April 9, 2025

Mr. Rusty Shaw
ExxonMobil Corporation
22777 Springwoods Village Parkway
Spring, Texas 77389

Re: Monitoring, Reporting and Verification (MRV) Plan for Shute Creek Facility

Dear Mr. Shaw:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Shute Creek Facility, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Shute Creek Facility on March 17, 2025, as the final MRV plan. The MRV Plan Approval Number is 1002150-3. This decision is effective April 14, 2025 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78. In conjunction with this MRV plan approval, we recommend reviewing the Subpart PP regulations to determine whether your facility is required to report data as a supplier of carbon dioxide. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

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

Sincerely,

JULIUS BANKS

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Date: 2025.04.09 16:08:11 -04'00'

Julius Banks
Supervisor, Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for Shute Creek Facility

March 2025

Contents

Appendices

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted by Exxon Mobile Corporation (ExxonMobil) for the Shute Creek Facility (Shute Creek) acid gas injection (AGI) project located near LaBarge, Wyoming. Note that this evaluation pertains only to the subpart RR MRV plan for Shute Creek, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

1 Overview of Project

The introduction of the MRV plan states that ExxonMobil operates two AGI wells, AGI 2-18 and AGI 3-14, in the Madison Formation near LaBarge, Wyoming for the primary purpose of acid gas disposal with a secondary purpose of geologic sequestration of carbon dioxide (CO_2) in a subsurface geologic formation. The acid gas and CO_2 injected into the AGI wells are components of the natural gas produced by ExxonMobil from the Madison Formation. ExxonMobil has been operating the AGI wells since 2005 and intends to continue injection until the end-of-field-life of the LaBarge assets. Additionally, the MRV plan explains that because the volume of CO_2 associated with the natural gas production is greater than the volume that is able to be injected into the AGI wells, ExxonMobil is in the process of developing the Shute Creek (SC) 5-2 and SC 7-34 wells for the purpose of geologic sequestration of fluids consisting primarily of CO_2 in subsurface geologic formations. Like the AGI wells, the fluids that will be injected into the CO_2 injection wells are also components of the natural gas produced by ExxonMobil from the Madison Formation. Once operational, the CO_2 injection wells are expected to continue injection until the end-of-field-life of the LaBarge assets.

The MRV plan states that the Wyoming Oil and Gas Conservation Commission (WOGCC) regulates oil and gas activities in Wyoming. WOGCC classifies the AGI, SC 5-2, and SC 7-34 wells in LaBarge as Underground Injection Control (UIC) Class II wells. Section 2 of the MRV plan describes the planned injection volumes, environmental setting of the LaBarge Field, injection process, and reservoir modeling. The LaBarge field area is located in the southwestern corner of Wyoming, contained in Lincoln and Sublette counties. The producing field area is within the Green River Basin and is located due west of the Wind River Mountains along the Moxa Arch.

Section 2.3.5 of the MRV plan states that structural closure on the Madison Formation at the LaBarge field is quite large, with approximately 4,000 feet (ft) true vertical depth (TVD) of structural closure from the top of the structure to the gas-water contact (GWC). Spatially, the Madison Formation closure covers over 1,000 square miles, making it one of the largest gas fields in North America. The Madison is estimated to contain approximately 170 trillion cubic feet (Tcf) of raw gas and 20 Tcf of natural gas (primarily methane (CH_4)). At current rates of production, the estimated remaining field life is over 100 years. Spatially, the AGI and CO_2 injection wells have been located at or immediately adjacent to the SCTF, over 40 miles to the southeast from the main LaBarge production areas.

The MRV plan states that sour gas of up to 66% CO_2 and 5% hydrogen sulfide (H_2S) is currently produced from the Madison Formation at LaBarge. The majority of produced CO_2 is currently being sold by

ExxonMobil to other oilfield operators and is being used in EOR projects in the region. The sold volume, however, does not equal the total produced CO_2 and H_2S volumes, thereby requiring disposal. ExxonMobil has pursued the AGI program as a safe and reliable method to inject the acid gas into the Madison Formation into the aquifer below the field GWC. Gas composition in the AGI wells is based on plant injection needs and will vary between 35 - 50% CO_2 and 50 - 65% H_2S. The acid gas is injected at a depth of ~17,500 ft below the surface and approximately 43 miles away from the main producing areas of LaBarge

The MRV plan states that the volume of CO_2 sold and injected into the AGI wells does not equal the volume of CO_2 produced, so additional injection wells are required (SC 5-2 and SC 7-34). Gas composition to be injected into the CO_2 injection wells is planned to be approximately 99% CO_2 with minor amounts of CH_4, nitrogen, carbonyl sulfide (COS), ethane, and H_2S. For the SC 5-2 well, the gas is planned to be injected between depths of ~17,950 ft and ~19,200 ft measured depth (MD) approximately 35 miles away from the main producing areas of LaBarge. For the SC 7-34 well, the gas is planned to be injected between depths of ~16,740 ft and ~18,230 ft MD approximately 30 miles away from the main producing areas of LaBarge.

The MRV plan states that the AGI process transports the acid gas stripped in the Selexol process under pressure through a pipeline to two underground wells that are geologically suitable for storage of the acid gas (AGI 3-14 and AGI 2-18). The total depth of each well is about 18,015 ft for AGI 3-14 and 18,017 ft for AGI 2-18. Shute Creek forecasts the total volume of CO_2 stored in the AGI wells over the modeled injection period to be 53 million metric tons.

According to the MRV plan, the SC 5-2 process aims to capture CO_2 at Shute Creek that would otherwise be vented and compress it for injection in the aquifer below the GWC of the Madison and Bighorn-Gallatin formations. The injection system would enable additional CO_2 to be stripped in the Selexol process, pressurized, and transported to a CO_2 injection well, which is geologically suitable for injection, disposal, and sequestration of fluids primarily consisting of CO_2. After the acid gas treatment and dehydration, the gas will be routed to a new flash vessel which will enable capture up to 80 million standard cubic feet per day (MMSCFD) from Shute Creek then compressed with an air-cooled Heat Exchanger cooling system. The captured CO_2 will have the potential to be either sold or injected into a CO_2 injection well. Based on modeling, the approximate stream composition will be 99% CO_2, 0.8% methane, and 0.2% other mixed gases. This gas will be injected into the Madison Formation at a depth of ~17,950 feet and into the Bighorn-Gallatin Formation at a depth of ~19,200 feet approximately 33 miles from the nearest Madison gas producer in the LaBarge gas field.

According to the MRV plan, the SC 7-34 process aims to divert currently captured CO_2 produced from source wells during natural gas production that will not be sold to customers and route to permanent disposal in the aquifer below the GWC of the Madison and Bighorn-Gallatin formations. Captured CO_2 that is already routed from Shute Creek to the existing CO_2 sales building will be diverted and transported via flow line to a CO_2 injection well, which is geologically suitable for injection, disposal, and sequestration of fluids primarily consisting of CO_2. This process will enable disposal of up to 70 MMSCFD through an additional pump. The CO_2 will be cooled with an air-cooled Heat Exchanger cooling system. Based on modeling, the approximate stream composition is anticipated to be identical to the SC 5-2 with 99% CO_2, 0.8% methane, and 0.2% other mixed gases. This gas will be injected into the Madison

Formation at a depth of ~16,740 feet and into the Bighorn-Gallatin Formation at a depth of ~18,230 feet approximately 28 miles from the nearest Madison gas producer in the LaBarge gas field. Shute Creek forecasts the total volume of CO_2 stored in the CO_2 injection wells over the modeled injection period to be 180 million metric tons.

The description of the project provides the necessary information for 40 CFR 98.448(a)(6).

2 Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA)

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

According to the MRV plan, reservoir modeling for the AGI wells was performed using Schlumberger's (SLB) Petrel/Intersect, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time. After injecting 0.3 Tcf by year-end 2023, the current estimated acid gas plume size is approximately 21,350 ft in diameter (4.0 miles), which can be seen in Figure 3.1 of the MRV plan. With continuing injection of an additional 1.9 Tcf through year-end 2104, at which injection is expected to cease, the plume size is expected to grow to approximately 39,500 feet in diameter (7.5 miles), which can be seen in Figure 3.2 of the MRV plan. This model was run through the year 2986, at which the rate of growth of the free-phase gas plume was shown to be less than 0.25% annually. Using this model, the facility plans to define the MMA for the AGI wells as the maximum areal extent of the plume once it has reached stability, which is defined as the extent of the plume in the year 2205, plus a one-half mile buffer.

Regarding the CO_2 injection wells, the MRV plan notes that estimates of plume size assume that CO_2 is coinjected without flow control at both the SC 5-2 and SC 7-34 wells into both the Madison and Bighorn-Gallatin intervals. Having no flow control means that the amount of gas that enters each interval is for the most part a function of the permeability thickness (kh) of each interval. For the CO_2 injection wells, the model was run through 2986 to assess the potential for expansion of the plume after injection ceases at year-end 2104. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. The rate of growth of the free-phase gas plume was shown to be less than 0.25% annually. The MMAs for the CO_2 injection wells will be defined as the maximum extent of their respective plumes in the year 2205 plus a half mile buffer.

Shute Creek states that the AMA will be defined as the same boundary as the MMA for the AGI and CO_2 injection wells due to several factors: the lack of faulting in the MMA and injection area, the large distance from the LaBarge field production area and the low reservoir permeability, the LaBarge field production area is a large structural hydrocarbon trap, and finally the MMA encompassing the free phase CO_2 plume 100 years post-injection. Because there are no probable leakage pathways in the MMA, besides surface equipment, which is extensively monitored, Shute Creek believes it is appropriate to define the AMA as the same boundary as the MMA.

The delineations of the MMA and AMA were determined to be acceptable per the requirements in 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV plan are clearly delineated in the plan and are consistent with the definitions in 40 CFR 98.449

3 Identification of Potential Surface Leakage Pathways

As part of the MRV plan, the reporter must identify potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). Shute Creek identified the following as potential leakage pathways in Section 4 of their MRV plan that required consideration:

- Leakage from surface equipment (pipeline and wellhead)
- Leakage through wells
- Leakage through faults and fractures
- Leakage through the seal
- Leakage through natural or induced seismicity

3.1 Leakage from Surface Equipment

The MRV plan states that leakage from surface equipment is not likely due to the design of the AGI equipment associated with the AGI wells. This is based on the continuous surveillance, facility design, and routine inspections of the surface equipment. Field personnel monitor the AGI site continuously through the distributed control system (DCS). Additionally, daily visual inspection rounds are conducted at the AGI site and weekly visual inspection rounds are conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. Shute Creek also relies on the prevailing design of the injection sites, which includes wells with surface controlled subsurface safety valves (SCSSVs), which are set to trip closed if leakage is detected. The MRV plan states that this would eliminate any backflow out from the formation, minimizing leakage volumes. Inline inspections of the AGI injection pipelines using a smart pigging tool are conducted on a regular frequency to check the wall thickness of the pipeline to identify potential areas of corrosion.

Field personnel will monitor the CO_2 injection facilities continuously through the DCS. Additionally, visual inspections will be conducted on a routine basis providing an additional way to detect leaks in a timely manner. Surface isolation valves will also be installed for redundant protection. Inline inspections are not anticipated to occur on a regular basis because free water is not expected to accumulate due to the low dew point of the fluid.

According to the MRV plan, due to the design of the AGI and CO_2 injection facilities and extensive monitoring in place to reduce the risk of unplanned leakage, leakage from surface equipment is not likely. Even a minuscule amount of gas leakage would be immediately detected by the extensive monitoring systems in place at the facility, and this volume will be quantified based on the operating conditions at the time of release. Shute Creek states that any potential leakage from surface equipment would only occur during the lifetime operation of the well.

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

3.2 Leakage through AGI and CO_2 Injection Wells

The MRV plan states that there is no commercial production of oil or gas within the immediate area of Shute Creek. There is shallower production of gas from the Frontier and Dakota formations nearby in the Cow Hollow Field, at depths of 10,800 ft – 11,800 ft. A search of the WOGCC database demonstrated that there are no existing active Madison or Bighorn-Gallatin penetrations or production within the respective MMAs of the AGI or CO_2 injection well sites. The nearest established Madison production is greater than 35 miles to the north-northwest in the ExxonMobil LaBarge Deep Madison Field, which is the well field that supplies Shute Creek. One well (Whiskey Butte Unit 1, drilled in 1974 and operated by Wexpro Company), located approximately six miles from the AGI wells, partially penetrated 190 ft of the Madison formation (total depth 17,236 ft MD). This well never produced from the Madison Formation and instead was perforated thousands of ft above in the Frontier Formation. However, the well was ultimately plugged and abandoned in February 1992 and Shute Creek asserts that it does not pose a risk as a leakage pathway.

The MRV Plan states that early in the life of many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. The thin-wall wells that failed have been plugged and abandoned in accordance with regulatory standards. Madison wells that were subsequently drilled were cased using thick-walled/chrome tubulars due to the high H_2S and CO_2 content and subsequent corrosion effects, as well as to combat potential salt or sediment creep. Therefore, there is no current risk of failure as all wells currently use or have used thick-walled casing of sufficient strength to penetrate and/or produce from the Madison Formation.

Shute Creek explains that the risk from future drilling is also unlikely to pose a risk as a leakage pathway due to limited areal extent of the injection plumes as shown in Figures 3.2 – 3.8 in the MRV Plan). Therefore, the geological model can be used to delineate areas that should be avoided during drilling. This model has also history-matched the AGI injection that has occurred to date and suggests that future injection will closely follow the patterns resulting from the geological model simulation. Additionally, Shute Creek states that should future drilling occur, it would occur near the existing production area, which is greater than 40 miles away from the current AGI wells, approximately 35 miles away from SC 5-2, and 30 miles away from SC 7-34.

According to the MRV plan, leakage of CO_2 through oil, gas, and/or water wells completed and/or abandoned is not likely. Even a minuscule amount of gas leakage would be immediately detected, and immediate action would be taken to stop the release. Shute Creek states that any potential leakage from this pathway would only occur during the lifetime operation of the wells.

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

3.3 Leakage through Faults and Fractures

The MRV plan states that engineering and geologic analysis show no evidence of faulting or structuring around the AGI wells. The absence of faulting also tends to suggest that natural fracturing or permeability enhancement in the Madison Formation is also highly improbable. Natural fracturing along with systems of large, connected pores (karsts and vugs) could occur in the Bighorn-Gallatin Formation. Current-day regional scale thrust faulting has not been observed in the LaBarge area since the field has been under development. Shute Creek states that 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 MRV plan states that it has been documented that natural fracturing of reservoirs in the subsurface of LaBarge and surrounding areas are directly correlative to distance to thrust faults in the area. This correlation has been documented in subsurface wellbore image logs and also by surface geological mapping around the thrust faults in the LaBarge area. Therefore, there is a lack of faulting, as observed on 2D seismic panels, around and through the injection well sites. The MRV plan also states that the lack of significant natural fracturing in the Madison reservoir at and around the injection well sites, in conjunction with active inspection of wellbore image logs within the AGI wells themselves, indicates that natural fractures do not exist. ExxonMobil indicates that the reservoir quality for SC 5-2 is expected to be similar to the AGI wells' reservoir quality, and natural fractures are not anticipated at SC 5-2. Shute Creek states that prior to drilling, it worked with multiple service companies who provided a range of estimated fracture gradients for the Phosphoria, Weber/Amsden, Morgan, and Madison formations in the area. From this work, Shute Creek explains that based on these estimated fracture gradients, and a downhole fracture pressure of 12,167 psi, which corresponds to a surface injection pressure of approximately 5,500 psi, the injected acid gas will not initiate fractures in the confining zones of overlying strata. The MRV plan also states that facility limits exist that limit surface pressures to below 3,200 psi, which is well below the pressure required to fracture the formation, therefore, the probability of fracture is unlikely.

Shute Creek estimates the fracture gradient and overburden for the SC 5-2 injection well using offset well data. Offset well pressure integrity test (PIT) data from existing wells was analyzed and resulted in an overburden pressure of 18,883 psi and a fracture gradient of 0.88 psi/ft (15,203 psi) at the top of the Madison Formation (~17,232 ft MD/-10,541 TVDs). The fracture pressure at the top of the Madison Formation is estimated at approximately 15,203 psi, which corresponds to a fracture pressure at the surface of 7,685 psi. The projected facility average and maximum surface pressures are 3,430 psi and 6,170 psi, respectively. The MRV plan states that both are below the pressure required to fracture the formation; therefore, the probability of fracture is unlikely.

The MRV plan also states that the fracture gradient and overburden for the SC 7-34 well were also estimated on the basis of offset well data. Overburden estimates for the subject formations are based on offset well density logs. Expected formation integrity is primarily based on offset well pressure integrity (PIT) data. Because offset PITs did not result in leakoff, fracture gradient is assumed to be above test pressures. Therefore, the lowest possible fracture gradient constrained by the PITs has a vertical effective stress ratio of 0.55. An analysis of published regional data suggests a vertical effective stress ratio of 0.67 is more likely. Fracture gradient constraints were generalized with an effective horizontal to vertical effective stress ratio of 0.67 to be extrapolated to the target formation. These analyses result in an overburden of 18,705 psi and fracture gradient of 0.90 psi/foot (15,034 psi) at the top of the Madison Formation (approximately 16,744 feet MD / -10,055 feet TVDs) and overburden of 19,934 psi and fracture gradient of 0.90 psi/foot (16,017 psi) at the estimated top of the Bighorn-Gallatin Formation (approximately 17,815 feet MD / -11,126 feet TVDs).

According to the MRV plan, based on results of the site characterization including the lack of faulting or open fractures in the injection intervals and the operational limitations on injections pressures, CO_2 leakage to the surface via faults or fractures is highly unlikely. Given the lack of faulting and fracturing discussed above, leakage through small undetected faults or fractures (if presented and not yet observed) would be contained by the overlying high-quality sealing formations, resulting in no CO_2 leakage to surface. Shute Creek states that if a CO_2 leak were to occur through the confining zone due to faults or fractures, it would most likely occur during active injection.

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

3.4 Leakage through the Formation Seal

According to the MRV plan, the ultimate top seal to the disposal reservoir is provided by the evaporitic sequences within the Thaynes Formation. The MRV plan states that the natural seal is the reason that the LaBarge gas field exists in the first place – the gas has been trapped in the LaBarge structure over a large amount of geologic time. The rock that forms the natural seal is impermeable to helium (He), a gas with a much smaller molecular volume than CO_2. Thus, if the reservoir seal material is impermeable to He, then it follows that it is also impermeable to CO_2. Shute Creek states the Thaynes Formation's sealing effect is also demonstrated by the fact that all gas production shallower than the Thaynes is void of sour gases, while all gas production below it is enriched in sour gases. The MRV plan states that although natural creep of the salty sediments below the Nugget Formation is possible, this behavior does not disturb the sediments to the degree necessary to breach the reservoir seal of the Madison Formation. Further, if this salty sediment were to flow on a scale large enough to create a leakage pathway from the Madison Formation to the surface, Shute Creek acknowledges that natural gases trapped in the formation would have leaked into the atmosphere during the long course of geological time. The MRV plan asserts that because the gas remains trapped at pressure in the Madison Formation, it must follow that any natural reactivation or flowage of salt-rich sediments that has occurred over the geological history of the LaBarge field area has not created any pathways for gas leakage to the surface.

According to the MRV plan, based on results of the site characterization including the sealing capacity of confining intervals and Triassic evaporitic sequences and the operational limitations on injections pressures, CO_2 leakage to the surface via faults or fractures is highly unlikely. Given the number, thickness, and quality of the confining units above the Madison and Bighorn-Gallatin injection intervals, any potential CO_2 leakage to the surface would be negligible. Shute Creek states that if a CO_2 leak were to occur through the multiple formation seals, it would most likely occur during active injection.

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

3.5 Leakage through Natural or Induced Seismicity

As stated in the MRV plan, there is a low level of background seismicity in the greater Moxa Arch area. There has been no observed evidence of faulting in the Madison interval using commercially available 2D seismic data within 13.5 miles of the proposed CO_2 injection well sites. The MRV plan also states that there has also been no reported seismic activity attributed to active injection operations at the AGI injection wells. Shute Creek states that the nearest induced seismic events were observed over 20 miles to the southwest of the proposed SC 7-34 well site. These are attributed to mineral mining operations, and not naturally occurring geological fault activity. The closest naturally occurring seismic activity was a 1.8 magnitude earthquake in 1983 located 7.2 miles to the west at a depth of 10.1 miles according to the Advanced National Seismic System (ANSS) Catalogue and the Wyoming State Geological Survey's (WSGS) historic records. Significant earthquake activity is defined as >3.5 Richter scale. The nearest recorded significant naturally occurring earthquake activity (> M3.5) has been detected over 50 miles away to the west in Idaho and Utah. Reported earthquake activity is believed to be related to the easternmost extension of the Basin and Range province, unrelated to the Moxa Arch.

The MRV plan also states that additional geomechanical modeling has been completed in the area around the AGI and CO_2 injection well sites. The modeling was completed to understand the potential for fault slip on the Darby fault far west of the injection and disposal sites. No fault slip is observed at the simulated fault locations or throughout the model. Lack of fault slip then equates to lack of modeled induced seismicity from injection.

According to the MRV plan, due to the lack of significant earthquake activity in the area, the lack of induced seismicity over the period of injection at the AGI wells, and the geomechanical modeling results showing a lack of fault slip, Shute Creek considers the likelihood of CO_2 leakage to surface caused by natural or induced seismicity to be unlikely. Shute Creek states that if a leak of CO_2 to the surface occurs as a result of a seismic event, it would likely occur at the time of the seismic event or shortly thereafter.

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

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

40 CFR 98.448(a)(3) requires that an MRV plan contains a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan includes a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Section 5 of the amended MRV plan discusses the strategy that Shute Creek will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in the previous section to meet the requirements in 40 CFR 98.448(a)(3). As part of ongoing operations, Shute Creek continuously monitors and collects flow, pressure, temperature, and gas composition data in the DCS. This data is monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. Additionally, Shute Creek maintains in-field gas detectors to detect H_2S and CO_2 in the vicinity. If one of the gas detectors alarms, it would trigger an immediate response to address the situation. In some instances, more than one detector alarming will trigger automatic equipment isolation/shutdown to mitigate the leak. The MRV plan states that leakage detection for the wells will incorporate several monitoring programs including visual inspection of the surface facilities and wellheads, injection well monitoring and mechanical integrity tests (MIT), and DCS surveillance. A summary table of Shute Creek's detection strategies can be found in Table 5.1 of the MRV plan and is reproduced below.

Potential Leakage Pathway	Detection Monitoring Program	Monitoring Location
Surface Equipment	DCS Surveillance Visual Inspections Inline Inspections Gas Alarms Personal H_2S Monitors	From injection flow meter to injection wellhead
Wells	DCS Surveillance Visual Inspections MIT Gas Alarms Personal H_2S Monitors	Injection well – from wellhead to injection formation
Faults and Fractures, Formation Seal, Lateral Migration	DCS Surveillance Gas Alarms	Injection well – from wellhead to injection formation
Natural or Induced Seismicity	DCS Surveillance Gas Alarms ANSS Catalogue	Injection well – from wellhead to injection formation Regional data

The MRV plan states that responses to leaks are covered in Shute Creek's Emergency Response Plan (ERP), which is updated annually. If there is a report or indication of a leak from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-person control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and H_2S monitors for the AGI site and CO_2 monitors for the CO_2 injection site will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Pressure from the system will be relieved to the flare, not vented, due to the dangerous composition of the gas. The MRV plan also states that the ERP will be updated to include the CO_2 injection facilities and corresponding wells after commencement of operations. If a leak occurs at the CO_2 injection site, pressure from the affected CO_2 injection well will be relieved locally to atmosphere within the well site fence line.

4.1 Detection of Leakage from Surface Equipment

The MRV plan states that field personnel monitor the AGI facility continuously through the Distributed Control System (DCS). Additionally, daily visual inspection rounds are conducted of the AGI facility and weekly visual inspections are conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner Once leakage has been detected and confirmed, Shute Creek will estimate the mass of CO_2 emitted from leakage points at the surface based on operating conditions at the time of the release – pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of leak. The annual mass of CO_2 that is emitted by surface leakage will be calculated in accordance with Equation RR-10.

Table 5.1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected from surface equipment. Thus, the MRV plan provides adequate characterization of Shute Creek's approach to detect potential leakage from surface equipment as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through AGI and CO_2 Wells

The MRV plan states that the facility reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and annual MIT. Gas detectors located at the well sites which alarm at 10 ppm H_2S and 5,000 ppm CO_2 would be triggered if a leak from the wellbore to the atmosphere occurred. If there is indication of a leak, leakage through AGI and CO_2 wells will be estimated once leakage has been detected and confirmed. Shute Creek will take actions to quantify the leak and estimate the mass of CO_2 emitted based on operating conditions at the time of the release – pressure and flow rate, size of the leakage point opening, and estimated duration of leak.

Table 5.1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through AGI and CO_2 wells. Thus, the MRV plan provides adequate characterization of Shute Creek's approach to detect potential leakage through existing wells as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage through Faults and Fractures, Formation Seal, or Lateral Migration

The MRV plan states that Shute Creek continuously monitors and collects flow, pressure, temperature, and gas composition data in the DCS. This data is monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. If there is indication of leakage of CO_2 through faults and fractures, the formation seal, or lateral migration as potentially indicated by abnormal operational data, Shute Creek will take actions to quantify the leak (e.g., reservoir modeling and engineering estimates) and take mitigative actions to stop leakage. Given the unlikelihood of leakage from these pathways, the facility will estimate mass of CO_2 detected leaking to the surface in these instances on a case-by-case basis utilizing quantification methods such as engineering analysis of surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the reservoir performance.

Table 5.1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through faults, fractures, formation seal, or lateral migration. Thus, the MRV plan provides adequate characterization of Shute Creek's approach to detect potential leakage through faults, fractures, formation seal, or lateral migration as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage through Natural or Induced Seismicity

As stated in the MRV plan, there is low level of background seismicity detected in the area. If a seismic event occurs at the time of AGI or CO_2 injection, Shute Creek will consult the ANSS Catalogue to verify whether the seismic event was due to the injection in the AGI or CO_2 injection wells and quantify any leak of CO_2 to the surface based on operating conditions at the time of the event – pressure and flow rate, size of the leakage point opening, and estimated duration of leak.

Relying on the DCS infrastructure and operating procedures in place at the existing facility, Shute Creek uses existing automatic data systems to identify and investigate excursions from expected performance that could indicate CO_2 leakage.

Table 5.1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through natural or induced seismicity. Thus, the MRV plan provides adequate characterization of Shute Creek's approach to detect potential leakage through natural or induced seismicity as required by 40 CFR 98.448(a)(3).

4.5 Determination of Baselines

Section 7 of the MRV plan identifies the strategies that Shute Creek will use to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR 98.448(a)(4). Shute Creek uses existing automatic data systems to identify and investigate excursions from expected performance that could indicate CO_2 leakage. The following describes Shute Creek's approach to collection baseline information.

Visual Inspections

The MRV plan states that field personnel conduct daily inspections of the AGI facility and weekly inspections of the AGI well sites. The CO_2 injection facility and well sites will undergo weekly visual inspections. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize the possibility of CO_2 leakage. If an issue is identified, a work order will be generated to correct the issue.

H_2S Detection

The MRV plan states that CO_2 injected into the AGI wells is injected with H_2S at a concentration of 50 - 65% (500,000 - 650,000 ppm). H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. Additionally, all field personnel are required to wear H_2S monitors, which alarm at 5 ppm. Any gas detector alarm or personal H_2S monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the gas detectors and monitors are working correctly.

CO_2 Detection

Shute Creek states that the CO_2 injected into the CO_2 injection wells will be at a concentration around 99%. CO_2 gas detectors will be installed around the well site, which trigger 0.5% CO_2. The MRV plan asserts that at this concentration, CO_2 leakage would trigger an alarm.

Continuous Parameter Monitoring

The MRV plan states that the DCS of Shute Creek 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 this allowable window, this will trigger further investigation to determine if the issue poses a leak threat.

Well Testing

Shute Creek states that on an annual basis, the subsurface and wellhead valves are leak tested for mechanical integrity testing as required by the WOGCC. Results from this type of testing are compared to previous MIT data to evaluate whether well integrity has been compromised.

Additionally, inline inspections are conducted of the AGI flow lines using a smart pig to identify potential areas of corrosion in the pipeline. Results from this type of testing are compared to previous data to evaluate whether pipeline integrity has been compromised. The operations at Shute Creek will have the ability to conduct inline inspections on the SC 5-2 flow lines, however inline inspections are not anticipated to occur frequently because no free water is expected to accumulate due to the low dew point of the fluid.

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

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

5.1 Calculation of Mass of CO_2 Received

The MRV plan states that since the CO_2 received by the AGI and CO_2 injection wells is wholly injected and not mixed with any other supply of CO_2, the annual mass of CO_2 received would be equal to the annual mass of CO_2 injected. Shute Creek states that no CO_2 is received in containers.

Shute Creek provides an acceptable approach to calculating the mass of CO_2 received in accordance with subpart RR requirements.

5.2 Calculation of Mass of CO_2 Injected

As stated in the MRV plan, volumetric flow meters are used to measure the injection volumes at the AGI wells and are proposed for use to measure the injection volumes at the CO_2 injection wells. Equation RR-5 will be used to calculate the annual total mass of CO_2 injected. Equation RR-6 will be used to aggregate injection data for the AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34 wells.

Shute Creek provides an acceptable approach to calculating the mass of CO_2 injected in accordance with subpart RR requirements.

5.3 Calculation of Mass of CO_2 Produced

The MRV plan states that the facility will not produce injected CO_2, therefore will not calculate produced

CO_2 according to the requirements of subpart RR. As explained in Section 3.2 of the MRV plan, the distance (approximately 43 miles) between the injection site and the LaBarge production field area and the LaBarge's geologic structure ensures that injected CO_2 will not come into contact with production wells. Figure 2.7 of the MRV plan further illustrates the relationship between the injection and production sites. Based on this and other modeling information presented in the MRV plan, it is a reasonable conclusion that the facility will not produce any injected CO2.

Shute Creek provides an acceptable approach to calculating the mass of CO_2 injected in accordance with subpart RR requirements.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage and Equipment Leaks

The MRV plan states that due to the high H_2S concentration of the AGI fluids and the high CO_2 concentration of the CO_2 injection fluid, fugitive leakage would be detected and managed as an upset event in the same way that CO_{2E} (CO_2 emitted by surface leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time, including pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of the leak. As states in the MRV plan, gas detectors are in operation continuously to survey the area for leaks; even a small leak would trigger an alarm. Parameter CO_{2FI} (total CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead) will be calculated in accordance with procedures outlined in subpart W as required by 40 CFR 98.444(d). At the AGI wells, there are no CO_2 emissions from venting due to the high H_2S concentration of the acid gas; blowdown emissions are sent to the flares and are reported under subpart W. This process occurs upstream of the flow meter and would therefore not contribute to the CO_{2FI} calculation. At the CO_2 injection wells, venting would occur in the event of depressurizing for maintenance or testing, which would be measured during time of event consistent with 40 CFR 98.233.

Shute Creek provides an acceptable approach to calculating the mass of CO_2 emitted by surface leakage and equipment leaks in accordance with subpart RR requirements.

5.5 Calculation of Mass of CO_2 Sequestered in Subsurface Geologic Formations

According to the MRV plan, since Shute Creek is not actively producing oil or natural gas or any fluids as part of the AGI process or CO_2 injection processes, Equation RR-12 will be used to quantify CO_2 injected and sequestered. Parameter CO_{2I} (total CO_2 injected through all injection wells) will be determined using Equation RR-5, as outlined above in Section 7.2 of the MRV plan. Parameters CO_{2E} and CO_{2FI} will be measured using the leakage quantification procedure described above.

Shute Creek provides an acceptable approach to calculating the mass of CO_2 sequestered in subsurface geologic formations in accordance with subpart RR requirements. EPA notes that if the conditions at the facility were to change such that the facility produced previously injected CO_2, then the facility may be required to use equation RR-11 and revise the MRV plan per 40 CFR 98.448(d).

6 Summary of Findings

The subpart RR MRV plan for Shute Creek Facility meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specify the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the Shute Creek MRV plan.

Subpart RR MRV Plan Requirement	Shute Creek Facility MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 3 of the MRV plan describes the MMA and AMA. The AMA boundary was established by superimposing the area based on a half-mile buffer around the anticipated plume location when the plume has reached stability (2205 for AGI and CO_2 injection wells). Since the AMA boundary was determined to fall within the MMA boundary, the defined MMA was also used to define the effective AMA.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 4 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: leakage from surface equipment; leakage through AGI and CO_2; leakage through faults and fractures; leakage through the seal; and leakage from natural or induced seismicity. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Sections 5 7 of the MRV plan describe the strategy for how the facility would detect CO_2 leakage to the surface and how the leakage would be quantified, should leakage occur. Leaks would be detected using methods such as SCADA systems, MITs, groundwater sampling, and in-field monitors.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 6 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 7 of the MRV plan describes Shute Creek's approach to determining the amount of CO_2 sequestered using the subpart RR mass balance equation, including as related to calculation of total annual mass emitted from equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 1 of the MRV plan provides the well identification numbers for the Shute Creek wells (API No. 49-023-21687, 49-023-21674, 49-023-22499, 49-023-22500). WOGCC classifies the AGI, SC 5-2, and SC 7-34 wells in LaBarge as UIC Class II wells.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 8 of the MRV plan states that the mass of CO_2 sequestered in subsurface geologic formations is actively being calculated since this is a resubmission of a previously approved MRV plan.

Appendix A: Final MRV Plan

ExxonMobil Shute Creek Treating Facility Subpart RR Second Amended Monitoring, Reporting and Verification Plan

February 2025

Table of Contents

Introduction

Exxon Mobil Corporation (ExxonMobil) operates two acid gas injection (AGI) wells, AGI 2-18 and AGI 3-14 (collectively referred to as "the AGI wells") in the Madison Formation located near LaBarge, Wyoming for the primary purpose of acid gas disposal with a secondary purpose of geologic sequestration of carbon dioxide (CO_2) in a subsurface geologic formation. The acid gas and CO_2 injected into the AGI wells are components of the natural gas produced by ExxonMobil from the Madison Formation. ExxonMobil has been operating the AGI wells since 2005 and intends to continue injection until the end-of-field-life of the LaBarge assets. The AGI wells and facility (as further described in Section 2.7.1), located at the Shute Creek Treating Facility (SCTF), have been operational since 2005 and have been subject to the February 2018 monitoring, reporting, and verification (MRV) plan approved by EPA in June 2018 (the February 2018 MRV plan).

Because the volume of CO_2 associated with the natural gas production is greater than the volume that is able to be injected into the AGI wells, ExxonMobil is in the process of developing the Shute Creek (SC) 5-2 and SC 7-34 wells (collectively referred to as the "CO_2 injection wells" or "CO_2 disposal wells")[1] for the purpose of geologic sequestration of fluids consisting primarily of CO_2 in subsurface geologic formations. Like the AGI wells, the fluids that will be injected into the CO_2 injection wells are also components of the natural gas produced by ExxonMobil from the Madison Formation. Once operational, the CO_2 injection wells are expected to continue injection until the end-of-field life of the LaBarge assets.

ExxonMobil received the following approvals by the Wyoming Oil and Gas Conservation Commission (WOGCC) to develop the SC 5-2 well:

- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Madison Formation on November 12, 2019
- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Phosphoria, Weber, and Bighorn-Gallatin formations[2] on October 12, 2021
- Application for permit to drill (APD) on June 30, 2022

ExxonMobil received the following approvals by the WOGCC to develop the SC 7-34 well:

- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Madison and Bighorn-Gallatin formations on August 13, 2024
- APD on May 20, 2024

In October 2019, ExxonMobil submitted an amendment to the February 2018 MRV plan in accordance with 40 CFR §98.440-449 (Subpart RR – Geologic Sequestration of Carbon Dioxide) to provide for the monitoring, reporting and verification of geologic sequestration of CO_2 in the Madison Formation during the injection period for the SC 5-2 well (the October 2019 MRV plan). The October 2019 Amended MRV plan was approved by EPA on December 19, 2019.

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[1] *The terms "dispose" and "inject" and their variations may be used interchangeably throughout this document.*

[2] *While the Phosphoria and Weber formations were conditionally approved as exempted aquifers for disposal of fluids, these formations are no longer targets for the SC 5-2 and will not be addressed further in this document*

This second amended plan, dated October 2024 ("Second Amended MRV Plan") will address all wells collectively when applicable, and otherwise broken out into sub sections to address the specifics of the AGI wells and CO_2 injection wells respectively, as appropriate. This Second Amended MRV Plan meets the requirements of 40 CFR §98.440(c)(1).

The February 2018 MRV plan is the currently applicable MRV plan for the AGI wells. The October 2019 Amended MRV plan would have become the applicable plan once the SC 5-2 well began injection operations. ExxonMobil anticipates the SC 5-2 well will begin injection operations in 2025 and the SC 7-34 well will begin injection operations in 2026. At that time, this Second Amended MRV Plan will become the applicable plan for the AGI wells and CO_2 injection wells collectively, and will replace and supersede both the February 2018 and October 2019 Amended MRV plans. At that time, ExxonMobil will continue reporting under Subpart RR for the AGI wells, but will begin including the CO_2 injection wells on or before March 31 of the year after their respective injection begins. Once applicable, ExxonMobil anticipates this Second Amended MRV Plan will remain in effect until the end-of-field-life of the LaBarge assets, unless and until it is subsequently amended and superseded.

This Second Amended MRV Plan contains ten sections:

1. Section 1 contains facility information.

2. Section 2 contains the project description. This section describes the geology of the LaBarge Field, the history of the LaBarge field, an overview of the injection program and process, and provides the planned injection volumes. This section also demonstrates the suitability for secure geologic storage in the Madison and Bighorn-Gallatin formations.

3. Section 3 contains the delineation of the monitoring areas.

4. Section 4 evaluates the potential leakage pathways and demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

5. Section 5 provides information on the detection, verification, and quantification of leakage. Leakage detection incorporates several monitoring programs including routine visual inspections, hydrogen sulfide (H_2S) and CO_2 alarms, mechanical integrity testing of the well sites, and continuous surveillance of various parameters. Detection efforts will be focused towards managing potential leaks through the injection wells and surface equipment due to the improbability of leaks through the seal or faults and fractures.

6. Section 6 describes the determination of expected baselines to identify excursions from expected performance that could indicate CO_2 leakage.

7. Section 7 provides the site specific modifications to the mass balance equation and the methodology for calculating volumes of CO_2 sequestered.

8. Section 8 provides the estimated schedule for implementation of the Second Amended MRV Plan.

9. Section 9 describes the quality assurance program.

10. Section 10 describes the records retention process.

1.0 Facility Information

1. Reporter number: 523107

   The AGI wells currently do, and the CO_2 injection wells will, report under the Shute Creek Treating Facility (SCTF) Greenhouse Gas Reporting Program Identification number, which is: 523107.
2. Underground Injection Control (UIC) Permit Class: Class II

   The WOGCC regulates oil and gas activities in Wyoming. WOGCC classifies the AGI, SC 5-2, and SC 7-34 wells in LaBarge as UIC Class II wells.
3. UIC injection well identification numbers:

Well Name	*Well Identification Number*
AGI 2-18	49-023-21687
AGI 3-14	49-023-21674
SC 5-2	49-023-22499
SC 7-34	49-023-22500

2.0 Project Description

This section describes the planned injection volumes, environmental setting of the LaBarge Field, injection process, and reservoir modeling.

2.1 Geology of the LaBarge Field

The LaBarge field area is located in the southwestern corner of Wyoming, contained in Lincoln and Sublette counties. The producing field area is within the Green River Basin and the field is located due west of the Wind River Mountains along the Moxa Arch (Figure 2.1).

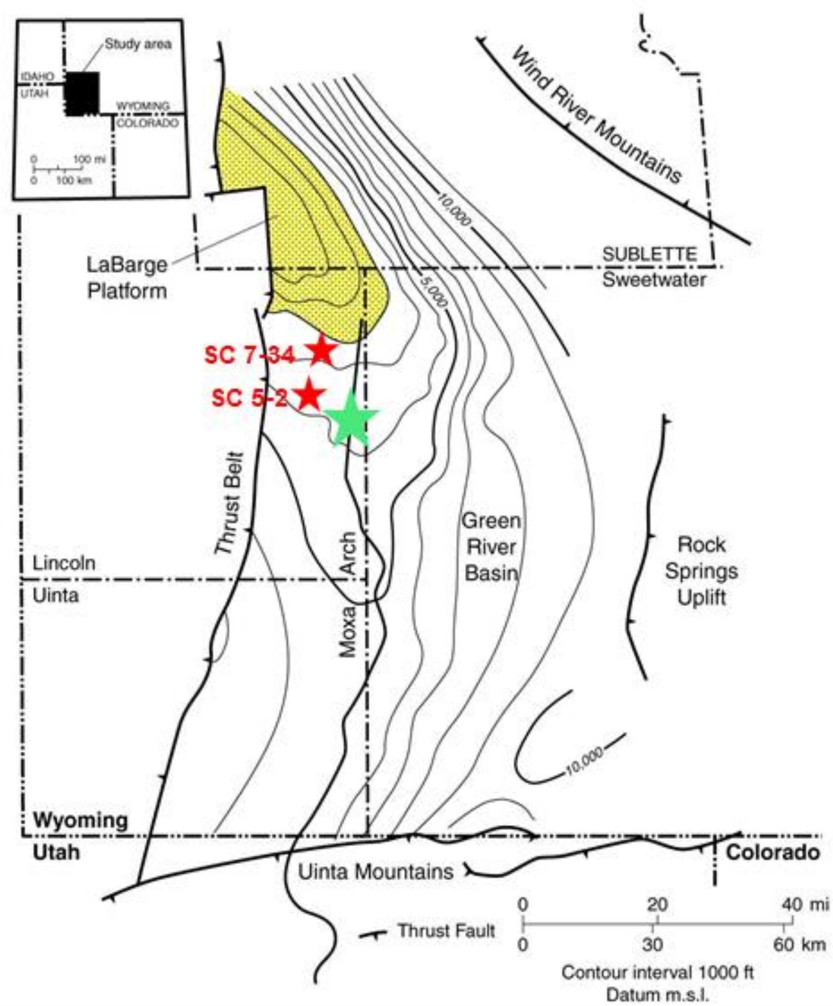

Figure 2.1 Location Map of the LaBarge Field, Wyoming. The location of the AGI wells is denoted with a green star, and the location of the CO_2 injection wells are denoted by the red stars.

2.2 Stratigraphy of the Greater LaBarge Field Area

The western region of Wyoming has been endowed in a very rich and prolific series of hydrocarbon reservoirs. Hydrocarbon production has been established or proven from a large number of stratigraphic intervals around Wyoming, ranging from reservoirs from Cenozoic to Paleozoic in age. Figure 2.2 shows a complete stratigraphic column applicable to the Greater Green River Basin in western Wyoming.

For the LaBarge field area, specifically, commercially producible quantities of hydrocarbons have been proven in the following intervals:

1. Upper Cretaceous Frontier Formation
2. Lower Cretaceous Muddy Formation
3. Permian Phosphoria Formation
4. Lower Jurassic Nugget Formation
5. Pennsylvanian Weber Formation
6. Mississippian Madison Formation

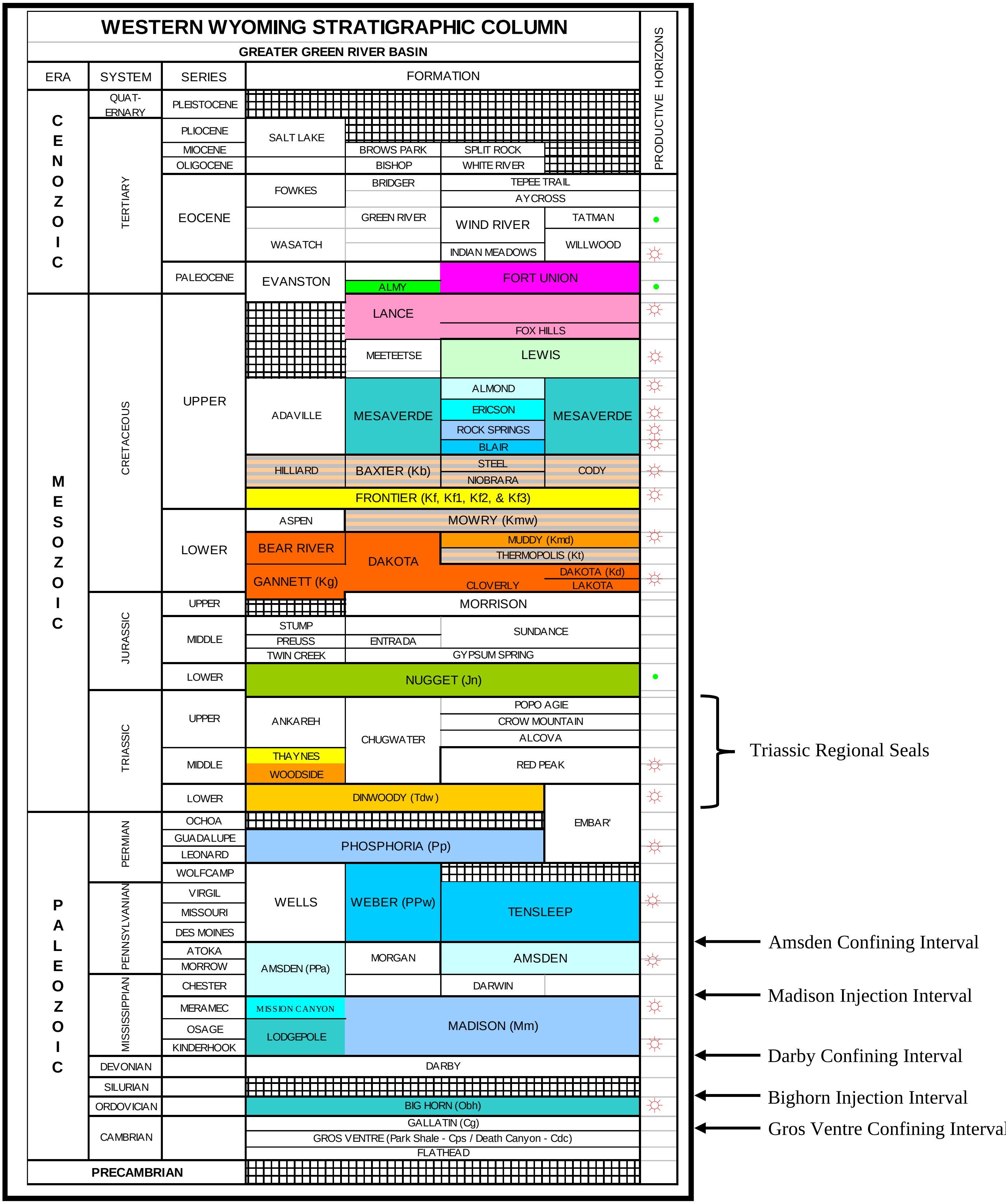

Figure 2.2 Generalized Stratigraphic Column for the Greater Green River Basin, Wyoming

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 closure to 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 (Figure 2.3).

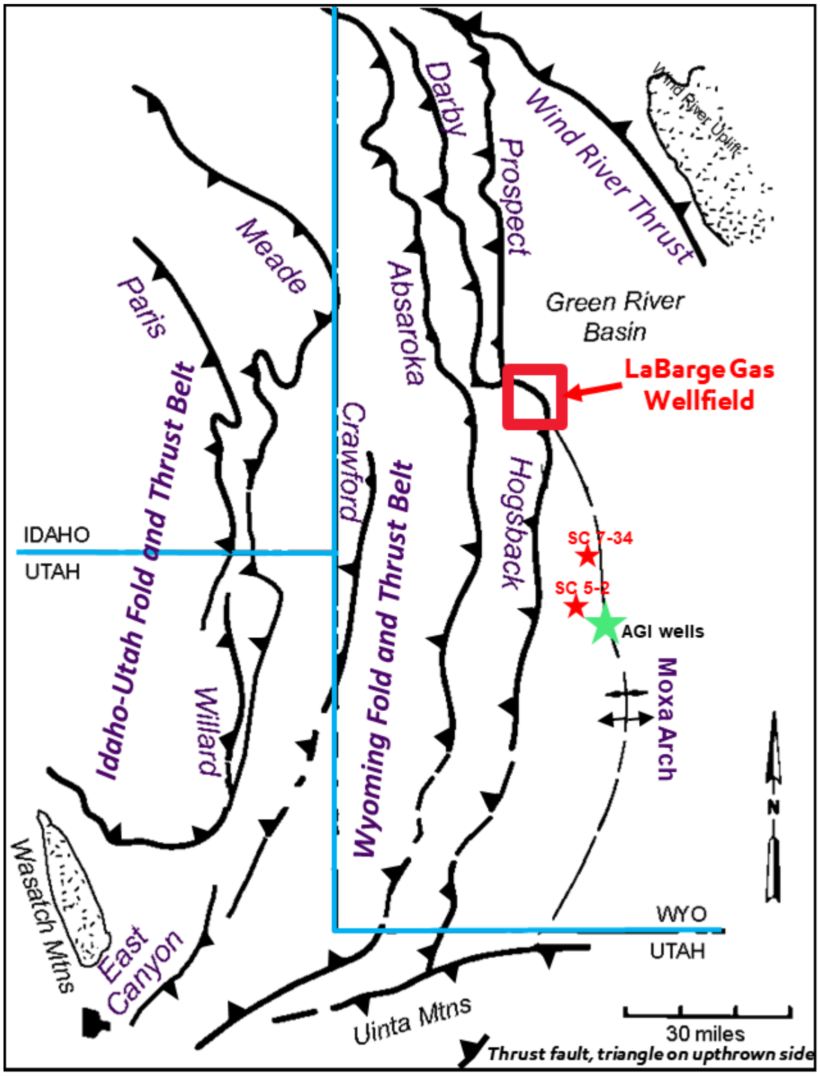

Figure 2.3 Schematic map showing location of Moxa Arch and regional thrust faults. The LaBarge field area is denoted by the red box. The approximate location of the AGI wells is denoted with a green star, and the approximate location of the CO_2 injection wells are denoted by the red stars.

The historical evaluation of structural styles at LaBarge has revealed that three principal styles of structuring have occurred in the area:

1. Basement-involved contraction
2. Deformation related to flowage of salt-rich Triassic strata
3. Basement-detached contraction

2.3.1 Basement-involved Contraction Events

Basement-involved contraction has been observed to most commonly result in thrust-cored monoclinal features being formed along the western edge of the LaBarge field area (Figure 2.3). These regional monoclinal features have been imaged extensively with 2D and 3D seismic data, and are easily recognizable on these data sets (Figure 2.4). At a smaller scale, the monoclinal features set up the LaBarge field structure, creating a hydrocarbon trapping configuration of the various reservoirs contained in the LaBarge productive section.

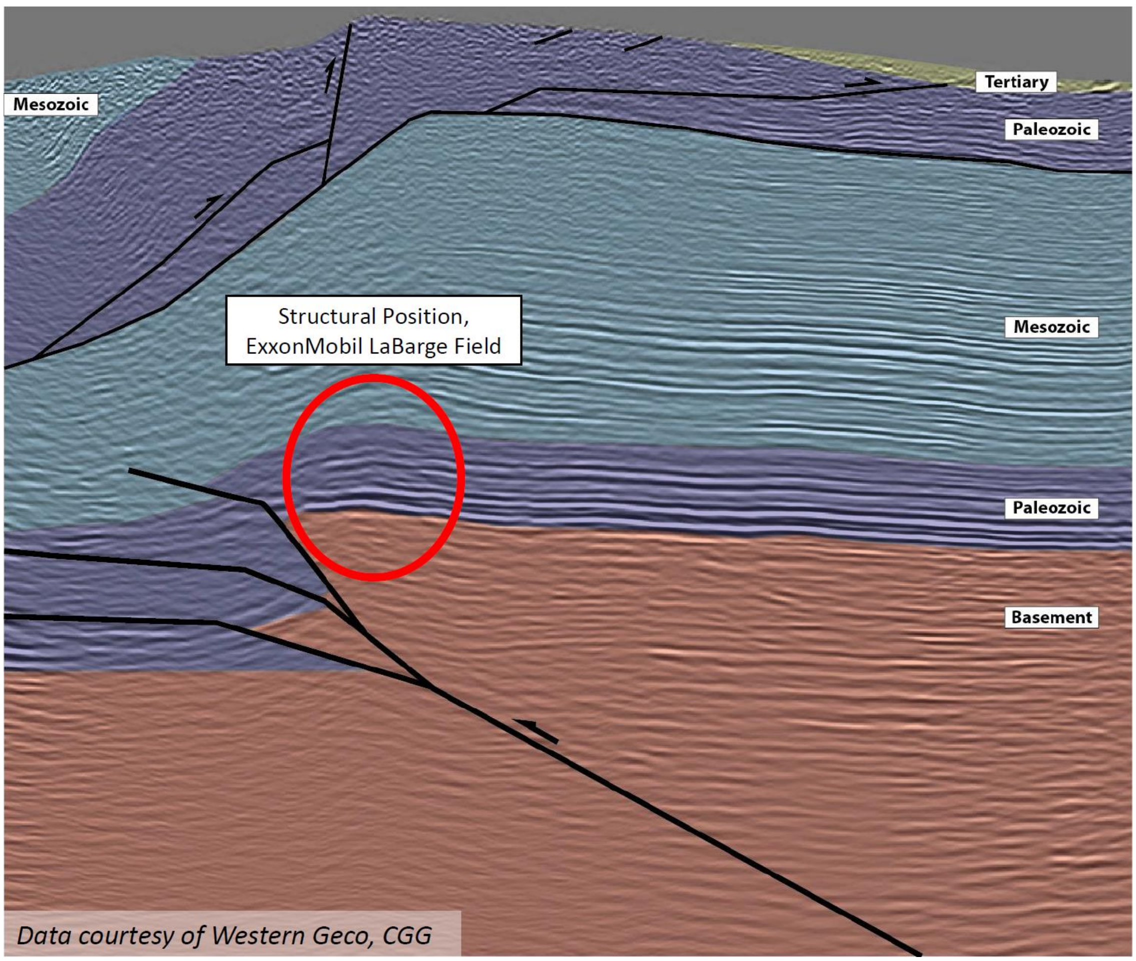

Figure 2.4 Example of thrust-cored monoclinal feature interpreted from 2D seismic data. The thrust-cored feature is believed to be a direct product of basement-involved contractional events.

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 outcrop 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 2.5 shows two seismic lines showing the Triassic salt-rich sediments and the 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.

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 many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. Subsequent drilling at LaBarge has used thicker-walled casing strings to successfully mitigate this sediment flowage issue.

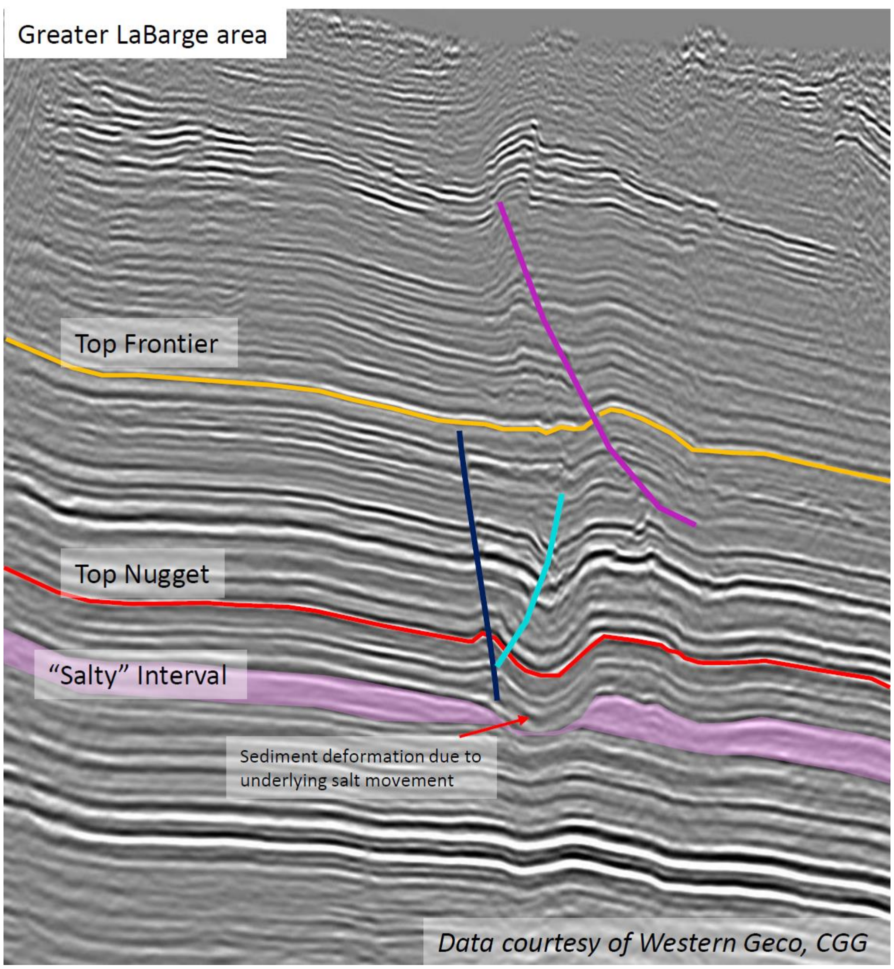

Figure 2.5 Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge field area

2.3.3 Basement-detached Contraction

The third main structural style observed at LaBarge field is those resultant from basement-detached contraction. These features have been well-documented, historically at LaBarge as many of these features have mapped fault expressions on the surface. Detachment and contraction along the basement typically creates three types of structural features:

1. Regional scale thrust faults
2. Localized, smaller scale thrust faults
3. Reactivation of Triassic salt-rich sediments resulting in local structural highs (section 2.3.2)

The basement-detached contraction features typically occur at a regional scale. The subsurface structural features formed through these contractional events are the same size or larger than the greater LaBarge field area. Very large faults are usually associated with these subsurface features, albeit via the reactivation of Triassic salt sediments which can result in additional localized structuring in the area (section 2.3.2).

2.3.4 Faulting and Fracturing of Reservoir Intervals

Reservoir permeability has been observed to increase with the presence of small-scale faults and fractures in almost all of the productive intervals of LaBarge field. Micro-fractures have been observed in core and on formation micro imager (FMI) logs. The fractures seen in the available core are typically filled with calcite, in general.

Empirically, reservoir permeability and increased hydrocarbon productivity have been observed in wells/penetrations that are correlative to areas located on or near structural highs or fault junctions. These empirical observations tend to suggest that these areas have a much higher natural fracture density than other areas or have a larger proportion of natural fractures that are open and not calcite filled. Lack of faulting, as is observed near areas adjacent to the AGI, SC 5-2, and SC 7-34 wells at LaBarge, tends to yield reservoir permeability that is dominated only by matrix or pore-to-pore flow that is generally inhibitive to fluid flow in the subsurface over long distances.

2.3.5 LaBarge Field Structure and Gas Resource of the Madison Formation

Structural closure on the Madison Formation at the LaBarge field is quite large, with approximately 4,000' true vertical depth (TVD) of structural closure from the top of the structure to the gas-water contact (GWC). Spatially, the Madison closure covers over 1,000 square miles making it one of the largest gas fields in North America.

The Madison Formation is estimated to contain in excess of 170 trillion cubic feet (TCF) of raw gas and 20 TCF of natural gas (CH_4). At current rates of production, the estimated remaining field life is over 100 years. Spatially, the AGI and CO_2 injection wells have been located at or immediately adjacent to the SCTF, over 40 miles to the southeast from the main LaBarge production areas.

2.4 History of the LaBarge Field Area

The LaBarge field was initially discovered in 1920 with the drilling of a shallow oil producing well. The generalized history of the LaBarge field area is as follows:

- 1907 Oil seeps observed near LaBarge, surface mapping of Tip Top anticline
- 1920 Texas Production Company drills shallow Hilliard sandstone discovery (10 BOPD)
- 1940's General Petroleum (G.P.) (Mobil) explores LaBarge area, surface and seismic mapping
- 1951 Tip Top Field discovered by G.P. (Frontier SS @ 1.8 MCFD, Nugget SS @ 266 BOPD)
- 1952 Belco discovers Frontier gas at Big Piney and LaBarge
- 1954 Belco commits gas to Pacific NW Pipeline, 33 SI gas wells
- 1956 Pacific NW Pipeline completed
- 1956-64 Active drilling of Frontier wells (structural traps)
- 1962 Mobil discovers Madison LS gas at Tip Top, chooses not to develop
- 1970 Exxon evaluates LaBarge area
- 1975-84 2nd major phase of Frontier drilling (stratigraphic traps)
- 1980 Section 29 of Oil Windfall Tax Act for tight gas sands passed (expired 01/01/94)
- 1981 Exxon discovers Madison gas on Lake Ridge Unit (LRU 1-03)
- 1986 First sales of Exxon Madison gas
- 1992 WOGCC approves 160 acre spacing for Frontier
- 1989-95 Chevron, Enron, PG & E, and Mobil actively drill Frontier targets
- 1999 Exxon and Mobil merge
- 2001-03 Active drilling of Acid Gas Injection wells 2-18 and 3-14
- 2005 Acid Gas Injection wells 2-18 and 3-14 begin operation
- 2019 WOGCC approves SC 5-2 CO_2 injection well
- 2022 Transfer of ownership of shallow horizons on TipTop and Hogsback
- 2023 Active drilling of SC 5-2 CO_2 injection well
- 2024 WOGCC approves SC 7-34 CO_2 injection well

Historically, Exxon held and operated the Lake Ridge and Fogarty Creek areas of the field, while Mobil operated the Tip Top and Hogsback field areas (Figure 2.6). The heritage operating areas were combined in 1999, with the merger of Exxon and Mobil to form ExxonMobil, into the greater LaBarge operating area. In general, heritage Mobil operations were focused upon shallow sweet gas development drilling while heritage Exxon operations focused upon deeper sour gas production.

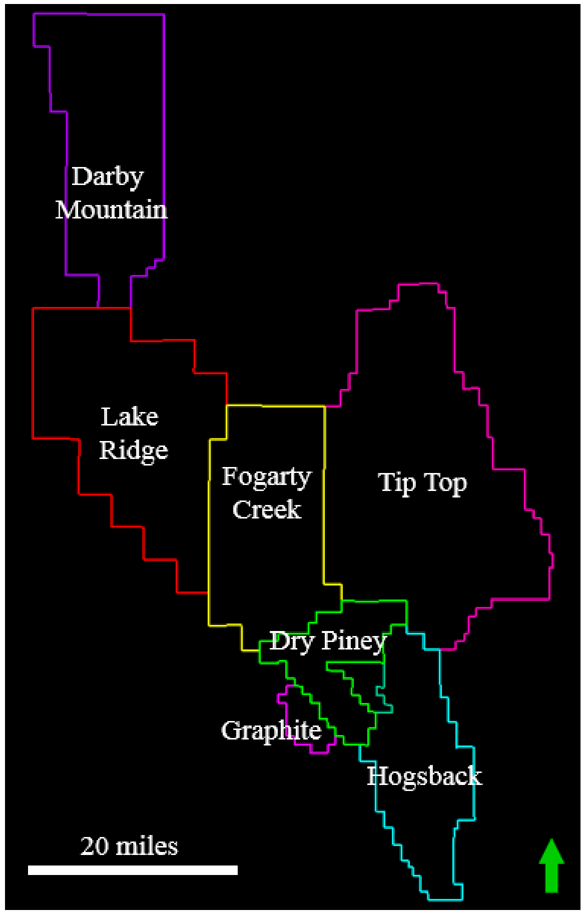

Figure 2.6 Historical unit map of the greater LaBarge field area prior to Exxon and Mobil merger in 1999

2.5 Initial Discovery of Gas and Early Commercial Production at LaBarge

ExxonMobil's involvement in LaBarge originates in the 1960's with Mobil's discovery of gas in the Madison Formation. The Madison discovery, however, was not commercially developed until much later in the 1980's following Exxon's Madison gas discovery on the Lake Ridge Unit. Subsequently, initial commercial gas production at LaBarge was first established in the Frontier Formation, while commercial oil production was established in the Nugget Formation.

Gas production from the Madison Formation was initiated in 1986 after the start-up of the SCTF, which expanded capacity to handle Madison gas. The total gas in-place for the Madison Formation at LaBarge is in excess of 170 TCF gross gas and is a world-class gas reserve economically attractive for production.

2.6 Gas Injection Program History at LaBarge

The Madison Formation, once commercial production of gas was established, was found to contain relatively low methane (CH_4) concentration and high carbon dioxide (CO_2) content. The average properties of Madison gas are:

1. 21% CH_4

2. 66% CO_2
3. 7% nitrogen (N_2)
4. 5% hydrogen sulfide (H_2S)
5. 0.6% helium (He)

Due to the abnormally high CO_2 and H_2S content of Madison gas, the CH_4 was stripped from the raw gas stream leaving a very large need for disposal of the CO_2 and H_2S that remained. For enhanced oil recovery (EOR) projects, CO_2 volumes have historically been sold from LaBarge to offset oil operators operating EOR oilfield projects. Originally, the SCTF contained a sulfur recovery unit (SRU) process to transform the H_2S in the gas stream to elemental sulfur. In 2005, the SRU's were decommissioned to debottleneck the plant and improve plant reliability. This created a need to establish reinjection of the H_2S, and entrained CO_2, to the subsurface.

2.6.1 Geological Overview of Acid Gas Injection and CO_2 Injection Programs

Sour gas of up to 66% CO_2 and 5% H_2S is currently produced from the Madison Formation at LaBarge. The majority of produced CO_2 is currently being sold by ExxonMobil to other oilfield operators and is being used in EOR projects in the region. The sold volume however, does not equal the total produced CO_2 and H_2S volumes, thereby requiring disposal.

ExxonMobil has pursued the AGI program as a safe and reliable method to re-inject the acid gas into the Madison Formation into the aquifer below the field GWC. Gas composition in the AGI wells is based on plant injection needs, and will vary between 35 - 50% CO_2 and 50 - 65% H_2S. The acid gas is injected at a depth of ~17,500 feet below the surface and approximately 43 miles away from the main producing areas of LaBarge.

The volume of CO_2 sold and CO_2 injected into the AGI wells does not equal the volume of CO_2 produced, so additional injection wells are required (SC 5-2 and SC 7-34). Gas composition to be injected into the CO_2 injection wells is planned to be approximately 99% CO_2 with minor amounts of methane, nitrogen, carbonyl sulfide (COS), ethane, and H_2S. For the SC 5-2 well, the gas is planned to be injected between depths of ~17,950 feet and ~19,200 feet measured depth (MD) approximately 35 miles away from the main producing areas of LaBarge. For the SC 7-34 well, the gas is planned to be injected between depths of ~16,740 feet and ~18,230 feet MD approximately 30 miles away from the main producing areas of LaBarge.

2.6.2 Reservoir Quality of Madison and Bighorn-Gallatin Formations at Injection Well Locations

The existing AGI wells were successfully drilled, logged, and evaluated prior to injection commencement. Figure 2.7 is a schematic diagram showing the relative location of AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34. Figures 2.8 and 2.9 are structure maps for the Madison and Bighorn-Gallatin formations, respectively, showing the relative location of the four wells.

Figure 2.10 shows Madison well logs for SC 5-2, AGI 3-14, and AGI 2-18. Petrophysical evaluation of these wells indicate that Madison limestone and dolomite sequences were penetrated, as expected. Total porosity ranges of the limestone sequences were determined to be between 0%

and 5%, while the dolomite sequences were found to be up to 20% total porosity. Injection fall-off testing indicated that the AGI wells exhibit greater than 2000 millidarcy-feet (md-ft) of permeability-height within the injection section. Figure 2.11 shows a table summarizing Madison and Bighorn-Gallatin reservoir properties from the SC 5-2, AGI 3-14, and AGI 2-18 wells. Madison reservoir quality for the SC 5-2 well is similar to the quality for the AGI wells, and is expected to be similar for the SC 7-34 well.

Bighorn-Gallatin reservoir quality for the SC 5-2 well is similar to the nearest Bighorn-Gallatin penetration at 1-12 Keller Raptor well (also referred to as the Amoco/Keller Rubow 1-12 well or the Keller Rubow-1 well), which shows interbedded dolostone and limestone sequences. In general, the degree of dolomitic recrystallization in the Bighorn-Gallatin is similar to the Madison Formation, which has resulted in comparable porosities and permeabilities despite a greater depth of burial. Bighorn-Gallatin total porosity from six LaBarge wells has been determined to be between 2 – 19% with permeabilities between 0.1 – 230 md.

Updated average Madison and Bighorn-Gallatin reservoir properties and well logs will be provided once the SC 7-34 well is drilled. Data will be submitted in the first annual monitoring report following commencement and operation of SC 7-34.

Figures 2.12 and 2.13 show the stratigraphic and structural cross sections of SC 5-2 and SC 7-34 in relation to AGI 3-14, AGI 2-18, and another analog well (1-12 Keller Raptor) penetrating the Madison and Bighorn-Gallatin formations further updip.

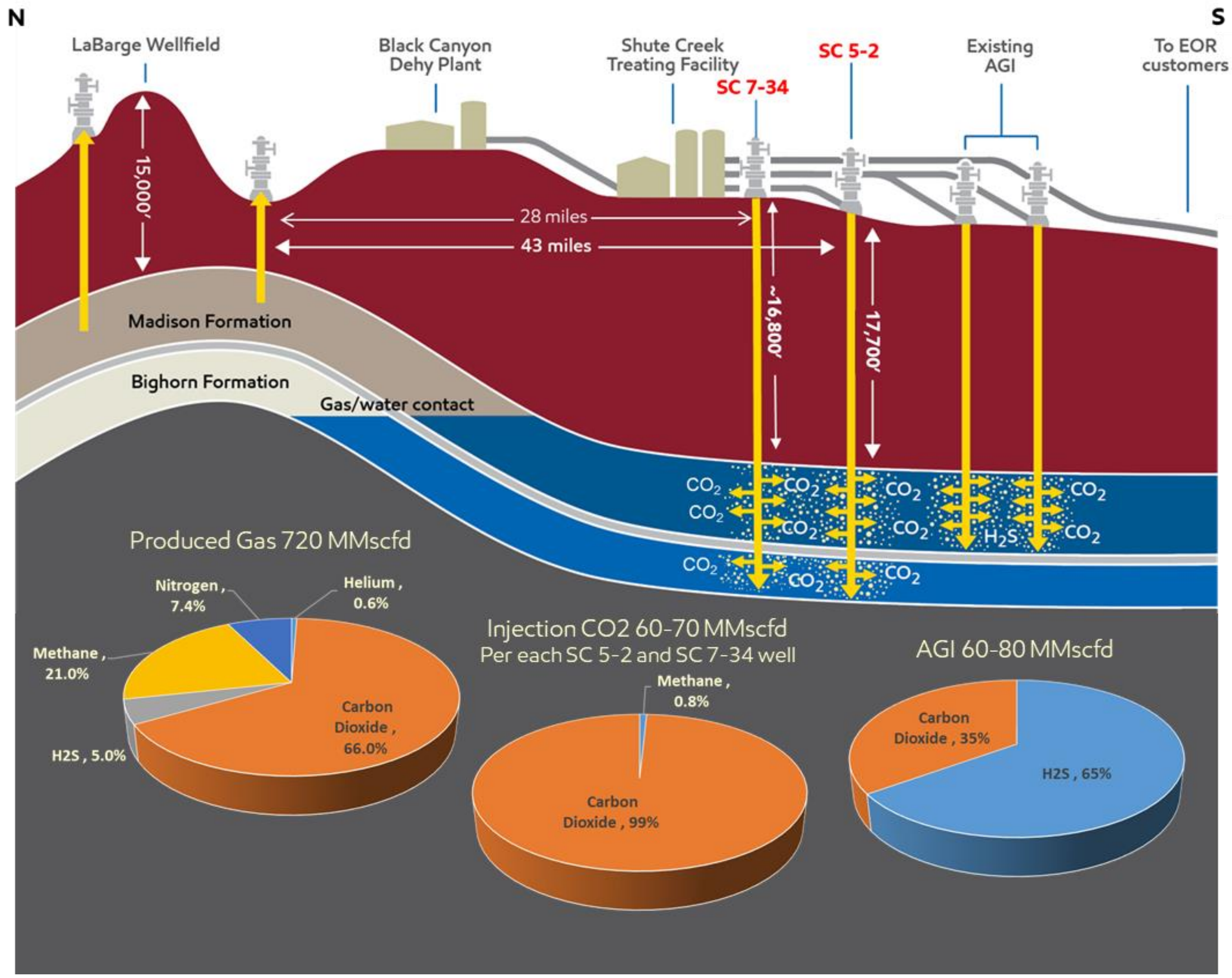

Figure 2.7 Schematic illustration of AGI injection program as currently used at LaBarge and CO_2 injection programs

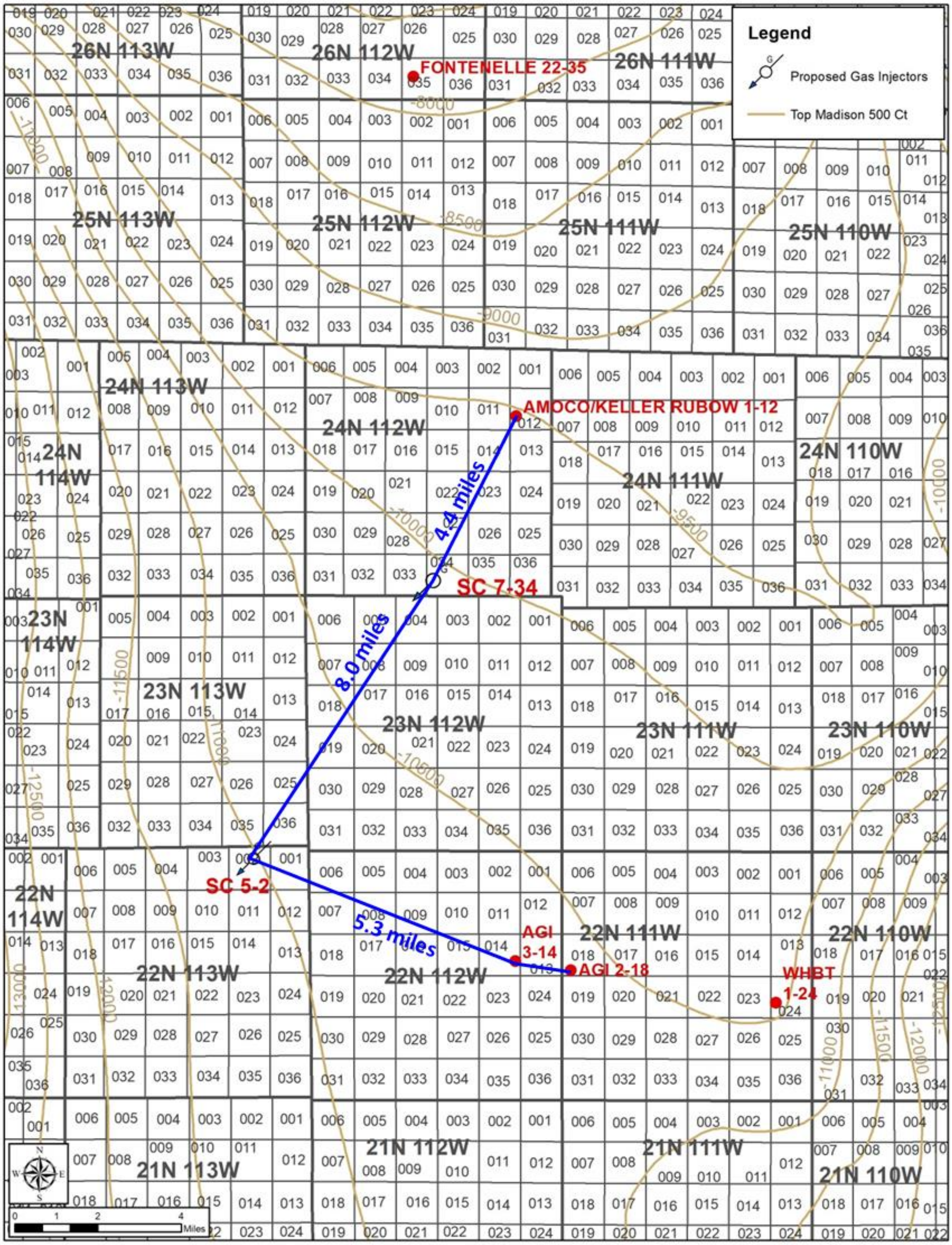

Figure 2.8 Madison structure map with relative well locations

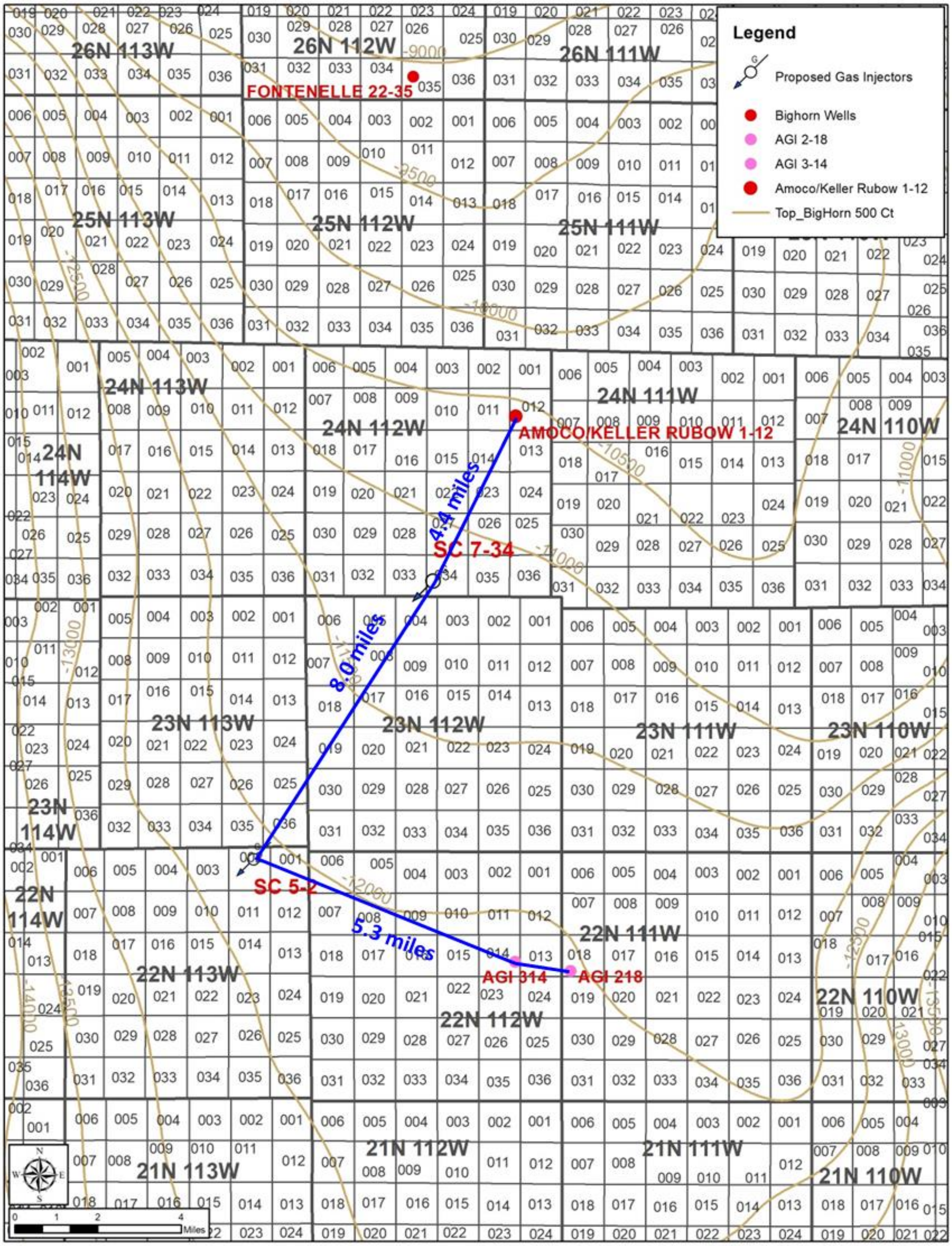

Figure 2.9 Bighorn-Gallatin structure map with relative well locations

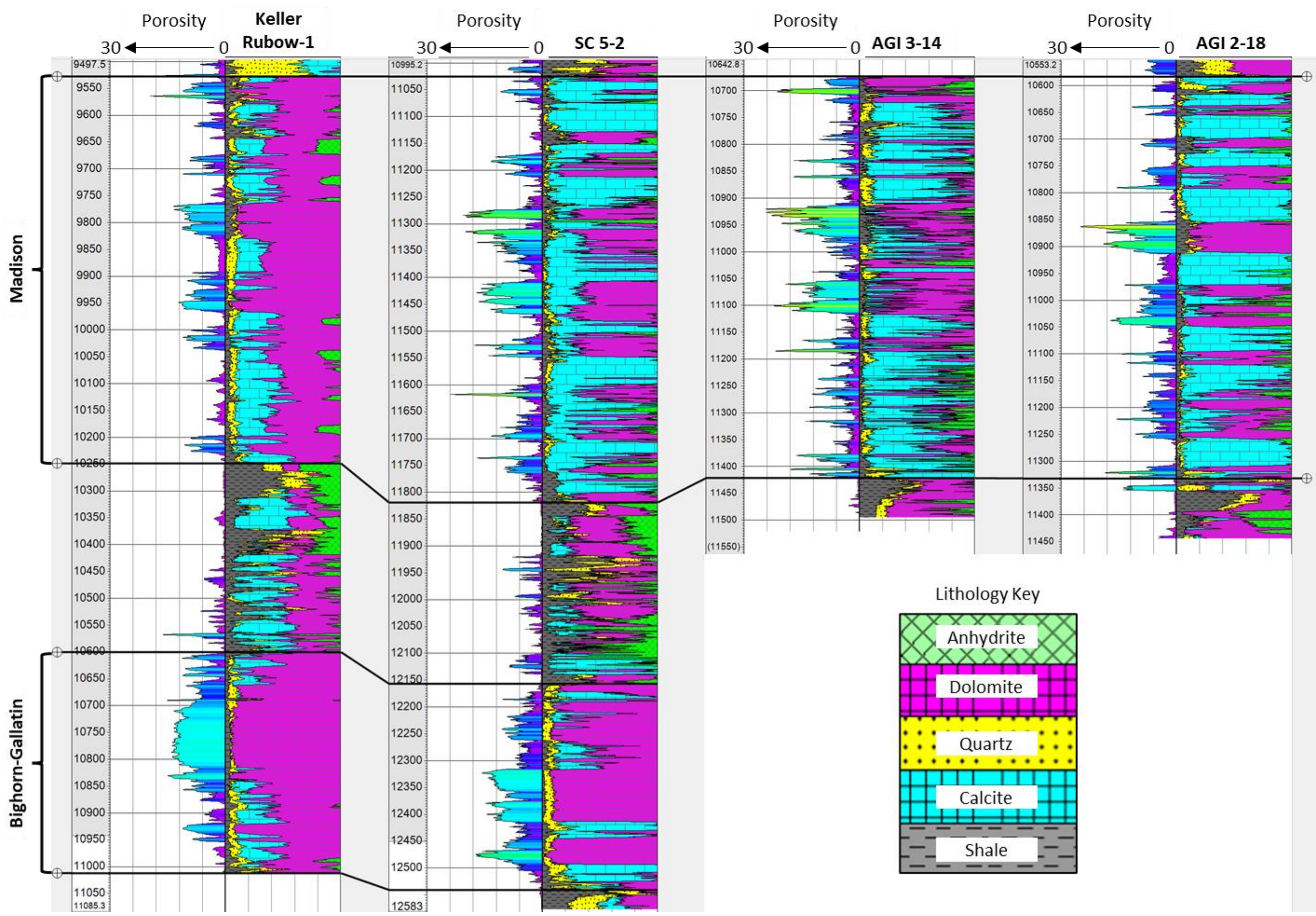

Figure 2.10 Well log sections from the Keller Rubow-1, SC 5-2, AGI 3-14, and AGI 2-18 injection wells across the Madison and Bighorn-Gallatin formations. SC 7-34 well logs are expected to be similar to offset wells.

	Bighorn-Gallatin	Madison		
	SC 5-2	SC 5-2	AGI 3-14	AGI 2-18
Net Pay (ft)	245	291	240	220
Avg Φ (%)	9%	10%	10%	9%
Avg k (md)	4	10	9	12
kh (md-ft)	~600*	~3000*	2300*	~2700*
Skin	-3.7	-3.5	-4.1	-4.5

* From injection / falloff test analysis

Figure 2.11 Average Madison and Bighorn-Gallatin reservoir properties of the SC 5-2 and AGI wells. SC 7-34 is expected to have similar properties.

From Figure 2.11, the parameters tabulated include:

1. *Net pay:* Madison section that exceeds 5% total porosity.
2. *Phi (ϕ):* Total porosity; the percent of the total bulk volume of the rock investigated that is not occupied by rock-forming matrix minerals or cements.
3. *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. Note that the measure of darcy assumes linear flow (i.e. pipe shaped).
4. *Kh:* Millidarcy-feet, which is a measure of the average permeability calculated at a 0.5 foot sample rate from the well log accumulated over the total net pay section encountered.
5. *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.

