.S. GOVERNMENT PRINTING OFFICE: 1963—O-683636

871-233

West Jal Unit
Well No. 1
Lea Co., New Mexico
Page 2

8) Flowed 24-1/2 hours through 1" choke, making no oil, 45 bbls. load water, 393 bbls. formation water and gas at rate of 266 MCF per day. FTP 200#, CP 2300#.
9) Ran flow meter, Gradionometer and Temperature Survey to determine water entry.
10) Shut well in seven hours, then ran Base Temperature Log 16,000-17,020'. Water channelling from bottom of well bore to 16,508'.
11) Set cement retainer at 16,250' and squeezed perfs. 16,499-16,614' with 150 sacks Class "H" cement containing 4/10ths of 1% CFR-2 and 1% Halad 9. Squeeze failed. WOC 4 hours.
12) Resqueezed perfs. 16,449-16,614' with 50 sacks Class "H" cement with 1% Halad 9, 4/10ths of 1% CFR-2 and 1/4# Flocele per sack and 150 sacks Class "H" containing 1% Halad 9 and 4/10ths of 1% CFR-2. Squeeze failed.
13) Attempted to pull cement retainer - stuck.
14) Milled and pushed cement retainer from 16,250' to 16,490'. Recovered cement retainer.
15) Drilled and pushed junk to 16,930'.
16) Ran 254 jts. (14,793') of 2-7/8" OD tubing and set packer at 14,810'. Swabbed 9 hours, recovering 60 bbls. load water with good show of gas.
17) Treated perfs. 16,449-16,614' with 500 gals. 15% NE acid with 2 ball sealers. Swabbed 7 hours, recovering 1 bbl. load water, flowing gas at rate of 50 MCF per day.
18) Treated perfs. 16,449-16,614' with 5000 gals. 15% NE acid and 27 ball sealers.
19) Ran Temperature Survey 15,000-16,958'.
20) Tested well. Well flowed at rate of 910 MCF per day on 23/64" choke, no oil, FTP 310#. Pulled tubing and packer.
21) Reran 457 jts. (14,940') of 2-7/8" OD 7.9# DSS-HT Atlas-Bradford Condition "A" tubing and set at 14,967'.
22) Circulated hole with corrosion inhibitor water. Released rig 11-8-72. Flowed and tested well.
23) On Dec. 11, 1972, treated perfs 16,449-16,614' with 12,500 gals. of 1% KCL water with 62# friction reducer, 25 gals. Adofoam and 25 gals. scale inhibitor, 20,000 gals. 20% retarded acid with 100# friction reducer, 40 gals. Adofoam, 160 gals. acid inhibitor, 1000# fluid loss agent and 40 gals. scale inhibitor and 7 ball sealers. All fluid contained 400 S.C.F Nitrogen per barrel.
24) Testing well.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

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—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO.: NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: ——

7. UNIT AGREEMENT NAME: ——

1. OIL WELL ☐ GAS WELL ☒ OTHER

2. NAME OF OPERATOR: Skelly Oil Company

8. FARM OR LEASE NAME: West Jal Unit

3. ADDRESS OF OPERATOR: P. O. Box 1351, Midland, TExas 79701

9. WELL NO.: 1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT: Undesignated Fusselman

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: Sec. 20-25S-36E

14. PERMIT NO.:

15. ELEVATIONS (Show whether DF, RT, GR, etc.): 3076' GR

12. COUNTY OR PARISH: Lea

13. STATE: New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Clean out & deepen to 17,086'	x		
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

1) Rigged up rotary tools 7-28-72. Pulled tubing and packer.
2) Set cement retainer at 11,390' and squeezed Strawn 7" OD casing perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 1% CFR-2 and 3# sand per sack. Squeeze failed. WOC 4 hours.
3) Resqueezed perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 5/10% of 1% CFR-2 and 3# sand per sack. Squeezed at 6500#. Reversed out 15 sacks.
4) After WOC 12 hours, drilled cement retainer at 11,390' and cement 11,390-11,755' with 6-1/2" bit.
5) Tested squeeze job to 3000#; held okay.
6) Drilled cement 11,790-11,832' and tested old squeeze job on perfs. 11,736-11,815' to 3000#; held okay.
7) Drilled cement 11,832-11,844'; pushed plus-plug to 11,976'. Drilled plug. Tagged junk at 12,002' and pushed to 12,312'.
8) Cleaned to top of 5-1/2" OD liner at 12,032', set cement retainer at 11,820' and found casing perfs. 11,849-11,894' open.
9) Squeezed 5-1/2" casing perfs. 11,849-11,894' with 50 sacks Class "H" with 1% CFR-2 and 100 sacks Class "H" with 1% CFR-2 and 3# sand per sack.
10) Dumped 20 sacks cement on retainer at 11,820', plugging back to 11,717'. Reversed out 90 sacks cement. WOC 12 hours.

(continued on page 2)

18. I hereby certify that the foregoing is true and correct

SIGNED ______ TITLE Lead Clerk DATE Dec. 18, 1972

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______
CONDITIONS OF APPROVAL, IF ANY:

ACCEPTED FOR RECORD
DEC 20 1972
U. S. GEOLOGICAL SURVEY
HOBBS, NEW MEXICO

*See Instructions on Reverse Side

11) Drilled cement 11,708-11,820'; cement retainer 11,820-11,822' and cement 11,822-11,861'. Cleaned out to top of liner at 12,032'.
12) Tested squeeze job to 2500#; held okay.
13) Drilled junk 12,312-12,748.5'; cement 12,748.5-12,760'; junk to 12,762'; cement 12,762-13,030'.
14) Tested old squeezed perfs. 13,005-13,030' to 2500#; held okay.
15) Milled and drilled cast iron bridge plug at 13,174' and pushed to 13,395'.
16) Tested 5-1/2" OD liner perfs. 13,247-13,360' to 2900#; could not pump into perfs.
17) Milled cast iron bridge plug 13,396-13,400'.
18) Tested perfs. 13,462-13,472' to 2700#; could not pump into perfs.
19) Milled and drilled out cement retainer 13,517-13,524'; cement 13,524-13,532'; cement 15,050-15,353'.
20) Milled and drilled cast iron bridge plug 15,340-15,858'. Washed over fish 15,858'; recovered fish. Cleaned out to old TD of 15,958'.
21) Drilled 4-3/4" new hole 15,958-16,498'.
22) Ran Drill Stem Test No. 1 (Silurian) 15,400-16,498'.
23) Drilled 4-3/4" hole 16,498' to total depth of 17,086' at 11 p.m. October 4, 1972.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instruction on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429 - A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- - -

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
- - -

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Section 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3102' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐
REPAIR WELL	☐	CHANGE PLANS	☐
(Other)			

SUBSEQUENT REPORT OF:

WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
(Other) Cement, perforate & treat			☒

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

1) Perforated 2-7/8"OD tubing at 11,696',11,297', 10,374; 9698'; 8892';8707',8403'. Circulated to remove mud from annulus. Work began 1-29-69.
2) Pulled tubing
3) Ran 2-7/8"OD tubing with "RTTS" Packer. Set packer at 11,448'.
4) Squeezed 7"OD casing perforations 11,736-11,894' with 150 sacks class "H" Cement with 1% CFR-2 per sack, maximum pressure 4600#, failed. W.O.C. 4 hours. Broke formation down with 5000#.
5) Squeezed 7"OD casing perforations 11,736-11,894" with 50 sacks Class "H" cement with 1% CFR-2 and 5# No. 3 sand per sack. Displaced 35 sacks into formation. Pulled tubing and packer.
6) WOC 36 hours. Ran tubing with 6-1/8" bit. Top of cement inside 7"OD casing at 11,595'. Washed and circulated cement to 11,620'. Drilled cement 11,620-11,700'. Drilled packer 11,700-705'. Drilled cement 11,705-755'.
7) Tested casing to 3000#, held okay.
8) Spotted 12 bbls. acid 11,755-11,443'.
9) Perforated 7"OD casing with 2 shots per foot as follows:

11,510 - 513'	3'	6 shots
11,517- 527'	10'	20 shots
11,536 - 540'	4'	8 shots
11,550 - 556'	6'	12 shots
11,561 - 567'	6'	12 shots
11,575 - 579'	4'	8 shots
11,660 - 667'	7'	14 shots

18. I hereby certify that the foregoing is true and correct

SIGNED ______ TITLE District Production Manager DATE 3-10-69

(This space for Federal or State office use)

APPROVED BY ______ TITLE (ORIGINAL SIGNED) V. N. Fletcher

CONDITIONS OF APPROVAL, IF ANY:

APPROVED
MAR 11 1969
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
~~73503~~ NM-034291-

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

7. UNIT AGREEMENT NAME
----

1. OIL WELL [ ] GAS WELL [X] OTHER

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface **1980 from North line and 660 from East line, Section 20**

20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3092' DF

12. COUNTY OR PARISH **Lea**
13. STATE **New Mexico**

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	[ ]	PULL OR ALTER CASING	[ ]	WATER SHUT-OFF	[ ]	REPAIRING WELL	[ ]
FRACTURE TREAT	[ ]	MULTIPLE COMPLETE	[ ]	FRACTURE TREATMENT	[ ]	ALTERING CASING	[ ]
SHOOT OR ACIDIZE	[ ]	ABANDON*	[ ]	SHOOTING OR ACIDIZING	[ ]	ABANDONMENT*	[ ]
REPAIR WELL	[ ]	CHANGE PLANS	[ ]	(Other)			[ ]
(Other) **Cement, Perforate & Treat**			[X]	(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)			

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

Squeeze present perforated interval 11,736-11,852', below packer set at 11,700', with 125 sacks cement. Drill out to 11,790'. Perforate 11,510-11,783' with 2 shots per foot. Treat perforations 11,510-11,783' with 300 gallons 15% acid with 3 stage treatment using Dowell J-182 as diverting agent. Inject 72 barrels distillate to remove diverting agent. Swab and test.

18. I hereby certify that the foregoing is true and correct

SIGNED (signed) C. R. DAVIS TITLE **District Operations Manager** DATE **1/24/69**

(This space for Federal or State office use)

APPROVED BY ____ TITLE ____
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
JAN 2. 1969
J. L. GORDON
ACTING DISTRICT ENGINEER

RT/jc

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- -

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
- -

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

1980' from North line and 660' from East line

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.
- -

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138'

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐
REPAIR WELL	☐	CHANGE PLANS	☐
(Other)			☐

SUBSEQUENT REPORT OF:

WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
(Other) Eliminate water production			☒

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

(1) Moved in and rigged up workover rig 10-21-68
(2) Set Schlumberger "plus" plug in 7"OD casing at 11,844'.
(3) Dumped 5' cement on top of plug, filling from 11,844' to 11,839'.
(4) Dumped 200 lbs. Hydromite on top of "plus" plug, filling back to 11,832'.
(5) Swabbed well.
(6) Apparent communications still exist between upper and lower perforations behind 7"OD casing. Objective to shut off lower perforations 11,860 - 11,894' and to decrease water production unsuccessful.
(7) Well returned to producing status 10-27-68 flowing 150 MCF gas per day through 7" OD casing perforations 11,736 - 11,894'.

18. I hereby certify that the foregoing is true and correct

SIGNED [signature] TITLE District Production Manager DATE 10-30-68

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
NOV , 1968
J L GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429 - A

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—" for such proposals.)

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
-----

1. OIL WELL ☐ GAS WELL XX OTHER

7. UNIT AGREEMENT NAME
-----

2. NAME OF OPERATOR
SKELLY OIL COMPANY

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL & 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO.
-----

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Clean, Determine Water Source, Eliminate Water Production			X
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

Moved in and rigged up Workover Rig. Killed well. Ran 1-5/8" drill pipe and fishing tools to top of fish at 9901', pushed to 9991', caught fish, circulated and pulled out of hole. Recovered 2 strings of fishing tools previously left in hole. Reran 1-5/8" drill pipe several times with fishing tools and recovered 1786' in several pieces of 5/16" wire line, and a chemica cutter.

Tagged bottom of 2-7/8"OD tubing at 11,715'. Knocked off one foot of tubing and a bull plug that had been previously cut off. Pushed and drove bull plug to 12,482'. Hit firm fill-up of formation cavings and left one-foot piece of 2-7/8"OD tubing and bull plug in hole at 12,482', leaving tubing open-ended at 11,715' with full 2-7/8" opening. Pulled drill pipe and fishing tools and installed Xmas tree. Ran Gradiomanometer, Continuous Flowmeter and Packer Flowmeter to determine water source. Surveys indicated water source being produced through casing perfora tions 11,883-11,894'.

Set packer at 11,883'. Returned to production status November 19, 1967, producing 38 bbls. oil, 800 bbls. water and 2,000 MCF gas per day from the Strawn Gas Pool through perforations 11736-11894' through 7"OD casing.

18. I hereby certify that the foregoing is true and correct

SIGNED (ORIGINAL SIGNED) V. E. Fletcher TITLE District Superintendent DATE April 25, 1968

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
APR 26 1968
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

SUBMIT IN DUPLICATE*
(See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. LEASE DESIGNATION AND SERIAL NO.: NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: ----------

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL ☒ DRY ☐ Other

7. UNIT AGREEMENT NAME: ----------

b. TYPE OF COMPLETION: NEW WELL ☐ WORK OVER ☒ DEEP-EN ☒ PLUG BACK ☐ DIFF. RESVR. ☒ Other

8. FARM OR LEASE NAME: West Jal Unit

2. NAME OF OPERATOR: Skelly Oil Company

9. WELL NO.: 1

3. ADDRESS OF OPERATOR: P. O. Box 1351, Midland, Texas 79701

10. FIELD AND POOL, OR WILDCAT: Undesignated Fusselman

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface 1980' FNL and 660' FEL Sec. 20-25S-36E
At top prod. interval reported below
At total depth

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec. 20-25S-36E

14. PERMIT NO. | DATE ISSUED

12. COUNTY OR PARISH: Lea | 13. STATE: New Mexico

15. DATE ~~SPUDDED~~ started 7-28-72 | 16. DATE T.D. REACHED 11-1-72 | 17. DATE COMPL. (Ready to prod.) 10-4-72 | 18. ELEVATIONS (DF, RKB, RT, GR, ETC.)* 3076' GR | 19. ELEV. CASINGHEAD ----

20. TOTAL DEPTH, MD & TVD 17,086' | 21. PLUG, BACK T.D., MD & TVD 17,020' | 22. IF MULTIPLE COMPL., HOW MANY* --- | 23. INTERVALS DRILLED BY → ROTARY TOOLS 15,958-17,086' | CABLE TOOLS ---

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*
16,449-16,614' (Fusselman)

25. WAS DIRECTIONAL SURVEY MADE: No

26. TYPE ELECTRIC AND OTHER LOGS RUN: BHC Sonic Gamma Ray with Caliper, Dual Laterolog, Continuous Dipmeter, Compensated Neutron & Formation Density

27. WAS WELL CORED: No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
20"	94#	869'	26"	1630 sacks	None
13-3/8"	72,61 & 68#	6300'	17-1/2"	3206 sacks	None
9-5/8"	53.5 & 47#	11,732'	12-1/4"	975 sacks	None

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
		(See attachment)		

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-7/8"	14,967'	None

31. PERFORATION RECORD (Interval, size and number)
16,449-16,614' (Fourteen .33" holes over 165' interval)

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
11,510-11,741'	200 sacks Class "H" Cement
11,849-11,894'	150 sacks Class "H" Cement
16,449-16,614'	350 sacks Class "H" Cement
	(See attachment)

33.* PRODUCTION

DATE FIRST PRODUCTION: 11-1-72 | PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump): Flowing | WELL STATUS (Producing or shut-in): Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
11-14-72	24	24/64"	→	-0-	5950	216	----

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
1900#	---	→	-0-	5950	216	---

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.): Sold | TEST WITNESSED BY

35. LIST OF ATTACHMENTS: 2 copies each: Borehole Compensated Sonic Log - Gamma Ray, Compensated Neutron-Formation Density, Dual Laterolog, Gammatron

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED C.J. Love TITLE Dist. Prod. Manager DATE Dec. 20, 1972

*(See Instructions and Spaces for Additional Data on Reverse Side)

2MOID3ST2M1

WILL RO. !.

Set Baker Calt Iron Bridge Plug at 13,400'. Spotted 2 aacka c••nt on top of bridge plug traa 13,-00' to 1.3,386'. Perto:rated 5--1/2" OD liner with 4 holea at 13,210' and 1queezed with 85 aacka ot caat. Drill.eel out oeaeat \o 13,386'• Perforated S-1/2" liner with 4 ahota per foot •• followa1 13,247-13,2'10', 13,272-1.3,275', 13,286-13,292', 13,298-13,320', 13,326-13,329', 1.3,343-13,345', 13,)56-13,360' tor a total ot 63• and 252 hol••• Treated tbroqh S-1/2" OD caaing liner pert•• 13,247-13,360' (intenala) with 2500 gallon• Mud Acid. Teated .-.11 Hftr&I houn with -n,lae to aall to meanre. Treated through 5-1/2" OD caeing liner perta. 13,21.7-13,360' (intenala) with 2500 gallons Mud Acid.. t'eelMI •li-'.aeveral hN. with TOIUM to -11 to meaaure. Treated through S-1/2" OD casing liner pert▪• 13,247-IJ,'601 (intenala) with 10,000 galana 1,- llegular Acid. Teated well aenral houri with wl111e to .all to m•an• Set Baker Caat Iron Model "I" Bridge Plug at 13,180'• Dmpecl 2 eacka ot cement on top ot plug, wbieh pl11g nll b&ek tra 13,180' to 1.3,166•. Pertorat.ed 5-1/2" OD liner with bole• per toot froa 13,0051 to 13,030• for a total of 251 and 100 hol••• Treated thrcnlgh 5-1/2" OD liner perte. 13,00S-13,030' with 5,000 gallons 15C Regular Acid. Teated well N'Yer&I hove with TOluae \oo ▪-II to aeanre. We teaJ>I'?'8,ril7 abandoned the teat.inc ot the Morrow Zone at t.hie t.m, Set Halliburton "DC" C... nt Retainer at 12,790' and aqueesed 85 eaeke ot CtllHlt into 5-1/2" OD liner perte. 13,005-13,030•. Plugged back total depth 12,7901• Pertorat.ed 7" OD casing with 4 bolea per toot aa tollowa1 11,736-II,7U', 11,781-11,787', II,801-II,815t, II,&1+,-11,852', 11,860-U,894' tor a total ot 55t and 220 holea. Set Baker Model "F" Production Packer at 11,700'• Ran 2-7/8" OD 6.1+0# Blltre•• threat! 1-80 tubing to 11,715' and ....ted in Baker Model"'" Production Packer at 11,700' with pert▪• 11,711-II,715'. Ot.ia l.allding nipple position No. I at II,709'. Ot.1• aid• doar ahitt. valft at U,698'. otie landing nipple poaition lo. 2 at 10,700'. otil lending nipple position lo. 3 at 9700'• Opened well up and flowed to pit to clean up. Shut well in tor 89 hove. After 89 houra with dead night T.P. 6218# fiowed and teated well 1n the toll.owing anner1

nowed 1-3/4 hour▪ on 10/64" choke, opening TP 6218# (W), FTP 6156pai., gas wltae 2,737 JEPPD and 7.6') 'bbl•• ot 52 degree correeted gra'Yit7 condenaate.
lu.t. two hour▪ tlowd through 12/64• ohoke, ITP 6075 pai. (17w), gas luae 4563 KCFPD .w1i and 6.60 bbla. of condenea.te.
lut two noura fiowd throUgh 14/6'+" choke, FTP 599S pei. (DW), gae wIUM 6025 MCFPD and 1.70 bbl•• or oonden•t••
Rut one and one halt hours tLowed through 16/64" choke, FTP 5915 p▪i• (IM), gas volUM 8009 ICFPD and undetel"lined 8Jl0\1llt or oonclen▪ate to pita.
Eatabliahed 24 hour In Maioo Ooneel"'fttion C.-d.eaion AOF Potential ot 310,000 tcFFD. Completed Ja.,.17 22, 1963, a1 a "Wildcat" CClll.J)letion in strawn (Penn117l'Y8Bian) toraation, Total cond.enate ree0Ye17 during 7-1/4 hn. t.eet waa 22,80 bbls. to tank and undetermined aaomt to pita.

Well now ahut in - waiting on ga• connection.

POBMATIOI RECORD

From	To	!!!j		
0	12,058	12,0,s		
12,058	12,152	94		
12,152	12,477	32,	Lime & Shale	- Top Atoka 12,152'
12,477	13,366	889	Sand	- Top Morrow 12,477'
13,366	14,S83	1,217	$ale	- Top Barp,ett Shale IJ,366•
14,583	14,685	102	Lhle	- 'lop Miasiaaippian 14,853'
14,685	1,,138	453	Chert	- Top Che. 14,685'
15,138	15,518	380	Shale	- Top Woodtorcl IS 131
15,518	15,9S8	440	L1M & Dolaite	- Top • {'5,518'
16,??	I5,9SI	Total Depth		
	12,790	Plugged Back Total Depth		

Geological Tops by Schlumberger Gama Ray Sonic log

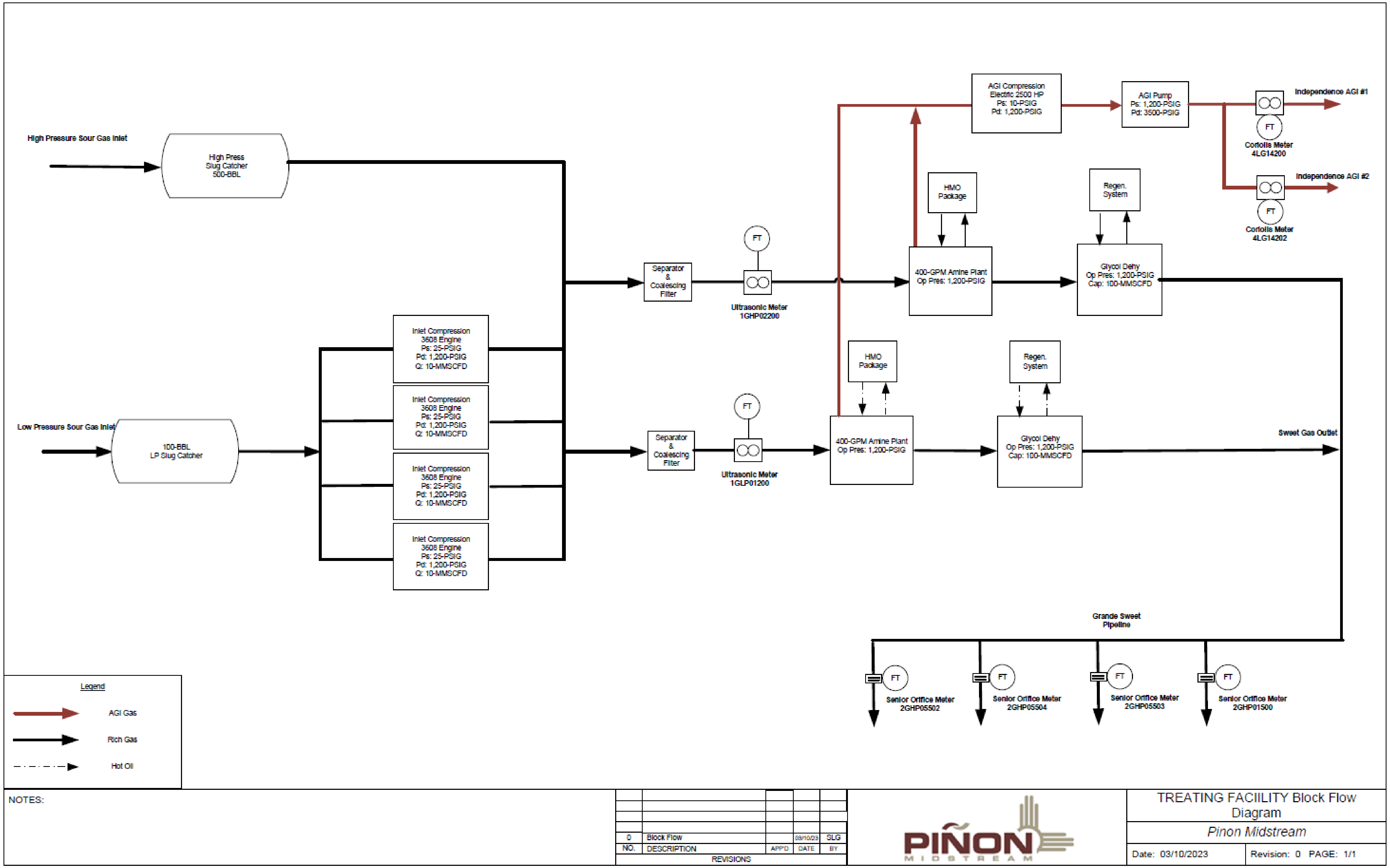

***Figure A10-1*: Treating Facility Block Flow Diagram**

Request for Additional Information: Pinon Midstream, LLC
February 8, 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.	NA	NA	The address for the Pinon facility in e-GGRT is in Houston, Texas, while the facility is located in New Mexico. The address should be that associated with the actual facility, so we request that the address be updated. Per 40 CFR 98.3(c)(1), if the facility does not have a physical street address, then you can provide a latitude and longitude for the facility. In general, please keep in mind that MRV plans are specific to individual facilities. Therefore, you may wish to consider updating the facility name in e-GGRT to something associated with the Independence AGI Wells or the Dark Horse Facility.	The address in e-GGRT has been changed to: Dark Horse Treating Facility 465 W NM Hwy 128 Jal, NM 88252

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
2.	1	1	"Piñon is authorized to inject and dispose of TAG, utilizing the Independence AGI Wells, at an aggregate combined maximum daily injection rate of up to 20 million standard cubic feet per day ("MMSCF/D"), which is the equivalent of approximately 8,200 barrels per day ("bpd"). If Independence AGI #1 is not injecting volumes of TAG, Independence AGI #2 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG. If Independence AGI #2 is not injecting volumes of TAG, Independence AGI #1 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG." Please also provide an equivalent quantity in metric tons of CO_2. Please provide a total anticipated injection quantity for the life of the project including quantities already injected and expected quantities to be injected. What total injection quantities are the plume models based on?	This section has been revised to provide the equivalent quantity of CO_2 in metric tons and to include the total injection quantities used in the simulations.
3.	2.1	3	"Greenhouse Gas Reporting Program ID is 582541." Please clarify if there are any other related facilities in e-GGRT and provide their ID numbers if applicable. We also recommend checking whether the Pinon facility has any prior year data that should be reported under Subpart UU. The Subpart UU source category comprises any well or group of wells that inject a CO2 stream into the subsurface.	This section has been revised to state that no other facilities are related to this MRV plan.
4.	3.3	13	". . . This caprock includes **335** feet of dense Woodford Shale overlain by at least **796** feet of Mississippian limestone (Figures 3.3-1 and 3.3-3)." Please double check these calculations and correct if necessary.	The reference to the figures has been changed to Table 3.3-1 in the revised MRV plan. These thickness values were directly calculated/sourced from this table.
5.	3.3	14	Figure 3.3-1 references Table 6; however, we did not identify a Table 6 in Section 6. Please check and confirm whether this is the correct reference.	The reference to Table 6 has been changed to Figure 3.3-1 in the revised MRV plan.

No.	MRV Plan		EPA Questions	Responses
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6.	3.9	30	"The Independence AGI Wells penetrate the lower Devonian Thirtyone formation and the Silurian Wristen and Fusselman formations and is bounded below by the Ordovician Montoya formation." We recommend rephrasing this sentence for clarity.	The sentence has been changed in the revised MRV plan as follows: "The Independence AGI Wells penetrate the lower Devonian Thirtyone formation and the Silurian Wristen and Fusselman formations and overlies the Ordovician Montoya formation."
7.	3.9.1	31	Figure 3.8-2 is referenced in the text but does not actually appear, please include the figure or update the reference as necessary.	The reference to Figure 3.8-2 has been changed to 3.9-1 in the revised MRV plan.
8.	3..9.1	32	Figure 3.9-1 only shows AGI #1 but not AGI #2. Is there a reason AGI #2 has not been added to the figure?	The figure has been revised to include the SHL for both AGI #1 and AGI #2.
9.	3.9.2	35	"An estimated maximum BHP corresponding to 9,730 psig at the top of Independence AGI#1 corresponded to the fracture pressure gradient was imposed on the Independence AGI #1 to ensure safe injection operations." We recommend rephrasing this sentence for clarity.	The sentence in the revised MRV plan has been changed as follows: "An estimated maximum BHP of 9,730 psig, based on the calculated fracture pressure gradient, was imposed on the Independence AGI #1 to ensure safe injection operations."
10.	3.9.2	37	"Simulations where there is no brine injection result in the plume extending farther northeast including passing the West Jal Deep B well (Figure 3.9-8), while if brine is injected then the plume is repelled towards the south and west, with some TAG flanking the northwest fault and extending northwest (Figure 3.9-9)." We recommend revising this sentence for clarity.	The sentences in the revised MRV plan have been changed as follows: "Simulations where there is no brine injection result in the plume extending farther northeast beyond the West Jal Deep B well (Figure 3.9-8). If brine is injected, then the plume is repelled towards the south and west, with some TAG flanking the northwest fault and extending northwest (Figure 3.9-9)."

No.	MRV Plan		EPA Questions	Responses
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11.	4	40	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 CO2 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 CO2 plume at the end of year t + 5. While the plan identifies the AMA, please provide a rationale/explanation for whether the AMA meets the definition in 40 CFR 98.449. E.g., What are the timeframes associated with the TAG plume in figure 4.1-1?	4.2 Changed to: " Per 40 CFR 98.449, AMA is defined as the area that will be monitored over a specific time interval from the first year of the period (n = 2023) to the last year in the period (t = 2053, a 30-year injection period). The boundary of the AMA 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 (2058, or year 35 of the simulation). The zone shown in Figure 4.1-1 has a one-half mile buffer beyond the stable plume size at year t+5. Piñon intends to define the AMA as the entirety of the MMA."
12.	5.6	42	"Additionally, there have been no seismic events, natural or induced, detected within the MMA for this MRV Plan." Please elaborate on the source of this data and clarify the time period in which there has been no seismic events.	Section 5.6 of the revised MRV plan has been updated to state that although USGS Earthquake Catalog did not reveal any seismic events within the MMA, and the New Mexico Tech Seismic Observatory (NMTSO) database showed 4 seismic events
13.	6	43	Please include a quantification strategy for each of the identified potential leakage pathways.	Section 6 has been changed in the revised MRV plan to include a quantification strategy for each potential leakage pathway.
14.	6.1	44	"Figure 2 7.2-1" This appears to be referencing Figure 7.2-1, please correct the reference.	The reference to the figure has been changed to "7.2-1".in the revised MRV plan.
15.	6.1	44	"Quantification of CO2 emissions from surface equipment and components will be estimated according to the requirements of 98.448 (d) of Subpart RR as discussed in Sections 8.4 and 10.1.5." Please double check whether the reference to 98.448(d) is correct.	The regulatory reference has been changed to 98.444 (d) in the revised MRV plan.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
16.	7.1	45	"Piñon field personnel conduct frequent periodic inspections…" Please clarify the frequency of inspections.	This section has been revised to specify the frequency of inspection.
17.	7.2.2	47	While there is a general diagram of the facility, we request that you include a process flow diagram showing relevant flow meters.	A process flow diagram has been included as Appendix 10.
18.	8.1	49	We recommend including a reference to Equation RR-3 in the discussion regarding CO_2 received.	The following sentences have been added to Section 8.1 of the revised MRV plan. "Piñon 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."

No.	MRV Plan		EPA Questions	Responses
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19.	8.1	49	"Although Piñon does not currently receive CO2 in containers for injection, they have chosen to include the flexibility in this MRV Plan to do so. If Piñon begins to receive CO2 in containers, they will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO2 received in containers. Piñon will adhere to the requirements in 40 CFR 98.444(a)(2) for determining the quarterly mass or volume of CO2 received in containers." Per 40 CFR 98.448(d)(1), you must revise and resubmit your MRV plan if you make any material changes to your monitoring or operational parameters that were not anticipated in the original plan. Examples of material changes include but are not limited to: Large changes in the volume of CO2 injected; the construction of new injection wells not identified in the MRV plan; failures of the monitoring system including monitoring system sensitivity, performance, location, or baseline; changes to surface land use that affects baseline or operational conditions; observed plume location that differs significantly from the predicted plume area used for developing the MRV plan; a change in the maximum monitoring area or active monitoring area; or a change in monitoring technology that would result in coverage or detection capability different from the MRV plan. It is not clear whether receiving CO_2 in containers would result in material changes to the project (e.g., if it led to a change to the volume of CO_2 injected or projected plume area). We recommend including a statement that the MRV plan will be resubmitted in accordance with 40 CFR 98.448(d)(1) if any material changes are made.	The following paragraph has been added to Section 8.1 of the revised MRV plan: "If CO_2 received in containers results in a material change as described in 40 CFR 98.448(d)(1), Piñon will submit a revised MRV plan addressing the material change."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
20.	8/9	50	Per 40 CFR 98.448(a)(7), please include a specific proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart. This date must be after expected baselines as required by paragraph 98.448 (a)(4) are established and the leakage detection and quantification strategy as required by paragraph 98.448 (a)(3) is implemented in the initial AMA.	Section 9 of the MRV plan has been revised to read: "Piñon intends to implement this MRV Plan on June 1, 2023, after it is approved by EPA."
21.	8.4	50	"The calculated total annual CO2 mass emitted by surface leakage is the parameter CO2E in Equation RR-12." It is not clear whether Pinon intends to sum both surface leakage and equipment/vented leakage in the parameter CO2E. Please note that these are separate terms in equation RR-12, and you may wish to clarify this section of your MRV plan.	Sections 8.4 and 8.5 have been modified in the revised MRV plan to clarify the determination of the parameters CO_{2E} and CO_{2FI} in Equation RR-12.
22.	Appendix 8	69	Equation RR-6: Not that you have included an incorrect suffix *x* for Flow meter in the equation instead of the correct suffix *u*. The equation should be listed as: $CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \quad \text{(Eq. RR-6)}$	This correction has been made in the revised MRV plan.

