UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

June 22, 2023

Mr. Adam Dunlop
Blue Flint Sequester Company, LLC
2841 3rd Street SW
Underwood, North Dakota 58576

Re: Monitoring, Reporting and Verification (MRV) Plan for Blue Flint Sequester Company, LLC

Dear Mr. Dunlop:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Blue Flint Sequester Company, LLC, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Blue Flint Sequester Company, LLC on April 26, 2023, as the final MRV plan. The MRV Plan Approval Number is 1014505-1. This decision is effective June 27, 2023 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78.

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,

K. Chin for

Julius Banks, Chief
Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for the Blue Flint Sequester Company, LLC

June 2023

Contents

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) Subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted by Midwest AgEnergy Group, LLC's Blue Flint Sequester Company, LLC (BFSC) for its carbon dioxide (CO_2) capture and storage (CCS) project located in Underwood, North Dakota. Note that this evaluation pertains only to the Subpart RR MRV plan for the BFSC, 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

Section 1 of the MRV plan provides a description of the Blue Flint CO_2 storage project. The MRV plan states that Blue Flint Capture Company, LLC (BFCC) plans to capture 200,000 metric tons of CO_2 annually over a 20-year period from the Blue Flint Ethanol, LLC (BFE) facility. According to the MRV plan summary, BFSC submitted a North Dakota Underground Injection Control (UIC) Class VI permit (storage facility permit [SFP]) application to the North Dakota Industrial Commission (NDIC) Department of Mineral Resources (DMR) on October 3, 2022.

According to the MRV plan, BFE is located six miles south of Underwood, North Dakota along the eastern flank of the Williston Basin. It produces about 200,000 metric tons of CO_2 annually as byproduct of the fermentation process. The MRV plan states that BFCC will utilize a liquefaction process to capture CO_2 produced from fermentation at the BFE facility. The captured CO_2 will be processed for compression and transported in a 3-mile-long CO_2 flowline to a single CO_2 injection well at the BFSC facility. A stratigraphic test well (MAG 1) was drilled for the Blue Flint CO_2 storage project and the MRV plan states that it will be converted into a UIC Class VI injection well. A second stratigraphic test well (MAG 2) will be drilled and converted into a monitoring well. The MRV plan explains that the CO_2 stream will be injected into the Broom Creek Formation, a predominantly sandstone reservoir and saline aquifer, at an approximate depth of 4,708 feet below the ground surface at the MAG 1 well location. The MAG 1 well has a surface elevation of 1,905 feet.

Section 1 of the MRV plan also describes the geologic setting of the Blue Flint CO_2 storage project. The Williston Basin is a sedimentary, hydrocarbon-bearing, intracratonic basin covering 150,000 square miles. BFSC states that there has been no significant commercial production of hydrocarbon resources in the immediate project area. As stated in the MRV plan, the closest oil and gas fields are 39 miles west of the western edge of the projected stabilized CO_2 plume boundary. The MRV plan states that although commercial oil and gas production is not present in the area surrounding the project, legacy oil and gas wells are present.

BFSC states that siltstones with interbedded anhydrite of the Lower Spearfish Formations uncomformably overlie the Broom Creek Formation and serve as the upper (primary) confining zone. Mixed layers of dolostone, limestone, and anhydrite of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone. The MRV plan also states that there is about 859 feet (average thickness) of impermeable rock, including the lower Piper-Spearfish, between the Broom Creek and the next overlying porous zone, the Inyan Kara Formation. An additional 2,512 feet (average thickness) of impermeable rock, including the Skull Creek, Mowry, Bell Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations, separate the Inyan Kara from the Fox Hills Formation (lowest underground source of drinking water [USDW]).

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

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

As part of the MRV plan, the reporter must identify and delineate both the maximum monitoring area (MMA) and active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines the 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 the 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.

BFSC states in Section 2 of the MRV plan that the area of review (AOR) boundary defined in the North Dakota SFP application will serve as the MMA and the AMA until facility closure (i.e., the point at which Blue Flint receives a certificate of project completion). As illustrated in the MRV plan, the AOR boundary, rounded to the nearest 40-acre tract, provides a 1-mile buffer around the modeled stabilized CO_2 plume. BFSC states that this 1-mile buffer area is larger and thereby exceeds the regulatory requirements for buffer areas around the free-phase CO_2 plume with respect to subpart RR definitions for the MMA and the AMA. BFSC will begin to monitor approximately one year prior to injection, during the active 20-year injection period, and for a minimum of 10 years after injection ceases.

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

3 Identification of Potential Surface Leakage Pathways

As part of the MRV plan, the reporter must identify potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). In section 3 of their MRV plan, BFSC identified the following potential leakage pathways that required consideration:

- Class VI Injection Well
- Monitoring Well
- Surface Components
- Class I Nonhazardous Disposal Wells
- Abandoned Oil and Gas Wells
    - Ellen Samuelson 1
    - Wallace O. Gradin 1
- Faults, Fractures, Bedding Plane Partings, and Seismicity
    - Stanton Fault
    - Natural or Induced Seismicity
- Confining System Pathways
    - Lateral Migration
    - Seal Diffusivity
    - Drilling Through the CO_2 Area

3.1 Class VI Injection Well (MAG 1)

As stated in the MRV plan, the MAG 1 well was spudded on October 11, 2020, as a stratigraphic test well and drilled to a depth of 9,213 feet into the Red River Formation. The MAG 1 well will be completed to NDIC Class VI construction standards as an injection well for the Blue Flint CO_2 storage project. BFSC states they will continuously monitor the temperature of the MAG 1 wellbore using distributed temperature sensing (DTS) fiber optic cable. They will also continuously monitor the wellbore pressure with at least one downhole, tubing conveyed pressure-temperature (P-T) gauge and digital surface pressure gauges on the tubing and well annulus. BFSC will test the tubing-casing annulus prior to injection and at least once every five years thereafter. Furthermore, BFSC will acquire an ultrasonic or alternative casing inspection log prior to injection to detect any potential mechanical integrity issues behind casing and repeated at least once every five years. The MRV plan states that the risk of surface leakage of CO_2 via the MAG 1 well is mitigated through:

- Monitoring operations with a surface leak detection plan;
- Preventing corrosion of well materials;
- Performing wellbore mechanical integrity testing;
- Monitoring the storage reservoir with a subsurface leak detection plan (environmental monitoring plan);
- Acting in accordance with the emergency remedial response plan.

According to the MRV plan, barriers associated with well construction that prevent reservoir fluids from reaching the surface include surface valves; injection tubing fitted with a packer set above the injection zone; annular casing and cement; and surface casing and cement. The MRV plan states that the potential for a surface leak from the MAG 1 injection well is present from the first day of injection through the post-injection phase. The risk of a surface leak begins to decrease after injection ceases and greatly decreases as the reservoir approaches original pressure conditions. Once injection ceases, the MAG 1 well will be properly plugged and abandoned following NDIC protocols, thereby further reducing any remaining risk of surface leakage from the wellbore. For these reasons, the likelihood of surface leakage of CO_2 from the MAG 1 well during injection or post-injection operations is described as very low

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through the Class VI injection well at BFSC.

3.2 Monitoring Well (MAG 2)

As stated in the MRV plan, the MAG 2 well is planned to spud prior to injection as a stratigraphic test well for the Blue Flint CO_2 storage project. The well will be drilled to the Amsden/Tyler formations and be converted into a monitoring well prior to injection. The MRV plan states that the MAG 2 well will be constructed to NDIC Class VI standards. Similar to the MAG 1 well, BFSC plans to monitor the MAG 2 well with continuous DTS fiber-optic cable, at least one tubing-conveyed P-T gauge, and digital surface pressure gauges on the tubing and well annulus. The MRV plan states that the tubing-casing annulus pressure will be tested prior to injection and at least once every five years. An ultrasonic or alternative casing inspection log will also be acquired prior to injection for detecting any potential mechanical integrity issues behind casing and repeated at least once every five years.

According to the MRV plan, barriers associated with well construction that prevent reservoir fluids from reaching the surface include the wellhead, tubing with packer, surface valves, surface casing and cement, and production casing and cement. The MRV plan states that since the MAG 2 well is located just inside the projected stabilized CO_2 plume boundary, the potential for a surface leak begins near the end of the 20-year injection period and continues during the post-injection phase of the project. The risk of a surface leak decreases after injection ceases as the reservoir approaches original pressure conditions. At the end of the post-injection monitoring phase, the MAG 2 well will be properly plugged and abandoned following NDIC protocols, thereby further reducing any remaining risk of surface leakage from the wellbore. For these reasons, BFSC states that the likelihood of surface leakage of CO_2 from the MAG 2 well during injection or post- injection operations is very low because of well construction and active monitoring.

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

3.3 Surface Components

As stated in the MRV plan, the flowline will be monitored continuously via dual flowmeters located at the liquefaction outlet and near the wellhead for performing mass balance calculations. The flowline will also be regularly inspected for any visual or auditory signs of equipment failure and monitored continuously with one pressure gauge at the liquefaction outlet and one near the wellhead. BFSC plans to mitigate the likelihood of CO_2 leakage that may occur via surface equipment through:

- Adhering to regulatory requirements for construction and operation of the site;
- Implementing the highest standards on material selection and construction processes for the flowlines and wells;
- Applying operational best practices and a robust mechanical integrity program as well as operating procedures; and
- Monitoring continuously via an automated and integrated system.

BFSC has determined that the likelihood of leakage through surface equipment during injection is very low, and the magnitude is limited to the volume of CO_2 in the flowline. The risk is constrained to the active injection phase of the project when surface equipment is in operation.

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

3.4 Class I Nonhazardous Disposal Wells

BFSC has identified one UIC Class I disposal well (Well #1) that is currently active within the Blue Flint CO_2 storage project area. According to the MRV plan, Well #1 is drilled to a depth of 4,046 feet into the Swift Formation and disposes nonhazardous wastewater into the Newcastle, Skull Creek, and Inyan Kara Formation. Although Well #1 lies within the MAG 1 storage facility AOR, the location of the well is outside of the projected stabilized plume boundary. Furthermore, the MRV plan states that the injection reservoir of Well #1 is 1,000 feet vertically above the CO_2 storage formation and is separated by multiple impermeable geologic seals. Although Well #1 is expected to remain an active injection well during operation of the Blue Flint CO_2 storage project, BFSC does not view Well #1 as an anticipated CO_2 surface pathway.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through Class I nonhazardous disposal wells.

3.5 Abandoned Oil and Gas Wells

Ellen Samuelson 1

The MRV plan states that the Ellen Samuelson 1 was spudded, plugged, and abandoned during the same year (1957). The well was drilled to a depth of 6,600 feet into the Mission Canyon Formation of the Madison Group, which is below the MAG 1 storage complex. The MRV plan states that the drilling, coring, and log data indicate that no commercial accumulations of hydrocarbons were present in any of the subsurface formations drilled. As the Ellen Samuelson 1 well is 7,140 feet beyond the edge of the projected stabilized plume boundary, BFSC does not anticipate CO_2 surface leakage to occur through the wellbore. Furthermore, the MRV plan states that the Ellen Samuelson 1 well was plugged and abandoned in accordance with NDIC requirements.

Wallace O. Gradin 1

Additionally, the MRV plan also states that the Wallace O. Gradin 1 well was spudded, plugged, and abandoned in 1969. The well was drilled to a depth of 4,240 feet into the Rierdon Formation, which is above the sealing formations associated with the MRV plan. Well testing was completed in potential hydrocarbon-bearing formations, but no commercial volumes were produced. The Wallace O. Gradin 1 well is located 11,850 feet beyond the projected stabilized plume boundary. Furthermore, the MRV plan states that the Wallace O. Gradin 1 well was plugged and abandoned in accordance with NDIC requirements.

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

3.6 Faults, Fractures, Bedding Plane Partings, and Seismicity

The MRV plan states that regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations could not be identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration reports.

Stanton Fault

BFSC states that the Stanton Fault was identified within the AOR boundary in previous literature. Based on the seismic data analyzed as part of the site characterization activities, BFSC believes this fault either does not exist or is confined to the Precambrian basement. The MRV plan states that the storage reservoir is approximately 5,000 feet above the Precambrian basement within the AOR. Therefore, the MRV plan states that no CO_2 leakage to the surface is anticipated due to the Stanton Fault.

Natural or Induced Seismicity

The MRV plan states that 13 seismic events were detected within the North Dakota portion of the Williston Basin between 1870 and 2015. The two closest events occurred 52.3 miles to the east (2.6 Richter [R]) and 55.8 miles to the southwest (0.2R) of the MAG 1 wellbore. BFSC states that a 1-year seismic forecast (including both induced and natural seismic events) released by the U.S. Geological

Survey (USGS) in 2016 determined that North Dakota has a very low risk (less than 1%) of experiencing any seismic events (induced and natural seismic) resulting in damage. BFSC determined that only two historic earthquakes in North Dakota (both 2.6R or lower) had the potential to be associated with oil and gas activities. Additionally, the MRV plan also states injection pressures into the MAG 1 well will not exceed 90% of the fracture pressure of the injection zone pursuant to NDAC 43-05-01-11.3. For these reasons, BFSC concluded that the probability of CO_2 leakage to the surface due to natural or induced seismicity is very low.

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

3.7 Confining System Pathways

The MRV plan states that leakage through confining system pathways could occur in the form of lateral migration, seal diffusivity, and drilling through the CO_2 area.

Lateral Migration

The MRV plan states that the upper confining zone (lower Piper and Spearfish Formations) will serve as the primary mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation. Together, these formations are laterally extensive and are found at depths starting at 4,560 feet below the surface with a combined thickness of 148 feet at the MAG 1 well. The lower Piper and Spearfish Formations are presumed to prevent lateral movement of the CO_2 with residual gas trapping (relative permeability and solubility trapping [dissolution of the CO_2 into the native formation brine]). Due to the geologic properties (lateral extent, mineralogy, permeability, and lack of faults and fractures) of the confining lithologic layers, BFSC believes that risk of surface leakage of CO_2 via lateral migration is very low.

Seal Diffusivity

BFSC also explains that several other formations will provide additional confinement above the lower Piper and Spearfish Formations. These formations include the upper Piper, Rierdon, and Swift Formations and have a combined thickness of 859 feet. The MRV plan states that these formations will provide another barrier between the Broom Creek formation and the next porous and permeable interval, the Inyan Kara Formation. Furthermore, there is 2,512 feet of impermeable rock (Skull Creek, Mowry, Bell Fourche, Greenhorn, Carlile, Niobrara, and Pierre formations) between the Inyan Kara Formation and the lowermost USDW, the Fox Hills Formation. BFSC determined that the risk of CO_2 leakage via seal diffusivity is very low due to the 3,371 feet of overlying confining layers above the injection formation.

Drilling Through the CO_2 Area

BFSC has determined that there is no significant commercial oil and gas activity within the project area. Therefore, the MRV plan states that it is unlikely that future wells would be drilled through the storage reservoir. The MRV plan states that the only exploration well near the edge of the project AOR, the Ellen Samuelson 1, recovered only drilling mud, salt water, and a very slight gas cut. BFSC determined that this exploration well was plugged and abandoned in 1957. The MRV plan states that the NDIC maintains authority to regulate and enforce oil and gas activity respective to the integrity of operations, including drilling of wells and underground storage of CO_2.

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

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

40 CFR 98.448(a)(3) requires that an MRV plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Section 4 of the MRV plan

Table 4-1. Summary of Blue Flint's Testing and Monitoring Strategy

METHOD (TARGET AREA/STRUCTURE)	SAMPLING FREQUENCY Pre-Injection Phase (Baseline – 1 year)	Injection Phase (20 years)	Post-Injection Phase (10 years minimum)
CO_2 Stream Analysis (capture)	Start-up	Quarterly	NA[1]
Surface Pressure Gauges (MAG 1, MAG 2, and flowline)	Start-up	Real time	Real time (MAG 2 only)
Mass Flow Metering (CO_2 injection well and flowline)	Start-up	Real time	NA
CO_2 Detection Stations (flowline risers, injection wellhead, and wellhead enclosure)	Start-up	Real time	NA
Corrosion Coupon Testing (flowline and well materials)	Baseline	Quarterly	NA
SCADA Automated Remote System (MAG 1, MAG 2, and flowline)	Start-up	Real time	Real time (MAG 2 only)
DTS (MAG 1 and MAG 2)	At well completion	Real time	Real time (MAG 2 only)
Surface and Bottomhole P–T Readings (MAG 1 and MAG 2)	At well completion	Real time	Real time (MAG 2 only)
Temperature Log (MAG 1 and MAG 2)	Baseline	Annually (but only if DTS fails)	Annually in MAG 2 (only if DTS fails)
USIT or Alternative CIL (MAG 1 and MAG 2)	Baseline	Perform during well workovers but no less than once every 5 years	Perform during well workovers but no less than once every 5 years (MAG 2 only)
Tubing–Casing Annulus Pressure Tests (MAG 1 and MAG 2)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but no less than once every 5 years (MAG 2 only)
Atmospheric Analysis	3–4 seasonal samples per semipermanent soil gas location	3–4 seasonal samples per soil gas profile station and CO_2 detection stations placed outside enclosures on MAG 1 well pad	None
Soil Gas Analysis (five semipermanent probe stations)	3–4 seasonal samples per location	NA	Sample soil gas probe locations at the start of the post-injection phase and prior to facility closure
Soil Gas Analysis (two permanent profile stations)	NA	3–4 seasonal samples annually per location	Sample SGPS 1[2] prior to MAG 1 reclamation; sample SGPS 2[2] annually until facility closure
Water Analysis: Shallow Aquifers (15 wells operated by Falkirk Mining Company) (R1:B)	Provide historical water sampling results	NA	TBD[3]
Water Analysis: Shallow Aquifers (up to five wells within or near AOR)	3–4 seasonal samples per location	NA	TBD
Water Analysis: Lowest USDW (Fox Hills monitoring well adjacent to MAG 1)	3–4 seasonal samples	3–4 seasonal samples annually	Annually until facility closure
Pulsed-Neutron Logs (MAG 2)	Baseline	Once in Year 4 and every 5 years thereafter until the end of injection	Perform in Year 21 and annually thereafter until well reaches full CO_2 saturation, then reduce to once every 4 years until facility closure
Pressure Falloff Test (MAG 1)	Baseline	Every 5 years	NA
Time-Lapse 2D Seismic Surveys (CO_2 plume)	Baseline	Repeat survey in Year 1 and Year 4. Reevaluate frequency in Year 4	TBD
Vertical Seismic Profiles (VSP) (CO_2 plume)	Evaluate feasibility for early time monitoring during CO_2 injection operations	TBD	NA
Passive Seismicity Monitoring (CO_2 storage complex)	Utilize existing USGS's network	Utilize existing USGS's network and supplement with additional equipment as necessary	Utilize existing USGS's network and supplement with additional equipment as necessary

[1] Not applicable.
[2] Locations of SGPS 1 and 2 are shown on Figure 5-1.
[3] To be determined.

discusses the strategies BFSC will employ for monitoring and quantifying surface leakage of CO_2 through the pathways identified in the previous section to meet the requirements of 40 CFR §98.448(a)(4). Section 5 of the MRV plan discusses the strategies that BFSC will use for establishing expected baselines for CO_2 leakage. Monitoring will occur during the planned 20-year injection period, or otherwise the cessation of operations, plus a proposed 10-year post-injection period. A summary table of BFSC's testing and monitoring strategies can be found in Table 4-1 of the MRV plan and copied below. A summary table of BFSC's monitoring strategies for detecting and quantifying surface leakage pathways associated with CO_2 injection can be found in Table 4-2 of the MRV plan and copied below.

Table 4-2. Monitoring Strategies for Detecting and Quantifying Surface Leakage Pathways Associated with CO_2 Injection

Monitoring Strategy (target area/structure)	Potential Surface Leakage Pathway: Wellbores	Faults and Fractures	Flowline and/or Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal	Detection Method	Quantification Method
Surface P–T Gauges (MAG 1, MAG 2, and flowline)	X		X			X	P–T gauge data will be recorded continuously in real-time by the SCADA system and sent to the operations center to detect any anomalous readings that require further investigation.	P–T gauge data may be needed in combination with metering data to accurately quantify volumes emitted by surface equipment.
Mass Flow Metering (CO_2 injection well and flowline)	X		X	X			Metering data (e.g., rate and volume/mass) will be recorded continuously in real-time by the SCADA system and sent to the operations center to detect any anomalous readings that require further investigation.	Mass balance and leak detection software calculations.
CO_2 Detection Stations (flowline risers, injection wellhead, and wellhead enclosure)	X		X	X		X	CO_2 detection station data will detect any anomalous readings that require further investigation.	CO_2 concentration data collected by each station inside the enclosure may be used in combination with the assumed workspace atmosphere conditions and known volume of the enclosure to quantify any surface leakage of CO_2.
DTS (MAG 1 and MAG 2)	X		X	X	X	X	Temperature data will be recorded continuously in real time by the SCADA system to detect any anomalous readings near or at the surface that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.
Temperature Log (MAG 1 and MAG 2)	X		X	X	X	X	Temperature logs will be collected to detect any anomalous readings near or at the surface of the wellbore that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.
USIT or Alternative CIL (MAG 1 and MAG 2)	X			X			Ultrasonic (or alternative) logs will be collected to detect potential pathways to the surface in the wellbore that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.
Atmospheric Analysis	X		X	X	X		CO_2 gas readings will be recorded continuously in real time by the SCADA system and sent to the operations center and atmospheric samples will be analyzed from soil gas sampling activities to detect any anomalous readings that require further investigation.	CO_2 concentration data collected from multiple detection stations and/or soil gas sampling sites over time could be used to estimate the amount of surface leakage of CO_2.
Soil Gas Analysis (five semipermanent probe stations)	X			X	X	X	Soil gas data will be collected to detect any anomalous readings just beneath or at the surface that require further investigation.	Additional field studies (e.g., vegetation survey) and soil gas sampling would be needed to provide an estimate of surface leakage of CO_2.
Soil Gas Analysis (two permanent profile stations)	X			X	X	X	Same as above.	Same as above.
Pulsed-Neutron Logs (MAG 2)	X			X	X	X	Logs will be collected to detect potential pathways to the surface in or near the wellbore that require further investigation.	The pulsed-neutron log is capable of quantifying the concentration of CO_2 near the wellbore. If a pathway of surface leakage of CO_2 is detected, additional field studies (i.e., atmospheric and soil gas analysis) would be needed to quantify the event.
Time-Lapse 2D Seismic Surveys (CO_2 plume)	X	X		X	X	X	Seismic data will be collected and could detect pathways for surface leakage of CO_2 that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.
VSP (CO_2 plume)	X	X		X	X	X	VSP data may be collected and could detect pathways for surface leakage of CO_2 that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.

BFSC states that the methodologies described above target the early detection of any abnormalities in operating parameters or deviations from baselines and equipment detection thresholds established for the MAG 1 injection project. The MRV plan states that these methodologies provide a verification process to validate whether a leak has occurred or if the system has lost mechanical integrity. BFSC plans to collect data during monitoring to calibrate the numerical model and to improve the prediction for the injectivity, CO_2 plume, and associated pressure front.

BFSC plans to use reservoir simulation modeling based on history-match data obtained from the monitoring program, to compare the initial numerical model with the development of the CO_2 plume and associated pressure front. BFSC will continuously calibrate the model with the acquisition of real-time data. BFSC will review the AOR and monitoring plan and if warranted, will revise the AOR and Monitoring plan every five years. The MRV plan states that monitoring data will be: 1) reviewed to determine if surface leakage of CO_2 is occurring; 2) verified by the operator with field personnel and/or technical experts; and 3) quantified in accordance with the strategies in the monitoring plan and any emergency remedial response actions that may be necessary. BFSC states that they will use model history-matching in combination with mechanical integrity data, geophysical surveys, and near-surface monitoring to identify, quantify, and verify CO_2 leaks.

4.1 Detection of Leakage Through the Class VI Injection Well (MAG 1)

Section 3.1 of the MRV plan states that the risk of surface CO_2 leakage from the MAG 1 well is very low. Nevertheless, the MRV plan states that a supervisory control and data acquisition (SCADA) system will be used to monitor for leaks through the MAG 1 well. CO_2 leakage through the MAG 1 well will be quantified using P-T gauge data, temperature data, and ultrasonic log data.

Thus, the MRV plan provides adequate characterization of BFSC's approach to detect potential leakage through the Class VI injection well as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage Through the Monitoring Well (MAG 2)

Section 3.2 of the MRV plan states that the risk of surface CO_2 leakage from the MAG 2 well is very low. Nevertheless, the MRV plan states that a SCADA system will be used to monitor for leaks from the MAG 2 well. CO_2 leakage from the MAG 2 well will be quantified using P-T gauge data, temperature data, and ultrasonic log data.

Thus, the MRV plan provides adequate characterization of BFSC's approach to detect potential leakage through the reservoir monitoring well as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage Through Surface Components

Section 3.3 of the MRV plan states that the likelihood of CO_2 leakage through surface equipment is very low. BFSC would detect CO_2 leakage from surface components, physical inspections, pressure gauges, and automated warning systems. Mass balance equations, leak detection software, CO_2 concentration data, and P-T gauge data would be used to quantify volumes of CO_2 leaked from surface components.

Thus, the MRV plan provides adequate characterization of BFSC's approach to detect potential leakage through surface components as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage Through Class I Nonhazardous Disposal Wells

Section 3.4 of the MRV plan states that the only the Class I nonhazardous disposal well within the BFSC project area is not anticipated as a surface leakage pathway. In the event of CO_2 surface leakage through the Class I nonhazardous disposal well, the well's gauge system would be used for detection. Additional field studies (i.e., atmospheric and soil gas analysis) would be needed for leakage quantification.

Thus, the MRV plan provides adequate characterization of BFSC's approach to detect potential leakage through Class I nonhazardous disposal wells as required by 40 CFR 98.448(a)(3).

4.5 Detection of Leakage Through Abandoned Oil and Gas Wells

According to Section 3.5 of the MRV plan, the two abandoned oil and gas wells, the Ellen Samuelson 1 and the Wallace O. Gradin 1 wells are not anticipated CO_2 surface leakage pathways. The MRV plan describes that in the event of CO_2 leakage through abandoned wellbores, seismic data, and Vertical Seismic Profiles (VSP) will be used for detection. Additional field studies (i.e., atmospheric and soil gas analysis) would be needed to quantify the volume of CO_2 leakage.

Thus, the MRV plan provides adequate characterization of BFSC's approach to detect potential leakage through abandoned oil and gas wells as required by 40 CFR 98.448(a)(3).

4.6 Detection of Leakage Through Faults, Fractures, Bedding Plane Partings, and Seismicity

Stanton Fault

Section 3.6.1 of the MRV plan states that no CO_2 leakage is anticipated to the surface due to faults or fractures. In the event of CO_2 leakage through faults or fractures, the MRV plan states that BFSC will use seismic data and VSP data as a detection strategy. BFSC states that additional field studies (i.e., atmospheric and soil gas analysis) would be needed to estimate the volumes of CO_2 leakage through faults and fractures.

Natural or Induced Seismicity

Section 3.6.2 of the MRV plan states that potential leakage resulting from natural or induced seismicity was shown to be very low. Nevertheless, the MRV plan states that periodic seismic surveys and surface monitoring of the storage facility area will be used to detect potential surface leaks and associated magnitude throughout the operational and post-injection phases. BFSC states that additional field studies (i.e., atmospheric and soil gas analysis) would be needed to estimate CO_2 leakage volumes due to natural or induced seismicity.

Thus, the MRV plan provides adequate characterization of BFSC's approach to detect potential leakage through faults, fractures, bedding plane partings, and seismicity as required by 40 CFR 98.448(a)(3).

4.7 Detection of Leakage Through Confining System Pathways

Lateral Migration

Section 3.7.1 of the MRV plan states that the risk of surface leakage of CO_2 via lateral migration is very low. In the event of CO_2 leakage through lateral migration, BFSC states that they would detect leakage with their Supervisory Control and Data Acquisition (SCADA) system, temperature logs, soil gas data, seismic data, and vertical seismic profiles (VSP). Quantification of CO_2 leakage through lateral migration will be accomplished via field studies, the pulsed-neutron log in the MAG 2 well, and soil gas sampling.

Seal Diffusivity

Section 3.7.2 states that the risk of CO_2 leakage via seal diffusivity is very low. Even so, the MRV plan describes that CO_2 leakage via seal diffusivity will be detected with a SCADA system, temperature logs, soil gas data, seismic data, and VSP. Quantification of CO_2 leakage through seal diffusivity will be accomplished via field studies, the pulsed-neutron log in the MAG 2 well, and soil gas sampling.

Drilling Through the CO_2 Area

Section 3.7.3 states that it is unlikely that future wells would be drilled through the storage reservoir. Should future wells be drilled within the BFSC project area. The MRV plan states that the NDIC maintains the authority to regulate and enforce oil and gas activity with respect to the integrity of operations including drilling of wells and underground storage of CO_2.

Thus, the MRV plan provides adequate characterization of BFSC's approach to detect potential leakage through confining system pathways as required by 40 CFR 98.448(a)(3).

4.8 Determination of Baselines

Section 5 of the MRV plan identifies the strategies that BFSC will use to establish the baselines for monitoring CO_2 surface leakage per §98.448(a)(4). BFSC will establish a pre-injection baseline by implementing a monitoring program approximately 1 year prior to CO_2 injection designed to coincide with seasonal changes. The MRV plan states that this baseline will include samples and analysis from near surface and deep subsurface environments, such as soil gas in the vadose zone, shallow groundwater down to the lowest USDW, and the storage reservoir. Baselines will provide the background concentration of CO_2 for comparative analysis to samples collected during operational and post-injection phases. The MRV plan also states that the pre-injection baseline characterization is important to providing context to any future investigation of suspected leakage of CO_2 within the AOR. Determination of baseline concentrations is a requirement of the North Dakota SFP.

Surface and Near-Surface Baselines

As of September 2022, BFSC has initiated a baseline surface and near surface sampling program. Baseline data gathering includes measuring chemical concentrations of ambient air and soil gas samples (i.e., O_2, N_2, and CO_2) and groundwater (e.g., pH, total dissolved solids, alkalinity, major cations/anions, and trace metals) as well as characterizing their naturally occurring stable and radiocarbon (^{14}C) isotopic signatures of the soil gas and groundwater for comparison with the isotopic signature of the CO_2 stream.

Subsurface Baselines

BFSC will also collect pre-injection baseline data in the CO_2 injection well (MAG 1) and monitoring well (MAG 2). The MRV plan also states that the time-lapse saturation data will be collected in the MAG 2 well only and will be useful for confirming the CO_2 injection profile in the storage reservoir as well as ensuring there are no signs of out-of-zone migration into formations overlying the storage reservoir, otherwise known as the above-zone monitoring interval. BFSC has selected time-lapse geophysical surveys as the primary monitoring method to track the extent of the CO_2 plume within the storage reservoir. The MRV plan states that BFSC will complete a 2D seismic survey prior to injection to establish baseline conditions in the storage reservoir.

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

Section 6 of the MRV plan provides the equations that BFSC will use to calculate sequestration volumes. BFSC states that the Blue Flint CO_2 storage project area is a geologic CO_2 storage site in a saline aquifer with no associated production from the CO_2 storage complex. Thus, two Coriolis mass flowmeters will be installed to meter injected CO_2 and the flowmeter closest to the wellhead is the primary metering station.

5.1 Calculation of Mass of CO_2 Received

The MRV plan states that annual mass of CO_2 received will be calculated by using the mass of CO_2 injected pursuant to 40 CFR § 98.444(a)(4) and 40 CFR § 98.444(b). The point of measurement for the mass of CO_2 received (injected) will be the primary metering station located closest to the injection wellhead.

BFSC provides an acceptable approach for calculating the mass of CO_2 received under Subpart RR.

5.2 Calculation of Mass of CO_2 Stored

The MRV plan states that the annual mass of stored CO_2 is calculated from Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{[Eq. 1]}$$

Where:

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

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells.

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

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

BFSC provides an acceptable approach for calculating the mass of CO_2 stored under Subpart RR.

5.3 Calculation of Mass of CO_2 Injected (CO_{2I})

The MRV plan states that BFSC will use mass flow metering to measure the flow of the injected CO_2 stream and calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the mass flow at standard conditions by the CO_2 concentration in the flow at standard conditions, according to Equation RR-4 from 40 CFR Part 98, Subpart RR (Equation 2):

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_2,p,u} \qquad \text{[Eq. 2]}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by Flowmeter u.

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

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flowmeter.

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

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

The MRV plan states if the monitoring and surveillance plan detects a deviation from the threshold established for each method, BFSC will conduct a detailed analysis based on technology available and type of leak to quantify the CO_2 volume to the best of its capabilities. The process for quantifying any leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the leak, and numerical and predictive models, among others. The MRV plan also states that BFSC will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98-Subpart RR (Equation 3):

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{[Eq. 3]}$$

Where:

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

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

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

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

The MRV plan states the annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead (CO_{2FI}) will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan proposed in R1:5.0 of the SFP.

BFSC provides an acceptable approach for calculating the mass of CO_2 emitted by equipment leaks and vented emissions under Subpart RR.

6 Summary of Findings

The Subpart RR MRV plan for Midwest AgEnergy Group's Blue Flint Sequester Company facility meets the requirements of 40 CFR 98.238. The regulatory provisions of 40 CFR 98.238(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in BFSC's MRV plan.

Subpart RR MRV Plan Requirement	BFSC MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 2 of the MRV plan delineates and describes the MMA and AMA. The MRV plan states that the modeled AOR boundary exceeds the regulatory requirements of the MMA and AMA with a 1-mile buffer around the projected stabilized plume, which is greater than the required half-mile buffer. As a result, BFSC proposes to use the AOR boundary as the MMA and AMA boundaries.
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 3 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: the class VI injection well, the monitoring well, surface components, the class I nonhazardous disposal well, abandoned oil and gas wells, faults, fractures, bedding plane partings, and seismicity, and confining system pathways. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways. BFSC determined the probability of leakage through each pathway to be either very low or not anticipated.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 4 of the MRV plan describes the strategies that BFSC will use to detect and quantify potential CO_2 leakage to the surface should it occur. The MRV plan identifies the following quantification strategies: field inspections, engineering equations, atmospheric and soil gas analysis, groundwater sampling, and model history matching in combination with mechanical integrity data, and geophysical surveys. The MRV plan states that quantification of CO_2 leakage will be calculated based on operating conditions at the time of

	the event, and provides possible quantification strategies in Table 4-2.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 5 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage. BFSC will establish a pre-injection baseline by implementing a monitoring program approximately 1-year prior to CO_2 injection. Beginning in September 2022, BFSC has been collecting and analyzing air, soil, and groundwater samples to establish surface and near surface baselines. The MRV plan states that time-lapse geophysical surveys will be the primary subsurface monitoring method and that a 2D seismic survey will be conducted prior to injection to establish baseline conditions in the storage reservoir.
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 6 of the MRV plan describes BFSC's approach to determining the total amount of CO_2 sequestered using the Subpart RR mass balance equations, including 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 identifies the MAG 1 wellbore's UIC number and permit class. The MAG 1 wellbore is pending approval from the NDIC as a Class VI injection well.
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 7 of the MRV plan states that the project will commence collecting data for calculating total amount sequestered according to the equations outlined in Section 6 of this MRV plan at the placed-in-service date.

Appendix A: Final MRV Plan

BLUE FLINT SEQUESTER COMPANY, LLC MONITORING, REPORTING, AND VERIFICATION PLAN

Class VI CO_2 Injection Well

Reporter Number: 583181

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STORAGE FACILITY PERMIT DESIGNATION

Within the text of this monitoring, reporting, and verification plan, Blue Flint Sequester Company's storage facility permit application is designated as follows:

Reference 1: Blue Flint Sequester Company, LLC Carbon Dioxide Geologic Storage Facility Permit Application

Section 1 – Pore Space Access
Section 2 – Geologic Exhibits
Section 3 – Geologic Model Construction and Numerical Simulation of CO_2 Injection
Section 4 – Area of Review
Section 5 – Testing and Monitoring Plan
Section 6 – Post-Injection Site Care and Facility Closure Plan
Section 7 – Emergency and Remedial Response Plan
Section 8 – Worker Safety Plan
Section 9 – Well Casing and Cementing Program
Section 10 – Plugging Plan
Section 11 – Injection Well and Storage Operations
Section 12 – Financial Assurance and Demonstration Plan
Appendix A – MAG 1 Formation Fluid Sampling
Appendix B – Historic Freshwater Well Fluid Sampling
Appendix C – Quality Assurance and Surveillance Plan
Appendix D – Storage Facility Permit Regulatory Compliance Table

REFERENCING CONVENTION

Below are three formatted examples of the referencing convention this document will follow:

- R1:4.1.1
- R1:C1.3
- R1:6.1.1, Figure 6-1

R1 refers to Reference 1 as designated hereto, and numbers or letters that appear after the colon represent the appropriate section or appendix from the storage facility permit. Thus:

- R1:4.1.1 would direct the reader to Section 4.1.1 (Area of Review Section, Written Description Subsection) within the storage facility permit application.

- R1:C1.3 would direct the reader to Section 1.3 (Corrosion Monitoring and Prevention Plan) of Appendix C (Quality Assurance and Surveillance Plan) within the storage facility permit application.

- R1:6.1.1, Figure 6-1 would direct the reader to Figure 6-1 in Section 6.1.1 (Pre- and Postinjection Pressure Differential) within the storage facility permit application.

MRV PLAN SUMMARY

Midwest AgEnergy (MAG) is moving toward a zero-carbon footprint through a multi-phased initiative "vision carbon zero." MAG, the owner of Blue Flint Ethanol, LLC; Blue Flint Capture Company, LLC; and Blue Flint Sequester Company, LLC (Blue Flint) is developing a carbon capture and storage (CCS) project for the Blue Flint Ethanol (BFE) facility in Underwood, North Dakota. Blue Flint proposes a compliant Greenhouse Gas Reporting Program (GHGRP) Subpart RR monitoring, reporting, and verification (MRV) plan in support of the storage project. As required under Title 40 Code of Federal Regulations (CFR) § 98.448, this plan includes 1) delineation of the maximum and active monitoring areas; 2) identification of potential surface leakage pathways and the likelihood, magnitude, and timing of surface leakage of carbon dioxide (CO_2) through these pathways within the maximum monitoring area (MMA); 3) a strategy for detecting and quantifying any surface leakage of CO_2; 4) a strategy for establishing the expected baselines for monitoring; and 5) a summary of the CO_2 accounting (mass balance) approach.

Blue Flint submitted a North Dakota Underground Injection Control (UIC) Class VI permit (storage facility permit [SFP]) application to the North Dakota Industrial Commission (NDIC) Department of Mineral Resources (DMR) on October 3, 2022. The U.S. Environmental Protection Agency (EPA) granted North Dakota primacy to administer the UIC Class VI Program on April 24, 2018, for injection wells located within the state, except within Indian lands (83 Federal Register 17758, 40 CFR § 147.1751; EPA Docket No. EPA-HQ-OW-2013-0280). Blue Flint's public hearing at the NDIC DMR took place on March 21, 2023 (NDIC Case No. 29888). The SFP includes plans applicable to the requirements of 40 CFR Part 98 Subpart RR. Monitoring aspects contained in this MRV plan that have been carried over from the testing and monitoring strategy in the SFP include 1) sampling of the CO_2 stream, 2) a leak detection and corrosion monitoring plan for the surface piping and wellhead, 3) mechanical integrity testing and leak detection for injection and monitoring wells, and 4) an environmental monitoring program that includes sampling of soil gas and groundwater and time-lapse seismic surveys.

1.0 PROJECT OVERVIEW

1.1 Project Description

The BFE facility, located 6 miles south of Underwood, North Dakota, produces over 70 million gallons of ethanol annually, along with about 200,000 tons of dry distillers' grains and about 10 tons of corn oil. A by-product of fermentation is a nearly pure stream of CO_2 (99%+ dry by volume). The BFE facility produces about 200,000 metric tons of CO_2 annually.

Blue Flint plans to capture approximately 200,000 metric tons of CO_2 annually over a 20-year period from the BFE facility. The captured CO_2 will be processed for compression and transported in a 3-mile-long CO_2 flowline to a single CO_2 injection well. A stratigraphic test well (MAG 1) was drilled for the Blue Flint CO_2 storage project. This wellbore will be converted into a UIC Class VI injection well, and a second stratigraphic test well (MAG 2) will be drilled and converted into a monitoring well. The CO_2 stream will be injected into the Broom Creek Formation, a predominantly sandstone reservoir and saline aquifer, at a depth of 4,708 feet below the ground surface at the MAG 1 well location. The MAG 1 well has a surface elevation of 1,905 feet. The location of the BFE facility, planned CO_2 flowline, and injection and monitoring wells are provided in Figure 1-1, with respect to the extent of CO_2 storage delineated as the projected stabilized plume boundary.

1.2 Geologic Setting

The Blue Flint CO_2 storage project is located along the eastern flank of the Williston Basin where there has been no significant commercial production of hydrocarbon resources. Figure 1-2 provides a state reference map to illustrate the geographic distribution of oil and gas fields (undifferentiated) in North Dakota. The closest oil and gas fields to the project are 39 miles west of the western edge of the projected stabilized CO_2 plume boundary, demonstrating that there has been no commercial development of hydrocarbon resources within the immediate project area

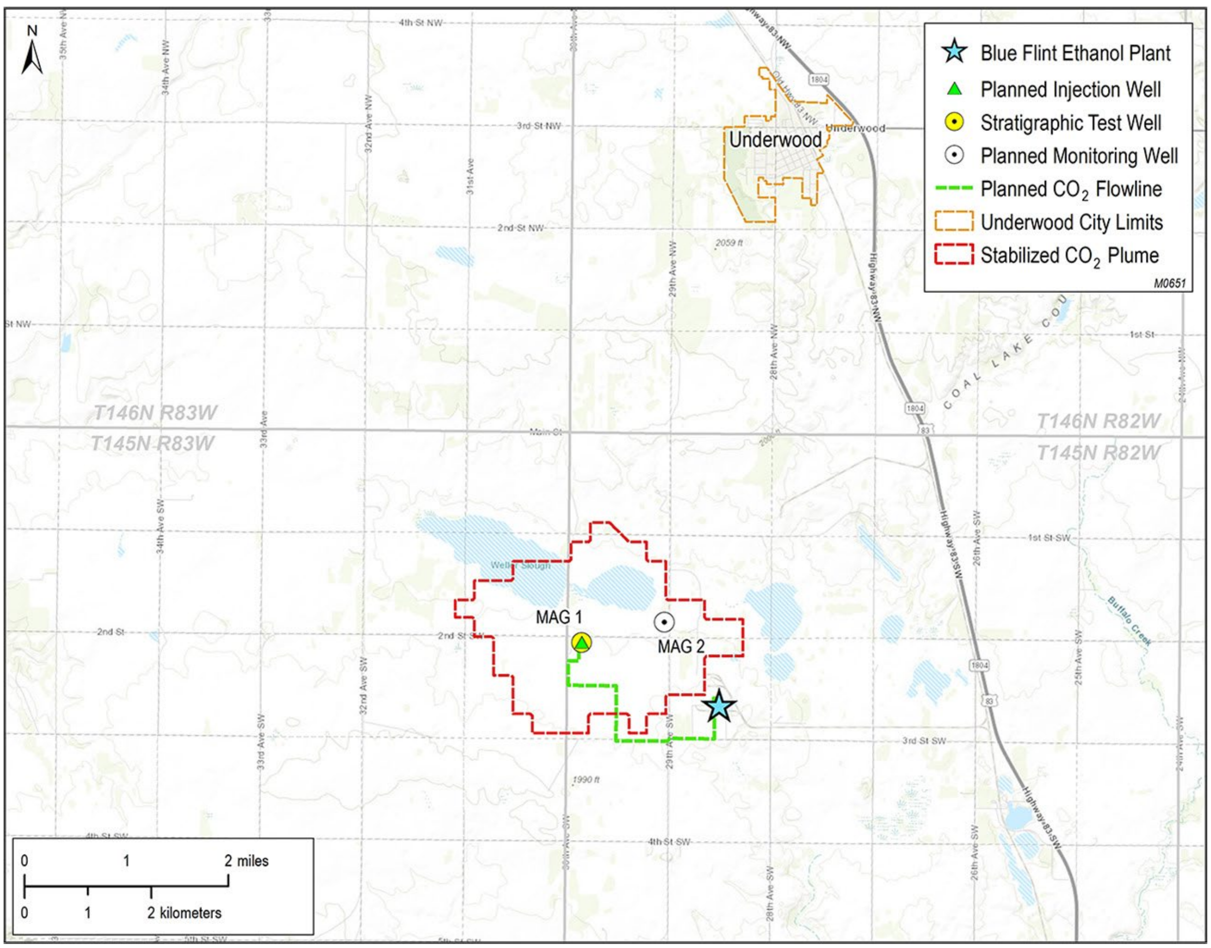


Figure 1-1. Location of the BFE facility, planned CO_2 flowline, and planned wells: CO_2 injection well (MAG 1) and monitoring well (MAG 2). The red outline indicates the projected stabilized CO_2 plume boundary.

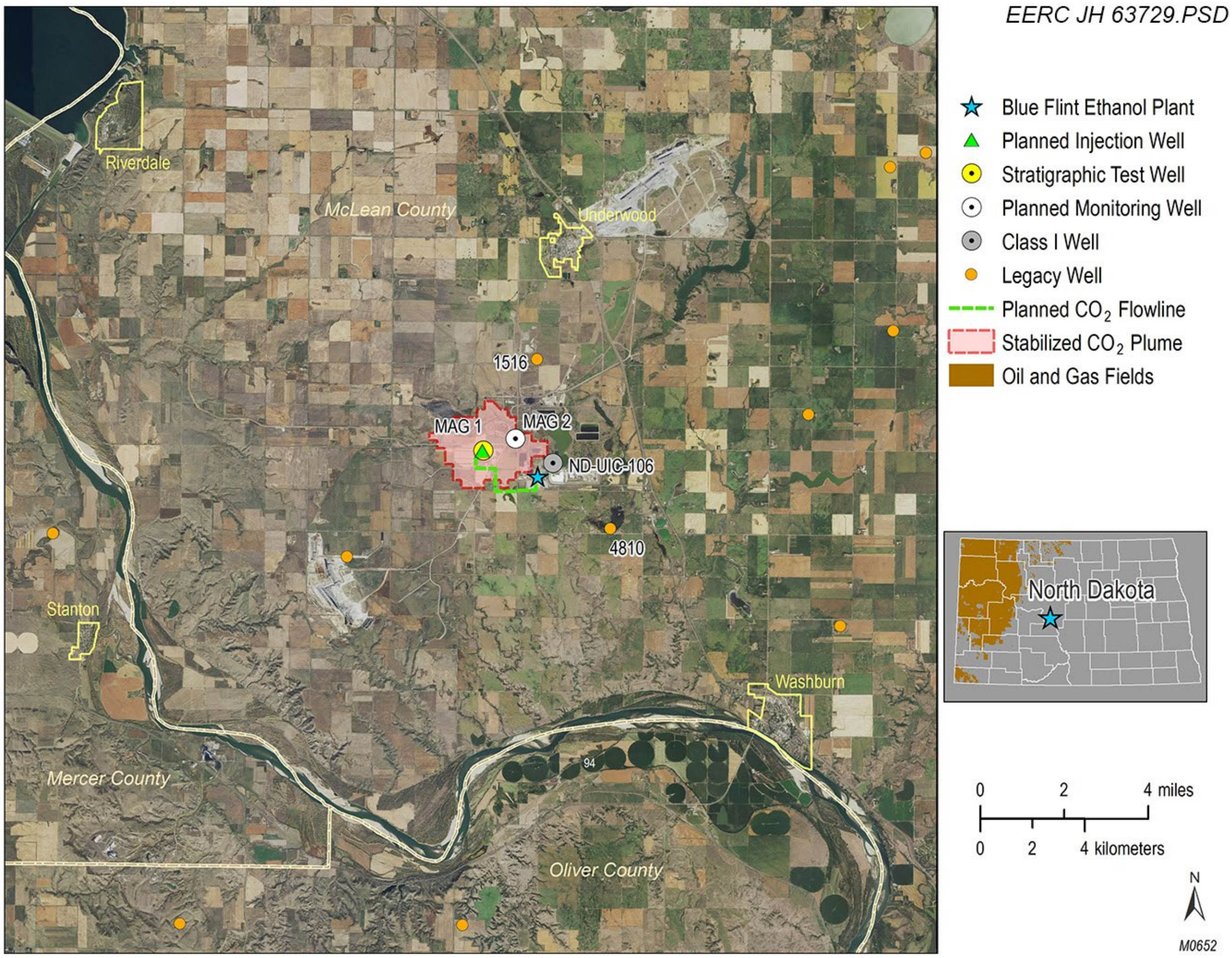


Figure 1-2. Map illustrating the locations of existing legacy wellbores around the projected stabilized CO_2 plume extent for the Blue Flint CO_2 storage project and nearby towns (outlined and labeled in yellow). The state reference map also reveals the geographic distribution of oil and gas fields in North Dakota. The closest oil and gas field is approximately 39 miles west of the Blue Flint CO_2 storage project.

(R1:2.6). The Williston Basin is a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. The basin is hydrocarbon-bearing, with over 38,000 wells drilled in North Dakota for production of commercial accumulations of oil and gas from subsurface reservoirs. Although commercial oil and gas production is not present in the area surrounding the project, legacy oil and gas exploration wells are present. Figure 1-2 also identifies the legacy wells surrounding the projected stabilized CO_2 plume area, with identification numbers provided for the two nearest wells to the geologic CO_2 storage site.

A standard stratigraphic column of the Williston Basin for the area of Underwood, North Dakota is provided in Figure 1-3. The target storage reservoir is the Broom Creek Formation, a predominantly sandstone interval (R1:2.3). Siltstones with interbedded anhydrite of the lower Piper and Spearfish Formations unconformably overlie the Broom Creek and serve as the upper (primary) confining zone (R1:2.4.1). Mixed layers of dolostone, limestone, and anhydrite of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone (R1:2.4.3). Together, the lower Piper–Spearfish, Broom Creek, and Amsden Formations comprise the CO_2 storage complex. There is about 859 feet (average thickness across the project area) of impermeable rock, including the lower Piper–Spearfish, between the Broom Creek and the next overlying porous zone, the Inyan Kara Formation (R1:2.4.2). An additional 2,512 feet (average thickness across the project area) of impermeable rock, including the Skull Creek, Mowry, Bell Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations, separate the Inyan Kara from the Fox Hills Formation (lowest underground source of drinking water [USDW]).

1.3 Description of CO_2 Project Facilities and Injection Process

The BFE facility will utilize a liquefaction process to capture CO_2 produced from fermentation. Figure 1-4 provides a facility flow diagram. The liquefaction process includes processing to remove oxygen and other non-condensable gases before gas is compressed and flowed to the injection well through a FlexSteel CO_2 flowline for geologic storage into the Broom Creek Formation.

1.4 Facility Information

Reporter Number: Blue Flint – 583181
UIC Permit Class: The MAG 1 wellbore will be permitted as a Class VI injection well
Well Identification Number: NDIC File No. 37833, API No. 33-055-00196-00-00

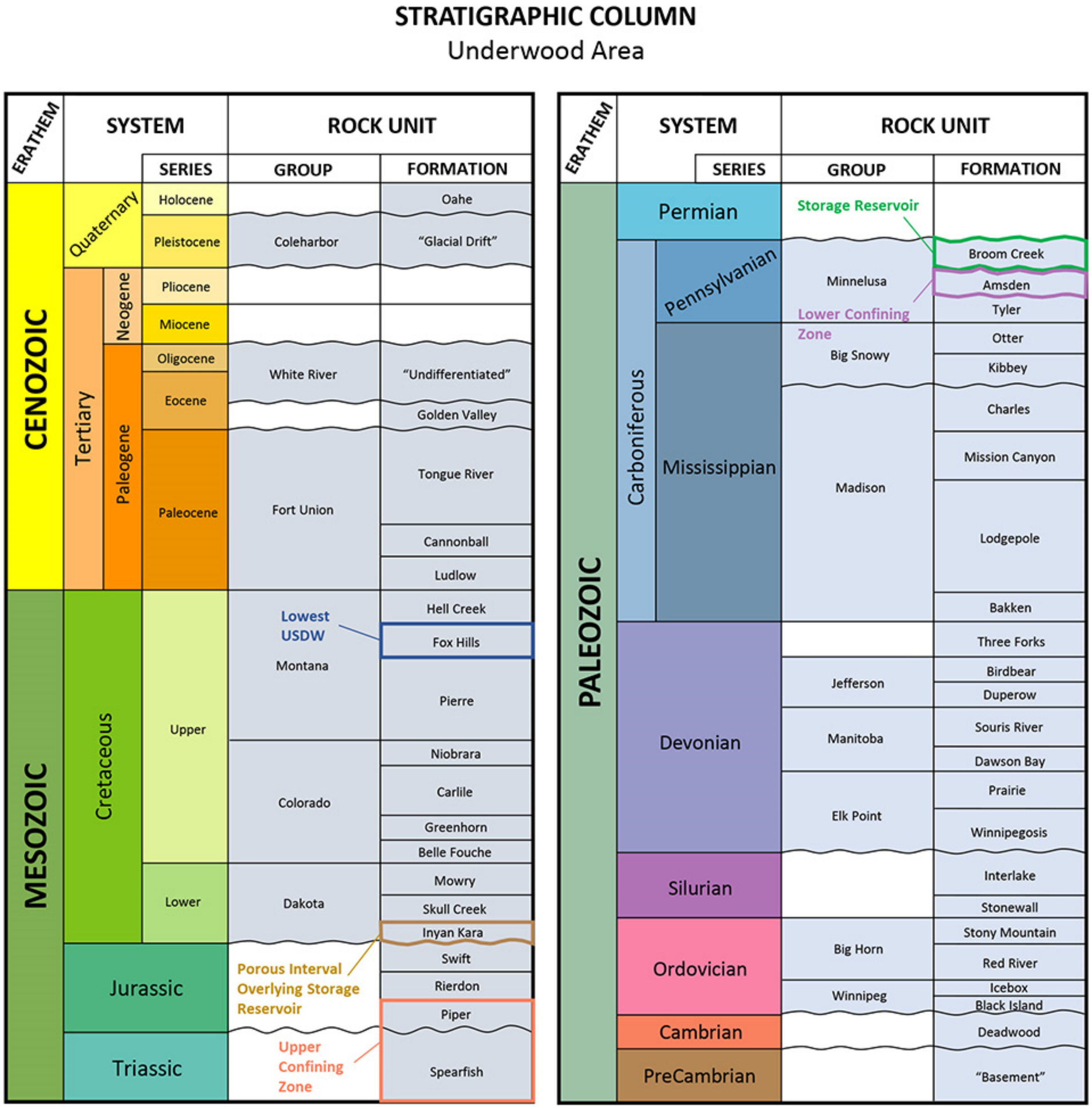
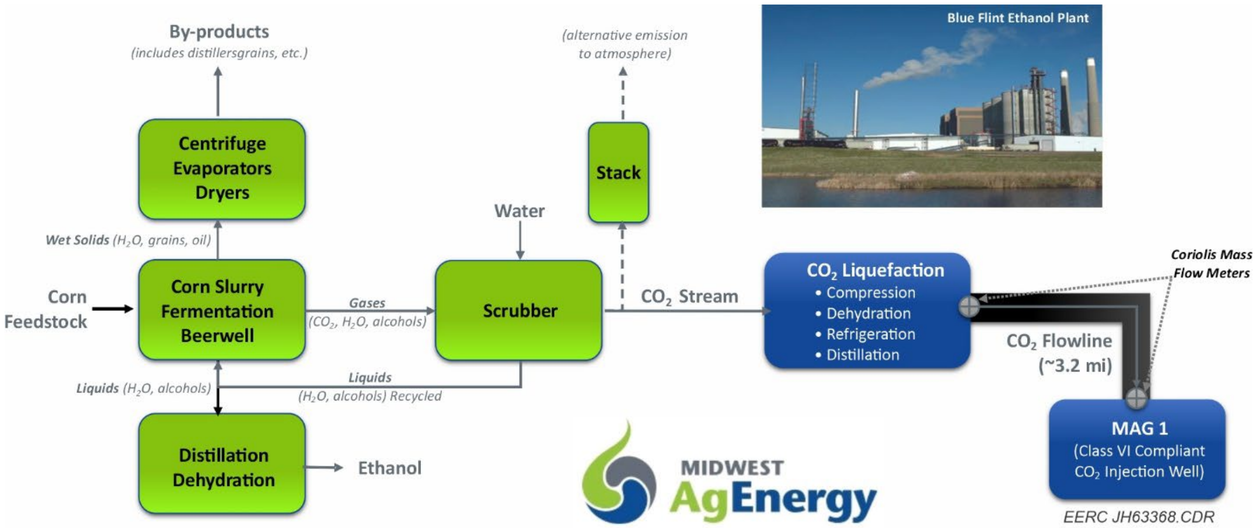


Figure 1-3. Stratigraphic column of the Williston Basin for the Underwood area, identifying the CO_2 storage complex as well as the next porous interval overlying the storage reservoir and lowest USDW underlying the Blue Flint CO_2 storage project area. Figure modified after Murphy and others (2009) and Bluemle and others (1981).



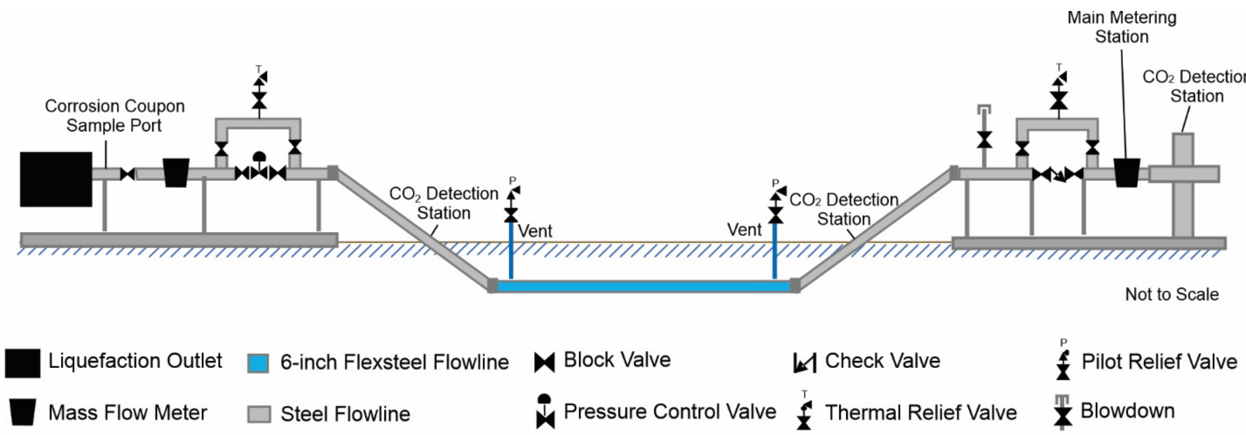


Figure 1-4. a) Process flow diagram of the CO_2 capture process at the BFE facility. b) Generalized flow diagram illustrating major CCS components of the surface facilities from the liquefaction outlet to the CO_2 injection well. The main metering station will be located adjacent to the injection wellhead as shown.

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

The area of review (AOR) boundary defined in the North Dakota SFP application (R1:4.0) will serve as the MMA and the active monitoring area (AMA) until facility closure (i.e., the point at which Blue Flint receives a certificate of project completion). As illustrated in Figure 2-1, the AOR boundary provides a 1-mile buffer around the stabilized CO_2 plume, rounding to the nearest 40-acre tract. This 1-mile buffer area is larger and thereby exceeds the regulatory requirements for buffer areas around the free-phase CO_2 plume with respect to subpart RR definitions for the MMA and the AMA. Blue Flint will begin to monitor approximately 1 year prior to injection, during the active 20-year injection period, and for a minimum of 10 years after injection ceases.

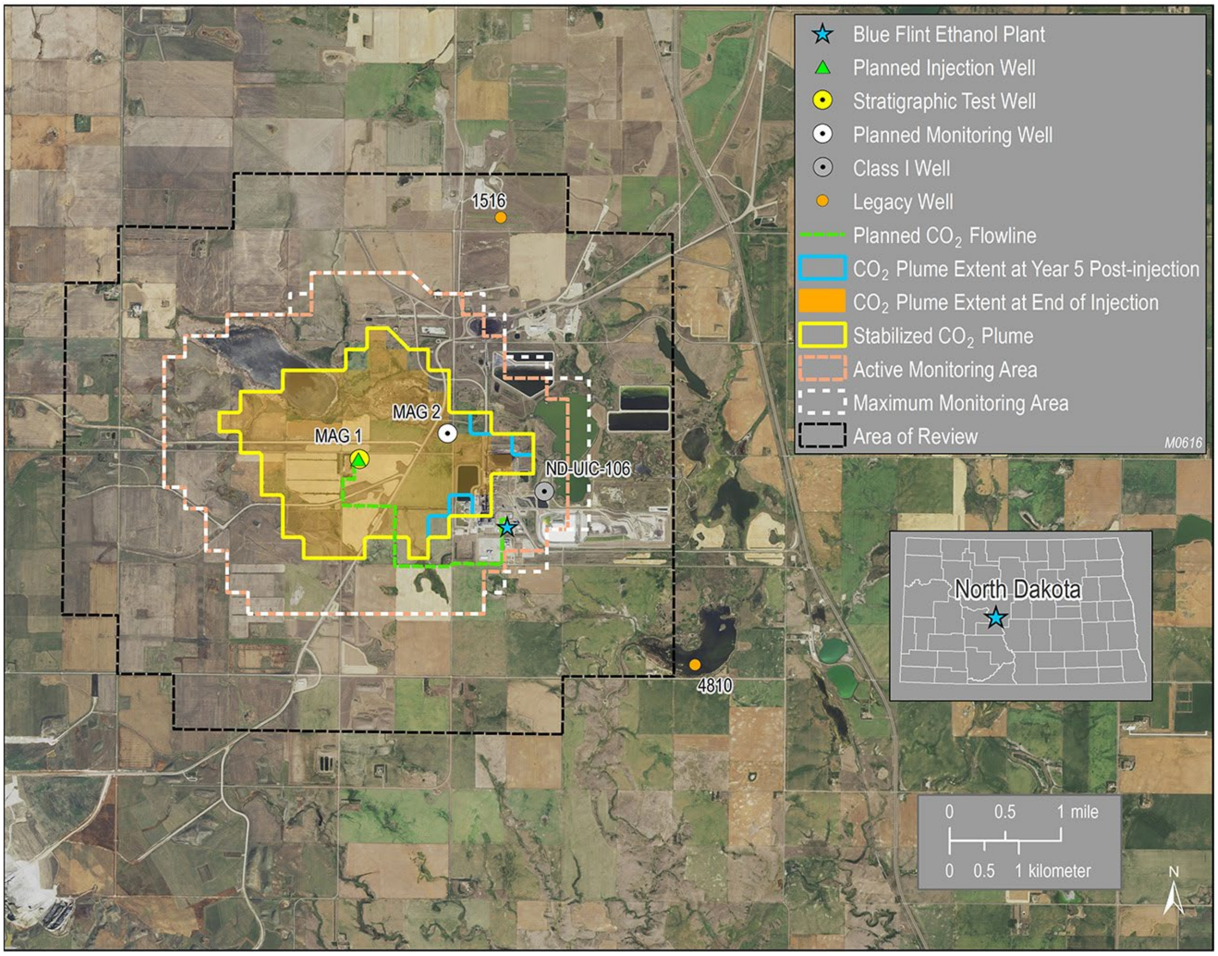


Figure 2-1. Map showing the AOR relative to the calculated MMA and AMA boundaries. In this case, "n" was set at Year 1 of injection and "t" set was set at Year 20 (end of injection) for calculating the AMA.

Subpart RR regulations require the operator to delineate an MMA and an AMA. The MMA is a geographic area that must be monitored and is defined as an area that is greater than or equal to the projected stabilized CO_2 plume boundary plus an all-around buffer zone of at least one-half mile (40 CFR § 98.449 [Subpart RR]). An operator may stage monitoring efforts over time by defining time intervals with respect to an AMA. The AMA is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the 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 and 2) the area projected to contain the free-phase CO_2 plume at the end of Year t + 5. Blue Flint calculated the MMA and AMA according to these regulatory definitions, as shown in Figure 2-1.

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). The proposed AOR in Figure 2-1 is in accordance with the above regulations, providing a 1-mile buffer and rounding to the nearest 40-acre tract outside the modeled CO_2 plume boundary.

3.0 EVALUATION OF POTENTIAL SURFACE LEAKAGE PATHWAYS

Subpart RR requirements specify that the operator must identify potential surface leakage pathways and evaluate the magnitude, timing, and likelihood of surface leakage of CO_2 through these pathways within the MMA (40 CFR § 98.448[a][2]). Blue Flint identifies the potential surface leakage pathways as follows:

1. Class VI injection well
2. Monitoring well
3. Surface components
4. Class I nonhazardous disposal well
5. Abandoned oil and gas wells
6. Faults, fractures, bedding plane partings, and seismicity
7. Confining system pathways

3.1 Class VI Injection Well (MAG 1)

The MAG 1 well (NDIC File No. 37833) spudded on October 11, 2020, as a stratigraphic test well and drilled to a depth of 9,213 feet into the Red River Formation (R1:9.1). This well was drilled to gather geologic data for the development of Blue Flint's North Dakota SFP application. The MAG 1 well will be completed to NDIC Class VI construction standards as an injection well for the Blue Flint CO_2 storage project. The temperature profile of the MAG 1 wellbore will be continuously monitored with temperature distributed temperature sensing (DTS) fiber-optic cable. In addition, pressure in the wellbore will be continuously monitored with at least one downhole, tubing-conveyed P–T (pressure–temperature) gauge and digital surface pressure gauges on the tubing and well annulus. The tubing-casing annulus pressure will be tested prior to injection and at least once every 5 years. An ultrasonic or alternative casing inspection log will also be acquired prior to injection for detecting any potential mechanical integrity issues behind casing and repeated at least once every 5 years (R1:5.4).

The risk of surface leakage of CO_2 via the MAG 1 is mitigated through:

- Monitoring operations with a surface leak detection plan, as described in R1:5.2.

- Preventing corrosion of well materials, following the preemptive measures in R1:5.3 and 5.6.

- Performing wellbore mechanical integrity testing, as described in R1:5.4 and summarized in Table 3-1 of this MRV plan.

- Monitoring the storage reservoir with a subsurface leak detection plan (environmental monitoring plan), as described in R1:5.7 and Table 4-1 of this MRV plan.

- Acting in accordance with the emergency remedial response plan in R1:7.4.

Table 3-1. Overview of Blue Flint's Mechanical Integrity Testing Plan

Activity	Baseline Frequency	Operational Frequency (20-year period)
External Mechanical Integrity Testing		
Ultrasonic Imaging Tool (USIT) or Alternative Casing Inspection Log (CIL)	Acquire baseline in MAG 1 and MAG 2.	Perform during well workovers but no less than once every 5 years.
DTS	Install at completion of MAG 1 and MAG 2.	Continuous monitoring.
Temperature Logging	Acquire baseline in MAG 1 and MAG 2.	Perform annually but only as a backup if DTS fails.
Internal Mechanical Integrity Testing		
Tubing-Casing Annulus Pressure Testing	Perform in MAG 1 and MAG 2 prior to injection. Install digital surface pressure gauges.	Perform during well workovers but no less than once every 5 years. Digital surface pressure gauges will monitor annulus pressures continuously.
Surface and Tubing-Conveyed P–T Gauges	Install gauges in the MAG 1 and MAG 2 prior to injection.	Gauges will monitor temperatures and pressures in the tubing continuously.
USIT or Alternative CIL	Acquire baseline in MAG 1 and MAG 2.	Perform during well workovers but no less than once every 5 years.

The likelihood of surface leakage of CO_2 from the MAG 1 well during injection or post-injection operations is very low because of well construction and active monitoring. Barriers associated with well construction that prevent reservoir fluids from reaching the surface include surface valves, injection tubing fitted with a packer set above the injection zone, annular casing, cement, and surface casing and cement. Integrity of these barriers is actively monitored with DTS along the casing and surface gauges on the tubing and well annulus. Active monitoring ensures integrity of well barriers and early detection of leaks. A supervisory control and data acquisition (SCADA) system is used to monitor for leaks. The detection time specified in R1:5.2, Table 5-3, and Table 3-2 of this MRV plan greatly minimizes the magnitude of any surface leakage and provides the potential to estimate volumes. The potential for a surface leak from the MAG 1 injection well is present from the first day of injection through the post-injection phase. The risk of a surface leak begins to decrease after injection ceases and greatly decreases as the reservoir approaches original pressure conditions. Once injection ceases, the MAG 1 will be properly plugged and abandoned following NDIC protocols, thereby further reducing any remaining risk of surface leakage from the wellbore.

Table 3-2. Performance Targets for Detecting Leaks in Surface Equipment with SCADA System

Leak Size, Mscfpd*	Detection Time, minutes
10	<2
>1	<5
<1 and >0.5	<60

* Thousand standard cubic feet per day.

3.2 Monitoring Well (MAG 2)

The MAG 2 well (NDIC File No. TBD) is planned to spud prior to injection as a stratigraphic test well for the Blue Flint CO_2 storage project. The well will be drilled to the Amsden/Tyler Formations. This stratigraphic test well will be converted into a monitoring well prior to injection and will be constructed to NDIC Class VI standards. Like MAG 1, the well will be monitored with continuous DTS fiber-optic cable, at least one tubing-conveyed P–T gauge, and digital surface pressure gauges on the tubing and well annulus. The tubing-casing annulus pressure will be tested prior to injection and at least once every 5 years. An ultrasonic or alternative casing inspection log will also be acquired prior to injection for detecting any potential mechanical integrity issues behind casing and repeated at least once every 5 years (R1:5.4 and Table 3-1 of this MRV plan).

The likelihood of surface leakage of CO_2 from the MAG 2 well during injection or post-injection operations is very low because of well construction and active monitoring. Barriers associated with well construction that prevent reservoir fluids from reaching the surface include the wellhead, tubing with packer, surface valves, surface casing and cement, and production casing and cement. The integrity of these barriers is actively monitored with DTS along the casing, tubing-conveyed P–T gauges, and surface P–T gauges. Since the MAG 2 well is located just inside the projected stabilized CO_2 plume boundary, the potential for a surface leak begins near the end of the 20-year injection period and continues during the post-injection phase of the project. The risk of a surface leak decreases after injection ceases as the reservoir approaches original pressure conditions. At the end of the post-injection monitoring phase, the MAG 2 will be properly plugged and abandoned following NDIC protocols, thereby further reducing any remaining risk of surface leakage from the wellbore.

3.3 Surface Components

Surface components of the injection system, including the flowline and CO_2 injection wellhead (MAG 1), will be monitored with leak detection equipment (Figure 1-4b). The flowline will be monitored continuously via dual flowmeters located at the liquefaction outlet and near the wellhead for performing mass balance calculations. The flowline will also be regularly inspected for any visual or auditory signs of equipment failure and monitored continuously with one pressure gauge at the liquefaction outlet and one near the wellhead. CO_2 detection stations will be located on the flowline risers and at the CO_2 injection wellhead for identifying the presence of CO_2 external to surface equipment. The leak detection equipment will be integrated with automated warning systems and shutoffs that notify Blue Flint's operations center, giving the operator the ability to remotely isolate the system. Further details of the surface leak detection system are given in R1:5.2.

The likelihood of any surface leakage of CO_2 occurring via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.
- Implementing the highest standards on material selection and construction processes for the flowlines and wells.
- Applying operational best practices and a robust mechanical integrity program as well as operating procedures.
- Monitoring continuously via an automated and integrated system.

The likelihood of leakage through surface equipment during injection is very low, and the magnitude is limited to the volume of CO_2 in the flowline. The risk is constrained to the active injection phase of the project when surface equipment is in operation.

3.4 Class I Nonhazardous Disposal Well

One UIC Class I disposal well is currently active within the Blue Flint CO_2 storage project area (Figure 1-2). Well #1 (North Dakota Department of Environmental Quality Well No. 11673) disposes of nonhazardous wastewater. Well #1 was drilled to a depth of 4,046 feet into the Swift Formation and is completed in multiple porous zones within the Newcastle, Skull Creek, and Inyan Kara Formations. Well #1 is equipped with digital surface pressure gauges on the tubing and the tubing-casing annulus for continuous, real-time monitoring for mechanical integrity of the wellbore. The gauges have built-in alarms to notify the operator of readings outside of operational parameters and a seal pot system for maintaining constant pressure on the annulus and detecting leaks.

Well #1 is not an anticipated surface leakage pathway; however, it is included in the analysis since the well lies within the storage facility area of the AOR. Well #1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally or vertically. The location of the well is outside of the projected stabilized plume boundary, and the associated injection reservoir lies over 1,000 feet vertically above the CO_2 storage formation that is separated by multiple impermeable geologic seals. Well #1 is expected to remain an active injection well during operation of the Blue Flint CO_2 storage project, which greatly minimizes the possibility of flow to the Class I disposal well.

3.5 Abandoned Oil and Gas Wells

3.5.1 Ellen Samuelson 1

The Ellen Samuelson 1 (NDIC File No. 1516) well spudded on September 14, 1957, and was shortly thereafter plugged and abandoned on October 18, 1957. The well was drilled to a depth of 6,600 feet into the Mission Canyon Formation of the Madison Group, which is below the storage reservoir complex (Figure 1-3 for stratigraphic reference). Drilling, coring, and log data obtained from the well indicated no commercial accumulations of hydrocarbons were present in any of the subsurface formations drilled.

The Ellen Samuelson 1 well is not an anticipated surface leakage pathway; however, it is included in the analysis since the well is just inside the AOR boundary (Figure 2-1). The Ellen Samuelson 1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally. Figure 2-1 of this MRV plan illustrates the location of the well outside of the projected stabilized plume boundary. The Ellen Samuelson 1 is 7,140 feet beyond the edge of the projected stabilized plume boundary and has been plugged and abandoned in accordance with NDIC requirements.

3.5.2 Wallace O. Gradin 1

The Wallace O. Gradin 1 (NDIC File No. 4810) well spudded on December 1, 1969, and was shortly thereafter plugged and abandoned on December 10, 1969. The well was drilled to a depth of 4,240 feet into the Rierdon Formation. The well tested subsurface formations for hydrocarbon potential but did not produce volumes sufficient for commercial consideration.

The Wallace O. Gradin 1 well is not an anticipated surface leakage pathway; however, it is included in the analysis since the well is located just outside the AOR boundary (Figure 2-1). The Wallace O. Gradin 1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally or vertically and the Rierdon Formation in which the well is completed lies above the sealing formations associated with the CO_2 storage project. Figure 2-1 of this MRV plan illustrates the location of the well is outside of the projected stabilized plume boundary. The Wallace O. Gradin 1 is 11,850 feet beyond the projected stabilized plume boundary and has been plugged and abandoned in accordance with NDIC requirements.

3.6 Faults, Fractures, Bedding Plane Partings, and Seismicity

Regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations cannot be identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration reports (R1:2.5).

3.6.1 Stanton Fault

A regional fault was identified within the AOR boundary in previous literature. It has been described as a northeast-southwest trending, basement-rooted fault; however, there is uncertainty whether this fault exists. Figure 3-1 illustrates the surface projection of the suspected fault. Based on the seismic data analyzed as part of the site characterization activities, Figures 3-2 and 3-3, it appears that the fault does not exist, or if it does, it is limited to the Precambrian basement. The storage reservoir is approximately 5,000 feet above the Precambrian basement within the AOR, and there is no fault extending from the basement, as evidenced by the seismic data that show no visible offset in the overlying stratigraphy. Therefore, no CO_2 leakage is anticipated to surface at any time of any magnitude because CO_2 is not anticipated to come into contact with any basement features. The Stanton Fault is mentioned in this MRV plan because the path of the fault was identified within the AOR boundary.

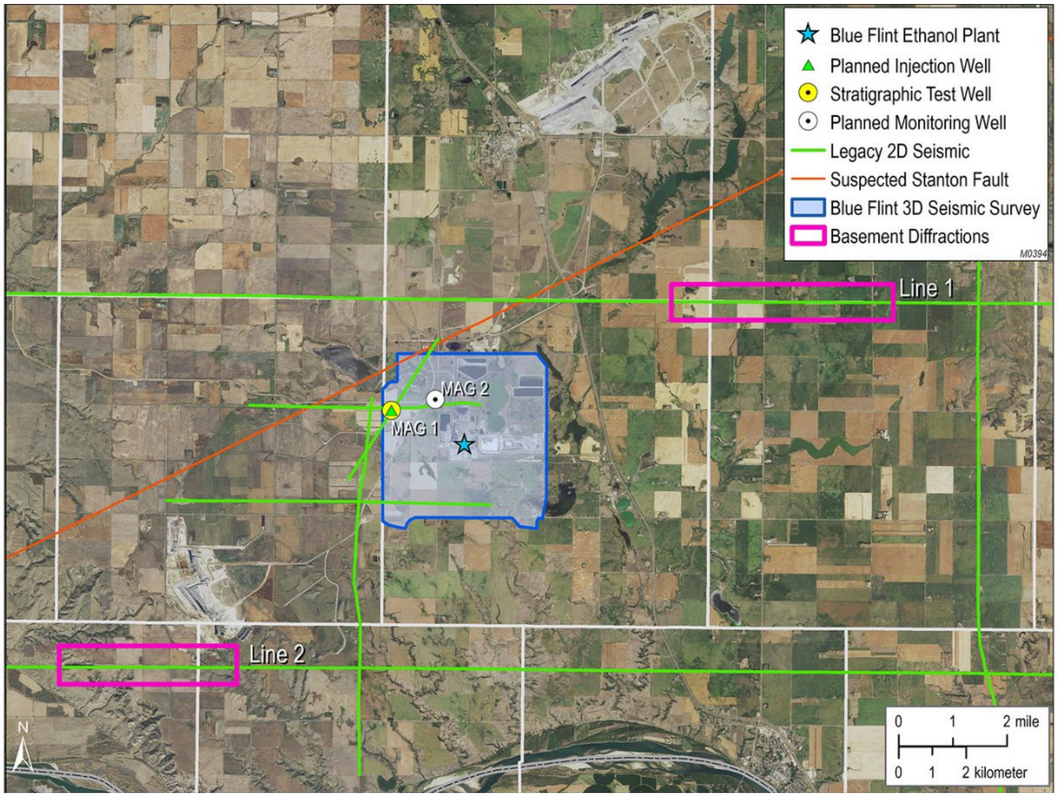


Figure 3-1. Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016) relative to the project wells and BFE facility. Also shown are legacy 2D seismic lines and a 3D seismic survey that were evaluated to characterize potential surface leakage pathways. Lines 1 and 2 are shown as Figures 3-2 and 3-3, respectively.

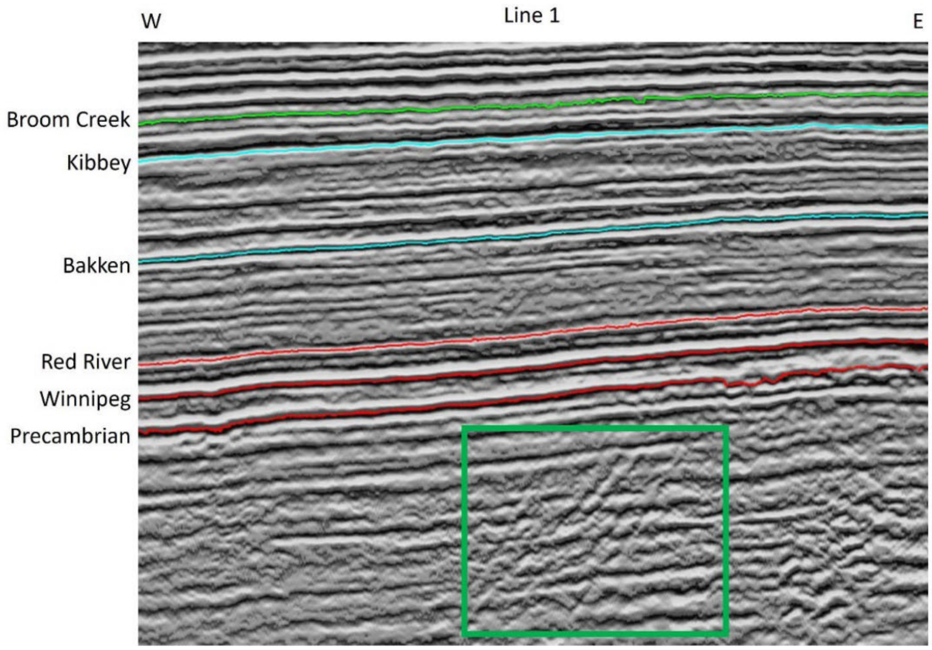


Figure 3-2. Cross section of Line 1, showing interpreted seismic horizons (colored lines) and area where diffractions are present within the Precambrian basement (green box).

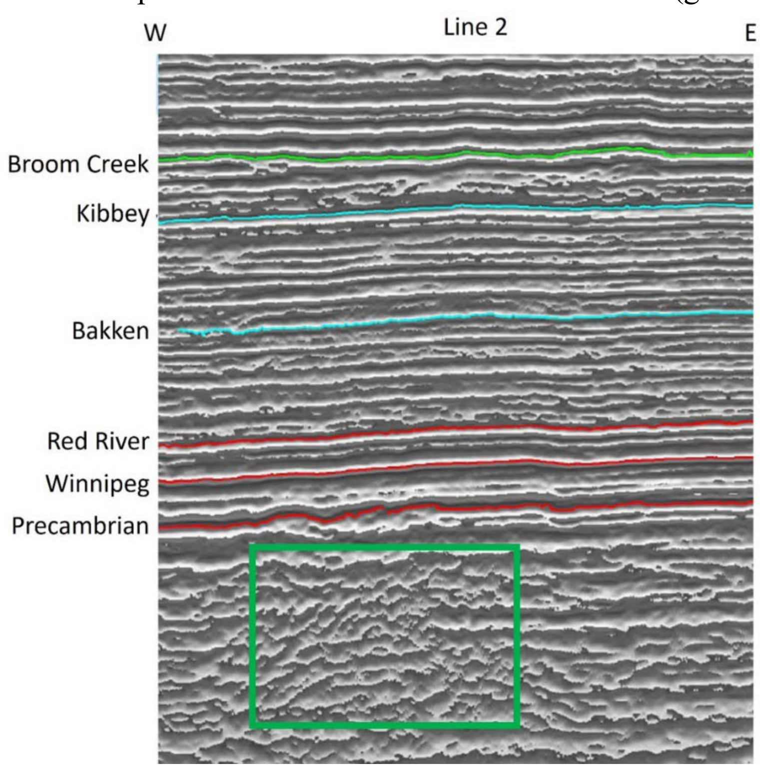


Figure 3-3. Cross section of Line 2, showing interpreted seismic horizons (colored lines) and area where diffractions are present within the Precambrian basement (green box).

3.6.2 *Natural or Induced Seismicity*

Through the geologic site characterization and corrective action review processes, leakage resulting from natural or induced seismicity was shown to be very low. Periodic seismic surveys and surface monitoring of the storage facility area will be used to detect potential surface leaks and associated magnitude throughout the operational and post-injection phases.

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment (R1:2.5.2). As illustrated in Figure 3-4, a total of 13 seismic events were detected within the North Dakota portion of the Williston Basin between 1870 and 2015 (Anderson, 2016). The two closest recorded seismic events to the Blue Flint CO_2 storage project occurred 52.3 miles to the east and 55.8 miles southwest of the MAG 1 wellbore, with estimated magnitudes of 2.6 and 0.2, respectively, as shown in Table 3-3.

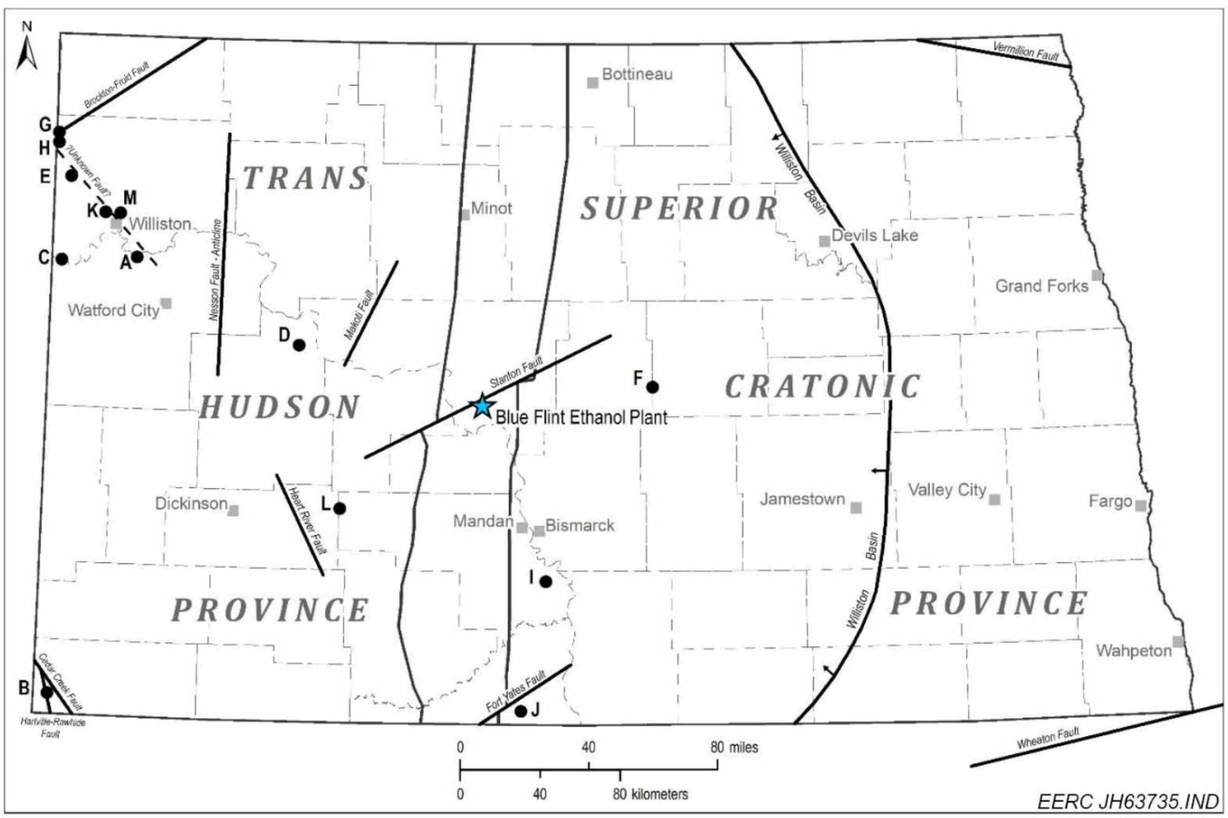


Figure 3-4. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 3-3.

Table 3-3. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, miles	Longitude	Latitude	City or Vicinity of Earthquake	Map Label	Distance to BFE, miles
September 28, 2012	3.3	0.4[1]	−103.48	48.01	Southeast of Williston	A	117.0
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	162.9
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	136.4
August 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	60.1
January 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	146.7
November 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	52.3
November 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	156.2
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	154.8
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	58.0
May 13, 1947	3.7[2]	Unknown	−100.90	46.00	Selfridge	J	96.1
October 26, 1946	3.7[2]	Unknown	−103.70	48.20	Williston	K	131.5
April 29, 1927	0.2[2]	Unknown	−102.10	46.90	Hebron	L	55.8
August 8, 1915	3.7[2]	Unknown	−103.60	48.20	Williston	M	127.3

[1] Estimated depth.

[2] Magnitude estimated from reported modified Mercalli intensity (MMI) value.

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of earthquake events occurring in North Dakota that would cause damage to infrastructure, with less than two damaging earthquake events predicted to occur over a 10,000-year period (Figure 3-5) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by USGS in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) state there is very little seismic activity near injection wells in the Williston Basin. They noted only two historic earthquakes in North Dakota (both magnitude 2.6 or lower events) that had the potential to be associated with oil and gas activities. This indicates relatively stable geologic conditions in the region surrounding the proposed injection site.

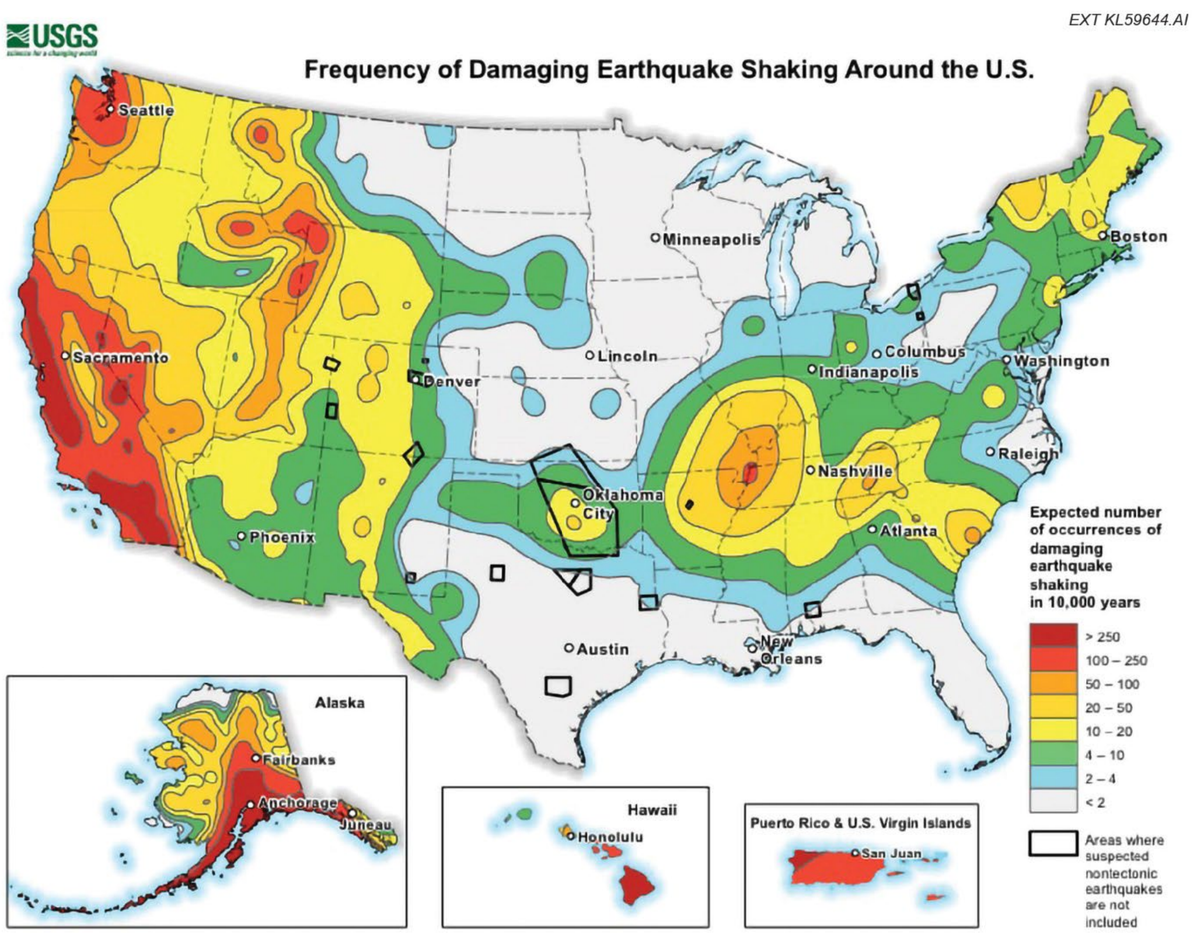


Figure 3-5. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the absence of known or suspected local or regional faults suggest that the probability is very low for seismicity to interfere with CO_2 containment. The magnitude of any seismic event in the vicinity is expected to be 2.6 or below based on the historical data gathered and analyzed. In addition, Blue Flint will ensure that injection pressures do not exceed 90 percent of the fracture pressure of the injection zone pursuant to NDAC § 43-05-01-11.3(1), thereby minimizing the potential for induced seismicity from injection operations.

3.7 Confining System Pathways

Confining system pathways include any potential for migration of CO_2 beyond their lateral extent, the potential for CO_2 to diffuse upward through confining zones, and the potential for future wells that may penetrate confining zones. Limitations to the confining system pathways considered are discussed next and presented in context to the AOR boundary.

3.7.1 Lateral Migration

For the Blue Flint CO_2 storage project, the primary mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the upper confining zone (lower Piper and Spearfish Formations defined earlier in Section 1.2), which will contain the buoyant CO_2 under the effects of relative permeability and capillary pressure (R1:2.3.2). Together, the lower Piper and Spearfish Formations are laterally extensive formations that begin 4,560 feet below the surface and have a combined thickness of 148 feet at the MAG 1 well (R1:2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), as discussed further in R1:3.4.

The risk of surface leakage of CO_2 via lateral migration is very low, as demonstrated by the geologic characteristics of the storage reservoir (R1:2.3) and upper confining zone (R1:2.4.1) (e.g., lateral extent and continuity, mineralogy, low permeability/high sealing capacity, and lack of regional faults or fractures) coupled with the modeling and simulation work (R1:3.0) that was performed for the Blue Flint CO_2 storage project.

3.7.2 Seal Diffusivity

Several other formations provide additional confinement above the lower Piper and Spearfish Formations (R1:2.4.2), including upper Piper, Rierdon, and Swift Formations, which make up the secondary group of confining formations. Together with the lower Piper and Spearfish, these formations are 859 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next porous and permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 2,512 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation. Confining layers above the Inyan Kara include the Skull Creek, Mowry, Bell Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Figure 1-3 for stratigraphic reference).

The risk of leakage via seal diffusivity is very low, as there is a total of 3,371 feet of overlying confining layers, which presents a very low risk to the Blue Flint CO_2 storage project.

The presence of multiple thick impermeable layers and laterally extensive formations drastically reduces potential leakage pathways through geologic formations.

3.7.3 Drilling Through the CO_2 Area

There is no significant commercial oil and gas activity within the project area, and it is unlikely that future wells would be drilled through the storage reservoir. Supporting evidence includes one exploration well near the edge of the project AOR: the Ellen Samuelson 1 (discussed in Section 3.5.1). The well spudded on September 14, 1957, and was drilled to a depth of 6,600 feet into the Mission Canyon Formation. Drill stem tests (DSTs) within the Madison Group recovered only drilling mud, salt water, and a very slight gas cut. Exploration concluded with plugging and abandonment on October 18, 1957.

NDIC maintains authority to regulate and enforce oil and gas activity respective to the integrity of operations, including drilling of wells and underground storage of CO_2.

3.8 Monitoring, Response, and Reporting Plan for CO_2 Loss

Blue Flint proposes a robust monitoring program in the SFP (R1:5.0 and 6.0) and is summarized in Table 4-1 of this MRV plan. The program covers surveillance of injection performance (R1:5.1 and 5.2), corrosion and mechanical integrity protocols (R1:5.3, 5.4, 5.6, and 6.2), baseline testing and logging plans for the MAG 1 and MAG 2 wellbores (R1:5.5), monitoring of near-surface conditions (R1:5.7.1, 5.7.2, and 6.2.1), and direct and indirect monitoring of the CO_2 plume and associated pressure front in the storage reservoir (R1:5.7.3 and 6.2.2). To compliment the monitoring program, Blue Flint proposes a detailed emergency remedial and response plan (R1:7.0) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting in the event of an unplanned loss of CO_2 from the Blue Flint CO_2 storage project area.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

Table 4-1 summarizes the monitoring strategy for each of the three project phases, and Table 4-2 summarizes the strategy for detecting and quantifying surface leakage pathways associated with CO_2 injection. These methodologies target early detection of any abnormalities in operating parameters or deviations from baselines and equipment detection thresholds established for the Blue Flint CO_2 storage project. These methodologies provide a verification process to validate if a leak has occurred or if the system has lost mechanical integrity. The data collected during monitoring are also used to calibrate the numerical model and improve the prediction for the injectivity, CO_2 plume, and associated pressure front.

Blue Flint will use reservoir simulation modeling, based on history-matched data obtained from the monitoring program, to compare the initial numerical model with the development of the CO_2 plume and associated pressure front. The model will be continuously calibrated with the

Table 4-1. Summary of Blue Flint's Testing and Monitoring Strategy

METHOD (TARGET AREA/STRUCTURE)	SAMPLING FREQUENCY Pre-Injection Phase (Baseline – 1 year)	Injection Phase (20 years)	Post-Injection Phase (10 years minimum)
CO_2 Stream Analysis (capture)	Start-up	Quarterly	NA[1]
Surface Pressure Gauges (MAG 1, MAG 2, and flowline)	Start-up	Real time	Real time (MAG 2 only)
Mass Flow Metering (CO_2 injection well and flowline)	Start-up	Real time	NA
CO_2 Detection Stations (flowline risers, injection wellhead, and wellhead enclosure)	Start-up	Real time	NA
Corrosion Coupon Testing (flowline and well materials)	Baseline	Quarterly	NA
SCADA Automated Remote System (MAG 1, MAG 2, and flowline)	Start-up	Real time	Real time (MAG 2 only)
DTS (MAG 1 and MAG 2)	At well completion	Real time	Real time (MAG 2 only)
Surface and Bottomhole P–T Readings (MAG 1 and MAG 2)	At well completion	Real time	Real time (MAG 2 only)
Temperature Log (MAG 1 and MAG 2)	Baseline	Annually (but only if DTS fails)	Annually in MAG 2 (only if DTS fails)
USIT or Alternative CIL (MAG 1 and MAG 2)	Baseline	Perform during well workovers but no less than once every 5 years	Perform during well workovers but no less than once every 5 years (MAG 2 only)
Tubing–Casing Annulus Pressure Tests (MAG 1 and MAG 2)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but no less than once every 5 years (MAG 2 only)
Atmospheric Analysis	3–4 seasonal samples per semipermanent soil gas location	3–4 seasonal samples per soil gas profile station and CO_2 detection stations placed outside enclosures on MAG 1 well pad	None
Soil Gas Analysis (five semipermanent probe stations)	3–4 seasonal samples per location	NA	Sample soil gas probe locations at the start of the post-injection phase and prior to facility closure
Soil Gas Analysis (two permanent profile stations)	NA	3–4 seasonal samples annually per location	Sample SGPS 1[2] prior to MAG 1 reclamation; sample SGPS 2[2] annually until facility closure
Water Analysis: Shallow Aquifers (15 wells operated by Falkirk Mining Company) (R1:B)	Provide historical water sampling results	NA	TBD[3]
Water Analysis: Shallow Aquifers (up to five wells within or near AOR)	3–4 seasonal samples per location	NA	TBD
Water Analysis: Lowest USDW (Fox Hills monitoring well adjacent to MAG 1)	3–4 seasonal samples	3–4 seasonal samples annually	Annually until facility closure
Pulsed-Neutron Logs (MAG 2)	Baseline	Once in Year 4 and every 5 years thereafter until the end of injection	Perform in Year 21 and annually thereafter until well reaches full CO_2 saturation, then reduce to once every 4 years until facility closure
Pressure Falloff Test (MAG 1)	Baseline	Every 5 years	NA
Time-Lapse 2D Seismic Surveys (CO_2 plume)	Baseline	Repeat survey in Year 1 and Year 4. Reevaluate frequency in Year 4	TBD
Vertical Seismic Profiles (VSP) (CO_2 plume)	Evaluate feasibility for early time monitoring during CO_2 injection operations	TBD	NA
Passive Seismicity Monitoring (CO_2 storage complex)	Utilize existing USGS's network	Utilize existing USGS's network and supplement with additional equipment as necessary	Utilize existing USGS's network and supplement with additional equipment as necessary

[1] Not applicable.
[2] Locations of SGPS 1 and 2 are shown on Figure 5-1.
[3] To be determined.

Table 4-2. Monitoring Strategies for Detecting and Quantifying Surface Leakage Pathways Associated with CO_2 Injection

Monitoring Strategy (target area/structure)	Potential Surface Leakage Pathway						Detection Method	Quantification Method
	Wellbores	Faults and Fractures	Flowline and/or Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal		
Surface P–T Gauges (MAG 1, MAG 2, and flowline)	X		X			X	P–T gauge data will be recorded continuously in real-time by the SCADA system and sent to the operations center to detect any anomalous readings that require further investigation.	P–T gauge data may be needed in combination with metering data to accurately quantify volumes emitted by surface equipment.
Mass Flow Metering (CO_2 injection well and flowline)	X		X	X			Metering data (e.g., rate and volume/mass) will be recorded continuously in real-time by the SCADA system and sent to the operations center to detect any anomalous readings that require further investigation.	Mass balance and leak detection software calculations.
CO_2 Detection Stations (flowline risers, injection wellhead, and wellhead enclosure)	X		X	X		X	CO_2 detection station data will detect any anomalous readings that require further investigation.	CO_2 concentration data collected by each station inside the enclosure may be used in combination with the assumed workspace atmosphere conditions and known volume of the enclosure to quantify any surface leakage of CO_2.
DTS (MAG 1 and MAG 2)	X		X	X	X	X	Temperature data will be recorded continuously in real time by the SCADA system to detect any anomalous readings near or at the surface that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.
Temperature Log (MAG 1 and MAG 2)	X		X	X	X	X	Temperature logs will be collected to detect any anomalous readings near or at the surface of the wellbore that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.
USIT or Alternative CIL (MAG 1 and MAG 2)	X			X			Ultrasonic (or alternative) logs will be collected to detect potential pathways to the surface in the wellbore that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.
Atmospheric Analysis	X		X	X	X		CO_2 gas readings will be recorded continuously in real time by the SCADA system and sent to the operations center and atmospheric samples will be analyzed from soil gas sampling activities to detect any anomalous readings that require further investigation.	CO_2 concentration data collected from multiple detection stations and/or soil gas sampling sites over time could be used to estimate the amount of surface leakage of CO_2.
Soil Gas Analysis (five semipermanent probe stations)	X			X	X	X	Soil gas data will be collected to detect any anomalous readings just beneath or at the surface that require further investigation.	Additional field studies (e.g., vegetation survey) and soil gas sampling would be needed to provide an estimate of surface leakage of CO_2.
Soil Gas Analysis (two permanent profile stations)	X			X	X	X	Same as above.	Same as above.
Pulsed-Neutron Logs (MAG 2)	X			X	X	X	Logs will be collected to detect potential pathways to the surface in or near the wellbore that require further investigation.	The pulsed-neutron log is capable of quantifying the concentration of CO_2 near the wellbore. If a pathway of surface leakage of CO_2 is detected, additional field studies (i.e., atmospheric and soil gas analysis) would be needed to quantify the event.
Time-Lapse 2D Seismic Surveys (CO_2 plume)	X	X		X	X	X	Seismic data will be collected and could detect pathways for surface leakage of CO_2 that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.
VSP (CO_2 plume)	X	X		X	X	X	VSP data may be collected and could detect pathways for surface leakage of CO_2 that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.

acquisition of real-time data. The AOR and monitoring plan will be reviewed and if warranted, revised at least every 5 years. The history-match data model identifies conditions that differ from the initial model and deviations in the operating conditions. Monitoring data will be 1) reviewed to determine if surface leakage of CO_2 is occurring, 2) verified by the operator with field personnel and/or technical experts, and 3) quantified in accordance with the quantification strategies in the monitoring plan and any emergency remedial response actions that may be necessary. Model history-matching in combination with mechanical integrity data, geophysical surveys, and near-surface monitoring provide a robust means to identify, quantify, and verify leaks. Blue Flint will adhere to the reporting in accordance with NDAC § 43-05-01-18, which specifies circumstances that warrant 30-day and 24-hour reporting.

A quality assurance and surveillance plan (QASP) is provided in R1:C, which details the specifications (e.g., detection thresholds and limits) for the monitoring equipment associated with the Blue Flint CO_2 storage project.

5.0 DETERMINATION OF BASELINES

Blue Flint will establish a pre-injection baseline by implementing a monitoring program approximately 1 year prior to CO_2 injection designed to coincide with seasonal changes. This baseline will include samples and analysis from near-surface and deep subsurface environments, such as soil gas in the vadose zone, shallow groundwater down to the lowest USDW, and the storage reservoir. Baselines provide the background concentration of CO_2 for comparative analysis to samples collected during operational and post-injection phases. Pre-injection baseline characterization is paramount to provide context to any future investigation of suspected leakage of CO_2 within the AOR.

5.1 Surface and Near-Surface Baselines

A baseline surface and near-surface sampling program has been initiated for the Blue Flint CO_2 storage project as of September 2022. Baseline data gathering includes measuring chemical concentrations of ambient air and soil gas samples (i.e., O_2, N_2, and CO_2) and groundwater (e.g., pH, total dissolved solids, alkalinity, major cations/anions, and trace metals) as well as characterizing their naturally occurring stable and radiocarbon isotopic signatures for comparison with the CO_2 stream. Figure 5-1 identifies the baseline sampling locations for establishing surface and near-surface baseline conditions. The ambient air samples are collected at the same locations as the soil gas samples. There are five planned soil gas-sampling locations and up to five existing groundwater wells from within or up to 0.25 miles outside of the AOR. Baseline water samples are also being obtained from a new Fox Hills monitoring well drilled adjacent to the MAG 1 wellbore. For additional information regarding surface and near-surface baselines, refer to R1:5.7.1 and 5.7.2.

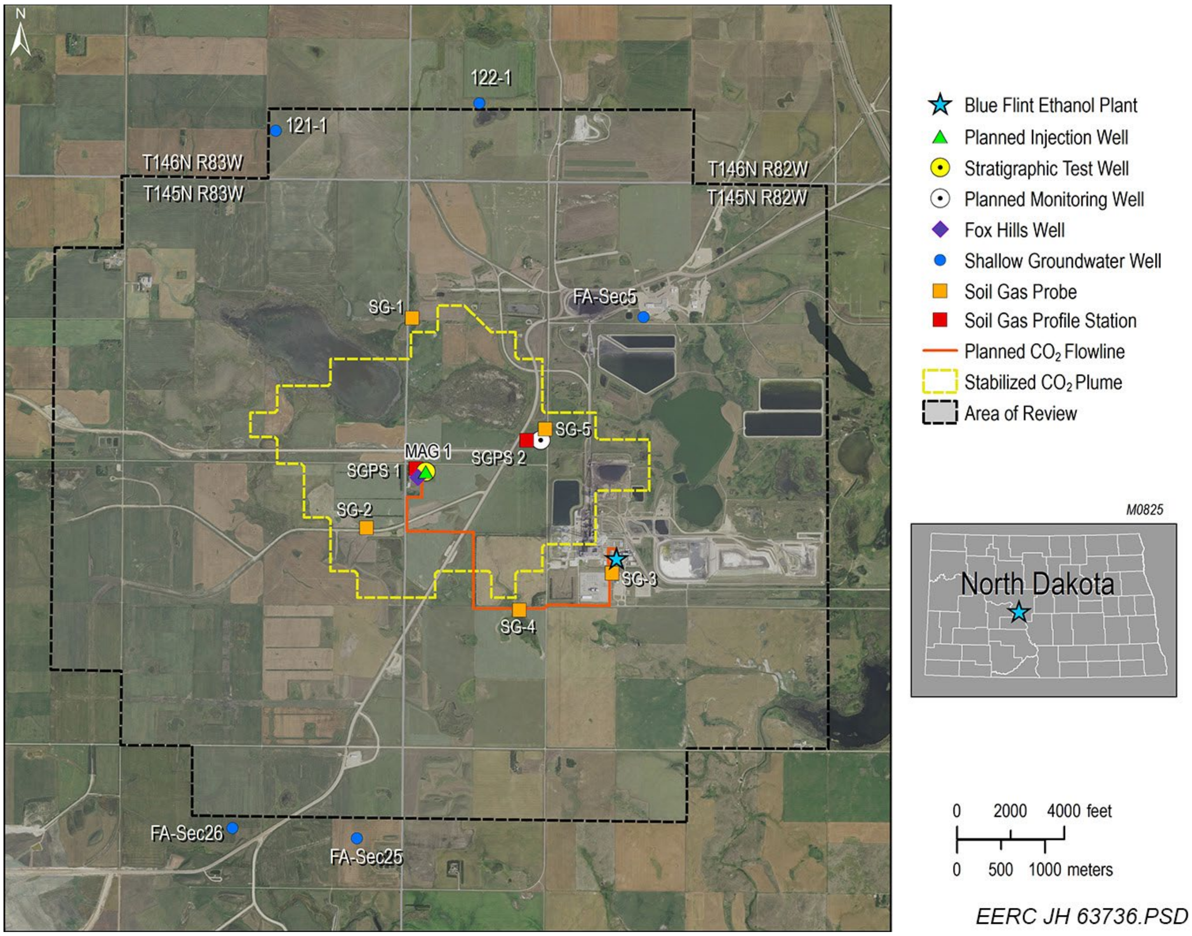


Figure 5-1. Blue Flint's planned baseline and monitoring program for soil gas, shallow groundwater aquifers, and the Fox Hills Aquifer.

5.2 Subsurface Baselines

Pre-injection baseline data will be collected in the CO_2 injection well (MAG 1) and monitoring well (MAG 2) for the Blue Flint CO_2 storage project. Table 3-1 summarizes the baseline well-testing and logging plan activities for establishing mechanical integrity in both wells. A pulsed-neutron log will be acquired from the MAG 2 wellbore prior to injection for confirming the CO_2 injection profile in the storage reservoir as well as ensuring there are no signs of out-of-zone migration into formations overlying the storage reservoir, otherwise known as the above-zone monitoring interval.

Blue Flint has selected time-lapse geophysical surveys as the primary monitoring method to track the extent of the CO_2 plume within the storage reservoir. A 2D seismic survey will be collected prior to injection to establish baseline conditions in the storage reservoir. A baseline VSP may also be collected to determine the feasibility of the technique to monitor the CO_2 plume. Figure 5-2 illustrates the planned baseline seismic survey design for the project with respect to the projected 5-year CO_2 plume and the stabilized CO_2 plume boundaries.

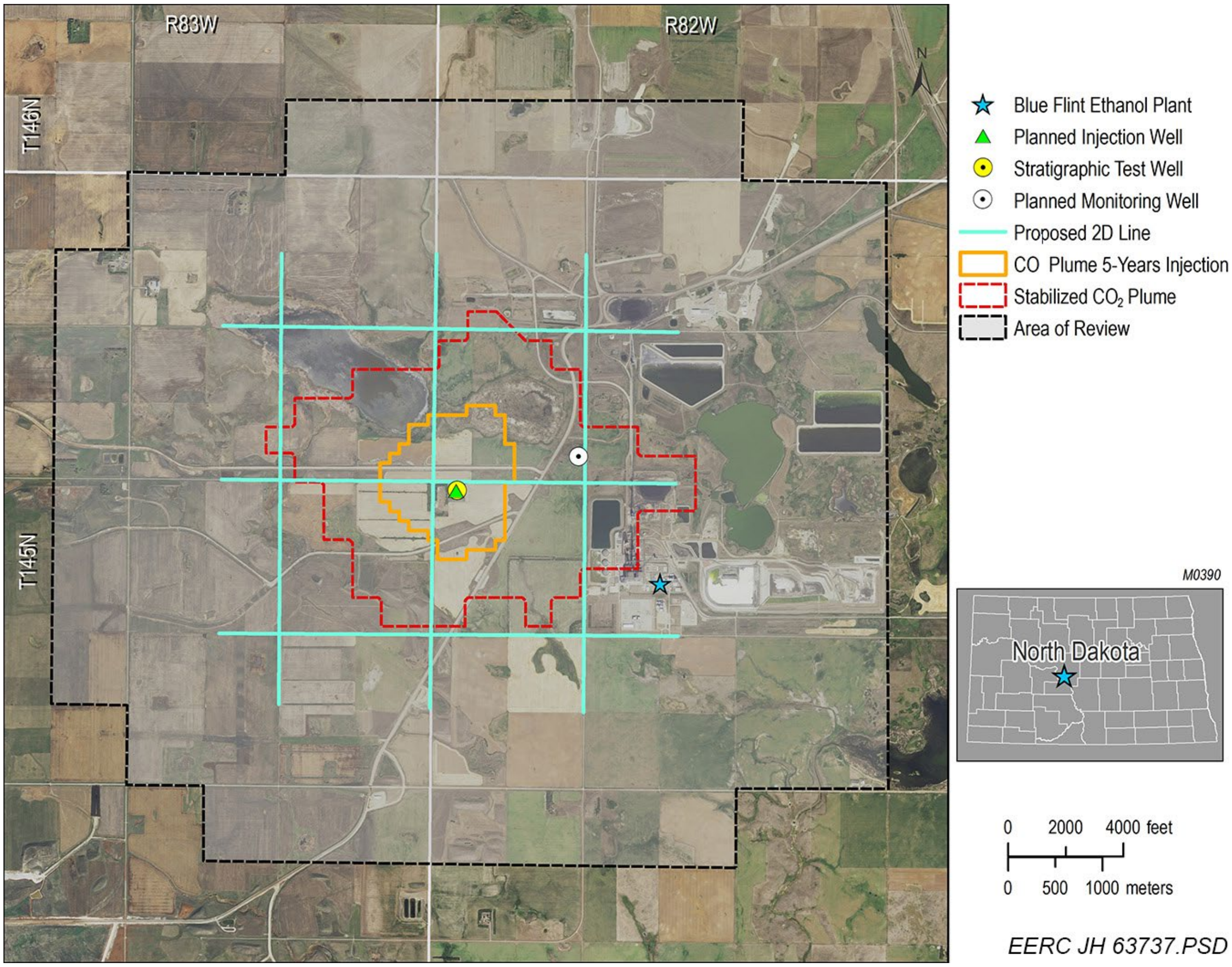


Figure 5-2. Planned 2D seismic design near the MAG 1 well to establish baseline conditions for tracking the CO_2 plume in the storage reservoir.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The Blue Flint CO_2 storage project area is a geologic CO_2 storage site in a saline aquifer with no associated production from the CO_2 storage complex. Two Coriolis mass flowmeters will be installed to meter injected CO_2 (Figure 1-4b). The flowmeter closest to the wellhead is the primary metering station.

Annual mass of CO_2 received will be calculated by using the mass of CO_2 injected pursuant to 40 CFR § 98.444(a)(4) and 40 CFR § 98.444(b). The point of measurement for the mass of CO_2 received (injected) will be the primary metering station located closest to the injection wellhead.

Annual mass of stored CO_2 is calculated from Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad \text{[Eq. 1]}$$

Where:

CO_2 = Total annual CO_2 mass stored in subsurface geologic formations (metric tons) at the facility.
CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells.
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage.
CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of Part 98.

Mass of CO_2 Injected (CO_{2I}):
Blue Flint will use mass flow metering to measure the flow of the injected CO_2 stream and calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the mass flow at standard conditions by the CO_2 concentration in the flow at standard conditions, according to Equation RR-4 from 40 CFR Part 98, Subpart RR (Equation 2):

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_2,p,u} \quad \text{[Eq. 2]}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by Flowmeter u.
$Q_{p,u}$ = Quarterly mass flow rate measurement for Flowmeter u in Quarter p (metric tons per quarter).
$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flowmeter.

Mass of CO_2 Emitted by Surface Leakage (CO_{2E}):
Blue Flint characterized, in detail, potential leakage paths on the surface and subsurface (Section 3.0 of this MRV plan), concluding that the probability is very low in each scenario. However, the monitoring plan summarized in Table 4-1 includes activities for establishing baseline conditions at the storage site, and the surface leakage of CO_2 detection and quantification strategy outlined in Table 4-2 provides several means by which surface leakage is identified and quantified.

If the monitoring and surveillance plan detects a deviation from the threshold established for each method, the project will conduct a detailed analysis based on technology available and type of leak to quantify the CO_2 volume to the best of its capabilities. The process for quantifying any leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the leak, and numerical and predictive models, among others.

Blue Flint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98-Subpart RR (Equation 3):

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \quad \text{[Eq. 3]}$$

Where:

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

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

Annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead (CO_{2FI}) will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented within 90 days of the placed-in-service date of the capture and storage equipment, including the Class VI injection well (MAG 1) and monitoring well (MAG 2). The project will not be placed in service until successfully completing performance testing, an essential milestone in achieving substantial completion. At the placed-in-service date, the project will commence collecting data for calculating total amount sequestered according to equations outlined in Section 6.0 of this MRV plan. Other greenhouse gas reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time.

This MRV plan will be in effect during the operational and post-injection monitoring phases of the project. In the post-injection phase, Blue Flint will prepare and submit a facility closure application to North Dakota, which will demonstrate nonendangerment of any USDWs and provide long-term assurance of CO_2 containment in the storage reservoir in accordance with North Dakota statutes and regulations. Once the facility closure application is approved by North Dakota, Blue Flint will submit a request to discontinue reporting under this MRV plan consistent with North Dakota and Subpart RR requirements (see 40 CFR § 98.441[b][2][ii]).

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for Blue Flint monitoring techniques and data management is provided in the quality assurance and surveillance plan found in R1:C.

Blue Flint will ensure compliance with the quality assurance requirement in 40 CFR § 98.444:

CO_2 received:

- The quarterly flow rate of CO_2 will be reported from continuous measurement at the main metering station (identified in Figure 1-4b).

- The CO_2 concentration will be reported as an average from measurements obtained at least quarterly from the CO_2 compressors.

Flowmeter provision:

- Operated continuously, except as necessary for maintenance and calibration.

- Operated using calibration and accuracy requirements in 40 CFR § 98.3(i).

- Operated in conformance with consensus-based standards organizations including, but not limited to, American Society for Testing and Materials (ASTM) International, the American National Standards Institute, the American Gas Association, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

9.0 MRV PLAN REVISIONS

In the event there is a material change to the monitoring and/or operational parameters of the Blue Flint CO_2 storage project that is not anticipated in this MRV plan, this MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in § 98.448(d). Blue Flint may also submit supplemental revisions to this MRV plan, which take into consideration responses, inquiries, and final determinations from the regulatory agencies having jurisdiction in R1 and the associated UIC Class VI drilling permit.

10.0 RECORDS RETENTION

Blue Flint will follow the record retention requirements specified by 40 CFR § 98.3(g). In addition, it will follow the requirements in Subpart RR 40 CFR § 98.447-Subpart RR by maintaining the following records for at least 3 years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the 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 and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

These data will be collected, generated, and aggregated as required for reporting purposes.

11.0 REFERENCES

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U.S. Geological Survey, 2016, For the first time, new USGS maps identify the potential for ground shaking from both human-induced and natural earthquakes in 2016: www.usgs.gov/news/featured-story/induced-earthquakes-raise-chances-damaging-shaking-2016 (accessed June 2022).

Appendix B: Submissions and Responses to Requests for Additional Information

BLUE FLINT SEQUESTER COMPANY, LLC
MONITORING, REPORTING, AND VERIFICATION PLAN

Class VI CO_2 Injection Well

Reporter Number: 583181

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Continued . . .

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LIST OF FIGURES

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STORAGE FACILITY PERMIT DESIGNATION

Within the text of this monitoring, reporting, and verification plan, Blue Flint Sequester Company's storage facility permit application is designated as follows:

Reference 1: Blue Flint Sequester Company, LLC Carbon Dioxide Geologic Storage Facility Permit Application

Section 1 – Pore Space Access
Section 2 – Geologic Exhibits
Section 3 – Geologic Model Construction and Numerical Simulation of CO_2 Injection
Section 4 – Area of Review
Section 5 – Testing and Monitoring Plan
Section 6 – Post-Injection Site Care and Facility Closure Plan
Section 7 – Emergency and Remedial Response Plan
Section 8 – Worker Safety Plan
Section 9 – Well Casing and Cementing Program
Section 10 – Plugging Plan
Section 11 – Injection Well and Storage Operations
Section 12 – Financial Assurance and Demonstration Plan
Appendix A – MAG 1 Formation Fluid Sampling
Appendix B – Historic Freshwater Well Fluid Sampling
Appendix C – Quality Assurance and Surveillance Plan
Appendix D – Storage Facility Permit Regulatory Compliance Table

REFERENCING CONVENTION

Below are three formatted examples of the referencing convention this document will follow:

- R1:4.1.1
- R1:C1.3
- R1:6.1.1, Figure 6-1

R1 refers to Reference 1 as designated hereto, and numbers or letters that appear after the colon represent the appropriate section or appendix from the storage facility permit. Thus:

- R1:4.1.1 would direct the reader to Section 4.1.1 (Area of Review Section, Written Description Subsection) within the storage facility permit application.

- R1:C1.3 would direct the reader to Section 1.3 (Corrosion Monitoring and Prevention Plan) of Appendix C (Quality Assurance and Surveillance Plan) within the storage facility permit application.

- R1:6.1.1, Figure 6-1 would direct the reader to Figure 6-1 in Section 6.1.1 (Pre- and Postinjection Pressure Differential) within the storage facility permit application.

MRV PLAN SUMMARY

Midwest AgEnergy (MAG) is moving toward a zero-carbon footprint through a multi-phased initiative "vision carbon zero." MAG, the owner of Blue Flint Ethanol, LLC; Blue Flint Capture Company, LLC; and Blue Flint Sequester Company, LLC (Blue Flint) is developing a carbon capture and storage (CCS) project for the Blue Flint Ethanol (BFE) facility in Underwood, North Dakota. Blue Flint proposes a compliant Greenhouse Gas Reporting Program (GHGRP) Subpart RR monitoring, reporting, and verification (MRV) plan in support of the storage project. As required under Title 40 Code of Federal Regulations (CFR) § 98.448, this plan includes 1) delineation of the maximum and active monitoring areas; 2) identification of potential surface leakage pathways and the likelihood, magnitude, and timing of surface leakage of carbon dioxide (CO_2) through these pathways within the maximum monitoring area (MMA); 3) a strategy for detecting and quantifying any surface leakage of CO_2; 4) a strategy for establishing the expected baselines for monitoring; and 5) a summary of the CO_2 accounting (mass balance) approach.

Blue Flint submitted a North Dakota Underground Injection Control (UIC) Class VI permit (storage facility permit [SFP]) application to the North Dakota Industrial Commission (NDIC) Department of Mineral Resources (DMR) on October 3, 2022. The U.S. Environmental Protection Agency (EPA) granted North Dakota primacy to administer the UIC Class VI Program on April 24, 2018, for injection wells located within the state, except within Indian lands (83 Federal Register 17758, 40 CFR § 147.1751; EPA Docket No. EPA-HQ-OW-2013-0280). Blue Flint's public hearing at the NDIC DMR took place on March 21, 2023 (NDIC Case No. 29888). The SFP includes plans applicable to the requirements of 40 CFR Part 98 Subpart RR. Monitoring aspects contained in this MRV plan that have been carried over from the testing and monitoring strategy in the SFP include 1) sampling of the CO_2 stream, 2) a leak detection and corrosion monitoring plan for the surface piping and wellhead, 3) mechanical integrity testing and leak detection for injection and monitoring wells, and 4) an environmental monitoring program that includes sampling of soil gas and groundwater and time-lapse seismic surveys.

1.0 PROJECT OVERVIEW

1.1 Project Description

The BFE facility, located 6 miles south of Underwood, North Dakota, produces over 70 million gallons of ethanol annually, along with about 200,000 tons of dry distillers' grains and about 10 tons of corn oil. A by-product of fermentation is a nearly pure stream of CO_2 (99%+ dry by volume). The BFE facility produces about 200,000 metric tons of CO_2 annually.

Blue Flint plans to capture approximately 200,000 metric tons of CO_2 annually over a 20-year period from the BFE facility. The captured CO_2 will be processed for compression and transported in a 3-mile-long CO_2 flowline to a single CO_2 injection well. A stratigraphic test well (MAG 1) was drilled for the Blue Flint CO_2 storage project. This wellbore will be converted into a UIC Class VI injection well, and a second stratigraphic test well (MAG 2) will be drilled and converted into a monitoring well. The CO_2 stream will be injected into the Broom Creek Formation, a predominantly sandstone reservoir and saline aquifer, at a depth of 4,708 feet below the ground surface at the MAG 1 well location. The MAG 1 well has a surface elevation of 1,905 feet. The location of the BFE facility, planned CO_2 flowline, and injection and monitoring wells are provided in Figure 1-1, with respect to the extent of CO_2 storage delineated as the projected stabilized plume boundary.

1.2 Geologic Setting

The Blue Flint CO_2 storage project is located along the eastern flank of the Williston Basin where there has been no significant commercial production of hydrocarbon resources. Figure 1-2 provides a state reference map to illustrate the geographic distribution of oil and gas fields (undifferentiated) in North Dakota. The closest oil and gas fields to the project are 39 miles west of the western edge of the projected stabilized CO_2 plume boundary, demonstrating that there has been no commercial development of hydrocarbon resources within the immediate project area

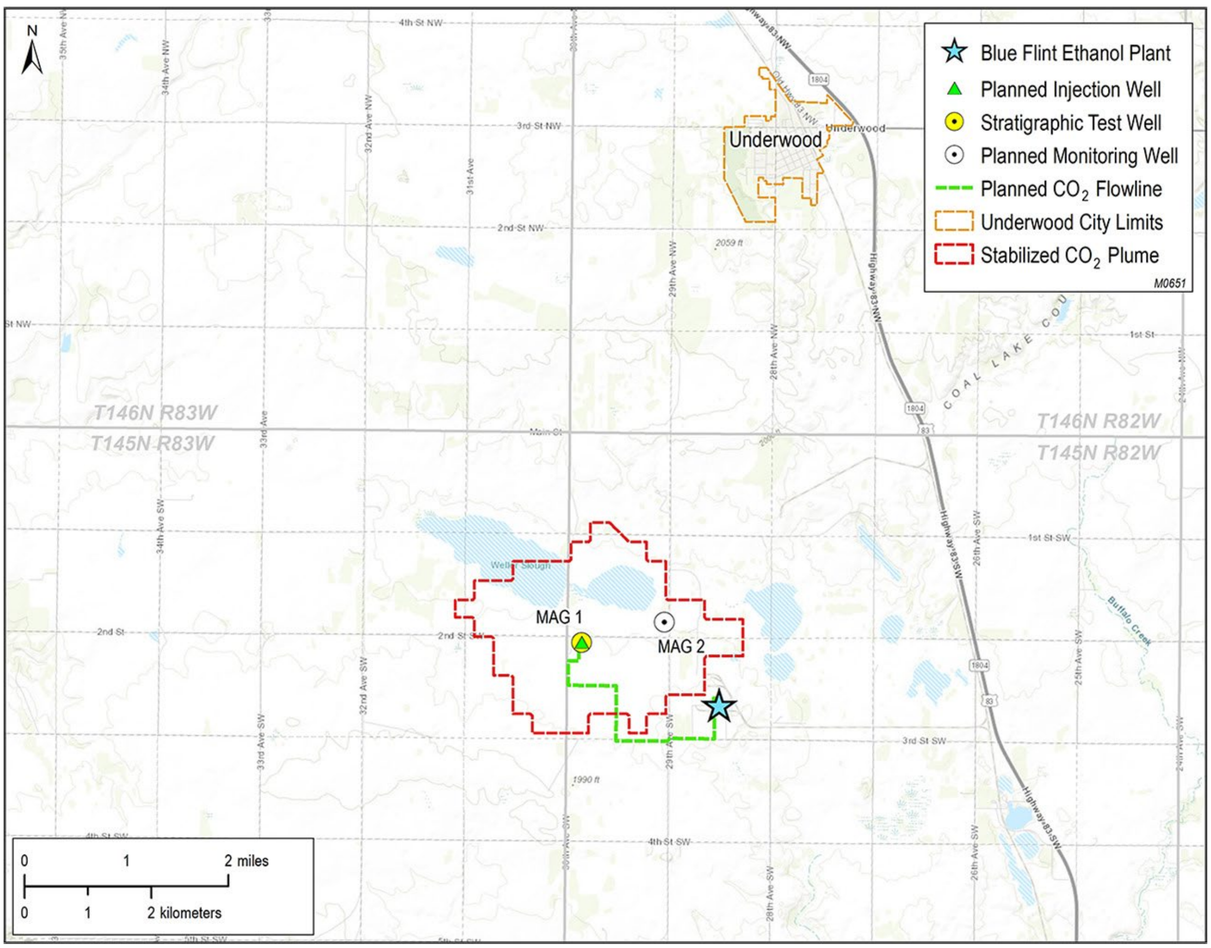

Figure 1-1. Location of the BFE facility, planned CO_2 flowline, and planned wells: CO_2 injection well (MAG 1) and monitoring well (MAG 2). The red outline indicates the projected stabilized CO_2 plume boundary.

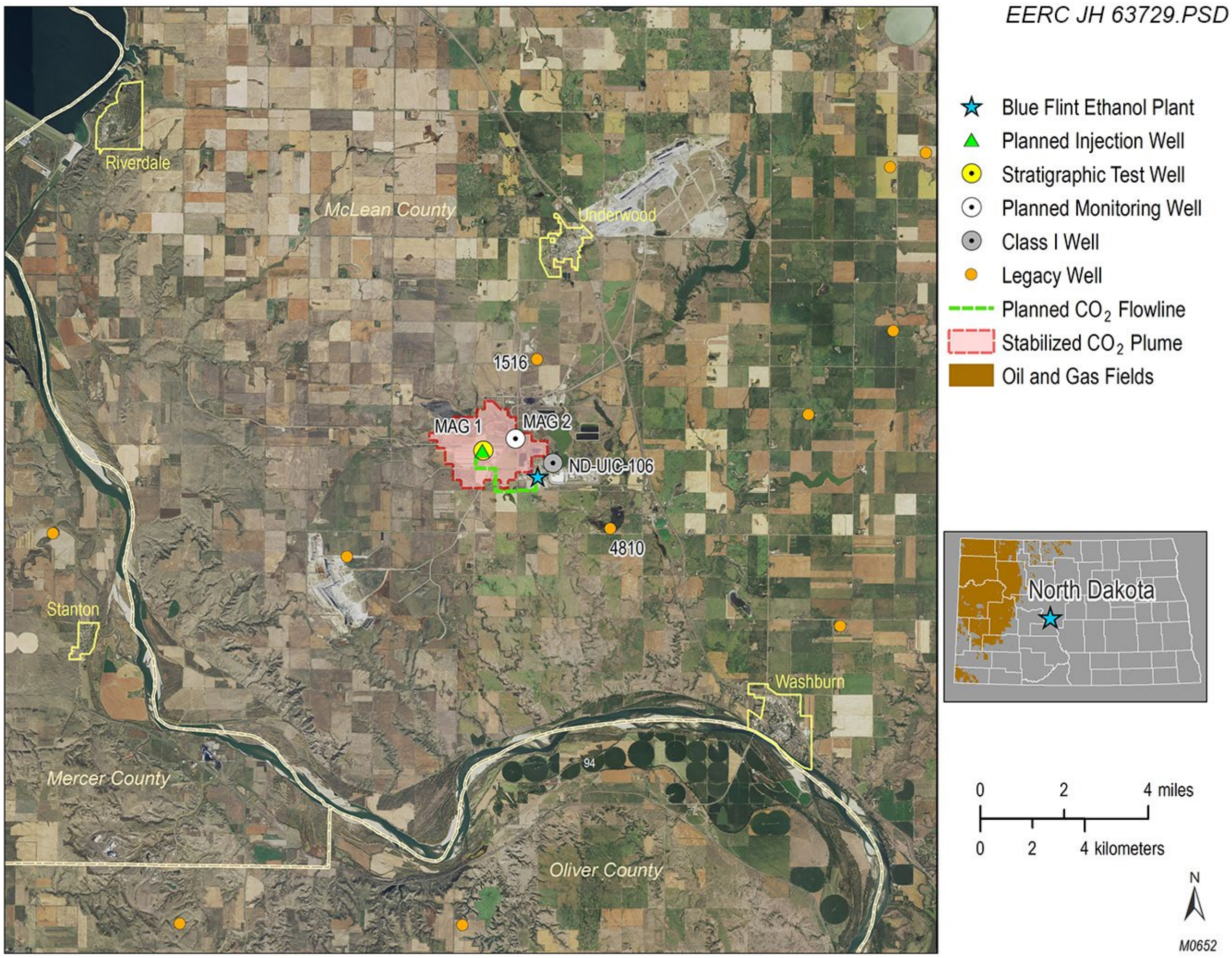

Figure 1-2. Map illustrating the locations of existing legacy wellbores around the projected stabilized CO_2 plume extent for the Blue Flint CO_2 storage project and nearby towns (outlined and labeled in yellow). The state reference map also reveals the geographic distribution of oil and gas fields in North Dakota. The closest oil and gas field is approximately 39 miles west of the Blue Flint CO_2 storage project.

(R1:2.6). The Williston Basin is a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. The basin is hydrocarbon-bearing, with over 38,000 wells drilled in North Dakota for production of commercial accumulations of oil and gas from subsurface reservoirs. Although commercial oil and gas production is not present in the area surrounding the project, legacy oil and gas exploration wells are present. Figure 1-2 also identifies the legacy wells surrounding the projected stabilized CO_2 plume area, with identification numbers provided for the two nearest wells to the geologic CO_2 storage site.

A standard stratigraphic column of the Williston Basin for the area of Underwood, North Dakota is provided in Figure 1-3. The target storage reservoir is the Broom Creek Formation, a predominantly sandstone interval (R1:2.3). Siltstones with interbedded anhydrite of the lower Piper and Spearfish Formations unconformably overlie the Broom Creek and serve as the upper (primary) confining zone (R1:2.4.1). Mixed layers of dolostone, limestone, and anhydrite of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone (R1:2.4.3). Together, the lower Piper–Spearfish, Broom Creek, and Amsden Formations comprise the CO_2 storage complex. There is about 859 feet (average thickness across the project area) of impermeable rock, including the lower Piper–Spearfish, between the Broom Creek and the next overlying porous zone, the Inyan Kara Formation (R1:2.4.2). An additional 2,512 feet (average thickness across the project area) of impermeable rock, including the Skull Creek, Mowry, Bell Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations, separate the Inyan Kara from the Fox Hills Formation (lowest underground source of drinking water [USDW]).

1.3 Description of CO_2 Project Facilities and Injection Process

The BFE facility will utilize a liquefaction process to capture CO_2 produced from fermentation. Figure 1-4 provides a facility flow diagram. The liquefaction process includes processing to remove oxygen and other non-condensable gases before gas is compressed and flowed to the injection well through a FlexSteel CO_2 flowline for geologic storage into the Broom Creek Formation.

1.4 Facility Information

Reporter Number: Blue Flint – 583181
UIC Permit Class: The MAG 1 wellbore will be permitted as a Class VI injection well
Well Identification Number: NDIC File No. 37833, API No. 33-055-00196-00-00

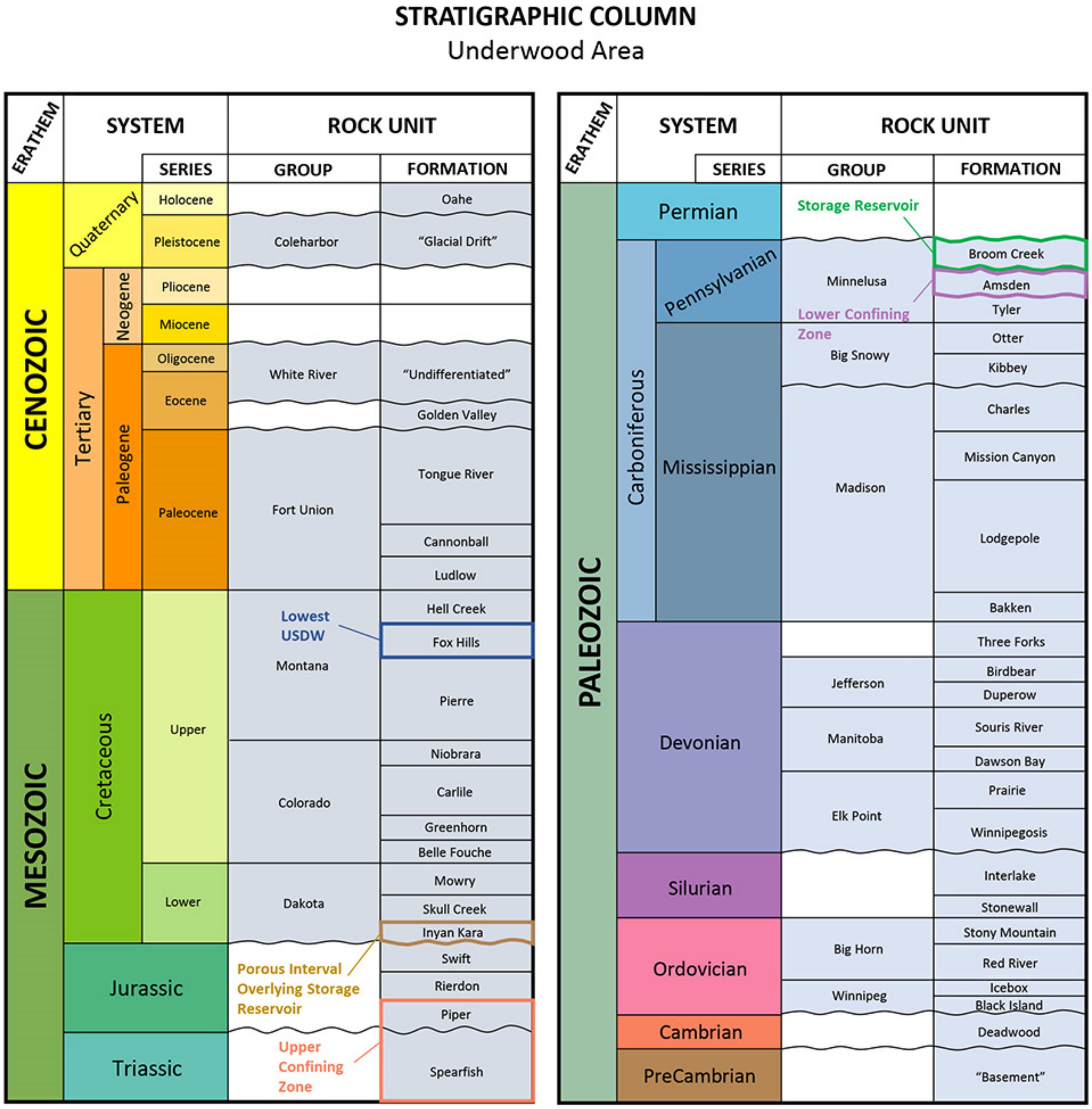

Figure 1-3. Stratigraphic column of the Williston Basin for the Underwood area, identifying the CO_2 storage complex as well as the next porous interval overlying the storage reservoir and lowest USDW underlying the Blue Flint CO_2 storage project area. Figure modified after Murphy and others (2009) and Bluemle and others (1981).

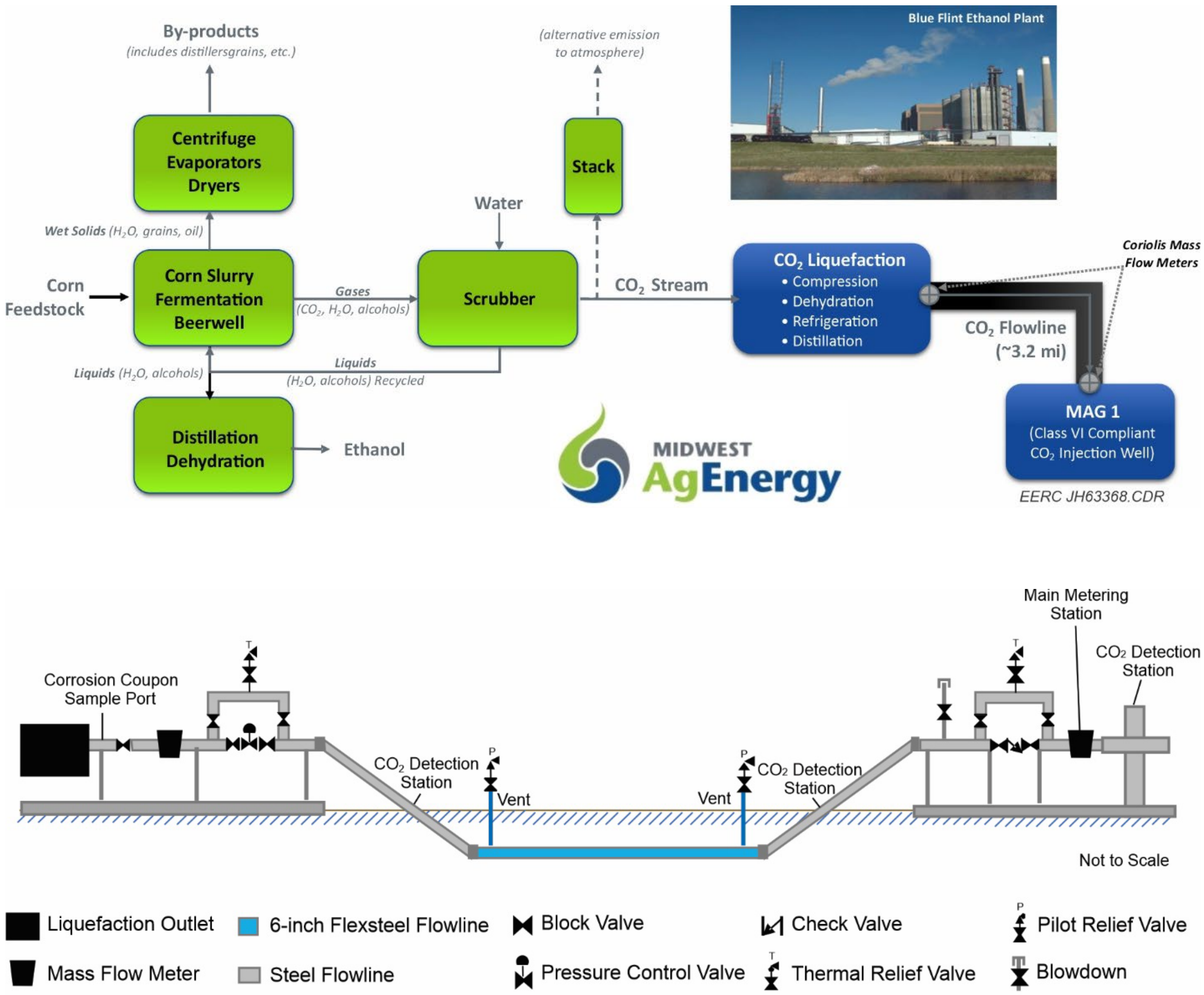

Figure 1-4. a) Process flow diagram of the CO_2 capture process at the BFE facility. b) Generalized flow diagram illustrating major CCS components of the surface facilities from the liquefaction outlet to the CO_2 injection well. The main metering station will be located adjacent to the injection wellhead as shown.

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

The area of review (AOR) boundary defined in the North Dakota SFP application (R1:4.0) will serve as the MMA and the active monitoring area (AMA) until facility closure (i.e., the point at which Blue Flint receives a certificate of project completion). As illustrated in Figure 2-1, the AOR boundary provides a 1-mile buffer around the stabilized CO_2 plume, rounding to the nearest 40-acre tract. This 1-mile buffer area is larger and thereby exceeds the regulatory requirements for buffer areas around the free-phase CO_2 plume with respect to subpart RR definitions for the MMA and the AMA. Blue Flint will begin to monitor approximately 1 year prior to injection, during the active 20-year injection period, and for a minimum of 10 years after injection ceases.

