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Technical Review of Subpart RR MRV Plan for Dry Piney Jackalope Gas Processing Facility

January 2026

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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 Blue Spruce Operating, LLC (BSO) for its carbon dioxide (CO₂) capture and storage (CCS) project, the Dry Piney Jackalope Gas Processing Facility and Dry Piney State Acid Gas Injection Wells, located in Sublette County, Wyoming. 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

The introduction of the MRV plan states that Blue Spruce Operating, LLC (BSO) is developing the Dry Piney Jackalope Gas Processing Facility (DPJGPF) in the southwest section of Sublette County, Wyoming. The plan explains the DPJGPF will process approximately 400 million standard cubic feet of gas per day of raw inlet gas produced from nine production wells that will be completed in the Madison Formation in and immediately adjacent to the federal Dry Piney Unit (DPU), located near the crest of the greater Labarge Field. The DPJGPF will utilize industrial gas processes to separate and refine products, such as helium and methane, from the raw gas stream, resulting in an acid gas waste gas stream that predominantly contains carbon dioxide and hydrogen sulfide which will be diverted and injected into five acid gas injection (AGI) wells, the Dry Piney State 12-16, Dry Piney State 3-16 AGI, Dry Piney State 8-16 AGI, Dry Piney State 14-16 AGI, and Dry Piney State 16-16 AGI wells. The AGI wells will be positioned approximately 10.5 miles to the east-northeast of the DPJGPF, and the combined acid gas will be transported via pipeline from the DPJGPF and injected into the Dry Piney State (DPS) AGI wells.

The MRV plan explains that BSO is in process of obtaining authority to inject fluids through Underground Injection Control (UIC) Class II acid-gas disposal wells into the Madison and Bighorn Formations from the Wyoming Oil and Gas Conservation Commission (WOGCC). Of the five DPS AGI wells, DPS 12-16 has been drilled, but not completed, and the remaining four wells have an approved permit to drill.

Section 2 of the MRV plan outlines the geologic context, injection volumes, and reservoir modeling conducted by BSO for the five DPS AGI wells. The MRV plan identifies the Madison and Bighorn Formations as the primary injection interval targets for the project. The Amsden Formation is the overlying confining interval positioned immediately above the Madison Formation and is known to be an effective seal in the area as demonstrated by oil and gas trapped in the Madison, indicating permeabilities in the range of 0.001 millidarcy (md) or less.

The MRV plan also identifies the Devonian Darby Formation as both the underlying confining interval for the Madison Formation and the overlying confining interval to the Bighorn Formation. The Darby Formation was devoid of volatile species in the fluid inclusion volatile (FIV) analysis data suggesting a seal between the Madison and Bighorn Formations. Differing gas compositions between the Madison and Bighorn observed in fluid samples collected via wireline logging in the Dry Piney State 12-16 corroborates separation of the two injection zones. The ability of the Darby to form an effective seal between the Madison and Bighorn suggests permeabilities on the order of 0.001 md or less.

Finally, the MRV plan identifies the lower confining layer to the Bighorn Dolomite is the Cambrian interval including the low porosity Gallatin Limestone, the Gros Ventre Shale, and shales within the Flathead Sandstone. Very few penetrations into the Cambrian strata across Wyoming exist. The Cambrian is at least 131' thick in the Dry Piney State 12-16 and the USGS reports porosity ranging from 2 to 8% and permeabilities of <0.01 md, often in the nanodarcy range.

BSO intends to inject for 50 years, with a total injection quantity of acid gas of 5.25 trillion cubic feet (TCF), and the anticipated total volume of CO₂ stored over the modeled injection period to be

approximately 4.87 TCF (257.6 million metric tons). The DPS AGI wells will inject a CO₂ stream that contains approximately 92.4% CO₂, 6.93% H₂S and 0.5% CH₄ by molar volume and anticipates beginning injection in 2028 and ceasing injection in 2078.

It is not feasible to inject into both the Madison and Bighorn Formations in the same well due to differing reservoir pressures. The Madison Formation was observed to have an average reservoir pressure of 6,686 pounds per square inch (psi), which is more than 500 psi less than the Bighorn Formation average of 7,206 psi. The MRV plan states injection and sequestration of CO₂ and H₂S is planned to target the Madison Formation in four proposed wells and the Bighorn Formation in the drilled but uncompleted Dry Piney State 12-16. Based on gas compositional analysis of fluid samples taken in the Dry Piney State 12-16 well, the Madison and Bighorn Formations have uneconomic quantities of CH₄ (< 5%) and He (< 0.25%) at the downdip location of the AGI area near the gas water contact (GWC). The CO₂ concentration at the DPS AGI location is approximately 89% in the Madison Formation and approximately 95% in the Bighorn Formation.

The MRV plan states injection into the Madison and Bighorn Formations is not expected to contaminate potential production at the AGI area. Because the injected gas composition is expected to be 92.4% CO₂, 6.93% H₂S and 0.5% methane, the injected gas is anticipated to be denser than the less CO₂-rich gas up structural dip to the west in the production area. Therefore, measurable quantities of injected gas are not forecasted to “break-through” or contaminate production in the DPU and LaBarge Field area, which is located structurally updip and 10.5 miles to the west-southwest, during the 50-year production life of the project. This is demonstrated through the dynamic reservoir simulation modeling.

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 MMA 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 CO₂ plume until the CO₂ plume has stabilized plus an all-around buffer zone of at least one-half mile.” Subpart RR defines AMA 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 AMA 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.” See 40 CFR 98.449.

The MRV plan indicates that a dynamic reservoir model will be utilized for the project. The model incorporates geologic data collected from all wells with available data, seismic data, and historic production and injection data from ExxonMobil LaBarge Field operations to predict the size and location of the plume, as well as understand how the plume diameter changes over time. According to the

reservoir modeling results, after 50 years of post-injection monitoring (year = 2128), the injected gas will remain in the reservoir, and no expansion of the free-phase CO₂ plume is observed after that point in time. The model was run through year 2578 to assess the potential for expansion of the plume after acid gas injection ceases. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. Expansion of the plume to a diameter of approximately 50,000 ft (9.5 miles) occurs by the year 2128 as the gas plume stabilizes due to gravity segregation and dispersion. At this point, the rate of movement of the free-phase CO₂ plume (incremental injected CO₂ volume) has essentially ceased, demonstrating plume stability. The spatial extent of the acid gas free-phase CO₂ plume is shown in Figure 2.8-2 of the MRV plan.

Section 3.1 of the MRV plan states that the MMA is defined as equal to or greater than the area expected to contain the free-phase CO₂ plume until the CO₂ plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling indicates that during the 50-year post-injection stabilization period, a modest amount of migration up-dip occurs because injection pressure is no longer forcing the plume down structural dip. As the plume expands slightly in the absence of injection pressure, the plume shifts up structural dip to the southwest. The MRV plan states that to ensure the delineation of the maximum extents of the plume, BSO took the conservative approach to use the union of the 50-year plume boundary and the 100-year plume boundary to capture the maximum (max) plume extent as depicted in Figure 3.1-2 of the MRV plan, even though modeling suggests any free-phase CO₂ will evacuate from the western extent of the 50-year plume outline. This combined plume extent, defined by the 50-year plume outline plus the 100-year stabilized plume outline (2128) plus a one-half mile buffer is used to define an MMA.

BSO identified 9 faults within the anticipated MMA. The MRV plan states according to EPA regulation, “the buffer is intended to encompass leaks that might migrate laterally as they move towards the surface. EPA has determined that the buffer zone of at least one-half mile will have an acceptable probability of encountering leaks in many circumstances.” BSO incorporated the faults extending beyond the stabilized plume (plus a one-half mile buffer) to define an extended MMA. The extended MMA comprises the union of two areas: the area covered by the initial MMA plus a one-half mile buffer and the area covered by the fault traces extending beyond the stabilized plume plus a one-half mile buffer as the faults represent known potential leakage pathways. Figure 3.1-4 of the MRV plan shows the final MMA.

Section 3.2 of the MRV plan states that the AMA is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the AMA is established by superimposing two areas:

- Area 1: The area projected to contain the free-phase CO₂ plume at the end of year (t), plus an all-around buffer of one-half mile if known leakage pathways extend laterally more than one-half mile.
- Area 2: The area projected to contain the free-phase CO₂ plume at the end of year t + 5.

BSO states t = 2128, which corresponds to a 50-year injection period plus a 50-year post-injection period during which the plume stabilizes, for the purpose of calculating an AMA. After applying the criteria

defined by Subpart RR, BSO believes it is appropriate to establish an AMA that is the same size as the MMA. The evaluation with $t = 2128$ demonstrates that the AMA is contained within the MMA, and therefore, BSO considers the AMA equal to the MMA.

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 CO₂ in the MMA and the likelihood, magnitude, and timing of surface leakage of CO₂ through these pathways pursuant to 40 CFR 98.448(a)(2). In Section 4 of their MRV plan, BSO identified the following potential leakage pathways that required consideration:

- Surface Equipment
- Existing Wells
- Confining Units
- Faults and Fractures
- Lateral Migration
- Seismicity

To assess risk estimates for the potential leakage pathways BSO used a 5x5 risk matrix to evaluate leakage likelihood and magnitude, shown in Figure 4.1-1 of the MRV plan and is copied below.

		Magnitude				
		Insignificant 1	Minor 2	Significant 3	Major 4	Severe 5
Likelihood	Almost certain 5	Medium 5	High 10	Very high 15	Extreme 20	Extreme 25
	Likely 4	Medium 4	Medium 8	High 12	Very high 16	Extreme 20
	Moderate 3	Low 3	Medium 6	Medium 9	High 12	Very high 15
	Unlikely 2	Very Low 2	Low 4	Medium 6	Medium 8	High 10
	Very Unlikely 1	Very Low 1	Very Low 2	Low 3	Medium 4	Medium 5

3.1 Leakage Through Surface Equipment

Section 4.1 of the MRV plan states that potential leakage from surface equipment will likely be de minimis due to the design of the AGI facilities. The facilities are designed to minimize leak points such as

valves and flanges and use welded connections where possible instead. The only surface equipment located between the mass flow meter and the wellhead are valves, transmitters, and flanged connection points on the pipelines, and the equipment will not be configured to blow down or vent between the mass flow meter used for calculating injected CO₂ and the wellhead. The MRV plan states due to the presence of H₂S in the AGI stream, fixed H₂S gas detectors will be prevalent around the gas processing plant, AGI facility and wellheads, which will alarm at 10 ppm. CO₂ gas detectors will be present at the AGI facility due to the high concentration of CO₂, which will alarm at 5,000 ppm. Additionally, all field personnel are required to wear personal H₂S monitors for safety reasons at all times without exception, which will alarm at 5 ppm H₂S. Although damage to or failure of pipelines and surface equipment can result in unplanned losses of CO₂ entrained in the acid gas, at the anticipated concentration of H₂S in the injection volumes, even a small leak would trigger an alarm, and immediate action would be taken to stop the leak.

The MRV plan states due to the standards enforced during construction, the monitoring equipment in place for immediate detection, and the regular inspections and maintenance, the probability of such leakage is considered “very unlikely.”

The MRV plan asserts depending on the component's failure mode, the magnitude and timing of a leak can vary greatly. Surface component leakage or venting is only a concern during the life of injection operations. Once the injection has ceased, the surface components will no longer be able to store or transport CO₂, eliminating any potential risk of leakage. Therefore, the magnitude of such a leakage is considered to vary from insignificant to severe according to scenarios. The timing is also variable in the sense that potential leakage could occur at any time from start-up to cessation of injection operations.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected from surface equipment.

3.2 Leakage Through Wells within MMA

Leakage through Existing Wellbores

In Section 4.2 of the MRV plan, BSO considered and evaluated all wells drilled, completed, or approved within the MMA in its risk assessment, regardless of well type (oil, gas, water injection, groundwater well, etc.) or well status (producing oil, producing gas, plugged and abandoned, etc.). Only one other well besides the Dry Piney State 12-16 penetrates the confining and injection zone, the Tip Top T16X-16S. This well is located in the one-half mile buffer and is not located within the stabilized plume at year 2128. Additionally, this well was subsequently plugged and abandoned. The well is located on the same pad as another actively producing shallow well. Neither well is operated by BSO but if the abandoned well was leaking, the operator would observe an increase in H₂S on the shared well pad. If the operator's H₂S gas monitor did alarm, further investigation into CO₂ leakage could be conducted.

The MRV plan states all other wells within the MMA, including groundwater wells, regardless of current status, were drilled and abandoned or completed at total depths that are at least 3,000 feet above the

top of the shallowest injection zone (the Madison Formation). Of the 741 existing petroleum-related wells in the AMA/MMA, 448 (60.5%) are plugged and abandoned (“PA”), 221 (29.8%) are currently producing shallow sweet gas (PRODGAS), 41 (5.5%) are currently producing shallow sweet oil, 18 (2.3%) are currently shut-in, temporarily abandoned, or have an unknown status, and finally, 13 (1.8%) are water injection wells for the shallow sweet oil system. Note that no wells in the AMA/MMA produce gas from the Madison or Bighorn injection zones. BSO analyzed the likelihood of leakage through the existing wells based on the following value assignment table (reproduced below) depending on depth above injection zone and whether or not the well is located within the stabilized plume area:

LIKELIHOOD	WITHIN PLUME	OUTSIDE PLUME (WITHIN MMA)	
> 3,000 FT ABOVE INJ ZONE	1	1	3 = Moderate
< 3,000 FT ABOVE INJ ZONE	2	1	2 = Unlikely
PENETRATES INJ ZONE	3	2	1 = Very Unlikely

The results of the “likelihood” assessment for the wells located within the MMA can be observed in Appendix A of the MRV plan. All wells, except the Tip Top T62X-16S, were assigned a value of “very unlikely” due to being either outside the plume area and or having a total depth greater than 3,000 feet above the injection zone. The Tip Top T62X-16S well was assigned a value of “unlikely” because it penetrates the Madison and Bighorn injection zones, and it is located outside of the stabilized plume area.

BSO also performed a “magnitude” assessment of the wells located within the MMA using another assignment table (reproduced below).

MAGNITUDE	WITHIN PLUME	OUTSIDE PLUME (WITHIN MMA)	
> 3,000 FT ABOVE INJ ZONE	1	1	3 = Significant
< 3,000 FT ABOVE INJ ZONE	2	1	2 = Minor
PENETRATES INJ ZONE	3	1	1 = Insignificant

The MRV states the magnitude of all wells were assigned a value of “insignificant” due to either being outside the plume area or having a total depth greater than 3,000 feet above the injection zone. Additionally, in terms of operational timing, however unlikely, leakage could potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures.

Leakage through Future Wellbores

The MRV plan states there are no existing producing wells completed in the Madison or Bighorn Formations within the AMA or MMA, and it is highly unlikely that there will be Madison or Bighorn production wells drilled in the MMA/AMA in the future owing to the high initial CO₂ and low initial methane and helium concentrations, likely rendering future production wells uneconomic. Additionally, WOGCC has jurisdiction over the approval of regulating future oil and gas exploration, drilling, and production, providing additional protections to the development of future wells penetrating the Madison or Bighorn Formations within the AMA or MMA.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected through wells in the MMA.

3.3 Leakage Through Confining Units

Section 4.3 of the MRV plan states that the area closest to the injection wells with the highest concentration of free-phase CO₂ would likely be most prone to this leakage pathway. The shale, anhydrite and salt-rich Triassic Evaporites confining unit in the Dry Piney State AGI area serves as the overall deep sour gas system seal and the ultimate confining unit to both the Madison and the Bighorn injection zones. The MRV plan asserts the fact that gas (especially helium with its small molecular size) remains trapped at pressure in the Madison and Bighorn Formations, it must follow that any natural reactivation or movement of salt-rich sediments that has occurred over the geological history of the LaBarge Field has not created any pathways for gas leakage to the surface. The likelihood of CO₂ leakage through the Triassic Evaporites confining unit is therefore “very unlikely.”

Additionally, the MRV plan states in addition to the Triassic Evaporites, the Amsden (422 ft thick) is the immediately adjacent and overlying confining unit to the Madison. Also, the Darby (302 ft thick) is the underlying confining unit for the Madison and the overlying confining unit for the Bighorn injection zone. Analysis of a fluid sample collected during wireline logging demonstrated different gas compositions in the Madison and Bighorn, indicating the Darby Formation is a confining unit that has hydraulically separated the Madison and Bighorn Formations over geologic time. Therefore, the likelihood of CO₂ leakage through the Darby Formation confining unit is “very unlikely.”

Overall, the MRV plan states all these confining zones generally have low porosity (< 2%) and low permeability (< 0.001 md) intervals that provide high seal integrity. So long as the injection pressure is limited to less than the fracture pressure of the confining zones, the likelihood of CO₂ leakage through this potential pathway to surface is determined to be “very unlikely.”

The MRV plan states that based on reservoir simulation results conducted by BSO, the relative difference in porosity and permeability of the low porosity and low permeability of the Amsden confining unit compared to the high porosity and high permeability of the Madison injection zone suggests the free-phase CO₂ plume stays entirely within the Madison Formation. Therefore, any potential leakage upward into the confining zone would be considered insignificant. Likewise, the Bighorn Formation is highly porous and permeable relative to its overlying Darby confining unit, so

plume modeling indicates that all injected CO₂ stays within the Bighorn injection zone. Therefore, any potential leakage upward into the confining zone would be considered insignificant.

The MRV plan states in terms of timing, however unlikely, leakage could potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. However, BSO states that the injection wells would not inject above the fracture pressure in any case, thus reducing further risk of leakage.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected from the confining units.

3.4 Leakage Through Faults and Fractures

According to Section 4.4 of the MRV plan, faults were identified (numbered 1 through 9) and evaluated using seismic interpretation, shown in Figures 4.4-1 and 4.4-2 of the MRV plan. Any fault that intersects and extends beyond the stabilized plume outline at year 2128 was brought into the analysis as a potential leakage pathway and the MMA includes a one-half mile buffer around any fault that extended beyond the stabilized plume. The MRV notes that no faults within the MMA are observed at the surface, nor does seismic interpretation suggest that any faults in the MMA extend to the surface.

The MRV plan states in the vertical dimension, only three faults extend completely through or above the Triassic Evaporites confining interval. Despite observing seismic discontinuities interpreted as faults extending through the Triassic Evaporites interval, there is no evidence that these faults are open and providing an active pathway for CO₂ leakage upward through the geologic column to surface, as evidenced by the existence of a shallow (Frontier, Bear River, Mowry and Gannett) sweet gas petroleum system (minor CO₂, no H₂S, no helium) that is currently being produced by approximately 166 wells within the MMA. Because the MMA encompasses a half-mile buffer zone to ensure there is no risk of leakage due to lateral migration associated with faults, and gas analyses indicate there is no upward migration along faults, the likelihood of leakage through faults is considered “very unlikely.”

A detailed analysis of the nine identified faults in the MMA and the fault systems is provided in Section 4.4 of the MRV plan. In summary, BSO characterizes the overall risk of potential leakage along faults in the MMA as very low. There are no instances where a fault intersects the plume in a position in which the plume is anticipated to have a concentration greater than 5% net incremental CO₂ above the naturally occurring in-situ background CO₂ contained in the injection zones. Therefore, the magnitude of potential leakage would be insignificant.

The MRV plan states in terms of timing, however unlikely, leakage could potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. BSO, of course, would not inject above fracture pressure in any case, thus reducing

further risk of leakage. It is also possible any leakage would occur during the 50 years of post-injection plume growth during plume stabilization.

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

3.5 Leakage From Lateral Migration

Section 4.5 of the MRV plan states regional evaluation of the geology and the geological model covering the entire LaBarge structure suggest that the Madison and Bighorn injection zones have adequate storage capacity, and their respective confining zones are uniform across the MMA. Therefore, all lateral migration is expected to occur within the injection zones. Dynamic simulation indicates that the injected free-phase CO₂ plume will be contained within the injection zones. Due to the lack of hydraulic connection to outcrops and continuity of confining units across the entire structure, potential leakage of CO₂ to the surface due to lateral migration would require an additional leakage pathway, most likely lateral migration within the injection zones to faults and fractures, previously discussed. Therefore, BSO views the likelihood of CO₂ leakage to the surface or out of the injection zones due to lateral migration as “very unlikely.”

The MRV plan states based on simulation results the free-phase CO₂ plume is projected to be contained within the injection zones within the MMA as depicted on Figure 3.1-4. The confining zones are thick and continuous, which would prevent any upward migration through the confining zone even if lateral migration beyond the MMA occurs. Because the free-phase CO₂ plume is delineated using a 0.5% net incremental increase in CO₂, if leakage through this potential pathway were to occur it would be considered insignificant relative to the large amount of in-situ CO₂ naturally present in the injection zones.

The MRV plan states in terms of timing, however unlikely, leakage could potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. It is also possible any leakage would occur during the 50 years of post-injection plume growth during plume stabilization.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO₂ leakage that could be expected from lateral migration.

3.6 Leakage From Seismicity

Section 4.6 of the MRV plan states due to the depths relative to the injection zones and confining units at the Dry Piney State injection area and the small magnitude of the seismic events since 2015, combined with the fact that BSO will inject at pressures below fracture opening pressure, BSO considers the likelihood of CO₂ emissions to the surface along potential leakage pathways caused by seismicity or induced seismicity to be “very unlikely.”

The impact of a seismic event on confining zones, wells and surface installation integrity can vary greatly according to events' magnitude or frequency. BSO identified 10 seismic events within 20 miles of the AGI wells since 2015. However, based on the relative depths of seismic events' focal points ranging from 25,000 to 100,000 feet below the injection zones and confining units, and the small magnitudes recorded within 20 miles of the Dry Piney State injection area, BSO considers the magnitude of potential leakage due to seismicity to be insignificant. Further, if an unprecedented natural seismic event were to occur that impacted the integrity of any of the Dry Piney State AGI wells or the related infrastructure, BSO would shut down operations immediately, limiting potential release of CO₂ from wellhead and other surface equipment, thus minimizing leakage to an insignificant amount.

The MRV plan states in terms of operational timing, and induced seismicity, however unlikely, leakage could potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO₂ leakage that could be expected from seismicity.

4 Strategy for Detection and Quantifying Surface Leakage of CO₂ and for Establishing Expected Baselines for Monitoring

40 CFR 98.448(a)(3) requires that an MRV plan contains a strategy for detecting and quantifying any surface leakage of CO₂, and 40 CFR 98.448(a)(4) requires that an MRV plan includes a strategy for establishing the expected baselines for monitoring potential CO₂ leakage. Section 5 of the MRV plan discusses the strategies that BSO will employ for detecting and quantifying surface leakage of CO₂ through the pathways identified in the previous section to meet the requirements of 40 CFR 98.448(a)(3). BSO considers H₂S to be a proxy for CO₂ leakage to the surface and as such will employ and expand upon methodologies detailed in the BSO H₂S Contingency Plan to detect, verify, and quantify CO₂ surface leakage close to the plant equipment. Monitoring will occur during the planned 50-year injection period and the 50-year post-injection period. The plume is stabilized after the 50 years post-injection. A summary table of BSO's detection strategies can be found in Table 5.1 of the MRV plan and is reproduced below.

Potential Leakage Pathway	Detection Monitoring Program
Surface Equipment	• Distributed Control System (DCS) surveillance of plant operations • Visual Inspections • Inline Inspections • Fixed in-field gas monitors • Personal Gas Monitors • "Optical" CO₂ Detection via Satellite or LIDAR Data Imaging

Dry Piney State AGI Wells(including approved, but not yet drilled AGI wells)	• DCS surveillance of well operating parameters • Visual Inspections • Mechanical Integrity Tests (MIT) • In-well Pressure & Temperature sensors • Fixed in-field gas monitors • Personal Gas Monitors • “Optical” CO₂ Detection via Satellite or LIDAR Data Imaging
Existing shallow oil, gas and groundwater wells	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • “Optical” CO₂ Detection via Satellite or LIDAR Data Imaging • Produced gas composition surveillance of existing shallow oil & gas wells • Groundwater monitoring • CO₂ flux monitoring network
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • “Optical” CO₂ Detection via Satellite or LIDAR Data Imaging • Produced gas composition surveillance of existing shallow oil & gas wells • Groundwater monitoring • CO₂ flux monitoring network
Confining Units	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • “Optical” CO₂ Detection via Satellite or LIDAR Data Imaging • Produced gas composition surveillance of existing shallow oil & gas wells • Groundwater monitoring • CO₂ flux monitoring network
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • “Optical” CO₂ Detection via Satellite or LIDAR Data Imaging • Produced gas composition surveillance of existing shallow oil & gas wells • Groundwater monitoring • CO₂ flux monitoring network
Natural and Induced Seismicity	• DCS surveillance of well operating parameters • “Optical” CO₂ Detection via Satellite or LIDAR Data Imaging • Seismic monitoring station

4.1 Detecting Leakage from Surface Equipment

Section 5.1 of the MRV plan states that BSO will implement several tiers of monitoring for leakage from surface equipment including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H₂S sensors, and continual monitoring and collection of operational parameters including flow, pressure, temperature and gas compositional data. The data will be monitored continuously by qualified technicians who will follow response and reporting protocols when the system delivers alerts and alarms that data is not within acceptable operating limits. In the case that detection of a leak occurs, it would trigger an immediate response to address and characterize the leakage. In some instances, more than one detector alarming would trigger automatic equipment isolation and/or shutdown to mitigate the leak.

The MRV plan also states that BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or LIDAR to visually observe potential CO₂ plumes at the surface. These new methods would be utilized over the entire MMA and would provide insights into leakage from point sources such as surface equipment.

Section 5.1 and Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected from surface equipment. Thus, the MRV plan provides adequate characterization of BSO's approach to detect potential leakage from surface equipment as required by 40 CFR 98.448(a)(3).

4.2 Detecting Leakage from Approved Not Yet Drilled Wells

Section 5.2 of the MRV plan states that there are four additional Dry Piney State AGI wells that are in the permitting process but are not-yet-drilled wells within the MMA. Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones including more frequent monitoring during drilling operations, and all drilling of this injection zone will have an H₂S contingency plan in place due to the known naturally occurring H₂S in-situ. This applies to BSO and other operators drilling new wells through or within the Madison and Bighorn injection zones within the MMA.

The MRV plan also explains detection and verification of potential leakage would be conducted by mudlogging procedures utilizing mass spectrometry gas detection that can detect and confirm the presence in relative concentrations of CO₂, H₂S, helium and other components. BSO plans to drill the remaining four Dry Piney State AGI wells before the injection period begins, so in this scenario, CO₂ and H₂S encountered would be naturally occurring rather than confirmation of leakage of injected volumes.

Section 5.2 and Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected through approved not yet drilled wells. Thus, the MRV plan provides adequate characterization of BSO's approach to detect potential leakage through future wells within the MMA as required by 40 CFR 98.448(a)(3).

4.3 Detecting Leakage from Existing Shallow Oil, Gas, and Groundwater Wells

Dry Piney State 12-16 Well

Section 5.3.1 of the MRV plan states BSO will continuously monitor and collect flow, pressure, temperature, and gas composition data in its data collection system. This data will be monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits.

Additionally, to monitor leakage and wellbore integrity, BSO will deploy multiple pressure and temperature gauges, Distributed Temperature Sensing (DTS) and a fiber optic Distributed Acoustic Sensing (DAS) line to monitor pressures and temperatures during active and shut-in injection operations. Real time evaluation and control by BSO operations personnel of the pressure and temperature data will enable remote action if needed.

The MRV plan states if operational parameter monitoring and MIT failures indicate a CO₂ leak has occurred, BSO will take actions to quantify the leak based on operating conditions at the time of the detection including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or LIDAR to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into leakage from point sources such as the existing Dry Piney State 12-16 wellbore.

Other Existing Wells Within the MMA

According to the MRV plan, BSO will use their CO₂ monitoring network and well surveillance by other operators of existing wells to provide an indication of any CO₂ leakage through existing wells within the MMA. Existing wells within the MMA that are still producing oil and gas are generally subject to routine (monthly or annual) gas composition analysis. To the extent possible, BSO will work with other operators to integrate and utilize gas composition data into its leakage detection and quantification plan, as new or increased concentrations of CO₂, H₂S and/or helium would signify potential leakage via this pathway, and any potential CO₂ leakage would likely be detected via this method much sooner than shallower investigation methods that will also be employed, such as soil CO₂ flux and groundwater monitoring, from locations throughout the MMA.

The MRV plan states the verification process would involve repeating the gas analysis that shows departure from baseline, both at the same laboratory and possibly a second independent laboratory, as well as checking well records to ensure there is not an operational issue that would cause an increase in casing or tubing pressure. With an assumed detection period of 1-3 months, approximately 1 to 1.25 million metric tons of CO₂ could be leaked before detection.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or LIDAR to observe

potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into leakage from point sources such as existing wellbores, or plume sources such as from faults, leaking confining units and/or lateral migration.

Section 5.3 and Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected through existing wells. Thus, the MRV plan provides adequate characterization of BSO's approach to detect potential leakage through existing wells within the MMA as required by 40 CFR 98.448(a)(3).

4.4 Detecting Leakage through Confining Units and Faults and Fractures

Sections 5.4 and 5.5 of the MRV provide strategies for the detection of leakage through confining units and faults and fractures. The MRV plan states that the continuous operational monitoring of the Dry Piney State AGI wells will provide an indicator if CO₂ leaks out of the injection zone. Additionally, soil CO₂ flux, groundwater monitoring and produced gas composition from locations throughout the MMA will also provide an indication of CO₂ leakage to the surface. If changes in operating parameters or other monitoring techniques indicate leakage of CO₂ through the confining units, BSO will take actions to quantify the amount of CO₂ released and take mitigative action to stop it, including shutting in the wells.

If leakage through the confining zone is suspected via shallow gas wells, verification would involve repeating the gas analysis that shows departure from baseline, both at the same laboratory and possibly a second independent laboratory and checking well records to ensure there is not an operational issue that would cause an increase in casing or tubing pressure. Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage at the surface on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or LIDAR to observe potential non-point source CO₂ plumes in the event leakage through the confining unit was due to an unobservable fault or fracture network not identified during seismic interpretation. These potential methods would be utilized over the entire MMA and would provide insights into location of plume source leaks such as from leaking confining units.

Sections 5.4, 5.5, and Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected through confining units and fracture and faults. Thus, the MRV plan provides adequate characterization of BSO's approach to detect potential leakage through fracture and faults and confining units as required by 40 CFR 98.448(a)(3).

4.5 Detecting Leakage through Lateral Migration

Section 5.6 of the MRV plan states continuous monitoring within the MMA during and after the period of injection will provide an indication of the movement of the CO₂ plume migration in the injection zones. If monitoring of operational parameters indicates that the CO₂ plume extends beyond the area modeled, BSO will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO₂ migration. It is anticipated that leakage due to lateral migration would

still need to leak upward through the confining units, and similar methods and techniques discussed under confining units would apply.

Section 5.6 and Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected from lateral migration. Thus, the MRV plan provides adequate characterization of BSO's approach to detect potential leakage from lateral migration as required by 40 CFR 98.448(a)(3).

4.6 Detecting Leakage through Natural or Induced Seismicity

Section 5.7 of the MRV plan states to monitor the influence of natural and/or induced seismicity, BSO will use the established Advanced National Seismic System (ANSS) and an onsite seismometer that will be installed. The network consists of seismic monitoring stations that detect and locate seismic events in real time. Continuous monitoring helps differentiate between natural and induced seismicity. If the monitoring systems indicate a seismic event, BSO will assess the integrity of the DPJGPF and Dry Piney State AGI wells. If the event caused CO₂ leaks, BSO will act to quantify the mass of CO₂ emitted to the surface based on operational conditions at the time the leak was detected. It is anticipated that leakage due to natural or induced seismicity would occur as leakage through the confining units or along faults and therefore would be detected at the surface using similar methods and techniques discussed in those section would apply.

Section 5.7 and Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected from natural or induced seismicity. Thus, the MRV plan provides adequate characterization of BSO's approach to detect potential leakage from natural or induced seismicity as required by 40 CFR 98.448(a)(3).

4.7 Quantifying CO₂ Leakage

Surface Equipment

Section 5.8.1 of the MRV plan states for normal operations, quantification of emissions of CO₂ from surface equipment will be assessed by employing the methods detailed in Subpart W according to the requirements of 40 CFR 98.444(d) of Subpart RR. Quantification of major leakage events from surface equipment as identified by the detection techniques listed in Table 5.1 of the MRV plan will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified, the leakage location will be isolated to prevent additional emissions to the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. Additionally, BSO may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

Leakage in the Subsurface

Section 5.8.2 of the MRV plan states leaks associated with the point sources at the facility, such as the injection wells, and identified by failed MITs, variations of operational parameters outside acceptable ranges, and in-well pressure and temperature sensors can be addressed immediately after the injection well has been shut in. Quantification of the mass of CO₂ emitted during the leak will depend on characterization of the subsurface leak, operational conditions at the time of the leak, and knowledge of the geology and hydrogeology at the leakage site.

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, due to lateral migration or which may be initiated by seismic events and may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations. For example, if changes in operating parameters or monitoring techniques indicate leakage of CO₂ via shallow wells through the confining units or faults and fractures, verification of the leak would involve repeating a gas analysis that shows a departure from baseline. Alternatively, soil CO₂ flux, groundwater monitoring and produced gas composition from locations throughout the MMA can provide indications of CO₂ leakage to the surface and can be compared to the established baselines discussed in Section 4.8 below. In the event a leakage plume is identified via optical imaging technique such as LIDAR or satellite-based hyperspectral imaging, weather and atmospheric conditions will be utilized in a modeling-based approach to quantify CO₂ leakage, as well as measurement of CO₂ flux at surface near the surface leakage location via eddy covariance, accumulation chamber or tenting.

4.8 Determination of Baselines

Section 6 of the MRV plan identifies the strategies that BSO will undertake to establish the expected baselines for CO₂ surface leakage per 40 CFR 98.448(a)(4). Prior to the start of continuous injection, the MRV plan identified the following data to compare with future data to detect surface leakage:

Visual Inspections

The MRV plan states field personnel will conduct daily inspections of the AGI facilities and weekly inspections of the AGI well site. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize the possibility of CO₂ leakage.

Fixed In-Field and Personal H₂S Gas Monitors

The MRV plan states that compositional analysis of BSO's gas injectate at the Dry Piney State AGI area indicates an H₂S concentration of 6.93% thus requiring BSO to develop and maintain an H₂S Contingency Plan (Plan) according to the WOGCC and BLM regulations. The baseline expectation for H₂S, and therefore CO₂, would be 0 ppm with no alarms during routine operations. Departure from this baseline would require investigation to ensure there are no leaks from surface equipment at the gas plant or AGI location.

CO₂ Detection Monitoring Network and Optical Data Imagery

The MRV plan states that BSO will set up a monitoring network for CO₂ leakage detection in the MMA/AMA. BSO will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project to allow identification of any deviation from baseline analyses that may suggest a leak.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or LIDAR to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into the location of surface leakage from any of the identified pathways. In order to establish a baseline, the satellite or LIDAR data imaging methodology would be employed on a semi-annual basis for two years, then annually.

Continuous Parameter Monitoring

The MRV plan states that the DCS of the plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS, and engineering and operations are alerted if a parameter is outside the allowable window.

Well Surveillance and Gas Composition Monitoring

BSO will adhere to the requirements of WOGCC rules governing the construction, operation and closing of an injection well. It includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times.

Additionally, to the extent possible, BSO will work with area operators of existing shallow gas wells to monitor a subset of existing oil and gas wells for CO₂ leakage. Production gas samples will be collected and analyzed on a quarterly basis for 12 months to establish baseline data. After establishing the gas composition baseline, samples will be collected and analyzed annually. Samples will be collected according to standard industry methods for production well gas sampling.

Seismic Monitoring Station

BSO will install a seismometer and a digital recorder to monitor and record data for any seismic event at the DPJGPF and Dry Piney State AGI well site. BSO will ensure that the seismic monitoring station is configured such that it can record and report data to third parties as necessary. BSO will also monitor the ANSS network for seismicity in the injection area. A report will be periodically generated with a map showing the magnitudes of recorded events from seismic activity.

Ground Water Monitoring

Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

Soil CO₂ Flux Monitoring

Soil CO₂ flux will be collected on a monthly basis for 12 months to establish a baseline and understand seasonal and other variations in the Dry Piney State AGI area. After the baseline is established, data will be collected quarterly for three years, then annually. Due to the climate in the area, soil CO₂ flux samples will be collected on the schedule proposed above as weather conditions and seasonality allow. BSO will target surface locations associated with plugged and abandoned wells, as well as areas directly above faults for initial baseline monitoring locations.

BSO expects the Commercial Online Date to be approximately October 2028 and will begin collecting baseline data at least 12 months in advance of this expected date, beginning in 2027. Thus, BSO provides an acceptable approach for detecting and quantifying surface leakage and for establishing the expected baselines for monitoring CO₂ surface leakage 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 7 of the MRV plan provides the equations that Dry Piney will use to calculate the mass of CO₂ sequestered annually.

5.1 Calculation of Mass of CO₂ Received

According to Section 7.1 of the MRV plan, the CO₂ received for these injection wells will be wholly injected and not mixed with any other supplies of CO₂, thus the annual mass of CO₂ injected will equal the quantity of CO₂ received at the receiving flow meter. Therefore, in accordance with 40 CFR 98.444(a)(4), Dry Piney has elected to use the mass of CO₂ injected as the mass of CO₂ received instead of using Equation RR-1 or RR-2. Since the CO₂ received by the AGI process is wholly injected and not mixed with any other supply of CO₂, the annual mass of CO₂ injected would be equal to the annual mass of CO₂ received, as calculated using Equation RR-4 per 40 CFR 98.444(a)(4):

$$CO_{2,u} = \sum_{p=1}^4 Q_{p,u} * C_{CO_2,p,u}$$

(Equation RR-4)

Where:

CO_{2,u} = Annual CO₂ mass injected (metric tons) as measured by flow meter u.

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

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

p = Quarter of the year.

u = Flow meter.

BSO's approach to calculating the mass of CO₂ received is acceptable for the Subpart RR requirements.

5.2 Calculation of Mass of CO₂ Injected

Section 7.2 of the MRV plan states mass flow meters will be used to measure the injected mass of CO₂ at each well. Equation RR-4 (in Section 7.1) will be used to calculate the annual total mass of CO₂ injected into each well. Equation RR-6 will be used to aggregate injection data for the AGI wells. Equation RR-6 is below:

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

(Equation RR-6)

Where:

CO_{2I} = Total annual CO₂ mass injected (metric tons) through all injection wells.

CO_{2,u} = Annual CO₂ mass injected (metric tons) as measured by flow meter u.

u = Flow meter.

BSO provides an acceptable approach to calculation the mass of CO₂ injected in accordance with Subpart RR requirements.

Calculation of Mass of CO₂ Produced

Section 7.3 of the MRV plan states AGI wells will not be part of an enhanced oil or enhanced gas recovery process, nor does reservoir simulation show the free-phase CO₂ plume reaching any existing or future production wells, therefore, there will be no injected CO₂ produced and/or recycled.

Calculation of Mass of CO₂ Emitted by Surface Leakage and Equipment Leaks

Section 7.4 of the MRV plan states it is not appropriate to conduct a leak survey at the AGI well sites due to the components being unsafe-to-monitor and extensive monitoring systems in place. Entry to the AGI well pad will require the individual to wear a personal gas monitor capable of detecting CO₂ and H₂S, thus allowing immediate identification of possible leakage from surface equipment. Due to the high H₂S and CO₂ concentrations of the AGI fluids, fugitive leakage would be detected and managed as an upset event and calculated based on operating conditions at that time.

The MRV plan states parameters CO_{2E} (CO_2 emitted by surface leakage) and CO_{2FI} (CO_2 emitted from equipment leaks from surface equipment between the flow meter used to measure injection quantity and the injection wellhead) will be measured using the leakage quantification procedures described earlier in section 4.7 of this plan. BSO will estimate the mass of CO_2 emitted from leakage points from the flow meter to the injection wellhead based on operating conditions at the time of the release – pipeline pressure, temperature, flow rate, size of the leakage point opening, and estimated duration of leak. At the AGI wells, there will be no CO_2 emissions from venting due to the high H_2S concentration of the AGI fluid; blowdown emissions are sent to the flares and are reported under Subpart W for the gas plant. Venting AGI well injection gas would only occur in the event of depressurizing for maintenance or testing, which would be measured during the time of event.

The MRV plan states in the event that surface leakage is detected, the leakage would be quantified and be used to estimate the mass emitted from each pathway and summed using Equation RR-10:

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

(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

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

5.3 Calculation of Mass of CO_2 Sequestered in Subsurface Geologic Formations

Since BSO is not actively producing oil or natural gas or any other fluids as part of the AGI process, Equation RR-12 will be used to quantify CO_2 injected and sequestered.

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

(Equation RR-12)

Where:

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

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

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the mass flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of 40 CFR 98.

BSO provides an acceptable approach for calculating the mass of CO_2 sequestered in subsurface geologic formations under Subpart RR.

6 Summary of Findings

The Subpart RR MRV plan for the BSO facility meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in BSO's MRV plan for Dry Piney.

Subpart RR MRV Plan Requirement	BSO MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA).	Section 3 of the MRV plan delineates the MMA and AMA. The MMA is defined by the stabilized plume after 100 years of density drift plus a one-half mile buffer following the 50-year injection period, which was preceded by 50 years of post-injection monitoring. The MRV plan defines the AMA as the same area as the MMA.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 4 of the MRV plan identifies the following potential surface leakage pathways and evaluates the likelihood, magnitude, and timing of surface leakage through each: surface equipment, existing wells within the MMA, confining units, faults and fractures, lateral migration, and seismicity.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2 .	Section 5 of the MRV plan discusses the strategy that BSO will use to detect and quantify any surface leakage of CO_2 . The MRV plan states that any mass of CO_2 detected leaking to the surface will be quantified by using but not limited to engineering analysis on surface and subsurface measurement data, inspections, gas monitors, and satellite or LIDAR data of the sequestering reservoir performance.

40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO ₂ surface leakage.	Section 6 of the MRV plan describes the strategy that BSO will use for establishing the expected baselines for monitoring CO ₂ surface leakage. BSO's strategy will use visual inspections, CO ₂ /H ₂ S detection, continuous parameter monitoring, well surveillance and gas composition monitoring, seismic stations, operational data, continuous monitoring, and groundwater and soil monitoring.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 7 of the MRV plan summarizes the considerations that BSO intends to use to calculate site-specific variables for the mass balance equation.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 1 of the MRV plan identifies the well identification numbers used for the UIC permit and the UIC class for the BSO injection wells. The wells are permitted as Class II and regulated by Wyoming Oil and Gas Conservation Commission.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 8 of the MRV plan states that the MRV plan is to be implemented upon receiving EPA approval. It also states that BSO expects the Commercial Online Date (COD) to be approximately October 2028. BSO will begin collecting baseline data at least 12 months in advance of this expected date, beginning in 2027.

Appendix A: Submissions and Responses to Requests for Additional Information



BLUE SPRUCE OPERATING LLC
DRY PINEY “JACKALOPE”
GAS PROCESSING FACILITY &
DRY PINEY STATE ACID GAS INJECTION WELLS
Subpart RR Monitoring, Reporting and Verification Plan

Sublette County, Wyoming

Original Submission - August 2025

First Revision – October 2025

Second Revision – December 2025

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INTRODUCTION

Blue Spruce Operating LLC (“BSO”) intends to drill and inject into five acid gas injection (“AGI”) wells in the Madison and/or Bighorn Formations near La Barge, Wyoming for the primary purposes of acid gas disposal and permanent geologic sequestration of carbon dioxide (“CO₂”) in a subsurface geologic formation. One injection well, the Dry Piney State 12-16, has been drilled but is not yet completed or actively injecting. BSO plans to begin initial injection operations in the AGI wells in 2028 and intends to continue injection until the end-of-life of the Dry Piney assets, estimated to occur around 2078.

BSO is in process of obtaining authority to inject fluids through Class II acid-gas disposal wells into the Madison and Bighorn Formations from the Wyoming Oil and Gas Conservation Commission (“WOGCC”). BSO will also request aquifer exemptions for the Madison and Bighorn Formations from the WOGCC. The fluids to be injected into the AGI wells are waste components of natural gas that will be produced and processed by BSO from the Madison Formation.

BSO has developed this monitoring, reporting and verification (“MRV”) plan in accordance with 40 CFR 98.440-449 (Subpart RR – Geologic Sequestration of Carbon Dioxide) to provide for monitoring, reporting, and verification of permanent geologic sequestration into the Madison and Bighorn Formations during the injection period. This plan meets the requirements in 98.440(c)(1).

This MRV plan contains ten sections:

- Section 1.0 contains facility information.
- Section 2.0 contains a description of the Dry Piney project, including descriptions of the geology and history of the LaBarge Field, an overview of the injection program, and highlights the suitability of the Madison and Bighorn Formations for permanent geologic sequestration.
- Section 3.0 contains the definition and delineation of monitoring areas.
- Section 4.0 evaluates the potential leakage pathways and demonstrates that the risk of CO₂ leakage to atmosphere through identified pathways is very low.
- Section 5.0 provides an overview of the detection, verification, and quantification of potential leakage pathways.
- Section 6.0 describes the determination of expected baselines to identify excursions from expected performance that could indicate CO₂ leakage.

- Section 7.0 provides the site-specific modifications to the mass balance equation and the methodology for calculating volumes of CO₂ sequestered.
- Section 8.0 provides the estimated schedule for implementation of the MRV plan.
- Section 9.0 describes the quality assurance program.
- Section 10.0 describes the records retention process.

1.0 FACILITY INFORMATION

Facility Name: Dry Piney Jackalope Gas Processing Facility (“DPJGPF”)

Facility Address: 296 Graphite Hollow Rd – BLM 5321, Big Piney, WY 83113

Facility Owner Name: Blue Spruce Operating LLC

Facility Owner Address: PO Box 2460, Pinedale, WY 82941

Date of Original Submittal: August 4, 2025

Date of 2nd Revision Submittal: December 11, 2025

MRV Report Point of Contact: Andrew Moses

Designated Representative: Andrew Moses

Alternate Designated Representative: Scott Gutberlet

MRV Plan ID #: TBD

The Dry Piney Jackalope Gas Processing Facility (“DPJGPF”) will process approximately 400 million standard cubic feet of gas per day (“MMscfpd”) of raw inlet gas produced from nine production wells (one drilled and waiting on completion, eight permitted) that will be completed in the Madison Formation in and immediately adjacent to the federal Dry Piney Unit (“DPU”), located near the crest of the greater LaBarge Field. The DPJGPF will utilize proven industrial gas processes to separate and refine saleable products, including helium and methane, from the raw gas stream resulting in a waste gas stream that predominantly contains carbon dioxide and hydrogen sulfide (“H₂S”), collectively referred to as acid gas. DPJGPF will be situated adjacent to the DPU within the gas production area, while the acid gas injection area is located approximately 10.5 miles to the east-northeast of DPJGPF. The AGI wells will be positioned approximately 1,350 feet true vertical depth (“TVD”) down structural dip from the DPU production area. Rather than separating and venting CO₂ from the acid gas waste stream, the combined acid gas will be transported via pipeline from DPJGPF and injected into the Dry Piney State (“DPS”) AGI wells to the east-northeast to capture and permanently sequester 100% of the CO₂ in the waste stream.

The AGI wells will report under the Dry Piney Jackalope Gas Processing Facility Greenhouse Gas Reporting Program Identification Number which is 591065. The AGI wells will be Class II per the Underground Injection Control (“UIC”) Permit Classification system. In addition to regulating the oil and gas activities in the state, the WOGCC has jurisdiction over UIC Class II wells in Wyoming. The 10-digit well identification numbers and current status for the AGI wells are listed below.

• DRY PINEY STATE 12-16	49-035-31390-0000	DRILLED, NOT COMPLETED
• DRY PINEY STATE 3-16 AGI	49-035-31455-0000	APPROVED PERMIT TO DRILL
• DRY PINEY STATE 8-16 AGI	49-035-31456-0000	APPROVED PERMIT TO DRILL
• DRY PINEY STATE 14-16 AGI	49-035-31457-0000	APPROVED PERMIT TO DRILL
• DRY PINEY STATE 16-16 AGI	49-035-31458-0000	APPROVED PERMIT TO DRILL

2.0 PROJECT DESCRIPTION

This section provides an overview of the geologic setting of the LaBarge Field area, the history of oil and gas development and AGI history in the area, and the planned AGI process and program.

2.1 GEOLOGY OF THE LABARGE FIELD AREA

The LaBarge Field is in Sublette and Lincoln counties of southwest Wyoming, along the western flank of the Greater Green River Basin (“GGRB”) geological province (**Figure 2.1.1**). The productive area is in the foothills of the Wyoming Range, due west of the Wind River Mountains near the northern termination of the sub-regional Moxa Arch and includes the Dry Piney Unit.

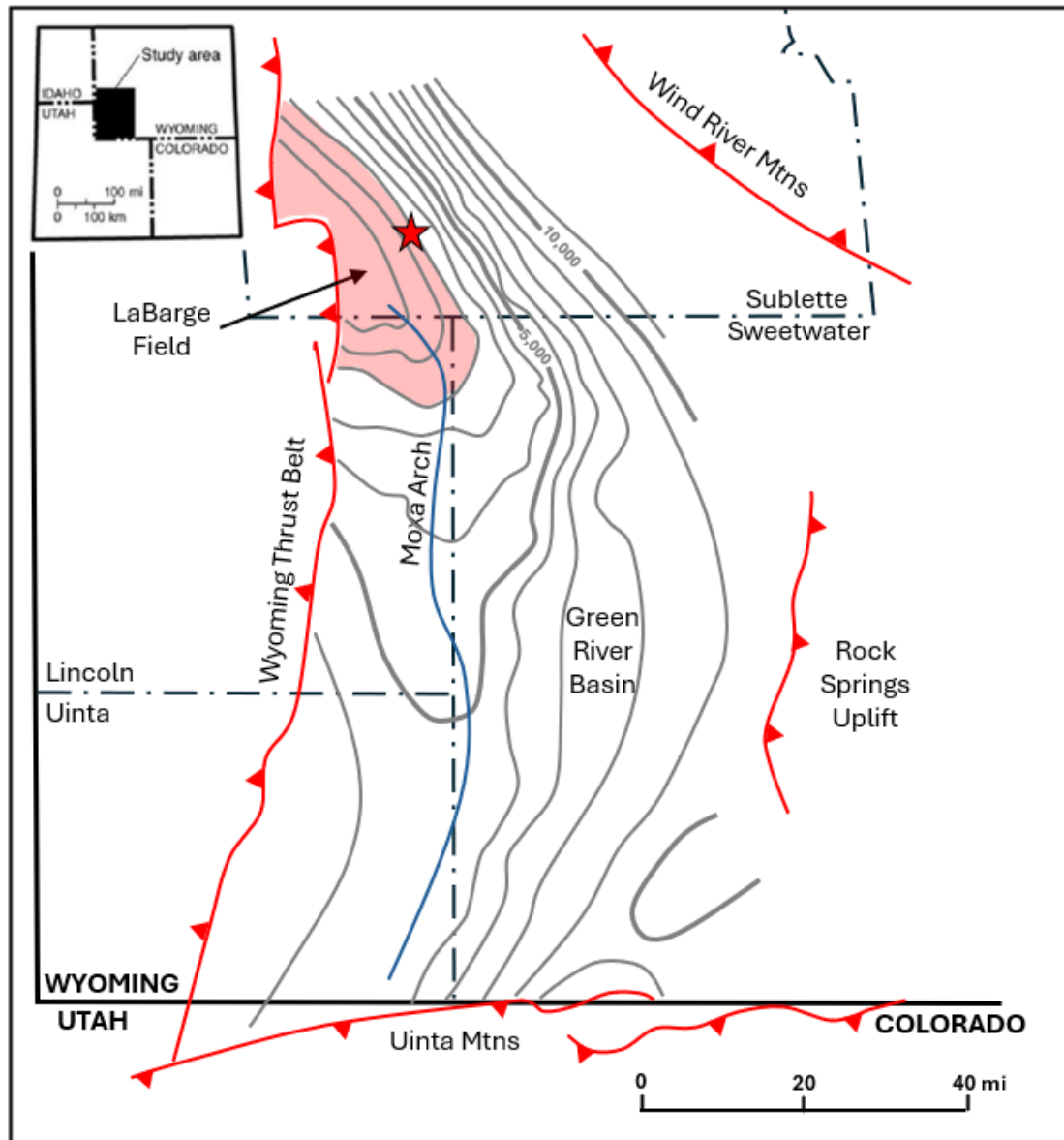


Figure 2.1-1: Location map of the LaBarge Field area, which includes Dry Piney Unit, denoted by pink shading. The DPS AGI injection area is denoted by the red star near the eastern extent of the LaBarge Field area. Modified from the USGS Greater Green River Basin Assessment.

2.2 STRATIGRAPHY OF THE GREATER LABARGE FIELD AREA

The GGRB stratigraphic record spans Precambrian through Eocene time and associated sediments or unconformities (**Figure 2.2-1**). Existing hydrocarbon production has been established through many stratigraphic intervals in the GGRB, generally from reservoirs of Paleozoic through Cenozoic age. There are two dominant styles of gas-prone petroleum systems within the GGRB, a “shallow” sweet system (lacking helium and H₂S with a minor or de minimis CO₂ component) and a “deep” sour system (with notable helium, H₂S and

CO₂ gas components). There are also two shallow oil-prone petroleum systems in the field, one produces from the Jurassic Nugget sandstone but is limited to localized structural traps, the other produces from local stratigraphic traps in the undifferentiated Tertiary, Wasatch, Almy, Fort Union and/or Mesaverde units. The Cenozoic gas-prone hydrocarbon system is sweet, relatively shallow in depth (7,000-9,000 ft TVD), regionally pervasive and generally produces from clastic sequences comprised of alternating sands interpreted to be shorelines and sealed by mud rocks (deeper water deposits) associated with fluctuating sea level of the Western Interior Seaway during Cretaceous time. The Paleozoic hydrocarbon system is deep (14,000 to 17,000 ft TVD), sour (contains H₂S, CO₂ and helium in addition to hydrocarbons), is confined to the LaBarge Field near the crest of the LaBarge “Platform” (**Figure 2.1-1**) and is primarily hosted in carbonate (dominantly dolomitic) reservoirs of Mississippian and Ordovician age. The confining units for the primary Madison and Bighorn sour gas reservoirs are comprised of shales and salt-rich sediments of Triassic age (“Triassic Evaporites”) and anhydrites in the Pennsylvanian-aged Amsden Formation and Devonian-aged Darby Formation and tight limestones and shales in the Cambrian section underlying the Bighorn. In the LaBarge Field area, including DPU, commercially producible quantities of hydrocarbons have been proven and developed in the following intervals:

- Tertiary Wasatch, Fort Union & Undifferentiated (Mesozoic, shallow, oil)
- Upper Cretaceous Mesaverde Formation (Cenozoic, shallow, sweet gas & oil)
- Upper Cretaceous Frontier Formation (Cenozoic, shallow, sweet gas)
- Lower Cretaceous Bear River Formation (Cenozoic, shallow, sweet gas)
- Jurassic Nugget Formation (Cenozoic, shallow, oil)
- Permian Phosphoria Formation (Paleozoic, deep, sour gas)
- Pennsylvanian Weber (Wells) Formation (Paleozoic, deep, sour gas)
- Mississippian Madison Formation (Paleozoic, deep, sour gas)

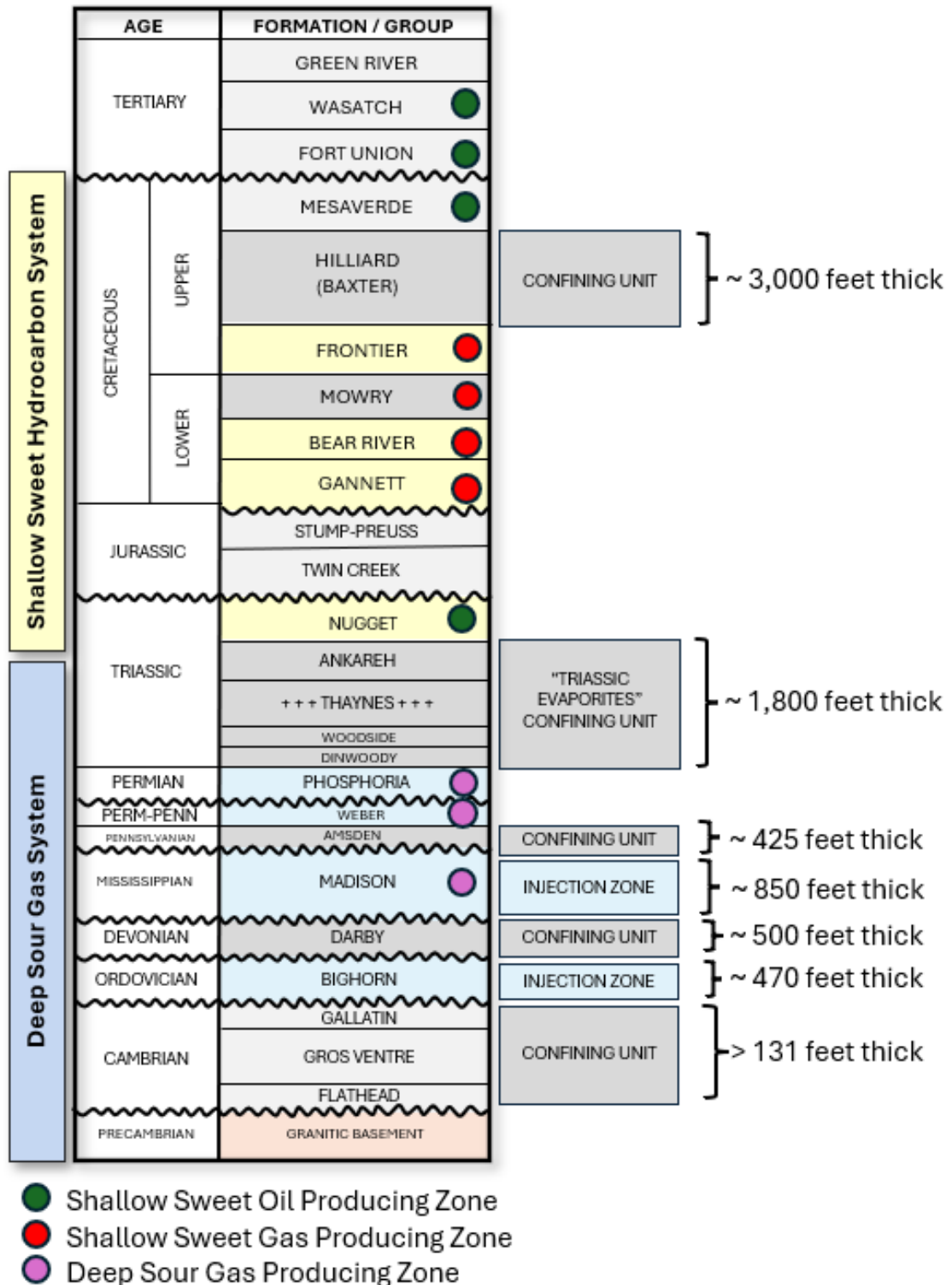


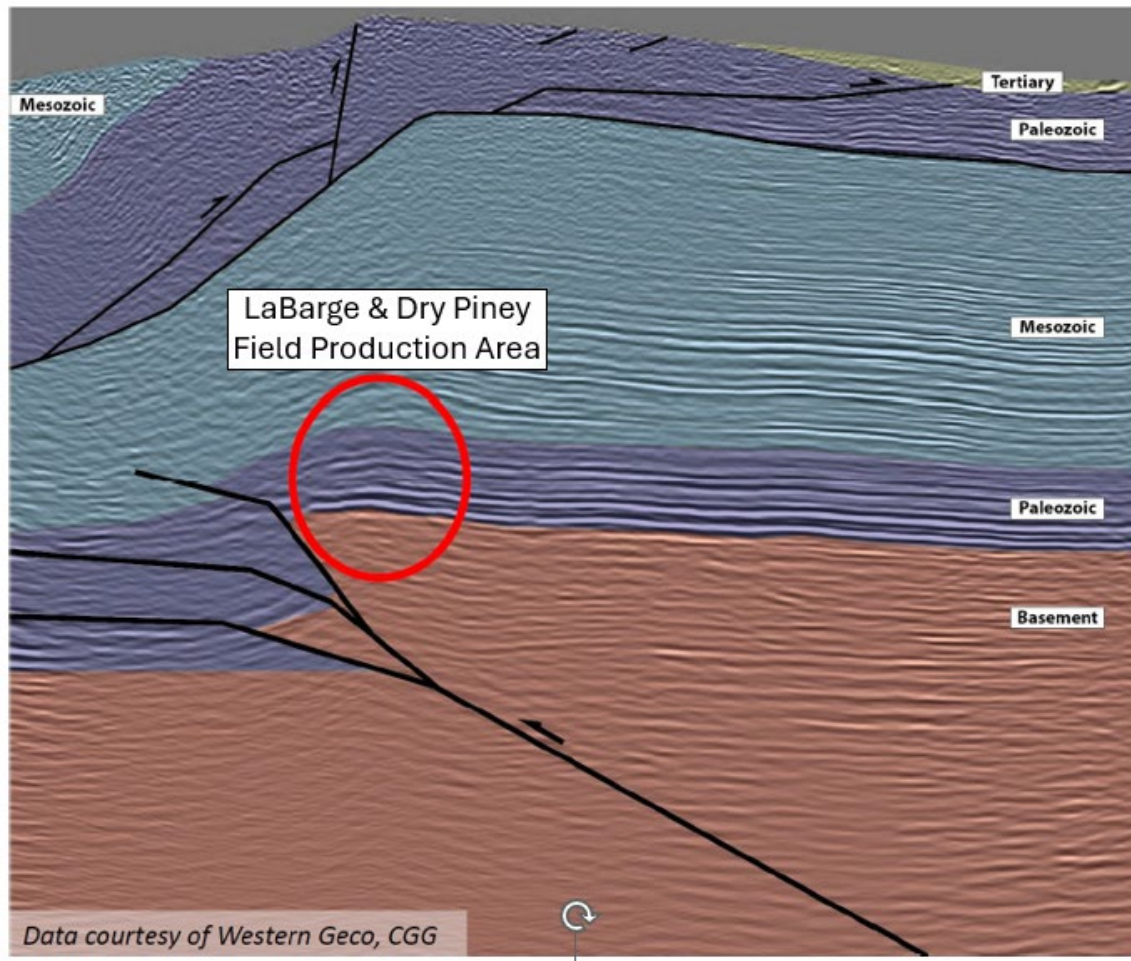
Figure 2.2-1: Generalized stratigraphic column for the western Greater Green River Basin area in Wyoming. The Madison and Bighorn injection zones and associated Triassic Evaporites, Amsden and Darby confining units are identified. Modified from Lamerson, 1982.

2.3 STRUCTURAL GEOLOGY OF THE LABARGE FIELD AREA

The LaBarge Field area lies at the junction of three regional tectonic features: the Wyoming Fold and Thrust Belt to the west, the north-south trending Moxa Arch that provides the structural closure of the LaBarge Field, and the Green River Basin to the east. On a regional scale, the Moxa Arch delineates the eastern limit of several regional north-south thrust faults that span the distance between the Wasatch Mountains of Utah to the Wind River Mountains of Wyoming. The historical evaluation of structural styles at LaBarge has defined that three principal styles of structural development have occurred in the area: Basement-involved contraction, deformation related to flowage of salt-rich Triassic strata and Basement-detached contraction.

2.3.1 BASEMENT-INVOLVED CONTRACTION EVENTS

Basement-involved contraction has been observed to most commonly result in thrust-cored monoclinial features being formed along the western edge of the LaBarge Field area (**Figure 2.3-1**). These regional monoclinial features have been imaged extensively with two dimensional (“2D”) and three dimensional (“3D”) seismic data and are easily recognizable on these data sets. At a smaller scale, the monoclinial features set up the LaBarge Field structure, creating hydrocarbon trapping configuration of the various reservoirs contained in the LaBarge productive section. The resulting LaBarge and Dry Piney Field gas accumulations in the sub-thrust Paleozoic section are hydraulically separate and disconnected from the Paleozoic section in the hanging wall thrust sheets that are at and near the surface in the area (**Section 2.3.3**).



2.3-1: Example of thrust-cored monoclinal feature interpreted to be a product of basement-involved contractional events. Note the LaBarge & Dry Piney Field Production Area of the sub-thrust Paleozoic section is hydraulically isolated and not in communication with the near-surface Paleozoic section in the hanging wall thrust sheets. From ExxonMobil Amended MRV Plan dated October 2019.

2.3.2 DEFORMATION OF FLOWAGE FROM TRIASSIC SALT-RICH STRATA

The second most common style of deformation in the LaBarge Field area is the result of flowage from Triassic strata that contain significant amounts of salt. These Triassic sediments have been observed in outcrops to be comprised of interbedded salt and siltstone intervals. At LaBarge, it is not typical to observe thick, continuous sections of pure salt, but rather interbedded salt and siltstone sections. The “salty sediments” of this interval have been determined to later evacuate and/or flow, which results in local structural highs being developed around these areas. **Figure 2.3-2** contains a seismic line illustrating the Triassic salt-rich sediments and structuring. The salt-induced local structural features generated via salt evacuation can and do create small local hydrocarbon traps associated with these sediments. These smaller, localized structures

are of a much smaller scale than the main monoclinal hydrocarbon trap of the larger LaBarge Field.

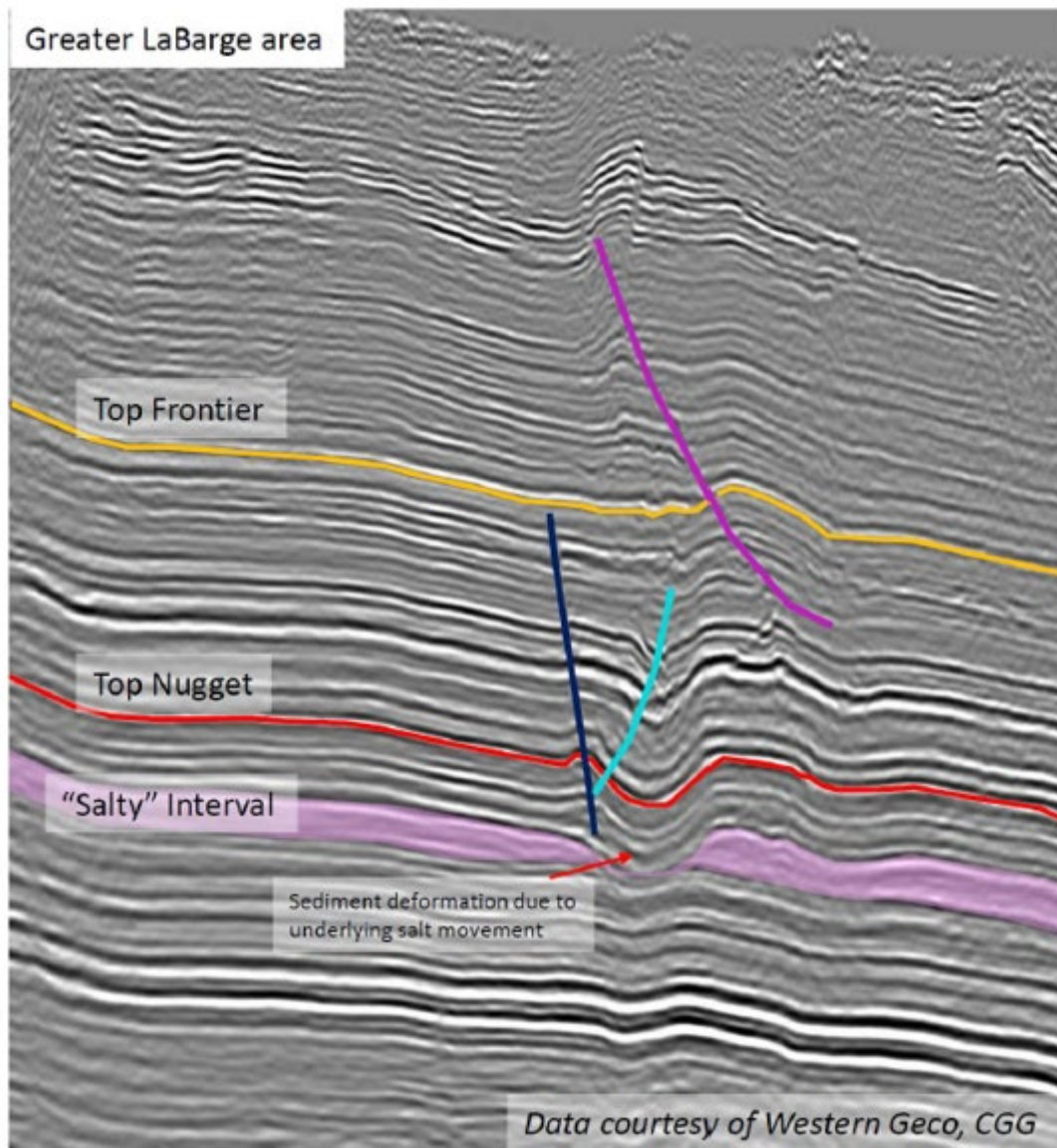


Figure 2.3-2: Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge Field area. From ExxonMobil Amended MRV Plan dated October 2019.

The active deformation behavior of these Triassic sediments has been empirically characterized through the drilling history of the LaBarge Field. Early in the life of several wells drilled in the LaBarge Field area, wells drilled with thin-walled casing were susceptible to failure due to casing shearing across the Triassic interval. Subsequent wells drilled in the field area used thicker-walled casing strings and successfully mitigated the salt-sediment flowage issue.

2.3.3 BASEMENT-DETACHED CONTRACTION

The third main structural style observed in the LaBarge Field area is basement-detached contraction (**Figure 2.3-3**). These features have been well-documented at LaBarge as many of these features have mapped fault expressions on the surface. The Paleozoic outcrops mapped in the overthrust belt are not in hydraulic communication with the productive sub-thrust Madison Formation, which is a function of a basement-involved contraction event as discussed in **Section 2.3.1** and noted on **Figure 2.3-1**. The lack of hydraulic communication between the sub-thrust injection zones and the outcrops of the same formations is important because the world-class LaBarge and Dry Piney Field production area would not exist otherwise and therefore, the risk of CO₂ leakage via lateral migration is exponentially reduced (**Figure 2.3-1**). Detachment and contraction along the basement typically create three types of structural features: Regional scale thrust faults, localized smaller-scale thrust faults, and reactivation of Triassic salt-rich sediments resulting in local structural highs.

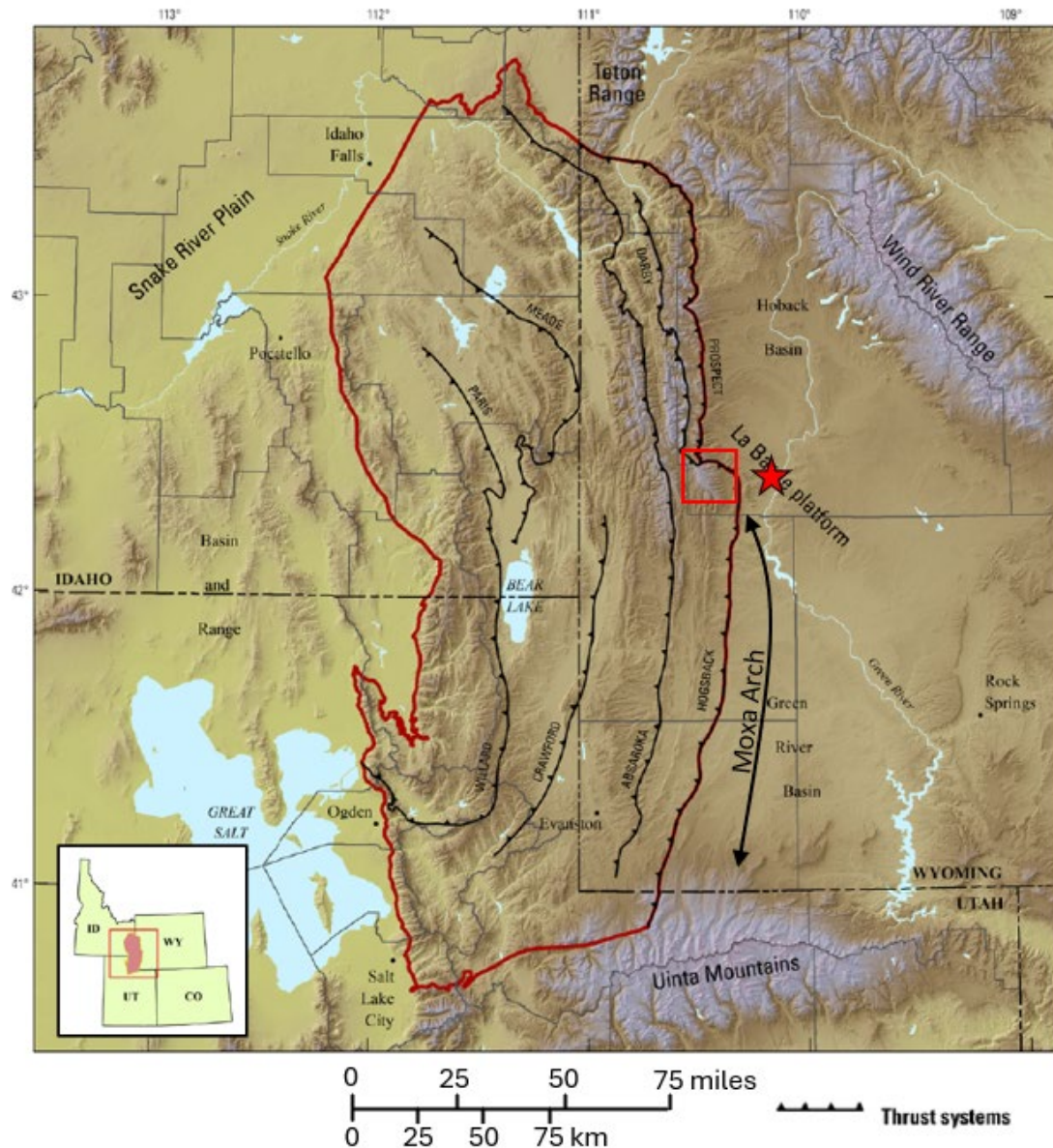


Figure 2.3-3: Map showing location of the Moxa Arch and regional thrust faults of the Wyoming Range. The LaBarge/Dry Piney Unit production field area is denoted by the red box, and the approximate injection area is denoted by the red star. Modified from Buursink et al, 2014.

2.3.4 FAULTING AND FRACTURING OF RESERVOIR INTERVALS

Reservoir permeability in the LaBarge Field has been found to increase in areas with small-scale faults and fractures, across nearly all productive zones. Micro-fractures have been identified both in core samples and on borehole micro-imaging logs, with the fractures in the core typically filled with calcite.

In general, wells located near structural highs or fault junctions tend to show higher reservoir permeability and improved hydrocarbon productivity. This suggests that these areas may have a significantly higher density of natural fractures, or a greater proportion of open fractures compared to calcite-filled ones. In contrast, areas with little to no significant faulting, such as the planned AGI area, typically exhibit reservoir permeability driven by matrix or pore-to-pore flow. Matrix permeability is usually less effective in supporting fluid movement over long distances and creates an ideal environment for permanent carbon dioxide containment.

There are a limited number of faults in the eastern DPS AGI area of the LaBarge Field, and those that do exist are characterized as near vertical, possess near zero offset and are limited in aerial extent. Most faults are detected by subtle discontinuities in seismic reflectors and may or may not be combined with abrupt local dip changes. Generally, the faults do not extend upward through or above the Triassic Evaporites confining layer which is the primary seal for the sour helium-rich hydrocarbon system. The small subset of faults that do appear to extend upward through the Triassic Evaporites confining unit are not active leakage pathways from the Madison and Bighorn injection zones to shallower geologic units, as evidenced by the lack of CO₂ and H₂S in gas composition analyses of shallow gas wells located near said faults. In no case are any faults observable or mappable at the surface. See **Table 2.6** for a summary of gas composition in select wells, and **Sections 2.6.3** and **4.4** for further discussion of faults and fractures as a potential leakage pathway.

2.3.5 LABARGE FIELD STRUCTURE AND GAS RESOURCE OF THE MADISON FORMATION

Structural closure at the sub-thrust Madison Formation level in the LaBarge Field area is very large, with approximately 4,000 ft TVD of structural closure from the top of the structure to the gas-water contact (“GWC”). Spatially, the Madison closure covers over 800 square miles, making it one of the largest conventional gas fields in North America.

The Madison Formation is estimated to contain more than 300 trillion cubic ft (“TCF”) of raw gas and 20 TCF of natural gas (methane). At current rates of production, and including the addition of BSO’s planned production wells, the estimated remaining field life is over 100 years. Spatially, the Madison and Bighorn injection wells are located approximately 10.5 miles to the east-northeast of the DPIGPF and LaBarge Field (DPU) production area.

Structural configuration and lateral continuity of the Madison and Bighorn producing and injection zones provide both a tremendous gas-in-place (production) and storage capacity (injection) resource. Sub-units in the Madison and Bighorn reservoir and injection zones (Sections 2.6.2 and 2.6.3), along with their associated confining units (Sections 2.6.3 and 2.6.4) can be confidently correlated over approximately 75 miles via well control and an extensive industry library of seismic data.

2.4 PETROLEUM PRODUCTION HISTORY OF THE LABARGE FIELD AREA

The LaBarge Field in southwestern Wyoming has a rich history of oil and gas exploration and production, marked by significant discoveries and technological advancements. Below is a detailed timeline highlighting key events in the development of the area.

1840s: Oil was reported by emigrants who used it to grease their wagon wheels.

1907: Initial drilling activities commenced near the future site of Calpet, close to the southern border of what would become the LaBarge Oil Field. These early efforts faced challenges due to the field's remote location, approximately 35 miles from the nearest railhead in Opal, making transportation of heavy drilling equipment difficult.

1920s–1930s: Early Exploration & First Production

- Drilling success in 1923 and the discovery of oil in 1924 marked the beginning of commercial production.
- Initial wells targeted shallow Tertiary & Upper Cretaceous sandstone reservoirs but faced limitations due to transportation challenges.

1940s–1950s: Expansion & Geological Studies

- Increased geological surveys by General Petroleum (a Mobil predecessor) helped better define the field's oil and gas potential.
- Belco Development Company (an EOG Resources predecessor) discovers natural gas in the Frontier Formation.
- By 1956, completion of a Pacific Northwest natural gas pipeline provided takeaway capacity and the LaBarge area was recognized as a key gas-producing region in Wyoming.

1960s–1970s: Infrastructure & Pipeline Development

- In 1962, Mobil discovers deep Paleozoic (Madison) gas at Tip Top, elects to not develop further due to economic and technological constraints associated with the sour gas.
- Investment in infrastructure, including pipeline construction, facilitated the transport of shallow oil and gas.
- Shallow development lead by General Petroleum, Belco and Mountain Fuel Supply Company (QEP Resources predecessor), focused on structural traps in the Frontier Formation.
- Natural gas production increased, paving the way for larger-scale operations in later decades.

1980s–1990s: ExxonMobil & Large-Scale Gas Production

- In 1981, Exxon discovers Madison gas in the Lake Ridge Unit.
- During the mid-1980's, Exxon develops Madison gas in Lake Ridge, Fogarty Creek and Graphite Units and begins construction of Shute Creek Treating Facility and associated infrastructure.
- Exxon began operations at the Shute Creek Treating Facility in 1986, focusing on natural gas with a high CO₂ content.
- In 1999, Exxon and Mobil merge, EOG Resources spins out from Enron (Belco Development Company successor).

2000s: Environmental Initiatives & CO₂ Capture

- ExxonMobil launched carbon capture and storage (“CCS”) projects to reduce emissions.
- Between 2001 and 2005, ExxonMobil drills and begins injection into initial AGI wells to dispose of hydrogen sulfide and minor carbon dioxide volumes.
- CO₂ from the field was increasingly used for enhanced oil recovery in other reservoirs.

2010s: Advanced Gas Processing & New Technologies

- In 2010, QEP Resources spins off from Questar (Mountain Fuel Supply Company successor).
- ExxonMobil tested new gas separation technologies, including the Controlled Freeze Zone (“CFZ™”) process.
- The LaBarge Field cemented its role as a crucial CO₂ supplier for enhanced oil recovery in the Rockies.

2020s: Continued Production & Energy Transition

- In 2020, BSO acquired leasehold to develop the Madison in the DPU area from QEP Resources and EOG Resources.
- In 2024, BSO drilled the Dry Piney 4-36 production test well in DPU and confirmed the Madison gas composition, including higher than anticipated helium, and encountered higher reservoir pressures than expected.
- In 2025, BSO drilled and acquired geologic data in the Dry Piney State 12-16 injection well.
- Ongoing investments by ExxonMobil and BSO in CCS align with efforts to reduce the field's carbon footprint.

2.5 INITIAL DISCOVERY OF MADISON GAS AND EARLY COMMERCIALITY AT LABARGE

Mobil discovered significant natural gas reserves in the Madison Formation within the LaBarge Field area in 1962. However, due to economic and technological constraints, commercial development did not commence immediately. It was not until the 1980s that large-scale production became viable, following Exxon's successful discovery of Madison gas in the Lake Ridge Unit, which helped justify the necessary infrastructure investments.

Meanwhile, commercial gas production from the Frontier Formation began earlier, in 1956, after the completion of the Pacific Northwest Pipeline. This crucial pipeline provided the market access needed to support Belco Development's Frontier gas production program, enabling steady extraction and transportation of natural gas from the region.

Oil production from the Nugget Sandstone Formation was established later, though on a much smaller scale compared to gas production.

The Madison Formation's vast gas reserves remained largely untapped until Exxon initiated production in 1986 with the startup of the Shute Creek Treating Facility. This facility was critical in processing the high-CO₂ and high-H₂S natural gas from the Madison Formation, separating methane, nitrogen, carbon dioxide, and helium to make the gas commercially viable.

The Madison Formation at LaBarge contains an estimated total gross gas in-place volume exceeding 300 TCF. Since production began in 1986, ExxonMobil (Exxon and Mobil merged in 1999) has cumulatively extracted approximately 8.7 TCF of raw gas from the Madison Formation with production continuing today at approximately 700-720 MMscfpd.

BSO plans to produce approximately 7.3 TCF of raw gas during its 50-year project life.

2.6 ACID GAS INJECTION PROGRAM HISTORY AT LABARGE

ExxonMobil has been injecting acid gas into the Madison Formation in two Class II AGI wells since 2005. ExxonMobil drilled a third Class II AGI well in 2023 and is currently working to bring it online, with injection operations expected to begin in 2025. ExxonMobil has a fourth Class II AGI well currently approved to drill by the WOGCC, and a fifth Class II AGI well in the permitting process. All ExxonMobil Class II AGI wells are located about 45 miles south of the LaBarge Field production area and are targeting the Madison and/or Bighorn Formations below the GWC.

The Madison Formation raw gas production contains a relatively low methane (CH₄) concentration and high carbon dioxide (CO₂) content. The average gas composition of Madison gas produced by ExxonMobil is as follows:

- 21% Methane (CH₄)
- 66% Carbon Dioxide (CO₂)
- 7% Nitrogen (N₂)
- 5% Hydrogen Sulfide (H₂S)
- 0.6% Helium (He)

Due to the high CO₂ and H₂S content of Madison gas, there was a significant need for CO₂ and H₂S disposal after separating and marketing the saleable products (primarily CH₄ and He). ExxonMobil has historically sold a significant portion of the excess CO₂ into the enhanced oil recovery (“EOR”) market and vented the remainder. The Shute Creek Treating Facility (“SCTF”) originally contained a sulfur recovery unit to transform the waste H₂S gas to elemental sulfur. Around 2005, due to poor economics, ExxonMobil decommissioned the sulfur recovery units to debottleneck and improve reliability at SCTF. This generated the need to inject the H₂S and entrained CO₂ into the Madison subsurface via AGI wells. In 2022, ExxonMobil received federal permits to expand its carbon capture program at SCTF to capture the remaining CO₂ volumes not sold into the EOR market and were therefore historically vented to the atmosphere. The previously vented CO₂ volumes will be injected into the recently drilled SC 5-2 AGI well, expected to begin operations in mid-late 2025.

2.6.1 GEOLOGICAL OVERVIEW OF THE BSO AGI PROGRAM

BSO anticipates producing sour gas very similar in composition to that produced by ExxonMobil, and is represented by the following components based on reservoir fluid sampling in the Dry Piney 4-36 well drilled by BSO:

- 20.5% Methane (CH₄)
- 67.0% Carbon Dioxide (CO₂)
- 7.4% Nitrogen (N₂)
- 4.5% Hydrogen Sulfide (H₂S)
- 0.6% Helium (He)

BSO plans to capture and dispose of all the CO₂ and H₂S waste gas after the saleable products (CH₄ and He) have been separated, processed and refined at the DPIGPF. Nitrogen will either be vented, sold into the local market, and/or utilized in the helium liquefaction process in the gas processing facility.

BSO has pursued the AGI program as a proven, safe, and reliable method to dispose of the acid gas waste stream into the Madison and Bighorn Formations based upon ExxonMobil’s successful 20-year injection history into the Madison Formation on the same geologic structure. ExxonMobil injects acid gas below the GWC, but BSO plans to target the Madison and Bighorn Formations for injection just above the GWC. BSO’s evaluation indicates that more favorable injection rates will potentially be obtained for a longer

duration above the GWC, thus requiring fewer AGI wells to handle the CO₂ and H₂S waste gas stream requiring disposal. Waste gas composition for disposal will be approximately 92.4% CO₂ and 6.93% H₂S and 0.5% methane by molar volume. The acid gas will be injected at depths ranging approximately 14,800 feet to 16,500 feet TVD below the surface and will be located near the GWC approximately 10.5 miles to the east-northeast of the main DPU (LaBarge Field) production areas (**Figure 2.6-1**). The depth range represents the depth of the shallowest perforation near the top of the Madison Formation to depth of the deepest perforation near the base of the Bighorn Formation. It is important to note that the in-situ gas compositions in the Madison and Bighorn Formations at the DPS AGI area are significantly higher in CO₂ and significantly lower in both methane and helium than in the DPU production area due to gravity segregation over geologic time.

In the DPS AGI area, the average Madison gas composition is:

- 4.6% Methane (CH₄)
- 89.4% Carbon Dioxide (CO₂)
- 4.4% Nitrogen (N₂)
- 1.2% Hydrogen Sulfide (H₂S)
- 0.24% Helium (He)

In the DPS AGI area, the average Bighorn gas composition is:

- 0.5% Methane (CH₄)
- 96.2% Carbon Dioxide (CO₂)
- 2.5% Nitrogen (N₂)
- 0.5% Hydrogen Sulfide (H₂S)
- 0.25% Helium (He)

The gas compositions above are the average concentrations based on gas analyses conducted on fluid samples collected during wireline logging of the Dry Piney State 12-16 well drilled by BSO in 2025.

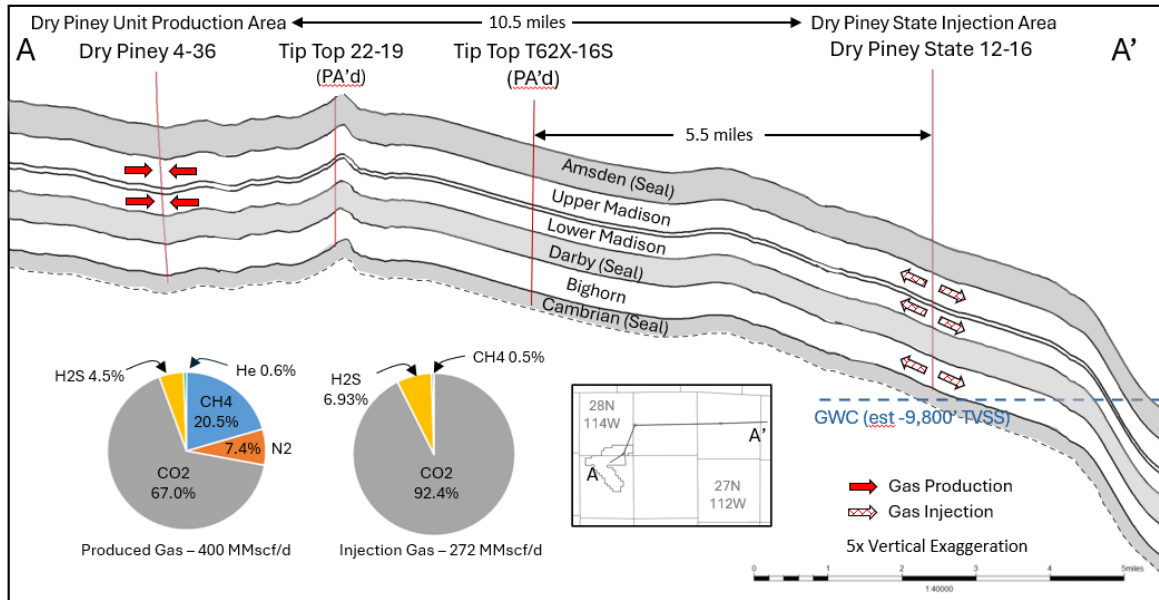


Figure 2.6-1: Schematic illustration showing location of proposed Dry Piney State 12-16 well and injection area near gas-water contact (GWC) relative to the Dry Piney Unit production area approximately 10.5 miles to the west. Two plugged and abandoned Tip Top wells penetrate the Madison & Bighorn Formations between the BSO production and injection areas, but only the Tip Top T62X-16S is within the Maximum Monitoring Area defined in Section 3.0. Vertical exaggeration is 5x.

2.6.2 RESERVOIR QUALITY OF THE MADISON AND BIGHORN FORMATIONS IN AGI WELLS

BSO's proposed AGI wells are approximately 10.5 miles east of the Dry Piney Unit production area and the 2024 BSO Dry Piney 4-36 well. There are two plugged and abandoned wells that penetrate the Madison and Bighorn Formations between the production and injection areas, the 1962 Mobil Tip Top Unit 22-19 well and the 2008 ExxonMobil Tip Top T62X-16S. The Tip Top T62X-16S logs are not publicly available, so reservoir quality is unknown at that location (**Figure 2.6-2**). As will be discussed in later sections, the Tip Top T62X-16S is the only well in the Maximum Monitoring and Active Monitoring Areas that penetrates the Madison and Bighorn injection zones. BSO completed drilling and logging the Dry Piney State 12-16 well in the injection area in June 2025. Extensive data was acquired in both BSO wells to allow evaluation of the reservoir quality and storage capacity of the Madison and Bighorn Formations in the Dry Piney Unit production area and the DPS AGI area. Forty-one wells on the LaBarge structure have sufficient publicly available data to integrate into a petrophysical model, the results of which have been integrated into a geologic model that characterizes Madison and Bighorn reservoir quality regionally and locally in the DPS AGI area.

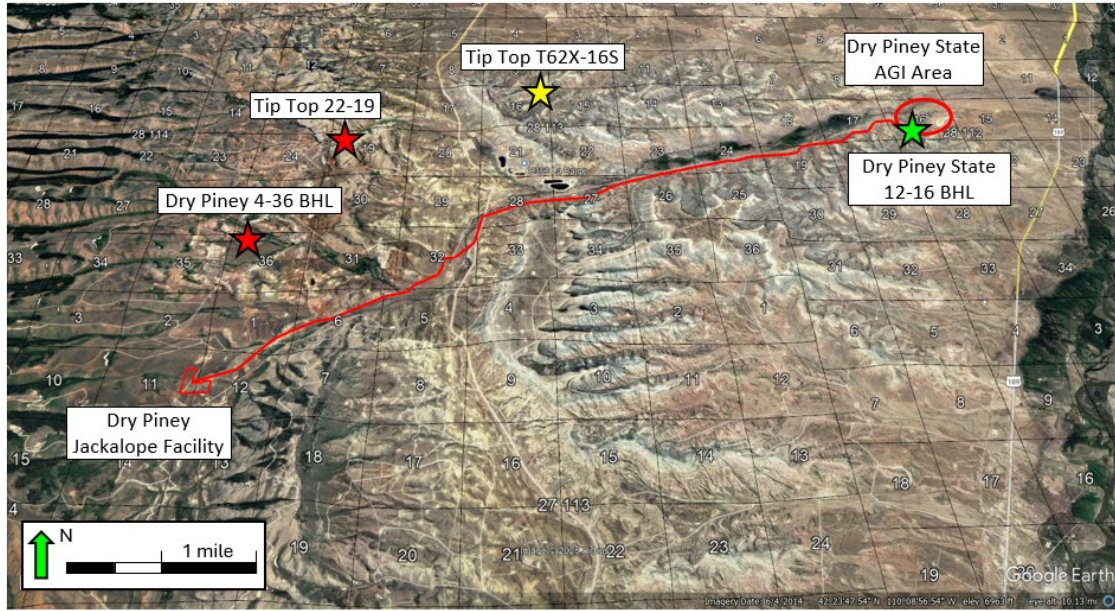


Figure 2.6-2: Map showing the relative position of the BSO proposed AGI area (red circle) and Dry Piney State 12-16 (green star) relative to the Tip Top Unit 22-19 and the BSO Dry Piney 4-36 wells (red stars). Logs unavailable for the Tip Top T62X-16S well (yellow star). The DPIJGPF is denoted by a red rectangular box and the proposed pipeline route between DPIJGPF and the DPS AGI area is the red line.

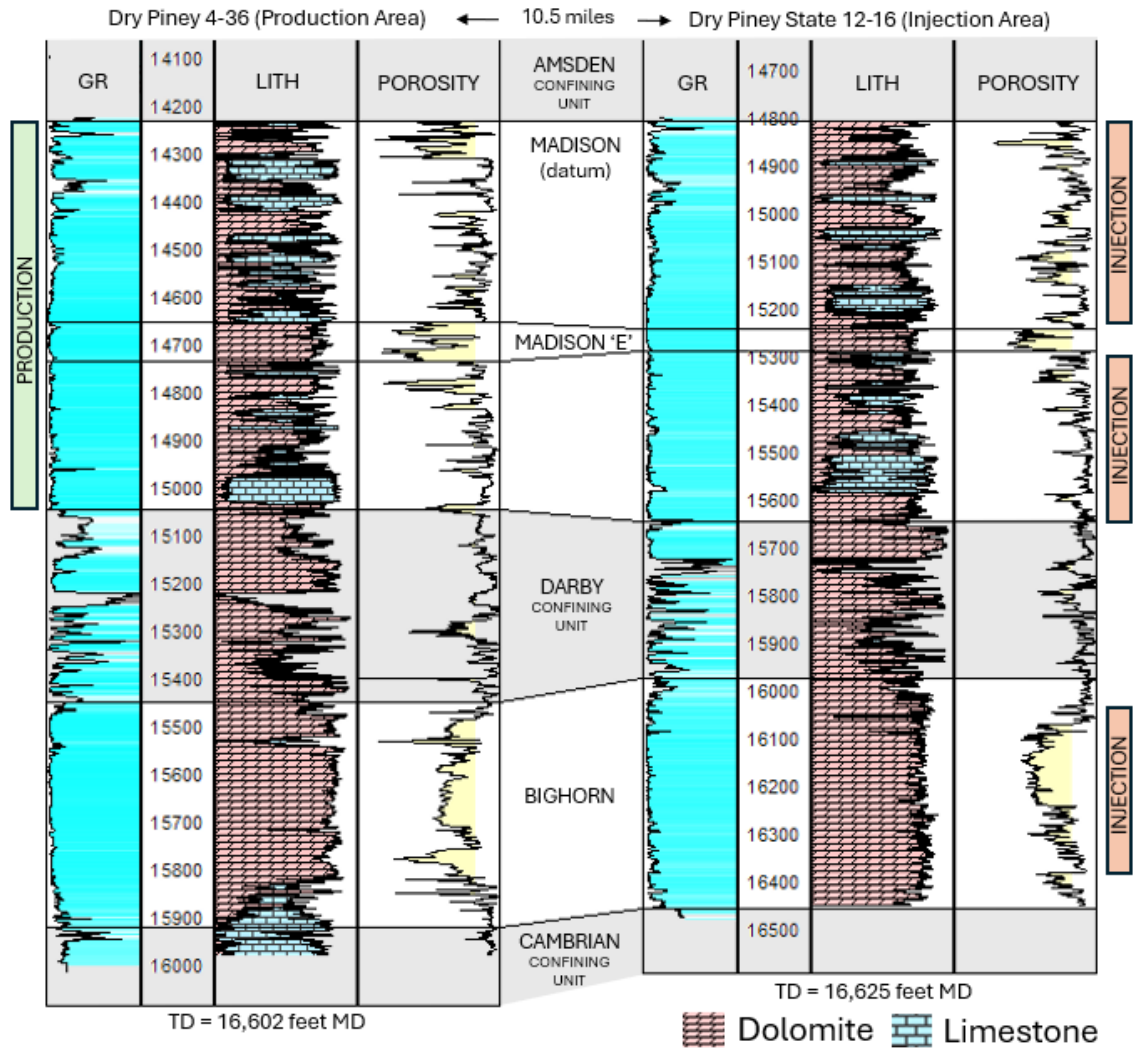


Figure 2.6-3: Stratigraphic cross-section showing Dry Piney 4-36 well (Production Area) and Dry Piney State 12-16 (Injection Area). Madison well top is the stratigraphic datum. Gamma Ray (GR), lithology (LITH) and Porosity logs displayed. Note that porosity over 5% is shaded in yellow. Madison production interval denoted by the green bar to the left of the Dry Piney 4-36 and Madison & Bighorn Injection intervals denoted by orange bars to the right of the Dry Piney State 12-16. The confining units immediately above and below the Madison and Bighorn are shaded in gray. Production area and Injection area are separated by approximately 10.5 miles.

Petrophysical evaluation of these wells indicates that the Madison Formation is comprised of alternating limestone and dolomite intervals (**Figure 2.6-3**). In general, the limestone intervals possess lower porosity averaging 0-5%, whereas the “pay” dolomite intervals greater than 5% porosity average 9.7% porosity and act as the primary reservoir lithofacies. Overall, the Madison Formation averages 5.5% porosity. The Bighorn Formation is primarily dolomite and contains a relatively high porosity zone (>12%)

approximately 175 ft thick in the middle of the formation. The “pay” in the Bighorn Formation averages 10.7% porosity, while the overall Bighorn averages 7.7% porosity. Core permeability indicates both the Madison and Bighorn dolomites range from 1 to 500 millidarcies (“md”), with an average of around 10 md in both the Madison and Bighorn. The reservoir quality of the Madison and Bighorn Formations in the Dry Piney State 12-16 injection well are summarized in **Figure 2.6-4**, and future injection wells in the DPS AGI area are anticipated to be similar.

Formation	Madison	Bighorn
Net Pay (ft)	343	309
Avg Phi (%)	9.7	10.5
Avg K (mD)	10	10
Kh (md-ft)	3430	3090
Skin	-4.0 to -4.5*	-4.0 to -4.5^

Figure 2.6-4 – Average reservoir properties for the Dry Piney State 12-16 injection well. Future AGI wells are expected to have similar properties. * Skin as reported by other operators injecting into same formation based on injectivity and fall-off tests. ^ Bighorn skin factor is assumed to be similar to Madison owing to similar Avg Phi and Avg K reservoir properties.

From **Figure 2.6-4**, the parameters tabulated include:

- Net Pay: Feet of Madison and Bighorn intervals that exceed 5% total porosity.
- Avg Phi: Average total porosity (the percent of the total bulk volume of the rock investigated that is not occupied by rock-forming matrix minerals or cements).
- Avg K: Air permeability, which is measured in units of darcy – a measure of the ability of fluids to move from pore to pore in a rock.
- Kh: Millidarcy-ft, which is a measure of the average permeability multiplied by the total net pay section encountered.
- Skin: Relative measure of damage or stimulation enhancement to formation permeability in a well completion. Negative skin values indicate enhancement of permeability through the completion whereas positive values indicate hindrance of permeability or damage via the completion.

2.6.3 SEISMIC EXPRESSION OF MADISON & BIGHORN FORMATIONS AT AGI WELL LOCATIONS

Seismic expression of the Madison and Bighorn Formations at the proposed DPS AGI area indicates that the planned injection wells are located on the plunging eastern limb of the Moxa Arch. The eastern limb dips to the northeast at approximately 3 to 5 degrees depending on location. Nine faults with minimal offset and limited aerial extent were

identified in the seismic data within the Maximum Monitoring Area (“MMA”, **Section 3.0**), with the nearest fault occurring approximately 3.4 miles north of the DPS AGI location. *It is important to note that none of the faults in the MMA are observed at the surface, nor does seismic interpretation suggest that any faults in the MMA extend to the surface.* The faults are characterized by discontinuity and change in local structural dip of seismic reflectors, rather than significant offset, and are generally constrained to the geologic units below the Triassic Evaporite confining unit. All but three of the faults (Faults 5, 6 and 7, **Figure 2.6-5**) terminate below, and therefore do not extend vertically above, the Triassic Evaporite confining layer. As discussed further in Section 4.4 there is very low to low risk of the faults impacting the ability of the Triassic Evaporite confining unit to maintain its seal integrity within the MMA. As observed on **Figure 2.6-6**, Fault 1 is limited to the Madison Formation and deeper. There are no faults evident on a west to east seismic panel through the DPS AGI area (**Figure 2.6-7**). Faults 5, 6 and 7 were observed to extend vertically above the Triassic Evaporite confining layer in the proposed AGI area (**Figure 2.6-8**). Extensive Frontier and Bear River gas production development has occurred in the vicinity of these faults in and near the Birch Creek Unit (“BCU”) in Township 27 North, Range 113 West (**Figure 2.6-5**), providing the opportunity for baseline monitoring and early detection and quantification of potential CO₂ leakage if these faults act as leakage pathways (See **Sections 4.4, 5.3** and **5.6** for further discussion). Of particular interest is the BCU No. 1 well, which was drilled to the Nugget, then plugged back to the Frontier in 1957 and provides a key baseline data point in terms of gas composition, as it is the deepest well near Faults 5, 6 and 7. Faults 5, 6 and 7 terminate in the Frontier Formation, and do not extend upward into the approximately 3,000-foot thick Hilliard (Baxter) Shale confining zone. If Faults 5, 6 and 7 were acting as a conduit for CO₂ leakage from the existing naturally occurring CO₂ and H₂S resource in-place, CO₂ and H₂S would be detected in the gas analyses conducted on samples collected from wells near these faults. **Table 2.6** summarizes the gas analyses for shallow wells near Faults 5, 6 and 7, demonstrating the lack of significant CO₂ (defined as > 2.0 mole % “mol%”) and no H₂S or helium and therefore the lack of an active leakage pathway via these faults. Gas analysis reports showing the concentration measurements below for the wells in **Table 2.6** are available in **Appendix D**.

Well ID	Well Name	CO ₂ (mol%)	H ₂ S (mol%)	Helium (mol%)	Nitrogen (mol%)	Oxygen (mol%)
4903505496	UNIT MCGINNIS (GRBU) No. 10-9	0.28	0.00	NA	0.31	0.00
4903522369	BIRCH CREEK UNIT No. 185	0.29	0.00	NA	0.98	0.00
4903521959	BIRCH CREEK UNIT No. 166	0.27	0.00	NA	1.21	0.00
4903522282	COOPERS No. 1-8	0.21	0.00	NA	0.86	0.00
4903522371	BIRCH CREEK UNIT No. 187	0.83	0.00	NA	0.42	0.00
4903522145	BIRCH CREEK UNIT No. 124	0.77	0.00	NA	0.92	0.00
4903522384	COOPERS No. 7-31	0.70	0.00	NA	0.37	0.00
4903520672	FEDERAL No. 30-31	0.35	0.00	NA	0.34	0.00
4903522370	BIRCH CREEK UNIT No. 134	0.46	0.00	NA	0.57	0.00

Table 2.6 – Summary of key parameters in select existing producing gas wells within the MMA that have publicly available gas analyses. Note the lack of significant CO₂ (defined as > 2.0 mol%), no H₂S, and minor nitrogen and oxygen. All values reported are in mol%. Historically, helium is not routinely analyzed as it is commonly accepted that there is insufficient helium to be recovered from the shallow sweet gas system. Helium will be measured in BSO's planned baseline data sampling program. Significant increases in CO₂, H₂S and/or helium concentrations will be utilized as a CO₂ leakage detection methodology discussed in later sections. See **Appendix D** for gas analysis laboratory reports for source of data in Table 2.6.

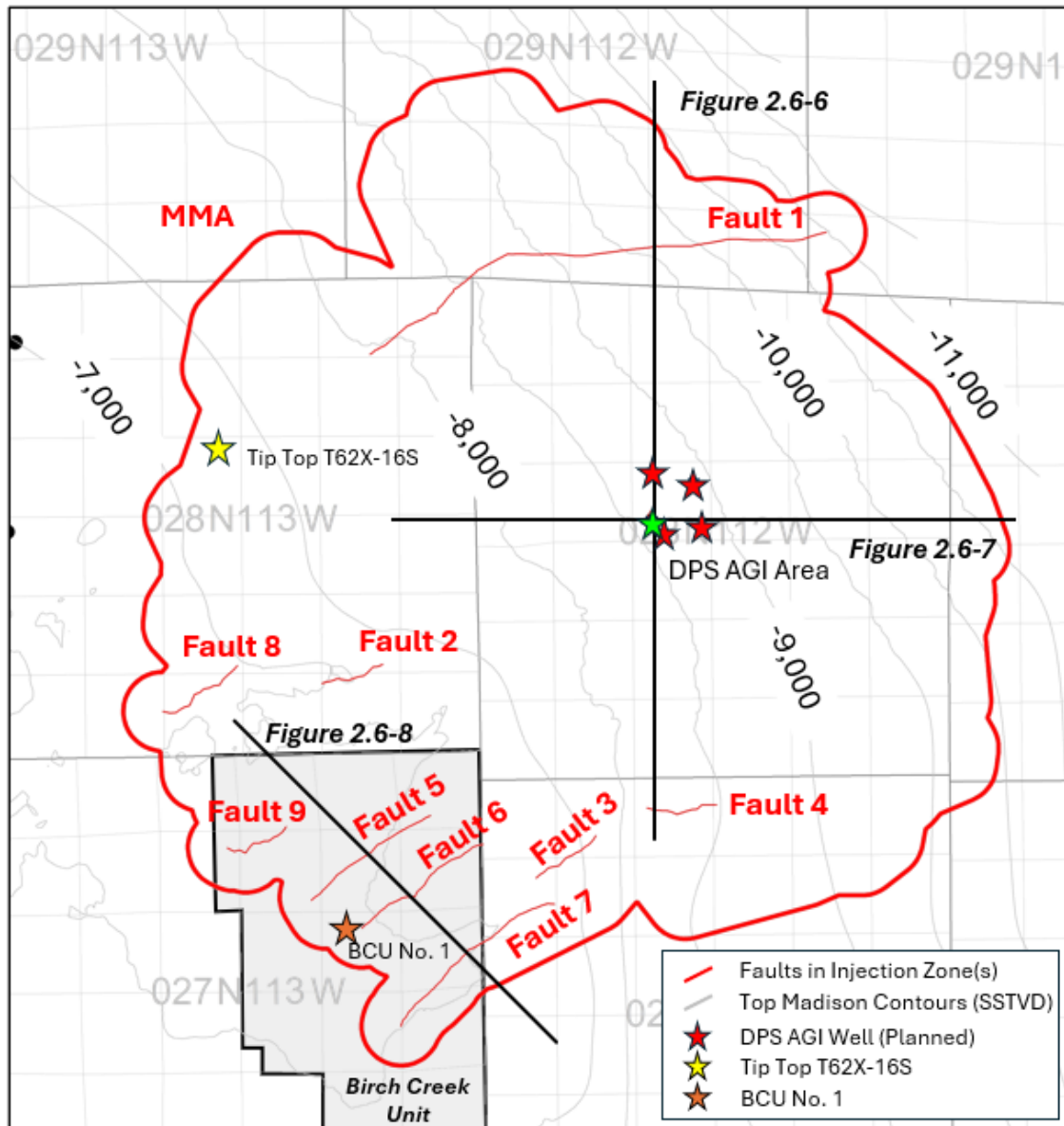


Figure 2.6-5: Madison Structure (TVDSS, 500 ft contour interval) reference map showing N-S (**Figure 2.6-6**) and W-E (**Figure 2.6-7**) seismic lines through the DPS AGI area, including the DPS 12-16 well (green star) and future DPS AGI wells (red stars). Note the fault traces (red lines) of minor faults observed during seismic interpretation. “Fault 1” is displayed on N-S seismic line in **Figure 2.6-6**, and Faults 5, 6 & 7 are displayed on the NW-SE seismic-based cross-section line in **Figure 2.6-8**. The Maximum Monitoring Area (“MMA”) is shown as the red polygon. See Section 3.0 for further discussion of the MMA and the Active Monitoring Area (“AMA”). The Tip Top T62X-16S (yellow star) is the only well within the MMA that penetrates the Madison and/or Bighorn injection zones, other than the DPS 12-16 well. Note that the Tip Top T62X-16S well does not intersect the stabilized plume at any point in time (**Figure 2.8-2**). There are numerous existing shallow gas wells in the Birch Creek Unit near Faults 5, 6 and 7 that will potentially be utilized as baseline sampling wells

for early detection of CO₂ leakage along Faults 5, 6 and 7 as potential pathways, including the BCU No. 1 (orange star) which was drilled to the Nugget Formation before being plugged back and completed in the Frontier Formation. It is important to note that no faults are observed at the surface, nor does seismic interpretation suggest that any faults extend to the surface.

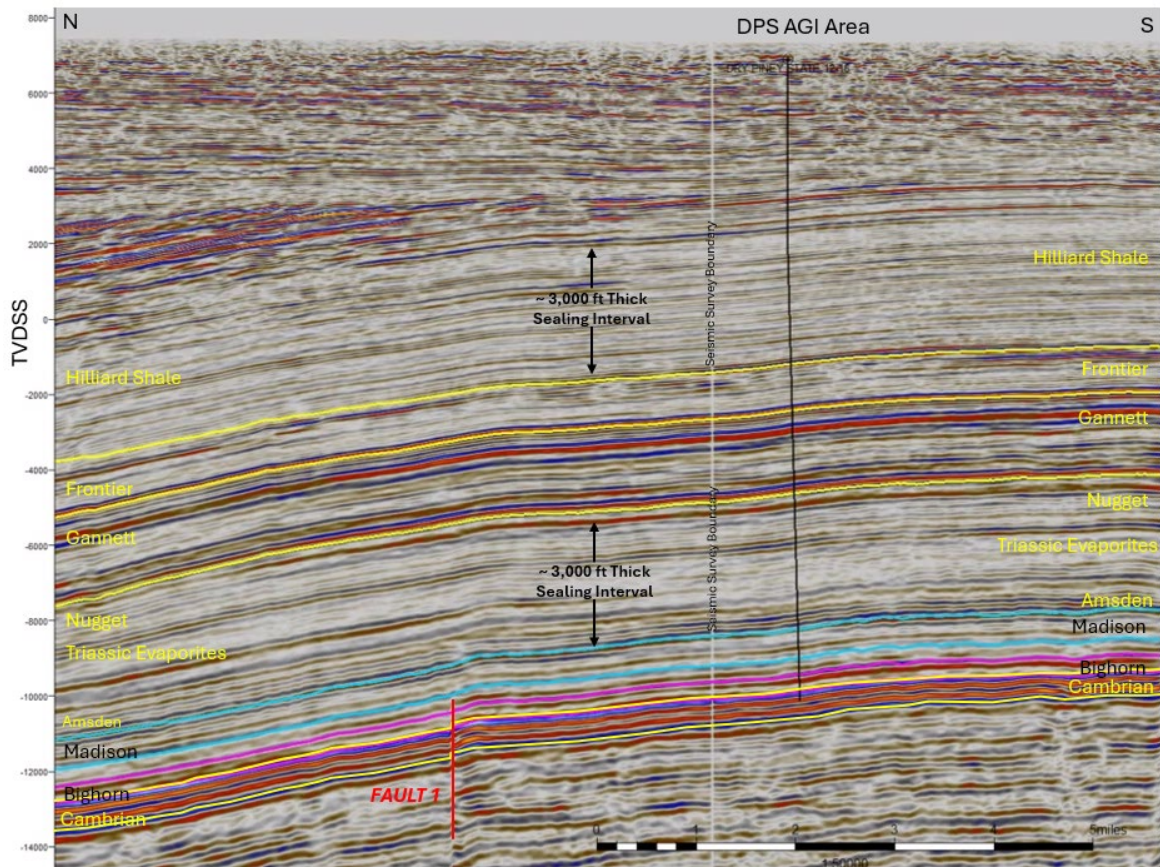


Figure 2.6-6: Seismic line from 3D volume, oriented N to S through the proposed Dry Piney State 12-16 injection well location, shows one minor fault (Fault 1) with minimal vertical offset that dies out before extending above the Madison Formation. Note vertical seam with no data is a boundary between seismic volumes, not a fault. Vertical exaggeration is 2X.