MONITORING, REPORTING, AND VERIFICATION PLAN

Independence AGI #1 and #2 Wells

Pinon Midstream, LLC

Version Number: 1.0
Version Date: December, 2022

Contents

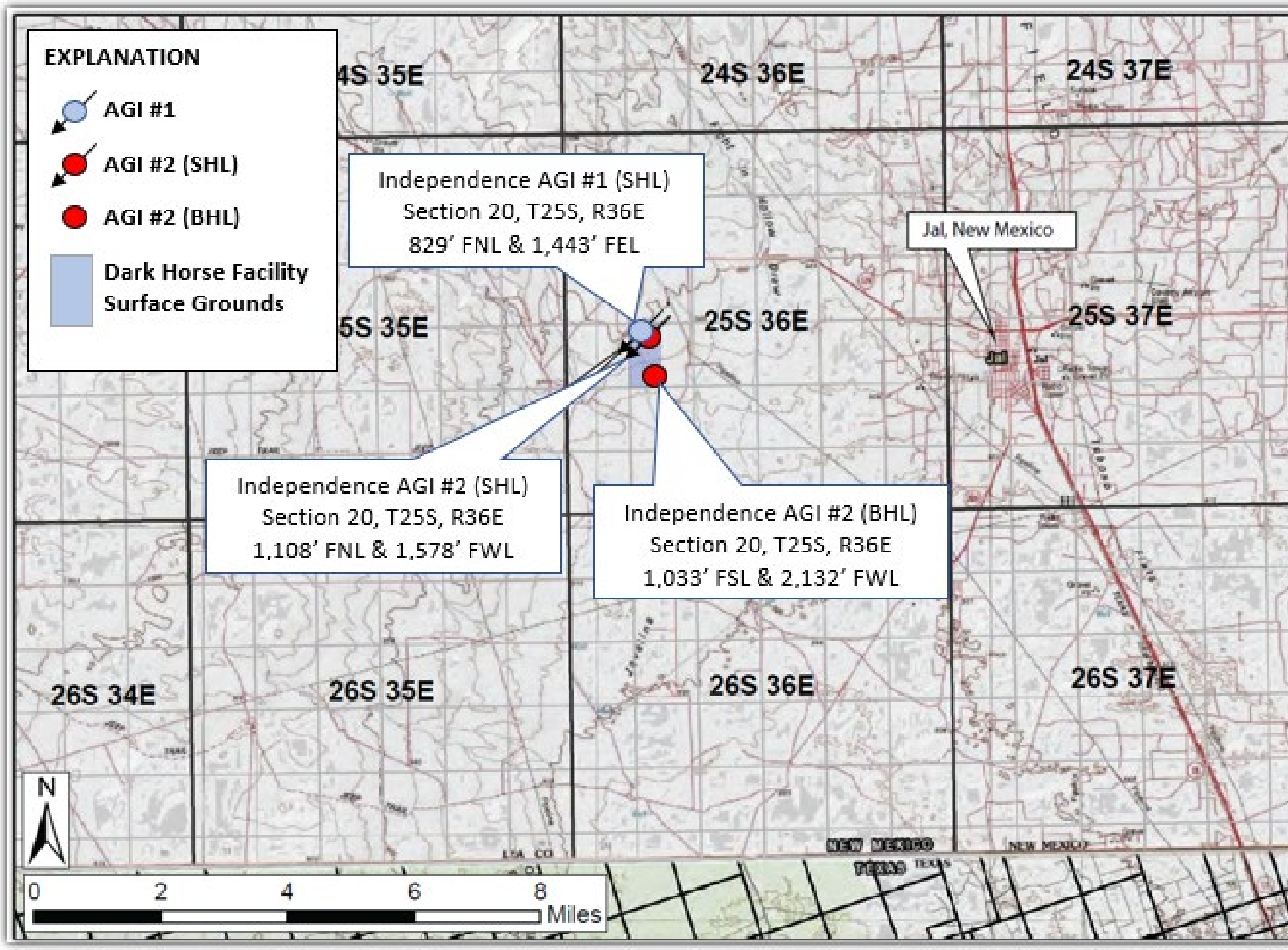
1 Introduction

Ameredev II, LLC (together with its affiliates, "**Ameredev**") is an oil and natural gas producer operating in portions of the Delaware Basin located in southeastern New Mexico and western Texas. In 2020 Ameredev began evaluating methods for treating its sour natural gas production in Lea County, New Mexico to remove and permanently sequester large quantities of hydrogen sulfide ("$\mathbf{H_2S}$") and carbon dioxide ("$\mathbf{CO_2}$") commingled in its produced natural gas stream. On July 10, 2020, Ameredev filed an application with New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division ("**NMOCD**") seeking to drill an acid gas injection ("**AGI**") well approximately six (6) miles west of Jal in Lea County, New Mexico for the injection and permanent sequestration of treated acid gas ("**TAG**"). The application was heard and approved at a New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Commission ("**NMOCC**") hearing held on October 8, 2020. The approved order (Order No. R-21455-A) was subsequently issued at the November 4, 2020 NMOCC hearing and the final, approved, Class II injection permit was issued on November 11, 2020. The Independence AGI #001 vertical well (API 30-025-48081; "**Independence AGI #1**") was spud on December 27, 2020 by Ameredev.

In December of 2020, certain affiliates of Ameredev and other outside investors funded Pinon Midstream, LLC ("**Piñon**") to construct and operate the Dark Horse Sour Gas Treating Facility (the "**Dark Horse Facility**") adjacent to the Independence AGI #1 (Figure 1-1) and Ameredev subsequently contributed and assigned the Independence AGI #1 to Piñon on May 21, 2021. Piñon became the operator of record for the Independence AGI #1 on August 24, 2021. Upon completion in late August 2021, treatment of sour natural gas (using amine to isolate H_2S and CO_2) and the injection of TAG into Independence AGI #1 commenced at the Dark Horse Facility (a full description of the treating and injection process is provided in Section 3.8). On March 31, 2022 the NMOCC authorized the drilling of the Independence AGI #002 deviated well (API 30-025-49974; "**Independence AGI #2**") (together the "**Independence AGI Wells**"), which commenced during the summer of 2022.

Independence AGI #1 is permitted to inject into the Devonian Thirtyone and Upper Silurian Wristen and Fusselman Formations from a true vertical depth ("**TVD**") of approximately 16,230 to 17,900 feet (the "**AGI #1 Injection Zone**") and at a maximum surface pressure of approximately 4,779 pounds per square inch gauge ("**psig**"). Independence AGI #2 is permitted to inject into the Devonian Thirtyone Formation and Upper Silurian Wristen and Fusselman Formations from a TVD of approximately 16,080 to 17,683 feet (the "**AGI #2 Injection Zone**", and together with the AGI #1 Injection Zone, the "**Siluro-Devonian Injection Zone**") and at a maximum surface pressure of approximately 5,005 psig. In accordance with NMOCC Order No. R-21455-A (as amended by Order No. R-21455-B, the "**NMOCC Order**"), Piñon is authorized to inject and dispose of TAG, utilizing the Independence AGI Wells, at an aggregate *combined* maximum daily injection rate of up to 20 million standard cubic feet per day ("**MMSCF/D**"), which is the equivalent of approximately 8,200 barrels per day ("**bpd**"). If Independence AGI #1 is not injecting volumes of TAG, Independence AGI #2 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG. If Independence AGI #2 is not injecting volumes of TAG, Independence AGI #1 is permitted to inject up to a total of 20 MMSCF/D (~8,200 bpd) of TAG.

Piñon has chosen to submit this Monitoring, Reporting, and Verification Plan (the "**MRV Plan**") to the United States Environmental Protection Agency (the "**EPA**") for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (the "**GHGRP**") for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. Piñon intends to utilize the Independence AGI Wells for the injection and disposal of TAG for another approximately thirty (30) years.



<u>Figure 1-1</u>: Location of Dark Horse Facility and the Independence AGI Wells. The approximate surface hole location ("SHL") and the approximate bottom hole location ("BHL") are indicated for both Independence AGI Wells. (Modified from Figure 1 of Class II permit application for Independence AGI #2, Geolex, Inc.)

This MRV Plan contains twelve (12) sections:

<u>Section 1</u> is this Introduction.

<u>Section 2</u> contains facility information.

<u>Section 3</u> contains the project description.

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

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

<u>Section 6</u> describes the detection, verification, and quantification of leakage from the identified potential sources of leakage.

<u>Section 7</u> describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

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

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

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

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

Section 12 includes Appendices supporting the narrative of the MRV Plan

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is 582541.

2.2 Underground injection control ("UIC") well identification numbers

This MRV Plan is for the Independence AGI Wells (*see* Appendix 1). The details of the injection process are provided in Section 3.8.

2.3 UIC permit class

The NMOCD has issued UIC Class II Acid Gas Injection ("**AGI**") permits for the Independence AGI Wells under its State Rule 19.15.26 NMAC (*see* Appendix 2). All oil- and natural gas-related wells located near the Independence 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

Parts of the following project description have been taken from the Class II permit applications for (i) Independence AGI #1, prepared by Geolex, Inc. for Ameredev, dated July 10, 2020; and (ii) Independence AGI #2, also prepared by Geolex, Inc. for Piñon, dated November 4, 2021.

3.1 General Geologic Setting / Surficial Geology

The Dark Horse Facility is located adjacent to the Independence AGI Wells as shown in Figure 3.1-1. The site lies on the eastern flank of the Pecos River Basin within the Javelina Basin. Referred to as the South Plain by Nicholson & Clepsch (1961), the region exhibits irregular topography without integrated drainage. Surficial sediments commonly consist of unconsolidated alluvium and eolian sands. There are no observed surface bodies of water, or groundwater discharge sites within one (1) mile of the Independence AGI Wells. The Dark Horse Facility overlies Quaternary alluvium overlying the Triassic redbeds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater. The thick sequences of Permian rocks that underlie these deposits are described in Section 3.2.2.

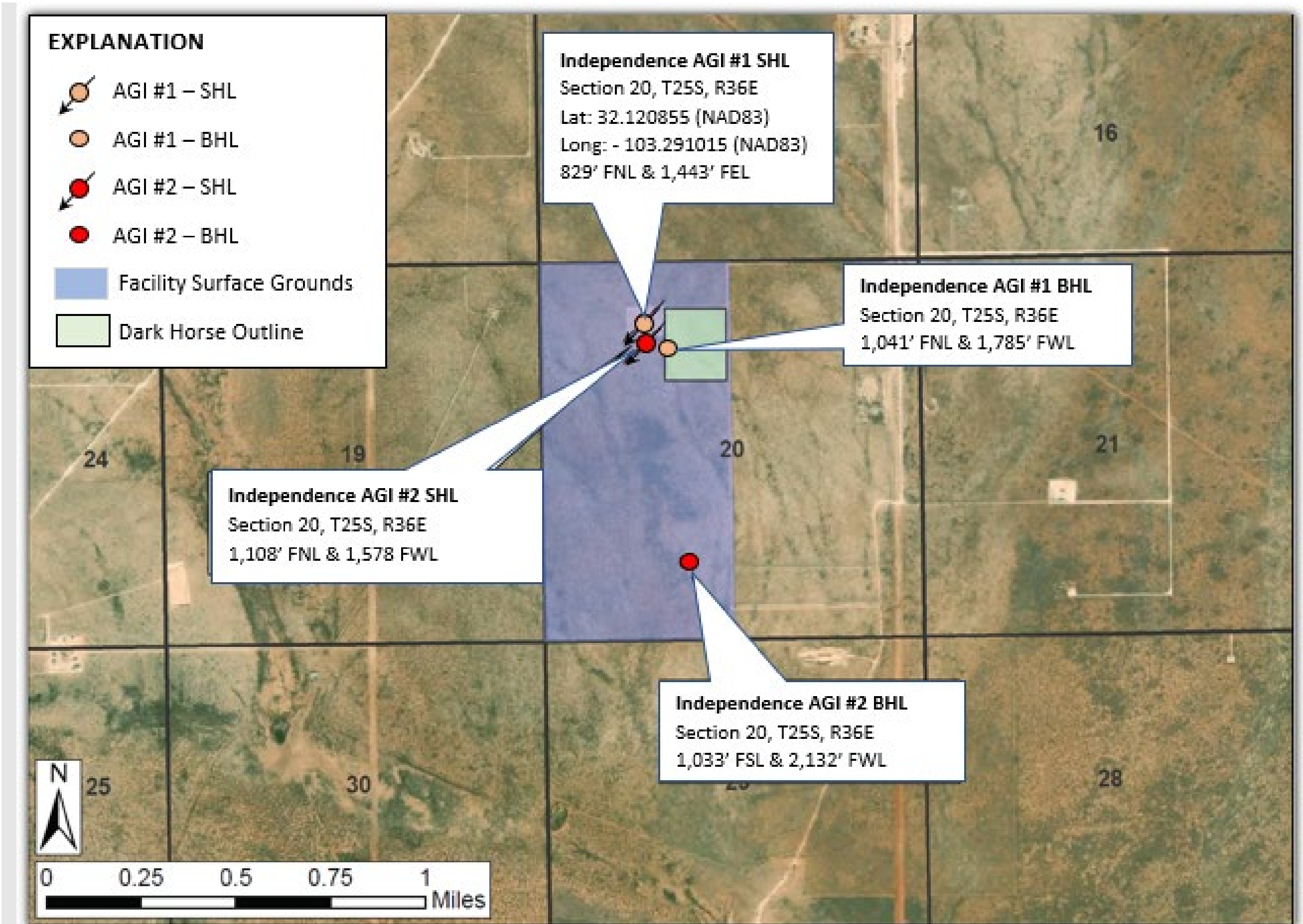


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__Figure 3.1-1__: Map showing location of Dark Horse Facility and the Independence AGI Wells in Section 20, T25S, R36E NMPM. The BHL of the Independence AGI #1 sidetrack is 446' southeast of the SHL. The SHL and the BHL for Independence AGI #2 are shown. (Modified from Figure 2 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.2 Bedrock Geology

3.2.1 Basin Development

The Dark Horse Facility is 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. The Permian Basin and its sedimentary fill have been formed and controlled by tectonism of varying degrees and sedimentation events that began in the Precambrian and throughout the Cenozoic (Neogene). Early Paleozoic deposition took place in the Late Cambrian as marginal areas of the North American craton began to be flooded by marine seas. Late Cambrian sediments comprised of basal siliciclastic sands and muds from areas of exposed Precambrian igneous, metamorphic, and sedimentary rocks and shallow-water carbonates.

Parts of the following basin development descriptions in this subsection have been modified and summarized from Ruppel (2019). Flooding continued across the North American craton throughout the Early Ordovician, establishing a widespread shallow-water carbonate platform. The Ellenburger Formation (Figure 3.2-2) rocks are derived from peritidal and shallow subtidal carbonates. These sediments were exposed during one of the sea-level drops during the Ordovician deposition resulting in karstification and dolomitization. During the Early to Middle Paleozoic time, the Permian Basin region was occupied by a relatively shallow basin called the Tobosa Basin. The first rapid subsidence and formation of the Tobosa Basin began in Simpson time (Middle

Ordovician), and subsidence slowly diminished into the Early Devonian (Ewing, 2019). Subsequent tectonic history of the Tobosa and Permian Basins will be discussed throughout this section.

Early Paleozoic deposition is mostly defined by multiple high-frequency sea-level changes, karsting, and erosional events. Large-scale shift in facies and environments indicate tectonic and/or eustatic controls on sediment distribution patterns. Simpson Group (Middle Ordovician) rocks unconformably overlie Ellenburger Formation rocks at a widespread hiatus caused by Early Ordovician to Middle Ordovician relative sea-level fall. Simpson rocks are a cyclic succession of lime mudstones and quartz sandstones and were deposited during the subsequent reflooding of the shelf. Carbonate-dominated Montoya Formation (Late Ordovician) and Fusselman Formation (Latest Ordovician -Early Silurian) rocks overlie the Simpson Group and indicate a shift and deepening of Tobosa Basin. These rocks are indicative of an overall relative sea level rise.

Middle Silurian-Early Devonian Wristen Group and Thirtyone Formation rocks indicate differential subsidence in the area and represented a deepening and expansion of the basin. Wristen Group rocks comprised of carbonate mudstones and wackestones of the Wink Formation, which underlies the shallow-water carbonate platform packstones, grainstones, and reef facies (corals and stromatoporoids) of the Fasken Formation and the deep-water lime mudstones of the Frame Formation. These facies outline the position of a Silurian platform margin and imply a downwarping of the North American craton. Although Wristen and Fusselman show evidence of numerous high-frequency sea-level changes, the larger-scale change in facies and depositional environments indicates tectonic and/or eustatic controls on sediment distribution patterns. The Silurian platform margin is a recurring feature that controls facies distribution through the Late Mississippian, suggesting tectonic and/or basement terrain control. The rocks of the Thirtyone Formation (Early Devonian) consist of platform carbonate grainstones and packstones surrounding calcareous, radiolarian-rich basin facies.

According to Ruppel (2019) and Ruppel and others, (2020a), a major episode of relative sea-level fall in the Middle Devonian is documented by an absence of Late Early Devonian and early Middle Devonian rocks. Late Devonian Woodford rocks overlie eroded and karsted Silurian (Wristen Group), Early Devonian Thirtyone, and older rocks. Local folding of these rocks below the Woodford suggests that the hiatus may have been at least partially driven by tectonic events. Evidence from the distribution of later Mississippian rocks indicates that the tectonic event caused uplift and localized deformation of pre-Middle Devonian rocks and changed subsidence and depositional patterns across the entire region.

Following the Middle Devonian Permian Basin-area uplift and emergence, Late Devonian marine transgression flooded the region with anoxic bottom-water seas and deposited black, organic-rich biosiliceous mudstones of the Woodford Formation (Ruppel, 2019). Sea-level fall-and-rise sequences defined the Early and Late Mississippian and were even more pronounced during the Pennsylvanian. In the Late Mississippian, initial collision occurred between Laurentia and Gondwanaland, and the Marathon-Ouachita orogenic belt first started to form in northeastern North America (Yang and Dorobek, 1995) with tractions propagating toward the southwest, impacting the Permian Basin by the Middle Pennsylvanian Epoch (Desmoinesian, 310 Ma) (Horne, 2021). Mississippian limestones and the Barnett Formation shales were deposited following a marine transgression that resulted in the development of an extensive carbonate platform, surrounded by a deep-water, organic-rich mud basin.

Collision along the western and southwestern margins of Laurentia, combined with tractions from the Marathon-Ouachita thrusting in the southeast, resulted in northwest-southeast-trending uplifts throughout the western United States known as the Ancestral Rocky Mountain orogeny, which began in Early Pennsylvanian time and continued into the Early Permian (Horne, 2021). The Pennsylvanian tectonic setting in the Permian Basin is the product of the combined Ancestral Rocky Mountain and Marathon–Ouachita effects occurring along the southwest and southeast margins of Laurentia. These events contributed to basin evolution and specific structural domains and styles. In the Permian Basin, the Ancestral Rocky Mountain

orogeny is responsible for the uplift of the Central Basin Platform and the major structural development of the Midland and Delaware Basins (Horne, 2021).

During Desmoinesian to early Missourian sedimentation, Permian Basin deformation reached its peak. The antecedent Tobosa Basin was tectonically differentiated, formed into the crustal uplifts and sub-basins that now characterize the Central Basin Platform, Midland Basin, and Delaware Basin. Throughout Pennsylvanian and most of Permian sedimentation, tectonics coupled with glacial eustacy played an important role in the development of regional facies. Middle to Late Pennsylvanian saw decreasing tectonic deformation activity, and by the Wolfcampian time (Early Permian), deformation was limited to subsidence within the structures formed by the existing uplifts and basins (e.g., Delaware and Midland Basins, Central Basin Platform). The continual subsidence of the Delaware basin affected sediment infilling, with some areas accumulating as much as 12,000 ft of basin-fill sediment. Marine transgression eventually submerged uplifts and became the location of carbonate sedimentation, while the basins became filled with organic-rich siliceous muds. By the end of the Wolfcampian, the major Permian Basin physiographic features (Central Basin Platform, Delaware and Midland Basins) were fully developed, and controlled sedimentation types and location for the remainder of the Paleozoic.

The Middle Permian (Leonardian and Guadalupian) was punctuated by cyclic sediment deposition during sea-level eustatic events. The Leonardian was a time of gradual global warming from the icehouse climates of the late Carboniferous to warmer and more arid greenhouse climates of the later Permian and Mesozoic (Tabor, 2004). The Leonardian marked the beginning of the last stages of the formation of Pangea, producing greater restriction of open ocean connections to the Permian Basin (Ruppel, 2020b). The abundance of tidal-flat facies, evaporites, and reflux dolomites in Leonardian rocks reflects the development of much more arid conditions compared with those in the earlier Permian (Ruppel, 2020b). In the shelf areas (Central Basin Platform and Northern, Northwestern, and Eastern Shelves) (Figure 3.2-1), sedimentation was characterized by shallow-water carbonate production and deposition during sea-level rise, and by shelf exposure and sand-silt deposition during sea-level fall and subsequent shelf exposure. In the Delaware and Midland basins, sedimentation was characterized by cyclic intervals of detrital carbonate-sediment transport into the basins by sea-level highs, and by sand-silt transport and deposition during sea-level falls. Dolomitization of carbonate-shelf deposits occurred during the more regionally arid climates of the Leonardian and the Guadalupian as a product of the Permian Basin area being situated at the equator and from refluxing brines created during periods of sea-level highstand events. Deposition of evaporites became more common in the shelf areas during this time, likely in response to the increasingly arid environment and/or decreased accommodation. By the end of the Guadalupian, the Midland Basin was largely filled, and peritidal muds and evaporite deposition dominated. Sea-level fall and closure of the Hovey Channel (Figure 3.2-1) cut off the Delaware Basin from its marine supply, resulting in regional exposure and nondeposition and the filling of the basin with evaporites of the Castille Formation (Lopingian “Ochoa” Series) (Ruppel, 2019). Most of the rocks deposited during Lopingian “Ochoan” time were evaporites such as anhydrite, halite, and potash minerals with minor amounts of limestone, mudstone, and siltstone and are subdivided into (ascending) Castile Formation, Salado Formation, Rustler Formation, and Dewey Lake Red Beds. Most of the early Ochoan deposition was confined to the Delaware Basin (Bachman, 1984).

3.2.2 Stratigraphy

Figure 3.2-2 is a generalized stratigraphic column showing the formations that underlie the Dark Horse Facility and the Independence AGI Wells. The sequences of Ordovician through Permian rocks are described below.

Ordovician. Below the Silurian Fusselman Formation lies about 400 feet of Ordovician Montoya Formation cherty carbonates which overlies about 400 feet of Ordovician Simpson Group sandstones, shales, and tight limestones. These formations are underlain by the Lower Ordovician Ellenburger Formation which is a thick, carbonate-dominated sequence composed of dolostones and limestones. It is 0-1,000 feet thick in

southeastern New Mexico. The Ellenburger carbonates sit on a veneer of Cambrian to Lower Ordovician Bliss Sandstone and granite wash on the Precambrian basement.

During the Early Ordovician, much of the United States was covered by a shallow sea, and southeast New Mexico was a shallow-water shelf with deep water conditions to the south. Due to sea-level changes and regional tectonic activity, the entire lower Paleozoic interval (Ellenburger through Devonian) was periodically subjected to subaerial exposure and prolonged periods of karst and karst-terrain formation, most especially in the Ellenburger, Fusselman and Devonian strata. The cave systems collapsed with subsequent burial, creating brecciated and fractured carbonate bodies that formed many of the Ellenberger reservoirs and created complex pore networks. The result of these exposure events was the development of numerous horizons of karst-related secondary porosity with solution-enlarged fractures, vugs, and small cavities and caves. Particularly in the Ellenburger and Fusselman strata, solution features from temporally distinct karst events became interconnected with each successive episode, so there could be some degree of vertical continuity in parts of the Fusselman section that could lead to enhanced vertical and horizontal permeability. The Ellenburger is well below the Siluro-Devonian Injection Zone, so it is unlikely to be affected by any proposed activity.

Devonian and Silurian. The Devonian Thirtyone Formation, the Silurian Fusselman Formation, and the Silurian Wristen Group consist of interbedded dolomites and dolomitic limestones and are collectively often referred to as the Siluro-Devonian. In the Middle Devonian, regional marine transgression deposited mostly black, organic-matter-rich siliceous muds of the Woodford Formation (Ruppel, 2019). The Siluro-Devonian Injection Zone does not contain economic hydrocarbons closer than fifteen (15) miles away from the well sites. There have been no commercially significant deposits of oil or natural gas found in the Devonian or Silurian rocks in the vicinity of the Independence AGI Wells and there is no current or foreseeable production at these depths within a two (2) mile radius around the Independence AGI Wells (Figure 3.7-1). Adjacent wells have shown that these formations are primarily water-bearing and are routinely approved as produced-water injection zones in this area.

Mississippian. According to Broadhead (2017), the Mississippian section unconformably overlies the Woodford Formation shales throughout most of southeastern New Mexico and, in places, unconformably overlies the Silurian Fusselman Formation or Ordovician strata in limited areas. These units reach a maximum thickness of 1,400 ft in the Tatum Basin northwest of Hobbs, New Mexico and constitute a major portion of the stratigraphic section. The Mississippian section in southeastern New Mexico is subdivided into the Lower Mississippian limestone (Kinderhookian to Osagean age) and various Upper Mississippian units. The Upper Mississippian section consists of the Barnett Shale in the basinal area to the south and the Meramec and Chester units on the shelf to the north. The Mississippian strata constitute the least developed of the major stratigraphic units in southeastern New Mexico and oil and natural gas production has been from relatively small and widely scattered reservoirs (Broadhead, 2017). The Chester Formation consists of several hundred feet of shales and basinal limestones which are underlain by several hundred feet of Osage limestone.

Pennsylvanian. The Pennsylvanian-age strata is comprised of (ascending) Morrow, Atoka, Strawn, Canyon, and Cisco. Within this entire sequence, the Morrow is a major natural gas producing zone, with smaller contributions from the overlying Atoka and Strawn. The Morrowan strata are dominantly siliciclastic and consist of interbedded shales and lenticular sandstones deposited in multiple regressive sequences and represent basinward migration of nearhore, sand-rich facies tracts from the erosion of exposed Precambrian rocks (Broadhead, 2017). The overlying Atokan strata are also dominantly siliciclastic, with sandstones and shales being deposited in fluvial-deltaic and strandline environments (Broadhead, 2017). The Middle Pennsylvanian (Desmoinesian) Strawn strata is composed of ramp limestones interbedded with marine shales and minor sandstones, and both sandstone and limestone reservoirs are productive (Broadhead, 2017). Although there was past production of oil and natural gas from the Pennsylvanian Strawn pool, there are no active wells in that pool within two (2) miles of the Dark Horse Facility nor are there any natural gas producing

wells in any pools. The Upper Pennsylvanian strata are informally referred to as the Canyon (Missourian) and Cisco (Virgilian) groups, and are composed of interbedded carbonates, dark-gray to black shales, and minor sandstones (Broadhead, 2017). These groups contain prolific oil reservoirs in southeastern New Mexico.

Permian. The overlying Permian rocks found in the Delaware Basin are divided into four (4) series, the Lopingian ("Ochoa") (most recent), Guadalupe, Cisuralian ("Leonard"), and Hueco ("Wolfcamp") (oldest) (Figure 3.2-2). Numerous oil pools have been identified in these rocks (*see* Appendix 3, Table 3a). Active oil producing reservoirs within two (2) miles of the Dark Horse Facility include the following Permian pools: Tansil, Yates, Seven Rivers, Delaware, Bone Spring, and Wolfcamp. New oil wells permitted but not yet drilled are primarily targeting the Bone Spring and the Wolfcamp pools. The rock units of the Permian series are discussed in more detail below.

Permian Hueco ("Wolfcamp") Group. The Lower Permian Wolfcampian strata in the Permian Basin record deposition in deepwater basins surrounded by shallow-water carbonate platforms, where the Wolfcampian platform carbonate succession exposed in southeastern New Mexico comprises a complex record of deposition mainly controlled by fluctuations in glacio-eustatic sea level (Fu and others, 2020). The Wolfcamp is extremely variable in lithology in response to changes in the environment of deposition. In the area of the Dark Horse Facility, it is composed of dark skeletal to fine-grained limestone, fine-grained sand to coarse silt, and shale in these basin facies. Horizontal wells are being drilled in the Bone Spring and Wolfcamp; however, most activity is primarily to the west of the Dark Horse Facility.

Permian Leonardian Series. The Cisuralian ("Leonard Series"), sediments in shelf areas (Central Basin Platform, Northwest Shelf, etc.) are characterized by shallow-water carbonate-sediment production and deposition during sea-level rise, and by shelf flooding and quartz-dominated sand-silt deposition during sea-level fall and shelf exposure (Ruppel, 2019). In the Delaware Basin, this pattern of sea-level control on sediment supply resulted in the deposition of cyclic intervals of detrital carbonate-sediment transport to basins during sea-level highs and by quartz sand-silt transport and deposition during sea-level falls (Ruppel, 2019). Overall, the Leonard succession is one of punctuated upward shallowing from deep-water, outer-platform—platform-margin settings to inner-platform, peritidal conditions (Ruppel, 2020b).

The Bone Spring Formation is present only in the Delaware Basin and is stratigraphically equivalent to the Abo and Yeso Formations of the Northwest Shelf and Central Basin Platform, attains a maximum thickness of about 4,000 ft in southern Eddy County, New Mexico, and has been productive from several plays in the basin (Broadhead, 2017). The Bone Spring stratigraphy consists of alternating carbonate and siliciclastic successions that were deposited in marine slope and basin-floor environments, where sandstones and siltstones are widespread on the basin floor, whereas carbonates are thickest in periplatform areas (Nance and Hamiln, 2020; Saller and others, 1989). Most Bone Spring carbonate slope deposits accumulated by transport from shallow-water environments on the shelf during highstands of sea level and the siliciclastic deposits were transported basinwards during lowstands of sea level (Nance and Hamlin, 2020). Most of the carbonates are detrital, composed of bioclasts and lithoclasts derived from surrounding shallow-water platforms, and the siliciclastic members were deposited primarily on the basin floor in widespread submarine-fan complexes (Nance and Hamlin, 2020).

Permian Guadalupe Series. The Upper Permian Guadalupian-age strata are found on both Northwest Shelf and Central Basin Platform, and in the Delaware Basin. The Goat Seep/Capitan Reef system, a profoundly critical component of the Permian Basin Guadalupian paleogeography, prominently divides the shelves of the Central Basin Platform, the Northwestern Shelf, and the Western Shelf from the Delaware Basin (Nance, 2020a). Units on the shelf and platform comprise of (ascending) the San Andres Formation and the Artesia Group (*see* Figure 3.2-2). The five (5) formations of the Artesia Group include (ascending) Grayburg, Queen, Seven Rivers, Yates, and Tansill. The Delaware Basin equivalents of the reef trend include the Delaware Mountain Group: (ascending) Brushy Canyon, Cherry Canyon, and Bell Canyon. The Artesia Group comprises as much as 2,650 ft of stratigraphically cyclic, mixed-siliciclastic/carbonate/evaporite platform strata

deposited shelfward of the Guadalupian Capitan Reef system that rims the Delaware Basin (Nance, 2020a). These formations have provided significant oil and natural gas production in southeastern New Mexico, and widespread, reddish-colored evaporitic shales and evaporites provide effective vertical and lateral seals (Broadhead, 2017).

According to Nance (2020a), Artesia facies tracts include, from basin to shelf, immediate-back-reef carbonate grainstone to packstone; shelf-crest pisolite-bearing carbonate shoals; lagoonal wackestone to mudstone and siliciclastic siltstone; algal-laminated, tidal-flat carbonate packstone to wackestone and fine to very fine grained sandstone; beach-ridge fine sandstone; siliciclastic-sabkha anhydrite and halite; brine-pool and evaporitic-lagoon anhydritic dolomite, dolomitic anhydrite, anhydrite, and halite; and eolian to fluvial siliciclastics. During sea-level highstand, siliciclastics are limited to updip areas, whereas eolian-siliciclastic depositional environments migrate downdip during sea-level lowstands. During transgressions, siliciclastics in more basin-proximal positions were reworked by marine and marginal processes. Reservoir quality was impacted mostly by dissolution of feldspar and carbonate allochems and precipitation of authigenic feldspar, clay, and evaporite.