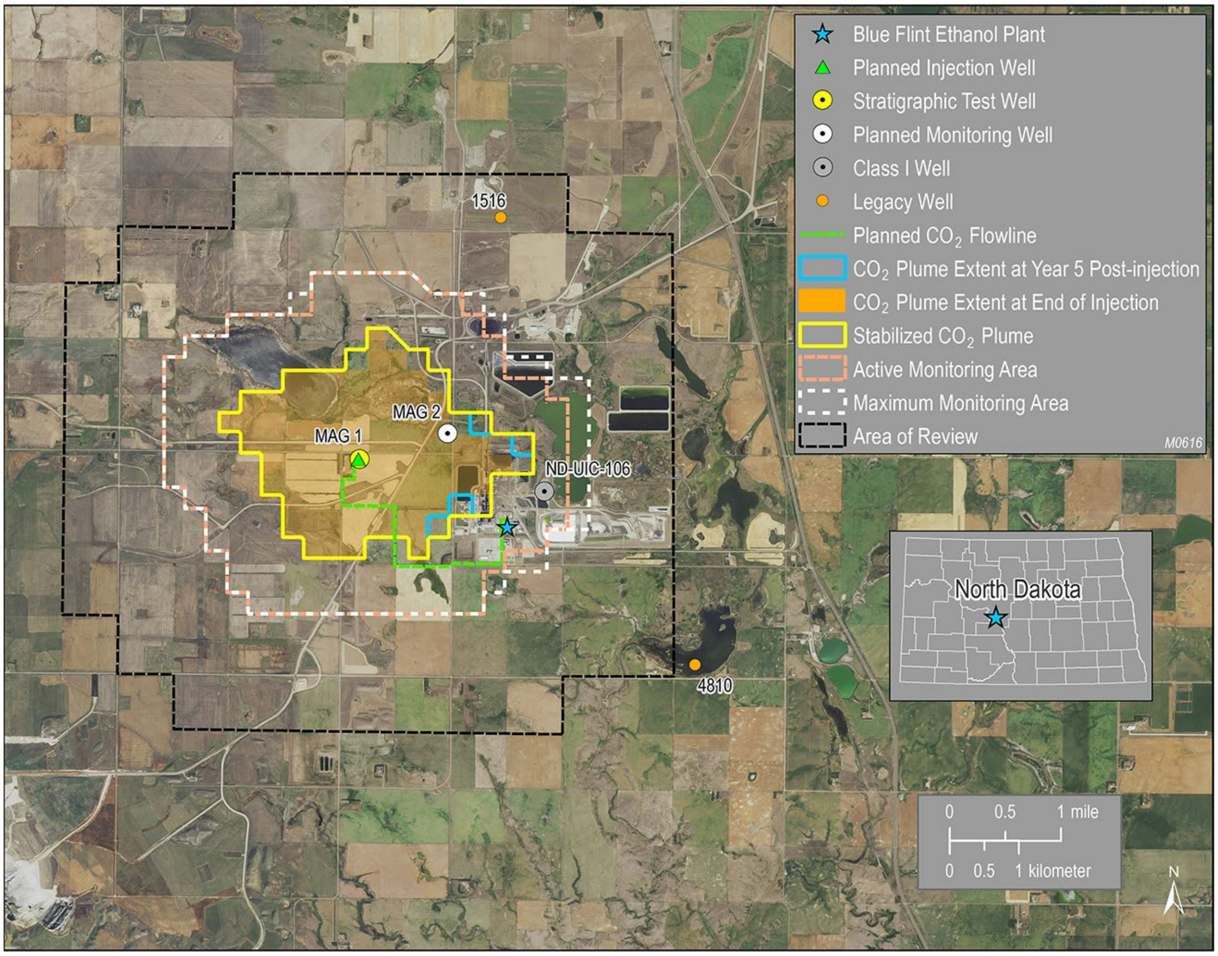

Figure 2-1. Map showing the AOR relative to the calculated MMA and AMA boundaries. In this case, "n" was set at Year 1 of injection and "t" set was set at Year 20 (end of injection) for calculating the AMA.

Subpart RR regulations require the operator to delineate an MMA and an AMA. The MMA is a geographic area that must be monitored and is defined as an area that is greater than or equal to the projected stabilized CO_2 plume boundary plus an all-around buffer zone of at least one-half mile (40 CFR § 98.449 [Subpart RR]). An operator may stage monitoring efforts over time by defining time intervals with respect to an AMA. The AMA is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the 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 and 2) the area projected to contain the free-phase CO_2 plume at the end of Year t + 5. Blue Flint calculated the MMA and AMA according to these regulatory definitions, as shown in Figure 2-1.

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). The proposed AOR in Figure 2-1 is in accordance with the above regulations, providing a 1-mile buffer and rounding to the nearest 40-acre tract outside the modeled CO_2 plume boundary.

3.0 EVALUATION OF POTENTIAL SURFACE LEAKAGE PATHWAYS

Subpart RR requirements specify that the operator must identify potential surface leakage pathways and evaluate the magnitude, timing, and likelihood of surface leakage of CO_2 through these pathways within the MMA (40 CFR § 98.448[a][2]). Blue Flint identifies the potential surface leakage pathways as follows:

1. Class VI injection well
2. Monitoring well
3. Surface components
4. Class I nonhazardous disposal well
5. Abandoned oil and gas wells
6. Faults, fractures, bedding plane partings, and seismicity
7. Confining system pathways

3.1 Class VI Injection Well (MAG 1)

The MAG 1 well (NDIC File No. 37833) spudded on October 11, 2020, as a stratigraphic test well and drilled to a depth of 9,213 feet into the Red River Formation (R1:9.1). This well was drilled to gather geologic data for the development of Blue Flint's North Dakota SFP application. The MAG 1 well will be completed to NDIC Class VI construction standards as an injection well for the Blue Flint CO_2 storage project. The temperature profile of the MAG 1 wellbore will be continuously monitored with temperature distributed temperature sensing (DTS) fiber-optic cable. In addition, pressure in the wellbore will be continuously monitored with at least one downhole, tubing-conveyed P–T (pressure–temperature) gauge and digital surface pressure gauges on the tubing and well annulus. The tubing-casing annulus pressure will be tested prior to injection and at least once every 5 years. An ultrasonic or alternative casing inspection log will also be acquired prior to injection for detecting any potential mechanical integrity issues behind casing and repeated at least once every 5 years (R1:5.4).

The risk of surface leakage of CO_2 via the MAG 1 is mitigated through:

- Monitoring operations with a surface leak detection plan, as described in R1:5.2.

- Preventing corrosion of well materials, following the preemptive measures in R1:5.3 and 5.6.

- Performing wellbore mechanical integrity testing, as described in R1:5.4 and summarized in Table 3-1 of this MRV plan.

- Monitoring the storage reservoir with a subsurface leak detection plan (environmental monitoring plan), as described in R1:5.7 and Table 4-1 of this MRV plan.

- Acting in accordance with the emergency remedial response plan in R1:7.4.

Table 3-1. Overview of Blue Flint's Mechanical Integrity Testing Plan

Activity	Baseline Frequency	Operational Frequency (20-year period)
External Mechanical Integrity Testing		
Ultrasonic Imaging Tool (USIT) or Alternative Casing Inspection Log (CIL)	Acquire baseline in MAG 1 and MAG 2.	Perform during well workovers but no less than once every 5 years.
DTS	Install at completion of MAG 1 and MAG 2.	Continuous monitoring.
Temperature Logging	Acquire baseline in MAG 1 and MAG 2.	Perform annually but only as a backup if DTS fails.
Internal Mechanical Integrity Testing		
Tubing-Casing Annulus Pressure Testing	Perform in MAG 1 and MAG 2 prior to injection. Install digital surface pressure gauges.	Perform during well workovers but no less than once every 5 years. Digital surface pressure gauges will monitor annulus pressures continuously.
Surface and Tubing-Conveyed P–T Gauges	Install gauges in the MAG 1 and MAG 2 prior to injection.	Gauges will monitor temperatures and pressures in the tubing continuously.
USIT or Alternative CIL	Acquire baseline in MAG 1 and MAG 2.	Perform during well workovers but no less than once every 5 years.

The likelihood of surface leakage of CO_2 from the MAG 1 well during injection or post-injection operations is very low because of well construction and active monitoring. Barriers associated with well construction that prevent reservoir fluids from reaching the surface include surface valves, injection tubing fitted with a packer set above the injection zone, annular casing, cement, and surface casing and cement. Integrity of these barriers is actively monitored with DTS along the casing and surface gauges on the tubing and well annulus. Active monitoring ensures integrity of well barriers and early detection of leaks. A supervisory control and data acquisition (SCADA) system is used to monitor for leaks. The detection time specified in R1:5.2, Table 5-3, and Table 3-2 of this MRV plan greatly minimizes the magnitude of any surface leakage and provides the potential to estimate volumes. The potential for a surface leak from the MAG 1 injection well is present from the first day of injection through the post-injection phase. The risk of a surface leak begins to decrease after injection ceases and greatly decreases as the reservoir approaches original pressure conditions. Once injection ceases, the MAG 1 will be properly plugged and abandoned following NDIC protocols, thereby further reducing any remaining risk of surface leakage from the wellbore.

Table 3-2. Performance Targets for Detecting Leaks in Surface Equipment with SCADA System

Leak Size, Mscfpd*	Detection Time, minutes
10	<2
>1	<5
<1 and >0.5	<60

* Thousand standard cubic feet per day.

3.2 Monitoring Well (MAG 2)

The MAG 2 well (NDIC File No. TBD) is planned to spud prior to injection as a stratigraphic test well for the Blue Flint CO_2 storage project. The well will be drilled to the Amsden/Tyler Formations. This stratigraphic test well will be converted into a monitoring well prior to injection and will be constructed to NDIC Class VI standards. Like MAG 1, the well will be monitored with continuous DTS fiber-optic cable, at least one tubing-conveyed P–T gauge, and digital surface pressure gauges on the tubing and well annulus. The tubing-casing annulus pressure will be tested prior to injection and at least once every 5 years. An ultrasonic or alternative casing inspection log will also be acquired prior to injection for detecting any potential mechanical integrity issues behind casing and repeated at least once every 5 years (R1:5.4 and Table 3-1 of this MRV plan).

The likelihood of surface leakage of CO_2 from the MAG 2 well during injection or post-injection operations is very low because of well construction and active monitoring. Barriers associated with well construction that prevent reservoir fluids from reaching the surface include the wellhead, tubing with packer, surface valves, surface casing and cement, and production casing and cement. The integrity of these barriers is actively monitored with DTS along the casing, tubing-conveyed P–T gauges, and surface P–T gauges. Since the MAG 2 well is located just inside the projected stabilized CO_2 plume boundary, the potential for a surface leak begins near the end of the 20-year injection period and continues during the post-injection phase of the project. The risk of a surface leak decreases after injection ceases as the reservoir approaches original pressure conditions. At the end of the post-injection monitoring phase, the MAG 2 will be properly plugged and abandoned following NDIC protocols, thereby further reducing any remaining risk of surface leakage from the wellbore.

3.3 Surface Components

Surface components of the injection system, including the flowline and CO_2 injection wellhead (MAG 1), will be monitored with leak detection equipment (Figure 1-4b). The flowline will be monitored continuously via dual flowmeters located at the liquefaction outlet and near the wellhead for performing mass balance calculations. The flowline will also be regularly inspected for any visual or auditory signs of equipment failure and monitored continuously with one pressure gauge at the liquefaction outlet and one near the wellhead. CO_2 detection stations will be located on the flowline risers and at the CO_2 injection wellhead for identifying the presence of CO_2 external to surface equipment. The leak detection equipment will be integrated with automated warning systems and shutoffs that notify Blue Flint's operations center, giving the operator the ability to remotely isolate the system. Further details of the surface leak detection system are given in R1:5.2.

The likelihood of any surface leakage of CO_2 occurring via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.
- Implementing the highest standards on material selection and construction processes for the flowlines and wells.
- Applying operational best practices and a robust mechanical integrity program as well as operating procedures.
- Monitoring continuously via an automated and integrated system.

The likelihood of leakage through surface equipment during injection is very low, and the magnitude is limited to the volume of CO_2 in the flowline. The risk is constrained to the active injection phase of the project when surface equipment is in operation.

3.4 Class I Nonhazardous Disposal Well

One UIC Class I disposal well is currently active within the Blue Flint CO_2 storage project area (Figure 1-2). Well #1 (North Dakota Department of Environmental Quality Well No. 11673) disposes of nonhazardous wastewater. Well #1 was drilled to a depth of 4,046 feet into the Swift Formation and is completed in multiple porous zones within the Newcastle, Skull Creek, and Inyan Kara Formations. Well #1 is equipped with digital surface pressure gauges on the tubing and the tubing-casing annulus for continuous, real-time monitoring for mechanical integrity of the wellbore. The gauges have built-in alarms to notify the operator of readings outside of operational parameters and a seal pot system for maintaining constant pressure on the annulus and detecting leaks.

Well #1 is not an anticipated surface leakage pathway; however, it is included in the analysis since the well lies within the storage facility area of the AOR. Well #1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally or vertically. The location of the well is outside of the projected stabilized plume boundary, and the associated injection reservoir lies over 1,000 feet vertically above the CO_2 storage formation that is separated by multiple impermeable geologic seals. Well #1 is expected to remain an active injection well during operation of the Blue Flint CO_2 storage project, which greatly minimizes the possibility of flow to the Class I disposal well.

3.5 Abandoned Oil and Gas Wells

3.5.1 Ellen Samuelson 1

The Ellen Samuelson 1 (NDIC File No. 1516) well spudded on September 14, 1957, and was shortly thereafter plugged and abandoned on October 18, 1957. The well was drilled to a depth of 6,600 feet into the Mission Canyon Formation of the Madison Group, which is below the storage reservoir complex (Figure 1-3 for stratigraphic reference). Drilling, coring, and log data obtained from the well indicated no commercial accumulations of hydrocarbons were present in any of the subsurface formations drilled.

The Ellen Samuelson 1 well is not an anticipated surface leakage pathway; however, it is included in the analysis since the well is just inside the AOR boundary (Figure 2-1). The Ellen Samuelson 1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally. Figure 2-1 of this MRV plan illustrates the location of the well outside of the projected stabilized plume boundary. The Ellen Samuelson 1 is 7,140 feet beyond the edge of the projected stabilized plume boundary and has been plugged and abandoned in accordance with NDIC requirements.

3.5.2 Wallace O. Gradin 1

The Wallace O. Gradin 1 (NDIC File No. 4810) well spudded on December 1, 1969, and was shortly thereafter plugged and abandoned on December 10, 1969. The well was drilled to a depth of 4,240 feet into the Rierdon Formation. The well tested subsurface formations for hydrocarbon potential but did not produce volumes sufficient for commercial consideration.

The Wallace O. Gradin 1 well is not an anticipated surface leakage pathway; however, it is included in the analysis since the well is located just outside the AOR boundary (Figure 2-1). The Wallace O. Gradin 1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally or vertically and the Rierdon Formation in which the well is completed lies above the sealing formations associated with the CO_2 storage project. Figure 2-1 of this MRV plan illustrates the location of the well is outside of the projected stabilized plume boundary. The Wallace O. Gradin 1 is 11,850 feet beyond the projected stabilized plume boundary and has been plugged and abandoned in accordance with NDIC requirements.

3.6 Faults, Fractures, Bedding Plane Partings, and Seismicity

Regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations cannot be identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration reports (R1:2.5).

3.6.1 Stanton Fault

A regional fault was identified within the AOR boundary in previous literature. It has been described as a northeast-southwest trending, basement-rooted fault; however, there is uncertainty whether this fault exists. Figure 3-1 illustrates the surface projection of the suspected fault. Based on the seismic data analyzed as part of the site characterization activities, Figures 3-2 and 3-3, it appears that the fault does not exist, or if it does, it is limited to the Precambrian basement. The storage reservoir is approximately 5,000 feet above the Precambrian basement within the AOR, and there is no fault extending from the basement, as evidenced by the seismic data that show no visible offset in the overlying stratigraphy. Therefore, no CO_2 leakage is anticipated to surface at any time of any magnitude because CO_2 is not anticipated to come into contact with any basement features. The Stanton Fault is mentioned in this MRV plan because the path of the fault was identified within the AOR boundary.

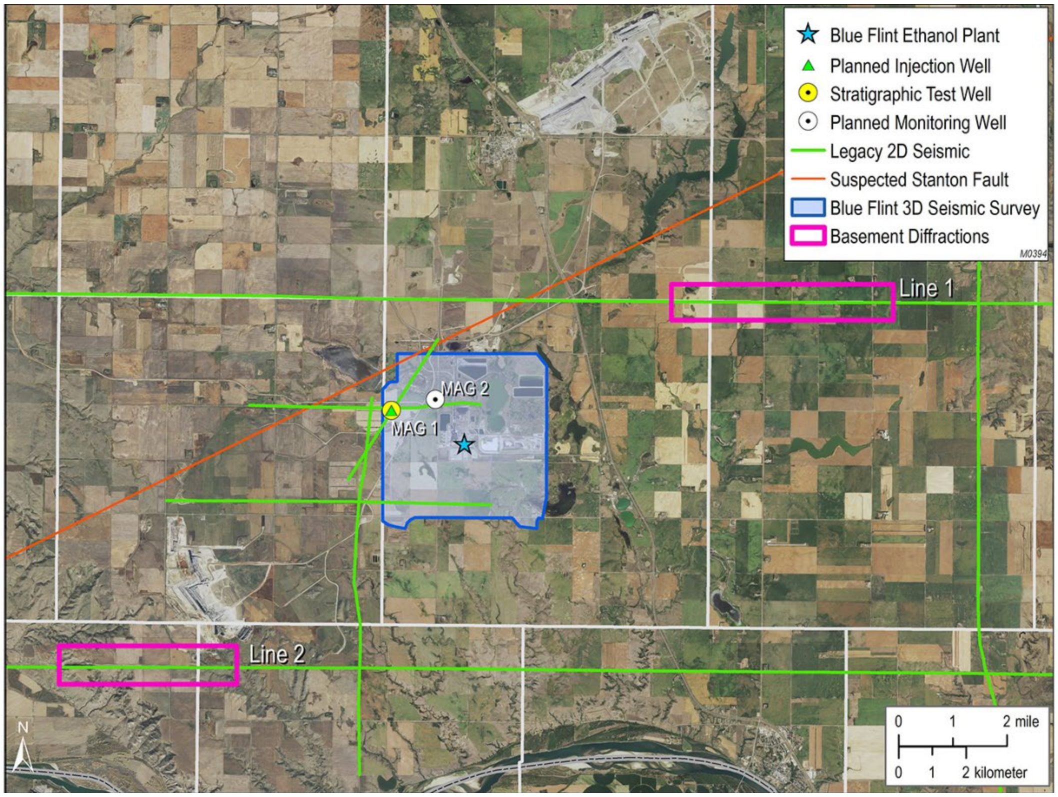

Figure 3-1. Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016) relative to the project wells and BFE facility. Also shown are legacy 2D seismic lines and a 3D seismic survey that were evaluated to characterize potential surface leakage pathways. Lines 1 and 2 are shown as Figures 3-2 and 3-3, respectively.

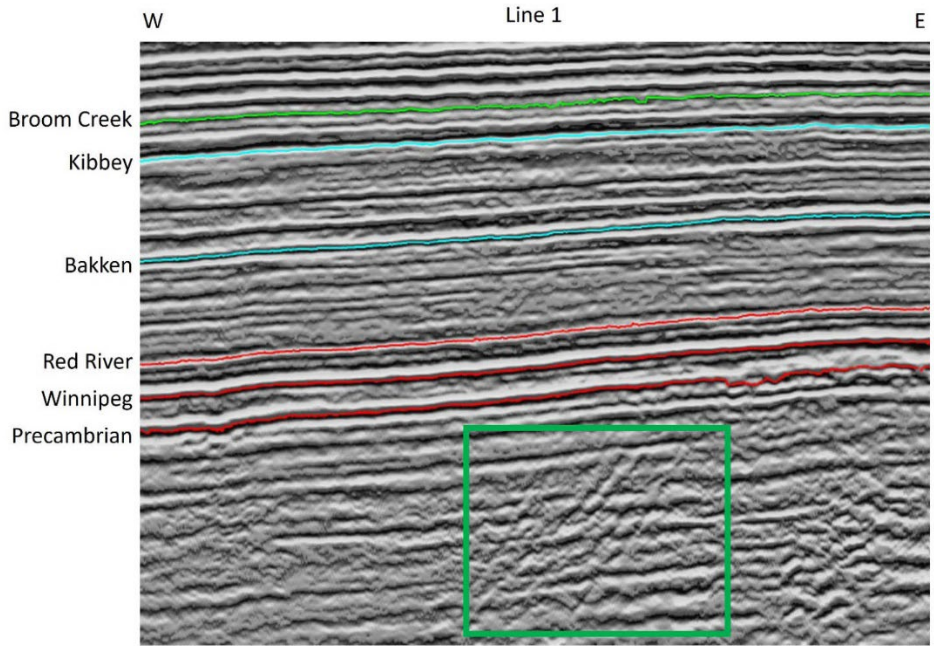

Figure 3-2. Cross section of Line 1, showing interpreted seismic horizons (colored lines) and area where diffractions are present within the Precambrian basement (green box).

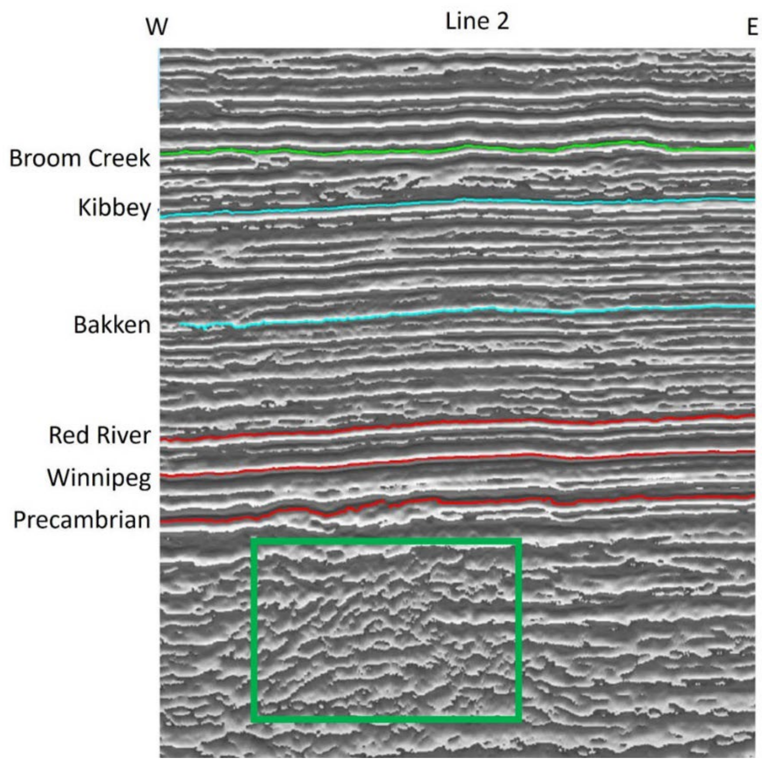

Figure 3-3. Cross section of Line 2, showing interpreted seismic horizons (colored lines) and area where diffractions are present within the Precambrian basement (green box).

3.6.2 Natural or Induced Seismicity

Through the geologic site characterization and corrective action review processes, leakage resulting from natural or induced seismicity was shown to be very low. Periodic seismic surveys and surface monitoring of the storage facility area will be used to detect potential surface leaks and associated magnitude throughout the operational and post-injection phases.

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment (R1:2.5.2). As illustrated in Figure 3-4, a total of 13 seismic events were detected within the North Dakota portion of the Williston Basin between 1870 and 2015 (Anderson, 2016). The two closest recorded seismic events to the Blue Flint CO_2 storage project occurred 52.3 miles to the east and 55.8 miles southwest of the MAG 1 wellbore, with estimated magnitudes of 2.6 and 0.2, respectively, as shown in Table 3-3.

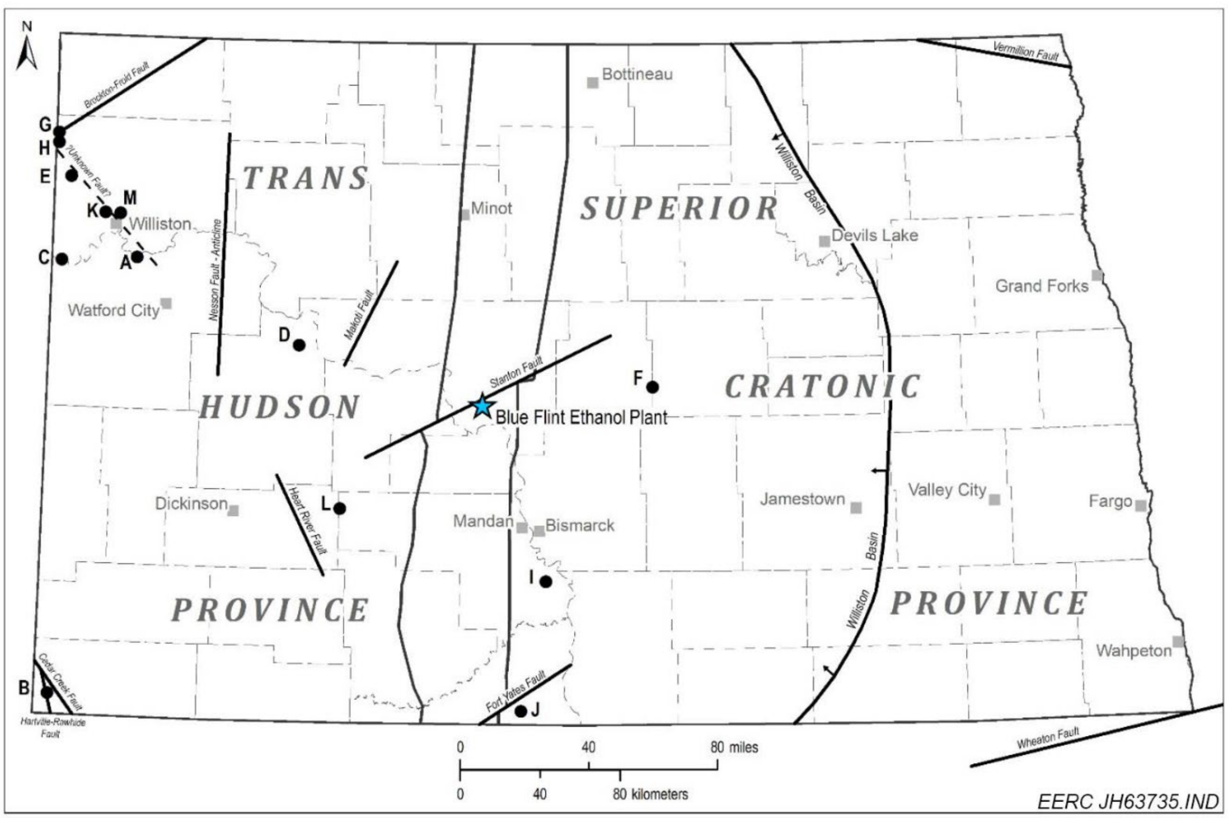

Figure 3-4. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 3-3.

Table 3-3. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, miles	Longitude	Latitude	City or Vicinity of Earthquake	Map Label	Distance to BFE, miles
September 28, 2012	3.3	0.4[1]	−103.48	48.01	Southeast of Williston	A	117.0
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	162.9
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	136.4
August 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	60.1
January 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	146.7
November 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	52.3
November 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	156.2
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	154.8
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	58.0
May 13, 1947	3.7[2]	Unknown	−100.90	46.00	Selfridge	J	96.1
October 26, 1946	3.7[2]	Unknown	−103.70	48.20	Williston	K	131.5
April 29, 1927	0.2[2]	Unknown	−102.10	46.90	Hebron	L	55.8
August 8, 1915	3.7[2]	Unknown	−103.60	48.20	Williston	M	127.3

[1] Estimated depth.

[2] Magnitude estimated from reported modified Mercalli intensity (MMI) value.

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of earthquake events occurring in North Dakota that would cause damage to infrastructure, with less than two damaging earthquake events predicted to occur over a 10,000-year period (Figure 3-5) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by USGS in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) state there is very little seismic activity near injection wells in the Williston Basin. They noted only two historic earthquakes in North Dakota (both magnitude 2.6 or lower events) that had the potential to be associated with oil and gas activities. This indicates relatively stable geologic conditions in the region surrounding the proposed injection site.

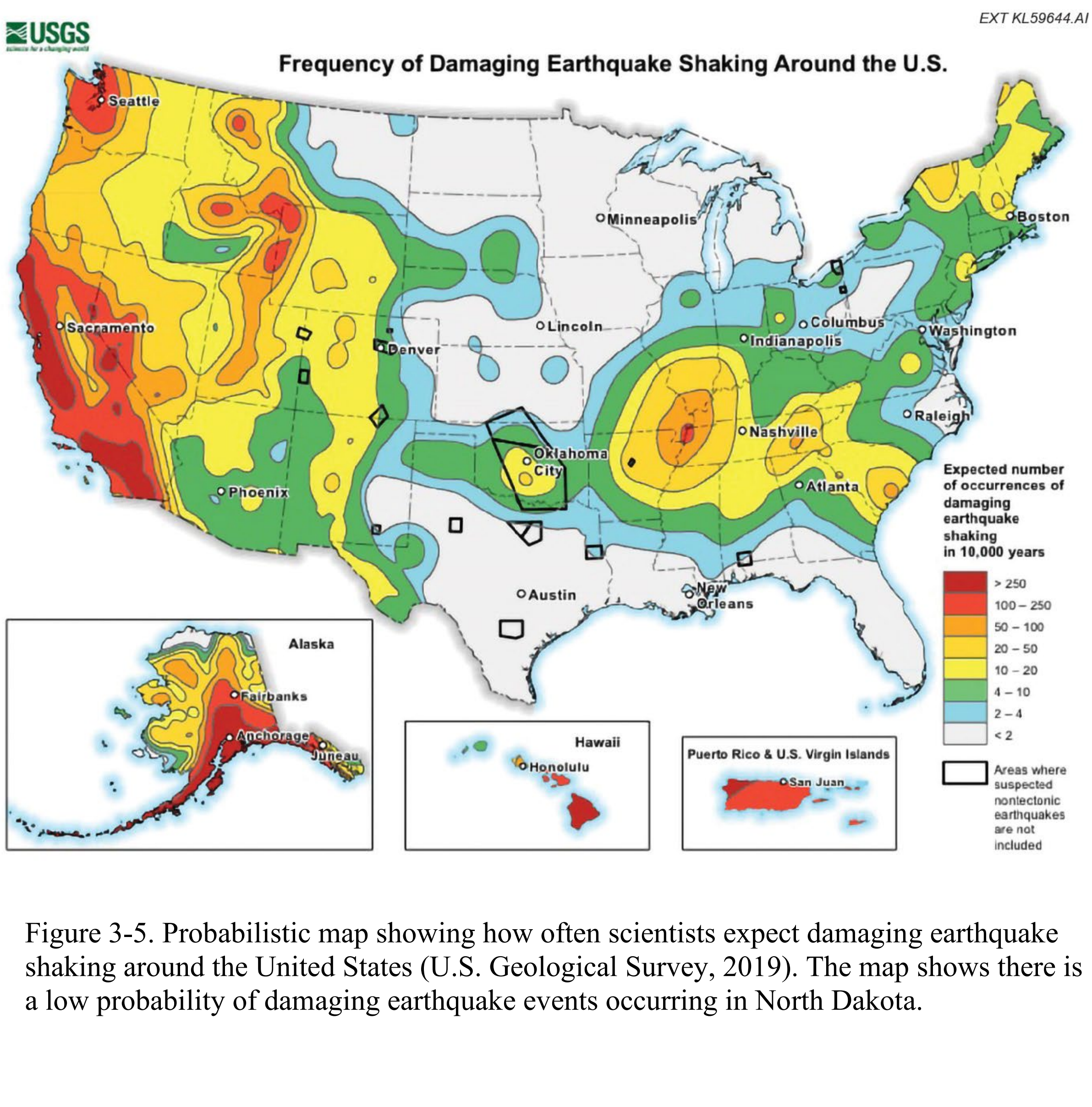

Figure 3-5. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the absence of known or suspected local or regional faults suggest that the probability is very low for seismicity to interfere with CO_2 containment. The magnitude of any seismic event in the vicinity is expected to be 2.6 or below based on the historical data gathered and analyzed. In addition, Blue Flint will ensure that injection pressures do not exceed 90 percent of the fracture pressure of the injection zone pursuant to NDAC § 43-05-01-11.3(1), thereby minimizing the potential for induced seismicity from injection operations.

3.7 Confining System Pathways

Confining system pathways include any potential for migration of CO_2 beyond their lateral extent, the potential for CO_2 to diffuse upward through confining zones, and the potential for future wells that may penetrate confining zones. Limitations to the confining system pathways considered are discussed next and presented in context to the AOR boundary.

3.7.1 Lateral Migration

For the Blue Flint CO_2 storage project, the primary mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the upper confining zone (lower Piper and Spearfish Formations defined earlier in Section 1.2), which will contain the buoyant CO_2 under the effects of relative permeability and capillary pressure (R1:2.3.2). Together, the lower Piper and Spearfish Formations are laterally extensive formations that begin 4,560 feet below the surface and have a combined thickness of 148 feet at the MAG 1 well (R1:2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), as discussed further in R1:3.4.

The risk of surface leakage of CO_2 via lateral migration is very low, as demonstrated by the geologic characteristics of the storage reservoir (R1:2.3) and upper confining zone (R1:2.4.1) (e.g., lateral extent and continuity, mineralogy, low permeability/high sealing capacity, and lack of regional faults or fractures) coupled with the modeling and simulation work (R1:3.0) that was performed for the Blue Flint CO_2 storage project.

3.7.2 Seal Diffusivity

Several other formations provide additional confinement above the lower Piper and Spearfish Formations (R1:2.4.2), including upper Piper, Rierdon, and Swift Formations, which make up the secondary group of confining formations. Together with the lower Piper and Spearfish, these formations are 859 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next porous and permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 2,512 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation. Confining layers above the Inyan Kara include the Skull Creek, Mowry, Bell Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Figure 1-3 for stratigraphic reference).

The risk of leakage via seal diffusivity is very low, as there is a total of 3,371 feet of overlying confining layers, which presents a very low risk to the Blue Flint CO_2 storage project.

The presence of multiple thick impermeable layers and laterally extensive formations drastically reduces potential leakage pathways through geologic formations.

3.7.3 Drilling Through the CO_2 Area

There is no significant commercial oil and gas activity within the project area, and it is unlikely that future wells would be drilled through the storage reservoir. Supporting evidence includes one exploration well near the edge of the project AOR: the Ellen Samuelson 1 (discussed in Section 3.5.1). The well spudded on September 14, 1957, and was drilled to a depth of 6,600 feet into the Mission Canyon Formation. Drill stem tests (DSTs) within the Madison Group recovered only drilling mud, salt water, and a very slight gas cut. Exploration concluded with plugging and abandonment on October 18, 1957.

NDIC maintains authority to regulate and enforce oil and gas activity respective to the integrity of operations, including drilling of wells and underground storage of CO_2.

3.8 Monitoring, Response, and Reporting Plan for CO_2 Loss

Blue Flint proposes a robust monitoring program in the SFP (R1:5.0 and 6.0) and is summarized in Table 4-1 of this MRV plan. The program covers surveillance of injection performance (R1:5.1 and 5.2), corrosion and mechanical integrity protocols (R1:5.3, 5.4, 5.6, and 6.2), baseline testing and logging plans for the MAG 1 and MAG 2 wellbores (R1:5.5), monitoring of near-surface conditions (R1:5.7.1, 5.7.2, and 6.2.1), and direct and indirect monitoring of the CO_2 plume and associated pressure front in the storage reservoir (R1:5.7.3 and 6.2.2). To compliment the monitoring program, Blue Flint proposes a detailed emergency remedial and response plan (R1:7.0) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting in the event of an unplanned loss of CO_2 from the Blue Flint CO_2 storage project area.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

Table 4-1 summarizes the monitoring strategy for each of the three project phases, and Table 4-2 summarizes the strategy for detecting and quantifying surface leakage pathways associated with CO_2 injection. These methodologies target early detection of any abnormalities in operating parameters or deviations from baselines and equipment detection thresholds established for the Blue Flint CO_2 storage project. These methodologies provide a verification process to validate if a leak has occurred or if the system has lost mechanical integrity. The data collected during monitoring are also used to calibrate the numerical model and improve the prediction for the injectivity, CO_2 plume, and associated pressure front.

Blue Flint will use reservoir simulation modeling, based on history-matched data obtained from the monitoring program, to compare the initial numerical model with the development of the CO_2 plume and associated pressure front. The model will be continuously calibrated with the

Table 4-1. Summary of Blue Flint's Testing and Monitoring Strategy

METHOD (TARGET AREA/STRUCTURE)	SAMPLING FREQUENCY		
	Pre-Injection Phase (Baseline – 1 year)	Injection Phase (20 years)	Post-Injection Phase (10 years minimum)
CO_2 Stream Analysis (capture)	Start-up	Quarterly	NA[1]
Surface Pressure Gauges (MAG 1, MAG 2, and flowline)	Start-up	Real time	Real time (MAG 2 only)
Mass Flow Metering (CO_2 injection well and flowline)	Start-up	Real time	NA
CO_2 Detection Stations (flowline risers, injection wellhead, and wellhead enclosure)	Start-up	Real time	NA
Corrosion Coupon Testing (flowline and well materials)	Baseline	Quarterly	NA
SCADA Automated Remote System (MAG 1, MAG 2, and flowline)	Start-up	Real time	Real time (MAG 2 only)
DTS (MAG 1 and MAG 2)	At well completion	Real time	Real time (MAG 2 only)
Surface and Bottomhole P–T Readings (MAG 1 and MAG 2)	At well completion	Real time	Real time (MAG 2 only)
Temperature Log (MAG 1 and MAG 2)	Baseline	Annually (but only if DTS fails)	Annually in MAG 2 (only if DTS fails)
USIT or Alternative CIL (MAG 1 and MAG 2)	Baseline	Perform during well workovers but no less than once every 5 years	Perform during well workovers but no less than once every 5 years (MAG 2 only)
Tubing–Casing Annulus Pressure Tests (MAG 1 and MAG 2)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but no less than once every 5 years (MAG 2 only)
Atmospheric Analysis	3–4 seasonal samples per semipermanent soil gas location	3–4 seasonal samples per soil gas profile station and CO_2 detection stations placed outside enclosures on MAG 1 well pad	None
Soil Gas Analysis (five semipermanent probe stations)	3–4 seasonal samples per location	NA	Sample soil gas probe locations at the start of the post-injection phase and prior to facility closure
Soil Gas Analysis (two permanent profile stations)	NA	3–4 seasonal samples annually per location	Sample SGPS 1[2] prior to MAG 1 reclamation; sample SGPS 2[2] annually until facility closure
Water Analysis: Shallow Aquifers (15 wells operated by Falkirk Mining Company) (R1:B)	Provide historical water sampling results	NA	TBD[3]
Water Analysis: Shallow Aquifers (up to five wells within or near AOR)	3–4 seasonal samples per location	NA	TBD
Water Analysis: Lowest USDW (Fox Hills monitoring well adjacent to MAG 1)	3–4 seasonal samples	3–4 seasonal samples annually	Annually until facility closure
Pulsed-Neutron Logs (MAG 2)	Baseline	Once in Year 4 and every 5 years thereafter until the end of injection	Perform in Year 21 and annually thereafter until well reaches full CO_2 saturation, then reduce to once every 4 years until facility closure
Pressure Falloff Test (MAG 1)	Baseline	Every 5 years	NA
Time-Lapse 2D Seismic Surveys (CO_2 plume)	Baseline	Repeat survey in Year 1 and Year 4. Reevaluate frequency in Year 4	TBD
Vertical Seismic Profiles (VSP) (CO_2 plume)	Evaluate feasibility for early time monitoring during CO_2 injection operations	TBD	NA
Passive Seismicity Monitoring (CO_2 storage complex)	Utilize existing USGS's network	Utilize existing USGS's network and supplement with additional equipment as necessary	Utilize existing USGS's network and supplement with additional equipment as necessary

[1] Not applicable.
[2] Locations of SGPS 1 and 2 are shown on Figure 5-1.
[3] To be determined.

Table 4-2. Monitoring Strategies for Detecting and Quantifying Surface Leakage Pathways Associated with CO_2 Injection

Monitoring Strategy (target area/structure)	Potential Surface Leakage Pathway: Wellbores	Faults and Fractures	Flowline and/or Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal	Detection Method	Quantification Method
Surface P–T Gauges (MAG 1, MAG 2, and flowline)	X		X			X	P–T gauge data will be recorded continuously in real-time by the SCADA system and sent to the operations center to detect any anomalous readings that require further investigation.	P–T gauge data may be needed in combination with metering data to accurately quantify volumes emitted by surface equipment.
Mass Flow Metering (CO_2 injection well and flowline)	X		X	X			Metering data (e.g., rate and volume/mass) will be recorded continuously in real-time by the SCADA system and sent to the operations center to detect any anomalous readings that require further investigation.	Mass balance and leak detection software calculations.
CO_2 Detection Stations (flowline risers, injection wellhead, and wellhead enclosure)	X		X	X		X	CO_2 detection station data will detect any anomalous readings that require further investigation.	CO_2 concentration data collected by each station inside the enclosure may be used in combination with the assumed workspace atmosphere conditions and known volume of the enclosure to quantify any surface leakage of CO_2.
DTS (MAG 1 and MAG 2)	X		X	X	X	X	Temperature data will be recorded continuously in real time by the SCADA system to detect any anomalous readings near or at the surface that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.
Temperature Log (MAG 1 and MAG 2)	X		X	X	X	X	Temperature logs will be collected to detect any anomalous readings near or at the surface of the wellbore that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.
USIT or Alternative CIL (MAG 1 and MAG 2)	X			X			Ultrasonic (or alternative) logs will be collected to detect potential pathways to the surface in the wellbore that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.
Atmospheric Analysis	X		X	X	X		CO_2 gas readings will be recorded continuously in real time by the SCADA system and sent to the operations center and atmospheric samples will be analyzed from soil gas sampling activities to detect any anomalous readings that require further investigation.	CO_2 concentration data collected from multiple detection stations and/or soil gas sampling sites over time could be used to estimate the amount of surface leakage of CO_2.
Soil Gas Analysis (five semipermanent probe stations)	X			X	X	X	Soil gas data will be collected to detect any anomalous readings just beneath or at the surface that require further investigation.	Additional field studies (e.g., vegetation survey) and soil gas sampling would be needed to provide an estimate of surface leakage of CO_2.
Soil Gas Analysis (two permanent profile stations)	X			X	X	X	Same as above.	Same as above.
Pulsed-Neutron Logs (MAG 2)	X			X	X	X	Logs will be collected to detect potential pathways to the surface in or near the wellbore that require further investigation.	The pulsed-neutron log is capable of quantifying the concentration of CO_2 near the wellbore. If a pathway of surface leakage of CO_2 is detected, additional field studies (i.e., atmospheric and soil gas analysis) would be needed to quantify the event.
Time-Lapse 2D Seismic Surveys (CO_2 plume)	X	X		X	X	X	Seismic data will be collected and could detect pathways for surface leakage of CO_2 that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.
VSP (CO_2 plume)	X	X		X	X	X	VSP data may be collected and could detect pathways for surface leakage of CO_2 that require further investigation.	Additional field studies (i.e., atmospheric and soil gas analysis) would complement this detection method to provide estimates of surface leakage of CO_2.

acquisition of real-time data. The AOR and monitoring plan will be reviewed and if warranted, revised at least every 5 years. The history-match data model identifies conditions that differ from the initial model and deviations in the operating conditions. Monitoring data will be 1) reviewed to determine if surface leakage of CO_2 is occurring, 2) verified by the operator with field personnel and/or technical experts, and 3) quantified in accordance with the quantification strategies in the monitoring plan and any emergency remedial response actions that may be necessary. Model history-matching in combination with mechanical integrity data, geophysical surveys, and near-surface monitoring provide a robust means to identify, quantify, and verify leaks. Blue Flint will adhere to the reporting in accordance with NDAC § 43-05-01-18, which specifies circumstances that warrant 30-day and 24-hour reporting.

A quality assurance and surveillance plan (QASP) is provided in R1:C, which details the specifications (e.g., detection thresholds and limits) for the monitoring equipment associated with the Blue Flint CO_2 storage project.

5.0 DETERMINATION OF BASELINES

Blue Flint will establish a pre-injection baseline by implementing a monitoring program approximately 1 year prior to CO_2 injection designed to coincide with seasonal changes. This baseline will include samples and analysis from near-surface and deep subsurface environments, such as soil gas in the vadose zone, shallow groundwater down to the lowest USDW, and the storage reservoir. Baselines provide the background concentration of CO_2 for comparative analysis to samples collected during operational and post-injection phases. Pre-injection baseline characterization is paramount to provide context to any future investigation of suspected leakage of CO_2 within the AOR.

5.1 Surface and Near-Surface Baselines

A baseline surface and near-surface sampling program has been initiated for the Blue Flint CO_2 storage project as of September 2022. Baseline data gathering includes measuring chemical concentrations of ambient air and soil gas samples (i.e., O_2, N_2, and CO_2) and groundwater (e.g., pH, total dissolved solids, alkalinity, major cations/anions, and trace metals) as well as characterizing their naturally occurring stable and radiocarbon isotopic signatures for comparison with the CO_2 stream. Figure 5-1 identifies the baseline sampling locations for establishing surface and near-surface baseline conditions. The ambient air samples are collected at the same locations as the soil gas samples. There are five planned soil gas-sampling locations and up to five existing groundwater wells from within or up to 0.25 miles outside of the AOR. Baseline water samples are also being obtained from a new Fox Hills monitoring well drilled adjacent to the MAG 1 wellbore. For additional information regarding surface and near-surface baselines, refer to R1:5.7.1 and 5.7.2.

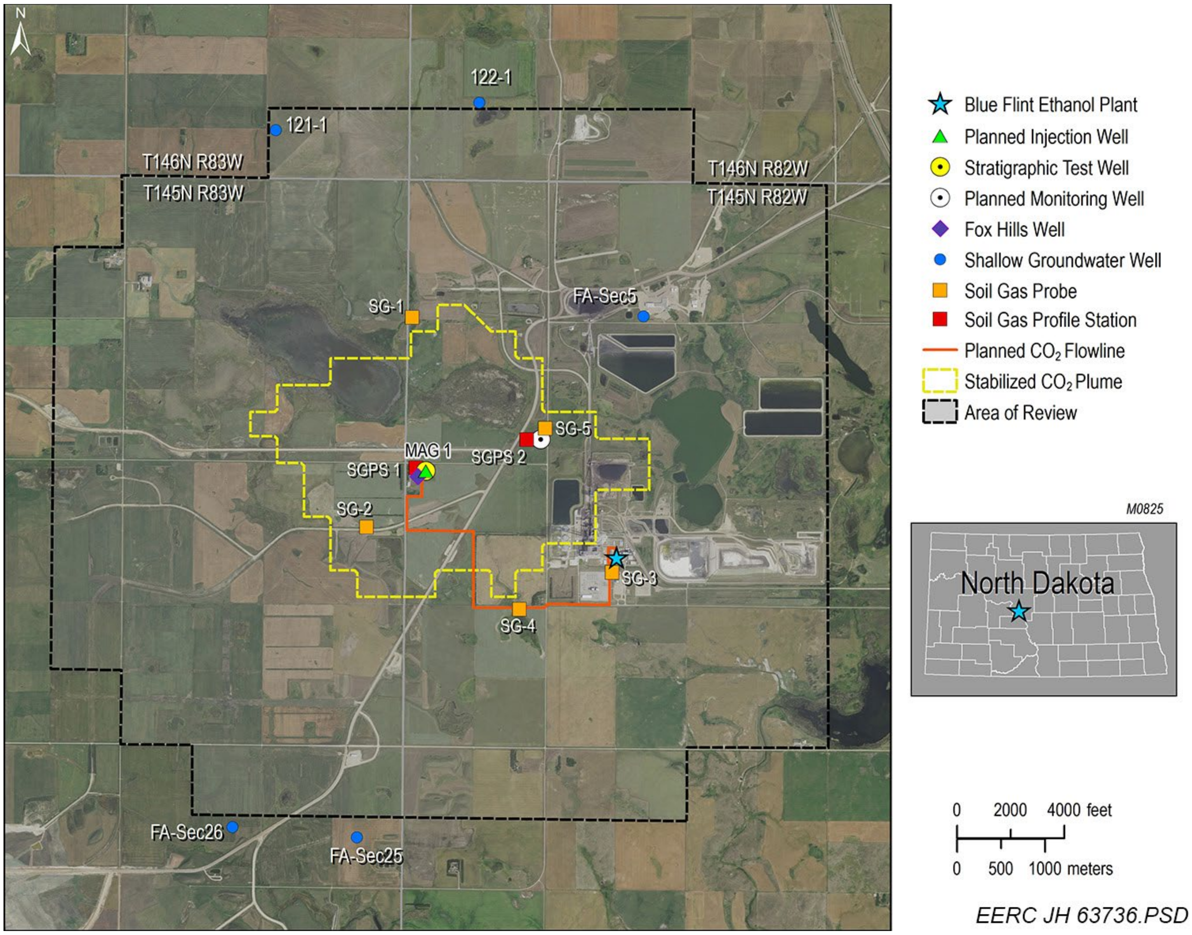

Figure 5-1. Blue Flint's planned baseline and monitoring program for soil gas, shallow groundwater aquifers, and the Fox Hills Aquifer.

5.2 Subsurface Baselines

Pre-injection baseline data will be collected in the CO_2 injection well (MAG 1) and monitoring well (MAG 2) for the Blue Flint CO_2 storage project. Table 3-1 summarizes the baseline well-testing and logging plan activities for establishing mechanical integrity in both wells. A pulsed-neutron log will be acquired from the MAG 2 wellbore prior to injection for confirming the CO_2 injection profile in the storage reservoir as well as ensuring there are no signs of out-of-zone migration into formations overlying the storage reservoir, otherwise known as the above-zone monitoring interval.

Blue Flint has selected time-lapse geophysical surveys as the primary monitoring method to track the extent of the CO_2 plume within the storage reservoir. A 2D seismic survey will be collected prior to injection to establish baseline conditions in the storage reservoir. A baseline VSP may also be collected to determine the feasibility of the technique to monitor the CO_2 plume. Figure 5-2 illustrates the planned baseline seismic survey design for the project with respect to the projected 5-year CO_2 plume and the stabilized CO_2 plume boundaries.

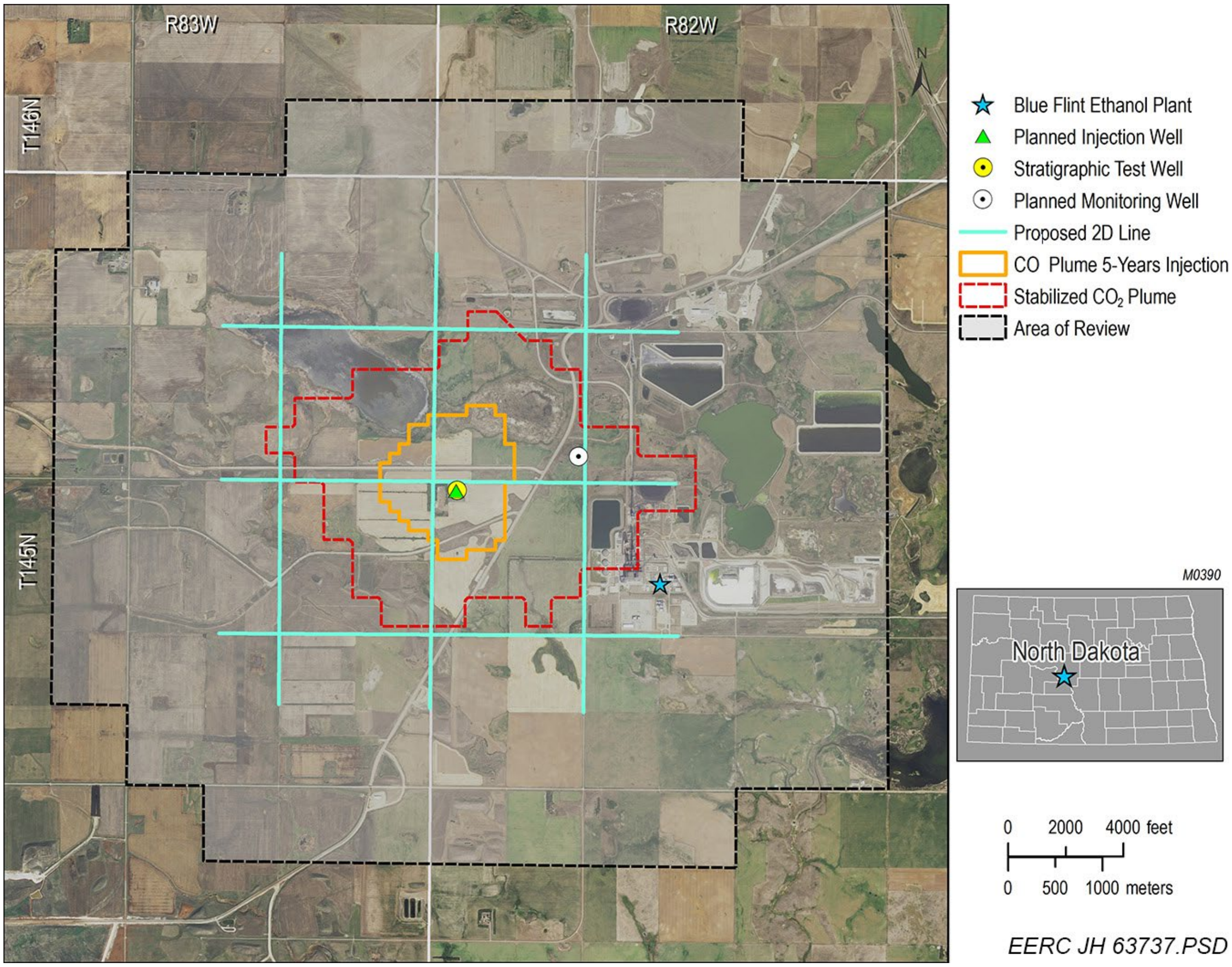

Figure 5-2. Planned 2D seismic design near the MAG 1 well to establish baseline conditions for tracking the CO_2 plume in the storage reservoir.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The Blue Flint CO_2 storage project area is a geologic CO_2 storage site in a saline aquifer with no associated production from the CO_2 storage complex. Two Coriolis mass flowmeters will be installed to meter injected CO_2 (Figure 1-4b). The flowmeter closest to the wellhead is the primary metering station.

Annual mass of CO_2 received will be calculated by using the mass of CO_2 injected pursuant to 40 CFR § 98.444(a)(4) and 40 CFR § 98.444(b). The point of measurement for the mass of CO_2 received (injected) will be the primary metering station located closest to the injection wellhead.

Annual mass of stored CO_2 is calculated from Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad \text{[Eq. 1]}$$

Where:

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

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells.

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

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

<u>Mass of CO_2 Injected (CO_{2I})</u>:

Blue Flint will use mass flow metering to measure the flow of the injected CO_2 stream and calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the mass flow at standard conditions by the CO_2 concentration in the flow at standard conditions, according to Equation RR-4 from 40 CFR Part 98, Subpart RR (Equation 2):

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_2,p,u} \quad \text{[Eq. 2]}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by Flowmeter u.

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

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flowmeter.

<u>Mass of CO_2 Emitted by Surface Leakage (CO_{2E}):</u>

Blue Flint characterized, in detail, potential leakage paths on the surface and subsurface (Section 3.0 of this MRV plan), concluding that the probability is very low in each scenario. However, the monitoring plan summarized in Table 4-1 includes activities for establishing baseline conditions at the storage site, and the surface leakage of CO_2 detection and quantification strategy outlined in Table 4-2 provides several means by which surface leakage is identified and quantified.

If the monitoring and surveillance plan detects a deviation from the threshold established for each method, the project will conduct a detailed analysis based on technology available and type of leak to quantify the CO_2 volume to the best of its capabilities. The process for quantifying any leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the leak, and numerical and predictive models, among others.

Blue Flint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98-Subpart RR (Equation 3):

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{[Eq. 3]}$$

Where:

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

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

Annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead (CO_{2FI}) will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented within 90 days of the placed-in-service date of the capture and storage equipment, including the Class VI injection well (MAG 1) and monitoring well (MAG 2). The project will not be placed in service until successfully completing performance testing, an essential milestone in achieving substantial completion. At the placed-in-service date, the project will commence collecting data for calculating total amount sequestered according to equations outlined in Section 6.0 of this MRV plan. Other greenhouse gas reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time.

This MRV plan will be in effect during the operational and post-injection monitoring phases of the project. In the post-injection phase, Blue Flint will prepare and submit a facility closure application to North Dakota, which will demonstrate nonendangerment of any USDWs and provide long-term assurance of CO_2 containment in the storage reservoir in accordance with North Dakota statutes and regulations. Once the facility closure application is approved by North Dakota, Blue Flint will submit a request to discontinue reporting under this MRV plan consistent with North Dakota and Subpart RR requirements (see 40 CFR § 98.441[b][2][ii]).

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for Blue Flint monitoring techniques and data management is provided in the quality assurance and surveillance plan found in R1:C.

Blue Flint will ensure compliance with the quality assurance requirement in 40 CFR § 98.444:

CO_2 received:

- The quarterly flow rate of CO_2 will be reported from continuous measurement at the main metering station (identified in Figure 1-4b).

- The CO_2 concentration will be reported as an average from measurements obtained at least quarterly from the CO_2 compressors.

Flowmeter provision:

- Operated continuously, except as necessary for maintenance and calibration.

- Operated using calibration and accuracy requirements in 40 CFR § 98.3(i).

- Operated in conformance with consensus-based standards organizations including, but not limited to, American Society for Testing and Materials (ASTM) International, the American National Standards Institute, the American Gas Association, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

9.0 MRV PLAN REVISIONS

In the event there is a material change to the monitoring and/or operational parameters of the Blue Flint CO_2 storage project that is not anticipated in this MRV plan, this MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in § 98.448(d). Blue Flint may also submit supplemental revisions to this MRV plan, which take into consideration responses, inquiries, and final determinations from the regulatory agencies having jurisdiction in R1 and the associated UIC Class VI drilling permit.

10.0 RECORDS RETENTION

Blue Flint will follow the record retention requirements specified by 40 CFR § 98.3(g). In addition, it will follow the requirements in Subpart RR 40 CFR § 98.447-Subpart RR by maintaining the following records for at least 3 years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the 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 and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

These data will be collected, generated, and aggregated as required for reporting purposes.

11.0 REFERENCES

Anderson, F.J., 2016, North Dakota earthquake catalog (1870–2015): North Dakota Geological Survey Miscellaneous Series No. 93.

Bluemle, J.P., Anderson, S.B., and Carlson, C.G., 1981, Williston Basin stratigraphic nomenclature chart: North Dakota Geological Survey Miscellaneous Series No. 61.

Frohlich, C., Walter, J.I., and Gale, J.F.W., 2015, Analysis of transportable array (USArray) data shows seismic events are scarce near injection wells in the Williston Basin, 2008–2011: Seismological Research Letters, v. 86, no. 2A, March/April.

Murphy, E.C., Nordeng, S.H., Juenker, B.J., and Hoganson, J.W., 2009, North Dakota stratigraphic column: North Dakota Geological Survey Miscellaneous Series No. 91.

Sims, P.K., Peterman, Z.E., Hildenbrand, T.G., and Mahan, S.A., 1991, Precambrian basement map of the Trans-Hudson orogen and adjacent terranes, northern Great Plains, USA: U.S. Geological Survey, No. 2214.

U.S. Geological Survey, 2019, Frequency of damaging earthquake shaking around the U.S.: www.usgs.gov/media/images/frequency-damaging-earthquake-shaking-around-us (accessed June 2022).

U.S. Geological Survey, 2016, For the first time, new USGS maps identify the potential for ground shaking from both human-induced and natural earthquakes in 2016: www.usgs.gov/news/featured-story/induced-earthquakes-raise-chances-damaging-shaking-2016 (accessed June 2022).

Request for Additional Information: Blue Flint Sequester Company, LLC
April 10, 2023

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	Referencing Convention	NA	While it is acceptable for an MRV plan to reference supplemental information in a permit, all information pertinent to the MRV plan should be included in the plan itself. We recommend reviewing the plan to ensure that all necessary details are readily available to the reader within the text of the MRV plan. For example, • Section 3.1 of the MRV plan references the detection time contained in R1:5.2, Table 5-3 of the SFP but does not state what it is. We recommend stating the detection time directly in section 3.1. • Section 3.5.1 of the MRV plan discusses the location of the Ellen Samuelson 1 well relative to the stablized plume boundary and references Figure 4-3 of the SFP but does not include the figure in the MRV plan. We recommend including the figure in the plan and/or stating in this section the estimated distance between this well and the plume.	A thorough review of the MRV plan was conducted to determine whether all information pertinent to the MRV plan discussion was included. A total of 3 tables and 7 figures were added to sections 3.0 (3 tables and 4 figures) and 5.0 (2 figures) of the revised MRV plan to reduce the number of references to the SFP material. The changes include: Table 5-3 referenced from the SFP was added to Section 3.1 of the MRV plan as Table 3-2 as requested. In Section 3.5.1, instead of referencing Figure 4-3 out of the SFP, a direct reference to the MRV plan was provided with Figure 2-1. In addition, distances from each legacy well to the edge of the stabilized plume boundary are provided in the text as requested.
2.	1.0	3	"The target storage reservoir is the Broom Creek Formation, a predominantly sandstone interval lying about 4,700 feet below the BFSC facility (R1:2.3)." The sentence above does not state what the elevation of the BFSC facility is. Please clarify what the elevation of the BFSC facility is in the MRV plan.	To address this request, the frame of reference was updated from the BFE facility to the MAG 1 well location. A surface elevation measurement and depth to the Broom Creek Formation at the MAG 1 well location are provided in the updated text in Section 1.1 of the MRV plan.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	3.5.1/3.5.2	11/12	"The Ellen Samuelson 1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally. The location of the well is outside of the projected stabilized plume boundary, and the well has been plugged and abandoned in accordance with NDIC requirements (R1:4.2, Figure 4-3)." Even though the Ellen Samuelson 1 well is outside of the projected stabilized plume boundary, the actual CO2 plume may behave differently than the forecasted or modelled CO2 plume. Please note that if the plume behaves differently than forecasted and new leakage pathways are identified, you may need to update and resubmit your MRV Plan per 40 CFR 98.448(d)(1). We recommend stating in the MRV plan that any of the changes listed at 40 CFR 98.448(d) would result in a MRV plan resubmission.	Section 9.0 "MRV Plan Revisions" was added to the MRV plan to clarify that Blue Flint will comply with the requirements under 40 CFR § 98.448(d).
4.	4.0	17	"Additional field studies and soil gas sampling would be needed to provide an estimate of surface leakage of CO_2 using this method." For seismic surveys and VSP, please elaborate on what additional field studies would be needed to provide an estimate of surface leakage.	Clarification was added for both seismic and VSP line items under the "Quantification Method" column in Table 4-2 to address this request. The seismic methods are capable to detecting surface leakage *pathways*. To quantify the surface leakage, atmospheric and/or soil gas sampling (both already part of the monitoring strategy) may be utilized to provide these estimates.

BLUE FLINT SEQUESTER COMPANY, LLC MONITORING, REPORTING, AND VERIFICATION PLAN

Class VI CO_2 Injection Well

Reporter Number: 583181

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

STORAGE FACILITY PERMIT DESIGNATION

Within the text of this monitoring, reporting, and verification plan, Blue Flint Sequester Company's storage facility permit application is designated as follows:

Reference 1: Blue Flint Sequester Company, LLC Carbon Dioxide Geologic Storage Facility Permit Application

Section 1 – Pore Space Access
Section 2 – Geologic Exhibits
Section 3 – Geologic Model Construction and Numerical Simulation of CO_2 Injection
Section 4 – Area of Review
Section 5 – Testing and Monitoring Plan
Section 6 – Post-injection Site Care and Facility Closure Plan
Section 7 – Emergency and Remedial Response Plan
Section 8 – Worker Safety Plan
Section 9 – Well Casing and Cementing Program
Section 10 – Plugging Plan
Section 11 – Injection Well and Storage Operations
Section 12 – Financial Assurance and Demonstration Plan
Appendix A – MAG 1 Formation Fluid Sampling
Appendix B – Historic Freshwater Well Fluid Sampling
Appendix C – Quality Assurance and Surveillance Plan
Appendix D – Storage Facility Permit Regulatory Compliance Table

REFERENCING CONVENTION

Below are three formatted examples of the referencing convention this document will follow:

- R1:4.1.1
- R1:C1.3.2
- R1:6.1.1.1, Figure 6-1

R1 refers to Reference 1 as designated hereto, and numbers or letters that appear after the colon represent the appropriate section or appendix from the storage facility permit. Thus:

- RA:4.1.1 would direct the reader to Section 4.1.1 (Area of Review Section, Written Description Subsection) within the storage facility permit application.

- R1:C1.3 would direct the reader to Section 1.3 (Corrosion Monitoring and Prevention Plan) of Appendix C (Quality Assurance and Surveillance Plan) within the storage facility permit application.

- R1:6.1.1.1, Figure 6-1 would direct the reader to Figure 6-1 in Section 6.1.1 (Pre- and Postinjection Pressure Differential) within the storage facility permit application.

MRV PLAN SUMMARY

Midwest AgEnergy (MAG) is moving towards a zero-carbon footprint through a multi-phased initiative "vision carbon zero". MAG, the owner of Blue Flint Ethanol, LLC, Blue Flint Capture Company, LLC, and Blue Flint Sequester Company, LLC (Blue Flint) is developing a carbon capture and carbon storage (CCS) project for the Blue Flint Ethanol (BFE) facility located in Underwood, North Dakota. Blue Flint proposes a compliant Greenhouse Gas Reporting Program (GHGRP) Subpart RR monitoring, reporting, and verification (MRV) plan in support of the storage project. As required under Title 40 Code of Federal Regulations (CFR) §98.448, this plan includes: 1) delineation of the maximum and active monitoring areas; 2) identification of potential surface leakage pathways and the likelihood, magnitude, and timing of surface leakage of carbon dioxide (CO_2) through these pathways within the maximum monitoring area; 3) a strategy for detecting and quantifying any surface leakage of CO_2; 4) a strategy for establishing the expected baselines for monitoring; and 5) a summary of the CO_2 accounting (mass balance) approach.

Blue Flint submitted a North Dakota Underground Injection Control (UIC) Class VI permit (storage facility permit [SFP]) application to the North Dakota Industrial Commission (NDIC) Department of Mineral Resources (DMR) on October 3, 2022. The SFP includes a testing and monitoring plan applicable to the MRV plan requirements of 40 CFR Part 98 Subpart RR. The Environmental Protection Agency (EPA) granted North Dakota primacy to administer the UIC Class VI program on April 24, 2018 for injection wells located within the state, except within Indian lands (83 Federal Register 17758, 40 CFR § 147.1751; EPA Docket No. EPA-HQ-OW-2013-0280). Plans developed for the North Dakota SFP are referenced within this MRV plan (see preceding sections on SFP designation and referencing convention). Monitoring aspects of the plan include sampling of the CO_2 stream, a leak detection and corrosion monitoring plan for the surface piping and wellhead, mechanical integrity testing and leak detection for injection and monitoring wells, and an environmental monitoring program that includes sampling of soil gas and groundwater, and time-lapse seismic surveys.

1.0 PROJECT OVERVIEW

1.1 Project Description

The BFE facility is located 6 miles south of Underwood, North Dakota. The BFE facility produces over 70 million gallons of ethanol annually along with about 200,000 tons dry distillers' grains and about 10 tons of corn oil. A by-product of fermentation at the facility is a nearly pure stream of CO_2 (99%+ dry by volume). The BFE facility produces about 200,000 metric tons of CO_2 annually.

Blue Flint plans to capture 200,000 metric tons of CO_2 annually over a 20-year period from the BFE facility. The captured CO_2 will be processed for compression and transported in a 3-mile-long CO_2 flowline to a single CO_2 injection well. A stratigraphic test well (MAG 1) was drilled for the Blue Flint CO_2 storage project. This wellbore will be converted into a UIC Class VI injection well, and a second stratigraphic test well (MAG 2) will be drilled and converted into a reservoir-monitoring well. The CO_2 stream will be injected into the Broom Creek Formation, a predominantly sandstone reservoir and saline aquifer, at an approximate depth of 4,700 feet below the BFE facility. The location of the BFE facility and planned CO_2 flowline and injection/monitoring wells are provided in Figure 1-1 with respect to the extent of CO_2 storage delineated as the stabilized plume boundary.

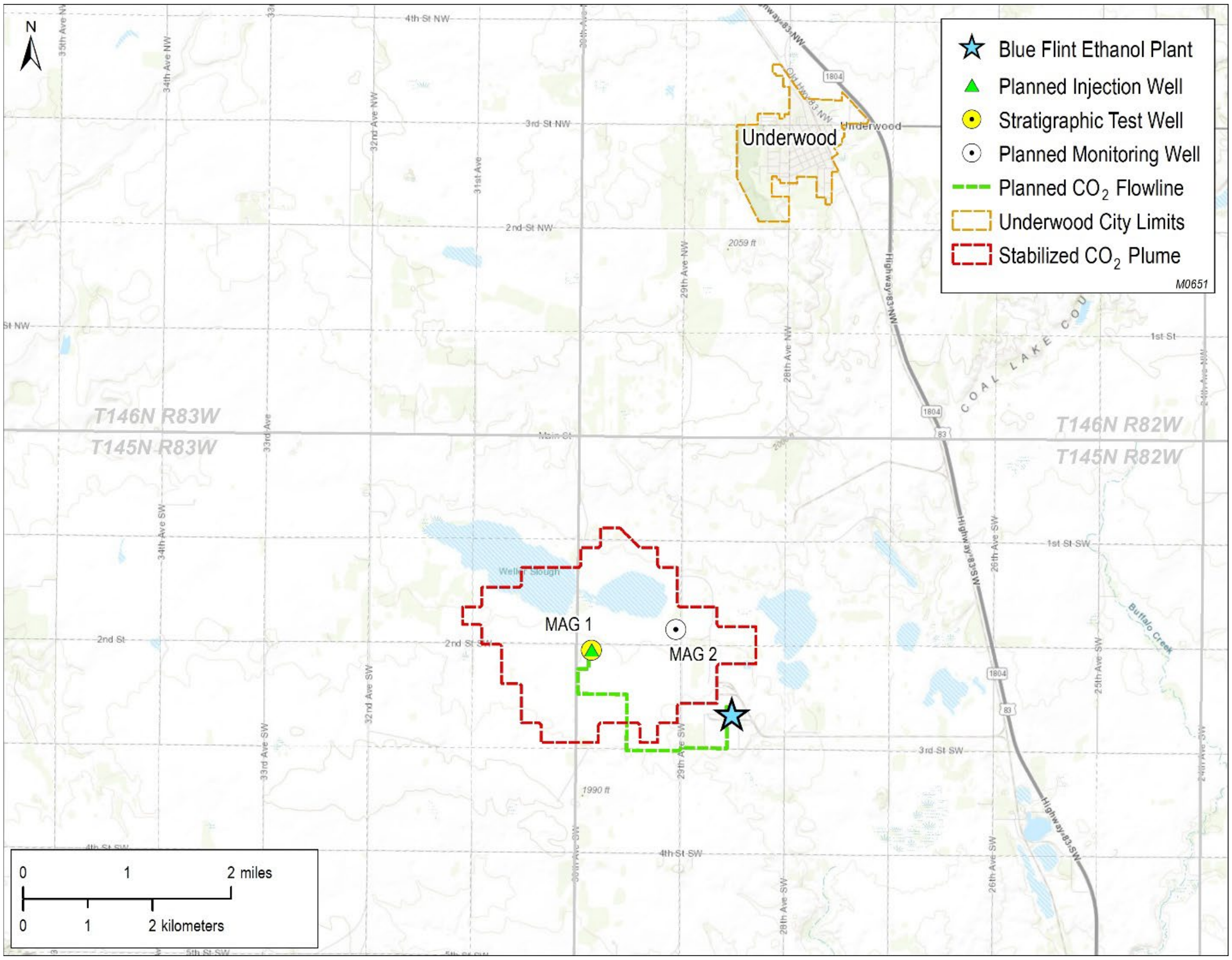

Figure 1-1. Location of the BFE facility, CO_2 flowline, and planned wells: CO_2 injection well (MAG 1), reservoir-monitoring well (MAG 2). The red outline indicates the stabilized CO_2 plume boundary.

1.2 Geologic Setting

The Blue Flint CO_2 storage project is located along the eastern flank of the Williston Basin where there has been no significant commercial production of hydrocarbon resources. Figure 1-2 provides a state reference map to illustrate the geographic distribution of oil and gas fields (undifferentiated) in North Dakota. The closest oil and gas fields to the project are 39 miles west of the western edge of the stabilized CO_2 plume boundary, demonstrating there has been no commercial development of hydrocarbon resources within the immediate project area (R1:2.6). The Williston Basin is a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. The basin is hydrocarbon-bearing, with over 38,000 wells drilled in North Dakota for production of commercial accumulations of oil and gas from subsurface reservoirs. Although commercial oil and gas production is not present in the area surrounding the project, legacy oil and gas exploration wells are present. Figure 1-2 also identifies the legacy wells surrounding the projected stabilized CO_2 plume area, with identification numbers provided for the two nearest wells to the geologic CO_2 storage site.

A standard stratigraphic column of the Williston Basin for the surrounding area of Underwood, North Dakota is provided in Figure 1-3. The target storage reservoir is the Broom Creek Formation, a predominantly sandstone interval lying about 4,700 feet below the BFE facility (R1:2.3). Siltstones with interbedded anhydrite of the lower Piper and Spearfish Formations unconformably overlie the Broom Creek and serve as the upper (primary) confining zone (R1:2.4.1). Mixed layers of dolostone, limestone and anhydrite of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone (R1:2.4.3). Together, the lower Piper-Spearfish, Broom Creek, and Amsden Formations comprise the CO_2 storage complex. There is about 859 feet (average thickness) of impermeable rock, including the lower Piper-Spearfish, between the Broom Creek and the next overlying porous zone, the Inyan Kara Formation (R1:2.4.2). An additional 2,442 feet (average thickness) of impermeable rock, including the Skull Creek, Mowry, Bell Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations, separate the Inyan Kara from the Fox Hills Formation (lowest underground source of drinking water [USDW]).

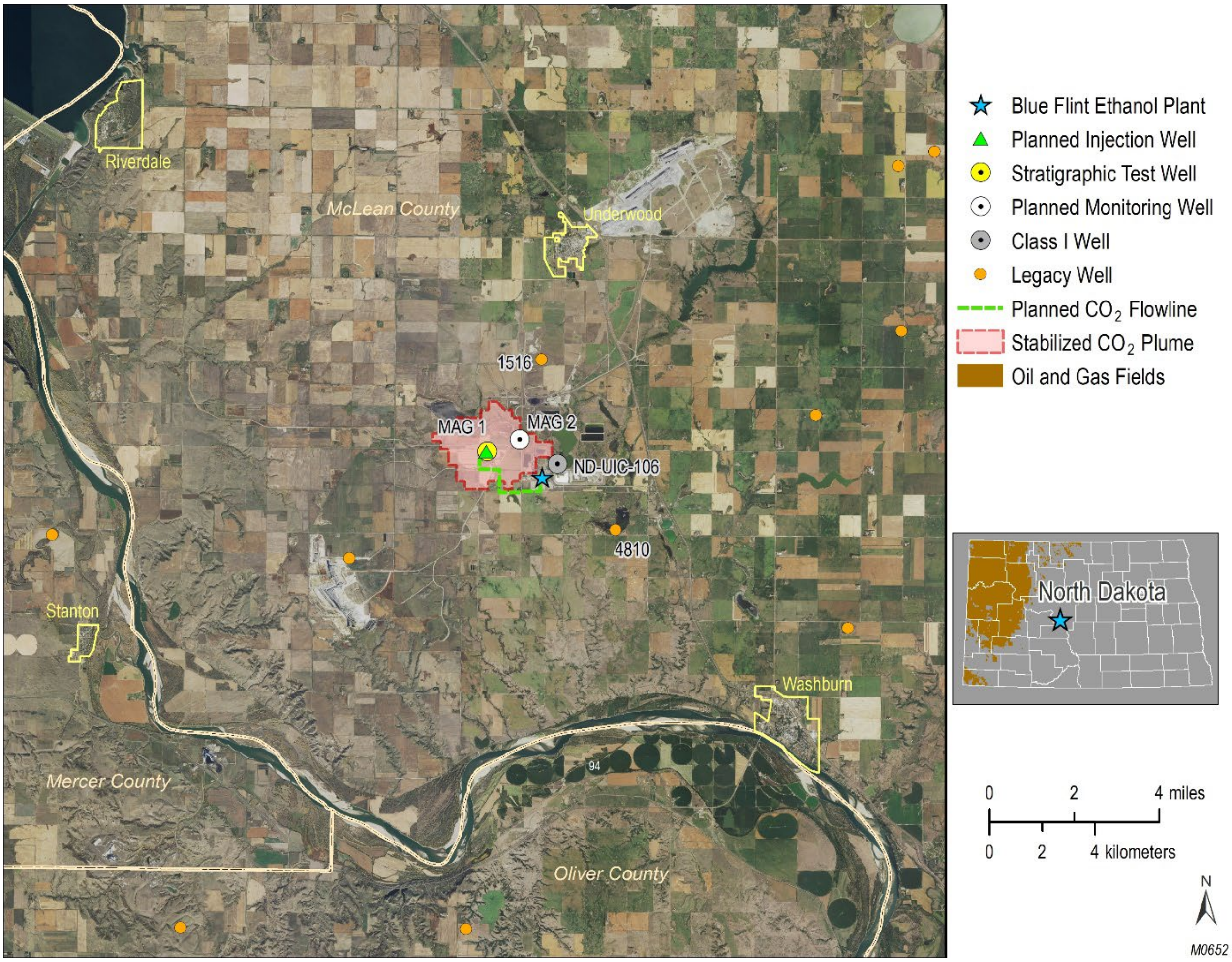

Figure 1-2. Map illustrating the locations of existing legacy wellbores around the projected stabilized CO_2 plume extent for the Blue Flint CO_2 storage project and nearby towns (outlined and labeled in yellow). The state reference map also reveals the geographic distribution of oil and gas fields in North Dakota. The closest oil and gas field is approximately 39 miles west of the Blue Flint CO_2 storage project.

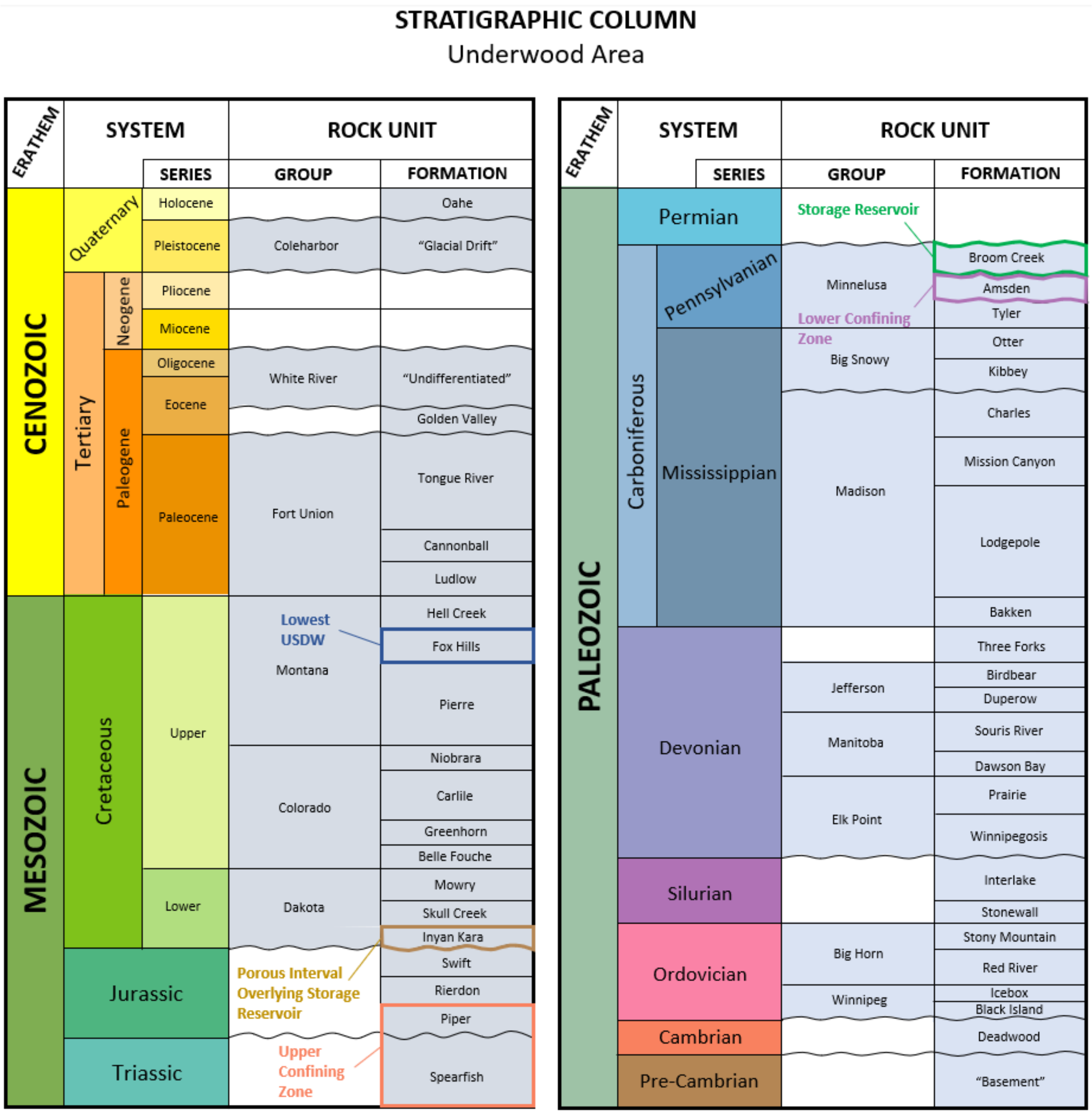

Figure 1-3. Stratigraphic column of the Williston Basin for the Underwood area, identifying the CO_2 storage complex as well as the dissipation interval and lowest USDW underlying the Blue Flint CO_2 storage project area. Figure modified after Murphy and others (2009) and Bluemle and others (1981).

1.3 Description of CO_2 Project Facilities and Injection Process

The BFE facility will utilize a liquefaction process to capture CO_2 produced from fermentation. Figure 1-4 provides a facility flow diagram.

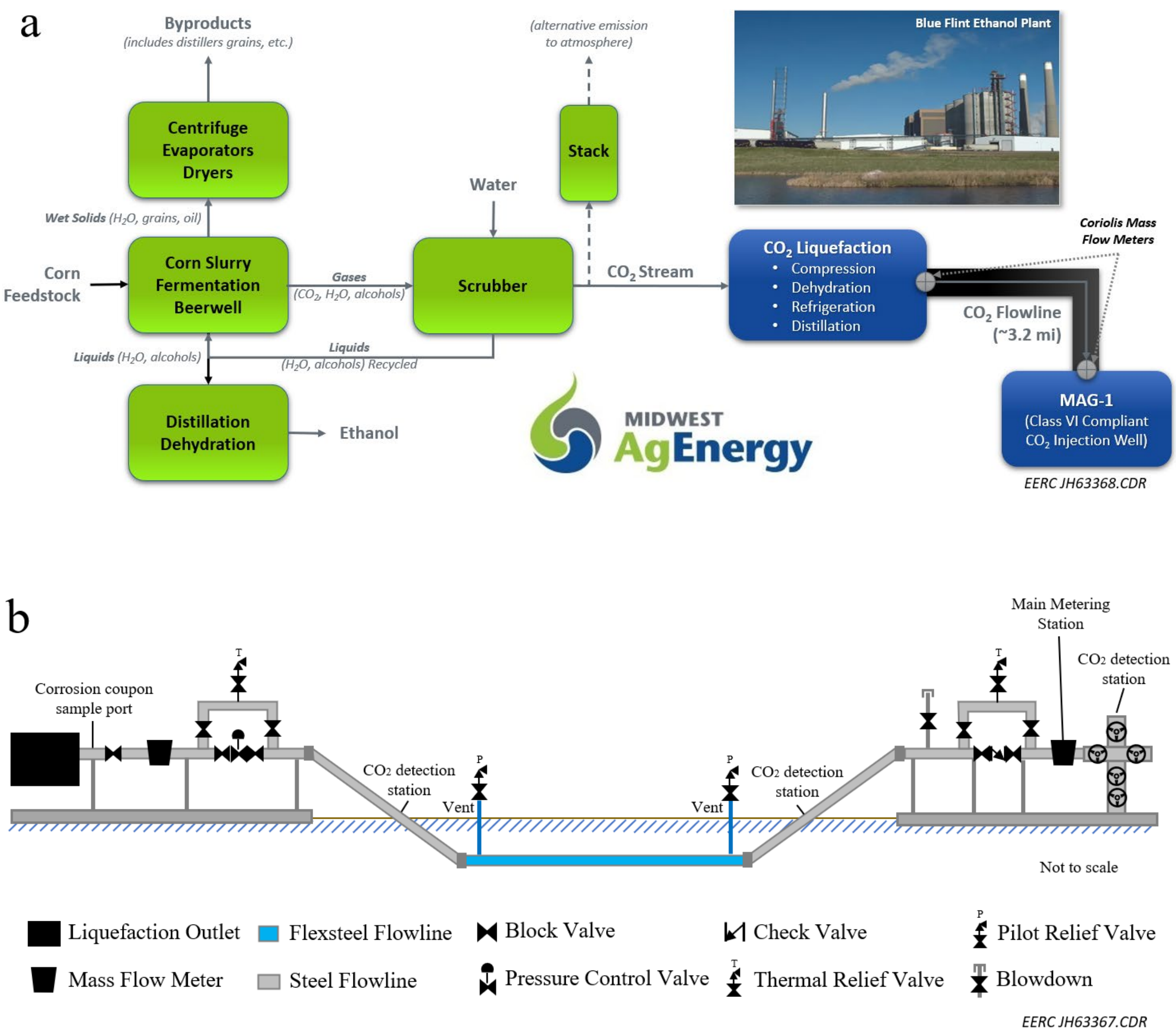

Figure 1-4. a) Process flow diagram of the CO_2 capture process at the BFE facility. b) Generalized flow diagram illustrating major CCS components of the surface facilities from the liquefaction outlet to the CO_2 injection well. The main metering station will be located adjacent to the injection wellhead as shown.

The liquefaction process includes processing to remove oxygen and other non-condensable gases before gas is compressed and flowed to the injection well through a FlexSteel CO_2 flowline for geologic storage into the Broom Creek Formation.

1.4 Facility Information

Reporter Number: Blue Flint – 583181
UIC Permit Class: The MAG 1 wellbore will be permitted as a Class VI injection well
Well Identification Number: NDIC File No. 37833, API No. 33-055-00196-00-00

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

The area of review (AOR) boundary defined in the North Dakota SFP application (R1:4.0) will serve as the maximum monitoring area (MMA) and the active monitoring area (AMA) until facility closure (i.e., the point at which Blue Flint receives a certificate of project completion). As illustrated in Figure 2-1, the AOR boundary provides a one-mile buffer around the stabilized CO_2 plume, rounding to the nearest 40-acre tract. This one-mile buffer area is larger and thereby exceeds the regulatory requirements for buffer areas around the free-phase CO_2 plume with respect to subpart RR definitions for the MMA and the AMA. Blue Flint will begin to monitor approximately one year prior to injection, during the active period of the project over 20 years, and for a minimum of 10 years after injection ceases.

Subpart RR regulations require the operator to delineate a MMA and an AMA. The MMA is a geographic area that must be monitored and is defined as an area that is greater than or equal to the projected stabilized CO_2 plume boundary plus an all-around buffer zone of at least one-half mile (40 CFR § 98.449 [Subpart RR]). An operator may stage monitoring efforts over time by defining time intervals with respect to an AMA. The AMA is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the 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. Blue Flint calculated the MMA and AMA according to these regulatory definitions, as shown in Figure 2-1.

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). The proposed AOR in Figure 2-1 is in accordance with the above regulations, providing a one-mile buffer and rounding to the nearest 40-acre tract outside the modeled CO_2 plume boundary.

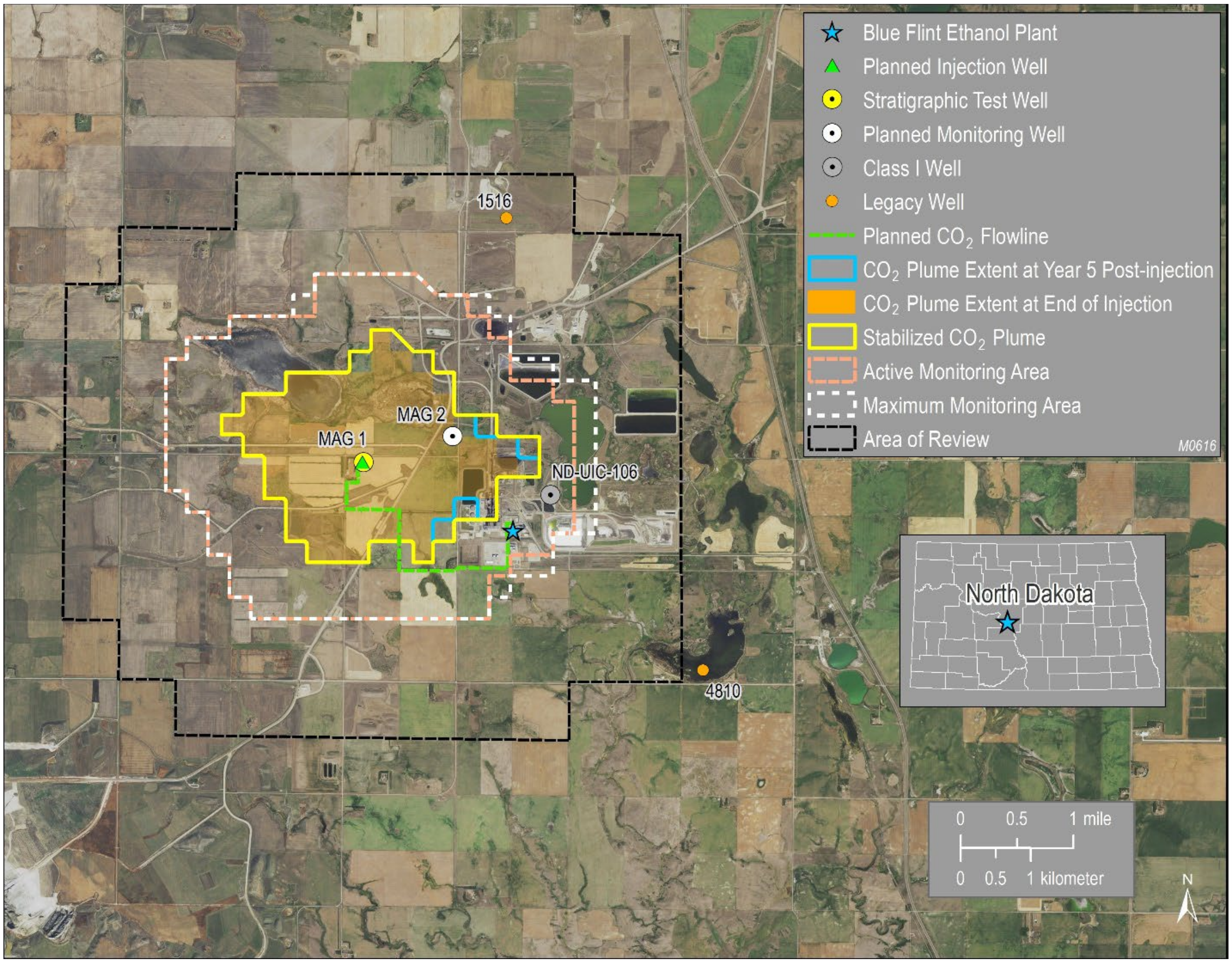

Figure 2-1. Map showing the AOR relative to the calculated MMA and AMA boundaries. In this case, "n" was set at Year 1 of injection and "t" set was set at Year 20 (end of injection) for calculating the AMA.

3.0 EVALUATION OF POTENTIAL SURFACE LEAKAGE PATHWAYS

Subpart RR requirements specify that the operator must identify potential surface leakage pathways and evaluate the magnitude, timing, and likelihood of surface leakage of CO_2 through these pathways within the MMA (40 CFR § 98.448[a][2]). Blue Flint identifies the potential surface leakage pathways as follows:

1. Class VI injection well
2. Reservoir-monitoring well
3. Surface components
4. Class I nonhazardous disposal well
5. Abandoned oil and gas wells
6. Faults, fractures, bedding plane partings, and seismicity
7. Confining system pathways

3.1 Class VI Injection Well (MAG 1)

The MAG 1 well (NDIC File No. 37833) spudded on October 11, 2020 as a stratigraphic test well to a depth of 9,213 feet into the Red River Formation (R1:9.1). This well was drilled to gather geologic data for the development of MAG's North Dakota SFP application. The MAG 1 well will be completed to NDIC Class VI construction standards as an injection well for the Blue Flint CO_2 storage project. The temperature profile of the MAG 1 wellbore will be continuously monitored with temperature distributed temperature sensing (DTS) fiber-optic cable. In addition, pressure in the wellbore will be continuously monitored with at least one downhole, tubing-conveyed P-T (pressure-temperature) gauge and digital surface pressure gauges on the tubing and well annulus. The tubing-casing annulus pressure will be tested prior to injection and at least once every five years. An ultrasonic log will also be acquired prior to injection for detecting any potential mechanical integrity issues behind casing at least once every five years (R1:5.4).

The risk of surface leakage of CO_2 via the MAG 1 is mitigated through:

- Monitoring operations with a surface leak detection plan, as described in R1:5.2.
- Preventing corrosion of well materials, following the preemptive measures in R1:5.3 and 5.6.
- Performing wellbore mechanical integrity testing, as described in R1:5.4, and summarized in R1:5.4, Table 5-4.
- Monitoring the storage reservoir with a subsurface leak detection plan (environmental monitoring plan), as described in R1:5.7.
- Acting in accordance with the emergency remedial response plan in R1:7.4.

The likelihood of surface leakage of CO_2 from the MAG 1 well during injection or post-injection operations is very low because of well construction and active monitoring. Barriers associated with well construction that prevent reservoir fluids from reaching the surface include surface valves, injection tubing fitted with a packer set above the injection zone, annular casing, cement, and surface casing and cement. Integrity of these barriers is actively monitored with DTS along the casing, and surface gauges on the tubing and well annulus. Active monitoring ensures integrity of well barriers and early detection of leaks. A supervisory control and data acquisition (SCADA) system is used to monitor for leaks. The detection time specified in R1:5.2, Table 5-3 greatly minimizes the magnitude of any surface leakage and provides the potential to estimate volumes. The potential for a surface leak from the MAG 1 injection well is present from the first day of injection through the post-injection period. The risk of a surface leak begins to decrease after injection ceases and greatly decreases as the reservoir approaches original pressure conditions. Once the injection period ceases, the MAG 1 will be properly plugged and abandoned following NDIC protocols, thereby further reducing any remaining risk of surface leakage from the wellbore.

3.2 Reservoir-Monitoring Well (MAG 2)

The MAG 2 (NDIC File No. TBD) well is planned to spud prior to injection as a stratigraphic test well for the Blue Flint CO_2 storage project. The well will be drilled to the Amsden/Tyler Formations. This stratigraphic test well will be converted into a reservoir-monitoring well prior to injection and will be constructed to NDIC Class VI standards. Like the MAG 1, the well will be monitored with continuous DTS fiber-optic cable, at least one tubing-conveyed P-T gauge, and digital surface pressure gauges on the tubing and well annulus. The tubing-casing annulus pressure will be tested prior to injection and at least once every five years. An ultrasonic log will also be acquired prior to injection for detecting any potential mechanical integrity issues behind casing at least once every five years (R1:5.4).

The likelihood of surface leakage of CO_2 from the MAG 2 well during injection or post-injection operations is very low because of well construction and active monitoring. Barriers associated with well construction that prevent reservoir fluids from reaching the surface include the wellhead, tubing with packer, surface valves, surface casing and cement, and production casing and cement. Integrity of these barriers is actively monitored with DTS along the casing, tubing-conveyed P-T gauges, and surface P-T gauges. Since the MAG 2 well is located just inside the projected stabilized CO_2 plume boundary, the potential for a surface leak begins near the end of the 20-year injection period and continues during the post-injection phase of the project. The risk of a surface leak decreases after injection ceases as the reservoir approaches original pressure conditions. Once the post-injection period ceases, the MAG 2 will be properly plugged and abandoned following NDIC protocols, thereby further reducing any remaining risk of surface leakage from the wellbore.

3.3 Surface Components

Surface components of the injection system, including the flowline and CO_2 injection wellhead (MAG 1), will be monitored with leak detection equipment (Figure 1-4b). The flowline will be monitored continuously via dual flowmeters located at the liquefaction outlet and near the wellhead for performing mass balance calculations. The flowline will also be regularly inspected for any visual or auditory signs of equipment failure and monitored continuously with one pressure gauge at the liquefaction outlet and one near the wellhead. CO_2 detection stations will be located on the flowline risers and at the CO_2 injection wellhead for identifying the presence of CO_2 external to surface equipment. The leak detection equipment will be integrated with automated warning systems and shutoffs that notify Blue Flint's operations center, giving the operator the ability to remotely isolate the system. Further details of the surface leak detection system are given in R1:5.2 and 5.3.

The likelihood of any surface leakage of CO_2 occurring via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.
- Implementing the highest standards on material selection and construction processes for the flowlines and wells.

- Applying operational best practices and a robust mechanical integrity program as well as operating procedures.

- Monitoring continuously via an automated and integrated system.

The likelihood of leakage through surface equipment during injection is very low, and the magnitude is limited to the volume of CO_2 in the flowline. The risk is constrained to the active injection period of the project when surface equipment is in operation.

3.4 Class I Nonhazardous Disposal Well

One UIC Class I disposal well is currently active within the Blue Flint CO_2 storage project area (Figure 1-2). Well #1 (North Dakota Department of Environmental Quality Well No. 11673) disposes of nonhazardous wastewater. Well #1 was drilled to the Swift Formation and is completed in multiple porous zones within the Newcastle, Skull Creek, and Inyan Kara Formations. Well #1 is equipped with digital surface pressure gauges on the tubing and the tubing-casing annulus for continuous, real-time monitoring for mechanical integrity of the wellbore. The gauges have built-in alarms to notify the operator of readings outside of operational parameters and a seal pot system for maintaining constant pressure on the annulus and detecting leaks.

Well #1 is not an anticipated surface leakage pathway; however, it is included in the analysis since the well lies within the storage facility area of the AOR. Well #1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally or vertically. The location of the well is outside of the projected stabilized plume boundary, and the associated injection reservoir lies over 1,000 feet vertically above the CO_2 storage formation that is separated by multiple impermeable geologic seals. Well #1 is expected to remain an active injection well during operation of the Blue Flint CO_2 storage project, which greatly minimizes the possibility of flow to the Class I disposal well. No surface leakage of CO_2 is anticipated at this location because Well #1 does not intersect the stabilized CO_2 plume boundary.

3.5 Abandoned Oil and Gas Wells

3.5.1 Ellen Samuelson 1

The Ellen Samuelson 1 (NDIC File No. 1516) well spudded on September 14, 1957 and was shortly thereafter plugged and abandoned on October 18, 1957. The well was drilled to the Mission Canyon Formation of the Madison Group, which is below the storage reservoir complex (Figure 1-3). Drilling, coring, and log data obtained from the well indicated no commercial accumulations of hydrocarbons were present in any of the subsurface formations drilled.

The Ellen Samuelson 1 well is not an anticipated surface leakage pathway; however, it is included in the analysis since the well is just inside the AOR boundary (Figure 2-1). The Ellen Samuelson 1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally. The location of the well is outside of the projected stabilized plume boundary, and the well has been plugged and abandoned in accordance with NDIC requirements (R1:4.2, Figure 4-3).

3.5.2 Wallace O. Gradin 1

The Wallace O. Gradin 1 (NDIC File No. 4810) well spudded on December 1, 1969 and was shortly thereafter plugged and abandoned on December 10, 1969. The well was drilled to the Rierdon Formation. The well tested subsurface formations for hydrocarbon potential but did not produce volumes sufficient for commercial consideration.

The Wallace O. Gradin 1 well is not an anticipated surface leakage pathway; however, it is included in the analysis since the well is located just outside the AOR boundary (Figure 2-1). The Wallace O. Gradin 1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally or vertically. The location of the well is outside of the projected stabilized plume boundary, and the Rierdon Formation in which the well is completed lies above the sealing formations associated with the CO_2 storage project. The well has been plugged and abandoned in accordance with NDIC requirements (R1:4.2, Figure 4-3).

3.6 Faults, Fractures, Bedding Plane Partings, and Seismicity

Regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations cannot be identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration reports (R1:2.5).

3.6.1 Stanton Fault

A regional fault was identified within the AOR boundary in previous literature (R1:2.5.1, Figures 2-65 and 2-66). It has been described as a northeast-southwest trending, basement-rooted fault; however, there is uncertainty whether this fault exists. Based on the seismic data analyzed as part of the site characterization activities, it appears that the fault does not exist, or if it does it is limited to the Precambrian basement (R1:2.5.1, Figures 2-67 and 2-68). The storage reservoir is approximately 5,000 feet above the Precambrian basement within the AOR and there is no fault extending from the basement, as evidenced by the seismic data which shows no visible offset in the overlying stratigraphy. Therefore, there is no anticipated CO_2 leakage to surface at any time of any magnitude because CO_2 is not anticipated to come into contact with any basement features. The Stanton Fault is mentioned in this MRV plan because the path of the fault was identified within the AOR boundary.

3.6.2 Natural or Induced Seismicity

Through the geologic site characterization and corrective action review process provided in the SFP, leakage resulting from natural or induced seismicity was shown to be very low. Periodic seismic survey and/or surface monitoring of the storage facility area is used to detect potential surface leaks and associated magnitude throughout the operational and post-injection periods.

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment (R1:2.5.2). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The two closest recorded seismic events to the Blue Flint CO_2 storage project occurred 52.3 miles to the east and 55.8 miles southwest of the MAG 1 wellbore, with estimated magnitudes of 2.6 and 0.2, respectively (R1:2.5.2, Table 2-21).

A 1-year seismic forecast (including both induced and natural seismic events) released by the U.S. Geological Survey (USGS) in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) state there is very little seismic activity near injection wells in the Williston Basin. They noted only two historic earthquakes in North Dakota (both magnitude 2.6 or lower events) that had the potential to be associated with oil and gas activities. This indicates relatively stable geologic conditions in the region surrounding the proposed injection site.

The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the absence of known or suspected local or regional faults suggest that the probability is very low for seismicity to interfere with CO_2 containment. The magnitude of any seismic event in the vicinity is expected to be 2.6 or below based on the historical data gathered and analyzed. Injection pressures are forecast to operate at a buffer below the maximum allowable injection pressure (R1:11.0, Table 11-1), minimizing the potential for induced seismicity from injection operations.

3.7 Confining System Pathways

Confining system pathways include any potential for migration of CO_2 beyond their lateral extent, the potential for CO_2 to diffuse upward through confining zones, and the potential for future wells that may penetrate confining zones. Limitations to the confining system pathways considered are discussed next and presented in context to the AOR boundary.

3.7.1 Lateral Migration

For the Blue Flint CO_2 storage project, the primary mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the upper confining zone (lower Piper and Spearfish Formations defined earlier in Section 1.2), which will contain the buoyant CO_2 under the effects of relative permeability and capillary pressure (R1:2.3.2). Together, the lower Piper and Spearfish Formations are laterally extensive formations that begin 4,340 feet below the surface and have a combined thickness of 387 feet at the MAG 1 wellsite (R1:2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), as discussed in R1:3.4.

The risk of surface leakage of CO_2 via lateral migration is very low, as demonstrated by the geologic characteristics of the storage reservoir (R1:2.3) and upper confining zone (R1:2.4.1) (e.g., lateral extent and continuity, mineralogy, low permeability/high sealing capacity, and lack of regional faults or fractures) coupled with the modeling and simulation work (R1:3.0) that was performed for the Blue Flint CO_2 storage project.

3.7.2 Seal Diffusivity

Several other formations provide additional confinement above the lower Piper and Spearfish Formations (R1:2.4.2), including upper Piper, Rierdon, and Swift Formations, which make up the secondary group of confining formations. Together with the lower Piper and Spearfish, these formations are 859 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next porous and permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 2,442 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation. Confining layers above the Inyan Kara include the Skull Creek, Mowry, Bell Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (see Figure 1-3 for stratigraphic reference).

The risk of leakage via seal diffusivity is very low, as there is a total of 3,371 feet of overlying confining layers, which presents a very low risk to the Blue Flint CO_2 storage project. The presence of multiple thick impermeable layers and laterally extensive formations drastically reduces potential leakage pathways through geologic formations.

3.7.3 Drilling Through the CO_2 Area

There is no significant commercial oil and gas activity within the project area, and it is unlikely that future wells would be drilled through the storage reservoir, which sits approximately 4,700 feet below the BFE facility. Supporting evidence includes one exploration well near the edge of the project AOR: the Ellen Samuelson 1 (discussed in Section 3.4.1). The well spudded on September 14, 1957 and was drilled to a depth of 6,600 feet into the Mission Canyon Formation. Drillstem tests (DSTs) within the Madison Group recovered only drilling mud, salt water, and a very slight gas cut. Exploration concluded with plugging and abandonment on October 18, 1957.

The NDIC maintains authority to regulate and enforce oil and gas activity respective to the integrity of operations including drilling of wells and underground storage of carbon dioxide.

3.8 Monitoring, Response, and Reporting Plan for CO_2 Loss

Blue Flint proposes a robust monitoring program in the SFP (R1:5.0 and 6.0 and summarized in R1:5.0, Table 5-1). The program covers surveillance of injection performance (R1:5.1 and 5.2), corrosion and mechanical integrity protocols (R1:5.3, 5.4, 5.6 and 6.2), baseline testing and logging plans for the MAG 1 and MAG 2 wellbores (R1:5.5), monitoring of near-surface conditions (R1:5.7.1, 5.7.2, and 6.2.1), and direct and indirect monitoring of the CO_2 plume and associated pressure front in the storage reservoir (R1:5.7.3 and 6.2.2). To compliment the monitoring program, Blue Flint proposes a detailed emergency remedial and response plan (R1:7.0) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting in the event of an unplanned loss of CO_2 from the Blue Flint CO_2 storage project area.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

Table 4-1 summarizes the monitoring strategy for each of the three project phases, and Table 4-2 summarizes the strategy for detecting and quantifying surface leakage pathways associated with CO_2 injection. These methodologies target early detection of any abnormalities in operating parameters or deviations from baselines and equipment detection thresholds established for the Blue Flint CO_2 storage project. These methodologies provide a verification process to validate if a leak has occurred or if the system has lost mechanical integrity. The data collected during monitoring are also used to calibrate the numerical model and improve the prediction for the injectivity, CO_2 plume, and associated pressure front.

Blue Flint will use reservoir simulation modeling, based on history-matched data obtained from the monitoring program, to compare the initial numerical model with the development of the CO_2 plume and associated pressure front. The model will be continuously calibrated with the acquisition of real-time data. The AOR and monitoring plan will be reviewed and if warranted, revised at least every 5 years. The history-match data model identifies conditions that differ from the initial model and deviations in the operating conditions. Monitoring data will be: 1) reviewed to determine if surface leakage of CO_2 is occurring; 2) verified by the operator with field personnel and/or technical experts; and 3) quantified in accordance with the quantification strategies in the monitoring plan and any emergency remedial response actions that may be necessary. Model history-matching in combination with mechanical integrity data, geophysical surveys, and near-surface monitoring provide a robust means to identify, quantify, and verify leaks. Blue Flint will adhere to the reporting in accordance with NDAC § 43-05-01-18, which specifies circumstances that warrant 30-day and 24-hour reporting.

A quality assurance and surveillance plan (QASP) is provided in R1:Appendix C, which details the specifications (e.g., detection thresholds and limits) for the monitoring equipment associated with the Blue Flint CO_2 storage project.

Table 4-1. Summary of Blue Flint's Testing and Monitoring Strategy

METHOD (TARGET AREA/STRUCTURE)	SAMPLING FREQUENCY		
	Pre-injection Phase (Baseline – 1 year)	**Injection Phase (20 years)**	**Post-injection Phase (10 years minimum)**
CO_2 Stream Analysis (capture)	Start-up	Quarterly	NA[1]
Surface Pressure Gauges (MAG 1, MAG 2, and flowline)	Start-up	Real time	Real time (MAG 2 only)
Mass Flow Metering (CO_2 injection well and flowline)	Start-up	Real time	NA
CO_2 Detection Stations (flowline risers, injection wellhead, and wellhead enclosure)	Start-up	Real time	NA
Corrosion Coupon Testing (flowline and well materials)	Baseline	Quarterly in Year 1, then annually thereafter	NA
SCADA Automated Remote System (MAG 1, MAG 2, and flowline)	Start-up	Real time	Real time (MAG 2 only)
DTS (MAG 1 and MAG 2)	At well completion	Real time	Real time (MAG 2 only)
Surface and Bottomhole P-T Readings (MAG 1 and MAG 2)	At well completion	Real time	Real time (MAG 2 only)
Temperature Log (MAG 1 and MAG 2)	Baseline	Annually (but only if other methods fail)	Annually in MAG 2 (only if DTS fails)
Ultrasonic Imaging Tool (USIT) or Alternative Casing Inspection Log (MAG 1 and MAG 2)	Baseline	Perform during well workovers but no less than once every 5 years	Perform during well workovers but no less than once every 5 years (MAG 2 only)
Tubing–Casing Annulus Pressure Tests (MAG 1 and MAG 2)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but no less than once every 5 years
Soil Gas Analysis (5 semi-permanent probe stations)	3–4 seasonal samples per location	N/A	Sample soil gas probe locations at the start of the PISC period and prior to facility closure
Soil Gas Analysis (2 permanent profile stations)	N/A	3–4 seasonal samples annually per location	Sample SGPS01 prior to MAG 1 reclamation; sample SGPS02 annually until facility closure
Water Analysis: Shallow Aquifers (15 wells operated by Falkirk Mining Company) (R1:Appendix B)	Provide historical water sampling results	NA	TBD[2]
Water Analysis: Shallow Aquifers (up to 5 wells within or near AOR)	3–4 seasonal samples per location	NA	TBD
Water Analysis: Lowest USDW (Fox Hills monitoring well adjacent to MAG 1)	3–4 seasonal samples	3–4 seasonal samples annually	\Annually until facility closure
Pulsed-Neutron Logs (MAG 2)	Baseline	Once in Year 4 and every 5 years thereafter until the end of injection	Annually until well reaches full CO_2 saturation then reduce to once every 4 years until facility closure
Pressure Falloff Test (MAG 1)	Baseline	Every 5 years	NA
Time-Lapse 2D Seismic Surveys (CO_2 plume)	Baseline	Repeat survey in Year 1 and Year 4. Reevaluate frequency in Year 4	TBD
Vertical Seismic Profiles (VSP) (CO_2 plume)	Evaluate feasibility for early-time monitoring during CO_2 injection operations	TBD	NA
Passive Seismicity Monitoring (CO_2 storage complex)	Utilize existing U.S. Geological Survey's network	Utilize existing U.S. Geological Survey's network and supplement with additional equipment as necessary	Utilize existing U.S. Geological Survey's network and supplement with additional equipment as necessary

[1] Not applicable [2] To be determined

Table 4-2. Monitoring Strategies for Detecting and Quantifying Surface Leakage Pathways Associated with CO_2 Injection

Monitoring Strategy (target area/structure) / Potential Surface Leakage Pathway	Wellbores	Faults and Fractures	Flowline and/or Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal	Detection Method	Quantification Method
Surface P-T Gauges (MAG 1, MAG 2, and flowline)	X		X			X	P-T gauge data will be recorded continuously in real-time by the SCADA system and sent to the operations center to detect any anomalous readings that require further investigation.	P-T gauge data may be needed in combination with metering data to accurately quantify volumes emitted by surface equipment.
Mass Flow Metering (CO_2 injection well and flowline)	X		X	X			Metering data (e.g., rate and volume/mass) will be recorded continuously in real-time by the SCADA system and sent to the operations center to detect any anomalous readings that require further investigation.	Mass balance and leak detection software calculations
CO_2 Detection Stations (flowline risers, injection wellhead, and wellhead enclosure)	X		X	X		X	CO_2 detection station data will detect any anomalous readings that require further investigation.	CO_2 concentration data collected by each station inside the enclosure may be used in combination with the assumed workspace atmosphere conditions and known volume of the enclosure to quantify any surface leakage of CO_2.
DTS (MAG 1 and MAG 2)	X		X	X	X	X	Temperature data will be recorded continuously in real time by the SCADA system to detect any anomalous readings near or at the surface that require further investigation.	NA
Temperature Log (MAG 1 and MAG 2)	X		X	X	X	X	Temperature log will be collected to detect any anomalous readings near or at the surface of the wellbore that require further investigation.	NA
USIT or Alternative Casing Inspection Log (MAG 1 and MAG 2)	X			X			Ultrasonic (or alternative) log will be collected to detect potential pathways to the surface in the wellbore that require further investigation.	NA
Soil Gas Analysis (5 semi-permanent probe stations)	X			X	X	X	Soil gas data will be collected to detect any anomalous readings just beneath or at the surface that require further investigation.	Additional field studies and soil gas sampling would be needed to provide an estimate of surface leakage of CO_2 using this method.
Soil Gas Analysis (2 permanent profile stations)	X			X	X	X	Same as above	Same as above
Pulsed-Neutron Logs (MAG 2)	X			X	X	X	Log will be collected to detect potential pathways to the surface in or near the wellbore that require further investigation.	The pulsed-neutron log is capable of quantifying the concentration of CO_2 near the wellbore. If pathway of surface leakage of CO_2 is detected, additional field studies and sampling (e.g., atmospheric and soil gas) would have to further delineate the extents and concentrations to quantify the event.
Time-Lapse 2D Seismic Surveys (CO_2 plume)	X	X		X	X	X	Seismic data will be collected and could detect pathways for surface leakage of CO_2 that require further investigation.	Additional field studies would be needed to provide an estimate of surface leakage of CO_2 using this method.
VSP (CO_2 plume)	X	X		X	X	X	VSP data may be collected and could detect pathways for surface leakage of CO_2 that require further investigation.	Additional field studies would be needed to provide an estimate of surface leakage of CO_2 using this method.

5.0 DETERMINATION OF BASELINES

Blue Flint will establish a pre-injection baseline by implementing a monitoring program approximately 1-year prior to CO_2 injection designed to coincide with seasonal changes. This baseline will include samples and analysis from near-surface and deep subsurface environments, such as soil gas in the vadose zone, shallow groundwater down to the lowest USDW, and storage reservoir information. Baselines provide the background concentration of CO_2 for comparative analysis to samples collected during operational and post-injection periods. Pre-injection baseline characterization is paramount to provide context to any future investigation of suspected leakage of CO_2 within the AOR. Determination of baseline concentrations is a requirement of the North Dakota SFP. A detailed description is provided in R1:5.1 through 5.7.

5.1 Surface and Near-Surface Baselines

A baseline surface and near-surface sampling program has been initiated for the Blue Flint CO_2 storage project as of September 2022. Baseline data gathering included measuring chemical concentrations of the soil gas (i.e., O_2, N_2, and CO_2) and groundwater (e.g., pH, total dissolved solids, alkalinity, major cations/anions, and trace metals) as well as characterizing the naturally occurring stable and radiocarbon (^{14}C) isotopic signatures of the soil gas and groundwater for comparison with the isotopic signature of the CO_2 stream. The data will be obtained from up to 5 soil gas-sampling locations and up to 5 existing groundwater wells from within or up to 0.25 miles outside of the AOR (R1:5.7.2, Figure 5-5). Baseline water samples are also being obtained from a new Fox Hills monitoring well adjacent to the MAG 1 wellbore. For additional information regarding surface and near-surface baselines, refer to R1:5.7.1 and 5.7.2.

5.2 Subsurface Baselines

Pre-injection baseline data will be collected in the CO_2 injection well (MAG 1) and reservoir-monitoring well (MAG 2) for the Blue Flint CO_2 storage project, as described in R1:5.5. The data acquisition schedule for the backup temperature and pulsed-neutron logging is presented in R1:5.4, Table 5-4 and R1:5.7, Table 5-6, respectively. The time-lapse saturation data will be collected in the MAG 2 only and will be useful for confirming the CO_2 injection profile in the storage reservoir as well as ensuring there are no signs of out-of-zone migration into formations overlying the storage reservoir, otherwise known as the above-zone monitoring interval. The temperature logging data will be useful as a backup method with respect to DTS data for confirming wellbore mechanical integrity and informing the geologic model and simulations.

Blue Flint has selected time-lapse geophysical surveys as the primary monitoring method to track the extent of the CO_2 plume within the storage reservoir (R1:5.7.3.3). A 2D seismic survey will be collected to establish baseline conditions in the storage reservoir. A baseline VSP may also be collected to determine the feasibility of the technique to monitor the CO_2 plume. For additional information regarding subsurface baselines, refer to R1:5.7.3.3.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The Blue Flint CO_2 storage project area is a geologic CO_2 storage site in a saline aquifer with no associated production from the CO_2 storage complex. Two Coriolis mass flowmeters will be installed to meter injected CO_2 (Figure 1-4b). The flowmeter closest to the wellhead is the primary metering station.

Annual mass of CO_2 received will be calculated by using the mass of CO_2 injected pursuant to 40 CFR § 98.444(a)(4) and 40 CFR § 98.444(b). The point of measurement for the mass of CO_2 received (injected) will be the primary metering station located closest to the injection wellhead.

Annual mass of stored CO_2 is calculated from Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{[Eq. 1]}$$

Where:

CO_2 = Total annual CO_2 mass stored in subsurface geologic formations (metric tons) at the facility.
CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells.
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage.
CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of Part 98.

Mass of CO_2 Injected (CO_{2I}):

Blue Flint will use mass flow metering to measure the flow of the injected CO_2 stream and calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the mass flow at standard conditions by the CO_2 concentration in the flow at standard conditions, according to Equation RR-4 from 40 CFR Part 98, Subpart RR (Equation 2):

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_2,p,u} \qquad \text{[Eq. 2]}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by Flowmeter u.
$Q_{p,u}$ = Quarterly mass flow rate measurement for Flowmeter u in Quarter p at standard conditions (standard cubic meters per quarter).
$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flowmeter.

Mass of CO_2 Emitted by Surface Leakage (CO_{2E}):

Blue Flint characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in R1:5.0, to detect any leak and defined a baseline for monitoring.

If the monitoring and surveillance plan detects a deviation from the threshold established for each method, the project will conduct a detailed analysis based on technology available and type of leak to quantify the CO_2 volume to the best of its capabilities. The process for quantifying any leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the leak, and numerical and predictive models, among others.

Blue Flint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98-Subpart RR (Equation 3):

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{[Eq. 3]}$$

Where:

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

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

Annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead (CO_{2FI}) will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan proposed in R1:5.0.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented within 90 days of the placed-in-service date of the capture and storage equipment, including the Class VI injection well (MAG 1) and storage reservoir-monitoring well (MAG 2). The project will not be placed in service until successfully completing performance testing, an essential milestone in achieving substantial completion. At the placed-in-service date, the project will commence collecting data for calculating total amount sequestered according to equations outlined in Section 6.0 of this MRV plan. Other greenhouse gas reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time.

This MRV plan will be in effect during the operational and post-injection monitoring periods. In the post-injection period, Blue Flint will prepare and submit a facility closure application to North Dakota, which will demonstrate nonendangerment of any USDWs and provide long-term assurance of CO_2 containment in the storage reservoir in accordance with North Dakota statutes and regulations. Once the facility closure application is approved by North Dakota, Blue Flint will submit a request to discontinue reporting under this MRV plan consistent with North Dakota and Subpart RR requirements (see 40 CFR § 98.441[b][2][ii]).

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for Blue Flint monitoring techniques and data management is provided in the quality assurance and surveillance plan found in R1:Appendix C.

Blue Flint will ensure compliance with the quality assurance requirement in 40 CFR § 98.444:

CO_2 received:

- The quarterly flow rate of CO_2 will be reported from continuous measurement at the main metering station (identified in Figure 1-4b).
- The CO_2 concentration will be reported as an average from measurements obtained at least quarterly from the CO_2 compressors.

Flowmeter provision:

- Operated continuously, except as necessary for maintenance and calibration.
- Operated using calibration and accuracy requirements in 40 CFR § 98.3(i).
- Operated in conformance with consensus-based standards organizations including, but not limited to, American Society for Testing and Materials (ASTM) International, the American National Standards Institute, the American Gas Association, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

9.0 RECORDS RETENTION

Blue Flint will follow the record retention requirements specified by 40 CFR § 98.3(g). In addition, it will follow the requirements in Subpart RR 40 CFR § 98.447-Subpart RR by maintaining the following records for at least 3 years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the 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 and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

These data will be collected, generated, and aggregated as required for reporting purposes.

10.0 REFERENCES

Anderson, F.J., 2016, North Dakota earthquake catalog (1870–2015): North Dakota Geological Survey Miscellaneous Series No. 93.

Bluemle, J.P., Anderson, S.B., and Carlson, C.G., 1981, Williston Basin stratigraphic nomenclature chart: North Dakota Geological Survey Miscellaneous Series No. 61.

Frohlich, C., Walter, J.I., and Gale, J.F.W., 2015, Analysis of transportable array (USArray) data shows seismic events are scarce near injection wells in the Williston Basin, 2008–2011: Seismological Research Letters, v. 86, no. 2A, March/April.

Murphy, E.C., Nordeng, S.H., Juenker, B.J., and Hoganson, J.W., 2009, North Dakota stratigraphic column: North Dakota Geological Survey Miscellaneous Series No. 91.

U.S. Geological Survey, 2019, Frequency of damaging earthquake shaking around the U.S. www.usgs.gov/media/images/frequency-damaging-earthquake-shaking-around-us (accessed June 2022).

U.S. Geological Survey, 2016, www.usgs.gov/news/featured-story/induced-earthquakes-raise-chances-damaging-shaking-2016 (accessed June 2022).

Request for Additional Information: Blue Flint Sequester Company, LLC
February 21, 2023

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	NA	NA	Please ensure that acronyms are defined in the MRV plan. For example, P-T is not defined in the MRV Plan.	P-T (pressure-temperature) is now defined in the text. Other acronyms now defined in the text include BFE, CCS, and UIC.
2.	NA	NA	We recommend doing and additional review for consistency, spelling, punctuation, etc. For example: • "Postinjection" vs. "Post-injection" • "pathway however is" vs. "pathway; however, it"	The term "postinjection" appears once in the MRV plan and is a directly quote from the North Dakota storage facility permit application. North Dakota Class VI regulations and permitting documents do not use a hyphen to separate terms such as "postinjection" or "preinjection". Any occurrence of terms missing hyphens in the MRV plan are limited to direct quotes from the SFP and cannot be changed. The second bullet – along with other minor grammatical errors found throughout the text – have been addressed.
3.	NA	NA	The MRV plan does not appear to describe how Blue Flint will calculate CO_2 received. Please clarify.	Clarified in Section 6.0 of the MRV plan. Pursuant to 40 CFR § 98.444(a)(4), MAG will follow the requirements of paragraph (b) of this section to calculate CO_2 received.
4.	Table of Contents	i	The table of contents has two subsections labeled 3.4, which results in the use of incorrect labels for the remaining subsections of section 3. Please correct this in the text as well as the table of contents.	The inconsistency in the labeling in Section 3.0 of the MRV plan has been addressed, and the table of contents has been updated to reflect the changes made.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	Referencing Convention	iv	While it is acceptable for an MRV plan to reference a permit, all information required by subpart RR should be included in the MRV plan itself. We recommend reviewing the MRV plan for references to the permit to check whether more information should be added within the MRV plan. For example, • Section 3.1 of the MRV plan references the detection time contained in R1:5.3 of the SFP but does not state what it is. • Section 3.5.1 of the MRV plan discusses the distance of the Stanton fault relative to the MAG 1 well within the AOR and references Figure 2-65 of the SFP but does not include the figure in the MRV plan.	The incorrect reference to R1:5.3 was provided. The reference has been corrected to R1:5.2, Table 5-3. Additional references to figures in the North Dakota SFP application were added to Section 3.5.1 of the MRV plan and the section was rewritten to provide the reader with additional context and details on the Stanton Fault.
6.	Referencing Convention	iv	"Below are three formatted examples of the referencing convention **in this document will follow**:" This sentence is unclear, please consider revising.	Removed "in" from the phrase to clarify.
7.	1.1	2	The predicted plume in Figure 1-1 appears to be rounded to the nearest 40-acre tract. Is there a more precise plume model available?	The stabilized CO_2 plume boundary presented in Figure 1-1 is not rounded to the nearest 40-acre tract. The resolution of the boundary is controlled by the cell size used in the geologic model and simulations, which in this case is 1,000 by 1,000 ft. The stabilized CO_2 plume boundary as shown in Figure 1-1 is the most precise CO_2 plume model available.
8.	1.2	3	"Siltstones with interbedded anhydrite of the lower Piper and Spearfish Formations unconformably overlie the Broom Creek and serve as the upper (primary) confining zone (R1:2.4.1)." The Picard Formation is highlighted in Figure 1-3 with the lower Piper-Spearfish Formations, but it is not mentioned in the MRV Plan's geologic discussion. Please address.	The Piper Formation has several formally recognized Members within it, including but not limited to the Picard and Kline. Figure 1-3, which lists Group and Formation names only, was updated to exclude the Picard, as there is no discussion of the Picard Member in the text of the MRV plan and the figure is not meant to identify geologic formations in so much detail.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
9.	2.0	7	"Blue Flint proposes that the AOR boundary serves as the MMA and the AMA boundary **until site closure**." Please clarify what is meant by "site closure."	Pursuant to 40 Code of Federal Regulations (CFR) § 146.81(d), site closure refers to the point in time in which the operator is released from post-injection site care responsibilities. This term is used synonymously in the MRV plan with facility closure under North Dakota Administrative Code (NDAC) § 43-05-01-19. To be more consistent with NDAC terminology, all occurrences of the term "site closure" have been updated to read "facility closure". In addition, brief clarification of what is meant by facility closure is now provided in the first sentence of Section 2.0 of the text.
10.	2.0	7	"Figure 2-1 illustrates how the AOR is demonstrably larger than the AMA or MMA." The MRV plan both delineates an AMA/MMA based on subpart RR definitions and explains that the AOR is larger than those. Please clarify in the MRV plan whether the AOR boundary will be used as the AMA/MMA.	To clarify for the reader and address this EPA question, Section 2.0 was given a new introductory sentence clearly stating that the AOR will serve as the MMA and AMA. To reduce the number of times this statement is then made throughout Section 2.0, the referenced sentence was deleted to be more concise.
11.	3.1	9	"The temperature profile of the MAG 1 wellbore **will continuously monitored with** temperature distributed temperature sensing (DTS) fiber optic cable." This sentence is unclear, please consider revising.	Added "be" between "will" and "continuously" to correct this sentence.
12.	3.1	9	"Periodic casing inspection (wall thickness) logs will also **be used detect any** potential mechanical integrity issues (R1:5.4)." This sentence is unclear, please consider revising.	Rewrote this sentence in Section 3.1 and added two new sentences to clarify the mechanical integrity testing plan for the MAG 1 injection well.
13.	3.4	11, 12	"There is extremely limited likelihood, magnitude, or timing of any CO_2 at the surface of Well #1." This phrase is used in multiple instances in the discussion of surface leakage pathways. Please elaborate/clarify what is meant by "limited likelihood, magnitude or timing" of CO_2. Also, we recommend adding "leakage" after CO_2.	This sentence was updated in the MRV plan to read, "No surface leakage of CO_2 is anticipated at this location because the well does not intersect the stabilized CO_2 plume boundary" to define the likelihood, magnitude, and timing of CO2 surface leakage more precisely for each pathway where this phrase appeared.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
14.	3.4	11	"The well was drilled to the Mission Canyon Formation of the Madison Group. Drilling, coring, and log data obtained from the well indicated no commercial accumulations of hydrocarbons were present in any of the subsurface formations drilled." You may consider revising the following paragraph to state that the Mission Canyon Formation is located below the injection interval. The MRV plan does this for the Wallace O. Gradin 1 well, but not for the Ellen Samuelson 1 well.	Added the following to the MRV plan to address this EPA comment, "The well was drilled to the Mission Canyon Formation of the Madison Group, which is below the storage reservoir complex."
15.	3.5.1	12	"Through the geologic site characterization review process, the suspected Stanton Fault is not an anticipated surface leakage pathway; however, it is included in the analysis since the suspected fault falls within the AOR boundary." Please clarify whether the Stanton fault is a potential leakage pathway and whether the MRV plan addresses potential leakage from this pathway.	This section on the Stanton fault was rewritten to better clarify why the Stanton Fault was included in the MRV plan, even though it is not an anticipated surface leakage pathway.
16.	3.6.1	13	"For the Blue Flint CO_2 storage project, the primary mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the upper confining zone (lower Piper and Spearfish Formations defined earlier in Section 1.2), which will contain the buoyant CO_2 under the effects of relative permeability and **cmag 2llary** pressure (R1:2.3.2)." Please consider clarifying this sentence.	This spelling error has been fixed in the text.
17.	4.0	15	"Table 4-2 summarizes the strategy for detecting and quantifying surface leakage pathways associated with CO2 injection." Table 4-2 appears to focus on strategies for detecting CO2 leakage but does not explain how leaks would be quantified. Please elaborate on how potential leakage would be quantified from these pathways.	Added "Detection Method" and "Quantification Method" columns to Table 4-2 and filled in descriptions for each monitoring strategy capable to detecting and/or quantifying surface leakage of CO2.

BLUE FLINT SEQUESTER COMPANY, LLC MONITORING, REPORTING, AND VERIFICATION PLAN

Class VI CO_2 Injection Well

Reporter Number: 583181

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

STORAGE FACILITY PERMIT DESIGNATION

Within the text of this monitoring, reporting, and verification plan, Blue Flint Sequester Company's storage facility permit is designated as follows:

Reference 1: Blue Flint Sequester Company, LLC Carbon Dioxide Geologic Storage Facility Permit Application

Section 1 – Pore Space Access
Section 2 – Geologic Exhibits
Section 3 – Geologic Model Construction and Numerical Simulation of CO_2 Injection
Section 4 – Area of Review
Section 5 – Testing and Monitoring Plan
Section 6 – Post-injection Site Care and Facility Closure Plan
Section 7 – Emergency and Remedial Response Plan
Section 8 – Worker Safety Plan
Section 9 – Well Casing and Cementing Program
Section 10 – Plugging Plan
Section 11 – Injection Well and Storage Operations
Section 12 – Financial Assurance and Demonstration Plan
Appendix A – MAG 1 Formation Fluid Sampling
Appendix B – Historic Freshwater Well Fluid Sampling
Appendix C – Quality Assurance and Surveillance Plan
Appendix D – Storage Facility Permit Regulatory Compliance Table

REFERENCING CONVENTION

Below are three formatted examples of the referencing convention in this document will follow:

- R1:4.1.1
- R1:C1.3.2
- R1:6.1.1.1, Figure 6-1

R1 refers to Reference 1 as designated hereto, and numbers or letters that appear after the colon represent the appropriate section or appendix from the storage facility permit (SFP). Thus:

- RA:4.1.1 would direct the reader to Section 4.1.1 (Area of Review Section, Written Description Subsection) within the SFP.

- R1:C1.3 would direct the reader to Section 1.3 (Corrosion Monitoring and Prevention Plan) of Appendix C (Quality Assurance and Surveillance Plan) within the SFP.

- R1:6.1.1.1, Figure 6-1 would direct the reader to Figure 6-1 in Section 6.1.1 (Pre- and Postinjection Pressure Differential) within the SFP.

MRV PLAN SUMMARY

Midwest AgEnergy (MAG) is moving towards a zero-carbon footprint through a multi-phased initiative “vision carbon zero”. MAG, the owner of Blue Flint Ethanol, LLC, Blue Flint Capture Company, LLC, and Blue Flint Sequester Company, LLC (Blue Flint) is developing a carbon capture and carbon storage project for the Blue Flint Ethanol facility (BFE) located in Underwood, North Dakota. Blue Flint proposes a compliant Greenhouse Gas Reporting Program (GHGRP) Subpart RR monitoring, reporting, and verification (MRV) plan in support of the storage project. As required under Title 40 Code of Federal Regulations (CFR) §98.448, this plan includes: 1) delineation of the maximum and active monitoring areas; 2) identification of potential surface leakage pathways and the likelihood, magnitude, and timing of surface leakage of carbon dioxide (CO_2) through these pathways within the maximum monitoring area; 3) a strategy for detecting and quantifying any surface leakage of CO_2; 4) a strategy for establishing the expected baselines for monitoring; and 5) a summary of the CO_2 accounting (mass balance) approach.

Blue Flint submitted a North Dakota UIC Class VI permit (storage facility permit [SFP]) application to the North Dakota Industrial Commission (NDIC) Department of Mineral Resources (DMR) on October 3, 2022. The SFP includes a testing and monitoring plan applicable to the MRV plan requirements of 40 CFR Part 98 Subpart RR. The Environmental Protection Agency (EPA) granted North Dakota primacy to administer an UIC program on April 24, 2018 for Class VI injection wells located within the state, except within Indian lands (83 Federal Register 17758, 40 CFR § 147.1751; EPA Docket No. EPA-HQ-OW-2013-0280). Plans developed for the North Dakota SFP are referenced within this MRV plan (see preceding sections on SFP designation and referencing convention). Monitoring aspects of the plan include sampling of the CO_2 stream, a leak detection and corrosion monitoring plan for the surface piping and wellhead, mechanical integrity testing and leak detection for injection and monitoring wells, and an environmental monitoring program that includes sampling of soil gas and groundwater, and time-lapse seismic surveys.

1.0 PROJECT OVERVIEW

1.1 Project Description

The Blue Flint Ethanol facility is located 6 miles south of Underwood, North Dakota. The BFE facility produces over 70 million gallons of ethanol annually along with about 200,000 tons dry distillers’ grains and about 10 tons of corn oil. A by-product of fermentation at the facility is a nearly pure stream of CO_2 (99%+ dry by volume). The BFE facility produces about 200,000 metric tons of CO_2 annually.

Blue Flint plans to capture 200,000 metric tons of CO_2 annually over a 20-year period from the BFE facility. The captured CO_2 will be processed for compression and transported in a 3-mile-long CO_2 flowline to a single CO_2 injection well. A stratigraphic test well (MAG 1) was drilled for the Blue Flint CO_2 storage project. This wellbore will be converted into a UIC Class VI injection well, and a second stratigraphic test well (MAG 2) will be drilled and converted to a reservoir-monitoring well. The CO_2 stream will be injected into the Broom Creek Formation, a predominantly sandstone reservoir and saline aquifer at an approximate depth of 4,700 feet. The location of the BFE facility and future injection/monitoring wells are provided in Figure 1-1 with respect to the extent of CO_2 storage delineated as the stabilized plume boundary.

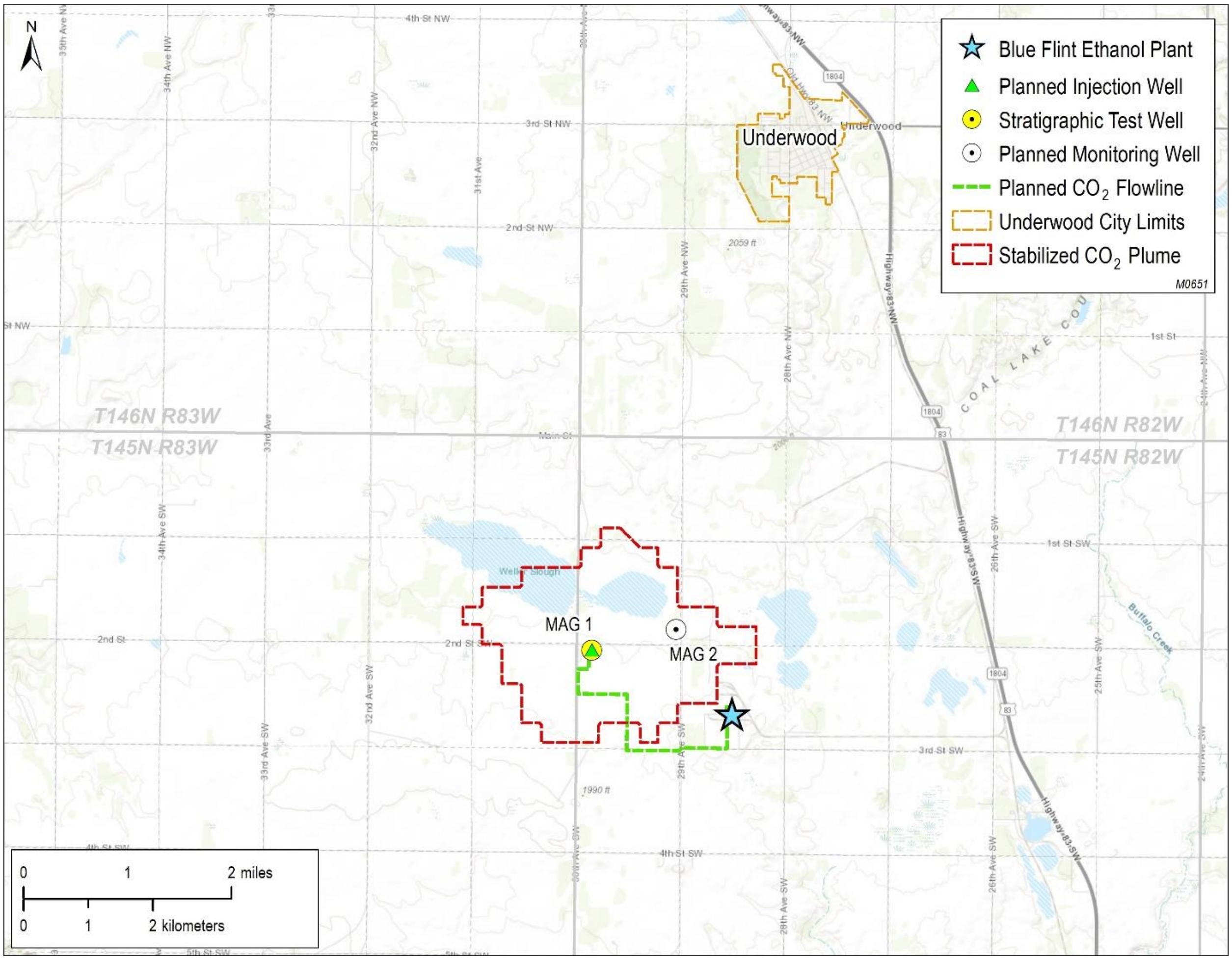

Figure 1-1. Location of the BFE facility and planned wells: CO_2 injection well (MAG 1), reservoir-monitoring well (MAG 2), and CO_2 flowline. The red outline indicates the stabilized CO_2 plume boundary.

1.2 Geologic Setting

The Blue Flint CO_2 storage project is located along the eastern flank of the Williston Basin where there has been no significant commercial production of hydrocarbon resources. Figure 1-2 provides a state reference map to illustrate the geographic distribution of oil and gas fields (undifferentiated) in North Dakota. The closest oil and gas fields to the project are located 39 miles west of the western edge of the stabilized CO_2 plume boundary, demonstrating there has been no commercial development of hydrocarbon resources within the immediate project area (R1:2.6). The Williston Basin is a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. The basin is hydrocarbon-bearing, with over 38,000 wells drilled in North Dakota for production of commercial accumulations of oil and gas from subsurface reservoirs. Although commercial oil and gas production is not present in the area surrounding the project legacy oil and gas exploration wells are present. Figure 1-2 identifies wells surrounding the predicted stabilized CO_2 plume area, with identification numbers provided for the two nearest wells to the geologic CO_2 storage site.

A standard stratigraphic column of the Williston Basin for the surrounding area of Underwood, North Dakota is provided in Figure 1-3. The target storage reservoir is the Broom Creek Formation, a predominantly sandstone interval lying about 4,700 feet below the BFE facility (R1:2.3). Siltstones with interbedded anhydrite of the lower Piper and Spearfish Formations unconformably overlie the Broom Creek and serve as the upper (primary) confining zone (R1:2.4.1). Mixed layers of dolostone, limestone and anhydrite of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone (R1:2.4.3). Together, the Amsden, Broom Creek, and lower Piper-Spearfish Formations comprise the CO_2 storage complex. There is about 859 feet (average thickness) of impermeable rock, including the lower Piper-Spearfish, between the Broom Creek and the next overlying porous zone, the Inyan Kara Formation (R1:2.4.2). An additional 2,442 feet (average thickness) of impermeable rock, including the Skull Creek, Mowry, Bell Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations, separate the Inyan Kara from the Fox Hills Formation (lowest underground source of drinking water [USDW]).

