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

October 2019

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Introduction

Exxon Mobil Corporation (ExxonMobil) operates two acid gas injection (AGI) wells in the Madison reservoir located near LaBarge, Wyoming for the primary purpose of acid gas disposal with a subsidiary purpose of geologic sequestration of carbon dioxide (CO_2) in a subsurface geologic formation. The acid gas and CO2 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 Shute Creek Treating Facility AGI facility and wells have been operational since 2005 and have been subject to the February 2018 monitoring, reporting, and verification (MRV) plan (approved by EPA as of June 2018).

Because the amount of CO2 associated with the natural gas production is greater than the amount injected into the AGI wells, ExxonMobil is in the process of developing an additional Underground Injection Control (UIC) well, Shute Creek (SC) 5-2, for the primary purpose of disposal, with a subsidiary purpose of, geologic sequestration of fluids consisting primarily of excess CO2. ExxonMobil has received authority to inject fluids through the SC 5-2 disposal well into the Madison Formation by the Wyoming Oil and Gas Conservation Commission ("WOGCC"). WOGCC has also approved an aquifer exemption for the Madison Formation. ExxonMobil has filed an application to drill SC 5-2 from WOGCC. Like the AGI wells, the fluids to be injected into SC 5-2 are also components of the natural gas produced by ExxonMobil from the Madison formation. Once operational, SC 5-2 is expected to continue injection until the end-of-field life of the LaBarge assets.

Since SC 5-2 will inject into the same reservoir as the AGI wells, ExxonMobil is amending 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 in the Madison reservoir during the injection period. This amended plan, dated October 2019 ("Amended MRV Plan") will address all wells collectively when applicable, and otherwise broken out into sub sections to address the specifics of either the AGI wells or the SC 5-2 well, as appropriate. This Amended MRV Plan meets the requirements of §98.440(c)(1).

The February 2018 MRV plan is the currently applicable MRV plan for the AGI wells. ExxonMobil anticipates SC 5-2 will begin injection operations sometime prior to 2024. At that time, this Amended MRV Plan will become the applicable plan for the AGI wells and SC 5-2, and will replace and supersede the February 2018 MRV plan. At that time, ExxonMobil will continue reporting under Subpart RR for the AGI wells, but will begin including the SC 5-2 well on or before March 31 of the year after SC 5-2 injection begins. Once applicable, ExxonMobil anticipates this 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 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 reservoir.

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, 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 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 and SC 5-2 wells 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 Wyoming Oil and Gas Conservation Commission (WOGCC) regulates oil and gas activities in Wyoming. WOGCC classifies both the AGI and SC 5-2 wells in LaBarge as UIC Class II wells.
3. UIC injection well identification numbers:

Well Name	AGI 2-18	AGI 3-14	SC 5-2
Well Identification Number	4902321687	4902321674	Not yet Assigned

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 2.9 shows the relative location of the three wells.

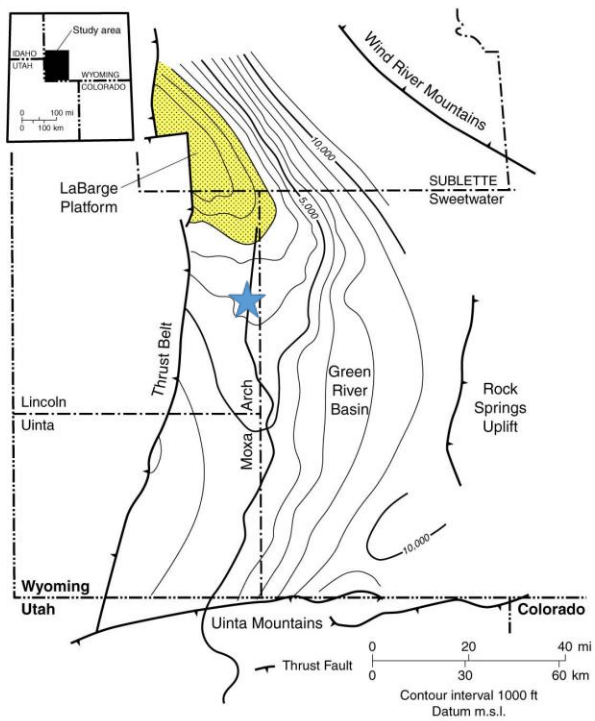

Figure 2.1 Location Map of the LaBarge Field, Wyoming. The injection area for the AGI wells and SC 5-2 is denoted by the blue star.

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

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 2.9 shows the relative location between the three wells.

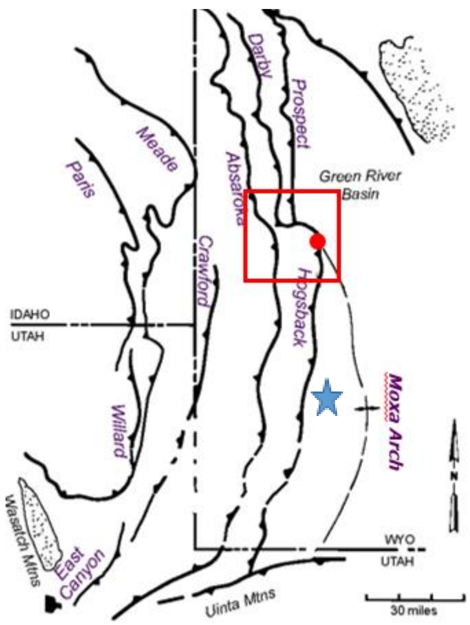

Figure 2.3 Schematic map showing location of Moxa Arch, regional thrust faults. The LaBarge field area is denoted by the red box and the approximate injection area for AGI wells and SC 5-2 is denoted by the blue star.

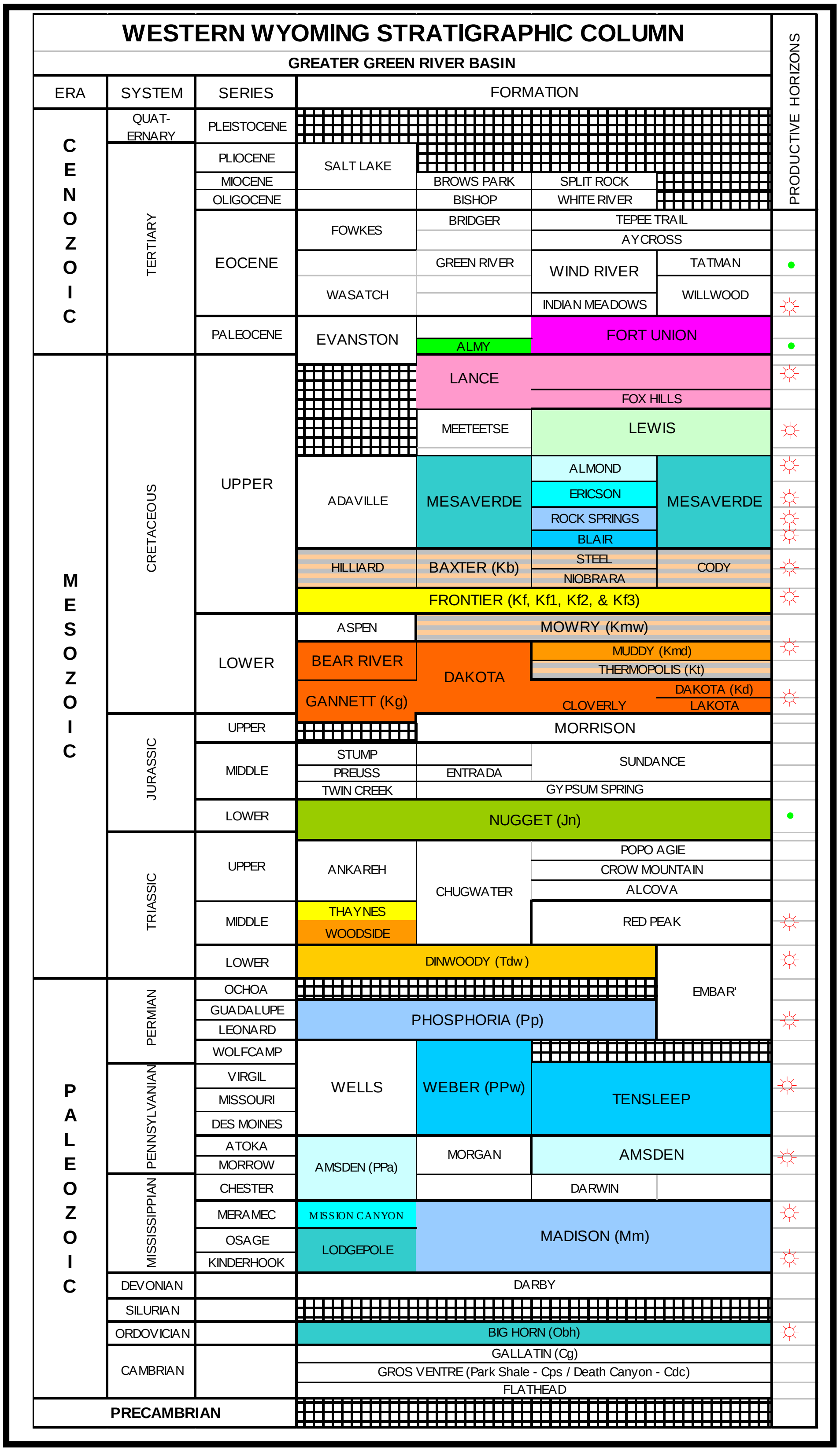

Figure 2.2 Generalized Stratigraphic Column for the Greater Green River Basin, Wyoming

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.

