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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.

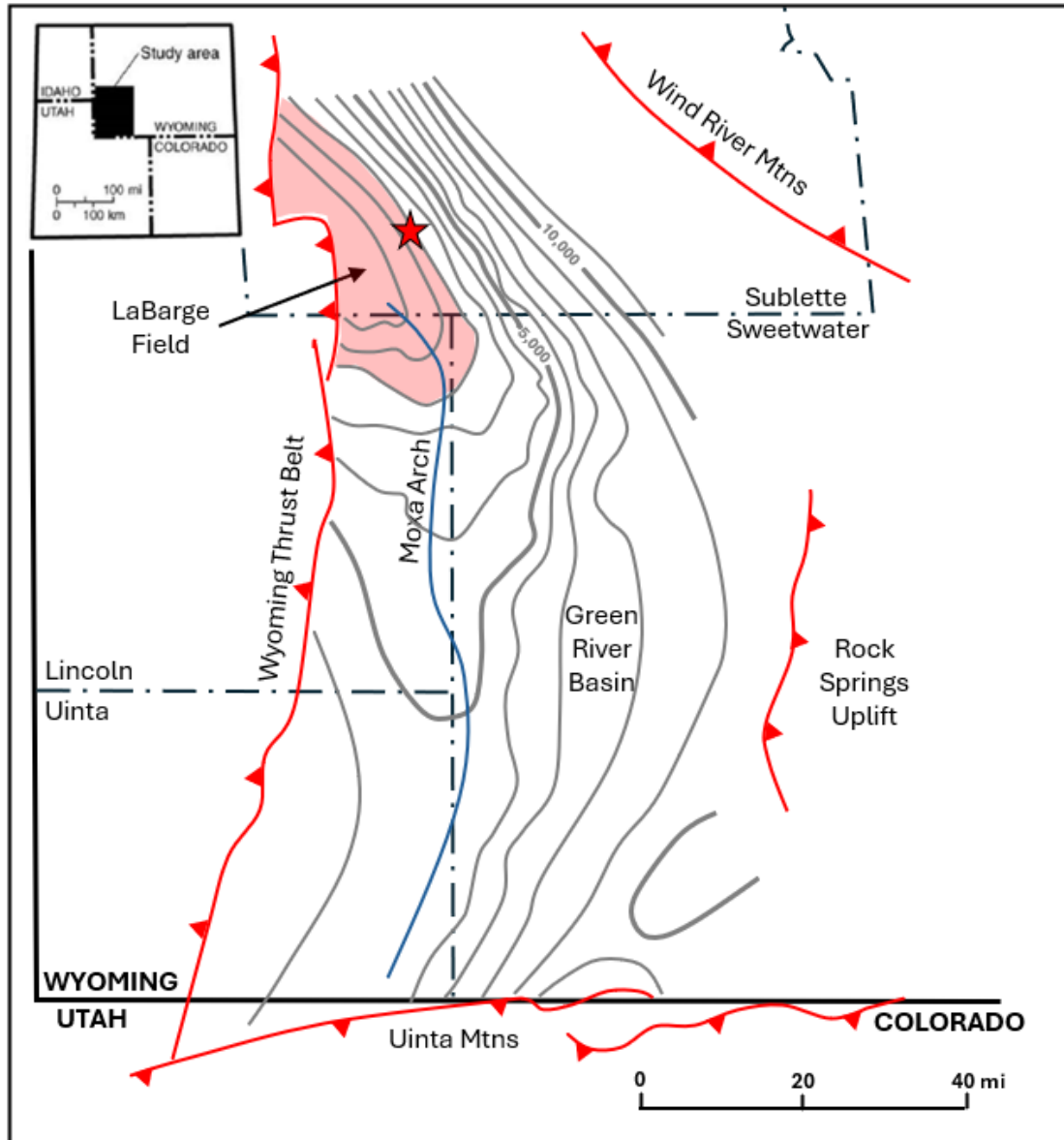


Figure 2.1-1: Location map of the LaBarge Field area, which includes Dry Piney Unit, denoted by pink shading. The DPS AGI injection area is denoted by the red star near the eastern extent of the LaBarge Field area. Modified from the USGS Greater Green River Basin Assessment.

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)

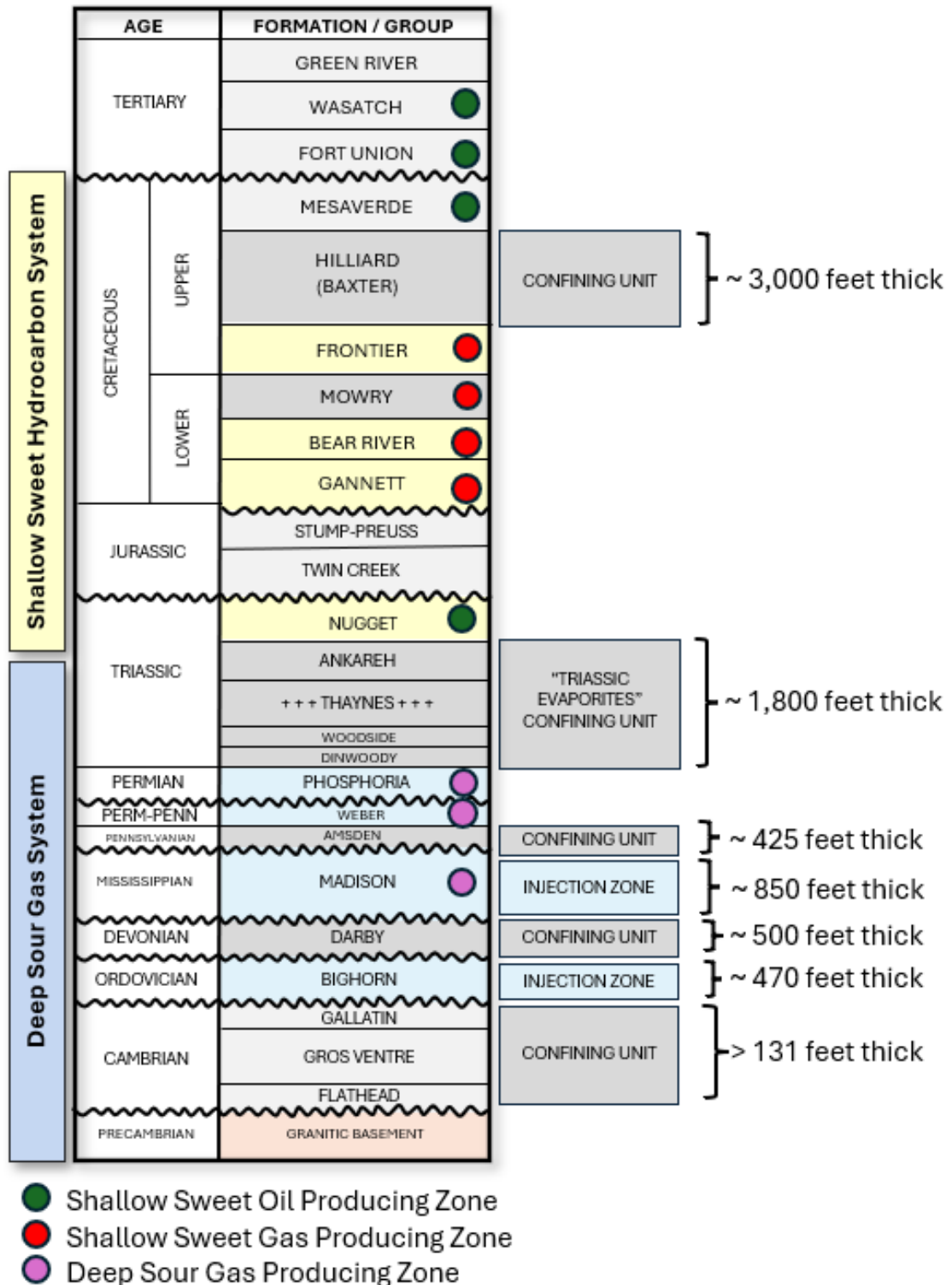


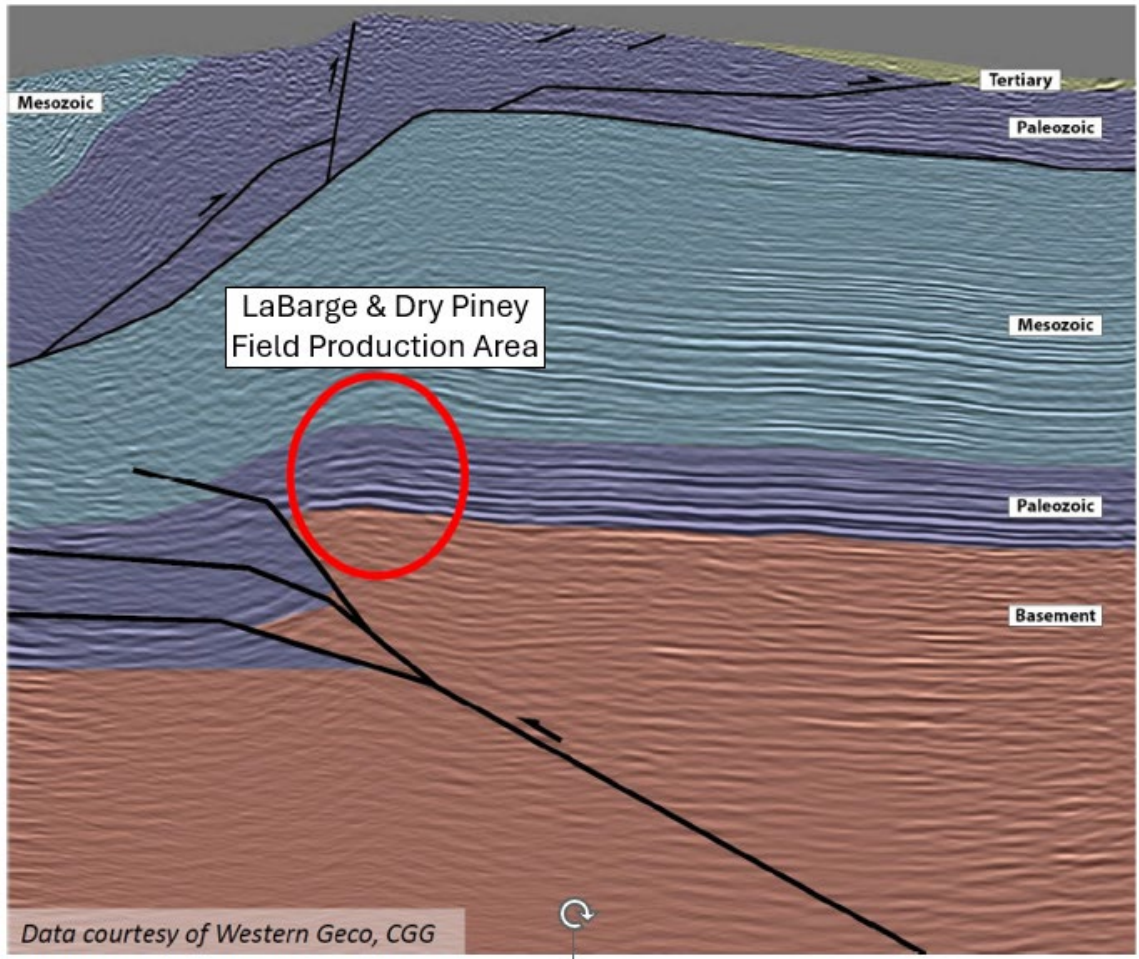
Figure 2.2-1: Generalized stratigraphic column for the western Greater Green River Basin area in Wyoming. The Madison and Bighorn injection zones and associated Triassic Evaporites, Amsden and Darby confining units are identified. Modified from Lamerson, 1982.

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.

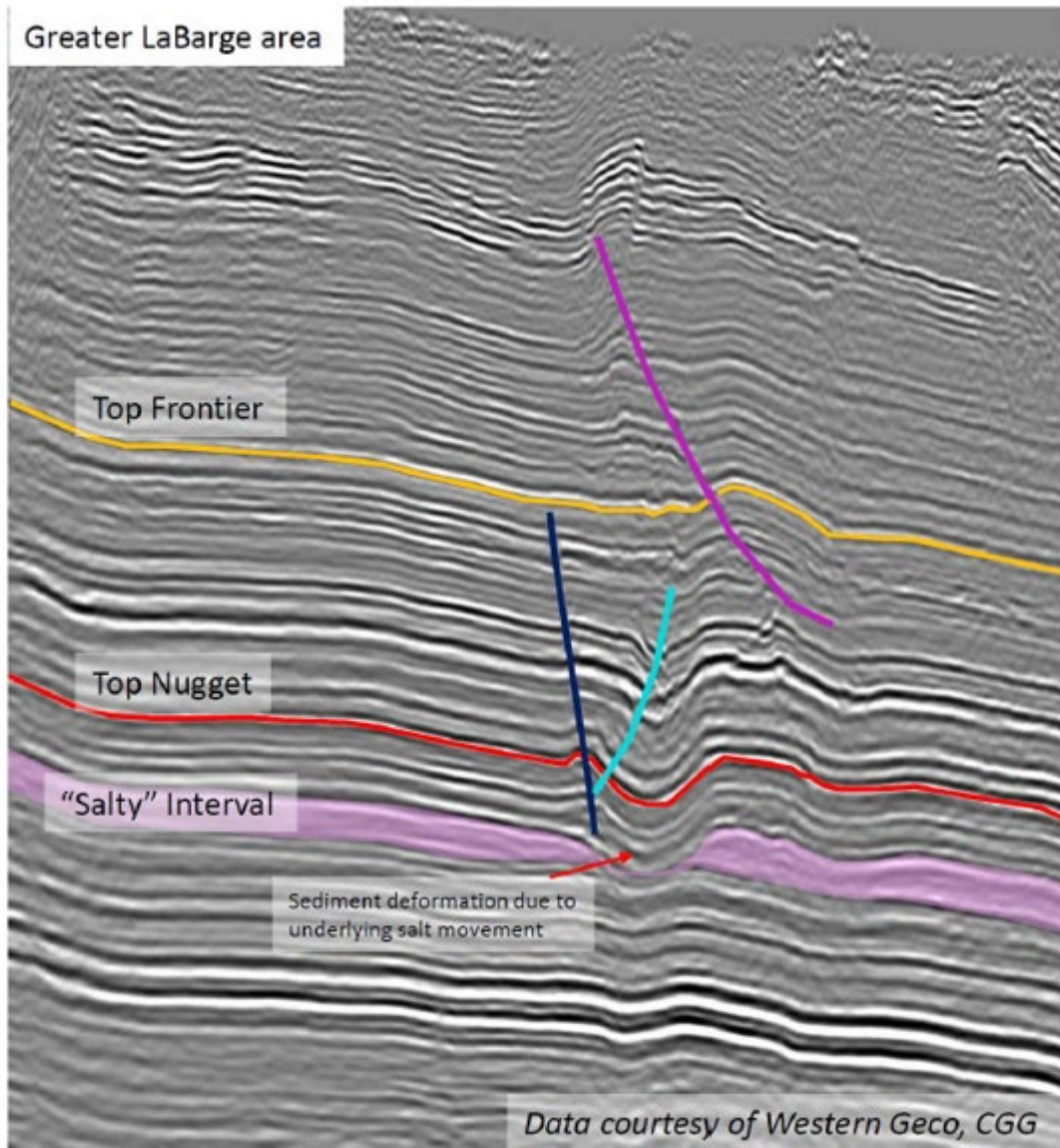


Figure 2.3-2: Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge Field area. From ExxonMobil Amended MRV Plan dated October 2019.