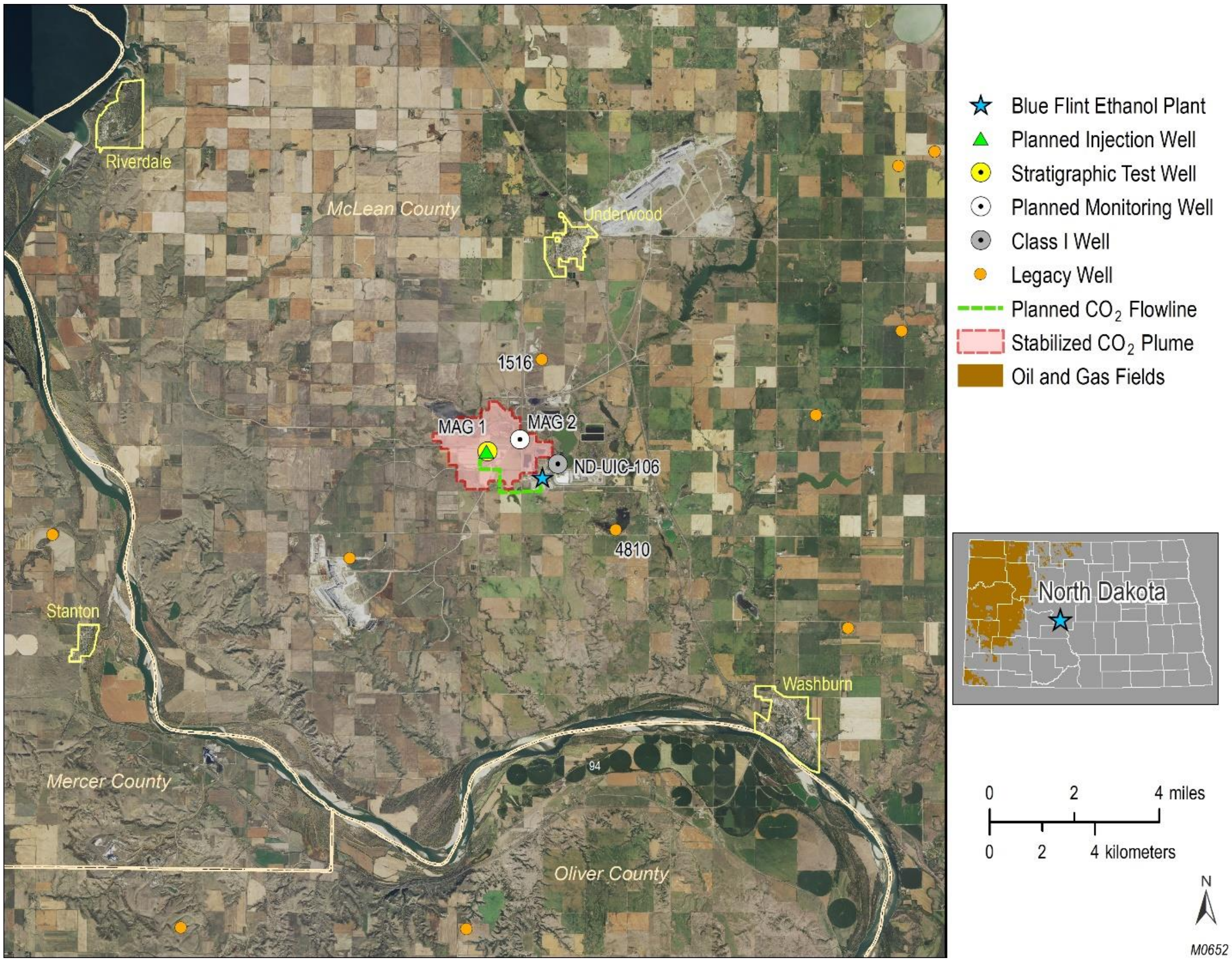

Figure 1-2. Map illustrating the locations of existing wellbores around the predicted stabilized CO_2 plume extent for the Blue Flint CO_2 storage project and nearby towns (outlined and labeled in yellow). The state reference map also reveals the geographic distribution of oil and gas fields in North Dakota. The closest oil and gas field is approximately 39 miles west of the Blue Flint CO_2 storage project.

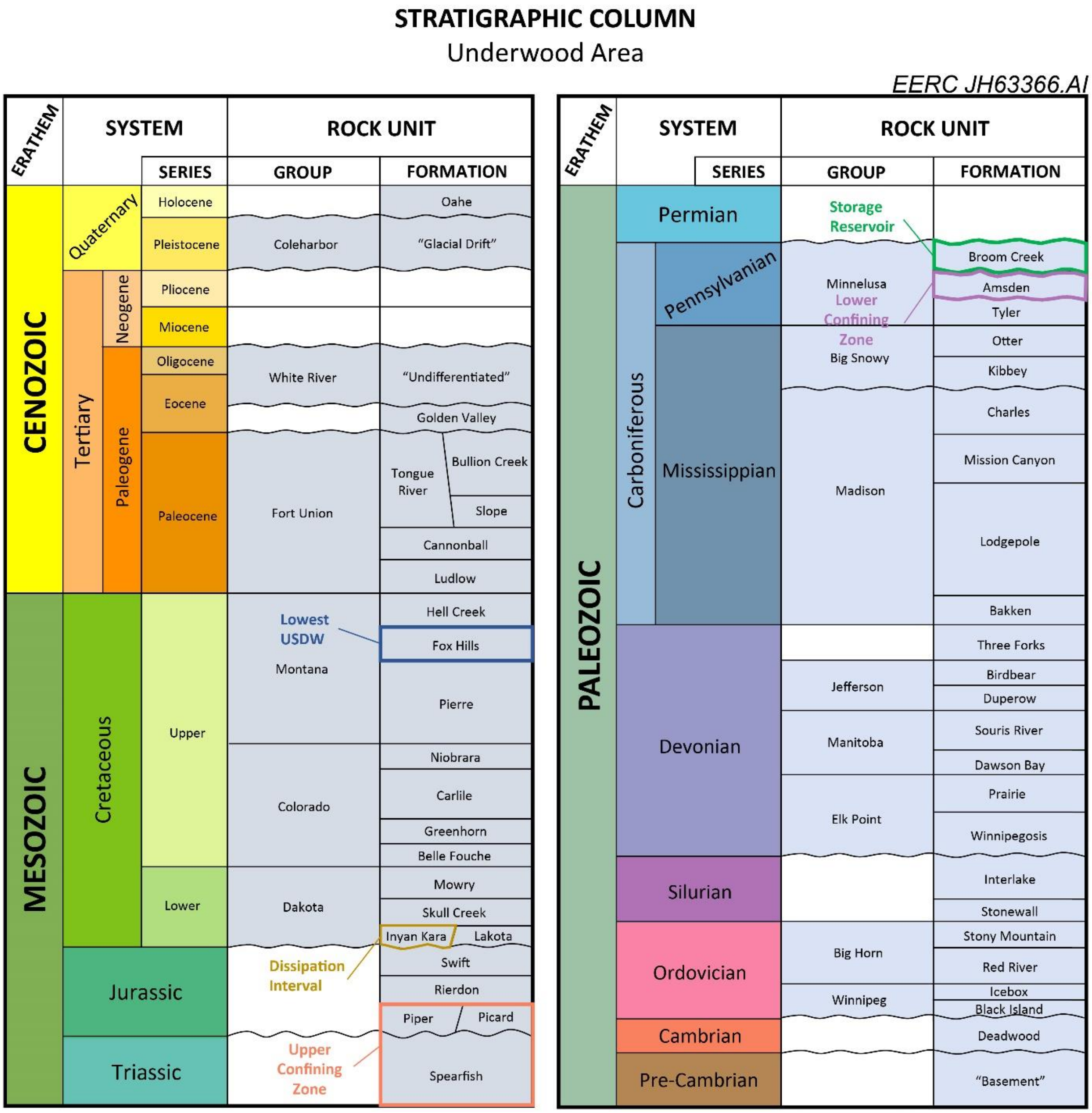

Figure 1-3. Stratigraphic column of the Williston Basin for the Underwood area, identifying the CO_2 storage complex as well as the dissipation interval and lowest USDW underlying the Blue Flint CO_2 storage project area. Figure modified after Murphy and others (2009) and Bluemle and others (1981).

1.3 Description of CO_2 Project Facilities and Injection Process

The BFE facility will utilize a liquefaction process to capture CO_2 produced from fermentation. Figure 1-4 provides a facility flow diagram.

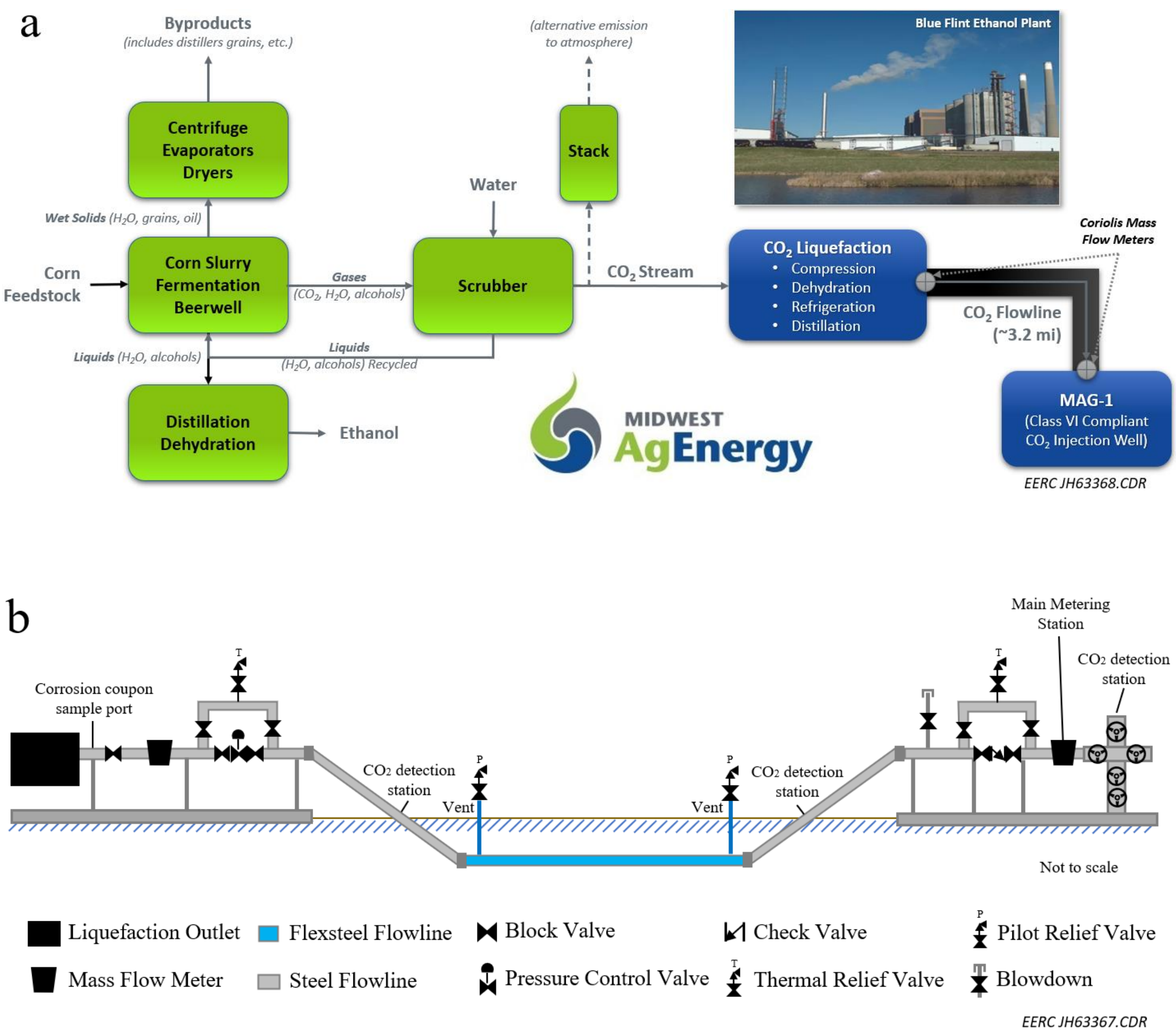

Figure 1-4. a) Process flow diagram of the CO_2 capture process at the BFE facility. b) Generalized flow diagram illustrating major CCS components of the surface facilities from the liquefaction outlet to the CO_2 injection well. The main metering station will be located adjacent to the injection wellhead as shown.

The liquefaction process includes processing to remove oxygen and other non-condensable gases before gas is compressed and flowed to the injection well through a FlexSteel CO_2 flowline for geologic storage into the Broom Creek Formation.

1.4 Facility Information

Reporter Number: Blue Flint – 583181
UIC Permit Class: The MAG 1 wellbore will be permitted as a Class VI injection well
Well Identification Number: NDIC File No. 37833, API No. 33-055-00196-00-00

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

Blue Flint has defined an area of review (AOR) within the SFP (R1:4) submitted to the NDIC. The boundary of the AOR provides a one-mile buffer rounding to the nearest 40-acre tract around the stabilized CO_2 plume illustrated in Figure 2.1. This one-mile buffer area is larger and thereby exceeds the regulatory requirements for buffer areas around the free-phase CO_2 plume with respect to subpart RR definitions for the maximum monitoring area (MMA) and the active monitoring area (AMA). Blue Flint proposes that the AOR boundary serves as the MMA and the AMA boundary until site closure. Blue Flint will begin to monitor approximately one year prior to injection, during the active period of the project over 20 years, and for a minimum of 10 years after injection ceases.

Subpart RR regulations require the operator to delineate a maximum monitoring area (MMA) and an active monitoring area (AMA). The MMA is a geographic area that must be monitored and is defined as an area that is greater than or equal to the predicted stabilized CO_2 plume boundary plus an all-around buffer zone of at least one-half mile (40 CFR § 98.449 [Subpart RR]). An operator may stage monitoring efforts over time by defining time intervals with respect to an AMA. The AMA is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the 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. Figure 2.1 delineates the MMA and the AMA according to the regulatory definitions and illustrates how the AOR boundary exceeds the minimum definition of the boundary. Specific to the Blue Flint CO_2 storage project, Blue Flint proposes to monitor within the AOR as established through the SFP until site closure.

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). The proposed AOR in Figure 2-1 is in accordance with the above regulations, providing a one-mile buffer and rounding to the nearest 40-acre tract outside the modeled CO_2 plume boundary. Figure 2-1 illustrates how the AOR is demonstrably larger than the AMA or MMA.

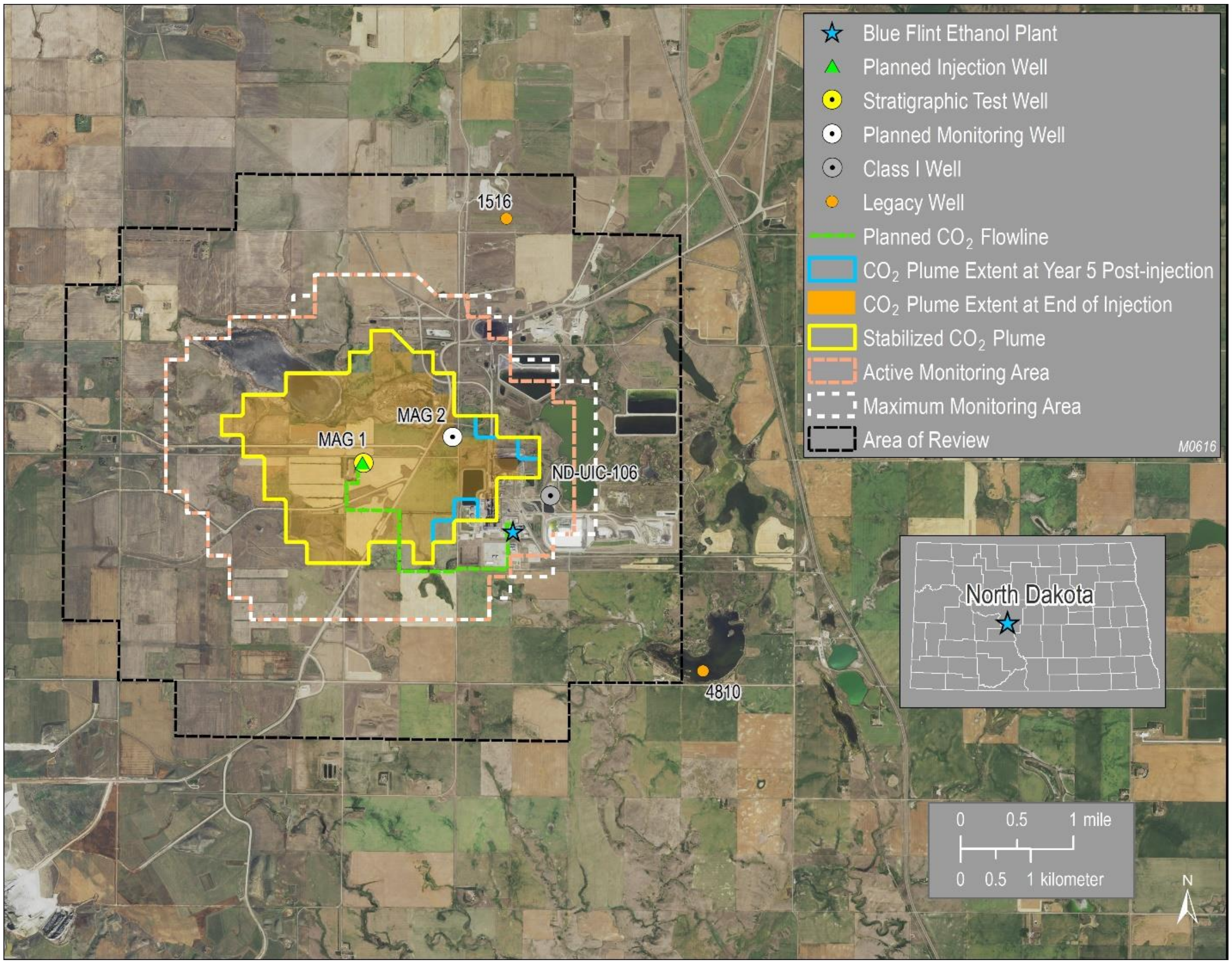

Figure 2-1. Map showing the AOR relative to the calculated MMA and AMA boundaries. In this case, "n" was set at Year 1 of injection and "t" set was set at Year 20 (end of injection) for calculating the AMA.

3.0 EVALUATION OF POTENTIAL SURFACE LEAKAGE PATHWAYS

Subpart RR requirements specify that the operator must identify potential surface leakage pathways and evaluate the magnitude, timing, and likelihood of surface leakage of CO_2 through these pathways within the MMA (40 CFR § 98.448[a][2]). Blue Flint identifies the potential surface leakage pathways as follows:

1. Class VI injection well
2. Reservoir-monitoring well
3. Surface components
4. Class I nonhazardous disposal well
5. Abandoned oil and gas wells
6. Faults, fractures, bedding plane partings, and seismicity
7. Confining System Pathways

3.1 Class VI Injection Well (MAG 1)

The MAG 1 well (NDIC File No. 37833) spudded on October 11, 2020 as a stratigraphic test well to a depth of 9,213 feet into the Red River Formation (R1:9.1). This well was drilled to gather geologic data to support the development of a North Dakota SFP and will be completed to NDIC Class VI construction standards as an injection well for the Blue Flint CO_2 storage project. The temperature profile of the MAG 1 wellbore will continuously monitored with temperature distributed temperature sensing (DTS) fiber optic cable. In addition, pressure in the wellbore will be continuously monitored with at least one downhole, tubing-conveyed P-T gauge and digital surface pressure gauges on the tubing and well annulus. Periodic casing inspection (wall thickness) logs will also be used detect any potential mechanical integrity issues (R1:5.4).

The risk of surface leakage of CO_2 via the MAG 1 is mitigated through:

- Monitoring operations with a surface leak detection plan, as described in R1:5.2.

- Preventing corrosion of well materials, following the preemptive measures in R1:5.3 and 5.6.

- Performing wellbore mechanical integrity testing, as described in R1:5.4, and summarized in R1: 5.4, Table 5-4.

- Monitoring the storage reservoir with a subsurface leak detection plan (environmental monitoring plan), as described in R1:5.7.

- Acting in accordance with the emergency remedial response plan in R1:7.4.

The likelihood of surface leakage of CO_2 from the MAG 1 well during injection or post-injection operations is very low because of well construction and active monitoring. Barriers associated with well construction that prevent reservoir fluids from reaching the surface include surface valves, injection tubing fitted with a packer set above the injection zone, annular casing, cement, and surface casing and cement. Integrity of these barriers is actively monitored with DTS along the casing, and surface gauges on the tubing and well annulus. Active monitoring ensures integrity of well barriers and early detection of leaks. A supervisory control and data acquisition (SCADA) system is used to monitor for leaks. The detection time specified in R1:5.3 greatly minimizes the magnitude of any surface leakage and provides the potential to estimate volumes. The potential for a surface leak from the MAG 1 injection well is present from the first day of injection through the post-injection period. The risk of a surface leak begins to decrease after injection ceases and greatly decreases as the reservoir approaches original pressure conditions. Once the injection period ceases, the MAG 1 will be properly plugged and abandoned following NDIC protocols, thereby further reducing any remaining risk of surface leakage from the wellbore.

3.2 Reservoir-Monitoring Well (MAG 2)

The MAG 2 (NDIC File No. TBD) well is planned to spud prior to injection as a stratigraphic test well for the Blue Flint CO_2 storage project. The well will be drilled to the Amsden/Tyler

Formations. Once the SFP is issued, this stratigraphic test well will be converted into a reservoir-monitoring well and constructed to Class VI standards. Like the MAG 1, the well will be monitored with continuous DTS fiber optic cable, at least one tubing-conveyed P-T gauge, digital surface pressure gauges on the tubing and well annulus, and periodic casing inspection (wall thickness) logs to detect any potential mechanical integrity issues (R1:5.4 and 6.2).

The likelihood of surface leakage of CO_2 from the MAG 2 well during injection or post-injection operations is very low because of well construction and active monitoring. Barriers associated with well construction that prevent reservoir fluids from reaching the surface include the wellhead, tubing with packer, surface valves, surface well casing and cement, and production casing and cement. Integrity of these barriers is actively monitored with DTS along the casing, tubing conveyed downhole gauges, and surface gauges. Since the MAG 2 well is located just inside the projected stabilized CO_2 plume boundary, the potential for a surface leak begins near the end of the 20-year injection period and continues during the post-injection phase of the project. The risk of a surface leak decreases after injection ceases as the reservoir approaches original pressure conditions. Once the post-injection period ceases, the MAG 2 will be properly plugged and abandoned following NDIC protocols, thereby further reducing any remaining risk of surface leakage from the wellbore.

3.3 Surface Components

Surface components of the injection system, including the flowline and CO_2 injection wellhead (MAG 1), will be monitored with leak detection equipment (Figure 1-4b). The flowline will be monitored continuously via dual flowmeters located at the liquefaction outlet and near the wellhead for performing mass balance calculations. The flowline will also be regularly inspected for any visual or auditory signs of equipment failure and monitored continuously with one pressure gauge at the capture facility outlet and one at the wellhead. CO_2 detection stations for identifying the presence of CO_2 external to surface equipment will be located on the flowline risers and at the CO_2 injection wellhead. The leak detection equipment will be integrated with automated warning systems that notify Blue Flint's operations center, giving the operator the ability to remotely isolate the system. Further details of the surface leak detection system are given in R1:5.2 and 5.3.

The likelihood of any surface leakage of CO_2 occurring via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.
- Implementing the highest standards on material selection and construction processes for the flowlines and wells.
- Applying operational best practices and a robust mechanical integrity program as well as operating procedures.
- Monitoring continuously via an automated and integrated system.

The likelihood of leakage through surface equipment during injection is very low, and the magnitude is limited to the volume of CO_2 in the flowline. The risk is constrained to the active injection period of the project when surface equipment is in operation.

3.4 Class I Nonhazardous Disposal Well

One UIC Class I disposal well is currently active within the Blue Flint CO_2 storage project area (Figure 1-2). Well #1 (North Dakota Department of Environmental Quality Well No. 11673) disposes of nonhazardous wastewater. Well #1 was drilled to the Swift Formation and is completed in multiple zones within the Newcastle, Skull Creek, and Inyan Kara Formations. Well #1 is equipped with digital surface pressure gauges on the tubing and the tubing-casing annulus for continuous, real-time monitoring for mechanical integrity of the wellbore. The gauges have built-in alarms to notify the operator of readings outside of operational parameters and a seal pot system for maintaining constant pressure on the annulus and detecting leaks.

Well #1 is not an anticipated surface leakage pathway however is included in the analysis since the well lies within the storage facility area of the AOR. Well #1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally or vertically. The location of the well is outside of the projected stabilized plume boundary and the associated injection reservoir lies over 1000 feet vertically above the CO_2 storage formation separated by multiple impermeable geologic seals. Well #1 is expected to remain an active injection well coinciding with the CO_2 storage project period which greatly minimizing the possibility of flow to the injection well. There is extremely limited likelihood, magnitude, or timing of any CO_2 at the surface of Well #1.

3.4 Abandoned Oil and Gas Wells

3.4.1 Ellen Samuelson 1

The Ellen Samuelson 1 (NDIC File No. 1516) well spudded on September 14, 1957 and shortly thereafter plugged and abandoned on October 18, 1957. The well was drilled to the Mission Canyon Formation of the Madison Group. Drilling, coring, and log data obtained from the well indicated no commercial accumulations of hydrocarbons were present in any of the subsurface formations drilled.

The Ellen Samuelson 1 well is not an anticipated surface leakage pathway; however, it is included in the analysis since the well is just inside the AOR boundary (Figure 2-1). The Ellen Samuelson 1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally. The location of the well is outside of the projected stabilized plume boundary and the well has been plugged and abandoned in accordance with NDIC requirements (R1:4.2, Figure 4-3). There is extremely limited likelihood, magnitude, or timing of any CO_2 at the surface of the Ellen Samuelson 1.

3.4.2 Wallace O. Gradin 1

The Wallace O. Gradin 1 (NDIC File No. 4810) well spudded on December 1, 1969 and shortly thereafter plugged and abandoned on December 10, 1969. The well was drilled to the Rierdon Formation. The well tested subsurface formations for hydrocarbon potential but did not produce volumes sufficient for commercial consideration.

The Wallace O. Gradin 1 well is not an anticipated surface leakage pathway; however, it is included in the analysis since the well is located just outside the AOR boundary (Figure 2-1). The Wallace O. Gradin 1 is not anticipated as a surface leakage pathway because CO_2 will not intersect the well laterally or vertically. The location of the well is outside of the projected stabilized plume boundary and the Rierdon Formation in which the well is completed lies above the sealing formations associated with the CO_2 storage project. The well has been plugged and abandoned in accordance with NDIC requirements (R1:4.2, Figure 4-3). There is extremely limited likelihood, magnitude, or timing of any CO_2 at the surface of the Wallace O. Gradin 1.

3.5 Faults, Fractures, Bedding Plane Partings, and Seismicity

Regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations cannot be identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration reports (R1:2.5).

3.5.1 Stanton Fault

Through the geologic site characterization review process, the suspected Stanton Fault is not an anticipated surface leakage pathway; however, it is included in the analysis since the suspected fault falls within the AOR boundary (R1:2.5.1, Figures 2-65 and 2-66). Despite the presence of diffractions in the Precambrian basement observed from 2D and 3D seismic data used to characterize the subsurface within the project AOR, there is no observable offset in formations overlying the Precambrian basement. The storage reservoir is approximately 5,000 feet above the Precambrian basement within the AOR. In addition, lack of historical earthquake occurrences in the area suggests that if the suspected Stanton Fault does exist it is inactive.

The Stanton Fault is a suspected basement-rooted fault that trends southwest-northeast and is interpreted by Sims and others (1991) and Anderson (2016) to be approximately 0.7 miles to the west of the MAG 1 wellbore (R1:2.5.1, Figure 2-65). Sims and others (1991) used available borehole and regional gravity and magnetic data to interpret subsurface structure in the Williston Basin, leading to considerable uncertainty in the location, extents, and nature of the interpreted feature from the overall lack of control points (wells) and inability of the gravity and magnetic data sets to directly measure and locate faults. In addition, no studies describing the vertical extent of the suspected Stanton Fault or the impact on overlying sedimentary rocks have been published.

3.5.2 Natural or Induced Seismicity

Through the geologic site characterization and corrective action review process provided in the SFP, leakage resulting from natural or induced seismicity was shown to be very low. Periodic seismic survey and/or surface monitoring of the storage facility area is used to detect potential surface leaks and associated magnitude throughout the operational and post injection periods.

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment (R1:2.5.2). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The two closest recorded seismic events to the Blue Flint CO_2 storage project occurred 52.3 miles to the east and 55.8 miles southwest of the MAG 1 wellbore, with estimated magnitudes of 2.6 and 0.2, respectively (R1:2.5.2, Table 2-21).

A 1-year seismic forecast (including both induced and natural seismic events) released by the U.S. Geological Survey (USGS) in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) state there is very little seismic activity near injection wells in the Williston Basin. They noted only two historic earthquakes in North Dakota (both magnitude 2.6 or lower events) that had the potential to be associated with oil and gas activities. This indicates relatively stable geologic conditions in the region surrounding the proposed injection site.

The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the absence of known or suspected local or regional faults suggest that the probability is very low for seismicity to interfere with CO_2 containment. The magnitude of any seismic event in the vicinity is expected to be 2.6 or below based on the historical. Injection pressures are forecast to operate at a buffer below the maximum allowable injection pressure (R1:11, Table 11-1) minimizing the potential for induced seismicity from injection operations.

3.6 Confining System Pathways

Confining system pathways include any potential for migration of CO_2 beyond their lateral extent, the potential for CO_2 to diffuse upward through confining zones, and the potential for future wells that may penetrate confining zones. Aspects regarding potential limitations are presented in context to the AOR.

3.6.1 Lateral Migration

For the Blue Flint CO_2 storage project, the primary mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the upper confining zone (lower Piper and Spearfish Formations defined earlier in Section 1.2), which will contain the buoyant CO_2 under the effects of relative permeability and capillary pressure (R1:2.3.2). Together, the lower Piper and Spearfish Formations are laterally extensive formations that begin 4,340 feet below the surface and have a combined thickness of 387 feet at the MAG 1 wellsite (R1:2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), as discussed in R1:3.4.

The risk of surface leakage of CO_2 via lateral migration is very low, as demonstrated by the geologic characteristics of the storage reservoir (R1:2.3) and upper confining zone (R1:2.4.1) (e.g., lateral extent and continuity, mineralogy, low permeability/high sealing capacity, and lack of regional faults or fractures) coupled with the modeling and simulation work (R1:3) that was performed for the Blue Flint CO_2 storage project.

3.6.2 Seal Diffusivity

Several other formations provide additional confinement above the lower Piper and Spearfish Formations (R1:2.4.2), including upper Piper, Rierdon, and Swift Formations, which make up the secondary group of confining formations. Together with the lower Piper and Spearfish, these formations are 859 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 2,442 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation. Confining layers above the Inyan Kara include the Skull Creek, Mowry, Bell Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (see Figure 1-3 for stratigraphic reference).

The risk of leakage via seal diffusivity is very low, as there is a total of 3,371 feet of overlying confining layers, which presents a very low risk to the Blue Flint CO_2 storage project. The presence of multiple thick impermeable layers and laterally extensive formations drastically reduces potential leakage pathways through geologic formations.

3.6.3 Drilling Through the CO_2 Area

There is no significant commercial oil and gas activity within the project area, and it is unlikely that future wells would be drilled through the storage reservoir, which sits approximately 4,700 feet below the ground surface. Supporting evidence includes one exploration well near the edge of the project AOR: the Ellen Samuelson 1 (discussed in Section 3.4.1). The well spudded on September 14, 1957 and was drilled to a depth of 6,600 feet into the Mission Canyon Formation. Drillstem tests (DSTs) within the Madison Group recovered only drilling mud, salt water, and a very slight gas cut. Exploration concluded with plugging and abandonment on October 18, 1957.

The NDIC maintains authority under North Dakota Century Code (NDCC) and Administrative Code (NDAC) to regulate and enforce oil and gas activity respective to the integrity of operations including drilling of wells and underground storage of carbon dioxide.

3.7 Monitoring, Response, and Reporting Plan for CO_2 Loss

Blue Flint proposes a robust monitoring program in the SFP (R1:5 and 6 and summarized in R1: 5.0, Table 5-1). The program covers surveillance of injection performance (R1:5.1 and 5.2), corrosion and mechanical integrity protocols (R1: 5.3, 5.4, 5.6 and 6.2), baseline testing and logging plans for the MAG 1 and MAG 2 wellbores (R1:5.5), monitoring of near-surface conditions (R1:5.7.1, 5.7.2, and 6.2.1), and direct and indirect monitoring of the CO_2 plume (R1:5.7.3 and 6.2.2). To compliment the monitoring program, Blue Flint proposes a detailed emergency remedial and response plan (R1:7) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting in the event of an unplanned loss of CO_2 from the Blue Flint CO_2 storage project area.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

Table 4-1 summarizes the monitoring strategy for each of the three project phases, and Table 4-2 summarizes the strategy for detecting and quantifying surface leakage pathways associated with CO_2 injection. These methodologies target early detection of any abnormalities in operating parameters or deviations from baselines and equipment detection thresholds established for the Blue Flint CO_2 storage project. These methodologies provide a verification process to validate if a leak has occurred or if the system has lost mechanical integrity. The data collected during monitoring are also used to calibrate the numerical model and improve the prediction for the injectivity, CO_2 plume, and associated pressure front.

Blue Flint will use reservoir simulation modeling, based on history-matched data obtained from the monitoring program, to compare the initial numerical model with the development of the CO_2 plume and associated pressure front. The model will be continuously calibrated with the acquisition of real-time data. Every 5 years, the AOR and monitoring plan will be reviewed and if warranted, revised. The history-match data model identifies conditions that differ from the initial model and deviations in the operating conditions. Data will be reviewed to determine if CO_2 leakage is occurring, verified by field personnel, and estimated. Model history-matching in combination with mechanical integrity data, geophysical surveys, and near-surface monitoring provide a robust means to identify, quantify, and verify leaks. Blue Flint will adhere to the reporting in accordance with NDAC § 43-05-01-18, which specifies circumstances that warrant 30-day and 24-hour reporting.

A quality assurance and surveillance plan (QASP) is provided in R1:Appendix C, which details the specifications (e.g., detection thresholds and limits) for the monitoring equipment associated with the Blue Flint CO_2 storage project.

Table 4-1. Summary of Blue Flint's Testing and Monitoring Strategy

METHOD (TARGET AREA/STRUCTURE)	SAMPLING FREQUENCY		
	Pre-injection Phase (Baseline – 1 year)	**Injection Phase (20 years)**	**Post-injection Phase (10 years)**
CO_2 Stream Analysis (capture)	Start-up	Quarterly	NA[1]
Surface Pressure Gauges (MAG 1, MAG 2, and flowline)	Start-up	Real time	Real time (MAG 2 only)
Mass Flow Metering (CO_2 injection well and flowline)	Start-up	Real time	NA
CO_2 Detection Stations (flowline risers, injection wellhead, and wellhead enclosures)	Start-up	Real time	NA
Corrosion Coupon Testing (flowline and well materials)	Baseline	Quarterly in Year 1, then annually thereafter	NA
SCADA[2] Automated Remote System (MAG 1, MAG 2, and flowline)	Start-up	Real time	Real time (MAG 2 only)
DTS (MAG 1 and MAG 2)	At well completion	Real time	Real time (MAG 2 only)
Surface and Bottomhole P-T Readings (MAG 1 and MAG 2)	At well completion	Real time	Real time (MAG 2 only)
Temperature Log (MAG 1 and MAG 2)	Baseline	Annually (but only if other methods fail)	Annually in MAG 2 (only if DTS fails)
Ultrasonic Imaging Tool (USIT) or Alternative Casing Inspection Log (MAG 1 and MAG 2)	Baseline	Perform during well workovers but no less than once every 5 years	Perform during well workovers but no less than once every 5 years (MAG 2 only)
Tubing–Casing Annulus Pressure Tests (MAG 1 and MAG 2)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but no less than once every 5 years
Soil Gas Analysis (5 semi-permanent probe stations)	3–4 seasonal samples per location	N/A	Sample soil gas probe locations at the start of the PISC period and prior to site closure
Soil Gas Analysis (2 permanent profile stations)	N/A	3–4 seasonal samples annually per location	Sample SGPS01 prior to MAG 1 reclamation; sample SGPS02 annually until site closure
Water Analysis: Shallow Aquifers (15 wells operated by Falkirk Mining Company) (R1:Appendix B)	Provide historical water sampling results	NA	TBD[3]
Water Analysis: Shallow Aquifers (up to 5 wells within or near AOR)	3–4 seasonal samples per location	NA	TBD
Water Analysis: Lowest USDW (Fox Hills monitoring well adjacent to MAG 1)	3–4 seasonal samples	3–4 seasonal samples annually	Annually until site closure
Pulsed-Neutron Logs (MAG 2)	Baseline	Once in Year 4 and every 5 years thereafter until the end of injection	Annually until well reaches full CO_2 saturation then reduce to once every 4 years until site closure
Pressure Falloff Test (MAG 1)	Baseline	Every 5 years	NA
Time-Lapse 2D Seismic Surveys (CO_2 plume)	Baseline	Repeat survey in Year 1 and Year 4. Reevaluate frequency in Year 4	TBD
Vertical Seismic Profiles (VSP) (CO_2 plume)	Evaluate feasibility for early-time monitoring during CO_2 injection operations	TBD	NA
Passive Seismicity Monitoring (CO_2 storage complex)	Utilize existing U.S. Geological Survey's network	Utilize existing U.S. Geological Survey's network and supplement with additional equipment as necessary	Utilize existing U.S. Geological Survey's network and supplement with additional equipment as necessary

[1] Not applicable [2] Supervisory control and data acquisition [3] To be determined

Table 4-2. Monitoring Strategies for Detecting and Quantifying Leakage Pathways Associated with CO_2 Injection

Monitoring Strategy (target area/structure) / Potential Leakage Pathway	Wellbores	Faults and Fractures	Flowline and/or Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis (capture)			X			
Surface Pressure Gauges (MAG 1, MAG 2, and flowline)	X		X			X
Mass Flow Metering (CO_2 injection well and flowline)	X		X	X		
CO_2 Detection Stations (flowline risers, injection wellhead, and wellhead enclosures)	X		X	X		X
Corrosion Coupon Testing (flowline and well materials)	X		X	X		
SCADA Automated Remote System (MAG 1, MAG 2, and flowline)	X		X	X		
DTS (MAG 1 and MAG 2)	X		X	X	X	X
Surface and Bottomhole P-T Readings (MAG 1 and MAG 2)	X		X	X	X	X
Temperature Log (MAG 1 and MAG 2)	X		X	X	X	X
Ultrasonic Imaging Tool (USIT) or Alternative Casing Inspection Log (MAG 1 and MAG 2)	X			X		
Tubing–Casing Annulus Pressure Tests (MAG 1 and MAG 2)	X			X		
Soil Gas Analysis (5 semi-permanent probe stations)	X			X	X	X
Soil Gas Analysis (2 permanent profile stations)	X			X	X	X
Water Analysis: Shallow Aquifers (15 wells operated by Falkirk Mining Company) (R1:Appendix B)	X			X	X	X
Water Analysis: Shallow Aquifers (up to 5 wells within 1-mile of AOR)	X			X	X	X
Water Analysis: Lowest USDW (Fox Hills monitoring well adjacent to MAG 1)	X	X		X	X	X
Pulsed-Neutron Logs (MAG 2)	X			X	X	X
Pressure Falloff Test (MAG 1)	X			X	X	
Time-Lapse 2D Seismic Surveys (CO_2 plume)	X	X		X	X	X
Vertical Seismic Profiles (VSP) (CO_2 plume)	X	X		X	X	X
Passive Seismicity Monitoring (CO_2 storage complex)		X		X	X	

5.0 DETERMINATION OF BASELINES

Blue Flint will establish a pre-injection baseline by implementing a monitoring program approximately 1-year prior to CO_2 injection designed to coincide with seasonal changes. This baseline will include samples and analysis from near-surface and deep subsurface environments, such as soil gas in the vadose zone, shallow groundwater down to the lowest USDW, and storage reservoir information. Baselines provide the background concentration of CO_2, for comparative analysis to samples collected during operational and post-injection periods. Pre-injection baseline characterization is paramount to provide context to any future investigation of suspected leakage of CO_2 within the AOR. Determination of baseline concentrations is a requirement of the North Dakota SFP. A detailed description is provided in R1:5.1 through 5.7.

5.1 Surface and Near-Surface Baselines

A baseline surface and near-surface sampling program has been initiated for the Blue Flint CO_2 storage project as of September 2022. Baseline data gathering included measuring chemical concentrations of the soil gas (i.e., O_2, N_2, and CO_2) and groundwater (e.g., pH, total dissolved solids, alkalinity, major cations/anions, and trace metals) as well as characterizing the naturally occurring stable and radiocarbon (^{14}C) isotopic signatures of the soil gas and groundwater for comparison with the isotopic signature of the CO_2 stream. The data will be obtained from up to 5 soil gas-sampling locations and up to 5 existing groundwater wells from within or 0.25 miles of the AOR (R1:5.7.2, Figure 5-5). Baseline water samples are also being obtained from a new Fox Hills monitoring well adjacent to the MAG 1 wellbore. For additional information regarding surface and near-surface baselines, refer to R1:5.7.1 and 5.7.2.

5.2 Subsurface Baselines

Pre-injection baseline data will be collected in the CO_2 injection well (MAG 1) and reservoir-monitoring well (MAG 2) for the Blue Flint CO_2 storage project, as described in R1:5.5. The data acquisition schedule for the backup temperature and pulsed-neutron logging is presented in R1:5.4, Table 5-4 and R1:5.7, Table 5-6, respectively. The time-lapse saturation data will be collected in the MAG 2 only and will be useful for confirming the CO_2 injection profile in the storage reservoir as well as ensuring there are no signs of out-of-zone migration into formations overlying the storage reservoir, otherwise known as the above-zone monitoring interval. The temperature logging data will be useful as a backup method with respect to DTS data for confirming wellbore mechanical integrity and informing the geologic model and simulations.

Blue Flint has selected time-lapse geophysical surveys as the primary monitoring method to track the extent of the CO_2 plume within the storage reservoir (R1:5.7.3.3). A 2D seismic survey will be collected to establish baseline conditions in the storage reservoir. A baseline vertical seismic profile (VSP) may also be collected to determine the feasibility of the technique to monitor the CO_2 plume. For additional information regarding subsurface baselines, refer to R1:5.7.3.3.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The Blue Flint CO_2 storage project area is a geologic CO_2 storage site in a saline aquifer with no associated production from the CO_2 storage complex. Two Coriolis mass flowmeters will be installed to meter injected CO_2 (Figure 1-4b). The flowmeter closest to the wellhead is the primary metering station.

Annual mass of stored CO_2 is calculated from Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{[Eq. 1]}$$

Where:

CO_2 = Total annual CO_2 mass stored in subsurface geologic formations (metric tons) at the facility.
CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells.
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage.
CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of Part 98.

Mass of CO_2 Injected (CO_{2I}):
Blue Flint will use mass flow metering to measure the flow of the injected CO_2 stream and will calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the mass flow at standard conditions by the CO_2 concentration in the flow at standard conditions, according to Equation RR-4 from 40 CFR Part 98, Subpart RR (Equation 2):

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_2,p,u} \qquad \text{[Eq. 2]}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by Flowmeter u.
$Q_{p,u}$ = Quarterly mass flow rate measurement for Flowmeter u in Quarter p at standard conditions (standard cubic meters per quarter).
$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flowmeter.

Mass of CO_2 Emitted by Surface Leakage (CO_{2E}):
Blue Flint characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in R1:5, to detect any leak and defined a baseline for monitoring.

If the monitoring and surveillance plan detects a deviation from the threshold established for each method, the project will conduct a detailed analysis based on technology available and type of leak to quantify the CO_2 volume to the best of its capabilities. The process for quantifying any leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the leak, and numerical and predictive models, among others.

Blue Flint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98-Subpart RR (Equation 3):

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{[Eq. 3]}$$

Where:

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

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

Annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead (CO_{2FI}) will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan proposed in R1:5.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented within 90 days of the placed-in-service date of the capture and storage equipment, including the Class VI injection well (MAG 1) and storage reservoir-monitoring well (MAG 2). The project will not be placed in service until successfully completing performance testing, an essential milestone in achieving substantial completion. At the placed-in-service date, the project will commence collecting data for calculating total amount sequestered according to equations outlined in Section 6.0 of this MRV plan. Other greenhouse gas reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time.

This MRV plan will be in effect during the operational and post-injection monitoring periods. In the post-injection period, Blue Flint will prepare and submit a site closure application to North Dakota, which will demonstrate non-endangerment of any USDWs and provide long-term assurance of CO_2 containment in the storage reservoir in accordance with North Dakota statutes and regulations. Once the site closure application is approved by North Dakota, Blue Flint will submit a request to discontinue reporting under this MRV plan consistent with North Dakota and Subpart RR requirements (see 40 CFR § 98.441[b][2][ii])

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for Blue Flint monitoring techniques and data management is provided in the quality assurance and surveillance plan found in R1: Appendix C.

Blue Flint will ensure compliance with the quality assurance requirement in 40 CFR § 98.444:

CO_2 received:

- The quarterly flow rate of CO_2 will be reported from continuous measurement at the main metering station (identified in Figure 1-4b).

- The CO_2 concentration will be reported as an average from measurements obtained at least quarterly from the CO_2 compressors.

Flowmeter provision:

- Operated continuously, except as necessary for maintenance and calibration.

- Operated using calibration and accuracy requirements in 40 CFR § 98.3(i).

- Operated in conformance with consensus-based standards organizations including, but not limited to, American Society for Testing and Materials (ASTM) International, the American National Standards Institute, the American Gas Association, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

9.0 RECORDS RETENTION

Blue Flint will follow the record retention requirements specified by 40 CFR § 98.3(g). In addition, it will follow the requirements in Subpart RR 40 CFR § 98.447-Subpart RR by maintaining the following records for at least 3 years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the 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 and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

These data will be collected, generated, and aggregated as required for reporting purposes.

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BLUE FLINT SEQUESTER COMPANY, LLC

Carbon Dioxide Geologic Storage Facility Permit Application

Prepared for:

Tamara Madche

North Dakota Industrial Commission
Oil & Gas Division
600 East Boulevard Avenue
Department 405
Bismarck, ND 58505-0840

Prepared by:

Midwest AgEnergy Group
2841 3rd Street Southwest
Underwood, ND 58576

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

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BLUE FLINT SEQUESTER COMPANY, LLC
CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT APPLICATION

PERMIT APPLICATION SUMMARY

Blue Flint Sequester Company, LLC (Blue Flint), a subsidiary of Midwest AgEnergy Group, LLC (MAG), along with its project partners and affiliates, requests consideration of this storage facility permit (SFP) application for the geologic storage of carbon dioxide (CO_2) near the Blue Flint Ethanol (BFE) facility, located 6 miles south of Underwood, North Dakota (Figure PS-1).

Owned and operated by MAG, the BFE facility purchases about 25 million bushels of corn a year from approximately 500 local corn producers and produces over 70 million gallons of ethanol each year along with about 200,000 tons of dry distillers' grains and about 10 tons of corn oil. A by-product of fermentation at the facility is a nearly pure stream of CO_2 (99+% by volume). The BFE facility produces about 200,000 metric tons per year of CO_2, which is currently scrubbed and released into the atmosphere.

The Blue Flint CO_2 storage project plans to annually inject 200,000 metric tons of CO_2 sourced from BFE for a period of 20 years for permanent geologic storage. The capture facility for the project will be located within the existing BFE facility. Plans are to capture, dehydrate, and compress the CO_2 stream and then transport the supercritical fluid via a 3-mile, 4-inch FlexSteel flowline to the MAG 1 CO_2 injection well (Figure PS-1). The captured CO_2 will be injected into the Broom Creek Formation, a sandstone reservoir and saline aquifer underlying the BFE facility and surrounding region.

The Broom Creek Formation, and more specifically its CO_2 storage potential, has been the subject of numerous studies conducted by the North Dakota Geological Survey (NDGS), the U.S. Geological Survey (USGS), and the Energy & Environmental Research Center (EERC). It is deemed an ideal storage candidate because of its superior reservoir quality, depth, and impermeable upper and lower confining zones. Subsurface characterization efforts conducted by MAG, including acquisition of a 3D seismic survey and drilling, testing, and coring a stratigraphic test well, MAG 1 (NDIC [North Dakota Industrial Commission] File No. 37833), confirmed the presence and suitability of the Broom Creek Formation at the Blue Flint project site for geologic storage of CO_2.

The following SFP application provides detailed geologic exhibits generated from site characterization activities. Additionally, computational modeling and simulation for predictive CO_2 movement forecasting was performed in conjunction with pore space access determination. These pieces lay the foundation for area of review determination, which is, in turn, the basis for the required supporting permit plans: emergency and remedial response, financial assurance demonstration, worker safety, testing and monitoring, well casing and cementing, plugging, and postinjection site care and facility closure. The SFP also includes descriptions of the planned injection well (MAG 1), planned monitoring well (MAG 2), and planned injection and storage/monitoring operations. A Blue Flint project SFP Regulatory Compliance Table (Appendix D) has been generated to provide a crosswalk of the specific application components addressing each permit requirement.

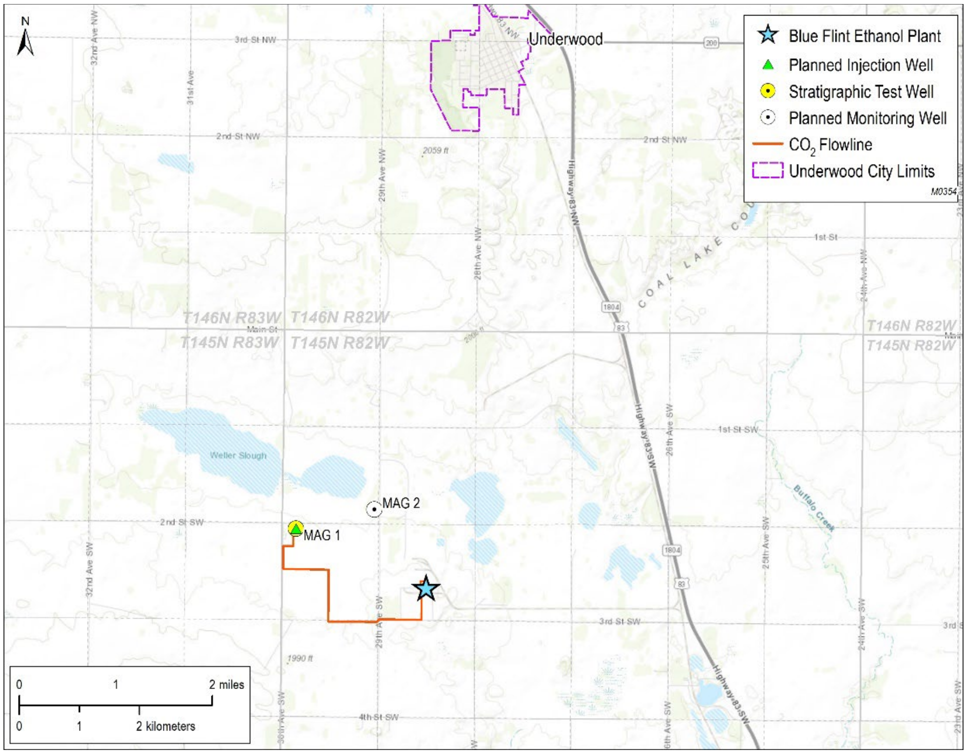

Figure PS-1. Location of the Blue Flint CO_2 storage project in relation to the city of Underwood, North Dakota.

1.0 PORE SPACE ACCESS

1.0 PORE SPACE ACCESS

North Dakota statute explicitly grants title to pore space in all strata underlying the surface of lands and waters to the owner of the overlying surface estate; i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] § 47-31-03). Prior to issuance of the SFP, the storage operator is mandated by North Dakota statute for geologic storage of CO_2 to obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir (NDCC § 38-22-08(5)). The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation (NDCC § 38-22-10). Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application. Surface access for any potential above ground activities is not included in pore space amalgamation.

Blue Flint has identified the surface and mineral estate owners within the horizontal boundaries of the Blue Flint CO_2 storage facility area. With the exception of coal extraction, no mineral lessees or operators of mineral extraction activities are within the facility area or within 0.5 miles (0.8 kilometers) of its outside boundary. Blue Flint will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made (NDCC §§ 38-22-06(3) and (4) and North Dakota Administrative Code [NDAC] §§ 43-05-01-08(1) and (2)).

All owners, lessees, and operators that require notification have been identified in accordance with North Dakota law, which vests the title to the pore space in all strata underlying the surface of lands and water to the owner of the overlying surface estate (NDCC § 47-31-03). The identification of pore space owners indicates that there was no severance of pore space or leasing of pore space to a third-party from the surface estate prior to 2009. All surface owners and pore space owners and lessees are the same owner of record.

A map showing the extent of the pore space that will be occupied by CO_2 over the life of the Blue Flint CO_2 storage project, including the storage reservoir boundary and 0.5 miles (0.8 kilometers) outside of the storage reservoir boundary with a description of pore space ownership, surface owner, and pore space lessees of record is illustrated in Figure 1-1.

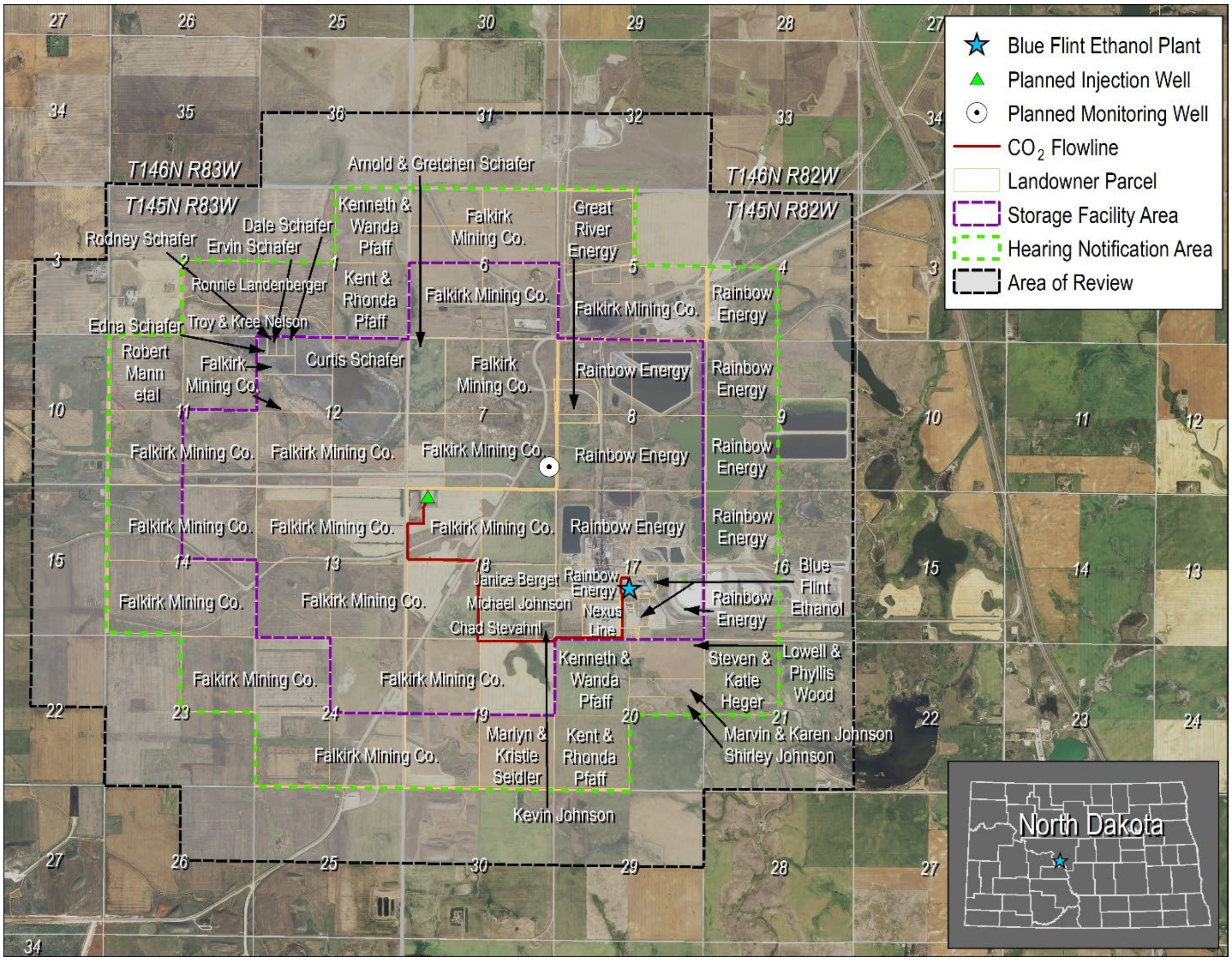

Figure 1-1. Storage facility area map showing pore space ownership.

2.0 GEOLOGIC EXHIBITS

2.0 GEOLOGIC EXHIBITS

2.1 Overview of Project Area Geology

The proposed Blue Flint CO_2 storage project will be situated near the BFE facility, located south of Underwood, North Dakota (Figure 2-1). This project site is on the eastern flank of the Williston Basin.

Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted via the Plains CO_2 Reduction (PCOR) Partnership, the Williston Basin has been identified as an excellent candidate for long-term CO_2 storage because of the thick sequence of clastic and carbonate sedimentary rocks and subtle structural character and tectonic stability of the basin (Peck and others, 2014; Glazewski and others, 2015).

The target CO_2 storage reservoir for the project is the Broom Creek Formation, a predominantly sandstone unit 4,708 ft below the surface at the MAG 1 stratigraphic test well location (Figure 2-1). Sixty-one feet of shales, siltstones, and interbedded evaporites of the undifferentiated Spearfish and Opeche Formations, hereinafter referred to as the Spearfish Formation, unconformably overlie the Broom Creek Formation. Eighty-seven feet of shales, siltstones, and anhydrites of the lower Piper Formation (undifferentiated Picard, Poe, and Dunham Members) overlie the Spearfish Formation. Together, the lower Piper and Spearfish Formations serve as the primary upper confining zone (Figure 2-2). The Amsden Formation (dolostone, limestone, anhydrite, and sandstone) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-2). Together, the lower Piper, Spearfish, Broom Creek, and Amsden Formations make up the CO_2 storage complex for the Blue Flint project (Table 2-1).

Including the Spearfish and lower Piper Formations, there is 859 ft (average thickness across the simulation area) of impermeable rock formations between the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. An additional 2,442 ft (average thickness across the simulation area) of impermeable rock formations separates the Inyan Kara Formation and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-2).

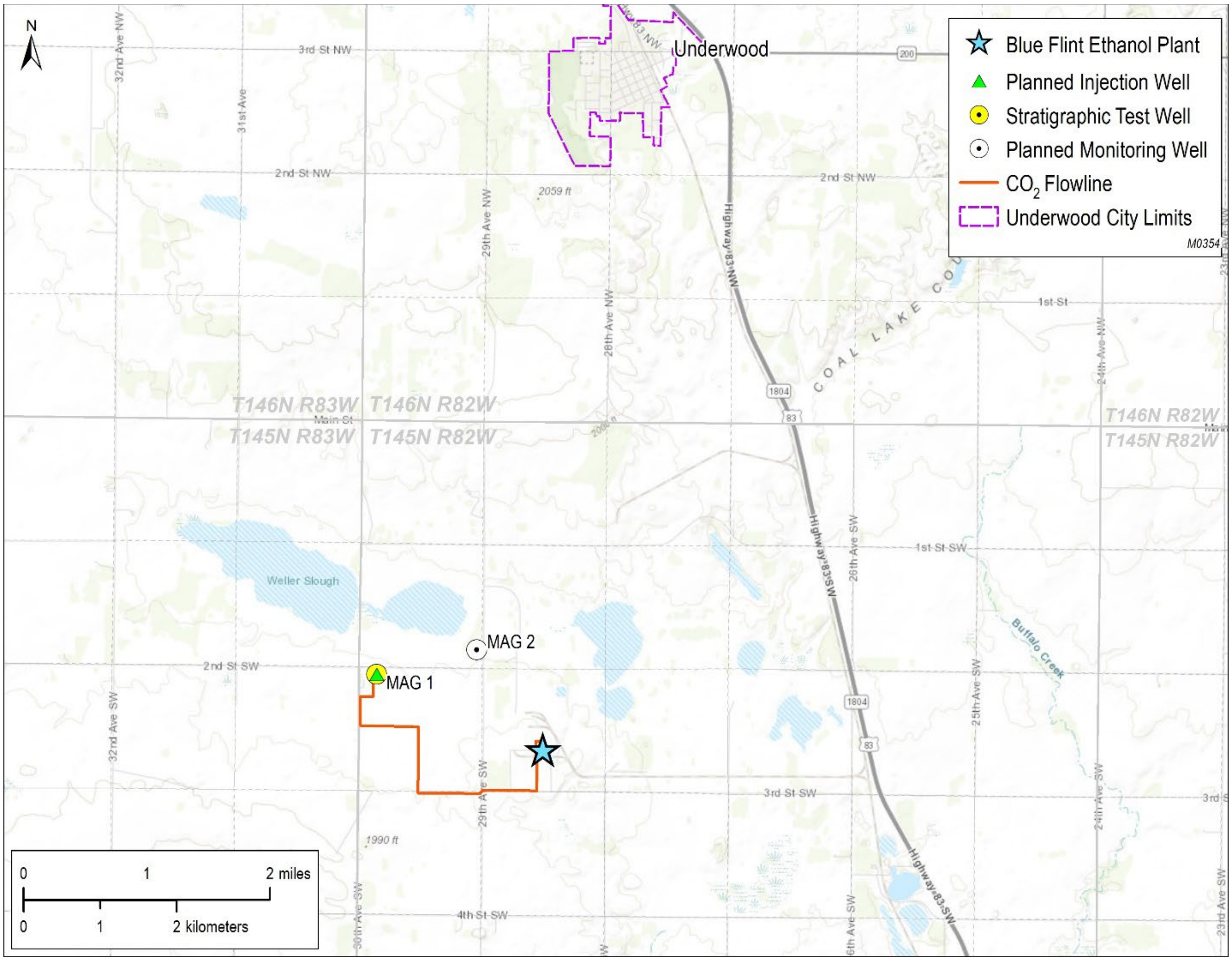

Figure 2-1. Topographic map of the project area showing the planned injection well, the planned monitoring well, and the BFE plant (blue star).

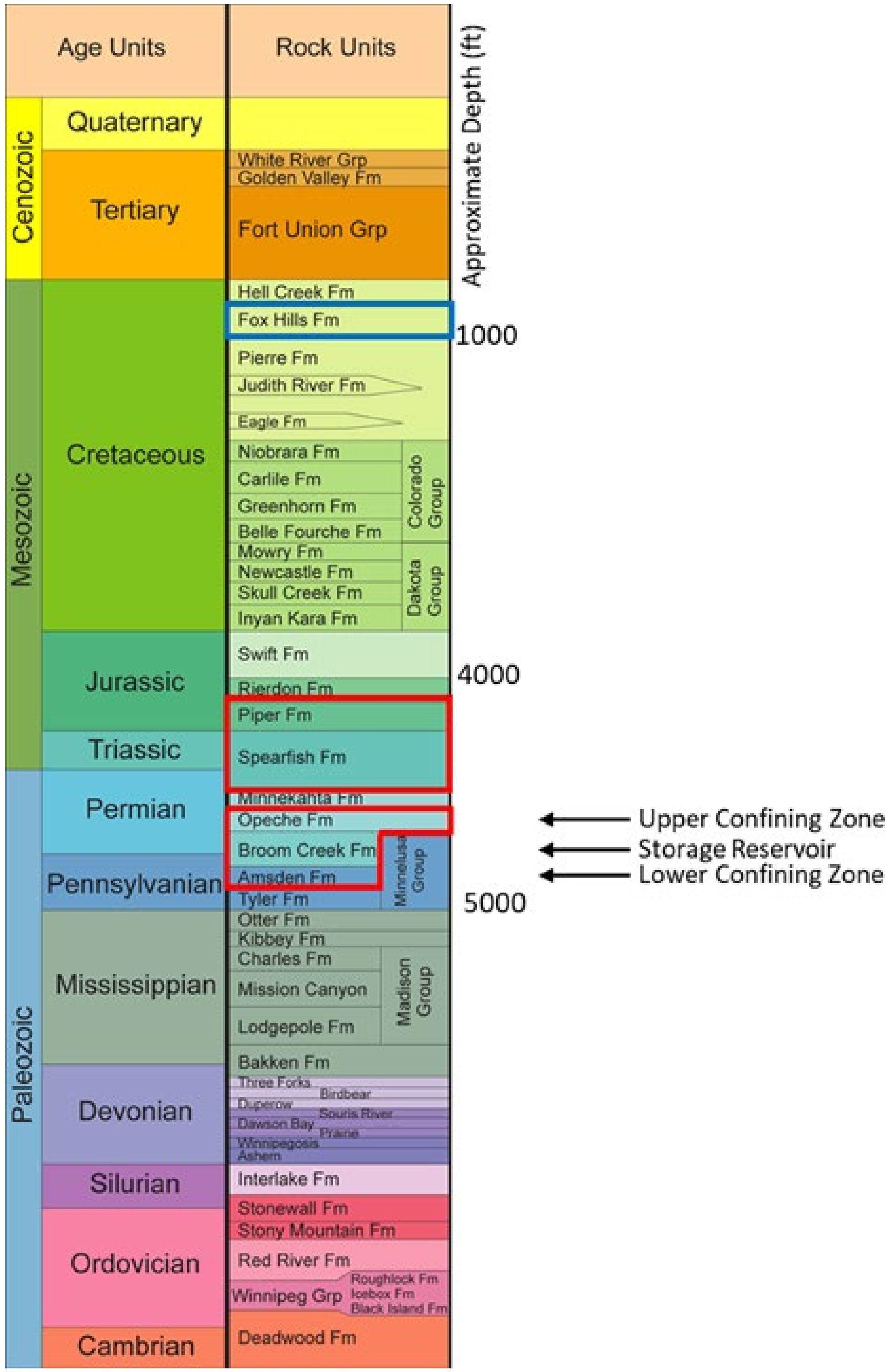

Figure 2-2. Stratigraphic column identifying the potential storage reservoirs and confining zones (outlined in red) and the lowest USDW (outlined in blue). The Minnekahta Formation is not present at this site.

Table 2-1. Formations Making up the Blue Flint CO_2 Storage Complex (average values calculated from the geologic model properties within simulation model area shown in Figure 2-3)

	Formation	Purpose	Average Thickness, ft	Average Depth, MD* ft	Lithology
Storage Complex	Lower Piper Formation	Upper confining zone	153	4,458	Shale/anhydrite/ siltstone
	Spearfish Formation	Upper confining zone	22	4,611	Shale/anhydrite/siltstone
	Broom Creek Formation	Storage reservoir (i.e., injection zone)	102	4,633	Sandstone/dolostone
	Amsden Formation	Lower confining zone	217	4,735	Dolostone/limestone/ anhydrite/sandstone

* Measured depth.

2.2 Data and Information Sources

Several sets of data were used to characterize the injection and confining zones to establish their suitability for the storage and containment of injected CO_2. Data sets used for characterization included both existing data (e.g., from published literature, publicly available databases, private data from brokers), and site-specific data acquired specifically to characterize the storage complex.

2.2.1 Existing Data

Existing data used to characterize the geology beneath the Blue Flint project site included publicly available well logs and formation top depths acquired from NDIC's online database. Well log data and interpreted formation top depths were acquired for 120 wellbores within the 5,500-square-mile (mi^2) area covered by the geologic model of the proposed storage site (Figure 2-3). Well data were used to characterize the depth, thickness, and extent of the subsurface geologic formations. Legacy 2D seismic data (70 miles) were licensed to characterize the subsurface geology in the project area and confirm the interpreted extent of the Broom Creek Formation (Figure 2-3).

Existing laboratory measurements for core samples from the Broom Creek Formation and its confining zones were available from four wells shown in Figure 2-4: Flemmer-1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), J-LOC1 (NDIC File No. 37380), and ANG 1 (Well No. ND-UIC-101) in addition to data from the site-specific stratigraphic test well, MAG 1 (NDIC File No. 37833). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and were integrated with newly acquired site-specific data.

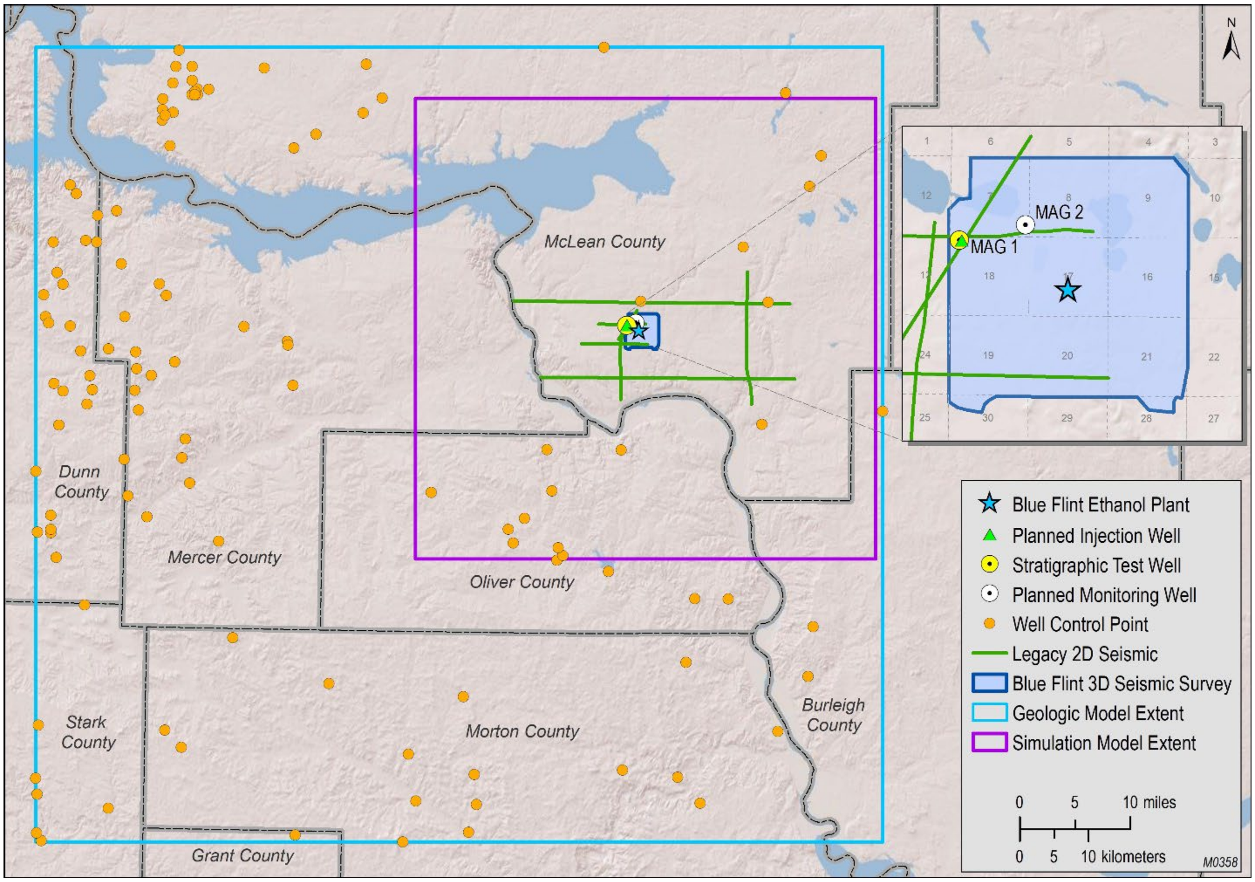

Figure 2-3. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones.

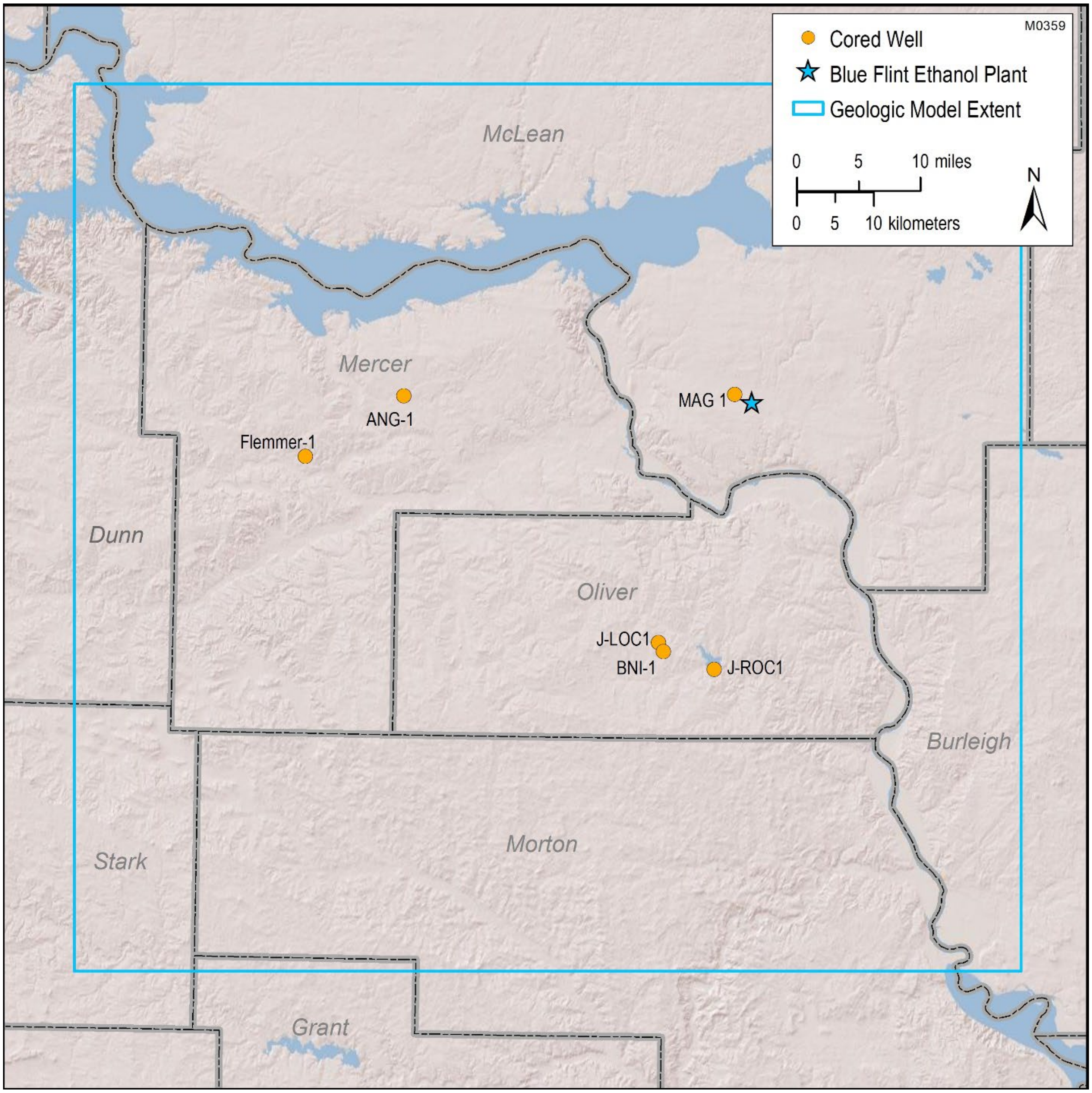

Figure 2-4. Map showing the spatial relationship between the Blue Flint project area and wells where the Broom Creek Formation core samples were collected. Wells with core data include the Flemmer-1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), ANG 1 (Well No. ND-UIC-101), J-LOC1(NDIC File No. 37380), and the MAG 1 (NDIC File No. 37833).

2.2.2 Site-Specific Data

Site-specific efforts to characterize the proposed storage complex generated multiple data sets, including geophysical well logs, petrophysical data, and 3D seismic data. The MAG 1 well was drilled in 2020 specifically to gather subsurface geologic data to support the development of a CO_2 storage facility permit and serve as a future CO_2 injection well. Downhole logs were acquired, and sidewall core (SW Core) was collected from the proposed storage complex (i.e., the Lower Piper, Spearfish, Broom Creek, and Amsden Formations) at the time the well was drilled (Figure 2-5). In May 2022, fluid samples and temperature and pressure measurements were collected from the Broom Creek in the MAG 1 well.

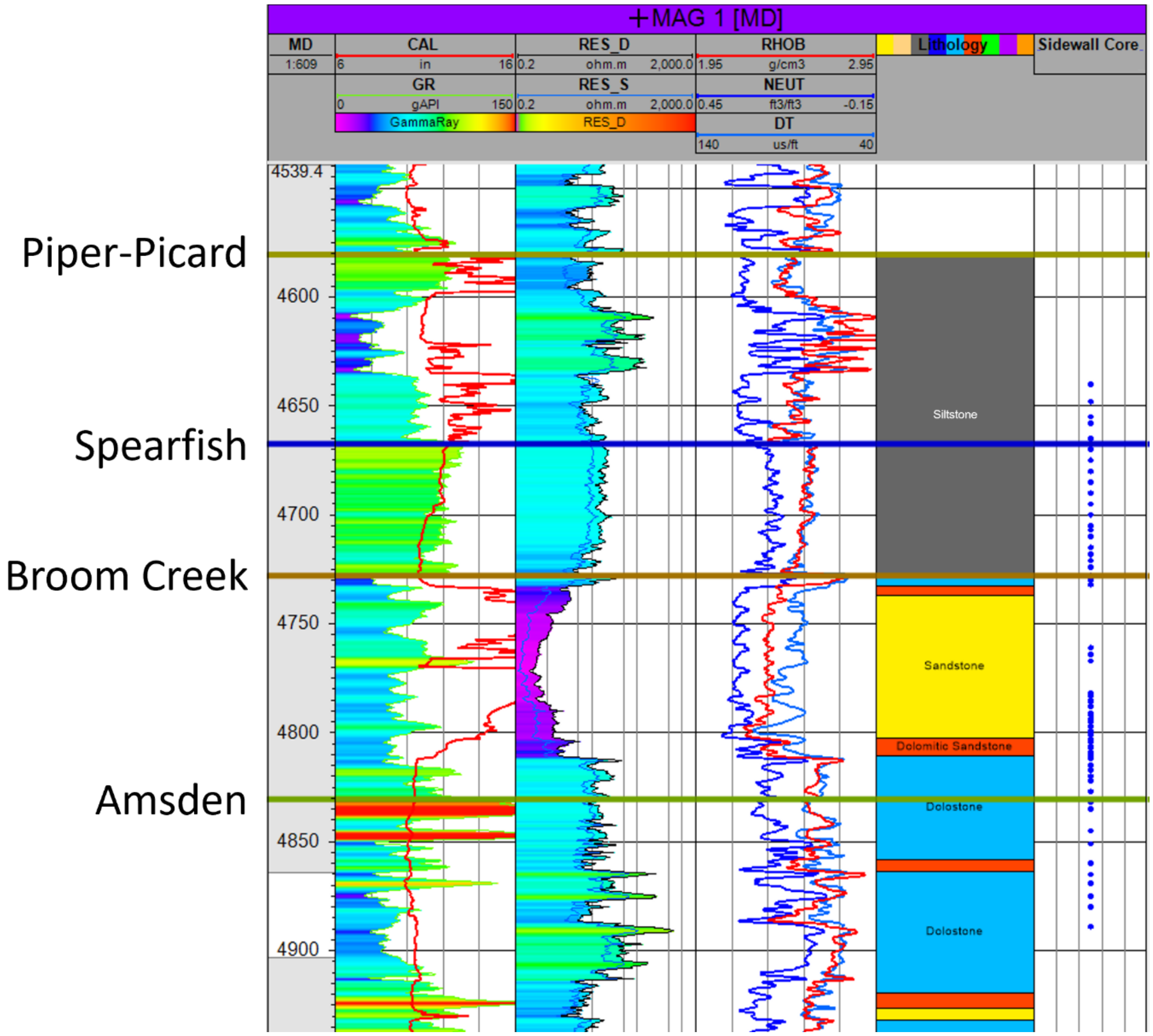

Figure 2-5. Well log display showing the vertical relationship of SW Core plugs taken from the Broom Creek Formation and confining zones. The 50 SW Core plugs are noted as blue circles on the far-right track. The Piper-Picard top denotes the top of the lower Piper Formation.

Site-specific and existing data were used to assess the suitability of the storage complex for safe and permanent storage of CO_2. Site-specific data were also used as inputs for geologic model construction (Section 3.2), numerical simulations of CO_2 injection (Section 3.3.1), geochemical simulation (Sections 2.3.3, 2.4.1.2, and 2.4.3.2), and geomechanical analysis (Section 2.4.4). The site-specific data improved the understanding of the subsurface and directly informed the selection of monitoring technologies, development of the timing and frequency of collecting monitoring data, and interpretation of monitoring data with respect to potential subsurface risks. Furthermore, these data guided and influenced the design and operation of site equipment and infrastructure.

2.2.2.1 Geophysical Well Logs

Openhole wireline geophysical well logs were acquired in the MAG 1 well across the proposed Broom Creek storage complex. The logging suite included caliper, spontaneous potential (SP), gamma ray (GR), density, porosity (neutron, density), dipole sonic, resistivity, and a full-bore formation microimager (FMI) log.

The acquired well logs were used to pick formation top depths and interpret lithology, petrophysical properties, and time-to-depth shifting of seismic data. Formation top depths were picked from the Fox Hills Formation to the Amsden Formation. The site-specific formation top depths were added to the existing data of the 120 wellbores within the 5,500-mi^2 area covered by the proposed storage site to understand the geologic extent, depth, and thickness of the subsurface geologic strata. Formation top depths of the lower Piper, Spearfish, Broom Creek, and Amsden Formations were interpolated to create structural surfaces which served as inputs for the 3D geologic model construction.

2.2.2.2 Core Sample Analyses

Fifty 1.5" SW Core samples were recovered from the Broom Creek storage complex in MAG 1: five samples from the lower Piper Formation, twelve from the Spearfish Formation, twenty-three from the Broom Creek Formation, and ten from the Amsden Formation. Forty-two of the SW Core samples were analyzed to determine petrophysical properties. This core was analyzed to characterize the lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations and correlated to the well log data. Core analysis also included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), thin-section analysis, and capillary entry pressure measurements. The results were used to inform geologic modeling and predictive simulation inputs and assumptions.

2.2.2.3 Formation Temperature and Pressure

Broom Creek Formation temperature and pressure measurements were collected from MAG 1 with a packer module. To collect a formation fluid sample, the Broom Creek Formation had to be perforated due to the cement sheath created while drilling out an extended cement plug in the lower portion of the wellbore. The Broom Creek Formation was perforated from 4,733 to 4,740 ft, and a packer was set at 4,096 ft with a tailpipe, dial sensor mandrel, and 4-ft perforated sub below the packer. Pressure and temperature sensors were set at depths of 4,735 and 4,741 ft, and the measurements recorded are shown in Tables 2-2 and 2-3. The calculated pressure and temperature gradients from MAG 1 were used to model the formation temperature and pressure profiles for use in the numerical simulations of CO_2 injection.

Table 2-2. Description of MAG 1 Temperature Measurements and Calculated Temperature Gradients

Formation	Sensor Depth, ft	Temperature, °F
Broom Creek	4,735	118.9
Broom Creek	4,741	118.6
Broom Creek Temperature Gradient, °F/ft	0.02*	

* The temperature gradient is the measured temperature minus the average annual surface temperature of 40°F, divided by the associated test depth.

Table 2-3. Description of MAG 1 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Sensor Depth, ft	Formation Pressure, psi
Broom Creek	4,735	2,427.00
Broom Creek	4,741	2,427.28
Mean Broom Creek Pressure, psi	2,427.14	
Broom Creek Pressure Gradient, psi/ft	0.50*	

* The pressure gradient is an average of the sensor-measured pressures minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.

2.2.2.4 Fluid Samples

A fluid sample from the Broom Creek Formation was collected from the MAG 1 wellbore by perforating an interval from 4,733 to 4,740 ft and then swabbing the well until formation fluid flowed back to surface for collection. Samples were analyzed by Minnesota Valley Testing Laboratories (MVTL), a state-certified lab, as well as the EERC. The salinity values from the MAG 1 samples are shown in Table 2-4. More detailed fluid sample analysis reports can be found in Appendix A. Fluid sample analysis results were used as inputs for geochemical modeling and dynamic reservoir simulations.

Table 2-4. Description of Fluid Sample Test and Corresponding Total Dissolved Solids (TDS) Value

Formation	Well	Test Depth, ft	MVTL TDS, mg/L	EERC Lab TDS, mg/L
Broom Creek	MAG 1	4,733–4,740	28,700	28,600

2.2.2.5 Seismic Survey

A 9- mi^2 3D seismic survey centered on the BFE facility was conducted December 2019 through January 2020 (Figure 2-6). The 3D seismic data allowed for visualization of deep geologic formations at lateral spatial intervals as short as tens of feet. The seismic data were used for assessment of the geologic structure and well placement.

Data products generated from the interpretation of the 3D seismic data were used as inputs into the geologic model that was used to simulate migration of the CO_2 plume. The 3D seismic data and MAG 1 well logs were used to interpret surfaces for the formations of interest within the survey area. These surfaces were converted to depth using the time-to-depth relationship derived from the MAG 1 dipole sonic log. The depth-converted surfaces for the storage reservoir and upper and lower confining zones were used as inputs for the geologic model. These surfaces captured detailed information about the structure and varying thickness of the formations between wells. A poststack inversion of the 3D seismic data was done using the MAG 1 well logs. Given the uncertainty in sonic log values related to washouts in the Broom Creek Formation in the MAG 1 well, indicated by the caliper log shown in Figure 2-5, inversion results of the 3D seismic data were not used to inform property distribution in the geologic model.

Interpretation of the 3D seismic data and legacy 2D seismic data suggests there are no major stratigraphic pinch-outs or structural features with associated spill points in the area of review. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were observed in the 2D and 3D seismic data in the area of review.

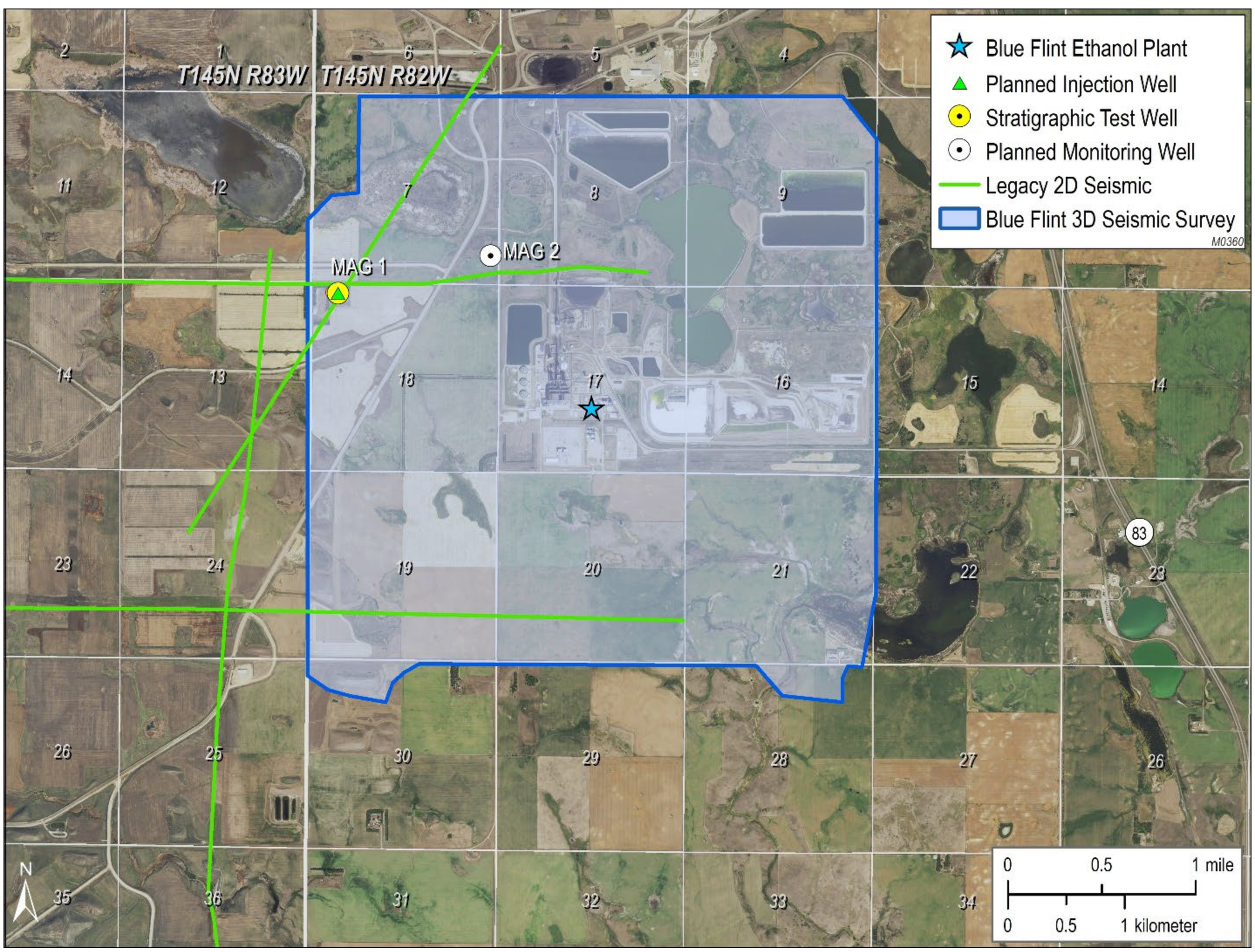

Figure 2-6. Map showing the 2D and 3D seismic surveys in the Blue Flint project area.

2.3 Storage Reservoir (injection zone)

Regionally, the Broom Creek Formation is laterally extensive in the storage facility area (Figure 2-7) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals), dolomitic sandstone, and dolostone layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by the Spearfish and the lower Piper Formation (Figure 2-2) (Murphy and others, 2009).

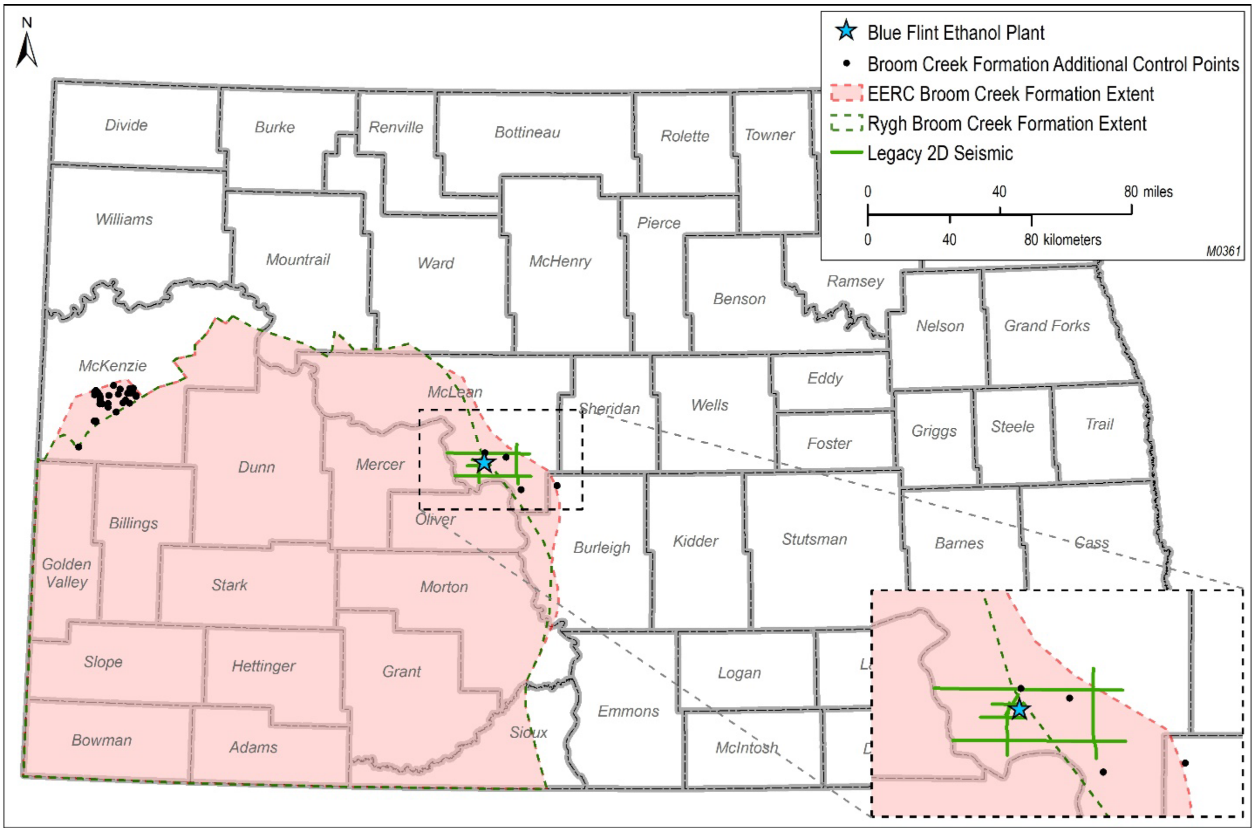

Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (red dashed line). This extent was modified from Rygh (1990) (green dashed line) based on new well control points shown outside of the green-dashed line. Legacy 2D seismic lines are depicted by green lines.

The top of the Broom Creek Formation is located at a depth of 4,708 ft below ground level at MAG 1 well and is made up of 66 ft of sandstone, 13 ft of dolomitic sandstone, and 24 ft of dolostone. Other wells within the simulation model extent show minor anhydrite intervals are also present in the Broom Creek Formation. Across the simulation model area, the Broom Creek Formation ranges in thickness from 0 to 313 ft (Figure 2-8), with an average thickness of 102.5 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 0 to 262 ft, with an average thickness of 63 ft. Although the Broom Creek Formation does pinch out in the simulation model area, the 2D and 3D seismic data suggest there are no major stratigraphic pinch-outs in the Broom Creek Formation in

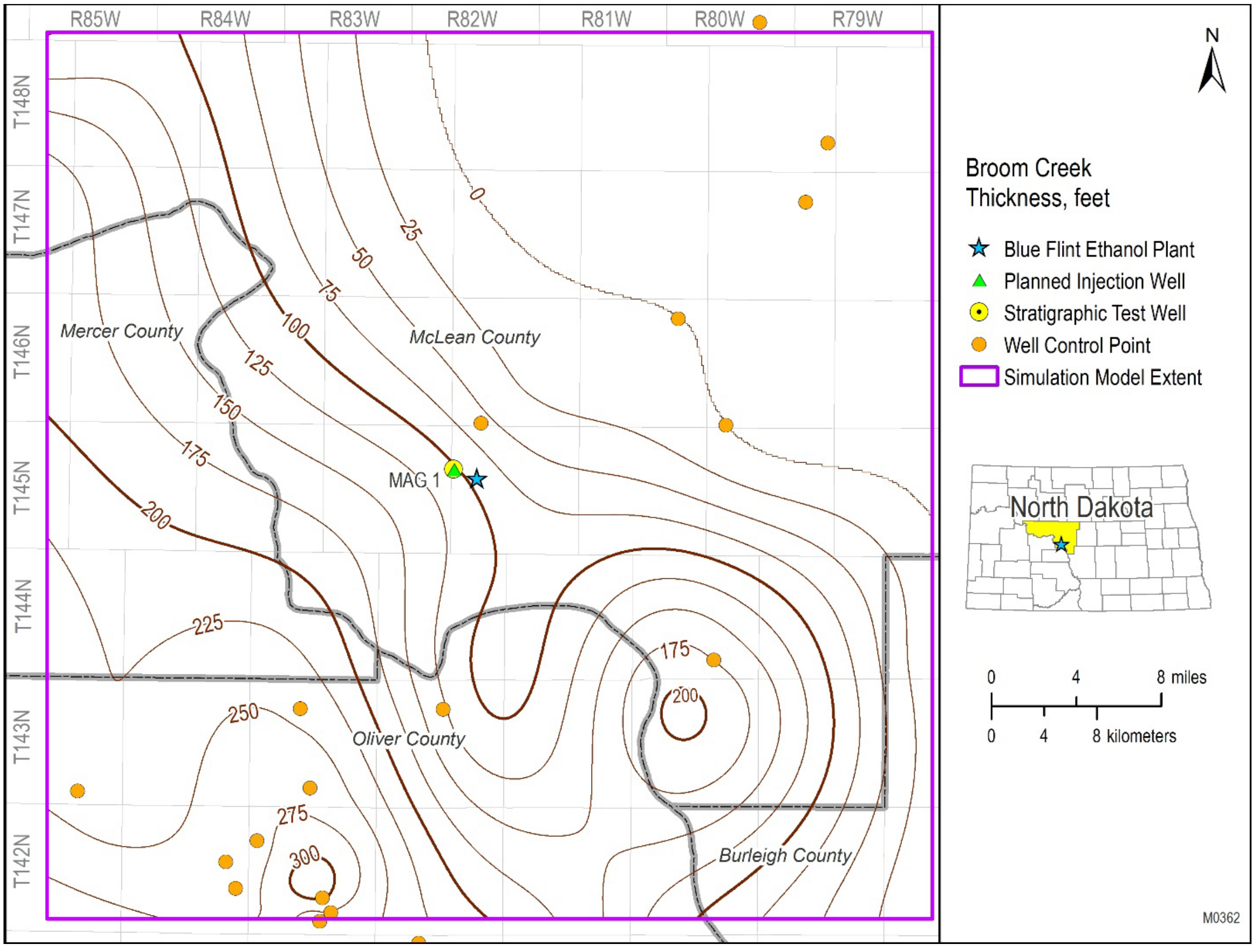

Figure 2-8. Isopach map of the Broom Creek Formation in the greater Blue Flint project area. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

the storage facility area. The thickness of the Broom Creek Formation at the MAG 1 well is 103 ft. The 2D seismic data and well log interpolation suggest the Broom Creek Formation pinches out 10–15 miles to the east of the MAG 1 well (Figure 2-7).

The top of the Broom Creek Formation was picked across the project area based on the stratigraphic transition from a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation to a relatively high GR signature representing the siltstones of the Spearfish Formation (Figure 2-9). This transition is also noted with a drop in bulk density (RHOB) and compressional sonic values (DT) and an increase in neutron porosity (NPHI) and resistivity (LLD, LLS). The top of the Amsden Formation was placed at the top of a relatively high GR package representing the transition between argillaceous dolostone and the sandstones of the Broom Creek Formation that can be correlated across the project area. Seismic data collected as part of site characterization efforts (Figure 2-10) were used to reinforce structural correlation and

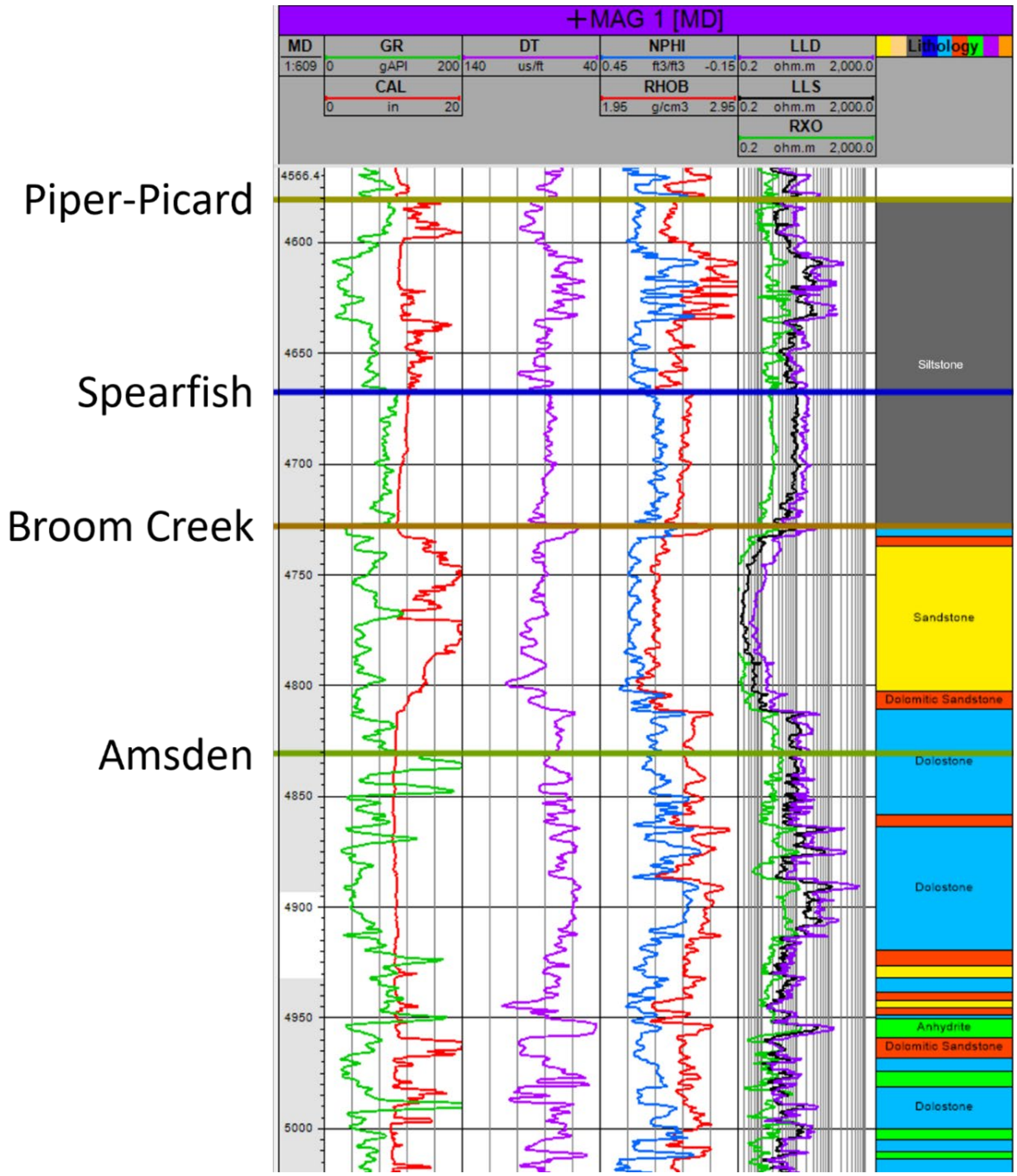

Figure 2-9. Well log display of the interpreted lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations in MAG 1.

thickness estimations of the storage reservoir. The combined structural correlation and seismic interpretation indicate that the formation is continuous across the area near MAG 1 (Figure 2-10 and 2-11). This stratigraphic pinch out of the Broom Creek Formation to the east shows the formation pinching out into the overlying Piper-Picard and the underlying Amsden formations (Figure 2-10 and 2-11). The siltstones of the Piper-Picard and dolostones of the Amsden formation act as a lateral seal where the Broom Creek pinches out. A structure map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figures 2-12 and 2-13).

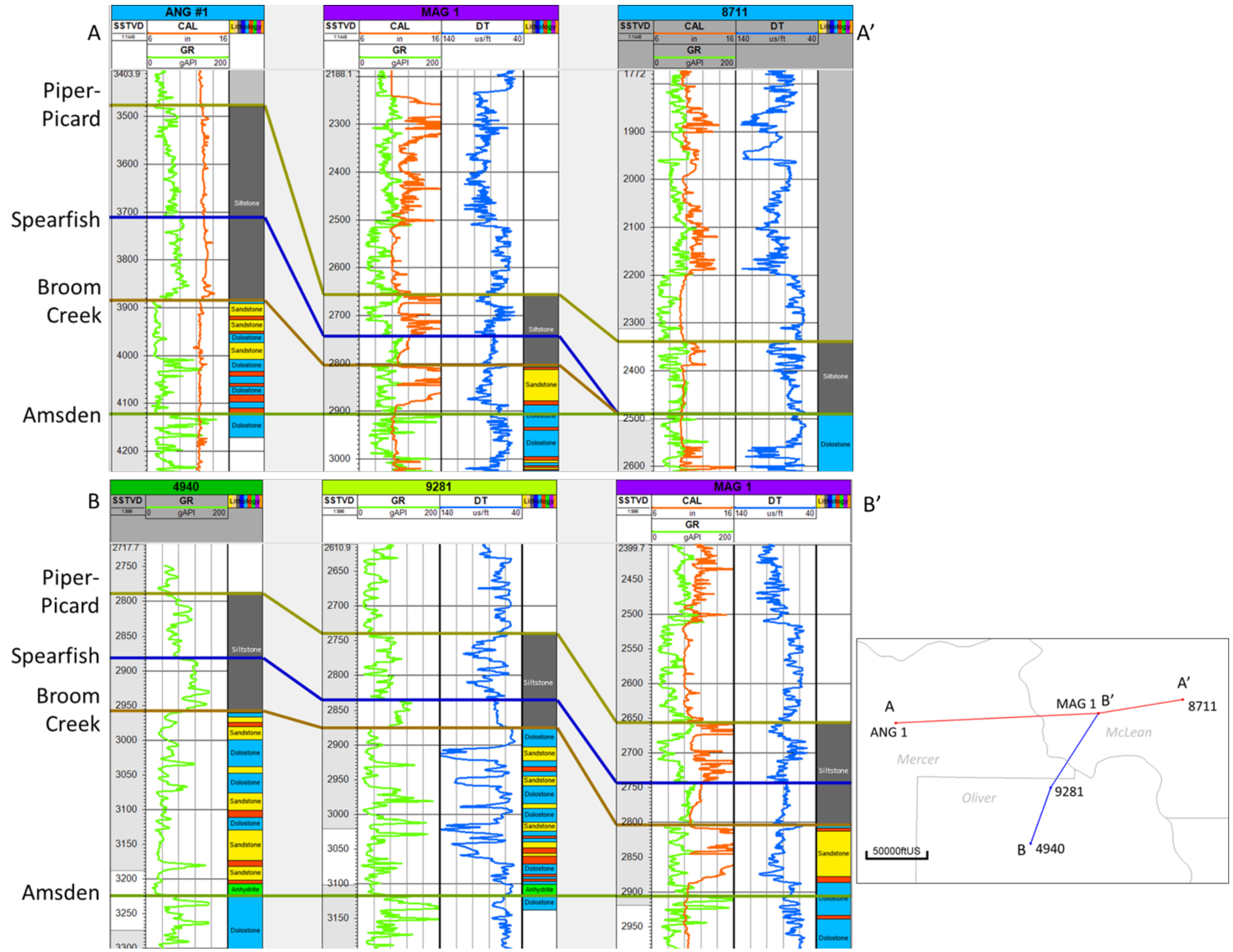

Figure 2-10. Regional well log stratigraphic cross sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) interpreted lithology log. The different depth scales are used between AA' and BB' for image display purposes.

Note: Wells in these cross sections are spaced evenly. These figures do not portray the relative distance between wells. Because of the spacing, structure may appear more drastic than it actually is.

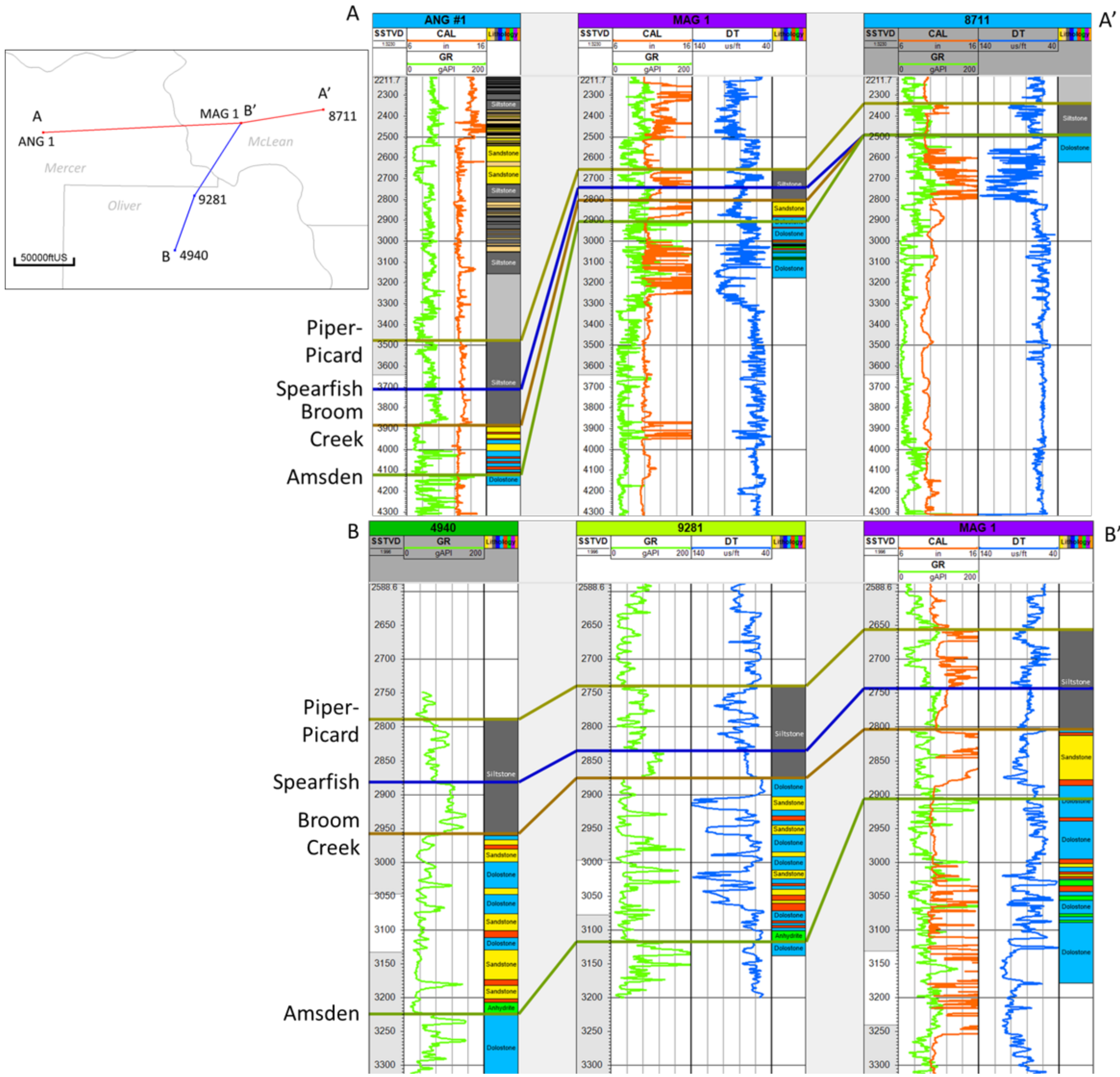

Figure 2-11. Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. Displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) interpreted lithology log. The different depth scales are used between AA' and BB' for image display purposes.

Note: Wells in these cross sections are spaced evenly. These figures do not portray the relative distance between wells. Because of the spacing, structure may appear more drastic than it actually is.

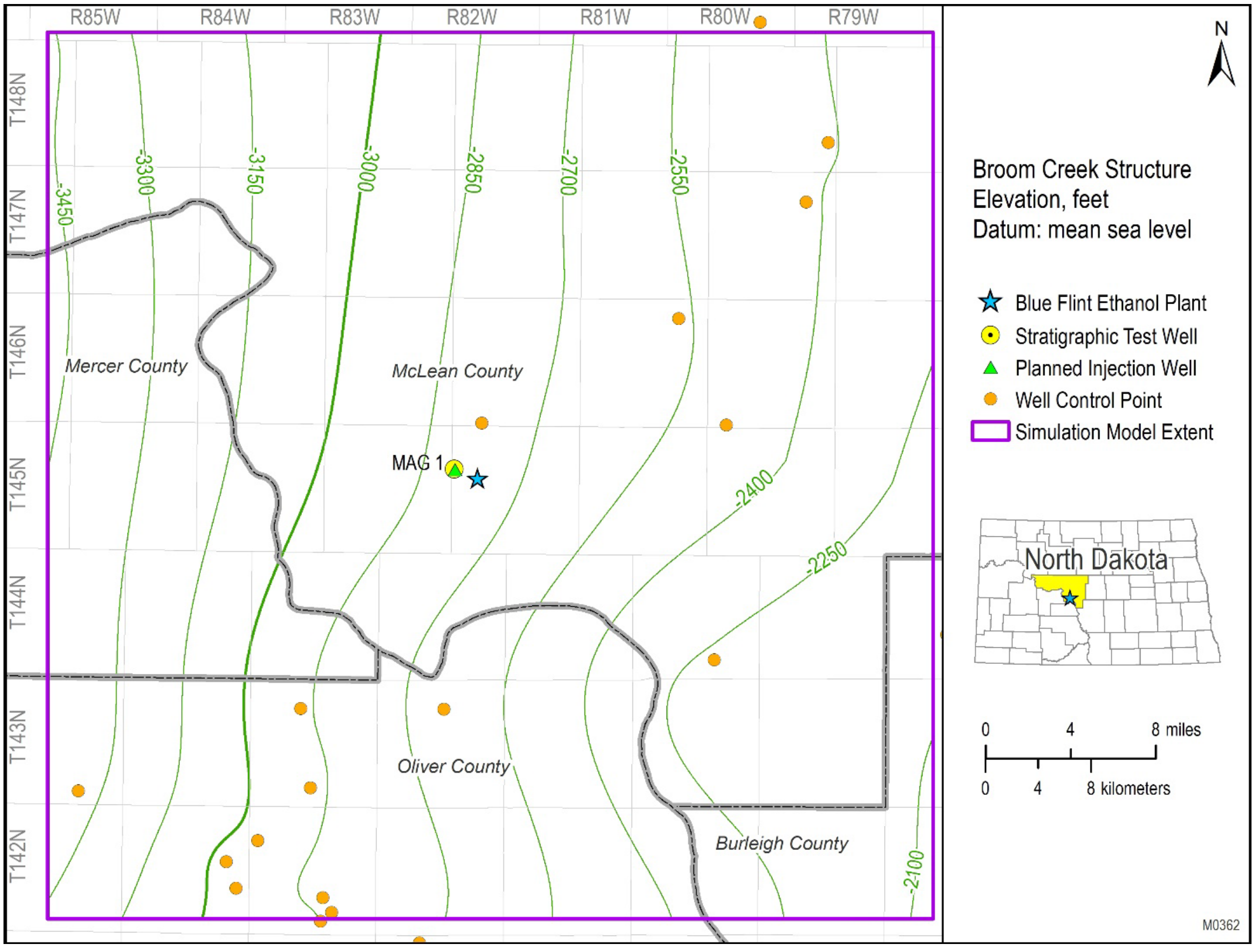

Figure 2-12. Structure map of the Broom Creek Formation across the greater Blue Flint project area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

Eighteen of the 1.5-in. SW Core plugs collected from the Broom Creek Formation were sampled and used to determine the distribution of porosity and permeability values throughout the formation (Table 2-5 and Figure 2-14). All but four samples were successfully tested in the lab. Some of the samples tested were fractured or chipped which could have resulted in optimistic porosity and/or permeability measurements. The range in porosity and permeability predominantly captures the sandstone variability as this rock type was prominent in the sampling program.

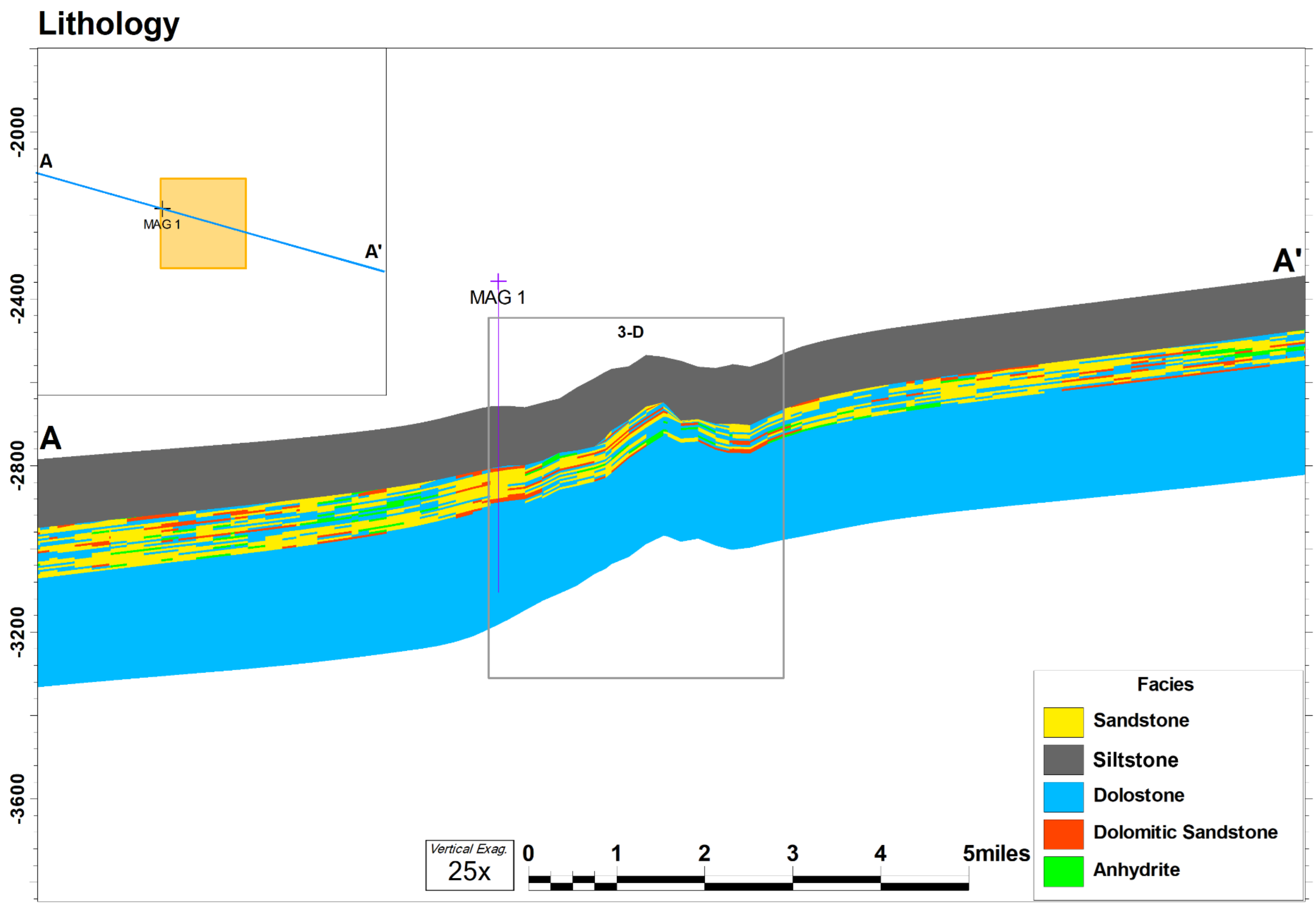

Figure 2-13. Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level.

Table 2-5. Description of CO_2 Storage Reservoir (injection zone) at the MAG 1 Well

Injection Zone Properties	
Property	**Description**
Formation Name	Broom Creek
Lithology	Sandstone, dolomitic sandstone, dolostone
Formation Top Depth, ft	4,708
Thickness, ft	103 (sandstone 66, dolomitic sandstone 13, dolostone 24)
Capillary Entry Pressure (brine/CO_2), psi	0.866

Geologic Properties			
Formation	**Property**	**Laboratory Analysis**	**Simulation Model Property Distribution**
Broom Creek (sandstone)	Porosity, %*	24.12 (21.42–27.80)	19.15 (0.0–36.00)
	Permeability, mD**	298.16 (140.70–929.84)	132.83 (0–3237.4)
Broom Creek (dolomitic sandstone)	Porosity, %*	20.85 (16.13–23.83)	15.87 (1.0–29.25)
	Permeability, mD**	81.91 (16.40–257.00)	50.13 (0–650.70)
Broom Creek (dolostone)	Porosity, %*	10.50 (5.83–15.91)	7.85 (0.0–24.65)
	Permeability, mD**	1.01 (0.01–178.60)	0.76 (0.0–519.32)

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses. Values measured at 2,400 psi.

** Permeability values are reported as the geometric mean followed by the range of values in parentheses. Values measured at 2,400 psi.

Core-derived measurements from MAG 1 were used as the foundation for the generation of porosity and permeability properties within the 3D geologic model. The SW Core plug sample measurements showed good agreement with the simulation model property distribution at the location of MAG 1. This agreement gave confidence to the geologic model, which is a spatially and computationally larger data set created with the extrapolation of porosity and permeability from offset well logs. The simulation model property distribution statistics shown in Table 2-5 are derived from a combination of the SW Core plug analysis and the larger data set derived from offset well logs.

Sandstone intervals in the Broom Creek Formation are associated with low GR, low density, high porosity (neutron, density, and sonic), low resistivity due to brine salinity, and high sonic slowness measurements. The dolostone intervals in the formation are associated with an increase in GR measurements compared to the sandstone intervals, in addition to high density, low porosity (neutron, density, and sonic), high resistivity, and low sonic slowness measurements. The dolomitic sandstone intervals in the formation are the transitions between sandstone and dolostone, where the porosity begins to decrease and density beings to increase in a transition from predominantly sandstone to dolostone (Figure 2-9).

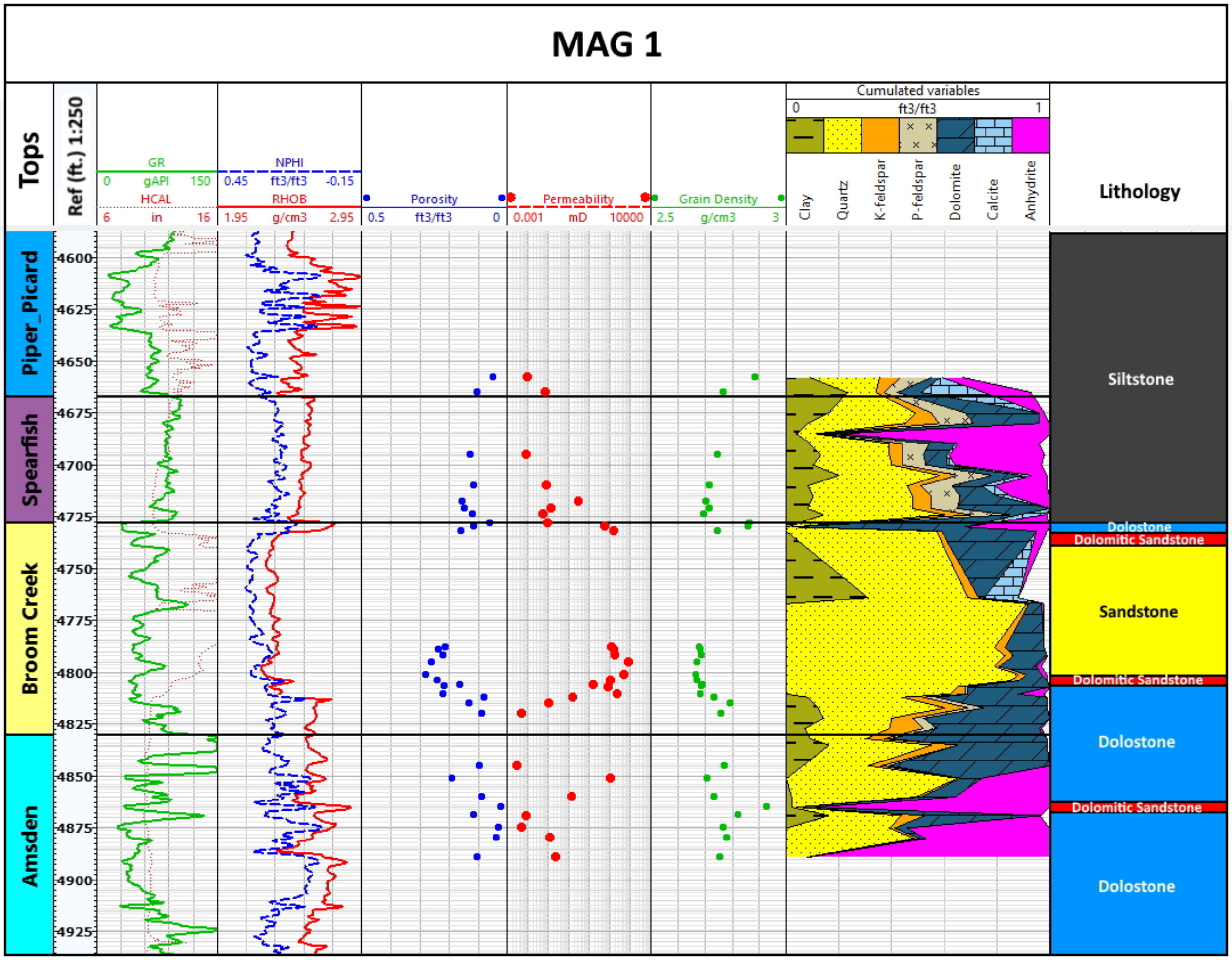

Figure 2-14. Vertical distribution of core-derived porosity and permeability values and the laboratory-derived mineralogic characteristics in the Blue Flint storage complex from MAG 1. Logs displayed in tracks from left to right are 1) formation designation, 2) measured depth track, 3) GR and caliper, 4) neutron and density, 5) core porosity, 6) core permeability, 7) core grain density, 6) XRD mineralogic characteristics, and 7) facies designation.

2.3.1 Mineralogy

Thin-section analysis of Broom Creek shows that quartz, dolomite, anhydrite, and clay (mainly illite/muscovite) are the dominant minerals. Throughout these intervals are the occurrence of feldspar (mainly K-feldspar) and iron oxide. Anhydrite obstructs the intercrystalline porosity in the upper part of the formation and dolomite in the middle and lower parts. The contact between grains is tangential. The porosity is due to the dissolution of anhydrite in the upper part and the dissolution of quartz and feldspar in the middle and lower parts. Figures 2-15, 2-16, and 2-17 show thin-section images representative of the upper, middle, and lower Broom Creek Formation.

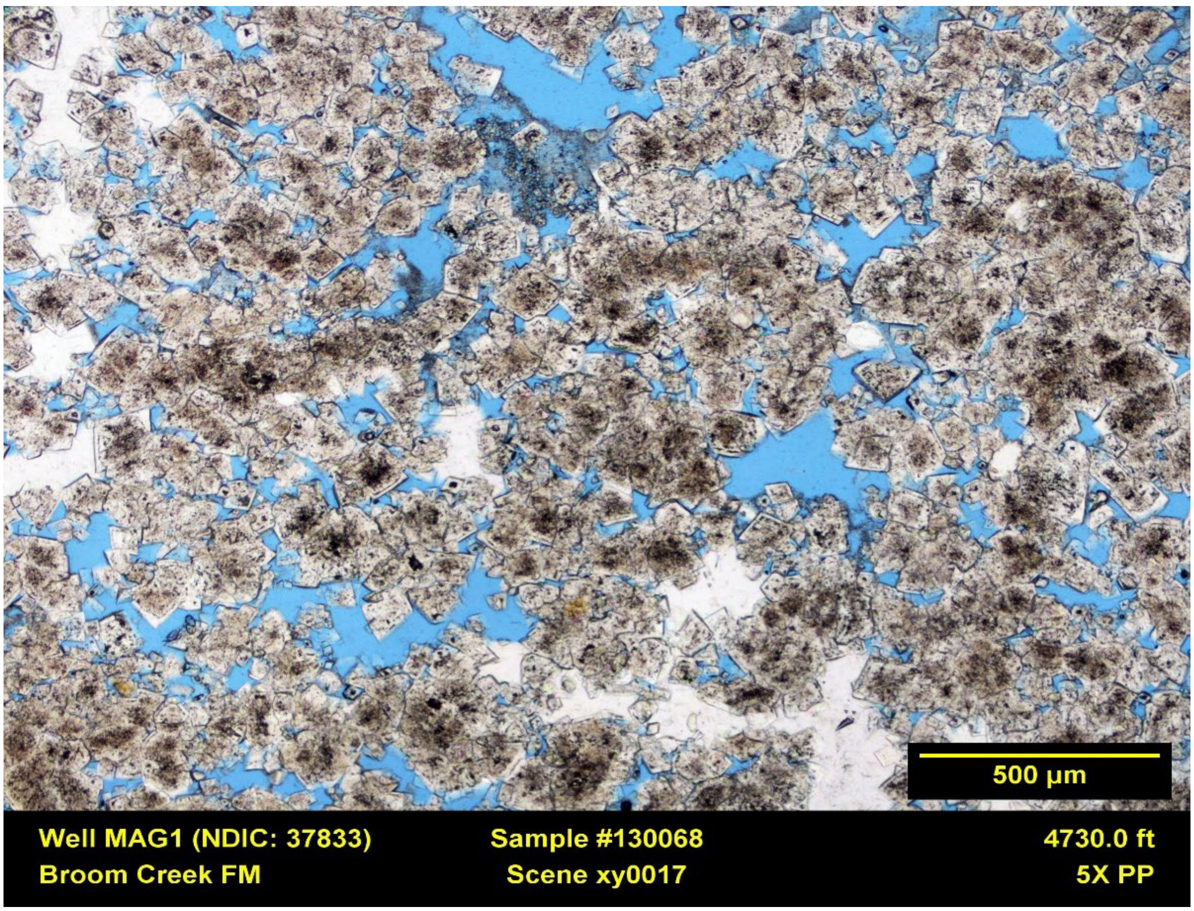

Figure 2-15. Thin section in upper Broom Creek Formation. This interval is primarily dolomite (gray) with anhydritic cement.

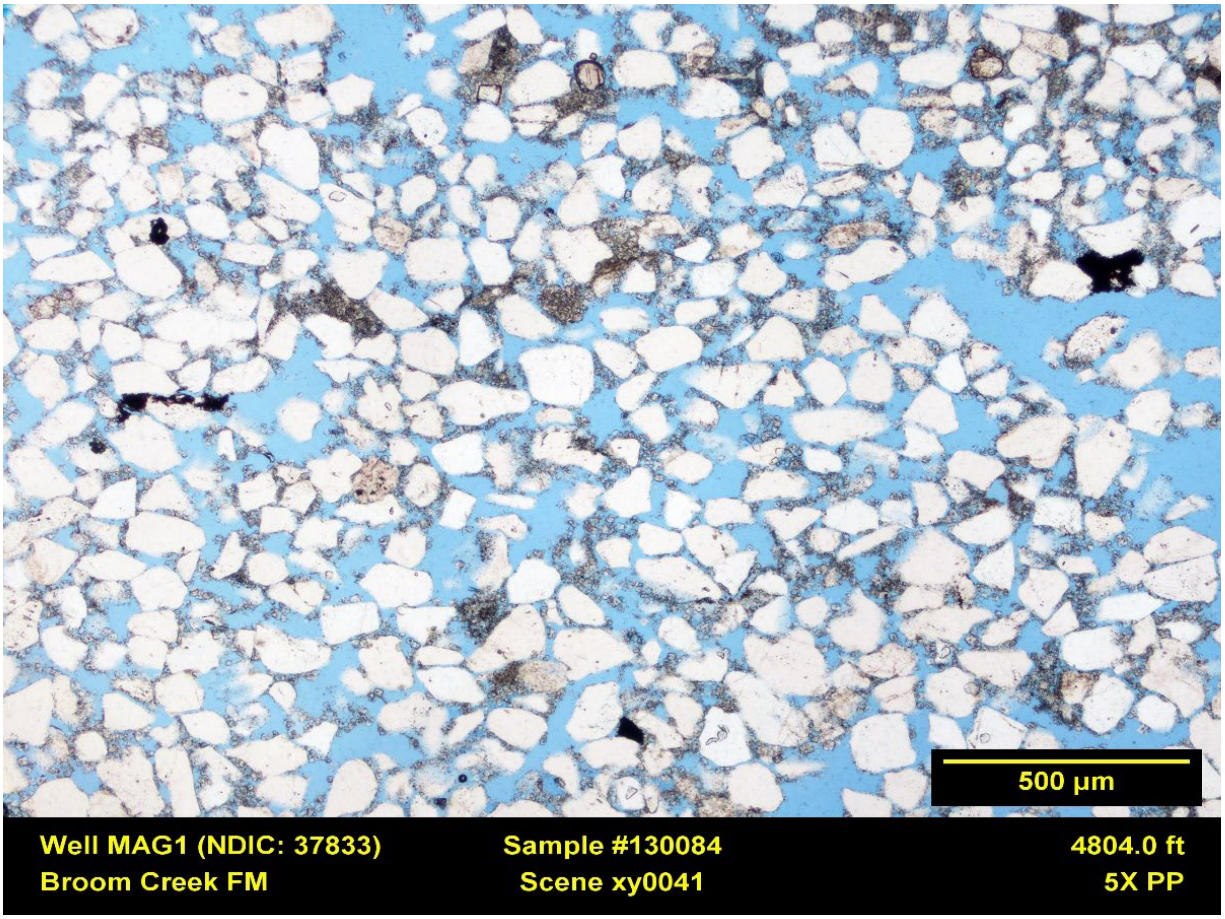

Figure 2-16. Thin section in middle Broom Creek Formation. This interval is dominated by fine-grained quartz and minor dolomite. Porosity is high in this interval.

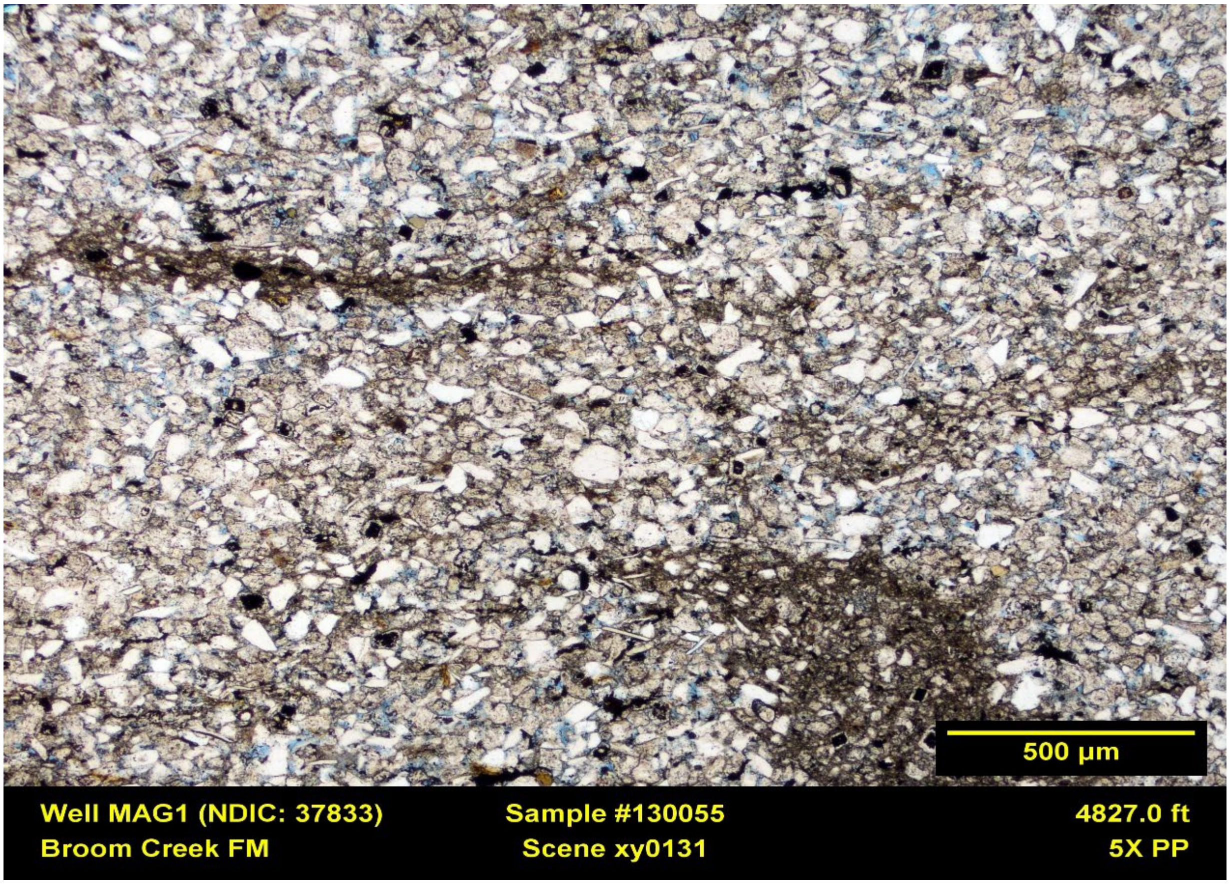

Figure 2-17. Thin section in lower Broom Creek Formation. This interval is a laminated silty mudstone. The matrix is dominated by clay and quartz.

XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation mainly comprises quartz, dolomite, clay, and anhydrite (Table 2-6). XRF data are shown in Figure 2-18 for the Broom Creek Formation.

Table 2-6. XRD Analysis in the Broom Creek Reservoir from MAG 1. Only major constituents are shown.

Sample Name	STAR No.	Depth, feet	% Clay	% K-Feldspar	% P-Feldspar	% Quartz	% Calcite	% Dolomite	% Ankerite	% Anhydrite	% Halite
Broom Creek	130068	4,730	0.0	0.0	0.0	1.5	0.0	65.9	0.0	32.3	0.2
Broom Creek	130067	4,732	0.0	2.2	0.0	56.8	0.0	36.2	0.0	3.9	0.9
Broom Creek	130066	4,764	31.5	3.9	0.0	38.1	12.9	2.4	0.0	0.0	5.9
Broom Creek	130065	4,767	0.0	1.4	0.0	91.0	0.0	4.9	0.0	1.2	1.5
Broom Creek	130064	4,788	0.0	3.8	0.0	78.8	0.0	15.3	0.0	0.0	1.0
Broom Creek	130088	4,792	0.0	3.2	0.0	82.6	0.0	13.1	0.0	0.2	0.8
Broom Creek	130063	4,797	0.0	2.3	0.0	79.4	0.0	13.9	0.5	2.3	1.6
Broom Creek	130085	4,801	0.0	3.1	0.0	87.8	0.0	6.4	0.0	1.7	1.0
Broom Creek	130084	4,804	0.0	3.1	0.0	85.2	0.0	10.5	0.0	0.0	1.2
Broom Creek	130083	4,807	0.0	3.1	0.7	64.7	0.0	30.6	0.0	0.0	0.9
Broom Creek	130082	4,810.5	0.5	6.2	0.9	62.4	0.0	18.6	0.0	9.6	1.4
Broom Creek	130060	4,812	7.8	8.4	4.7	36.5	0.0	42.1	0.0	0.0	0.2
Broom Creek	130058	4,817	12.2	9.4	5.6	48.0	0.0	23.9	0.0	0.0	0.4
Broom Creek	130056	4,822	13.8	7.5	4.4	26.1	0.0	47.5	0.0	0.0	0.4
Broom Creek	130055	4,827	7.2	12.8	4.7	32.2	0.0	39.4	0.0	0.6	0.5

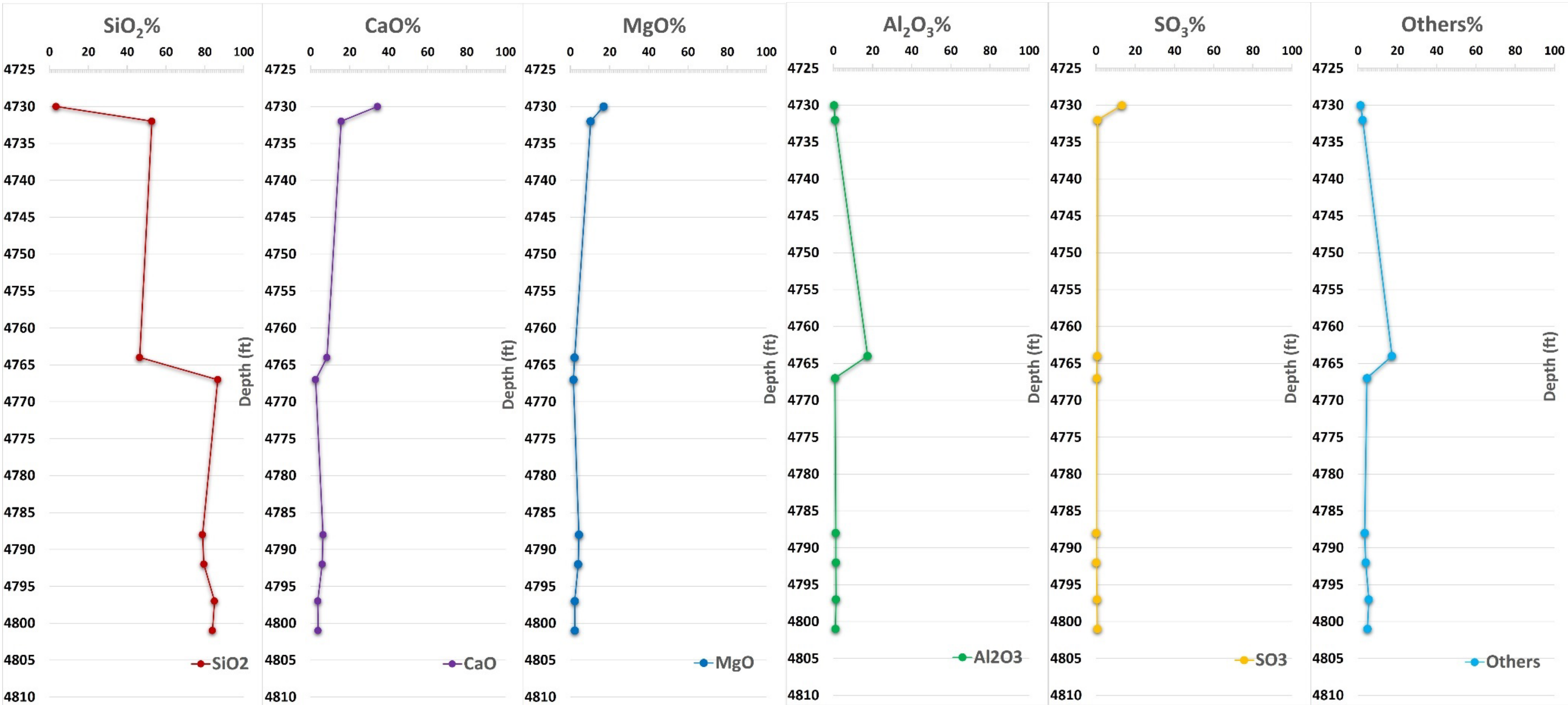

Figure 2-18. XRF analysis in Broom Creek Formation from MAG 1.

2.3.2 Mechanism of Geologic Confinement

For the Blue Flint project area, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the upper confining formations (Spearfish Formation and the lower Piper Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure. Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), confining the CO_2 within the proposed storage reservoir. After injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation; therefore, this process is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.

2.3.3 Geochemical Information of Injection Zone

Geochemical simulation has been performed to calculate the effects of introducing the CO_2 stream to the injection zone.

The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package GEM. GEM is also the primary simulation software used for evaluation of the reservoir's dynamic behavior resulting from the expected CO_2 injection. For this geochemical modeling study, the injection scenario consisted of a single injection well injecting for a 20-year period with maximum BHP (bottomhole pressure) and maximum gas injection rate (STG, surface gas rate) constraints of 2,970 psi and 200,000 tonnes per year (tpy), respectively. A postinjection period of 25 years was run in the model to evaluate any dynamic behavior and/or geochemical reaction after the CO_2 injection is stopped. The injection stream consists of mostly CO_2 (>99.98%) and some minor components (Table 2-7). For simulation, 100% CO_2 was assumed as the injection stream is mostly CO_2 (>99.98%) This geochemical scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared (Figure 2-19 and Figure 2-20).