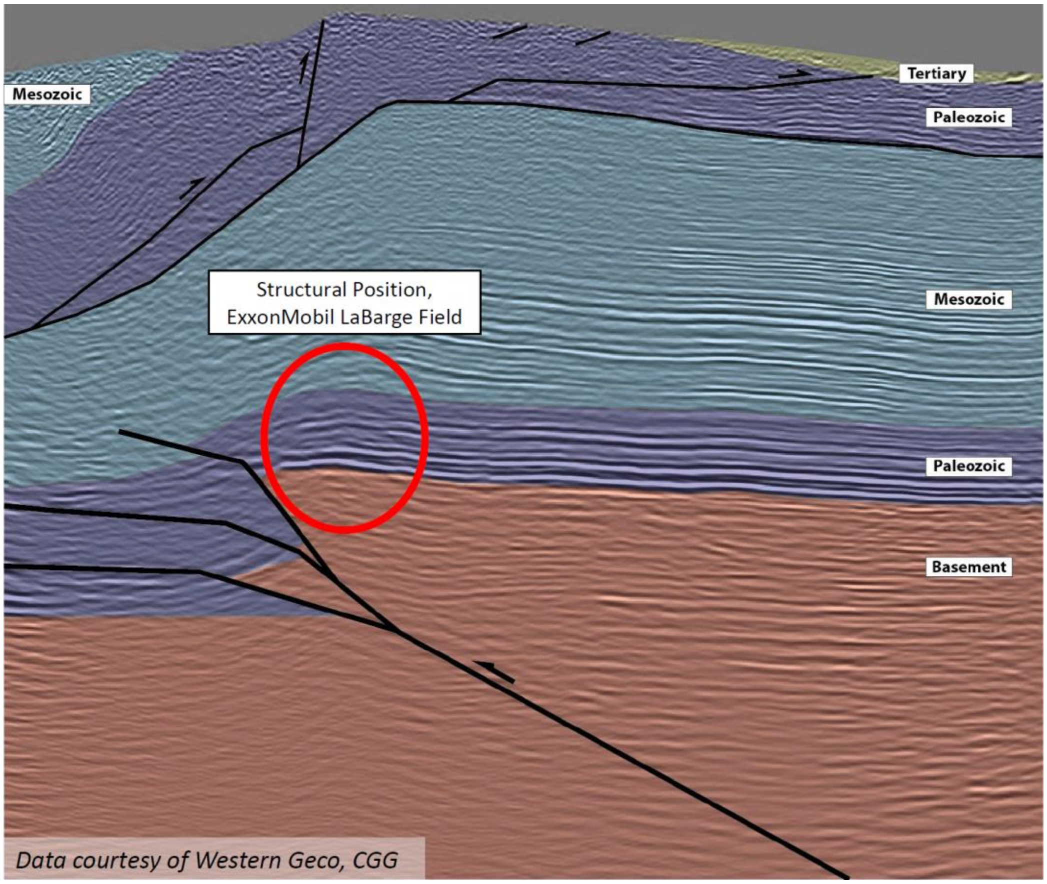

Figure 2.4 Example of thrust-cored monoclinal feature interpreted from 2D seismic data. The thrust-cored feature is believed to be a direct product of basement-involved contractional events.

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 the 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.

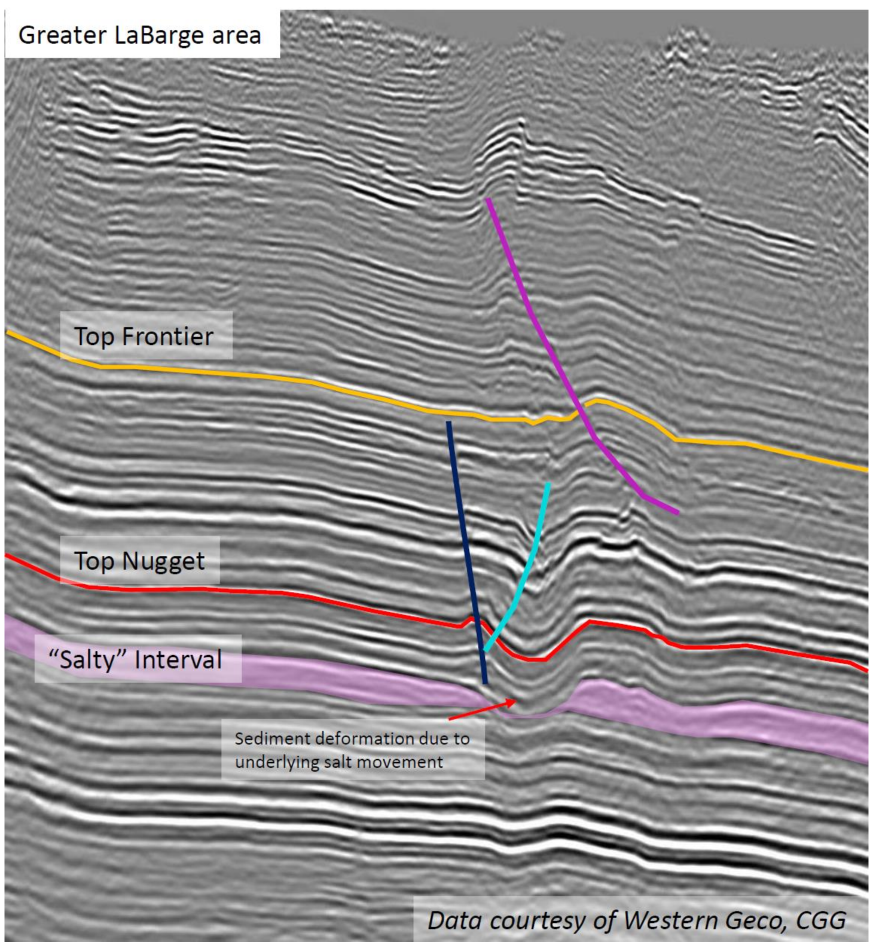

Figure 2.5 Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge field area

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 that 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 in an area, as is observed in the area of the existing AGI wells and area of the SC 5-2 well 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 is estimated to contain approximately 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 Madison 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 (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 Wyoming Oil & Gas Commission 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
- 2005 Acid Gas Injection Wells begin operation
- 2019 WOGCC approves SC 5-2 disposal 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.

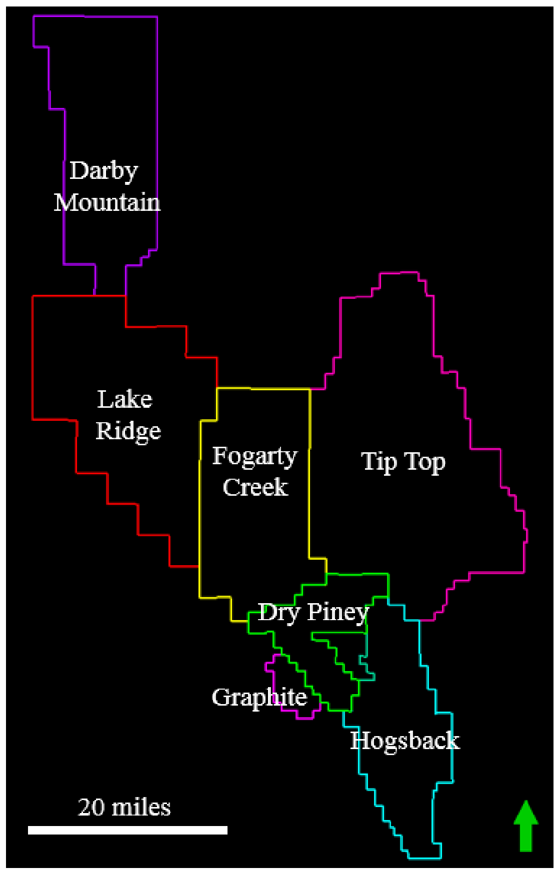

Figure 2.6 Unit map of the greater LaBarge field area

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 carbonate 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 167 TCF gross gas and is a world-class gas reserve that was felt to be 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 projects (EOR), CO_2 volumes have been historically sold from LaBarge to offset oil operators operating EOR oilfield projects. Originally, the SCTF contained a sulfur recovery unit 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 Injection Program

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 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 sold volume of CO_2 and CO_2 injected into the AGI wells does not equal the CO_2 gas produced, so the additional injection well, SC 5-2, is required. Gas composition is planned to be 99% CO_2 with minor amounts of methane, nitrogen, H_2O, COS, argon, and H_2S. The gas is planned to be injected at a depth of ~17,250 feet MD approximately 35 miles away from the main producing areas of LaBarge.