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.

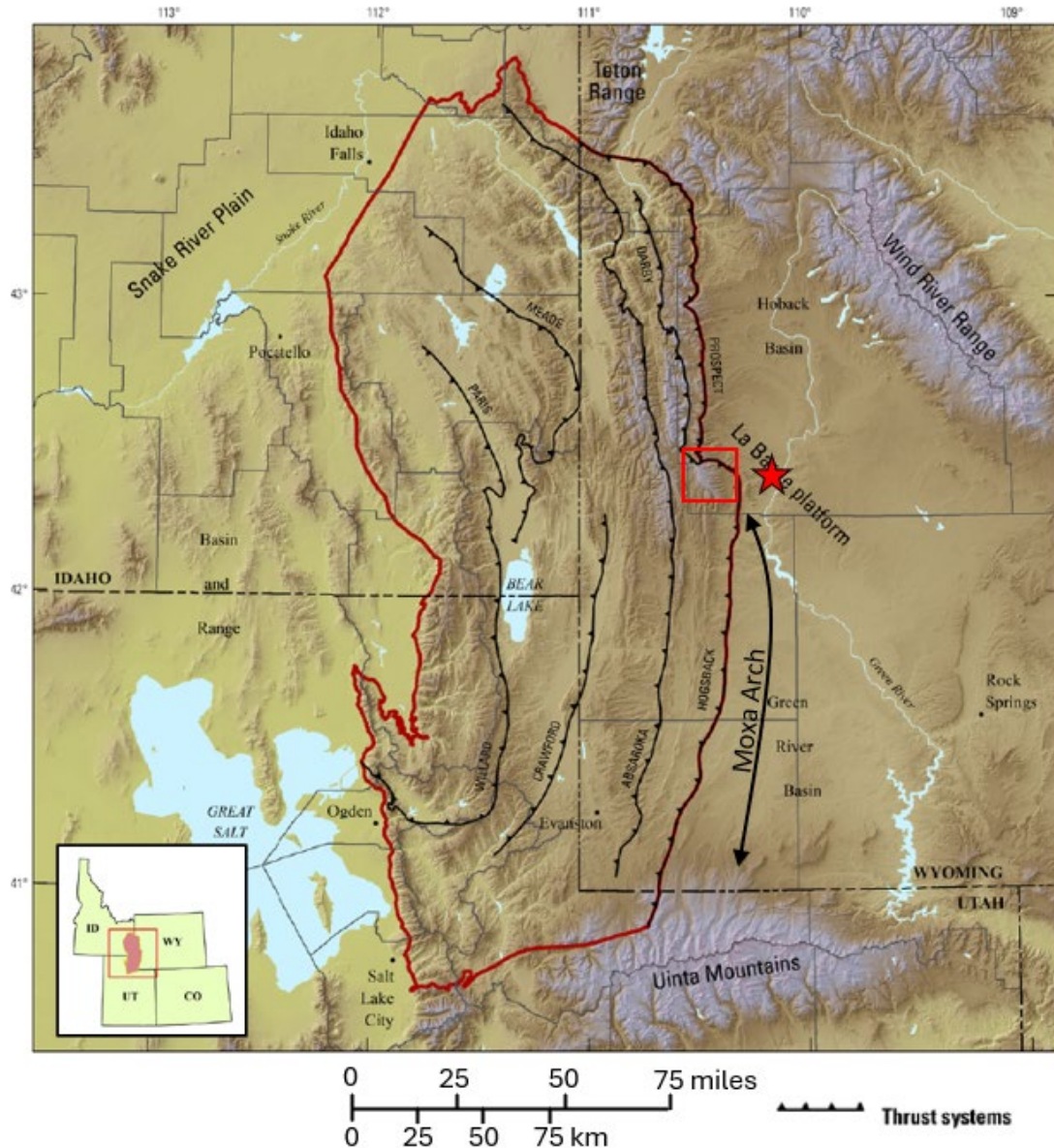


Figure 2.3-3: Map showing location of the Moxa Arch and regional thrust faults of the Wyoming Range. The LaBarge/Dry Piney Unit production field area is denoted by the red box, and the approximate injection area is denoted by the red star. Modified from Buursink et al, 2014.

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 DPJGPF 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 DPJGPF. 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.

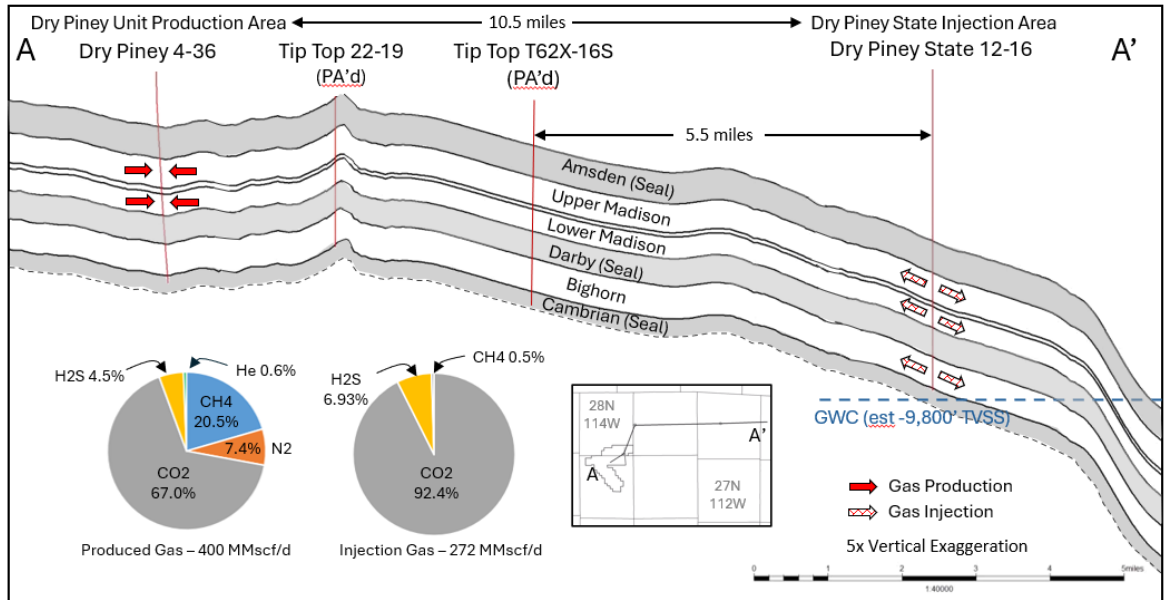


Figure 2.6-1: Schematic illustration showing location of proposed Dry Piney State 12-16 well and injection area near gas-water contact (GWC) relative to the Dry Piney Unit production area approximately 10.5 miles to the west. Two plugged and abandoned Tip Top wells penetrate the Madison & Bighorn Formations 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.

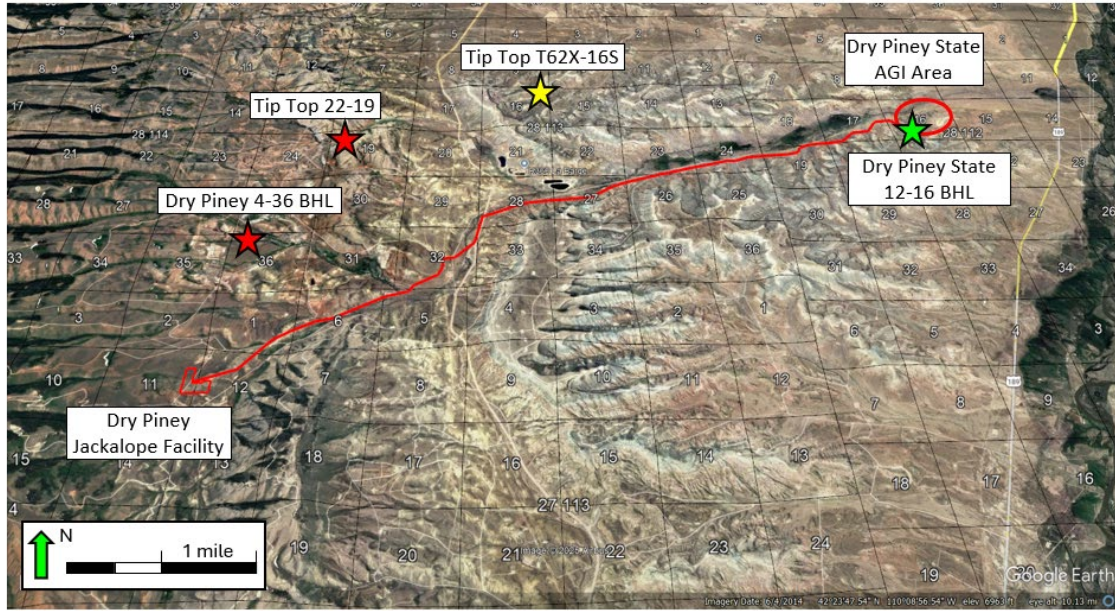


Figure 2.6-2: Map showing the relative position of the BSO proposed AGI area (red circle) and Dry Piney State 12-16 (green star) relative to the Tip Top Unit 22-19 and the BSO Dry Piney 4-36 wells (red stars). Logs unavailable for the Tip Top T62X-16S well (yellow star). The DPJGPF is denoted by a red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

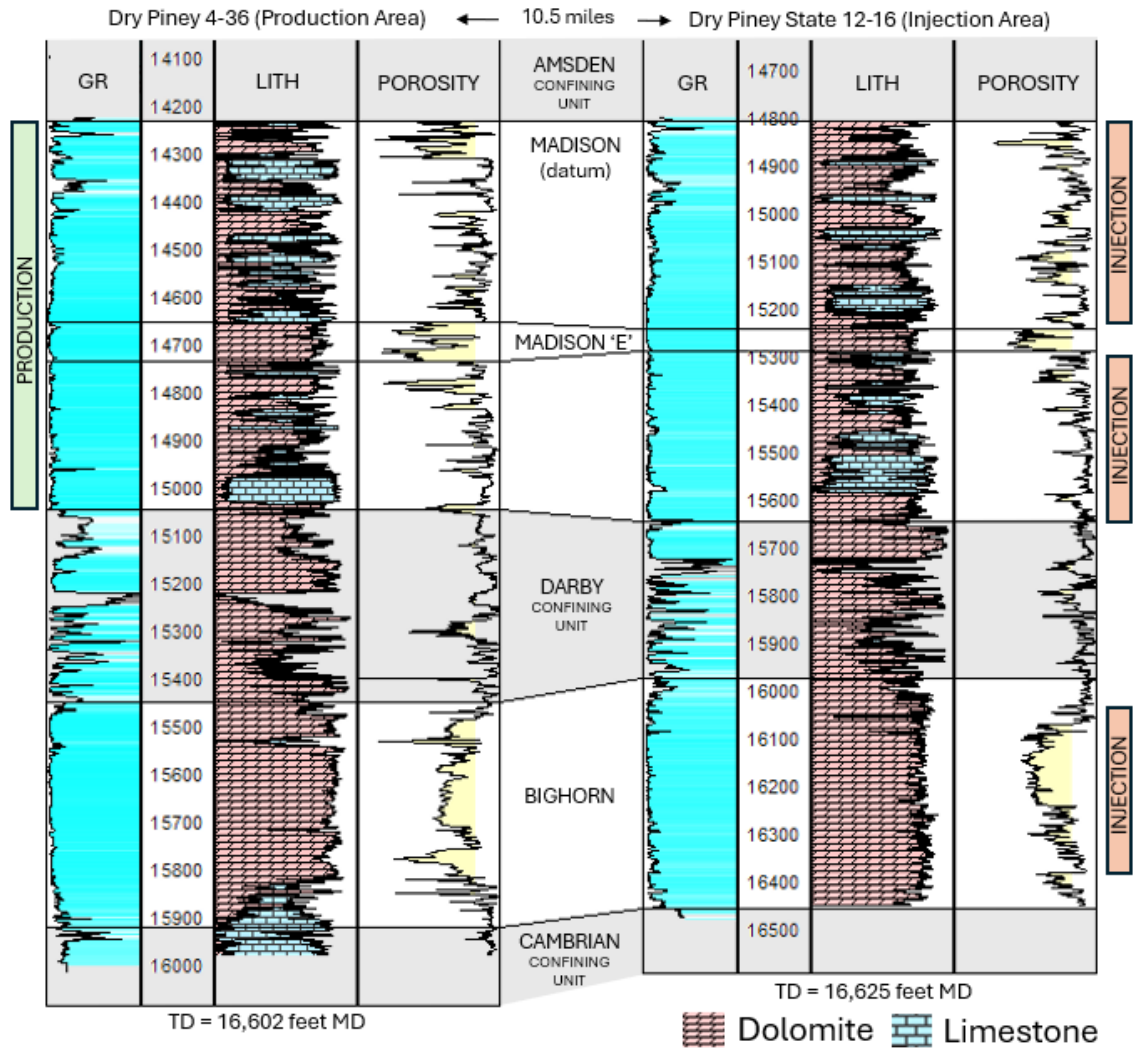


Figure 2.6-3: Stratigraphic cross-section showing Dry Piney 4-36 well (Production Area) and Dry Piney State 12-16 (Injection Area). Madison well top is the stratigraphic datum. Gamma Ray (GR), lithology (LITH) and Porosity logs displayed. Note that porosity over 5% is shaded in yellow. Madison production 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.