The scenario with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (80% of bulk reservoir volume) and average formation brine composition (20% of bulk reservoir volume). XRD data from the 15 Broom Creek formation core samples were used to inform the mineralogical composition of the Broom Creek Formation (Table 2-8). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Reported ionic composition of the Broom Creek Formation water is listed in Table 2-9.

Table 2-7. Injection Stream Composition

Component	Mole Percentage, %
Carbon Dioxide	99.983861
Water	0.001123
Oxygen	0.001
Nitrogen	0.000094
Methane	0.000001
Acetaldehyde	0.004008
Hydrogen Sulfide	0.000283
Dimethyl Sulfide	0.000095
Ethyl Acetate	0.001527
Isopentyl Acetate	0.000191
Methanol	0.002395
Ethanol	0.005041
Acetone	0.000095
n-Propanol	0.000095
n-Butanol	0.000191

Table 2-8. XRD Results for MAG 1 Broom Creek Core Sample

Mineral Data	%
Illite	5
K-Feldspar	4.83
Albite	1.43
Quartz	59.74
Dolomite	25.44
Anhydrite	3.56

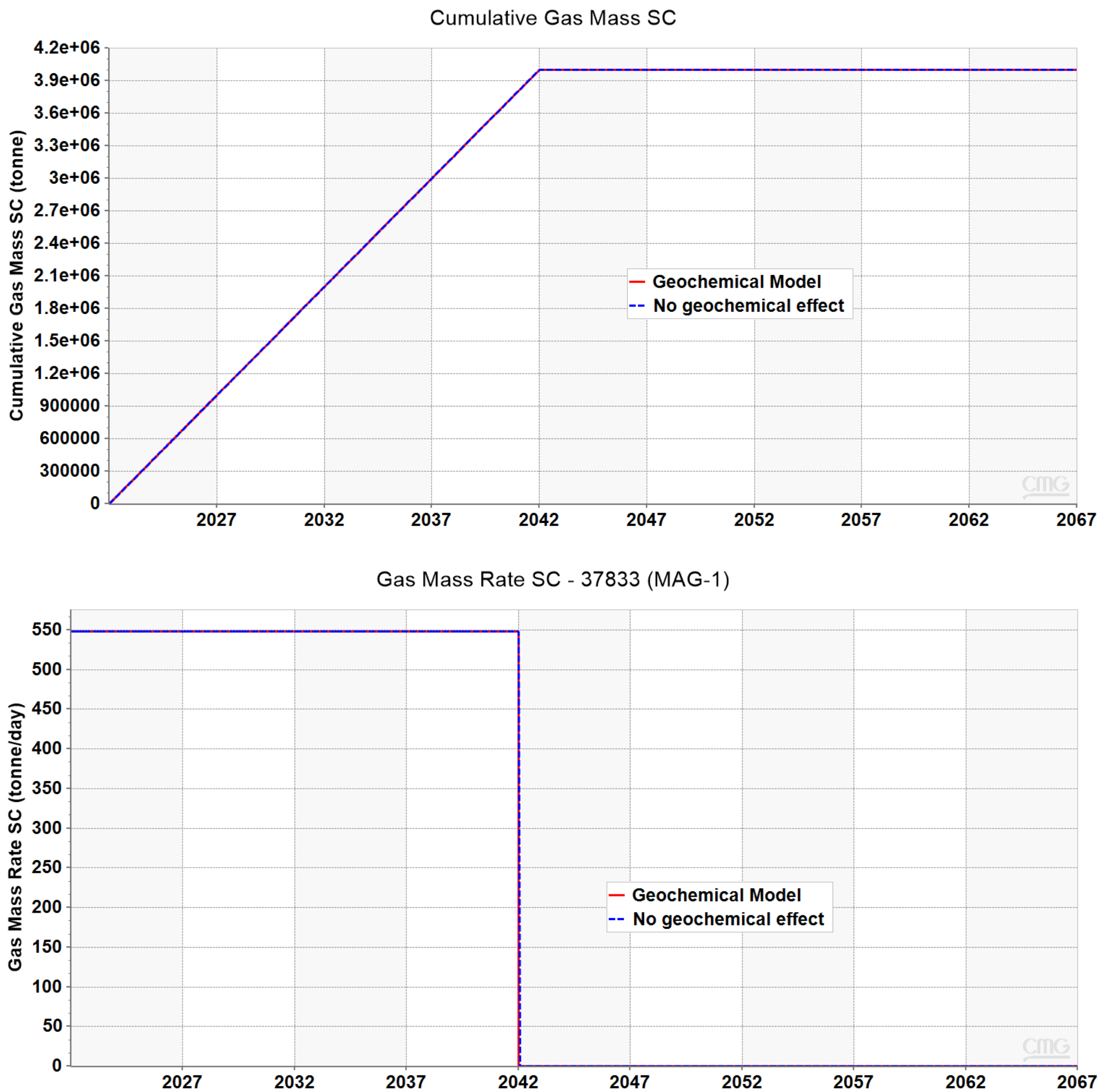

Figure 2-19. Upper graph shows cumulative injection vs. time; the bottom figure shows the gas injection rate vs. time. There is no observable difference in injection due to geochemical reactions.

Figure 2-20. Upper graph shows wellhead pressure vs. time; the bottom figure shows the bottomhole pressure vs. time. There is no observable difference in pressures due to geochemical reactions.

Table 2-9. Broom Creek Water Ionic Composition, expressed in molality

Component	mg/L	Molality
CO_3^{2-}	0.61	0.000001
Ca^{2+}	823	0.020204
Mg^{2+}	187	0.00757
K^+	90.9	0.0022876
Na^+	9020	0.386022
H^+	3.3E-05	3.2E-08
SO_4^{2-}	7350	0.0752816
Al^{3+}	3.00E-06	1E-10
Cl^-	11600	0.3218884
HCO_3^-	249	0.00401522
OH^-	0.025743	1.49E-06
TDS	28600	N/A

Figure 2-21 shows the concentration of CO_2, in molality, in the reservoir after 20 years of injection plus 25 years of postinjection for the geochemistry model case, and Figure 2-22 shows the same information for the nongeochemistry model for comparisons. The results do not show an evident difference in the CO_2 gas molality fraction between both cases as seen in the previous figures for volume injected and injection pressure simulation results.

The pH of the reservoir brine changes in the vicinity of the CO_2 accumulation, as shown in Figure 2-23. The pH of the Broom Creek native brine sample is 7.48 whereas the fluid pH goes down to approximately 5.17 in the CO_2-flooded areas as a result of CO_2 dissolution in the brine.

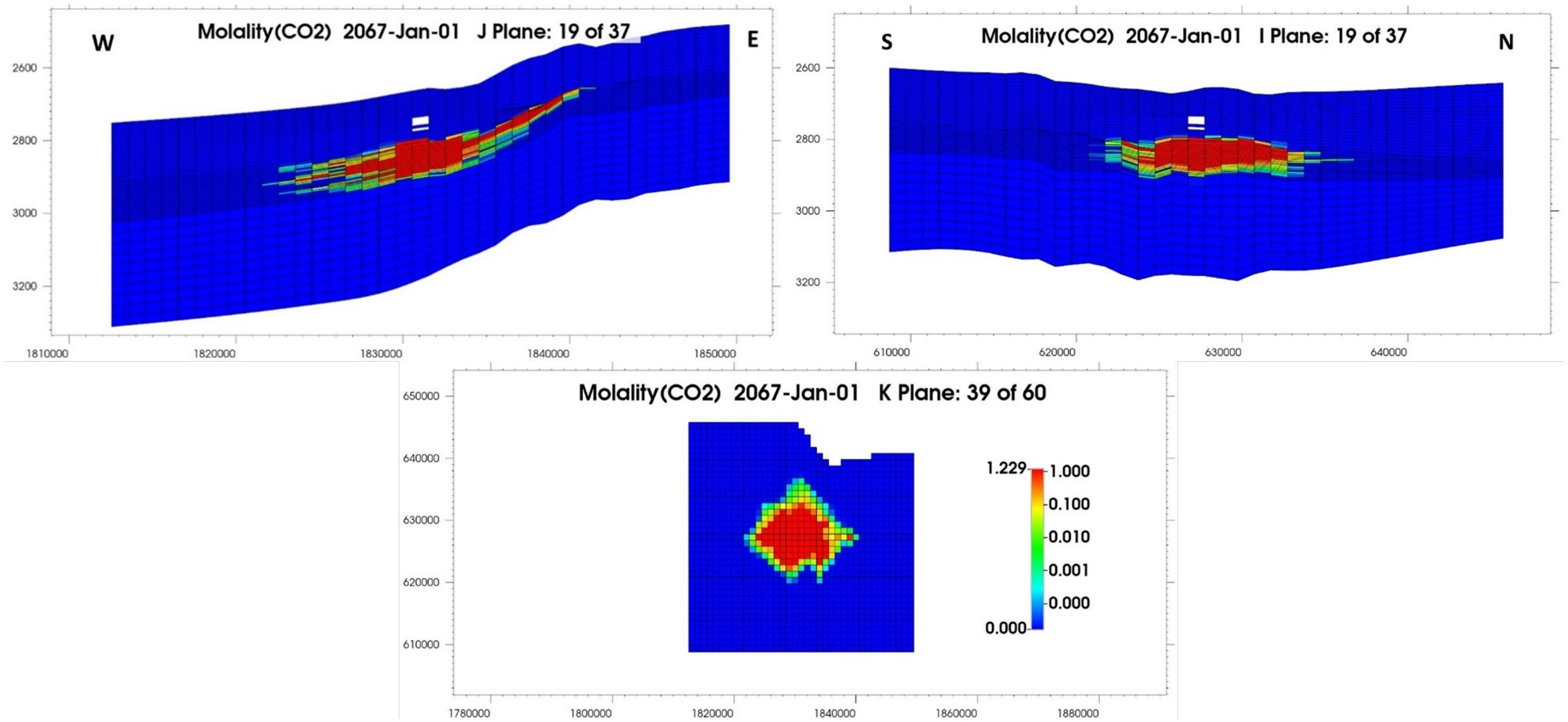

Figure 2-21. CO_2 molality for the geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of simulation in Layer k = 39. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

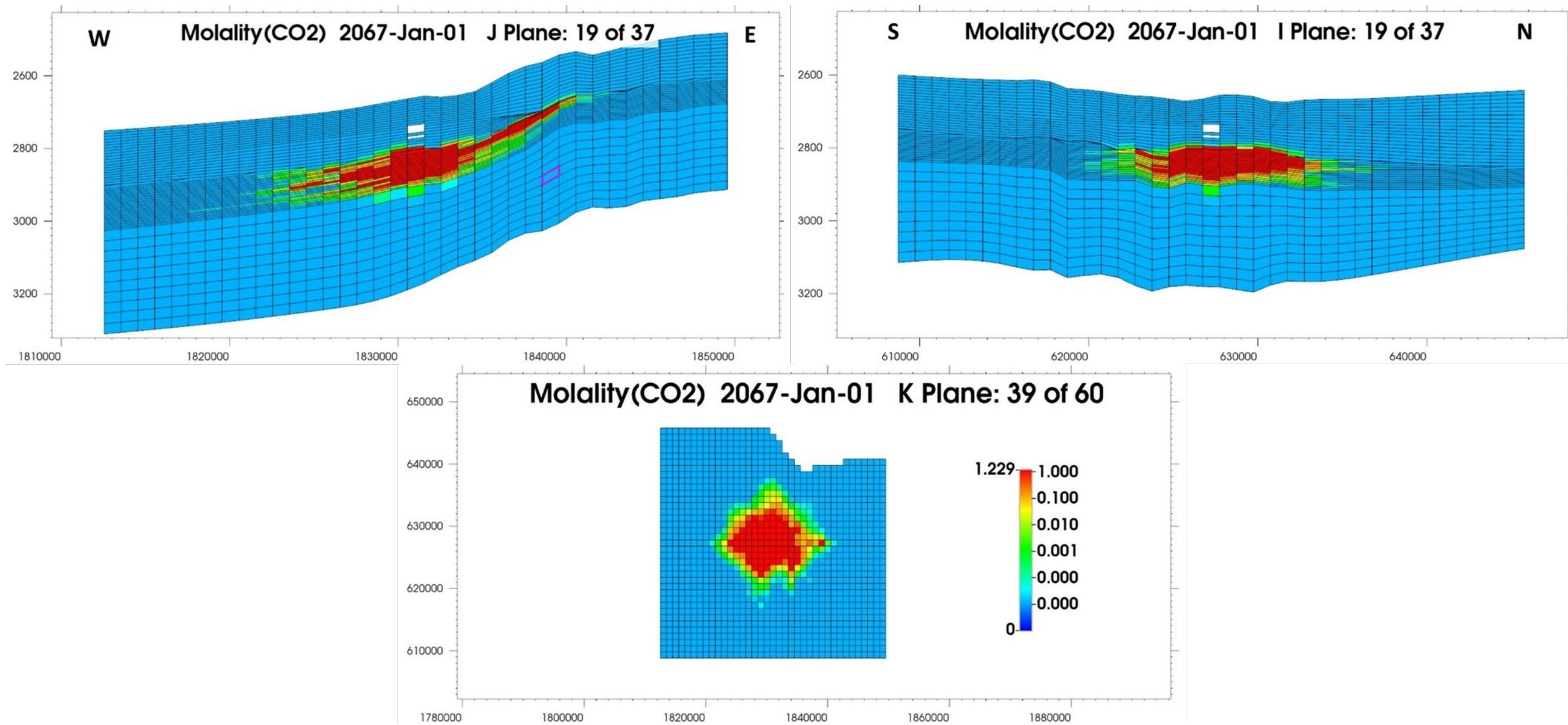

Figure 2-22. CO_2 molality for the non-geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of simulation in Layer k = 39. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

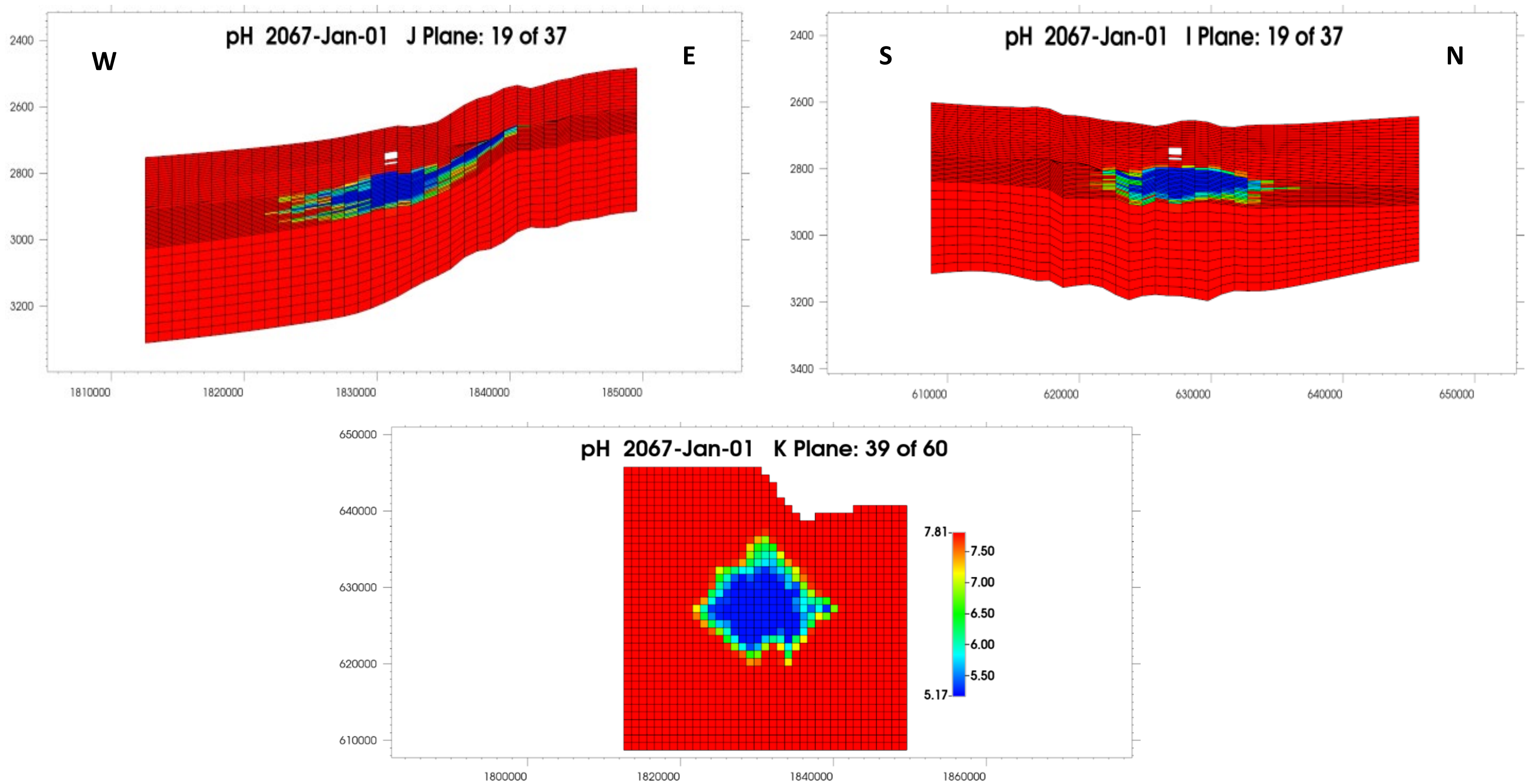

Figure 2-23. Geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the pH of formation brine in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

Figure 2-24 shows the mass of mineral dissolution and precipitation due to geochemical reaction in the Broom Creek Formation. Dolomite is the most prominent dissolved mineral. Albite and K-feldspar gradually dissolves over time. Illite initially dissolves and then starts precipitating 3 years after injection stops. Quartz and anhydrite are the minerals that experienced the most precipitation over time.

Figures 2-25 and 2-26 provide an indication of the change in distribution of the mineral that experienced the most dissolution, dolomite, and the mineral that experienced the most precipitation, quartz, respectively. Considering the apparent net dissolution of minerals in the system, as indicated in Figure 2-24, there is an associated net increase in porosity in the affected areas, as shown in Figure 2-27. However, the porosity change is small, less than 0.04% porosity units, equating to a maximum increase in average porosity from 22.6% to 22.64% after the 20-year injection period.

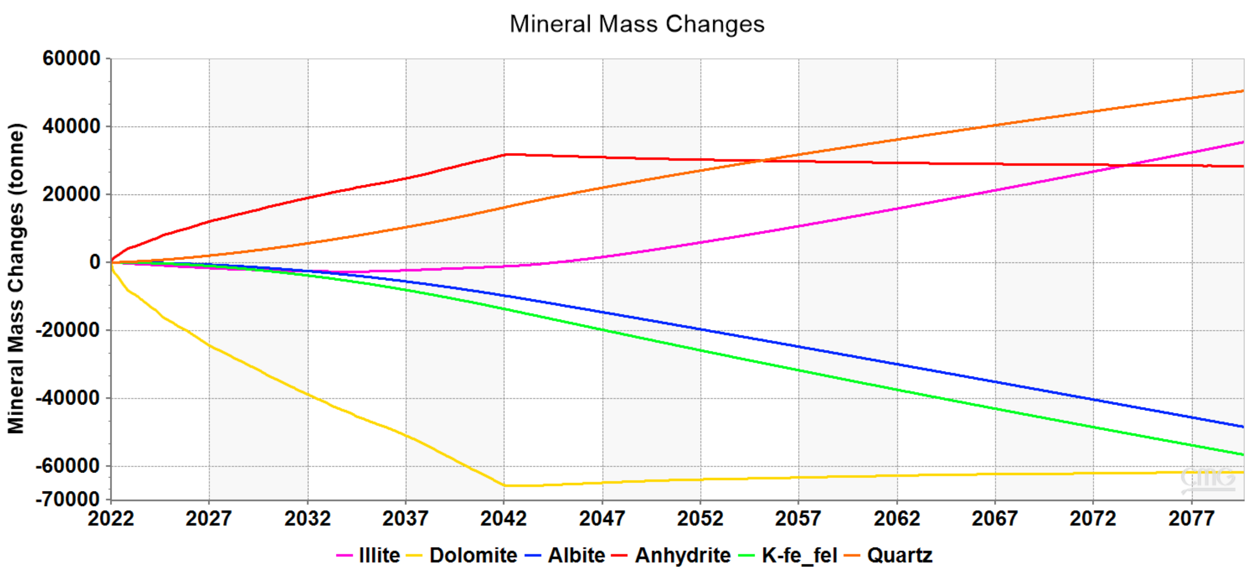

Figure 2-24. Dissolution and precipitation quantities of reservoir minerals because of CO_2 injection. Dissolution of albite, K-feldspar (K-fe_fel), and dolomite with precipitation of illite, quartz, and anhydrite was observed.

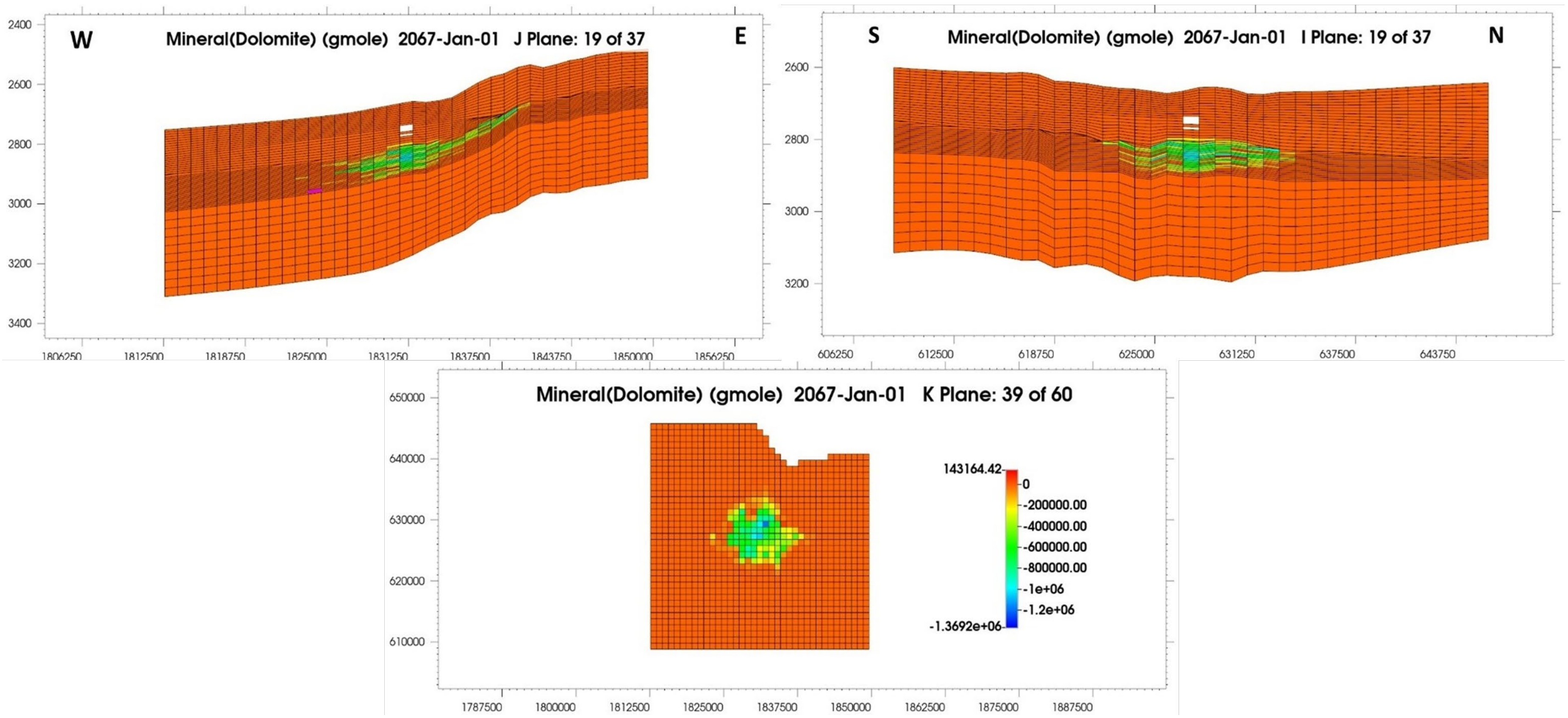

Figure 2-25. Change in molar distribution of dolomite, the most prominent dissolved mineral at the end of the 20-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

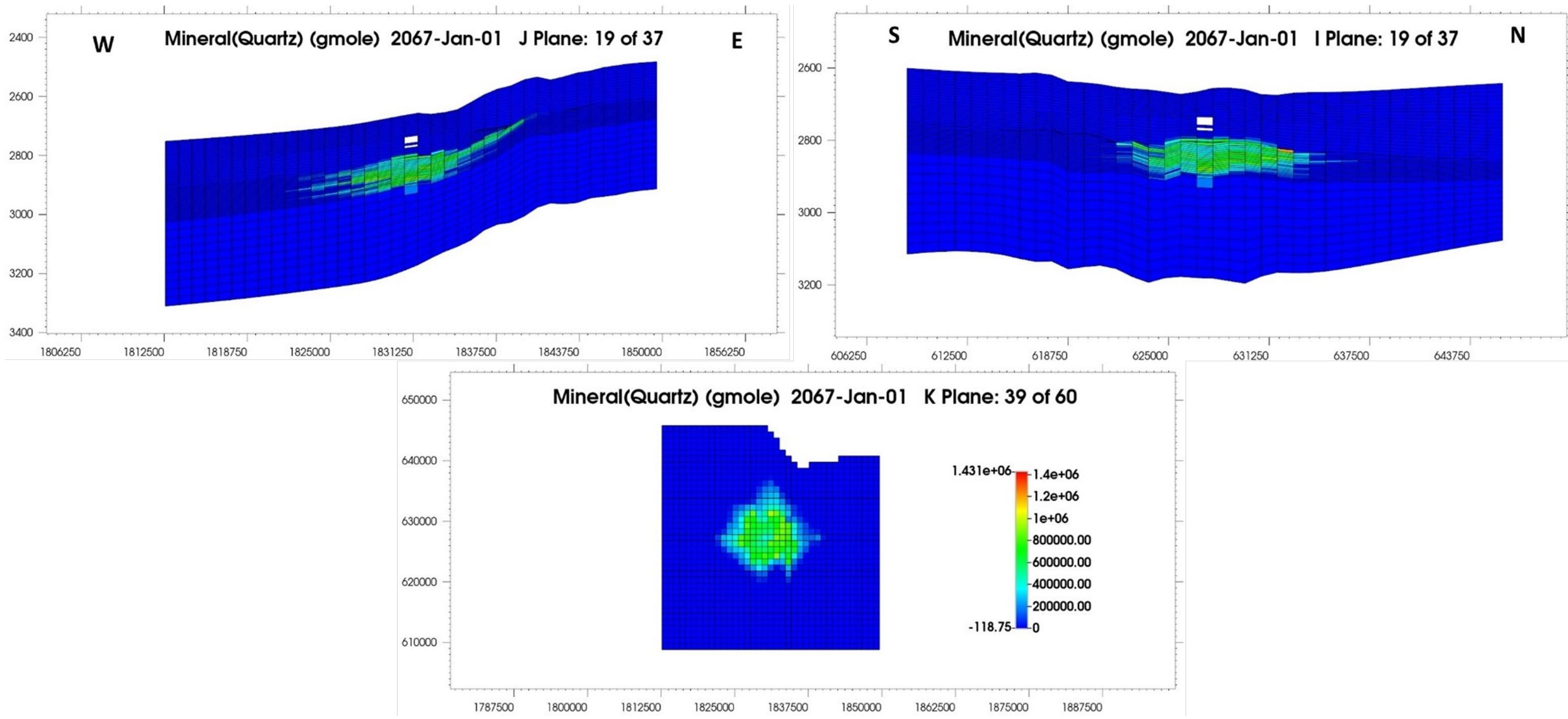

Figure 2-26. Change in molar distribution of quartz, the most prominent precipitated mineral at the end of the 20-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

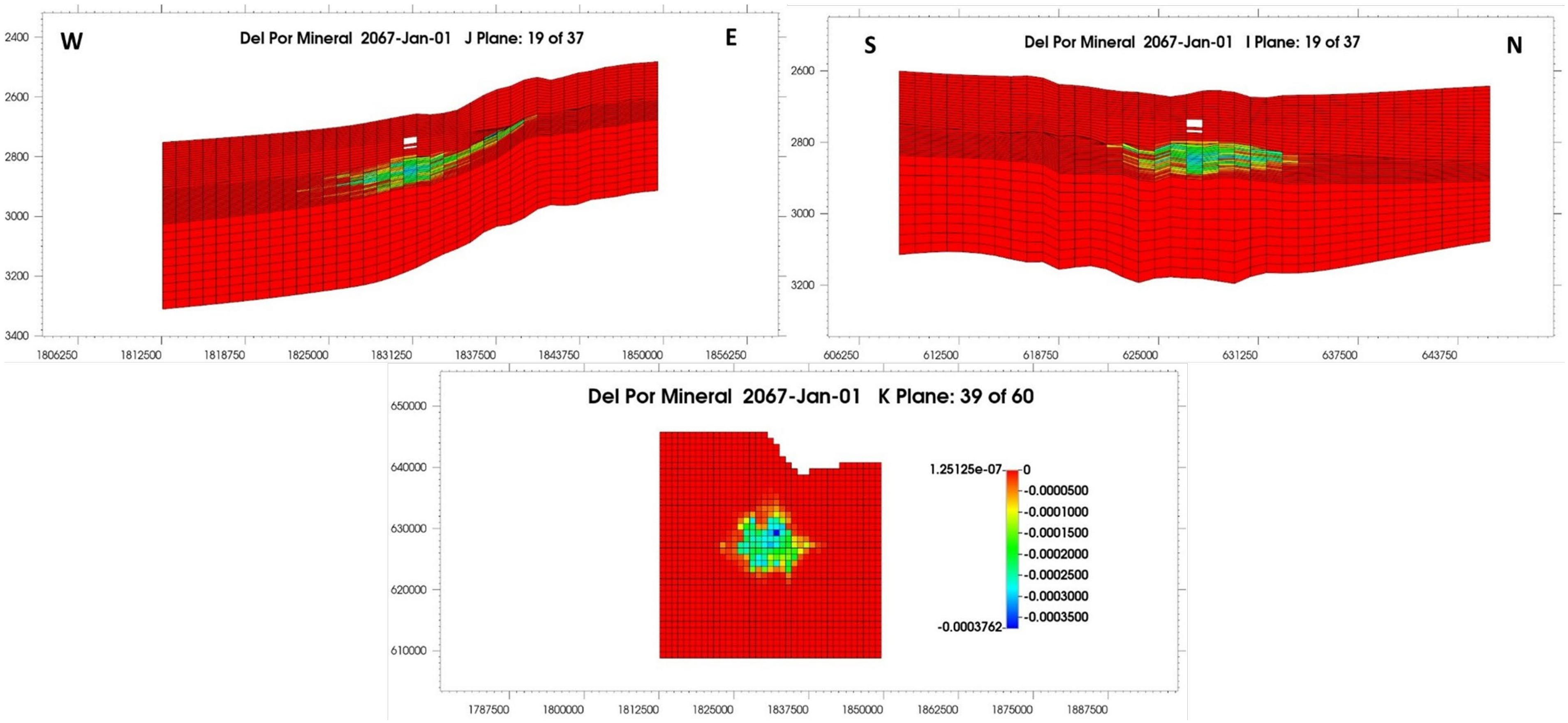

Figure 2-27. Change in porosity due to net geochemical dissolution at the end of the 20-year injection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

2.4 Confining Zones

The confining zones for the Broom Creek Formation are the overlying Spearfish Formation and the lower Piper Formation and the underlying Amsden Formation (Figure 2-2, Table 2-10). Both the overlying and underlying confining formations consist primarily of impermeable rock layers.

Table 2-10. Properties of Upper and Lower Confining Zones in Simulation Area

Confining Zone Properties	Upper Confining Zone		Lower Confining Zone
Stratigraphic Unit	Lower Piper	Spearfish	Amsden
Lithology	Shale/anhydrite/ siltstone	Shale/anhydrite/ siltstone	Dolostone/limestone/ anhydrite/sandstone
Average Formation Top Depth (MD), ft	4,458	4,611	4,735
Thickness, ft	153	22	217
Capillary Entry Pressure (brine/CO_2), psi	2.512	12.245	26.134
Depth below Lowest Identified USDW, ft (MAG 1)	3,488	3,575	3,738

Formation	Property	Laboratory Analysis	Simulation Model Property Distribution
Lower Piper	Porosity, %*	*** (4.8,10.50)	3.00 (0.00–8.00)
	Permeability, mD**	*** (0.01,0.074)	0.064 (0.000–0.147)
Spearfish	Porosity, %*	13.14 (11.62–15.38)	2.00 (0.00–8.00)
	Permeability, mD**	0.116 (0.009–3.087)	0.11 (0.000–0.272)
Amsden	Porosity, %*	8.48 (2.15–18.80)	1.00 (0.00–6.00)
	Permeability, mD**	0.062 (0.0003–117)	0.683 (0.000–3.473)

* Porosity values recorded at 2,400-psi confining pressure are reported as the arithmetic mean followed by the range of values in parenthesis.
** Permeability values recorded at 2,400-psi confining pressure are reported as the geometric mean followed by the range of values in parenthesis.
*** Average not available for two samples.

2.4.1 Upper Confining Zone

In the Blue Flint project area, the upper confining zone, the lower Piper and Spearfish Formations, consists of siltstone with interbedded anhydrite (Table 2-10). The upper confining zone is laterally extensive across the project area (Figure 2-28) and is 4,560 ft below the land surface and 148 ft thick (lower Piper Formation, 87 ft [Figures 2-29 and 2-30], Spearfish Formation, 61 ft [Figures 2-31 and 2-32]) as observed in the MAG 1 well. The contact between the underlying Broom Creek Formation sandstone and the upper confining zone is an unconformity that can be correlated across the Broom Creek Formation extent where the resistivity and GR logs show a significant change across the contact. A relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation changes to a relatively high GR signature representing the siltstones of the Spearfish Formation (Figure 2-9).

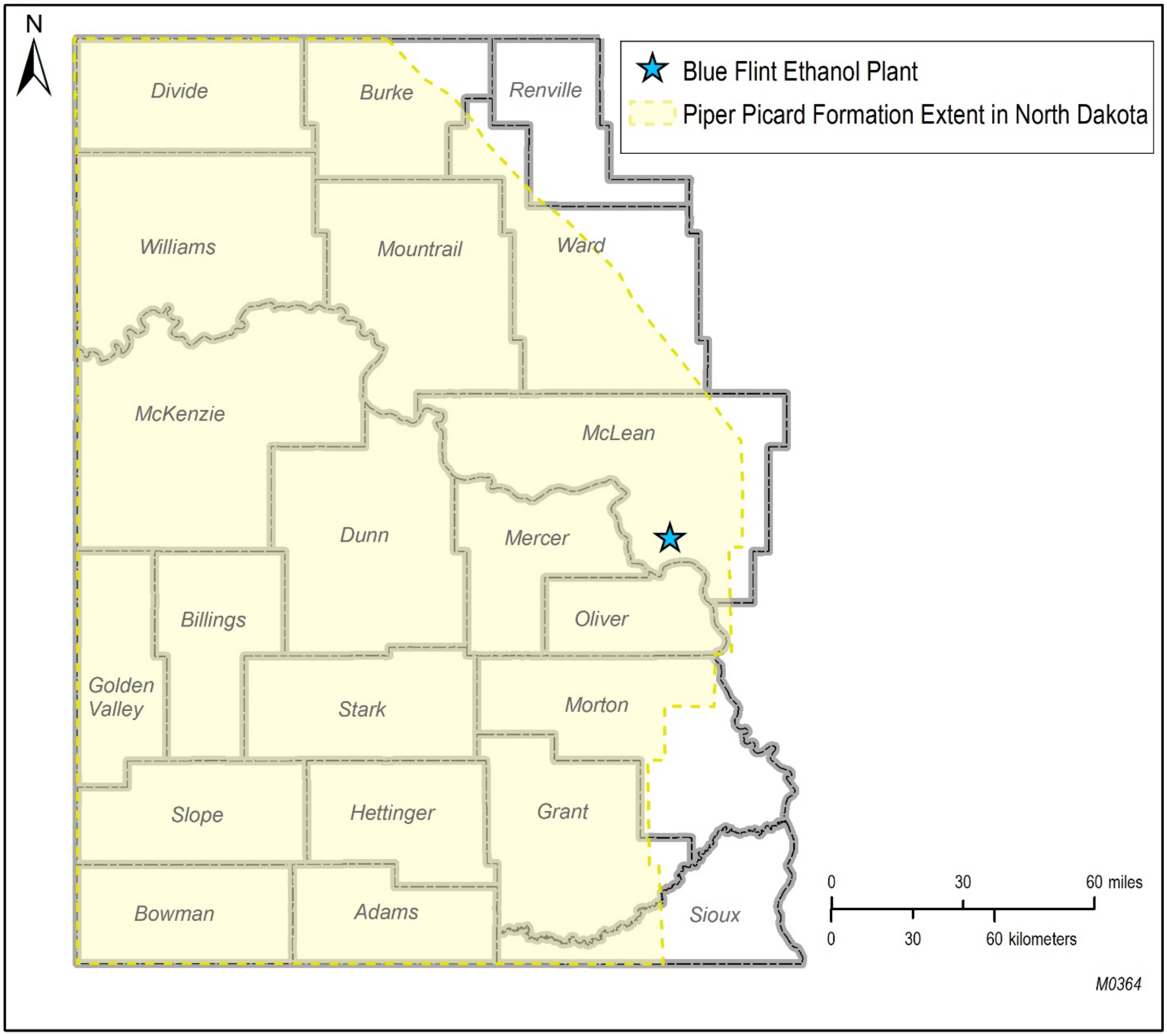

Figure 2-28. Areal extent of the lower Piper Formation in western North Dakota (modified from Carlson, 1993).

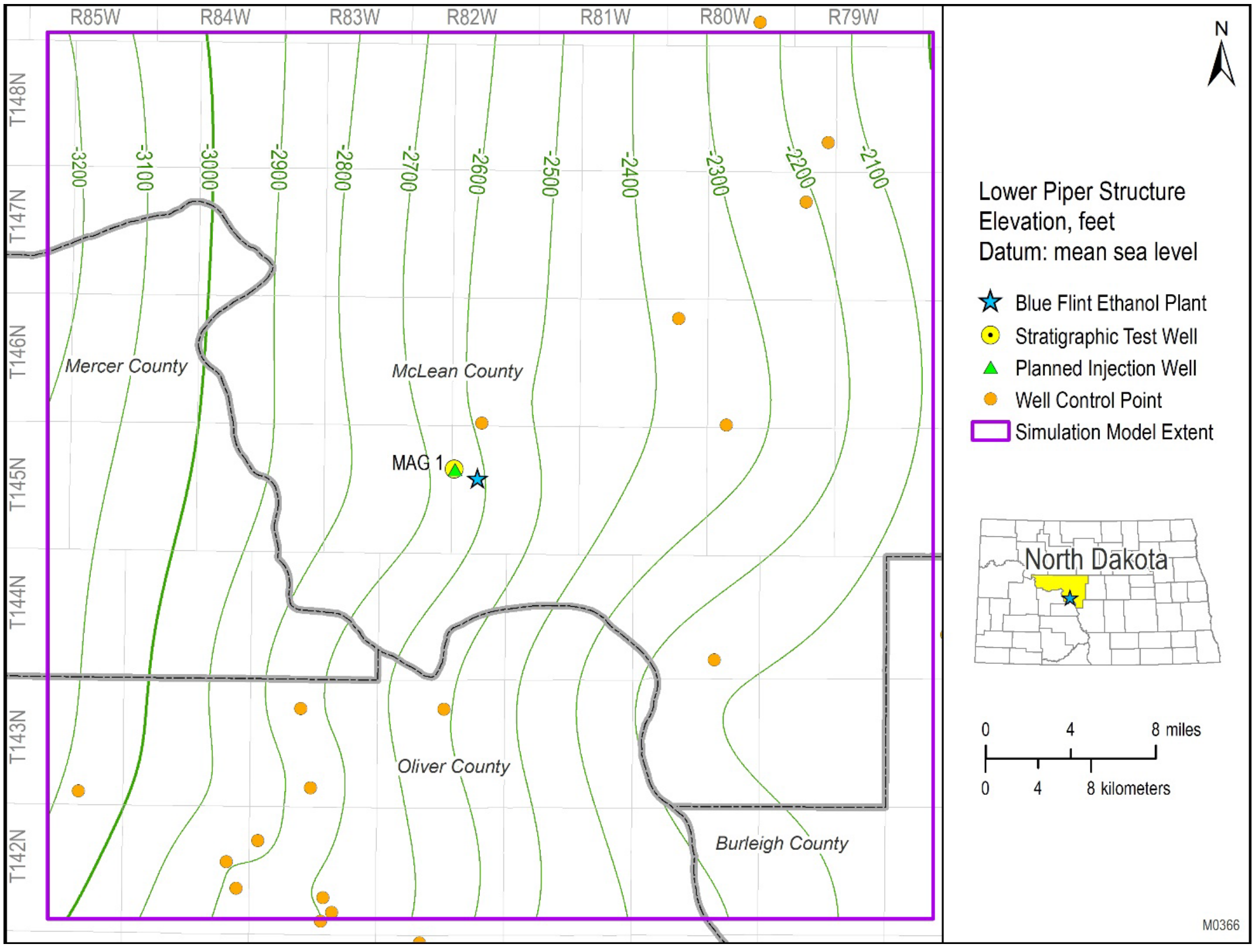

Figure 2-29. Structure map of the lower Piper Formation across the greater Blue Flint project area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

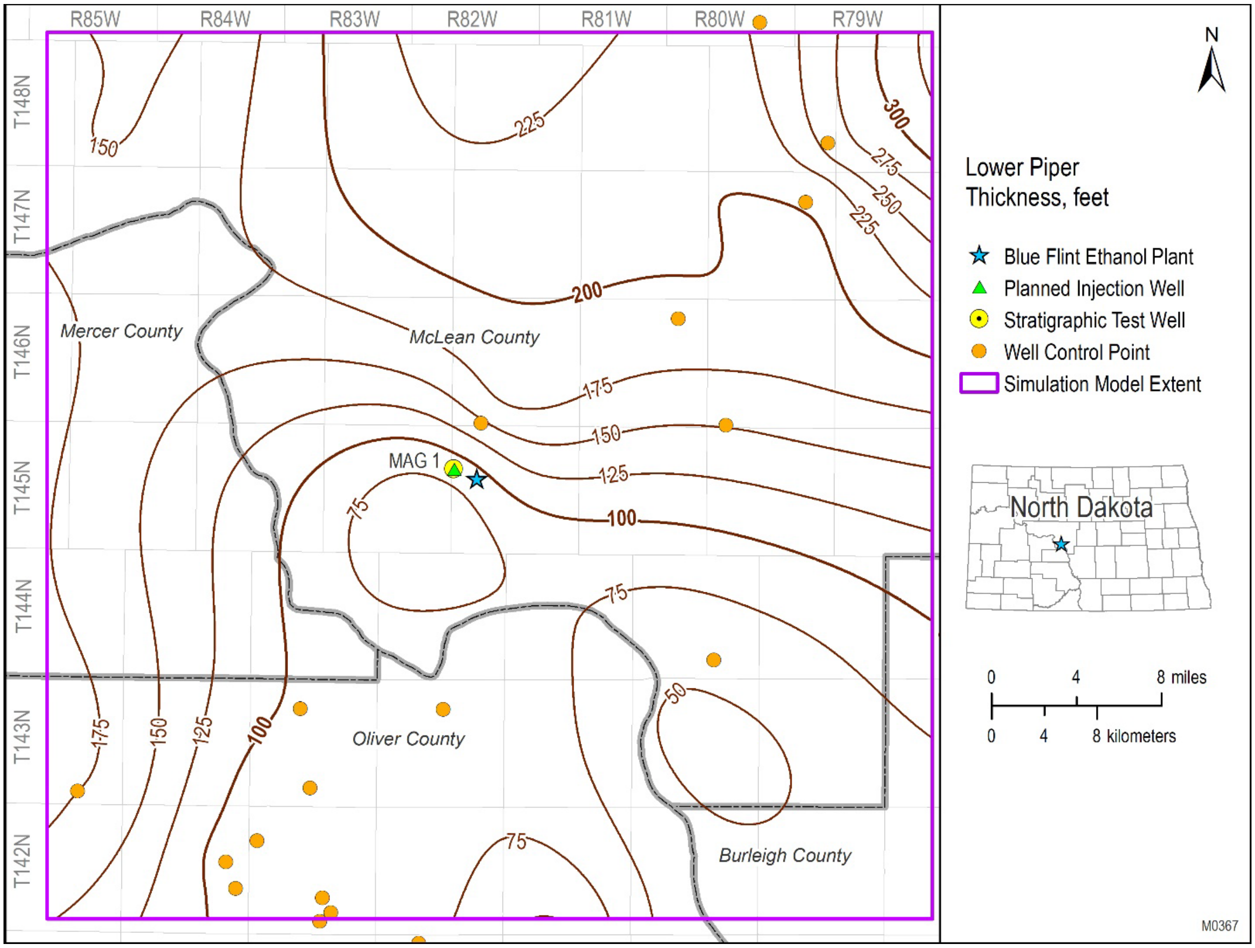

Figure 2-30. Isopach map of the lower Piper Formation in the greater Blue Flint project area. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

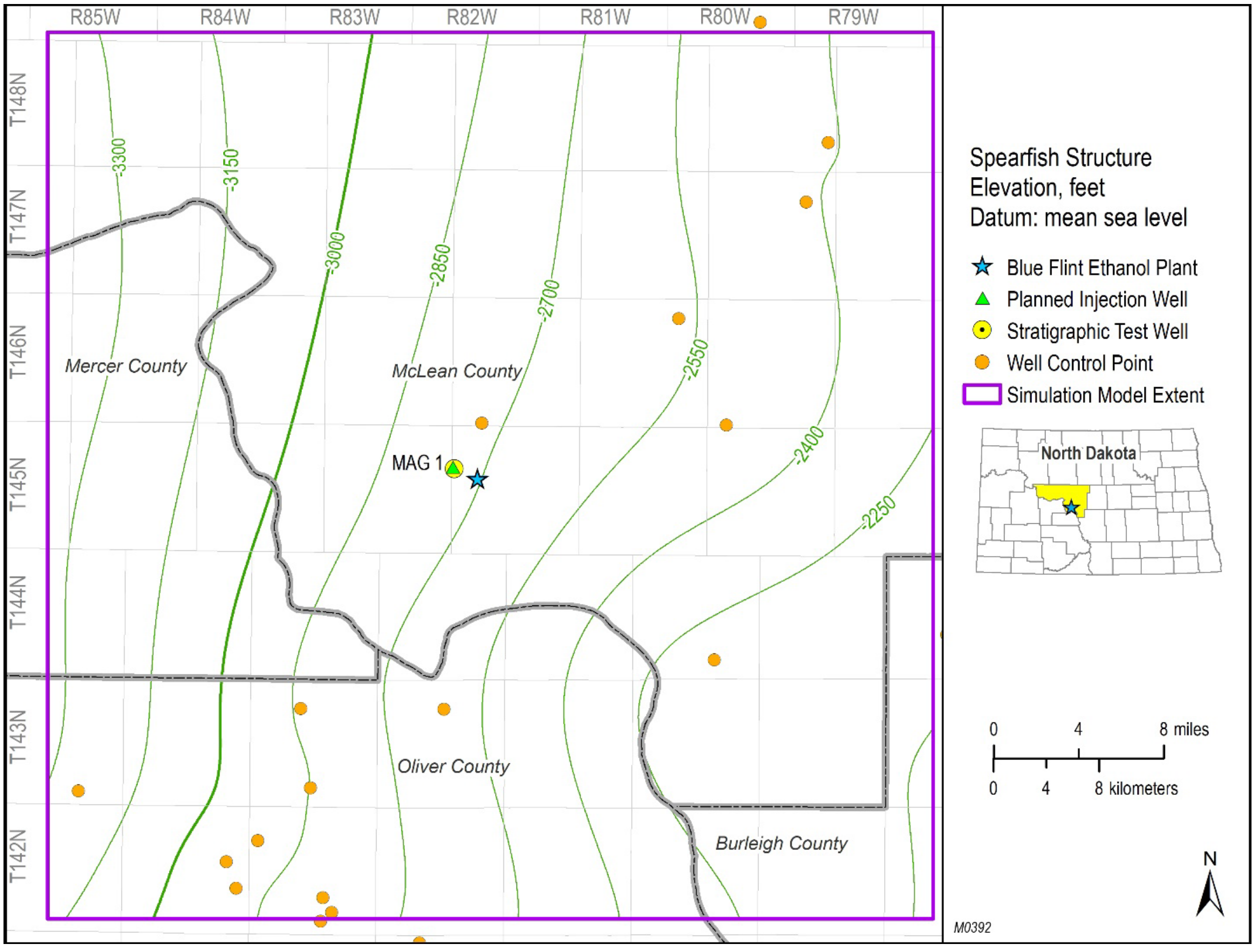

Figure 2-31. Structure map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

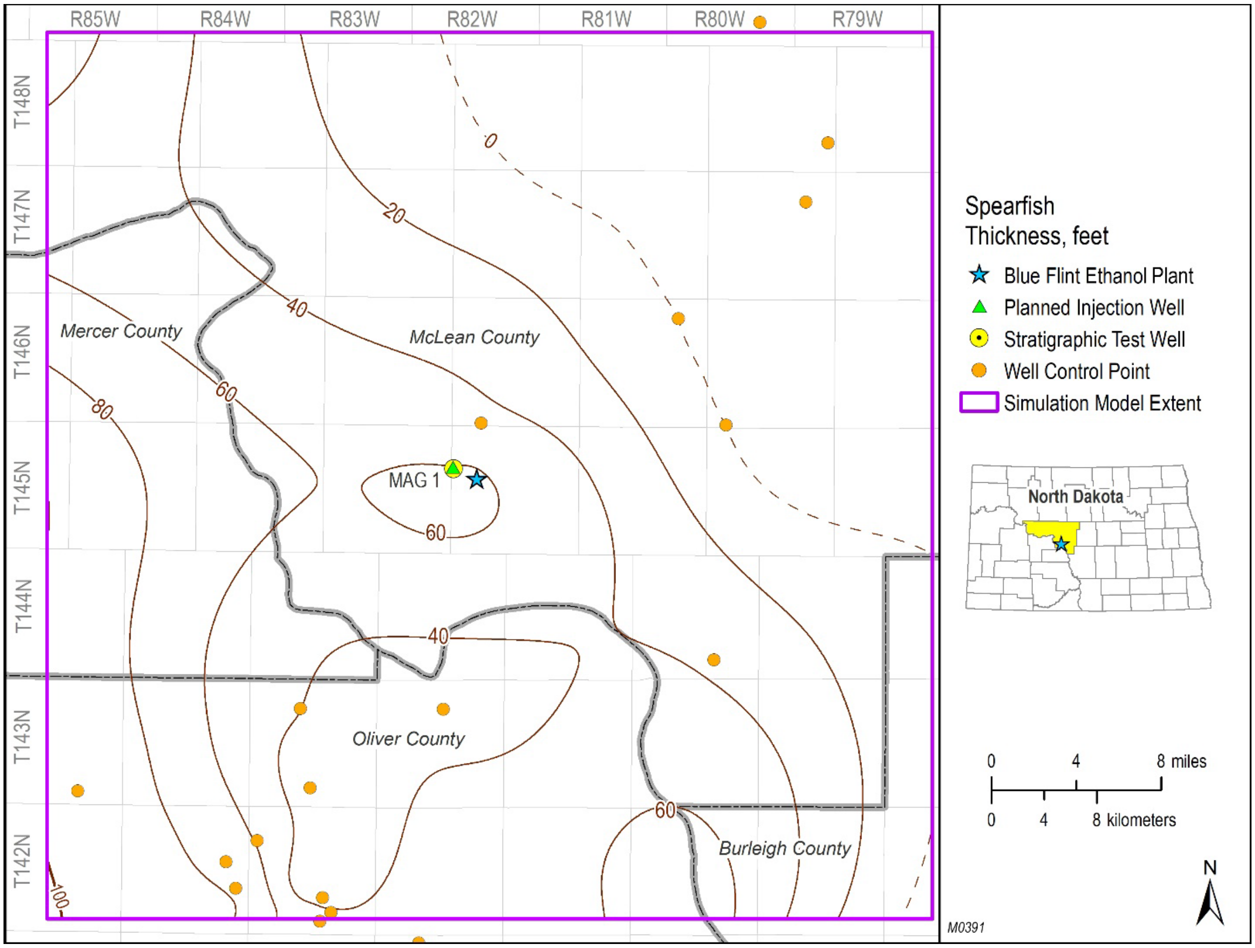

Figure 2-32. Isopach map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

Laboratory measurements of the porosity and permeability from eight SW Core samples (six Spearfish Formation and two lower Piper Formation) taken from MAG 1 can be found in Table 2-11. Because of the fractured or chipped nature of some samples, the permeability and porosity values measured are higher than the matrix would suggest. The lithology from the sidewall-cored sections of the Spearfish Formation is primarily siltstone.

In situ fluid pressure testing was not performed in the Spearfish or lower Piper Formations in the MAG 1 well. The low permeability values shown in Table 2-11 suggest any fluid within the Spearfish Formation is pore- and capillary-bound fluid and likely not mobile. Several documented attempts by others to draw down reservoir fluid in order to measure the reservoir pressure or collect an in situ fluid sample using a modular formation dynamics tester (MDT) tool in the undifferentiated Spearfish/Opeche and other similar low-permeability intervals suggest collecting this information is not feasible. The Tundra SGS (secure geologic storage) SFP applications

Table 2-11. Spearfish and Lower Piper Formation SW Core Sample Porosity and Permeability from MAG 1

Formation	Sample Depth, ft	Porosity %	Permeability, mD
Piper	4,658*	4.8	0.01
Piper	4,665*	10.50	0.074
Spearfish	4,695*	12.52	0.009
Spearfish	4,710	11.62	0.090
Spearfish	4,718*	15.38	3.087
Spearfish	4,721	14.49	0.141
Spearfish	4,724	11.69	0.059
	Range	(4.8–15.38)	(0.009–3.087)
Values Measured at 2400 psi			

* Sample is fractured or chipped. The measured permeability and/or porosity may be higher than its real value.

describe unsuccessful attempts to measure in situ fluid pressure because of the low permeability of the formations tested, the undifferentiated Spearfish/Opeche Formation, and the Icebox Formation (North Dakota Industrial Commission, 2021a, b). The Red Trail Energy SFP application also describes unsuccessful attempts to collect these data in the low-permeability Opeche Formation (North Dakota Industrial Commission, 2021c).

2.4.1.1 Mineralogy

The combined interpretation of SW Core samples, well logs, and thin sections shows that the Spearfish and lower Piper Formations are dominated by clays (mainly illite/muscovite), quartz, anhydrite, feldspar (mainly K-feldspar), and dolomite. Sixteen depth intervals in the Spearfish and Lower Piper Formations were sampled for thin-section creation, XRD mineralogical determination, and XRF bulk chemical analysis. For the assessment, thin sections and XRD provide independent confirmation of the mineralogical constituents of each of these intervals. Thin-section analysis of the siltstone intervals shows that clay, quartz, and anhydrite are the dominant minerals. Throughout these intervals are occurrences of dolomite, feldspar, and iron oxides (Figures 2-33, 2-34, and 2-35). The contacts between grains are typically separated by a clay matrix, with more rare occurrences of contacts between quartz grains as tangential to long.

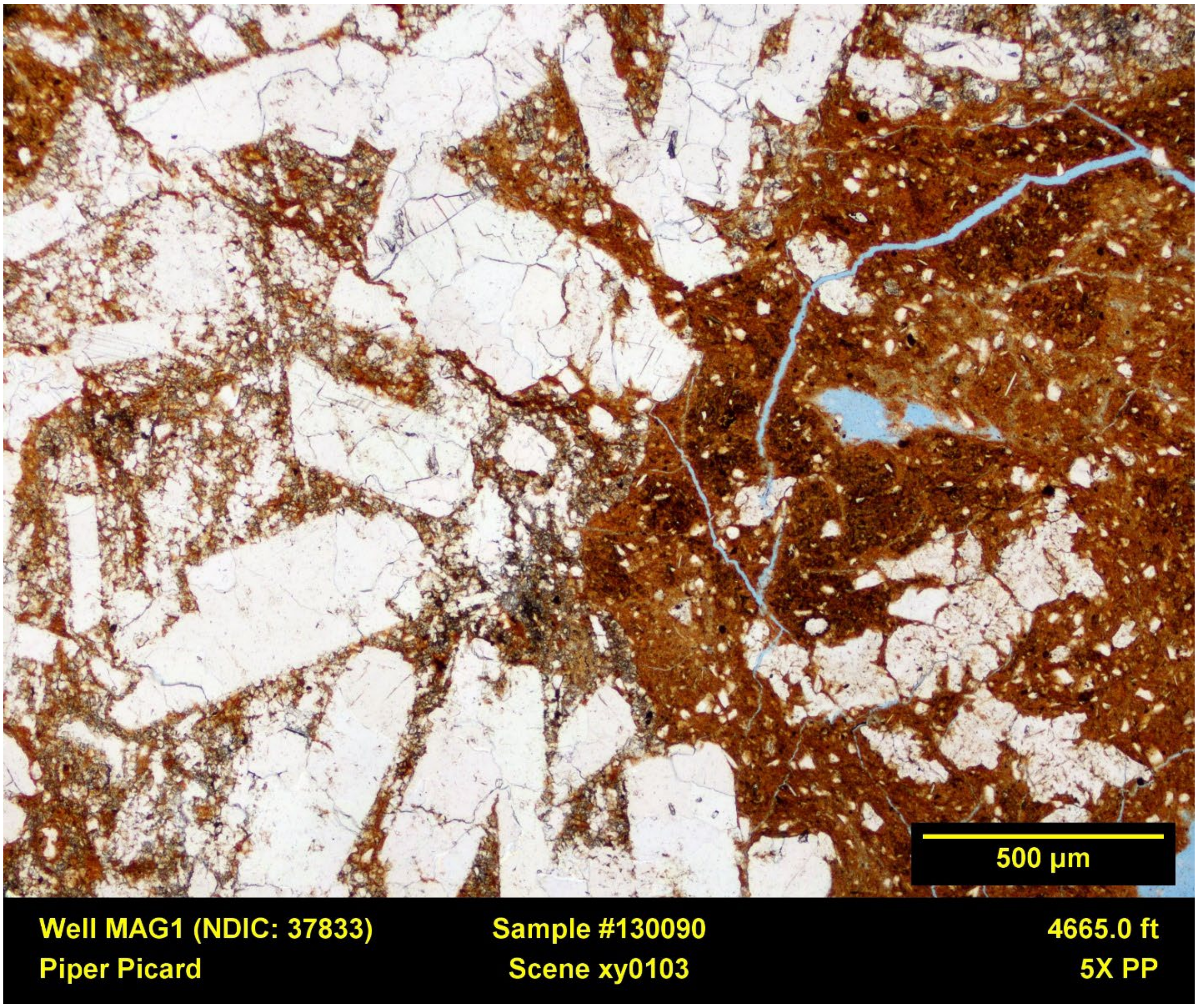

Figure 2-33. Thin section of Piper Formation. In this example, clay (brown) and anhydrite (white) dominate the depth interval. Minor porosity is observed (blue).

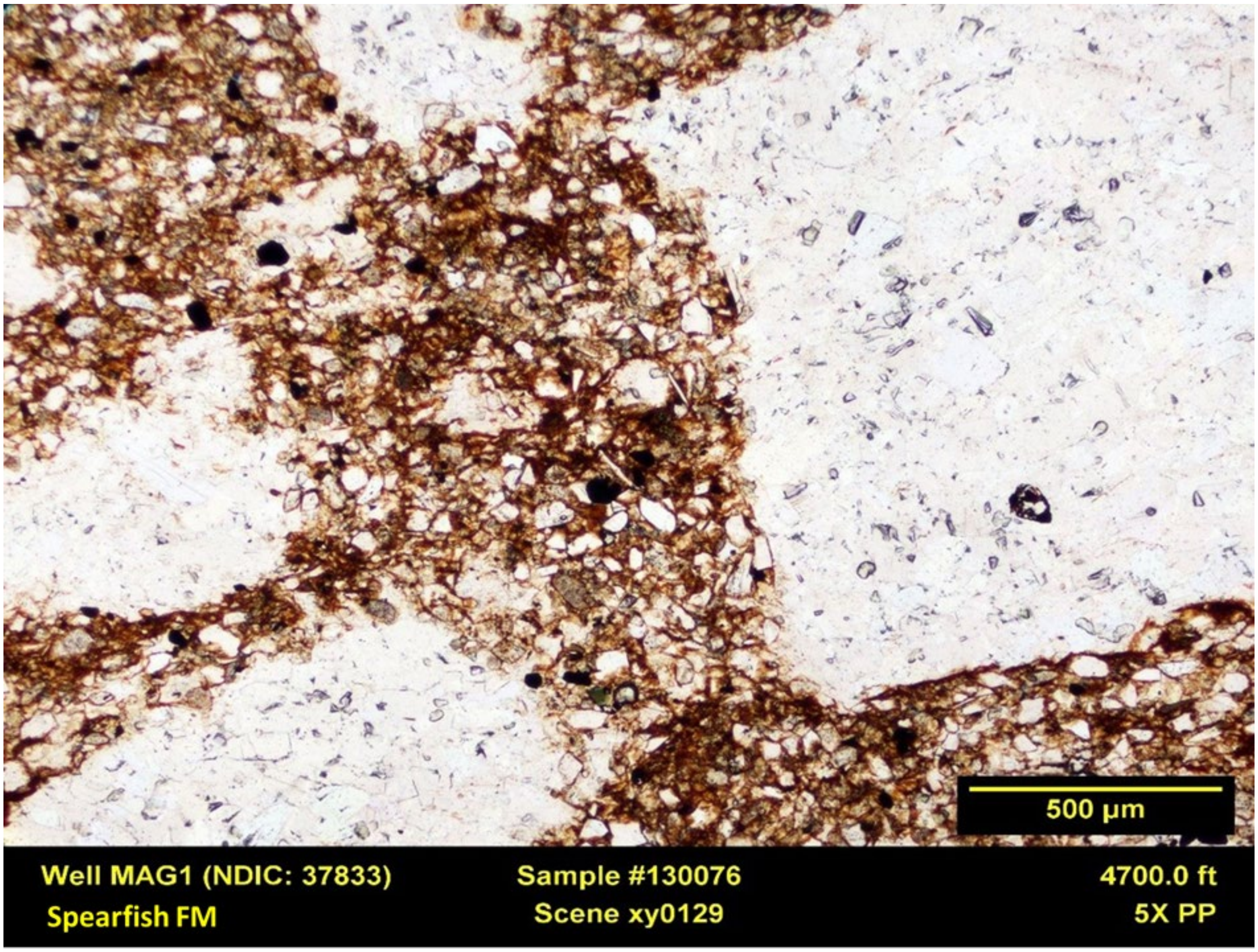

Figure 2-34. Thin section of Spearfish Formation. In this example, clay (brown), quartz (small white grains), anhydrite (large white grains), and iron oxides (black grains) dominate the depth interval. No porosity is observed.

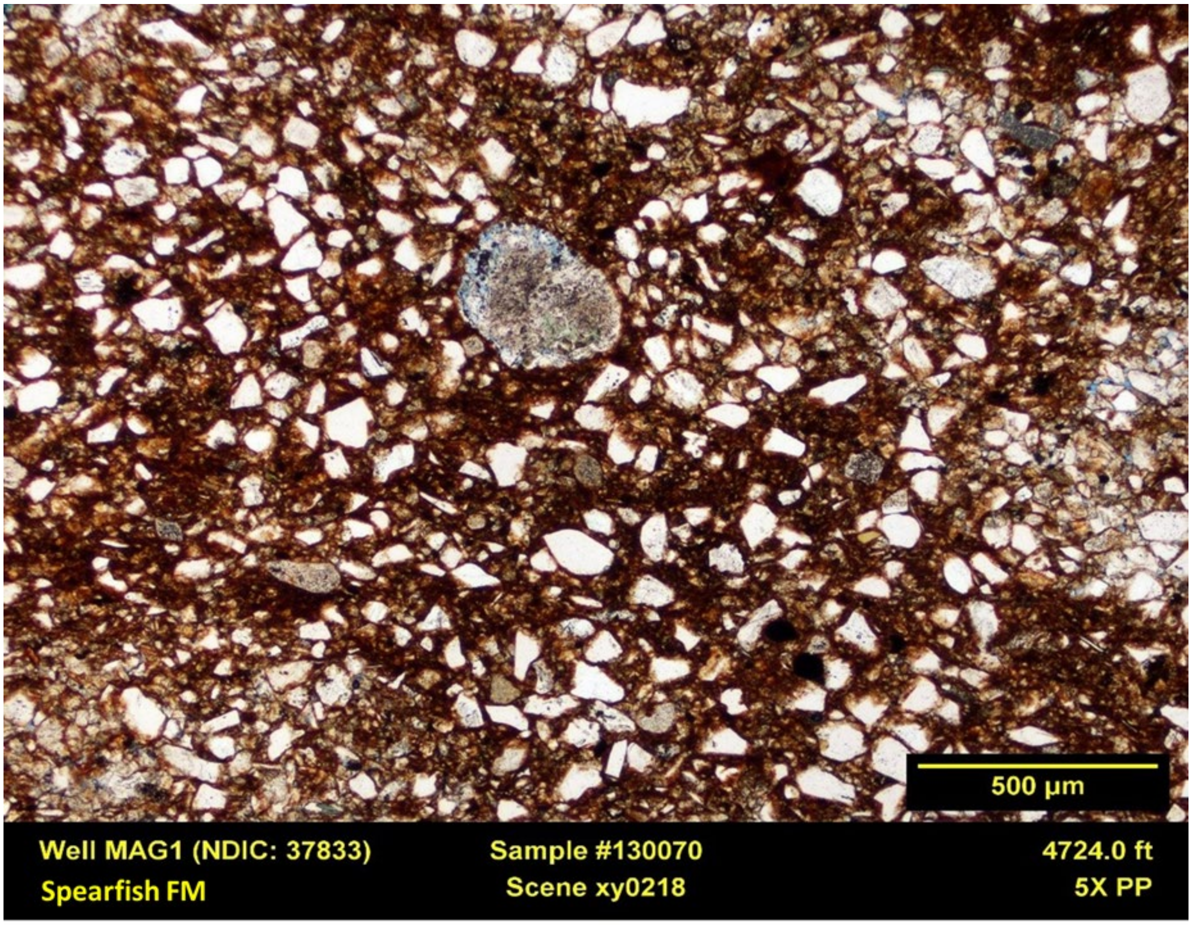

Figure 2-35. Thin section of Spearfish Formation. In this example, clay (brown) and quartz (white) dominate the depth interval. Minor intergranular and intragranular porosity are observed (blue).

XRD data from the SW Core samples in the cap rock intervals supported the thin-section analysis. Table 2-12 shows the major mineral phases identified for the samples representing these intervals. XRF data related to the upper confining zones are presented in Figure 2-36.

Table 2-12. XRD Analysis in the Upper Confining Intervals (Spearfish and Lower Piper) from MAG 1 Well. Only major constituents are shown.

Formation	STAR No.	Depth, feet	% Clay	% K-Feldspar	% P-Feldspar	% Quartz	% Calcite	% Dolomite	% Ankerite	% Anhydrite	% Halite
Piper	130095	4,640	37.7	7.6	11.9	26.2	1.2	3.3	1.5	7.9	0.7
Piper	130094	4,648	4.5	0.4	0.0	1.2	0.0	0.0	0.0	93.7	0.2
Piper	130093	4,655	27.4	1.8	4.8	7.1	2.5	2.7	1.6	50.7	0.0
Piper	130091	4,658	9.1	0.0	4.2	4.8	19.5	0.0	0.4	62.1	0.0
Piper	130090	4,665	23.3	2.8	5.3	11.3	24.1	8.9	6.8	17.5	0.0
Spearfish	130081	4,675	16.4	6.2	13.2	33.4	0.0	28.3	0.0	1.6	0.4
Spearfish	130080	4,680	7.5	12.7	12.5	36.7	0.0	25.0	0.0	4.9	0.6
Spearfish	130079	4,685	3.7	1.4	2.9	6.5	0.1	5.1	0.0	80.4	0.0
Spearfish	130078	4,690	9.3	5.5	10.2	29.5	0.6	10.0	3.5	30.8	0.4
Spearfish	130077	4,695	13.0	4.5	8.1	25.8	0.8	8.7	2.6	35.7	0.3
Spearfish	130076	4,700	9.7	4.1	9.3	30.3	2.7	7.6	2.4	33.2	0.4
Spearfish	130075	4,705	19.8	7.3	12.8	37.7	4.1	11.5	0.0	5.6	0.7
Spearfish	130074	4,710	8.3	5.3	11.8	38.5	4.6	11.0	0.0	19.7	0.4
Spearfish	130073	4,715	9.6	6.6	11.4	37.9	4.5	13.9	0.0	15.4	0.4
Spearfish	130071	4,721	8.0	6.7	10.2	39.6	0.0	34.9	0.0	0.0	0.0
Spearfish	130070	4,724	13.8	9.8	15.3	46.0	10.2	3.3	0.0	0.8	0.6

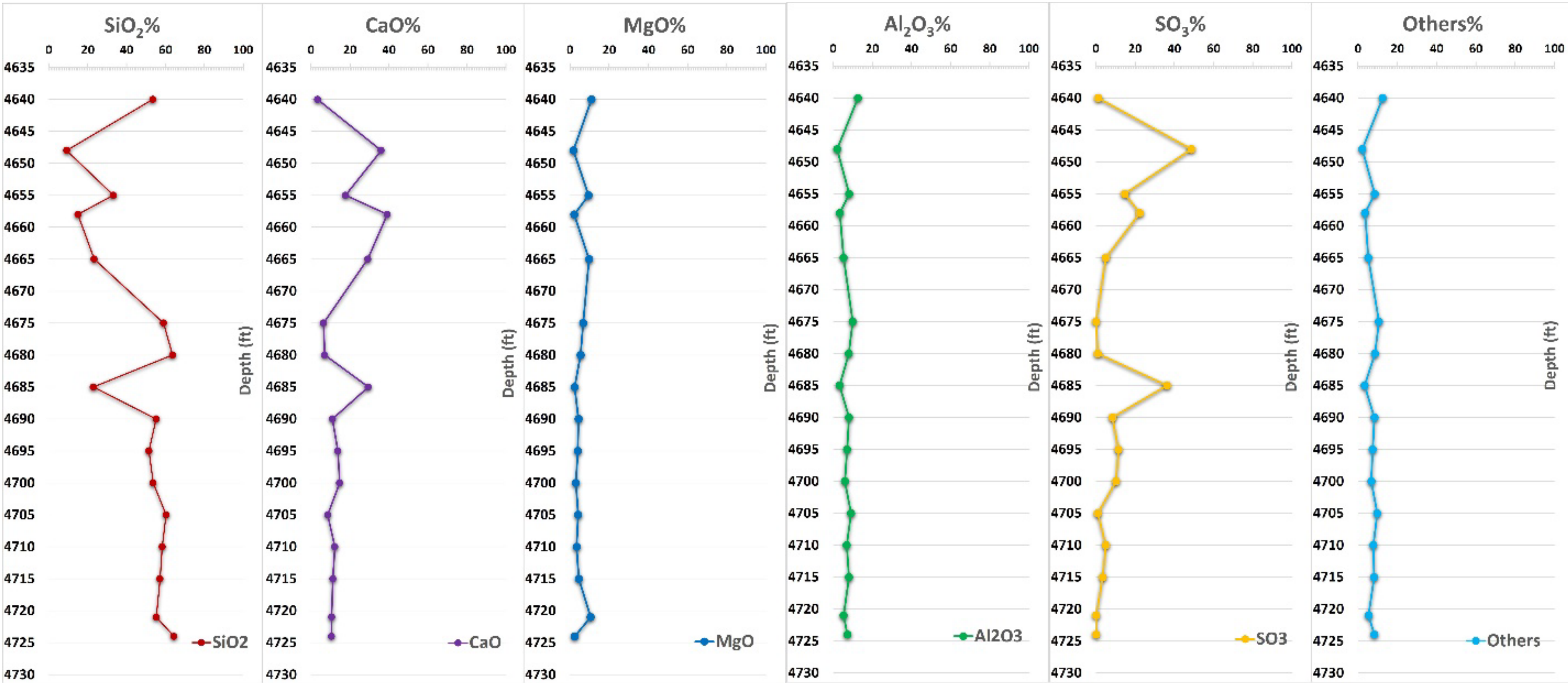

Figure 2-36. XRF analysis in the upper confining zone (Spearfish and lower Piper Formations) from MAG 1.

2.4.1.2 Geochemical Interaction

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected CO_2 stream on the Spearfish Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Spearfish Formation by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the confining zone. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock–CO_2 exposure boundary. The mineralogical composition of the Spearfish Formation was honored (Table 2-13). Formation brine composition was assumed to be the same as the known composition from the Broom Creek Formation injection zone below (Table 2-14). For simulation, 100% CO_2 was used as discussed in Section 2.3.1. The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). This overestimate was done to ensure that the degree and pace of geochemical change would not be underestimated. This geochemical simulation was run for 45 years to represent 20 years of injection plus 25 years of postinjection. The simulation was performed at reservoir pressure and temperature conditions.

Table 2-13. Mineral Composition of the Spearfish Derived from XRD Analysis of MAG 1 Core Samples

Minerals, wt%	
Illite	10.5
Chlorite	2.5
K-Feldspar	4.5
Albite	8.2
Quartz	25.8
Dolomite	8.7
Anhydrite	35.8

Table 2-14. Formation Water Chemistry from Broom Creek Formation Fluid Samples from MAG 1

pH	7.48	TDS	28,600 mg/L
Total Alkalinity	204 mg/L $CaCO_3$	Calcium	823 mg/L
Bicarbonate	249 mg/L $CaCO_3$	Magnesium	187 mg/L
Carbonate	0 mg/L $CaCO_3$	Sodium	9,020 mg/L
Hydroxide	0 mg/L $CaCO_3$	Potassium	90.9 mg/L
Sulfate	7,350 mg/L	Strontium	18.4 mg/L
Chloride	11,600 mg/L		

Results showed geochemical processes at work. Figures 2-37 through 2-41 show results from geochemical modeling. Figure 2-37 shows change in fluid pH over time as CO_2 enters the system. For the cell at the CO_2 interface, C1, the pH starts declining from an initial pH of 7.48 and goes down to a level of 4.9 after 11 years of simulation time. pH starts to increase after 18 years of simulation time and reaches to 5.5 by the 45 years of simulation. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH only begins to change after Year 20. Lastly, the pH is unaffected in Cell C3, indicating CO_2 does not penetrate this cell within the first 45 years.

Figure 2-38 shows the change in mineral dissolution and precipitation in grams per cubic meter of rock. The dashed lines are for Cell C1; solid lines that are only faintly seen in the figure are for Cell C2, 1.0 to 2.0 meters into the cap rock. The net change due to precipitation or dissolution in Cell C2 is less than 2 kg per cubic meter per year with very little dissolution or precipitation taking place after injection ceases in Year 2043. Albite, K-feldspar, and anhydrite start to dissolve from the beginning of the simulation period while illite, quartz, and dolomite start to precipitate for Cell C1 at the same time. Any effects in Cell C3 are too small to represent at this scale.

Figure 2-39 represents the initial fractions of potentially reactive minerals in the Spearfish Formation based on XRD data shown in Table 2-13. The expected dissolution of these minerals in weight percentage is also shown for Cells 1 and Cell 2 of the model. In Cell 1, albite, K-feldspar, anhydrite, and chlorite are the primary minerals that dissolve. In Cell 2, albite and K-feldspar are the two primary minerals that dissolve. Dissolution (%) in Cell 2 is minimal (< 0.1%) and too small to plot in Figure 2-39.

Figure 2-40 represents expected minerals to be precipitated in weight (%) shown for Cells C1 and C2 of the model. In Cell 1, illite, quartz, and dolomite are the minerals to be precipitated. In Cell 2, illite and quartz are the minerals to be precipitated.

Figure 2-41 shows the change in porosity of the cap rock for Cells C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 0.2% change during the life of the simulation. Cell 1 experiences an initial 0.006% increase in porosity as it is first exposed to CO_2 because of dissolution, but the change is temporary. At later times, Cell 1 experiences a porosity decrease of 0.13%. No significant porosity changes were observed for Cell 2 and Cell 3.

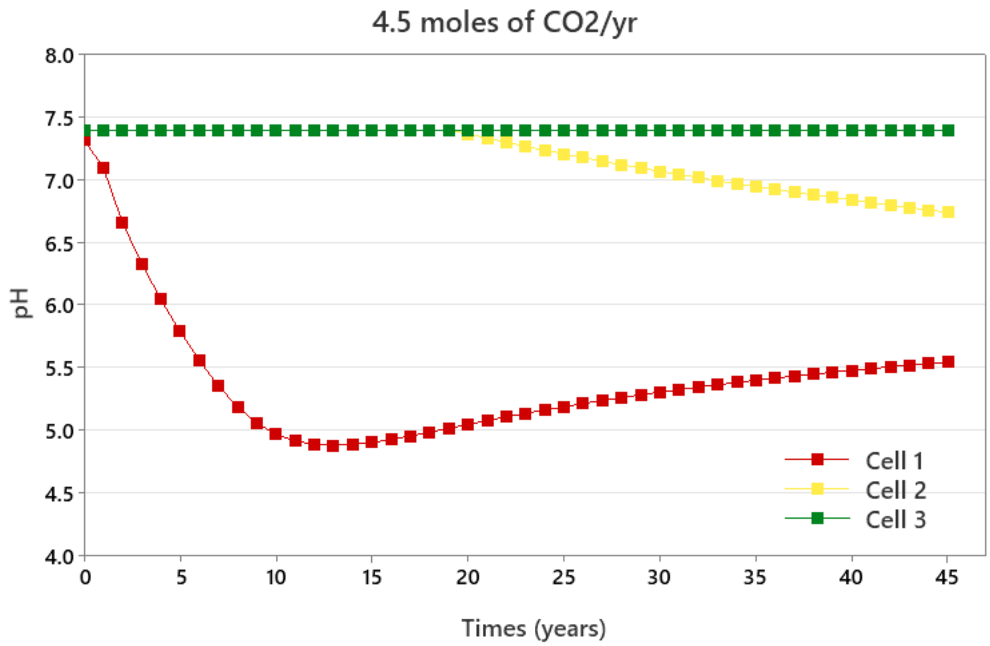

Figure 2-37. Change in fluid pH vs. time. Red line shows pH for the center of Cell C1, 0.5 meters above the Spearfish Formation cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. pH for Cell C2 does not begin to change until after Year 16.

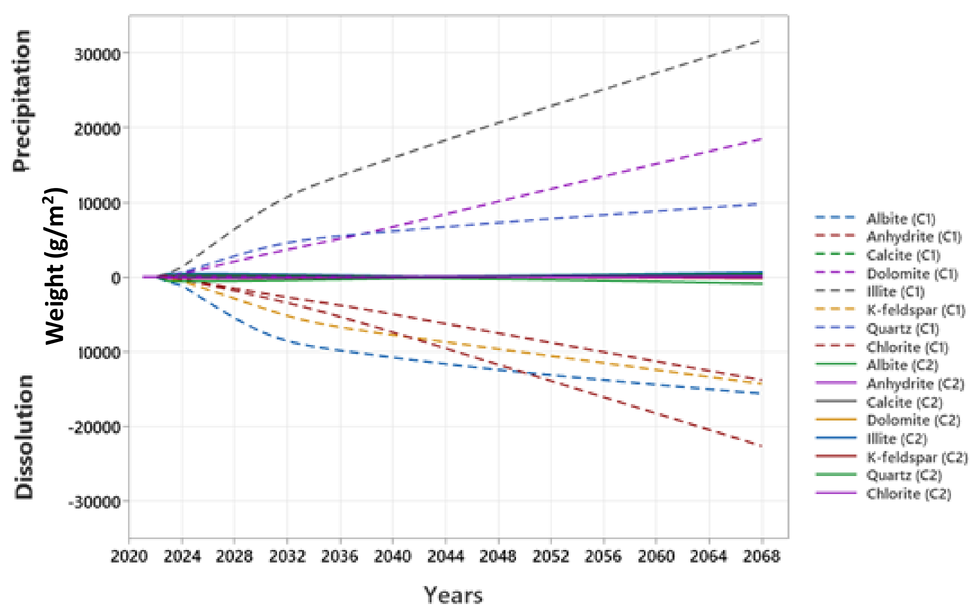

Figure 2-38. Dissolution and precipitation of minerals in the Spearfish Formation cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2, 1.5 meters above the cap rock base; these changes are barely visible. Results from Cell C3, 2.5 meters above the cap rock base, are not shown as they are too small to be seen at this scale.

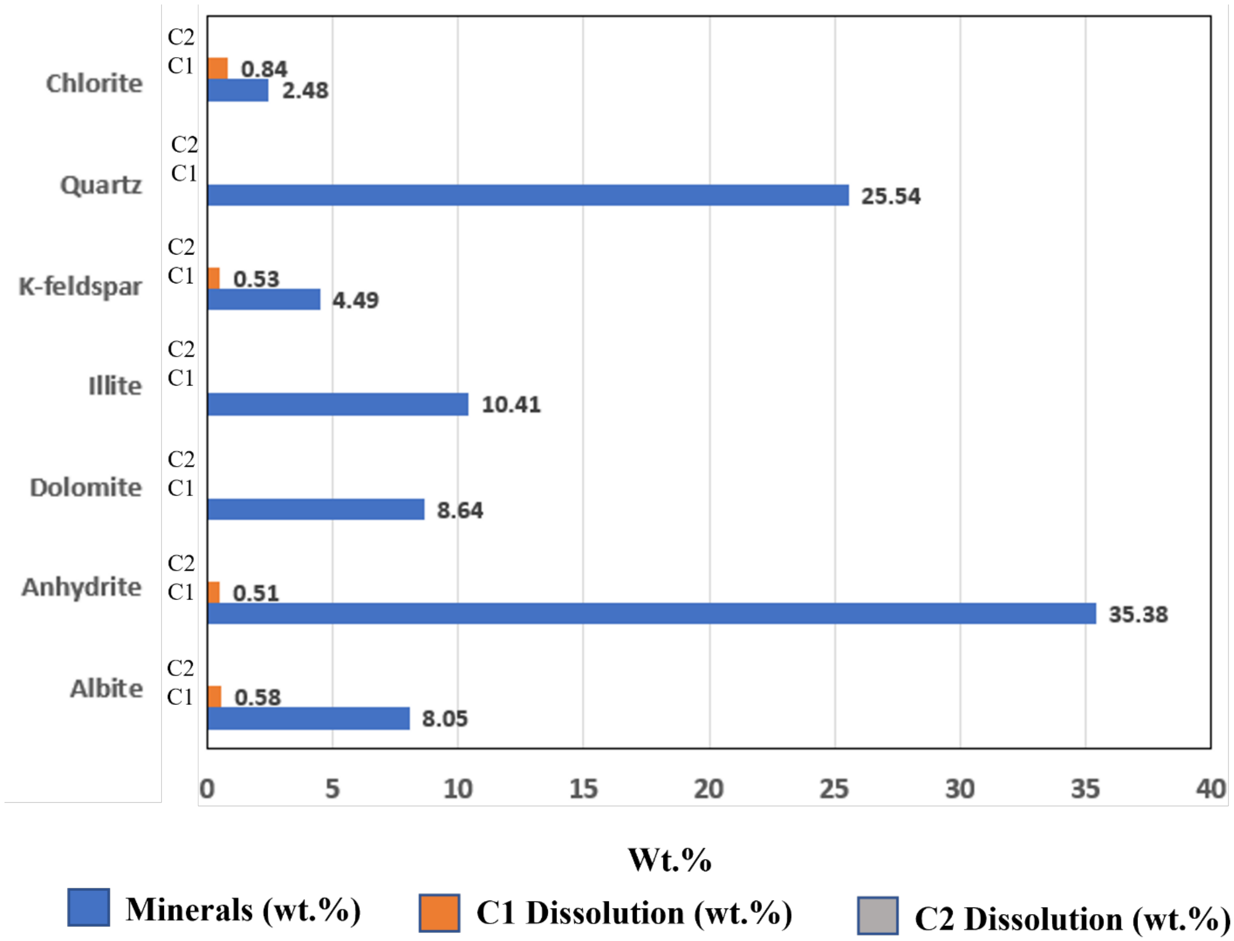

Figure 2-39. Weight percentage (wt%) of potentially reactive minerals present in the Spearfish Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray, too small to see in the figure) after 20 years of injection plus 25 years of postinjection.

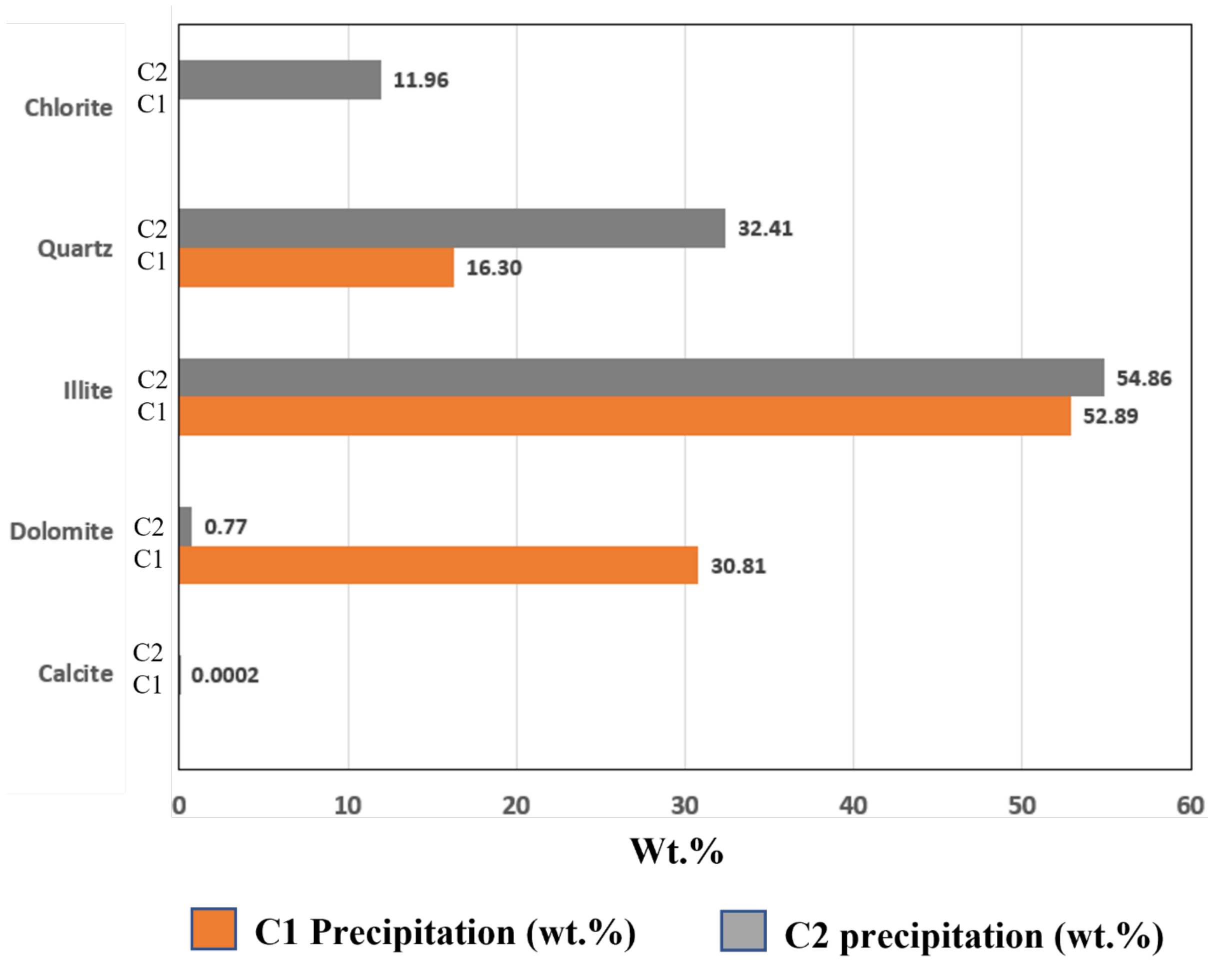

Figure 2-40. Weight percentage (wt%) of precipitated minerals in the Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time.

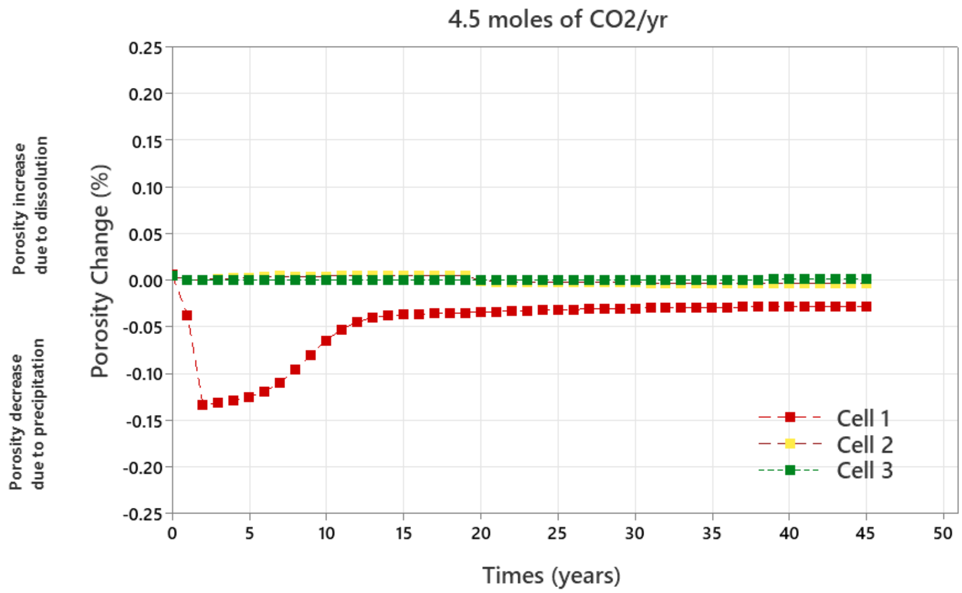

Figure 2-41. Change in percent porosity of the Spearfish cap rock. Red line shows porosity change calculated for Cell C1 at 0.5 meters above the cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation.

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the lower Piper interval. Impermeable rocks above the primary seal include the upper Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-15). Together with the Spearfish and lower Piper intervals, these intervals are 859 ft thick on average across the simulation area and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-42). Above the Inyan Kara Formation at the MAG 1 well, 2,512 ft of impermeable rocks acts as an additional seal between the Inyan Kara sandstone interval and lowermost USDW, the Fox Hills Formation (see Figure 2-43). Confining layers above the Inyan Kara sandstone interval include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-15).

Table 2-15. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the MAG 1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,092	1,316	0
Niobrara	Shale	2,408	328	1,316
Carlile	Shale	2,736	261	1,644
Greenhorn	Shale	2,997	53	1,905
Belle Fourche	Shale	3,050	250	1,958
Mowry	Shale	3,300	58	2,208
Skull Creek	Shale	3,375	229	2,282
Swift	Shale	3,831	382	2,739
Rierdon	Shale	4,213	221	3,121
Piper (Kline Member)	Limestone	4,434	147	3,342

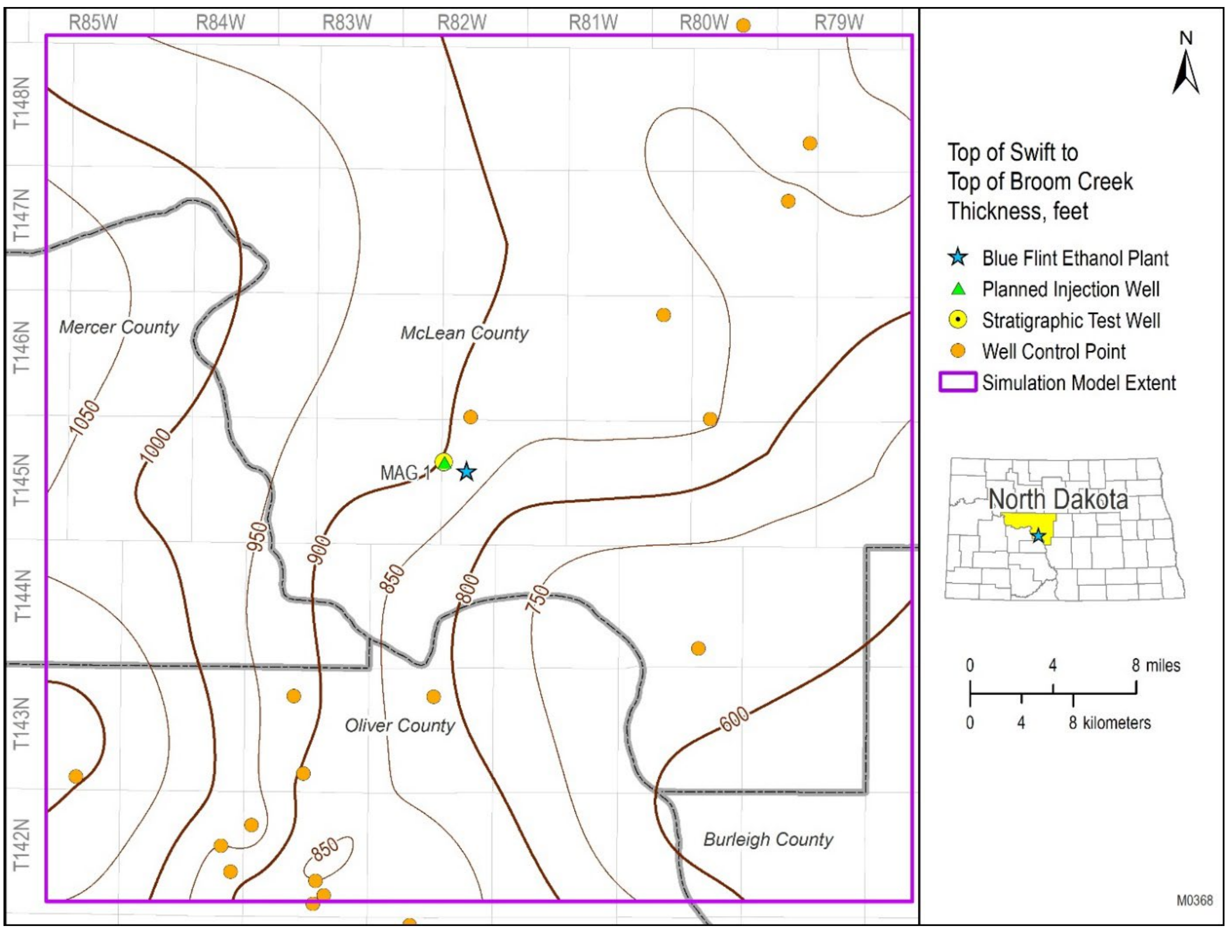

Figure 2-42. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

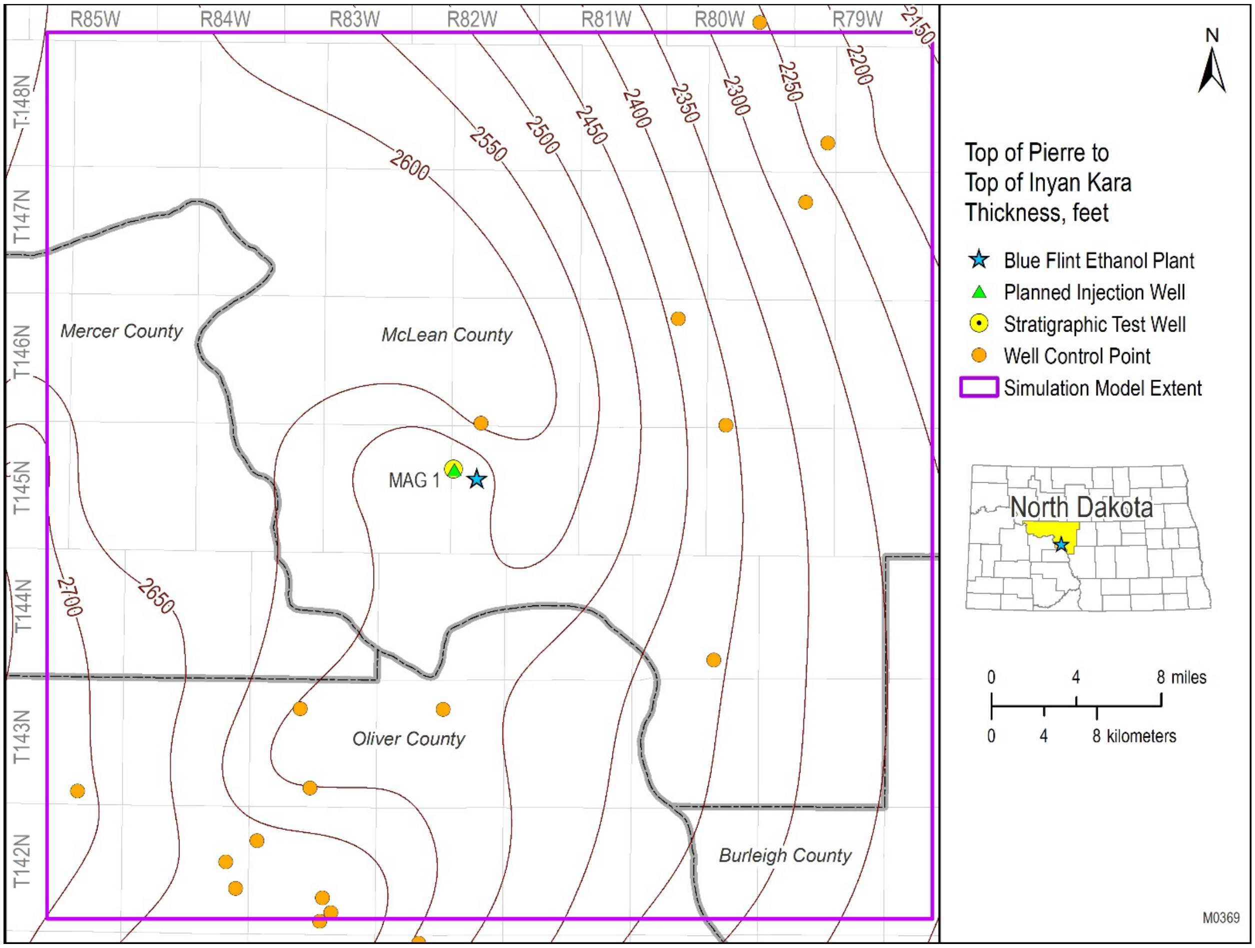

Figure 2-43. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

The formations between the Broom Creek and Inyan Kara Formations and between the Inyan Kara Formation and lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988).

Sandstones of the Inyan Kara Formation comprise the first unit, with relatively high porosity and permeability above the injection zone and the primary sealing formation. The Inyan Kara represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring digital temperature sensor (DTS) data for the Inyan Kara Formation using the downhole fiber-optic cable provides an additional opportunity for mitigation and remediation (Section 5). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at MAG 1 is approximately 3,604 ft, and the interval itself is about 228 ft thick.

2.4.3 Lower Confining Zone

The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, limestone, and anhydrite. The Amsden Formation does include some thin sandstone and dolomitic sandstone intervals on the order of 4–6 inches thick (Figure 2-9). The sandstone intervals in the Amsden Formation are isolated from the sandstones of the Broom Creek Formation by thick impermeable dolostone intervals (Figure 2-9). The top of the Amsden Formation was placed at the top of an argillaceous dolostone, which has relatively high GR character that can be correlated across the project area (Figure 2-9). The Amsden Formation is 4,810 ft below land surface and 276 ft thick at the Blue Flint site as determined at the MAG 1 well (Figures 2-44 and 2-45).

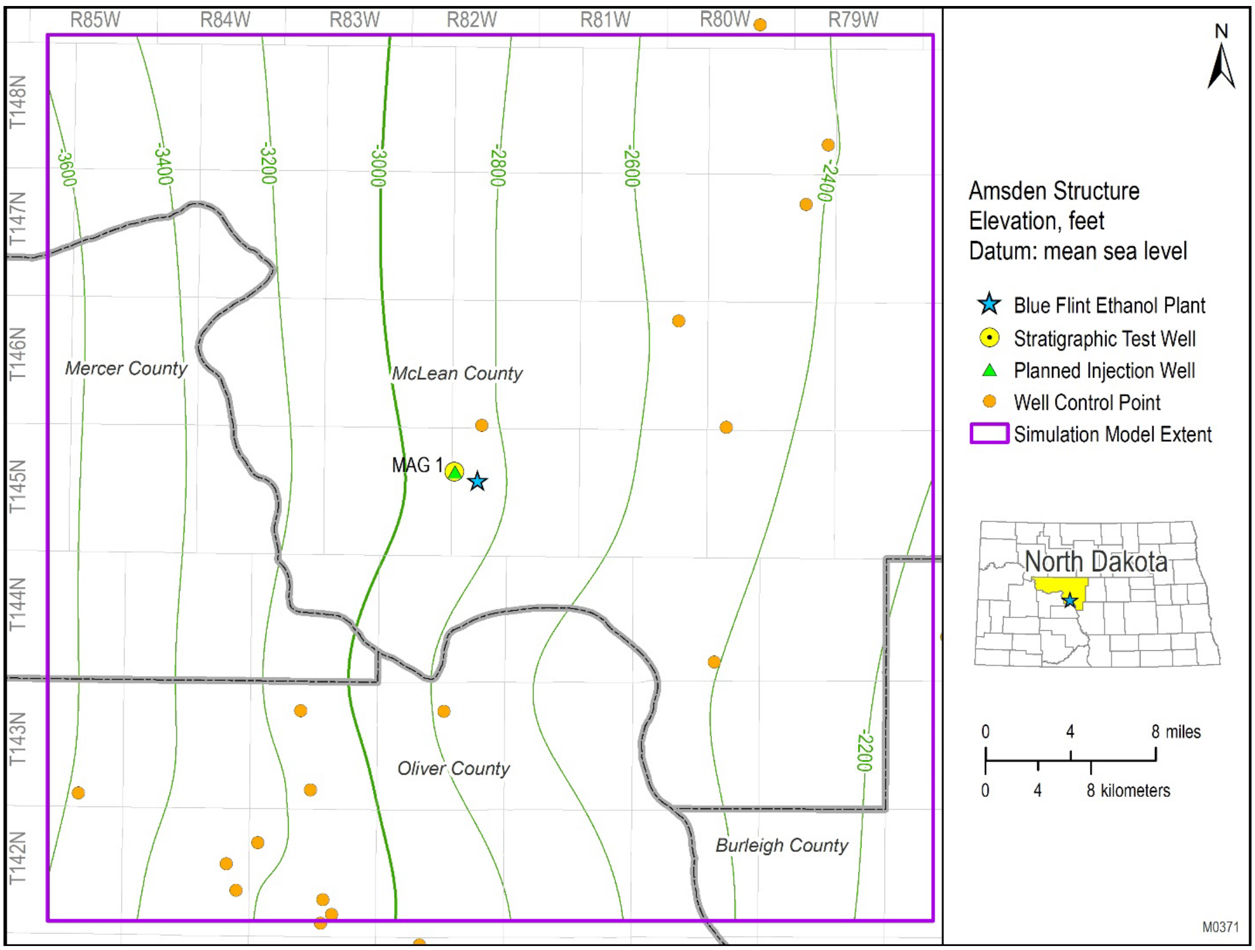

Figure 2-44. Structure map of the Amsden Formation across the greater Blue Flint project area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

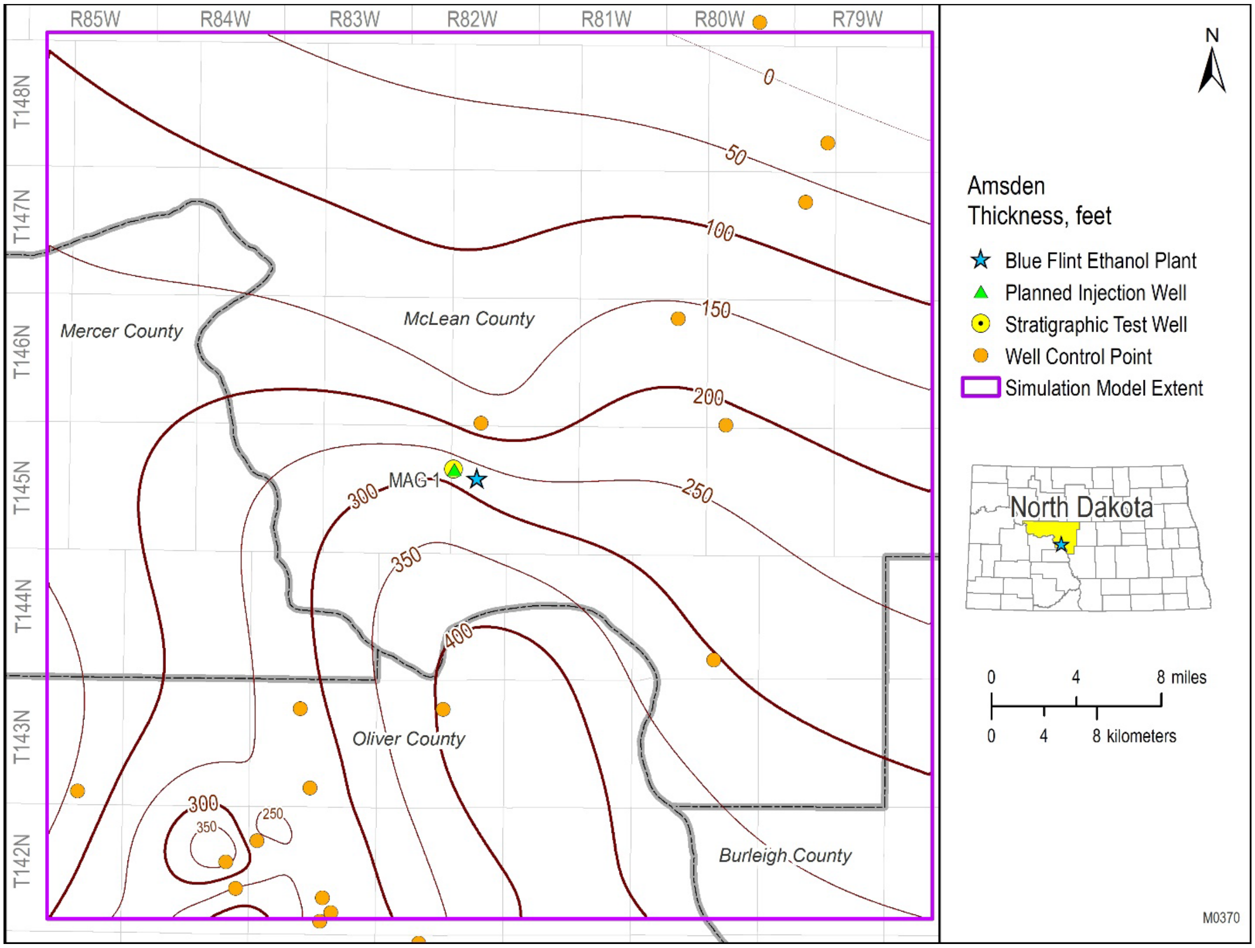

Figure 2-45. Isopach map of the Amsden Formation across the greater Blue Flint project area. The convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

The contact between the underlying Amsden Formation and the overlying Broom Creek Formation is evident on wireline logs as there is a lithological change from the dolostone and anhydrite beds of the Amsden Formation to the porous sandstones of the Broom Creek Formation. This lithologic change is also recognized in the SW Core samples from MAG 1. The lithology of the sidewall-cored section of the Amsden Formation from MAG 1 is the predominant dolostone and anhydrite and lesser predominant lithologies of shaly sandstone and siltstone. Table 2-16 shows the range of porosity and permeability values of the SW Core samples from the Amsden Formation.

Table 2-16. Amsden SW Core Sample Porosity and Permeability from MAG 1

Sample Depth, ft	Porosity %	Permeability, mD
4,845	9.59	0.003
4,851*	18.80	117
4,860*	8.86	1.46
4,865	2.15	0.0003
4,869	11.56	0.009
4,875**	2.9	0.005
4,880*	3.74	0.134
4,889*	10.26	0.239
Range	(2.15–18.80)	(0.0003–117)
Values measured at 2,400 psi		

* Sample is fractured or chipped. The measured permeability and/or porosity may be higher than its real value.

** Sample is very short; the measured porosity may be higher than its real value because of lack of conformation of boot material to plug surface.

2.4.3.1 Mineralogy

Well logs and the thin-section analyses show that the Amsden Formation comprises dolostone, sandstone, anhydrite, and limestone. The porosity averages 7%, and permeability is very low. Figures 2-46, 2-47, and 2-48 show thin-section images representative of the Amsden Formation.

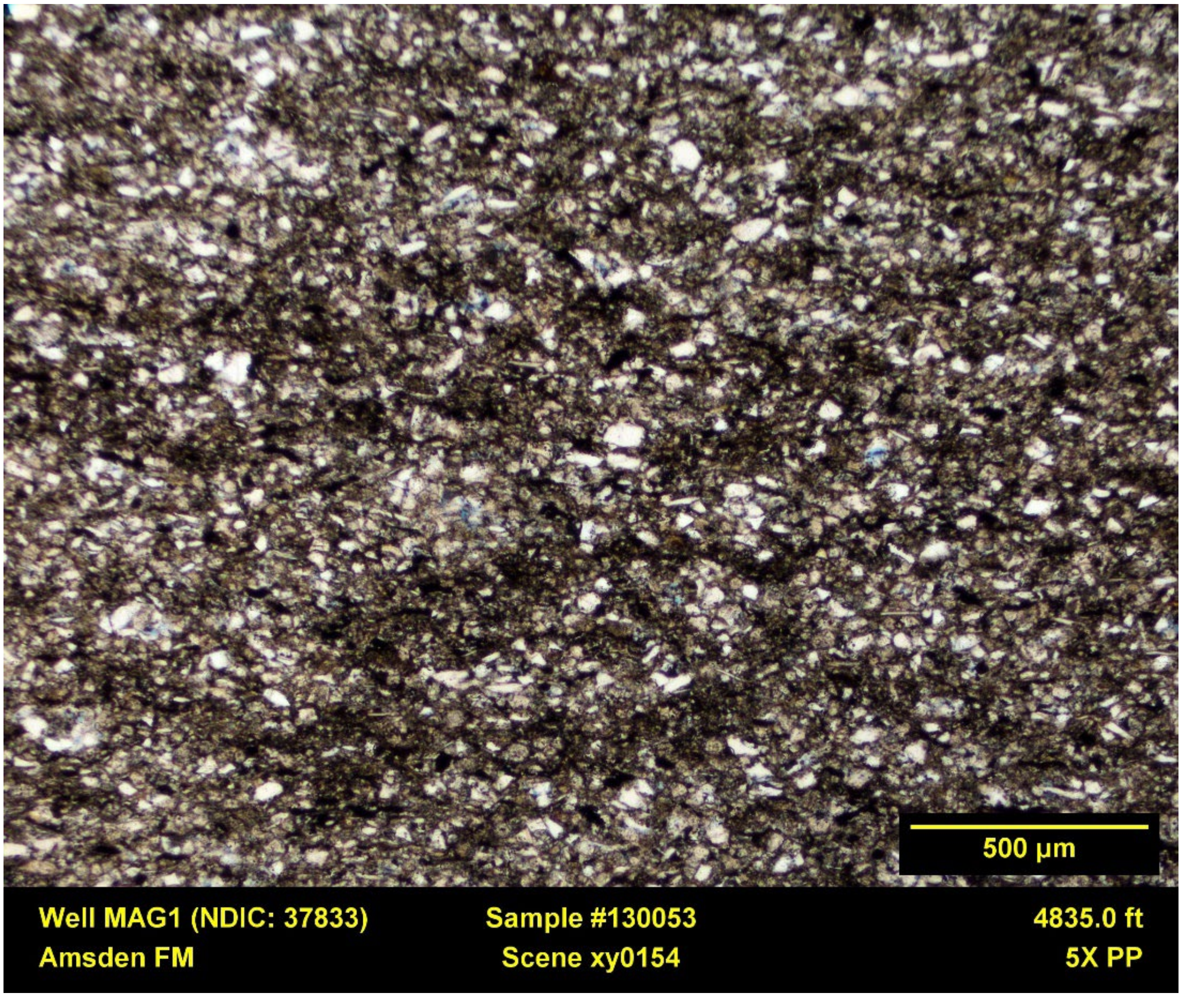

Figure 2-46. Thin section in the Amsden Formation. This example shows a dolomite matrix (gray/brown) with quartz grains distributed throughout. Minor porosity is observed.

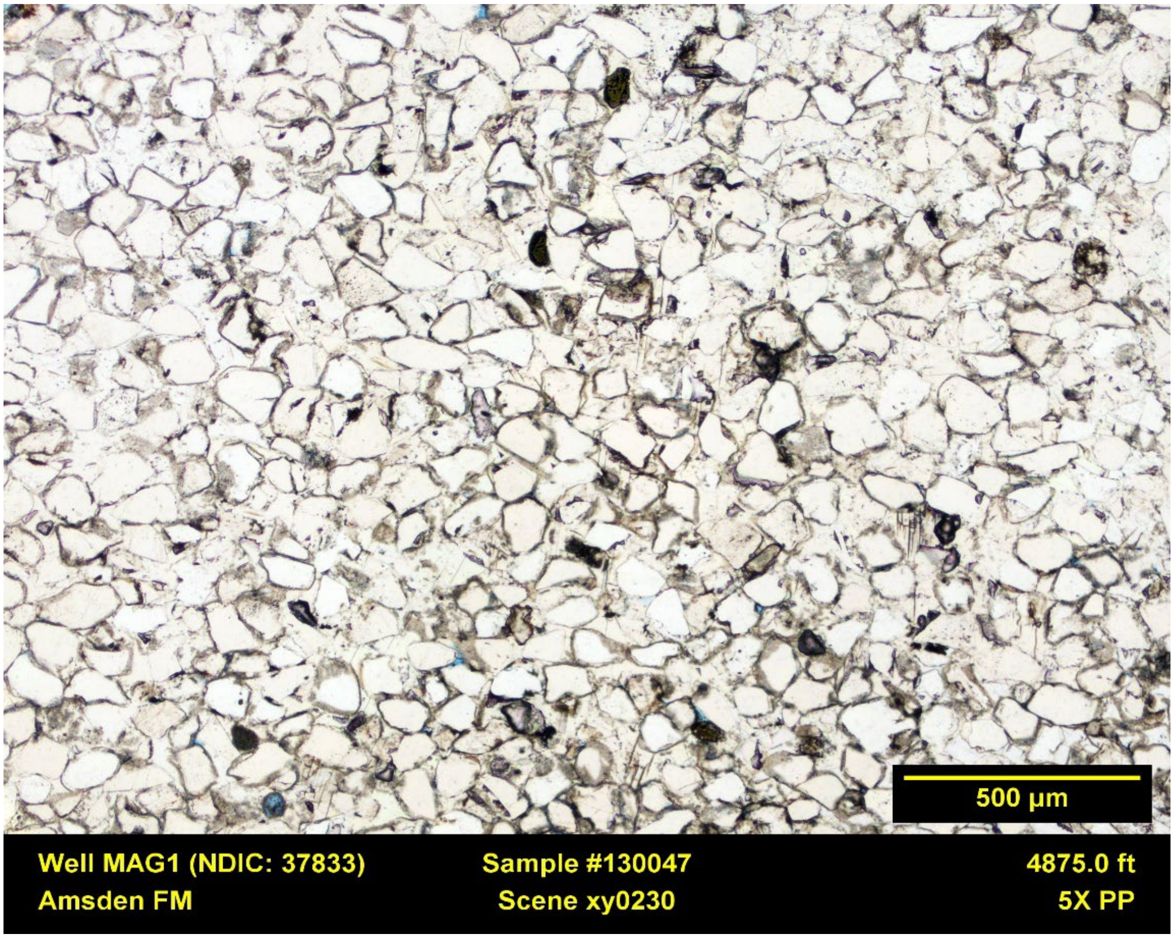

Figure 2-47. Thin section in the Amsden Formation. This interval is dominated by anhydrite and quartz. In this example, quartz grains are tightly cemented, and almost no porosity is observed.

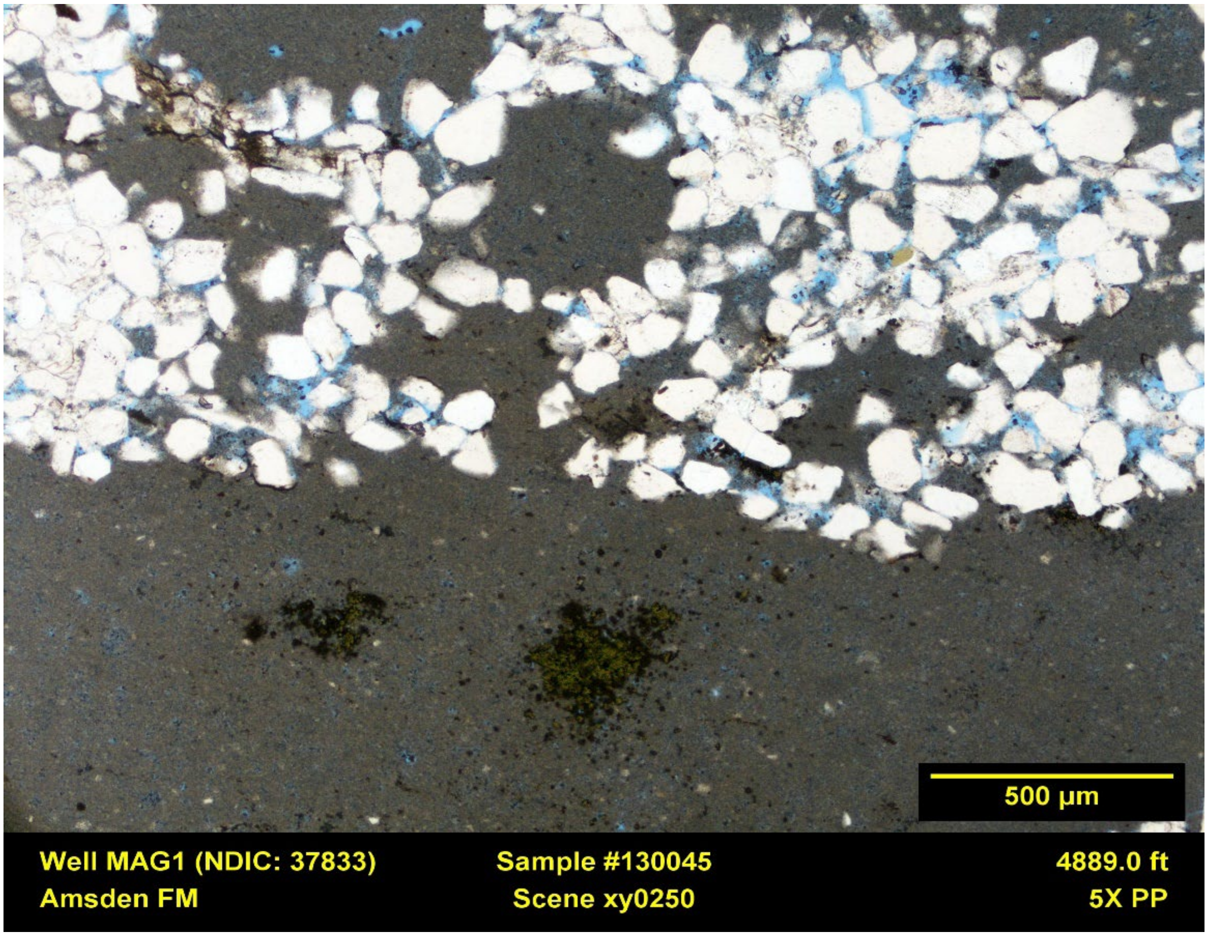

Figure 2-48. Thin section in the Amsden Formation. This interval shows a fine micritic dolomite with minor quartz grains. Porosity is generally low and found to be intergranular or due to the dissolution of dolomite in this example.

XRD was performed, and the results confirm the observations made during core observation, thin-section description, and well log analysis. Amsden intervals show that dolomite, anhydrite, quartz, and clay are the dominant minerals (Table 2-17). XRF data are presented in Figure 2-49 for the Amsden Formation.

Table 2-17. XRD Analysis in the Lower Confining Zone (Amsden Formation) from MAG 1 Well. Only major constituents are shown.

Formation	STAR No.	Depth, ft	% Clay	% K-Feldspar	% P-Feldspar	% Quartz	% Calcite	% Dolomite	% Ankerite	% Anhydrite	% Halite
Amsden	130054	4,832	8.8	7.0	2.3	21.4	0.0	59.6	0.0	0.0	0.5
Amsden	130053	4,835	16.1	9.7	0.0	39.4	0.0	33.7	0.0	0.0	0.4
Amsden	130052	4,845	6.4	5.4	2.5	25.1	0.0	60.6	0.0	0.0	0.0
Amsden	130051	4,851	0.0	1.1	0.0	64.7	0.0	7.6	0.0	26.2	0.5
Amsden	130050	4,860	2.0	2.2	0.0	47.1	0.0	12.8	0.0	35.9	0.0
Amsden	130049	4,865	2.2	0.0	0.0	1.7	0.0	7.2	0.0	88.9	0.0
Amsden	130048	4,869	16.3	9.3	0.4	27.4	0.0	44.4	0.0	0.0	0.4
Amsden	130047	4,875	0.0	2.2	0.0	39.0	0.0	5.1	0.0	53.7	0.0
Amsden	130046	4,880	0.0	1.7	0.0	48.6	0.0	1.6	0.0	48.2	0.0
Amsden	130045	4,889	0.0	0.6	0.0	7.6	0.0	0.0	0.0	91.7	0.0

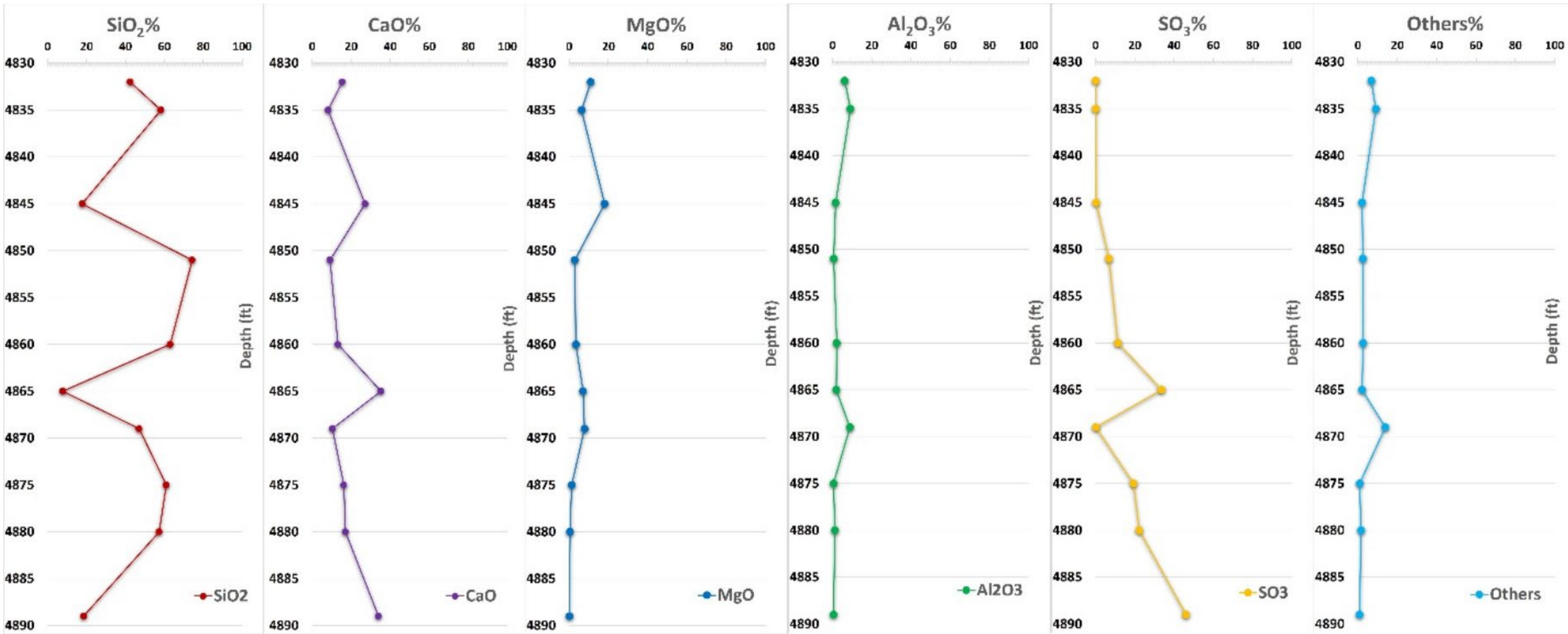

Figure 2-49. XRF analysis in the lower confining zone (Amsden Formation) from MAG 1.

2.4.3.2 Geochemical Interaction

The Broom Creek Formation's underlying confining layer, the Amsden Formation, was investigated using PHREEQC geochemical software. A vertically oriented 1D simulation was created using a stack of thirteen cells, each cell 1 meter in thickness. The formation was exposed to CO_2 at the top boundary of the simulation which was allowed to enter the system by advection and dispersion processes. Direct contact between the Amsden Formation and free-phase saturation from the injection stream is not expected to occur. Results were calculated at the center of each cell below the confining layer–CO_2 exposure boundary. The mineralogical composition of the Amsden Formation was honored (Table 2-18). The Amsden Formation brine composition was assumed to be the same as the known composition from the Broom Creek Formation injection zone above (Table 2-15). The CO_2 stream composition used in the simulation was 100% CO_2. The maximum formation temperature and pressure projected from CMG simulation results described in Section 3.1 were used to represent the potential maximum pore pressure and temperature levels. The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change.

Table 2-18. Mineral Composition of the Amsden Formation Derived from XRD Analysis of MAG 1 Core Samples at a Depth of 4,832 ft MD

Minerals, wt%	
Illite	8.81
K-Feldspar	6.96
Albite	2.29
Quartz	21.44
Dolomite	59.62

Figure 2-50 shows change in fluid pH over 45 years of simulation time as CO_2 enters the system. Initial change in pH in all of the cells from 7.48 to 7.2 is related to initial equilibration of the model. For the cell at the CO_2 interface, C1, the pH begins to decline significantly after Year 3, declines to a level of 6.0 after 7 years of injection, and slowly declines further to 5.4 after an additional 10 years of postinjection. Progressively less or slower pH change occurs for each cell as the distance of the cell from the CO_2 interface increases.

Figure 2-51 shows that CO_2 does not penetrate more than 11 meters (represented by Cells C12–C13) within the 45 years of simulation.

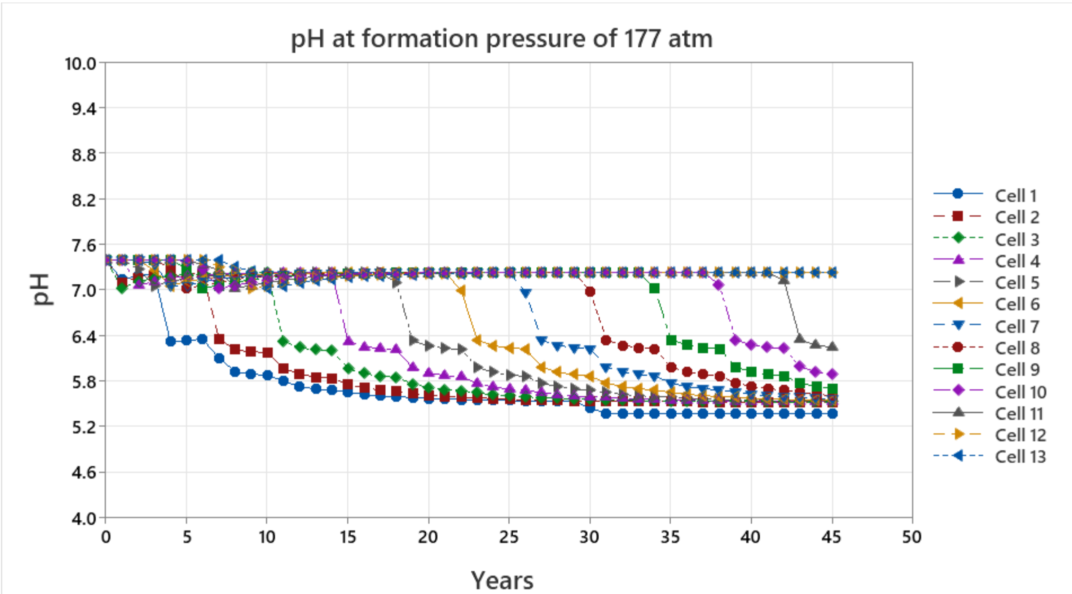

Figure 2-50. Change in fluid pH in the Amsden Formation underlying confining layer for Cells C1–C13.

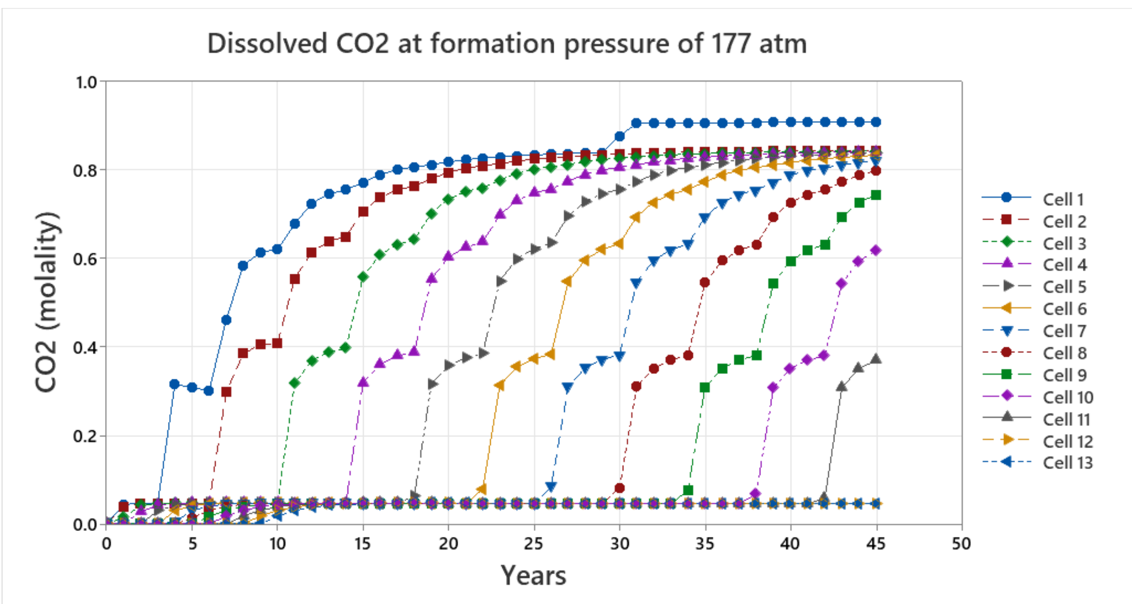

Figure 2-51. CO_2 concentration (molality) in the Amsden Formation underlying confining layer for Cells C1–C13.

Figure 2-52 shows the changes in mineral dissolution and precipitation in grams per cubic meter over simulation years. For Cells C1 and C2, albite and K-feldspar start to dissolve from the beginning of the simulation period while quartz and illite clays start to precipitate.

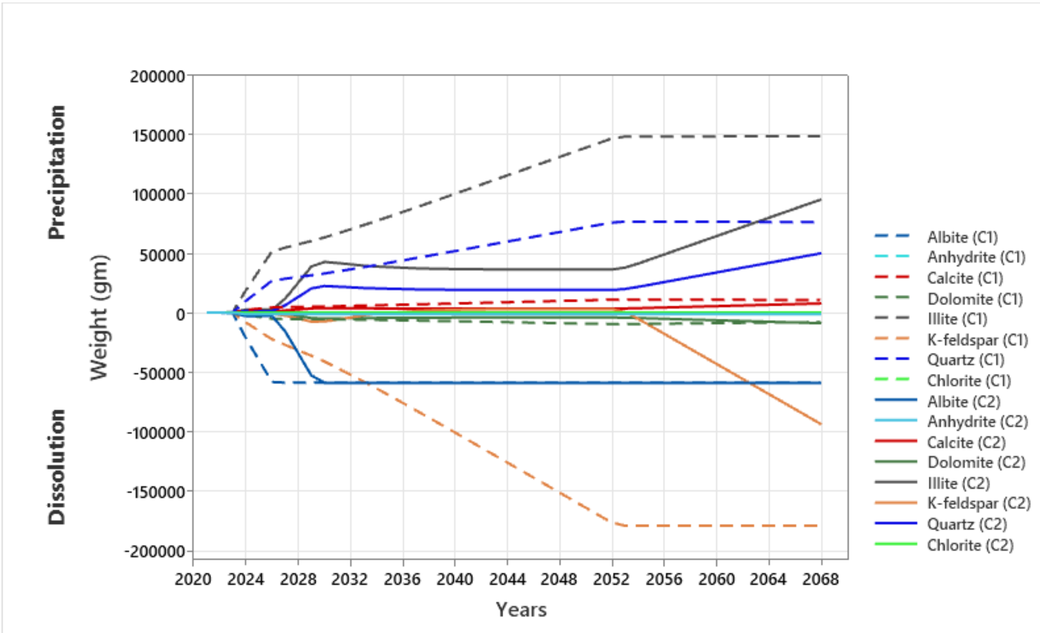

Figure 2-52. Dissolution and precipitation of minerals in the Amsden Formation underlying confining layer. Dashed lines show results for Cell C1, 0 to 1 meter below the Amsden top. Solid lines show results for Cell C2, 1 to 2 meters below the Amsden top.

Figure 2-53 represents the initial fractions of potentially reactive minerals in the Amsden Formation based on the XRD data shown in Table 2-18. The expected dissolution of these minerals in weight percentage is also shown for Cells C1 and C2 of the model. In Cells 1 and 2, albite and K-feldspar are the primary minerals that dissolve. Dolomite dissolution in Cell 1 and 2 is insignificant compared to other minerals. No dissolution is observed for illite and quartz. The dissolved minerals are almost completely replaced by the precipitation of other minerals, as shown in Figure 2-54.

Figure 2-54 represents expected minerals to be precipitated in weight percentage (wt%) shown for Cells C1 and C2 of the model. In Cell 1 and 2, illite, quartz, and calcite are the minerals to be precipitated.

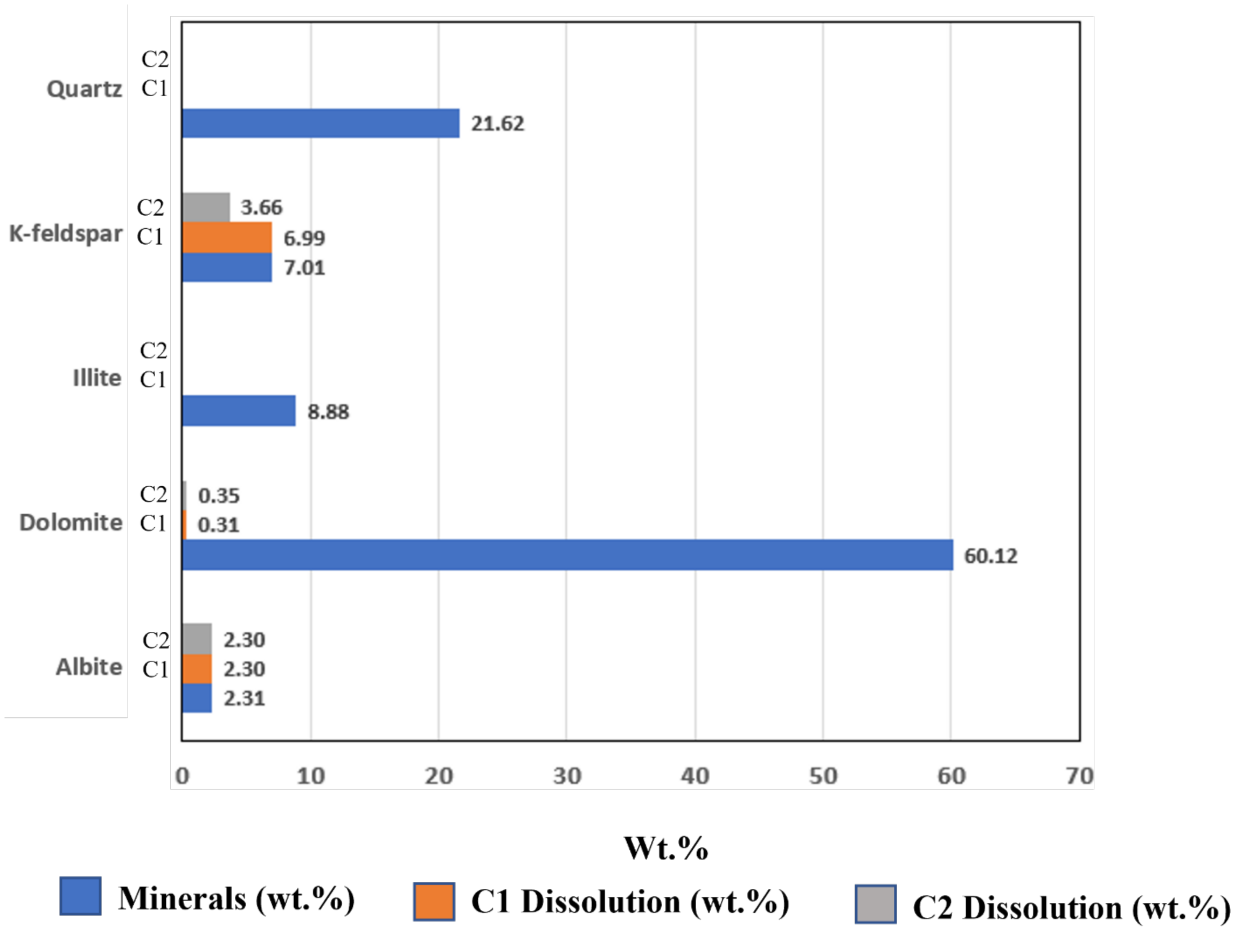

Figure 2-53. Weight percentage (wt%) of potentially reactive minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time.

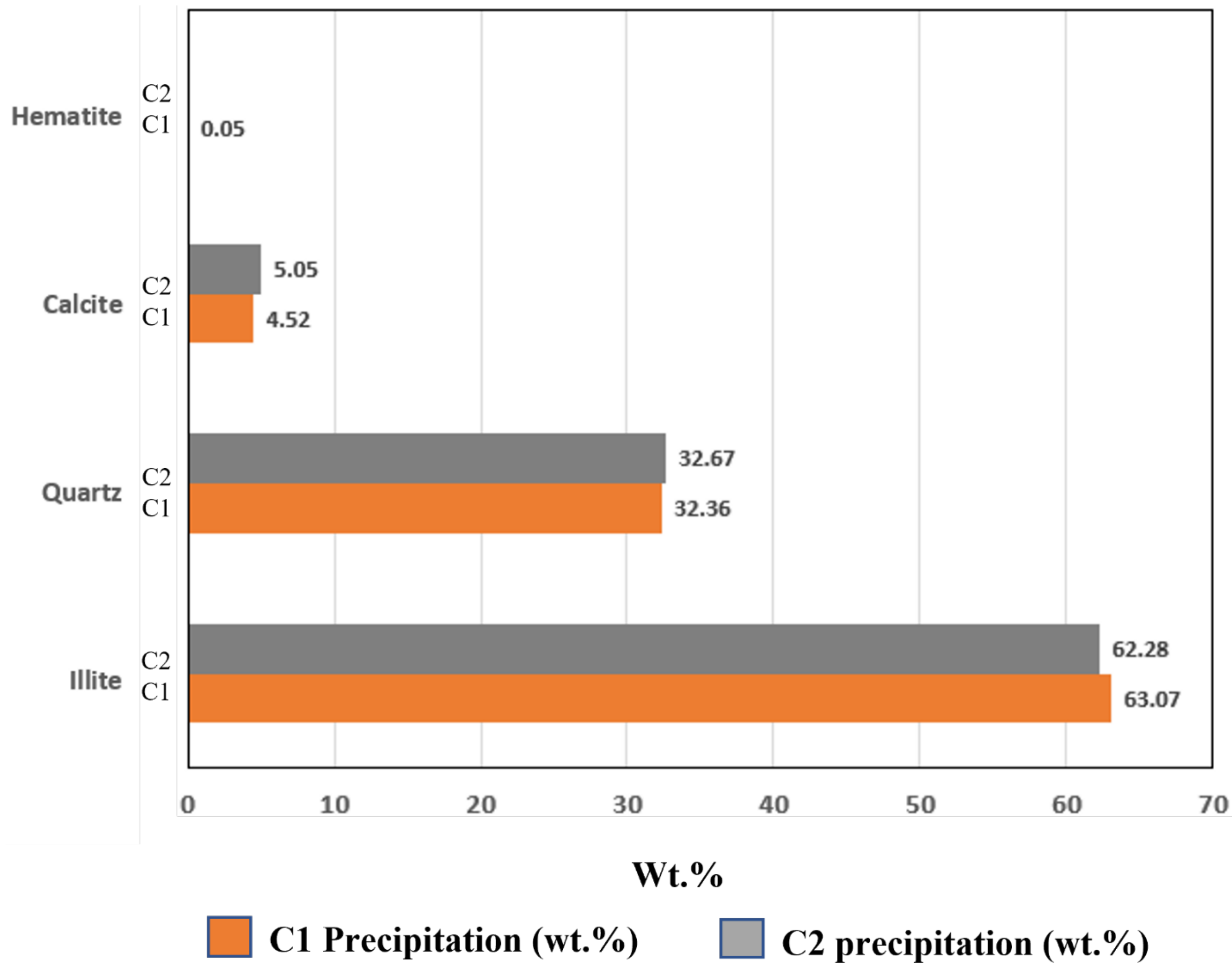

Figure 2-54. Weight percentage (wt%) of precipitated minerals in the Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time.

Change in porosity (% units) of the Amsden Formation underlying confining layer is displayed in Figure 2-55 for Cells C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 0.4% change during the life of the simulation. Cell C1 shows an initial porosity increase of 0.04%, but this change is temporary. At later times, Cells C1–C3 experience a porosity decrease up to 2.5%. No significant porosity changes were observed in Cells C1–C3 after 12 years of injection. Cells C4–C13 showed similar results, with net porosity change being less than 0.4%.