Figures 2.7 and 2.8 are schematic diagrams illustrating the AGI program and proposed SC 5-2 injection program, respectively.

2.6.2 Reservoir Quality of Madison Formation in Injection Wells

The existing AGI wells were successfully drilled, logged, and evaluated prior to injection commencement. Figure 2.7 is a schematic of two of the AGI wells (3-14 and 2-18). Figure 2.9 shows the relative location AGI 2-18, AGI 3-14, SC 5-2, as well as another well penetrating the Madison further updip. Figure 2.10 are well logs for AGI 3-14 and 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. Reservoir quality for the SC 5-2 injection well is expected to be similar to the AGI well quality. Updated average reservoir properties and well logs will be provided once the SC 5-2 well is drilled. Data will be submitted in the first annual monitoring report following commencement and operation of SC 5-2. Figure 2.11 shows a table summarizing the reservoir properties determined from the 3-14 and 2-18 wells. Figure 2.12 and Figure 2.13 show the stratigraphic and structural cross section of SC 5-2 in relation to AGI 3-14, AGI 2-18, and another well penetrating the Madison further updip.

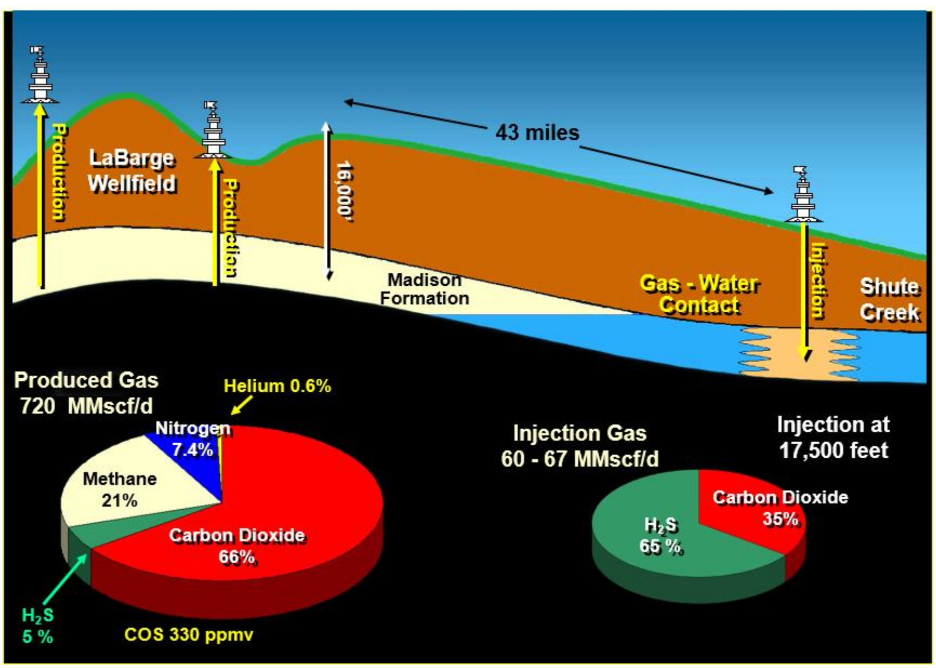

Figure 2.7 Schematic illustration of AGI injection program as currently used at LaBarge