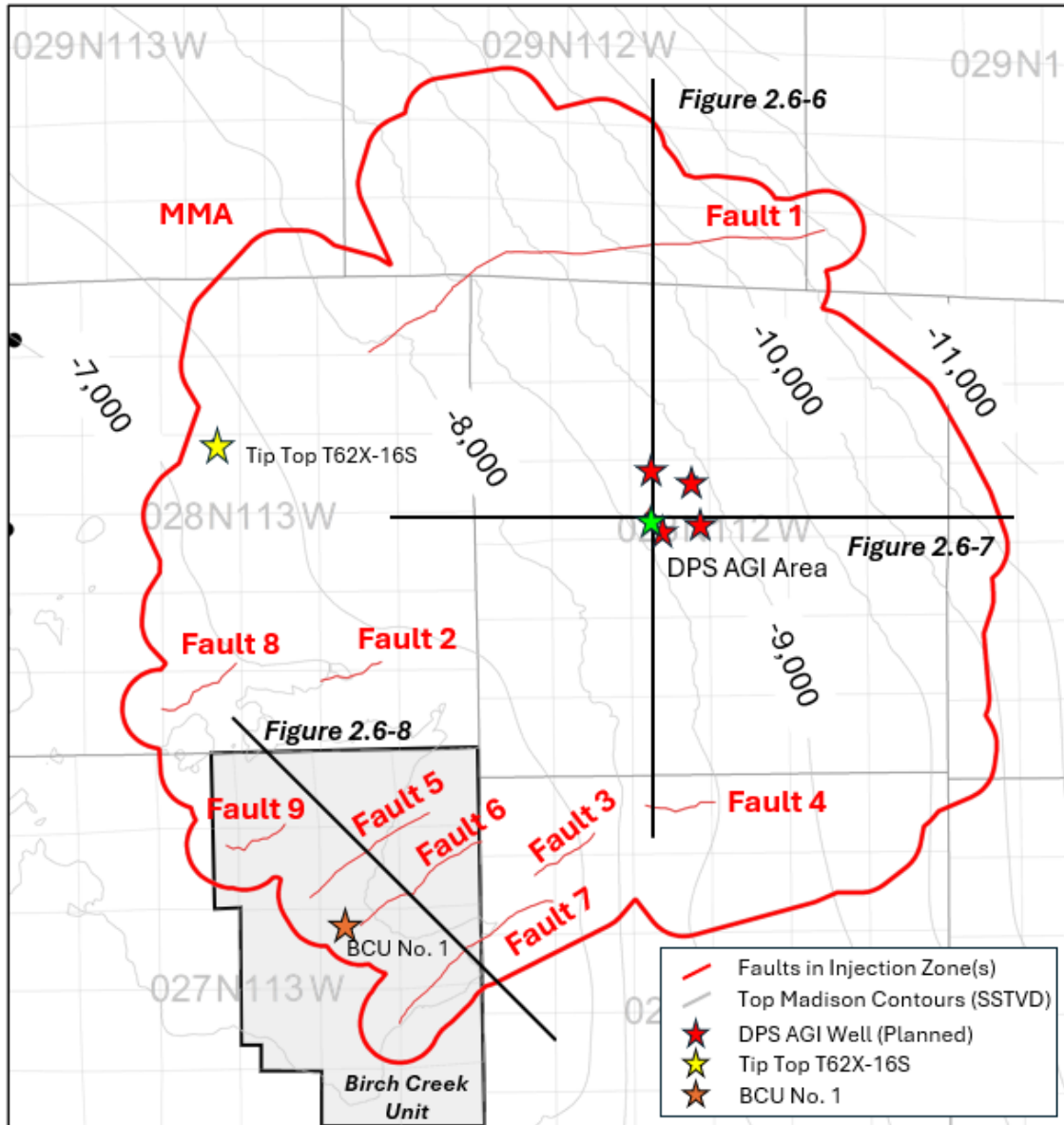


Figure 2.6-5: Madison Structure (TVDSS, 500 ft contour interval) reference map showing N-S (**Figure 2.6-6**) and W-E (**Figure 2.6-7**) seismic lines through the DPS AGI area, including the DPS 12-16 well (green star) and future DPS AGI wells (red stars). Note the fault traces (red lines) of minor faults 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.

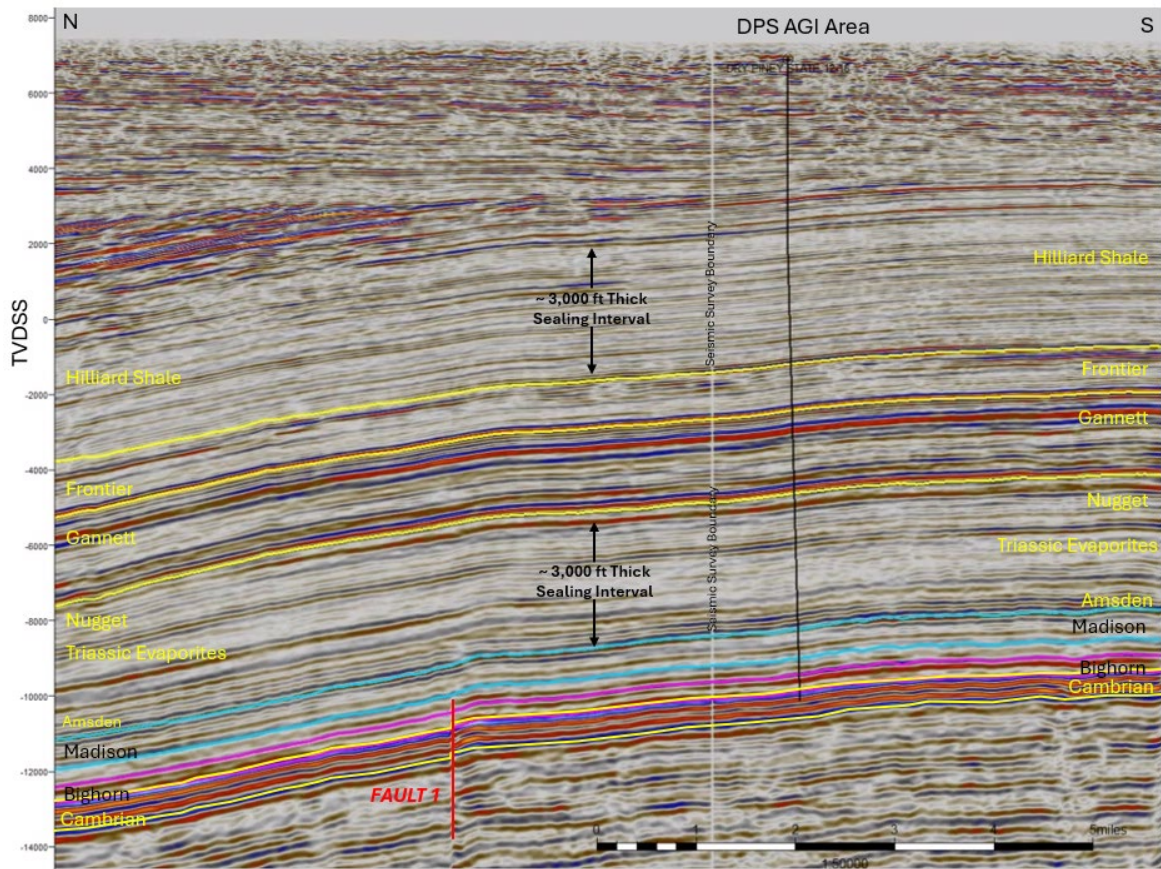


Figure 2.6-6: Seismic line from 3D volume, oriented N to S through the proposed Dry Piney State 12-16 injection well location, shows one minor fault (Fault 1) with minimal vertical offset that dies out before extending above the Madison Formation. Note vertical seam with no data is a boundary between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

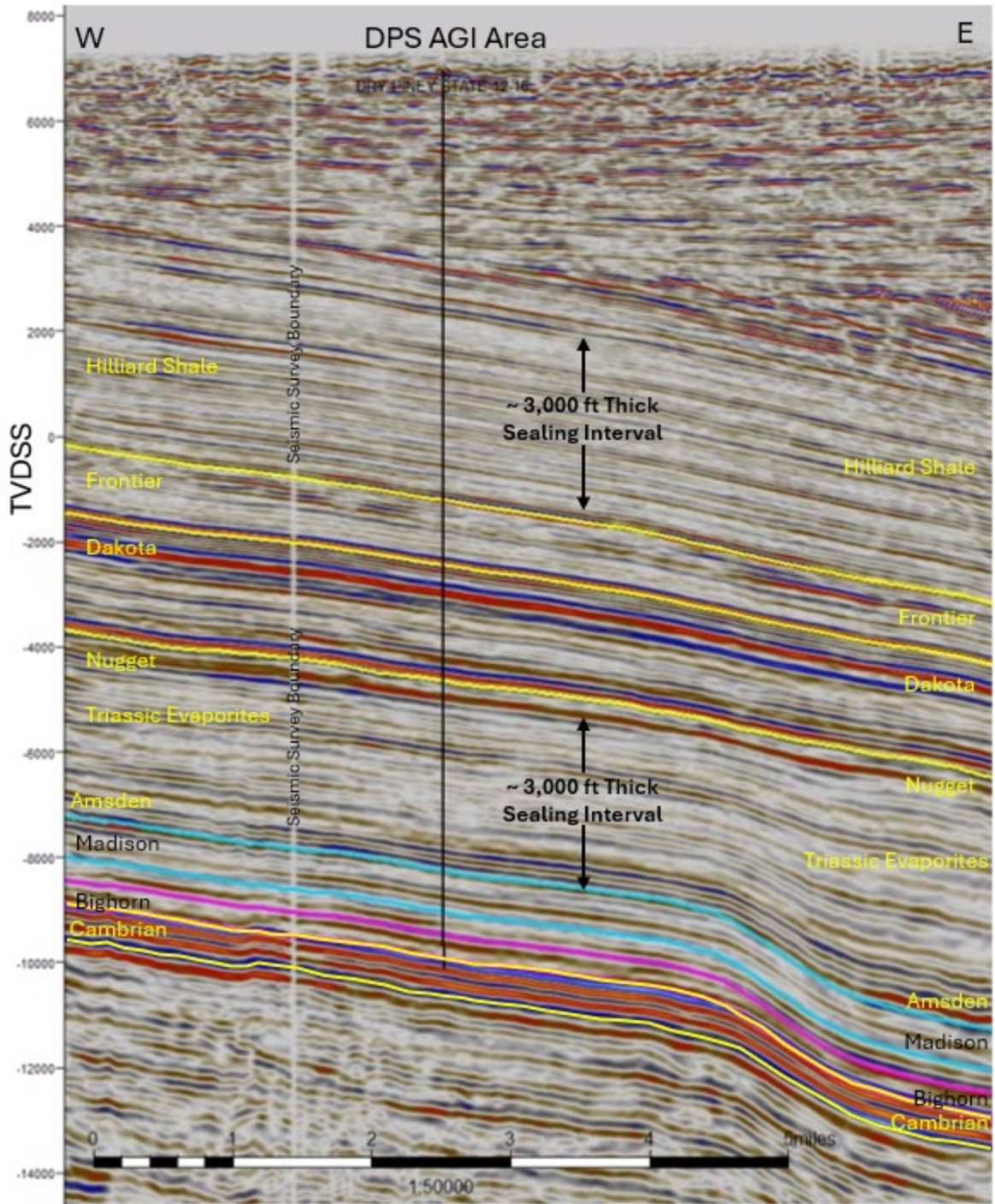


Figure 2.6-7: Seismic line from 3D volume, oriented W to E through the proposed Dry Piney State 12-16 injection well location, shows no faulting. Note vertical seam with no data is a boundary between seismic volumes, not a fault. Vertical exaggeration is 2X.

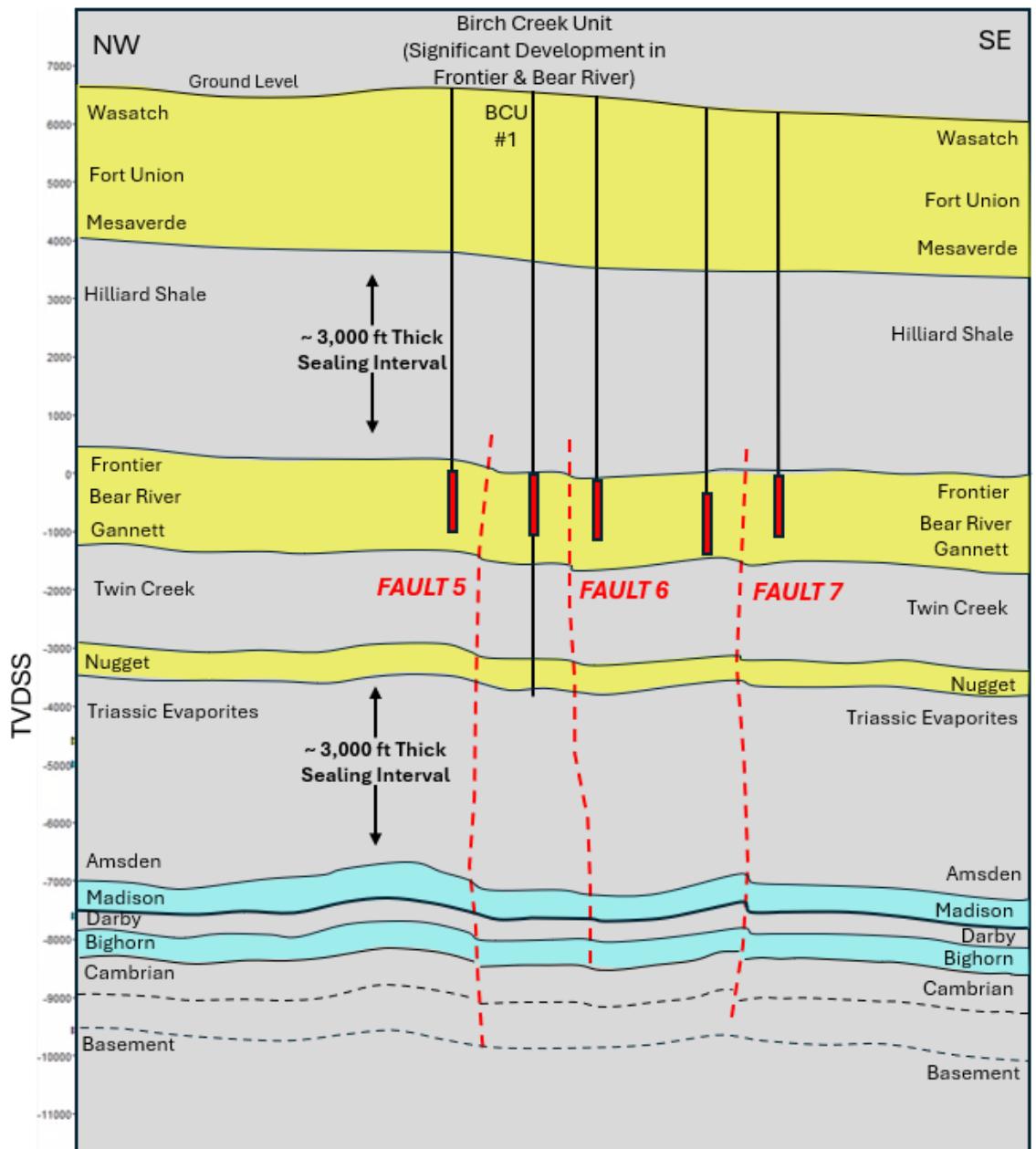


Figure 2.6-8: Cross-section derived from seismic line extracted from a 3D volume, oriented NW to SE perpendicular to Faults 5, 6 and 7 southwest of the DPS AGI area (see **Figure 2.6-5** for reference map). BSO does not have permission to show this seismic data. Vertical black lines and red boxes illustrate 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.