The Delaware Mountain Group of the Delaware Basin comprises up to 4,500 ft of arkosic to subarkosic sandstone, siltstone, and carbonate debrites that were deposited in deep water, mainly during lowstand and early transgressive sea-level stages, and primary depositional processes include density-current flow and suspension settling (Nance, 2020b). The Delaware Mountain Group is restricted to slope-and-basin areas and was sourced from shelf-sediment areas through poorly exposed incised valleys, and interbedded carbonate units thicken shelfward and are typically correlative to "reef"-margin-complex carbonate sources along the shelf margin (Nance, 2020b).

Permian Lopingian ("Ochoa") Series. The youngest of the Permian Basin sediments are referred to as the Lopingian ("Ochoa") Series. The Ochoan series includes the Castile, Salado, Rustler, and Dewey Lake formations. Ochoan units on the shelf include the Salado, Rustler, and Dewey Lake Formations. *Castile Formation* usage is restricted to the deposits within the Delaware Basin only (Figure 3.2-2). The Ochoan in the Permian Basin contains no hydrocarbon reservoirs on the shelf (Nance, 2020a). The basal Salado Formation forms the ultimate top seal for the underlying Guadalupian reservoirs and effectively inhibits hydrocarbon migration into Ochoan units (Nance, 2020a). Lack of a seal above the Ochoan precludes widespread entrapment within the interval of hydrocarbons that may have been generated within the series. Ochoan strata are not hydrocarbon productive in the Permian Basin except for a few very small, isolated reservoirs in the Castile Anhydrite in the northern part of the Delaware Basin (Broadhead, 2017). The Castile is considered to be the top seal for Delaware Basin hydrocarbon reservoirs and is responsible for controlling migration of hydrocarbons from basinal source beds into reservoirs on the surrounding shelves (Hills, 1984). Anhydrite is the dominant rock type in the Castile Formation, along with limestone interlaminated in anhydrite, thin beds of limestone, and minor amounts of dolomite and magnesite, and halite is present as several massive beds in the formation in the subsurface but is much less prominent than the halite in the overlying Salado Formation (Bachman, 1984). The interlaminated anhydrite and limestone are distinctive lithologic features of the Castile Formation and are thought to represent annual cycles of sedimentation (Bachman, 1984).

The regionally extensive Salado Formation includes thick evaporite deposits and records a long-term salinity crisis in the region (Nance, 2020a). The Salado includes halite, minor beds of anhydrite, and commercial deposits of potash minerals (Bachman, 1984). The contact between the Castile and the overlying Salado Formations is sharp and most places and is between massive beds of anhydrite in the Castile and a sequence dominated by halite, potash minerals, and thin beds of anhydrite in the Salado (Bachman, 1984). The Rustler Formation overlies the Salado, and consists of dolomite, evaporites, and siliciclastics and marks the last major migration of marine waters into the Permian Basin (Ruppel, 2019). Red beds of terrigenous sands in the Rustler Formation resulted from eolian sediment transport. These red beds grade downwards into evaporites

of the Salado and Castile Formations and are composed of red-orange silts and sandstones with interbeds of gypsum or anhydrite and halite. The Rustler carbonates, evaporites, and siliciclastics mark a relatively abbreviated return of marginal-marine conditions to the region (Nance, 2020a). The Dewey Lake Formation rests conformably on the Rustler Formation and consists mainly of redbeds and minor gypsum, alternating thin, even beds of moderately reddish-brown to moderately reddish-orange siltstone and fine-grained sandstone (Bachman, 1984). The Dewey Lake sediments mark the youngest episode of preserved Permian deposition in the region, after which a significant net-depositional hiatus prevailed until the onset of Late Triassic sediment accumulation (Nance, 2020a). Beds of Triassic age rest unconformably on, and overlap, the Dewey Lake Formation, and exposures of these rocks in southeastern New Mexico are dark reddish-brown, cross-laminated, poorly sorted conglomerate sandstones with interbeds of dark reddish-brown sandy shale (Bachman, 1984). These Triassic units were deposited in a fluvial—deltaic—lacustrine system and signaled the onset of net deposition during overall wetter conditions after a protracted period of net nondeposition (Nance, 2020a; Bachman, 1984).

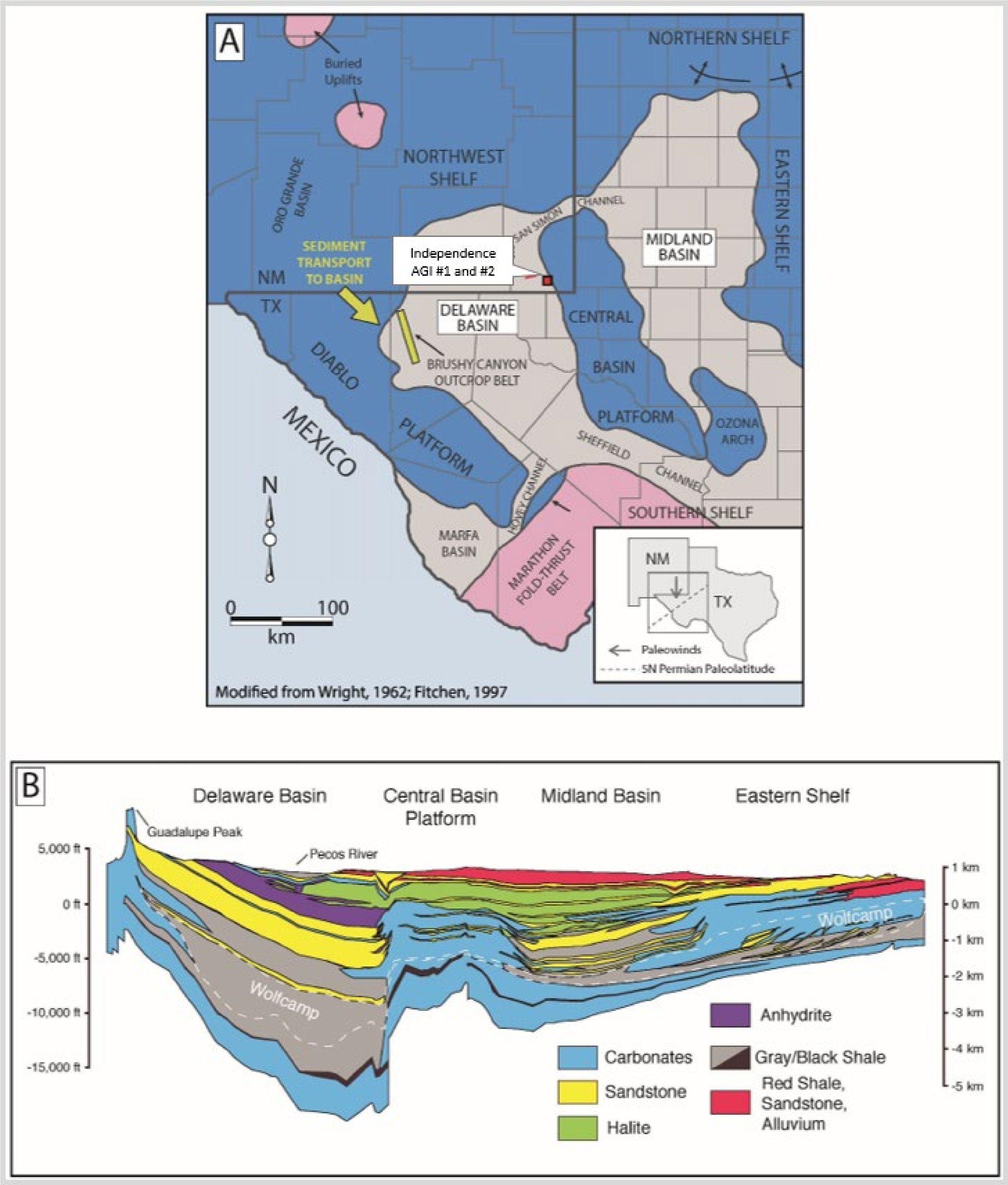


__Figure 3.2-1__: Structural setting (panel A) and general lithologies (panel B) of the Permian Basin. The location of the Independence AGI Wells is shown by the red square. (Modified from Wright, 1962; Fitchen, 1997) (Modified from Figure 12 of Class II permit application for Independence AGI #2, Geolex, Inc.).

Age		Stratigraphic Units: Northwest Shelf and Central Basin Platform		Stratigraphic Units: Delaware Basin	
Triassic			Chinle		Chinle
			Santa Rosa		Santa Rosa
Permian	Lopingian ("Ochoan")		Dewey Lake		Dewey Lake
			Rustler		Rustler
			Salado		Salado
					Castile
	Guadalupian	Artesia Group	Tansill	Delaware Mountain Group	Bell Canyon
		Artesia Group	Yates		
		Artesia Group	Seven Rivers	Delaware Mountain Group	Cherry Canyon
		Artesia Group	Queen		
		Artesia Group	Grayburg		
			San Andres	Delaware Mountain Group	Brushy Canyon
	Cisuralian ("Leonardian")		Glorieta		
		Yeso	Paddock		Bone Spring
		Yeso	Blinebry		
		Yeso	Tubb		
		Yeso	Drinkard		
			Abo		
	Wolfcampian		Hueco ("Wolfcamp")		Hueco ("Wolfcamp")
Pennsylvanian	Virgilian		Cisco; Bough		Cisco
	Missourian		Canyon		Canyon
	Des Moinesian		Strawn		Strawn
	Atokan		Atoka		Atoka
	Morrowan		Morrow		Morrow
Miss.	Upper		Undivided		Barnett
	Lower				undivided limestone
Dev.	Upper		Woodford		Woodford
	Middle				
	Lower		Thirtyone		Thirtyone
Sil.	Upper		Wristen		Wristen
	Middle				
	Lower		Fusselman		Fusselman
Ord.	Upper		Montoya		Montoya
	Middle		Simpson		Simpson
	Lower		Ellenburger		Ellenburger
Cambrian			Bliss		Bliss
Precambrian			igneous, metamorphics, volcanics		igneous, metamorphics, volcanics

<u>Figure 3.2-2</u>: Generalized stratigraphic correlation chart for the Permian Basin region (modified from Broadhead, 2017).

3.2.3 Faulting

The Permian Basin region has a complex tectonic history, shaped by several convergent and divergent events from the Proterozoic through the Cenozoic (Neogene). The Delaware Basin is defined by a complex network of basement-rooted faults. Recent regional 3D structural framework and kinematic models by Horne et al. (2021) provides interpretations of basement-rooted faults in the Delaware Basin. This region contains more than 650 basement-rooted fault surfaces, dominated by "primary" north-northwest—south-southeast-striking high-angle reverse faults that bound "secondary" fault orientations west-northwest—east-southeast and west-southwest—east-northeast (Horne et al., 2021). Their kinematic model suggests that the primary structural grain formed first in response to the encroaching Ancestral Rocky Mountain orogenic front, and the secondary fault zones formed under the combined stresses from the Ancestral Rocky Mountain and Marathon-Ouachita convergence fronts, which compartmentalized the Delaware Basin and Central Basin Platform (Horne et al., 2021).

To identify subsurface structures in the area of the Independence AGI Wells, Geolex evaluated and interpreted licensed seismic survey data (WesternGeco South Lea Survey) covering the Lea County area of interest. These findings and interpretations specific to the Dark Horse Facility area are discussed further in Section 3.5.

3.3 Lithologic and Reservoir Characteristics of the Siluro-Devonian Formations

The Siluro-Devonian Injection Zone includes the Devonian Thirtyone Formation, Silurian Wristen Group and Fusselman Formation, collectively referred to as the Siluro-Devonian. These strata commonly include numerous intervals of dolomites and dolomitic limestones with moderate to high primary porosity. Additionally, the Siluro-Devonian Injection Zone includes significant regions of secondary, solution-enlarged porosity produced during periods where strata were subaerially exposed and significant karst features developed. These karst features are frequently developed in the Fusselman Formation and include solution enlarged cavities and fractures. Fracture networks through the Siluro-Devonian section are substantial enough to provide additional permeability that is not readily apparent on geophysical well logs. The porous zones of the Siluro-Devonian are separated by tight limestones and dolomites.

In evaluating the location of the Independence AGI Wells, an in-depth review of licensed seismic survey data (WesternGeco – South Lea Survey) was completed to support the evaluation that the Siluro-Devonian reservoir exhibited sufficient porosity potential to accommodate the needs of the Independence AGI Wells. Seismic inversion data, specifically impedance attributes, were evaluated to identify reservoir targets with significant porosity potential in the Siluro-Devonian reservoir. As a result of this review, the location in Section 20, T25S, R36E was selected as it was observed to overlay an expansive region of porosity in the upper Devonian, Wristen, and Fusselman strata.

Based on the geologic evaluation of the subsurface, AGI was recommended between depths of approximately 16,080 to 17,683 feet TVD (16,477 to 18,080 feet measured depth). Figure 3.3-1 includes a type log of the Siluro-Devonian Injection Zone that includes the formation tops identified at that location and illustrates the sufficient low-porosity intervals overlying the target injection reservoir. Anticipated formation tops underlying the Independence AGI #2 location are included in the following Table 3.3-1. In the area of the Independence AGI Wells, depth to Devonian strata increases to the southwest and the Independence AGI Wells lie downdip of a structural high to the east (Figure 3.3-2).

Units overlying the Siluro-Devonian Injection Zone provide an excellent caprock to prevent the upward migration of injectate out of the target reservoir. This caprock includes 335 feet of dense Woodford Shale overlain by at least 796 feet of Mississippian limestone (Figures 3.3-1 and 3.3-3). These units will provide a geologic seal above the porous carbonates of the Siluro-Devonian Injection Zone providing protection to shallow groundwater resources and overlying pay intervals.

Figure 3.3-3 includes structural cross section A-A' covering the area of Independence AGI #2 and highlights the lateral extent of available upper Devonian porosity and the regional coverage of overlying caprock in the area. As shown in Figure 3.3-2, there are two (2) faults located approximately one (1) mile east and one (1) mile north from the SHLs of the Independence AGI Wells. These structures were identified through review of licensed 3D seismic survey data and are discussed further in Section 3.5.

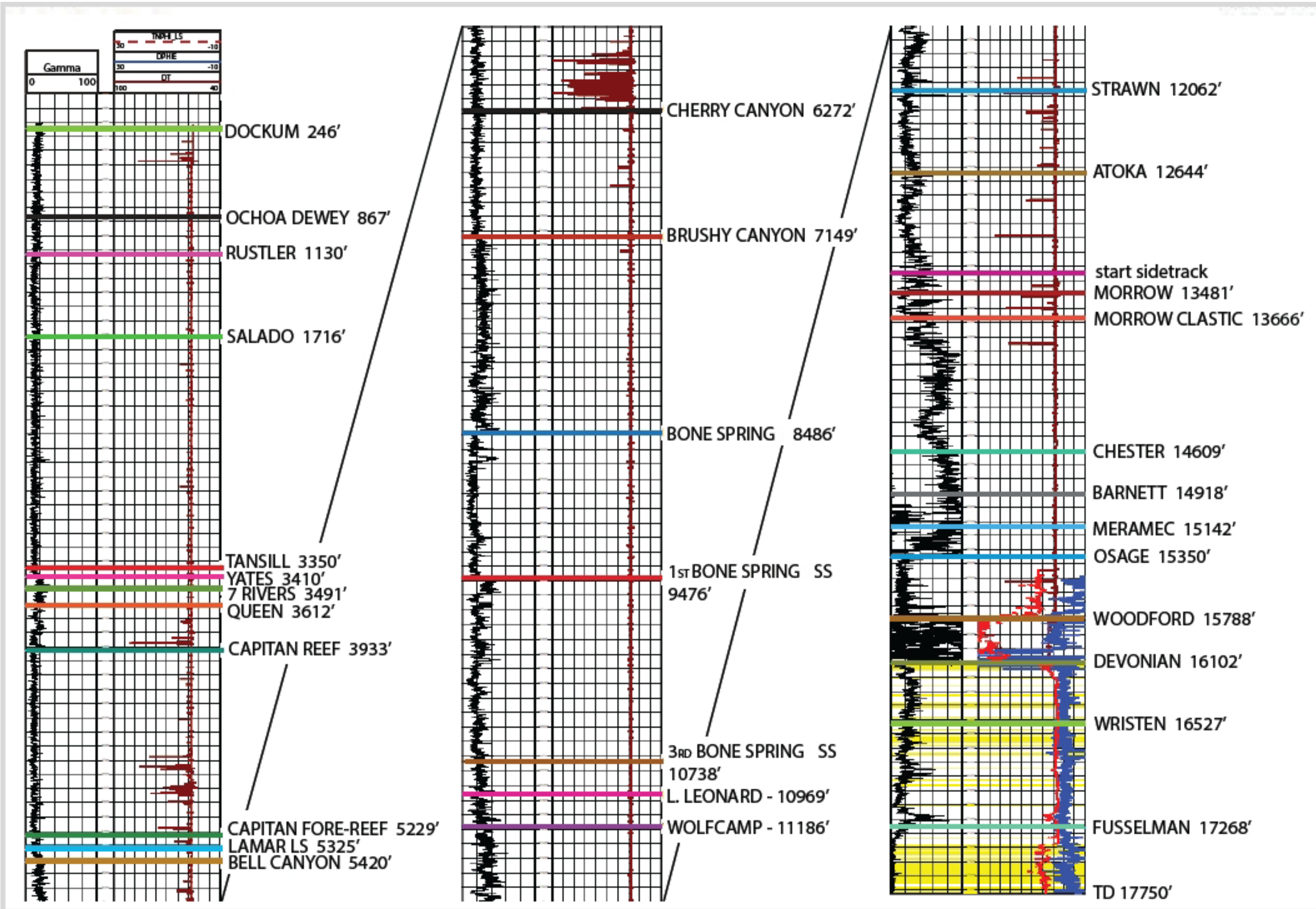
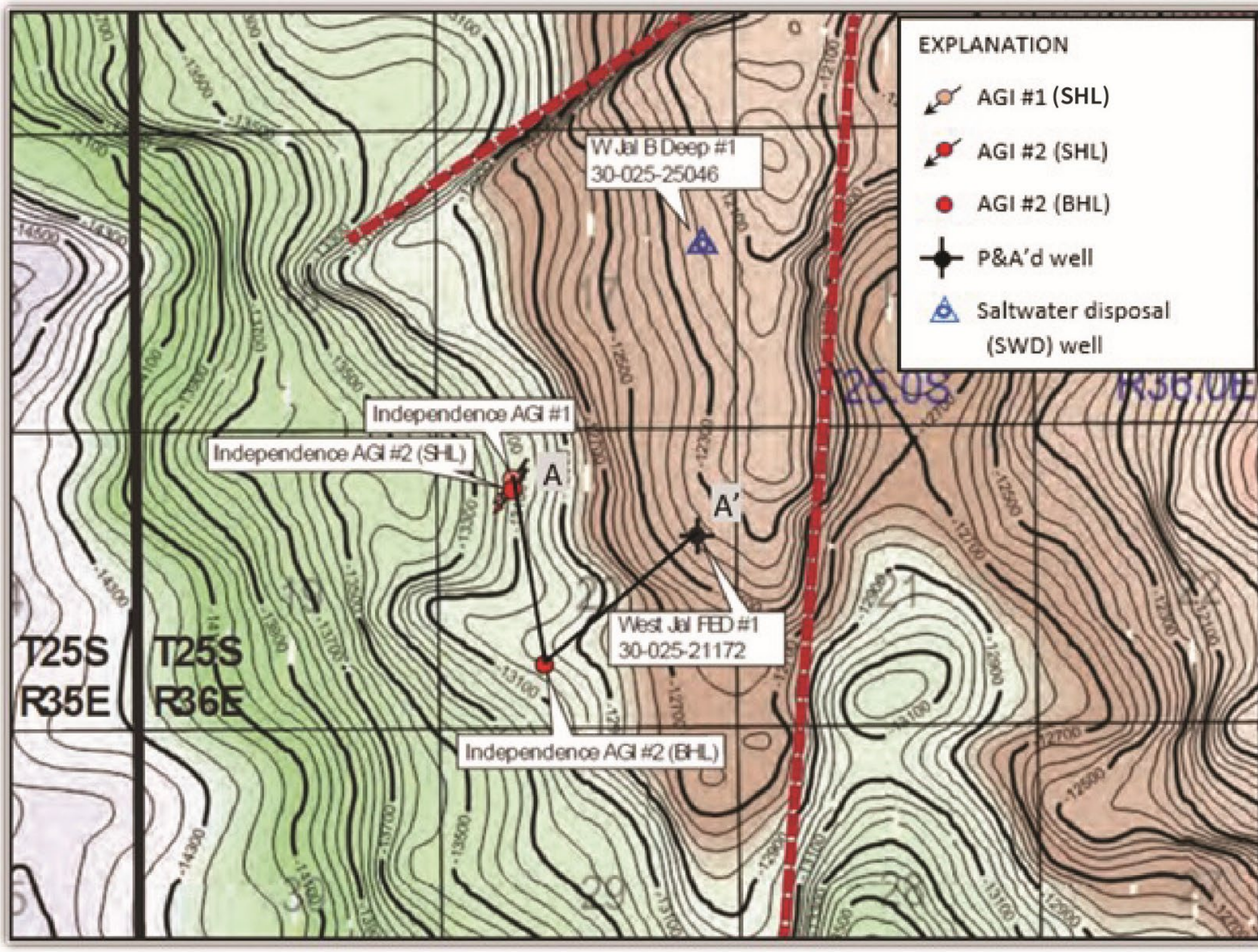


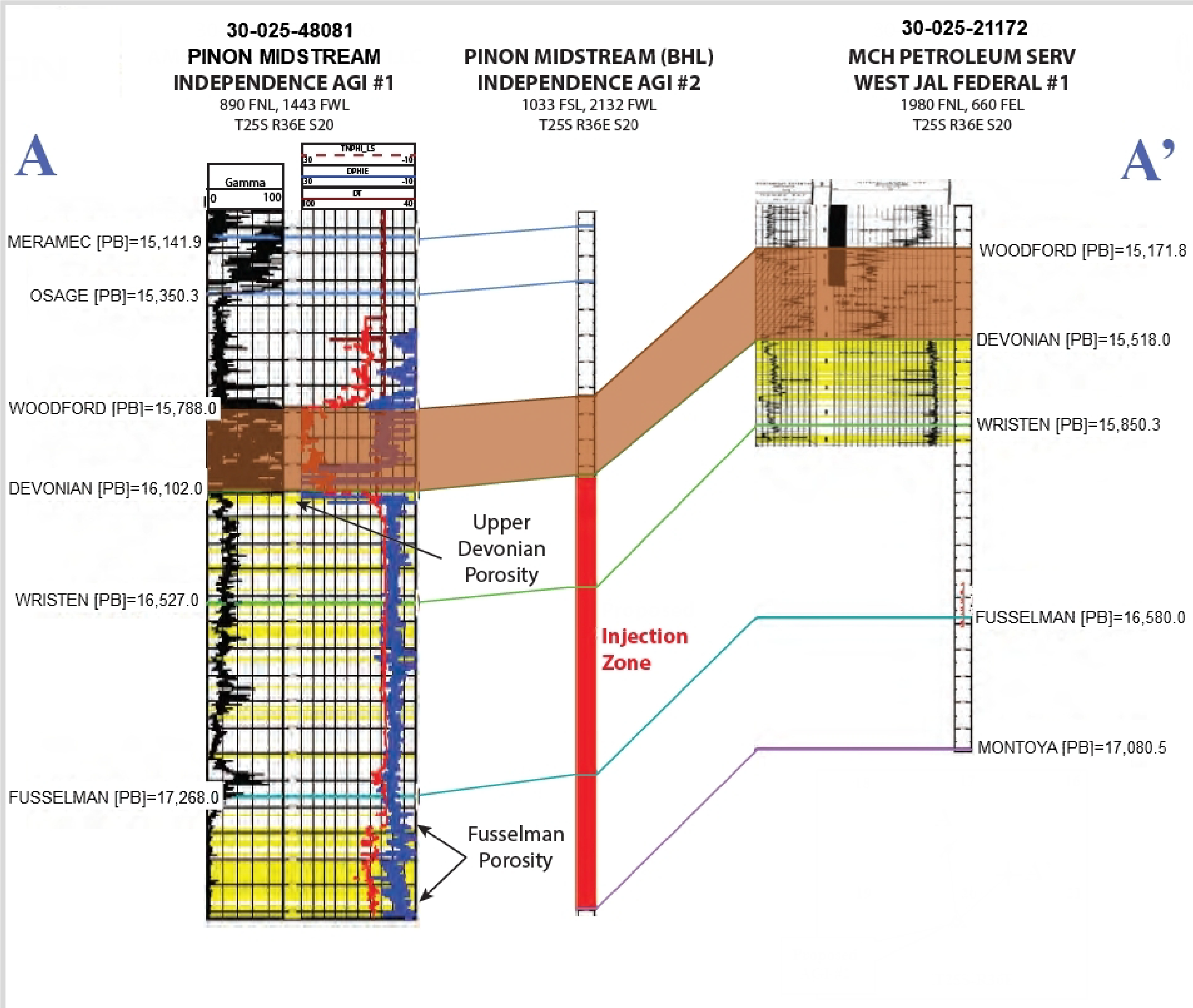
Figure 3.3-1: Type log of the Independence AGI #1, illustrating identified formation tops in TVD. Estimated formation tops for the Independence AGI #2 are included in Table 6. (Modified from Figure 14 of Class II permit application for Independence AGI #2, Geolex, Inc.)

<u>Table 3.3-1</u>: Anticipated formation tops at the Independence AGI #2 location. (Extracted from Table 6 of Class II permit application for Independence AGI #2, Geolex, Inc.)

FORMATION	DEPTH (TVD)	DEPTH (MD)	FORMATION	DEPTH (TVD)	DEPTH (MD)
Dockum	485	485	Bone Spring	8,467	8,632
Ochoa-Dewey	747	747	Wolfcamp	11,131	11,387
Rustler	1,130	1,130	Strawn	12,004	12,289
Salado	1,720	1,720	Atoka	12,733	13,044
Tansill	3,401	3,401	Morrow	13,541	13,880
Yates	3,461	3,461	Barnett	14,949	15,336
7 Rivers	3,542	3,542	Osage	15,380	15,703
Queen	3,663	3,663	Woodford	15,745	16,142
Capitan Reef	3,935	3,943	Devonian	16,080	16,477
Bell Canyon	5,425	5,484	Wristen	16,467	16,864
Cherry Canyon	6,277	6,364	Fusselman	17,201	17,598
Brushy Canyon	7,058	7,174	Montoya	17,684	18,081



<u>Figure 3.3-2</u>: Structure contour map showing the top of the Siluro-Devonian target reservoir. Two (2) faults identified in review of 3D seismic data are shown with red dashes. Also, shown are wells within 1 mile of the Independence AGI Wells that penetrate the Siluro-Devonian target zone. Cross section A – A' is shown in <u>Figure 3.3-3</u>. (Modified from Figure 15 of Class II permit application for Independence AGI #2, Geolex, Inc.)



<u>Figure 3.3-3</u>: Structural cross section A-A' showing porosity profile from nearby wells penetrating the Siluro-Devonian Injection Zone and regional extent of overlying Woodford Shale caprock. The Independence AGI #2 Injection Zone is from 16,080 feet TVD to 17,683 feet TVD (red bar). (Modified from Figure 16 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.4 Chemistry of Siluro-Devonian Interval Formation Fluids

A review of formation waters from the U.S. Geological Survey National Produced Waters Geochemical Database v. 2.3 identified twenty-one (21) wells with analyses of fluid samples collected from the Siluro-Devonian interval. These samples were collected from wells within approximately fifteen (15) miles of the Independence AGI Wells. Results of laboratory analysis to determine their composition are summarized in Table 3.4-1. These results have been supplemented with samples collected from Independence AGI #1 on May 31, 2021 which show Total Dissolved Solids ("**TDS**") values ranging from 109,000 to 115,000 parts per million ("**ppm**").

*__Table 3.4-1__: Summary of Siluro-Devonian produced water analyses from nearby wells (U.S. Geological Survey National Produced Water Geochemical Database v. 2.3) * (Extracted from Table 7 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

API	WELL NAME	CONCENTRATION (parts per million)							
		TDS	HCO3	Ca	Cl	K + Na	Mg	Na	SO4
3002548081	Ind. AGI 1	110000	342	5600	68000	32559	759	31800	664
3002510945	Hill-federal D 1	112959	288	6264	67390	34340	1912	-	2765
3002510947	EC Hill-federal 1	35639	-	1369	22070		592	11608	-
3002511126	JR Holt A3	116415	154	7501	71110	34680	1767	-	1203
3002511196	S. Mattix Unit 3	68431	990	3180	40960	21690	974	-	637
3002511202	S. Mattix Unit 11	67130	853	5075	40430	16950	2348	-	1474
3002511383	Hodges B 3	81712	722	4320	47500	25400	1030	-	2740
3002511556	Blocker-federal 4	57675	595	2850	34030	18370	619	-	1211
3002511747	Ab Coates FED D2	82794	977	2408	47200	28190	851	-	3168
3002511760	Ida Wimberley 5	63817	360	2774	35870	20750	621	-	3442
3002811763	Ida Wimberley 9	61040	900	2680	35600	19560	800	-	1500
3002511765	Carlson-federal A3	66418	690	3002	37650	20390	1339	-	3347
3002511812	Clyde Lanehart 1	99879	687	4753	60410	32610	828	-	591
3002511818	Copper 1	27506	1089	1384	15270	8144	540	-	1079
3002511863	Arnott Ramsay B3	158761	476	17240	100300	35400	5345	-	-
3002511886	Dabbs 1	101036	540	5393	61630	30380	2183	-	910
3002511890	Sam Dabbs 1	85150	675	5368	50260	25130	1395	-	2322
3002511907	Arnott Ramsay F9	58220	367	1546	32790	-	278	20430	2816
3002511950	Farnsworth FED 6	31931	302	7196	20450	1151	2241	-	591
3002512272	LE Elliott FED H1	58687	761	3004	35460	18980	482	-	-
3002512286	JB McGhee 1	62392	552	2696	34380	20060	702	-	4002
3002521601	North Custer Mt 1	>64,000	1610	2136	36230	21830	403	-	1950

These analyses report TDS in the area of the Independence AGI Wells ranging from 27,506 to 158,761 ppm with an average of 75,981 ppm. The primary constituent in sampled formation waters is the chloride ion, with an average concentration of 45,227 ppm. The closest well, Independence AGI #1, at approximately 3,000 feet away from the Independence AGI #2 BHL, has reservoir fluids with a TDS value of approximately 110,000 ppm, and chloride ions in concentrations of approximately 68,000 ppm. Based on this data, the Siluro-Devonian reservoir fluids are anticipated to be completely compatible with the TAG injectate.

3.5 Potential for Induced Seismicity in the area of the Dark Horse Facility

To evaluate the potential for seismic events in response to injected fluids, Piñon conducted an induced-seismicity risk assessment for the area surrounding the Independence AGI Wells. This estimate (a) models the impact of seven (7) injection wells over a thirty (30) year injection period, and (b) estimates the fault-slip probability associated with the simulated injection scenario(s). This analysis was completed utilizing the Stanford Center for Induced and Triggered Seismicity's Fault Slip Potential ("**FSP**") model developed by Walsh and Zoback, 2016.

To identify subsurface structures in the area of the Independence AGI Wells, Piñon evaluated and interpreted licensed seismic survey data (WesternGeco – South Lea Survey) covering the Lea County area of interest. Based on this review, Piñon identified eight (8) subsurface faults in the area surrounding the Independence AGI Wells (<u>Figure 3.5-1</u>). The closest fault is observed to be located approximately one (1) mile east of the

Independence AGI Wells. Major faults in the area (those exhibiting significant lateral extent) generally strike NNW-SSE with minor faults striking NE-SW and NW to SE.

Due to the location of faults relative to the Independence AGI Wells and the general low density of injection wells in the immediate area of the Independence AGI Wells, it is anticipated that the injection scenario(s) will not pose any elevated risk of injection-induced fault slip. To support the interpretation that these structures would not be affected by operation of the Independence AGI Wells, a fault-slip probability analysis was completed to quantify the risk associated with injection operations in the area surrounding the Independence AGI Wells, and although the risk of induced seismicity is low, a seismic monitoring station was installed at the facility prior to the commencement of injection into Independence AGI #1. The station transmits data to the New Mexico Tech Seismic Network and will aid the state in seismicity interpretations.

To calculate the fault-slip probability for the model simulations, input parameters characterizing the local stress field, reservoir characteristics, subsurface features, and injected fluids are required. Parameters utilized and their sources for the area surrounding the Independence AGI Wells are included in Table 3.5-1. Additionally, Table 3.5-2 details the injection volume characteristics and locations of the injection wells modeled in the injection scenario(s). To ensure the model simulations provide a conservative estimation of induced-seismicity risk, injection wells included in the simulations were modeled utilizing their maximum anticipated daily injection volumes as recorded by NMOCD approved permits. Due to the minimal reported injection volume of the Jal North Ranch SWD #1, a potential of 10,000 bpd was assumed to account for the potential of increased injection rates due to future needs of the operator or any future workover that may improve the injectivity of this well.