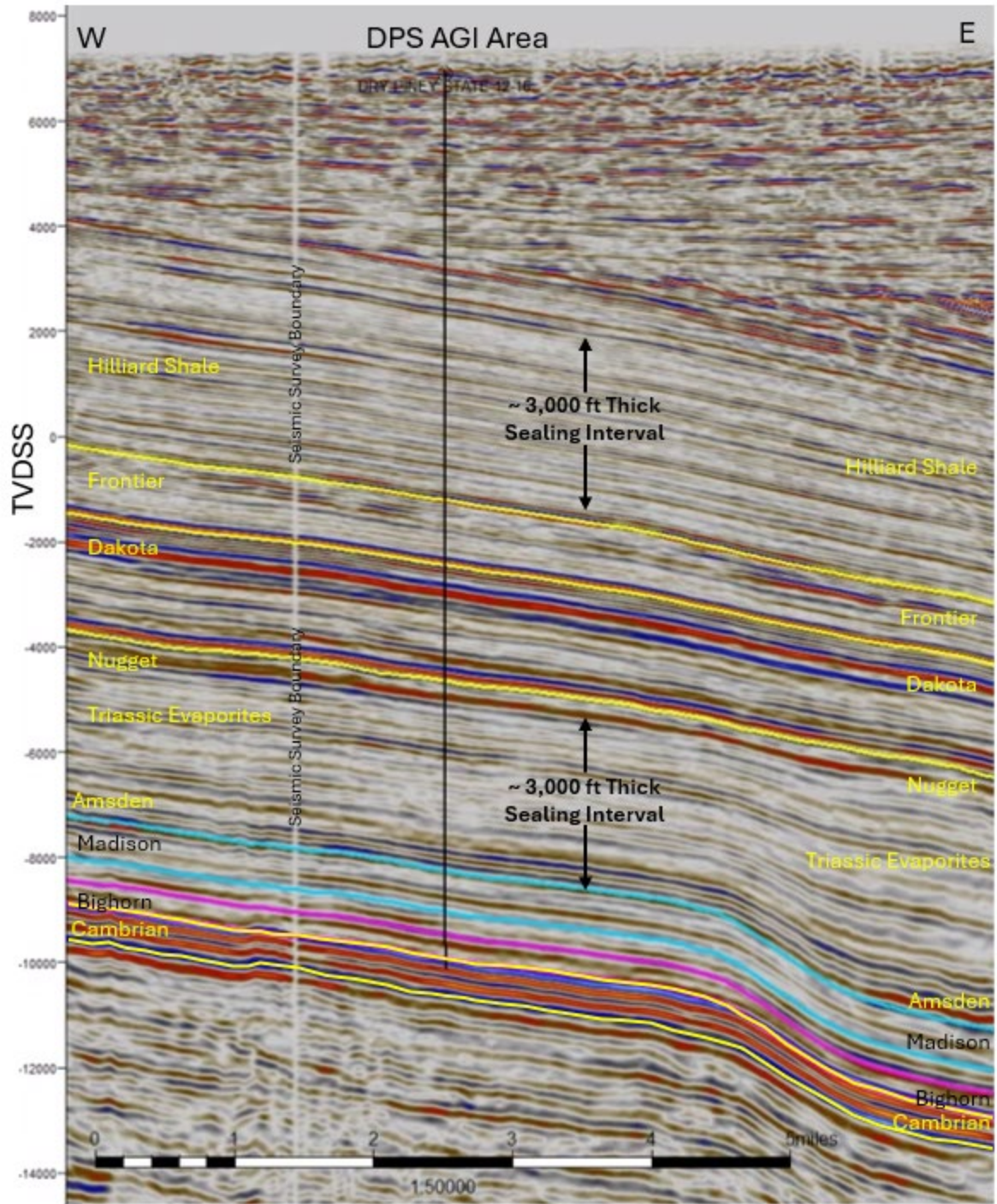


Figure 2.6-7: Seismic line from 3D volume, oriented W to E through the proposed Dry Piney State 12-16 injection well location, shows no faulting. Note vertical seam with no data is a boundary between seismic volumes, not a fault. Vertical exaggeration is 2X.

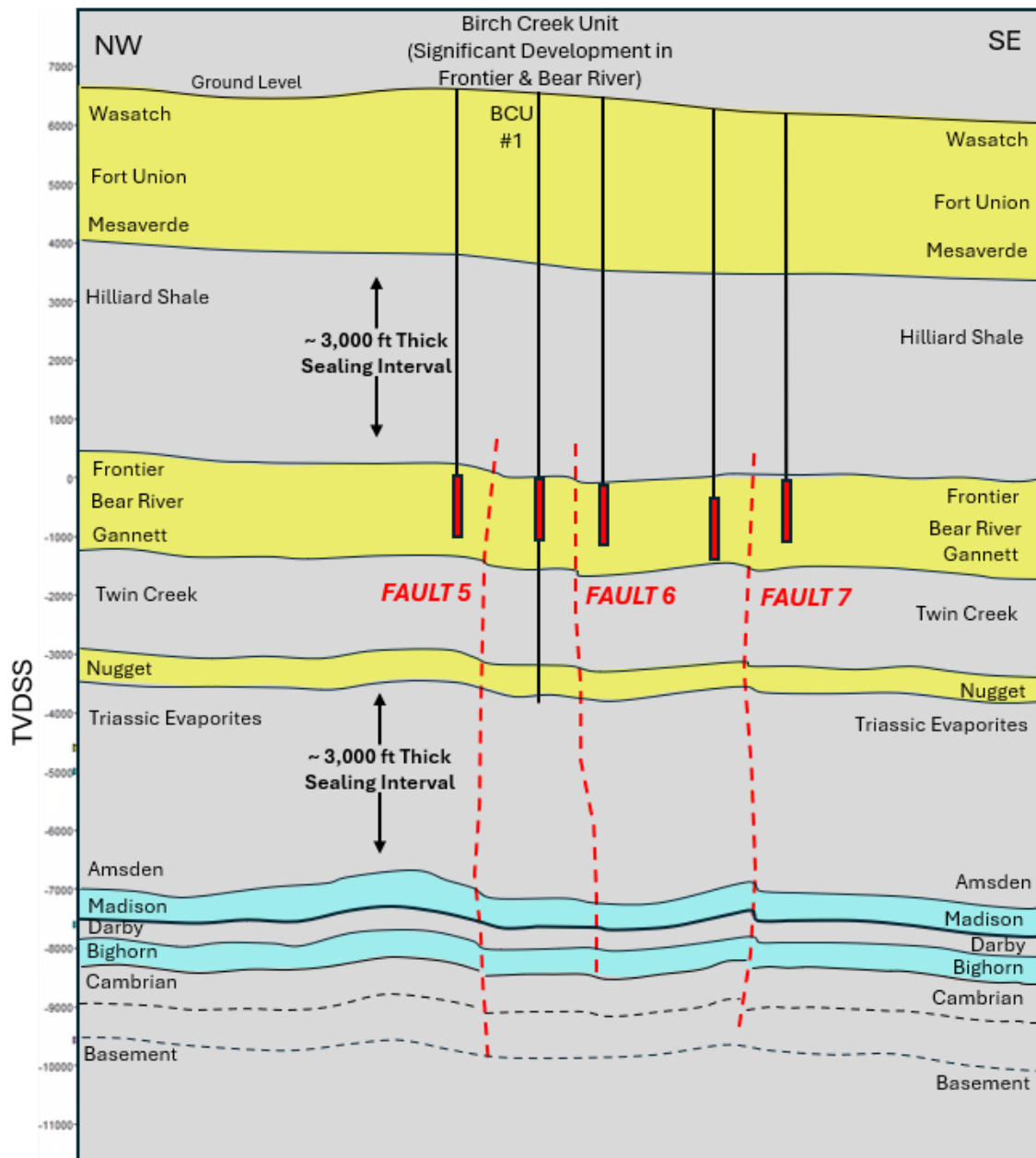


Figure 2.6-8: Cross-section derived from seismic line extracted from a 3D volume, oriented NW to SE perpendicular to Faults 5, 6 and 7 southwest of the DPS AGI area (see **Figure 2.6-5** for reference map). BSO does not have permission to show this seismic data. Vertical black lines and red boxes illustrate BCU wells and approximate completion depths in the Frontier & Bear River intervals proximal to Faults 5, 6 & 7. Of particular interest is the BCU #1 well, which was drilled to the Nugget, then plugged back to the Frontier in 1957 and provides a key baseline data point in terms of gas composition. Note that Faults 5, 6 and 7 die out into the base of the approximately 3,000-foot-thick Hilliard (Baxter) Shale

confining zone. If Faults 5, 6 and 7 were acting as a conduit for CO₂ leakage from the existing naturally-occurring CO₂ and H₂S resource in the Madison and Bighorn Formations, CO₂ and H₂S would be detected in the gas analyses conducted in wells near these faults, and they are not (Table 2.6 and Appendix D). Vertical exaggeration is 2X.

2.6.4 DESCRIPTION OF OVERLYING & UNDERLYING CONFINING UNITS

The Amsden Formation is the overlying confining interval positioned immediately above the Madison Formation (**Figures 2.2-1 & 2.6-1**). Regionally, the Amsden Formation, including its basal Darwin sandstone member, is typically found to be 300 to 500 feet thick. ExxonMobil performed Mercury Injection Capillary Pressure (“MICP”) tests along with fluid inclusion volatile (“FIV”) analysis in their 2008 Tip Top well (Becker and Lynds, 2012) which indicated the entire Amsden Formation serves as a confining layer for the Madison (**Figure 2.6-9**). The Amsden Formation is present and exhibits similar thickness and log response at the Dry Piney State 12-16 location compared to Madison well penetrations in the LaBarge Field and also ExxonMobil’s AGI disposal wells approximately 45 miles to the south, demonstrating consistency across the entire Moxa Arch. The Amsden is known to be an effective seal in the area as demonstrated by oil and gas trapped in the Madison, indicating permeabilities in the range of 0.001 md or less.

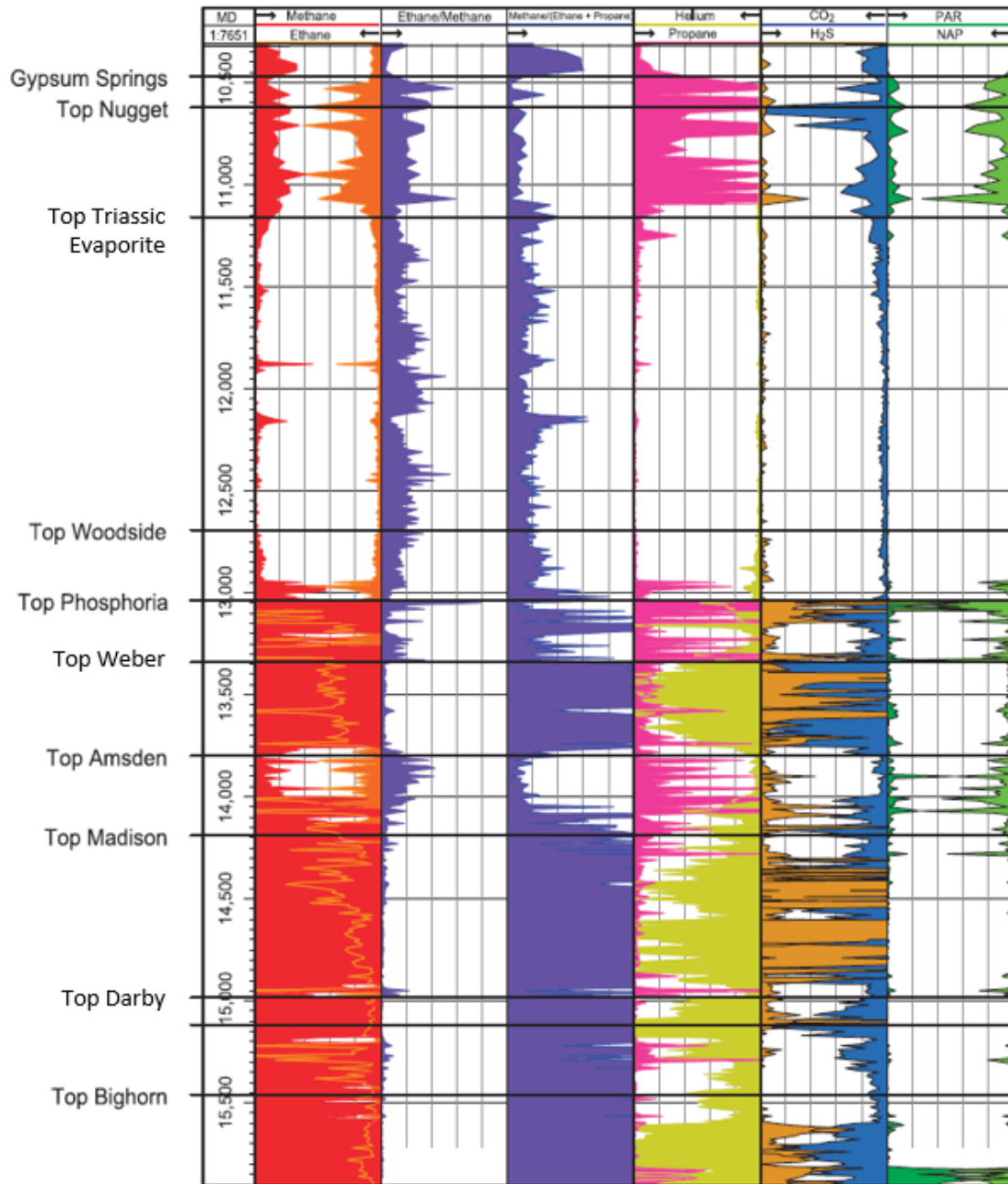


Figure 2.6-9: Modified from Becker & Lynds, 2012. Summary of fluid-inclusion volatile analysis in the Tip Top T62X-16S well located approximately midway between the DPU production area and the DPS AGI area, and the only well that penetrates the injection zones in the MMA. Confining units are identified by intervals where volatile species are absent, such as the Darby, Amsden and Triassic Evaporite intervals. Arrows show the direction of an increase in volatiles species, and depths are in measured depth. METH = methane, ETH = ethane, PROP = propane, PAR = paraffins and NAP = naphthenes.

The Devonian Darby Formation acts as both the underlying confining interval for the Madison Formation and the overlying confining interval to the Bighorn Formation (**Figures 2.2-1 & 2.6-1**). Due to its depth and infrequency of penetration, relatively little is known about the Darby Formation. The 2008 ExxonMobil Tip Top T62X-16S well penetrated the full Darby interval that was observed to be 490 feet thick. Like the confining intervals overlying the Madison Formation, the Darby Formation was devoid of volatile species in FIV data suggesting a seal between the Madison and Bighorn Formations. Additionally, reservoir pressure data obtained by ExxonMobil in the Tip Top T62X-16S well indicates that the Madison and Bighorn reservoirs are separate and distinct due to the apparent original reservoir pressure in the Bighorn Formation and the apparent reduced reservoir pressure in the Madison Formation due to structurally up dip production over the last approximately 40 years (Becker and Lynds, 2012). The average porosity of the Darby is calculated to be approximately 4% and is 302 feet thick at the Dry Piney State 12-16 location. Reservoir pressure data obtained during wireline logging at the Dry Piney State 12-16 indicates the Darby is the confining interval to the Bighorn. Differing gas compositions between the Madison and Bighorn observed in fluid samples collected via wireline logging in the Dry Piney State 12-16 corroborates separation of the two injection zones. The ability of the Darby to form an effective seal between the Madison and Bighorn suggests permeabilities on the order of 0.001 md or less.

The lower confining layer to the Bighorn Dolomite is the Cambrian interval (**Figures 2.2-1 & 2.6-1**), including the low porosity Gallatin Limestone, the Gros Ventre Shale and shales within the Flathead Sandstone. Very few penetrations into the Cambrian strata across Wyoming exist. The Cambrian is at least 131' thick in the Dry Piney State 12-16 and the USGS reports porosity ranging from 2 to 8% and permeabilities of <0.01 md, often in the nanodarcy range.

In addition to the confining units immediately adjacent to and overlying or underlying the Madison and Bighorn injection zones, the Triassic Evaporites interval is an approximately 1,800-foot thick sequence comprised of shales and salt-rich sediments that creates an ideal seal for the broader "sour gas system" as discussed in numerous previous sections, including **Section 2.2** which discusses stratigraphy of the Greater Green River Basin. Combined with the shales of the Woodside, Dinwoody and Ankareh formations, the Triassic Evaporites confining zone is nearly 3,000 feet thick. Further, above the shallow sweet gas productive intervals, namely the Frontier and Bear River Formations, is another confining unit comprised of the approximately 3,000-foot-thick Hilliard (Baxter) Shale that acts as the seal for hydrocarbons in the region. The Hilliard Shale is a thick succession of low permeability mudrocks deposited during the late Cretaceous period and is associated with the maximum extent of the Western Interior Seaway.

2.7 DESCRIPTION OF THE INJECTION PROCESS

The purpose of the AGI process is to take the CO₂ and H₂S removed from the produced raw gas at DPJGPF and permanently sequester it into the Madison and Bighorn Formations. Production of raw gas will be from the Madison Formation only in the DPU production area. Injection and sequestration of CO₂ and H₂S is planned to target the Madison Formation in four proposed wells and the Bighorn Formation in the drilled but uncompleted Dry Piney State 12-16 (Figure 2.7-1).

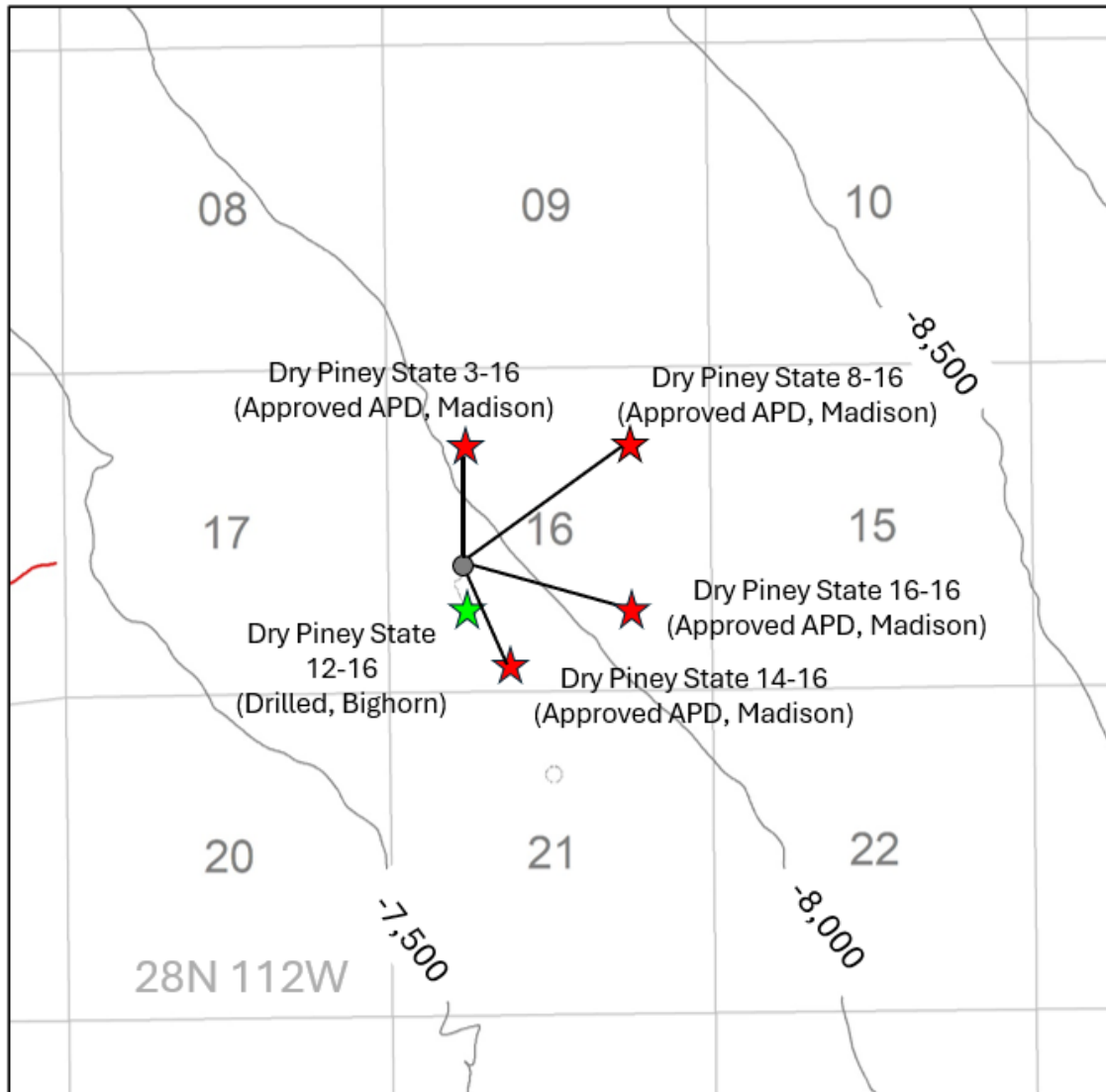


Figure 2.7-1: Map showing the existing drilled (but not completed) Dry Piney State 12-16 well and the future DPS AGI wells. Dry Piney State 12-16 will inject into the Bighorn, while the four future injection wells are anticipated to target the Madison for injection. Contours are top Madison structure (SSTVD, 500 ft contour interval).

It is not feasible to inject into both the Madison and Bighorn Formations in the same well due to differing reservoir pressures. Based on reservoir pressure data obtained while drilling the Dry Piney State 12-16 well, the Madison Formation was observed to have an average reservoir pressure of 6,686 pounds per square inch (psi), which is more than 500 psi less than the Bighorn Formation average of 7,206 psi. Unless the well is configured with a dual completion, it is assumed all injected volumes would enter the Madison due to its lower reservoir pressure. A dual completion would require reduced tubing and casing diameters which would materially limit injection rates. Based on gas compositional analysis of fluid samples taken in the Dry Piney State 12-16 well, the Madison and Bighorn Formations have uneconomic quantities of CH₄ (< 5%) and He (< 0.25%) at the downdip location of the AGI area near the GWC. The CO₂ concentration at the DPS AGI location is approximately 89% in the Madison Formation and approximately 95% in the Bighorn Formation. Both formations also contain equal to or greater than 0.5% H₂S, confirming the extent of the naturally occurring sour gas system that already exists in the AGI area. As such, injection into the Madison and Bighorn Formations is not expected to contaminate potential production at the AGI area. Because the injected gas composition is expected to be 92.4% CO₂, 6.93% H₂S and 0.5% methane, the injected gas is anticipated to be denser than the less CO₂-rich gas up structural dip to the west in the production area (**Figure 2.7-2**). Therefore, measurable quantities of injected gas are not forecasted to “break-through” or contaminate production in the DPU area, structurally up dip and 10.5 miles to the west, during the 50-year production life of the project. This is demonstrated through the dynamic reservoir simulation modeling and can be noted in **Figure 3.1-1** which shows an outline of the injected volume plume extent after 50 years.

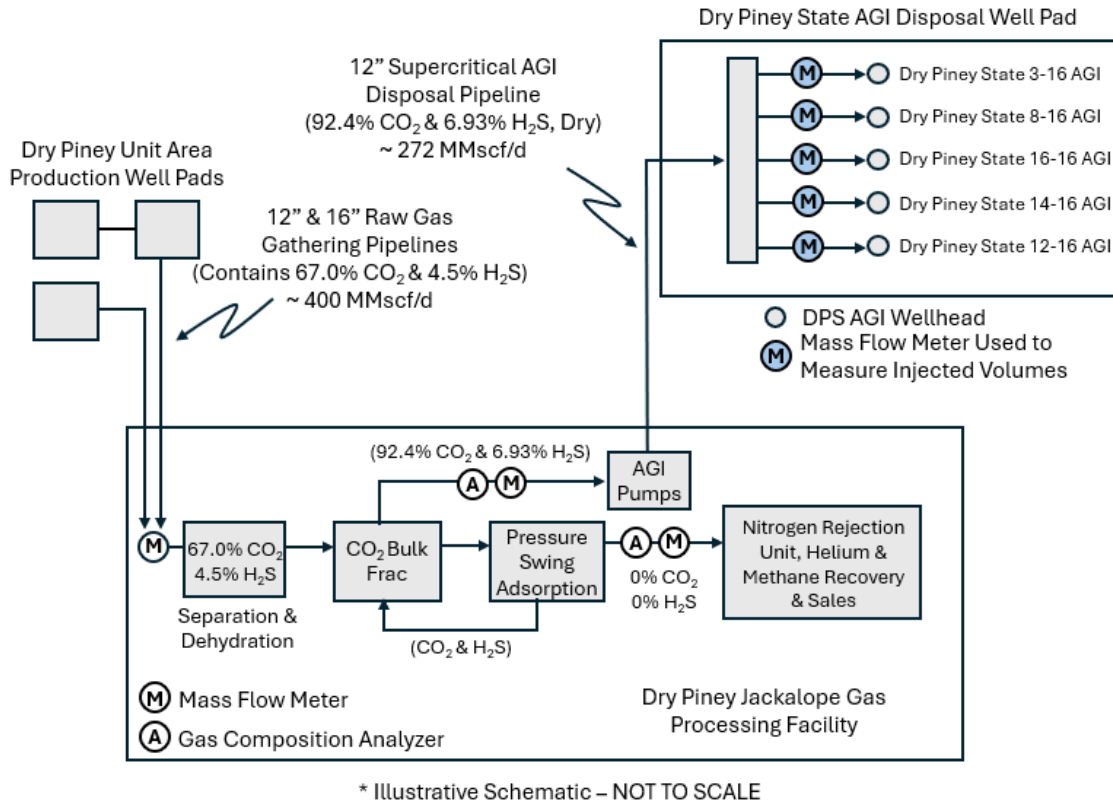


Figure 2.7-3: Schematic Diagram (NOT TO SCALE) showing CO₂ flow path from production well pads in Dry Piney Unit Area through Dry Piney Jackalope Gas Processing Facility to permanent sequestration in the Dry Piney State AGI wells. Note that the produced raw gas stream contains approximately 67.0% CO₂ and 4.5% H₂S. After initial plant inlet separation and dehydration, the CO₂ and H₂S components are removed from the raw gas stream through CO₂ Bulk Fractionation and Pressure Swing Adsorption processes and pumped to the Dry Piney State AGI Disposal wells for sequestration. Gas composition analyzers and mass flow meters will verify gas composition and the volume of CO₂ after the CO₂ Bulk Fractionation and Pressure Swing Adsorption processes. The combined CO₂ and H₂S waste gas stream will be pumped in a supercritical state via pipeline to the Dry Piney State AGI wells, with an expected gas composition of approximately 92.4% CO₂ and 6.93% H₂S. Note that a gas composition analyzer will be used to verify that all CO₂ and H₂S have been separated and captured by the Bulk Fractionation and Pressure Swing Adsorption processes (that is, 0% CO₂ and 0% H₂S enters the downstream Nitrogen Rejection Unit before advancing to Helium and Methane recovery processes and sales points). Once at the Dry Piney State AGI well pad, the individual CO₂ and H₂S streams will be metered at each well head to account for actual volumes injected and sequestered, and the CO₂ component will be calculated based on the gas composition.

The AGI system transports the dense-phase supercritical acid gas stripped from the bulk fractionation process under pressure through a pipeline to the five-well Dry Piney State

AGI area (**Figures 2.6-2 and 2.7-1**). See **Figure 2.7-3** for a process flow diagram that identifies the CO₂ flow path from the inlet of the DPJGPF to the AGI wells and the associated meter locations that will be used for Subpart RR reporting. The five AGI wells will inject acid gas into the Madison or Bighorn Formations, which are geologically suitable for permanent storage and sequestration of the acid gas. The AGI system will consist of a series of process and injection pumps to increase the mid-pressure liquid from the bulk fractionation at the DPJGPF to the well injection pressure. Free water will not be present in any part of the pipeline system, removing the risk of internal corrosion.

The AGI pipeline will be constructed, tested, and maintained in accordance with the latest industry standards and codes. The high-pressure AGI pipeline will be constructed of carbon steel and will be approximately 11.13 miles in length. The AGI area is approximately 10.5 miles northeast of the DPU production area, but the pipeline length is longer due to the selected route versus “as the crow flies.” The AGI pipeline will be outfitted with the necessary instrumentation and hardware to monitor operation from a control room and to detect leaks. Shutdown valves will be installed on the pipeline system to safely isolate the pipeline during a leak or under other possible emergency conditions.

The total depth (“TD”) of each AGI well will range from 16,600 feet (Bighorn) to 15,750 feet (Madison) TVD depending on whether the Madison or Bighorn Formation is targeted. Measured depths will be higher than the TVD depth range and depends on the directional plan for each specific well with higher deviations resulting in higher measured depths.

While planning the drilling of the AGI wells, BSO worked with a reputable service company who provided a range of fracture gradients for the formations comprising the deep sour helium petroleum system including the Triassic Evaporite interval (Ankareh, Thaynes and Woodside Formations), Phosphoria, Amsden, Madison, Darby, Bighorn and Cambrian Formations in the area. Fracture gradient and overburden for the AGI wells were estimated based on offset well data. Shear and compressional sonic data combined with density data from existing offset wells was analyzed and yielded an estimated overburden pressure of 1.0 psi/ft. Based on a frac gradient of 0.87 pounds per square inch (“psi”)/ft for the Triassic Evaporite interval, 0.87 psi/ft for the Phosphoria, 0.87 psi/ft for the Amsden, 0.857 psi/ft for the Madison, 0.92 psi/ft for the Darby, 0.862 psi/ft for the Bighorn, and 0.92 psi/ft for the Cambrian, BSO does not anticipate reaching or exceeding fracture pressures during injection operations for any Formations.

With a downhole fracture pressure of 12,698 psi in the Madison Formation (based on a top perforation TVD of 14,823 ft) which corresponds to a surface injection pressure of approximately 6,265 psi, the injected acid gas will likely not initiate fractures in the Madison Formation and therefore not create fractures out of zone into the overlying or underlying confining units. Facility controls will exist to limit surface injection pressures to below 5,400 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture initiation is minimal. The Madison Formation is

anticipated to be encountered in a narrow TVD depth range in the Dry Piney State injection area, with the Dry Piney State 12-16 being the shallowest and the Dry Piney State 8-16 being the deepest at approximately 200 ft TVD deeper. Therefore, fracture pressures will be very similar amongst the five disposal wells and will range from approximately 12,698 psi to 12,875 psi.

With a downhole fracture pressure of 13,843 psi in the Bighorn Formation (based on top of perforation TVD of 16,066 ft) which corresponds to a surface injection pressure of approximately 6,871 psi, the injected acid gas will not initiate fractures in the Bighorn Formation and therefore, will likely not create fractures out of zone into the overlying or underlying confining units. Facility controls will exist to limit surface injection pressures to below 5,400 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture initiation is minimal. The DPS 12-16 will likely be the only Bighorn Formation injection well in the Dry Piney State injection area.

With the Bighorn fracture pressure of 13,843 psi, the overlying Darby Formation will maintain its sealing ability without induced fractures from injection into the Bighorn with a higher fracture gradient (relative to the Bighorn) of 0.92 psi/ft fracture gradient and a corresponding 14,401 fracture pressure calculated at its top (approximately 15,685 ft MD / 15,653 ft TVD).

The projected facility maximum surface pressure of 5,400 psi corresponds to downhole fracture pressures of 11,920 psi and 12,193 psi for the Madison and Bighorn Formations, respectively. Both are below the pressure required to fracture the formation; therefore, the probability of inducing fractures is minimal, which in turn will reduce the risk of leakage of CO₂ along various subsurface leakage pathways that will be discussed in later sections.

2.8 PLANNED INJECTION VOLUMES

Figure 2.8-1 is a long-term injection forecast through the life of the acid gas injection project, anticipated to be 50 years in length, showing total injection of 5.25 TCF. It is important to note that this is just a forecast – actual injection volumes will be collected, calculated, and reported as required by Subpart RR. Additionally, the volumes provided in **Figure 2.8-1** are the total amount of gas to be injected, not just the CO₂ portion which is expected to represent approximately 92.4% of the waste gas stream. BSO forecasts the total volume of CO₂ stored over the modeled injection period to be approximately 4.87 TCF (257.6 million metric tons).

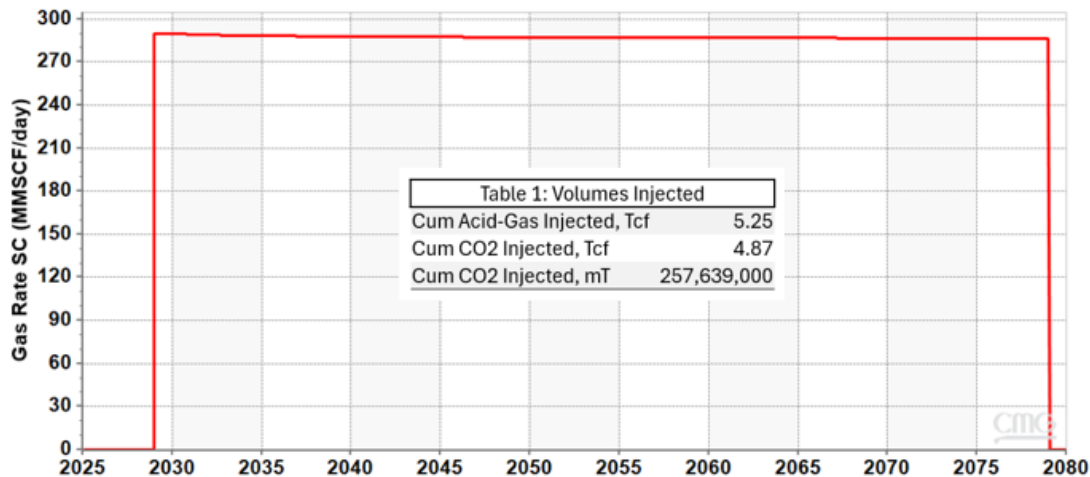


Figure 2.8-1: Long term injection forecast showing waste gas (combined CO₂ & H₂S) volume of 5.25 TCF to be injected into all five BSO injection wells throughout the life of the 50-year project. The CO₂-only volume is 4.87 TCF (257.6 million metric tons).

Figure 2.8-2 captures the evolution of the acid gas plume for the DPS AGI wells at various time intervals after initiation of injection in 2028: 5, 10, 20, 30, 40, 50 and 100 years. The maximum extent of the plume is estimated to span approximately 50,000 feet (about 9.5 miles) and occurs after a 50-year injection period and a 50-year shut-in period in year 2128, at which time the plume achieves stabilization. Interestingly, the entire 50-year plume (2078) appears to migrate up geologic structure to the southwest, after pressure from active injection ceases and the plume is no longer forced down structural dip by the injection pressure. The plume expands modestly after 50 years of injection (2078) and achieves stabilization after moving up structural dip after 50 years of shut-in, in year 2128.

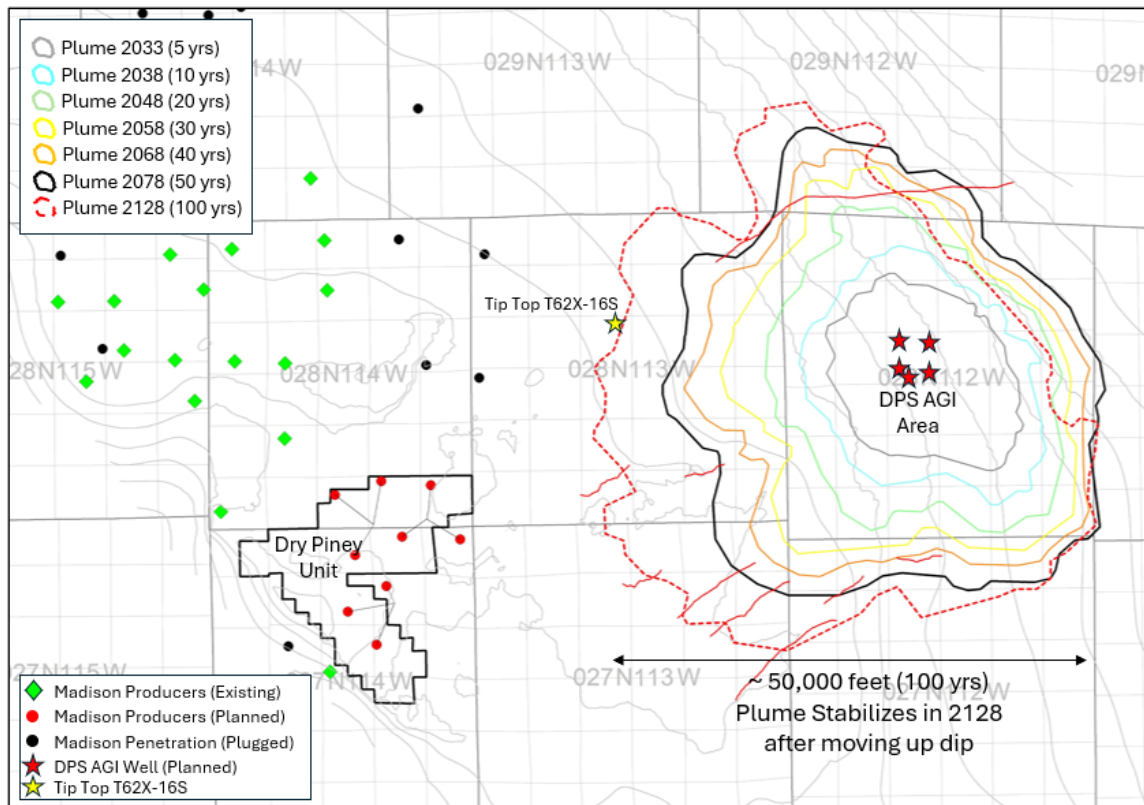


Figure 2.8-2: Spatial extent of the acid gas free-phase CO₂ plume (> 0.5% net incremental CO₂ above naturally occurring in-situ CO₂) at years 2033, 2038, 2048, 2058, 2068, 2078 and the stabilized plume at 2128. After 50 years of injection, followed by a 50-year shut-in period (stabilization), the plume spans a diameter of approximately 50,000 feet (year 2128, red-dashed polygon). Note that although the plume migrates up structural dip during the stabilization period, at no point in time does the plume reach existing wells producing from the Madison Formation, future well locations planned to produce from the Madison Formation, nor existing wells that have penetrated the Madison Formation.

3.0 DELINEATION OF MONITORING AREA

3.1 MAXIMUM MONITORING AREA (MMA)

Per 40 CFR 98.449, the MMA is defined as equal to or greater than the area expected to contain the free-phase CO₂ plume until the CO₂ plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from all wells with available data, seismic data, and historic production and injection data from ExxonMobil LaBarge Field operations, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time. According to the reservoir modeling results, after 50 years of post-injection monitoring (year = 2128), the injected gas will remain in the reservoir, and no expansion of the free-phase CO₂ plume is observed after that point in time (**Figure 3.1-1**). The model

was run through 2578 to assess the potential for expansion of the plume after acid gas injection ceases. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. Expansion of the plume to a diameter of approximately 50,000 ft (9.5 miles) occurs by the year 2128 as the gas plume stabilizes due to gravity segregation and dispersion. At this point, the rate of movement of the free-phase CO₂ plume (incremental injected CO₂ volume) has essentially ceased, demonstrating plume stability.

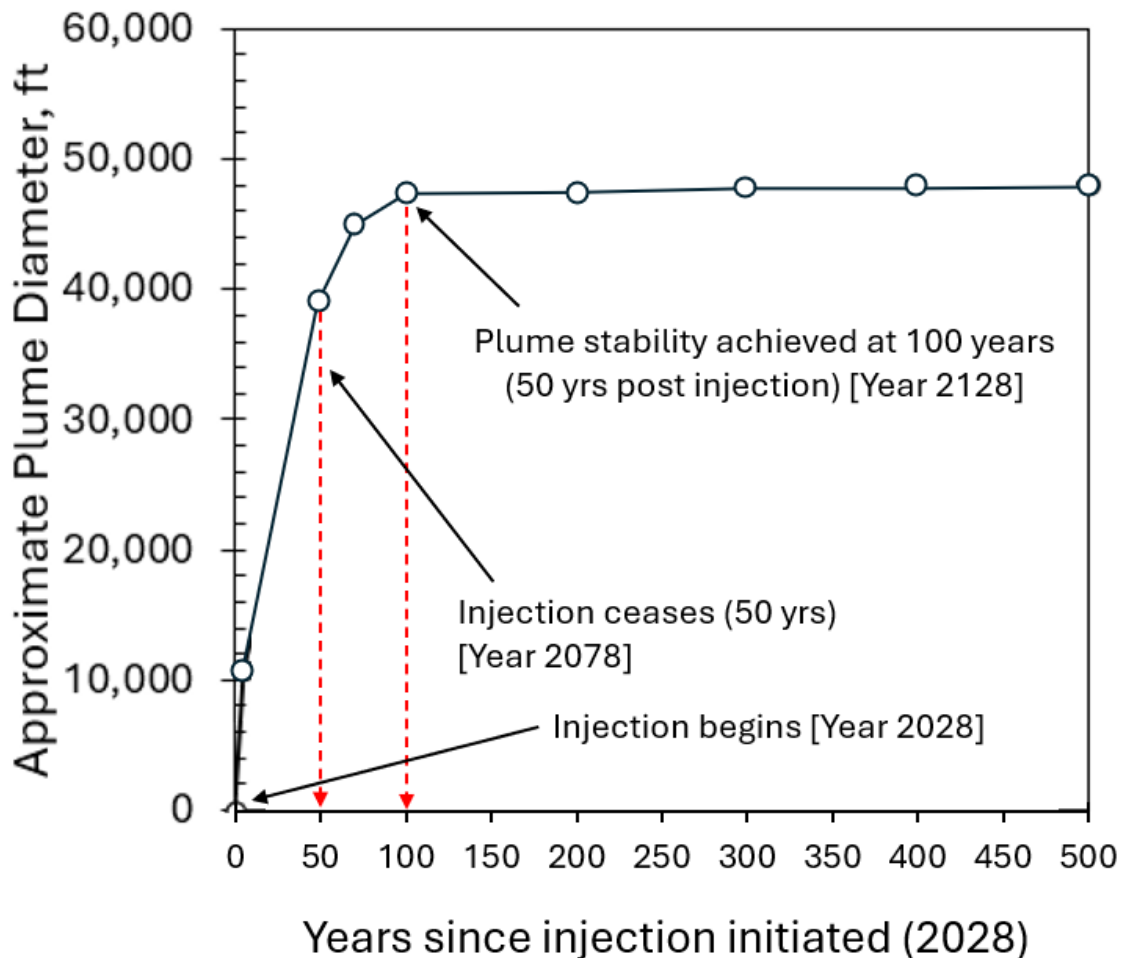


Figure 3.1-1: Plot showing predicted approximate maximum plume diameter over time through injection phase (first 50 years) and out to 500 years (450 years post-injection). Note that at approximately 100 years (50 years post-injection) the plume stabilizes at approximately 50,000 feet in diameter as shown in **Figure 3.1-2**.

Reservoir modeling indicates that during the 50-year post-injection stabilization period, a modest amount of migration up-dip occurs because injection pressure is no longer forcing the plume down structural dip. As the plume expands slightly in the absence of injection pressure, the plume shifts up structural dip to the southwest. As such, and to ensure the delineation of the maximum extents of the plume, BSO took the conservative approach

to use the union of the 50-year plume boundary and the 100-year plume boundary to capture the maximum (“max”) plume extent as depicted in **Figure 3.1-2**, even though modeling suggests any free-phase CO₂ will evacuate from the western extent of the 50-year plume outline. This combined plume extent, defined by the 50-year plume outline plus the 100-year stabilized plume outline (2128) plus a one-half mile buffer is used to define an MMA (**Figure 3.1-2**).

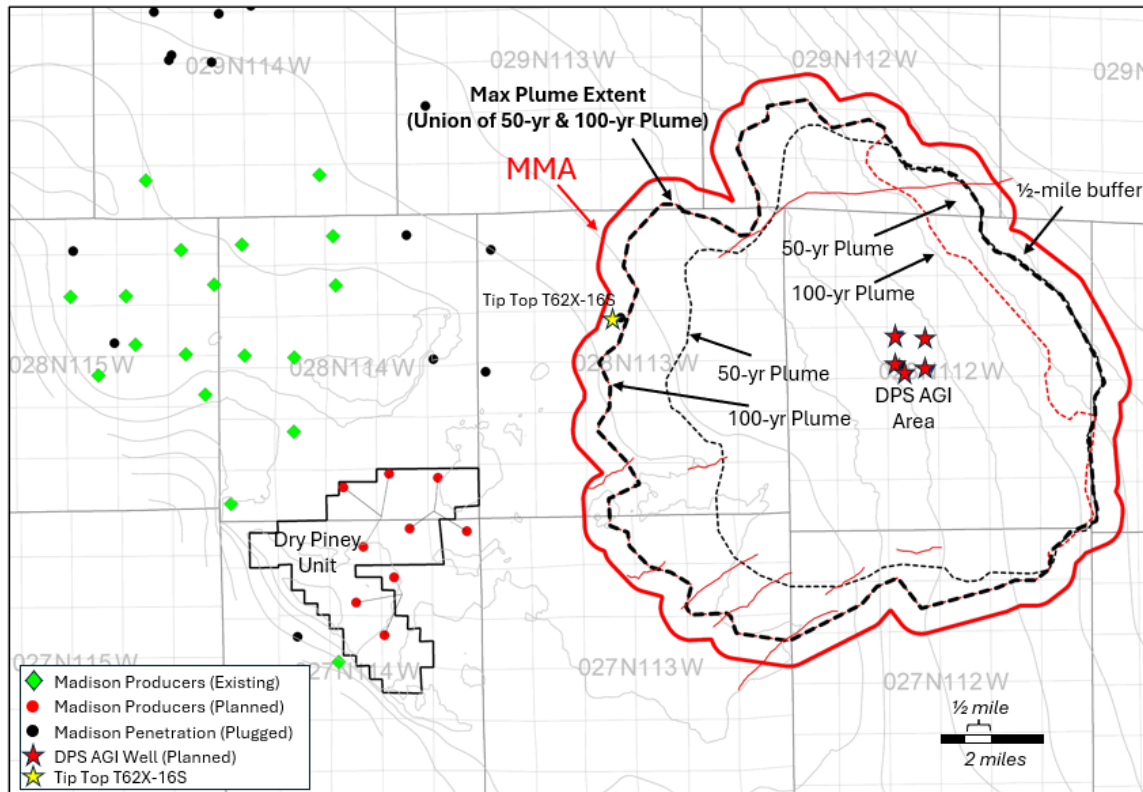


Figure 3.1-2: Area covered by the maximum extent of the combined stabilized plume at year 2128 as well as the area to the west that was occupied by the plume at 50 years of injection (2078) before migrating up structural dip to the west during the plume stabilization period. The bold, black-dashed line represents the combined maximum extent of the plume area, while the solid red polygon represents the maximum plume extent plus an all-around one-half mile buffer to define the MMA.

In addition, according to EPA regulation, “the buffer is intended to encompass leaks that might migrate laterally as they move towards the surface. EPA has determined that the buffer zone of at least one-half mile will have an acceptable probability of encountering leaks in many circumstances.”

Therefore, BSO considered identified faults extending beyond the stabilized plume (plus a one-half mile buffer) to define an extended MMA (**Figure 3.1-3**). The extended MMA

comprises the union of two areas: the area covered by the initial MMA plus a one-half mile buffer and the area covered by the fault traces extending beyond the stabilized plume plus a one-half mile buffer (**Figure 3.1-3**) as the faults represent known potential leakage pathways. **Figure 3.1-4** shows the final MMA in a red polygon, as defined by 40 CFR 98.449 of Subpart RR.

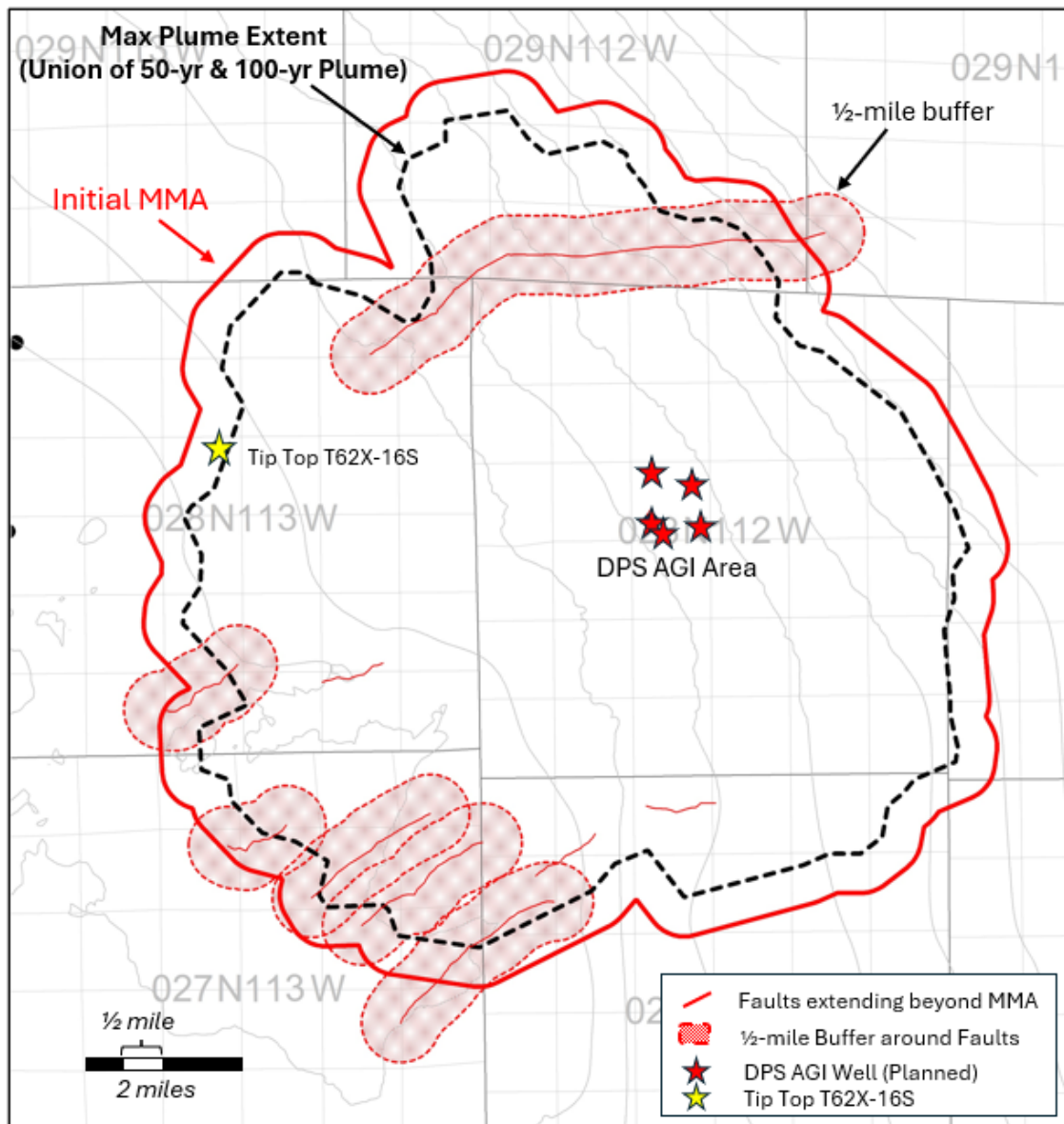


Figure 3.1-3: Map showing initial MMA (red polygon) with 1/2-mile buffer around faults extending beyond maximum plume extent after stabilization (black dashed line).

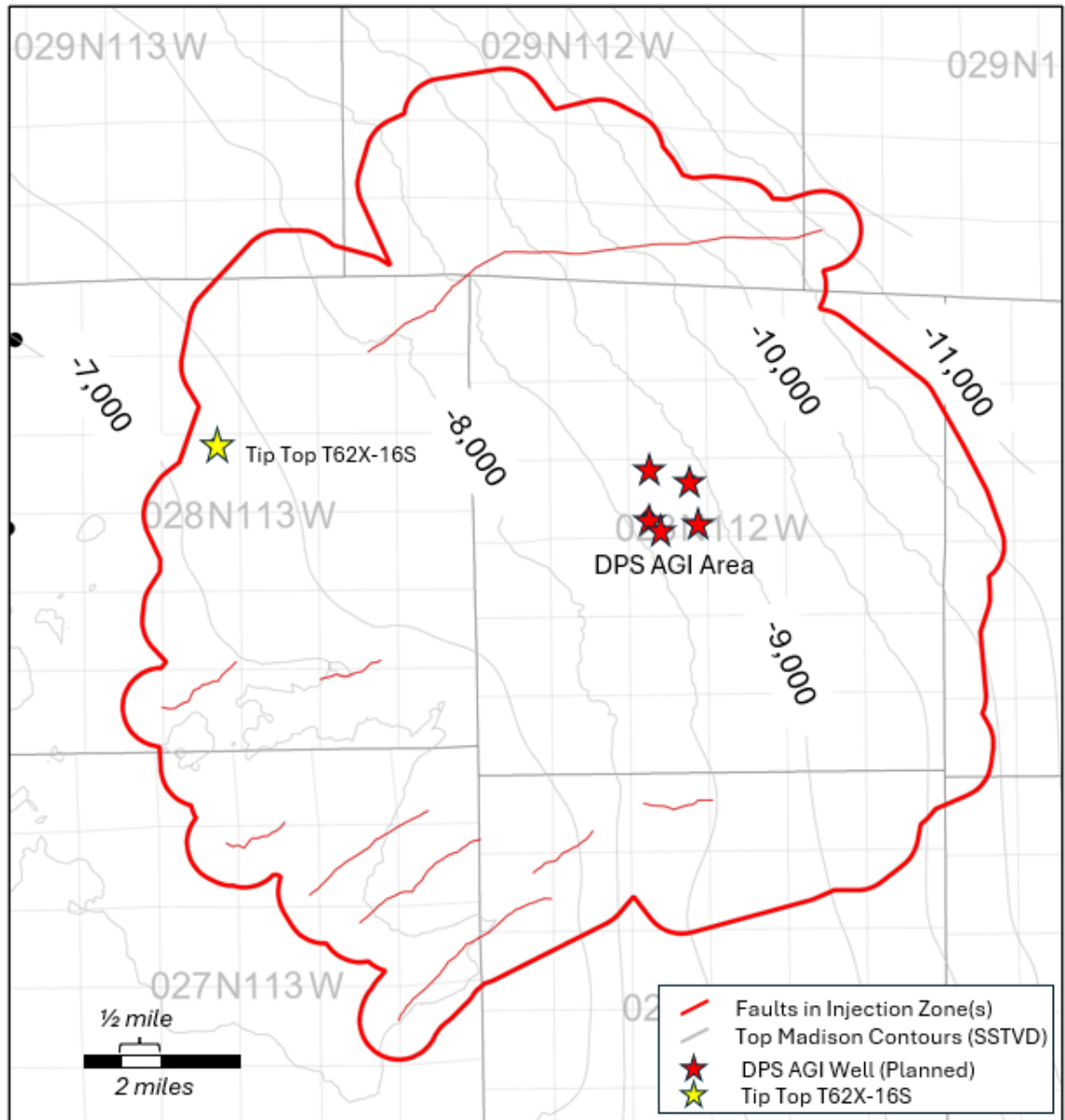


Figure 3.1-4: Map showing the extended, final MMA proposed by BSO to fully encompass the maximum extents of the modeled plume plus an all-around ½-mile buffer, as well as an additional ½-mile buffer around any known potential leakage pathways (in this case faults that extend beyond the maximum plume extent). Final MMA is bold red polygon. The Tip Top T62X-16S is the only existing, non-DPS AGI well within the MMA that penetrates the Triassic Evaporite confining unit and injection zones (yellow star).

Because the Dry Piney State AGI area has an in-situ pre-injection CO₂ composition of greater than 89% in the Madison and greater than 95% in the Bighorn, as evidenced by gas composition analysis conducted on reservoir fluid samples obtained in the Dry Piney State 12-16 well, BSO delineated the “free-phase” CO₂ plume where a “net incremental increase in CO₂ gas saturation” is greater than 0.5%. Calculation of the volume-weighted

average gas saturation at various time steps was used to determine the acid gas plume area, with the “free-phase” plume boundary defined as the area with an increase in net incremental CO₂ gas saturation of greater than 0.5% (absolute) above in-situ concentrations resulting from injected volumes. An incremental change in gas saturation of 0.5% is well below the lowest gas saturation that can be confidently detected by formation evaluation methods in reservoirs with rock properties such as those found in the Madison Formation.

3.2 ACTIVE MONITORING AREA (AMA)

As defined in 40 CFR 98.449 of Subpart RR, the AMA is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the AMA is established by superimposing two areas:

- Area 1: The area projected to contain the free-phase CO₂ plume at the end of year t, plus and all-around buffer of one-half mile if known leakage pathways extend laterally more than one-half mile.
- Area 2: The area projected to contain the free-phase CO₂ plume at the end of year t + 5.

BSO has chosen t = 2128, which corresponds to a 50-year injection period plus a 50-year post-injection period during which the plume stabilizes, for the purpose of calculating an AMA. The plume at t = 2128 is the black-dashed polygon in **Figure 3.1-3**, and the plume at year t plus and all-around buffer of one-half mile including known leakage pathways is the red polygon in **Figure 3.1-4**.

The area defined by Area 1 above is plotted and delineated by the red polygon in **Figure 3.1-4** and is coincident with the MMA. It is greater than the area projected to contain the free-phase CO₂ plume at the end of year t = 2128, plus an all-around buffer zone of one-half mile, because it encompasses the identified leakage pathways in **Figure 3.1-2**.

The area defined by Area 2 above is plotted in **Figure 3.1-3** and corresponds to the black-dashed line (plume at t + 5 = 2133). According to the superimposition of Areas 1 and 2, the AMA will be coincident with the MMA which is the area delineated by the red polygon in **Figure 3.1-3** and **Figure 3.1-4**.

After applying the criteria defined by Subpart RR, BSO believes it is appropriate to establish an AMA that is the same size as the MMA. The evaluation with t = 2128 demonstrates that the AMA is contained within the MMA, and therefore, BSO considers the AMA equal to the MMA.

4.0 IDENTIFICATION AND EVALUATION OF PATHWAYS FOR LEAKAGE TO THE SURFACE

Subpart RR at 40 CFR 448(a)(2) requires the identification of potential surface leakage pathways and the evaluation of the likelihood, magnitude and timing of surface leakage of CO₂ through these pathways. BSO has identified and evaluated the potential CO₂ leakage pathways to the surface.

An evaluation of each of the potential leakage pathways is described in the following paragraphs:

- Risk of leakage from surface equipment;
- Risk of leakage through existing wells;
- Risk of leakage through the confining units;
- Risk of leakage through faults and fractures;
- Risk of leakage through due to lateral migration;
- Risk of leakage due to seismicity.

Risk estimates for the potential leakage pathways were made using a 5x5 risk matrix (**Figure 4.1-1**) to evaluate leakage likelihood and magnitude.

		Magnitude				
		Insignificant 1	Minor 2	Significant 3	Major 4	Severe 5
Likelihood	Almost certain 5	Medium 5	High 10	Very high 15	Extreme 20	Extreme 25
	Likely 4	Medium 4	Medium 8	High 12	Very high 16	Extreme 20
	Moderate 3	Low 3	Medium 6	Medium 9	High 12	Very high 15
	Unlikely 2	Very Low 2	Low 4	Medium 6	Medium 8	High 10
	Very Unlikely 1	Very Low 1	Very Low 2	Low 3	Medium 4	Medium 5

Figure 4.1-1: 5x5 risk matrix used to quantify collective risk based on Likelihood and Magnitude.

As will be demonstrated in the following sections, the risk of leakage likely to result in loss of CO₂ to the atmosphere from the potential leakage pathways outlined above is "very low". Further, given the relatively high concentration of H₂S in the AGI injection stream, any leakage through identified or unexpected leakage pathways would be immediately detected by instrumentation (with alarms and shutdowns) in many cases, with associated actions pursued to address any leakage, thereby minimizing the amount of CO₂ released to the atmosphere.

4.1 POTENTIAL LEAKAGE FROM SURFACE EQUIPMENT

Potential leakage from surface equipment will likely be de minimis due to the design of the AGI facilities. The facilities are designed to minimize leak points such as valves and flanges and use welded connections where possible instead. The only surface equipment located between the mass flow meter and the wellhead are valves, transmitters, and flanged connection points on the pipelines, and the equipment will not be configured to blow down or vent between the mass flow meter used for calculating injected CO₂ and the wellhead. Due to the presence of H₂S in the AGI injection stream at a concentration of 6.9% (69,000 parts per million or “ppm”), fixed H₂S gas detectors will be prevalent around the gas processing plant, AGI facility and wellheads, which will alarm at 10 ppm. CO₂ gas detectors will be present at the AGI facility due to the high concentration of CO₂, which will alarm at 5,000 ppm. Additionally, all field personnel are required to wear personal H₂S monitors for safety reasons at all times without exception, which will alarm at 5 ppm H₂S. Although damage to or failure of pipelines and surface equipment can result in unplanned losses of CO₂ entrained in the acid gas, at the anticipated concentration of H₂S in the injection volumes, even a small leak would trigger an alarm, and immediate action would be taken to stop the leak. Additionally, the AGI wells will be monitored with methods outlined in Sections 5 and 6.

BSO will reduce the risk of unplanned leakage from surface facilities through continuous surveillance, facility design, and routine maintenance and inspections. Field personnel will monitor the AGI facility continuously through a supervisory control system. Additionally, daily visual inspection rounds will be conducted of the AGI facility and weekly visual inspection rounds will be conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. BSO will also rely on the prevailing design of the facility, which includes AGI wells with surface controlled subsurface safety valves (“SCSSVs”), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes. Also, the wells have multiple surface isolation valves for redundant protection. Inline inspections of the AGI pipeline using a smart pigging tool will be conducted on the pipeline in accordance with applicable code. The smart pig tool will identify pipeline anomalies, including internal and external corrosion, and those anomalies will be assessed per applicable codes and standards.

Likelihood:

Although mitigative measures are in place to minimize CO₂ emissions from surface equipment, such emissions are possible. Any leaks from surface equipment would result in immediate (timing) emissions of CO₂ to the atmosphere, the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak.

The injection wells and the pipeline that carries CO₂ to it are the most likely surface components of the system to allow CO₂ to leak to the surface. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable source of the leakage.

Another possible source of leakage is if the surface components are damaged by an accident or natural disaster, which releases CO₂.

Therefore, BSO infers that there is a potential risk for leakage via this route. However, due to the standards enforced during construction, the monitoring equipment in place for immediate detection, and the regular inspections and maintenance, the probability of such leakage is considered “very unlikely.”

Magnitude and Timing:

Depending on the component's failure mode, the magnitude and timing of a leak can vary greatly. For example, a rapid break or rupture could release thousands of pounds of CO₂ into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO₂ over several hours or days. Due to the presence of relatively high concentrations of H₂S in the injection gas stream and the constant monitoring of the acid gas pipeline pressures, any leaks would be detected quickly, thus minimizing the magnitude of potential leakage.

Surface component leakage or venting is only a concern during the life of injection operations. Once the injection has ceased, the surface components will no longer be able to store or transport CO₂, eliminating any potential risk of leakage.

Therefore, the magnitude of such a leakage is considered to vary from insignificant to severe according to scenarios. The timing is also variable in the sense that potential leakage could occur at any time from start-up to cessation of injection operations.

4.2 POTENTIAL LEAKAGE FROM EXISTING WELLS

Existing oil and gas wells within the MMA/AMA, as delineated in **Section 3**, are shown in **Figure 4.2-1** and detailed in **Appendix A**. Existing groundwater wells in the MMA are shown in **Figure 4.2-2** and detailed in **Appendix C**.

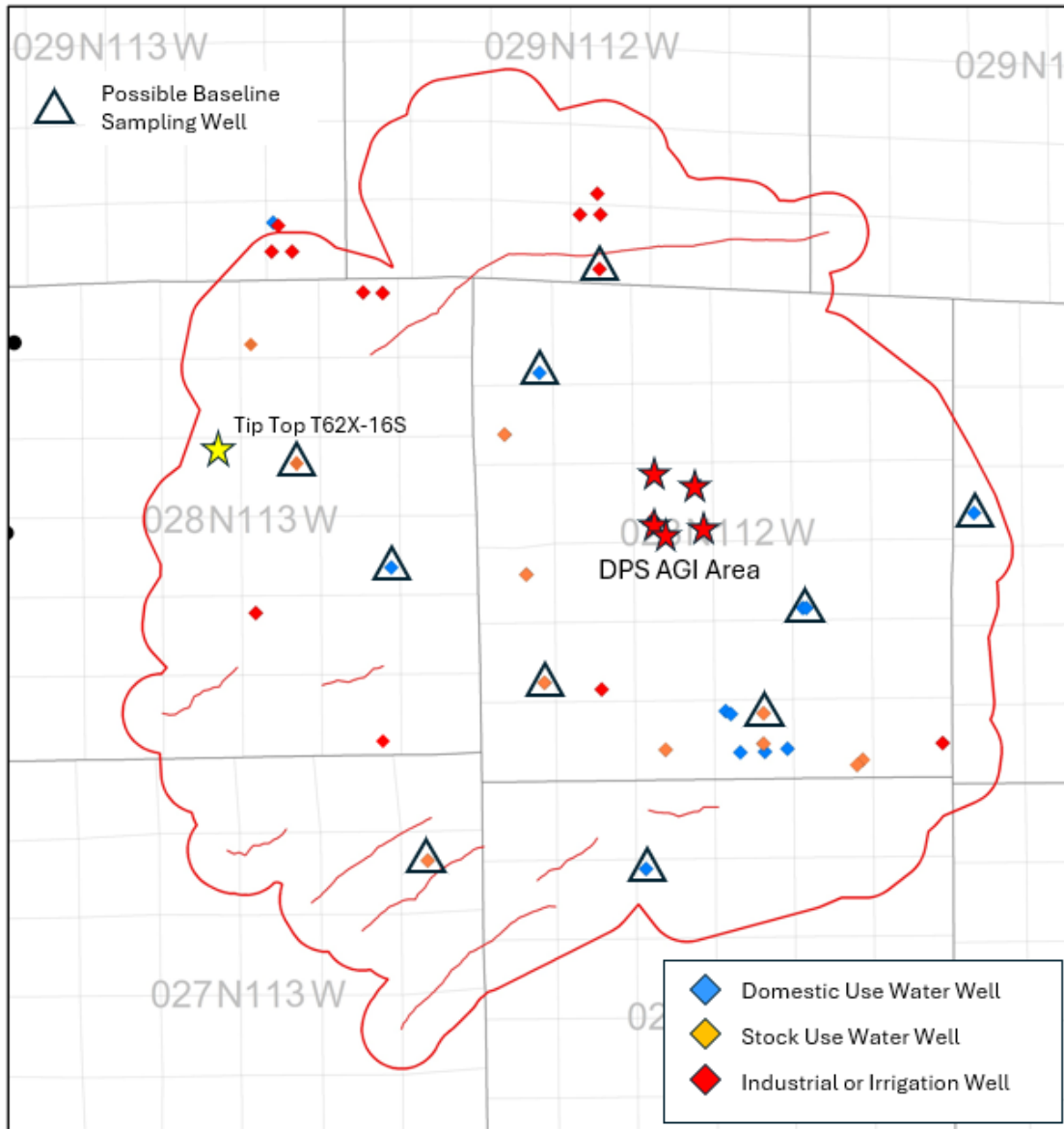


Figure 4.2-2: Map showing locations of existing groundwater wells within the AMA/MMA. Existing groundwater wells are color-coded according to the legend in the figure. Black triangles represent possible candidates for baseline gas composition analysis as part of BSO's strategy for establishing expected baselines, discussed further in Section 6.0, 6.3 and 6.5. Possible baseline candidate wells are bold and italicized in Appendix C.

BSO considered and evaluated all wells drilled, completed, or approved within the MMA in its risk assessment, regardless of well type (oil, gas, water injection, groundwater well, etc.) or well status (producing oil, producing gas, plugged and abandoned, etc.). Only one well, other than the existing Dry Piney State 12-16 well (and future Dry Piney State AGI wells), in the MMA penetrates the confining zones and injection zone, the Tip Top T62X-16S. Although in the MMA, the Tip Top T62X-16S is located within the one-half mile buffer

and is located outside of the stabilized plume at year 2128. The Tip Top T62X-16S was drilled in 2009 and subsequently plugged and abandoned the same year using 7 cement plugs via 5 cement retainers totaling approximately 9,511 feet of cement within the wellbore (See Appendix B for the Tip Top T62X-16S wellbore diagram). The well is drilled from the same well pad as a shallow Frontier sweet gas production well, the Tip Top T62X-16SH well. Neither well is operated by BSO, but because the deep Tip Top T62X-16S well penetrates both the confining zone and the injection zone which contains approximately 70% CO₂ and 4-5% (40,000 to 50,000 ppm) H₂S, it would be reasonable to assume that if the well was leaking since it was plugged and abandoned, the lease operator for the actively producing shallow Tip Top T62X-16SH well would observe an increase in H₂S readings on fixed or personal gas monitors generally set to alarm at 10 ppm on the shared well pad. If the operator's H₂S gas monitor did alarm, further investigation into CO₂ leakage could be conducted.

All other wells within the MMA, including groundwater wells, regardless of current status, were drilled and abandoned or completed at total depths that are at least 3,000 feet above the top of the shallowest injection zone (the Madison Formation). The top of the Triassic Evaporites confining unit is approximately 2,900 feet above the top of the Madison Formation, so none of the wells within the MMA (except the Tip Top T62X-16S) penetrate the Triassic Evaporites confining unit, the Amsden confining unit or the Madison or Bighorn injection zones.

Of the 741 existing petroleum-related wells in the AMA/MMA, 480 (64.8%) of them have total depths (TD) greater than 10,000 feet above the Madison injection zone, significantly reducing the risk of CO₂ leakage to surface due to the vertical separation of the injection zone and the deepest portion of the respective wellbore (**Figure 4.2-3**). 735 of the existing wells (99.2%) have a TD greater than 5,000 feet above the Madison injection zone, again minimizing risk of CO₂ leakage to surface through these wellbores due to the vertical separation between the wellbore and the injection zone. Of the 6 existing wellbores that have a TD less than 5,000 feet above the Madison injection zone, all but one (Tip Top T62X-16S) have a TD greater than 3,300 feet above the injection zone. Of the 6 existing wellbores that have a TD less than 5,000 feet above the Madison injection zone, all but one (State J No. 1) are outside of the stabilized plume area after 100 years. The State J No. 1 has been identified as a good candidate for a possible baseline monitoring well for CO₂ leakage along this potential leakage pathway (**Figure 4.2-1, Figure 4.2-3 and Appendices B and D**).

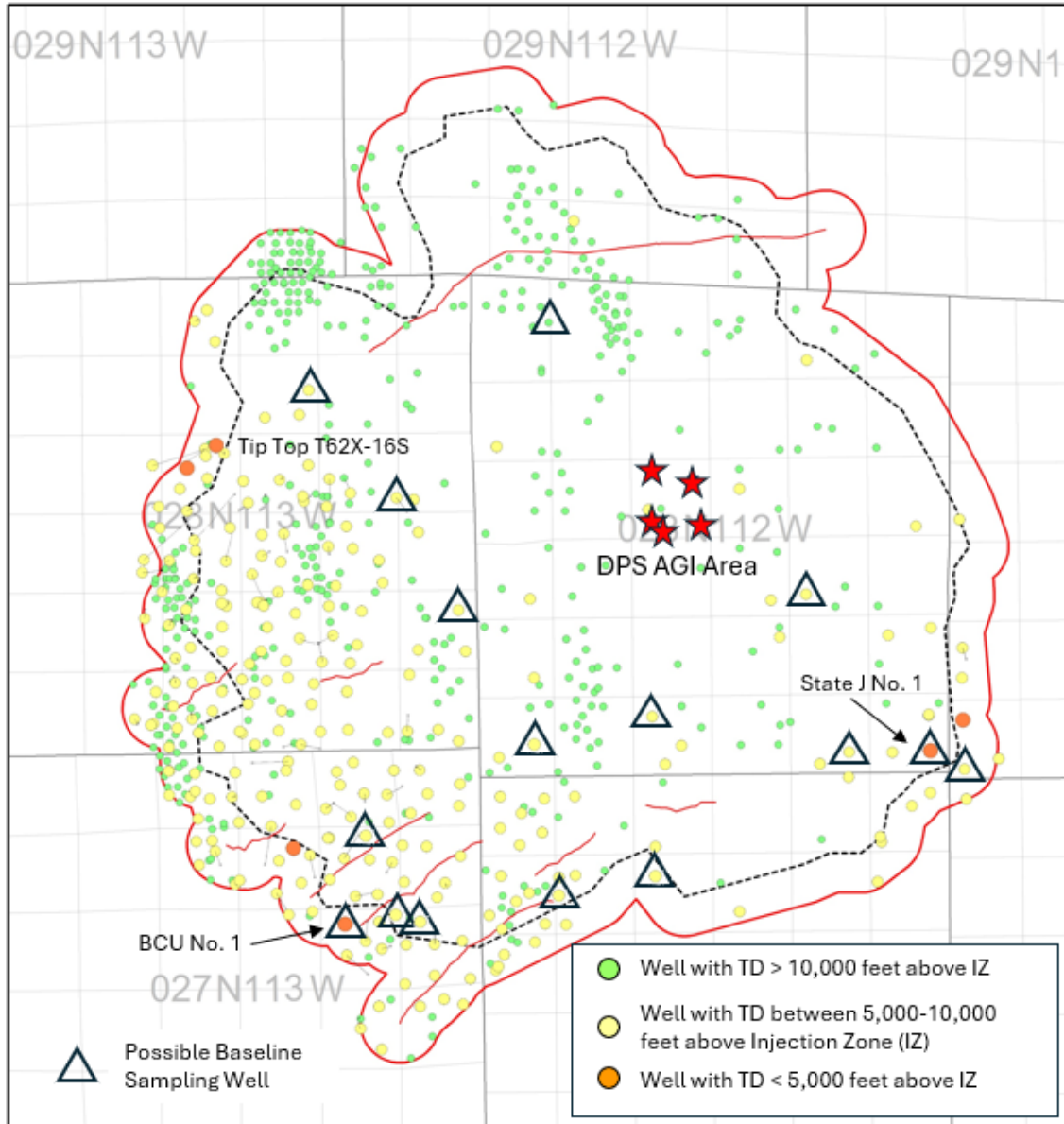


Figure 4.2-3: Map showing vertical separation between Total Depth (“TD”) of all existing oil and gas wells in the MMA (red polygon) and the top of the upper (Madison) injection zone (“IZ”). 480 of the 741 wells (64.8%) reach TD at least 10,000 feet above the Madison injection zone (green circles). 255 (34.4%) of the wells reach TD between 5,000 and 10,000 feet above the Madison injection zone (yellow circles), meaning 99.2% of existing wells in the MMA reach TD over 5,000 feet above the Madison injection zone. Only 6 wells reach TD less than 5,000 feet above the Madison injection zone, and only the Tip Top T62X-16S penetrates the injection zone. Of the 6 wells that reach TD less than 5,000 feet above the Madison, only the State J No. 1 is within the stabilized plume boundary (black-dashed polygon). Possible baseline gas analysis wells are denoted by black triangles. None of the

wells with an available gas analysis indicate CO₂ concentrations over 2.0 mol% or H₂S concentration above 0.0 mol%.

Of the 741 existing petroleum-related wells in the AMA/MMA, 448 (60.5%) are plugged and abandoned (“PA”), 221 (29.8%) are currently producing shallow sweet gas (PROD-GAS), 41 (5.5%) are currently producing shallow sweet oil, 18 (2.3%) are currently shut-in, temporarily abandoned, or have an unknown status, and finally, 13 (1.8%) are water-injection wells for the shallow sweet oil system. Note that no wells in the AMA/MMA produce gas from the Madison or Bighorn injection zones.

Likelihood:

Even though the risk of CO₂ leakage through the wells that do not penetrate confining zones is very unlikely, (the CO₂ would have to leak through the confining zone or upward along a fault first), BSO did not omit any potential source of leakage in the risk analysis. BSO analyzed the likelihood of leakage through the existing wells based on the following value assignment table depending on depth above injection zone and whether or not the well is located within the stabilized plume area:

LIKELIHOOD	WITHIN PLUME	OUTSIDE PLUME (WITHIN MMA)	
> 3,000 FT ABOVE INJ ZONE	1	1	3 = Moderate
< 3,000 FT ABOVE INJ ZONE	2	1	2 = Unlikely
PENETRATES INJ ZONE	3	2	1 = Very Unlikely

The results of the “likelihood” assessment for the wells located within the MMA can be observed in Appendix A. All wells, except the Tip Top T62X-16S, were assigned a value of “very unlikely” due to being either outside the plume area and or having a total depth greater than 3,000 feet above the injection zone, which also means the total depth is above the Triassic Evaporite confining unit. The Tip Top T62X-16S well was assigned a value of “unlikely” because although it penetrates the Madison and Bighorn injection zones, it is located outside of the stabilized plume area. Additionally, the Tip Top T62X-16S well is plugged and abandoned with no signs of leakage from the existing high in-situ CO₂ and H₂S reservoir since 2009.

Magnitude and Timing:

Using the deep, plugged and abandoned Tip Top T62X-16S well that shares a well pad with the shallow Tip Top T62X-16SH well as an example, the magnitude of potential leakage is insignificant. Any leakage from the Tip Top T62X-16S would be detected almost immediately due to the presence of H₂S in both the in-situ gas in the injection zone and in the free-phase plume. In this sense, most leakage from existing wells would be quickly detected using many of the same methodologies as for potential leakage from surface

equipment, including fixed and personal monitors whether by BSO or other operators' personnel. Additionally, all wells producing into an active gathering system undergo gas composition analyses at least annually to ensure the production stream meets pipeline specifications, particularly with respect to the presence of H₂S. Because existing wells that currently have a producing status produce from the shallow "sweet" petroleum system lack any H₂S, any indications of the presence of H₂S during gas analysis would cause alarm plus an immediate well shut-in and would be investigated by the operator and pipeline company immediately. In that case, early detection leads to an immediate response and minimization of the magnitude of potential leakage. With regard to timing, BSO believes it would take millions of years ("geologic time") for CO₂ to migrate upward through the Amsden and Triassic Evaporites confining units into existing wells over 3,000 feet above the injection zone due to the fact that the Triassic Evaporites confining unit has contained helium for tens of millions of years, which is a much smaller molecule size than CO₂. Therefore, it stands to reason that, so long as BSO does not exceed the fracture gradient of the confining units during injection operations, that a confining unit that can contain helium over geologic time can also continue to contain CO₂ over geologic time. In other words, the duration required for a small amount of CO₂ to get to the atmosphere via upward migration through the approximately 3,000-foot thick, shale and salt-rich Triassic Evaporite section, after migrating upward through the adjacent and overlying Amsden confining unit would be millions of years based on the fact that there are two distinct petroleum systems in the area, with the shallow sweet gas system being characterized by very low (< 2%) CO₂, no H₂S and no helium in gas analyses, compared to the deep sour gas system targeted for injection that has 65% CO₂, 5% H₂S and measurable helium (> 0.5%). If CO₂, H₂S or helium have not migrated upward through the confining units over geologic time thus far, it would stand to reason that the likelihood of large amounts of CO₂ leaking upward in the near-term timeframe is very unlikely. In terms of operational timing, however unlikely, leakage would potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. BSO, of course, would not inject above fracture pressure in any case, thus further reducing risk of leakage.

MAGNITUDE	WITHIN PLUME	OUTSIDE PLUME (WITHIN MMA)	
> 3,000 FT ABOVE INJ ZONE	1	1	3 = Significant
< 3,000 FT ABOVE INJ ZONE	2	1	2 = Minor
PENETRATES INJ ZONE	3	1	1 = Insignificant

The results of the "magnitude" assessment for the wells located within the MMA can be observed in Appendix A. All wells were assigned a value of "insignificant" due to being either outside the plume area and or having a total depth greater than 3,000 feet above

the injection zone and therefore above the Amsden and Triassic Evaporite confining units. The Tip Top T62X-16S well was also assigned a value of “insignificant” because although it penetrates the Madison and Bighorn injection zones, it is located outside of the stabilized plume area. Additionally, the Tip Top T62X-16S well shares a well pad with the Tip Top T62X-16SH well and potential leakage into the shallower well would be detected within a short time frame by the lease operator.

To conclude, likelihood of CO₂ leakage to the surface via existing wells is considered “very unlikely” and the magnitude is considered “insignificant”. Therefore, using the combined risk matrix for likelihood and magnitude, all wells in the MMA have a “very low” risk of potential leakage. It should be noted that Dry Piney State AGI wells were not included in this analysis, as any potential leakage would be addressed in Section 4.1 that discusses Surface Equipment, as the future DPS AGI wells will be operated by BSO and will be continuously monitored.

There are no existing producing wells completed in the Madison or Bighorn Formations within the AMA or MMA, and it is highly unlikely that there will be Madison or Bighorn production wells drilled in the MMA/AMA in the future owing to the high initial CO₂ and low initial methane and helium concentrations, likely rendering future production wells uneconomic.

4.3 POTENTIAL LEAKAGE THROUGH THE CONFINING UNITS

BSO considered and evaluated leakage through the confining zones above and below the Madison and Bighorn injection zones. See **Section 2.6.4** for discussion of confining units. The area closest to the injection wells with the highest concentration of free-phase CO₂ would likely be most prone to this leakage pathway.

Likelihood:

The shale, anhydrite and salt-rich Triassic Evaporites confining unit in the Dry Piney State AGI area serves as the overall deep sour gas system seal and the ultimate confining unit to both the Madison and the Bighorn injection zones. The shale, anhydrite and salt-rich lithologies that form the sealing capacity of this confining unit is impermeable to helium, a gas with a much smaller molecular volume than CO₂. If the reservoir seal material is impermeable to helium, then it follows that it is also impermeable to CO₂. Although natural creep of the salty sediments in the Triassic Evaporites confining unit is possible, this behavior does not disturb the sediments to the degree necessary to breach the reservoir seal of the Madison Formation. If this salty sediment were to flow on a scale large enough to create a leakage pathway from the Madison Formation to the surface, the natural gases trapped in the formation would have already escaped to the atmosphere over geologic time. The fact that gas (especially helium with its small molecular size) remains trapped at pressure in the Madison and Bighorn Formations, it must follow that any natural reactivation or movement of salt-rich sediments that has occurred over the

geological history of the LaBarge Field has not created any pathways for gas leakage to the surface. The likelihood of CO₂ leakage through the Triassic Evaporites confining unit is therefore “very unlikely”.

In addition to the Triassic Evaporites, the Amsden (422 ft thick) is the immediately adjacent and overlying confining unit to the Madison. Although partial fractures were observed on an eight-pad image log through the Amsden Formation overlying the Madison in the Dry Piney State 12-16, there were no complete fractures observed. The image log analyst noted that the partial fractures were generally faint in appearance and were often only observed on a single frequency resistivity or impedance image of the eight image tracks available at a given depth. No faults were observed on the image log, but several anhydrite stringers with 0% porosity and 0 md permeability were observed. The likelihood of CO₂ leakage through the Amsden Formation is “very unlikely”.

The Darby (302 ft thick) is the underlying confining unit for the Madison and the overlying confining unit for the Bighorn injection zone. There were only two complete natural fractures observed in the Darby and they were located at the very base of the interval. It could not be determined whether these two fractures were open or calcite-filled on the image log. Analysis of a fluid sample collected during wireline logging demonstrated different gas compositions in the Madison and Bighorn, indicating the Darby Formation is a confining unit that has hydraulically separated the Madison and Bighorn Formations over geologic time. Therefore, the likelihood of CO₂ leakage through the Darby Formation confining unit is “very unlikely”.

Collectively, all these confining zones generally have low porosity (< 2%) and low permeability (< 0.001 md) intervals that provide high seal integrity. So long as the injection pressure is limited to less than the fracture pressure of the confining zones, the likelihood of CO₂ leakage through this potential pathway to surface is determined to be “very unlikely.”

Magnitude and Timing:

Based on reservoir simulation results conducted by BSO, the relative difference in porosity and permeability of the low porosity and low permeability of the Amsden confining unit compared to the high porosity and high permeability of the Madison injection zone suggests the free-phase CO₂ plume stays entirely within the Madison Formation. Therefore, any potential leakage upward into the confining zone would be considered insignificant. Likewise, the Bighorn Formation is highly porous and permeable relative its overlying Darby confining unit, so plume modeling indicates that all injected CO₂ stays within the Bighorn injection zone. Therefore, any potential leakage upward into the confining zone would be considered insignificant.

In terms of timing, however unlikely, leakage would potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant

volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. BSO, of course, would not inject above fracture pressure in any case, thus reducing further risk of leakage.

To conclude, likelihood of CO₂ leakage to the surface through the confining units is considered “very unlikely” and the magnitude is considered “insignificant”. Therefore, using the combined risk matrix for likelihood and magnitude, this potential leakage pathway warrants a “very low” risk of potential leakage.

4.4 POTENTIAL LEAKAGE THROUGH FAULTS AND FRACTURES

Likelihood:

A thorough geological evaluation of the injection zone and confining units was performed (see **Section 2**) to understand the regional and local geology of the LaBarge structure and Dry Piney State injection area, as well as to understand the distribution of faults and fractures. **Figure 4.4-1** shows the fault traces within the Dry Piney State injection evaluation area that are stratigraphically within the Madison and Bighorn injection zones. *It is important to note that no faults within the MMA are observed at the surface, nor does seismic interpretation suggest that any faults in the MMA extend to the surface.*

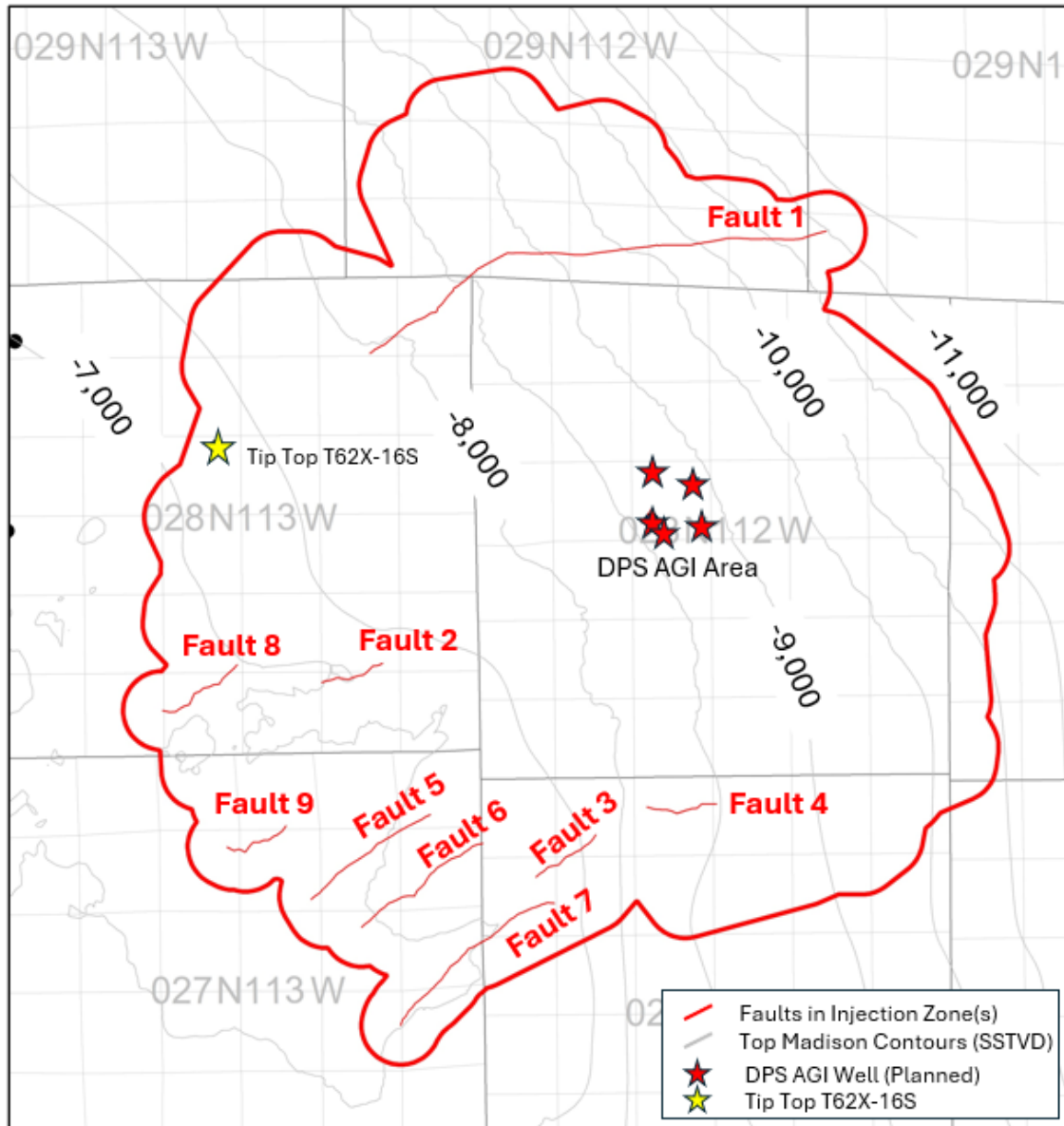


Figure 4.4-1: Map showing the location of faults (numbered 1 through 9) within the AMA/MMA that are at Madison and Bighorn depth. It is important to note that none of these faults are observed at the surface, nor does seismic interpretation suggest that any of these faults extend to the surface.

Faults were identified (numbered 1 through 9) and evaluated using seismic interpretation. Any fault that intersects and extends beyond the stabilized plume outline at year 2128 was brought into the analysis as a potential leakage pathway and the MMA includes a one-half mile buffer around any fault that extended beyond the stabilized plume (**Section 3.1**). In the vertical dimension, only three faults extend completely through or above the Triassic Evaporites confining interval. Despite observing seismic discontinuities interpreted as faults extending through the Triassic Evaporites interval, there is no

evidence that these faults are open and providing an active pathway for CO₂ leakage upward through the geologic column to surface, as evidenced by the existence of a shallow (Frontier, Bear River, Mowry and Gannett) sweet gas petroleum system (minor CO₂, no H₂S, no helium) that is currently being produced by approximately 166 wells within the MMA. If any of the three faults that extend upward through the confining unit were acting as a leakage pathway, gas analyses from wells producing in the MMA would indicate the presence of significant CO₂, H₂S and likely helium. Gas analyses are publicly available in producing gas wells are depicted as orange squares as shown on **Figure 4.2-1**. No H₂S or significant CO₂ (defined as > 2 mol%) is observed in available gas analyses from producing wells, indicating that the faults are not currently leakage pathways. Additionally, as discussed in **Section 3.1**, the MMA was extended to capture a one-half mile buffer around any fault that intersects and extends beyond the stabilized free-phase CO₂ plume at year 2128. Because the MMA encompasses a half-mile buffer zone to ensure there is no risk of leakage due to lateral migration associated with faults, and gas analyses indicate there is no upward migration along faults, the likelihood of leakage through faults is considered “very unlikely.”

The closest identified fault is Fault 1 (**Figure 4.4-1**) which is located approximately 3.4 miles north of the Dry Piney State injection area. Fault 1 penetrates the Madison and Bighorn injection zones, and Amsden and Darby confining zones, but notably does not extend upward into or through the Triassic Evaporites confining unit. Fault 1 exhibits the most laterally continuous fault trace in the area but is encompassed entirely within the extended MMA to provide the additional one-half mile buffer since Fault 1 does intersect the plume before and after plume stabilization. Therefore, the risk of leakage through Fault 1 is very unlikely.

Faults 2, 3 and 4 are the next closest to the Dry Piney State injection area and are located approximately 3.9 miles to the southwest. Fault traces for Faults 2, 3 and 4 are all relatively short in the lateral dimension, and do not extend upward through the Triassic Evaporites confining unit. The entirety of fault traces for Faults 2, 3 and 4 are all contained within the stabilized plume and do not extend beyond the MMA. Therefore, the risk of leakage along Faults 2, 3 and 4 due to lateral or upward migration is considered “very unlikely”.

Faults 5, 6 and 7 are located approximately 3.9 miles southwest of the Dry Piney State injection area. Fault traces for Faults 5, 6 and 7 are all relatively short in the lateral dimension. Faults 5, 6 and 7 extend upward through the Triassic Evaporites confining unit but die out above the Frontier producing interval. As previously stated, within the developed area of Faults 5, 6 and 7, no indications of CO₂, H₂S, and helium are seen in any wells, suggesting that they do not act as leakage pathways (See **Section 2.6.3**, **Figure 2.6** and **Appendix D** for data and discussion). The fault traces for Faults 5, 6 and 7 intersect and extend beyond the stabilized plume, as such the MMA was expanded to fully

encompass a half-mile buffer around the entirety of the fault traces for Faults 5, 6 and 7. Although Faults 5, 6 and 7 extend through the shallowest confining unit and intersect the stabilized plume, the risk of leakage along Faults 5, 6 and 7 due to lateral or upward migration is considered “unlikely” because gas analyses from shallow production indicate that the faults are not acting as leakage pathways from the deep sour gas system which contains a high concentration of naturally-occurring CO₂, H₂S and helium at pressures significantly higher than the shallow gas systems. As long as BSO does not exceed fracture pressures during injection operations, there is no reason to assume that these faults will open and become active CO₂ leakage pathways.

Finally, Faults 8 and 9 are located approximately 5.5 and 6.0 miles, respectively, from the Dry Piney State injection area. Fault traces for Faults 8 and 9 are relatively short and are contained entirely within the extended MMA. Faults 8 and 9 do intersect the edge of the stabilized plume. Faults 8 and 9 do not extend upward into or through the Triassic Evaporites confining unit. Therefore, the risk of leakage along Faults 8 and 9 is considered “very unlikely.”

Magnitude and Timing:

Reservoir modeling results indicate that the leading edge of the free-phase plume (ranging from 0.5 to 5% net incremental CO₂) will reach Fault 1 between 20 and 30 years after injection begins (**Figure 4.4-2**). Fault 1 does not extend upward through or above the Triassic Evaporites confining unit, and the maximum plume concentration is anticipated to be < 5% net incremental increase in CO₂. During the 50-year injection period Fault 1 does not intersect the plume in an area modeled to have greater than a 5% net incremental CO₂ concentration. Therefore, the magnitude of potential leakage of CO₂ to the surface is considered insignificant. Despite Fault 1 intersecting the Darby confining unit between the Madison and Bighorn injection zones, differing gas compositions between the Madison and Bighorn confirm that the two injection zones are hydraulically separate and Fault 1 is not an active leakage pathway so long as BSO maintains injection pressures below fracture pressure.

BSO concludes that the potential for leakage through Fault 1 is very low.

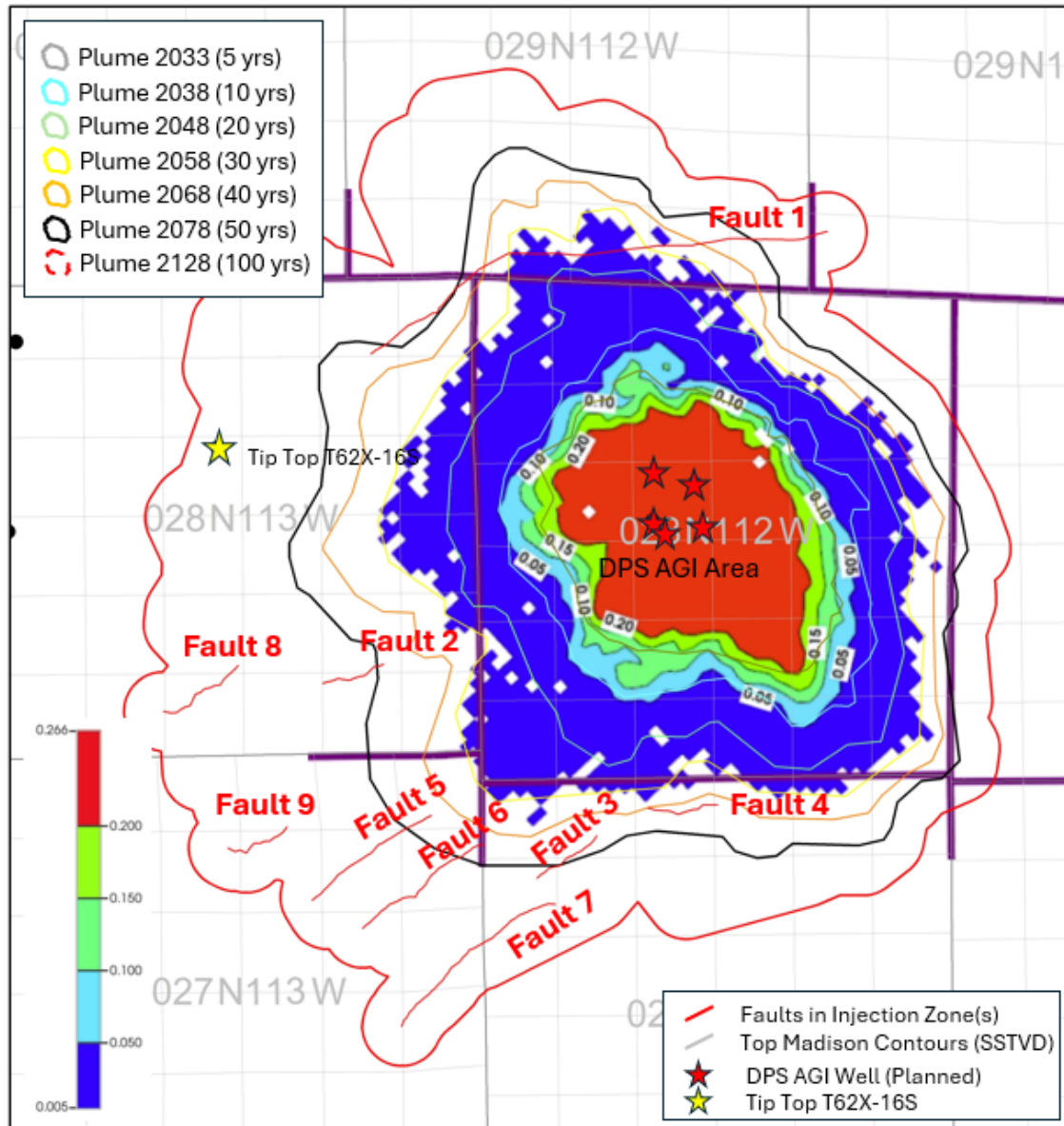


Figure 4.4-2: Map showing free-phase plume with less than 5% CO₂ concentration reaching Fault 1 between 20 and 30 years after injection begins. 30-year plume (year 2058) depicted.

Reservoir modeling results indicate that the outward edge of the free-phase plume (ranging from 0.5 to 5% net incremental CO₂) will reach Faults 2, 3 and 4 between 40 and 50 years after injection begins (**Figure 4.4-3**). Faults 2, 3 and 4 do not extend upward through or above the Triassic Evaporites confining unit, and the maximum plume concentration is anticipated to be < 5% net incremental increase in CO₂. During the 50-year active injection period Faults 2, 3 and 4 do not intersect the plume in an area modeled to have greater than a 5% net incremental CO₂ concentration. Therefore, the magnitude of potential leakage of CO₂ to the surface is considered insignificant. Despite Faults 2, 3

and 4 intersecting the Darby confining unit between the Madison and Bighorn injection zones, differing gas compositions between the Madison and Bighorn confirm that the two injection zones are hydraulically separate and Faults 2, 3 and 4 are not active leakage pathways so long as BSO maintains injection pressures below fracture pressure.

BSO concludes that the potential for leakage through Faults 2, 3 and 4 is very low.

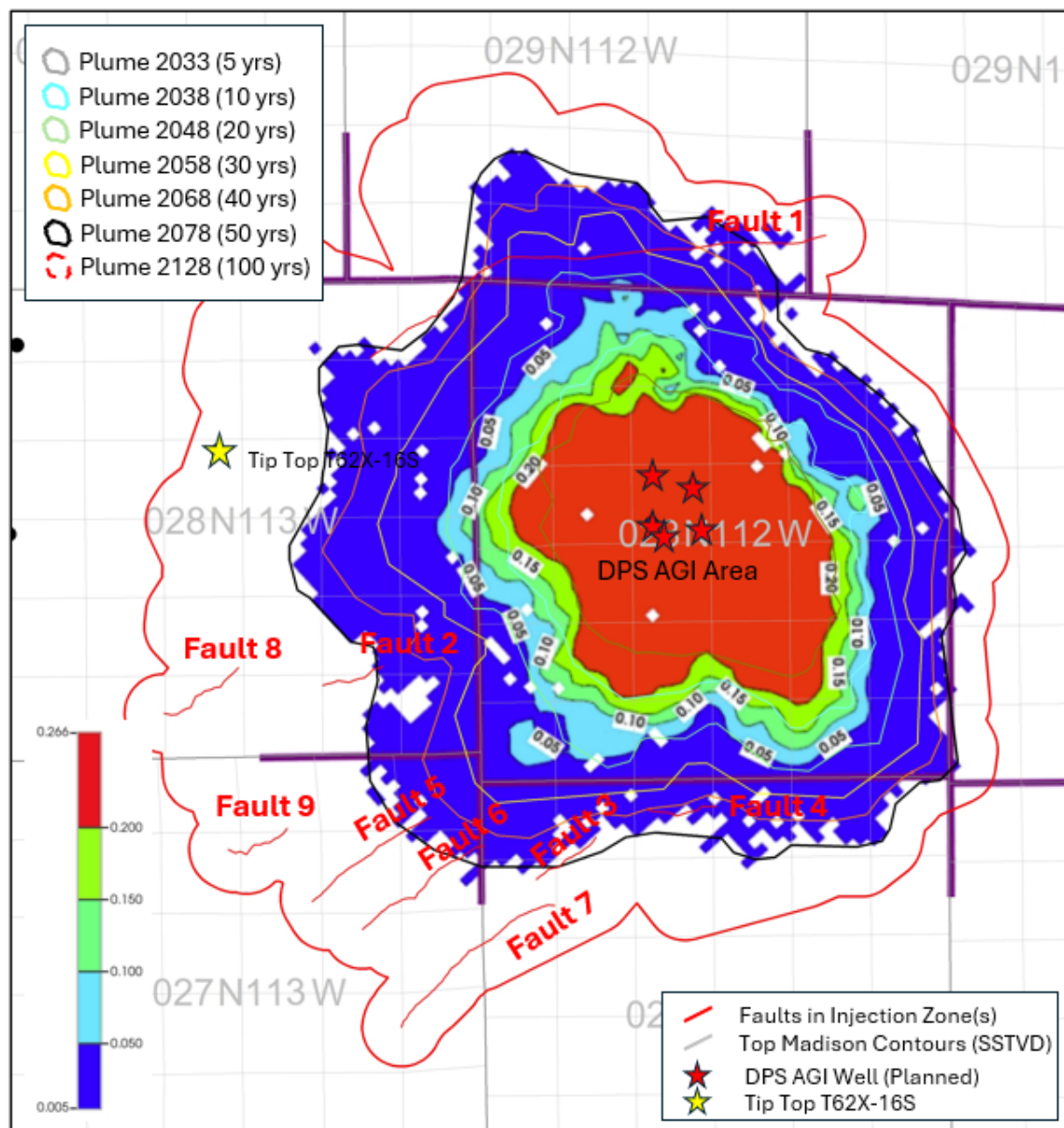


Figure 4.4-3: Map showing free-phase plume with less than 5% CO₂ concentration reaching Faults 2, 3 and 4 in approximately 50 years. 50-year plume (year 2078) depicted.

Reservoir modeling results indicate that the free-phase plume will reach Faults 5 and 6 between 40 and 50 years after injection begins (**Figure 4.4-3**), and Fault 7 during the plume stabilization period between 50 and 100 years after injection initiates. Faults 5, 6

and 7 extend upward through the Triassic Evaporites confining unit. During the 50-year active injection period, Faults 5, 6 and 7 do not intersect the plume in an area modeled to have greater than a 5% net incremental CO₂ concentration. Therefore, the magnitude of potential leakage of CO₂ to the surface is considered insignificant even if Faults 5, 6 and/or 7 were to act as leakage pathways. Although Faults 5, 6 and 7 intersect the Darby confining unit between the Madison and Bighorn injection zones, differing gas compositions between the Madison and Bighorn confirm that the two injection zones are hydraulically separate. Furthermore, despite Faults 5, 6 and 7 extending upward through and above the Triassic Evaporite confining unit, gas analyses from shallow wells in the vicinity of Faults 5, 6 and 7 (locations shown in **Figure 4.2-1**, and analyses including in **Appendix E**) do not show the presence of significant concentrations of CO₂ (> 2 mol%), H₂S, or helium (See **Section 2.6.3**, **Table 2.6** and **Appendix D**). Therefore, it can be ascertained that Faults 5, 6 and 7 are not active leakage pathways through the Triassic Evaporite confining unit so long as BSO maintains injection pressures below fracture pressure.

BSO concludes that the likelihood for potential for leakage along Faults 5, 6 and 7 is “unlikely” and the magnitude is insignificant, resulting in an overall risk assessment of “very low” for leakage along these faults.

Reservoir modeling results indicate that the outward edge of the stabilized free-phase plume (ranging from 0.5 to 5% net incremental CO₂) will reach Faults 8 and 9 between 90 and 100 years after injection begins, which equates to between 40 and 50 years after injection ceases. (**Figure 4.4-4**). Faults 8 and 9 do not extend upward through or above the Triassic Evaporites confining unit, and the maximum plume concentration is anticipated to be < 5% net incremental increase in CO₂. During the 50-year active injection period Faults 8 and 9 do not intersect the plume. Therefore, the magnitude of potential leakage of CO₂ to the surface is considered insignificant.

BSO concludes that the potential for leakage through Faults 8 and 9 is very low.

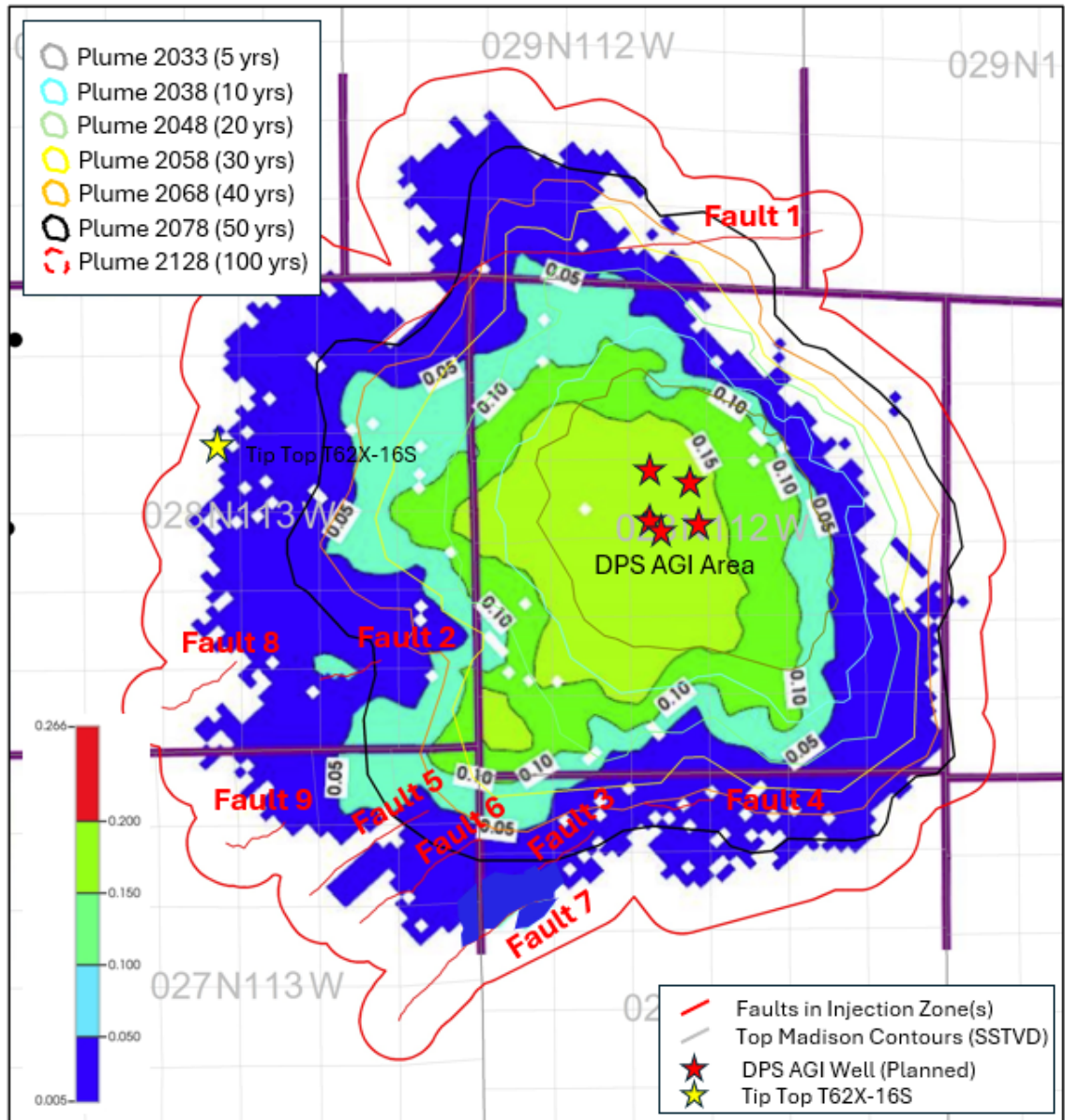


Figure 4.4-4: Map showing free-phase plume with less than 5% CO₂ concentration reaching Faults 5, 6 and 7 in approximately 90-100 years. 100-year plume (year 2128) depicted.

To summarize, BSO characterizes the overall risk of potential leakage along faults in the MMA as very low. The closest fault (Fault 1) is approximately 3.4 miles north of the Dry Piney State injection area. The leading edge of the free-phase CO₂ plume, at a concentration of 0.5 to 5% net incremental CO₂ is not expected to reach the closest fault until between 20 and 30 years after injection has been initiated. Only three faults extend upward through the Triassic Evaporite confining unit, but gas analyses indicate that these faults are not leakage pathways due to the lack of appreciable CO₂, H₂S or helium as would be expected if these faults provided a conduit to the deep sour gas system. In no case,

does a fault intersect the plume in a position in which the plume is anticipated to have a concentration greater than 5% net incremental CO₂ above the naturally occurring in-situ background CO₂ contained in the injection zones. Therefore, the magnitude of potential leakage would be insignificant.

In terms of timing, however unlikely, leakage would potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. BSO, of course, would not inject above fracture pressure in any case, thus reducing further risk of leakage. It is also possible any leakage would occur during the 50 years of post-injection plume growth during plume stabilization.