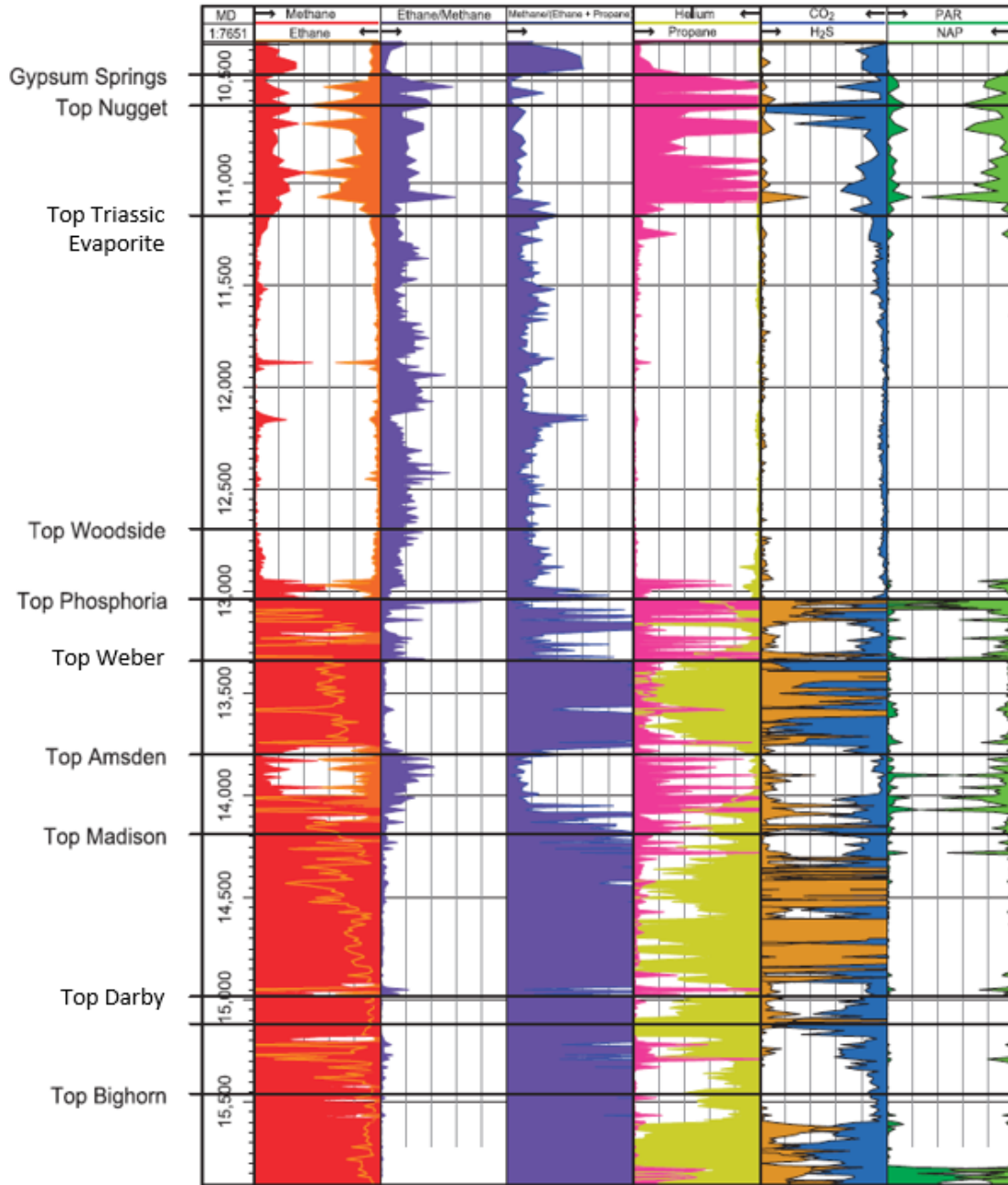


Figure 2.6-9: Modified from Becker & Lynds, 2012. Summary of fluid-inclusion volatile analysis in the Tip Top T62X-16S well located approximately midway between the DPU production area and the DPS AGI area, and the only well that penetrates the injection zones in the MMA. Confining units are identified 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).

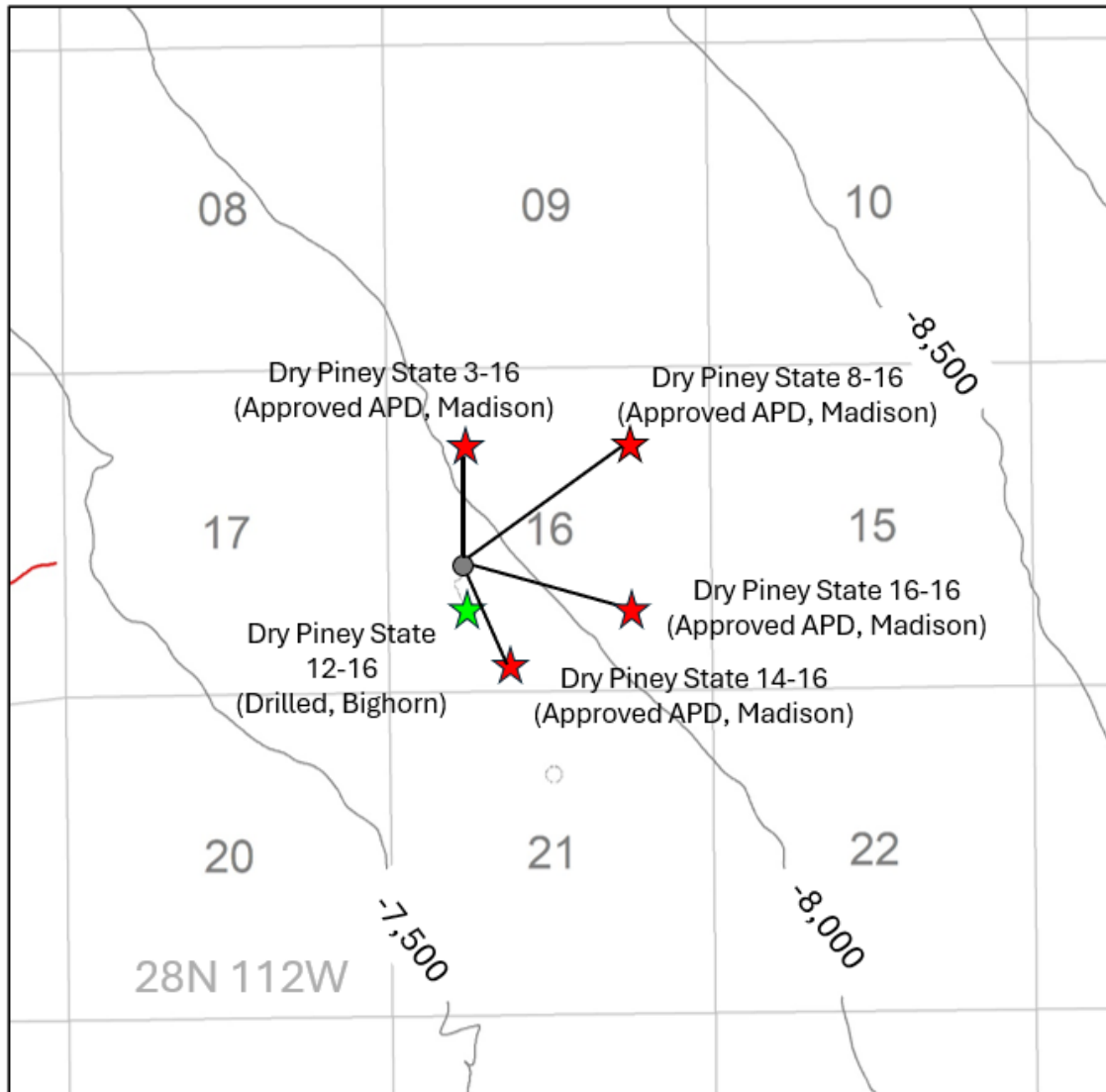
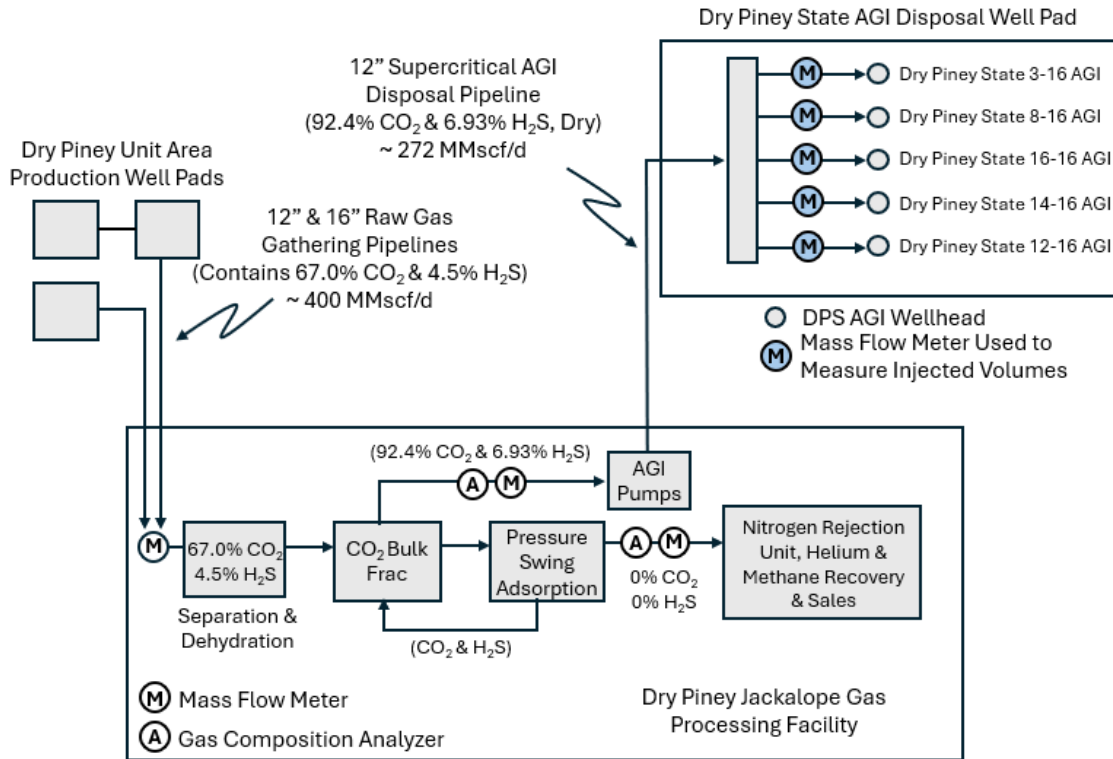


Figure 2.7-1: Map showing the existing drilled (but not completed) Dry Piney State 12-16 well and the future DPS AGI wells. Dry Piney State 12-16 will inject into the Bighorn, while the four future injection wells are anticipated to target the Madison for injection. Contours are top Madison structure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



* Illustrative Schematic – NOT TO SCALE

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).

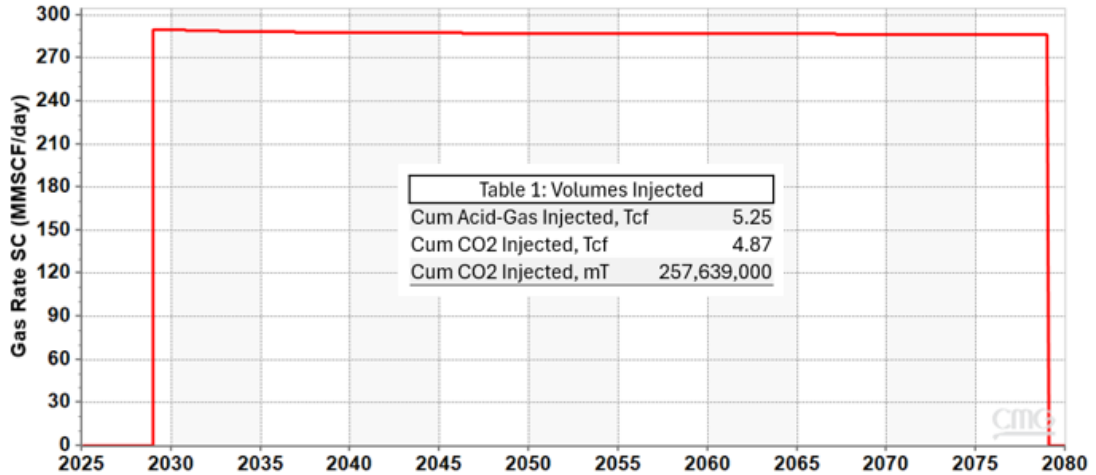


Figure 2.8-1: Long term injection forecast showing waste gas (combined CO₂ & H₂S) volume of 5.25 TCF to be injected into all five BSO injection wells throughout the life of the 50-year project. The CO₂-only volume is 4.87 TCF (257.6 million metric tons).

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.

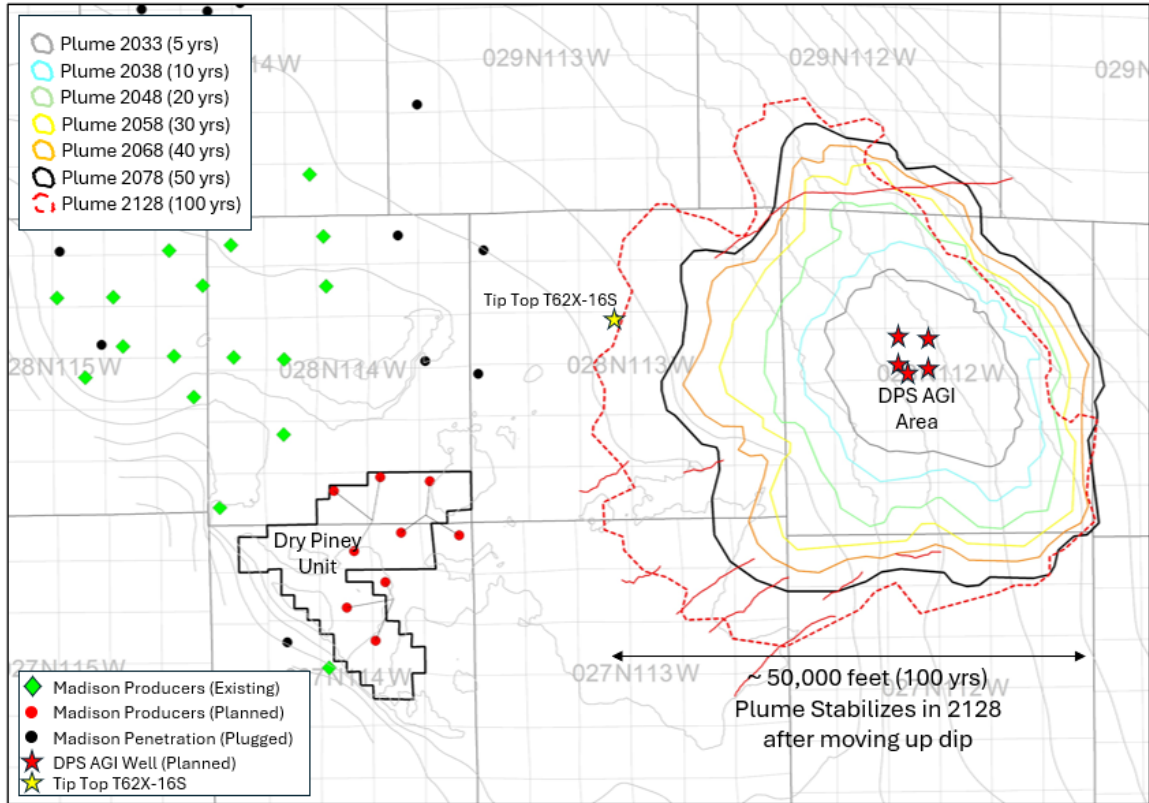


Figure 2.8-2: Spatial extent of the acid gas free-phase CO₂ plume (> 0.5% net incremental CO₂ above naturally occurring in-situ CO₂) at years 2033, 2038, 2048, 2058, 2068, 2078 and the stabilized plume at 2128. After 50 years of injection, followed by a 50-year shut-in period (stabilization), the plume 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.