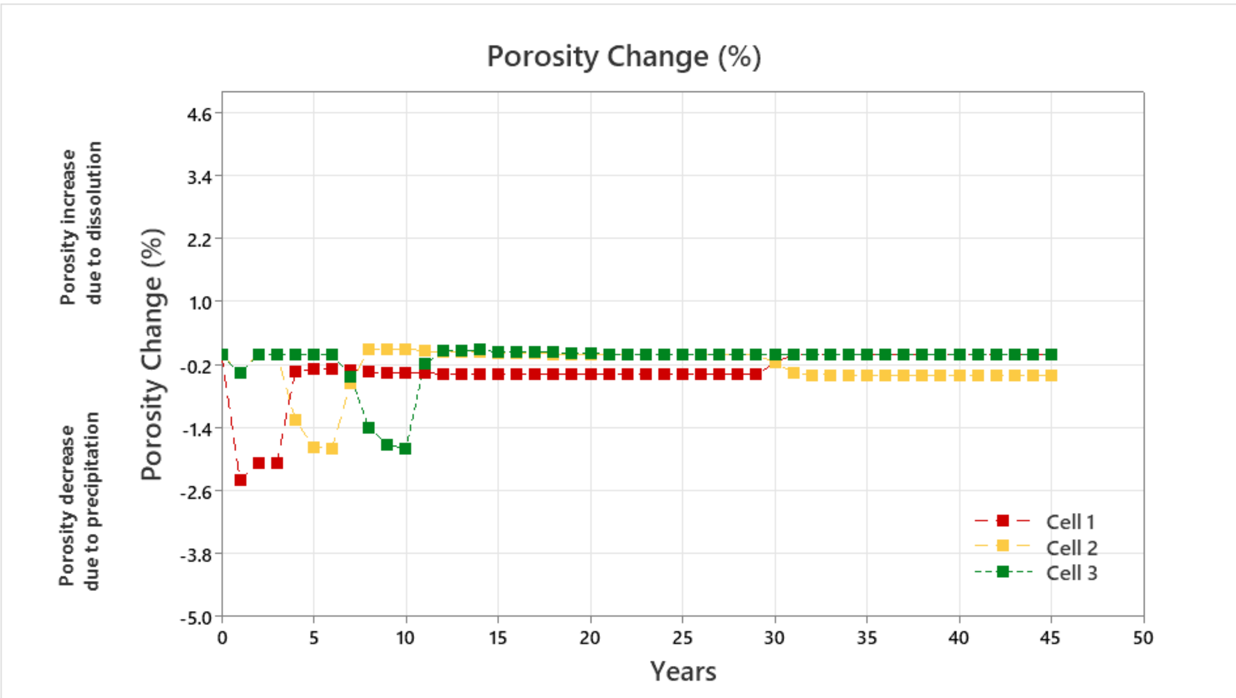

Figure 2-55. Change in percent porosity in the Amsden Formation underlying confining layer. Red line shows porosity change for Cell C1, 0 to 1 meter below the Amsden Formation top. Yellow line shows Cell C2, 1 to 2 meters below the Amsden Formation top. Green line shows Cell C3, 2 to 3 meters below the Amsden top. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation.

2.4.4 Geomechanical Information of Confining Zone

2.4.4.1 Borehole Image Fracture Analysis

Borehole image logs were used to evaluate fractures within the upper and lower confining zones. The natural fractures and in situ stress directions were assessed through the interpretation of the FMI log acquired from the MAG 1 well. The FMI log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed.

Figures 2-56a, 2-56b, 2-57, 2-58, and 2-59 show sections of the interpreted borehole imagery and the primary features observed in the Piper, Spearfish Formation and Amsden Formation, respectively. Drilling induced fractures were observed in the Piper Formation as shown in Figure 2-56a in the far-right track. The far-right track on Figure 2-56b demonstrates that the tool provides information on surface boundaries and bedding features that characterize the Spearfish Formation. Figure 2-57 shows that features that have an electrically conductive signal in Spearfish Formation are observed. The logged interval of the Amsden Formation shows the main features represented by horizontal and oblique stratification fractures (Figure 2-58) and the presence of rare resistive fractures (Figure 2-59). Rose diagrams showing dip, dip azimuth, and strikes for conductive and drilling induced fractures observed in the borehole imagery are shown in Figures 2-60–2-62. These two fracture types were studied to evaluate potential leakage pathways as well as maximum horizontal stress. The diagrams shown in Figures 2-60 and 2-61 provide the dip orientation of the electrically conductive features in Spearfish and Amsden Formations, respectively. Breakouts were not identified in Spearfish or Amsden Formations. The drilling-induced fractures observed in the Piper Formation are oriented NE–SW ; these features are parallel to the maximum horizontal stress (SHmax), (Figure 2-62).

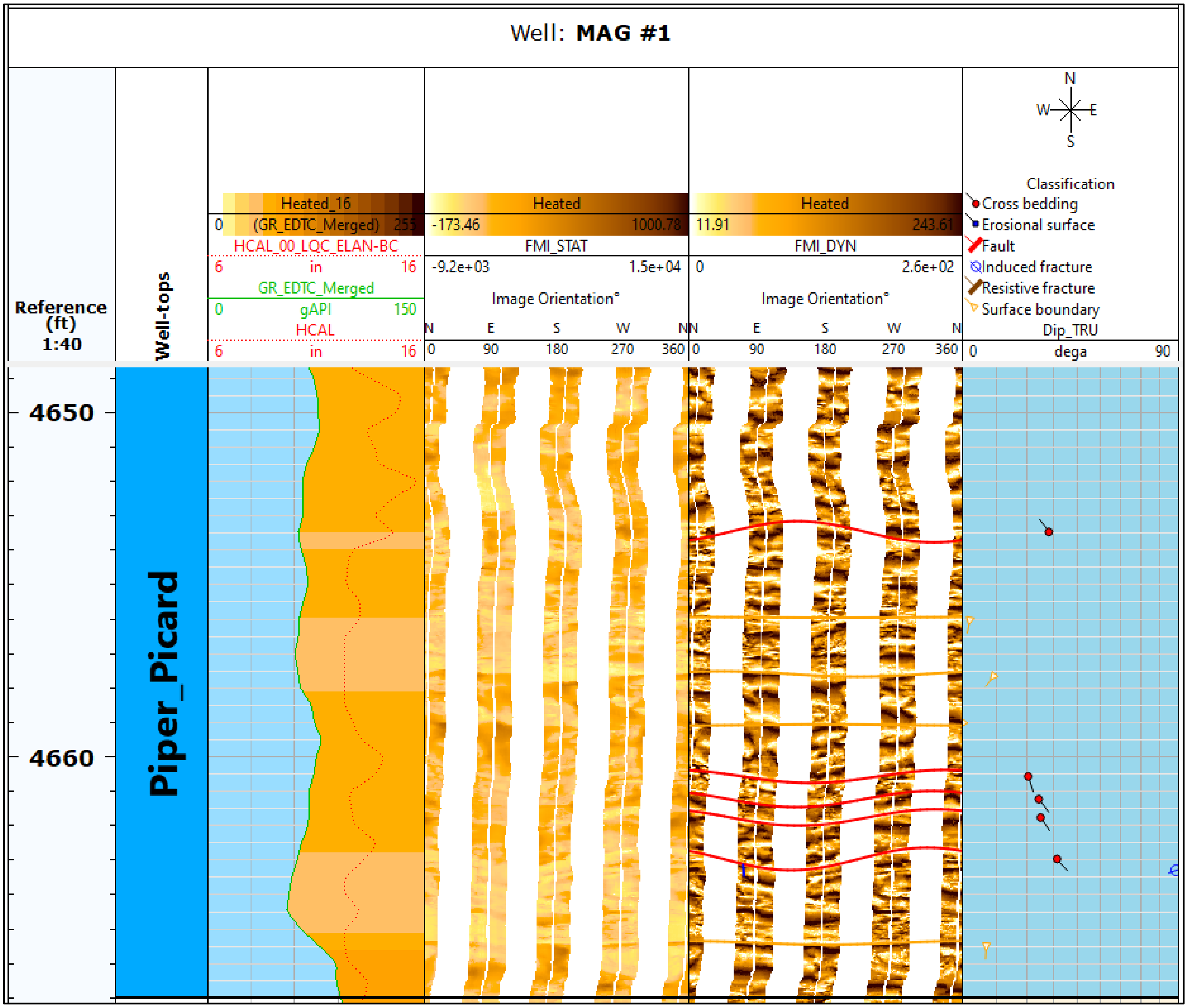

Figure 2-56a. Examples of the interpreted FMI log for the MAG 1 well showing one of the drilling induced fractures observed in the Piper Formation.

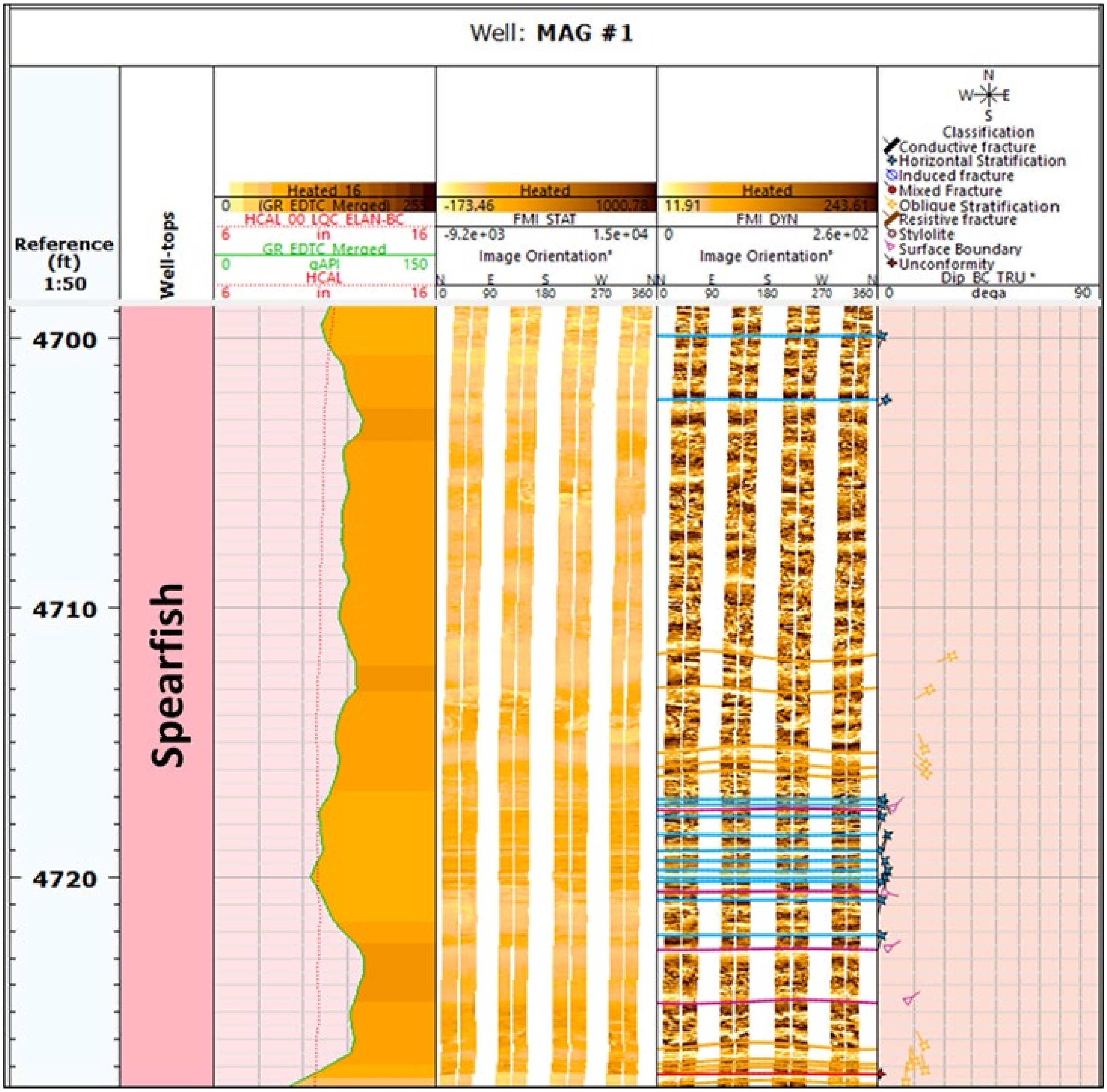

Figure 2-56b. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Spearfish Formation FMI image analysis.

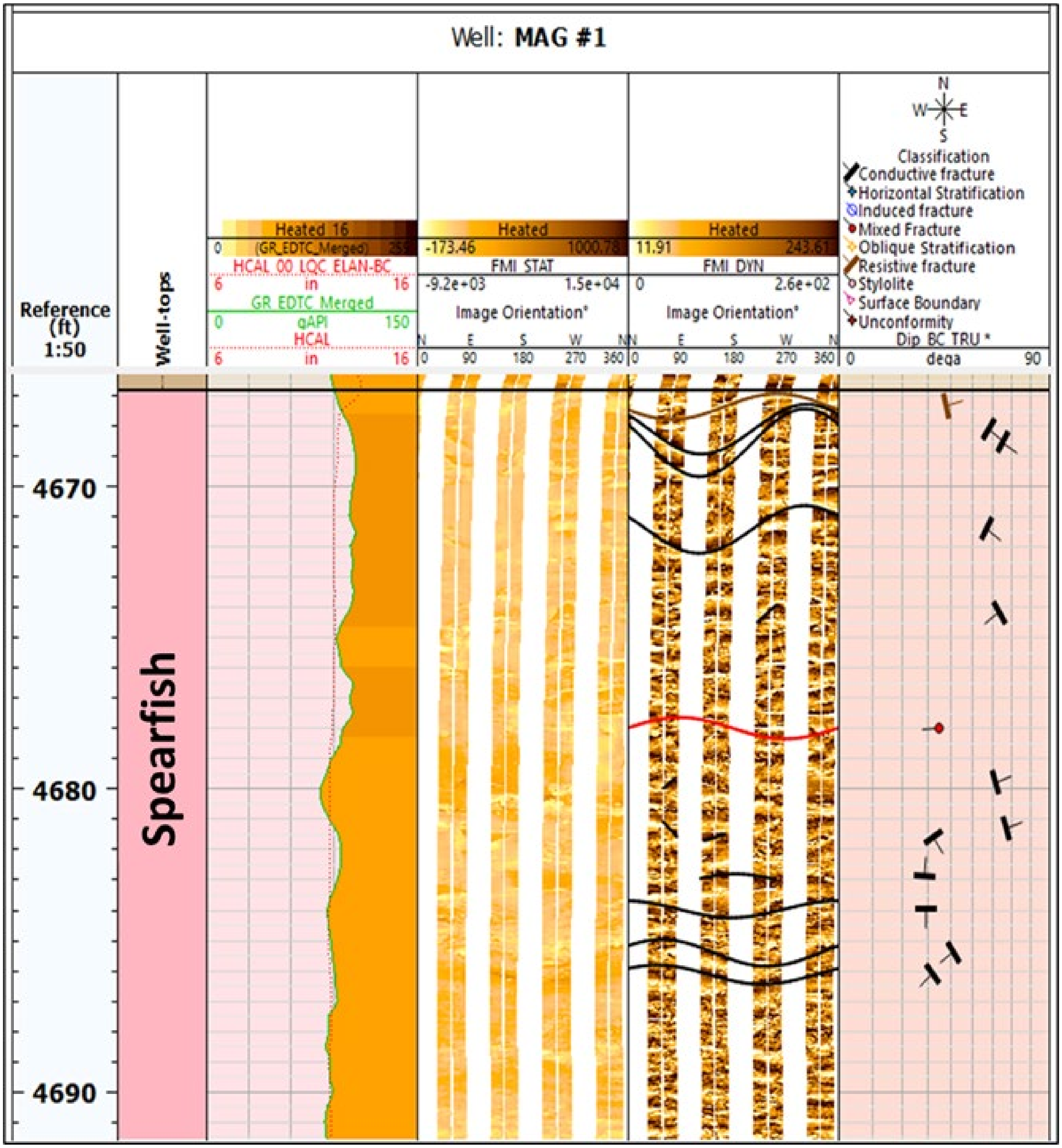

Figure 2-57. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, resistive fracture, mixed fracture, horizontal stratification, and oblique stratification) seen in Spearfish Formation FMI image analysis.

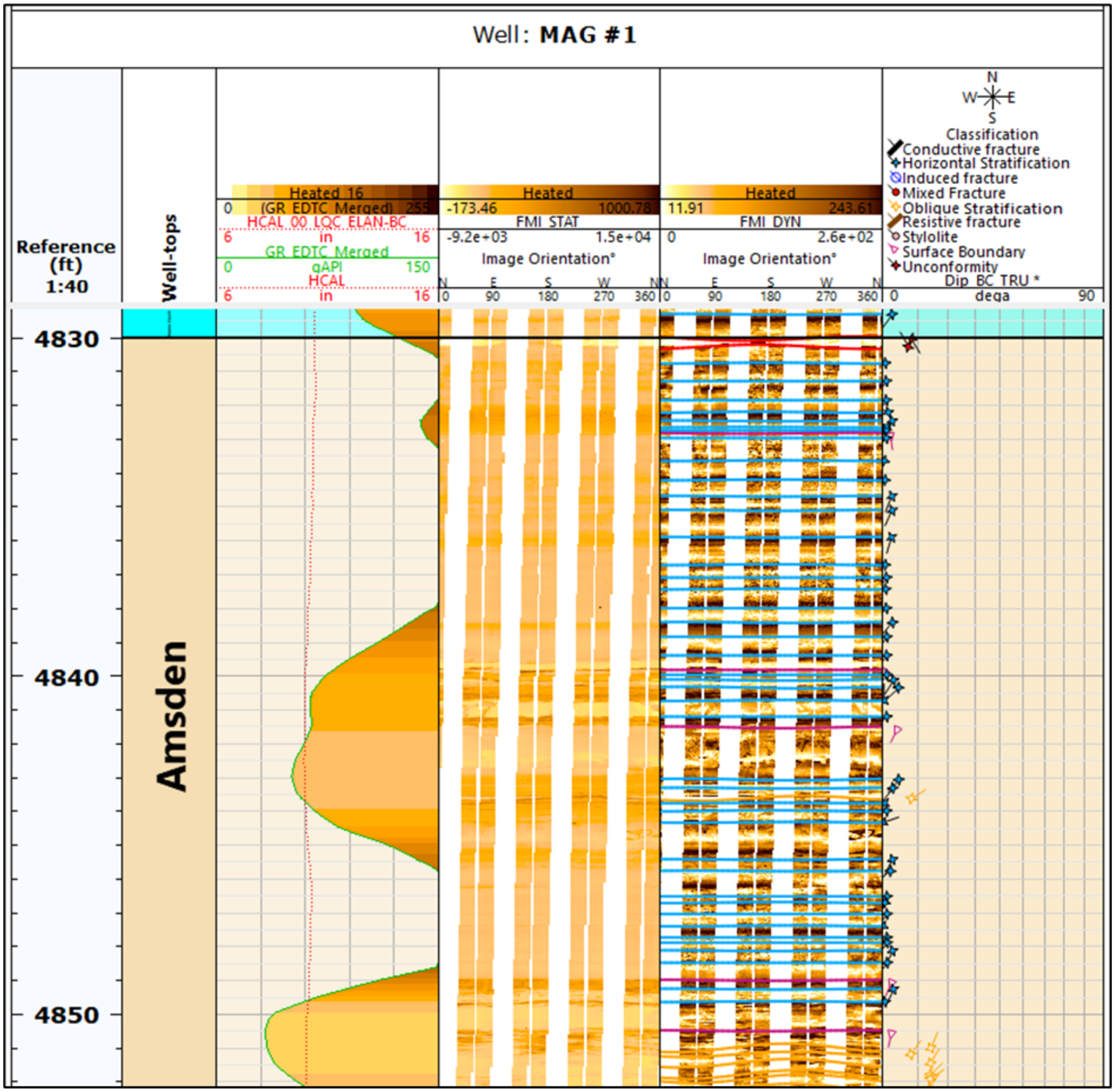

Figure 2-58. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis.

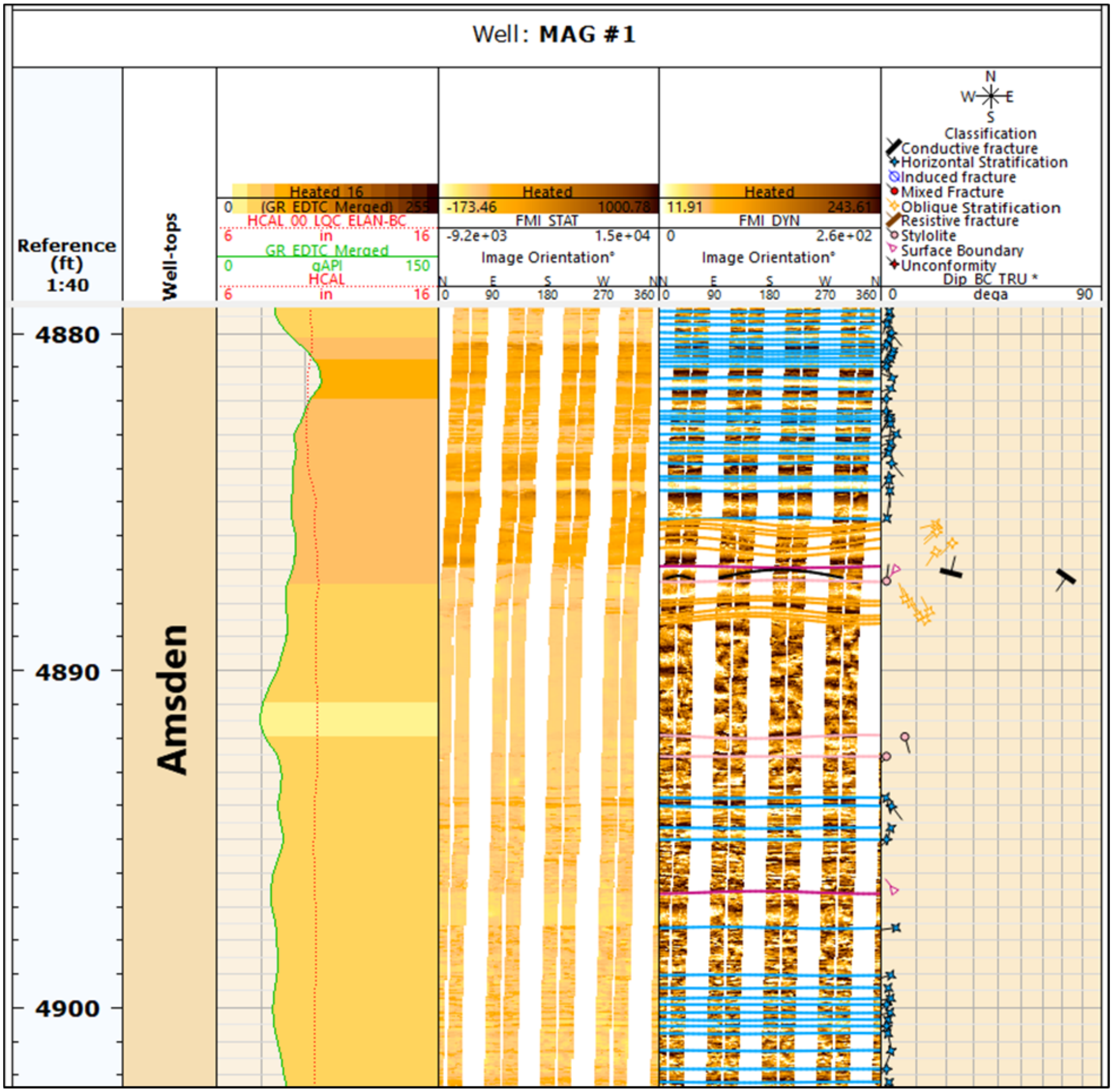

Figure 2-59. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, stylolites, horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis.

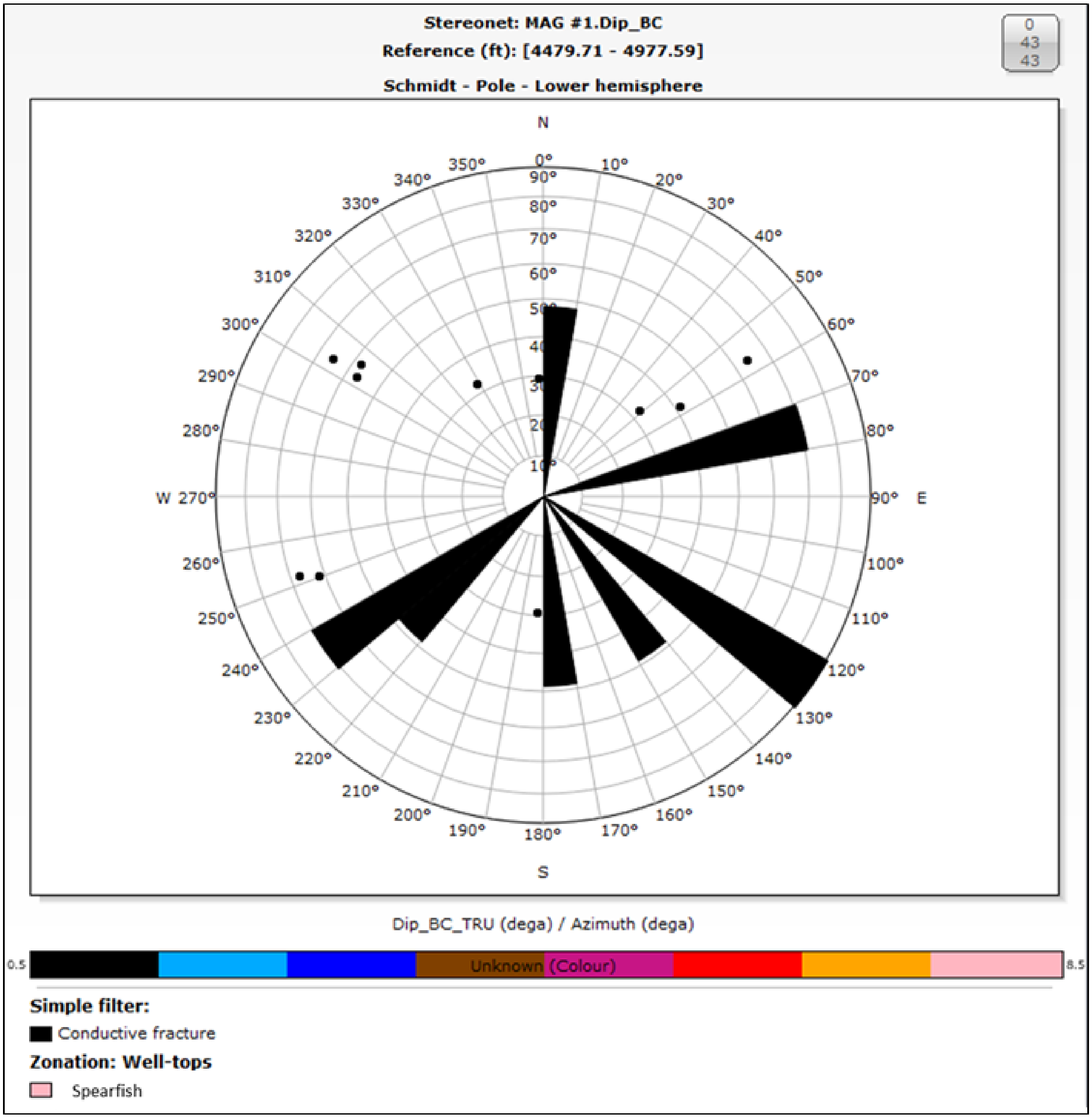

Figure 2-60. This example shows the dip azimuth and dip angle for conductive fractures seen in the Spearfish Formation.

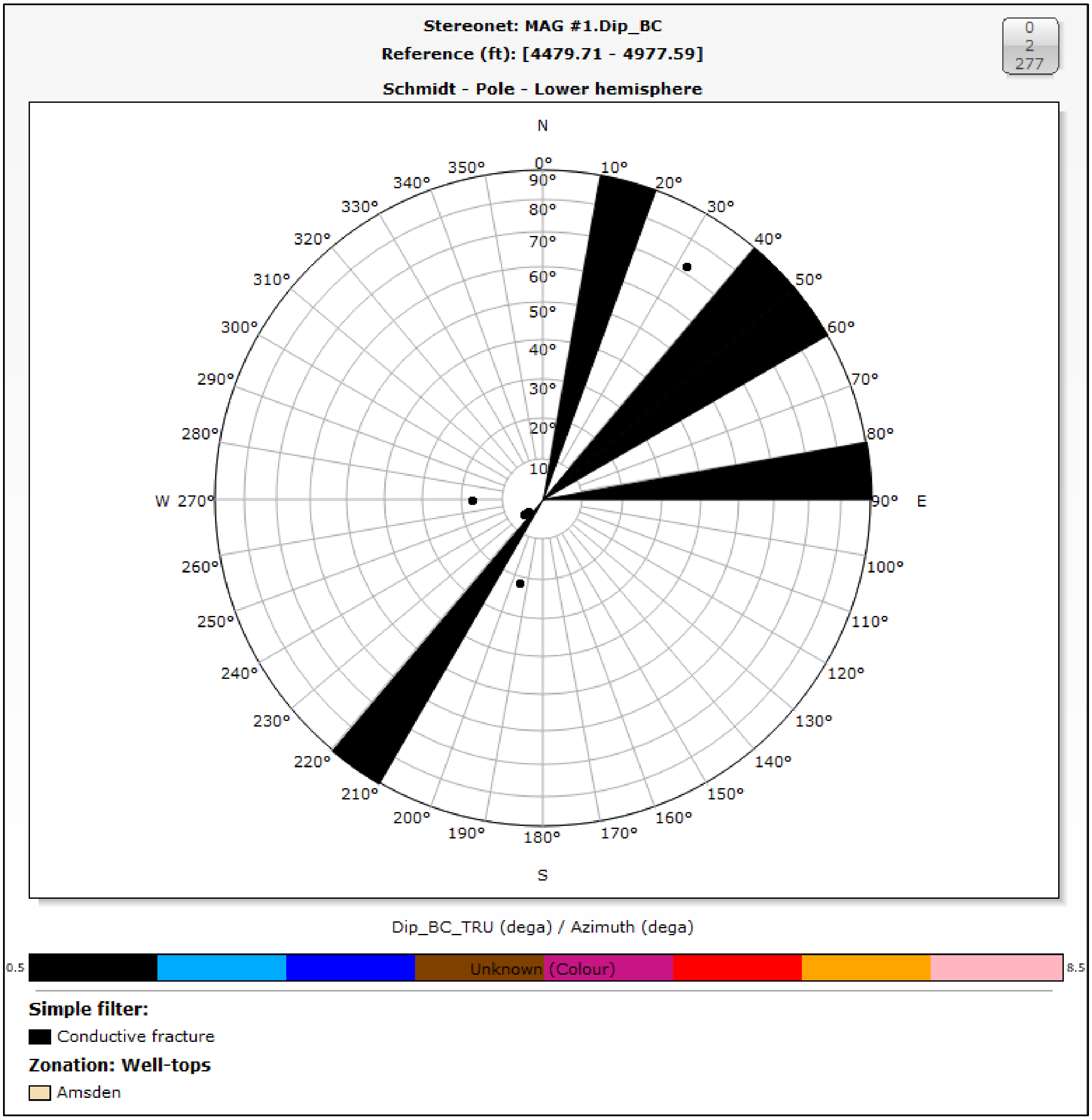

Figure 2-61. This example shows the dip azimuth and dip angle for conductive fractures seen in the Amsden Formation.

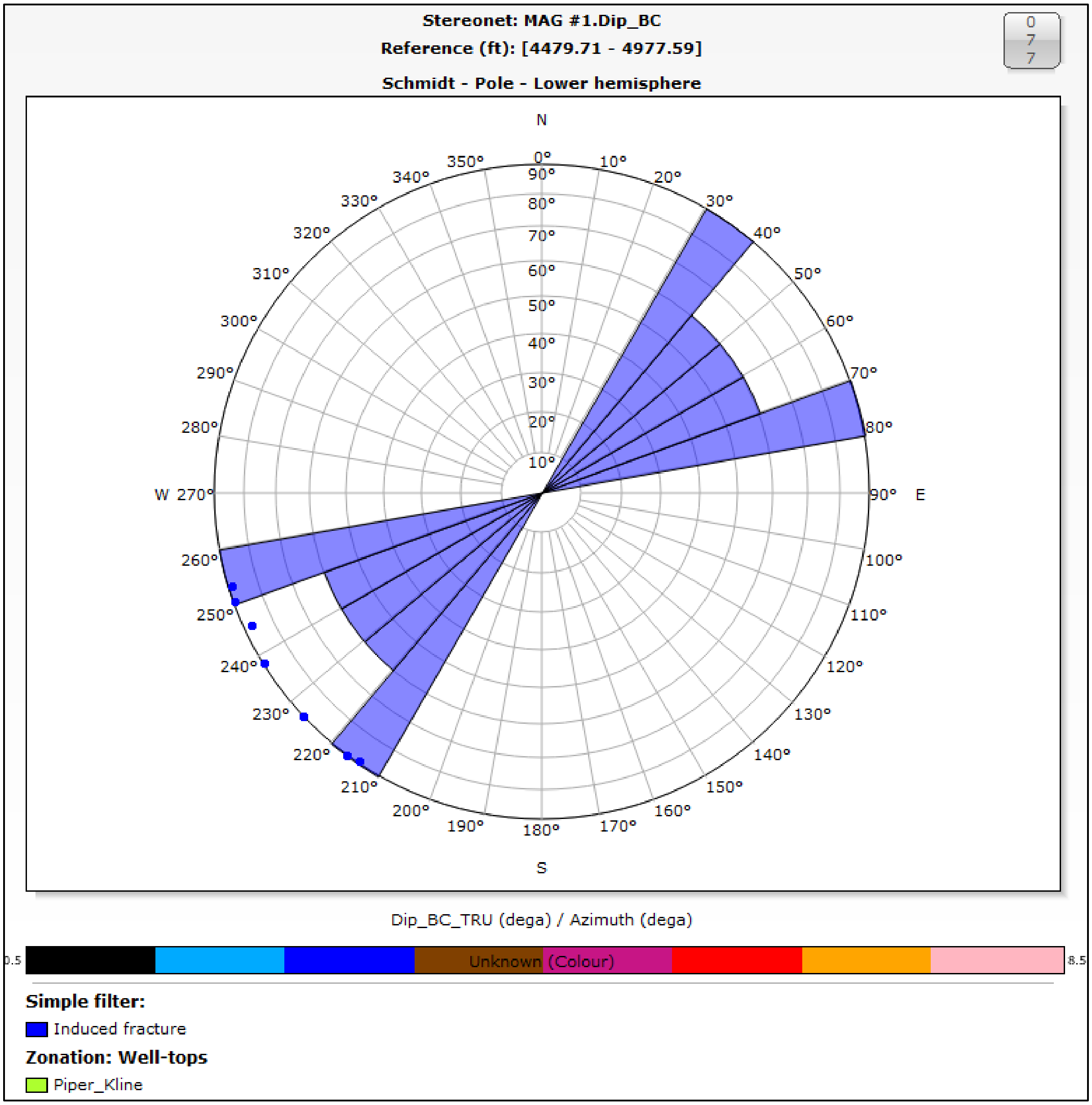

Figure 2-62. This example shows the orientation of drilled-induced fractures in the Piper Formation.

2.4.4.2 Stress, Ductility and Rock Strength

A 1D MEM was derived using the log data from MAG 1 well. Logs were edited to account for washouts in the Broom Creek and Amsden Formation sections using multilinear regressions. Geomechanical parameters in the Spearfish, Broom Creek, and Amsden Formations were estimated using the 1D MEM. The 1D MEM was used to estimate the vertical stress, pore pressure, minimum and maximum horizontal stresses (Shmin, SHmax), Poisson's ratio, Young's modulus, shear and bulk moduli, tensile, uniaxial compressive strength, and friction angle (Figure 2-63, Figure 2-64, and Figure 2-65). Table 2-19 shows the average and range of elastic and dynamic parameters, and stresses in the Spearfish, Broom Creek, and Amsden Formations.

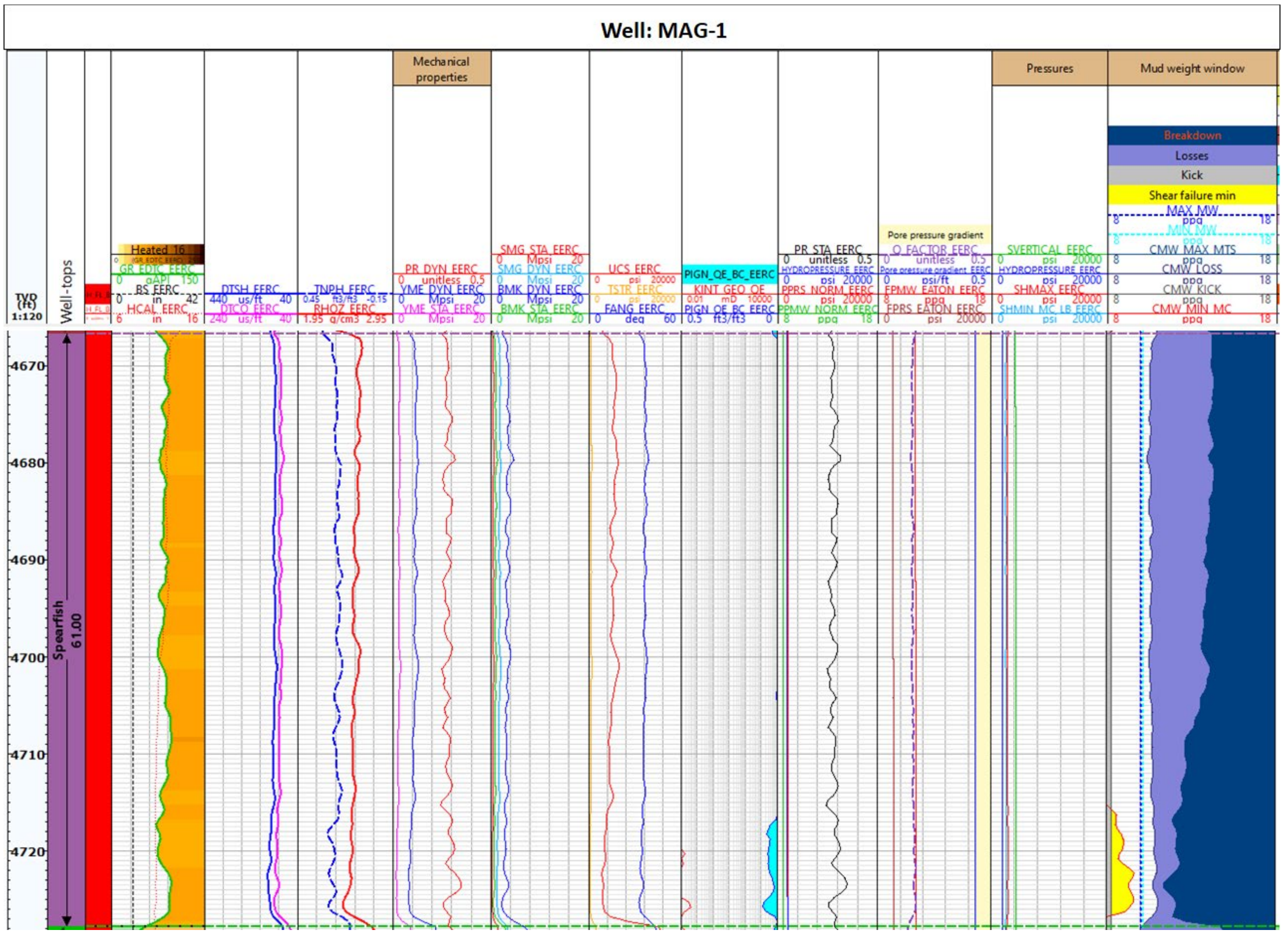

Figure 2-63. Geomechanical parameters in the Spearfish Formation. Track 1, bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, and dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static bulk modulus. Track 7, UCS, tensile, friction angle. Track 8, effective porosity and permeability log. Track 9, static Poisson's ratio, hydropressure, pore pressure (in psi and ppg). Track 10, pore pressure gradient, Q factor. Track 11, vertical stress, hydropressure, SHmax, Shmin. Track 12, wellbore stability.

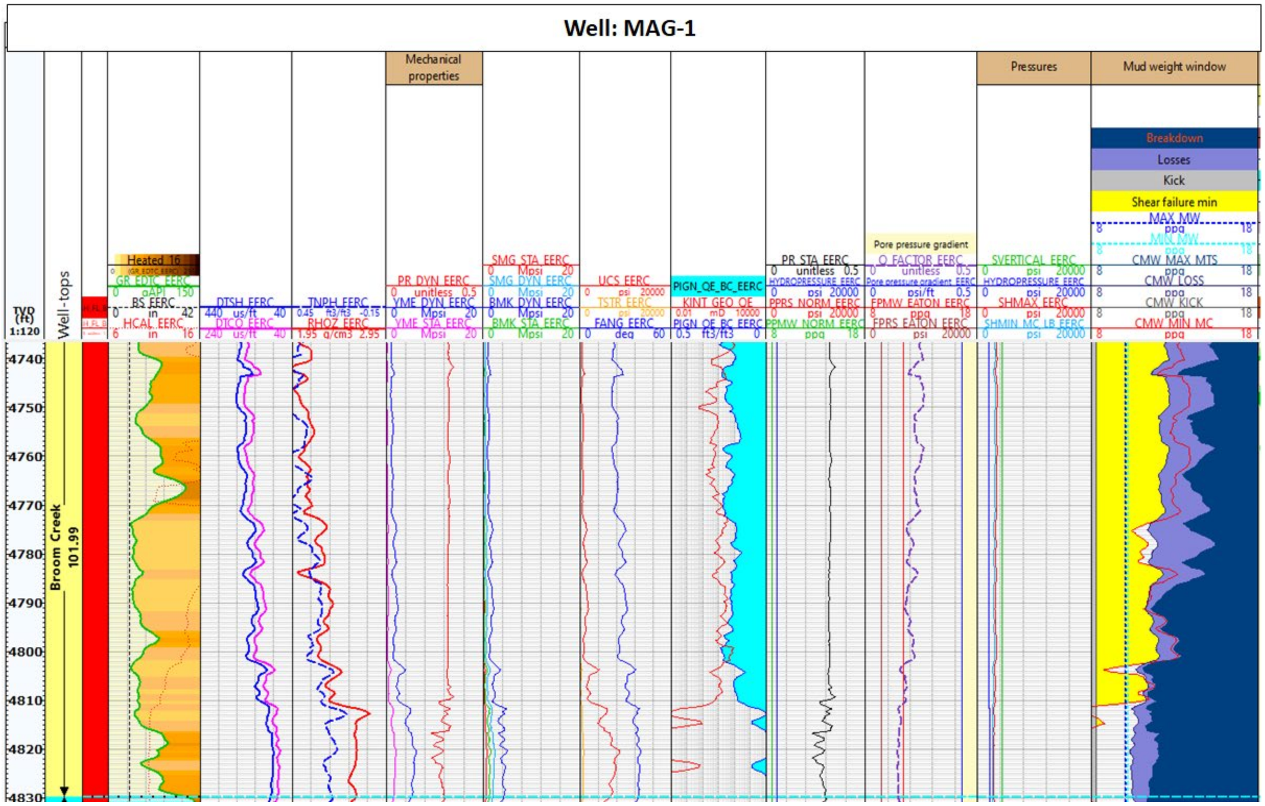

Figure 2-64. Geomechanical parameters in the Broom Creek Formation. Track 1, bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static bulk modulus. Track 7, UCS, tensile, friction angle. Track 8, effective porosity and permeability log. Track 9, static Poisson's ratio, hydropressure, pore pressure (in psi and ppg). Track 10, pore pressure gradient, Q factor. Track 11, vertical stress, hydropressure, SHmax, Shmin. Track 12, wellbore stability.

Since the SW Core samples collected from the MAG 1 well were horizontally oriented, it was not possible to determine ductility and rock strength through laboratory testing. The dimensions of the SW Core samples were inadequate for multistage triaxial testing. The static properties (Young's modulus, Poisson's ratio, bulk modulus, shear modulus, uniaxial strain modulus) and the dynamic properties (Young's modulus, Poisson's ratio) were estimated through the evaluation of the 1D MEM in the Spearfish, Broom Creek, and Amsden Formations. The dynamic parameters determined using the 1D MEM were converted into static parameters using specific equations derived from global correlations of dynamic to static parameters (Tutuncu and Sharma, 1992; Yale and Walters, 2016; Nowakowski, 2005; Yale and others, 1995; Zhang and Bentley, 2005; Yale and Jamieson, 1994).

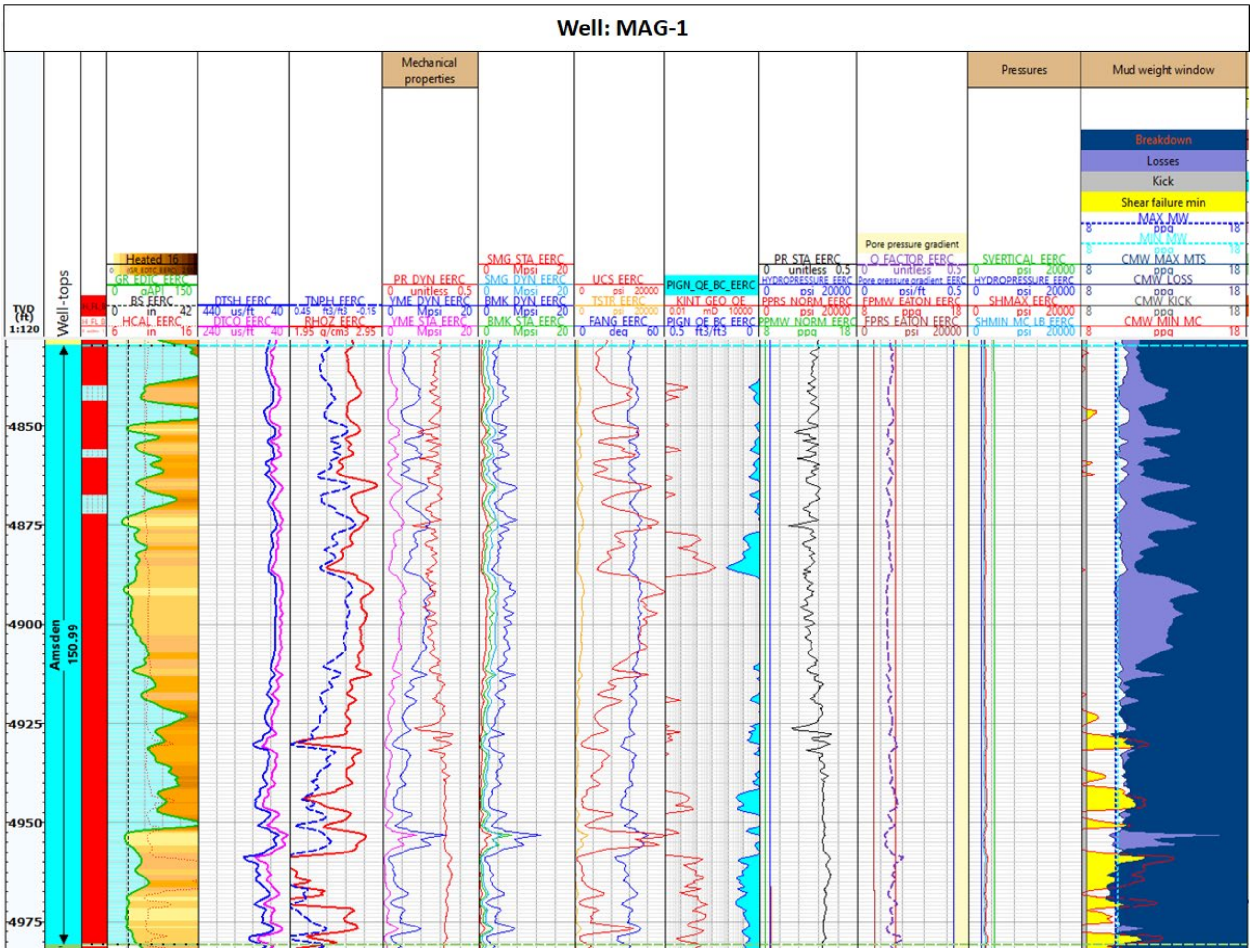

Figure 2-65. Geomechanical parameters in the Amsden Formation. Track 1, Bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static bulk modulus. Track 7, UCS, tensile, friction angle. Track 8, effective porosity and permeability log. Track 9, static Poisson's ratio, hydropressure, pore pressure (in psi and ppg). Track 10, pore pressure gradient, Q factor. Track 11, vertical stress, hydropressure, SHmax, Shmin. Track 12, wellbore stability.

Table 2-19. Ranges and Averages of the Elastic Properties Estimated from 1D MEM in Spearfish, Broom Creek and Amsden Formations: Static Young's Modulus (E_Stat), Static Poisson's Ratio (n_Stat), Static Bulk Modulus (K), Static Shear Modulus (G), Uniaxial Strain Modulus (P), Dynamic Young's Modulus (E_Dyn), and Dynamic Poisson's ratio (n_Dyn) in the Spearfish, Broom Creek, and Amsden Formations

Formation	Stats	E_Stat, Mpsi	n_Stat, unitless	K, Mpsi	G, Mpsi	P, psi	E_Dyn, Mpsi	n_Dyn, unitless
Spearfish	Min	0.665	0.243	0.493	0.256	2821	3.090	0.243
	Max	1.554	0.347	1.365	0.616	6591	5.213	0.347
	Average	1.159	0.281	0.884	0.453	4916	4.331	0.281
Broom Creek	Min	0.089	0.231	0.084	0.034	378	0.896	0.231
	Max	3.774	0.347	3.288	1.429	15884	8.963	0.347
	Average	0.573	0.313	0.479	0.221	2430	2.444	0.313
Amsden	Min	0.117	0.152	0.137	0.043	495	1.057	0.152
	Max	6.869	0.364	6.774	2.581	29140	13.026	0.364
	Average	1.945	0.286	1.47	0.764	8249	5.707	0.286

Log data were used to characterize stress in the storage complex to determine the fracture pressure gradient. In the injection zone, the parameters used to calculate stress were determined from the sand intervals in the Broom Creek Formation section. Rock strength defines the limit at which the stress conditions might induce the rock to mechanically fail. The unconfined compressive strength can be determined directly from rock mechanics tests, but in the MAG 1 well case, it was empirically estimated from well log data. Poisson's ratio was estimated using the available well logs, which resulted in an average value for the Broom Creek Formation of 0.32. The Biot factor was calculated using the effective porosity, static bulk modulus, and permeability, resulting in a range of 0.89-1. The pore pressure and hydropressure gradient were estimated using the true vertical depth (TVD), vertical stress (Sv), compressional slowness, and compressional velocity, respectively. The pore pressure and hydropressure gradients are equal to 0.448 and 0.429 psi/ft, respectively. In situ stresses such as Sv, maximum horizontal stress (SHmax), and minimum horizontal stress (Shmin) were calculated using specific parameters and methods (Table 2-20). Sv, which is related to the overburden or lithostatic pressure, is an important parameter in geomechanical modeling. In the Broom Creek Formation, overburden pressure was estimated through the bulk density log to the surface using the extrapolation method, resulting in an overburden gradient of 0.911 psi/ft. The poroelastic horizontal strain model is the most used method for horizontal stress calculation. The poroelastic horizontal strain model can be expressed using static Young's modulus, Poisson ratio, Biot's constant, overburden stress, and pore pressure. The poroelastic horizontal strain model was used to estimate the minimum horizontal stress (Plumb and Hickman, 1985; Aadnoy, 1990; Aadnoy and Bell, 1998; Brudy and Zoback, 1999). The SHmax is estimated from Shmin and process zone stress (as function of porosity). Based on the calculated stresses, the stress regime that can be seen in the Spearfish, Broom Creek, and Amsden Formations is a normal stress regime where Sv > SHmax > Shmin. Shmin magnitude could not be calibrated using the closure pressure measurements obtained from the openhole MDT microfracture in situ stress test because it was not performed in the MAG 1 well because of the large washout in the vicinity of the intervals of interest. The fracture gradient (FG) is calculated from pore pressure and overburden gradient. With the absence of closure pressure measurements

Table 2-20. Ranges and Averages of the Sv, Hydropressure, Shmin, and Friction Angle (Fang) Estimated from 1D MEM in the Spearfish, Broom Creek, and Amsden Formations

Formation	Stats	Sv, Vertical Stress, psi	Hydropressure, psi	Shmin, psi	Fang, Friction Angle, degrees
Spearfish	Min	4,238	2,006	2,522	33
	Max	4,306	2,032	2,711	39
	Average	4,272	2,019	2,602	36
Broom Creek	Min	4,306	2,032	2,442	21
	Max	4,407	2,076	3,132	44
	Average	4,355	2,054	2,876	29
Amsden	Min	4,407	2,076	2,477	27
	Max	4,574	2,141	3,051	48
	Average	4,493	2,109	2,669	39

in the Broom Creek Formation from in situ testing, a fracture gradient of 0.69 psi/ft was calculated in Schlumberger's Techlog software through the Matthew and Kelly method (Zhang and Yin, 2017). Equation 1 shows the equation used to derive the fracture gradient.

$$Fracture\ Gradient = K * \left(\sigma_v - \alpha P_p\right) + \alpha P_p \qquad \text{[Eq. 1]}$$

Where:

σ_v is the overburden gradient.
α is Biot coefficient.
P_p is pore pressure.
K is the stress ratio (unitless) which Mathews and Kelly calculate with empirical correlation shown in Equation 2.

$$K = (-3.0 * 10^{-9}) * TVD_{RefGL}{}^2 + (8.0 * 10^{-5}) * TVD_{RefGL} + 0.2347 \qquad \text{[Eq. 2]}$$

Where:

TVD_{RefGL} is true vertical depth minus Kelly Bushing.

2.5 Faults, Fractures, and Seismic Activity

In the area of review, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from MAG 1 that suggest the injection interval, Broom Creek Formation (28,600 mg/L), is isolated from the next permeable interval, the Inyan Kara Formation (15,600 mg/L) (Appendix A).

A regional structural feature, the Stanton Fault, is discussed in this section. This section also discusses the seismic history of North Dakota and the low probability that seismic activity will interfere with containment.

2.5.1 Stanton Fault

The Stanton Fault is a suspected Precambrian basement fault interpreted by Sims and others (1991), who–interpreted this northeast-southwest trending feature using available borehole data and regional gravity and magnetic data. The Stanton Fault is interpreted by Sims and others (1991) to be approximately 0.7 miles from the MAG 1 well (Figure 2-66). Given the resolution of the regional gravity and magnetic data and limited amount of borehole data used to interpret this suspected fault, there is a lot of uncertainty in the lateral extent and the location of the feature. No studies describing the possible vertical extent of this feature or impact on overlying sedimentary layers have been published. Lack of historical earthquakes in the area suggests that if the suspected Stanton Fault does exist it is inactive.

2D and 3D seismic data were used to characterize the subsurface within the project area and determine if the suspected Stanton Fault or other faults are present within the area of review. There is no indication of faulting within the 3D seismic data. Along the 2D seismic lines, there are areas where diffractions within the Precambrian basement can be seen and areas where there are discontinuities and flexures along seismic reflection events at the top of and within the Precambrian basement. These features may indicate the presence of faults.

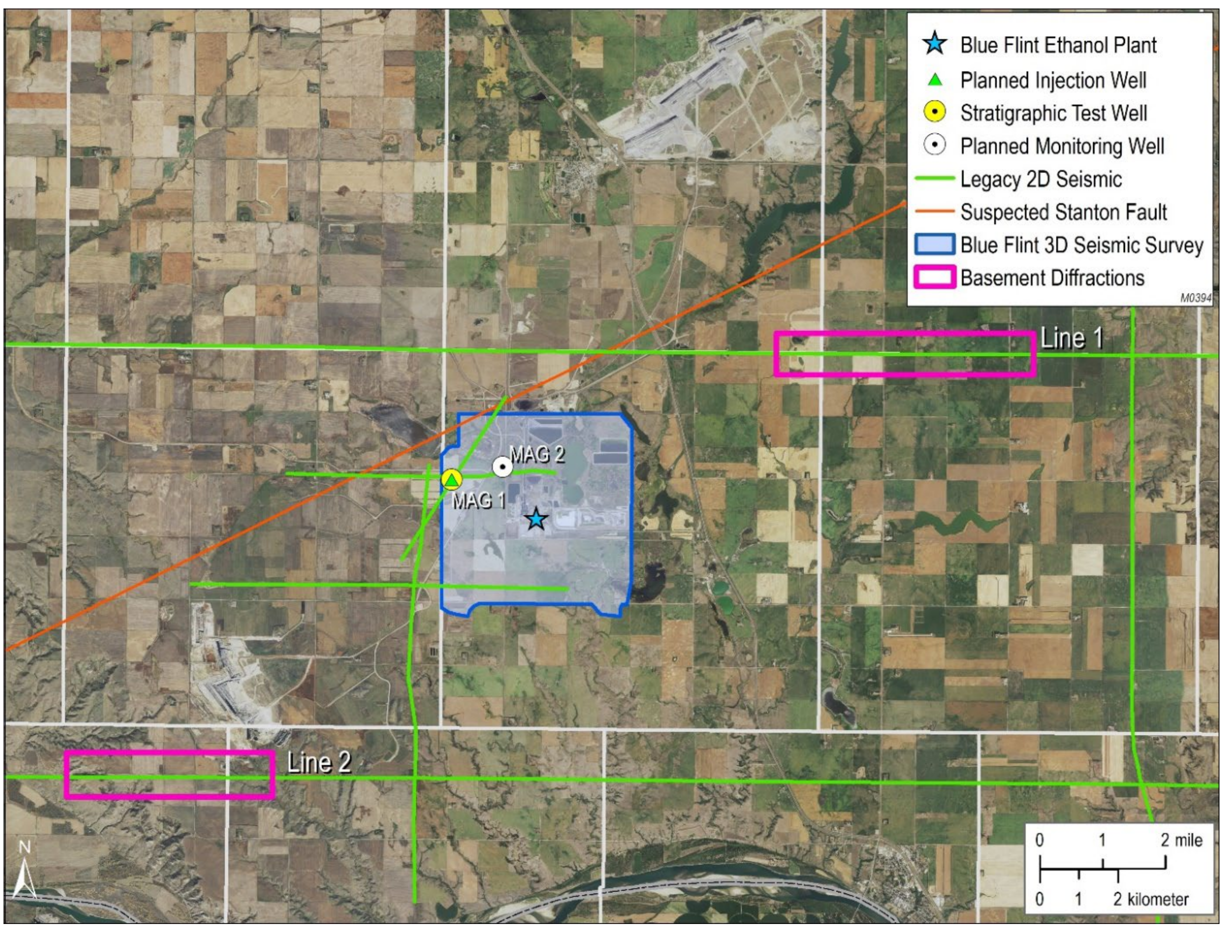

Figure 2-66. Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016).

On Lines 1 and 2, shown in Figure 2-67 and 2-68, respectively, the diagonal seismic features within the Precambrian basement may be diffractions indicating the location of a structural feature such as a fault. However, there is no visible offset within the formations that directly overly the Precambrian basement, suggesting that if a fault is present it is confined to the Precambrian basement.

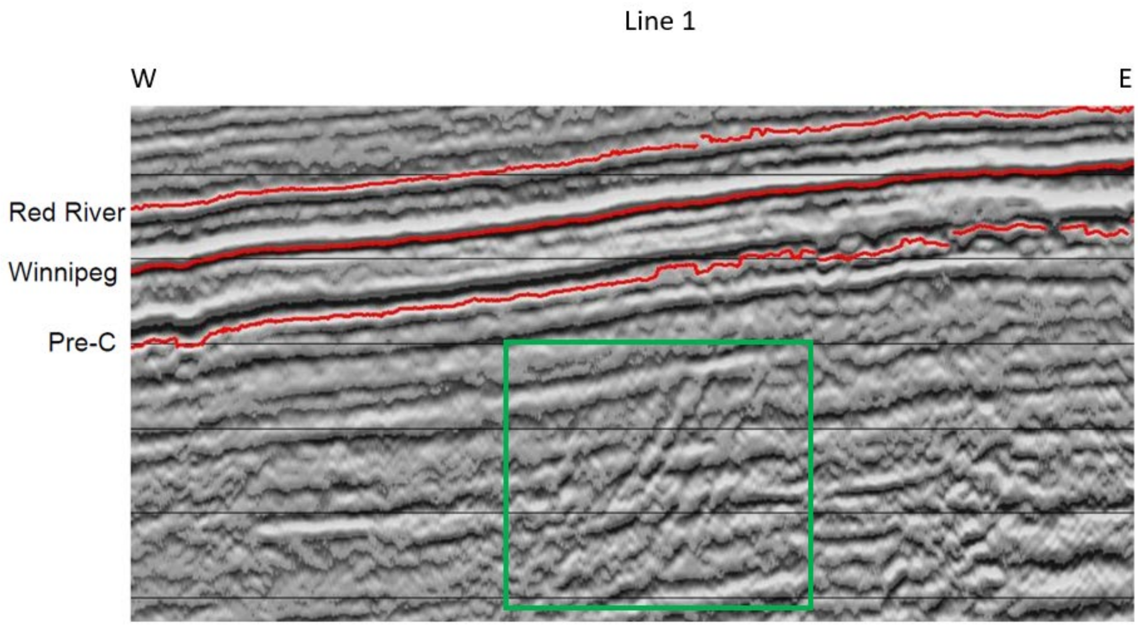

Figure 2-67. Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box).

On Lines 1 and 2, there are also discontinuities and flexures in several places along the interpreted top of the Precambrian basement and within the Precambrian basement that may also indicate the presence of faults. If these seismic features do correspond to faults, there is no indication that these features are present in the formations overlying the Precambrian basement and, therefore, do not have sufficient vertical extent to transect the storage reservoir and confining zones which are more than 5,000 feet above the basement.

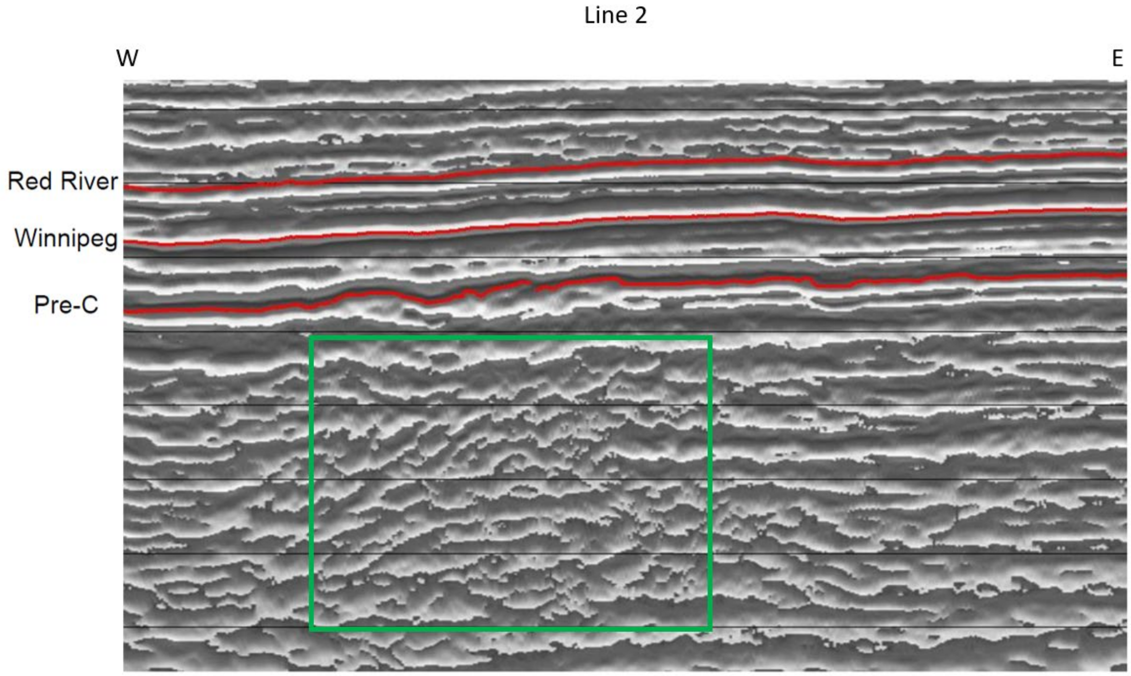

Figure 2-68. Cross section of Line 2 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box).

2.5.2 Seismic Activity

The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that "the Williston Basin as a whole is in an overburden compressive stress regime," which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2022).

Between 1870 and 2015, 13 earthquakes were detected within the North Dakota portion of the Williston Basin (Table 2-21) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-69). The earthquake recorded closest to the project area occurred in 2008 52.3 miles to the east, near Goodrich, North Dakota (Table 2-21). The magnitude of this earthquake is estimated to have been 2.6.

Table 2-21. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, miles	Longitude	Latitude	City or Vicinity of Earthquake	Map Label	Distance to Blue Flint Ethanol, miles
Sept. 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	117.0
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	162.9
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	136.4
Aug. 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	60.1
Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	146.7
Nov. 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	52.3
Nov. 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	156.2
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	154.8
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	58.0
May 13, 1947	3.7**	U	−100.90	46.00	Selfridge	J	96.1
Oct. 26, 1946	3.7**	U	−103.70	48.20	Williston	K	131.5
April 29, 1927	0.2**	U	−102.10	46.90	Hebron	L	55.8
Aug. 8, 1915	3.7**	U	−103.60	48.20	Williston	M	127.3

* Estimated depth.
** Magnitude estimated from reported modified Mercalli intensity (MMI) value.

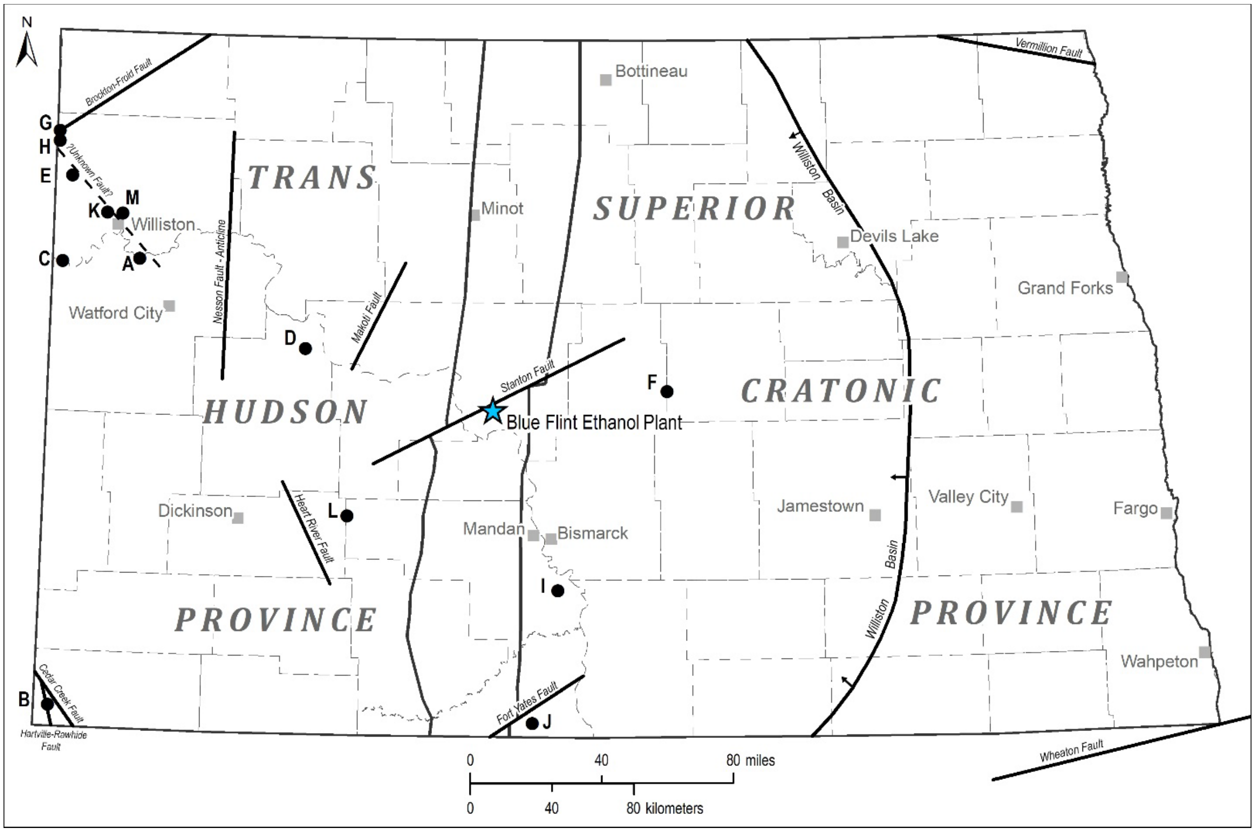

Figure 2-69. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-21.

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of earthquake events occurring in North Dakota that would cause damage to infrastructure, with less than two damaging earthquake events predicted to occur over a 10,000-year time period (Figure 2-70) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by USGS in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) state there is very little seismic activity near the injection wells in the Williston Basin. They noted only two historic earthquake events in North Dakota that could be associated with nearby oil and gas activities. Additionally, no earthquakes occurring along the Stanton Fault have been reported. This indicates stable geologic conditions in the region surrounding the potential injection site. The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the small volume of CO_2 injected as part of this project suggest the probability that seismicity interfering with CO_2 containment is low.

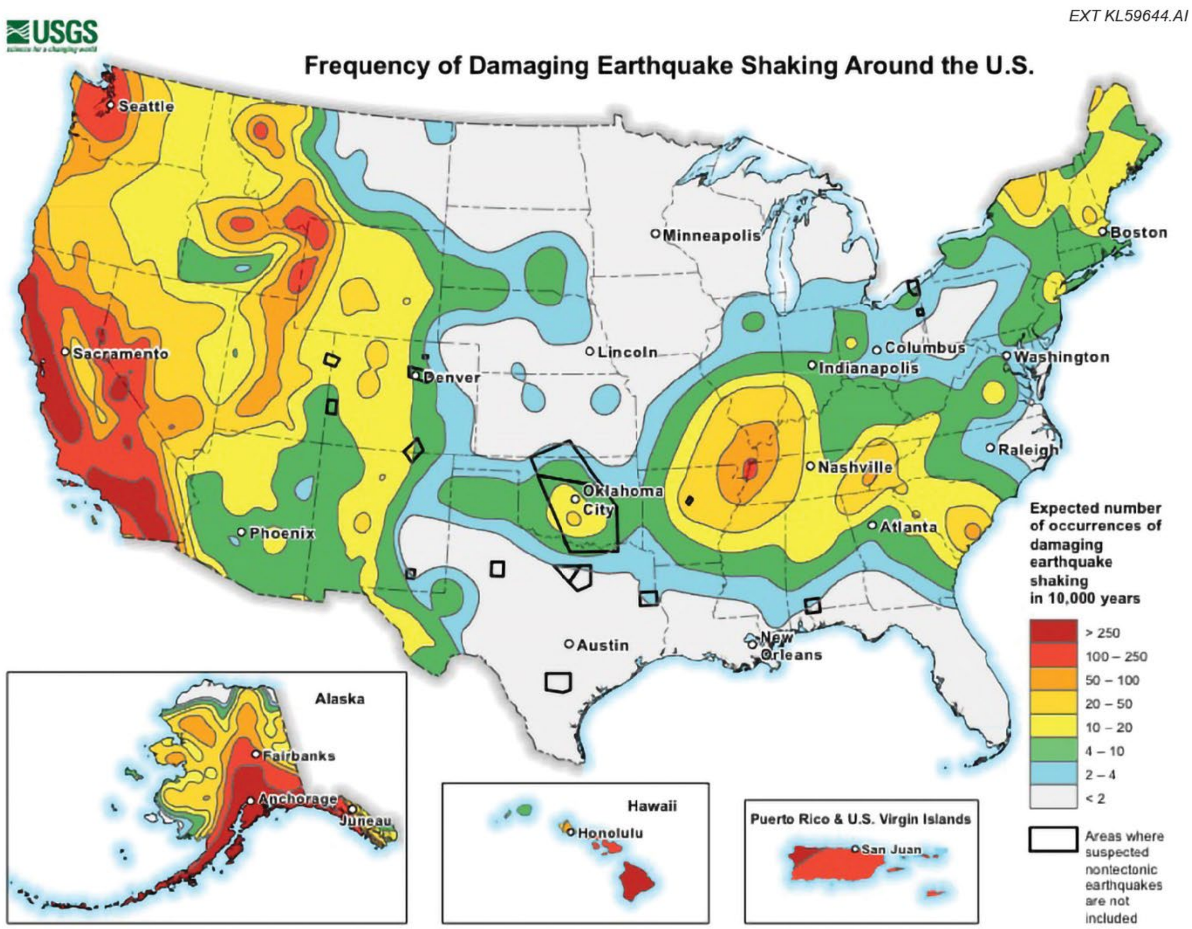

Figure 2-70. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

2.6 Potential Mineral Zones

There has been no historic hydrocarbon exploration in, or production from, formations above the Deadwood Formation in the storage facility area. The only hydrocarbon exploration well near the storage facility area, the Ellen Samuelson 1 (NDIC File No. 1516), located 2.5 miles to the northeast of the MAG 1 well was drilled in 1957 to explore potential hydrocarbons in the Madison Formation. The well was dry and did not suggest the presence of hydrocarbons. There are no known producible accumulations of hydrocarbons in the storage facility area.

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a horizontal well could be used to produce the hydrocarbon while avoiding drilling through the CO_2 plume, or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available while the MAG 1 well is in operation, which will allow prospective operators to design an appropriate well control strategy via increased drilling mud weight. Pressure increase in the Broom Creek caused by injection of CO_2 will relax postinjection as the area returns to its preinjection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the CO_2 should be designed to include an intermediate casing string placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place.

Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations (NDCC § 57-51-01(11)) define a shallow gas zone as gas produced from a zone that consists of "strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation [Jurassic], from which gas may be produced."

Lignite coal is currently mined at the Falkirk Mine, operated by the Falkirk Mining Company, a wholly owned subsidiary of North American Coal Corporation, which is located within the project area. The Falkirk Mine produces from the Hagel coal seam for power generation feedstock at Rainbow Energy's Coal Creek Station. The Hagel coal seam is the lowermost major lignite present in the area in the Sentinel Butte Formation (Figure 2-71).

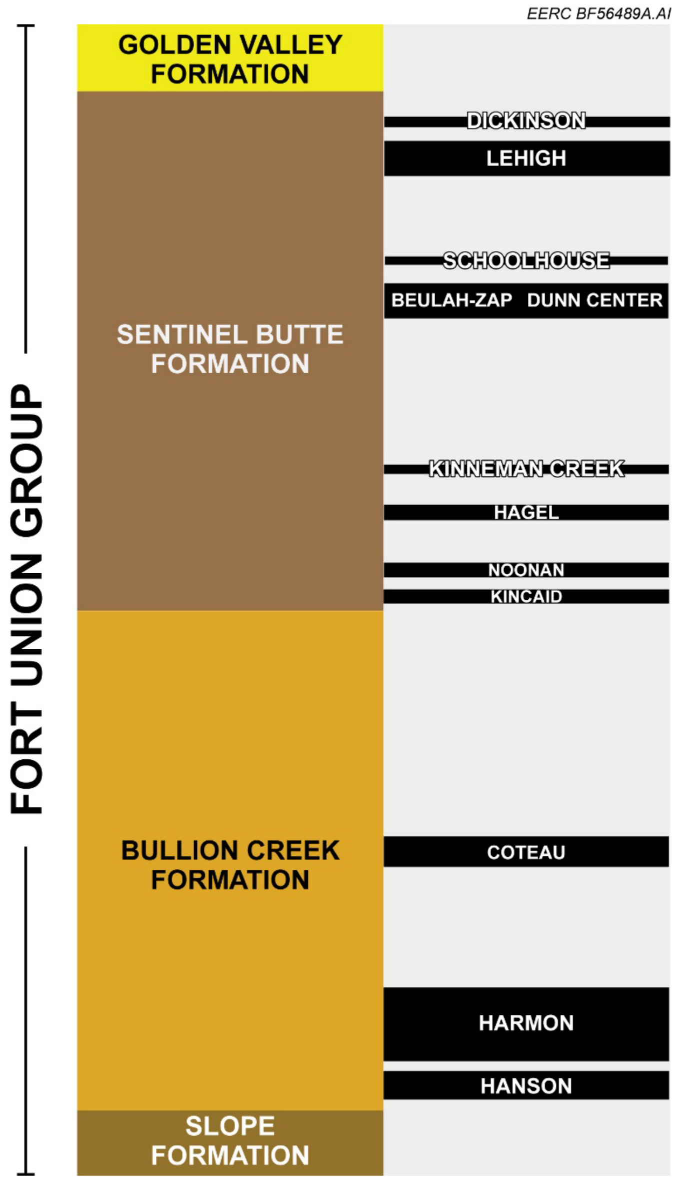

Figure 2-71. Coal beds of the Sentinel Butte and Bullion Creek (Tongue River) Formations showing the lignite coals in western North Dakota (Zygarlicke and others, 2019).

The Hagel coal seam is divided into two seams: the Hagel A and the Hagel B. The Hagel A lignite bed averages 5.7 ft thick with a range from 0.5 to 11.5 ft. The Hagel B bed has a mean thickness of approximately 1.8 ft, ranging in thickness from 0.5 to 6.3 ft. (Figure 2-72) (Zygarlicke and others, 2019). Coal seams in the Bullion Creek Formation exist in the area below the Hagel seam (Figure 2-71) but are too deep to be economically mined.

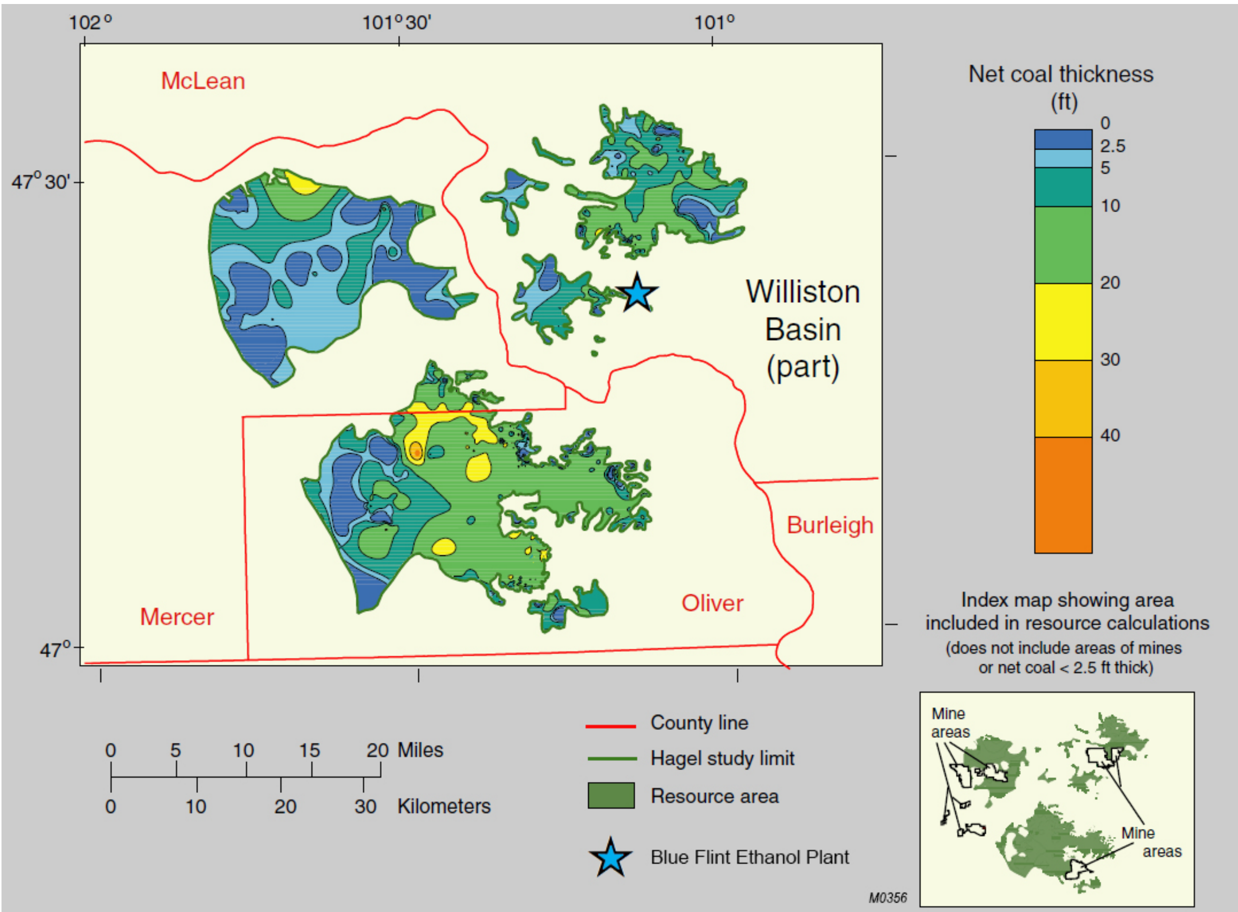

Figure 2-72. Hagel net coal isopach map (modified from Ellis and others, 1999).

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3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION

3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION

3.1 Introduction

Multiple sets of publicly available and newly acquired site-specific subsurface data were analyzed and interpreted (Section 2.2). The data and interpretations were used as inputs to Schlumberger's Petrel software (Schlumberger, 2020) to construct a geologic model of the injection zone: the Broom Creek Formation, the upper confining zone: the lower Piper and Spearfish Formations, and the lower confining zone: the Amsden Formation. The geologic model encompasses a 76-mile × 72-mile area around the proposed storage site to characterize the geologic extent, depth, and thickness of the subsurface geologic strata (Figure 2-3). Geologic properties were distributed within the 3D model, including lithofacies, porosity, and permeability.

The geologic model and properties served as inputs for numerical simulations of CO_2 injection using Computer Modelling Group Ltd.'s (CMG's) GEM software (Computer Modelling Group Ltd., 2019). Numerical simulations of CO_2 injection were conducted to assess potential CO_2 injection rate, disposition of injected CO_2, wellhead pressure (WHP), bottomhole pressure (BHP), and pressure changes in the storage reservoir throughout the expected injection time frame and postinjection period. Results of the numerical simulations were then used to determine the project's area of review (AOR) pursuant to North Dakota's geologic CO_2 storage regulations.

3.2 Overview of Simulation Activities

3.2.1 Modeling of the Injection Zone and Overlying and Underlying Seals

A geologic model was constructed to characterize the injection zone and upper and lower confining zones. Activities included data aggregation, structural framework creation, data analysis, and property distribution. Major inputs for the geologic model included geophysical logs from nearby wells and core sample measurements, which acted as control points during the distribution of the geologic properties throughout the modeled area, and seismic survey data. The geologic properties distributed throughout the model include the effective porosity, permeability, and lithofacies.

Because of the uncertainty in sonic log values related to washouts in the Broom Creek Formation in the MAG 1 well, inversion results of the site-specific 3D seismic data were not used to inform property distribution in the geologic model. Instead, publicly available variograms reported in the Tundra SGS (secure geologic storage) facility permit were used to inform the distribution of the lithofacies and petrophysical properties in the geologic model. The variograms reported in the Tundra SGS (secure geologic storage) facility permit were selected as they provide a generalized representation of the property distributions expected within the Broom Creek Formation (North Dakota Industrial Commission, 2021).

3.2.2 Structural Framework Construction

Schlumberger's Petrel software was used to interpolate structural surfaces for the lower Piper (Picard Member), Spearfish, Broom Creek, and Amsden Formations. Input data included formation top depths from the online North Dakota Industrial Commission (NDIC) database; core data collected from the MAG 1, Flemmer 1, ANG 1, J-LOC 1, and BNI-1 wells (Figure 2-4); and two 3D seismic surveys (Figure 2-3) conducted at the Flemmer 1 and MAG 1 wellsites. The interpolated data were used to constrain the model extent in 3D space.

3.2.3 Data Analysis and Property Distribution

3.2.3.1 Confining Zones (lower Piper, Spearfish, and Amsden Formations)

The upper confining zone (lower Piper and Spearfish Formations), and the lower confining zone (Amsden Formation) were each assigned a single lithology, based on their primary lithology determined by well log analysis to be siltstone and dolostone, respectively. Porosity and permeability logs were upscaled from a well log scale to the scale of the geologic model grid to serve as control points for property distributions. The control points were used in combination with the publicly available variograms and Gaussian random function simulation algorithms to distribute the properties. A 3,000-ft-major and minor axis length variogram model in the lateral direction and a 6-ft vertical variogram length were used within the lower Piper Formation. The variogram used within the Spearfish Formation was the same as the one used for the lower Piper Formation, except the lateral variogram is a 4,000-ft-diameter circle. A major axis length of 6,000 ft and a minor axis length of 3,000 ft were used for the Amsden Formation along an azimuth of 155° with a vertical variogram of 5 ft.

3.2.3.2 Injection Zone (Broom Creek Formation)

Prior variogram assessments completed for use in a similar storage facility permit application, the Tundra SGS CO_2 storage project, were used to assign variogram ranges within the injection zone. Variogram mapping investigations, as noted in the Tundra SGS application, investigated the size and shape of variograms in several different azimuthal directions, which indicated that geobody structures with the following dimensions were present in the Broom Creek Formation: major axis range of 5,000 ft, minor axis range of 4,500 ft, and an azimuth of 155° (NDIC, 2021). Well logs recorded from the MAG 1 wellbore served as the basis for deriving a vertical variogram length of 7 ft. The variogram ranges were used to distribute lithofacies and petrophysical properties.

Lithofacies classifications were interpreted from well log data and correlated with descriptions of core taken from the MAG 1, BNI-1, J-LOC 1, Flemmer 1, and ANG 1 wells. Four lithofacies were identified within the Broom Creek Formation: 1) sandstone, 2) dolostone, 3) dolomitic sandstone, and 4) anhydrite. Lithofacies logs were generated from gamma ray, density, neutron porosity, and resistivity logs. The lithofacies logs were upscaled to the resolution of the 3D model to serve as control points for geostatistical distribution using sequential indicator simulation (Figure 2-13 and Figure 3-1).

Prior to distributing the porosity and permeability properties, total porosity (PHIT), effective porosity (PHIE), and permeability (KNIT) well logs were estimated and compared with core porosity and permeability measurements to ensure good agreement with the five wells: MAG 1, Flemmer 1, J-LOC 1, BNI-1and ANG 1.

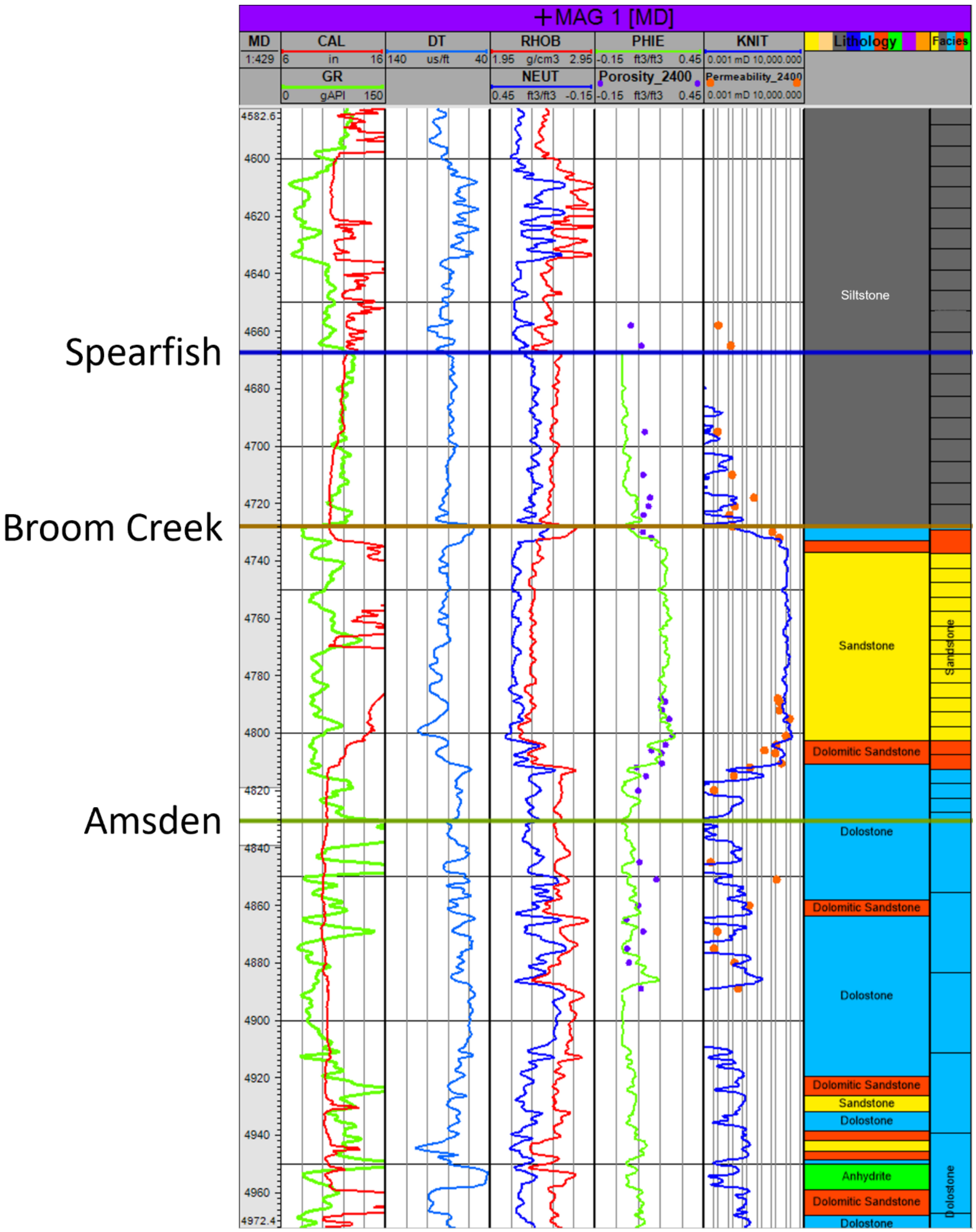


Figure 3-1. Lithofacies classification in MAG 1 well. Well logs displayed in tracks from left to right are 1) gamma ray (green) and caliper (red), 2) delta time (light blue), 3) neutron porosity (blue) and density (red), 4) effective porosity (green) and core sample porosity (purple dots), 5) predicted intrinsic permeability (blue) and core sample permeability (orange dots), 6) interpreted lithology, and 7) upscaled lithology.

A PHIE property (effective porosity; total porosity less occupied or isolated pore space) was distributed using calculated PHIE well logs, upscaled to the resolution of the 3D model as control points and variogram structures described previously with Gaussian random function simulation and conditioned to the distributed lithofacies. A permeability property was distributed using the same variables and algorithm but cokriged to the PHIE volume (Figures 3-2 and 3-3).

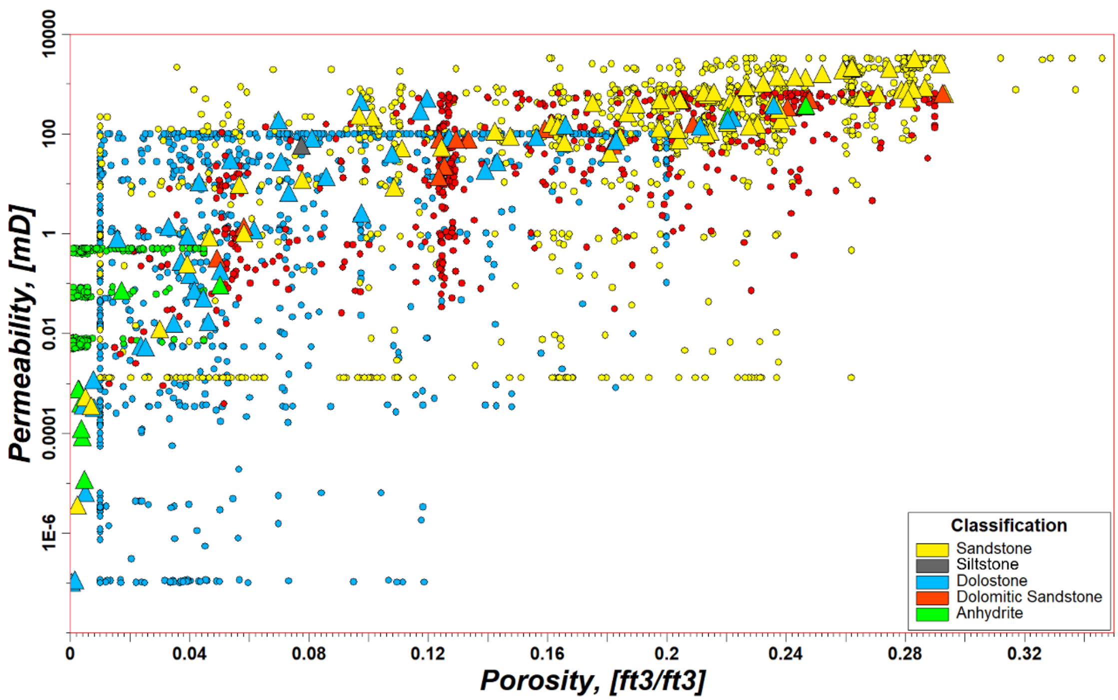


Figure 3-2. Illustration of the relationship between the modeled porosity and permeability. Upscaled well log values are represented by triangles, while circles represent distributed values. Values are colored according to lithofacies classification, as seen in Figure 3-3.

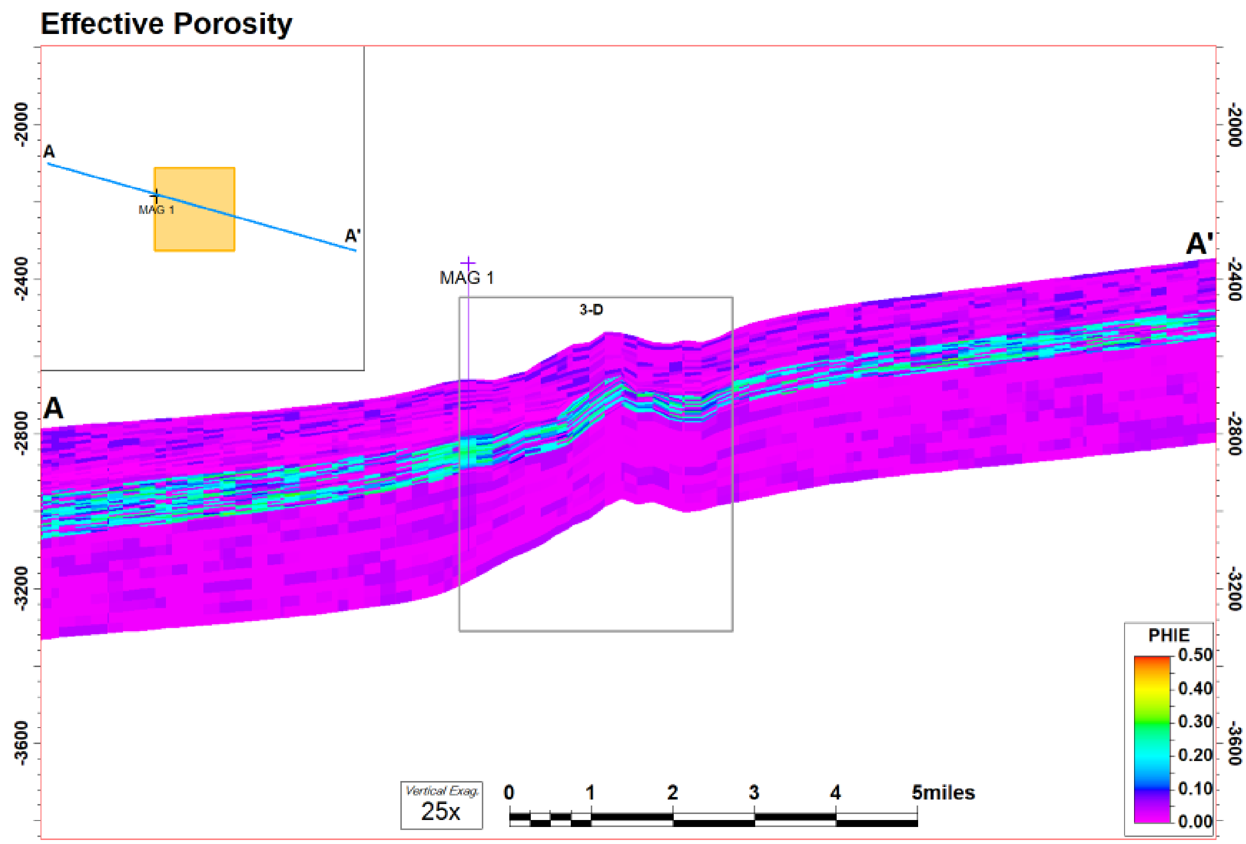


Figure 3-3. Distributed PHIE property along a northwest–southeast cross section. The distributed PHIE property was used to distribute permeability throughout the model. Units on the y-axis represent feet below mean sea level (25× vertical exaggeration shown).

3.3 Numerical Simulation of CO_2 Injection

3.3.1 Simulation Model Development

Numerical simulations of CO_2 injection into the Broom Creek Formation were conducted using the geologic model described above. Simulations were carried out using CMG GEM, a compositional reservoir simulation module. Both measured temperature and pressure, along with the reference datum depth, were used to initialize the reservoir equilibrium conditions for performing numerical simulation. Figure 3-4 displays a 2D view of the simulation model with the permeability property and MAG 1 injection well.

The simulation model boundaries were assigned infinite-acting conditions along the western and southern boundaries and partially closed along the northern and eastern boundaries, as the Broom Creek Formation partially pinches out in the northern and eastern parts of the modeled area. The reservoir was assumed to be 100% brine-saturated with a measured initial formation salinity of 28,600 mg/L total dissolved solids (TDS) (Table 3-1).

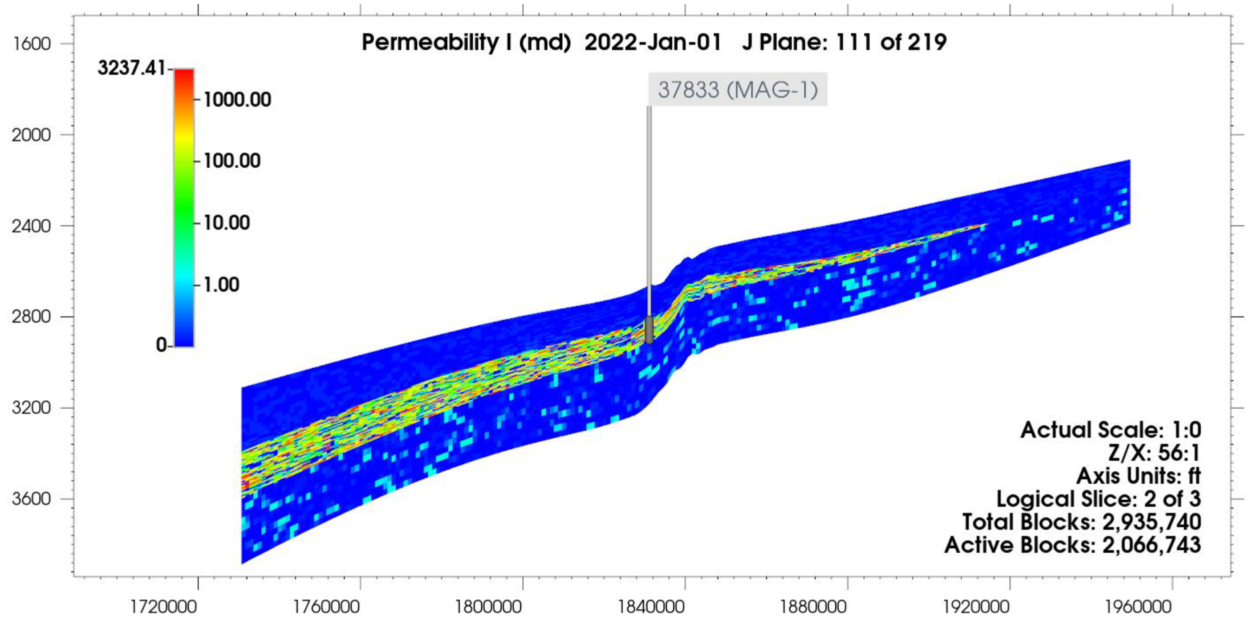


Figure 1-4. Cross-sectional view of the simulation model with the permeability property and injection well displayed. The low-permeability layers (blue) at the top and bottom of the figure should be noted. These layers represent the lower Piper and Spearfish Formations (upper confining zone) and the Amsden Formation (lower confining zone). The varied permeability of the Broom Creek Formation is shown between these layers.

Table 3-1. Summary of Reservoir Properties in the Simulation Model

Formation	Average Permeability, mD	Average Porosity, %	Initial Pressure, P_i, psi	Salinity, mg/L	Boundary Condition
Spearfish	0.068	5.1	2,448.8 (at 4,782.7 ft MD[1])	28,600	Partially infinite
Broom Creek	629.5	22.6			
Amsden	18.4	7.8			

[1] Measured depth.

Numerical simulations of CO_2 injection performed allowed CO_2 to dissolve into the native formation brine. Mercury injection capillary pressure (MICP) data for the Spearfish, Broom Creek, and Amsden Formations were used to generate relative permeability and the capillary curves for the five representative lithofacies in the simulation model (sandstone, siltstone, dolomite, dolomitic sands, and anhydrite) (Figures 3-6–3-8). Samples tested within the Spearfish, Broom Creek, and Amsden Formations included siltstone, sandstone, and dolomite lithologies. The siltstone (Spearfish) and dolomite (Amsden) values were assigned to anhydrite and dolomitic sandstone lithofacies, respectively, for both capillary entry pressure and relative permeability, as there were no available samples of these rock types from the MICP calculations. The main reason is both siltstone and anhydrite represent low perm facies. As for the dolomitic sandstone, the dolomite relative permeability data was used because the dolomitic sandstones within the Broom Creek Formation are expected to be more similar to dolomite rather than to sandstone. Anhydrite and dolomitic sandstone facies intervals in the reservoir are sparse and very thin; therefore, these relative permeability assumptions are not expected to impact injectivity or CO_2 plume extent (Figure 3-5). Figure 3-5 shows the facies distribution in the simulation model. Please note the red and yellow colors represent the anhydrite (red) and dolomitic sandstone (yellow), respectively and these facies barely exist around the injection point.

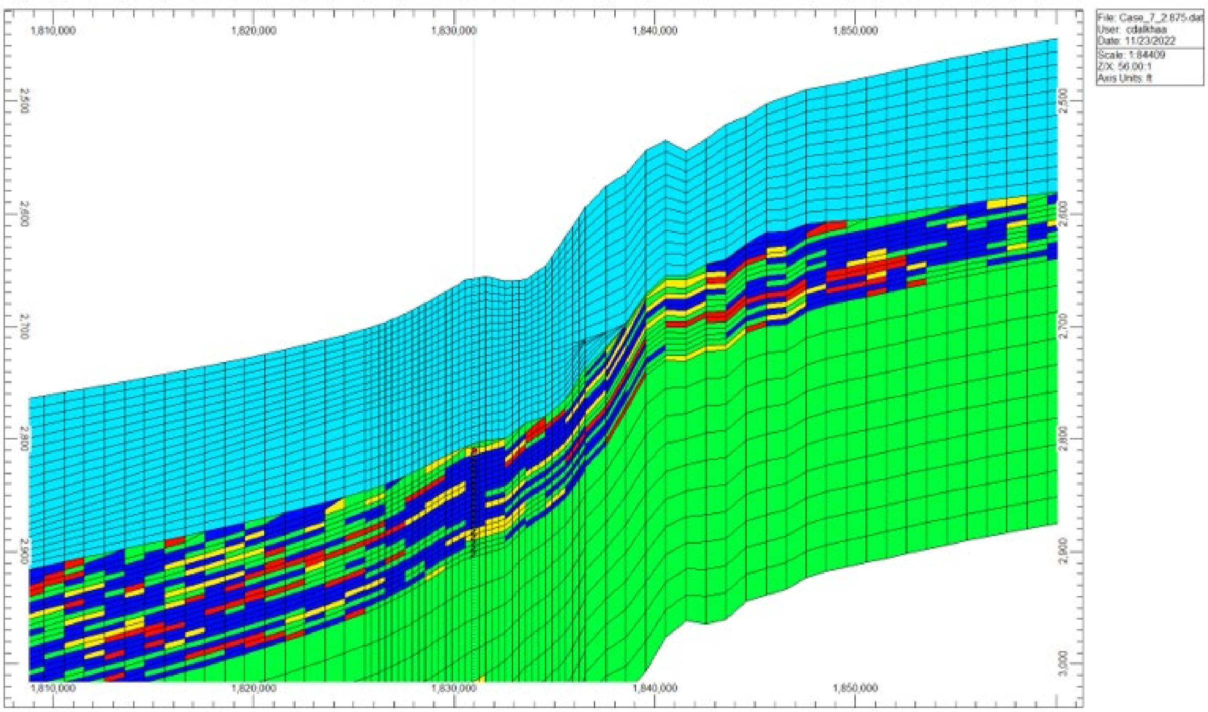
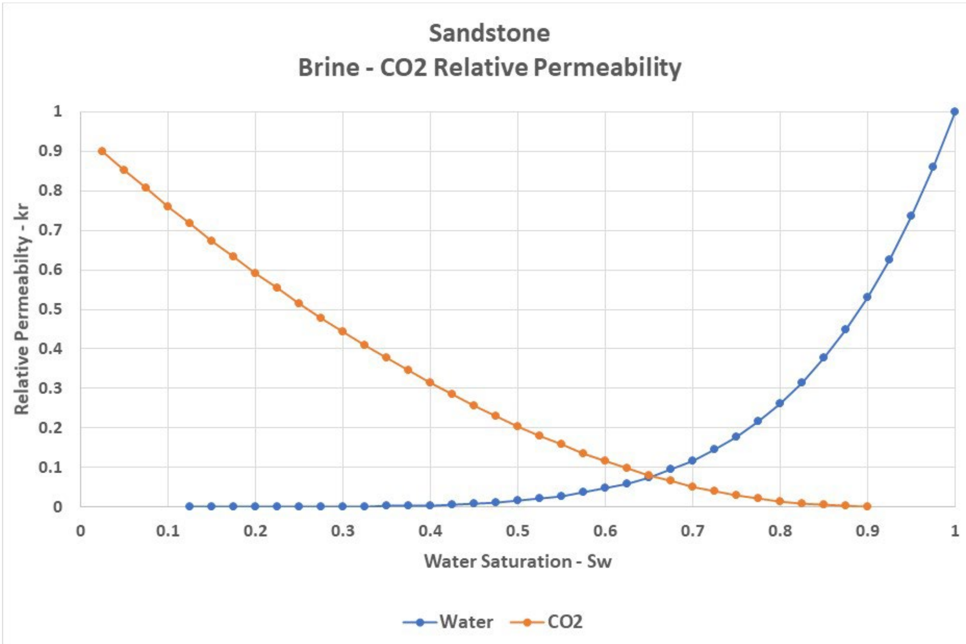


Figure 3-5. Facies distributions in the simulation model. Low permeability indicated by the color teal is siltstone. Other facies representations in the model are red representing anhydrite, yellow representing dolomitic sandstone, blue representing sandstone, and green representing dolomite.



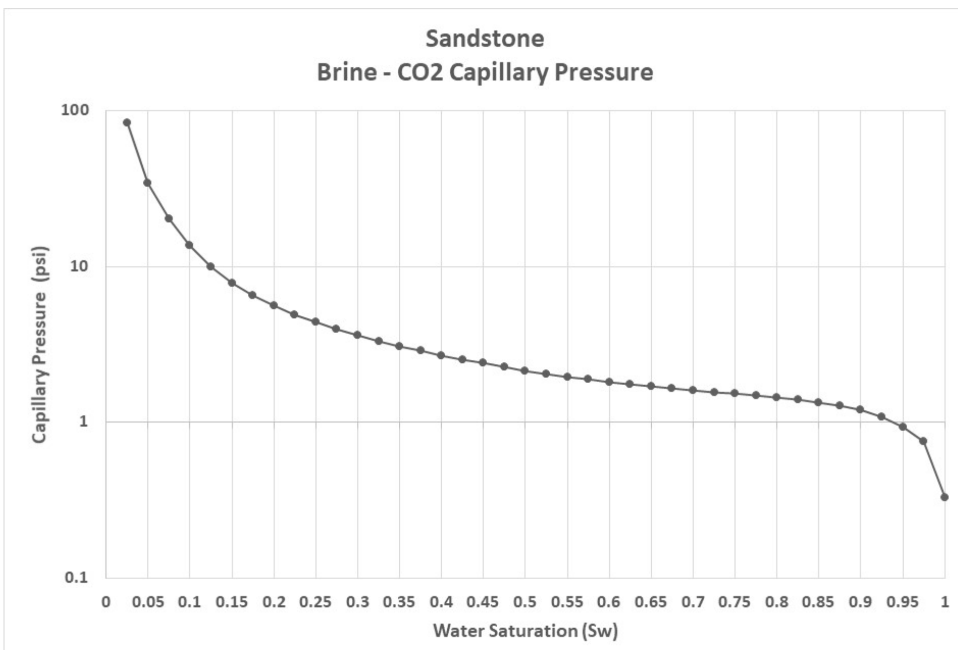
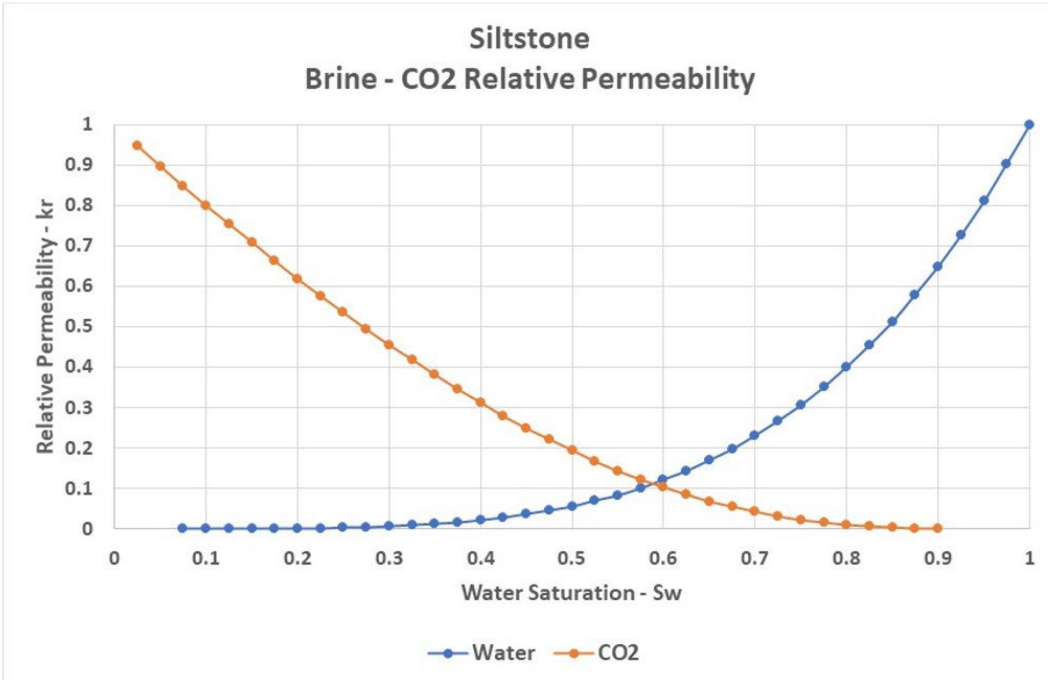


Figure 3-6. Relative permeability (top) and capillary pressure curves (bottom) for the sandstone rock type in the Broom Creek Formation.



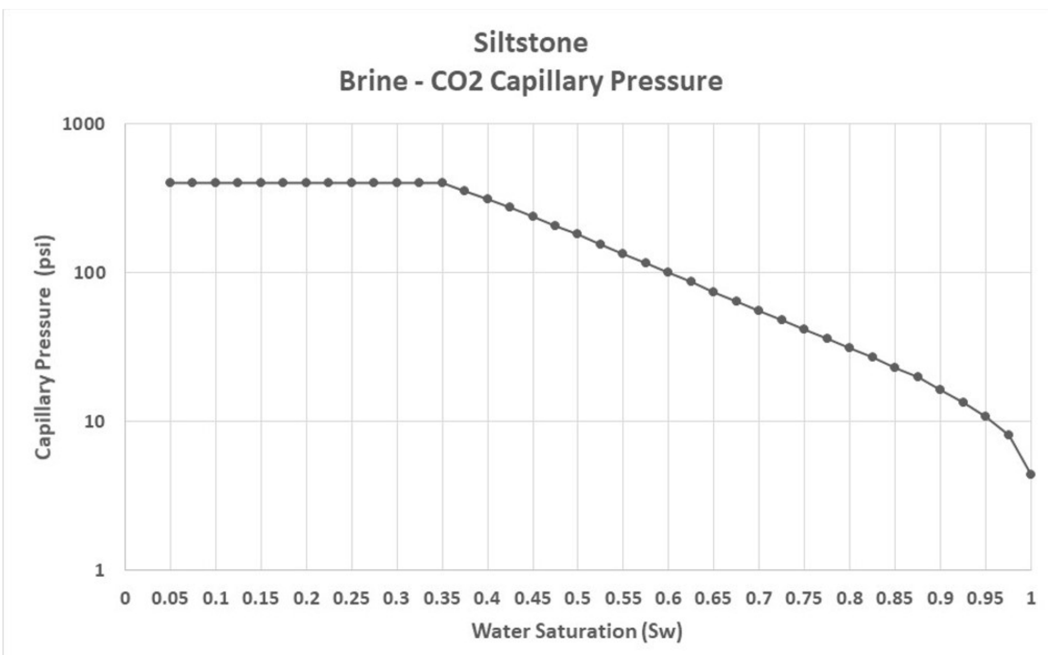


Figure 3-7. Relative permeability (top) and capillary pressure curves (bottom) for the siltstone rock type in the Spearfish Formation.

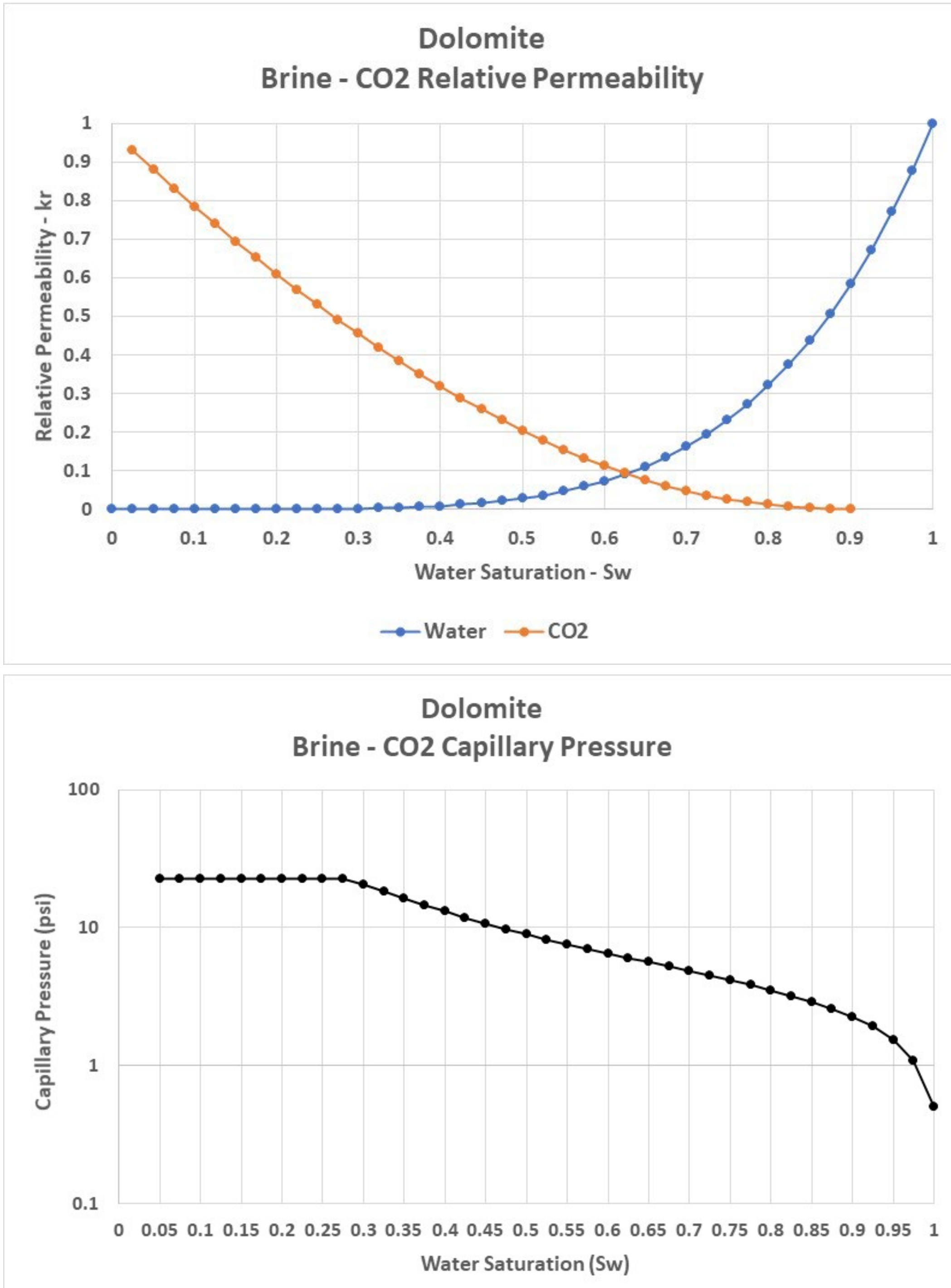


Figure 3-8. Relative permeability (top) and capillary pressure curves (bottom) for the dolomite rock type in the Amsden Formation.

Capillary pressure curves calculated from MICP data were modified to the model scale based on the permeability and porosity values of the simulation model and used in the numerical simulations. These modified capillary pressure curves are also shown in Figures 3-6–3-8. The capillary entry pressure values applied in the model were determined by deriving a ratio between the reservoir quality index of core samples and modeled properties to scale the capillary entry pressure value derived from core testing (Table 3-2).

Temperature and pressure data recorded in the MAG 1 wellbore were used to derive a temperature and pressure gradient to initialize the numerical simulation model for the proposed injection site. In combination with depth, a temperature gradient of 0.025°F/ft was used to calculate subsurface temperatures throughout the study area. A pressure reading recorded from the Broom Creek Formation was used to derive a pore pressure gradient of 0.512 psi/ft. The fracture gradient was obtained from a geomechanical analysis, resulting in an average of 0.69 psi/ft. The maximum allowable BHP of 2,970 psi was estimated to be 90% of the fracture gradient multiplied by the depth of the top perforation in the injection zone, the Broom Creek Formation, and used as the injection constraint in the numerical simulation of the expected injection scenario.

3.3.2 Sensitivity Analysis

Because the availability of data for this study included well logs, core sample data, and rock–fluid properties, the need for typical sensitivity studies of influential reservoir parameters has been reduced. A preliminary sensitivity analysis made to the wellbore model parameters suggested, at the given injection volume rates and BHP conditions, the wellhead temperature played a prominent role in determining WHP response. Sensitivity simulations of different wellhead temperatures indicated that injection at a higher wellhead temperature would require a higher WHP. For evaluating the expected injection design, a wellhead temperature value of 60°F was chosen that most closely represents the expected operational temperature.

3.4 Simulation Results

The target injection rate of 200,000 tonnes per year (tpy) (548 tonnes per day) was consistently achievable over 20 years (Figure 3-9), translating to a cumulative 4 MMt of CO_2 injection (Figure 3-10). Simulations of CO_2 injection with the given well constraints, listed in Table 3-3, predicted the BHP would not reach the maximum BHP constraint of 2,970 psi (90% of the formation fracture pressure) as a result of injecting the target CO_2 volume of 200,000 tpy. The predicted maximum BHP and the average BHP during the 20 year injection period were 2,661 and 2,570 psi (Figure 3-11), respectively.

Table 3-2. Core and Model Properties Showing the Multiplication Factor Used to Calculate Capillary Entry Pressure Used in the Simulation Model

	Core					Model				
	Porosity (fraction)	Permeability, mD	Capillary Entry Pressure, A/Hg, psi	Capillary Entry Pressure B/CO_2, psi	Reservoir Quality Index	Porosity (fraction)	Permeability*, mD	Capillary Entry Pressure B/CO_2, psi	Reservoir Quality Index	Multiplication Factor
Spearfish	0.125	0.028	58.3	12.245	0.015	0.051	0.068	5.018	0.036	0.410
Broom Creek	0.238	129	4.16	0.867	0.731	0.226	629.500	0.382	1.657	0.441
Amsden	0.096	0.011	126	26.134	0.011	0.078	18.400	0.576	0.482	0.022

* Pore volume weighted average.

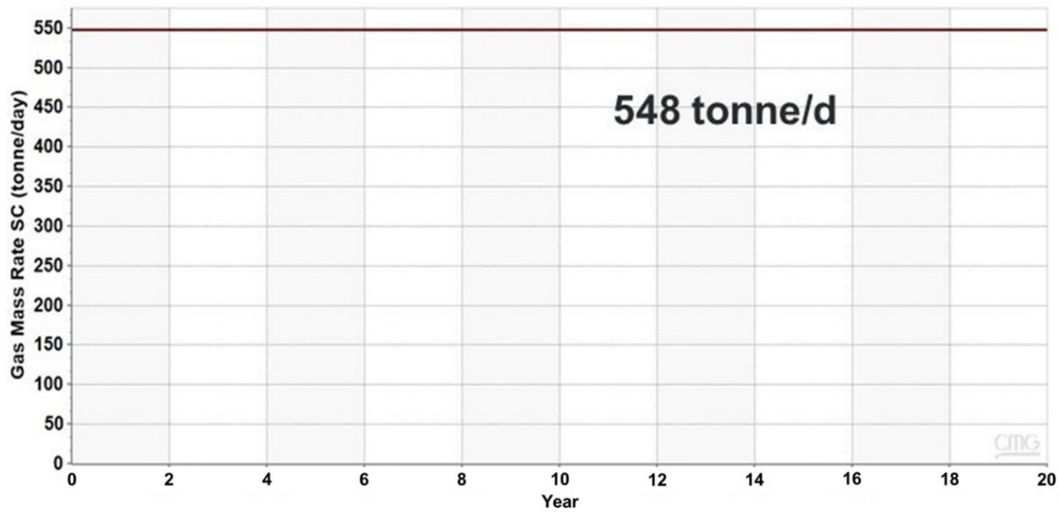


Figure 3-9. Mass injection rate over 20 years of injection with the expected injection rate.

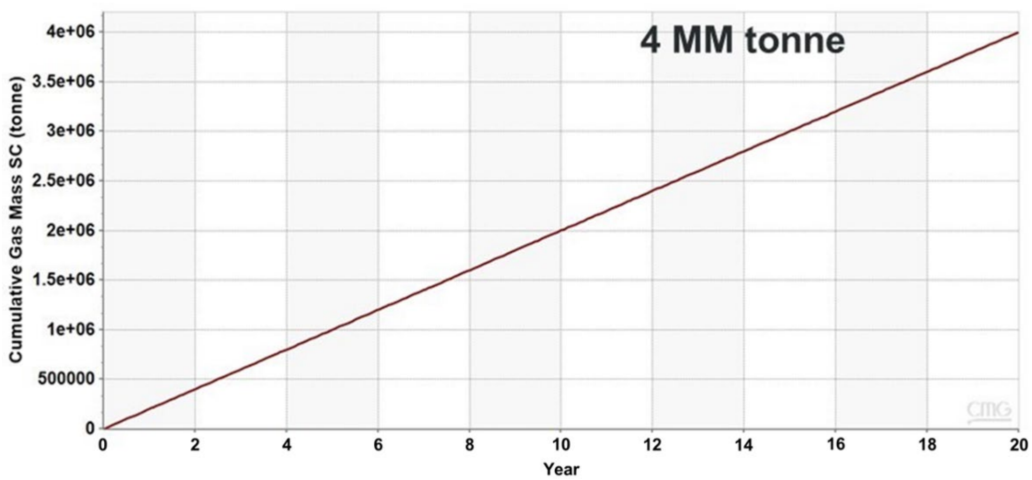


Figure 3-10. Cumulative injected gas mass over 20 years of injection with the expected injection rate.

Table 3-3. Well Constraints and Wellbore Model in the Simulation Model

Injection rate	Well Constraint, maximum BHP	Tubing Size	Wellhead Temperature	Downhole Temperature
200,000 tonnes/year for 20 years	2,970 psi	2.875 in.	60°F	119.6°F

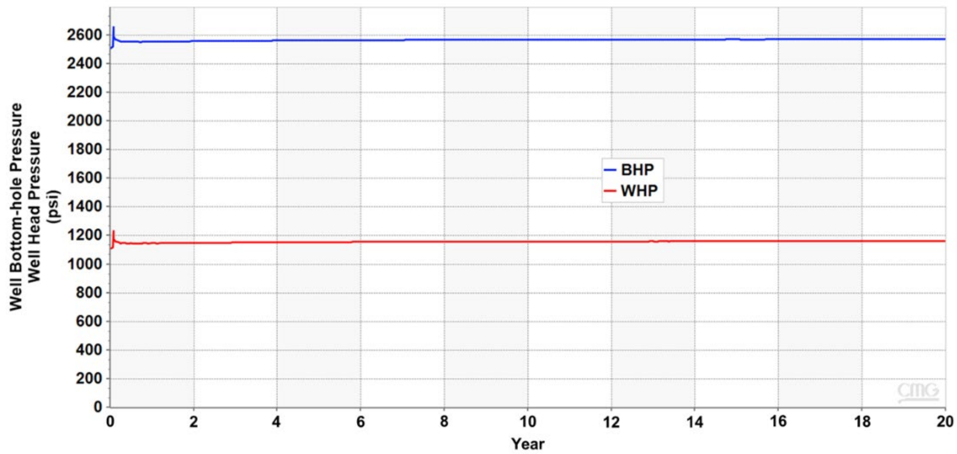


Figure 3-11. WHP and BHP response with the expected injection rate.

WHP depends on several factors, including injection rate, injection tubing parameters (tubing size and relative toughness), and surface injection temperature. For the designed injection rate and tubing size of 2.875 in., the predicted maximum WHP and average WHP during the 20 year injection period were 1,236 and 1,158 psi (Figure 3-11), respectively.

During and after injection, supercritical CO_2 (free-phase CO_2) accounts for the majority of CO_2 observed in the modeled pore space. Throughout the injection operation, a portion of the free-phase CO_2 is trapped in the pore space through a process known as residual trapping. Residual trapping can occur as a function of low CO_2 saturation and inability to flow under the effects of relative permeability. CO_2 also dissolves into the formation brine throughout injection operations (and continues afterward), although the rate of dissolution slows over time. The free-phase CO_2 transitions to either residually trapped or dissolved CO_2 during the postinjection period, resulting in a decline in the mass of free-phase CO_2. The relative portions of supercritical, trapped, and dissolved CO_2 can be tracked throughout the duration of the simulation (Figure 3-12).

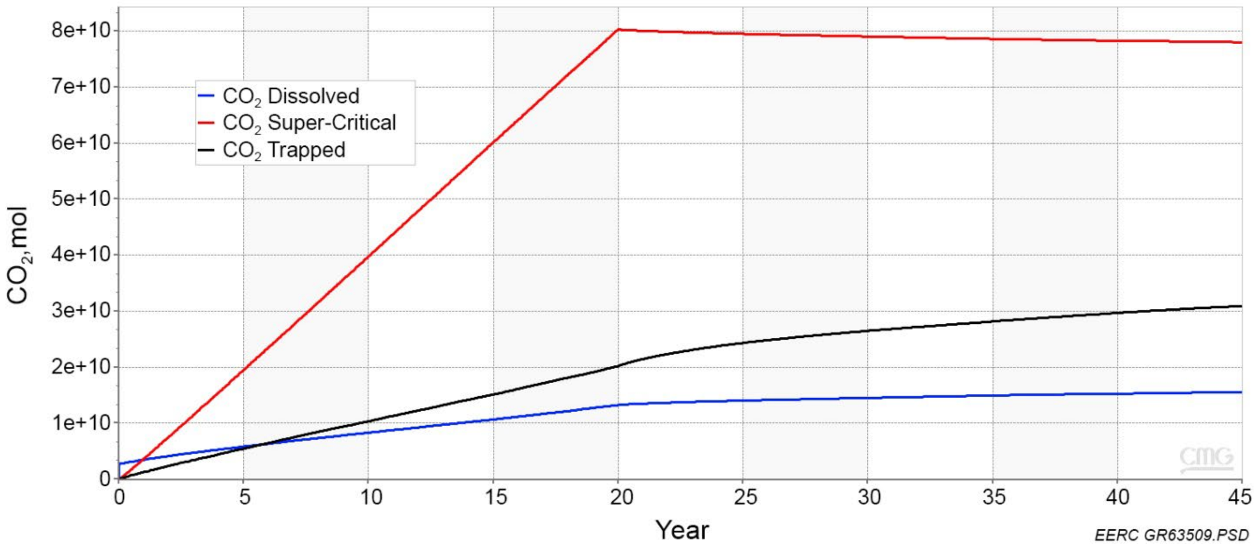


Figure 3-12. Simulated total super-critical free-phase CO_2, trapped CO_2, and dissolved CO_2 in brine.

The pressure front (Figure 3-13) shows the distribution of average pressure increase throughout the Broom Creek Formation after 1, 10, and 20 years of injection as well as 10 years postinjection (stabilization year). A maximum increase of 113.2 psi was estimated in the near-wellbore area at the end of the 20-year injection period.

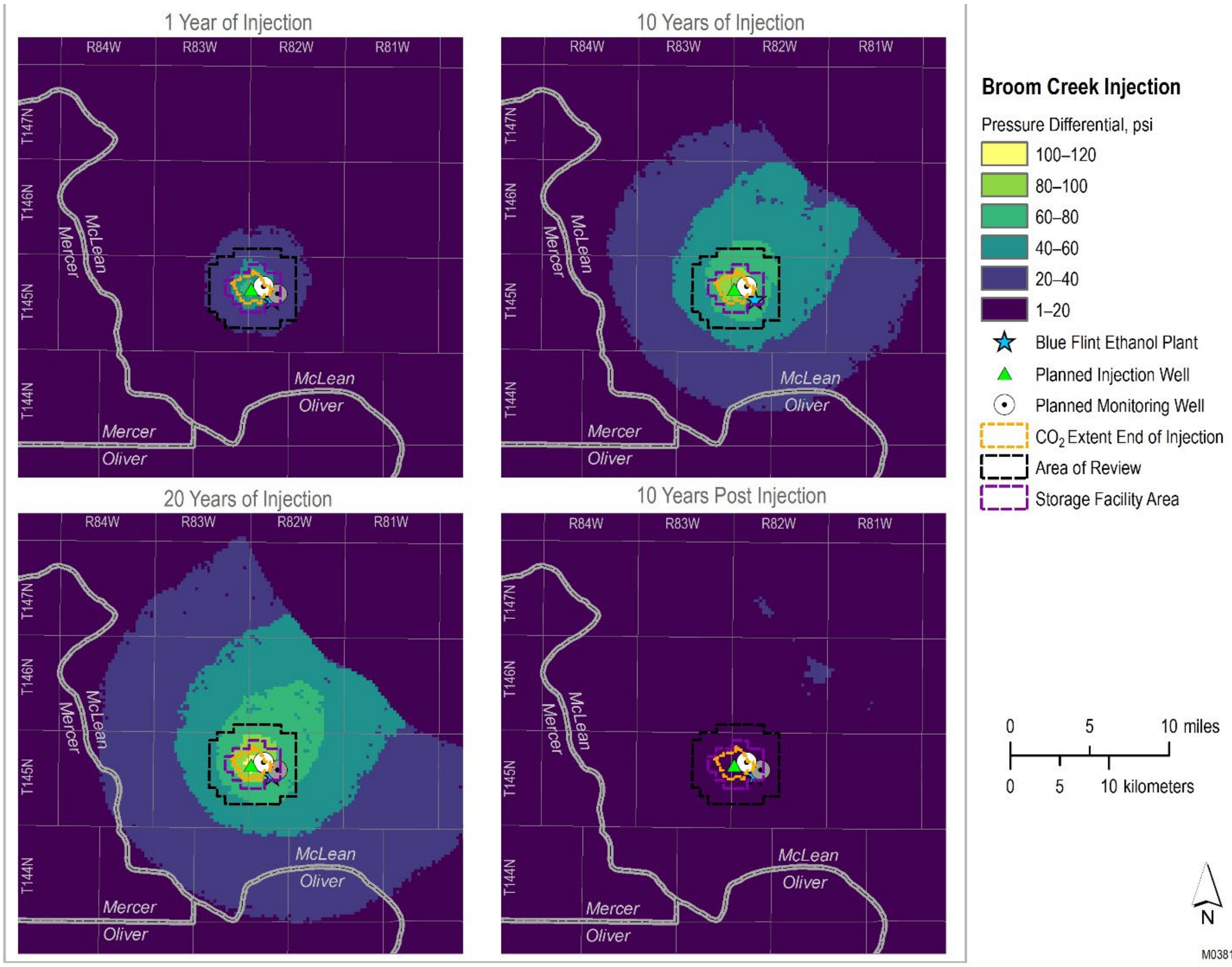


Figure 3-13. Top left, top right, and bottom left display average pressure increase within the Broom Creek Formation after 1, 10, and 20 years of simulated CO_2 injection operation. Bottom right displays pressure differential during 10 years of postinjection (plume stabilization year).

Long-term CO_2 migration potential was also investigated through the numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase CO_2 injected into the formation rises to the bottom of the upper confining zone or lower-permeability layers present in the Broom Creek Formation and then outward. This process results in a higher concentration of CO_2 at the center which gradually spreads out toward the model edges where the CO_2 saturation is lower. Trapped CO_2 saturations, employed in the model to represent fractions of CO_2 trapped in small pores as immobile, tiny bubbles, ultimately immobilize the CO_2 plume and limit the plume's lateral migration and spreading. Figure 3-14 shows the CO_2 saturation at the injection well at the end of injection in north-to-south and east-to-west cross-sectional views.

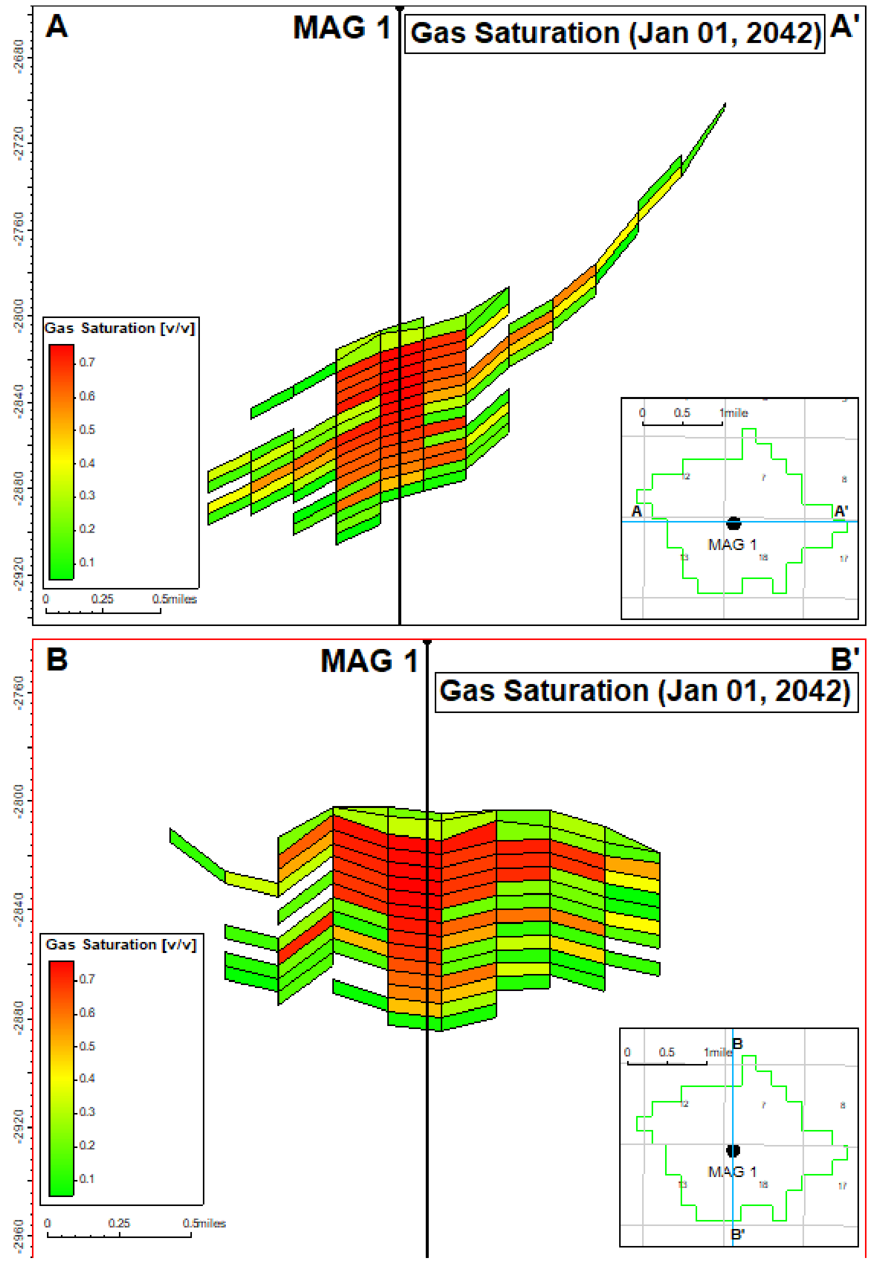


Figure 3-14. CO_2 plume cross section of MAG 1 at the end of injection displayed by a) west to east and b) north to south (50× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

3.4.1 *Maximum Injection Pressures and Rates*

An additional case was run to determine the maximum storage potential if the well was only limited by the maximum calculated downhole pressure of 2,970 psi (90% of the formation fracture pressure). In this scenario, the MAG 1 well was able to inject at a daily average rate of 2,729 tonnes/day of CO_2 with a 2.875-in. diameter tubing, achieving a total injection volume of 19.9 MMt of CO_2. The predicted average WHP, using the designed injection tubing of 2.875 inches, was 4,300 psi (Figure 3-15).

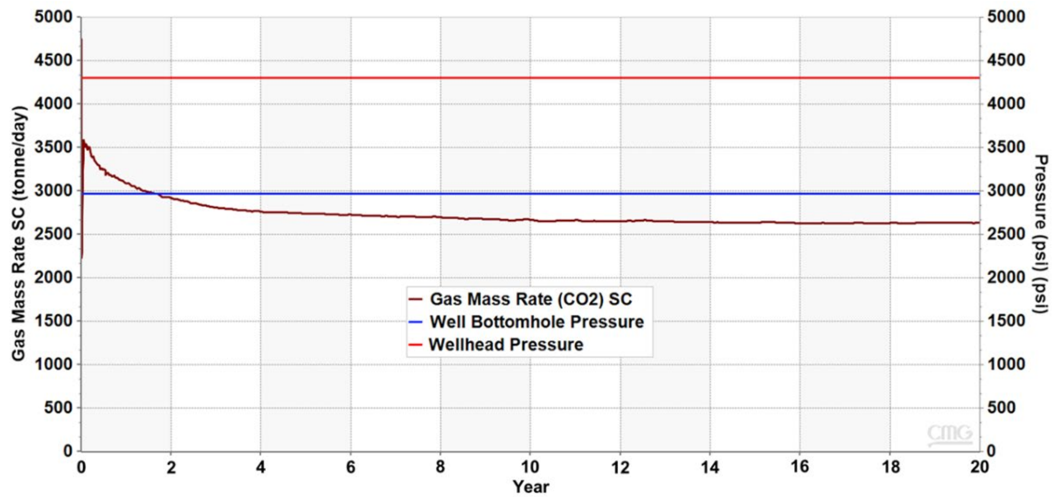


Figure 3-15. Maximum pressures and rate response when the well was operated without any injection rate limits.

3.4.2 *Stabilized Plume and Storage Facility Area*

Movement of the injected CO_2 plume is driven by the potential energy found in the buoyant force of the injected CO_2. As the plume spreads out within the reservoir and CO_2 is trapped residually through the effects of relative permeability and dissolution, the potential energy of the buoyant CO_2 is gradually lost. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized. The extent of the stabilized plume is important for determining the project's AOR and the corresponding scale and scope of the project's monitoring plans.

Plume stabilization can be visualized at the microscale as CO_2 being unable to exit its current pore space and enter the neighboring pore space, but at the macroscale, these interactions cannot be measured. Instead, plume stabilization may be estimated using the tools available to predict the CO_2 plume's extent.

For the Blue Flint project the CO_2 plume was simulated in 5-year time steps until the rate of total areal extent change slowed to less than 0.15 square miles per 5-year time step to define the stabilized plume extent boundary (Figure 3-13) and the associated buffers and boundaries. This estimate is anticipated to be regularly updated during the CO_2 storage operation as data collected from the site are used to update predictions made about the behavior of the injected CO_2.

3.5 Delineation of the Area of Review

The North Dakota Administrative Code (NDAC) defines AOR as the region surrounding the geologic storage project where underground sources of drinking water (USDWs) may be endangered by CO_2 injection activity (NDAC § 43-05-01-05). The primary endangerment risk is the potential for vertical migration of CO_2 and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the CO_2 plume within the storage reservoir.

However, the CO_2 plume has an associated pressure front where CO_2 injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the CO_2 plume. Therefore, the AOR encompasses both the areal extent of the CO_2 plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the CO_2 plume, AOR delineation focuses on the pressure front.

The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the underground injection control (UIC) program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure.

In this document, "storage reservoir" refers to the Broom Creek Formation (the injection zone), "potential thief zone" refers to the Inyan Kara Formation, and "lowest USDW" refers to the Fox Hills Formation.

3.5.1 EPA Methods 1 and 2: AOR Delineation for Class VI Wells

EPA guidance for AOR evaluation includes several computational methods for estimating the pressure buildup in the storage reservoir in response to CO_2 injection and the resultant areal extent of pressure buildup above a "critical threshold pressure" that could potentially drive higher-salinity formation fluids from the storage reservoir up an open conduit to the lowest USDW (U.S. Environmental Protection Agency, 2013). The following equations and analytical approach define the EPA methods used to delineate AOR. Each method can be applied both at a single location (e.g., the MAG 1 stratigraphic well) using site-specific data or for each vertical stack of grid cells in a geocellular model, considering the varying stratigraphic thickness between storage reservoir and lowest USDW.