As discussed in Section 2.6.3, engineering and geologic analysis show no evidence of faulting with significant offset or complex structuring around the AGI wells. The absence of significant faulting also tends to suggest that regionally extensive natural fracturing or permeability enhancement in the Madison or Bighorn Formations is also very unlikely, and any natural fracturing or permeability enhancement is limited to a very localized area.

Current-day regional scale thrust faulting has not been observed in the LaBarge Field since the field has been under development. There is no concern of reactivation of these thrust faults and it is hypothesized that regional structuring similar in size to the Laramide Orogeny (formation of the Rocky Mountains) would be required to generate new thrust faults of significant size to produce subsurface structures of the scale and magnitude of the LaBarge Field. The activation of the salty sediments (which exist below the Nugget Formation and above the Madison Formation at LaBarge) is a phenomenon that was only observed to damage thin-wall cased wells, with thick-wall cased wells having sufficient strength to prevent flowage of these salt sediments.

It has been documented that natural fracturing of reservoirs in the subsurface of LaBarge and surrounding areas are directly correlative to distance to thrust faults in the area. This correlation has been documented in subsurface wellbore image logs and also by surface geological mapping around the thrust faults in the LaBarge Field. It therefore follows that a lack of significant faulting, as observed on 2D seismic panels around and through the AGI well site, will yield formations void of natural fracturing, and the necessary significant faults are not present to generate pervasive natural fractures of regional extent. The presumed lack of significant natural fracturing in the Madison reservoir at and around the AGI well sites suggest that all flow in the Madison and Bighorn must be from pore to pore, and that ability for fluids to flow will depend solely upon the natural intergranular porosity and permeability of the Madison and Bighorn. It should be noted that the permeability of the Madison and Bighorn is low or 'tight' according to industry definitions of 'tight' and therefore has minimal capability to freely flow fluids through only the pore system of the Madison and Bighorn. Accordingly, there is little potential for lateral migration of the

injection fluids once injection ceases, as the injection pressure will be the only impetus to induce lateral movement of the injected fluids. Note the limited areal growth of the free-phase plume after 50 years of injection (Figure 3.2) compared to 50 years after injection has ceased (Figure 3.4).

4.5 POTENTIAL LEAKAGE DUE TO LATERAL MIGRATION

Likelihood:

Regional evaluation of the geology (**Section 2.0**) and the geological model covering the entire LaBarge structure suggest that the Madison and Bighorn injection zones have adequate storage capacity, and their respective confining zones are uniform across the MMA. Therefore, all lateral migration is expected to occur within the injection zones. In addition, dynamic simulations indicate that the injected free-phase CO₂ plume will be contained within the injection zones covering the areas depicted by various time increments (**Figure 2.8-2**). Extensive modeling shows that after injection ceases (year = 2078) there is minimal continued lateral migration within the injection zone until plume stabilization at year 2128. It is also important to note that the injection zones in the sub-thrust Paleozoic section on the LaBarge structure are not hydraulically connected to local outcrops of the Madison and Bighorn Formations, as discussed in **Section 2.3.1** and **Section 2.3.3**. Due to the lack of hydraulic connection to outcrops and continuity of confining units across the entire structure, potential leakage of CO₂ to the surface due to lateral migration would require an additional leakage pathway, most likely lateral migration within the injection zones to faults and fractures as discussed in Section 4.4.

Therefore, BSO views the likelihood of CO₂ leakage to the surface or out of the injection zones due to lateral migration as “very unlikely.”

Magnitude and Timing:

Based on simulation results the free-phase CO₂ plume is projected to be contained within the injection zones within the MMA as depicted on **Figure 3.1-4**. The confining zones are thick and continuous, which would prevent any upward migration through the confining zone even if lateral migration beyond the MMA occurs. Because the free-phase CO₂ plume is delineated using a 0.5% net incremental increase in CO₂, if leakage through this potential pathway were to occur it would be considered insignificant relative to the large amount of in-situ CO₂ naturally present in the injection zones.

In terms of timing, however unlikely, leakage would potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. BSO, of course, would not inject above fracture pressure in any case, thus reducing further risk of leakage. It is also possible any

leakage would occur during the 50 years of post-injection plume growth during plume stabilization.

Therefore, the overall risk of leakage due to lateral migration is considered to be very low.

4.6 POTENTIAL LEAKAGE DUE TO SEISMICITY

Likelihood:

Figure 4.6-1 highlights the recorded seismic events since 2015 in the region of the Dry Piney State AGI area according to the United State Geologic Survey's "ANSS Comprehensive Earthquake Catalog". Within 20 miles, a total of 10 events occurred with magnitudes that ranged from M 1.1 – M 2.3 and depths from 10.8 kilometers ("km") to 34.8 km. The closest event to the Dry Piney State injection wells was a M 2.3 event, 2.25 miles away at a depth of 34.8 kilometers (approximately 100,000 ft below the injection zones and confining units). Three other events occurred within 5 miles of the Dry Piney State injection area and ranged in magnitude from M 1.2 to M 2.1, at depths of 10.8 to 16.6 km. All events within a 20-mile radius occurred at depths greater than 10.8 kilometers (approximately 25,000 feet deeper than the injection zones and confining units).

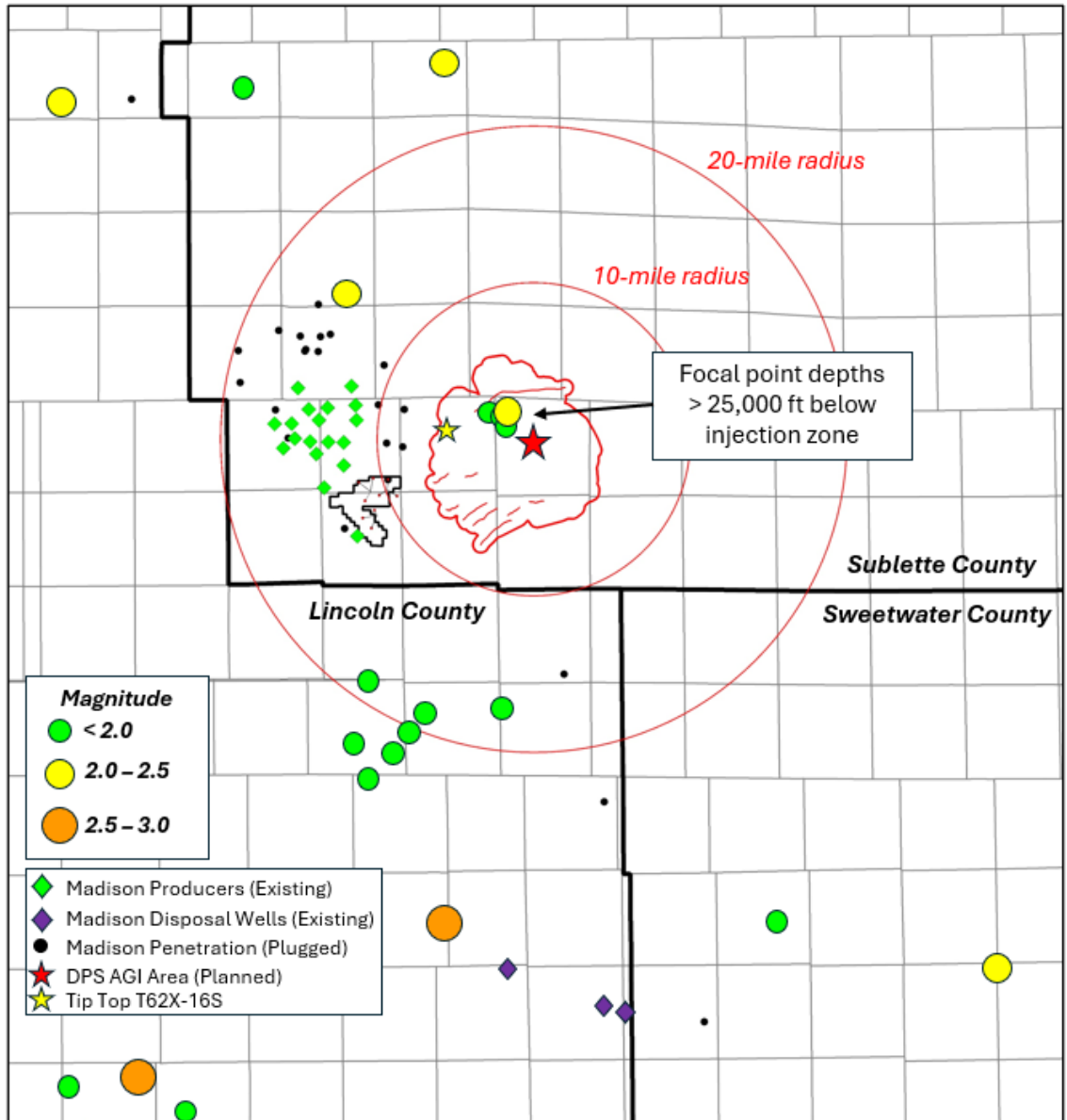


Figure 4.6-1: Map depicting seismic events as reported in the ANSS Earthquake Catalog from October 2015 to October 2025. Note that there are no “significant” (Magnitude > 3.5) within 20 miles of the DPS AGI area, or within the broader map area, including near existing disposal wells injecting into the Madison Formation (purple diamonds).

Significant earthquake activity is defined as greater than 3.5 on the Richter scale. The nearest recorded significant naturally occurring earthquake activity to the proposed Dry Piney State 12-16 has been detected over 20 miles away to the west in the Thrust Belt (M3.8, 2/25/2007, ANSS Catalogue 2018). Reported earthquake activity is believed to be related to the easternmost extension of the Basin and Range province (Eaton, 1982), unrelated to the Moxa Arch. There has also been no reported seismic activity attributed

to active injection operations at the ExxonMobil AGI 2-18 and AGI 3-14 or other disposal wells.

Due to the depths relative to the injection zones and confining units at the Dry Piney State injection area and the small magnitude of the seismic events since 2015, combined with the fact that BSO will inject at pressures below fracture opening pressure, BSO considers the likelihood of CO₂ emissions to the surface along potential leakage pathways caused by seismicity or induced seismicity to be “very unlikely”.

Magnitude and Timing:

The impact of a seismic event on confining zones, wells and surface installation integrity can vary greatly according to events’ magnitude or frequency. However, based on the relative depths of seismic events’ focal points ranging from 25,000 to 100,000 feet below the injection zones and confining units, and the small magnitudes recorded within 20 miles of the Dry Piney State injection area, BSO considers the magnitude of potential leakage due to seismicity to be insignificant. Further, if an unprecedented natural seismic event were to occur that impacted the integrity of any of the Dry Piney State AGI wells or the related infrastructure, BSO would shut down operations immediately, limiting potential release of CO₂ from wellhead and other surface equipment, thus minimizing leakage to an insignificant amount.

In terms of operational timing, and induced seismicity, however unlikely, leakage would potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. BSO, of course, would not inject above fracture pressure in any case, thus reducing further risk of leakage.

To summarize, BSO considers the risk of CO₂ leakage following a seismic event to be very unlikely and insignificant for a combined risk assessment of “very low”. Monitoring of seismic events in the vicinity of the Dry Piney State AGI wells is discussed in **Section 5.7**.

5.0 DETECTION, VERIFICATION AND QUANTIFICATION OF CO₂ SURFACE LEAKAGE

Subpart RR at 40 CFR 448(a)(3) requires a strategy for detecting and quantifying surface leakage of CO₂. BSO will employ the following strategy for detecting, verifying, and quantifying CO₂ leakage to the surface through the potential pathways for CO₂ surface leakage identified in Section 4. BSO considers H₂S to be a proxy for CO₂ leakage to the surface and as such will employ and expand upon methodologies detailed in the BSO H₂S Contingency Plan to detect, verify, and quantify CO₂ surface leakage close to the plant equipment. Table 5.1 summarizes the monitoring techniques that will be employed to identify leaks.

Monitoring will occur during the duration of injection period and the 50-year post-injection period. The plume is stabilized after 50 years without injection (year 2128).

TABLE 5.1 – LEAK DETECTION MONITORING PROGRAMS

Potential Leakage Pathway	Detection Monitoring Program
Surface Equipment	• Distributed Control System (“DCS”) surveillance of plant operations • Visual Inspections • Inline Inspections • Fixed in-field gas monitors • Personal Gas Monitors • “Optical” CO₂ Detection via Satellite or Lidar Data Imaging
Dry Piney State AGI Wells (including approved, but not yet drilled AGI wells)	• DCS surveillance of well operating parameters • Visual Inspections • Mechanical Integrity Tests (“MIT”) • In-well Pressure & Temperature sensors • Fixed in-field gas monitors • Personal Gas Monitors • “Optical” CO₂ Detection via Satellite or Lidar Data Imaging
Existing shallow oil, gas and groundwater wells	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • “Optical” CO₂ Detection via Satellite or Lidar Data Imaging • Produced gas composition surveillance of existing shallow oil & gas wells • Groundwater monitoring • CO₂ flux monitoring network
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • “Optical” CO₂ Detection via Satellite or Lidar Data Imaging • Produced gas composition surveillance of existing shallow oil & gas wells

	• Groundwater monitoring • CO₂ flux monitoring network
Confining Units	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • "Optical" CO₂ Detection via Satellite or Lidar Data Imaging • Produced gas composition surveillance of existing shallow oil & gas wells • Groundwater monitoring • CO₂ flux monitoring network
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • "Optical" CO₂ Detection via Satellite or Lidar Data Imaging • Produced gas composition surveillance of existing shallow oil & gas wells • Groundwater monitoring • CO₂ flux monitoring network
Natural and Induced Seismicity	• DCS surveillance of well operating parameters • "Optical" CO₂ Detection via Satellite or Lidar Data Imaging • Seismic monitoring station

5.1 LEAKAGE DETECTION AND VERIFICATION FROM SURFACE EQUIPMENT

BSO will implement several tiers of monitoring for leakage from surface equipment including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H₂S sensors, and continual monitoring and collection of operational parameters including flow, pressure, temperature and gas compositional data. The data will be monitored continuously by qualified technicians who will follow response and reporting protocols when the system delivers alerts and alarms that data is not within acceptable operating limits. Leaks from surface equipment will be detected by BSO field personnel, wearing personal H₂S monitors, following daily and weekly inspection and maintenance protocols which will include reporting and responding to any detected leakage events.

BSO will also maintain in-field gas monitors to detect H₂S and CO₂. The in-field gas monitors will be connected to the Distributed Control System ("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. In some instances, more than one detector alarming would trigger automatic equipment isolation and/or shutdown to mitigate the leak. In this case, leakage would be detected almost immediately with minimal (less than one metric ton) anticipated leakage rates and volumes. The verification process would involve repeating the measurement, recalibrating the measurement device and repeating the measurement, and/or taking a second measurement with a redundant device.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to visually observe potential CO₂ plumes at the surface. These new methods would be utilized over the entire MMA and would provide insights into leakage from point sources such as surface equipment. Once identified via hyperspectral imaging or Lidar, leakage would be verified using proven and accepted detection approaches previously discussed such as soil CO₂ flux monitoring.

5.2 LEAKAGE DETECTION AND VERIFICATION FROM APPROVED NOT YET DRILLED WELLS

Currently there are four additional Dry Piney State AGI wells that are in the permitting process but are not-yet-drilled wells within the MMA. Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones including more frequent monitoring during drilling operations, and all drilling of this injection zone is required to have an H₂S contingency plan in place due to the known naturally occurring H₂S in-situ. This applies to BSO and other operators drilling new wells through or within the Madison and Bighorn injection zones within the MMA. Due to the known naturally occurring H₂S in-situ in the injection zones, the WOGCC and the Bureau of Land Management (“BLM”), if applicable, require an H₂S contingency plan to be in place as part of the drilling plan submitted as part of the application for permit to drill (“APD”). The H₂S contingency plan includes standards for personnel and equipment safety and H₂S detection and monitoring during well drilling, completion, well workovers, and well servicing operations all of which apply for wells drilled into or through the Dry Piney State injection area MMA. Detection and verification of potential leakage would be conducted by mudlogging procedures utilizing mass spectrometry gas detection that can detect and confirm the presence in relative concentrations of CO₂, H₂S, helium and other components. To clarify, BSO plans to drill the remaining four Dry Piney State AGI wells before the injection period begins, so in this scenario, CO₂ and H₂S encountered would be naturally occurring rather than confirmation of leakage of injected volumes.

5.3 LEAKAGE DETECTION AND VERIFICATION FROM EXISTING WELLS

5.3.1 DRY PINEY STATE 12-16 WELL

As part of ongoing BSO operations, BSO will continuously monitor and collect flow, pressure, temperature, and gas composition data in its data collection system. This data

will be monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits.

To monitor leakage and wellbore integrity, BSO will deploy multiple pressure and temperature gauges, Distributed Temperature Sensing (“DTS”) and a fiber optic Distributed Acoustic Sensing (“DAS”) line to monitor pressures and temperatures during active and shut-in injection operations. Two gauges are designated to monitor the tubing (reservoir) pressure and temperature: one gauge at the surface, a second gauge downhole above the packer, and a third gauge monitors the annular space between the tubing and the long string casing. The DTS system is clamped to the tubing, and it monitors the temperature profile of the annulus. DTS can detect variation in the temperature profile events throughout the tubing and or casing. Temperature variation could be an indicator of leaks. Data from temperature and pressure gauges will be recorded by an interrogator housed in the onsite control building. DTS temperature data is recorded by a separate interrogator that is also housed in the onsite control building. Data from both interrogators are transmitted to a remote location for daily real time or historical data analysis. Real time evaluation and control by BSO operations personnel of the pressure and temperature data will enable remote action if needed.

If operational parameter monitoring and MIT failures indicate a CO₂ leak has occurred, BSO will take actions to quantify the leak based on operating conditions at the time of the detection including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. In this case, leakage would be detected almost immediately with minimal (less than one metric ton) anticipated leakage rates and volumes. The verification process would involve repeating the measurement, recalibrating the measurement device and repeating the measurement, and/or taking a second measurement with a redundant device.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into leakage from point sources such as the existing Dry Piney State 12-16 wellbore. Once identified, leakage would be verified using the proven approaches previously discussed such as soil CO₂ flux monitoring.

5.3.2 OTHER EXISTING WELLS WITHIN THE MMA

The CO₂ monitoring network described in **Section 6.3** and well surveillance by other operators of existing wells will provide an indication of any CO₂ leakage through existing wells withing the MMA. Existing wells within the MMA that are still producing oil and gas are generally subject to routine (monthly or annual) gas composition analysis. To the

extent possible, BSO will work with other operators to integrate and utilize gas composition data into its leakage detection and quantification plan, as new or increased concentrations of CO₂, H₂S and/or helium would signify potential leakage via this pathway, and any potential CO₂ leakage would likely be detected via this method (see Section 6.9 for additional detail) much sooner than shallower investigation methods that will also be employed such as soil CO₂ flux and groundwater monitoring from locations throughout the MMA. See **Sections 6.7, 6.8** for details. See **Section 2.6.3, Table 2.6** and **Appendix D** for existing public gas analyses from potential baseline sampling well candidates. Due to the routine gas analysis sampling of existing oil and gas wells flowing into a gas gathering system, BSO assumes any potential leakage via existing wells would be detected within 1-3 months and noted by a sharp increase in CO₂ and H₂S over background levels established during baseline monitoring with an associated casing and/or tubing pressure increase noted by the operator of the relevant well. The verification process would involve repeating the gas analysis that shows departure from baseline, both at the same laboratory and possibly a second independent laboratory and checking well records to ensure there is not an operational issue that would cause an increase in casing or tubing pressure. With an assumed detection period of 1-3 months, approximately 1 to 1.25 million metric tons of CO₂ could be leaked before detection.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into leakage from point sources such as existing wellbores, or plume sources such as from faults, leaking confining units and/or lateral migration. Once identified, leakage would be verified using the same gas composition or soil CO₂ flux verification approaches previously discussed, as well as repeating the optical imaging technique to ensure repeatability.

5.4 LEAKAGE THROUGH THE CONFINING UNITS

As discussed in **Section 4.3**, it is very unlikely that CO₂ leakage to the surface will occur through the confining zone. Continuous operational monitoring of the Dry Piney State AGI wells, described in **Sections 5.3.1 and 6.5**, will provide an indicator if CO₂ leaks out of the injection zone. Additionally, soil CO₂ flux, groundwater monitoring and produced gas composition from locations throughout the MMA will also provide an indication of CO₂ leakage to the surface. See **Sections 6.7, 6.8 and 6.9** for details.

If changes in operating parameters or other monitoring techniques listed in **Table 5.1** indicate leakage of CO₂ through the confining units, BSO will take actions to quantify the amount of CO₂ released and take mitigative action to stop it, including shutting in the wells (see **Section 5.8**). It is anticipated that leakage through the confining units would be detected at the surface within 12-18 months, or possibly much sooner if detected via existing shallow gas wells, which would potentially allow detection before surface leakage

via gas composition or pressure changes as discussed in **Section 5.3**. If leakage through the confining zone is suspected via shallow gas wells, verification would involve repeating the gas analysis that shows departure from baseline, both at the same laboratory and possibly a second independent laboratory and checking well records to ensure there is not an operational issue that would cause an increase in casing or tubing pressure. If leakage through the confining zone is suspected via soil CO₂ flux analysis, the verification process would involve repeating the measurement, recalibrating the measurement device and repeating the measurement, and/or taking a second measurement with a redundant device, in addition to potentially adding more soil CO₂ flux locales via denser sampling grid and/or more frequent sampling intervals. With an assumed detection period of 12-18 months, approximately 4.5 to 6.75 million metric tons of CO₂ could be leaked before detection at surface.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage at the surface on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential non-point source CO₂ plumes in the event leakage through the confining unit was due to an unobservable fault or fracture network not identified during seismic interpretation. These potential methods would be utilized over the entire MMA and would provide insights into location of plume source leaks such as from leaking confining units. Once identified, leakage would be verified using the same gas composition or soil CO₂ flux verification approaches previously discussed, as well as repeating the optical imaging technique to ensure repeatability.

5.5 LEAKAGE DUE TO FAULTS AND FRACTURES

As discussed in **Section 4.4**, it is very unlikely that CO₂ leakage to the surface will occur through faults. However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO₂ leakage to the surface, BSO will identify which of the pathways listed in this section are responsible for the leak, including the possibility of unidentified faults or fractures within the MMA. BSO will take measures to quantify the mass of CO₂ emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, soil CO₂ flux, groundwater monitoring and produced gas composition from locations throughout the MMA will also provide an indication of CO₂ leakage to the surface. See **Sections 6.7, 6.8 and 6.9** for details. See **Section 5.8** for additional information on quantification strategies. It is anticipated that leakage through the confining units would be detected at the surface within 12-18 months, or possibly much sooner if detected via existing shallow gas wells, which would potentially allow detection before surface leakage via gas composition or pressure changes as discussed in **Section 5.3**. If leakage through the confining zone is suspected via shallow gas wells, verification would involve repeating the gas analysis that shows departure from baseline, both at the

same laboratory and possibly a second independent laboratory and checking well records to ensure there is not an operational issue that would cause an increase in casing or tubing pressure. If leakage through the confining zone is suspected via soil CO₂ flux analysis, the verification process would involve repeating the measurement, recalibrating the measurement device and repeating the measurement, and/or taking a second measurement with a redundant device, in addition to potentially adding more soil CO₂ flux locales via denser sampling grid and/or more frequent sampling intervals. With an assumed detection period of 12-18 months, approximately 4.5 to 6.75 million metric tons of CO₂ could be leaked before detection.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into location of plume source leaks such as leakage along faults and fractures. Once identified, leakage would be verified using the same gas composition or soil CO₂ flux verification approaches previously discussed, as well as repeating the optical imaging technique to ensure repeatability.

5.6 LEAKAGE DUE TO LATERAL MIGRATION

Continuous monitoring within the MMA during and after the period of injection will provide an indication of the movement of the CO₂ plume migration in the injection zones. The CO₂ monitoring network described in **Section 6.3**, and routine well surveillance will provide an indicator if CO₂ leaks out of the injection zone. Additionally, soil CO₂ flux, groundwater monitoring and produced gas composition from locations throughout the MMA will also provide an indication of CO₂ leakage to the surface. See Sections 6.7, 6.8 and 6.9 for details.

If monitoring of operational parameters or other monitoring methods listed in Table 5.1 indicates that the CO₂ plume extends beyond the area modeled in **Section 3.0** and presented in **Section 4.5**, BSO will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO₂ migration. As this scenario would be considered a material change per 40CFR98.448(d)(1), BSO will submit a revised MRV plan as required by 40CFR98.448(d). It is anticipated that leakage due to lateral migration would still need to leak upward through the confining units, and therefore, like the detection of leakage from confining units, leakage due to lateral migration would be detected at the surface within 12-18 months. Detection of leakage could possibly occur much sooner if detected via existing shallow gas wells, which would potentially allow detection before surface leakage via gas composition or pressure changes as discussed in **Section 5.3**. If leakage through the confining zone or due to lateral migration is suspected via shallow gas wells, verification would involve repeating the gas analysis that shows departure from baseline, both at the same laboratory and possibly a second independent laboratory and checking well records to ensure there is not an operational issue that

would cause an increase in casing or tubing pressure. If leakage through the confining zone or due to lateral migration is suspected via soil CO₂ flux analysis, the verification process would involve repeating the measurement, recalibrating the measurement device and repeating the measurement, and/or taking a second measurement with a redundant device, in addition to potentially adding more soil CO₂ flux locales via denser sampling grid and/or more frequent sampling intervals. With an assumed detection period of 12-18 months, approximately 4.5 to 6.75 million metric tons of CO₂ could be leaked before detection.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into location of plume source leaks such as leakage due to lateral migration. Once identified, leakage would be verified using the same gas composition or soil CO₂ flux verification approaches previously discussed, as well as repeating the optical imaging technique to ensure repeatability.

5.7 LEAKAGE DUE TO NATURAL OR INDUCED SEISMICITY

In order to monitor the influence of natural and/or induced seismicity, BSO will use the established ANSS seismic network and an onsite seismometer that will be installed. The network consists of seismic monitoring stations that detect and locate seismic events in real time. Continuous monitoring helps differentiate between natural and induced seismicity.

If the monitoring systems indicate a seismic event, BSO will assess the integrity of the DPJGPF and Dry Piney State AGI wells. If the event caused CO₂ leaks, BSO will act to quantify the mass of CO₂ emitted to the surface based on operational conditions at the time the leak was detected. See Section 6.6 for details regarding seismic monitoring and analysis. See Section 5.8 for additional information on quantification strategies.

It is anticipated that leakage due to natural or induced seismicity would occur as leakage through the confining units or along faults and therefore would be detected at the surface within 12-18 months like in the case of migration through confining units. Leakage could possibly be identified sooner if detected via existing shallow gas wells, which would potentially allow detection before surface leakage via gas composition or pressure changes as discussed in Section 5.3. If leakage due to seismicity is through the confining zone or along faults is suspected via shallow gas wells, verification would involve repeating the gas analysis that shows departure from baseline, both at the same laboratory and possibly a second independent laboratory and checking well records to ensure there is not an operational issue that would cause an increase in casing or tubing pressure. If leakage due to seismicity is through the confining zone or along faults is suspected via soil CO₂ flux analysis, the verification process would involve repeating the measurement,

recalibrating the measurement device and repeating the measurement, and/or taking a second measurement with a redundant device, in addition to potentially adding more soil CO₂ flux locales via denser sampling grid and/or more frequent sampling intervals. With an assumed detection period of 12-18 months, approximately 4.5 to 6.75 million metric tons of CO₂ could be leaked before detection.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into location of plume source leaks such as from faults, lateral migration or through confining units due to natural or induced seismicity. Once identified, leakage would be verified using the same gas composition or soil CO₂ flux verification approaches previously discussed, as well as repeating the optical imaging technique to ensure repeatability.

5.8 STRATEGY FOR QUANTIFYING CO₂ LEAKAGE AND RESPONSE

5.8.1 LEAKAGE FROM SURFACE EQUIPMENT

For normal operations, quantification of emissions of CO₂ from surface equipment will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR. Quantification of major leakage events from surface equipment as identified by the detection techniques listed in Table 5.1 will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified, the leakage location will be isolated to prevent additional emissions to the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. BSO has standard operating procedures to report and quantify all pipeline leaks in accordance with applicable regulations, including Department of Transportation (DOT) Part 195. BSO will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by BSO or third parties. Additionally, BSO may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

5.8.2 LEAKAGE IN THE SUBSURFACE

Selection of a quantification strategy for leaks that occur in the subsurface will be based on the leak detection method (Table 5.1) that identifies the leak. Leaks associated with the point sources, such as the injection wells, and identified by failed MITs, variations of operational parameters outside acceptable ranges, and in-well pressure and temperature sensors can be addressed immediately after the injection well has been shut in. Quantification of the mass of CO₂ emitted during the leak will depend on characterization

of the subsurface leak, operational conditions at the time of the leak, and knowledge of the geology and hydrogeology at the leakage site. Conservative estimates of the mass of CO₂ emitted to the surface will be made assuming that all CO₂ released during the leak will reach the surface. BSO may choose to estimate the emissions to the surface more accurately by employing transport, geochemical, or reactive transport model simulations.

If detected and verified, quantification of leakage from existing oil and gas wells within the MMA will be estimated through a combination of pressure and gas composition data combined with operating parameters at the time of the leak, that can be used in material balance equations. Other direct measurements such as accumulation chambers or tenting would be employed to measure leakage rates to allow calibration of material balance estimation.

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, due to lateral migration or which may be initiated by seismic events and may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations. In the event a leakage plume is identified via optical imaging technique such as Lidar or satellite-based hyperspectral imaging, weather and atmospheric conditions will be utilized in a modeling-based approach to quantify CO₂ leakage, as well as measurement of CO₂ flux at surface near the surface leakage location via eddy covariance, accumulation chamber or tenting. These methods would allow direct measurement of the leak rate at the surface, which would provide a good estimation of total leakage, as well as calibration of optical imaging modeling.

5.8.3 LEAKAGE AT THE SURFACE

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO₂ leaking back to the surface emphasizing the importance of monitoring network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO₂ flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 5.8.1, or from the subsurface. In the latter case, CO₂ flux monitoring methodologies, as described in Section 6.8, will be employed to quantify the surface leaks.

6.0 STRATEGY FOR ESTABLISHING EXPECTED BASELINES FOR MONITORING CO₂ SURFACE LEAKAGE

BSO will use its automatic distributed control system to continuously monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO₂. BSO considers H₂S to be a proxy for CO₂ leakage to the surface and as such will

employ and expand upon methodologies detailed in its H₂S contingency plan to establish baselines for monitoring CO₂ surface leakage. The following describes BSO's strategy for collecting baseline information.

6.1 VISUAL INSPECTIONS

Field personnel will conduct daily inspections of the AGI facilities and weekly inspections of the AGI well site. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize the possibility of CO₂ leakage. If an issue is identified, a work order will be generated to correct the issue.

6.2 FIXED IN-FIELD AND PERSONAL H₂S GAS MONITORS

Compositional analysis of BSO's gas injectate at the Dry Piney State AGI area indicates an H₂S concentration of 6.93% thus requiring BSO to develop and maintain an H₂S Contingency Plan (Plan) according to the WOGCC and BLM regulations. As previously stated, BSO considers H₂S to be an excellent proxy for CO₂ leaks at the plant and the AGI site. The Plan contains procedures to provide for an organized response to an unplanned release of H₂S from the plant or the associated Dry Piney State AGI wells and documents procedures that would be followed in case of such an event. The baseline expectation for H₂S, and therefore CO₂, would be 0 ppm with no alarms during routine operations. Departure from this baseline would require investigation to ensure there are no leaks from surface equipment at the gas plant or AGI location.

6.2.1 FIXED IN-FIELD H₂S GAS MONITORS

The DPJGPF utilizes numerous fixed-point monitors, strategically located throughout the plant, to detect the presence of H₂S in ambient air. The Dry Piney State AGI well site will also employ fixed-point monitors located across the well pad to mitigate varying weather conditions (wind directions). The monitors are connected to the local control system or the DCS Safety Instrumented System, which is designed for safety-critical devices and operations. Upon detection of H₂S at 10 ppm at any detector, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of H₂S at 90 ppm at any monitor, visible red beacons are activated, and an evacuation alarm is sounded throughout the plant at which time all personnel will proceed immediately to a designated evacuation area.

6.2.2 HANDHELD AND PERSONAL H₂S GAS MONITORS

Handheld gas detection monitors are available at strategic locations around the plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, Lower Explosive Limit ("LEL") for hydrocarbons in the atmosphere, H₂S and CO₂.

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the plant and at the Dry Piney State AGI wells site must wear personal H₂S monitoring devices to assist them in detecting the presence of unsafe levels of H₂S. Personal monitoring devices will give an audible alarm and vibrate at 10 ppm.

6.3 CO₂ DETECTION MONITORING NETWORK AND OPTICAL DATA IMAGERY

In addition to the handheld gas detection monitors described above, BSO will set up a monitoring network for CO₂ leakage detection in the MMA/AMA as defined in Section 3.1 and 3.2. In addition, there will be periodic produced gas composition analysis (**Section 6.5**), groundwater chemistry analysis (**Section 6.7**), and soil CO₂ flux sampling (**Section 6.8**) within the MMA. Once the network is set up, BSO will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project to allow identification of any deviation from baseline analyses that may suggest a leak.

BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into the location of surface leakage from any of the identified pathways. In order to establish a baseline, the satellite or Lidar data imaging methodology would be employed on a semi-annual basis for two years, then annually.

6.4 CONTINUOUS PARAMETER MONITORING

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

6.5 WELL SURVEILLANCE AND GAS COMPOSITION MONITORING

BSO will adhere to the requirements of WOGCC rules governing the construction, operation and closing of an injection well. It includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, WOGCC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. BSO's Routine Operations and Maintenance Procedures for the Dry Piney State AGI wells will ensure frequent periodic inspection of the well and opportunities to detect leaks and implement corrective action.

Additionally, to the extent possible, BSO will work with area operators of existing shallow gas wells to monitor a subset of existing oil and gas wells for CO₂ leakage as defined in **Sections 4.2 and 5.3**. Production gas samples will be collected and analyzed on a quarterly

basis for 12 months to establish baseline data. After establishing the gas composition baseline, samples will be collected and analyzed annually. Samples will be collected according to standard industry methods for production well gas sampling.

The gas compositional analysis will include at least methane, ethane, propane, isobutane, n-butane, heptanes, octanes, nonanes, decanes plus, nitrogen, carbon dioxide, oxygen, hydrogen sulfide and helium. See **Table 6.5** for parameters to be measured during baseline analyses which will be compiled and compared with regional historical data to determine patterns of change in produced gas composition not related to injection processes at the Dry Piney State injection area. A report of produced gas composition will be developed from this analysis. Any produced gas composition samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

<i>Parameters</i>
Methane (mol%)
Ethane (mol%)
Propane (mol%)
Isobutane (mol%)
n-Butane (mol%)
Heptanes (mol%)
Octanes (mol%)
Nonanes (mol%)
Decanes Plus (mol%)
Nitrogen (mol%)
Carbon Dioxide (mol%)
Hydrogen Sulfide (mol%)
Helium (mol%)

Table 6.5: Parameters and constituents that will be tested for in gas composition analyses conducted on select existing shallow gas wells to establish a baseline.

6.6 SEISMIC MONITORING STATION

BSO will install a seismometer and a digital recorder to monitor and record data for any seismic event at the DPJGPF and Dry Piney State AGI well site. BSO will ensure that the seismic monitoring station is configured such that it can record and report data to third parties as necessary. BSO will also monitor the ANSS network for seismicity in the injection area. A report will be periodically generated with a map showing the magnitudes of recorded events from seismic activity. By examining historical data, a seismic baseline prior to the start of injection can be well established and used to verify anomalous events

that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

6.7 GROUNDWATER MONITORING

BSO will monitor groundwater wells for CO₂ leakage as defined in **Section 4.2**. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 6.7** for parameters to be measured during baseline analyses which will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Dry Piney State injection area. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

<i>Parameters</i>
pH
Alkalinity as HCO ³⁻ (mg/L)
Chloride (mg/L)
Fluoride (mg/L)
Bromide (mg/L)
Nitrate (NO ₃ ⁻) (mg/L)
Phosphate (mg/L)
Sulfate (SO ₄ ²⁻) (mg/L)
Lithium (mg/L)
Sodium (mg/L)
Potassium (mg/L)
Magnesium (mg/L)
Calcium (mg/L)
Total Dissolved Solids (mg/L)
Total Cations (meq/L)
Total Anions (meq/L)
Percent Difference (%)
Oxidation-Reduction Potential (mv)
Non-Purgeable Organic Carbon (ppm)

Table 6.7: *Parameters and constituents that will be analyzed in groundwater chemistry samples to establish a baseline from existing groundwater wells.*

6.8 SOIL CO₂ FLUX MONITORING

Soil flux data will be used to assess any migration of CO₂ through the soil and its escape to the atmosphere. By taking CO₂ soil flux measurements at periodic intervals, BSO can continuously characterize the interaction between the subsurface and surface. Actionable recommendations can be made based on the collected data.

Soil CO₂ flux will be collected on a monthly basis for 12 months to establish a baseline and understand seasonal and other variations in the Dry Piney State AGI area. After the baseline is established, data will be collected quarterly for three years, then annually. Due to the climate in the area, soil CO₂ flux samples will be collected on the schedule proposed above as weather conditions and seasonality allow. BSO will target surface locations associated with plugged and abandoned wells, as well as areas directly above faults for initial baseline monitoring locations.

Soil CO₂ flux measurements will be taken using a LI-COR LI-8100A flux chamber, or similar instrument, at pre planned locations at the site. PVC soil collars (8cm diameter) will be

installed in accordance with the LI-8100A specifications where possible. Measurements will be subsequently made by placing the LI-8100A chamber on the soil collars and using the integrated iOS app to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. The soil collars will be left in place such that each subsequent measurement campaign will use the same locations and collars during data collection. In the event it is not possible to install soil collars, a different permanent marker such as rebar post will be installed so subsequent measurements can be taken in the same location.

7.0 CONSIDERATIONS USED TO CALCULATE SITE-SPECIFIC VARIABLES FOR THE MASS BALANCE EQUATION

To accommodate for site-specific conditions, as provided in 40 CFR 98.448, BSO proposes to modify quantifying equipment leaks by using a risk-driven approach. Due to the high H₂S concentration of the AGI fluids, leaks pose a risk to personnel. Additionally, as mentioned above, even a small leak of this high H₂S gas would trigger an alarm to the operations team. BSO will identify leaks through continuous surveillance and leak detection systems and will alarm operations to take immediate action to stop the release. This continuous surveillance using fixed gas detectors will identify leaks better than annual leak surveys due to the fact that the gas detectors are in operation at all times. When detected, fugitive leakage would be managed as an upset event and calculated for that event based on operating conditions at that time.

Below describes how BSO will calculate the mass of CO₂ injected, emitted, and sequestered.

7.1 MASS OF CO₂ RECEIVED

§98.443 states that “you must calculate the mass of CO₂ received using CO₂ received equations... unless you follow the procedures in §98.444(a)(4).” §98.444(a)(4) states that “if the CO₂ you receive is wholly injected and is not mixed with any other supply of CO₂, you may report the annual mass of CO₂ injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO₂ received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO₂ received.” Since the CO₂ received by the AGI process is wholly injected and not mixed with any other supply of CO₂, the annual mass of CO₂ injected would be equal to the annual mass of CO₂ received, as calculated using Equation RR-4 per CFR 98.444(a)(4):

$$CO_{2,u} = \sum_{p=1}^4 Q_{p,u} * C_{CO_2,p,u}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.
 $Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter)
 $C_{CO_2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2 , express as a decimal fraction).
p = Quarter of the year.
u = Flow meter.

7.2 MASS OF CO_2 INJECTED

Mass flow meters will be used to measure the injected mass of CO_2 at each well. Equation RR-4 (in Section 7.1) will be used to calculate the annual total mass of CO_2 injected into each well. Equation RR-6 will be used to aggregate injection data for the AGI wells. Equation RR-6 is below:

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

Where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) through all injection wells.
 $CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.
u = Flow meter.

7.3 MASS OF CO_2 PRODUCED

The AGI wells will not be part of an enhanced oil or enhanced gas recovery process, nor does reservoir simulation show the free-phase CO_2 plume reaching any existing or future production wells, therefore, there will be no injected CO_2 produced and/or recycled.

7.4 MASS OF CO_2 EMITTED BY SURFACE LEAKAGE AND EQUIPMENT LEAKS

It is not appropriate to conduct a leak survey at the AGI well sites due to the components being unsafe-to-monitor and extensive monitoring systems in place. Entry to the AGI well pad will require the individual to wear a personal gas monitor capable of detecting CO_2 and H_2S , thus allowing immediate identification of possible leakage from surface equipment. Due to the high H_2S and CO_2 concentrations of the AGI fluids, fugitive leakage would be detected and managed as an upset event in the same way that CO_2E (CO_2 emitted by surface leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time. As already mentioned, gas detectors are in operation continuously to survey the area for leaks; even a small leak would trigger an alarm. This methodology is consistent with 40

CFR 98.448(5), which provides the opportunity for an operator to calculate site-specific variables for the mass balance equation.

Therefore, parameters CO₂E and CO₂FI (CO₂ emitted from equipment leaks from surface equipment between the flow meter used to measure injection quantity and the injection wellhead) will be measured using the leakage quantification procedures described earlier in this plan. BSO will estimate the mass of CO₂ emitted from leakage points from the flow meter to the injection wellhead based on operating conditions at the time of the release – pipeline pressure, temperature, flow rate, size of the leakage point opening, and estimated duration of leak. At the AGI wells, there will be no CO₂ emissions from venting due to the high H₂S concentration of the AGI fluid; blowdown emissions are sent to the flares and are reported under Subpart W for the gas plant. Venting AGI well injection gas would only occur in the event of depressurizing for maintenance or testing, which would be measured during time of event. To clarify, no venting or “blowdown” emissions would occur after metering for Subpart RR due to the position of the flow meters used to measure injection quantity relative to the injection wellheads (Figure 2.15). Therefore, no venting or blowdown emissions would be included in the calculation for CO₂FI which is the total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions from equipment located on the surface between the flow meters used to measure injection quantity and the injection wellheads.

In the event that surface leakage is detected, the leakage would be quantified and be used to estimate the mass emitted from each pathway and summed using Equation RR-10:

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

Where:

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

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

x = Leakage pathway.

7.5 MASS OF CO₂ SEQUESTERED IN SUBSURFACE GEOLOGIC FORMATIONS

Since BSO is not actively producing oil or natural gas or any other fluids as part of the AGI process, Equation RR-12 will be used to quantify CO₂ injected and sequestered. Parameter CO₂I (CO₂ injected in the well or group of wells annually) will be determined using Equation RR-4, as outlined above in Section 7.2. Parameters CO₂E and CO₂FI will be measured using the leakage quantification procedure described above in Section 7.4. CO₂

in the AGI fluids is not vented from equipment due to the high H₂S concentration. Equation RR-12 is as follows:

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

Where:

CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

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

CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the mass flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W.

8.0 ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

Upon approval by the EPA, this MRV Plan will become the applicable plan for the Dry Piney State AGI wells. BSO expects the Commercial Online Date (“COD”) to be approximately October 2028. BSO will begin collecting baseline data at least 12 months in advance of this expected date, beginning in 2027. At COD, BSO will begin collecting data to enable calculation of the total amount of CO₂ sequestered based on the equations in Section 7.0. Once the MRV Plan becomes applicable, BSO will report under Subpart RR for the AGI wells. Once applicable, BSO anticipates this MRV Plan will remain in effect until the end-of-field-life of BSO’s DPU and AGI assets, unless and until it is subsequently amended and superseded.

9.0 QUALITY ASSURANCE PROGRAM

9.1 MONITORING QA/QC

In accordance with the applicable requirements of 40 CFR 98.444, BSO will incorporate the following provisions into its QA/QC programs:

CO₂ Injected

- The mass of CO₂ injected will be measured with a mass flow meter for each AGI well and will be monitored continuously, allowing the mass injected to be compiled quarterly.
- A continuous gas composition analyzer will measure the concentrations for each representative stream.
- The continuous composition measurements will be averaged over the quarterly period to determine the quarterly CO₂ composition of the injected stream.

- The CO₂ analyzers will be calibrated according to manufacturers' recommendations.

CO₂ emissions from equipment leaks and vented emissions of CO₂

- Gas detectors are operated continuously except as necessary for maintenance and calibration.
- Gas detectors will be operated and calibrated according to manufacturer recommendations and API standards.

Measurement Devices

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

General

- CO₂ concentration will be measured using continuous gas analyzers, which is an industry standard practice.
- All measured volumes of CO₂ will be converted to standard cubic feet at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 MISSING DATA PROCEDURES

In the event BSO is unable to collect data needed for the mass balance calculations, 40 CFR 98.445 procedures for estimating missing data will be used as follows:

- If a quarterly quantity of CO₂ injected is missing, it will be estimated using a representative quantity of CO₂ injected from the nearest previous time period at a similar injection pressure.
- For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment at the facility that are reported in this subpart, missing data estimation procedures will be followed in accordance with those specified in subpart W of 40 CFR Part 98.

9.3 MRV PLAN REVISIONS

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

10.0 RECORDS RETENTION

BSO will follow the record retention requirements of CFR 98.3(g). Additionally, it will retain the following records from AGI well sites for at least three years:

- Quarterly records of injected CO₂ including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO₂ emitted from equipment leaks of CO₂, from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035058210000	GOVT	No. 1-W	PA	WASATCH	145	16325	13347	NO	1	1	1
49035058210000	GOVT	No. 1-W	PA	WASATCH	145	16325	13347	NO	1	1	1
49035057920000	FEDERAL	No. 8	PA	TERTIARY	228	15661	12683	YES	1	1	1
49035057350000	GOVT	No. 1-W	PA	TERTIARY	90	15180	12202	YES	1	1	1
49035058240000	GOVT	No. 1-W	PA	TERTIARY	85	14755	11777	YES	1	1	1
49035252220000	NORTH LABARGE UNIT	No. 103-04X	PA	TERTIARY	35	14473	11495	NO	1	1	1
49035241210000	NORTH LABARGE UNIT	No. 101-33D	PA	TERTIARY	60	14077	11099	NO	1	1	1
49035058130000	HADDENHAM	No. 1	PA	TERTIARY	385	14010	11032	YES	1	1	1
49035054970000	FEDERAL	No. 1W	PA	TERTIARY	135	13765	10787	YES	1	1	1
49035223880000	BX	No. 20-20	PA	HILLIARD	215	13652	10674	NO	1	1	1
49035247660000	CHIMNEY BUTTE UNIT	No. 113-36H	PA	TERTIARY	40	13641	10663	YES	1	1	1
49035054300000	LABARGE UNIT	No. 1	PA	TERTIARY	195	13505	10527	NO	1	1	1
49035056490000	GOVT	No. 1	PA	ALMY	960	13430	10452	YES	1	1	1
49035054030000	GOVT	No. 1-W	PA	TERTIARY	130	13305	10327	NO	1	1	1
49035235250000	TIP TOP UNIT	No. T37X-15GH	SHUT-IN	WASATCH	865	13198	10220	YES	1	1	1
49035056350000	MCDONALD DRAW UNIT	No. 1	PA	WASATCH	900	13196	10218	YES	1	1	1
49035058140000	GOVT	No. 2	PA	TERTIARY	1070	13165	10187	YES	1	1	1
49035053490000	FEDERAL	No. 1W	PA	TERTIARY	195	13075	10097	NO	1	1	1
49035057480000	CHAMBERLAIN PATENTED	No. 7-B	PA	ALMY	890	12934	9956	NO	1	1	1
49035056060000	FED W-0256493	No. 65	PA	TERTIARY	1729	12806	9828	YES	1	1	1
49035055880000	BNG	No. 6-33	PA	ALMY	1260	12800	9822	NO	1	1	1
49035056800000	SHALLOW UNIT	No. 2	PROD - GAS	ALMY	986	12759	9781	NO	1	1	1
49035057220000	BNG	No. 5-20	PA	ALMY	1000	12757	9779	NO	1	1	1
49035056340000	LABARGE SHALLOW UNIT	No. 4	PA	ALMY	1056	12691	9713	NO	1	1	1
49035056440000	LABARGE UNIT	No. 64	PA	TERTIARY	1790	12654	9676	NO	1	1	1
49035059380000	TRESNER STATE	No. 11-36	PA	ALMY	1742	12654	9676	NO	1	1	1
49035207770000	TIP TOP UNIT	No. 115-21	PROD - OIL	MESAVERDE	1220	12627	9649	NO	1	1	1
49035057210000	STATE	No. C-5	PA	ALMY	1340	12611	9633	YES	1	1	1
49035207070000	TIP TOP UNIT	No. 112-21	PROD - OIL	ALMY	1200	12608	9630	NO	1	1	1
49035057640000	BIG PINEY	No. C-5	PA	ALMY	1340	12604	9626	NO	1	1	1
49035203010000	TIP TOP UNIT	No. 95-21	PA	MESAVERDE	1230	12594	9616	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035059470000	TRESNER STATE	No. 10-36	PA	FORT UNION	1850	12586	9608	NO	1	1	1
49035059500000	TRESNER STATE	No. 20-36	PA	ALMY	1895	12564	9586	NO	1	1	1
49035211930000	BNG	No. 57A-21 WIW	INJ - WATER	TERTIARY	1250	12563	9585	YES	1	1	1
49035203600000	TIP TOP UNIT W48908	No. 97-21	INJ - WATER	MESAVERDE	1265	12542	9564	NO	1	1	1
49035058920000	C	No. 27	PA	ALMY	1800	12527	9549	YES	1	1	1
49035056520000	GOVT	No. 3	PA	ALMY	1208	12514	9536	NO	1	1	1
49035207620000	BNG	No. 114-28	PROD - OIL	MESAVERDE	1336	12508	9530	NO	1	1	1
49035057290000	BNG E-024353	No. 58	PA	MESAVERDE	1350	12503	9525	NO	1	1	1
49035057270000	BNG	No. 57-21	PA	MESAVERDE	1287	12501	9523	NO	1	1	1
49035057340000	BNG	No. 77-21	PROD - OIL	MESAVERDE	1351	12498	9520	NO	1	1	1
49035059290000	TRESNER STATE	No. 3-36	PA	ALMY	1854	12485	9507	NO	1	1	1
49035203000000	BNG	No. 94-21	PA	MESAVERDE	1320	12482	9504	NO	1	1	1
49035056730000	SHALLOW UNIT	No. 67-28	PA	WASATCH	1250	12462	9484	NO	1	1	1
49035057200000	TIP TOP UNIT	No. 76	TA	MESAVERDE	1306	12457	9479	NO	1	1	1
49035211380000	BNG	No. 94A-21	PA	MESAVERDE	1350	12455	9477	NO	1	1	1
49035056890000	SHALLOW W-0256492	No. 54-28	PROD - OIL	MESAVERDE	1343	12422	9444	NO	1	1	1
49035059300000	BIG PINEY MESAVERDE	No. 42-B	PA	ALMY	1899	12420	9442	NO	1	1	1
49035058830000	FED W-07828	No. C41	PA	ALMY	1800	12419	9441	YES	1	1	1
49035057110000	SHALLOW UN W-0256492	No. 44	PA	MESAVERDE	1436	12381	9403	NO	1	1	1
49035203040000	BNG	No. 96-28 WIW	TA	MESAVERDE	1339	12380	9402	YES	1	1	1
49035056560000	SHALLOW UNIT	No. 68	PA	WASATCH	1392	12372	9394	NO	1	1	1
49035056900000	TIP TOP SHALLOW UNIT	No. 52-28	PA	MESAVERDE	1391	12357	9379	NO	1	1	1
49035057040000	BNG	No. 41-28	PROD - OIL	MESAVERDE	1418	12353	9375	YES	1	1	1
49035211700000	BNG	No. 119-21	INJ - WATER	TERTIARY	1515	12336	9358	NO	1	1	1
49035211370000	BNG	No. 116-28	PROD - OIL	MESAVERDE	1480	12312	9334	NO	1	1	1
49035056660000	SHALLOW UNIT	No. 60-28	PA	MESAVERDE	1500	12309	9331	YES	1	1	1
49035057070000	SHALLOW UN W-0256492	No. 46	PROD - OIL	MESAVERDE	1589	12250	9272	NO	1	1	1
49035060440000	MCDONALD DRAW	No. 60-21	PA	TERTIARY	3874	12249	9271	NO	1	1	1
49035057370000	C MCGINNIS	No. 19-23	PA	MESAVERDE	3188	12248	9270	YES	1	1	1
49035056920000	BNG	No. 1-28	PROD - GAS	ALMY	1388	12243	9265	NO	1	1	1
49035207610000	BNG	No. 113-28	PA	MESAVERDE	1580	12242	9264	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

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49035056630000	TIP TOP UNIT	No. C-71-27	PA	TERTIARY	2265	12196	9218	YES	1	1	1
49035208390000	BIG PINEY SHALLOW UN	No. 84-3	PA	TERTIARY	2045	12186	9208	YES	1	1	1
49035211710000	BNG	No. 120-28	PA	MESAVERDE	1575	12171	9193	YES	1	1	1
49035059040000	FEDERAL	No. C-44	PA	WASATCH	2383	12162	9184	NO	1	1	1
49035059740000	MCDONALD DRAW UNIT	No. 63-33	PA	TERTIARY	3396	12108	9130	YES	1	1	1
49035060080000	MCDONALD DRAW UNIT	No. 75-29	PA	WASATCH	3050	12103	9125	YES	1	1	1
49035203640000	UNIT	No. 104-5	PA	ALMY	3175	12097	9119	YES	1	1	1
49035058720000	MCDONALD DRAW UNIT	No. 49	PA	ALMY	3250	12064	9086	YES	1	1	1
49035059990000	MCDONALD DRAW UNIT	No. 31-27	PA	TERTIARY	3600	12064	9086	YES	1	1	1
49035207710000	BNG	No. 117-21	PA	MESAVERDE	1755	12063	9085	NO	1	1	1
49035055900000	BNG E-022209	No. 55-33	PROD - OIL	MESAVERDE	2071	12062	9084	NO	1	1	1
49035057100000	BNG	No. 53-29	PA	MESAVERDE	1750	12061	9083	NO	1	1	1
49035204650000	BNG	No. 102-33	PROD - OIL	MESAVERDE	2050	12057	9079	NO	1	1	1
49035058630000	LIU	No. 22-3	PA	TERTIARY	3730	12052	9074	YES	1	1	1
49035200870000	HAIGHT-GOVT	No. 3	PA	ALMY	3800	12037	9059	NO	1	1	1
49035058760000	MCDONALD DRAW UNIT	No. 73	PA	TERTIARY	2939	12029	9051	YES	1	1	1
49035056960000	SHALLOW UNIT	No. 75-28	PROD - OIL	MESAVERDE	1775	12025	9047	NO	1	1	1
49035060040000	MCDONALD DRAW	No. 40-28	PA	WASATCH	3450	12025	9047	YES	1	1	1
49035055770000	CP	No. 2-4	PROD - GAS	WASATCH	2084	12020	9042	NO	1	1	1
49035204700000	SADDLE RIDGE UNIT	No. 105-4	PA	MESAVERDE	2375	12020	9042	NO	1	1	1
49035058860000	MCDONALD DRAW	No. 74-6	PA	TERTIARY	2880	12019	9041	YES	1	1	1
49035204230000	TARTERS ISLAND UNIT	No. 3-1S	PA	WASATCH	4585	12019	9041	NO	1	1	1
49035204230000	TARTERS ISLAND UNIT	No. 3-1S	PA	WASATCH	4585	12019	9041	NO	1	1	1
49035204630000	SADDLE RIDGE UNIT	No. 101-33	PROD - OIL	MESAVERDE	2223	12018	9040	NO	1	1	1
49035055970000	BNG	No. BNG 80-32	SHUT-IN	MESAVERDE	1898	12015	9037	NO	1	1	1
49035205040000	SADDLE RIDGE UNIT	No. BNG 107-32	PA	MESAVERDE	1900	12008	9030	NO	1	1	1
49035050000000	MCDONALD DRAW UNIT	No. 67	PA	ALMY	3310	12003	9025	YES	1	1	1
49035204730000	BNG	No. 106	PA	MESAVERDE	2050	12002	9024	NO	1	1	1
49035208380000	C	No. 85-3	PROD - GAS	ALMY	2250	11993	9015	YES	1	1	1
49035058640000	MCDONALD DRAW	No. 72-6	PA	TERTIARY	2950	11992	9014	YES	1	1	1
49035204260000	SADDLE RIDGE UNIT	No. 98-4	PA	MESAVERDE	2035	11992	9014	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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49035055750000	BNG	No. 84-04	SHUT-IN	MESAVERDE	2266	11982	9004	NO	1	1	1
49035062970000	MCDONALD DRAW UNIT	No. 83-33	PA	TERTIARY	3364	11981	9003	YES	1	1	1
49035204690000	BNG	No. 104-33	PROD - GAS	MESAVERDE	1974	11967	8989	NO	1	1	1
49035206930000	BIG PINEY SAND UNIT	No. 27-31	PA	ALMY	3000	11961	8983	NO	1	1	1
49035063170000	LONG ISLAND UNIT	No. 24-2	PA	WASATCH	4520	11943	8965	NO	1	1	1
49035063170000	LONG ISLAND UNIT	No. 24-2	PA	WASATCH	4520	11943	8965	NO	1	1	1
49035056190000	SADDLE RIDGE UNIT	No. BNG 79-32	PA	MESAVERDE	1901	11939	8961	NO	1	1	1
49035055470000	BNG	No. 86-04 WIW	SHUT-IN	MESAVERDE	2427	11938	8960	NO	1	1	1
49035063100000	MCDONALD DRAW	No. 86-28	PA	ALMY	3439	11938	8960	YES	1	1	1
49035055960000	BNG	No. 85	PA	MESAVERDE	2509	11933	8955	YES	1	1	1
49035055820000	BNG	No. 71	PA	MESAVERDE	1994	11931	8953	NO	1	1	1
49035056090000	FED E-022209	No. 693	PA	MESAVERDE	1993	11930	8952	NO	1	1	1
49035059490000	MCDONALD DRAW UNIT	No. 44	PA	WASATCH	3500	11930	8952	YES	1	1	1
49035200690000	GOVT-HEIGHT	No. 1	PA	TERTIARY	3735	11925	8947	YES	1	1	1
49035055870000	SADDLE RIDGE UNIT	No. BNG 47-33	INJ - WATER	MESAVERDE	2327	11924	8946	NO	1	1	1
49035056150000	BNG	No. 40-32	PA	MESAVERDE	1900	11924	8946	NO	1	1	1
49035056670000	UNIT W-48908	No. C-66	PA	TERTIARY	2110	11923	8945	YES	1	1	1
49035059870000	MCDONALD DRAW UNIT	No. 24-33WIW	PA	TERTIARY	3550	11917	8939	YES	1	1	1
49035059350000	MCDONALD DRAW UNIT	No. 46	PA	WASATCH	3400	11916	8938	YES	1	1	1
49035055610000	BNG	No. 89-T	PA	MESAVERDE	2700	11914	8936	NO	1	1	1
49035058930000	MCDONALD DR E-023340	No. 71	PA	TERTIARY	2900	11911	8933	YES	1	1	1
49035059580000	MCDONALD DRAW UNIT	No. 61	PROD - OIL	WASATCH	3531	11908	8930	YES	1	1	1
49035221580000	BLACK CANYON CREEK	No. 1-32	PA	MESAVERDE	1964	11908	8930	NO	1	1	1
49035204310000	BNG	No. 99-4	PA	MESAVERDE	2532	11906	8928	NO	1	1	1
49035059730000	LONG ISLAND UNIT	No. 2	PA	WASATCH	4393	11904	8926	YES	1	1	1
49035059730000	LONG ISLAND UNIT	No. 2	PA	WASATCH	4393	11904	8926	YES	1	1	1
49035059450000	MCDONALD DRAW UNIT	No. 48-34	INJ - WATER	WASATCH	3619	11900	8922	YES	1	1	1
49035055700000	CP	No. 3-4 WIW	TA	WASATCH	2180	11893	8915	NO	1	1	1
49035058870000	MCDONALD DRAW UNIT	No. 69	PA	WASATCH	3415	11893	8915	YES	1	1	1
49035060130000	MCDONALD DRAW	No. 35-28	PA	WASATCH	3446	11880	8902	YES	1	1	1
49035063110000	MCDONALD DRAW	No. 85-28	PA	WASATCH	3475	11878	8900	YES	1	1	1

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49035055550000	BNG	No. 90	PA	MESAVERDE	2301	11876	8898	NO	1	1	1
49035059360000	MCDONALD DRAW UNIT	No. 62	PA	WASATCH	3362	11875	8897	YES	1	1	1
49035059690000	MCDONALD DRAW UNIT	No. 45-33	PA	WASATCH	3403	11870	8892	YES	1	1	1
49035059880000	MCDONALD DRAW UNIT	No. 42-33	PA	WASATCH	3440	11870	8892	YES	1	1	1
49035056270000	BNG	No. 72-33 WIW	SHUT-IN	MESAVERDE	2000	11863	8885	NO	1	1	1
49035056390000	BNG	No. BNG 78-32	PA	MESAVERDE	1872	11861	8883	NO	1	1	1
49035059150000	MCDONALD DRAW UNIT	No. 53-34	PA	WASATCH	3320	11851	8873	YES	1	1	1
49035059540000	MCDONALD DRAW UNIT	No. 59-33	PA	TERTIARY	3380	11849	8871	YES	1	1	1
49035056940000	SHALLOW UNIT	No. 82	PROD - GAS	MESAVERDE	1938	11837	8859	YES	1	1	1
49035056290000	SADDLE RIDGE UNIT	No. BNG 59-32	PA	MESAVERDE	1890	11825	8847	NO	1	1	1
49035062900000	MCDONALD DRAW UNIT	No. 81-34	PA	WASATCH	3605	11823	8845	YES	1	1	1
49035060110000	MCDONALD DRAW UNIT	No. 28-28	PA	TERTIARY	3600	11820	8842	YES	1	1	1
49035055510000	BNG	No. 88-04	PROD - OIL	MESAVERDE	2700	11816	8838	NO	1	1	1
49035203500000	MCDONALD DRAW UNIT	No. 103-5	PA	ALMY	3631	11809	8831	YES	1	1	1
49035056420000	BNG	No. 20-32	PA	MESAVERDE	1917	11805	8827	NO	1	1	1
49035216070000	MCDONALD DRAW UNIT	No. 203-33	PA	ALMY	3360	11799	8821	YES	1	1	1
49035057710000	BIG PINEY UNIT	No. C-25	PA	ALMY	2160	11794	8816	YES	1	1	1
49035060020000	BIG PINEY P SAND	No. 8	PA	FORT UNION	2983	11780	8802	NO	1	1	1
49035056590000	BNG	No. 73-28	PA	MESAVERDE	1950	11778	8800	NO	1	1	1
49035050050000	BIG PINEY P SAND	No. 10-31	PA	FORT UNION	3019	11775	8797	NO	1	1	1
49035058510000	MCDONALD DRAW UNIT	No. 80-4	PA	WASATCH	3675	11768	8790	YES	1	1	1
49035215600000	MCDONALD DRAW UNIT	No. 2-33	PROD - OIL	MESAVERDE	3422	11764	8786	YES	1	1	1
49035058730000	C	No. 43 B-03	PA	TERTIARY	2438	11757	8779	YES	1	1	1
49035056810000	GOVT	No. 9	PA	MESAVERDE	2053	11754	8776	YES	1	1	1
49035058710000	MCDONALD DRAW UNIT	No. 57-05 WIW	INJ - WATER	WASATCH	3610	11750	8772	YES	1	1	1
49035063770000	MCDONALD DRAW UNIT	No. 66-5	PA	TERTIARY	3600	11748	8770	YES	1	1	1
49035216650000	MCDONALD DRAW UNIT	No. 207-28	PA	ALMY	3552	11746	8768	YES	1	1	1
49035203320000	MCDONALD DRAW UNIT	No. 102	PA	ALMY	3505	11744	8766	YES	1	1	1
49035203310000	MCDONALD DRAW UNIT	No. 101-34	PA	WASATCH	3510	11738	8760	YES	1	1	1
49035215500000	MCDONALD DRAW UNIT	No. 200-33	PROD - OIL	ALMY	3509	11738	8760	YES	1	1	1
49035056470000	BNG	No. 24	PA	MESAVERDE	2071	11736	8758	NO	1	1	1

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API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035207040000	BIG PINEY UNIT	No. 80-25	PA	ALMY	2337	11735	8757	YES	1	1	1
49035203150000	MCDONALD DRAW UNIT	No. 97-33	PA	MESAVERDE	3350	11734	8756	YES	1	1	1
49035215610000	MCDONALD DRAW UNIT	No. 202-33	PROD - OIL	ALMY	3425	11726	8748	YES	1	1	1
49035201000000	KLAENHAMMER STATE	No. 1	PA	WASATCH	4600	11725	8747	YES	1	1	1
49035201000000	KLAENHAMMER STATE	No. 1	PA	WASATCH	4600	11725	8747	YES	1	1	1
49035062960000	MCDONALD DRAW UNIT	No. 82-05	PA	WASATCH	3550	11724	8746	YES	1	1	1
49035202520000	PAVLISIN	No. 13-11	PA	FORT UNION	3800	11724	8746	YES	1	1	1
49035057380000	BNG	No. 10	PA	MESAVERDE	2185	11722	8744	NO	1	1	1
49035058610000	MCDONALD DRAW UNIT	No. 55	PROD - OIL	WASATCH	3635	11722	8744	YES	1	1	1
49035209100000	JOHNSON GULCH	No. 1-1	PA	MESAVERDE	2850	11718	8740	YES	1	1	1
49035203280000	MCDONALD DRAW	No. 100-50	PA	WASATCH	3535	11717	8739	YES	1	1	1
49035059190000	PSU W-0125390	No. E-22	PA	ALMY	2820	11713	8735	NO	1	1	1
49035058410000	MCDONALD DRAW UNIT	No. 54	PA	WASATCH	3610	11700	8722	YES	1	1	1
49035202770000	BELCO FEDERAL	No. 5-2	PA	WASATCH	4550	11698	8720	NO	1	1	1
49035202770000	BELCO FEDERAL	No. 5-2	PA	WASATCH	4550	11698	8720	NO	1	1	1
49035058540000	MCDONALD DR E-023340	No. 64	PA	ALMY	3630	11695	8717	YES	1	1	1
49035203120000	MCDONALD DRAW UNIT	No. 99	PA	ALMY	3565	11694	8716	YES	1	1	1
49035059250000	MCDONALD DRAW UNIT	No. 50	PA	WASATCH	3618	11691	8713	YES	1	1	1
49035058880000	MCDONALD DRAW UNIT	No. 52	PA	WASATCH	3615	11686	8708	YES	1	1	1
49035215930000	MCDONALD DRAW UNIT	No. 204-33	PA	MESAVERDE	3350	11686	8708	YES	1	1	1
49035058380000	MCDONALD DRAW	No. 65-4	PA	WASATCH	3810	11685	8707	YES	1	1	1
49035059240000	BIG PINEY P SAND	No. 21-31	PA	FORT UNION	2908	11685	8707	NO	1	1	1
49035058580000	MCDONALD DRAW UNIT	No. 68	PA	WASATCH	3600	11684	8706	YES	1	1	1
49035059090000	MCDONALD DRAW UNIT	No. 51-34	PA	WASATCH	3670	11682	8704	YES	1	1	1
49035058490000	MCDONALD DRAW UNIT	No. 58-5	PA	WASATCH	3815	11678	8700	YES	1	1	1
49035063180000	MCDONALD DRAW	No. 77-33	PA	ALMY	3200	11672	8694	YES	1	1	1
49035203130000	MCDONALD DRAW UNIT	No. 98-05	PA	ALMY	3810	11669	8691	YES	1	1	1
49035204680000	SADDLE RIDGE E022209	No. 103-33	PA	MESAVERDE	2578	11667	8689	NO	1	1	1
49035059230000	BIG PINEY P SAND	No. 19-31	PA	FORT UNION	2885	11652	8674	NO	1	1	1
49035208870000	MCDONALD DRAW UNIT	No. 106-5	PROD - OIL	ALMY	3630	11652	8674	YES	1	1	1
49035059100000	MCDONALD DRAW	No. 47	PROD - OIL	WASATCH	3660	11642	8664	YES	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035225630000	LONG ISLAND UNIT	No. 1-36	PA	MESAVERDE	4450	11634	8656	YES	1	1	1
49035225630000	LONG ISLAND UNIT	No. 1-36	PA	MESAVERDE	4450	11634	8656	YES	1	1	1
49035200230000	MCDONALD DRAW UNIT	No. 88-5	PA	TERTIARY	3655	11625	8647	YES	1	1	1
49035055800000	LABARGE UNIT	No. 68	PA	MESAVERDE	2904	11620	8642	YES	1	1	1
49035059940000	LONG ISLAND UNIT	No. 1	PA	WASATCH	5065	11619	8641	NO	1	1	1
49035059940000	LONG ISLAND UNIT	No. 1	PA	WASATCH	5065	11619	8641	NO	1	1	1
49035058150000	GOVT	No. 1	PA	TERTIARY	2290	11600	8622	YES	1	1	1
49035071380000	WELL	No. S-14-21	PA	TERTIARY	2460	11593	8615	YES	1	1	1
49035204430000	NORTH LABARGE	No. 100-33	PA	MESAVERDE	2698	11593	8615	YES	1	1	1
49035058520000	LONE ISLAND	No. 19-3	PA	MESAVERDE	4270	11581	8603	YES	1	1	1
49035209340000	MCDONALD DRAW UNIT	No. 5-108-8	UNKNOWN	ALMY	3430	11580	8602	YES	1	1	1
49035059810000	BIG PINEY P SAND	No. 5	PA	ALMY	3195	11576	8598	NO	1	1	1
49035063290000	BELCO-MCDONALD DRAW	No. 78-6	PA	ALMY	3231	11572	8594	YES	1	1	1
49035059080000	BPMVU	No. 27	PA	ALMY	1744	11571	8593	YES	1	1	1
49035215000000	CHAWA	No. 1-26	SPUD	TERTIARY	2325	11571	8593	YES	1	1	1
49035050030000	BIG PINEY P SAND	No. 12	PA	ALMY	3265	11561	8583	NO	1	1	1
49035055270000	FLETCHER	No. 2	PA	MESAVERDE	2800	11550	8572	NO	1	1	1
49035062940000	NORTH LABARGE SH UN	No. 11-9	PA	MESAVERDE	2243	11546	8568	NO	1	1	1
49035062930000	NORTH LABARGE SH UN	No. 12-9	PA	MESAVERDE	2775	11529	8551	NO	1	1	1
49035225940000	LONG ISLAND	No. 2-3	PA	TRANSITION	4409	11511	8533	YES	1	1	1
49035201540000	MORGAN GOVT	No. 2	PA	MESAVERDE	4060	11493	8515	YES	1	1	1
49035214400000	NORTH LABARGE SH UN	No. 20-9E	PA	MESAVERDE	2875	11492	8514	NO	1	1	1
49035056300000	FED W-48904	No. 66	PA	WASATCH	2550	11478	8500	NO	1	1	1
49035057090000	SHALLOW UN W-0256492	No. 70	PA	MESAVERDE	2300	11468	8490	YES	1	1	1
49035057870000	MARK	No. 1	PA	MESAVERDE	4612	11457	8479	YES	1	1	1
49035059820000	GOVT MIRACLE	No. 1	PA	WASATCH	4950	11454	8476	YES	1	1	1
49035059820000	GOVT MIRACLE	No. 1	PA	WASATCH	4950	11454	8476	YES	1	1	1
49035058960000	MCDONALD DRAW UNIT	No. 8	PA	WASATCH	3683	11447	8469	YES	1	1	1
49035209460000	MCDONALD DRAW UNIT	No. 5-110	PA	MESAVERDE	3650	11425	8447	YES	1	1	1
49035216560000	SANIBEL	No. 1-4D	PA	MESAVERDE	4335	11413	8435	YES	1	1	1
49035050020000	BIG PINEY UT E023584	No. 11-1	PA	MESAVERDE	2503	11406	8428	YES	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035200360000	MCDONALD DRAW	No. 89-12	PA	TERTIARY	2954	11399	8421	YES	1	1	1
49035055730000	FLETCHER	No. 1	PA	HILLIARD	3241	11382	8404	NO	1	1	1
49035059950000	MCDONALD DRAW UNIT	No. 11	PA	MESAVERDE	4517	11381	8403	YES	1	1	1
49035214520000	NORTH LABARGE SH UN	No. 25-9ED	SHUT-IN	MESAVERDE	2915	11374	8396	NO	1	1	1
49035058570000	LONG ISLAND	No. 17-3	PA	MESAVERDE	4521	11369	8391	YES	1	1	1
49035055360000	BNG	No. 91-4	PA	MESAVERDE	3080	11363	8385	NO	1	1	1
49035226430000	TIP TOP SHALLOW	No. 130-20	PROD - GAS	TRANSITION	2515	11336	8358	NO	1	1	1
49035059630000	BIG PINEY P SAND	No. 14-31	PA	FORT UNION	3504	11281	8303	NO	1	1	1
49035208260000	BPMVU	No. 15-32	PROD - OIL	MESAVERDE	3190	11264	8286	NO	1	1	1
49035202480000	FEDERAL	No. 16-7	PA	MESAVERDE	3410	11255	8277	YES	1	1	1
49035208890000	BPMVU	No. 15-36	PROD - GAS	MESAVERDE	3308	11253	8275	NO	1	1	1
49035207060000	BPMVU	No. 14-48	PA	MESAVERDE	3220	11244	8266	YES	1	1	1
49035054920000	BIRCH CREEK UNIT	No. 64	PA	MESAVERDE	3071	11241	8263	NO	1	1	1
49035208270000	BPMVU	No. 15-30	INJ - WATER	MESAVERDE	3295	11235	8257	NO	1	1	1
49035056210000	LABARGE UNIT	No. 67	PA	WASATCH	3046	11232	8254	YES	1	1	1
49035057700000	MCDONALD DRAW UNIT	No. 22-17	PA	TERTIARY	3272	11227	8249	YES	1	1	1
49035208810000	TRESNER STATE	No. 33	PA	ALMY	3400	11221	8243	NO	1	1	1
49035059480000	TRESNER STATE	No. 33-36	PA	ALMY	3439	11216	8238	NO	1	1	1
49035057630000	MCDONALD DRAW UNIT	No. 37-18	PA	WASATCH	3151	11212	8234	YES	1	1	1
49035213960000	BIG MESA	No. 34-27	PA	HILLIARD	2600	11205	8227	YES	1	1	1
49035057610000	MCDONALD DRAW UNIT	No. 25	PA	TERTIARY	3257	11192	8214	YES	1	1	1
49035059390000	BPMVU	No. 15-8	PA	MESAVERDE	3249	11182	8204	NO	1	1	1
49035059030000	BPMVU	No. 14-1	PROD - OIL	MESAVERDE	3200	11180	8202	YES	1	1	1
49035058950000	BIG PINEY P SAND	No. 28-31	PA	ALMY	3326	11176	8198	NO	1	1	1
49035057690000	MCDONALD DRAW UNIT	No. 26-18	PA	TERTIARY	3245	11174	8196	YES	1	1	1
49035063080000	LIU	No. 23-10	PA	MESAVERDE	4216	11173	8195	YES	1	1	1
49035058390000	MCDONALD DRAW UNIT	No. 36-5	PA	MESAVERDE	4010	11170	8192	YES	1	1	1
49035058500000	BIG PINEY P SAND	No. 32	PA	ALMY	3363	11169	8191	NO	1	1	1
49035225990000	BIG MESA	No. 37-34	PA	MESAVERDE	3324	11165	8187	YES	1	1	1
49035058890000	BPMVU	No. 14-34	PROD - OIL	MESAVERDE	3155	11163	8185	YES	1	1	1
49035214230000	N LABARGE SHALLOW	No. 4-4E	PA	MESAVERDE	3210	11160	8182	NO	1	1	1

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035058810000	BPMVU	No. 14-43	PROD - OIL	MESAVERDE	3150	11156	8178	YES	1	1	1
49035059180000	BPMVU	No. 2-38	PROD - GAS	MESAVERDE	3138	11155	8177	NO	1	1	1
49035207330000	BPMVU	No. 14-49	PROD - OIL	MESAVERDE	3191	11155	8177	YES	1	1	1
49035206940000	BPMVU	No. 15-27	PROD - OIL	MESAVERDE	3425	11150	8172	NO	1	1	1
49035056930000	GRACE	No. 2	PA	MESAVERDE	4265	11149	8171	YES	1	1	1
49035056990000	BIG PINEY UNIT	No. C-31	PA	ALMY	3007	11145	8167	YES	1	1	1
49035058910000	BPMVU	No. 14-02 WIW	PA	MESAVERDE	3206	11144	8166	YES	1	1	1
49035059000000	BIG PINEY MESAVERDE	No. 14-36	INJ - WATER	MESAVERDE	3183	11143	8165	YES	1	1	1
49035063790000	BPMVU	No. 15-22	PROD - GAS	MESAVERDE	3200	11138	8160	YES	1	1	1
49035059070000	BPMVU	No. 23-3	PA	MESAVERDE	3142	11134	8156	NO	1	1	1
49035231460000	BPMVU	No. B 238-36	PROD - OIL	MESAVERDE	3436	11132	8154	NO	1	1	1
49035059370000	BPMVU	No. 15-23	PROD - OIL	MESAVERDE	3379	11130	8152	NO	1	1	1
49035207030000	BPMVU	No. 15-28	PA	MESAVERDE	3365	11123	8145	NO	1	1	1
49035059310000	BPMVU	No. BB 15-18	PROD - GAS	MESAVERDE	3317	11121	8143	NO	1	1	1
49035059460000	BPMVU	No. 15-17	PROD - GAS	MESAVERDE	3378	11118	8140	NO	1	1	1
49035058550000	FEDERAL	No. C-45	PA	WASATCH	3305	11111	8133	YES	1	1	1
49035216550000	GASPARILLA	No. 1-19D	PA	ALMY	3249	11111	8133	YES	1	1	1
49035230200000	BPMVU	No. B 236-36	PROD - OIL	MESAVERDE	3470	11110	8132	NO	1	1	1
49035057860000	MCDONALD DRAW UNIT	No. 30-8	PA	TERTIARY	3605	11109	8131	YES	1	1	1
49035058850000	MCDONALD DRAW UNIT	No. 56-5	PA	MESAVERDE	4291	11107	8129	YES	1	1	1
49035200100000	MCDONALD DRAW UNIT	No. 87	PA	MESAVERDE	3300	11104	8126	YES	1	1	1
49035059140000	BPMVU	No. 15-25	INJ - WATER	MESAVERDE	3305	11099	8121	YES	1	1	1
49035059170000	BPMVU	No. 15-13	PROD - GAS	MESAVERDE	3225	11099	8121	NO	1	1	1
49035231570000	BPMVU	No. B-241-36	PROD - GAS	MESAVERDE	3370	11096	8118	NO	1	1	1
49035058900000	BPMVU	No. BB 14-42	INJ - WATER	MESAVERDE	3237	11095	8117	YES	1	1	1
49035059020000	BB	No. 8-26	PROD - GAS	ALMY	3196	11094	8116	YES	1	1	1
49035231420000	BPMVU	No. B234-36	PA	MESAVERDE	3507	11087	8109	NO	1	1	1
49035216480000	MCDONALD DRAW UNIT	No. 208-6	PROD - GAS	MESAVERDE	3921	11078	8100	YES	1	1	1
49035059200000	BPMVU	No. 15-2	PA	MESAVERDE	3266	11077	8099	NO	1	1	1
49035055840000	LABARGE UNIT	No. 63	PA	MESAVERDE	3336	11072	8094	YES	1	1	1
49035059010000	BPMV	No. 14-33	PA	MESAVERDE	3272	11069	8091	YES	1	1	1

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49035207270000	BPMVU	No. 14-76	PROD - GAS	MESAVERDE	3210	11067	8089	YES	1	1	1
49035213430000	BIG MESA	No. 14-27	PA	MESAVERDE	3500	11067	8089	YES	1	1	1
49035214680000	SWEET P SAND UNIT	No. 1-36	PROD - GAS	MESAVERDE	3415	11066	8088	NO	1	1	1
49035060060000	MCDONALD DRAW UNIT	No. 20-28	PA	MESAVERDE	4350	11062	8084	YES	1	1	1
49035201030000	LONG ISLAND UNIT	No. 42-15	PA	MESAVERDE	4080	11061	8083	YES	1	1	1
49035059570000	BPMVU	No. 15-16	PROD - GAS	MESAVERDE	3430	11054	8076	NO	1	1	1
49035058820000	BPMVU	No. 14-38	PROD - OIL	MESAVERDE	3230	11053	8075	YES	1	1	1
49035058800000	FEDERAL	No. C-37	PA	TERTIARY	3412	11052	8074	YES	1	1	1
49035058650000	GOVT C	No. 9	PA	MESAVERDE	3098	11051	8073	YES	1	1	1
49035059270000	BPMVU	No. 47-35	PA	MESAVERDE	3226	11051	8073	NO	1	1	1
49035202350000	LONG ISLAND UNIT	No. 55-22	PA	FORT UNION	4010	11043	8065	YES	1	1	1
49035059160000	BPMVU	No. 15-19	PROD - GAS	MESAVERDE	3327	11042	8064	YES	1	1	1
49035231690000	BPMVU	No. B 239-36	PROD - GAS	TRANSITION	3550	11036	8058	NO	1	1	1
49035058840000	BPMVU	No. 8-35	PA	MESAVERDE	3220	11026	8048	YES	1	1	1
49035231470000	BPMVU	No. B 240-36	PA	MESAVERDE	3490	11023	8045	NO	1	1	1
49035058770000	BPMVU	No. 39-3	PA	MESAVERDE	3210	11022	8044	YES	1	1	1
49035214910000	C	No. 95-23	PROD - GAS	MESAVERDE	2710	11021	8043	YES	1	1	1
49035057320000	MCDONALD DRAW UNIT	No. 41-20	PA	WASATCH	3603	11019	8041	YES	1	1	1
49035058660000	FEDERAL	No. C-16	PA	MESAVERDE	3326	11019	8041	YES	1	1	1
49035201370000	BELCO-FEDERAL	No. 24-2	PA	MESAVERDE	4100	11013	8035	YES	1	1	1
49035056280000	STATE	No. 61-36C	PA	MESAVERDE	2963	11008	8030	YES	1	1	1
49035201730000	BELCO GOVT	No. 1-20	PA	ALMY	3515	11001	8023	YES	1	1	1
49035206020000	BPMVU	No. 14-75	PA	ALMY	3265	10997	8019	YES	1	1	1
49035057520000	BIG PINEY UT E023584	No. C-11	PA	ALMY	2928	10994	8016	YES	1	1	1
49035058690000	FEDERAL	No. C-40	PA	MESAVERDE	3400	10986	8008	YES	1	1	1
49035202800000	MCDONALD DRAW UNIT	No. 96-31	PA	ALMY	3085	10986	8008	YES	1	1	1
49035206240000	BIG PINEY UNIT	No. 76-25	PA	MESAVERDE	3113	10983	8005	YES	1	1	1
49035063160000	LIU	No. 18-23	PA	MESAVERDE	4284	10980	8002	YES	1	1	1
49035059510000	BPMVU	No. UNIT 2-35	PROD - GAS	MESAVERDE	3395	10979	8001	NO	1	1	1
49035215180000	C	No. 96-23	PROD - GAS	MESAVERDE	2728	10978	8000	YES	1	1	1
49035056020000	LONG ISLAND UNIT	No. 13-34	PA	MESAVERDE	3697	10977	7999	YES	1	1	1

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49035208300000	BPMVU	No. 14-74	PROD - OIL	MESAVERDE	3245	10971	7993	YES	1	1	1
49035209350000	MCDONALD DRAW UNIT	No. 1-107-29	PA	ALMY	3339	10970	7992	YES	1	1	1
49035056580000	MCDONALD DRAW UNIT	No. 32	PA	TERTIARY	3365	10968	7990	YES	1	1	1
49035055620000	BIRCH CREEK UNIT	No. 53	PA	MESAVERDE	3406	10966	7988	YES	1	1	1
49035213950000	ANCHO	No. 31-27	PA	MESAVERDE	2800	10966	7988	YES	1	1	1
49035057010000	BIG PINEY UNIT	No. C-58	PA	MESAVERDE	3151	10961	7983	YES	1	1	1
49035058970000	FEDERAL	No. C-24	PA	ALMY	3449	10957	7979	YES	1	1	1
49035205990000	BPMVU	No. 15-26	PA	MESAVERDE	3510	10956	7978	NO	1	1	1
49035207830000	BPMVU	No. 14-51	PROD - OIL	ALMY	3380	10955	7977	YES	1	1	1
49035203610000	TARTERS ISLAND	No. 2-33	PA	ALMY	3300	10952	7974	YES	1	1	1
49035056460000	MCDONALD DRAW UNIT	No. 33	PA	WASATCH	3225	10949	7971	YES	1	1	1
49035205610000	C	No. 74-22	PROD - OIL	MESAVERDE	2785	10946	7968	YES	1	1	1
49035214720000	BPMVU	No. 1-109-3	PA	MESAVERDE	3310	10946	7968	NO	1	1	1
49035057240000	STATE	No. C-6	PA	MESAVERDE	3525	10944	7966	YES	1	1	1
49035056500000	GRACE	No. 1	PA	MESAVERDE	4215	10941	7963	YES	1	1	1
49035202610000	FEE	No. 53-34	PA	MESAVERDE	3600	10940	7962	YES	1	1	1
49035228260000	MCDONALD DRAW UNIT	No. 126-30	PA	ALMY	3110	10938	7960	YES	1	1	1
49035056640000	MCDONALD DRAW UNIT	No. 21-29	PA	TERTIARY	3295	10935	7957	YES	1	1	1
49035057500000	BIG PINEY UNIT	No. C-51	PA	MESAVERDE	3180	10935	7957	YES	1	1	1
49035200950000	MORGAN-GOVT	No. 1	PA	MESAVERDE	4115	10935	7957	YES	1	1	1
49035231580000	BB	No. 242-36	PA	MESAVERDE	3550	10935	7957	NO	1	1	1
49035202780000	BELCO-FEDERAL	No. 1-27	PA	MESAVERDE	3944	10933	7955	YES	1	1	1
49035206960000	WYOMING 1115-023	No. C79-23	PA	MESAVERDE	2800	10931	7953	YES	1	1	1
49035053460000	BIRCH CREEK UNIT	No. 34	PROD - OIL	MESAVERDE	2610	10929	7951	NO	1	1	1
49035056850000	MCDONALD DRAW UNIT	No. 23	PA	TERTIARY	3290	10927	7949	YES	1	1	1
49035056320000	MCDONALD DRAW UNIT	No. 34	PA	TERTIARY	3170	10926	7948	YES	1	1	1
49035056510000	MCDONALD DRAW UNIT	No. 19-29	PA	TERTIARY	3225	10924	7946	YES	1	1	1
49035215390000	WAHOO	No. 1-34D	PA	MESAVERDE	3450	10924	7946	YES	1	1	1
49035216220000	WYNKOOP	No. 1-16	PA	MESAVERDE	3309	10920	7942	NO	1	1	1
49035056250000	MCDONALD DRAW UNIT	No. 15	PA	TERTIARY	3245	10915	7937	YES	1	1	1
49035063140000	LIU	No. 16-23	PA	MESAVERDE	4200	10911	7933	YES	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035056600000	BIG PINEY UNIT	No. C-57	PA	MESAVERDE	3460	10907	7929	YES	1	1	1
49035205630000	BIG PINEY UNIT	No. 72-25	PA	MESAVERDE	3160	10905	7927	YES	1	1	1
49035226130000	BIG MESA	No. 35-27D	PA	MESAVERDE	3557	10903	7925	YES	1	1	1
49035059280000	MCDONALD DRAW UNIT	No. 7	PA	MESAVERDE	4150	10901	7923	YES	1	1	1
49035053680000	BIRCH CREEK UNIT	No. 24	PA	MESAVERDE	2675	10895	7917	NO	1	1	1
49035209430000	C	No. 86-22 WIW	INJ - WATER	MESAVERDE	2910	10889	7911	YES	1	1	1
49035057360000	BIG PINEY UNIT	No. C-52	PROD - OIL	MESAVERDE	2855	10886	7908	YES	1	1	1
49035070270000	UNKNOWN	No. C-15	PA	MESAVERDE	3170	10884	7906	NO	1	1	1
49035205600000	C	No. 73-23	PROD - OIL	MESAVERDE	2948	10876	7898	YES	1	1	1
49035057720000	BIG PINEY UNIT	No. C 8-14	PA	MESAVERDE	3061	10872	7894	YES	1	1	1
49035055910000	LONG ISLAND UNIT	No. 9	PA	MESAVERDE	3890	10865	7887	YES	1	1	1
49035054630000	BIRCH CREEK UNIT	No. 60	PA	MESAVERDE	2657	10862	7884	NO	1	1	1
49035221390000	BIRCH CREEK UNIT	No. 177A	PA	MESAVERDE	2698	10861	7883	YES	1	1	1
49035057970000	GOVT	No. 1	PA	MESAVERDE	4907	10855	7877	YES	1	1	1
49035201850000	MCDONALD DRAW UNIT	No. 92-32	PA	ALMY	3240	10839	7861	YES	1	1	1
49035063400000	MCDONALD DRAW	No. 76-06	PA	MESAVERDE	4019	10838	7860	YES	1	1	1
49035056480000	STATE	No. C-591	PA	MESAVERDE	3275	10836	7858	YES	1	1	1
49035215230000	WAZEE	No. 1-16	PA	MESAVERDE	3220	10836	7858	NO	1	1	1
49035216510000	MCDONALD DRAW UNIT	No. 209-6	PA	MESAVERDE	3948	10835	7857	YES	1	1	1
49035202260000	MCDONALD DRAW UNIT	No. 93	PA	ALMY	3390	10834	7856	YES	1	1	1
49035057930000	GOVT	No. C-20	PA	MESAVERDE	3058	10831	7853	YES	1	1	1
49035200820000	LONG ISLAND UNIT	No. 39-34	PA	MESAVERDE	3854	10831	7853	YES	1	1	1
49035201450000	LORENZ-GOVT	No. 2	PA	MESAVERDE	3654	10830	7852	YES	1	1	1
49035200020000	FIGURE FOUR	No. M-7	PA	MESAVERDE	3500	10829	7851	YES	1	1	1
49035202270000	MCDONALD DRAW UNIT	No. 94-32	PA	ALMY	3352	10829	7851	YES	1	1	1
49035056720000	BIG PINEY	No. C-69-2	PA	HILLIARD	3350	10822	7844	YES	1	1	1
49035059640000	GOVT E	No. 20	PA	FORT UNION	4003	10822	7844	YES	1	1	1
49035058780000	MCDONALD DRAW UNIT	No. 70-06	PROD - OIL	MESAVERDE	4084	10820	7842	YES	1	1	1
49035209380000	UNIT	No. 1-109-32	PA	ALMY	3343	10820	7842	YES	1	1	1
49035057590000	LONG ISLAND UNIT	No. 14-15	PA	MESAVERDE	4427	10818	7840	YES	1	1	1
49035056380000	MCDONALD DRAW UNIT	No. 14-29	PA	TERTIARY	3305	10816	7838	YES	1	1	1

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035201150000	WISE-GOVT	No. 1	PA	MESAVERDE	4100	10815	7837	YES	1	1	1
49035059210000	TRESNER STATE	No. 6-36	PA	MESAVERDE	3680	10814	7836	NO	1	1	1
49035057820000	MCDONALD DRAW UNIT	No. 10	PA	MESAVERDE	3680	10813	7835	YES	1	1	1
49035053780000	BIRCH CREEK UNIT	No. 29	PA	MESAVERDE	2665	10812	7834	NO	1	1	1
49035104370000	MCDONALD DRAW UNIT	No. 27-20	PA	MESAVERDE	3600	10803	7825	YES	1	1	1
49035201740000	MCDONALD DRAW UNIT	No. 90-32	PA	ALMY	3160	10803	7825	YES	1	1	1
49035057650000	BIG PINEY UNIT	No. C18-14	PA	MESAVERDE	3075	10802	7824	YES	1	1	1
49035201800000	MCDONALD DRAW UNIT	No. 91	PA	ALMY	3253	10796	7818	YES	1	1	1
49035056180000	LONG ISLAND UNIT	No. 20-36	PA	MESAVERDE	4307	10795	7817	YES	1	1	1
49035056690000	BIG PINEY UNIT	No. C-56	PA	MESAVERDE	3637	10795	7817	YES	1	1	1
49035202290000	MCDONALD DRAW UNIT	No. 95	PA	ALMY	3171	10789	7811	YES	1	1	1
49035213700000	BIG MESA	No. 21-34	PA	HILLIARD	3695	10773	7795	YES	1	1	1
49035056550000	MCDONALD DRAW UNIT	No. 18	PA	MESAVERDE	3440	10765	7787	YES	1	1	1
49035056860000	MCDONALD DRAW UNIT	No. 2	PA	MESAVERDE	3491	10764	7786	YES	1	1	1
49035057130000	MCDONALD DRAW UNIT	No. 1	PA	MESAVERDE	3545	10759	7781	YES	1	1	1
49035055530000	GREEN RIVER BEND UN	No. T-25	PA	TERTIARY	3120	10758	7780	YES	1	1	1
49035216350000	CHAWA	No. 2-26	PA	MESAVERDE	3613	10757	7779	YES	1	1	1
49035200750000	GOVT-LORENZ	No. 1	PA	MESAVERDE	3650	10754	7776	YES	1	1	1
49035216250000	BIG PINEY MESAVERDE	No. 1-115-3-AJL	PA	MESAVERDE	3415	10750	7772	YES	1	1	1
49035201080000	GREEN RIVER BEND UN	No. T-77-6	PA	MESAVERDE	3290	10744	7766	YES	1	1	1
49035060230000	BIG PINEY P SAND	No. 2-30	PA	MESAVERDE	4183	10739	7761	NO	1	1	1
49035216240000	ROCOTILLO	No. 1-26	PA	MESAVERDE	3130	10736	7758	YES	1	1	1
49035055020000	GREEN RIVER BEND UN	No. T-73-8	PA	WASATCH	3225	10735	7757	YES	1	1	1
49035056010000	LONG ISLAND UNIT	No. 7 YOSE	PA	MESAVERDE	4000	10734	7756	YES	1	1	1
49035206270000	MILLS UNIT	No. 78-26	PA	MESAVERDE	3000	10733	7755	YES	1	1	1
49035201210000	GREEN RIVER BEND UN	No. T81-7	PA	ALMY	2876	10731	7753	YES	1	1	1
49035054190000	BIRCH CREEK UNIT	No. 57	PA	MESAVERDE	2884	10730	7752	NO	1	1	1
49035056610000	LONG ISLAND UNIT	No. 8	PA	MESAVERDE	4004	10730	7752	YES	1	1	1
49035057420000	BIG PINEY UNIT	No. C47-22	PA	MESAVERDE	3100	10729	7751	YES	1	1	1
49035057790000	BIG PINEY UNIT	No. C-2	PA	MESAVERDE	3161	10727	7749	YES	1	1	1
49035054350000	BIRCH CREEK UNIT	No. 55	PA	MESAVERDE	3050	10720	7742	NO	1	1	1

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API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035055330000	GREEN RIVER BEND UN	No. T-56-5	PA	TRANSITION	3362	10701	7723	YES	1	1	1
49035228380000	GREEN RIVER BEND UN	No. T 300-6	PA	MESAVERDE	3313	10696	7718	YES	1	1	1
49035201110000	GREEN RIVER BEND UN	No. T80-7	PA	ALMY	2905	10695	7717	YES	1	1	1
49035202670000	FEDERAL	No. 10-13	PA	MESAVERDE	3892	10692	7714	YES	1	1	1
49035057430000	BIG PINEY UNIT	No. C-50	PA	MESAVERDE	3151	10691	7713	YES	1	1	1
49035213070000	LITTLE MESA	No. 33-25	PA	MESAVERDE	3750	10691	7713	YES	1	1	1
49035212220000	C	No. 89-22D	PROD - GAS	MESAVERDE	3140	10690	7712	YES	1	1	1
49035058230000	C	No. 15	PA	MESAVERDE	3170	10679	7701	YES	1	1	1
49035211920000	C	No. 87-22	PROD - OIL	MESAVERDE	3100	10678	7700	YES	1	1	1
49035055490000	BIRCH CREEK UNIT	No. 59	PA	HILLIARD	3654	10675	7697	YES	1	1	1
49035053890000	BIRCH CREEK UNIT	No. 4	PA	MESAVERDE	2700	10669	7691	NO	1	1	1
49035055810000	MCDONALD DRAW UNIT	No. 16	PA	TERTIARY	3255	10668	7690	YES	1	1	1
49035211910000	C	No. 90-22	PROD - OIL	MESAVERDE	3100	10667	7689	YES	1	1	1
49035058030000	FEDERAL	No. C-14	PA	MESAVERDE	3230	10665	7687	YES	1	1	1
49035056230000	MCDONALD DRAW UNIT	No. 9-32	PA	MESAVERDE	3555	10660	7682	YES	1	1	1
49035057560000	MCDONALD DRAW UNIT	No. 3	PA	MESAVERDE	4040	10659	7681	YES	1	1	1
49035202470000	FEDERAL	No. 8-1	PA	MESAVERDE	4026	10653	7675	YES	1	1	1
49035058700000	GOVT C	No. 3	PA	MESAVERDE	3554	10652	7674	YES	1	1	1
49035057550000	BIG PINEY	No. C-1-23	PA	TRANSITION	3150	10651	7673	YES	1	1	1
49035057510000	BIG PINEY UNIT	No. C-53	PA	MESAVERDE	3701	10646	7668	YES	1	1	1
49035206290000	BIG PINEY UNIT	No. 77-23	PA	MESAVERDE	3425	10646	7668	YES	1	1	1
49035054570000	BIRCH CREEK UNIT	No. 49	PA	MESAVERDE	2954	10645	7667	YES	1	1	1
49035201050000	SWIGERT-FEDERAL	No. 1	PA	TERTIARY	3289	10644	7666	YES	1	1	1
49035057140000	MILLS	No. C-46	PA	MESAVERDE	3110	10643	7665	YES	1	1	1
49035055720000	MCDONALD DRAW UNIT	No. 4	PA	MESAVERDE	3440	10633	7655	YES	1	1	1
49035055380000	BIRCH CREEK UNIT	No. 65	PA	MESAVERDE	3082	10628	7650	YES	1	1	1
49035053770000	BIRCH CREEK UNIT	No. 80	PA	MESAVERDE	2825	10627	7649	NO	1	1	1
49035056430000	MCDONALD DRAW UNIT	No. 13-29	PA	MESAVERDE	3493	10616	7638	YES	1	1	1
49035216230000	POPEYE	No. 1-11	PA	MESAVERDE	3494	10616	7638	YES	1	1	1
49035056540000	MCDONALD DRAW UNIT	No. 17-29	PA	TERTIARY	3570	10609	7631	YES	1	1	1
49035058750000	FEDERAL	No. C-30	PA	MESAVERDE	3868	10603	7625	NO	1	1	1

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49035214880000	SWEET P	No. 2-2	PA	MESAVERDE	3800	10602	7624	YES	1	1	1
49035062980000	GREEN RIVER BEND UN	No. T-75-1	PA	MESAVERDE	2925	10575	7597	YES	1	1	1
49035212460000	C	No. 88-22	PROD - OIL	MESAVERDE	3150	10575	7597	YES	1	1	1
49035213180000	LITTLE MESA	No. 14-24D	PA	MESAVERDE	3307	10569	7591	YES	1	1	1
49035059320000	FED E-024355	No. 5	PA	MESAVERDE	4401	10567	7589	YES	1	1	1
49035056220000	UNIT	No. 11-36	PA	MESAVERDE	4975	10565	7587	YES	1	1	1
49035056240000	MCDONALD DRAW UNIT	No. 29	PA	MESAVERDE	3500	10564	7586	YES	1	1	1
49035215650000	RED HILL	No. T1-18	PA	MESAVERDE	2950	10562	7584	NO	1	1	1
49035205010000	TARTERS ISLAND UNIT	No. 5-4	PA	MESAVERDE	3495	10552	7574	YES	1	1	1
49035057470000	MCGINNIS VICTOR	No. 3-D	PA	MESAVERDE	3611	10551	7573	YES	1	1	1
49035057310000	BNG	No. 11-13	PROD - GAS	ALMY	3177	10549	7571	YES	1	1	1
49035057000000	CHURCH BUTTE-023554	No. C-48	PA	MESAVERDE	3300	10547	7569	YES	1	1	1
49035200990000	GREEN RIVER BEND UN	No. T79	PA	MESAVERDE	2975	10547	7569	YES	1	1	1
49035215290000	HABANERO	No. 2-3	PA	MESAVERDE	3600	10544	7566	YES	1	1	1
49035057840000	CHURCH BUTTE UNIT	No. C-10	PA	MESAVERDE	3586	10543	7565	YES	1	1	1
49035213540000	C WIW	No. 92-22	INJ - WATER	MESAVERDE	3200	10543	7565	YES	1	1	1
49035213550000	C WIW	No. 91-22	PROD - OIL	HILLIARD	3200	10543	7565	YES	1	1	1
49035215300000	BONITA	No. 1-35	PA	MESAVERDE	3048	10543	7565	YES	1	1	1
49035056880000	GOVT	No. C-70-2	PA	HILLIARD	3285	10541	7563	YES	1	1	1
49035217000000	GREEN RIVER BEND UN	No. T205-7	PA	ALMY	2915	10538	7560	YES	1	1	1
49035201260000	CHORNEY-FEDERAL	No. 43-5	PA	MESAVERDE	3450	10528	7550	YES	1	1	1
49035215710000	JALAPENO	No. 1-14	PA	MESAVERDE	3398	10520	7542	YES	1	1	1
49035057990000	FEDERAL C	No. 21	PA	MESAVERDE	3814	10517	7539	YES	1	1	1
49035215020000	GREEN RIVER BEND UN	No. T204-7	PA	MESAVERDE	2959	10510	7532	YES	1	1	1
49035214760000	HABANERO	No. 1-3	PA	MESAVERDE	3600	10494	7516	YES	1	1	1
49035060250000	GOVT E	No. 4	PA	MESAVERDE	4489	10493	7515	NO	1	1	1
49035215430000	PASILLA	No. 1-15D	PA	MESAVERDE	3550	10492	7514	YES	1	1	1
49035057530000	BIG PINEY	No. C-13	PA	MESAVERDE	3400	10481	7503	YES	1	1	1
49035213650000	TIP TOP UNIT	No. 94-27	PA	MESAVERDE	3250	10481	7503	YES	1	1	1
49035058980000	BIG PINEY P SAND	No. 29	PA	MESAVERDE	4062	10478	7500	NO	1	1	1
49035213640000	C	No. 93-22	INJ - WATER	MESAVERDE	3250	10476	7498	YES	1	1	1

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49035215010000	GREEN RIVER BEND UN	No. T203-7	PA	MESAVERDE	3018	10465	7487	YES	1	1	1
49035055280000	BIRCH CREEK UNIT	No. 47	PA	MESAVERDE	2950	10447	7469	YES	1	1	1
49035055560000	MCDONALD DRAW UNIT	No. 6	PA	MESAVERDE	3490	10446	7468	YES	1	1	1
49035056870000	CHIMNEY BUTTE	No. D-4	PA	MESAVERDE	3826	10430	7452	YES	1	1	1
49035058680000	DRY PINEY	No. 36 X	PA	MESAVERDE	4003	10422	7444	YES	1	1	1
49035056140000	STATE	No. C-62	PA	MESAVERDE	3850	10413	7435	YES	1	1	1
49035057890000	W-0637	No. C-12	PA	MESAVERDE	3315	10389	7411	YES	1	1	1
49035214730000	GREEN RIVER BEND UN	No. T201-7	PA	MESAVERDE	3100	10383	7405	YES	1	1	1
49035213310000	LITTLE MESA	No. 23-14D	PA	MESAVERDE	3587	10337	7359	YES	1	1	1
49035207850000	BIG PINEY UNIT	No. 81-25C	PA	MESAVERDE	4125	10292	7314	YES	1	1	1
49035055300000	FEDERAL	No. 78-4	PA	HILLIARD	4138	10253	7275	NO	1	1	1
49035071300000	FEDERAL	No. D-2	PA	HILLIARD	4633	10252	7274	YES	1	1	1
49035206260000	C	No. 75-36	PROD - GAS	MESAVERDE	4050	10224	7246	YES	1	1	1
49035055570000	BIRCH CREEK UNIT	No. 11	PA	HILLIARD	3648	10177	7199	YES	1	1	1
49035056450000	STATE	No. 60	PA	MESAVERDE	4051	10142	7164	YES	1	1	1
49035056050000	MADONALD DRAW UNIT	No. 12-32	PA	MESAVERDE	3600	9860	6882	YES	1	1	1
49035225470000	BX	No. 20-20X	PROD - GAS	HILLIARD	4431	9412	6434	NO	1	1	1
49035223930000	BX	No. 37-28	PROD - GAS	HILLIARD	4394	9405	6427	YES	1	1	1
49035224680000	BX	No. 44-34	PROD - GAS	HILLIARD	5176	9334	6356	YES	1	1	1
49035226320000	BX	No. 101-17	PROD - GAS	HILLIARD	4578	9332	6354	NO	1	1	1
49035220110000	BX	No. 12-16	PROD - GAS	HILLIARD	4940	9294	6316	NO	1	1	1
49035220100000	BX	No. 11-16	PROD - GAS	HILLIARD	5000	9229	6251	NO	1	1	1
49035224550000	BX	No. 42-27	PROD - GAS	ALMY	4555	9201	6223	YES	1	1	1
49035220460000	CHIMNEY BUTTE	No. B1-15	PROD - GAS	HILLIARD	4995	9141	6163	YES	1	1	1
49035211220000	TERMINATION DR	No. 3-15	PROD - GAS	HILLIARD	4976	9136	6158	YES	1	1	1
49035210700000	NEW FORK MESA	No. 1-15	PROD - GAS	HILLIARD	5126	8970	5992	YES	1	1	1
49035211260000	TERMINATION	No. 2-10	PROD - GAS	HILLIARD	5060	8937	5959	YES	1	1	1
49035600290000	STATE-J	No. 3	PA	FRONTIER	7325	8167	5189	YES	1	1	1
49035210830000	NORTH LABARGE	No. UNIT 57-33	PROD - GAS	HILLIARD	6504	7636	4658	NO	1	1	1
49035211660000	NORTH LABARGE UNIT	No. 65-33	PROD - GAS	FRONTIER	6552	7574	4596	NO	1	1	1
49035211620000	NORTH LABARGE UNIT	No. 58-04	PROD - GAS	FRONTIER	6592	7553	4575	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035211610000	NORTH LABARGE SH UN	No. 66-4	PROD - GAS	FRONTIER	7021	7497	4519	NO	1	1	1
49035054100000	FEDERAL	No. 1	PA	FRONTIER	6270	7430	4452	NO	1	1	1
49035056110000	LABARGE UNIT	No. 14	PA	FRONTIER	6772	7051	4073	NO	1	1	1
49035245980000	TIP TOP UNIT	No. T41X-21GH	SO	FRONTIER	7345	7039	4061	NO	1	1	1
49035208200000	NORTH LABARGE UNIT	No. 36-33	PROD - GAS	FRONTIER	7700	6888	3910	NO	1	1	1
49035055500000	NORTH LABARGE UNIT	No. 21-04	PROD - GAS	FRONTIER	7305	6868	3890	NO	1	1	1
49035055050000	NORTH LABARGE SH UN	No. 19	PA	FRONTIER	7125	6843	3865	NO	1	1	1
49035055350000	BNG	No. 27-04	SHUT-IN	FRONTIER	7604	6842	3864	NO	1	1	1
49035211830000	TIP TOP UNIT	No. T82X-32G	PROD - GAS	FRONTIER	6930	6805	3827	NO	1	1	1
49035201470000	TIP TOP UNIT	No. T26-16S	PROD - GAS	FRONTIER	7730	6781	3803	NO	1	1	1
49035208340000	CHIMNEY BUTTE UNIT	No. 35-34	PA	FRONTIER	7715	6780	3802	YES	1	1	1
49035259540000	NORTH LABARGE UNIT	No. 103-04	PROD - GAS	FRONTIER	7750	6758	3780	NO	1	1	1
49035253850000	NORTH LABARGE UNIT	No. 117-09	PROD - GAS	FRONTIER	7664	6753	3775	NO	1	1	1
49035204860000	CHIMNEY BUTTE UNIT	No. 20-34	PROD - GAS	FRONTIER	7680	6752	3774	YES	1	1	1
49035200240000	CHIMNEY BUTTE UNIT	No. 18-34	PROD - GAS	FRONTIER	7730	6744	3766	YES	1	1	1
49035209650000	NORTH LABARGE UNIT	No. 44-34	PA	FRONTIER	7750	6731	3753	YES	1	1	1
49035203790000	HOGSBACK UNIT	No. F11X-27G	PROD - GAS	FRONTIER	7055	6727	3749	YES	1	1	1
49035209730000	NORTH LABARGE UNIT	No. 49-9	PROD - GAS	FRONTIER	7637	6727	3749	NO	1	1	1
49035223870000	BIRCH CREEK UNIT	No. 188	PROD - GAS	FRONTIER	7700	6727	3749	NO	1	1	1
49035203180000	NORTH LABARGE UNIT	No. 24-33	PROD - GAS	FRONTIER	7127	6725	3747	NO	1	1	1
49035240280000	NORTH LABARGE UNIT	No. 104-04	PROD - GAS	FRONTIER	7427	6719	3741	NO	1	1	1
49035209830000	NORHT LABARGE UNIT	No. 46-33	PROD - GAS	FRONTIER	7750	6718	3740	NO	1	1	1
49035055680000	BIRCH CREEK E-022247	No. 7	PROD - GAS	FRONTIER	7765	6716	3738	YES	1	1	1
49035056680000	TIP TOP UNIT	No. T76-28G	PROD - GAS	FRONTIER	7352	6708	3730	YES	1	1	1
49035209670000	NORTH LABARGE	No. 45-33	PA	FRONTIER	7850	6707	3729	YES	1	1	1
49035210320000	NORTH LABARGE UNIT	No. 40-33	PROD - GAS	FRONTIER	7800	6695	3717	YES	1	1	1
49035055690000	BNG	No. 51-4	PROD - GAS	FRONTIER	7917	6688	3710	NO	1	1	1
49035209660000	CHIMNEY BUTTE UNIT	No. 27-34	PROD - GAS	FRONTIER	7450	6668	3690	YES	1	1	1
49035056070000	BNG	No. 49-33	PROD - GAS	FRONTIER	7630	6666	3688	YES	1	1	1
49035211670000	NORTH LABARGE UNIT	No. 50-9D	PA	FRONTIER	7669	6649	3671	NO	1	1	1
49035057030000	TIP TOP UNIT	No. T32-28G	PROD - GAS	FRONTIER	7142	6629	3651	YES	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035203470000	TIP TOP UNIT	No. F21X-33G	PROD - GAS	FRONTIER	7300	6624	3646	NO	1	1	1
49035209720000	NORTH LABARGE SH UN	No. 48-4	PROD - GAS	FRONTIER	7858	6619	3641	NO	1	1	1
49035242350000	NORTH LABARGE UNIT	No. 100-33ED	PA	FRONTIER	7518	6611	3633	NO	1	1	1
49035202750000	TIP TOP UNIT	No. F11X-2	PA	FRONTIER	7190	6581	3603	YES	1	1	1
49035234780000	TIP TOP UNIT	No. T87X-16GH	PROD - GAS	FRONTIER	7602	6572	3594	YES	1	1	1
49035212070000	TIP TOP UNIT	No. T47X-21G	PROD - GAS	FRONTIER	7275	6570	3592	NO	1	1	1
49035056710000	TIP TOP UNIT	No. 45-27	PA	FRONTIER	7651	6523	3545	YES	1	1	1
49035054560000	FIGURE FOUR W023066A	No. 2	PA	FRONTIER	8035	6509	3531	NO	1	1	1
49035203760000	BIG PINEY UNIT	No. F-22	PROD - GAS	FRONTIER	7450	6508	3530	YES	1	1	1
49035208250000	CHIMNEY BUTTE UNIT	No. 23-34	PROD - GAS	FRONTIER	7630	6504	3526	YES	1	1	1
49035055310000	BIRCH CREEK E-022247	No. 6	PROD - GAS	FRONTIER	7885	6488	3510	NO	1	1	1
49035056120000	BNG	No. 15-32	PROD - GAS	FRONTIER	7340	6484	3506	NO	1	1	1
49035211800000	TIP TOP UNIT	No. T74X-28G	PROD - GAS	FRONTIER	7324	6483	3505	YES	1	1	1
49035203190000	CHIMNEY BUTTE UNIT	No. 19-34	PROD - GAS	FRONTIER	7463	6477	3499	YES	1	1	1
49035218310000	TIP TOP UNIT	No. T27X-28G	PROD - GAS	FRONTIER	7272	6476	3498	NO	1	1	1
49035235310000	TIP TOP UNIT	No. T54X-22G	SO	FRONTIER	7340	6476	3498	YES	1	1	1
49035063210000	TIP TOP UNIT	No. T44-21G	PROD - GAS	FRONTIER	7510	6475	3497	NO	1	1	1
49035208080000	TIP TOP UNIT	No. T63X-27P	PROD - GAS	FRONTIER	7300	6457	3479	YES	1	1	1
49035212410000	TIP TOP UNIT	No. T13X-28G	PROD - GAS	FRONTIER	7301	6454	3476	NO	1	1	1
49035056360000	BNG	No. 29-33	PROD - GAS	FRONTIER	8050	6452	3474	NO	1	1	1
49035219320000	TIP TOP UNIT	No. T72X-29G	PROD - GAS	FRONTIER	7190	6450	3472	NO	1	1	1
49035055950000	BNG	No. 28-33	PROD - GAS	FRONTIER	8055	6449	3471	YES	1	1	1
49035212900000	33G TIP TOP UNIT	No. T11X	PROD - GAS	MOWRY	7350	6441	3463	NO	1	1	1
49035057160000	TIP TOP UNIT	No. T78-21G	PROD - GAS	FRONTIER	7417	6427	3449	YES	1	1	1
49035205360000	MILLS	No. 1-22	PROD - GAS	FRONTIER	7300	6427	3449	YES	1	1	1
49035212170000	G1 TIP TOP UNIT	No. T86X20	PROD - GAS	FRONTIER	7480	6409	3431	NO	1	1	1
49035059680000	MCDONALD DRAW UNIT	No. 43-34	PA	FRONTIER	9157	6388	3410	YES	1	1	1
49035218290000	TIP TOP UNIT	No. T72X-28P	PROD - GAS	FRONTIER	7410	6387	3409	YES	1	1	1
49035210060000	CHIMNEY BUTTE UNIT	No. 26-34	PROD - GAS	FRONTIER	7406	6383	3405	YES	1	1	1
49035211810000	TIP TOP	No. T36X-28G	PROD - GAS	FRONTIER	7410	6367	3389	NO	1	1	1
49035055160000	FEDERAL	No. 4	PA	FRONTIER	9010	6357	3379	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035205430000	MILLS PATENTED	No. 2-23	PROD - GAS	FRONTIER	7372	6353	3375	YES	1	1	1
49035234760000	TIP TOP UNIT	No. T72X-16S	PROD - GAS	FRONTIER	7851	6351	3373	NO	1	1	1
49035212910000	32G TIP TOP UNIT	No. T66X	PROD - GAS	MOWRY	7404	6340	3362	NO	1	1	1
49035211840000	TIP TOP UNIT	No. T34-27P	PROD - GAS	FRONTIER	7449	6335	3357	YES	1	1	1
49035205440000	UNIT W-02985	No. 22-35	PA	FRONTIER	7460	6321	3343	YES	1	1	1
49035208070000	TIP TOP UNIT	No. T57X-27G	PROD - GAS	FRONTIER	7795	6317	3339	YES	1	1	1
49035212190000	20G3 TIP TOP UNIT	No. T86X	PROD - GAS	FRONTIER	7510	6301	3323	NO	1	1	1
49035224370000	BIRCH CREEK UNIT	No. 186	PA	BEAR RIVER	8040	6300	3322	YES	1	1	1
49035055990000	CHIMNEY BUTTE UNIT	No. 11	PROD - GAS	FRONTIER	7655	6287	3309	YES	1	1	1
49035203550000	TARTERS ISLAND	No. 1-33	SHUT-IN	FRONTIER	7989	6263	3285	YES	1	1	1
49035231930000	TIP TOP UNIT	No. T72X-21G	PROD - GAS	MOWRY	7775	6258	3280	YES	1	1	1
49035209780000	CHURCH BUTTE E023554	No. 36-26	PROD - GAS	FRONTIER	8100	6255	3277	YES	1	1	1
49035208090000	TIP TOP UNIT	No. T55X-22G	PROD - GAS	FRONTIER	7590	6253	3275	YES	1	1	1
49035211330000	GREEN RIVER BEND	No. 186-4	PA	FRONTIER	7901	6244	3266	YES	1	1	1
49035212180000	20G2 TIP TOP UNIT	No. T86X	PROD - GAS	MOWRY	7587	6224	3246	NO	1	1	1
49035213270000	TIP TOP UNIT	No. T34X-22G	PROD - GAS	FRONTIER	7705	6209	3231	YES	1	1	1
<i>49035054960000*</i>	<i>UNIT MCGINNIS (GRBU)</i>	<i>No. 10-9</i>	<i>PROD - GAS</i>	<i>FRONTIER</i>	<i>7915</i>	<i>6198</i>	<i>3220</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035212940000	RED HILL	No. 2-18	PROD - GAS	FRONTIER	7210	6191	3213	NO	1	1	1
49035205510000	RED HILL	No. 1-18	PROD - GAS	FRONTIER	7353	6189	3211	NO	1	1	1
49035231830000	CHIMNEY BUTTE	No. 106-26	PROD - GAS	FRONTIER	8171	6183	3205	YES	1	1	1
49035205400000	GREEN RIVER BEND UN	No. 67-6	PA	FRONTIER	7635	6172	3194	YES	1	1	1
49035055170000	GREEN RIVER BEND UN	No. 33	PROD - GAS	FRONTIER	7585	6148	3170	YES	1	1	1
49035211210000	NO CHIMNEY E-024756	No. 4-23	PROD - GAS	FRONTIER	7686	6140	3162	YES	1	1	1
49035204740000	GREEN RIVER BEND UN	No. 57-6	PROD - GAS	FRONTIER	7740	6138	3160	YES	1	1	1
49035210270000	CHIMNEY BUTTE NORTH	No. 2-23	PROD - GAS	FRONTIER	7630	6132	3154	YES	1	1	1
49035215540000	FIGURE FOUR CANYON	No. 4-12	PROD - GAS	BEAR RIVER	9235	6116	3138	NO	1	1	1
49035215540000	FIGURE FOUR CANYON	No. 4-12	PROD - GAS	BEAR RIVER	9235	6116	3138	NO	1	1	1
49035218280000	GREEN RIVER BEND UN	No. 109-6	PROD - GAS	FRONTIER	7939	6114	3136	YES	1	1	1
49035209540000	HIGHWAY 189 W-11255	No. 20-27	PA	FRONTIER	8760	6108	3130	YES	1	1	1
49035211310000	TARTERS ISLAND	No. 8-33	PA	FRONTIER	8050	6090	3112	YES	1	1	1
49035211320000	CHIMNEY BUTTE UNIT	No. 38-14	PROD - GAS	FRONTIER	7950	6090	3112	YES	1	1	1