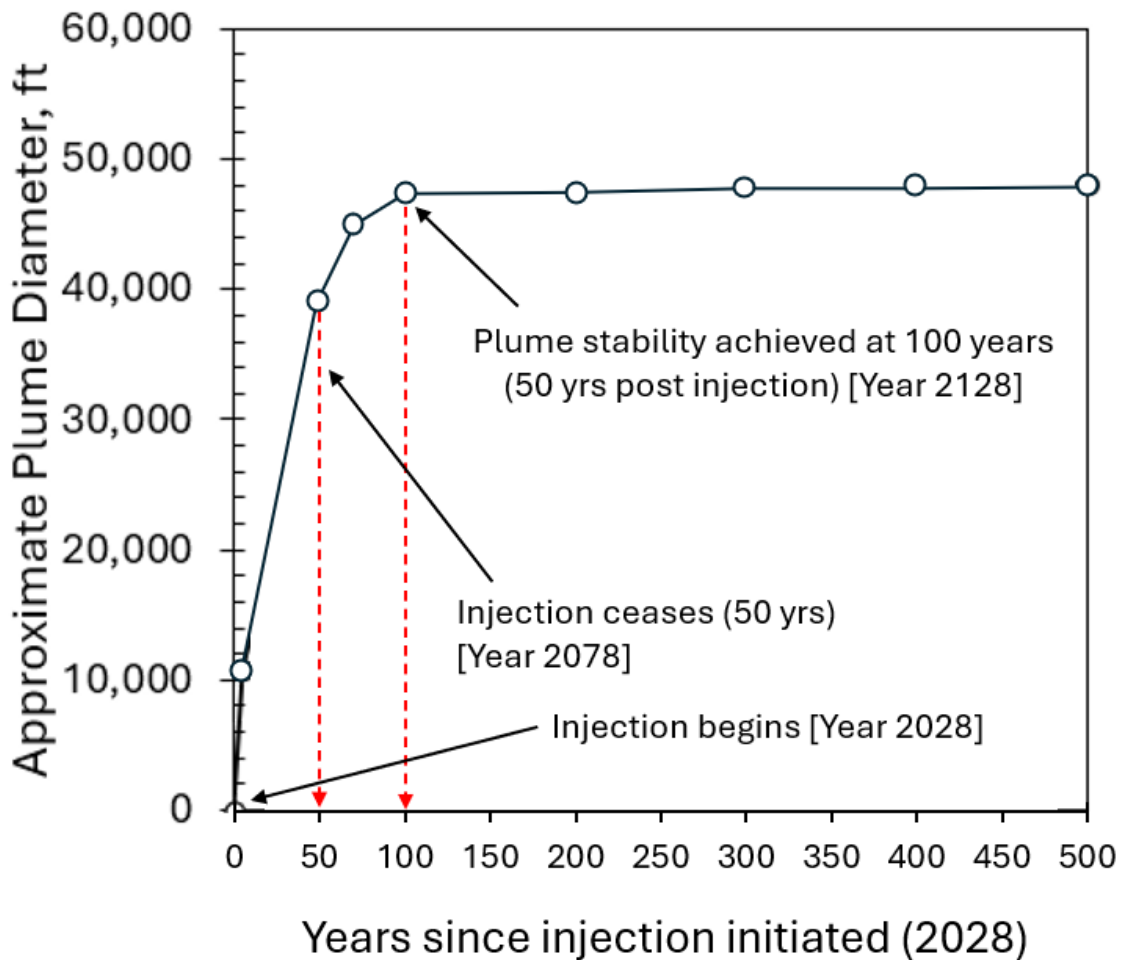


Figure 3.1-1: Plot showing predicted approximate maximum plume diameter over time through injection phase (first 50 years) and out to 500 years (450 years post-injection). Note that at approximately 100 years (50 years post-injection) the plume stabilizes at approximately 50,000 feet in diameter as shown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

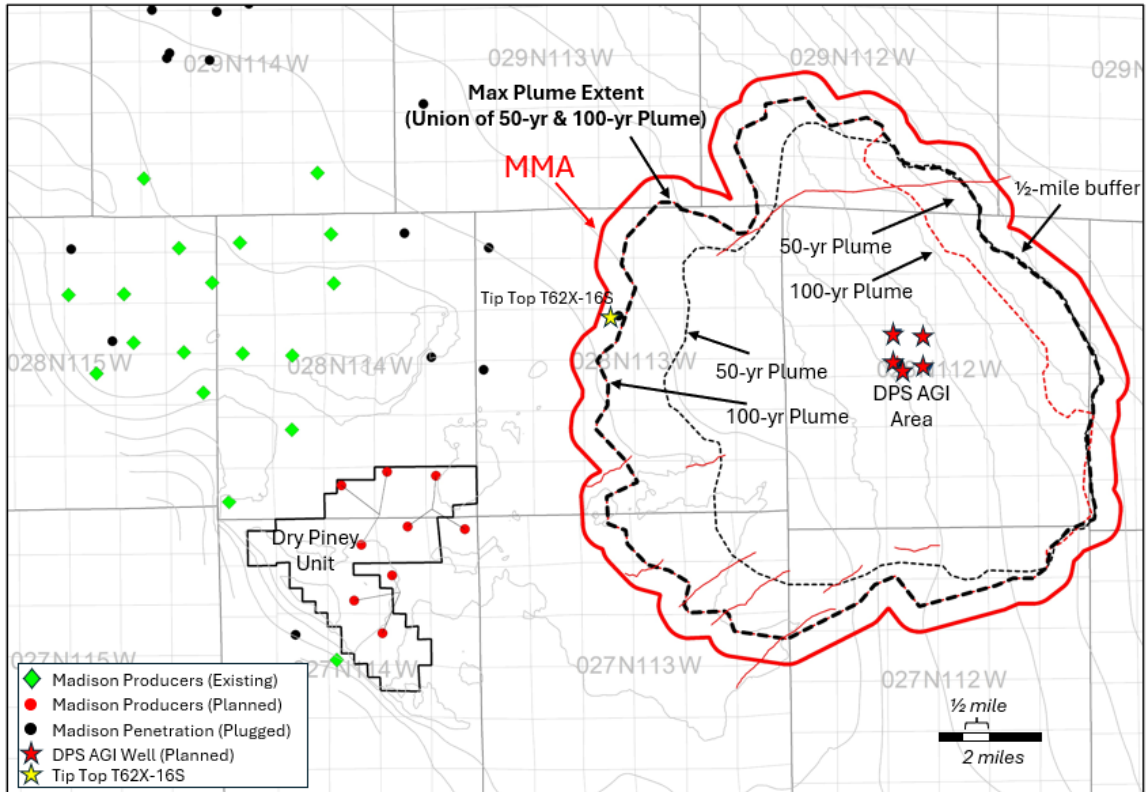


Figure 3.1-2: Area covered by the maximum extent of the combined stabilized plume at year 2128 as well as the area to the west that was occupied by the plume at 50 years of injection (2078) before migrating up structural dip to the west during the plume stabilization period. The bold, black-dashed line 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.

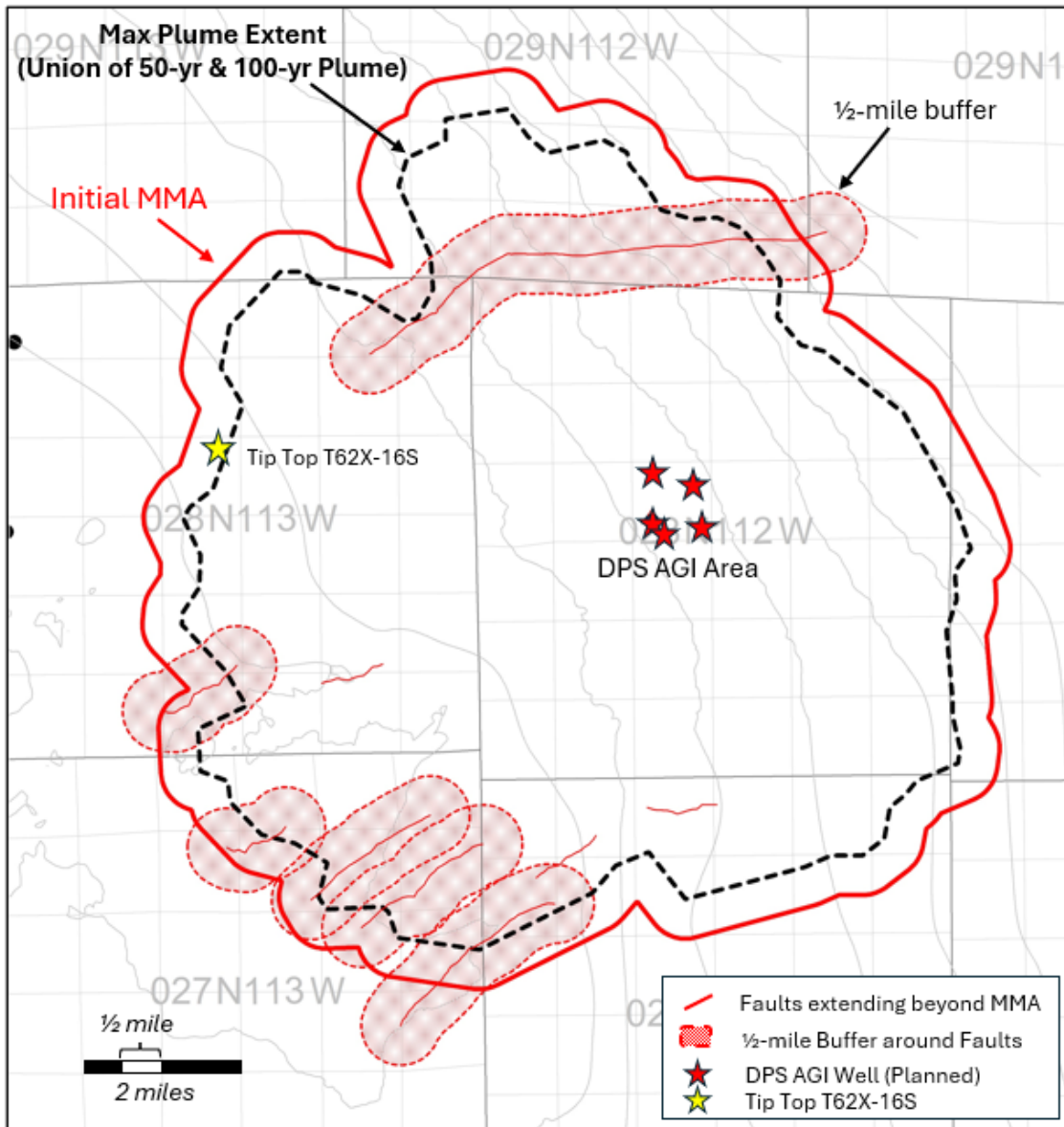


Figure 3.1-3: Map showing initial MMA (red polygon) with 1/2-mile buffer around faults extending beyond maximum plume extent after stabilization (black dashed line).

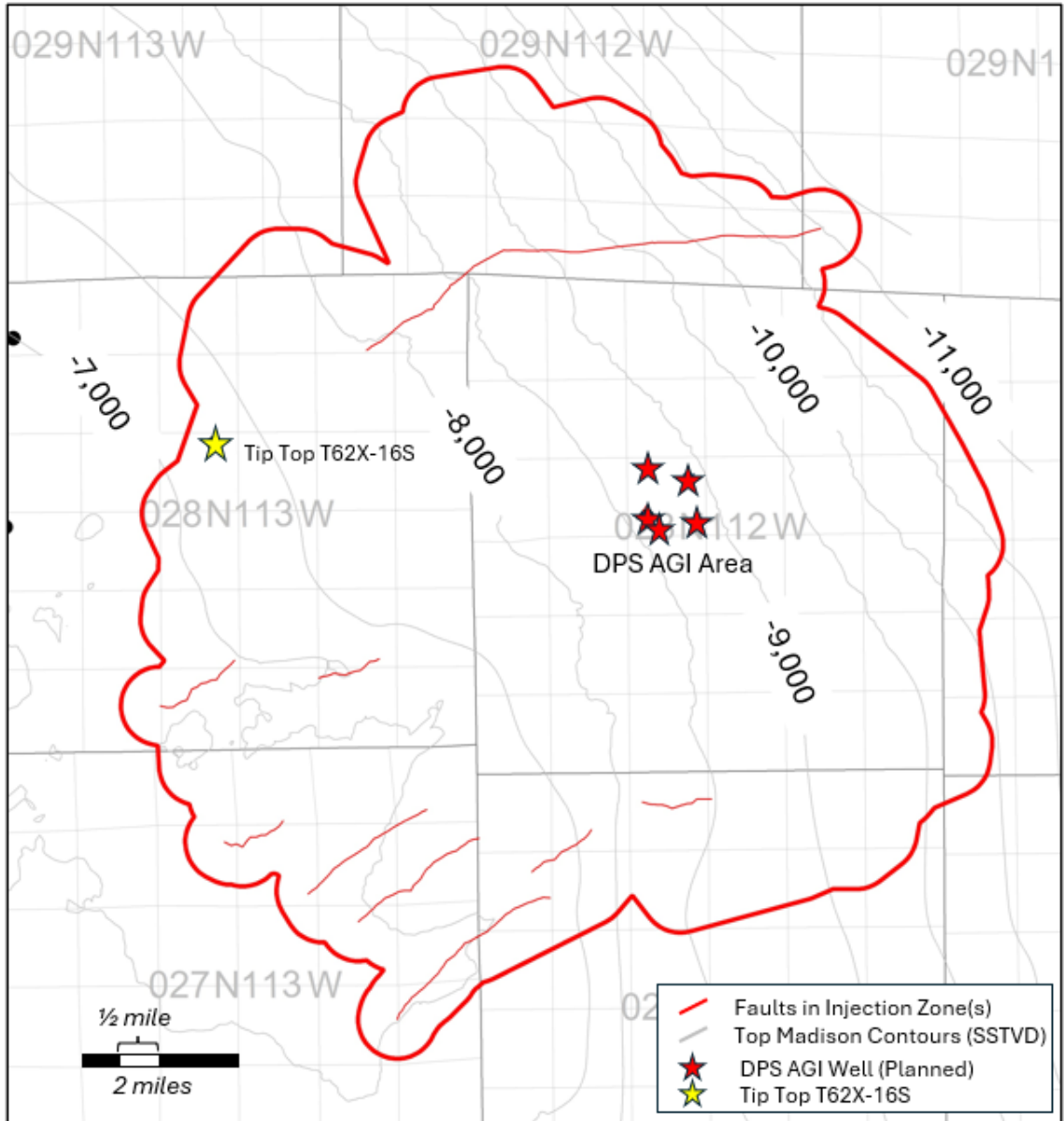


Figure 3.1-4: Map showing the extended, final MMA proposed by BSO to fully encompass the maximum extents of the modeled plume plus an all-around ½-mile buffer, as well as an additional ½-mile buffer around any known potential leakage pathways (in this case faults that extend beyond the maximum plume 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**.