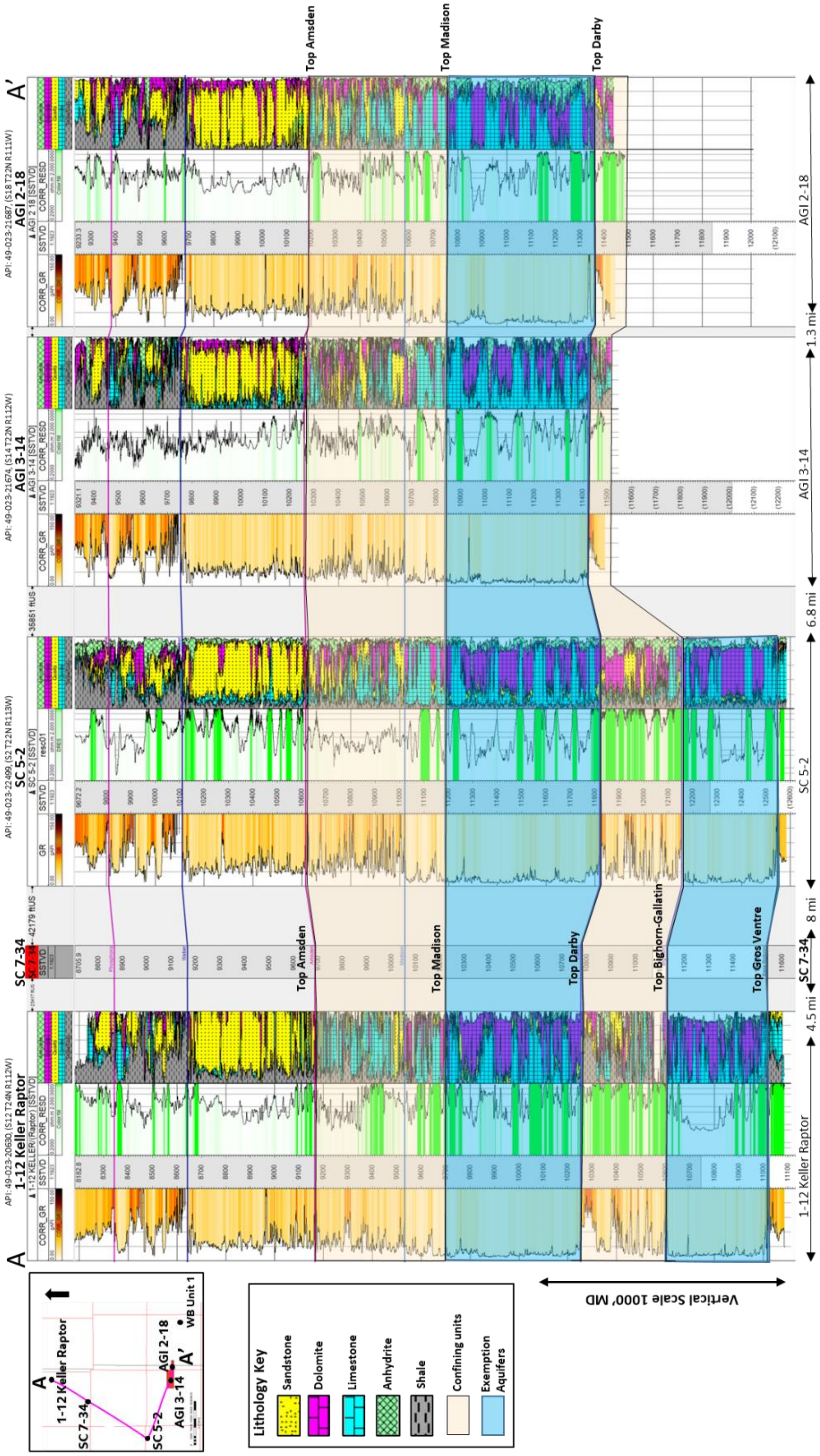

Figure 2.12 Stratigraphic Cross Section of Existing Madison and Bighorn-Gallatin Wells and the SC 7-34 Well

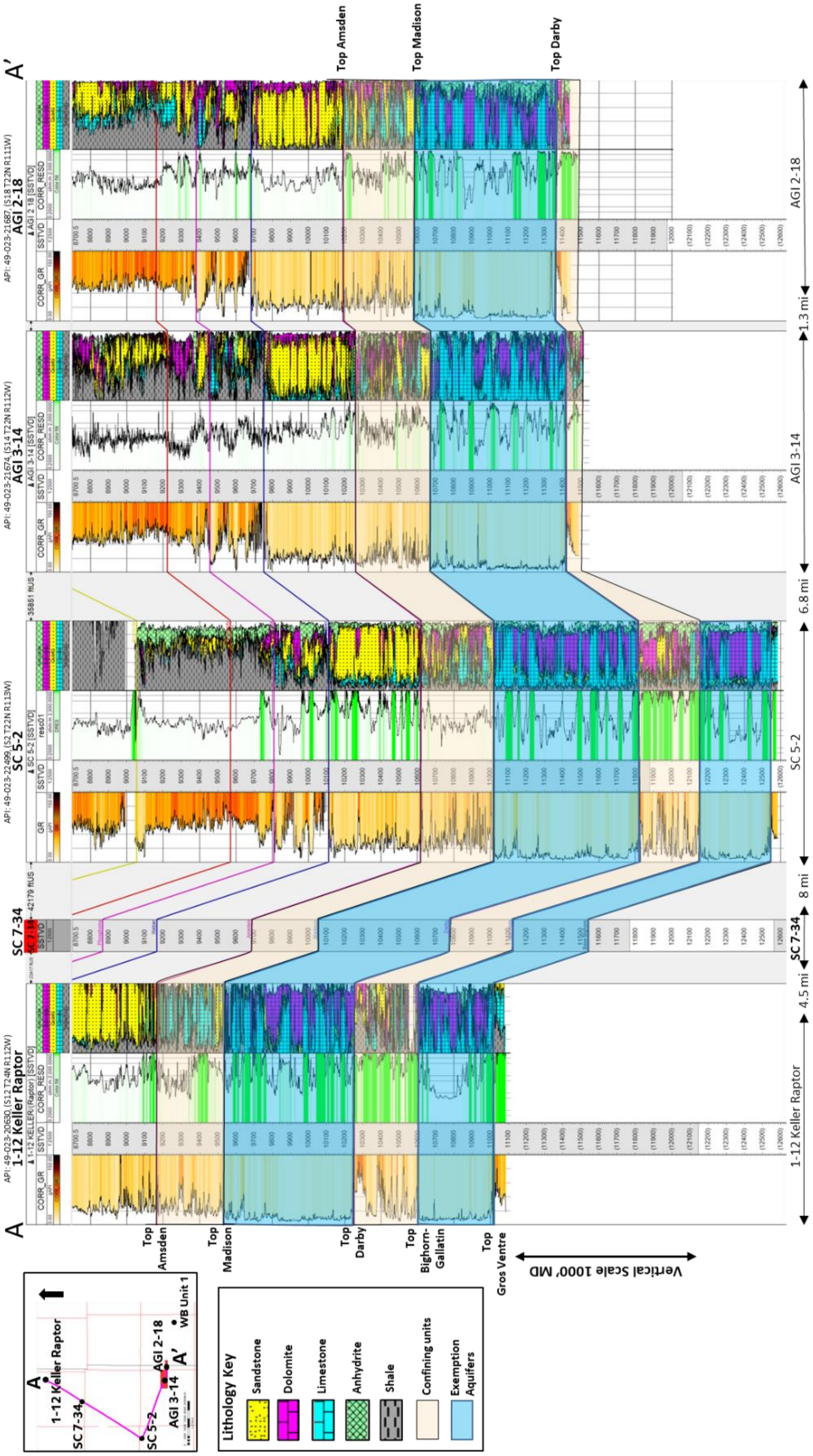

Figure 2.13 Structural Cross Section of Existing Madison and Bighorn-Gallatin Wells and the SC 7-34 Well

2.6.3 Seismic Expression of Madison and Bighorn-Gallatin Formations at CO_2 Injection Well Locations

Seismic expression of the Madison and Bighorn-Gallatin formations at the SC 5-2 and SC 7-34 injection locations indicate that the CO_2 injection wells are located on the plunging crest of the Moxa Arch with little to no structuring observable on the seismic data around these wells. Faulting is also not indicated by the seismic data. Figure 2.14 shows an east-west oriented 2D seismic at the SC 5-2 well location at approximately five times vertical exaggeration. Figure 2.15 shows an east-west oriented 2D seismic at the SC 7-34 well location at approximately four times vertical exaggeration.

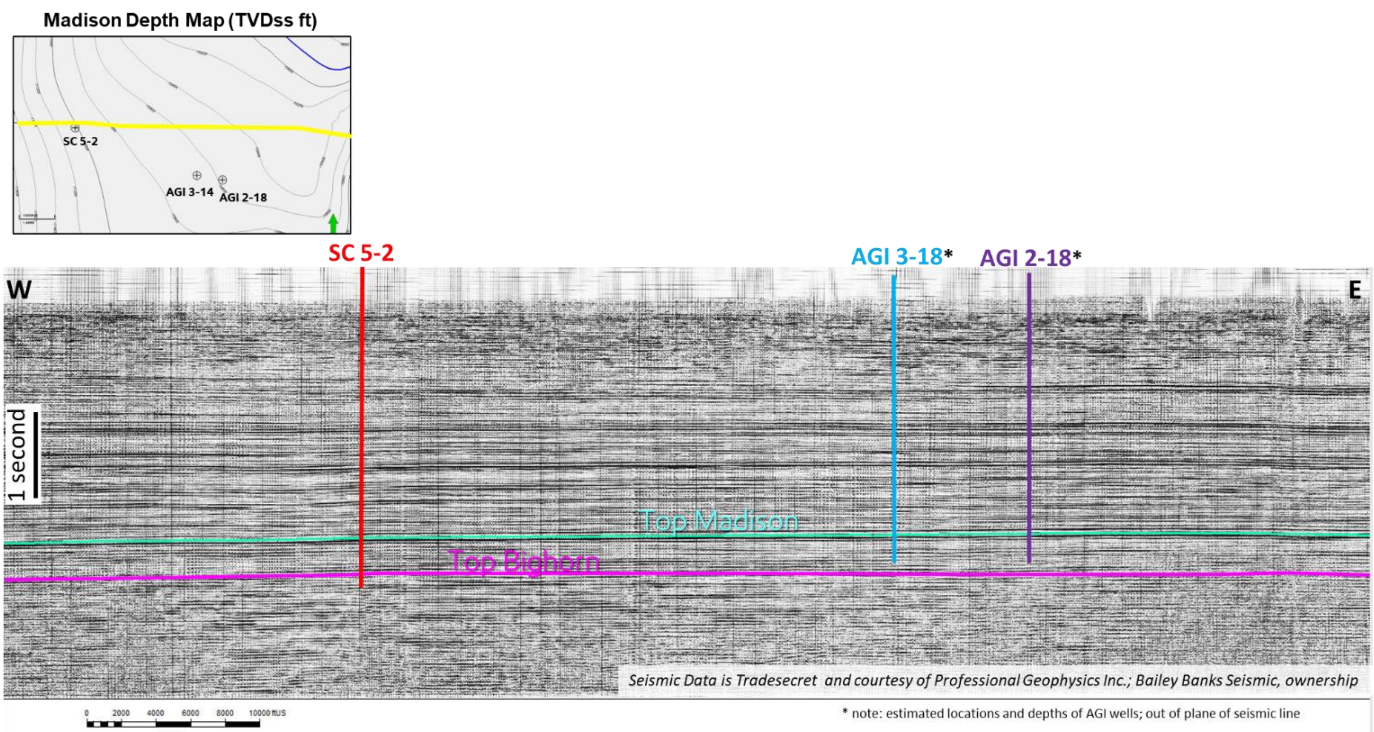

Figure 2.14 2D Seismic traverses around the SC 5-2 injection well location shows no evidence of faulting or structuring around the well location

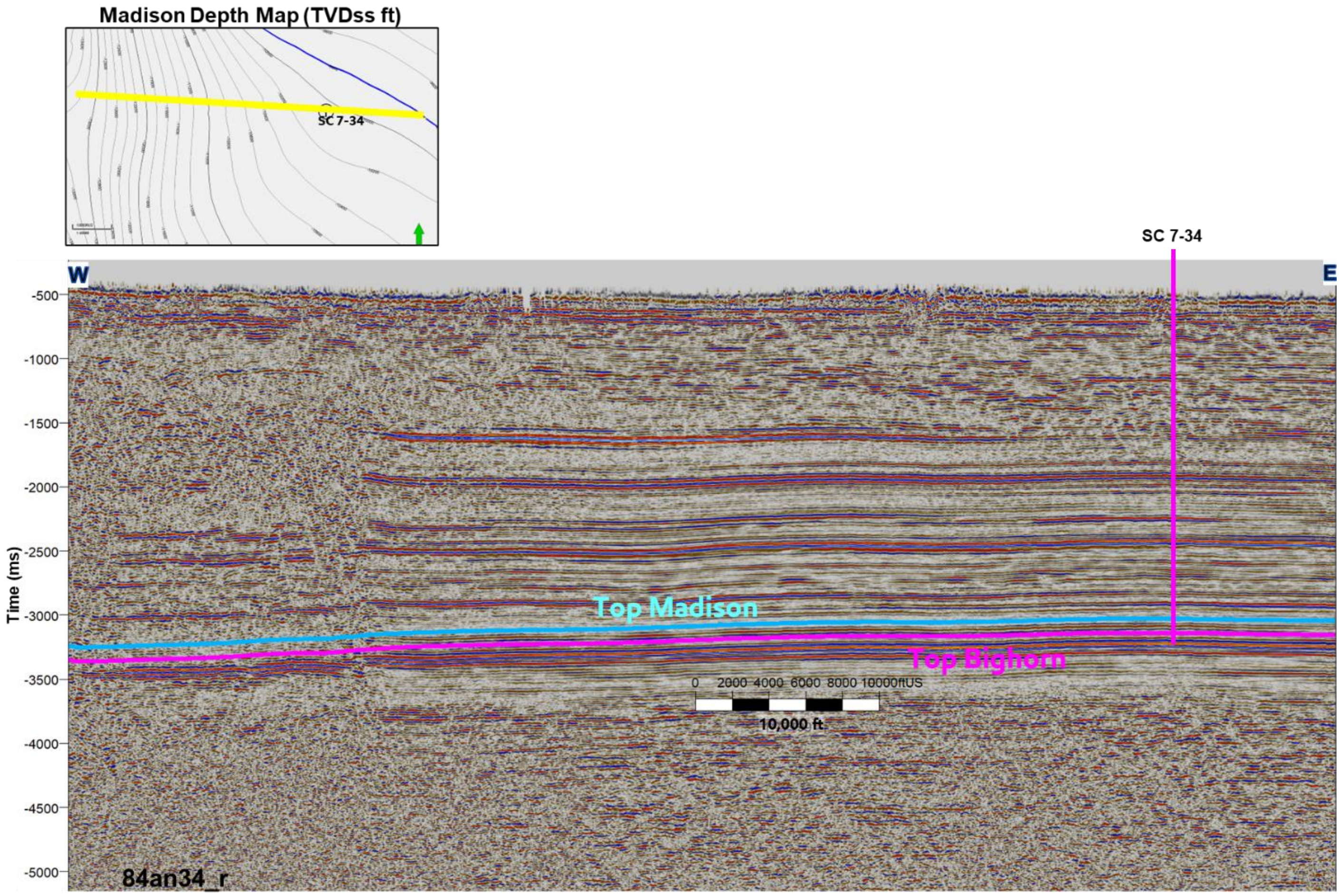

Figure 2.15 2D Seismic traverses around the SC 7-34 injection well location shows no evidence of faulting or structuring around the well location

2.7 Description of the Injection Process

2.7.1 Description of the AGI Process

The AGI facility was commissioned for eliminating the Claus Sulfur Recovery Units (SRU) bottleneck, reducing plant downtime, and reducing operating costs. The purpose of the AGI process is to take the H_2S and some of the CO_2 removed from the produced raw gas and inject it back into the Madison Formation. Raw gas is produced out of the Madison Formation and acid gas is injected into the aquifer below the GWC of the Madison Formation. The Madison reservoir contains very little CH_4 and He at the injection locations under SCTF, where the AGI wells are located. Thus, there is no concern of contaminating the production from the LaBarge well field 43 miles away.

The AGI process transports the acid gas stripped in the Selexol process under pressure through a pipeline to two underground wells that are geologically suitable for storage of the acid gas (AGI 3-14 and AGI 2-18). There are three parallel compressor trains. Two trains are required for full

capacity; the third train is a spare. The low pressure feed from the Selexol process enters the first stage suction and is compressed through four stages of compression. The high pressure acid gas from the Selexol process requires only three stages of compression. The fourth stage discharge acid gas must be condensed prior to pumping to prevent damage from vapors. Fourth stage discharge acid gas is cooled in three heat exchangers prior to entering the pump. Dense phase aerial coolers are located downstream of the pumps; they remove heat generated by pumping and increase the density of the fluid. The liquid H_2S/CO_2 is commingled downstream of the dense phase coolers and divided into the two injection wells over 38 miles from the nearest Madison gas producer in the LaBarge gas field. The approximate stream composition being injected is 50 - 65% H_2S and 35 - 50% CO_2. Each injection well has a dedicated six-inch carbon steel pipeline. The length of pipeline from the AGI battery limit to the injection wells is about:

- 3,200 feet to AGI 3-14
- 12,400 feet to AGI 2-18

The AGI flow lines are buried with seven feet of cover. Heat tracing is provided for the aboveground portions of the lines to prevent the fluid from cooling to the point where free water settles out. Free water and liquid H_2S/CO_2 form acids, which could lead to corrosive conditions. Additionally, the gas is dehydrated before it enters the flow line, reducing the possibility of free water formation, and the water content of the gas is continuously monitored. The liquid H_2S/CO_2 flows via the injection lines to two injection wells. The total depth of each well is about:

- 18,015 feet for AGI 3-14
- 18,017 feet for AGI 2-18.

2.7.2 Description of the CO_2 Injection Process

The CO_2 injection program was initiated primarily because the volume of CO_2 associated with the natural gas production is greater than the volume that is able to be injected into the AGI wells.

2.7.2.1 Description of the SC 5-2 Process

The SC 5-2 process aims to capture CO_2 at the SCTF that would otherwise be vented, and compress it for injection in the aquifer below the GWC of the Madison and Bighorn-Gallatin formations.

The injection system would enable additional CO_2 to be stripped in the Selexol process, pressurized, and transported to a CO_2 injection well, which is geologically suitable for injection, disposal and sequestration of fluids primarily consisting of CO_2. The process will be built into the existing Selexol trains at SCTF. After the acid gas treatment and dehydration, the gas will be routed to a new flash vessel which will enable capture up to 80 million standard cubic feet per day (MMSCFD) from SCTF then compressed with an air cooled Heat Exchanger cooling system. The captured CO_2 will have the potential to be either sold or injected into a CO_2 injection well. Based on modeling, the approximate stream composition will be 99% CO_2, 0.8% methane and 0.2% other mixed gases.

From the CO_2 compressors, an eight inch flow line of approximately 10.1 miles would take the fluids to the SC 5-2 injection well site. The flow line would be buried at depths necessary to avoid and protect existing facilities, roads, and crossings, and will be buried at a minimum below the frost line. The fluids will have a sufficient dew point that free water formation is not expected to accumulate along the pipeline or well. The water content of the gas will be continuously monitored. The gas will be transported via flow line to the SC 5-2 well and injected into the Madison Formation at a depth of ~17,950 feet and into the Bighorn-Gallatin Formation at a depth of ~19,200 feet approximately 33 miles from the nearest Madison gas producer in the LaBarge gas field. Based on geological models, the risk of contaminating production from the LaBarge well field or interacting with the AGI wells or SC 7-34 well approximately 7 miles and 8 miles away, respectively, is improbable due to the relatively tight reservoir quality of the Madison and Bighorn-Gallatin formations, the significant distance between the SC 5-2 injection site and the producing well field, and the volume and rate of injection at the SC 5-2 site.

2.7.2.2 Description of the SC 7-34 Process

The SC 7-34 process aims to divert currently captured CO_2 produced from source wells during natural gas production that will not be sold to customers and route to permanent disposal in the aquifer below the GWC of the Madison and Bighorn-Gallatin formations.

Captured CO_2 that is already routed from SCTF to the existing CO_2 sales building will be diverted and transported via flow line to a CO_2 injection well, which is geologically suitable for injection, disposal, and sequestration of fluids primarily consisting of CO_2. This process will enable disposal of up to 70 MMSCFD through an additional pump. The CO_2 will be cooled with an air cooled Heat Exchanger cooling system. Based on modeling, the approximate stream composition is anticipated to be identical to the SC 5-2 with 99% CO_2, 0.8% methane, and 0.2% other mixed gases.

From the CO_2 compressors, an eight inch flow line of approximately 12.4 miles would take the fluids to the SC 7-34 injection well site. The flow line would be buried at depths necessary to avoid and protect existing facilities, roads, and crossings, and will be buried at a minimum below the frost line. The fluids will have a sufficient dew point that free water formation is not expected to accumulate along the pipeline or well. The water content of the gas will be continuously monitored. The gas will flow via the injection lines to the SC 7-34 well and injected into the Madison Formation at a depth of ~16,740 feet and into the Bighorn-Gallatin Formation at a depth of ~18,230 feet approximately 28 miles from the nearest Madison gas producer in the LaBarge gas field. Based on geological models, the risk of contaminating production from the LaBarge well field 30 miles away or interacting with the SC 5-2 well or AGI wells approximately 8 and 9 miles away, respectively, is improbable due to the relatively tight reservoir quality of the Madison and Bighorn-Gallatin formations, the significant distance between the SC 7-34 injection site and the producing well field, and the volume and rate of injection at the SC 7-34 site.

2.8 Planned Injection Volumes

2.8.1 Acid Gas Injection Volumes

Figure 2.16 is a long-term injection forecast throughout the life of the acid gas injection project. It is based on historic and predicted data. 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 below are the total amount of gas to be injected into the AGI wells, not just the CO_2 portion. ExxonMobil forecasts the total volume of CO_2 stored in the AGI wells over the modeled injection period to be approximately 53 million metric tons.

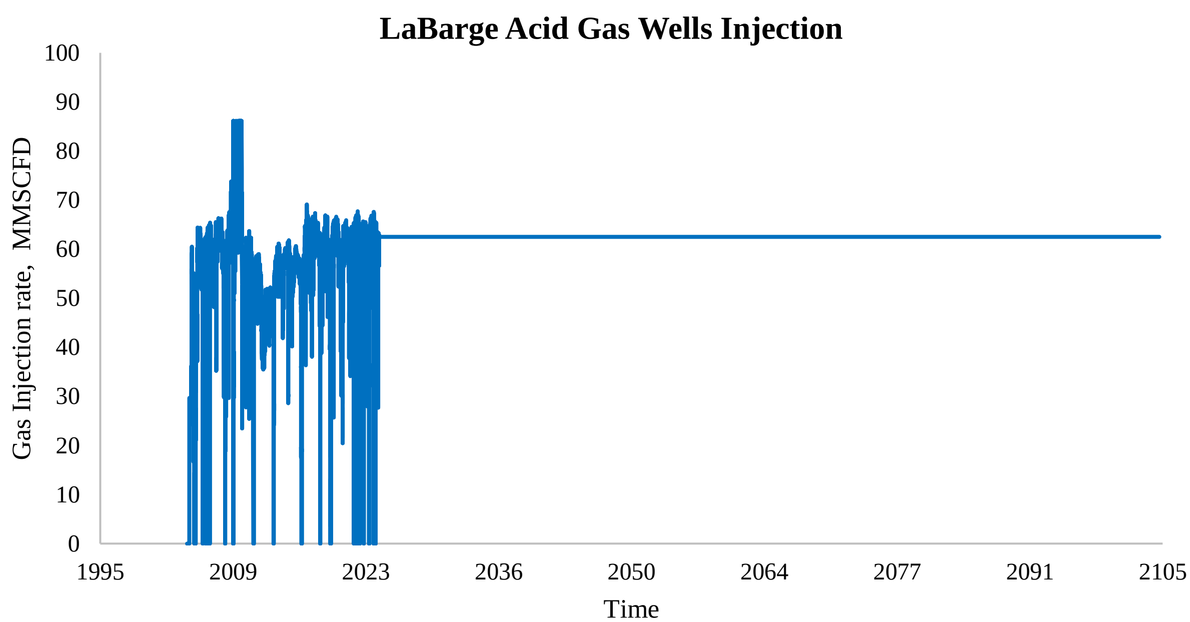

Figure 2.16 – Planned Acid Gas and CO_2 Injection Volumes

2.8.2 CO_2 Injection Wells Volumes

Figure 2.17 below is a long-term average injection forecast through the life of the CO_2 injection wells. 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 below are the total amount of fluids to be injected, but does not include any portion of the Acid Gas Injection project gas. The non-CO_2 portion of the injection stream is expected to be 1% or less of the injected volume. ExxonMobil forecasts the total volume of CO_2 stored in the CO_2 injection wells over the modeled injection period to be approximately 180 million metric tons.

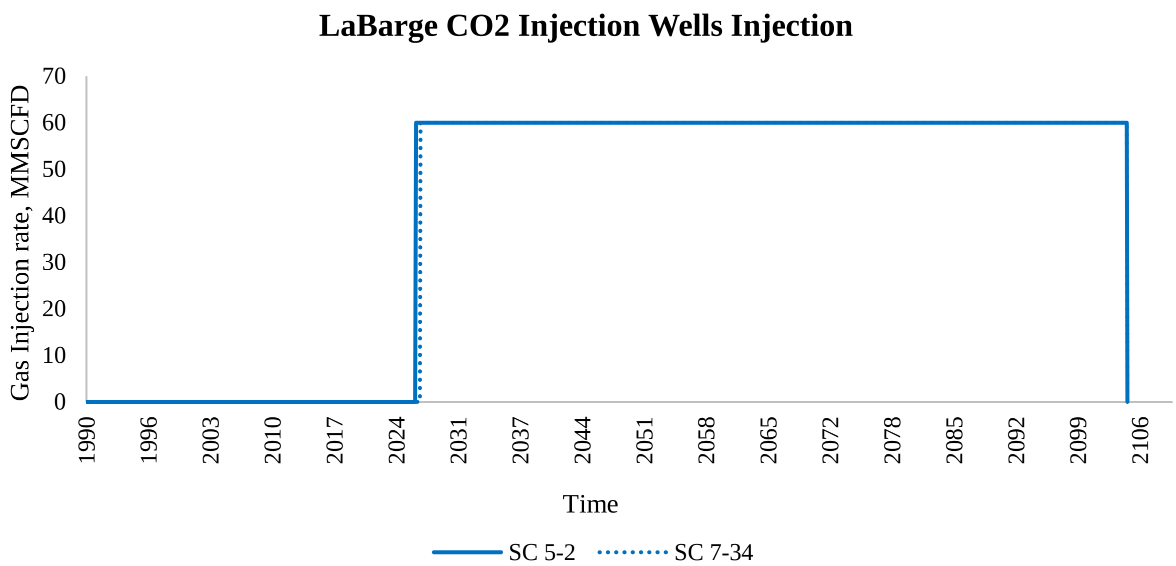

Figure 2.17 – Planned Average CO_2 Injection Well Volumes

3.0 Delineation of Monitoring Area

3.1 Maximum Monitoring Area (MMA)

3.1.1 AGI Wells MMA

Per 40 CFR **§** 98.449, the MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling using Schlumberger's (SLB) Petrel/Intersect, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the acid gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 1%. A gas saturation of 1% is well below the lowest gas saturation that can be confidently detected by formation evaluation methods in reservoirs with rock properties such as those found in the Madison Formation.

After injecting 0.3 trillion cubic feet (TCF) by year-end 2023, the current estimated acid gas plume size is approximately 21,350 feet in diameter (4.0 miles) (see Figure 3.1). With continuing injection of an additional 1.9 TCF through year-end 2104, at which injection is expected to cease, the plume size is expected to grow to approximately 39,500 feet in diameter (7.5 miles) (see Figure 3.2).

The model was run through 2986 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. The rate of growth of the free-phase gas plume is less than 0.25% areally per

year, demonstrating plume stability. Figure 3.3 below shows the expansion of the plume to a diameter of approximately 40,470 feet (7.7 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the MMA will be defined by Figure 3.3, which is the maximum areal extent of the plume once it has reached stability (defined by the extent of the plume in 2205, which is a 7.7-mile diameter) plus the buffer zone of one-half mile.

3.1.2 CO_2 Injection Wells MMA

Per 40 CFR **§** 98.449, the MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the CO_2 gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 1%.

Note that estimates of plume size assume that CO_2 is coinjected without flow control at both the SC 5-2 and SC 7-34 wells into both the Madison and Bighorn-Gallatin intervals. Having no flow control means that the amount of gas that enters each interval is for the most part a function of the permeability thickness (kh) of each interval. There is limited data, especially for the Bighorn-Gallatin, with few well penetrations, all of which are a significant distance from the target formation. Therefore, the anticipated plume sizes are based on simulation results relying on best estimates from available data regarding the Madison and Bighorn-Gallatin reservoir quality.

The model was run through 2986 to assess the potential for expansion of the plume after injection ceases at year-end 2104. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. The rate of growth of the free-phase gas plume is less than 0.25% areally per year, demonstrating plume stability.

3.1.2.1 SC 5-2 MMA

Assuming SC 5-2 begins injecting in 2025, 0.02 TCF of CO_2 will have been injected by mid-2026 and the gas plume will just begin to form. Figure 3.4 shows expected average gas saturations at mid-2026 and the location of the AGI wells relative to the SC 5-2 injection well. After injecting 1.7 TCF at year-end 2104, injection is expected to cease. The SC 5-2 CO_2 plume size is expected to grow to approximately 23,650 feet in diameter (4.5 miles) (see Figure 3.5).

Figure 3.6 below shows the expansion of the SC 5-2 plume to a diameter of approximately 24,500 feet (4.6 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the SC 5-2 MMA will be defined by Figure 3.6, which is the maximum areal extent of the SC 5-2 plume once it has reached stability (defined by the extent of the plume in 2205, which is a 4.6-mile diameter) plus the buffer zone of one-half mile.

3.1.2.2 SC 7-34 MMA

SC 7-34 is assumed to begin injection mid-2026. After injecting 1.7 TCF at year-end 2104, injection is expected to cease. The SC 7-34 CO_2 plume size is expected to grow to approximately 22,100 feet in diameter (4.2 miles) (see Figure 3.7).

Figure 3.8 below shows the expansion of the SC 7-34 plume to a diameter of approximately 24,976 feet (4.7 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the SC 7-34 MMA will be defined by Figure 3.8, which is the maximum areal extent of the SC 7-34 plume once it has reached stability (defined by the extent of the plume in 2205, which is a 4.6-mile diameter) plus the buffer zone of one-half mile.

3.2 Active Monitoring Area (AMA)

Per 40 CFR **§** 98.449, the AMA is the superimposed areas projected to contain the free phase CO_2 plume at the end of the year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile and the area projected to contain the free phase CO_2 plume at the end of year t+5, where t is the last year in the monitoring period.

ExxonMobil proposes to define the AMA as the same boundary as the MMA for the AGI and CO_2 injection wells. The following factors were considered in defining this boundary:

1. Lack of faulting in the MMA yields no vertical pathways for fluids to move vertically out of the Madison or Bighorn-Gallatin formations to shallower intervals.
2. Lack of faulting in the injection area does not create enhanced reservoir permeability through natural fracturing and all flow of injected fluids will be darcy flow from pore to pore.
3. Distance from the LaBarge production field area is large (35+ miles) and reservoir permeability is generally low which naturally inhibits flow aerially from injectionsite.
4. The LaBarge field production area is a large structural hydrocarbon trap that has sealed and trapped hydrocarbons for large geologic periods of time. There is no reason to believe that any injection fluids that may migrate outwards from the injection site to the larger LaBarge structure would not also be effectively trapped at the LaBarge structure over geological time.
5. If t is defined as the final year of injection coinciding with end of field life for the LaBarge assets, the MMA encompasses the free phase CO_2 plume 100 years post-injection, and therefore satisfies and exceeds the AMA area.

The purpose of the AMA is to allow for a practical and cost-effective monitoring program throughout the life of the project. Because there are no probable leakage pathways in the MMA, besides surface equipment which is extensively monitored, ExxonMobil believes it is appropriate to define the AMA as the same boundary as the MMA. Additionally, due to the high H_2S content of the injected gas stream into the AGI wells, monitoring of leaks is essential to operations and

personnel safety, so a full-scale monitoring program has already been implemented at the AGI sites, as will be discussed below.

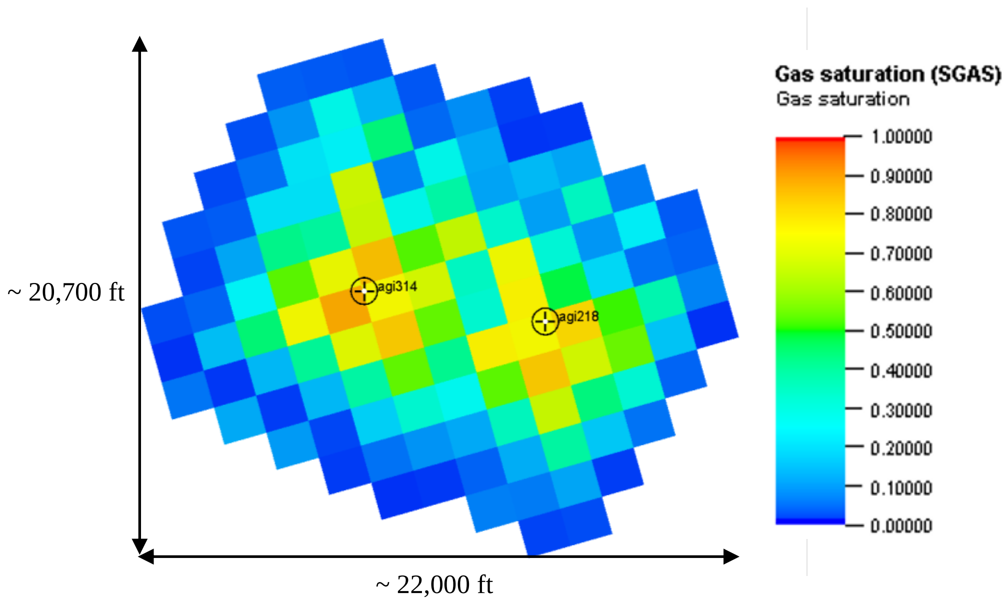

Figure 3.1 – AGI Estimated Gas Saturations at Year-end 2023

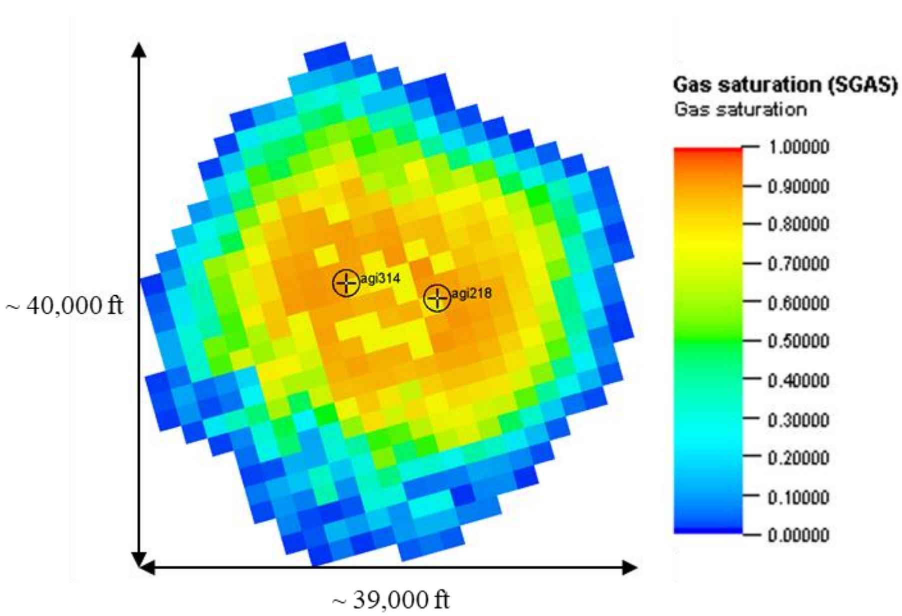

Figure 3.2 – AGI Predicted Gas Saturations at Year-end 2104

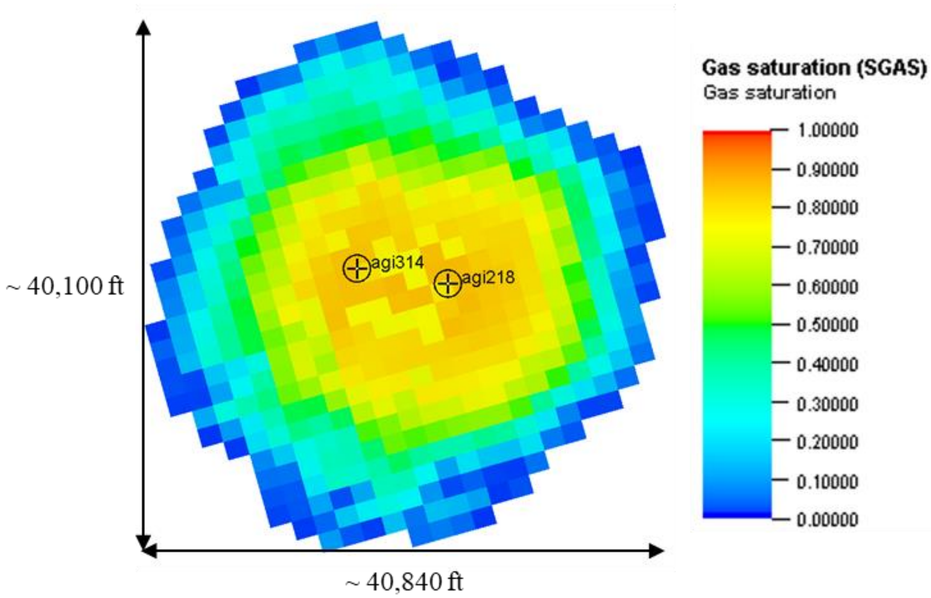

Figure 3.3 – AGI Predicted Gas Saturations at Year-end 2205

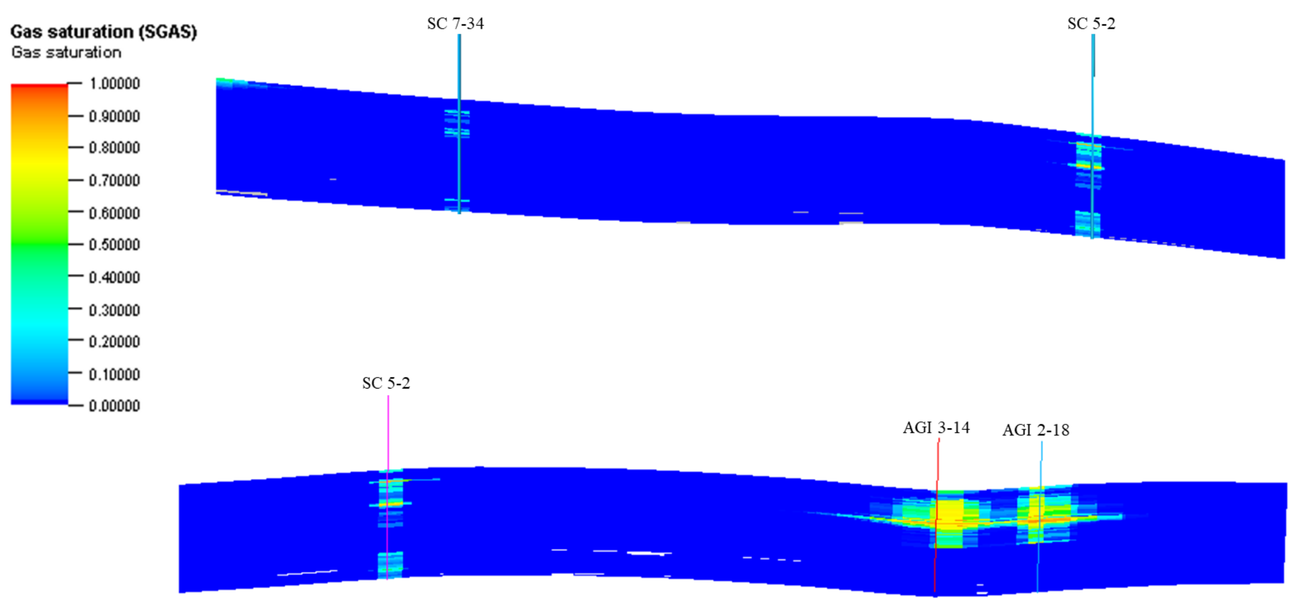

Figure 3.4 – Predicted Gas Saturations at Year-end 2027

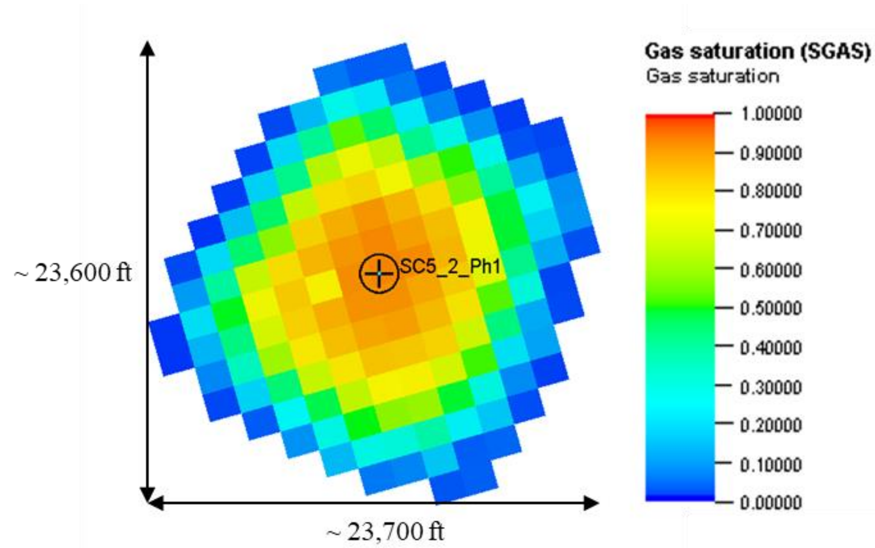

Figure 3.5 – SC 5-2 Predicted Gas Saturations at Year-end 2104

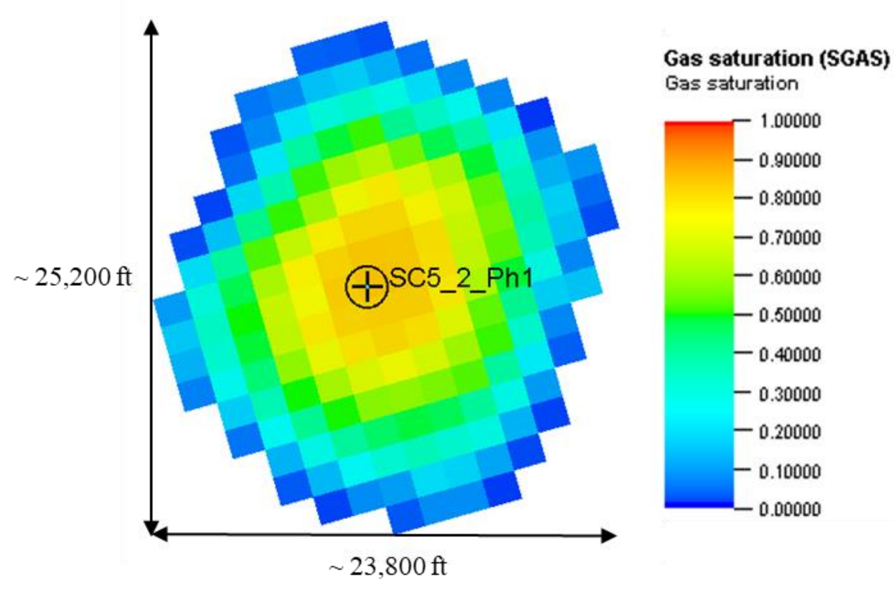

Figure 3.6 – SC 5-2 CO_2 Predicted Gas Saturations at Year-end 2205

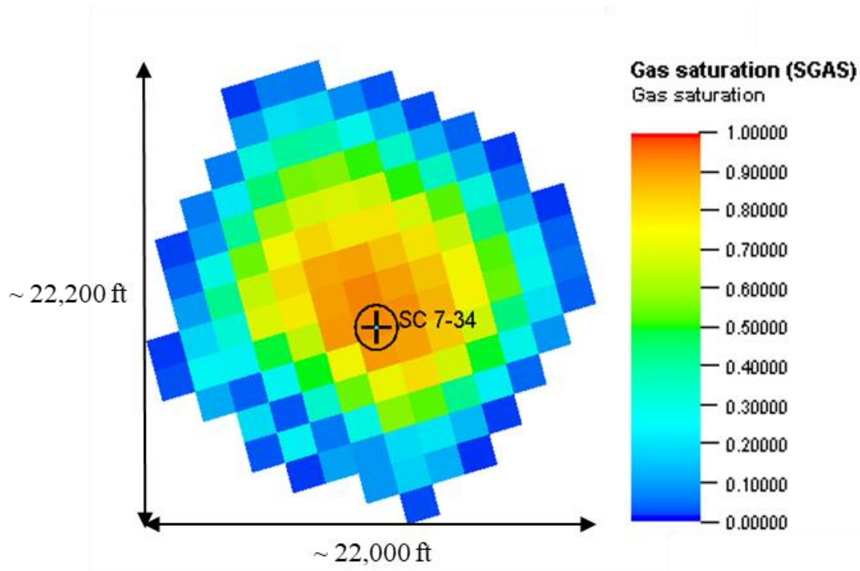

Figure 3.7 – SC 7-34 Predicted Gas Saturations at Year-end 2104

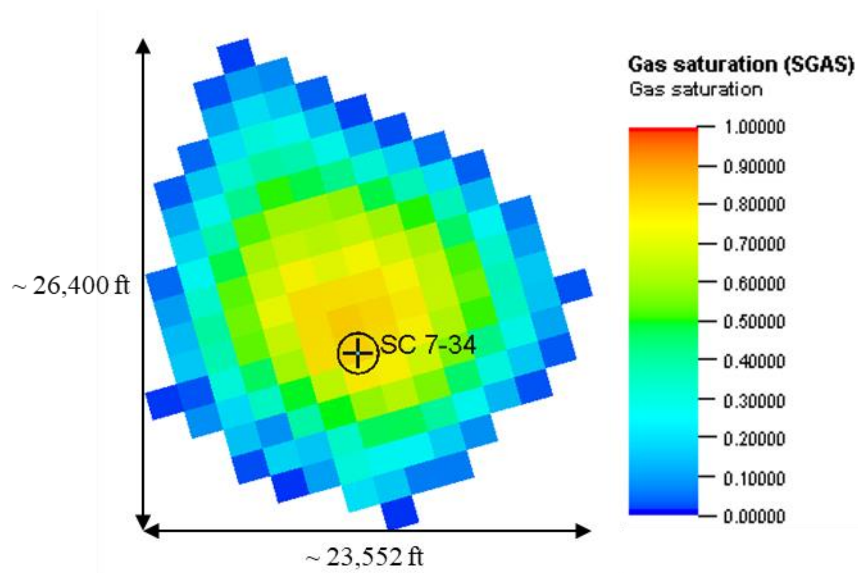

Figure 3.8 – SC 7-34 Predicted Gas Saturations at Year-end 2205

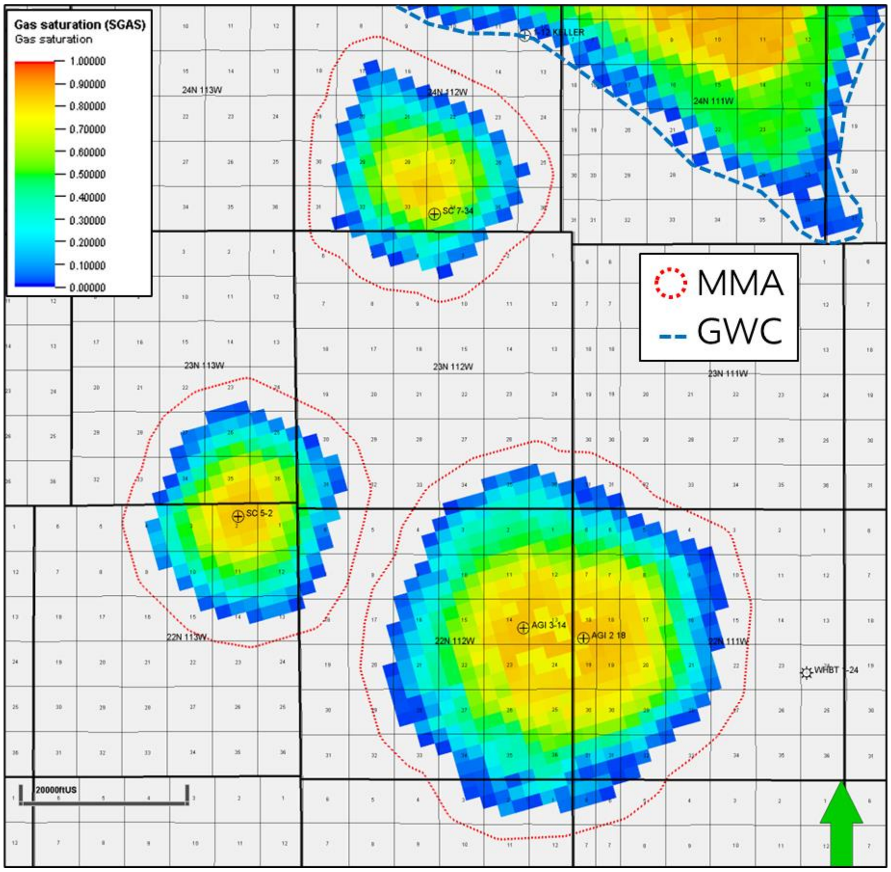

Figure 3.9 - Gas saturation plumes for AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34 at the time of plume stabilization (year 2205) with half mile buffer limit of MMA (red polygons). Plumes are displayed at zone of largest aerial extent (within Madison Formation) relative to the LaBarge gas field in the same gas-bearing zone (gas water contact displayed in dashed blue polygon).

4.0 Evaluation of Potential Pathways for Leakage to the Surface

This section assesses the potential pathways for leakage of injected CO_2 to the surface. ExxonMobil has identified the potential leakage pathways within the monitoring area as:

- Leakage from surface equipment (pipeline and wellhead)
- Leakage through wells
- Leakage through faults and fractures
- Leakage through the seal
- Leakage through natural or induced seismicity

As will be demonstrated in the following sections, there are no leakage pathways that are likely to result in loss of CO_2 to the atmosphere. Further, given the relatively high concentration of H_2S in the AGI injection stream, any leakage through identified or unexpected leakage pathways would be immediately detected by alarms and addressed, thereby minimizing the amount of CO_2 released to the atmosphere from the AGI wells.

4.1 Leakage from Surface Equipment

Leakage from surface equipment is not likely due to the design of the AGI and CO_2 injection facilities. The AGI facilities were designed to minimize leak points such as valves and flanges, and use welded connections where possible instead. The only surface equipment located between the flow meter and the wellhead are valves, transmitters, and flanged connection points on the pipelines. Due to the presence of H_2S in the AGI injection stream at a concentration of approximately 50 - 65% (500,000 - 650,000 parts per million (ppm)), H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. CO_2 gas detectors will be present at the CO_2 injection facilities due to high concentration of CO_2, which alarm at 5,000 PPM. Additionally, all field personnel are required to wear H_2S monitors for safety reasons, which alarm at 5 ppm H_2S. Although damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2 entrained in the acid gas, at the AGI well concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm, and immediate action would be taken to stop the leak. Additionally, the CO_2 injection wells would be monitored with methods outlined in sections five and six.

ExxonMobil reduces the risk of unplanned leakage from surface facilities through continuous surveillance, facility design, and routine inspections. Field personnel monitor the AGI facility continuously through the Distributed Control System (DCS). Additionally, daily visual inspection rounds are conducted of the AGI facility and weekly visual inspections are conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. ExxonMobil also relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSVs), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes. Additionally, the AGI wells have multiple surface isolation valves for redundant protection. Inline inspections of the AGI injection pipelines using a smart pigging tool are conducted on a regular frequency to check the wall thickness of the pipeline to identify potential areas of corrosion.

Field personnel will monitor the CO_2 injection facilities continuously through the DCS. Additionally, visual inspections will be conducted on a routine basis providing an additional way to detect leaks in a timely manner. Surface isolation valves will also be installed for redundant protection. Inline inspections are not anticipated to occur on a regular frequency because free water is not expected to accumulate due to the low dew point of the fluid.

<u>Likelihood</u>
Due to the design of the AGI and CO_2 injection facilities and extensive monitoring in place to reduce the risk of unplanned leakage, leakage from surface equipment is not likely.

<u>Magnitude</u>
Given the high concentrations of H_2S and CO_2 in the respective injection streams, ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. Even a minuscule amount of gas leakage would be immediately detected by the extensive monitoring systems currently in place at the facility as described above and treated as an upset event warranting immediate action to stop the leak. Should leakage be detected from surface equipment, the volume of CO_2 released will be quantified based

on the operating conditions at the time of release, as stated in Section 7.4 in accordance with 40 CFR 98.448(5).

Timing

As stated above, even a minuscle amount of gas leakage would be immediately detected and immediate action would be taken to stop the release. Any potential leakage from surface equipment would only occur during the lifetime operation of the wells. Once injection ceases, the surface equipment will be decommissioned and will not pose a risk as a leakage pathway.

4.2 Leakage through AGI and CO2 Injection Wells

Leakage of CO_2 through oil, gas, and/or water wells completed and/or abandoned is not likely. There is no commercial production of oil or gas within the immediate area of the SCTF. There is shallower production of gas from the Frontier and Dakota formations nearby in the Cow Hollow Field, at depths of 10,800' – 11,800'. A search of the WOGCC database demonstrated that there are no existing active Madison or Bighorn-Gallatin penetrations or production within the respective MMAs of the AGI or CO_2 injection well sites. The nearest established Madison production is greater than 35 miles to the north-northwest in the ExxonMobil LaBarge Deep Madison Field, which is the well field that supplies SCTF. One well (Whiskey Butte Unit 1, drilled in 1974 and operated by Wexpro Company), which was located approximately 6 miles from the AGI wells, partially penetrated 190 feet of the Madison Formation (total depth 17,236 feet MD). This well never produced from the Madison Formation and instead was perforated thousands of feet above in the Frontier Formation. The well was ultimately plugged and abandoned in February 1992. Examination of the plugging and abandonment records and the wellbore diagram constructed from those records indicates that risk of the well as a leakage pathway is highly unlikely. Two additional Madison penetrations are located between the well field and the SC 5-2 and AGI wells; both penetrations are outside the boundary of the MMA and therefore likely do not pose a risk as a leakage pathway. Keller Rubow 1-12 was plugged and abandoned in 1996. Fontenelle II Unit 22-35 was drilled to the Madison Formation but currently is only perforated and producing from thousands of feet above in the Frontier Formation.

As mentioned in Section 2.3.2, early in the life of many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. The thin-wall wells that failed have been plugged and abandoned in accordance with regulatory standards. Madison wells that were subsequently drilled were cased using thick-walled/chrome tubulars due to the high H_2S and CO_2 content and subsequent corrosion effects, as well as to combat potential salt or sediment creep. Therefore, there is no current risk of failure as all wells currently use or have used thick-walled casing of sufficient strength to penetrate and/or produce from the Madison Formation.

Future drilling is also unlikely to pose a risk as a leakage pathway due to limited areal extent of the injection plumes as shown in Figures 3.2 – 3.8. Therefore, the geological model can be used to delineate areas that should be avoided during drilling. This model has also history-matched the AGI wells injection that has occurred to date and suggests that future injection will closely follow the patterns resulting from the geological model simulation. Additionally, should future drilling occur, it would occur near the existing production area, which is greater than 40 miles away from

the current AGI wells, approximately 35 miles away from SC 5-2, and approximately 30 miles away from SC 7-34.

ExxonMobil reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and annual mechanical integrity testing (MIT). As indicated in Section 4.1, visual inspections of the well sites are performed on a routine basis, which serves as a proactive and preventative method for identifying leaks in a timely manner. Gas detectors located at the well sites which alarm at 10 ppm H_2S and 5,000 ppm CO_2 would be triggered if a leak from the wellbore to the atmosphere occurred. Additionally, SCSSV's and surface isolation valves are installed at the AGI wells, which would close in the event of leakage, preventing losses. Mechanical integrity testing is conducted on an annual basis and consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. If the MIT demonstrated a leak, the well would be isolated and the leak would be mitigated as appropriate to prevent leakage to the atmosphere.

<u>Likelihood</u>
There are no existing active Madison or Bighorn-Gallatin penetrations or production within the respective MMAs of the AGI and CO_2 injection well sites. As stated in Section 4.1, ExxonMobil relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSVs), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes.

<u>Magnitude</u>
Given the high concentrations of H_2S and CO_2 in the respective injection streams, ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. Should leakage result from the injection wellbores and into the atmosphere, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7.4 in accordance with 40 CFR 98.448(5).

<u>Timing</u>
As stated above, even a minuscle amount of gas leakage would be immediately detected and immediate action would be taken to stop the release. Any potential leakage from the AGI or CO_2 injection wells would only occur during the lifetime operation of the wells. Once injection ceases, the wells will be plugged and abandoned and will not pose a risk as a leakage pathway.

4.3 Leakage through Faults and Fractures

As discussed in Section 2.6.3, engineering and geologic analysis show no evidence of faulting or structuring around the AGI wells. As a result, the risk of leakage through this pathway is highly improbable. The absence of faulting also tends to suggest that natural fracturing or permeability enhancement in the Madison Formation is also highly improbable. Natural fracturing along with systems of large connected pores (karsts and vugs) could occur in the Bighorn-Gallatin Formation. However, because those enhanced permability areas would be limited to the Bighorn-Gallatin Formation and would not be extended to the sealing formations above, the risk of leakage through this pathway is also highly improbable.

Current-day regional scale thrust faulting has not been observed in the LaBarge area since the field has been under development. There is no concern of reactivation of these thrust faults and it is hypothesized that regional structuring similar in size to the Laramide Orogeny (formation of the Rocky Mountains) would be required to generate new thrust faults of significant size to produce subsurface structures of the scale and magnitude of the LaBarge field. The activation of the salty sediments (which exist below the Nugget Formation and above the Madison Formation at LaBarge) is a phenomenon that was only observed to damage thin-wall cased wells, with thick-wall cased wells having sufficient strength to prevent flowage of these salt sediments. It is believed that weakness in the casing of thin-wall cased wells contributes to the ability of the salty sediments to flow local to the wellbore, shearing casing, as this is a point of weakness in the structural integrity of the wellbore at this depth. Once thick-walled casing was introduced, failures have decreased or have been eliminated.

It has been documented that natural fracturing of reservoirs in the subsurface of LaBarge and surrounding areas are directly correlative to distance to thrust faults in the area. This correlation has been documented in subsurface wellbore image logs and also by surface geological mapping around the thrust faults in the LaBarge area. It therefore follows that a lack of faulting, as observed on 2D seismic panels around and through the AGI and CO_2 injection well sites, will yield formations void of natural fracturing, and the necessary faults are not present to generate pervasive natural fractures. The lack of significant natural fracturing in the Madison Formation at and around the AGI well sites, in conjunction with active inspection of wellbore image logs within the AGI wells themselves, indicates that natural fractures do not exist, that all flow in the Madison 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. It should be noted that the permeability of the Madison 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. Likewise, the low expected connected permeability of the Bighorn-Gallatin has minimal capability to freely flow fluids through its only pore system. Accordingly, there is little potential for lateral migration of the injection fluids.

Prior to drilling the AGI wells, ExxonMobil worked with multiple service companies who provided a range of fracture gradients for the Phosphoria, Weber/Amsden, Morgan, and Madison formations in the area. Based on a frac gradient of 0.85 pounds per square inch (psi)/foot for the Madison, 0.82 psi/foot for the Morgan, 0.80 psi/foot for the Weber/Amsden, and 0.775 psi/foot for the Phosphoria, and a downhole fracture pressure of 12,167 psi, which corresponds to a surface injection pressure of ~5,500 psi, the injected acid gas will not initiate fractures in the confining zones of overlying strata. Facility limits exist that limit surface pressures to below 3,200 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture is unlikely.

Fracture gradient and overburden for the SC 5-2 well were estimated on the basis of offset well data. Offset well pressure integrity test (PIT) data from existing wells was analyzed and resulted in an overburden of 18,883 psi and a fracture gradient of 0.88 psi/foot (15,203 psi) at the top of the Madison Formation (~17,232 feet MD / -10,541 feet Total Vertical Depth subsea (TVDss)) and overburden of 20,388 psi and a fracture gradient of 0.885 psi/foot at the top of the Bighorn-Gallatin Formation (~18,531 feet MD / -11,840 feet TVDss). The fracture pressure at the top of

the Madison Formation is estimated at approximately 15,203 psi which corresponds to a fracture pressure at the surface of 7,685 psi. The projected facility average and maximum surface pressures are 3,430 psi and 6,170 psi, respectively. Both are below the pressure required to fracture the formation; therefore, the probability of fracture is unlikely.

Fracture gradient and overburden for the SC 7-34 well were also estimated on the basis of offset well data. Overburden estimates for the subject formations are based on offset well density logs. Expected formation integrity is primarily based on offset well pressure integrity (PIT) data. Because offset PITs did not result in leakoff, fracture gradient is assumed to be above test pressures. Therefore, the lowest possible fracture gradient constrained by the PITs has a vertical effective stress ratio of 0.55. An analysis of published regional data suggests a vertical effective stress ratio of 0.67 is more likely. Fracture gradient constraints were generalized with an effective horizontal to vertical effective stress ratio of 0.67 to be extrapolated to the target formation. These analyses result in an overburden of 18,705 psi and fracture gradient of 0.90 psi/foot (15,034 psi) at the top of the Madison Formation (approximately 16,744 feet MD / -10,055 feet TVDss) and overburden of 19,934 psi and fracture gradient of 0.90 psi/foot (16,017 psi) at the estimated top of the Bighorn-Gallatin Formation (approximately 17,815 feet MD / -11,126 feet TVDss).

<u>Likelihood</u>
Based on results of the the site characterization including the lack of faulting or open fractures in the injection intervals and the operational limitations on injections pressures, CO_2 leakage to the surface via faults or fractures is highly unlikely.

<u>Magnitude</u>
Given the lack of faulting and fracturing discussed above, leakage through small undetected faults or fractures (if presented and not yet observed) would be contained by the overlying high-quality sealing formations, discussed in more detail in Section 4.4 below, resulting in no CO_2 leakage to surface.

<u>Timing</u>
If a CO_2 leak were to occur through the confining zone due to faults or fractures, it would most likely occur during active injection. Limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. However, if diffusion through the confining zone were to occur, other CO_2 trapping mechanisms such as mineralization and solution in existing formation waters would reduce the magnitude and timing of emission to the surface.

4.4 Leakage through the Formation Seal

Leakage through the seal of the Madison Formation is highly improbable. An ultimate top seal to the disposal reservoir is provided by the evaporitic sequences within the Thaynes Formation. In fact, the natural seal is the reason the LaBarge gas field exists in the first place – the gas has been trapped in the LaBarge structure over a large amount of geologic time. The rock that forms the natural seal is impermeable to Helium (He), a gas with a much smaller molecular volume than CO_2. If the reservoir seal material is impermeable to He, then it follows that it is also impermeable to CO_2. The Thaynes Formation's sealing effect is also demonstrated by the fact that all gas

production shallower than the Thaynes is void of sour gas, while all gas production below it is enriched in sour gases. Formation Inclusion Volatile (FIV) analysis of rock cuttings documents the lack of CO_2 present throughout and above the Triassic regional seals (Ankareh, Thaynes, Woodside, and Dinwoody formations, Figure 2.2) from wells within the LaBarge gas field producing area as well as the AGI injection area.

Although natural creep of the salty sediments below the Nugget Formation is possible, this behavior does not disturb the sediments to the degree necessary to breach the reservoir seal of the Madison Formation. If this salty sediment were to flow on a scale large enough to create a leakage pathway from the Madison Formation to the surface, the natural gases trapped in the formation would have leaked into the atmosphere during the long course of geological time up to this point. The fact that gas remains trapped at pressure in the Madison Formation, it must follow that any natural reactivation or movement of salt-rich sediments that has occurred over the geological history of the LaBarge field area has not created any pathways for gas leakage to the surface.

Wells are monitored to ensure that the injected gases stay sequestered. Any escaped acid gas from the AGI wells will be associated with H_2S, which has the potential to harm field operators. The CO_2 injection wellheads will be monitored with local CO_2 gas heads, which detect low levels of CO_2. The CO_2 injected cannot escape without immediate detection, as expanded upon in the below sections.

<u>Likelihood</u>
Based on results of the the site characterization including the sealing capacity of confining intervals and Triassic evaporitic sequences and the operational limitations on injections pressures, CO_2 leakage to the surface via faults or fractures is highly unlikely.

<u>Magnitude</u>
Given the number, thickness, and quality of the confining units above the Madison and Bighorn-Gallatin injection intervals, as illustrated in Figure 2.2, any potential CO_2 leakage to the surface would be negligible and detected by surface monitoring systems at the injection site. Although highly unlikely, any CO2 leakage would likely occur near the injection well, which is where reservoir pressure is highest as a result of injection.

<u>Timing</u>
If a CO_2 leak were to occur through the multiple formation seals, it would most likely occur during active injection. Limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. However, if diffusion through the confining zone were to occur, other CO_2 trapping mechanisms such as mineralization and solution in existing formation waters would reduce the magnitude and timing of emission to the surface.

4.5 Leakage through Natural or Induced Seismicity

In the greater Moxa Arch area, there is a low level of background seismicity (Advanced National Seismic System (ANSS) Catalogue, 2018, University of Utah Seismograph Stations). Across North America, induced seismicity is sometimes hypothesized as being related to reactivation of basement-involved faults via oilfield waste fluid injection (Ellsworth 2013). There has been no

observed evidence of faulting in the Madison interval using commercially available 2D seismic data within 13.5 miles of the proposed CO_2 injection well sites. There has also been no reported seismic activity attributed to active injection operations at the AGI injection wells. The nearest induced seismic events were observed over 20 miles to the southwest of the proposed SC 7-34 well site. These are attributed to mineral mining operations, and not naturally occurring geological fault activity (USGS, Pechmann et al 1995). The closest naturally occurring seismic activity was a 1.8 magnitude earthquake in 1983 located 7.2 miles to the west at a depth of 10.1 miles according to the ANSS Catalogue and the Wyoming State Geological Survey's historic records. Significant earthquake activity is defined as >3.5 Richter scale (ANSS Catalogue 2018, University of Utah Seismograph Stations). The nearest recorded significant naturally occurring earthquake activity (> M3.5) has been detected over 50 miles away to the west in Idaho and Utah. 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.

Additional geomechanical modeling has been completed in the area around the AGI and CO_2 injection well sites. The modeling was completed to understand the potential for fault slip on the Darby fault far west of the injection and disposal sites. No fault slip is observed at the simulated fault locations or throughout the model. Lack of fault slip then equates to lack of modeled induced seismity from injection.

Likelihood

Due to the lack of significant earthquake activity in the area, the lack of induced seismicity over the period of injection at the AGI wells, and the geomechanical modeling results showing a lack of fault slip, ExxonMobil considers the likelihood of CO_2 leakage to surface caused by natural or induced seismicity to be unlikely.

Magnitude

If a seismic event occurs at the time of AGI or CO_2 injection, ExxonMobil will consult the ANSS Catalogue to verify whether the seismic event was due to the injection in the AGI or CO_2 injection wells and quantify any leak of CO_2 to the surface.

Timing

If a leak of CO_2 to the surface occurs as a result of a seismic event, it would likely occur at the time of the seismic event or shortly thereafter.

5.0 Detection, Verification, and Quantification of Leakage

5.1 Leakage Detection

As part of ongoing operations, SCTF continuously monitors and collects flow, pressure, temperature, and gas composition data in the Distributed Control System (DCS). This data is monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. Additionally, SCTF maintains in-field gas detectors to detect H_2S and CO_2 in the vicinity. If one of the gas detectors

alarmed, it would trigger an immediate response to address the situation. In some instances, more than one detector alarming will trigger automatic equipment isolation/shutdown to mitigate the leak.

Leakage detection for the wells will incorporate several monitoring programs including visual inspection of the surface facilities and wellheads, injection well monitoring and MIT, and DCS surveillance. Table 5.1 provides general information on the potential leakage pathways, monitoring programs to detect leakage, and location of monitoring. Monitoring will occur for the duration of injection. As will be discussed in Section 7.0 below, ExxonMobil will quantify equipment leaks by using a risk-driven approach and continuous surveillance.

Table 5.1 - Monitoring Programs

Potential Leakage Pathway	**Detection Monitoring Program**	**Monitoring Location**
Surface Equipment	DCS Surveillance Visual Inspections Inline Inspections Gas Alarms Personal H_2S Monitors	From injection flow meter to injection wellhead
Wells	DCS Surveillance Visual Inspections MIT Gas Alarms Personal H_2S Monitors	Injection well – from wellhead to injection formation
Faults and Fractures, Formation Seal, Lateral Migration	DCS Surveillance Gas Alarms	Injection well – from wellhead to injection formation
Natural or Induced Seismicity	DCS Surveillance Gas Alarms ANSS Catalogue	Injection well – from wellhead to injection formation Regional data

5.2 Leakage Verification

Responses to leaks are covered in the SCTF's Emergency Response Plan (ERP), which is updated annually. If there is a report or indication of a leak from the AGI facility from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and H_2S monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Pressure from the AGI system will be relieved to the flare, not vented, due to the dangerous composition of the gas.

The ERP will be updated to include the CO_2 injection facilities and corresponding wells after commencement of operations. If there is a report or indication of a leak from the CO_2 injection facilities from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and gas monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Once isolated from the CO_2 injection flowline, pressure from the affected CO_2 injection well will be relieved locally to atmosphere within the well site fence line.

5.3 Leakage Quantification

Examples of leakage quantification methods for the potential leakage pathways identified in Table 5.1 are outlined below. All calculations associated with quantifiying leakage will be maintained as outlined in Section 10.0.

<u>Leakage from Surface Equipment</u>

The leakage from surface equipment will be estimated once leakage has been detected and confirmed. As further described in Section 7.4, ExxonMobil will estimate the mass of CO_2 emitted from leakage points at the surface based on operating conditions at the time of the release – pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of leak. The annual mass of CO_2 that is emitted by surface leakage will be calculated in accordance with Equation RR-10.

<u>Leakage through AGI and CO_2 Wells</u>

As stated in Section 4.2, ExxonMobil reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and annual mechanical integrity testing (MIT). Gas detectors located at the well sites which alarm at 10 ppm H_2S and 5,000 ppm CO_2 would be triggered if a leak from the wellbore to the atmosphere occurred. If there is indication of a leak, leakage through AGI and CO_2 wells will be estimated once leakage has been detected and confirmed. ExxonMobil will take actions to quantify the leak and estimate the mass of CO_2 emitted based on operating conditions at the time of the release – pressure and flow rate, size of the leakage point opening, and estimated duration of leak.

Leakage through Faults and Fractures, Formation Seal, or Lateral Migration

As stated in Section 4.3, engineering and geologic analysis show no evidence of faulting or structuring around the AGI wells and the risk of leakage through this pathway is highly unlikely. Given the lack of faulting and fracturing, leakage through small undetected faults or fractures (if presented and not yet observed) would be contained by the overlying high-quality sealing formations, resulting in no CO_2 leakage to surface.

Further, as stated in Section 4.4, leakage through the formation seal is highly improbable due to the geology of the field which has demonstrably trapped and retained both hydrocarbon and non-hydrocarbon gases over long periods of geologic time. Additionally, limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. Wells are continuously monitored to ensure that the injected gases stay sequestered and any escaped gas would be immediately detected.

As stated in Section 5.1, SCTF continuously monitors and collects flow, pressure, temperature, and gas composition data in the DCS. This data is monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. If there is indication of leakage of CO_2 through faults and fractures, the formation seal, or lateral migration as potentially indicated by abnormal operational data, ExxonMobil will take actions to quantify the leak (e.g., reservoir modeling and engineering estimates) and take mitigative actions to stop leakage. Given the unliklihood of leakage from these pathways, ExxonMobil will estimate mass of CO_2 detected leaking to the surface in these instances on a case-by-case basis utilizing quantification methods such as engineering analysis of surface and subsurface measurement data, dynamic reservoic modeling, and history-matching of the reservoir performance.

Leakage through Natural or Induced Seismicity

As stated in Section 4.5, there is low level of background seismicity detected in the area. If a seismic event occurs at the time of AGI or CO_2 injection, ExxonMobil will consult the ANSS Catalogue to verify whether the seismic event was due to the injection in the AGI or CO_2 injection wells and quantify any leak of CO_2 to the surface based on operating conditions at the time of the event – pressure and flow rate, size of the leakage point opening, and estimated duration of leak.

6.0 Determination of Baselines

ExxonMobil uses existing automatic data systems to identify and investigate excursions from expected performance that could indicate CO_2 leakage. The following describes ExxonMobil's approach to collecting baseline information.

Visual Inspections

Field personnel conduct daily inspections of the AGI facility and weekly inspections of the AGI well sites. The CO_2 injection facility and well sites will undergo weekly visual inspections. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize

the possibility of CO_2 leakage. If an issue is identified, a work order will be generated to correct the issue.

H_2S Detection – AGI Wells

The CO_2 injected into the AGI wells is injected with H_2S at a concentration of 50 - 65% (500,000 - 650,000 ppm). H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. At this high of a concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm. Additionally, all field personnel are required to wear H_2S monitors for safety reasons. Personal monitors alarm at 5 ppm. Any gas detector alarm or personal H_2S monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the gas detectors and monitors are working correctly.

CO_2 Detection – CO_2 Injection Wells

The CO_2 injected into the CO_2 injection wells will be at a concentration of approximately 99%. CO_2 gas detectors will be installed around the well sites, which will trigger at 0.5% CO_2, therefore even a miniscule amount of gas leakage would trigger an alarm.

Continuous Parameter Monitoring

The DCS of the SCTF 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.

Well Testing

On an annual basis, the subsurface and wellhead valves are leak tested for mechanical integrity testing (MIT) as required by the WOGCC. Results from this type of testing are compared to previous MIT data to evaluate whether well integrity has been compromised.

Additionally, inline inspections are conducted of the AGI flow lines through the use of a smart pig to identify potential areas of corrosion in the pipeline. Results from this type of testing are compared to previous data to evaluate whether pipeline integrity has been compromised. The operations at the SCTF will have the ability to conduct inline inspections on the SC 5-2 and SC 7-34 flow lines, however inline inspections are not anticipated to occur frequently because no free water is expected to accumulate.

7.0 Site Specific Modifications to the Mass Balance Equation

To accommodate for site-specific conditions, as provided in 40 CFR 98.448, ExxonMobil proposes to modify quantifying equipment leaks by using a risk-driven approach. Due to the high H_2S concentration of the AGI fluids, monitoring poses a risk to personnel. Additionally, as mentioned above, even a small leak of this high H_2S gas would trigger an alarm. A small leak at the CO_2 injection wells would also trigger an alarm, as mentioned above. ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to

stop the release. This continuous surveillance using gas detectors identifies leaks better than an annual leak survey would 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 ExxonMobil will calculate the mass of CO_2 injected, emitted, and sequestered.

7.1 Mass of CO_2 Received

§98.443 states that "you must calculate the mass of CO_2 received using CO_2 received equations… unless you follow the procedures in §98.444(a)(4)." §98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." Since the CO_2 received by the AGI and CO_2 injection wells are wholly injected and not mixed with any other supply of CO_2, the annual mass of CO_2 injected would be equal to the annual mass of CO_2 received. No CO_2 is received in containers.

7.2 Mass of CO_2 Injected

Volumetric flow meters are used to measure the injection volumes at the AGI wells and are proposed for use to measure the injection volumes at the CO_2 injection wells. Equation RR-5 will be used to calculate the annual total mass of CO_2 injected.

Equation RR-6 will be used to aggregate injection data for the AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34 wells.

7.3 Mass of CO_2 Produced

We will not produce injected CO_2 (as discussed in section 3.2 and illustrated in figure 2.7), hence we do not plan to calculate produced CO_2 according to the requirements of Subpart RR.

7.4 Mass of CO_2 Emitted by Surface Leakage and Equipment Leaks

It is not appropriate to conduct a leak survey at the AGI or the CO_2 injection well sites due to the components being unsafe-to-monitor and extensive monitoring systems in place. Entry to the AGI wells requires the individual to don a full face respirator supplied to breathing air, which would make completion of a leak survey very difficult. Due to the high H_2S concentration of the AGI fluids and the high CO_2 concentration of the CO_2 injection fluid, fugitive leakage would be detected and managed as an upset event in the same way that CO_2E (CO_2 emitted by surface leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time, including pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of the leak. 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.

Parameter CO_2FI (total CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead) will be calculated in accordance with procedures outlined in Subpart W as required by 40 CFR 98.444(d). At the AGI wells, there are no CO_2 emissions from venting due to the high H_2S concentration of the acid gas; blowdown emissions are sent to the flares and are reported under Subpart W for the SCTF. This process occurs upstream of the flow meter and would therefore not contribute to the CO_2FI calculation. At the CO_2 injection wells, venting would occur in the event of depressurizing for maintenance or testing, which would be measured during time of event consistent with 40 CFR 98.233.

7.5 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Since ExxonMobil is not actively producing oil or natural gas or any other fluids as part of the AGI process or CO_2 injection processes, Equation RR-12 will be used to quantify CO_2 injected and sequestered. Parameter CO_2I (total CO_2 injected through all injection wells) will be determined using Equation RR-5, as outlined above in Section 7.2. Parameters CO_2E and CO_2FI will be measured using the leakage quantification procedure described above in Section 7.4. CO_2 in the AGI fluids is not vented from equipment due to the high H_2S concentration.

8.0 Estimated Schedule for Implementation of Second Amended MRV Plan

The SCTF AGI facility and wells have been operational since 2005 and have been subject to the February 2018 MRV plan (approved by EPA in June 2018). Beginning with the start of injection of CO_2 and fluids into the CO_2 injection wells, this Second Amended MRV Plan will become the applicable plan for the AGI and CO_2 injection wells and will replace and supersede the February 2018 MRV plan for the AGI wells. Until that time, the February 2018 MRV plan will remain the applicable MRV plan for the AGI wells. Once the Second Amended MRV Plan becomes the applicable MRV plan, ExxonMobil will continue reporting under Subpart RR for the AGI wells, but will begin including the CO_2 injection wells on or before March 31 of the year after their respective injection begins. Once applicable, ExxonMobil anticipates this Second Amended MRV Plan will remain in effect until the end-of-field-life of the LaBarge 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, ExxonMobil has incorporated the following provisions into its QA/QC programs:

<u>CO_2 *Injected*</u>

- The injected CO_2 stream for the AGI wells will be measured upstream of the volumetric flow meter at the three AGI compressors, at which measurement of the CO_2 is representative of the CO_2 stream being injected, with a continuously-measuring online process analyzer. The flow rate is measured continuously, allowing the flow rate to be compiled quarterly.

- The injected CO_2 stream for the CO_2 injection wells will be measured with a volumetric flow meter and continuously-measuring online process analyzer upstream of the wellhead, at which measurement of the CO_2 is representative of the CO_2 stream being injected. The flow rate will be measured continuously, allowing the flow rate to be compiled quarterly.
- The continuous composition measurements will be averaged over the quarterly period to determine the quarterly CO_2 composition of the injected stream.
- The CO_2 analyzers are calibrated according to manufacturer recommendations.

CO_2 *emissions from equipment leaks and vented emissions of CO_2*
- Gas detectors are operated continuously except as necessary for maintenance and calibration.
- Gas detectors will be operated and calibrated according to manufacturer recommendations and API standards.

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

General
- The CO_2 concentration is measured using continuously-measuring online process analyzers, which is an industry standard practice.
- All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 Missing Data Procedures

In the event ExxonMobil 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 CO_2 injected is missing, it will be estimated using a representative quantity of CO_2 injected from the nearest previous time period at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in 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, ExxonMobil will revise and submit another amended MRV plan within 180 days to the Administrator for approval.

10.0 Records Retention

ExxonMobil will follow the record retention requirements of 98.3(g). Additionally, it will retain the following records from the AGI and CO_2 injection well sites for at least three years:

- Quarterly records of injected CO_2 for the AGI wells including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO_2 for the CO_2 injection wells 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 CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Appendix B: Submissions and Responses to Requests for Additional Information

ExxonMobil Shute Creek Treating Facility Subpart RR Second Amended Monitoring, Reporting and Verification Plan

February 2025

Table of Contents

Introduction

Exxon Mobil Corporation (ExxonMobil) operates two acid gas injection (AGI) wells, AGI 2-18 and AGI 3-14 (collectively referred to as "the AGI wells") in the Madison Formation located near LaBarge, Wyoming for the primary purpose of acid gas disposal with a secondary purpose of geologic sequestration of carbon dioxide (CO_2) in a subsurface geologic formation. The acid gas and CO_2 injected into the AGI wells are components of the natural gas produced by ExxonMobil from the Madison Formation. ExxonMobil has been operating the AGI wells since 2005 and intends to continue injection until the end-of-field-life of the LaBarge assets. The AGI wells and facility (as further described in Section 2.7.1), located at the Shute Creek Treating Facility (SCTF), have been operational since 2005 and have been subject to the February 2018 monitoring, reporting, and verification (MRV) plan approved by EPA in June 2018 (the February 2018 MRV plan).

Because the volume of CO_2 associated with the natural gas production is greater than the volume that is able to be injected into the AGI wells, ExxonMobil is in the process of developing the Shute Creek (SC) 5-2 and SC 7-34 wells (collectively referred to as the "CO_2 injection wells" or "CO_2 disposal wells")[1] for the purpose of geologic sequestration of fluids consisting primarily of CO_2 in subsurface geologic formations. Like the AGI wells, the fluids that will be injected into the CO_2 injection wells are also components of the natural gas produced by ExxonMobil from the Madison Formation. Once operational, the CO_2 injection wells are expected to continue injection until the end-of-field life of the LaBarge assets.

ExxonMobil received the following approvals by the Wyoming Oil and Gas Conservation Commission (WOGCC) to develop the SC 5-2 well:

- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Madison Formation on November 12, 2019
- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Phosphoria, Weber, and Bighorn-Gallatin formations[2] on October 12, 2021
- Application for permit to drill (APD) on June 30, 2022

ExxonMobil received the following approvals by the WOGCC to develop the SC 7-34 well:

- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Madison and Bighorn-Gallatin formations on August 13, 2024
- APD on May 20, 2024

In October 2019, ExxonMobil submitted an amendment to the February 2018 MRV plan in accordance with 40 CFR §98.440-449 (Subpart RR – Geologic Sequestration of Carbon Dioxide) to provide for the monitoring, reporting and verification of geologic sequestration of CO_2 in the Madison Formation during the injection period for the SC 5-2 well (the October 2019 MRV plan). The October 2019 Amended MRV plan was approved by EPA on December 19, 2019.

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[1] *The terms"dispose" and "inject" and their variations may be used interchangeably throughout this document.*

[2] *While the Phosphoria and Weber formations were conditionally approved as exempted aquifers for disposal of fluids, these formations are no longer targets for the SC 5-2 and will not be addressed further in this document*

This second amended plan, dated October 2024 (“Second Amended MRV Plan”) will address all wells collectively when applicable, and otherwise broken out into sub sections to address the specifics of the AGI wells and CO_2 injection wells respectively, as appropriate. This Second Amended MRV Plan meets the requirements of 40 CFR §98.440(c)(1).

The February 2018 MRV plan is the currently applicable MRV plan for the AGI wells. The October 2019 Amended MRV plan would have become the applicable plan once the SC 5-2 well began injection operations. ExxonMobil anticipates the SC 5-2 well will begin injection operations in 2025 and the SC 7-34 well will begin injection operations in 2026. At that time, this Second Amended MRV Plan will become the applicable plan for the AGI wells and CO_2 injection wells collectively, and will replace and supersede both the February 2018 and October 2019 Amended MRV plans. At that time, ExxonMobil will continue reporting under Subpart RR for the AGI wells, but will begin including the CO_2 injection wells on or before March 31 of the year after their respective injection begins. Once applicable, ExxonMobil anticipates this Second Amended MRV Plan will remain in effect until the end-of-field-life of the LaBarge assets, unless and until it is subsequently amended and superseded.

This Second Amended MRV Plan contains ten sections:

1. Section 1 contains facility information.

2. Section 2 contains the project description. This section describes the geology of the LaBarge Field, the history of the LaBarge field, an overview of the injection program and process, and provides the planned injection volumes. This section also demonstrates the suitability for secure geologic storage in the Madison and Bighorn-Gallatin formations.

3. Section 3 contains the delineation of the monitoring areas.

4. Section 4 evaluates the potential leakage pathways and demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

5. Section 5 provides information on the detection, verification, and quantification of leakage. Leakage detection incorporates several monitoring programs including routine visual inspections, hydrogen sulfide (H_2S) and CO_2 alarms, mechanical integrity testing of the well sites, and continuous surveillance of various parameters. Detection efforts will be focused towards managing potential leaks through the injection wells and surface equipment due to the improbability of leaks through the seal or faults and fractures.

6. Section 6 describes the determination of expected baselines to identify excursions from expected performance that could indicate CO_2 leakage.

7. Section 7 provides the site specific modifications to the mass balance equation and the methodology for calculating volumes of CO_2 sequestered.