EPA Method 1 (*pressure front based on bringing the injection zone and USDW to equivalent hydraulic heads*) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW (U.S. Environmental Protection Agency, 2013).

Under Method 1, the maximum pressure increase that may be sustained in the injection zone (critical threshold pressure increase) is given by Equation 1:

$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_I \quad \text{[Eq. 1]}$$

Where:

P_u is the initial fluid pressure in the USDW (Pa).
ρ_i is the storage reservoir fluid density (mg/m^3).
g is the acceleration due to gravity (m/s^2).
z_u is the representative elevation of the USDW (m amsl).
z_i is the representative elevation of the injection zone (m amsl).
P_i is the initial pressure in the injection zone (Pa).
$\Delta P_{i,f}$ is the critical threshold pressure increase (Pa).

Equation 1 assumes that the hypothetical open borehole is perforated exclusively within the injection zone and USDW. If $\Delta P_{i,f} = 0$, then the reservoir and USDW are in hydrostatic equilibrium; if $\Delta P_{i,f} > 0$, then the reservoir is underpressurized relative to the USDW; and if $\Delta P_{i,f} < 0$, then the reservoir is overpressurized relative to the USDW.

In scenarios where the storage reservoir and USDW are in hydrostatic equilibrium ($\Delta P_{i,f} = 0$), EPA Method 2 (*pressure front based on displacing fluid initially present in the borehole*) can be used to calculate the critical pressure threshold. Method 2 was originally presented by Nicot and others (2008) and Bandilla and others (2012). Method 2 calculates the critical threshold pressure increase (ΔP_c), which is the fluid pressure increase sufficient to drive formation fluids into the lowermost USDW. This ΔP_c is determined using Equations 2 and 3, assuming 1) hydrostatic conditions, 2) initially linear densities in the borehole, and 3) constant density once the injection zone fluid Is lifted to the top of the borehole (i.e., uniform density approach):

$$\Delta P_C = \frac{1}{2}\, g\, \xi\, (Z_u - Z_i)^2 \quad \text{[Eq. 2]}$$

Where ξ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{Z_u - Z_i} \quad \text{[Eq. 3]}$$

Where:

ΔP_c is the critical threshold pressure increase (Pa).
g is the acceleration of gravity (m/s^2).
z_u is the elevation of the base of the lowermost USDW (m amsl).
z_i is the elevation of the top of the injections zone (m amsl).
P_i is the fluid density in the injection zone (kg/m^3).
P_u is the fluid density in the USDW (kg/m^3).

3.5.2 Risk-Based AOR Delineation

The methods described by EPA (2013) for estimating the AOR under the Class VI rule (40 U.S. Code of Federal Regulations [CFR] 146.81 et seq.) were developed assuming that the storage reservoirs would be in hydrostatic equilibrium with overlying aquifers. However, in the state of North Dakota, and potentially elsewhere around the United States, candidate storage reservoirs are already overpressurized relative to overlying aquifers and thus subject to potential vertical formation fluid migration from the storage reservoir to the lowermost USDW, even prior to the planned storage project. Consequently, applying EPA (2013) methods to these geologic situations essentially results in an infinite AOR, which makes regulatory compliance infeasible.

Several researchers have recognized the need for alternative methods for estimating the AOR for locations that are already overpressurized relative to overlying aquifers. For example, Birkholzer and others (2014) described the unnecessary conservatism in EPA's definition of critical pressure, which could lead to a heavy burden on storage facility permit (SFP) applicants. As an alternative, Burton-Kelly and others (2021) proposed a risk-based reinterpretation of this framework that would allow for a reduction in the AOR while ensuring protection of drinking water resources.

A computational framework for estimating a risk-based AOR was proposed by Oldenburg and others (2014, 2016), who compared formation fluid leakage through a hypothetical open flow path in the baseline scenario (no CO_2 injection) to the incrementally larger leakage that would occur in the CO_2 injection case. The modeling for the risk-based AOR used semianalytical solutions to single-phase flow equations to model reservoir pressurization and vertical migration through leaky wells. These semianalytical solutions were extensions of earlier work for formation fluid leakage through abandoned wellbores by Raven and others (1990) and Avci (1994), which were creatively solved, coded, and compiled in FORTRAN under the name ASLMA (Analytical Solution for Leakage in Multilayered Aquifers) and extensively described by Cihan and others (2011, 2012) (hereafter "ASLMA Model").

Recently, White and others (2020) outlined a similar risk-based approach for evaluating the AOR using the National Risk Assessment Partnership (NRAP) Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS). However, NRAP-IAM-CS and the subsequent open-sourced version (NRAP-Open-IAM) are constrained to the assumption that the storage reservoir is in hydrostatic equilibrium with overlying aquifers and, therefore, may not accurately estimate the AOR for storage projects located in regions where the storage reservoir is overpressurized relative to overlying aquifers.

Building a geologic model in a commercial-grade software platform (like Petrel; Schlumberger, 2020) and running fluid flow simulations using numerical reservoir simulation in a commercial-grade software platform (like CMG's compositional simulator, GEM) provide the "gold standard" for estimating pressure buildup in response to CO_2 injection (e.g., Bosshart and others, 2018). However, these numerical reservoir simulations are typically limited to the storage reservoir and primary seal formation (cap rock) and do not include the geologic units overlying the cap rock because of the computational burden of conducting such a complex simulation. In addition, geologic modeling of the overlying units may add a substantial amount of time and effort during prefeasibility-phase projects that are unwarranted given the amount of uncertainty that may be present if only a few nearby wells can be used for characterization activities. Earlier studies (e.g., Nicot and others, 2008; Birkholzer and others, 2009; Bandilla and others, 2012; Cihan and others, 2011, 2012) have shown that far-field fluid pressure changes outside of the CO_2 plume domain can be reasonably described by a single-phase flow calculation by representing CO_2 injection as an equivalent-volume injection of brine (Oldenburg and others, 2014).

The semianalytical solutions embedded within the ASLMA Model have been shown to compare with the numerical model, TOUGH2-ECO2-N, and provided accurate results for pressures beyond the CO_2 plume zone (Birkholzer and others, 2009; Cihan and others, 2011, 2012). Therefore, the proposed workflow for delineating a risk-based AOR uses the ASLMA Model to examine pressure buildup in the storage reservoir and resultant effects of this buildup on the vertical migration of formation fluid via (single) hypothetical leaky wellbores located at progressively greater distances from the injection well (Figure 3-16).

An important distinction between EPA Methods 1 and 2, which both calculate a critical pressure threshold (either $\Delta P_{i,f}$ for Method 1 or ΔP_c for Method 2) and the risk-based AOR approach is that the risk-based approach 1) calculates and maps the potential incremental flow of

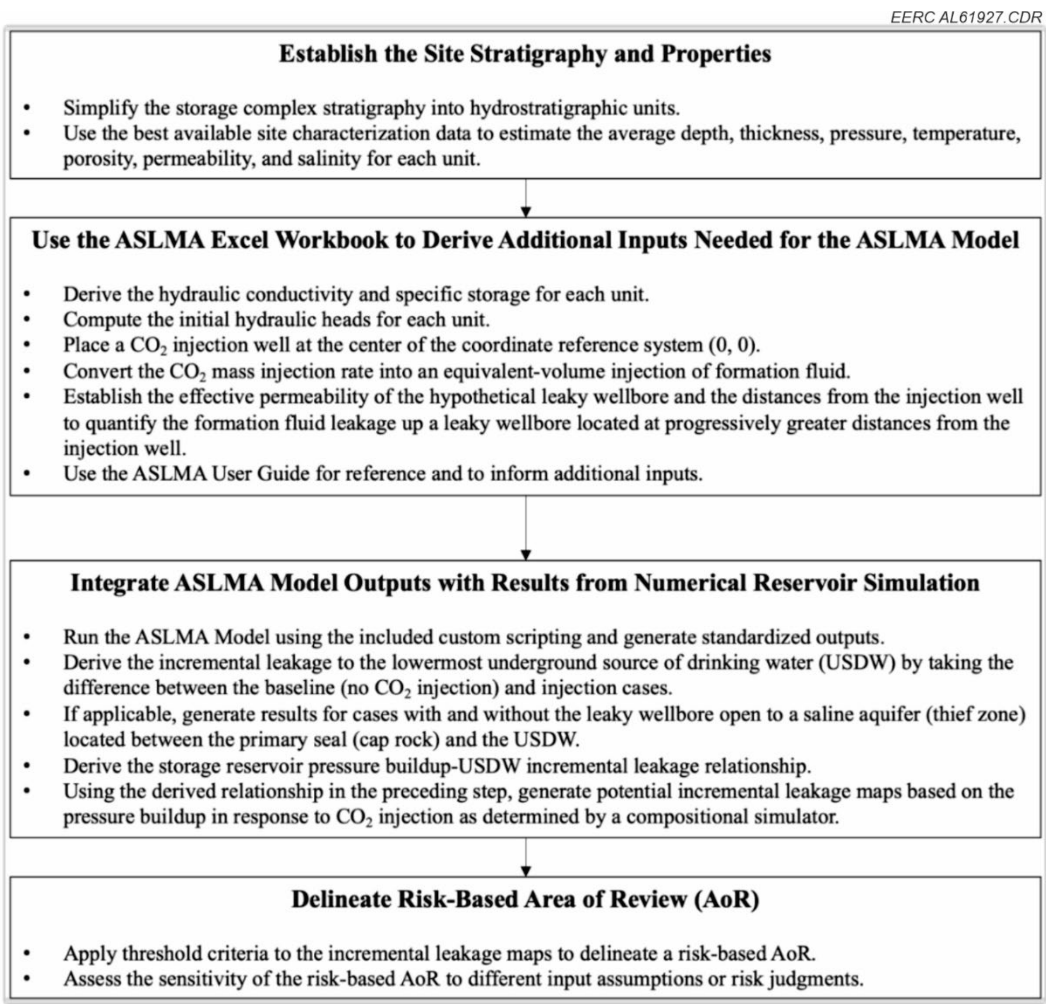


Figure 3-16. Workflow for delineating a risk-based AOR for a SFP (modified from Burton-Kelly and others, 2021).

formation fluids from the storage reservoir to the USDW that could occur and then 2) delineates the areal extent beyond which no significant leakage would occur. Therefore, the region beyond which no significant leakage would occur does not present an endangerment to the USDW; hence, the region inside of this areal extent is the risk-based AOR.

3.5.3 Critical Threshold Pressure Increase Estimation

For the purposes of delineating AOR for the project study area, constant fluid densities for the lowermost USDW (Fox Hills Formation) and injection zone (Broom Creek Formation) were used in the calculations. Respective fluid densities were used to represent the injection zone fluids (ρ_i), which are estimated based on the in situ estimated brine salinity, temperature, and pressure at the MAG 1 stratigraphic test well.

Application of EPA Method 1 (Equation 1) using site-specific data from the MAG 1 well shows that the injection zone in the project area is overpressurized with respect to the lowest USDW (i.e., Method 1 $\Delta P_{i,f} < 0$). An example of the EPA Method 1 application showing negative $\Delta P_{i,f}$ (relative overpressure) is given in Table 3-4, with similar results when applied to each column of the grid cells in the Broom Creek Formation simulation model.

Table 3-1. EPA Method 1 Critical Threshold Pressure Increase Calculated at the MAG 1 Wellbore Location Using Measured and Calculated Data Shown in Table 3-2

Depth,* ft	Depth,* m	P_i Injection Zone Pressure, MPa	P_u USDW Base Pressure, MPa	ρ_i Injection Zone Density, kg/m³	Z_u USDW Base Elevation, m amsl	Z_i Reservoir Elevation, m amsl	$\Delta P_{i,f}$ Threshold Pressure Increase, MPa	$\Delta P_{i,f}$ Threshold Pressure Increase, psi
4,731	1,442	16.41	3.15	1,006	276	−855	−2.11	−306

* Ground surface elevation is 581 m above mean sea level. Depth provided is the reference depth used for the CMG simulation.

In accordance with EPA (2013) guidance, the combination of a) a Method 1 negative $\Delta P_{i,f}$ value across the project area and b) lack of evidence for hydrostatic equilibrium between the reservoir and the USDW (i.e., Method 2 does not apply) indicates that a risk-based approach to AOR delineation may be pursued.

3.5.4 Risk-Based AOR Calculations

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). The inputs, assumptions, and results discussed here provide the necessary details for reproducing and verifying the results. A macro-enabled Microsoft Excel file was used to define the inputs and calculations that were employed in the method (hereafter "ASLMA Workbook").

3.5.4.1 Initial Hydraulic Heads

The original ASLMA Model (Cihan and others, 2011) initially assumed hydrostatic pressure distributions in the entire system. The current work uses a modified version of the ASLMA Model to simulate pressure perturbations and leakage rates when there are initial head differences in the aquifers (Oldenburg and others, 2014). The initial hydraulic heads are calculated assuming a total head based on the unit-specific elevations and pressures. The total heads are entered into the ASLMA Model and establish the initial pressure conditions for the storage complex prior to CO_2 injection.

For example, the initial reference case total heads for the storage reservoir (Aquifer 1), potential thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-5 and illustrate the state of overpressure in the storage complex, as Aquifer 1 has a greater initial hydraulic head than Aquifers 2 and 3. Therefore, the storage complex requires different treatment than the default AOR calculations described by EPA (2013). Details on the calculations of initial hydraulic head are provided in Burton-Kelly and others (2021).

Table 3-2. Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex

Hydrostratigraphic Unit	Depth to Top,* m	Thickness, m	Pressure, MPa	Temperature, °C	Salinity, ppm	Brine Density, kg/m^3	Porosity, %	Permeability,		HCON, m/d	Specific Storage, m^{-1}	Total Head, m
								mD	m^2			
Overlying Units to Ground Surface (not directly modeled)	0	215										
Aquifer 3 (USDW – Fox Hills Fm)	215	90	2.6	12.5	1,800	1,002	34.4	280	2.76E-13	1.92-01	5.56E-06	591
Aquitard 2 (Pierre Fm–Inyan Kara Fm)	305	788	7.0	25.3	16,300		10	0.1	9.87E-17	9.30E-05	9.26E-06	585
Aquifer 2 (Thief Zone – Inyan Kara Fm)	1,093	69	11.3	37.8	16,300	1,008	22.4	42.1	4.16E-14	5.06E-02	5.25E-06	593
Aquitard 1 (Swift–Broom Creek Fm) (primary upper seal)	1,161	273	13.0	42.7	28,600		10	0.1	9.87E-17	1.30E-04	9.31E-06	583
Aquifer 1 (Storage Reservoir – Broom Creek Fm)	1,435	32	16.5	68.3	28,600	1,003	18.2	121.3	1.20E-13	2.31E-01	5.15E-06	808

* Ground surface elevation 614 m amsl.

3.5.4.2 CO_2 Injection Parameters

The ASLMA Model for the project used a Broom Creek CO_2 injection rate that matched the simulation scenario. A single injector is placed at the center of the ASLMA Model grid at an x,y-location of (0,0) in the coordinate reference system. The ASLMA Model requires the CO_2 injection rate to be converted into an equivalent-volume injection of formation fluid in units of cubic meters per day. Microsoft Excel Visual Basic for Applications (VBA) functions were used to estimate the CO_2 density from the storage reservoir pressure and temperature, which resulted in an estimated density, shown in Table 3-6. The CO_2 mass injection rate and CO_2 density are then used to derive the daily equivalent-volume injection rate, shown in Table 3-6.

Table 3-3. CO_2 Density and Injection Parameters Used for the ASLMA Model

CO_2 Density, Reservoir Conditions, kg/m^3	Injection Period	Injection Rate, m^3 per day	Injection Period, years
580	1	944	20

3.5.4.3 Hypothetical Leaky Wellbore

In the project area, few wellbores are known to exist that penetrate the primary seal of the Broom Creek storage reservoir. However, for heuristic, "what-if" scenario modeling, which is needed to generate the data for delineating a risk-based AOR, a single hypothetical leaky wellbore is inserted into the ASLMA Model at 1, 2, …, 100 km from the CO_2 injection well. The pressure buildup in the storage reservoir at each distance, along with the recorded cumulative volume of formation fluid vertically migrating through the leaky wellbore from the storage reservoir to the USDW (i.e., from Aquifer 1 to Aquifer 3) throughout the 12-year injection period, provides the data set needed to derive the risk-based AOR.

Published ranges for the effective permeability of a leaky wellbore (Figure 3-17) have included an "open wellbore" with an effective permeability as high as 10^{-5} m^2 (10^{10} mD) to values more representative of leakage through a wellbore annulus of 10^{-12} to 10^{-10} m^2 (10^3 to 10^5 mD) (Watson and Bachu, 2008, 2009; Celia and others, 2011). Carey (2017) provides probability distributions for the effective permeability of potentially leaking wells at CO_2 storage sites and estimated a wide range from 10^{-20} to 10^{-10} m^2 (10^{-5} to 10^5 mD). For the project Broom Creek ASLMA Model, the effective permeability of the leaky wellbore is set to 10^{-16} m^2 (0.1 mD), which is a conservative (highly permeable) value near the top of the published range for the effective permeability of potentially leaking wells at CO_2 storage sites (Figure 3-17).

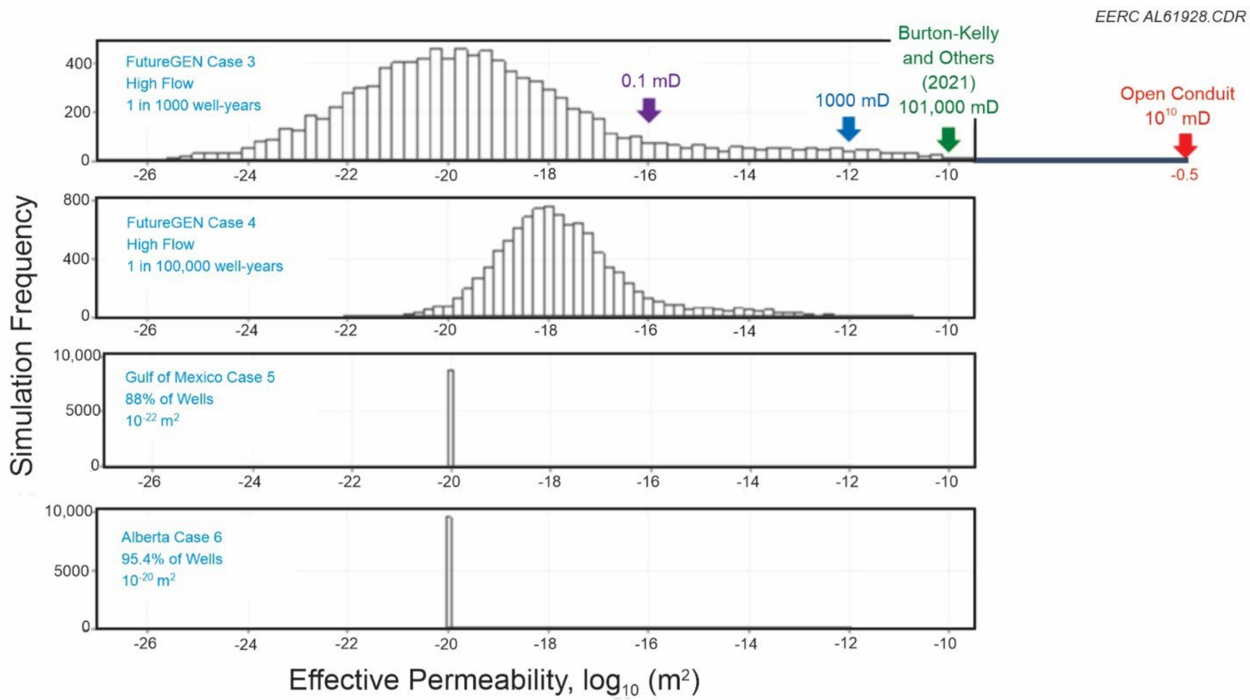


Figure 3-17. Histograms describing the expected frequency of leaky wellbore effective permeabilities under different scenarios. The ASLMA Model used for AOR delineation used a value of approximately 0.1 mD (constructed from data presented by Carey [2017]).

The current work uses the ASLMA Model Type 1 feature (focused leakage only) for the nominal model response, which makes the conservative assumption that the aquitards are impermeable. This assumption prevents the pressure from diffusing into the overlying aquitards, resulting in a greater pressure buildup in the storage reservoir and a commensurately greater amount of formation fluid vertically migrating from the storage reservoir through the leaky wellbore. The conservative assumption of Model Type 1 rather than Model Type 3 (coupled focused and diffuse leakage) provides an added level of protection to the delineation of a risk-based AOR by projecting a larger pressure buildup in the storage reservoir than a scenario in which pressure is allowed to dissipate through the upper seal and, therefore, a greater leakage of formation fluid up the leaky wellbore.

3.5.4.4 Saline Aquifer Thief Zone

As shown in Table 3-5, a saline aquifer (Aquifer 2, Inyan Kara Formation) exists between the primary seal above the storage reservoir and USDW (Aquifer 3, Fox Hills Formation). Formation fluid migrating up a leaky wellbore that is open to Aquifer 2 will preferentially flow into Aquifer 2, and the continued flow up the wellbore and into the USDW will be reduced. Therefore, the presence of Aquifer 2 may act as a thief zone and reduces the potential for formation fluid impacts to the groundwater.

The thief zone phenomenon was described by Nordbotten and others (2004) as an "elevator model" by analogy with an elevator full of people on the main floor, who then get off at various floors as the elevator moves up, such that only very few people ride all the way to the top floor. The term "thief zone" is also used in the oil and gas industry to describe a formation encountered during drilling into which circulating fluids can be lost. Models with and without opening the leaky wellbore to Aquifer 2 (Inyan Kara Formation) were run and evaluated to quantify the effect of a thief zone on the risk-based AOR.

3.5.4.5 Aquifer- and Aquitard-Derived Properties

The ASLMA Model assumes homogeneous properties within each hydrostratigraphic unit (Table 3-5). For each unit shown in Table 3-5, pressure, temperature, porosity, permeability, and salinity are used to derive two key inputs for the ASLMA Model: hydraulic conductivity (HCON) and specific storage (SS). Average porosity and permeability values were derived as follows: Broom Creek, from distributed properties in the geologic model; Inyan Kara, from MAG 1 core data and regional well logs; and Fox Hills, from regional well log data. Porosity is represented as an arithmetic mean and permeability as a geometric mean value within each hydrostratigraphic unit (excluding nonsandstone rock types).

VBA functions included in the ASLMA Workbook are used to estimate the formation fluid density and viscosity from the aquifer or aquitard pressure, temperature, and salinity inputs, which are then used to estimate the HCON and SS. The estimated reference case HCON for the storage reservoir (Aquifer 1), thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-5. Details about the HCON and SS derivations are provided in supporting information for Burton-Kelly and others (2021).

3.5.5 Risk-Based AOR Results

3.5.5.1 Relating Pressure Buildup to Incremental Leakage with ASLMA Model and Compositional Simulation

Figure 3-18 shows the relationship between the maximum pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 (USDW) for scenarios with and without the leaky wellbore open to Aquifer 2 (thief zone). In the case where the leaky wellbore is closed to Aquifer 2, there is no incremental leakage to Aquifer 2. The curvilinear relationship between pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 is used to predict the incremental leakage from the pressure buildup map produced by the compositional simulation of the geocellular model. The average simulated pressure buildup in the reservoir is represented by a raster (grid) map of pressure buildup values. For each raster value (grid cell map location), the relationship between pressure buildup and incremental leakage (Figure 3-18) is used to predict incremental leakage using a linear interpolation between the points making up the curve. The estimated cumulative leakage potential from Aquifer 1 to Aquifer 3 along a hypothetical leaky wellbore without injection occurring (i.e., leakage due to natural overpressure) and no thief zone is shown in Table 3-7.

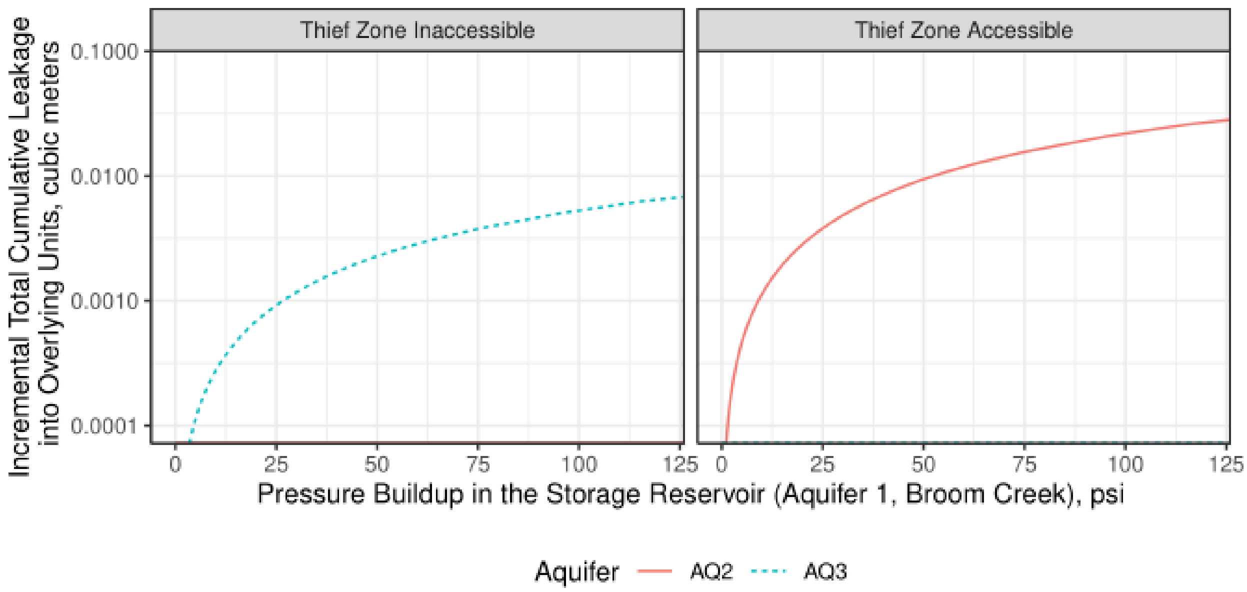


Figure 3-18. Relationship between pressure buildup (x-axis, psi) in the storage reservoir (Aquifer 1, Broom Creek) and incremental total cumulative leakage (y-axis, m^3) into Aquifer 2 (thief zone, Inyan Kara, red solid line) and Aquifer 3 (USDW, Fox Hills, dashed blue line). In the left-hand scenario, the leaky wellbore is closed to Aquifer 2 (Inyan Kara), so all flow is from the storage reservoir to the USDW. In the right-hand scenario, the leaky wellbore is open to Aquifer 2 (Inyan Kara), so the vast majority of flow is from the storage reservoir to the thief zone, and the curve showing flow into the USDW is not visible on this plot.

3.5.5.2 Incremental Leakage Maps and AOR Delineation

The pressure buildup–incremental leakage relationship, shown in Figure 3-18, results in the incremental leakage map, shown in Figure 3-19, which show the estimated total cumulative incremental leakage potential from a hypothetical leaky well into Aquifer 3 (USDW) over the entire injection period if the hypothetical leaky wellbore is not open to the thief zone.

The final step of the risk-based AOR workflow is to apply a threshold criterion to the incremental leakage maps to delineate a risk-based AOR. For the Broom Creek Formation injection at the project site, a threshold of 1 m^3 of potential incremental flow into the Fox Hills Formation USDW along a hypothetical leaky wellbore over the injection period is established. A value of 1 m^3 is the lowest meaningful value that can be produced by the ASLMA Model; although the model can return smaller values, they likely represent statistical noise. This potential incremental flow threshold is greater than all calculated potential incremental flow values described by the curve in Figure 3-18. The maximum vertically averaged change in pressure in the storage reservoir at the end of the simulated injection period and the corresponding flow over the injection period are shown in Table 3-7. This pressure is below the potential incremental flow threshold of 1 m^3. Therefore, the storage reservoir pressure buildup is not a deciding factor in determining the AOR extent.

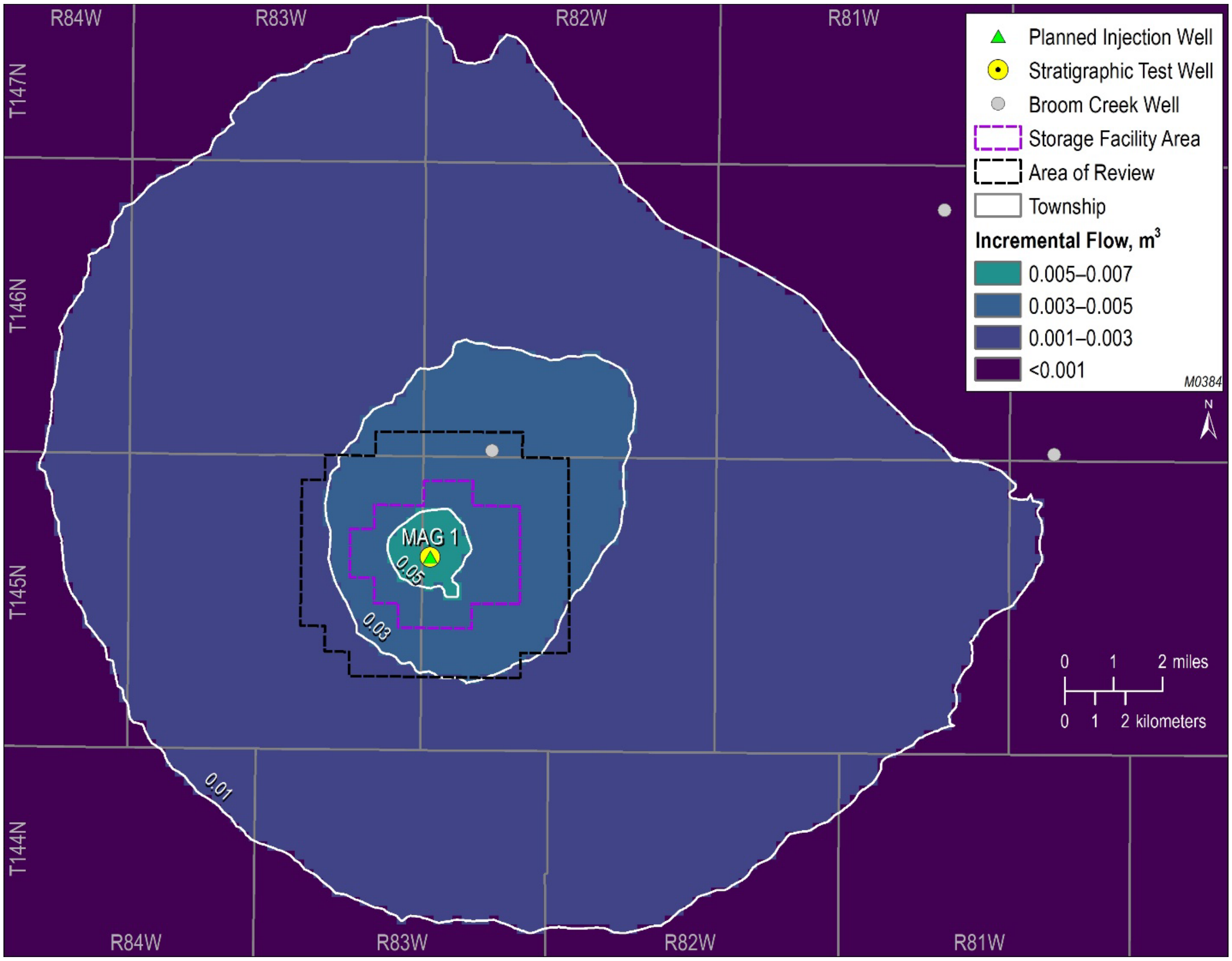


Figure 3-19. Map of potential incremental leakage into the USDW at the end of 20 years of CO_2 injection for the scenario where the hypothetical leaky wellbore is closed to Aquifer 2 (thief zone).

Table 3-4. Summary Results from the Risk-Based AOR Method of Estimated Potential Cumulative Leakage after 20 years of Injection and No Thief Zone

Maximum Vertically Averaged Change in Reservoir Pressure, psi	113.2
Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore *Without* Injection, m^3	0.019
Maximum Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore *Attributable to* Injection, m^3	0.005

The assumptions and calculations used to determine the risk-based AOR at the project site incorporate at least four safety factors for the protection of groundwater resources. If the ASLMA Model has resulted in an underestimation of the amount of potential leakage over the injection period, such underestimation is likely to be mitigated by:

- The statistical overestimation of hypothetical leaky wellbore permeability compared to known and estimated values in the literature—A more statistically likely hypothetical leaky wellbore permeability would be lower and allow less flow into the USDW.

- The lack of communication between the hypothetical leaky wellbore and Inyan Kara Formation, which would act as a thief zone—A real leaky wellbore would likely communicate with the Inyan Kara Formation, which would receive much, if not all, of the brine leaked from the storage reservoir.

- The low density of known legacy wellbores in the Blue Flint project area—CO_2 injection is proposed to occur in an area with few available leakage pathways.

- The continued overpressurized nature of the Broom Creek Formation with respect to overlying saline aquifers, over relatively short (e.g., 50-year) timescales, overpressurized aquifers with leakage pathways would demonstrate a change in upward flow rate and corresponding pressure (Oldenburg and others, 2016).

The risk-based method detailed above shows that storage reservoir pressure buildup is not necessary for determining AOR because the potential incremental flow into the USDW is below the identified threshold of 1 m^3. Therefore, the AOR is delineated as the storage facility area plus a 1-mile buffer (Figure 3-20). Figure 3-21 illustrates the land use within the AOR.

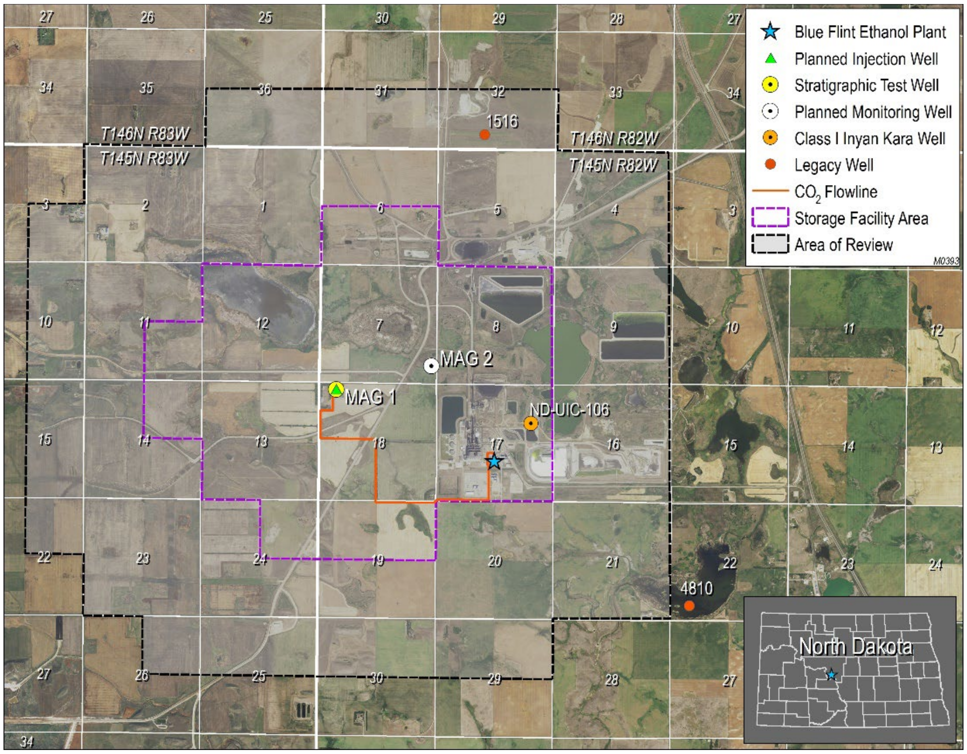


Figure 3-20. Final AOR estimations of the project storage facility area in relation to nearby legacy wells. Shown is the storage facility area (purple polygon) and AOR (black polygon). Orange circles represent legacy oil and gas wells near the storage facility area.

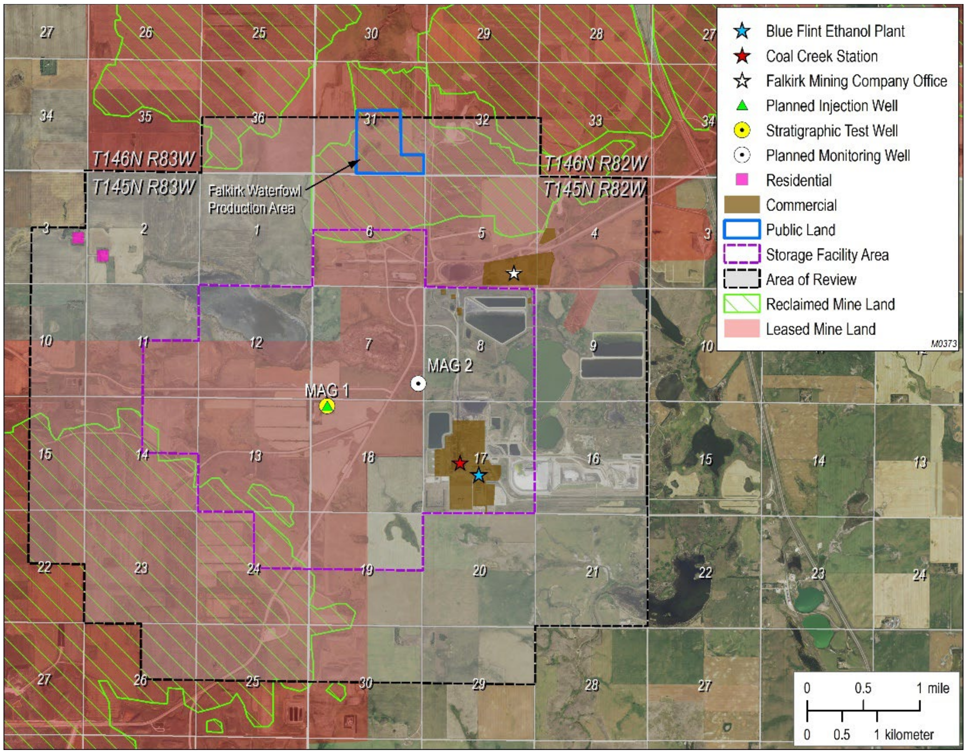


Figure 3-21. Land use in and around the AOR of the project storage facility.

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4.0 AREA OF REVIEW

4.0 AREA OF REVIEW

4.1 Area of Review (AOR) Delineation

4.1.1 Written Description

North Dakota geologic storage of CO_2 regulations require that each storage facility permit (SFP) delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water [USDW] may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO_2 plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the MAG 1 well (NDIC File No. 37833) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-5]).

NDAC § 43-05-01-05(1)(b)(3) requires "[a] review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 4-1), the resulting AOR for the geologic storage project is delineated as being 1 mile from the SFP boundary. This extent ensures compliance with existing state regulations.

All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 3-20 and 4-2) by a professional engineer pursuant to NDAC § 43-05-01-05(1)(b)(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected CO_2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 through 4-4, and Figure 4-3 through Figure 4-5).

An extensive geologic and hydrogeologic characterization performed by a team of geologists from the EERC uncovered no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.

This section of the SFP application is accompanied by maps and tables that include information required and in accordance with NDAC § 43-05-01-05(1)(a) and (b) and § 43-05-01-05.1(2), such as the storage facility area, location of any proposed injection wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05(1)(a) and (b)(3) and § 43-05-01-05.1(2). Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1.

4.1.2 Supporting Maps

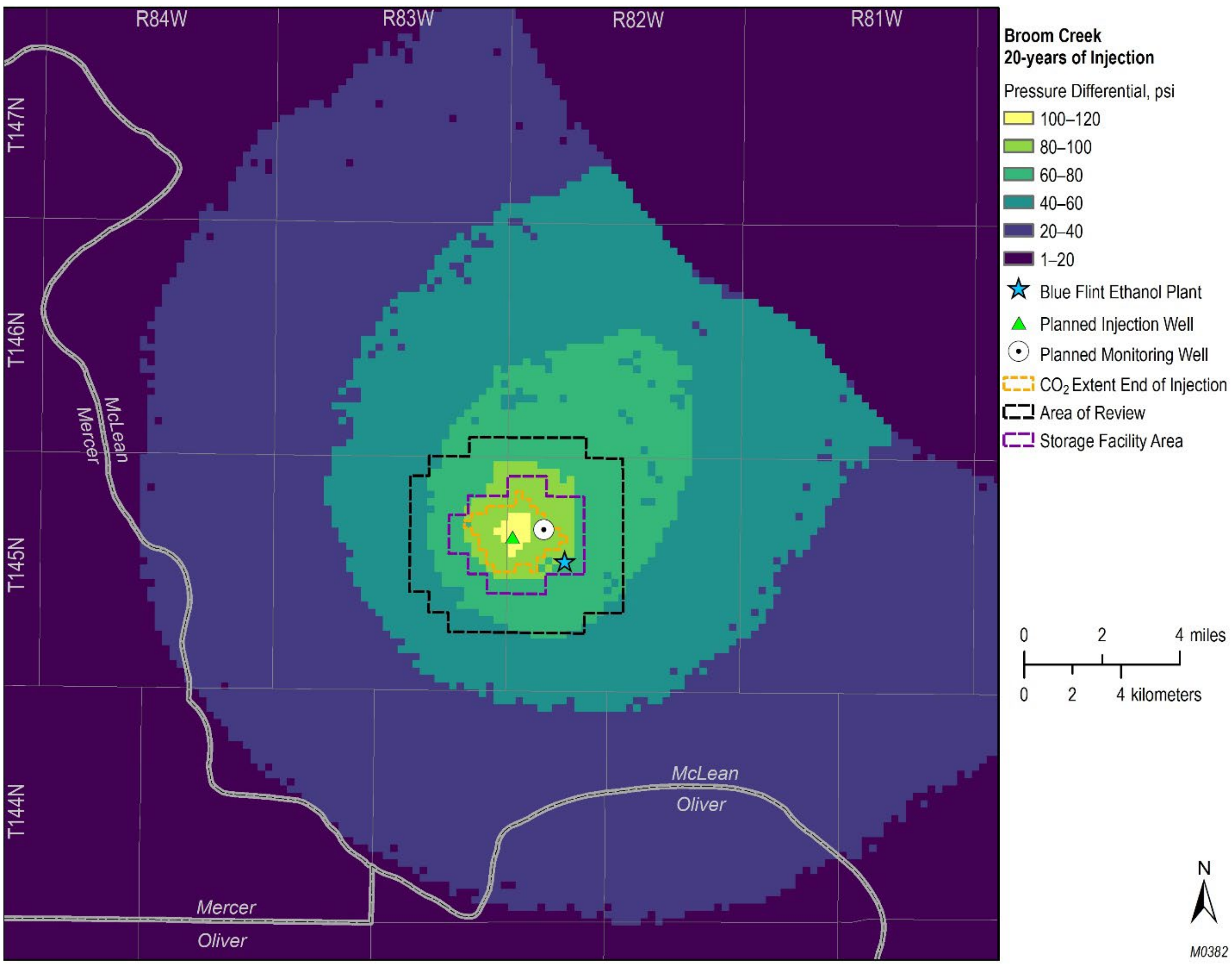

Figure 4-1. Pressure map showing the maximum subsurface pressure influence associated with CO_2 injection in the Broom Creek Formation. Shown is the CO_2 plume extent after end of injection, the storage facility area, and the 1-mile AOR boundary in relation to the maximum subsurface pressure influence.

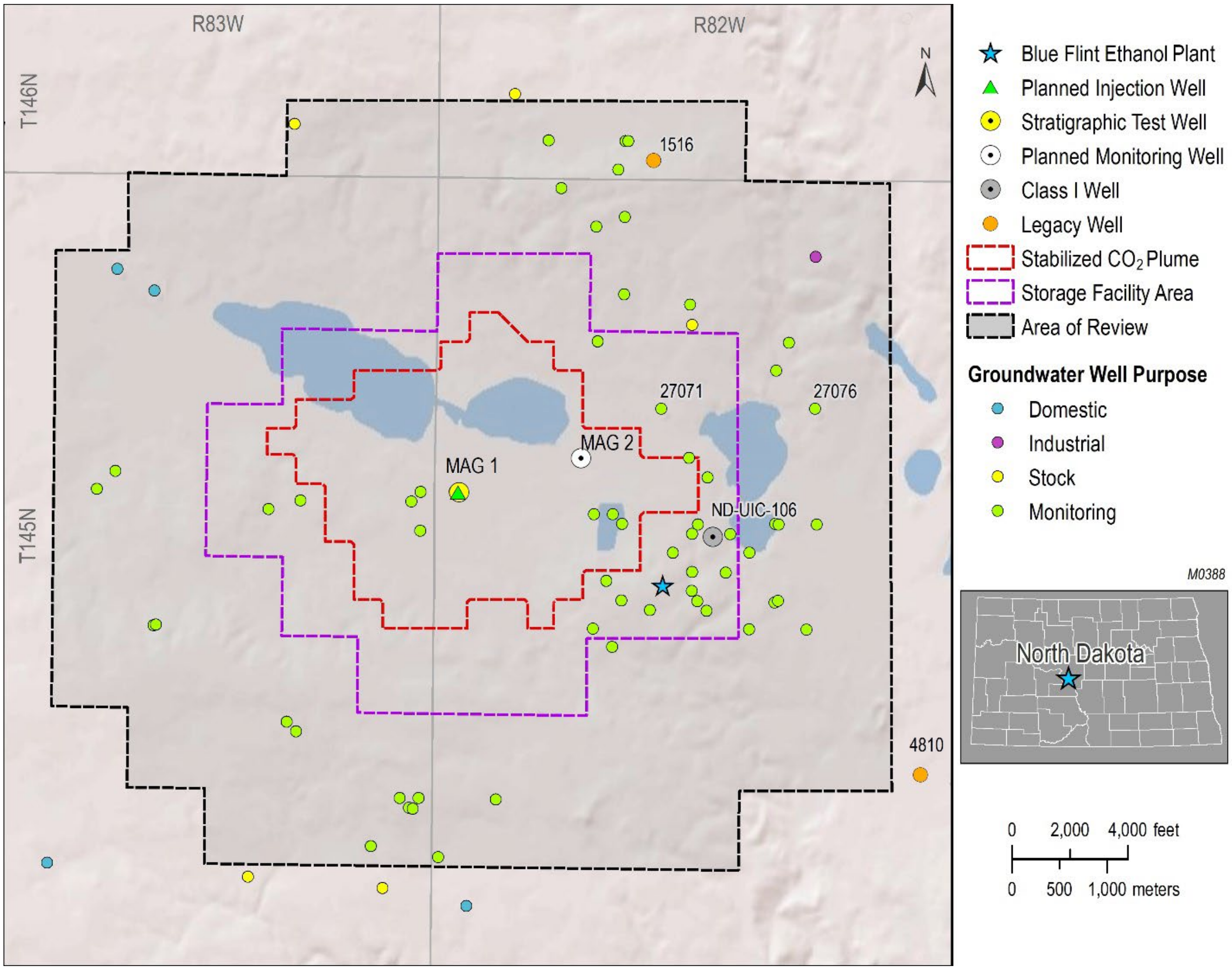

Figure 4-2. AOR map in relation to nearby groundwater wells. Shown are the stabilized CO_2 plume extent postinjection (dashed red boundary), storage facility area (dashed purple boundary), and 1-mile AOR (dashed black boundary). All groundwater wells in the AOR are identified above. All observation/monitoring wells shown are shallow groundwater wells associated with the mine activities. No springs are present in the AOR.

Table 4-1. Investigated and Identified Surface and Subsurface Features (Figures 3-20, 4-1 and 4-2)

Surface and Subsurface Features	Investigated and Identified (Figures 4-1–4-5)	Investigated But Not Found in AOR
Producing (active) Wells		X
Abandoned Wells	X	
Plugged Wells or Dry Holes	X	
Deep Stratigraphic Boreholes	X	
Subsurface Cleanup Sites		X
Surface Bodies of Water	X	
Springs		X
Water Wells	X	
Mines (surface and subsurface)	X	
Quarries		X
Subsurface Structures (e.g., coal mines)		X
Location of Proposed Wells	X	
*Location of Proposed Cathodic Protection Boreholes		X
Any Existing Aboveground Facilities	X	
Roads	X	
State Boundary Lines		X
County Boundary Lines		X
Indian Boundary Lines		X
Other Pertinent Surface Features	X	

* There are no plans for cathodic protection for the injection well (MAG 1).

4.2 Corrective Action Evaluation

Table 4-2. Wells in AOR Evaluated for Corrective Action*

Well File No.	Operator	Well Name	Spud Date	Surface Casing o.d., inches	Surface Casing Seat, ft	Long-String Casing o.d., inches	Long-String Casing seat, inches	Hole Direction	TD, ft	TVD, ft	Status	Plug Date	TWN	RNG	Section	Qtr/Qtr	County	Corrective Action Needed
1516	H. Hanson Oil Syndicate	Ellen Samuelson 1	9/14/1957	10.75	462	Openhole		Vertical	6,600	6,600	P&A	10/18/1957	146N	82W	32	SE/SW	McLean	No
ND-UIC-106**	Great River Energy	Well #1	10/10/2014	11.75	1,232	7		3531	Vertical	4,046	4,046	NA	145N	82W	17	SE/NE	McLean	No
4810	W. H. HUNT TRUST ESTATE	Wallace O. Gradin 1	12/1/1969	8.625	233	Openhole		Vertical	4240	4240	P&A	12/6/1969	145N	82W	22	SW/SW	McLean	No

* TD is total depth, and TVD is true vertical depth.
**ND-UIC-106 is classified as a Class I disposal well.

Table 4-3. Ellen Samuelson 1 (NDIC File No. 1516) Well Evaluation

Well Name: Ellen Samuelson 1 (NDIC File No. 1516)

Cement Plugs				
Number	Interval, ft		Thickness, ft	Volume, sacks
1	5,940			20
2	5,480			20
3	4,730			20
4	3,670			20
5	Base of Surface			25
6	Top of Surface			5

* Data and information are provided from well-plugging report found in NDIC database.

Formation		
Name	Estimated Top, ft	Cement Plug Class G*
10¾" Casing Shoe	462	Cement Plug 5 isolates the 10¾" casing shoe.
Pierre	1,055	
Mowry	3,355	Top of Inyan Kara Formation is not covered by cement. However, Cement Plug 4 isolates Dakota Group.
Inyan Kara	3,655	
Swift	3,912	
Kibby Lime	5,272	Cement Plugs 3, 2, and 1 isolate the formations below the Broom Creek Formation.

Spud Date: 9/14/1957
Total Depth: 6,600 (Mission Canyon Formation)

Surface Casing: 10¾" casing set at 462, cement to surface with 200 sacks Class G cement.

Openhole plugging

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Ellen Samuelson 1 well (NDIC File No. 1516) will not be in contact with the CO_2 plume, and pressure increase in the Broom Creek Formation at this well location is predicted to be approximately 76 psi. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled and plugged.

* Cement Type is assumed to be Class G as no cement type was on file.

Table 4-4. Well #1 (ND-UIC-106) Well Evaluation

Well Name: Well #1 (ND-UIC-106)

Formation		Cement Plug Remarks
Name	Estimated Top, ft	
11¾" Casing Shoe	1,232	Production Casing Cement isolates the 11¾" casing shoe.
Pierre	1,110	
Mowry	3,190	
Inyan Kara	3,531	
Production Casing	3,531	

Spud Date: 10/10/2014
Total Depth: 4,046 (Inyan Kara Formation)

Surface Casing: 11¾" casing set at 1,232, cement to surface

Production Casing: 7" casing set at 3,531, cement to surface

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Well #1 well (ND-UIC-106) will not be in contact with the CO_2 plume, and the well does not penetrate the Broom Creek Formation. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled above the Broom Creek Formation.

Additional information: Well #1 is classified as a Class I disposal well for nonhazardous waste injection into the Inyan Kara.

Table 4-5. Wallace O. Gradin 1 (NDIC File No. 4810) Well Evaluation

Well Name: Wallace O. Gradin 1 (NDIC File No. 4810)

Cement Plugs				
Number	Interval, ft		Thickness, ft	Volume, sacks
1	3181	3249	68	20
2	1152	1220	68	20
3	204	270	66	20
4	0	16	16	5

*Data and information are provided from well-plugging report found in NDIC database.

Formation		Cement Plug Remarks
Name	Estimated Top, ft	
8.625" Casing Shoe	233	8-5/8" J-55, 20# casing. Set at 233'. Cemented w/ 135 sks 8-5/8", 20# casing capacity is 2.7328 lin ft per ft^3. Plug 1 at surface and plug 2 at surface casing shoe.
Pierre	915	Plug 3 is 200' into the Pierre Fm. Fox Hills Formation isolated by plug 2 and 3.
Mowry	3195	Cement Plug 3 isolates the uppermost Inyan Kara porosity.
Newcastle	3249	
Swift	3745	
Rierdon	4083	Well file reports TD in Piper Formation.

Spud Date: 12/01/1969
Total Depth: 4083 ft

Openhole plugging

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Wallace O. Gradin 1 (NDIC File No. 4810) well will not be in contact with the CO_2 plume, and the well does not penetrate the Broom Creek Formation. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled above the Broom Creek Formation.

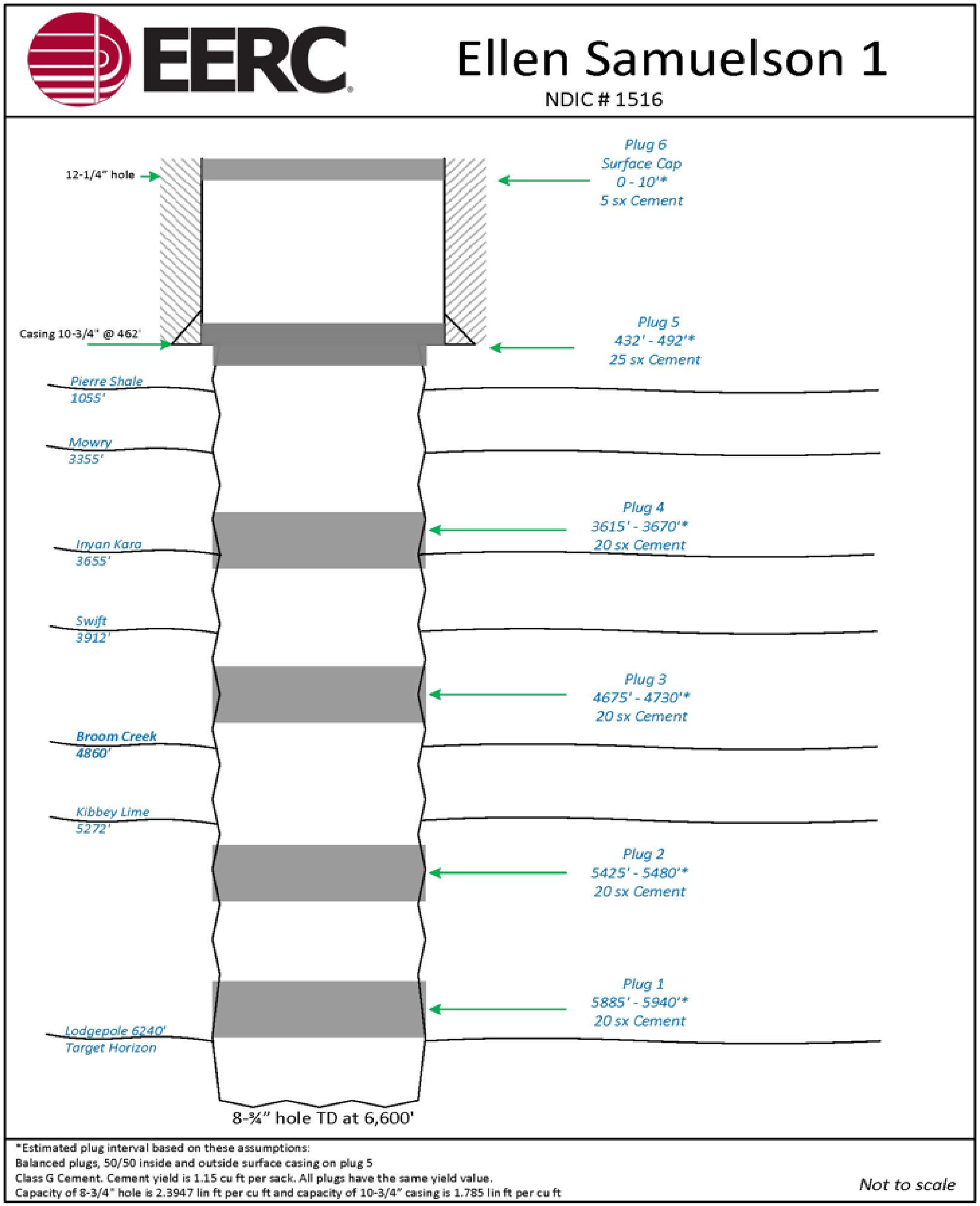

Figure 4-3. Ellen Samuelson 1 (NDIC File No. 1516) well schematic showing the location of cement plugs.

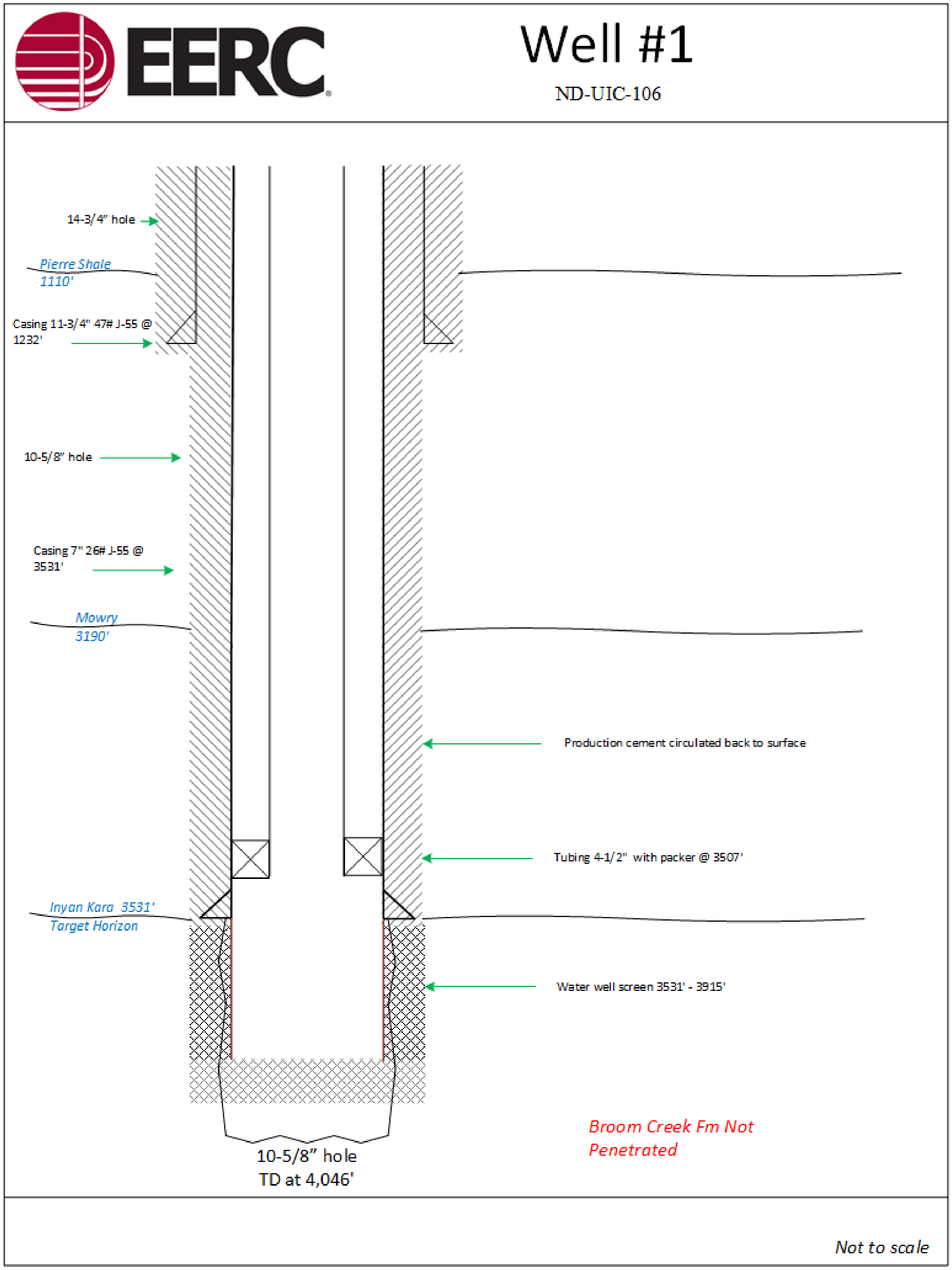

Figure 4-4. Well #1 (ND-UIC-106) well schematic.

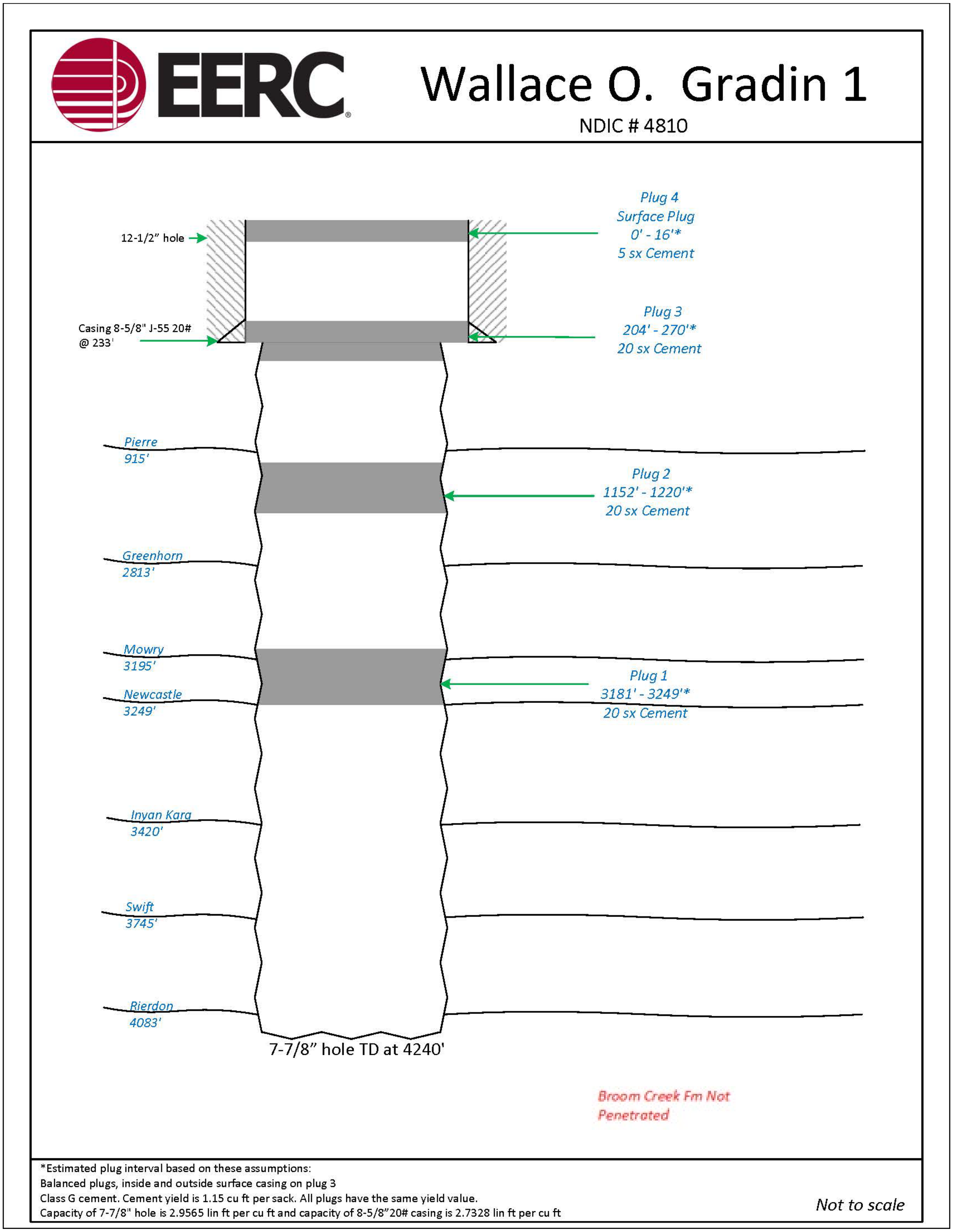

Figure 4-5. Wallace O. Gradin 1 (NDIC File No. 4810) well schematic showing the location of cement plugs.

4.3 Reevaluation of AOR and Corrective Action Plan

BFE will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place no later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following:

- Any changes to the monitoring and operational data prior to the scheduled Reevaluation Date will be identified.
- Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and the computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and the operational data to be utilized as the basis for that update will be identified.
- The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.

4.4 Protection of USDWs (Broom Creek Formation)

4.4.1 Introduction of USDW Protection

The primary confining zone and additional overlying confining zones geologically isolate the Fox Hills and Hell Creek Formations, the lowest USDW in the area of investigation from the underlying injection zone. The Spearfish Formation is the primary confining zone for the injection zone with additional confining layers above, geologically isolating all USDWs from the injection zone. The uppermost confining layer is the Pierre Formation, an impermeable shale in excess of 1,000 ft thick, providing an additional seal for all USDWs in the region.

4.4.2 Geology of USDW Formations

The hydrogeology of western North Dakota is composed of several shallow freshwater-bearing formations of the Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin (Figure 4-6). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1,000 and 1,500 ft thick (Thamke and others, 2014).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formation; the overlying Cannonball, Tongue River, and Sentinel Butte Formation of the Tertiary Fort Union Group; and the Tertiary Golden Valley Formation (Figure 4-7). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the area of investigation (Bluemle, 1971).

The lowest USDW in the area of investigation is the Fox Hills Formation, which together with the overlying Hell Creek Formation, is a confined aquifer system. The Hell Creek Formation is a poorly consolidated unit composed of interbedded sandstone, siltstone, and claystones with occasional carbonaceous beds, all fluvial origin. The underlying Fox Hills Formation is interpreted

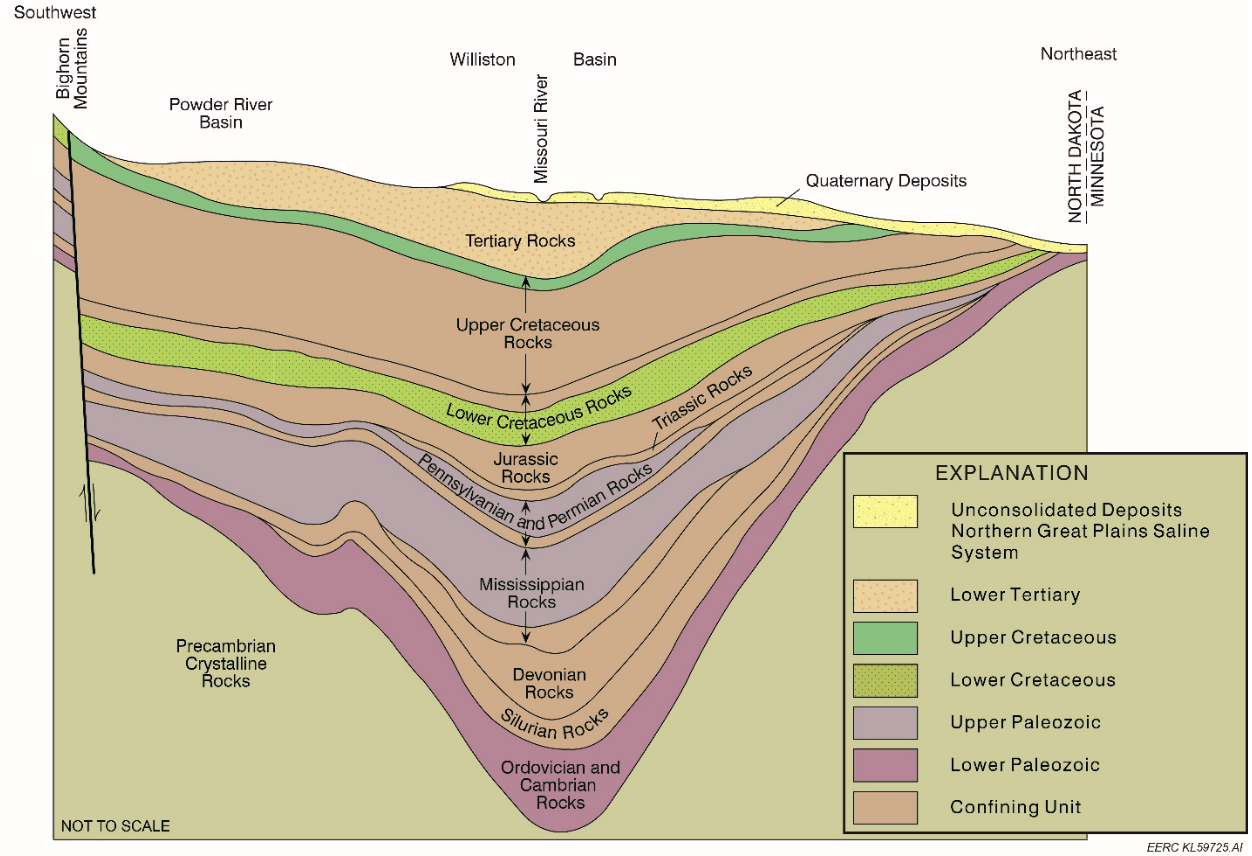

Figure 4-6. Major aquifer systems of the Williston Basin.

as interbedded nearshore marine deposits of sand, silt, and shale deposited as part of the final Western Interior Seaway retreat (Fischer, 2013). The Fox Hills Formation in the area of investigation is approximately 700 to 900 ft deep and 350–450 ft thick (Bluemle, 1971). The structure of the Fox Hills and Hell Creek Formations follows that of the Williston Basin, dipping gently toward the center of the basin to the northwest of the area of investigation (Figure 4-8).

The Pierre Shale is a thick, regionally extensive shale unit which forms the lower boundary of the Fox Hills–Hell Creek system, also isolating all overlying freshwater aquifers from the deeper saline aquifer systems. The Pierre Shale is a dark gray to black marine shale and is typically over 1,000 ft thick in the area of investigation (Thamke and others, 2014).

Era	Period	Group	Formation	Freshwater Aquifer(s) Present
Cenozoic	Quaternary		Glacial Drift	Yes
	Tertiary		Golden Valley	Yes
		Fort Union	Sentinel Butte	Yes
			Tongue River	Yes
			Cannonball	Yes
Mesozoic	Cretaceous		Hell Creek	Yes
			Fox Hills	Yes
			Pierre	No
		Colorado	Niobrara	No
			Carlile	No
			Greenhorn	No
			Belle Fourche	No

Figure 4-7. Upper stratigraphy of McLean County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Bluemle, 1971).

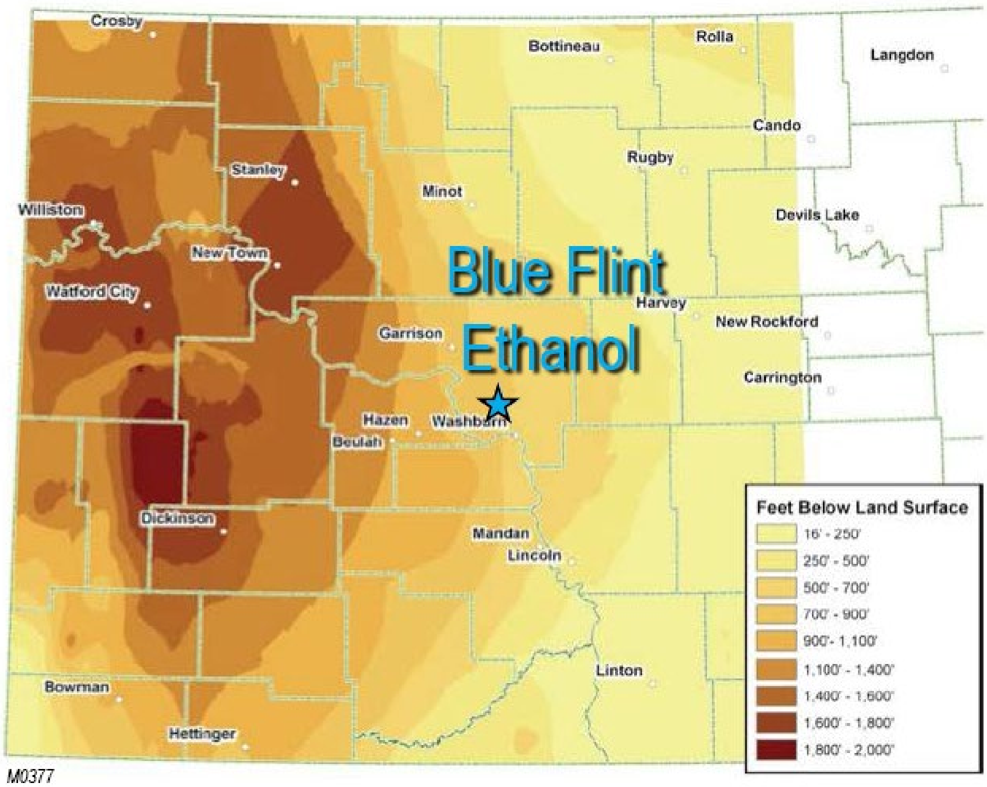

Figure 4-8. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

4.4.3 Hydrology of USDW Formations

The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the area of investigation is to the northeast (Figure 4-9). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,500 ppm (Klausing, 1974). Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Honeyman, 2007). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering.

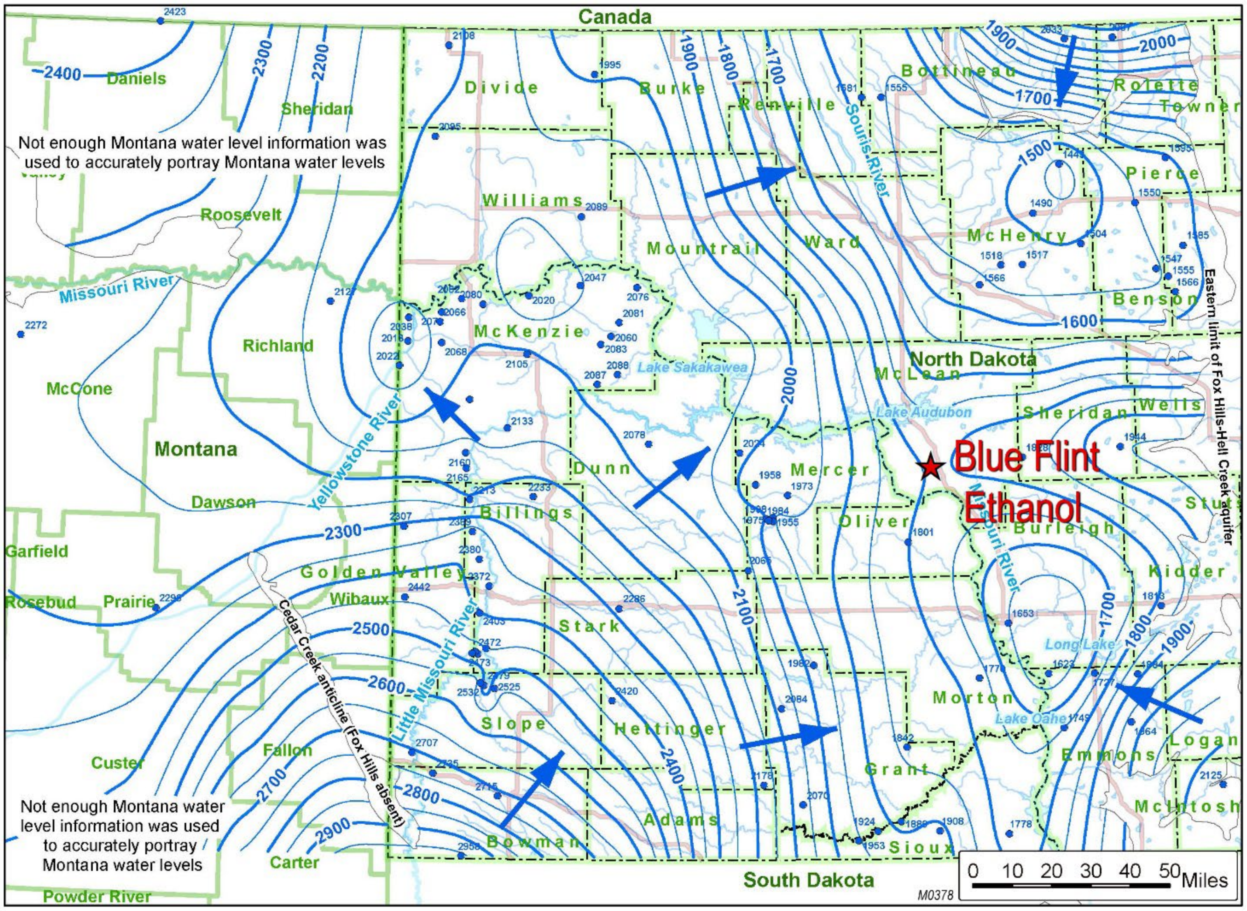

Figure 4-9. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in central McLean County (modified from Fischer, 2013).

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the area of investigation. A cross section of these formations is presented in Figure 4-10. The upper formations are generally used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. The basal sandstone member of the Tongue River is persistent and a reliable source of groundwater in the region. The thickness of this basal sand ranges from approximately 50 to 200 ft and can be found at a depth of approximately 550 ft. Tongue River groundwaters are generally sodium bicarbonate with a TDS of approximately 1,000 ppm (Klausing, 1974).

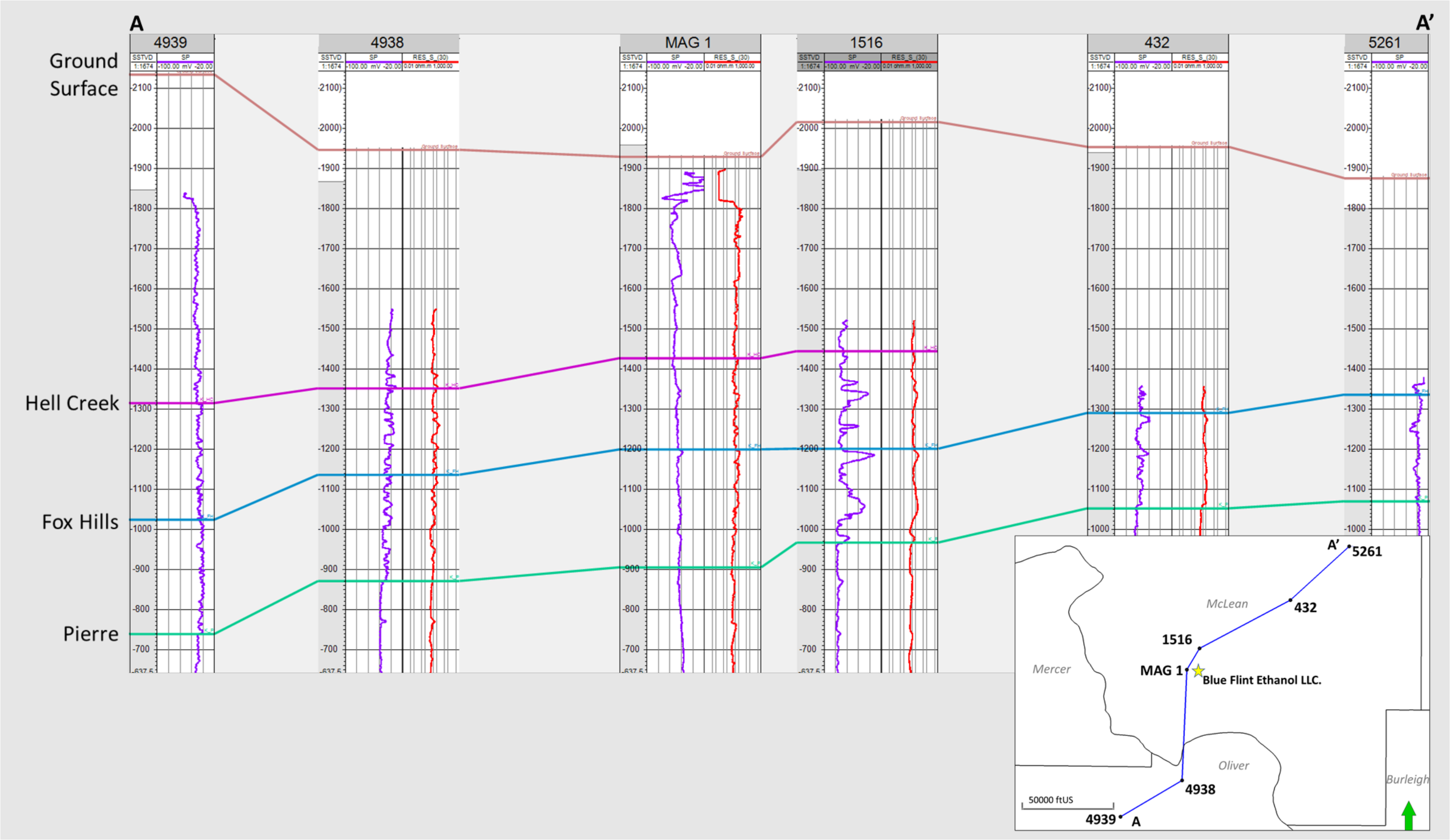

Figure 4-10. Southwest to northeast cross section of the major aquifer layers in McLean County. The black dots on the inset map represent the locations of the six wells used to create the cross section. The wells are labeled with their designation at the top of the cross section.

The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. The upper Sentinel Butte is approximately 150 ft thick in the area of investigation (Hemish, 1975). TDS concentrations in the Sentinel Butte Formation are approximately 1,000 ppm (Klausing, 1974). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers.

4.4.4 Protection for USDWs

The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AOR. The injection zone (Broom Creek Formation) and the lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and siltstone formations (Figure 4-6). The primary seal of the injection zone is the Permian-aged Spearfish and the Jurassic-aged Piper, Rierdon, and Swift Formations, all of which overlie the Broom Creek Formation. These formations will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation.

Above the Swift is the confined saltwater aquifer system of the Inyan Kara Formation, which extends across much of the Williston Basin. The Inyan Kara will be monitored for temperature and pressure changes in the injection well (MAG 1) and the monitoring well (MAG 2). The Pierre Formation is the thickest shale formation in the area of investigation and the primary geologic barrier between the USDWs and the Inyan Kara. The geologic strata overlying the injection zone consist of multiple impermeable rock layers that are free of transmissive faults or fractures and provide adequate isolation of the USDWs from CO_2 injection activities in the area of investigation.

4.5 References

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5.0 TESTING AND MONITORING PLAN

5.0 TESTING AND MONITORING PLAN

This testing and monitoring plan includes 1) a plan for analyzing the injected CO_2 stream, 2) leak detection and corrosion-monitoring plans for surface facilities and well components of the CO_2 injection system, 3) a well-testing and logging plan, and 4) an environmental monitoring and verification plan to ensure CO_2 is stored safely and permanently in the storage reservoir. The combination of the foregoing monitoring efforts is used to verify that the geologic storage project is operating as permitted and is protecting all USDWs. Another goal of this testing and monitoring plan is to establish baseline conditions at the Blue Flint CO_2 storage project site, including but not limited to the injection and monitoring wellbores, soil gas, groundwaters from surface to lowest USDW (Fox Hills Aquifer[1]), and the storage reservoir complex. An overview of the testing and monitoring efforts is provided in Table 5-1.

Blue Flint will review this testing and monitoring plan at a minimum of every 5 years to ensure the monitoring and verification strategies remain appropriate for demonstrating containment of CO_2 in the storage reservoir and conformance with predictive modeling and simulations. If needed, amendments to this testing and monitoring plan (e.g., technologies applied, frequency of testing, etc.) will be submitted to the NDIC for approval. Results of pertinent analyses and data evaluations conducted as part of this testing and monitoring plan will be compiled and reported as required.

Details of the individual efforts for this testing and monitoring plan are provided in the remainder of this section and in Section 6 (Postinjection Site Care and Facility Closure Plan).

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[1] The Fox Hills Aquifer underlying the Blue Flint CO_2 storage project site and western North Dakota is a confined aquifer system that does not receive measurable flow from overlying aquifers or the underlying Pierre Shale. The overlying confining layer in the Hell Creek Formation comprises impermeable clays, and the underlying Pierre Shale serves as the lower confining layer (Trapp and Croft, 1975). Recharge occurs hundreds of miles to the southwest in the Black Hills of South Dakota, where the corresponding geologic layers are exposed at the surface. Flow within the aquifer is to the east with a rate on the order of single feet per year. Groundwater in the Fox Hills Aquifer at the Blue Flint CO_2 storage project site is geochemically stable, as it is isolated from its source of recharge and does not receive other sources of recharge (Fischer, 2013). The aquifer itself is a quartz-rich sand and is not known to contain reactive mineralogy. Minimal geochemical variation can be expected to occur across the site, attributable to minor variations in the geologic composition of the aquifer sediments.

Table 5-1. Overview of Blue Flint's Testing and Monitoring Plan

	Monitoring Type	Equipment/Testing	Target Area
Surface Monitoring	CO_2 Stream Analysis	Compositional and isotopic testing	CO_2 liquefaction outlet at the capture facility
	Surface Facilities Leak Detection	CO_2 detection stations on flowline risers and wellheads, pressure gauges, dual flowmeters, and SCADA* system	Flowline from capture facility to injection wellhead
	Flowline Corrosion Detection	Flow-through corrosion coupon system	Flowline from capture facility to injection wellhead
	Continuous Recording of Injection Pressure, Rate, and Volume	Surface pressure-temperature gauges and flowmeters installed at the capture facility and injection wellhead with shutoff alarms	Surface-to-reservoir (CO_2 injection well)
Wellbore Monitoring	External Mechanical Integrity Testing	Ultrasonic imaging tool (USIT) or electromagnetic casing inspection log and distributed temperature sensing (DTS)	Well infrastructure
	Internal Mechanical Integrity Testing	Tubing-conveyed pressure–temperature gauges, surface digital gauges, and annulus pressure testing	Well infrastructure
	Downhole Corrosion Detection	Flow-through corrosion coupon system	Well materials
Environmental Monitoring	Atmosphere	CO_2 detection stations outside injection wellhead enclosure and gas analyzer sample blanks at soil gas profile stations	Well pads
	Near Surface	Compositional and isotopic analysis of soil gas and shallow groundwater down to the Fox Hills	Vadose zone and lowest USDW
	Above-Zone Monitoring Interval	DTS and pulsed-neutron logs (PNLs) over the Inyan Kara and Spearfish intervals	Downhole tubing and casing strings
	Direct Reservoir	DTS, PNLs, tubing-conveyed bottomhole pressure-temperature-(BHP/T) gauges, and pressure falloff testing	Storage reservoir
	Indirect Reservoir	Time-lapse 2D seismic and surface seismometer stations	Entire storage complex

* Supervisory control and data acquisition.

5.1 CO_2 Stream Analysis

Prior to injection, Blue Flint determined the chemical content of the captured CO_2 stream via laboratory testing performed by Salof, Ltd. The chemical content is 99.98% dry CO_2 (by volume) and 0.02% other chemical components, as specified in Table 5-2. The CO_2 stream will be sampled at the liquefaction outlet quarterly and analyzed using methods and standards generally accepted by industry to determine its chemical and physical characteristics, including composition, corrosiveness, temperature, and density.

Table 5-2. Chemical Content of the captured CO_2

Chemical Content	Volume %
Carbon Dioxide	99.98
Water, Oxygen, Nitrogen, Hydrogen Sulfide, C_2^+, and Hydrocarbons	Trace amounts of each (0.02 total)
Total	100.00

5.2 Surface Facilities Leak Detection Plan

The purpose of this leak detection plan is to monitor the surface facilities from the liquefaction outlet to the injection wellsite during the operational phase of the Blue Flint CO_2 storage project. Figure 5-1 is a map showing the surface facilities layout. Figure 5-2 illustrates a generalized flow diagram of surface connections from the liquefaction outlet to the MAG 1 injection wellsite.

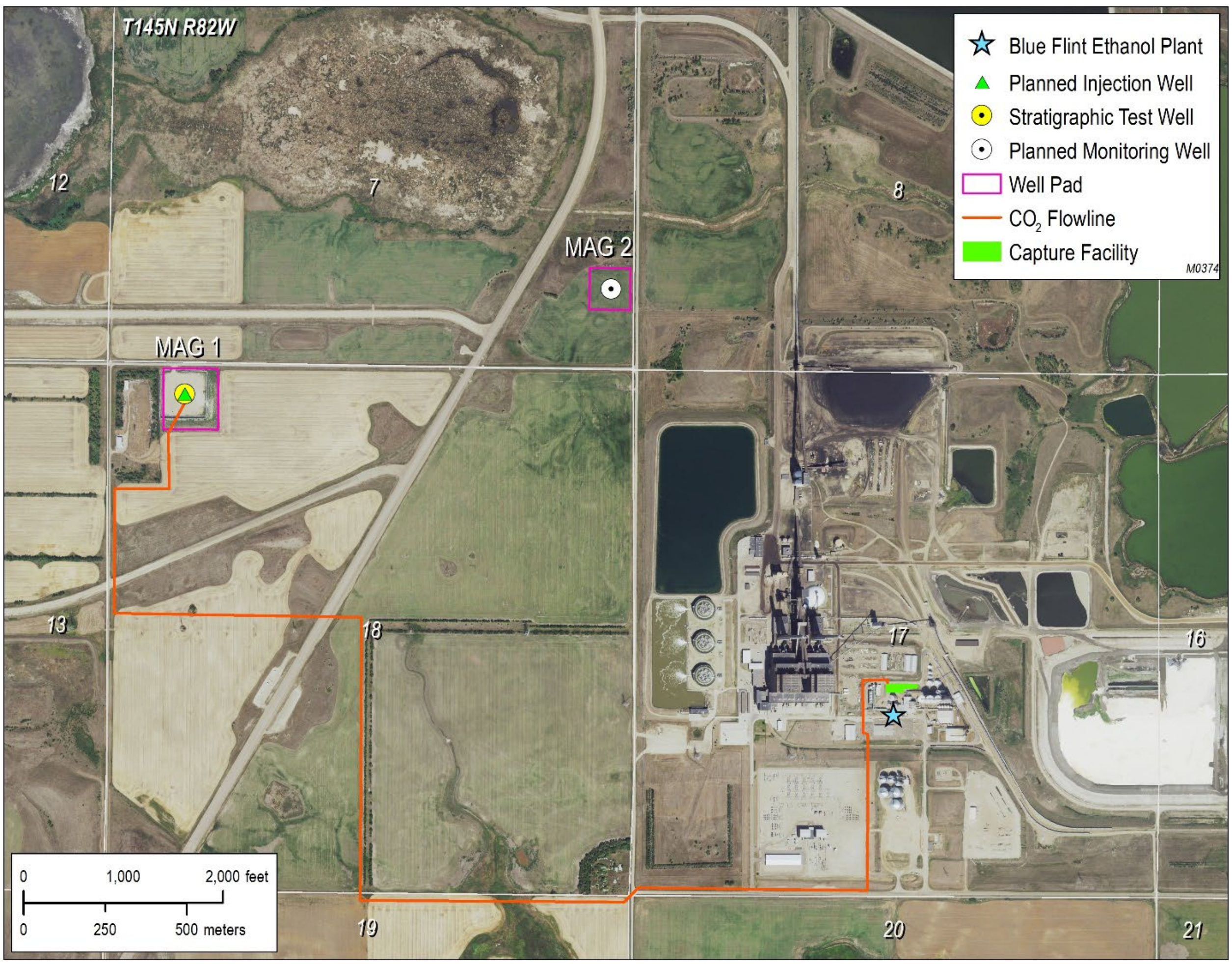

Figure 5-1. Site map showing the surface facilities layout for the Blue Flint CO_2 storage project.

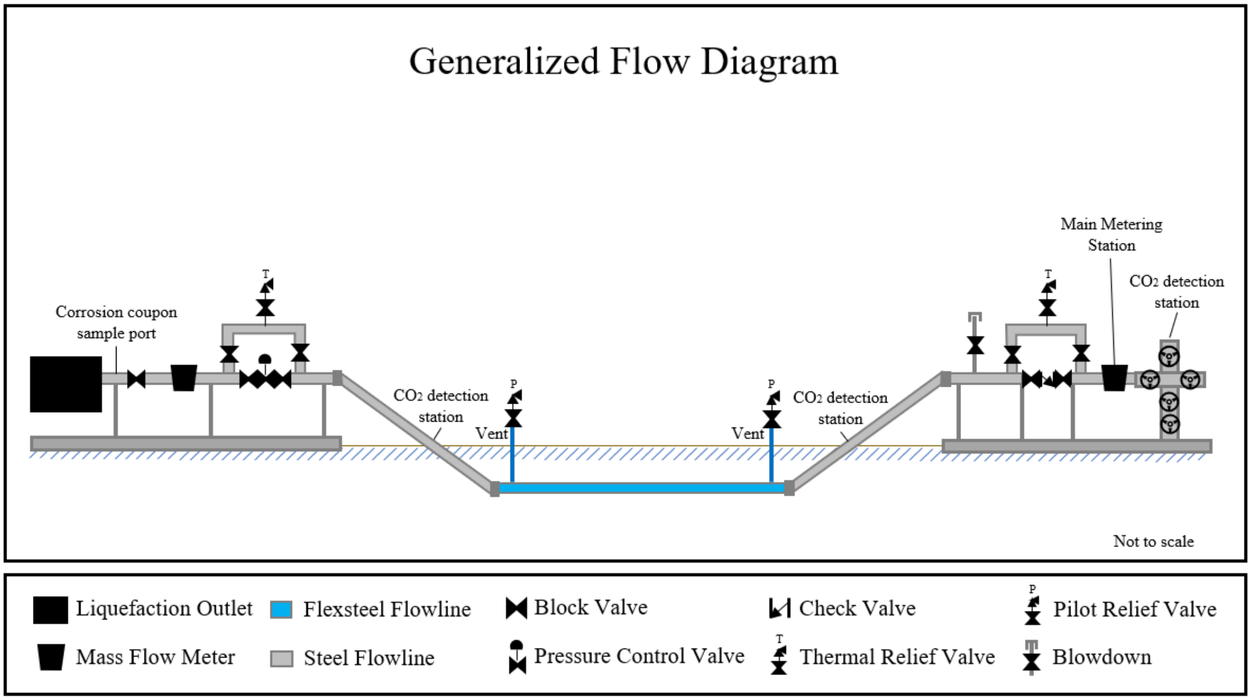

Figure 5-2. Diagram of surface connections and major components of the CCS system from the liquefaction outlet to the MAG 1 wellsite.

Surface components of the injection system, including the flowline and CO_2 injection wellhead, will be monitored with leak detection equipment. The flowline will be monitored continuously via dual flowmeters located at the liquefaction outlet and near the wellhead for performing mass balance calculations. The flowline will also be regularly inspected for any visual or auditory signs of equipment failure and monitored continuously with one pressure gauge at the capture facility outlet and one at the wellhead. CO_2 detection stations will be located on the flowline risers and the CO_2 injection wellhead. The leak detection equipment will be integrated with automated warning systems that notify Blue Flint's operations center, giving the operator the ability to remotely close the valves in the event of an anomalous reading.

Performance targets designed for the Blue Flint CO_2 storage project to detect potential leaks in the flowline are provided in Table 5-3. The performance targets are dependent upon the actual performance of instrumentation (e.g., pressure gauges) and the SCADA system (described further in Attachment A-1 of Appendix C), which uses software to track the status of the flowline in real time by comparing live pressure and flow rate data to a comprehensive predictive model. The performance targets assume a flow rate of approximately 550 metric tons of CO_2 per day. An alarm will trigger on the SCADA system if a volume deviation of more than 1% is registered.

Table 5-3. Performance Targets for Detecting Leaks in Surface Equipment with SCADA

Leak Size, Mscfpd*	Detection Time, minutes
10	<2
>1	<5
<1 and >0.5	<60

* Thousand standard cubic feet per day.

CO_2 detection stations will be mounted on the inside of the wellhead enclosures to detect any potential indoor leaks. An additional CO_2 detection station will be mounted outside the injection wellhead enclosure to detect any potential atmospheric leaks at the wellsite. The stations can detect CO_2 concentrations as low as 2% by volume and have an integrated alarm system for increases of from 0% to 0.4% and 0.4% to 0.8% by volume. The stations are further described in Appendix C (Attachment A-2).

Field personnel will have multigas detectors with them for wellsite visits or flowline inspections to detect potential leaks from the equipment. The multigas detectors will primarily monitor CO_2 levels in workspace atmospheres.

Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be made available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

5.3 Flowline Corrosion Prevention and Detection Plan

The purpose of this corrosion prevention and detection plan is to monitor the flowline and well materials during the operational phase of the project to ensure that all materials meet the minimum standards for material strength and performance.

5.3.1 Corrosion Prevention

The chemical composition of the CO_2 stream is highly pure and dry (Table 5-2), and the target moisture level for the CO_2 stream is estimated to be up to 12 ppm by volume. These factors help to prevent corrosion of the surface facilities. In addition, the flowline construction materials will be CO_2-resistant in accordance with API 17J (2017) requirements. The flowline will be constructed using FlexSteel, a 3-layer flexible steel pipe product. The inner and outer layers contain a CO_2-resistant polyethylene liner, and the middle layer comprises reinforcing steel. FlexSteel product specifications can be found in Appendix C (Attachment A-3).

5.3.2 Corrosion Detection

The flowline will use the corrosion coupon method to monitor for corrosion throughout the operational phase of the project, focusing on the loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. A coupon sample port will be located near the liquefaction outlet, and sampling will occur quarterly during the first year of injection and once a year thereafter. The process that will be used to conduct each coupon test is described in Appendix C under Section 1.3.

5.4 Wellbore Mechanical Integrity Testing

External mechanical integrity in the CO_2 injection well (MAG 1) and deep monitoring well (MAG 2) will be demonstrated with the following:

1) A USIT (described in Attachment A-4 of Appendix C), in combination with variable-density and cement bond logs will be used to establish the baseline external mechanical integrity behind the injection casing. The USIT log or another casing inspection logging (CIL) method will be run during well workovers but no less than once every 5 years.

2) DTS installed in the long-string casing will continuously monitor the temperature profile of the wellbore from the storage reservoir to surface.

3) A baseline temperature log will be run in case DTS fails and temperature log data are needed in the future.

Internal mechanical integrity in the MAG 1 and MAG 2 will be demonstrated with the following:

1) A tubing-casing annulus pressure test prior to injection and during well workovers but no less than once every 5 years. The tubing-casing annulus pressure will be continuously monitored with a surface digital pressure gauge at each wellhead.

2) The tubing pressure will be continuously monitored with tubing-conveyed BHP/T gauges and a digital surface pressure gauge.

3) USIT or another method may be used during well workovers but no less than once every 5 years.

Table 5-4 summarizes the foregoing mechanical integrity testing plan. Blue Flint will conduct an initial annulus pressure test to confirm the mechanical integrity of the tubing-casing annulus and confer with NDIC to confirm the annulus pressure test procedure satisfies all regulatory requirements prior to conducting the test.

Table 5-4. Overview of Blue Flint's Mechanical Integrity Testing Plan

Activity	Baseline Frequency*	Operational Frequency (20-year period)
External Mechanical Integrity Testing		
USIT or alternative CIL	Acquire baseline in MAG 1 and MAG 2.	Perform during well workovers but no less than once every 5 years.
DTS	Install at completion of MAG 1 and MAG 2.	Continuous monitoring.
Temperature Logging	Acquire baseline in MAG 1 and MAG 2.	Perform annually but only as a backup if DTS fails.
Internal Mechanical Integrity Testing		
Tubing-Casing Annulus Pressure Testing	Perform in MAG 1 and MAG 2 prior to injection. Install digital surface pressure gauges.	Perform during well workovers but no less than once every 5 years. Digital surface pressure gauges will monitor annulus pressures continuously.
Surface and Tubing-Conveyed BHP/T Gauges	Install gauges in the MAG 1 and MAG 2 prior to injection.	Gauges will monitor temperatures and pressures in the tubing continuously.
USIT or alternative CIL	Acquire baseline in MAG 1 and MAG 2.	Perform no more than once every 5 years during well workovers.

* The baseline monitoring effort has been initiated as of the writing of this permit application.

5.5 Well Testing and Logging Plan

Table 5-5 describes the testing and logging plan developed for the MAG 1 wellbore (exclusive of any coring) to establish baseline conditions. Included in the table is a description of fluid sampling and pressure testing performed. The logging and testing plan for the MAG 2 wellbore will be the same as what is presented in Table 5-5, with the addition of a PNL but excluding dipole, elemental capture spectroscopy (ECS), fluid swab, and FMI. Table 5-4 and Table 5-6 (see Section 5.7) detail the frequency with which logging data will be acquired and in which wellbores throughout the operational period of the project.

Wellbore data collected from MAG 1 have been integrated with the geologic model and to inform the reservoir simulations that are used to characterize the initial state of the reservoir before injection operations (Section 3). The simulated CO_2 plume extents informed the timing and frequency of the application of the direct and indirect monitoring methods of the testing and monitoring plan.

Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore

OH/CH* Depth, ft	Logging/Testing	Justification	NDAC § 43-05-01
Surface Section			
OH 1340-0	Triple combo (resistivity, bulk density, density and neutron porosity, GR, caliper, and spontaneous potential [SP])	Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume.	11.2(1)(b)(1)
CH 1260-0	Ultrasonic, casing collar locator (CCL), variable-density log (VDL), GR, and temperature log	Identified cement bond quality radially. Interpreted minor cement channeling throughout several isolated intervals and determined good azimuthal cement coverage and zonal isolation.	11.2(1)(b)(2)
Intermediate Section			
OH 4170-1334	Triple Combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP)	Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. Provided input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve test design and interpretations. Generated core-log correlations.	11.2(1)(c)(1)
OH 4170-1334	Dipole sonic	Identified mechanical properties in intermediate section.	11.2(1)(c)(1)
OH 4170-3070	Dielectric scanner	Quantified petrophysical properties and salinity calculations within the intermediate zones (Inyan Kara Formation). Provided information on rock properties and fluid distribution as inputs for reservoir evaluation and management.	11.2(4)
CH 4070-30	Ultrasonic, CCL, VDL, GR, and temperature log	Identified cement bond quality radially. Interpreted good azimuthal cement coverage and casing condition. Evaluated the cement top and zonal isolation.	11.2(1)(c)(2)
Long-string Section			
OH 7068-4163	Triple combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP)	Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume.	11.2(1)(c)(1)
OH 7556-4163	Dipole sonic	Identified mechanical properties of the rock including stress anisotropy. Provided compression and shear waves for seismic tie in and quantitative analysis of seismic data.	11.2(1)(c)(1)
OH 5250-4250	Fullbore FMI	Verified no fracture networks exist in the Broom Creek Formation or confining layers to ensure safe storage of CO_2.	11.2(1)(c)(1)
OH 4741 and 4735	BHP/T survey	Measured Broom Creek Formation pressure and temperature in the wellbore.	11.2(2)
OH 4740-4733	Fluid swab	Collected fluid sample from the Broom Creek Formation for analysis.	11.2(2)
CH** TBD	Ultrasonic, CCL, VDL, and GR	Will identify cement bond quality radially and determine azimuthal cement coverage. Will evaluate the cement top and zonal isolation.	11.2(1)(b)(2)

* OH/CH – openhole/cased-hole
** Planned activity at the time of writing this permit to be completed prior to injection.

5.6 Wellbore Corrosion Prevention and Detection Plan

To prevent corrosion of the well materials, the following preemptive measures will be implemented in the MAG 1 and MAG 2 wellbores: 1) cement in the injection well opposite the injection interval and extending 1850 feet uphole will be CO_2-resistant; 2) the well casing will also be CO_2-resistant from the bottomhole to a depth just above the Spearfish Formation (upper confining zone); 3) the well tubing (poly-lined) will be CO_2-resistant from the injection interval to surface; 4) the packer (Ni-Plated) will be CO_2-resistant; and 5) the packer fluid will be an industry standard corrosion inhibitor.

To detect possible signs of corrosion in the MAG 1 and MAG 2, corrosion coupon samples will be used which will be constructed from the well materials. The corrosion coupon method is described in Section 5.3.2 of this testing and monitoring plan. In addition, the USIT or an equivalent wall thickness or imaging tool (e.g., EM CIL) may also be considered for detecting corrosion in the MAG 1 and MAG 2 wellbores. The USIT (or equivalent tool) may be used during workovers but no less than every 5 years.

5.7 Environmental Monitoring Plan

To verify the injected CO_2 is contained in the storage reservoir and to protect all USDWs, multiple environments will be monitored.

The surface atmosphere environment will be monitored via air sampling at soil gas profile stations installed near the MAG 1 and MAG 2 and a CO_2 detection station installed outside the injection wellhead enclosure.

The near-surface environment will be monitored via soil gas profile stations, shallow groundwater wells, and one dedicated Fox Hills Formation (lowest USDW) monitoring well.

The deep subsurface environment, defined as the region from below the lowest USDW to the base of the storage reservoir, will be monitored with multiple methods, starting with the above-zone monitoring interval (AZMI) or the geologic interval from the Spearfish Formation to the Inyan Kara Formation. The AZMI will be monitored with DTS in the MAG 1 and MAG 2 as well as PNLs in the MAG 2 (further described in Attachment A-5 of Appendix C).

The storage reservoir will be monitored with both direct and indirect methods. Direct methods include DTS and BHP/T measurements in the MAG 1 and MAG 2, as well as PNLs in the MAG 2. Indirect methods include time-lapse seismic and passive seismicity. During injection operations, pressure falloff testing to demonstrate storage reservoir injectivity in the MAG 1 wellbore will be carried out at least once every 5 years. These efforts will provide additional assurance that surface and near-surface environments are protected and that the injected CO_2 is safely and permanently stored in the storage reservoir.

Table 5-6 summarizes the environmental baseline and operational monitoring plans for the Blue Flint CO_2 storage project. Further details regarding these efforts are provided in the remainder of this section of the testing and monitoring plan.

Table 5-6. Summary of Environmental Baseline and Operational Monitoring

Activity	Baseline Frequency*	Operational Frequency (20-year period)
Atmosphere		
Wellsite (workplace) Atmosphere Sampling (Figures 5-3 and 5-4)	At start-up, install CO_2 detection stations placed outside well enclosures at the MAG 1 location.	Stations provide continuous monitoring of CO_2 conditions at the well pad.
Ambient Atmosphere Sampling (Figure 5-4)	Sample 3–4 events at each soil gas probe location (SG-1 through SG-5) prior to injection.	Sample 3–4 events per year at each soil gas profile station (SGPS 1 and SGPS 2). Sampling will piggyback on the planned soil gas monitoring plan (described below).
Soil Gas Monitoring		
Soil Gas Sampling (Figures 5-3 through 5-5)	Sample 3–4 events per probe location (i.e., SG-1 through SG-5) prior to injection. Perform concentration and isotopic testing on all samples.	Sample 3–4 events per year at each soil gas profile station (i.e., SGPS 1 and SGPS 2). Perform concentration and periodic isotopic testing on all samples.
Shallow Groundwater		
Up to 5 Stock Wells (3 Operated by Falkirk Mining Company) (Figure 5-5)	Sample 3-4 events per well prior to injection. Perform water quality and isotopic testing on all samples.	Shift sampling program to the dedicated Fox Hills monitoring well near the MAG 1 well.
Lowest USDW		
Dedicated Fox Hills Monitoring Well Sampling at MAG 1 (Figure 5-5)	Sample 3–4 events per well. Perform water quality and isotopic testing on all samples	Sample 3–4 events per well annually. Perform water quality and periodic isotopic testing on all samples.
AZMI		
DTS	Install during completion of MAG 1 and MAG 2.	Monitor temperature changes continuously in the MAG 1 and MAG 2.
PNL	Perform in MAG 2 prior to injection. Run log from the Spearfish Formation through the Inyan Kara Formation to establish baseline conditions.	Collect PNL in MAG 2 at Year 4 and every 5 years thereafter until end of injection. Run log from the Spearfish Formation through the Inyan Kara Formation to confirm containment in the storage reservoir.
Storage Reservoir (direct)		
DTS	Install during completion of the MAG 1 and MAG 2.	Monitor temperature changes continuously in the MAG 1 and MAG 2.
PNL	Perform in MAG 2 prior to injection. Run log from the Amsden Formation through the Spearfish Formation to establish baseline conditions.	Collect PNL in MAG 2 at Year 4 and every 5 years thereafter until end of injection. Run log from the Amsden Formation through the Spearfish Formation to determine the Broom Creek Formation's saturation profile.
BHP/T Readings	Install BHP/T gauges over the storage reservoir in MAG 1 and MAG 2 prior to injection.	Collect BHP/T readings continuously from the storage reservoir in MAG 1 and MAG 2.
Pressure Falloff Testing	Conduct once prior to injection.	Perform at least once every five years.

* The baseline (preinjection) monitoring effort has not yet begun as of the writing of this permit application.

Continued…

Table 5-6. Summary of Environmental Baseline and Operational Monitoring (continued)

Activity	Baseline Frequency	Operational Frequency (20-year period)
Storage Reservoir (indirect)		
Time-Lapse 2D Seismic Surveys (Figure 5-5)	Collect baseline fence 2D seismic survey.	Repeat 2D seismic survey in Year 1 and Year 4. At Year 4 following the start of injection, reevaluate frequency based on plume growth and seismic results.
Passive Seismicity Monitoring (Figure 5-7)	Utilize existing U.S. Geological Survey's network.	Utilize existing U.S. Geological Survey's network and supplement with additional equipment as necessary.

5.7.1 Atmospheric Monitoring

Figures 5-3 and 5-4 illustrate the planned well pad design at MAG 1 and MAG 2 and the locations of the CO_2 detection stations that will be used to monitor workspace atmospheres to ensure a safe work environment. As mentioned in Section 5.2 of this testing and monitoring plan, field personnel will be equipped with multigas detectors with them for wellsite visits or flowline inspections to detect potential leaks as an added safety precaution.

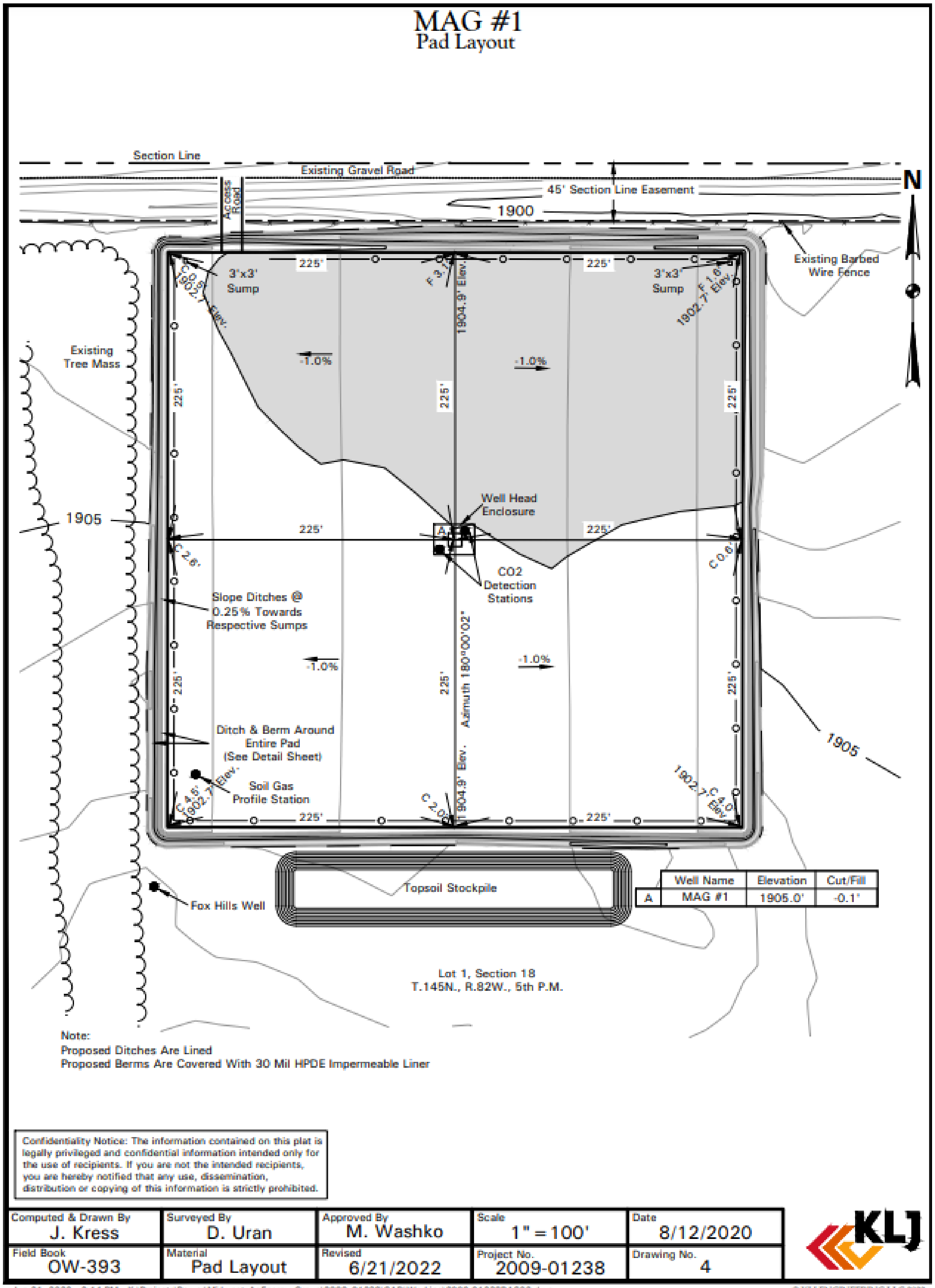

Figure 5-3. Well pad design for the MAG 1 CO_2-injection well. Indicated on the drawing are the locations of the CO_2 detection stations for atmospheric monitoring at the wellsite, the locations of the soil gas profile stations, and the Fox Hills Formation monitoring well.

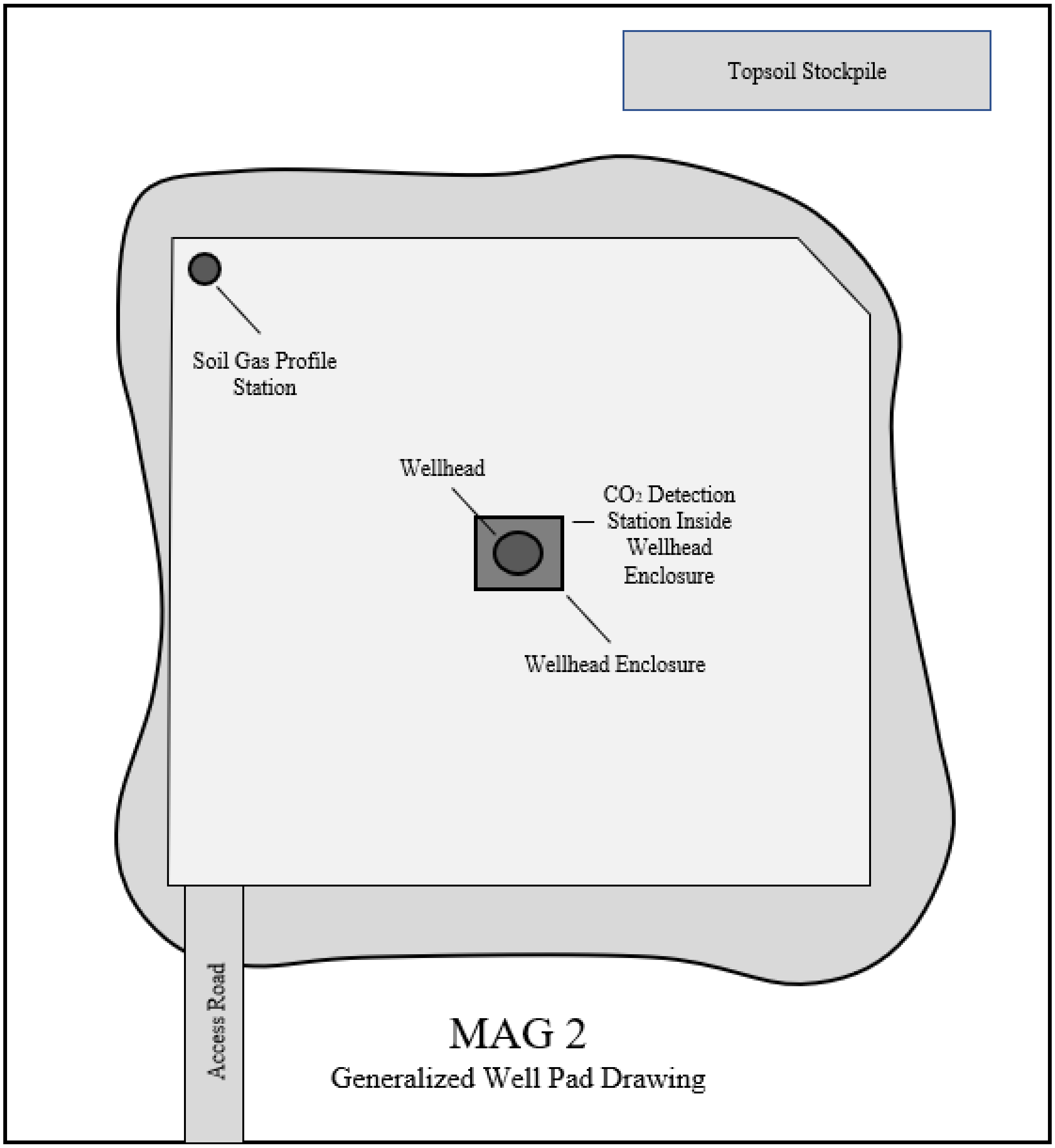

Figure 5-4. Well pad design for the MAG 2 deep monitoring well. Indicated on the drawing are the location of the CO_2 detection station as well as the location of the soil gas profile station.

Ambient atmospheric samples will be obtained quarterly at each of the soil gas profile stations (later described in Section 5.6.2). Field personnel collecting the soil gas samples will use a handheld soil gas analyzer to obtain an atmospheric sample to calibrate the instrument before obtaining soil gas measurements, and measurements of ambient N_2, CO_2, and O_2 will be recorded. QA/QC (quality assurance/quality control) methods regarding ambient air sampling are provided in Appendix C.

5.7.2 *Soil Gas and Groundwater Monitoring*

Blue Flint plans to initiate soil gas sampling (Figure 5-5) in September 2022 to establish baseline conditions at the Blue Flint CO_2 storage project site and anticipates completing the sampling program by July 2023. Soil gas will be sampled via semi-permanent probe stations at five locations (SG-1 through SG-5) within the predicted 20-year CO_2 plume boundary 3-4 times prior to injection. Once injection begins, the soil gas sampling frequency will remain the same but shift to two soil gas profile stations to be installed: one soil gas profile station near the MAG 1 (SGPS 1); one soil gas profile station near the MAG 2 (SGPS 2).

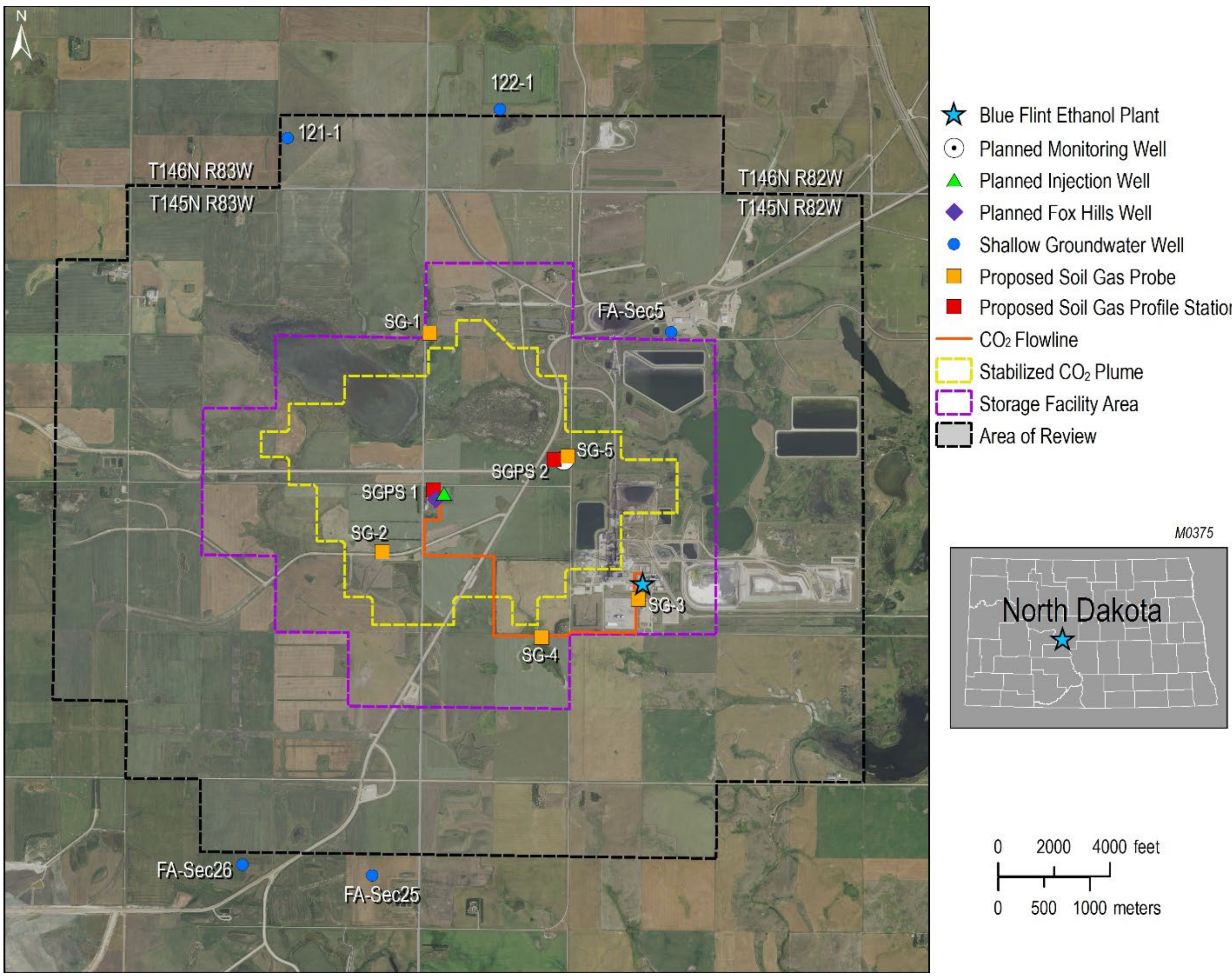

Figure 5-5. Blue Flint's planned baseline and monitoring program for soil gas, shallow groundwater aquifers, and the Fox Hills Aquifer.

Soil gas analytes will include concentrations of CO_2, O_2, and N_2 as well as isotopic ratios for $^{13}CO_2$, $^{14}CO_2$, $\delta^{13}C_1$, and δD_{C_1} (further described in Appendix C). The results of the soil gas sampling program will be provided to NDIC prior to injection.

Blue Flint also plans to initiate a baseline groundwater sampling program in up to five existing shallow groundwater (stock) wells within 1 mile of the AOR, collecting 3-4 samples from each well prior to injection. In addition, Blue Flint will drill one dedicated Fox Hills Formation (lowest USDW) monitoring well near the MAG 1 well and acquire samples at the same frequency (Figure 5-5). Once injection begins, groundwater sampling will only occur at the dedicated Fox Hills monitoring well, collecting samples 3-4 times annually. Sample frequencies are further described in Table 5-6, and water analytes will include pH, conductivity, total dissolved solids, and alkalinity as well as major cations/anions and trace metals (further described in Appendix C). A state-certified laboratory analysis will be provided to NDIC prior to injection for all groundwater testing.

Water chemistry reports from active groundwater monitoring sites that are within or near the AOR and operated by the Falkirk Mining Company are provided in Appendix B.

5.7.3 Deep Subsurface Monitoring

Blue Flint will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure relative to the permitted storage reservoir. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and postoperational periods.[2] The methods described in Table 5-6 will be used to characterize the CO_2 plume's saturation and pressure within the AOR.

Blue Flint will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan (Ayash and others, 2017) at least once every 5 years. During each review, monitoring and operational data will be analyzed, and the AOR will be reevaluated. Based on this reevaluation, it will either be demonstrated that 1) no amendment to the testing and monitoring program is needed or 2) modifications are necessary to ensure proper monitoring of storage performance is achieved moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by NDIC. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of the CO_2 plume and pressure distribution relative to the permitted geologic storage facility. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will, in turn, be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

[2] Monitoring efforts for the postinjection period are described in Section 6: "Postinjection Site Care and Facility Closure Plan."

5.7.3.1 AZMI Monitoring

Prior to injection, Blue Flint will acquire PNL data in the MAG 2 well from the storage reservoir (Broom Creek Formation) up through the Spearfish Formation (upper confining zone) and Inyan Kara Formation (upper dissipation interval) (see Figure 2-2 for stratigraphic reference). PNLs will be run in MAG 2 at Year 4 and then every five years thereafter until the end of injection. These time-lapse saturation data will be used to monitor for CO_2 saturation in the AZMI (i.e., first few formations above the storage reservoir) as an assurance-monitoring technique to monitor the performance of the storage reservoir complex. Monitoring of the overlying interval can provide an early warning of out-of-zone migration of fluids, providing sufficient time for the development and implementation of mitigation strategies to ensure these migrating fluids do not impact a USDW or reach the surface.

5.7.3.2 Direct Reservoir Monitoring

DTS fiber installed in the MAG 1 and MAG 2 will directly monitor the temperature in the storage reservoir continuously. BHP/T readings will also be continuously recorded in the MAG 1 and MAG 2 wellbores via tubing-conveyed gauges. To track the migration of the CO_2 plume in the subsurface, PNLs will be performed in the MAG 2 at Year 4 and every five years thereafter until the end of CO_2 injection. The temperature and saturation profiles collected over the storage reservoir will provide information about the uniformity of CO_2 injectivity within the injection interval. The pressure data will be used primarily to ensure the pressure differential in the Broom Creek Formation conforms to numerical simulations.

5.7.3.3 Indirect Reservoir Monitoring

Indirect monitoring at the Blue Flint CO_2 storage project will include time-lapse 2D seismic surveys and passive seismicity monitoring. These indirect monitoring methods are described below and presented in Table 5-6.

To track the extent of the CO_2 plume within the storage reservoir over time, a 2D seismic survey was selected. The fence design was preferred over an alternative geometry (e.g., radial lines extending in all directions from the MAG 1 well location) or a 3D seismic acquisition for managing field logistics because of nearby active mining activities. Figure 5-6 illustrates the proposed 2D seismic survey that will be acquired prior to injection, in Year 1 of injection, and then in Year 4 of injection. At Year 4 of injection, the seismic survey design and frequency will be reevaluated. If necessary, the time-lapse seismic monitoring plan will be adapted based on updated simulations of the predicted extents of the CO_2 plume, including extending the 2D lines to capture additional data as the CO_2 plume expands. Repeat 2D seismic surveys will demonstrate conformance between the reservoir model simulation and site performance and monitor the evolution of the CO_2 plume. Because the fiber installed in the MAG 1 and MAG 2 wellbores will be capable of collecting distributed acoustic sensing (DAS) information (Figures 9-1 and 9-3), Blue Flint may also evaluate the feasibility of performing vertical seismic profiles (VSPs) to track the migration of the free-phase CO_2 plume in the storage reservoir.

Blue Flint plans to utilize the U.S. Geological Survey (USGS) existing seismicity network to monitor for seismic events larger than magnitude 2.7 in or near the AOR to inform the ERRP (emergency and remedial response plan) (Section 7) as an added safety precaution. Figure 5-7 provides the locations of existing USGS seismicity stations in North Dakota and the surrounding region.

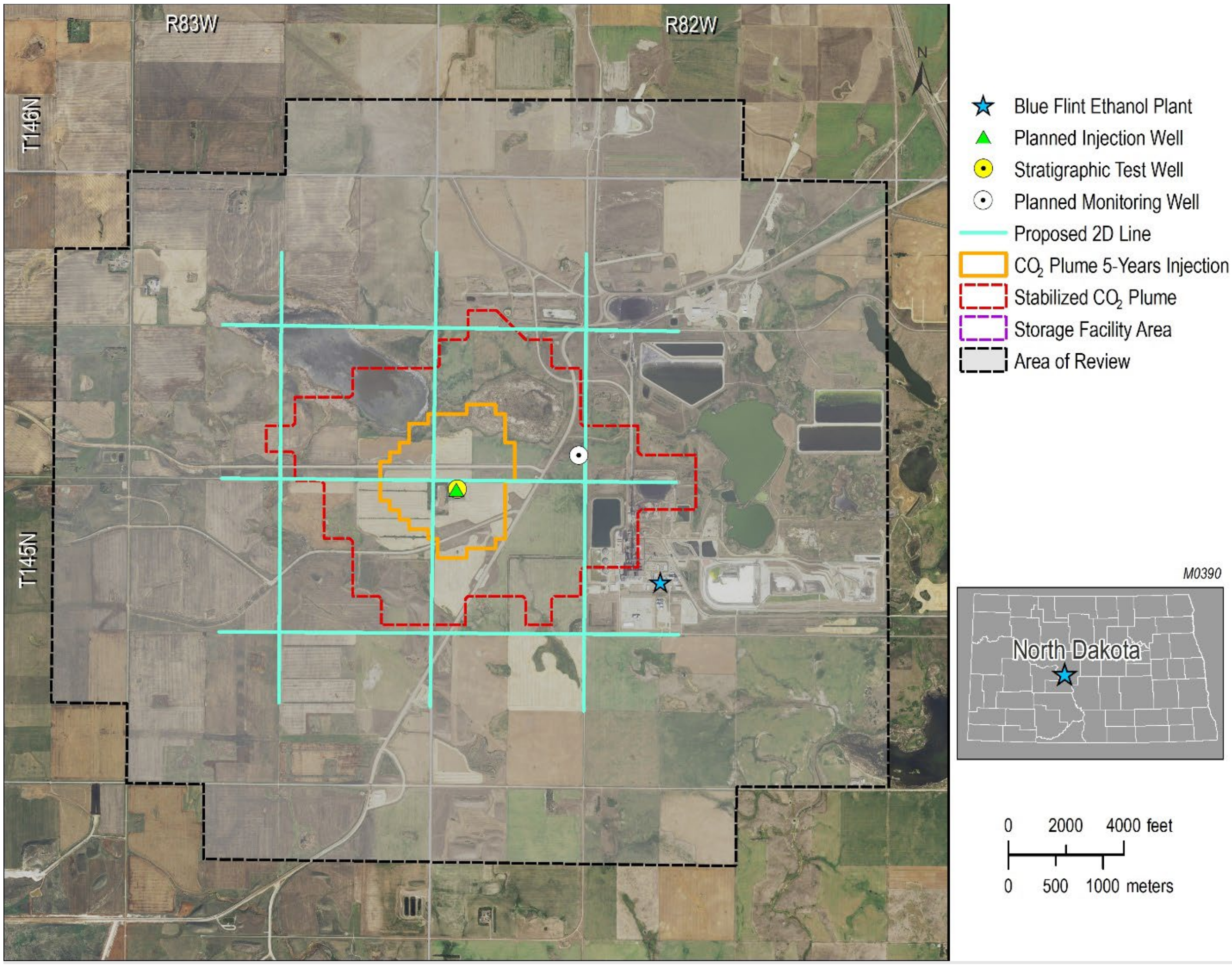

Figure 5-6. Locations of the proposed 2D seismic lines for the fence design near the MAG 1 well to establish a baseline and monitoring for the Blue Flint CO_2 storage project during Years 1–4 of injection.

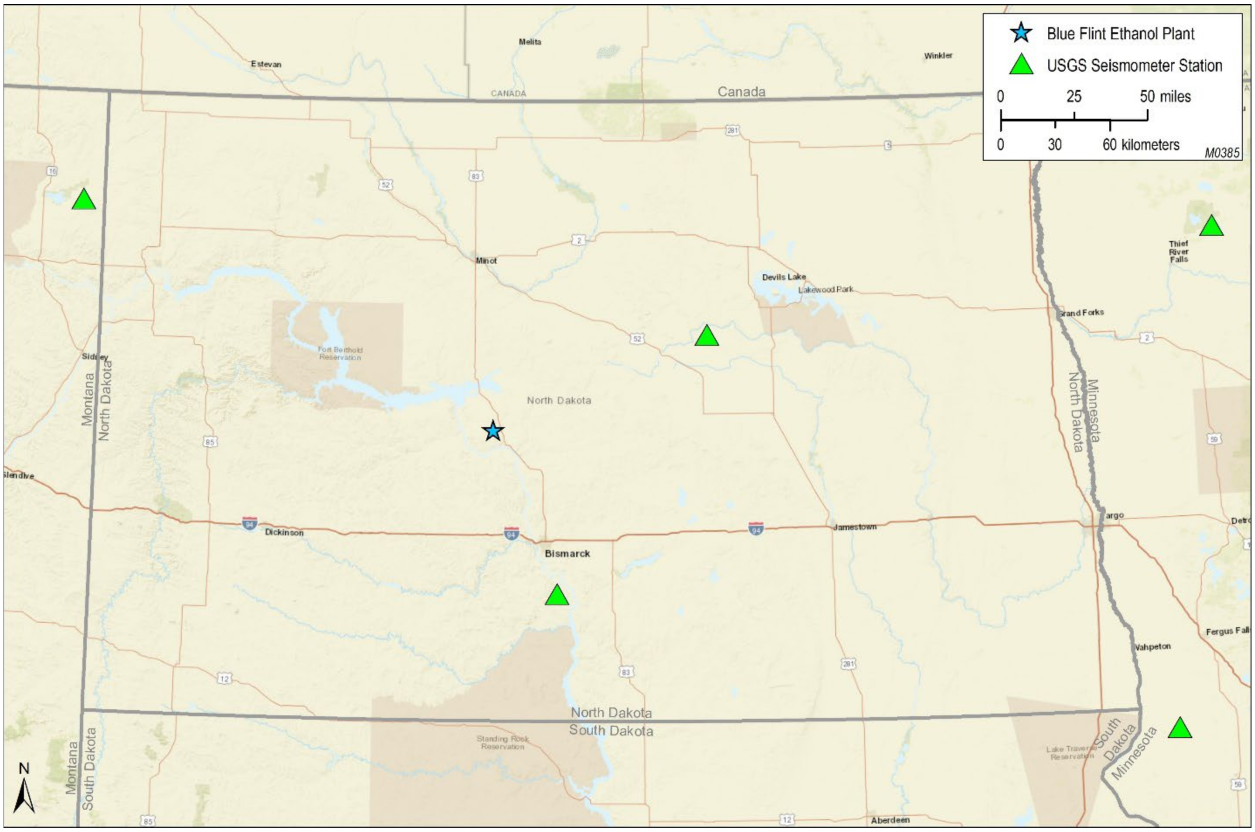

Figure 5-7. Locations of USGS seismometer stations in North Dakota and the surrounding region.

5.8 References

API SPEC 17J (R2021), 2017, Specification for unbonded flexible pipe: American Petroleum Institute, 2014, STANDARD 05/01/2014, Fourth Edition, Includes Errata 1 (September 2016), Errata 2 (May 2017), and Addendum 1 (2017).

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6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

This postinjection site care (PISC) and facility closure plan describes the activities that Blue Flint will perform following the cessation of CO_2 injection to achieve final closure of the site. A primary component of this plan is a postinjection monitoring program that will provide evidence that the injected CO_2 plume is stable (i.e., CO_2 migration will be unlikely to move beyond the boundary of the storage facility area). Based on simulations of the predicted CO_2 plume movement following the cessation of CO_2 injection, it is projected that the CO_2 plume will stabilize within the storage facility area boundary (Section 3.0). Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current predictions of the CO_2 plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO_2 plume. The nature and duration of that extension will be determined based on an update of this plan and NDIC approval.

In addition to Blue Flint executing this postinjection monitoring plan, the CO_2 injection well will be plugged as described in the plugging plan of this permit application (Section 10.0). All surface equipment not associated with long-term monitoring will be removed, and the surface land of the site will be reclaimed to as close as is practical to its original condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site for submission as part of a site-closure report.

6.1 Predicted Postinjection Subsurface Conditions

6.1.1 Pre- and Postinjection Pressure Differential

Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of CO_2 injection. The simulations were conducted for 20 years of CO_2 injection at a rate of 200,000 metric tons per year, followed by a PISC period of 10 years.

Figure 6-1 illustrates the predicted pressure differential at the conclusion of CO_2 injection. At the time that CO_2 injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of up to 120 psi at the location of the CO_2 injection well. There is insufficient pressure increase caused by CO_2 injection to move more than 1 cubic meter of formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the AOR delineation of this permit application (Section 3.0).

Figure 6-2 illustrates the predicted gradual pressure decrease following the cessation of CO_2 injection, with the pressure at the injection well at the end of the PISC period anticipated to decrease 80 to 100 psi as compared to the pressure at the time CO_2 injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions.

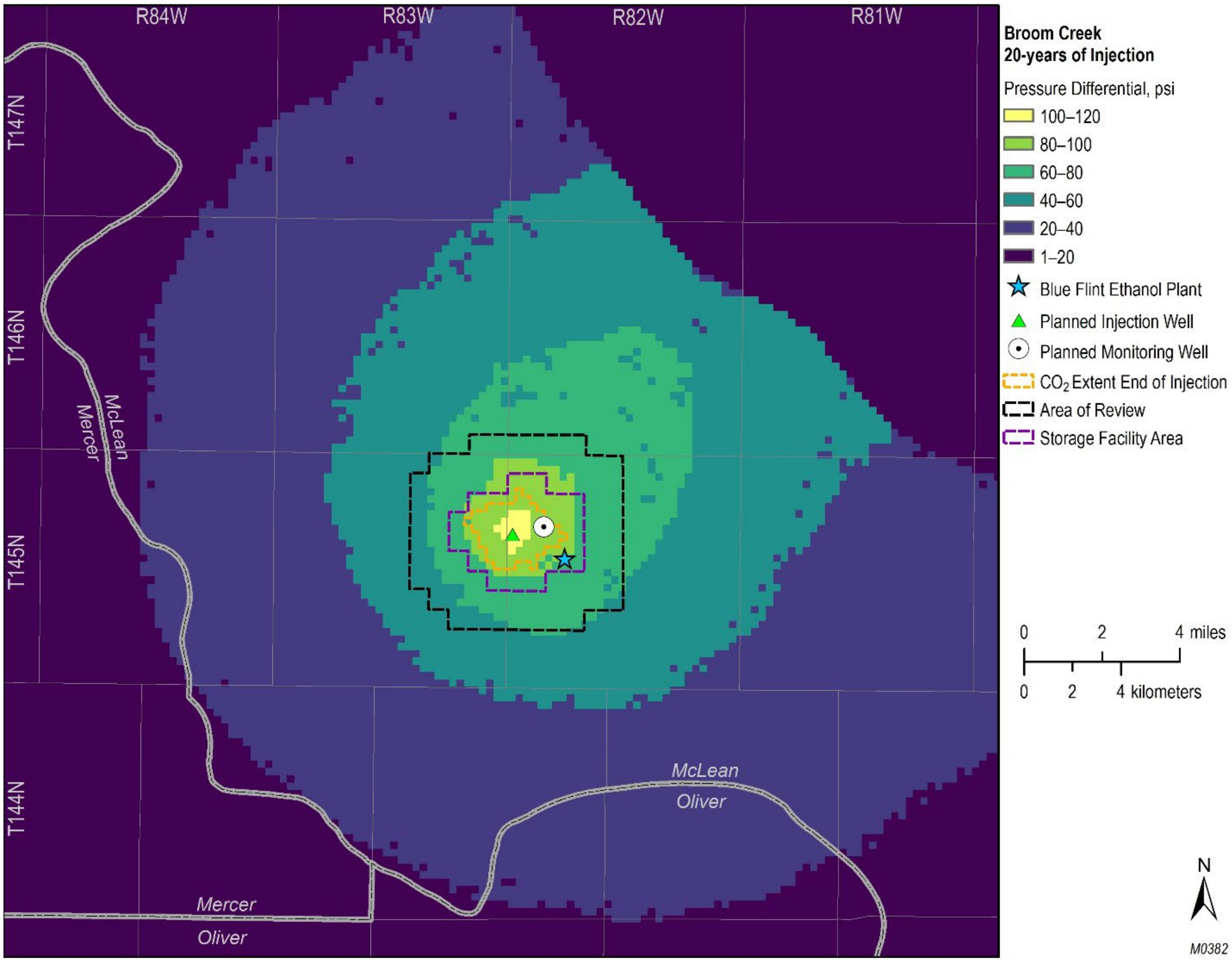

Figure 6-1. Predicted pressure increase in storage reservoir following 20 years of CO_2 injection at a rate of 200,000 metric tons per year.