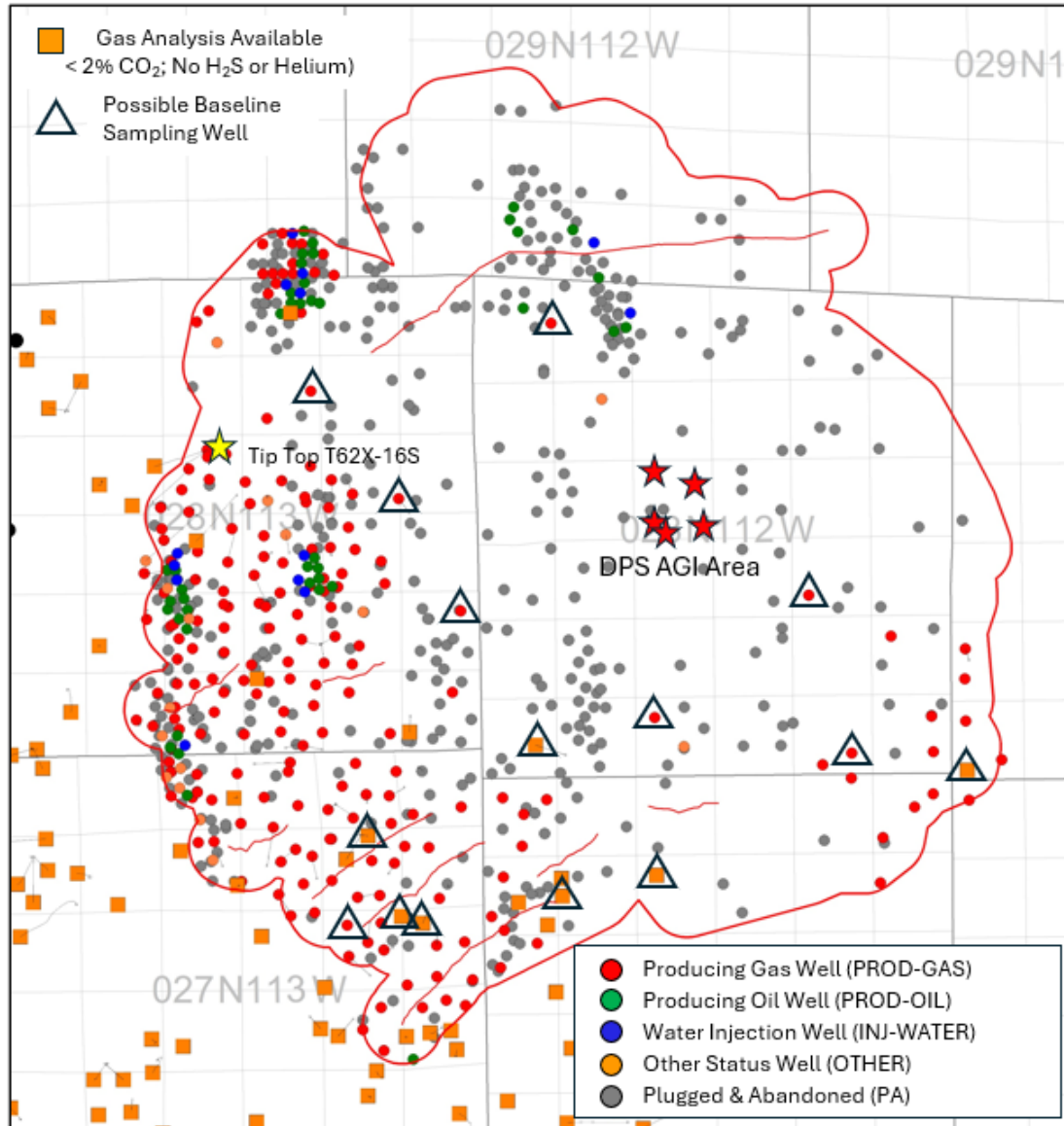


Figure 4.2-1: Map showing locations of existing oil and gas wells within the AMA/MMA. Existing oil, gas and other petroleum-related wells are color-coded according to the legend in the figure. Orange squares represent wells that have publicly available gas analyses that can be used to help establish 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 the same select wells.

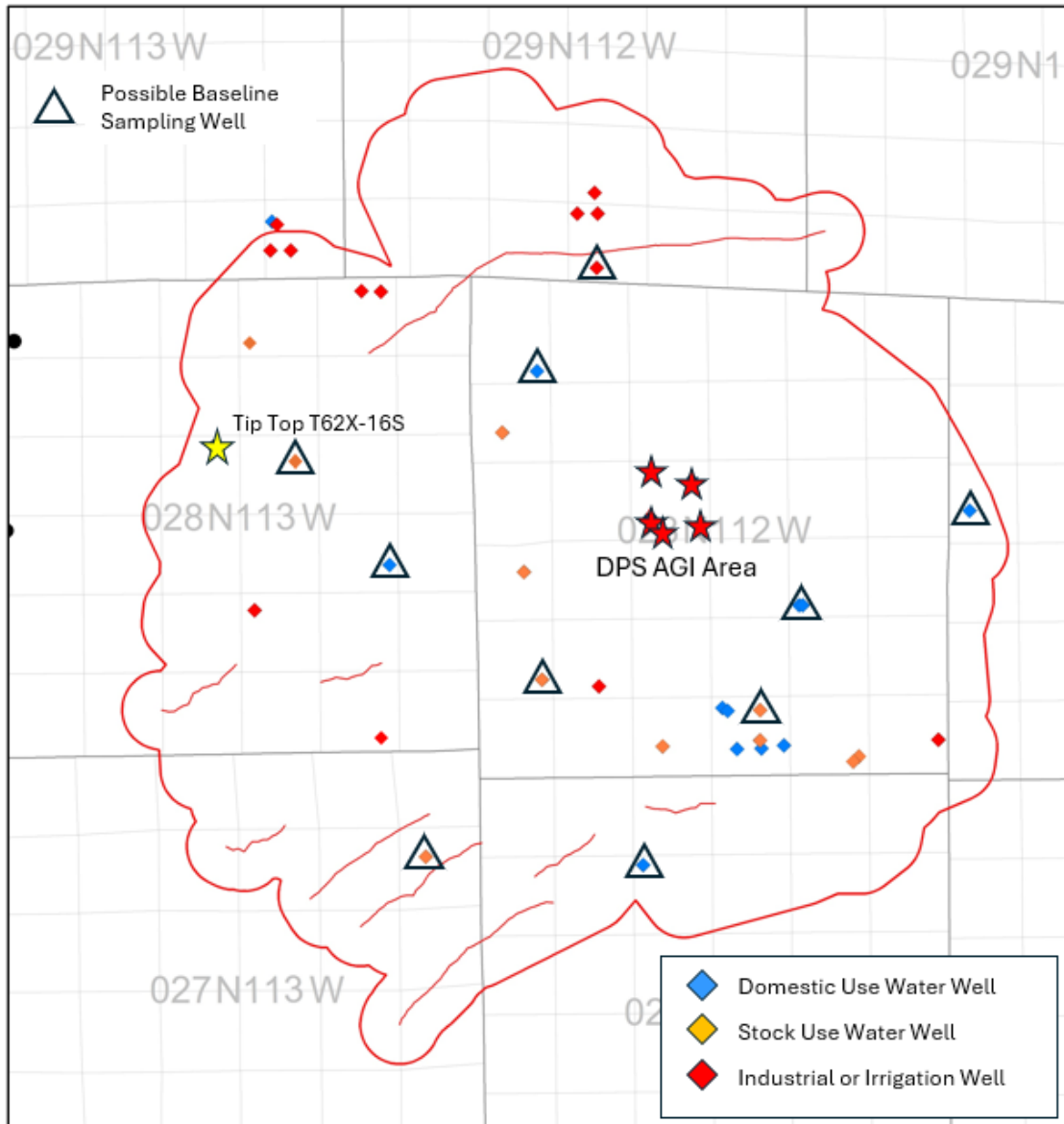


Figure 4.2-2: Map showing locations of existing groundwater wells within the AMA/MMA. Existing groundwater wells are color-coded according to the legend in the figure. Black triangles represent possible candidates for baseline gas composition analysis as part of BSO’s strategy for establishing expected 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 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**).

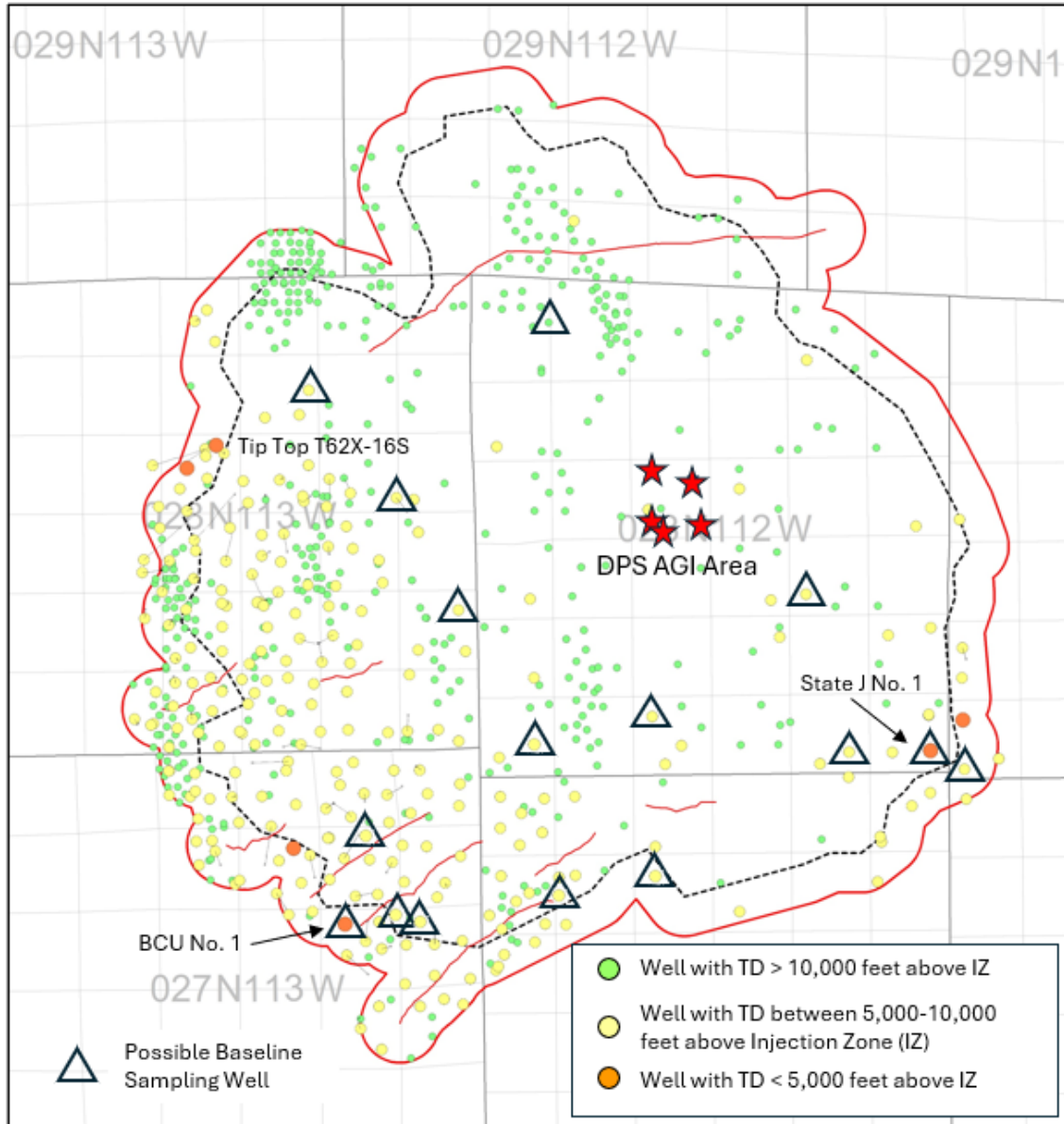


Figure 4.2-3: Map showing vertical separation between Total Depth (“TD”) of all existing oil and gas wells in the MMA (red polygon) and the top of the upper (Madison) injection zone (“IZ”). 480 of the 741 wells (64.8%) reach TD at least 10,000 feet above the Madison injection zone (green circles). 255 (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.*

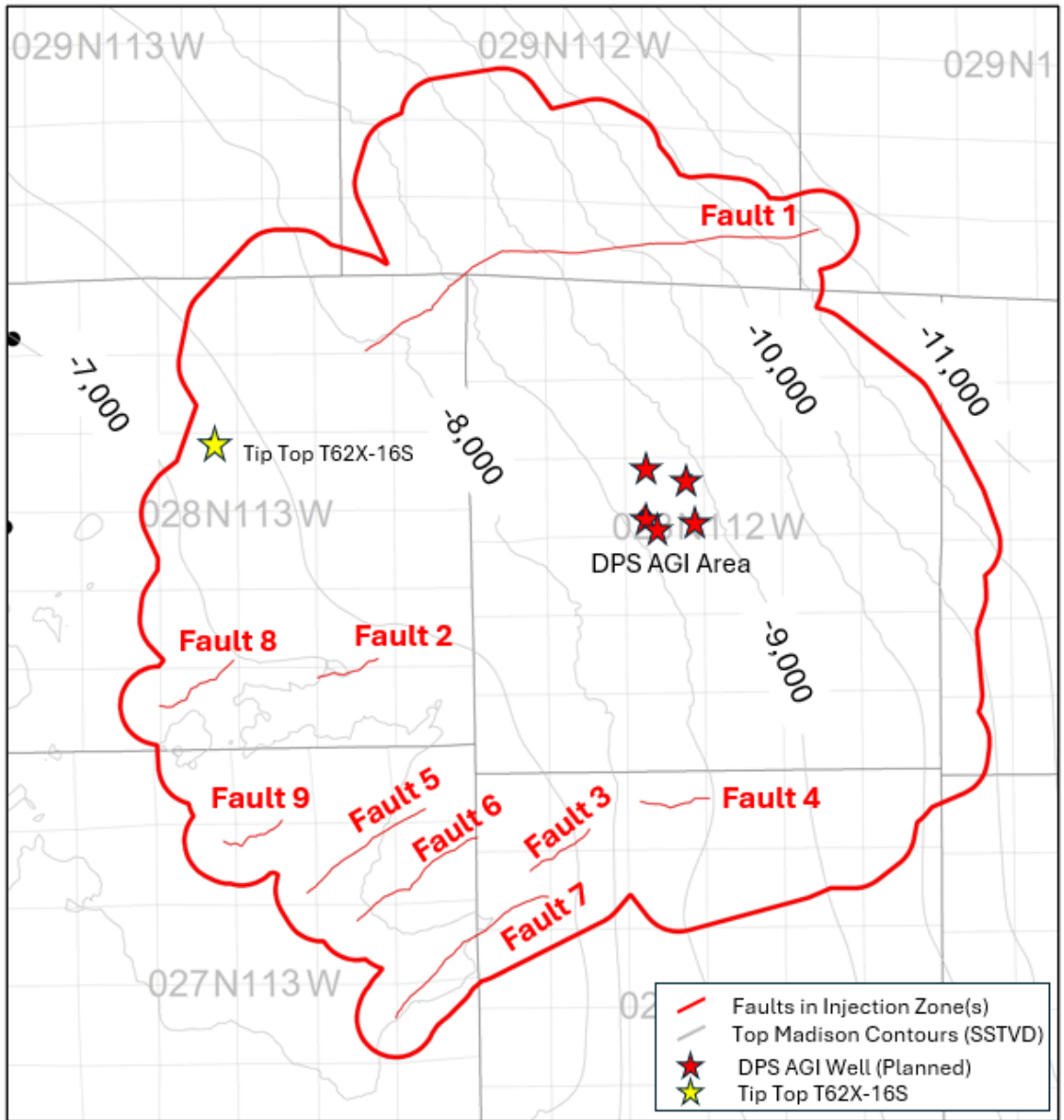


Figure 4.4-1: Map showing the location of faults (numbered 1 through 9) within the AMA/MMA that are at Madison and Bighorn depth. It is important to note that none of these faults are observed at the surface, nor does seismic interpretation suggest that any of these faults extend to the surface.

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.