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API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035212440000	TIP TOP UNIT	No. T31X-27G2	PROD - GAS	MUDDY	7680	6085	3107	YES	1	1	1
49035210030000	HIGHWAY 189 W-112555	No. 40-22	PA	FRONTIER	8858	6083	3105	YES	1	1	1
49035211240000	CHIMNEY BUTTES	No. 28-23	PROD - GAS	FRONTIER	7930	6079	3101	YES	1	1	1
49035253990000	GREEN RIVER BENT UNT	No. 284-07	PA	FRONTIER	7390	6076	3098	YES	1	1	1
49035055940000	CHIMNEY BUTTE UNIT	No. 17-35	PROD - GAS	FRONTIER	7703	6049	3071	YES	1	1	1
49035231210000	GREEN RIVER BEND UN	No. 230-07	PROD - GAS	FRONTIER	7360	6038	3060	YES	1	1	1
<i>49035056130000</i>	<i>GREEN RIVER BEND</i>	<i>No. 16-33</i>	<i>PROD - GAS</i>	<i>FRONTIER</i>	<i>8169</i>	<i>6034</i>	<i>3056</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035212970000	TIP TOP UNIT	No. T86X-27G1	PROD - GAS	MOWRY	7854	6034	3056	YES	1	1	1
49035205180000	GREEN RIVER BEND UN	No. 59-7	PA	FRONTIER	7480	6030	3052	YES	1	1	1
49035212990000	TIP TOP UNIT	No. T86X-27G3	PROD - GAS	MOWRY	7870	6015	3037	YES	1	1	1
49035055440000	GREEN RIVER BEND UN	No. 7	PROD - GAS	MOWRY	8110	5995	3017	YES	1	1	1
49035207880000	WOLD W-80186	No. 24-10	PROD - GAS	FRONTIER	7905	5986	3008	YES	1	1	1
49035055760000	MCDONALD DRAW UNIT	No. 4-A	PA	FRONTIER	8011	5979	3001	YES	1	1	1
49035055540000	BIRCH CREEK UNIT	No. 10	PA	FRONTIER	7820	5972	2994	YES	1	1	1
49035212980000	TIP TOP UNIT	No. T86X-27G2	PROD - GAS	MOWRY	7920	5966	2988	YES	1	1	1
49035228820000	TIP TOP UNIT	No. T55X-15G	PROD - GAS	MUDDY	8157	5946	2968	YES	1	1	1
49035056080000	CHIMNEY BUTTE UNIT	No. 3-34	PROD - GAS	MUDDY	8304	5945	2967	YES	1	1	1
49035055000000	BIRCH CREEK UNIT	No. 5	PROD - GAS	BEAR RIVER	8360	5939	2961	NO	1	1	1
49035226490000	TIP TOP UNIT	No. T87X-15G	PROD - GAS	FRONTIER	8110	5929	2951	YES	1	1	1
49035054840000	GREEN RIVER BEND UN	No. 15	PROD - GAS	FRONTIER	7612	5925	2947	YES	1	1	1
49035211250000	BIRCH CREEK UNIT	No. 125	PROD - GAS	FRONTIER	8545	5906	2928	YES	1	1	1
49035231810000	CHIMNEY BUTTE UNIT	No. 110-15	PROD - GAS	FRONTIER	8200	5902	2924	YES	1	1	1
49035210410000	TIP TOP UNIT	No. T18-X27	PROD - GAS	MUDDY	8575	5900	2922	YES	1	1	1
49035225420000	CHIMNEY BUTTE UNIT	No. 102-36D	PROD - GAS	FRONTIER	8320	5886	2908	YES	1	1	1
49035223780000	GREEN RIVER BEND UN	No. 301-7-D	PA	FRONTIER	7766	5885	2907	YES	1	1	1
49035224880000	GREEN RIVER BEND UN	No. 302-6	PA	FRONTIER	8120	5885	2907	YES	1	1	1
49035200310000	BIRCH CREEK E-022247	No. 88	PROD - GAS	BEAR RIVER	8400	5883	2905	YES	1	1	1
49035214000000	TIP TOP UNIT	No. 15-23G	PROD - GAS	MOWRY	7915	5863	2885	YES	1	1	1
49035054490000	GREEN RIVER BEND UN	No. 35-7	PROD - GAS	FRONTIER	7503	5862	2884	YES	1	1	1
49035204400000	BIRCH CREEK UNIT	No. 100	PROD - GAS	BEAR RIVER	7730	5859	2881	NO	1	1	1
49035210040000	BIRCH CREEK UNIT	No. 110	PROD - GAS	BEAR RIVER	7668	5858	2880	YES	1	1	1

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49035053590000	BIRCH CREEK UNIT	No. 15	PROD - GAS	BEAR RIVER	7839	5853	2875	NO	1	1	1
49035210640000	BIRCH CREEK	No. 128	PROD - GAS	BEAR RIVER	8500	5853	2875	YES	1	1	1
49035207530000	FEDERAL	No. 30-1	PROD - GAS	MOWRY	9513	5851	2873	YES	1	1	1
49035055080000	BIRCH CREEK UNIT	No. 61	PROD - GAS	BEAR RIVER	8318	5833	2855	YES	1	1	1
49035231000000	CHIMNEY BUTTE UNIT	No. 104-36	PA	BEAR RIVER	8415	5829	2851	YES	1	1	1
49035200440000	BIRCH CREEK UNIT	No. 89	PA	BEAR RIVER	7700	5825	2847	YES	1	1	1
49035056750000	CHINMEY BUTTE UNIT	No. 16	PA	MUDDY	8605	5820	2842	YES	1	1	1
49035209900000	BIRCH CREEK UNIT	No. 107	PROD - GAS	BEAR RIVER	7680	5817	2839	NO	1	1	1
49035204410000	BIRCH CREEK UNIT	No. 101	PROD - GAS	BEAR RIVER	7770	5812	2834	YES	1	1	1
49035213290000	TIP TOP UNIT	No. T48X-16S	PROD - GAS	MUDDY	8675	5812	2834	YES	1	1	1
<i>49035223690000*</i>	<i>BIRCH CREEK UNIT</i>	<i>No. 185</i>	<i>PROD - GAS</i>	<i>BEAR RIVER</i>	<i>7720</i>	<i>5812</i>	<i>2834</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
<i>49035219590000*</i>	<i>BIRCH CREEK UNIT</i>	<i>No. 166</i>	<i>PROD - GAS</i>	<i>BEAR RIVER</i>	<i>8017</i>	<i>5805</i>	<i>2827</i>	<i>NO</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035275680000	TIP TOP UNIT	No. T62X-16SH	PROD - GAS	MUDDY	8430	5799	2821	NO	1	1	1
49035056400000	CHIMNEY BUTTE UNIT	No. 2-35	PROD - GAS	MUDDY	8453	5798	2820	YES	1	1	1
49035056980000	CHURCH BUTTE E023554	No. 9-26	PA	MUDDY	8113	5795	2817	YES	1	1	1
49035210500000	SFE	No. 4-24	PA	FRONTIER	8100	5792	2814	YES	1	1	1
49035224850000	COOPERS	No. 2-7	SHUT-IN	FRONTIER	7860	5783	2805	NO	1	1	1
49035203710000	BIRCH CREEK UNIT	No. 95	PROD - GAS	BEAR RIVER	7907	5780	2802	YES	1	1	1
49035204340000	BIRCH CREEK UNIT	No. 92	PROD - GAS	BEAR RIVER	7670	5778	2800	NO	1	1	1
49035203690000	BIRCH CREEK E-022247	No. 97	PROD - GAS	BEAR RIVER	7975	5773	2795	YES	1	1	1
49035222730000	MERLIN	No. 1-13D	PROD - GAS	FRONTIER	8100	5772	2794	YES	1	1	1
49035209910000	BIRCH CREEK UNIT	No. 106	PROD - GAS	BEAR RIVER	7678	5770	2792	NO	1	1	1
49035212210000	BIRCH CREEK UNIT	No. 127	PROD - GAS	BEAR RIVER	7890	5766	2788	YES	1	1	1
49035210750000	BIRCH CREEK UNIT	No. 114	PROD - GAS	BEAR RIVER	8125	5756	2778	NO	1	1	1
49035055070000	BIRCH CREEK UNIT	No. 12	PA	BEAR RIVER	7951	5755	2777	YES	1	1	1
49035200450000	BIRCH CREEK UNIT	No. 90	PA	BEAR RIVER	7957	5755	2777	NO	1	1	1
49035054940000	BIRCH CREEK UNIT	No. 3	PROD - GAS	BEAR RIVER	8054	5751	2773	YES	1	1	1
<i>49035222820000*</i>	<i>COOPERS</i>	<i>No. 1-8</i>	<i>PROD - GAS</i>	<i>FRONTIER</i>	<i>7886</i>	<i>5744</i>	<i>2766</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035212710000	CHIMNEY BUTTE UNIT	No. 39-4	PROD - GAS	MUDDY	8473	5735	2757	NO	1	1	1
49035211560000	CHIMNEY BUTTE UNIT	No. 29-14D	PROD - GAS	FRONTIER	8300	5733	2755	YES	1	1	1
49035243950000	BIRCH CREEK UNIT	No. 199	PROD - GAS	BEAR RIVER	8575	5733	2755	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

**** Well has existing Gas Analysis (See Appendix D)***

APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035212400000	TIP TOP UNIT	No. T31X-27G1	PROD - GAS	MUDDY	8041	5725	2747	YES	1	1	1
<i>49035223710000*</i>	<i>BIRCH CREEK UNIT</i>	<i>No. 187</i>	<i>PROD - GAS</i>	<i>BEAR RIVER</i>	<i>7770</i>	<i>5722</i>	<i>2744</i>	<i>NO</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035208520000	STATE J	No. 2	PA	MOWRY	9665	5715	2737	YES	1	1	1
49035212860000	TIP TOP UNIT	No. T12X26G	PROD - GAS	MUDDY	8095	5711	2733	YES	1	1	1
49035055600000	BIRCH CREEK UNIT	No. 9	PA	BEAR RIVER	8081	5704	2726	YES	1	1	1
<i>49035221450000*</i>	<i>BIRCH CREEK UNIT</i>	<i>No. 124</i>	<i>PROD - GAS</i>	<i>BEAR RIVER</i>	<i>7805</i>	<i>5702</i>	<i>2724</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035217780000	BIRCH CREEK UNIT	No. 177	PROD - GAS	BEAR RIVER	7910	5694	2716	YES	1	1	1
49035213990000	TIP TOP UNIT	No. T44X-4G	PROD - GAS	MUDDY	8512	5690	2712	NO	1	1	1
49035053830000	BIRCH CREEK UNIT	No. 25	PROD - GAS	BEAR RIVER	7723	5687	2709	NO	1	1	1
49035239520000	BIRCH CREEK UNIT	No. 194	PROD - GAS	BEAR RIVER	7700	5679	2701	NO	1	1	1
49035070030000	BIRCH CREEK UNIT	No. 87	PROD - GAS	BEAR RIVER	7860	5678	2700	YES	1	1	1
49035203720000	BIRCH CREEK UNIT	No. 94	PROD - GAS	BEAR RIVER	7875	5678	2700	YES	1	1	1
49035207760000	USA AMOCO	No. A-M-1	PROD - GAS	BEAR RIVER	10415	5676	2698	NO	1	1	1
49035207760000	USA AMOCO	No. A-M-1	PROD - GAS	BEAR RIVER	10415	5676	2698	NO	1	1	1
49035058530000	CHIMNEY BUTTE UNIT	No. 1-4	TA	MUDDY	8416	5668	2690	YES	1	1	1
49035054460000	GREEN RIVER BEND UN	No. 26	PA	MUDDY	8003	5666	2688	NO	1	1	1
49035207440000	SPLIT RIVER	No. 31-2	PROD - GAS	MOWRY	9440	5662	2684	YES	1	1	1
49035217790000	BIRCH CREEK UNIT	No. 156	PA	FRONTIER	8020	5660	2682	YES	1	1	1
49035234790000	BIRCH CREEK UNIT	No. 197	PROD - GAS	BEAR RIVER	7900	5657	2679	YES	1	1	1
49035221440000	BIRCH CREEK UNIT	No. 126	PROD - GAS	BEAR RIVER	8065	5656	2678	NO	1	1	1
<i>49035208690000</i>	<i>CRAIG'S DRAW II FEE</i>	<i>No. 1-23</i>	<i>PROD - GAS</i>	<i>BEAR RIVER</i>	<i>9400</i>	<i>5649</i>	<i>2671</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035221420000	BIRCH CREEK UNIT	No. 122	PROD - GAS	BEAR RIVER	7990	5647	2669	NO	1	1	1
49035213050000	BIRCH CREEK UNIT	No. 141	PROD - GAS	BEAR RIVER	7820	5643	2665	NO	1	1	1
<i>49035223840000*</i>	<i>COOPERS</i>	<i>No. 7-31D</i>	<i>SHUT-IN</i>	<i>FRONTIER</i>	<i>8450</i>	<i>5630</i>	<i>2652</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
<i>49035056970000</i>	<i>CHIMNEY BUTTE UNIT</i>	<i>No. 13-25</i>	<i>PROD - GAS</i>	<i>FRONTIER</i>	<i>8526</i>	<i>5626</i>	<i>2648</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035204420000	BIRCH CREEK UNIT	No. 102	PA	BEAR RIVER	7970	5626	2648	YES	1	1	1
49035211010000	BIRCH CREEK UNIT	No. 130	PROD - GAS	BEAR RIVER	7750	5621	2643	NO	1	1	1
<i>49035208040000</i>	<i>YOSE CATTLE COMPANY</i>	<i>No. 40-35</i>	<i>PROD - GAS</i>	<i>MOWRY</i>	<i>9300</i>	<i>5620</i>	<i>2642</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035054950000	GREEN RIVER BEND UN	No. 9	PA	MUDDY	8137	5613	2635	YES	1	1	1
49035207550000	HANSON	No. 20-1	PROD - GAS	BEAR RIVER	10300	5610	2632	NO	1	1	1
49035207550000	HANSON	No. 20-1	PROD - GAS	BEAR RIVER	10300	5610	2632	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

**** Well has existing Gas Analysis (See Appendix D)***

APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035054250000	GREEN RIVER BEND UN	No. 5	PA	MUDDY	7800	5608	2630	NO	1	1	1
49035210050000	BIRCH CREEK UNIT	No. 111	PROD - GAS	BEAR RIVER	7690	5602	2624	NO	1	1	1
49035213900000	TIP TOP UNIT	No. T82X-21G2	PROD - GAS	MUDDY	8430	5593	2615	YES	1	1	1
49035055180000	BIRCH CREEK UNIT	No. 78	PROD - GAS	BEAR RIVER	7862	5591	2613	YES	1	1	1
49035055450000	GRN RIVER BEND UNIT	No. 11	PA	BEAR RIVER	8298	5585	2607	YES	1	1	1
49035056790000	MCDONALD DRAW UNIT	No. 6	PA	MUDDY	8489	5580	2602	YES	1	1	1
49035221410000	BIRCH CREEK UNIT	No. 119	PROD - GAS	BEAR RIVER	7798	5577	2599	YES	1	1	1
49035207630000	SPLIT RIVER FEE	No. 24-35	PROD - GAS	MOWRY	9132	5574	2596	YES	1	1	1
49035244320000	BIRCH CREEK UNIT	No. 173	PROD - GAS	BEAR RIVER	8210	5573	2595	YES	1	1	1
49035206720000*	FEDERAL	No. 30-31	PROD - GAS	BEAR RIVER	10537	5571	2593	NO	1	1	1
49035206720000	FEDERAL	No. 30-31	PROD - GAS	BEAR RIVER	10537	5571	2593	NO	1	1	1
49035203700000	BIRCH CREEK UNIT	No. 96	PROD - GAS	BEAR RIVER	7954	5565	2587	YES	1	1	1
49035058090000	FEDERAL W-04629	No. C-22	PA	FRONTIER	8330	5561	2583	YES	1	1	1
49035211080000	BIRCH CREEK UNIT	No. 132	PROD - GAS	BEAR RIVER	7960	5557	2579	NO	1	1	1
49035211070000	BIRCH CREEK UNIT	No. 118	PROD - GAS	BEAR RIVER	8255	5550	2572	YES	1	1	1
49035221460000	BIRCH CREEK UNIT	No. 135	PROD - GAS	BEAR RIVER	8090	5543	2565	YES	1	1	1
49035208640000	STATE J	No. 3	PROD - GAS	BEAR RIVER	9950	5542	2564	YES	1	1	1
49035208050000	CHAPEL FEE	No. 10-25	PROD - GAS	MOWRY	9827	5541	2563	YES	1	1	1
49035200460000	BIRCH CREEK UNIT	No. 91	PROD - GAS	BEAR RIVER	7930	5537	2559	YES	1	1	1
49035219610000	BIRCH CREEK UNIT	No. 174	PROD - GAS	BEAR RIVER	7885	5537	2559	NO	1	1	1
49035055980000	CHIMNEY BUTTE UNIT	No. 14-36	PA	MUDDY	8160	5533	2555	YES	1	1	1
49035219640000	BIRCH CREEK	No. 168	PROD - GAS	BEAR RIVER	8242	5529	2551	NO	1	1	1
49035057770000	CHIMNEY BUTTE UNIT	No. 5-14	PROD - GAS	MUDDY	8369	5527	2549	YES	1	1	1
49035220380000	LONG GREEN	No. 2-25	PA	BEAR RIVER	10180	5527	2549	YES	1	1	1
49035210280000	BIRD CANYON	No. 10-1	PROD - GAS	BEAR RIVER	10360	5502	2524	NO	1	1	1
49035219330000	BIRCH CREEK UNIT	No. 172	PA	BEAR RIVER	8089	5502	2524	YES	1	1	1
49035057080000	UNIT E-024469	No. 12	PA	MUDDY	8811	5497	2519	YES	1	1	1
49035223700000*	BIRCH CREEK UNIT	No. 134	PROD - GAS	BEAR RIVER	7911	5486	2508	YES	1	1	1
49035213980000	TIP TOP UNIT	No. T33X-16SH	PROD - GAS	FRONTIER	8912	5468	2490	NO	1	1	1
49035240180000	BIRCH CREEK UNIT	No. 148	PROD - GAS	BEAR RIVER	7920	5466	2488	NO	1	1	1
49035057680000	UNIT	No. 10	PA	MUDDY	8550	5463	2485	YES	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

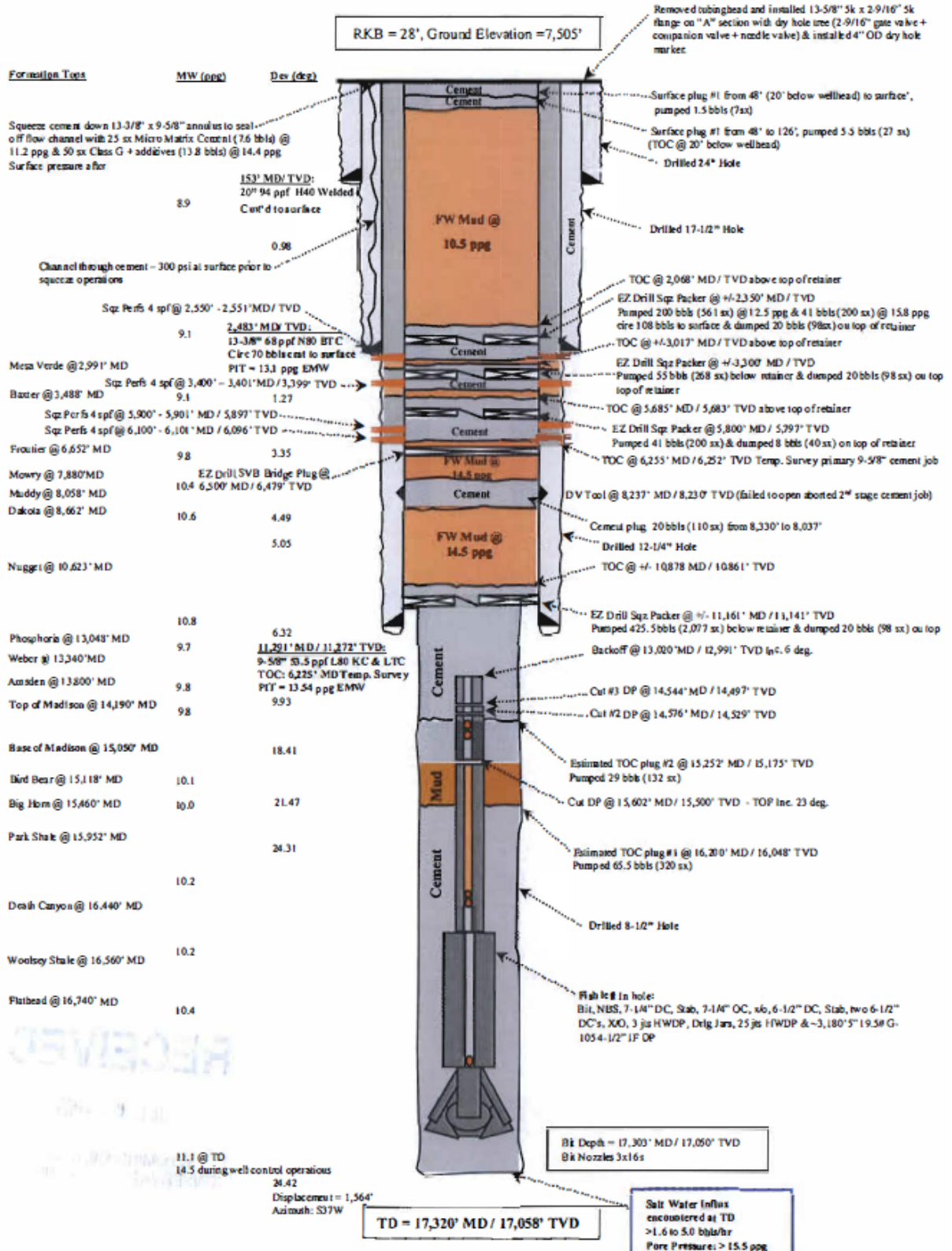
API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035240160000	BIRCH CREEK UNIT	No. 195	PROD - GAS	BEAR RIVER	7896	5460	2482	NO	1	1	1
49035054320000	BIRCH CREEK UNIT	No. 26	PROD - GAS	BEAR RIVER	7855	5457	2479	YES	1	1	1
49035221400000	BIRCH CREEK UNIT	No. 179	PROD - GAS	BEAR RIVER	8030	5453	2475	YES	1	1	1
49035057800000	BIG PINEY	No. 4	PA	MUDDY	9025	5450	2472	YES	1	1	1
49035056650000	CHIMNEY BUTTE UNIT	No. 16	PA	BEAR RIVER	8600	5445	2467	YES	1	1	1
49035209640000	FIGURE FOUR CANYON	No. 8-30	PROD - GAS	BEAR RIVER	10270	5441	2463	NO	1	1	1
49035212630000	BIRCH CREEK UNIT	No. 146	PROD - GAS	BEAR RIVER	8040	5423	2445	YES	1	1	1
49035206750000	CHAPEL CANYON	No. 30-18	PA	FRONTIER	10840	5412	2434	YES	1	1	1
49035206750000	CHAPEL CANYON	No. 30-18	PA	FRONTIER	10840	5412	2434	YES	1	1	1
49035240170000	BIRCH CREEK UNIT	No. 137	PROD - GAS	BEAR RIVER	7965	5412	2434	NO	1	1	1
49035218540000	FIGURE FOUR CANYON	No. 16-30D	PROD - GAS	FRONTIER	10555	5367	2389	NO	1	1	1
49035208560000	FIGURE FOUR CANYON	No. 7-31D	PROD - GAS	BEAR RIVER	10975	5297	2319	NO	1	1	1
49035208560000	FIGURE FOUR CANYON	No. 7-31D	PROD - GAS	BEAR RIVER	10975	5297	2319	NO	1	1	1
49035234800000	BIRCH CREEK UNIT	No. 198	PROD - GAS	BEAR RIVER	8350	5281	2303	YES	1	1	1
49035244310000	BIRCH CREEK UNIT	No. 164	PROD - GAS	BEAR RIVER	9004	5259	2281	YES	1	1	1
49035213020000	BIRCH CREEK UNIT	No. 115	PROD - GAS	BEAR RIVER	8330	5209	2231	YES	1	1	1
49035215410000	CHIMNEY BUTTE UNIT	No. 46-36	PA	GANNETT	9220	5147	2169	YES	1	1	1
49035206350000	DRY PINEY-STATE	No. 13-16	PA	MORRISON	9738	5139	2161	YES	1	1	1
49035206550000	CHAPEL CANYON UNIT	No. 1-2	PA	MORRISON	11080	5052	2074	YES	1	1	1
49035209530000	N CHIMNEY BUTTE	No. 1-23	PROD - GAS	MORRISON	8720	5045	2067	YES	1	1	1
49035205810000	TARTERS ISLAND	No. 5-13	PA	MORRISON	11050	5031	2053	YES	1	1	1
49035204790000	TARTERS ISL W-053450	No. 4-15	PA	GANNETT	10136	5023	2045	YES	1	1	1
<i>49035206980000</i>	<i>STATE J</i>	<i>No. 1</i>	<i>PROD - GAS</i>	<i>MORRISON</i>	<i>10650</i>	<i>4930</i>	<i>1952</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035206870000	FEDERAL W-62791	No. 10-31	PROD - GAS	GANNETT	10944	4830	1852	NO	1	1	1
49035219630000	BIRCH CREEK UNIT	No. 180	PROD - GAS	FRONTIER	9560	4610	1632	NO	1	1	1
49035213470000	TIP TOP UNIT	No. T77X-17G	PROD - GAS	FRONTIER	9877	4164	1186	NO	1	1	1
<i>49035054500000</i>	<i>BIRCH CREEK UNIT</i>	<i>No. 1</i>	<i>PROD - GAS</i>	<i>NUGGET</i>	<i>10176</i>	<i>3315</i>	<i>337</i>	<i>NO</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035265090000	TIP TOP UNIT	No. T62X-16S	PA	FLATHEAD	17320	-3087	-6065	NO	2	1	2

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

**** Well has existing Gas Analysis (See Appendix D)***

APPENDIX B – WELLBORE DIAGRAM FOR PLUGGED TIP TOP T62X-16S WELL

TTU T62X-16S – Final P&A Wellbore Sketch 11/12/2009



APPENDIX C: EXISTING GROUNDWATER WELLS IN THE AMA/MMA

Water Right Number	Well Name	Primary Water Use	Total Depth (Ft)	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimated)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
<i>P67558.OW</i>	<i>FEAR-ENERGETICS #1</i>	<i>DOMESTIC</i>	<i>435</i>	<i>16035</i>	<i>13060</i>	<i>NO</i>	<i>1</i>	<i>1</i>	<i>1</i>
P69145.OW	BELNORTH MONITORING WELL #2	MONITORING	40	15700	12725	YES	1	1	1
P69146.OW	BELNORTH MONITORING WELL #3	MONITORING	40	15650	12675	YES	1	1	1
P69144.OW	BELNORTH MONITORING WELL #1	MONITORING	40	15530	12555	YES	1	1	1
P179733.OW	SCHAFFER #4	DOMESTIC	140	14860	11885	YES	1	1	1
<i>P1542.OW</i>	<i>MCDONALD DRAW UNIT #3</i>	<i>INDUSTRIAL</i>	<i>554</i>	<i>14766</i>	<i>11791</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
<i>P29520.OW</i>	<i>SCHAFFER #3</i>	<i>DOMESTIC</i>	<i>413</i>	<i>14587</i>	<i>11612</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
P22740.OP	YOSE #1	DOMESTIC	59	14541	11566	YES	1	1	1
P22741.OP	YOSE #2	STOCK	59	14541	11566	YES	1	1	1
P23983.OP	DRY PINEY CREEK SPRING #3	STOCK	4	14521	11546	YES	1	1	1
P72539.OW	CHRIS #1	DOMESTIC	138	14442	11467	YES	1	1	1
P191399.OW	HOFFMAN NO. 1 WELL	DOMESTIC	260	14310	11335	YES	1	1	1
P61286.OW	STATE J #1(W.S)	INDUSTRIAL	740	14170	11195	YES	1	1	1
<i>P10645.OW</i>	<i>REARDON WELL #3</i>	<i>DOMESTIC</i>	<i>585</i>	<i>14145</i>	<i>11170</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
P1010.OW	WATER WELL #1	INDUSTRIAL	337	14143	11168	NO	1	1	1
P22745.OP	YOSE-LONG ISLAND UNIT #13	DOMESTIC	480	14110	11135	YES	1	1	1
<i>P22747.OP</i>	<i>YOSE - LONG ISLAND UNIT #39</i>	<i>STOCK</i>	<i>600</i>	<i>14080</i>	<i>11105</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
P89323.OW	LITTLE MESA WELL	STOCK	190	14040	11065	YES	1	1	1
P22744.OP	YOSE-LONG ISLAND UNIT #9	STOCK	500	14040	11065	YES	1	1	1
P9618.OP	TWIN PEAKS WELL #529	STOCK	153	14037	11062	YES	1	1	1
P9344.OP	DRY BASIN WELL #306	STOCK	95	13985	11010	YES	1	1	1
P22737.OW	YOSE-LONG ISLAND UNIT #53	DOMESTIC	600	13930	10955	YES	1	1	1
<i>P56643.OW</i>	<i>GREEN VALLEY WELL #1</i>	<i>DOMESTIC</i>	<i>125</i>	<i>13905</i>	<i>10930</i>	<i>NO</i>	<i>1</i>	<i>1</i>	<i>1</i>
<i>P9615.OP</i>	<i>YOSE DRAW WELL #125</i>	<i>STOCK</i>	<i>170</i>	<i>13880</i>	<i>10905</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
P23530.OP	BIRD SPRING 330	STOCK	4	13846	10871	YES	1	1	1
P23985.OW	WILDCAT SPRING & PIPELINE #4064	STOCK	4	13846	10871	YES	1	1	1
P1345.OW	BIG PINEY "P" SAND UNIT #2	INDUSTRIAL	650	13800	10825	NO	1	1	1
<i>P9374.OP</i>	<i>REARDON CANYON WELL #515</i>	<i>STOCK</i>	<i>217</i>	<i>13788</i>	<i>10813</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
P2331.OW	BIG PINEY MESA VERDE UNIT SUPPLY #3	INDUSTRIAL	681	13779	10804	NO	1	1	1
<i>P114.OW</i>	<i>C-19 WATER WELL</i>	<i>DOMESTIC</i>	<i>31</i>	<i>13749</i>	<i>10774</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>

APPENDIX C: EXISTING GROUNDWATER WELLS IN THE AMA/MMA

P177439.0W	CALPET MONITOR #10, 11 AND #12	MONITORING	105	13650	10675	YES	1	1	1
P2063.0W	GULF OIL CORP BIG PINEY MESAVERDE #1	INDUSTRIAL	765	13600	10625	NO	1	1	1
<i>P8438.0P</i>	<i>WILD CAT CANYON #1</i>	<i>STOCK</i>	<i>200</i>	<i>13450</i>	<i>10475</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
P1268.0W	MCDONALD DRAW UNIT WSW #1	INDUSTRIAL	900	13250	10275	YES	1	1	1



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CONSERVATION COMMISSION

Gas Sample Analysis

4903505496 - UNIT MCGINNIS (GRBU) No. 10-9

Company: EOG
Meter Number: WY9023101
Meter Label: Green River Bend 10-09
Field Name: BIG PINEY

API # 49-035-05496
S. 9, T27N, R112W

Analyst: LEATHAM
Cylinder Pressure: 0
Line Pressure: 80

Sample Date: 06/15/2016 at 11:42:10
Test Dates: 06/15/2016 - 06/15/2016
Flowing Temp: 76°F

Gas Analysis by Chromatograph

NAME	MOLE%	BTU	SG	GPM
nitrogen	.3113	0	0.003	0
methane	94.6715	958.3943	0.5244	0
co2	.2783	0	0.0042	0
ethane	2.8613	50.7536	0.0297	0.765
h2s	.0000	0	0	0
propane	.9032	22.778	0.0138	0.2488
ibutane	.1407	4.586	0.0028	0.046
nbutane	.2377	7.7724	0.0048	0.0749
ipentane	.1126	4.5154	0.0028	0.0412
npentane	.1345	5.4042	0.0034	0.0487
hexanes	.0759	3.6181	0.0023	0.0312
heptanes	.1253	6.9107	0.0043	0.0578
octanes	.1276	7.9922	0.005	0.0654
nonanes	.0201	1.4095	0.0009	0.0113
IDEAL TOTAL:	100	1074.1344	0.6013	1.3903

Gross BTU / Real Cu Ft @ 60°F			Gasoline Content	
Pressure:	14.73	14.65	15.025	Pressure: 14.73
Dry:	1076.6976	1070.836	1098.3132	Propane GPM: 0.2488
Sat:	1059.2141	1053.3508	1080.8363	Butane GPM: 0.121
Act. BTU:	1076.6976	1070.836	1098.3132	Gasoline GPM: 0.2905
SpecGrav:	0.6025	0.6025	0.6026	26# Gasoline GPM: 0.4031
Z:	0.9976	0.9976	0.9976	Total GPM: 1.3903

Sulfur Content		Dewpoints	
Mercaptans ppm:	N/A	H2O #/mmcf:	N/A
H2S ppm:	1.0	Hydrocarbon F:	N/A
		@ psig:	N/A

Comments:

Gastec Tube 4LB = 1.0 ppm
H2S below detectable limit of chromatograph

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

4903522369 - BIRCH CREEK UNIT No. 185

LIMS ID: N/A Description: Birch Creek #185
 Analysis Date/Time: 10/24/01 15:26 Field: Birch Creek
 Analyst Initials: BRS ML#: BC185
 Instrument ID: Instrument 1 GC Method: Quesbtex
 Data File: QPC06.D
 Date Sampled: 23-Oct-01

Component	Mol%	Wt%	LV%
Methane	85.8824	71.0521	79.2941
Ethane	7.0675	10.9594	10.3235
Propane	3.4784	7.9099	5.2240
Isobutane	0.5042	1.5112	0.8989
n-Butane	0.8848	2.6521	1.5204
Neopentane	0.0100	0.0371	0.0208
Isopentane	0.2068	0.7695	0.4126
n-Pentane	0.2096	0.7799	0.4137
2,2-Dimethylbutane	0.0053	0.0234	0.0120
2,3-Dimethylbutane	0.0272	0.1209	0.0607
2-Methylpentane	0.0423	0.1878	0.0956
3-Methylpentane	0.0250	0.1113	0.0557
n-Hexane	0.0613	0.2722	0.1373
Heptanes	0.3053	1.4377	0.6306
Octanes	0.0129	0.0752	0.0348
Nonanes	0.0041	0.0229	0.0089
Decanes plus	0.0000	0.0000	0.0000
Nitrogen	0.9837	1.4211	0.5878
Carbon Dioxide	0.2892	0.6563	0.2686
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties**Units**

Gross BTU/Real CF	1172.0	BTU/SCF at 60°F and 14.73 psia
Sat. Gross BTU/Real CF	1152.9	BTU/SCF at 60°F and 14.73 psia
Gas Compressibility (Z)	0.9970	
Specific Gravity	0.6711	air=1
Avg Molecular Weight	19.392	gm/mole
Propane GPM	0.956314	gal/MCF
Butane GPM	0.442893	gal/MCF
Gasoline GPM	0.335142	gal/MCF
26# Gasoline GPM	0.613688	gal/MCF
Total GPM	1.734569	gal/MCF
Base Mol%	99.892	%v/v

Sample Temperature: 66 °F
 Sample Pressure: 157 psig
 Hydrogen Sulfide 0.0000 Mole%

Reviewed By: AS

035-21959

PRECISION MEASUREMENT, INC.
P.O. Box 3659
746 North Circle Drive
Casper, WY. 82602

4903521959 - BIRCH CREEK UNIT No. 166

7/25/00 2:01 PM
Phone: 307-237-9327
800-624-7260
Fax: 307-677-4139
E Mail: pmi@trib.com

GAS ANALYSIS REPORT

Analysis For: CHEVRON USA
Field Name: BIRCH CREEK
Well Name: BIRCH CREEK 166
Station Number:
Purpose: EMISSIONS TESTING
Sample Deg. F: 77.8
Volume/Day:
Formation:
Line PSIG: 151
Line PSIA:

Run No: 4830-3
Date Run: 7/19/00
Date Sampled: 7/18/00
Producer: CHEVRON
County: SUBLETTE
State: WYOMING
Sampled By: C.G.M.
Atmos Deg. F: 68

Pressure Base: 14.730
Real BTU Dry: 1093.074
Real BTU Wet: 1073.945

Calc. Ideal Gravity: 0.611
Calc. Real Gravity: 0.612
Field Gravity:
Standard Pressure: 14.696
BTU Dry: 1090.566
BTU Wet: 1071.590
Z Factor: 0.997
Average Mol Weight: 17.989
Average CuFt/Gal: 38.495
Ethane+ GPM: 2.073
Propane+ GPM: 0.865
Butane+ GPM: 0.422
Pentane+ GPM: 0.218
Hexanes + GPM: 0.140
Heptanes + GPM: 0.063
Octanes + GPM: 0.012
Nonanes + GPM: 0.003

BTEx Components, 100 % of Total Volume

N-Hexane: 0.0316
Benzene: 0.0049
Toluene: 0.0080
Ethylbenzene: None Detected
Xylenes: None Detected

Analysis By: C.G.Martin

GAS COMPONENTS

		MOL%	GPM
Oxygen	O2:	0.000	
Carbon Dioxide	CO2:	0.270	
Nitrogen	N2:	1.210	
Hydrogen Sulfide	H2S:	0.0000	
Methane	C1:	91.201	
Ethane	C2:	4.531	1.208
Propane	C3:	1.613	0.443
Iso-Butane	IC4:	0.247	0.081
Nor-Butane	NC4:	0.392	0.123
Iso-Pentane	IC5:	0.109	0.040
Nor-Pentanes	NC5:	0.107	0.039
Hexanes	C6:	0.187	0.077
Heptanes	C7:	0.110	0.051
Octanes	C8:	0.018	0.009
Nonanes	C9:	0.005	0.003
Decanes	C10:	0.000	0.000
Totals		100.000	2.073

SW SW 24 27 13
Sublette
Bear River
Frontier

Remarks:
PULLED BEFORE DEHY

PRECISION MEASUREMENT, INC.
P.O. Box 3859
745 North Circle Drive
Casper, WY. 82602

SWNW 8 27 112
Sublette

49-035-22282

3/17/01 5:01 PM
Phone: 307-237-9327
800-624-7260
Fax: 307-577-4139
E Mail: pmf@trib.com

4903522282 - COOPERS No. 1-8

GAS ANALYSIS REPORT

Analysis For: EOG RESOURCES
Field Name: BIG PINEY
Well Name: COOPERS 1-8
Station Number: off Separator
Purpose:
Sample Deg. F:
Volume/Day:
Formation: Frontier
Line PSIG:
Line PSIA:

wet gas
AP-WAI
EOG

Run No: 5084-3
Date Run: 3/16/01
Date Sampled: 3/06/01
Producer: EOG/FRONTEIR
County: SUBLETTE
State: WYOMING
Sampled By:
Atmos Deg. F:

Pressure Base: 14.730
Real BTU Dry: 1092.862
Real BTU Wet: 1073.737

Calc. Ideal Gravity: 0.608
Calc. Real Gravity: 0.607
Field Gravity:

Standard Pressure: 14.696
BTU Dry: 1090.354
BTU Wet: 1071.382
Z Factor: 0.998
Average Mol Weight: 17.852
Average CuFt/Gal: 38.304
Ethane+ GPM: 1.955
Propane+ GPM: 0.841
Butane+ GPM: 0.401
Pentane+ GPM: 0.206
Hexanes + GPM: 0.144
Heptanes + GPM: 0.084
Octanes + GPM: 0.023
Nonanes + GPM: 0.000

GAS COMPONENTS			
		MOL%	GPM
Oxygen	O2:	0.000	
Carbon Dioxide	CO2:	0.212	
Nitrogen	N2:	0.864	
Hydrogen Sulfide	H2S:	0.0000	
Methane	C1:	92.039	
Ethane	C2:	4.179	1.115
Propane	C3:	1.602	0.440
Iso-Butane	IC4:	0.233	0.076
Nor-Butane	NC4:	0.376	0.118
Iso-Pentane	IC5:	0.085	0.031
Nor-Pentanes	NC5:	0.088	0.032
Hexanes	C6:	0.146	0.060
Heptanes	C7:	0.132	0.061
Octanes	C8:	0.045	0.023
Nonanes	C9:	0.000	0.000
Decanes	C10:	0.000	0.000
Totals		100.000	1.955

BTEX Components, 100 % of Total Volume

N-Hexane: 0.0307
Benzene: 0.0075
Toluene: 0.0225
Ethylbenzene: None Detected
Xylenes: None Detected

Analysis By: J.A. PROPP
Approved By: CEM

Hexane - N Hexane - Benzene = Hexane
.46 - .0307 - .0075 = 0.1078

Heptane - Toluene = Heptane

Remarks: 0.132 - .0225 = .1095
CORRECTED FOR AIR CONTAMINATION BY: 58.382%

QUESTAR APPLIED TECHNOLOGY

49-035-22371

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

4903522371 - BIRCH CREEK UNIT No. 187

LIMS ID:	N/A	Description:	Birch Creek # 187
Analysis Date/Time:	7/12/01 13:50	Field:	Birch Creek
Analyst Initials:	AST	ML#:	Chevron
Instrument ID:	Instrument 1	GC Method:	Quesbtex
Data File:	QPC18.D		
Date Sampled:	11-Jul-01		

NE SW 24 27 113
Sublette
Bear River
& Frontier
wet gas

Component	Mol%	Wt%	LV%
Methane	92.2122	83.0646	88.5254
Ethane	4.1305	6.9740	6.2735
Propane	1.4499	3.5899	2.2641
Isobutane	0.2242	0.7316	0.4156
n-Butane	0.3477	1.1348	0.6212
Neopentane	0.0038	0.0155	0.0083
Isopentane	0.0881	0.3571	0.1828
n-Pentane	0.0831	0.3367	0.1706
2,2-Dimethylbutane	0.0028	0.0136	0.0066
2,3-Dimethylbutane	0.0094	0.0455	0.0218
2-Methylpentane	0.0194	0.0940	0.0457
3-Methylpentane	0.0114	0.0552	0.0264
n-Hexane	0.0285	0.1379	0.0664
Heptanes	0.1281	0.6665	0.2783
Octanes	0.0088	0.0563	0.0251
Nonanes	0.0031	0.0184	0.0069
Decanes plus	0.0000	0.0000	0.0000
Nitrogen	0.4210	0.6623	0.2616
Carbon Dioxide	0.8280	2.0461	0.7997
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties**Units**

Gross BTU/Real CF	1082.1	BTU/SCF at 60°F and 14.73 psia
Sat. Gross BTU/Real CF	1064.5	BTU/SCF at 60°F and 14.73 psia
Gas Compressibility (Z)	0.9975	
Specific Gravity	0.6164	air=1
Avg Molecular Weight	17.810	gm/mole
Propane GPM	0.398620	gal/MCF
Butane GPM	0.182551	gal/MCF
Gasoline GPM	0.142467	gal/MCF
26# Gasoline GPM	0.252060	gal/MCF
Total GPM	0.723857	gal/MCF
Base Mol%	99.864	%v/v

Sample Temperature:	73	°F
Sample Pressure:	400	psig
Hydrogen Sulfide	0.0000	Mole%

Reviewed By:

035-22145

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7252

LIMS ID: N/A Description: Birch Creek # 124
 Analysis Date/Time: 9/14/00 10:51 Field: Birch Creek
 Analyst Initials: AST ML#: 124
 Instrument ID: Instrument 1 GC Method: Quesblex
 Data File: QPC93.D
 Date Sampled: 13-Sep-00 4903522145 - BIRCH CREEK UNIT No. 124

Component	Mol%	Wt%	LV%
Methane	86.8426	72.8092	80.8920
Ethane	6.4339	10.1106	9.4814
Propane	3.0634	7.0597	4.6416
Isobutane	0.4391	1.3338	0.7898
n-Butane	0.7787	2.3653	1.3499
Neopentane	0.0084	0.0318	0.0178
Isopentane	0.1756	0.6622	0.3535
n-Pentane	0.1775	0.6692	0.3535
2,2-Dimethylbutane	0.0042	0.0191	0.0097
2,3-Dimethylbutane	0.0228	0.1028	0.0514
2-Methylpentane	0.0355	0.1601	0.0811
3-Methylpentane	0.0207	0.0933	0.0466
n-Hexane	0.0520	0.2342	0.1176
Heptanes	0.2266	1.0712	0.4996
Octanes	0.0247	0.1357	0.0590
Nonanes	0.0038	0.0213	0.0083
Decanes plus	0.0000	0.0000	0.0000
Nitrogen	0.9180	1.3439	0.5534
Carbon Dioxide	0.7725	1.7766	0.7239
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Gross BTU/Real CF	1147.1	BTU/SCF at 60°F and 14.73 psia
Sat. Gross BTU/Real CF	1128.4	BTU/SCF at 60°F and 14.73 psia
Gas Compressibility (Z)	0.8971	
Specific Gravity	0.8622	air=1
Avg Molecular Weight	19.135	gm/mole
Propane GPM	0.842218	gal/MCF
Butane GPM	0.386270	gal/MCF
Gasoline GPM	0.276954	gal/MCF
26# Gasoline GPM	0.522125	gal/MCF
Total GPM	1.507862	gal/MCF
Base Mol%	100.198	%v/v

Sample Temperature: 72 °F
 Sample Pressure: 255 psig
 Hydrogen Sulfide: 0.0000 Mole%

Reviewed By: _____

Bear River
 Frontier
 NE NW 13 27 13
 Sublette

Birch Creek Unit
 Condensates

PRECISION MEASUREMENT, INC.
P.O. Box 3659
746 North Circle Drive
Casper, WY. 82601

49-035-22384

12/10/01 2:18 PM
Phone: 307-237-9327
800-624-7260
Fax: 307-577-4138
E-Mail: pmi@trib.com

GAS ANALYSIS REPORT
4903522384 - COOPERS No. 7-31

Analysis For: EOG RESOURCES
Field Name: BIG PINEY
Well Name: COOPERS 7-31
Station Number:
Purpose: NEW WELL
Sample Deg. F: 75
Volume/Day:
Formation:
Line PSIG: 95
Line PSIA:

Run No: 5431-3
Date Run: 12/18/01
Date Sampled: 12/3/01
Producer: EOG RESOURCES
County: SUBLETTE
State: WYOMING
Sampled By: JEFF DAHL
Atmos Deg. F: 28

NW SW 38-28-13
SUBLETTE
Frontier 2

Pressure Base: 14.730
Real BTU Dry: 1047.960
Real BTU Wet: 1029.620

GAS COMPONENTS			
		MOL%	GPM
Oxygen	O2:	0.000	
Carbon Dioxide	CO2:	0.697	
Nitrogen	N2:	0.370	
Hydrogen Sulfide	H2S:	0.0000	
Methane	C1:	95.104	
Ethane	C2:	2.757	0.735
Propane	C3:	0.657	0.181
Iso-Butane	IC4:	0.073	0.024
Nor-Butane	NC4:	0.122	0.038
Iso-Pentane	IC5:	0.032	0.012
Nor-Pentanes	NC5:	0.034	0.012
Hexanes	C6:	0.064	0.026
Heptanes	C7:	0.053	0.024
Octanes	C8:	0.032	0.016
Nonanes	C9:	0.006	0.003
Decanes	C10:	0.000	0.000
Totals		100.000	1.072

Calc. Ideal Gravity: 0.585
Calc. Real Gravity: 0.586
Field Gravity:
Standard Pressure: 14.696
BTU Dry: 1045.555
BTU Wet: 1027.362
Z Factor: 0.998
Average Mol Weight: 17.099
Average CuF/Gal: 38.228
Ethane+ GPM: 1.072
Propane+ GPM: 0.337
Butane+ GPM: 0.156
Pentane+ GPM: 0.094
Hexanes + GPM: 0.070
Heptanes + GPM: 0.044
Octanes + GPM: 0.019
Nonanes + GPM: 0.003

BTEX Components, 100 % of Total Volume
N-Hexane: 0.0168
Benzene: 0.0061
Toluene: 0.0099
Ethylbenzene: None Detected
Xylenes: None Detected

Analysis By: S.G. WALLACE
Approved By: *ES*

Remarks:

C6 .064 - N Hexane .0168 - Benzene .0061 = .0411 C6
C7 .053 - Toluene .0099 = .0431
VOC = 1.072
C8+ = .037

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

4903520672 - FEDERAL 30-31

LIMS ID:	N/A	Description:	Bird Canyon 30-31
Analysis Date/Time:	8/17/01 11:49	Field:	Bird Canyon
Analyst Initials:	AST	ML#:	90933
Instrument ID:	Instrument 1	GC Method:	Quesbtex
Data File:	QPC98.D		
Date Sampled:	08/16/01		

Component	Mol%	Wt%	LV%
Methane	96.6432	93.0212	95.1995
Ethane	2.1649	3.9057	3.3739
Propane	0.3425	0.9062	0.5488
Isobutane	0.0336	0.1171	0.0639
n-Butane	0.0515	0.1795	0.0943
Neopentane	0.0009	0.0039	0.0020
Isopentane	0.0108	0.0466	0.0229
n-Pentane	0.0098	0.0426	0.0207
2,2-Dimethylbutane	0.0005	0.0024	0.0011
2,3-Dimethylbutane	0.0000	0.0000	0.0000
2-Methylpentane	0.0021	0.0110	0.0051
3-Methylpentane	0.0014	0.0071	0.0033
n-Hexane	0.0034	0.0178	0.0082
Heptanes	0.0375	0.2028	0.0774
Octanes	0.0017	0.0113	0.0048
Nonanes	0.0040	0.0264	0.0094
Decanes plus	0.0000	0.0000	0.0000
Nitrogen	0.3432	0.5769	0.2188
Carbon Dioxide	0.3490	0.9215	0.3459
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Gross BTU/Real CF	1033.6	BTU/SCF at 60°F and 14.73 psia
Sat. Gross BTU/Real CF	1016.9	BTU/SCF at 60°F and 14.73 psia
Gas Compressibility (Z)	0.9979	
Specific Gravity	0.5769	air = 1
Avg Molecular Weight	16.668	gm/mole
Propane GPM	0.094163	gal/MCF
Butane GPM	0.027167	gal/MCF
Gasoline GPM	0.024438	gal/MCF
26# Gasoline GPM	0.040751	gal/MCF
Total GPM	0.145881	gal/MCF
Base Mol%	99.545	%v/v

Sample Temperature:	78	°F
Sample Pressure:	279	psig
Hydrogen Sulfide	0.0000	Mole%

Reviewed By: _____

Bear River
Substitute
Tom

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

4903522370 - BIRCH CREEK UNIT No. 134

49-035-22370

LIMS ID:	N/A	Description:	Birch Creek # 134
Analysis Date/Time:	10/24/01 12:50	Field:	Birch Creek
Analyst Initials:	AST	ML#:	134
Instrument ID:	Instrument 1	GC Method:	Quesbtex
Data File:	QPC04.D		
Date Sampled:	23-Oct-01		

Component	Mol%	Wt%	LV%
Methane	88.9961	76.8272	83.6151
Ethane	5.9148	9.5704	8.7919
Propane	2.4558	5.8272	3.7532
Isobutane	0.3599	1.1255	0.6529
n-Butane	0.6268	1.9604	1.0960
Neopentane	0.0070	0.0271	0.0148
Isopentane	0.1435	0.5569	0.2912
n-Pentane	0.1438	0.5582	0.2888
2,2-Dimethylbutane	0.0037	0.0172	0.0086
2,3-Dimethylbutane	0.0177	0.0822	0.0403
2-Methylpentane	0.0278	0.1287	0.0639
3-Methylpentane	0.0166	0.0769	0.0375
n-Hexane	0.0401	0.1860	0.0914
Heptanes	0.2122	1.0427	0.4443
Octanes	0.0100	0.0611	0.0276
Nonanes	0.0041	0.0230	0.0088
Decanes plus	0.0000	0.0000	0.0000
Nitrogen	0.5650	0.8516	0.3435
Carbon Dioxide	0.4551	1.0777	0.4302
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties

Units

Gross BTU/Real CF	1131.0	BTU/SCF at 60°F and 14.73 psia
Sat. Gross BTU/Real CF	1112.6	BTU/SCF at 60°F and 14.73 psia
Gas Compressibility (Z)	0.9973	
Specific Gravity	0.6432	air=1
Avg Molecular Weight	18.584	gm/mole
Propane GPM	0.675171	gal/MCF
Butane GPM	0.314637	gal/MCF
Gasoline GPM	0.229766	gal/MCF
26# Gasoline GPM	0.427098	gal/MCF
Total GPM	1.219737	gal/MCF
Base Mol%	99.923	%v/v

Sample Temperature:	74	°F
Sample Pressure:	185	psig
Hydrogen Sulfide	0.0000	Mole%

Reviewed By:

AST

*Dearline 7500 is Frontier 7100
NW 11 27 113
Sublette*

APPENDIX E – REFERENCES

- Becker, T.P., and Lynds, R., 2012, A Geologic Deconstruction of One of the World's Largest Natural Accumulations of CO₂, Moxa Arch, Southwestern Wyoming: AAPG Bulletin, Vol. 96, No. 9, Pg. 1643-1664.
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Request for Additional Information: Dry Piney Jackalope Gas Processing Facility
December 4, 2025

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	Please conduct a final grammar review before submittal.	BSO has conducted a final grammar review before submittal.
2.	2	21, 22, 37	Please ensure that the concentrations listed for the composition of the AGI injection stream and the average AGI formations are consistent across the MRV plan. For example, on page 37, it states “The CO₂ concentration at the DPS AGI location is approximately 89% in the Madison and approximately 95% in the Bighorn Formation. Both formations also contain over 1.5% H₂S, confirming the extent of the naturally-occurring sour gas system that already exists in the AGI area.” These percentages differ from the DPS AGI gas compositions provided on page 22 that show the composition of H₂S to be 1.2% and 0.5% for the Madison and Bighorn formation, respectively. Similarly, the injected gas composition is stated to be 92.4% CO₂, 6.93% H₂S, and 0.5% CH₄ on pages 22 and 37. However, Figures 2.6-1 and 2.7-3 represent the expected gas composition as 93% CO₂ and 7% H₂S. Additionally, the produced gas concentration of 5% H₂S in Figures 2.6-1 and 2.7-3 is inconsistent with the stated concentration of 4.5% on page 21.	Section 2 AGI stream compositions have been revised to correct typos and ensure internal consistency. “The CO₂ concentration at the DPS AGI location is approximately 89% in the Madison and approximately 95% in the Bighorn Formation. Both formations also contain over 0.5% H₂S, confirming the extent of the naturally-occurring sour gas system that already exists in the AGI area.” All injected gas compositions have been updated to reflect the correct 92.4% CO₂, 6.93% H₂S, and 0.5% Methane in text and Figures 2.6-1 and 2.7-3. Produced gas concentration of 4.5% H₂S has been updated in text and Figures 2.6-1 and 2.7-3.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	2.6.1, 2.7	22, 40	On page 22, the MRV plan states that “The acid gas will be injected at depths ranging approximately 14,800 ft to 17,000 ft TVD below the surface”. This appears to be inconsistent with the description provided on page 40 that states “The total depth (“TD”) of each AGI well will range from 16,600 feet (Bighorn) to 15,750 feet (Madison) TVD depending on whether the Madison or Bighorn Formation is targeted” Please revise these sections for consistency as needed.	These depth inconsistencies have been addressed in the following manner: “The acid gas will be injected at depths ranging approximately 14,800 feet to 16,500 ft TVD below the surface...” ...The depth range represents the depth of the shallowest injection perforation near the top of the Madison Formation to depth of the deepest injection perforation near the base of the Bighorn Formation. The 16,600 feet (Bighorn) and the 15,750 feet (Madison) TVD depths cited on page 40 reference the Total Depth of the wells, not the injection perforation depth range cited above.
4.	2.7	40-41	On page 40-41, the MRV plan states “The Madison Formation is anticipated to be encountered in a narrow TVD depth range in the Dry Piney State injection area, with the Dry Piney State 12-16 being the shallowest and the Dry Piney State 1-16 being the deepest at approximately 200 ft TVD deeper.” Dry Piney State 1-16 is not mentioned elsewhere in the MRV plan. Please revise this section for consistency and/or utilize consistent naming conventions when referring to the wells.	Dry Piney State 1-16 was a typo, and has been updated to reflect the correct well name and number Dry Piney State 8-16 as below: “The Madison Formation is anticipated to be encountered in a narrow TVD depth range in the Dry Piney State injection area, with the Dry Piney State 12-16 being the shallowest and the Dry Piney State 8-16 being the deepest at approximately 200 ft TVD deeper.”
5.	3.1	45-47	Figures 3.1-2, 3.1-3, and 3.1-4 do not provide a distance scale that clearly presents that the buffer added to the projected plume boundary is ½ mile. Please revise these figures accordingly.	Figures 3.1-2, 3.1-3, and 3.1-4 have been updated to include a two-mile long scale bar that shows a single 1-mile division and two ½-mile divisions to clearly present that the buffers added to the projected plume are ½ mile in distance.



BLUE SPRUCE OPERATING LLC
DRY PINEY “JACKALOPE”
GAS PROCESSING FACILITY &
DRY PINEY STATE ACID GAS INJECTION WELLS
Subpart RR Monitoring, Reporting and Verification Plan

Sublette County, Wyoming

Original Submission - August 2025

First Revision – October 2025

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INTRODUCTION

Blue Spruce Operating LLC (“BSO”) intends to drill and inject into five acid gas injection (“AGI”) wells in the Madison and/or Bighorn Formations near La Barge, Wyoming for the primary purposes of acid gas disposal and permanent geologic sequestration of carbon dioxide (“CO₂”) in a subsurface geologic formation. One injection well, the Dry Piney State 12-16, has been drilled but is not yet completed or actively injecting. BSO plans to begin initial injection operations in the AGI wells in 2028 and intends to continue injection until the end-of-life of the Dry Piney assets, estimated to occur around 2078.

BSO is in process of obtaining authority to inject fluids through Class II acid-gas disposal wells into the Madison and Bighorn Formations from the Wyoming Oil and Gas Conservation Commission (“WOGCC”). BSO will also request aquifer exemptions for the Madison and Bighorn Formations from the WOGCC. The fluids to be injected into the AGI wells are waste components of natural gas that will be produced and processed by BSO from the Madison Formation.

BSO has developed this monitoring, reporting and verification (“MRV”) plan in accordance with 40 CFR 98.440-449 (Subpart RR – Geologic Sequestration of Carbon Dioxide) to provide for monitoring, reporting, and verification of permanent geologic sequestration into the Madison and Bighorn Formations during the injection period. This plan meets the requirements in 98.440(c)(1).

This MRV plan contains ten sections:

- Section 1.0 contains facility information.
- Section 2.0 contains a description of the Dry Piney project, including descriptions of the geology and history of the LaBarge field, an overview of the injection program, and highlights the suitability of the Madison and Bighorn Formations for permanent geologic sequestration.
- Section 3.0 contains the definition and delineation of monitoring areas.
- Section 4.0 evaluates the potential leakage pathways and demonstrates that the risk of CO₂ leakage to atmosphere through identified pathways is very low.
- Section 5.0 provides an overview of the detection, verification, and quantification of potential leakage pathways.
- Section 6.0 describes the determination of expected baselines to identify excursions from expected performance that could indicate CO₂ leakage.

- Section 7.0 provides the site-specific modifications to the mass balance equation and the methodology for calculating volumes of CO₂ sequestered.
- Section 8.0 provides the estimated schedule for implementation of the MRV plan.
- Section 9.0 describes the quality assurance program.
- Section 10.0 describes the records retention process.

1.0 FACILITY INFORMATION

Facility Name: Dry Piney Jackalope Gas Processing Facility (“DPJGPF”)

Facility Address: 296 Graphite Hollow Rd – BLM 5321, Big Piney, WY 83113

Facility Owner Name: Blue Spruce Operating LLC

Facility Owner Address: PO Box 2460, Pinedale, WY 82941

Date of Original Submittal: August 4, 2025

Date of Revision Submittal: October 24, 2025

MRV Report Point of Contact: Andrew Moses

Designated Representative: Andrew Moses

Alternate Designated Representative: Scott Gutberlet

MRV Plan ID #: TBD

The Dry Piney Jackalope Gas Processing Facility (“DPJGPF”) will process approximately 400 million standard cubic feet of gas per day (“MMscfpd”) of raw inlet gas produced from nine production wells (one drilled, eight permitted) that will be completed in the Madison Formation in and immediately adjacent to the federal Dry Piney Unit (“DPU”), located near the crest of the greater LaBarge Field. The DPJGPF will utilize proven industrial gas processes to separate and refine saleable products, including helium and methane, from the raw gas stream resulting in a waste gas stream that predominantly contains carbon dioxide and hydrogen sulfide (“H₂S”), collectively referred to as acid gas. DPJGPF will be situated adjacent to the DPU within the gas production area, while the acid gas injection area is located approximately 10.5 miles to the east-northeast of DPJGPF. The AGI wells will be positioned approximately 1,350 feet true vertical depth (“TVD”) down structural dip from the DPU production area. Rather than separating and venting CO₂ from the acid gas waste stream, the combined acid gas will be transported via pipeline from DPJGPF and injected into the Dry Piney State (“DPS”) AGI wells to the east-northeast to capture and permanently sequester 100% of the CO₂ in the waste stream.

The AGI wells will report under the Dry Piney Jackalope Gas Processing Facility Greenhouse Gas Reporting Program Identification Number which is 591065. The AGI wells will be Class II per the Underground Injection Control (“UIC”) Permit Classification system. In addition to regulating the oil and gas activities in the state, the WOGCC has jurisdiction over UIC Class II wells in Wyoming. The 10-digit well identification numbers and current status for the AGI wells are listed below.

• DRY PINEY STATE 12-16	49-035-31390-0000	DRILLED, NOT COMPLETED
• DRY PINEY STATE 3-16 AGI	49-035-31455-0000	APPROVED PERMIT TO DRILL
• DRY PINEY STATE 8-16 AGI	49-035-31456-0000	APPROVED PERMIT TO DRILL
• DRY PINEY STATE 14-16 AGI	49-035-31457-0000	APPROVED PERMIT TO DRILL
• DRY PINEY STATE 16-16 AGI	49-035-31458-0000	APPROVED PERMIT TO DRILL

2.0 PROJECT DESCRIPTION

This section provides an overview of the geologic setting of the LaBarge field area, the history of oil and gas development and AGI history in the area, and the planned AGI process and program.

2.1 GEOLOGY OF THE LABARGE FIELD AREA

The LaBarge Platform Field area is in Sublette and Lincoln counties of southwest Wyoming, along the western flank of the Greater Green River Basin (“GGRB”) geological province (**Figure 2.1.1**). The productive area is in the foothills of the Wyoming Range, due west of the Wind River Mountains near the northern termination of the sub-regional Moxa Arch and includes the Dry Piney Unit.

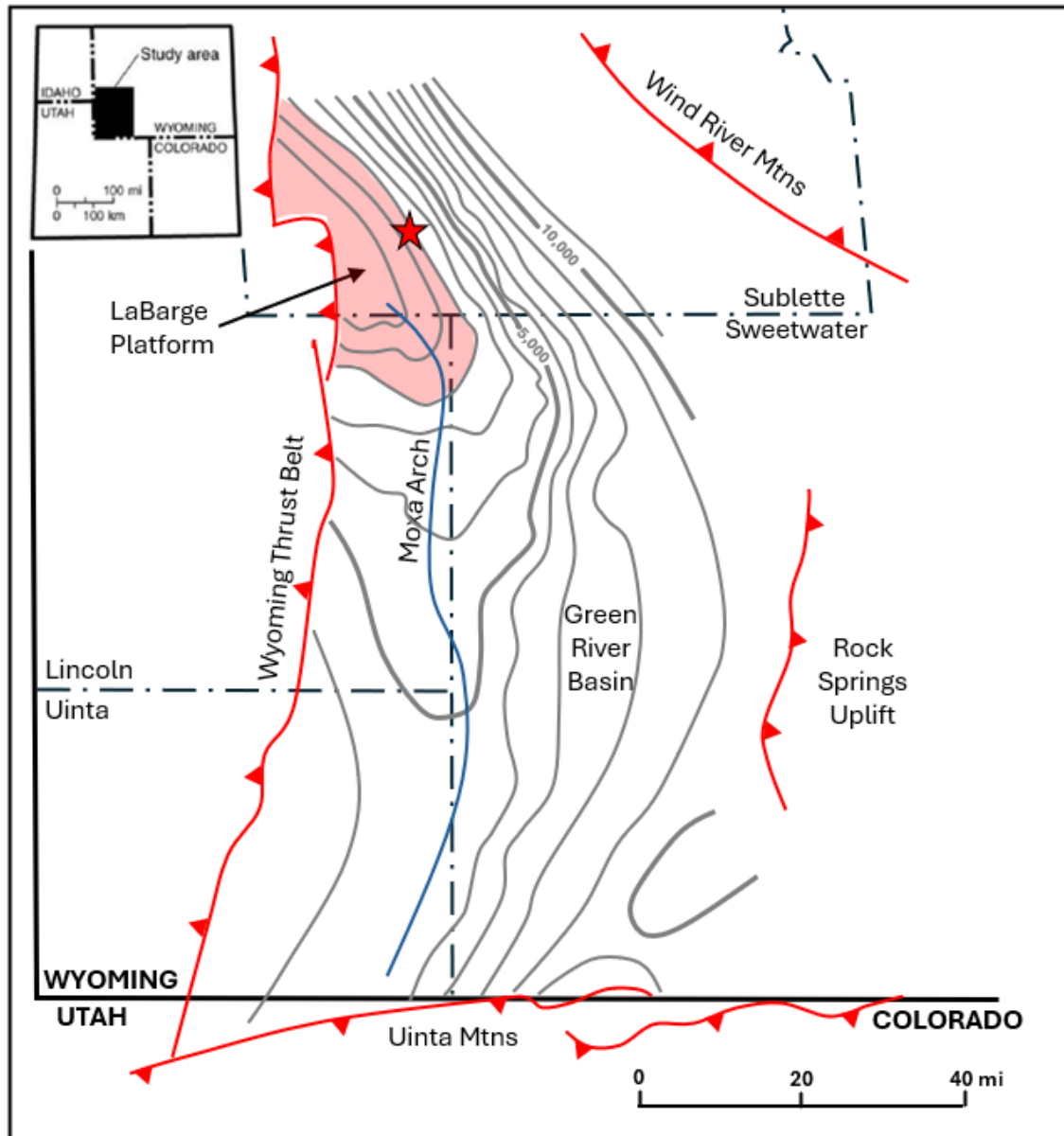


Figure 2.1-1: Location map of the LaBarge Platform Field area, which includes Dry Piney Unit, denoted by pink shading. The DPS AGI injection area is denoted by the red star near the eastern extent of the LaBarge Platform Field area. Modified from the USGS Greater Green River Basin Assessment.

2.2 STRATIGRAPHY OF THE GREATER LABARGE FIELD AREA

The GGRB stratigraphic record spans Precambrian through Eocene time and associated sediments or unconformities (**Figure 2.2-1**). Existing hydrocarbon production has been established through many stratigraphic intervals in the GGRB, generally from reservoirs of Paleozoic through Cenozoic age. There are two dominant styles of gas-prone petroleum systems within the GGRB, a “shallow” sweet system (lacking helium and H₂S with a minor

or de minimis CO₂ component) and a “deep” sour system (with notable helium, H₂S and CO₂ gas components). There are also two shallow oil-prone petroleum systems in the field, one produces from the Jurassic Nugget sandstone but is limited to localized structural traps, the other produces from local stratigraphic traps in the undifferentiated Tertiary, Wasatch, Almy, Fort Union and/or Mesaverde units. The Cenozoic gas-prone hydrocarbon system is sweet, relatively shallow in depth (7,000-9,000 ft TVD), regionally pervasive and generally produces from clastic sequences comprised of alternating sands interpreted to be shorelines and sealed by mud rocks (deeper water deposits) associated with fluctuating sea level of the Western Interior Seaway during Cretaceous time. The Paleozoic hydrocarbon system is deep (14,000 to 17,000 ft TVD), sour (contains H₂S, CO₂ and helium in addition to hydrocarbons), is confined to the LaBarge Field near the crest of the LaBarge “Platform” (**Figure 2.1-1**) and is primarily hosted in carbonate (dominantly dolomitic) reservoirs of Mississippian and Ordovician age. The confining units for the primary Madison and Bighorn sour gas reservoirs are comprised of shales and salt-rich sediments of Triassic age (“Triassic Evaporites”) and anhydrites in the Pennsylvanian-aged Amsden Formation and Devonian-aged Darby Formation and tight limestones and shales in the Cambrian section underlying the Bighorn. In the LaBarge field area, including DPU, commercially producible quantities of hydrocarbons have been proven and developed in the following intervals:

- Tertiary Wasatch, Fort Union & Undifferentiated (Mesozoic, shallow, oil)
- Upper Cretaceous Mesaverde Formation (Cenozoic, shallow, sweet gas & oil)
- Upper Cretaceous Frontier Formation (Cenozoic, shallow, sweet gas)
- Lower Cretaceous Bear River Formation (Cenozoic, shallow, sweet gas)
- Jurassic Nugget Formation (Cenozoic, shallow, oil)
- Permian Phosphoria Formation (Paleozoic, deep, sour gas)
- Pennsylvanian Weber (Wells) Formation (Paleozoic, deep, sour gas)
- Mississippian Madison Formation (Paleozoic, deep, sour gas)

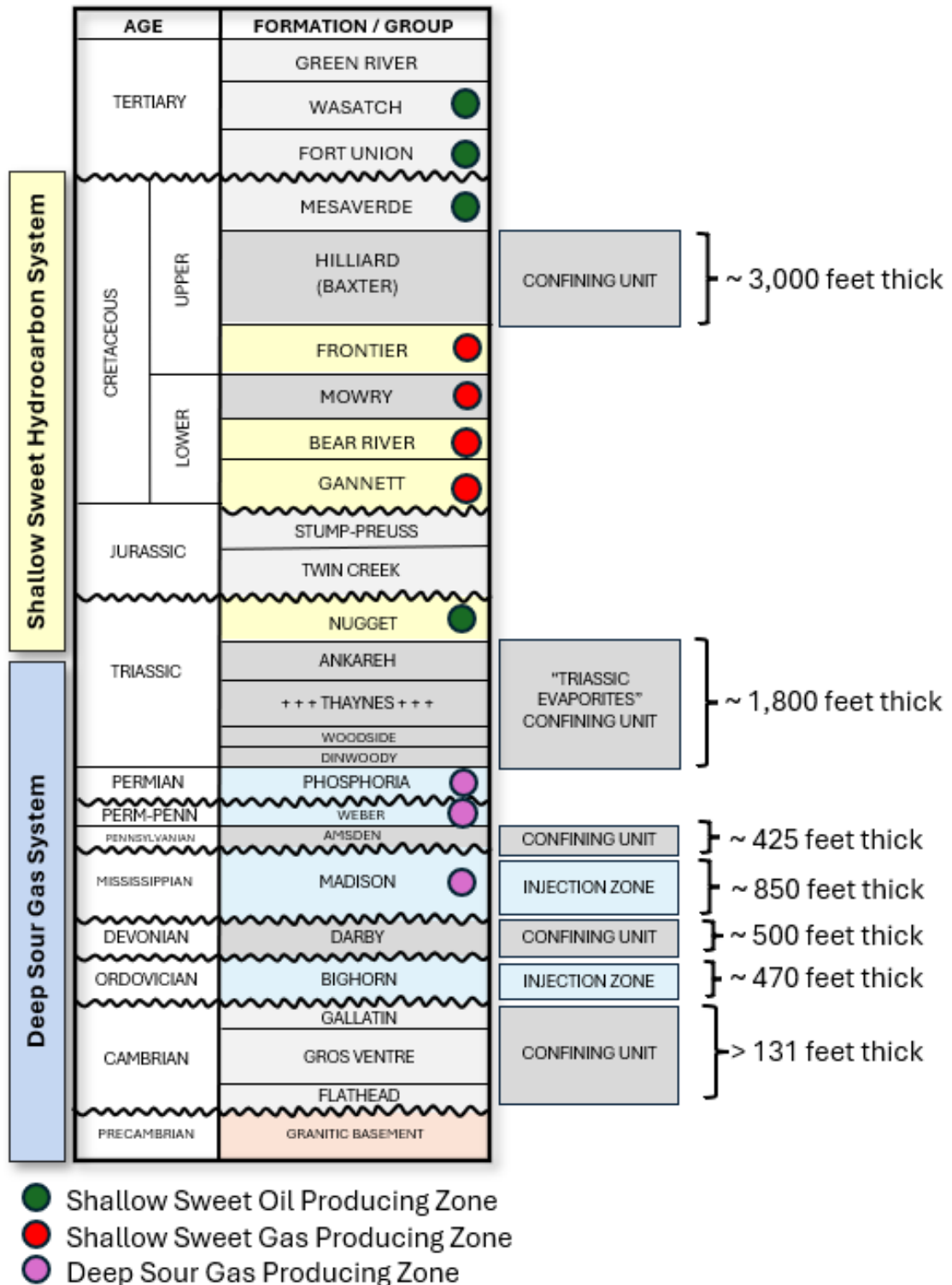


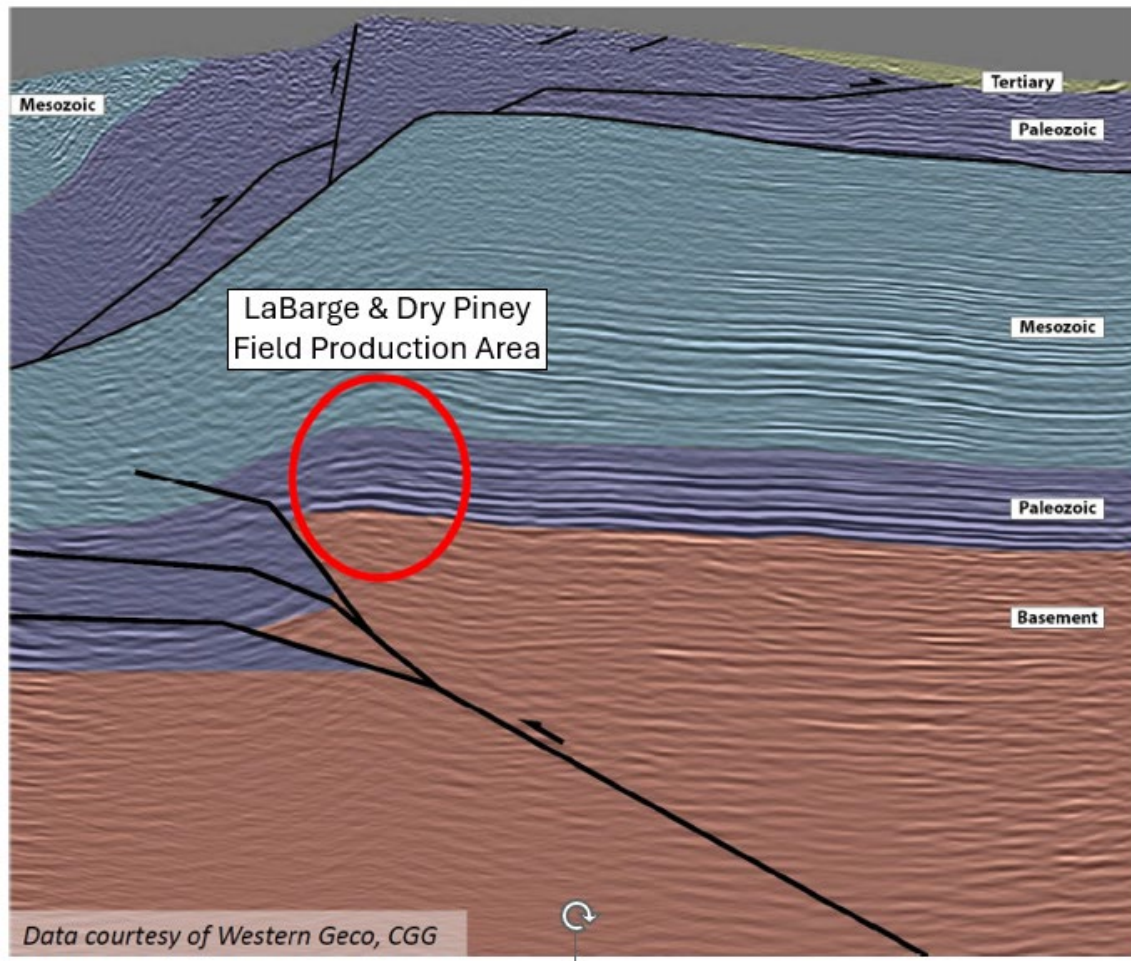
Figure 2.2-1: Generalized stratigraphic column for the western Greater Green River Basin area in Wyoming. The Madison and Bighorn injection zones and associated Triassic Evaporites, Amsden and Darby confining units are identified. Modified from Lamerson, 1982.

2.3 STRUCTURAL GEOLOGY OF THE LABARGE FIELD AREA

The LaBarge field area lies at the junction of three regional tectonic features: the Wyoming Fold and Thrust Belt to the west, the north-south trending Moxa Arch that provides the structural closure of the LaBarge field, and the Green River Basin to the east. On a regional scale, the Moxa Arch delineates the eastern limit of several regional north-south thrust faults that span the distance between the Wasatch Mountains of Utah to the Wind River Mountains of Wyoming. The historical evaluation of structural styles at LaBarge has defined that three principal styles of structural development have occurred in the area: Basement-involved contraction, deformation related to flowage of salt-rich Triassic strata and Basement-detached contraction.

2.3.1 BASEMENT-INVOLVED CONTRACTION EVENTS

Basement-involved contraction has been observed to most commonly result in thrust-cored monoclinial features being formed along the western edge of the LaBarge field area (**Figure 2.3-1**). These regional monoclinial features have been imaged extensively with two dimensional (“2D”) and three dimensional (“3D”) seismic data and are easily recognizable on these data sets. At a smaller scale, the monoclinial features set up the LaBarge field structure, creating hydrocarbon trapping configuration of the various reservoirs contained in the LaBarge productive section. The resulting LaBarge and Dry Piney Field gas accumulations in the sub-thrust Paleozoic section are hydraulically separate and disconnected from the Paleozoic section in the hanging wall thrust sheets that are at and near the surface in the area (**Section 2.3.3**).



2.3-1: Example of thrust-cored monoclinial feature interpreted to be a product of basement-involved contractional events. Note the LaBarge & Dry Piney Field Production Area of the sub-thrust Paleozoic section is hydraulically isolated and not in communication with the near-surface Paleozoic section in the hanging wall thrust sheets. From ExxonMobil Amended MRV Plan dated October 2019.

2.3.2 DEFORMATION OF FLOWAGE FROM TRIASSIC SALT-RICH STRATA

The second most common style of deformation in the LaBarge field area is the result of flowage from Triassic strata that contain significant amounts of salt. These Triassic sediments have been observed in outcrops to be comprised of interbedded salt and siltstone intervals. At LaBarge, it is not typical to observe thick, continuous sections of pure salt, but rather interbedded salt and siltstone sections. The “salty sediments” of this interval have been determined to later evacuate and/or flow, which results in local structural highs being developed around these areas. **Figure 2.3-2** contains a seismic line illustrating the Triassic salt-rich sediments and structuring. The salt-induced local structural features generated via salt evacuation can and do create small local hydrocarbon traps associated with these sediments. These smaller, localized structures

are of a much smaller scale than the main monoclinal hydrocarbon trap of the larger LaBarge field.

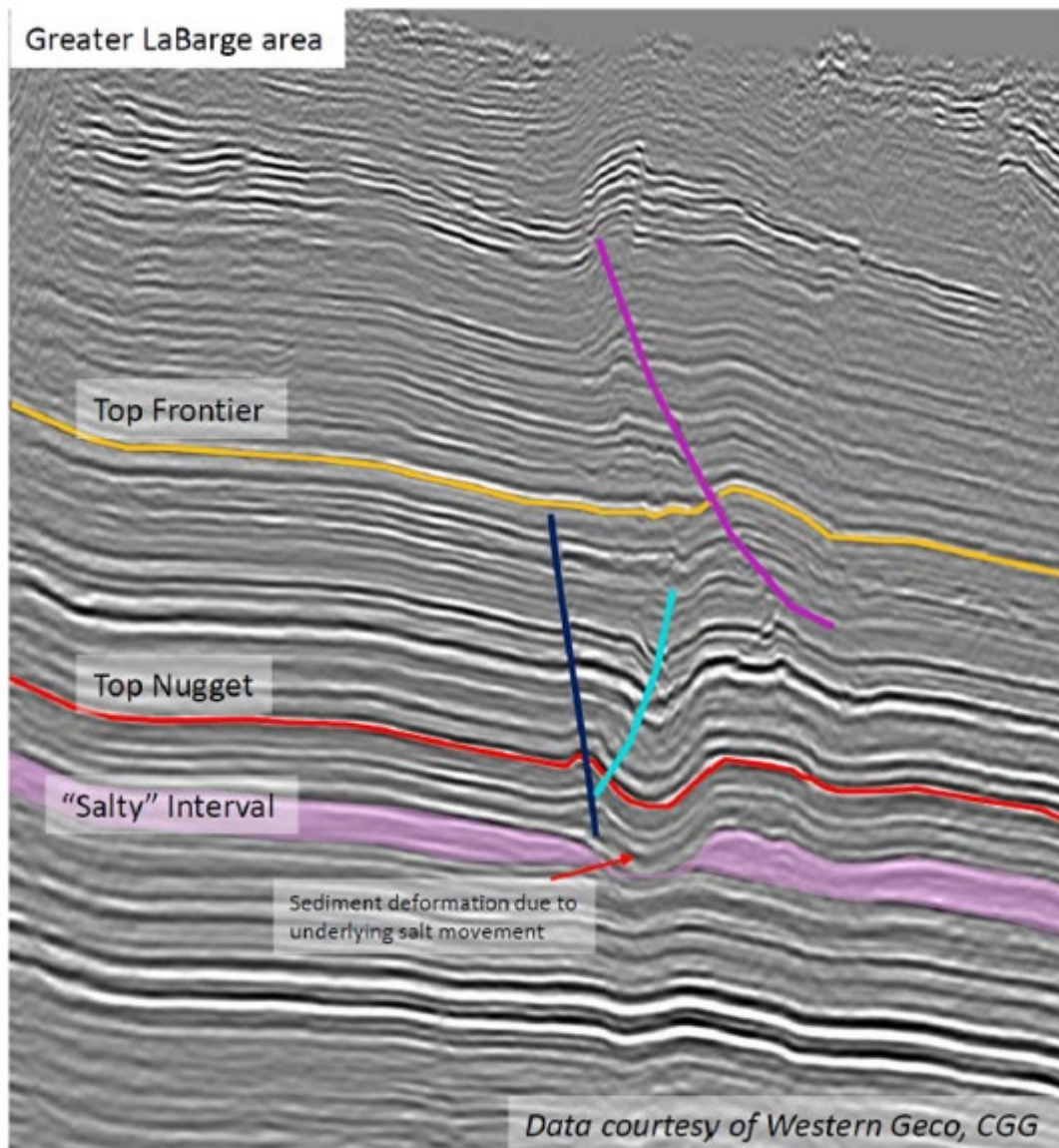


Figure 2.3-2: Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge field area. From ExxonMobil Amended MRV Plan dated October 2019.

The active deformation behavior of these Triassic sediments has been empirically characterized through the drilling history of the LaBarge field. Early in the life of several wells drilled in the LaBarge field area, wells drilled with thin-walled casing were susceptible to failure due to casing shearing across the Triassic interval. Subsequent wells drilled in the field area used thicker-walled casing strings and successfully mitigated the salt-sediment flowage issue.

2.3.3 BASEMENT-DETACHED CONTRACTION

The third main structural style observed in the LaBarge field area is basement-detached contraction (**Figure 2.3-3**). These features have been well-documented, historically at LaBarge as many of these features have mapped fault expressions on the surface. The Paleozoic outcrops mapped in the overthrust belt are not in hydraulic communication with the productive sub-thrust Madison Formation, which is a function of a basement-involved contraction event as discussed in **Section 2.3.1** and noted on **Figure 2.3-1**. The lack of hydraulic communication between the sub-thrust injection zones and the outcrops of the same formations is important because the world-class LaBarge and Dry Piney Field production area would not exist otherwise and therefore, the risk of CO₂ leakage via lateral migration is exponentially reduced (**Figure 2.3-1**). Detachment and contraction along the basement typically create three types of structural features: Regional scale thrust faults, localized smaller-scale thrust faults, and reactivation of Triassic salt-rich sediments resulting in local structural highs.

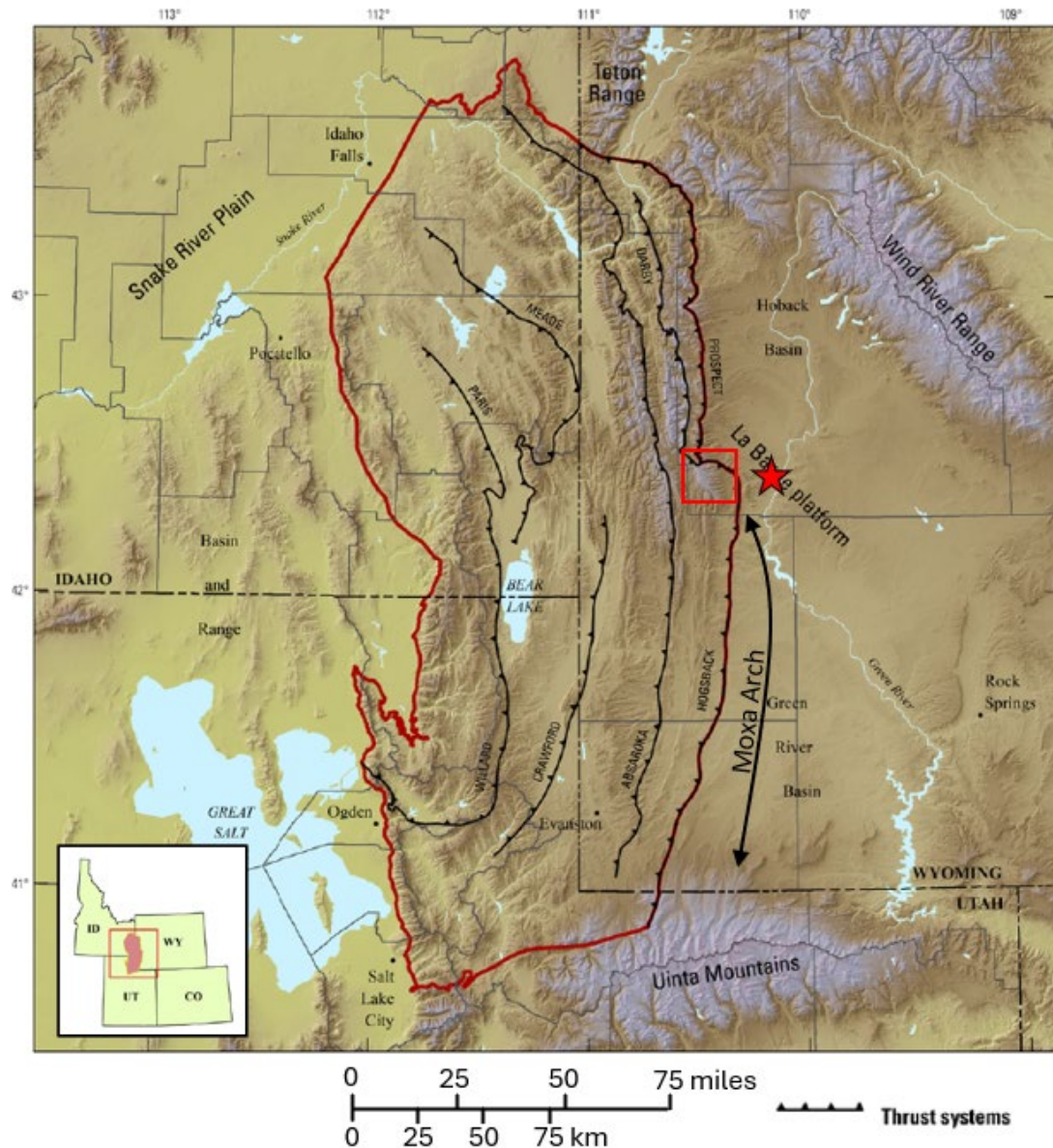


Figure 2.3-3: Map showing location of the Moxa Arch and regional thrust faults of the Wyoming Range. The LaBarge/Dry Piney Unit production field area is denoted by the red box, and the approximate injection area is denoted by the red star. Modified from Buursink et al, 2014.

2.3.4 FAULTING AND FRACTURING OF RESERVOIR INTERVALS

Reservoir permeability in the LaBarge field has been found to increase in areas with small-scale faults and fractures, across nearly all productive zones. Micro-fractures have been identified both in core samples and on borehole micro-imaging logs, with the fractures in the core typically filled with calcite.

In general, wells located near structural highs or fault junctions tend to show higher reservoir permeability and improved hydrocarbon productivity. This suggests that these areas may have a significantly higher density of natural fractures, or a greater proportion of open fractures compared to calcite-filled ones. In contrast, areas with little to no significant faulting, such as the planned AGI area, typically exhibit reservoir permeability driven by matrix or pore-to-pore flow. Matrix permeability is usually less effective in supporting fluid movement over long distances and creates an ideal environment for permanent carbon dioxide containment.

There are a limited number of faults in the eastern DPS AGI area of the LaBarge field, and those that do exist are characterized as near vertical, possess near zero offset and are limited in aerial extent. Most faults are detected by subtle discontinuities in seismic reflectors and may or may not be combined with abrupt local dip changes. Generally, the faults do not extend upward through or above the Triassic Evaporites confining layer which is the primary seal for the sour helium-rich hydrocarbon system. The small subset of faults that do appear to extend upward through the Triassic Evaporites confining unit are not active leakage pathways from the Madison and Bighorn injection zones to shallower geologic units, as evidenced by the lack of CO₂ and H₂S in gas composition analyses of shallow gas wells located near said faults. In no case are any faults observable or mappable at the surface. See **Table 2.6** for a summary of gas composition in select wells, and **Sections 2.6.3** and **4.4** for further discussion of faults and fractures as a potential leakage pathway.

2.3.5 LABARGE FIELD STRUCTURE AND GAS RESOURCE OF THE MADISON FORMATION

Structural closure at the sub-thrust Madison Formation level in the LaBarge field area is very large, with approximately 4,000 ft TVD of structural closure from the top of the structure to the gas-water contact (“GWC”). Spatially, the Madison closure covers over 800 square miles, making it one of the largest conventional gas fields in North America.

The Madison Formation is estimated to contain more than 300 trillion cubic ft (“TCF”) of raw gas and 20 TCF of natural gas (methane). At current rates of production, and including the addition of BSO’s planned production wells, the estimated remaining field life is over 100 years. Spatially, the Madison and Bighorn injection wells are located approximately 10.5 miles to the east-northeast of the DPIGPF and LaBarge field (DPU) production area.

Structural configuration and lateral continuity of the Madison and Bighorn producing and injection zones provide both a tremendous gas-in-place (production) and storage capacity (injection) resource. Sub-units in the Madison and Bighorn reservoir and injection zones (Sections 2.6.2 and 2.6.3), along with their associated confining units (Sections 2.6.3 and 2.6.4) can be confidently correlated over approximately 75 miles via well control and an extensive industry library of seismic data.

2.4 PETROLEUM PRODUCTION HISTORY OF THE LABARGE FIELD AREA

The LaBarge field in southwestern Wyoming has a rich history of oil and gas exploration and production, marked by significant discoveries and technological advancements. Below is a detailed timeline highlighting key events in the development of the area.

1840s: Oil was reported by emigrants who used it to grease their wagon wheels.

1907: Initial drilling activities commenced near the future site of Calpet, close to the southern border of what would become the LaBarge Oil Field. These early efforts faced challenges due to the field's remote location, approximately 35 miles from the nearest railhead in Opal, making transportation of heavy drilling equipment difficult.

1920s–1930s: Early Exploration & First Production

- Drilling success in 1923 and the discovery of oil in 1924 marked the beginning of commercial production.
- Initial wells targeted shallow Tertiary & Upper Cretaceous sandstone reservoirs but faced limitations due to transportation challenges.

1940s–1950s: Expansion & Geological Studies

- Increased geological surveys by General Petroleum (a Mobil predecessor) helped better define the field's oil and gas potential.
- Belco Development Company (an EOG Resources predecessor) discovers natural gas in the Frontier Formation.
- By 1956, completion of a Pacific Northwest pipeline provided takeaway capacity and the LaBarge area was recognized as a key gas-producing region in Wyoming.

1960s–1970s: Infrastructure & Pipeline Development

- In 1962, Mobil discovers Paleozoic (Madison) gas at Tip Top, elects to not develop further due to economic and technological constraints associated with the sour gas.
- Investment in infrastructure, including pipeline construction, facilitated the transport of shallow oil and gas.
- Shallow development lead by General Petroleum, Belco and Mountain Fuel Supply Company (QEP Resources predecessor), focused on structural traps in the Frontier Formation.
- Natural gas production increased, paving the way for larger-scale operations in later decades.

1980s–1990s: ExxonMobil & Large-Scale Gas Production

- In 1981, Exxon discovers Madison gas in the Lake Ridge Unit.
- During the mid-1980's, Exxon develops Madison gas in Lake Ridge, Fogarty Creek and Graphite Units and begins construction of Shute Creek Treating Facility and associated infrastructure.
- Exxon began operations at the Shute Creek Treating Facility in 1986, focusing on natural gas with a high CO₂ content.
- In 1999, Exxon and Mobil merge, EOG Resources spins out from Enron (Belco Development Company successor).

2000s: Environmental Initiatives & CO₂ Capture

- ExxonMobil launched carbon capture and storage (“CCS”) projects to reduce emissions.
- Between 2001 and 2005, ExxonMobil drills and begins injection into initial AGI wells to dispose of hydrogen sulfide and minor carbon dioxide volumes.
- CO₂ from the field was increasingly used for enhanced oil recovery in other reservoirs.

2010s: Advanced Gas Processing & New Technologies

- In 2010, QEP Resources spins off from Questar (Mountain Fuel Supply Company successor).
- ExxonMobil tested new gas separation technologies, including the Controlled Freeze Zone (“CFZ™”) process.
- The LaBarge field cemented its role as a crucial CO₂ supplier for enhanced oil recovery in the Rockies.

2020s: Continued Production & Energy Transition

- In 2020, BSO acquired leasehold to develop the Madison in the DPU area from QEP Resources and EOG Resources.
- In 2024, BSO drilled the Dry Piney 4-36 production test well in DPU and confirmed the Madison gas composition, including higher than anticipated helium, and encountered higher reservoir pressures than expected.
- In 2025, BSO drilled and acquired geologic data in the Dry Piney State 12-16 injection well.
- Ongoing investments by ExxonMobil and BSO in CCS align with efforts to reduce the field's carbon footprint.

2.5 INITIAL DISCOVERY OF MADISON GAS AND EARLY COMMERCIALITY AT LABARGE

Mobil discovered significant natural gas reserves in the Madison Formation within the LaBarge field area in 1962. However, due to economic and technological constraints, commercial development did not commence immediately. It was not until the 1980s that large-scale production became viable, following Exxon's successful discovery of Madison gas in the Lake Ridge Unit, which helped justify the necessary infrastructure investments.

Meanwhile, commercial gas production from the Frontier Formation began earlier, in 1956, after the completion of the Pacific Northwest Pipeline. This crucial pipeline provided the market access needed to support Belco Development's Frontier gas production program, enabling steady extraction and transportation of natural gas from the region.

Oil production from the Nugget Sandstone Formation was established later, though on a much smaller scale compared to gas production.

The Madison Formation's vast gas reserves remained largely untapped until Exxon initiated production in 1986 with the startup of the Shute Creek Treating Facility. This facility was critical in processing the high-CO₂ and high-H₂S natural gas from the Madison Formation, separating methane, nitrogen, carbon dioxide, and helium to make the gas commercially viable.

The Madison Formation at LaBarge contains an estimated total gross gas in-place volume exceeding 300 TCF. Since production began in 1986, ExxonMobil (Exxon and Mobil merged in 1999) has cumulatively extracted approximately 8.7 TCF of raw gas from the Madison Formation with production continuing today at approximately 700-720 MMscfpd.

BSO plans to produce approximately 7.3 TCF of raw gas during its 50-year project life.

2.6 ACID GAS INJECTION PROGRAM HISTORY AT LABARGE

ExxonMobil has been injecting acid gas into the Madison Formation in two Class II AGI wells since 2005. ExxonMobil drilled a third Class II AGI well in 2023 and is currently working to bring it online, with injection operations expected to begin in 2025. ExxonMobil has a fourth Class II AGI well currently approved to drill by the WOGCC, and a fifth in the permitting process. All Class II AGI wells are located about 45 miles to the south of the LaBarge field production area and are targeting the Madison and/or Bighorn Formations below the GWC.

The Madison Formation raw gas production contains a relatively low methane (CH₄) concentration and a high carbon dioxide (CO₂) content. The average gas composition of Madison gas produced by ExxonMobil is as follows:

- 21% Methane (CH₄)
- 66% Carbon Dioxide (CO₂)
- 7% Nitrogen (N₂)
- 5% Hydrogen Sulfide (H₂S)
- 0.6% Helium (He)

Due to the high CO₂ and H₂S content of Madison gas, there was a significant need for CO₂ and H₂S disposal after separating and marketing the saleable products (primarily CH₄ and He). ExxonMobil has historically sold a significant portion of the excess CO₂ into the enhanced oil recovery (“EOR”) market and vented the remainder. The Shute Creek Treating Facility (“SCTF”) originally contained a sulfur recovery unit to transform the waste H₂S gas to elemental sulfur. Around 2005, due to poor economics, ExxonMobil decommissioned the sulfur recovery units to debottleneck and improve reliability at SCTF. This generated the need to inject the H₂S and entrained CO₂ into the Madison subsurface via AGI wells. In 2022, ExxonMobil received federal permits to expand its carbon capture program at SCTF to capture the remaining CO₂ volumes not sold into the EOR market and were therefore historically vented to the atmosphere. The previously vented CO₂ volumes will be injected into the recently drilled SC 5-2 AGI well, expected to begin operations in mid-late 2025.

2.6.1 GEOLOGICAL OVERVIEW OF THE BSO AGI PROGRAM

BSO anticipates producing sour gas very similar in composition to that produced by ExxonMobil, and is represented by the following components based on reservoir fluid sampling in the Dry Piney 4-36 well drilled by BSO:

- 20.5% Methane (CH₄)
- 67% Carbon Dioxide (CO₂)
- 7% Nitrogen (N₂)
- 4.5% Hydrogen Sulfide (H₂S)
- 0.6% Helium (He)

BSO plans to capture and dispose of all the CO₂ and H₂S waste gas after the saleable products (CH₄ and He) have been separated, processed and refined at the DPIGPF. Nitrogen will either be vented, sold into the local market, and/or utilized in the helium liquefaction process in the gas processing facility.

BSO has pursued the AGI program as a proven, safe, and reliable method to dispose of the acid gas waste stream into the Madison and Bighorn Formations based upon ExxonMobil’s successful 20-year injection history into the Madison Formation on the same geologic structure. ExxonMobil injects acid gas below the GWC, but BSO plans to target the Madison and Bighorn Formations for injection just above the GWC. BSO’s evaluation indicates that more favorable injection rates will potentially be obtained for a longer

duration above the GWC, thus requiring fewer AGI wells to handle the CO₂ and H₂S waste gas stream requiring disposal. Waste gas composition for disposal will be approximately 92.4% CO₂ and 6.93% H₂S and 0.5% methane by molar volume. The acid gas will be injected at depths ranging approximately 14,800 ft to 17,000 ft TVD below the surface and will be located near the GWC approximately 10.5 miles to the east-northeast of the main DPU (LaBarge field) production areas (**Figure 2.6-1**). It is important to note that the in-situ gas compositions in the Madison and Bighorn Formations at the DPS AGI area are significantly higher in CO₂ and significantly lower in both methane and helium than in the DPU production area due to gravity segregation over geologic time.

In the DPS AGI area, the average Madison gas composition is:

- 4.6% Methane (CH₄)
- 89.4% Carbon Dioxide (CO₂)
- 4.4% Nitrogen (N₂)
- 1.2% Hydrogen Sulfide (H₂S)
- 0.24% Helium (He)

In the DPS AGI area, the average Bighorn gas composition is:

- 0.5% Methane (CH₄)
- 96.2% Carbon Dioxide (CO₂)
- 2.5% Nitrogen (N₂)
- 0.5% Hydrogen Sulfide (H₂S)
- 0.25% Helium (He)

The gas compositions above are the average concentrations based on gas analyses conducted on fluid samples collected during wireline logging of the Dry Piney State 12-16 well drilled by BSO in 2025.

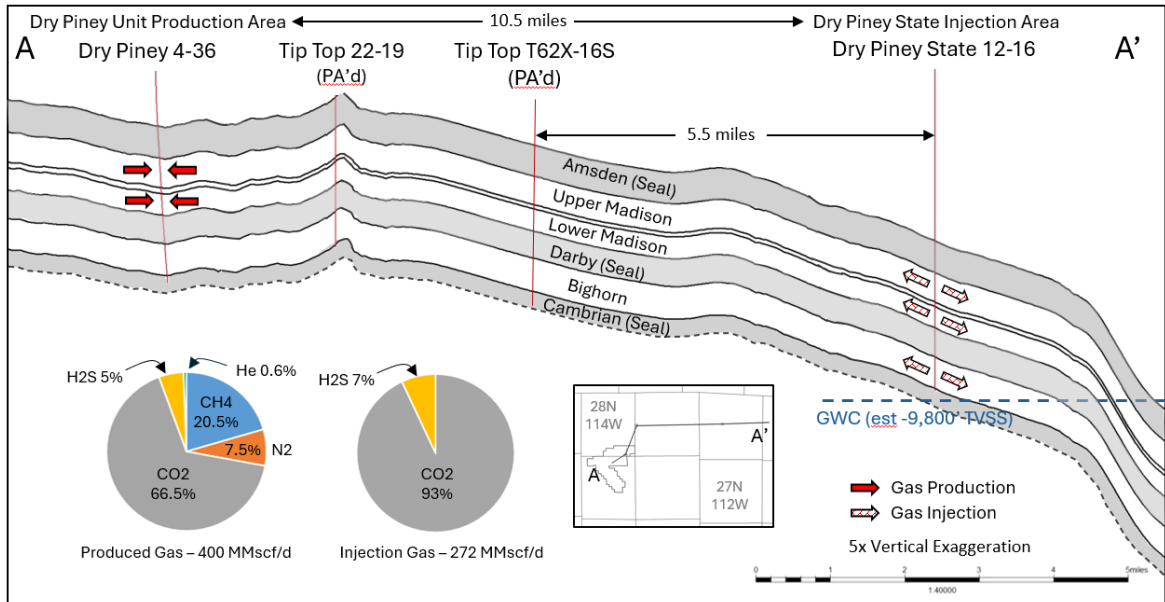


Figure 2.6-1: Schematic illustration showing location of proposed Dry Piney State 12-16 well and injection area near gas-water contact (GWC) relative to the Dry Piney Unit production area approximately 10.5 miles to the west. Two plugged and abandoned Tip Top wells penetrate the Madison & Bighorn Formations between the BSO production and injection areas, but only the Tip Top T62X-16S is within the Maximum Monitoring Area defined in Section 3.0. Vertical exaggeration is 5x.