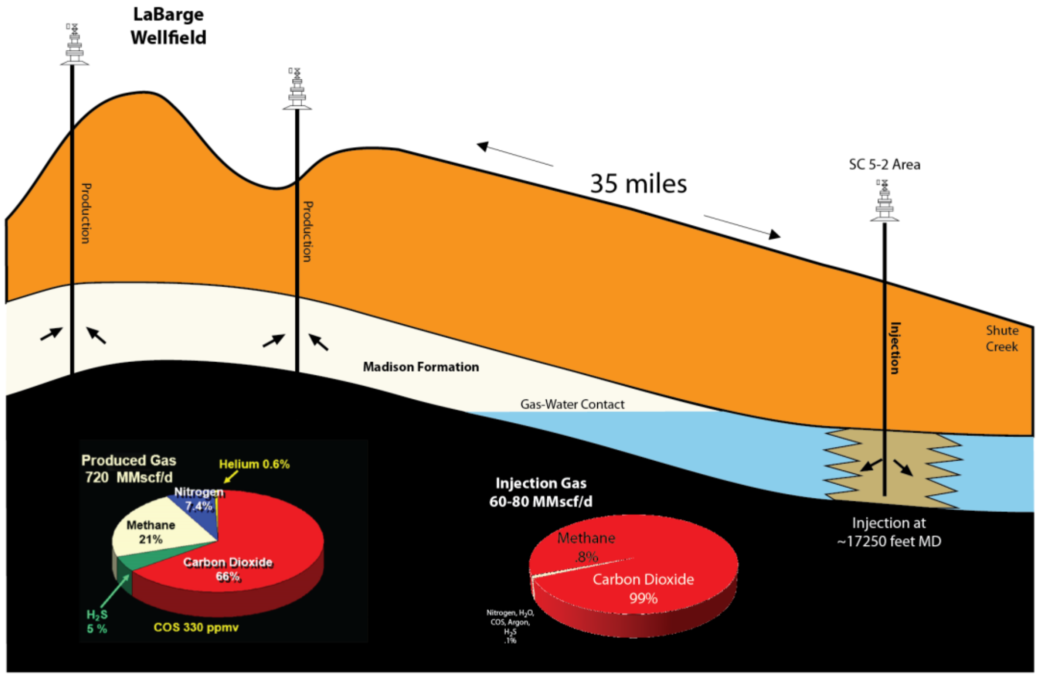

Figure 2.8 Schematic illustration of proposed SC 5-2 injection program

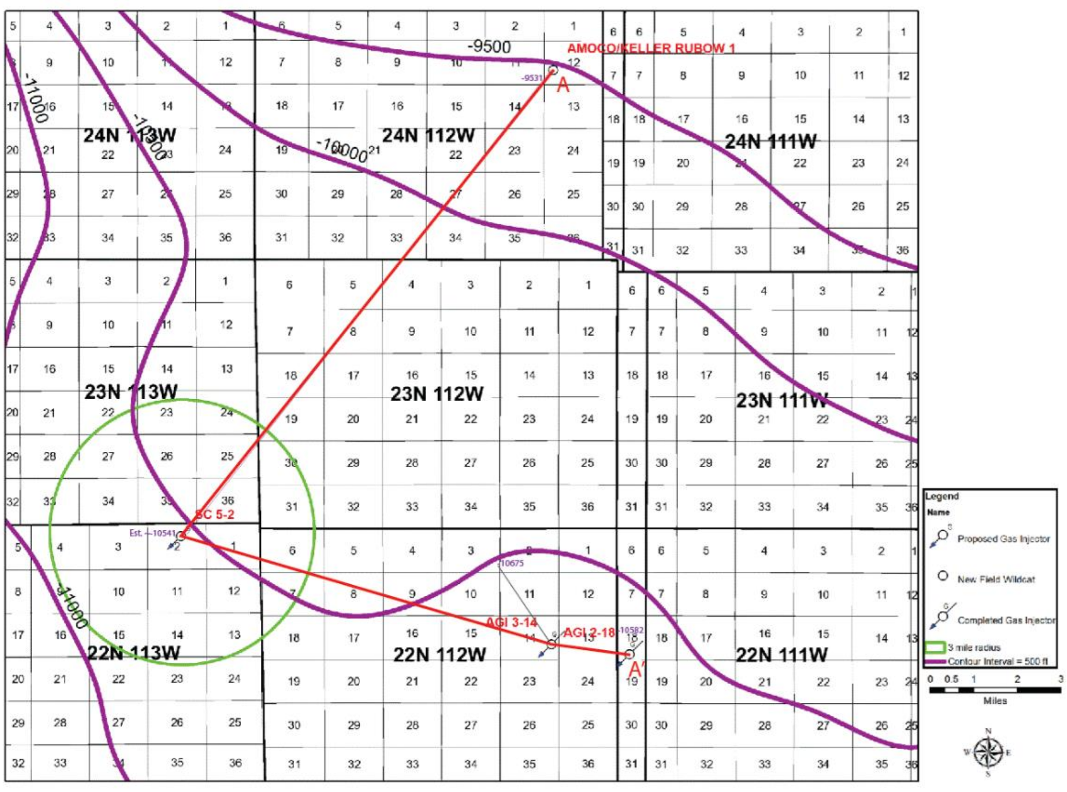

Figure 2.9 Madison Structure Map

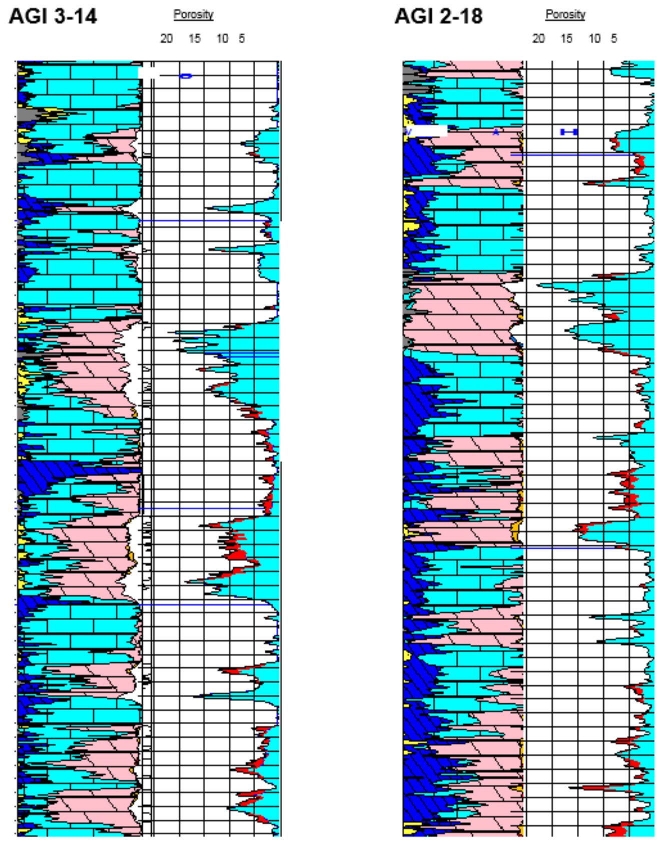

Figure 2.10 Well log sections from the AGI 3-14 and 2-18 injections wells across the Madison formation. Well log for SC 5-2 will be provided upon well completion. SC 5-2 Injection Well logs are expected to be similar to AGI wells.

AGI WELLS

	PRE-DRILL	ACTUAL	
		AGI 3-14	AGI 2-18
Net Pay (ft)	210	240	220
Avg ϕ (%)	7%	10%	9%
Avg k (md)	9	9	12
kh (md.ft)	1900	2300*	~2700*
Skin	0	-4.1*	-4.5*

* From injection / falloff test analysis

Figure 2.11 Average reservoir properties of the AGI Wells. SC 5-2 is expected to have similar properties.

To be updated post-drill: 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.

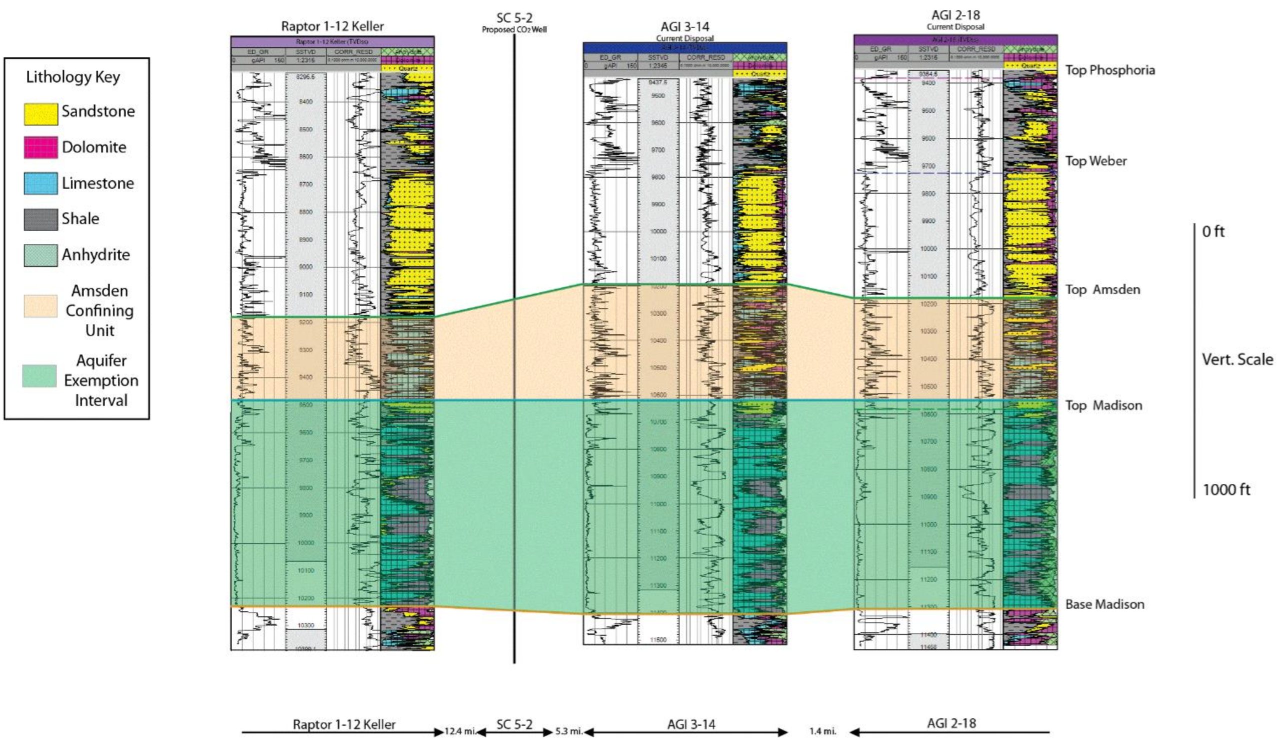

Figure 2.12 Stratigraphic Cross Section of Existing Madison Wells and the Proposed SC 5-2 Well

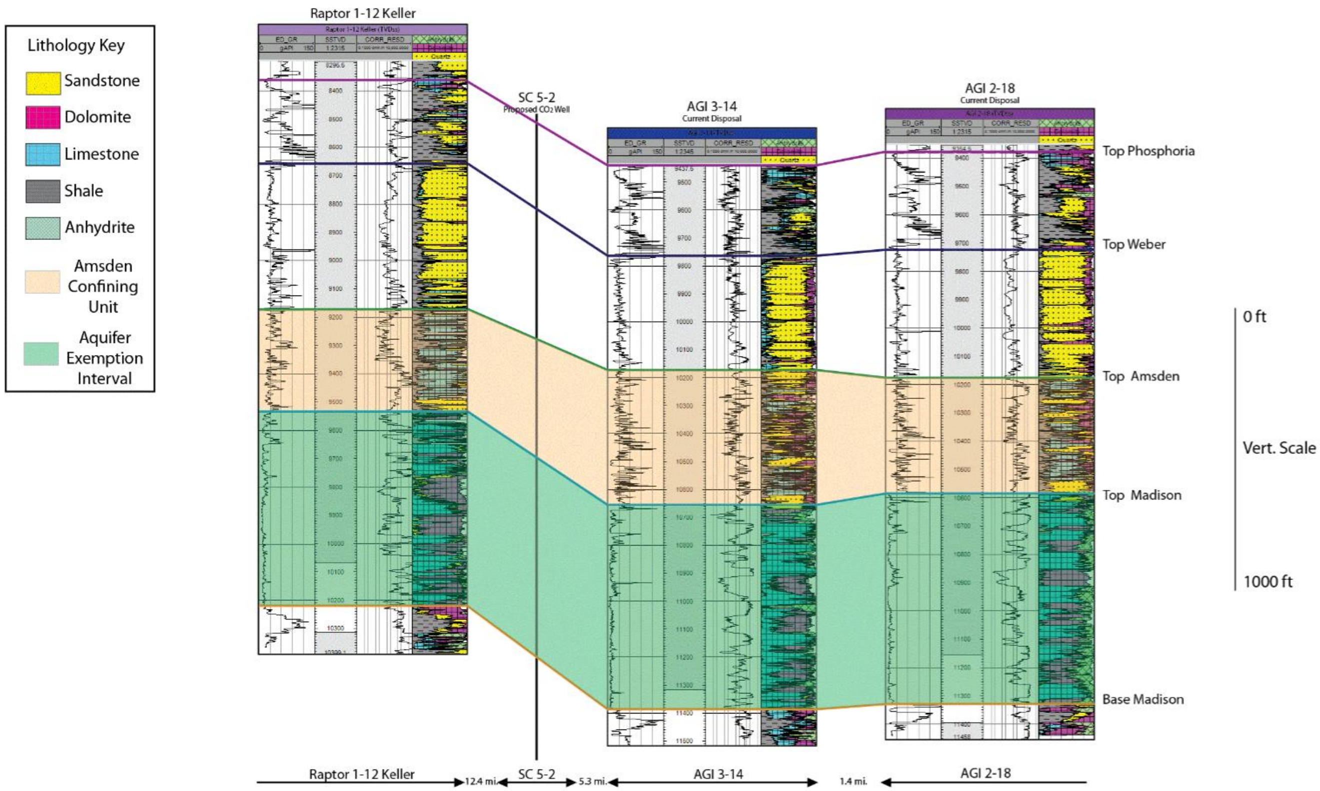

Figure 2.13 Structural Cross Section of Existing Madison Wells and the Proposed SC 5-2 Well