8. Section 8 provides the estimated schedule for implementation of the Second Amended MRV Plan.

9. Section 9 describes the quality assurance program.

10. Section 10 describes the records retention process.

1.0 Facility Information

1. Reporter number: 523107

   The AGI wells currently do, and the CO_2 injection wells will, report under the Shute Creek Treating Facility (SCTF) Greenhouse Gas Reporting Program Identification number, which is: 523107.
2. Underground Injection Control (UIC) Permit Class: Class II

   The WOGCC regulates oil and gas activities in Wyoming. WOGCC classifies the AGI, SC 5-2, and SC 7-34 wells in LaBarge as UIC Class II wells.
3. UIC injection well identification numbers:

Well Name	*Well Identification Number*
AGI 2-18	49-023-21687
AGI 3-14	49-023-21674
SC 5-2	49-023-22499
SC 7-34	49-023-22500

2.0 Project Description

This section describes the planned injection volumes, environmental setting of the LaBarge Field, injection process, and reservoir modeling.

2.1 Geology of the LaBarge Field

The LaBarge field area is located in the southwestern corner of Wyoming, contained in Lincoln and Sublette counties. The producing field area is within the Green River Basin and the field is located due west of the Wind River Mountains along the Moxa Arch (Figure 2.1).

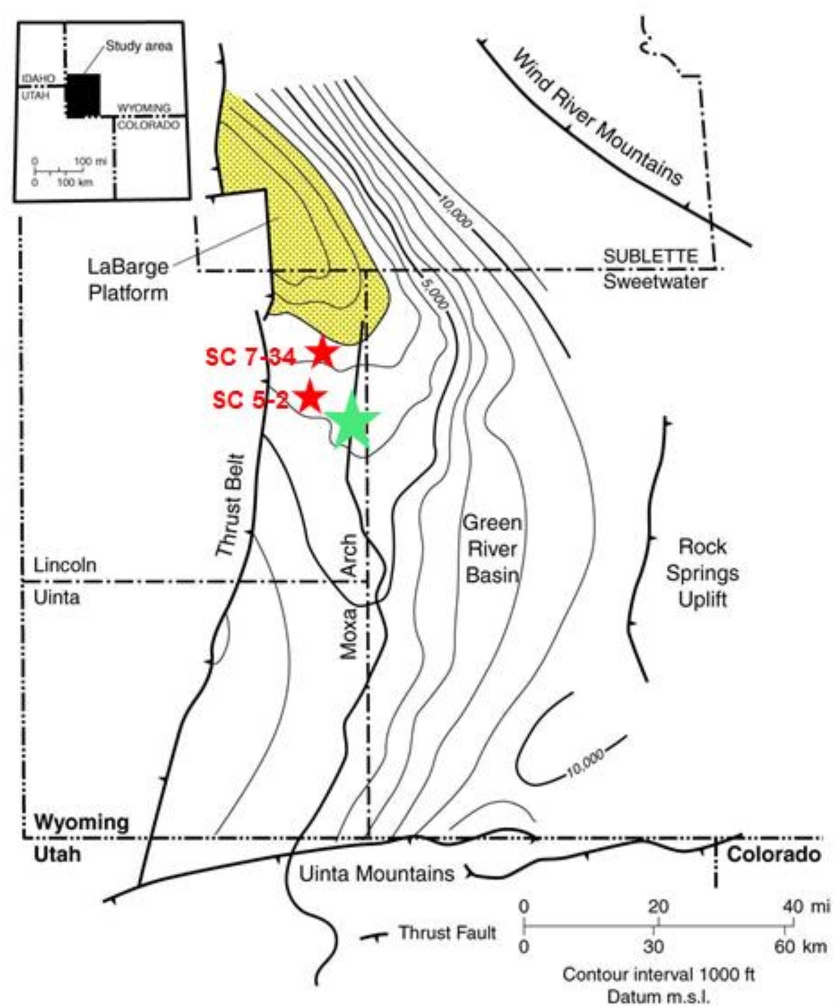

Figure 2.1 Location Map of the LaBarge Field, Wyoming. The location of the AGI wells is denoted with a green star, and the location of the CO_2 injection wells are denoted by the red stars.

2.2 Stratigraphy of the Greater LaBarge Field Area

The western region of Wyoming has been endowed in a very rich and prolific series of hydrocarbon reservoirs. Hydrocarbon production has been established or proven from a large number of stratigraphic intervals around Wyoming, ranging from reservoirs from Cenozoic to Paleozoic in age. Figure 2.2 shows a complete stratigraphic column applicable to the Greater Green River Basin in western Wyoming.

For the LaBarge field area, specifically, commercially producible quantities of hydrocarbons have been proven in the following intervals:

1. Upper Cretaceous Frontier Formation
2. Lower Cretaceous Muddy Formation
3. Permian Phosphoria Formation
4. Lower Jurassic Nugget Formation
5. Pennsylvanian Weber Formation
6. Mississippian Madison Formation

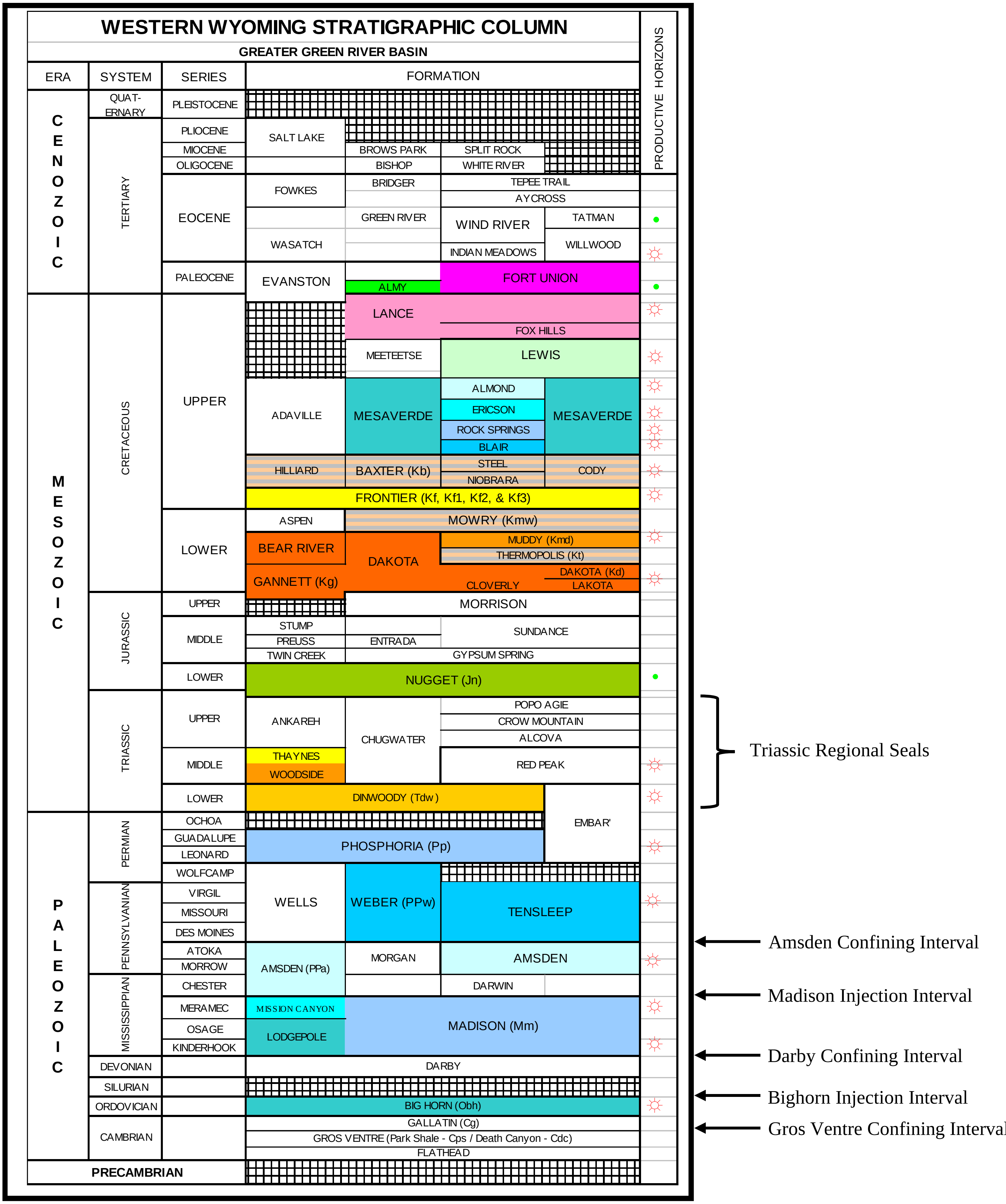

Figure 2.2 Generalized Stratigraphic Column for the Greater Green River Basin, Wyoming

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 closure to 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 (Figure 2.3).

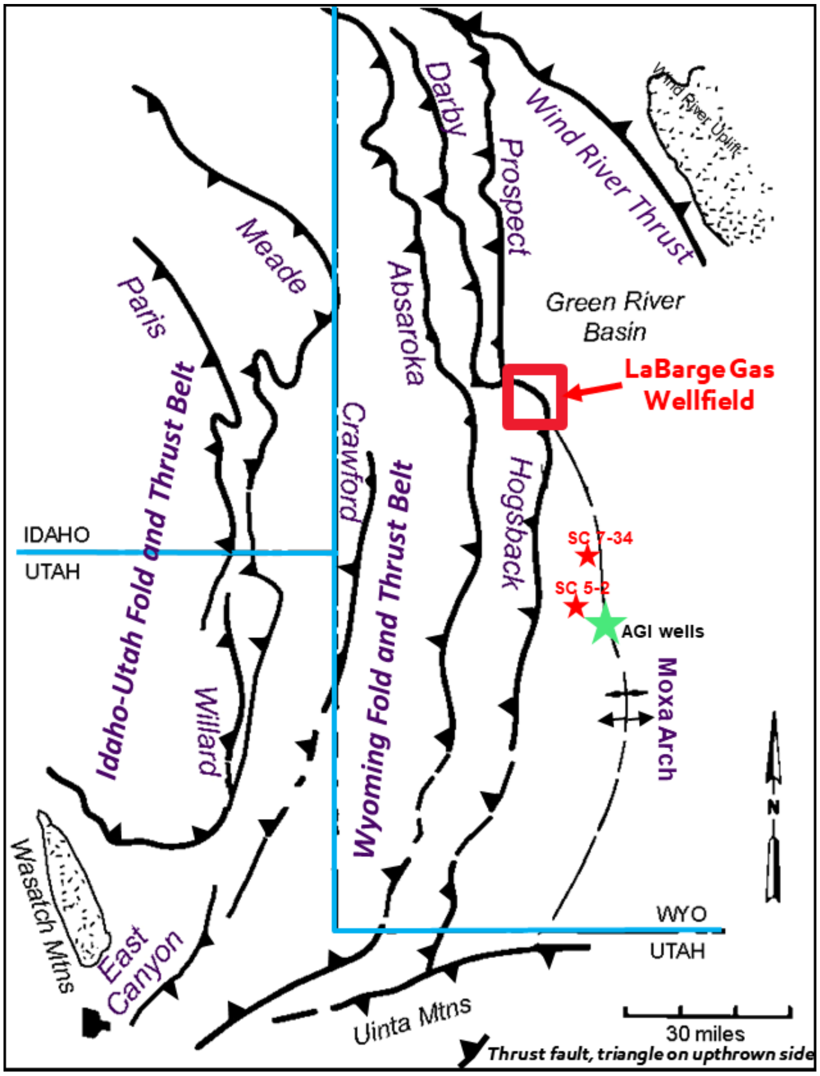

Figure 2.3 Schematic map showing location of Moxa Arch and regional thrust faults. The LaBarge field area is denoted by the red box. The approximate location of the AGI wells is denoted with a green star, and the approximate location of the CO_2 injection wells are denoted by the red stars.

The historical evaluation of structural styles at LaBarge has revealed that three principal styles of structuring have occurred in the area:

1. Basement-involved contraction
2. Deformation related to flowage of salt-rich Triassic strata
3. Basement-detached contraction

2.3.1 Basement-involved Contraction Events

Basement-involved contraction has been observed to most commonly result in thrust-cored monoclinal features being formed along the western edge of the LaBarge field area (Figure 2.3). These regional monoclinal features have been imaged extensively with 2D and 3D seismic data, and are easily recognizable on these data sets (Figure 2.4). At a smaller scale, the monoclinal features set up the LaBarge field structure, creating a hydrocarbon trapping configuration of the various reservoirs contained in the LaBarge productive section.

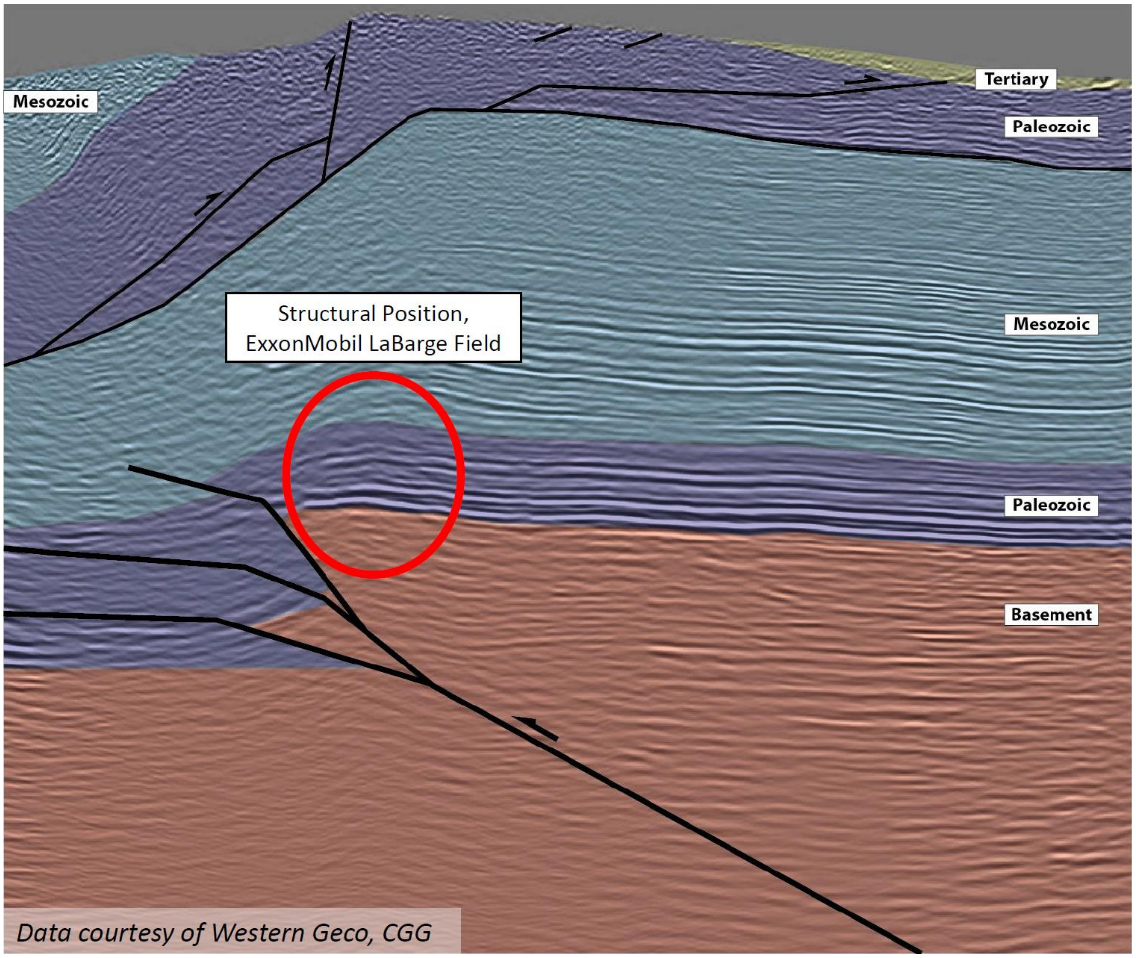

Figure 2.4 Example of thrust-cored monoclinal feature interpreted from 2D seismic data. The thrust-cored feature is believed to be a direct product of basement-involved contractional events.

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 outcrop 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 2.5 shows two seismic lines showing the Triassic salt-rich sediments and the 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.

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 many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. Subsequent drilling at LaBarge has used thicker-walled casing strings to successfully mitigate this sediment flowage issue.

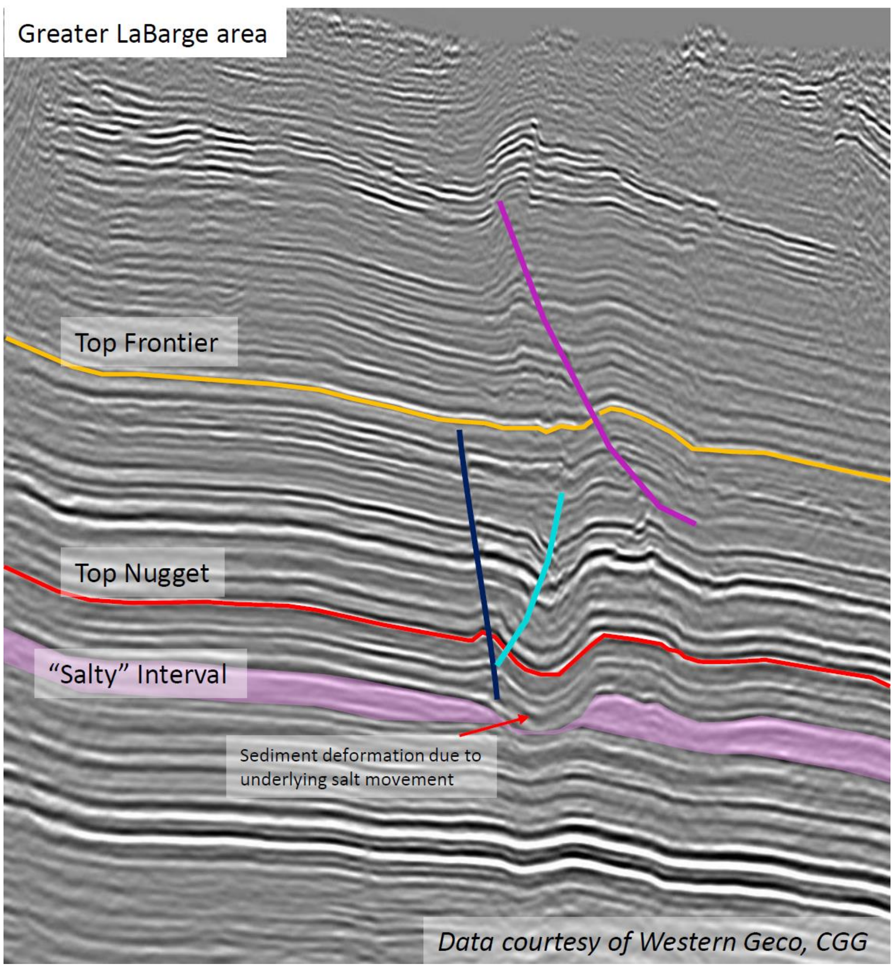

Figure 2.5 Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge field area

2.3.3 Basement-detached Contraction

The third main structural style observed at LaBarge field is those resultant from basement-detached contraction. These features have been well-documented, historically at LaBarge as many of these features have mapped fault expressions on the surface. Detachment and contraction along the basement typically creates three types of structural features:

1. Regional scale thrust faults
2. Localized, smaller scale thrust faults
3. Reactivation of Triassic salt-rich sediments resulting in local structural highs (section 2.3.2)

The basement-detached contraction features typically occur at a regional scale. The subsurface structural features formed through these contractional events are the same size or larger than the greater LaBarge field area. Very large faults are usually associated with these subsurface features, albeit via the reactivation of Triassic salt sediments which can result in additional localized structuring in the area (section 2.3.2).

2.3.4 Faulting and Fracturing of Reservoir Intervals

Reservoir permeability has been observed to increase with the presence of small-scale faults and fractures in almost all of the productive intervals of LaBarge field. Micro-fractures have been observed in core and on formation micro imager (FMI) logs. The fractures seen in the available core are typically filled with calcite, in general.

Empirically, reservoir permeability and increased hydrocarbon productivity have been observed in wells/penetrations that are correlative to areas located on or near structural highs or fault junctions. These empirical observations tend to suggest that these areas have a much higher natural fracture density than other areas or have a larger proportion of natural fractures that are open and not calcite filled. Lack of faulting, as is observed near areas adjacent to the AGI, SC 5-2, and SC 7-34 wells at LaBarge, tends to yield reservoir permeability that is dominated only by matrix or pore-to-pore flow that is generally inhibitive to fluid flow in the subsurface over long distances.

2.3.5 LaBarge Field Structure and Gas Resource of the Madison Formation

Structural closure on the Madison Formation at the LaBarge field is quite large, with approximately 4,000’ true vertical depth (TVD) of structural closure from the top of the structure to the gas-water contact (GWC). Spatially, the Madison closure covers over 1,000 square miles making it one of the largest gas fields in North America.

The Madison Formation is estimated to contain in excess of 170 trillion cubic feet (TCF) of raw gas and 20 TCF of natural gas (CH_4). At current rates of production, the estimated remaining field life is over 100 years. Spatially, the AGI and CO_2 injection wells have been located at or immediately adjacent to the SCTF, over 40 miles to the southeast from the main LaBarge production areas.

2.4 History of the LaBarge Field Area

The LaBarge field was initially discovered in 1920 with the drilling of a shallow oil producing well. The generalized history of the LaBarge field area is as follows:

- 1907 Oil seeps observed near LaBarge, surface mapping of Tip Top anticline
- 1920 Texas Production Company drills shallow Hilliard sandstone discovery (10 BOPD)
- 1940's General Petroleum (G.P.) (Mobil) explores LaBarge area, surface and seismic mapping
- 1951 Tip Top Field discovered by G.P. (Frontier SS @ 1.8 MCFD, Nugget SS @ 266 BOPD)
- 1952 Belco discovers Frontier gas at Big Piney and LaBarge
- 1954 Belco commits gas to Pacific NW Pipeline, 33 SI gas wells
- 1956 Pacific NW Pipeline completed
- 1956-64 Active drilling of Frontier wells (structural traps)
- 1962 Mobil discovers Madison LS gas at Tip Top, chooses not to develop
- 1970 Exxon evaluates LaBarge area
- 1975-84 2nd major phase of Frontier drilling (stratigraphic traps)
- 1980 Section 29 of Oil Windfall Tax Act for tight gas sands passed (expired 01/01/94)
- 1981 Exxon discovers Madison gas on Lake Ridge Unit (LRU 1-03)
- 1986 First sales of Exxon Madison gas
- 1992 WOGCC approves 160 acre spacing for Frontier
- 1989-95 Chevron, Enron, PG & E, and Mobil actively drill Frontier targets
- 1999 Exxon and Mobil merge
- 2001-03 Active drilling of Acid Gas Injection wells 2-18 and 3-14
- 2005 Acid Gas Injection wells 2-18 and 3-14 begin operation
- 2019 WOGCC approves SC 5-2 CO_2 injection well
- 2022 Transfer of ownership of shallow horizons on TipTop and Hogsback
- 2023 Active drilling of SC 5-2 CO_2 injection well
- 2024 WOGCC approves SC 7-34 CO_2 injection well

Historically, Exxon held and operated the Lake Ridge and Fogarty Creek areas of the field, while Mobil operated the Tip Top and Hogsback field areas (Figure 2.6). The heritage operating areas were combined in 1999, with the merger of Exxon and Mobil to form ExxonMobil, into the greater LaBarge operating area. In general, heritage Mobil operations were focused upon shallow sweet gas development drilling while heritage Exxon operations focused upon deeper sour gas production.

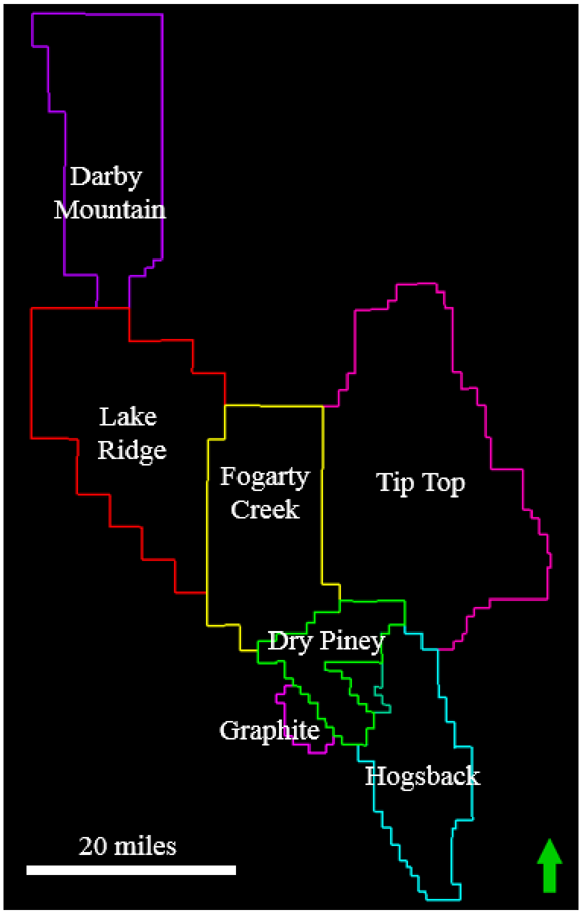

Figure 2.6 Historical unit map of the greater LaBarge field area prior to Exxon and Mobil merger in 1999

2.5 Initial Discovery of Gas and Early Commercial Production at LaBarge

ExxonMobil's involvement in LaBarge originates in the 1960's with Mobil's discovery of gas in the Madison Formation. The Madison discovery, however, was not commercially developed until much later in the 1980's following Exxon's Madison gas discovery on the Lake Ridge Unit. Subsequently, initial commercial gas production at LaBarge was first established in the Frontier Formation, while commercial oil production was established in the Nugget Formation.

Gas production from the Madison Formation was initiated in 1986 after the start-up of the SCTF, which expanded capacity to handle Madison gas. The total gas in-place for the Madison Formation at LaBarge is in excess of 170 TCF gross gas and is a world-class gas reserve economically attractive for production.

2.6 Gas Injection Program History at LaBarge

The Madison Formation, once commercial production of gas was established, was found to contain relatively low methane (CH_4) concentration and high carbon dioxide (CO_2) content. The average properties of Madison gas are:

1. 21% CH_4

2. 66% CO_2
3. 7% nitrogen (N_2)
4. 5% hydrogen sulfide (H_2S)
5. 0.6% helium (He)

Due to the abnormally high CO_2 and H_2S content of Madison gas, the CH_4 was stripped from the raw gas stream leaving a very large need for disposal of the CO_2 and H_2S that remained. For enhanced oil recovery (EOR) projects, CO_2 volumes have historically been sold from LaBarge to offset oil operators operating EOR oilfield projects. Originally, the SCTF contained a sulfur recovery unit (SRU) process to transform the H_2S in the gas stream to elemental sulfur. In 2005, the SRU's were decommissioned to debottleneck the plant and improve plant reliability. This created a need to establish reinjection of the H_2S, and entrained CO_2, to the subsurface.

2.6.1 Geological Overview of Acid Gas Injection and CO_2 Injection Programs

Sour gas of up to 66% CO_2 and 5% H_2S is currently produced from the Madison Formation at LaBarge. The majority of produced CO_2 is currently being sold by ExxonMobil to other oilfield operators and is being used in EOR projects in the region. The sold volume however, does not equal the total produced CO_2 and H_2S volumes, thereby requiring disposal.

ExxonMobil has pursued the AGI program as a safe and reliable method to re-inject the acid gas into the Madison Formation into the aquifer below the field GWC. Gas composition in the AGI wells is based on plant injection needs, and will vary between 35 - 50% CO_2 and 50 - 65% H_2S. The acid gas is injected at a depth of ~17,500 feet below the surface and approximately 43 miles away from the main producing areas of LaBarge.

The volume of CO_2 sold and CO_2 injected into the AGI wells does not equal the volume of CO_2 produced, so additional injection wells are required (SC 5-2 and SC 7-34). Gas composition to be injected into the CO_2 injection wells is planned to be approximately 99% CO_2 with minor amounts of methane, nitrogen, carbonyl sulfide (COS), ethane, and H_2S. For the SC 5-2 well, the gas is planned to be injected between depths of ~17,950 feet and ~19,200 feet measured depth (MD) approximately 35 miles away from the main producing areas of LaBarge. For the SC 7-34 well, the gas is planned to be injected between depths of ~16,740 feet and ~18,230 feet MD approximately 30 miles away from the main producing areas of LaBarge.

2.6.2 Reservoir Quality of Madison and Bighorn-Gallatin Formations at Injection Well Locations

The existing AGI wells were successfully drilled, logged, and evaluated prior to injection commencement. Figure 2.7 is a schematic diagram showing the relative location of AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34. Figures 2.8 and 2.9 are structure maps for the Madison and Bighorn-Gallatin formations, respectively, showing the relative location of the four wells.

Figure 2.10 shows Madison well logs for SC 5-2, AGI 3-14, and AGI 2-18. Petrophysical evaluation of these wells indicate that Madison limestone and dolomite sequences were penetrated, as expected. Total porosity ranges of the limestone sequences were determined to be between 0%

and 5%, while the dolomite sequences were found to be up to 20% total porosity. Injection fall-off testing indicated that the AGI wells exhibit greater than 2000 millidarcy-feet (md-ft) of permeability-height within the injection section. Figure 2.11 shows a table summarizing Madison and Bighorn-Gallatin reservoir properties from the SC 5-2, AGI 3-14, and AGI 2-18 wells. Madison reservoir quality for the SC 5-2 well is similar to the quality for the AGI wells, and is expected to be similar for the SC 7-34 well.

Bighorn-Gallatin reservoir quality for the SC 5-2 well is similar to the nearest Bighorn-Gallatin penetration at 1-12 Keller Raptor well (also referred to as the Amoco/Keller Rubow 1-12 well or the Keller Rubow-1 well), which shows interbedded dolostone and limestone sequences. In general, the degree of dolomitic recrystallization in the Bighorn-Gallatin is similar to the Madison Formation, which has resulted in comparable porosities and permeabilities despite a greater depth of burial. Bighorn-Gallatin total porosity from six LaBarge wells has been determined to be between 2 – 19% with permeabilities between 0.1 – 230 md.

Updated average Madison and Bighorn-Gallatin reservoir properties and well logs will be provided once the SC 7-34 well is drilled. Data will be submitted in the first annual monitoring report following commencement and operation of SC 7-34.

Figures 2.12 and 2.13 show the stratigraphic and structural cross sections of SC 5-2 and SC 7-34 in relation to AGI 3-14, AGI 2-18, and another analog well (1-12 Keller Raptor) penetrating the Madison and Bighorn-Gallatin formations further updip.

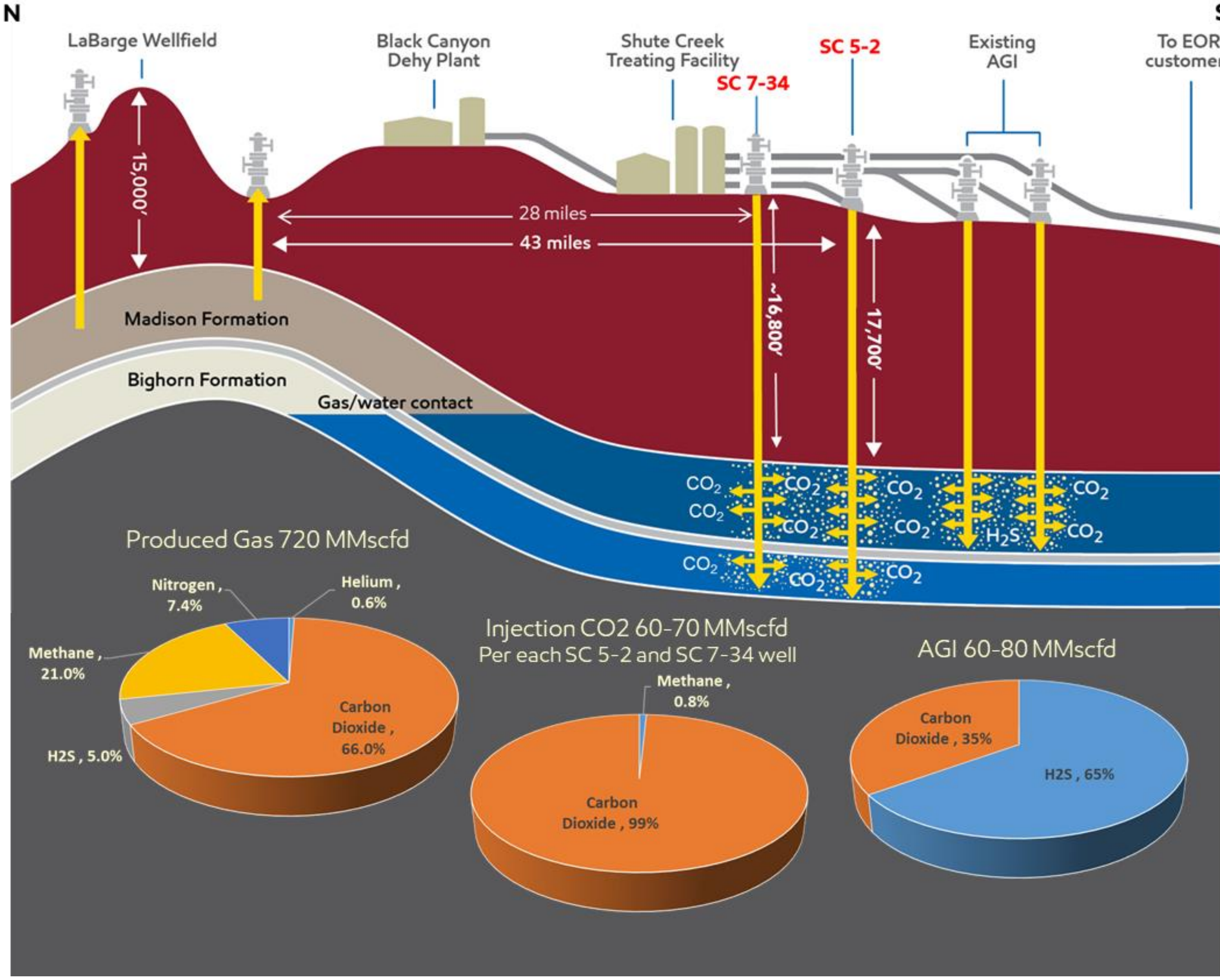

Figure 2.7 Schematic illustration of AGI injection program as currently used at LaBarge and CO_2 injection programs

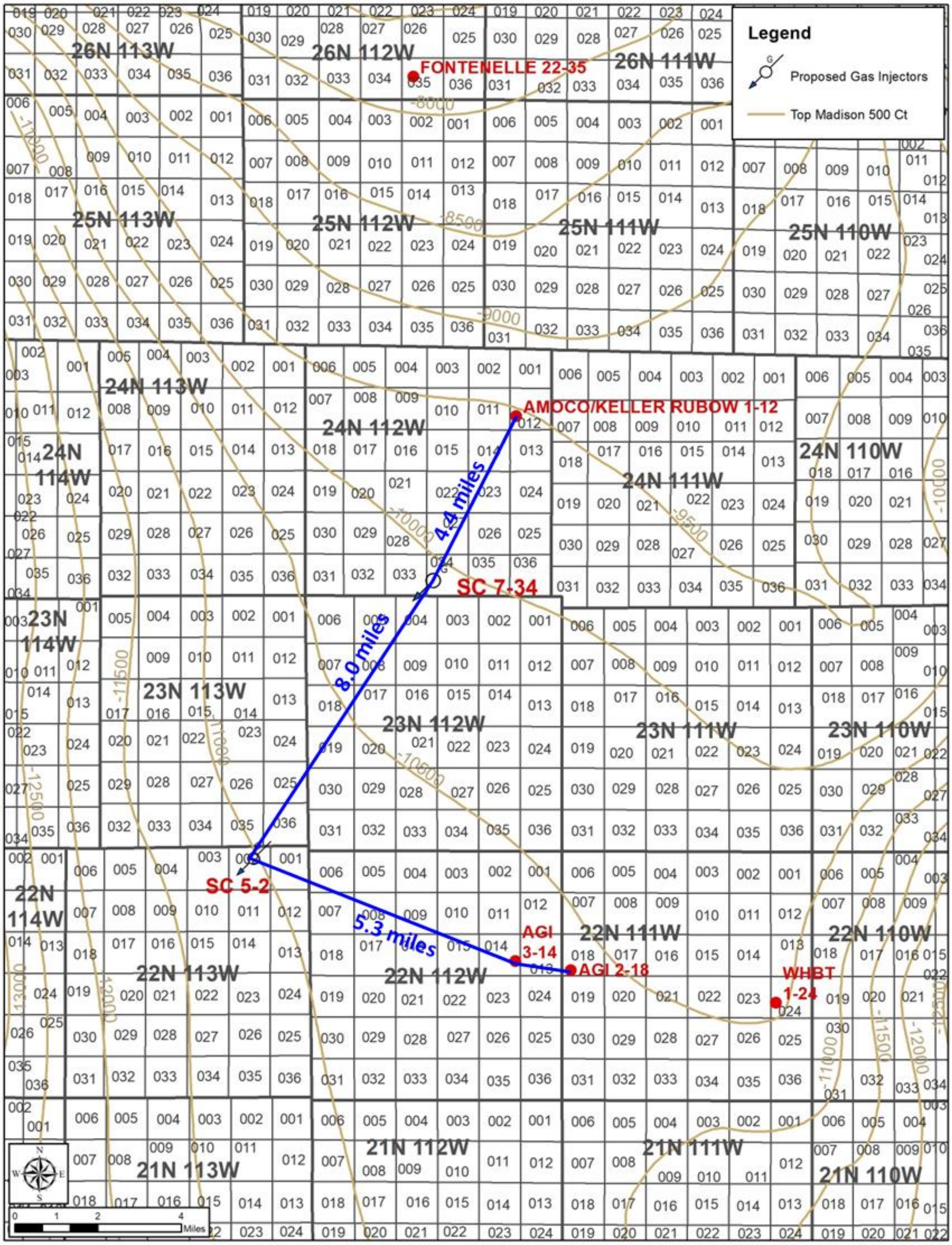

Figure 2.8 Madison structure map with relative well locations

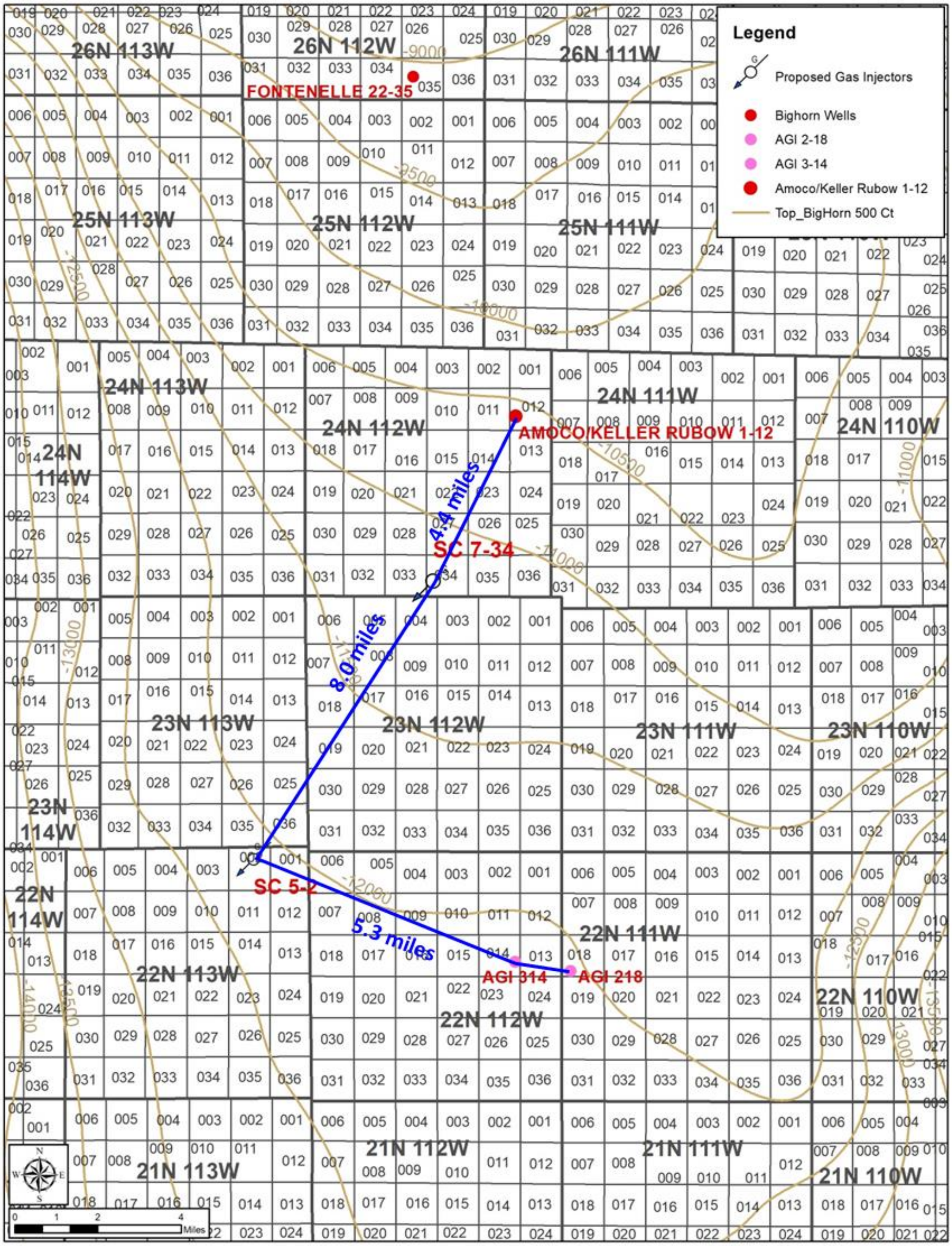

Figure 2.9 Bighorn-Gallatin structure map with relative well locations

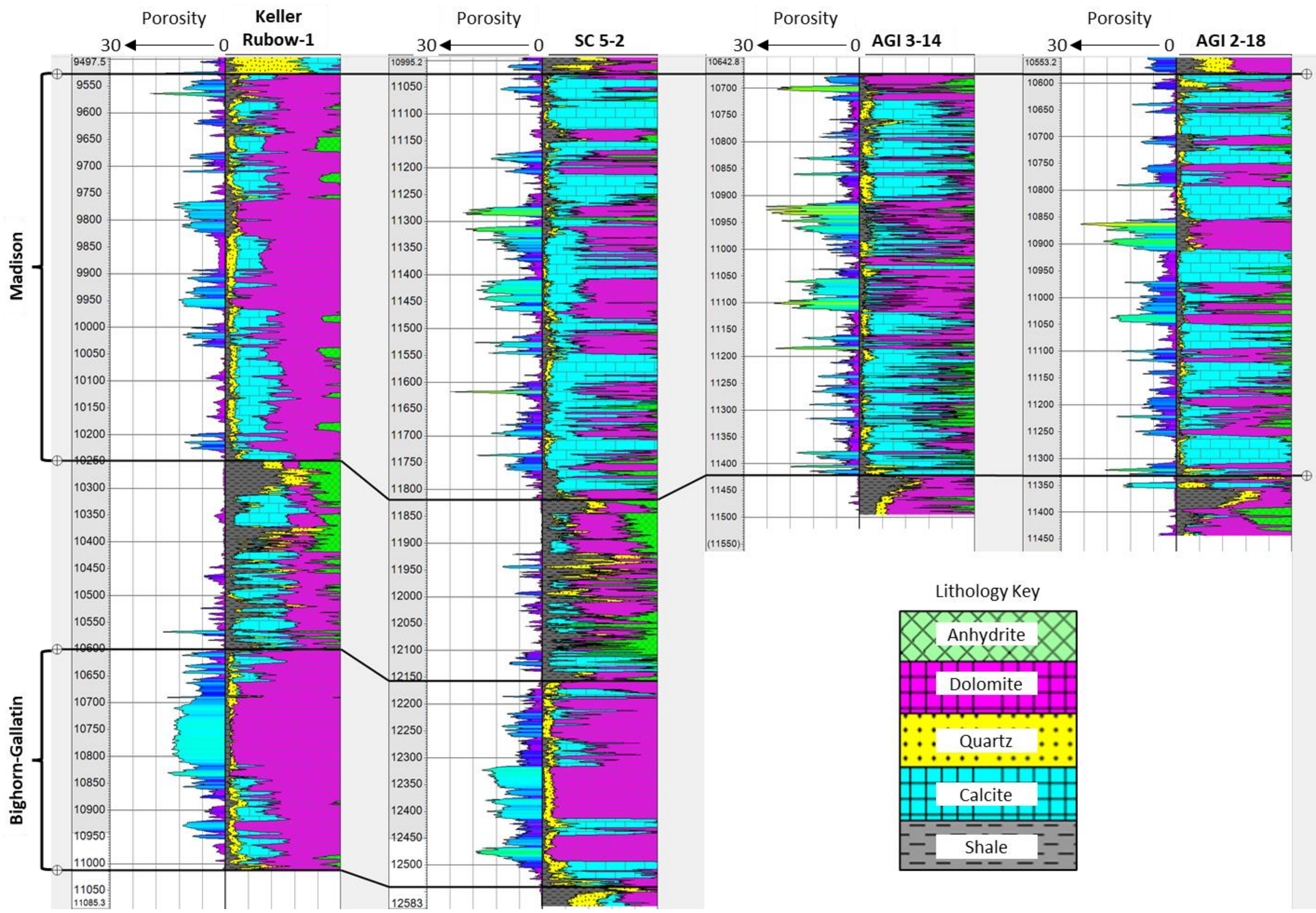

Figure 2.10 Well log sections from the Keller Rubow-1, SC 5-2, AGI 3-14, and AGI 2-18 injection wells across the Madison and Bighorn-Gallatin formations. SC 7-34 well logs are expected to be similar to offset wells.

	Bighorn-Gallatin	Madison		
	SC 5-2	SC 5-2	AGI 3-14	AGI 2-18
Net Pay (ft)	245	291	240	220
Avg Φ (%)	9%	10%	10%	9%
Avg k (md)	4	10	9	12
kh (md-ft)	~600*	~3000*	2300*	~2700*
Skin	-3.7	-3.5	-4.1	-4.5

* From injection / falloff test analysis

Figure 2.11 Average Madison and Bighorn-Gallatin reservoir properties of the SC 5-2 and AGI wells. SC 7-34 is expected to have similar properties.

From Figure 2.11, the parameters tabulated include:

1. *Net pay:* Madison section that exceeds 5% total porosity.
2. *Phi (ϕ):* Total porosity; the percent of the total bulk volume of the rock investigated that is not occupied by rock-forming matrix minerals or cements.
3. *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. Note that the measure of darcy assumes linear flow (i.e. pipe shaped).
4. *Kh:* Millidarcy-feet, which is a measure of the average permeability calculated at a 0.5 foot sample rate from the well log accumulated over the total net pay section encountered.
5. *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.

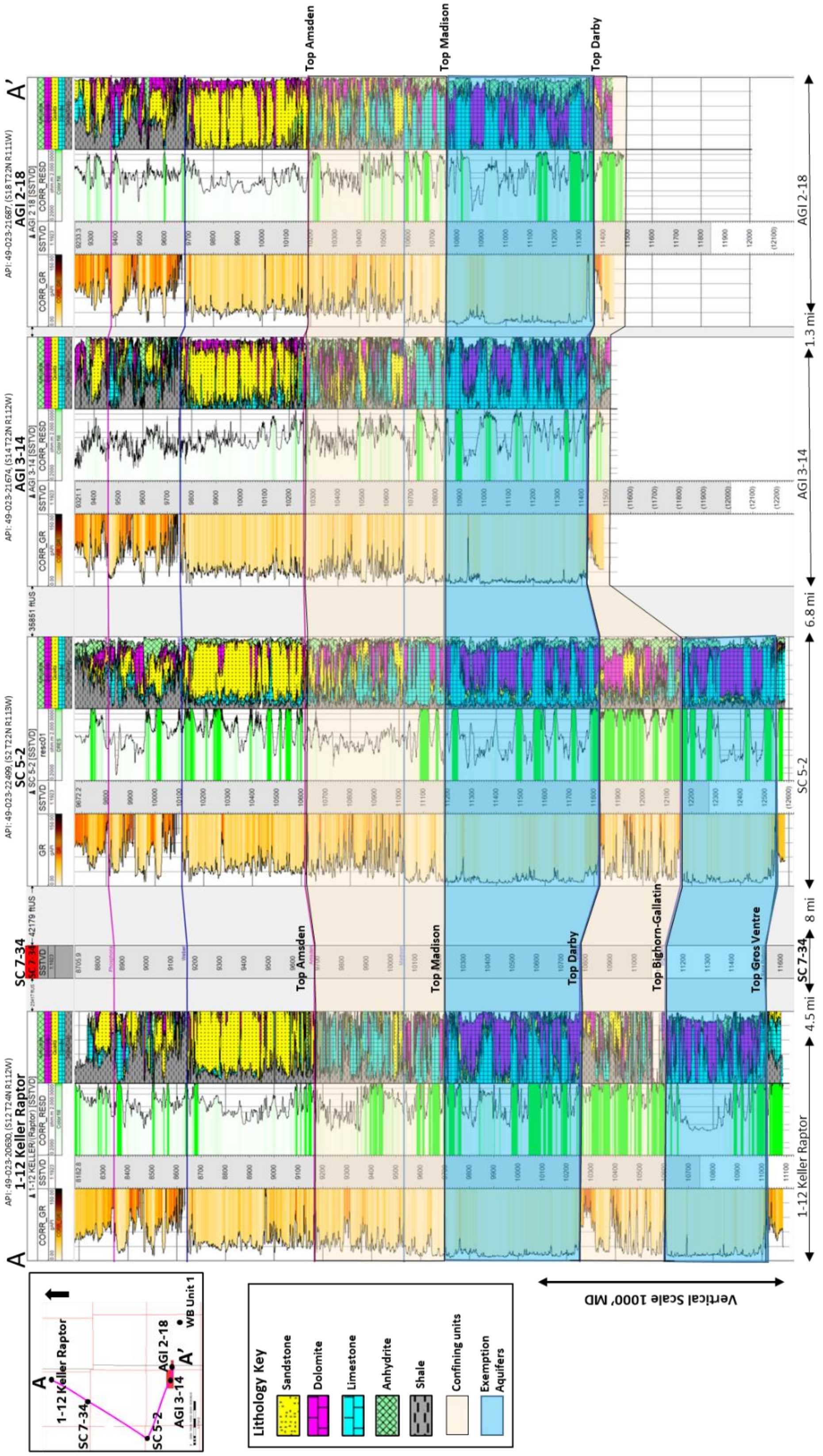

Figure 2.12 Stratigraphic Cross Section of Existing Madison and Bighorn-Gallatin Wells and the SC 7-34 Well

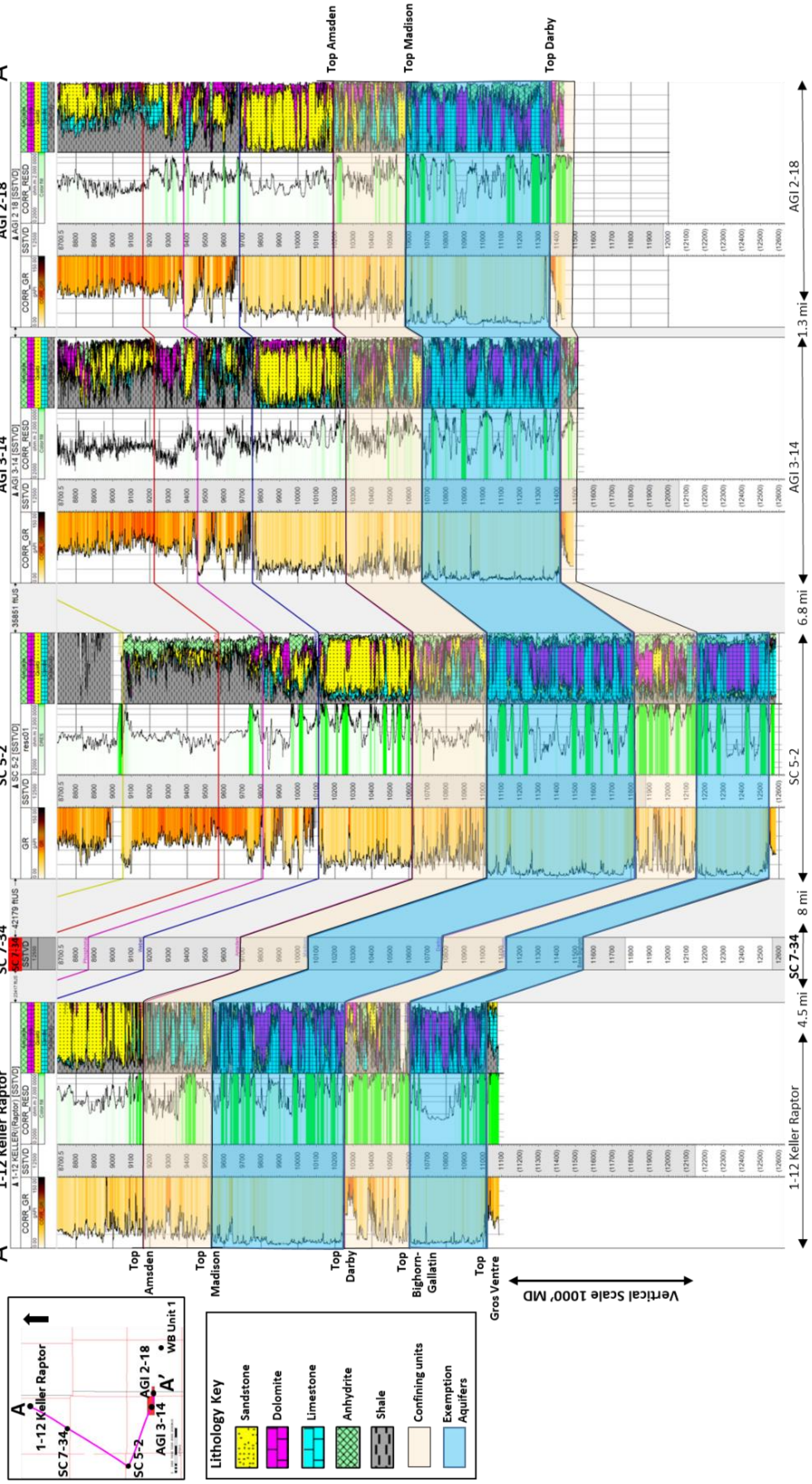

Figure 2.13 Structural Cross Section of Existing Madison and Bighorn-Gallatin Wells and the SC 7-34 Well

2.6.3 Seismic Expression of Madison and Bighorn-Gallatin Formations at CO_2 Injection Well Locations

Seismic expression of the Madison and Bighorn-Gallatin formations at the SC 5-2 and SC 7-34 injection locations indicate that the CO_2 injection wells are located on the plunging crest of the Moxa Arch with little to no structuring observable on the seismic data around these wells. Faulting is also not indicated by the seismic data. Figure 2.14 shows an east-west oriented 2D seismic at the SC 5-2 well location at approximately five times vertical exaggeration. Figure 2.15 shows an east-west oriented 2D seismic at the SC 7-34 well location at approximately four times vertical exaggeration.

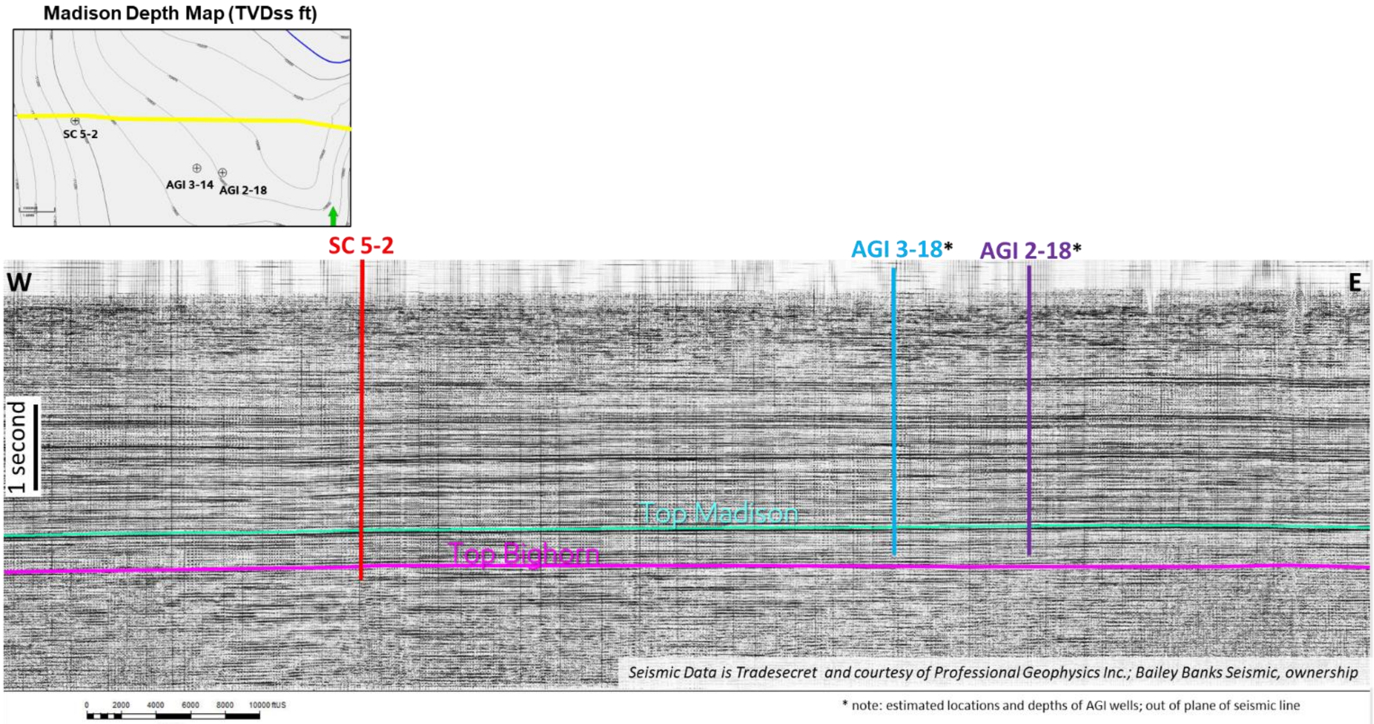

Figure 2.14 2D Seismic traverses around the SC 5-2 injection well location shows no evidence of faulting or structuring around the well location

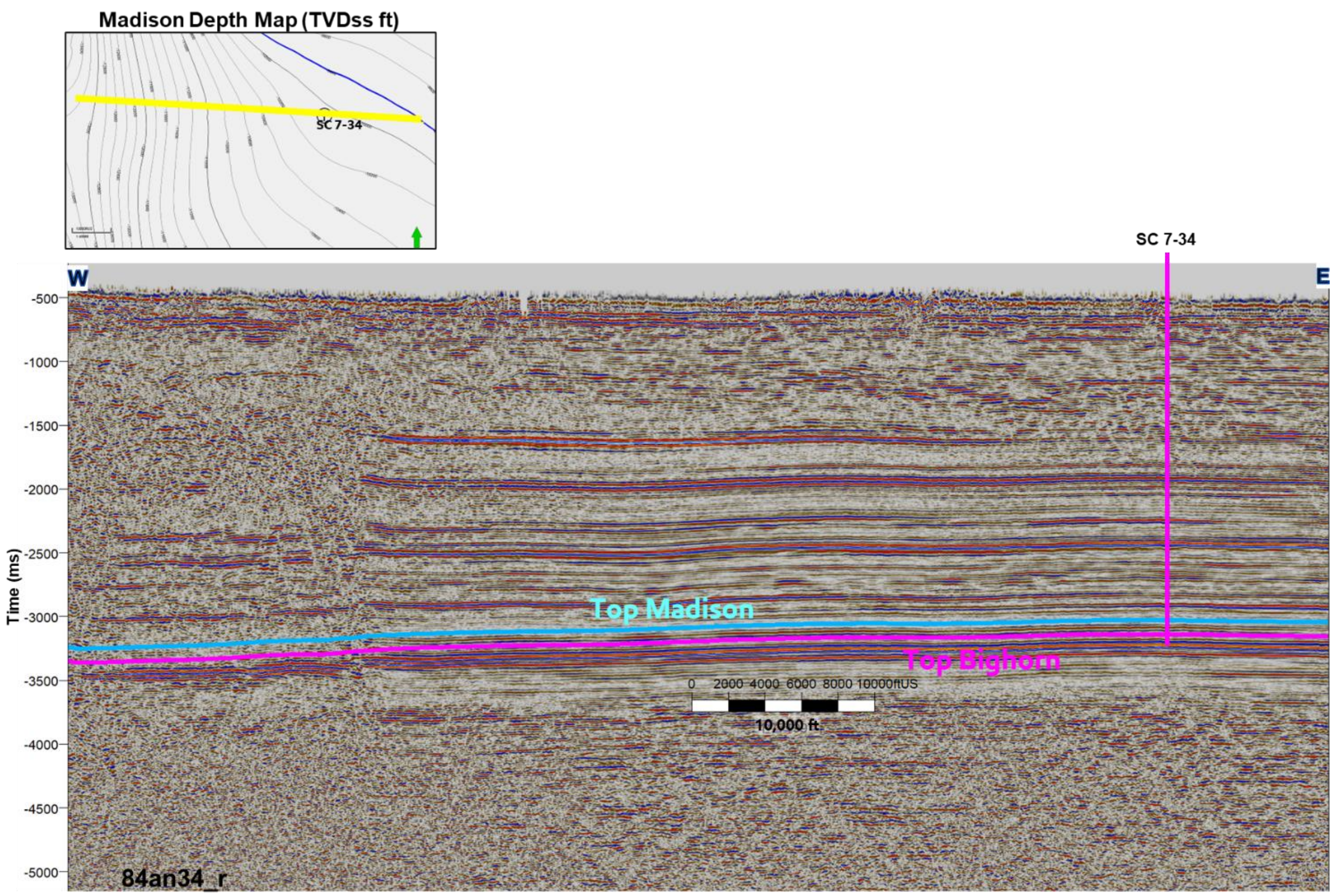

Figure 2.15 2D Seismic traverses around the SC 7-34 injection well location shows no evidence of faulting or structuring around the well location

2.7 Description of the Injection Process

2.7.1 Description of the AGI Process

The AGI facility was commissioned for eliminating the Claus Sulfur Recovery Units (SRU) bottleneck, reducing plant downtime, and reducing operating costs. The purpose of the AGI process is to take the H_2S and some of the CO_2 removed from the produced raw gas and inject it back into the Madison Formation. Raw gas is produced out of the Madison Formation and acid gas is injected into the aquifer below the GWC of the Madison Formation. The Madison reservoir contains very little CH_4 and He at the injection locations under SCTF, where the AGI wells are located. Thus, there is no concern of contaminating the production from the LaBarge well field 43 miles away.

The AGI process transports the acid gas stripped in the Selexol process under pressure through a pipeline to two underground wells that are geologically suitable for storage of the acid gas (AGI 3-14 and AGI 2-18). There are three parallel compressor trains. Two trains are required for full

capacity; the third train is a spare. The low pressure feed from the Selexol process enters the first stage suction and is compressed through four stages of compression. The high pressure acid gas from the Selexol process requires only three stages of compression. The fourth stage discharge acid gas must be condensed prior to pumping to prevent damage from vapors. Fourth stage discharge acid gas is cooled in three heat exchangers prior to entering the pump. Dense phase aerial coolers are located downstream of the pumps; they remove heat generated by pumping and increase the density of the fluid. The liquid H_2S/CO_2 is commingled downstream of the dense phase coolers and divided into the two injection wells over 38 miles from the nearest Madison gas producer in the LaBarge gas field. The approximate stream composition being injected is 50 - 65% H_2S and 35 - 50% CO_2. Each injection well has a dedicated six-inch carbon steel pipeline. The length of pipeline from the AGI battery limit to the injection wells is about:

- 3,200 feet to AGI 3-14
- 12,400 feet to AGI 2-18

The AGI flow lines are buried with seven feet of cover. Heat tracing is provided for the aboveground portions of the lines to prevent the fluid from cooling to the point where free water settles out. Free water and liquid H_2S/CO_2 form acids, which could lead to corrosive conditions. Additionally, the gas is dehydrated before it enters the flow line, reducing the possibility of free water formation, and the water content of the gas is continuously monitored. The liquid H_2S/CO_2 flows via the injection lines to two injection wells. The total depth of each well is about:

- 18,015 feet for AGI 3-14
- 18,017 feet for AGI 2-18.

2.7.2 Description of the CO_2 Injection Process

The CO_2 injection program was initiated primarily because the volume of CO_2 associated with the natural gas production is greater than the volume that is able to be injected into the AGI wells.

2.7.2.1 Description of the SC 5-2 Process

The SC 5-2 process aims to capture CO_2 at the SCTF that would otherwise be vented, and compress it for injection in the aquifer below the GWC of the Madison and Bighorn-Gallatin formations.

The injection system would enable additional CO_2 to be stripped in the Selexol process, pressurized, and transported to a CO_2 injection well, which is geologically suitable for injection, disposal and sequestration of fluids primarily consisting of CO_2. The process will be built into the existing Selexol trains at SCTF. After the acid gas treatment and dehydration, the gas will be routed to a new flash vessel which will enable capture up to 80 million standard cubic feet per day (MMSCFD) from SCTF then compressed with an air cooled Heat Exchanger cooling system. The captured CO_2 will have the potential to be either sold or injected into a CO_2 injection well. Based on modeling, the approximate stream composition will be 99% CO_2, 0.8% methane and 0.2% other mixed gases.

From the CO_2 compressors, an eight inch flow line of approximately 10.1 miles would take the fluids to the SC 5-2 injection well site. The flow line would be buried at depths necessary to avoid and protect existing facilities, roads, and crossings, and will be buried at a minimum below the frost line. The fluids will have a sufficient dew point that free water formation is not expected to accumulate along the pipeline or well. The water content of the gas will be continuously monitored. The gas will be transported via flow line to the SC 5-2 well and injected into the Madison Formation at a depth of ~17,950 feet and into the Bighorn-Gallatin Formation at a depth of ~19,200 feet approximately 33 miles from the nearest Madison gas producer in the LaBarge gas field. Based on geological models, the risk of contaminating production from the LaBarge well field or interacting with the AGI wells or SC 7-34 well approximately 7 miles and 8 miles away, respectively, is improbable due to the relatively tight reservoir quality of the Madison and Bighorn-Gallatin formations, the significant distance between the SC 5-2 injection site and the producing well field, and the volume and rate of injection at the SC 5-2 site.

2.7.2.2 Description of the SC 7-34 Process

The SC 7-34 process aims to divert currently captured CO_2 produced from source wells during natural gas production that will not be sold to customers and route to permanent disposal in the aquifer below the GWC of the Madison and Bighorn-Gallatin formations.

Captured CO_2 that is already routed from SCTF to the existing CO_2 sales building will be diverted and transported via flow line to a CO_2 injection well, which is geologically suitable for injection, disposal, and sequestration of fluids primarily consisting of CO_2. This process will enable disposal of up to 70 MMSCFD through an additional pump. The CO_2 will be cooled with an air cooled Heat Exchanger cooling system. Based on modeling, the approximate stream composition is anticipated to be identical to the SC 5-2 with 99% CO_2, 0.8% methane, and 0.2% other mixed gases.

From the CO_2 compressors, an eight inch flow line of approximately 12.4 miles would take the fluids to the SC 7-34 injection well site. The flow line would be buried at depths necessary to avoid and protect existing facilities, roads, and crossings, and will be buried at a minimum below the frost line. The fluids will have a sufficient dew point that free water formation is not expected to accumulate along the pipeline or well. The water content of the gas will be continuously monitored. The gas will flow via the injection lines to the SC 7-34 well and injected into the Madison Formation at a depth of ~16,740 feet and into the Bighorn-Gallatin Formation at a depth of ~18,230 feet approximately 28 miles from the nearest Madison gas producer in the LaBarge gas field. Based on geological models, the risk of contaminating production from the LaBarge well field 30 miles away or interacting with the SC 5-2 well or AGI wells approximately 8 and 9 miles away, respectively, is improbable due to the relatively tight reservoir quality of the Madison and Bighorn-Gallatin formations, the significant distance between the SC 7-34 injection site and the producing well field, and the volume and rate of injection at the SC 7-34 site.

2.8 Planned Injection Volumes

2.8.1 Acid Gas Injection Volumes

Figure 2.16 is a long-term injection forecast throughout the life of the acid gas injection project. It is based on historic and predicted data. 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 below are the total amount of gas to be injected into the AGI wells, not just the CO_2 portion. ExxonMobil forecasts the total volume of CO_2 stored in the AGI wells over the modeled injection period to be approximately 53 million metric tons.

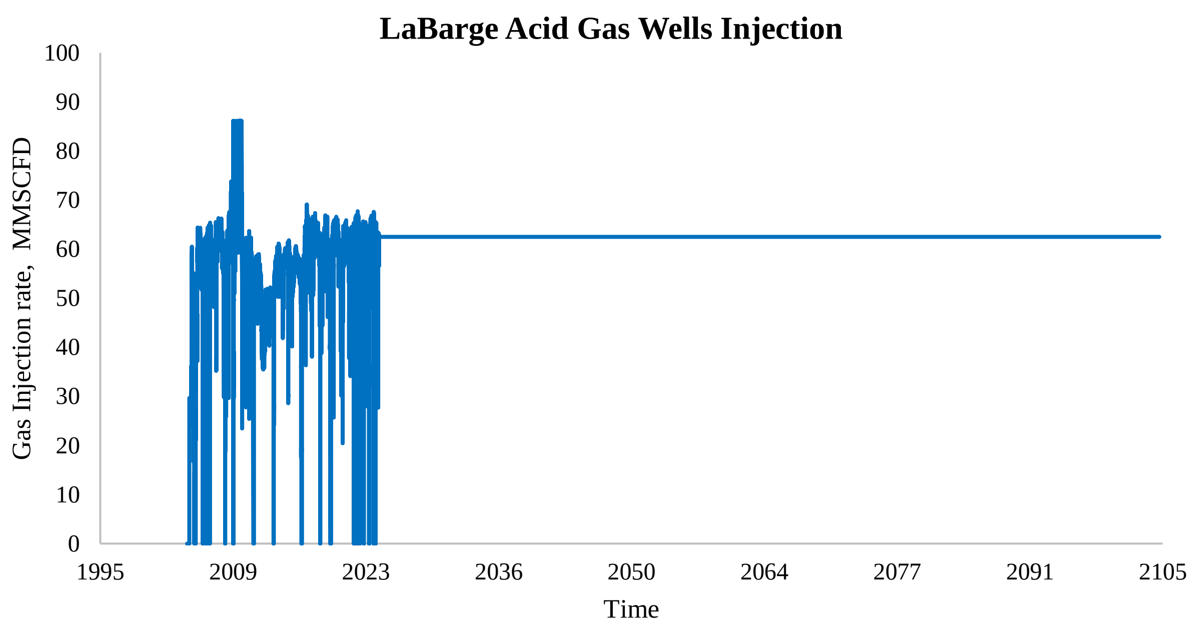

Figure 2.16 – Planned Acid Gas and CO_2 Injection Volumes

2.8.2 CO_2 Injection Wells Volumes

Figure 2.17 below is a long-term average injection forecast through the life of the CO_2 injection wells. 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 below are the total amount of fluids to be injected, but does not include any portion of the Acid Gas Injection project gas. The non-CO_2 portion of the injection stream is expected to be 1% or less of the injected volume. ExxonMobil forecasts the total volume of CO_2 stored in the CO_2 injection wells over the modeled injection period to be approximately 180 million metric tons.

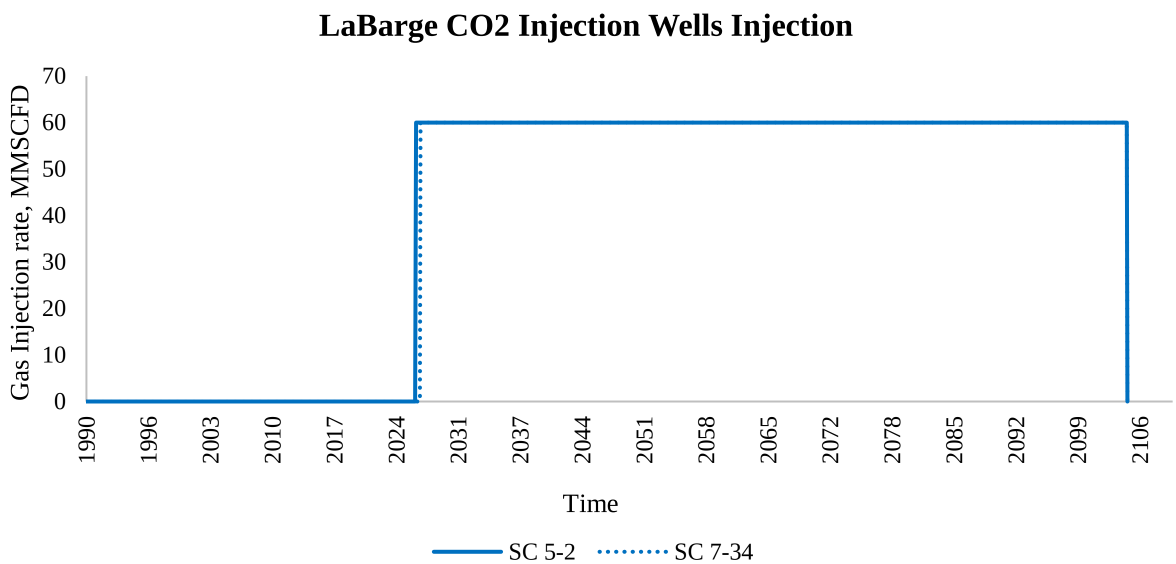

Figure 2.17 – Planned Average CO_2 Injection Well Volumes

3.0 Delineation of Monitoring Area

3.1 Maximum Monitoring Area (MMA)

3.1.1 AGI Wells MMA

Per 40 CFR **§** 98.449, the MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling using Schlumberger's (SLB) Petrel/Intersect, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the acid gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 1%. A gas saturation of 1% is well below the lowest gas saturation that can be confidently detected by formation evaluation methods in reservoirs with rock properties such as those found in the Madison Formation.

After injecting 0.3 trillion cubic feet (TCF) by year-end 2023, the current estimated acid gas plume size is approximately 21,350 feet in diameter (4.0 miles) (see Figure 3.1). With continuing injection of an additional 1.9 TCF through year-end 2104, at which injection is expected to cease, the plume size is expected to grow to approximately 39,500 feet in diameter (7.5 miles) (see Figure 3.2).

The model was run through 2986 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. The rate of growth of the free-phase gas plume is less than 0.25% areally per

year, demonstrating plume stability. Figure 3.3 below shows the expansion of the plume to a diameter of approximately 40,470 feet (7.7 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the MMA will be defined by Figure 3.3, which is the maximum areal extent of the plume once it has reached stability (defined by the extent of the plume in 2205, which is a 7.7-mile diameter) plus the buffer zone of one-half mile.

3.1.2 CO_2 Injection Wells MMA

Per 40 CFR **§** 98.449, the MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the CO_2 gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 1%.

Note that estimates of plume size assume that CO_2 is coinjected without flow control at both the SC 5-2 and SC 7-34 wells into both the Madison and Bighorn-Gallatin intervals. Having no flow control means that the amount of gas that enters each interval is for the most part a function of the permeability thickness (kh) of each interval. There is limited data, especially for the Bighorn-Gallatin, with few well penetrations, all of which are a significant distance from the target formation. Therefore, the anticipated plume sizes are based on simulation results relying on best estimates from available data regarding the Madison and Bighorn-Gallatin reservoir quality.

The model was run through 2986 to assess the potential for expansion of the plume after injection ceases at year-end 2104. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. The rate of growth of the free-phase gas plume is less than 0.25% areally per year, demonstrating plume stability.

3.1.2.1 SC 5-2 MMA

Assuming SC 5-2 begins injecting in 2025, 0.02 TCF of CO_2 will have been injected by mid-2026 and the gas plume will just begin to form. Figure 3.4 shows expected average gas saturations at mid-2026 and the location of the AGI wells relative to the SC 5-2 injection well. After injecting 1.7 TCF at year-end 2104, injection is expected to cease. The SC 5-2 CO_2 plume size is expected to grow to approximately 23,650 feet in diameter (4.5 miles) (see Figure 3.5).

Figure 3.6 below shows the expansion of the SC 5-2 plume to a diameter of approximately 24,500 feet (4.6 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the SC 5-2 MMA will be defined by Figure 3.6, which is the maximum areal extent of the SC 5-2 plume once it has reached stability (defined by the extent of the plume in 2205, which is a 4.6-mile diameter) plus the buffer zone of one-half mile.

3.1.2.2 SC 7-34 MMA

SC 7-34 is assumed to begin injection mid-2026. After injecting 1.7 TCF at year-end 2104, injection is expected to cease. The SC 7-34 CO_2 plume size is expected to grow to approximately 22,100 feet in diameter (4.2 miles) (see Figure 3.7).

Figure 3.8 below shows the expansion of the SC 7-34 plume to a diameter of approximately 24,976 feet (4.7 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the SC 7-34 MMA will be defined by Figure 3.8, which is the maximum areal extent of the SC 7-34 plume once it has reached stability (defined by the extent of the plume in 2205, which is a 4.6-mile diameter) plus the buffer zone of one-half mile.

3.2 Active Monitoring Area (AMA)

Per 40 CFR **§** 98.449, the AMA is the superimposed areas projected to contain the free phase CO_2 plume at the end of the year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile and the area projected to contain the free phase CO_2 plume at the end of year t+5, where t is the last year in the monitoring period.

ExxonMobil proposes to define the AMA as the same boundary as the MMA for the AGI and CO_2 injection wells. The following factors were considered in defining this boundary:

1. Lack of faulting in the MMA yields no vertical pathways for fluids to move vertically out of the Madison or Bighorn-Gallatin formations to shallower intervals.
2. Lack of faulting in the injection area does not create enhanced reservoir permeability through natural fracturing and all flow of injected fluids will be darcy flow from pore to pore.
3. Distance from the LaBarge production field area is large (35+ miles) and reservoir permeability is generally low which naturally inhibits flow aerially from injectionsite.
4. The LaBarge field production area is a large structural hydrocarbon trap that has sealed and trapped hydrocarbons for large geologic periods of time. There is no reason to believe that any injection fluids that may migrate outwards from the injection site to the larger LaBarge structure would not also be effectively trapped at the LaBarge structure over geological time.
5. If t is defined as the final year of injection coinciding with end of field life for the LaBarge assets, the MMA encompasses the free phase CO_2 plume 100 years post-injection, and therefore satisfies and exceeds the AMA area.

The purpose of the AMA is to allow for a practical and cost-effective monitoring program throughout the life of the project. Because there are no probable leakage pathways in the MMA, besides surface equipment which is extensively monitored, ExxonMobil believes it is appropriate to define the AMA as the same boundary as the MMA. Additionally, due to the high H_2S content of the injected gas stream into the AGI wells, monitoring of leaks is essential to operations and

personnel safety, so a full-scale monitoring program has already been implemented at the AGI sites, as will be discussed below.