2.6.2 RESERVOIR QUALITY OF THE MADISON AND BIGHORN FORMATIONS IN AGI WELLS

BSO's proposed AGI wells are approximately 10.5 miles east of the Dry Piney Unit production area and the 2024 BSO Dry Piney 4-36 well. There are two plugged and abandoned wells that penetrate the Madison and Bighorn Formations between the production and injection areas, the 1962 Mobil Tip Top Unit 22-19 well and the 2008 ExxonMobil Tip Top T62X-16S. The Tip Top T62X-16S logs are not publicly available, so reservoir quality is unknown at that location (**Figure 2.6-2**). As will be discussed in later sections, the Tip Top T62X-16S is the only well in the Maximum Monitoring and Active Monitoring Areas that penetrates the Madison and Bighorn injection zones. BSO completed drilling and logging the Dry Piney State 12-16 well in the injection area in June 2025. Extensive data was acquired in both BSO wells to allow evaluation of the reservoir quality and storage capacity of the Madison and Bighorn Formations in the Dry Piney Unit production area and the DPS AGI area. Forty-one wells on the LaBarge structure have sufficient publicly available data to integrate into a petrophysical model, the results of which have been integrated into a geologic model that characterizes Madison and Bighorn reservoir quality regionally and locally in the DPS AGI area.

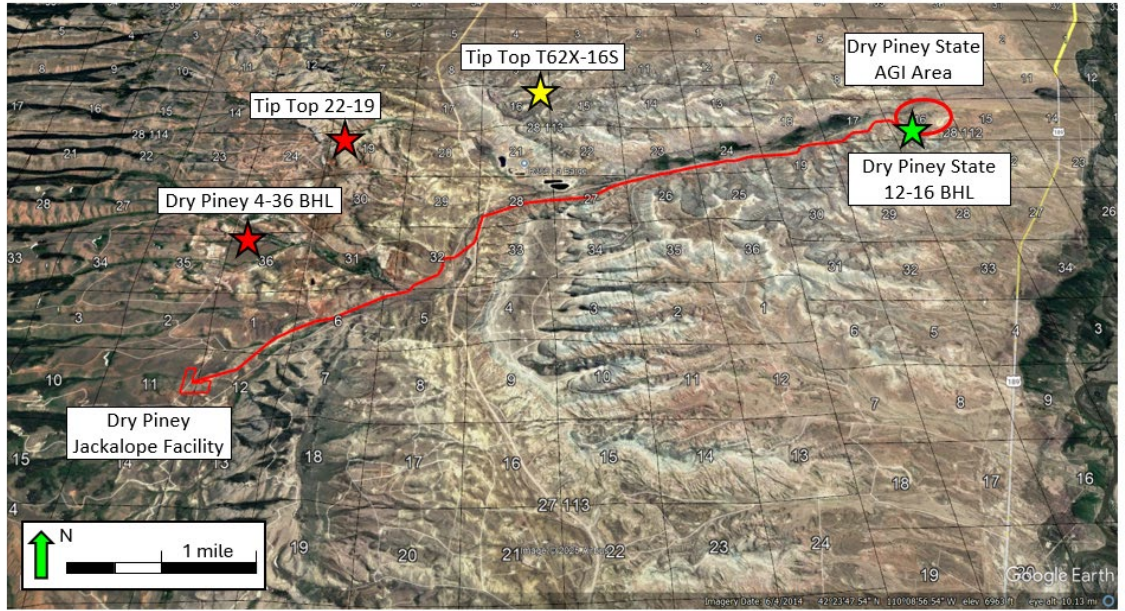


Figure 2.6-2: Map showing the relative position of the BSO proposed AGI area (red circle) and Dry Piney State 12-16 (green star) relative to the Tip Top Unit 22-19 and the BSO Dry Piney 4-36 wells (red stars). Logs unavailable for the Tip Top T62X-16S well (yellow star). The DPIJGPF is denoted by a red rectangular box and the proposed pipeline route between DPIJGPF and the DPS AGI area is the red line.

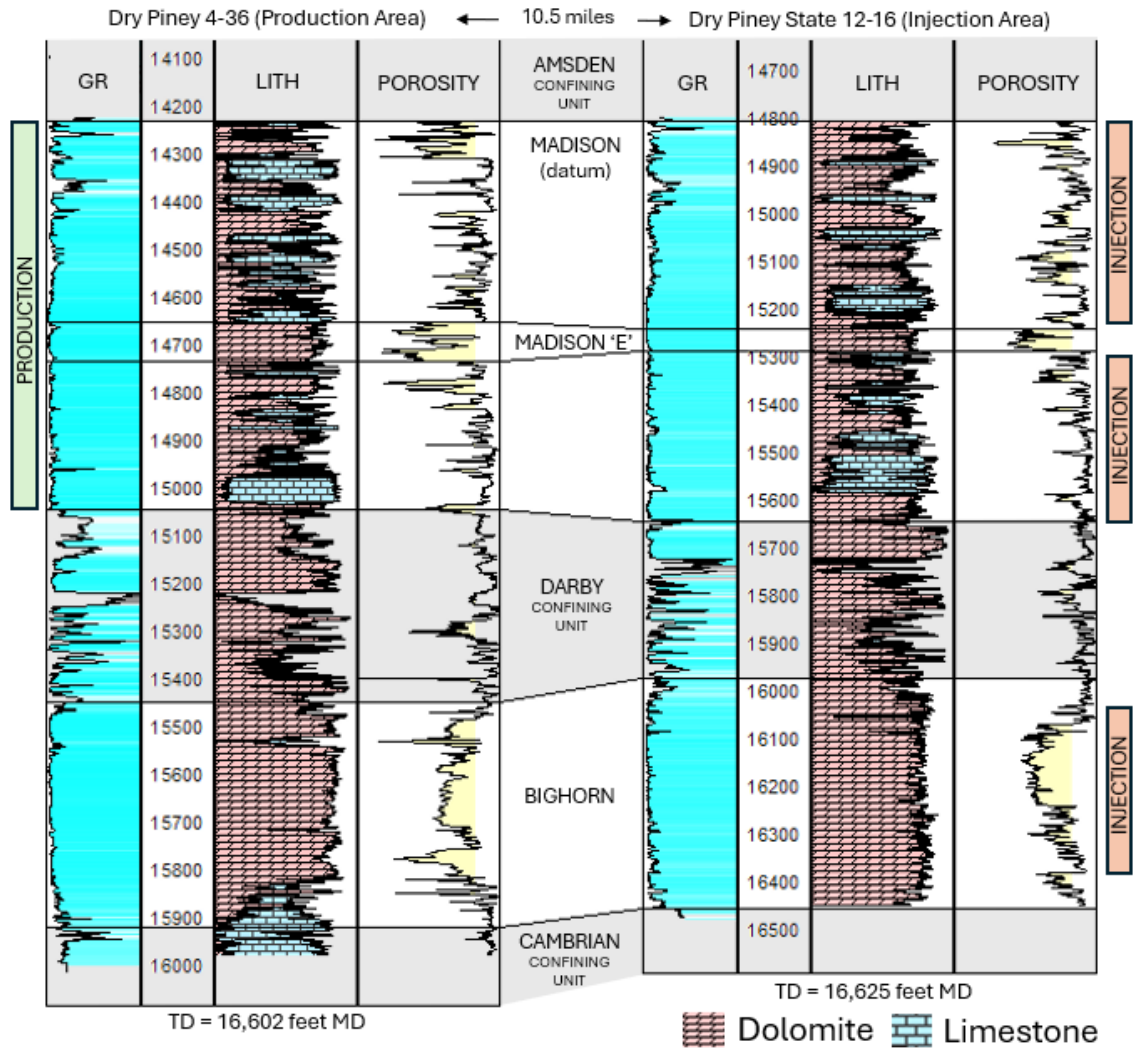


Figure 2.6-3: Stratigraphic cross-section showing Dry Piney 4-36 well (Production Area) and Dry Piney State 12-16 (Injection Area). Madison well top is the stratigraphic datum. Gamma Ray (GR), lithology (LITH) and Porosity logs displayed. Note that porosity over 5% is shaded in yellow. Madison production interval denoted by green bar to left of Dry Piney 4-36 and Madison & Bighorn Injection intervals denoted by orange bars to right of Dry Piney State 12-16. The confining units immediately above and below the Madison and Bighorn are shaded in gray. Production area and Injection area are separated by approximately 10.5 miles.

Petrophysical evaluation of these wells indicates that the Madison Formation is comprised of alternating limestone and dolomite intervals (**Figure 2.6-3**). In general, the limestone intervals possess lower porosity averaging 0-5%, whereas the “pay” dolomite intervals greater than 5% porosity average 9.7% porosity and act as the primary reservoir lithofacies. Overall, the Madison averages 5.5% porosity. The Bighorn Formation is primarily dolomite and contains a relatively high porosity zone (>12%) approximately 175

ft thick in the middle of the formation. The “pay” in the Bighorn Formation averages 10.7% porosity, while the overall Bighorn averages 7.7% porosity. Core permeability indicates both the Madison and Bighorn dolomites range from 1 to 500 millidarcies (“md”), with an average of around 10 md in both the Madison and Bighorn. The reservoir quality of the Madison and Bighorn Formations in the Dry Piney State 12-16 injection well are summarized in **Figure 2.6-4**, and future injection wells in the DPS AGI area are anticipated to be similar.

Formation	Madison	Bighorn
Net Pay (ft)	343	309
Avg Phi (%)	9.7	10.5
Avg K (mD)	10	10
Kh (md-ft)	3430	3090
Skin	-4.0 to -4.5*	-4.0 to -4.5^

Figure 2.6-4 – Average reservoir properties for the Dry Piney State 12-16 injection well. Future AGI wells are expected to have similar properties. * Skin as reported by other operators injecting into same formation based on injectivity and fall-off tests. ^ Bighorn skin factor assumed to be similar to Madison owing to similar Avg Phi and Avg K reservoir properties.

From **Figure 2.6-4**, the parameters tabulated include:

- Net Pay: Feet of Madison and Bighorn intervals that exceed 5% total porosity.
- Avg Phi: Average total porosity (the percent of the total bulk volume of the rock investigated that is not occupied by rock-forming matrix minerals or cements).
- Avg K: Air permeability, which is measured in units of darcy – a measure of the ability of fluids to move from pore to pore in a rock.
- Kh: Millidarcy-ft, which is a measure of the average permeability multiplied by the total net pay section encountered.
- Skin: Relative measure of damage or stimulation enhancement to formation permeability in a well completion. Negative skin values indicate enhancement of permeability through the completion whereas positive values indicate hindrance of permeability or damage via the completion.

2.6.3 SEISMIC EXPRESSION OF MADISON & BIGHORN FORMATIONS AT AGI WELL LOCATIONS

Seismic expression of the Madison and Bighorn Formations at the proposed DPS AGI area indicates that the planned injection wells are located on the plunging eastern limb of the Moxa Arch. The eastern limb dips to the northeast at approximately 3 to 5 degrees depending on location. Nine faults with minimal offset and limited aerial extent were

identified in the seismic data within the Maximum Monitoring Area (“MMA”, **Section 3.0**), with the nearest fault occurring approximately 3.4 miles north of the DPS AGI location. *It is important to note that none of faults in the MMA are observed at the surface, nor does seismic interpretation suggest that any faults in the MMA extend to the surface.* The faults are characterized by discontinuity and change in local structural dip of seismic reflectors, rather than significant offset, and are generally constrained to the geologic units below the Triassic Evaporite confining unit. All but three of the faults (Faults 5, 6 and 7, **Figure 2.6-5**) terminate below, and therefore do not extend vertically above, the Triassic Evaporite confining layer. As discussed further in Section 4.4 there is very low to low risk of the faults impacting the ability of the Triassic Evaporite confining unit to maintain its seal integrity within the MMA. As observed on **Figure 2.6-6**, Fault 1 is limited to the Madison Formation and deeper. There are no faults evident on a west to east seismic panel through the DPS AGI area (**Figure 2.6-7**). Faults 5, 6 and 7 were observed to extend vertically above the Triassic Evaporite confining layer in the proposed AGI area (**Figure 2.6-8**). Extensive Frontier and Bear River gas production development has occurred in the vicinity of these faults in and near the Birch Creek Unit (“BCU”) in Township 27 North, Range 113 West (**Figure 2.6-5**), providing the opportunity for baseline monitoring and early detection and quantification of potential CO₂ leakage if these faults act as leakage pathways (See **Sections 4.4, 5.3** and **5.6** for further discussion). Of particular interest is the BCU No. 1 well, which was drilled to the Nugget, then plugged back to the Frontier in 1957 and would provide a key baseline data point in terms of gas composition, as it is the deepest well near Faults 5, 6 and 7. Faults 5, 6 and 7 terminate in the Frontier Formation, and do not extend upward into the approximately 3,000-foot thick Hilliard (Baxter) Shale confining zone. If Faults 5, 6 and 7 were acting as a conduit for CO₂ leakage from the existing naturally occurring CO₂ and H₂S resource in-place, CO₂ and H₂S would be detected in the gas analyses conducted on samples collected from wells near these faults. **Table 2.6** summarizes the gas analyses for shallow wells near Faults 5, 6 and 7, demonstrating the lack of significant CO₂ (defined as > 2.0 mole % “mol%”) and no H₂S or helium and therefore lack of an active leakage pathway via these faults. Gas analysis reports showing the concentration measurements below for the wells in **Table 2.6** are available in **Appendix D**.

Well ID	Well Name	CO ₂ (mol%)	H ₂ S (mol%)	Helium (mol%)	Nitrogen (mol%)	Oxygen (mol%)
4903505496	UNIT MCGINNIS (GRBU) No. 10-9	0.28	0.00	NA	0.31	0.00
4903522369	BIRCH CREEK UNIT No. 185	0.29	0.00	NA	0.98	0.00
4903521959	BIRCH CREEK UNIT No. 166	0.27	0.00	NA	1.21	0.00
4903522282	COOPERS No. 1-8	0.21	0.00	NA	0.86	0.00
4903522371	BIRCH CREEK UNIT No. 187	0.83	0.00	NA	0.42	0.00
4903522145	BIRCH CREEK UNIT No. 124	0.77	0.00	NA	0.92	0.00
4903522384	COOPERS No. 7-31	0.70	0.00	NA	0.37	0.00
4903520672	FEDERAL No. 30-31	0.35	0.00	NA	0.34	0.00
4903522370	BIRCH CREEK UNIT No. 134	0.46	0.00	NA	0.57	0.00

Table 2.6 – Summary of key parameters in select existing producing gas wells within the MMA that have publicly available gas analyses. Note lack of significant CO₂ (defined as > 2.0 mol%), no H₂S, and minor nitrogen and oxygen. All values reported are in mol%. Historically, helium is not routinely analyzed as it is commonly accepted that there is insufficient helium to be recovered from the shallow sweet gas system. Helium will be measured in BSO's planned baseline data sampling program. Significant increases in CO₂, H₂S and/or helium concentrations will be utilized as a CO₂ leakage detection methodology discussed in later sections. See **Appendix D** for gas analysis laboratory reports for source of data in Table 2.6.

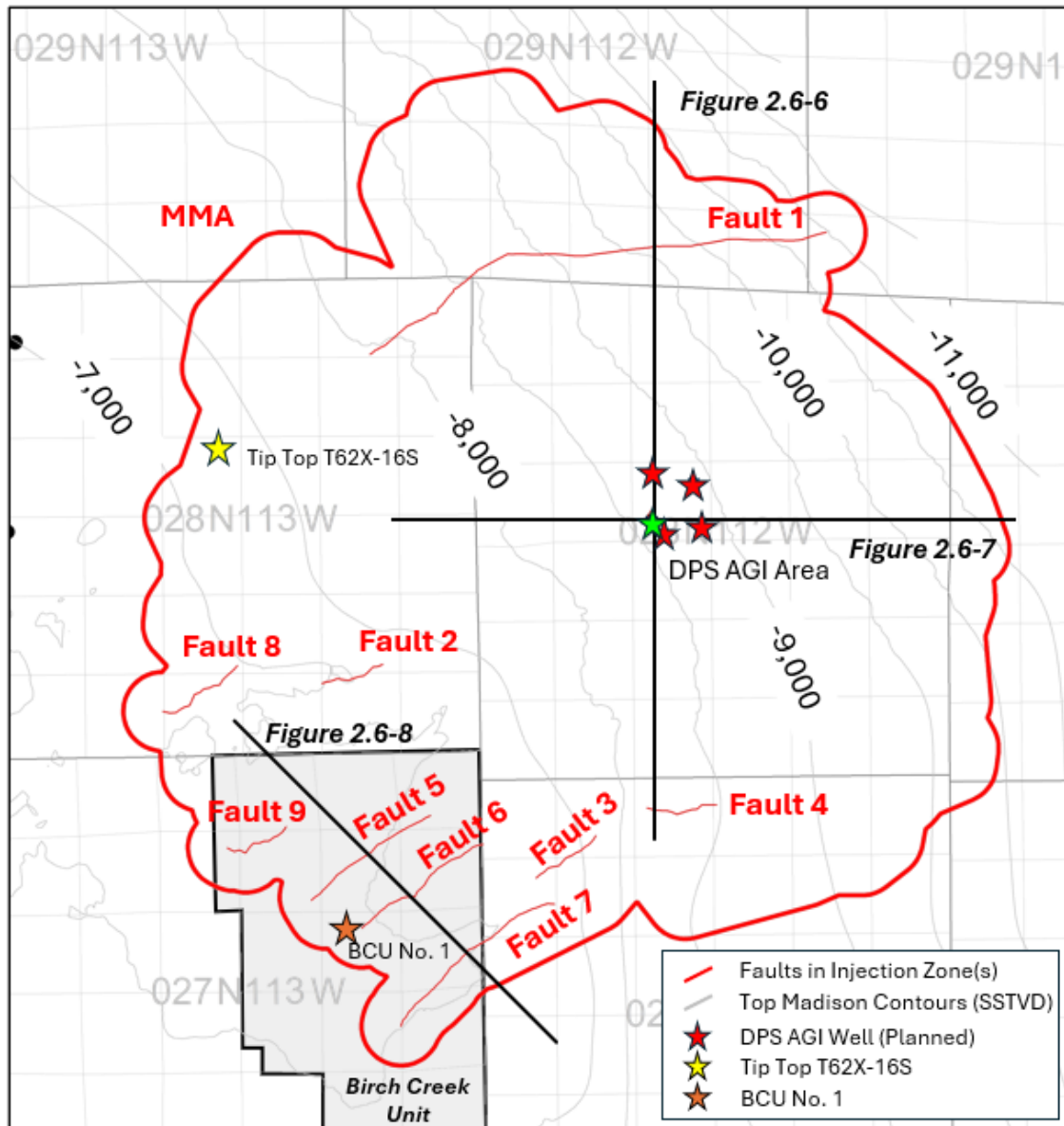


Figure 2.6-5: Madison Structure (TVDSS, 500 ft contour interval) reference map showing N-S (**Figure 2.6-6**) and W-E (**Figure 2.6-7**) seismic lines through the DPS AGI area, including the DPS 12-16 well (green star) and future DPS AGI wells (red stars). Note the fault traces (red lines) of minor faults observed during seismic interpretation. “Fault 1” is displayed on N-S seismic line in **Figure 2.6-6**, and Faults 5, 6 & 7 are displayed on NW-SE seismic-based cross-section line in **Figure 2.6-8**. The Maximum Monitoring Area (“MMA”) is shown as the red polygon. See Section 3.0 for further discussion of the MMA and the Active Monitoring Area (“AMA”). The Tip Top T62X-16S (yellow star) is the only well within the MMA that penetrates the Madison and/or Bighorn injection zones, other than the DPS 12-16 well. Note that the Tip Top T62X-16S well does not intersect the stabilized plume at any point in time (**Figure 2.8-2**). There are numerous existing shallow gas wells in the Birch Creek Unit near Faults 5, 6 and 7 that will potentially be utilized as baseline sampling wells

for early detection of CO₂ leakage along Faults 5, 6 and 7 as potential pathways, including the BCU No. 1 (orange star) which was drilled to the Nugget Formation before being plugged back and completed in the Frontier Formation. It is important to note that no faults are observed at the surface, nor does seismic interpretation suggest that any faults extend to the surface.

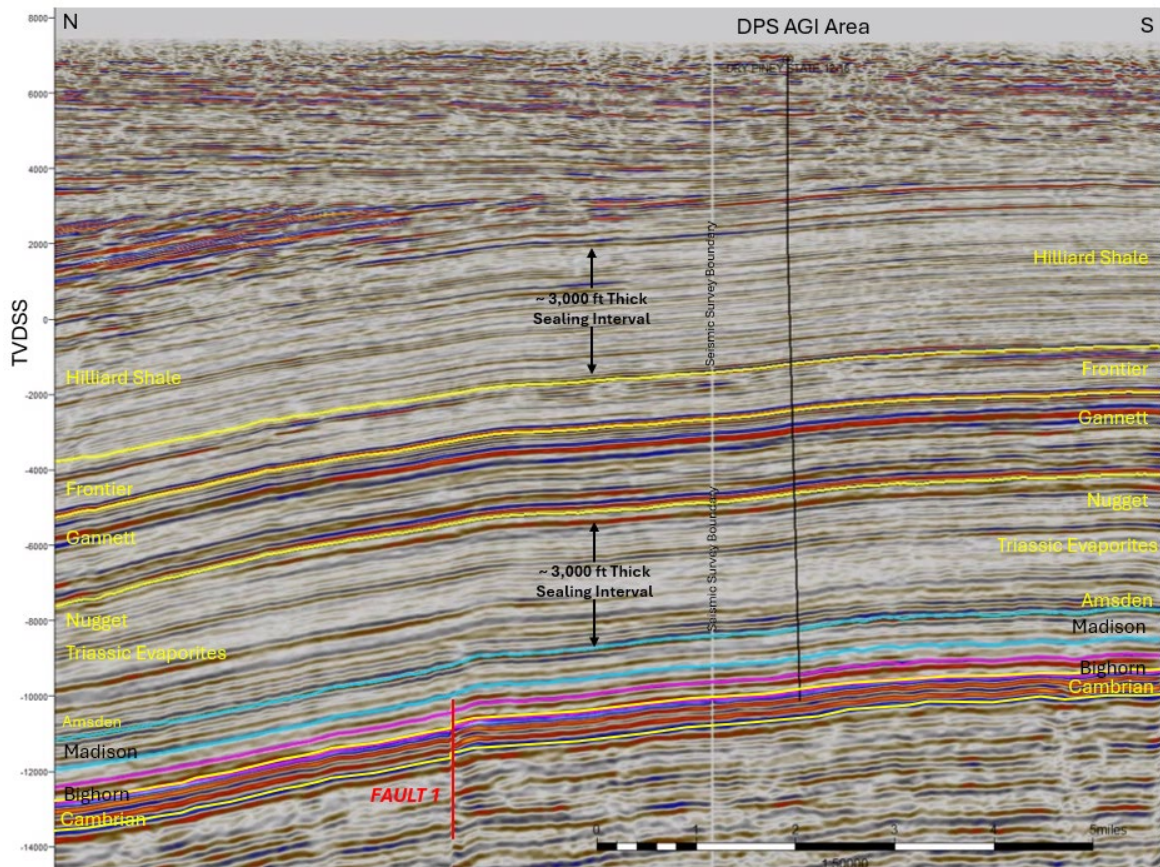


Figure 2.6-6: Seismic line from 3D volume, oriented N to S through the proposed Dry Piney State 12-16 injection well location, shows one minor fault (Fault 1) with minimal vertical offset that dies out before extending above the Madison Formation. Note vertical seam with no data is a boundary between seismic volumes, not a fault. Vertical exaggeration is 2X.

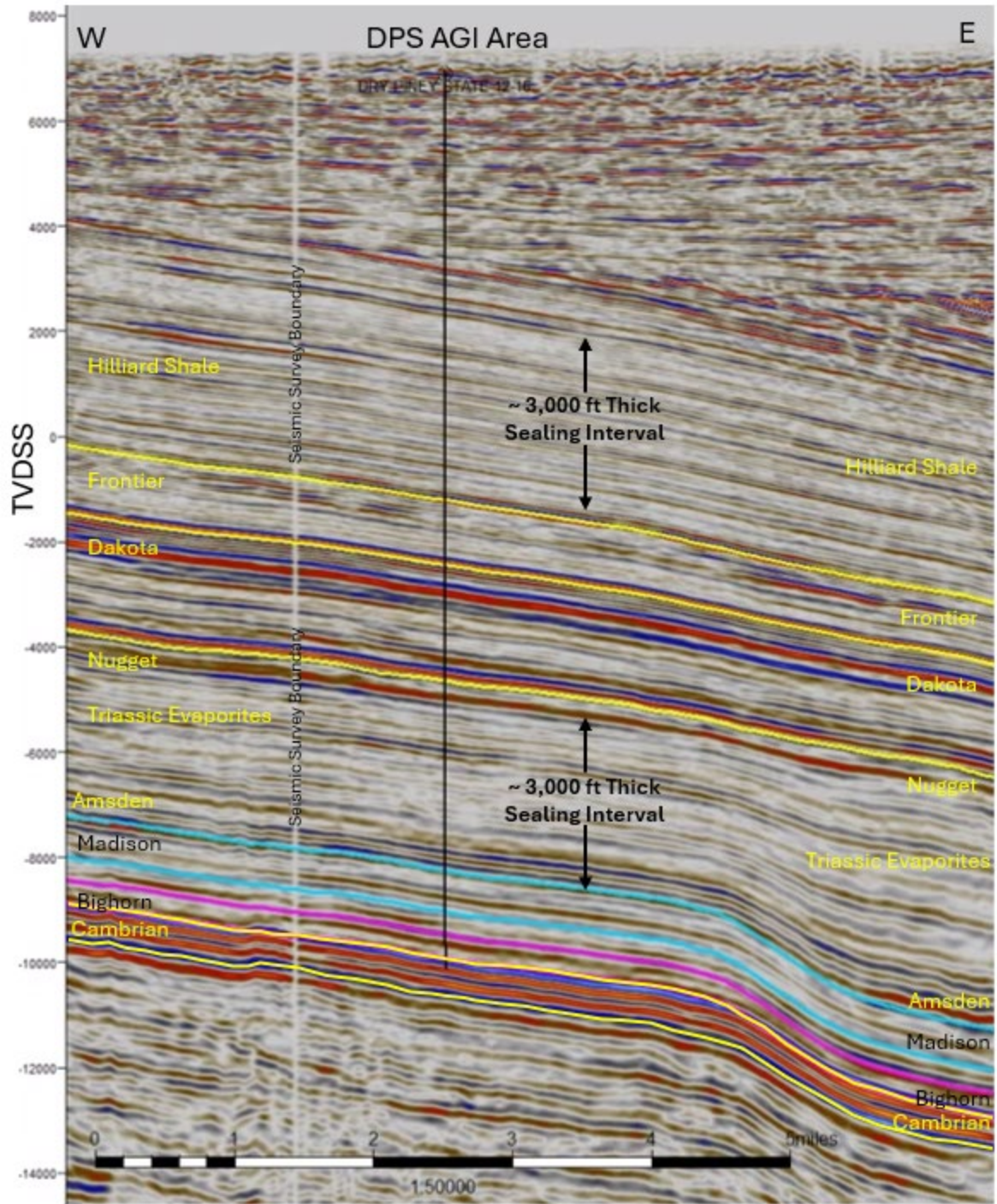


Figure 2.6-7: Seismic line from 3D volume, oriented W to E through the proposed Dry Piney State 12-16 injection well location, shows no faulting. Note vertical seam with no data is a boundary between seismic volumes, not a fault. Vertical exaggeration is 2X.

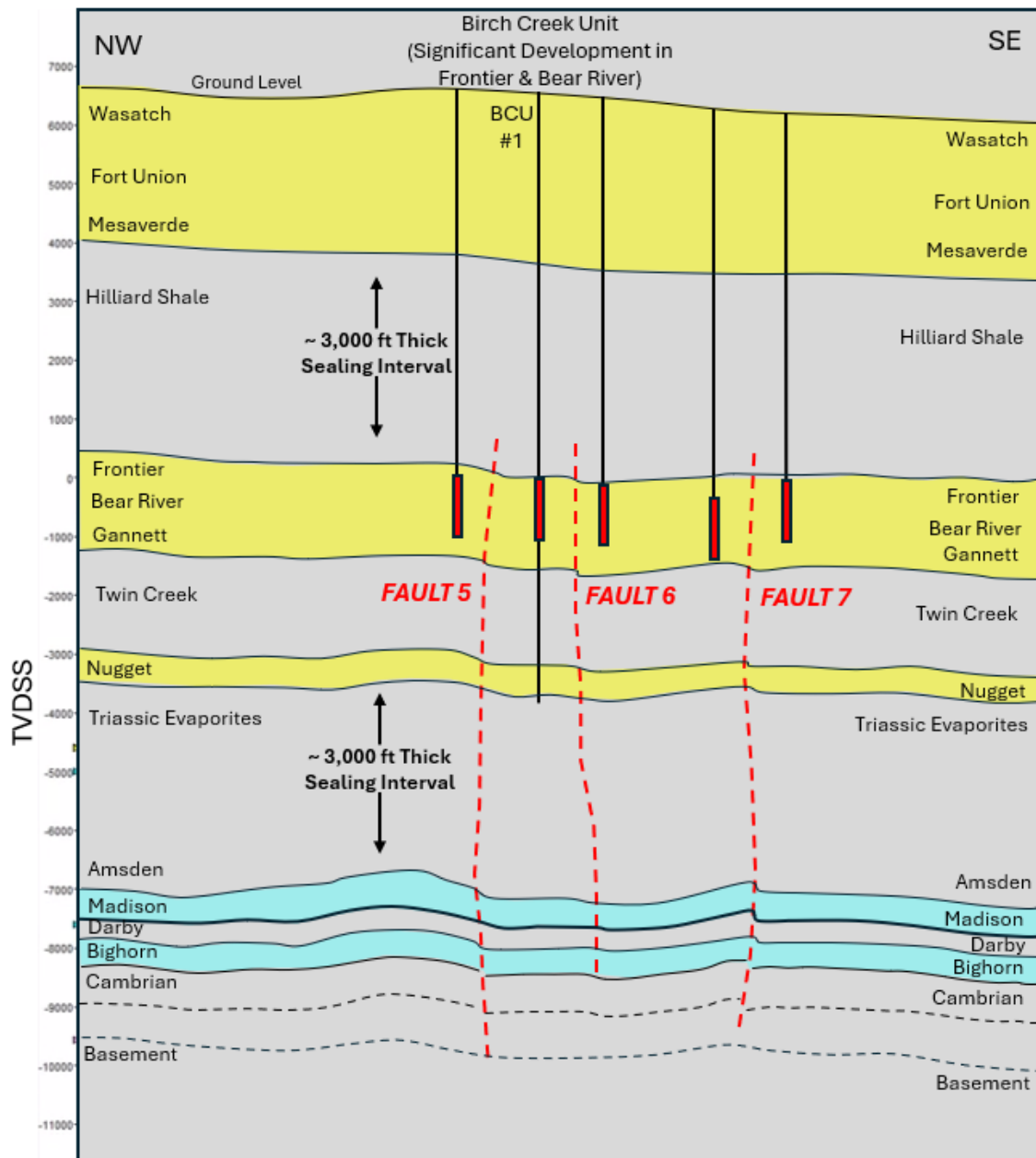


Figure 2.6-8: Cross-section derived from seismic line extracted from a 3D volume, oriented NW to SE perpendicular to Faults 5, 6 and 7 southwest of the DPS AGI area (see **Figure 2.6-5** for reference map). BSO does not have permission to show this seismic data. Vertical black lines and red boxes illustrate BCU wells and approximate completion depths in the Frontier & Bear River interval proximal to Faults 5, 6 & 7. Of particular interest is the BCU #1 well, which was drilled to the Nugget, then plugged back to the Frontier in 1957 and would provide a key baseline data point in terms of gas composition. Note that Faults 5, 6 and 7 die out into the base of the ~ 3,000-foot thick Hilliard (Baxter) Shale confining

zone. *If Faults 5, 6 and 7 were acting as a conduit for CO₂ leakage from the existing naturally-occurring CO₂ and H₂S resource in the Madison and Bighorn, CO₂ and H₂S would be detected in the gas analyses conducted in wells near these faults, and they are not (Table 2.6 and Appendix D). Vertical exaggeration is 2X.*

2.6.4 DESCRIPTION OF OVERLYING & UNDERLYING CONFINING UNITS

The Amsden Formation is the overlying confining interval positioned immediately above the Madison Formation (**Figures 2.2-1 & 2.6-1**). Regionally, the Amsden Formation, including its basal Darwin sandstone member, is typically found to be 300 to 500 feet thick. ExxonMobil performed Mercury Injection Capillary Pressure (“MICP”) tests along with fluid inclusion volatile (“FIV”) analysis in their 2008 Tip Top well (Becker and Lynds, 2012) which indicated the entire Amsden Formation serves as a confining layer for the Madison (**Figure 2.6-9**). The Amsden Formation is present and exhibits similar thickness and log response at the Dry Piney State 12-16 location compared to Madison well penetrations in the LaBarge well field and also ExxonMobil’s AGI disposal wells approximately 45 miles to the south, demonstrating consistency across the entire Moxa Arch. The Amsden is known to be an effective seal in the area as demonstrated by oil and gas trapped in the Madison, indicating permeabilities in the range of 0.001 md or less.

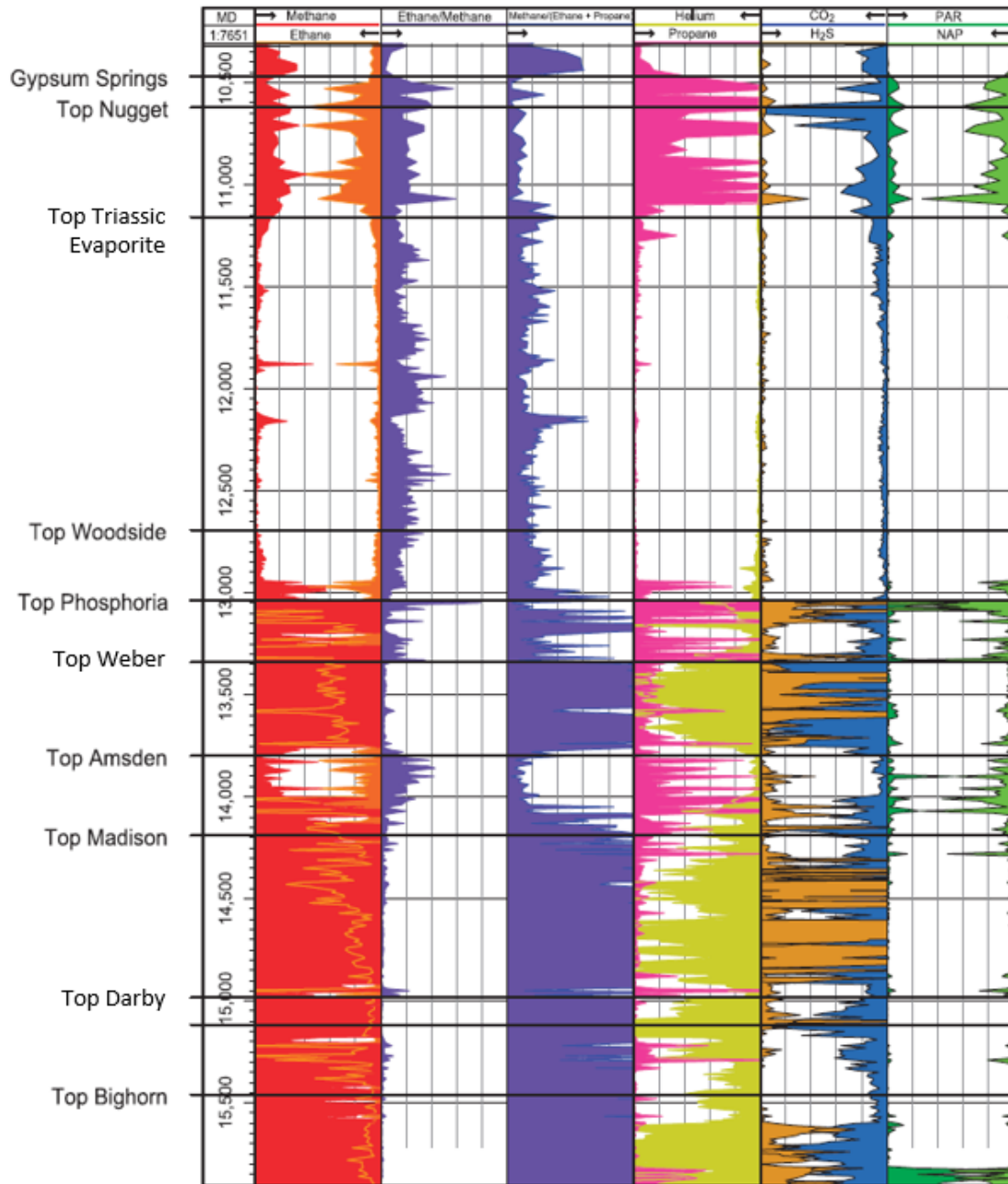


Figure 2.6-9: Modified from Becker & Lynds, 2012. Summary of fluid-inclusion volatile analysis in the Tip Top T62X-16S well located approximately midway between the DPU production area and the DPS AGI area, and the only well that penetrates the injection zones in the MMA. Confining units are identified by intervals where volatile species are absent, such as the Darby, Amsden and Triassic Evaporite intervals. Arrows show the direction of an increase in volatiles species, and depths are in measured depth. METH = methane, ETH = ethane, PROP = propane, PAR = paraffins and NAP = naphthenes.

The Devonian Darby Formation acts as both the underlying confining interval for the Madison Formation and the overlying confining interval to the Bighorn Formation (**Figures 2.2-1 & 2.6-1**). Due to its depth and infrequency of penetration, relatively little is known about the Darby Formation. The 2008 ExxonMobil Tip Top T62X-16S well penetrated the full Darby interval that was observed to be 490 feet thick. Like the confining intervals overlying the Madison Formation, the Darby Formation was devoid of volatile species in FIV data suggesting a seal between the Madison and Bighorn Formations. Additionally, reservoir pressure data obtained by ExxonMobil in the Tip Top T62X-16S well indicates that the Madison and Bighorn reservoirs are separate and distinct due to the apparent original reservoir pressure in the Bighorn Formation and the apparent reduced reservoir pressure in the Madison Formation due to structurally up dip production over the last approximately 40 years (Becker and Lynds, 2012). The average porosity of the Darby is calculated to be approximately 4% and is 302 feet thick at the Dry Piney State 12-16 location. Reservoir pressure data obtained during wireline logging at the Dry Piney State 12-16 indicates the Darby is the confining interval to the Bighorn. Differing gas compositions between the Madison and Bighorn observed in fluid samples collected via wireline logging in the Dry Piney State 12-16 corroborates separation of the two injection zones. The ability of the Darby to form an effective seal between the Madison and Bighorn suggests permeabilities on the order of 0.001 md or less.

The lower confining layer to the Bighorn Dolomite is the Cambrian interval (**Figures 2.2-1 & 2.6-1**), including the low porosity Gallatin Limestone, the Gros Ventre Shale and shales within the Flathead Sandstone. Very few penetrations into the Cambrian strata across Wyoming exist. The Cambrian is at least 131' thick in the Dry Piney State 12-16 and the USGS reports porosity ranging from 2 to 8% and permeabilities of <0.01 md, often in the nanodarcy range.

In addition to the confining units immediately adjacent to and overlying or underlying the Madison and Bighorn injection zones, the Triassic Evaporites interval is an approximately 1,800-foot thick sequence comprised of shales and salt-rich sediments that creates an ideal seal for the broader "sour gas system" as discussed in numerous previous sections, including **Section 2.2** which discusses stratigraphy of the Greater Green River Basin. Combined with the shales of the Woodside, Dinwoody and Ankareh formations, the Triassic Evaporites confining zone is nearly 3,000 feet thick. Further, above the shallow sweet gas productive intervals, namely the Frontier and Bear River Formations, is another confining unit comprised by the approximately 3,000-foot-thick Hilliard (Baxter) Shale that acts as the seal for hydrocarbons in the region. The Hilliard Shale is a thick succession of low permeability mudrocks deposited during the late Cretaceous period and is associated with the maximum extent of the Western Interior Seaway.

2.7 DESCRIPTION OF THE INJECTION PROCESS

The purpose of the AGI process is to take the CO₂ and H₂S removed from the produced raw gas at DPJGPF and permanently sequester it into the Madison and Bighorn Formations. Production of raw gas will be from the Madison Formation only in the DPU production area. Injection and sequestration of CO₂ and H₂S is planned to target the Madison Formation in four proposed wells and the Bighorn Formation in the drilled but uncompleted Dry Piney State 12-16 (Figure 2.7-1).

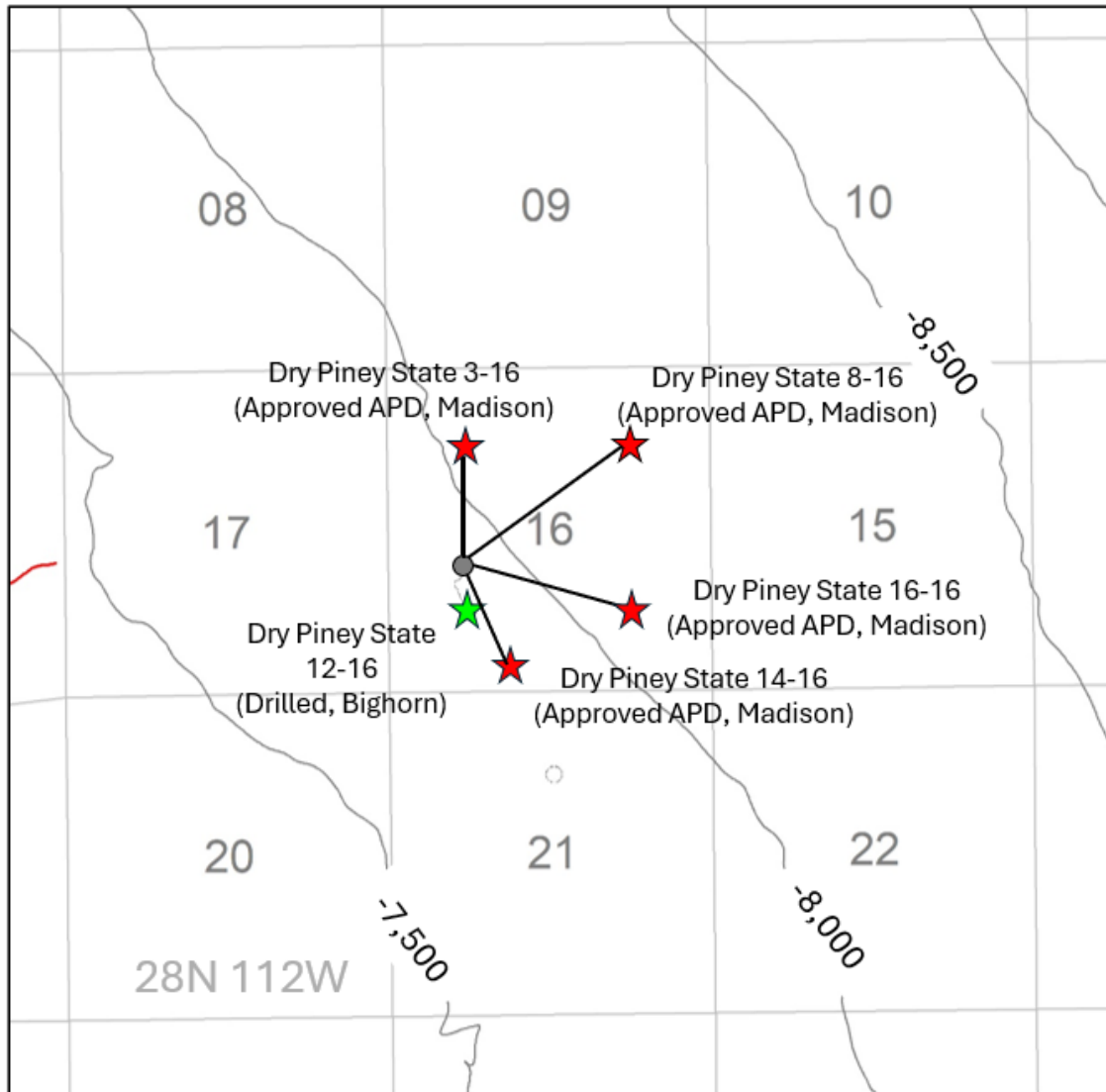


Figure 2.7-1: Map showing the existing drilled (but not completed) Dry Piney State 12-16 well and the future DPS AGI wells. Dry Piney State 12-16 will inject into the Bighorn, while the four future injection wells are anticipated to target the Madison for injection. Contours are top Madison structure (SSTVD, 500 ft contour interval).

It is not feasible to inject into both the Madison and Bighorn Formations in the same well due to differing reservoir pressures. Based on reservoir pressure data obtained while drilling the Dry Piney State 12-16 well, the Madison Formation was observed to have an average reservoir pressure of 6,686 pounds per square inch (psi), which is more than 500 psi less than the Bighorn Formation average of 7,206 psi. Unless the well is configured with a dual completion, it is assumed all injected volumes will enter the Madison due to its lower reservoir pressure. A dual completion would require reduced tubing and casing diameters which would materially limit injection rates. Based on gas compositional analysis of fluid samples taken in the Dry Piney State 12-16 well, the Madison and Bighorn Formations have uneconomic quantities of CH₄ (< 5%) and He (< 0.25%) at the downdip location of the AGI area near the GWC. The CO₂ concentration at the DPS AGI location is approximately 89% in the Madison and approximately 95% in the Bighorn Formation. Both formations also contain over 1.5% H₂S, confirming the extent of the naturally-occurring sour gas system that already exists in the AGI area. As such, injection into the Madison and Bighorn Formations is not expected to contaminate potential production at the AGI area. Because the injected gas composition is expected to be 92.4% CO₂, 6.93% H₂S and 0.5% methane, the injected gas is anticipated to be denser than the less CO₂-rich gas up structural dip to the west in the production area (**Figure 2.7-2**). Therefore, measurable quantities of injected gas are not forecasted to “break-through” or contaminate production in the DPU area, structurally up dip and 10.5 miles to the west, during the 50-year production life of the project. This is demonstrated through the dynamic reservoir simulation modeling and can be noted on **Figure 3.1-1** which shows an outline of the plume extent of injected volumes after 50 years.

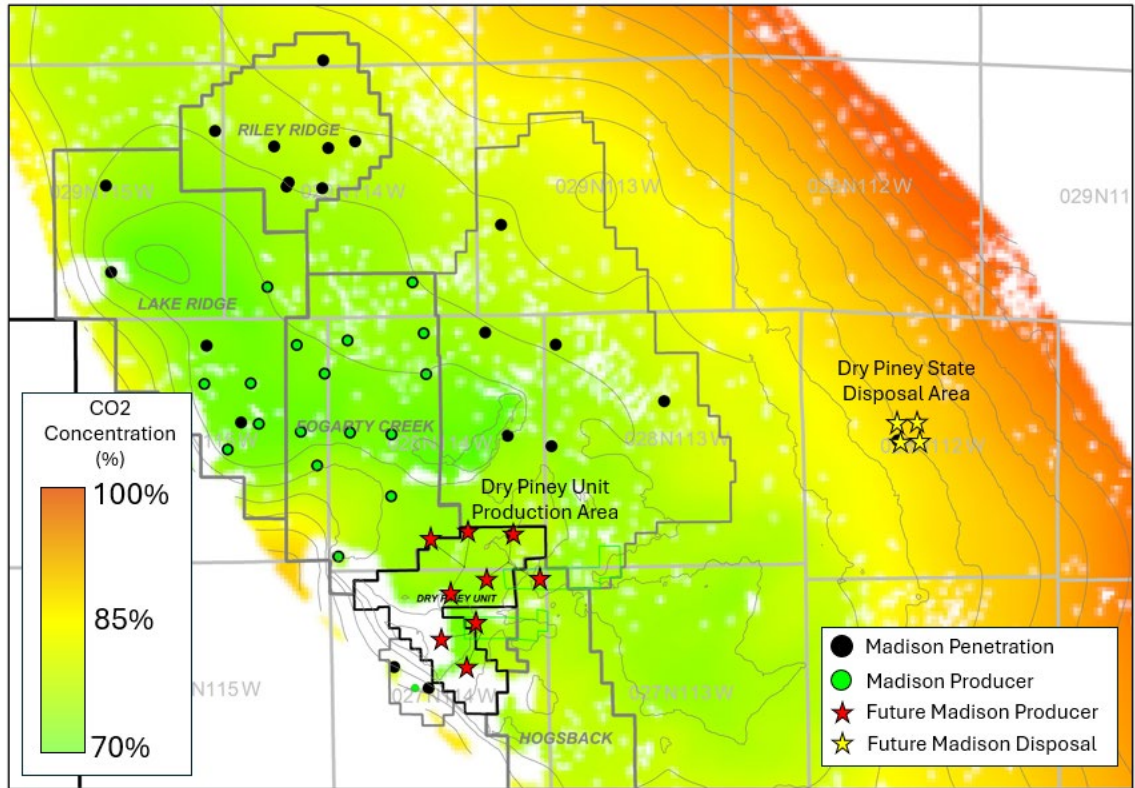


Figure 2.7-2: Regional map showing existing (pre-injection) in-situ CO₂ concentration (%) across the LaBarge Field in the upper Madison. Note the lower CO₂ concentration (<70%) in the Dry Piney Unit production area compared to the higher initial in-situ CO₂ concentration (> 89%) in the Dry Piney State injection area due to gravity segregation over geologic time. It is important to reemphasize that BSO will be injecting into a zone that already has a naturally occurring in-situ CO₂ concentration over 89% BEFORE injection begins.

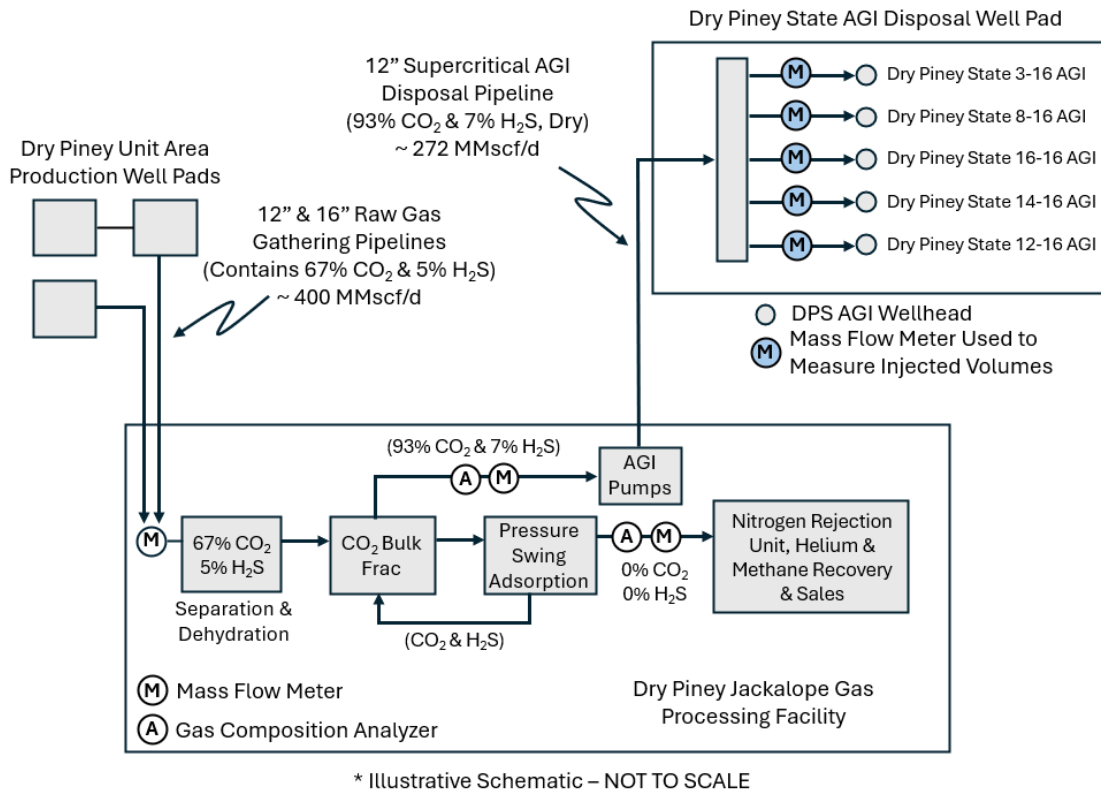


Figure 2.7-3: Schematic Diagram (NOT TO SCALE) showing CO₂ flow path from production well pads in Dry Piney Unit Area through Dry Piney Jackalope Gas Processing Facility to permanent sequestration in the Dry Piney State AGI wells. Note that the produced raw gas stream contains approximately 67% CO₂ and 5% H₂S. After initial plant inlet separation and dehydration, the CO₂ and H₂S components are removed from the raw gas stream through CO₂ Bulk Fractionation and Pressure Swing Adsorption processes and pumped to the Dry Piney State AGI Disposal wells for sequestration. Gas composition analyzers and mass flow meters will verify gas composition and the volume of CO₂ after the CO₂ Bulk Fractionation and Pressure Swing Adsorption processes. The combined CO₂ and H₂S waste gas stream will be pumped in a supercritical state via pipeline to the Dry Piney State AGI wells, with an expected gas composition of approximately 93% CO₂ and 7% H₂S. Note that a gas composition analyzer will be used to verify that all CO₂ and H₂S have been separated and captured by the Bulk Fractionation and Pressure Swing Adsorption processes (that is, 0% CO₂ or H₂S enters the downstream Nitrogen Rejection Unit before advancing to Helium and Methane recovery processes and sales points). Once at the Dry Piney State AGI well pad, the individual CO₂ and H₂S streams will be metered immediately before each well head to account for actual volumes injected and sequestered, and the CO₂ component will be calculated based on the gas composition.

The AGI system transports the dense-phase supercritical acid gas stripped from the bulk fractionation process under pressure through a pipeline to the five-well Dry Piney State

AGI area (**Figures 2.6-2 and 2.7-1**). See **Figure 2.7-3** for a process flow diagram that identifies the CO₂ flow path from the inlet of the DPJGPF to the AGI wells and the associated meter locations that will be used for Subpart RR reporting. The five AGI wells will inject acid gas into the Madison or Bighorn Formations, which are geologically suitable for permanent storage and sequestration of the acid gas. The AGI system will consist of a series of process and injection pumps to increase the mid-pressure liquid from the bulk fractionation at the DPJGPF to the well injection pressure. Free water will not be present in any part of the pipeline system, removing the threat of internal corrosion.

The AGI pipeline will be constructed, tested, and maintained in accordance with the latest industry standards and codes. The high-pressure AGI pipeline will be constructed of carbon steel and will be approximately 11.13 miles in length. The AGI area is approximately 10.5 miles northeast of the DPU production area, but the pipeline length is longer due to the selected route versus “as the crow flies.” The AGI pipeline will be outfitted with the necessary instrumentation and hardware to monitor operation from a control room and to detect leaks. Shutdown valves will be installed on the pipeline system to safely isolate the pipeline during a leak or under other possible emergency conditions.

The total depth (“TD”) of each AGI well will range from 16,600 feet (Bighorn) to 15,750 feet (Madison) TVD depending on whether the Madison or Bighorn Formation is targeted. Measured depths will be higher than the TVD depth range and depends on the directional plan for each specific well with higher deviations resulting in higher measured depths.

While planning the drilling of the AGI wells, BSO worked with a reputable service company who provided a range of fracture gradients for the formations comprising the deep sour helium petroleum system including the Triassic Evaporite interval (Ankareh, Thaynes and Woodside Formations), Phosphoria, Amsden, Madison, Darby, Bighorn and Cambrian Formations in the area. Fracture gradient and overburden for the AGI wells were estimated based on offset well data. Shear and compressional sonic data combined with density data from existing offset wells was analyzed and yielded an estimated overburden pressure of 1.0 psi/ft. Based on a frac gradient of 0.87 pounds per square inch (psi)/ft for the Triassic Evaporite interval, 0.87 psi/ft for the Phosphoria, 0.87 psi/ft for the Amsden, 0.857 psi/ft for the Madison, 0.92 psi/ft for the Darby, 0.862 psi/ft for the Bighorn, and 0.92 psi/ft for the Cambrian, BSO does not anticipate reaching or exceeding fracture pressures during injection operations for any Formations.

With a downhole fracture pressure of 12,698 psi in the Madison Formation (based on top of perforation TVD of 14,823 ft) which corresponds to a surface injection pressure of approximately 6,265 psi, the injected acid gas will likely not initiate fractures in the Madison Formation and therefore not create fractures out of zone into the overlying or underlying confining units. Facility controls exist that limit surface injection pressures to below 5,400 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture initiation is minimal. The Madison Formation is

anticipated to be encountered in a narrow TVD depth range in the Dry Piney State injection area, with the Dry Piney State 12-16 being the shallowest and the Dry Piney State 1-16 being the deepest at approximately 200 ft TVD deeper. Therefore, fracture pressures will be very similar amongst the five disposal wells and will range from approximately 12,698 psi to 12,875 psi.

With a downhole fracture pressure of 13,843 psi in the Bighorn Formation (based on top of perforation TVD of 16,066 ft) which corresponds to a surface injection pressure of approximately 6,871 psi, the injected acid gas will not initiate fractures in the Bighorn Formation and, therefore, will likely not create fractures out of zone into the overlying or underlying confining units. Facility controls exist that limit surface injection pressures to below 5,400 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture initiation is minimal. The DPS 12-16 will likely be the only Bighorn Formation injection well in the Dry Piney State injection area.

With the Bighorn fracture pressure of 13,843 psi, the overlying Darby Formation will maintain its sealing ability without induced fractures from injection into the Bighorn with a higher fracture gradient (relative to the Bighorn) of 0.92 psi/ft fracture gradient and a corresponding 14,401 fracture pressure calculated at its top (approximately 15,685 ft MD / 15,653 ft TVD).

The projected facility maximum surface pressure of 5,400 psi corresponds to downhole fracture pressures of 11,920 psi and 12,193 psi for the Madison and Bighorn Formations, respectively. Both are below the pressure required to fracture the formation; therefore, the probability of inducing fractures is minimal, which in turn will reduce the risk of leakage of CO₂ along various subsurface leakage pathways that will be discussed in later sections.

2.8 PLANNED INJECTION VOLUMES

Figure 2.8-1 is a long-term injection forecast through the life of the acid gas injection project, anticipated to be 50 years in length, showing total injection of 5.25 TCF. It is important to note that this is just a forecast – actual injection volumes will be collected, calculated, and reported as required by Subpart RR. Additionally, the volumes provided in **Figure 2.8-1** are the total amount of gas to be injected, not just the CO₂ portion which is expected to represent approximately 92.4% of the waste gas stream. BSO forecasts the total volume of CO₂ stored over the modeled injection period to be approximately 4.87 TCF (257.6 million metric tons).

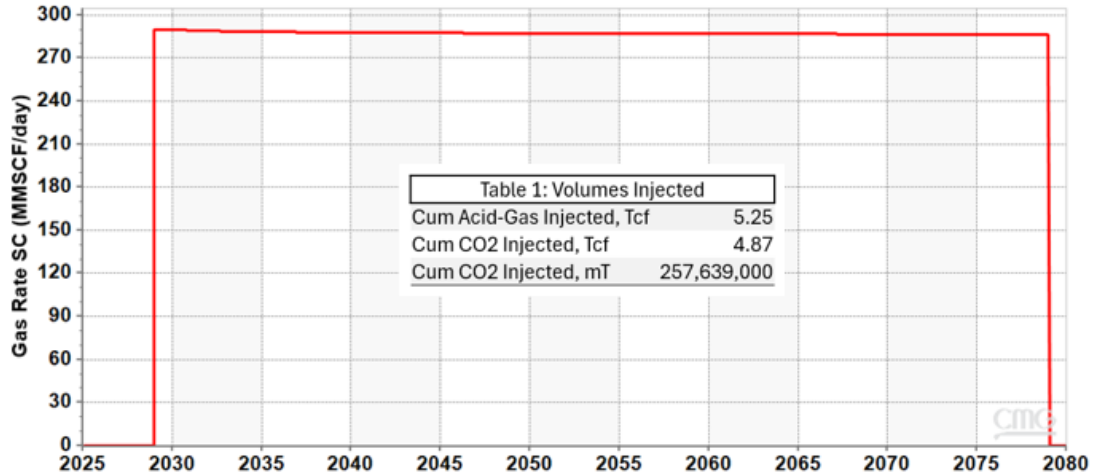


Figure 2.8-1: Long term injection forecast showing waste gas (combined CO₂ & H₂S) volume of 5.25 TCF to be injected into all five BSO injection wells throughout the life of the 50-year project. The CO₂-only volume is 4.87 TCF (257.6 million metric tons).

Figure 2.8-2 captures the evolution of the acid gas plume for the DPS AGI wells at various time intervals after initiation of injection in 2028: 5, 10, 20, 30, 40, 50 and 100 years. The maximum extent of the plume is estimated to span approximately 50,000 feet (about 9.5 miles) and occurs after a 50-year injection period and a 50-year shut-in period in year 2128, at which time the plume achieves stabilization. Interestingly, the entire 50-year plume (2078) appears to migrate up geologic structure to the southwest, after pressure from active injection ceases and the plume is no longer forced down structural dip by the injection pressure. The plume expands modestly after 50 years of injection (2078) and achieves stabilization after moving up structural dip after 50 years of shut-in, in year 2128.

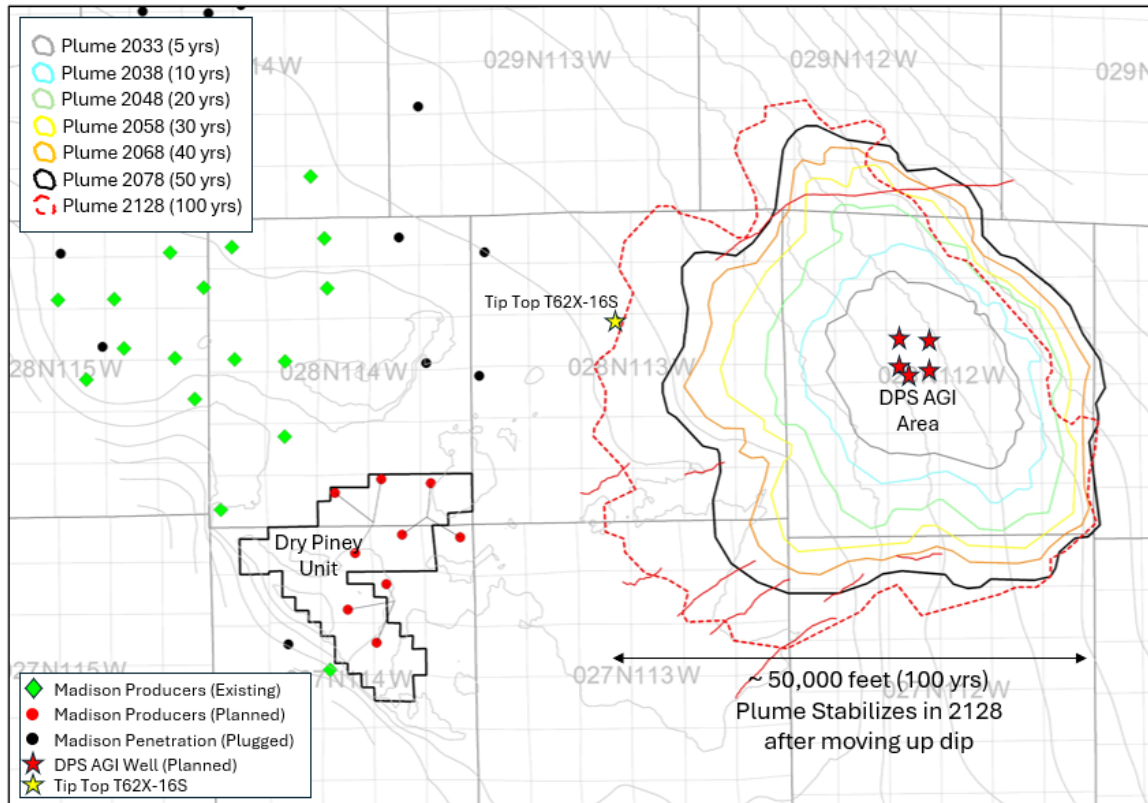


Figure 2.8-2: Spatial extent of the acid gas free-phase CO₂ plume (> 0.5% net incremental CO₂ above naturally occurring in-situ CO₂) at years 2033, 2038, 2048, 2058, 2068, 2078 and the stabilized plume at 2128. After 50 years of injection, followed by a 50-year shut-in period (stabilization), the plume spans a diameter of approximately 50,000 feet (year 2128, red-dashed polygon). Note that although the plume migrates up structural dip during the stabilization period, at no point in time does the plume reach existing wells producing from the Madison, future well locations planned to produce from the Madison, nor existing wells that have penetrated the Madison Formation.

3.0 DELINEATION OF MONITORING AREA

3.1 MAXIMUM MONITORING AREA (MMA)

Per 40 CFR 98.449, the MMA is defined as equal to or greater than the area expected to contain the free-phase CO₂ plume until the CO₂ plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from all wells with available data, seismic data, and historic production and injection data from ExxonMobil LaBarge field operations, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time. According to the reservoir modeling results, after 50 years of post-injection monitoring (year = 2128), the injected gas will remain in the reservoir, and no expansion of the free-phase CO₂ plume is observed after that point in time (**Figure 3.1-1**). The model

was run through 2578 to assess the potential for expansion of the plume after acid gas injection ceases. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. Expansion of the plume to a diameter of approximately 50,000 ft (9.5 miles) occurs by the year 2128 as the gas plume stabilizes due to gravity segregation and dispersion. At this point, the rate of movement of the free-phase CO₂ plume (incremental injected CO₂ volume) has essentially ceased, demonstrating plume stability.

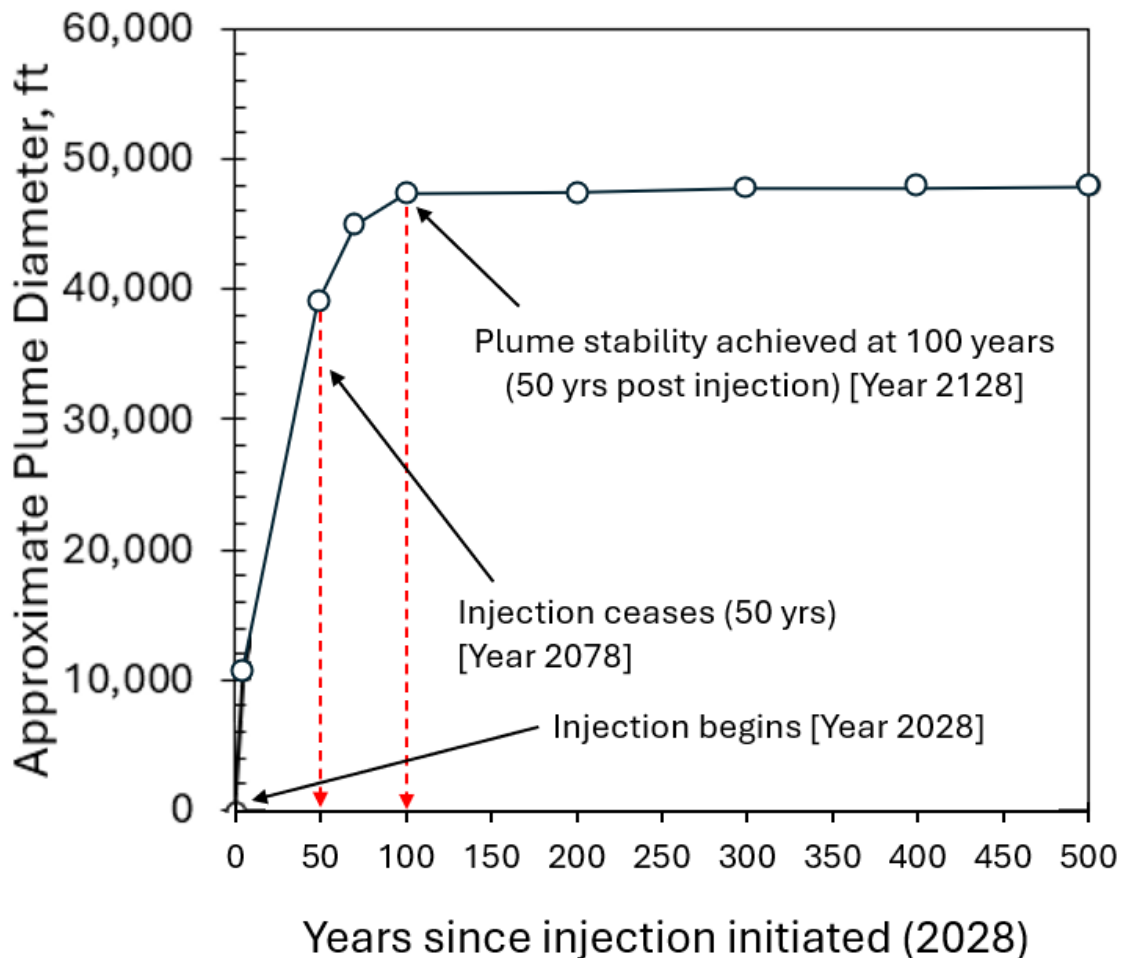


Figure 3.1-1: Plot showing predicted approximate maximum plume diameter over time through injection phase (first 50 years) and out to 500 years (450 years post-injection). Note that at approximately 100 years (50 years post-injection) the plume stabilizes at approximately 50,000 feet in diameter as shown in **Figure 3.1-2**.

Reservoir modeling indicates that during the 50-year post-injection stabilization period, a modest amount of migration up-dip occurs because injection pressure is no longer forcing the plume down structural dip. As the plume expands slightly in the absence of injection pressure, the plume shifts up structural dip to the southwest. As such, and to ensure the delineation of the maximum extents of the plume, BSO took the conservative approach

to use the union of the 50-year plume boundary and the 100-year plume boundary to capture the maximum (“max”) plume extent as depicted in **Figure 3.1-2**, even though modeling suggests any free-phase CO₂ will evacuate from the western extent of the 50-year plume outline. This combined plume extent, defined by the 50-year plume outline plus the 100-year stabilized plume outline (2128) plus a one-half mile buffer is used to define an MMA (**Figure 3.1-2**).

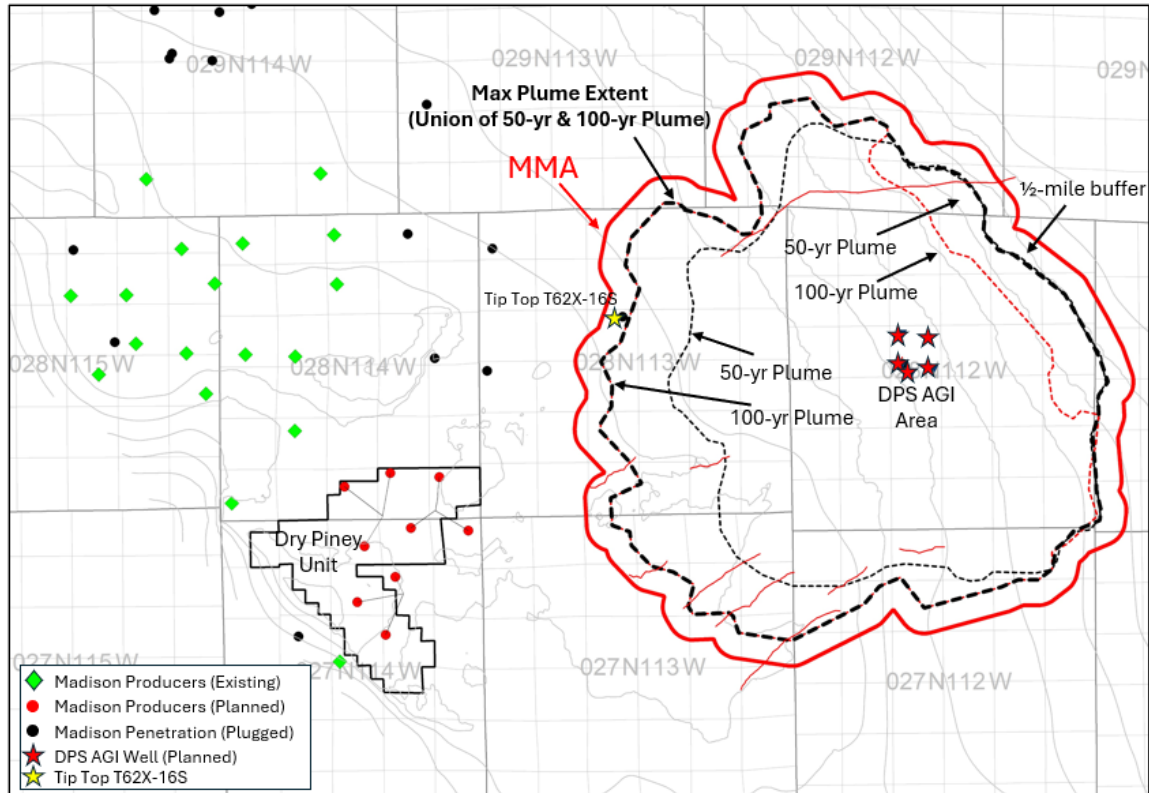


Figure 3.1-2: Area covered by the maximum extents of the combined stabilized plume at year 2128 as well as the area to the west that was occupied by the plume at 50 years of injection (2078) before migrating up structural dip to the west during the plume stabilization period. The bold, black-dashed line represents the combined maximum extent of the plume area, while the solid red polygon represents the maximum plume extent plus an all-around one-half mile buffer to define the MMA.

In addition, according to EPA regulation, “the buffer is intended to encompass leaks that might migrate laterally as they move towards the surface. EPA has determined that the buffer zone of at least one-half mile will have an acceptable probability of encountering leaks in many circumstances.”

Therefore, BSO considered identified faults extending beyond the stabilized plume (plus a one-half mile buffer) to define an extended MMA (**Figure 3.1-3**). The extended MMA comprises the union of two areas: the area covered by the initial MMA plus a one-half

mile buffer and the area covered by the fault traces extending beyond the stabilized plume plus a one-half mile buffer (**Figure 3.1-3**) as the faults represent known potential leakage pathways. **Figure 3.1-4** shows the final MMA in a red polygon, as defined by 40 CFR 98.449 of Subpart RR.

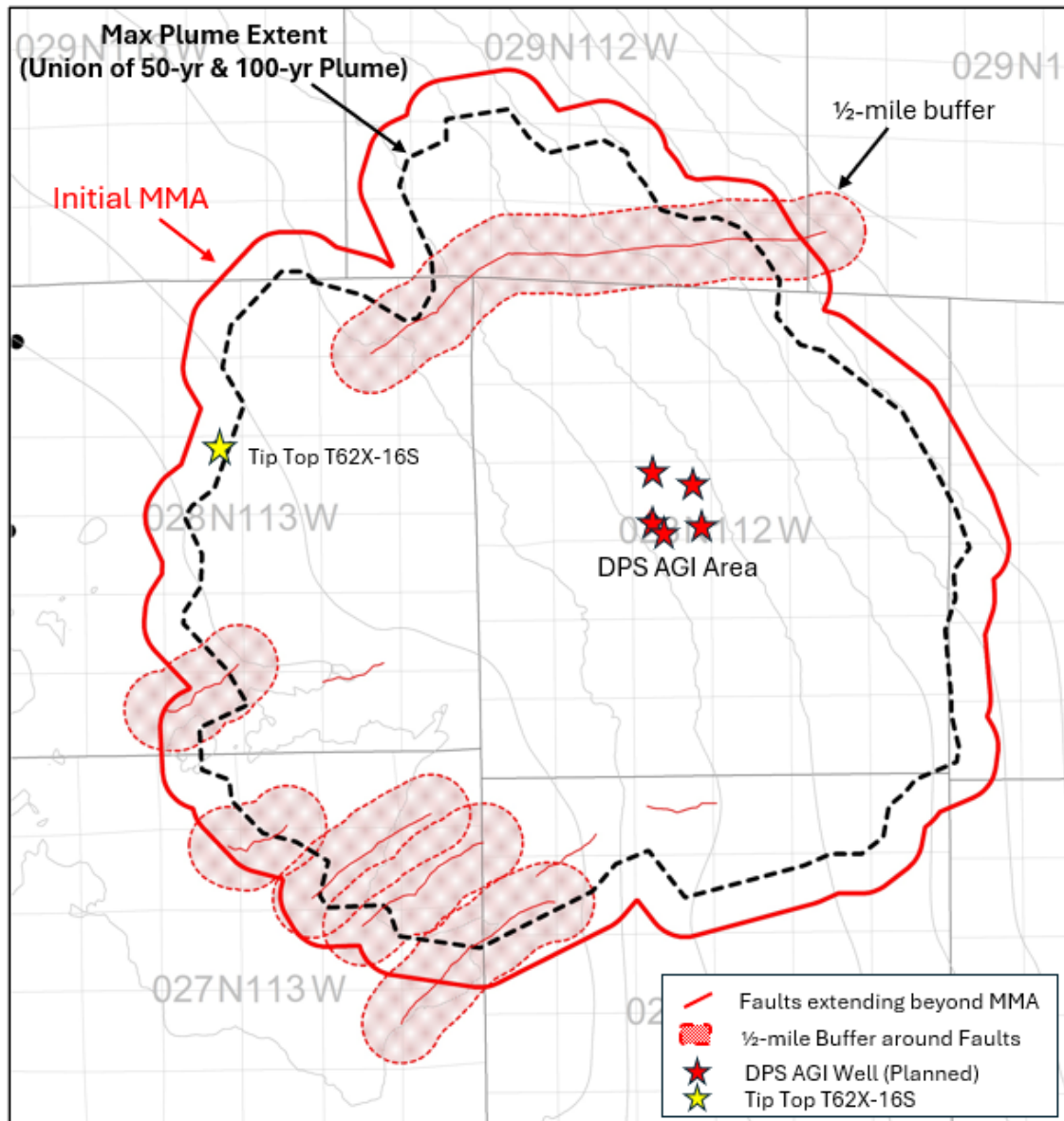


Figure 3.1-3: Map showing initial MMA (red polygon) with 1/2-mile buffer around faults extending beyond maximum plume extent after stabilization (black dashed line).

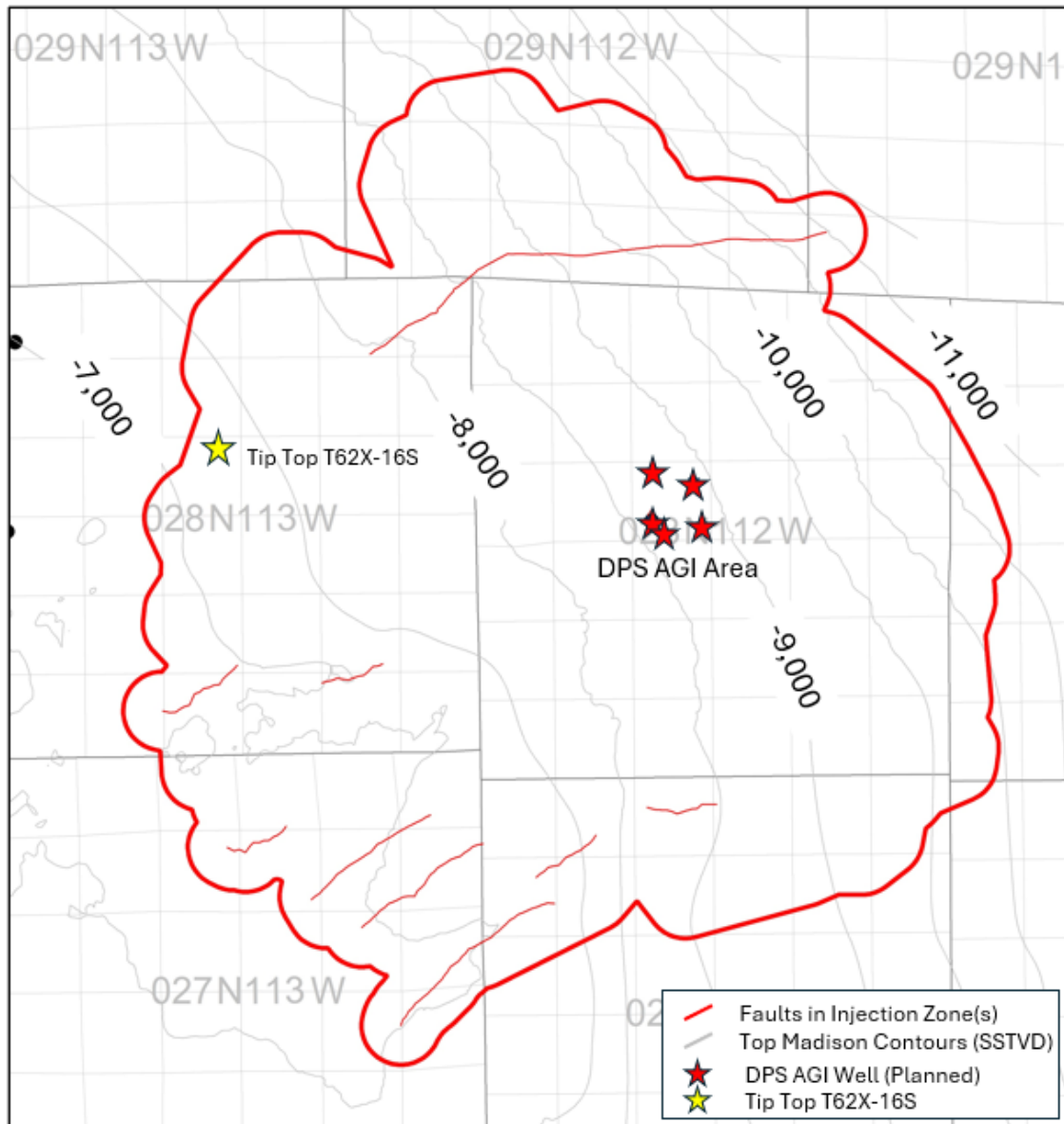


Figure 3.1-4: Map showing the extended, final MMA proposed by BSO to fully encompass the maximum extents of modeled plume plus an all-around ½-mile buffer, as well as an additional ½-mile buffer around any known potential leakage pathways (in this case faults that extend beyond the maximum plume extent). Final MMA is bold red polygon. The Tip Top T62X-16S is the only existing, non-DPS AGI well within the MMA that penetrates the Triassic Evaporite confining unit and injection zones (yellow star).

Because the Dry Piney State AGI area has an in-situ pre-injection CO₂ composition of greater than 89% in the Madison and greater than 95% in the Bighorn, as evidenced by gas composition analysis conducted on reservoir fluid samples obtained in the Dry Piney State 12-16 well, BSO delineated the “free-phase” CO₂ plume where a “net incremental CO₂ gas saturation” is greater than 0.5%. Calculation of the volume-weighted average gas

saturation at various time steps was used to determine the acid gas plume area, with the “free-phase” plume boundary defined as the area with an increase in net incremental CO₂ gas saturation of greater than 0.5% (absolute) above in-situ concentrations resulting from injected volumes. An incremental change in gas saturation of 0.5% is well below the lowest gas saturation that can be confidently detected by formation evaluation methods in reservoirs with rock properties such as those found in the Madison Formation.

3.2 ACTIVE MONITORING AREA (AMA)

As defined in 40 CFR 98.449 of Subpart RR, the AMA is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the AMA is established by superimposing two areas:

- Area 1: The area projected to contain the free-phase CO₂ plume at the end of year t, plus and all-around buffer of one-half mile if known leakage pathways extend laterally more than one-half mile.
- Area 2: The area projected to contain the free-phase CO₂ plume at the end of year t + 5.

BSO has chosen t = 2128, which corresponds to a 50-year injection period plus a 50-year post-injection period during which the plume stabilizes, for the purpose of calculating an AMA. The plume at t = 2128 is the black-dashed polygon in **Figure 3.1-3**, and the plume at year t plus and all-around buffer of one-half mile including known leakage pathways is the red polygon in **Figure 3.1-4**.

The area defined by Area 1 above is plotted and delineated by the red polygon in **Figure 3.1-4** and is coincident with the MMA. It is greater than the area projected to contain the free-phase CO₂ plume at the end of year t = 2128, plus an all-around buffer zone of one-half mile, because it encompasses the identified leakage pathways in **Figure 3.1-2**.

The area defined by Area 2 above is plotted in **Figure 3.1-3** and corresponds to the black-dashed line (plume at t + 5 = 2133). According to the superimposition of Areas 1 and 2, the AMA will be coincident with the MMA which is the area delineated by the red polygon in **Figure 3.1-3** and **Figure 3.1-4**.

After applying the criteria defined by Subpart RR, BSO believes it is appropriate to establish an AMA that is the same size as the MMA. The evaluation with t = 2128 demonstrates that the AMA is contained within the MMA, and therefore, BSO considers the AMA equal to the MMA.

4.0 IDENTIFICATION AND EVALUATION OF PATHWAYS FOR LEAKAGE TO THE SURFACE

Subpart RR at 40 CFR 448(a)(2) requires the identification of potential surface leakage pathways and the evaluation of the likelihood, magnitude and timing of surface leakage of CO₂ through

these pathways. BSO has identified and evaluated the potential CO₂ leakage pathways to the surface.

An evaluation of each of the potential leakage pathways is described in the following paragraphs:

- Risk of leakage from surface equipment;
- Risk of leakage through existing wells;
- Risk of leakage through the confining units;
- Risk of leakage through faults and fractures;
- Risk of leakage through due to lateral migration;
- Risk of leakage due to seismicity.

Risk estimates for the potential leakage pathways were made using a 5x5 risk matrix (**Figure 4.1-1**) to evaluate leakage likelihood and magnitude.

		Magnitude 				
		Insignificant 1	Minor 2	Significant 3	Major 4	Severe 5
 Likelihood	Almost certain 5	Medium 5	High 10	Very high 15	Extreme 20	Extreme 25
	Likely 4	Medium 4	Medium 8	High 12	Very high 16	Extreme 20
	Moderate 3	Low 3	Medium 6	Medium 9	High 12	Very high 15
	Unlikely 2	Very Low 2	Low 4	Medium 6	Medium 8	High 10
	Very Unlikely 1	Very Low 1	Very Low 2	Low 3	Medium 4	Medium 5

Figure 4.1-1: 5x5 risk matrix used to quantify collective risk based on Likelihood and Magnitude.

As will be demonstrated in the following sections, risk of leakage likely to result in loss of CO₂ to the atmosphere from the potential leakage pathways outlined above is "very low". Further, given the relatively high concentration of H₂S in the AGI injection stream, any leakage through identified or unexpected leakage pathways would be immediately detected by instrumentation (with alarms and shutdowns) in many cases, with associated actions pursued to address any leakage, thereby minimizing the amount of CO₂ released to the atmosphere.

4.1 POTENTIAL LEAKAGE FROM SURFACE EQUIPMENT

Potential leakage from surface equipment will likely be de minimis due to the design of the AGI facilities. The facilities were designed to minimize leak points such as valves and flanges and use welded connections where possible instead. The only surface equipment located between the mass flow meter and the wellhead are valves, transmitters, and

flanged connection points on the pipelines, and the equipment will not be configured to blow down or vent between the mass flow meter used for calculating injected CO₂ and the wellhead. Due to the presence of H₂S in the AGI injection stream at a concentration of approximately 7% (70,000 parts per million or “ppm”), fixed H₂S gas detectors will be prevalent around the gas processing plant, AGI facility and wellheads, which alarm at 10 ppm. CO₂ gas detectors will be present at the AGI facility due to the high concentration of CO₂, which alarm at 5,000 ppm. Additionally, all field personnel are required to wear personal H₂S monitors for safety reasons at all times without exception, which alarm at 5 ppm H₂S. Although damage to or failure of pipelines and surface equipment can result in unplanned losses of CO₂ entrained in the acid gas, at the anticipated concentration of H₂S in the injection volumes, even a small leak would trigger an alarm, and immediate action would be taken to stop the leak. Additionally, the AGI wells will be monitored with methods outlined in Sections 5 and 6.

BSO will reduce the risk of unplanned leakage from surface facilities through continuous surveillance, facility design, and routine maintenance and inspections. Field personnel will monitor the AGI facility continuously through a supervisory control system. Additionally, visual inspection rounds will be conducted of the AGI facility and weekly visual inspection rounds will be conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. BSO will also rely on the prevailing design of the facility, which includes AGI wells with surface controlled subsurface safety valves (“SCSSVs”), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes. Also, the wells have multiple surface isolation valves for redundant protection. Inline inspections of the AGI pipeline using a smart pigging tool will be conducted on the pipeline in accordance with applicable code. The smart pig tool will identify pipeline anomalies, including internal and external corrosion, and those anomalies will be assessed per applicable codes and standards.

Likelihood:

Although mitigative measures are in place to minimize CO₂ emissions from surface equipment, such emissions are possible. Any leaks from surface equipment would result in immediate (timing) emissions of CO₂ to the atmosphere, the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak.

The injection wells and the pipeline that carries CO₂ to it are the most likely surface components of the system to allow CO₂ to leak to the surface. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable source of the leakage.

Another possible source of leakage is when the surface components are damaged by an accident or natural disaster, which releases CO₂.

Therefore, BSO infers that there is a potential risk for leakage via this route. However, due to the standards enforced during construction, the monitoring equipment in place for immediate detection, and the regular inspections and maintenance, the probability of such leakage is considered “very unlikely.”

Magnitude and Timing:

Depending on the component's failure mode, the magnitude and timing of the leak can vary greatly. For example, a rapid break or rupture could release thousands of pounds of CO₂ into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO₂ over several hours or days. Due to the presence of relatively high concentrations of H₂S in the injection gas stream and the constant monitoring of the acid gas pipeline pressures, any leaks would be detected quickly, thus minimizing the magnitude of potential leakage.

Surface component leakage or venting is only a concern during the life of injection operations. Once the injection has ceased, the surface components will no longer be able to store or transport CO₂, eliminating any potential risk of leakage.

Therefore, the magnitude of such a leakage is considered to vary from insignificant to severe according to scenarios. The timing is also variable in the sense that potential leakage could occur at any time from start-up to cessation of injection operations.

4.2 POTENTIAL LEAKAGE FROM EXISTING WELLS

Existing oil and gas wells within the MMA/AMA, as delineated in **Section 3**, are shown in **Figure 4.2-1** and detailed in **Appendix A**. Existing groundwater wells in the MMA are showing in **Figure 4.2-2** and detailed in **Appendix C**.

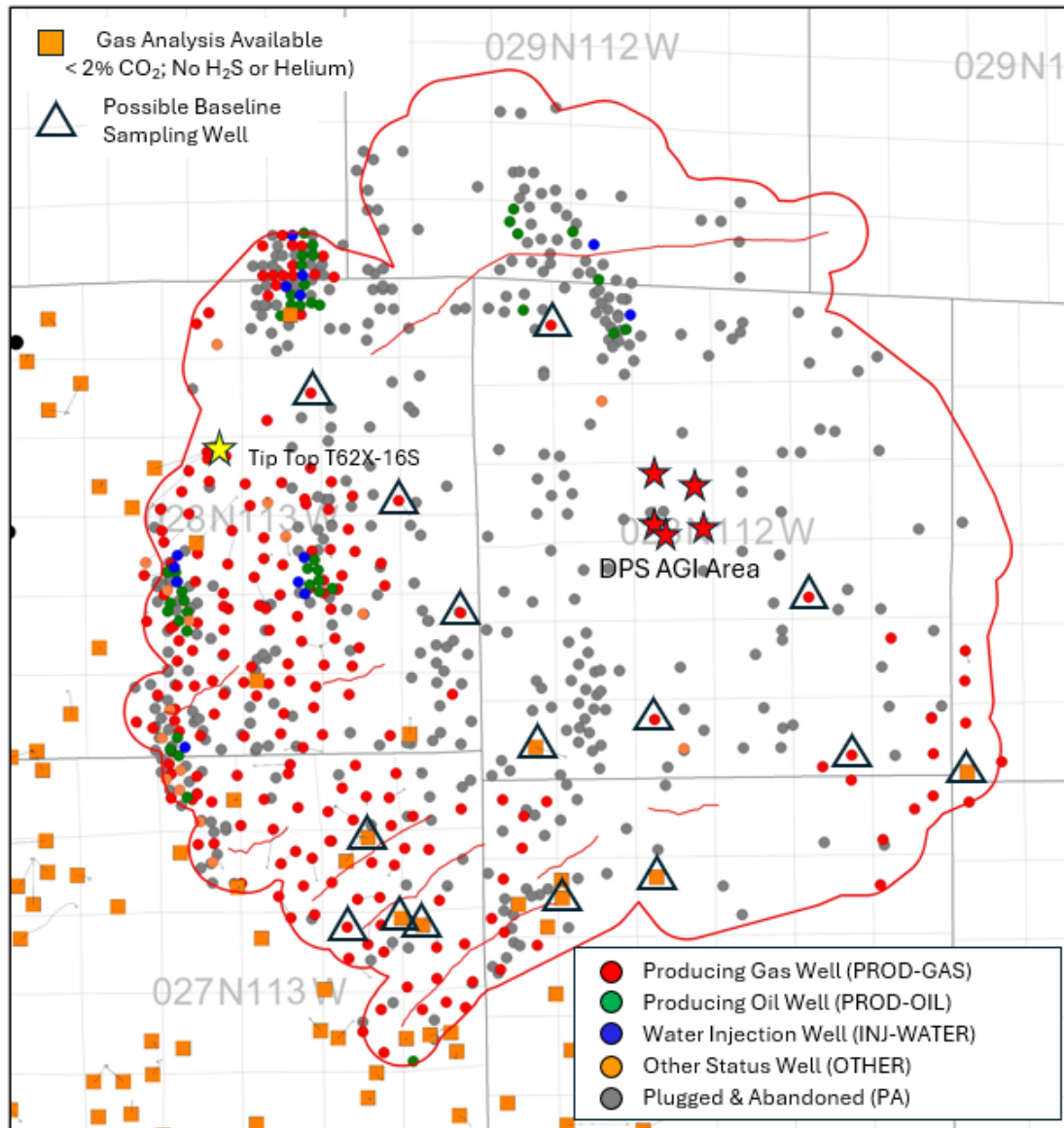


Figure 4.2-1: Map showing locations of existing oil and gas wells within the AMA/MMA. Existing oil, gas and other petroleum-related wells are color-coded according to the legend in the figure. Orange squares represent wells that have publicly available gas analyses that can be used to help establish a gas composition baseline, demonstrating gas compositions that contain less than 2 mol% CO₂, no H₂S, and no helium (if helium was measured). Black triangles represent possible candidates for baseline gas composition analysis as part of BSO's strategy for establishing expected baselines, discussed further in Section 6.0, 6.3 and 6.5. See Table 2.6 for a summary of existing gas compositional data from potential candidate wells for baseline analysis, and Appendix D for laboratory reports from same select wells.

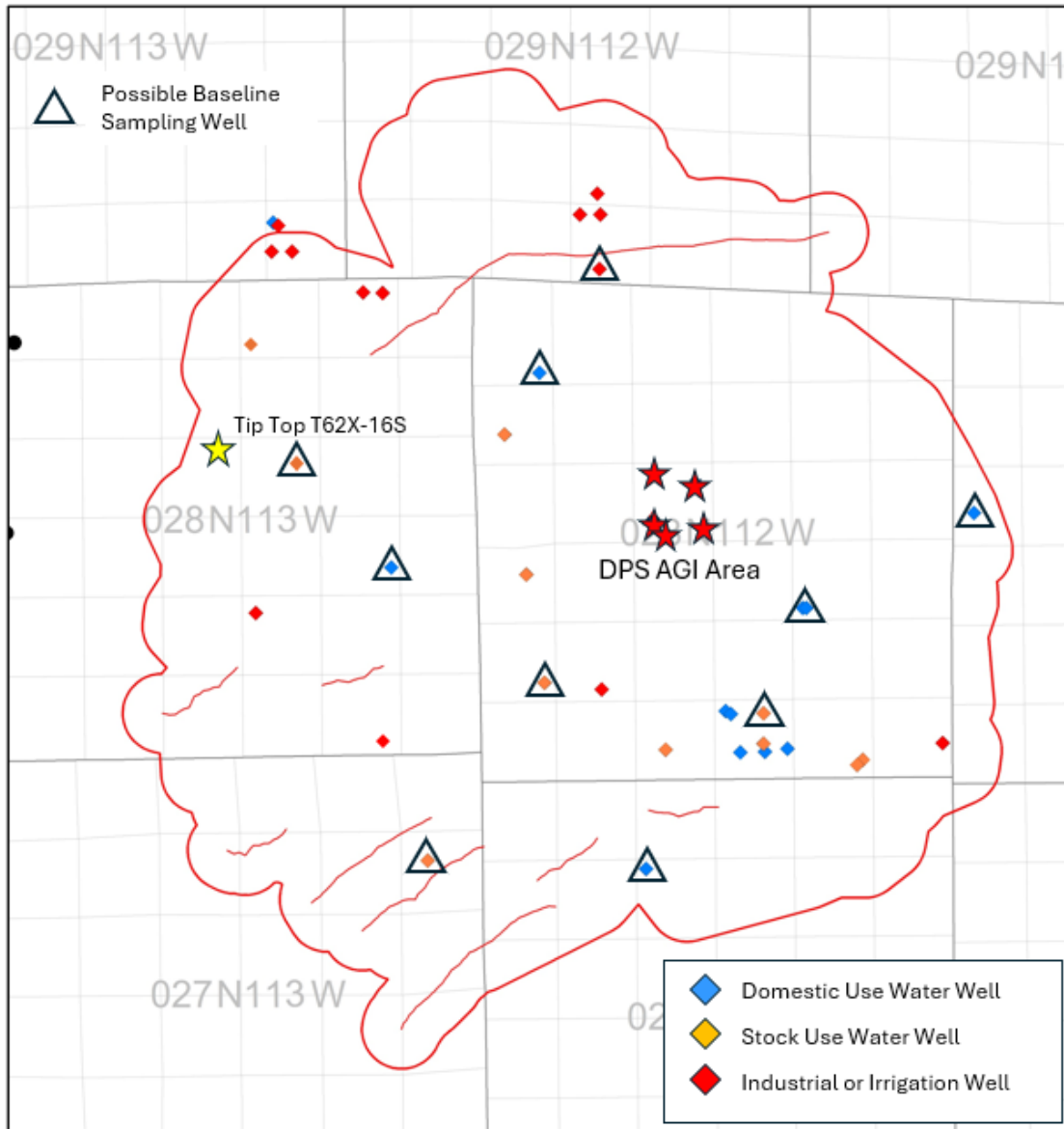


Figure 4.2-2: Map showing locations of existing groundwater wells within the AMA/MMA. Existing groundwater wells are color-coded according to the legend in the figure. Black triangles represent possible candidates for baseline gas composition analysis as part of BSO's strategy for establishing expected baselines, discussed further in Section 6.0, 6.3 and 6.5. Possible baseline candidate wells are bold and italicized in Appendix C.

BSO considered and evaluated all wells drilled, completed, or approved within the MMA in its risk assessment, regardless of well type (oil, gas, water injection, groundwater well, etc.) or well status (producing oil, producing gas, plugged and abandoned, etc.). Only one well, other than the existing Dry Piney State 12-16 well (and future Dry Piney State AGI wells), in the MMA penetrates the confining zones and injection zone, the Tip Top T62X-16S. Although in the MMA, the Tip Top T62X-16S is located within the one-half mile buffer

and is located outside of the stabilized plume at year 2128. The Tip Top T62X-16S was drilled in 2009 and subsequently plugged and abandoned the same year using 7 cement plugs via 5 cement retainers totaling approximately 9,511 feet of cement within the wellbore (See Appendix B for the Tip Top T62X-16S wellbore diagram). The well is drilled from the same well pad as a shallow Frontier sweet gas production well, the Tip Top T62X-16SH well. Neither well is operated by BSO, but because the deep T62X-16 well penetrates both the confining zone and the injection zone which contains approximately 70% CO₂ and 4-5% (40,000 to 50,000 ppm) H₂S, it would be reasonable to assume that if the well was leaking since it was plugged and abandoned, the lease operator for the actively producing shallow T62X-16SH well would observe an increase in H₂S readings on fixed or personal gas monitors generally set to alarm at 10 ppm on the shared well pad. If the operator's H₂S gas monitor did alarm, further investigation into CO₂ leakage could be conducted.

All other wells within the MMA, including groundwater wells, regardless of current status, were drilled and abandoned or completed at total depths that are at least 3,000 feet above the top of the shallowest injection zone (the Madison Formation). The top of the Triassic Evaporites confining unit is approximately 2,900 feet above the top of the Madison Formation, so none of the wells within the MMA (except the Tip Top T62X-16S) penetrate the Triassic Evaporites confining unit, the Amsden confining unit or the Madison or Bighorn injection zones.

Of the 741 existing petroleum-related wells in the AMA/MMA, 480 (64.8%) of them have total depths (TD) greater than 10,000 feet above the Madison injection zone, significantly reducing the risk of CO₂ leakage to surface due to the vertical separation of the injection zone and the deepest portion of the respective wellbore (**Figure 4.2-3**). 735 of the existing wells (99.2%) have a TD greater than 5,000 feet above the Madison injection zone, again minimizing risk of CO₂ leakage to surface through these wellbores due to the vertical separation between the wellbore and the injection zone. Of the 6 existing wellbores that have a TD less than 5,000 feet above the Madison injection zone, all but one (Tip Top T62X-16S) have a TD greater than 3,300 feet above the injection zone. Of the 6 existing wellbore that have a TD less than 5,000 feet above the Madison injection zone, all but one (State J No. 1) are outside of the stabilized plume area after 100 years. The State J No. 1 has been identified as a good candidate for a possible baseline monitoring well for CO₂ leakage along this potential leakage pathway (**Figure 4.2-1, Figure 4.2-3 and Appendices B and D**).

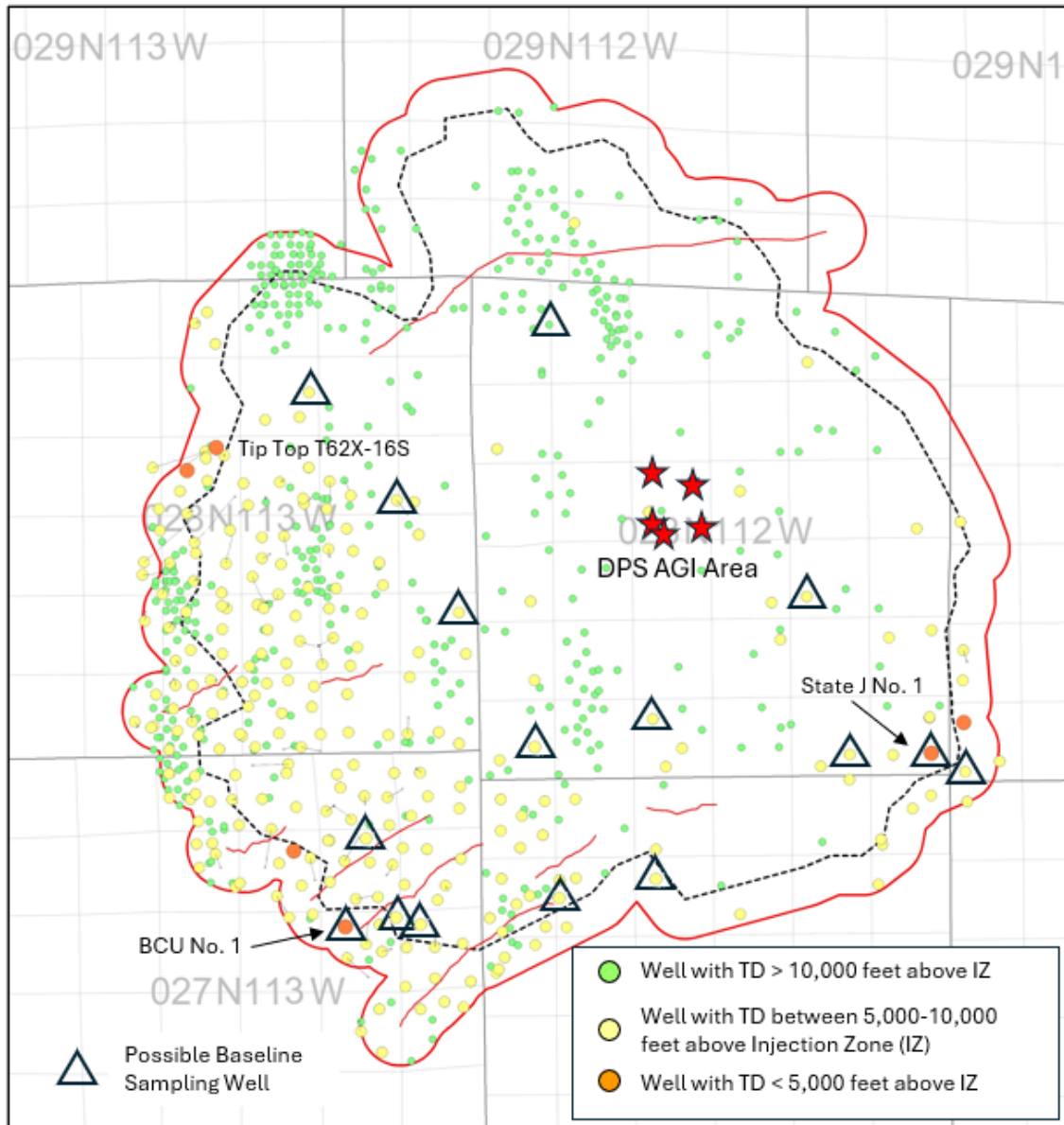


Figure 4.2-3: Map showing vertical separation between Total Depth (“TD”) of all existing oil and gas wells in the MMA (red polygon) and the top of the upper (Madison) injection zone (“IZ”). 480 of the 741 wells (64.8%) reach TD at least 10,000 feet above the Madison injection zone (green circles). 255 (34.4%) of the wells reach TD between 5,000 and 10,000 feet above the Madison injection zone (yellow circles), meaning 99.2% of existing wells in the MMA reach TD over 5,000 feet above the Madison injection zone. Only 6 wells reach TD less than 5,000 feet above the Madison injection zone, and only the Tip Top T62X-16S penetrates the injection zone. Of the 6 wells that reach TD less than 5,000 feet above the Madison, only the State J No. 1 is within the stabilized plume boundary (black-dashed polygon). Possible baseline gas analysis wells are denoted by black triangles. None of the

wells with an available gas analysis indicate CO₂ concentrations over 2.0 mol% or H₂S concentration above 0.0 mol%.

Of the 741 existing petroleum-related wells in the AMA/MMA, 448 (60.5%) are plugged and abandoned (“PA”), 221 (29.8%) are currently producing shallow sweet gas (PROD-GAS), 41 (5.5%) are currently producing shallow sweet oil, 18 (2.3%) are currently shut-in, temporarily abandoned, or have an unknown status, and finally, 13 (1.8%) are water-injection wells for the shallow sweet oil system. Note that no wells in the AMA/MMA produce gas from the Madison or Bighorn injection zones.

Likelihood:

Even though the risk of CO₂ leakage through the wells that do not penetrate confining zones is very unlikely, (the CO₂ would have to leak through the confining zone or upward along a fault first), BSO did not omit any potential source of leakage in the risk analysis. BSO analyzed the likelihood of leakage through the existing wells based on the following value assignment table depending on depth above injection zone and whether or not the well is located within the stabilized plume area:

LIKELIHOOD	WITHIN PLUME	OUTSIDE PLUME (WITHIN MMA)	
> 3,000 FT ABOVE INJ ZONE	1	1	3 = Moderate
< 3,000 FT ABOVE INJ ZONE	2	1	2 = Unlikely
PENETRATES INJ ZONE	3	2	1 = Very Unlikely

The results of the “likelihood” assessment for the wells located within the MMA can be observed in Appendix A. All wells, except the Tip Top T62X-16S, were assigned a value of “very unlikely” due to being either outside the plume area and or having a total depth greater than 3,000 feet above the injection zone, which also means the total depth is above the Triassic Evaporite confining unit. The Tip Top T62X-16S well was assigned a value of “unlikely” because although it penetrates the Madison and Bighorn injection zones, it is located outside of the stabilized plume area. Additionally, the T62X-16S well is plugged and abandoned with no signs of leakage from the existing high in-situ CO₂ and H₂S reservoir since 2009.

Magnitude and Timing:

Using the deep, plugged and abandoned Tip Top T62X-16S well that shares a well pad with the shallow Tip Top T62X-16SH well as an example, the magnitude of potential leakage is insignificant. Any leakage from the T62X-16S would be detected almost immediately due to the presence of H₂S in both the in-situ gas in the injection zone and in the free-phase plume. In this sense, most leakage from existing wells would be quickly detected using many of the same methodologies as for potential leakage from surface equipment,

including fixed and personal monitors whether by BSO or other operators' personnel. Additionally, all wells producing into an active gathering system undergo gas composition analyses at least annually to ensure the production stream meets pipeline specifications, particularly with respect to the presence of H₂S. Because any existing wells that currently have a producing status produce from the shallow "sweet" petroleum system lack any H₂S, any indications of the presence of H₂S during gas analysis would cause alarm plus an immediate well shut-in and would be investigated by the operator and pipeline company immediately. In that case, early detection leads to an immediate response and minimization of the magnitude of potential leakage. With regard to timing, BSO believes it would take millions of years ("geologic time") for CO₂ to migrate upward through the Amsden and Triassic Evaporites confining units into existing wells over 3,000 feet above the injection zone due to the fact that the Triassic Evaporites confining unit has contained helium for tens of millions of years, which is a much smaller molecule size than CO₂. Therefore, it stands to reason that, so long as BSO does not exceed fracture gradient of the confining units during injection operations, that a confining unit that can contain helium over geologic time can also continue to contain CO₂ over geologic time. In other words, the duration required for a small amount of CO₂ to get to the atmosphere via upward migration through the approximately 3,000-foot thick, shale and salt-rich Triassic Evaporite section, after migrating upward through the adjacent and overlying Amsden confining unit would be millions of years based on the fact that there are two distinct petroleum systems in the area, with the shallow sweet gas system being characterized by very low (< 2%) CO₂, no H₂S and no helium in gas analyses, compared to the deep sour gas system targeted for injection that has 65% CO₂, 5% H₂S and measurable helium (> 0.5%). If CO₂, H₂S or helium have not migrated upward through the confining units over geologic time thus far, it would stand to reason that the likelihood of large amounts of CO₂ leaking upward in near-term timeframe is very unlikely. In terms of operational timing, however unlikely, leakage would potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. BSO, of course, would not inject above fracture pressure in any case, thus further reducing risk of leakage.

MAGNITUDE	WITHIN PLUME	OUTSIDE PLUME (WITHIN MMA)	
> 3,000 FT ABOVE INJ ZONE	1	1	3 = Significant
< 3,000 FT ABOVE INJ ZONE	2	1	2 = Minor
PENETRATES INJ ZONE	3	1	1 = Insignificant

The results of the “magnitude” assessment for the wells located within the MMA can be observed in Appendix A. All wells were assigned a value of “insignificant” due to being either outside the plume area and or having a total depth greater than 3,000 feet above the injection zone and therefore above the Amsden and Triassic Evaporite confining units. The Tip Top T62X-16S well was also assigned a value of “insignificant” because although it penetrates the Madison and Bighorn injection zones, it is located outside of the stabilized plume area. Additionally, the T62X-16S well shares a well pad with the T62X-16SH well and potential leakage into the shallower well would be detected within a short time frame by the lease operator.

To conclude, likelihood of CO₂ leakage to the surface via existing wells is considered “very unlikely” and the magnitude is considered “insignificant”. Therefore, using the combined risk matrix for likelihood and magnitude, all wells in the MMA have a “very low” risk of potential leakage. It should be noted that Dry Piney State AGI wells were not included in this analysis, as any potential leakage would be addressed in Section 4.1 that discusses Surface Equipment, as the future DPS AGI wells will be operated by BSO and will be continuously monitored.

There are no existing producing wells completed in the Madison or Bighorn Formations within the AMA or MMA, and it is highly unlikely that there will be Madison or Bighorn production wells drilled in the MMA/AMA in the future owing to the high initial CO₂ and low initial methane and helium concentrations, likely rendering future production wells uneconomic.

4.3 POTENTIAL LEAKAGE THROUGH THE CONFINING UNITS

BSO considered and evaluated leakage through the confining zones above and below the Madison and Bighorn injection zones. See **Section 2.6.4** for discussion of confining units. The area closest to the injection wells with the highest concentration of free-phase CO₂ would likely be most prone to this leakage pathway.