2.6.3 Seismic Expression of Madison Formation at SC 5-2 Proposed Location

Seismic expression of the Madison formation at the proposed SC 5-2 injection location indicates that the planned injection well is located on the plunging crest of the Moxa Arch with little to no structuring observable on the seismic data. Faulting is also not indicated by the seismic data. Figure 2.14 shows an east-west oriented 2D seismic at the SC 5-2 proposed injection area at five times vertical exaggeration.

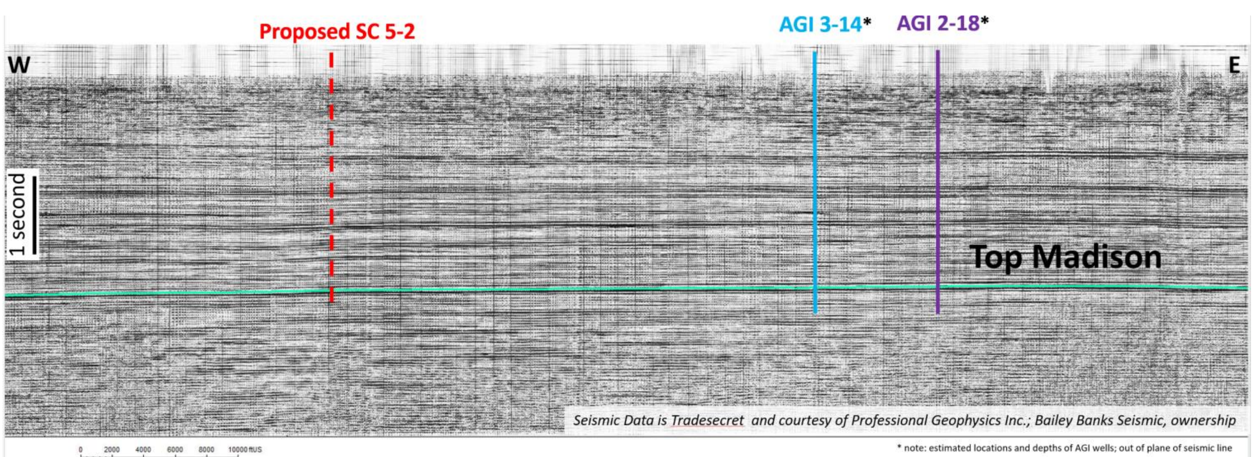

Figure 2.14 Seismic traverses around the proposed SC 5-2 injection well location shows no evidence of faulting or structuring around the well location

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 bottleneck, reducing plant downtime, and reducing operating costs. The purpose of AGI 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 reservoir. Production of raw gas and injection of acid gas are out of and into the Madison Formation. The Madison reservoir fluid contains very little CH_4 and He at the lower 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 system 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. 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 to the two injection wells (3-14 and 2-18). 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 SC 5-2 Process

The SC 5-2 injection project was initiated primarily to reduce excess CO2 emissions produced from source wells during natural gas operations. The project aims to capture CO_2 at the Shute Creek Treating Facility that would otherwise be vented, and compress it for injection into the Madison Formation.

The injection system would enable additional CO_2 to be stripped in the Selexol process, pressurized, and transported to injection well SC 5-2, 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 MMSCFD from Shute Creek Treating Facility then compressed with a closed loop cooling system. The captured CO_2 will have the potential to be either sold or injected into SC 5-2. Based on modeling, the approximate stream composition will be 99% CO_2, .8% Methane and .2% other mixed gases.

From the CO_2 compressors, a ten inch flow line of approximately 9.2 miles would take the fluidsto the injection site. The flow line would be buried with seven feet of cover. The fluids will have a sufficient dew point that free water formation is not expected to accumulate along the pipeline nor well. The water content of the gas will be continuously monitored. The gas will flow via the injection lines to the SC 5-2 well and injected at a proposed depth of 17,250 ft. Based on geological models, the risk of contaminating production from the LaBarge well field 35 miles away or interacting with the AGI Wells approximately 7 miles away is improbable.

2.8 Planned Injection Volumes

2.8.1 Acid Gas Injection Volumes

The below graph is a long-term injection forecast through 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, not just the CO_2 portion. ExxonMobil forecasts the total volume of CO_2 stored over the modeled injection period to be approximately 37 million metric tons.

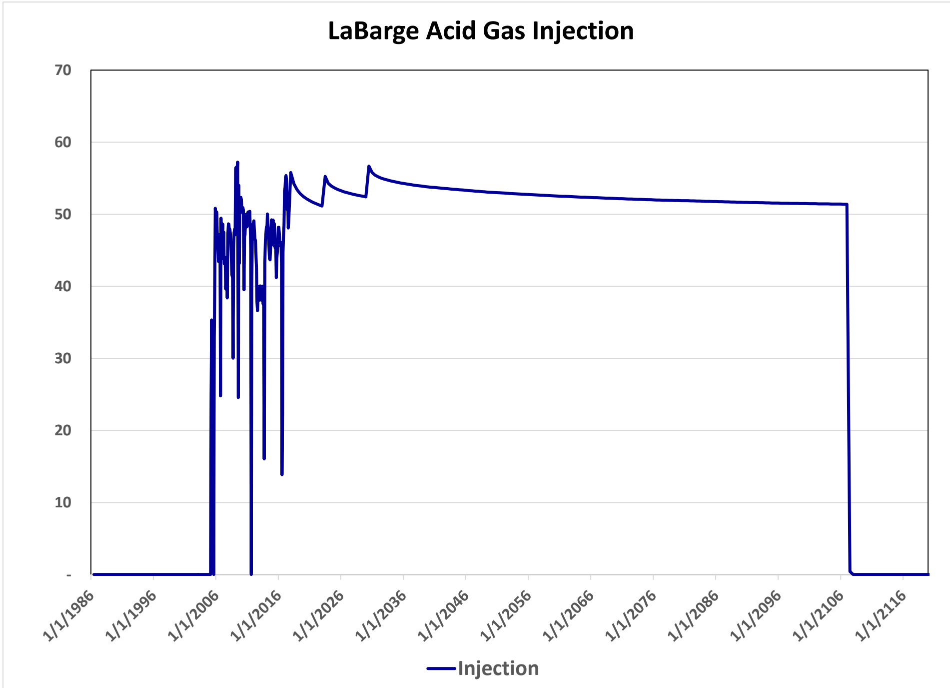

Figure 2.15– Planned Acid Gas Injection Volumes

2.8.2 SC 5-2 Injection Volumes

The graph below is a long-term injection forecast through the life of the SC 5-2 CO_2 injection project. 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 over the modeled injection period to be approximately 129 million metric tons.