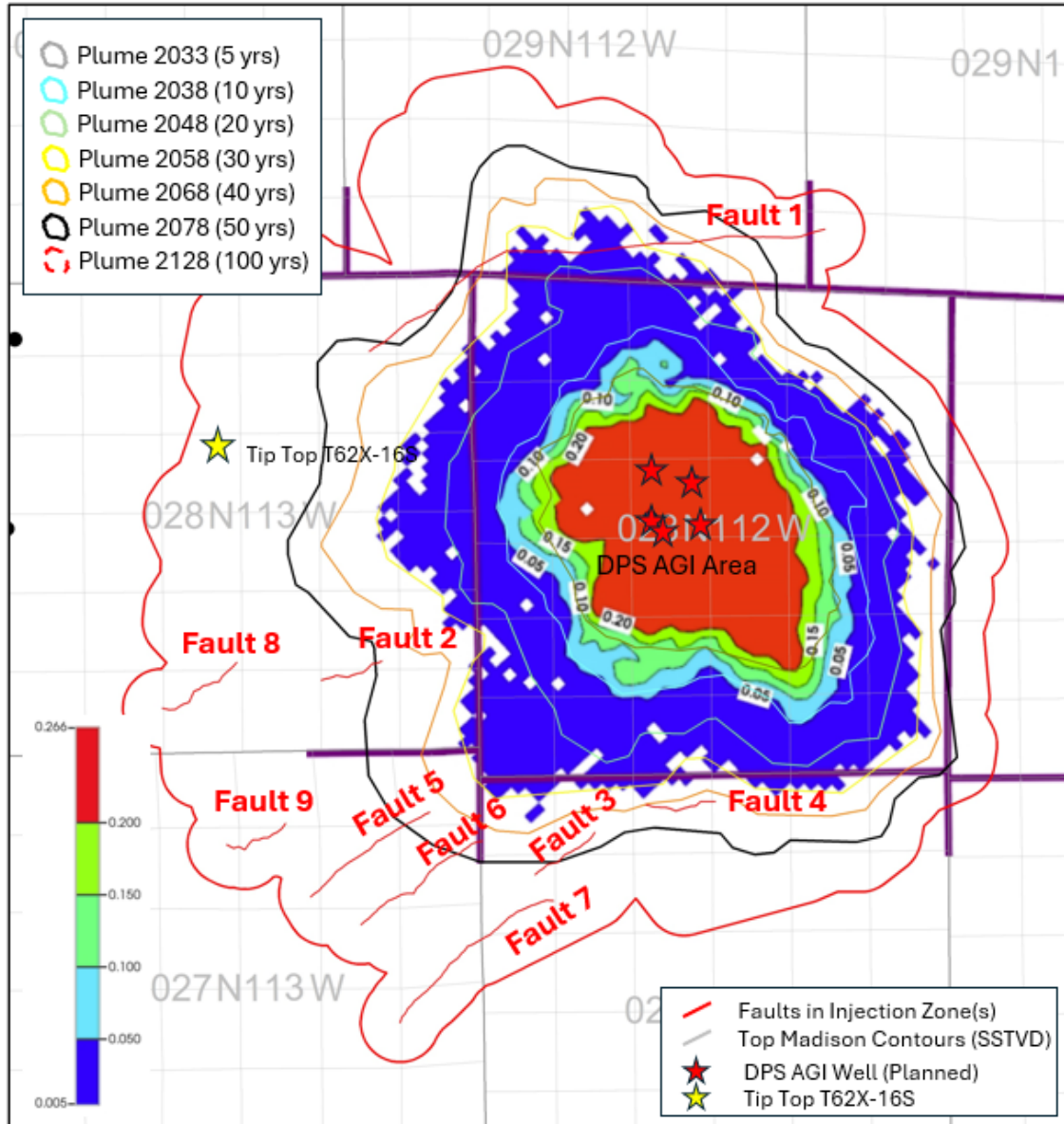


Figure 4.4-2: Map showing free-phase plume with less than 5% CO₂ concentration reaching Fault 1 between 20 and 30 years after injection begins. 30-year plume (year 2058) depicted.

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.

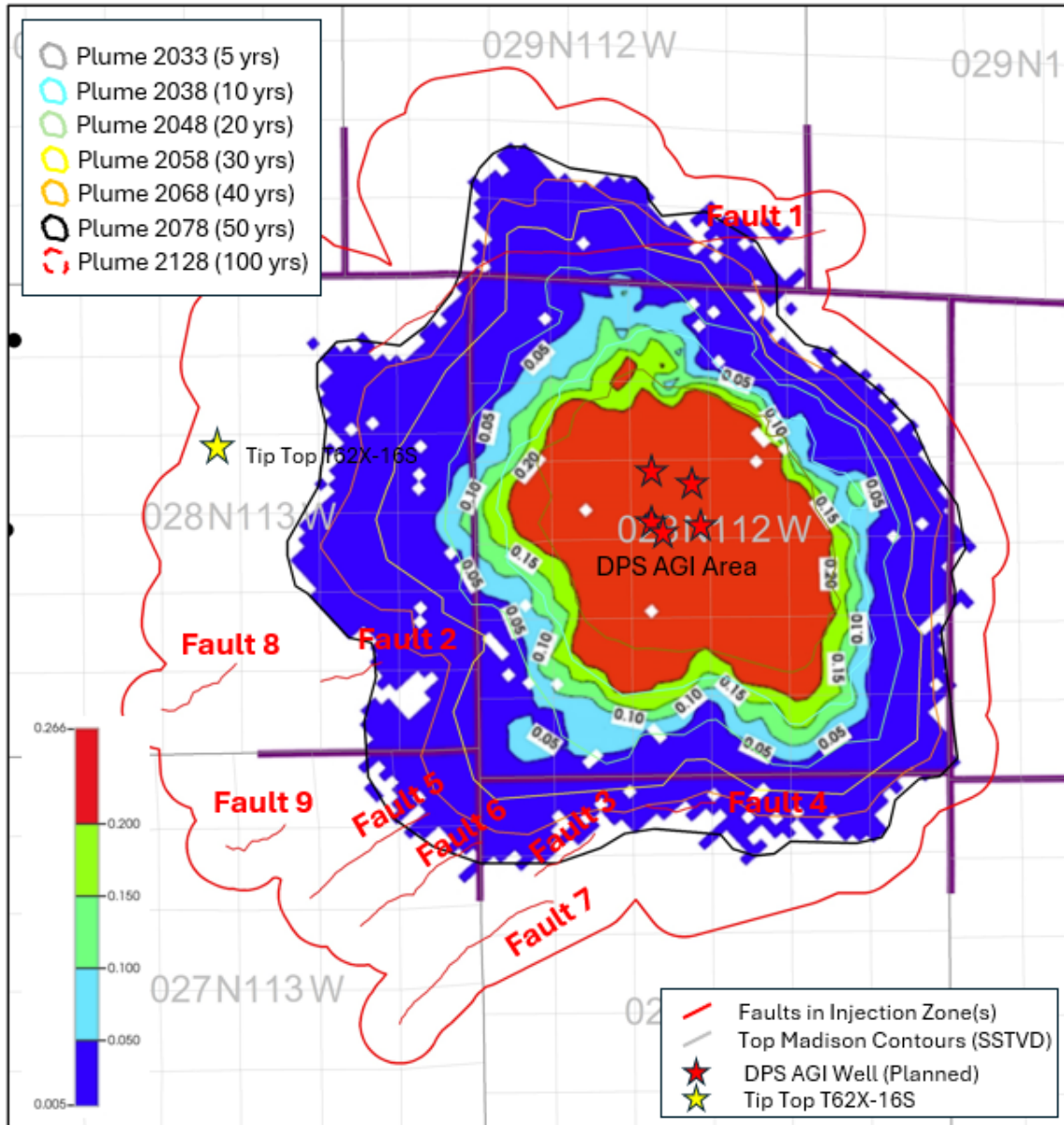


Figure 4.4-3: Map showing free-phase plume with less than 5% CO₂ concentration reaching Faults 2, 3 and 4 in approximately 50 years. 50-year plume (year 2078) depicted.

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.

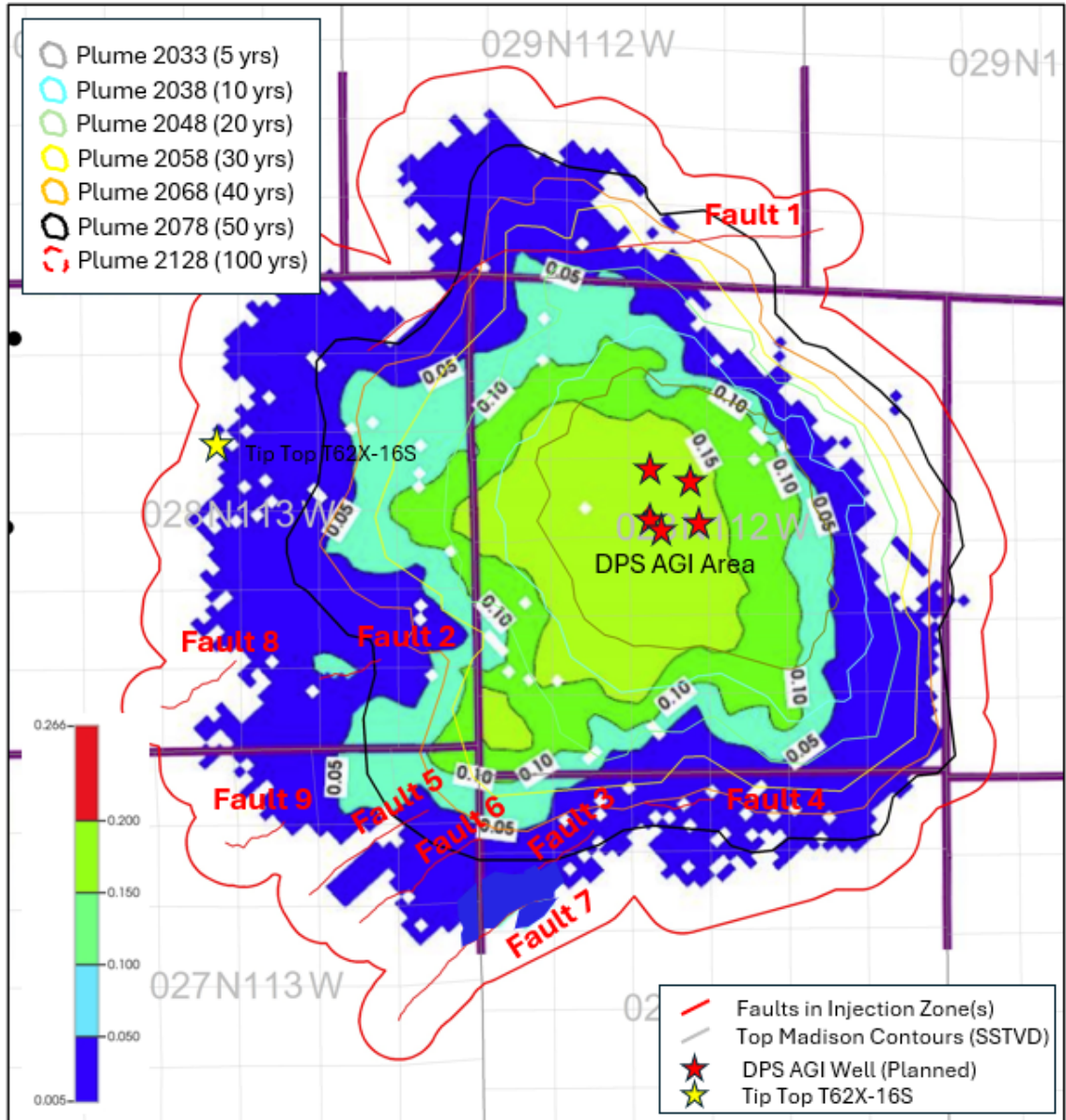


Figure 4.4-4: Map showing free-phase plume with less than 5% CO₂ concentration reaching Faults 5, 6 and 7 in approximately 90-100 years. 100-year plume (year 2128) depicted.

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).

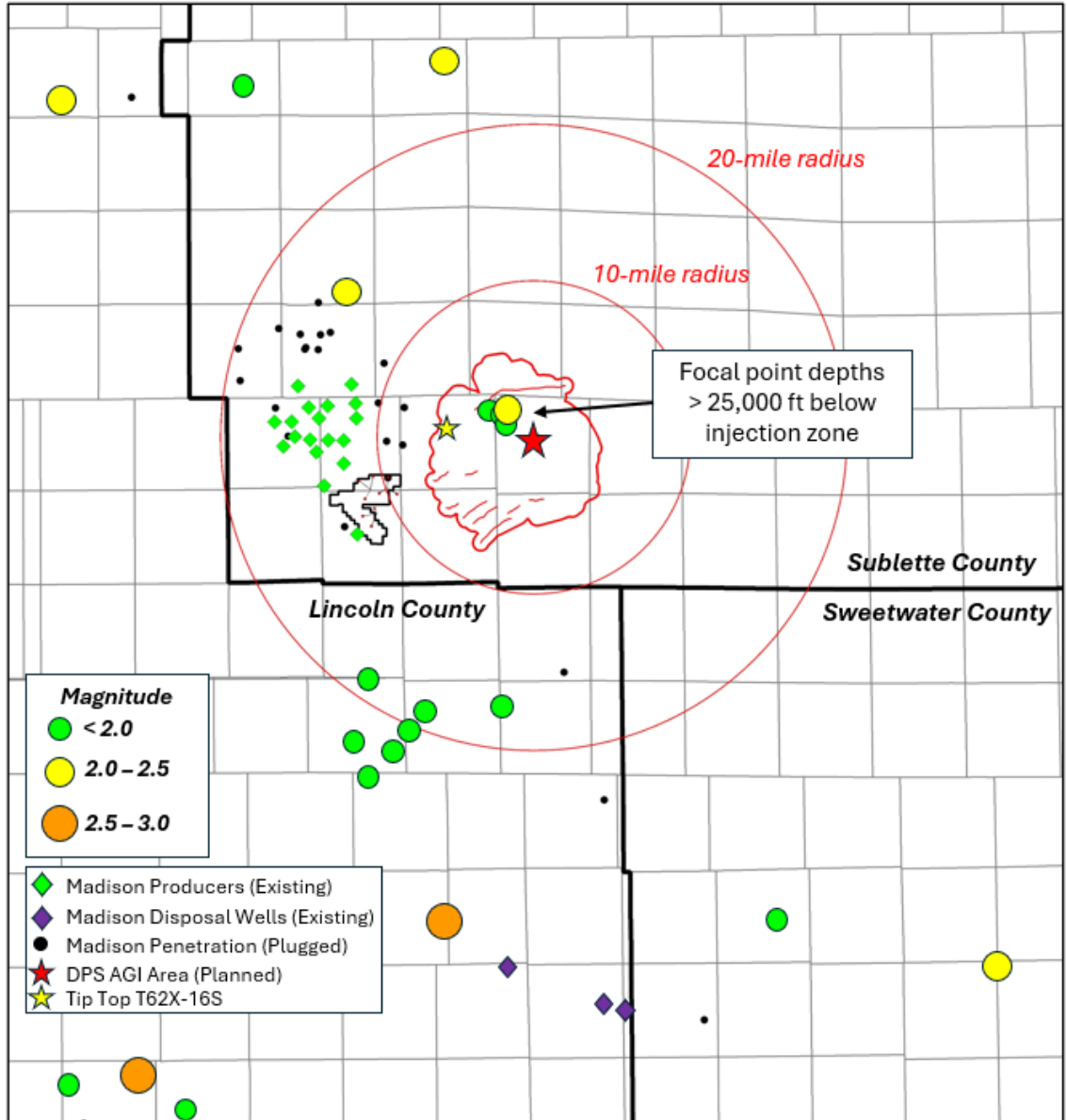


Figure 4.6-1: Map depicting seismic events as reported in the ANSS Earthquake Catalog from October 2015 to October 2025. Note that there are no “significant” (Magnitude > 3.5) within 20 miles of the DPS AGI area, or within the broader map area, including near existing disposal wells injecting into the 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 | <ul style="list-style-type: none"> • 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) | <ul style="list-style-type: none"> • 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 | <ul style="list-style-type: none"> • 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 | <ul style="list-style-type: none"> • 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 |

| | |
|--------------------------------|---|
| | <ul style="list-style-type: none"> • Groundwater monitoring • CO₂ flux monitoring network |
| Confining Units | <ul style="list-style-type: none"> • 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 | <ul style="list-style-type: none"> • 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 | <ul style="list-style-type: none"> • 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.

| Parameters |
|-------------------------|
| 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.

| Parameters |
|--|
| 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)
 $C_{CO_2,p,u}$ = 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 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.