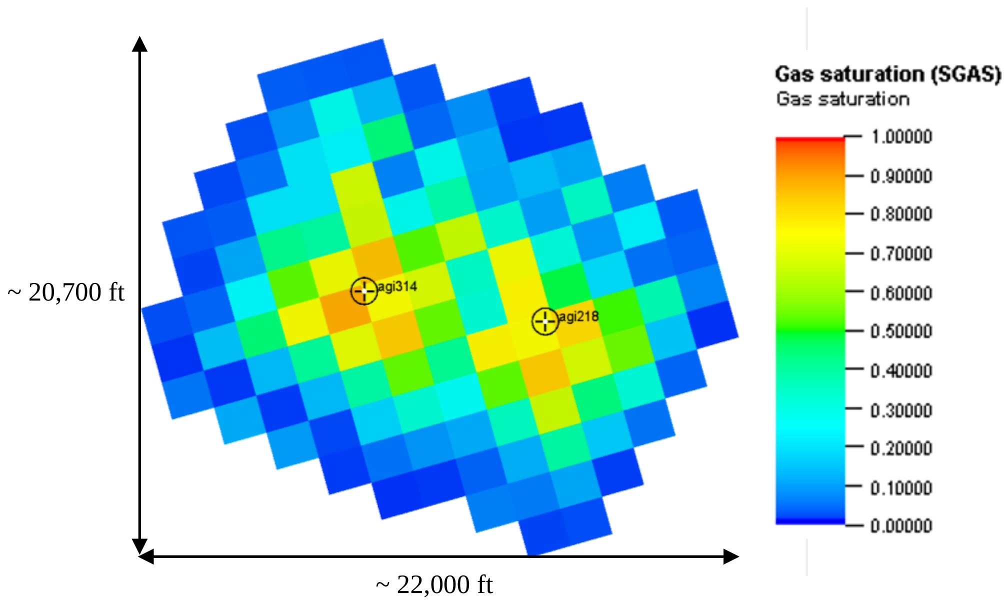

Figure 3.1 – AGI Estimated Gas Saturations at Year-end 2023

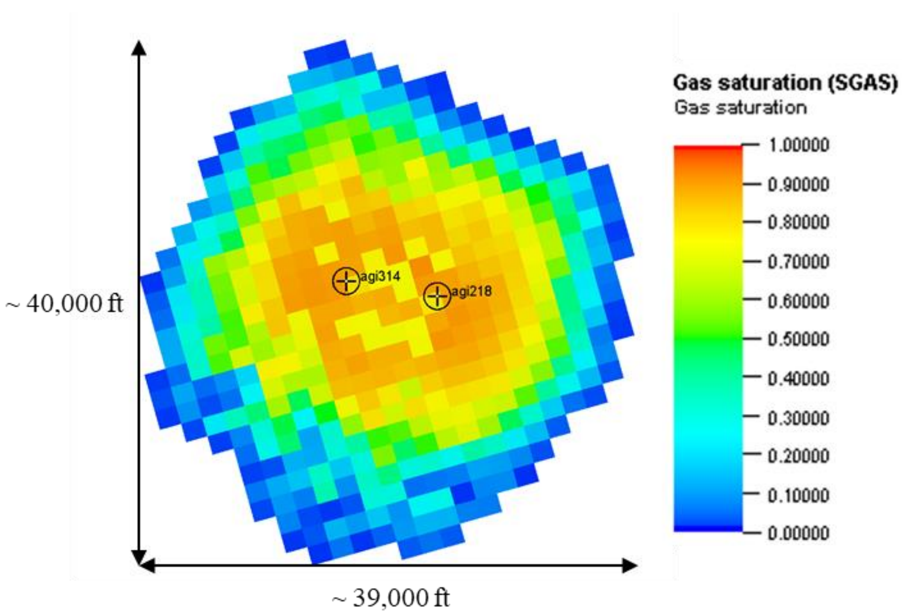

Figure 3.2 – AGI Predicted Gas Saturations at Year-end 2104

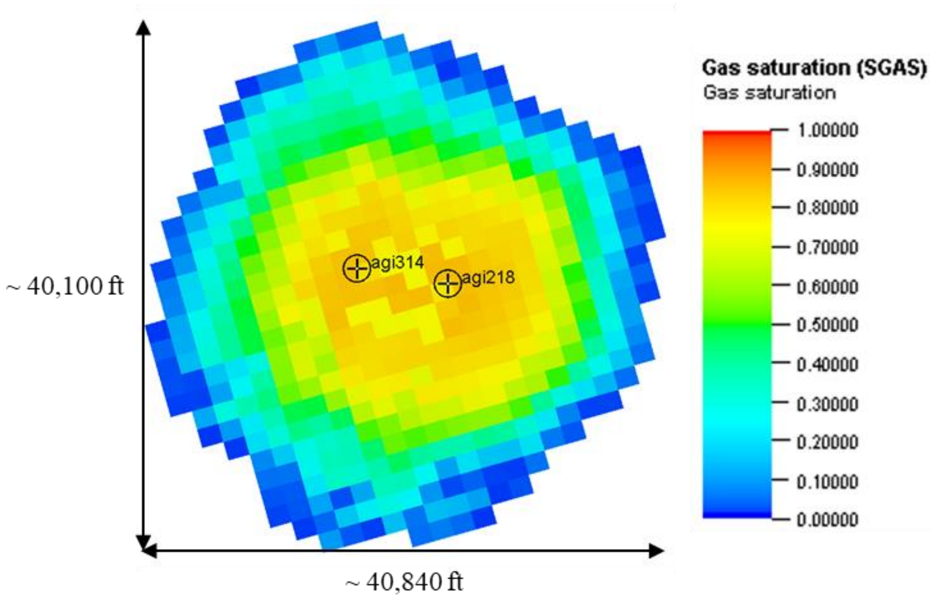

Figure 3.3 – AGI Predicted Gas Saturations at Year-end 2205

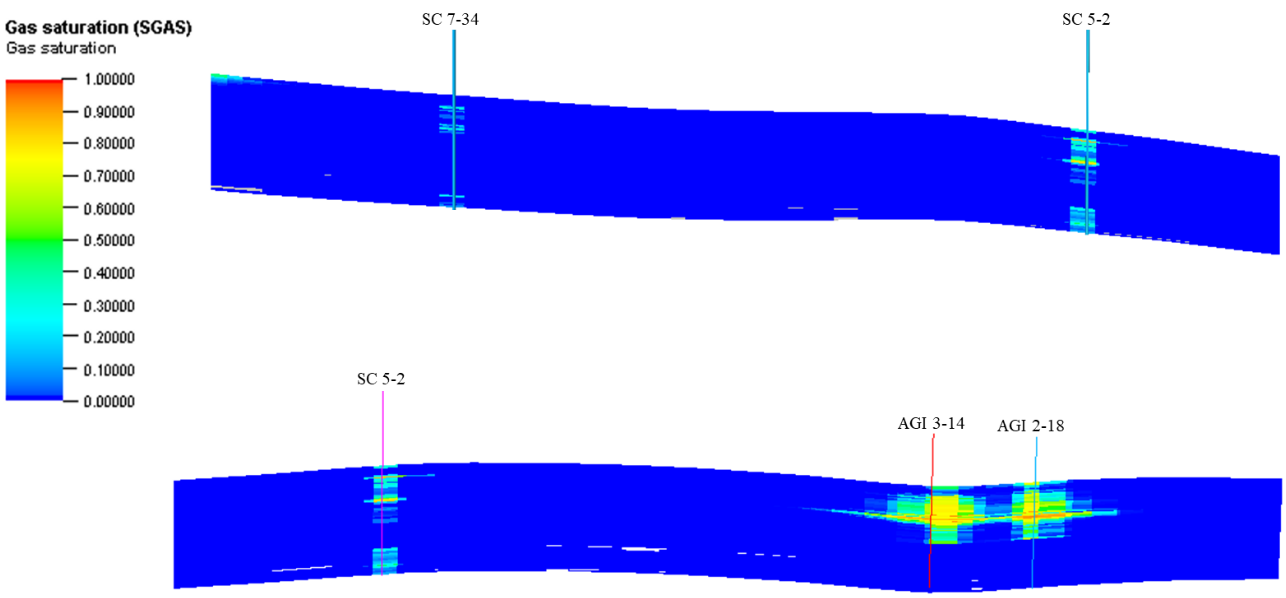

Figure 3.4 – Predicted Gas Saturations at Year-end 2027

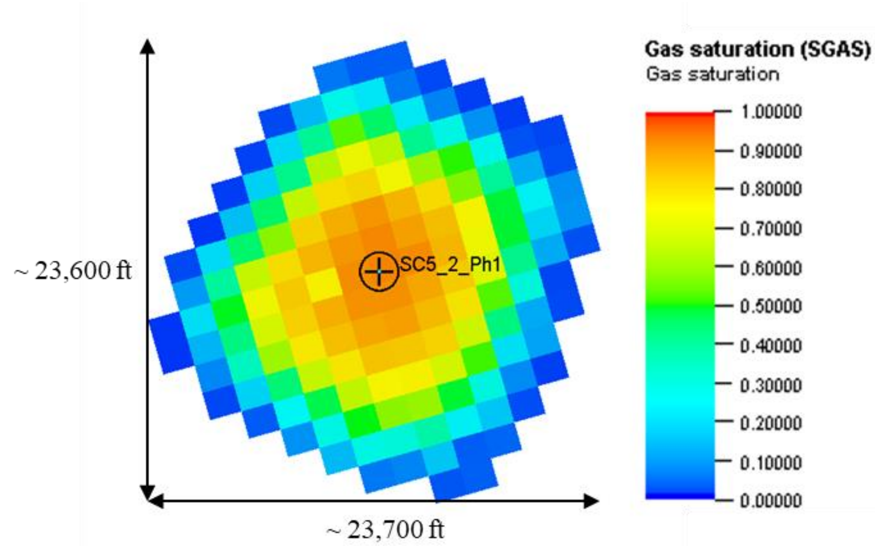

Figure 3.5 – SC 5-2 Predicted Gas Saturations at Year-end 2104

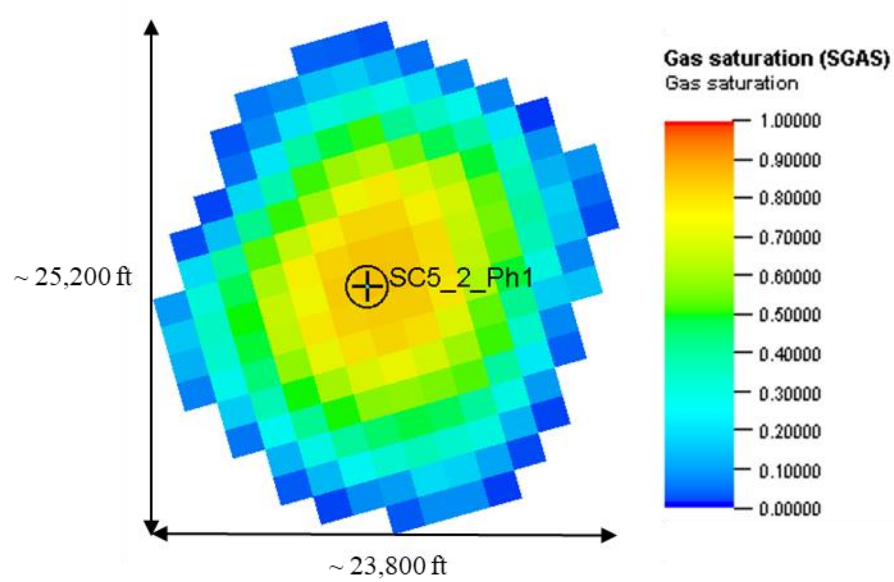

Figure 3.6 – SC 5-2 CO_2 Predicted Gas Saturations at Year-end 2205

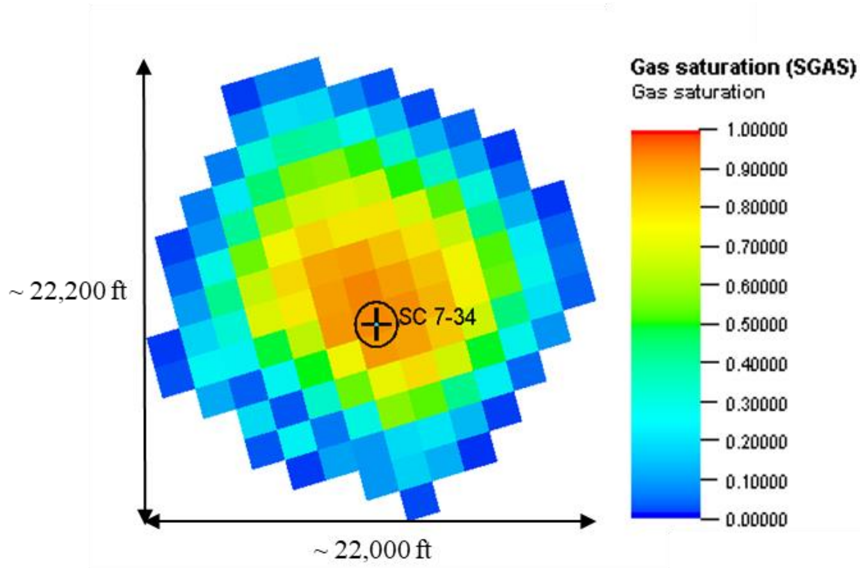

Figure 3.7 – SC 7-34 Predicted Gas Saturations at Year-end 2104

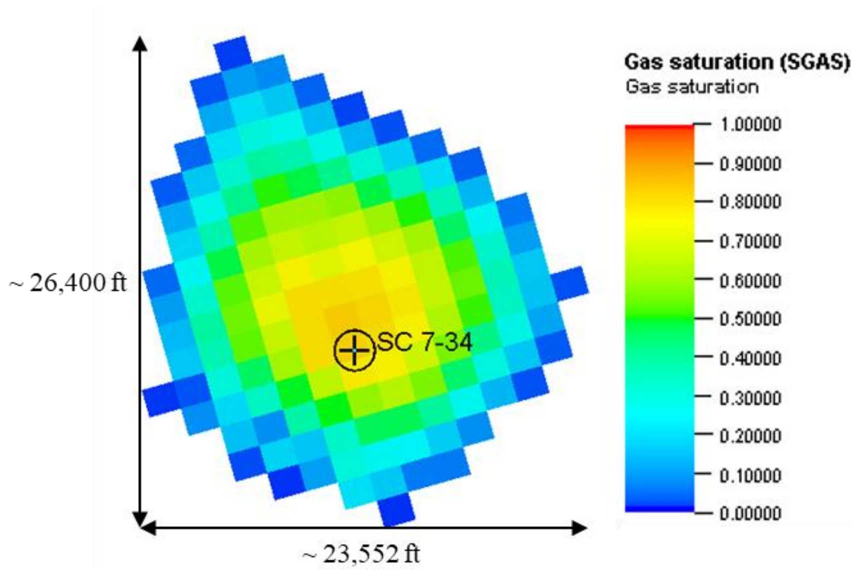

Figure 3.8 – SC 7-34 Predicted Gas Saturations at Year-end 2205

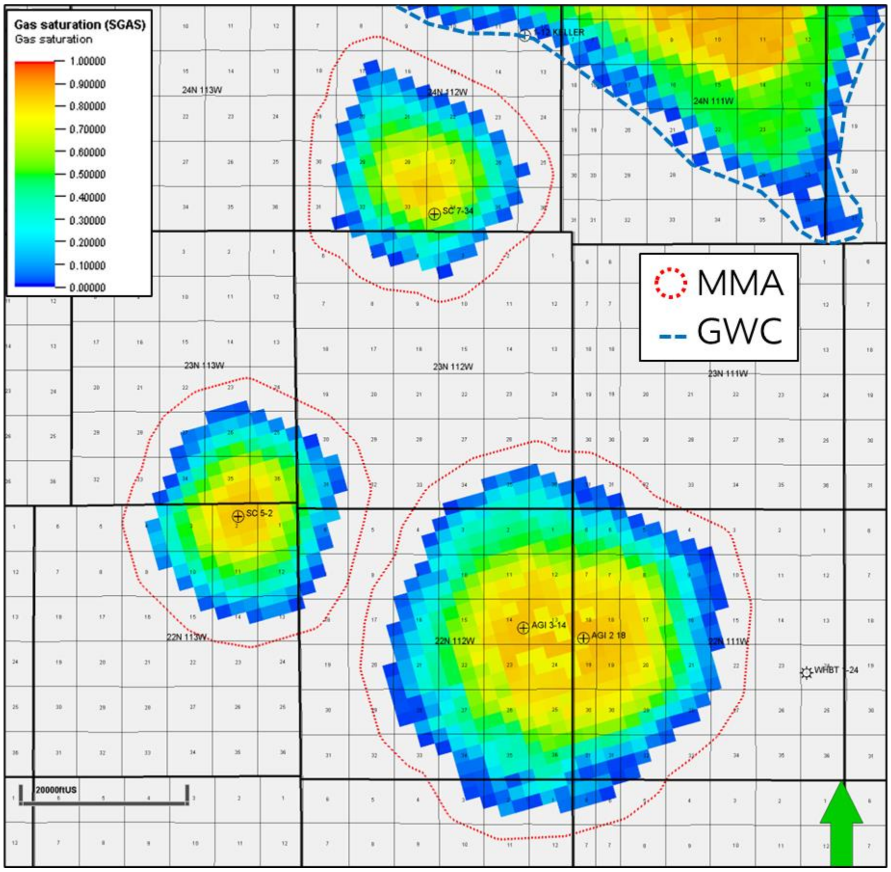

Figure 3.9 - Gas saturation plumes for AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34 at the time of plume stabilization (year 2205) with half mile buffer limit of MMA (red polygons). Plumes are displayed at zone of largest aerial extent (within Madison Formation) relative to the LaBarge gas field in the same gas-bearing zone (gas water contact displayed in dashed blue polygon).

4.0 Evaluation of Potential Pathways for Leakage to the Surface

This section assesses the potential pathways for leakage of injected CO_2 to the surface. ExxonMobil has identified the potential leakage pathways within the monitoring area as:

- Leakage from surface equipment (pipeline and wellhead)
- Leakage through wells
- Leakage through faults and fractures
- Leakage through the seal
- Leakage through natural or induced seismicity

As will be demonstrated in the following sections, there are no leakage pathways that are likely to result in loss of CO_2 to the atmosphere. Further, given the relatively high concentration of H_2S in the AGI injection stream, any leakage through identified or unexpected leakage pathways would be immediately detected by alarms and addressed, thereby minimizing the amount of CO_2 released to the atmosphere from the AGI wells.

4.1 Leakage from Surface Equipment

Leakage from surface equipment is not likely due to the design of the AGI and CO_2 injection facilities. The AGI facilities were designed to minimize leak points such as valves and flanges, and use welded connections where possible instead. The only surface equipment located between the flow meter and the wellhead are valves, transmitters, and flanged connection points on the pipelines. Due to the presence of H_2S in the AGI injection stream at a concentration of approximately 50 - 65% (500,000 - 650,000 parts per million (ppm)), H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. CO_2 gas detectors will be present at the CO_2 injection facilities due to high concentration of CO_2, which alarm at 5,000 PPM. Additionally, all field personnel are required to wear H_2S monitors for safety reasons, which alarm at 5 ppm H_2S. Although damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2 entrained in the acid gas, at the AGI well concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm, and immediate action would be taken to stop the leak. Additionally, the CO_2 injection wells would be monitored with methods outlined in sections five and six.

ExxonMobil reduces the risk of unplanned leakage from surface facilities through continuous surveillance, facility design, and routine inspections. Field personnel monitor the AGI facility continuously through the Distributed Control System (DCS). Additionally, daily visual inspection rounds are conducted of the AGI facility and weekly visual inspections are conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. ExxonMobil also relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSVs), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes. Additionally, the AGI wells have multiple surface isolation valves for redundant protection. Inline inspections of the AGI injection pipelines using a smart pigging tool are conducted on a regular frequency to check the wall thickness of the pipeline to identify potential areas of corrosion.

Field personnel will monitor the CO_2 injection facilities continuously through the DCS. Additionally, visual inspections will be conducted on a routine basis providing an additional way to detect leaks in a timely manner. Surface isolation valves will also be installed for redundant protection. Inline inspections are not anticipated to occur on a regular frequency because free water is not expected to accumulate due to the low dew point of the fluid.

<u>Likelihood</u>
Due to the design of the AGI and CO_2 injection facilities and extensive monitoring in place to reduce the risk of unplanned leakage, leakage from surface equipment is not likely.

<u>Magnitude</u>
Given the high concentrations of H_2S and CO_2 in the respective injection streams, ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. Even a minuscule amount of gas leakage would be immediately detected by the extensive monitoring systems currently in place at the facility as described above and treated as an upset event warranting immediate action to stop the leak. Should leakage be detected from surface equipment, the volume of CO_2 released will be quantified based

on the operating conditions at the time of release, as stated in Section 7.4 in accordance with 40 CFR 98.448(5).

Timing

As stated above, even a minuscle amount of gas leakage would be immediately detected and immediate action would be taken to stop the release. Any potential leakage from surface equipment would only occur during the lifetime operation of the wells. Once injection ceases, the surface equipment will be decommissioned and will not pose a risk as a leakage pathway.

4.2 Leakage through AGI and CO2 Injection Wells

Leakage of CO_2 through oil, gas, and/or water wells completed and/or abandoned is not likely. There is no commercial production of oil or gas within the immediate area of the SCTF. There is shallower production of gas from the Frontier and Dakota formations nearby in the Cow Hollow Field, at depths of 10,800' – 11,800'. A search of the WOGCC database demonstrated that there are no existing active Madison or Bighorn-Gallatin penetrations or production within the respective MMAs of the AGI or CO_2 injection well sites. The nearest established Madison production is greater than 35 miles to the north-northwest in the ExxonMobil LaBarge Deep Madison Field, which is the well field that supplies SCTF. One well (Whiskey Butte Unit 1, drilled in 1974 and operated by Wexpro Company), which was located approximately 6 miles from the AGI wells, partially penetrated 190 feet of the Madison Formation (total depth 17,236 feet MD). This well never produced from the Madison Formation and instead was perforated thousands of feet above in the Frontier Formation. The well was ultimately plugged and abandoned in February 1992. Examination of the plugging and abandonment records and the wellbore diagram constructed from those records indicates that risk of the well as a leakage pathway is highly unlikely. Two additional Madison penetrations are located between the well field and the SC 5-2 and AGI wells; both penetrations are outside the boundary of the MMA and therefore likely do not pose a risk as a leakage pathway. Keller Rubow 1-12 was plugged and abandoned in 1996. Fontenelle II Unit 22-35 was drilled to the Madison Formation but currently is only perforated and producing from thousands of feet above in the Frontier Formation.

As mentioned in Section 2.3.2, early in the life of many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. The thin-wall wells that failed have been plugged and abandoned in accordance with regulatory standards. Madison wells that were subsequently drilled were cased using thick-walled/chrome tubulars due to the high H_2S and CO_2 content and subsequent corrosion effects, as well as to combat potential salt or sediment creep. Therefore, there is no current risk of failure as all wells currently use or have used thick-walled casing of sufficient strength to penetrate and/or produce from the Madison Formation.

Future drilling is also unlikely to pose a risk as a leakage pathway due to limited areal extent of the injection plumes as shown in Figures 3.2 – 3.8. Therefore, the geological model can be used to delineate areas that should be avoided during drilling. This model has also history-matched the AGI wells injection that has occurred to date and suggests that future injection will closely follow the patterns resulting from the geological model simulation. Additionally, should future drilling occur, it would occur near the existing production area, which is greater than 40 miles away from

the current AGI wells, approximately 35 miles away from SC 5-2, and approximately 30 miles away from SC 7-34.

ExxonMobil reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and annual mechanical integrity testing (MIT). As indicated in Section 4.1, visual inspections of the well sites are performed on a routine basis, which serves as a proactive and preventative method for identifying leaks in a timely manner. Gas detectors located at the well sites which alarm at 10 ppm H_2S and 5,000 ppm CO_2 would be triggered if a leak from the wellbore to the atmosphere occurred. Additionally, SCSSV's and surface isolation valves are installed at the AGI wells, which would close in the event of leakage, preventing losses. Mechanical integrity testing is conducted on an annual basis and consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. If the MIT demonstrated a leak, the well would be isolated and the leak would be mitigated as appropriate to prevent leakage to the atmosphere.

<u>Likelihood</u>
There are no existing active Madison or Bighorn-Gallatin penetrations or production within the respective MMAs of the AGI and CO_2 injection well sites. As stated in Section 4.1, ExxonMobil relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSVs), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes.

<u>Magnitude</u>
Given the high concentrations of H_2S and CO_2 in the respective injection streams, ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. Should leakage result from the injection wellbores and into the atmosphere, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7.4 in accordance with 40 CFR 98.448(5).

<u>Timing</u>
As stated above, even a minuscle amount of gas leakage would be immediately detected and immediate action would be taken to stop the release. Any potential leakage from the AGI or CO_2 injection wells would only occur during the lifetime operation of the wells. Once injection ceases, the wells will be plugged and abandoned and will not pose a risk as a leakage pathway.

4.3 Leakage through Faults and Fractures

As discussed in Section 2.6.3, engineering and geologic analysis show no evidence of faulting or structuring around the AGI wells. As a result, the risk of leakage through this pathway is highly improbable. The absence of faulting also tends to suggest that natural fracturing or permeability enhancement in the Madison Formation is also highly improbable. Natural fracturing along with systems of large connected pores (karsts and vugs) could occur in the Bighorn-Gallatin Formation. However, because those enhanced permability areas would be limited to the Bighorn-Gallatin Formation and would not be extended to the sealing formations above, the risk of leakage through this pathway is also highly improbable.

Current-day regional scale thrust faulting has not been observed in the LaBarge area since the field has been under development. There is no concern of reactivation of these thrust faults and it is hypothesized that regional structuring similar in size to the Laramide Orogeny (formation of the Rocky Mountains) would be required to generate new thrust faults of significant size to produce subsurface structures of the scale and magnitude of the LaBarge field. The activation of the salty sediments (which exist below the Nugget Formation and above the Madison Formation at LaBarge) is a phenomenon that was only observed to damage thin-wall cased wells, with thick-wall cased wells having sufficient strength to prevent flowage of these salt sediments. It is believed that weakness in the casing of thin-wall cased wells contributes to the ability of the salty sediments to flow local to the wellbore, shearing casing, as this is a point of weakness in the structural integrity of the wellbore at this depth. Once thick-walled casing was introduced, failures have decreased or have been eliminated.

It has been documented that natural fracturing of reservoirs in the subsurface of LaBarge and surrounding areas are directly correlative to distance to thrust faults in the area. This correlation has been documented in subsurface wellbore image logs and also by surface geological mapping around the thrust faults in the LaBarge area. It therefore follows that a lack of faulting, as observed on 2D seismic panels around and through the AGI and CO_2 injection well sites, will yield formations void of natural fracturing, and the necessary faults are not present to generate pervasive natural fractures. The lack of significant natural fracturing in the Madison Formation at and around the AGI well sites, in conjunction with active inspection of wellbore image logs within the AGI wells themselves, indicates that natural fractures do not exist, that all flow in the Madison 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. It should be noted that the permeability of the Madison 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. Likewise, the low expected connected permeability of the Bighorn-Gallatin has minimal capability to freely flow fluids through its only pore system. Accordingly, there is little potential for lateral migration of the injection fluids.

Prior to drilling the AGI wells, ExxonMobil worked with multiple service companies who provided a range of fracture gradients for the Phosphoria, Weber/Amsden, Morgan, and Madison formations in the area. Based on a frac gradient of 0.85 pounds per square inch (psi)/foot for the Madison, 0.82 psi/foot for the Morgan, 0.80 psi/foot for the Weber/Amsden, and 0.775 psi/foot for the Phosphoria, and a downhole fracture pressure of 12,167 psi, which corresponds to a surface injection pressure of ~5,500 psi, the injected acid gas will not initiate fractures in the confining zones of overlying strata. Facility limits exist that limit surface pressures to below 3,200 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture is unlikely.

Fracture gradient and overburden for the SC 5-2 well were estimated on the basis of offset well data. Offset well pressure integrity test (PIT) data from existing wells was analyzed and resulted in an overburden of 18,883 psi and a fracture gradient of 0.88 psi/foot (15,203 psi) at the top of the Madison Formation (~17,232 feet MD / -10,541 feet Total Vertical Depth subsea (TVDss)) and overburden of 20,388 psi and a fracture gradient of 0.885 psi/foot at the top of the Bighorn-Gallatin Formation (~18,531 feet MD / -11,840 feet TVDss). The fracture pressure at the top of

the Madison Formation is estimated at approximately 15,203 psi which corresponds to a fracture pressure at the surface of 7,685 psi. The projected facility average and maximum surface pressures are 3,430 psi and 6,170 psi, respectively. Both are below the pressure required to fracture the formation; therefore, the probability of fracture is unlikely.

Fracture gradient and overburden for the SC 7-34 well were also estimated on the basis of offset well data. Overburden estimates for the subject formations are based on offset well density logs. Expected formation integrity is primarily based on offset well pressure integrity (PIT) data. Because offset PITs did not result in leakoff, fracture gradient is assumed to be above test pressures. Therefore, the lowest possible fracture gradient constrained by the PITs has a vertical effective stress ratio of 0.55. An analysis of published regional data suggests a vertical effective stress ratio of 0.67 is more likely. Fracture gradient constraints were generalized with an effective horizontal to vertical effective stress ratio of 0.67 to be extrapolated to the target formation. These analyses result in an overburden of 18,705 psi and fracture gradient of 0.90 psi/foot (15,034 psi) at the top of the Madison Formation (approximately 16,744 feet MD / -10,055 feet TVDss) and overburden of 19,934 psi and fracture gradient of 0.90 psi/foot (16,017 psi) at the estimated top of the Bighorn-Gallatin Formation (approximately 17,815 feet MD / -11,126 feet TVDss).

<u>Likelihood</u>
Based on results of the the site characterization including the lack of faulting or open fractures in the injection intervals and the operational limitations on injections pressures, CO_2 leakage to the surface via faults or fractures is highly unlikely.

<u>Magnitude</u>
Given the lack of faulting and fracturing discussed above, leakage through small undetected faults or fractures (if presented and not yet observed) would be contained by the overlying high-quality sealing formations, discussed in more detail in Section 4.4 below, resulting in no CO_2 leakage to surface.

<u>Timing</u>
If a CO_2 leak were to occur through the confining zone due to faults or fractures, it would most likely occur during active injection. Limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. However, if diffusion through the confining zone were to occur, other CO_2 trapping mechanisms such as mineralization and solution in existing formation waters would reduce the magnitude and timing of emission to the surface.

4.4 Leakage through the Formation Seal

Leakage through the seal of the Madison Formation is highly improbable. An ultimate top seal to the disposal reservoir is provided by the evaporitic sequences within the Thaynes Formation. In fact, the natural seal is the reason the LaBarge gas field exists in the first place – the gas has been trapped in the LaBarge structure over a large amount of geologic time. The rock that forms the natural seal is impermeable to Helium (He), a gas with a much smaller molecular volume than CO_2. If the reservoir seal material is impermeable to He, then it follows that it is also impermeable to CO_2. The Thaynes Formation's sealing effect is also demonstrated by the fact that all gas

production shallower than the Thaynes is void of sour gas, while all gas production below it is enriched in sour gases. Formation Inclusion Volatile (FIV) analysis of rock cuttings documents the lack of CO_2 present throughout and above the Triassic regional seals (Ankareh, Thaynes, Woodside, and Dinwoody formations, Figure 2.2) from wells within the LaBarge gas field producing area as well as the AGI injection area.

Although natural creep of the salty sediments below the Nugget Formation is possible, this behavior does not disturb the sediments to the degree necessary to breach the reservoir seal of the Madison Formation. If this salty sediment were to flow on a scale large enough to create a leakage pathway from the Madison Formation to the surface, the natural gases trapped in the formation would have leaked into the atmosphere during the long course of geological time up to this point. The fact that gas remains trapped at pressure in the Madison Formation, it must follow that any natural reactivation or movement of salt-rich sediments that has occurred over the geological history of the LaBarge field area has not created any pathways for gas leakage to the surface.

Wells are monitored to ensure that the injected gases stay sequestered. Any escaped acid gas from the AGI wells will be associated with H_2S, which has the potential to harm field operators. The CO_2 injection wellheads will be monitored with local CO_2 gas heads, which detect low levels of CO_2. The CO_2 injected cannot escape without immediate detection, as expanded upon in the below sections.

Likelihood

Based on results of the the site characterization including the sealing capacity of confining intervals and Triassic evaporitic sequences and the operational limitations on injections pressures, CO_2 leakage to the surface via faults or fractures is highly unlikely.

Magnitude

Given the number, thickness, and quality of the confining units above the Madison and Bighorn-Gallatin injection intervals, as illustrated in Figure 2.2, any potential CO_2 leakage to the surface would be negligible and detected by surface monitoring systems at the injection site. Although highly unlikely, any CO2 leakage would likely occur near the injection well, which is where reservoir pressure is highest as a result of injection.

Timing

If a CO_2 leak were to occur through the multiple formation seals, it would most likely occur during active injection. Limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. However, if diffusion through the confining zone were to occur, other CO_2 trapping mechanisms such as mineralization and solution in existing formation waters would reduce the magnitude and timing of emission to the surface.

4.5 Leakage through Natural or Induced Seismicity

In the greater Moxa Arch area, there is a low level of background seismicity (Advanced National Seismic System (ANSS) Catalogue, 2018, University of Utah Seismograph Stations). Across North America, induced seismicity is sometimes hypothesized as being related to reactivation of basement-involved faults via oilfield waste fluid injection (Ellsworth 2013). There has been no

observed evidence of faulting in the Madison interval using commercially available 2D seismic data within 13.5 miles of the proposed CO_2 injection well sites. There has also been no reported seismic activity attributed to active injection operations at the AGI injection wells. The nearest induced seismic events were observed over 20 miles to the southwest of the proposed SC 7-34 well site. These are attributed to mineral mining operations, and not naturally occurring geological fault activity (USGS, Pechmann et al 1995). The closest naturally occurring seismic activity was a 1.8 magnitude earthquake in 1983 located 7.2 miles to the west at a depth of 10.1 miles according to the ANSS Catalogue and the Wyoming State Geological Survey's historic records. Significant earthquake activity is defined as >3.5 Richter scale (ANSS Catalogue 2018, University of Utah Seismograph Stations). The nearest recorded significant naturally occurring earthquake activity (> M3.5) has been detected over 50 miles away to the west in Idaho and Utah. 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.

Additional geomechanical modeling has been completed in the area around the AGI and CO_2 injection well sites. The modeling was completed to understand the potential for fault slip on the Darby fault far west of the injection and disposal sites. No fault slip is observed at the simulated fault locations or throughout the model. Lack of fault slip then equates to lack of modeled induced seismity from injection.

<u>Likelihood</u>
Due to the lack of significant earthquake activity in the area, the lack of induced seismicity over the period of injection at the AGI wells, and the geomechanical modeling results showing a lack of fault slip, ExxonMobil considers the likelihood of CO_2 leakage to surface caused by natural or induced seismicity to be unlikely.

<u>Magnitude</u>
If a seismic event occurs at the time of AGI or CO_2 injection, ExxonMobil will consult the ANSS Catalogue to verify whether the seismic event was due to the injection in the AGI or CO_2 injection wells and quantify any leak of CO_2 to the surface.

<u>Timing</u>
If a leak of CO_2 to the surface occurs as a result of a seismic event, it would likely occur at the time of the seismic event or shortly thereafter.

5.0 Detection, Verification, and Quantification of Leakage

5.1 Leakage Detection

As part of ongoing operations, SCTF continuously monitors and collects flow, pressure, temperature, and gas composition data in the Distributed Control System (DCS). This data is monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. Additionally, SCTF maintains in-field gas detectors to detect H_2S and CO_2 in the vicinity. If one of the gas detectors

alarmed, it would trigger an immediate response to address the situation. In some instances, more than one detector alarming will trigger automatic equipment isolation/shutdown to mitigate the leak.

Leakage detection for the wells will incorporate several monitoring programs including visual inspection of the surface facilities and wellheads, injection well monitoring and MIT, and DCS surveillance. Table 5.1 provides general information on the potential leakage pathways, monitoring programs to detect leakage, and location of monitoring. Monitoring will occur for the duration of injection. As will be discussed in Section 7.0 below, ExxonMobil will quantify equipment leaks by using a risk-driven approach and continuous surveillance.

Table 5.1 - Monitoring Programs

Potential Leakage Pathway	Detection Monitoring Program	Monitoring Location
Surface Equipment	DCS Surveillance Visual Inspections Inline Inspections Gas Alarms Personal H_2S Monitors	From injection flow meter to injection wellhead
Wells	DCS Surveillance Visual Inspections MIT Gas Alarms Personal H_2S Monitors	Injection well – from wellhead to injection formation
Faults and Fractures, Formation Seal, Lateral Migration	DCS Surveillance Gas Alarms	Injection well – from wellhead to injection formation
Natural or Induced Seismicity	DCS Surveillance Gas Alarms ANSS Catalogue	Injection well – from wellhead to injection formation Regional data

5.2 Leakage Verification

Responses to leaks are covered in the SCTF's Emergency Response Plan (ERP), which is updated annually. If there is a report or indication of a leak from the AGI facility from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and H_2S monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Pressure from the AGI system will be relieved to the flare, not vented, due to the dangerous composition of the gas.

The ERP will be updated to include the CO_2 injection facilities and corresponding wells after commencement of operations. If there is a report or indication of a leak from the CO_2 injection facilities from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and gas monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Once isolated from the CO_2 injection flowline, pressure from the affected CO_2 injection well will be relieved locally to atmosphere within the well site fence line.

5.3 Leakage Quantification

Examples of leakage quantification methods for the potential leakage pathways identified in Table 5.1 are outlined below. All calculations associated with quantifiying leakage will be maintained as outlined in Section 10.0.

<u>Leakage from Surface Equipment</u>

The leakage from surface equipment will be estimated once leakage has been detected and confirmed. As further described in Section 7.4, ExxonMobil will estimate the mass of CO_2 emitted from leakage points at the surface based on operating conditions at the time of the release – pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of leak. The annual mass of CO_2 that is emitted by surface leakage will be calculated in accordance with Equation RR-10.

<u>Leakage through AGI and CO_2 Wells</u>

As stated in Section 4.2, ExxonMobil reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and annual mechanical integrity testing (MIT). Gas detectors located at the well sites which alarm at 10 ppm H_2S and 5,000 ppm CO_2 would be triggered if a leak from the wellbore to the atmosphere occurred. If there is indication of a leak, leakage through AGI and CO_2 wells will be estimated once leakage has been detected and confirmed. ExxonMobil will take actions to quantify the leak and estimate the mass of CO_2 emitted based on operating conditions at the time of the release – pressure and flow rate, size of the leakage point opening, and estimated duration of leak.

Leakage through Faults and Fractures, Formation Seal, or Lateral Migration

As stated in Section 4.3, engineering and geologic analysis show no evidence of faulting or structuring around the AGI wells and the risk of leakage through this pathway is highly unlikely. Given the lack of faulting and fracturing, leakage through small undetected faults or fractures (if presented and not yet observed) would be contained by the overlying high-quality sealing formations, resulting in no CO_2 leakage to surface.

Further, as stated in Section 4.4, leakage through the formation seal is highly improbable due to the geology of the field which has demonstrably trapped and retained both hydrocarbon and non-hydrocarbon gases over long periods of geologic time. Additionally, limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. Wells are continuously monitored to ensure that the injected gases stay sequestered and any escaped gas would be immediately detected.

As stated in Section 5.1, SCTF continuously monitors and collects flow, pressure, temperature, and gas composition data in the DCS. This data is monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. If there is indication of leakage of CO_2 through faults and fractures, the formation seal, or lateral migration as potentially indicated by abnormal operational data, ExxonMobil will take actions to quantify the leak (e.g., reservoir modeling and engineering estimates) and take mitigative actions to stop leakage. Given the unliklihood of leakage from these pathways, ExxonMobil will estimate mass of CO_2 detected leaking to the surface in these instances on a case-by-case basis utilizing quantification methods such as engineering analysis of surface and subsurface measurement data, dynamic reservoic modeling, and history-matching of the reservoir performance.

Leakage through Natural or Induced Seismicity

As stated in Section 4.5, there is low level of background seismicity detected in the area. If a seismic event occurs at the time of AGI or CO_2 injection, ExxonMobil will consult the ANSS Catalogue to verify whether the seismic event was due to the injection in the AGI or CO_2 injection wells and quantify any leak of CO_2 to the surface based on operating conditions at the time of the event – pressure and flow rate, size of the leakage point opening, and estimated duration of leak.

6.0 Determination of Baselines

ExxonMobil uses existing automatic data systems to identify and investigate excursions from expected performance that could indicate CO_2 leakage. The following describes ExxonMobil's approach to collecting baseline information.

Visual Inspections

Field personnel conduct daily inspections of the AGI facility and weekly inspections of the AGI well sites. The CO_2 injection facility and well sites will undergo weekly visual inspections. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize

the possibility of CO_2 leakage. If an issue is identified, a work order will be generated to correct the issue.

H_2S Detection – AGI Wells

The CO_2 injected into the AGI wells is injected with H_2S at a concentration of 50 - 65% (500,000 - 650,000 ppm). H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. At this high of a concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm. Additionally, all field personnel are required to wear H_2S monitors for safety reasons. Personal monitors alarm at 5 ppm. Any gas detector alarm or personal H_2S monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the gas detectors and monitors are working correctly.

CO_2 Detection – CO_2 Injection Wells

The CO_2 injected into the CO_2 injection wells will be at a concentration of approximately 99%. CO_2 gas detectors will be installed around the well sites, which will trigger at 0.5% CO_2, therefore even a miniscule amount of gas leakage would trigger an alarm.

Continuous Parameter Monitoring

The DCS of the SCTF 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.

Well Testing

On an annual basis, the subsurface and wellhead valves are leak tested for mechanical integrity testing (MIT) as required by the WOGCC. Results from this type of testing are compared to previous MIT data to evaluate whether well integrity has been compromised.

Additionally, inline inspections are conducted of the AGI flow lines through the use of a smart pig to identify potential areas of corrosion in the pipeline. Results from this type of testing are compared to previous data to evaluate whether pipeline integrity has been compromised. The operations at the SCTF will have the ability to conduct inline inspections on the SC 5-2 and SC 7-34 flow lines, however inline inspections are not anticipated to occur frequently because no free water is expected to accumulate.

7.0 Site Specific Modifications to the Mass Balance Equation

To accommodate for site-specific conditions, as provided in 40 CFR 98.448, ExxonMobil proposes to modify quantifying equipment leaks by using a risk-driven approach. Due to the high H_2S concentration of the AGI fluids, monitoring poses a risk to personnel. Additionally, as mentioned above, even a small leak of this high H_2S gas would trigger an alarm. A small leak at the CO_2 injection wells would also trigger an alarm, as mentioned above. ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to

stop the release. This continuous surveillance using gas detectors identifies leaks better than an annual leak survey would 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 ExxonMobil will calculate the mass of CO_2 injected, emitted, and sequestered.

7.1 Mass of CO_2 Received

§98.443 states that "you must calculate the mass of CO_2 received using CO_2 received equations… unless you follow the procedures in §98.444(a)(4)." §98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." Since the CO_2 received by the AGI and CO_2 injection wells are wholly injected and not mixed with any other supply of CO_2, the annual mass of CO_2 injected would be equal to the annual mass of CO_2 received. No CO_2 is received in containers.

7.2 Mass of CO_2 Injected

Volumetric flow meters are used to measure the injection volumes at the AGI wells and are proposed for use to measure the injection volumes at the CO_2 injection wells. Equation RR-5 will be used to calculate the annual total mass of CO_2 injected.

Equation RR-6 will be used to aggregate injection data for the AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34 wells.

7.3 Mass of CO_2 Produced

We will not produce injected CO_2 (as discussed in section 3.2 and illustrated in figure 2.7), hence we do not plan to calculate produced CO_2 according to the requirements of Subpart RR.

7.4 Mass of CO_2 Emitted by Surface Leakage and Equipment Leaks

It is not appropriate to conduct a leak survey at the AGI or the CO_2 injection well sites due to the components being unsafe-to-monitor and extensive monitoring systems in place. Entry to the AGI wells requires the individual to don a full face respirator supplied to breathing air, which would make completion of a leak survey very difficult. Due to the high H_2S concentration of the AGI fluids and the high CO_2 concentration of the CO_2 injection fluid, fugitive leakage would be detected and managed as an upset event in the same way that CO_2E (CO_2 emitted by surface leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time, including pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of the leak. 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.

Parameter CO_2FI (total CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead) will be calculated in accordance with procedures outlined in Subpart W as required by 40 CFR 98.444(d). At the AGI wells, there are no CO_2 emissions from venting due to the high H_2S concentration of the acid gas; blowdown emissions are sent to the flares and are reported under Subpart W for the SCTF. This process occurs upstream of the flow meter and would therefore not contribute to the CO_2FI calculation. At the CO_2 injection wells, venting would occur in the event of depressurizing for maintenance or testing, which would be measured during time of event consistent with 40 CFR 98.233.

7.5 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Since ExxonMobil is not actively producing oil or natural gas or any other fluids as part of the AGI process or CO_2 injection processes, Equation RR-12 will be used to quantify CO_2 injected and sequestered. Parameter CO_2I (total CO_2 injected through all injection wells) will be determined using Equation RR-5, as outlined above in Section 7.2. Parameters CO_2E and CO_2FI will be measured using the leakage quantification procedure described above in Section 7.4. CO_2 in the AGI fluids is not vented from equipment due to the high H_2S concentration.

8.0 Estimated Schedule for Implementation of Second Amended MRV Plan

The SCTF AGI facility and wells have been operational since 2005 and have been subject to the February 2018 MRV plan (approved by EPA in June 2018). Beginning with the start of injection of CO_2 and fluids into the CO_2 injection wells, this Second Amended MRV Plan will become the applicable plan for the AGI and CO_2 injection wells and will replace and supersede the February 2018 MRV plan for the AGI wells. Until that time, the February 2018 MRV plan will remain the applicable MRV plan for the AGI wells. Once the Second Amended MRV Plan becomes the applicable MRV plan, ExxonMobil will continue reporting under Subpart RR for the AGI wells, but will begin including the CO_2 injection wells on or before March 31 of the year after their respective injection begins. Once applicable, ExxonMobil anticipates this Second Amended MRV Plan will remain in effect until the end-of-field-life of the LaBarge 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, ExxonMobil has incorporated the following provisions into its QA/QC programs:

CO_2 *Injected*

- The injected CO_2 stream for the AGI wells will be measured upstream of the volumetric flow meter at the three AGI compressors, at which measurement of the CO_2 is representative of the CO_2 stream being injected, with a continuously-measuring online process analyzer. The flow rate is measured continuously, allowing the flow rate to be compiled quarterly.

- The injected CO_2 stream for the CO_2 injection wells will be measured with a volumetric flow meter and continuously-measuring online process analyzer upstream of the wellhead, at which measurement of the CO_2 is representative of the CO_2 stream being injected. The flow rate will be measured continuously, allowing the flow rate to be compiled quarterly.
- The continuous composition measurements will be averaged over the quarterly period to determine the quarterly CO_2 composition of the injected stream.
- The CO_2 analyzers are calibrated according to manufacturer recommendations.

<u>CO_2 *emissions from equipment leaks and vented emissions of CO_2*</u>

- 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.

<u>*Measurement Devices*</u>

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

<u>*General*</u>

- The CO_2 concentration is measured using continuously-measuring online process analyzers, which is an industry standard practice.
- All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 Missing Data Procedures

In the event ExxonMobil 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 CO_2 injected is missing, it will be estimated using a representative quantity of CO_2 injected from the nearest previous time period at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in 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, ExxonMobil will revise and submit another amended MRV plan within 180 days to the Administrator for approval.

10.0 Records Retention

ExxonMobil will follow the record retention requirements of 98.3(g). Additionally, it will retain the following records from the AGI and CO_2 injection well sites for at least three years:

- Quarterly records of injected CO_2 for the AGI wells including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO_2 for the CO_2 injection wells 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 CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Request for Additional Information: Shute Creek Facility
February 4, 2025

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	7.3	47	"The AGI and CO2 injection wells are not part of an enhanced oil recovery process, therefore, there is no CO2 produced and/or recycled." Please note that subpart RR requirements to calculate CO2 produced are not dependent on whether a facility conducts enhanced oil recovery. See 40 CFR 98.443(d). Please revise this section to explain why the facility does not anticipate producing any injected CO2, and/or provide references to other sections of the MRV plan that support this determination.	Statement in Section 7.3 has been revised to provide reference to other sections that support this determination (page 47). Revised section 7.3 text included below for review: "We will not produce injected CO2 (as discussed in section 3.2 and illustrated in figure 2.7), hence, we do not plan to calculate produced CO2 according to the requirements of Subpart RR."

ExxonMobil Shute Creek Treating Facility Subpart RR Second Amended Monitoring, Reporting and Verification Plan

December 2024

Table of Contents

Introduction

Exxon Mobil Corporation (ExxonMobil) operates two acid gas injection (AGI) wells, AGI 2-18 and AGI 3-14 (collectively referred to as "the AGI wells") in the Madison Formation located near LaBarge, Wyoming for the primary purpose of acid gas disposal with a secondary purpose of geologic sequestration of carbon dioxide (CO_2) in a subsurface geologic formation. The acid gas and CO_2 injected into the AGI wells are components of the natural gas produced by ExxonMobil from the Madison Formation. ExxonMobil has been operating the AGI wells since 2005 and intends to continue injection until the end-of-field-life of the LaBarge assets. The AGI wells and facility (as further described in Section 2.7.1), located at the Shute Creek Treating Facility (SCTF), have been operational since 2005 and have been subject to the February 2018 monitoring, reporting, and verification (MRV) plan approved by EPA in June 2018 (the February 2018 MRV plan).

Because the volume of CO_2 associated with the natural gas production is greater than the volume that is able to be injected into the AGI wells, ExxonMobil is in the process of developing the Shute Creek (SC) 5-2 and SC 7-34 wells (collectively referred to as the "CO_2 injection wells" or "CO_2 disposal wells")[1] for the purpose of geologic sequestration of fluids consisting primarily of CO_2 in subsurface geologic formations. Like the AGI wells, the fluids that will be injected into the CO_2 injection wells are also components of the natural gas produced by ExxonMobil from the Madison Formation. Once operational, the CO_2 injection wells are expected to continue injection until the end-of-field life of the LaBarge assets.

ExxonMobil received the following approvals by the Wyoming Oil and Gas Conservation Commission (WOGCC) to develop the SC 5-2 well:

- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Madison Formation on November 12, 2019
- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Phosphoria, Weber, and Bighorn-Gallatin formations[2] on October 12, 2021
- Application for permit to drill (APD) on June 30, 2022

ExxonMobil received the following approvals by the WOGCC to develop the SC 7-34 well:

- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Madison and Bighorn-Gallatin formations on August 13, 2024
- APD on May 20, 2024

In October 2019, ExxonMobil submitted an amendment to the February 2018 MRV plan in accordance with 40 CFR §98.440-449 (Subpart RR – Geologic Sequestration of Carbon Dioxide) to provide for the monitoring, reporting and verification of geologic sequestration of CO_2 in the Madison Formation during the injection period for the SC 5-2 well (the October 2019 MRV plan). The October 2019 Amended MRV plan was approved by EPA on December 19, 2019.

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[1] *The terms "dispose" and "inject" and their variations may be used interchangeably throughout this document.*

[2] *While the Phosphoria and Weber formations were conditionally approved as exempted aquifers for disposal of fluids, these formations are no longer targets for the SC 5-2 and will not be addressed further in this document*

This second amended plan, dated October 2024 ("Second Amended MRV Plan") will address all wells collectively when applicable, and otherwise broken out into sub sections to address the specifics of the AGI wells and CO_2 injection wells respectively, as appropriate. This Second Amended MRV Plan meets the requirements of 40 CFR §98.440(c)(1).

The February 2018 MRV plan is the currently applicable MRV plan for the AGI wells. The October 2019 Amended MRV plan would have become the applicable plan once the SC 5-2 well began injection operations. ExxonMobil anticipates the SC 5-2 well will begin injection operations in 2025 and the SC 7-34 well will begin injection operations in 2026. At that time, this Second Amended MRV Plan will become the applicable plan for the AGI wells and CO_2 injection wells collectively, and will replace and supersede both the February 2018 and October 2019 Amended MRV plans. At that time, ExxonMobil will continue reporting under Subpart RR for the AGI wells, but will begin including the CO_2 injection wells on or before March 31 of the year after their respective injection begins. Once applicable, ExxonMobil anticipates this Second Amended MRV Plan will remain in effect until the end-of-field-life of the LaBarge assets, unless and until it is subsequently amended and superseded.

This Second Amended MRV Plan contains ten sections:

1. Section 1 contains facility information.

2. Section 2 contains the project description. This section describes the geology of the LaBarge Field, the history of the LaBarge field, an overview of the injection program and process, and provides the planned injection volumes. This section also demonstrates the suitability for secure geologic storage in the Madison and Bighorn-Gallatin formations.

3. Section 3 contains the delineation of the monitoring areas.

4. Section 4 evaluates the potential leakage pathways and demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

5. Section 5 provides information on the detection, verification, and quantification of leakage. Leakage detection incorporates several monitoring programs including routine visual inspections, hydrogen sulfide (H_2S) and CO_2 alarms, mechanical integrity testing of the well sites, and continuous surveillance of various parameters. Detection efforts will be focused towards managing potential leaks through the injection wells and surface equipment due to the improbability of leaks through the seal or faults and fractures.

6. Section 6 describes the determination of expected baselines to identify excursions from expected performance that could indicate CO_2 leakage.

7. Section 7 provides the site specific modifications to the mass balance equation and the methodology for calculating volumes of CO_2 sequestered.

8. Section 8 provides the estimated schedule for implementation of the Second Amended MRV Plan.

9. Section 9 describes the quality assurance program.

10. Section 10 describes the records retention process.

1.0 Facility Information

1. Reporter number: 523107
The AGI wells currently do, and the CO_2 injection wells will, report under the Shute Creek Treating Facility (SCTF) Greenhouse Gas Reporting Program Identification number, which is: 523107.
2. Underground Injection Control (UIC) Permit Class: Class II
The WOGCC regulates oil and gas activities in Wyoming. WOGCC classifies the AGI, SC 5-2, and SC 7-34 wells in LaBarge as UIC Class II wells.
3. UIC injection well identification numbers:

Well Name	*Well Identification Number*
AGI 2-18	49-023-21687
AGI 3-14	49-023-21674
SC 5-2	49-023-22499
SC 7-34	49-023-22500

2.0 Project Description

This section describes the planned injection volumes, environmental setting of the LaBarge Field, injection process, and reservoir modeling.

2.1 Geology of the LaBarge Field

The LaBarge field area is located in the southwestern corner of Wyoming, contained in Lincoln and Sublette counties. The producing field area is within the Green River Basin and the field is located due west of the Wind River Mountains along the Moxa Arch (Figure 2.1).

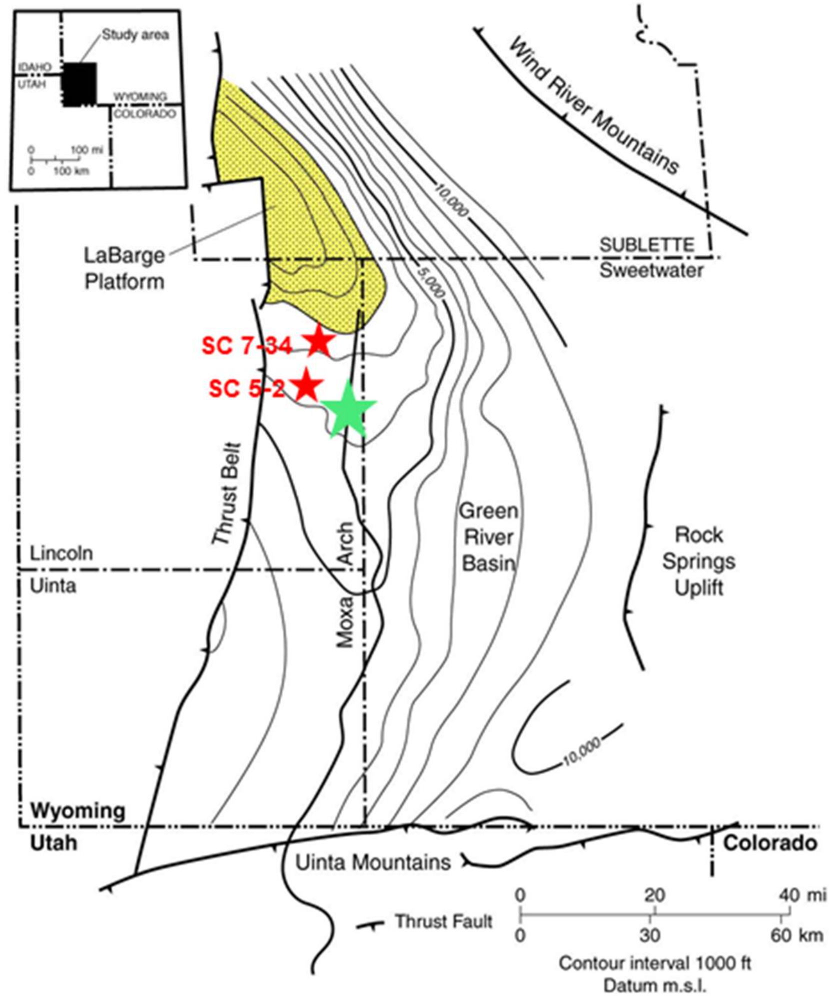

Figure 2.1 Location Map of the LaBarge Field, Wyoming. The location of the AGI wells is denoted with a green star, and the location of the CO_2 injection wells are denoted by the red stars.

2.2 Stratigraphy of the Greater LaBarge Field Area

The western region of Wyoming has been endowed in a very rich and prolific series of hydrocarbon reservoirs. Hydrocarbon production has been established or proven from a large number of stratigraphic intervals around Wyoming, ranging from reservoirs from Cenozoic to Paleozoic in age. Figure 2.2 shows a complete stratigraphic column applicable to the Greater Green River Basin in western Wyoming.

For the LaBarge field area, specifically, commercially producible quantities of hydrocarbons have been proven in the following intervals:

1. Upper Cretaceous Frontier Formation
2. Lower Cretaceous Muddy Formation
3. Permian Phosphoria Formation
4. Lower Jurassic Nugget Formation
5. Pennsylvanian Weber Formation
6. Mississippian Madison Formation

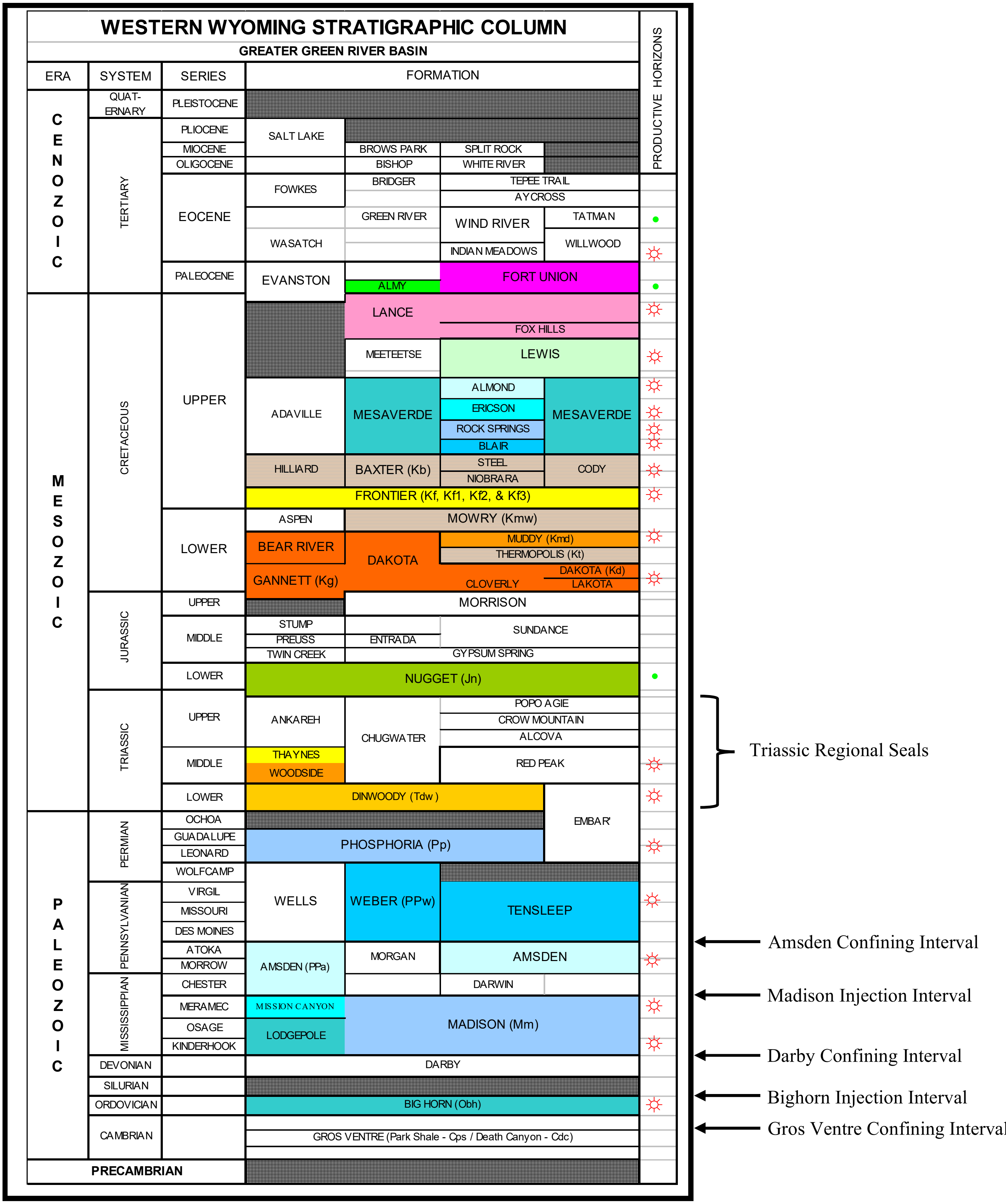

Figure 2.2 Generalized Stratigraphic Column for the Greater Green River Basin, Wyoming

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 closure to 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 (Figure 2.3).

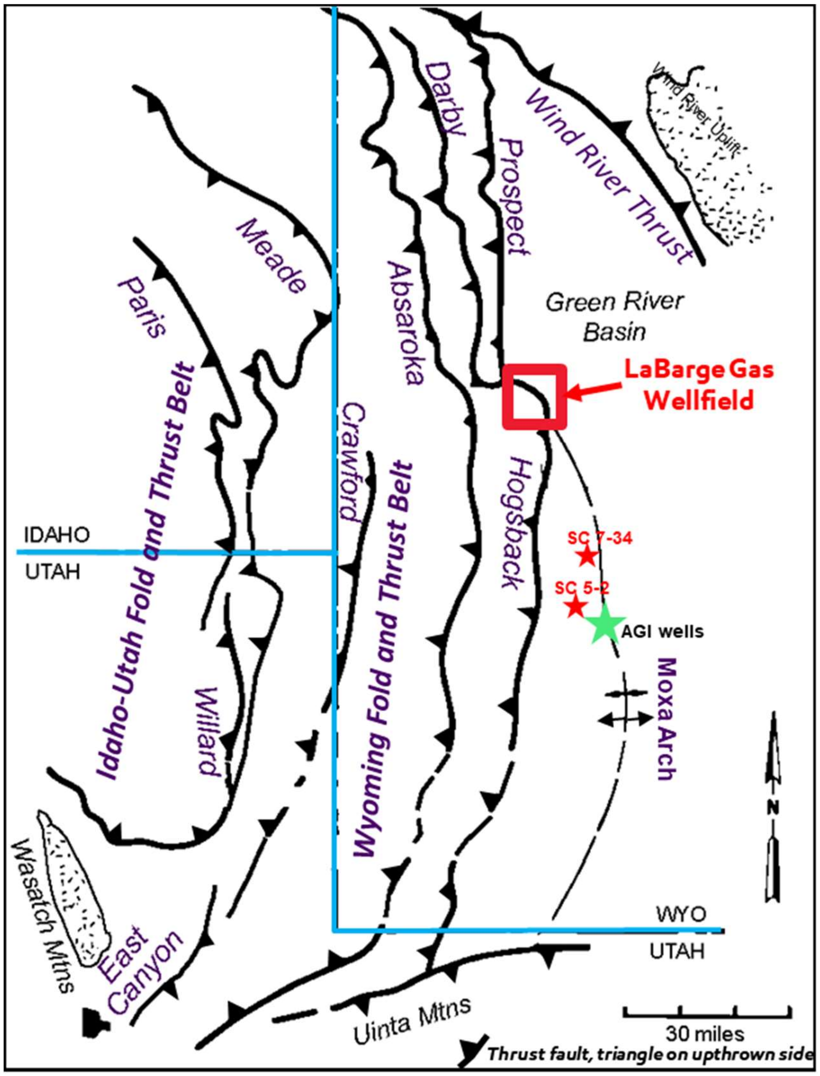

Figure 2.3 Schematic map showing location of Moxa Arch and regional thrust faults. The LaBarge field area is denoted by the red box. The approximate location of the AGI wells is denoted with a green star, and the approximate location of the CO_2 injection wells are denoted by the red stars.

The historical evaluation of structural styles at LaBarge has revealed that three principal styles of structuring have occurred in the area:

1. Basement-involved contraction
2. Deformation related to flowage of salt-rich Triassic strata
3. Basement-detached contraction

2.3.1 Basement-involved Contraction Events

Basement-involved contraction has been observed to most commonly result in thrust-cored monoclinal features being formed along the western edge of the LaBarge field area (Figure 2.3). These regional monoclinal features have been imaged extensively with 2D and 3D seismic data, and are easily recognizable on these data sets (Figure 2.4). At a smaller scale, the monoclinal features set up the LaBarge field structure, creating a hydrocarbon trapping configuration of the various reservoirs contained in the LaBarge productive section.

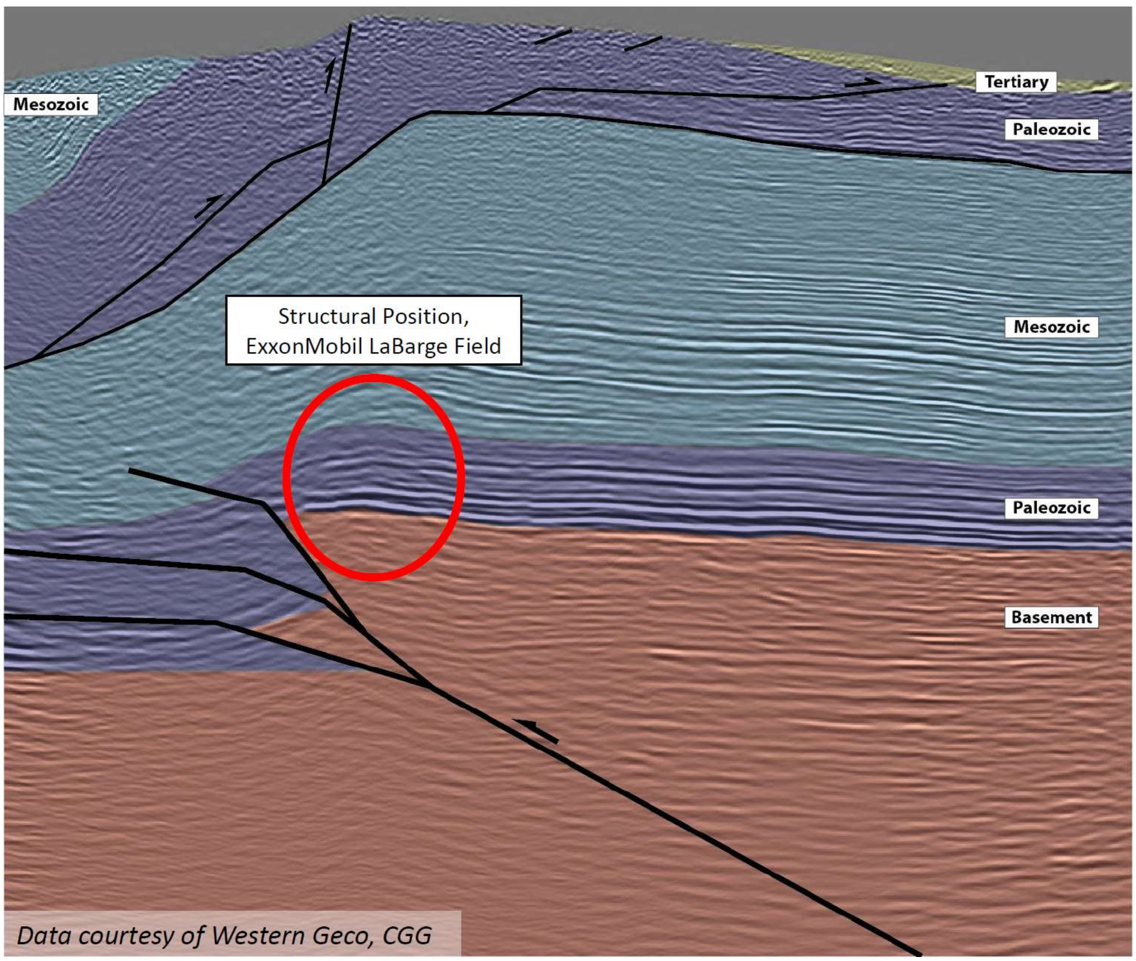

Figure 2.4 Example of thrust-cored monoclinal feature interpreted from 2D seismic data. The thrust-cored feature is believed to be a direct product of basement-involved contractional events.

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 outcrop 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 2.5 shows two seismic lines showing the Triassic salt-rich sediments and the 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.

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 many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. Subsequent drilling at LaBarge has used thicker-walled casing strings to successfully mitigate this sediment flowage issue.

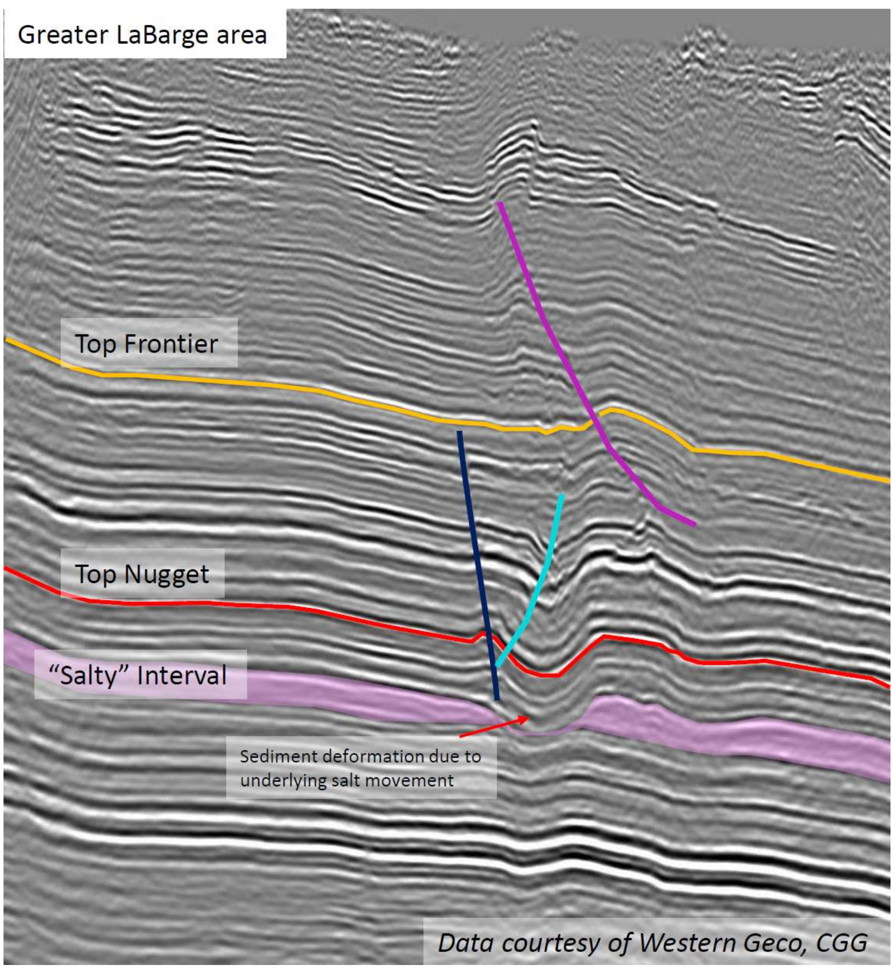

Figure 2.5 Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge field area

2.3.3 Basement-detached Contraction

The third main structural style observed at LaBarge field is those resultant from basement-detached contraction. These features have been well-documented, historically at LaBarge as many of these features have mapped fault expressions on the surface. Detachment and contraction along the basement typically creates three types of structural features:

1. Regional scale thrust faults
2. Localized, smaller scale thrust faults
3. Reactivation of Triassic salt-rich sediments resulting in local structural highs (section 2.3.2)

The basement-detached contraction features typically occur at a regional scale. The subsurface structural features formed through these contractional events are the same size or larger than the greater LaBarge field area. Very large faults are usually associated with these subsurface features, albeit via the reactivation of Triassic salt sediments which can result in additional localized structuring in the area (section 2.3.2).

2.3.4 Faulting and Fracturing of Reservoir Intervals

Reservoir permeability has been observed to increase with the presence of small-scale faults and fractures in almost all of the productive intervals of LaBarge field. Micro-fractures have been observed in core and on formation micro imager (FMI) logs. The fractures seen in the available core are typically filled with calcite, in general.

Empirically, reservoir permeability and increased hydrocarbon productivity have been observed in wells/penetrations that are correlative to areas located on or near structural highs or fault junctions. These empirical observations tend to suggest that these areas have a much higher natural fracture density than other areas or have a larger proportion of natural fractures that are open and not calcite filled. Lack of faulting, as is observed near areas adjacent to the AGI, SC 5-2, and SC 7-34 wells at LaBarge, tends to yield reservoir permeability that is dominated only by matrix or pore-to-pore flow that is generally inhibitive to fluid flow in the subsurface over long distances.

2.3.5 LaBarge Field Structure and Gas Resource of the Madison Formation

Structural closure on the Madison Formation at the LaBarge field is quite large, with approximately 4,000' true vertical depth (TVD) of structural closure from the top of the structure to the gas-water contact (GWC). Spatially, the Madison closure covers over 1,000 square miles making it one of the largest gas fields in North America.

The Madison Formation is estimated to contain in excess of 170 trillion cubic feet (TCF) of raw gas and 20 TCF of natural gas (CH_4). At current rates of production, the estimated remaining field life is over 100 years. Spatially, the AGI and CO_2 injection wells have been located at or immediately adjacent to the SCTF, over 40 miles to the southeast from the main LaBarge production areas.

2.4 History of the LaBarge Field Area

The LaBarge field was initially discovered in 1920 with the drilling of a shallow oil producing well. The generalized history of the LaBarge field area is as follows:

- 1907 Oil seeps observed near LaBarge, surface mapping of Tip Top anticline
- 1920 Texas Production Company drills shallow Hilliard sandstone discovery (10 BOPD)
- 1940's General Petroleum (G.P.) (Mobil) explores LaBarge area, surface and seismic mapping
- 1951 Tip Top Field discovered by G.P. (Frontier SS @ 1.8 MCFD, Nugget SS @ 266 BOPD)
- 1952 Belco discovers Frontier gas at Big Piney and LaBarge
- 1954 Belco commits gas to Pacific NW Pipeline, 33 SI gas wells
- 1956 Pacific NW Pipeline completed
- 1956-64 Active drilling of Frontier wells (structural traps)
- 1962 Mobil discovers Madison LS gas at Tip Top, chooses not to develop
- 1970 Exxon evaluates LaBarge area
- 1975-84 2nd major phase of Frontier drilling (stratigraphic traps)
- 1980 Section 29 of Oil Windfall Tax Act for tight gas sands passed (expired 01/01/94)
- 1981 Exxon discovers Madison gas on Lake Ridge Unit (LRU 1-03)
- 1986 First sales of Exxon Madison gas
- 1992 WOGCC approves 160 acre spacing for Frontier
- 1989-95 Chevron, Enron, PG & E, and Mobil actively drill Frontier targets
- 1999 Exxon and Mobil merge
- 2001-03 Active drilling of Acid Gas Injection wells 2-18 and 3-14
- 2005 Acid Gas Injection wells 2-18 and 3-14 begin operation
- 2019 WOGCC approves SC 5-2 CO_2 injection well
- 2022 Transfer of ownership of shallow horizons on TipTop and Hogsback
- 2023 Active drilling of SC 5-2 CO_2 injection well
- 2024 WOGCC approves SC 7-34 CO_2 injection well

Historically, Exxon held and operated the Lake Ridge and Fogarty Creek areas of the field, while Mobil operated the Tip Top and Hogsback field areas (Figure 2.6). The heritage operating areas were combined in 1999, with the merger of Exxon and Mobil to form ExxonMobil, into the greater LaBarge operating area. In general, heritage Mobil operations were focused upon shallow sweet gas development drilling while heritage Exxon operations focused upon deeper sour gas production.

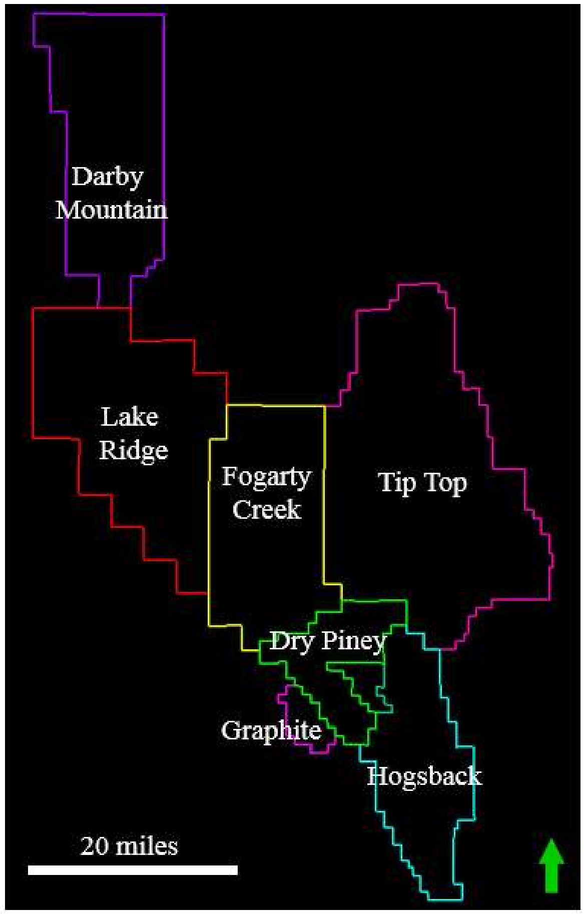

Figure 2.6 Historical unit map of the greater LaBarge field area prior to Exxon and Mobil merger in 1999

2.5 Initial Discovery of Gas and Early Commercial Production at LaBarge

ExxonMobil's involvement in LaBarge originates in the 1960's with Mobil's discovery of gas in the Madison Formation. The Madison discovery, however, was not commercially developed until much later in the 1980's following Exxon's Madison gas discovery on the Lake Ridge Unit. Subsequently, initial commercial gas production at LaBarge was first established in the Frontier Formation, while commercial oil production was established in the Nugget Formation.

Gas production from the Madison Formation was initiated in 1986 after the start-up of the SCTF, which expanded capacity to handle Madison gas. The total gas in-place for the Madison Formation at LaBarge is in excess of 170 TCF gross gas and is a world-class gas reserve economically attractive for production.

2.6 Gas Injection Program History at LaBarge

The Madison Formation, once commercial production of gas was established, was found to contain relatively low methane (CH_4) concentration and high carbon dioxide (CO_2) content. The average properties of Madison gas are:

1. 21% CH_4

2. 66% CO_2
3. 7% nitrogen (N_2)
4. 5% hydrogen sulfide (H_2S)
5. 0.6% helium (He)

Due to the abnormally high CO_2 and H_2S content of Madison gas, the CH_4 was stripped from the raw gas stream leaving a very large need for disposal of the CO_2 and H_2S that remained. For enhanced oil recovery (EOR) projects, CO_2 volumes have historically been sold from LaBarge to offset oil operators operating EOR oilfield projects. Originally, the SCTF contained a sulfur recovery unit (SRU) process to transform the H_2S in the gas stream to elemental sulfur. In 2005, the SRU's were decommissioned to debottleneck the plant and improve plant reliability. This created a need to establish reinjection of the H_2S, and entrained CO_2, to the subsurface.

2.6.1 Geological Overview of Acid Gas Injection and CO_2 Injection Programs

Sour gas of up to 66% CO_2 and 5% H_2S is currently produced from the Madison Formation at LaBarge. The majority of produced CO_2 is currently being sold by ExxonMobil to other oilfield operators and is being used in EOR projects in the region. The sold volume however, does not equal the total produced CO_2 and H_2S volumes, thereby requiring disposal.

ExxonMobil has pursued the AGI program as a safe and reliable method to re-inject the acid gas into the Madison Formation into the aquifer below the field GWC. Gas composition in the AGI wells is based on plant injection needs, and will vary between 35 - 50% CO_2 and 50 - 65% H_2S. The acid gas is injected at a depth of ~17,500 feet below the surface and approximately 43 miles away from the main producing areas of LaBarge.

The volume of CO_2 sold and CO_2 injected into the AGI wells does not equal the volume of CO_2 produced, so additional injection wells are required (SC 5-2 and SC 7-34). Gas composition to be injected into the CO_2 injection wells is planned to be approximately 99% CO_2 with minor amounts of methane, nitrogen, carbonyl sulfide (COS), ethane, and H_2S. For the SC 5-2 well, the gas is planned to be injected between depths of ~17,950 feet and ~19,200 feet measured depth (MD) approximately 35 miles away from the main producing areas of LaBarge. For the SC 7-34 well, the gas is planned to be injected between depths of ~16,740 feet and ~18,230 feet MD approximately 30 miles away from the main producing areas of LaBarge.

2.6.2 Reservoir Quality of Madison and Bighorn-Gallatin Formations at Injection Well Locations

The existing AGI wells were successfully drilled, logged, and evaluated prior to injection commencement. Figure 2.7 is a schematic diagram showing the relative location of AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34. Figures 2.8 and 2.9 are structure maps for the Madison and Bighorn-Gallatin formations, respectively, showing the relative location of the four wells.

Figure 2.10 shows Madison well logs for SC 5-2, AGI 3-14, and AGI 2-18. Petrophysical evaluation of these wells indicate that Madison limestone and dolomite sequences were penetrated, as expected. Total porosity ranges of the limestone sequences were determined to be between 0%

and 5%, while the dolomite sequences were found to be up to 20% total porosity. Injection fall-off testing indicated that the AGI wells exhibit greater than 2000 millidarcy-feet (md-ft) of permeability-height within the injection section. Figure 2.11 shows a table summarizing Madison and Bighorn-Gallatin reservoir properties from the SC 5-2, AGI 3-14, and AGI 2-18 wells. Madison reservoir quality for the SC 5-2 well is similar to the quality for the AGI wells, and is expected to be similar for the SC 7-34 well.

Bighorn-Gallatin reservoir quality for the SC 5-2 well is similar to the nearest Bighorn-Gallatin penetration at 1-12 Keller Raptor well (also referred to as the Amoco/Keller Rubow 1-12 well or the Keller Rubow-1 well), which shows interbedded dolostone and limestone sequences. In general, the degree of dolomitic recrystallization in the Bighorn-Gallatin is similar to the Madison Formation, which has resulted in comparable porosities and permeabilities despite a greater depth of burial. Bighorn-Gallatin total porosity from six LaBarge wells has been determined to be between 2 – 19% with permeabilities between 0.1 – 230 md.

Updated average Madison and Bighorn-Gallatin reservoir properties and well logs will be provided once the SC 7-34 well is drilled. Data will be submitted in the first annual monitoring report following commencement and operation of SC 7-34.

Figures 2.12 and 2.13 show the stratigraphic and structural cross sections of SC 5-2 and SC 7-34 in relation to AGI 3-14, AGI 2-18, and another analog well (1-12 Keller Raptor) penetrating the Madison and Bighorn-Gallatin formations further updip.