Likelihood:

The shale, anhydrite and salt-rich Triassic Evaporites confining unit in the Dry Piney State AGI area serves as the overall deep sour gas system seal and the ultimate confining unit to both the Madison and the Bighorn injection zones. The shale, anhydrite and salt-rich lithologies that form the sealing capacity of this confining unit is impermeable to helium, a gas with a much smaller molecular volume than CO₂. If the reservoir seal material is impermeable to helium, then it follows that it is also impermeable to CO₂. Although natural creep of the salty sediments in the Triassic Evaporites confining unit is possible, this behavior does not disturb the sediments to the degree necessary to breach the reservoir seal of the Madison Formation. If this salty sediment were to flow on a scale large enough to create a leakage pathway from the Madison Formation to the surface, the natural gases trapped in the formation would have already escaped to the atmosphere

over geologic time. The fact that gas (especially helium with its small molecular size) remains trapped at pressure in the Madison and Bighorn Formations, it must follow that any natural reactivation or movement of salt-rich sediments that has occurred over the geological history of the LaBarge field area has not created any pathways for gas leakage to the surface. The likelihood of CO₂ leakage through the Triassic Evaporites confining unit is therefore “very unlikely”.

In addition to the Triassic Evaporites, the Amsden (422 ft thick) is the immediately adjacent and overlying confining unit to the Madison. Although partial fractures were observed on an eight-pad image log through the Amsden Formation overlying the Madison in the Dry Piney State 12-16, there were no complete fractures observed. The image log analyst noted that the partial fractures were generally faint in appearance and were often only observed on a single frequency resistivity or impedance image of the eight image tracks available at a given depth. No faults were observed on the image log, but several anhydrite stringers with 0% porosity and 0 md permeability were observed. The likelihood of CO₂ leakage through the Amsden Formation is “very unlikely”.

The Darby (302 ft thick) is the underlying confining unit for the Madison and the overlying confining unit for the Bighorn injection zone. There were only two complete natural fractures observed in the Darby and were located at the very base of the interval. It could not be determined whether these two fractures were open or calcite-filled on the image log. Analysis of fluid sampled collected during wireline logging demonstrated different gas compositions in the Madison and Bighorn, indicating the Darby Formation is a confining unit that has hydraulically separated the Madison and Bighorn Formations over geologic time. Therefore, the likelihood of CO₂ leakage through the Darby Formation confining unit is “very unlikely”.

Collectively, all these confining zones generally have low porosity (< 2%) and low permeability (< 0.001 md) intervals that provide high seal integrity. So long as the injection pressure is limited to less than the fracture pressure of the confining zones, the likelihood of CO₂ leakage through this potential pathway to surface is determined to be “very unlikely.”

Magnitude and Timing:

Based on reservoir simulation results conducted by BSO, the relative difference in porosity and permeability of the low porosity and low permeability of the Amsden confining unit compared to the high porosity and high permeability of the Madison injection zone suggests the free-phase CO₂ plume stays entirely within the Madison Formation. Therefore, any potential leakage upward into the confining zone would be considered insignificant. Likewise, the Bighorn Formation is highly porous and permeable relative its overlying Darby confining unit, so plume modeling indicates that all injected CO₂ stays

within the Bighorn injection zone. Therefore, any potential leakage upward into the confining zone would be considered insignificant.

In terms of timing, however unlikely, leakage would potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. BSO, of course, would not inject above fracture pressure in any case, thus reducing further risk of leakage.

To conclude, likelihood of CO₂ leakage to the surface through the confining units is considered “very unlikely” and the magnitude is considered “insignificant”. Therefore, using the combined risk matrix for likelihood and magnitude, this potential leakage pathway warrants a “very low” risk of potential leakage.

4.4 POTENTIAL LEAKAGE THROUGH FAULTS AND FRACTURES

Likelihood:

A thorough geological evaluation of the injection zone and confining units was performed (see **Section 2**) to understand the regional and local geology of the LaBarge structure and Dry Piney State injection area, as well as to understand the distribution of faults and fractures. **Figure 4.4-1** shows the fault traces within the Dry Piney State injection evaluation area that are stratigraphically within the Madison and Bighorn injection zones. *It is important to note that no faults within the MMA are observed at the surface, nor does seismic interpretation suggest that any faults in the MMA extend to the surface.*

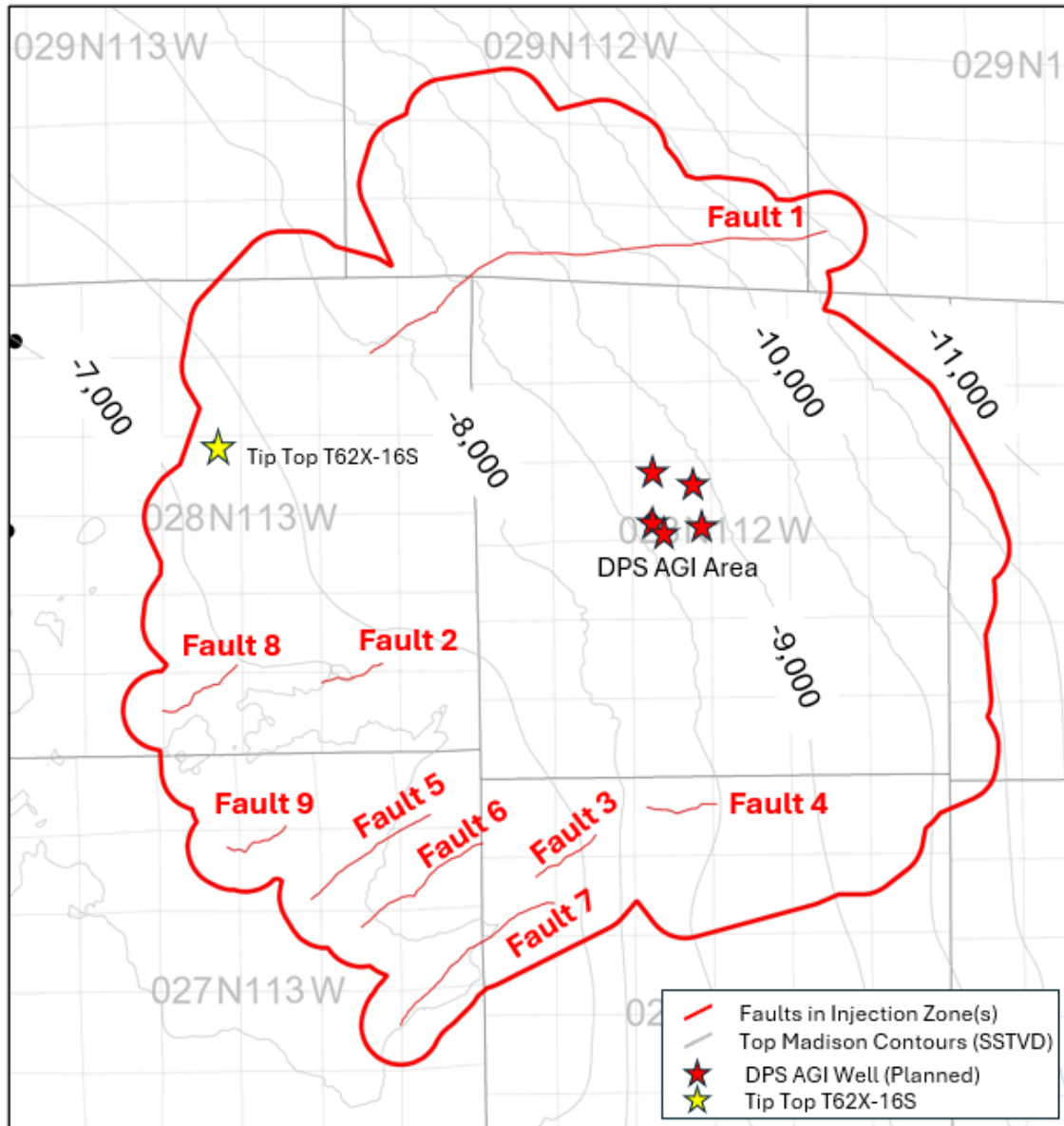


Figure 4.4-1: Map showing the location of faults (numbered 1 through 9) within the AMA/MMA that are at Madison and Bighorn depth. It is important to note that none of these faults are observed at the surface, nor does seismic interpretation suggest that any of these faults extend to the surface.

Faults were identified (numbered 1 through 9) and evaluated using seismic interpretation. Any fault that intersects and extends beyond the stabilized plume outline at year 2128 was brought into the analysis as a potential leakage pathway and the MMA includes a one-half mile buffer around any fault that extended beyond the stabilized plume (**Section 3.1**). In the vertical dimension, only three faults extend completely through or above the Triassic Evaporites confining interval. Despite observing seismic discontinuities interpreted as faults extending through the Triassic Evaporites interval, there is no

evidence that these faults are open and providing an active pathway for CO₂ leakage upward through the geologic column to surface, as evidenced by the existence of a shallow (Frontier, Bear River, Mowry and Gannett) sweet gas petroleum system (minor CO₂, no H₂S, no helium) that is currently being produced by approximately 166 wells within the MMA. If any of the three faults that extend upward through the confining unit were acting as a leakage pathway, gas analyses from wells producing in the MMA would indicate the presence of significant CO₂, H₂S and likely helium. Gas analyses are publicly available in producing gas wells are depicted as orange squares as shown on **Figure 4.2-1**. No H₂S or significant CO₂ (defined as > 2 mol%) is observed in available gas analyses from producing wells, indicating that the faults are not currently leakage pathways. Additionally, as discussed in **Section 3.1**, the MMA was extended to capture a one-half mile buffer around any fault that intersects and extends beyond the stabilized free-phase CO₂ plume at year 2128. Because the MMA encompasses a half-mile buffer zone to ensure there is no risk of leakage due to lateral migration associated with faults, and gas analyses indicate there is no upward migration along faults, the likelihood of leakage through faults is considered “very unlikely.”

The closest identified fault is Fault 1 (**Figure 4.4-1**) which is located approximately 3.4 miles north of the Dry Piney State injection area. Fault 1 penetrates the Madison and Bighorn injection zones, and Amsden and Darby confining zones, but notably does not extend upward into or through the Triassic Evaporites confining unit. Fault 1 exhibits the most laterally continuous fault trace in the area but is encompassed entirely within the extended MMA to provide the additional one-half mile buffer since Fault 1 does intersect the plume before and after plume stabilization. Therefore, the risk of leakage through Fault 1 is very unlikely.

Faults 2, 3, and 4 are the next closest to the Dry Piney State injection area and are located approximately 3.9 miles to the southwest. Fault traces for Faults 2, 3 and 4 are all relatively short in the lateral dimension, and do not extend upward through the Triassic Evaporites confining unit. The entirety of fault traces for Faults 2, 3 and 4 are all contained within the stabilized plume and do not extend beyond the MMA. Therefore, the risk of leakage along Faults 2, 3 or 4 due to lateral or upward migration is considered “very unlikely”.

Faults 5, 6, and 7 are located approximately 3.9 miles southwest of the Dry Piney State injection area. Fault traces for Faults 5, 6 and 7 are all relatively short in the lateral dimension. Faults 5, 6 and 7 extend upward through the Triassic Evaporites confining unit, but die out above the Frontier producing interval. As previously stated, within the developed area of Faults 5, 6, and 7, no indications of CO₂, H₂S, and helium are seen in any wells, suggesting that they do not act as leakage pathways (See **Section 2.6.3, Figure 2.6** and **Appendix D** for data and discussion). The fault traces for Faults 5, 6 and 7 intersect and extend beyond the stabilized plume, as such the MMA was expanded to fully

encompass a half-mile buffer around the entirety of the fault traces for Faults 5, 6 and 7. Although Faults 5, 6 and 7 extend through the shallowest confining unit and intersect the stabilized plume, the risk of leakage along Faults 5, 6 and 7 due to lateral or upward migration is considered “unlikely” because gas analyses from shallow production indicate that the faults are not acting as leakage pathways from the deep sour gas system which contains a high concentration of naturally-occurring CO₂, H₂S and helium at pressures significantly higher than the shallow gas systems. As long as BSO does not exceed fracture pressures during injection operations, there is no reason to assume that these faults will open and become active CO₂ leakage pathways.

Finally, Faults 8 and 9 are located approximately 5.5 and 6.0 miles, respectively, from the Dry Piney State injection area. Fault traces for Faults 8 and 9 are relatively short and are contained entirely within the extended MMA. Faults 8 and 9 do intersect the edge of the stabilized plume. Faults 8 and 9 do not extend upward into or through the Triassic Evaporites confining unit. Therefore, the risk of leakage along Faults 8 and 9 is considered “very unlikely.”

Magnitude and Timing:

Reservoir modeling results indicate that the leading edge of the free-phase plume (ranging from 0.5 to 5% net incremental CO₂) will reach Fault 1 between 20 and 30 years after injection begins (**Figure 4.4-2**). Fault 1 does not extend upward through or above the Triassic Evaporites confining unit, and the maximum plume concentration is anticipated to be < 5% net incremental increase in CO₂. During the 50-year injection period Fault 1 does not intersect the plume in an area modeled to have greater than a 5% net incremental CO₂ concentration. Therefore, the magnitude of potential leakage of CO₂ to the surface is considered insignificant. Despite Fault 1 intersecting the Darby confining unit between the Madison and Bighorn injection zones, differing gas compositions between the Madison and Bighorn confirm that the two injection zones are hydraulically separate and Fault 1 is not an active leakage pathway so long as BSO maintains injection pressures below fracture pressure.

BSO concludes that the potential for leakage through Fault 1 is very low.

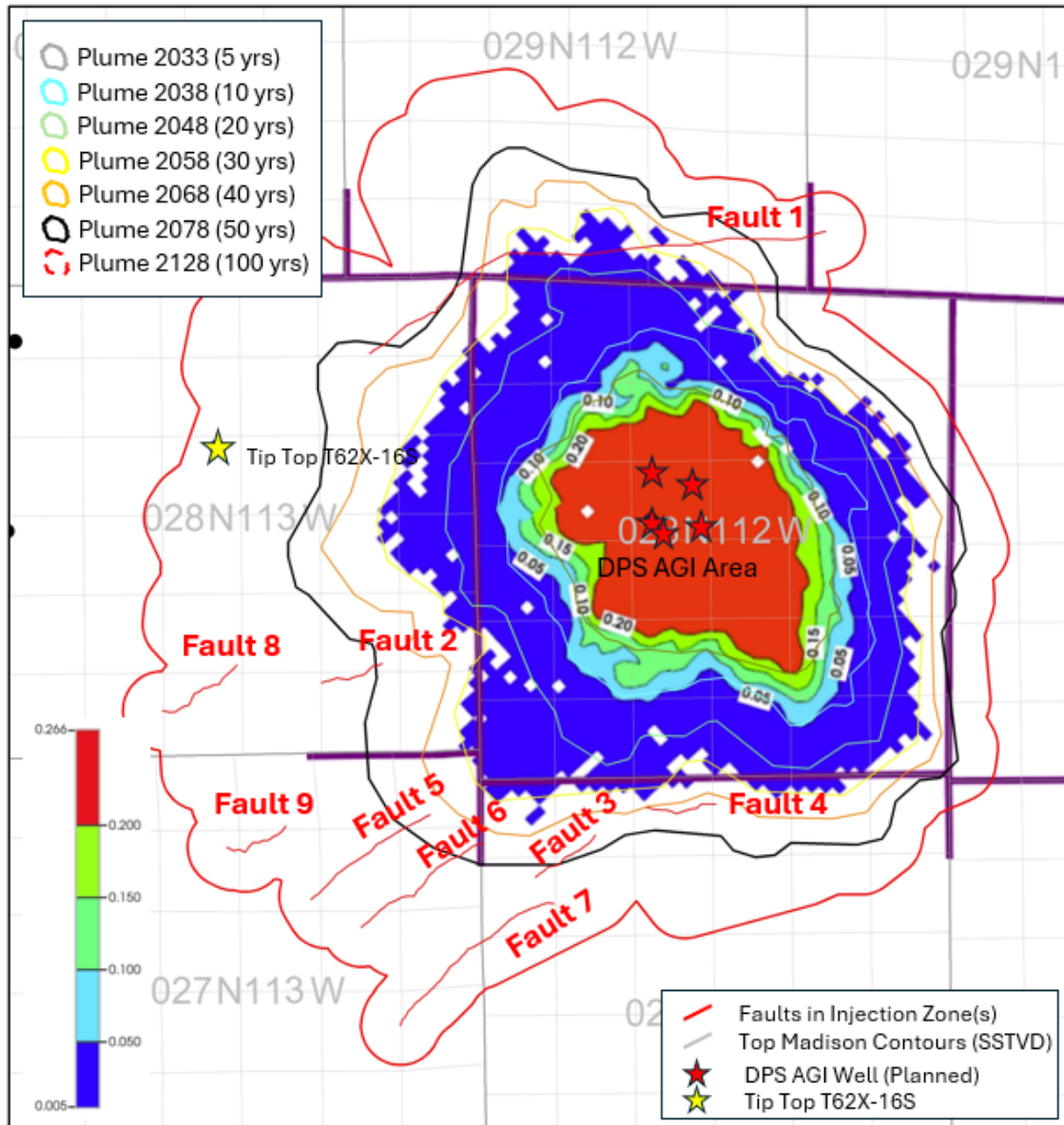


Figure 4.4-2: Map showing free-phase plume with less than 5% CO₂ concentration reaching Faults 1 between 20 and 30 years after injection begins. 30-year plume (year 2058) depicted.

Reservoir modeling results indicate that the outward edge of the free-phase plume (ranging from 0.5 to 5% net incremental CO₂) will reach Faults 2, 3, and 4 between 40 and 50 years after injection begins (**Figure 4.4-3**). Faults 2, 3 or 4 do not extend upward through or above the Triassic Evaporites confining unit, and the maximum plume concentration is anticipated to be < 5% net incremental increase in CO₂. During the 50-year active injection period Faults 2, 3 or 4 do not intersect the plume in an area modeled to have greater than a 5% net incremental CO₂ concentration. Therefore, the magnitude of potential leakage of CO₂ to the surface is considered insignificant. Despite Faults 2, 3

and 4 intersecting the Darby confining unit between the Madison and Bighorn injection zones, differing gas compositions between the Madison and Bighorn confirm that the two injection zones are hydraulically separate and Faults 2, 3 and 4 are not active leakage pathways so long as BSO maintains injection pressures below fracture pressure.

BSO concludes that the potential for leakage through Faults 2, 3 and 4 are very low.

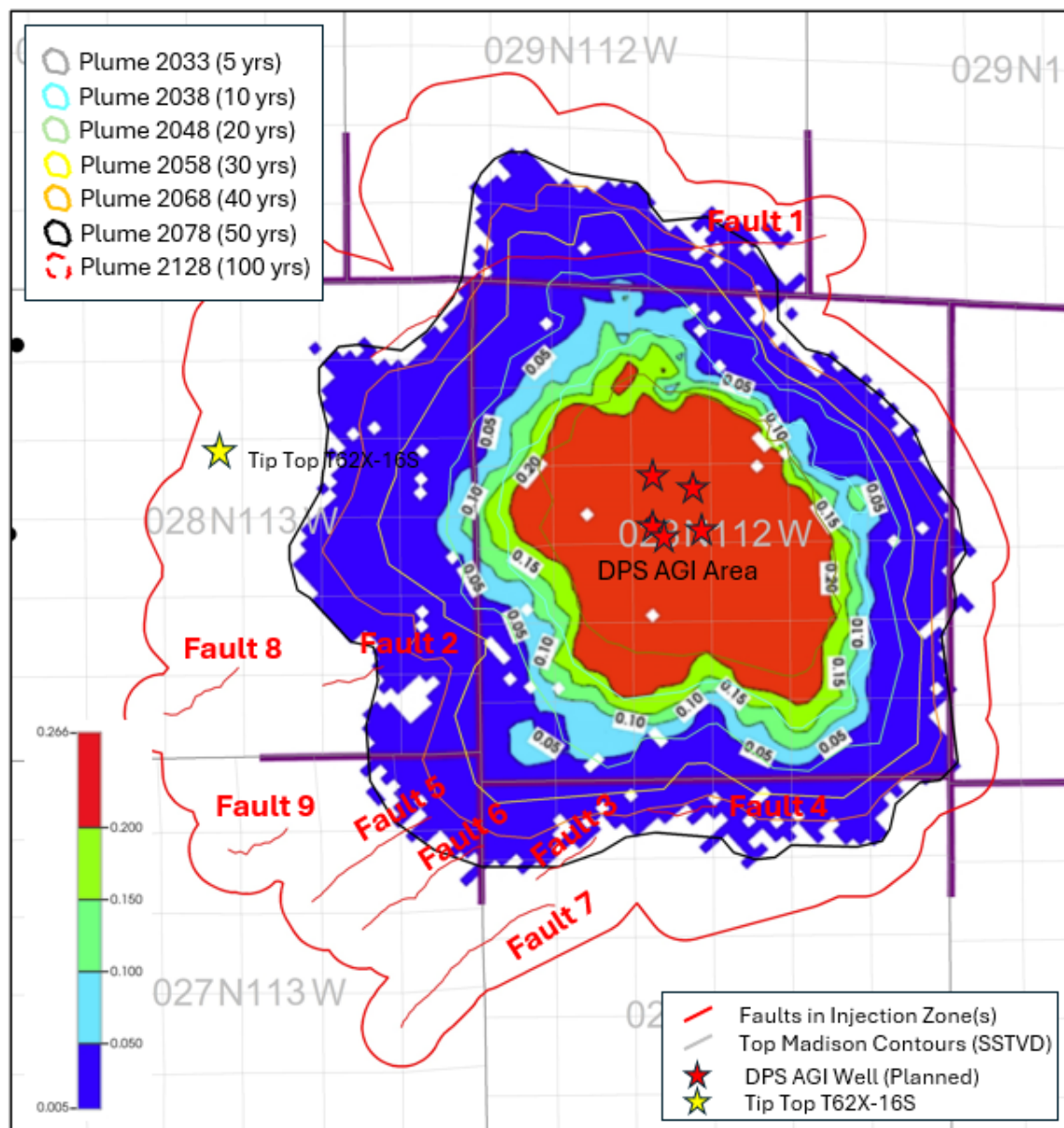


Figure 4.4-3: Map showing free-phase plume with less than 5% CO₂ concentration reaching Faults 2, 3 and 4 in approximately 50 years. 50-year plume (year 2078) depicted.

Reservoir modeling results indicate that the free-phase plume will reach Faults 5 and 6 between 40 and 50 years after injection begins (**Figure 4.4-3**), and Fault 7 during the plume stabilization period between 50 and 100 years after injection initiates. Faults 5, 6

or 7 extend upward through the Triassic Evaporites confining unit. During the 50-year active injection period Faults 5, 6 or 7 do not intersect the plume in an area modeled to have greater than a 5% net incremental CO₂ concentration. Therefore, the magnitude of potential leakage of CO₂ to the surface is considered insignificant even if Faults 5, 6 and/or 7 were to act as leakage pathways. Although Faults 5, 6 and 7 intersect the Darby confining unit between the Madison and Bighorn injection zones, differing gas compositions between the Madison and Bighorn confirm that the two injection zones are hydraulically separate. Furthermore, despite Faults 5, 6 and 7 extending upward through and above the Triassic Evaporite confining unit, gas analyses from shallow wells in the vicinity of Faults 5, 6 and 7 (locations shown in **Figure 4.2-1**, and analyses including in **Appendix E**) do not show the presence of significant concentrations of CO₂ (> 2 mol%), H₂S, or helium (See **Section 2.6.3**, **Table 2.6** and **Appendix D**). Therefore, it can be ascertained that Faults 5, 6 and 7 are not active leakage pathways through the Triassic Evaporite confining unit so long as BSO maintains injection pressures below fracture pressure.

BSO concludes that the likelihood for potential for leakage along Faults 5, 6 and 7 is “unlikely” and the magnitude is insignificant, resulting in an overall risk assessment of “very low” for leakage along these faults.

Reservoir modeling results indicate that the outward edge of the stabilized free-phase plume (ranging from 0.5 to 5% net incremental CO₂) will reach Faults 8 and 9 between 90 and 100 years after injection begins, which equates to between 40 and 50 years after injection ceases. (**Figure 4.4-4**). Faults 8 and 9 do not extend upward through or above the Triassic Evaporites confining unit, and the maximum plume concentration is anticipated to be < 5% net incremental increase in CO₂. During the 50-year active injection period Faults 8 and 9 do not intersect the plume. Therefore, the magnitude of potential leakage of CO₂ to the surface is considered insignificant.

BSO concludes that the potential for leakage through Faults 8 and 9 is very low.

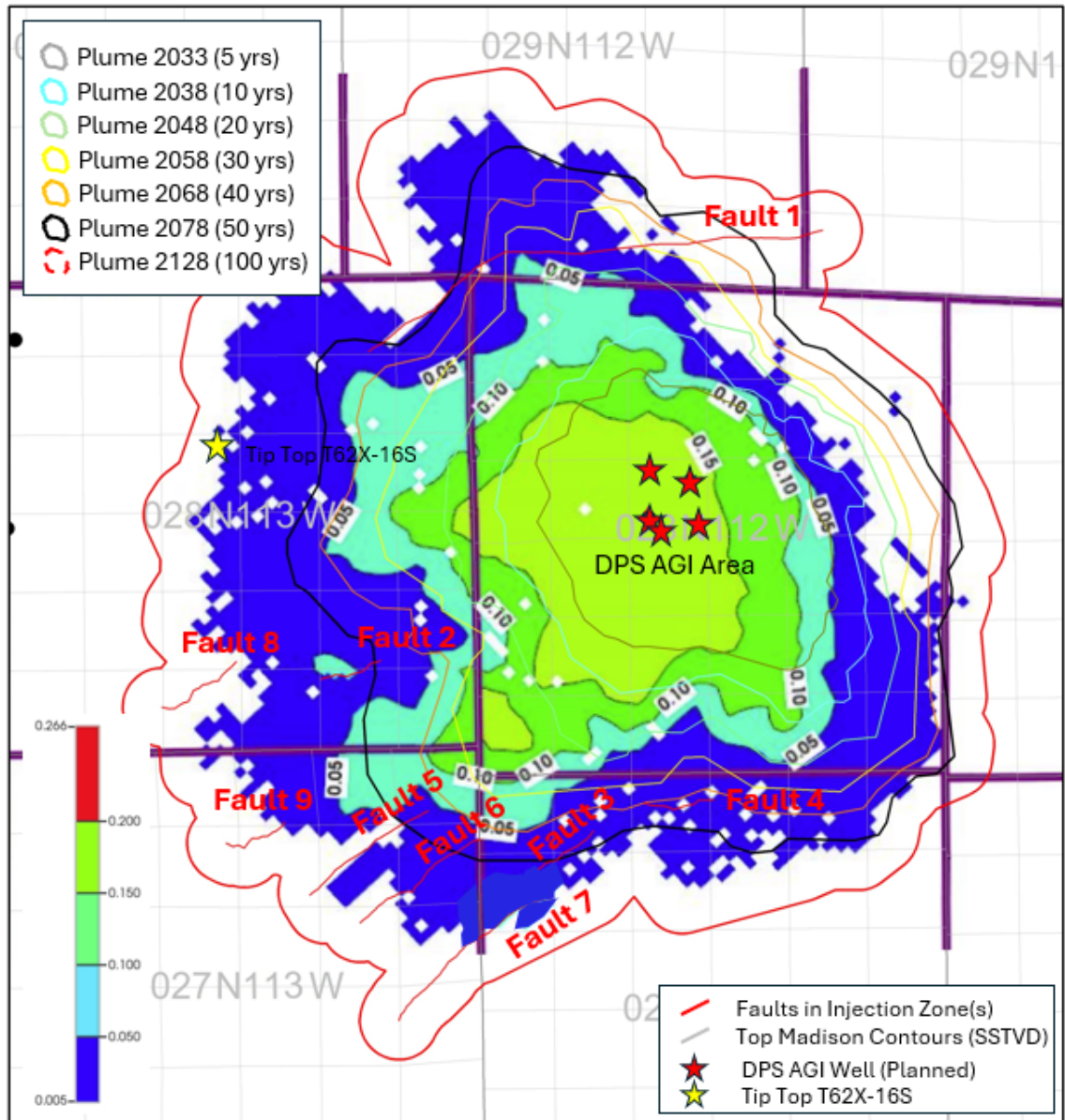


Figure 4.4-4: Map showing free-phase plume with less than 5% CO₂ concentration reaching Faults 5, 6 and 7 in approximately 90-100 years. 100-year plume (year 2128) depicted.

To summarize, BSO characterizes the overall risk of potential leakage along faults in the MMA as very low. The closest fault (Fault 1) is approximately 3.4 miles north of the Dry Piney State injection area. The leading edge of the free-phase CO₂ plume, at a concentration of 0.5 to 5% net incremental CO₂ is not expected to reach the closest fault until between 20 and 30 years after injection has been initiated. Only three faults extend upward through the Triassic Evaporite confining unit, but gas analyses indicate that these faults are not leakage pathways due to lack of appreciable CO₂, H₂S or helium as would be expected if these faults provide a conduit to the deep sour gas system. In no case, does a

fault intersect the plume in a position in which the plume is anticipated to have a concentration greater than 5% net incremental CO₂ above the naturally occurring in-situ background CO₂ contained in the injection zones. Therefore, the magnitude of potential leakage would be insignificant.

In terms of timing, however unlikely, leakage would potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. BSO, of course, would not inject above fracture pressure in any case, thus reducing further risk of leakage. It is also possible any leakage would occur during the 50 years of post-injection plume growth during plume stabilization.

As discussed in Section 2.6.3, engineering and geologic analysis show no evidence of faulting with significant offset or complex structuring around the AGI wells. The absence of significant faulting also tends to suggest that regionally extensive natural fracturing or permeability enhancement in the Madison or Bighorn Formations is also very unlikely, and any natural fracturing or permeability enhancement is limited to a very localized area.

Current-day regional scale thrust faulting has not been observed in the LaBarge area since the field has been under development. There is no concern of reactivation of these thrust faults and it is hypothesized that regional structuring similar in size to the Laramide Orogeny (formation of the Rocky Mountains) would be required to generate new thrust faults of significant size to produce subsurface structures of the scale and magnitude of the LaBarge field. The activation of the salty sediments (which exist below the Nugget Formation and above the Madison Formation at LaBarge) is a phenomenon that was only observed to damage thin-wall cased wells, with thick-wall cased wells having sufficient strength to prevent flowage of these salt sediments.

It has been documented that natural fracturing of reservoirs in the subsurface of LaBarge and surrounding areas are directly correlative to distance to thrust faults in the area. This correlation has been documented in subsurface wellbore image logs and also by surface geological mapping around the thrust faults in the LaBarge area. It therefore follows that a lack of significant faulting, as observed on 2D seismic panels around and through the AGI well site, will yield formations void of natural fracturing, and the necessary significant faults are not present to generate pervasive natural fractures of regional extent. The presumed lack of significant natural fracturing in the Madison reservoir at and around the AGI well sites suggest that all flow in the Madison and Bighorn must be from pore to pore, and that ability for fluids to flow will depend solely upon the natural intergranular porosity and permeability of the Madison and Bighorn. It should be noted that the permeability of the Madison and Bighorn is low or 'tight' according to industry definitions of 'tight' and therefore has minimal capability to freely flow fluids through only the pore system of the Madison and Bighorn. Accordingly, there is little potential for lateral migration of the

injection fluids once injection ceases, as the injection pressure will be the only impetus to induce lateral movement of the injected fluids. Note the limited areal growth of the free-phase plume after 50 years of injection (Figure 3.2) compared to 50 years after injection has ceased (Figure 3.4).

4.5 POTENTIAL LEAKAGE DUE TO LATERAL MIGRATION

Likelihood:

Regional evaluation of the geology (**Section 2.0**) and the geological model covering the entire LaBarge structure suggest that the Madison and Bighorn injection zones have adequate storage capacity and their respective confining zones are uniform across the MMA. Therefore, all lateral migration is expected to occur within the injection zones. In addition, dynamic simulations indicate that the injected free-phase CO₂ plume will be contained within the injection zones covering the areas depicted by various time increments (**Figure 2.8-2**). Extensive modeling shows that after injection ceases (year = 2078) there is minimal continued lateral migration within the injection zone until plume stabilization at year 2128. It is also important to note that the injection zones in the sub-thrust Paleozoic section on the LaBarge structure are not hydraulically connected to local outcrops of the Madison and Bighorn Formations, as discussed in **Section 2.3.1** and **Section 2.3.3**. Due to the lack of hydraulic connection to outcrops and continuity of confining units across the entire structure, potential leakage of CO₂ to the surface due to lateral migration would require an additional leakage pathway, most likely lateral migration within the injection zones to faults and fractures as discussed in Section 4.4.

Therefore, BSO views the likelihood of CO₂ leakage to the surface or out of the injection zones due to lateral migration as “very unlikely.”

Magnitude and Timing:

Based on simulation results the free-phase CO₂ plume is projected to be contained within the injection zones within the MMA as depicted on **Figure 3.1-4**. The confining zones are thick and continuous, which would prevent any upward migration through the confining zone even if lateral migration beyond the MMA occurs. Because the free-phase CO₂ plume is delineated using a 0.5% net incremental increase in CO₂, if leakage through this potential pathway were to occur it would be considered insignificant relative to the large amount of in-situ CO₂ naturally present in the injection zones.

In terms of timing, however unlikely, leakage would potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. BSO, of course, would not inject above fracture pressure in any case, thus reducing further risk of leakage. It is also possible any

leakage would occur during the 50 years of post-injection plume growth during plume stabilization.

Therefore, the overall risk of leakage due to lateral migration is considered to be very low.

4.6 POTENTIAL LEAKAGE DUE TO SEISMICITY

Likelihood:

Figure 4.6-1 highlights the recorded seismic events since 2015 in the region of the Dry Piney State AGI area according to the United State Geologic Survey's "ANSS Comprehensive Earthquake Catalog". Within 20 miles, a total of 10 events occurred with magnitudes that ranged from M 1.1 – M 2.3 and depths from 10.8 kilometers ("km") to 34.8 km. The closest event to the Dry Piney State injection wells was a M 2.3 event, 2.25 miles away at a depth of 34.8 kilometers (approximately 100,000 ft below the injection zones and confining units). Three other events occurred within 5 miles of the Dry Piney State injection area and ranged in magnitude from M 1.2 to M 2.1, at depths of 10.8 to 16.6 km. All events within a 20-mile radius occurred at depths greater than 10.8 kilometers (approximately 25,000 feet deeper than the injection zones and confining units).

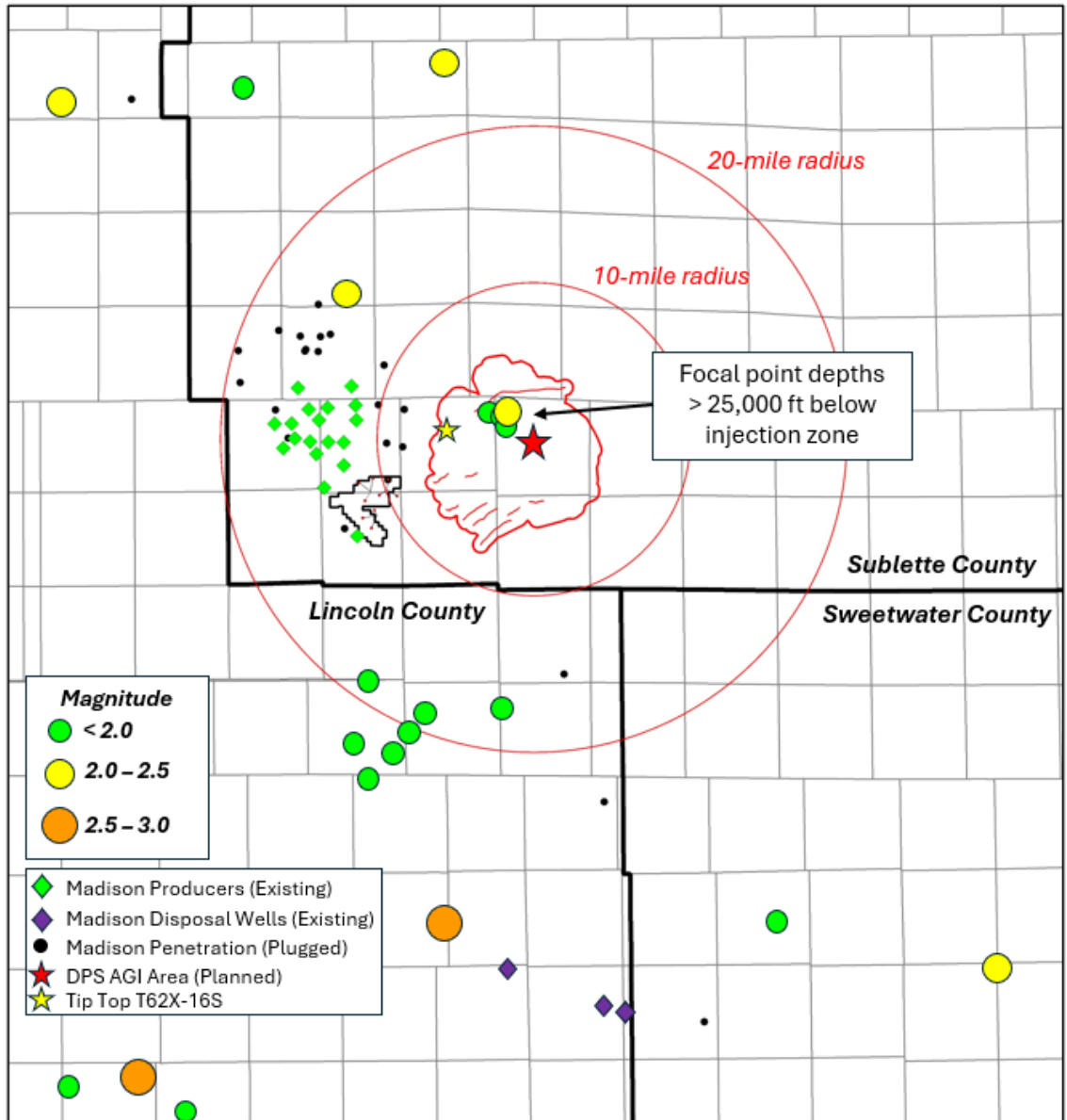


Figure 4.6-1: Map depicting seismic events as reported in the ANSS Earthquake Catalog from October 2015 to October 2025. Note that there are no “significant” (Magnitude > 3.5) within 20 miles of the DPS AGI area, or within the broader map area, including near existing disposal wells injecting into the Madison Formation (purple diamonds).

Significant earthquake activity is defined as greater than 3.5 Richter scale. The nearest recorded significant naturally occurring earthquake activity to the proposed Dry Piney State 12-16 has been detected over 20 miles away to the west in the Thrust Belt (M3.8, 2/25/2007, ANSS Catalogue 2018). Reported earthquake activity is believed to be related to the easternmost extension of the Basin and Range province (Eaton, 1982), unrelated to the Moxa Arch. There has also been no reported seismic activity attributed to active injection operations at the ExxonMobil AGI 2-18 and AGI 3-14 or other disposal wells.

Due to the depths relative to the injection zones and confining units at the Dry Piney State injection area and the small magnitude of the seismic events since 2015, combined with the fact that BSO will inject at pressures below fracture opening pressure, BSO considers the likelihood of CO₂ emissions to the surface along potential leakage pathways caused by seismicity or induced seismicity to be “very unlikely”.

Magnitude and Timing:

The impact of a seismic event on confining zones, wells and surface installation integrity can vary greatly according to events’ magnitude or frequency. However, based on the relative depths of seismic events’ focal points ranging from 25,000 to 100,000 feet below the injection zones and confining units, and the small magnitudes recorded within 20 miles of the Dry Piney State injection area, BSO considers the magnitude of potential leakage due to seismicity to be insignificant. Further, if an unprecedented natural seismic event were to occur that impacted the integrity of any of the Dry Piney State AGI wells or the related infrastructure, BSO would shut down operations immediately, limiting potential release of CO₂ from wellhead and other surface equipment, thus minimizing leakage to an insignificant amount.

In terms of operational timing, and induced seismicity, however unlikely, leakage would potentially occur near the end of injection operations (potentially 40 to 50 years after injection begins) after a significant volume of CO₂ has been emplaced in the injection area. At that time, injection wells may begin to experience increased injection pressures. BSO, of course, would not inject above fracture pressure in any case, thus reducing further risk of leakage.

To summarize, BSO considers the risk of CO₂ leakage following a seismic event to be very unlikely and insignificant for a combined risk assessment of “very low”. Monitoring of seismic events in the vicinity of the Dry Piney State AGI wells is discussed in **Section 5.7**.

5.0 DETECTION, VERIFICATION AND QUANTIFICATION OF SURFACE LEAKAGE OF CO₂

Subpart RR at 40 CFR 448(a)(3) requires a strategy for detecting and quantifying surface leakage of CO₂. BSO will employ the following strategy for detecting, verifying, and quantifying CO₂ leakage to the surface through the potential pathways for CO₂ surface leakage identified in Section 4. BSO considers H₂S to be a proxy for CO₂ leakage to the surface and as such will employ and expand upon methodologies detailed in their H₂S Contingency Plan to detect, verify, and quantify CO₂ surface leakage close to the plant equipment. Table 5.1 summarizes the monitoring techniques that will be employed to identify leaks.

Monitoring will occur during the duration of injection period and the 50-year post-injection period. The plume is stabilized after 50 years without injection (year 2128).

TABLE 5.1 – LEAK DETECTION MONITORING PROGRAMS

Potential Leakage Pathway	Detection Monitoring Program
Surface Equipment	• Distributed Control System (“DCS”) surveillance of plant operations • Visual Inspections • Inline Inspections • Fixed in-field gas monitors • Personal Gas Monitors • “Optical” CO₂ Detection via Satellite or Lidar Data Imaging
Dry Piney State AGI Wells (including approved, but not yet drilled AGI wells)	• DCS surveillance of well operating parameters • Visual Inspections • Mechanical Integrity Tests (“MIT”) • In-well Pressure & Temperature sensors • Fixed in-field gas monitors • Personal Gas Monitors • “Optical” CO₂ Detection via Satellite or Lidar Data Imaging
Existing shallow oil, gas and groundwater wells	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • “Optical” CO₂ Detection via Satellite or Lidar Data Imaging • Produced gas composition surveillance of existing shallow oil & gas wells • Groundwater monitoring • CO₂ flux monitoring network
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • “Optical” CO₂ Detection via Satellite or Lidar Data Imaging • Produced gas composition surveillance of existing shallow oil & gas wells • Groundwater monitoring

	• CO₂ flux monitoring network
Confining Units	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • "Optical" CO₂ Detection via Satellite or Lidar Data Imaging • Produced gas composition surveillance of existing shallow oil & gas wells • Groundwater monitoring • CO₂ flux monitoring network
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • "Optical" CO₂ Detection via Satellite or Lidar Data Imaging • Produced gas composition surveillance of existing shallow oil & gas wells • Groundwater monitoring • CO₂ flux monitoring network
Natural and Induced Seismicity	• DCS surveillance of well operating parameters • "Optical" CO₂ Detection via Satellite or Lidar Data Imaging • Seismic monitoring station

5.1 LEAKAGE DETECTION AND VERIFICATION FROM SURFACE EQUIPMENT

BSO will implement several tiers of monitoring for leakage from surface equipment including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H₂S sensors, and continual monitoring and collection of operational parameters including flow, pressure, temperature and gas compositional data. The data will be monitored continuously by qualified technicians who will follow response and reporting protocols when the system delivers alerts and alarms that data is not within acceptable operating limits. Leaks from surface equipment will be detected by BSO field personnel, wearing personal H₂S monitors, following daily and weekly inspection and maintenance protocols which will include reporting and responding to any detected leakage events.

BSO will also maintain in-field gas monitors to detect H₂S and CO₂. The in-field gas monitors will be connected to the Distributed Control System ("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. In some instances, more than one

detector alarming would trigger automatic equipment isolation and/or shutdown to mitigate the leak. In this case, leakage would be detected almost immediately with minimal (less than one metric ton) anticipated leakage rates and volumes. The verification process would involve repeating the measurement, recalibrating the measurement device and repeating the measurement, and/or taking a second measurement with a redundant device.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to visually observe potential CO₂ plumes at the surface. These new methods would be utilized over the entire MMA and would provide insights into leakage from point sources such as surface equipment. Once identified via hyperspectral imaging or Lidar, leakage would be verified using proven and accepted detection approaches previously discussed such as soil CO₂ flux monitoring.

5.2 LEAKAGE DETECTION AND VERIFICATION FROM APPROVED NOT YET DRILLED WELLS

Currently there are four additional Dry Piney State AGI wells that are in the permitting process but are not-yet-drilled wells within the MMA. Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones including more frequent monitoring during drilling operations, and all drilling of this injection zone is required to have an H₂S contingency plan in place due to the known naturally occurring H₂S in-situ. This applies to BSO and other operators drilling new wells through or within the Madison and Bighorn injection zones within the MMA. Due to the known naturally occurring H₂S in-situ in the injection zones, the WOGCC and the Bureau of Land Management (“BLM”), if applicable, require an H₂S contingency plan to be in place as part of the drilling plan submitted as part of the application for permit to drill (“APD”). The H₂S contingency plan includes standards for personnel and equipment safety and H₂S detection and monitoring during well drilling, completion, well workovers, and well servicing operations all of which apply for wells drilled into or through the Dry Piney State injection area MMA. Detection and verification of potential leakage would be conducted by mudlogging procedures utilizing mass spectrometry gas detection that can detect and confirm the presence in relative concentrations of CO₂, H₂S, helium and other components. To clarify, BSO plans to drill the remaining four Dry Piney State AGI wells before the injection period begins, so in this scenario, CO₂ and H₂S encountered would be naturally occurring rather than confirmation of leakage of injected volumes.

5.3 LEAKAGE DETECTION AND VERIFICATION FROM EXISTING WELLS

5.3.1 DRY PINEY STATE 12-16 WELL

As part of ongoing BSO operations, BSO will continuously monitor and collect flow, pressure, temperature, and gas composition data in its data collection system. This data will be monitored continuously by qualified technicians who follow response and

reporting protocols when the system delivers alerts that data is not within acceptable limits.

To monitor leakage and wellbore integrity, BSO will deploy multiple pressure and temperature gauges, Distributed Temperature Sensing (“DTS”) and a fiber optic Distributed Acoustic Sensing (“DAS”) line to monitor pressures and temperatures during active and shut-in injection operations. Two gauges are designated to monitor the tubing (reservoir) pressure and temperature: one gauge at the surface, a second gauge downhole above the packer, and a third gauge monitors the annular space between the tubing and the long string casing. The DTS system is clamped to the tubing, and it monitors the temperature profile of the annulus. DTS can detect variation in the temperature profile events throughout the tubing and or casing. Temperature variation could be an indicator of leaks. Data from temperature and pressure gauges will be recorded by an interrogator housed in the onsite control building. DTS temperature data is recorded by a separate interrogator that is also housed in the onsite control building. Data from both interrogators are transmitted to a remote location for daily real time or historical data analysis. Real time evaluation and control by BSO operations personnel of the pressure and temperature data will enable remote action if needed.

If operational parameter monitoring and MIT failures indicate a CO₂ leak has occurred, BSO will take actions to quantify the leak based on operating conditions at the time of the detection including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. In this case, leakage would be detected almost immediately with minimal (less than one metric ton) anticipated leakage rates and volumes. The verification process would involve repeating the measurement, recalibrating the measurement device and repeating the measurement, and/or taking a second measurement with a redundant device.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into leakage from point sources such as the existing Dry Piney State 12-16 wellbore. Once identified, leakage would be verified using the proven approaches previously discussed such as soil CO₂ flux monitoring.

5.3.2 OTHER EXISTING WELLS WITHIN THE MMA

The CO₂ monitoring network described in **Section 6.3** and well surveillance by other operators of existing wells will provide an indication of any CO₂ leakage through existing wells within the MMA. Existing wells within the MMA that are still producing oil and gas are generally subject to routine (monthly or annual) gas composition analysis. To the extent possible, BSO will work with other operators to integrate and utilize gas

composition data into its leakage detection and quantification plan, as new or increased concentrations of CO₂, H₂S and/or helium would signify potential leakage via this pathway, and any potential CO₂ leakage would likely be detected via this method (see Section 6.9 for additional detail) much sooner than shallower investigation methods that will also be employed such as soil CO₂ flux and groundwater monitoring from locations throughout the MMA. See **Sections 6.7, 6.8** for details. See **Section 2.6.3, Table 2.6** and **Appendix D** for existing public gas analyses from potential baseline sampling well candidates. Due to the routine gas analysis sampling of existing oil and gas wells flowing into a gas gathering system, BSO assumes any potential leakage via existing wells would be detected within 1-3 months and noted by a sharp increase in CO₂ and H₂S over background levels established during baseline monitoring with an associated casing and/or tubing pressure increase noted by the operator of the relevant well. The verification process would involve repeating the gas analysis that shows departure from baseline, both at the same laboratory and possibly a second independent laboratory and checking well records to ensure there is not an operational issue that would cause an increase in casing or tubing pressure. With an assumed detection period of 1-3 months, approximately 1 to 1.25 million metric tons of CO₂ could be leaked before detection.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into leakage from point sources such as existing wellbores, or plume sources such as from faults, leaking confining units and/or lateral migration. Once identified, leakage would be verified using the same gas composition or soil CO₂ flux verification approaches previously discussed, as well as repeating the optical imaging technique to ensure repeatability.

5.4 LEAKAGE THROUGH THE CONFINING UNITS

As discussed in **Section 4.3**, it is very unlikely that CO₂ leakage to the surface will occur through the confining zone. Continuous operational monitoring of the Dry Piney State AGI wells, described in **Sections 5.3.1 and 6.5**, will provide an indicator if CO₂ leaks out of the injection zone. Additionally, soil CO₂ flux, groundwater monitoring and produced gas composition from locations throughout the MMA will also provide an indication of CO₂ leakage to the surface. See **Sections 6.7, 6.8 and 6.9** for details.

If changes in operating parameters or other monitoring techniques listed in **Table 5.1** indicate leakage of CO₂ through the confining units, BSO will take actions to quantify the amount of CO₂ released and take mitigative action to stop it, including shutting in the wells (see **Section 5.8**). It is anticipated that leakage through the confining units would be detected at the surface within 12-18 months, or possibly much sooner if detected via existing shallow gas wells, which would potentially allow detection before surface leakage via gas composition or pressure changes as discussed in **Section 5.3**. If leakage through

the confining zone is suspected via shallow gas wells, verification would involve repeating the gas analysis that shows departure from baseline, both at the same laboratory and possibly a second independent laboratory and checking well records to ensure there is not an operational issue that would cause an increase in casing or tubing pressure. If leakage through the confining zone is suspected via soil CO₂ flux analysis, the verification process would involve repeating the measurement, recalibrating the measurement device and repeating the measurement, and/or taking a second measurement with a redundant device, in addition to potentially adding more soil CO₂ flux locales via denser sampling grid and/or more frequent sampling intervals. With an assumed detection period of 12-18 months, approximately 4.5 to 6.75 million metric tons of CO₂ could be leaked before detection at surface.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage at the surface on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential non-point source CO₂ plumes in the event leakage through the confining unit was due to an unobservable fault or fracture network not identified during seismic interpretation. These potential methods would be utilized over the entire MMA and would provide insights into location of plume source leaks such as from leaking confining units. Once identified, leakage would be verified using the same gas composition or soil CO₂ flux verification approaches previously discussed, as well as repeating the optical imaging technique to ensure repeatability.

5.5 LEAKAGE DUE TO FAULTS AND FRACTURES

As discussed in **Section 4.4**, it is very unlikely that CO₂ leakage to the surface will occur through faults. However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO₂ leakage to the surface, BSO will identify which of the pathways listed in this section are responsible for the leak, including the possibility of unidentified faults or fractures within the MMA. BSO will take measures to quantify the mass of CO₂ emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, soil CO₂ flux, groundwater monitoring and produced gas composition from locations throughout the MMA will also provide an indication of CO₂ leakage to the surface. See **Sections 6.7, 6.8 and 6.9** for details. See **Section 5.8** for additional information on quantification strategies. It is anticipated that leakage through the confining units would be detected at the surface within 12-18 months, or possibly much sooner if detected via existing shallow gas wells, which would potentially allow detection before surface leakage via gas composition or pressure changes as discussed in Section 5.3. If leakage through the confining zone is suspected via shallow gas wells, verification would involve repeating the gas analysis that shows departure from baseline, both at the same laboratory and possibly a second independent laboratory and checking well records

to ensure there is not an operational issue that would cause an increase in casing or tubing pressure. If leakage through the confining zone is suspected via soil CO₂ flux analysis, the verification process would involve repeating the measurement, recalibrating the measurement device and repeating the measurement, and/or taking a second measurement with a redundant device, in addition to potentially adding more soil CO₂ flux locales via denser sampling grid and/or more frequent sampling intervals. With an assumed detection period of 12-18 months, approximately 4.5 to 6.75 million metric tons of CO₂ could be leaked before detection.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into location of plume source leaks such as leakage along faults and fractures. Once identified, leakage would be verified using the same gas composition or soil CO₂ flux verification approaches previously discussed, as well as repeating the optical imaging technique to ensure repeatability.

5.6 LEAKAGE DUE TO LATERAL MIGRATION

Continuous monitoring within the MMA during and after the period of injection will provide an indication of the movement of the CO₂ plume migration in the injection zones. The CO₂ monitoring network described in **Section 6.3**, and routine well surveillance will provide an indicator if CO₂ leaks out of the injection zone. Additionally, soil CO₂ flux, groundwater monitoring and produced gas composition from locations throughout the MMA will also provide an indication of CO₂ leakage to the surface. See Sections 6.7, 6.8 and 6.9 for details.

If monitoring of operational parameters or other monitoring methods listed in Table 5.1 indicates that the CO₂ plume extends beyond the area modeled in **Section 3.0** and presented in **Section 4.5**, BSO will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO₂ migration. As this scenario would be considered a material change per 40CFR98.448(d)(1), BSO will submit a revised MRV plan as required by 40CFR98.448(d). It is anticipated that leakage due to lateral migration would still need to leak upward through the confining units, and therefore, like the detection of leakage from confining units, leakage due to lateral migration would be detected at the surface within 12-18 months. Detection of leakage could possibly occur much sooner if detected via existing shallow gas wells, which would potentially allow detection before surface leakage via gas composition or pressure changes as discussed in **Section 5.3**. If leakage through the confining zone or due to lateral migration is suspected via shallow gas wells, verification would involve repeating the gas analysis that shows departure from baseline, both at the same laboratory and possibly a second independent laboratory and checking well records to ensure there is not an operational issue that would cause an increase in casing or tubing pressure. If leakage through the confining

zone or due to lateral migration is suspected via soil CO₂ flux analysis, the verification process would involve repeating the measurement, recalibrating the measurement device and repeating the measurement, and/or taking a second measurement with a redundant device, in addition to potentially adding more soil CO₂ flux locales via denser sampling grid and/or more frequent sampling intervals. With an assumed detection period of 12-18 months, approximately 4.5 to 6.75 million metric tons of CO₂ could be leaked before detection.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into location of plume source leaks such as leakage due to lateral migration. Once identified, leakage would be verified using the same gas composition or soil CO₂ flux verification approaches previously discussed, as well as repeating the optical imaging technique to ensure repeatability.

5.7 LEAKAGE DUE TO NATURAL OR INDUCED SEISMICITY

In order to monitor the influence of natural and/or induced seismicity, BSO will use the established ANSS seismic network and an onsite seismometer that will be installed. The network consists of seismic monitoring stations that detect and locate seismic events in real time. Continuous monitoring helps differentiate between natural and induced seismicity.

If the monitoring systems indicate a seismic event, BSO will assess the integrity of the DPJGPF and Dry Piney State AGI wells. If the event caused CO₂ leaks, BSO will act to quantify the mass of CO₂ emitted to the surface based on operational conditions at the time the leak was detected. See Section 6.6 for details regarding seismic monitoring and analysis. See Section 5.8 for additional information on quantification strategies

It is anticipated that leakage due to natural or induced seismicity would occur as leakage through the confining units or along faults and therefore would be detected at the surface within 12-18 months like in the case of migration through confining units. Leakage could possibly be identified sooner if detected via existing shallow gas wells, which would potentially allow detection before surface leakage via gas composition or pressure changes as discussed in Section 5.3. If leakage due to seismicity is through the confining zone or along faults is suspected via shallow gas wells, verification would involve repeating the gas analysis that shows departure from baseline, both at the same laboratory and possibly a second independent laboratory and checking well records to ensure there is not an operational issue that would cause an increase in casing or tubing pressure. If leakage due to seismicity is through the confining zone or along faults is suspected via soil CO₂ flux analysis, the verification process would involve repeating the measurement, recalibrating the measurement device and repeating the measurement, and/or taking a

second measurement with a redundant device, in addition to potentially adding more soil CO₂ flux locales via denser sampling grid and/or more frequent sampling intervals. With an assumed detection period of 12-18 months, approximately 4.5 to 6.75 million metric tons of CO₂ could be leaked before detection.

Additionally, BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into location of plume source leaks such as from faults, lateral migration or through confining units due to natural or induced seismicity. Once identified, leakage would be verified using the same gas composition or soil CO₂ flux verification approaches previously discussed, as well as repeating the optical imaging technique to ensure repeatability.

5.8 STRATEGY FOR QUANTIFYING CO₂ LEAKAGE AND RESPONSE

5.8.1 LEAKAGE FROM SURFACE EQUIPMENT

For normal operations, quantification of emissions of CO₂ from surface equipment will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR. Quantification of major leakage events from surface equipment as identified by the detection techniques listed in Table 5.1 will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified, the leakage location will be isolated to prevent additional emissions to the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. BSO has standard operating procedures to report and quantify all pipeline leaks in accordance with applicable regulations, including Department of Transportation (DOT) Part 195. BSO will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by BSO or third parties. Additionally, BSO may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

5.8.2 LEAKAGE IN THE SUBSURFACE

Selection of a quantification strategy for leaks that occur in the subsurface will be based on the leak detection method (Table 5.1) that identifies the leak. Leaks associated with the point sources, such as the injection wells, and identified by failed MITs, variations of operational parameters outside acceptable ranges, and in-well pressure and temperature sensors can be addressed immediately after the injection well has been shut in. Quantification of the mass of CO₂ emitted during the leak will depend on characterization of the subsurface leak, operational conditions at the time of the leak, and knowledge of

the geology and hydrogeology at the leakage site. Conservative estimates of the mass of CO₂ emitted to the surface will be made assuming that all CO₂ released during the leak will reach the surface. BSO may choose to estimate the emissions to the surface more accurately by employing transport, geochemical, or reactive transport model simulations.

If detected and verified, quantification of leakage from existing oil and gas wells within the MMA will be estimated through a combination of pressure and gas composition data combined with operating parameters at the time of the leak, that can be used in material balance equations. Other direct measurements such as accumulation chambers or tenting would be employed to measure leakage rates to allow calibration of material balance estimation.

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, due to lateral migration or which may be initiated by seismic events and may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations. In the event a leakage plume is identified via optical imaging technique such as Lidar or satellite-based hyperspectral imaging, weather and atmospheric conditions will be utilized in a modeling-based approach to quantify CO₂ leakage, as well as measurement of CO₂ flux at surface near the surface leakage location via eddy covariance, accumulation chamber or tenting. These methods would allow direct measurement of the leak rate at the surface, which would provide a good estimation of total leakage, as well as calibration of optical imaging modeling.

5.8.3 LEAKAGE AT THE SURFACE

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO₂ leaking back to the surface emphasizing the importance of monitoring network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO₂ flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 5.8.1, or from the subsurface. In the latter case, CO₂ flux monitoring methodologies, as described in Section 6.8, will be employed to quantify the surface leaks.

6.0 STRATEGY FOR ESTABLISHING EXPECTED BASELINES FOR MONITORING CO₂ SURFACE LEAKAGE

BSO will use its automatic distributed control system to continuously monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO₂. BSO considers H₂S to be a proxy for CO₂ leakage to the surface and as such will employ and expand upon methodologies detailed in its H₂S contingency plan to establish

baselines for monitoring CO₂ surface leakage. The following describes BSO's strategy for collecting baseline information.

6.1 VISUAL INSPECTIONS

Field personnel will conduct daily inspections of the AGI facilities and weekly inspections of the AGI well site. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize the possibility of CO₂ leakage. If an issue is identified, a work order will be generated to correct the issue.

6.2 FIXED IN-FIELD AND PERSONAL H₂S GAS MONITORS

Compositional analysis of BSO's gas injectate at the Dry Piney State AGI area indicates an approximate H₂S concentration of 7% thus requiring BSO to develop and maintain an H₂S Contingency Plan (Plan) according to the WOGCC and BLM regulations. As previously stated, BSO considers H₂S to be an excellent proxy for CO₂ leaks at the plant and the AGI site. The Plan contains procedures to provide for an organized response to an unplanned release of H₂S from the plant or the associated Dry Piney State AGI wells and documents procedures that would be followed in case of such an event. The baseline expectation for H₂S, and therefore CO₂, would be 0 ppm with no alarms during routine operations. Departure from this baseline would require investigation to ensure there are no leaks from surface equipment at the gas plant or AGI location.

6.2.1 FIXED IN-FIELD H₂S GAS MONITORS

The DPJGPF utilizes numerous fixed-point monitors, strategically located throughout the plant, to detect the presence of H₂S in ambient air. The Dry Piney State AGI well site will also employ fixed-point monitors located across the well pad to mitigate varying weather conditions (wind directions). The monitors are connected to the local control system or the DCS Safety Instrumented System, which is designed for safety-critical devices and operations. Upon detection of H₂S at 10 ppm at any detector, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of H₂S at 90 ppm at any monitor, visible red beacons are activated and an evacuation alarm is sounded throughout the plant at which time all personnel will proceed immediately to a designated evacuation area.

6.2.2 HANDHELD AND PERSONAL H₂S GAS MONITORS

Handheld gas detection monitors are available at strategic locations around the plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, Lower Explosive Limit ("LEL") for hydrocarbons in the atmosphere, H₂S and CO₂.

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the plant and at the Dry Piney State AGI wells site must wear

personal H₂S monitoring devices to assist them in detecting the presence of unsafe levels of H₂S. Personal monitoring devices will give an audible alarm and vibrate at 10 ppm.

6.3 CO₂ DETECTION MONITORING NETWORK AND OPTICAL DATA IMAGERY

In addition to the handheld gas detection monitors described above, BSO will set up a monitoring network for CO₂ leakage detection in the MMA/AMA as defined in Section 3.1 and 3.2. In addition, there will be periodic produced gas composition analysis (**Section 6.5**), groundwater chemistry analysis (**Section 6.7**), and soil CO₂ flux sampling (**Section 6.8**) within the MMA. Once the network is set up, BSO will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project to allow identification of any deviation from baseline analyses that may suggest a leak.

BSO is investigating the use of optical imaging techniques to detect CO₂ leakage on a much broader spatial scale via the use of satellite based hyperspectral imaging and/or Lidar to observe potential CO₂ plumes. These potential methods would be utilized over the entire MMA and would provide insights into the location of surface leakage from any of the identified pathways. In order to establish a baseline, the satellite or Lidar data imaging methodology would be employed on a semi-annual basis for two years, then annually.

6.4 CONTINUOUS PARAMETER MONITORING

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

6.5 WELL SURVEILLANCE AND GAS COMPOSITION MONITORING

BSO will adhere to the requirements of WOGCC rules governing the construction, operation and closing of an injection well. It includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, WOGCC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. BSO's Routine Operations and Maintenance Procedures for the Dry Piney State AGI wells will ensure frequent periodic inspection of the well and opportunities to detect leaks and implement corrective action.

Additionally, to the extent possible, BSO will work with area operators of existing shallow gas wells to monitor a subset of existing oil and gas wells for CO₂ leakage as defined in **Sections 4.2 and 5.3**. Production gas samples will be collected and analyzed on a quarterly basis for 12 months to establish baseline data. After establishing the gas composition

baseline, samples will be collected and analyzed annually. Samples will be collected according to standard industry methods for production well gas sampling (citation?).

The gas compositional analysis will include at least methane, ethane, propane, isobutane, n-butane, heptanes, octanes, nonanes, decanes plus, nitrogen, carbon dioxide, oxygen, hydrogen sulfide and helium. See **Table 6.5** for parameters to be measured during baseline analyses, that will be compiled and compared with regional historical data to determine patterns of change in produced gas composition not related to injection processes at the Dry Piney State injection area. A report of produced gas composition will be developed from this analysis. Any produced gas composition samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

<i>Parameters</i>
Methane (mol%)
Ethane (mol%)
Propane (mol%)
Isobutane (mol%)
n-Butane (mol%)
Heptanes (mol%)
Octanes (mol%)
Nonanes (mol%)
Decanes Plus (mol%)
Nitrogen (mol%)
Carbon Dioxide (mol%)
Hydrogen Sulfide (mol%)
Helium (mol%)

Table 6.5: Parameters and constituents that will be tested for in gas composition analyses conducted on select existing shallow gas wells to establish a baseline.

6.6 SEISMIC MONITORING STATION

BSO will install a seismometer and a digital recorder to monitor and record data for any seismic event at the DPJGPF and Dry Piney State AGI well site. BSO will ensure that the seismic monitoring station is configured such that it can record and report data to third parties as necessary. BSO will also monitor the ANSS network for seismicity in the injection area. A report will be periodically generated with a map showing the magnitudes of recorded events from seismic activity. By examining historical data, a seismic baseline prior to the start of injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of

time can be extracted from the overall data set to identify anomalous events during that period.

6.7 GROUNDWATER MONITORING

BSO will monitor groundwater wells for CO₂ leakage as defined in **Section 4.2**. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 6.7** for parameters to be measured during baseline analyses, that will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Dry Piney State injection area. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

<i>Parameters</i>
pH
Alkalinity as HCO ₃ ⁻ (mg/L)
Chloride (mg/L)
Fluoride (mg/L)
Bromide (mg/L)
Nitrate (NO ₃ ⁻) (mg/L)
Phosphate (mg/L)
Sulfate (SO ₄ ²⁻) (mg/L)
Lithium (mg/L)
Sodium (mg/L)
Potassium (mg/L)
Magnesium (mg/L)
Calcium (mg/L)
Total Dissolved Solids (mg/L)
Total Cations (meq/L)
Total Anions (meq/L)
Percent Difference (%)
Oxidation-Reduction Potential (mv)

Non-Purgeable Organic Carbon (ppm)

Table 6.7: *Parameters and constituents that will be analyzed in groundwater chemistry samples to establish a baseline from existing groundwater wells.*

6.8 SOIL CO₂ FLUX MONITORING

Soil flux data will be used to assess any migration of CO₂ through the soil and its escape to the atmosphere. By taking CO₂ soil flux measurements at periodic intervals, BSO can continuously characterize the interaction between the subsurface and surface. Actionable recommendations can be made based on the collected data.

Soil CO₂ flux will be collected on a monthly basis for 12 months to establish a baseline and understand seasonal and other variations in the Dry Piney State AGI area. After the baseline is established, data will be collected quarterly for three years, then annually. Due to the climate in the area, soil CO₂ flux samples will be collected on the schedule proposed above as weather conditions and seasonality allow. BSO will target surface locations associated with plugged and abandoned wells, as well as areas directly above faults for initial baseline monitoring locations.

Soil CO₂ flux measurements will be taken using a LI-COR LI-8100A flux chamber, or similar instrument, at pre planned locations at the site. PVC soil collars (8cm diameter) will be installed in accordance with the LI-8100A specifications where possible. Measurements will be subsequently made by placing the LI-8100A chamber on the soil collars and using the integrated iOS app to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. The soil collars will be left in place such that each subsequent measurement campaign will use the same locations and collars during data collection. In the event it is not possible to install soil collars, a different permanent marker such as rebar post will be installed so subsequent measurements can be taken in the same location.

7.0 CONSIDERATIONS USED TO CALCULATE SITE-SPECIFIC VARIABLES FOR THE MASS BALANCE EQUATION

To accommodate for site-specific conditions, as provided in 40 CFR 98.448, BSO proposes to modify quantifying equipment leaks by using a risk-driven approach. Due to the high H₂S concentration of the AGI fluids, leaks pose a risk to personnel. Additionally, as mentioned above, even a small leak of this high H₂S gas would trigger an alarm to the operations team. BSO will identify leaks through continuous surveillance and leak detection systems and will alarm operations to take immediate action to stop the release. This continuous surveillance using fixed gas detectors will identify leaks better than annual leak surveys due to the fact that the gas

detectors are in operation at all times. When detected, fugitive leakage would be managed as an upset event and calculated for that event based on operating conditions at that time.

Below describes how BSO will calculate the mass of CO₂ injected, emitted, and sequestered.

7.1 MASS OF CO₂ RECEIVED

§98.443 states that “you must calculate the mass of CO₂ received using CO₂ received equations... unless you follow the procedures in §98.444(a)(4).” §98.444(a)(4) states that “if the CO₂ you receive is wholly injected and is not mixed with any other supply of CO₂, you may report the annual mass of CO₂ injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO₂ received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO₂ received.” Since the CO₂ received by the AGI process is wholly injected and not mixed with any other supply of CO₂, the annual mass of CO₂ injected would be equal to the annual mass of CO₂ received, as calculated using Equation RR-4 per CFR 98.444(a)(4):

$$CO_{2,u} = \sum_{p=1}^4 Q_{p,u} * C_{CO_2,p,u}$$

Where:

CO_{2,u} = Annual CO₂ mass injected (metric tons) as measured by flow meter u.

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

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

p = Quarter of the year.

u = Flow meter.

7.2 MASS OF CO₂ INJECTED

Mass flow meters will be used to measure the injected mass of CO₂ at each well. Equation RR-4 (in Section 7.1) will be used to calculate the annual total mass of CO₂ injected into each well. Equation RR-6 will be used to aggregate injection data for the AGI wells. Equation RR-6 is below:

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

Where:

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

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

u = Flow meter.

7.3 MASS OF CO_2 PRODUCED

The AGI wells will not be part of an enhanced oil or enhanced gas recovery process, nor does reservoir simulation show the free-phase CO_2 plume reaching any existing or future production wells, therefore, there will be no injected CO_2 produced and/or recycled.

7.4 MASS OF CO_2 EMITTED BY SURFACE LEAKAGE AND EQUIPMENT LEAKS

It is not appropriate to conduct a leak survey at the AGI well sites due to the components being unsafe-to-monitor and extensive monitoring systems in place. Entry to the AGI well pad will require the individual to wear a personal gas monitor capable of detecting CO_2 and H_2S , thus allowing immediate identification of possible leakage from surface equipment. Due to the high H_2S and CO_2 concentrations of the AGI fluids, fugitive leakage would be detected and managed as an upset event in the same way that CO_2E (CO_2 emitted by surface leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time. As already mentioned, gas detectors are in operation continuously to survey the area for leaks; even a small leak would trigger an alarm. This methodology is consistent with 40 CFR 98.448(5), which provides the opportunity for an operator to calculate site-specific variables for the mass balance equation.

Therefore, parameters CO_2E and CO_2FI (CO_2 emitted from equipment leaks from surface equipment between the flow meter used to measure injection quantity and the injection wellhead) will be measured using the leakage quantification procedures described earlier in this plan. BSO will estimate the mass of CO_2 emitted from leakage points from the flow meter to the injection wellhead based on operating conditions at the time of the release – pipeline pressure, temperature, flow rate, size of the leakage point opening, and estimated duration of leak. At the AGI wells, there will be no CO_2 emissions from venting due to the high H_2S concentration of the AGI fluid; blowdown emissions are sent to the flares and are reported under Subpart W for the gas plant. Venting AGI well injection gas would only occur in the event of depressurizing for maintenance or testing, which would be measured during time of event. To clarify, no venting or “blowdown” emissions would occur after metering for Subpart RR due to the position of the flow meters used to measure injection quantity relative to the injection wellheads (Figure 2.15). Therefore, no venting or blowdown emissions would be included in the calculation for CO_2FI which is the total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions from equipment located on the surface between the flow meters used to measure injection quantity and the injection wellheads.

In the event that surface leakage is detected, the leakage would be quantified and be used to estimate the mass emitted from each pathway and summed using Equation RR-10:

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

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.

7.5 MASS OF CO_2 SEQUESTERED IN SUBSURFACE GEOLOGIC FORMATIONS

Since BSO is not actively producing oil or natural gas or any other fluids as part of the AGI process, Equation RR-12 will be used to quantify CO_2 injected and sequestered. Parameter CO_{2I} (CO_2 injected in the well or group of wells annually) will be determined using Equation RR-4, as outlined above in Section 7.2. Parameters CO_{2E} and CO_{2FI} will be measured using the leakage quantification procedure described above in Section 7.4. CO_2 in the AGI fluids is not vented from equipment due to the high H_2S concentration. Equation RR-12 is as follows:

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

Where:

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

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

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

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

8.0 ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

Upon approval by the EPA, this MRV Plan will become the applicable plan for the Dry Piney State AGI wells. BSO expects the Commercial Online Date (“COD”) to be approximately October 2028. BSO will begin collecting baseline data at least 12 months in advance of this expected date,

beginning in 2027. At COD, BSO will begin collecting data to enable calculation of the total amount of CO₂ sequestered based on the equations in Section 7.0. Once the MRV Plan becomes applicable, BSO will report under Subpart RR for the AGI wells. Once applicable, BSO anticipates this MRV Plan will remain in effect until the end-of-field-life of BSO's DPU and AGI assets, unless and until it is subsequently amended and superseded.

9.0 QUALITY ASSURANCE PROGRAM

9.1 MONITORING QA/QC

In accordance with the applicable requirements of 40 CFR 98.444, BSO will incorporate the following provisions into its QA/QC programs:

CO₂ Injected

- The mass of CO₂ injected will be measured with a mass flow meter for each AGI well and will be monitored continuously, allowing the mass injected to be compiled quarterly.
- A continuous gas composition analyzer will measure the concentrations for each representative stream.
- The continuous composition measurements will be averaged over the quarterly period to determine the quarterly CO₂ composition of the injected stream.
- The CO₂ analyzers will be calibrated according to manufacturer recommendations.

CO₂ emissions from equipment leaks and vented emissions of CO₂

- Gas detectors are operated continuously except as necessary for maintenance and calibration.
- Gas detectors will be operated and calibrated according to manufacturer recommendations and API standards.

Measurement Devices

- Mass Flow meters will be operated continuously except as necessary for maintenance and calibration.
- Mass Flow meters will be calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i).
- Mass Flow meters will be operated according to an appropriate standard method published by a consensus-based standards organization.

- Mass Flow meter calibrations are traceable to National Institute of Standards and Technology (NIST).

General

- CO₂ concentration will be measured using continuous gas analyzers, which is an industry standard practice.
- All measured volumes of CO₂ will be converted to standard cubic feet at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 MISSING DATA PROCEDURES

In the event BSO is unable to collect data needed for the mass balance calculations, 40 CFR 98.445 procedures for estimating missing data will be used as follows:

- If a quarterly quantity of CO₂ injected is missing, it will be estimated using a representative quantity of CO₂ injected from the nearest previous time period at a similar injection pressure.
- For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment at the facility that are reported in this subpart, missing data estimation procedures will be followed in accordance with those specified in subpart W of 40 CFR Part 98.

9.3 MRV PLAN REVISIONS

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

10.0 RECORDS RETENTION

BSO will follow the record retention requirements of CFR 98.3(g). Additionally, it will retain the following records from AGI well sites for at least three years:

- Quarterly records of injected CO₂ including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways.

- Annual records of information used to calculate the CO₂ emitted from equipment leaks of CO₂, from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035058210000	GOVT	No. 1-W	PA	WASATCH	145	16325	13347	NO	1	1	1
49035058210000	GOVT	No. 1-W	PA	WASATCH	145	16325	13347	NO	1	1	1
49035057920000	FEDERAL	No. 8	PA	TERTIARY	228	15661	12683	YES	1	1	1
49035057350000	GOVT	No. 1-W	PA	TERTIARY	90	15180	12202	YES	1	1	1
49035058240000	GOVT	No. 1-W	PA	TERTIARY	85	14755	11777	YES	1	1	1
49035252220000	NORTH LABARGE UNIT	No. 103-04X	PA	TERTIARY	35	14473	11495	NO	1	1	1
49035241210000	NORTH LABARGE UNIT	No. 101-33D	PA	TERTIARY	60	14077	11099	NO	1	1	1
49035058130000	HADDENHAM	No. 1	PA	TERTIARY	385	14010	11032	YES	1	1	1
49035054970000	FEDERAL	No. 1W	PA	TERTIARY	135	13765	10787	YES	1	1	1
49035223880000	BX	No. 20-20	PA	HILLIARD	215	13652	10674	NO	1	1	1
49035247660000	CHIMNEY BUTTE UNIT	No. 113-36H	PA	TERTIARY	40	13641	10663	YES	1	1	1
49035054300000	LABARGE UNIT	No. 1	PA	TERTIARY	195	13505	10527	NO	1	1	1
49035056490000	GOVT	No. 1	PA	ALMY	960	13430	10452	YES	1	1	1
49035054030000	GOVT	No. 1-W	PA	TERTIARY	130	13305	10327	NO	1	1	1
49035235250000	TIP TOP UNIT	No. T37X-15GH	SHUT-IN	WASATCH	865	13198	10220	YES	1	1	1
49035056350000	MCDONALD DRAW UNIT	No. 1	PA	WASATCH	900	13196	10218	YES	1	1	1
49035058140000	GOVT	No. 2	PA	TERTIARY	1070	13165	10187	YES	1	1	1
49035053490000	FEDERAL	No. 1W	PA	TERTIARY	195	13075	10097	NO	1	1	1
49035057480000	CHAMBERLAIN PATENTED	No. 7-B	PA	ALMY	890	12934	9956	NO	1	1	1
49035056060000	FED W-0256493	No. 65	PA	TERTIARY	1729	12806	9828	YES	1	1	1
49035055880000	BNG	No. 6-33	PA	ALMY	1260	12800	9822	NO	1	1	1
49035056800000	SHALLOW UNIT	No. 2	PROD - GAS	ALMY	986	12759	9781	NO	1	1	1
49035057220000	BNG	No. 5-20	PA	ALMY	1000	12757	9779	NO	1	1	1
49035056340000	LABARGE SHALLOW UNIT	No. 4	PA	ALMY	1056	12691	9713	NO	1	1	1
49035056440000	LABARGE UNIT	No. 64	PA	TERTIARY	1790	12654	9676	NO	1	1	1
49035059380000	TRESNER STATE	No. 11-36	PA	ALMY	1742	12654	9676	NO	1	1	1
49035207770000	TIP TOP UNIT	No. 115-21	PROD - OIL	MESAVERDE	1220	12627	9649	NO	1	1	1
49035057210000	STATE	No. C-5	PA	ALMY	1340	12611	9633	YES	1	1	1
49035207070000	TIP TOP UNIT	No. 112-21	PROD - OIL	ALMY	1200	12608	9630	NO	1	1	1
49035057640000	BIG PINEY	No. C-5	PA	ALMY	1340	12604	9626	NO	1	1	1
49035203010000	TIP TOP UNIT	No. 95-21	PA	MESAVERDE	1230	12594	9616	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

**** Well has existing Gas Analysis (See Appendix D)***

APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035059470000	TRESNER STATE	No. 10-36	PA	FORT UNION	1850	12586	9608	NO	1	1	1
49035059500000	TRESNER STATE	No. 20-36	PA	ALMY	1895	12564	9586	NO	1	1	1
49035211930000	BNG	No. 57A-21 WIW	INJ - WATER	TERTIARY	1250	12563	9585	YES	1	1	1
49035203600000	TIP TOP UNIT W48908	No. 97-21	INJ - WATER	MESAVERDE	1265	12542	9564	NO	1	1	1
49035058920000	C	No. 27	PA	ALMY	1800	12527	9549	YES	1	1	1
49035056520000	GOVT	No. 3	PA	ALMY	1208	12514	9536	NO	1	1	1
49035207620000	BNG	No. 114-28	PROD - OIL	MESAVERDE	1336	12508	9530	NO	1	1	1
49035057290000	BNG E-024353	No. 58	PA	MESAVERDE	1350	12503	9525	NO	1	1	1
49035057270000	BNG	No. 57-21	PA	MESAVERDE	1287	12501	9523	NO	1	1	1
49035057340000	BNG	No. 77-21	PROD - OIL	MESAVERDE	1351	12498	9520	NO	1	1	1
49035059290000	TRESNER STATE	No. 3-36	PA	ALMY	1854	12485	9507	NO	1	1	1
49035203000000	BNG	No. 94-21	PA	MESAVERDE	1320	12482	9504	NO	1	1	1
49035056730000	SHALLOW UNIT	No. 67-28	PA	WASATCH	1250	12462	9484	NO	1	1	1
49035057200000	TIP TOP UNIT	No. 76	TA	MESAVERDE	1306	12457	9479	NO	1	1	1
49035211380000	BNG	No. 94A-21	PA	MESAVERDE	1350	12455	9477	NO	1	1	1
49035056890000	SHALLOW W-0256492	No. 54-28	PROD - OIL	MESAVERDE	1343	12422	9444	NO	1	1	1
49035059300000	BIG PINEY MESAVERDE	No. 42-B	PA	ALMY	1899	12420	9442	NO	1	1	1
49035058830000	FED W-07828	No. C41	PA	ALMY	1800	12419	9441	YES	1	1	1
49035057110000	SHALLOW UN W-0256492	No. 44	PA	MESAVERDE	1436	12381	9403	NO	1	1	1
49035203040000	BNG	No. 96-28 WIW	TA	MESAVERDE	1339	12380	9402	YES	1	1	1
49035056560000	SHALLOW UNIT	No. 68	PA	WASATCH	1392	12372	9394	NO	1	1	1
49035056900000	TIP TOP SHALLOW UNIT	No. 52-28	PA	MESAVERDE	1391	12357	9379	NO	1	1	1
49035057040000	BNG	No. 41-28	PROD - OIL	MESAVERDE	1418	12353	9375	YES	1	1	1
49035211700000	BNG	No. 119-21	INJ - WATER	TERTIARY	1515	12336	9358	NO	1	1	1
49035211370000	BNG	No. 116-28	PROD - OIL	MESAVERDE	1480	12312	9334	NO	1	1	1
49035056660000	SHALLOW UNIT	No. 60-28	PA	MESAVERDE	1500	12309	9331	YES	1	1	1
49035057070000	SHALLOW UN W-0256492	No. 46	PROD - OIL	MESAVERDE	1589	12250	9272	NO	1	1	1
49035060440000	MCDONALD DRAW	No. 60-21	PA	TERTIARY	3874	12249	9271	NO	1	1	1
49035057370000	C MCGINNIS	No. 19-23	PA	MESAVERDE	3188	12248	9270	YES	1	1	1
49035056920000	BNG	No. 1-28	PROD - GAS	ALMY	1388	12243	9265	NO	1	1	1
49035207610000	BNG	No. 113-28	PA	MESAVERDE	1580	12242	9264	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

**** Well has existing Gas Analysis (See Appendix D)***

APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035056630000	TIP TOP UNIT	No. C-71-27	PA	TERTIARY	2265	12196	9218	YES	1	1	1
49035208390000	BIG PINEY SHALLOW UN	No. 84-3	PA	TERTIARY	2045	12186	9208	YES	1	1	1
49035211710000	BNG	No. 120-28	PA	MESAVERDE	1575	12171	9193	YES	1	1	1
49035059040000	FEDERAL	No. C-44	PA	WASATCH	2383	12162	9184	NO	1	1	1
49035059740000	MCDONALD DRAW UNIT	No. 63-33	PA	TERTIARY	3396	12108	9130	YES	1	1	1
49035060080000	MCDONALD DRAW UNIT	No. 75-29	PA	WASATCH	3050	12103	9125	YES	1	1	1
49035203640000	UNIT	No. 104-5	PA	ALMY	3175	12097	9119	YES	1	1	1
49035058720000	MCDONALD DRAW UNIT	No. 49	PA	ALMY	3250	12064	9086	YES	1	1	1
49035059990000	MCDONALD DRAW UNIT	No. 31-27	PA	TERTIARY	3600	12064	9086	YES	1	1	1
49035207710000	BNG	No. 117-21	PA	MESAVERDE	1755	12063	9085	NO	1	1	1
49035055900000	BNG E-022209	No. 55-33	PROD - OIL	MESAVERDE	2071	12062	9084	NO	1	1	1
49035057100000	BNG	No. 53-29	PA	MESAVERDE	1750	12061	9083	NO	1	1	1
49035204650000	BNG	No. 102-33	PROD - OIL	MESAVERDE	2050	12057	9079	NO	1	1	1
49035058630000	LIU	No. 22-3	PA	TERTIARY	3730	12052	9074	YES	1	1	1
49035200870000	HAIGHT-GOVT	No. 3	PA	ALMY	3800	12037	9059	NO	1	1	1
49035058760000	MCDONALD DRAW UNIT	No. 73	PA	TERTIARY	2939	12029	9051	YES	1	1	1
49035056960000	SHALLOW UNIT	No. 75-28	PROD - OIL	MESAVERDE	1775	12025	9047	NO	1	1	1
49035060040000	MCDONALD DRAW	No. 40-28	PA	WASATCH	3450	12025	9047	YES	1	1	1
49035055770000	CP	No. 2-4	PROD - GAS	WASATCH	2084	12020	9042	NO	1	1	1
49035204700000	SADDLE RIDGE UNIT	No. 105-4	PA	MESAVERDE	2375	12020	9042	NO	1	1	1
49035058860000	MCDONALD DRAW	No. 74-6	PA	TERTIARY	2880	12019	9041	YES	1	1	1
49035204230000	TARTERS ISLAND UNIT	No. 3-1S	PA	WASATCH	4585	12019	9041	NO	1	1	1
49035204230000	TARTERS ISLAND UNIT	No. 3-1S	PA	WASATCH	4585	12019	9041	NO	1	1	1
49035204630000	SADDLE RIDGE UNIT	No. 101-33	PROD - OIL	MESAVERDE	2223	12018	9040	NO	1	1	1
49035055970000	BNG	No. BNG 80-32	SHUT-IN	MESAVERDE	1898	12015	9037	NO	1	1	1
49035205040000	SADDLE RIDGE UNIT	No. BNG 107-32	PA	MESAVERDE	1900	12008	9030	NO	1	1	1
49035050000000	MCDONALD DRAW UNIT	No. 67	PA	ALMY	3310	12003	9025	YES	1	1	1
49035204730000	BNG	No. 106	PA	MESAVERDE	2050	12002	9024	NO	1	1	1
49035208380000	C	No. 85-3	PROD - GAS	ALMY	2250	11993	9015	YES	1	1	1
49035058640000	MCDONALD DRAW	No. 72-6	PA	TERTIARY	2950	11992	9014	YES	1	1	1
49035204260000	SADDLE RIDGE UNIT	No. 98-4	PA	MESAVERDE	2035	11992	9014	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035055750000	BNG	No. 84-04	SHUT-IN	MESAVERDE	2266	11982	9004	NO	1	1	1
49035062970000	MCDONALD DRAW UNIT	No. 83-33	PA	TERTIARY	3364	11981	9003	YES	1	1	1
49035204690000	BNG	No. 104-33	PROD - GAS	MESAVERDE	1974	11967	8989	NO	1	1	1
49035206930000	BIG PINEY SAND UNIT	No. 27-31	PA	ALMY	3000	11961	8983	NO	1	1	1
49035063170000	LONG ISLAND UNIT	No. 24-2	PA	WASATCH	4520	11943	8965	NO	1	1	1
49035063170000	LONG ISLAND UNIT	No. 24-2	PA	WASATCH	4520	11943	8965	NO	1	1	1
49035056190000	SADDLE RIDGE UNIT	No. BNG 79-32	PA	MESAVERDE	1901	11939	8961	NO	1	1	1
49035055470000	BNG	No. 86-04 WIW	SHUT-IN	MESAVERDE	2427	11938	8960	NO	1	1	1
49035063100000	MCDONALD DRAW	No. 86-28	PA	ALMY	3439	11938	8960	YES	1	1	1
49035055960000	BNG	No. 85	PA	MESAVERDE	2509	11933	8955	YES	1	1	1
49035055820000	BNG	No. 71	PA	MESAVERDE	1994	11931	8953	NO	1	1	1
49035056090000	FED E-022209	No. 693	PA	MESAVERDE	1993	11930	8952	NO	1	1	1
49035059490000	MCDONALD DRAW UNIT	No. 44	PA	WASATCH	3500	11930	8952	YES	1	1	1
49035200690000	GOVT-HEIGHT	No. 1	PA	TERTIARY	3735	11925	8947	YES	1	1	1
49035055870000	SADDLE RIDGE UNIT	No. BNG 47-33	INJ - WATER	MESAVERDE	2327	11924	8946	NO	1	1	1
49035056150000	BNG	No. 40-32	PA	MESAVERDE	1900	11924	8946	NO	1	1	1
49035056670000	UNIT W-48908	No. C-66	PA	TERTIARY	2110	11923	8945	YES	1	1	1
49035059870000	MCDONALD DRAW UNIT	No. 24-33WIW	PA	TERTIARY	3550	11917	8939	YES	1	1	1
49035059350000	MCDONALD DRAW UNIT	No. 46	PA	WASATCH	3400	11916	8938	YES	1	1	1
49035055610000	BNG	No. 89-T	PA	MESAVERDE	2700	11914	8936	NO	1	1	1
49035058930000	MCDONALD DR E-023340	No. 71	PA	TERTIARY	2900	11911	8933	YES	1	1	1
49035059580000	MCDONALD DRAW UNIT	No. 61	PROD - OIL	WASATCH	3531	11908	8930	YES	1	1	1
49035221580000	BLACK CANYON CREEK	No. 1-32	PA	MESAVERDE	1964	11908	8930	NO	1	1	1
49035204310000	BNG	No. 99-4	PA	MESAVERDE	2532	11906	8928	NO	1	1	1
49035059730000	LONG ISLAND UNIT	No. 2	PA	WASATCH	4393	11904	8926	YES	1	1	1
49035059730000	LONG ISLAND UNIT	No. 2	PA	WASATCH	4393	11904	8926	YES	1	1	1
49035059450000	MCDONALD DRAW UNIT	No. 48-34	INJ - WATER	WASATCH	3619	11900	8922	YES	1	1	1
49035055700000	CP	No. 3-4 WIW	TA	WASATCH	2180	11893	8915	NO	1	1	1
49035058870000	MCDONALD DRAW UNIT	No. 69	PA	WASATCH	3415	11893	8915	YES	1	1	1
49035060130000	MCDONALD DRAW	No. 35-28	PA	WASATCH	3446	11880	8902	YES	1	1	1
49035063110000	MCDONALD DRAW	No. 85-28	PA	WASATCH	3475	11878	8900	YES	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035055550000	BNG	No. 90	PA	MESAVERDE	2301	11876	8898	NO	1	1	1
49035059360000	MCDONALD DRAW UNIT	No. 62	PA	WASATCH	3362	11875	8897	YES	1	1	1
49035059690000	MCDONALD DRAW UNIT	No. 45-33	PA	WASATCH	3403	11870	8892	YES	1	1	1
49035059880000	MCDONALD DRAW UNIT	No. 42-33	PA	WASATCH	3440	11870	8892	YES	1	1	1
49035056270000	BNG	No. 72-33 WIW	SHUT-IN	MESAVERDE	2000	11863	8885	NO	1	1	1
49035056390000	BNG	No. BNG 78-32	PA	MESAVERDE	1872	11861	8883	NO	1	1	1
49035059150000	MCDONALD DRAW UNIT	No. 53-34	PA	WASATCH	3320	11851	8873	YES	1	1	1
49035059540000	MCDONALD DRAW UNIT	No. 59-33	PA	TERTIARY	3380	11849	8871	YES	1	1	1
49035056940000	SHALLOW UNIT	No. 82	PROD - GAS	MESAVERDE	1938	11837	8859	YES	1	1	1
49035056290000	SADDLE RIDGE UNIT	No. BNG 59-32	PA	MESAVERDE	1890	11825	8847	NO	1	1	1
49035062900000	MCDONALD DRAW UNIT	No. 81-34	PA	WASATCH	3605	11823	8845	YES	1	1	1
49035060110000	MCDONALD DRAW UNIT	No. 28-28	PA	TERTIARY	3600	11820	8842	YES	1	1	1
49035055510000	BNG	No. 88-04	PROD - OIL	MESAVERDE	2700	11816	8838	NO	1	1	1
49035203500000	MCDONALD DRAW UNIT	No. 103-5	PA	ALMY	3631	11809	8831	YES	1	1	1
49035056420000	BNG	No. 20-32	PA	MESAVERDE	1917	11805	8827	NO	1	1	1
49035216070000	MCDONALD DRAW UNIT	No. 203-33	PA	ALMY	3360	11799	8821	YES	1	1	1
49035057710000	BIG PINEY UNIT	No. C-25	PA	ALMY	2160	11794	8816	YES	1	1	1
49035060020000	BIG PINEY P SAND	No. 8	PA	FORT UNION	2983	11780	8802	NO	1	1	1
49035056590000	BNG	No. 73-28	PA	MESAVERDE	1950	11778	8800	NO	1	1	1
49035050050000	BIG PINEY P SAND	No. 10-31	PA	FORT UNION	3019	11775	8797	NO	1	1	1
49035058510000	MCDONALD DRAW UNIT	No. 80-4	PA	WASATCH	3675	11768	8790	YES	1	1	1
49035215600000	MCDONALD DRAW UNIT	No. 2-33	PROD - OIL	MESAVERDE	3422	11764	8786	YES	1	1	1
49035058730000	C	No. 43 B-03	PA	TERTIARY	2438	11757	8779	YES	1	1	1
49035056810000	GOVT	No. 9	PA	MESAVERDE	2053	11754	8776	YES	1	1	1
49035058710000	MCDONALD DRAW UNIT	No. 57-05 WIW	INJ - WATER	WASATCH	3610	11750	8772	YES	1	1	1
49035063770000	MCDONALD DRAW UNIT	No. 66-5	PA	TERTIARY	3600	11748	8770	YES	1	1	1
49035216650000	MCDONALD DRAW UNIT	No. 207-28	PA	ALMY	3552	11746	8768	YES	1	1	1
49035203320000	MCDONALD DRAW UNIT	No. 102	PA	ALMY	3505	11744	8766	YES	1	1	1
49035203310000	MCDONALD DRAW UNIT	No. 101-34	PA	WASATCH	3510	11738	8760	YES	1	1	1
49035215500000	MCDONALD DRAW UNIT	No. 200-33	PROD - OIL	ALMY	3509	11738	8760	YES	1	1	1
49035056470000	BNG	No. 24	PA	MESAVERDE	2071	11736	8758	NO	1	1	1

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035207040000	BIG PINEY UNIT	No. 80-25	PA	ALMY	2337	11735	8757	YES	1	1	1
49035203150000	MCDONALD DRAW UNIT	No. 97-33	PA	MESAVERDE	3350	11734	8756	YES	1	1	1
49035215610000	MCDONALD DRAW UNIT	No. 202-33	PROD - OIL	ALMY	3425	11726	8748	YES	1	1	1
49035201000000	KLAENHAMMER STATE	No. 1	PA	WASATCH	4600	11725	8747	YES	1	1	1
49035201000000	KLAENHAMMER STATE	No. 1	PA	WASATCH	4600	11725	8747	YES	1	1	1
49035062960000	MCDONALD DRAW UNIT	No. 82-05	PA	WASATCH	3550	11724	8746	YES	1	1	1
49035202520000	PAVLISIN	No. 13-11	PA	FORT UNION	3800	11724	8746	YES	1	1	1
49035057380000	BNG	No. 10	PA	MESAVERDE	2185	11722	8744	NO	1	1	1
49035058610000	MCDONALD DRAW UNIT	No. 55	PROD - OIL	WASATCH	3635	11722	8744	YES	1	1	1
49035209100000	JOHNSON GULCH	No. 1-1	PA	MESAVERDE	2850	11718	8740	YES	1	1	1
49035203280000	MCDONALD DRAW	No. 100-50	PA	WASATCH	3535	11717	8739	YES	1	1	1
49035059190000	PSU W-0125390	No. E-22	PA	ALMY	2820	11713	8735	NO	1	1	1
49035058410000	MCDONALD DRAW UNIT	No. 54	PA	WASATCH	3610	11700	8722	YES	1	1	1
49035202770000	BELCO FEDERAL	No. 5-2	PA	WASATCH	4550	11698	8720	NO	1	1	1
49035202770000	BELCO FEDERAL	No. 5-2	PA	WASATCH	4550	11698	8720	NO	1	1	1
49035058540000	MCDONALD DR E-023340	No. 64	PA	ALMY	3630	11695	8717	YES	1	1	1
49035203120000	MCDONALD DRAW UNIT	No. 99	PA	ALMY	3565	11694	8716	YES	1	1	1
49035059250000	MCDONALD DRAW UNIT	No. 50	PA	WASATCH	3618	11691	8713	YES	1	1	1
49035058880000	MCDONALD DRAW UNIT	No. 52	PA	WASATCH	3615	11686	8708	YES	1	1	1
49035215930000	MCDONALD DRAW UNIT	No. 204-33	PA	MESAVERDE	3350	11686	8708	YES	1	1	1
49035058380000	MCDONALD DRAW	No. 65-4	PA	WASATCH	3810	11685	8707	YES	1	1	1
49035059240000	BIG PINEY P SAND	No. 21-31	PA	FORT UNION	2908	11685	8707	NO	1	1	1
49035058580000	MCDONALD DRAW UNIT	No. 68	PA	WASATCH	3600	11684	8706	YES	1	1	1
49035059090000	MCDONALD DRAW UNIT	No. 51-34	PA	WASATCH	3670	11682	8704	YES	1	1	1
49035058490000	MCDONALD DRAW UNIT	No. 58-5	PA	WASATCH	3815	11678	8700	YES	1	1	1
49035063180000	MCDONALD DRAW	No. 77-33	PA	ALMY	3200	11672	8694	YES	1	1	1
49035203130000	MCDONALD DRAW UNIT	No. 98-05	PA	ALMY	3810	11669	8691	YES	1	1	1
49035204680000	SADDLE RIDGE E022209	No. 103-33	PA	MESAVERDE	2578	11667	8689	NO	1	1	1
49035059230000	BIG PINEY P SAND	No. 19-31	PA	FORT UNION	2885	11652	8674	NO	1	1	1
49035208870000	MCDONALD DRAW UNIT	No. 106-5	PROD - OIL	ALMY	3630	11652	8674	YES	1	1	1
49035059100000	MCDONALD DRAW	No. 47	PROD - OIL	WASATCH	3660	11642	8664	YES	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035225630000	LONG ISLAND UNIT	No. 1-36	PA	MESAVERDE	4450	11634	8656	YES	1	1	1
49035225630000	LONG ISLAND UNIT	No. 1-36	PA	MESAVERDE	4450	11634	8656	YES	1	1	1
49035200230000	MCDONALD DRAW UNIT	No. 88-5	PA	TERTIARY	3655	11625	8647	YES	1	1	1
49035055800000	LABARGE UNIT	No. 68	PA	MESAVERDE	2904	11620	8642	YES	1	1	1
49035059940000	LONG ISLAND UNIT	No. 1	PA	WASATCH	5065	11619	8641	NO	1	1	1
49035059940000	LONG ISLAND UNIT	No. 1	PA	WASATCH	5065	11619	8641	NO	1	1	1
49035058150000	GOVT	No. 1	PA	TERTIARY	2290	11600	8622	YES	1	1	1
49035071380000	WELL	No. S-14-21	PA	TERTIARY	2460	11593	8615	YES	1	1	1
49035204430000	NORTH LABARGE	No. 100-33	PA	MESAVERDE	2698	11593	8615	YES	1	1	1
49035058520000	LONE ISLAND	No. 19-3	PA	MESAVERDE	4270	11581	8603	YES	1	1	1
49035209340000	MCDONALD DRAW UNIT	No. 5-108-8	UNKNOWN	ALMY	3430	11580	8602	YES	1	1	1
49035059810000	BIG PINEY P SAND	No. 5	PA	ALMY	3195	11576	8598	NO	1	1	1
49035063290000	BELCO-MCDONALD DRAW	No. 78-6	PA	ALMY	3231	11572	8594	YES	1	1	1
49035059080000	BPMVU	No. 27	PA	ALMY	1744	11571	8593	YES	1	1	1
49035215000000	CHAWA	No. 1-26	SPUD	TERTIARY	2325	11571	8593	YES	1	1	1
49035050030000	BIG PINEY P SAND	No. 12	PA	ALMY	3265	11561	8583	NO	1	1	1
49035055270000	FLETCHER	No. 2	PA	MESAVERDE	2800	11550	8572	NO	1	1	1
49035062940000	NORTH LABARGE SH UN	No. 11-9	PA	MESAVERDE	2243	11546	8568	NO	1	1	1
49035062930000	NORTH LABARGE SH UN	No. 12-9	PA	MESAVERDE	2775	11529	8551	NO	1	1	1
49035225940000	LONG ISLAND	No. 2-3	PA	TRANSITION	4409	11511	8533	YES	1	1	1
49035201540000	MORGAN GOVT	No. 2	PA	MESAVERDE	4060	11493	8515	YES	1	1	1
49035214400000	NORTH LABARGE SH UN	No. 20-9E	PA	MESAVERDE	2875	11492	8514	NO	1	1	1
49035056300000	FED W-48904	No. 66	PA	WASATCH	2550	11478	8500	NO	1	1	1
49035057090000	SHALLOW UN W-0256492	No. 70	PA	MESAVERDE	2300	11468	8490	YES	1	1	1
49035057870000	MARK	No. 1	PA	MESAVERDE	4612	11457	8479	YES	1	1	1
49035059820000	GOVT MIRACLE	No. 1	PA	WASATCH	4950	11454	8476	YES	1	1	1
49035059820000	GOVT MIRACLE	No. 1	PA	WASATCH	4950	11454	8476	YES	1	1	1
49035058960000	MCDONALD DRAW UNIT	No. 8	PA	WASATCH	3683	11447	8469	YES	1	1	1
49035209460000	MCDONALD DRAW UNIT	No. 5-110	PA	MESAVERDE	3650	11425	8447	YES	1	1	1
49035216560000	SANIBEL	No. 1-4D	PA	MESAVERDE	4335	11413	8435	YES	1	1	1
49035050020000	BIG PINEY UT E023584	No. 11-1	PA	MESAVERDE	2503	11406	8428	YES	1	1	1

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49035200360000	MCDONALD DRAW	No. 89-12	PA	TERTIARY	2954	11399	8421	YES	1	1	1
49035055730000	FLETCHER	No. 1	PA	HILLIARD	3241	11382	8404	NO	1	1	1
49035059950000	MCDONALD DRAW UNIT	No. 11	PA	MESAVERDE	4517	11381	8403	YES	1	1	1
49035214520000	NORTH LABARGE SH UN	No. 25-9ED	SHUT-IN	MESAVERDE	2915	11374	8396	NO	1	1	1
49035058570000	LONG ISLAND	No. 17-3	PA	MESAVERDE	4521	11369	8391	YES	1	1	1
49035055360000	BNG	No. 91-4	PA	MESAVERDE	3080	11363	8385	NO	1	1	1
49035226430000	TIP TOP SHALLOW	No. 130-20	PROD - GAS	TRANSITION	2515	11336	8358	NO	1	1	1
49035059630000	BIG PINEY P SAND	No. 14-31	PA	FORT UNION	3504	11281	8303	NO	1	1	1
49035208260000	BPMVU	No. 15-32	PROD - OIL	MESAVERDE	3190	11264	8286	NO	1	1	1
49035202480000	FEDERAL	No. 16-7	PA	MESAVERDE	3410	11255	8277	YES	1	1	1
49035208890000	BPMVU	No. 15-36	PROD - GAS	MESAVERDE	3308	11253	8275	NO	1	1	1
49035207060000	BPMVU	No. 14-48	PA	MESAVERDE	3220	11244	8266	YES	1	1	1
49035054920000	BIRCH CREEK UNIT	No. 64	PA	MESAVERDE	3071	11241	8263	NO	1	1	1
49035208270000	BPMVU	No. 15-30	INJ - WATER	MESAVERDE	3295	11235	8257	NO	1	1	1
49035056210000	LABARGE UNIT	No. 67	PA	WASATCH	3046	11232	8254	YES	1	1	1
49035057700000	MCDONALD DRAW UNIT	No. 22-17	PA	TERTIARY	3272	11227	8249	YES	1	1	1
49035208810000	TRESNER STATE	No. 33	PA	ALMY	3400	11221	8243	NO	1	1	1
49035059480000	TRESNER STATE	No. 33-36	PA	ALMY	3439	11216	8238	NO	1	1	1
49035057630000	MCDONALD DRAW UNIT	No. 37-18	PA	WASATCH	3151	11212	8234	YES	1	1	1
49035213960000	BIG MESA	No. 34-27	PA	HILLIARD	2600	11205	8227	YES	1	1	1
49035057610000	MCDONALD DRAW UNIT	No. 25	PA	TERTIARY	3257	11192	8214	YES	1	1	1
49035059390000	BPMVU	No. 15-8	PA	MESAVERDE	3249	11182	8204	NO	1	1	1
49035059030000	BPMVU	No. 14-1	PROD - OIL	MESAVERDE	3200	11180	8202	YES	1	1	1
49035058950000	BIG PINEY P SAND	No. 28-31	PA	ALMY	3326	11176	8198	NO	1	1	1
49035057690000	MCDONALD DRAW UNIT	No. 26-18	PA	TERTIARY	3245	11174	8196	YES	1	1	1
49035063080000	LIU	No. 23-10	PA	MESAVERDE	4216	11173	8195	YES	1	1	1
49035058390000	MCDONALD DRAW UNIT	No. 36-5	PA	MESAVERDE	4010	11170	8192	YES	1	1	1
49035058500000	BIG PINEY P SAND	No. 32	PA	ALMY	3363	11169	8191	NO	1	1	1
49035225990000	BIG MESA	No. 37-34	PA	MESAVERDE	3324	11165	8187	YES	1	1	1
49035058890000	BPMVU	No. 14-34	PROD - OIL	MESAVERDE	3155	11163	8185	YES	1	1	1
49035214230000	N LABARGE SHALLOW	No. 4-4E	PA	MESAVERDE	3210	11160	8182	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035058810000	BPMVU	No. 14-43	PROD - OIL	MESAVERDE	3150	11156	8178	YES	1	1	1
49035059180000	BPMVU	No. 2-38	PROD - GAS	MESAVERDE	3138	11155	8177	NO	1	1	1
49035207330000	BPMVU	No. 14-49	PROD - OIL	MESAVERDE	3191	11155	8177	YES	1	1	1
49035206940000	BPMVU	No. 15-27	PROD - OIL	MESAVERDE	3425	11150	8172	NO	1	1	1
49035056930000	GRACE	No. 2	PA	MESAVERDE	4265	11149	8171	YES	1	1	1
49035056990000	BIG PINEY UNIT	No. C-31	PA	ALMY	3007	11145	8167	YES	1	1	1
49035058910000	BPMVU	No. 14-02 WIW	PA	MESAVERDE	3206	11144	8166	YES	1	1	1
49035059000000	BIG PINEY MESAVERDE	No. 14-36	INJ - WATER	MESAVERDE	3183	11143	8165	YES	1	1	1
49035063790000	BPMVU	No. 15-22	PROD - GAS	MESAVERDE	3200	11138	8160	YES	1	1	1
49035059070000	BPMVU	No. 23-3	PA	MESAVERDE	3142	11134	8156	NO	1	1	1
49035231460000	BPMVU	No. B 238-36	PROD - OIL	MESAVERDE	3436	11132	8154	NO	1	1	1
49035059370000	BPMVU	No. 15-23	PROD - OIL	MESAVERDE	3379	11130	8152	NO	1	1	1
49035207030000	BPMVU	No. 15-28	PA	MESAVERDE	3365	11123	8145	NO	1	1	1
49035059310000	BPMVU	No. BB 15-18	PROD - GAS	MESAVERDE	3317	11121	8143	NO	1	1	1
49035059460000	BPMVU	No. 15-17	PROD - GAS	MESAVERDE	3378	11118	8140	NO	1	1	1
49035058550000	FEDERAL	No. C-45	PA	WASATCH	3305	11111	8133	YES	1	1	1
49035216550000	GASPARILLA	No. 1-19D	PA	ALMY	3249	11111	8133	YES	1	1	1
49035230200000	BPMVU	No. B 236-36	PROD - OIL	MESAVERDE	3470	11110	8132	NO	1	1	1
49035057860000	MCDONALD DRAW UNIT	No. 30-8	PA	TERTIARY	3605	11109	8131	YES	1	1	1
49035058850000	MCDONALD DRAW UNIT	No. 56-5	PA	MESAVERDE	4291	11107	8129	YES	1	1	1
49035200100000	MCDONALD DRAW UNIT	No. 87	PA	MESAVERDE	3300	11104	8126	YES	1	1	1
49035059140000	BPMVU	No. 15-25	INJ - WATER	MESAVERDE	3305	11099	8121	YES	1	1	1
49035059170000	BPMVU	No. 15-13	PROD - GAS	MESAVERDE	3225	11099	8121	NO	1	1	1
49035231570000	BPMVU	No. B-241-36	PROD - GAS	MESAVERDE	3370	11096	8118	NO	1	1	1
49035058900000	BPMVU	No. BB 14-42	INJ - WATER	MESAVERDE	3237	11095	8117	YES	1	1	1
49035059020000	BB	No. 8-26	PROD - GAS	ALMY	3196	11094	8116	YES	1	1	1
49035231420000	BPMVU	No. B234-36	PA	MESAVERDE	3507	11087	8109	NO	1	1	1
49035216480000	MCDONALD DRAW UNIT	No. 208-6	PROD - GAS	MESAVERDE	3921	11078	8100	YES	1	1	1
49035059200000	BPMVU	No. 15-2	PA	MESAVERDE	3266	11077	8099	NO	1	1	1
49035055840000	LABARGE UNIT	No. 63	PA	MESAVERDE	3336	11072	8094	YES	1	1	1
49035059010000	BPMV	No. 14-33	PA	MESAVERDE	3272	11069	8091	YES	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035207270000	BPMVU	No. 14-76	PROD - GAS	MESAVERDE	3210	11067	8089	YES	1	1	1
49035213430000	BIG MESA	No. 14-27	PA	MESAVERDE	3500	11067	8089	YES	1	1	1
49035214680000	SWEET P SAND UNIT	No. 1-36	PROD - GAS	MESAVERDE	3415	11066	8088	NO	1	1	1
49035060060000	MCDONALD DRAW UNIT	No. 20-28	PA	MESAVERDE	4350	11062	8084	YES	1	1	1
49035201030000	LONG ISLAND UNIT	No. 42-15	PA	MESAVERDE	4080	11061	8083	YES	1	1	1
49035059570000	BPMVU	No. 15-16	PROD - GAS	MESAVERDE	3430	11054	8076	NO	1	1	1
49035058820000	BPMVU	No. 14-38	PROD - OIL	MESAVERDE	3230	11053	8075	YES	1	1	1
49035058800000	FEDERAL	No. C-37	PA	TERTIARY	3412	11052	8074	YES	1	1	1
49035058650000	GOVT C	No. 9	PA	MESAVERDE	3098	11051	8073	YES	1	1	1
49035059270000	BPMVU	No. 47-35	PA	MESAVERDE	3226	11051	8073	NO	1	1	1
49035202350000	LONG ISLAND UNIT	No. 55-22	PA	FORT UNION	4010	11043	8065	YES	1	1	1
49035059160000	BPMVU	No. 15-19	PROD - GAS	MESAVERDE	3327	11042	8064	YES	1	1	1
49035231690000	BPMVU	No. B 239-36	PROD - GAS	TRANSITION	3550	11036	8058	NO	1	1	1
49035058840000	BPMVU	No. 8-35	PA	MESAVERDE	3220	11026	8048	YES	1	1	1
49035231470000	BPMVU	No. B 240-36	PA	MESAVERDE	3490	11023	8045	NO	1	1	1
49035058770000	BPMVU	No. 39-3	PA	MESAVERDE	3210	11022	8044	YES	1	1	1
49035214910000	C	No. 95-23	PROD - GAS	MESAVERDE	2710	11021	8043	YES	1	1	1
49035057320000	MCDONALD DRAW UNIT	No. 41-20	PA	WASATCH	3603	11019	8041	YES	1	1	1
49035058660000	FEDERAL	No. C-16	PA	MESAVERDE	3326	11019	8041	YES	1	1	1
49035201370000	BELCO-FEDERAL	No. 24-2	PA	MESAVERDE	4100	11013	8035	YES	1	1	1
49035056280000	STATE	No. 61-36C	PA	MESAVERDE	2963	11008	8030	YES	1	1	1
49035201730000	BELCO GOVT	No. 1-20	PA	ALMY	3515	11001	8023	YES	1	1	1
49035206020000	BPMVU	No. 14-75	PA	ALMY	3265	10997	8019	YES	1	1	1
49035057520000	BIG PINEY UT E023584	No. C-11	PA	ALMY	2928	10994	8016	YES	1	1	1
49035058690000	FEDERAL	No. C-40	PA	MESAVERDE	3400	10986	8008	YES	1	1	1
49035202800000	MCDONALD DRAW UNIT	No. 96-31	PA	ALMY	3085	10986	8008	YES	1	1	1
49035206240000	BIG PINEY UNIT	No. 76-25	PA	MESAVERDE	3113	10983	8005	YES	1	1	1
49035063160000	LIU	No. 18-23	PA	MESAVERDE	4284	10980	8002	YES	1	1	1
49035059510000	BPMVU	No. UNIT 2-35	PROD - GAS	MESAVERDE	3395	10979	8001	NO	1	1	1
49035215180000	C	No. 96-23	PROD - GAS	MESAVERDE	2728	10978	8000	YES	1	1	1
49035056020000	LONG ISLAND UNIT	No. 13-34	PA	MESAVERDE	3697	10977	7999	YES	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035208300000	BPMVU	No. 14-74	PROD - OIL	MESAVERDE	3245	10971	7993	YES	1	1	1
49035209350000	MCDONALD DRAW UNIT	No. 1-107-29	PA	ALMY	3339	10970	7992	YES	1	1	1
49035056580000	MCDONALD DRAW UNIT	No. 32	PA	TERTIARY	3365	10968	7990	YES	1	1	1
49035055620000	BIRCH CREEK UNIT	No. 53	PA	MESAVERDE	3406	10966	7988	YES	1	1	1
49035213950000	ANCHO	No. 31-27	PA	MESAVERDE	2800	10966	7988	YES	1	1	1
49035057010000	BIG PINEY UNIT	No. C-58	PA	MESAVERDE	3151	10961	7983	YES	1	1	1
49035058970000	FEDERAL	No. C-24	PA	ALMY	3449	10957	7979	YES	1	1	1
49035205990000	BPMVU	No. 15-26	PA	MESAVERDE	3510	10956	7978	NO	1	1	1
49035207830000	BPMVU	No. 14-51	PROD - OIL	ALMY	3380	10955	7977	YES	1	1	1
49035203610000	TARTERS ISLAND	No. 2-33	PA	ALMY	3300	10952	7974	YES	1	1	1
49035056460000	MCDONALD DRAW UNIT	No. 33	PA	WASATCH	3225	10949	7971	YES	1	1	1
49035205610000	C	No. 74-22	PROD - OIL	MESAVERDE	2785	10946	7968	YES	1	1	1
49035214720000	BPMVU	No. 1-109-3	PA	MESAVERDE	3310	10946	7968	NO	1	1	1
49035057240000	STATE	No. C-6	PA	MESAVERDE	3525	10944	7966	YES	1	1	1
49035056500000	GRACE	No. 1	PA	MESAVERDE	4215	10941	7963	YES	1	1	1
49035202610000	FEE	No. 53-34	PA	MESAVERDE	3600	10940	7962	YES	1	1	1
49035228260000	MCDONALD DRAW UNIT	No. 126-30	PA	ALMY	3110	10938	7960	YES	1	1	1
49035056640000	MCDONALD DRAW UNIT	No. 21-29	PA	TERTIARY	3295	10935	7957	YES	1	1	1
49035057500000	BIG PINEY UNIT	No. C-51	PA	MESAVERDE	3180	10935	7957	YES	1	1	1
49035200950000	MORGAN-GOVT	No. 1	PA	MESAVERDE	4115	10935	7957	YES	1	1	1
49035231580000	BB	No. 242-36	PA	MESAVERDE	3550	10935	7957	NO	1	1	1
49035202780000	BELCO-FEDERAL	No. 1-27	PA	MESAVERDE	3944	10933	7955	YES	1	1	1
49035206960000	WYOMING 1115-023	No. C79-23	PA	MESAVERDE	2800	10931	7953	YES	1	1	1
49035053460000	BIRCH CREEK UNIT	No. 34	PROD - OIL	MESAVERDE	2610	10929	7951	NO	1	1	1
49035056850000	MCDONALD DRAW UNIT	No. 23	PA	TERTIARY	3290	10927	7949	YES	1	1	1
49035056320000	MCDONALD DRAW UNIT	No. 34	PA	TERTIARY	3170	10926	7948	YES	1	1	1
49035056510000	MCDONALD DRAW UNIT	No. 19-29	PA	TERTIARY	3225	10924	7946	YES	1	1	1
49035215390000	WAHOO	No. 1-34D	PA	MESAVERDE	3450	10924	7946	YES	1	1	1
49035216220000	WYNKOOP	No. 1-16	PA	MESAVERDE	3309	10920	7942	NO	1	1	1
49035056250000	MCDONALD DRAW UNIT	No. 15	PA	TERTIARY	3245	10915	7937	YES	1	1	1
49035063140000	LIU	No. 16-23	PA	MESAVERDE	4200	10911	7933	YES	1	1	1