Daily maximum injection volumes utilized in the fault-slip probability model range from 4,265 to 30,000 bpd (Table 3.5-2). In submission of the Class II injection well applications, Piñon requested approval to operate the Independence AGI Wells for a period of at least thirty (30) years, however, the duration of the FSP model simulation was increased to forty (40) years to characterize the reservoir effects of injection wells that are currently operating and have been in operation since 2010. Figure 3.5-2 shows the resultant pressure front and single well radial pressure solutions, as predicted by the FSP model, after thirty (30) years of injection at the maximum injection rates.

For this study, limitations of the FSP model required a conservative approach be taken in determining the fault-slip probability of the injection scenario. Specifically, the FSP model is only capable of considering a single set of fluid characteristics and this study aims to model an injection scenario that includes both brine injection and AGI. To ensure a conservative fault-slip probability estimate, the Independence AGI Wells were simulated utilizing the characteristics of a brine injectate. This approach yields a more conservative model prediction as brine displays greater density, dynamic viscosity, and is significantly less compressible than TAG. For comparison, characteristics of TAG at the anticipated reservoir conditions, as modeled by AQUAlibrium™, are shown in Table 3.5-1.

Generally, faults considered in this assessment are predicted by the FSP model to have very low potential for injection-induced slip and operation of the Independence AGI Wells is not predicted by the model to contribute significantly to the estimate of risk (Table 3.5-3 and Figure 3.5-3). Table 3.5-3 summarizes the predicted pressure change along each fault segment and includes the model-derived pressure change necessary to induce slip for each feature. Fault-slip probability values range from 0.00 to 0.05 with the majority of fault segments predicted to have zero probability of slip (Table 3.5-3). Major faults (faults 4, 7, and 8 in Figure 3.5-1) in the area, which would have the greatest energy release potential upon slip, are predicted to have zero probability for slip in response to the modeled injection scenario.

In summary, no structures included in the modeled simulations are predicted to be at increased risk for injection-induced slip in response to the injection scenario presented. Features estimated to have a non-zero

slip potential are generally smaller-scale features and predicted probabilities are very low (≤ 0.05). Furthermore, subsequent model simulations in which contribution from Independence AGI #2 is excluded illustrate that operation of the Independence AGI #2 will have little impact on conditions near the identified faults in the area due to significantly lower proposed injection volumes in comparison to nearby brine injection wells.

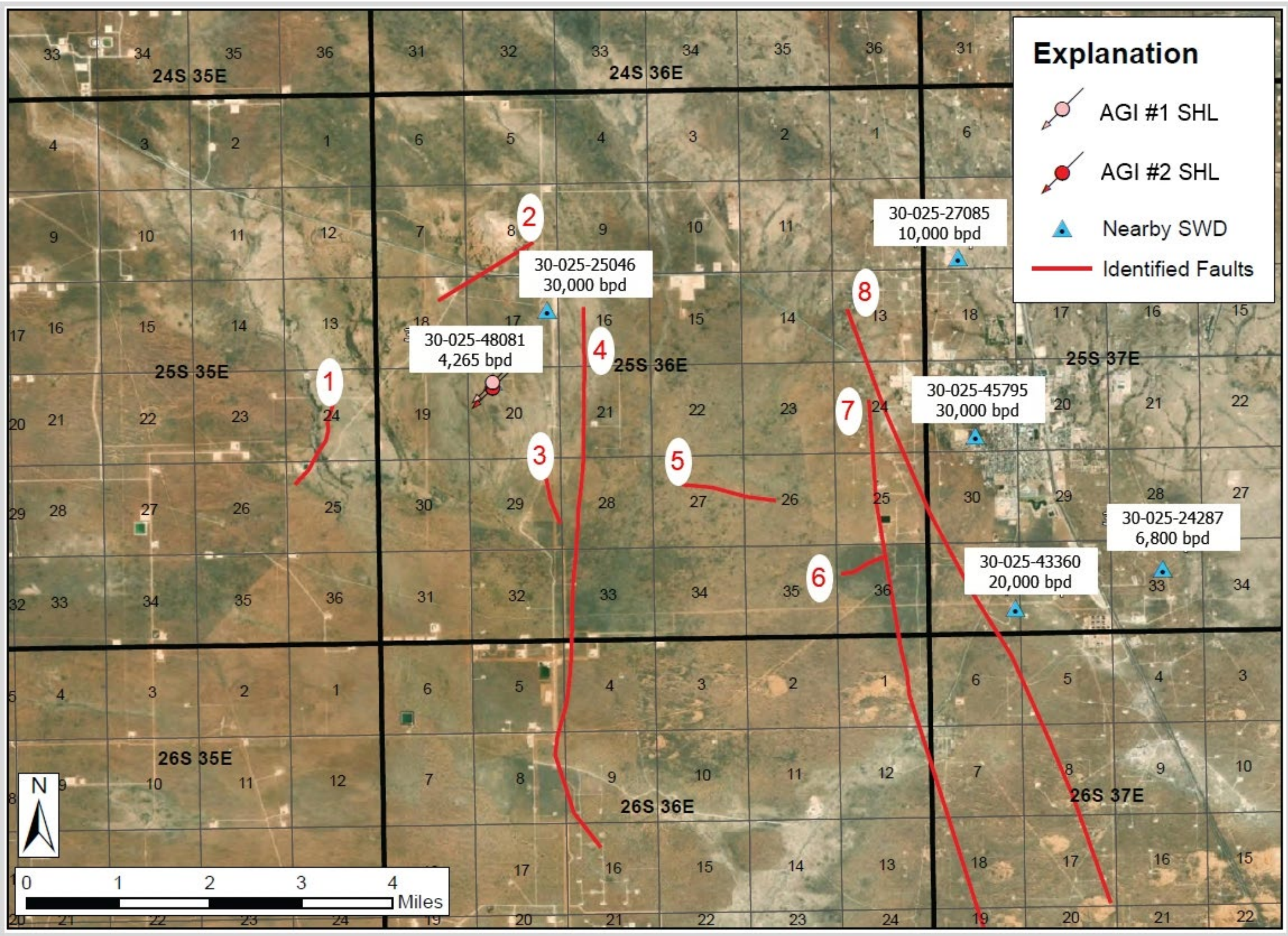


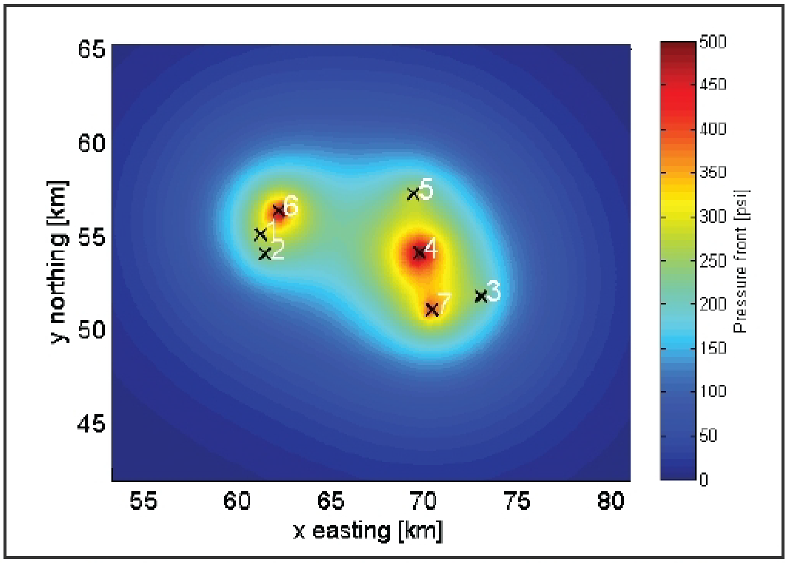
***Figure 3.5-1**: Map showing Siluro-Devonian injection wells and subsurface identified faults in the vicinity of the Independence AGI Wells. (Modified from Figure 18 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

***Table 3.5-1**: Input parameters and source material for FSP model simulations. (Extracted from Table 10 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

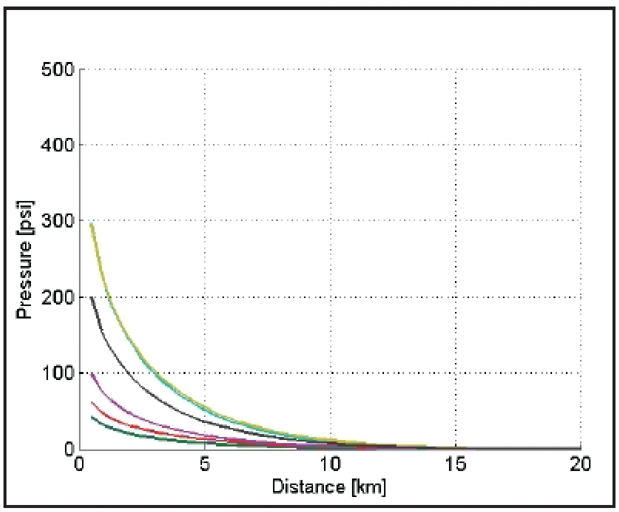
Modeled Parameter	Input Value	Variability (+/-)	UOM	Source
Stress				
Vertical Stress Gradient	1.05	0.105	psig/ft	Nearby well estimate
Max Horizontal Stress Direction	N75E	5	Deg	Lund Snee & Zoback, 2018
Reference Depth	17000		ft	Nearby well evaluation
Initial Res. Pressure Gradient	0.43	0.043	psig/ft	Lund Snee & Zoback, 2018 Nearby well evaluation
A_ϕ Parameter	0.6	0.06	-	Lund Snee & Zoback, 2018
Reference Friction Coefficient (μ)	0.6	0.06	-	Standard value
Hydrologic				
Aquifer Thickness	1500	0	ft	Nearby well evaluation
Porosity	3.5	0.35	%	Nearby well evaluation
Permeability	20	2	mD	Nearby well evaluation
Material Properties				
Density (Water)	1040	40	Kg/m^3	Standard value
Dynamic Viscosity (Water	0.0008	0.0001	Pa.s	Standard value
Fluid Compressibility (Water)	3.6×10^{-10}	0	Pa^{-1}	Standard value
Rock Compressibility	1.08×10^{-9}	0	Pa^{-1}	Standard value
Acid Gas Properties @ 7,370 psig & 228 °F				
Density	821.80	-	kg/m^3	AQUAlibrium™
Dynamic Viscosity	8.067×10^{-5}	-	Pa.s	AQUAlibrium™

***Table 3.5-2**: Location and characteristics of injection wells modeled in the FSP assessment. (Extracted from Table 11 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

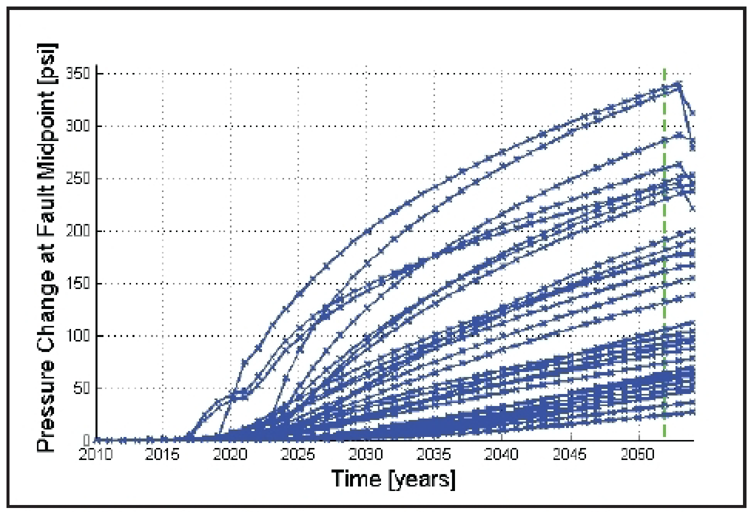
#	API	Well Name	LAT	LONG	Volume (bbls/day)	Start (year)	End (year)
1	3002548081	Independence AGI #1	32.120855	-103.291021	4265	2020	2052
2	-	Independence AGI #2	32.111454	-103.288812	4265	2022	2052
3	3002524287	Crosby Deep #2	32.089508	-103.166733	6800	2010	2052
4	3002545795	Sholes Deep SWD #1	32.110998	-103.201266	30000	2020	2052
5	3002527085	Jal N. Ranch SWD #1	32.139347	-103.203911	10000*	2017	2052
6	3002525046	West Jal B Deep #1	32.132091	-103.280708	30000	2015	2052
7	3002543360	Kimberly SWD #1	32.083537	-103.194274	20000	2019	2052



Panel A. Resultant pressure front after 30 years of injection operations at the maximum anticipated injection rates, as reported in **NMOCD** records



Panel B. Single well radial pressure solutions, as determined by the FSP model

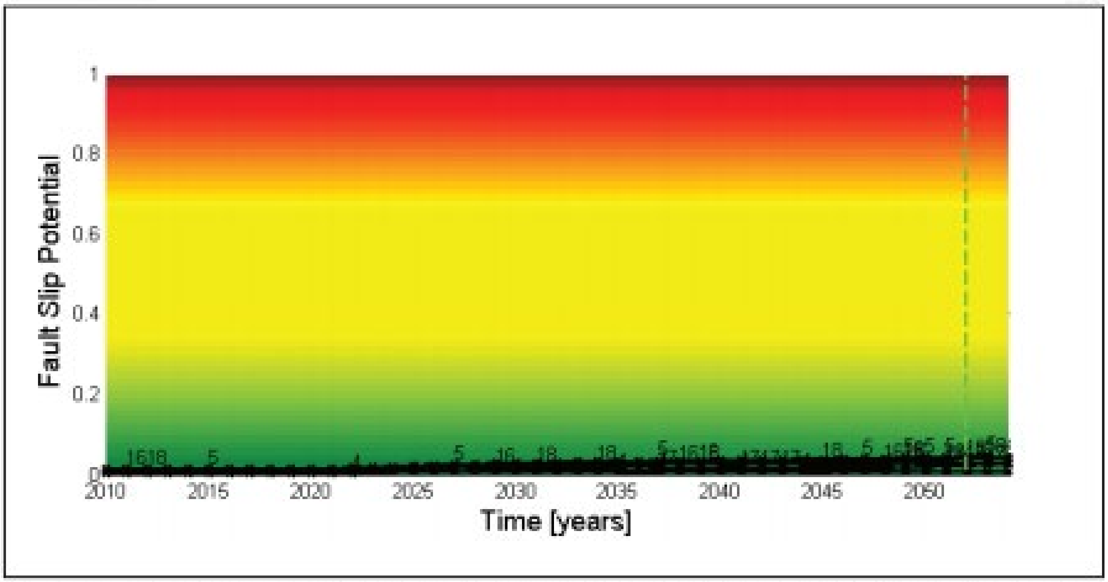


Panel C. Model-predicted pressure change through time at the midpoint of each fault segment included in the simulation

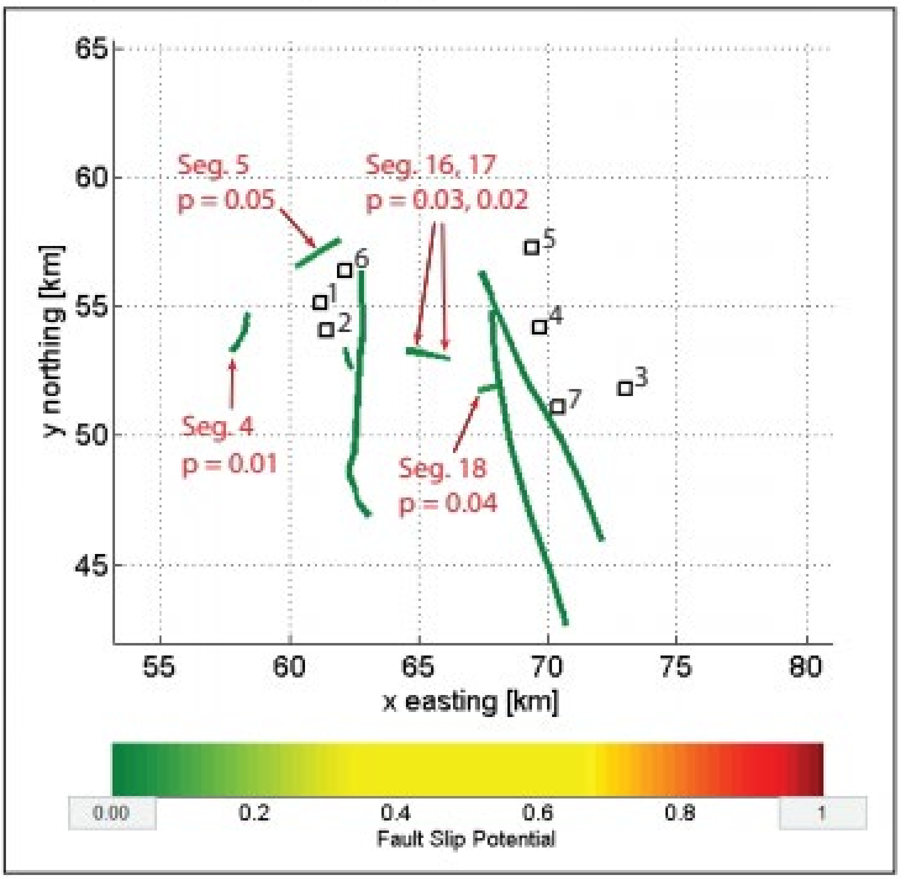
<u>Figure 3.5-2</u>: Summary of model-predicted pressure effects in response to the simulated seven (7) well injection scenario. (Extracted from Figure 19 of Class II permit application for Independence AGI #2, Geolex, Inc.)

<u>Table 3.5-3</u>: Summary of model-simulation results showing the required pressure change to induce fault slip, actual change in pressure as predicted by the FSP model, probability of fault slip at the end of the thirty (30) year injection scenario, and fault-slip probability when Independence AGI #2 is excluded from simulation. (Extracted from Table 12 of Class II permit application for Independence AGI #2, Geolex, Inc.)

Fault #	Segment #	ΔPressure necessary to induce fault slip	Actual ΔPressure at 2052	Fault Slip Potential at 2052	FSP (excluding AGI #2)
1	1	3137	109	0.00	0.00
	2	4357	103	0.00	0.00
	3	1786	93	0.00	0.00
	4	1201	83	0.01	0.01
2	5	1197	253	0.05	0.05
3	6	6869	186	0.00	0.00
	7	6298	168	0.00	0.00
4	8	5645	277	0.00	0.00
	9	4610	194	0.00	0.00
	10	5005	117	0.00	0.00
	11	2709	70	0.00	0.00
	12	5302	63	0.00	0.00
	13	6339	57	0.00	0.00
	14	6899	51	0.00	0.00
	15	4197	46	0.00	0.00
5	16	1101	192	0.03	0.03
	17	1085	199	0.02	0.02
6	18	1554	234	0.04	0.04
7	19	6012	290	0.00	0.00
	20	6680	241	0.00	0.00
	21	6914	133	0.00	0.00
	22	6758	61	0.00	0.00
	23	6931	33	0.00	0.00
	24	6590	25	0.00	0.00
8	25	6508	250	0.00	0.00
	26	6327	334	0.00	0.00
	27	5455	228	0.00	0.00
	28	6305	174	0.00	0.00
	29	6684	89	0.00	0.00



Panel A. Fault-slip probability throughout the entire simulated injection period. FSP model results suggest no significant risk of injection-induced slip along any feature included in the simulation.



Panel B. Map view illustrating the model-estimated slip potential of faults at the end fo the 42-year injection scenario. Any feature estimated to have a non-zero slip potential determination is labeled on the above map.

<u>Figure 3.5-3</u>: Summary of model-determined fault-slip probabilities over the simulated injection period (2010-2052). (Modified from Figure 20 of Class II permit application for Independence AGI #2, Geolex, Inc.)

3.6 Groundwater Hydrology in the Vicinity of the Dark Horse Facility

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are fifteen (15) water wells and points-of-diversion located within a two (2) mile radius of the Independence AGI Wells. Of these wells, the closest is located approximately 0.34 miles away and has a total depth of 505 feet (Figure 3.6-1 and Table 3.6-1). The remaining fourteen (14) wells within the two (2) mile radius have depths of approximately 240 to 600 feet deep, collecting water from Alluvium and the Triassic red beds. The shallow freshwater aquifer will be protected as the Independence AGI Wells are designed to isolate shallow zones via a five (5) string casing design including a surface casing interval that extends to 1,230 feet within the Rustler Formation, effectively isolating shallow groundwater resources (Figures A1-1 and A1-2).

The area surrounding the Independence AGI Wells is arid and there are no surface water bodies within a two (2) mile radius.

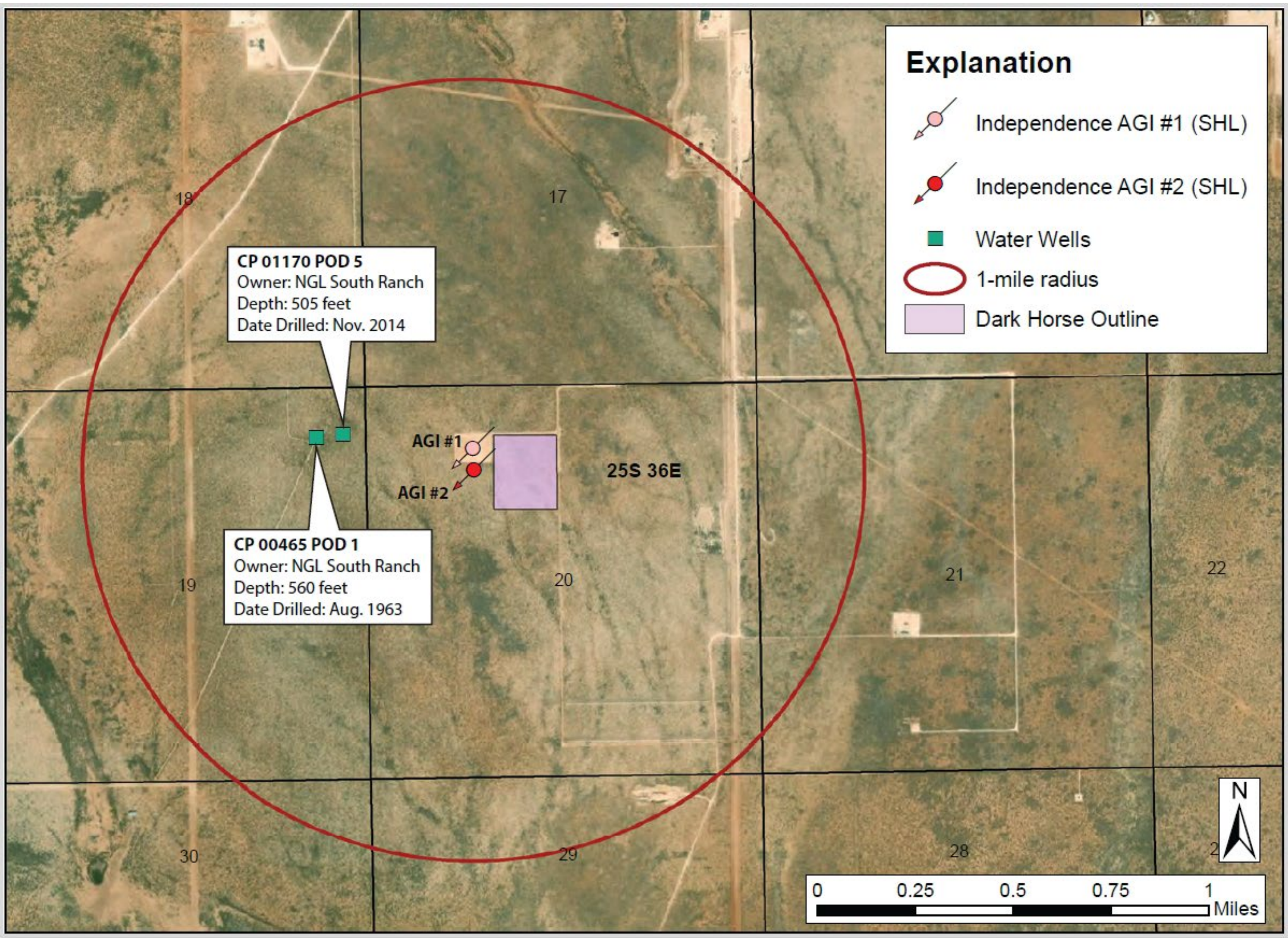


***Figure 3.6-1**: Reported water wells within 1-mile radius of the SHLs of the Independence AGI Wells. The BHLs for AGI #1 and #2 are not shown. (Extracted from Figure 17 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

Table 3.6-1: Water wells within one (1) mile of the Independence AGI Wells (Retrieved from the New Mexico Office of the State Engineer's Files on October 4, 2021). (Extracted from Table 8 of Class II permit application for Independence AGI #2, Geolex, Inc.)

POD #	Source	Use	Owner	LAT (NAD83)	LONG (NAD83)	Distance (miles)	Depth (feet)	Date Completed
CP 1170 POD 5	Shallow	Commercial	NGL South Ranch	32.121417	-103.296667	0.34	505	11/2014
CP 465 POD 1	Shallow	Commercial	NGL South Ranch	32.119465	-103.299882	0.53	560	08/1963

According to Order No. 190 of the New Mexico Office of the State Engineer signed March 22, 2021, the Capitan Underground Water Basin, within which the Independence AGI Wells lie, is closed indefinitely to new appropriations of water. Therefore, no new water wells are anticipated to be constructed during the Independence AGI Wells' anticipated thirty (30) year operation period. Due to the shallow completion depths of the few groundwater wells in the area surrounding the Independence AGI Wells, it is highly unlikely that groundwater wells will serve as conduits for CO_2 leakage to the surface.

Geolex conducted a review of Geology and Ground-Water Conditions in Southern Lea County, New Mexico (Nicholson and Clebsch, 1961) to identify published groundwater data representative of nearby water wells in the area surrounding the Independence AGI Wells. Table 3.6-2 summarizes the wells identified in this review and the results of those analyses.

Table 3.6- 2: Chemical analysis results of samples collected from water wells in the area surrounding the Independence AGI Wells (Nicholson and Clebsch, 1961 – Geology and Groundwater Conditions in Southern Lea County, New Mexico). (Taken from Table 9 of Class II permit application for Independence AGI #2, Geolex, Inc.)

Historical Owner	Location (T-R-S)	Location (Qtr-Qtr)	Depth (ft)	Ca (ppm)	Mg (ppm)	Na+K (ppm)	HCO_3 (ppm)	SO_4 (ppm)	Cl (ppm)	NO_3 (ppm)
Sun Oil Co.	25-37-15	NE/4 NE/4	-	307	98	271	145	737	610	9
City of Jal	25-37-19	NE/4 NE/4	500	55	49	170	376	280	71	0.4
City of Jal	25-37-19	SE/4 NE/4	450	34	43	175	264	286	54	0.5
City of Jal	25-37-20	NW/4 SW/4	70	-	-	-	150	145	168	7.6

This analysis confirms that the Independence AGI Wells pose no risk of contaminating groundwater in the area as (a) the well design includes material considerations to protect shallow groundwater resources, and (b) there are no identified conduits that would facilitate migration of injected fluids to freshwater-bearing strata nor to the surface.

3.7 Historical Operations

3.7.1 Operations within a 2-mile radius of the Independence AGI Wells

Appendix 3 summarizes in detail all NMOCD recorded wells within a two (2) mile radius of the Independence AGI Wells. These wells are shown in Figure 3.7-1 and include active, plugged, and new (permitted but not yet drilled) well locations. In total, there are fifty-four (54) wells within a two (2) mile radius of the Independence AGI Wells. Of these, there are ten (10) active wells, thirty-three (33) permitted wells, and eleven (11) plugged wells. Active wells in the area include one brine injection well completed across the Strawn through Fusselman formations, and nine (9) active oil and natural gas wells completed in various other strata.

There are two (2) third-party wells within two (2) miles of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone (Table 3.7-1). The first well is an active brine injection well (West Jal B Deep #1) located approximately one (1) mile from the Independence #2 SHL. This well was drilled to a total depth of 18,945 feet and is permitted to inject through perforated intervals of the Strawn through Fusselman strata. Despite being granted approval for injection into the Fusselman (approved June 2014), NMOCD records document no reports of work to drill out plugged intervals at 14,200 feet. There is a Form C-103- Sundry Notices and Reports on Wells - (submitted November 2018) that indicates the intent of BC&D Operating to drill out these intervals, but no subsequent reports confirming completion of this work have been identified. Additionally, reported injection volumes for this well do not appear to exhibit any significant increase that might indicate this work was completed. The second well penetrating the Siluro-Devonian Injection Zone is the plugged West Jal Unit #1, located approximately 0.67 miles from the Independence AGI #2 SHL. Final plugging operations were completed in April 1984 and all relevant plugging reports and documents are included in Appendix 9. The well is properly cemented through the Siluro-Devonian Injection Zone, and it is not anticipated to be negatively affected by the operation of the Independence AGI Wells.

***Table 3.7-1*: Wells located within a two (2) mile radius of the Independence AGI Wells that penetrate the Siluro-Devonian Injection Zone. (Additional details are provided in Appendix 3)**

API	Well Name	Pool	Status	TVD
30-025-21172	WEST JAL UNIT #1	Strawn	Plugged	17,086
30-025-48081	INDEPENDENCE AGI #1	Devonian - Fusselman	Active	17,750
30-025-49974	INDEPENDENCE AGI #2	Devonian - Fusselman	New	17,683 (proposed)
30-025-25046	WEST JAL B DEEP #001	Mississippian – Fusselman	Active	18,945

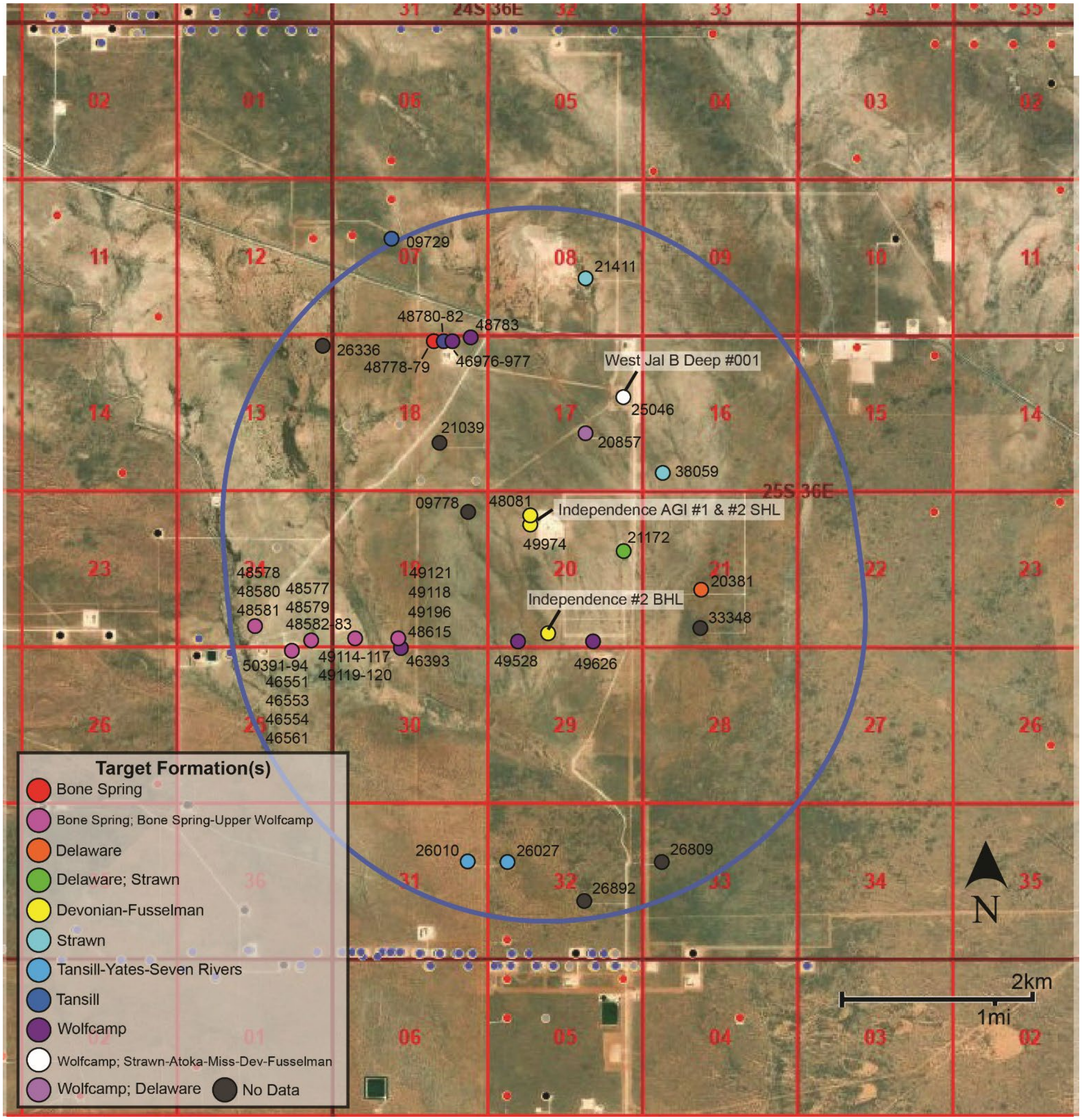


***Figure 3.7-1**: Location of all oil- and natural gas-related wells within a two (2) mile (blue line) of the Independence AGI Wells. Colors indicate target formations for the well. The oblong shape of the two (2) mile area accounts for the BHL of Independence AGI #2 as shown in Figure 3.1-1. Labels denote the last five (5) digits of API #30-025-XXXXX.*

3.8 Description of Injection Process

Once delivered to the Dark Horse Facility, sour natural gas is treated using amine to isolate H_2S and CO_2. The amine (which now contains H_2S and CO_2) is then regenerated which creates a TAG waste stream. This TAG waste stream is then routed to on-site compression facilities that compress the TAG waste stream into a dense phase (roughly 1,250 psig). The dense phase stream is then pumped to upwards of 2,500 psig prior to being sent to Independence AGI #1 (and when complete, Independence AGI #2), through a National Association of Corrosion Engineers ("**NACE**") rated pipe, for injection. Figure 3.8-1 is a schematic of the surface facilities for the Independence AGI Wells. The sweet natural gas that results from the amine scavenging process is then treated to remove water ("**H_2O**")and subsequently transported offsite, via pipeline, and redelivered to Piñon's customers at various delivery points.