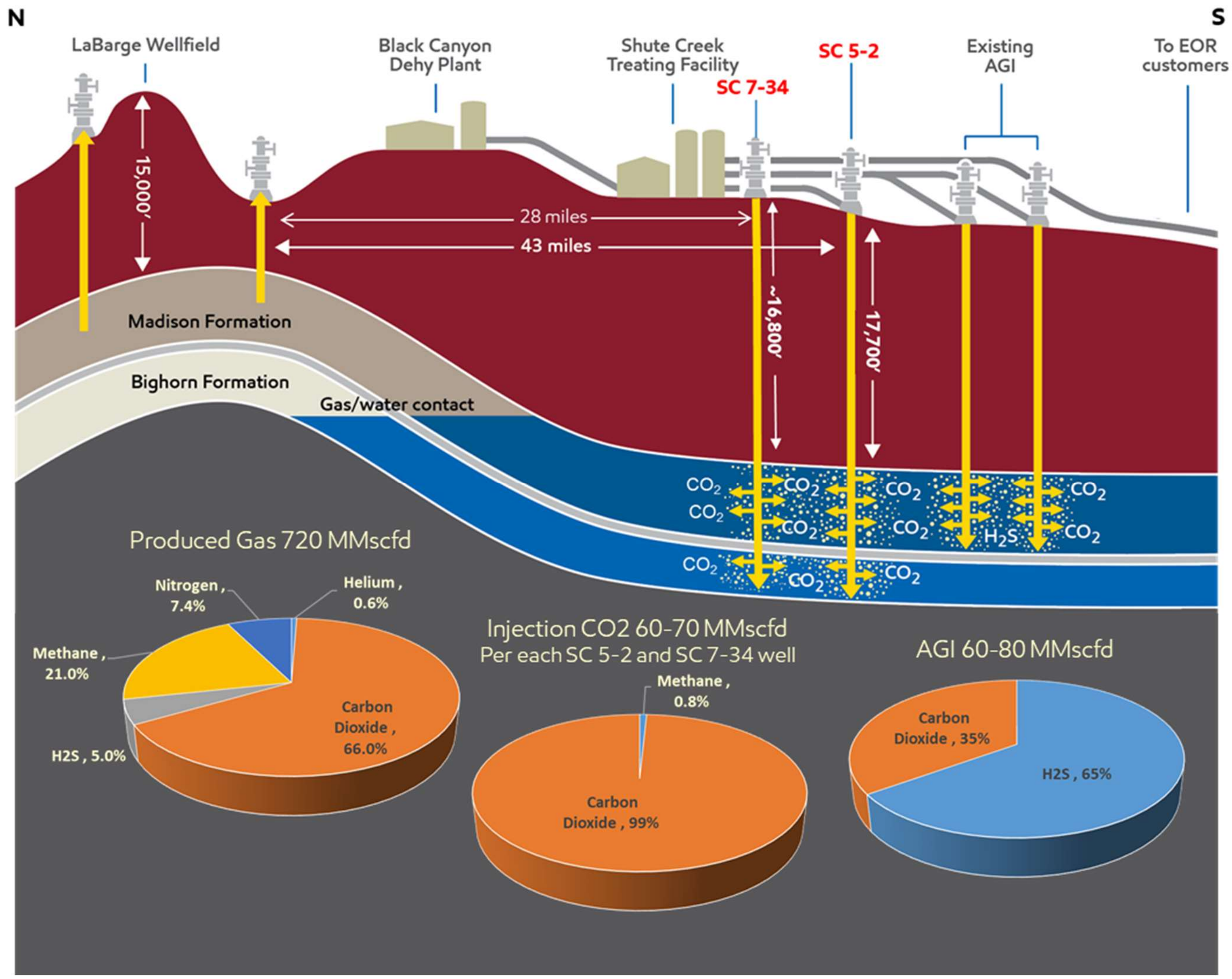

Figure 2.7 Schematic illustration of AGI injection program as currently used at LaBarge and CO_2 injection programs

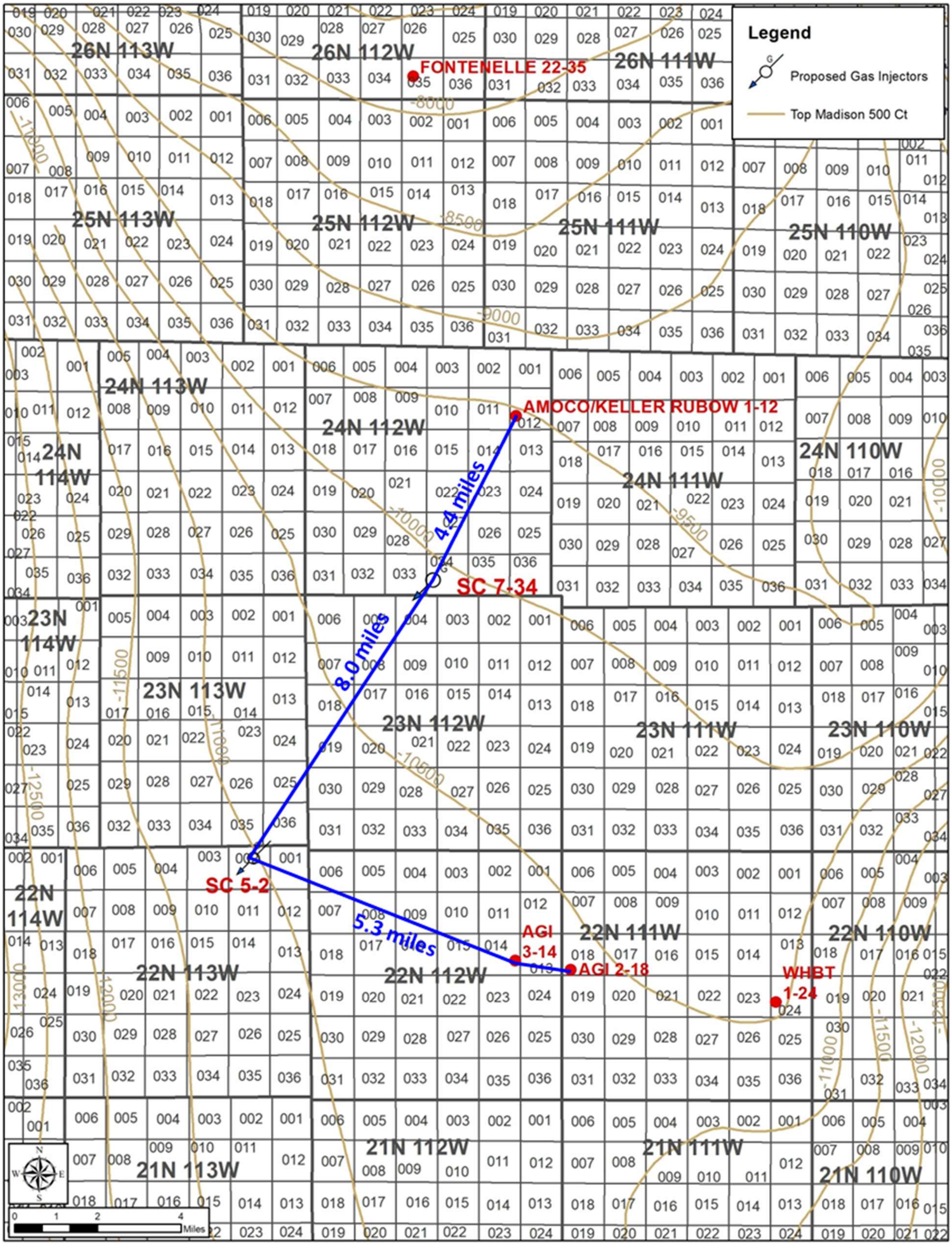

Figure 2.8 Madison structure map with relative well locations

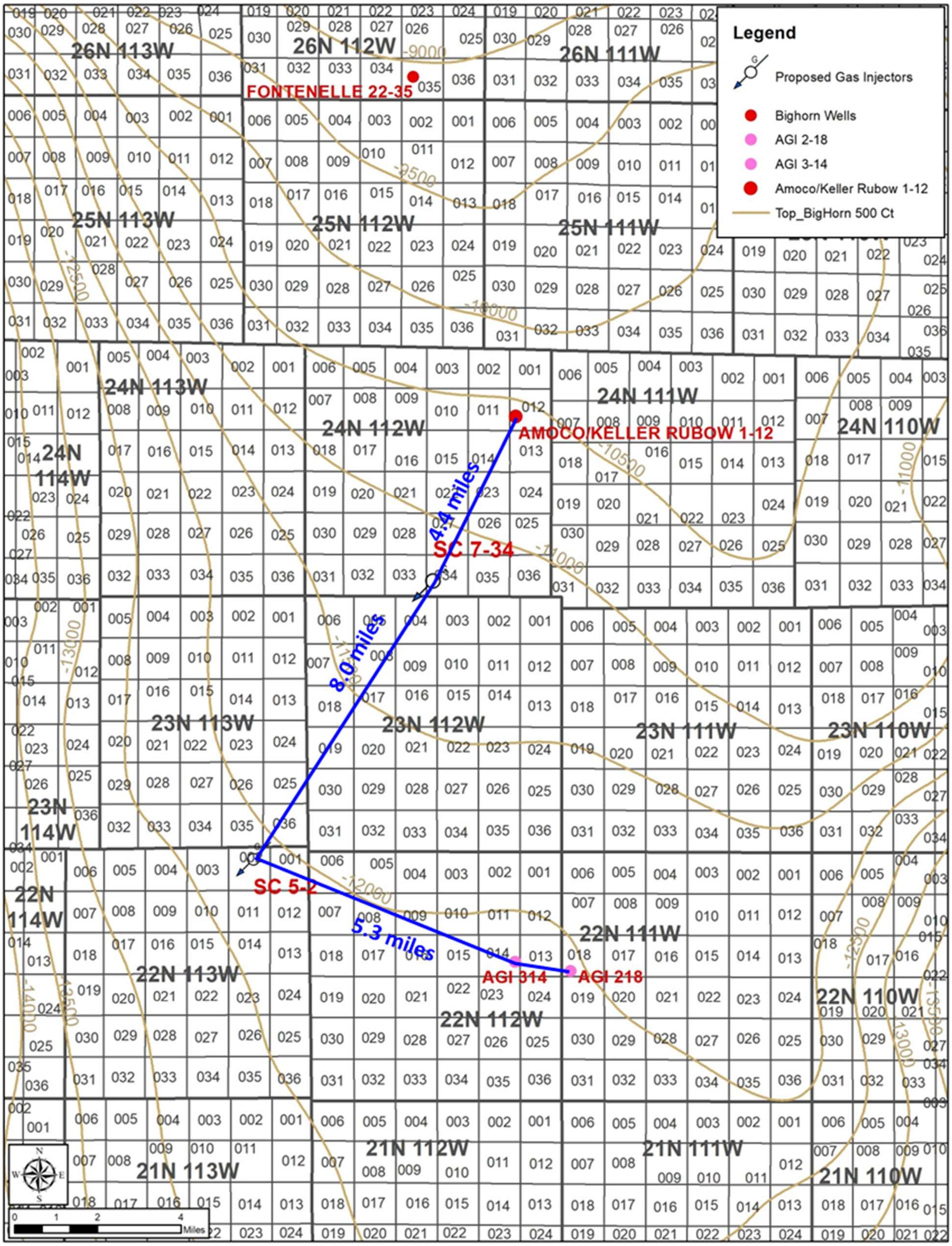

Figure 2.9 Bighorn-Gallatin structure map with relative well locations

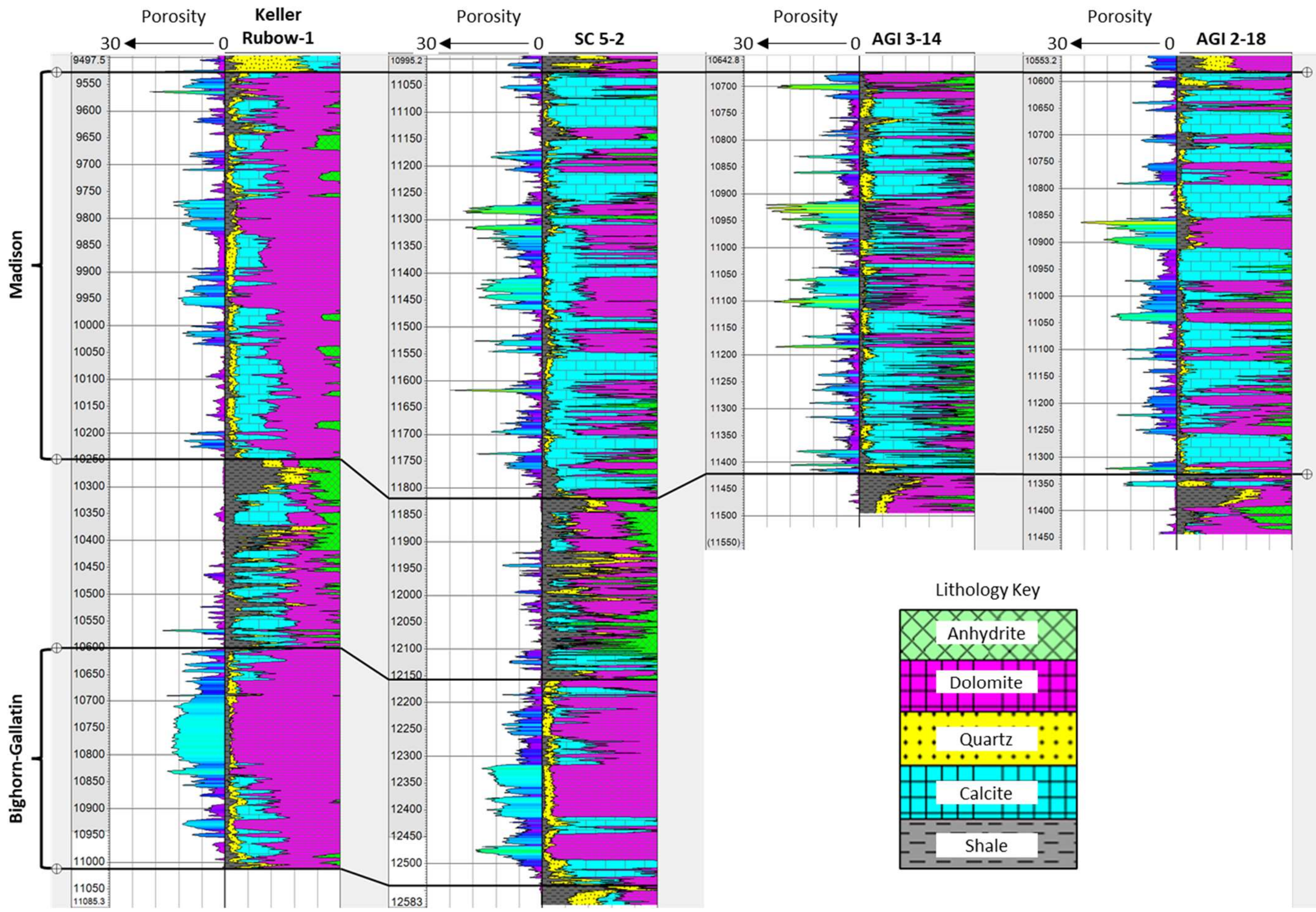

Figure 2.10 Well log sections from the Keller Rubow-1, SC 5-2, AGI 3-14, and AGI 2-18 injection wells across the Madison and Bighorn-Gallatin formations. SC 7-34 well logs are expected to be similar to offset wells.

	Bighorn-Gallatin	**Madison**		
	SC 5-2	**SC 5-2**	**AGI 3-14**	**AGI 2-18**
Net Pay (ft)	245	291	240	220
Avg Φ (%)	9%	10%	10%	9%
Avg k (md)	4	10	9	12
kh (md-ft)	~600*	~3000*	2300*	~2700*
Skin	-3.7	-3.5	-4.1	-4.5

* From injection / falloff test analysis

Figure 2.11 Average Madison and Bighorn-Gallatin reservoir properties of the SC 5-2 and AGI wells. SC 7-34 is expected to have similar properties.

From Figure 2.11, the parameters tabulated include:

1. *Net pay:* Madison section that exceeds 5% total porosity.
2. *Phi (ϕ):* Total porosity; the percent of the total bulk volume of the rock investigated that is not occupied by rock-forming matrix minerals or cements.
3. *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. Note that the measure of darcy assumes linear flow (i.e. pipe shaped).
4. *Kh:* Millidarcy-feet, which is a measure of the average permeability calculated at a 0.5 foot sample rate from the well log accumulated over the total net pay section encountered.
5. *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.

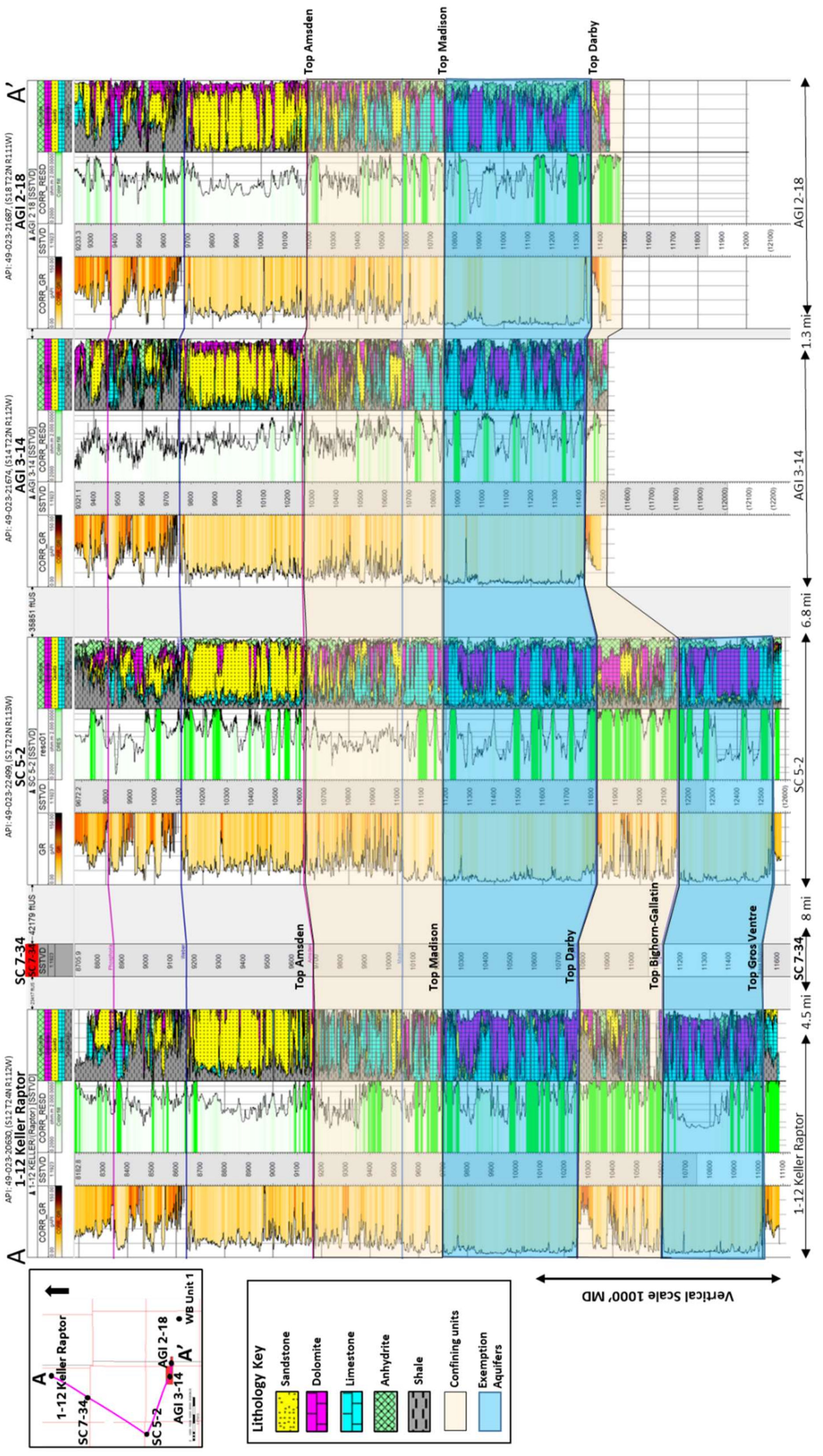

Figure 2.12 Stratigraphic Cross Section of Existing Madison and Bighorn-Gallatin Wells and the SC 7-34 Well

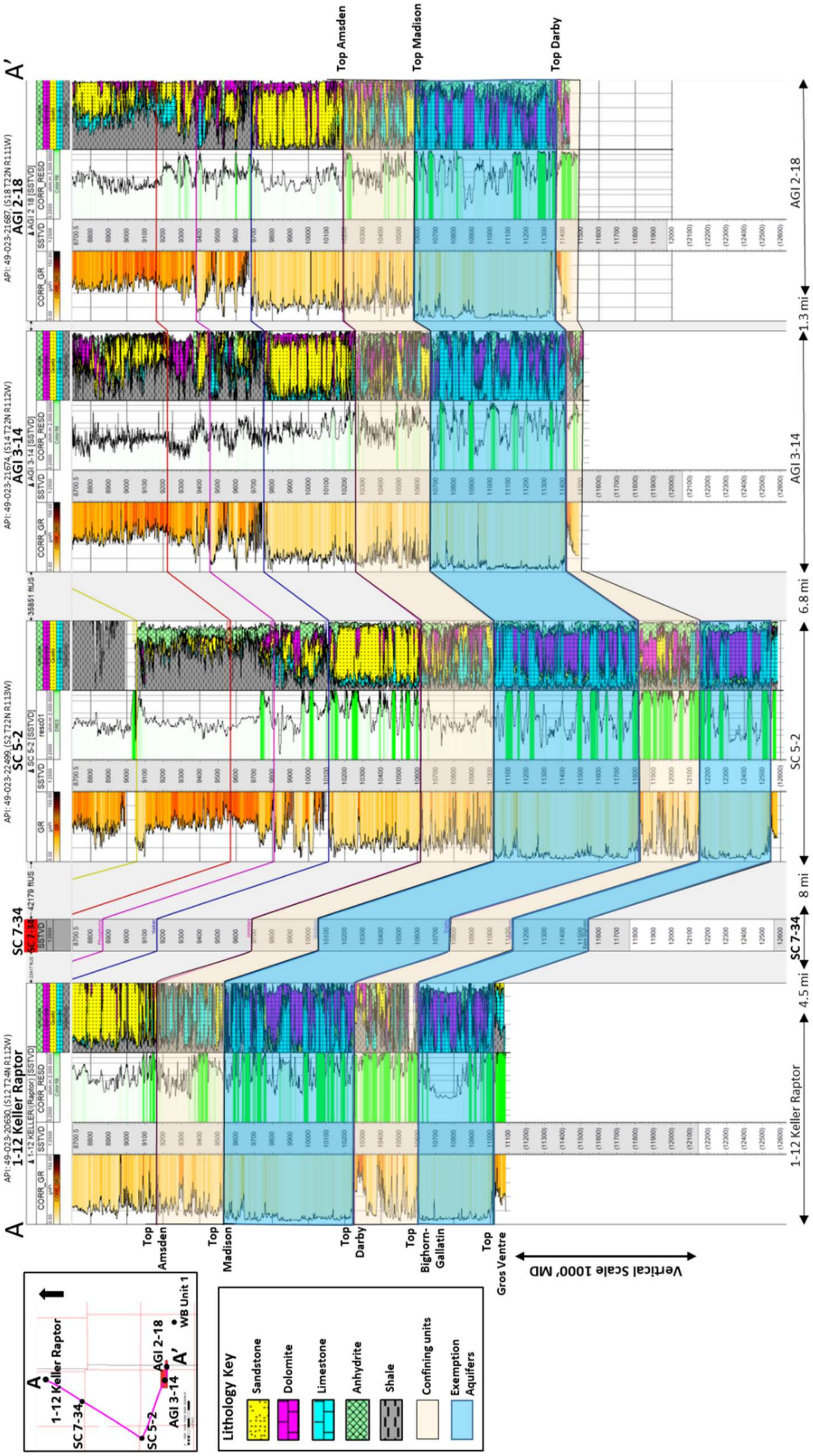

Figure 2.13 Structural Cross Section of Existing Madison and Bighorn-Gallatin Wells and the SC 7-34 Well

2.6.3 Seismic Expression of Madison and Bighorn-Gallatin Formations at CO_2 Injection Well Locations

Seismic expression of the Madison and Bighorn-Gallatin formations at the SC 5-2 and SC 7-34 injection locations indicate that the CO_2 injection wells are located on the plunging crest of the Moxa Arch with little to no structuring observable on the seismic data around these wells. Faulting is also not indicated by the seismic data. Figure 2.14 shows an east-west oriented 2D seismic at the SC 5-2 well location at approximately five times vertical exaggeration. Figure 2.15 shows an east-west oriented 2D seismic at the SC 7-34 well location at approximately four times vertical exaggeration.

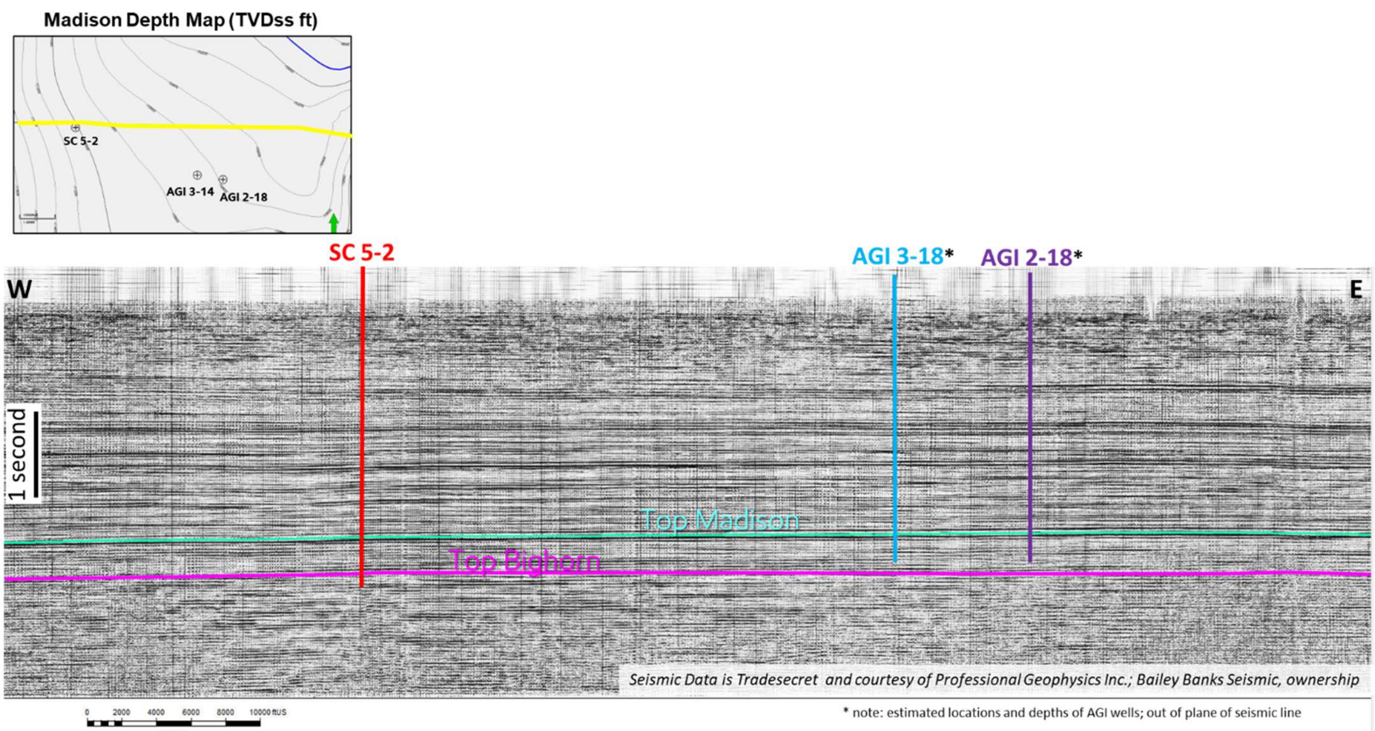

Figure 2.14 2D Seismic traverses around the SC 5-2 injection well location shows no evidence of faulting or structuring around the well location

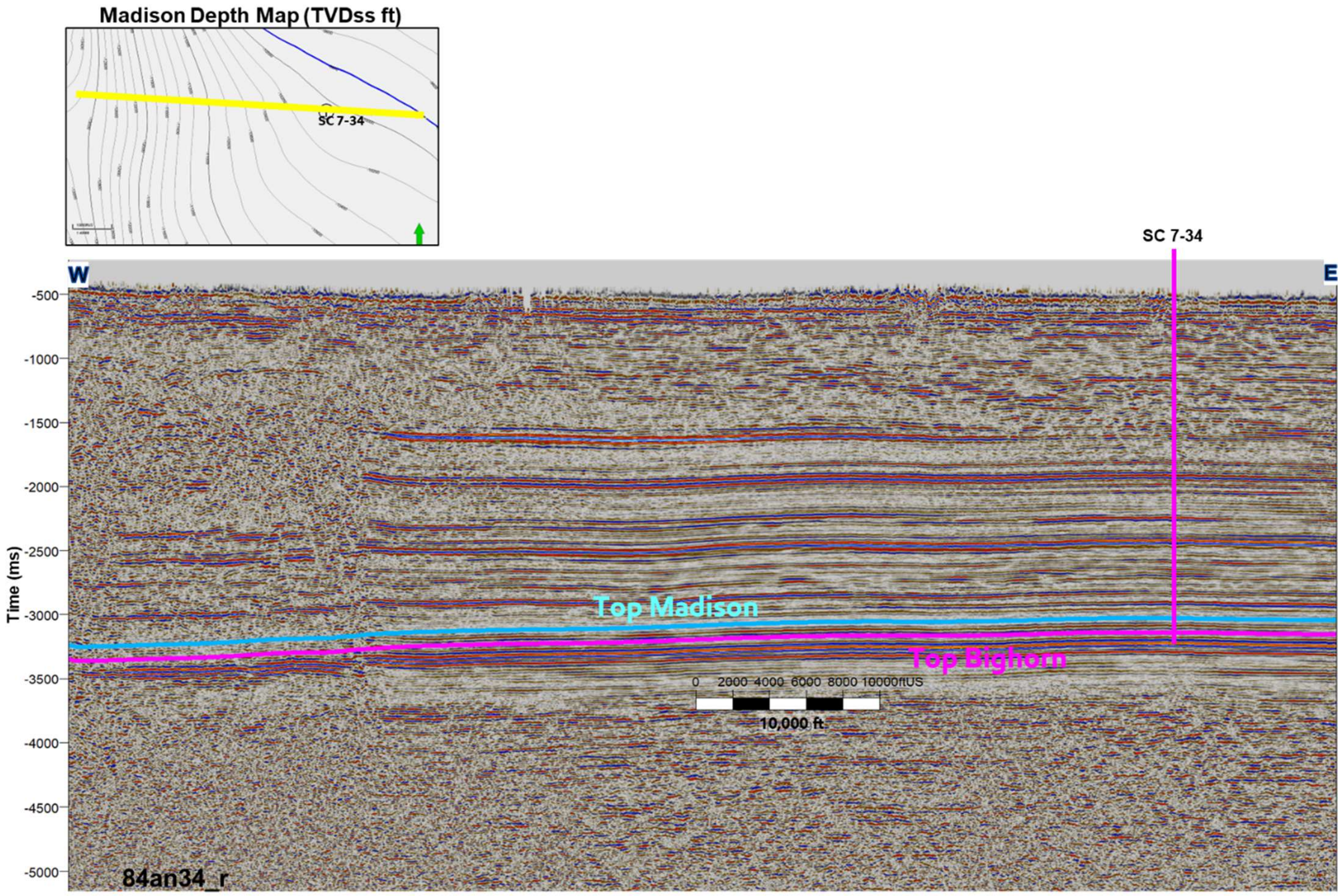

Figure 2.15 2D Seismic traverses around the SC 7-34 injection well location shows no evidence of faulting or structuring around the well location

2.7 Description of the Injection Process

2.7.1 Description of the AGI Process

The AGI facility was commissioned for eliminating the Claus Sulfur Recovery Units (SRU) bottleneck, reducing plant downtime, and reducing operating costs. The purpose of the AGI process is to take the H_2S and some of the CO_2 removed from the produced raw gas and inject it back into the Madison Formation. Raw gas is produced out of the Madison Formation and acid gas is injected into the aquifer below the GWC of the Madison Formation. The Madison reservoir contains very little CH_4 and He at the injection locations under SCTF, where the AGI wells are located. Thus, there is no concern of contaminating the production from the LaBarge well field 43 miles away.

The AGI process transports the acid gas stripped in the Selexol process under pressure through a pipeline to two underground wells that are geologically suitable for storage of the acid gas (AGI 3-14 and AGI 2-18). There are three parallel compressor trains. Two trains are required for full

capacity; the third train is a spare. The low pressure feed from the Selexol process enters the first stage suction and is compressed through four stages of compression. The high pressure acid gas from the Selexol process requires only three stages of compression. The fourth stage discharge acid gas must be condensed prior to pumping to prevent damage from vapors. Fourth stage discharge acid gas is cooled in three heat exchangers prior to entering the pump. Dense phase aerial coolers are located downstream of the pumps; they remove heat generated by pumping and increase the density of the fluid. The liquid H_2S/CO_2 is commingled downstream of the dense phase coolers and divided into the two injection wells over 38 miles from the nearest Madison gas producer in the LaBarge gas field. The approximate stream composition being injected is 50 - 65% H_2S and 35 - 50% CO_2. Each injection well has a dedicated six-inch carbon steel pipeline. The length of pipeline from the AGI battery limit to the injection wells is about:

- 3,200 feet to AGI 3-14
- 12,400 feet to AGI 2-18

The AGI flow lines are buried with seven feet of cover. Heat tracing is provided for the aboveground portions of the lines to prevent the fluid from cooling to the point where free water settles out. Free water and liquid H_2S/CO_2 form acids, which could lead to corrosive conditions. Additionally, the gas is dehydrated before it enters the flow line, reducing the possibility of free water formation, and the water content of the gas is continuously monitored. The liquid H_2S/CO_2 flows via the injection lines to two injection wells. The total depth of each well is about:

- 18,015 feet for AGI 3-14
- 18,017 feet for AGI 2-18.

2.7.2 Description of the CO_2 Injection Process

The CO_2 injection program was initiated primarily because the volume of CO_2 associated with the natural gas production is greater than the volume that is able to be injected into the AGI wells.

2.7.2.1 Description of the SC 5-2 Process

The SC 5-2 process aims to capture CO_2 at the SCTF that would otherwise be vented, and compress it for injection in the aquifer below the GWC of the Madison and Bighorn-Gallatin formations.

The injection system would enable additional CO_2 to be stripped in the Selexol process, pressurized, and transported to a CO_2 injection well, which is geologically suitable for injection, disposal and sequestration of fluids primarily consisting of CO_2. The process will be built into the existing Selexol trains at SCTF. After the acid gas treatment and dehydration, the gas will be routed to a new flash vessel which will enable capture up to 80 million standard cubic feet per day (MMSCFD) from SCTF then compressed with an air cooled Heat Exchanger cooling system. The captured CO_2 will have the potential to be either sold or injected into a CO_2 injection well. Based on modeling, the approximate stream composition will be 99% CO_2, 0.8% methane and 0.2% other mixed gases.

From the CO_2 compressors, an eight inch flow line of approximately 10.1 miles would take the fluids to the SC 5-2 injection well site. The flow line would be buried at depths necessary to avoid and protect existing facilities, roads, and crossings, and will be buried at a minimum below the frost line. The fluids will have a sufficient dew point that free water formation is not expected to accumulate along the pipeline or well. The water content of the gas will be continuously monitored. The gas will be transported via flow line to the SC 5-2 well and injected into the Madison Formation at a depth of ~17,950 feet and into the Bighorn-Gallatin Formation at a depth of ~19,200 feet approximately 33 miles from the nearest Madison gas producer in the LaBarge gas field. Based on geological models, the risk of contaminating production from the LaBarge well field or interacting with the AGI wells or SC 7-34 well approximately 7 miles and 8 miles away, respectively, is improbable due to the relatively tight reservoir quality of the Madison and Bighorn-Gallatin formations, the significant distance between the SC 5-2 injection site and the producing well field, and the volume and rate of injection at the SC 5-2 site.

2.7.2.2 Description of the SC 7-34 Process

The SC 7-34 process aims to divert currently captured CO_2 produced from source wells during natural gas production that will not be sold to customers and route to permanent disposal in the aquifer below the GWC of the Madison and Bighorn-Gallatin formations.

Captured CO_2 that is already routed from SCTF to the existing CO_2 sales building will be diverted and transported via flow line to a CO_2 injection well, which is geologically suitable for injection, disposal, and sequestration of fluids primarily consisting of CO_2. This process will enable disposal of up to 70 MMSCFD through an additional pump. The CO_2 will be cooled with an air cooled Heat Exchanger cooling system. Based on modeling, the approximate stream composition is anticipated to be identical to the SC 5-2 with 99% CO_2, 0.8% methane, and 0.2% other mixed gases.

From the CO_2 compressors, an eight inch flow line of approximately 12.4 miles would take the fluids to the SC 7-34 injection well site. The flow line would be buried at depths necessary to avoid and protect existing facilities, roads, and crossings, and will be buried at a minimum below the frost line. The fluids will have a sufficient dew point that free water formation is not expected to accumulate along the pipeline or well. The water content of the gas will be continuously monitored. The gas will flow via the injection lines to the SC 7-34 well and injected into the Madison Formation at a depth of ~16,740 feet and into the Bighorn-Gallatin Formation at a depth of ~18,230 feet approximately 28 miles from the nearest Madison gas producer in the LaBarge gas field. Based on geological models, the risk of contaminating production from the LaBarge well field 30 miles away or interacting with the SC 5-2 well or AGI wells approximately 8 and 9 miles away, respectively, is improbable due to the relatively tight reservoir quality of the Madison and Bighorn-Gallatin formations, the significant distance between the SC 7-34 injection site and the producing well field, and the volume and rate of injection at the SC 7-34 site.

2.8 Planned Injection Volumes

2.8.1 Acid Gas Injection Volumes

Figure 2.16 is a long-term injection forecast throughout the life of the acid gas injection project. It is based on historic and predicted data. 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 below are the total amount of gas to be injected into the AGI wells, not just the CO_2 portion. ExxonMobil forecasts the total volume of CO_2 stored in the AGI wells over the modeled injection period to be approximately 53 million metric tons.

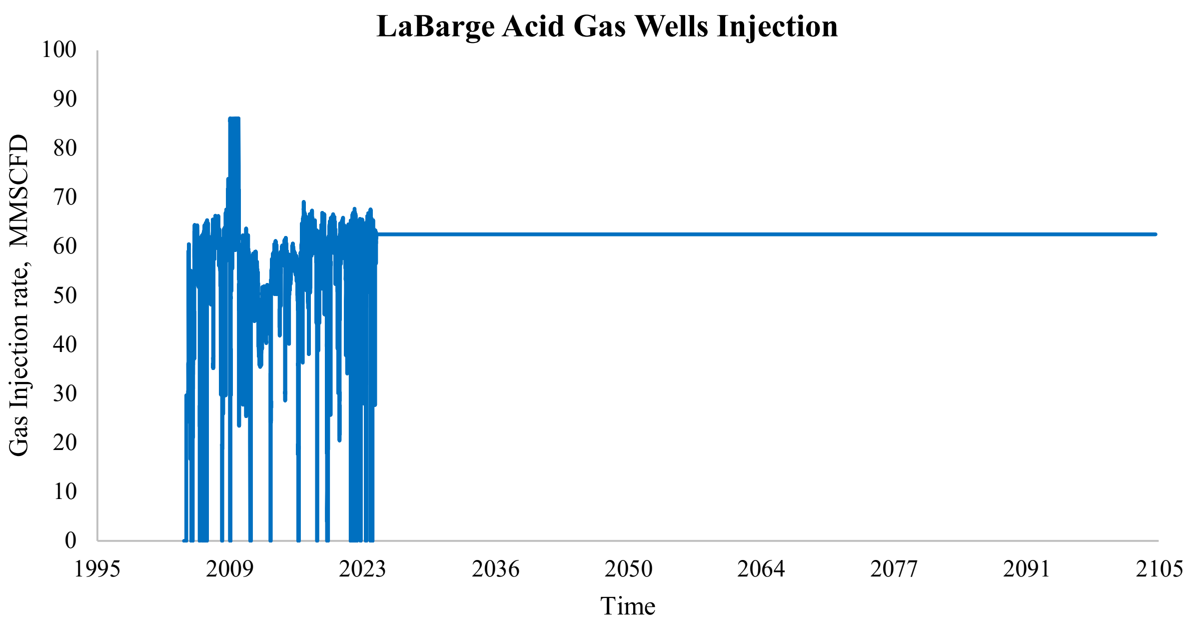

Figure 2.16 – Planned Acid Gas and CO_2 Injection Volumes

2.8.2 CO_2 Injection Wells Volumes

Figure 2.17 below is a long-term average injection forecast through the life of the CO_2 injection wells. 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 below are the total amount of fluids to be injected, but does not include any portion of the Acid Gas Injection project gas. The non-CO_2 portion of the injection stream is expected to be 1% or less of the injected volume. ExxonMobil forecasts the total volume of CO_2 stored in the CO_2 injection wells over the modeled injection period to be approximately 180 million metric tons.

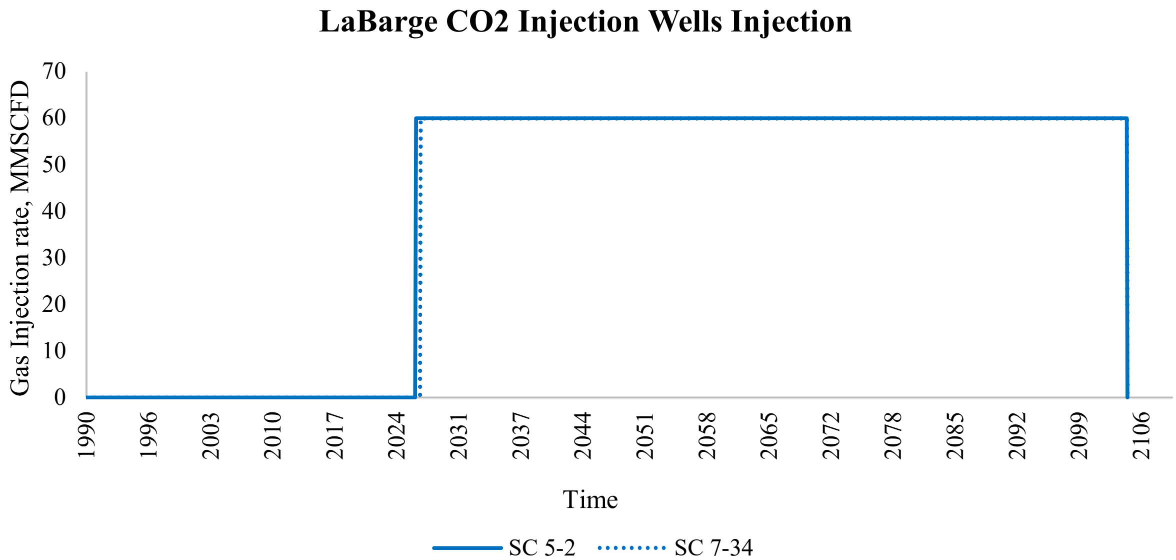

Figure 2.17 – Planned Average CO_2 Injection Well Volumes

3.0 Delineation of Monitoring Area

3.1 Maximum Monitoring Area (MMA)

3.1.1 AGI Wells MMA

Per 40 CFR § 98.449, the MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling using Schlumberger's (SLB) Petrel/Intersect, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the acid gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 1%. A gas saturation of 1% is well below the lowest gas saturation that can be confidently detected by formation evaluation methods in reservoirs with rock properties such as those found in the Madison Formation.

After injecting 0.3 trillion cubic feet (TCF) by year-end 2023, the current estimated acid gas plume size is approximately 21,350 feet in diameter (4.0 miles) (see Figure 3.1). With continuing injection of an additional 1.9 TCF through year-end 2104, at which injection is expected to cease, the plume size is expected to grow to approximately 39,500 feet in diameter (7.5 miles) (see Figure 3.2).

The model was run through 2986 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. The rate of growth of the free-phase gas plume is less than 0.25% areally per

year, demonstrating plume stability. Figure 3.3 below shows the expansion of the plume to a diameter of approximately 40,470 feet (7.7 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the MMA will be defined by Figure 3.3, which is the maximum areal extent of the plume once it has reached stability (defined by the extent of the plume in 2205, which is a 7.7-mile diameter) plus the buffer zone of one-half mile.

3.1.2 CO_2 Injection Wells MMA

Per 40 CFR § 98.449, the MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the CO_2 gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 1%.

Note that estimates of plume size assume that CO_2 is coinjected without flow control at both the SC 5-2 and SC 7-34 wells into both the Madison and Bighorn-Gallatin intervals. Having no flow control means that the amount of gas that enters each interval is for the most part a function of the permeability thickness (kh) of each interval. There is limited data, especially for the Bighorn-Gallatin, with few well penetrations, all of which are a significant distance from the target formation. Therefore, the anticipated plume sizes are based on simulation results relying on best estimates from available data regarding the Madison and Bighorn-Gallatin reservoir quality.

The model was run through 2986 to assess the potential for expansion of the plume after injection ceases at year-end 2104. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. The rate of growth of the free-phase gas plume is less than 0.25% areally per year, demonstrating plume stability.

3.1.2.1 SC 5-2 MMA

Assuming SC 5-2 begins injecting in 2025, 0.02 TCF of CO_2 will have been injected by mid-2026 and the gas plume will just begin to form. Figure 3.4 shows expected average gas saturations at mid-2026 and the location of the AGI wells relative to the SC 5-2 injection well. After injecting 1.7 TCF at year-end 2104, injection is expected to cease. The SC 5-2 CO_2 plume size is expected to grow to approximately 23,650 feet in diameter (4.5 miles) (see Figure 3.5).

Figure 3.6 below shows the expansion of the SC 5-2 plume to a diameter of approximately 24,500 feet (4.6 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the SC 5-2 MMA will be defined by Figure 3.6, which is the maximum areal extent of the SC 5-2 plume once it has reached stability (defined by the extent of the plume in 2205, which is a 4.6-mile diameter) plus the buffer zone of one-half mile.

3.1.2.2 SC 7-34 MMA

SC 7-34 is assumed to begin injection mid-2026. After injecting 1.7 TCF at year-end 2104, injection is expected to cease. The SC 7-34 CO_2 plume size is expected to grow to approximately 22,100 feet in diameter (4.2 miles) (see Figure 3.7).

Figure 3.8 below shows the expansion of the SC 7-34 plume to a diameter of approximately 24,976 feet (4.7 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the SC 7-34 MMA will be defined by Figure 3.8, which is the maximum areal extent of the SC 7-34 plume once it has reached stability (defined by the extent of the plume in 2205, which is a 4.6-mile diameter) plus the buffer zone of one-half mile.

3.2 Active Monitoring Area (AMA)

Per 40 CFR § 98.449, the AMA is the superimposed areas projected to contain the free phase CO_2 plume at the end of the year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile and the area projected to contain the free phase CO_2 plume at the end of year t+5, where t is the last year in the monitoring period.

ExxonMobil proposes to define the AMA as the same boundary as the MMA for the AGI and CO_2 injection wells. The following factors were considered in defining this boundary:

1. Lack of faulting in the MMA yields no vertical pathways for fluids to move vertically out of the Madison or Bighorn-Gallatin formations to shallower intervals.
2. Lack of faulting in the injection area does not create enhanced reservoir permeability through natural fracturing and all flow of injected fluids will be darcy flow from pore to pore.
3. Distance from the LaBarge production field area is large (35+ miles) and reservoir permeability is generally low which naturally inhibits flow aerially from injectionsite.
4. The LaBarge field production area is a large structural hydrocarbon trap that has sealed and trapped hydrocarbons for large geologic periods of time. There is no reason to believe that any injection fluids that may migrate outwards from the injection site to the larger LaBarge structure would not also be effectively trapped at the LaBarge structure over geological time.
5. If t is defined as the final year of injection coinciding with end of field life for the LaBarge assets, the MMA encompasses the free phase CO_2 plume 100 years post-injection, and therefore satisfies and exceeds the AMA area.

The purpose of the AMA is to allow for a practical and cost-effective monitoring program throughout the life of the project. Because there are no probable leakage pathways in the MMA, besides surface equipment which is extensively monitored, ExxonMobil believes it is appropriate to define the AMA as the same boundary as the MMA. Additionally, due to the high H_2S content of the injected gas stream into the AGI wells, monitoring of leaks is essential to operations and

personnel safety, so a full-scale monitoring program has already been implemented at the AGI sites, as will be discussed below.

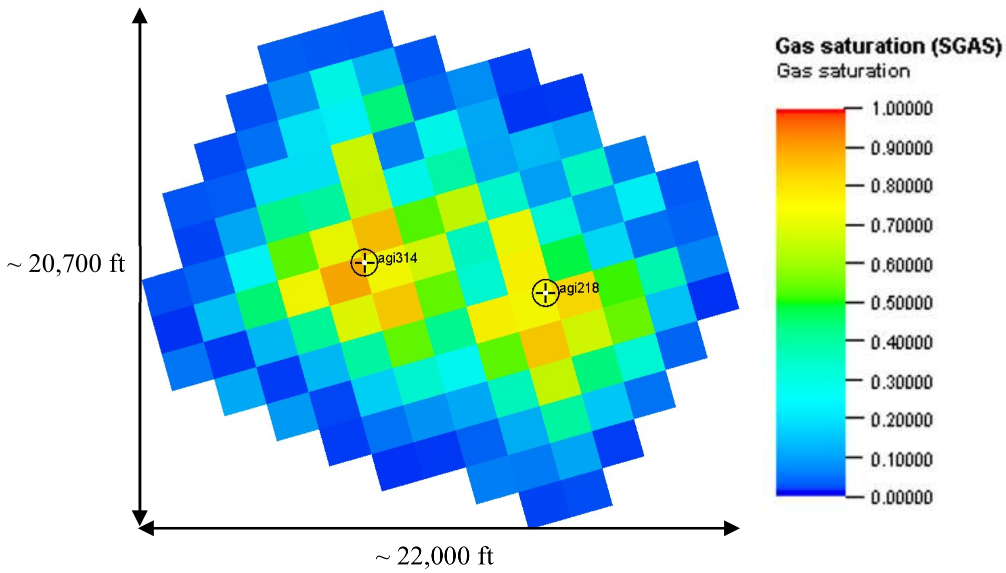

Figure 3.1 – AGI Estimated Gas Saturations at Year-end 2023

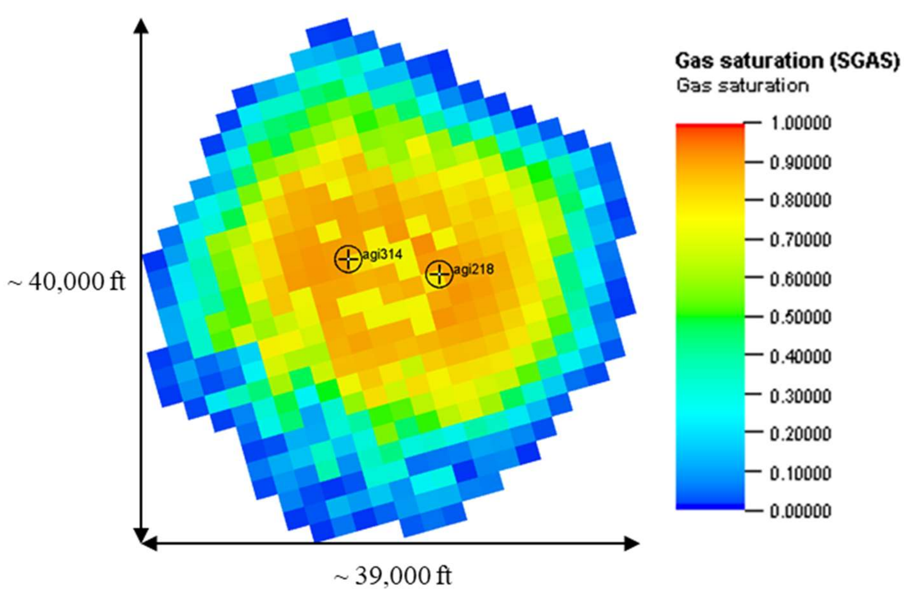

Figure 3.2 – AGI Predicted Gas Saturations at Year-end 2104

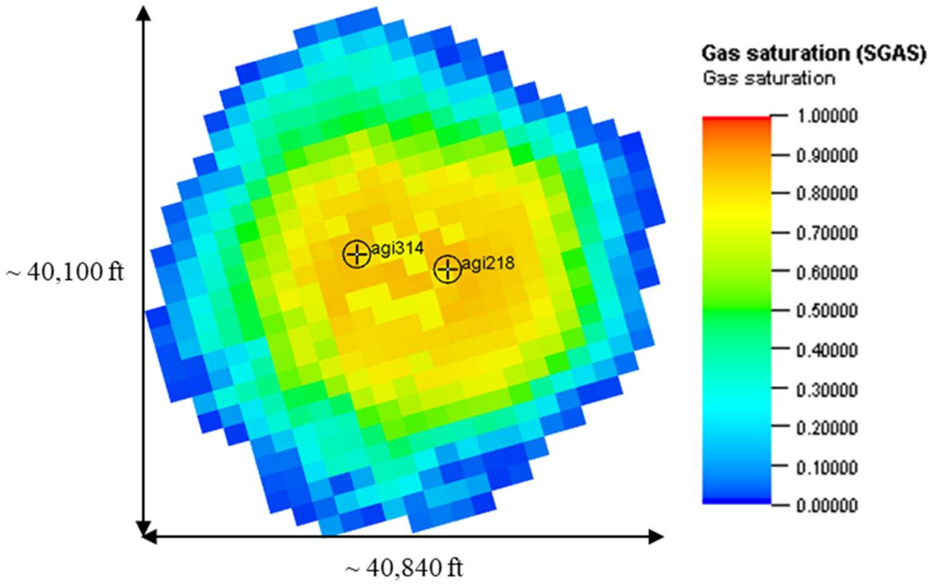

Figure 3.3 – AGI Predicted Gas Saturations at Year-end 2205

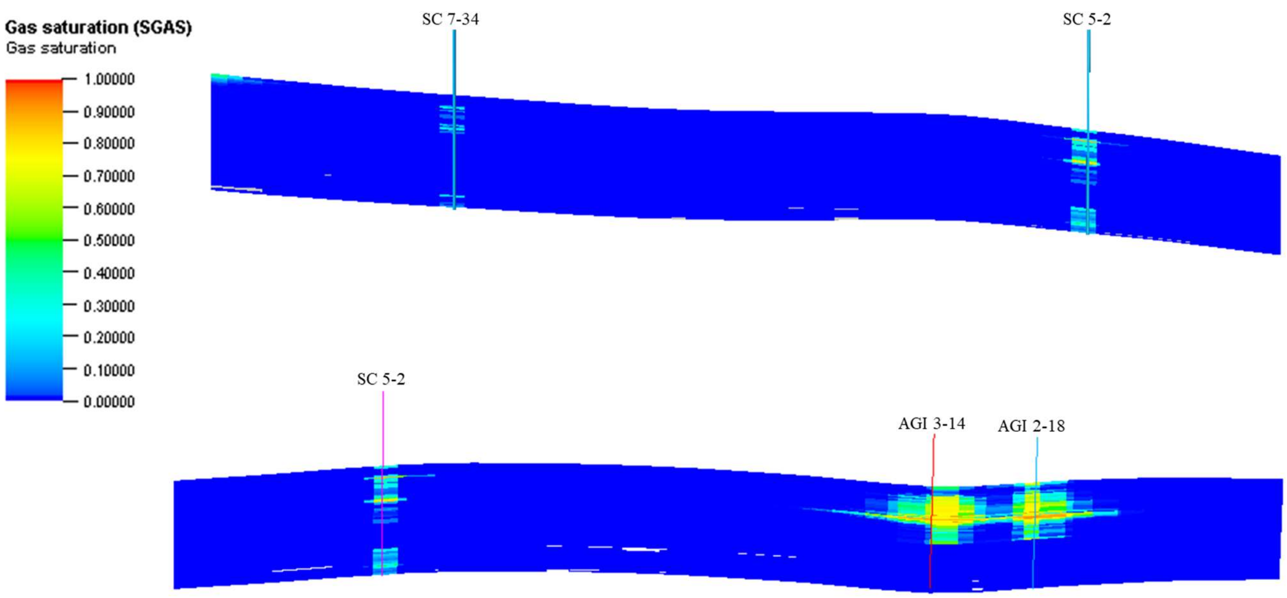

Figure 3.4 – Predicted Gas Saturations at Year-end 2027

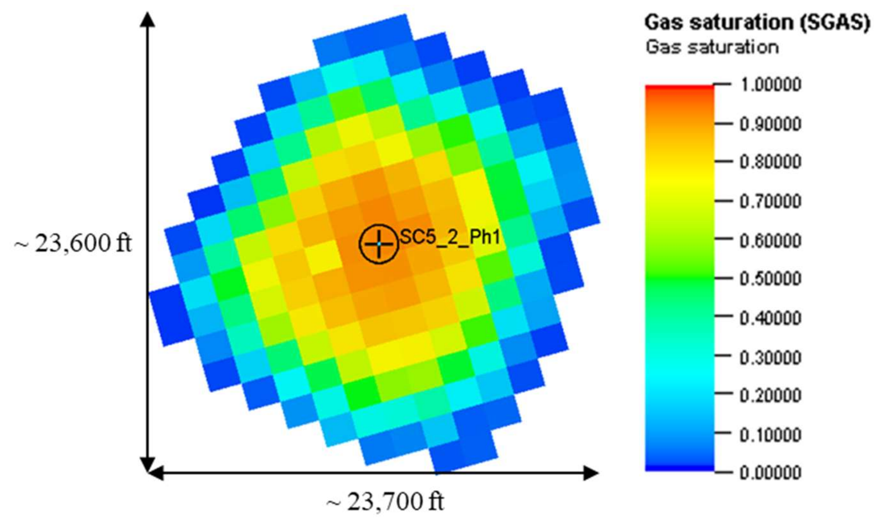

Figure 3.5 – SC 5-2 Predicted Gas Saturations at Year-end 2104

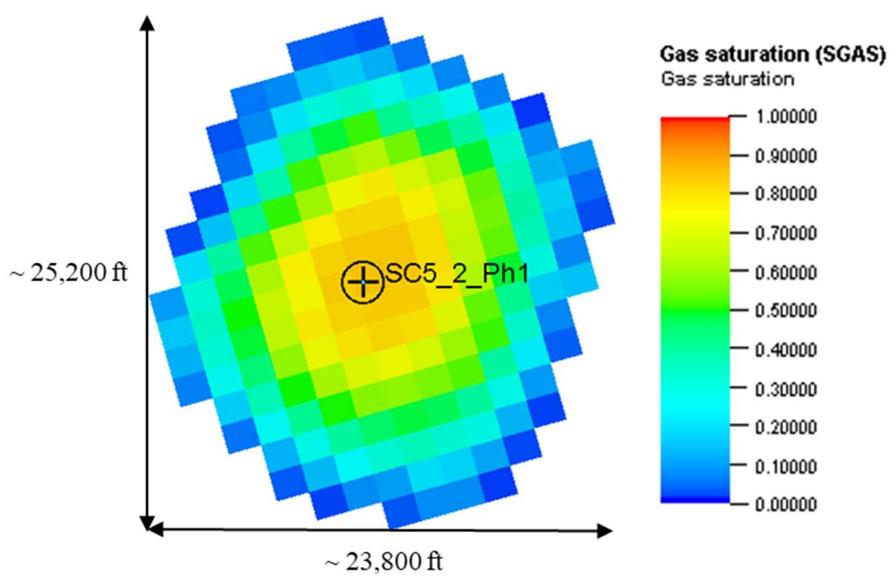

Figure 3.6 – SC 5-2 CO_2 Predicted Gas Saturations at Year-end 2205

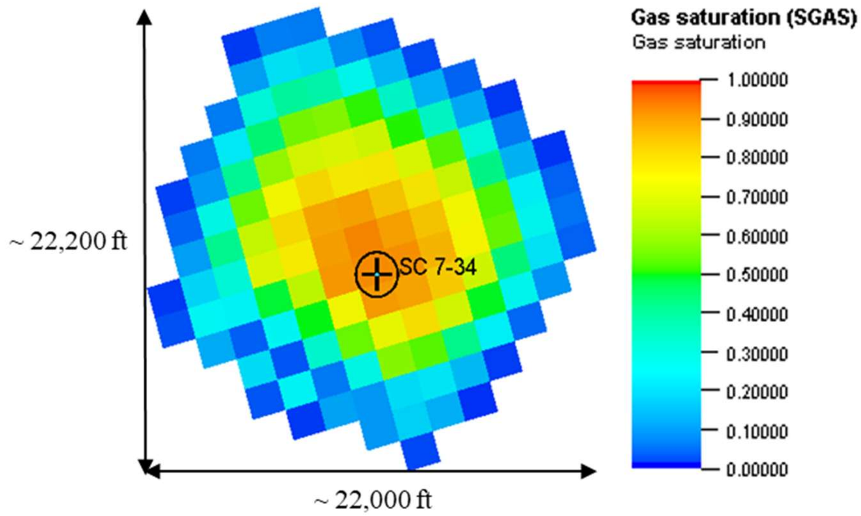

Figure 3.7 – SC 7-34 Predicted Gas Saturations at Year-end 2104

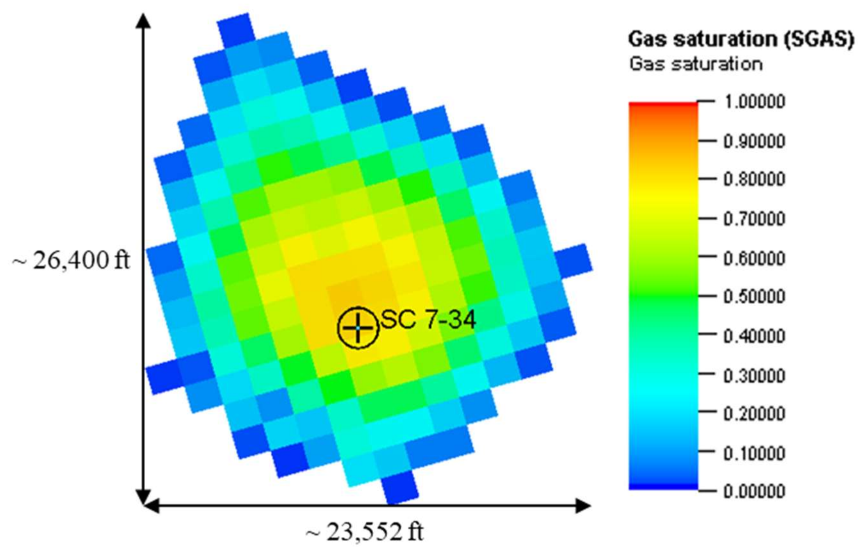

Figure 3.8 – SC 7-34 Predicted Gas Saturations at Year-end 2205

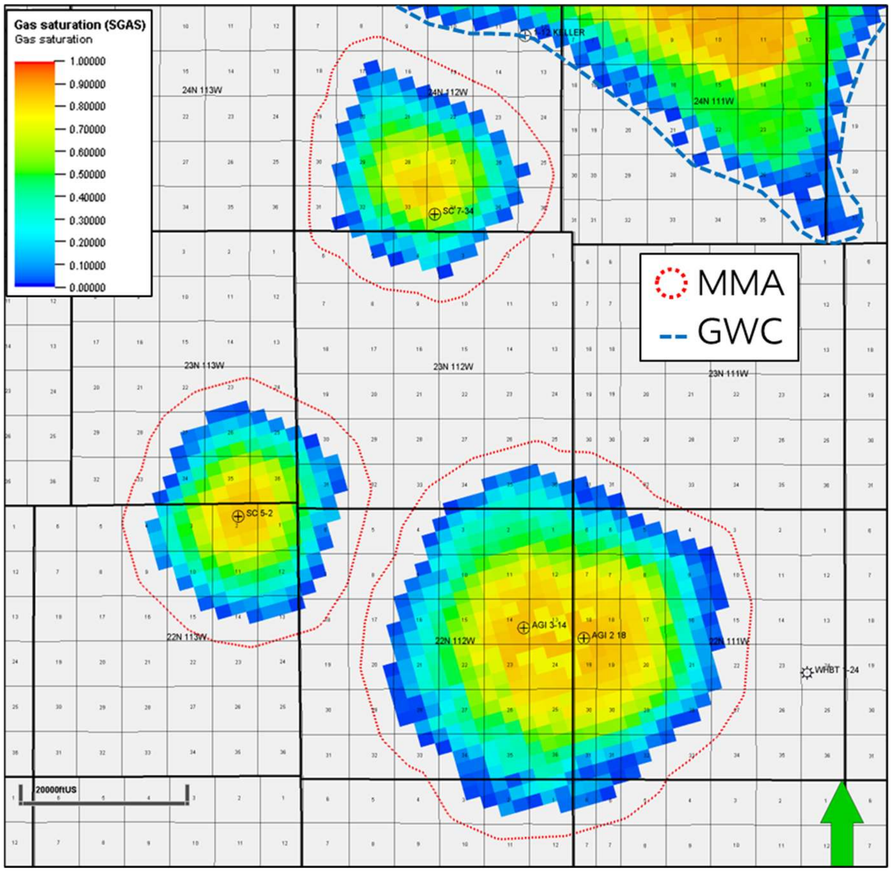

Figure 3.9 - Gas saturation plumes for AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34 at the time of plume stabilization (year 2205) with half mile buffer limit of MMA (red polygons). Plumes are displayed at zone of largest aerial extent (within Madison Formation) relative to the LaBarge gas field in the same gas-bearing zone (gas water contact displayed in dashed blue polygon).

4.0 Evaluation of Potential Pathways for Leakage to the Surface

This section assesses the potential pathways for leakage of injected CO_2 to the surface. ExxonMobil has identified the potential leakage pathways within the monitoring area as:

- Leakage from surface equipment (pipeline and wellhead)
- Leakage through wells
- Leakage through faults and fractures
- Leakage through the seal
- Leakage through natural or induced seismicity

As will be demonstrated in the following sections, there are no leakage pathways that are likely to result in loss of CO_2 to the atmosphere. Further, given the relatively high concentration of H_2S in the AGI injection stream, any leakage through identified or unexpected leakage pathways would be immediately detected by alarms and addressed, thereby minimizing the amount of CO_2 released to the atmosphere from the AGI wells.

4.1 Leakage from Surface Equipment

Leakage from surface equipment is not likely due to the design of the AGI and CO_2 injection facilities. The AGI facilities were designed to minimize leak points such as valves and flanges, and use welded connections where possible instead. The only surface equipment located between the flow meter and the wellhead are valves, transmitters, and flanged connection points on the pipelines. Due to the presence of H_2S in the AGI injection stream at a concentration of approximately 50 - 65% (500,000 - 650,000 parts per million (ppm)), H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. CO_2 gas detectors will be present at the CO_2 injection facilities due to high concentration of CO_2, which alarm at 5,000 PPM. Additionally, all field personnel are required to wear H_2S monitors for safety reasons, which alarm at 5 ppm H_2S. Although damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2 entrained in the acid gas, at the AGI well concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm, and immediate action would be taken to stop the leak. Additionally, the CO_2 injection wells would be monitored with methods outlined in sections five and six.

ExxonMobil reduces the risk of unplanned leakage from surface facilities through continuous surveillance, facility design, and routine inspections. Field personnel monitor the AGI facility continuously through the Distributed Control System (DCS). Additionally, daily visual inspection rounds are conducted of the AGI facility and weekly visual inspections are conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. ExxonMobil also relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSVs), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes. Additionally, the AGI wells have multiple surface isolation valves for redundant protection. Inline inspections of the AGI injection pipelines using a smart pigging tool are conducted on a regular frequency to check the wall thickness of the pipeline to identify potential areas of corrosion.

Field personnel will monitor the CO_2 injection facilities continuously through the DCS. Additionally, visual inspections will be conducted on a routine basis providing an additional way to detect leaks in a timely manner. Surface isolation valves will also be installed for redundant protection. Inline inspections are not anticipated to occur on a regular frequency because free water is not expected to accumulate due to the low dew point of the fluid.

<u>Likelihood</u>
Due to the design of the AGI and CO_2 injection facilities and extensive monitoring in place to reduce the risk of unplanned leakage, leakage from surface equipment is not likely.

<u>Magnitude</u>
Given the high concentrations of H_2S and CO_2 in the respective injection streams, ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. Even a minuscule amount of gas leakage would be immediately detected by the extensive monitoring systems currently in place at the facility as described above and treated as an upset event warranting immediate action to stop the leak. Should leakage be detected from surface equipment, the volume of CO_2 released will be quantified based

on the operating conditions at the time of release, as stated in Section 7.4 in accordance with 40 CFR 98.448(5).

Timing

As stated above, even a minuscle amount of gas leakage would be immediately detected and immediate action would be taken to stop the release. Any potential leakage from surface equipment would only occur during the lifetime operation of the wells. Once injection ceases, the surface equipment will be decommissioned and will not pose a risk as a leakage pathway.

4.2 Leakage through AGI and CO2 Injection Wells

Leakage of CO_2 through oil, gas, and/or water wells completed and/or abandoned is not likely. There is no commercial production of oil or gas within the immediate area of the SCTF. There is shallower production of gas from the Frontier and Dakota formations nearby in the Cow Hollow Field, at depths of 10,800' – 11,800'. A search of the WOGCC database demonstrated that there are no existing active Madison or Bighorn-Gallatin penetrations or production within the respective MMAs of the AGI or CO_2 injection well sites. The nearest established Madison production is greater than 35 miles to the north-northwest in the ExxonMobil LaBarge Deep Madison Field, which is the well field that supplies SCTF. One well (Whiskey Butte Unit 1, drilled in 1974 and operated by Wexpro Company), which was located approximately 6 miles from the AGI wells, partially penetrated 190 feet of the Madison Formation (total depth 17,236 feet MD). This well never produced from the Madison Formation and instead was perforated thousands of feet above in the Frontier Formation. The well was ultimately plugged and abandoned in February 1992. Examination of the plugging and abandonment records and the wellbore diagram constructed from those records indicates that risk of the well as a leakage pathway is highly unlikely. Two additional Madison penetrations are located between the well field and the SC 5-2 and AGI wells; both penetrations are outside the boundary of the MMA and therefore likely do not pose a risk as a leakage pathway. Keller Rubow 1-12 was plugged and abandoned in 1996. Fontenelle II Unit 22-35 was drilled to the Madison Formation but currently is only perforated and producing from thousands of feet above in the Frontier Formation.

As mentioned in Section 2.3.2, early in the life of many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. The thin-wall wells that failed have been plugged and abandoned in accordance with regulatory standards. Madison wells that were subsequently drilled were cased using thick-walled/chrome tubulars due to the high H_2S and CO_2 content and subsequent corrosion effects, as well as to combat potential salt or sediment creep. Therefore, there is no current risk of failure as all wells currently use or have used thick-walled casing of sufficient strength to penetrate and/or produce from the Madison Formation.

Future drilling is also unlikely to pose a risk as a leakage pathway due to limited areal extent of the injection plumes as shown in Figures 3.2 – 3.8. Therefore, the geological model can be used to delineate areas that should be avoided during drilling. This model has also history-matched the AGI wells injection that has occurred to date and suggests that future injection will closely follow the patterns resulting from the geological model simulation. Additionally, should future drilling occur, it would occur near the existing production area, which is greater than 40 miles away from

the current AGI wells, approximately 35 miles away from SC 5-2, and approximately 30 miles away from SC 7-34.

ExxonMobil reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and annual mechanical integrity testing (MIT). As indicated in Section 4.1, visual inspections of the well sites are performed on a routine basis, which serves as a proactive and preventative method for identifying leaks in a timely manner. Gas detectors located at the well sites which alarm at 10 ppm H_2S and 5,000 ppm CO_2 would be triggered if a leak from the wellbore to the atmosphere occurred. Additionally, SCSSV's and surface isolation valves are installed at the AGI wells, which would close in the event of leakage, preventing losses. Mechanical integrity testing is conducted on an annual basis and consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. If the MIT demonstrated a leak, the well would be isolated and the leak would be mitigated as appropriate to prevent leakage to the atmosphere.

<u>Likelihood</u>

There are no existing active Madison or Bighorn-Gallatin penetrations or production within the respective MMAs of the AGI and CO_2 injection well sites. As stated in Section 4.1, ExxonMobil relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSVs), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes.

<u>Magnitude</u>

Given the high concentrations of H_2S and CO_2 in the respective injection streams, ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. Should leakage result from the injection wellbores and into the atmosphere, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7.4 in accordance with 40 CFR 98.448(5).

<u>Timing</u>

As stated above, even a minuscle amount of gas leakage would be immediately detected and immediate action would be taken to stop the release. Any potential leakage from the AGI or CO_2 injection wells would only occur during the lifetime operation of the wells. Once injection ceases, the wells will be plugged and abandoned and will not pose a risk as a leakage pathway.

4.3 Leakage through Faults and Fractures

As discussed in Section 2.6.3, engineering and geologic analysis show no evidence of faulting or structuring around the AGI wells. As a result, the risk of leakage through this pathway is highly improbable. The absence of faulting also tends to suggest that natural fracturing or permeability enhancement in the Madison Formation is also highly improbable. Natural fracturing along with systems of large connected pores (karsts and vugs) could occur in the Bighorn-Gallatin Formation. However, because those enhanced permability areas would be limited to the Bighorn-Gallatin Formation and would not be extended to the sealing formations above, the risk of leakage through this pathway is also highly improbable.

Current-day regional scale thrust faulting has not been observed in the LaBarge area since the field has been under development. There is no concern of reactivation of these thrust faults and it is hypothesized that regional structuring similar in size to the Laramide Orogeny (formation of the Rocky Mountains) would be required to generate new thrust faults of significant size to produce subsurface structures of the scale and magnitude of the LaBarge field. The activation of the salty sediments (which exist below the Nugget Formation and above the Madison Formation at LaBarge) is a phenomenon that was only observed to damage thin-wall cased wells, with thick-wall cased wells having sufficient strength to prevent flowage of these salt sediments. It is believed that weakness in the casing of thin-wall cased wells contributes to the ability of the salty sediments to flow local to the wellbore, shearing casing, as this is a point of weakness in the structural integrity of the wellbore at this depth. Once thick-walled casing was introduced, failures have decreased or have been eliminated.

It has been documented that natural fracturing of reservoirs in the subsurface of LaBarge and surrounding areas are directly correlative to distance to thrust faults in the area. This correlation has been documented in subsurface wellbore image logs and also by surface geological mapping around the thrust faults in the LaBarge area. It therefore follows that a lack of faulting, as observed on 2D seismic panels around and through the AGI and CO_2 injection well sites, will yield formations void of natural fracturing, and the necessary faults are not present to generate pervasive natural fractures. The lack of significant natural fracturing in the Madison Formation at and around the AGI well sites, in conjunction with active inspection of wellbore image logs within the AGI wells themselves, indicates that natural fractures do not exist, that all flow in the Madison 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. It should be noted that the permeability of the Madison 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. Likewise, the low expected connected permeability of the Bighorn-Gallatin has minimal capability to freely flow fluids through its only pore system. Accordingly, there is little potential for lateral migration of the injection fluids.

Prior to drilling the AGI wells, ExxonMobil worked with multiple service companies who provided a range of fracture gradients for the Phosphoria, Weber/Amsden, Morgan, and Madison formations in the area. Based on a frac gradient of 0.85 pounds per square inch (psi)/foot for the Madison, 0.82 psi/foot for the Morgan, 0.80 psi/foot for the Weber/Amsden, and 0.775 psi/foot for the Phosphoria, and a downhole fracture pressure of 12,167 psi, which corresponds to a surface injection pressure of ~5,500 psi, the injected acid gas will not initiate fractures in the confining zones of overlying strata. Facility limits exist that limit surface pressures to below 3,200 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture is unlikely.

Fracture gradient and overburden for the SC 5-2 well were estimated on the basis of offset well data. Offset well pressure integrity test (PIT) data from existing wells was analyzed and resulted in an overburden of 18,883 psi and a fracture gradient of 0.88 psi/foot (15,203 psi) at the top of the Madison Formation (~17,232 feet MD / -10,541 feet Total Vertical Depth subsea (TVDss)) and overburden of 20,388 psi and a fracture gradient of 0.885 psi/foot at the top of the Bighorn-Gallatin Formation (~18,531 feet MD / -11,840 feet TVDss). The fracture pressure at the top of

the Madison Formation is estimated at approximately 15,203 psi which corresponds to a fracture pressure at the surface of 7,685 psi. The projected facility average and maximum surface pressures are 3,430 psi and 6,170 psi, respectively. Both are below the pressure required to fracture the formation; therefore, the probability of fracture is unlikely.

Fracture gradient and overburden for the SC 7-34 well were also estimated on the basis of offset well data. Overburden estimates for the subject formations are based on offset well density logs. Expected formation integrity is primarily based on offset well pressure integrity (PIT) data. Because offset PITs did not result in leakoff, fracture gradient is assumed to be above test pressures. Therefore, the lowest possible fracture gradient constrained by the PITs has a vertical effective stress ratio of 0.55. An analysis of published regional data suggests a vertical effective stress ratio of 0.67 is more likely. Fracture gradient constraints were generalized with an effective horizontal to vertical effective stress ratio of 0.67 to be extrapolated to the target formation. These analyses result in an overburden of 18,705 psi and fracture gradient of 0.90 psi/foot (15,034 psi) at the top of the Madison Formation (approximately 16,744 feet MD / -10,055 feet TVDss) and overburden of 19,934 psi and fracture gradient of 0.90 psi/foot (16,017 psi) at the estimated top of the Bighorn-Gallatin Formation (approximately 17,815 feet MD / -11,126 feet TVDss).

<u>Likelihood</u>
Based on results of the the site characterization including the lack of faulting or open fractures in the injection intervals and the operational limitations on injections pressures, CO_2 leakage to the surface via faults or fractures is highly unlikely.

<u>Magnitude</u>
Given the lack of faulting and fracturing discussed above, leakage through small undetected faults or fractures (if presented and not yet observed) would be contained by the overlying high-quality sealing formations, discussed in more detail in Section 4.4 below, resulting in no CO_2 leakage to surface.

<u>Timing</u>
If a CO_2 leak were to occur through the confining zone due to faults or fractures, it would most likely occur during active injection. Limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. However, if diffusion through the confining zone were to occur, other CO_2 trapping mechanisms such as mineralization and solution in existing formation waters would reduce the magnitude and timing of emission to the surface.

4.4 Leakage through the Formation Seal

Leakage through the seal of the Madison Formation is highly improbable. An ultimate top seal to the disposal reservoir is provided by the evaporitic sequences within the Thaynes Formation. In fact, the natural seal is the reason the LaBarge gas field exists in the first place – the gas has been trapped in the LaBarge structure over a large amount of geologic time. The rock that forms the natural seal is impermeable to Helium (He), a gas with a much smaller molecular volume than CO_2. If the reservoir seal material is impermeable to He, then it follows that it is also impermeable to CO_2. The Thaynes Formation's sealing effect is also demonstrated by the fact that all gas

production shallower than the Thaynes is void of sour gas, while all gas production below it is enriched in sour gases. Formation Inclusion Volatile (FIV) analysis of rock cuttings documents the lack of CO_2 present throughout and above the Triassic regional seals (Ankareh, Thaynes, Woodside, and Dinwoody formations, Figure 2.2) from wells within the LaBarge gas field producing area as well as the AGI injection area.

Although natural creep of the salty sediments below the Nugget Formation is possible, this behavior does not disturb the sediments to the degree necessary to breach the reservoir seal of the Madison Formation. If this salty sediment were to flow on a scale large enough to create a leakage pathway from the Madison Formation to the surface, the natural gases trapped in the formation would have leaked into the atmosphere during the long course of geological time up to this point. The fact that gas remains trapped at pressure in the Madison Formation, it must follow that any natural reactivation or movement of salt-rich sediments that has occurred over the geological history of the LaBarge field area has not created any pathways for gas leakage to the surface.

Wells are monitored to ensure that the injected gases stay sequestered. Any escaped acid gas from the AGI wells will be associated with H_2S, which has the potential to harm field operators. The CO_2 injection wellheads will be monitored with local CO_2 gas heads, which detect low levels of CO_2. The CO_2 injected cannot escape without immediate detection, as expanded upon in the below sections.

Likelihood

Based on results of the the site characterization including the sealing capacity of confining intervals and Triassic evaporitic sequences and the operational limitations on injections pressures, CO_2 leakage to the surface via faults or fractures is highly unlikely.

Magnitude

Given the number, thickness, and quality of the confining units above the Madison and Bighorn-Gallatin injection intervals, as illustrated in Figure 2.2, any potential CO_2 leakage to the surface would be negligible and detected by surface monitoring systems at the injection site. Although highly unlikely, any CO2 leakage would likely occur near the injection well, which is where reservoir pressure is highest as a result of injection.

Timing

If a CO_2 leak were to occur through the multiple formation seals, it would most likely occur during active injection. Limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. However, if diffusion through the confining zone were to occur, other CO_2 trapping mechanisms such as mineralization and solution in existing formation waters would reduce the magnitude and timing of emission to the surface.

4.5 Leakage through Natural or Induced Seismicity

In the greater Moxa Arch area, there is a low level of background seismicity (Advanced National Seismic System (ANSS) Catalogue, 2018, University of Utah Seismograph Stations). Across North America, induced seismicity is sometimes hypothesized as being related to reactivation of basement-involved faults via oilfield waste fluid injection (Ellsworth 2013). There has been no

observed evidence of faulting in the Madison interval using commercially available 2D seismic data within 13.5 miles of the proposed CO_2 injection well sites. There has also been no reported seismic activity attributed to active injection operations at the AGI injection wells. The nearest induced seismic events were observed over 20 miles to the southwest of the proposed SC 7-34 well site. These are attributed to mineral mining operations, and not naturally occurring geological fault activity (USGS, Pechmann et al 1995). The closest naturally occurring seismic activity was a 1.8 magnitude earthquake in 1983 located 7.2 miles to the west at a depth of 10.1 miles according to the ANSS Catalogue and the Wyoming State Geological Survey's historic records. Significant earthquake activity is defined as >3.5 Richter scale (ANSS Catalogue 2018, University of Utah Seismograph Stations). The nearest recorded significant naturally occurring earthquake activity (> M3.5) has been detected over 50 miles away to the west in Idaho and Utah. 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.

Additional geomechanical modeling has been completed in the area around the AGI and CO_2 injection well sites. The modeling was completed to understand the potential for fault slip on the Darby fault far west of the injection and disposal sites. No fault slip is observed at the simulated fault locations or throughout the model. Lack of fault slip then equates to lack of modeled induced seismity from injection.

Likelihood

Due to the lack of significant earthquake activity in the area, the lack of induced seismicity over the period of injection at the AGI wells, and the geomechanical modeling results showing a lack of fault slip, ExxonMobil considers the likelihood of CO_2 leakage to surface caused by natural or induced seismicity to be unlikely.

Magnitude

If a seismic event occurs at the time of AGI or CO_2 injection, ExxonMobil will consult the ANSS Catalogue to verify whether the seismic event was due to the injection in the AGI or CO_2 injection wells and quantify any leak of CO_2 to the surface.

Timing

If a leak of CO_2 to the surface occurs as a result of a seismic event, it would likely occur at the time of the seismic event or shortly thereafter.

5.0 Detection, Verification, and Quantification of Leakage

5.1 Leakage Detection

As part of ongoing operations, SCTF continuously monitors and collects flow, pressure, temperature, and gas composition data in the Distributed Control System (DCS). This data is monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. Additionally, SCTF maintains in-field gas detectors to detect H_2S and CO_2 in the vicinity. If one of the gas detectors

alarmed, it would trigger an immediate response to address the situation. In some instances, more than one detector alarming will trigger automatic equipment isolation/shutdown to mitigate the leak.

Leakage detection for the wells will incorporate several monitoring programs including visual inspection of the surface facilities and wellheads, injection well monitoring and MIT, and DCS surveillance. Table 5.1 provides general information on the potential leakage pathways, monitoring programs to detect leakage, and location of monitoring. Monitoring will occur for the duration of injection. As will be discussed in Section 7.0 below, ExxonMobil will quantify equipment leaks by using a risk-driven approach and continuous surveillance.

Table 5.1 - Monitoring Programs

Potential Leakage Pathway	Detection Monitoring Program	Monitoring Location
Surface Equipment	DCS Surveillance Visual Inspections Inline Inspections Gas Alarms Personal H_2S Monitors	From injection flow meter to injection wellhead
Wells	DCS Surveillance Visual Inspections MIT Gas Alarms Personal H_2S Monitors	Injection well – from wellhead to injection formation
Faults and Fractures, Formation Seal, Lateral Migration	DCS Surveillance Gas Alarms	Injection well – from wellhead to injection formation
Natural or Induced Seismicity	DCS Surveillance Gas Alarms ANSS Catalogue	Injection well – from wellhead to injection formation Regional data

5.2 Leakage Verification

Responses to leaks are covered in the SCTF's Emergency Response Plan (ERP), which is updated annually. If there is a report or indication of a leak from the AGI facility from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and H_2S monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Pressure from the AGI system will be relieved to the flare, not vented, due to the dangerous composition of the gas.

The ERP will be updated to include the CO_2 injection facilities and corresponding wells after commencement of operations. If there is a report or indication of a leak from the CO_2 injection facilities from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and gas monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Once isolated from the CO_2 injection flowline, pressure from the affected CO_2 injection well will be relieved locally to atmosphere within the well site fence line.

5.3 Leakage Quantification

Examples of leakage quantification methods for the potential leakage pathways identified in Table 5.1 are outlined below. All calculations associated with quantifiying leakage will be maintained as outlined in Section 10.0.

Leakage from Surface Equipment

The leakage from surface equipment will be estimated once leakage has been detected and confirmed. As further described in Section 7.4, ExxonMobil will estimate the mass of CO_2 emitted from leakage points at the surface based on operating conditions at the time of the release – pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of leak. The annual mass of CO_2 that is emitted by surface leakage will be calculated in accordance with Equation RR-10.

Leakage through AGI and CO_2 Wells

As stated in Section 4.2, ExxonMobil reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and annual mechanical integrity testing (MIT). Gas detectors located at the well sites which alarm at 10 ppm H_2S and 5,000 ppm CO_2 would be triggered if a leak from the wellbore to the atmosphere occurred. If there is indication of a leak, leakage through AGI and CO_2 wells will be estimated once leakage has been detected and confirmed. ExxonMobil will take actions to quantify the leak and estimate the mass of CO_2 emitted based on operating conditions at the time of the release – pressure and flow rate, size of the leakage point opening, and estimated duration of leak.

Leakage through Faults and Fractures, Formation Seal, or Lateral Migration

As stated in Section 4.3, engineering and geologic analysis show no evidence of faulting or structuring around the AGI wells and the risk of leakage through this pathway is highly unlikely. Given the lack of faulting and fracturing, leakage through small undetected faults or fractures (if presented and not yet observed) would be contained by the overlying high-quality sealing formations, resulting in no CO_2 leakage to surface.

Further, as stated in Section 4.4, leakage through the formation seal is highly improbable due to the geology of the field which has demonstrably trapped and retained both hydrocarbon and non-hydrocarbon gases over long periods of geologic time. Additionally, limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. Wells are continuously monitored to ensure that the injected gases stay sequestered and any escaped gas would be immediately detected.

As stated in Section 5.1, SCTF continuously monitors and collects flow, pressure, temperature, and gas composition data in the DCS. This data is monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. If there is indication of leakage of CO_2 through faults and fractures, the formation seal, or lateral migration as potentially indicated by abnormal operational data, ExxonMobil will take actions to quantify the leak (e.g., reservoir modeling and engineering estimates) and take mitigative actions to stop leakage. Given the unliklihood of leakage from these pathways, ExxonMobil will estimate mass of CO_2 detected leaking to the surface in these instances on a case-by-case basis utilizing quantification methods such as engineering analysis of surface and subsurface measurement data, dynamic reservoic modeling, and history-matching of the reservoir performance.

Leakage through Natural or Induced Seismicity

As stated in Section 4.5, there is low level of background seismicity detected in the area. If a seismic event occurs at the time of AGI or CO_2 injection, ExxonMobil will consult the ANSS Catalogue to verify whether the seismic event was due to the injection in the AGI or CO_2 injection wells and quantify any leak of CO_2 to the surface based on operating conditions at the time of the event – pressure and flow rate, size of the leakage point opening, and estimated duration of leak.

6.0 Determination of Baselines

ExxonMobil uses existing automatic data systems to identify and investigate excursions from expected performance that could indicate CO_2 leakage. The following describes ExxonMobil's approach to collecting baseline information.

Visual Inspections

Field personnel conduct daily inspections of the AGI facility and weekly inspections of the AGI well sites. The CO_2 injection facility and well sites will undergo weekly visual inspections. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize

the possibility of CO_2 leakage. If an issue is identified, a work order will be generated to correct the issue.

H_2S Detection – AGI Wells

The CO_2 injected into the AGI wells is injected with H_2S at a concentration of 50 - 65% (500,000 - 650,000 ppm). H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. At this high of a concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm. Additionally, all field personnel are required to wear H_2S monitors for safety reasons. Personal monitors alarm at 5 ppm. Any gas detector alarm or personal H_2S monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the gas detectors and monitors are working correctly.

CO_2 Detection – CO_2 Injection Wells

The CO_2 injected into the CO_2 injection wells will be at a concentration of approximately 99%. CO_2 gas detectors will be installed around the well sites, which will trigger at 0.5% CO_2, therefore even a miniscule amount of gas leakage would trigger an alarm.

Continuous Parameter Monitoring

The DCS of the SCTF 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.

Well Testing

On an annual basis, the subsurface and wellhead valves are leak tested for mechanical integrity testing (MIT) as required by the WOGCC. Results from this type of testing are compared to previous MIT data to evaluate whether well integrity has been compromised.

Additionally, inline inspections are conducted of the AGI flow lines through the use of a smart pig to identify potential areas of corrosion in the pipeline. Results from this type of testing are compared to previous data to evaluate whether pipeline integrity has been compromised. The operations at the SCTF will have the ability to conduct inline inspections on the SC 5-2 and SC 7-34 flow lines, however inline inspections are not anticipated to occur frequently because no free water is expected to accumulate.

7.0 Site Specific Modifications to the Mass Balance Equation

To accommodate for site-specific conditions, as provided in 40 CFR 98.448, ExxonMobil proposes to modify quantifying equipment leaks by using a risk-driven approach. Due to the high H_2S concentration of the AGI fluids, monitoring poses a risk to personnel. Additionally, as mentioned above, even a small leak of this high H_2S gas would trigger an alarm. A small leak at the CO_2 injection wells would also trigger an alarm, as mentioned above. ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to

stop the release. This continuous surveillance using gas detectors identifies leaks better than an annual leak survey would 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 ExxonMobil will calculate the mass of CO_2 injected, emitted, and sequestered.

7.1 Mass of CO_2 Received

§98.443 states that "you must calculate the mass of CO_2 received using CO_2 received equations… unless you follow the procedures in §98.444(a)(4)." §98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." Since the CO_2 received by the AGI and CO_2 injection wells are wholly injected and not mixed with any other supply of CO_2, the annual mass of CO_2 injected would be equal to the annual mass of CO_2 received. No CO_2 is received in containers.

7.2 Mass of CO_2 Injected

Volumetric flow meters are used to measure the injection volumes at the AGI wells and are proposed for use to measure the injection volumes at the CO_2 injection wells. Equation RR-5 will be used to calculate the annual total mass of CO_2 injected.

Equation RR-6 will be used to aggregate injection data for the AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34 wells.

7.3 Mass of CO_2 Produced

The AGI and CO_2 injection wells are not part of an enhanced oil recovery process, therefore, there is no CO_2 produced and/or recycled.

7.4 Mass of CO_2 Emitted by Surface Leakage and Equipment Leaks

It is not appropriate to conduct a leak survey at the AGI or the CO_2 injection well sites due to the components being unsafe-to-monitor and extensive monitoring systems in place. Entry to the AGI wells requires the individual to don a full face respirator supplied to breathing air, which would make completion of a leak survey very difficult. Due to the high H_2S concentration of the AGI fluids and the high CO_2 concentration of the CO_2 injection fluid, fugitive leakage would be detected and managed as an upset event in the same way that CO_2E (CO_2 emitted by surface leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time, including pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of the leak. 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.

Parameter CO_2FI (total CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead) will be calculated in accordance with procedures outlined in Subpart W as required by 40 CFR 98.444(d). At the AGI wells, there are no CO_2 emissions from venting due to the high H_2S concentration of the acid gas; blowdown emissions are sent to the flares and are reported under Subpart W for the SCTF. This process occurs upstream of the flow meter and would therefore not contribute to the CO_2FI calculation. At the CO_2 injection wells, venting would occur in the event of depressurizing for maintenance or testing, which would be measured during time of event consistent with 40 CFR 98.233.