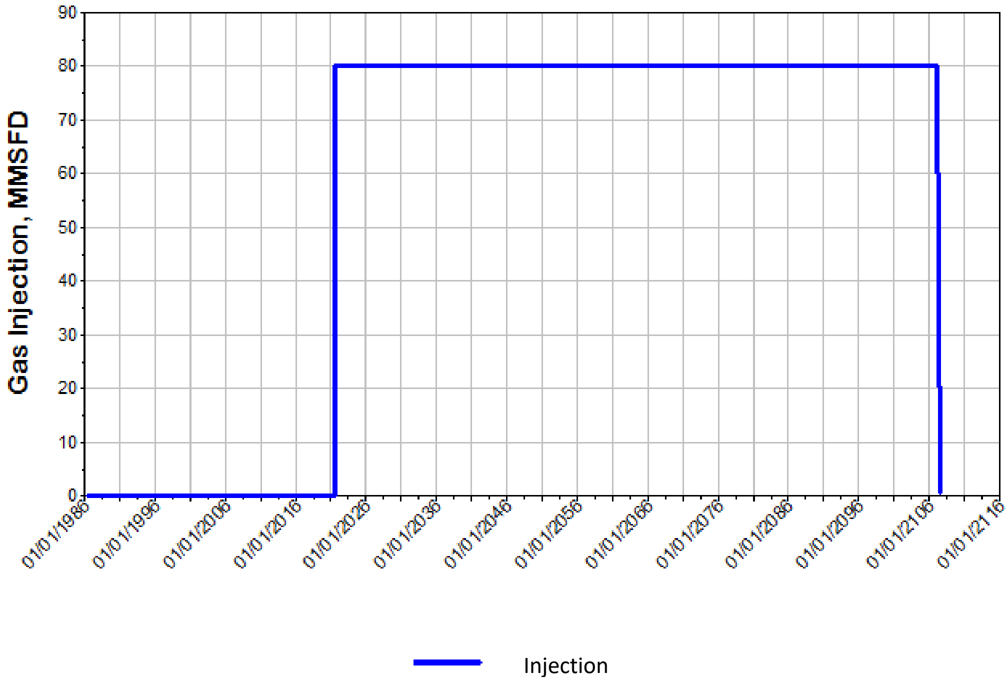

Figure 2.16 – Planned SC 5-2 Injection Volumes

3.0 Delineation of Monitoring Area

3.1 Maximum Monitoring Area (MMA)

3.1.1 AGI 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 0.5%. A gas saturation of 0.5% is well below the lowest gas saturation that can be confidently detected by formation evaluation methods in reservoirs with rock properties such as those found in the Madison formation.

After injecting 0.2 TCF by year-end 2017, the estimated acid gas plume size is approximately 15,000 feet in diameter (2.84 miles) (see Figure 3.1). With continuing injection of an additional 1.7 TCF through year-end 2106, at which injection is expected to cease, the plume size is expected to grow to approximately 36,000 feet in diameter (6.82 miles) (see Figure 3.2). Figure 3.3 shows how the predicted plume average diameter is expected to change over time.

The model was run through July 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. Expansion of the plume to a diameter of approximately 42,000 feet (7.95 miles) occurs by the year 2500 as the gas plume settles due to gravity segregation and dispersion. The plume is expected to continue settling, with a modeled plume size of approximately 44,000 feet (8.33 miles) by July 2986, 1000 years after production of the LaBarge field started and over 800 years after injection was shut-in. At this point, the rate of movement of the free-phase gas plume has decreased to less than four feet per year, demonstrating plume stability. Therefore, the MMA will be defined by Figure 3.4, which is the maximum areal extent of the plume once it has reached stability (defined by the extent of the plume in July 2986, which is an 8.3-mile diameter) plus the buffer zone of one-half mile.

3.1.2 SC 5-2 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 0.5%.

Assuming injection begins in 2021, 0.03 TCF of CO_2 has been injected by mid-2022 and the gas plume has just started to form. Figure 3.5 shows average gas saturations at mid-2022 and the location of the AGI wells relative to the SC 5-2 injection well. After injecting 2.5 TCF at year-end 2106 injection is expected to cease. The SC 5-2 CO_2 plume size is expected to grow to approximately 33,000 feet in diameter (6.3 miles) (see Figure 3.6).

Figure 3.3 shows how the predicted plume average diameter is expected to change over time. 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. Expansion of the plume to a diameter of approximately 37,000 feet (7.0 miles) occurs by the year 2500 as the gas plume settles due to gravity segregation and dispersion. The plume is expected to continue settling, with a modeled plume size of approximately 40,000 feet (7.6 miles) by year end 2986, 1000 years after production of the LaBarge field started and over 800 years after injection was shut-in. At this point, the rate of movement of the free-phase gas plume has decreased to less than four feet per year, demonstrating plume stability. Therefore, the MMA will be defined by Figure 3.4, which is the maximum areal extent of the plume once it has reached stability (defined by the extent of the plume at year end 2986, which is a 7.6-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 both the AGI and SC 5-2 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 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 formation 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 maximum monitoring area, 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.