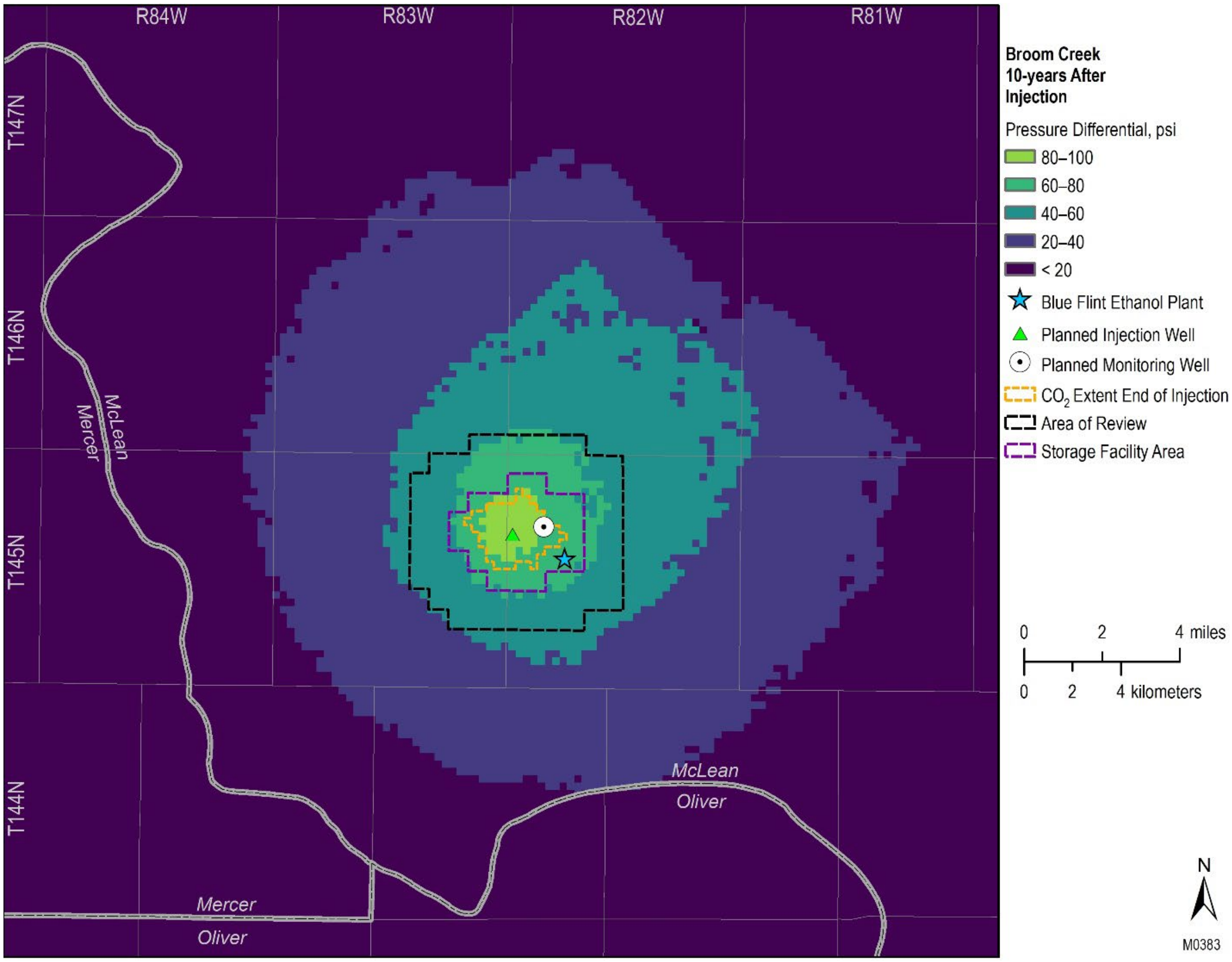

Figure 6-2. Predicted pressure decrease in the storage reservoir over a 10-year period following the cessation of CO_2 injection.

6.1.2 Predicted Extent of CO_2 Plume

Figure 6-2 illustrates the extent of the CO_2 plume following the planned 10-year PISC period (also called the stabilized plume), which is based on numerical simulation predictions. The results of these simulations predict that 99% of the separate-phase CO_2 mass would be contained within an area of 2.96 mi^2 at the end of CO_2 injection. As shown in Figure 6-2, the areal extent of the CO_2 plume is not predicted to change substantially over the planned PISC period.

Additional simulations beyond the 10-year PISC period were also performed and predict that at no time will the boundary of the stabilized plume at the site, which is shown in Figure 6-2, extend beyond the boundary of the storage facility area. If such a determination can be made following the planned 10-year PISC period, the CO_2 plume will meet the definition of stabilization as presented in NDCC § 38-22-17(5)(d) and qualify the geologic storage site for receipt of a certificate of project completion.

6.2 Postinjection Testing and Monitoring Plan

A summary of the postinjection testing and monitoring plan that will be implemented during the 10-year postinjection period is provided in Tables 6-1 and 6-2. Table 6-1 includes a plan to monitor wellbore stability (mechanical integrity and corrosion monitoring plans) and assumes the MAG 1 wellbore will be plugged after injection ceases and that the MAG 2 wellbore will monitor the storage reservoir until site closure. Table 6-2 summarizes environmental monitoring efforts to track the CO_2 plume in the storage reservoir and protect USDWs.

Table 6-1. Overview of Blue Flint's PISC MAG 2 Mechanical Integrity Testing and Corrosion Monitoring Plan

Activity	Postinjection Frequency (10-year period)
External Mechanical Integrity Testing	
DTS	Continuous monitoring.
USIT or Electromagnetic Casing Inspection Log	Perform during well workovers but no less than once every 5 years.
Internal Mechanical Integrity Testing	
Tubing–Casing Pressure Testing	Perform during well workovers but not more frequently than once every 5 years. Digital surface gauges will monitor tubing and annulus pressures continuously.
Surface and Tubing-Conveyed BHP/T Gauges	Gauges will monitor temperatures and pressures in the tubing continuously.
Corrosion Monitoring	
USIT or Electromagnetic Casing Inspection Log	Perform during well workovers but no less than once every 5 years.

6.2.1 Soil Gas and Groundwater Monitoring

Six soil gas-monitoring locations (i.e., two SGPSs and four soil probe locations) will be sampled during the proposed PISC period. Additionally, one dedicated monitoring well in the Fox Hills Formation (i.e., lowest USDW) near the MAG 1 well will be sampled. Figure 6-3 identifies the locations of the soil gas-monitoring locations and the dedicated Fox Hills Formation monitoring well. All samples will likely be analyzed for the same list of parameters as described in the testing and monitoring plan (Section 5.0); however, the final target list of analytical parameters may be reduced for the PISC period based on an evaluation of the monitoring results that are generated during the 20-year injection period of the storage operations. Additional sampling of groundwater in the PISC period may occur on active and accessible shallow groundwater wells within the AOR.

Table 6-2. Overview of Blue Flint's PISC Monitoring Plan

Activity	Postinjection Frequency (10-year period)
Soil Gas	
SGPSs (SGPS01 and SGPS02) (Figure 6-3)	Sample SGPS01 prior to MAG 1 reclamation. Sample SGPS02 annually until site closure.
Soil Gas Probe Locations (SG01 to SG04) (Figure 6-3)	Sample soil gas probe locations at the start of the PISC period and prior to site closure.
Shallow Groundwater	
Shallow Groundwater Wells	Sampling may be performed on active and accessible shallow groundwater wells in the AOR prior to site closure.
Lowest USDW	
Dedicated Fox Hills Monitoring Well near the MAG 1 (Figure 6-3)	Sample the dedicated Fox Hills monitoring well annually until site closure.
Above-Zone Monitoring Interval (AZMI) Monitoring	
DTS	Continuous monitoring
PNL	Perform PNL in the MAG 2 well annually from the Spearfish up through the Inyan Kara until the near-wellbore environment reaches full CO_2 saturation (anticipated during the injection stage). Reduce frequency to every 4 years thereafter.
Storage Reservoir (direct)	
DTS	Continuous monitoring
PNL	Perform PNL in the MAG 2 well annually until the near-wellbore environment reaches full CO_2 saturation (anticipated during the injection stage). Reduce frequency to every 4 years thereafter.
Storage Reservoir (indirect)	
2D Time-Lapse Seismic (Figure 6-4)	Actual design and frequency to be determined based on reevaluations of the testing and monitoring plan (Section 5.0) and migration of the CO_2 plume over time.
Passive Seismicity	USGS seismic network, supplemented with additional stations as needed.

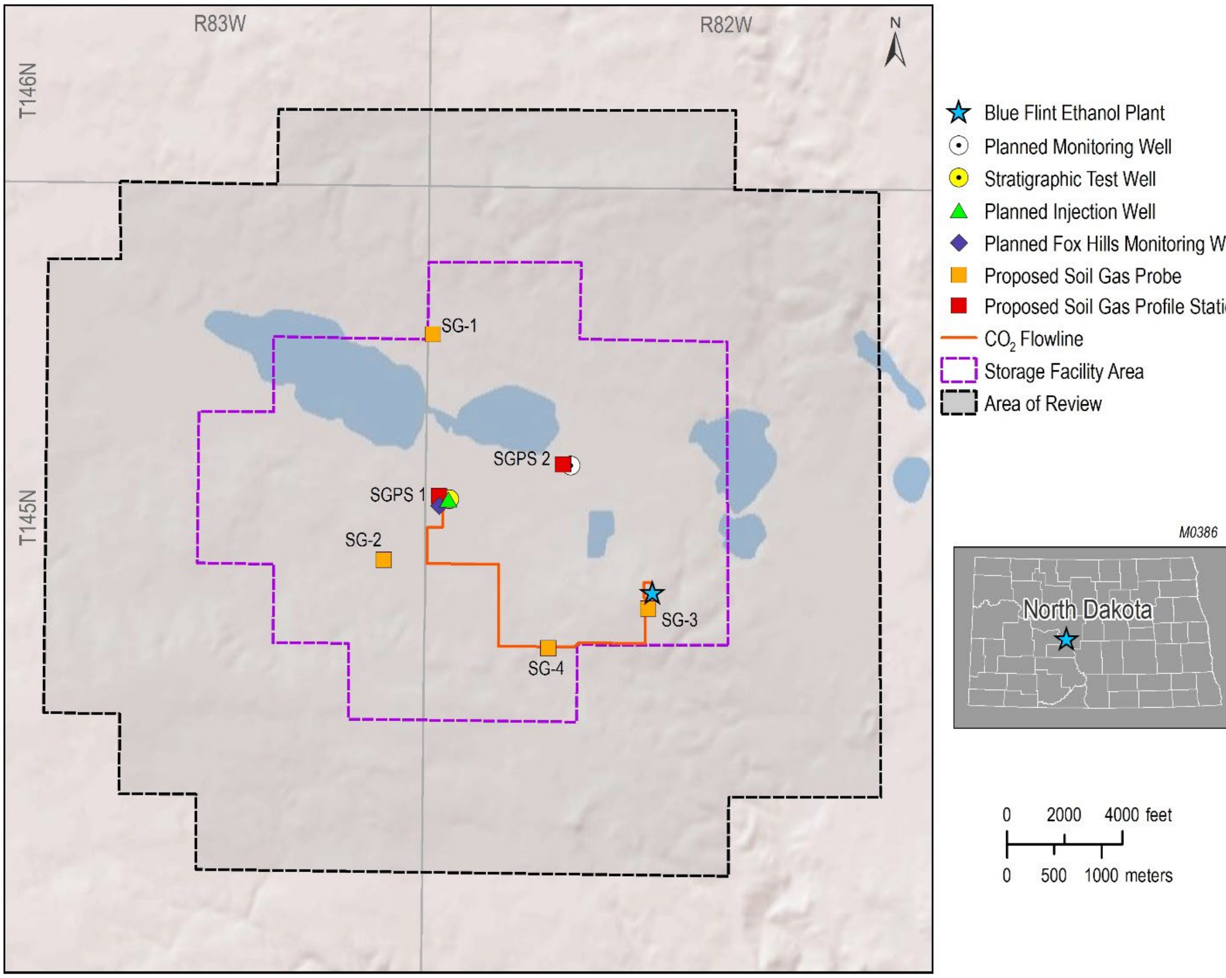

Figure 6-3. Soil gas- and groundwater well-sampling locations included in the PISC monitoring program.

6.2.2 CO_2 Plume Monitoring

The design and frequency of the 2D time-lapse seismic survey will depend on how the CO_2 plume is migrating and the results of the adaptive management approach (Section 5.6.3). As stated in Table 5-6 and Section 5.6.3.3 of the testing and monitoring plan, the 2D seismic survey design and frequency will be repeatedly reevaluated and updated as necessary starting in Year 4 of injection.

Existing seismicity stations and the network maintained by the USGS (Figure 5-7) will be used to monitor for any seismic events that may occur during the postinjection period of the Blue Flint CO_2 storage project.

6.3 Schedule for Submitting Postinjection Monitoring Results

All PISC-monitoring data and monitoring results will be submitted to NDIC in annual reports. These reports will be submitted within 60 days of the anniversary date on which the CO_2 injection ceased.

The annual reports will contain information and data generated during the reporting period, including seismic data acquisition, formation monitoring data, soil gas and groundwater sample analytical results, and simulation results from updated site models and numerical simulations.

6.3.1 PISC Plan

Blue Flint will submit a final site closure plan and notify NDIC at least 90 days prior to its intent to close the site. The site closure plan will describe a set of closure activities that will be performed, following approval by NDIC, at the end of the PISC period. Site closure activities will include the plugging of all wells that are not planned for continued use in monitoring the closed site; the decommissioning of storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring; the reclaiming of the surface land of the site to as close as is practical to its original condition; and abandonment of flowlines pursuant to NDAC Section 43-02-03-34.1.

Any flowlines buried less than 3 feet below final contour will be removed (e.g., the planned flowline segment at the capture facility on Blue Flint Ethanol property and the above-ground portion of the flowline at the injection wellsite). Associated costs during the PISC period are outlined in Section 12, which include the type and frequency of monitoring as well as equipment costs, plugging of the injection well, and site reclamation.

As part of the PISC monitoring and closure plan and in accordance with NDAC 43-05-01-19(5), the MAG 1 injection well will be plugged and abandoned and the injection well pad will be reclaimed. Reclamation of the MAG 1 well and the injection pad includes wellhead removal, sump removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, reclamation of the flowline at the injection pad, and the P&A of SGPS01.

The dedicated Fox Hills monitoring well adjacent to the MAG 1 injection wellsite will remain, at a minimum, until site closure. At the time of site closure, NDIC and Blue Flint will decide if the Fox Hills well adjacent to the MAG 1 wellsite will be plugged and abandoned with the site location reclaimed or if the ownership of the Fox Hills well will transfer to the State.

6.3.2 Site Closure Plan

To comply with NDAC 43-05-01-19(2), the MAG 2 well will be used for deep subsurface monitoring during the PISC period and will be plugged and abandoned as part of site closure activities. Reclamation of the MAG 2 well and well pad at site closure includes wellhead removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, and the P&A of SGPS02.

As part of the final assessment, Blue Flint will work with NDIC to determine which wells and monitoring equipment will remain and transfer to the State for continued postclosure monitoring. The dedicated Fox Hills monitoring well drilled adjacent to the MAG 1 injection well and soil gas profile stations may transfer ownership to the State or a third party, pending NDIC review and approval of the PISC plan and final assessment pursuant to 43-05-01-19. Cost estimates for the PISC and closure periods can be found in Section 12 in the scenario that transfer to the State or a third party does not occur.

6.3.3 Submission of Site Closure Report, Survey, and Deed

A site closure report will be prepared and submitted to NDIC within 90 days of the execution of the PISC and facility closure plan. This report will provide NDIC with a final assessment that documents the location of the stored CO_2 in the reservoir, describes its characteristics, and demonstrates the stability of the CO_2 plume in the reservoir over time. The site closure report will also document the following:

- Plugging records of the injection well and monitoring well.
- Location of the sealed injection well and monitoring well on a plat survey that has been submitted to the local zoning authority.
- Notifications to state and local authorities as required by NDAC § 43-05-01-19.
- Records regarding the nature, composition, and volume of the injected CO_2.
- Postinjection monitoring records.

At the same time, Blue Flint will also provide NDIC with a copy of an accurate plat certified by a registered surveyor that has been submitted to the county recorder's office designated by NDIC. The plat will indicate the location of the injection well and monitoring well relative to permanently surveyed benchmarks pursuant to NDAC § 43-05-01-19.

Lastly, Blue Flint will record a notation on the deed (or any other title search document) to the property on which the injection well and monitoring well were located pursuant to NDAC § 43-05-01-19.

7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

Blue Flint Sequester Company LLC (Blue Flint) and Blue Flint Ethanol LLC, operator of the Blue Flint Ethanol (BFE) facility, will enter into an agreement whereby Blue Flint employees, contractors and agents are required to follow the BFE facility emergency action plans, including, but not limited to, the BFE facility response plan. This emergency and remedial response plan (ERRP) for the geologic storage project 1) describes the local resources and infrastructure in proximity to the project site; 2) identifies events that have the potential to endanger USDWs during the construction, operation, and postinjection site care periods of the geologic storage project, building upon the screening-level risk assessment (SLRA); and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing BFE facility response plan and risk management plan (and incorporated into the BFE Integrated Contingency Plan [ICP]) is described, emphasizing the facility response team and command structure, facility evacuation plans, HazMat (hazardous materials) capabilities, and emergency communication plans. Lastly, procedures are presented for regularly conducting an evaluation of the adequacy of the ERRP and updating it, if warranted, over the lifetime of the geologic storage project. Copies of this ERRP are available at the Blue Flint's office and the BFE facility.

7.1 Background

CO_2 produced at the BFE facility will be captured and geologically stored in close proximity to the plant location (see Table 7-1 for a listing of relevant BFE environmental permits). The projected composition of the captured gas is 99.98% dry CO_2 (by volume), with trace quantities (0.02% by volume) of water, nitrogen, oxygen, hydrogen sulfide, C_2^+ and hydrocarbons. Figure 5-1 identifies the BFE facility location, as well as the planned capture facility, the CO_2 flowline, and the CO_2 injection well (MAG 1) and monitoring well (MAG 2). The well locations, including latitudes and longitudes, are provided below (Table 7-2).

Table 7-1. Environmental Permits Issued to BFE

Permit	Permit Number	Issuing Agency
Risk Management Plan	10000098136	EPA
Facility Response Plan	FRP08D0017	EPA
Air Permit to Operate – Title V	AOP-28450 V2.0	NDDEQ
Industrial Storm Water Permit	NDR05-0000	NDDEQ
Alcohol Fuel Producer Permit	AFP-ND-15003	ATF

Table 7-2. Well Name and Location Information for the CO_2 Injection Well (MAG 1) and Monitoring Well (MAG 2) of the Geologic Storage Operations

Well Name	Purpose	NDIC File No.	Quarter/Quarter	Section	Township	Range	Latitude	Longitude
MAG 1	CO_2 Injection Well	37833	Lot 1	18	145N	82W	47.385185	101.182135
MAG 2	Monitoring Well	TBD*	SE4	19	145N	82W	TBD	TBD

* TBD = to be determined

The primary Blue Flint contacts for the geologic storage project and their contact information are listed in Table 7-3.

Table 7-3. Primary Blue Flint Project Contacts

Individual	Title	Contact Information Office Phone Number
Jeff Zueger	CEO	(701) 442-7501
Adam Dunlop	Director – Regulatory & Technical Services	(701) 442-7503
Travis Strickland	Plant Manager	(701) 442-7502
Jeff Martian	Process Engineer	(701) 442-7512

Contact names and information for the complete facility response team (Table 7-6) as well as key local emergency organizations/agencies (Table 7-8) and specific contractors and equipment vendors able to respond to potential leaks or loss of containment (Table 7-9) are provided in a separate section of this ERRP (Section 7.6, Emergency Communications Plan).

7.2 Local Resources and Infrastructure

Local resources in the vicinity of the geologic storage project that may be impacted as a result of an emergency event include: 1) the holding ponds associated with the Coal Creek Station (owned by Rainbow Energy Center); 2) the Weller Slough and Turtle Lake Aquifers; and 3) the Falkirk Mining Company leased mine land, including reclaimed mine land.

The infrastructure in the vicinity of the project that may be impacted as a result of an emergency event is shown in Figure 5-1, and includes: 1) BFE facility; 2) the CO_2 injection wellhead (MAG 1) and the monitoring wellhead (MAG 2); 3) nearby commercial and residential structures; and 4) the CO_2 flowline. Figure 3-20 shows land use within the area of review (AOR), including commercial, residential, and public lands, if any, as required in NDAC § 43-05-01-13.

7.3 Identification of Potential Emergency Events

7.3.1 Definition of an Emergency Event

An emergency event is an event that poses an immediate, or acute, risk to human health, resources, or infrastructure and requires a rapid, immediate response. This ERRP focuses on emergency events that have the potential to move injection fluid or formation fluid in a manner that may endanger USDWs or lead to an accidental release of CO_2 to the atmosphere during the construction, operation or postinjection site care project periods.

7.3.2 Potential Project Emergency Events and Their Detection

The SLRA for the project developed a list of potential technical project risks (i.e., a risk register) which were placed into the following six technical risk categories:

1. Injectivity
2. Storage capacity
3. Containment – lateral migration of CO_2

4. Containment – pressure propagation
5. Containment – vertical migration of CO_2 or formation water brine via injection wells, other wells, or inadequate confining zones
6. Natural Disasters (induced seismicity)

Based on a review of these technical risk categories, a list of the geologic storage project events that could potentially result in the movement of injection fluid or formation fluid in a manner that may endanger a USDW and require an emergency response was developed for inclusion in this ERRP. These events and means for their detection are provided in Table 7-4.

In addition to the foregoing technical project risks, the occurrence of a natural disaster (e.g., naturally occurring earthquake, tornado, lightning strike, etc.) also represents an event for which an emergency response action may be warranted. For example, an earthquake or weather-related disaster (e.g., tornado or lightning strike) has the potential to result in injection well problems (integrity loss, leakage, or malfunction) and may also disrupt surface and subsurface storage operations. These events are addressed in the BFE emergency response plans and will be extended to the geologic storage operations.

7.4 Emergency Response Actions

The response actions that will be taken to address the events listed in Table 7-4, as well as potential natural disasters, will follow the same protocol. This protocol consists of the following actions:

- The facility response plan qualified individual (QI) (see Section 7.6, Emergency Communications Plan) will be notified immediately and, as soon as practical and within 24 hours, of that notification, make an initial assessment of the severity of the event (i.e., does it represent an emergency event?) to ensure all necessary steps have been taken to identify and characterize any release pursuant to NDAC Section 43-05-01-13(2)(b).
- If determined to be an emergency event, the QI or designee shall notify the NDIC Department of Mineral Resources (DMR) Underground Injection Control (UIC) program director (see Section 7.6, Emergency Communications Plan, Table 7-7) within 24 hours of the emergency event determination (pursuant to NDAC § 43-05-01-13) and implement the emergency communications plan.
- Following these actions, the geologic storage project operator will:
    1. Initiate a project shutdown plan and immediately cease CO_2 injection. (However, in some circumstances, the operator may, in consultation with the NDIC DMR UIC Program director, determine whether gradual or temporary cessation of injection is more appropriate).
    2. Shut in the CO_2 injection well (close flow valve).
    3. Vent CO_2 from surface facilities.
    4. Limit access to the wellhead to authorized personnel only, equipped with appropriate personal protection equipment (PPE).

Table 7-4. Potential Project Emergency Events and Their Detection

Potential Emergency Events	Detection of Emergency Events
Failure of CO_2 Flowline from Capture System to CO_2 Injection Wellhead	• Computational flowline continuous monitoring and leak detection system (LDS). Instrumentation at both ends of the flowline for each injection well collects pressure, temperature, and flow data. The LDS software uses the pressure readings and flow rates in and out of the line to produce a real-time model and predictive model. By monitoring deviations between the real-time model and the predictive model, the software detects flowline leaks. • Frozen ground at leak site may be observed. • CO_2 monitors located on the flowline risers detect a release of CO_2 from the flowline connection and/or wellhead.
Integrity Failure of Injection or Monitoring Well	• Pressure monitoring reveals wellhead pressure exceeds the shutdown pressure specified in the permit. • Annulus pressure indicates a loss of external or internal well containment. • Mechanical integrity test results identify a loss of mechanical integrity. • CO_2 monitors located inside and outside the enclosed wellhead building detect a release of CO_2 from the wellhead.
Monitoring Equipment Failure of Injection Well	Failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure is detected.
Storage Reservoir Unable to Contain the Formation Fluid or Stored CO_2	Elevated concentrations of indicator parameter(s) in soil gas, groundwater, and/or surface water sample(s) are detected.

5. If warranted, initiate the evacuation of the BFE plant and associated geologic storage project facilities in accordance with the facility response plan and communicate with local emergency authorities to initiate evacuation plans of nearby residents.
6. Perform the necessary actions to determine the cause of the event and, in consultation with the NDIC DMR UIC program director, identify and implement appropriate emergency response actions (see Table 7-5, for details regarding the specific actions that will be taken to determine the cause and, if required, mitigation of each of the events listed in Table 7-4).

Table 7-5. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions

Failure of CO_2 Flowline from the CO_2 Capture System to CO_2 Injection Wellhead	• The CO_2 release and its location will be detected by the LDS and/or CO_2 wellhead monitors, which will trigger a BFE alarm, alerting plant system operators to take necessary action. • If warranted, initiate an evacuation plan in tandem with an appropriate workspace and/or ambient air-monitoring program near the location of failure to monitor the presence of CO_2 and its natural dispersion following the shutdown of the flowline using practices similar to those used to develop the risk management plan. • The flowline failure will be inspected to determine the root cause of the flowline failure. • Repair/replace the damaged flowline, and if warranted, put in place the measures necessary to eliminate such events in the future.
Integrity Failure of Injection or Monitoring Well	• Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure. • Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the NDIC DMR UIC program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Monitoring Equipment Failure of Injection Well	• Monitor well pressure, temperature, and annulus pressure (manually, if necessary) to determine the cause and extent of failure. • Identify and, if necessary, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).

Continued . . .

Table 7-5. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Storage Reservoir Unable to Contain the Formation Fluid or Stored CO_2	• Collect a confirmation sample(s) of groundwater from the Fox Hills monitoring well, and soil gas profile station, and analyze the samples for indicator parameters (see Testing and Monitoring Plan in Section 5.0 of the SFP application). • If the presence of indicator parameters is confirmed, develop (in consultation with the NDIC DMR UIC program director) a case-specific work plan to: 1. Install additional monitoring points near the impacted area to delineate the extent of impact: a. If a USDW is impacted above drinking water standards, arrange for an alternate potable water supply for all users of that USDW. b. If a surface release of CO_2 to the atmosphere is confirmed, initiate an evacuation plan, if warranted, in tandem with an appropriate workspace and/or ambient air-monitoring program at the appropriate incident boundary to monitor the presence of CO_2 and its natural dispersion following the termination of CO_2 injection following practices similar to those used to develop the risk management plan. c. If surface release of CO_2 to surface waters is confirmed, implement appropriate surface water-monitoring program to determine if water quality standards are exceeded. 2. Proceed with efforts, if necessary, to a) remediate the USDW to achieve compliance with drinking water standards (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" the impacted drinking water to mitigate CO_2/brine impacts) and/or b) manage surface waters using natural attenuation (i.e., natural processes, e.g., biological degradation, active in the environment that can reduce contaminant concentrations) or active treatment to achieve compliance with applicable water quality standards. • Continue all remediation and monitoring at an appropriate frequency (as determined by BFE management designee and the NDIC DMR UIC program director) until unacceptable adverse impacts have been fully addressed.

Continued . . .

Table 7-5. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Natural Disasters (seismicity)	• Identify when the event occurred and the epicenter and magnitude of the event. • If magnitude is greater than 2.7: 1. Determine whether there is a connection with injection activities. 2. Demonstrate all project wells have maintained mechanical integrity. 3. If a loss of CO_2 containment is determined, proceed as described above to evaluate, and if warranted, mitigate the loss of containment.
Natural Disasters	• Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure. • If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate extent of any impacts. • If impacts or endangerment are detected, identify and implement appropriate response actions in accordance with the facility response plan (in consultation with the NDIC DMR UIC program director).

7.5 Response Personnel/Equipment and Training

7.5.1 Response Personnel and Equipment

All BFE plant and geologic storage project personnel will have undergone hazardous waste operations and emergency response (HAZWOPER) training in accordance with guidelines produced and maintained by the Occupational Safety and Health Administration (OSHA) (OSHA 29 Code of Federal Regulations [CFR] § 1910.120). In addition, assistance has been secured from local (Washburn and Underwood, North Dakota) and McLean County emergency services to implement this ERRP (see Table 7-6).

Equipment (including appropriate PPE) needed in the event of an emergency and remedial response will vary, depending on the emergency event. Response actions (e.g., cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. However, when specialized equipment (such as a drilling rig or logging equipment or potable water hauling, etc.) is required, the Director – Regulatory & Technical Services (see Table 7-3) shall be responsible for its procurement, including maintenance of the list of contractors and equipment vendors (see Section 7.6, Emergency Communications Plan).

7.5.2 *Staff Training and Exercise Procedures*

BFE will integrate the training of the emergency response personnel of the geologic storage project into the standard operating procedures and plant operations training programs, which are described in the ICP. Periodic training will be provided, not less than annually, to protect all necessary plant and project personnel. The training efforts will be documented in accordance with the requirements of the BFE plans which, at a minimum, will include a record of the trainee name, date of training, type of training (e.g., initial or refresher), and instructor name. BFE will also work with local emergency response personnel to perform coordinated training exercises associated with potential emergency events such as a significant release of CO_2 to the atmosphere.

7.6 Emergency Communications Plan

An incident command system is identified in the facility response plan that specifies the organization of a facility response team and team member roles and responsibilities in the event of an emergency. The organizational structure of this system is provided below, along with the identification and contact information of each member of the facility response team (see Table 7-6).

The following table contains the contact information for designated QIs.

Table 7-6. Internal Emergency Notification Phone List

Team Member	Phone Number	Response Time (hours)	Emergency Responsibility	Level of Training
Travis Strickland Plant Manager	H: 701-462-3937 C: 701-202-7107	24	QI	Initial Facility Response Plan, Training Elements for Oil Spill Response and National Preparedness for Response Exercise Program (PREP)
Adam Dunlop, Director – Regulatory & Technical Services	H: 701-250-4893 C: 701-527-5198	24	QI	Initial Facility Response Plan, Training Elements for Oil Spill Response and National Preparedness for Response Exercise Program (PREP)
Jeff Martian Process Engineer	W:701-442-7512 C: 605-201-1587	24		BFE Employee spill response training
Cory Gullickson Maintenance Manager	W: 701-442-7506 C: 701-391-2306	24	Assistant QI	BFE Employee spill response training
Alyssa Hollinshead HSE Coordinator	W:701-442-7519 C: 970-581-0510	24		BFE Employee spill response training
Shift Lead	W: 701-442-7520	24	Assistant QI	BFE Employee spill response training

Table 7-7. NDIC DMR UIC Contact

Company	Service	Location	Phone
NDIC DMR	Class VI/CCUS Supervisor	Bismarck, ND	701.328.8020

The QI or designee is responsible for establishing and maintaining communications with appropriate off-site persons and/or agencies, including, but not limited to, the following:

Table 7-8. Off-site Emergency Notification Phone List

Mclean Sheriff Department*	701.462.8103
Washburn Fire Department (Primary)*	701.462.8558
Underwood Fire Department (Secondary)*	701.442.5224
Washburn Ambulance	701.462.8431
REC CCS Ambulance	701.442.5696
Falkirk Mine Ambulance/Fire Fighters	701.442.5751
McLean County Sheriff's Office	701.462.8103
North Dakota Highway Patrol	701.327.2447
North Dakota Highway Department	701.327.2447
North Dakota Poison Control	800.222.1222
Washburn Medical Clinic	701.462.3389
Turtle Lake Hospital	701.448.2331
Bismarck St. Alexius Hospital	701.530.7000
Bismarck Sanford Hospital	701.323.6000
Mclean County Emergency Management*	701.462.8541
State Emergency Response Commission*	833.997.7455

* Those persons/agencies above marked with an asterisk have received a copy of the BFE emergency response action plan.

Table 7-9. Potential Contractor and Services Providers

Company	Service	Phone
Clean Harbors	Oil spill Removal Organization (OSRO), Collection, & Storage	701.774.2201
Garner Environmental Services	OSRO & Spill Cleanup Services	855.774.1200

Lastly, the facility response plan contact list also includes addresses and contact information for the neighboring facilities and occupied residences located within a 1-mile radius of geologic storage project. Because indicated local and regional emergency agencies (Table 7-8) are provided a copy of the facility response plan, the QI or designee may rely upon emergency agency assistance when it is necessary and appropriate to alert the applicable neighboring facilities and residents in order to allow the operator to focus time and resources on response measures (see also Section 7.4 [5]).

7.7 ERRP Review and Updates

This ERRP shall be reviewed:

- At least annually following its approval by NDIC.
- Within 1 year of AOR reevaluation.
- Within a prescribed period (to be determined by NDIC) following any significant changes to the project, e.g., injection process, the injection rate, etc.
- As required by NDIC DMR.

If the review indicates that no amendments to the ERRP are necessary, BFE will provide the documentation supporting the "no amendment necessary" determination to the UIC program director.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to NDIC as soon as reasonably practicable, but in no event later than 1 year following the commencement of a review.

8.0 WORKER SAFETY PLAN

8.0 WORKER SAFETY PLAN

Blue Flint Sequester Company LLC (Blue Flint) and Blue Flint Ethanol LLC, operator of the Blue Flint Ethanol (BFE) facility, will enter into an agreement whereby Blue Flint employees, contractors and agents are required to follow the BFE facility worker safety plans. BFE facility maintains and implements a plantwide safety program that meets all state and federal requirements for worker safety protections, including OSHA and the National Fire Protection Association (NFPA). This program is described in the BFE safety plan, which includes a list of training programs that are currently in place and the frequency with which they will be reviewed and, if necessary, updated.

The CO_2 safety training program of BFE facility identifies the dangers of CO_2 and requires all employees and visitors to wear the proper PPE and to perform their duties in ways that prevent the discharge of CO_2. Project personnel will participate in annual safety training to include familiarization with operating procedures and equipment configurations that are appropriate to their job assignment as well as ERRP procedures, equipment, and instrumentation. New personnel, if appropriate, will receive similar instruction prior to beginning their work. Lastly, contractors and visitors will undergo an orientation that ensures all persons on-site are trained and aware of the dangers of CO_2. Initial training will be conducted by, or under the supervision of, the safety director or his designated representative, and all trainers will be thoroughly familiar with the project operations plan and ERRP.

Refresher training will be conducted at least annually for all project personnel. Monthly briefings will be provided to operations personnel according to their respective responsibilities and will highlight recent operating incidents, lessons learned based on actual experience in operating the equipment, and recent storage reservoir-monitoring information.

Only personnel who have been properly trained will participate in the project activities of drilling, construction, operations, and equipment repair. A record including the person's name, date and type of training, and the signatures of the trainee and instructor will be maintained.

9.0 WELL CASING AND CEMENTING PROGRAM

9.0 WELL CASING AND CEMENTING PROGRAM

Blue Flint plans to reenter and convert MAG 1 (API 3305500196, File No. 37833) into a CO_2 injection well, complying with NDIC Class VI underground injection control (UIC) injection well construction requirements. The targeted injection horizon is the Broom Creek Formation. The project includes the installation of a monitoring well, MAG 2, to monitor and record real-time pressure and temperature data and monitor CO_2 saturations as well as utilize the data for history matching in the modeling and simulations, as required in the testing and monitoring plan.

9.1 CO_2 Injection Well – MAG 1 Well Casing and Cementing Programs

The MAG 1 well was permitted and drilled as a stratigraphic test well on October 11, 2020, under NDIC governance. The original well design was to drill the entire stratigraphic column from surface to the Precambrian formation to characterize potential storage reservoirs and seals for CO_2 geological sequestration.

The surface and intermediate wellbore sections were drilled, logged, cased, and cemented without major operational issues. The 13.375-in. surface casing was set at 1,330 ft, with a 10.75-in. intermediate casing set at 4,163 ft. While drilling the 9.5-in. long-string interval, severe lost circulation events were encountered at the Interlake (8,120 ft) and Red River (8,708 ft) Formations. The drilling reached a depth of 9,213 ft when a lost circulation event caused the drill pipe and bottomhole assembly (BHA) to get stuck. Unsuccessful fishing operations were performed, resulting in a section of drill pipe and the BHA, the "fish," in the wellbore from 7,575 to 9,072 ft.

The well was conditioned from the base of the intermediate casing to the top of the fish, and the sidewall cores and electronic logs were conducted for characterization of the Broom Creek Formation as well as the associated confining formations. Upon completion of the coring and logging, the wellbore was temporarily plugged and abandoned. Because of the inability to reach total depth, cement plugs were set across the following intervals: 1) a CO_2-resistant cement plug from 7,566 to 6,531 ft, 2) a conventional cement plug from 4,729 to 4,374 ft, and 3) a cast iron bridge plug (CIBP) set in the 10.75-in. intermediate casing at 4,090 ft and topped with five sacks of conventional cement.

On May 13, 2022, the well was reentered by drilling out the CIBP and the upper cement plug at 4,729 ft. A new CO_2-resistant cement plug was set from 4,815 to 5,480 ft to isolate the Madison Formation group in order to collect representative fluid samples and measure the reservoir pressure in the Broom Creek Formation. The reservoir pressure and temperature values were captured, and fluid samples were collected by swabbing the well. The well was temporarily abandoned on June 7, 2022, with a CIBP set at 4,080 ft and topped with ten sacks of conventional cement, as shown in Figure 9-1, for a current, as-constructed wellbore schematic of the MAG 1 well.

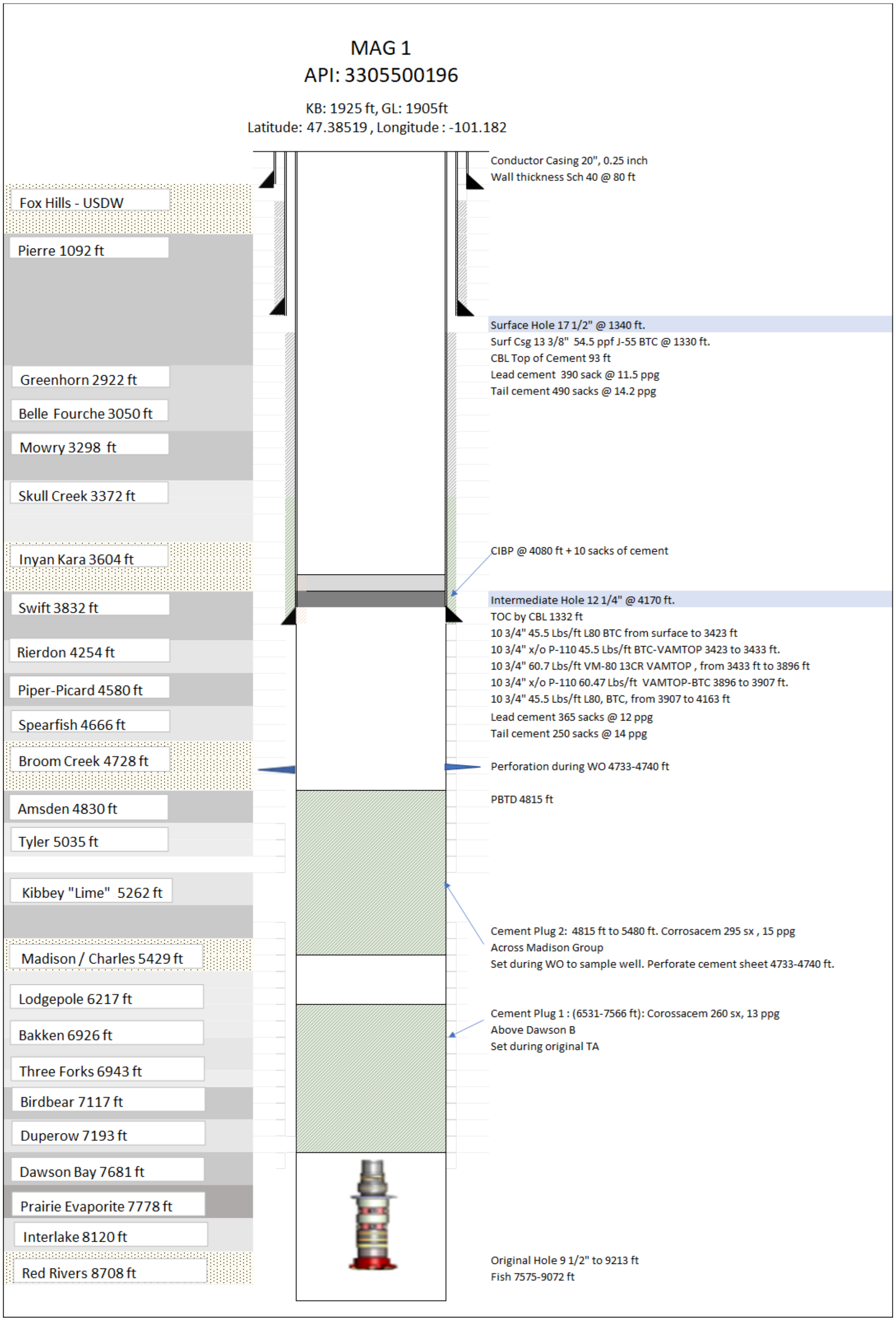

Figure 9-1. MAG 1 as-constructed wellbore schematic.
Note: top of cement (TOC), workover (WO).

To convert the existing stratigraphic wellbore into a CO_2 injection well, Blue Flint plans to reenter the MAG 1 well, drill out the CIBP and Cement Plug 2 from 4,815 to 5,150 ft, condition the open hole, install and cement 7-in. long-string casing from surface to 5,150 ft. The Broom Creek Formation will be perforated, and injection will be performed by setting injection tubing and packer above the Broom Creek perforations, as shown in Figure 9-2, the proposed design for the conversion of MAG 1 to a CO_2 injection well.

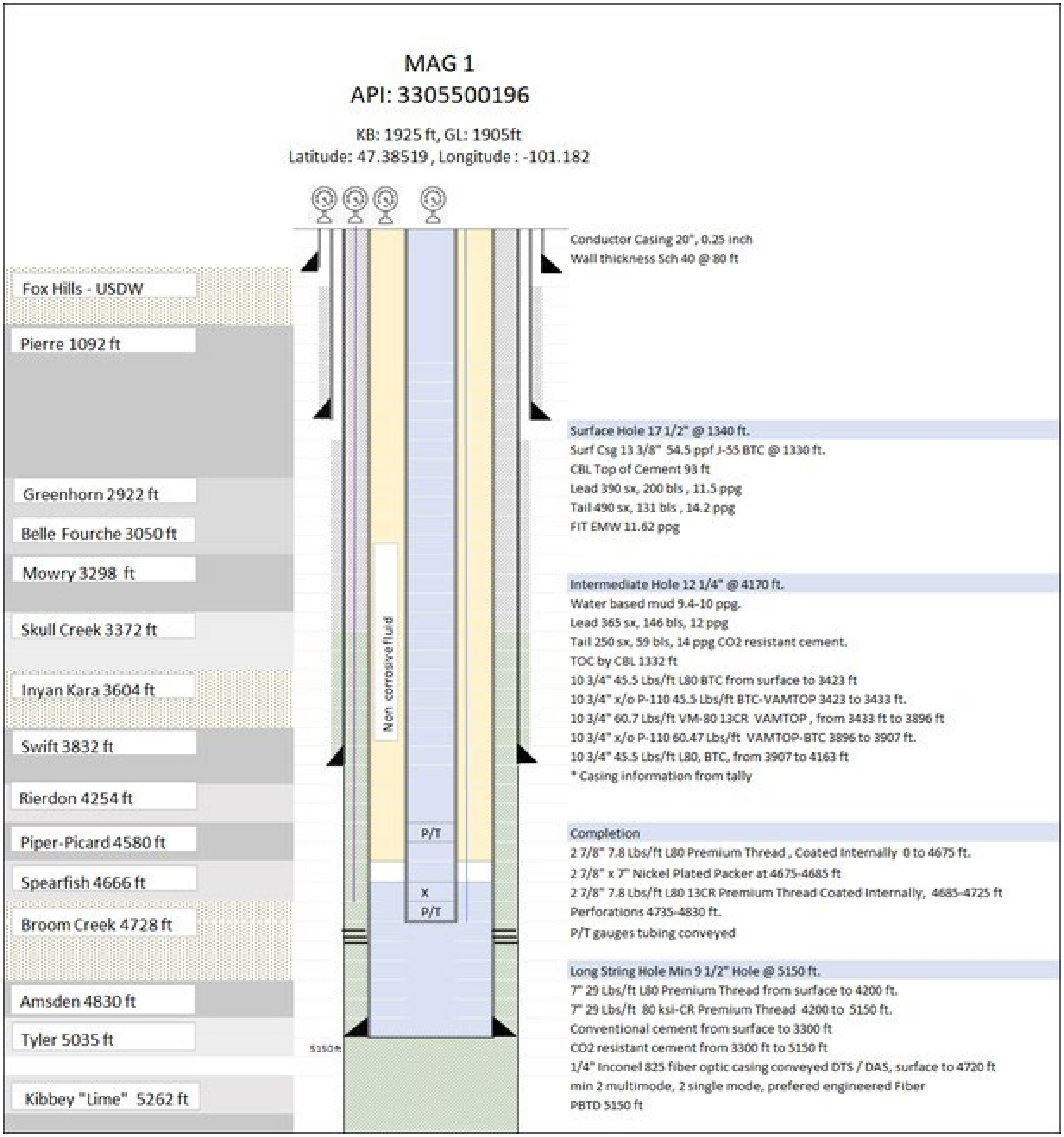

Figure 9-2. MAG 1 Proposed wellbore schematic as a CO_2 injection well. Casing-conveyed fiber-optic cable shown in purple from surface to the Broom Creek Formation.

Tables 9-1 through 9-4 provide the casing and cement programs for the MAG 1 drilling program as of October 11, 2020, which demonstrate compliance of the executed well construction program with NDAC § 43-05-01-09 and § 43-05-01-09(2) for conversion into a CO_2 storage injection well.

Table 9-1. CO_2 Injection Well MAG 1 – Well Information

Well Name:	**MAG 1**	**NDIC No.:**		**API No.:**	**3305500196**
County:	McLean	**State:**	ND	**Operator:**	Midwest AgEnergy Group, LLC
Location:	Sect. 18, T145N R82W	**Footages:**	295 FNL 740 FWL	**Total Depth:**	9,213 ft

FNL: From the north line.
FWL: From the west line.

Table 9-2. CO_2 Injection Well MAG 1 – Casing Program

Section	Hole Size, in.	Casing o.d., in.	Weight, lb/ft	Grade	Connection*	Top Depth, ft	Bottom Depth, ft	Objective
Surface	17½	13⅜	54.5	J55	BTC	0	1,330	Isolate Fox Hills
Intermediate	12¼	10¾	45.5	L80	BTC	0	3,433	Isolate Inyan Kara
Intermediate	12¼	10¾	60.7	VM-80 13CR	VAM TOP	3,433	3,907	Isolate Inyan Kara
Intermediate	12¼	10¾	45.5	L80	BTC	3,907	4,163	Isolate Inyan Kara
Long String	9½	7	29	L80	Premium	0	4,200	
Long String	9½	7	29	L80 CR13	Premium	4,200	5,150	Injection target

BTC: Buttress.

Table 9-3. CO_2 Injection Well MAG 1 – Casing Properties

o.d., in.	Grade	Weight, lb/ft	Con-nect.	i.d., in.	Drift, in.	Burst, psi	Collapse, psi	Yield Strength, Klb	
								Body	Conn.
13⅜	J55	54.5	BTC	12.615	12.459	2,730	1,130	853	909
10¾	L80	45.5	BTC	9.95	9.875	5,210	2,470	1,040	1,062
10¾	VM-80 13CR	60.7	VAM TOP	9.66	9.504	7,100	5,170	1,398	1,398
7	L80	29	M-M	6.184	6.059	8,160	7,030	676	676
7	L80 CR13	29	M-M	6.184	6.059	8,390	7,030	676	676

M-M: Premium metal to metal connection.

Table 9-4. CO_2 Injection Well MAG 1 – Cement Program

Casing, in.	Tail		Lead		Excess, %	Volume, sacks
	Slurry	Interval, ft	Slurry	Interval, ft		
13⅜	Varicem*, 14.2 ppg	800–1,330	Varicem*, 11.5 ppg	93–800**	50–100	880
10¾	Corrosacem*** 14 ppg	2,750–4,163	Neo Cement* 12 ppg	1,332–2,750**	50–100	616
7	CO_2-resistant Slurry 14.5 ppg	3,300–5,150	Portland cement + additive 11.5–12.5 ppg	0–3,300	50	1,034

* Varicem and Neo cement are conventional portland cement slurry plus additives.
** The cement top was obtained from the CBL–USIT log.
*** Corrosacem is an enhanced portland cement blend to resist the degradation by CO_2 reaction.

Evaluation of the need for a two-stage cementing job for the long-string section will be conducted considering the wellbore condition and hydraulic pressure simulation of the cementing operation. Communication for approval from the North Dakota Department of Mineral Resources (DMR) will occur prior to installation.

9.2 Monitoring Well MAG 2 – Well Casing and Cementing Programs

To meet testing and monitoring requirements, a monitor well, MAG 2, will be drilled through the Broom Creek reservoir into the Amsden/Tyler lower confining seals, as shown in Figure 9-3, MAG 2 proposed wellbore design.

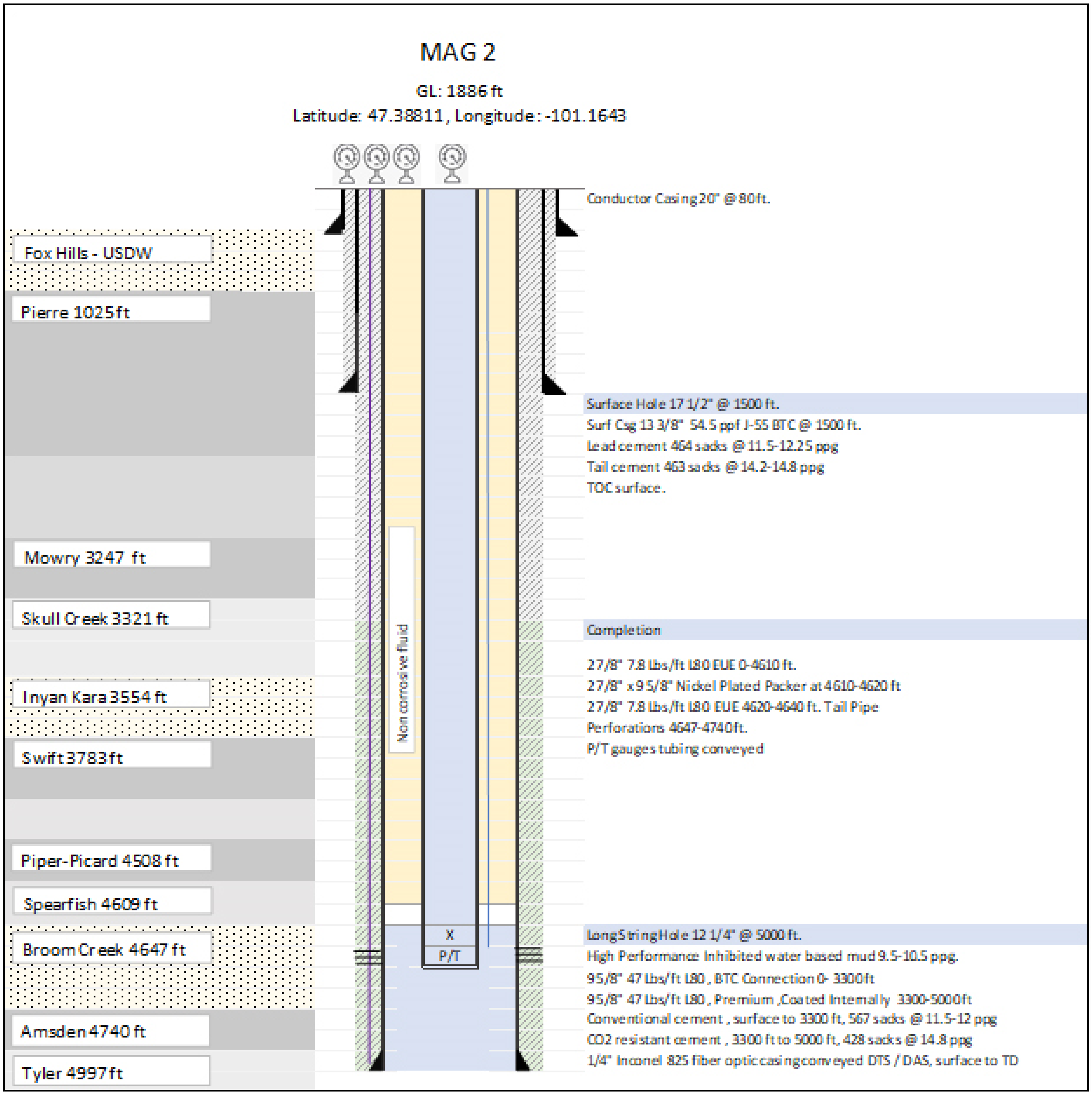

Figure 9-3. Monitor Well MAG 2 proposed wellbore schematic. Casing-conveyed fiber-optic cable shown in purple from surface to the Broom Creek Formation.

Tables 9-5 through 9-8 provide the proposed casing and cement programs for MAG 2, which demonstrate compliance for the well construction program with NDAC § 43-05-01-09 and § 43-05-01-09(2) for a CO_2 monitoring well.

Table 9-5. Monitor Well MAG 2 – Well Information

Well Name:	**MAG 2**				
County:	McLean	**State:**	ND		
Location:	Sect. 7, T145N R82W	**Footages*:**	820 FSL 165 FEL	**Total Depth:**	5,000 ft

* Estimates; location has not been surveyed

Table 9-6. Monitor Well MAG 2 – Casing Program

Section	Hole Size, in.	Casing o.d., in.	Weight, lb/ft	Grade	Conn.	Top Depth, ft	Bottom Depth, ft	Objective
Surface	17½	13⅜	54.5	J55	BTC	0	1,500	Isolate Fox Hills
Long String	12¼	9⅝	47	L80	BTC	0	3,300	
Long String	12¼	9⅝	47	L80 Coated	Premium*	3,300	5,000	Monitoring zone

Table 9-7. Monitor Well MAG 2 – Casing Properties

o.d., in.	Grade	Weight, lb/ft	Connection	i.d., in.	Drift, in.	Burst, psi	Collapse, psi	Yield Strength, Klb Body	Yield Strength, Klb Connection
13 ⅜	J55	54.5	BTC	12.615	12.459	2,730	1,130	853	909
9 ⅝	L80	47	BTC	8.681	8.525	6,870	4,750	1,086	1,122
9 ⅝	L80	47	Premium*	8.681	8.525	6,870	4,750	1,086	1,086

* Connection will be compatible with the internal coating requirements.

Table 9-8. Monitor Well MAG 2 – Cement Program

Casing, in.	Tail Slurry	Tail Interval, ft	Lead Slurry	Lead Interval, ft	Excess, %	Volume, sacks
13⅜	Portland cement + additives, 14.2–14.8 ppg	1,000–1,500	Portland cement + additives, 11.5–12.5 ppg	0–1,000	100	927
9⅝	CO_2-resistant cement, 14.8 ppg	3,300–5,000	Portland cement + additives, 11.5–12 ppg	0–3,300	50	996

Evaluation of the need for a two-stage cementing job for the long-string section will be conducted considering the wellbore condition and hydraulic pressure simulation of the cementing operation. Communication for approval from the North Dakota DMR will occur prior to installation.

10.0 PLUGGING PLAN

10.0 PLUGGING PLAN

The proposed plug and abandonment (P&A) procedure for the MAG 1 well is intended to be interpreted as proposed conditions and does not reflect the current as-constructed state for the MAG 1 well. Also, the plugging operations are likely to occur at different times in the life cycle of the injector well, MAG 1, and the monitor well, MAG 2. The MAG 1 well is planned for P&A once the CO_2 injection operation ceases. The CO_2 monitor well, MAG 2, is planned for P&A after verification and approval that the CO_2 plume has stabilization.

A proposed P&A procedure will be provided to the NDIC. After approval, ample notification will be given to allow an NDIC representative to be present during the plugging operations. The P&A events will be documented by a workover supervisor during P&A execution. The records of the P&A events shall demonstrate the utilization of CO_2-compatible materials used and complete isolation of the injection zone.

10.1 MAG 1: P&A Program

The proposed MAG 1 CO_2 injection well schematic is provided in Figure 10-1.

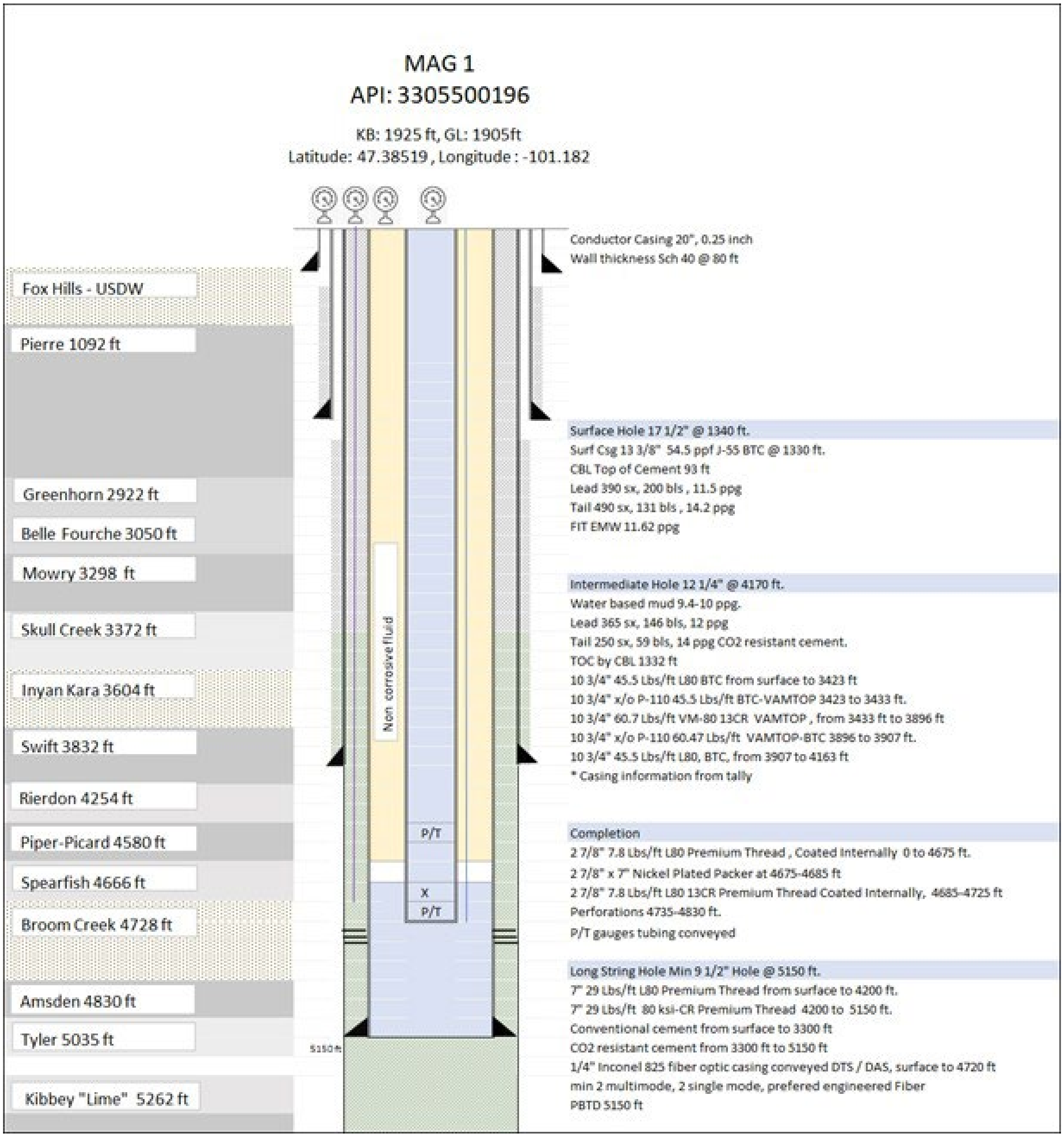

Figure 10-1. Proposed CO_2 injection well schematic for MAG 1.

The NDIC will be contacted and an intent to plug and abandon form for MAG 1 will be filed for approval. Final adjustments to the proposed P&A procedure will be made based on current wellbore conditions and NDIC field inspector recommendations. Currently, the proposed P&A procedure for the well is as follows.

Proposed P&A Procedure:

1. After injection operations have been terminated, the well will be flushed with a kill fluid with a calculated fluid weight for proper execution. A minimum of three tubing volumes will be pumped, remaining below the fracture pressure and ensuring control of the well.

2. Move-in (MI) and rig up (RU) workover rig onto the MAG 1 well. All CO_2 flowlines and valves will be marked and noted by the rig supervisor prior to MI and RU.

3. Conduct and document a safety meeting.

4. Record bottomhole pressure (BHP) from downhole gauges and calculate kill fluid density. BHP measurements will be taken by using the installed tubing-conveyed downhole pressure gauges. In case the gauges are not functional, the operator may use surface tubing pressure gauges to calculate kill mud density.

5. Test the pump and line to 5,000 psi or 90% of maximum pump pressure. Fill tubing with kill fluid. Bleeding off occasionally may be necessary to remove all air from the system. Wait for well to stabilize. Shut in tubing. Monitor tubing pressure.

6. Test casing annulus to 1,500 psi and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

   Note: If failure in long-string casing is identified, the operator will prepare a plan to repair the well prior to P&A.

7. If both casing and tubing are dead, then nipple up blowout preventers (NU BOPs).

   Contingency: If the well is not dead or the pressure cannot be bled off via tubing, RU wireline and set plug in lower-profile nipple below packer. Unlatch tubing from the packer and circulate tubing and annulus with kill weight fluid until the well is on control. After casing and tubing pressure are zero, nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with work string in case the packer needs to be unlatched.

8. Pull out of hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release tubing and retrieve packer, RU electric line and make a cut on the tubing string just above the packer. The cut must be made above the packer at least 5 to 10 ft MD. Pull the tubing string out of hole and proceed to the next step. If problems are noted, update the cement remediation plan. A cement retainer might be used to force cement through the packer if it cannot be removed.

9. Pick up work string and trip in hole (TIH) with bit to condition wellbore.

10. Pull out of hole and RU logging unit. Confirm external mechanical integrity by running one of the tests listed below as options. Rig down logging truck.

    - Activated neutron log
    - Noise log
    - Production logging tool (PLT)
    - Tracers
    - Temperature log
    - DTS (distributed-temperature sensing) survey (no required logging unit)

11. TIH with work string and cement retainer to the top of Plug 1. Circulate well, set retainer, and perform injectivity test. RU equipment for cementing operations.

12. Mix and pump CO_2-resistant slurry to cover the Broom Creek Formation and isolate from the Dakota Group in accordance with program. Under displaced two barrels of cement. Disconnect from retainer and finish displacing the last two barrels on top of the cement retainer. Check for flow. Pull work string 150 ft and circulate.

13. Pull up hole, set a balanced plug with CO_2-resistant cement, 15.8 ppg, across Dakota Group and isolate it from the Fox Hills USDW. Pull out above plug and circulate. Wait on setting time and tag top of the plug.

14. Pull up hole, set balanced plug with Class G cement + additive, 15.8 ppg, to cover the shoe of the surface casing. Pull out above the plug and circulate. Wait on setting time and tag top of the plug.

15. Pull up hole, set surface plug with Class G cement + additive, 15.8 ppg, to isolate the top of surface casing.

16. Lay down all work string. Rig down all equipment and move out.

17. Dig out wellhead and cut off casing 5 ft below ground level (GL). Weld ½-in. steel cap on casing with well name, date inscribed, and information that it was used for CO_2 injection.

18. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

19. Within 60 days, submit Form 7 plugging report after plugging operations are complete – NDAC § 43-05-01-11.5(4).

20. Submit notice of intent to reclaim to NDIC 30 days in advance prior to reclamation – NDAC § 43-05-01-18(10d).

The proposed P&A plan for MAG 1 is summarized in Table 10-1 and provided in Figure 10-2.

Table 10-1. Summary of P&A Plan for MAG 1

Cement Plug Number	Interval Range, ft	Thickness, ft	Volume, sacks	Notes
1	4,550–5,150	600	225	CO_2-resistant slurry, 15.8 ppg, 1.11 ft^3/sx Squeezed cement job to isolate perforations
2	3,350–3,850	500	103	CO_2-resistant slurry, 15.8 ppg, 1.11 ft^3/sx Balanced plug
3	1,000–1,500	500	99	Conventional cement, 15.8 ppg, 1.16 ft^3/sx Balanced plug
4	0–80	80	16	Conventional cement, 15.8 ppg, 1.16 ft^3/sx Balanced plug

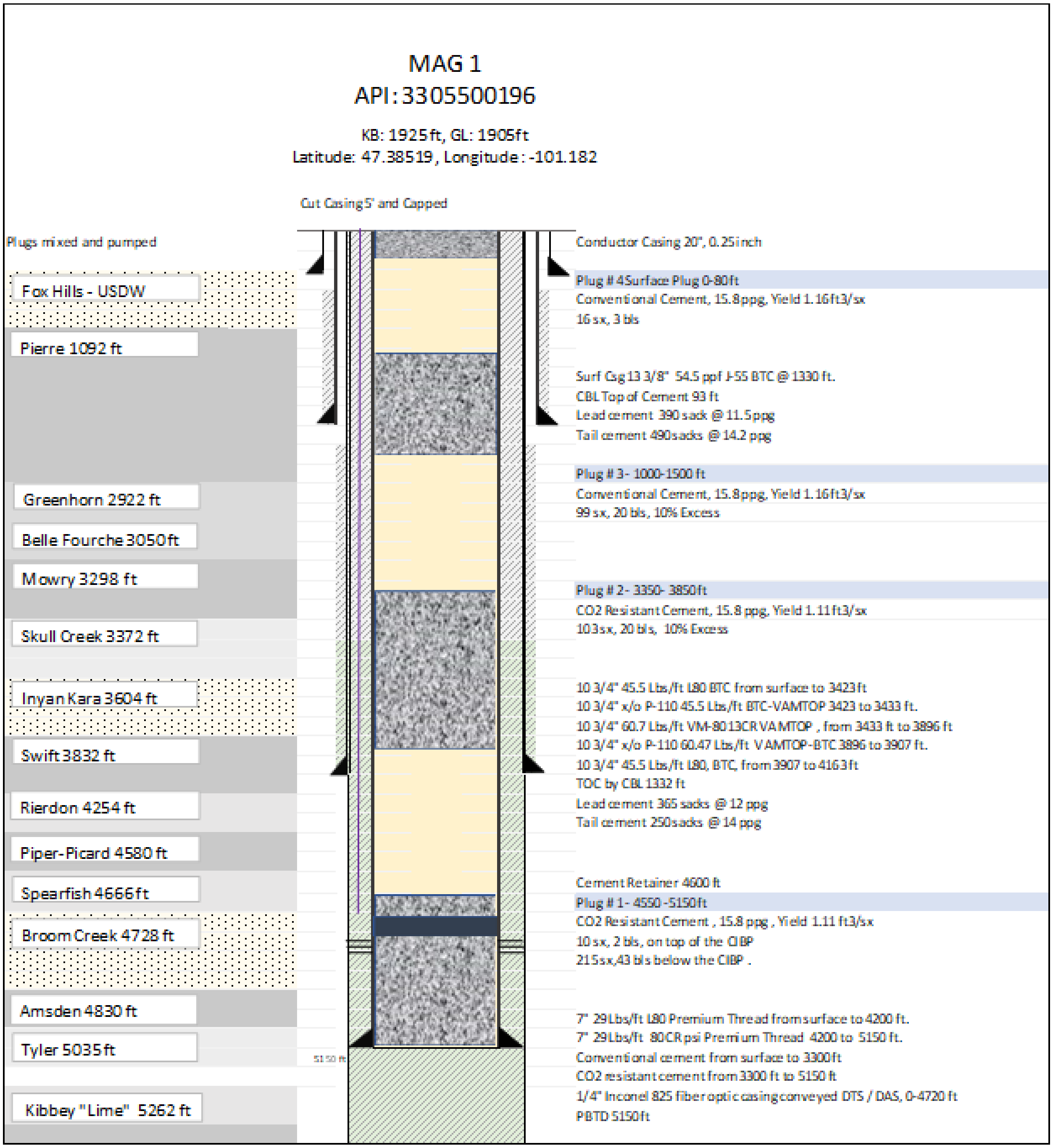

Figure 10-2. Schematic of proposed P&A plan for MAG 1.

10.2 MAG 2 P&A Program

The MAG 2 wellbore is to be plugged and abandoned when the CO_2 plume has stabilized and monitoring of the plume extent is no longer necessary.

A proposed CO_2-monitoring well schematic of MAG 2 is provided in Figure 10-3.

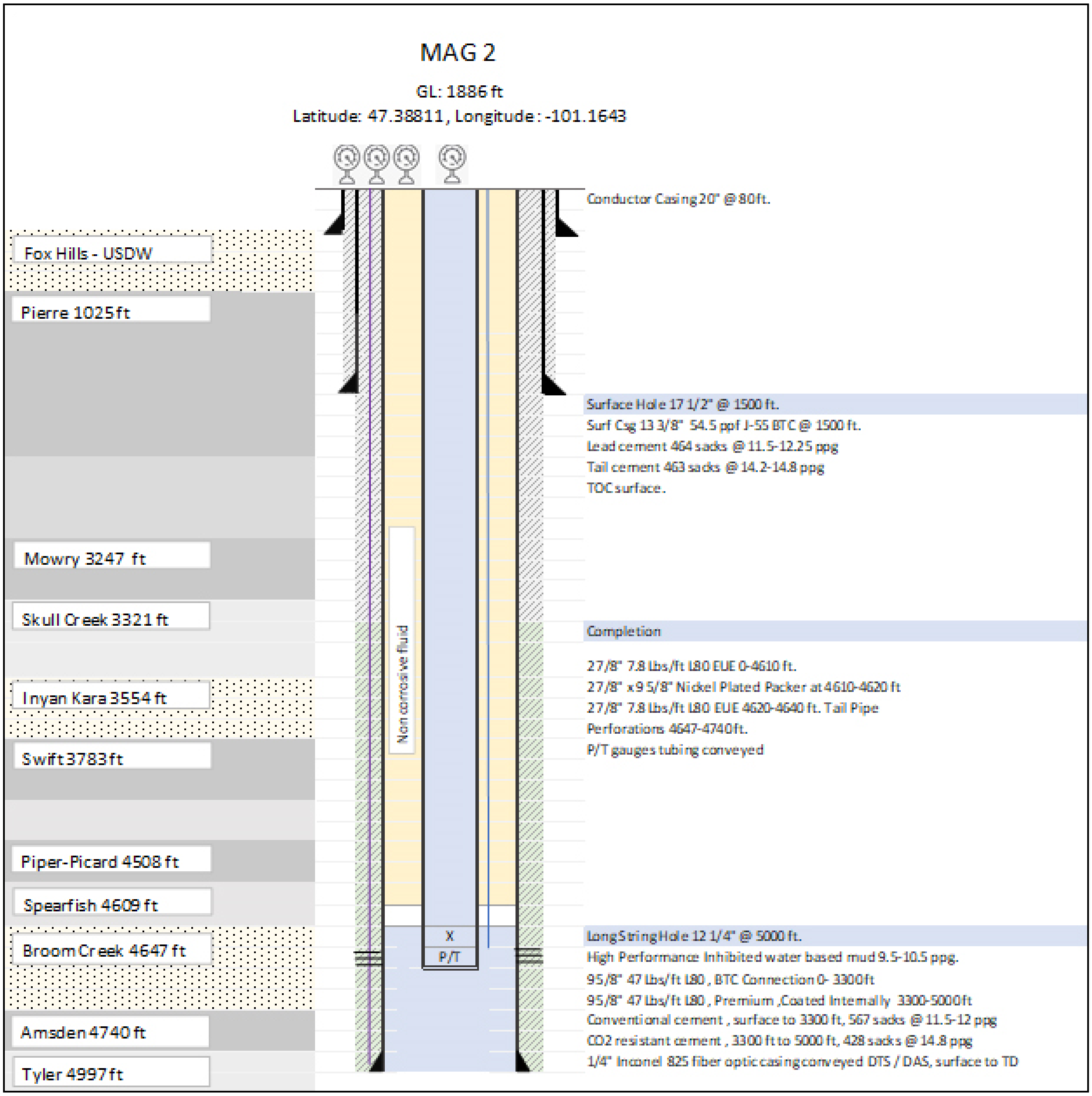

Figure 10-3. Proposed monitoring wellbore schematic for MAG 2.

The proposed procedure for P&A of the MAG 2 wellbore will be performed as follows.

1. MI rig onto MAG 2 and RU.

2. Conduct and document a safety meeting.

3. Test the pump and line to 5,000 psi or 90% of maximum pump pressure. Fill tubing with kill fluid. Bleeding off occasionally may be necessary to remove all air from the system. Monitor tubing and annulus pressure.

4. Test casing annulus to 1,500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

   Note: If failure in long-string casing is identified, the operator will prepare a plan to repair the well prior to P&A.

5. If both casing and tubing are dead, then NU BOPs.

   Contingency: If the well is not dead or the pressure cannot be bled off via tubing, RU wireline and set plug in lower-profile nipple below packer. Unlatch the tubing from the packer and circulate tubing and annulus with kill weight fluid until the well is on control. After casing and tubing pressure are zero, nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with work string in case the packer needs to be unlatched.

6. Pull out of hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release tubing and retrieve packer, RU electric line and make cut on tubing string just above packer. A cut must be made above the packer at least 5 to 10 ft MD. Pull the work string out of hole and proceed to next step. If problems are noted, update the cement remediation plan. A cement retainer might be used to force cement through the packer if it cannot be removed.

7. Pick up work string and TIH with bit to condition wellbore.

8. Pull out of the hole and RU logging unit. Confirm external mechanical integrity by running one or a combination of the tests listed below as options. Rig down logging truck.

   - Activated neutron log
   - Noise log
   - PLT
   - Tracers
   - Temperature log
   - CBL–USIT
   - DTS survey (no required logging unit)

9. TIH work string with cement retainer to the top of Plug 1. Circulate well, set retainer, and perform injectivity test. RU equipment for cementing operations.

10. Mix and pump CO_2-resistant slurry to cover the Broom Creek Formation and isolate from the Dakota Group in accordance with program. Under displaced four barrels of cement. Disconnect from retainer and finish displacing the last four barrels on top of the cement retainer. Check for flow. Pull work string 150 ft and circulate.

11. Pull up hole, set balanced plug with CO_2-resistant cement, 15.8 ppg, to cover Dakota Group and isolate it from the Fox Hills USDW. Pull out above the plug and circulate. Wait on setting time and tag top of the plug.

12. Pull up hole, set balanced plug with Class G cement + additive, 15.8 ppg, to cover the shoe of the surface casing. Pull out above the plug and circulate. Wait on setting time and tag top of the plug.

13. Pull up hole, set surface plug with Class G cement + additive, 15.8 ppg, to isolate the top of surface casing.

14. Lay down all work string. Rig down all equipment and move out.

15. Dig out wellhead and cut off casing 5 ft below GL. Clean cellar to where a plate can be welded with well information.

16. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

17. Within 60 days, submit Form 7 plugging report after plugging operations are complete – NDAC § 43-05-01-11.5(4).

18. Submit notice of intent to reclaim to NDIC 30 days in advance prior to reclamation – NDAC § 43-05-01-18(10d).

The proposed P&A plan for MAG 2 is summarized in Table 10-2 and provided in Figure 10-4.

Table 10-2. Summary of P&A Plan for MAG 2

Cement Plug Number	Interval Range, ft	Thickness, ft	Volume, sacks	Note
1	4,550–5,000	450	333	CO_2-resistant slurry, 15.8 ppg, 1.11 ft^3/sx Squeezed cement job to isolate perforations
2	3,300–3,800	500	203	CO_2-resistant slurry, 15.8 ppg, 1.11 ft^3/sx Balanced plug
3	1,300–1,800	500	195	Conventional cement, 15.8 ppg, 1.16 ft^3/sx Balanced plug
4	0–80	80	31	Conventional cement, 15.8 ppg, 1.16 ft^3/sx Balanced plug

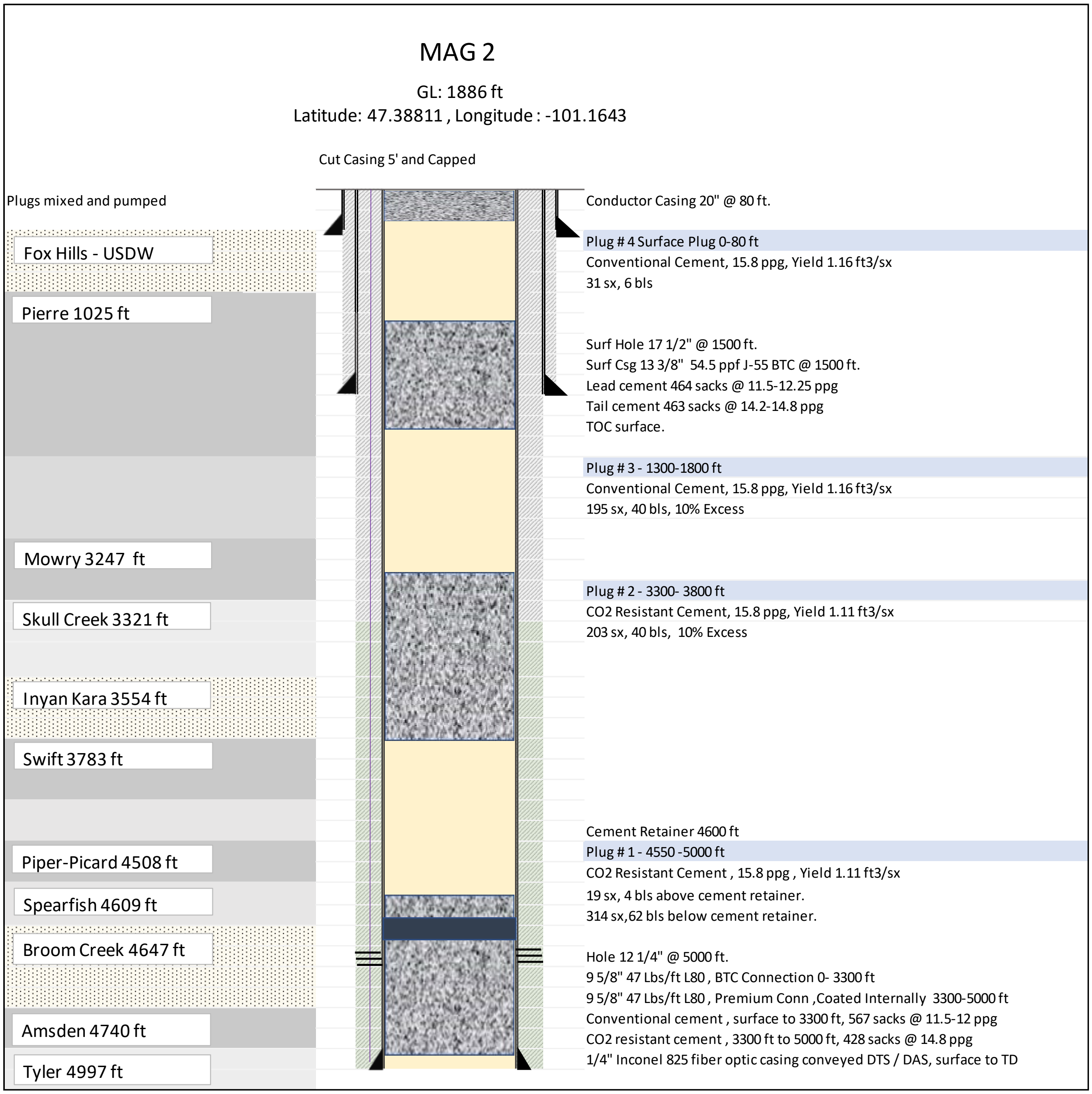

Figure 10-4. Schematic of proposed abandonment plan for monitoring well MAG 2.

11.0 INJECTION WELL AND STORAGE OPERATIONS

11.0 INJECTION WELL AND STORAGE OPERATIONS

This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as documented in NDAC § 43-05-01-05 (Table 11-1) and § 43-05-01-11.3.

Table 11-1. MAG 1 Proposed Injection Well Operating Parameters

Item	Values	Description/Comments
Injected Volume		
Total Injected Volume	4,000,000 tonnes	Based on 200,000 tonnes/year for 20 years at an average daily injection rate of 548 tonnes/day
Injection Rates		
Average Injection Rate	548 tonnes/day (10.35 MMscf/day)	Based on 200,000 tonnes/year for 20 years of injection (using 365 operating days per year)
Average Maximum Daily Injection Rate	2,729 tonnes/day (51.56 MMscf/day)	Based on maximum bottomhole injection pressure (2,970 psi)
Pressures		
Formation Fracture Pressure at Top Perforation	3,300 psi	Based on geomechanical analysis of formation fracture gradient as 0.69 psi/ft (see Section 2.0)
Average Surface Injection Pressure	1,158 psi	Based on 200,000 tonnes/year for 20 years at an average daily injection rate of 548 tonnes/day) using the designed 2.875-inch tubing
Surface Maximum Injection Pressure	4,300 psi	Based on maximum bottomhole injection pressure (2,970 psi) using the designed 2.875-inch tubing
Average Bottomhole Pressure (BHP)	2,570 psi	Based on average daily injection rate of 548 tonnes/day
Calculated Maximum BHP	2,970 psi	Based on 90% of the formation fracture pressure of 3,300 psi

11.1 MAG 1 Well – Proposed Completion Procedure to Conduct Injection Operations

As described in Section 9.1, the MAG 1 well will be reentered and completed as a CO_2 injector (Figures 11-1 and 11-2 and Tables 11-2 through 11-4). The following proposed completion procedure outlines the steps necessary to complete and test the well.

1. Rig up workover (WO) rig and equipment, check pressure in the casing, and release pressure if any.

2. Remove night cap and nipple up blowout preventer (BOP).

3. Test BOP to maximum anticipated surface pressure (MASP).

4. Pick up work string, scraper, and bit to clean out residual cement.

5. Run in the hole and tag plug back total depth (PBTD). Condition casing if needed.

6. Circulate the wellbore with brine, compatible with the formation, estimated at 10 ppg, with a reservoir pressure gradient of 0.512 psi/ft.

7. Trip out of hole (TOOH) work string with bit and scraper.

8. Test casing for 30 minutes to 1,500 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the operator will be required to assess the root cause and correct it.

9. Conduct safety meeting to discuss logging and perforating operations.

10. Rig up logging truck.

11. Install and test lubricator.

12. Run cementing evaluation logs by program.
    Note: run cement bond logs without pressure as a first pass and repeat pass with 1,000 psi pressure. If cementing logs show poor bonding or a low top of cement, the results will be communicated to the NDIC and an action plan will be prepared.

13. Round trip a magnetic tool and casing collar locator (CCL) to identify location of the fiber-optic cable.
    Note: DTS/DAS (distributed temperature sensing/distributed acoustic sensing) fiber-optic cable will be run along the exterior of the long-string casing. Special clamps, bands, and centralizers are installed to protect the fiber and provide a marker for wireline operations.

14. Perforate the Broom Creek Formation, minimum of 6 spf (shots per foot), 36.7-inch-deep penetration, 0.37-inch diameter, and 60° phase (ensure shots do not penetrate fiber-optic cable). Actual perforation depths and design will be determined by designated geologist and engineers, and based on the log analysis review, as well as selected contractor.

15. TOOH with perforating guns.

16. Rig down logging truck and lubricator.

17. Pick up retrievable testing packer with downhole gauges and run in the hole with work string to the top of the perforations.

18. Set packer above perforations to isolation and test the annulus to ensure seal and no communication with backside.

19. Perform an injectivity test/step rate test (SRT) with clean brine compatible with formation.

20. If the well shows poor injectivity, perform a near-wellbore/perforation cleanout using a designed concentration of acid. Adjust acid formulation and volumes with water samples and compatibility test. Maximum injection pressure is not to exceed formation fracture pressure as determined in SRT.

21. Unset packer and circulate hole if acid cleanout is performed.

22. TOOH and lay down temporary packer and work string.

23. Rig up spooler and prepare rig floor to install completion injection assembly (injection tubing and packer).

24. Pick up and run completion assembly in accordance with program.

25. Displace the well with inhibited packer fluid.

26. Set injection packer within 50 ft above the top perforations, according to manufacturer recommendations and NDIC requirements. Test backside/annulus of tubing/casing to designated pressure during operations.

27. Install tubing hanger and cable connectors.

28. Nipple down BOP.

29. Install injection tree.

30. Rig down WO rig and equipment.

31. Move in wireline unit and perform through-tubing cased-hole logging in accordance with program (rigless).

Table 11-2. MAG 1 Proposed Upper Completion

Description	o.d., in.	Depth, ft	Grade	Weight, lb/ft	Connection	i.d., in.	Drift i.d., in.
Tubing	2⅞	0–4,675	L80	7.8	Premium	2.323	2.229
2⅞-in. × 7-in. Nickel-Plated Packer + Pressure/Temperature (P/T) Gauge							
Tubing	2⅞	4,685–4,425	L80 13 CR	7.8	Premium	2.323	2.229
P/T Gauge							

Table 11-3. MAG 1 Tubing Properties

o.d., in.	Grade	Weight, lb/ft	Connection	i.d., in.	Drift i.d., in.	Collapse, psi	Burst, psi	Tension, Klb
2⅞	L80	7.8	Premium	2.323	2.229	13,890	13,440	180
2⅞	L80 13 CR	7.8	Premium	2.323	2.229	13,890	13,440	180

Table 11-4. MAG 1 Cased-Hole Logging

Description	Depth, ft	Comments
CBL (cement bond log)–VDL (variable density log)–CCL–USIT (ultrasonic imaging tool)	0–5,120*	Cement/casing log; 30-ft shoe track
CIL (casing inspection log)	0–4,685*	Baseline; run through tubing
Temperature Log	0–4,685*	Baseline; run through tubing
Pulsed Activated Neutron	0–4,685*	Baseline; run through tubing

* Estimated, will be adjusted with actual tally.

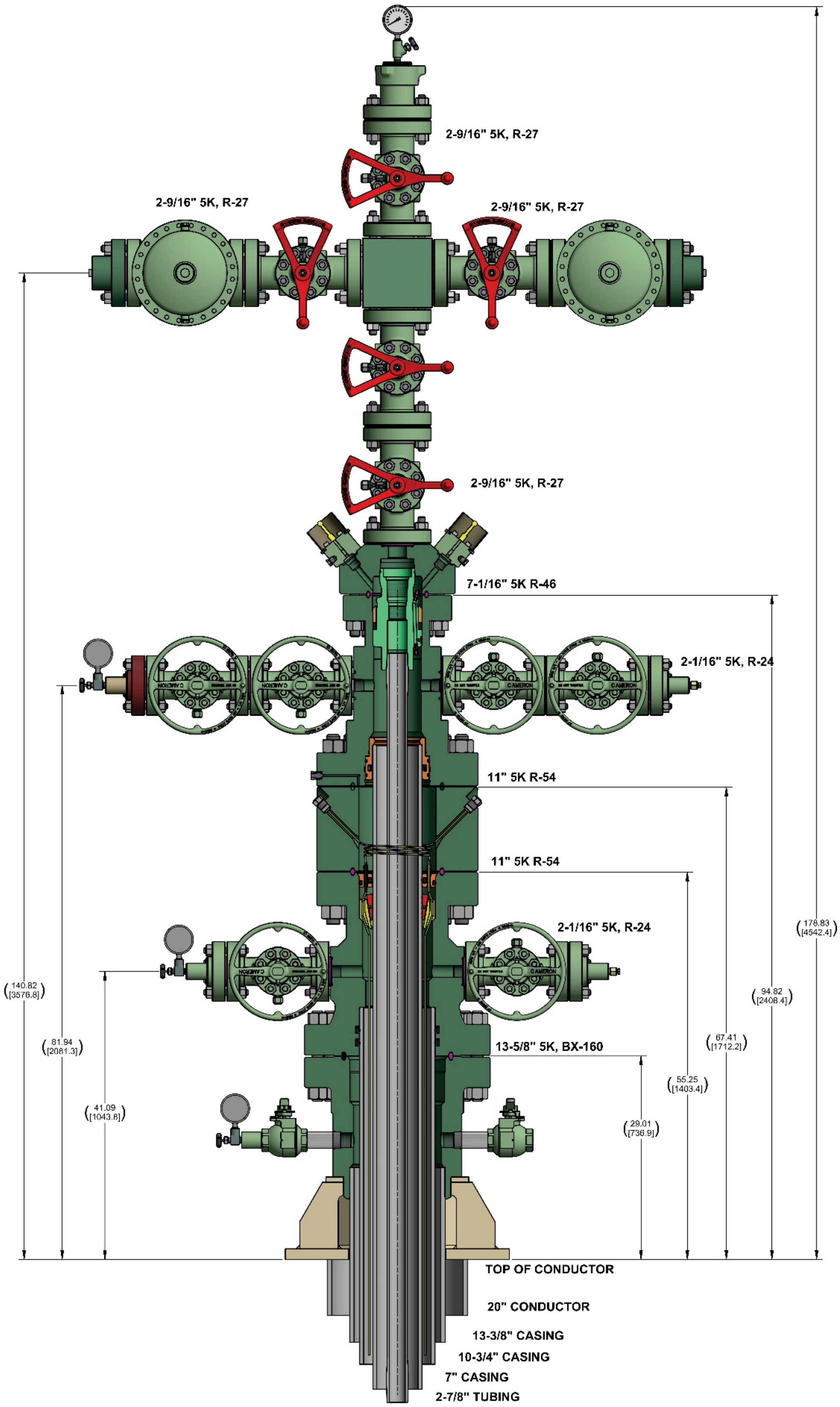

Figure 11-1. MAG 1 proposed CO_2-resistant wellhead schematic.

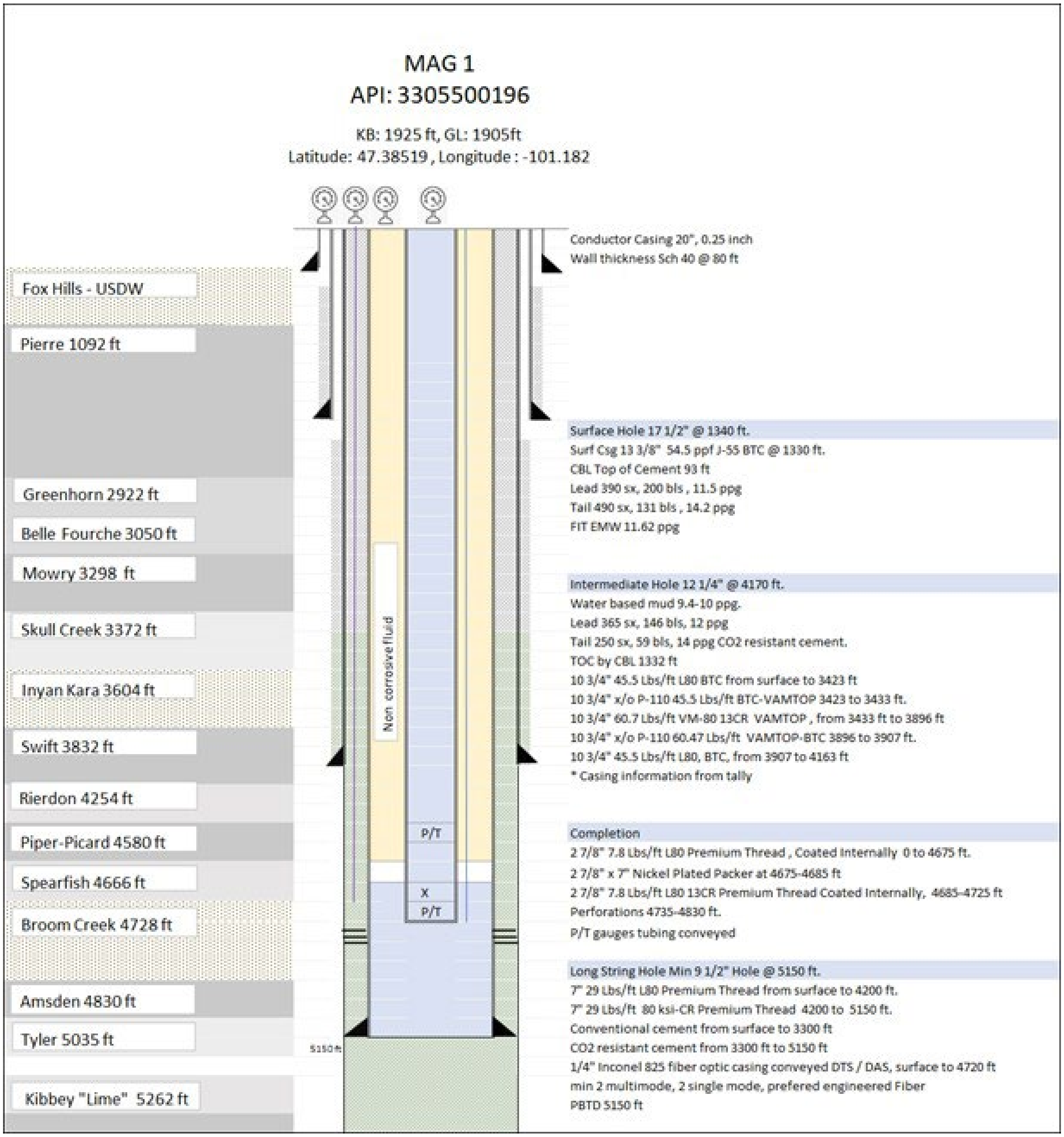

Figure 11-2. MAG 1 proposed completed wellbore schematic.

11.2 MAG 2 Well – Proposed Procedure for Monitoring Well Operations

MAG 2 will be constructed as a CO_2-monitoring well (Figures 11-3 and 11-4 and Tables 11-5 through 11-7) to support deep subsurface monitoring of MAG 1, the CO_2 stream injection well. Monitoring of the CO_2 plume extent and the storage reservoir pressure will be conducted continuously through the use of the casing-conveyed fiber-optic cable installed on the outside the long string and pressure/temperature gauges deployed along the outside of the tubing. Monitoring will be conducted during injection operations as well as during the postinjection site closure (PISC) which are also discussed in more detail in the Testing and Monitoring section of this permit application. Monitoring methods will include a combination of formation-monitoring methods (e.g., downhole pressure, downhole temperature, and pulsed-neutron capture/reservoir saturation tool logs) to verify casing mechanical integrity and support CO_2 plume stabilization evaluations.

The following proposed completion procedure outlines the steps necessary to complete and test the well.

1. Rig up WO rig and equipment, check pressure in the casing, and release pressure if any.

2. Remove night cap and nipple up BOP.

3. Test BOP to MASP.

4. Pick up work string, scraper, and bit to clean out residual cement.

5. Run in the hole and tag PBTD and condition casing if needed.

6. TOOH work string with bit and scraper.

7. Displace the well with formation-compatible brine, estimated at 10 ppg, with a reservoir pressure gradient of 0.512 psi/ft.

8. Test casing for 30 minutes with 1,500 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the operator will be required to assess the root cause and correct it.

9. Conduct safety meeting to discuss logging and perforating operations.

10. Rig up logging truck.

11. Install and test lubricator.

12. Run cased-hole logs by program.
    Note: run CBL/VDL and USIT logs without pressure as a first pass and repeat run with 1,000 psi of pressure as a second pass.
    Note: If CBLs show poor bonding, the results will be communicated to NDIC and an action plan will be prepared.

13. Run magnetic survey to identify fiber-optic orientation and complement with oriented perforating guns. An oriented gun should be used to avoid any damage to the external fiber optic.

14. Perforate the Broom Creek Formation, minimum 4 spf (shots per foot). Actual perforation depths, design, and phasing will be determined by designated geologist and engineers based on the log analysis review.
    Note: DTS/DAS fiber-optic cable will be run along the exterior of the long-string casing. Special clamps, bands, and centralizers are installed to protect the fiber and provide a marker for wireline operations.

15. Pull guns out of the hole.

16. Rig down logging truck.

17. Rig up spooler and prepare rig floor to run upper completion assembly (tubing and packer).

18. Run completion assembly in accordance with program.

19. Circulate well with inhibited packer fluid.

20. Set packer within 50 ft above the top perforations, according to manufacturer recommendations and NDIC requirements. Test backside/annulus of tubing/casing to designated pressure.

21. Install tubing hanger and cable connectors.

22. Nipple down BOP.

23. Install tree.

24. Rig down WO rig and equipment.

25. Move in wireline unit and perform through-tubing cased-hole logging in accordance with program (rigless).

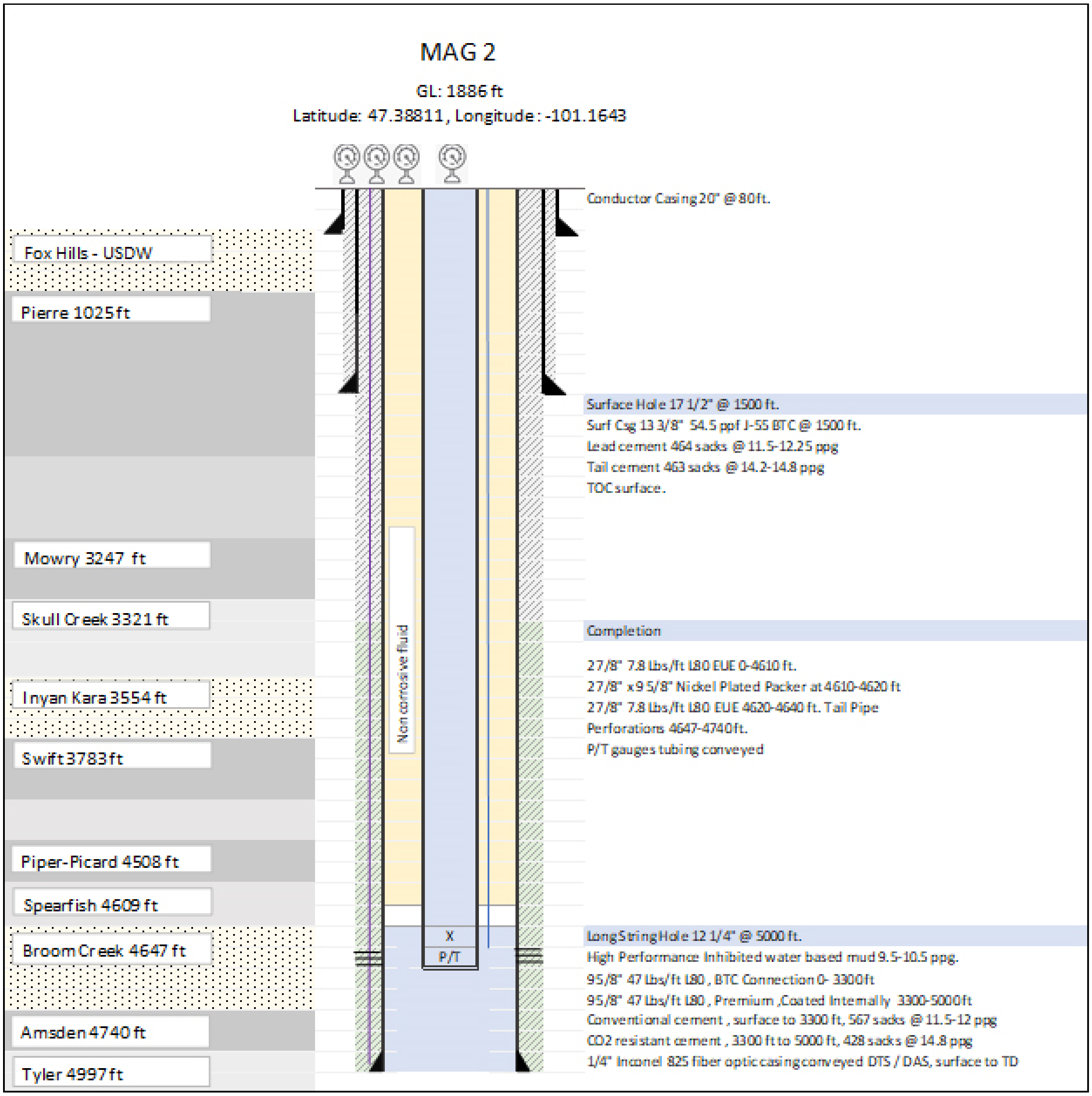

Figure 11-3. MAG 2 proposed completed wellbore schematic.

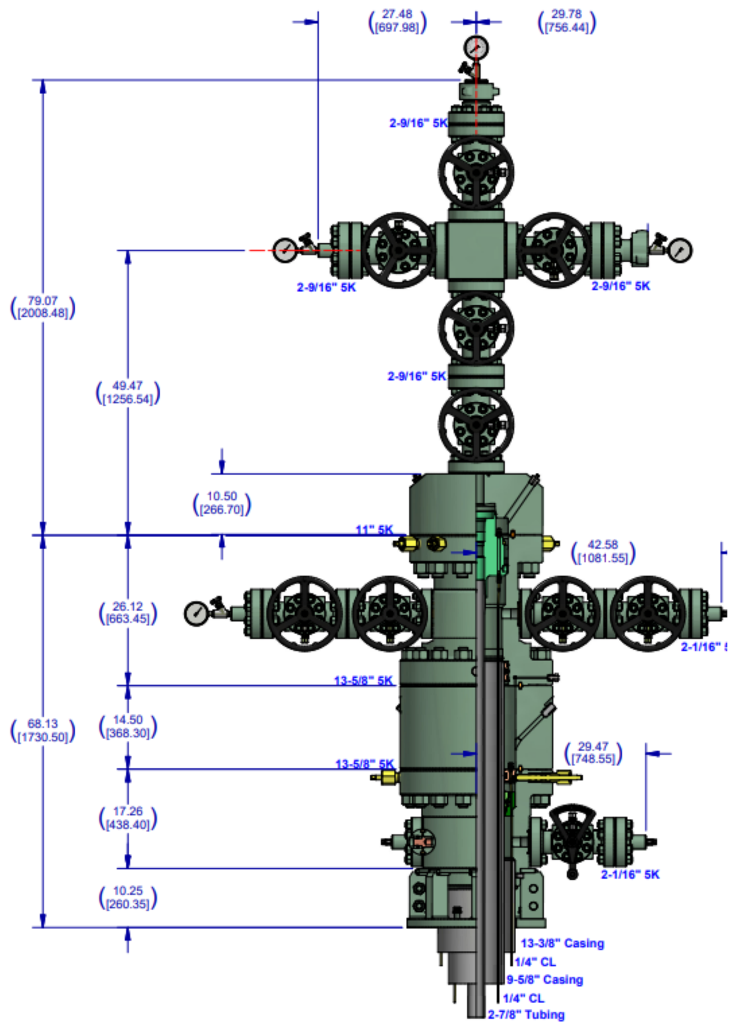

Figure 11-4. MAG 2 proposed wellhead schematic.

Table 11-5. MAG 2 Proposed Upper Completion

Description	o.d., in.	Depth, ft	Grade	Weight, lb/ft	Connection	i.d., in.	Drift i.d., in.
Tubing	2⅞	0–4,610	L80	7.8	EUE (external upset end)	2.323	2.229
2⅞-in. × 9⅝-in. Nickel-Plated Packer							
Tubing (tail pipe)	2⅞	4,620–4,640	L80	7.8	EUE	2.323	2.229

Table 11-6. MAG 2 Tubing Properties

o.d., in.	Grade	Weight, lb/ft	Connection	i.d., in.	Drift i.d., in.	Collapse, psi	Burst, psi	Tension, Klb
2⅞	L80	7.8	Premium	2.323	2.229	13,890	13,440	180

Table 11-7. MAG 2 Cased-Hole Logging

Description	Depth, ft	Comments
CBL–VDL–CCL–USIT	0–4,970*	Cement/Casing Log; 30-ft shoe track
CIL	0–4,640*	Baseline; run through tubing
Temperature Log	0–4,640*	Baseline; run through tubing
Pulsed Activated Neutron	0–4,640*	Baseline; run through tubing

* Estimated; will be adjusted with actual tally.

12.0 FINANCIAL ASSURANCE AND DEMONSTRATION PLAN

12.0 FINANCIAL ASSURANCE AND DEMONSTRATION PLAN

This financial assurance and demonstration plan (FADP) is provided to meet the regulatory requirements for the geologic storage of CO_2 as prescribed by the state of North Dakota in North Dakota Administrative Code (NDAC) § 43-05-01-09.1. The storage facility permit (SFP) application must demonstrate that a financial instrument is in place that is sufficient to cover the costs associated with the following actions:

- Pursuant to NDAC § 43-05-01-05.1, corrective action on all active and abandoned wells, which are within the AOR (area of review) and penetrate the confining zone, and have the potential to endanger USDWs (underground sources of drinking water) through the subsurface movement of the injected CO_2 or other fluids.

- Pursuant to NDAC § 43-05-01-11.5, plugging of injection wells.

- Pursuant to NDAC § 43-05-01-19, implementation of postinjection site care (PISC) and facility closure activities, which includes the 10-year PISC monitoring program.

- Pursuant to NDAC § 43-05-01-13, implementation of ERRP (emergency and remedial response plan) actions.

This FADP identifies the financial instruments that will be established (Section 12.2) and provides cost estimates for each of the above actions (Section 12.3) based on the information that is provided in the SFP application.

12.1 Facility Information

The facility name, facility contact, and injection well locations are provided below:

Facility Name:	Blue Flint Sequester Company, LLC
Facility Contact:	Adam Dunlop
Injection Well Locations:	MAG 1 (NDIC File No. 37833) NW/NW of Section 18 T145N, R82.

12.2 Financial Instruments

Blue Flint is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments:

- Blue Flint will plan to increase existing well bonding or secure other financial instrument to cover costs of plugging the injection well in accordance with NDAC § 43-05-01-11.5.

- No corrective action estimates have been provided as there are no legacy wellbores within the AOR; thus, no action is necessary.

- Blue Flint will establish a bond, escrow account, third-party insurance policy, or other financial instrument to ensure funds are available for PISC and facility closure activities in accordance with NDAC § 43-05-01-19.

- A third-party pollution liability insurance policy with an aggregate limit of $9 million will be secured to cover the costs of implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13.

The estimated total costs of these activities are presented in Table 12-1. Section 12.3 of this FADP provides additional details of the financial responsibility cost estimates for each activity.

Table 12-1. Cost Estimates for Activities to Be Covered

Activity	Estimated Total Cost
Corrective Action on Wells in the AOR	$0
Plugging of Injection Well	$100,000
PISC and Facility Closure	$2,467,550
Emergency and Remedial Response (including endangerment to USDWs)	$9,000,000
Total	$11,567,550

The company providing insurance will meet all the following criteria:

1. The company is authorized to transact business in North Dakota.

2. The company has either passed the specified financial strength requirements based on credit ratings or has met a minimum rating, minimum capitalization, and ability to pass the rating, when applicable.

3. The third-party insurance can be maintained until such time that the North Dakota Industrial Commission (NDIC) determines that the storage operator has fulfilled its financial obligations.

The third-party insurance, which identifies Blue Flint as the covered party, will be provided by one or a combination of the companies shown below: The Applicant has procured indicated terms for commercial Environmental Impairment Liability ('EIL') insurance coverage to fund covered emergency and remedial response actions to protect underground sources of drinking water arising out of sequestration operations. Coverage terms are of an indicative/estimated nature only at this time, as firm and bindable terms are not possible this far in advance of commencement of sequestration operations; however, at this time a coverage limit of $9 million per occurrence/aggregate is contemplated and likely expected to be provided by one or a combination of the following insurers:

- Ascot Insurance Group – AM Best Rated 'A' (Excellent)
- Aspen Insurance Group – AM Best Rated 'A' (Excellent)
- W.R. Berkley Insurance Group – AM Best Rated 'A+' (Superior)
- Ironshore Insurance Company (Liberty Mutual Group) – AM Best Rated 'A' (Excellent)

Final coverage terms and costs will be determined upon full underwriting and firm/bindable quotations to be issued by insurers 30–60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations.

The third-party insurance companies listed above meet both of the following criteria, as specified in NDAC §43-05-01-09.1(1)(g):

1. The companies satisfy financial strength requirements based on credit ratings in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa).

2. The companies meet a minimum rating (minimum rating based on an issuer, credit, securities, or financial strength rating as a demonstration of financial stability) and minimum capitalization (i.e., demonstration that minimum thresholds are met for the following financial ratios: debt–equity, assets–liabilities, cash return on liabilities, liquidity, and net profit) and are able to pass bond rating in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa), when applicable.

12.3 Financial Responsibility Cost Estimates

12.3.1 Corrective Action

Blue Flint implemented the following workflow to estimate costs associated with corrective action activities: 1) delineate the AOR and 2) identify and evaluate active and abandoned legacy wells within the AOR (i.e., MAG 1) to ensure they meet the minimum completion standards for geologic storage of CO_2 and need no corrective action. Based on the results of the well evaluations, no correction action was needed.

12.3.2 Plugging of Injection Wells

Blue Flint implemented the following approach to estimate costs associated with the plugging of the injection well: assume plugging of one Class VI injection well at a total cost of $100,000 per well, the MAG 1 well.

12.3.3 Implementation of PISC and Facility Closure Activities

The breakdown of estimated costs totaling $2.272 million for implementing the PISC as described in the PISC and facility closure plan is provided in Table 12-2a, which includes the following monitoring activities: a) formation monitoring (i.e., downhole pressure and temperature surveys, pulsed-neutron logs), b) near-surface monitoring (i.e., soil gas and Fox Hills Formation testing) and mechanical integrity well tests (i.e., injection well annulus pressure, ultrasonic logs), and c) coordinated repeat 2D seismic surveys. Table 12-2a covers the estimated costs in the time period between cessation of injection activities and issuance of the certificate of project completion. The MAG 1 wellbore will be plugged upon cessation of injection, with plugging cost estimates provided in Table 12-1. As part of PISC monitoring activities, the deep subsurface monitoring well, MAG 2, and the Fox Hills monitoring well will remain until site closure. The MAG 2 wellbore will monitor the storage reservoir until site closure, with cost estimates for plugging and site closure activities provided in Table 12-2b.

Table 12-2a Cost Estimate[1] for PISC Activities for the Blue Flint CO_2 Storage Project. The Cost Estimate Assumes a 10-year PISC Period.

Activity	Frequency	Unit Cost	Total
Injection Pad Reclamation (MAG 1)			
Reclamation Costs of the Injection Pad of MAG 1	Prior to closure	\$50,000	\$50,000
Flowline Abandonment and Closure	Once	\$21,000	\$21,000
SGPS01 P&A[3]	Prior to closure	\$10,000	\$10,000
Flowline Reclamation at the Capture Facility			
Flowline Abandonment and Closure	Once	\$21,000	\$21,000
Wellbore Monitoring (MAG 2)			
Pulsed-Neutron Logging (saturation monitoring, reservoir, and AZMI[2])	Annually until full CO_2 saturation occurs within storage reservoir; reduce to once every 4 years thereafter.	\$45,000	\$180,000
Temperature Logging (external mechanical integrity)	Annually (if needed)	\$10,000	\$100,000
USIT Logging (corrosion monitoring)	Once every 5 years	\$55,000	\$110,000
Annulus Pressure Testing (internal mechanical integrity)	Once every 5 years	\$8,000	\$16,000
Near-Surface Monitoring			
SGPS01 – Sampling and Analysis	Once	\$4,450	\$4,450
SGPS02 – Sampling and Analysis	Annually	\$4,450	\$44,500
SG01-SG04 – Sampling and Analysis	Once at start of PISC and once prior to closure	\$4,450	\$35,600
Up to Five Groundwater Wells – Sampling and Analysis	Once prior to closure	\$2,000	\$10,000
One Dedicated Fox Hills Well – Sampling and Analysis	Annually	\$2,000	\$20,000
Storage Complex Monitoring			
Time-Lapse 2D Fence Seismic Survey Acquisition and Processing	Once every 5 years	\$825,000	\$1,650,000
Total for PISC Activities			\$2,272,550

[1] Does not include interpretation and reporting. Costs are based on today's pricing and do not account for inflation.
[2] Above-zone monitoring interval.
[3] Plugging and abandonment assumed unless NDIC requests transfer of ownership.

Table 12-2b Cost Estimate[1] for Site Closure and Remediation Activities for the Blue Flint CO_2 Storage Project

Activity	Timing	Description	Total
Closure and Reclamation Costs			
Plugging of the MAG 2 Monitoring Well	Prior to closure	Plugging activities described in Section 10 Plugging Plan	$100,000
Reclamation Costs of the Monitoring Pad of MAG 2	Prior to closure	Wellhead removal, sump removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, general labor	$50,000
Fox Hills Monitoring Well P&A[2]	Prior to closure	Pipe removal, pad reclamation (rock removal and soil coverage), reseeding, general labor	$35,000
SGPS02 P&A[2]	Prior to closure	Plugging and abandonment of SGPS01 and SGPS02	$10,000
Total for Closure Activities			$195,000

[1] Does not include interpretation and reporting. Costs are based on today's pricing and do not account for inflation.
[2] Plugging and abandonment assumed unless NDIC requests transfer of ownership.

Table 12-2b lists the costs for the closure of the site and activities related to injection and monitoring of CCS activities which demonstrate a total of $195 thousand. As listed in Section 6.0 PISC, Subsection 6.3.1 PISC Plan, Blue Flint plans to initiate site closure activities that will include the plugging of all wells that are not planned for continued use in monitoring the closed site; the decommissioning of storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring; and the reclaiming of the surface land of the site to as close as is practical to its original condition.

As described in 6.3.2 Site Closure Plan, the Fox Hills monitoring well and the two soil gas profile stations are available for transfer of ownership to the state. Table 12-2b demonstrates the costs for the plugging and abandonment of one of two soil gas profile stations (SGPS02) and the Fox Hills monitoring well in the case the state does not request transfer of ownership. SGPS01's plugging and abandonment cost is shown in Table 12-2a in the case it is not transferred to the state. The five groundwater sampling wells listed in Table 12-2a do not require remediation and were not incorporated into cost estimates as the wells were not constructed as part of the project and are privately owned by third parties. This brings the total for PISC and closure activities to $2.467 million.

12.3.4 Implementation of Emergency and Remedial Response Actions

12.3.4.1 Emergency Response Actions

A review of the technical risk categories for Blue Flint identified a list of events that could potentially result in the movement of injected CO_2 or formation fluids in a manner that may endanger a USDW and require an emergency response. These events are as follows:

- Injectivity
- Storage capacity
- Containment – lateral migration of CO_2
- Containment – pressure propagation
- Containment – vertical migration of CO_2 or formation water brine via injection wells, other wells, or inadequate confining zones
- Natural disasters (induced seismicity)

If it is determined that one or more of these events have occurred, the emergency response actions that will be implemented are described in the ERRP (Section 7). These response actions are summarized in Tables 7-3 and 7-4.

12.3.4.2 Estimation of Costs of Emergency Response Actions

Estimating the costs of implementing the emergency response actions in Tables 7-3 and 7-4 is challenging since remediation measures specifically dedicated to CO_2 storage impacts are poorly documented, with one of the more important data gaps being the lack of precise knowledge of the leakage mechanisms and associated impacts (Manceau and others, 2014). Without this knowledge, it is not possible to design appropriate remedial measures. Furthermore, to date, no remediation action following CO_2 leakage after geologic storage has ever been implemented mainly because of the absence of established impacts (Manceau and others, 2014). Consequently, the degree of maturity of remediation measures in the carbon capture and storage (CCS) field is low, making it necessary to rely on literature that is primarily based on modeling or analogies with other pollutants, e.g., the analogy between CO_2 and volatile organic compounds, the latter having been addressed extensively in the literature. Additionally, for the remedial measures, costs and time for adequate removal are generally site-dependent, and no information is specifically available in this area in the CCS field.

Based on this current situation, two key technical manuscripts were relied upon to identify and estimate the costs of mitigation/remediation technologies to address undesired migration of CO_2 from a geological storage unit (Manceau and others, 2014; Bielicki and others, 2014).

<u>12.3.4.2.1 Identification of Remediation Technologies</u>

Manceau and others (2014) identified several remediation technologies/strategies that are available to address the potential impacted media that may result from an emergency event. These impacted media and remediation measures are listed in Table 12-3. The impacted media in Table 12-3 include surface and groundwater/USDWs, vadose zone, indoor settings, and atmosphere; the

Table 12-3. Proposed Technologies/Strategies for Remediation of Potential Impacted Media

Impacted Media	Potential Remedial Measures
Groundwater/USDW	Monitored natural attenuation
	Pump-and-treat
	Air sparging
	Permeable reactive barrier
	Extraction/injection
	Biological remediation
Vadose Zone	Monitored natural attenuation
	Soil vapor extraction
	pH adjustment (via spreading of alkaline supplements, irrigation, and drainage)
Surface Water	Passive systems, e.g., natural attenuation
	Active treatment systems
Atmosphere	Passive systems, e.g., natural mixing, dispersion
Indoor/Workplace Settings	Sealing of leak points
	Depressurization
	Ventilation

remedial measures include a combination of active (e.g., air sparging) and passive (e.g., dispersion, natural attenuation) systems. However, it is important to note that, at this time, there is no widely accepted methodology for designing intervention and remediation plans for CO_2 geologic storage projects. Consequently, there remains a need for establishing the best field-applied and test practices for mitigating an undesired CO_2 migration. This effort will be based on a combination of available literature and experience that is gained over time in existing CO_2 storage projects.

12.3.4.2.2 Estimation of Costs for Implementing Emergency Event Responses

Given the lack of a site-specific estimate of implementing the emergency event responses at the CO_2 geologic storage site of Blue Flint, cost estimates developed by Bielicki and others (2014) were used to derive a cost range for the project related to the undesired migration of CO_2 from a geologic storage unit. Extrapolating these literature costs, which were based on a case study site in the Michigan Sedimentary Basin, to Blue Flint only provides an order-of-magnitude estimate of the potential costs because of the significant site-specific differences in the storage projects; however, the range of costs estimated in this manner are believed to be conservatively high in nature, making them more than sufficient for informing the value of the financial instrument that must be secured for the project, as described in the financial responsibility demonstration plan.

Case Study Description

Bielicki and others (2014) examined the costs associated with remediating undesired migration of CO_2 from a geologic storage unit as part of a case study of an extreme leakage situation. The case study involved the continuous annual injection of 9.5 Mt (9,500,000 metric tons) of CO_2 into the Mt. Simon sandstone of the Michigan Sedimentary Basin over a period of 30 years. It assumed every well in the basin was a potential leakage pathway and that no action was taken to mitigate any of these leakage pathways. In addition, eight UIC (underground injection control) Class I injection wells, which were located within approximately 1 mile of the CO_2 injection well, were also identified as leakage pathways. Four hundred probabilistic simulations of the CO_2 injection were performed and produced estimates of the area of the CO_2 plume as well as leakage rates of CO_2 from the storage reservoir to four aquifers as well as to the surface.

Cost Estimates

Story lines were developed for the site based on 1) risk assessments for the geologic storage of CO_2; 2) consequences of leakage; 3) lay and expert opinion of leakage risk; 4) modeling of CO_2 injection and leakage for the case study; and 5) input from local experts, oil and gas engineers, academics, attorneys, and other environmental professionals familiar with the Michigan Sedimentary Basin. Cost estimates for managing leakage events were then generated for first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) projects based on a low-cost and high-cost story line. These cost estimates provided a breakdown of the costs into the following categories:

- Find and fix a leak
- Environmental remediation
- Injection interruption
- Technical remedies for damages
- Legal costs
- Business disruption to others, e.g., natural gas storage
- Labor burden to others

Of interest for the financial responsibility demonstration plan is the environmental remediation cost estimate, which was provided for a leak scenario where there was interference with groundwater as well as a scenario where there was groundwater interference combined with CO_2 migration to the surface.

Environmental Remediation – Low-Cost and High-Cost Story Line

The low-cost and high-cost story lines for the two components of environmental remediation, groundwater interference and migration to the surface, are summarized in Table 12-4. As shown in Table 12-4, the low-cost story lines are characterized by independent leak scenarios that either result in interference with groundwater or CO_2 migration to the surface. On the other hand, the high-cost story lines are interrelated, where it is assumed that the high-cost story line for CO_2 migration to the surface is conditional upon the existence of the high-cost story line for groundwater interference.

Estimated Environmental Remediation Costs – FOAK and NOAK Projects

Based on the above story lines, the estimated environmental remediation costs for the high-cost story lines are basically the same for both FOAK and NOAK projects:

- High-cost story line – Groundwater interference alone: ~ $13M
- High-cost story line – Groundwater interference with CO_2 migration to the surface: $15M to $16M

Table 12-4. Low-Cost and High-Cost Story Line for Environmental Remediation

Low-Cost Story Line	
Groundwater Interference	• A small amount of CO_2 migrates into a deep formation that has a total dissolved solids concentration of ~9000 ppm. By definition, this unit is a USDW, but the state has abundant water resources, and there are no foreseeable uses for water from this unit. • Regulators require that two monitoring wells be drilled into the affected USDW and three monitoring wells be drilled into the lowermost potable aquifer (total dissolved solids concentration of <1000 ppm) to verify the extent of the impacts of the leak. No legal action is taken. • Injection is halted from the time that the leak is discovered until monitoring confirms that containment is effective (9 months). • The UIC regulator determines that no additional remedial actions are necessary.
CO_2 Migration to the Surface	• A leaking well provides a pathway whereby CO_2 discharges directly to the atmosphere. • Neither CO_2 nor brine leaks into the subsurface formation outside the injection formation in significant quantities. • The CO_2 injection is halted for 5 days, and the leaking well is promptly plugged.
High-Cost Story Line	
Groundwater Interference	• A community water system reports elevated arsenic. Monitoring suggests that the native arsenic in the formation may have been mobilized by pH changes in the aquifer caused by CO_2 impacts to the aquifer. • A new water supply well is installed to serve the community, and the former water supply wells are plugged and capped. • Potable water is provided to the affected households during the 6 months required to drill the new water supply wells. • Groundwater regulators take legal action on the geologic storage operator to force remediation of the affected USDW using pump-and-treat technology. • UIC regulators require remedial action to remove, through a CO_2 extraction well, an accumulation of CO_2 that has the potential to affect the drinking water. • CO_2 injection is halted for 1 year during these remediation activities.
CO_2 Migration to the Surface	• The high-cost story line for groundwater is required. • A hyperspectral survey completed during the diagnostic monitoring program identifies surface leakage in a sparsely populated area. • Elevated CO_2 concentrations are detected by a soil gas survey and by indoor air quality sampling in the basements of several residences. • Affected residents are housed in a local hotel for several nights while venting systems are installed in their basements. • A soil-venting system is installed at the site. • CO_2 injection is halted for a year during these remediation activities.

12.3.4.2.3 Input for the Financial Responsibility Demonstration Plan

The estimated costs for the environmental remediation of the high-cost story line for the case study, \$15M to \$16M, likely represents a high estimate of similar costs for Blue Flint. This statement is based primarily on the fact that the quantity of CO_2 injection of the case study (9,500,000 metric tons of CO_2 per year) is significantly larger than the planned injection quantity of Blue Flint (from 200,000 metric tons of CO_2 per year). Furthermore, the case study site had 450,000 active and abandoned wells, 400,000 of which penetrate the shallow subsurface to provide for drinking water, irrigation, and industrial uses. In contrast, there is one proposed CO_2 injection well (MAG 1) and one monitoring well (MAG 2) located in the area of Blue Flint. As such, the extreme leakage scenario of the case study represents a more extensive leakage scenario than could exist at the Blue Flint site. Accordingly, even though the same remedial technologies and strategies may be used at both sites to address CO_2 migration, it is assumed that the cost estimates provided for the case study represent a high cost that is unlikely to be incurred for the Blue Flint project. It is on this basis that the value of $9M has been used for the emergency and remedial response portion of the financial instrument that will be put in place for Blue Flint.

To provide additional perspective for this $9M cost estimate for environmental remediation, two other cost estimates for the remediation of potential environmental impacts associated with the geologic storage of CO_2 were found in the literature. These costs ranged from $9M to $34M. The source of the lower limit ($9M) was a 2012 study (Trabucchi and others, 2012) which estimated the damages, i.e., dollars necessary to remediate or compensate for harm should a release occur at a commercial storage site (i.e., FutureGen 1.0 located in Jewett, Texas) that planned to inject 1,000,000 metric tons of CO_2 per year. This study estimated the "most likely" (50th percentile) total damages to be approximately $8.7M and the "upper end" (95th and 99th percentiles) of the total damages to be approximately $20.1M and $26.2M, respectively (all estimates in 2020 dollars). Given that that the quantity of CO_2 injection of this case study (1,000,000 metric tons of CO_2 per year) is significantly larger than the planned injection quantity of Blue Flint (from 200,000 metric tons of CO_2 per year) the lower limit of $9M is a conservatively high estimate for Blue Flint.

The upper limit of the range ($34M) came from a Class VI UIC permit, which was issued to Archer Daniels Midland (ADM) by the U.S. Environmental Protection Agency (Underground Injection Control Permit – Class VI, Permit No. IL-115-6A-0001). As part of the financial responsibility demonstration plan of the ADM permit, a cost estimate of $33.8M was provided for the cost element, emergency, and remedial response, which is slightly higher than the 99th percentile cost estimate of $26.2M for the FutureGen 1.0 site. The planned injection rate for the ADM geologic storage project was ~1,200,000 metric tons per year.[1]

12.4 References

Bielicki, J.M., Pollak, M.F., Fitts, J.P., Peters, C.A., and Wilson, E.J., 2013, Causes and financial consequences of geologic CO_2 storage reservoir leakage and interference with other subsurface resources: International Journal of Greenhouse Gas Control, v. 20, p. 272–284.

Manceau, J.C., Hatzignatiou, D.G., Latour, L.L, Jensen, N.B., and Réveillére, A., 2014, Mitigation and remediation technologies and practices in case of undesired migration of CO_2 from a geological storage unit—current status: International Journal of Greenhouse Gas Control, v. 22, p. 272–290.

[1] It should be noted that both of these examples are injecting CO_2 at a rate 5–6 times higher than the planned injection at the Blue Flint facility, which suggests that these cost estimates are likely higher than the costs that will be required for Blue Flint Sequester Company, LLC.

Trabucchi, C., Donlan, M., Huguenin, M, Konopka, M., and Bolthrunis, S., 2012, Valuation of potential risks arising from a model, commercial-scale CCS project site: Prepared for CCS Valuation Sponsor Group, June 1, 2012.

APPENDIX A

MAG 1 FORMATION FLUID SAMPLING

MVTL

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL

Report Date: 12 Nov 20
Lab Number: 20-W4389
Work Order #:82-3067
Account #: 021017
Date Sampled: 2 Nov 20 13:45
Date Received: 2 Nov 20 15:15
Sampled By: MVTL Field Services

PO #: CC#990-81100-002

Temp at Receipt: 5.5C ROI

Adam Dunlop
Midwest Ag Energy - Blue Flint
2841 3rd St SW
Underwood ND 58576

Project Name: MAG1

Sample Description: Inyan Kara Upper

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	3 Nov 20	HT
pH	* 7.7	units	N/A	SM4500-H+-B-11	3 Nov 20 17:00	HT
Conductivity (EC)	24500	umhos/cm	N/A	SM2510B-11	3 Nov 20 17:00	HT
pH - Field	7.87	units	NA	SM 4500 H+ B	2 Nov 20 13:45	DJN
Temperature - Field	19.7	Degrees C	NA	SM 2550B	2 Nov 20 13:45	DJN
Total Alkalinity	428	mg/l CaCO3	20	SM2320B-11	3 Nov 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	3 Nov 20 17:00	HT
Bicarbonate	428	mg/l CaCO3	20	SM2320B-11	3 Nov 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	3 Nov 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	3 Nov 20 17:00	HT
Conductivity - Field	26360	umhos/cm	1	EPA 120.1	2 Nov 20 13:45	DJN
Total Organic Carbon	746	mg/l	0.5	SM5310C-11	11 Nov 20 23:56	NAS
Sulfate	1100	mg/l	5.00	ASTM D516-11	6 Nov 20 10:02	SD
Chloride	11500	mg/l	2.0	SM4500-Cl-E-11	4 Nov 20 8:37	EV
Nitrate-Nitrite as N	< 1 @	mg/l	0.20	EPA 353.2	5 Nov 20 10:12	EV
Ammonia-Nitrogen as N	36.2	mg/l	0.20	EPA 350.1	10 Nov 20 11:46	SD
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	6 Nov 20 13:06	MDE
Total Dissolved Solids	17000	mg/l	10	USGS I1750-85	4 Nov 20 9:30	HT
Calcium - Total	581	mg/l	1.0	6010D	5 Nov 20 11:27	MDE
Magnesium - Total	38.8	mg/l	1.0	6010D	5 Nov 20 11:27	MDE
Sodium - Total	5600	mg/l	1.0	6010D	5 Nov 20 11:27	MDE
Potassium - Total	139	mg/l	1.0	6010D	5 Nov 20 11:27	HT
Iron - Total	0.74	mg/l	0.10	6010D	11 Nov 20 10:12	MDE
Manganese - Total	0.25	mg/l	0.05	6010D	11 Nov 20 10:12	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL

Adam Dunlop
Midwest Ag Energy - Blue Flint
2841 3rd St SW
Underwood ND 58576

Report Date: 12 Nov 20
Lab Number: 20-W4389
Work Order #:82-3067
Account #: 021017
Date Sampled: 2 Nov 20 13:45
Date Received: 2 Nov 20 15:15
Sampled By: MVTL Field Services

Project Name: MAG1

PO #: CC#990-81100-002

Sample Description: Inyan Kara Upper

Temp at Receipt: 5.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Strontium - Dissolved	23.4	mg/l	0.10	6010D	9 Nov 20 12:31	MDE
Arsenic - Dissolved	< 0.004 +	mg/l	0.0020	6020B	9 Nov 20 11:20	MDE
Barium - Dissolved	0.4902	mg/l	0.0020	6020B	9 Nov 20 11:20	MDE
Cadmium - Dissolved	< 0.002 +	mg/l	0.0005	6020B	9 Nov 20 11:20	MDE
Chromium - Dissolved	< 0.004 +	mg/l	0.0020	6020B	9 Nov 20 11:20	MDE
Copper - Dissolved	< 0.004 +	mg/l	0.0020	6020B	9 Nov 20 11:20	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	9 Nov 20 11:20	MDE
Molybdenum - Dissolved	0.0353	mg/l	0.0020	6020B	9 Nov 20 11:20	MDE
Selenium - Dissolved	< 0.02 +	mg/l	0.0050	6020B	9 Nov 20 11:20	MDE
Silver - Dissolved	< 0.002 +	mg/l	0.0005	6020B	9 Nov 20 11:20	MDE

* Holding time exceeded

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
# = Due to concentration of other analytes
! = Due to sample quantity
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL

Report Date: 12 Nov 20
Lab Number: 20-W4390
Work Order #:82-3067
Account #: 021017
Date Sampled: 2 Nov 20 13:52
Date Received: 2 Nov 20 15:15
Sampled By: MVTL Field Services

Adam Dunlop
Midwest Ag Energy - Blue Flint
2841 3rd St SW
Underwood ND 58576

Project Name: MAG1

PO #: CC#990-81100-002

Sample Description: Inyan Kara Lower

Temp at Receipt: 5.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	3 Nov 20	HT
pH	* 8.1	units	N/A	SM4500-H+-B-11	3 Nov 20 17:00	HT
Conductivity (EC)	22524	umhos/cm	N/A	SM2510B-11	3 Nov 20 17:00	HT
pH - Field	8.35	units	NA	SM 4500 H+ B	2 Nov 20 13:52	DJN
Temperature - Field	19.0	Degrees C	NA	SM 2550B	2 Nov 20 13:52	DJN
Total Alkalinity	393	mg/l CaCO3	20	SM2320B-11	3 Nov 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	3 Nov 20 17:00	HT
Bicarbonate	393	mg/l CaCO3	20	SM2320B-11	3 Nov 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	3 Nov 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	3 Nov 20 17:00	HT
Conductivity - Field	24178	umhos/cm	1	EPA 120.1	2 Nov 20 13:52	DJN
Total Organic Carbon	889	mg/l	0.5	SM5310C-11	11 Nov 20 23:56	NAS
Sulfate	1110	mg/l	5.00	ASTM D516-11	6 Nov 20 10:02	SD
Chloride	9520	mg/l	2.0	SM4500-Cl-E-11	4 Nov 20 8:37	EV
Nitrate-Nitrite as N	< 1 @	mg/l	0.20	EPA 353.2	5 Nov 20 10:12	EV
Ammonia-Nitrogen as N	37.1	mg/l	0.20	EPA 350.1	10 Nov 20 11:46	SD
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	6 Nov 20 13:06	MDE
Total Dissolved Solids	15600	mg/l	10	USGS I1750-85	4 Nov 20 9:30	HT
Calcium - Total	516	mg/l	1.0	6010D	5 Nov 20 11:27	MDE
Magnesium - Total	34.6	mg/l	1.0	6010D	5 Nov 20 11:27	MDE
Sodium - Total	5130	mg/l	1.0	6010D	5 Nov 20 11:27	MDE
Potassium - Total	140	mg/l	1.0	6010D	5 Nov 20 11:27	MDE
Iron - Total	< 0.5 @	mg/l	0.10	6010D	11 Nov 20 10:12	MDE
Manganese - Total	< 0.25 @	mg/l	0.05	6010D	11 Nov 20 10:12	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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! = Due to sample quantity   + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 12 Nov 20
Lab Number: 20-W4390
Work Order #:82-3067
Account #: 021017
Date Sampled: 2 Nov 20 13:52
Date Received: 2 Nov 20 15:15
Sampled By: MVTL Field Services

Adam Dunlop
Midwest Ag Energy - Blue Flint
2841 3rd St SW
Underwood ND 58576

Project Name: MAG1

Sample Description: Inyan Kara Lower

PO #: CC#990-81100-002

Temp at Receipt: 5.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Strontium - Dissolved	21.4	mg/l	0.10	6010D	9 Nov 20 12:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	9 Nov 20 11:20	MDE
Barium - Dissolved	0.2619	mg/l	0.0020	6020B	9 Nov 20 11:20	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	9 Nov 20 11:20	MDE
Chromium - Dissolved	0.0020	mg/l	0.0020	6020B	9 Nov 20 11:20	MDE
Copper - Dissolved	0.0041	mg/l	0.0020	6020B	9 Nov 20 11:20	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	9 Nov 20 11:20	MDE
Molybdenum - Dissolved	0.0523	mg/l	0.0020	6020B	9 Nov 20 11:20	MDE
Selenium - Dissolved	< 0.01 ^	mg/l	0.0050	6020B	9 Nov 20 11:20	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	9 Nov 20 11:20	MDE

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
# = Due to concentration of other analytes
! = Due to sample quantity
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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15 North 23rd Street -- Stop 9018 / Grand Forks, ND 58202-9018 / Phone: (701) 777-5000 Fax: 777-5181
Web Site: www.undeerc.org

ANALYTICAL RESEARCH LAB - Final Results

July 20, 2022

Set Number: 55028
Fund#: 27026
PI: Ian Feole
Contact Person: Ian Feole

Request Date: Tuesday, June 7, 2022
Due Date: Tuesday, June 21, 2022
Set Description: Midwest AgEnergy - MAG-1 Broom Creek Formation Water

Sample	Parameter	Result	
55028-01	**MAG-1 Broom Creek 6/4/22**		
	Alkalinity, as Bicarbonate (HCO3-)	249	mg/L
	Alkalinity, as Carbonate (CO3=)	0	mg/L
	Alkalinity, as Hydroxide (OH-)	0	mg/L
	Alkalinity, Total as CaCO3	204	mg/L
	Bromide	21.8	mg/L
	Calcium	823	mg/L
	Chloride	11600	mg/L
	Conductivity at 25°C	39900	µS/cm
	Density	1.02	g/mL
	Magnesium	187	mg/L
	pH	7.48	
	Potassium	90.9	mg/L
	Sodium	9020	mg/L
	Strontium	18.4	mg/L
	Sulfate	7350	mg/L
	Total Dissolved Solids	28600	mg/L

Distribution ____________________ Date __________

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Member ACIL

Account #: 74217 **Client:** Neset Consulting
Workorder: Mag #1 (1427)

Jean Datahan
Neset Consulting
6844 Hwy 40
Tioga, ND 58852

Certificate of Analysis

Approval

All data reported has been reviewed and approved by:

C. Carroll

Claudette Carroll, Lab Manager Bismarck, ND

Analyses performed under Minnesota Department of Health Accreditation conforms to the current TNI standards.

NEW ULM LAB CERTIFICATIONS:
MN LAB # 027-015-125 ND WW/DW # R-040

BISMARCK LAB CERTIFICATIONS:
MN LAB # 038-999-267 ND W/DW # ND-016 SD SDWA

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Account #: 74217 **Client:** Neset Consulting

Workorder Summary

Workorder Comments

All analytes with dilution factors greater than 1 (displayed in DF column) required dilution due to matrix or high concentration of target analyte unless otherwise noted and reporting limits (RDL column) have been adjusted accordingly.

Workorder amended (project name). 14 Jul 22

Sample Comments

1427001 (Broom Creek) - Sample

Temperature received outside of the 0 - 6 °C range specified by EPA requirements. Client has authorized MVTL to proceed with analysis through direct communication or authorization letter retained on file with customer service.

Task Comments

1427001 - 618013 - GENb/346

Sample required dilution due to matrix. Reporting limit has been raised.

Analysis Results Comments

1427001 (Broom Creek)

The reporting limit for this analyte has been raised to account for the reporting limit verification standard.
(Copper, Dissolved)

1427001 (Broom Creek)

Sample required dilution due to matrix. Reporting limit has been raised.
(Nitrate + Nitrite as N)

1427001 (Broom Creek)

Sample analyzed beyond holding time.(pH)

Account #: 74217   Client: Neset Consulting

Analytical Results

Lab ID:	1427001	**Date Collected:**	06/04/2022 13:40	**Matrix:**	Groundwater
Sample ID:	Broom Creek	**Date Received:**	06/06/2022 08:00	**Collector:**	MVTL Field Service

Temp @ Receipt (C): 26.6   **Received on Ice:** Yes

Calculated

Method: SM1030F

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Cation Summation	**463**	meq/L		1	07/14/2022 15:43	07/14/2022 15:43	CW		
Anion Summation	**557**	meq/L		1	07/14/2022 15:43	07/14/2022 15:43	CW		
Percent Difference	**-9.20**	%		1	07/14/2022 15:43	07/14/2022 15:43	CW		

Inorganic Chemistry

Method: ASTM D516-11

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Sulfate	**7940**	mg/L	250	50	06/10/2022 11:25	06/10/2022 11:25	EJV	MA,NDA	

Method: EPA 350.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Ammonia as N	**14.5**	mg/L	0.2	2	06/07/2022 15:37	06/07/2022 15:37	EMS		

Method: EPA 353.2

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Nitrate + Nitrite as N	<2	mg/L	2	10	06/09/2022 09:27	06/09/2022 09:27	EJV	MA,NDA	*

Method: SM 5310C-2014

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Total Organic Carbon	**89.8**	mg/L	0.5	500	06/14/2022 08:48	06/14/2022 08:48	NS	MA,NDA	

Method: SM2320 B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Alkalinity, Total	**176**	mg/L as CaCO3	20.5	1	06/08/2022 15:21	06/08/2022 15:21	RAA	MA,NDA	
Alkalinity, Phenolphthalein	<20.5	mg/L as CaCO3	20.5	1	06/08/2022 15:21	06/08/2022 15:21	RAA		
Carbonate	<20.5	mg/L as CaCO3	20.5	1	06/08/2022 15:21	06/08/2022 15:21	RAA		
Bicarbonate	**176**	mg/L as CaCO3	20.5	1	06/08/2022 15:21	06/08/2022 15:21	RAA		
Hydroxide	<20.5	mg/L as CaCO3	20.5	1	06/08/2022 15:21	06/08/2022 15:21	RAA		

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www.MVTL.com

Member ACIL

Account #: 74217 Client: Neset Consulting

Analytical Results

Lab ID:	1427001	**Date Collected:**	06/04/2022 13:40	**Matrix:**	Groundwater
Sample ID:	Broom Creek	**Date Received:**	06/06/2022 08:00	**Collector:**	MVTL Field Service

Temp @ Receipt (C): 26.6 **Received on Ice:** Yes

Inorganic Chemistry

Method: SM2510 B-2011 EC

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Specific Conductance	**34490**	umhos/cm	1	1	06/06/2022 18:31	06/06/2022 18:31	AMC	MA,NDA	

Method: SM4500 H+ B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
pH	**7.6**	units	0.1	1	06/08/2022 15:21	06/08/2022 15:21	RAA	MA,NDA	*

Method: SM4500-Cl-E 2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Chloride	**13800**	mg/L	200	100	06/09/2022 17:05	06/09/2022 17:05	EJV	MA,NDA	

Method: USGS I-1750-85

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Total Dissolved Solids	**28700**	mg/L	10	1	06/07/2022 15:49	06/07/2022 15:49	AMC	MA,NDA	

Metals

Method: EPA 245.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Mercury, Dissolved	<0.0002	mg/L	0.0002	1	06/24/2022 11:00	06/28/2022 09:00	MDE	MA,NDA	

Method: EPA 6010D

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Calcium	**937**	mg/L	10	10	06/06/2022 17:20	06/23/2022 12:06	SLZ	MA,NDA	
Magnesium	**197**	mg/L	10	10	06/06/2022 17:20	06/23/2022 12:06	SLZ	MA,NDA	
Sodium	**9080**	mg/L	50	50	06/06/2022 17:20	06/23/2022 12:13	SLZ	MA,NDA	
Potassium	**110**	mg/L	10	10	06/06/2022 17:20	06/23/2022 12:06	SLZ	MA,NDA	
Iron	**33.8**	mg/L	1	10	06/06/2022 17:20	06/09/2022 14:46	SLZ	MA,NDA	
Manganese	<0.5	mg/L	0.5	10	06/06/2022 17:20	06/09/2022 14:46	SLZ	MA,NDA	
Barium, Dissolved	<1	mg/L	1	10	06/06/2022 17:20	06/09/2022 14:44	SLZ	MA,NDA	
Strontium, Dissolved	**17.0**	mg/L	1	10	06/06/2022 17:20	06/09/2022 14:44	SLZ	MA,NDA	

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

Account #: 74217 **Client:** Neset Consulting

Analytical Results

Lab ID:	1427001	**Date Collected:**	06/04/2022 13:40	**Matrix:**	Groundwater
Sample ID:	Broom Creek	**Date Received:**	06/06/2022 08:00	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	26.6	**Received on Ice:**	Yes		

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Arsenic, Dissolved	<0.008	mg/L	0.008	20	06/06/2022 17:20	07/06/2022 13:59	MDE	MA,NDA	
Chromium, Dissolved	**0.0085**	mg/L	0.008	20	06/06/2022 17:20	07/06/2022 13:59	MDE	MA,NDA	
Lead, Dissolved	<0.002	mg/L	0.002	20	06/06/2022 17:20	07/06/2022 13:59	MDE	MA,NDA	
Selenium, Dissolved	<0.02	mg/L	0.02	20	06/06/2022 17:20	07/06/2022 13:59	MDE	MA,NDA	
Silver, Dissolved	<0.002	mg/L	0.002	20	06/06/2022 17:20	07/06/2022 13:59	MDE	MA,NDA	
Cadmium, Dissolved	<0.002	mg/L	0.002	20	06/06/2022 17:20	07/06/2022 13:59	MDE	MA,NDA	
Molybdenum, Dissolved	**1.010**	mg/L	0.008	20	06/06/2022 17:20	07/06/2022 13:59	MDE	MA,NDA	
Copper, Dissolved	<0.008	mg/L	0.008	20	06/06/2022 17:20	07/06/2022 13:59	MDE	MA,NDA	*

Sampling Information

Method: 120.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Specific Conductance - Field	**35976**	umhos/cm	1	1	06/04/2022 13:40	06/04/2022 13:40	JSM		

Method: 150.2

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
pH - Field	**7.36**	units	0.01	1	06/04/2022 13:40	06/04/2022 13:40	JSM		

Method: 170.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Temperature - Field C	**31.21**	degrees C		1	06/04/2022 13:40	06/04/2022 13:40	JSM		

Method: SM2110

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Appearance - Field	Slightly Turbid			1	06/04/2022 13:40	06/04/2022 13:40	JSM		

Minnesota Valley Testing Laboratories
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Neset Consulting
WO: 1427

Chain of Custody Record

Report To:	**Neset Consulting**	CC:	Project Name: May #1
Attn:	Jean Datahan		Event:
Address:	6844 Hwy 40 Tioga, ND 58852		Sampled By: Jerry [signature]
Phone:	701-664-1492		
Email:	jeandatahan@nestconsulting.com		

	Sample Information				Sample Containers										Field Readings				
Lab Number	Sample ID	Date	Time	Sample Type	1 Liter Raw	500 mL HNO3	500 mL HNO3 (filtered)	250 mL H2SO4		TOC (set of 3)					Temp (°C)	Spec. Cond.	pH	Appearance	Analysis Required
001	Broom Creek	4 Jun 22	1340	GW	X	X	X	X		X					31.21	35,976	7.36	ST	Neset GW well List

Comments:

ST = Slightly Turbid

Relinquished By		Sample Condition		Received By	
Name	Date/Time	Location	Temp (°C)	Name	Date/Time
1 [signature]	4 June 22 1520	Log In Walk In #2	ROI 26.6 TM562 / TM805	[signature]	6 Jun 22 0800
2					

APPENDIX B

HISTORIC FRESHWATER WELL FLUID SAMPLING

HISTORIC FRESHWATER WELL FLUID SAMPLING

The Falkirk Mining Company (FMC), a wholly owned subsidiary of North American Coal Corporation, has implemented a shallow groundwater monitoring program since the 1970s as part of its operations at the Falkirk Mine. The shallow groundwater monitoring program has established baselines of water quality for many of the freshwater aquifer systems within the Blue Flint CO_2 storage project AOR.