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035056600000	BIG PINEY UNIT	No. C-57	PA	MESAVERDE	3460	10907	7929	YES	1	1	1
49035205630000	BIG PINEY UNIT	No. 72-25	PA	MESAVERDE	3160	10905	7927	YES	1	1	1
49035226130000	BIG MESA	No. 35-27D	PA	MESAVERDE	3557	10903	7925	YES	1	1	1
49035059280000	MCDONALD DRAW UNIT	No. 7	PA	MESAVERDE	4150	10901	7923	YES	1	1	1
49035053680000	BIRCH CREEK UNIT	No. 24	PA	MESAVERDE	2675	10895	7917	NO	1	1	1
49035209430000	C	No. 86-22 WIW	INJ - WATER	MESAVERDE	2910	10889	7911	YES	1	1	1
49035057360000	BIG PINEY UNIT	No. C-52	PROD - OIL	MESAVERDE	2855	10886	7908	YES	1	1	1
49035070270000	UNKNOWN	No. C-15	PA	MESAVERDE	3170	10884	7906	NO	1	1	1
49035205600000	C	No. 73-23	PROD - OIL	MESAVERDE	2948	10876	7898	YES	1	1	1
49035057720000	BIG PINEY UNIT	No. C 8-14	PA	MESAVERDE	3061	10872	7894	YES	1	1	1
49035055910000	LONG ISLAND UNIT	No. 9	PA	MESAVERDE	3890	10865	7887	YES	1	1	1
49035054630000	BIRCH CREEK UNIT	No. 60	PA	MESAVERDE	2657	10862	7884	NO	1	1	1
49035221390000	BIRCH CREEK UNIT	No. 177A	PA	MESAVERDE	2698	10861	7883	YES	1	1	1
49035057970000	GOVT	No. 1	PA	MESAVERDE	4907	10855	7877	YES	1	1	1
49035201850000	MCDONALD DRAW UNIT	No. 92-32	PA	ALMY	3240	10839	7861	YES	1	1	1
49035063400000	MCDONALD DRAW	No. 76-06	PA	MESAVERDE	4019	10838	7860	YES	1	1	1
49035056480000	STATE	No. C-591	PA	MESAVERDE	3275	10836	7858	YES	1	1	1
49035215230000	WAZEE	No. 1-16	PA	MESAVERDE	3220	10836	7858	NO	1	1	1
49035216510000	MCDONALD DRAW UNIT	No. 209-6	PA	MESAVERDE	3948	10835	7857	YES	1	1	1
49035202260000	MCDONALD DRAW UNIT	No. 93	PA	ALMY	3390	10834	7856	YES	1	1	1
49035057930000	GOVT	No. C-20	PA	MESAVERDE	3058	10831	7853	YES	1	1	1
49035200820000	LONG ISLAND UNIT	No. 39-34	PA	MESAVERDE	3854	10831	7853	YES	1	1	1
49035201450000	LORENZ-GOVT	No. 2	PA	MESAVERDE	3654	10830	7852	YES	1	1	1
49035200020000	FIGURE FOUR	No. M-7	PA	MESAVERDE	3500	10829	7851	YES	1	1	1
49035202270000	MCDONALD DRAW UNIT	No. 94-32	PA	ALMY	3352	10829	7851	YES	1	1	1
49035056720000	BIG PINEY	No. C-69-2	PA	HILLIARD	3350	10822	7844	YES	1	1	1
49035059640000	GOVT E	No. 20	PA	FORT UNION	4003	10822	7844	YES	1	1	1
49035058780000	MCDONALD DRAW UNIT	No. 70-06	PROD - OIL	MESAVERDE	4084	10820	7842	YES	1	1	1
49035209380000	UNIT	No. 1-109-32	PA	ALMY	3343	10820	7842	YES	1	1	1
49035057590000	LONG ISLAND UNIT	No. 14-15	PA	MESAVERDE	4427	10818	7840	YES	1	1	1
49035056380000	MCDONALD DRAW UNIT	No. 14-29	PA	TERTIARY	3305	10816	7838	YES	1	1	1

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API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035201150000	WISE-GOVT	No. 1	PA	MESAVERDE	4100	10815	7837	YES	1	1	1
49035059210000	TRESNER STATE	No. 6-36	PA	MESAVERDE	3680	10814	7836	NO	1	1	1
49035057820000	MCDONALD DRAW UNIT	No. 10	PA	MESAVERDE	3680	10813	7835	YES	1	1	1
49035053780000	BIRCH CREEK UNIT	No. 29	PA	MESAVERDE	2665	10812	7834	NO	1	1	1
49035104370000	MCDONALD DRAW UNIT	No. 27-20	PA	MESAVERDE	3600	10803	7825	YES	1	1	1
49035201740000	MCDONALD DRAW UNIT	No. 90-32	PA	ALMY	3160	10803	7825	YES	1	1	1
49035057650000	BIG PINEY UNIT	No. C18-14	PA	MESAVERDE	3075	10802	7824	YES	1	1	1
49035201800000	MCDONALD DRAW UNIT	No. 91	PA	ALMY	3253	10796	7818	YES	1	1	1
49035056180000	LONG ISLAND UNIT	No. 20-36	PA	MESAVERDE	4307	10795	7817	YES	1	1	1
49035056690000	BIG PINEY UNIT	No. C-56	PA	MESAVERDE	3637	10795	7817	YES	1	1	1
49035202290000	MCDONALD DRAW UNIT	No. 95	PA	ALMY	3171	10789	7811	YES	1	1	1
49035213700000	BIG MESA	No. 21-34	PA	HILLIARD	3695	10773	7795	YES	1	1	1
49035056550000	MCDONALD DRAW UNIT	No. 18	PA	MESAVERDE	3440	10765	7787	YES	1	1	1
49035056860000	MCDONALD DRAW UNIT	No. 2	PA	MESAVERDE	3491	10764	7786	YES	1	1	1
49035057130000	MCDONALD DRAW UNIT	No. 1	PA	MESAVERDE	3545	10759	7781	YES	1	1	1
49035055530000	GREEN RIVER BEND UN	No. T-25	PA	TERTIARY	3120	10758	7780	YES	1	1	1
49035216350000	CHAWA	No. 2-26	PA	MESAVERDE	3613	10757	7779	YES	1	1	1
49035200750000	GOVT-LORENZ	No. 1	PA	MESAVERDE	3650	10754	7776	YES	1	1	1
49035216250000	BIG PINEY MESAVERDE	No. 1-115-3-AJ	PA	MESAVERDE	3415	10750	7772	YES	1	1	1
49035201080000	GREEN RIVER BEND UN	No. T-77-6	PA	MESAVERDE	3290	10744	7766	YES	1	1	1
49035060230000	BIG PINEY P SAND	No. 2-30	PA	MESAVERDE	4183	10739	7761	NO	1	1	1
49035216240000	ROCOTILLO	No. 1-26	PA	MESAVERDE	3130	10736	7758	YES	1	1	1
49035055020000	GREEN RIVER BEND UN	No. T-73-8	PA	WASATCH	3225	10735	7757	YES	1	1	1
49035056010000	LONG ISLAND UNIT	No. 7 YOSE	PA	MESAVERDE	4000	10734	7756	YES	1	1	1
49035206270000	MILLS UNIT	No. 78-26	PA	MESAVERDE	3000	10733	7755	YES	1	1	1
49035201210000	GREEN RIVER BEND UN	No. T81-7	PA	ALMY	2876	10731	7753	YES	1	1	1
49035054190000	BIRCH CREEK UNIT	No. 57	PA	MESAVERDE	2884	10730	7752	NO	1	1	1
49035056610000	LONG ISLAND UNIT	No. 8	PA	MESAVERDE	4004	10730	7752	YES	1	1	1
49035057420000	BIG PINEY UNIT	No. C47-22	PA	MESAVERDE	3100	10729	7751	YES	1	1	1
49035057790000	BIG PINEY UNIT	No. C-2	PA	MESAVERDE	3161	10727	7749	YES	1	1	1
49035054350000	BIRCH CREEK UNIT	No. 55	PA	MESAVERDE	3050	10720	7742	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035055330000	GREEN RIVER BEND UN	No. T-56-5	PA	TRANSITION	3362	10701	7723	YES	1	1	1
49035228380000	GREEN RIVER BEND UN	No. T 300-6	PA	MESAVERDE	3313	10696	7718	YES	1	1	1
49035201110000	GREEN RIVER BEND UN	No. T80-7	PA	ALMY	2905	10695	7717	YES	1	1	1
49035202670000	FEDERAL	No. 10-13	PA	MESAVERDE	3892	10692	7714	YES	1	1	1
49035057430000	BIG PINEY UNIT	No. C-50	PA	MESAVERDE	3151	10691	7713	YES	1	1	1
49035213070000	LITTLE MESA	No. 33-25	PA	MESAVERDE	3750	10691	7713	YES	1	1	1
49035212220000	C	No. 89-22D	PROD - GAS	MESAVERDE	3140	10690	7712	YES	1	1	1
49035058230000	C	No. 15	PA	MESAVERDE	3170	10679	7701	YES	1	1	1
49035211920000	C	No. 87-22	PROD - OIL	MESAVERDE	3100	10678	7700	YES	1	1	1
49035055490000	BIRCH CREEK UNIT	No. 59	PA	HILLIARD	3654	10675	7697	YES	1	1	1
49035053890000	BIRCH CREEK UNIT	No. 4	PA	MESAVERDE	2700	10669	7691	NO	1	1	1
49035055810000	MCDONALD DRAW UNIT	No. 16	PA	TERTIARY	3255	10668	7690	YES	1	1	1
49035211910000	C	No. 90-22	PROD - OIL	MESAVERDE	3100	10667	7689	YES	1	1	1
49035058030000	FEDERAL	No. C-14	PA	MESAVERDE	3230	10665	7687	YES	1	1	1
49035056230000	MCDONALD DRAW UNIT	No. 9-32	PA	MESAVERDE	3555	10660	7682	YES	1	1	1
49035057560000	MCDONALD DRAW UNIT	No. 3	PA	MESAVERDE	4040	10659	7681	YES	1	1	1
49035202470000	FEDERAL	No. 8-1	PA	MESAVERDE	4026	10653	7675	YES	1	1	1
49035058700000	GOVT C	No. 3	PA	MESAVERDE	3554	10652	7674	YES	1	1	1
49035057550000	BIG PINEY	No. C-1-23	PA	TRANSITION	3150	10651	7673	YES	1	1	1
49035057510000	BIG PINEY UNIT	No. C-53	PA	MESAVERDE	3701	10646	7668	YES	1	1	1
49035206290000	BIG PINEY UNIT	No. 77-23	PA	MESAVERDE	3425	10646	7668	YES	1	1	1
49035054570000	BIRCH CREEK UNIT	No. 49	PA	MESAVERDE	2954	10645	7667	YES	1	1	1
49035201050000	SWIGERT-FEDERAL	No. 1	PA	TERTIARY	3289	10644	7666	YES	1	1	1
49035057140000	MILLS	No. C-46	PA	MESAVERDE	3110	10643	7665	YES	1	1	1
49035055720000	MCDONALD DRAW UNIT	No. 4	PA	MESAVERDE	3440	10633	7655	YES	1	1	1
49035055380000	BIRCH CREEK UNIT	No. 65	PA	MESAVERDE	3082	10628	7650	YES	1	1	1
49035053770000	BIRCH CREEK UNIT	No. 80	PA	MESAVERDE	2825	10627	7649	NO	1	1	1
49035056430000	MCDONALD DRAW UNIT	No. 13-29	PA	MESAVERDE	3493	10616	7638	YES	1	1	1
49035216230000	POPEYE	No. 1-11	PA	MESAVERDE	3494	10616	7638	YES	1	1	1
49035056540000	MCDONALD DRAW UNIT	No. 17-29	PA	TERTIARY	3570	10609	7631	YES	1	1	1
49035058750000	FEDERAL	No. C-30	PA	MESAVERDE	3868	10603	7625	NO	1	1	1

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035214880000	SWEET P	No. 2-2	PA	MESAVERDE	3800	10602	7624	YES	1	1	1
49035062980000	GREEN RIVER BEND UN	No. T-75-1	PA	MESAVERDE	2925	10575	7597	YES	1	1	1
49035212460000	C	No. 88-22	PROD - OIL	MESAVERDE	3150	10575	7597	YES	1	1	1
49035213180000	LITTLE MESA	No. 14-24D	PA	MESAVERDE	3307	10569	7591	YES	1	1	1
49035059320000	FED E-024355	No. 5	PA	MESAVERDE	4401	10567	7589	YES	1	1	1
49035056220000	UNIT	No. 11-36	PA	MESAVERDE	4975	10565	7587	YES	1	1	1
49035056240000	MCDONALD DRAW UNIT	No. 29	PA	MESAVERDE	3500	10564	7586	YES	1	1	1
49035215650000	RED HILL	No. T1-18	PA	MESAVERDE	2950	10562	7584	NO	1	1	1
49035205010000	TARTERS ISLAND UNIT	No. 5-4	PA	MESAVERDE	3495	10552	7574	YES	1	1	1
49035057470000	MCGINNIS VICTOR	No. 3-D	PA	MESAVERDE	3611	10551	7573	YES	1	1	1
49035057310000	BNG	No. 11-13	PROD - GAS	ALMY	3177	10549	7571	YES	1	1	1
49035057000000	CHURCH BUTTE-023554	No. C-48	PA	MESAVERDE	3300	10547	7569	YES	1	1	1
49035200990000	GREEN RIVER BEND UN	No. T79	PA	MESAVERDE	2975	10547	7569	YES	1	1	1
49035215290000	HABANERO	No. 2-3	PA	MESAVERDE	3600	10544	7566	YES	1	1	1
49035057840000	CHURCH BUTTE UNIT	No. C-10	PA	MESAVERDE	3586	10543	7565	YES	1	1	1
49035213540000	C WIW	No. 92-22	INJ - WATER	MESAVERDE	3200	10543	7565	YES	1	1	1
49035213550000	C WIW	No. 91-22	PROD - OIL	HILLIARD	3200	10543	7565	YES	1	1	1
49035215300000	BONITA	No. 1-35	PA	MESAVERDE	3048	10543	7565	YES	1	1	1
49035056880000	GOVT	No. C-70-2	PA	HILLIARD	3285	10541	7563	YES	1	1	1
49035217000000	GREEN RIVER BEND UN	No. T205-7	PA	ALMY	2915	10538	7560	YES	1	1	1
49035201260000	CHORNEY-FEDERAL	No. 43-5	PA	MESAVERDE	3450	10528	7550	YES	1	1	1
49035215710000	JALAPENO	No. 1-14	PA	MESAVERDE	3398	10520	7542	YES	1	1	1
49035057990000	FEDERAL C	No. 21	PA	MESAVERDE	3814	10517	7539	YES	1	1	1
49035215020000	GREEN RIVER BEND UN	No. T204-7	PA	MESAVERDE	2959	10510	7532	YES	1	1	1
49035214760000	HABANERO	No. 1-3	PA	MESAVERDE	3600	10494	7516	YES	1	1	1
49035060250000	GOVT E	No. 4	PA	MESAVERDE	4489	10493	7515	NO	1	1	1
49035215430000	PASILLA	No. 1-15D	PA	MESAVERDE	3550	10492	7514	YES	1	1	1
49035057530000	BIG PINEY	No. C-13	PA	MESAVERDE	3400	10481	7503	YES	1	1	1
49035213650000	TIP TOP UNIT	No. 94-27	PA	MESAVERDE	3250	10481	7503	YES	1	1	1
49035058980000	BIG PINEY P SAND	No. 29	PA	MESAVERDE	4062	10478	7500	NO	1	1	1
49035213640000	C	No. 93-22	INJ - WATER	MESAVERDE	3250	10476	7498	YES	1	1	1

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49035215010000	GREEN RIVER BEND UN	No. T203-7	PA	MESAVERDE	3018	10465	7487	YES	1	1	1
49035055280000	BIRCH CREEK UNIT	No. 47	PA	MESAVERDE	2950	10447	7469	YES	1	1	1
49035055560000	MCDONALD DRAW UNIT	No. 6	PA	MESAVERDE	3490	10446	7468	YES	1	1	1
49035056870000	CHIMNEY BUTTE	No. D-4	PA	MESAVERDE	3826	10430	7452	YES	1	1	1
49035058680000	DRY PINEY	No. 36 X	PA	MESAVERDE	4003	10422	7444	YES	1	1	1
49035056140000	STATE	No. C-62	PA	MESAVERDE	3850	10413	7435	YES	1	1	1
49035057890000	W-0637	No. C-12	PA	MESAVERDE	3315	10389	7411	YES	1	1	1
49035214730000	GREEN RIVER BEND UN	No. T201-7	PA	MESAVERDE	3100	10383	7405	YES	1	1	1
49035213310000	LITTLE MESA	No. 23-14D	PA	MESAVERDE	3587	10337	7359	YES	1	1	1
49035207850000	BIG PINEY UNIT	No. 81-25C	PA	MESAVERDE	4125	10292	7314	YES	1	1	1
49035055300000	FEDERAL	No. 78-4	PA	HILLIARD	4138	10253	7275	NO	1	1	1
49035071300000	FEDERAL	No. D-2	PA	HILLIARD	4633	10252	7274	YES	1	1	1
49035206260000	C	No. 75-36	PROD - GAS	MESAVERDE	4050	10224	7246	YES	1	1	1
49035055570000	BIRCH CREEK UNIT	No. 11	PA	HILLIARD	3648	10177	7199	YES	1	1	1
49035056450000	STATE	No. 60	PA	MESAVERDE	4051	10142	7164	YES	1	1	1
49035056050000	MADONALD DRAW UNIT	No. 12-32	PA	MESAVERDE	3600	9860	6882	YES	1	1	1
49035225470000	BX	No. 20-20X	PROD - GAS	HILLIARD	4431	9412	6434	NO	1	1	1
49035223930000	BX	No. 37-28	PROD - GAS	HILLIARD	4394	9405	6427	YES	1	1	1
49035224680000	BX	No. 44-34	PROD - GAS	HILLIARD	5176	9334	6356	YES	1	1	1
49035226320000	BX	No. 101-17	PROD - GAS	HILLIARD	4578	9332	6354	NO	1	1	1
49035220110000	BX	No. 12-16	PROD - GAS	HILLIARD	4940	9294	6316	NO	1	1	1
49035220100000	BX	No. 11-16	PROD - GAS	HILLIARD	5000	9229	6251	NO	1	1	1
49035224550000	BX	No. 42-27	PROD - GAS	ALMY	4555	9201	6223	YES	1	1	1
49035220460000	CHIMNEY BUTTE	No. B1-15	PROD - GAS	HILLIARD	4995	9141	6163	YES	1	1	1
49035211220000	TERMINATION DR	No. 3-15	PROD - GAS	HILLIARD	4976	9136	6158	YES	1	1	1
49035210700000	NEW FORK MESA	No. 1-15	PROD - GAS	HILLIARD	5126	8970	5992	YES	1	1	1
49035211260000	TERMINATION	No. 2-10	PROD - GAS	HILLIARD	5060	8937	5959	YES	1	1	1
49035600290000	STATE-J	No. 3	PA	FRONTIER	7325	8167	5189	YES	1	1	1
49035210830000	NORTH LABARGE	No. UNIT 57-33	PROD - GAS	HILLIARD	6504	7636	4658	NO	1	1	1
49035211660000	NORTH LABARGE UNIT	No. 65-33	PROD - GAS	FRONTIER	6552	7574	4596	NO	1	1	1
49035211620000	NORTH LABARGE UNIT	No. 58-04	PROD - GAS	FRONTIER	6592	7553	4575	NO	1	1	1

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49035211610000	NORTH LABARGE SH UN	No. 66-4	PROD - GAS	FRONTIER	7021	7497	4519	NO	1	1	1
49035054100000	FEDERAL	No. 1	PA	FRONTIER	6270	7430	4452	NO	1	1	1
49035056110000	LABARGE UNIT	No. 14	PA	FRONTIER	6772	7051	4073	NO	1	1	1
49035245980000	TIP TOP UNIT	No. T41X-21GH	SO	FRONTIER	7345	7039	4061	NO	1	1	1
49035208200000	NORTH LABARGE UNIT	No. 36-33	PROD - GAS	FRONTIER	7700	6888	3910	NO	1	1	1
49035055500000	NORTH LABARGE UNIT	No. 21-04	PROD - GAS	FRONTIER	7305	6868	3890	NO	1	1	1
49035055050000	NORTH LABARGE SH UN	No. 19	PA	FRONTIER	7125	6843	3865	NO	1	1	1
49035055350000	BNG	No. 27-04	SHUT-IN	FRONTIER	7604	6842	3864	NO	1	1	1
49035211830000	TIP TOP UNIT	No. T82X-32G	PROD - GAS	FRONTIER	6930	6805	3827	NO	1	1	1
49035201470000	TIP TOP UNIT	No. T26-16S	PROD - GAS	FRONTIER	7730	6781	3803	NO	1	1	1
49035208340000	CHIMNEY BUTTE UNIT	No. 35-34	PA	FRONTIER	7715	6780	3802	YES	1	1	1
49035259540000	NORTH LABARGE UNIT	No. 103-04	PROD - GAS	FRONTIER	7750	6758	3780	NO	1	1	1
49035253850000	NORTH LABARGE UNIT	No. 117-09	PROD - GAS	FRONTIER	7664	6753	3775	NO	1	1	1
49035204860000	CHIMNEY BUTTE UNIT	No. 20-34	PROD - GAS	FRONTIER	7680	6752	3774	YES	1	1	1
49035200240000	CHIMNEY BUTTE UNIT	No. 18-34	PROD - GAS	FRONTIER	7730	6744	3766	YES	1	1	1
49035209650000	NORTH LABARGE UNIT	No. 44-34	PA	FRONTIER	7750	6731	3753	YES	1	1	1
49035203790000	HOGSBACK UNIT	No. F11X-27G	PROD - GAS	FRONTIER	7055	6727	3749	YES	1	1	1
49035209730000	NORTH LABARGE UNIT	No. 49-9	PROD - GAS	FRONTIER	7637	6727	3749	NO	1	1	1
49035223870000	BIRCH CREEK UNIT	No. 188	PROD - GAS	FRONTIER	7700	6727	3749	NO	1	1	1
49035203180000	NORTH LABARGE UNIT	No. 24-33	PROD - GAS	FRONTIER	7127	6725	3747	NO	1	1	1
49035240280000	NORTH LABARGE UNIT	No. 104-04	PROD - GAS	FRONTIER	7427	6719	3741	NO	1	1	1
49035209830000	NORHT LABARGE UNIT	No. 46-33	PROD - GAS	FRONTIER	7750	6718	3740	NO	1	1	1
49035055680000	BIRCH CREEK E-022247	No. 7	PROD - GAS	FRONTIER	7765	6716	3738	YES	1	1	1
49035056680000	TIP TOP UNIT	No. T76-28G	PROD - GAS	FRONTIER	7352	6708	3730	YES	1	1	1
49035209670000	NORTH LABARGE	No. 45-33	PA	FRONTIER	7850	6707	3729	YES	1	1	1
49035210320000	NORTH LABARGE UNIT	No. 40-33	PROD - GAS	FRONTIER	7800	6695	3717	YES	1	1	1
49035055690000	BNG	No. 51-4	PROD - GAS	FRONTIER	7917	6688	3710	NO	1	1	1
49035209660000	CHIMNEY BUTTE UNIT	No. 27-34	PROD - GAS	FRONTIER	7450	6668	3690	YES	1	1	1
49035056070000	BNG	No. 49-33	PROD - GAS	FRONTIER	7630	6666	3688	YES	1	1	1
49035211670000	NORTH LABARGE UNIT	No. 50-9D	PA	FRONTIER	7669	6649	3671	NO	1	1	1
49035057030000	TIP TOP UNIT	No. T32-28G	PROD - GAS	FRONTIER	7142	6629	3651	YES	1	1	1

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49035203470000	TIP TOP UNIT	No. F21X-33G	PROD - GAS	FRONTIER	7300	6624	3646	NO	1	1	1
49035209720000	NORTH LABARGE SH UN	No. 48-4	PROD - GAS	FRONTIER	7858	6619	3641	NO	1	1	1
49035242350000	NORTH LABARGE UNIT	No. 100-33ED	PA	FRONTIER	7518	6611	3633	NO	1	1	1
49035202750000	TIP TOP UNIT	No. F11X-2	PA	FRONTIER	7190	6581	3603	YES	1	1	1
49035234780000	TIP TOP UNIT	No. T87X-16GH	PROD - GAS	FRONTIER	7602	6572	3594	YES	1	1	1
49035212070000	TIP TOP UNIT	No. T47X-21G	PROD - GAS	FRONTIER	7275	6570	3592	NO	1	1	1
49035056710000	TIP TOP UNIT	No. 45-27	PA	FRONTIER	7651	6523	3545	YES	1	1	1
49035054560000	FIGURE FOUR W023066A	No. 2	PA	FRONTIER	8035	6509	3531	NO	1	1	1
49035203760000	BIG PINEY UNIT	No. F-22	PROD - GAS	FRONTIER	7450	6508	3530	YES	1	1	1
49035208250000	CHIMNEY BUTTE UNIT	No. 23-34	PROD - GAS	FRONTIER	7630	6504	3526	YES	1	1	1
49035055310000	BIRCH CREEK E-022247	No. 6	PROD - GAS	FRONTIER	7885	6488	3510	NO	1	1	1
49035056120000	BNG	No. 15-32	PROD - GAS	FRONTIER	7340	6484	3506	NO	1	1	1
49035211800000	TIP TOP UNIT	No. T74X-28G	PROD - GAS	FRONTIER	7324	6483	3505	YES	1	1	1
49035203190000	CHIMNEY BUTTE UNIT	No. 19-34	PROD - GAS	FRONTIER	7463	6477	3499	YES	1	1	1
49035218310000	TIP TOP UNIT	No. T27X-28G	PROD - GAS	FRONTIER	7272	6476	3498	NO	1	1	1
49035235310000	TIP TOP UNIT	No. T54X-22G	SO	FRONTIER	7340	6476	3498	YES	1	1	1
49035063210000	TIP TOP UNIT	No. T44-21G	PROD - GAS	FRONTIER	7510	6475	3497	NO	1	1	1
49035208080000	TIP TOP UNIT	No. T63X-27P	PROD - GAS	FRONTIER	7300	6457	3479	YES	1	1	1
49035212410000	TIP TOP UNIT	No. T13X-28G	PROD - GAS	FRONTIER	7301	6454	3476	NO	1	1	1
49035056360000	BNG	No. 29-33	PROD - GAS	FRONTIER	8050	6452	3474	NO	1	1	1
49035219320000	TIP TOP UNIT	No. T72X-29G	PROD - GAS	FRONTIER	7190	6450	3472	NO	1	1	1
49035055950000	BNG	No. 28-33	PROD - GAS	FRONTIER	8055	6449	3471	YES	1	1	1
49035212900000	33G TIP TOP UNIT	No. T11X	PROD - GAS	MOWRY	7350	6441	3463	NO	1	1	1
49035057160000	TIP TOP UNIT	No. T78-21G	PROD - GAS	FRONTIER	7417	6427	3449	YES	1	1	1
49035205360000	MILLS	No. 1-22	PROD - GAS	FRONTIER	7300	6427	3449	YES	1	1	1
49035212170000	G1 TIP TOP UNIT	No. T86X20	PROD - GAS	FRONTIER	7480	6409	3431	NO	1	1	1
49035059680000	MCDONALD DRAW UNIT	No. 43-34	PA	FRONTIER	9157	6388	3410	YES	1	1	1
49035218290000	TIP TOP UNIT	No. T72X-28P	PROD - GAS	FRONTIER	7410	6387	3409	YES	1	1	1
49035210060000	CHIMNEY BUTTE UNIT	No. 26-34	PROD - GAS	FRONTIER	7406	6383	3405	YES	1	1	1
49035211810000	TIP TOP	No. T36X-28G	PROD - GAS	FRONTIER	7410	6367	3389	NO	1	1	1
49035055160000	FEDERAL	No. 4	PA	FRONTIER	9010	6357	3379	NO	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035205430000	MILLS PATENTED	No. 2-23	PROD - GAS	FRONTIER	7372	6353	3375	YES	1	1	1
49035234760000	TIP TOP UNIT	No. T72X-16S	PROD - GAS	FRONTIER	7851	6351	3373	NO	1	1	1
49035212910000	32G TIP TOP UNIT	No. T66X	PROD - GAS	MOWRY	7404	6340	3362	NO	1	1	1
49035211840000	TIP TOP UNIT	No. T34-27P	PROD - GAS	FRONTIER	7449	6335	3357	YES	1	1	1
49035205440000	UNIT W-02985	No. 22-35	PA	FRONTIER	7460	6321	3343	YES	1	1	1
49035208070000	TIP TOP UNIT	No. T57X-27G	PROD - GAS	FRONTIER	7795	6317	3339	YES	1	1	1
49035212190000	20G3 TIP TOP UNIT	No. T86X	PROD - GAS	FRONTIER	7510	6301	3323	NO	1	1	1
49035224370000	BIRCH CREEK UNIT	No. 186	PA	BEAR RIVER	8040	6300	3322	YES	1	1	1
49035055990000	CHIMNEY BUTTE UNIT	No. 11	PROD - GAS	FRONTIER	7655	6287	3309	YES	1	1	1
49035203550000	TARTERS ISLAND	No. 1-33	SHUT-IN	FRONTIER	7989	6263	3285	YES	1	1	1
49035231930000	TIP TOP UNIT	No. T72X-21G	PROD - GAS	MOWRY	7775	6258	3280	YES	1	1	1
49035209780000	CHURCH BUTTE E023554	No. 36-26	PROD - GAS	FRONTIER	8100	6255	3277	YES	1	1	1
49035208090000	TIP TOP UNIT	No. T55X-22G	PROD - GAS	FRONTIER	7590	6253	3275	YES	1	1	1
49035211330000	GREEN RIVER BEND	No. 186-4	PA	FRONTIER	7901	6244	3266	YES	1	1	1
49035212180000	20G2 TIP TOP UNIT	No. T86X	PROD - GAS	MOWRY	7587	6224	3246	NO	1	1	1
49035213270000	TIP TOP UNIT	No. T34X-22G	PROD - GAS	FRONTIER	7705	6209	3231	YES	1	1	1
<i>49035054960000*</i>	<i>UNIT MCGINNIS (GRBU)</i>	<i>No. 10-9</i>	<i>PROD - GAS</i>	<i>FRONTIER</i>	<i>7915</i>	<i>6198</i>	<i>3220</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035212940000	RED HILL	No. 2-18	PROD - GAS	FRONTIER	7210	6191	3213	NO	1	1	1
49035205510000	RED HILL	No. 1-18	PROD - GAS	FRONTIER	7353	6189	3211	NO	1	1	1
49035231830000	CHIMNEY BUTTE	No. 106-26	PROD - GAS	FRONTIER	8171	6183	3205	YES	1	1	1
49035205400000	GREEN RIVER BEND UN	No. 67-6	PA	FRONTIER	7635	6172	3194	YES	1	1	1
49035055170000	GREEN RIVER BEND UN	No. 33	PROD - GAS	FRONTIER	7585	6148	3170	YES	1	1	1
49035211210000	NO CHIMNEY E-024756	No. 4-23	PROD - GAS	FRONTIER	7686	6140	3162	YES	1	1	1
49035204740000	GREEN RIVER BEND UN	No. 57-6	PROD - GAS	FRONTIER	7740	6138	3160	YES	1	1	1
49035210270000	CHIMNEY BUTTE NORTH	No. 2-23	PROD - GAS	FRONTIER	7630	6132	3154	YES	1	1	1
49035215540000	FIGURE FOUR CANYON	No. 4-12	PROD - GAS	BEAR RIVER	9235	6116	3138	NO	1	1	1
49035215540000	FIGURE FOUR CANYON	No. 4-12	PROD - GAS	BEAR RIVER	9235	6116	3138	NO	1	1	1
49035218280000	GREEN RIVER BEND UN	No. 109-6	PROD - GAS	FRONTIER	7939	6114	3136	YES	1	1	1
49035209540000	HIGHWAY 189 W-11255	No. 20-27	PA	FRONTIER	8760	6108	3130	YES	1	1	1
49035211310000	TARTERS ISLAND	No. 8-33	PA	FRONTIER	8050	6090	3112	YES	1	1	1
49035211320000	CHIMNEY BUTTE UNIT	No. 38-14	PROD - GAS	FRONTIER	7950	6090	3112	YES	1	1	1

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035212440000	TIP TOP UNIT	No. T31X-27G2	PROD - GAS	MUDDY	7680	6085	3107	YES	1	1	1
49035210030000	HIGHWAY 189 W-112555	No. 40-22	PA	FRONTIER	8858	6083	3105	YES	1	1	1
49035211240000	CHIMNEY BUTTES	No. 28-23	PROD - GAS	FRONTIER	7930	6079	3101	YES	1	1	1
49035253990000	GREEN RIVER BENT UNT	No. 284-07	PA	FRONTIER	7390	6076	3098	YES	1	1	1
49035055940000	CHIMNEY BUTTE UNIT	No. 17-35	PROD - GAS	FRONTIER	7703	6049	3071	YES	1	1	1
49035231210000	GREEN RIVER BEND UN	No. 230-07	PROD - GAS	FRONTIER	7360	6038	3060	YES	1	1	1
<i>49035056130000</i>	<i>GREEN RIVER BEND</i>	<i>No. 16-33</i>	<i>PROD - GAS</i>	<i>FRONTIER</i>	<i>8169</i>	<i>6034</i>	<i>3056</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035212970000	TIP TOP UNIT	No. T86X-27G1	PROD - GAS	MOWRY	7854	6034	3056	YES	1	1	1
49035205180000	GREEN RIVER BEND UN	No. 59-7	PA	FRONTIER	7480	6030	3052	YES	1	1	1
49035212990000	TIP TOP UNIT	No. T86X-27G3	PROD - GAS	MOWRY	7870	6015	3037	YES	1	1	1
49035055440000	GREEN RIVER BEND UN	No. 7	PROD - GAS	MOWRY	8110	5995	3017	YES	1	1	1
49035207880000	WOLD W-80186	No. 24-10	PROD - GAS	FRONTIER	7905	5986	3008	YES	1	1	1
49035055760000	MCDONALD DRAW UNIT	No. 4-A	PA	FRONTIER	8011	5979	3001	YES	1	1	1
49035055540000	BIRCH CREEK UNIT	No. 10	PA	FRONTIER	7820	5972	2994	YES	1	1	1
49035212980000	TIP TOP UNIT	No. T86X-27G2	PROD - GAS	MOWRY	7920	5966	2988	YES	1	1	1
49035228820000	TIP TOP UNIT	No. T55X-15G	PROD - GAS	MUDDY	8157	5946	2968	YES	1	1	1
49035056080000	CHIMNEY BUTTE UNIT	No. 3-34	PROD - GAS	MUDDY	8304	5945	2967	YES	1	1	1
49035055000000	BIRCH CREEK UNIT	No. 5	PROD - GAS	BEAR RIVER	8360	5939	2961	NO	1	1	1
49035226490000	TIP TOP UNIT	No. T87X-15G	PROD - GAS	FRONTIER	8110	5929	2951	YES	1	1	1
49035054840000	GREEN RIVER BEND UN	No. 15	PROD - GAS	FRONTIER	7612	5925	2947	YES	1	1	1
49035211250000	BIRCH CREEK UNIT	No. 125	PROD - GAS	FRONTIER	8545	5906	2928	YES	1	1	1
49035231810000	CHIMNEY BUTTE UNIT	No. 110-15	PROD - GAS	FRONTIER	8200	5902	2924	YES	1	1	1
49035210410000	TIP TOP UNIT	No. T18-X27	PROD - GAS	MUDDY	8575	5900	2922	YES	1	1	1
49035225420000	CHIMNEY BUTTE UNIT	No. 102-36D	PROD - GAS	FRONTIER	8320	5886	2908	YES	1	1	1
49035223780000	GREEN RIVER BEND UN	No. 301-7-D	PA	FRONTIER	7766	5885	2907	YES	1	1	1
49035224880000	GREEN RIVER BEND UN	No. 302-6	PA	FRONTIER	8120	5885	2907	YES	1	1	1
49035200310000	BIRCH CREEK E-022247	No. 88	PROD - GAS	BEAR RIVER	8400	5883	2905	YES	1	1	1
49035214000000	TIP TOP UNIT	No. 15-23G	PROD - GAS	MOWRY	7915	5863	2885	YES	1	1	1
49035054490000	GREEN RIVER BEND UN	No. 35-7	PROD - GAS	FRONTIER	7503	5862	2884	YES	1	1	1
49035204400000	BIRCH CREEK UNIT	No. 100	PROD - GAS	BEAR RIVER	7730	5859	2881	NO	1	1	1
49035210040000	BIRCH CREEK UNIT	No. 110	PROD - GAS	BEAR RIVER	7668	5858	2880	YES	1	1	1

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APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035053590000	BIRCH CREEK UNIT	No. 15	PROD - GAS	BEAR RIVER	7839	5853	2875	NO	1	1	1
49035210640000	BIRCH CREEK	No. 128	PROD - GAS	BEAR RIVER	8500	5853	2875	YES	1	1	1
49035207530000	FEDERAL	No. 30-1	PROD - GAS	MOWRY	9513	5851	2873	YES	1	1	1
49035055080000	BIRCH CREEK UNIT	No. 61	PROD - GAS	BEAR RIVER	8318	5833	2855	YES	1	1	1
49035231000000	CHIMNEY BUTTE UNIT	No. 104-36	PA	BEAR RIVER	8415	5829	2851	YES	1	1	1
49035200440000	BIRCH CREEK UNIT	No. 89	PA	BEAR RIVER	7700	5825	2847	YES	1	1	1
49035056750000	CHINMEY BUTTE UNIT	No. 16	PA	MUDDY	8605	5820	2842	YES	1	1	1
49035209900000	BIRCH CREEK UNIT	No. 107	PROD - GAS	BEAR RIVER	7680	5817	2839	NO	1	1	1
49035204410000	BIRCH CREEK UNIT	No. 101	PROD - GAS	BEAR RIVER	7770	5812	2834	YES	1	1	1
49035213290000	TIP TOP UNIT	No. T48X-16S	PROD - GAS	MUDDY	8675	5812	2834	YES	1	1	1
49035223690000*	BIRCH CREEK UNIT	No. 185	PROD - GAS	BEAR RIVER	7720	5812	2834	YES	1	1	1
49035219590000*	BIRCH CREEK UNIT	No. 166	PROD - GAS	BEAR RIVER	8017	5805	2827	NO	1	1	1
49035275680000	TIP TOP UNIT	No. T62X-16SH	PROD - GAS	MUDDY	8430	5799	2821	NO	1	1	1
49035056400000	CHIMNEY BUTTE UNIT	No. 2-35	PROD - GAS	MUDDY	8453	5798	2820	YES	1	1	1
49035056980000	CHURCH BUTTE E023554	No. 9-26	PA	MUDDY	8113	5795	2817	YES	1	1	1
49035210500000	SFE	No. 4-24	PA	FRONTIER	8100	5792	2814	YES	1	1	1
49035224850000	COOPERS	No. 2-7	SHUT-IN	FRONTIER	7860	5783	2805	NO	1	1	1
49035203710000	BIRCH CREEK UNIT	No. 95	PROD - GAS	BEAR RIVER	7907	5780	2802	YES	1	1	1
49035204340000	BIRCH CREEK UNIT	No. 92	PROD - GAS	BEAR RIVER	7670	5778	2800	NO	1	1	1
49035203690000	BIRCH CREEK E-022247	No. 97	PROD - GAS	BEAR RIVER	7975	5773	2795	YES	1	1	1
49035222730000	MERLIN	No. 1-13D	PROD - GAS	FRONTIER	8100	5772	2794	YES	1	1	1
49035209910000	BIRCH CREEK UNIT	No. 106	PROD - GAS	BEAR RIVER	7678	5770	2792	NO	1	1	1
49035212210000	BIRCH CREEK UNIT	No. 127	PROD - GAS	BEAR RIVER	7890	5766	2788	YES	1	1	1
49035210750000	BIRCH CREEK UNIT	No. 114	PROD - GAS	BEAR RIVER	8125	5756	2778	NO	1	1	1
49035055070000	BIRCH CREEK UNIT	No. 12	PA	BEAR RIVER	7951	5755	2777	YES	1	1	1
49035200450000	BIRCH CREEK UNIT	No. 90	PA	BEAR RIVER	7957	5755	2777	NO	1	1	1
49035054940000	BIRCH CREEK UNIT	No. 3	PROD - GAS	BEAR RIVER	8054	5751	2773	YES	1	1	1
49035222820000*	COOPERS	No. 1-8	PROD - GAS	FRONTIER	7886	5744	2766	YES	1	1	1
49035212710000	CHIMNEY BUTTE UNIT	No. 39-4	PROD - GAS	MUDDY	8473	5735	2757	NO	1	1	1
49035211560000	CHIMNEY BUTTE UNIT	No. 29-14D	PROD - GAS	FRONTIER	8300	5733	2755	YES	1	1	1
49035243950000	BIRCH CREEK UNIT	No. 199	PROD - GAS	BEAR RIVER	8575	5733	2755	NO	1	1	1

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API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035212400000	TIP TOP UNIT	No. T31X-27G1	PROD - GAS	MUDDY	8041	5725	2747	YES	1	1	1
<i>49035223710000*</i>	<i>BIRCH CREEK UNIT</i>	<i>No. 187</i>	<i>PROD - GAS</i>	<i>BEAR RIVER</i>	<i>7770</i>	<i>5722</i>	<i>2744</i>	<i>NO</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035208520000	STATE J	No. 2	PA	MOWRY	9665	5715	2737	YES	1	1	1
49035212860000	TIP TOP UNIT	No. T12X26G	PROD - GAS	MUDDY	8095	5711	2733	YES	1	1	1
49035055600000	BIRCH CREEK UNIT	No. 9	PA	BEAR RIVER	8081	5704	2726	YES	1	1	1
<i>49035221450000*</i>	<i>BIRCH CREEK UNIT</i>	<i>No. 124</i>	<i>PROD - GAS</i>	<i>BEAR RIVER</i>	<i>7805</i>	<i>5702</i>	<i>2724</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035217780000	BIRCH CREEK UNIT	No. 177	PROD - GAS	BEAR RIVER	7910	5694	2716	YES	1	1	1
49035213990000	TIP TOP UNIT	No. T44X-4G	PROD - GAS	MUDDY	8512	5690	2712	NO	1	1	1
49035053830000	BIRCH CREEK UNIT	No. 25	PROD - GAS	BEAR RIVER	7723	5687	2709	NO	1	1	1
49035239520000	BIRCH CREEK UNIT	No. 194	PROD - GAS	BEAR RIVER	7700	5679	2701	NO	1	1	1
49035070030000	BIRCH CREEK UNIT	No. 87	PROD - GAS	BEAR RIVER	7860	5678	2700	YES	1	1	1
49035203720000	BIRCH CREEK UNIT	No. 94	PROD - GAS	BEAR RIVER	7875	5678	2700	YES	1	1	1
49035207760000	USA AMOCO	No. A-M-1	PROD - GAS	BEAR RIVER	10415	5676	2698	NO	1	1	1
49035207760000	USA AMOCO	No. A-M-1	PROD - GAS	BEAR RIVER	10415	5676	2698	NO	1	1	1
49035058530000	CHIMNEY BUTTE UNIT	No. 1-4	TA	MUDDY	8416	5668	2690	YES	1	1	1
49035054460000	GREEN RIVER BEND UN	No. 26	PA	MUDDY	8003	5666	2688	NO	1	1	1
49035207440000	SPLIT RIVER	No. 31-2	PROD - GAS	MOWRY	9440	5662	2684	YES	1	1	1
49035217790000	BIRCH CREEK UNIT	No. 156	PA	FRONTIER	8020	5660	2682	YES	1	1	1
49035234790000	BIRCH CREEK UNIT	No. 197	PROD - GAS	BEAR RIVER	7900	5657	2679	YES	1	1	1
49035221440000	BIRCH CREEK UNIT	No. 126	PROD - GAS	BEAR RIVER	8065	5656	2678	NO	1	1	1
<i>49035208690000</i>	<i>CRAIG'S DRAW II FEE</i>	<i>No. 1-23</i>	<i>PROD - GAS</i>	<i>BEAR RIVER</i>	<i>9400</i>	<i>5649</i>	<i>2671</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035221420000	BIRCH CREEK UNIT	No. 122	PROD - GAS	BEAR RIVER	7990	5647	2669	NO	1	1	1
49035213050000	BIRCH CREEK UNIT	No. 141	PROD - GAS	BEAR RIVER	7820	5643	2665	NO	1	1	1
<i>49035223840000*</i>	<i>COOPERS</i>	<i>No. 7-31D</i>	<i>SHUT-IN</i>	<i>FRONTIER</i>	<i>8450</i>	<i>5630</i>	<i>2652</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
<i>49035056970000</i>	<i>CHIMNEY BUTTE UNIT</i>	<i>No. 13-25</i>	<i>PROD - GAS</i>	<i>FRONTIER</i>	<i>8526</i>	<i>5626</i>	<i>2648</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035204420000	BIRCH CREEK UNIT	No. 102	PA	BEAR RIVER	7970	5626	2648	YES	1	1	1
49035211010000	BIRCH CREEK UNIT	No. 130	PROD - GAS	BEAR RIVER	7750	5621	2643	NO	1	1	1
<i>49035208040000</i>	<i>YOSE CATTLE COMPANY</i>	<i>No. 40-35</i>	<i>PROD - GAS</i>	<i>MOWRY</i>	<i>9300</i>	<i>5620</i>	<i>2642</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035054950000	GREEN RIVER BEND UN	No. 9	PA	MUDDY	8137	5613	2635	YES	1	1	1
49035207550000	HANSON	No. 20-1	PROD - GAS	BEAR RIVER	10300	5610	2632	NO	1	1	1
49035207550000	HANSON	No. 20-1	PROD - GAS	BEAR RIVER	10300	5610	2632	NO	1	1	1

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49035054250000	GREEN RIVER BEND UN	No. 5	PA	MUDDY	7800	5608	2630	NO	1	1	1
49035210050000	BIRCH CREEK UNIT	No. 111	PROD - GAS	BEAR RIVER	7690	5602	2624	NO	1	1	1
49035213900000	TIP TOP UNIT	No. T82X-21G2	PROD - GAS	MUDDY	8430	5593	2615	YES	1	1	1
49035055180000	BIRCH CREEK UNIT	No. 78	PROD - GAS	BEAR RIVER	7862	5591	2613	YES	1	1	1
49035055450000	GRN RIVER BEND UNIT	No. 11	PA	BEAR RIVER	8298	5585	2607	YES	1	1	1
49035056790000	MCDONALD DRAW UNIT	No. 6	PA	MUDDY	8489	5580	2602	YES	1	1	1
49035221410000	BIRCH CREEK UNIT	No. 119	PROD - GAS	BEAR RIVER	7798	5577	2599	YES	1	1	1
49035207630000	SPLIT RIVER FEE	No. 24-35	PROD - GAS	MOWRY	9132	5574	2596	YES	1	1	1
49035244320000	BIRCH CREEK UNIT	No. 173	PROD - GAS	BEAR RIVER	8210	5573	2595	YES	1	1	1
49035206720000*	FEDERAL	No. 30-31	PROD - GAS	BEAR RIVER	10537	5571	2593	NO	1	1	1
49035206720000	FEDERAL	No. 30-31	PROD - GAS	BEAR RIVER	10537	5571	2593	NO	1	1	1
49035203700000	BIRCH CREEK UNIT	No. 96	PROD - GAS	BEAR RIVER	7954	5565	2587	YES	1	1	1
49035058090000	FEDERAL W-04629	No. C-22	PA	FRONTIER	8330	5561	2583	YES	1	1	1
49035211080000	BIRCH CREEK UNIT	No. 132	PROD - GAS	BEAR RIVER	7960	5557	2579	NO	1	1	1
49035211070000	BIRCH CREEK UNIT	No. 118	PROD - GAS	BEAR RIVER	8255	5550	2572	YES	1	1	1
49035221460000	BIRCH CREEK UNIT	No. 135	PROD - GAS	BEAR RIVER	8090	5543	2565	YES	1	1	1
49035208640000	STATE J	No. 3	PROD - GAS	BEAR RIVER	9950	5542	2564	YES	1	1	1
49035208050000	CHAPEL FEE	No. 10-25	PROD - GAS	MOWRY	9827	5541	2563	YES	1	1	1
49035200460000	BIRCH CREEK UNIT	No. 91	PROD - GAS	BEAR RIVER	7930	5537	2559	YES	1	1	1
49035219610000	BIRCH CREEK UNIT	No. 174	PROD - GAS	BEAR RIVER	7885	5537	2559	NO	1	1	1
49035055980000	CHIMNEY BUTTE UNIT	No. 14-36	PA	MUDDY	8160	5533	2555	YES	1	1	1
49035219640000	BIRCH CREEK	No. 168	PROD - GAS	BEAR RIVER	8242	5529	2551	NO	1	1	1
49035057770000	CHIMNEY BUTTE UNIT	No. 5-14	PROD - GAS	MUDDY	8369	5527	2549	YES	1	1	1
49035220380000	LONG GREEN	No. 2-25	PA	BEAR RIVER	10180	5527	2549	YES	1	1	1
49035210280000	BIRD CANYON	No. 10-1	PROD - GAS	BEAR RIVER	10360	5502	2524	NO	1	1	1
49035219330000	BIRCH CREEK UNIT	No. 172	PA	BEAR RIVER	8089	5502	2524	YES	1	1	1
49035057080000	UNIT E-024469	No. 12	PA	MUDDY	8811	5497	2519	YES	1	1	1
49035223700000*	BIRCH CREEK UNIT	No. 134	PROD - GAS	BEAR RIVER	7911	5486	2508	YES	1	1	1
49035213980000	TIP TOP UNIT	No. T33X-16SH	PROD - GAS	FRONTIER	8912	5468	2490	NO	1	1	1
49035240180000	BIRCH CREEK UNIT	No. 148	PROD - GAS	BEAR RIVER	7920	5466	2488	NO	1	1	1
49035057680000	UNIT	No. 10	PA	MUDDY	8550	5463	2485	YES	1	1	1

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

**** Well has existing Gas Analysis (See Appendix D)***

APPENDIX A: EXISTING OIL AND GAS WELLS IN THE AMA/MMA

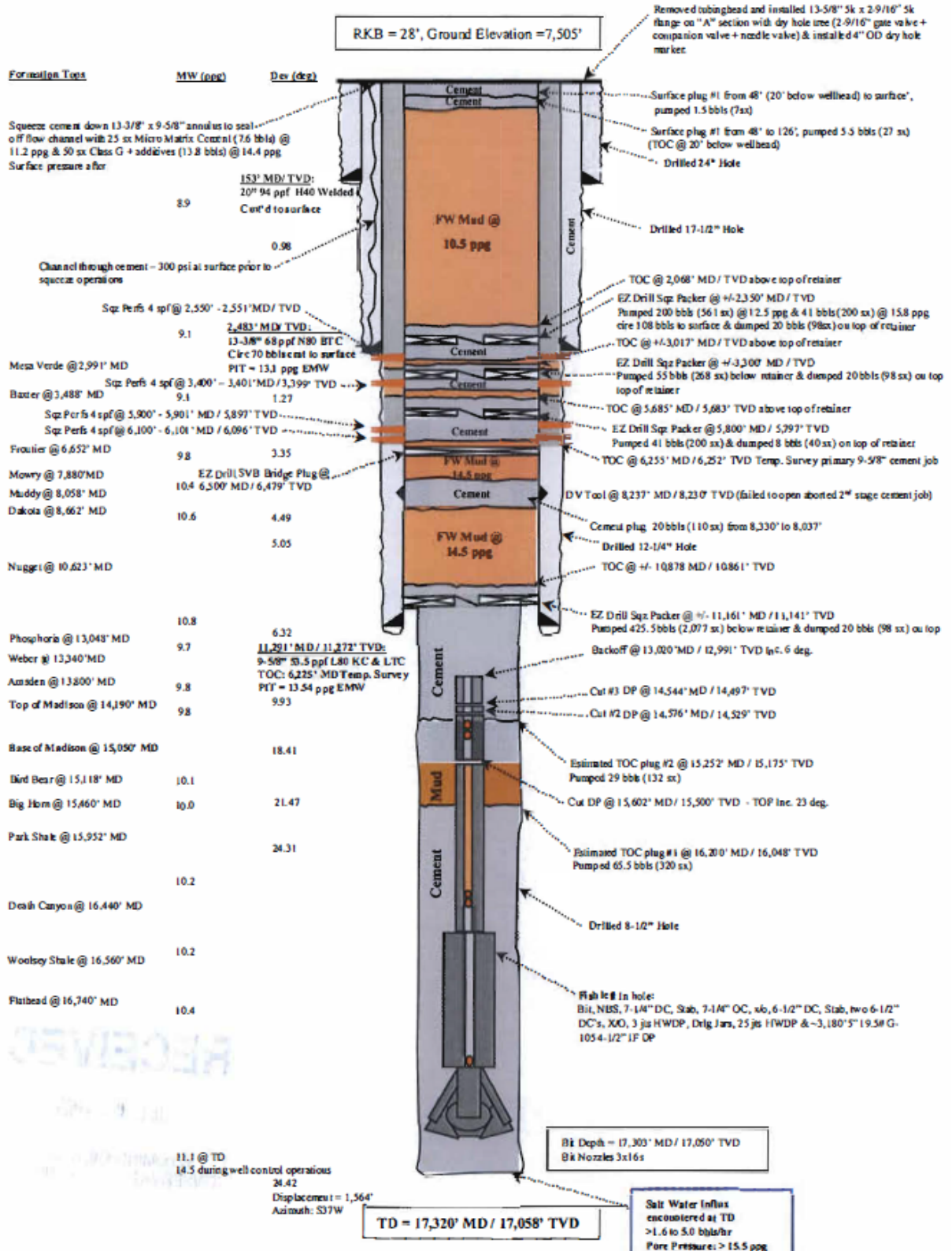
API Number	Well Name	Well Number	WOGCC Status	WOGCC Formation at Total Depth (TD)	TD	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimate)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
49035240160000	BIRCH CREEK UNIT	No. 195	PROD - GAS	BEAR RIVER	7896	5460	2482	NO	1	1	1
49035054320000	BIRCH CREEK UNIT	No. 26	PROD - GAS	BEAR RIVER	7855	5457	2479	YES	1	1	1
49035221400000	BIRCH CREEK UNIT	No. 179	PROD - GAS	BEAR RIVER	8030	5453	2475	YES	1	1	1
49035057800000	BIG PINEY	No. 4	PA	MUDDY	9025	5450	2472	YES	1	1	1
49035056650000	CHIMNEY BUTTE UNIT	No. 16	PA	BEAR RIVER	8600	5445	2467	YES	1	1	1
49035209640000	FIGURE FOUR CANYON	No. 8-30	PROD - GAS	BEAR RIVER	10270	5441	2463	NO	1	1	1
49035212630000	BIRCH CREEK UNIT	No. 146	PROD - GAS	BEAR RIVER	8040	5423	2445	YES	1	1	1
49035206750000	CHAPEL CANYON	No. 30-18	PA	FRONTIER	10840	5412	2434	YES	1	1	1
49035206750000	CHAPEL CANYON	No. 30-18	PA	FRONTIER	10840	5412	2434	YES	1	1	1
49035240170000	BIRCH CREEK UNIT	No. 137	PROD - GAS	BEAR RIVER	7965	5412	2434	NO	1	1	1
49035218540000	FIGURE FOUR CANYON	No. 16-30D	PROD - GAS	FRONTIER	10555	5367	2389	NO	1	1	1
49035208560000	FIGURE FOUR CANYON	No. 7-31D	PROD - GAS	BEAR RIVER	10975	5297	2319	NO	1	1	1
49035208560000	FIGURE FOUR CANYON	No. 7-31D	PROD - GAS	BEAR RIVER	10975	5297	2319	NO	1	1	1
49035234800000	BIRCH CREEK UNIT	No. 198	PROD - GAS	BEAR RIVER	8350	5281	2303	YES	1	1	1
49035244310000	BIRCH CREEK UNIT	No. 164	PROD - GAS	BEAR RIVER	9004	5259	2281	YES	1	1	1
49035213020000	BIRCH CREEK UNIT	No. 115	PROD - GAS	BEAR RIVER	8330	5209	2231	YES	1	1	1
49035215410000	CHIMNEY BUTTE UNIT	No. 46-36	PA	GANNETT	9220	5147	2169	YES	1	1	1
49035206350000	DRY PINEY-STATE	No. 13-16	PA	MORRISON	9738	5139	2161	YES	1	1	1
49035206550000	CHAPEL CANYON UNIT	No. 1-2	PA	MORRISON	11080	5052	2074	YES	1	1	1
49035209530000	N CHIMNEY BUTTE	No. 1-23	PROD - GAS	MORRISON	8720	5045	2067	YES	1	1	1
49035205810000	TARTERS ISLAND	No. 5-13	PA	MORRISON	11050	5031	2053	YES	1	1	1
49035204790000	TARTERS ISL W-053450	No. 4-15	PA	GANNETT	10136	5023	2045	YES	1	1	1
<i>49035206980000</i>	<i>STATE J</i>	<i>No. 1</i>	<i>PROD - GAS</i>	<i>MORRISON</i>	<i>10650</i>	<i>4930</i>	<i>1952</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035206870000	FEDERAL W-62791	No. 10-31	PROD - GAS	GANNETT	10944	4830	1852	NO	1	1	1
49035219630000	BIRCH CREEK UNIT	No. 180	PROD - GAS	FRONTIER	9560	4610	1632	NO	1	1	1
49035213470000	TIP TOP UNIT	No. T77X-17G	PROD - GAS	FRONTIER	9877	4164	1186	NO	1	1	1
<i>49035054500000</i>	<i>BIRCH CREEK UNIT</i>	<i>No. 1</i>	<i>PROD - GAS</i>	<i>NUGGET</i>	<i>10176</i>	<i>3315</i>	<i>337</i>	<i>NO</i>	<i>1</i>	<i>1</i>	<i>1</i>
49035265090000	TIP TOP UNIT	No. T62X-16S	PA	FLATHEAD	17320	-3087	-6065	NO	2	1	2

Bold Italicized Wells Indicate Potential Wells in BSO Gas Sampling Program

**** Well has existing Gas Analysis (See Appendix D)***

APPENDIX B – WELLBORE DIAGRAM FOR PLUGGED TIP TOP T62X-16S WELL

TTU T62X-16S – Final P&A Wellbore Sketch 11/12/2009



APPENDIX C: EXISTING GROUNDWATER WELLS IN THE AMA/MMA

Water Right Number	Well Name	Primary Water Use	Total Depth (Ft)	TD Feet Above Upper Injection Zone (Estimated)	TD Feet Above Upper Confining Unit (Estimated)	Within Plume ?	Likelihood (1-5)	Magnitude (1-5)	Total Risk Rating (0-25)
<i>P67558.0W</i>	<i>FEAR-ENERGETICS #1</i>	<i>DOMESTIC</i>	<i>435</i>	<i>16035</i>	<i>13060</i>	<i>NO</i>	<i>1</i>	<i>1</i>	<i>1</i>
P69145.0W	BELNORTH MONITORING WELL #2	MONITORING	40	15700	12725	YES	1	1	1
P69146.0W	BELNORTH MONITORING WELL #3	MONITORING	40	15650	12675	YES	1	1	1
P69144.0W	BELNORTH MONITORING WELL #1	MONITORING	40	15530	12555	YES	1	1	1
P179733.0W	SCHAFFER #4	DOMESTIC	140	14860	11885	YES	1	1	1
<i>P1542.0W</i>	<i>MCDONALD DRAW UNIT #3</i>	<i>INDUSTRIAL</i>	<i>554</i>	<i>14766</i>	<i>11791</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
<i>P29520.0W</i>	<i>SCHAFFER #3</i>	<i>DOMESTIC</i>	<i>413</i>	<i>14587</i>	<i>11612</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
P22740.0P	YOSE #1	DOMESTIC	59	14541	11566	YES	1	1	1
P22741.0P	YOSE #2	STOCK	59	14541	11566	YES	1	1	1
P23983.0P	DRY PINEY CREEK SPRING #3	STOCK	4	14521	11546	YES	1	1	1
P72539.0W	CHRIS #1	DOMESTIC	138	14442	11467	YES	1	1	1
P191399.0W	HOFFMAN NO. 1 WELL	DOMESTIC	260	14310	11335	YES	1	1	1
P61286.0W	STATE J #1(W.S)	INDUSTRIAL	740	14170	11195	YES	1	1	1
<i>P10645.0W</i>	<i>REARDON WELL #3</i>	<i>DOMESTIC</i>	<i>585</i>	<i>14145</i>	<i>11170</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
P1010.0W	WATER WELL #1	INDUSTRIAL	337	14143	11168	NO	1	1	1
P22745.0P	YOSE-LONG ISLAND UNIT #13	DOMESTIC	480	14110	11135	YES	1	1	1
<i>P22747.0P</i>	<i>YOSE - LONG ISLAND UNIT #39</i>	<i>STOCK</i>	<i>600</i>	<i>14080</i>	<i>11105</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
P89323.0W	LITTLE MESA WELL	STOCK	190	14040	11065	YES	1	1	1
P22744.0P	YOSE-LONG ISLAND UNIT #9	STOCK	500	14040	11065	YES	1	1	1
P9618.0P	TWIN PEAKS WELL #529	STOCK	153	14037	11062	YES	1	1	1
P9344.0P	DRY BASIN WELL #306	STOCK	95	13985	11010	YES	1	1	1
P22737.0W	YOSE-LONG ISLAND UNIT #53	DOMESTIC	600	13930	10955	YES	1	1	1
<i>P56643.0W</i>	<i>GREEN VALLEY WELL #1</i>	<i>DOMESTIC</i>	<i>125</i>	<i>13905</i>	<i>10930</i>	<i>NO</i>	<i>1</i>	<i>1</i>	<i>1</i>
<i>P9615.0P</i>	<i>YOSE DRAW WELL #125</i>	<i>STOCK</i>	<i>170</i>	<i>13880</i>	<i>10905</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
P23530.0P	BIRD SPRING 330	STOCK	4	13846	10871	YES	1	1	1
P23985.0W	WILDCAT SPRING & PIPELINE #4064	STOCK	4	13846	10871	YES	1	1	1
P1345.0W	BIG PINEY "P" SAND UNIT #2	INDUSTRIAL	650	13800	10825	NO	1	1	1
<i>P9374.0P</i>	<i>REARDON CANYON WELL #515</i>	<i>STOCK</i>	<i>217</i>	<i>13788</i>	<i>10813</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
P2331.0W	BIG PINEY MESA VERDE UNIT SUPPLY #3	INDUSTRIAL	681	13779	10804	NO	1	1	1
<i>P114.0W</i>	<i>C-19 WATER WELL</i>	<i>DOMESTIC</i>	<i>31</i>	<i>13749</i>	<i>10774</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>

Bold Italicized Wells are Candidates for Baseline Sampling Wells

APPENDIX C: EXISTING GROUNDWATER WELLS IN THE AMA/MMA

P177439.0W	CALPET MONITOR #10, 11 AND #12	MONITORING	105	13650	10675	YES	1	1	1
P2063.0W	GULF OIL CORP BIG PINEY MESAVERDE #1	INDUSTRIAL	765	13600	10625	NO	1	1	1
<i>P8438.0P</i>	<i>WILD CAT CANYON #1</i>	<i>STOCK</i>	<i>200</i>	<i>13450</i>	<i>10475</i>	<i>YES</i>	<i>1</i>	<i>1</i>	<i>1</i>
P1268.0W	MCDONALD DRAW UNIT WSW #1	INDUSTRIAL	900	13250	10275	YES	1	1	1



Applied Technology Services
1210 D Street, Rock Springs, WY 82901 (307) 352-7292

RECEIVED

NOV 28 2016

WYOMING OIL & GAS
CONSERVATION COMMISSION

Gas Sample Analysis

4903505496 - UNIT MCGINNIS (GRBU) No. 10-9

Company: EOG
Meter Number: WY9023101
Meter Label: Green River Bend 10-09
Field Name: BIG PINEY

API # 49-035-05496
S. 9, T27N, R112W

Analyst: LEATHAM
Cylinder Pressure: 0
Line Pressure: 80

Sample Date: 06/15/2016 at 11:42:10
Test Dates: 06/15/2016 - 06/15/2016
Flowing Temp: 76°F

Gas Analysis by Chromatograph

NAME	MOLE%	BTU	SG	GPM
nitrogen	.3113	0	0.003	0
methane	94.6715	958.3943	0.5244	0
co2	.2783	0	0.0042	0
ethane	2.8613	50.7536	0.0297	0.765
h2s	.0000	0	0	0
propane	.9032	22.778	0.0138	0.2488
ibutane	.1407	4.586	0.0028	0.046
nbutane	.2377	7.7724	0.0048	0.0749
ipentane	.1126	4.5154	0.0028	0.0412
npentane	.1345	5.4042	0.0034	0.0487
hexanes	.0759	3.6181	0.0023	0.0312
heptanes	.1253	6.9107	0.0043	0.0578
octanes	.1276	7.9922	0.005	0.0654
nonanes	.0201	1.4095	0.0009	0.0113
IDEAL TOTAL:	100	1074.1344	0.6013	1.3903

Gross BTU / Real Cu Ft @ 60°F			Gasoline Content	
Pressure:	14.73	14.65	15.025	Pressure: 14.73
Dry:	1076.6976	1070.836	1098.3132	Propane GPM: 0.2488
Sat:	1059.2141	1053.3508	1080.8363	Butane GPM: 0.121
Act. BTU:	1076.6976	1070.836	1098.3132	Gasoline GPM: 0.2905
SpecGrav:	0.6025	0.6025	0.6026	26# Gasoline GPM: 0.4031
Z:	0.9976	0.9976	0.9976	Total GPM: 1.3903

Sulfur Content		Dewpoints	
Mercaptans ppm:	N/A	H2O #/mmcf:	N/A
H2S ppm:	1.0	Hydrocarbon F:	N/A
		@ psig:	N/A

Comments:

Gastec Tube 4LB = 1.0 ppm
H2S below detectable limit of chromatograph

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

4903522369 - BIRCH CREEK UNIT No. 185

LIMS ID: N/A Description: Birch Creek #185
 Analysis Date/Time: 10/24/01 15:26 Field: Birch Creek
 Analyst Initials: BRS ML#: BC185
 Instrument ID: Instrument 1 GC Method: Quesbtex
 Data File: QPC06.D
 Date Sampled: 23-Oct-01

Component	Mol%	Wt%	LV%
Methane	85.8824	71.0521	79.2941
Ethane	7.0675	10.9594	10.3235
Propane	3.4784	7.9099	5.2240
Isobutane	0.5042	1.5112	0.8989
n-Butane	0.8848	2.6521	1.5204
Neopentane	0.0100	0.0371	0.0208
Isopentane	0.2068	0.7695	0.4126
n-Pentane	0.2096	0.7799	0.4137
2,2-Dimethylbutane	0.0053	0.0234	0.0120
2,3-Dimethylbutane	0.0272	0.1209	0.0607
2-Methylpentane	0.0423	0.1878	0.0956
3-Methylpentane	0.0250	0.1113	0.0557
n-Hexane	0.0613	0.2722	0.1373
Heptanes	0.3053	1.4377	0.6306
Octanes	0.0129	0.0752	0.0348
Nonanes	0.0041	0.0229	0.0089
Decanes plus	0.0000	0.0000	0.0000
Nitrogen	0.9837	1.4211	0.5878
Carbon Dioxide	0.2892	0.6563	0.2686
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties**Units**

Gross BTU/Real CF	1172.0	BTU/SCF at 60°F and 14.73 psia
Sat. Gross BTU/Real CF	1152.9	BTU/SCF at 60°F and 14.73 psia
Gas Compressibility (Z)	0.9970	
Specific Gravity	0.6711	air=1
Avg Molecular Weight	19.392	gm/mole
Propane GPM	0.956314	gal/MCF
Butane GPM	0.442893	gal/MCF
Gasoline GPM	0.335142	gal/MCF
26# Gasoline GPM	0.613688	gal/MCF
Total GPM	1.734569	gal/MCF
Base Mol%	99.892	%v/v

Sample Temperature: 66 °F
 Sample Pressure: 157 psig
 Hydrogen Sulfide: 0.0000 Mole%

Reviewed By: AS

035-21959

PRECISION MEASUREMENT, INC.
P.O. Box 3659
746 North Circle Drive
Casper, WY. 82602

4903521959 - BIRCH CREEK UNIT No. 166

7/25/00 2:01 PM
Phone: 307-237-9327
800-624-7260
Fax: 307-677-4139
E Mail: pmi@trib.com

GAS ANALYSIS REPORT

Analysis For: CHEVRON USA
Field Name: BIRCH CREEK
Well Name: BIRCH CREEK 166
Station Number:
Purpose: EMISSIONS TESTING
Sample Deg. F: 77.8
Volume/Day:
Formation:
Line PSIG: 151
Line PSIA:

Run No: 4830-3
Date Run: 7/19/00
Date Sampled: 7/18/00
Producer: CHEVRON
County: SUBLETTE
State: WYOMING
Sampled By: C.G.M.
Atmos Deg. F: 68

GAS COMPONENTS

		MOL%	GPM
Oxygen	O2:	0.000	
Carbon Dioxide	CO2:	0.270	
Nitrogen	N2:	1.210	
Hydrogen Sulfide	H2S:	0.0000	
Methane	C1:	91.201	
Ethane	C2:	4.531	1.208
Propane	C3:	1.613	0.443
Iso-Butane	IC4:	0.247	0.081
Nor-Butane	NC4:	0.392	0.123
Iso-Pentane	IC5:	0.109	0.040
Nor-Pentanes	NC5:	0.107	0.039
Hexanes	C6:	0.187	0.077
Heptanes	C7:	0.110	0.051
Octanes	C8:	0.018	0.009
Nonanes	C9:	0.005	0.003
Decanes	C10:	0.000	0.000
Totals		100.000	2.073

Pressure Base: 14.730
Real BTU Dry: 1093.074
Real BTU Wet: 1073.945

Calc. Ideal Gravity: 0.611
Calc. Real Gravity: 0.612
Field Gravity:
Standard Pressure: 14.696
BTU Dry: 1090.566
BTU Wet: 1071.590
Z Factor: 0.997
Average Mol Weight: 17.989
Average CuFt/Gal: 38.495
Ethane+ GPM: 2.073
Propane+ GPM: 0.865
Butane+ GPM: 0.422
Pentane+ GPM: 0.218
Hexanes + GPM: 0.140
Heptanes + GPM: 0.063
Octanes + GPM: 0.012
Nonanes + GPM: 0.003

BTEx Components, 100 % of Total Volume

N-Hexane: 0.0316
Benzene: 0.0049
Toluene: 0.0080
Ethylbenzene: None Detected
Xylenes: None Detected

Analysis By: C.G.Martin

Remarks:
PULLED BEFORE DEHY

SW SW 24 27 13
Sublette
Bear River
Frontier

PRECISION MEASUREMENT, INC.
P.O. Box 3859
745 North Circle Drive
Casper, WY. 82602

SWNW 8 27 112
Sublette

49-035-22282

3/17/01 5:01 PM
Phone: 307-237-9327
800-624-7260
Fax: 307-577-4139
E Mail: pmf@trib.com

4903522282 - COOPERS No. 1-8

GAS ANALYSIS REPORT

Analysis For: EOG RESOURCES
Field Name: BIG PINEY
Well Name: COOPERS 1-8
Station Number: off Separator
Purpose:
Sample Deg. F:
Volume/Day:
Formation: Frontier
Line PSIG:
Line PSIA:

wet gas
AP-WAI
EOG

Run No: 5084-3
Date Run: 3/16/01
Date Sampled: 3/06/01
Producer: EOG/FRONTEIR
County: SUBLETTE
State: WYOMING
Sampled By:
Atmos Deg. F:

Pressure Base: 14.730
Real BTU Dry: 1092.862
Real BTU Wet: 1073.737

Calc. Ideal Gravity: 0.608
Calc. Real Gravity: 0.607
Field Gravity:

Standard Pressure: 14.696
BTU Dry: 1090.354
BTU Wet: 1071.382
Z Factor: 0.998
Average Mol Weight: 17.852
Average CuFt/Gal: 38.304
Ethane+ GPM: 1.955
Propane+ GPM: 0.841
Butane+ GPM: 0.401
Pentane+ GPM: 0.206
Hexanes + GPM: 0.144
Heptanes + GPM: 0.084
Octanes + GPM: 0.023
Nonanes + GPM: 0.000

GAS COMPONENTS			
		MOL%	GPM
Oxygen	O2:	0.000	
Carbon Dioxide	CO2:	0.212	
Nitrogen	N2:	0.864	
Hydrogen Sulfide	H2S:	0.0000	
Methane	C1:	92.039	
Ethane	C2:	4.179	1.115
Propane	C3:	1.602	0.440
Iso-Butane	IC4:	0.233	0.076
Nor-Butane	NC4:	0.376	0.118
Iso-Pentane	IC5:	0.085	0.031
Nor-Pentanes	NC5:	0.088	0.032
Hexanes	C6:	0.146	0.060
Heptanes	C7:	0.132	0.061
Octanes	C8:	0.045	0.023
Nonanes	C9:	0.000	0.000
Decanes	C10:	0.000	0.000
Totals		100.000	1.955

BTEX Components, 100 % of Total Volume

N-Hexane: 0.0307
Benzene: 0.0075
Toluene: 0.0225
Ethylbenzene: None Detected
Xylenes: None Detected

Analysis By: J.A. PROPP
Approved By: CEM

Hexane - N Hexane - Benzene = Hexane
.46 - .0307 - .0075 = 0.1078

Heptane - Toluene = Heptane

Remarks: 0.132 - .0225 = .1095
CORRECTED FOR AIR CONTAMINATION BY: 58.382%

QUESTAR APPLIED TECHNOLOGY

49-035-22371

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

4903522371 - BIRCH CREEK UNIT No. 187

LIMS ID:	N/A	Description:	Birch Creek # 187
Analysis Date/Time:	7/12/01 13:50	Field:	Birch Creek
Analyst Initials:	AST	ML#:	Chevron
Instrument ID:	Instrument 1	GC Method:	Quesbtex
Data File:	QPC18.D		
Date Sampled:	11-Jul-01		

NE SW 24 27 113
Sublette
Bear River
& Frontier
wet gas

Component	Mol%	Wt%	LV%
Methane	92.2122	83.0646	88.5254
Ethane	4.1305	6.9740	6.2735
Propane	1.4499	3.5899	2.2641
Isobutane	0.2242	0.7316	0.4156
n-Butane	0.3477	1.1348	0.6212
Neopentane	0.0038	0.0155	0.0083
Isopentane	0.0881	0.3571	0.1828
n-Pentane	0.0831	0.3367	0.1706
2,2-Dimethylbutane	0.0028	0.0136	0.0066
2,3-Dimethylbutane	0.0094	0.0455	0.0218
2-Methylpentane	0.0194	0.0940	0.0457
3-Methylpentane	0.0114	0.0552	0.0264
n-Hexane	0.0285	0.1379	0.0664
Heptanes	0.1281	0.6665	0.2783
Octanes	0.0088	0.0563	0.0251
Nonanes	0.0031	0.0184	0.0069
Decanes plus	0.0000	0.0000	0.0000
Nitrogen	0.4210	0.6623	0.2616
Carbon Dioxide	0.8280	2.0461	0.7997
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties**Units**

Gross BTU/Real CF	1082.1	BTU/SCF at 60°F and 14.73 psia
Sat. Gross BTU/Real CF	1064.5	BTU/SCF at 60°F and 14.73 psia
Gas Compressibility (Z)	0.9975	
Specific Gravity	0.6164	air=1
Avg Molecular Weight	17.810	gm/mole
Propane GPM	0.398620	gal/MCF
Butane GPM	0.182551	gal/MCF
Gasoline GPM	0.142467	gal/MCF
26# Gasoline GPM	0.252060	gal/MCF
Total GPM	0.723857	gal/MCF
Base Mol%	99.864	%v/v

Sample Temperature:	73	°F
Sample Pressure:	400	psig
Hydrogen Sulfide	0.0000	Mole%

Reviewed By:



035-22145

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7252

LIMS ID: N/A Description: Birch Creek # 124
 Analysis Date/Time: 9/14/00 10:51 Field: Birch Creek
 Analyst Initials: AST ML#: 124
 Instrument ID: Instrument 1 GC Method: Quesblex
 Data File: QPC93.D
 Date Sampled: 13-Sep-00 4903522145 - BIRCH CREEK UNIT No. 124

Component	Mol%	Wt%	LV%
Methane	86.8426	72.8092	80.8920
Ethane	6.4339	10.1106	9.4814
Propane	3.0634	7.0597	4.6416
Isobutane	0.4391	1.3338	0.7898
n-Butane	0.7787	2.3653	1.3499
Neopentane	0.0084	0.0318	0.0178
Isopentane	0.1756	0.6622	0.3535
n-Pentane	0.1775	0.6692	0.3535
2,2-Dimethylbutane	0.0042	0.0191	0.0097
2,3-Dimethylbutane	0.0228	0.1028	0.0514
2-Methylpentane	0.0355	0.1601	0.0811
3-Methylpentane	0.0207	0.0933	0.0466
n-Hexane	0.0520	0.2342	0.1176
Heptanes	0.2266	1.0712	0.4996
Octanes	0.0247	0.1357	0.0590
Nonanes	0.0038	0.0213	0.0083
Decanes plus	0.0000	0.0000	0.0000
Nitrogen	0.9180	1.3439	0.5534
Carbon Dioxide	0.7725	1.7766	0.7239
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Gross BTU/Real CF	1147.1	BTU/SCF at 60°F and 14.73 psia
Sat. Gross BTU/Real CF	1128.4	BTU/SCF at 60°F and 14.73 psia
Gas Compressibility (Z)	0.8971	
Specific Gravity	0.8622	air=1
Avg Molecular Weight	19.135	gm/mole
Propane GPM	0.842218	gal/MCF
Butane GPM	0.386270	gal/MCF
Gasoline GPM	0.276954	gal/MCF
26# Gasoline GPM	0.522125	gal/MCF
Total GPM	1.507862	gal/MCF
Base Mol%	100.198	%v/v

Sample Temperature: 72 °F
 Sample Pressure: 255 psig
 Hydrogen Sulfide: 0.0000 Mole%

Reviewed By: _____

Bear River
 Frontier
 NE NW 13 27 13
 Sublette

Birch Creek Unit
 Condensates

PRECISION MEASUREMENT, INC.
P.O. Box 3659
746 North Circle Drive
Casper, WY. 82601

49-035-22384

12/10/01 2:18 PM
Phone: 307-237-9327
800-624-7260
Fax: 307-577-4138
E-Mail: pmi@trib.com

GAS ANALYSIS REPORT
4903522384 - COOPERS No. 7-31

Analysis For: EOG RESOURCES
Field Name: BIG PINEY
Well Name: COOPERS 7-31
Station Number:
Purpose: NEW WELL
Sample Deg. F: 75
Volume/Day:
Formation:
Line PSIG: 95
Line PSIA:

Run No: 5431-3
Date Run: 12/18/01
Date Sampled: 12/3/01
Producer: EOG RESOURCES
County: SUBLETTE
State: WYOMING
Sampled By: JEFF DAHL
Atmos Deg. F: 28

Pressure Base: 14.730
Real BTU Dry: 1047.960
Real BTU Wet: 1029.620

GAS COMPONENTS			
		MOL%	GPM
Oxygen	O2:	0.000	
Carbon Dioxide	CO2:	0.697	
Nitrogen	N2:	0.370	
Hydrogen Sulfide	H2S:	0.0000	
Methane	C1:	95.104	
Ethane	C2:	2.757	0.735
Propane	C3:	0.657	0.181
Iso-Butane	IC4:	0.073	0.024
Nor-Butane	NC4:	0.122	0.038
Iso-Pentane	IC5:	0.032	0.012
Nor-Pentanes	NC5:	0.034	0.012
Hexanes	C6:	0.064	0.026
Heptanes	C7:	0.053	0.024
Octanes	C8:	0.032	0.016
Nonanes	C9:	0.006	0.003
Decanes	C10:	0.000	0.000
Totals		100.000	1.072

Calc. Ideal Gravity: 0.585
Calc. Real Gravity: 0.586
Field Gravity:
Standard Pressure: 14.696
BTU Dry: 1045.555
BTU Wet: 1027.362
Z Factor: 0.998
Average Mol Weight: 17.099
Average CuF/Gal: 38.228
Ethane+ GPM: 1.072
Propane+ GPM: 0.337
Butane+ GPM: 0.156
Pentane+ GPM: 0.094
Hexanes + GPM: 0.070
Heptanes + GPM: 0.044
Octanes + GPM: 0.019
Nonanes + GPM: 0.003

BTEX Components, 100 % of Total Volume
N-Hexane: 0.0168
Benzene: 0.0061
Toluene: 0.0099
Ethylbenzene: None Detected
Xylenes: None Detected

Analysis By: S.G. WALLACE
Approved By: *ES*

Remarks:

C6 .064 - N Hexane .0168 - Benzene .0061 = .0411 C6
C7 .053 - Toluene .0099 = .0431
VOC = 1.072
C8+ = .037

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

4903520672 - FEDERAL 30-31

LIMS ID:	N/A	Description:	Bird Canyon 30-31
Analysis Date/Time:	8/17/01 11:49	Field:	Bird Canyon
Analyst Initials:	AST	ML#:	90933
Instrument ID:	Instrument 1	GC Method:	Quesbtex
Data File:	QPC98.D		
Date Sampled:	08/16/01		

Component	Mol%	Wt%	LV%
Methane	96.6432	93.0212	95.1995
Ethane	2.1649	3.9057	3.3739
Propane	0.3425	0.9062	0.5488
Isobutane	0.0336	0.1171	0.0639
n-Butane	0.0515	0.1795	0.0943
Neopentane	0.0009	0.0039	0.0020
Isopentane	0.0108	0.0466	0.0229
n-Pentane	0.0098	0.0426	0.0207
2,2-Dimethylbutane	0.0005	0.0024	0.0011
2,3-Dimethylbutane	0.0000	0.0000	0.0000
2-Methylpentane	0.0021	0.0110	0.0051
3-Methylpentane	0.0014	0.0071	0.0033
n-Hexane	0.0034	0.0178	0.0082
Heptanes	0.0375	0.2028	0.0774
Octanes	0.0017	0.0113	0.0048
Nonanes	0.0040	0.0264	0.0094
Decanes plus	0.0000	0.0000	0.0000
Nitrogen	0.3432	0.5769	0.2188
Carbon Dioxide	0.3490	0.9215	0.3459
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties		Units
Gross BTU/Real CF	1033.6	BTU/SCF at 60°F and 14.73 psia
Sat. Gross BTU/Real CF	1016.9	BTU/SCF at 60°F and 14.73 psia
Gas Compressibility (Z)	0.9979	
Specific Gravity	0.5769	air = 1
Avg Molecular Weight	16.668	gm/mole
Propane GPM	0.094163	gal/MCF
Butane GPM	0.027167	gal/MCF
Gasoline GPM	0.024438	gal/MCF
26# Gasoline GPM	0.040751	gal/MCF
Total GPM	0.145881	gal/MCF
Base Mol%	99.545	%v/v

Sample Temperature:	78	°F
Sample Pressure:	279	psig
Hydrogen Sulfide	0.0000	Mole%

Reviewed By: _____

Bear River
Substitute

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

4903522370 - BIRCH CREEK UNIT No. 134

49-035-22370

LIMS ID:	N/A	Description:	Birch Creek # 134
Analysis Date/Time:	10/24/01 12:50	Field:	Birch Creek
Analyst Initials:	AST	ML#:	134
Instrument ID:	Instrument 1	GC Method:	Quesbtex
Data File:	QPC04.D		
Date Sampled:	23-Oct-01		

Component	Mol%	Wt%	LV%
Methane	88.9961	76.8272	83.6151
Ethane	5.9148	9.5704	8.7919
Propane	2.4558	5.8272	3.7532
Isobutane	0.3599	1.1255	0.6529
n-Butane	0.6268	1.9604	1.0960
Neopentane	0.0070	0.0271	0.0148
Isopentane	0.1435	0.5569	0.2912
n-Pentane	0.1438	0.5582	0.2888
2,2-Dimethylbutane	0.0037	0.0172	0.0086
2,3-Dimethylbutane	0.0177	0.0822	0.0403
2-Methylpentane	0.0278	0.1287	0.0639
3-Methylpentane	0.0166	0.0769	0.0375
n-Hexane	0.0401	0.1860	0.0914
Heptanes	0.2122	1.0427	0.4443
Octanes	0.0100	0.0611	0.0276
Nonanes	0.0041	0.0230	0.0088
Decanes plus	0.0000	0.0000	0.0000
Nitrogen	0.5650	0.8516	0.3435
Carbon Dioxide	0.4551	1.0777	0.4302
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties**Units**

Gross BTU/Real CF	1131.0	BTU/SCF at 60°F and 14.73 psia
Sat. Gross BTU/Real CF	1112.6	BTU/SCF at 60°F and 14.73 psia
Gas Compressibility (Z)	0.9973	
Specific Gravity	0.6432	air=1
Avg Molecular Weight	18.584	gm/mole
Propane GPM	0.675171	gal/MCF
Butane GPM	0.314637	gal/MCF
Gasoline GPM	0.229766	gal/MCF
26# Gasoline GPM	0.427098	gal/MCF
Total GPM	1.219737	gal/MCF
Base Mol%	99.923	%v/v

Sample Temperature:	74	°F
Sample Pressure:	185	psig
Hydrogen Sulfide	0.0000	Mole%

Reviewed By:

AST

Dearline 7500 is Frontier 7100
NW 11 27 113
Sublette

APPENDIX E – REFERENCES

- Becker, T.P., and Lynds, R., 2012, A Geologic Deconstruction of One of the World's Largest Natural Accumulations of CO₂, Moxa Arch, Southwestern Wyoming: AAPG Bulletin, Vol. 96, No. 9, Pg. 1643-1664.
- Buursink, M.L., Slucher, E.R., Brennan, S.T., Doolan, C.A., Drake, R.M., II, Merrill, M.D., Warwick, P.D., Blondes, M.S., Freeman, P.A., Cahan, S.M., DeVera, C.A., and Lohr, C.D., 2014, Geologic framework for the national assessment of carbon dioxide storage resources—Greater Green River Basin, Wyoming, Colorado, and Utah, and Wyoming-Idaho-Utah Thrust Belt, chap. E of Warwick, P.D., and Corum, M.D., eds., Geologic framework for the national assessment of carbon dioxide storage resources: U.S. Geological Survey Open-File Report 2012–1024–E, 50 p.
- Eaton, G.P., 1982, The Basin and Range Province: Origin and Tectonic Significance: Annual Review of Earth and Planetary Sciences, Vol. 10, Pg. 409.
- Kirschbaum, M.A., and Roberts, L.N.R., 2005, Geologic Assessment of Undiscovered Oil and Gas Resources in the Mowry Composite Total Petroleum System, Southwestern Wyoming Province, Wyoming, Colorado, and Utah, in U.S. Geological Survey Southwestern Wyoming Province Assessment Team, eds., Petroleum Systems and Geologic Assessment of Oil and Gas in the Southwestern Wyoming Province, Wyoming, Colorado, and Utah: U.S. Geological Survey Digital Data Series DDS-69-D, Chapter 5, 23 p.
- Lamerson, P.R., 1982, The Fossil Basin and Its Relationship to the Absaroka Thrust System, Wyoming and Utah: Rocky Mountain Geologists Geologic Studies of the Cordilleran Thrust Belt, Vol. 1, Pg. 279-340.
- U.S. Geological Survey, Earthquake Hazards Program, 2025, Advanced National Seismic System (ANSS) Comprehensive Catalog of Earthquake Events: <https://earthquake.usgs.gov/earthquakes/search/> (accessed October 2025)
- US EPA, O., 2015, *Procedures for Groundwater Sampling in the Laboratory Services and Applied Science Division*: <https://www.epa.gov/quality/procedures-groundwater-sampling-laboratory-services-and-applied-science-division> (accessed October 2025)
- Xiao, Ting et al., 2024, A review of risk and uncertainty assessment for geologic carbon storage: Renewable and Sustainable Energy Reviews, Vol. 189, Part B, 113945.

Request for Additional Information: Dry Piney Jackalope Gas Processing Facility
September 23, 2025

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	We recommend including a clear process flow diagram that identifies the CO ₂ flow path through the facility, including the locations of flow meters to be used for subpart RR reporting.	Added a figure (Figure 2.7-3) in Section 2.7 to show a clear process flow diagram that identifies the CO ₂ flow path from facility inlet to injection wellhead, showing locations of mass flow meters to be used for subpart RR reporting.
2.	N/A	N/A	Please ensure that all acronyms are defined during the first use within the MRV plan. For example, “H ₂ S” and “TVD” appear without definition when first introduced.	All acronyms are defined during the first use within the revised MRV plan.
3.	2.0	7-29	We recommend including a description for the lower confining seal of the target injection interval and identifying the seal it on applicable figures.	Updated applicable Figures 2.2-1, 2.6-1, 2.6-6, 2.6-7 and 2.6-8 to include the “Cambrian” lower confining seal for the Bighorn target injection interval and confirmed labels for Amsden & Darby on all applicable figures. Cambrian was already noted on Figure 2.6-3. Darby Formation is the lower confining seal for Madison Fm and was included on figures. Added text in Section 2.6.4 DESCRIPTION OF OVERLYING & UNDERLYING CONFINING LAYERS to better address all confining layers.
4.	3.1	32	“With continuing injection of an additional 4.7 TCF through year-end 2078, at which time injection is expected to cease after a 50-year project life, the plume size is expected to grow to approximately 45,000 ft in diameter (8.5 miles, see Figure 3.2).” page 31 This statement does not appear to align with Figure 3.3 on page 33, which shows that when injection ceases in 2078, the approximate plume diameter is 35,000 ft. Please revise or clarify these sections accordingly.	Section 3.1 has been revised to provide a much more thorough description of how the Maximum Monitoring Area was determined. Updated Figure 3.1-1 (formerly Figure 3.2) has been corrected to show that the approximate plume diameter is 40,000 feet at the end of project life (50 years of injection, year 2078) with plume stabilization around 100 years after injection, year 2128). Stabilized plume diameter is approximately 50,000 feet.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	3.1	32	“Figure 3.3 shows how the predicted plume average diameter is expected to change over time after cessation of injection, which indicates plume stability is achieved around 50 years post-injection in 2178” This statement does not appear to align with Figure 3.3 on page 33, which shows that plume stability is achieved at 100 years, or 50 years post-injection, in 2128. Please revise or clarify these sections accordingly.	Section 3.1 has been revised to provide a much more thorough description of how the Maximum Monitoring Area was determined. Updated Figure 3.1-1 (formerly Figure 3.2) has been corrected to show that the approximate plume diameter is 40,000 feet at the end of project life (50 years of injection, year 2078) with plume stabilization around 100 years after injection, year 2128). Stabilized plume diameter is approximately 50,000 feet.
6.	3.2	34	Per 40 CFR 98.449, the 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. Please define the last year in the period (t) for the area that will be monitored over a specific time interval.	The boundary of the Active Monitoring Area is established by (1) the area projected to contain the free phase CO₂ at end of year t (Year 2128), plus an all-around buffer zone of one-half mile and (2) the area projected to contain the free-phase CO₂ plume at the end of year t (Year 2128) + 5 (Year 2133). The last year in the period (t) for the area that will be monitored is Year 2128. The MRV Plan Section 3.2 has been updated to include the 40 CFR 98.449 language and provide the definition of the last year in the period (t) for the area that will be monitored over a specific time interval.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
7.	4.0	35-42	40 CFR 98.448(a)(2) requires that the MRV plan include a discussion of ‘the likelihood, magnitude, and timing of surface leakage of CO₂’ through the identified potential leakage pathways. In addition to listing the possible leakage pathways and their monitoring strategies, please provide a clear characterization of the likelihood, magnitude, and timing of leakage for each potential leakage pathway. Within Section 4 of the MRV plan, not all identified potential pathways for leakage discuss the magnitude and timing of leakage. For example, the format of such a characterization might look like: “leakage from XYZ pathway is unlikely but possible. If it did occur, it would be most likely when pressures are highest during XYZ timeframe, and the leakage could result in XYZ kgs/metric tons before being addressed...” Additionally, we recommend discussing the potential for leakage through pathways such as natural seismic activity and lateral migration.	BSO has provided a comprehensive update to Section 4.0 to more thoroughly and systematically address “the likelihood, magnitude and timing of surface leakage of CO₂” through the identified leakage pathways. Added a discussion addressing the potential for leakage through natural and or induced seismicity as well as due to lateral migration. As in the case of the previously identified leakage pathways, systematically addressed the “the likelihood, magnitude and timing of surface leakage of CO₂”.
8.	5.0	42-44	40 CFR 98.448(a)(3) requires that the MRV plan include a strategy “for detecting and quantifying any surface leakage of CO₂.” Within Section 5, it appears that there is no detection or quantification strategy for faults and fractures, formation seal, and lateral migration. Please provide a corresponding strategy for all identified potential leakage pathways. For example, please clarify whether any of the other identified monitoring strategies could potentially apply to these pathways. Additionally, please provide more examples of quantification strategies for all leakage pathways.	BSO has provided a comprehensive update to Section 5.0 to more thoroughly and systematically address strategies for “detecting and quantifying any surface leakage of CO₂.” A corresponding strategy for detection and quantification has been added for all identified potential leakage pathways. Specific examples of quantification strategies for all leakage pathways have been provided.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
9.	7.0	45	Please revise the title to section 7.0 “Site Specific Modifications to the Mass Balance Equation” and review the plan as modifications cannot be made to the equations in subpart RR. Note that subpart RR does allow for “considerations you intend to use to calculate site-specific variables for the mass balance equation.”	The title of Section 7.0 has been revised to “Considerations Used To Calculate Site-Specific Variables For The Mass Balance Equation”.
10.	7.1-7.4	46-47	Please revise the equations in sections 7.1, 7.2, and 7.4. The value under the sigma summation symbol should be the number “1”, not the letter “l”. Additionally, the equation in 7.2 should contain a capital “U” above the sigma. Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Equations 7.1, 7.2 and 7.4 have been revised to reflect the corrections necessary. This section of the MRV plan has been reviewed and revised as necessary to ensure all equations listed are consistent with the text in 40 CFR 98.443.
11.	7.4	47	On page 47, it states “At the AGI wells, there will be no CO₂ emissions from venting due to the high H₂S concentration of the AGI fluid; blowdown emissions are sent to the flares and are reported under Subpart W for the gas plant. Venting AGI well injection gas would only occur in the event of depressurizing for maintenance or testing, which would be measured during time of event.” Please clarify the above statement. It is possible that in addition to subpart W reporting, blowdown emissions that are sent to the flares must be included in the calculation for CO_{2FI}, which is defined as “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 this part.” For example, if the blowdown emissions occur after metering for Subpart RR, then they need to be included in Subpart RR reporting. Reporting the emissions under Subpart W does not account for them in Subpart RR mass balance equations.	Language in Section 7.4 regarding venting and blowdown emissions has been clarified by noting that no venting or blowdown would occur in the system after metering for Subpart RR, as can be seen by the relative position of the flow meter used to measure injection quantity and the injection wellhead, per new Figure 2.15 (CO ₂ Flow Diagram).

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
12.	8.0	48	40 CFR 98.448(a)(7) requires that the MRV plan includes a “proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart. This date must be after expected baselines as required by paragraph (a)(4) of this section are established and the leakage detection and quantification strategy as required by paragraph (a)(3) of this section is implemented in the initial AMA.” Please include this date within the MRV plan.	The proposed date at which time BSO will begin collecting data to calculate the total amount of CO₂ sequestered has been added to the MRV Plan in Section 8.0. The proposed date is October 2028.
13.	9.1	48	On page 48 of the MRV plan, it states “The mass of CO₂ injected will be measured with a mass meter for each AGI well and will be monitored continuously, allowing the mass injected to be compiled quarterly.” Please clarify whether this should say “mass flow meter”.	Section 9.1 has been revised to clarify that measurement devices used will be “Mass Flow Meter(s)”. The MRV Plan was corrected for the specific paragraph noted and updated to clarify that the sentence should say “mass flow meter”.



BLUE SPRUCE OPERATING LLC
DRY PINEY “JACKALOPE”
GAS PROCESSING FACILITY &
DRY PINEY STATE AGI WELLS

Subpart RR Monitoring, Reporting and Verification Plan

Sublette County, Wyoming

August 2025

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INTRODUCTION

Blue Spruce Operating LLC (“BSO”) intends to drill and inject into five acid gas injection (AGI) wells in the Madison and/or Bighorn Formations near La Barge, Wyoming for the primary purposes of acid gas disposal and permanent geologic sequestration of carbon dioxide (CO₂) in a subsurface geologic formation. One injection well, the Dry Piney State 12-16, has been drilled but is not yet completed or actively injecting. BSO plans to begin initial injection operations in the AGI wells in 2028 and intends to continue injection until the end-of-life of the Dry Piney assets, estimated to occur around 2078.

BSO is in process of obtaining authority to inject fluids through Class II acid-gas disposal wells into the Madison and Bighorn Formations from the Wyoming Oil and Gas Conservation Commission (“WOGCC”). BSO will also request aquifer exemptions for the Madison and Bighorn Formations from the WOGCC. The fluids to be injected into the AGI wells are waste components of natural gas that will be produced and processed by BSO from the Madison Formation.

BSO has developed this monitoring, reporting and verification (MRV) plan in accordance with 40 CFR 98.440-449 (Subpart RR – Geologic Sequestration of Carbon Dioxide) to provide for monitoring, reporting, and verification of permanent geologic sequestration into the Madison and Bighorn Formations during the injection period. This plan meets the requirements in 98.440(c)(1).

This MRV plan contains ten sections:

- Section 1.0 contains facility information.
- Section 2.0 contains a description of the Dry Piney project, including descriptions of the geology and history of the LaBarge field, an overview of the injection program, and highlights the suitability of the Madison and Bighorn Formations for permanent geologic sequestration.
- Section 3.0 contains the definition and delineation of monitoring areas.
- Section 4.0 evaluates the potential leakage pathways and demonstrates that the risk of CO₂ leakage to atmosphere through identified pathways is minimal.
- Section 5.0 provides an overview of the detection, verification, and quantification of potential leakage pathways.
- Section 6.0 describes the determination of expected baselines to identify excursions from expected performance that could indicate CO₂ leakage.
- Section 7.0 provides the site-specific modifications to the mass balance equation and the methodology for calculating volumes of CO₂ sequestered.

- Section 8.0 provides the estimated schedule for implementation of the MRV plan.
- Section 9.0 describes the quality assurance program.
- Section 10.0 describes the records retention process.

1.0 FACILITY INFORMATION

Facility Name: Dry Piney Jackalope Gas Processing Facility (“DPJGPF”)

Facility Address: 296 Graphite Hollow Rd – BLM 5321, Big Piney, WY 83113

Facility Owner Name: Blue Spruce Operating LLC

Facility Owner Address: PO Box 2460, Pinedale, WY 82941

Date of Submittal: August 4th, 2025

MRV Report Point of Contact: Andrew Moses

Designated Representative: Andrew Moses

Alternate Designated Representative: Scott Gutberlet

MRV Plan ID #: TBD

The Dry Piney Jackalope Gas Processing Facility (“DPJGPF”) will process approximately 400 MMscfpd (“millions of standard cubic feet of gas per day”) of raw inlet gas produced from nine production wells (one drilled, eight permitted) that will be completed in the Madison Formation in and immediately adjacent to the federal Dry Piney Unit (“DPU”), located near the crest of the greater LaBarge Field. The DPJGPF will utilize proven industrial processes to separate and refine saleable products, including helium and methane, from the raw gas stream resulting in a waste gas stream that predominantly contains carbon dioxide and hydrogen sulfide (acid gas). DPJGPF will be situated adjacent to the DPU within the gas production area, while the acid gas injection area is located approximately 10.5 miles to the east-northeast of DPJGPF. The AGI wells will be positioned approximately 1,350 ft TVD down structural dip from the DPU production area. Rather than separating and venting the CO₂ from the acid gas waste stream, the combined acid gas will be transported via pipeline from DPJGPF and injected into the AGI wells to the east-northeast to capture and permanently sequester 100% of the CO₂ in the waste stream.

The AGI wells will report under the Dry Piney Jackalope Gas Processing Facility Greenhouse Gas Reporting Program Identification Number which is 591065. The AGI wells will be Class II per the Underground Injection Control (“UIC”) Permit Classification system. In addition to regulating the oil and gas activities in the state, the Wyoming Oil and Gas Conservation Commission (“WOGCC”) has jurisdiction over UIC Class II wells in Wyoming. The 10-digit API well identification numbers

for the AGI wells are listed below. The AGI well identification numbers will be provided once they are assigned.

• DRY PINEY STATE 12-16	49-035-31390-0000	DRILLED, NOT COMPLETED
• DRY PINEY STATE 3-16	NOT YET ASSIGNED	IN PERMITTING PHASE
• DRY PINEY STATE 8-16	NOT YET ASSIGNED	IN PERMITTING PHASE
• DRY PINEY STATE 16-16	NOT YET ASSIGNED	IN PERMITTING PHASE
• DRY PINEY 6-21	NOT YET ASSIGNED	IN PERMITTING PHASE

2.0 PROJECT DESCRIPTION

This section provides an overview of the geologic setting of the LaBarge field area, the history of oil and gas development and AGI history in the area, and the planned AGI process and program.

2.1 GEOLOGY OF THE LABARGE FIELD AREA

The LaBarge Platform Field area is in Sublette and Lincoln counties of southwest Wyoming, along the western flank of the Greater Green River Basin (“GGRB”) geological province (Figure 2.1). The productive area is in the foothills of the Wyoming Range, due west of the Wind River Mountains near the northern termination of the sub-regional Moxa Arch and includes the Dry Piney Unit.

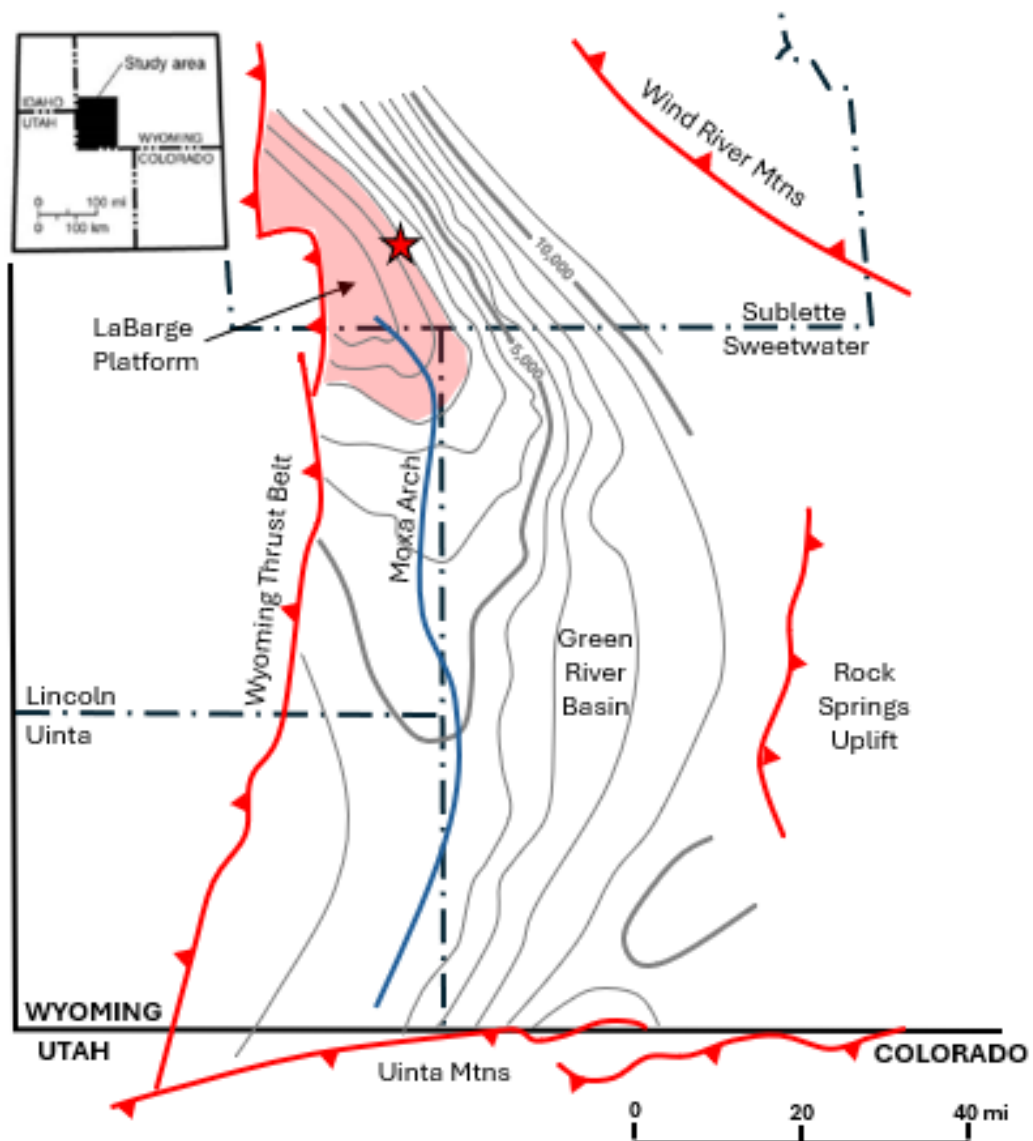


Figure 2.1: Location map of the LaBarge Platform Field area, which includes Dry Piney Unit, denoted by pink shading. The Dry Piney State injection area is denoted by the red star. Modified from the USGS Greater Green River Basin Assessment.