7.3 MASS OF CO₂ 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 CO₂ plume reaching any existing or future production wells, therefore, there will be no injected CO₂ produced and/or recycled.

7.4 MASS OF CO₂ 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 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 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. 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

**** 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 |

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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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| 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 |

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|----------------|----------------------|-------------|--------------|-------------------------------------|------|--|---|----------------|------------------|-----------------|--------------------------|
| 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

**** 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) |
|-----------------------|---------------------------|------------------|-------------------|-------------------------------------|-------------|--|---|----------------|------------------|-----------------|--------------------------|
| 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 |

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) |
|----------------|----------------------|---------------|--------------|-------------------------------------|------|--|---|----------------|------------------|-----------------|--------------------------|
| 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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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 |

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-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

**** 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) |
|----------------|---------------------|-------------|--------------|-------------------------------------|------|--|---|----------------|------------------|-----------------|--------------------------|
| 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 |

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) |
|----------------|---------------------|-------------|--------------|-------------------------------------|------|--|---|----------------|------------------|-----------------|--------------------------|
| 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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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) |
|----------------|---------------------|----------------|--------------|-------------------------------------|------|--|---|----------------|------------------|-----------------|--------------------------|
| 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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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 |

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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

**** 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) |
|------------------------|-----------------------------|-----------------|-------------------|-------------------------------------|-------------|--|---|----------------|------------------|-----------------|--------------------------|
| 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 |
| 49035054960000* | UNIT MCGINNIS (GRBU) | No. 10-9 | PROD - GAS | FRONTIER | 7915 | 6198 | 3220 | YES | 1 | 1 | 1 |
| 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 |

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) |
|-----------------------|-------------------------|------------------|-------------------|-------------------------------------|-------------|--|---|----------------|------------------|-----------------|--------------------------|
| 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 |
| 49035056130000 | GREEN RIVER BEND | No. 16-33 | PROD - GAS | FRONTIER | 8169 | 6034 | 3056 | YES | 1 | 1 | 1 |
| 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 |

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) |
|------------------------|-------------------------|----------------|-------------------|-------------------------------------|-------------|--|---|----------------|------------------|-----------------|--------------------------|
| 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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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 |
| 49035223710000* | BIRCH CREEK UNIT | No. 187 | PROD - GAS | BEAR RIVER | 7770 | 5722 | 2744 | NO | 1 | 1 | 1 |
| 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 |
| 49035221450000* | BIRCH CREEK UNIT | No. 124 | PROD - GAS | BEAR RIVER | 7805 | 5702 | 2724 | YES | 1 | 1 | 1 |
| 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 |
| 49035208690000 | CRAIG'S DRAW II FEE | No. 1-23 | PROD - GAS | BEAR RIVER | 9400 | 5649 | 2671 | YES | 1 | 1 | 1 |
| 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 |
| 49035223840000* | COOPERS | No. 7-31D | SHUT-IN | FRONTIER | 8450 | 5630 | 2652 | YES | 1 | 1 | 1 |
| 49035056970000 | CHIMNEY BUTTE UNIT | No. 13-25 | PROD - GAS | FRONTIER | 8526 | 5626 | 2648 | YES | 1 | 1 | 1 |
| 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 |
| 49035208040000 | YOSE CATTLE COMPANY | No. 40-35 | PROD - GAS | MOWRY | 9300 | 5620 | 2642 | YES | 1 | 1 | 1 |
| 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

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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) |
|------------------------|-------------------------|------------------|-------------------|-------------------------------------|--------------|--|---|----------------|------------------|-----------------|--------------------------|
| 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 |

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

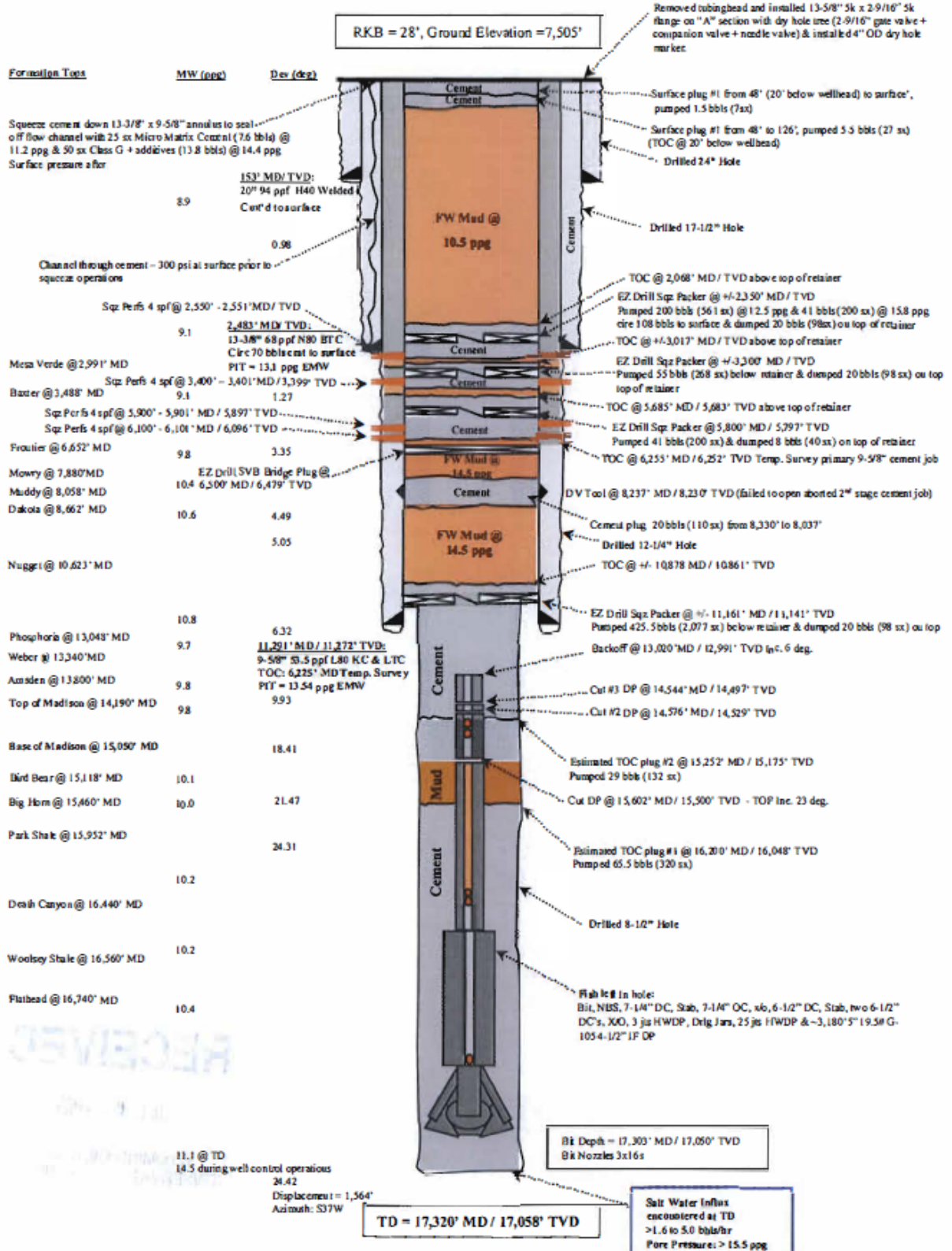
| API Number | Well Name | Well Number | WOGCC Status | WOGCC Formation at Total Depth (TD) | TD | TD Feet Above Upper Injection Zone (Estimated) | TD Feet Above Upper Confining Unit (Estimate) | Within Plume ? | Likelihood (1-5) | Magnitude (1-5) | Total Risk Rating (0-25) |
|-----------------------|-------------------------|--------------|-------------------|-------------------------------------|--------------|--|---|----------------|------------------|-----------------|--------------------------|
| 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 |
| 49035206980000 | STATE J | No. 1 | PROD - GAS | MORRISON | 10650 | 4930 | 1952 | YES | 1 | 1 | 1 |
| 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 |
| 49035054500000 | BIRCH CREEK UNIT | No. 1 | PROD - GAS | NUGGET | 10176 | 3315 | 337 | NO | 1 | 1 | 1 |
| 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.OP</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

Gas Sample Analysis
4903505496 - UNIT MCGINNIS (GRBU) No. 10-9

WYOMING OIL & GAS
CONSERVATION COMMISSION

Company: EOG
Meter Number: WY9023101
Meter Label: Green River Bend 10-09 API # 49-035-05496
Field Name: BIG PINEY S. 9, T27N, R112W

Analyst: LEATHAM Sample Date: 06/15/2016 at 11:42:10
Cylinder Pressure: 0 Test Dates: 06/15/2016 - 06/15/2016
Line Pressure: 80 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 TECH

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

4903522369 - BIRCH CREEK UNIT No. 185

49-035-22369

| | | | |
|---------------------|----------------|--------------|------------------|
| IS 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

Bear River 7500 E FRONTIER 7100
 NE 14 27 113
 Sublease

035-21959

PRECISION MEASUREMENT, INC.
 P.O. Box 3659
 746 North Circle Drive
 Casper, WY. 826020

4903521959 - BIRCH CREEK UNIT No. 166

7/23/00 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

*NW SW 24 27 13
 Sublette
 Bear River
 Frontier*

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 |

BTEX Components, 100 % of Total Volume

N-Hexane: 0.03160
 Benzene: 0.00430
 Toluene: 0.00800
 Ethylbenzene: None Detected
 Xylenes: None Detected

Analysis By: C.G.Martin

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: pml@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:

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:

wet gas
AP-WAI
EOG

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-Pentane | 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 |

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

BTEX Components, 100 % of Total Volume
 N-Hexane: 0.0307e
 Benzene: 0.0075e
 Toluene: 0.0225
 Ethylbenzene: None Detected
 Xylenes: None Detected

Hexane - N Hexane - Benzene = Hexane
.146 - .0307 - .0075 = 0.1078

Heptane - Toluene = Heptane
 Remarks: 0.132 - 0.0225 = 0.1095
 CORRECTED FOR AIR CONTAMINATION BY: 58.382%

Analysis By: J.A. PROPP
 Approved By: *CSM*

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: AST

035-22145

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307)852-72920

| | | | |
|---------------------|---------------|---------------------------------------|-------------------|
| 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: | Quesbtex |
| Data File: | QPC83.D | | |
| Date Sampled: | 13-Sep-000 | 4903522145 - BIRCH CREEK UNIT No. 124 | |

| Component | Mol% | Wt% | LV% |
|--------------------|-----------------|-----------------|-----------------|
| Methane | 86.8428 | 72.8092 | 80.8920 |
| Ethane | 6.43390 | 10.1108 | 9.4814 |
| Propane | 3.06340 | 7.0597 | 4.6418 |
| Isobutane | 0.43910 | 1.3338 | 0.7898 |
| n-Butane | 0.77870 | 2.3653 | 1.3499 |
| Neopentane | 0.00840 | 0.0318 | 0.0178 |
| Isopentane | 0.17580 | 0.66220 | 0.3535 |
| n-Pentane | 0.17750 | 0.66920 | 0.3535 |
| 2,2-Dimethylbutane | 0.00420 | 0.01910 | 0.0097 |
| 2,3-Dimethylbutane | 0.02280 | 0.10280 | 0.0514 |
| 2-Methylpentane | 0.03550 | 0.16010 | 0.0811 |
| 3-Methylpentane0 | 0.02070 | 0.09330 | 0.0466 |
| n-Hexane0 | 0.05200 | 0.23420 | 0.1176 |
| Heptanes0 | 0.22660 | 1.07120 | 0.4898 |
| Octanes0 | 0.02470 | 0.13570 | 0.05900 |
| Nonanes0 | 0.00380 | 0.02130 | 0.00830 |
| Decanes plus | 0.00000 | 0.00000 | 0.0000 |
| Nitrogen0 | 0.91800 | 1.34390 | 0.5534 |
| Carbon Dioxide0 | 0.77250 | 1.77660 | 0.7239 |
| Oxygen0 | 0.00000 | 0.00000 | 0.0000 |
| Total | 100.0000 | 100.0000 | 100.0000 |

*Bear River
Frontier
NE NW 13 27 13
Sublette*

| | | |
|--------------------------------|-----------|--------------------------------|
| Gross BTU/Real CF0 | 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) | 0.9971 | |
| Specific Gravity | 0.8622 | air=1 |
| Avg Molecular Weight | 19.135 | gm/mole |
| Propane GPM | 0.8422180 | gal/MCF |
| Butane GPM | 0.3862700 | gal/MCF |
| Gasoline GPM | 0.2769540 | gal/MCF |
| 26# Gasoline GPM | 0.5221250 | gal/MCF |
| Total GPM | 1.5078620 | gal/MCF |
| Base Mol% | 100.198 | %v/v |
| | | |
| Sample Temperature: | 72 | *F0 |
| Sample Pressure: | 255 | psig0 |
| Hydrogen Sulfide | 0.0000 | Mole% |

*Birch Creek Unit
Condensates*

Reviewed By: _____

PRECISION MEASUREMENTS, INC.
 P.O. Box 5659
 746 North Circle Drive
 Casper, WY. 82602

49-035-22384

12/18/01 2:58 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:

*NW SW 38-28-13
 SUBLETTE
 Frontier 2*

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: 1029.6200

| 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: | 0.005 | 0.003 |
| Decanes | C10: | 0.000 | 0.000 |
| Totals | | 100.000 | 1.072 |

Calc. Ideal Gravity: 0.5850
 Calc. Real Gravity: 0.586
 Field Gravity:
 Standard Pressure: 14.6960
 BTU Dry: 1045.555
 BTU Wet: 1027.362
 Z Factor: 0.998
 Average Mol Weight: 17.099
 Average CuFUGal: 38.228
 Ethane+ GPM: 1.072
 Propane+ GPM: 0.337
 Butane+ GPM: 0.156
 Pentane+ GPM: 0.0940
 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: 0.00610
 Toluene: 0.0099
 Ethylbenzene: None Detected
 Xylenes: None Detected

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

Remarks:

C6 .064 - N Hexane .0168 - Benzene .00610 = .0411 C6
C7 .053 - Toluene .0099 = .0431
VOC = 1.072
C8+ = .037

035-20672

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% |

*Bear River
Substate*

Reviewed By: _____

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 |
| Avg Molecular Weight | 18.584 |
| 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 |

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

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

Reviewed By:

AST

APPENDIX E – REFERENCES

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