7.5 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Since ExxonMobil is not actively producing oil or natural gas or any other fluids as part of the AGI process or CO_2 injection processes, Equation RR-12 will be used to quantify CO_2 injected and sequestered. Parameter CO_2I (total CO_2 injected through all injection wells) will be determined using Equation RR-5, as outlined above in Section 7.2. Parameters CO_2E and CO_2FI will be measured using the leakage quantification procedure described above in Section 7.4. CO_2 in the AGI fluids is not vented from equipment due to the high H_2S concentration.

8.0 Estimated Schedule for Implementation of Second Amended MRV Plan

The SCTF AGI facility and wells have been operational since 2005 and have been subject to the February 2018 MRV plan (approved by EPA in June 2018). Beginning with the start of injection of CO_2 and fluids into the CO_2 injection wells, this Second Amended MRV Plan will become the applicable plan for the AGI and CO_2 injection wells and will replace and supersede the February 2018 MRV plan for the AGI wells. Until that time, the February 2018 MRV plan will remain the applicable MRV plan for the AGI wells. Once the Second Amended MRV Plan becomes the applicable MRV plan, ExxonMobil will continue reporting under Subpart RR for the AGI wells, but will begin including the CO_2 injection wells on or before March 31 of the year after their respective injection begins. Once applicable, ExxonMobil anticipates this Second Amended MRV Plan will remain in effect until the end-of-field-life of the LaBarge 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, ExxonMobil has incorporated the following provisions into its QA/QC programs:

CO_2 *Injected*

- The injected CO_2 stream for the AGI wells will be measured upstream of the volumetric flow meter at the three AGI compressors, at which measurement of the CO_2 is representative of the CO_2 stream being injected, with a continuously-measuring online process analyzer. The flow rate is measured continuously, allowing the flow rate to be compiled quarterly.

- The injected CO_2 stream for the CO_2 injection wells will be measured with a volumetric flow meter and continuously-measuring online process analyzer upstream of the wellhead, at which measurement of the CO_2 is representative of the CO_2 stream being injected. The flow rate will be measured continuously, allowing the flow rate to be compiled quarterly.
- The continuous composition measurements will be averaged over the quarterly period to determine the quarterly CO_2 composition of the injected stream.
- The CO_2 analyzers are calibrated according to manufacturer recommendations.

CO_2 emissions from equipment leaks and vented emissions of CO_2

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

Measurement Devices

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

General

- The CO_2 concentration is measured using continuously-measuring online process analyzers, which is an industry standard practice.
- All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 Missing Data Procedures

In the event ExxonMobil 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 CO_2 injected is missing, it will be estimated using a representative quantity of CO_2 injected from the nearest previous time period at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in 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, ExxonMobil will revise and submit another amended MRV plan within 180 days to the Administrator for approval.

10.0 Records Retention

ExxonMobil will follow the record retention requirements of 98.3(g). Additionally, it will retain the following records from the AGI and CO_2 injection well sites for at least three years:

- Quarterly records of injected CO_2 for the AGI wells including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO_2 for the CO_2 injection wells 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 CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

ExxonMobil Shute Creek Treating Facility Subpart RR Second Amended Monitoring, Reporting and Verification Plan

October 2024

Table of Contents

Request for Additional Information: Shute Creek Facility
September 17, 2024

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	We recommend adding a process flow diagram (with locations of flow meters that will be used for subpart RR equations, etc.) to illustrate the path of CO_2 at the facility.	The Shute Creek Treating Facility is a complex process with countless PFDs for the various process areas. We believe providing even a high-level PFD of the process would only over-complicate the understanding of the path of CO2 at the facility and associated measurement points and thus do not recommend inclusion of one in this plan.
2.	N/A	N/A	Please review the figures included in the MRV plan to ensure that all text is legible, scale bars, and legends are scaled appropriately, etc. For example, the legends in Figures 3.1-3.8 of the MRV plan are illegible.	Figures have been resized so that all information is legible including the legends in Figures 3.1 – 3.8.
3.	2.2	7	We recommend identifying the upper/lower confining units and injection zones in the discussion or in Figure 2.2 of the MRV plan.	Updated Figure 2.2 to include upper/lower confining units and injection zones (page 7).
4.	3.1.1	28	Please specify what geologic/reservoir modelling software was utilized for the modeling for this project.	Schlumberger (SLB) Petrel/Intersect. Added to Section 3.1.1 (page 28).
5.	3.1/3.2	28-33	Please add a comprehensive figure or figures that show the AGI and CO2 injection wells, modeled plumes, and AMA/MMA. Please also include a figure showing any other wells that overlap the AMA/MMA as applicable. Please also ensure that the discussion in the MRV plan explains how the delineated AMA/MMA are consistent with the definitions in 40 CFR 98.449.	Figure 3.9 added (page 35) to show AGI and CO2 injection wells, modeled plumes, and AMA/MMA on same figure. There are no other wells that penetrate the target injection zones within the AMA or MMA as stated in Section 4.2 (page 37). The MMA and AMA are defined in Sections 3.1 and 3.2, respectively (pages 28 – 30).

Introduction

Exxon Mobil Corporation (ExxonMobil) operates two acid gas injection (AGI) wells, AGI 2-18 and AGI 3-14 (collectively referred to as "the AGI wells") in the Madison Formation located near LaBarge, Wyoming for the primary purpose of acid gas disposal with a secondary purpose of geologic sequestration of carbon dioxide (CO_2) in a subsurface geologic formation. The acid gas and CO_2 injected into the AGI wells are components of the natural gas produced by ExxonMobil from the Madison Formation. ExxonMobil has been operating the AGI wells since 2005 and intends to continue injection until the end-of-field-life of the LaBarge assets. The AGI wells and facility (as further described in Section 2.7.1), located at the Shute Creek Treating Facility (SCTF), have been operational since 2005 and have been subject to the February 2018 monitoring, reporting, and verification (MRV) plan approved by EPA in June 2018 (the February 2018 MRV plan).

Because the volume of CO_2 associated with the natural gas production is greater than the volume that is able to be injected into the AGI wells, ExxonMobil is in the process of developing the Shute Creek (SC) 5-2 and SC 7-34 wells (collectively referred to as the "CO_2 injection wells" or "CO_2 disposal wells")[1] for the purpose of geologic sequestration of fluids consisting primarily of CO_2 in subsurface geologic formations. Like the AGI wells, the fluids that will be injected into the CO_2 injection wells are also components of the natural gas produced by ExxonMobil from the Madison Formation. Once operational, the CO_2 injection wells are expected to continue injection until the end-of-field life of the LaBarge assets.

ExxonMobil received the following approvals by the Wyoming Oil and Gas Conservation Commission (WOGCC) to develop the SC 5-2 well:

- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Madison Formation on November 12, 2019
- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Phosphoria, Weber, and Bighorn-Gallatin formations[2] on October 12, 2021
- Application for permit to drill (APD) on June 30, 2022

ExxonMobil received the following approvals by the WOGCC to develop the SC 7-34 well:

- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Madison and Bighorn-Gallatin formations on August 13, 2024
- APD on May 20, 2024

In October 2019, ExxonMobil submitted an amendment to the February 2018 MRV plan in accordance with 40 CFR §98.440-449 (Subpart RR – Geologic Sequestration of Carbon Dioxide) to provide for the monitoring, reporting and verification of geologic sequestration of CO_2 in the Madison Formation during the injection period for the SC 5-2 well (the October 2019 MRV plan). The October 2019 Amended MRV plan was approved by EPA on December 19, 2019.

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[1] *The terms "dispose" and "inject" and their variations may be used interchangeably throughout this document.*

[2] *While the Phosphoria and Weber formations were conditionally approved as exempted aquifers for disposal of fluids, these formations are no longer targets for the SC 5-2 and will not be addressed further in this document*

This second amended plan, dated October 2024 ("Second Amended MRV Plan") will address all wells collectively when applicable, and otherwise broken out into sub sections to address the specifics of the AGI wells and CO_2 injection wells respectively, as appropriate. This Second Amended MRV Plan meets the requirements of 40 CFR §98.440(c)(1).

The February 2018 MRV plan is the currently applicable MRV plan for the AGI wells. The October 2019 Amended MRV plan would have become the applicable plan once the SC 5-2 well began injection operations. ExxonMobil anticipates the SC 5-2 well will begin injection operations in 2025 and the SC 7-34 well will begin injection operations in 2026. At that time, this Second Amended MRV Plan will become the applicable plan for the AGI wells and CO_2 injection wells collectively, and will replace and supersede both the February 2018 and October 2019 Amended MRV plans. At that time, ExxonMobil will continue reporting under Subpart RR for the AGI wells, but will begin including the CO_2 injection wells on or before March 31 of the year after their respective injection begins. Once applicable, ExxonMobil anticipates this Second Amended MRV Plan will remain in effect until the end-of-field-life of the LaBarge assets, unless and until it is subsequently amended and superseded.

This Second Amended MRV Plan contains ten sections:

1. Section 1 contains facility information.

2. Section 2 contains the project description. This section describes the geology of the LaBarge Field, the history of the LaBarge field, an overview of the injection program and process, and provides the planned injection volumes. This section also demonstrates the suitability for secure geologic storage in the Madison and Bighorn-Gallatin formations.

3. Section 3 contains the delineation of the monitoring areas.

4. Section 4 evaluates the potential leakage pathways and demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

5. Section 5 provides information on the detection, verification, and quantification of leakage. Leakage detection incorporates several monitoring programs including routine visual inspections, hydrogen sulfide (H_2S) and CO_2 alarms, mechanical integrity testing of the well sites, and continuous surveillance of various parameters. Detection efforts will be focused towards managing potential leaks through the injection wells and surface equipment due to the improbability of leaks through the seal or faults and fractures.

6. Section 6 describes the determination of expected baselines to identify excursions from expected performance that could indicate CO_2 leakage.

7. Section 7 provides the site specific modifications to the mass balance equation and the methodology for calculating volumes of CO_2 sequestered.

8. Section 8 provides the estimated schedule for implementation of the Second Amended MRV Plan.

9. Section 9 describes the quality assurance program.

10. Section 10 describes the records retention process.

1.0 Facility Information

1. Reporter number: 523107
   The AGI wells currently do, and the CO_2 injection wells will, report under the Shute Creek Treating Facility (SCTF) Greenhouse Gas Reporting Program Identification number, which is: 523107.
2. Underground Injection Control (UIC) Permit Class: Class II
   The WOGCC regulates oil and gas activities in Wyoming. WOGCC classifies the AGI, SC 5-2, and SC 7-34 wells in LaBarge as UIC Class II wells.
3. UIC injection well identification numbers:

Well Name	*Well Identification Number*
AGI 2-18	49-023-21687
AGI 3-14	49-023-21674
SC 5-2	49-023-22499
SC 7-34	49-023-22500

2.0 Project Description

This section describes the planned injection volumes, environmental setting of the LaBarge Field, injection process, and reservoir modeling.

2.1 Geology of the LaBarge Field

The LaBarge field area is located in the southwestern corner of Wyoming, contained in Lincoln and Sublette counties. The producing field area is within the Green River Basin and the field is located due west of the Wind River Mountains along the Moxa Arch (Figure 2.1).

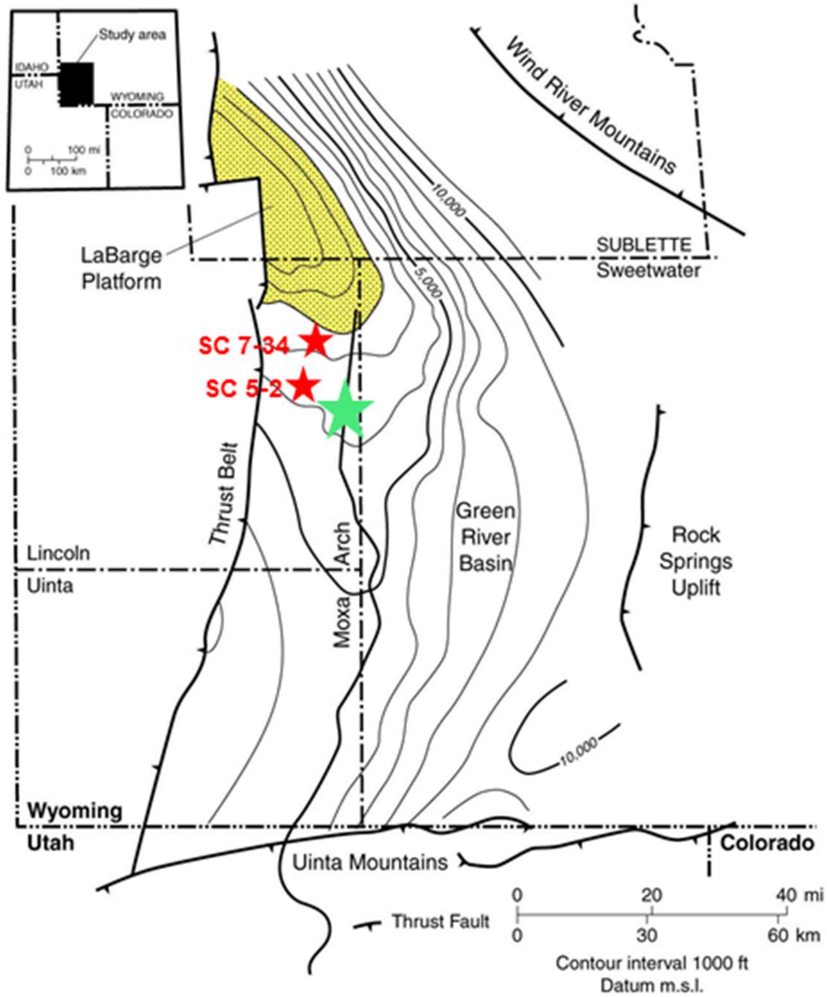

Figure 2.1 Location Map of the LaBarge Field, Wyoming. The location of the AGI wells is denoted with a green star, and the location of the CO_2 injection wells are denoted by the red stars.

2.2 Stratigraphy of the Greater LaBarge Field Area

The western region of Wyoming has been endowed in a very rich and prolific series of hydrocarbon reservoirs. Hydrocarbon production has been established or proven from a large number of stratigraphic intervals around Wyoming, ranging from reservoirs from Cenozoic to Paleozoic in age. Figure 2.2 shows a complete stratigraphic column applicable to the Greater Green River Basin in western Wyoming.

For the LaBarge field area, specifically, commercially producible quantities of hydrocarbons have been proven in the following intervals:

1. Upper Cretaceous Frontier Formation
2. Lower Cretaceous Muddy Formation
3. Permian Phosphoria Formation
4. Lower Jurassic Nugget Formation
5. Pennsylvanian Weber Formation
6. Mississippian Madison Formation

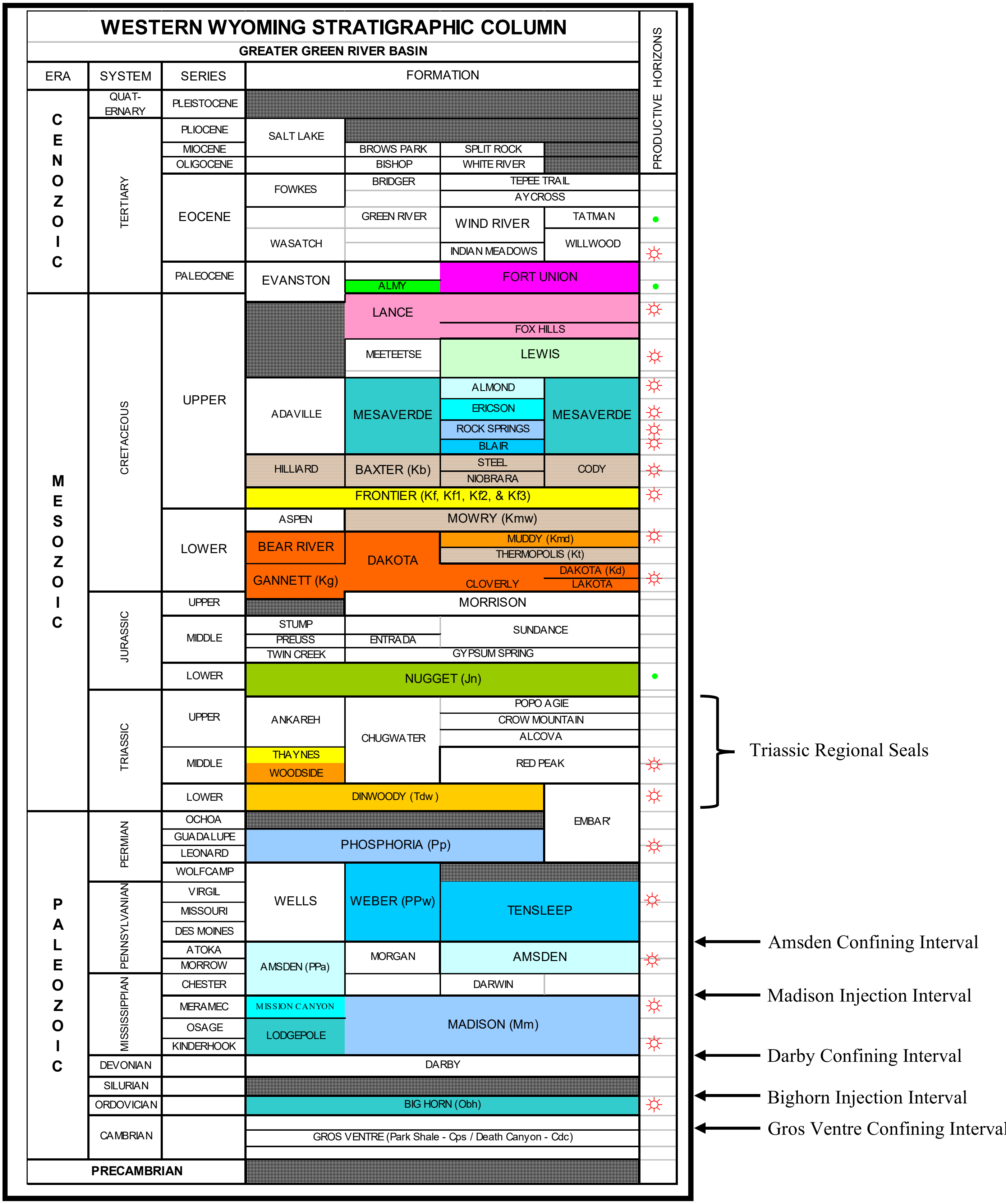

Figure 2.2 Generalized Stratigraphic Column for the Greater Green River Basin, Wyoming

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 closure to 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 (Figure 2.3).

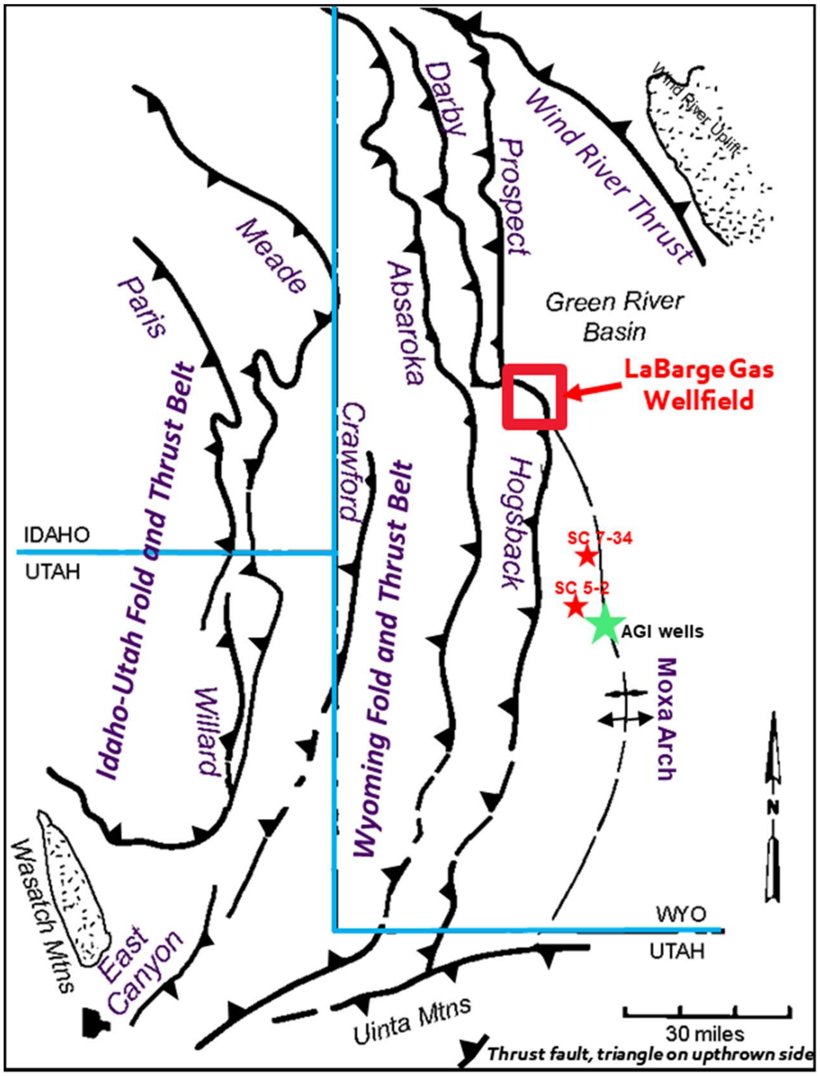

Figure 2.3 Schematic map showing location of Moxa Arch and regional thrust faults. The LaBarge field area is denoted by the red box. The approximate location of the AGI wells is denoted with a green star, and the approximate location of the CO_2 injection wells are denoted by the red stars.

The historical evaluation of structural styles at LaBarge has revealed that three principal styles of structuring have occurred in the area:

1. Basement-involved contraction
2. Deformation related to flowage of salt-rich Triassic strata
3. Basement-detached contraction

2.3.1 Basement-involved Contraction Events

Basement-involved contraction has been observed to most commonly result in thrust-cored monoclinal features being formed along the western edge of the LaBarge field area (Figure 2.3). These regional monoclinal features have been imaged extensively with 2D and 3D seismic data, and are easily recognizable on these data sets (Figure 2.4). At a smaller scale, the monoclinal features set up the LaBarge field structure, creating a hydrocarbon trapping configuration of the various reservoirs contained in the LaBarge productive section.

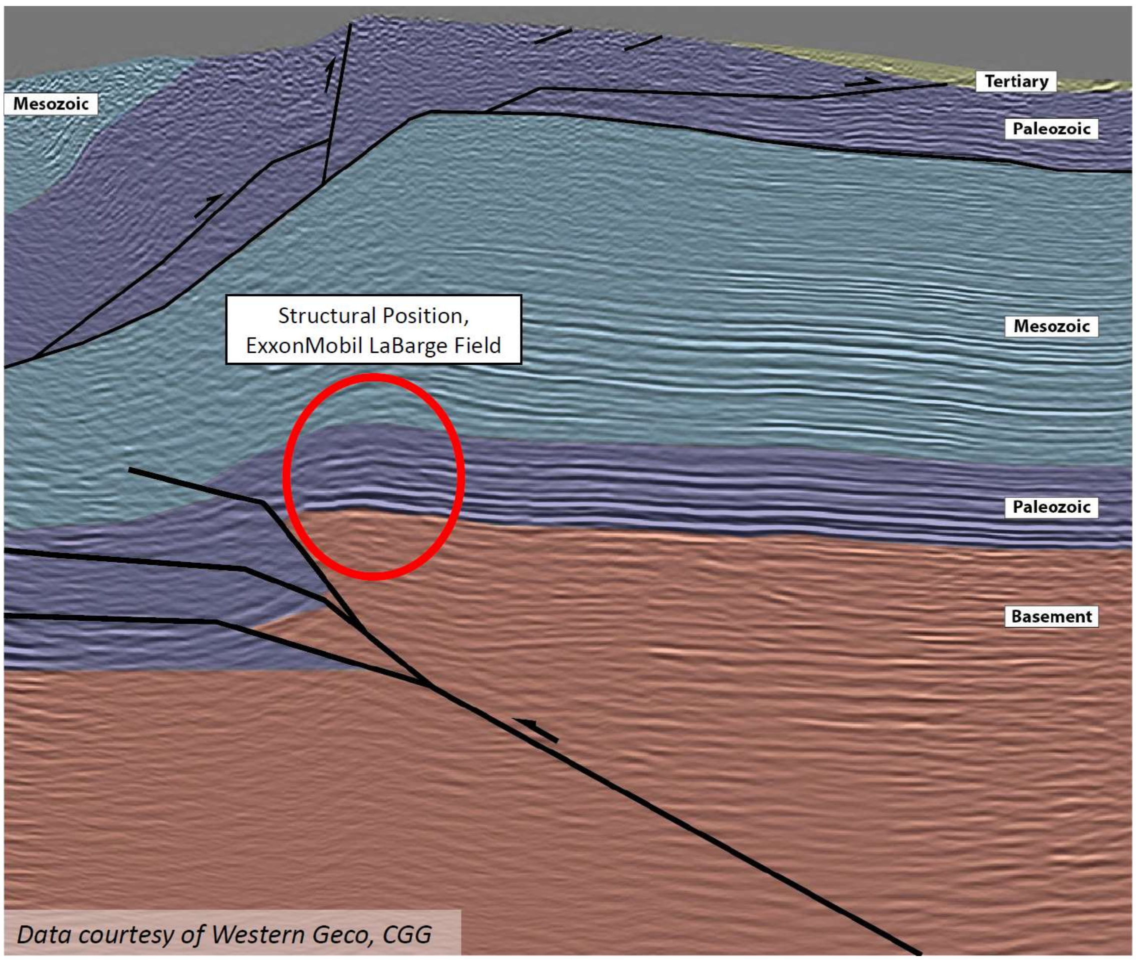

Figure 2.4 Example of thrust-cored monoclinal feature interpreted from 2D seismic data. The thrust-cored feature is believed to be a direct product of basement-involved contractional events.

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 outcrop 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 2.5 shows two seismic lines showing the Triassic salt-rich sediments and the 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.

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 many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. Subsequent drilling at LaBarge has used thicker-walled casing strings to successfully mitigate this sediment flowage issue.

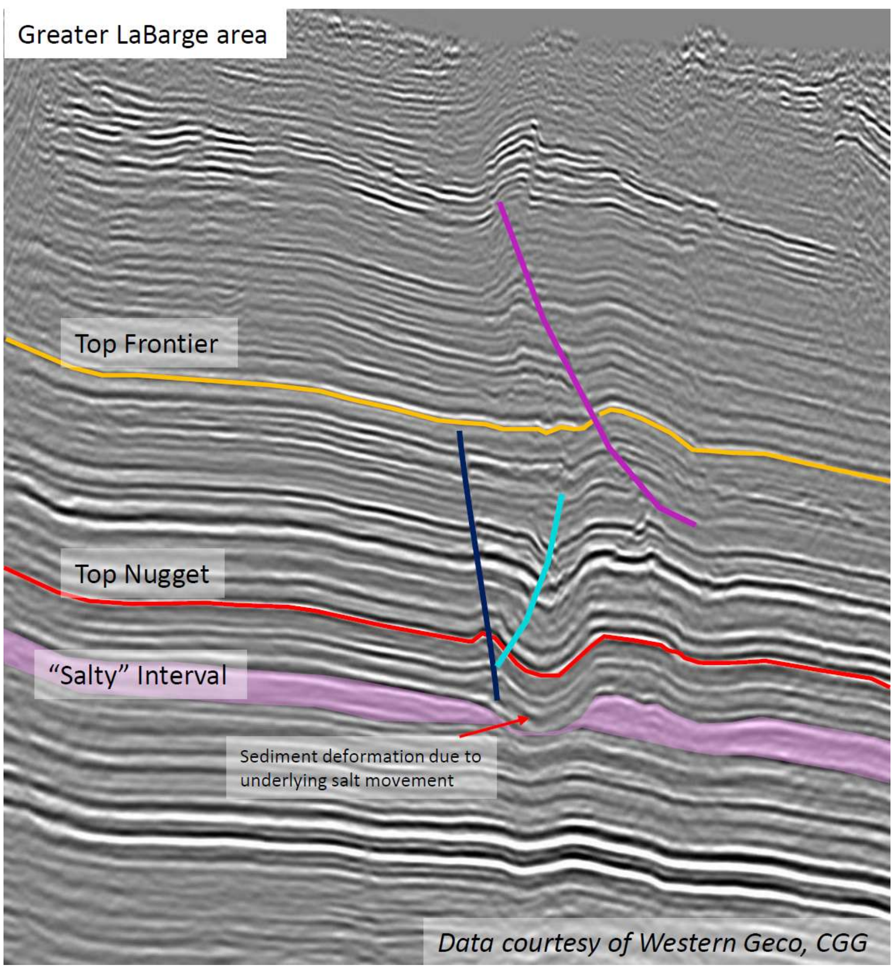

Figure 2.5 Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge field area

2.3.3 Basement-detached Contraction

The third main structural style observed at LaBarge field is those resultant from basement-detached contraction. These features have been well-documented, historically at LaBarge as many of these features have mapped fault expressions on the surface. Detachment and contraction along the basement typically creates three types of structural features:

1. Regional scale thrust faults
2. Localized, smaller scale thrust faults
3. Reactivation of Triassic salt-rich sediments resulting in local structural highs (section 2.3.2)

The basement-detached contraction features typically occur at a regional scale. The subsurface structural features formed through these contractional events are the same size or larger than the greater LaBarge field area. Very large faults are usually associated with these subsurface features, albeit via the reactivation of Triassic salt sediments which can result in additional localized structuring in the area (section 2.3.2).

2.3.4 Faulting and Fracturing of Reservoir Intervals

Reservoir permeability has been observed to increase with the presence of small-scale faults and fractures in almost all of the productive intervals of LaBarge field. Micro-fractures have been observed in core and on formation micro imager (FMI) logs. The fractures seen in the available core are typically filled with calcite, in general.

Empirically, reservoir permeability and increased hydrocarbon productivity have been observed in wells/penetrations that are correlative to areas located on or near structural highs or fault junctions. These empirical observations tend to suggest that these areas have a much higher natural fracture density than other areas or have a larger proportion of natural fractures that are open and not calcite filled. Lack of faulting, as is observed near areas adjacent to the AGI, SC 5-2, and SC 7-34 wells at LaBarge, tends to yield reservoir permeability that is dominated only by matrix or pore-to-pore flow that is generally inhibitive to fluid flow in the subsurface over long distances.

2.3.5 LaBarge Field Structure and Gas Resource of the Madison Formation

Structural closure on the Madison Formation at the LaBarge field is quite large, with approximately 4,000' true vertical depth (TVD) of structural closure from the top of the structure to the gas-water contact (GWC). Spatially, the Madison closure covers over 1,000 square miles making it one of the largest gas fields in North America.

The Madison Formation is estimated to contain in excess of 170 trillion cubic feet (TCF) of raw gas and 20 TCF of natural gas (CH_4). At current rates of production, the estimated remaining field life is over 100 years. Spatially, the AGI and CO_2 injection wells have been located at or immediately adjacent to the SCTF, over 40 miles to the southeast from the main LaBarge production areas.

2.4 History of the LaBarge Field Area

The LaBarge field was initially discovered in 1920 with the drilling of a shallow oil producing well. The generalized history of the LaBarge field area is as follows:

- 1907 Oil seeps observed near LaBarge, surface mapping of Tip Top anticline
- 1920 Texas Production Company drills shallow Hilliard sandstone discovery (10 BOPD)
- 1940's General Petroleum (G.P.) (Mobil) explores LaBarge area, surface and seismic mapping
- 1951 Tip Top Field discovered by G.P. (Frontier SS @ 1.8 MCFD, Nugget SS @ 266 BOPD)
- 1952 Belco discovers Frontier gas at Big Piney and LaBarge
- 1954 Belco commits gas to Pacific NW Pipeline, 33 SI gas wells
- 1956 Pacific NW Pipeline completed
- 1956-64 Active drilling of Frontier wells (structural traps)
- 1962 Mobil discovers Madison LS gas at Tip Top, chooses not to develop
- 1970 Exxon evaluates LaBarge area
- 1975-84 2nd major phase of Frontier drilling (stratigraphic traps)
- 1980 Section 29 of Oil Windfall Tax Act for tight gas sands passed (expired 01/01/94)
- 1981 Exxon discovers Madison gas on Lake Ridge Unit (LRU 1-03)
- 1986 First sales of Exxon Madison gas
- 1992 WOGCC approves 160 acre spacing for Frontier
- 1989-95 Chevron, Enron, PG & E, and Mobil actively drill Frontier targets
- 1999 Exxon and Mobil merge
- 2001-03 Active drilling of Acid Gas Injection wells 2-18 and 3-14
- 2005 Acid Gas Injection wells 2-18 and 3-14 begin operation
- 2019 WOGCC approves SC 5-2 CO_2 injection well
- 2022 Transfer of ownership of shallow horizons on TipTop and Hogsback
- 2023 Active drilling of SC 5-2 CO_2 injection well
- 2024 WOGCC approves SC 7-34 CO_2 injection well

Historically, Exxon held and operated the Lake Ridge and Fogarty Creek areas of the field, while Mobil operated the Tip Top and Hogsback field areas (Figure 2.6). The heritage operating areas were combined in 1999, with the merger of Exxon and Mobil to form ExxonMobil, into the greater LaBarge operating area. In general, heritage Mobil operations were focused upon shallow sweet gas development drilling while heritage Exxon operations focused upon deeper sour gas production.

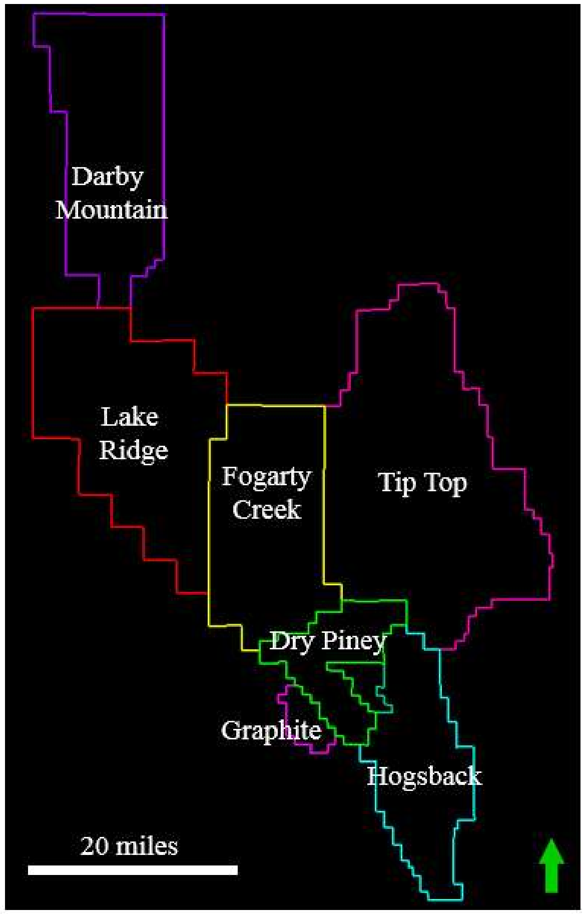

Figure 2.6 Historical unit map of the greater LaBarge field area prior to Exxon and Mobil merger in 1999

2.5 Initial Discovery of Gas and Early Commercial Production at LaBarge

ExxonMobil's involvement in LaBarge originates in the 1960's with Mobil's discovery of gas in the Madison Formation. The Madison discovery, however, was not commercially developed until much later in the 1980's following Exxon's Madison gas discovery on the Lake Ridge Unit. Subsequently, initial commercial gas production at LaBarge was first established in the Frontier Formation, while commercial oil production was established in the Nugget Formation.

Gas production from the Madison Formation was initiated in 1986 after the start-up of the SCTF, which expanded capacity to handle Madison gas. The total gas in-place for the Madison Formation at LaBarge is in excess of 170 TCF gross gas and is a world-class gas reserve economically attractive for production.

2.6 Gas Injection Program History at LaBarge

The Madison Formation, once commercial production of gas was established, was found to contain relatively low methane (CH_4) concentration and high carbon dioxide (CO_2) content. The average properties of Madison gas are:

1. 21% CH_4

2. 66% CO_2
3. 7% nitrogen (N_2)
4. 5% hydrogen sulfide (H_2S)
5. 0.6% helium (He)

Due to the abnormally high CO_2 and H_2S content of Madison gas, the CH_4 was stripped from the raw gas stream leaving a very large need for disposal of the CO_2 and H_2S that remained. For enhanced oil recovery (EOR) projects, CO_2 volumes have historically been sold from LaBarge to offset oil operators operating EOR oilfield projects. Originally, the SCTF contained a sulfur recovery unit (SRU) process to transform the H_2S in the gas stream to elemental sulfur. In 2005, the SRU's were decommissioned to debottleneck the plant and improve plant reliability. This created a need to establish reinjection of the H_2S, and entrained CO_2, to the subsurface.

2.6.1 Geological Overview of Acid Gas Injection and CO_2 Injection Programs

Sour gas of up to 66% CO_2 and 5% H_2S is currently produced from the Madison Formation at LaBarge. The majority of produced CO_2 is currently being sold by ExxonMobil to other oilfield operators and is being used in EOR projects in the region. The sold volume however, does not equal the total produced CO_2 and H_2S volumes, thereby requiring disposal.

ExxonMobil has pursued the AGI program as a safe and reliable method to re-inject the acid gas into the Madison Formation into the aquifer below the field GWC. Gas composition in the AGI wells is based on plant injection needs, and will vary between 35 - 50% CO_2 and 50 - 65% H_2S. The acid gas is injected at a depth of ~17,500 feet below the surface and approximately 43 miles away from the main producing areas of LaBarge.

The volume of CO_2 sold and CO_2 injected into the AGI wells does not equal the volume of CO_2 produced, so additional injection wells are required (SC 5-2 and SC 7-34). Gas composition to be injected into the CO_2 injection wells is planned to be approximately 99% CO_2 with minor amounts of methane, nitrogen, carbonyl sulfide (COS), ethane, and H_2S. For the SC 5-2 well, the gas is planned to be injected between depths of ~17,950 feet and ~19,200 feet measured depth (MD) approximately 35 miles away from the main producing areas of LaBarge. For the SC 7-34 well, the gas is planned to be injected between depths of ~16,740 feet and ~18,230 feet MD approximately 30 miles away from the main producing areas of LaBarge.

2.6.2 Reservoir Quality of Madison and Bighorn-Gallatin Formations at Injection Well Locations

The existing AGI wells were successfully drilled, logged, and evaluated prior to injection commencement. Figure 2.7 is a schematic diagram showing the relative location of AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34. Figures 2.8 and 2.9 are structure maps for the Madison and Bighorn-Gallatin formations, respectively, showing the relative location of the four wells.

Figure 2.10 shows Madison well logs for SC 5-2, AGI 3-14, and AGI 2-18. Petrophysical evaluation of these wells indicate that Madison limestone and dolomite sequences were penetrated, as expected. Total porosity ranges of the limestone sequences were determined to be between 0%

and 5%, while the dolomite sequences were found to be up to 20% total porosity. Injection fall-off testing indicated that the AGI wells exhibit greater than 2000 millidarcy-feet (md-ft) of permeability-height within the injection section. Figure 2.11 shows a table summarizing Madison and Bighorn-Gallatin reservoir properties from the SC 5-2, AGI 3-14, and AGI 2-18 wells. Madison reservoir quality for the SC 5-2 well is similar to the quality for the AGI wells, and is expected to be similar for the SC 7-34 well.

Bighorn-Gallatin reservoir quality for the SC 5-2 well is similar to the nearest Bighorn-Gallatin penetration at 1-12 Keller Raptor well (also referred to as the Amoco/Keller Rubow 1-12 well or the Keller Rubow-1 well), which shows interbedded dolostone and limestone sequences. In general, the degree of dolomitic recrystallization in the Bighorn-Gallatin is similar to the Madison Formation, which has resulted in comparable porosities and permeabilities despite a greater depth of burial. Bighorn-Gallatin total porosity from six LaBarge wells has been determined to be between 2 – 19% with permeabilities between 0.1 – 230 md.

Updated average Madison and Bighorn-Gallatin reservoir properties and well logs will be provided once the SC 7-34 well is drilled. Data will be submitted in the first annual monitoring report following commencement and operation of SC 7-34.

Figures 2.12 and 2.13 show the stratigraphic and structural cross sections of SC 5-2 and SC 7-34 in relation to AGI 3-14, AGI 2-18, and another analog well (1-12 Keller Raptor) penetrating the Madison and Bighorn-Gallatin formations further updip.

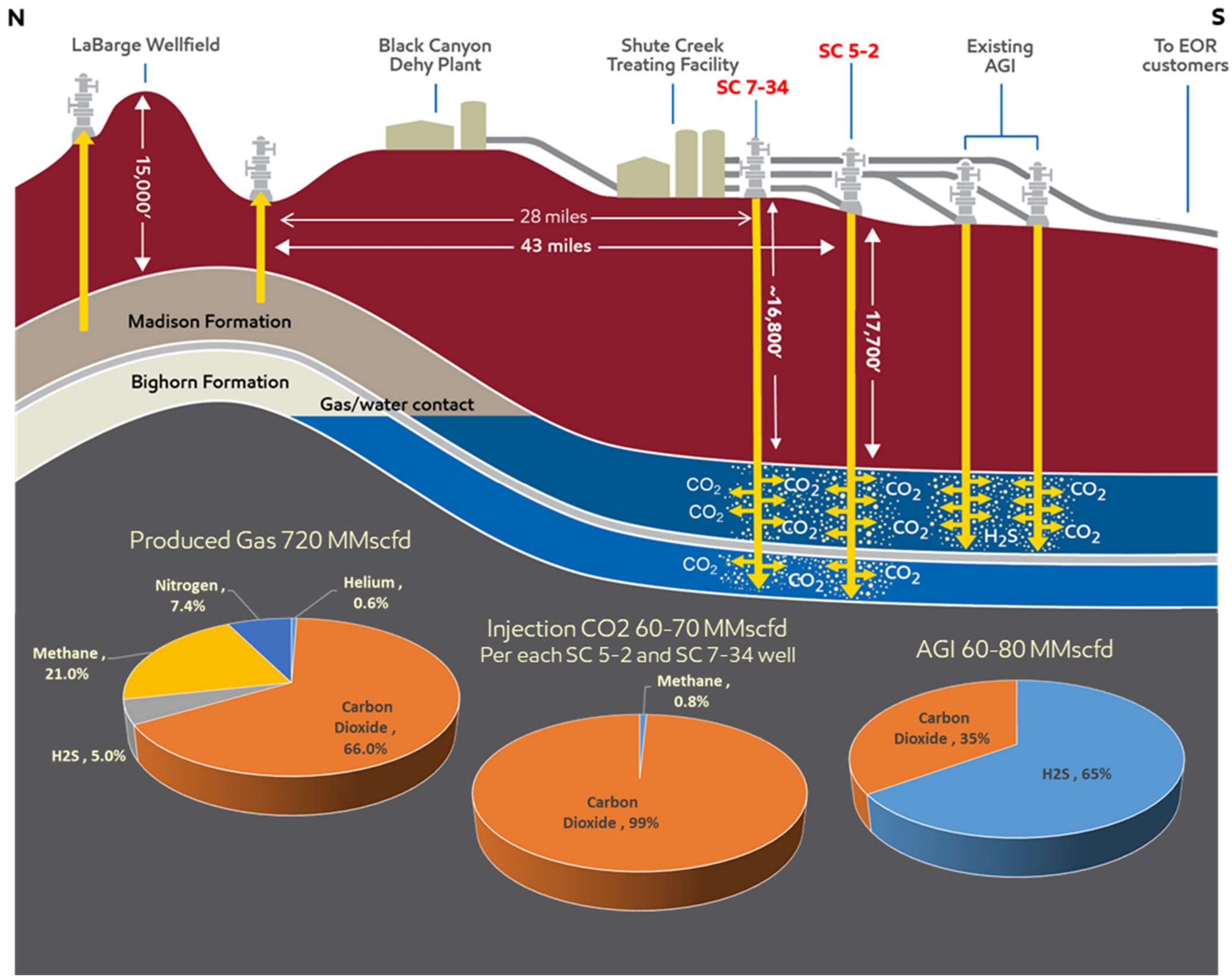

Figure 2.7 Schematic illustration of AGI injection program as currently used at LaBarge and CO_2 injection programs

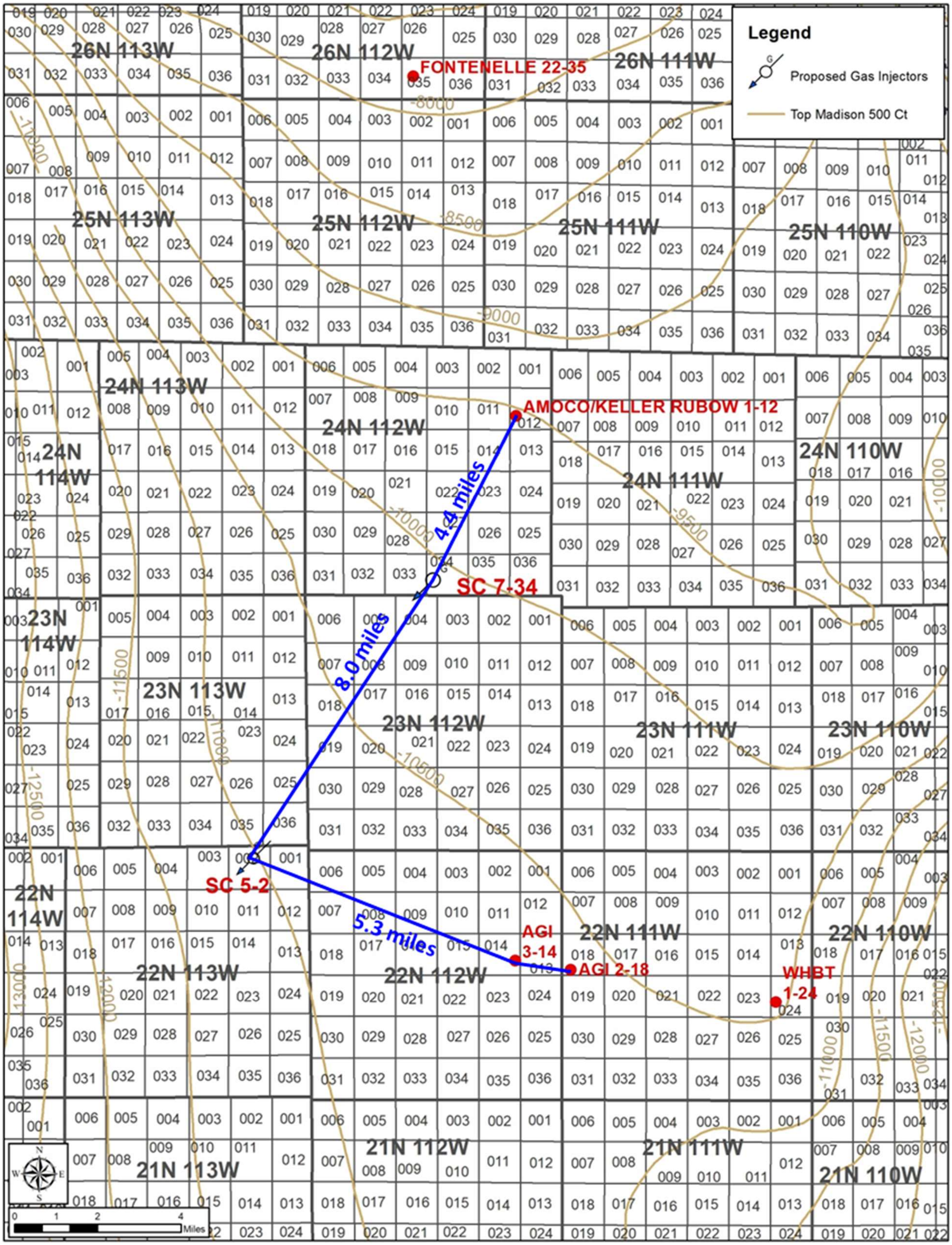

Figure 2.8 Madison structure map with relative well locations

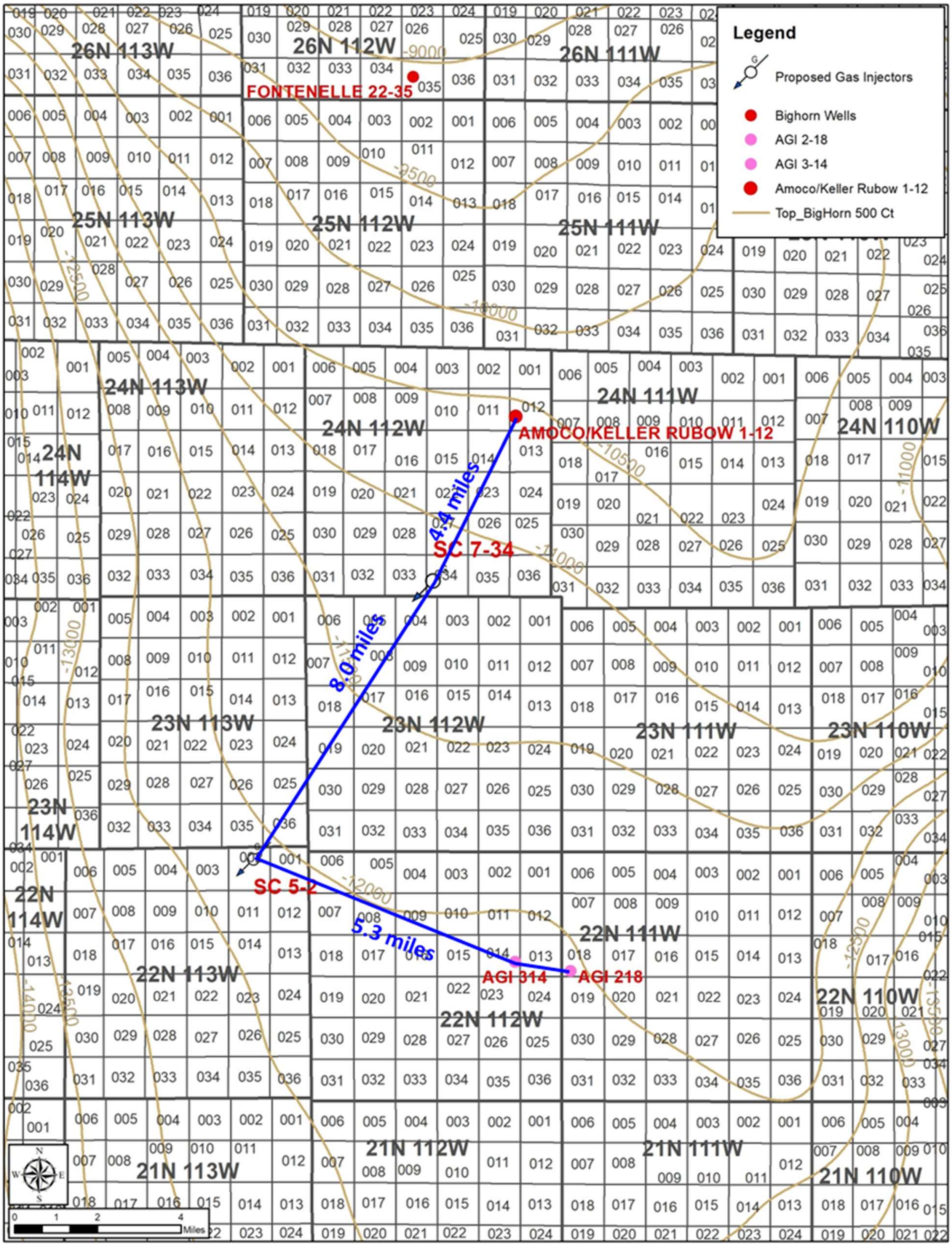

Figure 2.9 Bighorn-Gallatin structure map with relative well locations

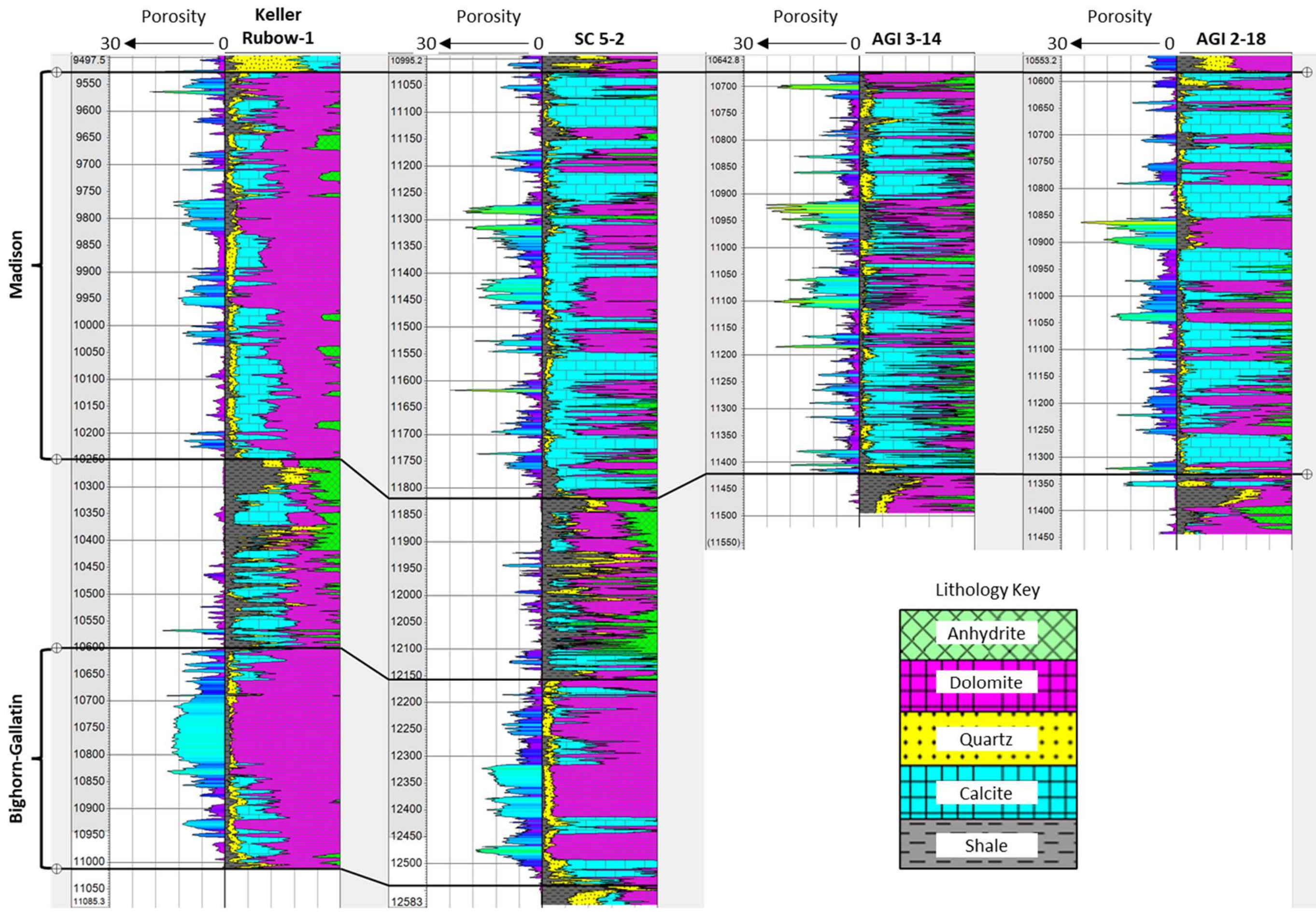

Figure 2.10 Well log sections from the Keller Rubow-1, SC 5-2, AGI 3-14, and AGI 2-18 injection wells across the Madison and Bighorn-Gallatin formations. SC 7-34 well logs are expected to be similar to offset wells.

	Bighorn-Gallatin	Madison		
	SC 5-2	SC 5-2	AGI 3-14	AGI 2-18
Net Pay (ft)	245	291	240	220
Avg Φ (%)	9%	10%	10%	9%
Avg k (md)	4	10	9	12
kh (md-ft)	~600*	~3000*	2300*	~2700*
Skin	-3.7	-3.5	-4.1	-4.5

* From injection / falloff test analysis

Figure 2.11 Average Madison and Bighorn-Gallatin reservoir properties of the SC 5-2 and AGI wells. SC 7-34 is expected to have similar properties.

From Figure 2.11, the parameters tabulated include:

1. *Net pay:* Madison section that exceeds 5% total porosity.
2. *Phi (ϕ):* Total porosity; the percent of the total bulk volume of the rock investigated that is not occupied by rock-forming matrix minerals or cements.
3. *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. Note that the measure of darcy assumes linear flow (i.e. pipe shaped).
4. *Kh:* Millidarcy-feet, which is a measure of the average permeability calculated at a 0.5 foot sample rate from the well log accumulated over the total net pay section encountered.
5. *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.

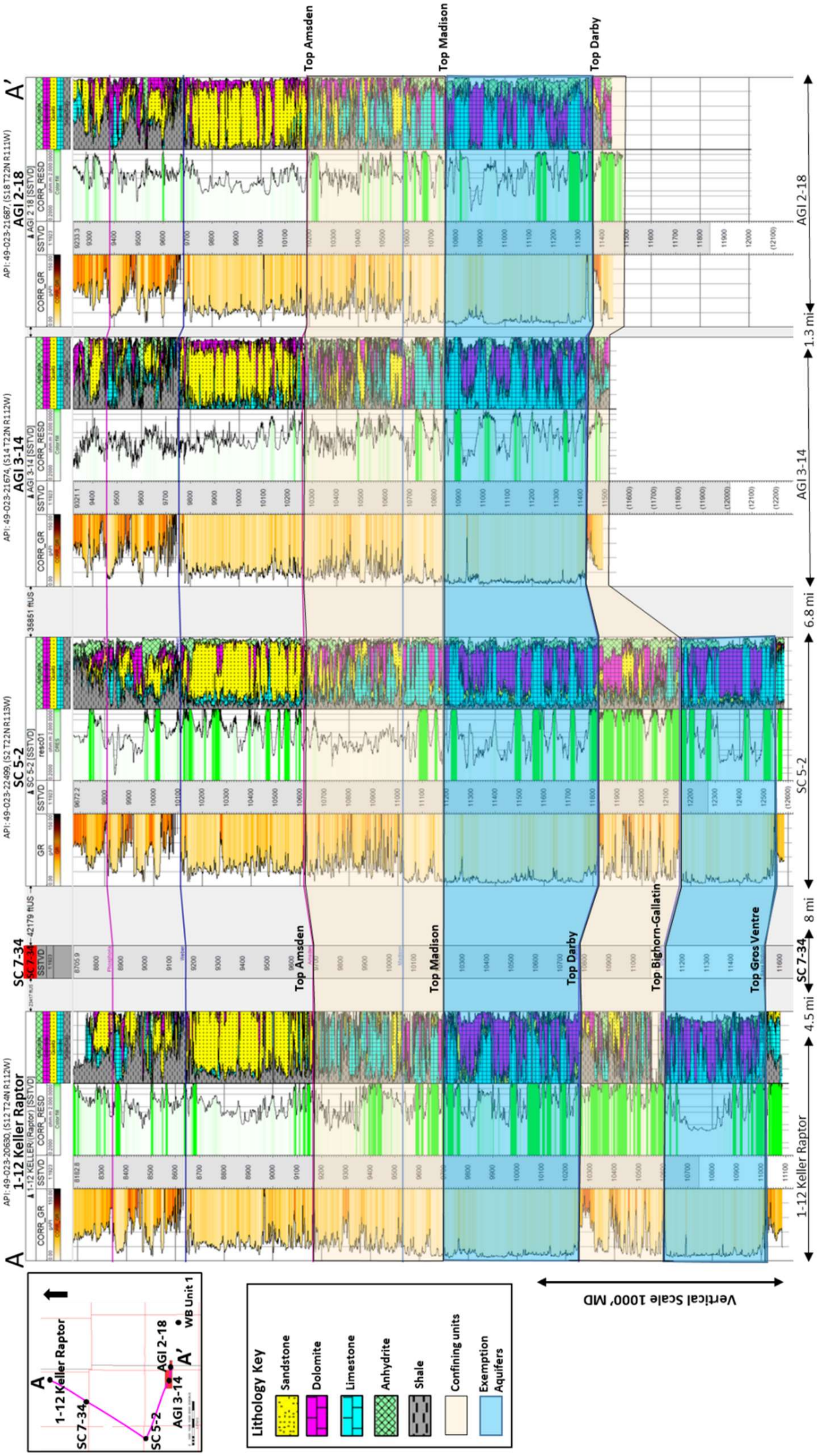

Figure 2.12 Stratigraphic Cross Section of Existing Madison and Bighorn-Gallatin Wells and the SC 7-34 Well

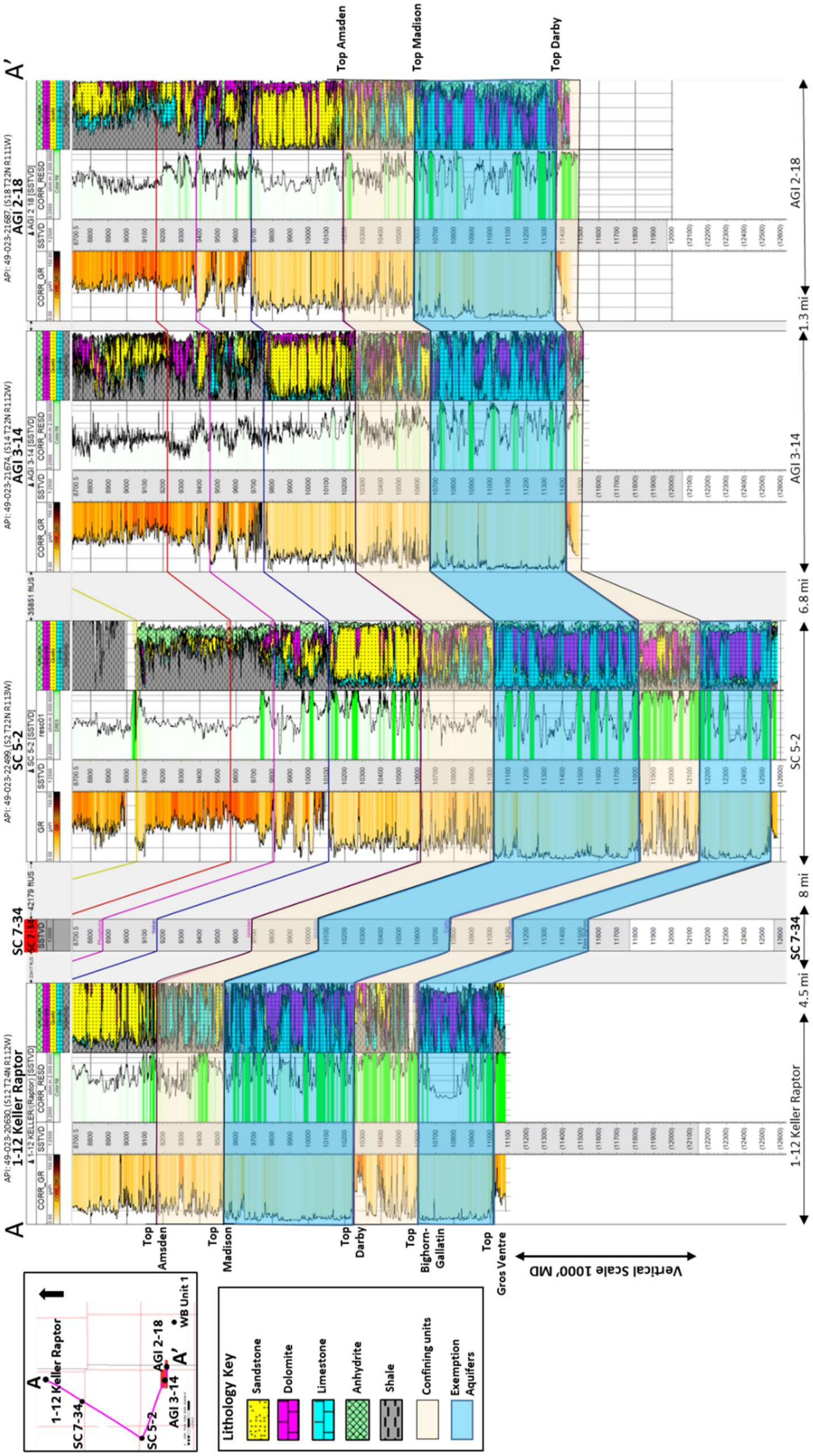

Figure 2.13 Structural Cross Section of Existing Madison and Bighorn-Gallatin Wells and the SC 7-34 Well

2.6.3 Seismic Expression of Madison and Bighorn-Gallatin Formations at CO_2 Injection Well Locations

Seismic expression of the Madison and Bighorn-Gallatin formations at the SC 5-2 and SC 7-34 injection locations indicate that the CO_2 injection wells are located on the plunging crest of the Moxa Arch with little to no structuring observable on the seismic data around these wells. Faulting is also not indicated by the seismic data. Figure 2.14 shows an east-west oriented 2D seismic at the SC 5-2 well location at approximately five times vertical exaggeration. Figure 2.15 shows an east-west oriented 2D seismic at the SC 7-34 well location at approximately four times vertical exaggeration.

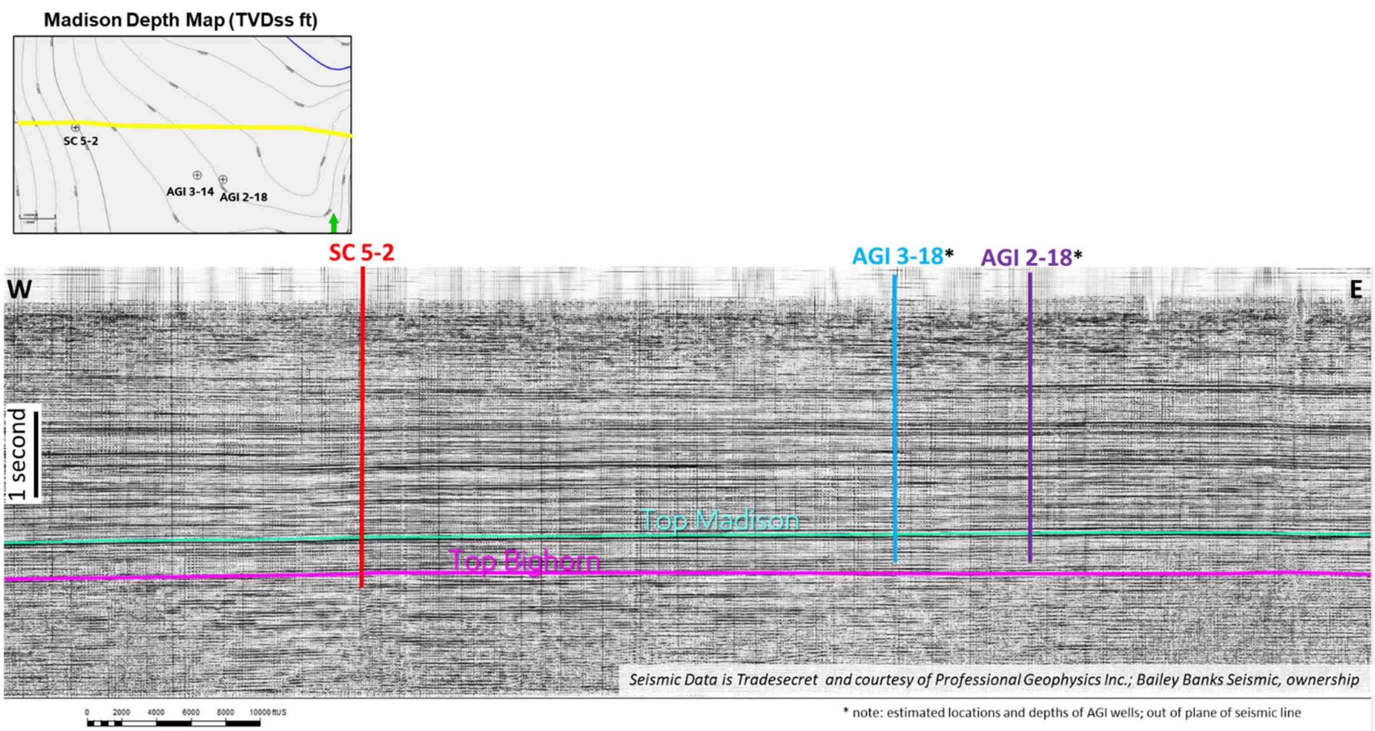

Figure 2.14 2D Seismic traverses around the SC 5-2 injection well location shows no evidence of faulting or structuring around the well location

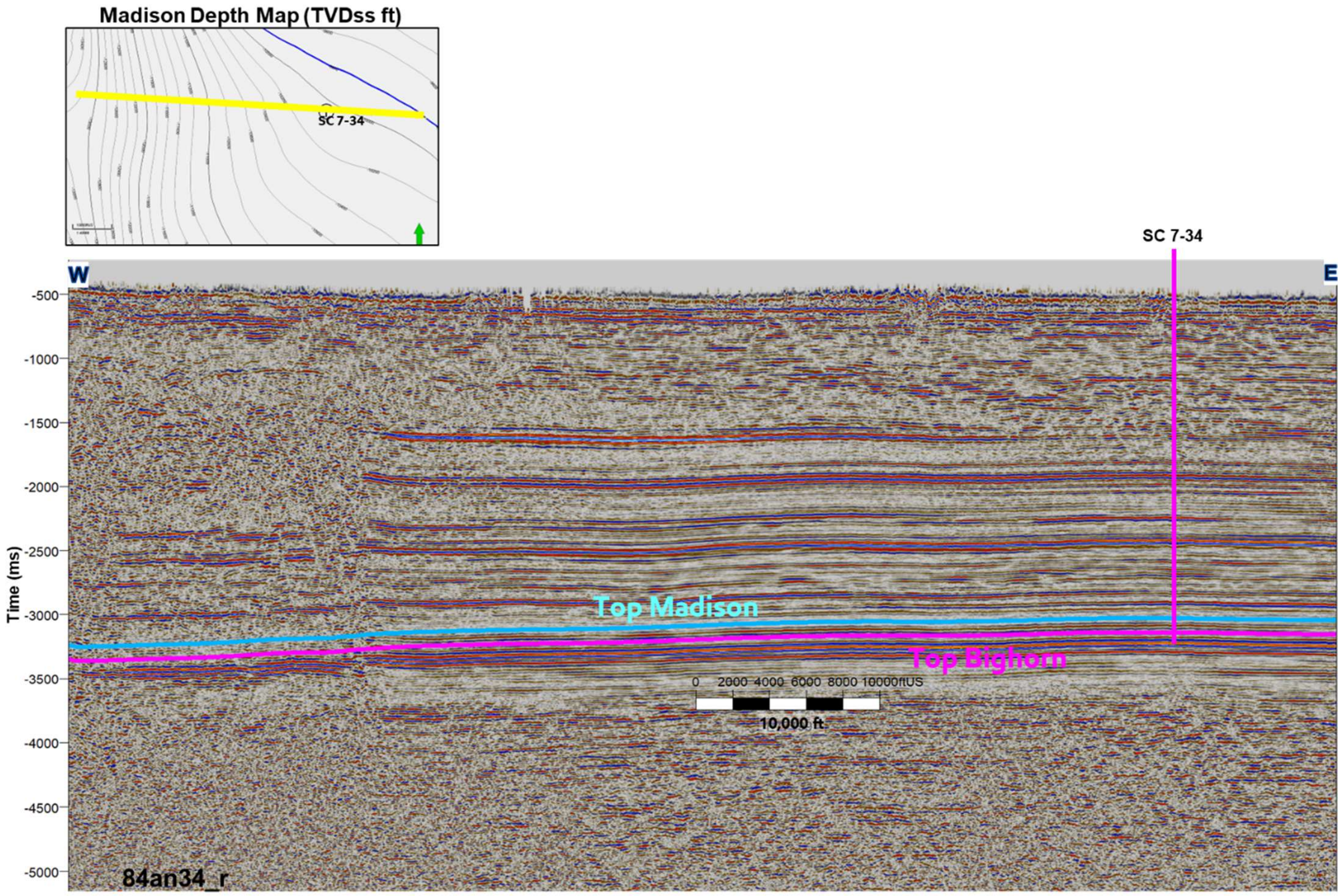

Figure 2.15 2D Seismic traverses around the SC 7-34 injection well location shows no evidence of faulting or structuring around the well location

2.7 Description of the Injection Process

2.7.1 Description of the AGI Process

The AGI facility was commissioned for eliminating the Claus Sulfur Recovery Units (SRU) bottleneck, reducing plant downtime, and reducing operating costs. The purpose of the AGI process is to take the H_2S and some of the CO_2 removed from the produced raw gas and inject it back into the Madison Formation. Raw gas is produced out of the Madison Formation and acid gas is injected into the aquifer below the GWC of the Madison Formation. The Madison reservoir contains very little CH_4 and He at the injection locations under SCTF, where the AGI wells are located. Thus, there is no concern of contaminating the production from the LaBarge well field 43 miles away.

The AGI process transports the acid gas stripped in the Selexol process under pressure through a pipeline to two underground wells that are geologically suitable for storage of the acid gas (AGI 3-14 and AGI 2-18). There are three parallel compressor trains. Two trains are required for full

capacity; the third train is a spare. The low pressure feed from the Selexol process enters the first stage suction and is compressed through four stages of compression. The high pressure acid gas from the Selexol process requires only three stages of compression. The fourth stage discharge acid gas must be condensed prior to pumping to prevent damage from vapors. Fourth stage discharge acid gas is cooled in three heat exchangers prior to entering the pump. Dense phase aerial coolers are located downstream of the pumps; they remove heat generated by pumping and increase the density of the fluid. The liquid H_2S/CO_2 is commingled downstream of the dense phase coolers and divided into the two injection wells over 38 miles from the nearest Madison gas producer in the LaBarge gas field. The approximate stream composition being injected is 50 - 65% H_2S and 35 - 50% CO_2. Each injection well has a dedicated six-inch carbon steel pipeline. The length of pipeline from the AGI battery limit to the injection wells is about:

- 3,200 feet to AGI 3-14
- 12,400 feet to AGI 2-18

The AGI flow lines are buried with seven feet of cover. Heat tracing is provided for the aboveground portions of the lines to prevent the fluid from cooling to the point where free water settles out. Free water and liquid H_2S/CO_2 form acids, which could lead to corrosive conditions. Additionally, the gas is dehydrated before it enters the flow line, reducing the possibility of free water formation, and the water content of the gas is continuously monitored. The liquid H_2S/CO_2 flows via the injection lines to two injection wells. The total depth of each well is about:

- 18,015 feet for AGI 3-14
- 18,017 feet for AGI 2-18.

2.7.2 Description of the CO_2 Injection Process

The CO_2 injection program was initiated primarily because the volume of CO_2 associated with the natural gas production is greater than the volume that is able to be injected into the AGI wells.

2.7.2.1 Description of the SC 5-2 Process

The SC 5-2 process aims to capture CO_2 at the SCTF that would otherwise be vented, and compress it for injection in the aquifer below the GWC of the Madison and Bighorn-Gallatin formations.

The injection system would enable additional CO_2 to be stripped in the Selexol process, pressurized, and transported to a CO_2 injection well, which is geologically suitable for injection, disposal and sequestration of fluids primarily consisting of CO_2. The process will be built into the existing Selexol trains at SCTF. After the acid gas treatment and dehydration, the gas will be routed to a new flash vessel which will enable capture up to 80 million standard cubic feet per day (MMSCFD) from SCTF then compressed with an air cooled Heat Exchanger cooling system. The captured CO_2 will have the potential to be either sold or injected into a CO_2 injection well. Based on modeling, the approximate stream composition will be 99% CO_2, 0.8% methane and 0.2% other mixed gases.

From the CO_2 compressors, an eight inch flow line of approximately 10.1 miles would take the fluids to the SC 5-2 injection well site. The flow line would be buried at depths necessary to avoid and protect existing facilities, roads, and crossings, and will be buried at a minimum below the frost line. The fluids will have a sufficient dew point that free water formation is not expected to accumulate along the pipeline or well. The water content of the gas will be continuously monitored. The gas will be transported via flow line to the SC 5-2 well and injected into the Madison Formation at a depth of ~17,950 feet and into the Bighorn-Gallatin Formation at a depth of ~19,200 feet approximately 33 miles from the nearest Madison gas producer in the LaBarge gas field. Based on geological models, the risk of contaminating production from the LaBarge well field or interacting with the AGI wells or SC 7-34 well approximately 7 miles and 8 miles away, respectively, is improbable due to the relatively tight reservoir quality of the Madison and Bighorn-Gallatin formations, the significant distance between the SC 5-2 injection site and the producing well field, and the volume and rate of injection at the SC 5-2 site.

2.7.2.2 Description of the SC 7-34 Process

The SC 7-34 process aims to divert currently captured CO_2 produced from source wells during natural gas production that will not be sold to customers and route to permanent disposal in the aquifer below the GWC of the Madison and Bighorn-Gallatin formations.

Captured CO_2 that is already routed from SCTF to the existing CO_2 sales building will be diverted and transported via flow line to a CO_2 injection well, which is geologically suitable for injection, disposal, and sequestration of fluids primarily consisting of CO_2. This process will enable disposal of up to 70 MMSCFD through an additional pump. The CO_2 will be cooled with an air cooled Heat Exchanger cooling system. Based on modeling, the approximate stream composition is anticipated to be identical to the SC 5-2 with 99% CO_2, 0.8% methane, and 0.2% other mixed gases.

From the CO_2 compressors, an eight inch flow line of approximately 12.4 miles would take the fluids to the SC 7-34 injection well site. The flow line would be buried at depths necessary to avoid and protect existing facilities, roads, and crossings, and will be buried at a minimum below the frost line. The fluids will have a sufficient dew point that free water formation is not expected to accumulate along the pipeline or well. The water content of the gas will be continuously monitored. The gas will flow via the injection lines to the SC 7-34 well and injected into the Madison Formation at a depth of ~16,740 feet and into the Bighorn-Gallatin Formation at a depth of ~18,230 feet approximately 28 miles from the nearest Madison gas producer in the LaBarge gas field. Based on geological models, the risk of contaminating production from the LaBarge well field 30 miles away or interacting with the SC 5-2 well or AGI wells approximately 8 and 9 miles away, respectively, is improbable due to the relatively tight reservoir quality of the Madison and Bighorn-Gallatin formations, the significant distance between the SC 7-34 injection site and the producing well field, and the volume and rate of injection at the SC 7-34 site.

2.8 Planned Injection Volumes

2.8.1 Acid Gas Injection Volumes

Figure 2.16 is a long-term injection forecast throughout the life of the acid gas injection project. It is based on historic and predicted data. 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 below are the total amount of gas to be injected into the AGI wells, not just the CO_2 portion. ExxonMobil forecasts the total volume of CO_2 stored in the AGI wells over the modeled injection period to be approximately 53 million metric tons.

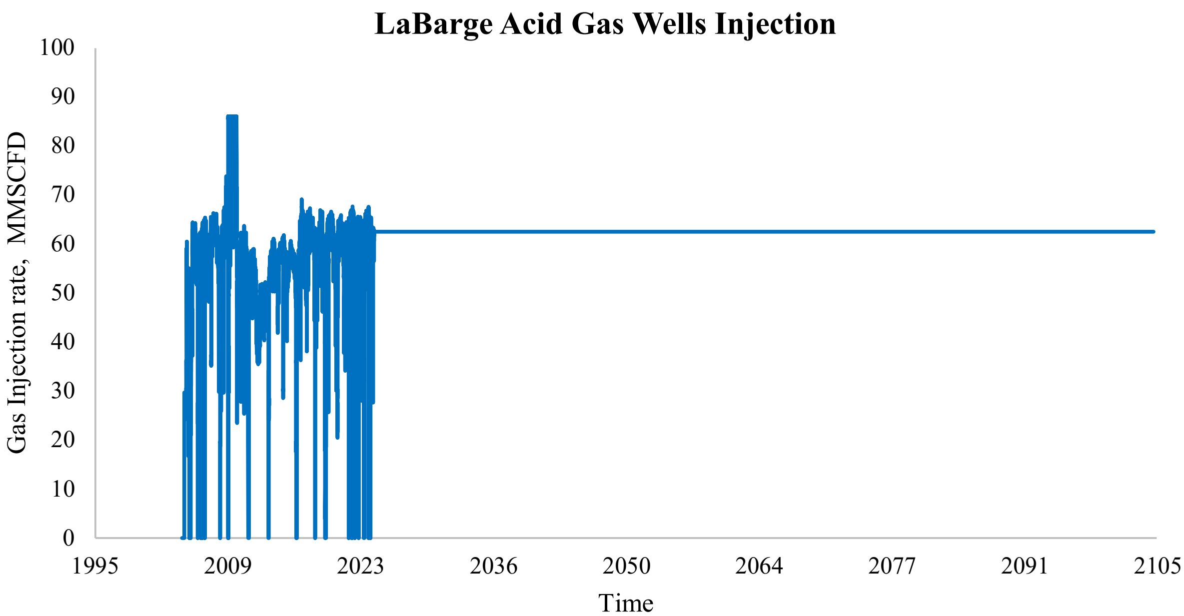

Figure 2.16 – Planned Acid Gas and CO_2 Injection Volumes

2.8.2 CO_2 Injection Wells Volumes

Figure 2.17 below is a long-term average injection forecast through the life of the CO_2 injection wells. 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 below are the total amount of fluids to be injected, but does not include any portion of the Acid Gas Injection project gas. The non-CO_2 portion of the injection stream is expected to be 1% or less of the injected volume. ExxonMobil forecasts the total volume of CO_2 stored in the CO_2 injection wells over the modeled injection period to be approximately 180 million metric tons.

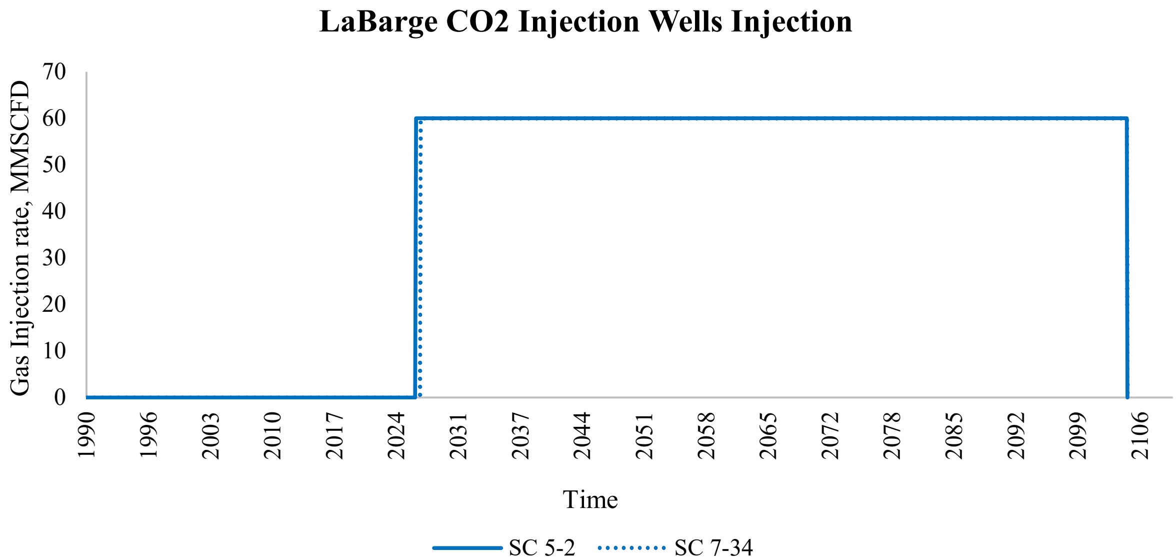

Figure 2.17 – Planned Average CO_2 Injection Well Volumes

3.0 Delineation of Monitoring Area

3.1 Maximum Monitoring Area (MMA)

3.1.1 AGI Wells MMA

Per 40 CFR § 98.449, the MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling using Schlumberger's (SLB) Petrel/Intersect, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the acid gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 1%. A gas saturation of 1% is well below the lowest gas saturation that can be confidently detected by formation evaluation methods in reservoirs with rock properties such as those found in the Madison Formation.

After injecting 0.3 trillion cubic feet (TCF) by year-end 2023, the current estimated acid gas plume size is approximately 21,350 feet in diameter (4.0 miles) (see Figure 3.1). With continuing injection of an additional 1.9 TCF through year-end 2104, at which injection is expected to cease, the plume size is expected to grow to approximately 39,500 feet in diameter (7.5 miles) (see Figure 3.2).

The model was run through 2986 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. The rate of growth of the free-phase gas plume is less than 0.25% areally per

year, demonstrating plume stability. Figure 3.3 below shows the expansion of the plume to a diameter of approximately 40,470 feet (7.7 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the MMA will be defined by Figure 3.3, which is the maximum areal extent of the plume once it has reached stability (defined by the extent of the plume in 2205, which is a 7.7-mile diameter) plus the buffer zone of one-half mile.

3.1.2 CO_2 Injection Wells MMA

Per 40 CFR § 98.449, the MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the CO_2 gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 1%.

Note that estimates of plume size assume that CO_2 is coinjected without flow control at both the SC 5-2 and SC 7-34 wells into both the Madison and Bighorn-Gallatin intervals. Having no flow control means that the amount of gas that enters each interval is for the most part a function of the permeability thickness (kh) of each interval. There is limited data, especially for the Bighorn-Gallatin, with few well penetrations, all of which are a significant distance from the target formation. Therefore, the anticipated plume sizes are based on simulation results relying on best estimates from available data regarding the Madison and Bighorn-Gallatin reservoir quality.