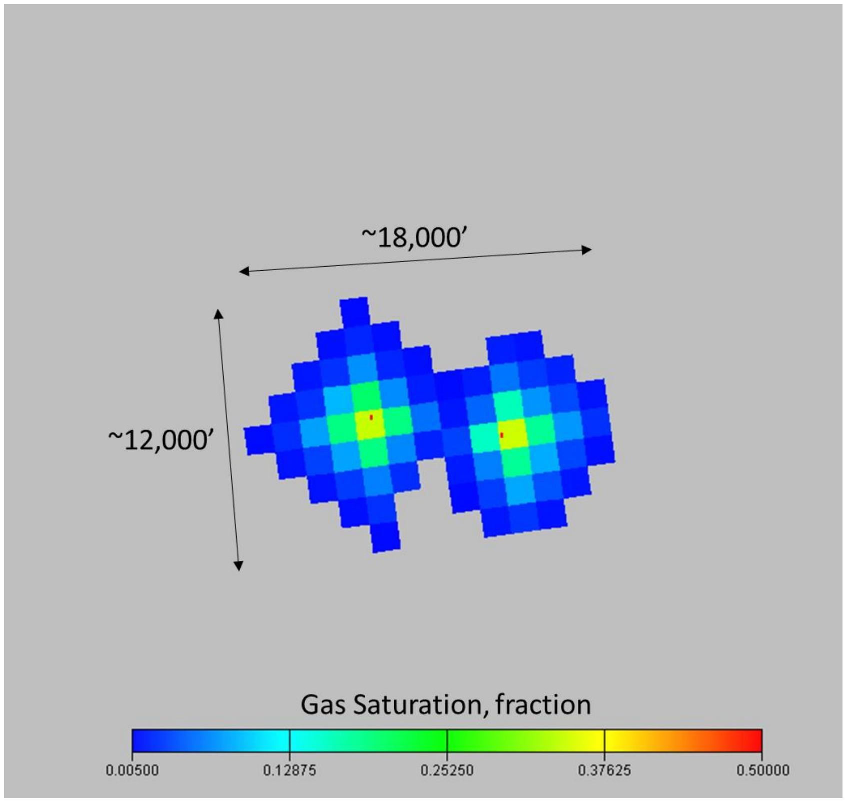

Figure 3.1 – AGI Gas Saturations at Year-end 2017

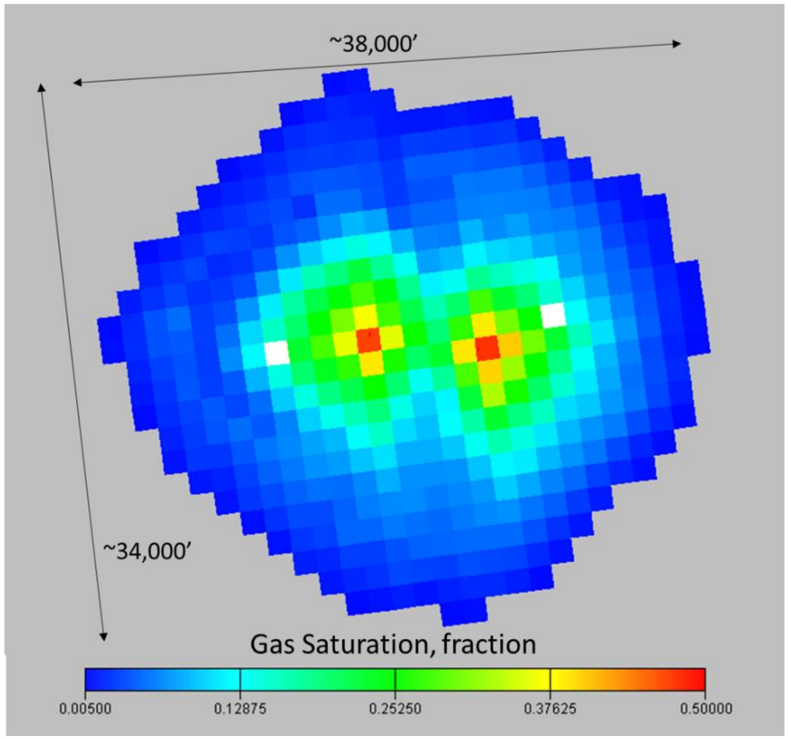

Figure 3.2 – AGI Gas Saturations at Year-end 2106

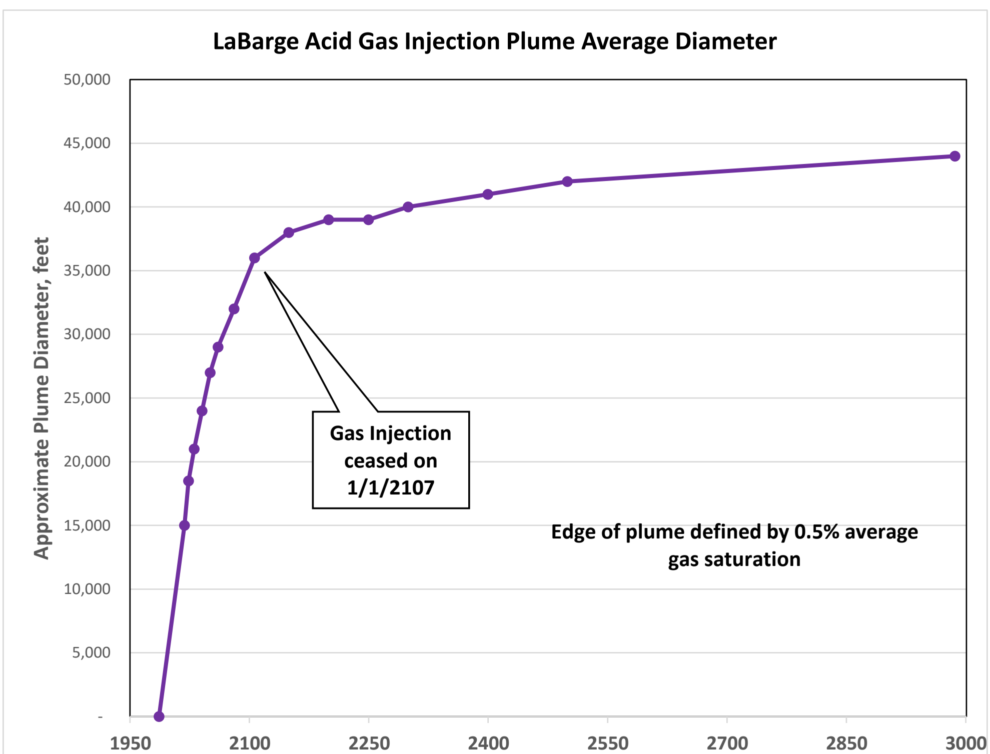

Figure 3.3 – Predicted LaBarge AGI Plume Diameter

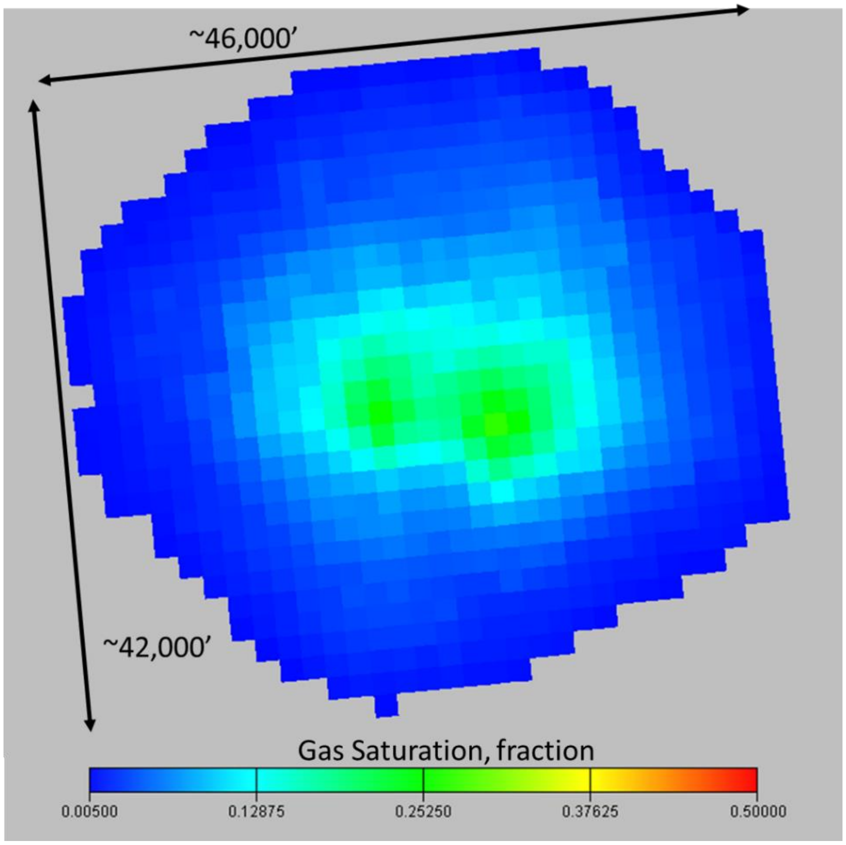

Figure 3.4 – AGI Gas Saturations at Year-end 2986

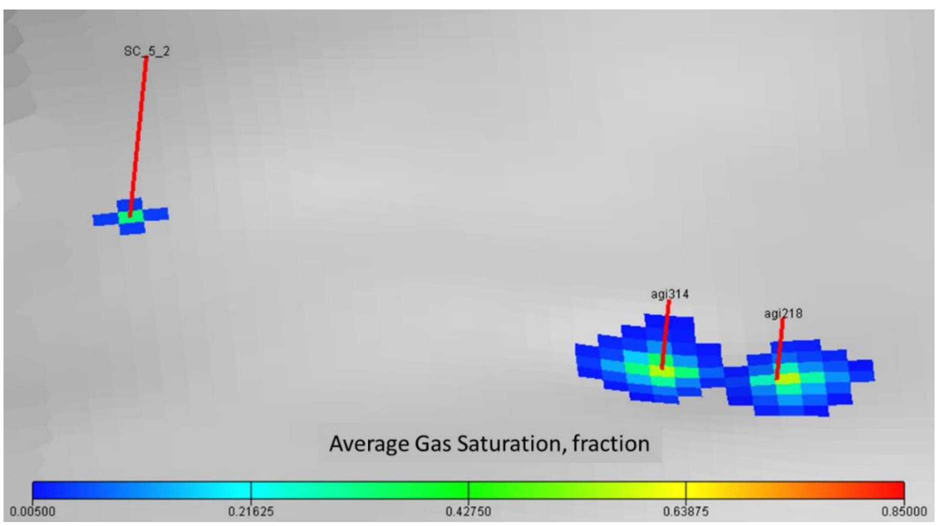

Figure 3.5 – Gas Saturations at mid Year-end 2022

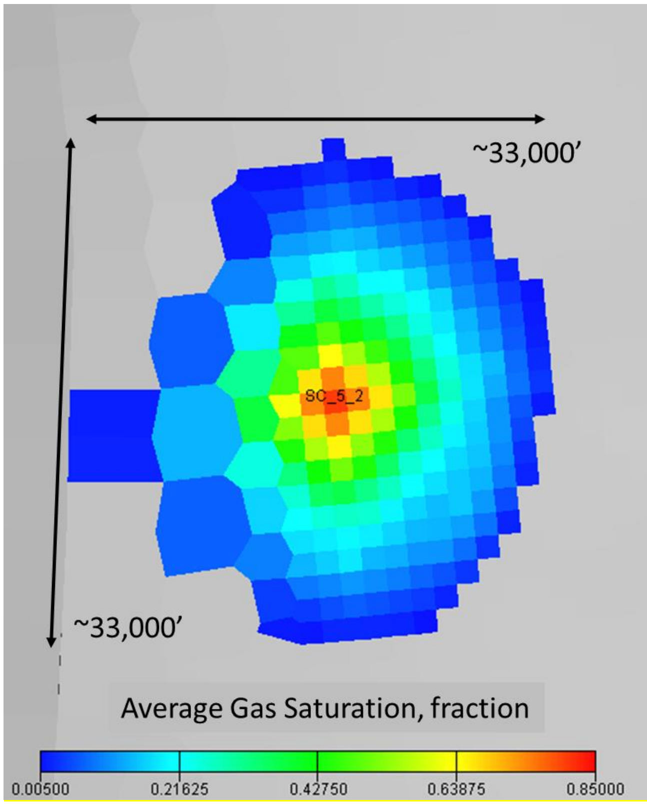

Figure 3.6 – SC 5-2 Gas Saturations at Year-end 2106

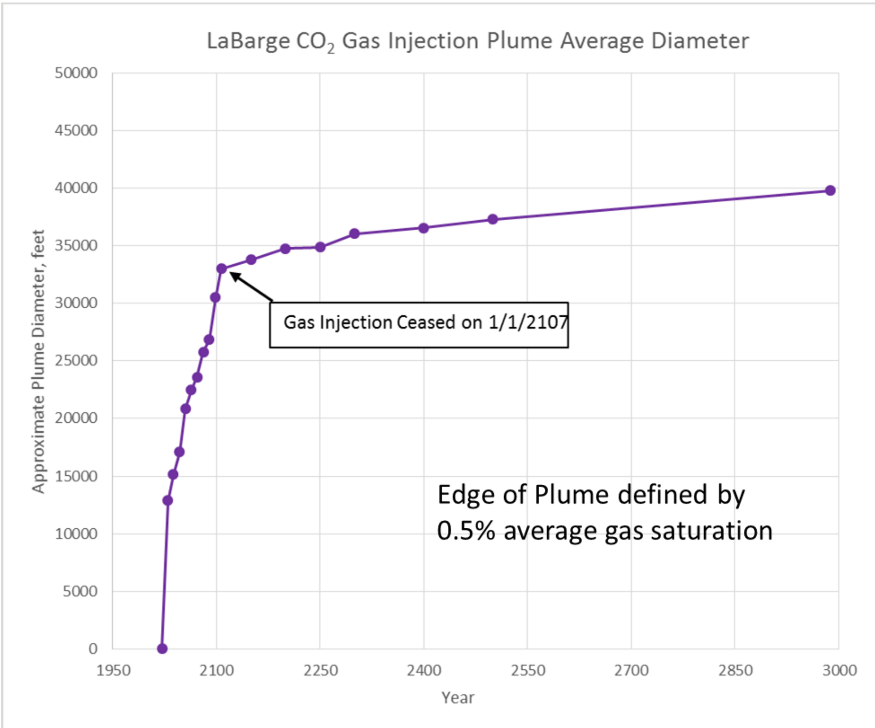

Figure 3.7 –SC 5-2 Predicted LaBarge CO_2 Plume Diameter

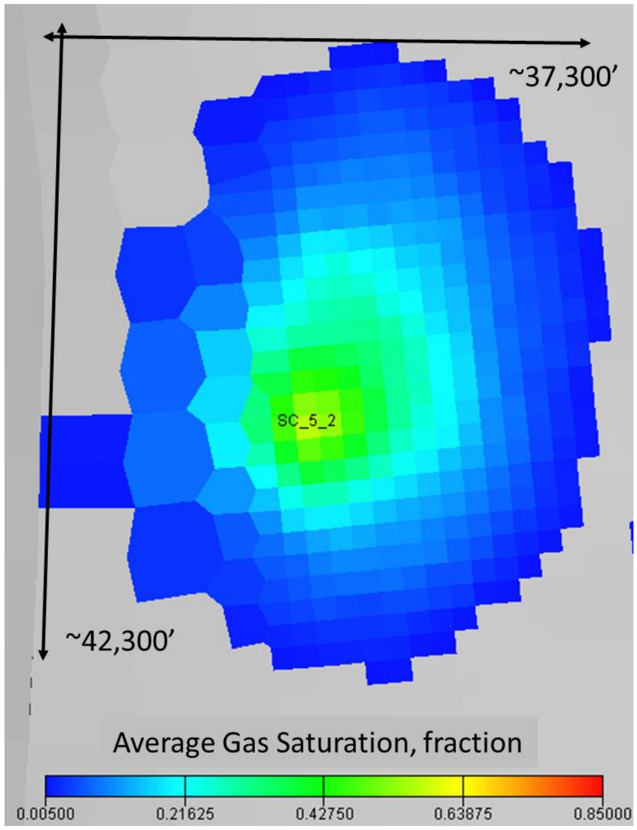

Figure 3.8 – SC 5-2 CO_2 Gas Saturations at Year-end 2986

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.

4.1 Leakage from Surface Equipment

Leakage from surface equipment is not likely due to the design of the AGI and SC 5-2 injection facilities. The facilities were designed to minimize leak points such as valves and flanges, and use welded connections where possible instead. The only surface equipment located between the flow meter and the wellhead are valves, transmitters, and flanged connection points on the pipelines. Due to the presence of H_2S in the AGI injection stream 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. CO_2 gas detectors will be present at the SC 5-2 injection facility due to high concentration of CO_2, which alarm at 5000 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 SC 5-2 well 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 controls system (DCS). Additionally, daily visual inspection rounds are conducted of the AGI facility and weekly visual inspections rounds 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 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 SC 5-2 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. The SC 5-2 well is also designed with a SCSSV, which will trip closed if leakage is detected. This would eliminate backflow out from the formation, minimizing leakage volumes. 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 SC 5-2 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 Madison penetrations or production within the respective MMAs of both the AGI and proposed SC 5-2 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 operated by Wexpro Company), which was located approximately six miles from the AGI wells, was drilled to the Madison formation back in 1974. However, the well never produced from the Madison formation and instead was perforated and had casing installed thousands of feet above in the Frontier formation. The well was ultimately plugged and abandoned in February 1992 and 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 P&A'd 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 the Madison formation.

Future drilling also does not pose a risk as a leakage pathway. Future drilling hazards are implied via the geological model presented in Figures 3.2 and 3.4, which shows that there is limited areal extent of the injection plume. 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, should future drilling occur, it would occur near the existing production area, which is greater than 40 miles away from the current acid gas injection wells and more than 35 miles away from SC 5-2.
ExxonMobil reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and mechanical integrity testing (MIT). As indicated in Section 4.1, visual inspections of the well sites are performed on a routine basis, which serves as a proactive and preventative method for identifying leaks in a timely manner. Gas detectors are located at the well sites which alarm at 10 ppm H_2S and 5000 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 wells, which would close in the event of leakage, preventing losses. Mechanical integrity testing is conducted on an annual basis and consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. If MIT demonstrated a leak, the well would be isolated and the leak would be mitigated as appropriate to prevent leakage to the atmosphere.

Should leakage result from the injection wellbores and into the atmosphere, the volume of 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 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 SC 5-2 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 reservoir 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. 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 Formation, 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 injection 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/ft (15,203 psi) at the top of the Madison Formation (~17,232 ft MD / -10,541 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.