For the period of September 2021 through March 2022, the TAG stream at the Dark Horse Facility averaged 57.076% CO_2 and 38.703% H_2S by volume, with hydrocarbons (C1 – C7) and H_2O comprising the remaining volume.

The anticipated duration of TAG injection into the Independence AGI Wells at the Dark Horse Facility is approximately thirty (30) years.

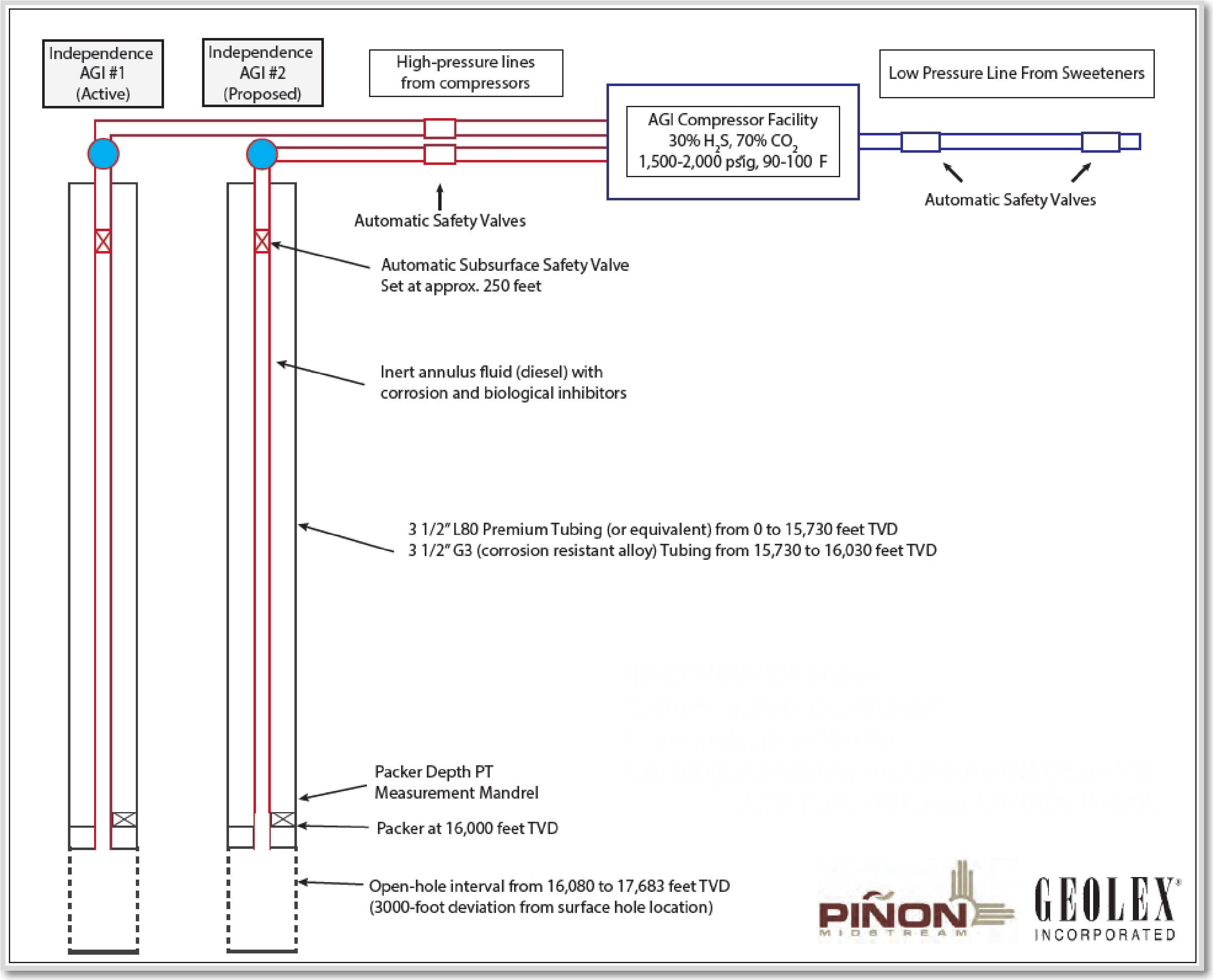


***Figure 3.8-1**: Schematic of surface facilities at the Dark Horse Facility and the Independence AGI Wells. (Modified from Figure 3 of Class II permit application for Independence AGI #2, Geolex, Inc.)*

3.9 Reservoir Characterization Modeling

The Independence AGI Wells penetrate the lower Devonian Thirtyone formation and the Silurian Wristen and Fusselman formations and is bounded below by the Ordovician Montoya formation. The upper Devonian Woodford formation serves as the primary containment seal with thick shales having an estimated permeability in the nanodarcy range.

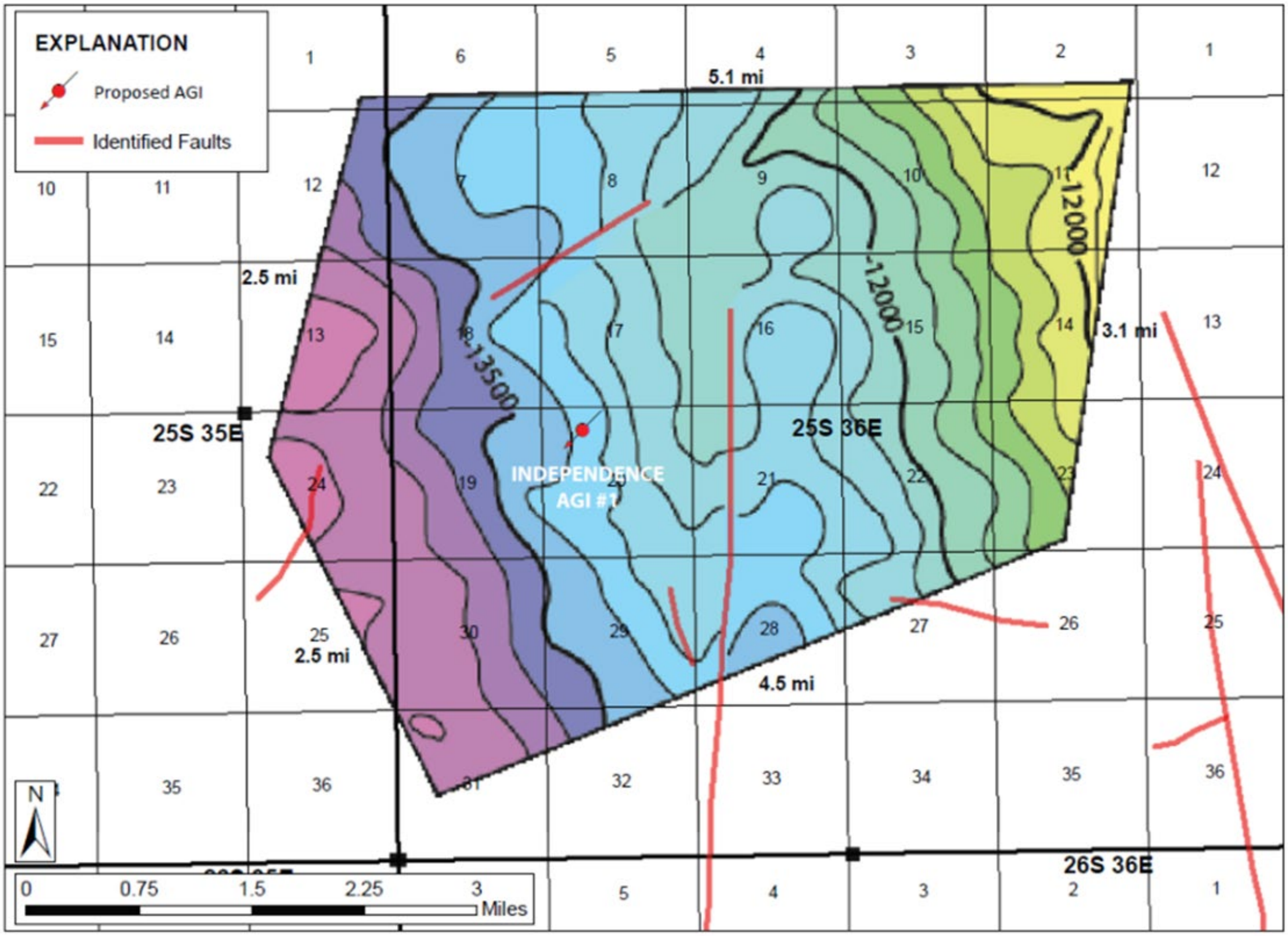
Schlumberger's Petrel (Version 2020.4) software was used to construct the geological models used in this work. Schlumberger's simulation software Eclipse Compositional E300 (Version 2020.1) was used in the reservoir simulations presented in this MRV Plan with simulation results and visuals provided by Geolex Inc. The model simulates solubility trapping of the injected TAG in the formation water and/or the portion of the TAG that can exist in a supercritical phase. The modeling did not consider CO_2 storage attributed to mineral and geomechanical trapping mechanisms. Also, the model did not implicitly model storage attributed to residual trapping because insufficient information was available to develop the hysteresis effects.

Though the Independence AGI Wells were modeled separately, similar constraints were used for both models. The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. The injection

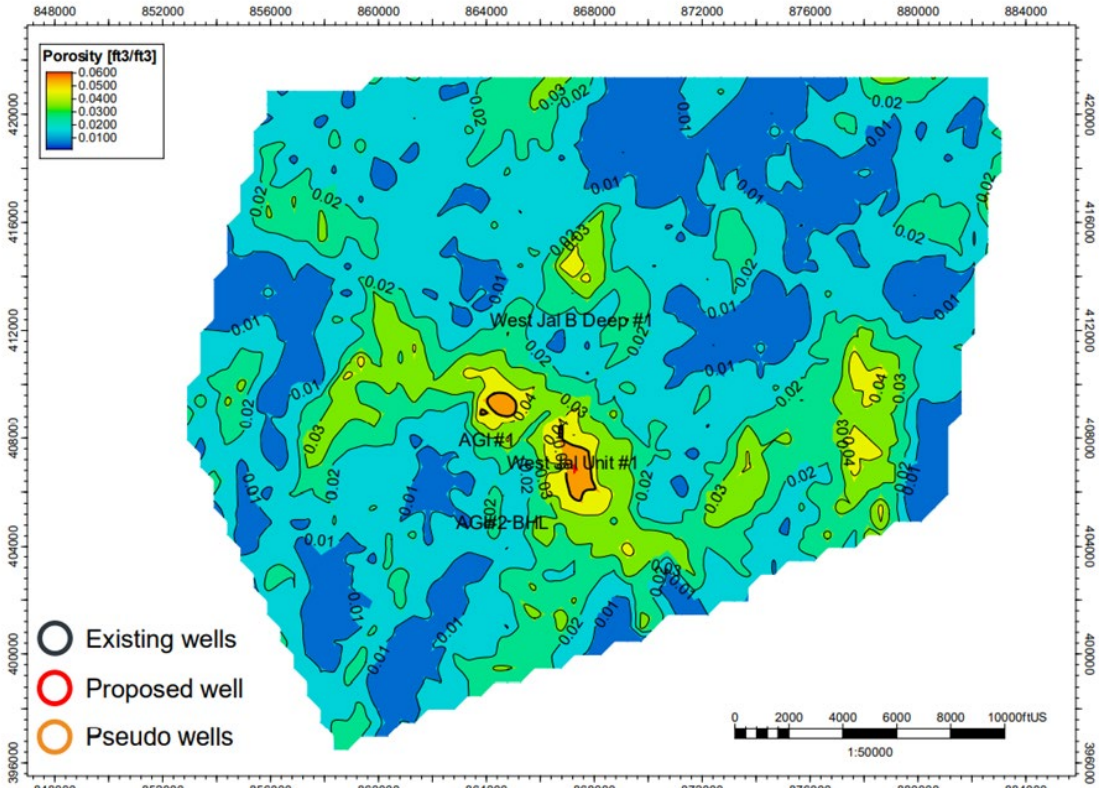
gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Both TAG components are assumed to be soluble into the aqueous phase. An irreducible water saturation of 0.17 is used to generate the relative permeability curves for the gas/water system. The external boundary conditions are specified to be Neumann boundaries and hence no-flow with respect to mass.

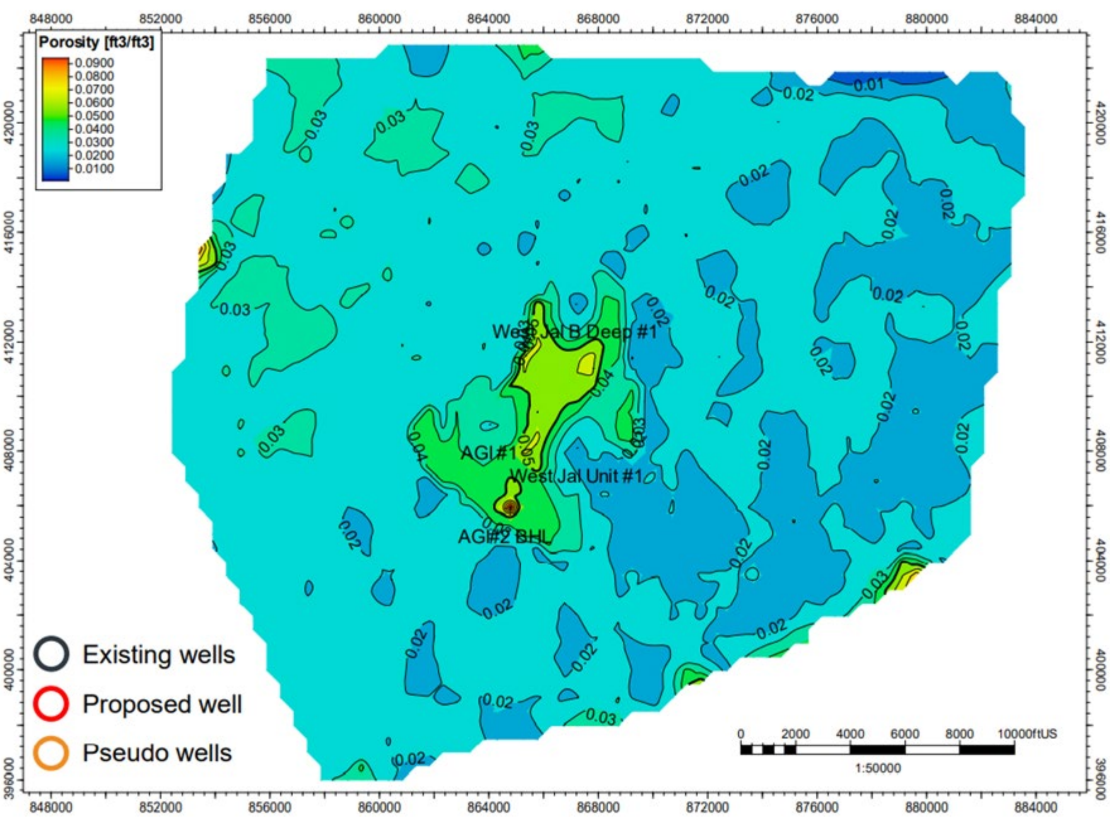
3.9.1 AGI Injection Characterization and Modeling

Formation tops were picked from the few well logs available for the area and geophysical measurements and mapped to construct the structural surfaces for the Silurian-Devonian reservoir between the underlying Montoya and capping Woodford formations. The geologic model extends approximately twenty (20) square miles with an irregular polygonal edge (Figure 3.8-2) and includes relevant subsurface features (e.g. faults, folds) and nearby injection wells. The simulation grid is comprised of 292 simulation layers characterizing eight (8) discrete zones. Horizontal spacing is uniform at 500 × 500 feet throughout the model, and the numerical grid overall contains 923,000 grid cells. Figure 3.9-1 shows the structural surface for Layer 1, covering the top of the reservoir immediately below the Woodford cap. Porosity data derived from the Independence AGI #1 well logs augmented by 3D seismic survey impedance data along with drill-stem and injection tests were used to populate the model porosity values (Figure 3.9-2). A porosity-permeability relationship was established to develop a correlation to populate 3D distribution of permeability (Figure 3.9-3). The permeability distribution signifies a fairly tight formation with typical values ranging from 1.0 to 79.0 millidarcies. Figure 3.9-4 shows the permeability distribution in Layer 1 of the model at the top of the Devonian Thirtyone Formation (*see* Section 3.3.1).

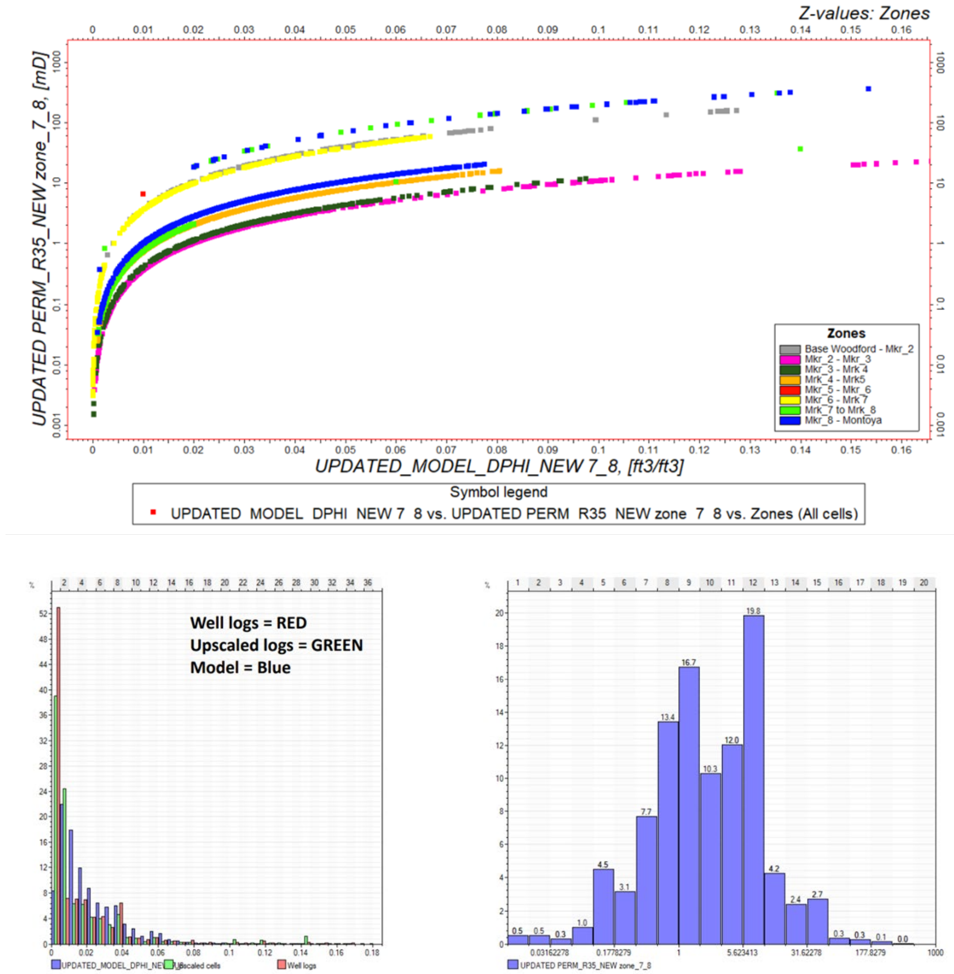


<u>Figure 3.9-1</u>: Structural surface for top of Layer 1 (top) of the geological and numerical model.

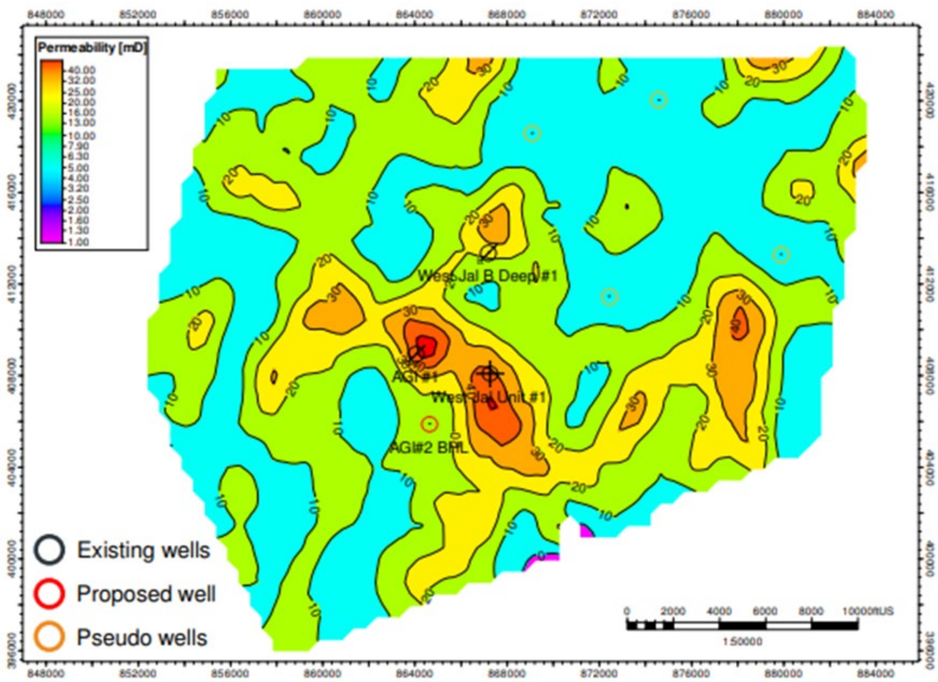




<u>Figure 3.9-2</u>: Model layer porosities for Zone 1 (top) and Zones 7 and 8 (bottom). Porosities are based on 2 wells, 3D seismic impedance surveys, and well stem tests.



<u>Figure 3.9-3</u>: Geological zones and ranges of the properties for the Siluro-Devonian geologic model



<u>Figure 3.9-4</u>: Graphic showing the permeability distribution in Layer 1 of the model representing the Thirtyone formation. Plan view.

3.9.2 Simulation Modeling for the Independence AGI Wells

Once the geological model was established, numerical modeling was performed to:

1. Assess the maximum injection rate with respect to estimated maximum bottomhole pressure ("**BHP**") to ensure safe operation, and

2. Estimate the modeled extent of the injected TAG after thirty (30) year injection period and five (5) year post injection monitoring period.

The reservoir is assumed to be initially saturated with 100% brine and exhibit hydrostatic equilibrium with the initial pressure based on the measured pressure at the top of the reservoir pre-injection. The injection gas has two (2) components, H_2S and CO_2, with a mole fraction of 30% and 70%, respectively. Permeability curves for the multiphase gas/water system are defined for three (3) material ranges with a residual liquid saturation between 40% and 65%. An estimated maximum BHP corresponding to 9,730 psig at the top of Independence AGI#1 corresponded to the fracture pressure gradient was imposed on the Independence AGI #1 to ensure safe injection operations. This pressure was important for Independence AGI #1 in the model scenario where all TAG was injected into Independence AGI #1, but otherwise simulations showed pressure at the Independence AGI Wells remaining below this threshold. In all simulations where West Jal Deep B injected 30,000 bpd of brine into the reservoir, the West Jal Deep B would need to decrease injectivity to remain below its permitted threshold pressure. Present modeling work does not indicate sufficient connectivity between the West Jal Deep B and the Independence AGI Wells to impact AGI injectivity under all other modeled scenarios. <u>Figure 3.9-5</u> shows the calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1. AGI rates are lower than target numbers and limited data are available so a more detailed calibration cannot yet be constructed. An injection forecast model was performed for a period of thirty (30) years with injection and then a five (5) year post-injection rest period to ascertain fluid movement and pressure evolution. <u>Figure 3.9-6</u> shows the injection profile for the forecasting period which showed that the target injection rate could be hit in all scenarios except Scenario 5. The model showed that all the injected gas remained in the reservoir and there was no change in the size of the TAG extent compared at the end of injection and five (5) year post injection period.

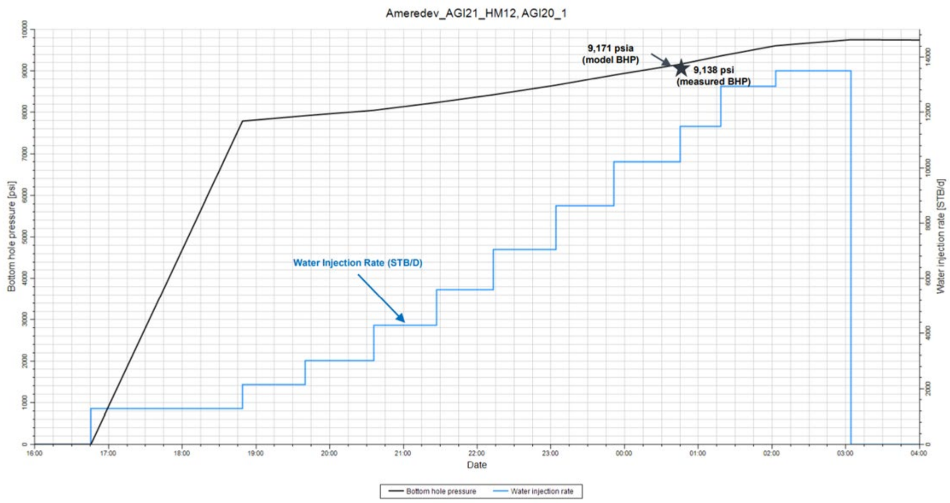


***Figure 3.9-5**: Graph showing calibrated cumulative gas injection and field pressure profile during pressure testing at Independence AGI #1.*

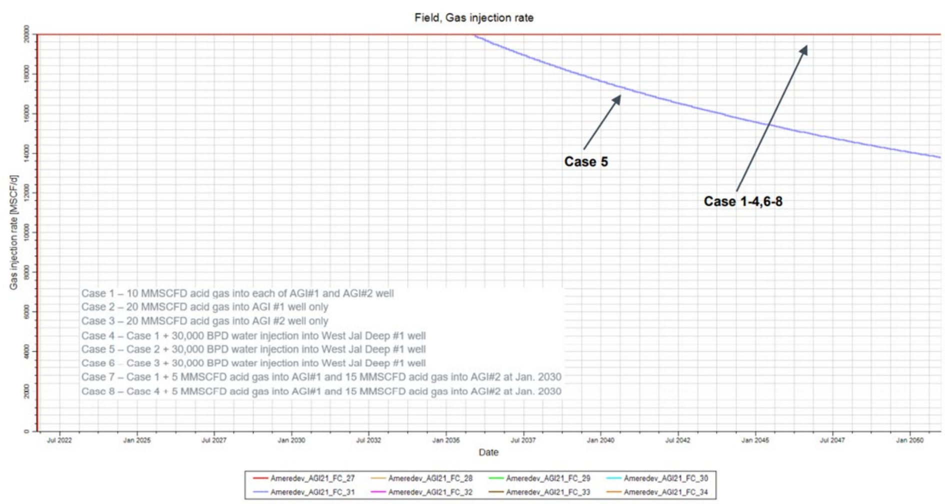


***Figure 3.9-6**: Graph showing the forecast profile for the injection rate and cumulative injection volume over the simulated period*

A considerable source of uncertainty in the plume model relates to the injectivity of the West Jal Deep B well located about one (1) mile northeast of Independence AGI #1. This well is permitted to dispose of up to 30,000 bpd of brine into several reservoirs, including the Siluro-Devonian reservoir used by the Independence AGI Wells, and other shallower reservoirs. It is unclear from publicly available data how this fluid is planned to be partitioned between the various injection layers. Modeling for the present application considered two (2) end-member scenarios: (a) All West Jal Deep B injection is into shallower reservoirs and does not interact with the Siluro-Devonian one (cases 1,2,3), or (b) all West Jal Deep B volumes are injected into the Siluro-Devonian reservoir (cases 4,5,6,7,8). The brine injection at this well is significant for several reasons:

- High volumes of brine injection within the Siluro-Devonian in relatively close proximity of the Independence AGI Wells may raise pressure in the reservoir;

- Pressure from the brine injection pushes against the advancing gas front, directing flow south and west away from the well; and
- The West Jal Deep B wellbore could be a potential leakage pathway if injection ceases and the supercritical fluid plume from the Independence AGI Wells reaches it. Simulations that do not include injections at this well have the TAG plume area including this well.

In all simulations with injection at West Jal Deep B, the local pressure at the brine injection well rapidly rises to the breakover point and the injection rate begins dropping within the first two (2) years of that well's operation to maintain pressures below 80% of the breakover threshold and ensure no rock fracturing occurs (Figure 3.9-7). It is unknown how in reality this will translate to well operations within the Siluro-Devonian reservoir. Simulations do not indicate that the pressure increase from this well will adversely affect the Independence AGI Wells due to the early shut down of the brine injection well. Simulations where there is no brine injection result in the plume extending farther northeast including passing the West Jal Deep B well (Figure 3.9-8), while if brine is injected then the plume is repelled towards the south and west, with some TAG flanking the northwest fault and extending northwest (Figure 3.9-9). Simulations suggest a pressure impact on Independence AGI #1 that could result in curtailed injections under a scenario with all TAG injection in Independence AGI #1 and West Jal Deep B active (Case 5, *see* Figure 3.9.6).

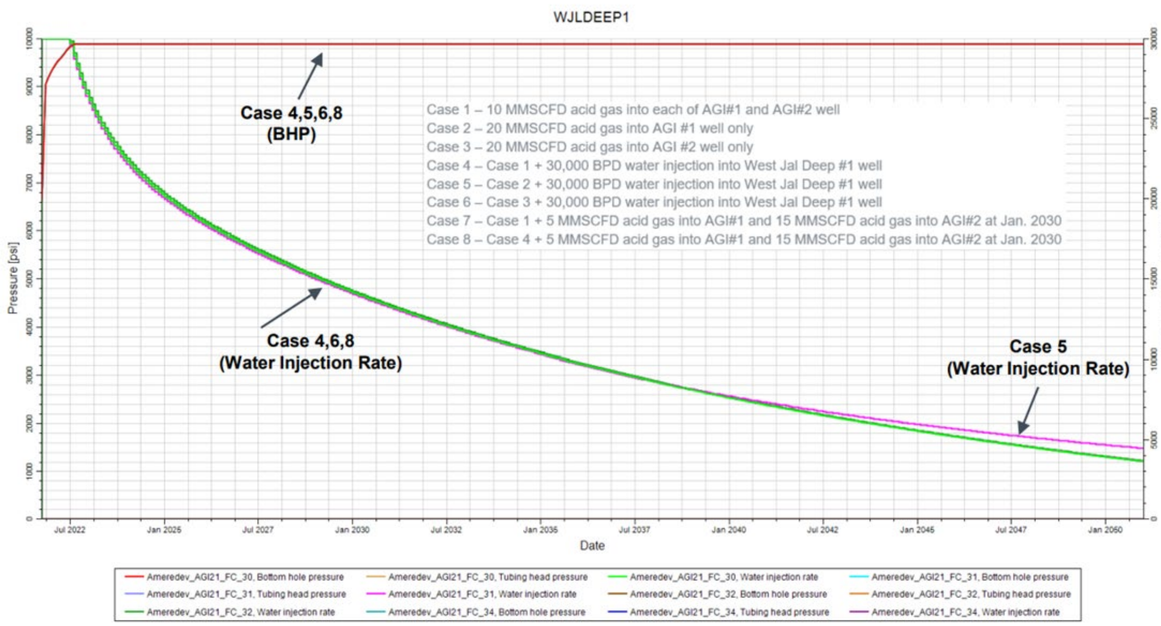


Figure 3.9-7: Graph showing the injection profile of the West Jal Deep B brine injection well under different injection scenarios.