The model was run through 2986 to assess the potential for expansion of the plume after injection ceases at year-end 2104. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. The rate of growth of the free-phase gas plume is less than 0.25% areally per year, demonstrating plume stability.

3.1.2.1 SC 5-2 MMA

Assuming SC 5-2 begins injecting in 2025, 0.02 TCF of CO_2 will have been injected by mid-2026 and the gas plume will just begin to form. Figure 3.4 shows expected average gas saturations at mid-2026 and the location of the AGI wells relative to the SC 5-2 injection well. After injecting 1.7 TCF at year-end 2104, injection is expected to cease. The SC 5-2 CO_2 plume size is expected to grow to approximately 23,650 feet in diameter (4.5 miles) (see Figure 3.5).

Figure 3.6 below shows the expansion of the SC 5-2 plume to a diameter of approximately 24,500 feet (4.6 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the SC 5-2 MMA will be defined by Figure 3.6, which is the maximum areal extent of the SC 5-2 plume once it has reached stability (defined by the extent of the plume in 2205, which is a 4.6-mile diameter) plus the buffer zone of one-half mile.

3.1.2.2 SC 7-34 MMA

SC 7-34 is assumed to begin injection mid-2026. After injecting 1.7 TCF at year-end 2104, injection is expected to cease. The SC 7-34 CO_2 plume size is expected to grow to approximately 22,100 feet in diameter (4.2 miles) (see Figure 3.7).

Figure 3.8 below shows the expansion of the SC 7-34 plume to a diameter of approximately 24,976 feet (4.7 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the SC 7-34 MMA will be defined by Figure 3.8, which is the maximum areal extent of the SC 7-34 plume once it has reached stability (defined by the extent of the plume in 2205, which is a 4.6-mile diameter) plus the buffer zone of one-half mile.

3.2 Active Monitoring Area (AMA)

Per 40 CFR § 98.449, the AMA is the superimposed areas projected to contain the free phase CO_2 plume at the end of the year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile and the area projected to contain the free phase CO_2 plume at the end of year t+5, where t is the last year in the monitoring period.

ExxonMobil proposes to define the AMA as the same boundary as the MMA for the AGI and CO_2 injection wells. The following factors were considered in defining this boundary:

1. Lack of faulting in the MMA yields no vertical pathways for fluids to move vertically out of the Madison or Bighorn-Gallatin formations to shallower intervals.
2. Lack of faulting in the injection area does not create enhanced reservoir permeability through natural fracturing and all flow of injected fluids will be darcy flow from pore to pore.
3. Distance from the LaBarge production field area is large (35+ miles) and reservoir permeability is generally low which naturally inhibits flow aerially from injectionsite.
4. The LaBarge field production area is a large structural hydrocarbon trap that has sealed and trapped hydrocarbons for large geologic periods of time. There is no reason to believe that any injection fluids that may migrate outwards from the injection site to the larger LaBarge structure would not also be effectively trapped at the LaBarge structure over geological time.
5. If t is defined as the final year of injection coinciding with end of field life for the LaBarge assets, the MMA encompasses the free phase CO_2 plume 100 years post-injection, and therefore satisfies and exceeds the AMA area.

The purpose of the AMA is to allow for a practical and cost-effective monitoring program throughout the life of the project. Because there are no probable leakage pathways in the MMA, besides surface equipment which is extensively monitored, ExxonMobil believes it is appropriate to define the AMA as the same boundary as the MMA. Additionally, due to the high H_2S content of the injected gas stream into the AGI wells, monitoring of leaks is essential to operations and

personnel safety, so a full-scale monitoring program has already been implemented at the AGI sites, as will be discussed below.

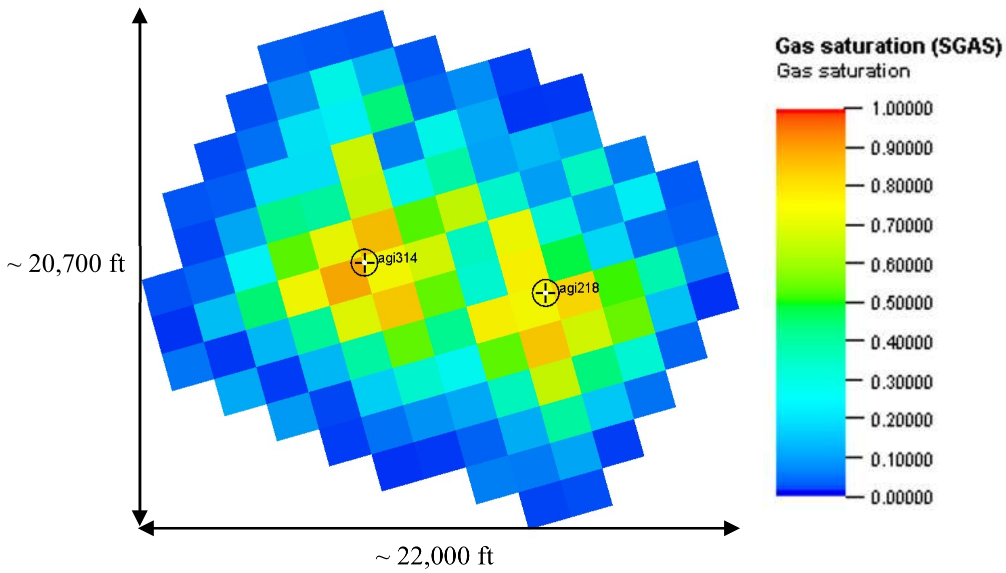

Figure 3.1 – AGI Estimated Gas Saturations at Year-end 2023

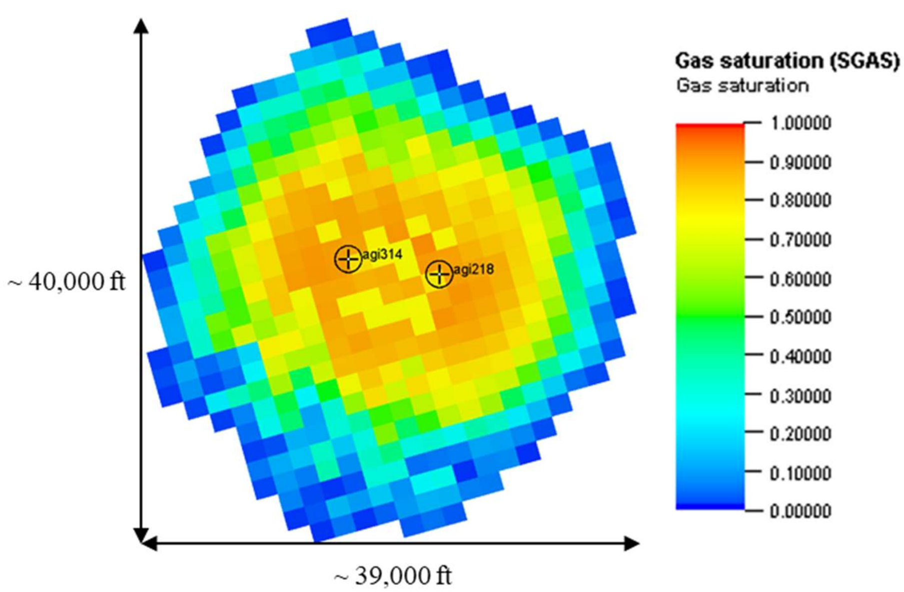

Figure 3.2 – AGI Predicted Gas Saturations at Year-end 2104

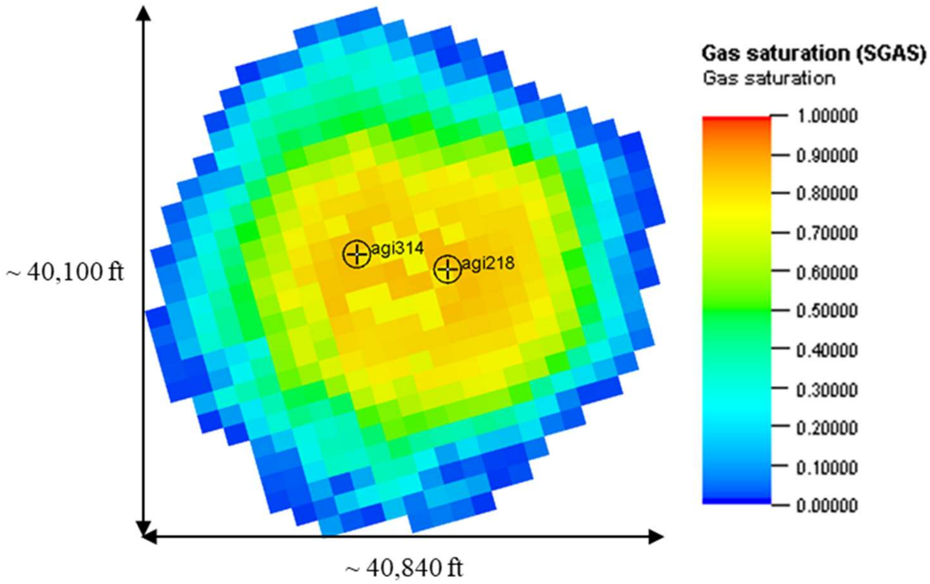

Figure 3.3 – AGI Predicted Gas Saturations at Year-end 2205

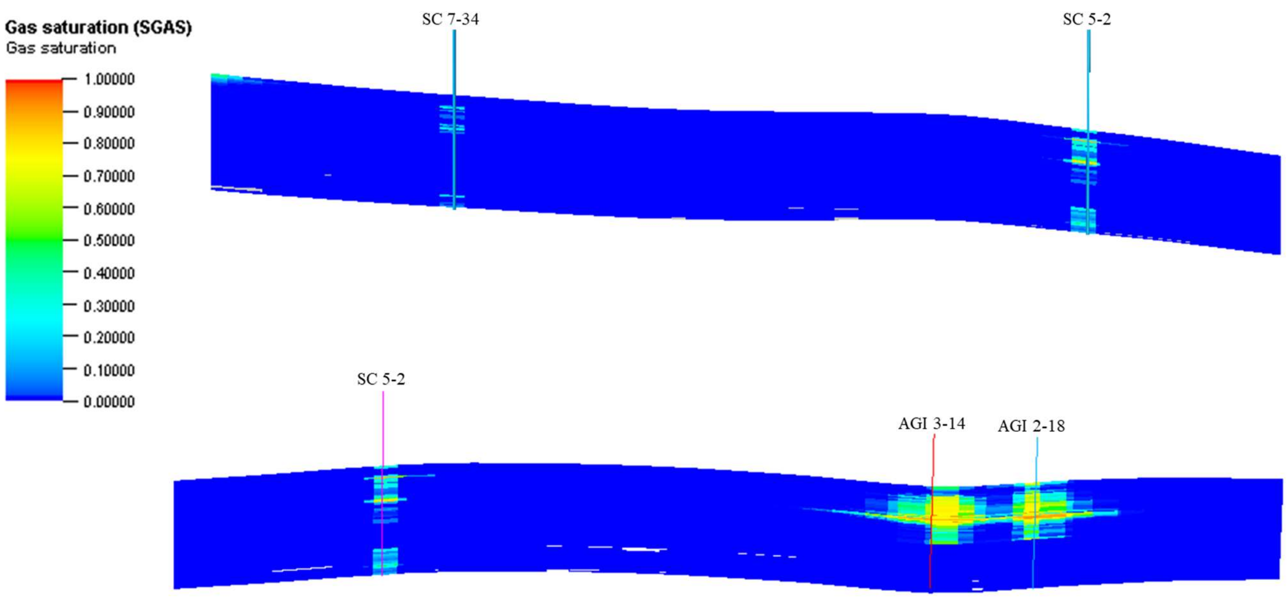

Figure 3.4 – Predicted Gas Saturations at Year-end 2027

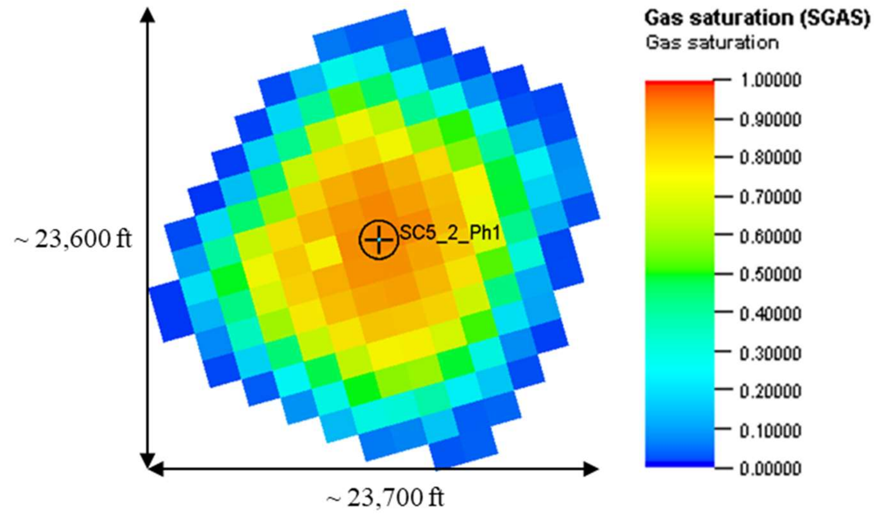

Figure 3.5 – SC 5-2 Predicted Gas Saturations at Year-end 2104

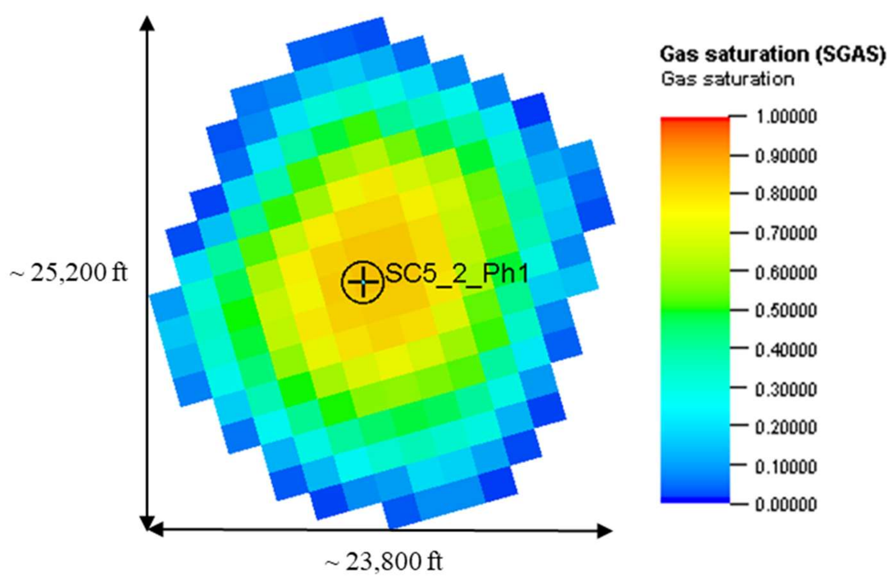

Figure 3.6 – SC 5-2 CO_2 Predicted Gas Saturations at Year-end 2205

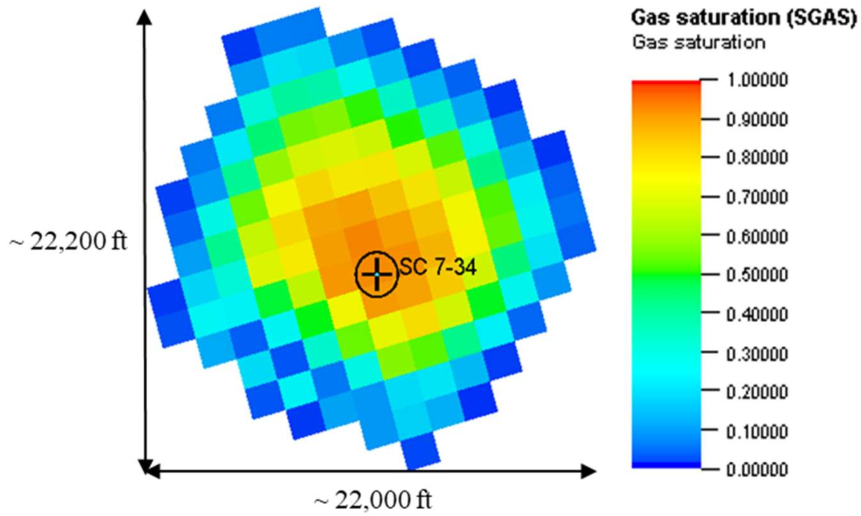

Figure 3.7 – SC 7-34 Predicted Gas Saturations at Year-end 2104

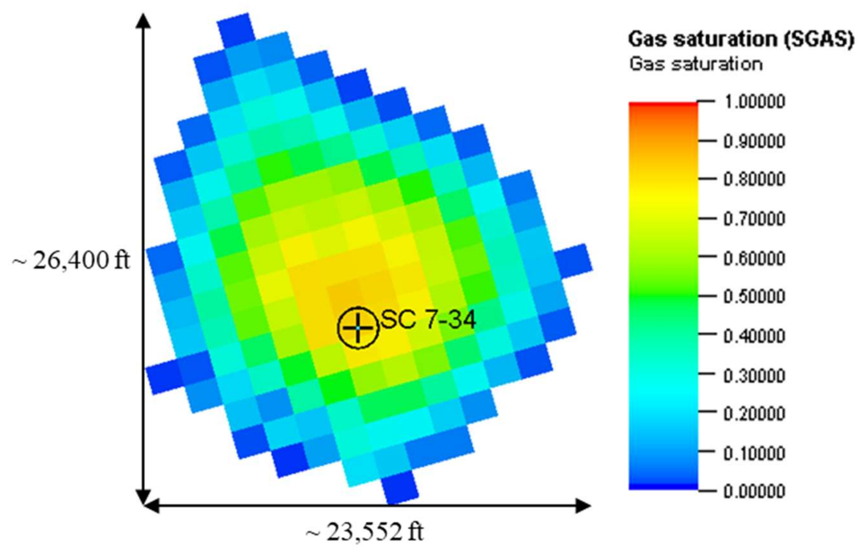

Figure 3.8 – SC 7-34 Predicted Gas Saturations at Year-end 2205

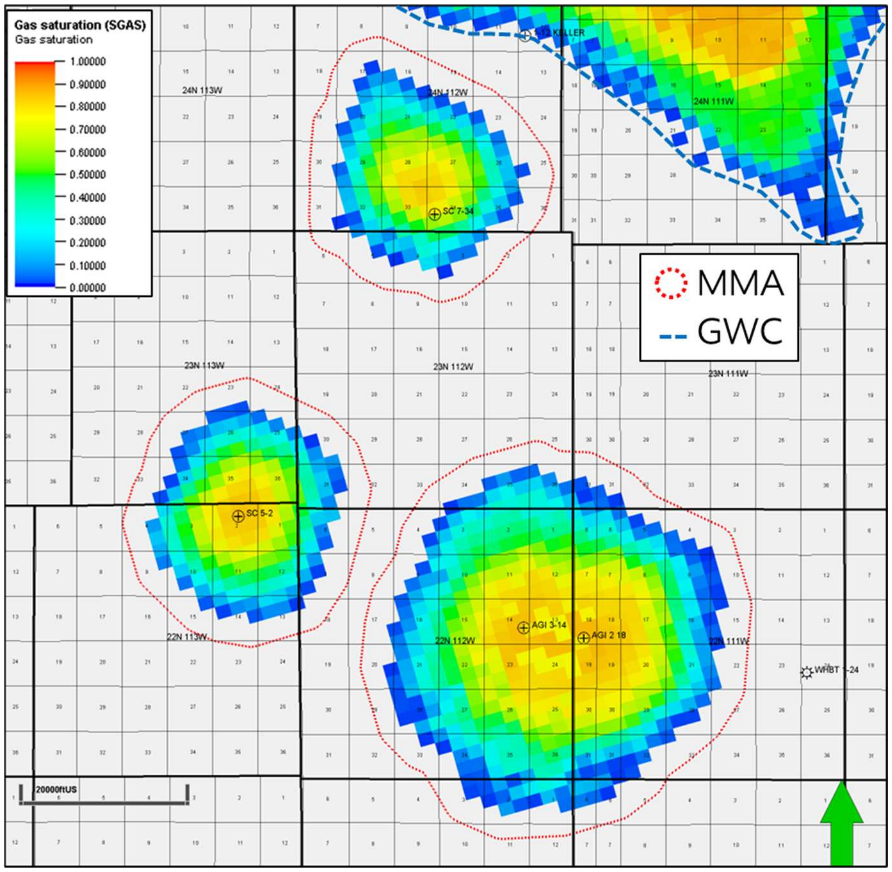

Figure 3.9 - Gas saturation plumes for AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34 at the time of plume stabilization (year 2205) with half mile buffer limit of MMA (red polygons). Plumes are displayed at zone of largest aerial extent (within Madison Formation) relative to the LaBarge gas field in the same gas-bearing zone (gas water contact displayed in dashed blue polygon).

4.0 Evaluation of Potential Pathways for Leakage to the Surface

This section assesses the potential pathways for leakage of injected CO_2 to the surface. ExxonMobil has identified the potential leakage pathways within the monitoring area as:

- Leakage from surface equipment (pipeline and wellhead)
- Leakage through wells
- Leakage through faults and fractures
- Leakage through the seal
- Leakage through natural or induced seismicity

As will be demonstrated in the following sections, there are no leakage pathways that are likely to result in loss of CO_2 to the atmosphere. Further, given the relatively high concentration of H_2S in the AGI injection stream, any leakage through identified or unexpected leakage pathways would be immediately detected by alarms and addressed, thereby minimizing the amount of CO_2 released to the atmosphere from the AGI wells.

4.1 Leakage from Surface Equipment

Leakage from surface equipment is not likely due to the design of the AGI and CO_2 injection facilities. The AGI facilities were designed to minimize leak points such as valves and flanges, and use welded connections where possible instead. The only surface equipment located between the flow meter and the wellhead are valves, transmitters, and flanged connection points on the pipelines. Due to the presence of H_2S in the AGI injection stream at a concentration of approximately 50 - 65% (500,000 - 650,000 parts per million (ppm)), H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. CO_2 gas detectors will be present at the CO_2 injection facilities due to high concentration of CO_2, which alarm at 5,000 PPM. Additionally, all field personnel are required to wear H_2S monitors for safety reasons, which alarm at 5 ppm H_2S. Although damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2 entrained in the acid gas, at the AGI well concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm, and immediate action would be taken to stop the leak. Additionally, the CO_2 injection wells would be monitored with methods outlined in sections five and six.

ExxonMobil reduces the risk of unplanned leakage from surface facilities through continuous surveillance, facility design, and routine inspections. Field personnel monitor the AGI facility continuously through the Distributed Control System (DCS). Additionally, daily visual inspection rounds are conducted of the AGI facility and weekly visual inspections are conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. ExxonMobil also relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSVs), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes. Additionally, the AGI wells have multiple surface isolation valves for redundant protection. Inline inspections of the AGI injection pipelines using a smart pigging tool are conducted on a regular frequency to check the wall thickness of the pipeline to identify potential areas of corrosion.

Field personnel will monitor the CO_2 injection facilities continuously through the DCS. Additionally, visual inspections will be conducted on a routine basis providing an additional way to detect leaks in a timely manner. Surface isolation valves will also be installed for redundant protection. Inline inspections are not anticipated to occur on a regular frequency because free water is not expected to accumulate due to the low dew point of the fluid.

<u>Likelihood</u>
Due to the design of the AGI and CO_2 injection facilities and extensive monitoring in place to reduce the risk of unplanned leakage, leakage from surface equipment is not likely.

<u>Magnitude</u>
Given the high concentrations of H_2S and CO_2 in the respective injection streams, ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. Even a minuscule amount of gas leakage would be immediately detected by the extensive monitoring systems currently in place at the facility as described above and treated as an upset event warranting immediate action to stop the leak. Should leakage be detected from surface equipment, the volume of CO_2 released will be quantified based

on the operating conditions at the time of release, as stated in Section 7.4 in accordance with 40 CFR 98.448(5).

Timing

As stated above, even a minuscle amount of gas leakage would be immediately detected and immediate action would be taken to stop the release. Any potential leakage from surface equipment would only occur during the lifetime operation of the wells. Once injection ceases, the surface equipment will be decommissioned and will not pose a risk as a leakage pathway.

4.2 Leakage through AGI and CO2 Injection Wells

Leakage of CO_2 through oil, gas, and/or water wells completed and/or abandoned is not likely. There is no commercial production of oil or gas within the immediate area of the SCTF. There is shallower production of gas from the Frontier and Dakota formations nearby in the Cow Hollow Field, at depths of 10,800' – 11,800'. A search of the WOGCC database demonstrated that there are no existing active Madison or Bighorn-Gallatin penetrations or production within the respective MMAs of the AGI or CO_2 injection well sites. The nearest established Madison production is greater than 35 miles to the north-northwest in the ExxonMobil LaBarge Deep Madison Field, which is the well field that supplies SCTF. One well (Whiskey Butte Unit 1, drilled in 1974 and operated by Wexpro Company), which was located approximately 6 miles from the AGI wells, partially penetrated 190 feet of the Madison Formation (total depth 17,236 feet MD). This well never produced from the Madison Formation and instead was perforated thousands of feet above in the Frontier Formation. The well was ultimately plugged and abandoned in February 1992. Examination of the plugging and abandonment records and the wellbore diagram constructed from those records indicates that risk of the well as a leakage pathway is highly unlikely. Two additional Madison penetrations are located between the well field and the SC 5-2 and AGI wells; both penetrations are outside the boundary of the MMA and therefore likely do not pose a risk as a leakage pathway. Keller Rubow 1-12 was plugged and abandoned in 1996. Fontenelle II Unit 22-35 was drilled to the Madison Formation but currently is only perforated and producing from thousands of feet above in the Frontier Formation.

As mentioned in Section 2.3.2, early in the life of many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. The thin-wall wells that failed have been plugged and abandoned in accordance with regulatory standards. Madison wells that were subsequently drilled were cased using thick-walled/chrome tubulars due to the high H_2S and CO_2 content and subsequent corrosion effects, as well as to combat potential salt or sediment creep. Therefore, there is no current risk of failure as all wells currently use or have used thick-walled casing of sufficient strength to penetrate and/or produce from the Madison Formation.

Future drilling is also unlikely to pose a risk as a leakage pathway due to limited areal extent of the injection plumes as shown in Figures 3.2 – 3.8. Therefore, the geological model can be used to delineate areas that should be avoided during drilling. This model has also history-matched the AGI wells injection that has occurred to date and suggests that future injection will closely follow the patterns resulting from the geological model simulation. Additionally, should future drilling occur, it would occur near the existing production area, which is greater than 40 miles away from

the current AGI wells, approximately 35 miles away from SC 5-2, and approximately 30 miles away from SC 7-34.

ExxonMobil reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and annual mechanical integrity testing (MIT). As indicated in Section 4.1, visual inspections of the well sites are performed on a routine basis, which serves as a proactive and preventative method for identifying leaks in a timely manner. Gas detectors located at the well sites which alarm at 10 ppm H_2S and 5,000 ppm CO_2 would be triggered if a leak from the wellbore to the atmosphere occurred. Additionally, SCSSV's and surface isolation valves are installed at the AGI wells, which would close in the event of leakage, preventing losses. Mechanical integrity testing is conducted on an annual basis and consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. If the MIT demonstrated a leak, the well would be isolated and the leak would be mitigated as appropriate to prevent leakage to the atmosphere.

<u>Likelihood</u>
There are no existing active Madison or Bighorn-Gallatin penetrations or production within the respective MMAs of the AGI and CO_2 injection well sites. As stated in Section 4.1, ExxonMobil relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSVs), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes.

<u>Magnitude</u>
Given the high concentrations of H_2S and CO_2 in the respective injection streams, ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. Should leakage result from the injection wellbores and into the atmosphere, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7.4 in accordance with 40 CFR 98.448(5).

<u>Timing</u>
As stated above, even a minuscle amount of gas leakage would be immediately detected and immediate action would be taken to stop the release. Any potential leakage from the AGI or CO_2 injection wells would only occur during the lifetime operation of the wells. Once injection ceases, the wells will be plugged and abandoned and will not pose a risk as a leakage pathway.

4.3 Leakage through Faults and Fractures

As discussed in Section 2.6.3, engineering and geologic analysis show no evidence of faulting or structuring around the AGI wells. As a result, the risk of leakage through this pathway is highly improbable. The absence of faulting also tends to suggest that natural fracturing or permeability enhancement in the Madison Formation is also highly improbable. Natural fracturing along with systems of large connected pores (karsts and vugs) could occur in the Bighorn-Gallatin Formation. However, because those enhanced permability areas would be limited to the Bighorn-Gallatin Formation and would not be extended to the sealing formations above, the risk of leakage through this pathway is also highly improbable.

Current-day regional scale thrust faulting has not been observed in the LaBarge area since the field has been under development. There is no concern of reactivation of these thrust faults and it is hypothesized that regional structuring similar in size to the Laramide Orogeny (formation of the Rocky Mountains) would be required to generate new thrust faults of significant size to produce subsurface structures of the scale and magnitude of the LaBarge field. The activation of the salty sediments (which exist below the Nugget Formation and above the Madison Formation at LaBarge) is a phenomenon that was only observed to damage thin-wall cased wells, with thick-wall cased wells having sufficient strength to prevent flowage of these salt sediments. It is believed that weakness in the casing of thin-wall cased wells contributes to the ability of the salty sediments to flow local to the wellbore, shearing casing, as this is a point of weakness in the structural integrity of the wellbore at this depth. Once thick-walled casing was introduced, failures have decreased or have been eliminated.

It has been documented that natural fracturing of reservoirs in the subsurface of LaBarge and surrounding areas are directly correlative to distance to thrust faults in the area. This correlation has been documented in subsurface wellbore image logs and also by surface geological mapping around the thrust faults in the LaBarge area. It therefore follows that a lack of faulting, as observed on 2D seismic panels around and through the AGI and CO_2 injection well sites, will yield formations void of natural fracturing, and the necessary faults are not present to generate pervasive natural fractures. The lack of significant natural fracturing in the Madison Formation at and around the AGI well sites, in conjunction with active inspection of wellbore image logs within the AGI wells themselves, indicates that natural fractures do not exist, that all flow in the Madison 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. It should be noted that the permeability of the Madison 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. Likewise, the low expected connected permeability of the Bighorn-Gallatin has minimal capability to freely flow fluids through its only pore system. Accordingly, there is little potential for lateral migration of the injection fluids.

Prior to drilling the AGI wells, ExxonMobil worked with multiple service companies who provided a range of fracture gradients for the Phosphoria, Weber/Amsden, Morgan, and Madison formations in the area. Based on a frac gradient of 0.85 pounds per square inch (psi)/foot for the Madison, 0.82 psi/foot for the Morgan, 0.80 psi/foot for the Weber/Amsden, and 0.775 psi/foot for the Phosphoria, and a downhole fracture pressure of 12,167 psi, which corresponds to a surface injection pressure of ~5,500 psi, the injected acid gas will not initiate fractures in the confining zones of overlying strata. Facility limits exist that limit surface pressures to below 3,200 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture is unlikely.

Fracture gradient and overburden for the SC 5-2 well were estimated on the basis of offset well data. Offset well pressure integrity test (PIT) data from existing wells was analyzed and resulted in an overburden of 18,883 psi and a fracture gradient of 0.88 psi/foot (15,203 psi) at the top of the Madison Formation (~17,232 feet MD / -10,541 feet Total Vertical Depth subsea (TVDss)) and overburden of 20,388 psi and a fracture gradient of 0.885 psi/foot at the top of the Bighorn-Gallatin Formation (~18,531 feet MD / -11,840 feet TVDss). The fracture pressure at the top of

the Madison Formation is estimated at approximately 15,203 psi which corresponds to a fracture pressure at the surface of 7,685 psi. The projected facility average and maximum surface pressures are 3,430 psi and 6,170 psi, respectively. Both are below the pressure required to fracture the formation; therefore, the probability of fracture is unlikely.

Fracture gradient and overburden for the SC 7-34 well were also estimated on the basis of offset well data. Overburden estimates for the subject formations are based on offset well density logs. Expected formation integrity is primarily based on offset well pressure integrity (PIT) data. Because offset PITs did not result in leakoff, fracture gradient is assumed to be above test pressures. Therefore, the lowest possible fracture gradient constrained by the PITs has a vertical effective stress ratio of 0.55. An analysis of published regional data suggests a vertical effective stress ratio of 0.67 is more likely. Fracture gradient constraints were generalized with an effective horizontal to vertical effective stress ratio of 0.67 to be extrapolated to the target formation. These analyses result in an overburden of 18,705 psi and fracture gradient of 0.90 psi/foot (15,034 psi) at the top of the Madison Formation (approximately 16,744 feet MD / -10,055 feet TVDss) and overburden of 19,934 psi and fracture gradient of 0.90 psi/foot (16,017 psi) at the estimated top of the Bighorn-Gallatin Formation (approximately 17,815 feet MD / -11,126 feet TVDss).

Likelihood
Based on results of the the site characterization including the lack of faulting or open fractures in the injection intervals and the operational limitations on injections pressures, CO_2 leakage to the surface via faults or fractures is highly unlikely.

Magnitude
Given the lack of faulting and fracturing discussed above, leakage through small undetected faults or fractures (if presented and not yet observed) would be contained by the overlying high-quality sealing formations, discussed in more detail in Section 4.4 below, resulting in no CO_2 leakage to surface.

Timing
If a CO_2 leak were to occur through the confining zone due to faults or fractures, it would most likely occur during active injection. Limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. However, if diffusion through the confining zone were to occur, other CO_2 trapping mechanisms such as mineralization and solution in existing formation waters would reduce the magnitude and timing of emission to the surface.

4.4 Leakage through the Formation Seal

Leakage through the seal of the Madison Formation is highly improbable. An ultimate top seal to the disposal reservoir is provided by the evaporitic sequences within the Thaynes Formation. In fact, the natural seal is the reason the LaBarge gas field exists in the first place – the gas has been trapped in the LaBarge structure over a large amount of geologic time. The rock that forms the natural seal is impermeable to Helium (He), a gas with a much smaller molecular volume than CO_2. If the reservoir seal material is impermeable to He, then it follows that it is also impermeable to CO_2. The Thaynes Formation's sealing effect is also demonstrated by the fact that all gas

production shallower than the Thaynes is void of sour gas, while all gas production below it is enriched in sour gases. Formation Inclusion Volatile (FIV) analysis of rock cuttings documents the lack of CO_2 present throughout and above the Triassic regional seals (Ankareh, Thaynes, Woodside, and Dinwoody formations, Figure 2.2) from wells within the LaBarge gas field producing area as well as the AGI injection area.

Although natural creep of the salty sediments below the Nugget Formation is possible, this behavior does not disturb the sediments to the degree necessary to breach the reservoir seal of the Madison Formation. If this salty sediment were to flow on a scale large enough to create a leakage pathway from the Madison Formation to the surface, the natural gases trapped in the formation would have leaked into the atmosphere during the long course of geological time up to this point. The fact that gas remains trapped at pressure in the Madison Formation, it must follow that any natural reactivation or movement of salt-rich sediments that has occurred over the geological history of the LaBarge field area has not created any pathways for gas leakage to the surface.

Wells are monitored to ensure that the injected gases stay sequestered. Any escaped acid gas from the AGI wells will be associated with H_2S, which has the potential to harm field operators. The CO_2 injection wellheads will be monitored with local CO_2 gas heads, which detect low levels of CO_2. The CO_2 injected cannot escape without immediate detection, as expanded upon in the below sections.

Likelihood

Based on results of the the site characterization including the sealing capacity of confining intervals and Triassic evaporitic sequences and the operational limitations on injections pressures, CO_2 leakage to the surface via faults or fractures is highly unlikely.

Magnitude

Given the number, thickness, and quality of the confining units above the Madison and Bighorn-Gallatin injection intervals, as illustrated in Figure 2.2, any potential CO_2 leakage to the surface would be negligible and detected by surface monitoring systems at the injection site. Although highly unlikely, any CO2 leakage would likely occur near the injection well, which is where reservoir pressure is highest as a result of injection.

Timing

If a CO_2 leak were to occur through the multiple formation seals, it would most likely occur during active injection. Limitations on injection pressure are established to prevent a breach of the confining zone due to the injection activity. However, if diffusion through the confining zone were to occur, other CO_2 trapping mechanisms such as mineralization and solution in existing formation waters would reduce the magnitude and timing of emission to the surface.

4.5 Leakage through Natural or Induced Seismicity

In the greater Moxa Arch area, there is a low level of background seismicity (Advanced National Seismic System (ANSS) Catalogue, 2018, University of Utah Seismograph Stations). Across North America, induced seismicity is sometimes hypothesized as being related to reactivation of basement-involved faults via oilfield waste fluid injection (Ellsworth 2013). There has been no

observed evidence of faulting in the Madison interval using commercially available 2D seismic data within 13.5 miles of the proposed CO_2 injection well sites. There has also been no reported seismic activity attributed to active injection operations at the AGI injection wells. The nearest induced seismic events were observed over 20 miles to the southwest of the proposed SC 7-34 well site. These are attributed to mineral mining operations, and not naturally occurring geological fault activity (USGS, Pechmann et al 1995). The closest naturally occurring seismic activity was a 1.8 magnitude earthquake in 1983 located 7.2 miles to the west at a depth of 10.1 miles according to the ANSS Catalogue and the Wyoming State Geological Survey's historic records. Significant earthquake activity is defined as >3.5 Richter scale (ANSS Catalogue 2018, University of Utah Seismograph Stations). The nearest recorded significant naturally occurring earthquake activity (> M3.5) has been detected over 50 miles away to the west in Idaho and Utah. 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.

Additional geomechanical modeling has been completed in the area around the AGI and CO_2 injection well sites. The modeling was completed to understand the potential for fault slip on the Darby fault far west of the injection and disposal sites. No fault slip is observed at the simulated fault locations or throughout the model. Lack of fault slip then equates to lack of modeled induced seismity from injection.

<u>Likelihood</u>
Due to the lack of significant earthquake activity in the area, the lack of induced seismicity over the period of injection at the AGI wells, and the geomechanical modeling results showing a lack of fault slip, ExxonMobil considers the likelihood of CO_2 leakage to surface caused by natural or induced seismicity to be unlikely.

<u>Magnitude</u>
If a seismic event occurs at the time of AGI or CO_2 injection, ExxonMobil will consult the ANSS Catalogue to verify whether the seismic event was due to the injection in the AGI or CO_2 injection wells and quantify any leak of CO_2 to the surface.

<u>Timing</u>
If a leak of CO_2 to the surface occurs as a result of a seismic event, it would likely occur at the time of the seismic event or shortly thereafter.

5.0 Detection, Verification, and Quantification of Leakage

5.1 Leakage Detection

As part of ongoing operations, SCTF continuously monitors and collects flow, pressure, temperature, and gas composition data in the Distributed Control System (DCS). This data is monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. Additionally, SCTF maintains in-field gas detectors to detect H_2S and CO_2 in the vicinity. If one of the gas detectors

alarmed, it would trigger an immediate response to address the situation. In some instances, more than one detector alarming will trigger automatic equipment isolation/shutdown to mitigate the leak.

Leakage detection for the wells will incorporate several monitoring programs including visual inspection of the surface facilities and wellheads, injection well monitoring and MIT, and DCS surveillance. Table 5.1 provides general information on the potential leakage pathways, monitoring programs to detect leakage, and location of monitoring. Monitoring will occur for the duration of injection. As will be discussed in Section 7.0 below, ExxonMobil will quantify equipment leaks by using a risk-driven approach and continuous surveillance.

Table 5.1 - Monitoring Programs

Potential Leakage Pathway	**Detection Monitoring Program**	**Monitoring Location**
Surface Equipment	DCS Surveillance Visual Inspections Inline Inspections Gas Alarms Personal H_2S Monitors	From injection flow meter to injection wellhead
Wells	DCS Surveillance Visual Inspections MIT Gas Alarms Personal H_2S Monitors	Injection well – from wellhead to injection formation
Faults and Fractures, Formation Seal, Lateral Migration	DCS Surveillance Gas Alarms	Injection well – from wellhead to injection formation
Natural or Induced Seismicity	DCS Surveillance Gas Alarms ANSS Catalogue	Injection well – from wellhead to injection formation Regional data

5.2 Leakage Verification

Responses to leaks are covered in the SCTF's Emergency Response Plan (ERP), which is updated annually. If there is a report or indication of a leak from the AGI facility from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and H_2S monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Pressure from the AGI system will be relieved to the flare, not vented, due to the dangerous composition of the gas.

The ERP will be updated to include the CO_2 injection facilities and corresponding wells after commencement of operations. If there is a report or indication of a leak from the CO_2 injection facilities from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and gas monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Once isolated from the CO_2 injection flowline, pressure from the affected CO_2 injection well will be relieved locally to atmosphere within the well site fence line.

5.3 Leakage Quantification

The leakage from surface equipment will be estimated once leakage has been detected and confirmed. As further described in Section 7.4, ExxonMobil will estimate the mass of CO_2 emitted from leakage points at the surface based on operating conditions at the time of the release – pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of leak. The annual mass of CO2 that is emitted by surface leakage will be calculated in accordance with Equation RR-10.

6.0 Determination of Baselines

ExxonMobil uses existing automatic data systems to identify and investigate excursions from expected performance that could indicate CO_2 leakage. The following describes ExxonMobil's approach to collecting baseline information.

Visual Inspections

Field personnel conduct daily inspections of the AGI facility and weekly inspections of the AGI well sites. The CO_2 injection facility and well sites will undergo weekly visual inspections. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize the possibility of CO_2 leakage. If an issue is identified, a work order will be generated to correct the issue.

H_2S Detection – AGI Wells

The CO_2 injected into the AGI wells is injected with H_2S at a concentration of 50 - 65% (500,000 - 650,000 ppm). H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. At this high of a concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm. Additionally, all field personnel are required to wear H_2S monitors for safety reasons. Personal monitors alarm at 5 ppm. Any gas detector alarm or personal H_2S monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the gas detectors and monitors are working correctly.

CO_2 Detection – CO_2 Injection Wells

The CO_2 injected into the CO_2 injection wells will be at a concentration of approximately 99%. CO_2 gas detectors will be installed around the well sites, which will trigger at 0.5% CO_2, therefore even a miniscule amount of gas leakage would trigger an alarm.

Continuous Parameter Monitoring

The DCS of the SCTF 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.

Well Testing

On an annual basis, the subsurface and wellhead valves are leak tested for mechanical integrity testing (MIT) as required by the WOGCC. Results from this type of testing are compared to previous MIT data to evaluate whether well integrity has been compromised.

Additionally, inline inspections are conducted of the AGI flow lines through the use of a smart pig to identify potential areas of corrosion in the pipeline. Results from this type of testing are compared to previous data to evaluate whether pipeline integrity has been compromised. The operations at the SCTF will have the ability to conduct inline inspections on the SC 5-2 and SC 7-34 flow lines, however inline inspections are not anticipated to occur frequently because no free water is expected to accumulate.

7.0 Site Specific Modifications to the Mass Balance Equation

To accommodate for site-specific conditions, as provided in 40 CFR 98.448, ExxonMobil proposes to modify quantifying equipment leaks by using a risk-driven approach. Due to the high H_2S concentration of the AGI fluids, monitoring poses a risk to personnel. Additionally, as mentioned above, even a small leak of this high H_2S gas would trigger an alarm. A small leak at the CO_2 injection wells would also trigger an alarm, as mentioned above. ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. This continuous surveillance using gas detectors identifies leaks better than an annual leak survey would 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 ExxonMobil will calculate the mass of CO_2 injected, emitted, and sequestered.

7.1 Mass of CO_2 Received

§98.443 states that "you must calculate the mass of CO_2 received using CO_2 received equations… unless you follow the procedures in §98.444(a)(4)." §98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." Since the CO_2 received by the AGI and CO_2 injection wells are wholly injected and not mixed with any other supply of CO_2, the annual mass of CO_2 injected would be equal to the annual mass of CO_2 received. No CO_2 is received in containers.

7.2 Mass of CO_2 Injected

Volumetric flow meters are used to measure the injection volumes at the AGI wells and are proposed for use to measure the injection volumes at the CO_2 injection wells. Equation RR-5 will be used to calculate the annual total mass of CO_2 injected.

Equation RR-6 will be used to aggregate injection data for the AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34 wells.

7.3 Mass of CO_2 Produced

The AGI and CO_2 injection wells are not part of an enhanced oil recovery process, therefore, there is no CO_2 produced and/or recycled.

7.4 Mass of CO_2 Emitted by Surface Leakage and Equipment Leaks

It is not appropriate to conduct a leak survey at the AGI or the CO_2 injection well sites due to the components being unsafe-to-monitor and extensive monitoring systems in place. Entry to the AGI wells requires the individual to don a full face respirator supplied to breathing air, which would make completion of a leak survey very difficult. Due to the high H_2S concentration of the AGI fluids and the high CO_2 concentration of the CO_2 injection fluid, fugitive leakage would be detected and managed as an upset event in the same way that CO_2E (CO_2 emitted by surface leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time, including pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of the leak. 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.

For parameter CO_2FI (total CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead), a similar approach would be taken for any equipment leakage. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time, including pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of the leak. At the AGI wells, there are no CO_2 emissions from venting due to the high H_2S concentration of the acid gas; blowdown emissions are sent to the flares and are reported under Subpart W for the SCTF. This process occurs upstream of the flow meter and would therefore not contribute to the CO_2FI calculation. At the CO_2 injection wells, venting would occur in the event of depressurizing for maintenance or testing, which would be measured during time of event consistent with 40 CFR 98.233.

7.5 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Since ExxonMobil is not actively producing oil or natural gas or any other fluids as part of the AGI process or CO_2 injection processes, Equation RR-12 will be used to quantify CO_2 injected and sequestered. Parameter CO_2I (total CO_2 injected through all injection wells) will be determined using Equation RR-5, as outlined above in Section 7.2. Parameters CO_2E and CO_2FI will be measured using the leakage quantification procedure described above in Section 7.4. CO_2 in the AGI fluids is not vented from equipment due to the high H_2S concentration.

8.0 Estimated Schedule for Implementation of Second Amended MRV Plan

The SCTF AGI facility and wells have been operational since 2005 and have been subject to the February 2018 MRV plan (approved by EPA in June 2018). Beginning with the start of injection of CO_2 and fluids into the CO_2 injection wells, this Second Amended MRV Plan will become the applicable plan for the AGI and CO_2 injection wells and will replace and supersede the February 2018 MRV plan for the AGI wells. Until that time, the February 2018 MRV plan will remain the applicable MRV plan for the AGI wells. Once the Second Amended MRV Plan becomes the applicable MRV plan, ExxonMobil will continue reporting under Subpart RR for the AGI wells, but will begin including the CO_2 injection wells on or before March 31 of the year after their respective injection begins. Once applicable, ExxonMobil anticipates this Second Amended MRV Plan will remain in effect until the end-of-field-life of the LaBarge 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, ExxonMobil has incorporated the following provisions into its QA/QC programs:

<u>CO_2 *Injected*</u>

- The injected CO_2 stream for the AGI wells will be measured upstream of the volumetric flow meter at the three AGI compressors, at which measurement of the CO_2 is representative of the CO_2 stream being injected, with a continuously-measuring online process analyzer. The flow rate is measured continuously, allowing the flow rate to be compiled quarterly.
- The injected CO_2 stream for the CO_2 injection wells will be measured with a volumetric flow meter and continuously-measuring online process analyzer upstream of the wellhead,

at which measurement of the CO_2 is representative of the CO_2 stream being injected. The flow rate will be measured continuously, allowing the flow rate to be compiled quarterly.
- The continuous composition measurements will be averaged over the quarterly period to determine the quarterly CO_2 composition of the injected stream.
- The CO_2 analyzers are calibrated according to manufacturer recommendations.

CO_2 *emissions from equipment leaks and vented emissions of* CO_2
- Gas detectors are operated continuously except as necessary for maintenance and calibration.
- Gas detectors will be operated and calibrated according to manufacturer recommendations and API standards.

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

General
- The CO_2 concentration is measured using continuously-measuring online process analyzers, which is an industry standard practice.
- All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 Missing Data Procedures

In the event ExxonMobil 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 CO_2 injected is missing, it will be estimated using a representative quantity of CO_2 injected from the nearest previous time period at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in 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, ExxonMobil will revise and submit another amended MRV plan within 180 days to the Administrator for approval.

10.0 Records Retention

ExxonMobil will follow the record retention requirements of 98.3(g). Additionally, it will retain the following records from the AGI and CO_2 injection well sites for at least three years:

- Quarterly records of injected CO_2 for the AGI wells including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO_2 for the CO_2 injection wells 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 CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Request for Additional Information: Shute Creek Facility
December 10, 2024

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	5.3	44	In the previous RFAI, we asked that you please elaborate on the types of quantification methods that may be implemented by the facility and how they correspond to each of the identified potential surface leakage pathways. While additional information regarding quantification was added, please provide example quantification strategies that could be applied to the different types of surface leakage pathways described. For example, what methods might be considered for leakage through well bores vs. leakage through faults or seismicity?	Additional information regarding quantification strategies for the potential leakage pathways have been added to Section 5.3 (pages 44-45).
2.	7.4	46-47	"For parameter CO_2FI (total CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead), a similar approach would be taken for any equipment leakage. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time, including pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of the leak." Leakage from surface equipment must be calculated according to 40 CFR 98.444(d). Please review 40 CFR 98.443(f)(2) and 40 CFR 98.444(d) and revise the above statement above as necessary to reflect these requirements.	Statement in Section 7.4 has been revised to reflect the requirements outlined by EPA (page 48).

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
6.	4	N/A	40 CFR 98.448(a)(2) requires that the MRV plan contain a characterization of "the likelihood, magnitude, and timing, of surface leakage of CO2" through the identified leakage pathways. In addition to listing the possible leakage pathways and their monitoring strategies, please ensure each surface leakage pathway contains a clear characterization of the likelihood, magnitude, and timing of potential leakage.	Additional information added in Sections 4.1 – 4.4 regarding likelihood, magnitude, and timing of potential leakage through the possible leakage pathways (pages 36 – 41).
7.	4	N/A	The MRV plan does not consider potential leakage through natural or induced seismicity. In the MRV plan, please clarify whether these were evaluated as potential leakage pathways and add information about these pathways as necessary. The discussion of the monitoring methods being utilized should also be updated as appropriate.	Added Section 4.5 regarding potential leakage through natural or induced seismicity (pages 41 – 42). Added Natural or Induced Seismicity to Table 5.1 – Monitoring Programs (page 43).
8.	4.2	35	"Examination of the plugging and abandonment records and the wellbore diagram constructed from those records indicates that the well does not pose a risk as a leakage pathway" While leakage from wellbores may not be likely, it is not impossible. Please revise this and other statements in the MRV plan that state there is no leakage risk.	Revised statements in the MRV plan as requested (page 37).
9.	5.1	41	Table 5.1 states that leakage from faults and fractures, formation seal, and lateral migration are "highly improbable", which implies that there is a nonzero risk of leakage from these pathways. Please include a discussion of how leakage through these identified pathways may be monitored or detected.	Table 5.1 revised (page 43). Additional information added in Sections 4.1 – 4.5 regarding how potential leakage through these identified pathways may be detected (pages 36 – 42).

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
10.	5.3	42	Please elaborate on the types of quantification methods that may be implemented by this facility and how they correspond to each of the identified potential leakage pathways.	Additional information added in Sections 4.1 – 4.5 regarding how potential leakage through these identified pathways may be detected (pages 36 – 42). Additional information regarding quantification of potential leakage is further addressed in Section 7.4 of the plan (pages 46 – 47).
11.	7.4	43	"ExxonMobil will estimate the mass of CO_2 emitted from leakage points from the flow meter to the injection wellhead based on operating conditions at the time of the release – pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of leak. At the AGI wells, there are no CO_2 emissions from venting due to the high H_2S concentration of the acid gas; blowdown emissions are sent to the flares and are reported under Subpart W for the SCTF." Please note that emissions from "surface leakage" and emissions from "equipment and vented emissions" are represented by separate terms in equation RR-12. Subpart RR requires that CO2fl be calculated according to procedures in subpart W. Please also note that data reported under subpart W are not duplicative with leakage/emissions used in subpart RR. Emissions reported under subpart RR are used in calculating a net sequestration amount and are not added to a facility's total emissions. Please review 40 CFR 98.443 and 40 CFR 98.444(d) and revise the above statement above as necessary to reflect this.	Given the high concentrations of H2S and CO2 in the respective injection streams, ExxonMobil identifies leaks through continuous surveillance and alarms. Any leakage, whether at the surface of the injection well site or from equipment, would be immediately identified and treated as an upset event. The volume of CO2 released would be quantified based on the operating conditions at the time of release, as stated in Section 7.4 in accordance with 40 CFR 98.448(5). Additional language added to clarify calculation methodology for vented emissions (pages 46 – 47).

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
12.	Multiple	Multiple	"The acid gas and CO2 injected into the AGI wells are components of the natural gas produced by ExxonMobil from the Madison Formation." (p. 3) "The AGI and CO2 injection wells are not part of an enhanced oil recovery process, therefore, there is no CO2 produced and/or recycled." (p. 44) The MRV plan explains that this facility is injecting CO2 and Acid Gas into the same formation from which it was produced. Where applicable, please elaborate the discussion or explanation for why produced CO2 would not need to be measured for this project. E.g., would it be possible that any injected CO2 reaches the producing wells? A figure showing the distance between the injection wells/plumes and production wells would be helpful. Relatedly, we recommend reviewing figure 2.3 and/or its scale bar for accuracy, as the producing wellfield appears to be within just a few miles of the nearest CO2 injection well.	Figure 2.3 has been updated to better reflect the location of the producing wellfield relative to the injection wells (page 8). The acid gas and CO2 are components of the natural gas produced by ExxonMobil from the Madison Formation. While the acid gas and CO2 are injected back into the same formation from which it was produced, the reinjection occurs in the aquifer below the gas/water contact (GWC) as demonstrated in Figure 2.7 (page 16). The text has been updated throughout the document to reiterate injection into the aquifer below the GWC. As illustrated in Section 3.2, simulation models demonstrate CO2 injection below the GWC of the producing LaBarge gas field. Injecting into the aquifer below the GWC will provide no pressure support or CO2 contamination of the producing well field given both the distance from injection sites to producing locations and the reservoir quality of the Madison and Bighorn-Gallatin injection zones (pages 30 – 35).

ExxonMobil Shute Creek Treating Facility Subpart RR Second Amended Monitoring, Reporting and Verification Plan

August 2024

Table of Contents

Introduction

Exxon Mobil Corporation (ExxonMobil) operates two acid gas injection (AGI) wells, AGI 2-18 and AGI 3-14 (collectively referred to as "the AGI wells") in the Madison Formation located near LaBarge, Wyoming for the primary purpose of acid gas disposal with a secondary purpose of geologic sequestration of carbon dioxide (CO_2) in a subsurface geologic formation. The acid gas and CO_2 injected into the AGI wells are components of the natural gas produced by ExxonMobil from the Madison Formation. ExxonMobil has been operating the AGI wells since 2005 and intends to continue injection until the end-of-field-life of the LaBarge assets. The AGI wells and facility (as further described in Section 2.7.1), located at the Shute Creek Treating Facility (SCTF), have been operational since 2005 and have been subject to the February 2018 monitoring, reporting, and verification (MRV) plan approved by EPA in June 2018 (the February 2018 MRV plan).

Because the volume of CO_2 associated with the natural gas production is greater than the volume that is able to be injected into the AGI wells, ExxonMobil is in the process of developing the Shute Creek (SC) 5-2 and SC 7-34 wells (collectively referred to as the "CO_2 injection wells" or "CO_2 disposal wells")[1] for the purpose of geologic sequestration of fluids consisting primarily of CO_2 in subsurface geologic formations. Like the AGI wells, the fluids that will be injected into the CO_2 injection wells are also components of the natural gas produced by ExxonMobil from the Madison Formation. Once operational, the CO_2 injection wells are expected to continue injection until the end-of-field life of the LaBarge assets.

ExxonMobil received the following approvals by the Wyoming Oil and Gas Conservation Commission (WOGCC) to develop the SC 5-2 well:

- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Madison Formation on November 12, 2019
- Aquifer exemption and conditional approval to dispose of fluids consisting primarily of CO_2 into the Phosphoria, Weber, and Bighorn-Gallatin formations[2] on October 12, 2021
- Application for permit to drill (APD) on June 30, 2022

ExxonMobil has filed an additional application with the WOGCC to develop the SC 7-34 well to dispose of fluids consisting primarily of CO_2 into the Madison and Bighorn-Gallatin formations. A hearing on the application was held on March 11, 2024 by the WOGCC and ExxonMobil is awaiting issuance of the aquifer exemption and conditional approval. ExxonMobil received approval by WOGCC for an APD for the SC 7-34 well on May 20, 2024.

In October 2019, ExxonMobil submitted an amendment to the February 2018 MRV plan in accordance with 40 CFR §98.440-449 (Subpart RR – Geologic Sequestration of Carbon Dioxide) to provide for the monitoring, reporting and verification of geologic sequestration of CO_2 in the Madison Formation during the injection period for the SC 5-2 well (the October 2019 MRV plan). The October 2019 Amended MRV plan was approved by EPA on December 19, 2019.

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[1] *The terms"dispose" and "inject" and their variations may be used interchangeably throughout this document.*

[2] *While the Phosphoria and Weber formations were conditionally approved as exempted aquifers for disposal of fluids, these formations are no longer targets for the SC 5-2 and will not be addressed further in this document*

This second amended plan, dated August 2024 (“Second Amended MRV Plan”) will address all wells collectively when applicable, and otherwise broken out into sub sections to address the specifics of the AGI wells and CO_2 injection wells respectively, as appropriate. This Second Amended MRV Plan meets the requirements of 40 CFR §98.440(c)(1).

The February 2018 MRV plan is the currently applicable MRV plan for the AGI wells. The October 2019 Amended MRV plan would have become the applicable plan once the SC 5-2 well began injection operations. ExxonMobil anticipates the SC 5-2 well will begin injection operations in 2025 and the SC 7-34 well will begin injection operations in 2026. At that time, this Second Amended MRV Plan will become the applicable plan for the AGI wells and CO_2 injection wells collectively, and will replace and supersede both the February 2018 and October 2019 Amended MRV plans. At that time, ExxonMobil will continue reporting under Subpart RR for the AGI wells, but will begin including the CO_2 injection wells on or before March 31 of the year after their respective injection begins. Once applicable, ExxonMobil anticipates this Second Amended MRV Plan will remain in effect until the end-of-field-life of the LaBarge assets, unless and until it is subsequently amended and superseded.

This Second Amended MRV Plan contains ten sections:

1. Section 1 contains facility information.

2. Section 2 contains the project description. This section describes the geology of the LaBarge Field, the history of the LaBarge field, an overview of the injection program and process, and provides the planned injection volumes. This section also demonstrates the suitability for secure geologic storage in the Madison and Bighorn-Gallatin formations.

3. Section 3 contains the delineation of the monitoring areas.

4. Section 4 evaluates the potential leakage pathways and demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

5. Section 5 provides information on the detection, verification, and quantification of leakage. Leakage detection incorporates several monitoring programs including routine visual inspections, hydrogen sulfide (H_2S) and CO_2 alarms, mechanical integrity testing of the well sites, and continuous surveillance of various parameters. Detection efforts will be focused towards managing potential leaks through the injection wells and surface equipment due to the improbability of leaks through the seal or faults and fractures.

6. Section 6 describes the determination of expected baselines to identify excursions from expected performance that could indicate CO_2 leakage.

7. Section 7 provides the site specific modifications to the mass balance equation and the methodology for calculating volumes of CO_2 sequestered.

8. Section 8 provides the estimated schedule for implementation of the Second Amended MRV Plan.

9. Section 9 describes the quality assurance program.

10. Section 10 describes the records retention process.

1.0 Facility Information

1. Reporter number: 523107
   The AGI wells currently do, and the CO_2 injection wells will, report under the Shute Creek Treating Facility (SCTF) Greenhouse Gas Reporting Program Identification number, which is: 523107.
2. Underground Injection Control (UIC) Permit Class: Class II
   The WOGCC regulates oil and gas activities in Wyoming. WOGCC classifies the AGI and SC 5-2 wells in LaBarge as UIC Class II wells. ExxonMobil anticipates that the SC 7-34 well will also classify as a UIC Class II well.
3. UIC injection well identification numbers:

Well Name	*Well Identification Number*
AGI 2-18	49-023-21687
AGI 3-14	49-023-21674
SC 5-2	49-023-22499
SC 7-34	49-023-22500

2.0 Project Description

This section describes the planned injection volumes, environmental setting of the LaBarge Field, injection process, and reservoir modeling.

2.1 Geology of the LaBarge Field

The LaBarge field area is located in the southwestern corner of Wyoming, contained in Lincoln and Sublette counties. The producing field area is within the Green River Basin and the field is located due west of the Wind River Mountains along the Moxa Arch (Figure 2.1).

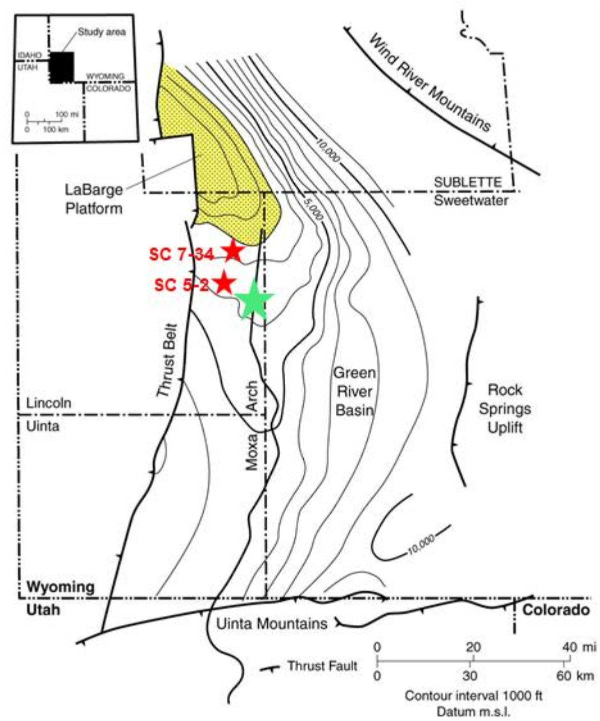

Figure 2.1 Location Map of the LaBarge Field, Wyoming. The location of the AGI wells is denoted with a green star, and the location of the CO_2 injection wells are denoted by the red stars.

2.2 Stratigraphy of the Greater LaBarge Field Area

The western region of Wyoming has been endowed in a very rich and prolific series of hydrocarbon reservoirs. Hydrocarbon production has been established or proven from a large number of stratigraphic intervals around Wyoming, ranging from reservoirs from Cenozoic to Paleozoic in age. Figure 2.2 shows a complete stratigraphic column applicable to the Greater Green River Basin in western Wyoming.

For the LaBarge field area, specifically, commercially producible quantities of hydrocarbons have been proven in the following intervals:

1. Upper Cretaceous Frontier Formation
2. Lower Cretaceous Muddy Formation
3. Permian Phosphoria Formation
4. Lower Jurassic Nugget Formation
5. Pennsylvanian Weber Formation
6. Mississippian Madison Formation

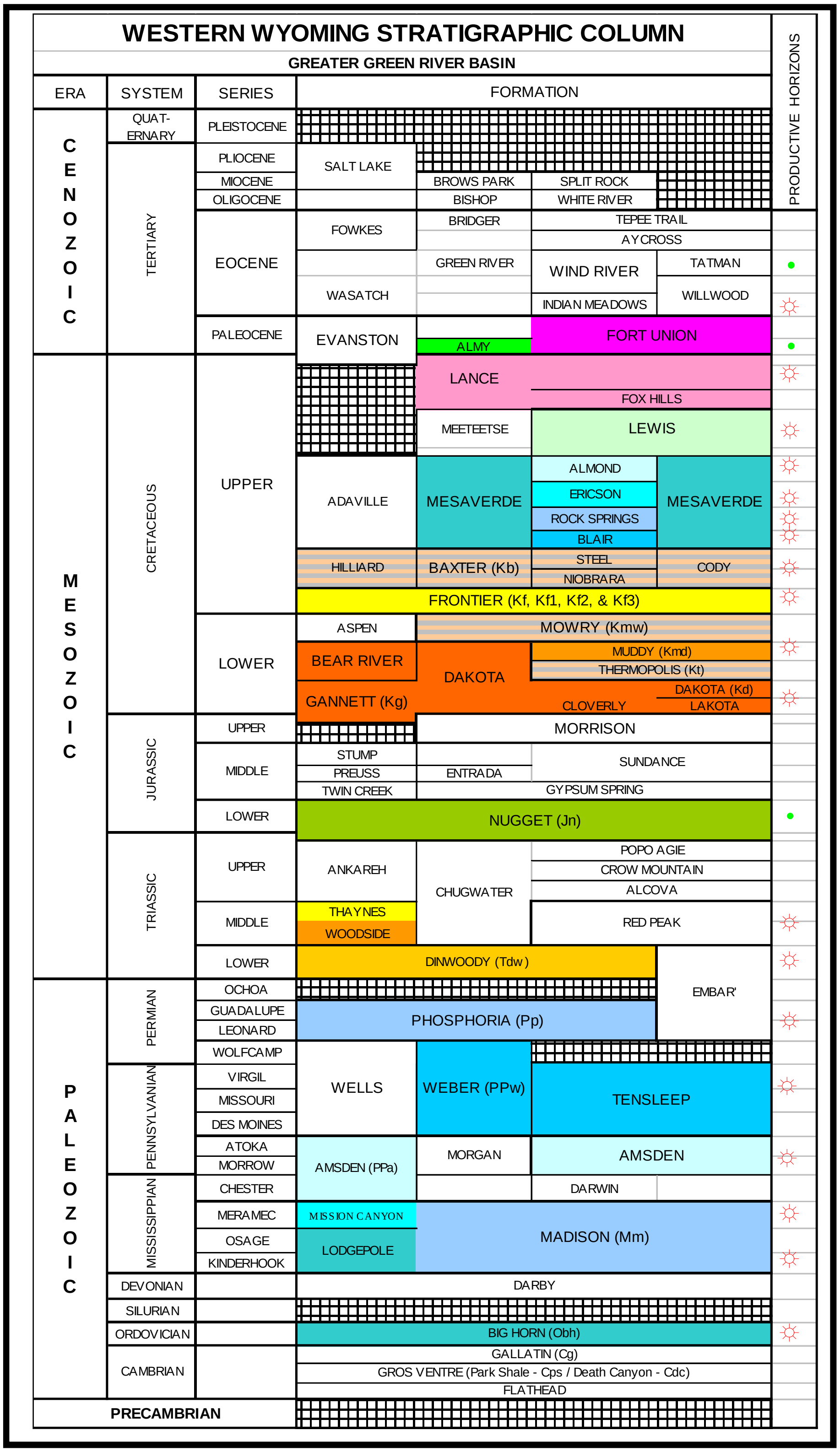

Figure 2.2 Generalized Stratigraphic Column for the Greater Green River Basin, Wyoming

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 closure to 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 (Figure 2.3).

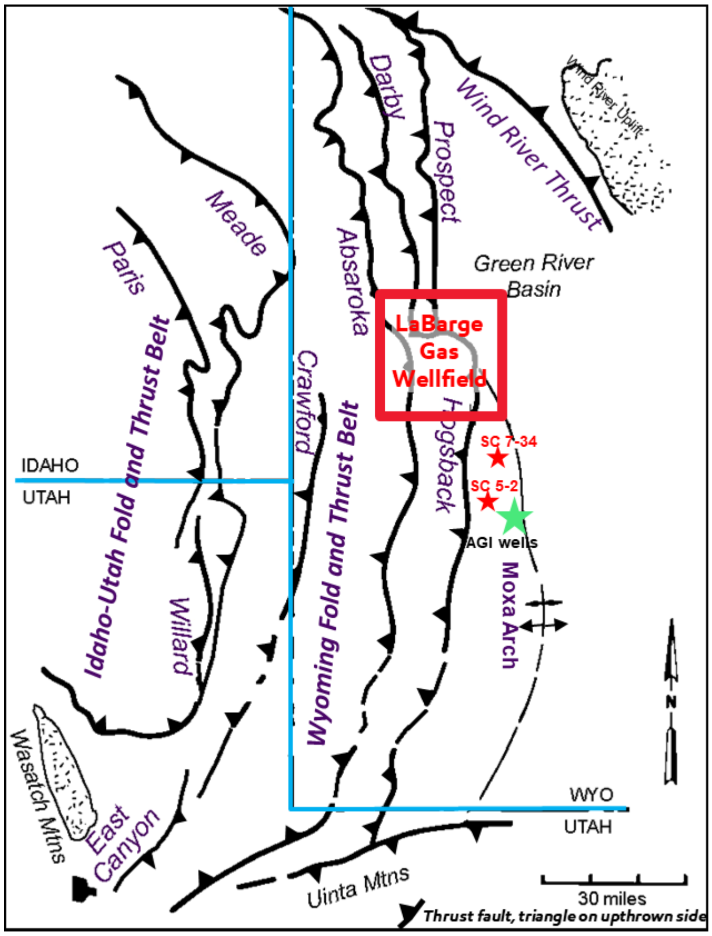

Figure 2.3 Schematic map showing location of Moxa Arch and regional thrust faults. The LaBarge field area is denoted by the red box. The approximate location of the AGI wells is denoted with a green star, and the approximate location of the CO_2 injection wells are denoted by the red stars.

The historical evaluation of structural styles at LaBarge has revealed that three principal styles of structuring have occurred in the area:

1. Basement-involved contraction
2. Deformation related to flowage of salt-rich Triassic strata
3. Basement-detached contraction

2.3.1 Basement-involved Contraction Events

Basement-involved contraction has been observed to most commonly result in thrust-cored monoclinal features being formed along the western edge of the LaBarge field area (Figure 2.3). These regional monoclinal features have been imaged extensively with 2D and 3D seismic data, and are easily recognizable on these data sets (Figure 2.4). At a smaller scale, the monoclinal features set up the LaBarge field structure, creating a hydrocarbon trapping configuration of the various reservoirs contained in the LaBarge productive section.

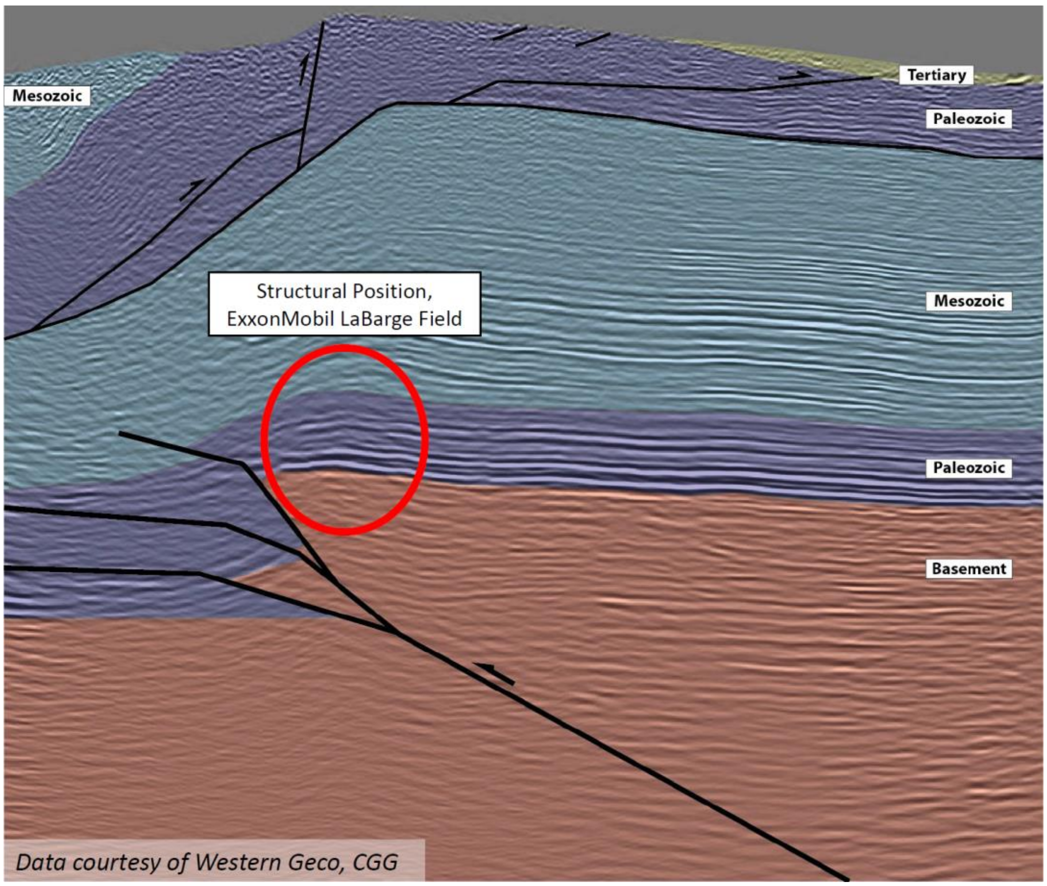

Figure 2.4 Example of thrust-cored monoclinal feature interpreted from 2D seismic data. The thrust-cored feature is believed to be a direct product of basement-involved contractional events.

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 outcrop 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 2.5 shows two seismic lines showing the Triassic salt-rich sediments and the 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.

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 many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. Subsequent drilling at LaBarge has used thicker-walled casing strings to successfully mitigate this sediment flowage issue.

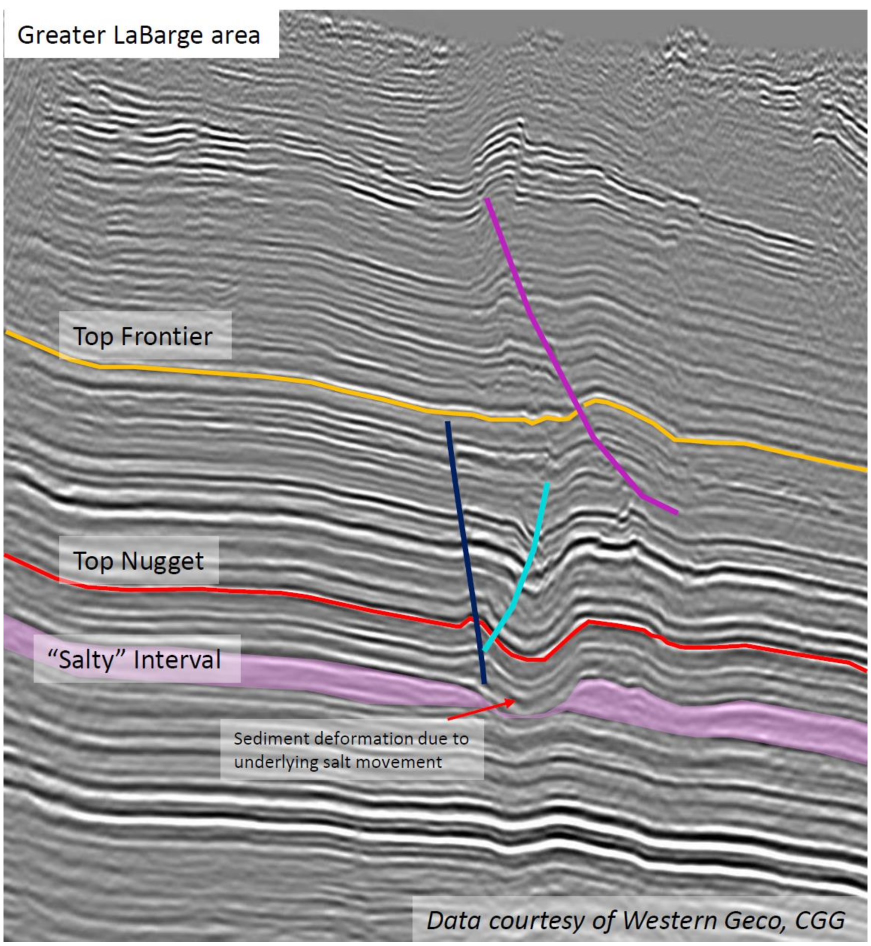

Figure 2.5 Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge field area

2.3.3 Basement-detached Contraction

The third main structural style observed at LaBarge field is those resultant from basement-detached contraction. These features have been well-documented, historically at LaBarge as many of these features have mapped fault expressions on the surface. Detachment and contraction along the basement typically creates three types of structural features:

1. Regional scale thrust faults
2. Localized, smaller scale thrust faults
3. Reactivation of Triassic salt-rich sediments resulting in local structural highs (section 2.3.2)

The basement-detached contraction features typically occur at a regional scale. The subsurface structural features formed through these contractional events are the same size or larger than the greater LaBarge field area. Very large faults are usually associated with these subsurface features, albeit via the reactivation of Triassic salt sediments which can result in additional localized structuring in the area (section 2.3.2).

2.3.4 Faulting and Fracturing of Reservoir Intervals

Reservoir permeability has been observed to increase with the presence of small-scale faults and fractures in almost all of the productive intervals of LaBarge field. Micro-fractures have been observed in core and on formation micro imager (FMI) logs. The fractures seen in the available core are typically filled with calcite, in general.

Empirically, reservoir permeability and increased hydrocarbon productivity have been observed in wells/penetrations that are correlative to areas located on or near structural highs or fault junctions. These empirical observations tend to suggest that these areas have a much higher natural fracture density than other areas or have a larger proportion of natural fractures that are open and not calcite filled. Lack of faulting, as is observed near areas adjacent to the AGI, SC 5-2, and SC 7-34 wells at LaBarge, tends to yield reservoir permeability that is dominated only by matrix or pore-to-pore flow that is generally inhibitive to fluid flow in the subsurface over long distances.

2.3.5 LaBarge Field Structure and Gas Resource of the Madison Formation

Structural closure on the Madison Formation at the LaBarge field is quite large, with approximately 4,000' true vertical depth (TVD) of structural closure from the top of the structure to the gas-water contact (GWC). Spatially, the Madison closure covers over 1,000 square miles making it one of the largest gas fields in North America.

The Madison Formation is estimated to contain in excess of 170 trillion cubic feet (TCF) of raw gas and 20 TCF of natural gas (CH_4). At current rates of production, the estimated remaining field life is over 100 years. Spatially, the AGI and CO_2 injection wells have been located at or immediately adjacent to the SCTF, over 40 miles to the southeast from the main LaBarge production areas.

2.4 History of the LaBarge Field Area

The LaBarge field was initially discovered in 1920 with the drilling of a shallow oil producing well. The generalized history of the LaBarge field area is as follows:

- 1907 Oil seeps observed near LaBarge, surface mapping of Tip Top anticline
- 1920 Texas Production Company drills shallow Hilliard sandstone discovery (10 BOPD)
- 1940's General Petroleum (G.P.) (Mobil) explores LaBarge area, surface and seismic mapping
- 1951 Tip Top Field discovered by G.P. (Frontier SS @ 1.8 MCFD, Nugget SS @ 266 BOPD)
- 1952 Belco discovers Frontier gas at Big Piney and LaBarge
- 1954 Belco commits gas to Pacific NW Pipeline, 33 SI gas wells
- 1956 Pacific NW Pipeline completed
- 1956-64 Active drilling of Frontier wells (structural traps)
- 1962 Mobil discovers Madison LS gas at Tip Top, chooses not to develop
- 1970 Exxon evaluates LaBarge area
- 1975-84 2nd major phase of Frontier drilling (stratigraphic traps)
- 1980 Section 29 of Oil Windfall Tax Act for tight gas sands passed (expired 01/01/94)
- 1981 Exxon discovers Madison gas on Lake Ridge Unit (LRU 1-03)
- 1986 First sales of Exxon Madison gas
- 1992 WOGCC approves 160 acre spacing for Frontier
- 1989-95 Chevron, Enron, PG & E, and Mobil actively drill Frontier targets
- 1999 Exxon and Mobil merge
- 2001-03 Active drilling of Acid Gas Injection wells 2-18 and 3-14
- 2005 Acid Gas Injection wells 2-18 and 3-14 begin operation
- 2019 WOGCC approves SC 5-2 CO_2 injection well
- 2022 Transfer of ownership of shallow horizons on TipTop and Hogsback
- 2023 Active drilling of SC 5-2 CO_2 injection well
- 2024 WOGCC aquifer exemption hearing for the SC 7-34 CO_2 injection well

Historically, Exxon held and operated the Lake Ridge and Fogarty Creek areas of the field, while Mobil operated the Tip Top and Hogsback field areas (Figure 2.6). The heritage operating areas were combined in 1999, with the merger of Exxon and Mobil to form ExxonMobil, into the greater LaBarge operating area. In general, heritage Mobil operations were focused upon shallow sweet gas development drilling while heritage Exxon operations focused upon deeper sour gas production.

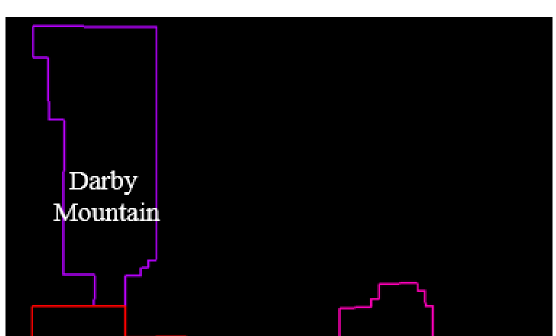

Figure 2.6 Historical unit map of the greater LaBarge field area prior to Exxon and Mobil merger in 1999

2.5 Initial Discovery of Gas and Early Commercial Production at LaBarge

ExxonMobil's involvement in LaBarge originates in the 1960's with Mobil's discovery of gas in the Madison Formation. The Madison discovery, however, was not commercially developed until much later in the 1980's following Exxon's Madison gas discovery on the Lake Ridge Unit. Subsequently, initial commercial gas production at LaBarge was first established in the Frontier Formation, while commercial oil production was established in the Nugget Formation.

Gas production from the Madison Formation was initiated in 1986 after the start-up of the SCTF, which expanded capacity to handle Madison gas. The total gas in-place for the Madison Formation at LaBarge is in excess of 170 TCF gross gas and is a world-class gas reserve economically attractive for production.

2.6 Gas Injection Program History at LaBarge

The Madison Formation, once commercial production of gas was established, was found to contain relatively low methane (CH_4) concentration and high carbon dioxide (CO_2) content. The average properties of Madison gas are:

1. 21% CH_4
2. 66% CO_2
3. 7% nitrogen (N_2)
4. 5% hydrogen sulfide (H_2S)
5. 0.6% helium (He)

Due to the abnormally high CO_2 and H_2S content of Madison gas, the CH_4 was stripped from the raw gas stream leaving a very large need for disposal of the CO_2 and H_2S that remained. For enhanced oil recovery (EOR) projects, CO_2 volumes have historically been sold from LaBarge to offset oil operators operating EOR oilfield projects. Originally, the SCTF contained a sulfur recovery unit (SRU) process to transform the H_2S in the gas stream to elemental sulfur. In 2005, the SRU's were decommissioned to debottleneck the plant and improve plant reliability. This created a need to establish reinjection of the H_2S, and entrained CO_2, to the subsurface.

2.6.1 Geological Overview of Acid Gas Injection and CO_2 Injection Programs

Sour gas of up to 66% CO_2 and 5% H_2S is currently produced from the Madison Formation at LaBarge. The majority of produced CO_2 is currently being sold by ExxonMobil to other oilfield operators and is being used in EOR projects in the region. The sold volume however, does not equal the total produced CO_2 and H_2S volumes, thereby requiring disposal.

ExxonMobil has pursued the AGI program as a safe and reliable method to re-inject the acid gas into the Madison Formation below the field GWC. Gas composition in the AGI wells is based on plant injection needs, and will vary between 35 - 50% CO_2 and 50 - 65% H_2S. The acid gas is injected at a depth of ~17,500 feet below the surface and approximately 43 miles away from the main producing areas of LaBarge.

The volume of CO_2 sold and CO_2 injected into the AGI wells does not equal the volume of CO_2 produced, so additional injection wells are required (SC 5-2 and SC 7-34). Gas composition to be injected into the CO_2 injection wells is planned to be approximately 99% CO_2 with minor amounts of methane, nitrogen, carbonyl sulfide (COS), ethane, and H_2S. For the SC 5-2 well, the gas is planned to be injected between depths of ~17,950 feet and ~19,200 feet measured depth (MD) approximately 35 miles away from the main producing areas of LaBarge. For the SC 7-34 well, the gas is planned to be injected between depths of ~16,740 feet and ~18,230 feet MD approximately 30 miles away from the main producing areas of LaBarge.

2.6.2 Reservoir Quality of Madison and Bighorn-Gallatin Formations at Injection Well Locations

The existing AGI wells were successfully drilled, logged, and evaluated prior to injection commencement. Figure 2.7 is a schematic diagram showing the relative location of AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34. Figures 2.8 and 2.9 are structure maps for the Madison and Bighorn-Gallatin formations, respectively, showing the relative location of the four wells.

Figure 2.10 shows Madison well logs for SC 5-2, AGI 3-14, and AGI 2-18. Petrophysical evaluation of these wells indicate that Madison limestone and dolomite sequences were penetrated, as expected. Total porosity ranges of the limestone sequences were determined to be between 0% and 5%, while the dolomite sequences were found to be up to 20% total porosity. Injection fall-off testing indicated that the AGI wells exhibit greater than 2000 millidarcy-feet (md-ft) of permeability-height within the injection section. Figure 2.11 shows a table summarizing Madison and Bighorn-Gallatin reservoir properties from the SC 5-2, AGI 3-14, and AGI 2-18 wells. Madison reservoir quality for the SC 5-2 well is similar to the quality for the AGI wells, and is expected to be similar for the SC 7-34 well.