4.4 Leakage through the Formation Seal

Leakage through the seal of the Madison reservoir is highly improbable. An ultimate top seal to the disposal reservoir is provided by the evaporitic sequences within the Thaynes Formation. In fact, the natural seal is the reason the reservoir 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 AGI wells will be associated with H_2S, which has the potential to cause injury to ExxonMobil employees. Although the SC 5-2 Well will have lower concentrations of H_2S, the wellhead 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 DCS. These data are monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. 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 Distributed Control System (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 facility's Emergency Contingency Plan (ECP), which is updated annually. If there is report or indication of a leak from the AGI Facilities from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and 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 ECP will be updated to include SC 5-2 after commencement of operations. If there is report or indication of a leak from SC 5-2 Facilites 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 CO2 injection flowline, pressure from the CO2 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 facilities and weekly inspections of the AGI well sites. The SC 5-2 well site 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 – SC 5-2

The CO_2 injected into SC 5-2 will be at a concentration around 99%. CO_2 gas detectors will be installed around the well site, which trigger 0.5% CO_2. At this high concentration of CO_2 leakage would trigger an alarm.

Continuous Parameter Monitoring

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

Well Testing

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 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 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 SC 5-2 well 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 process and SC 5-2 process is 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 each well. 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 wells AGI 2-18, AGI 3-14 and SC 5-2.

7.3 Mass of CO_2 Produced

The AGI and SC 5-2 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 AGI or SC 5-2 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 SC 5-2 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 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 gas plant. Venting SC 5-2 injection gas would only 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 SC 5-2 process, Equation RR-12 will be used to quantify CO_2 injected and sequestered. Parameter CO_2I will be determined used Equation RR-4, as outlined above in Section 7.2. Parameters CO_2E and CO_2FI will be measured using the leakage quantification procedure described above in Section 7.4. CO_2 in the AGI fluids is not vented from equipment due to the high H_2S concentration.

8.0 Estimated Schedule for Implementation of 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 CO2 and fluids for SC 5-2, this Amended MRV Plan will become the applicable plan for the AGI wells and SC 5-2, 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 Amended MRV Plan becomes the applicable MRV plan, ExxonMobil will continue reporting under Subpart RR for the AGI wells, but will begin including the SC 5-2 well on or before March 31 of the year after SC 5-2 injection begins. Once applicable, ExxonMobil anticipates this 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 flow rate of CO_2 injected is measured with a volumetric flow meter for each injection well and is monitored continuously, allowing the flow rate to be compiled quarterly.
- 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 continuous gas composition analyzer.
- The injected CO_2 stream for the SC 5-2 well will be measured with a volumetric flow meter and continuous gas composition analyzer upstream of the wellhead.
- 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

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

Measurement Devices

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

General

- The CO_2 concentration is measured using continuous gas 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 an 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 both AGI and SC 5-2 injection well sites for at least three years:

- Quarterly records of injected CO_2 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.