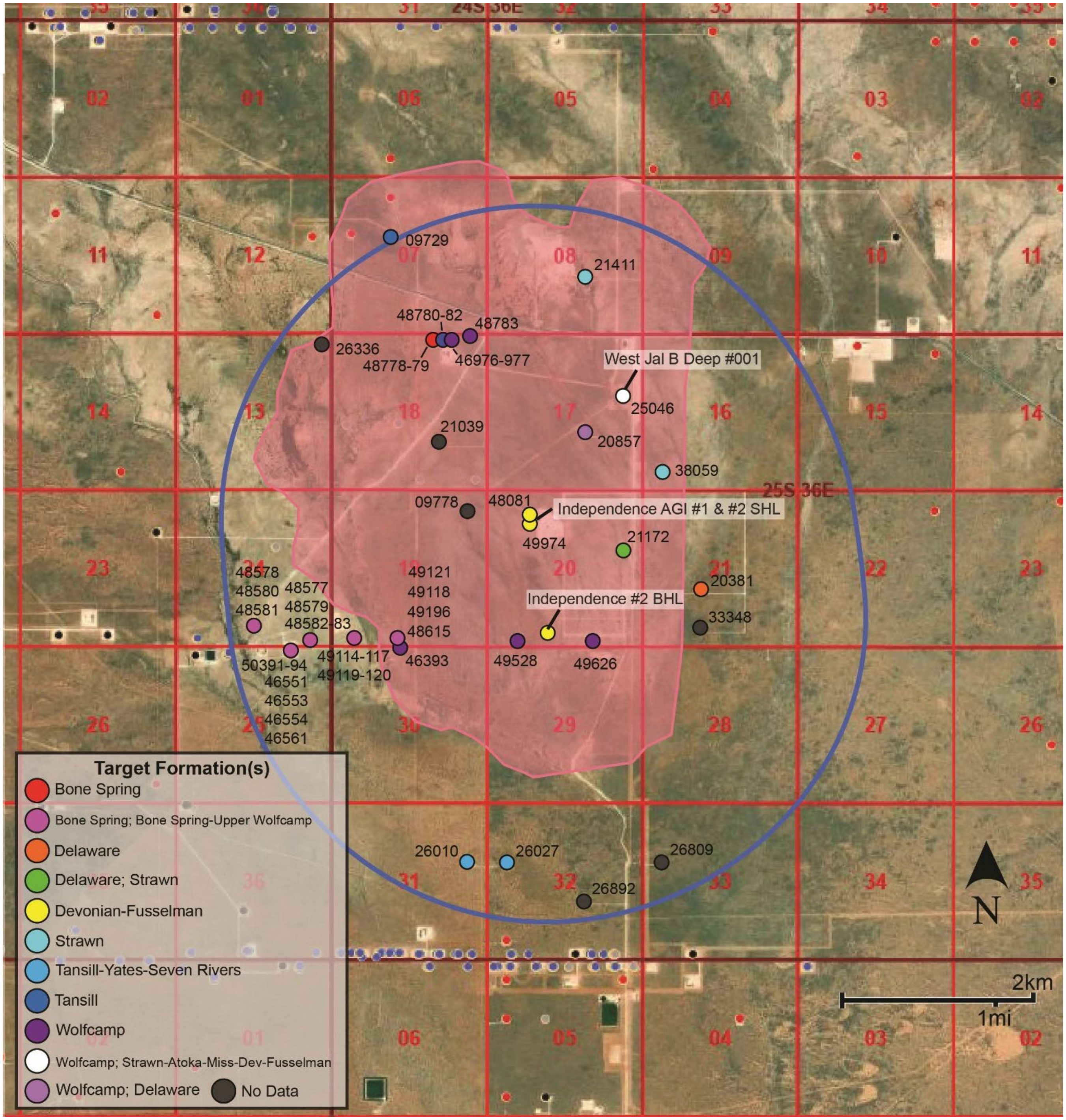


***Figure 3.9-8**: Map showing the largest lateral extent of the TAG when the West Jal Deep B well does not inject into the Siluro-Devonian. Colors indicate target formations for the well. Blue ellipse is a two (2) mile radius as per Figure 3.7-1. West Jal Deep B is the white dot northeast of the Independence AGI Wells.*

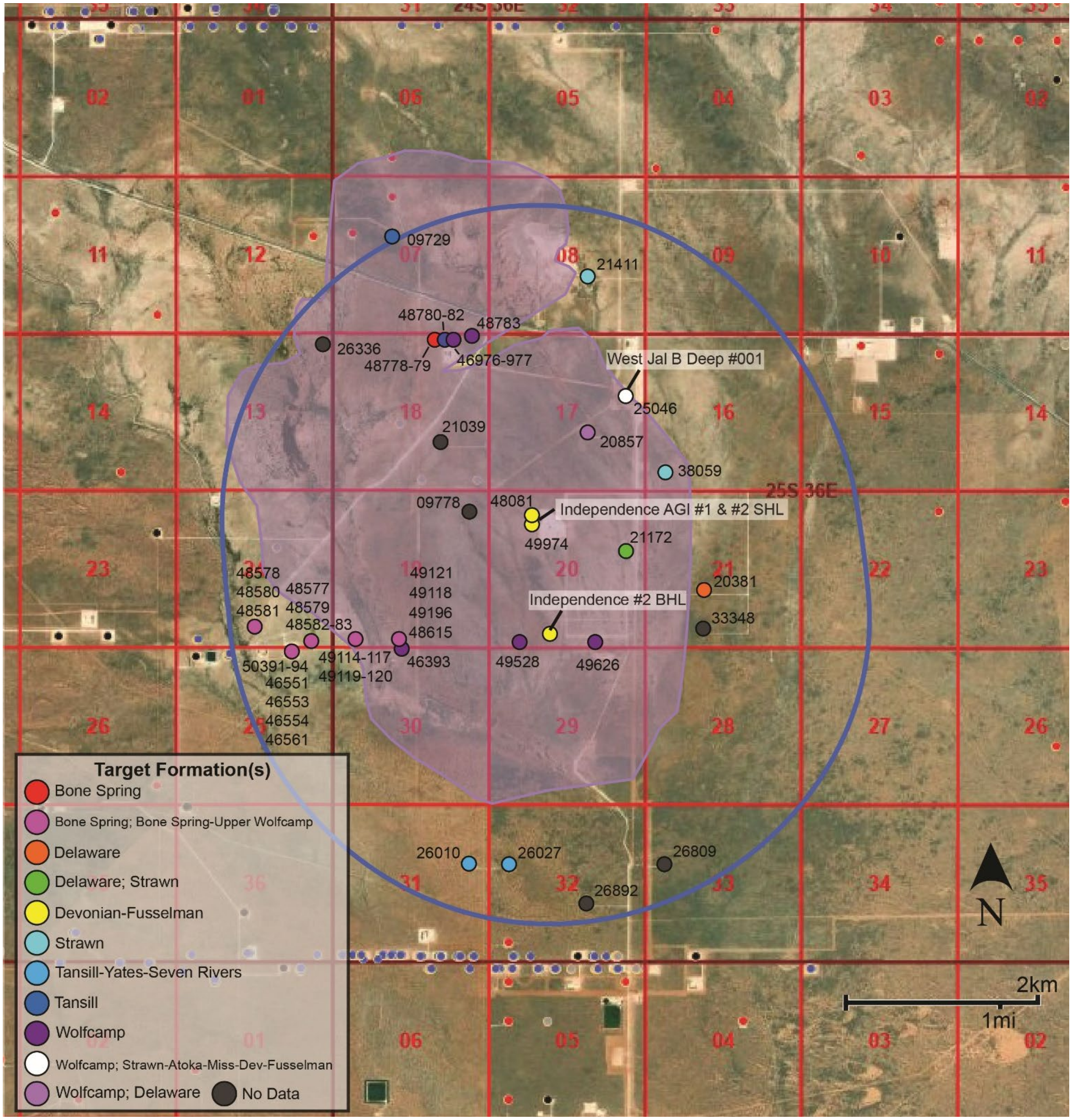


***Figure 3.9-9**: Map showing the largest lateral extent of the TAG when the West Jal Deep B well injects an initial rate of 30,000 bpd of brine into the Siluro-Devonian. Colors indicate target formations for the well. Blue ellipse is two (2) mile radius as per Figure 3.7-1.*

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 3.9.

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 (Figure 4.1-1).

4.2 AMA – Active Monitoring Area

Piñon intends to define the AMA as the same area as the MMA.

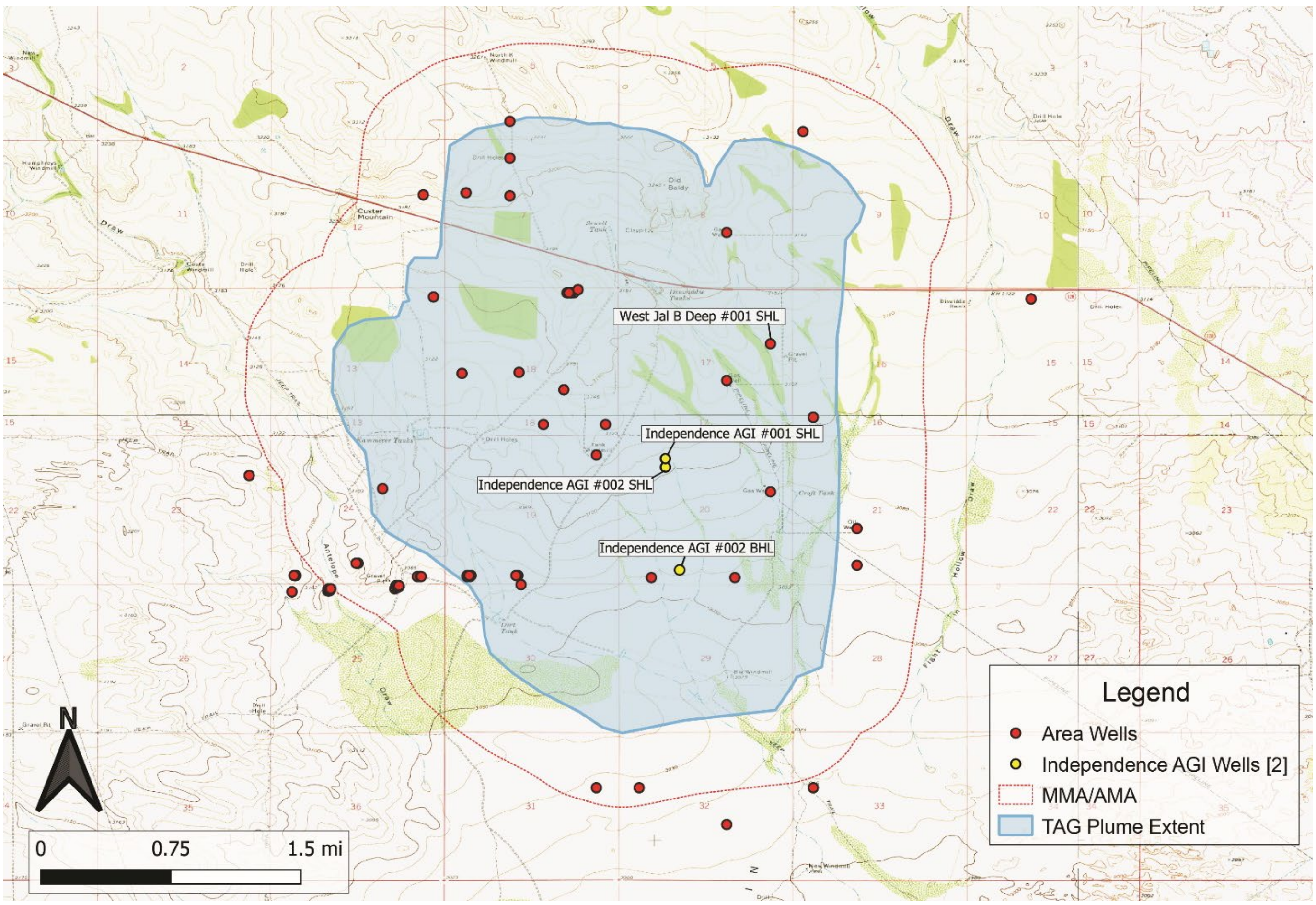


Figure 4.1-1: MMA and AMA for the Independence AGI Wells.

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 and the reservoir modeling described in Section 3.9, Piñon 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 treating facilities. To minimize this potential for leakage, the construction, operation, and maintenance of sour gas treating facilities 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, Piñon 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, Piñon implements several methods for detecting gas leaks at the surface. These methods are described in more detail in Sections 6 and 7. Detection is followed up by immediate response.

5.2 Potential Leakage from Approved, Not Yet Drilled Wells

Appendix 3 and Figure 3.7-1 show a number of wells in the area, many of which have approved permits to drill but are not yet drilled. The new oil and natural gas wells are targeting various production zones, more than 4,000 feet above the Siluro-Devonian Injection Zone for the Independence AGI Wells. All new oil and natural gas wells and injection wells are subject to the requirements of regulations governing sealing off strata (19.16.16.10) and casing and tubing requirements (19.16.16.10) to prevent the contents of production or injection zones from passing into other strata. To minimize the likelihood of leaks from new wells, NMAC 19.15.26.9 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."

5.3 Potential Leakage from Existing Wells

As shown in Figure 3.7-1 and detailed in Appendix 3, there are several existing oil- and natural gas-related wells within a two (2) mile radius around the Independence AGI Wells (Figure 4.1-1). The deep wells discussed in Section 3.7.2 (*see* Table 3.7-1) also lie within the MMA/AMA. They are discussed below.

Independence AGI #1 has an open hole interval between 16,122 and 17,709 feet with more than 300 feet of Woodford Shale immediately above (*see* Figure A1-1). Independence AGI #2, which has recently been drilled, has a proposed open hole interval between 16,080 and 17,683 feet (*see* Figure A1-2). The combined depth to the Siluro-Devonian Injection Zone, cement program for both wells illustrated in Figures A1-1 and 2, existence of suitable confining layers above the Siluro-Devonian Injection Zone described in Section 3, and continuous monitoring of well operational parameters indicates that leakage of CO_2 to the surface via the Independence AGI Wells themselves is unlikely.

The West Jal B Deep Well No. 1 (API 30-025-25046) brine injection well is located one (1) mile northeast of the surface hole locations of the Independence AGI Wells. Additional details for this well are presented in Section 3.7.2. Therefore, Piñon concludes that the potential for CO_2 leakage to the surface through this potential leakage pathway is unlikely.

The West Jal Unit #1 well (API 30-025-21172) was plugged and abandoned in April 1984. The plugging documents presented in Appendix 9 indicate that the well is properly plugged through the Siluro-Devonian Injection Zone. Therefore, Piñon concludes that the potential for CO_2 leakage to the surface through this potential leakage pathway is unlikely.

The remaining wells within the MMA are completed in zones more than 4,000 feet above the Siluro-Devonian Injection Zone. Therefore, Piñon concludes that the potential for CO_2 leakage to the surface through this potential leakage pathway is unlikely.

5.4 Potential Leakage through Fractures and Faults

Faults and fractures were discussed in Section 3.2.3 and the potential for induced seismicity was discussed in Section 3.5. The reservoir characterization modeling (Section 3.9) and the delineation of the monitoring areas (Section 4) show that the TAG plume reaches the faults shown in Figure 3.5-1 during the thirty (30) year injection period and the five (5) year post injection monitoring period. Vertical permeability may be present parallel to the plane of the fault vertically, especially where the two main faults intersect. A review of available drilling fluid records was conducted to evaluate regional reservoir pressure conditions in the Delaware basin. Above the Siluro-Devonian injection reservoir, mud weights utilized range from 12.1 to 15.1 pounds per gallon, while for the injection reservoir less dense fluids were used (average of 9.0 pounds per gallon). These support the interpretation that the overlying productive zones in this area are overpressured with respect to the target reservoir, which would produce a downward gradient through any fault-parallel permeability. The pressure differential between the overlying interval and target interval will act as a barrier preventing vertical migration even along localized open conduits. Therefore, Piñon concludes that the potential for CO_2 leakage to the surface through this potential leakage path is unlikely.

5.5 Potential Leakage through the Confining / Seal System

The subsurface lithologic characterization presented in Section 3.2.2 describes the thick sequence of Mississippian through Permian strata overlying the Siluro-Devonian Injection Zone and reveals the existence of several excellent confining zone layers.

Therefore, it is unlikely that TAG injected into the Siluro-Devonian Injection Zone 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. Section 6.3 describes operational monitoring in place to prevent CO_2 leakage from the Independence AGI Wells.

5.6 Potential Leakage due to Natural / Induced Seismicity

The potential for leaks initiated by induced seismicity was addressed in Section 3.5. It was concluded that generally, faults considered in this assessment do not display significant potential for injection-induced slip and the Independence AGI #2 is not predicted by the FSP model to contribute significantly to the total resultant pressure front. Piñon concludes that the likelihood for the creation and/or opening of vertical conduits for CO_2 leakage to the surface due to induced seismicity is low. Nevertheless, the NMOCC Order requires Piñon to install, operate, and monitor for the life of the project a seismic monitoring station or stations described in more detail in Section 7.6.

Additionally, there have been no seismic events, natural or induced, detected within the MMA for this MRV Plan. Therefore, Piñon concludes that the likelihood, magnitude, and timing of leakage of CO_2 to the surface due to natural seismicity is minimal.

5.7 Potential Leakage due to Lateral Migration

Lateral migration of the injected TAG was addressed in the simulation modeling detailed in Section 3.9. The results of that modeling indicate the TAG is unlikely to migrate laterally beyond approximately 2.5 miles within the Siluro-Devonian Injection Zone to encounter any conduits to the surface.

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. Piñon 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. Piñon considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ 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 five (5) year post-injection period.

***Table 6.1* – Summary of Leak Detection Monitoring**

Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system ("DCS") surveillance of facility operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/H_2S and low explosive level ("LEL") monitoring network • Personal and hand-held gas monitors
Independence AGI #1	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests ("MIT") • Fixed in-field gas monitors/H_2S and LEL monitoring network • Personal and hand-held gas monitors
Existing Other Operator Active Wells	• Monitoring of well operating parameters • Visual inspections • MITs
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/H_2S and LEL monitoring network

6.1 Leakage from Surface Equipment

Piñon 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 Piñon using in-field monitors which detect H_2S. 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. Additionally, Piñon field personnel, wearing personal H_2S monitors, follow daily and weekly inspection protocols which include reporting and responding to any detected leakage events.

Piñon's internal operational documents and protocols detail the steps to be taken to verify leaks of H_2S. The following description of the gas detection equipment at the Dark Horse Facility was summarized from the H_2S Contingency Plan:

Fixed Monitors

The Dark Horse Facility has numerous ambient H_2S detectors placed strategically throughout the facility to detect possible leaks. Upon detection of H_2S concentrations of 10 ppm at any detector, visible beacons are activated and an alarm is sounded. Upon detection of H_2S concentrations of 90 ppm at any detector, an evacuation alarm is sounded throughout the Dark Horse Facility at which time all personnel will proceed immediately to a designated evacuation area. The Dark Horse Facility 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 ("**PLC**"), and then to the DCS. The monitors are equipped with amber beacons. The beacon is activated upon detection of H_2S concentrations of 10 ppm. The Dark Horse Facility horns are activated with a continuous warbling alarm upon detection of H_2S concentrations of 10 ppm and a facility-wide siren upon detection of H_2S concentrations of 90 ppm. All monitoring equipment is Rosemount brand. The control panel is a twenty-four (24) channel monitor box, and the fixed point H_2S sensor heads are model number ST320A-100-ASSY.

The Dark Horse Facility will monitor the inlet sour natural gas steam and sweet natural gas stream concentrations of H_2S via H_2S analyzers with sample points located on the north/south-oriented pipe rack (Figure 2 7.2-1). Concentrations of H_2S in the TAG stream will be sampled near the AGI pumps located on the west side of the Dark Horse Facility. All H_2S analyzers are model T224, manufactured by Analytical Systems KECO.

The monitors can also be viewed on the PLC displays located at the Dark Horse Facility and the locations of ambient H_2S sensors are shown on the plot plan (*see* Figure 2 7.2-1). Immediate action is required for any alarm occurrence or malfunction. All H_2S sensors are calibrated monthly.

Personal and Handheld H_2S Monitors

All personnel working at the Dark Horse Facility wear personal H_2S monitors, which are required to alarm and vibrate upon detection of H_2S concentrations of 10 ppm. Handheld gas detection monitors are available at strategic locations around the Dark Horse Facility so that facility 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.

Quantification of CO_2 emissions from surface equipment and components will be estimated according to the requirements of 98.448 (d) of Subpart RR as discussed in Sections 8.4 and 10.1.5.

6.2 Leakage from Approved Not Yet Drilled Wells

Aside from Independence AGI #2, other approved but not yet drilled wells target zones more than 4,000 feet above the Siluro-Devonian Injection Zone. Therefore, no additional monitoring is required for these well over and above what is already required by NMOCC rules and orders.

6.3 Leakage from Existing Wells

6.3.1 Independence AGI #1

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

6.4 Leakage from Fractures and Faults

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through faults. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone.

6.5 Leakage through the Confining / Seal System

As discussed in Section 5, it is unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone.

6.6 Leakage due to Natural / Induced Seismicity

Continuous operational monitoring of the Independence AGI Wells, described in Sections 6.3 and 7.5 coupled with a detection of a seismic event by the seismic stations described in Section 7.6 will provide an indicator if CO_2 leaks out of the Siluro-Devonian Injection Zone due to a seismic event.

6.7 Leakage due to Lateral Migration

Continuous operational monitoring of the Independence 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 Siluro-Devonian 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 Siluro-Devonian Injection Zone.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

Subpart RR at 40 CFR 448(a)(4) requires a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. Piñon 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 Piñon's strategy for collecting baseline information.

7.1 Visual Inspection

Piñon 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 Dark Horse Facility.

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

Compositional analysis of gas injectate at the Dark Horse Facility indicates an approximate H_2S concentration of 38.7% thus requiring Piñon to develop and maintain an H_2S Contingency Plan according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). Piñon considers H_2S to be a proxy for CO_2 leaks at the Dark Horse Facility. The H_2S Contingency Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the Dark Horse Facility or the associated Independence 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 Dark Horse Facility utilizes numerous fixed-point monitors, strategically located throughout the facility, to detect the presence of H_2S in ambient air (Figure 7.2-1). The sensors are connected to the Control Room alarm panel's PLCs, and then to the DCS. Upon detection of H_2S concentrations of 10 ppm at any monitor, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of H_2S concentrations of 90 ppm at any monitor, an evacuation alarm is sounded throughout the Dark Horse Facility 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 Dark Horse Facility so that facility 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 Oxide ("**CO**").

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the Dark Horse Facility 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 upon detection of H_2S concentrations of 10 ppm.

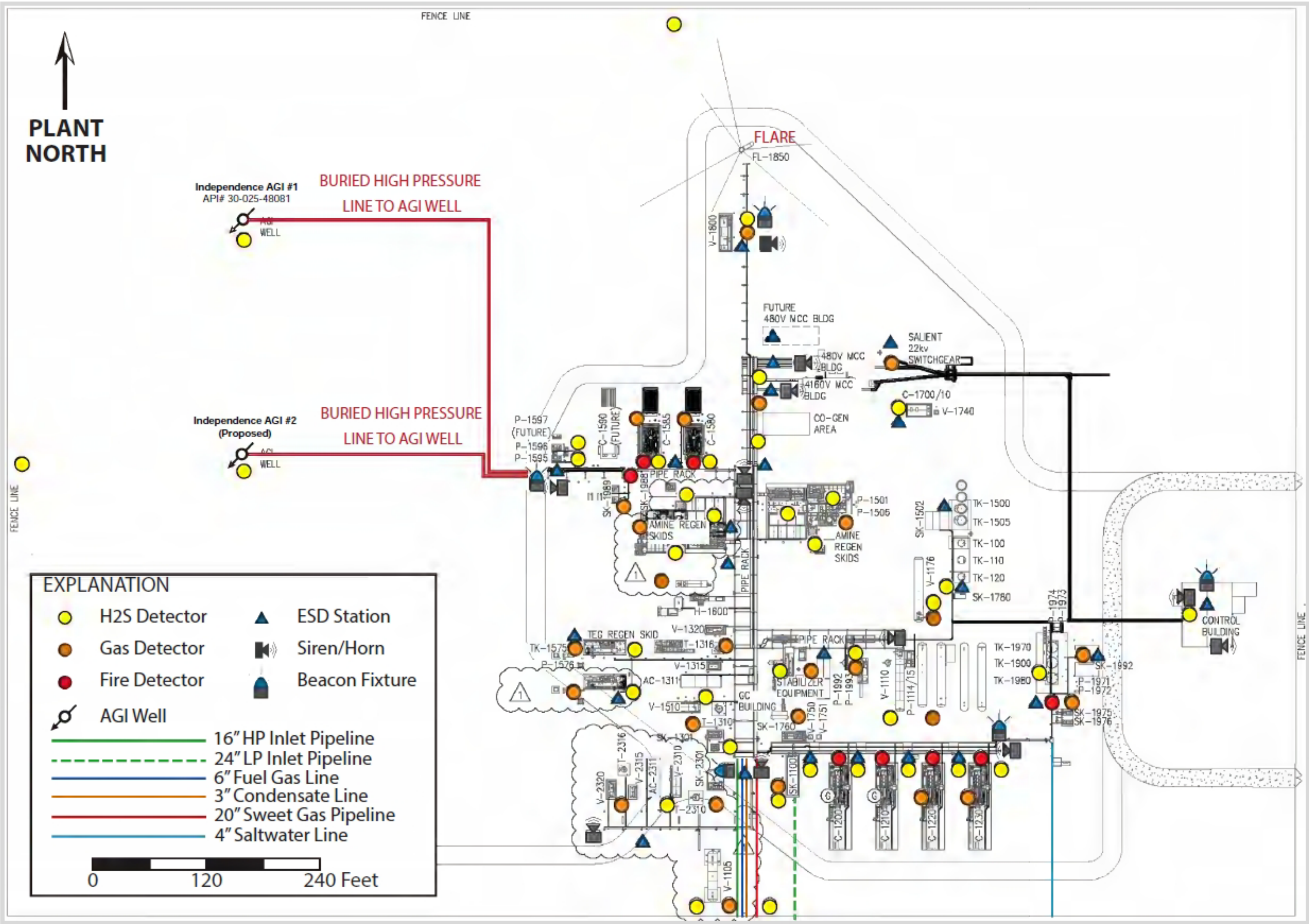


***Figure 7.2-1**: Detailed Dark Horse Facility schematic illustrating the location of major process units, all emergency equipment, H_2S and gas detection sensors, sirens and beacons, and major gas flow lines at the facility (Taken from Figure 2 of the H_2S Contingency Plan for Dark Horse Gas Treatment Facility, Geolex, Inc.). The yellow circles indicate the location of fixed H_2S sensors.*

7.3 CO_2 Detection

Any CO_2 release to the surface would be accompanied by H_2S and therefore the H_2S monitors will serve as a CO_2 release warning system both at the facility and in the field. In addition to the fixed and personal monitors described in Section 7, Piñon will establish and operate a monitoring program to detect H_2S leakages within the AMA. The scope of work will include H_2S monitoring at the AGI well site and atmospheric monitoring near identified penetrations of the Siluro-Devonian Injection Zone within the AMA. Upon approval of the MRV Plan and for the five (5) year post-injection period, Piñon will have these monitoring processes and systems in place.

7.4 Continuous Parameter Monitoring

The DCS of the Dark Horse Facility 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.

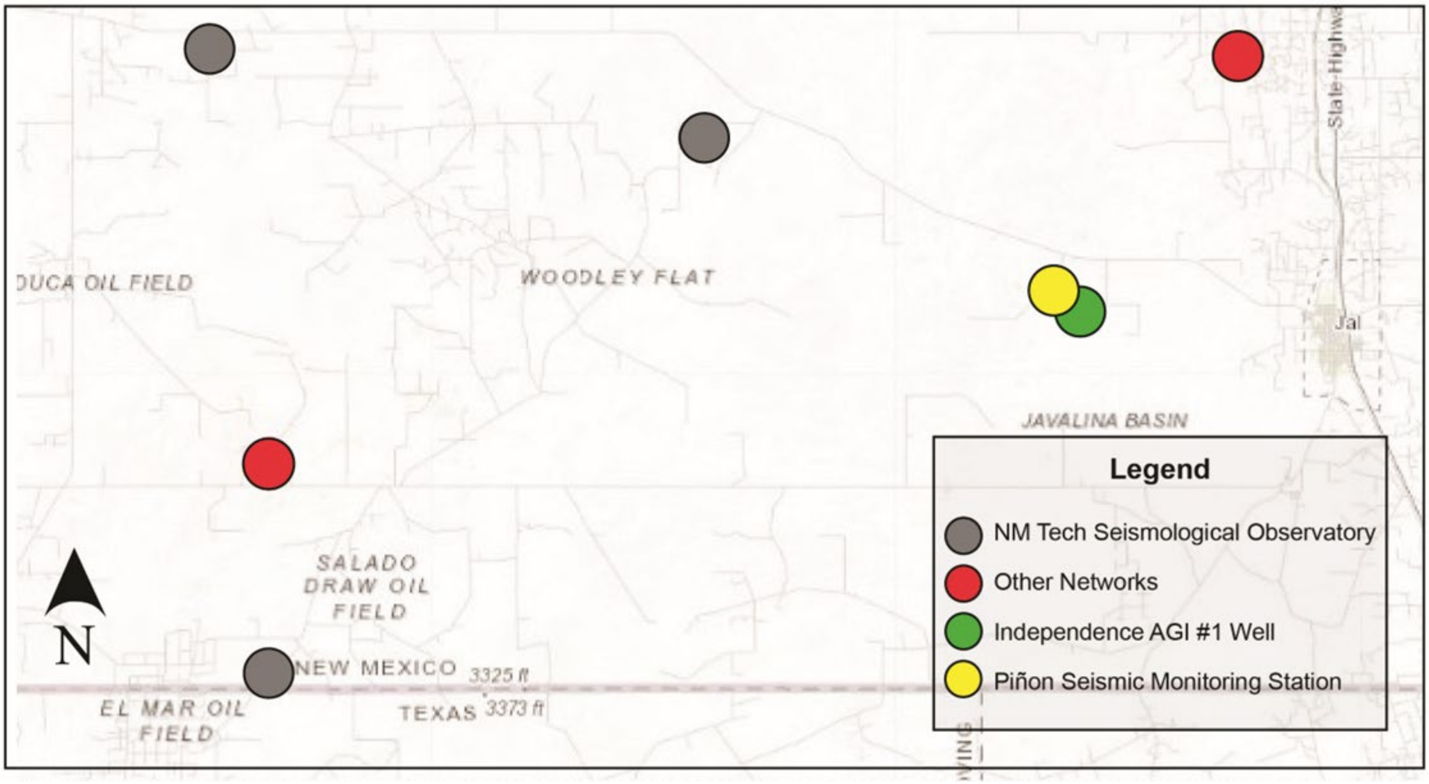
7.5 Well Surveillance

Piñon 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. Piñon's Routine Operations and Maintenance Procedures for the Independence AGI Wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic Monitoring Stations

Piñon owns 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 Dark Horse Facility. The seismic station will meet the requirements of the NMOCC Order to "install, operate, and monitor for the life of this Order a seismic monitoring station or stations. OCD shall be responsible for coordinating with the Manager of the New Mexico Tech Seismological Observatory at the New Mexico Bureau of Geology and Mineral Resources for appropriate specifications for the equipment and the required reporting procedure for the monitoring data."

Additionally, Figure 7-1 shows the location of other seismic monitoring stations in the vicinity of the Independence AGI Wells.



<u>Figure 7-1</u>: Location of seismic monitoring stations in the vicinity of the Independence AGI Wells.

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve (12) Subpart RR equations used to calculate the mass of CO_2 sequestered annually. Appendix 8 includes the twelve (12) equations from Subpart RR. Not all of these equations apply to Piñon's current operations at the Dark Horse Facility but are included in the event Piñon's operations change in such a way that their use is required.

8.1 CO_2 Received

Currently, Piñon receives sour natural gas at the Dark Horse Facility through three (3) pipelines: the Hondo High Pressure Sour Gas Pipeline (owned and operated by Piñon), the Franklin Mountain Low Pressure Pipeline (owned and operated by Franklin Mountain Energy) and the Ameredev II Low Pressure Pipeline (owned and operated by Ameredev).

Although Piñon does not currently receive CO_2 in containers for injection, they have chosen to include the flexibility in this MRV Plan to do so. If Piñon begins to receive CO_2 in containers, they will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. Piñon will adhere to the requirements in 40 CFR 98.444(a)(2) for determining the quarterly mass or volume of CO_2 received in containers.

8.2 CO_2 Injected

Piñon injects CO_2 into the existing Independence AGI #1. Upon its completion, Piñon will commence injection of CO_2 into Independence AGI #2. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the Independence AGI Wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the Independence AGI Wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12.

8.3 CO_2 Produced / Recycled

Piñon does not produce oil or natural gas or any other liquid at the Dark Horse Facility so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

As required by 98.448 (d) of Subpart RR, Piñon 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. 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. 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 Piñon does not actively produce oil or natural gas or any other fluid at the Dark Horse Facility, Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations. 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.

9 Estimated Schedule for Implementation of MRV Plan

Piñon will implement this MRV Plan as soon as it is approved by EPA.