Bighorn-Gallatin reservoir quality for the SC 5-2 well is similar to the nearest Bighorn-Gallatin penetration at 1-12 Keller Raptor well (also referred to as the Amoco/Keller Rubow 1-12 well or the Keller Rubow-1 well), which shows interbedded dolostone and limestone sequences. In general, the degree of dolomitic recrystallization in the Bighorn-Gallatin is similar to the Madison Formation, which has resulted in comparable porosities and permeabilities despite a greater depth of burial. Bighorn-Gallatin total porosity from six LaBarge wells has been determined to be between 2 – 19% with permeabilities between 0.1 – 230 md.

Updated average Madison and Bighorn-Gallatin reservoir properties and well logs will be provided once the SC 7-34 well is drilled. Data will be submitted in the first annual monitoring report following commencement and operation of SC 7-34.

Figures 2.12 and 2.13 show the stratigraphic and structural cross sections of SC 5-2 and SC 7-34 in relation to AGI 3-14, AGI 2-18, and another analog well (1-12 Keller Raptor) penetrating the Madison and Bighorn-Gallatin formations further updip.

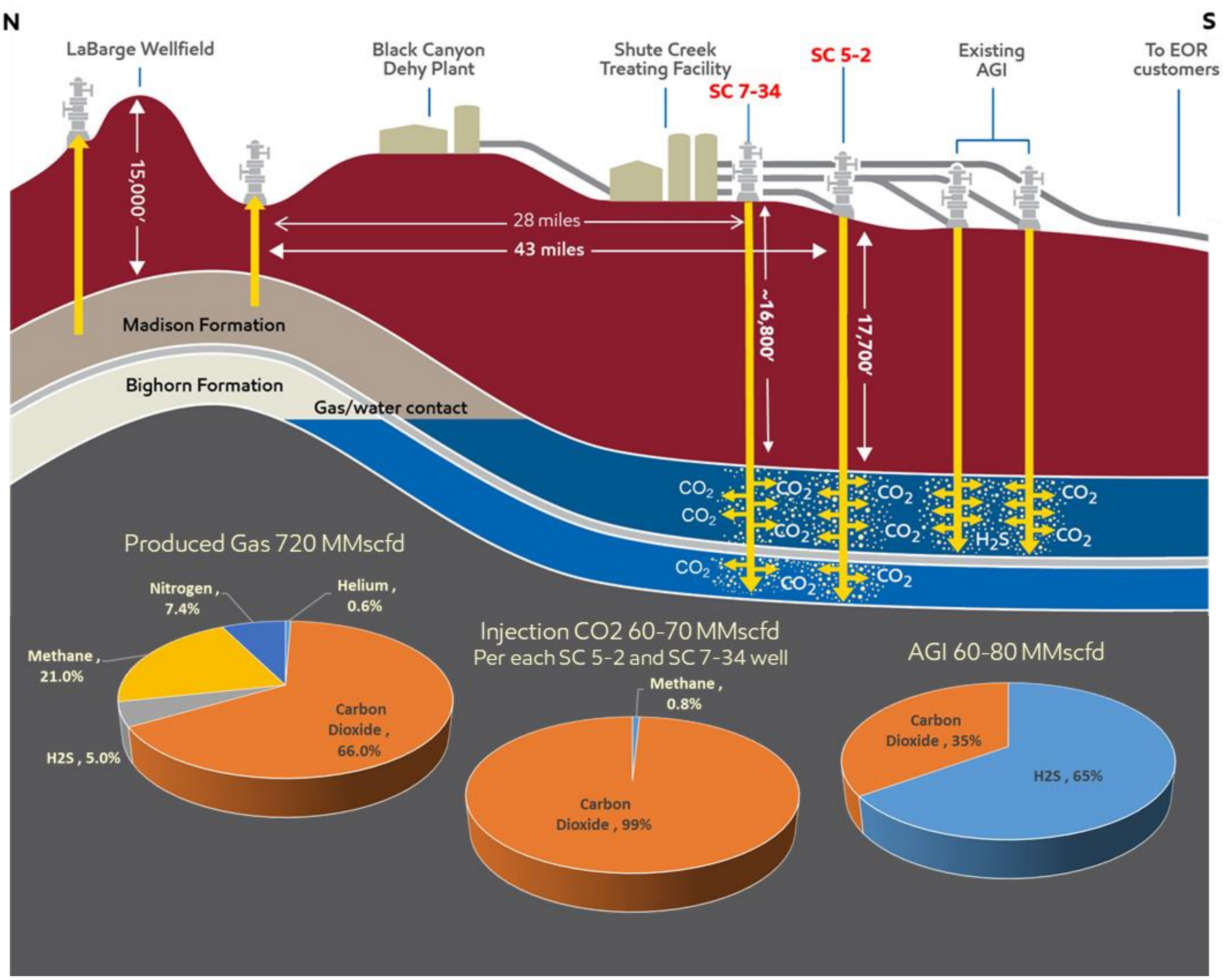

Figure 2.7 Schematic illustration of AGI injection program as currently used at LaBarge and CO_2 injection programs

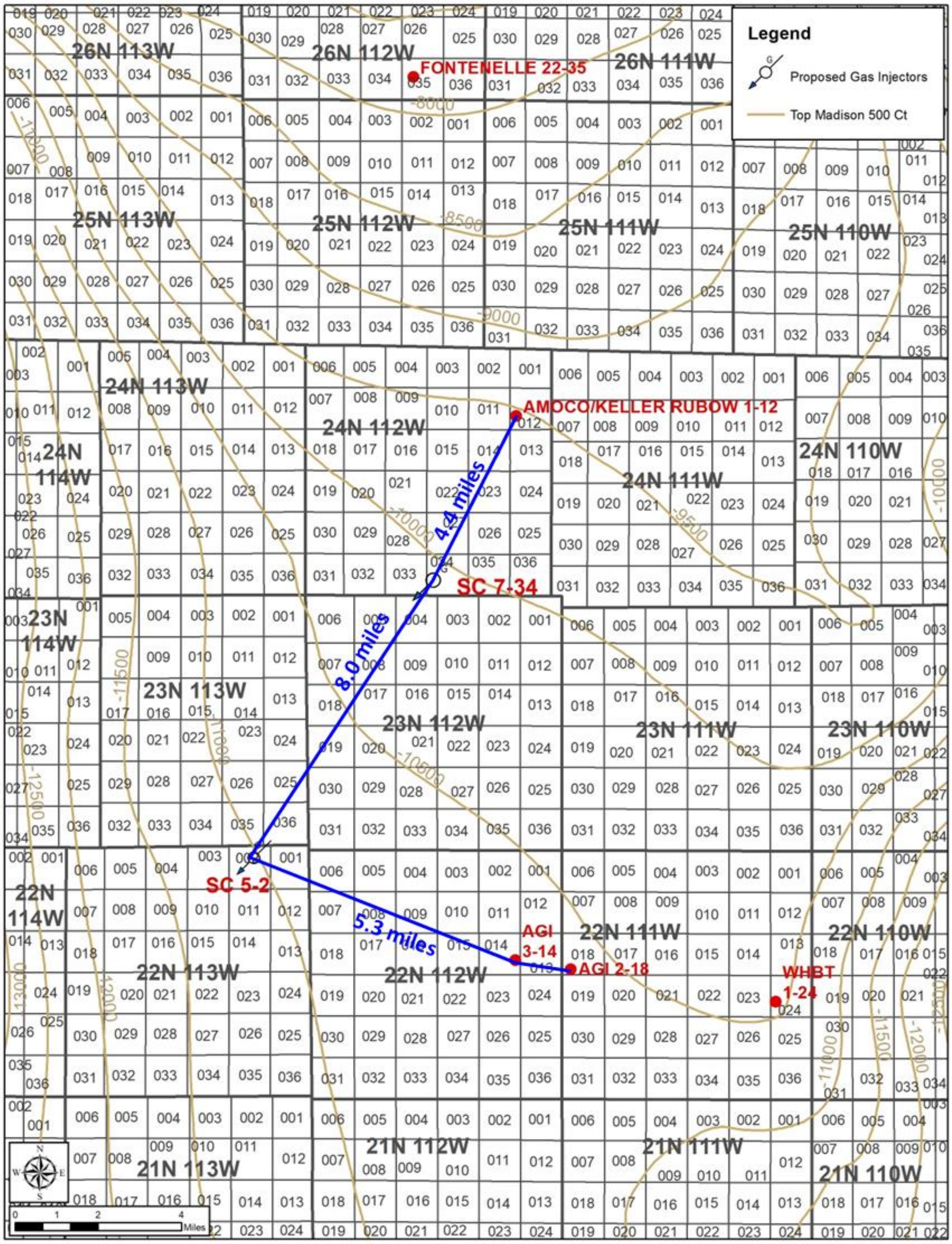

Figure 2.8 Madison structure map with relative well locations

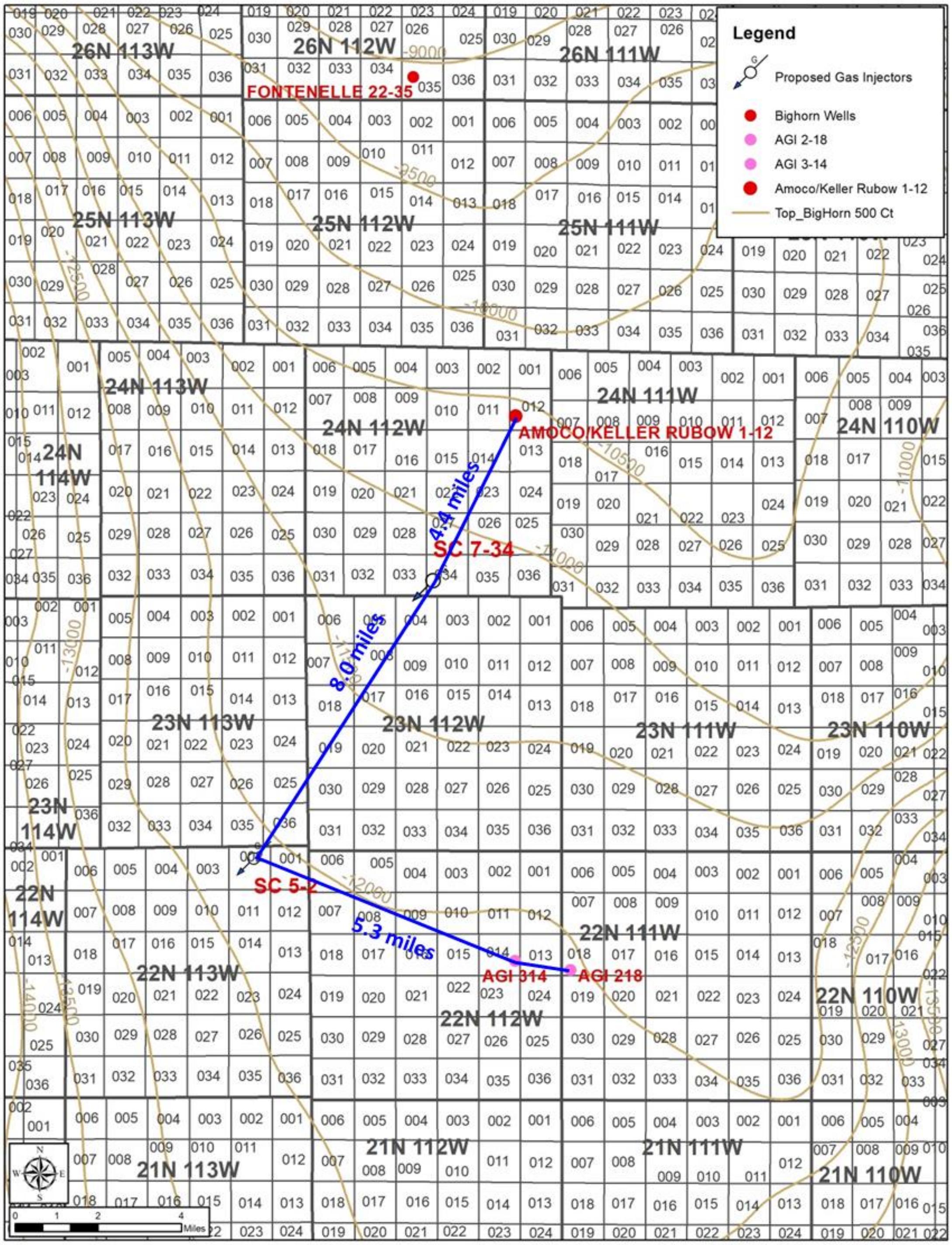

Figure 2.9 Bighorn-Gallatin structure map with relative well locations

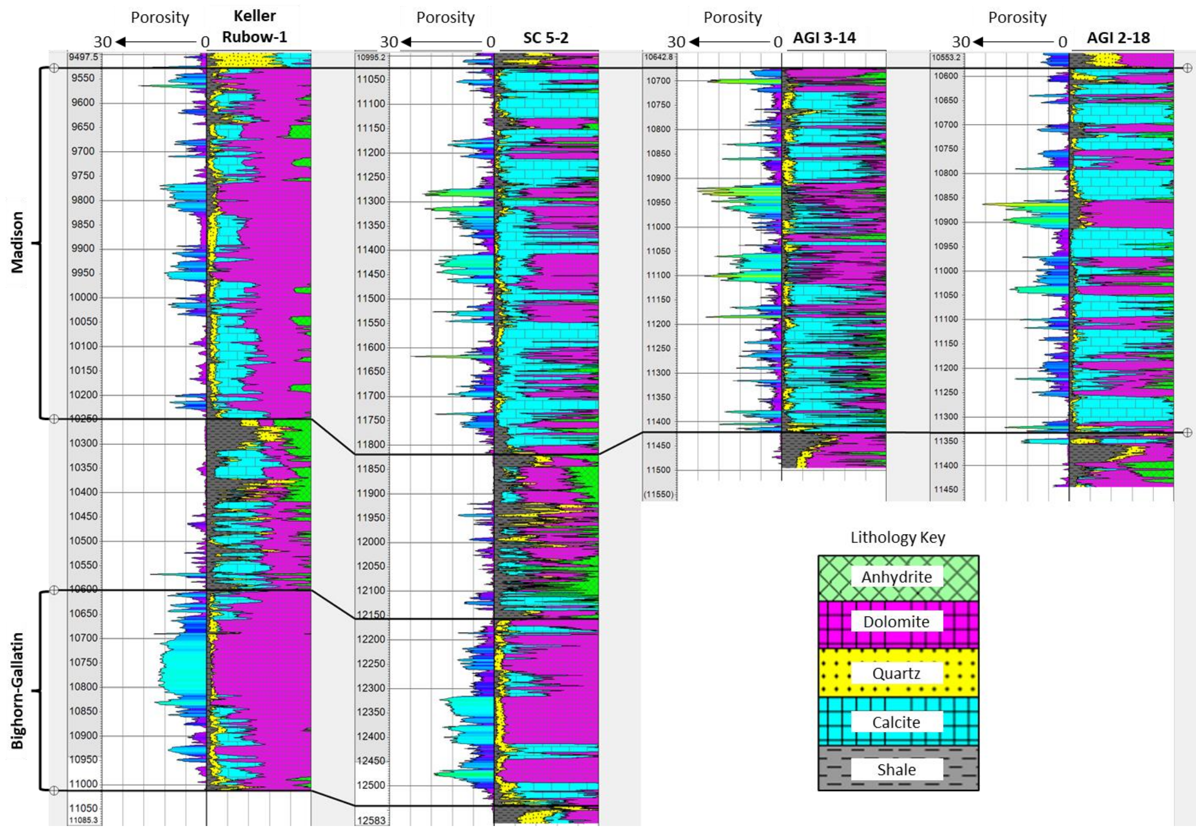

Figure 2.10 Well log sections from the Keller Rubow-1, SC 5-2, AGI 3-14, and AGI 2-18 injection wells across the Madison and Bighorn-Gallatin formations. SC 7-34 well logs are expected to be similar to offset wells.

	Bighorn-Gallatin	Madison		
	SC 5-2	SC 5-2	AGI 3-14	AGI 2-18
Net Pay (ft)	245	291	240	220
Avg Φ (%)	9%	10%	10%	9%
Avg k (md)	4	10	9	12
kh (md-ft)	~600*	~3000*	2300*	~2700*
Skin	-3.7	-3.5	-4.1	-4.5

* From injection / falloff test analysis

Figure 2.11 Average Madison and Bighorn-Gallatin reservoir properties of the SC 5-2 and AGI wells. SC 7-34 is expected to have similar properties.

From Figure 2.11, the parameters tabulated include:

1. *Net pay:* Madison section that exceeds 5% total porosity.
2. *Phi (ϕ):* Total porosity; the percent of the total bulk volume of the rock investigated that is not occupied by rock-forming matrix minerals or cements.
3. *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. Note that the measure of darcy assumes linear flow (i.e. pipe shaped).

4. *Kh:* Millidarcy-feet, which is a measure of the average permeability calculated at a 0.5 foot sample rate from the well log accumulated over the total net pay section encountered.
5. *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.

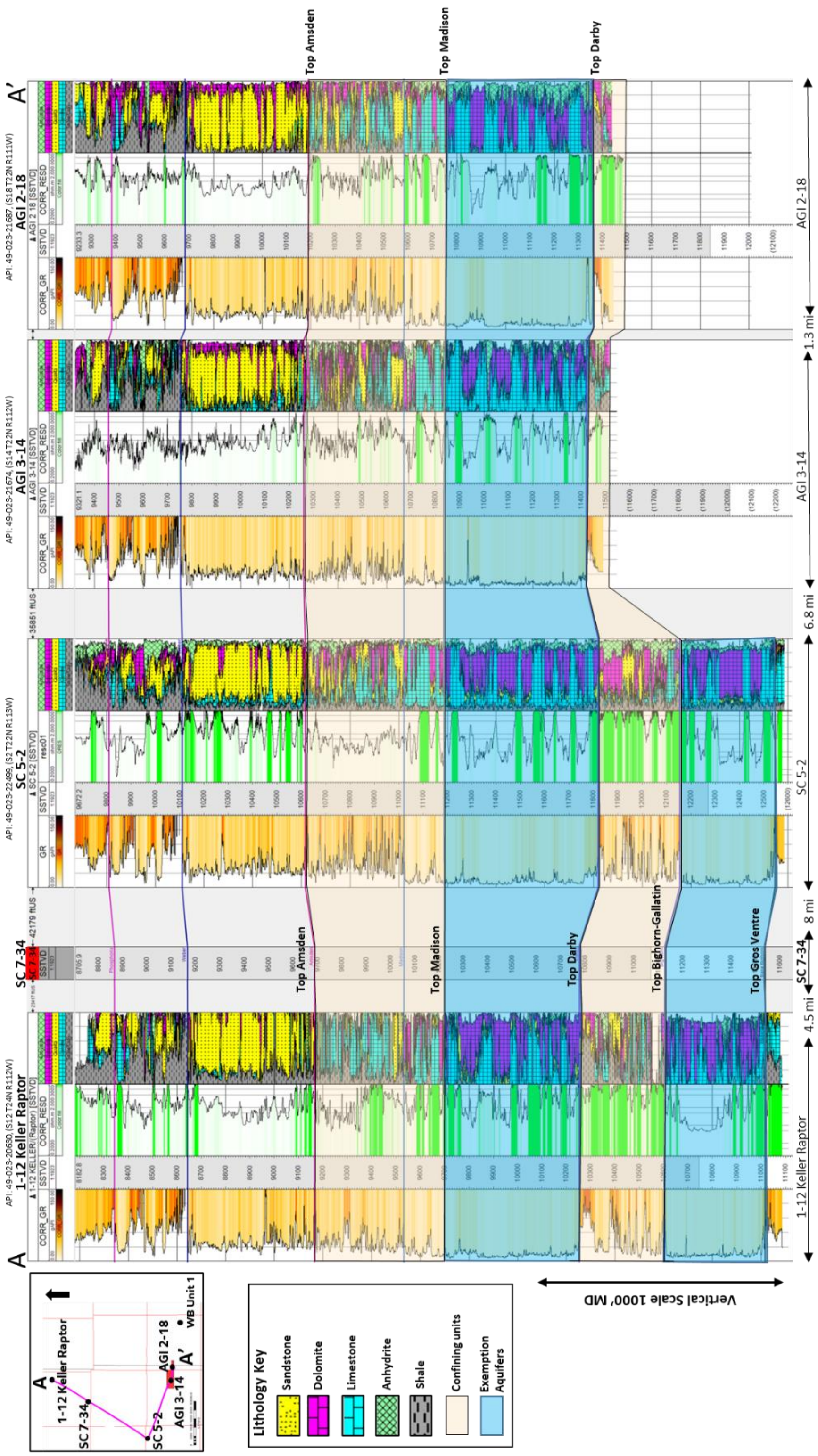

Figure 2.12 Stratigraphic Cross Section of Existing Madison and Bighorn-Gallatin Wells and the SC 7-34 Well

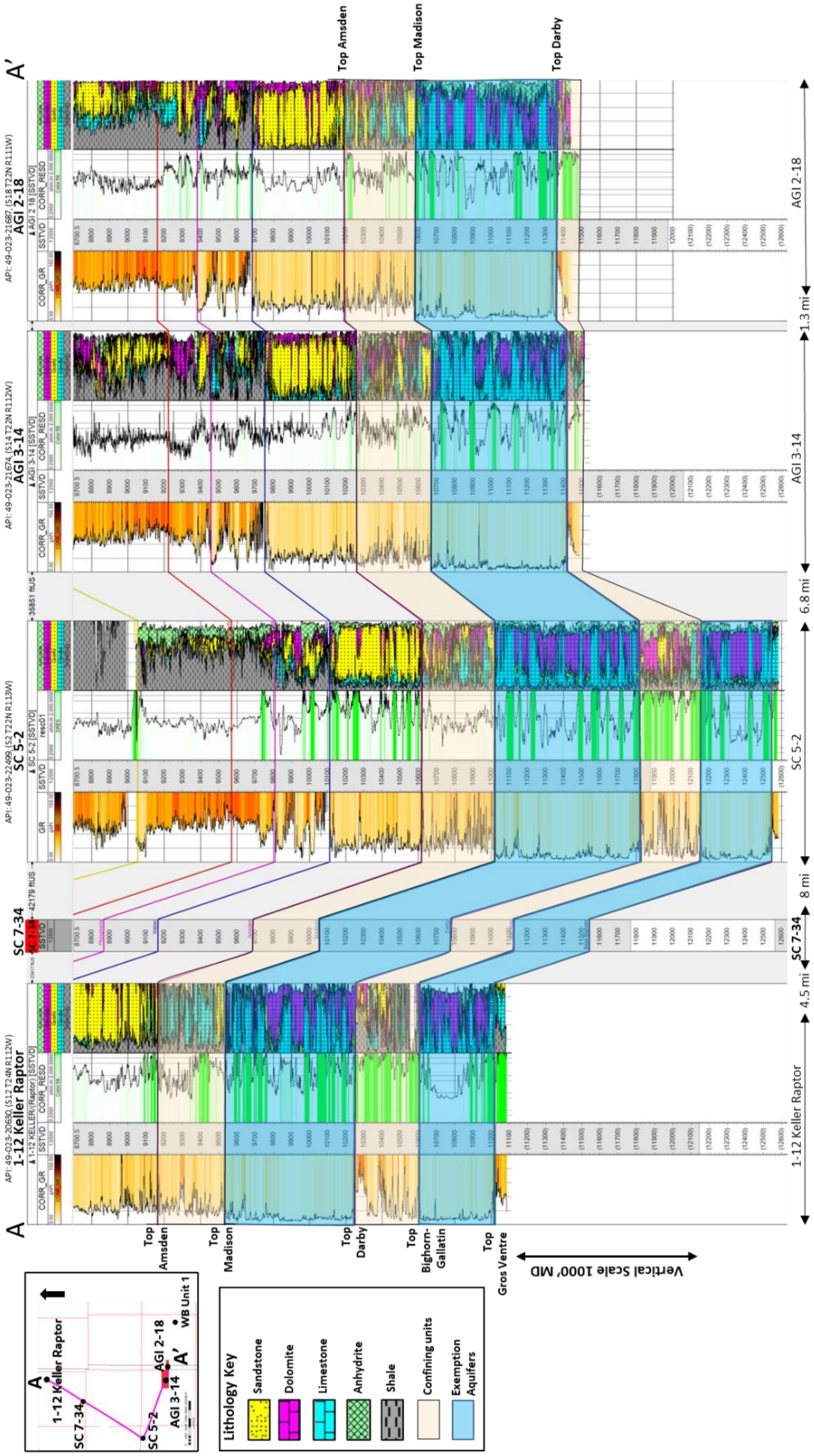

Figure 2.13 Structural Cross Section of Existing Madison and Bighorn-Gallatin Wells and the SC 7-34 Well

2.6.3 Seismic Expression of Madison and Bighorn-Gallatin Formations at CO_2 Injection Well Locations

Seismic expression of the Madison and Bighorn-Gallatin formations at the SC 5-2 and SC 7-34 injection locations indicate that the CO_2 injection wells are located on the plunging crest of the Moxa Arch with little to no structuring observable on the seismic data around these wells. Faulting is also not indicated by the seismic data. Figure 2.14 shows an east-west oriented 2D seismic at the SC 5-2 well location at approximately five times vertical exaggeration. Figure 2.15 shows an east-west oriented 2D seismic at the SC 7-34 well location at approximately four times vertical exaggeration.

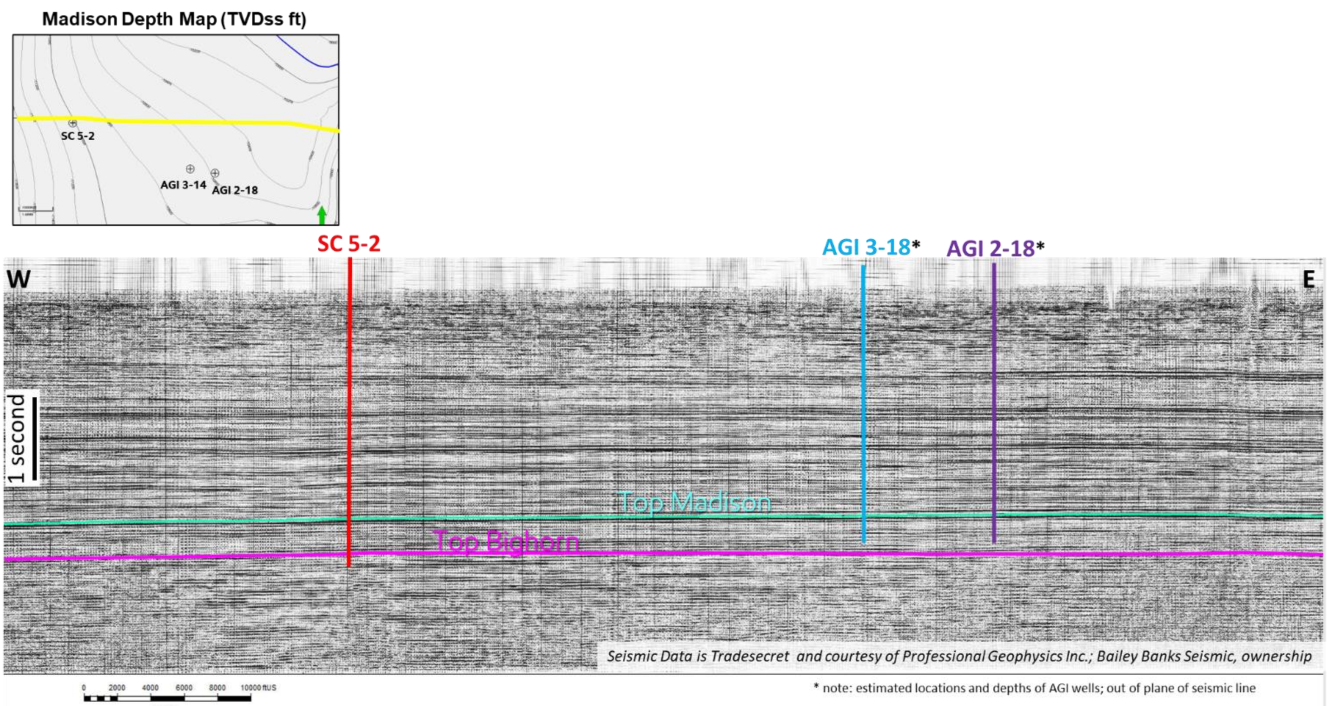

Figure 2.14 2D Seismic traverses around the SC 5-2 injection well location shows no evidence of faulting or structuring around the well location

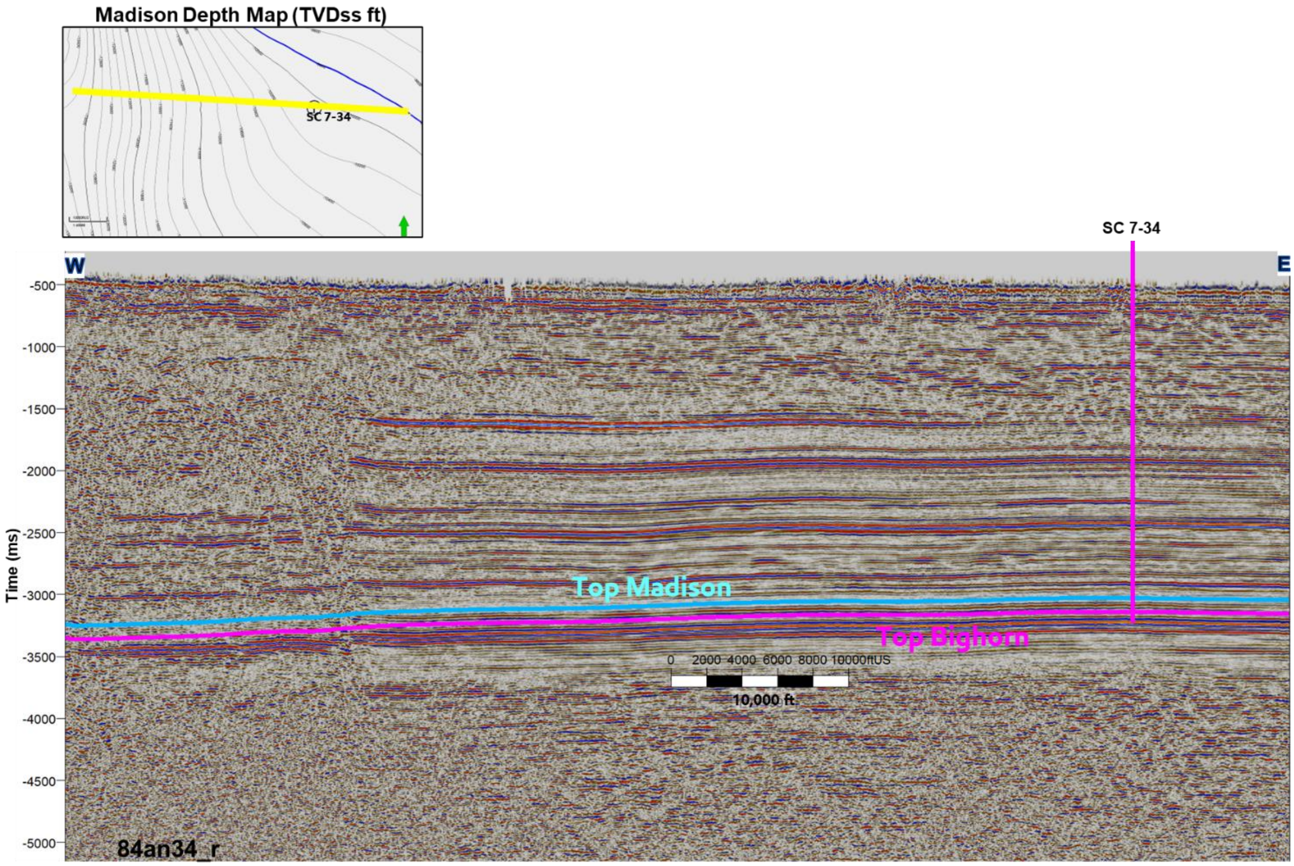

Figure 2.15 2D Seismic traverses around the SC 7-34 injection well location shows no evidence of faulting or structuring around the well location

2.7 Description of the Injection Process

2.7.1 Description of the AGI Process

The AGI facility was commissioned for eliminating the Claus Sulfur Recovery Units (SRU) bottleneck, reducing plant downtime, and reducing operating costs. The purpose of the AGI process is to take the H_2S and some of the CO_2 removed from the produced raw gas and inject it back into the Madison Formation. Raw gas is produced out of the Madison Formation and acid gas is injected back into the Madison Formation. The Madison reservoir contains very little CH_4 and He at the injection locations under SCTF, where the AGI wells are located. Thus, there is no concern of contaminating the production from the LaBarge well field 43 miles away.

The AGI process transports the acid gas stripped in the Selexol process under pressure through a pipeline to two underground wells that are geologically suitable for storage of the acid gas (AGI 3-14 and AGI 2-18). There are three parallel compressor trains. Two trains are required for full capacity; the third train is a spare. The low pressure feed from the Selexol process enters the first stage suction and is compressed through four stages of compression. The high pressure acid gas from the Selexol process requires only three stages of compression. The fourth stage discharge acid gas must be condensed prior to pumping to prevent damage from vapors. Fourth stage discharge acid gas is cooled in three heat exchangers prior to entering the pump. Dense phase aerial coolers are located downstream of the pumps; they remove heat generated by pumping and increase the density of the fluid. The liquid H_2S/CO_2 is commingled downstream of the dense phase coolers and divided into the two injection wells. The approximate stream composition being injected is 50 - 65% H_2S and 35 - 50% CO_2. Each injection well has a dedicated six-inch carbon steel pipeline. The length of pipeline from the AGI battery limit to the injection wells is about:

- 3,200 feet to AGI 3-14
- 12,400 feet to AGI 2-18

The AGI flow lines are buried with seven feet of cover. Heat tracing is provided for the aboveground portions of the lines to prevent the fluid from cooling to the point where free water settles out. Free water and liquid H_2S/CO_2 form acids, which could lead to corrosive conditions. Additionally, the gas is dehydrated before it enters the flow line, reducing the possibility of free water formation, and the water content of the gas is continuously monitored. The liquid H_2S/CO_2 flows via the injection lines to two injection wells. The total depth of each well is about:

- 18,015 feet for AGI 3-14
- 18,017 feet for AGI 2-18.

2.7.2 Description of the CO_2 Injection Process

The CO_2 injection program was initiated primarily because the volume of CO_2 associated with the natural gas production is greater than the volume that is able to be injected into the AGI wells.

2.7.2.1 Description of the SC 5-2 Process

The SC 5-2 process aims to capture CO_2 at the SCTF that would otherwise be vented, and compress it for injection into the Madison and Bighorn-Gallatin formations.

The injection system would enable additional CO_2 to be stripped in the Selexol process, pressurized, and transported to a CO_2 injection well, which is geologically suitable for injection, disposal and sequestration of fluids primarily consisting of CO_2. The process will be built into the existing Selexol trains at SCTF. After the acid gas treatment and dehydration, the gas will be routed to a new flash vessel which will enable capture up to 80 million standard cubic feet per day (MMSCFD) from SCTF then compressed with an air cooled Heat Exchanger cooling system. The captured CO_2 will have the potential to be either sold or injected into a CO_2 injection well. Based on modeling, the approximate stream composition will be 99% CO_2, 0.8% methane and 0.2% other mixed gases.

From the CO_2 compressors, an eight inch flow line of approximately 10.1 miles would take the fluids to the SC 5-2 injection well site. The flow line would be buried at depths necessary to avoid and protect existing facilities, roads, and crossings, and will be buried at a minimum below the frost line. The fluids will have a sufficient dew point that free water formation is not expected to accumulate along the pipeline or well. The water content of the gas will be continuously monitored. The gas will be transported via flow line to the SC 5-2 well and injected into the Madison Formation at a depth of ~17,950 feet and into the Bighorn-Gallatin Formation at a depth of ~19,200 feet. Based on geological models, the risk of contaminating production from the LaBarge well field 35 miles away or interacting with the AGI wells or SC 7-34 well approximately 7 miles and 8 miles away, respectively, is improbable.

2.7.2.2 Description of the SC 7-34 Process

The SC 7-34 process aims to divert currently captured CO_2 produced from source wells during natural gas production that will not be sold to customers and route to permanent disposal into the Madison and Bighorn-Gallatin formations.

Captured CO_2 that is already routed from SCTF to the existing CO_2 sales building will be diverted and transported via flow line to a CO_2 injection well, which is geologically suitable for injection, disposal, and sequestration of fluids primarily consisting of CO_2. This process will enable disposal of up to 70 MMSCFD through an additional pump. The CO_2 will be cooled with an air cooled Heat Exchanger cooling system. Based on modeling, the approximate stream composition is anticipated to be identical to the SC 5-2 with 99% CO_2, 0.8% methane, and 0.2% other mixed gases.

From the CO_2 compressors, an eight inch flow line of approximately 12.4 miles would take the fluids to the SC 7-34 injection well site. The flow line would be buried at depths necessary to avoid and protect existing facilities, roads, and crossings, and will be buried at a minimum below the frost line. The fluids will have a sufficient dew point that free water formation is not expected to accumulate along the pipeline or well. The water content of the gas will be continuously monitored. The gas will flow via the injection lines to the SC 7-34 well and injected into the Madison Formation at a depth of ~16,740 feet and into the Bighorn-Gallatin Formation at a depth of ~18,230 feet. Based on geological models, the risk of contaminating production from the LaBarge well field 30 miles away or interacting with the SC 5-2 well or AGI wells approximately 8 and 9 miles away, respectively, is improbable.

2.8 Planned Injection Volumes

2.8.1 Acid Gas Injection Volumes

Figure 2.16 is a long-term injection forecast throughout the life of the acid gas injection project. It is based on historic and predicted data. 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 below are the total amount of gas to be injected into the AGI wells, not just the CO_2 portion. ExxonMobil forecasts the total volume of CO_2 stored in the AGI wells over the modeled injection period to be approximately 53 million metric tons.

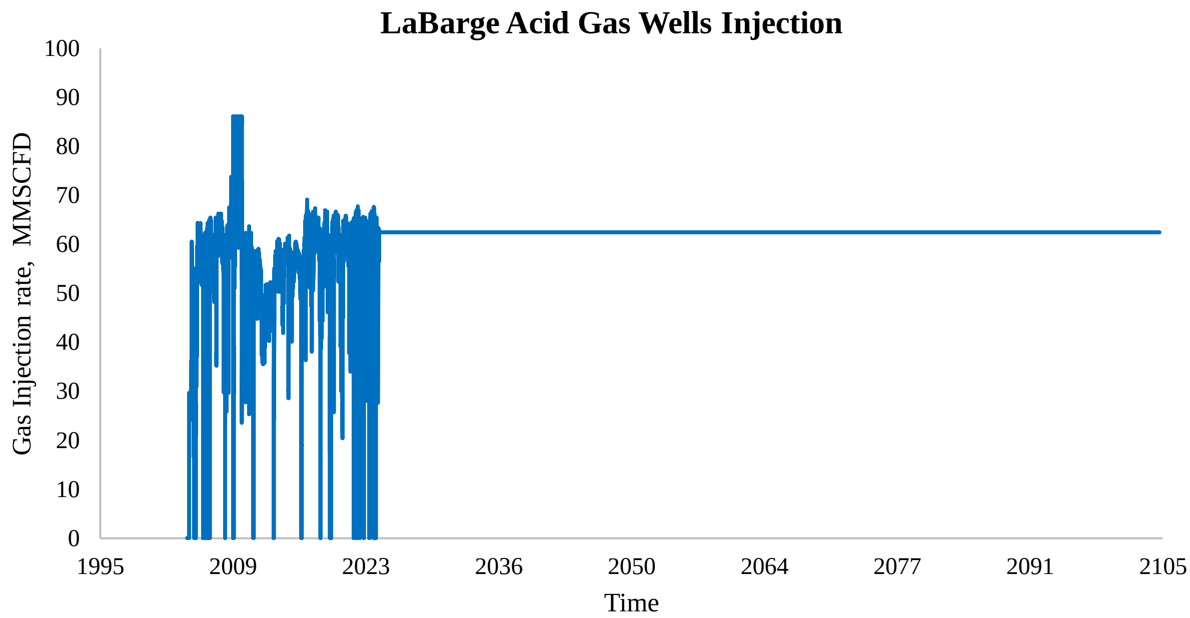

Figure 2.16 – Planned Acid Gas and CO_2 Injection Volumes

2.8.2 CO_2 Injection Wells Volumes

Figure 2.17 below is a long-term average injection forecast through the life of the CO_2 injection wells. 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 below are the total amount of fluids to be injected, but does not include any portion of the Acid Gas Injection project gas. The non-CO_2 portion of the injection stream is expected to be 1% or less of the injected volume. ExxonMobil forecasts the total volume of CO_2 stored in the CO_2 injection wells over the modeled injection period to be approximately 180 million metric tons.

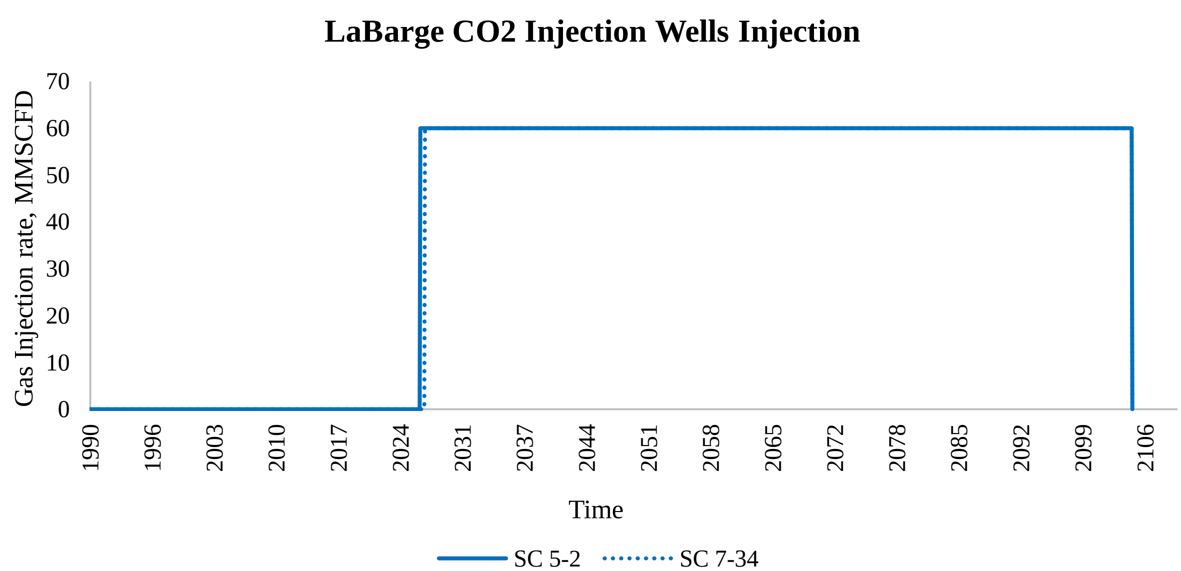

Figure 2.17 – Planned Average CO_2 Injection Well Volumes

3.0 Delineation of Monitoring Area

3.1 Maximum Monitoring Area (MMA)

3.1.1 AGI Wells MMA

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the acid gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 1%. A gas saturation of 1% is well below the lowest gas saturation that can be confidently detected by formation evaluation methods in reservoirs with rock properties such as those found in the Madison Formation.

After injecting 0.3 trillion cubic feet (TCF) by year-end 2023, the current estimated acid gas plume size is approximately 21,350 feet in diameter (4.0 miles) (see Figure 3.1). With continuing injection of an additional 1.9 TCF through year-end 2104, at which injection is expected to cease, the plume size is expected to grow to approximately 39,500 feet in diameter (7.5 miles) (see Figure 3.2).

The model was run through 2986 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. The rate of growth of the free-phase gas plume is less than 0.25% areally per year, demonstrating plume stability. Figure 3.3 below shows the expansion of the plume to a diameter of approximately 40,470 feet (7.7 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the MMA will be defined by Figure 3.3, which is the maximum areal extent of the plume once it has reached stability (defined by the extent of the plume in 2205, which is a 7.7-mile diameter) plus the buffer zone of one-half mile.

3.1.2 CO_2 Injection Wells MMA

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the CO_2 gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 1%.

Note that estimates of plume size assume that CO_2 is coinjected without flow control at both the SC 5-2 and SC 7-34 wells into both the Madison and Bighorn-Gallatin intervals. Having no flow control means that the amount of gas that enters each interval is for the most part a function of the permeability thickness (kh) of each interval. There is limited data, especially for the Bighorn-Gallatin, with few well penetrations, all of which are a significant distance from the target formation. Therefore, the anticipated plume sizes are based on simulation results relying on best estimates from available data regarding the Madison and Bighorn-Gallatin reservoir quality.

The model was run through 2986 to assess the potential for expansion of the plume after injection ceases at year-end 2104. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. The rate of growth of the free-phase gas plume is less than 0.25% areally per year, demonstrating plume stability.

3.1.2.1 SC 5-2 MMA

Assuming SC 5-2 begins injecting in 2025, 0.02 TCF of CO_2 will have been injected by mid-2026 and the gas plume will just begin to form. Figure 3.4 shows expected average gas saturations at mid-2026 and the location of the AGI wells relative to the SC 5-2 injection well. After injecting 1.7 TCF at year-end 2104, injection is expected to cease. The SC 5-2 CO_2 plume size is expected to grow to approximately 23,650 feet in diameter (4.5 miles) (see Figure 3.5).

Figure 3.6 below shows the expansion of the SC 5-2 plume to a diameter of approximately 24,500 feet (4.6 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the SC 5-2 MMA will be defined by Figure 3.6, which is the maximum areal extent of the SC 5-2 plume once it has reached stability (defined by the extent of the plume in 2205, which is a 4.6-mile diameter) plus the buffer zone of one-half mile.

3.1.2.2 SC 7-34 MMA

SC 7-34 is assumed to begin injection mid-2026. After injecting 1.7 TCF at year-end 2104, injection is expected to cease. The SC 7-34 CO_2 plume size is expected to grow to approximately 22,100 feet in diameter (4.2 miles) (see Figure 3.7).

Figure 3.8 below shows the expansion of the SC 7-34 plume to a diameter of approximately 24,976 feet (4.7 miles) by the year 2205, 100 years post end of injection, as the gas plume settles due to gravity segregation and dispersion. Therefore, the SC 7-34 MMA will be defined by Figure 3.8, which is the maximum areal extent of the SC 7-34 plume once it has reached stability (defined by the extent of the plume in 2205, which is a 4.6-mile diameter) plus the buffer zone of one-half mile.

3.2 Active Monitoring Area (AMA)

ExxonMobil proposes to define the AMA as the same boundary as the MMA for the AGI and CO_2 injection wells. The following factors were considered in defining this boundary:

1. Lack of faulting in the MMA yields no vertical pathways for fluids to move vertically out of the Madison or Bighorn-Gallatin formations to shallower intervals.

2. Lack of faulting in the injection area does not create enhanced reservoir permeability through natural fracturing and all flow of injected fluids will be darcy flow from pore to pore.
3. Distance from the LaBarge production field area is large (35+ miles) and reservoir permeability is generally low which naturally inhibits flow aerially from injection site.
4. The LaBarge field production area is a large structural hydrocarbon trap that has sealed and trapped hydrocarbons for large geologic periods of time. There is no reason to believe that any injection fluids that may migrate outwards from the injection site to the larger LaBarge structure would not also be effectively trapped at the LaBarge structure over geological time.

The purpose of the AMA is to allow for a practical and cost-effective monitoring program throughout the life of the project. Because there are no probable leakage pathways in the MMA, besides surface equipment which is extensively monitored, ExxonMobil believes it is appropriate to define the AMA as the same boundary as the MMA. Additionally, due to the high H_2S content of the injected gas stream into the AGI wells, monitoring of leaks is essential to operations and personnel safety, so a full-scale monitoring program has already been implemented at the AGI sites, as will be discussed below.

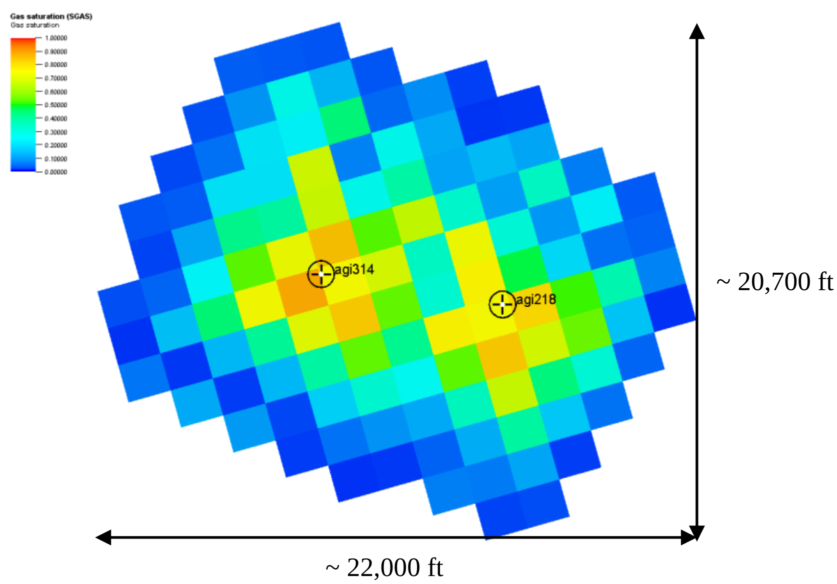

Figure 3.1 – AGI Estimated Gas Saturations at Year-end 2023

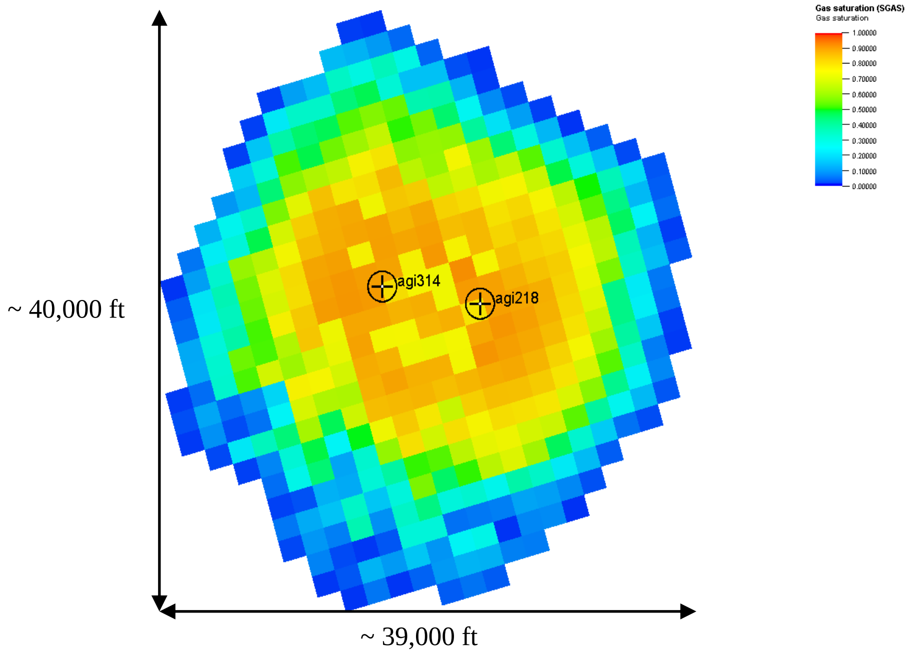

Figure 3.2 – AGI Predicted Gas Saturations at Year-end 2104

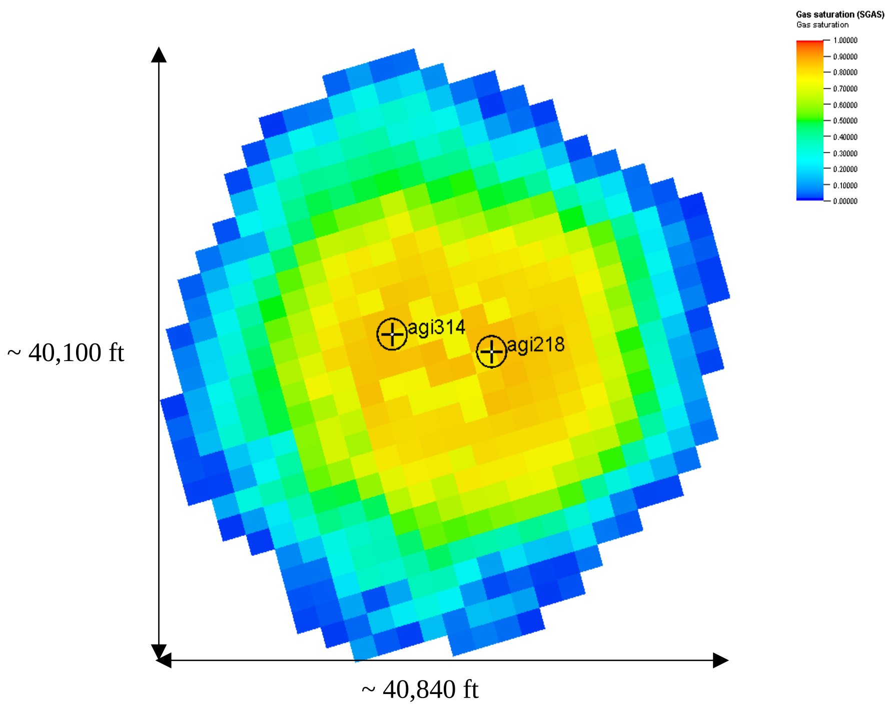

Figure 3.3 – AGI Predicted Gas Saturations at Year-end 2205

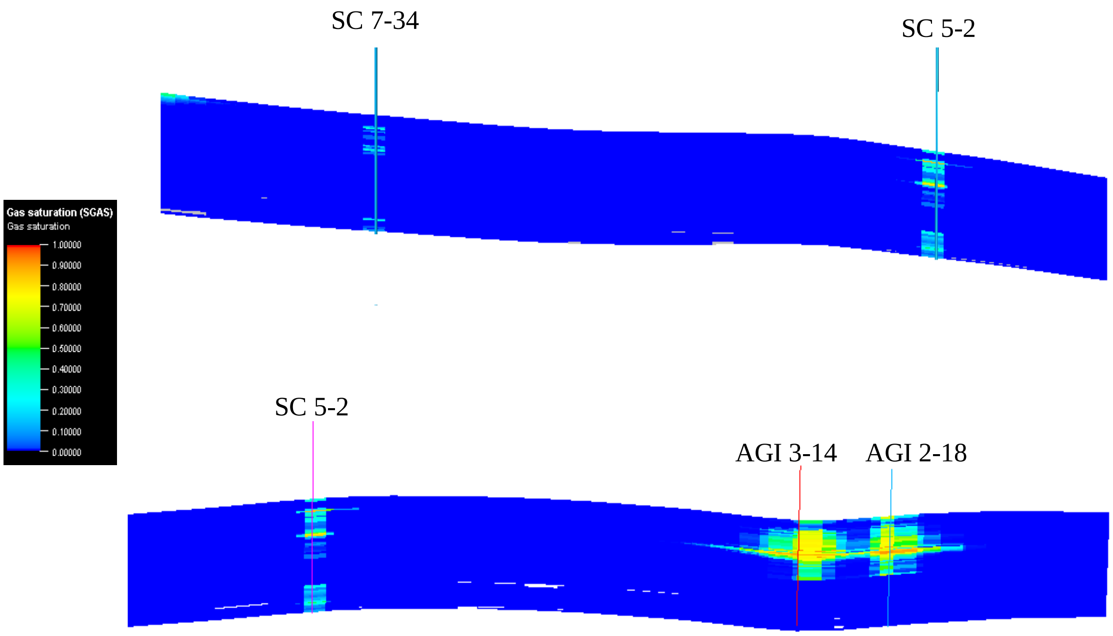

Figure 3.4 – Predicted Gas Saturations at Year-end 2027

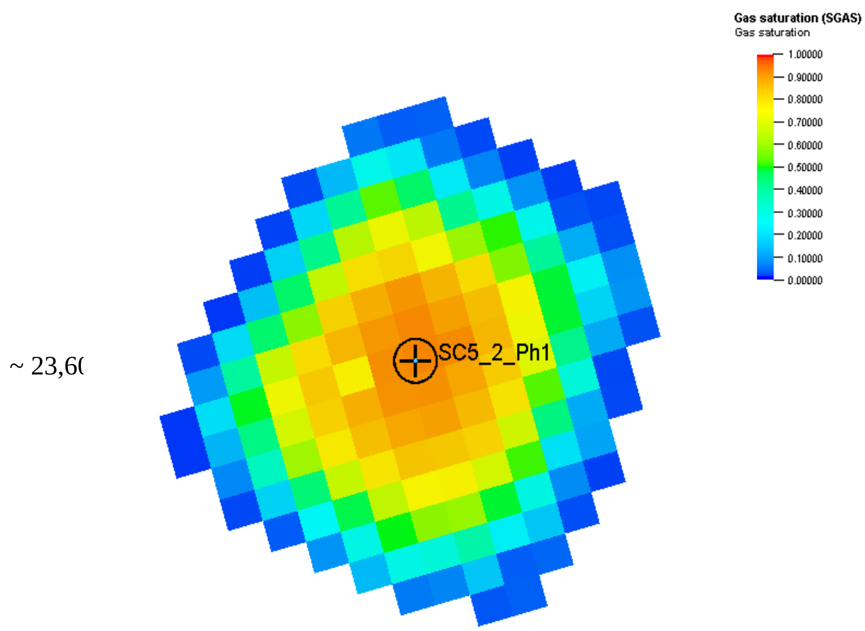

Figure 3.5 – SC 5-2 Predicted Gas Saturations at Year-end 2104

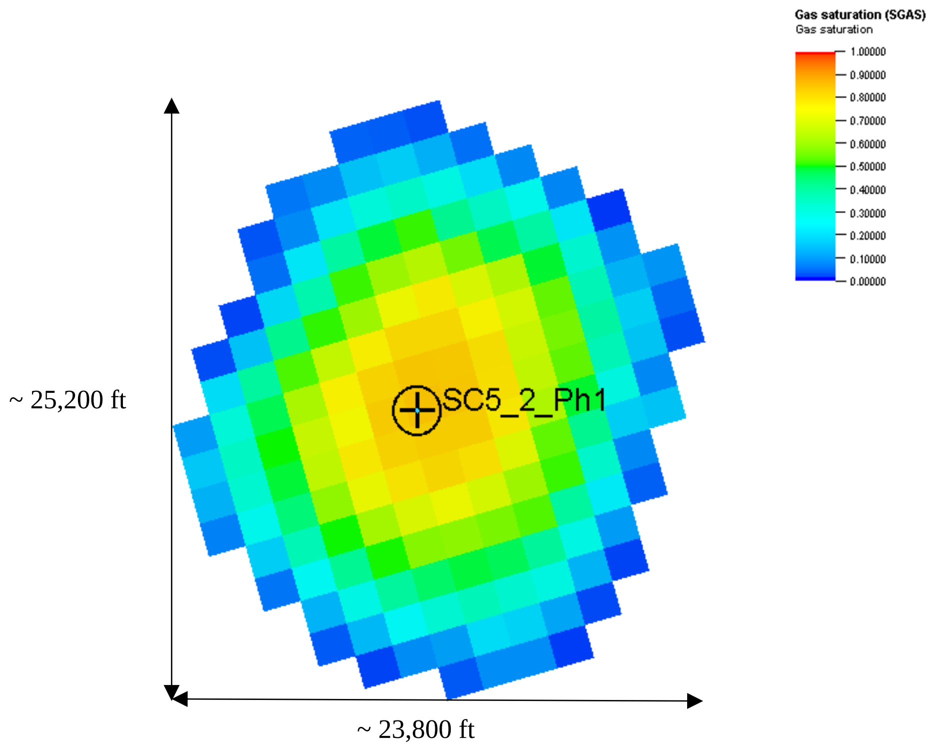

Figure 3.6 – SC 5-2 CO_2 Predicted Gas Saturations at Year-end 2205

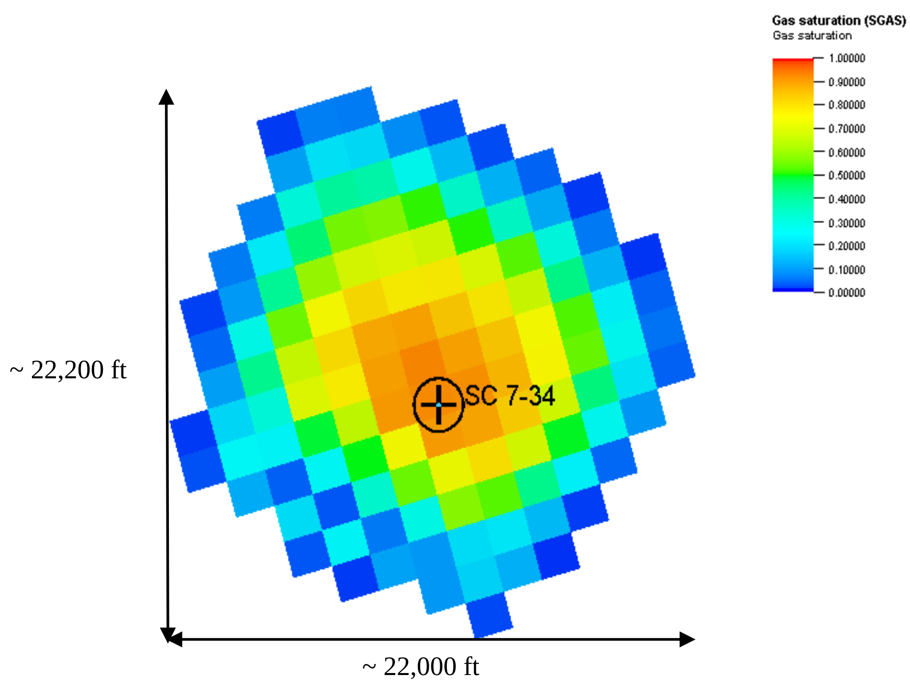

Figure 3.7 – SC 7-34 Predicted Gas Saturations at Year-end 2104

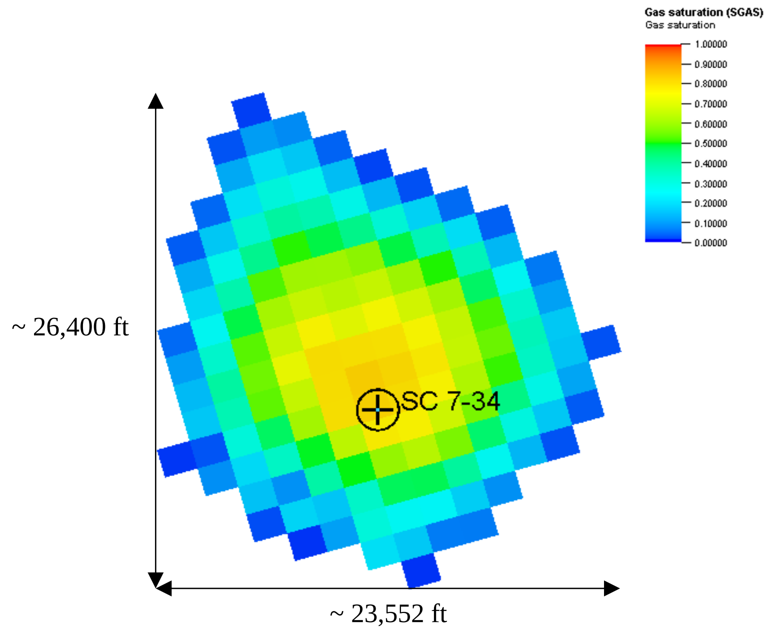

Figure 3.8 – SC 7-34 Predicted Gas Saturations at Year-end 2205

4.0 Evaluation of Potential Pathways for Leakage to the Surface

This section assesses the potential pathways for leakage of injected CO_2 to the surface. ExxonMobil has identified the potential leakage pathways within the monitoring area as:

- Leakage from surface equipment (pipeline and wellhead)
- Leakage through wells
- Leakage through faults and fractures
- Leakage through the seal

As will be demonstrated in the following sections, there are no leakage pathways that are likely to result in loss of CO_2 to the atmosphere. Further, given the relatively high concentration of H_2S in the AGI injection stream, any leakage through identified or unexpected leakage pathways would be immediately detected by alarms and addressed, thereby minimizing the amount of CO_2 released to the atmosphere from the AGI wells.

4.1 Leakage from Surface Equipment

Leakage from surface equipment is not likely due to the design of the AGI and CO_2 injection facilities. The AGI facilities were designed to minimize leak points such as valves and flanges, and use welded connections where possible instead. The only surface equipment located between the flow meter and the wellhead are valves, transmitters, and flanged connection points on the pipelines. Due to the presence of H_2S in the AGI injection stream at a concentration of approximately 50 - 65% (500,000 - 650,000 parts per million (ppm)), H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. CO_2 gas detectors will be present at the CO_2 injection facilities due to high concentration of CO_2, which alarm at 5,000 PPM. Additionally, all field personnel are required to wear H_2S monitors for safety reasons, which alarm at 5 ppm H_2S. Although damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2 entrained in the acid gas, at the AGI well concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm, and immediate action would be taken to stop the leak. Additionally, the CO_2 injection wells would be monitored with methods outlined in sections five and six.

ExxonMobil reduces the risk of unplanned leakage from surface facilities through continuous surveillance, facility design, and routine inspections. Field personnel monitor the AGI facility continuously through the Distributed Control System (DCS). Additionally, daily visual inspection rounds are conducted of the AGI facility and weekly visual inspections are conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. ExxonMobil also relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSVs), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes. Additionally, the AGI wells have multiple surface isolation valves for redundant protection. Inline inspections of the AGI injection pipelines using a smart pigging tool are conducted on a regular frequency to check the wall thickness of the pipeline to identify potential areas of corrosion.

Field personnel will monitor the CO_2 injection facilities continuously through the DCS. Additionally, visual inspections will be conducted on a routine basis providing an additional way to detect leaks in a timely manner. Surface isolation valves will also be installed for redundant protection. Inline inspections are not anticipated to occur on a regular frequency because free water is not expected to accumulate due to the low dew point of the fluid.

Should leakage be detected from surface equipment, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7.4 in accordance with 40 CFR 98.448(5).

4.2 Leakage through AGI and CO2 Injection Wells

Leakage of CO_2 through oil, gas, and/or water wells completed and/or abandoned is not likely. There is no commercial production of oil or gas within the immediate area of the SCTF. There is shallower production of gas from the Frontier and Dakota formations nearby in the Cow Hollow Field, at depths of 10,800' – 11,800'. A search of the WOGCC database demonstrated that there are no existing active Madison or Bighorn-Gallatin penetrations or production within the respective MMAs of the AGI or CO_2 injection well sites. The nearest established Madison production is greater than 35 miles to the north-northwest in the ExxonMobil LaBarge Deep Madison Field, which is the well field that supplies SCTF. One well (Whiskey Butte Unit 1, drilled in 1974 and operated by Wexpro Company), which was located approximately 6 miles from the AGI wells, partially penetrated 190 feet of the Madison Formation (total depth 17,236 feet MD). This well never produced from the Madison Formation and instead was perforated thousands of feet above in the Frontier Formation. The well was ultimately plugged and abandoned in February 1992. Examination of the plugging and abandonment records and the wellbore diagram constructed from those records indicates that the well does not pose a risk as a leakage pathway. Two additional Madison penetrations are located between the well field and the SC 5-2 and AGI wells; both penetrations are outside the boundary of the MMA and therefore do not pose a risk as a leakage pathway. Keller Rubow 1-12 was plugged and abandoned in 1996. Fontenelle II Unit

22-35 was drilled to the Madison Formation but currently is only perforated and producing from thousands of feet above in the Frontier Formation.

As mentioned in Section 2.3.2, early in the life of many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. The thin-wall wells that failed have been plugged and abandoned in accordance with regulatory standards. Madison wells that were subsequently drilled were cased using thick-walled/chrome tubulars due to the high H_2S and CO_2 content and subsequent corrosion effects, as well as to combat potential salt or sediment creep. Therefore, there is no current risk of failure as all wells currently use or have used thick-walled casing of sufficient strength to penetrate and/or produce from the Madison Formation.

Future drilling also does not pose a risk as a leakage pathway due to limited areal extent of the injection plumes as shown in Figures 3.2 – 3.8. Therefore, the geological model can be used to delineate areas that should be avoided during drilling. This model has also history-matched the AGI wells injection that has occurred to date and suggests that future injection will closely follow the patterns resulting from the geological model simulation. Additionally, should future drilling occur, it would occur near the existing production area, which is greater than 40 miles away from the current AGI wells, approximately 35 miles away from SC 5-2, and approximately 30 miles away from SC 7-34.

ExxonMobil reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and annual mechanical integrity testing (MIT). As indicated in Section 4.1, visual inspections of the well sites are performed on a routine basis, which serves as a proactive and preventative method for identifying leaks in a timely manner. Gas detectors located at the well sites which alarm at 10 ppm H_2S and 5,000 ppm CO_2 would be triggered if a leak from the wellbore to the atmosphere occurred. Additionally, SCSSV's and surface isolation valves are installed at the AGI wells, which would close in the event of leakage, preventing losses. Mechanical integrity testing is conducted on an annual basis and consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. If the MIT demonstrated a leak, the well would be isolated and the leak would be mitigated as appropriate to prevent leakage to the atmosphere.

Should leakage result from the injection wellbores and into the atmosphere, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7.4 in accordance with 40 CFR 98.448(5).

4.3 Leakage through Faults and Fractures

As discussed in Section 2.6.3, engineering and geologic analysis show no evidence of faulting or structuring around the AGI wells. As a result, the risk of leakage through this pathway is highly improbable. The absence of faulting also tends to suggest that natural fracturing or permeability enhancement in the Madison Formation is also highly improbable. Natural fracturing along with systems of large connected pores (karsts and vugs) could occur in the Bighorn-Gallatin Formation. However, because those enhanced permability areas would be limited to the Bighorn-Gallatin Formation and would not be extended to the sealing formations above, the risk of leakage through this pathway is also highly improbable.

Current-day regional scale thrust faulting has not been observed in the LaBarge area since the field has been under development. There is no concern of reactivation of these thrust faults and it is hypothesized that regional structuring similar in size to the Laramide Orogeny (formation of the Rocky Mountains) would be required to generate new thrust faults of significant size to produce subsurface structures of the scale and magnitude of the LaBarge field. The activation of the salty sediments (which exist below the Nugget Formation and above the Madison Formation at LaBarge) is a phenomenon that was only observed to damage thin-wall cased wells, with thick-wall cased wells having sufficient strength to prevent flowage of these salt sediments. It is believed that weakness in the casing of thin-wall cased wells contributes to the ability of the salty sediments to flow local to the wellbore, shearing casing, as this is a point of weakness in the structural integrity of the wellbore at this depth. Once thick-walled casing was introduced, failures have decreased or have been eliminated.

It has been documented that natural fracturing of reservoirs in the subsurface of LaBarge and surrounding areas are directly correlative to distance to thrust faults in the area. This correlation has been documented in subsurface wellbore image logs and also by surface geological mapping around the thrust faults in the LaBarge area. It therefore follows that a lack of faulting, as observed on 2D seismic panels around and through the AGI and CO_2 injection well sites, will yield formations void of natural fracturing, and the necessary faults are not present to generate pervasive natural fractures. The lack of significant natural fracturing in the Madison Formation at and around the AGI well sites, in conjunction with active inspection of wellbore image logs within the AGI wells themselves, indicates that natural fractures do not exist, that all flow in the Madison 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. It should be noted that the permeability of the Madison 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. Likewise, the low expected connected permeability of the Bighorn-Gallatin has minimal capability to freely flow fluids through its only pore system. Accordingly, there is little potential for lateral migration of the injection fluids.

Prior to drilling the AGI wells, ExxonMobil worked with multiple service companies who provided a range of fracture gradients for the Phosphoria, Weber/Amsden, Morgan, and Madison formations in the area. Based on a frac gradient of 0.85 pounds per square inch (psi)/foot for the Madison, 0.82 psi/foot for the Morgan, 0.80 psi/foot for the Weber/Amsden, and 0.775 psi/foot for the Phosphoria, and a downhole fracture pressure of 12,167 psi, which corresponds to a surface injection pressure of ~5,500 psi, the injected acid gas will not initiate fractures in the confining zones of overlying strata. Facility limits exist that limit surface pressures to below 3,200 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture is unlikely.

Fracture gradient and overburden for the SC 5-2 well were estimated on the basis of offset well data. Offset well pressure integrity test (PIT) data from existing wells was analyzed and resulted in an overburden of 18,883 psi and a fracture gradient of 0.88 psi/foot (15,203 psi) at the top of the Madison Formation (~17,232 feet MD / -10,541 feet Total Vertical Depth subsea (TVDss)) and overburden of 20,388 psi and a fracture gradient of 0.885 psi/foot at the top of the Bighorn-Gallatin Formation (~18,531 feet MD / -11,840 feet TVDss). The fracture pressure at the top of the Madison Formation is estimated at approximately 15,203 psi which corresponds to a fracture pressure at the surface of 7,685 psi. The projected facility average and maximum surface pressures are 3,430 psi and 6,170 psi, respectively. Both are below the pressure required to fracture the formation; therefore, the probability of fracture is unlikely.

Fracture gradient and overburden for the SC 7-34 well were also estimated on the basis of offset well data. Overburden estimates for the subject formations are based on offset well density logs. Expected formation integrity is primarily based on offset well pressure integrity (PIT) data. Because offset PITs did not result in leakoff, fracture gradient is assumed to be above test pressures. Therefore, the lowest possible fracture gradient constrained by the PITs has a vertical effective stress ratio of 0.55. An analysis of published regional data suggests a vertical effective stress ratio of 0.67 is more likely. Fracture gradient constraints were generalized with an effective horizontal to vertical effective stress ratio of 0.67 to be extrapolated to the target formation. These analyses result in an overburden of 18,705 psi and fracture gradient of 0.90 psi/foot (15,034 psi) at the top of the Madison Formation (approximately 16,744 feet MD / -10,055 feet TVDss) and overburden of 19,934 psi and fracture gradient of 0.90 psi/foot (16,017 psi) at the estimated top of the Bighorn-Gallatin Formation (approximately 17,815 feet MD / -11,126 feet TVDss).

4.4 Leakage through the Formation Seal

Leakage through the seal of the Madison Formation is highly improbable. An ultimate top seal to the disposal reservoir is provided by the evaporitic sequences within the Thaynes Formation. In fact, the natural seal is the reason the LaBarge gas field exists in the first place – the gas has been trapped in the LaBarge structure over a large amount of geologic time. The rock that forms the natural seal is impermeable to Helium (He), a gas with a much smaller molecular volume than CO_2. If the reservoir seal material is impermeable to He, then it follows that it is also impermeable to CO_2. The Thaynes Formation's sealing effect is also demonstrated by the fact that all gas production shallower than the Thaynes is void of sour gas, while all gas production below it is enriched in sour gases.

Although natural creep of the salty sediments below the Nugget Formation is possible, this behavior does not disturb the sediments to the degree necessary to breach the reservoir seal of the Madison Formation. If this salty sediment were to flow on a scale large enough to create a leakage pathway from the Madison Formation to the surface, the natural gases trapped in the formation would have leaked into the atmosphere during the long course of geological time up to this point. The fact that gas remains trapped at pressure in the Madison Formation, it must follow that any natural reactivation or movement of salt-rich sediments that has occurred over the geological history of the LaBarge field area has not created any pathways for gas leakage to the surface.

Wells are monitored to ensure that the injected gases stay sequestered. Any escaped acid gas from the AGI wells will be associated with H_2S, which has the potential to harm field operators. The CO_2 injection wellheads will be monitored with local CO_2 gas heads, which detect low levels of CO_2. The CO_2 injected cannot escape without immediate detection, as expanded upon in the below sections.

5.0 Detection, Verification, and Quantification of Leakage

5.1 Leakage Detection

As part of ongoing operations, SCTF continuously monitors and collects flow, pressure, temperature, and gas composition data in the Distributed Control System (DCS). This data is monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. Additionally, SCTF maintains in-field gas detectors to detect H_2S and CO_2 in the vicinity. If one of the gas detectors alarmed, it would trigger an immediate response to address the situation. In some instances, more than one detector alarming will trigger automatic equipment isolation/shutdown to mitigate the leak.

Leakage detection for the wells will incorporate several monitoring programs including visual inspection of the surface facilities and wellheads, injection well monitoring and MIT, and DCS surveillance. Table 5.1 provides general information on the leakage pathways, monitoring programs to detect leakage, and location of monitoring. Monitoring will occur for the duration of injection. As will be discussed in Section 7.0 below, ExxonMobil will quantify equipment leaks by using a risk-driven approach and continuous surveillance.

Table 5.1 - Monitoring Programs

Leakage Pathway	Detection Monitoring Program	Monitoring Location
Surface Equipment	DCS Surveillance Visual Inspections Inline Inspections Gas Alarms Personal H_2S Monitors	From injection flow meter to injection wellhead
Wells	DCS Surveillance Visual Inspections MIT Gas Alarms Personal H_2S Monitors	Injection well – from wellhead to injection formation
Faults and Fractures, Formation Seal, Lateral Migration	N/A – Leakage pathway is highly improbable	N/A

5.2 Leakage Verification

Responses to leaks are covered in the SCTF's Emergency Response Plan (ERP), which is updated annually. If there is a report or indication of a leak from the AGI facility from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and H_2S monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Pressure from the AGI system will be relieved to the flare, not vented, due to the dangerous composition of the gas.

The ERP will be updated to include the CO_2 injection facilities and corresponding wells after commencement of operations. If there is a report or indication of a leak from the CO_2 injection facilities from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and gas monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Once isolated from the CO_2 injection flowline, pressure from the affected CO_2 injection well will be relieved locally to atmosphere within the well site fence line.

5.3 Leakage Quantification

The leakage from surface equipment will be estimated once leakage has been detected and confirmed. Leakage quantification will consist of a methodology selected by ExxonMobil. Leakage estimating methods may potentially consist of modeling or engineering estimates based on operating conditions at the time of the leak such as temperatures, pressures, volumes, hole size, etc.

6.0 Determination of Baselines

ExxonMobil uses existing automatic data systems to identify and investigate excursions from expected performance that could indicate CO_2 leakage. The following describes ExxonMobil's approach to collecting baseline information.

Visual Inspections

Field personnel conduct daily inspections of the AGI facility and weekly inspections of the AGI well sites. The CO_2 injection facility and well sites will undergo weekly visual inspections. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize the possibility of CO_2 leakage. If an issue is identified, a work order will be generated to correct the issue.

H_2S Detection – AGI Wells

The CO_2 injected into the AGI wells is injected with H_2S at a concentration of 50 - 65% (500,000 - 650,000 ppm). H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. At this high of a concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm. Additionally, all field personnel are required to wear H_2S monitors for safety reasons. Personal monitors alarm at 5 ppm. Any gas detector alarm or personal H_2S monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the gas detectors and monitors are working correctly.

CO_2 Detection – CO_2 Injection Wells

The CO_2 injected into CO_2 injection wells will be at a concentration of approximately 99%. CO_2 gas detectors will be installed around the well sites, which will trigger at 0.5% CO_2. At 99% concentration of CO_2, leakage would trigger an alarm.

Continuous Parameter Monitoring

The DCS of the SCTF 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.

Well Testing

On an annual basis, the subsurface and wellhead valves are leak tested for mechanical integrity testing (MIT) as required by the WOGCC. Results from this type of testing are compared to previous MIT data to evaluate whether well integrity has been compromised.

Additionally, inline inspections are conducted of the AGI flow lines through the use of a smart pig to identify potential areas of corrosion in the pipeline. Results from this type of testing are compared to previous data to evaluate whether pipeline integrity has been compromised. The operations at the SCTF will have the ability to conduct inline inspections on the SC 5-2 and SC 7-34 flow lines, however inline inspections are not anticipated to occur frequently because no free water is expected to accumulate.

7.0 Site Specific Modifications to the Mass Balance Equation

To accommodate for site-specific conditions, as provided in 40 CFR 98.448, ExxonMobil proposes to modify quantifying equipment leaks by using a risk-driven approach. Due to the high H_2S concentration of the AGI fluids, monitoring poses a risk to personnel. Additionally, as mentioned above, even a small leak of this high H_2S gas would trigger an alarm. A small leak at the CO_2 injection wells would also trigger an alarm, as mentioned above. ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. This continuous surveillance using gas detectors identifies leaks better than an annual leak survey would 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 ExxonMobil will calculate the mass of CO_2 injected, emitted, and sequestered.

7.1 Mass of CO_2 Received

§98.443 states that "you must calculate the mass of CO_2 received using CO_2 received equations… unless you follow the procedures in §98.444(a)(4)." §98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." Since the CO_2 received by the AGI and CO_2 injection wells are wholly injected and not mixed with any other supply of CO_2, the annual mass of CO_2 injected would be equal to the annual mass of CO_2 received. No CO_2 is received in containers.

7.2 Mass of CO_2 Injected

Volumetric flow meters are used to measure the injection volumes at the AGI wells and are proposed for use to measure the injection volumes at the CO_2 injection wells. Equation RR-5 will be used to calculate the annual total mass of CO_2 injected.

Equation RR-6 will be used to aggregate injection data for the AGI 2-18, AGI 3-14, SC 5-2, and SC 7-34 wells.

7.3 Mass of CO_2 Produced

The AGI and CO_2 injection wells are not part of an enhanced oil recovery process, therefore, there is no CO_2 produced and/or recycled.

7.4 Mass of CO_2 Emitted by Surface Leakage and Equipment Leaks

It is not appropriate to conduct a leak survey at the AGI or the CO_2 injection well sites due to the components being unsafe-to-monitor and extensive monitoring systems in place. Entry to the AGI wells requires the individual to don a full face respirator supplied to breathing air, which would make completion of a leak survey very difficult. Due to the high H_2S concentration of the AGI fluids and the high CO_2 concentration of the CO_2 injection fluid, fugitive leakage would be detected and managed as an upset event in the same way that CO_2E (CO_2 emitted by surface leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time. As already mentioned, gas detectors are in operation continuously to survey the area for leaks; even a small leak would trigger an alarm. This methodology is consistent with 40 CFR 98.448(5), which provides the opportunity for an operator to calculate site-specific variables for the mass balance equation.

Therefore, parameters CO_2E and CO_2FI (total CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead) will be measured using the leakage quantification procedures described earlier in this plan. ExxonMobil will estimate the mass of CO_2 emitted from leakage points from the flow meter to the injection wellhead based on operating conditions at the time of the release – pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of leak. At the AGI wells, there are no CO_2 emissions from venting due to the high H_2S concentration of the acid gas; blowdown emissions are sent to the flares and are reported under Subpart W for the SCTF. Venting CO_2 injection gas would occur in the event of depressurizing for maintenance or testing, which would be measured during time of event.

7.5 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Since ExxonMobil is not actively producing oil or natural gas or any other fluids as part of the AGI process or CO_2 injection processes, Equation RR-12 will be used to quantify CO_2 injected and sequestered. Parameter CO_2I (total CO_2 injected through all injection wells) will be determined using Equation RR-5, as outlined above in Section 7.2. Parameters CO_2E and CO_2FI will be measured using the leakage quantification procedure described above in Section 7.4. CO_2 in the AGI fluids is not vented from equipment due to the high H_2S concentration.

8.0 Estimated Schedule for Implementation of Second Amended MRV Plan

The SCTF AGI facility and wells have been operational since 2005 and have been subject to the February 2018 MRV plan (approved by EPA in June 2018). Beginning with the start of injection of CO_2 and fluids into the CO_2 injection wells, this Second Amended MRV Plan will become the applicable plan for the AGI and CO_2 injection wells and will replace and supersede the February 2018 MRV plan for the AGI wells. Until that time, the February 2018 MRV plan will remain the applicable MRV plan for the AGI wells. Once the Second Amended MRV Plan becomes the applicable MRV plan, ExxonMobil will continue reporting under Subpart RR for the AGI wells, but will begin including the CO_2 injection wells on or before March 31 of the year after their respective injection begins. Once applicable, ExxonMobil anticipates this Second Amended MRV Plan will remain in effect until the end-of-field-life of the LaBarge 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, ExxonMobil has incorporated the following provisions into its QA/QC programs:

CO_2 *Injected*

- The injected CO_2 stream for the AGI wells will be measured upstream of the volumetric flow meter at the three AGI compressors, at which measurement of the CO_2 is representative of the CO_2 stream being injected, with a continuously-measuring online process analyzer. The flow rate is measured continuously, allowing the flow rate to be compiled quarterly.
- The injected CO_2 stream for the CO_2 injection wells will be measured with a volumetric flow meter and continuously-measuring online process analyzer upstream of the wellhead, at which measurement of the CO_2 is representative of the CO_2 stream being injected. The flow rate will be measured continuously, allowing the flow rate to be compiled quarterly.
- The continuous composition measurements will be averaged over the quarterly period to determine the quarterly CO_2 composition of the injected stream.
- The CO_2 analyzers are calibrated according to manufacturer recommendations.

CO_2 *emissions from equipment leaks and vented emissions of* CO_2

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

Measurement Devices

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

General

- The CO_2 concentration is measured using continuously-measuring online process analyzers, which is an industry standard practice.
- All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 Missing Data Procedures

In the event ExxonMobil 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 CO_2 injected is missing, it will be estimated using a representative quantity of CO_2 injected from the nearest previous time period at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in 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, ExxonMobil will revise and submit another amended MRV plan within 180 days to the Administrator for approval.

10.0 Records Retention

ExxonMobil will follow the record retention requirements of 98.3(g). Additionally, it will retain the following records from the AGI and CO_2 injection well sites for at least three years:

- Quarterly records of injected CO_2 for the AGI wells including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO_2 for the CO_2 injection wells 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 CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.