2.2 STRATIGRAPHY OF THE GREATER LABARGE FIELD AREA

The GGRB stratigraphic record spans Precambrian through Eocene time and associated sediments or unconformities (Figure 2.2). Existing hydrocarbon production has been established through many stratigraphic intervals in the GGRB, generally from reservoirs of Paleozoic through Cenozoic age. There are two dominant styles of gas-prone petroleum systems within the GGRB, a “shallow” sweet system (lacking helium and H_2S with a minor or de minimis CO_2 component) and a “deep” sour system (with notable helium, H_2S and CO_2 components). There is also an oil-prone petroleum system that is produced from the

Jurassic Nugget sandstone but is limited to localized structural traps. The Cenozoic hydrocarbon system is sweet, relatively shallow in depth (7,000-9,000 ft TVD), regionally pervasive and generally produces from clastic sequences comprised of alternating sands interpreted to be shorelines and sealed by mud rocks (deeper water deposits) associated with fluctuating sea level of the Western Interior Seaway during Cretaceous time. The Paleozoic hydrocarbon system is deep (14,000 to 17,000 ft TVD), sour (contains H₂S, CO₂ and helium in addition to hydrocarbons), is confined to the LaBarge Field near the crest of the LaBarge “Platform” and is primarily hosted in carbonate (dominantly dolomitic) reservoirs of Mississippian and Ordovician age. The sealing intervals for the primary Madison and Bighorn sour gas reservoirs are comprised of salt-rich sediments of Triassic age and anhydrites in the Pennsylvanian-aged Amsden Formation and Devonian-aged Darby Formation. In the LaBarge field area, including DPU, commercially producible quantities of hydrocarbons have been proven and developed in the following intervals:

- Upper Cretaceous Frontier Formation (Cenozoic, shallow, sweet gas)
- Lower Cretaceous Bear River Formation (Cenozoic, shallow, sweet gas)
- Jurassic Nugget Formation (Cenozoic, shallow, oil)
- Permian Phosphoria Formation (Paleozoic, deep, sour gas)
- Pennsylvanian Weber (Wells) Formation (Paleozoic, deep, sour gas)
- Mississippian Madison Formation (Paleozoic, deep, sour gas)

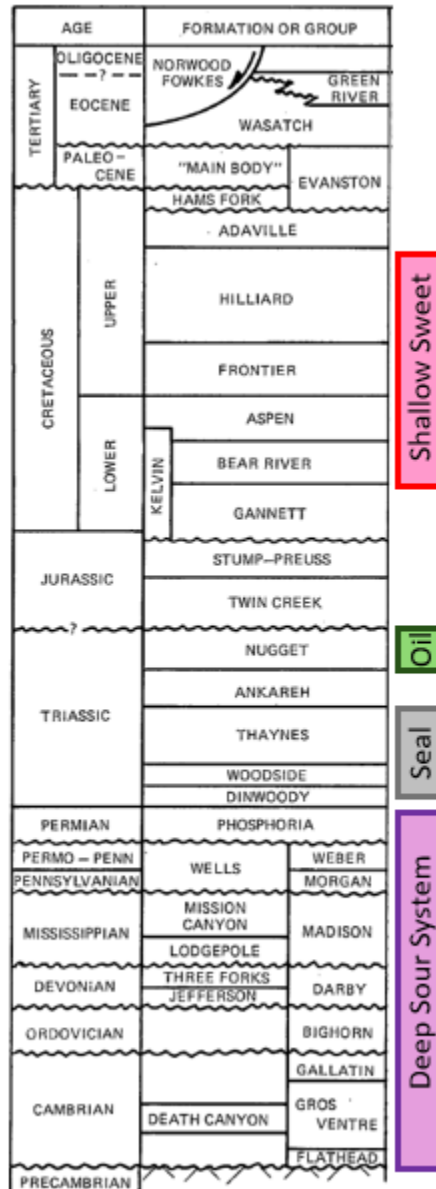


Figure 2.2: Generalized stratigraphic column for the western Greater Green River Basin area in Wyoming. Modified from Lamerson, 1982.

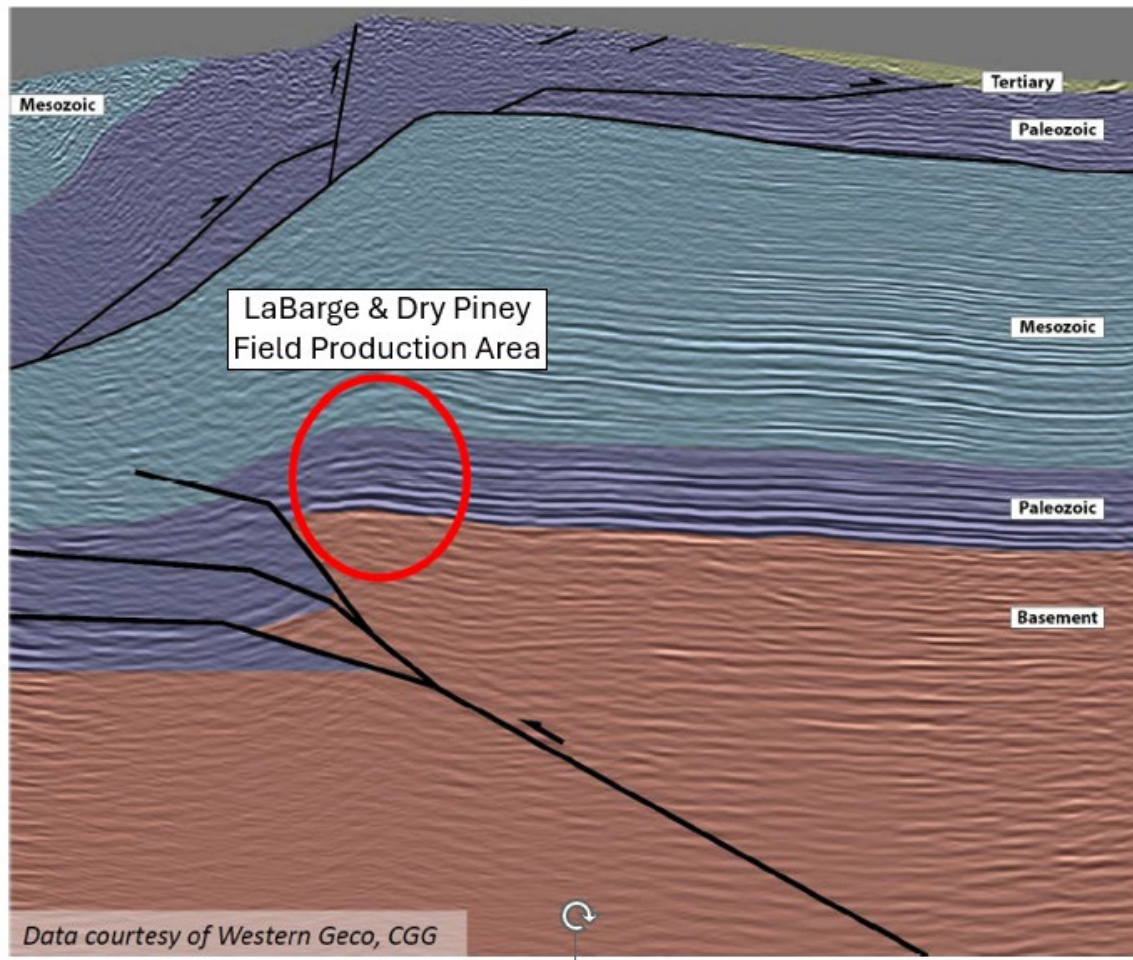
2.3 STRUCTURAL GEOLOGY OF THE LABARGE FIELD AREA

The LaBarge field area lies at the junction of three regional tectonic features: the Wyoming Fold and Thrust Belt to the west, the north-south trending Moxa Arch that provides the structural closure of the LaBarge field, and the Green River Basin to the east. On a regional scale, the Moxa Arch delineates the eastern limit of several regional north-south thrust faults that span the distance between the Wasatch Mountains of Utah to the Wind River Mountains of Wyoming. The historical evaluation of structural styles at LaBarge has defined that three principal styles of structural development have occurred

in the area: Basement-involved contraction, deformation related to flowage of salt-rich Triassic strata and Basement-detached contraction.

2.3.1 BASEMENT-INVOLVED CONTRACTION EVENTS

Basement-involved contraction has been observed to most commonly result in thrust-cored monoclinal features being formed along the western edge of the LaBarge field area (Figure 2.3). These regional monoclinal features have been imaged extensively with 2D and 3D seismic data and are easily recognizable on these data sets. At a smaller scale, the monoclinal features set up the LaBarge field structure, creating hydrocarbon trapping configuration of the various reservoirs contained in the LaBarge productive section.



2.3: Example of thrust-cored monoclinal feature interpreted to be a product of basement-involved contractional events. From ExxonMobil Amended MRV Plan dated October 2019.

2.3.2 DEFORMATION OF FLOWAGE FROM TRIASSIC SALT-RICH STRATA

The second most common style of deformation in the LaBarge field area is the result of flowage from Triassic strata that contain significant amounts of salt. These Triassic

sediments have been observed in outcrops to be comprised of interbedded salt and siltstone intervals. At LaBarge, it is not typical to observe thick, continuous sections of pure salt, but rather interbedded salt and siltstone sections. The “salty sediments” of this interval have been determined to later evacuate and/or flow, which results in local structural highs being developed around these areas. Figure 2.4 contains a seismic line illustrating the Triassic salt-rich sediments and structuring. The salt-induced local structural features generated via salt evacuation can and do create small local hydrocarbon traps associated with these sediments. These smaller, localized structures are of a much smaller scale than the main monoclinial hydrocarbon trap of the larger LaBarge field.

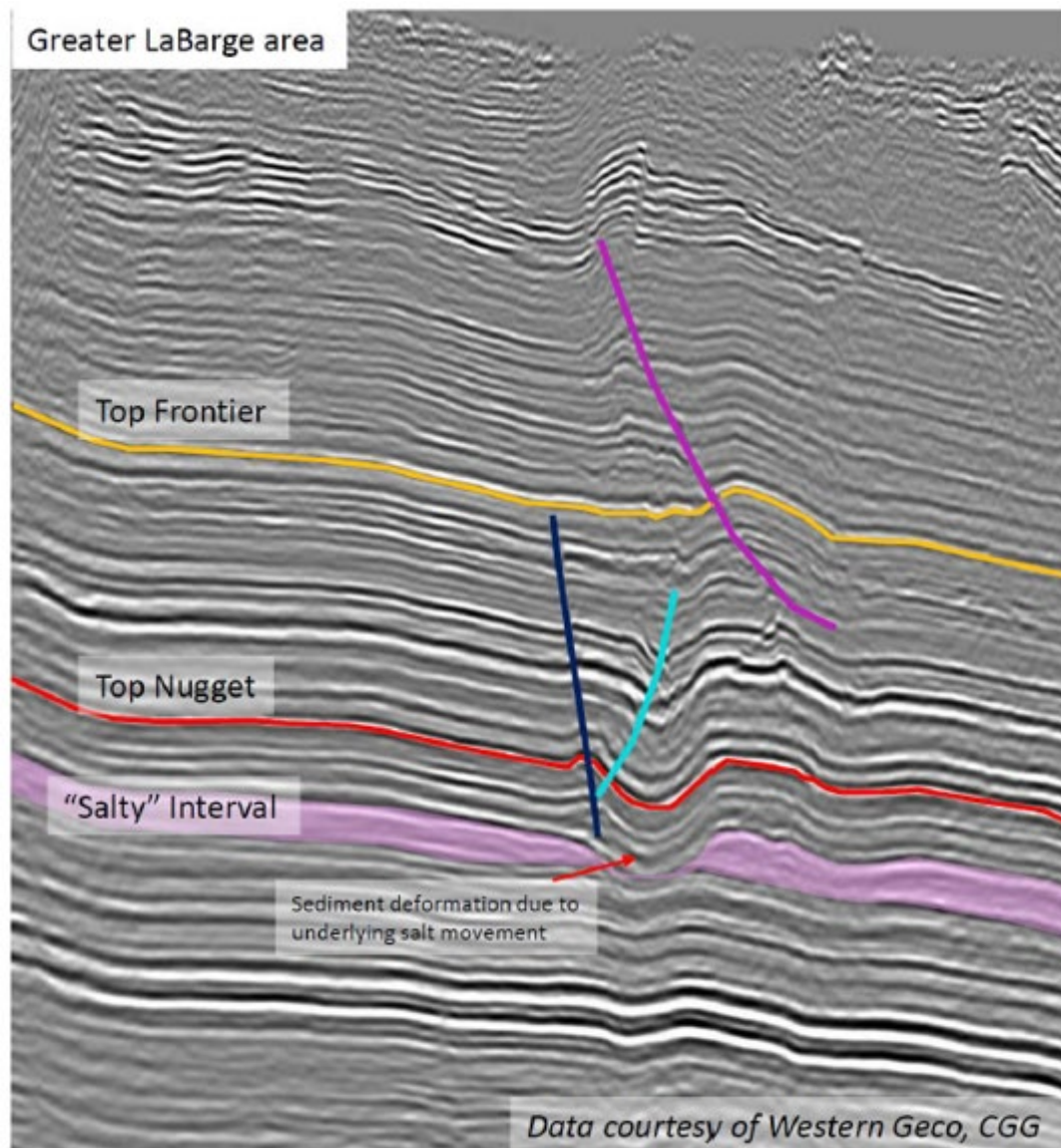


Figure 2.4: Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge field area. From ExxonMobil Amended MRV Plan dated October 2019.

The active deformation behavior of these Triassic sediments has been empirically characterized through the drilling history of the LaBarge field. Early in the life of several wells drilled in the LaBarge field area, wells drilled with thin-walled casing were susceptible to failure due to casing shearing across the Triassic interval. Subsequent wells drilled in the field area used thicker-walled casing strings and successfully mitigated the salt-sediment flowage issue.

2.3.3 BASEMENT-DETACHED CONTRACTION

The third main structural style observed in the LaBarge field area is basement-detached contraction (Figure 2.5). These features have been well-documented, historically at LaBarge as many of these features have mapped fault expressions on the surface. Detachment and contraction along the basement typically create three types of structural features: Regional scale thrust faults, localized smaller-scale thrust faults, and reactivation of Triassic salt-rich sediments resulting in local structural highs.

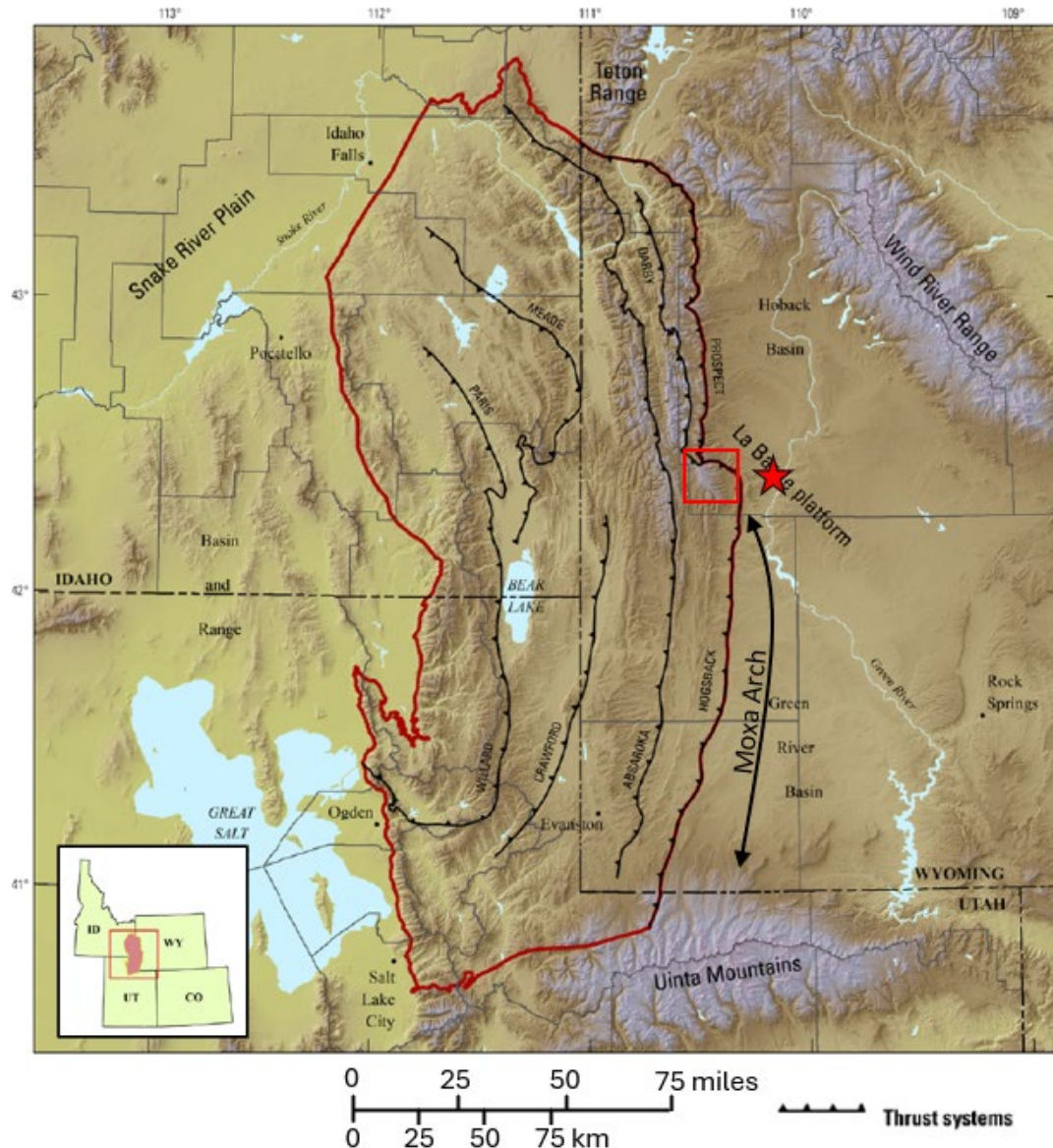


Figure 2.5: Map showing location of the Moxa Arch and regional thrust faults of the Wyoming Range. The LaBarge/Dry Piney Unit production field area is denoted by the red box and the approximate injection area is denoted by the red star. Modified from USGS Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources – Wyoming, Idaho, Utah Thrust Belt.

2.3.4 FAULTING AND FRACTURING OF RESERVOIR INTERVALS

Reservoir permeability in the LaBarge field has been found to increase in areas with small-scale faults and fractures, across nearly all productive zones. Micro-fractures have been identified both in core samples and on borehole micro-imaging logs, with the fractures in the core typically filled with calcite.

In general, wells located near structural highs or fault junctions tend to show higher reservoir permeability and improved hydrocarbon productivity. This suggests that these areas may have a significantly higher density of natural fractures, or a greater proportion of open fractures compared to calcite-filled ones. In contrast, areas with little to no significant faulting, such as the planned AGI area, typically exhibit reservoir permeability driven by matrix or pore-to-pore flow. Matrix permeability is usually less effective in supporting fluid movement over long distances and creates an ideal environment for permanent carbon dioxide containment.

There are a limited number of minor faults in the eastern Dry Piney State injection area of the LaBarge field, and those that do exist are characterized as near vertical, possess near zero offset and are limited in aerial extent. Most faults are detected by subtle discontinuities in seismic reflectors and may or may not be combined with abrupt local dip changes. In no case do the faults extend upward through or above the Triassic Evaporites confining layer which is the primary seal for the sour helium-rich hydrocarbon system.

2.3.5 LABARGE FIELD STRUCTURE AND GAS RESOURCE OF THE MADISON FORMATION

Structural closure at the Madison Formation level in the LaBarge field area is very large, with approximately 4,000 ft true vertical depth (TVD) of structural closure from the top of the structure to the gas-water contact (GWC). Spatially, the Madison closure covers over 800 square miles, making it one of the largest conventional gas fields in North America.

The Madison Formation is estimated to contain more than 300 trillion cubic ft (TCF) of raw gas and 20 TCF of natural gas (methane). At current rates of production, and including the addition of BSO's planned production wells, the estimated remaining field life is over 100 years. Spatially, the Madison and Bighorn injection wells are located approximately 10.5 miles to the east-northeast of the DPIGPF and LaBarge field (DPU) production area.

2.4 PETROLEUM PRODUCTION HISTORY OF THE LABARGE FIELD AREA

The LaBarge field in southwestern Wyoming has a rich history of oil and gas exploration and production, marked by significant discoveries and technological advancements. Below is a detailed timeline highlighting key events in the development of the area.

1840s: Oil was reported by emigrants who used it to grease their wagon wheels.

1907: Initial drilling activities commenced near the future site of Calpet, close to the southern border of what would become the LaBarge Oil Field. These early efforts faced challenges due to the field's remote location, approximately 35 miles from the nearest railhead in Opal, making transportation of heavy drilling equipment difficult.

1920s–1930s: Early Exploration & First Production

- Drilling success in 1923 and the discovery of oil in 1924 marked the beginning of commercial production.
- Initial wells targeted shallow sandstone reservoirs but faced limitations due to transportation challenges.

1940s–1950s: Expansion & Geological Studies

- Increased geological surveys by General Petroleum (a Mobil predecessor) helped better define the field's oil and gas potential.
- Belco Development Company (an EOG Resources predecessor) discovers natural gas in the Frontier Formation.
- By 1956, completion of a Pacific Northwest pipeline provided takeaway capacity and the LaBarge area was recognized as a key gas-producing region in Wyoming.

1960s–1970s: Infrastructure & Pipeline Development

- In 1962, Mobil discovers Paleozoic (Madison) gas at Tip Top, elects to not develop further due to economic and technological constraints associated with the sour gas.
- Investment in infrastructure, including pipeline construction, facilitated the transport of shallow oil and gas.
- Shallow development lead by General Petroleum, Belco and Mountain Fuel Supply Company (QEP Resources predecessor), focused on structural traps in the Frontier Formation.
- Natural gas production increased, paving the way for larger-scale operations in later decades.

1980s–1990s: ExxonMobil & Large-Scale Gas Production

- In 1981, Exxon discovers Madison gas in the Lake Ridge Unit.
- During mid-1980's, Exxon develops Madison gas in Lake Ridge, Fogarty Creek and Graphite Units and begins construction of Shute Creek Treating Facility and associated infrastructure.
- Exxon began operations at the Shute Creek Treating Facility in 1986, focusing on natural gas with high CO₂ content.
- In 1999, Exxon and Mobil merge, EOG Resources spins out from Enron (Belco Development Company successor).

2000s: Environmental Initiatives & CO₂ Capture

- ExxonMobil launched carbon capture and storage (CCS) projects to reduce emissions.
- Between 2001 and 2005, ExxonMobil drills and begins injection into initial AGI wells to dispose of hydrogen sulfide and minor carbon dioxide volumes.
- CO₂ from the field was increasingly used for enhanced oil recovery in other reservoirs.

2010s: Advanced Gas Processing & New Technologies

- In 2010, QEP Resources spins off from Questar (Mountain Fuel Supply Company successor).
- ExxonMobil tested new gas separation technologies, including the CFZ™ process.
- The LaBarge field cemented its role as a crucial CO₂ supplier for enhanced oil recovery in the Rockies.

2020s: Continued Production & Energy Transition

- In 2020, BSO acquired leasehold to develop the Madison in the DPU area from QEP Resources and EOG Resources.
- In 2024, BSO drilled the Dry Piney 4-36 production test well in DPU and confirmed the Madison gas composition, including higher than anticipated helium, and encountered higher reservoir pressures than expected.
- In 2025, BSO drilled and acquired geologic data in the Dry Piney State 12-16 injection well.
- Ongoing investments by ExxonMobil and BSO in CCS align with efforts to reduce the field's carbon footprint.

2.5 INITIAL DISCOVERY OF MADISON GAS AND EARLY COMMERCIALITY AT LABARGE

Mobil discovered significant natural gas reserves in the Madison Formation within the LaBarge field area in 1962. However, due to economic and technological constraints, commercial development did not commence immediately. It was not until the 1980s that large-scale production became viable, following Exxon's successful discovery of Madison gas in the Lake Ridge Unit, which helped justify the necessary infrastructure investments.

Meanwhile, commercial gas production from the Frontier Formation began earlier, in 1956, after the completion of the Pacific Northwest Pipeline. This crucial pipeline provided the market access needed to support Belco Development's Frontier gas production program, enabling steady extraction and transportation of natural gas from the region.

Oil production from the Nugget Sandstone Formation was established later, though on a smaller scale compared to gas production.

The Madison Formation's vast gas reserves remained largely untapped until Exxon initiated production in 1986 with the startup of the Shute Creek Treating Facility. This facility was critical in processing the high-CO₂ and high-H₂S natural gas from the Madison Formation, separating methane, nitrogen, carbon dioxide, and helium to make the gas commercially viable.

The Madison Formation at LaBarge contains an estimated total gross gas in-place volume exceeding 300 trillion cubic ft (TCF). Since production began in 1986, ExxonMobil has cumulatively extracted approximately 8.7 TCF of raw gas from the Madison Formation.

BSO plans to produce 7.3 TCF of raw gas during its 50-year project life.

2.6 ACID GAS INJECTION PROGRAM HISTORY AT LABARGE

ExxonMobil has been injecting acid gas into the Madison Formation into two AGI wells since 2005. ExxonMobil drilled a third AGI well in 2023 and is currently working to bring it online, with injection operations expected to begin in 2025. ExxonMobil has a fourth AGI well currently approved to drill by the WOGCC. All AGI wells are located about 45 miles to the south of the LaBarge field production area and are targeting the Madison and/or Bighorn Formations below the gas-water contact (GWC).

The Madison Formation raw gas production contains a relatively low methane (CH₄) concentration and a high carbon dioxide (CO₂) content. The average gas composition of Madison gas produced by ExxonMobil is as follows:

- 21% Methane (CH₄)
- 66% Carbon Dioxide (CO₂)
- 7% Nitrogen (N₂)
- 5% Hydrogen Sulfide (H₂S)
- 0.6% Helium (He)

Due to the high CO₂ and H₂S content of Madison gas, there was a significant need for CO₂ and H₂S disposal after separating and marketing the saleable products (primarily CH₄ and He). ExxonMobil has historically sold a significant portion of the excess CO₂ into the enhanced oil recovery (EOR) market and vented the remainder. The Shute Creek Treating Facility (SCTF) originally contained a sulfur recovery unit to transform the waste H₂S gas to elemental sulfur. In 2005 due to poor economics, ExxonMobil decommissioned the sulfur recovery units to debottleneck and improve reliability at SCTF. This generated the need to inject the H₂S and entrained CO₂ into the subsurface via AGI wells. In 2022, ExxonMobil received federal permits to expand its carbon capture program at SCTF to capture the remaining CO₂ volumes not sold into the EOR market or entrained in H₂S that were historically vented to atmosphere. The previously vented CO₂ volumes will be injected into the recently drilled SC 5-2 AGI well, expected to begin operations in 2025.

2.6.1 GEOLOGICAL OVERVIEW OF THE BSO AGI PROGRAM

BSO anticipates producing sour gas very similar in composition to that produced by ExxonMobil, and is represented by the following components based on reservoir fluid sampling in the Dry Piney 4-36 well drilled by BSO:

- 20.5% Methane (CH₄)
- 67% Carbon Dioxide (CO₂)
- 7% Nitrogen (N₂)
- 4.5% Hydrogen Sulfide (H₂S)
- 0.6% Helium (He)

BSO plans to capture and dispose all of the CO₂ and H₂S waste gas after the saleable products (CH₄ and He) have been separated, processed and refined at the DPJGPF. Nitrogen will either be vented, sold into the local market, or utilized in the helium liquefaction process in the gas processing facility.

BSO has pursued the AGI program as a safe and reliable method to inject the acid gas waste stream into the Madison and Bighorn Formations based upon ExxonMobil's successful injection history into the Madison Formation on the same geologic structure. ExxonMobil injects acid gas below the GWC, but BSO plans to target the Madison and Bighorn Formations for injection just above the GWC. BSO's evaluation indicates that more favorable injection rates will potentially be obtained for a longer duration above the GWC, thus requiring fewer AGI wells to handle the CO₂ and H₂S waste gas stream requiring disposal. Waste gas composition for disposal will be approximately 92.4% CO₂ and 6.93% H₂S and 0.5% methane by molar volume. The acid gas will be injected at depths ranging approximately 14,800 ft to 17,000 ft TVD below the surface and will be located near the GWC approximately 10.5 miles to the east-northeast of the main DPU (LaBarge field) production areas.

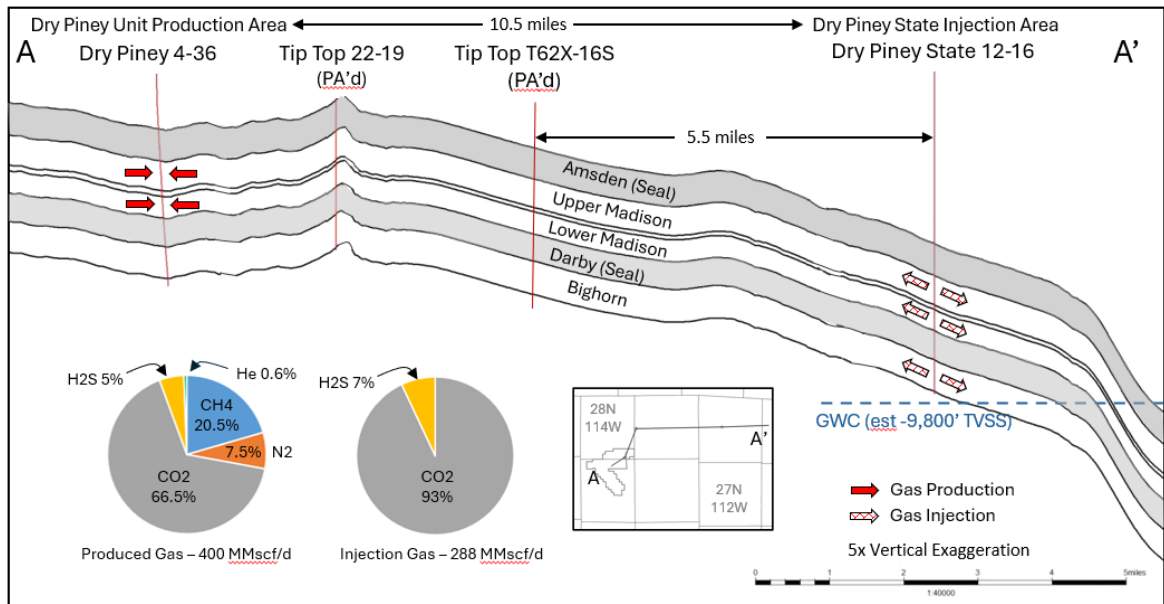


Figure 2.6: Schematic illustration showing location of proposed Dry Piney State 12-16 well and injection area near gas-water contact (GWC) relative to the Dry Piney Unit production area approximately 10.5 miles to the west. Two plugged and abandoned Tip Top wells penetrate the Madison & Bighorn Formations between the BSO production and injection areas. Vertical exaggeration is 5x.

2.6.2 RESERVOIR QUALITY OF THE MADISON FORMATION IN AGI WELLS

BSO proposed AGI wells are approximately 10.5 miles east of the Dry Piney Unit production area and 2024 BSO Dry Piney 4-36 well. There are two plugged and abandoned wells that penetrate the Madison and Bighorn Formations between the production and injection areas, the 1962 Mobil Tip Top Unit 22-19 well and the 2008 ExxonMobil Tip Top T62X-16S. The Tip Top T62X-16S logs are not publicly available, so reservoir quality is unknown at that location (Figure 2.7). BSO completed drilling and logging the Dry Piney State 12-16 well in the injection area in June 2025. Extensive data was acquired in both BSO wells to allow evaluation of the reservoir quality and storage capacity of the Madison and Bighorn Formations in the Dry Piney Unit production area and the Dry Piney State injection area. Forty-one wells on the LaBarge structure have sufficient publicly available data to integrate into a petrophysical model, the results of which have been integrated into a geologic model that characterizes Madison and Bighorn reservoir quality regionally and locally in the Dry Piney State injection area.

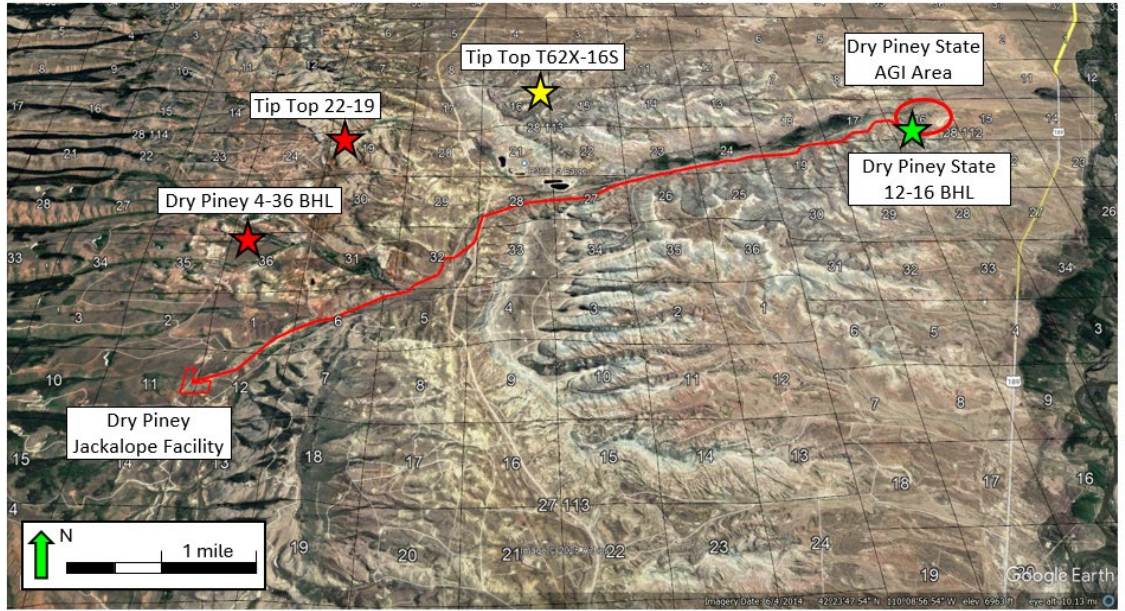


Figure 2.7: Map showing the relative position of the BSO proposed AGI area (red circle) and Dry Piney State 12-16 (green star) relative to the Tip Top Unit 22-19 and the BSO Dry Piney 4-36 wells (red stars). Logs unavailable for the Tip Top T62X-16S well (yellow star). The DPIJGPF is denoted by a red rectangular box and the proposed pipeline route between DPIJGPF and the Dry Piney State AGI area is the red line.

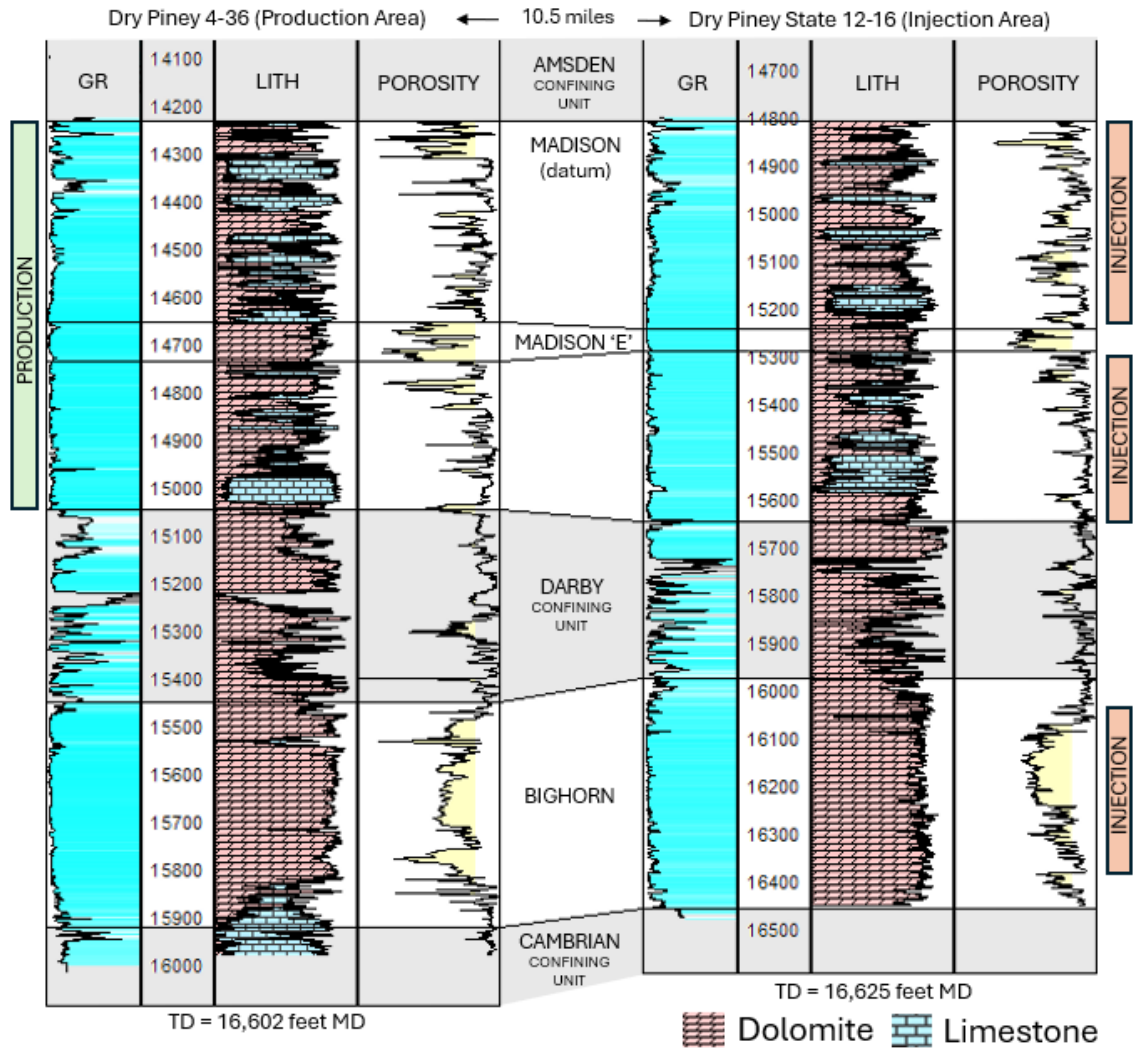


Figure 2.8 – Stratigraphic cross-section showing Dry Piney 4-36 well (Production Area) and Dry Piney State 12-16 (Injection Area). Madison well top is the stratigraphic datum. Gamma Ray (GR), lithology (LITH) and Porosity logs displayed. Note that porosity over 5% is shaded in yellow. Madison production interval denoted by green bar to left of Dry Piney 4-36 and Madison & Bighorn Injection intervals denoted by orange bars to right of Dry Piney State 12-16. The confining units immediately above and below the Madison and Bighorn are shaded in gray. Production area and Injection area are separated by approximately 10.5 miles.

Petrophysical evaluation of these wells indicates that the Madison Formation is comprised of alternating limestone and dolomite intervals. In general, the limestone intervals possess lower porosity averaging 0-5%, whereas the “pay” dolomite intervals greater than 5% porosity average 9.7% porosity and act as the primary reservoir lithofacies. Overall, the Madison averages 5.5% porosity. The Bighorn Formation is primarily dolomite and contains a relatively high porosity zone (>12%) approximately 175 ft thick in the middle of

the formation. The “pay” in the Bighorn Formation averages 10.7% porosity, while the overall Bighorn averages 7.7% porosity. Core permeability indicates both the Madison and Bighorn dolomites range from 1 to 500 millidarcies (md), with an average of around 10 md in both the Madison and Bighorn. The reservoir quality of the Madison and Bighorn Formations in the Dry Piney State 12-16 injection well are summarized in Figure 2.9, and future injection wells in the Dry Piney State injection area are anticipated to be similar.

Formation	Madison	Bighorn
Net Pay (ft)	343	309
Avg Phi (%)	9.7	10.5
Avg K (mD)	10	10
Kh (md-ft)	3430	3090
Skin	-4.0 to -4.5*	-4.0 to -4.5^

*Figure 2.9 – Average reservoir properties for the Dry Piney State 12-16 injection well. Future AGI wells are expected to have similar properties. * Skin as reported by other operators injecting into same formation based on injectivity and fall-off tests. ^ Bighorn skin factor assumed to be similar to Madison owing to similar Avg Phi and Avg K reservoir properties.*

From Figure 2.9, the parameters tabulated include:

- Net Pay: Feet of Madison and Bighorn intervals that exceed 5% total porosity.
- Avg Phi: Average total porosity (the percent of the total bulk volume of the rock investigated that is not occupied by rock-forming matrix minerals or cements).
- Avg K: Air permeability, which is measured in units of darcy – a measure of the ability of fluids to move from pore to pore in a rock.
- Kh: Millidarcy-ft, which is a measure of the average permeability multiplied by the total net pay section encountered.
- Skin: Relative measure of damage or stimulation enhancement to formation permeability in a well completion. Negative skin values indicate enhancement of permeability through the completion whereas positive values indicate hindrance of permeability or damage via the completion.

2.6.2 SEISMIC EXPRESSION OF MADISON & BIGHORN FORMATIONS AT AGI WELL LOCATIONS

Seismic expression of the Madison and Bighorn Formations at the proposed Dry Piney State AGI area indicates that the planned injection wells are located on the plunging eastern limb of the Moxa Arch. Several minor faults with limited offset and aerial extent

were observed in the seismic data within ten miles of the proposed AGI location. The faults are characterized by discontinuity and change in local structural dip of seismic reflectors, rather than significant offset, and are constrained to the geologic units below the Triassic Evaporite confining layer. Because the minor faults die out upward and do not extend vertically above the Triassic Evaporite confining layer, there is little to no risk of the fault impacting the ability of the Triassic Evaporite sealing interval to maintain its seal integrity. No evidence of faulting was observed to extend vertically above the Triassic Evaporite confining layer in the proposed AGI area (Figures 2.10, 2.11 and 2.12), thus limiting potential leakage pathways via faulting (discussed further in Section 4.3).

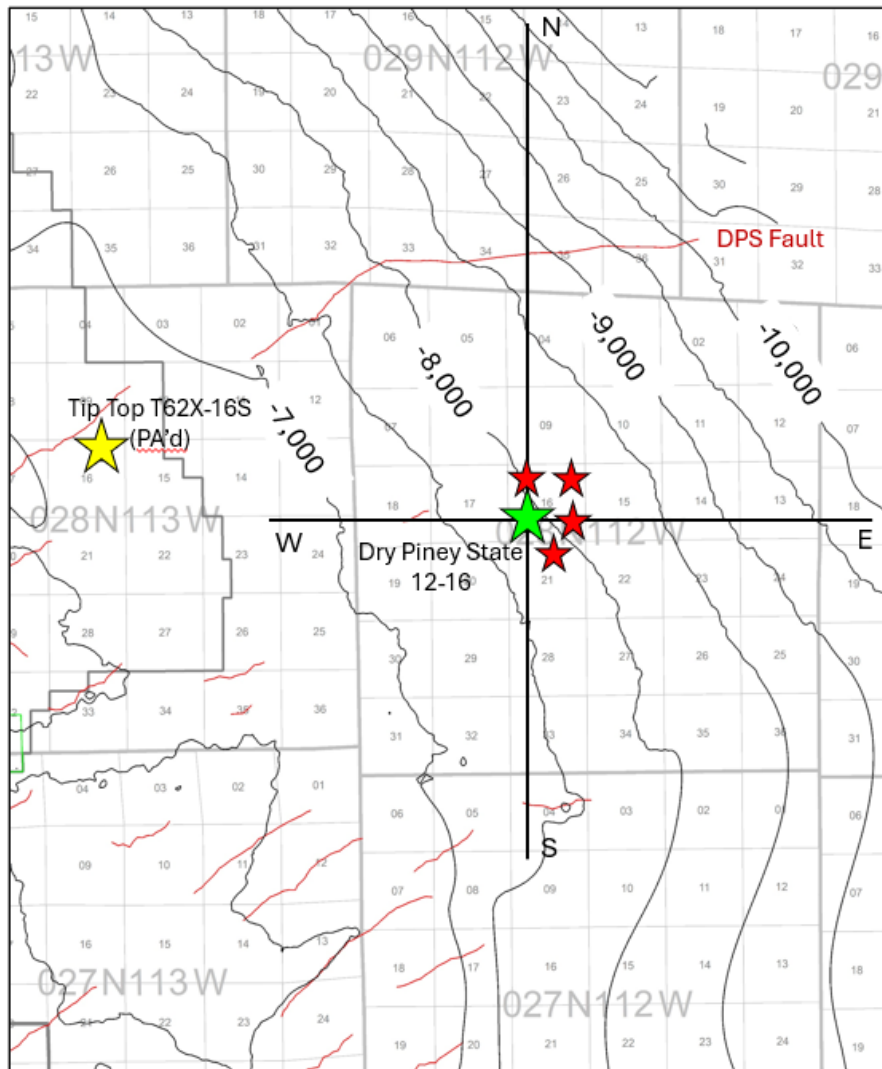


Figure 2.10 -- Madison Structure (TVDSS, 500 ft contour interval) reference map showing N-S (Figure 2.11) and W-E (Figure 2.12) seismic lines relative to the DPS AGI Area, including the DPS 12-16 well (green star) and future AGI wells (red stars). Note the fault traces (red lines) of minor faults observed during seismic interpretation. "DPS" Fault is displayed on N-S seismic line in Figure 2.11.

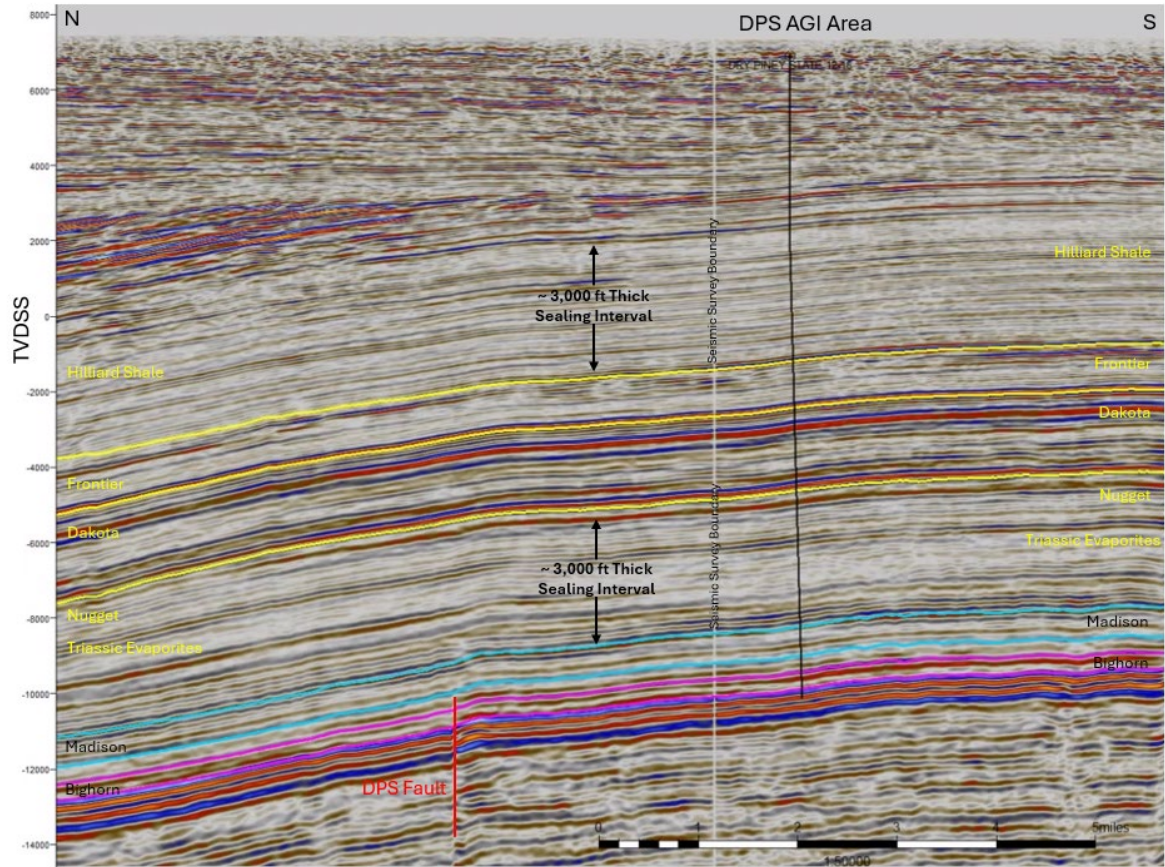


Figure 2.11 – Seismic line from 3D volume, oriented N to S through the proposed Dry Piney State 12-16 injection well location, shows one minor fault with minimal vertical offset that dies out before extending above the Madison Formation. Note vertical seam with no data is a boundary between seismic volumes, not a fault. Vertical exaggeration is 2X.

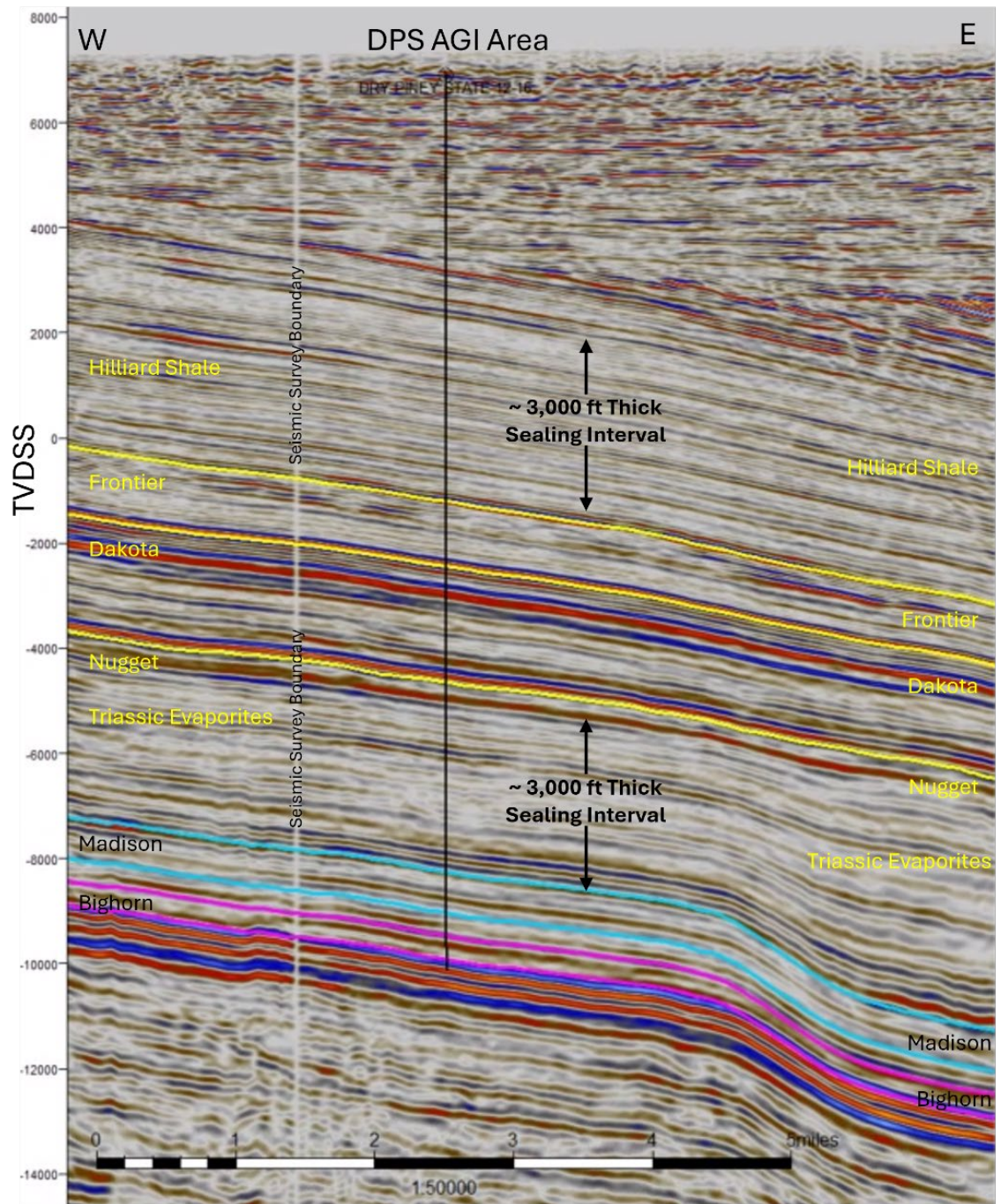


Figure 2.12 - Seismic line from 3D volume, oriented W to E through the proposed Dry Piney State 12-16 injection well location, shows no faulting. Note vertical seam with no data is a boundary between seismic volumes, not a fault. Vertical exaggeration is 2X.

2.7 DESCRIPTION OF THE INJECTION PROCESS

The purpose of the AGI process is to take the CO₂ and H₂S removed from the produced raw gas at DPJGPF and permanently sequester it into the Madison and Bighorn Formations. Production of raw gas will be from the Madison Formation only in the DPU

production area. Injection and sequestration of CO₂ and H₂S is planned to target the Madison Formation in four proposed wells and the Bighorn Formation in the drilled but uncompleted Dry Piney State 12-16 (Figure 2.13).

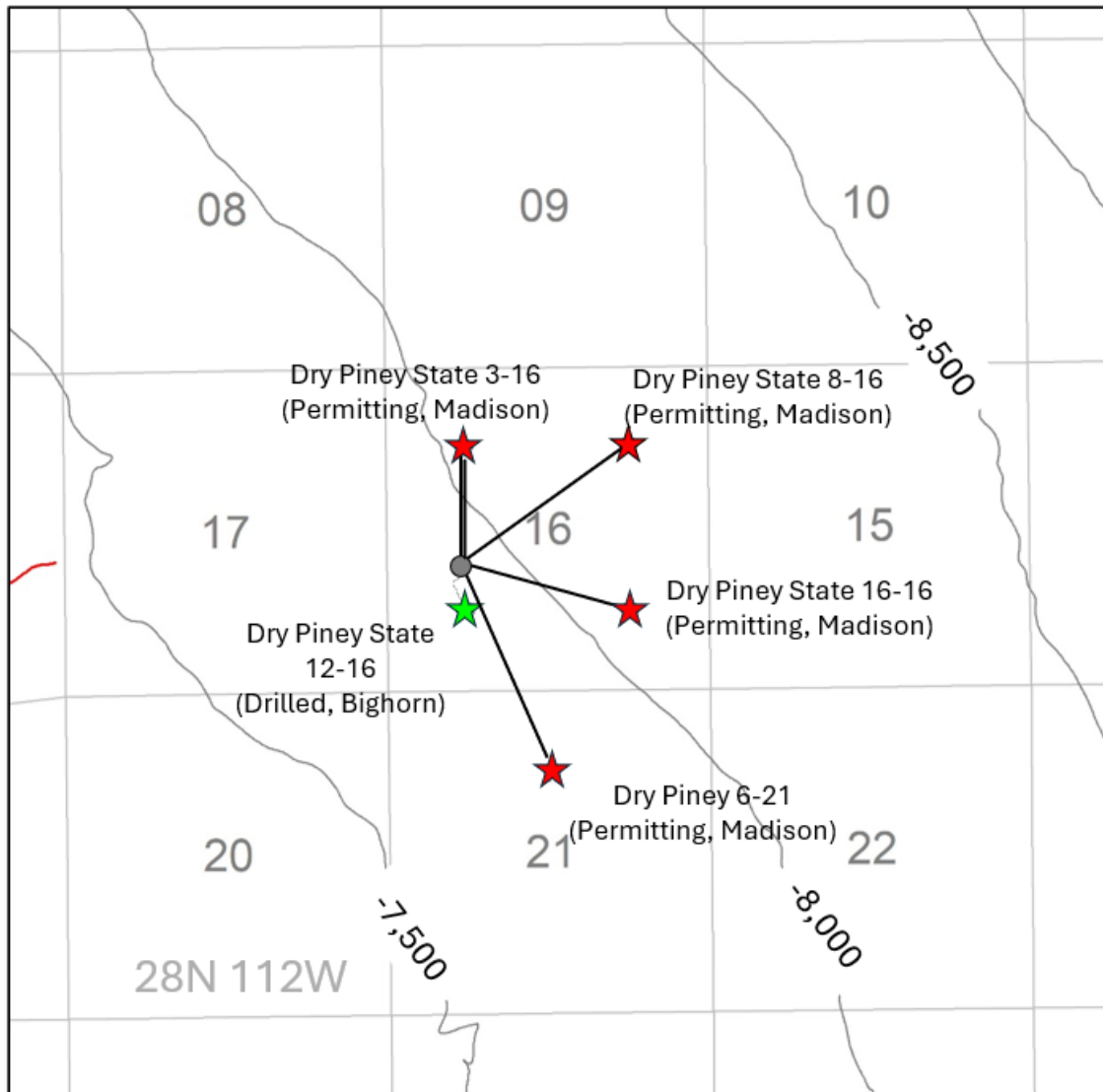


Figure 2.13 – Map showing the existing drilled (but not completed) Dry Piney State 12-16 well and the future Dry Piney State injection wells. Dry Piney State 12-16 will inject into the Bighorn, while the four future injection wells are anticipated to target the Madison for injection. Contours are top Madison structure (SSTVD, 500 ft contour interval).

It is not feasible to inject into both the Madison and Bighorn Formations in the same well due to differing reservoir pressures. Based on reservoir pressure data obtained while drilling the Dry Piney State 12-16 well, the Madison Formation was observed to have an average reservoir pressure of 6,686 pounds per square inch (psi), which is more than 500 psi less than the Bighorn Formation average of 7,206 psi. Unless the well is configured

with a dual completion, it is assumed all injected volumes will enter the Madison due to its lower reservoir pressure. A dual completion would require reduced tubing and casing diameters and would materially limit injection rates. Based on gas compositional analysis of fluid samples taken in the Dry Piney State 12-16 well, the Madison and Bighorn Formations have uneconomic quantities of CH₄ (< 5%) and He (< 0.25%) at the downdip location of the AGI area near the GWC. As such, injection into the Madison and Bighorn Formations is not expected to contaminate potential production at the AGI area. Because the injected gas composition is expected to be 92.4% CO₂, 6.93% H₂S and 0.5% methane, the injected gas is anticipated to be denser than the less CO₂-rich gas up structural dip to the west in the production area (Figure 2.14). Therefore, measurable quantities of injected gas are not forecasted to “break-through” or contaminate production in the DPU area, structurally up dip and 10.5 miles to the west, during the 50-year production life of the project. This is demonstrated through the dynamic reservoir simulation modeling and can be noted on Figure 3.2 which shows an outline of the plume extent of injected volumes after 50 years.

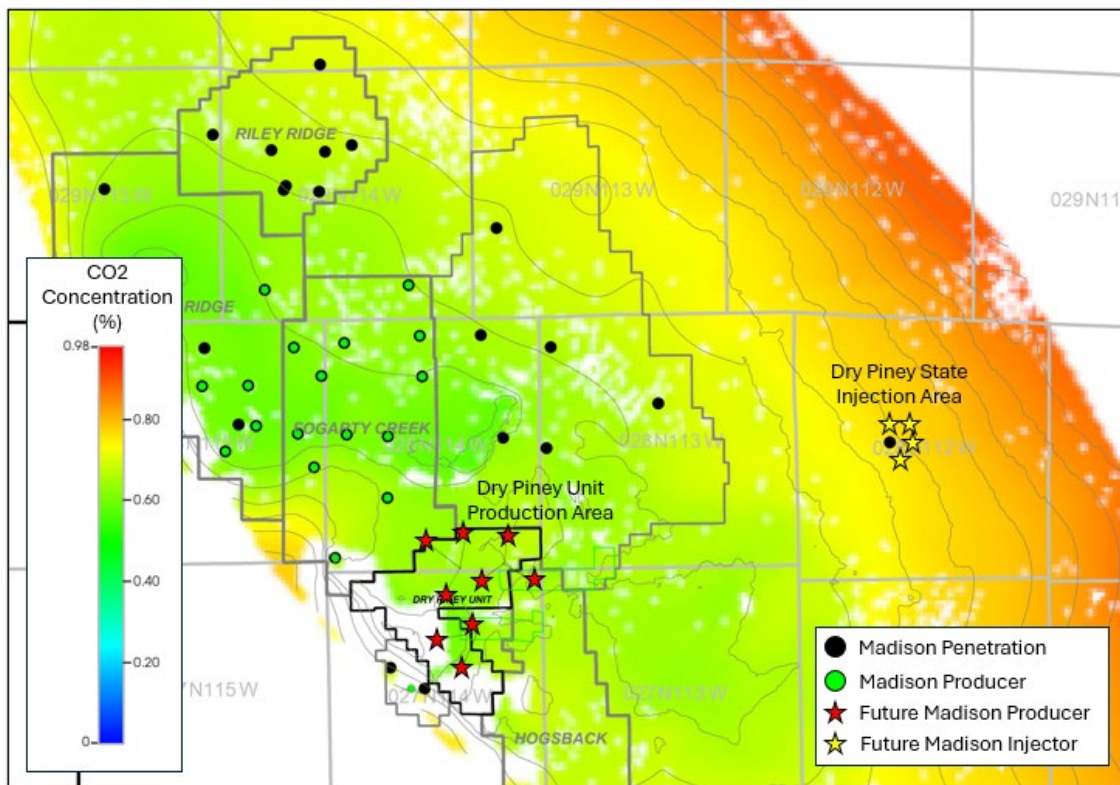


Figure 2.14 – Regional map showing in-situ CO₂ concentration (%) across the LaBarge Field in the upper Madison. Note the lower CO₂ concentration (<70%) in the Dry Piney Unit production area compared to the higher initial in-situ CO₂ concentration (> 80%) in the Dry Piney State injection area due to gravity segregation over geologic time.

The AGI system transports the dense-phase supercritical acid gas stripped from the bulk fractionation process under pressure through a pipeline to the five-well Dry Piney State AGI area (Figures 2.7 and 2.13). The five AGI wells will inject acid gas into the Madison or Bighorn Formations, which are geologically suitable for permanent storage and sequestration of the acid gas. The AGI system will consist of a series of process and injection pumps to increase the mid-pressure liquid from the bulk fractionation at the DPJGPF to the well injection pressure. Free water will not be present in any part of the pipeline system, removing the threat of internal corrosion.

The AGI pipeline will be constructed, tested, and maintained in accordance with the latest industry standards and codes. The high-pressure AGI pipeline will be constructed of carbon steel and be approximately 11.13 miles in length. The AGI pipeline will be outfitted with the necessary instrumentation and hardware to monitor operation from a control room and to detect leaks. Shutdown valves will be installed on the pipeline system to safely isolate the pipeline under an emergency condition.

The total depth of each AGI well will range from 16,600 ft (Bighorn) to 15,750 ft (Madison) TVD depending on whether the Madison or Bighorn Formation is targeted. Measured depths will be higher than the TVD depth range and depends on the directional plan for each specific well with higher deviations resulting in higher measured depths.

2.8 PLANNED INJECTION VOLUMES

Figure 2.15 is a long-term injection forecast through the life of the acid gas injection project, anticipated to be 50 years in length, showing total injection of 5.25 TCF. It is important to note that this is just a forecast – actual injection volumes will be collected, calculated, and reported as required by Subpart RR. Additionally, the volumes provided in Figure 2.15 are the total amount of gas to be injected, not just the CO₂ portion which is expected to represent approximately 92.4% of the waste gas stream. BSO forecasts the total volume of CO₂ stored over the modeled injection period to be approximately 4.87 TCF (257.6 million metric tons).

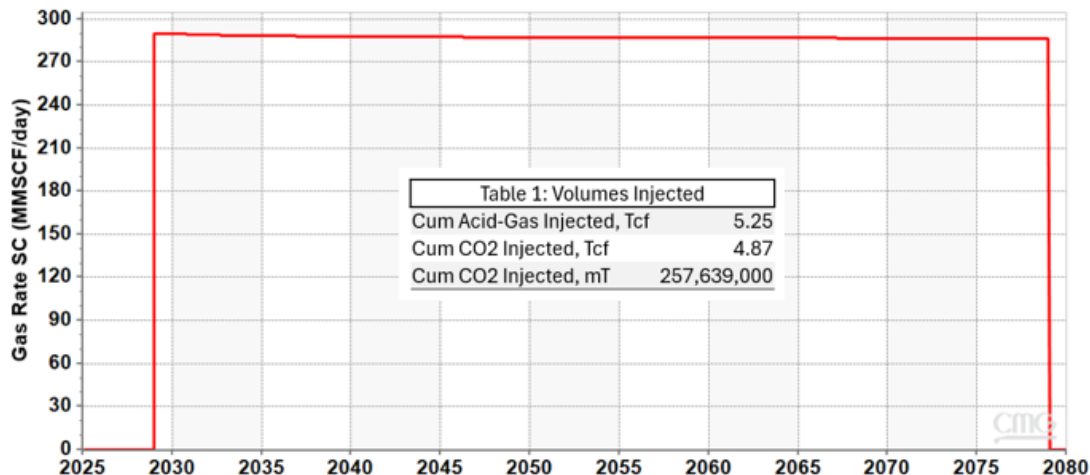


Figure 2.15 – Long term injection forecast showing waste gas (combined CO₂ & H₂S) volume of 5.25 TCF to be injected into all five BSO injection wells throughout the life of the 50-year project. The CO₂-only volume is 4.87 TCF (257.6 million metric tons).

3.0 DELINEATION OF MONITORING AREA

3.1 MAXIMUM MONITORING AREA (MMA)

Per CFR 98.949, the MMA is defined as equal to or greater than the area expected to contain the free-phase CO₂ plume until the CO₂ plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from all wells with available data, seismic data, and historic production and injection data from ExxonMobil LaBarge field operations, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Because the Dry Piney State AGI area has an in-situ pre-injection CO₂ composition of > 85% in the Madison and > 95% in the Bighorn, as evidenced by gas composition analysis conducted on reservoir fluid samples obtained in the Dry Piney State 12-16 well, BSO defines the “free-phase” CO₂ plume as a “net incremental CO₂ gas saturation” rather than simply defining where CO₂ gas saturation is greater than 0.5%. Calculation of the volume-weighted average gas saturation at various time steps was used to determine the acid gas plume area, with the “free-phase” plume boundary defined as the area with an increase in net incremental CO₂ gas saturation of greater than 0.5% (absolute) resulting from injected volumes. An incremental change in gas saturation of 0.5% is well below the lowest gas saturation that can be confidently detected by formation evaluation methods in reservoirs with rock properties such as those found in the Madison Formation.

After injecting 0.528 TCF by year-end 2033, the estimated acid gas plume size is approximately 13,500 ft in diameter (2.6 miles, see Figure 3.1).

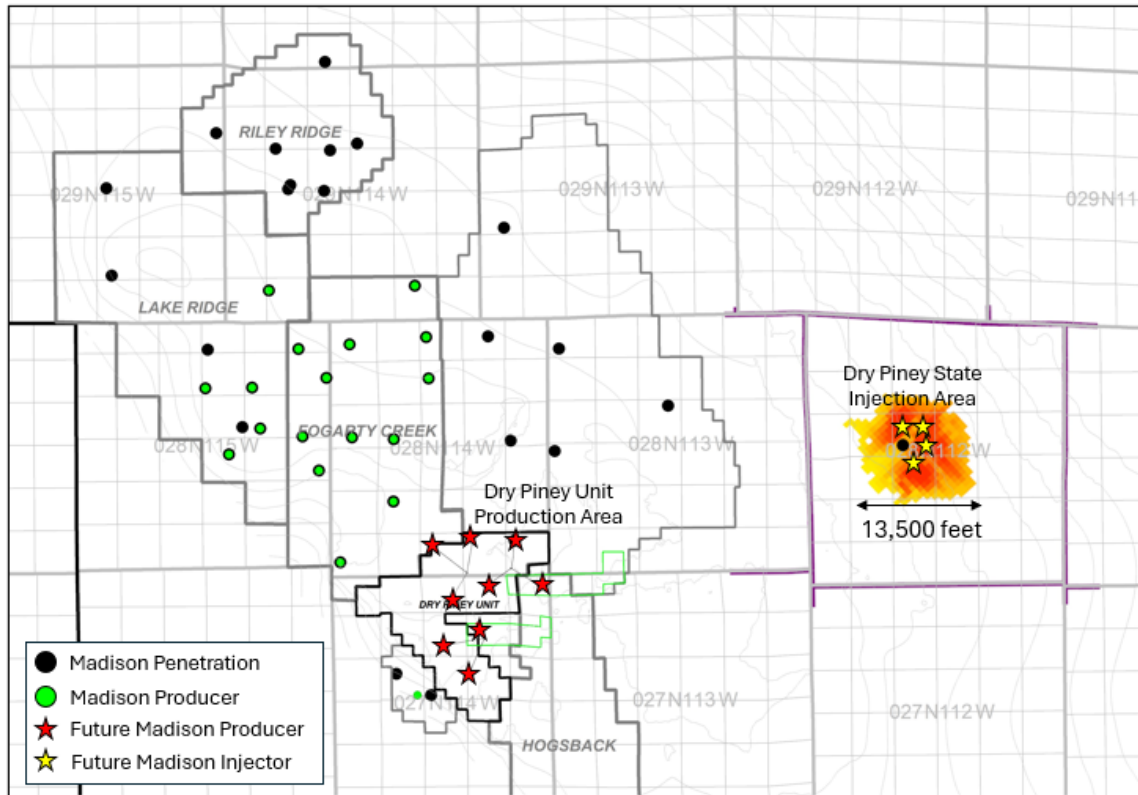


Figure 3.1 – Regional map showing free-phase CO₂ plume (incremental injected volumes) after 5 years (2033) and 0.528 TCF volume injected. The plume diameter is approximately 13,500 ft. The plume is defined by a net increase of 0.5% CO₂ concentration above the in-situ CO₂ concentration naturally occurring in the reservoir.

With continuing injection of an additional 4.7 TCF through year-end 2078, at which time injection is expected to cease after a 50-year project life, the plume size is expected to grow to approximately 45,000 ft in diameter (8.5 miles, see Figure 3.2).

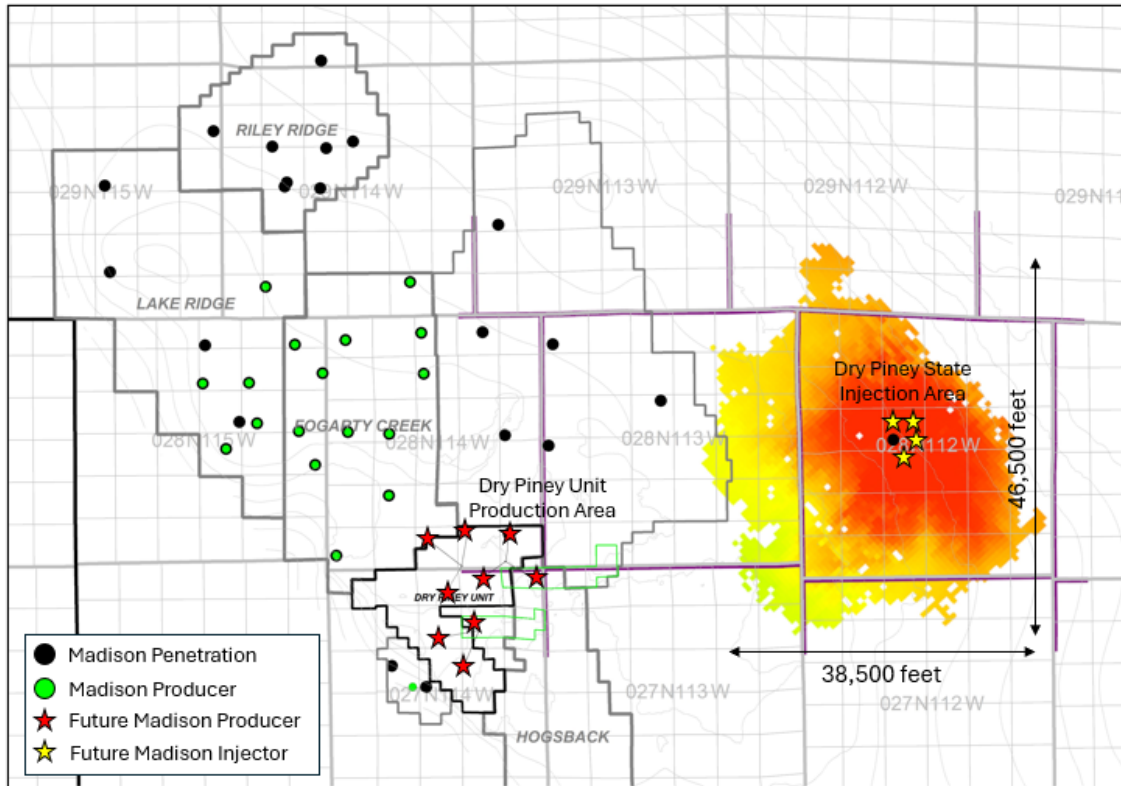


Figure 3.2 – Regional map showing free-phase CO₂ plume (incremental injected volumes) after 50 years (2078) and 5.25 TCF volume injected. The plume diameter is approximately 38,500 ft by 46,500 ft. The plume is defined by a net increase of 0.5% CO₂ concentration above the in-situ CO₂ concentration naturally occurring in the reservoir.

Figure 3.3 shows how the predicted plume average diameter is expected to change over time after cessation of injection, which indicates plume stability is achieved around 50 years post-injection in 2178.

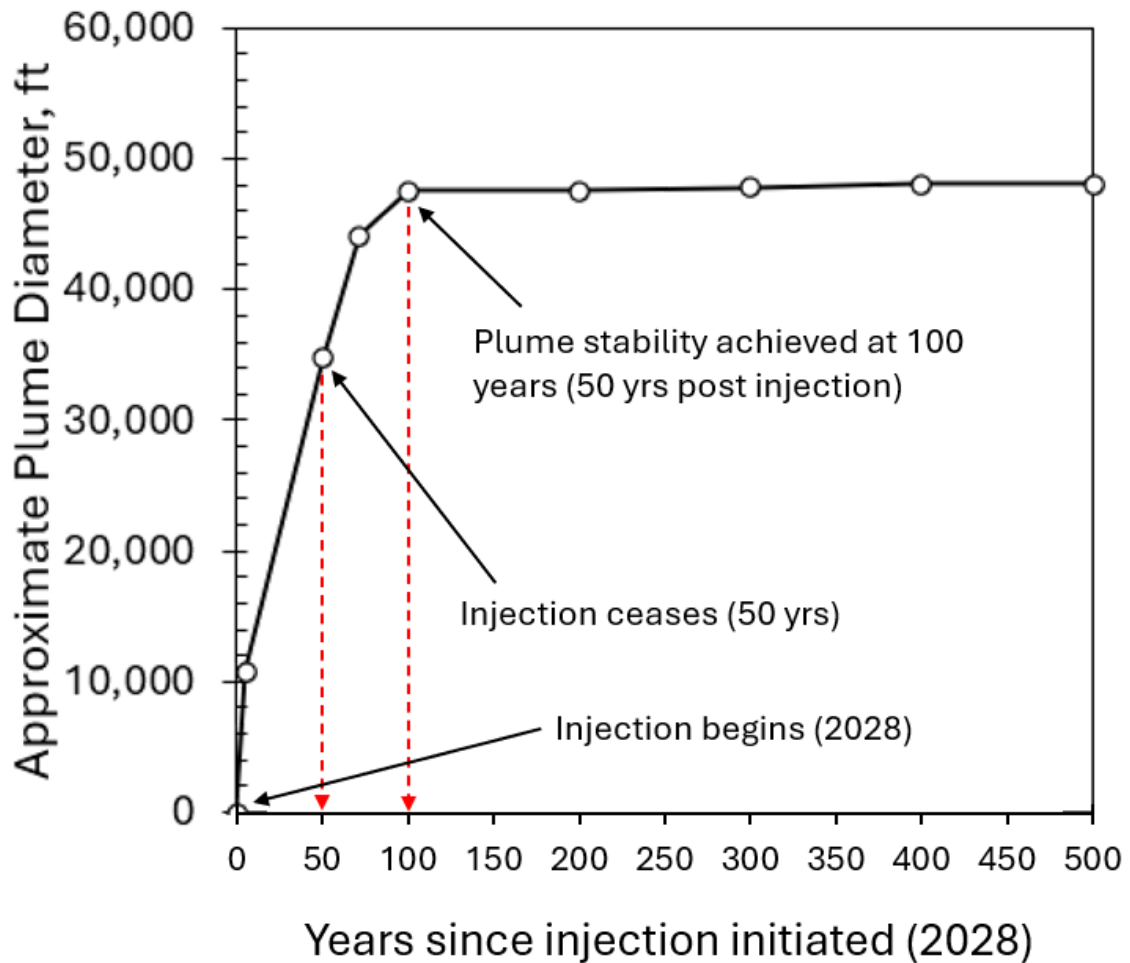


Figure 3.3 – Plot showing predicted average plume diameter over time through injection phase (first 50 years) and out to 500 years (450 years post-injection). Note that at approximately 100 years (50 years post-injection) the plume stabilizes at approximately 50,000 by 55,000 ft in diameter as shown in Figure 3.4.

The model was run through 2578 to assess the potential for expansion of the plume after acid gas injection ceases. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. Expansion of the plume to a diameter of approximately 50,000 ft (9.5 miles) occurs by the year 2128 as the gas plume settles due to gravity segregation and dispersion. At this point, the rate of movement of the free-phase CO₂ plume (incremental injected CO₂ volume) has essentially ceased, demonstrating plume stability. Therefore, the MMA will be defined by Figure 3.4, which is the maximum areal extent of the plume once it has reached stability (defined by the extent of the plume size in 2128, which is an approximately 9.5-mile diameter) plus the buffer zone of one-half mile.

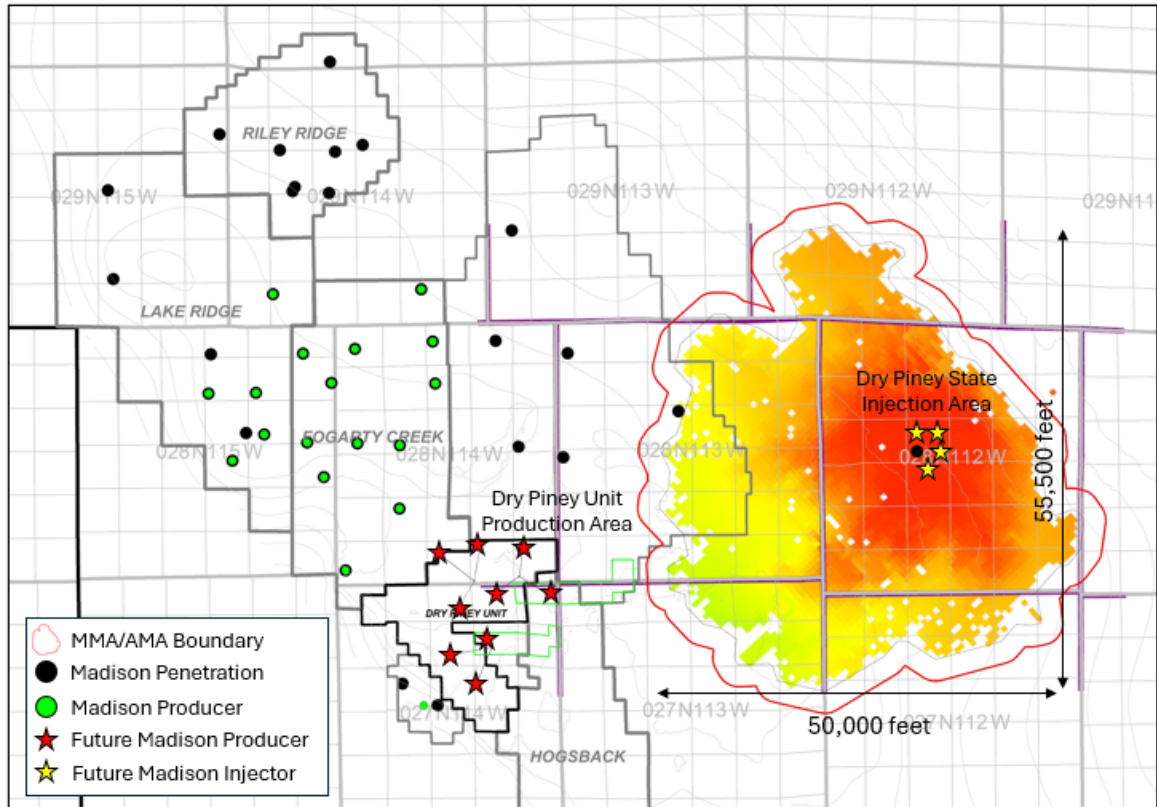


Figure 3.4 – Regional map showing free-phase CO₂ plume (incremental injected volumes) after 50 years (5.25 TCF volume injected) and 50 subsequent years of shut-in after injection ceases. The plume diameter stabilized at approximately 50,000 ft by 55,500 ft in 2128. The plume is defined by a net increase of 0.5% CO₂ concentration above the in-situ CO₂ concentration naturally occurring in the reservoir. Note the proposed MMA/AMA boundary in red, which encompasses a half-mile buffer around maximum plume extent.

3.2 ACTIVE MONITORING AREA (AMA)

BSO proposes to establish an AMA with the same boundary as the MMA for the five AGI wells. The following factors were considered in defining this boundary:

- Lack of faulting above the Madison Formation in the MMA yields no vertical pathways for fluids to move vertically out of the Madison into shallower intervals.
- Lack of significant faulting in the injection area does not create aerially extensive enhanced reservoir permeability through natural fracturing and all flow of injected fluids will be darcy flow from pore to pore beyond the two minor faults.
- Distance from the DPU production area is large (10.5 miles) and formation permeability is generally low which naturally inhibits flow aerially from injection site.
- The DPU and LaBarge field production area is a large structural hydrocarbon trap that has sealed and trapped hydrocarbons, CO₂ and helium in the Madison and

Bighorn Formations for long periods of geologic time. There is no reason to believe that any injection of fluids that may migrate outwards from the injection site to the larger LaBarge structure would not also be effectively trapped at the LaBarge structure over geologic time.

The purpose of the AMA is to allow for a practical and cost-effective monitoring program throughout the life of the project. Because leakage pathways from the subsurface in the MMA seem unlikely, and, since surface equipment will be extensively monitored, BSO believes it is appropriate to define the AMA as the same boundary as the MMA. Additionally, due to the high H₂S content of the injected gas stream into the AGI wells, monitoring of leaks is essential to operations and personnel safety, so a full-scale monitoring program will already be implemented at the AGI sites and pipeline system (discussed further below).

4.0 EVALUATION OF POTENTIAL PATHWAYS FOR LEAKAGE TO THE SURFACE

This section assesses the potential pathways for leakage of injected CO₂ to the surface. BSO has identified the potential leakage pathways within the monitoring area as:

- Leakage from pipeline and surface equipment (wellhead)
- Leakage through wells
- Leakage through faults and fractures
- Leakage through the seal

As will be demonstrated in the following sections, leakage pathways that are likely to result in loss of CO₂ to the atmosphere are unlikely. Further, given the relatively high concentration of H₂S in the AGI injection stream, any leakage through identified or unexpected leakage pathways would be immediately detected by instrumentation (with alarms and shutdowns), with associated actions pursued to address any leakage, thereby minimizing the amount of CO₂ released to the atmosphere.

4.1 LEAKAGE FROM SURFACE EQUIPMENT

Leakage from surface equipment will likely be de minimis due to the design of the AGI facilities. The facilities were designed to minimize leak points such as valves and flanges and use welded connections where possible instead. The only surface equipment located between the flow meter and the wellhead are valves, transmitters, and flanged connection points on the pipelines. Due to the presence of H₂S in the AGI injection stream at a concentration of approximately 7% (70,000 ppm), fixed H₂S gas detectors will be prevalent around the gas processing plant, AGI facility and wellheads, which alarm at 10 ppm. CO₂ gas detectors will be present at the AGI facility due to the high concentration of CO₂, which alarm at 5,000 ppm. Additionally, all field personnel are required to wear personal H₂S monitors for safety reasons, which alarm at 5 ppm H₂S. Although damage to or failure of pipelines and surface equipment can result in unplanned losses of CO₂

entrained in the acid gas, at the anticipated concentration of H₂S in the injection volumes, even a small leak would trigger an alarm, and immediate action would be taken to stop the leak. Additionally, the AGI wells will be monitored with methods outlined in Sections 5 and 6.

BSO will reduce the risk of unplanned leakage from surface facilities through continuous surveillance, facility design, and routine maintenance and inspections. Field personnel will monitor the AGI facility continuously through a supervisory control system. Additionally, visual inspection rounds will be conducted of the AGI facility and weekly visual inspection rounds will be conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. BSO will also rely on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSVs), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes. Also, the wells have multiple surface isolation valves for redundant protection. Inline inspections of the AGI pipeline using a smart pigging tool will be conducted on the pipeline in accordance with applicable code. The smart pig tool will identify pipeline anomalies, including internal and external corrosion, and those anomalies will be assessed per applicable codes and standards.

Should leakage be detected from surface equipment, the volume of CO₂ released will be quantified based on the operating conditions at the time of the release, as stated in Section 7.4 in accordance with 40 CFR 98.445(5).

4.2 LEAKAGE THROUGH AGI OR OTHER WELLS

Leakage of CO₂ through oil, gas, and/or water wells completed and/or abandoned is not likely. There are no existing producing wells completed in the Madison or Bighorn Formations within the AMA or MMA, and it is highly unlikely that there will be Madison or Bighorn production wells drilled in the MMA/AMA in the future owing to the high initial CO₂ and low initial methane and helium concentrations. There is shallower production of gas from the Frontier and Dakota formations approximately 5 miles to the west, at depths of 7,000 – 9,000 ft however, these wells do not penetrate the primary Triassic Evaporite, Amsden or Darby sealing intervals of the Madison and Bighorn Formations so leakage through shallow wells is considered highly unlikely. Due to H₂S being present in the gas stream, any potential leakage from a shallow wellbore, no matter how improbable, would be detected early during monthly and annual gas compositional analyses for sale to market from shallow production. A search of the WOGCC database demonstrated that there is only one existing Madison or Bighorn Formation penetration within the MMA/AMA, other than the drilled Dry Piney State 12-16 well which is currently waiting on completion. BSO intends to drill four additional injection wells near the existing Dry Piney State 12-16 and will drill all four future wells before any of the five planned injection wells are put into service in late 2028. The BSO injection wells will be monitored to ensure that the injected gases stay sequestered. Any escaped CO₂ from AGI wells will be

associated with H₂S, which has the potential to cause injury to personnel. The wellheads will be monitored with local CO₂ gas heads, which detect low levels of CO₂. The CO₂ injected cannot escape without immediate detection, as expanded upon in the below sections.

The 2008 ExxonMobil Tip Top T62X-16S is the only other well that penetrates the Triassic Evaporite confining layer in the MMA/AMA. While it penetrates the Madison and Bighorn, it was never produced and was plugged and abandoned according to industry's best practices in 2009. See Figure 4.1 for MMA/AMA map with relative position of the Tip Top T62X-16S and see Appendix A for the final wellbore diagram post-abandonment. The nearest established Madison production is greater than 12 miles to the west in the DPU/LaBarge field, which is the well field that supplies DPJGPF.

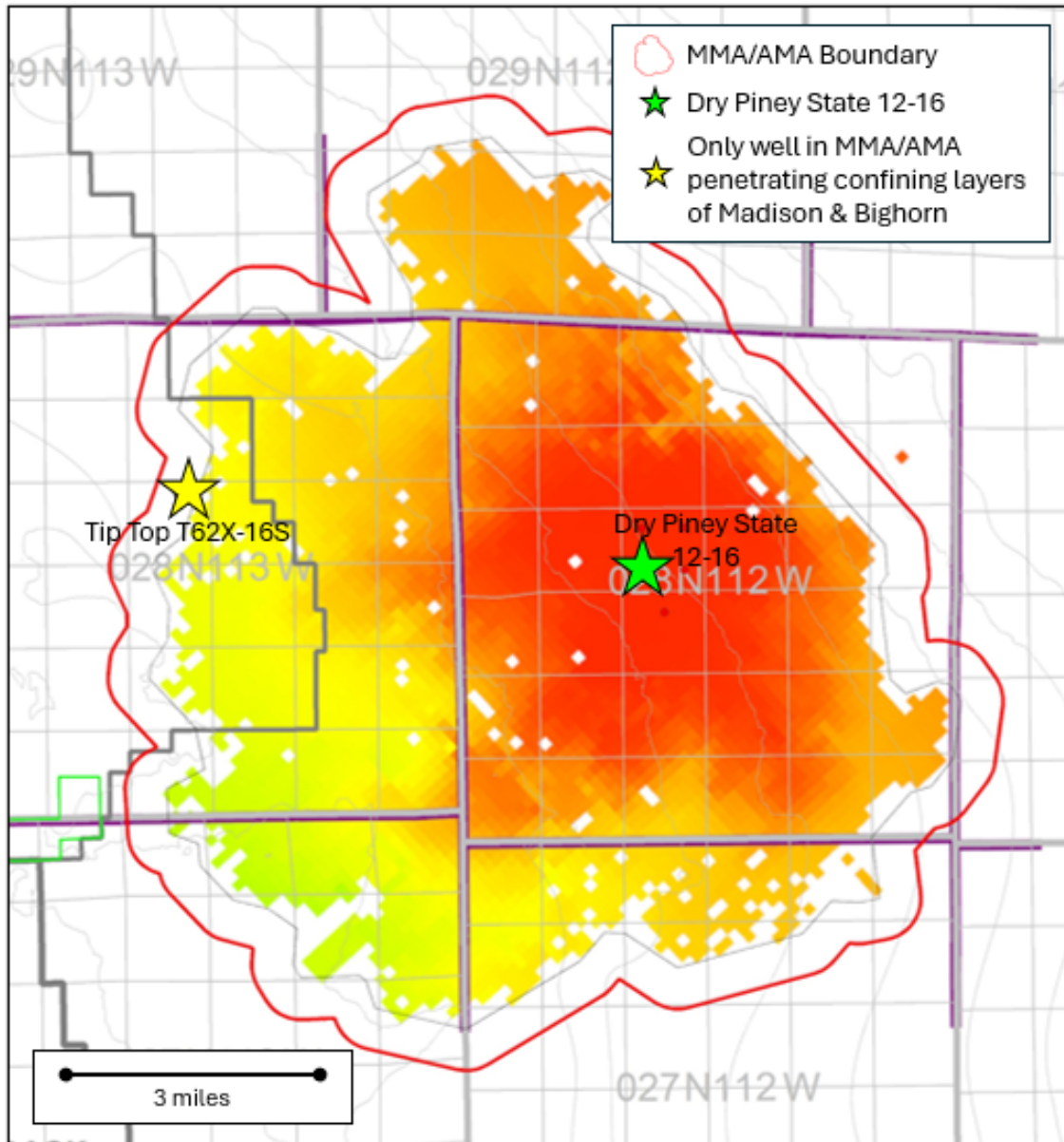


Figure 4.1 – Map showing MMA/AMA boundary with maximum plume diameter post-stabilization (50 years post-injection) in addition to the location of the only existing penetration of the Madison and Bighorn interval to be targeted for injection in the BSO Dry Piney State 12-16. Note that the Tip Top T62X-16S is within the half-mile buffer but beyond the maximum plume extent.

As mentioned in Section 2.3.2, early in the life of some wells targeting the Madison Formation in the LaBarge Field, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic Evaporite interval. The thin-wall wells that failed have been plugged and abandoned in accordance with regulatory standards. Madison wells that were subsequently drilled were cased using thick-walled tubulars across the

Triassic Evaporite interval to combat potential salt or sediment creep. Therefore, there is minimal current risk of failure as all wells currently use thick-walled casing of sufficient strength to penetrate and/or produce from the Madison formation. All current and proposed Madison producing wells are outside of the MMA/AMA and half-mile buffer.

Future drilling also does not pose a risk as a leakage pathway. Due to the high in-situ concentration of CO₂ and H₂S, and low in-situ concentration of methane and helium, the area within the MMA/AMA is highly unlikely to be targeted by future production wells as the economics to produce such gas would be severely challenging and would likely require an additional gas processing plant to be constructed, burdening economics even further. It is anticipated that all planned BSO AGI wells will be drilled before injection is initiated, so the likelihood of future drilling of additional injection wells within an existing injection plume is minimized. If additional injection wells must be drilled in the future, the geological model can be used to delineate areas within the "free-phase" net incremental CO₂ plume that should be avoided during drilling, such as areas near existing wells injecting into the Madison or Bighorn Formations. The BSO geologic model has also history-matched the ExxonMobil acid gas injection to date and suggests that future injection will closely follow the patterns resulting from the geological model simulation. BSO will reduce the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, leak detection, routine maintenance and inspections, and mechanical integrity testing (MIT). As indicated in Section 4.1, visual inspections of the well sites are performed on a routine basis, which serves as a proactive and preventative method for identifying leaks in a timely manner. Fixed gas detectors are located at the well sites, which alarm at 10 ppm H₂S and 5000 ppm CO₂ would be triggered if a leak from the wellbore to the atmosphere occurred. Additionally, SCSSV's and surface isolation valves are installed at the wells, which would close in the event of leakage, preventing losses. Mechanical integrity testing is conducted on an annual basis and consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. If MIT demonstrated a leak, the well would be isolated and the leak would be mitigated as appropriate to prevent leakage to the atmosphere.

Should leakage result from the injection wellbores and into the atmosphere, the volume of CO₂ released will be quantified based on the operating conditions at the time of release, as stated in Section 7.4 in accordance with 40 CFR 98.448(5).

4.3 LEAKAGE THROUGH FAULTS AND FRACTURES

As discussed in Section 2.6.3, engineering and geologic analysis show no evidence of significant faulting or structuring around the AGI wells. As a result, the risk of leakage through this pathway is highly improbable. The absence of significant faulting also tends to suggest that regionally extensive natural fracturing or permeability enhancement in the Madison or Bighorn Formations is also highly improbable, and any natural fracturing or

permeability enhancement is limited to a very localized area. The minor faults observed on seismic data are limited in both aerial and vertical extent and are confined stratigraphically to the geologic units below the Triassic Evaporite confining layer, therefore the risk of creating a leakage pathway through the Triassic Evaporite confining layer or higher in the geologic column is also highly improbable.

Current-day regional scale thrust faulting has not been observed in the LaBarge area since the field has been under development. There is no concern of reactivation of these thrust faults and it is hypothesized that regional structuring similar in size to the Laramide Orogeny (formation of the Rocky Mountains) would be required to generate new thrust faults of significant size to produce subsurface structures of the scale and magnitude of the LaBarge field. The activation of the salty sediments (which exist below the Nugget Formation and above the Madison Formation at LaBarge) is a phenomenon that was only observed to damage thin-wall cased wells, with thick-wall cased wells having sufficient strength to prevent flowage of these salt sediments.

It has been documented that natural fracturing of reservoirs in the subsurface of LaBarge and surrounding areas are directly correlative to distance to thrust faults in the area. This correlation has been documented in subsurface wellbore image logs and also by surface geological mapping around the thrust faults in the LaBarge area. It therefore follows that a lack of significant faulting, as observed on 2D seismic panels around and through the AGI well site, will yield formations void of natural fracturing, and the necessary significant faults are not present to generate pervasive natural fractures of regional extent. The presumed lack of significant natural fracturing in the Madison reservoir at and around the AGI well sites suggest that all flow in the Madison and Bighorn must be from pore to pore, and that ability for fluids to flow will depend solely upon the natural intergranular porosity and permeability of the Madison and Bighorn. It should be noted that the permeability of the Madison and Bighorn is low or 'tight' according to industry definitions of 'tight' and therefore has minimal capability to freely flow fluids through only the pore system of the Madison and Bighorn. Accordingly, there is little potential for lateral migration of the injection fluids once injection ceases, as the injection pressure will be the only impetus to induce lateral movement of the injected fluids. Note the limited areal growth of the free-phase plume after 50 years of injection (Figure 3.2) compared to 50 years after injection has ceased (Figure 3.4).

While planning the drilling of the AGI wells, BSO worked with a reputable service company who provided a range of fracture gradients for the formations comprising the deep sour helium petroleum system including the Triassic Evaporite interval (Ankareh, Thaynes and Woodside Formations), Phosphoria, Amsden, Madison, Darby, Bighorn and Cambrian Formations in the area. Fracture gradient and overburden for the AGI wells were estimated based on offset well data. Shear and compressional sonic data combined with density data from existing offset wells was analyzed and yielded an estimated overburden

pressure of 1.0 psi/ft. Based on a frac gradient of 0.87 pounds per square inch (psi)/ft for the Triassic Evaporite interval, 0.87 psi/ft for the Phosphoria, 0.87 psi/ft for the Amsden, 0.857 psi/ft for the Madison, 0.92 psi/ft for the Darby, 0.862 psi/ft for the Bighorn, and 0.92 psi/ft for the Cambrian, BSO does not anticipate reaching or exceeding fracture pressures during injection operations for any Formations.

With a downhole fracture pressure of 12,698 psi in the Madison Formation (based on top of perforation TVD of 14,823 ft) which corresponds to a surface injection pressure of approximately 6,265 psi, the injected acid gas will likely not initiate fractures in the Madison Formation and therefore not create fractures out of zone into the overlying or underlying confining units. Facility controls exist that limit surface injection pressures to below 5,400 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture is minimal. The Madison Formation is anticipated to be encountered in a narrow TVD depth range in the Dry Piney State injection area, with the Dry Piney State 12-16 being the shallowest and the Dry Piney State 1-16 being the deepest at approximately 200 ft TVD deeper. Therefore, fracture pressures will be very similar amongst the five disposal wells and will range from approximately 12,698 psi to 12,875 psi.

With a downhole fracture pressure of 13,843 psi in the Bighorn Formation (based on top of perforation TVD of 16,066 ft) which corresponds to a surface injection pressure of approximately 6,871 psi, the injected acid gas will not initiate fractures in the Bighorn Formation and, therefore, will likely not create fractures out of zone into the overlying or underlying confining units. Facility controls exist that limit surface injection pressures to below 5,400 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture is minimal. The DPS 12-16 is the only Bighorn Formation injection well in the Dry Piney State injection area.

With the Bighorn fracture pressure of 13,843 psi, the overlying Darby Formation will maintain its sealing ability without induced fractures from injection into the Bighorn with a higher fracture gradient (relative to the Bighorn) of 0.92 psi/ft fracture gradient and a corresponding 14,401 fracture pressure calculated at its top (approximately 15,685 ft MD / 15,653 ft TVD).

The projected facility maximum surface pressure of 5,400 psi corresponds to downhole fracture pressures of 11,920 psi and 12,193 psi for the Madison and Bighorn Formations, respectively. Both are below the pressure required to fracture the formation; therefore, the probability of fracture is minimal.

In the greater Moxa Arch area, there is a low level of background seismicity (Advanced National Seismic System (ANSS) Catalogue). Within several miles of the proposed well site, there has been no observed evidence of significant faulting in the Madison interval using proprietary 3D seismic data. There has also been no reported seismic activity

attributed to active injection operations at the AGI 2-18 and 3-14 disposal wells. Significant earthquake activity is defined as greater than 3.5 Richter scale. The nearest recorded significant naturally occurring earthquake activity to the proposed Dry Piney State 12-16 has been detected over 20 miles away to the west in the Thrust Belt (M3.8, 2/25/2007, ANSS Catalogue 2018). Reported earthquake activity is believed to be related to the easternmost extension of the Basin and Range province (Eaton, 1982), unrelated to the Moxa Arch. Based on the above analysis, the risk of induced seismicity at the disposal well location is low.

4.4 LEAKAGE THROUGH THE SEAL

Leakage through the seal of the Madison reservoir is highly improbable. An ultimate top seal to the disposal reservoir is provided by the evaporitic sequences within the Triassic Evaporites section, and within the Thaynes Formation in particular. The gas accumulation exists precisely because this natural seal has trapped hydrocarbons and helium in the LaBarge structure over geological time. The rock that forms the natural seal is impermeable to helium (He), a gas with a much smaller molecular volume than CO₂. If the reservoir seal material is impermeable to helium, then it follows that it is also impermeable to CO₂. The Thaynes Formation's sealing effect is also demonstrated by the fact that all gas production shallower than the Thaynes is void of sour gas and helium, while all gas production below it is enriched in sour gases and helium.

Although natural creep of the salty sediments below the Nugget formation is possible, this behavior does not disturb the sediments to the degree necessary to breach the reservoir seal of the Madison Formation. If this salty sediment were to flow on a scale large enough to create a leakage pathway from the Madison Formation to the surface, the natural gases trapped in the formation would have already escaped to the atmosphere over geologic time. The fact that gas remains trapped at pressure in the Madison Formation, it must follow that any natural reactivation or movement of salt-rich sediments that has occurred over the geological history of the LaBarge field area has not created any pathways for gas leakage to the surface.

5.0 DETECTION, VERIFICATION, AND QUANTIFICATION OF LEAKAGE

5.1 LEAKAGE DETECTION

As part of ongoing operations, DPJGPF will continuously monitor and collect flow, pressure, temperature, and gas composition data in the Supervisory Control System. The data will be monitored continuously by qualified technicians who will follow response and reporting protocols when the system delivers alerts and alarms that data is not within acceptable operating limits. Additionally, DPJGPF maintains in-field fixed gas detectors to detect H₂S and CO₂ in the vicinity. If one of the gas detectors alarmed, it would trigger an immediate response to address the situation. In some instances, more than one detector alarming would trigger automatic equipment isolation/shutdown to mitigate the leak.

Leakage detection for the wells will incorporate several monitoring programs including visual inspection of the surface facilities and wellheads, injection well monitoring and MIT, and Supervisory Control System surveillance. Table 5.1 provides general information on the leakage pathways, monitoring programs to detect leakage, and location of monitoring. Monitoring will occur for the duration of injection. As will be discussed in Section 7.0 below, BSO will quantify equipment leaks by using a risk-driven approach and continuous surveillance.

TABLE 5.1 –MONITORING PROGRAMS

Leakage Pathway	Detection Monitoring Program	Monitoring Location
Surface Equipment	Electronic Control Systems Surveillance Visual Inspections Inline Inspections Gas Alarms Personal H ₂ S Monitors	From injection flow meter to injection wellhead
Wells	Electronic Control Systems Surveillance Visual Inspections MIT Gas Alarms Personal H ₂ S Monitors	Injection well – from wellhead to injection formation
Faults and Fractures, Formation Seal, Lateral Migration	N/A – Leakage pathway is highly improbable	N/A

5.2 LEAKAGE VERIFICATION

Responses to leaks will be covered in the facility's Emergency Contingency Plan (ECP), which will be updated annually. If there is report or indication of a leak from the AGI Facilities from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and

locate the leak. Local wind speed, direction, and H₂S monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. The AGI system will be designed to allow for the gas to be relieved to the flare, not vented, to reduce the volume of the leak due to the dangerous composition of the gas. The ECP will be written and in place well before commencement of operations.

5.3 LEAKAGE QUANTIFICATION

The leakage from surface equipment will be calculated once leakage has been detected and confirmed. Leakage quantification will consist of a methodology employing modeling and engineering estimates based on operating conditions at the time of the leak such as temperatures, pressures, volumes, hole size, etc. to adequately quantify leaked volumes. The leakage volumes, if any, will be reported and used in the Mass Balance Equations detailed in Section 7.0.

6.0 DETERMINATION OF BASELINES

BSO will use automatic data systems to identify and investigate excursions from expected performance that could indicate CO₂ leakage. The following describes BSO's approach to collecting baseline information.

Visual Inspections

Field personnel will conduct daily inspections of the AGI facilities and weekly inspections of the AGI well sites. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize the possibility of CO₂ leakage. If an issue is identified, a work order will be generated to correct the issue.

H₂S Detection – AGI Wells

The CO₂ that will be injected into the AGI wells will be injected with H₂S at a concentration of approximately 6.9% (69,000 ppm). H₂S gas detectors will be prevalent around the AGI facility and well sites, which alarm at 10 ppm. At this high concentration of H₂S, even a miniscule amount of gas leakage would trigger an alarm. Additionally, all field personnel will be required to wear personal H₂S monitors for safety reasons. Personal monitors alarm at 5 ppm. Any gas detector alarm or personal H₂S monitor alarm will trigger an immediate response to ensure personnel are not at risk and to verify the gas detectors and monitors are working correctly.

CO₂ Detection – AGI Wells

The CO₂ that will be injected into the AGI wells will be at a concentration around 93%. CO₂ gas detectors will be installed around the well site, which trigger at 0.5% CO₂. At this concentration of CO₂, leakage would trigger an alarm.

Continuous Parameter Monitoring

The Supervisory Control System will monitor injection rates, pressures, temperatures, and composition on a continuous basis. The Supervisory Control System will be programmed to detect leaks and alarm operators if a process variable is outside the safe upper and lower limit of the design. If a process variable is outside the safe operating limits, operations will follow operating procedure protocol to assess and address the deviation to reduce the risk of a leak.

Well Testing

On an annual basis, the subsurface and wellhead valves will be leak tested for mechanical integrity as required by the WOGCC. Results from this type of testing are compared to previous MIT data to evaluate whether well integrity has been compromised.

Additionally, inline inspections will be conducted on the AGI pipelines through the use of smart pig technology to identify pipeline anomalies and assess the internal and external corrosion risks. The anomalies will be tracked and compared over time and assessed to determine if they are within code tolerances. DPJGPF will conduct inline inspection tool runs in accordance with codes, if applicable, and per the BSO integrity management program.

7.0 SITE SPECIFIC MODIFICATIONS TO THE MASS BALANCE EQUATION

To accommodate for site-specific conditions, as provided in 40 CFR 98.448, BSO proposes to modify quantifying equipment leaks by using a risk-driven approach. Due to the high H₂S concentration of the AGI fluids, leaks pose a risk to personnel. Additionally, as mentioned above, even a small leak of this high H₂S gas would trigger an alarm to the operations team. BSO will identify leaks through continuous surveillance and leak detection systems and will alarm operations to take immediate action to stop the release. This continuous surveillance using fixed gas detectors will identify leaks better than an annual leak surveys due to the fact that the gas detectors are in operation at all times. When detected, fugitive leakage would be managed as an upset event and calculated for that event based on operating conditions at that time.

Below describes how BSO will calculate the mass of CO₂ injected, emitted, and sequestered.

7.1 MASS OF CO₂ RECEIVED

§98.443 states that “you must calculate the mass of CO₂ received using CO₂ received equations... unless you follow the procedures in §98.444(a)(4).” §98.444(a)(4) states that “if the CO₂ you receive is wholly injected and is not mixed with any other supply of CO₂, you may report the annual mass of CO₂ injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO₂ received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO₂ received.” Since the CO₂ received by the AGI process is wholly injected and not mixed with any other supply of CO₂, the annual mass of CO₂ injected would be equal to the annual mass of CO₂ received, as calculated using Equation RR-4 per CFR 98.444(a)(4):.

$$CO_{2,u} = \sum_{p=l}^4 Q_{p,u} * C_{CO_2,p,u}$$

Where:

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

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

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

p = Quarter of the year.

u = Flow meter.

7.2 MASS OF CO_2 INJECTED

Mass flow meters will be used to measure the injected mass of CO_2 at each well. Equation RR-4 (in Section 7.1) will be used to calculate the annual total mass of CO_2 injected into each well. Equation RR-6 will be used to aggregate injection data for the AGI wells. Equation RR-6 is below:

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

Where:

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

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

u = Flow meter.

7.3 MASS OF CO_2 PRODUCED

The AGI wells will not be part of an enhanced oil or enhanced gas recovery process, nor does reservoir simulation show the free-phase CO_2 plume reaching any existing or future production wells, therefore, there will be no injected CO_2 produced and/or recycled.

7.4 MASS OF CO_2 EMITTED BY SURFACE LEAKAGE AND EQUIPMENT LEAKS

It is not appropriate to conduct a leak survey at the AGI well sites due to the components being unsafe-to-monitor and extensive monitoring systems in place. Entry to the AGI well pad will require the individual to wear a personal gas monitor capable of detecting CO_2 and H_2S , thus allowing immediate identification of possible leakage from surface equipment. Due to the high H_2S and CO_2 concentrations of the AGI fluids, fugitive leakage

would be detected and managed as an upset event in the same way that CO₂E (CO₂ emitted by surface leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time. As already mentioned, gas detectors are in operation continuously to survey the area for leaks; even a small leak would trigger an alarm. This methodology is consistent with 40 CFR 98.448(5), which provides the opportunity for an operator to calculate site-specific variables for the mass balance equation.

Therefore, parameters CO₂E and CO₂FI (CO₂ emitted from equipment leaks from surface equipment between the flow meter used to measure injection quantity and the injection wellhead) will be measured using the leakage quantification procedures described earlier in this plan. BSO will estimate the mass of CO₂ emitted from leakage points from the flow meter to the injection wellhead based on operating conditions at the time of the release – pipeline pressure, temperature, flow rate, size of the leakage point opening, and estimated duration of leak. At the AGI wells, there will be no CO₂ emissions from venting due to the high H₂S concentration of the AGI fluid; blowdown emissions are sent to the flares and are reported under Subpart W for the gas plant. Venting AGI well injection gas would only occur in the event of depressurizing for maintenance or testing, which would be measured during time of event.

In the event that surface leakage is detected, the leakage would be quantified and be used to estimate the mass emitted from each pathway and summed using Equation RR-10:

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

Where:

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

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

x = Leakage pathway.

7.5 MASS OF CO₂ SEQUESTERED IN SUBSURFACE GEOLOGIC FORMATIONS

Since BSO is not actively producing oil or natural gas or any other fluids as part of the AGI process, Equation RR-12 will be used to quantify CO₂ injected and sequestered. Parameter CO₂I (CO₂ injected in the well or group of wells annually) will be determined using Equation RR-4, as outlined above in Section 7.2. Parameters CO₂E and CO₂FI will be measured using the leakage quantification procedure described above in Section 7.4. CO₂

in the AGI fluids is not vented from equipment due to the high H₂S concentration. Equation RR-12 is as follows:

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

Where:

CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

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

CO_{2FI} = Total annual 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.

8.0 ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

Beginning with the start of injection of CO₂ and fluids for the AGI wells, this MRV Plan will become the applicable plan for the AGI wells. Once the MRV Plan becomes applicable, BSO will report under Subpart RR for the AGI wells. Once applicable, BSO anticipates this MRV Plan will remain in effect until the end-of-field-life of BSO's DPU and AGI assets, unless and until it is subsequently amended and superseded.

9.0 QUALITY ASSURANCE PROGRAM

9.1 MONITORING QA/QC

In accordance with the applicable requirements of 40 CFR 98.444, BSO will incorporate the following provisions into its QA/QC programs:

CO₂ Injected

- The mass of CO₂ injected will be measured with a mass meter for each AGI well and will be monitored continuously, allowing the mass injected to be compiled quarterly.
- A continuous gas composition analyzer will measure the concentrations for each representative stream.
- The continuous composition measurements will be averaged over the quarterly period to determine the quarterly CO₂ composition of the injected stream.
- The CO₂ analyzers are calibrated according to manufacturer recommendations.

CO₂ emissions from equipment leaks and vented emissions of CO₂

- Gas detectors are operated continuously except as necessary for maintenance and calibration.
- Gas detectors will be operated and calibrated according to manufacturer recommendations and API standards.

Measurement Devices

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

General

- CO₂ concentration will be measured using continuous gas analyzers, which is an industry standard practice.
- All measured volumes of CO₂ will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 MISSING DATA PROCEDURES

In the event BSO is unable to collect data needed for the mass balance calculations, 40 CFR 98.445 procedures for estimating missing data will be used as follows:

- If a quarterly quantity of CO₂ injected is missing, it will be estimated using a representative quantity of CO₂ injected from the nearest previous time period at a similar injection pressure.
- For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment at the facility that are reported in this subpart, missing data estimation procedures will be followed in accordance with those specified in subpart W of 40 CFR Part 98.

9.3 MRV PLAN REVISIONS

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

10.0 RECORDS RETENTION

BSO will follow the record retention requirements of CFR 98.3(g). Additionally, it will retain the following records from AGI well sites for at least three years:

- Quarterly records of injected CO₂ including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO₂ emitted from equipment leaks of CO₂, from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

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