10 GHG Monitoring and Quality Assurance Program

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

10.1 GHG Monitoring

As required by 40 CFR 98.3(g)(5)(i), Piñon'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 greenhouse gas ("**GHG**") calculations; and
- 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 will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association ("**GPA**") standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40 CFR 98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2 and RR-5, of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 15.025 pounds per square inch absolute ("psia") (Appendix 6). Piñon utilizes Coriolis metering to measure the dense phase injected TAG stream. Piñon utilizes the following two standards: American Petroleum Institute API 14.1 for measuring barrels and the American Gas Association AGA 7 for million cubic feet ("MCF") equivalent calculations.

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 Independence AGI Wells using accepted flow calculations for CO_2 according to the [AGA Report #3].

10.1.4 CO_2 produced.

Piñon does not produce CO_2 at the Dark Horse Facility.

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

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

10.1.6 Measurement devices.

As required by 40 CFR 98.444(e), Piñon 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 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute, the AGA, the GPA, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.
- All flow meter calibrations performed are National Institute of Standards and Technology ("**NIST**") traceable.

10.2 QA/QC Procedures

Piñon 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

Piñon will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or using a representative flow rate value from the nearest previous time period.

- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or using a representative concentration value from the 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

Piñon will revise the MRV Plan as needed to (a) reflect changes in monitoring instrumentation and quality assurance procedures; (b) improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or (c) address additional requirements as directed by the EPA or the State of New Mexico.

11 Records Retention

Piñon will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, Piñon will retain the following documents:

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

(b) 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

(c) The annual GHG reports.

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

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

(f) 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.

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

(h) 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.

(i) 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.

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

(k) 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.

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

13 Appendices

Appendix 1 - Independence AGI Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Independence AGI #1	30-025-48081	SHL 829' FNL, 1,443' FEL BHL of Sidetrack: 1041'FNL, 1785'FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120855 and -103.291021	Lea, NM	12/27/2020	17,750'	16,114'
Independence AGI #2	30-025-49974	SHL 1,180' FNL, 1,578' FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.120020 and -103.291015 BHL 1,033' FSL, 2,132' FWL Sec. 20, T25S, R36E, NMPM Latitude & Longitude (NAD83): 32.111581 and -103.289273	Lea, NM	Not Drilled Yet	17,683' TVD	approx. 16,000'

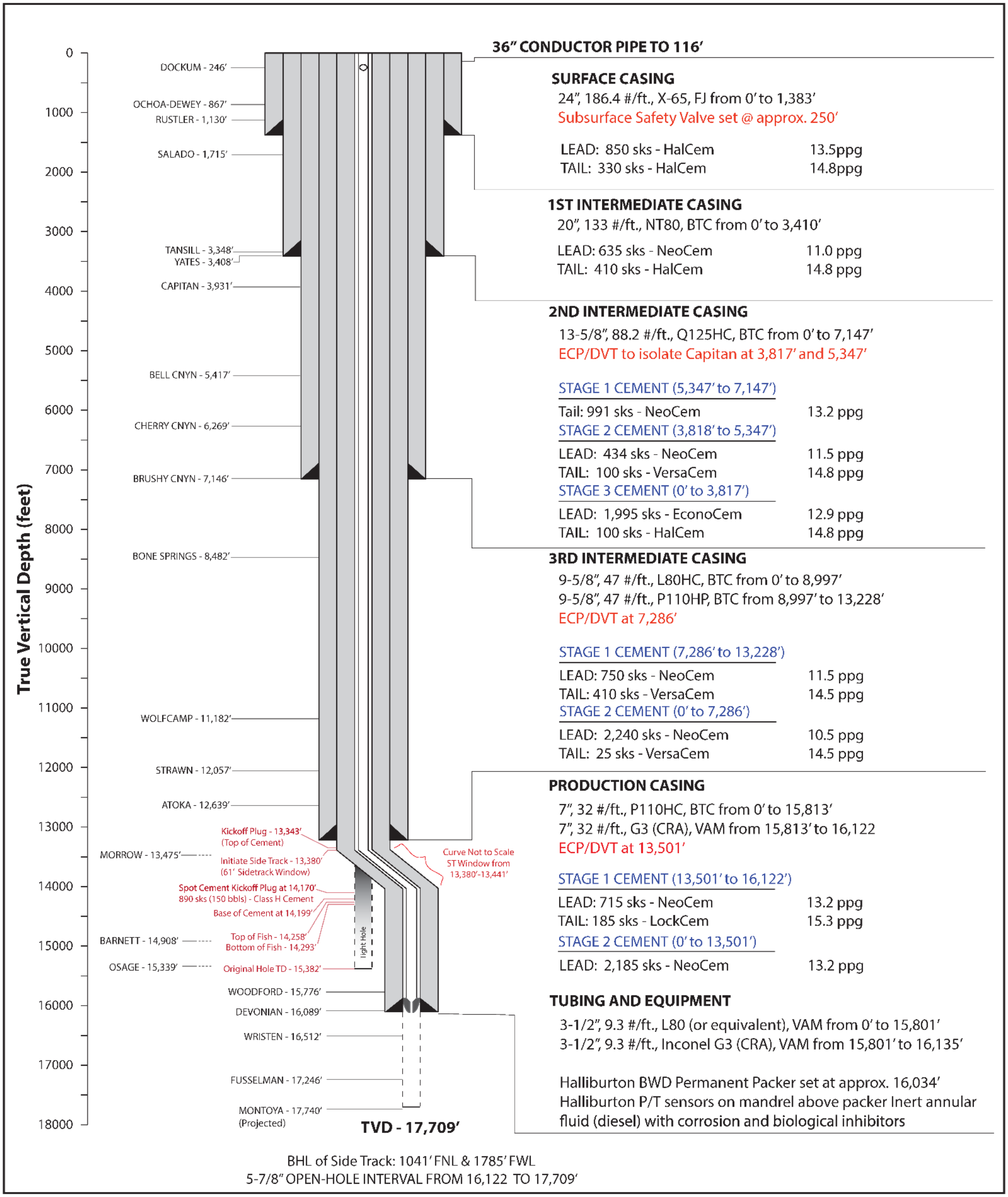


__Figure A1-1__: Independence AGI #1: As-drilled well schematic consisting of a surface string of casing, three (3) intermediate strings , and a production string with associating tubing/equipment and cement types. Original hole and sidetrack are shown. (Taken from End-of-Well Report for Independence AGI #1, Geolex, Inc.)

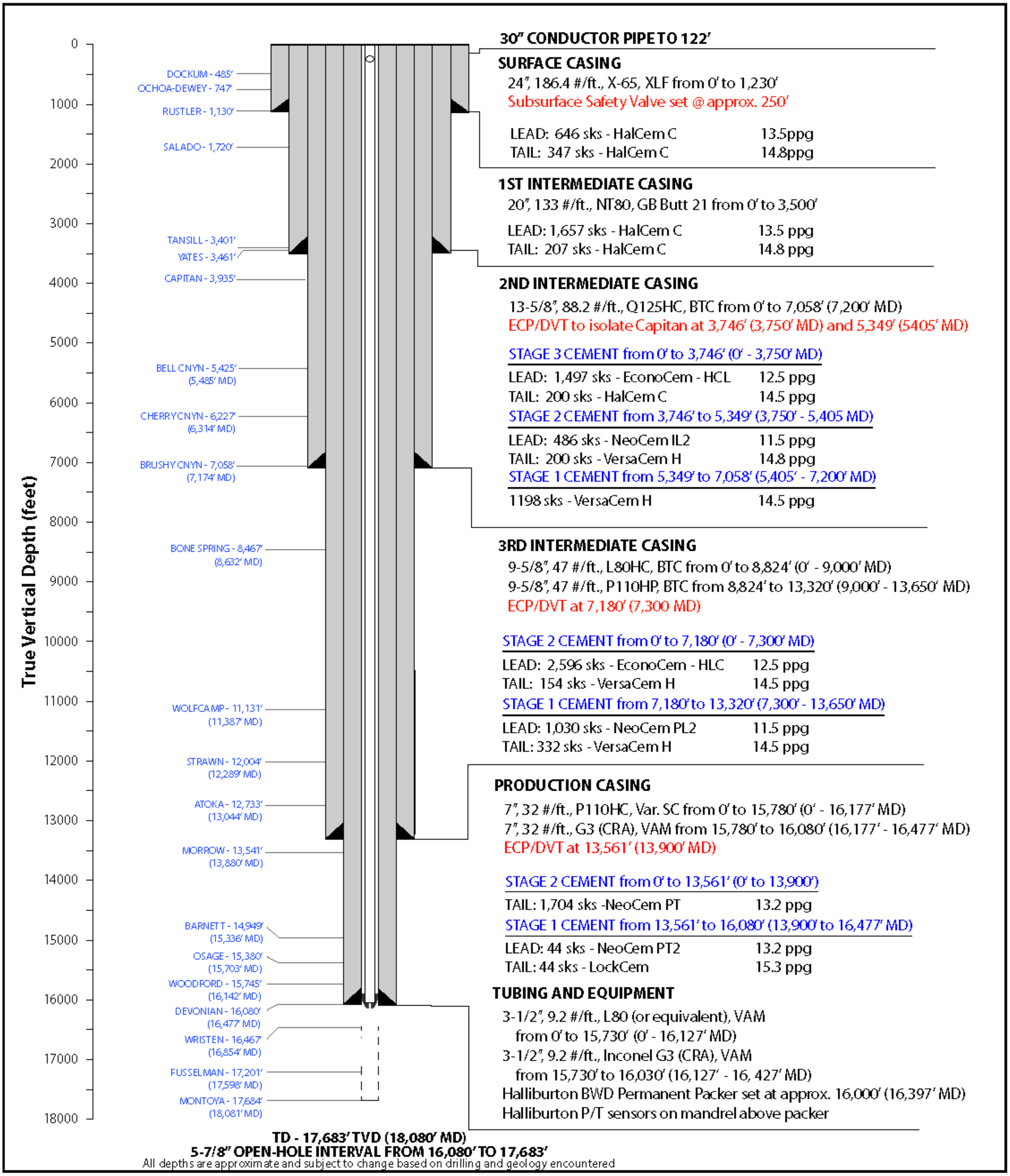


***Figure A1-2**: Independence AGI #2: Well schematic. (Taken from NMOCC Order 3/31/2022)*

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 - Oil and natural gas wells within 2-mile radius of the Independence AGI Wells

The data in the following table was obtained from the NMOCD database and is accurate as of 8/5/2022.

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-09729	PAN AM KELLY 7 FEDER	Oil	Plugged (site released)	JOHN H TRIGG	32.1466	-103.3063		1900	3,540	0	-	1/1/1900	CUSTER, TANSILL
30-025-09778	FEDERAL #1	Oil	Plugged (site released)	EDWARD C. DONAHUE	32.1212	-103.2978	No Data	1900	3,891	0	-	1/1/1900	No Data
30-025-20381	HERKIMER BQF FEDERAL #001H	Oil	Active	AMEREDEV OPERATING, LLC	32.114	-103.2722	H	1963	8,515	10,121	10,100	-	DELAWARE, WEST
30-025-20857	WEST JAL B #001	Brine Injection	New	BC & D OPERATING INC.	32.1285	-103.2850	V	1964	12,275	12,275	6,170	-	WOLFCAMP, WEST; DELAWARE
30-025-21039	WEST JAL 18 #1	Oil	Plugged (site released)	SKELLY OIL CO.	32.1276	-103.3010	No Data	1900	12,950	0	-	1/1/1900	No Data
30-025-21172	WEST JAL UNIT #1	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.1176	-103.2807	V	1961	17,086	17,086	-	4/4/1984	DELAWARE, WEST; JAL, STRAWN, WEST
30-025-21411	C ELLIOTT FEDERAL	Oil	Plugged (site released)	TEXACO EXPLORATION & PRODUCTION INC	32.143	-103.2850	V	1900	12,276	12,276	-	6/26/1993	STRAWN, WEST
30-025-25046	WEST JAL B DEEP #001	Brine Injection	Active	BC & D OPERATING INC.	32.1321	-103.2807	V	1975	18,945	18,945	14,175	-	STRAWN, WEST; WOLFCAMP, WEST; FUSSELMAN, WEST; ST-AT-MISS-DEV-FUS
30-025-26010	SPOTTED TAIL FED. #1	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2978	No Data	1900	3,336	0	-	1/1/1900	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26027	SITTING BULL A #001	Oil	Active	FULFER OIL & CATTLE LLC	32.0886	-103.2936	V	1978	3,368	3,368	-	-	SIOUX, TANSILL-YATES-SEVEN RIVERS
30-025-26336	FEDERAL 13 A #1	OIL	Plugged (site released)	GETTY OIL CO.	32.1367	-103.3138	V	1979	3,686	0	-	-	No Data
30-025-26809	LITTLE HAWK FEDERAL #	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.0886	-103.2765	No Data	1900	3,690	0	-	1/1/1900	No Data
30-025-26892	SITTING BULL #2	Oil	Plugged (site released)	GIFFORD, MITCHELL & WISENBAKER	32.085	-103.2850	No Data	1900	3,746	0	-	1/1/1900	No Data
30-025-33348	TEXACO WEST JAL 21 #001	Oil	Plugged (site released)	ENSERCH EXPLORATION INC.	32.1104	-103.2722	V	1996	7,700	7,700	-	4/25/1996	No Data
30-025-38059	DINWIDDIE STATE COM #001	Gas	Plugged (site released)	COG OPERATING LLC	32.1249	-103.2765	V	2006	12,192	12,192	-	12/12/2008	STRAWN, WEST
30-025-46393	NANDINA 25 36 31 FEDERAL COM #124H	Oil	New	AMEREDEV OPERATING, LLC	32.1085	-103.3052	H	-	0	23,130	-	-	WOLFCAMP, WEST
30-025-46533	SIOUX 25 36 STATE FEDERAL COM #008H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2019	12,149	22,150	22,117	-	UPPER WOLFCAMP
30-025-46551	SIOUX 25 36 STATE FEDERAL COM #009H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3175	H	2020	11,894	21,945	21,912	-	BONE SPRING
30-025-46553	SIOUX 25 36 STATE FEDERAL COM #012H	Oil	Active	CAZA OPERATING, LLC	32.1084	-103.3174	H	2020	11,994	22,350	22,319	-	BONE SPRING; UPPER WOLFCAMP
30-025-46554	SIOUX 25 36 STATE FEDERAL COM #013H	Oil	Active	CAZA OPERATING, LLC	32.1082	-103.3174	H	2020	11,725	21,962	21,930	-	BONE SPRING; UPPER WOLFCAMP
30-025-46561	SIOUX 25 36 STATE FEDERAL COM #010H	Oil	Active	CAZA OPERATING, LLC	32.1081	-103.3176	H	2020	12,107	22,209	22,175	-	UPPER WOLFCAMP
30-025-46976	BLACK MARLIN FEDERAL COM #204H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3002	H	2020	11,640	21,953	21,895	-	WOLFCAMP, WEST
30-025-46977	BLACK MARLIN FEDERAL COM #214H	Oil	Active	TAP ROCK OPERATING, LLC	32.1371	-103.3000	H	2020	11,741	22,055	21,994	-	WOLFCAMP, WEST
30-025-48081	INDEPENDENCE AGI #001	AGI	Active	Pinon Midstream, LLC	32.1208	-103.2910	V	2020	17,709	17,900	-	-	DEVONIAN-FUSSELMAN
30-025-48577	SANTA FE FEDERAL COM #603H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3154	H	-	0	21,874	-	-	BONE SPRING
30-025-48578	SANTA FE FEDERAL COM #704H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3212	H	-	0	22,063	-	-	WOLFCAMP, WEST
30-025-48579	SANTA FE FEDERAL COM #705H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3152	H	-	0	22,129	-	-	WOLFCAMP, WEST
30-025-48580	TRINITY FEDERAL #602H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3214	H	-	0	21,938	-	-	BONE SPRING
30-025-48581	TRINITY FEDERAL #703H	Oil	New	Franklin Mountain Energy LLC	32.1106	-103.3213	H	-	0	22,206	-	-	WOLFCAMP, WEST
30-025-48582	ZIA FEDERAL COM #604H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3151	H	-	0	21,973	-	-	BONE SPRING
30-025-48583	ZIA FEDERAL COM #706H	Oil	New	Franklin Mountain Energy LLC	32.1093	-103.3150	H	-	0	21,973	-	-	WOLFCAMP, WEST
30-025-48614	BLUE MARLIN STATE #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3102	H	-	0	19,502	-	-	WOLFCAMP, WEST
30-025-48615	BLUE MARLIN STATE #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	-	0	19,350	-	-	WOLFCAMP, WEST
30-025-48778	BLACK MARLIN FEDERAL COM #113H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3007	H	-	0	20,014	-	-	BONE SPRING
30-025-48779	BLACK MARLIN FEDERAL COM #114H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3006	H	-	0	20,056	-	-	BONE SPRING
30-025-48780	BLACK MARLIN FEDERAL COM #203H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3005	H	2021	11,786	21,842	21,879	-	WOLFCAMP, WEST
30-025-48781	BLACK MARLIN FEDERAL COM #206H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3003	H	-	0	21,981	-	-	WOLFCAMP, WEST
30-025-48782	BLACK MARLIN FEDERAL COM #213H	Oil	New	TAP ROCK OPERATING, LLC	32.1371	-103.3004	H	2021	0	22,140	22,073	-	WOLFCAMP, WEST

API	Well Name	Well Type	Well Status	Operator	Latitude	Longitude	Well Bore Direction	Spud Year	True Vertical Depth	Measured / Proposed Depth	Plugback Depth	Plug Date	Target Zones / Associated Pools
30-025-48783	BLACK MARLIN FEDERAL COM #216H	Oil	New	TAP ROCK OPERATING, LLC	32.1374	-103.2996	H	2021	0	22,258	22,258	-	WOLFCAMP, WEST
30-025-49115	BLUE MARLIN FEDERAL COM #111H	Oil	New	TAP ROCK OPERATING, LLC	32.1093	-103.3105	H	-	0	20,039	0	-	BONE SPRING
30-025-49116	BLUE MARLIN FEDERAL COM #112H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3105	H	-	0	20,217	0	-	BONE SPRING
30-025-49117	BLUE MARLIN FEDERAL COM #201H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3102	H	2021	11,613	21,985	21,923	-	WOLFCAMP, WEST
30-025-49118	BLUE MARLIN FEDERAL COM #202H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3056	H	2021	11,539	21,929	21,866	-	WOLFCAMP, WEST
30-025-49119	BLUE MARLIN FEDERAL COM #205H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3101	H	2021	11,533	21,980	21,916	-	WOLFCAMP, WEST
30-025-49120	BLUE MARLIN FEDERAL COM #211H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3103	H	2021	12,148	22,554	22,495	-	WOLFCAMP, WEST
30-025-49121	BLUE MARLIN FEDERAL COM #215H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3057	H	2021	11,720	22,188	22,120	-	WOLFCAMP, WEST
30-025-49196	BLUE MARLIN FEDERAL COM #212H	Oil	New	TAP ROCK OPERATING, LLC	32.1094	-103.3055	H	2021	12,003	22,422	22,389	-	WOLFCAMP, WEST
30-025-49528	DOGWOOD 25 36 20 FEDERAL COM #112H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2924	H	2021	0	22,356	0	-	WOLFCAMP, WEST
30-025-49626	DOGWOOD 25 36 20 FEDERAL COM #116H	Oil	New	AMEREDEV OPERATING, LLC	32.1092	-103.2842	H	-	0	22,080	0	-	WOLFCAMP, WEST
30-025-49974	INDEPENDENCE AGI #002	AGI	New	Pinon Midstream, LLC	32.1201	-103.2910	D	2022	17,683	18,080	0	-	DEVONIAN-FUSSELMAN
30-025-50391	SIOUX 25 36 STATE FEDERAL COM #020H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	22,710	0	-	UPPER WOLFCAMP
30-025-50392	SIOUX 25 36 STATE FEDERAL COM #021H	Oil	New	CAZA OPERATING, LLC	32.1084	-103.3172	H	-	0	20,244	0	-	BONE SPRING
30-025-50393	SIOUX 25 36 STATE FEDERAL COM #022H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	22,539	0	-	UPPER WOLFCAMP
30-025-50394	SIOUX 25 36 STATE FEDERAL COM #023H	Oil	New	CAZA OPERATING, LLC	32.1083	-103.3172	H	-	0	20,120	0	-	BONE SPRING

Appendix 4 - References

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Appendix 5 - Abbreviations and Acronyms

Abbreviations and acronyms not otherwise defined herein:

3D – 3 dimensional
API – American Petroleum Institute
CFR – Code of Federal Regulations
EOS – Equation of State
ft – foot (feet)
m – meter(s)
mg/l – milligrams per liter
MT -- Metric tonne
NG—Natural Gas
QA/QC – quality assurance/quality control
ST – Short Ton

Appendix 6 - Conversion Factors

Piñon reports CO_2 at standard conditions of temperature and pressure as defined in the State of New Mexico - 60°F and 15.025 psia (NMAC 19.15.2.7 (C)(16))

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the NIST. This online database is available at:

http://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner EOS at a wide range of temperatures and pressures.

At State of New Mexico standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.0027097 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb-moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2} = 0.0027097$$

$$MW_{CO2} = 44.0095$$

$$Density_{CO2} = 5.4092\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.4092\ x\ 10^{-2}\ \frac{MT}{Mcf}$$

The conversion factor 5.4092 x 10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Appendix 7 - Independence AGI Wells - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

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

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

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

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

Appendix 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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \quad \text{(Equation RR-2 for Pipelines)}$$

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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \quad \text{(Equation RR-2 for Containers)}$$

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

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,x} \qquad \text{(Equation RR-6)}$$

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

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

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

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

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.

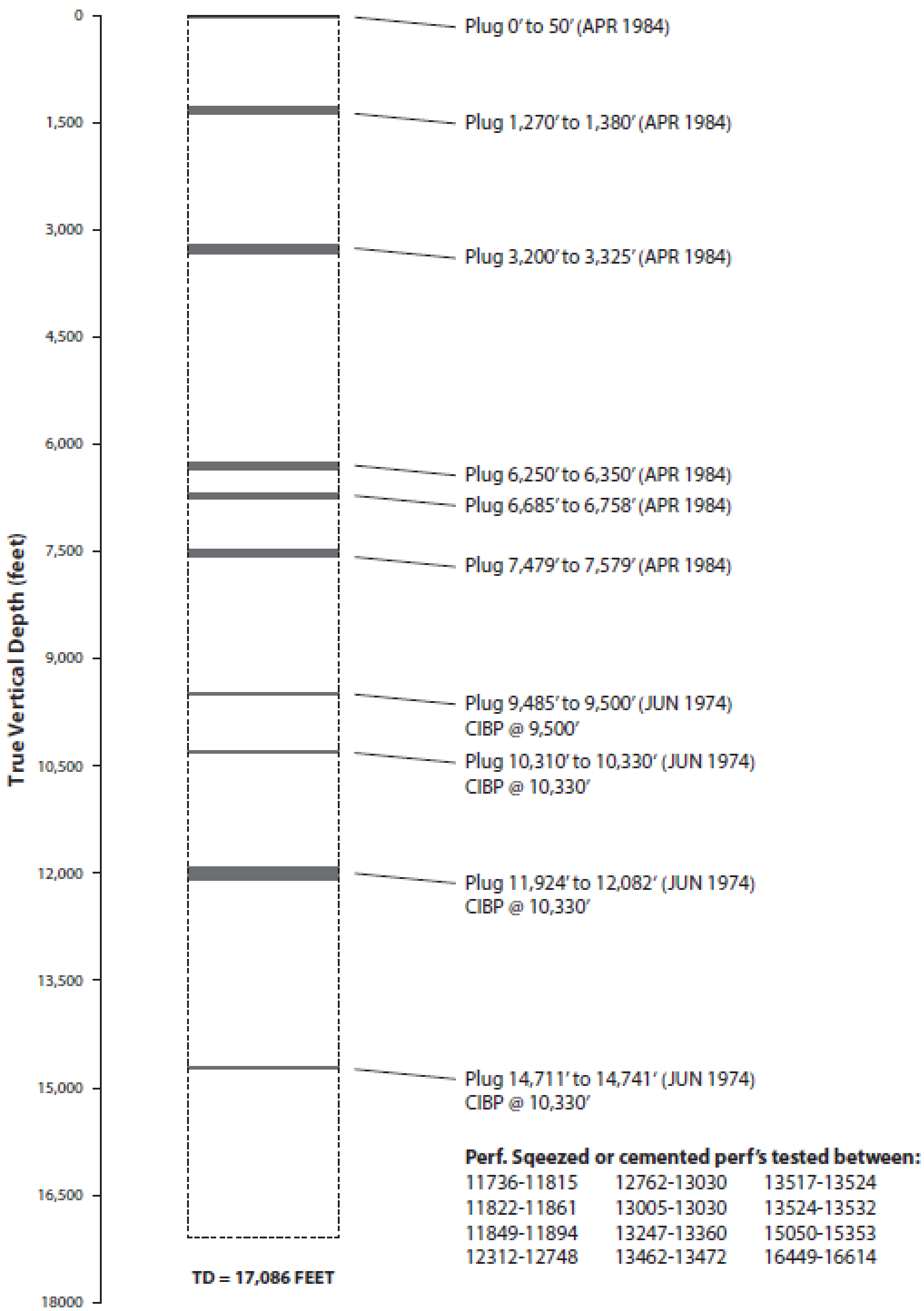
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

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 the GHGRP.

Appendix 9 - Plugging Records for West Jal Unit #1

TEXACO EXPLORATION AND PROD. - WEST JAL UNIT #1 PLUGGING DIAGRAM

Lease Name:	West Jal Unit #1	**Footage:**	1980 FNL and 660 FEL
API:	30-025-21172	**Well Type:**	Oil
Location:	Sec. 20, T25S, R36E	**Total Depth:**	17,086′
County, State:	Lea County, New Mexico	**Coordinates:**	32.117596, -103.280739 (NAD83)



*Schematic is properly scaled

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UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Buluu No. 1004-0135
Expires: March 31, 1993

5. Lease Designation and Serial No.
NJ

SUNDRY NOTICES AND REPORTS ON WELLS
Do not use this form for proposals to drill or to deepen or reentry to a different reservoir.
Use "APPLICATION FOR PERMIT-" for such proposals

SUBMIT IN TRIPLICATE

7. If Unit or CA, Agreement Designation

1. Type of Well
[X] Oil Well [ ] Gas Well [X] Other Reentry

8. Well Name and No.
f JA-/t:Jt!JLA-ffy

2. Name of Operator
MCH Petroleum Services

9. API Well No.
c30-025-2/112

3. Address and Telephone No.
-:1:)1 W. Ptw St: Midland, Tx 79705 915 683 4772

10. Field and Pool, or Exploratory Area
~~Undesignated~~ W.-SAl Delaware

4. Location of Well (footage, Sec., T., R., M., or Survey Description)
/'f4!0 PAt ,o FGL -S Z.0 , r- zs-S, 11- 'Tt'=
H S£NE 6J-,)1 h\.

11. County or Parish, State
Lea, NM

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

TYPE OF SUBMISSION	TYPE OF ACTION	
[g] Notice of Intent	D Abandonment	0 Change of Plans
	Recompletion	D New Construction
[J Subsequent Report	D Plugging Back	0 Non-Routine Fracturing
	D Casing Repair	[ ] Water Shut-Off
[ ] Final Abandonment Notice	D Altering Casing	D Conversion to Injection
	Other eNtAy	D Dispose Water
		(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abandoned by Texaco in 1983. MCH will drill out cement plugs and cibp@ 7,579' to a total depth of approx. 8,350'(inside casing). This will leave in place cibp at 9,500' and deeper. We will then test existing perforations@ 7,807'-7,857' and stimulate as necessary.
Mud Program: Fresh water will be used for the reentry inside casing.
BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO
GENERAL REQUIREMENTS AND
SPECIAL STIPULATIONS
ATTACHED

14. I hereby certify that the foregoing is true and correct
Signed Craig Huber Title Owner Date 4/13/93

(This space for Federal or State office use)
Approved by ''' 1ITC &r.n L MA ron; Title AR-A MANAG. Date JUN 4 1993
Conditions of approval, if any:

Title 18 U.S.C. Section 1001, makes 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.

*See Instruction on Reverse Side

G 31

Form 3160-3
(December 1990)

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 1004–0136
Expires: December 31, 1991

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR DEEPEN

1a. TYPE OF WORK: DRILL ☐ DEEPEN ☐

b. TYPE OF WELL: OIL WELL ☒ GAS WELL ☐ OTHER Reentry SINGLE ZONE ☒ MULTIPLE ZONE ☐

2. NAME OF OPERATOR: MCH Petroleum Services

3. ADDRESS AND TELEPHONE NO.: 708 W. Pine St., Midland, Tx 79705 915 683 4772

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*)
At surface 1980' FNL, 660' FEL sec 20 T-25S, R-36E Lea Co. NM
At proposed prod. zone SAme H SENE

5. LEASE DESIGNATION AND SERIAL NO.: NM 71792

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

7. UNIT AGREEMENT NAME:

8. FARM OR LEASE NAME, WELL NO.: West JAl Federal #1

9. API WELL NO.: 30-025-21172

10. FIELD AND POOL, OR WILDCAT: ~~Abandoned~~ W. JAl Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: S-20, T-25S, R36E

14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE*: 6 miles W. JAl, N.M.

12. COUNTY OR PARISH: Lea

13. STATE: NM

15. DISTANCE FROM PROPOSED* LOCATION TO NEAREST PROPERTY OR LEASE LINE, FT. (Also to nearest drlg. unit line, if any): 660'

16. NO. OF ACRES IN LEASE: 600

17. NO. OF ACRES ASSIGNED TO THIS WELL: 40

18. DISTANCE FROM PROPOSED LOCATION* TO NEAREST WELL, DRILLING, COMPLETED, OR APPLIED FOR, ON THIS LEASE, FT.:

19. PROPOSED DEPTH: 8350

20. ROTARY OR CABLE TOOLS: Pulling unit/Reverse unit

21. ELEVATIONS (Show whether DF, RT, GR, etc.): 3076' GL

22. APPROX. DATE WORK WILL START*: ASAP (Prior to 6/1/93 exp.)

23. PROPOSED CASING AND CEMENTING PROGRAM

SIZE OF HOLE	GRADE, SIZE OF CASING	WEIGHT PER FOOT	SETTING DEPTH	QUANTITY OF CEMENT
26	20		869' (In Place)	1630 sx.
17½	13 3/8	72, 68, 64	6300' (In Place)	3606 sx.
12¼	9 5/8	53.5, 47, 43.5	11,736 (in Place)	775 sx.
8 3/8	7	26	6735-12213 (Shot off @ 6735)	612 sx
6¼	5½ (LNR.)	(unk.)	12,032-15,400	450 sx.
(unk)	3½ (LNR.)	(unk)	14,967-17,084	250 sx.

MCH Petroleum Services proposes to reenter existing well originally drilled by Skelly Oil Company in 1961 and plug and abondoned by Texaco in 1983. MCH will drill out cement plugs and cibp @ 7,579' to a total depth of approx. 8,350' (inside casing). This will leave in place cibp at 9,500' and deeper. We will then test existing perforations @ 7,807'-7,857' and stimulate as necessary.

Mud Program: Fresh water will be used for the reentry inside casing.

BOP Program: BOP will be installed at the beginning and tested daily.

APPROVAL SUBJECT TO GENERAL REQUIREMENTS AND SPECIAL STIPULATIONS ATTACHED

IN ABOVE SPACE DESCRIBE PROPOSED PROGRAM: If proposal is to deepen, give data on present productive zone and proposed new productive zone. If proposal is to drill or deepen directionally, give pertinent data on subsurface locations and measured and true vertical depths. Give blowout preventer program, if any.

24.

SIGNED Craig Huber TITLE Owner DATE 4/13/93

(This space for Federal or State office use)

PERMIT NO. ______ APPROVAL DATE ______

Application approval 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.

CONDITIONS OF APPROVAL, IF ANY:

APPROVED BY ______ TITLE ______ DATE ______

*See Instructions On Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

Form 3160-5
(November 1983)
(Formerly 9-331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

P.O. BOX 1980
HOBBS, NEW MEXICO 88240

Form approved.
Budget Bureau No. 1004-0135
Expires August 31, 1985

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

1. OIL WELL [X] GAS WELL [ ] OTHER

7. UNIT AGREEMENT NAME
West Jal Unit

2. NAME OF OPERATOR
Getty Oil Company

8. FARM OR LEASE NAME

3. ADDRESS OF OPERATOR
P.O. Box 730, Hobbs, NM 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

Unit Ltr. H, 1980' FNL & 660' FEL

10. FIELD AND POOL, OR WILDCAT
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, T-25S, R-36E

BUREAU OF LAND ... APR ... DIST. 6 N. M. ROSWELL, NEW MEXICO

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138' D.F.

12. COUNTY OR PARISH
Lea

13. STATE
NM

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	[ ]	PULL OR ALTER CASING	[ ]	WATER SHUT-OFF	[ ]	REPAIRING WELL	[ ]
FRACTURE TREAT	[ ]	MULTIPLE COMPLETE	[ ]	FRACTURE TREATMENT	[ ]	ALTERING CASING	[ ]
SHOOT OR ACIDIZE	[ ]	ABANDON*	[ ]	SHOOTING OR ACIDIZING	[ ]	ABANDONMENT*	XX
REPAIR WELL	[ ]	CHANGE PLANS	[ ]	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

3/26/84 Rigged up. Pulled rods and pump. Unseat tbg. anchor and install BOP.
3/28/84 Pulled 2 7/8" buttress & 2 3/8" tbg. anchor. Ran 7" CI plug, set @ 7579'. Ran 2 3/8' to 4290'. By Halliburton, circ. 191 bbls. gel brine, pulled tbg. Perfs 4-0.25" holes @ 6400'. Circ. out 7" between 9 5/8". Ran 2 7/8" to 7554'.
3/29/84 Rigged up csg. puller unit. Pulled tbg. Remove BOP & 7" tbg. spool.
3/30/84 Weld 7" pull nipple. Cut 7" csg. @ 6735'. Pulled 11 jts 7", 26#, P-110 csg. 8 rd.
3/31/84 Layed down total 163 jts (est. 6525') 7", 8rd casing. Nipple down 9 5/8" head.
4/2/84 Weld on 9 5/8" pulled nipple. Attempted to pull slips with 500,000#. Set off primer cord around head, no movement. Left soaking in penetrating oil.
4/3/84 Dug out 13 3/8" csg. unflange head. Move pipe 1" with 600,000#. Cut off. Pulled nipple, installed BOP. Ran tbg to 5216'.
4/4/84 Spot 20 sxs cement on top of CIBP 7579-7479'. Spot 100' plug (45 sxs) at 6758-6685', 6350-6250', 3325-3200', 1380-1270'. Remove csg. head.
4/5/84 Rigged down. Installed 20 sxs. Plugged 0-50'. Installed dry hole marker. P&A.

18. I hereby certify that the foregoing is true and correct

SIGNED Donald J. Steinnerd TITLE Area Superintendent DATE April 11, 1984

for ~~Dale R. Crockett~~

(This space for Federal or State office use)

Orig. Sgd. ...

APPROVED BY ______ TITLE ______ DATE 6 8 8 7

CONDITIONS OF APPROVAL, IF ANY:

Approved as to plugging of the well bore. Liability under bond is retained until surface restoration is completed.

0+6-BLM-Roswell 1-Mr. J.A.-Midland
1-File 1-Laura Richardson-Midland
1-Engr Jim 1-BB, 1-JA
1-Foreman CK 1-SH, 1-CP 1-Southland Royalty Company, 1-ARCO

*See Instructions on Reverse Side

Title 18 U.S.C. Section 1001, makes 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.

N. M. OIL CONS. COMMISSION
P. O. BOX 1980
HOBBS, NEW MEXICO 88240

O+6 - BLM - P.O. Box 1857, Roswell, 1-File, 1-Engr.JIM, 1-Foreman CK

Form 9-331
Dec. 1973

1 - Laura Richardson-Midland

Form Approved.
Budget Bureau No. 42-R1424

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

BUREAU OF LAND MANAGEMENT
RECEIVED
JUL 25 1983
ROSWELL, NEW MEXICO

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 Form 9-331-C for such proposals.)

1. oil well XX gas well ☐ other

DIST. 6 N. M.

2. NAME OF OPERATOR
Getty Oil Company

3. ADDRESS OF OPERATOR
P.O. Box 730 Hobbs, NM 88240

4. LOCATION OF WELL (REPORT LOCATION CLEARLY. See space 17 below.)
AT SURFACE: Unit ltr. H, 1980' FNL & 660 FEL
AT TOP PROD. INTERVAL:
AT TOTAL DEPTH:

5. LEASE
NM-03429A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME
West Jal Unit

9. WELL NO.
1

10. FIELD OR WILDCAT NAME
West Jal Delaware

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20, 25S-36E

12. COUNTY OR PARISH
Lea

13. STATE
NM

14. API NO.

15. ELEVATIONS (SHOW DF, KDB, AND WD)
3138' D.F.

16. CHECK APPROPRIATE BOX TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

	REQUEST FOR APPROVAL TO:	SUBSEQUENT REPORT OF:
TEST WATER SHUT-OFF	☐	☐
FRACTURE TREAT	☐	☐
SHOOT OR ACIDIZE	☐	☐
REPAIR WELL	☐	☐
PULL OR ALTER CASING	☐	☐
MULTIPLE COMPLETE	☐	☐
CHANGE ZONES	☐	☐
ABANDON*	XX	☐
(other) Revised		

(NOTE: Report results of multiple completion or zone change on Form 9-330.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

Revised procedure as per conversation with Mr. Peter Chester 7/18/83:

1. Install B.O.P.
2. Set C.I.B.P. at +7860 w/35' cement on top.
3. Perforate 2 holes @ 6375' & squeeze with sufficient cement to bring cement to 6225'.
4. Set cement plug 1230-1330' top of salt. (in & behind casings).
5. Set 50' surface plug.
6. Install dry hole marker.
7. Restore location.

Subsurface Safety Valve: Manu. and Type ______ Set @ ______ Ft.

18. I hereby certify that the foregoing is true and correct

SIGNED Dale R. Crockett TITLE Area Superintendent DATE July 22, 1983

APPROVED

(This space for Federal or State office use)

APPROVED BY (Orig. Sgd.) ... M. CHESTER TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

SEP 14 1983

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE* (See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG *

5. LEASE DESIGNATION AND SERIAL NO.: NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: - - - - - -

7. UNIT AGREEMENT NAME: - - - - - -

8. FARM OR LEASE NAME: West Jal Unit

9. WELL NO.: 1

10. FIELD AND POOL, OR WILDCAT: UNDESIGNATED Jal Delaware, West

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec. 20-25S-36E

12. COUNTY OR PARISH: Lea

13. STATE: New Mexico

1a. TYPE OF WELL: OIL WELL [X] GAS WELL [ ] DRY [ ] Other

b. TYPE OF COMPLETION: NEW WELL [ ] WORK OVER [ ] DEEP-EN [ ] PLUG BACK [X] DIFF. RESVR. [X] Other

2. NAME OF OPERATOR: Skelly Oil Company

3. ADDRESS OF OPERATOR: P. O. Box 1351, Midland, Texas 79701

4. LOCATION OF WELL (*Report location clearly and in accordance with any State requirements*)*
At surface: Unit Letter H, 1980' FNL and 660' FEL, Sec. 20-25S-36E
At top prod. interval reported below
At total depth

14. PERMIT NO. | DATE ISSUED

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (*Ready to prod.*)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
- -	- -	5-28-74	3138' DF	- - -

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
17086'	9485' PBTD	- -	→	- -	- -

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*: 7807-7857' Delaware

25. WAS DIRECTIONAL SURVEY MADE: - - -

26. TYPE ELECTRIC AND OTHER LOGS RUN: None

27. WAS WELL CORED: - -

28. CASING RECORD (*Report all strings set in well*)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
No Change					

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
-	-	-	-	-
-	-	-	-	-

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-3/8"OD	7941'	- -
2-7/8"OD		- -

31. PERFORATION RECORD (*Interval, size and number*): 7807-7811', 7816-7828', 7853-7857', total 32 shots, 0.50" diameter, two shots per foot.

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
7807-7857'	750 gallons mud acid 5000 gallons 15% NE acid, 82 ball sealers, 9000# 20-40 sand, 9000 gallons lease oil

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (*Flowing, gas lift, pumping—size and type of pump*)	WELL STATUS (*Producing or shut-in*)
5-28-74	Pumping	Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
6-19-74	24	-	→	63	1	6	16

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
- -	63#	→	63	1	6	41°

34. DISPOSITION OF GAS (*Sold, used for fuel, vented, etc.*): Used for Fuel

TEST WITNESSED BY

35. LIST OF ATTACHMENTS: None

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED (Signed) D. R. Crow D. R. Crow TITLE Lead Clerk DATE 6-20-74

*(See Instructions and Spaces for Additional Data on Reverse Side)

INSTRUCTIONS

General: This form is designed for submitting a complete and correct well completion report and log on all types of lands and leases to either a Federal agency or a State agency, or both, pursuant to applicable Federal and/or State laws and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local, area, or regional procedures and practices, either are shown below or will be issued by, or may be obtained from, the local Federal and/or State office. See instructions on items 22 and 24, and 33, below regarding separate reports for separate completions.

If not filed prior to the time this summary record is submitted, copies of all currently available logs (drillers, geologists, sample and core analysis, all types electric, etc.), formation and pressure tests, and directional surveys, should be attached hereto, to the extent required by applicable Federal and/or State laws and regulations. All attachments should be listed on this form, see item 35.

Item 4: If there are no applicable State requirements, locations on Federal or Indian land should be described in accordance with Federal requirements. Consult local State or Federal office for specific instructions.

Item 18: Indicate which elevation is used as reference (where not otherwise shown) for depth measurements given in other spaces on this form and in any attachments.

Items 22 and 24: If this well is completed for separate production from more than one interval zone (multiple completion), so state in item 22, and in item 24 show the producing interval, or intervals, top(s), bottom(s) and name(s) (if any) for only the interval reported in item 33. Submit a separate report (page) on this form, adequately identified, for each additional interval to be separately produced, showing the additional data pertinent to such interval.

Item 29: "*Sacks Cement*": Attached supplemental records for this well should show the details of any multiple stage cementing and the location of the cementing tool.

Item 33: Submit a separate completion report on this form for each interval to be separately produced. (See instruction for items 22 and 24 above.)

37. SUMMARY OF POROUS ZONES:
SHOW ALL IMPORTANT ZONES OF POROSITY AND CONTENTS THEREOF; CORED INTERVALS; AND ALL DRILL-STEM TESTS, INCLUDING DEPTH INTERVAL TESTED, CUSHION USED, TIME TOOL OPEN, FLOWING AND SHUT-IN PRESSURES, AND RECOVERIES

FORMATION	TOP	BOTTOM	DESCRIPTION, CONTENTS, ETC.

38. GEOLOGIC MARKERS

NAME	TOP	
	MEAS. DEPTH	TRUE VERT. DEPTH

1) Squeezed Fusselman perfs. 16,449-16,614' with 100 sacks Class "H" cement, 5/10% CFR-2.
2) Spotted 25 sacks cement 14,711-14,741', 25 sacks 11,924-12,082' and set cast iron bridge plug at 10,330' and spotted 4 sacks cement 10,310-10,330'.
3) Perforated 7" OD casing in First Bone Springs formation with two 0.48 diameter holes per foot at 10,112-10,122' and 10,128-10,132'. (28 shots total)
4) Treated First Bone Springs perfs. 10,112-10,132 with 5500 gallons acid and 68 ball sealers.
5) Swab tested First Bone Springs perfs. 10,112-10,132' May 14, 1974, to May 21, 1974, for no oil, 14 bbls. water and slight show of gas in 5 hours.
6) Set cast iron bridge plug at 9500' and cemented with 3 sacks cement plugging back to 9485'.
7) Perforated 7" OD casing in Delaware formation with two 0.50" diameter holes per foot at 7807-7811', 7816-7824' and 7853-7857'. (32 shots total)
8) Treated Delaware perfs. 7807-7857' with 750 gallons mud acid, 5000 gallons 15% HE acid, 9000 gallons gelled lease oil, 9000# 20-40 sand and 22 ball sealers.
9) Returned well to production status 5-28-74 pumping Delaware perfs. 7807-7857' for 63 bbls. oil, 6 bbls. water and 1 MCFGPD.

8) Flowed 24-1/2 hours through 1" choke, making no oil, 45 bbls. load water, 393 bbls. formation water and gas at rate of 266 MCF per day. FTP 200#, CP 2300#.
9) Ran flow meter, Gradionometer and Temperature Survey to determine water entry.
10) Shut well in seven hours, then ran Base Temperature Log 16,000-17,020'. Water channelling from bottom of well bore to 16,508'.
11) Set cement retainer at 16,250' and squeezed perfs. 16,499-16,614' with 150 sacks Class "H" cement containing 4/10ths of 1% CFR-2 and 1% Halad 9. Squeeze failed. WOC 4 hours.
12) Resqueezed perfs. 16,449-16,614' with 50 sacks Class "H" cement with 1% Halad 9, 4/10ths of 1% CFR-2 and 1/4# Flocele per sack and 150 sacks Class "H" containing 1% Halad 9 and 4/10ths of 1% CFR-2. Squeeze failed.
13) Attempted to pull cement retainer - stuck.
14) Milled and pushed cement retainer from 16,250' to 16,490'. Recovered cement retainer.
15) Drilled and pushed junk to 16,930'.
16) Ran 254 jts. (14,793') of 2-7/8" OD tubing and set packer at 14,810'. Swabbed 9 hours, recovering 60 bbls. load water with good show of gas.
17) Treated perfs. 16,449-16,614' with 500 gals. 15% NE acid with 2 ball sealers. Swabbed 7 hours, recovering 1 bbl. load water, flowing gas at rate of 50 MCF per day.
18) Treated perfs. 16,449-16,614' with 5000 gals. 15% NE acid and 27 ball sealers.
19) Ran Temperature Survey 15,000-16,958'.
20) Tested well. Well flowed at rate of 910 MCF per day on 23/64" choke, no oil, FTP 310#. Pulled tubing and packer.
21) Reran 457 jts. (14,940') of 2-7/8" OD 7.9# DSS-HT Atlas-Bradford Condition "A" tubing and set at 14,967'.
22) Circulated hole with corrosion inhibitor water. Released rig 11-8-72. Flowed and tested well.
23) On Dec. 11, 1972, treated perfs 16,449-16,614' with 12,500 gals. of 1% KCL water with 62# friction reducer, 25 gals. Adofoam and 25 gals. scale inhibitor, 20,000 gals. 20% retarded acid with 100# friction reducer, 40 gals. Adofoam, 160 gals. acid inhibitor, 1000# fluid loss agent and 40 gals. scale inhibitor and 7 ball sealers. All fluid contained 400 S.C.F Nitrogen per barrel.
24) Testing well.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 1351, Midland, TExas 79701

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Undesignated Fusselman

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3076' GR

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF ☐ PULL OR ALTER CASING ☐
FRACTURE TREAT ☐ MULTIPLE COMPLETE ☐
SHOOT OR ACIDIZE ☐ ABANDON* ☐
REPAIR WELL ☐ CHANGE PLANS ☐
(Other)

SUBSEQUENT REPORT OF:

WATER SHUT-OFF ☐ REPAIRING WELL ☐
FRACTURE TREATMENT ☐ ALTERING CASING ☐
SHOOTING OR ACIDIZING ☐ ABANDONMENT* ☐
(Other) Clean out & deepen to 17,086' x

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

1) Rigged up rotary tools 7-28-72. Pulled tubing and packer.
2) Set cement retainer at 11,390' and squeezed Strawn 7" OD casing perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 1% CFR-2 and 3# sand per sack. Squeeze failed. WOC 4 hours.
3) Resqueezed perfs. 11,510-11,741' with 100 sacks Class "H" cement containing 5/10% of 1% CFR-2 and 3# sand per sack. Squeezed at 6500#. Reversed out 15 sacks.
4) After WOC 12 hours, drilled cement retainer at 11,390' and cement 11,390-11,755' with 6-1/2" bit.
5) Tested squeeze job to 3000#; held okay.
6) Drilled cement 11,790-11,832' and tested old squeeze job on perfs. 11,736-11,815' to 3000#; held okay.
7) Drilled cement 11,832-11,844'; pushed plus-plug to 11,976'. Drilled plug. Tagged junk at 12,002' and pushed to 12,312'.
8) Cleaned to top of 5-1/2" OD liner at 12,032', set cement retainer at 11,820' and found casing perfs. 11,849-11,894' open.
9) Squeezed 5-1/2" casing perfs. 11,849-11,894' with 50 sacks Class "H" with 1% CFR-2 and 100 sacks Class "H" with 1% CFR-2 and 3# sand per sack.
10) Dumped 20 sacks cement on retainer at 11,820', plugging back to 11,717'. Reversed out 90 sacks cement. WOC 12 hours.

(continued on page 2)

18. I hereby certify that the foregoing is true and correct

SIGNED ______ TITLE Lead Clerk DATE Dec. 18, 1972

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______
CONDITIONS OF APPROVAL, IF ANY:

ACCEPTED FOR RECORD
DEC 20 1972
U. S. GEOLOGICAL SURVEY
HOBBS, NEW MEXICO

*See Instructions on Reverse Side

11) Drilled cement 11,708-11,820'; cement retainer 11,820-11,822' and cement 11,822-11,861'. Cleaned out to top of liner at 12,032'.
12) Tested squeeze job to 2500#; held okay.
13) Drilled junk 12,312-12,748.5'; cement 12,748.5-12,760'; junk to 12,762'; cement 12,762-13,030'.
14) Tested old squeezed perfs. 13,005-13,030' to 2500#; held okay.
15) Milled and drilled cast iron bridge plug at 13,174' and pushed to 13,395'.
16) Tested 5-1/2" OD liner perfs. 13,247-13,360' to 2900#; could not pump into perfs.
17) Milled cast iron bridge plug 13,396-13,400'.
18) Tested perfs. 13,462-13,472' to 2700#; could not pump into perfs.
19) Milled and drilled out cement retainer 13,517-13,524'; cement 13,524-13,532'; cement 15,050-15,353'.
20) Milled and drilled cast iron bridge plug 15,340-15,858'. Washed over fish 15,858'; recovered fish. Cleaned out to old TD of 15,958'.
21) Drilled 4-3/4" new hole 15,958-16,498'.
22) Ran Drill Stem Test No. 1 (Silurian) 15,400-16,498'.
23) Drilled 4-3/4" hole 16,498' to total depth of 17,086' at 11 p.m. October 4, 1972.

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instruction on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

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—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO. NM - 03429 - A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME - - -

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME - - -

2. NAME OF OPERATOR: Skelly Oil Company

8. FARM OR LEASE NAME: West Jal Unit

3. ADDRESS OF OPERATOR: P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO. 1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1980' FNL and 660' FEL Section 20-25S-36E

10. FIELD AND POOL, OR WILDCAT: Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: 20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.): 3102' DF

12. COUNTY OR PARISH: Lea

13. STATE: New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF ☐ PULL OR ALTER CASING ☐
FRACTURE TREAT ☐ MULTIPLE COMPLETE ☐
SHOOT OR ACIDIZE ☐ ABANDON* ☐
REPAIR WELL ☐ CHANGE PLANS ☐
(Other) ☐

SUBSEQUENT REPORT OF:

WATER SHUT-OFF ☐ REPAIRING WELL ☐
FRACTURE TREATMENT ☐ ALTERING CASING ☐
SHOOTING OR ACIDIZING ☐ ABANDONMENT* ☐
(Other) Cement, perforate & treat ☒

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

1) Perforated 2-7/8"OD tubing at 11,696',11,297', 10,574; 9698'; 8892';8707',8403'. Circulated to remove mud from annulus. Work began 1-29-69.
2) Pulled tubing
3) Ran 2-7/8"OD tubing with "RTTS" Packer. Set packer at 11,448'.
4) Squeezed 7"OD casing perforations 11,736-11,894' with 150 sacks class "H" Cement with 1% CFR-2 per sack, maximum pressure 4600#, failed. W.O.C. 4 hours. Broke formation down with 5000#.
5) Squeezed 7"OD casing perforations 11,736-11,894" with 50 sacks Class "H" cement with 1% CFR-2 and 5# No. 3 sand per sack. Displaced 35 sacks into formation. Pulled tubing and packer.
6) WOC 36 hours. Ran tubing with 6-1/8" bit. Top of cement inside 7"OD casing at 11,595'. Washed and circulated cement to 11,620'. Drilled cement 11,620-11,700'. Drilled packer 11,700-705'. Drilled cement 11,705-755'.
7) Tested casing to 3000#, held okay.
8) Spotted 12 bbls. acid 11,755-11,443'.
9) Perforated 7"OD casing with 2 shots per foot as follows:

11,510 - 513'	3'	6 shots
11,517- 527'	10'	20 shots
11,536 - 540'	4'	8 shots
11,550 - 556'	6'	12 shots
11,561 - 567'	6'	12 shots
11,575 - 579'	4'	8 shots
11,660 - 667'	7'	14 shots

18. I hereby certify that the foregoing is true and correct

SIGNED ____________ TITLE District Production Manager DATE 3-10-69

(This space for Federal or State office use)

APPROVED BY ____________ TITLE (ORIGINAL SIGNED) V. H. Fletcher

CONDITIONS OF APPROVAL, IF ANY:

APPROVED
MAR 11 1969
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
~~73503~~ NM-034291

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

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—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
----

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface **1980 from North line and 660 from East line, Section 20**

20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Strawn Formation

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3092' DF

12. COUNTY OR PARISH **Lea**

13. STATE **New Mexico**

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐
REPAIR WELL	☐	CHANGE PLANS	☐
(Other) **Cement, Perforate & Treat**			☒

SUBSEQUENT REPORT OF:

WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
(Other)			☐

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

Squeeze present perforated interval 11,736-11,852', below packer set at 11,700', with 125 sacks cement. Drill out to 11,790'. Perforate 11,510-11,783' with 2 shots per foot. Treat perforations 11,510-11,783' with 300 gallons 15% acid with 3 stage treatment using Dowell J-182 as diverting agent. Inject 72 barrels distillate to remove diverting agent. Swab and test.

18. I hereby certify that the foregoing is true and correct

SIGNED (signed) C. R. DAVIS TITLE **District Operations Manager** DATE **1/24/69**

(This space for Federal or State office use)

APPROVED BY ______________ TITLE ______________

CONDITIONS OF APPROVAL, IF ANY:

APPROVED

JAN 2_ 1969

J. L. GORDON
ACTING DISTRICT ENGINEER

RT/jc

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

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—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
- -

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME
- -

2. NAME OF OPERATOR
Skelly Oil Company

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

1980' from North line and 660' from East line

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
20-25S-36E

14. PERMIT NO.
- -

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138'

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Eliminate water production			X
(Other)			☐	(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)			

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

(1) Moved in and rigged up workover rig 10-21-68
(2) Set Schlumberger "plus" plug in 7"OD casing at 11,844'.
(3) Dumped 5' cement on top of plug, filling from 11,844' to 11,839'.
(4) Dumped 200 lbs. Hydromite on top of "plus" plug, filling back to 11,832'.
(5) Swabbed well.
(6) Apparent communications still exist between upper and lower perforations behind 7"OD casing. Objective to shut off lower perforations 11,860 - 11,894' and to decrease water production unsuccessful.
(7) Well returned to producing status 10-27-68 flowing 150 MCF gas per day through 7" OD casing perforations 11,736 - 11,894'.

18. I hereby certify that the foregoing is true and correct

SIGNED [signature] TITLE District Production Manager DATE 10-30-68

(This space for Federal or State office use)

APPROVED BY ____________ TITLE ____________ APPROVED
CONDITIONS OF APPROVAL, IF ANY:

NOV , 1968

J L GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
NM - 03429 - A

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—" for such proposals.)

6. IF INDIAN, ALLOTTEE OR TRIBE NAME
-----

1. OIL WELL ☐ GAS WELL XX OTHER

7. UNIT AGREEMENT NAME
-----

2. NAME OF OPERATOR
SKELLY OIL COMPANY

8. FARM OR LEASE NAME
West Jal Unit

3. ADDRESS OF OPERATOR
P. O. Box 730 - Hobbs, New Mexico 88240

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

1980' FNL & 660' FEL Sec. 20-25S-36E

10. FIELD AND POOL, OR WILDCAT
Jal Strawn West

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 20-25S-36E

14. PERMIT NO.
-----

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
3138' DF

12. COUNTY OR PARISH
Lea

13. STATE
New Mexico

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other) Clean, Determine Water Source, Eliminate Water Production			X
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

Moved in and rigged up Workover Rig. Killed well. Ran 1-5/8" drill pipe and fishing tools to top of fish at 9901', pushed to 9991', caught fish, circulated and pulled out of hole. Recovered 2 strings of fishing tools previously left in hole. Reran 1-5/8" drill pipe several times with fishing tools and recovered 1786' in several pieces of 5/16" wire line, and a chemical cutter.

Tagged bottom of 2-7/8"OD tubing at 11,715'. Knocked off one foot of tubing and a bull plug that had been previously cut off. Pushed and drove bull plug to 12,482'. Hit firm fill-up of formation cavings and left one-foot piece of 2-7/8"OD tubing and bull plug in hole at 12,482', leaving tubing open-ended at 11,715' with full 2-7/8" opening. Pulled drill pipe and fishing tools and installed Xmas tree. Ran Gradiomanometer, Continuous Flowmeter and Packer Flowmeter to determine water source. Surveys indicated water source being produced through casing perforations 11,883-11,894'.

Set packer at 11,883'. Returned to production status November 19, 1967, producing 38 bbls. oil, 800 bbls. water and 2,000 MCF gas per day from the Strawn Gas Pool through perforations 11736-11894' through 7"OD casing.

18. I hereby certify that the foregoing is true and correct

SIGNED (ORIGINAL SIGNED) V. E. Fletcher TITLE District Superintendent DATE April 25, 1968

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

APPROVED
APR 26 1968
J. L. GORDON
ACTING DISTRICT ENGINEER

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE*
(See other instructions on reverse side)

Form approved.
Budget Bureau No. 42-R355.5.

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. LEASE DESIGNATION AND SERIAL NO. NM-03429-A

6. IF INDIAN, ALLOTTEE OR TRIBE NAME ----------

7. UNIT AGREEMENT NAME ----------

8. FARM OR LEASE NAME West Jal Unit

9. WELL NO. 1

10. FIELD AND POOL, OR WILDCAT Undesignated Fusselman

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA Sec. 20-25S-36E

12. COUNTY OR PARISH Lea

13. STATE New Mexico

1a. TYPE OF WELL: OIL WELL ☐ GAS WELL ☒ DRY ☐ Other

b. TYPE OF COMPLETION: NEW WELL ☐ WORK OVER ☒ DEEP-EN ☒ PLUG BACK ☐ DIFF. RESVR. ☒ Other

2. NAME OF OPERATOR Skelly Oil Company

3. ADDRESS OF OPERATOR P. O. Box 1351, Midland, Texas 79701

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface 1980' FNL and 660' FEL Sec. 20-25S-36E
At top prod. interval reported below
At total depth

14. PERMIT NO. DATE ISSUED

15. DATE ~~SPUDDED~~ started 7-28-72 | 16. DATE T.D. REACHED 11-1-72 | 17. DATE COMPL. (Ready to prod.) 10-4-72 | 18. ELEVATIONS (DF, RKB, RT, GR, ETC.)* 3076' GR | 19. ELEV. CASINGHEAD ---

20. TOTAL DEPTH, MD & TVD 17,086' | 21. PLUG, BACK T.D., MD & TVD 17,020' | 22. IF MULTIPLE COMPL., HOW MANY* --- | 23. INTERVALS DRILLED BY → ROTARY TOOLS 15,958-17,086' | CABLE TOOLS ---

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)* 16,449-16,614' (Fusselman)

25. WAS DIRECTIONAL SURVEY MADE No

26. TYPE ELECTRIC AND OTHER LOGS RUN BHC Sonic Gamma Ray with Caliper, Dual Laterolog, Continuous Dipmeter, Compensated Neutron & Formation Density

27. WAS WELL CORED No

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
20"	94#	869'	26"	1630 sacks	None
13-3/8"	72,61 & 68#	6300'	17-1/2"	3206 sacks	None
9-5/8"	53.5 & 47#	11,732'	12-1/4"	975 sacks	None

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)
		(See attachment)		

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-7/8"	14,967'	None

31. PERFORATION RECORD (Interval, size and number)
16,449-16,614' (Fourteen .33" holes over 165' interval)

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
11,510-11,741'	200 sacks Class "H" Cement
11,849-11,894'	150 sacks Class "H" Cement
16,449-16,614'	350 sacks Class "H" Cement
	(See attachment)

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
11-1-72	Flowing	Producing

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
11-14-72	24	24/64"	→	-0-	5950	216	----

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
1900#	---	→	-0-	5950	216	---

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.) Sold

TEST WITNESSED BY

35. LIST OF ATTACHMENTS 2 copies each: Borehole Compensated Sonic Log - Gamma Ray, Compensated Neutron-Formation Density, Dual Laterolog, Gammatron

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED C.J. Love TITLE Dist. Prod. Manager DATE Dec. 20, 1972

*(See Instructions and Spaces for Additional Data on Reverse Side)

2MOIDJ31214

WILL RO. !.

Set Baker Calt Iron Bridge Plug at 13,400'. Spotted 2 aacka c••nt on top of bridge plug traa 13,-00' to 1.3,386'. Perto:rated 5-1/2" OD liner with 4 holea at 13,210' and 1queezed with 85 aacka ot caat. Drill.eel out oeaeat \o 13,386'• Perforated S-1/2" liner with 4 ahota per foot •• followa1 13,247-13,2'10', 13,272-1.3,275', 13,286-13,292', 13,298-13,320', 13,326-13,329', 1.3,343-13,345', 13,)56-13,360' tor a total ot 63• and 252 hol••• Treated tbroqh S-1/2" OD caaing liner pert•• 13,247-13,360' (intenala) with 2500 gallon• Mud Acid. Teated .-.11 Hftr&I houn with -n,lae to aall to meanre. Treated through 5-1/2" OD caeing liner perta. 13,21.7-13,360' (intenala) with 2500 gallons Mud Acid.. t'eelMI •li-'aeveral hN. with TOIUM to -11 to meaaure. Treated through S-1/2" OD casing liner pert▪• 13,247-IJ,'601 (intenala) with 10,000 galana 1,- llegular Acid. Teated well aenral houri with wi1111e to .all to m•an• Set Baker Caat Iron Model "I" Bridge Plug at 13,180'• Dmlpecl 2 eacka ot cement on top ot plug, wbieh pl11g nll b&ek tra 13,180' to 1.3,166•. Pertorat.ed 5-1/2" OD liner with bole• per toot froa 13,0051 to 13,030• for a total of 251 and 100 hol••• Treated thrcnlgh 5-1/2" OD liner perte. 13,00S-13,030' with 5,000 gallons 15C Regular Acid. Teated well N'Yer&I hove with TOluae \oo ▪-II to aeanre. We teaJ>I'?'8,ril7 abandoned the teat.inc ot the Morrow Zone at t.hie t.m, Set Halliburton "DC" C... nt Retainer at 12,790' and aqueesed 85 eaeke ot CtilHilt into 5-1/2" OD liner perte. 13,005-13,030•. Plugged back total depth 12,7901• Pertorat.ed 7" OD casing with 4 bolea per toot aa tollowa1 11,736-II,7U', 11,781-11,787', II,801-II,815t, II,&1+,-11,852', 11,860-U,894' tor a total ot 55t and 220 holea. Set Baker Model "7" Production Packer at 11,700'• Ran 2-7/8" OD 6.1+0# Blltre•• threat! 1-80 tubing to 11,715' and ....ted in Baker Model"'" Production Packer at 11,700' with pert▪• 11,711-II,715'. Ot.ia l.allding nipple position No. I at II,709'. Ot.1• aid• doar ahitt. valft at U,698'. otie landing nipple poaition lo. 2 at 10,700'. otil lending nipple position lo. 3 at 9700'• Opened well up and flowed to pit to clean up. Shut well in tor 89 hove. After 89 houra with dead night T.P. 6218# flowed and teated well 1n the toll.owing anner1

nowed 1-3/4 hour▪ on 10/64" choke, opening TP 6218# (W), FTP 6156pai., gas wltae 2,737 JEPPD and 7.6') 'bbl•• ot 52 degree correeted gra'Yit7 condenaate.
lu.t. two hour▪ tlowd through 12/64• ohoke, ITP 6075 pai. (17W), gas luae 4563 KCFPD .w1i and 6.60 bbla. of condenea.te.
lut two noura fiowd throUgh 14/6'+" choke, FTP 599S pei. (DW), gae wIUM 6025 MCFPD and. 1.70 bbl•• or oonden•t••
Rut one and one halt hours tl.owed through 16/64" choke, PTP 5915 p▪i• (IM), gas volUM 8009 ICFPD and undetel"llined 8JI0\1llt or oonclen▪ate to pita.
Eatabliahed 24 hour In Maioo Ooneel"'fttion C.-d.eaion AOF Potential ot 310,000 tcFFD. Completed Ja.,.17 22, 1963, a1 a "Wildcat" CCIII.J)letion in strawn (Penn117I'Y8Bian) toraation, Total cond.enate ree0Ye17 during 7-1/4 hn. t.eet waa 22,80 bbls. to tank and undetermined aaomt to pita.

Well now ahut in - waiting on ga• connection.

POBMATIOI RECORD

From	To	!!!i		
0	12,058	12,0,s		
12,058	12,152	94		
12,152	12,477	32,	Lime & Shale	- Top Atoka 12,152'
12,477	13,366	889	Sand	- Top Morrow 12,477'
13,366	14,S83	1,217	$ale	- Top Barp,ett Shale IJ,366•
14,583	14,685	102	Lhle	- 'lop Miasiaaippian 14,853'
14,685	1,,138	453	Chert	- Top Che. 14,685'
15,138	15,518	380	Shale	- Top Wood.torcl IS 131
15,518	15,958	440	L1M & Dolaite	- Top • {'5,518'
15,9?8	I5,9SI	Total Depth		
	12,790	Plugged Back Total Depth		

Geological Tops by Schlumberger Gama Ray Sonic log