Hundreds of shallow groundwater wells (monitoring sites) have been drilled to date over the >50,000 acres leased to FMC. Each of the monitoring sites is tested annually to assess groundwater quality in the area. The monitoring sites sample from either surficial glacial aquifers of the Coleharbor Group (Pleistocene) or water-bearing coalbed (lignite) horizons of the Sentinel Butte and Bullion Creek Formations of the Fort Union Group (Paleocene) (U.S. Bureau of Land Management, 2017). Figure B-1 summarizes the stratigraphy and identifies which freshwater aquifers are present and under surveillance in the Underwood area.

ERATHEM	SYSTEM		SERIES	ROCK UNIT: GROUP	ROCK UNIT: FORMATION	FRESHWATER AQUIFER(S) PRESENT	FRESHWATER AQUIFER NAMES
CENOZOIC	Quaternary		Holocene		Oahe	No	
			Pleistocene	Coleharbor	"Glacial Drift"	Yes	Weller Slough and Turtle Lake
	Tertiary	Paleogene	Eocene		Golden Valley	No	
			Paleocene	Fort Union	Sentinel Butte	Yes	Hagel A and B coal beds and C sand
					Tongue River – Bullion Creek	Yes	Tavis Creek and Coal Lake Coulee coal beds and Hensler sand
					Tongue River – Slope	No	
					Cannonball	Yes	
					Ludlow	Yes	
MESOZOIC	Cretaceous		Upper	Montana	Hell Creek	Yes	
					Fox Hills	Yes	
					Pierre	No	

Figure B-1. Stratigraphic column showing the shallow subsurface geologic units and freshwater aquifer systems for the region in and around Underwood, North Dakota. Major freshwater aquifer systems under FMC's surveillance are indicated at far right (modified from Murphy and others [2009]).

Table B-1 summarizes the ranges of pH, electrical conductivity (EC), total dissolved solids (TDS), and total alkalinity measured from 15 active monitoring sites within the AOR. Figure B-2 is a map showing the locations of the selected monitoring sites. Monitoring sites were selected to establish baseline conditions for the Blue Flint CO_2 storage project if the wells 1) are operated by FMC, 2) have multiple years of recent (i.e., 2015 or later) geochemical results available, 3) and fall within a mile of the AOR.

The groundwater wells were drilled no more than 150 ft below ground surface and were perforated or screened along a 5–20-ft zone for sampling the horizons of interest. Groundwater wells represented in Table B-1 each have a minimum of four water chemistry samples collected and a maximum of seven. All water chemistries were determined by MVTL.

Table B-1. Summary of Water Chemistries at 15 Monitoring Sites in the AOR

Number of Wells	Water Samples	Data Vintage	Sampling Horizon	pH	EC, mS/cm	TDS, mg/L	Total Alkalinity, mg/L $CaCO_3$
3	19	2015–2021	Spoils	7.0–8.3	1,958–3,632	1,290–2,610	549–1,370
2	13	2015–2021	Sheet Sand	6.1–6.9	1,458–2,628	991–1,960	282–887
2	11	2015–2021	Coleharbor	6.7–7.6	1,673–2,210	1,130–1,670	399–496
1	7	2015–2021	Hagel A	6.4–6.8	1,496–1,819	1,010–1,400	360–388
1	7	2015–2021	Hagel A&B	5.9–6.2	2,538–3,560	2,040–3,070	261–278
3	21	2015–2021	Hagel B	6.2–7.5	1,329–2,013	830–1,450	270–443
1	5	2017–2021	C Sand	8.2–8.4	2,323–2,362	1,440–1,950	999–1,240
2	14	2015–2021	Tavis Creek	7.0–8.4	2,215–2,367	1,330–2,020	524–1,260

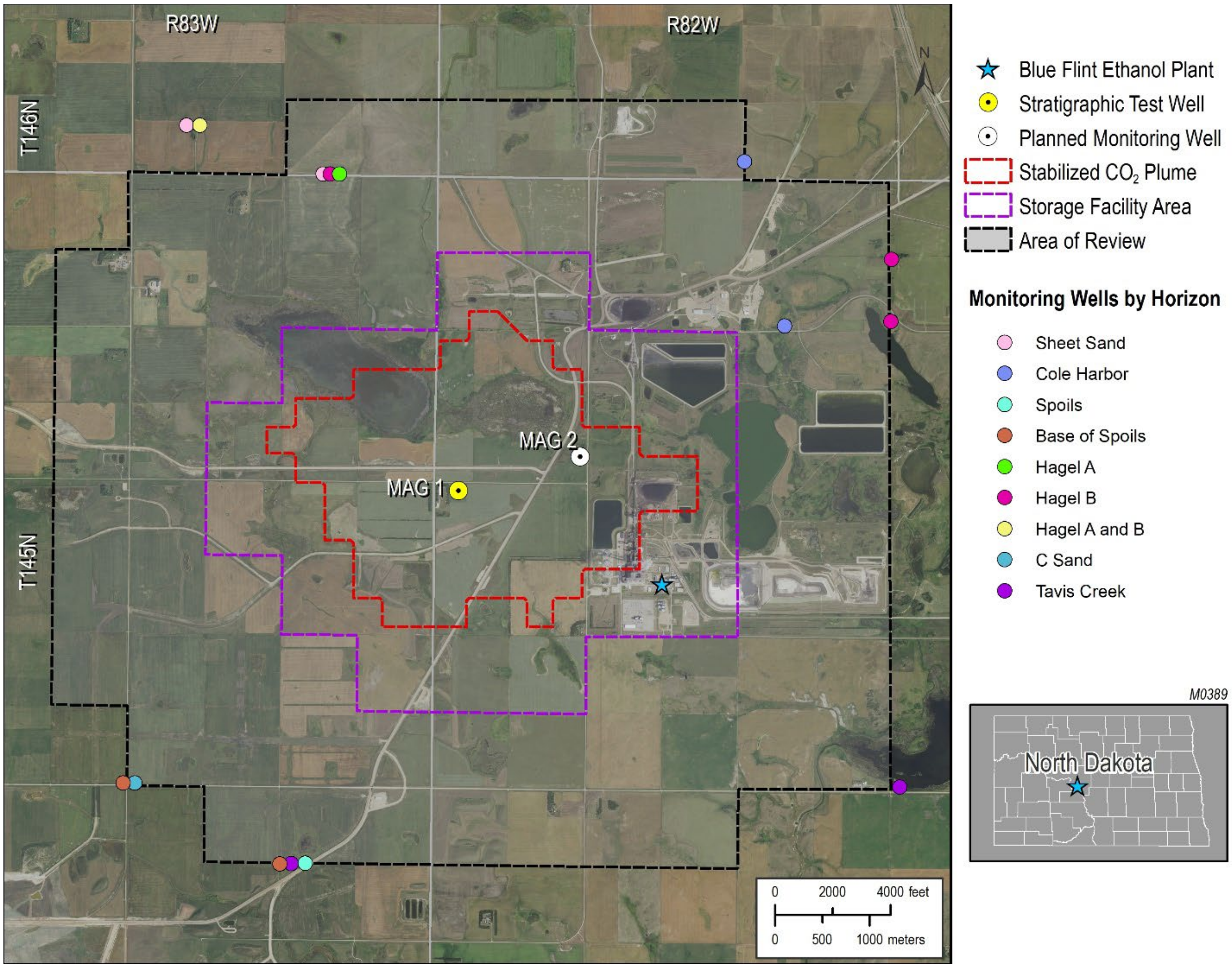

Figure B-2. Locations of the 15 monitoring sites operated by FMC with multiple years of recent (i.e., 2015 or later) water chemistry results available.

REFERENCES

Murphy, E.C., Nordeng, S.H., Juenker, B.J., and Hoganson, J.W., 2009, North Dakota stratigraphic column: North Dakota Geological Survey Miscellaneous Series 91.

U.S. Department of the Interior Bureau of Land Management, 2017, Environmental assessment DOI-BLM-MT-C030-2016-0020-EA: The Falkirk Mining Company Federal Coal Lease by Application, Dickinson, North Dakota, 121 p.

APPENDIX C

QUALITY ASSURANCE SURVEILLANCE PLAN

C1.0 QUALITY ASSURANCE AND SURVEILLANCE PLAN

The primary goal of the testing and monitoring plan (Section 5) of this storage facility permit application is to ensure that the geologic storage project is operating as permitted and is not endangering USDWs. In compliance with NDAC § 43-05-01-11.4 (Testing and Monitoring Requirements), this quality assurance and surveillance plan (QASP) was developed and is provided as part of the testing and monitoring plan.

C1.1 CO_2 Stream Analysis

NDAC § 43-05-01-11.4(1)(a) requires analysis of the CO_2 stream in compliance with applicable analytical methods and standards generally accepted by industry and with sufficient frequency to yield data representative of its chemical and physical characteristics. Blue Flint will collect samples of the injected CO_2 stream quarterly at the liquefaction outlet and analyze the CO_2 stream to determine the concentrations of CO_2, nitrogen, oxygen, hydrogen, water, hydrogen sulfide, carbon monoxide, and a suite of hydrocarbons (e.g., ethane, propane, n-butane, and methane) via a third party. Selected stable isotopes (i.e., isotopes of carbon dioxide [^{12}C and ^{13}C], methane [^{12}C and ^{13}C], and deuterium [^{2}H]) will also be sampled in the first year to establish a baseline. The isotopic analyses will be outsourced to commercial laboratories that will employ standard analytical QA/QC protocols used in the industry.

C1.2 Surface Facilities Leak Detection Plan

The surface leak detection and monitoring plan is outlined in Section 5.2. The SCADA system (described in Attachment A-1) will continuously monitor surface facilities operations in real time and be equipped with automated alarms that will notify the Blue Flint operations center in the event of an anomalous reading. A generalized specification sheet for the CO_2 detection stations (see Attachment A-2) will monitor CO_2 levels at each wellsite to ensure workspace atmospheres are safe.

C1.3 Corrosion Monitoring and Prevention Plan

C1.3.1 Corrosion Monitoring

The flow line will use the corrosion coupon method to monitor for corrosion in the flow line and injection wellbore throughout the operational phase of the project, focusing on loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. The coupon sample port will be located near the liquefaction outlet, and sampling will occur quarterly during the first year of injection and once a year thereafter.

The process that will be used to conduct each coupon test is described below.

C1.3.1.1 Sample Description

Corrosion coupons that are representative of the construction materials of the flowline and injection well that contact the CO_2 stream will be tested. Materials from these process components and/or conventional corrosion coupons of similar composition and specifications will be weighed, measured, and photographed prior to initial exposure.

C1.3.1.2 Sample Exposure

Each sample will be suspended in a flow-through apparatus, which will be located downstream of all processes (i.e., at the liquefaction outlet which connects to the start of the flowline). A parallel stream of high-pressure CO_2 will be withdrawn from the flowline, passed through the flow-through apparatus, and then routed back into a lower-pressure point upstream in the compression system. This loop will operate any time injection is occurring. The operation of this system will provide exposure of the samples to CO_2 representative of the composition, temperature, and pressures that will be present along the flowline, at the wellhead, and in the injection tubing.

C1.3.1.3 Sample Handling and Monitoring

The exposed materials/coupons will be handled and assessed for corrosion in accordance with either National Association of Colleges and Employers (NACE) Standard SP0775—Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations—(2018) or American Society for Testing Materials (ASTM) International Method G1-03—Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens—(2017) to determine and document corrosion rates based on mass loss. The coupons will be photographed, visually inspected for cracking and pitting with a minimum of 10× power, dimensionally measured (to within 25.4 micrometers), and weighed (to within 0.0001 gram).

C1.3.2 Corrosion Prevention

The corrosion prevention plan for the surface facilities and the wellbores is outlined in Sections 5.3.1 and 5.6, respectively. Attachment A-3 describes the specifications of the FlexSteel flowline. The wellbore designs, which show what corrosion-resistant materials will be used in the MAG 1 and MAG 2 wells, are shown in Section 9, Figures 9-1 and 9-3, respectively.

C1.4 Wellbore Mechanical Integrity Testing Plan

The plan for mechanical integrity testing of the CO_2 injection well and deep monitoring well can be found in Section 5.4 of this application. The specification sheet for the USIT is provided in Attachment A-4. Blue Flint will select third parties to perform logging and testing specified in the testing and monitoring plan. Blue Flint will also ensure that third parties apply proper QA/QC protocols to the tools to ensure their effectiveness and functionality and that all well testing procedures follow industry standards.

C1.5 Near-Surface Soil Gas and Groundwater Monitoring

Near-surface sampling discussed herein comprises 1) sampling of soil gas in the shallow vadose zone and 2) sampling groundwater aquifers (to the lowest USDW). Sampling and chemical analysis of these zones will provide concentrations of chemical constituents, including stable and radiogenic carbon isotopes to detect movement of the CO_2 out of the reservoir. These monitoring efforts will provide data to confirm that near-surface environments are not adversely impacted by CO_2 injection and storage operations.

C1.5.1 Soil Gas

Vadose zone soil gas monitoring directly measures the characteristics of the air space between soil components and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. A total of five semi-permanent soil gas locations will be sampled in the

SFA (as shown in Figure 5-5) to establish baseline conditions. Figure C-1 illustrates the schematic for the semi-permanent soil gas probes that will be used to collect baseline data.

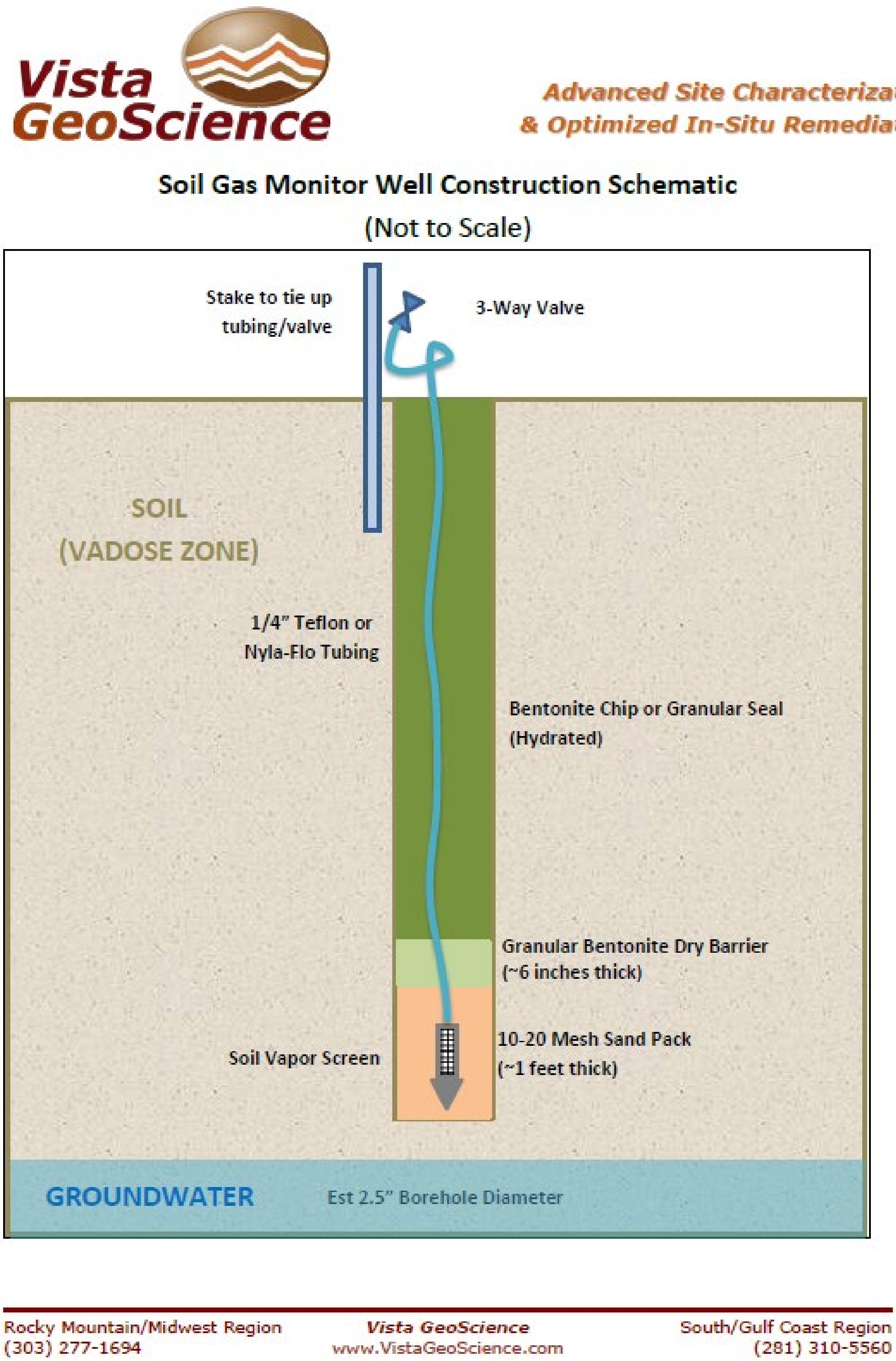

Figure C-1. Well schematic of the soil gas probe locations.

C1.5.1.1 Soil Gas-Sampling and Analysis Protocol

Section 5.7.2 of this application outlines the sampling plan for soil gas. Tables C-1 and C-2 indicate the analytes planned to be included in each soil gas analysis.

Blue Flint will select North Dakota service providers to install semi-permanent soil gas probe locations and soil gas profile stations, as well as sample soil gas and analyze all soil gas data. All soil gas samples are expected to be collected using a Post Run Tubing (PRT) sampling system from a projected target depth interval. Each location will be purged using a Landtec GEM 2000 or 5000 model equivalent. Field technicians will monitor and record O_2, CH_4, CO_2, and H_2S readings while purging each location. The purging of each location should continue until either an estimated three system volumes have been purged or until readings have stabilized. The samples will then be collected in sample bags. A duplicate pair of samples should be collected from one of the soil gas sampling locations, and a pair of ambient air "sample blank" samples should be collected from each location as well. After all samples have been collected, the samples will be shipped or delivered to a commercial laboratory in North Dakota for analysis.

C1.5.1.2 QA/QC Procedures

Commercial laboratories selected for the performing the chemical analyses on the soil gas samples will employ standard analytical QA/QC protocols used in the industry.

Table C-1. Soil Gas Analytes Identified with Field and Laboratory Instruments

Landtec GEM 2000 or 5000
Analyte
CO_2
O_2
H_2S
CH_4

Table C-2. Isotope Measurements of Soil Gas Samples

Isotope	Units
$\delta^{13}C$ of CO_2*	‰ (per mil)
$\delta^{13}C$ of CH_4*	‰ (per mil)
δD of CH_4*	‰ (per mil)

* Only measured if high enough concentration detected.

C1.5.2 Groundwater/USDW

Section 5.7.2 of this application describes the plan for monitoring groundwater (to the lowest USDW). The sampling procedure that Minnesota Valley Testing Laboratories (MVTL) (Bismarck, North Dakota) will utilize is described below.

C1.5.2.1 Groundwater-Sampling and Analysis Protocol

Baseline Groundwater Wells (five groundwater wells within 1 mile of the AOR and a dedicated Fox Hills monitoring well near the MAG 1 location)
Groundwater samples will be collected by MVTL from these wells using the wells' submersible pumps. MVTL will apply the following standard procedure for sampling the wells:

1. Determine the use of the well prior to sample collection (e.g., domestic, livestock, irrigation, municipal).

2. Purge the well using a measured bucket to determine the pumping rate when the valve is fully open.

    a. The longer the well has not been in use, the longer the well will need to be purged before sample collection. Purge time will also depend on the total depth of the well.

    b. For wells used daily, purge the well for 1–2 minutes. For wells used on a seasonal basis, such as livestock or irrigation, purge the well for 15 minutes, or longer if the well is over 100 feet deep. If the well has not been in use in the past year, three well volumes may need to be removed to ensure a freshwater sample can be collected.

3. Collect the sample.

    a. Once the well has been sufficiently purged, sample collection can proceed.
    b. Record the location of the sample point.
    c. Record the pumping rate and volume purged.
    d. Collect field readings: temperature, conductivity, and pH.
    e. Fill appropriate sample containers for analysis.

Two laboratories will be used to analyze the water samples: 1) MVTL will analyze samples for general parameters, anions, cations, metals (dissolved and total), and nonmetals (Tables C-3 and C-4); and 2) Blue Flint will select another North Dakota commercial laboratory for analyzing samples for stable isotopes (Table C-5).

Table C-3. Measurements of General Parameters for Groundwater Samples

Parameter	Method
pH	SM[1]4500-H+-B-11
Conductivity	SM2510B-11
Alkalinity	SM 2320B
Temperature	SM2550B
Total Dissolved Solids	SM 2540C
Total Inorganic Carbon	EPA[2] 9060
Dissolved Inorganic Carbon (DIC)	EPA 9060
Total Organic Carbon	SM 5310B
Dissolved Organic Carbon	SM 5310B
Total Mercury	EPA 7470A
Dissolved Mercury	EPA 245.2
Total Metals[3] (26 metals)	EPA 6010B/6020
Dissolved Metals[3] (26 metals)	EPA 200.7/200.8
Bromide	EPA 300.0
Chloride	EPA 300.0
Fluoride	EPA 300.0
Sulfate	EPA 300.0
Nitrite	EPA 353.2

[1] Standard method
[2] U.S. Environmental Protection Agency.
[3] See Table B-2 for entire sampling list of total and dissolved metals.

Table C-4. Total and Dissolved Metals and Cation Measurements for Groundwater Samples

Metals	Major Cations	Trace Metals
Antimony	Barium	Aluminum
Arsenic	Boron	Cobalt
Beryllium	Calcium	Lithium
Cadmium	Iron	Molybdenum
Chromium	Magnesium	Vanadium
Copper	Manganese	
Lead	Potassium	
Mercury	Silicon	
Nickel	Sodium	
Selenium	Strontium	
Silver	Phosphorus	
Thallium		
Zinc		

Table C-5. Stable Isotope Measurements and Dissolved Gases in Groundwater

Isotope	Units
δD H_2O	‰ (per mil)
$\delta^{18}O$ H_2O	‰ (per mil)
$\delta^{13}C$ DIC	‰ (per mil)
$\delta^{13}C$ Methane (if present)	‰ (per mil)
$\delta^{13}C$ Ethane (if present)	‰ (per mil)
$\delta^{13}C$ Propane (if present)	‰ (per mil)
δD Methane (if present)	‰ (per mil)
$\delta^{13}C$ CO_2 (if present)	‰ (per mil)

C1.5.2.2 Quality Assurance/Quality Control

Groundwater Wells

The laboratory analyses will be performed in accordance with the commercial laboratories' internal QA/QC procedures (e.g., Table C-3 and www.mvtl.com/QualityAssurance). In addition, duplicate samples will be taken to assess the combined accuracy of the field sampling and laboratory analysis methods. These duplicate samples will be collected at the same time and location for each of the groundwater wells.

C1.6 Storage Reservoir Monitoring

Monitoring of the storage reservoir during the injection operation includes monitoring with direct and indirect methods, as described in Section 5.7 of this application. Direct methods include monitoring: the injection flow rates and volumes; wellhead injection temperature and pressure; bottomhole injection pressure and temperature; saturation profile from the storage reservoir to the AZMI; and the tubing–casing annulus pressure or casing pressure. Indirect methods include time-lapse 2D seismic surveys and passive seismicity monitoring.

C1.6.1 Direct Methods

C1.6.1.1 Wireline Logging and Retrievable Monitoring

The wireline logging and retrievable monitoring that will be performed comprise PNLs, which include temperature and pressure data, ultrasonic logs, injection zone pressure falloff tests, and corrosion/wellbore integrity monitoring. The information provided by these monitoring efforts is as follows:

- USIT (described in Attachment A-4) or alternative casing inspection logging provides an assessment of the mechanical integrity and assessment of corrosion of the wellbore.

- PNL (example in Attachment A-5) provides information regarding gas saturation in the formations, which can be used to determine if the injected CO_2 is contained within the storage formation as well as ground truth information provided by the seismic surveys.

- Pressure falloff tests provide an assessment of the storage reservoir injectivity.

All wireline logging events will follow API (American Petroleum Institute) guidelines along with the standard operating procedures of a third-party wireline operator. More details regarding each of these monitoring techniques are provided below.

Ultrasonic Imaging Tool

The USIT indicates the quality of the cement bond at the cement–casing interface and provides casing inspection (corrosion detection, monitoring, and casing thickness analysis). The tool is deployed on wireline with a transmitter emitting ultrasonic pulses and measuring the reflected ultrasonic waveforms received from the internal and external casing interfaces. The entire circumference of the casing is scanned, enabling the evaluation of the radial cement bond and the detection of internal and external casing damage or deformation. The high angular and vertical tool resolutions can detect cement channels as narrow as 1.2 inches. Detailed measurement and mechanical specifications for the USIT tool are provided in Attachment A-4. The wireline operator will provide QA/QC procedures and tool calibration for this equipment.

Pulsed-Neutron Logs

PNLs provide formation evaluation and reservoir monitoring in cased holes. PNL is deployed as a wireline logging tool with an electronic pulsed-neutron source and one or more detectors that typically measure neutrons or GRs (Rose and others, 2015). High-speed digital signal electronics process the GR response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the GR energy and time relationship into concentrations of elements (Schlumberger, 2017).

Detection limits for CO_2 saturation for PNL tools vary with the logging speed as well as the formation porosity. Blue Flint plans to select a PNL service provider and tool and ensure the wireline operator provides QA/QC procedures and tool calibration for their equipment.

Description of Regular PNL Protocol

After the drilling and before CO_2 injection, a PNL will be run in the injection well and deep monitoring well to provide a baseline to which future PNL runs will be compared.

The following general procedure will be followed when running a PNL in the injection well and deep monitoring well:

1. Hold a safety meeting and ensure that all personnel are wearing proper PPE:
   a. Rig up PPE.
   b. Ensure that all safety precautions are taken.

2. Shut well in by closing the outside wing valve and upper master valve.

3. Rig up lubricator, and pressure-test connections and seals to 2000 pounds per square inch.

4. Open crown valve.

5. Open top master valve and proceed downhole to the injection packer with the PNL tool.

6. Make a 30-minute stop at the bottom of the hole and record a static BHP.

7. Proceed with running the PNL, making stops every 500 feet for five minutes each to record a static fluid pressure.

8. Once the logging tool is at the surface and in the lubricator, make a 5-minute stop to record the surface pressure in the tubing.

9. Close the crown valve and top master valve. Bleed pressure from the tree and lubricator.

10. Remove lubricator and replace the top cap and pressure gauge.

11. Open the top master valve, and again record the tubing and annular pressures.

12. Rig down the wireline company and clean the location.

13. Return the well to injection service by opening the outside wing valve.

<u>Injection Zone Pressure Falloff Test</u>
The injection zone pressure falloff test will be performed in the injection well prior to initiation of CO_2 injection activities and at least once every 5 years thereafter to demonstrate storage reservoir injectivity. Pressure data will be recorded during the pressure falloff test at the bottomhole.

C1.6.2 Indirect Monitoring Methods
The indirect monitoring that is planned for the project includes time-lapse seismic surveys and passive seismicity monitoring. This indirect monitoring method will characterize attributes associated with the injected CO_2, including plume extents, mass changes, pressure changes, and potential seismicity. Details regarding the application and quality of this method are provided in the remainder of this section:

C1.6.2.1 Time-Lapse Seismic Surveys
Application of time-lapse seismic surveys for monitoring changes in acoustic properties requires a quality preoperational seismic survey for baseline conditions. The monitor survey should be repeated as closely to the baseline conditions and parameters as possible. The seismic monitor data should be reprocessed simultaneously with the original baseline data or processed with the same steps and workflow to ensure repeatability. Repeatability is a measure of 4D seismic quality (Lumley and others, 1997, 2000) that can be quantified once the processed data are analyzed by an experienced 4D seismic interpreter.

C1.6.2.2 Passive Seismic Recording
Continuous monitoring of seismic activity will include USGS seismometer stations already operating in North Dakota (Figure 5-7). Additional seismometer stations may be installed as needed. The distributed acoustic sensing (DAS) fiber optic systems installed on the injection well MAG 1 and the monitoring well MAG 2, capable of autonomously and continuously measuring a wide range of seismicity (micro/macro events) with the installation of additional seismometer stations, may be used to supplement passive seismicity monitoring efforts as needed.

C1.7 Completed Well Logging

The well testing and logging plan is described in Section 5.5 of this application. Several continuous measurements of the storage formation properties were either made in the MAG 1 wellbore or are planned for the MAG 2 wellbore using wireline-logging techniques.

All wireline logging companies who perform work for the Blue Flint CO_2 Storage Project will employ standard analytical QA/QC protocols used in the industry.

C1.8 References

ASTM International, 2017, ASTM G1-03(2017)e1, Standard practice for preparing, cleaning, and evaluating corrosion specimens: West Conshohocken, Pennsylvania, ASTM International, www.astm.org/g0001-03r17e01.html (accessed April 2022).

Lumley, D.E., Behrens, R.A., and Wang, Z., 1997, Assessing the technical risk of a 4-D seismic project: The Leading Edge, v. 16, p. 1287–1292, doi: 10.1190/1.1437784.

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Attachment A-1 – Supervisory Control and Data Acquisition (SCADA) System

The SCADA system is a computer-based system or systems used by personnel in a control room that aims to collect and display information about the Blue Flint CO_2 storage injection operations in real time. This supervisory system collects data at an assigned time interval and stores the data in the historian server. Using Blue Flint operator process control selections, the SCADA will have the ability to send commands and control the storage injection network (i.e., start or stop pumps, open or close valves, control process equipment remotely, etc.).

In addition to monitoring and control ability, the SCADA system will include warnings, both audible and visual, to alert the Blue Flint control room, which is staffed 24/7, of near or excessive violations of set parameters within the system.

Atachment A-2 – CO_2 Detection Station Overview

Honeywell

Sensepoint XCD SPECIFICATIONS

Flammable, toxic and oxygen gas detector for industrial applications

Use	3 wire, 4-20mA and RS485 MODBUS output fixed point detector with in-built alarm and fault relays for the protection of personnel and plant from flammable, toxic and Oxygen hazards. Incorporates a transmitter with local display and fully configurable via non-intrusive magnetic switch interface.
Electrical	
Input Voltage Range	12 to 32VDC (24VDC nominal)
Max Power Consumption	Maximum power consumption is dependent on the type of gas sensor being used. Electrochemical cells = 3.7W, IR = 3.7W and catalytic = 4.9W. Maximum inrush current = 800mA at 24VDC
Current Output **Relays**	Sink or source 3 x 5A@250VAC. Selectable normally open or normally closed (switch) and energized/de-energised (programmable) Alarm relays default normally open/de-energized. Fault relay default normally open/energized
Communication	RS485, MODBUS RTU
Construction	
Material	Housing: Epoxy painted aluminium alloy ADC12 or 316 stainless steel Sensor: 316 stainless steel
Weight (approx)	Aluminium Alloy LM25: 4.4lbs 316 Stainless Steel: 11lbs
Mounting	Integral mounting plate with 4 x mounting holes suitable for M8 bolts. Optional pipe mounting kit for horizontal or vertical pipe Ø1.5 to 3" (2" nominal)
Cable Entries	UL\cUL versions: 2 x ¾"NPT conduit entries. Suitable blanking plug supplied for use if only 1 entry used. Seal to maintain IP rating; ATEX/IECEx versions: 2 x M20 cable entries
Environmental	
IP Rating	IP66 in accordance with EN60529:1992
Certified Temperature Range	-40ºF to +149ºF (-40ºC to +65ºC)

Detectable Gases and XCD Sensor Performance

Gas	User Selectable Full Scale Range	Default Range	Steps	User Selectable Cal Gas Range	Default Cal Point	Response Time (T90) Secs	Accuracy	Operating Temperature Min	Operating Temperature Max	Default Alarm Points A1	Default Alarm Points A2
Electrochemical Sensors											
Oxygen	25.0%Vol. only	25.0%Vol.	n/a	20.9%Vol. (Fixed)	20.9%Vol.	<30	<±0.5%Vol.	-20°C / -4°F	55°C / 131°F	19.5%Vol. ▼	23.5%Vol. ▲
Hydrogen Sulfide*	10.0 to 100.0ppm	50.0ppm	0.1ppm	30 to 70% of selected full scale range	25ppm	<50	<±1ppm	-20°C / -4°F	55°C / 131°F	10ppm ▲	20ppm ▲
Carbon Monoxide**	100 to 1,000ppm	300ppm	100ppm		100ppm	<30	<±6ppm	-20°C / -4°F	55°C / 131°F	30ppm ▲	100ppm ▲
Hydrogen	1,000ppm only	1,000ppm	n/a		500ppm	<65	<±25ppm	-20°C / -4°F	55°C / 131°F	200ppm ▲	400ppm ▲
Nitrogen Dioxide***	10.0 to 50.0ppm	10.0ppm	5.0ppm		5.0ppm	<40	<±3ppm	-20°C / -4°F	55°C / 131°F	5.0ppm ▲	10.0ppm ▲
* Lowest Alarm Limit = 1ppm; Lowest Detection Limit = .5ppm ** Lowest Alarm Limit = 15 ppm; Lowest Detection Limit = 10ppm *** Lowest Alarm Limit = 0.6 ppm; Lowest Detection Limit = 0.3ppm											
Catalytic Bead Sensors											
Flammable 1 to 8	20.0 to 100.0%LEL	100%LEL	10%LEL		50%LEL	<25	<±1.5%LEL	-20°C / -4°F	55°C / 131°F	20%LEL ▲	40%LEL ▲
Infrared Sensors											
Methane	20.0 to 100.0%LEL	100%LEL	10%LEL		50%LEL	<30	<±1.5%LEL	-20°C / -4°F	50°C / 122°F	20%LEL ▲	40%LEL ▲
Propane	20 to 100%LEL	100%LEL	10%LEL		50%LEL	<30	<±1%LEL	-20°C / -4°F	50°C / 122°F	20%LEL ▲	40%LEL ▲
Carbon Dioxide	2%Vol. only	2%Vol.	n/a		1%Vol.	<30	<±0.04%Vol.	-20°C / -4°F	50°C / 122°F	0.4%Vol. ▲	0.8%Vol. ▲

NOTE: For Cat Bead and Infrared sensors, Lowest Detectable Limit is 5% LEL and Lowest Alarm Level is 10% LEL.

▲ - Rising Alarm ▼ - Falling Alarm

Certification	
US, Latin America, Canada **European** **International**	UL/c-UL - Class I, Division 1, Groups B, C and D, Class I, Division 2, Groups B, C & D, Class II, Division 1, Groups E, F & G, Class II, Division 2, Groups F & G. -40°C to +65°C ATEX Ex II 2 GD Ex d IIC Gb T6 (Ta -40ºC to +65ºC) Ex tb IIIC T85°C Db IP66 IEC Ex d IIC Gb T6 (Ta -40ºC to +65ºC) Ex tb IIIC T85°C Db IP66
EMC	CE: EN50270:2006 EN6100-6-4:2007
Performance	UL508; CSA 22.2 No. 152 (flammable gasses, excludes infrared sensors); ATEX, IEC/EN60079-29-1:2007, EN45544, EN50104, EN50271; China: PA Pattern Measurement (for transmitter and toxic gas sensors) "CCCF" Shenyang for Flammable (fire dept approval)

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Please Note:

While every effort has been made to ensure accuracy in this publication, no responsibility can be accepted for errors or omissions. Data may change, as well as legislation, and you are strongly advised to obtain copies of the most recently issued regulations, standards, and guidelines. This publication is not intended to form the basis of a contract.

SS01082_v4 3/14

Attachment A-2. Measurement and mechanical specifications for Honeywell's CO_2 detection station.

Attachment A-3 – FlexSteel™ Overview

PRODUCT SHEET

FLEXSTEEL

FLEXSTEEL™ LINE PIPE

FlexSteel is the pipeline solution that couples the durability of steel with the installation, performance and cost benefits of spoolable pipe products. Highly corrosion resistant and more dependable than other pipeline solutions, FlexSteel combines the best features of all currently available line pipe options to deliver superior life cycle performance and value.

DURABLE BY DESIGN

Reinforced with a helically wound, steel-reinforced layer for structural integrity, FlexSteel line pipe performs where other pipeline solutions often fail. Durable enough to withstand pulsating and cyclic pressures, the system continues to perform to its original design specifications and will not derate over time.

APPLICATIONS

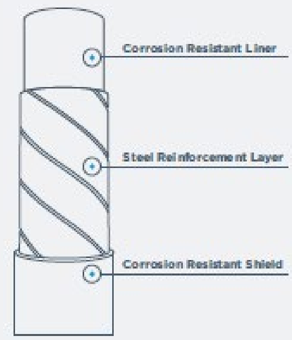
FlexSteel pipeline's unique characteristics make it the clear choice for increased safety and reliability in various environments and applications.

PRODUCTION LINES: FlexSteel is a smart investment that yields indisputable quality, safety, and performance advantages in multiphase, oil, and gas applications.

DISPOSAL LINES: Abrasion resistant and built to last, FlexSteel line pipe minimizes the risks associated with the transportation of highly corrosive produced water.

INJECTION LINES: Engineered to the highest quality standards, FlexSteel line pipe withstands pulsating and cyclic pressures often found in injection lines.

GATHERING LINES: Fast, easy, and cost effective installation coupled with extreme corrosion resistance make FlexSteel line pipe a natural choice for gathering pipelines.



2-INCH TO 8-INCH DIAMETER

Only 8-inch onshore spoolable pipeline with design pressures up to 3,000 psi.

CORROSION RESISTANT DESIGN

Designed to resist corrosion including microbiologically influenced corrosion (MIC).

BEST VALUE PIPELINE SOLUTION

Eliminates the need for expensive integrity management programs, and continuous maintenance services.

EXTREMEPERFORMANCEVALUEDURABILITY FLEXSTEELPIPE.COM

Attachment A-3. Measurement and mechanical specifications for FlexSteel's CO_2 flow line (continued).

Attachment A-3 – FlexSteel™ Overview (continued)

PRODUCT SHEET
US CUSTOMARY UNITS

FLEXSTEEL

	Nominal Size (in)	Nominal Pressure Rating (PSI)	Reel Pipe Length (ft)	Coil Pipe Length (ft)	Pipe Inside Diameter (in)	Pipe Outside Diameter (in)	Operating Bend Radius, OBR (ft)	Weight Empty in Air (lb/ft)	Specific Gravity	Minimum Burst Pressure (PSI)	OHTC, U (based on ID) (BTU/hr·ft²°F)	Maximum Installation Tension (lbf)
STANDARD PRODUCT	2	1,500	6,578	-	1.94	2.69	2.1	2.40	0.93	3,000	6.72	3,800
	2	2,250	4,462	-	1.94	2.85	2.2	3.53	1.23	4,500	6.91	10,500
	2	3,000	4,298	-	1.94	2.85	2.2	3.77	1.32	6,000	6.91	10,500
	3	750	4,560	-	2.82	3.65	2.8	3.53	0.74	1,500	5.75	8,000
	3	1,500	4,003	-	2.82	3.68	2.8	4.03	0.84	3,000	5.77	8,000
	3	2,250	2,871	-	2.82	3.81	2.9	5.46	1.06	4,500	5.86	9,000
	3	3,000	2,461	-	2.82	3.89	3.0	6.63	1.25	6,000	5.90	14,000
	4	750	3,264	-	3.67	4.58	3.5	4.76	0.63	1,500	5.08	8,000
	4	1,500	2,690	-	3.67	4.65	3.6	6.30	0.82	3,000	5.11	12,500
	4	2,250	1,821	-	3.67	4.81	3.7	8.79	1.08	4,500	5.17	20,000
	4	3,000	1,476	-	3.67	4.94	3.8	11.33	1.31	6,000	5.22	22,000
	6	750	1,230	2,543	5.60	6.89	5.3	9.52	0.56	1,500	3.67	20,000
	6	1,500	1,181	2,608	5.60	7.01	5.4	13.36	0.77	3,000	3.70	30,000
	6	2,250	837	1,509	5.60	7.17	5.5	18.34	1.02	4,500	3.73	30,000
	6	3,000	640	1,529	5.60	7.31	5.6	22.79	1.23	6,000	3.76	45,000
	8	750	607	-	7.63	9.19	7.1	15.87	0.53	1,500	2.97	30,000
	8	1,500	607	-	7.63	9.36	7.2	23.04	0.75	3,000	2.99	40,000
	8	2,250	459	-	7.63	9.58	7.4	32.11	1.01	4,500	3.02	45,000
MXL	8	750	-	1,260	7.25	8.77	6.8	15.85	0.58	1,500	3.18	25,000
	8	1,500	-	1,260	7.25	8.90	6.9	21.10	0.76	3,000	3.20	35,000
	8	2,250	-	1,260	7.25	9.12	7.0	29.52	1.02	4,500	3.22	40,000
	8	3,000	-	912	7.25	9.27	7.1	34.83	1.17	6,000	3.13	45,000

Standard Properties for All Pipe Sizes

Absolute Roughness, ε (ft)	5.0E-06 ft
Design Temperature (Water)	150°F
Design Temperature (Oil/Gas)	150°F

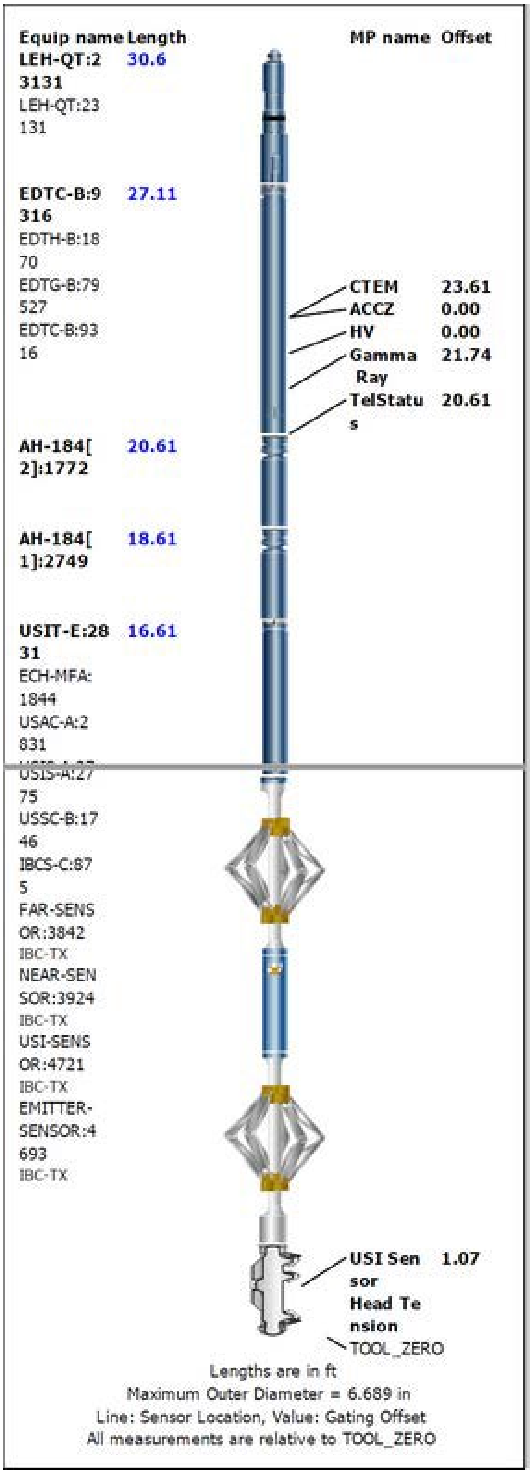
High-Temp Properties for All Pipe Sizes

Absolute Roughness, ε (ft)	5.0E-06 ft
Design Temperature (Water)	194°F
Design Temperature (Oil/Gas)	185°F

EXTREMEPERFORMANCEVALUEDURABILITY FLEXSTEELPIPE.COM

Attachment A-3 (continued). Measurement and mechanical specifications for FlexSteel's CO_2 flow line.

Attachment A-4 – Ultrasonic Imaging Tool (USIT)



Measurement Specifications

	Isolation Scanner Tool
Output†	Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image
Max. logging speed	Standard resolution (6 in, 10° sampling): 823 m/h [2,700 ft/h] High resolution (0.6 in, 5° sampling): 172 m/h [563 ft/h]
Range of measurement	Min. casing thickness: 0.38 cm [0.15 in] Max. casing thickness: 2.01 cm [0.79 in]
Vertical resolution	High resolution: 1.52 cm [0.6 in] High speed: 15.24 cm [6 in]
Acoustic impedance‡	Range: 0 to 10 Mrayl Resolution: 0.2 Mrayl Accuracy: 0 to 3.3 Mrayl = ±0.5 Mrayl, >3.3 Mrayl = ±15%
Flexural attenuation	Range: 0 to 2 dB/cm§ Resolution: 0.05 dB/cm§ Accuracy: 0.01 dB/cm§
Min. quantifiable channel width	30 mm [1.2 in]
Depth of investigation†	Casing and annulus up to 7.62 cm [3 in]
Mud type or weight limitation††	Conditions simulated before logging
Combinability	Bottom only, combinable with most wireline tools Telemetry: fast transfer bus (FTB) or enhanced FTB (EFTB)
Special applications	H_2S service

† Investigation of annulus width depends on the presence of third-interface echoes. Analysis and processing beyond cement evaluation can yield additional answers through additional outputs, including the Variable Density log (VDL) of the annulus waveform and polar movies in AVI format.

‡ Differentiation of materials by acoustic impedance alone requires a minimum gap of 0.5 MRayl between the fluid behind the casing and a solid.

§ For 8-mm [0.3-in] casing thickness.

†† Max. mud weight depends on the mud formulation, sub used, and casing size and weight, which are simulated before logging.

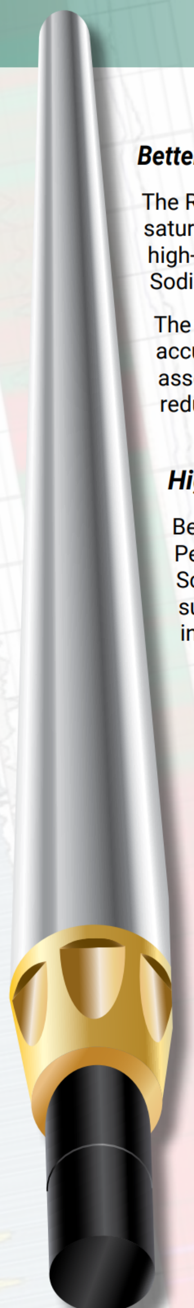
Mechanical Specifications

	Isolation Scanner Tool
Max. temperature	177 degC [350 degF]
Pressure range	1 to 138 MPa [145 to 20,000 psi]
Casing size—min.†	4½ in (min. pass-through restriction: 4 in)
Casing size—max.†	9⅝ in
Outside diameter	IBCS-A: 8.57 cm [3.375 in] IBCS-B: 11.36 cm [4.472 in] IBCS-C: 16.91 cm [6.657 in]
Length without sub	6.01 m [19.73 ft]
Weight without sub	151 kg [333 lbm]
Sub length, weight	IBCS-A: 61.22 cm [24.10 in], 7.59 kg [16.75 lbm] IBCS-B: 60.32 cm [23.75 in], 9.36 kg [20.64 lbm] IBCS-C: 60.32 cm [23.75 in], 10.73 kg [23.66 lbm]
Sub max. tension	10,000 N [2,250 lbf]
Sub max. compression	50,000 N [12,250 lbf]

† Limits for casing size depend on the sub used. Data can be acquired in casing larger than 9⅝ in with low-attenuation mud (e.g., water, brine).

Attachment A-4. Schlumberger's isolation scanner USIT used to provide evidence of external and internal mechanical integrity.

Attachment A-5 – Example of a Pulsed-Neutron Logging Tool



Better resolution leads to more accurate evaluation

The Reservoir Analysis tool features three gamma detectors for measuring reservoir saturation using Sigma and Carbon-Oxygen (C/O) techniques. Near and far detectors are high-resolution Lanthanum Chloride for Sigma and C/O detection, while the long spacing Sodium Iodide detector incorporates a spacing that is sensitive to gas and porosity.

The combined RAS/SGR log provides all the necessary measurements for computing accurately the volumes of clay, rock porosity and fluid saturations; and obtain a better assessment of reservoir properties which can help optimizing completion programs that reduce CAPEX by eliminating poor frac stages.

High-quality log data, and the expertise for advanced interpretation

Because data is only as good as its interpretation, our experienced Production Petrophysists, backed by available Reservoir Geoscience support from Hunter Well Science, employ advanced interpretation techniques to map RAS measurements into such properties as hydrocarbon saturation, porosity and rock type, delivering accurate information about reservoir properties.

Specifications		
Temperature rating	320°F	160°C
Pressure rating	15,000 psi	103.4 MPa
Diameter	1 11/16 in.	43 mm
Length	140.7 in.	3573 mm
Weight	44 lb	20 kg
Measure point - Near	84 in.	2134 mm
Measure point - Far	91 in.	2311 mm
Measure point - Long	101 in.	2565 mm
Materials	Corrosion resistant throughout	

Specifications courtesy of Hunter Well Science Limited

...when experience matters

Wireline Logging Solutions is staffed top to bottom by knowledgeable personnel, with deep understanding of this technology and how to get the most value from it. Our focus on service quality ensures rapid turnaround of a quality answer product, so you get the information you need, when you need it.

Attachment A-5. Measurement and mechanical specifications for Wireline Logging Solution's Reservoir Analysis tool.

APPENDIX D

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
Pore Space Amalgamation	NDCC §§ 38-22-06(3) and (4) NDAC §§ 43-05-01-08(1) and (2)	**NDCC § 38-22-06** 3. Notice of the hearing must be given to each mineral lessee, mineral owner, and pore space owner within the storage reservoir and within one-half mile of the storage reservoir's boundaries. 4. Notice of the hearing must be given to each surface owner of land overlying the storage reservoir and within one-half mile of the reservoir's boundaries. **NDAC § 43-05-01-08** 1. The commission shall hold a public hearing before issuing a storage facility permit. At least forty-five days prior to the hearing, the applicant shall give notice of the hearing to the following: a. Each operator of mineral extraction activities within the facility area and within one-half mile [.80 kilometer] of its outside boundary; b. Each mineral lessee of record within the facility area and within one-half mile [.80 kilometer] of its outside boundary; c. Each owner of record of the surface within the facility area and one-half mile [.80 kilometer] of its outside boundary; d. Each owner of record of minerals within the facility area and within one-half mile [.80 kilometer] of its outside boundary;	a. An affidavit of mailing certifying that all pore space owners and lessees within the storage reservoir boundary and within one-half mile outside of its boundary have been notified of the proposed carbon dioxide storage project;	**1.0 PORE SPACE ACCESS** (p. 1-1, paragraph 2) Blue Flint has identified the surface and mineral estate owners within the horizontal boundaries of the Blue Flint CO_2 storage facility area. With the exception of coal extraction, no mineral lessees or operators of mineral extraction activities are within the facility area or within 0.5 miles (0.8 kilometers) of its outside boundary. Blue Flint will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made (NDCC. §§ 38-22-06(3) and (4) and North Dakota Administrative Code [NDAC] §§ 43-05-01-08(1) and (2)).	The affidavit has not yet been prepared.
			b. A map showing the extent of the pore space that will be occupied by carbon dioxide over the life of the project;	**1.0 PORE SPACE ACCESS** (p. 1-1) North Dakota statute explicitly grants title to pore space in all strata underlying the surface of lands and waters to the owner of the overlying surface estate; i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] § 47-31-03). Prior to issuance of the SFP, the storage operator is mandated by North Dakota statute for geologic storage of CO2 to obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir (NDCC § 38-22-08(5)). The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation (NDCC § 38-22-10). Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application. Surface access for any potential above ground activities is not included in pore space amalgamation. Blue Flint has identified the surface and mineral estate owners within the horizontal boundaries of the Blue Flint CO_2 storage facility area. With the exception of coal extraction, no mineral lessees or operators of mineral extraction activities are within the facility area or within 0.5 miles (0.8 kilometers) of its outside boundary. Blue Flint will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made (NDCC. §§ 38-22-06(3) and (4) and North Dakota Administrative Code [NDAC] §§ 43-05-01-08(1) and (2)). All owners, lessees, and operators that require notification have been identified in accordance with North Dakota law, which vests the title to the pore space in all strata underlying the surface of lands and water to the owner of the overlying surface estate (NDCC § 47-31-03). The identification of pore space owners indicates that there was no severance of pore space or leasing of pore space to a third-party from the surface estate prior to 2009. All surface owners and pore space owners and lessees are the same owner of record. A map showing the extent of the pore space that will be occupied by CO_2 over the life of the Blue Flint CO_2 storage project, including the storage reservoir boundary and 0.5 miles (0.8 kilometers) outside of the storage reservoir boundary with a description of pore space ownership, surface owner, and pore space lessees of record is illustrated in Figure 1-1.	**Figure 1-1.** Storage facility area map showing pore space ownership.
			c. A map showing the storage reservoir boundary and one-half mile outside of the storage reservoir boundary with a description of pore space ownership;		**Figure 1-1.** Storage facility area map showing pore space ownership.
			d. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each operator of mineral extraction activities;		**Figure 1-1.** Storage facility area map showing pore space ownership.
			e. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each mineral lessee of record;		
			f. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each surface owner of record;		**Figure 1-1.** Storage facility area map showing pore space ownership.
			g. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each owner of record of minerals.		**Figure 1-1.** Storage facility area map showing pore space ownership.

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
		e. Each owner and each lessee of record of the pore space within the storage reservoir and within one-half mile [.80 kilometer] of the reservoir's boundary; and f. Any other persons as required by the commission. 2. The notice given by the applicant must contain: a. A legal description of the land within the facility area. b. The date, time, and place that the commission will hold a hearing on the permit application. c. A statement that a copy of the permit application and draft permit may be obtained from the commission.			
Geologic Exhibits	NDAC § 43-05-01-05 (1)(b)(1)	**NDAC § 43-05-01-05 (1)(b)** (1) The name, description, and average depth of the storage reservoirs;	a. Geologic description of the storage reservoir: Name Lithology Average thickness Average depth	**2.1 Overview of Project Area Geology** (p. 2-1) The proposed Blue Flint CO_2 storage project will be situated near the BFE facility, located south of Underwood, North Dakota (Figure 2-1). This project site is on the eastern flank of the Williston Basin. Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted via the Plains CO_2 Reduction (PCOR) Partnership, the Williston Basin has been identified as an excellent candidate for long-term CO_2 storage because of the thick sequence of clastic and carbonate sedimentary rocks and subtle structural character and tectonic stability of the basin (Peck and others, 2014; Glazewski and others, 2015). The target CO_2 storage reservoir for the project is the Broom Creek Formation, a predominantly sandstone unit 4,708 ft below the surface at the MAG 1 stratigraphic test well location (Figure 2-1). Sixty-one feet of shales, siltstones, and interbedded evaporites of the undifferentiated Spearfish and Opeche Formations, hereinafter referred to as the Spearfish Formation, unconformably overlie the Broom Creek Formation. Eighty-seven feet of shales, siltstones, and anhydrites of the lower Piper Formation (undifferentiated Picard, Poe, and Dunham Members) overlie the Spearfish Formation. Together, the lower Piper and Spearfish Formations serve as the primary upper confining zone (Figure 2-2). The Amsden Formation (dolostone, limestone, anhydrite, and sandstone) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-2). Together, the lower Piper, Spearfish, Broom Creek, and Amsden Formations make up the CO_2 storage complex for the Blue Flint project (Table 2-1). Including the Spearfish and lower Piper Formations, there is 859 ft (average thickness across the simulation area) of impermeable rock formations between the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. An additional 2,442 ft (average thickness across the simulation area) of impermeable rock formations separates the Inyan Kara Formation and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-2).	**Figure 2-1.** Topographic map of the project area showing the planned injection well, the planned monitoring well, and the Blue Flint Ethanol Plant (blue star). (p. 2-2) **Figure 2-2.** Stratigraphic column identifying the potential storage reservoirs and confining zones (outlined in red) and the lowest USDW (outlined in blue). (p. 2-3) **Table 2-1** Formations Making up the Blue Flint CO2 Storage Complex (average values calculated from the geologic model properties within simulation model area shown in Figure 2-3) (p. 2-4)

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description
(Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>Table 2-1. Formations Comprising the Blue Flint CO_2 Storage Complex (average values calculated from the simulation model and well log data)
<table>
<tr><th></th><th>Formation</th><th>Purpose</th><th>Average Thickness, ft</th><th>Average Depth, MD ft</th><th>Lithology</th></tr>
<tr><td rowspan="4">Storage Complex</td><td>Lower Piper Formation</td><td>Upper confining zone</td><td>153</td><td>4,458</td><td>Shale/anhydrite/ siltstone</td></tr>
<tr><td>Spearfish Formation</td><td>Upper confining zone</td><td>22</td><td>4,611</td><td>Shale/anhydrite/siltstone</td></tr>
<tr><td>Broom Creek Formation</td><td>Storage reservoir (i.e., injection zone)</td><td>102</td><td>4,633</td><td>Sandstone/dolostone</td></tr>
<tr><td>Amsden Formation</td><td>Lower confining zone</td><td>217</td><td>4,735</td><td>Dolostone/limestone/ anhydrite/sandstone</td></tr>
</table>
</td><td></td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(2)(k)</td><td>NDAC § 43-05-01-05(1)(b)(2)
(k) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;</td><td>b. Data on the injection zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:
Depth
Areal extent
Thickness
Mineralogy
Porosity
Permeability
Capillary pressure
Facies changes</td><td>SOURCE OF THE DATA:
2.2.1 Existing Data (p. 2-4)
Existing data used to characterize the geology beneath the Blue Flint project site included publicly available well logs and formation top depths acquired from NDIC's online database. Well log data and interpreted formation top depths were acquired for 120 wellbores within the 5,500-square-mile (mi2) area covered by the geologic model of the proposed storage site (Figure 2-3). Well data were used to characterize the depth, thickness, and extent of the subsurface geologic formations. Legacy 2D seismic data (70 miles) were licensed to characterize the subsurface geology in the project area and confirm the interpreted extent of the Broom Creek Formation (Figure 2-3).

Existing laboratory measurements for core samples from the Broom Creek Formation and its confining zones were available from four wells shown in Figure 2-4: Flemmer-1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), J-LOC1 (NDIC File No. 37380), and ANG 1 (Well No. ND-UIC-101) in addition to data from the site-specific stratigraphic test well, MAG 1 (NDIC File No. 37833). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and were integrated with newly acquired site-specific data.

2.2.2 Site-Specific Data (p. 2-6)
Site-specific efforts to characterize the proposed storage complex generated multiple data sets, including geophysical well logs, petrophysical data, and 3D seismic data. The MAG 1 well was drilled in 2020 specifically to gather subsurface geologic data to support the development of a CO_2 storage facility permit and serve as a future CO_2 injection well. Downhole logs were acquired, and sidewall core (SW Core) was collected from the proposed storage complex (i.e., the Lower Piper, Spearfish, Broom Creek, and Amsden Formations) at the time the well was drilled (Figure 2-5). In May 2022, fluid samples and temperature and pressure measurements were collected from the Broom Creek in the MAG 1 well.

Site-specific and existing data were used to assess the suitability of the storage complex for safe and permanent storage of CO_2. Site-specific data were also used as inputs for geologic model construction (Section 3.2), numerical simulations of CO_2 injection (Section 3.3.1), geochemical simulation (Sections 2.3.3, 2.4.1.2, and 2.4.3.2), and geomechanical analysis (Section 2.4.4). The site-specific data improved the understanding of the subsurface and directly informed the selection of monitoring technologies, development of the timing and frequency of collecting monitoring data, and interpretation of monitoring data with respect to potential subsurface risks. Furthermore, these data guided and influenced the design and operation of site equipment and infrastructure.</td><td>Figure 2-3. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. (p. 2-5)

Figure 2-4. Map showing the spatial relationship between the Blue Flint project area and wells where the Broom Creek Formation core samples were collected. (p. 2-6)

Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota. (p. 2-12)

Figure 2-8. Isopach map of the Broom Creek Formation in the greater Blue Flint project area. (p. 2-13)

Figure 2-9. Well log display of the interpreted lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations in MAG 1. (p. 2-14)

Figure 2-10. Regional well log stratigraphic cross</td></tr>
</table>

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
				DATA ON THE INJECTION ZONE: (continued below)	(continued below)

DATA ON THE INJECTION ZONE:

2.3 Storage Reservoir (injection zone) (p. 2-11)

Regionally, the Broom Creek Formation is laterally extensive in the storage facility area (Figure 2-7) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals), dolomitic sandstone, and dolostone layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by the Spearfish and the lower Piper Formation (Figure 2-2) (Murphy and others, 2009).

2.3.1 Mineralogy (p. 2-21)

Thin-section analysis of Broom Creek shows that quartz, dolomite, anhydrite, and clay (mainly illite/muscovite) are the dominant minerals. Throughout these intervals are the occurrence of feldspar (mainly K-feldspar) and iron oxide. Anhydrite obstructs the intercrystalline porosity in the upper part of the formation and dolomite in the middle and lower parts. The contact between grains is tangential. The porosity is due to the dissolution of anhydrite in the upper part and the dissolution of quartz and feldspar in the middle and lower parts. Figures 2-15, 2-16, and 2-17 show thin-section images representative of the upper, middle, and lower Broom Creek Formation.

Table 2-5. Description of CO_2 Storage Reservoir (injection zone) at the MAG 1 Well

Injection Zone Properties			
Property	**Description**		
Formation Name	**Broom Creek**		
Lithology	**Sandstone, dolomitic sandstone, dolostone**		
Formation Top Depth, ft	**4,708**		
Thickness, ft	**103 (sandstone 66, dolomitic sandstone 13, dolostone 24)**		
Capillary Entry Pressure (brine/CO_2), psi	**0.866**		
Geologic Properties			
Formation	**Property**	**Laboratory Analysis**	**Simulation Model Property Distribution**
Broom Creek (sandstone)	**Porosity, %***	**24.12 (21.42–27.80)**	**19.15 (0.0–36.00)**
	Permeability, mD**	**298.16 (140.70–929.84)**	**132.83 (0–3237.4)**
Broom Creek (dolomitic sandstone)	**Porosity, %***	**20.85 (16.13–23.83)**	**15.87 (1.0–29.25)**
	Permeability, mD**	**81.91 (16.40–257.00)**	**50.13 (0–650.70)**
Broom Creek (dolostone)	**Porosity, %***	**10.50 (5.83–15.91)**	**7.85 (0.0–24.65)**
	Permeability, mD**	**1.01 (0.01–178.60)**	**0.76 (0.0–519.32)**

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
** Permeability values are reported as the geometric mean followed by the range of values in parentheses.

sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. (p. 2-15)

Figure 2-11. Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. (p. 2-16)

Figure 2-12. Structure map of the Broom Creek Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-17)

Figure 2-13. Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. (p. 2-18)

Table 2-5. Description of CO_2 Storage Reservoir (injection zone) at the MAG 1 Well (p. 2-19)

Figure 2-14. Vertical distribution of core-derived porosity and permeability values and the laboratory-derived mineralogic characteristics in the Blue Flint storage complex from MAG 1. (p. 2-20)

Figure 2-15. Thin section in upper Broom Creek Formation. This interval is primarily dolomite (grey) with anhydritic cement. (p. 2-21)

Figure 2-16. Thin section in middle Broom Creek Formation. This interval is dominated by fine-grained quartz and minor dolomite.

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Table 2-6. XRD Analysis in the Broom Creek Reservoir from MAG 1. Only major constituents are shown.

Sample Name	STAR No.	Depth, feet	% Clay	% K-Feldspar	% P-Feldspar	% Quartz	% Calcite	% Dolomite	% Ankerite	% Anhydrite	% Halite
Broom Creek	130068	4,730	0.0	0.0	0.0	1.5	0.0	65.9	0.0	32.3	0.2
Broom Creek	130067	4,732	0.0	2.2	0.0	56.8	0.0	36.2	0.0	3.9	0.9
Broom Creek	130066	4,764	31.5	3.9	0.0	38.1	12.9	2.4	0.0	0.0	5.9
Broom Creek	130065	4,767	0.0	1.4	0.0	91.0	0.0	4.9	0.0	1.2	1.5
Broom Creek	130064	4,788	0.0	3.8	0.0	78.8	0.0	15.3	0.0	0.0	1.0
Broom Creek	130088	4,792	0.0	3.2	0.0	82.6	0.0	13.1	0.0	0.2	0.8
Broom Creek	130063	4,797	0.0	2.3	0.0	79.4	0.0	13.9	0.5	2.3	1.6
Broom Creek	130085	4,801	0.0	3.1	0.0	87.8	0.0	6.4	0.0	1.7	1.0
Broom Creek	130084	4,804	0.0	3.1	0.0	85.2	0.0	10.5	0.0	0.0	1.2
Broom Creek	130083	4,807	0.0	3.1	0.7	64.7	0.0	30.6	0.0	0.0	0.9
Broom Creek	130082	4,810.5	0.5	6.2	0.9	62.4	0.0	18.6	0.0	9.6	1.4
Broom Creek	130060	4,812	7.8	8.4	4.7	36.5	0.0	42.1	0.0	0.0	0.2
Broom Creek	130058	4,817	12.2	9.4	5.6	48.0	0.0	23.9	0.0	0.0	0.4
Broom Creek	130056	4,822	13.8	7.5	4.4	26.1	0.0	47.5	0.0	0.0	0.4
Broom Creek	130055	4,827	7.2	12.8	4.7	32.2	0.0	39.4	0.0	0.6	0.5

2.3.3 Geochemical Information of Injection Zone (p. 2-26)
Geochemical simulation has been performed to calculate the effects of introducing the CO_2 stream to the injection zone.

The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package GEM. GEM is also the primary simulation software used for evaluation of the reservoir's dynamic behavior resulting from the expected CO_2 injection. For this geochemical modeling study, the injection scenario consisted of a single injection well injecting for a 20-year period with maximum BHP (bottomhole pressure) and maximum gas injection rate (STG, surface gas rate) constraints of 2,970 psi and 200,000 tonnes per year (tpy), respectively. A postinjection period of 25 years was run in the model to evaluate any dynamic behavior and/or geochemical reaction after the CO_2 injection is stopped. The injection stream consists of mostly CO_2 (>99.98%) and some minor components (Table 2-7). For simulation, 100% CO_2 was assumed as the injection stream is mostly CO_2 (>99.98%) This geochemical scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared (Figure 2-19 and Figure 2-20).

The scenario with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (80% of bulk reservoir volume) and average formation brine composition (20% of bulk reservoir volume). XRD data from the 15 Broom Creek formation core samples were used to inform the mineralogical composition of the Broom

Porosity is high in this interval. (p. 2-22)

Figure 2-17. Thin section in lower Broom Creek Formation. This interval is a laminated silty mudstone. The matrix is dominated by clay and quartz. (p. 2-23)

Table 2-6. XRD Analysis in the Broom Creek Reservoir from MAG 1. Only major constituents are shown. (p. 2-24)

Figure 2-18. XRF analysis in Broom Creek Formation from MAG 1 (p. 2-25)

Table 2-7. Injection Stream Composition (p. 2-27)

Table 2-8. XRD Results for MAG 1 Broom Creek Core Sample (p. 2-27)

Figure 2-19. Upper graph shows cumulative injection vs. time; the bottom figure shows the gas injection rate vs. time. There is no observable difference in injection due to geochemical reactions. (p. 2-28)

Figure 2-20. Upper graph shows wellhead pressure vs. time; the bottom figure shows the bottomhole pressure vs. time. There is no observable difference in pressures due to geochemical reactions. (p. 2-29)

Table 2-9. Broom Creek Water Ionic Composition, expressed in molality (p. 2-30)

Figure 2-21. CO2 molality for the geochemistry case simulation results after 20

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
				Creek Formation (Table 2-8). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Reported ionic composition of the Broom Creek Formation water is listed in Table 2-9. Figure 2-24 shows the mass of mineral dissolution and precipitation due to geochemical reaction in the Broom Creek Formation. Dolomite is the most prominent dissolved mineral. Albite and K-feldspar gradually dissolves over time. Illite initially dissolves and then starts precipitating 3 years after injection stops. Quartz and anhydrite are the minerals that experienced the most precipitation over time. Figures 2-25 and 2-26 provide an indication of the change in distribution of the mineral that experienced the most dissolution, dolomite, and the mineral that experienced the most precipitation, quartz, respectively. Considering the apparent net dissolution of minerals in the system, as indicated in Figure 2-24, there is an associated net increase in porosity in the affected areas, as shown in Figure 2-27. However, the porosity change is small, less than 0.04% porosity units, equating to a maximum increase in average porosity from 22.6% to 22.64% after the 20-year injection period.	years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of simulation in Layer k = 39. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-31) **Figure 2-22.** CO_2 molality for the non-geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of simulation in Layer k = 39. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-32) **Figure 2-23.** Geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the pH of formation brine in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-33) **Figure 2-24**. Dissolution and precipitation quantities of reservoir minerals because of CO2 injection. Dissolution of albite, K-feldspar (K-fe_fel), and dolomite with

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
					precipitation of illite, quartz, and anhydrite was observed. (p. 2-34) **Figure 2-25.** Change in molar distribution of dolomite, the most prominent dissolved mineral at the end of the 20-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-35) **Figure 2-26.** Change in molar distribution of quartz, the most prominent precipitated mineral at the end of the 20-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p.2-36) **Figure 2-27.** Change in porosity due to net geochemical dissolution at the end of the 20-year injection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-37)
			c. Data on the confining zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs: Depth Areal extent Thickness Mineralogy Porosity Permeability Capillary pressure Facies changes	SOURCE OF THE DATA: *See discussion above under 2.2.1 Existing Data* AND **2.4 Confining Zones** (p. 2-38) The confining zones for the Broom Creek Formation are the overlying Spearfish Formation and the lower Piper Formation and the underlying Amsden Formation (Figure 2-2, Table 2-10). Both the overlying and underlying confining formations consist primarily of impermeable rock layers.	**Table 2-10**. Properties of Upper and Lower Confining Zones in Simulation Area (p. 2-38) **Figure 2-28.** Areal extent of the lower Piper Formation in western North Dakota (modified from Carlson, 1993). (p. 2-39) **Figure 2-29.** Structure map of the lower Piper Formation

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Table 2-10. Properties of Upper and Lower Confining Zones in Simulation Area

Confining Zone Properties	**Upper Confining Zone**		**Lower Confining Zone**
Stratigraphic Unit	Lower Piper	Spearfish	Amsden
Lithology	Shale/anhydrite/ siltstone	Shale/anhydrite/ siltstone	Dolostone/limestone/ anhydrite/sandstone
Average Formation Top Depth (MD), ft	4,458	4,611	4,735
Thickness, ft	153	22	217
Capillary Entry Pressure (brine/CO_2), psi	2.512	12.245	26.134
Depth below Lowest Identified USDW, ft (MAG 1)	3,488	3,575	3,738
Formation	**Property**	**Laboratory Analysis**	**Simulation Model Property Distribution**
Lower Piper	Porosity, %*	*** (4.8,10.50)	3.00 (0.00-8.00)
	Permeability, mD**	*** (0.01,0.074)	0.064 (0.000-0.147)
Spearfish	Porosity, %*	13.14 (11.62–15.38)	2.00 (0.00-8.00)
	Permeability, mD**	0.116 (0.009–3.087)	0.11 (0.000-0.272)
Amsden	Porosity, %*	8.48 (2.15–18.80)	1.00 (0.00-6.00)
	Permeability, mD**	0.062 (0.0003–117)	0.683 (0.000-3.473)

* Porosity values recorded at 2,400-psi confining pressure are reported as the arithmetic mean followed by the range of values in parenthesis.
** Permeability values recorded at 2,400-psi confining pressure are reported as the geometric mean followed by the range of values in parenthesis.
*** Average not available for two samples.

2.4.1 Upper Confining Zone (p. 2-39)
In the Blue Flint project area, the upper confining zone, the lower Piper and Spearfish Formations, consists of siltstone with interbedded anhydrite (Table 2-10). The upper confining zone is laterally extensive across the project area (Figure 2-28) and is 4,560 ft below the land surface and 148 ft thick (lower Piper Formation, 87 ft [Figures 2-29 and 2-30], Spearfish Formation, 61 ft [Figures 2-31 and 2-32]) as observed in the MAG 1 well. The contact between the underlying Broom Creek Formation sandstone and the upper confining zone is an unconformity that can be correlated across the Broom Creek Formation extent where the resistivity and GR logs show a significant change across the contact. A relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation changes to a relatively high GR signature representing the siltstones of the Spearfish Formation (Figure 2-9).

Laboratory measurements of the porosity and permeability from eight SW Core samples (six Spearfish Formation and two lower Piper Formation) taken from MAG 1 can be found in Table 2-11. Because of the fractured or chipped nature of some samples, the permeability and porosity values measured are higher than the matrix would suggest. The lithology from the sidewall-cored sections of the Spearfish Formation is primarily siltstone.

across the greater Blue Flint project area in feet below mean sea level. (p. 2-40)

Figure 2-30. Isopach map of the lower Piper Formation in the greater Blue Flint project area. (p. 2-41)

Figure 2-31. Structure map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area(p. 2-42)

Figure 2-32. Isopach map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area. (p. 2-43)

Table 2-11. Spearfish and Lower Piper Formation SW Core Sample Porosity and Permeability from MAG 1 (p. 2-44)

Figure 2-33: Thin section of Piper Formation. In this example, clay (brown) and anhydrite (white) dominate the depth interval. Minor porosity is observed (blue). (p. 2-45)

Figure 2-34: Thin section of Spearfish Formation. In this example, clay (brown), quartz (small white grains), anhydrite (large white grains), and iron oxides (black grains) dominate the depth interval. No porosity is observed. (p. 2-46)

Figure 2-35: Thin section of Spearfish Formation. In this example, clay (brown) and quartz (white) dominate the depth interval. Minor intergranular and intragranular porosity are observed (blue). (2-47)

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In situ fluid pressure testing was not performed in the Spearfish or lower Piper Formations in the MAG 1 well. The low permeability values shown in Table 2-11 suggest any fluid within the Spearfish Formation is pore- and capillary-bound fluid and likely not mobile. Several documented attempts by others to draw down reservoir fluid in order to measure the reservoir pressure or collect an in situ fluid sample using a modular formation dynamics tester (MDT) tool in the undifferentiated Spearfish/Opeche and other similar low-permeability intervals suggest collecting this information is not feasible. The Tundra SGS (secure geologic storage) SFP applications describe unsuccessful attempts to measure in situ fluid pressure because of the low permeability of the formations tested, the undifferentiated Spearfish/Opeche Formation, and the Icebox Formation (North Dakota Industrial Commission, 2021a, b). The Red Trail Energy SFP application also describes unsuccessful attempts to collect these data in the low-permeability Opeche Formation (North Dakota Industrial Commission, 2021c).

Table 2-11. Spearfish and Lower Piper Formation SW Core Sample Porosity and Permeability from MAG 1

Formation	Sample Depth, ft	Porosity %	Permeability, mD
Piper	4,658*	4.8	0.01
Piper	4,665*	10.50	0.074
Spearfish	4,695*	12.52	0.009
Spearfish	4,710	11.62	0.090
Spearfish	4,718*	15.38	3.087
Spearfish	4,721	14.49	0.141
Spearfish	4,724	11.69	0.059
	Range	(4.8–15.38)	(0.009–3.087)
	Values Measured at 2400 psi		

* Sample is fractured or chipped. The measured permeability and/or porosity may be higher than its real value.

XRD data from the sidewall core samples in the cap rock intervals supported the thin-section analysis. Table 2-11 shows the major mineral phases identified for the samples representing these intervals. XRF data related to the upper confining zones are presented in Figure 2-33.

Table 2-12. XRD Analysis in the Upper Confining Intervals (Spearfish and Lower Piper) from MAG 1 Well. Only major constituents are shown.

Formation	STAR No.	Depth, feet	% Clay	% K-Feldspar	% P-Feldspar	% Quartz	% Calcite	% Dolomite	% Ankerite	% Anhydrite	% Halite
Piper	130095	4,640	37.7	7.6	11.9	26.2	1.2	3.3	1.5	7.9	0.7
Piper	130094	4,648	4.5	0.4	0.0	1.2	0.0	0.0	0.0	93.7	0.2
Piper	130093	4,655	27.4	1.8	4.8	7.1	2.5	2.7	1.6	50.7	0.0
Piper	130091	4,658	9.1	0.0	4.2	4.8	19.5	0.0	0.4	62.1	0.0
Piper	130090	4,665	23.3	2.8	5.3	11.3	24.1	8.9	6.8	17.5	0.0
Spearfish	130081	4,675	16.4	6.2	13.2	33.4	0.0	28.3	0.0	1.6	0.4
Spearfish	130080	4,680	7.5	12.7	12.5	36.7	0.0	25.0	0.0	4.9	0.6
Spearfish	130079	4,685	3.7	1.4	2.9	6.5	0.1	5.1	0.0	80.4	0.0
Spearfish	130078	4,690	9.3	5.5	10.2	29.5	0.6	10.0	3.5	30.8	0.4
Spearfish	130077	4,695	13.0	4.5	8.1	25.8	0.8	8.7	2.6	35.7	0.3
Spearfish	130076	4,700	9.7	4.1	9.3	30.3	2.7	7.6	2.4	33.2	0.4
Spearfish	130075	4,705	19.8	7.3	12.8	37.7	4.1	11.5	0.0	5.6	0.7

Table 2-12. XRD Analysis in the Upper Confining Intervals (Spearfish and Lower Piper) from MAG 1 Well. Only major constituents are shown. (p. 2-48)

Figure 2-36. XRF analysis in the upper confining zone (Spearfish and lower Piper Formations) from MAG 1. (p. 2-49)

Table 2-13. Mineral Composition of the Spearfish Derived from XRD Analysis of MAG 1 Core Samples (p. 2-50)

Table 2-14. Formation Water Chemistry from Broom Creek Formation Fluid Samples from MAG 1 (p. 2-50)

Figure 2-37. Change in fluid pH vs. time. Red line shows pH for the center of Cell C1, 0.5 meters above the Spearfish Formation cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. pH for Cell C2 does not begin to change until after Year 16. (p. 2-52)

Figure 2-38. Dissolution and precipitation of minerals in the Spearfish Formation cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2, 1.5 meters above the cap rock base; these changes are barely visible. Results from Cell C3, 2.5 meters above

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Spearfish	130074	4,710	8.3	5.3	11.8	38.5	4.6	11.0	0.0	19.7	0.4
Spearfish	130073	4,715	9.6	6.6	11.4	37.9	4.5	13.9	0.0	15.4	0.4
Spearfish	130071	4,721	8.0	6.7	10.2	39.6	0.0	34.9	0.0	0.0	0.0
Spearfish	130070	4,724	13.8	9.8	15.3	46.0	10.2	3.3	0.0	0.8	0.6

2.4.1.1 Mineralogy (p. 2-44)
The combined interpretation of SW Core samples, well logs, and thin sections shows that the Spearfish and lower Piper Formations are dominated by clays (mainly illite/muscovite), quartz, anhydrite, feldspar (mainly K-feldspar), and dolomite. Sixteen depth intervals in the Spearfish and Lower Piper Formations were sampled for thin-section creation, XRD mineralogical determination, and XRF bulk chemical analysis. For the assessment, thin sections and XRD provide independent confirmation of the mineralogical constituents of each of these intervals. Thin-section analysis of the siltstone intervals shows that clay, quartz, and anhydrite are the dominant minerals. Throughout these intervals are occurrences of dolomite, feldspar, and iron oxides (Figures 2-33, 2-34, and 2-35). The contacts between grains are typically separated by a clay matrix, with more rare occurrences of contacts between quartz grains as tangential to long.

2.4.1.2 Geochemical Interaction (p. 2-50)
Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected CO_2 stream on the Spearfish Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Spearfish Formation by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the confining zone. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock–CO_2 exposure boundary. The mineralogical composition of the Spearfish Formation was honored (Table 2-13). Formation brine composition was assumed to be the same as the known composition from the Broom Creek Formation injection zone below (Table 2-14). For simulation, 100% CO_2 was used as discussed in Section 2.3.1. The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). This overestimate was done to ensure that the degree and pace of geochemical change would not be underestimated. This geochemical simulation was run for 45 years to represent 20 years of injection plus 25 years of postinjection. The simulation was performed at reservoir pressure and temperature conditions.

Results showed geochemical processes at work. Figures 2-37 through 2-41 show results from geochemical modeling. Figure 2-37 shows change in fluid pH over time as CO_2 enters the system. For the cell at the CO_2 interface, C1, the pH starts declining from an initial pH of 7.48 and goes down to a level of 4.9 after 11 years of simulation time. pH starts to increase after 18 years of simulation time and reaches to 5.5 by the 45 years of simulation. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH only begins to change after Year 20. Lastly, the pH is unaffected in Cell C3, indicating CO_2 does not penetrate this cell within the first 45 years.

Figure 2-38 shows the change in mineral dissolution and precipitation in grams per cubic meter of rock. The dashed lines are for Cell C1; solid lines that are only faintly seen in the figure are for Cell C2, 1.0 to 2.0 meters into the cap rock. The net change due to precipitation or dissolution in Cell C2 is less than 2 kg per cubic meter per year with very little dissolution or precipitation taking place after injection ceases in Year 2043. Albite, K-feldspar, and anhydrite start to dissolve from the beginning of the simulation period while illite, quartz, and dolomite start to precipitate for Cell C1 at the same time. Any effects in Cell C3 are too small to represent at this scale.

Figure 2-39 represents the initial fractions of potentially reactive minerals in the Spearfish Formation based on XRD data shown in Table 2-13. The expected dissolution of these minerals in weight percentage is also shown for Cells 1 and Cell 2 of the model. In Cell 1, albite, K-feldspar, anhydrite, and chlorite are the primary minerals that dissolve. In Cell 2, albite and K-feldspar are the two primary minerals that dissolve. Dissolution (%) in Cell 2 is minimal (< 0.1%) and too small to plot in Figure 2-39.

Figure 2-40 represents expected minerals to be precipitated in weight (%) shown for Cells C1 and C2 of the model. In Cell 1, illite, quartz, and dolomite are the minerals to be precipitated. In Cell 2, illite and quartz are the minerals to be precipitated.

the cap rock base, are not shown as they are too small to be seen at this scale. (p. 2-52)

Figure 2-39. Weight percentage (wt%) of potentially reactive minerals present in the Spearfish Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray, too small to see in the figure) after 20 years of injection plus 25 years of postinjection. (p. 2-53)

Figure 2-40. Weight percentage (wt%) of precipitated minerals in the Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time. (p. 2-54)

Figure 2-41. Change in percent porosity of the Spearfish cap rock. Red line shows porosity change calculated for Cell C1 at 0.5 meters above the cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation. (p. 2-55)

Table 2-15. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the MAG 1 well) (p. 2-56)

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Figure 2-41 shows the change in porosity of the cap rock for Cells C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 0.2% change during the life of the simulation. Cell 1 experiences an initial 0.006% increase in porosity as it is first exposed to CO_2 because of dissolution, but the change is temporary. At later times, Cell 1 experiences a porosity decrease of 0.13%. No significant porosity changes were observed for Cell 2 and Cell 3.

2.4.2 Additional Overlying Confining Zones (p. 2-55)
Several other formations provide additional confinement above the lower Piper interval. Impermeable rocks above the primary seal include the upper Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-15). Together with the Spearfish and lower Piper intervals, these intervals are 859 ft thick on average across the simulation area and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-42). Above the Inyan Kara Formation at the MAG 1 well, 2,512 ft of impermeable rocks acts as an additional seal between the Inyan Kara sandstone interval and lowermost USDW, the Fox Hills Formation (see Figure 2-43). Confining layers above the Inyan Kara sandstone interval include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-15).

Table 2-15. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the MAG 1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,092	1,316	0
Niobrara	Shale	2,408	328	1,316
Carlile	Shale	2,736	261	1,644
Greenhorn	Shale	2,997	53	1,905
Belle Fourche	Shale	3,050	250	1,958
Mowry	Shale	3,300	58	2,208
Skull Creek	Shale	3,375	229	2,282
Swift	Shale	3,831	382	2,739
Rierdon	Shale	4,213	221	3,121
Piper (Kline Member)	Limestone	4,434	147	3,342

2.4.3 Lower Confining Zones (p. 2-58)
The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, limestone, and anhydrite. The Amsden Formation does include some thin sandstone and dolomitic sandstone intervals on the order of 4–6 inches thick (Figure 2-9). The sandstone intervals in the Amsden Formation are isolated from the sandstones of the Broom Creek Formation by thick impermeable dolostone intervals (Figure 2-9). The top of the Amsden Formation was placed at the top of an argillaceous dolostone, which has relatively high GR character that can be correlated across the project area (Figure 2-9). The Amsden Formation is 4,810 ft below land surface and 276 ft thick at the Blue Flint site as determined at the MAG 1 well (Figures 2-44 and 2-45).

The contact between the underlying Amsden Formation and the overlying Broom Creek Formation is evident on wireline logs as there is a lithological change from the dolostone and anhydrite beds of the Amsden Formation to the porous sandstones of the Broom Creek Formation. This lithologic change is also recognized in the SW Core samples from MAG 1. The lithology of the sidewall-cored section of the Amsden Formation from MAG 1 is the predominant dolostone and anhydrite and lesser predominant lithologies of shaly sandstone and siltstone. Table 2-16 shows the range of porosity and permeability values of the SW Core samples from the Amsden Formation.

Table 2-15. Amsden SW Core Sample Porosity and Permeability from MAG 1

Sample Depth, ft	Porosity %	Permeability, mD
4,845	9.59	0.003
4,851*	18.80	117
4,860*	8.86	1.46
4,865	2.15	0.0003

Figure 2-42. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. (p. 2-56)

Figure 2-43. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. (p. 2-57)

Figure 2-44. Structure map of the Amsden Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-58)

Figure 2-45. Isopach map of the Amsden Formation across the greater Blue Flint project area. (p. 2-59)

Table 2-16. Amsden SW Core Sample Porosity and Permeability from MAG 1. (p. 2-60)

Figure 2-46. Thin section in the Amsden Formation. This example shows a dolomite matrix (gray/brown) with quartz grains distributed throughout. Minor porosity is observed. (p. 2-61)

Figure 2-47. Thin section in the Amsden Formation. This interval is dominated by anhydrite and quartz. In this example, quartz grains are tightly cemented, and almost no porosity is observed. (p. 2-62)

Figure 2-48. Thin section in the Amsden Formation. This interval shows a fine micritic dolomite with minor quartz grains. Porosity is generally

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)

Storage Facility Permit Application (continued):

4,869	11.56	0.009
4,875**	2.9	0.005
4,880*	3.74	0.134
4,889*	10.26	0.239
Range	(2.15–18.80)	(0.0003–117)
Values measured at 2,400 psi		

* Sample is fractured or chipped. The measured permeability and/or porosity may be higher than its real value.

** Sample is very short; the measured porosity may be higher than its real value because of lack of conformation of boot material to plug surface.

2.4.3.1 Mineralogy (p. 2-60)

Well logs and the thin-section analyses show that the Amsden Formation comprises dolostone, sandstone, anhydrite, and limestone. The porosity averages 7%, and permeability is very low. Figures 2-46, 2-47, and 2-48 show thin-section images representative of the Amsden Formation.

XRD was performed, and the results confirm the observations made during core observation, thin-section description, and well log analysis. Amsden intervals show that dolomite, anhydrite, quartz, and clay are the dominant minerals (Table 2-16). XRF data are presented in Figure 2-46 for the Amsden Formation.

Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the MAG 1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,092	1,316	0
Niobrara	Shale	2,408	328	1,316
Carlile	Shale	2,736	261	1,644
Greenhorn	Shale	2,997	53	1,905
Belle Fourche	Shale	3,050	250	1,958
Mowry	Shale	3,300	58	2,208
Skull Creek	Shale	3,375	229	2,282
Swift	Shale	3,831	382	2,739
Rierdon	Shale	4,213	221	3,121
Piper (Kline Member)	Limestone	4,434	147	3,342

Figure/Table Number and Description (continued):

low and found to be intergranular or due to the dissolution of dolomite in this example. (p. 2-63)

Table 2-17. XRD Analysis in the Lower Confining Zone (Amsden Formation) from MAG 1 Well. Only major constituents are shown. (p. 2-64)

Figure 2-49. XRF analysis in the lower confining zone (Amsden Formation) from MAG 1. (p. 2-65)

NDCC / NDAC Reference: NDAC § 43-05-01-05(1)(b)(2)

Requirement:

NDAC § 43-05-01-05(1)(b)

(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a

Regulatory Summary:

d. A description of the storage reservoir's mechanisms of geologic confinement characteristics with regard to preventing migration of carbon dioxide beyond the proposed storage reservoir, including:
- Rock properties
- Regional pressure gradients
- Adsorption processes

Storage Facility Permit Application:

2.2.2.3 Formation Temperature and Pressure (p. 2-8)

Broom Creek Formation temperature and pressure measurements were collected from MAG 1 with a packer module. To collect a formation fluid sample, the Broom Creek Formation had to be perforated due to the cement sheath created while drilling out an extended cement plug in the lower portion of the wellbore. The Broom Creek Formation was perforated from 4,733 to 4,740 ft, and a packer was set at 4,096 ft with a tailpipe, dial sensor mandrel, and 4-ft perforated sub below the packer. Pressure and temperature sensors were set at depths of 4,735 and 4,741 ft, and the measurements recorded are shown in Tables 2-2 and 2-3. The calculated pressure and temperature gradients from MAG 1 were used to model the formation temperature and pressure profiles for use in the numerical simulations of CO_2 injection.

Table 2-1. Description of MAG 1 Temperature Measurements and Calculated Temperature Gradients

Formation	Sensor Depth, ft	Temperature, °F
Broom Creek	4,735	118.9
Broom Creek	4,741	118.6
Broom Creek Temperature Gradient, °F/ft		0.02*

* The temperature gradient is the measured temperature minus the average annual surface temperature of 40°F, divided by the associated test depth.

Figure/Table Number and Description:

Table 2-2. Description of MAG 1 Temperature Measurements and Calculated Temperature Gradients (p. 2-9)

Table 2-3. Description of MAG 1 Formation Pressure Measurements and Calculated Pressure Gradients (p. 2-9)

Figure 2-63. Geomechanical parameters in the Spearfish Formation. (p. 2-81)

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description
(Page Number)</th></tr>
<tr><td></td><td></td><td>comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:</td><td></td><td>
Table 2-3. Description of MAG 1 Formation Pressure Measurements and Calculated Pressure Gradients
<table>
<tr><th>Formation</th><th>Sensor Depth, ft</th><th>Formation Pressure, psi</th></tr>
<tr><td>Broom Creek</td><td>4,735</td><td>2,427.00</td></tr>
<tr><td>Broom Creek</td><td>4,741</td><td>2,427.28</td></tr>
<tr><td>Mean Broom Creek Pressure, psi</td><td>2,427.14</td><td></td></tr>
<tr><td>Broom Creek Pressure Gradient, psi/ft</td><td>0.50*</td><td></td></tr>
</table>
* The pressure gradient is an average of the sensor measured pressures minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.

2.3.2 Mechanism of Geologic Confinement (p. 2-26)
For the Blue Flint project area, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the upper confining formations (Spearfish Formation and the lower Piper Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure. Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), confining the CO_2 within the proposed storage reservoir. After injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation; therefore, this process is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.

2.4.4.2 Stress, Ductility, and Rock Strength (p. 2-80)
A 1D MEM was derived using the log data from MAG 1 well. Logs were edited to account for washouts in the Broom Creek and Amsden Formation sections using multilinear regressions. Geomechanical parameters in the Spearfish, Broom Creek, and Amsden Formations were estimated using the 1D MEM. The 1D MEM was used to estimate the vertical stress, pore pressure, minimum and maximum horizontal stresses (Shmin, SHmax), Poisson's ratio, Young's modulus, shear and bulk moduli, tensile, uniaxial compressive strength, and friction angle (Figure 2-63, Figure 2-64, and Figure 2-65). Table 2-19 shows the average and range of elastic and dynamic parameters, and stresses in the Spearfish, Broom Creek, and Amsden Formations.

Table 2-19. Ranges and Averages of the Elastic Properties Estimated from 1D MEM in Spearfish, Broom Creek and Amsden Formations: Static Young's Modulus (E_Stat), Static Poisson's Ratio (n_Stat), Static Bulk Modulus (K), Static Shear Modulus (G), Uniaxial Strain Modulus (P), Dynamic Young's Modulus (E_Dyn), and Dynamic Poisson's ratio (n_Dyn) in the Spearfish, Broom Creek, and Amsden Formations
<table>
<tr><th>Formation</th><th>Stats</th><th>E_Stat, Mpsi</th><th>n_Stat, unitless</th><th>K, Mpsi</th><th>G, Mpsi</th><th>P, psi</th><th>E_Dyn, Mpsi</th><th>n_Dyn, unitless</th></tr>
<tr><td rowspan="3">Spearfish</td><td>Min</td><td>0.665</td><td>0.243</td><td>0.493</td><td>0.256</td><td>2821</td><td>3.090</td><td>0.243</td></tr>
<tr><td>Max</td><td>1.554</td><td>0.347</td><td>1.365</td><td>0.616</td><td>6591</td><td>5.213</td><td>0.347</td></tr>
<tr><td>Average</td><td>1.159</td><td>0.281</td><td>0.884</td><td>0.453</td><td>4916</td><td>4.331</td><td>0.281</td></tr>
<tr><td rowspan="3">Broom Creek</td><td>Min</td><td>0.089</td><td>0.231</td><td>0.084</td><td>0.034</td><td>378</td><td>0.896</td><td>0.231</td></tr>
<tr><td>Max</td><td>3.774</td><td>0.347</td><td>3.288</td><td>1.429</td><td>15884</td><td>8.963</td><td>0.347</td></tr>
<tr><td>Average</td><td>0.573</td><td>0.313</td><td>0.479</td><td>0.221</td><td>2430</td><td>2.444</td><td>0.313</td></tr>
<tr><td rowspan="3">Amsden</td><td>Min</td><td>0.117</td><td>0.152</td><td>0.137</td><td>0.043</td><td>495</td><td>1.057</td><td>0.152</td></tr>
<tr><td>Max</td><td>6.869</td><td>0.364</td><td>6.774</td><td>2.581</td><td>29140</td><td>13.026</td><td>0.364</td></tr>
<tr><td>Average</td><td>1.945</td><td>0.286</td><td>1.47</td><td>0.764</td><td>8249</td><td>5.707</td><td>0.286</td></tr>
</table>
</td><td>Figure 2-64. Geomechanical parameters in the Broom Creek Formation. (p. 2-82)

Figure 2-65. Geomechanical parameters in the Amsden Formation. (p. 2-83)

Table 2-19. Ranges and Averages of the Elastic Properties Estimated from 1D MEM in Spearfish, Broom Creek and Amsden Formations (p. 2-84)</td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(2)(g)</td><td>NDAC § 43-05-01-05(1)(b)(2)
(g) Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored carbon dioxide and</td><td>e. Identification of all characteristics controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir, including:
Structural spill points</td><td>2.2.2.6 Seismic Survey (p. 2-10)
A 9-square-mile 3D seismic survey centered on the BFE facility was conducted December 2019 through January 2020 (Figure 2-6). The 3D seismic data allowed for visualization of deep geologic formations at lateral spatial intervals as short as tens of feet. The seismic data were used for assessment of the geologic structure and well placement.</td><td>Figure 2-9. Well log display of the interpreted lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations in MAG 1. (p. 2-14)</td></tr>
</table>

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
		associated fluids within the storage reservoir;	Stratigraphic discontinuities	Data products generated from the interpretation of the 3D seismic data were used as inputs into the geologic model that was used to simulate migration of the CO_2 plume. The 3D seismic data and MAG 1 well logs were used to interpret surfaces for the formations of interest within the survey area. These surfaces were converted to depth using the time-to-depth relationship derived from the MAG 1 dipole sonic log. The depth-converted surfaces for the storage reservoir and upper and lower confining zones were used as inputs for the geologic model. These surfaces captured detailed information about the structure and varying thickness of the formations between wells. A poststack inversion of the 3D seismic data was done using the MAG 1 well logs. Given the uncertainty in sonic log values related to washouts in the Broom Creek Formation in the MAG 1 well, indicated by the caliper log shown in Figure 2-5, inversion results of the 3D seismic data were not used to inform property distribution in the geologic model. Interpretation of the 3D seismic data and legacy 2D seismic data suggests there are no major stratigraphic pinch-outs or structural features with associated spill points in the area of review. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were observed in the 2D and 3D seismic data in the area of review. ***2.3.2 Mechanism of Geologic Confinement*** (p. 2-26) *See discussion above under 2.3.2 Mechanism of Geologic Confinement*	**Figure 2-10.** Regional well log stratigraphic cross sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. (p. 2-15) **Figure 2-11**. Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. (p. 2-16) **Figure 2-12.** Structure map of the Broom Creek Formation across the greater Blue Flint project area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map. (p. 2-17) **Figure 2-13.** Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. (p. 2-18)
	NDAC § 43-05-01-05(1)(b)(2)(c)	**NDAC § 43-05-01-05(1)(b)(2)** (c) Any regional or local faulting;	f. Any regional or local faulting;	**2.5 Faults, Fractures, and Seismic Activity** (First two paragraphs on p. 2-85) In the area of review, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from MAG 1 that suggest the injection interval, Broom Creek Formation (28,600 mg/L), is isolated from the next permeable interval, the Inyan Kara Formation (15,600 mg/L) (Appendix A). A regional structural feature, the Stanton Fault, is discussed in this section. This section also discusses the seismic history of North Dakota and the low probability that seismic activity will interfere with containment. ***2.5.1 Stanton Fault*** (p. 2-86) The Stanton Fault is a suspected Precambrian basement fault interpreted by Sims and others (1991), who–interpreted this northeast-southwest trending feature using available borehole data and regional gravity and magnetic data. The Stanton Fault is interpreted by Sims and others (1991) to be approximately 0.7 miles from the MAG 1 well (Figure 2-66). Given the resolution of the regional gravity and magnetic data and limited amount of borehole data used to interpret this suspected fault, there is a lot of uncertainty in the lateral extent and the location of the feature. No studies describing the possible vertical extent of this feature or impact on overlying sedimentary layers have been published. Lack of historical earthquakes in the area suggests that if the suspected Stanton Fault does exist it is inactive.	**Figure 2-66.** Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016). (p. 2-87) **Figure 2-67**. Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box). (p. 2-88) **Figure 2-68.** Cross section of Line 1 showing interpreted seismic horizons

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
				2D and 3D seismic data were used to characterize the subsurface within the project area and determine if the suspected Stanton Fault or other faults are present within the area of review. There is no indication of faulting within the 3D seismic data. Along the 2D seismic lines, there are areas where diffractions within the Precambrian basement can be seen and areas where there are discontinuities and flexures along seismic reflection events at the top of and within the Precambrian basement. These features may indicate the presence of faults. On Lines 1 and 2, shown in Figure 2-67 and 2-68, respectively, the diagonal seismic features within the Precambrian basement may be diffractions indicating the location of a structural feature such as a fault. However, there is no visible offset within the formations that directly overly the Precambrian basement, suggesting that if a fault is present it is confined to the Precambrian basement. On Lines 1 and 2, there are also discontinuities and flexures in several places along the interpreted top of the Precambrian basement and within the Precambrian basement that may also indicate the presence of faults. If these seismic features do correspond to faults, there is no indication that these features are present in the formations overlying the Precambrian basement and, therefore, do not have sufficient vertical extent to transect the storage reservoir and confining zones which are more than 5,000 feet above the basement.	(red lines) and area where diffractions are present withing the Precambrian basement (green box). (p. 2-88)
	NDAC § 43-05-01-05(1)(b)(2)(j)	**NDAC § 43-05-01-05(1)(b)(2)** (j) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone in the area of review, and a determination that they would not interfere with containment;	g. Properties of known or suspected faults and fractures that may transect the confining zone in the area of review: Location Orientation Determination of the probability that they would interfere with containment	***2.5.1 Stanton Fault*** (p. 2-86) *See discussion above under 2.5.1 Stanton Fault*	**Figure 2-66.** Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016). (p. 2-87) **Figure 2-67**. Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box). (p. 2-88) **Figure 2-68.** Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box). (p. 2-88)
	NDAC §§ 43-05-01-05(1)(b)(2) and (1)(b)(2)(m)	**NDAC § 43-05-01-05(1)(b)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity,	h. Information on any regional tectonic activity, and the seismic history, including: The presence and depth of seismic sources; Determination of the probability that seismicity would interfere with containment;	***2.5.2 Seismic Activity*** (p. 2-89) The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that "the Williston Basin as a whole is in an overburden compressive stress regime," which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2022). Between 1870 and 2015, 13 earthquakes were detected within the North Dakota portion of the Williston Basin (Table 2-21) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-69). The earthquake recorded closest to the project area occurred in 2008 52.3 miles to the east, near Goodrich, North Dakota (Table 2-21). The magnitude of this earthquake is estimated to have been 2.6.	**Table 2-21**. Summary of Earthquakes Reported to Have Occurred in North Dakota (p. 2-90) **Figure 2-69.** Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). (p. 2-91) **Figure 2-70**. Probabilistic map showing how often scientists expect damaging earthquake shaking around

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description
(Page Number)</th></tr>
<tr><td></td><td></td><td>local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:

NDAC § 43-05-01-05(1)(b)(2)
(m) Information on the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment;</td><td></td><td>Table 2-21. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016)
<table>
<tr><th>Date</th><th>Magnitude</th><th>Depth, miles</th><th>Longitude</th><th>Latitude</th><th>City or Vicinity of Earthquake</th><th>Map Label</th><th>Distance to Blue Flint Ethanol, miles</th></tr>
<tr><td>Sept. 28, 2012</td><td>3.3</td><td>0.4*</td><td>−103.48</td><td>48.01</td><td>Southeast of Williston</td><td>A</td><td>117.0</td></tr>
<tr><td>June 14, 2010</td><td>1.4</td><td>3.1</td><td>−103.96</td><td>46.03</td><td>Boxelder Creek</td><td>B</td><td>162.9</td></tr>
<tr><td>March 21, 2010</td><td>2.5</td><td>3.1</td><td>−103.98</td><td>47.98</td><td>Buford</td><td>C</td><td>136.4</td></tr>
<tr><td>Aug. 30, 2009</td><td>1.9</td><td>3.1</td><td>−102.38</td><td>47.63</td><td>Ft. Berthold southwest</td><td>D</td><td>60.1</td></tr>
<tr><td>Jan. 3, 2009</td><td>1.5</td><td>8.3</td><td>−103.95</td><td>48.36</td><td>Grenora</td><td>E</td><td>146.7</td></tr>
<tr><td>Nov. 15, 2008</td><td>2.6</td><td>11.2</td><td>−100.04</td><td>47.46</td><td>Goodrich</td><td>F</td><td>52.3</td></tr>
<tr><td>Nov. 11, 1998</td><td>3.5</td><td>3.1</td><td>−104.03</td><td>48.55</td><td>Grenora</td><td>G</td><td>156.2</td></tr>
<tr><td>March 9, 1982</td><td>3.3</td><td>11.2</td><td>−104.03</td><td>48.51</td><td>Grenora</td><td>H</td><td>154.8</td></tr>
<tr><td>July 8, 1968</td><td>4.4</td><td>20.5</td><td>−100.74</td><td>46.59</td><td>Huff</td><td>I</td><td>58.0</td></tr>
<tr><td>May 13, 1947</td><td>3.7**</td><td>U</td><td>−100.90</td><td>46.00</td><td>Selfridge</td><td>J</td><td>96.1</td></tr>
<tr><td>Oct. 26, 1946</td><td>3.7**</td><td>U</td><td>−103.70</td><td>48.20</td><td>Williston</td><td>K</td><td>131.5</td></tr>
<tr><td>April 29, 1927</td><td>0.2**</td><td>U</td><td>−102.10</td><td>46.90</td><td>Hebron</td><td>L</td><td>55.8</td></tr>
<tr><td>Aug. 8, 1915</td><td>3.7**</td><td>U</td><td>−103.60</td><td>48.20</td><td>Williston</td><td>M</td><td>127.3</td></tr>
</table>
* Estimated depth.
** Magnitude estimated from reported modified Mercalli intensity (MMI) value.</td><td>the United States (U.S. Geological Survey, 2019). (p. 2-92)</td></tr>
<tr><td></td><td>NDAC §§ 43-05-01-05(1)(b)(2) and (1)(b)(2)(n)</td><td>NDAC § 43-05-01-05(1)(b)
(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any</td><td>i. Illustration of the regional geology, hydrogeology, and the geologic structure of the storage reservoir area:
Geologic maps
Topographic maps
Cross sections</td><td>2.1 Overview of Project Area Geology (p. 2-1)
See discussion above under 2.1 Overview of Project Area Geology

4.4.3 Hydrology of USDW Formations (p. 4-16)
The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the area of investigation is to the northeast (Figure 4-9). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,500 ppm (Klausing, 1974). Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Honeyman, 2007). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering.</td><td>Figure 2-1. Topographic map of the project area showing the planned injection well, the planned monitoring well, and the Blue Flint Ethanol Plant (p. 2-2)

Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (red dashed line). (p. 2-12)

Figure 2-10. Regional well log stratigraphic cross</td></tr>
</table>

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		regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following: **NDAC § 43-05-01-05(1)(b)(2)** (n) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the facility area; and		Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the area of investigation. A cross section of these formations is presented in Figure 4-10. The upper formations are generally used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. The basal sandstone member of the Tongue River is persistent and a reliable source of groundwater in the region. The thickness of this basal sand ranges from approximately 50 to 200 ft and can be found at a depth of approximately 550 ft. Tongue River groundwaters are generally sodium bicarbonate with a TDS of approximately 1,000 ppm (Klausing, 1974). The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. The upper Sentinel Butte is approximately 150 ft thick in the area of investigation (Hemish, 1975). TDS concentrations in the Sentinel Butte Formation are approximately 1,000 ppm (Klausing, 1974). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers.	sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. (p. 2-15) **Figure 2-11.** Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. (p. 2-16) **Figure 2-13.** Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. (p. 2-18) **Figure 2-29**. Structure map of the lower Piper Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-40) **Figure 4-9.** Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. (p. 4-17) **Figure 4-10.** Southwest to northeast cross section of the major aquifer layers in McLean County. (p. 4-18)
	NDAC § 43-05-01-05(1)(b)(2)(d)	**NDAC § 43-05-01-05(1)(b)(2)** (d) An isopach map of the storage reservoirs;	j. An isopach map of the storage reservoir(s);	See Figure 2-8 on p. 2-13	**Figure 2-8**. Isopach map of the Broom Creek Formation in the greater Blue Flint project area. (p. 2-13)
	NDAC § 43-05-01-05(1)(b)(2)(e)	**NDAC § 43-05-01-05(1)(b)(2)** (e) An isopach map of the primary and any secondary containment barrier for the storage reservoir;	k. An isopach map of the primary containment barrier for the storage reservoir;	See Figure 2-32 on p. 2-43	**Figure 2-32.** Isopach map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area. (p. 2-43)
			l. An isopach map of the secondary containment barrier for the storage reservoir;	See Figure 2-30 on p. 2-41 and Figure 2-43 on p. 2-57	**Figure 2-30.** Isopach map of the lower Piper Formation in the greater Blue Flint project area. (p. 2-41)

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					Figure 2-43. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone (p. 2-57)
	NDAC § 43-05-01-05(1)(b)(2)(f)	**NDAC § 43-05-01-05(1)(b)(2)** (f) A structure map of the top and base of the storage reservoirs;	m. A structure map of the top of the storage formation;	See Figure 2-12 on p. 2-17	**Figure 2-12.** Structure map of the Broom Creek Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-17)
			n. A structure map of the base of the storage formation;	See Figure 2-44 on p. 2-58	**Figure 2-44.** Structure map of the Amsden Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-58)
	NDAC § 43-05-01-05(1)(b)(2)(i)	**NDAC § 43-05-01-05(1)(b)(2)** (i) Structural and stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	o. Structural cross sections that describe the geologic conditions at the storage reservoir;	See Figure 2-11 on p. 2-16 and Figure 2-13 on p. 2-18	**Figure 2-11**. Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. (p. 2-16) **Figure 2-13.** Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level.. (p. 2-18)
			p. Stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	See Figure 2-10 on p. 2-15	**Figure 2-10.** Regional well log stratigraphic cross sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. (p. 2-15)
	NDAC § 43-05-01-05(1)(b)(2)(h)	**NDAC § 43-05-01-05(1)(b)(2)** (h) Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any;	q. Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any;	**3.4 Simulation Results** (p. 3-11) The target injection rate of 200,000 tonnes per year (tpy) (548 tonnes per day) was consistently achievable over 20 years (Figure 3-9), translating to a cumulative 4 MMt of CO_2 injection (Figure 3-10). Simulations of CO_2 injection with the given well constraints, listed in Table 3-3, predicted the BHP would not reach the maximum BHP constraint of 2,970 psi (90% of the formation fracture pressure) as a result of injecting the target CO_2 volume of 200,000 tpy. The predicted maximum BHP and the average BHP during the 20 year injection period were 2,661 and 2,570 psi (Figure 3-11), respectively. Long-term CO_2 migration potential was also investigated through the numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase CO_2 injected into the formation rises to the bottom of the upper confining zone or lower-permeability layers present in the Broom Creek Formation and then outward. This process results in a higher concentration of CO_2 at the center which gradually spreads out toward the model edges where the CO_2 saturation is lower. Trapped CO_2 saturations, employed in the model to represent fractions of CO_2 trapped in small pores as immobile, tiny bubbles, ultimately immobilize	**Figure 3-13.** Top left, top right, and bottom left display average pressure increase within the Broom Creek Formation after 1, 10, and 20 years of simulated CO_2 injection operation. (p. 3-16) **Figure 6-1.** Predicted pressure increase in storage reservoir following 20 years of CO_2 injection at a rate of

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				the CO_2 plume and limit the plume's lateral migration and spreading. Figure 3-14 shows the CO_2 saturation at the injection well at the end of injection in north-to-south and east-to-west cross-sectional views. ***6.1.1 Pre- and Postinjection Pressure Differential*** (p. 6-1) Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of CO_2 injection. The simulations were conducted for 20 years of CO_2 injection at a rate of 200,000 metric tons per year, followed by a PISC period of 10 years. Figure 6-1 illustrates the predicted pressure differential at the conclusion of CO_2 injection. At the time that CO_2 injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of up to 120 psi at the location of the CO_2 injection well. There is insufficient pressure increase caused by CO_2 injection to move more than 1 cubic meter of formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the AOR delineation of this permit application (Section 3.0). Figure 6-2 illustrates the predicted gradual pressure decrease following the cessation of CO_2 injection, with the pressure at the injection well at the end of the PISC period anticipated to decrease 80 to 100 psi as compared to the pressure at the time CO_2 injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions.	200,000 metric tons per year (p. 6-2) **Figure 6-2.** Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection (p. 6-3)
	NDAC § 43-05-01-05(1)(b)(2)(l)	**NDAC § 43-05-01-05(1)(b)(2)** (l) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream;	r. Geomechanical information on the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide: Fractures Stress Ductility Rock strength In situ fluid pressure	*2.4.4.1 Borehole Image Fracture Analysis* (p. 2-71) Borehole image logs were used to evaluate fractures within the upper and lower confining zones. The natural fractures and in situ stress directions were assessed through the interpretation of the FMI log acquired from the MAG 1 well. The FMI log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed. Figures 2-56a, 2-56b, 2-57, 2-58, and 2-59 show sections of the interpreted borehole imagery and the primary features observed in the Piper, Spearfish Formation and Amsden Formation, respectively. Drilling induced fractures were observed in the Piper Formation as shown in Figure 2-56a in the far-right track. The far-right track on Figure 2-56b demonstrates that the tool provides information on surface boundaries and bedding features that characterize the Spearfish Formation. Figure 2-57 shows that features that have an electrically conductive signal in Spearfish Formation are observed. The logged interval of the Amsden Formation shows the main features represented by horizontal and oblique stratification fractures (Figure 2-58) and the presence of rare resistive fractures (Figure 2-59). Rose diagrams showing dip, dip azimuth, and strikes for conductive and drilling induced fractures observed in the borehole imagery are shown in Figures 2-60–2-62. These two fracture types were studied to evaluate potential leakage pathways as well as maximum horizontal stress. The diagrams shown in Figures 2-60 and 2-61 provide the dip orientation of the electrically conductive features in Spearfish and Amsden Formations, respectively. Breakouts were not identified in Spearfish or Amsden Formations. The drilling-induced fractures observed in the Piper Formation are oriented NE–SW ; these features are parallel to the maximum horizontal stress (SHmax), (Figure 2-62). *2.4.4.2 Stress, Ductility and Rock Strength* (p. 2-80) A 1D MEM was derived using the log data from MAG 1 well. Logs were edited to account for washouts in the Broom Creek and Amsden Formation sections using multilinear regressions. Geomechanical parameters in the Spearfish, Broom Creek, and Amsden Formations were estimated using the 1D MEM. The 1D MEM was used to estimate the vertical stress, pore pressure, minimum and maximum horizontal stresses (Shmin, SHmax), Poisson's ratio, Young's modulus, shear and bulk moduli, tensile, uniaxial compressive strength, and friction angle (Figure 2-63, Figure 2-64, and Figure 2-65). Table 2-19 shows the average and range of elastic and dynamic parameters, and stresses in the Spearfish, Broom Creek, and Amsden Formations. Since the SW Core samples collected from the MAG 1 well were horizontally oriented, it was not possible to determine ductility and rock strength through laboratory testing. The dimensions of the SW Core samples were inadequate for multistage triaxial testing. The static properties (Young's modulus, Poisson's ratio, bulk modulus, shear modulus, uniaxial strain modulus) and the dynamic properties (Young's modulus, Poisson's ratio) were estimated through the evaluation of the 1D MEM in the Spearfish, Broom Creek, and Amsden Formations. The dynamic parameters determined using the 1D MEM were converted into static parameters using specific equations derived from global correlations of dynamic to static parameters (Tutuncu and Sharma, 1992; Yale and Walters, 2016; Nowakowski, 2005; Yale and others, 1995; Zhang and Bentley, 2005; Yale and Jamieson, 1994).	**Figure 2-56a.** Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Piper-Picard Formation FMI image analysis. (p. 2-73) **Figure 2-56b**. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Spearfish Formation FMI image analysis. (p. 2-74) **Figure 2-57**. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, resistive fracture, mixed fracture, horizontal stratification, and oblique stratification) seen in Spearfish Formation FMI image analysis. (p. 2-75)

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				Log data were used to characterize stress in the storage complex to determine the fracture pressure gradient. In the injection zone, the parameters used to calculate stress were determined from the sand intervals in the Broom Creek Formation section. Rock strength defines the limit at which the stress conditions might induce the rock to mechanically fail. The unconfined compressive strength can be determined directly from rock mechanics tests, but in the MAG 1 well case, it was empirically estimated from well log data. Poisson's ratio was estimated using the available well logs, which resulted in an average value for the Broom Creek Formation of 0.32. The Biot factor was calculated using the effective porosity, static bulk modulus, and permeability, resulting in a range of 0.89-1. The pore pressure and hydropressure gradient were estimated using the true vertical depth (TVD), vertical stress (Sv), compressional slowness, and compressional velocity, respectively. The pore pressure and hydropressure gradients are equal to 0.448 and 0.429 psi/ft, respectively. In situ stresses such as Sv, maximum horizontal stress (SHmax), and minimum horizontal stress (Shmin) were calculated using specific parameters and methods (Table 2-20). Sv, which is related to the overburden or lithostatic pressure, is an important parameter in geomechanical modeling. In the Broom Creek Formation, overburden pressure was estimated through the bulk density log to the surface using the extrapolation method, resulting in an overburden gradient of 0.911 psi/ft. The poroelastic horizontal strain model is the most used method for horizontal stress calculation. The poroelastic horizontal strain model can be expressed using static Young's modulus, Poisson ratio, Biot's constant, overburden stress, and pore pressure. The poroelastic horizontal strain model was used to estimate the minimum horizontal stress (Plumb and Hickman, 1985; Aadnoy, 1990; Aadnoy and Bell, 1998; Brudy and Zoback, 1999). The SHmax is estimated from Shmin and process zone stress (as function of porosity). Based on the calculated stresses, the stress regime that can be seen in the Spearfish, Broom Creek, and Amsden Formations is a normal stress regime where Sv > SHmax > Shmin. Shmin magnitude could not be calibrated using the closure pressure measurements obtained from the openhole MDT microfracture in situ stress test because it was not performed in the MAG 1 well because of the large washout in the vicinity of the intervals of interest. The fracture gradient (FG) is calculated from pore pressure and overburden gradient. With the absence of closure pressure measurements in the Broom Creek Formation from in situ testing, a fracture gradient of 0.69 psi/ft was calculated in Schlumberger's Techlog software through the Matthew and Kelly method (Zhang and Yin, 2017). Equation 1 shows the equation used to derive the fracture gradient. $Fracture\ Gradient = K * (\sigma_v - \alpha P_p) + \alpha P_p$ [Eq. 1] Where: σ_v is the overburden gradient. α is Biot coefficient. P_p is pore pressure. K is the stress ratio (unitless) which Mathews and Kelly calculate with empirical correlation shown in Equation 2. $K=(-3.0*10^{-9})*TVD_{RefGL}^2+(8.0*10^{-5})*TVD_{RefGL}+0.2347$ [Eq. 2] Where: TVD_{RefGL} is true vertical depth minus Kelly Bushing.	**Figure 2-58.** Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis. (p. 2-77) **Figure 2-59**. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, stylolites, horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis. (p. 2-77) **Figure 2-60.** This example shows the dip azimuth and dip angle for conductive fractures seen in the Spearfish Formation. (p. 2-78) **Figure 2-61.** This example shows the dip azimuth and dip angle for conductive fractures seen in the Amsden Formation. (p. 2-79) **Figure 2-62.** This example shows the orientation of drilled-induced fractures in the Piper Formation. (p. 2-80) **Figure 2-63.** Geomechanical parameters in the Spearfish Formation. (p. 2-81) **Figure 2-64**. Geomechanical parameters in the Broom Creek Formation. (p. 2-82) **Figure 2-65**. Geomechanical parameters in the Amsden Formation. (p. 2-83)

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					Table 2-19. Ranges and Averages of the Elastic Properties Estimated from 1D MEM in Spearfish, Broom Creek and Amsden Formations (p. 2-84) **Table 2-20.** Ranges and Averages of the Sv, Hydropressure, Shmin, and Friction Angle (Fang) Estimated from 1D MEM in the Spearfish, Broom Creek, and Amsden Formations (p. 2-85)
	NDAC § 43-05-01-05(1)(b)(2)(o)	**NDAC § 43-05-01-05(1)(b)(2)** (o) Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement, are free of transmissive faults or fractures, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	s. Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement: Free of transmissive faults Free of transmissive fractures Effect on pressure dissipation Utility for monitoring, mitigation, and remediation.	***2.4.2 Additional Overlying Confining Zones*** (pp. 2-55 and 2-56) Several other formations provide additional confinement above the lower Piper interval. Impermeable rocks above the primary seal include the upper Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-15). Together with the Spearfish and lower Piper intervals, these intervals are 859 ft thick on average across the simulation area and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-42). Above the Inyan Kara Formation at the MAG 1 well, 2,512 ft of impermeable rocks acts as an additional seal between the Inyan Kara sandstone interval and lowermost USDW, the Fox Hills Formation (see Figure 2-43). Confining layers above the Inyan Kara sandstone interval include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-15). The formations between the Broom Creek and Inyan Kara Formations and between the Inyan Kara Formation and lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988). Sandstones of the Inyan Kara Formation comprise the first unit, with relatively high porosity and permeability above the injection zone and the primary sealing formation. The Inyan Kara represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring digital temperature sensor (DTS) data for the Inyan Kara Formation using the downhole fiber-optic cable provides an additional opportunity for mitigation and remediation (Section 5). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at MAG 1 is approximately 3,604 ft, and the interval itself is about 228 ft thick.	**Table 2-15** Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the MAG 1 well) (p. 2-56) **Figure 2-42**. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. (p. 2-56) **Figure 2-43.** Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. (p. 2-57)
Area of Review Delineation	NDAC §§ 43-05-01-05(1)(j) and (1)(b)(3)	**NDAC § 43-05-01-05(1)** j. An area of review and corrective action plan that meets the requirements pursuant to section 43-05-01-05.1; **NDAC § 43-05-01-05(1)(b)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one	The carbon dioxide storage reservoir area of review includes the areal extent of the storage reservoir and one mile outside of the storage reservoir boundary, plus the maximum extent of the pressure front caused by injection activities. The area of review delineation must include the following:	***4.1.1 Written Description*** (p. 4-1) North Dakota geologic storage of CO_2 regulations require that each storage facility permit (SFP) delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water [USDW] may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO_2 plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the MAG 1 well (NDIC File No. 37833) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-5]). NDAC § 43-05-01-05(1)(b)(3) requires "[a] review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 4-	**Figure 4-2**. AOR map in relation to nearby groundwater wells. (p. 4-4)

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		mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following:		1), the resulting AOR for the geologic storage project is delineated as being 1 mile from the SFP boundary. This extent ensures compliance with existing state regulations. All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 3-20 and 4-2) by a professional engineer pursuant to NDAC § 43-05-01-05(1)(b)(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected CO_2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 and 4-3, and Figure 4-3 and Figure 4-4). An extensive geologic and hydrogeologic characterization performed by a team of geologists from the EERC uncovered no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement. This section of the SFP application is accompanied by maps and tables that include information required and in accordance with NDAC § 43-05-01-05(1)(a) and (b) and § 43-05-01-05.1(2), such as the storage facility area, location of any proposed injection wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05(1)(a) and (b)(3) and § 43-05-01-05.1(2). Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1. See Figure 4-2 on p. 4-4	
	NDAC §§ 43-05-01-05(1)(b)(3) and (1)(a)	**NDAC § 43-05-01-05(1)(b)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: **NDAC § 43-05-01-05(1)** a. A site map showing the boundaries of the storage reservoir and the location of all proposed wells, proposed cathodic protection boreholes, and surface facilities within the carbon dioxide storage facility area;	a. A map showing the following within the carbon dioxide reservoir area: i. Boundaries of the storage reservoir ii. Location of all proposed wells iii. Location of proposed cathodic protection boreholes iv. Any existing or proposed aboveground facilities;	**2.3 Storage Reservoir (injection zone)** (p. 2-11) See Figure 2-7 on page 2-12. ***5.7.2 Soil Gas and Groundwater Monitoring*** (p. 5-14) See Figure 5-5 on page 5-14. *3.5.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-29) See Figure 3-21 on page 3-33. **5.2 Surface Facilities Leak Detection Plan** (p. 5-3) See Figure 5-1 on page 5-3.	**Figure 2-7.** Areal extent of the Broom Creek Formation in North Dakota (p. 2-12) **Figure 5-5.** Blue Flint's planned baseline and monitoring program for soil gas, shallow groundwater aquifers, and the Fox Hills Aquifer. (p. 5-14) **Figure 3-21.** Land use in and around the AOR. (p. 3-33) **Figure 5-1.** Site map showing the surface facilities layout for the Blue Flint CO_2 storage project. (p. 5-3)
	NDAC § 43-05-01-05(1)(b)(2)(a)	**NDAC § 43-05-01-05(1)(b)(2)** (a) All wells, including water, oil, and natural gas exploration and	b. A map showing the following within the storage reservoir area and within one mile outside of its boundary:	***4.1.2 Supporting Maps*** (p. 4-3) See Figure 4-2 on page 4-4.	**Figure 4-2.** AOR map in relation to nearby groundwater wells. (p. 4-4)

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		development wells, and other manmade subsurface structures and activities, including coal mines, within the facility area and within one mile [1.61 kilometers] of its outside boundary;	i. All wells, including water, oil, and natural gas exploration and development wells ii. All other manmade subsurface structures and activities, including coal mines;	*3.5.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-29) See Figure 3-21 on page 3-33.	**Figure 3-21.** Land use in and around the AOR. (p. 3-33)
	NDAC § 43-05-01-05(1)(c) and NDAC § 43-05-01-05.1(1)(a)	**NDAC § 43-05-01-05(1)** c. The extent of the pore space that will be occupied by carbon dioxide as determined by utilizing all appropriate geologic and reservoir engineering information and reservoir analysis, which must include various computational models for reservoir characterization, and the projected response of the carbon dioxide plume and storage capacity of the storage reservoir. The computational model must be based on detailed geologic data collected to characterize the injection zones, confining zones, and any additional zones; **NDAC § 43-05-01-05.1(1)** a. The method for delineating the area of review, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	c. A description of the method used for delineating the area of review, including: i. The computational model to be used ii. The assumptions that will be made iii. The site characterization data on which the model will be based;	***3.5.2 Risk-Based AOR Delineation*** (p. 3-20) The methods described by EPA (2013) for estimating the AOR under the Class VI rule (40 U.S. Code of Federal Regulations [CFR] 146.81 et seq.) were developed assuming that the storage reservoirs would be in hydrostatic equilibrium with overlying aquifers. However, in the state of North Dakota, and potentially elsewhere around the United States, candidate storage reservoirs are already overpressurized relative to overlying aquifers and thus subject to potential vertical formation fluid migration from the storage reservoir to the lowermost USDW, even prior to the planned storage project. Consequently, applying EPA (2013) methods to these geologic situations essentially results in an infinite AOR, which makes regulatory compliance infeasible. Several researchers have recognized the need for alternative methods for estimating the AOR for locations that are already overpressurized relative to overlying aquifers. For example, Birkholzer and others (2014) described the unnecessary conservatism in EPA's definition of critical pressure, which could lead to a heavy burden on storage facility permit (SFP) applicants. As an alternative, Burton-Kelly and others (2021) proposed a risk-based reinterpretation of this framework that would allow for a reduction in the AOR while ensuring protection of drinking water resources. A computational framework for estimating a risk-based AOR was proposed by Oldenburg and others (2014, 2016), who compared formation fluid leakage through a hypothetical open flow path in the baseline scenario (no CO_2 injection) to the incrementally larger leakage that would occur in the CO_2 injection case. The modeling for the risk-based AOR used semianalytical solutions to single-phase flow equations to model reservoir pressurization and vertical migration through leaky wells. These semianalytical solutions were extensions of earlier work for formation fluid leakage through abandoned wellbores by Raven and others (1990) and Avci (1994), which were creatively solved, coded, and compiled in FORTRAN under the name ASLMA (Analytical Solution for Leakage in Multilayered Aquifers) and extensively described by Cihan and others (2011, 2012) (hereafter "ASLMA Model"). Recently, White and others (2020) outlined a similar risk-based approach for evaluating the AOR using the National Risk Assessment Partnership (NRAP) Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS). However, NRAP-IAM-CS and the subsequent open-sourced version (NRAP-Open-IAM) are constrained to the assumption that the storage reservoir is in hydrostatic equilibrium with overlying aquifers and, therefore, may not accurately estimate the AOR for storage projects located in regions where the storage reservoir is overpressurized relative to overlying aquifers. Building a geologic model in a commercial-grade software platform (like Petrel; Schlumberger, 2020) and running fluid flow simulations using numerical reservoir simulation in a commercial-grade software platform (like CMG's compositional simulator, GEM) provide the "gold standard" for estimating pressure buildup in response to CO_2 injection (e.g., Bosshart and others, 2018). However, these numerical reservoir simulations are typically limited to the storage reservoir and primary seal formation (cap rock) and do not include the geologic units overlying the cap rock because of the computational burden of conducting such a complex simulation. In addition, geologic modeling of the overlying units may add a substantial amount of time and effort during prefeasibility-phase projects that are unwarranted given the amount of uncertainty that may be present if only a few nearby wells can be used for characterization activities. Earlier studies (e.g., Nicot and others, 2008; Birkholzer and others, 2009; Bandilla and others, 2012; Cihan and others, 2011, 2012) have shown that far-field fluid pressure changes outside of the CO_2 plume domain can be reasonably described by a single-phase flow calculation by representing CO_2 injection as an equivalent-volume injection of brine (Oldenburg and others, 2014). The semianalytical solutions embedded within the ASLMA Model have been shown to compare with the numerical model, TOUGH2-ECO2-N, and provided accurate results for pressures beyond the CO_2 plume zone (Birkholzer and others, 2009; Cihan and others, 2011, 2012). Therefore, the proposed workflow for delineating a risk-based AOR uses the ASLMA Model to examine pressure buildup in the storage reservoir and resultant effects of this buildup on the vertical migration of formation fluid via (single) hypothetical leaky wellbores located at progressively greater distances from the injection well (Figure 3-16).	**Figure 3-16.** Workflow for delineating a risk-based AOR for a SFP. (p. 3-22)

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				An important distinction between EPA Methods 1 and 2, which both calculate a critical pressure threshold (either ΔPi,f for Method 1 or ΔPc for Method 2) and the risk-based AOR approach is that the risk-based approach 1) calculates and maps the potential incremental flow of formation fluids from the storage reservoir to the USDW that could occur and then 2) delineates the areal extent beyond which no significant leakage would occur. Therefore, the region beyond which no significant leakage would occur does not present an endangerment to the USDW; hence, the region inside of this areal extent is the risk-based AOR.	
	NDAC § 43-05-01-05.1(1)(b)(1-4)	**NDAC § 43-05-01-05.1(1)** b. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date; (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and (4) How corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	d. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) Any monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date; (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; (4) How corrective action will be conducted if necessary, including: a. What corrective action will be performed prior to injection b. How corrective action will be adjusted if there are changes in the area of review;	**4.3 Reevaluation of AOR and Corrective Action Plan** (p. 4-13) BFE will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place no later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following: • Any changes to the monitoring and operational data prior to the scheduled Reevaluation Date will be identified. • Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and the computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and the operational data to be utilized as the basis for that update will be identified. • The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.	N/A
	NDAC § 43-05-01-05(1)(b)(2)(b)	**NDAC § 43-05-01-05(1)(b)(2)** (b) All manmade surface structures that are intended for temporary or permanent human occupancy within the	e. A map showing the areal extent of all manmade surface structures that are intended for temporary or permanent human occupancy within the storage reservoir area,	*3.5.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-29) See Figure 3-21 on p. 3-33	**Figure 3-21.** Land use in and around the AOR. (p. 3-33)

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		facility area and within one mile [1.61 kilometers] of its outside boundary;	and within one mile outside of its boundary;		
	NDAC § 43-05-01-05(1)(b)(2)	**NDAC § 43-05-01-05(1)(b)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:	f. A map and cross section identifying any productive existing or potential mineral zones occurring within the storage reservoir area and within one mile outside of its boundary;	**2.6 Potential Mineral Zones** (p. 2-92) See Figure 2-71 and Figure 2-72.	**Figure 2-71.** Coal beds of the Sentinel Butte and Bullion Creek (Tongue River) Formations showing the lignite coals in western North Dakota (p. 2-94) **Figure 2-72.** Hagel net coal isopach map. (p. 2-95)
	NDAC § 43-05-01-05(1)(b)(3) and NDAC § 43-05-01-05.1(2)(b)	**NDAC § 43-05-01-05(1)(b)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area,	g. A map identifying all wells within the area of review, which penetrate the storage formation or primary or secondary seals overlying the storage formation.	*3.5.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-29) See Figure 3-20 on p. 3-32 for nearby legacy wells.	**Figure 3-20.** Final AOR in relation to nearby legacy wells. (p. 3-32)

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		which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: **NDAC § 43-05-01-05.1(2)** b. Using methods approved by the commission, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone. Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the commission may require;			
	NDAC § 43-05-01-05(1)(b)(3)(a) NDAC § 43-05-01-05(1)(b)(3)(b) NDAC § 43-05-01-05(1)(b)(3)(c)	**NDAC § 43-05-01-05(1)(b)(3)** (a) A determination that all abandoned wells have been plugged and all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping from the storage reservoir; **NDAC § 43-05-01-05(1)(b)(3)** (b) A description of each well's type, construction, date drilled, location, depth, record of plugging, and completion; **NDAC § 43-05-01-05(1)(b)(3)** (c) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all underground sources of drinking water, water wells, and springs	h. A review of these wells must include the following: (1) A determination that all abandoned wells have been plugged in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation; (2) A determination that all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation; (3) A description of each well: a. Type b. Construction c. Date drilled d. Location e. Depth	***4.1.1 Written Description*** (4th paragraph, p. 4-1) North Dakota geologic storage of CO_2 regulations require that each storage facility permit (SFP) delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water [USDW] may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO_2 plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the MAG 1 well (NDIC File No. 37833) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-5]). NDAC § 43-05-01-05(1)(b)(3) requires "[a] review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 4-1), the resulting AOR for the geologic storage project is delineated as being 1 mile from the SFP boundary. This extent ensures compliance with existing state regulations. ***4.1.2 Supporting Maps*** See Figure 4-2 on p. 4-4. **4.2 Corrective Action Evaluation (p. 4-8)** See Table 4-2 on p. 4-6, Table 4-3 on p. 4-7, Table 4-4 on p. 4-8, and Table 4-5 on p. 4-9.	**Figure 4-2.** AOR map in relation to nearby groundwater wells. Shown are the stabilized CO2 plume extent postinjection (dashed red boundary), storage facility area (dashed purple boundary), and 1-mile AOR (dashed black boundary). All groundwater wells in the AOR are identified above. All observation/monitoring wells shown are shallow groundwater wells associated with the mine activities. No springs are present in the AOR. (p. 4-4) **Figure 3-20.** Final AOR in relation to nearby legacy wells. Shown is the storage facility area (purple polygon) and AOR (black polygon). Orange circles represent legacy oil and gas wells near

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	NDAC §§ 43-05-01-05(1)(b)(3)(d) and (e) NDAC § 43-05-01-05(1)(b)(3)(f)	within the area of review; their positions relative to the injection zone; and the direction of water movement, where known; **NDAC § 43-05-01-05(1)(b)(3)** (d) Maps and cross sections of the area of review; **NDAC § 43-05-01-05(1)(b)(3)** (e) A map of the area of review showing the number or name and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, state-approved or United States environmental protection agency-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features, including structures intended for human occupancy, state, county, or Indian country boundary lines, and roads; **NDAC § 43-05-01-05(1)(b)(3)** (f) A list of contacts, submitted to the commission, when the area of review extends across state jurisdiction boundary lines;	f. Record of plugging g. Record of completion (4) Maps and stratigraphic cross sections of all underground sources of drinking water within the area of review indicating the following: a. Their positions relative to the injection zone b. The direction of water movement, where known c. General vertical and lateral limits d. Water wells e. Springs (5) Map and cross sections of the area of review; (6) A map of the area of review showing the following: a. Number or name and location of all injection wells b. Number or name and location of all producing wells c. Number or name and location of all abandoned wells d. Number of name and location of all plugged wells or dry holes e. Number or name and location of all deep stratigraphic boreholes f. Number or name and location of all state-approved or United States Environmental Protection Agency-approved subsurface cleanup sites g. Name and location of all surface bodies of water	See Figure 4-3 on p. 4-10, Figure 4-4 on p. 4-11, and Figure 4-5 on p. 4-12. **4.4 Protection of USDWs (Broom Creek Formation)** (p. 4-13) Figure 4-9 on page 4-17 and Figure 4-10 on page 4-18	the storage facility area. (p. 3-32) **Table 4-2.** Wells in AOR Evaluated for Corrective Action (p. 4-6) **Table 4-3**. Ellen Samuelson 1 (NDIC File No. 1516) Well Evaluation (p. 4-7) **Table 4-4.** Well #1 (ND-UIC-106) Well Evaluation (p. 4-8) **Table 4-5.** Wallace O. Gradin 1 (NDIC File No. 4810) Well Evaluation (p. 4-9) **Figure 4-3** Ellen Samuelson 1 (NDIC File No. 1516) well schematic showing the location of cement plugs. (p. 4-9) **Figure 4-4.** Well #1 (ND-UIC-106) well schematic. (p. 4-10) **Figure 4-5.** Wallace O. Gradin 1 (NDIC File No. 4810) well schematic showing the location of cement plugs. (p. 4-12) **Figure 4-9.** Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in central McLean County (modified from Fischer, 2013). (p. 4-17) **Figure 4-10**. Southwest to northeast cross section of the major aquifer layers in McLean County. The black dots on the inset map represent the locations of the

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			h. Name and location of all springs i. Name and location of all mines (surface and subsurface) j. Name and location of all quarries k. Name and location of all water wells l. Name and location of all other pertinent surface features m. Name and location of all structures intended for human occupancy n. Name and location of all state, county, or Indian country boundary lines o. Name and location of all roads (7) A list of contacts, submitted to the Commission, when the area of review extends across state jurisdiction boundary lines.		six wells used to create the cross section. The wells are labeled with their designation at the top of the cross section. (p. 4-18)
	NDAC § 43-05-01-05(1)(b)(3)(g)	**NDAC § 43-05-01-05(1)(b)(3)** (g) Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review; and	i. Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review.	See Appendices A (p. A-1) and B (p. B-1)	N/A
Required Plans	NDAC § 43-05-01-05(1)(k)	**NDAC § 43-05-01-05(1)** k. The storage operator shall comply with the financial responsibility requirements pursuant to section 43-05-01-9.1;	a. Financial Assurance Demonstration	**12.2 Financial Instruments** (pp. 12-1 and p. 12-2) Blue Flint is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments: • Blue Flint will increase the existing MAG 1 well bond to cover the costs of plugging the injection well in accordance with NDAC § 43-05-01-11.5. • Blue Flint will establish a bond, escrow account or other financial instrument to implement PISC and facility closure activities in accordance with NDAC § 43-05-01-19. • A third-party pollution liability insurance policy with an aggregate limit of $9 million will be secured to cover the costs of implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13.	**Table 12-1.** Cost estimates for Activities to Be Covered (p. 12-2)

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
				The estimated total costs of these activities are presented in Table 12-1. Section 12.2 of this FADP provides additional details of the financial responsibility cost estimates for each activity.	
	NDAC § 43-05-01-05(1)(d)	**NDAC § 43-05-01-05(1)(d)** d. An emergency and remedial response plan pursuant to section 43-05-01-13;	b. An emergency and remedial response plan;	**7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN** (p. 7-1) Blue Flint Sequester Company LLC (Blue Flint) and Blue Flint Ethanol LLC, operator of the Blue Flint Ethanol (BFE) facility, will enter into an agreement whereby Blue Flint employees, contractors and agents are required to follow the BFE facility emergency action plans, including, but not limited to, the BFE facility response plan. This emergency and remedial response plan (ERRP) for the geologic storage project 1) describes the local resources and infrastructure in proximity to the project site; 2) identifies events that have the potential to endanger USDWs during the construction, operation, and postinjection site care periods of the geologic storage project, building upon the screening-level risk assessment (SLRA); and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing BFE facility response plan and risk management plan (and incorporated into the BFE Integrated Contingency Plan [ICP]) is described, emphasizing the facility response team and command structure, facility evacuation plans, HazMat (hazardous materials) capabilities, and emergency communication plans. Lastly, procedures are presented for regularly conducting an evaluation of the adequacy of the ERRP and updating it, if warranted, over the lifetime of the geologic storage project. Copies of this ERRP are available at the Blue Flint's office and the BFE facility. Note: Refer to the following key tables: Table 7-4 on p. 7-5 and Table 7-5 on p. 7-6 through 7-8.	**Table 7-4**. Potential Project Emergency Events and Their Detection (p. 7-5) **Table 7-5.** Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (pp. 7-6 through 7-8)
	NDAC § 43-05-01-05(1)(e)	**NDAC § 43-05-01-05(1)** e. A detailed worker safety plan that addresses carbon dioxide safety training and safe working procedures at the storage facility pursuant to section 43-05-01-13;	c. A detailed worker safety plan that addresses the following: i. Carbon dioxide safety training ii. Safe working procedures at the storage facility;	**8.0 WORKER SAFETY PLAN** (p. 8-1)	N/A
	NDAC § 43-05-01-05(1)(f)	**NDAC § 43-05-01-05(1)** f. A corrosion monitoring and prevention plan for all wells and surface facilities pursuant to section 43-05-01-15;	d. A corrosion monitoring and prevention plan for all wells and surface facilities;	**5.3 Flowline Corrosion Prevention and Detection Plan (p. 5-5)** The purpose of this corrosion prevention and detection plan is to monitor the flowline and well materials during the operational phase of the project to ensure that all materials meet the minimum standards for material strength and performance. **5.3.1 Corrosion Prevention (p. 5-5)** The chemical composition of the CO_2 stream is highly pure and dry (Table 5-2), and the target moisture level for the CO_2 stream is estimated to be up to 12 ppm by volume. These factors help to prevent corrosion of the surface facilities. In addition, the flowline construction materials will be CO_2-resistant in accordance with API 17J (2017) requirements. The flowline will be constructed using FlexSteel, a 3-layer flexible steel pipe product. The inner and outer layers contain a CO_2-resistant polyethylene liner, and the middle layer comprises reinforcing steel. FlexSteel product specifications can be found in Appendix C (Attachment A-3). **5.3.2 Corrosion Detection (p. 5-5)** The flowline will use the corrosion coupon method to monitor for corrosion throughout the operational phase of the project, focusing on the loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. A coupon sample port will be located near the liquefaction outlet, and sampling will occur quarterly during the first year of injection and once a year thereafter. The process that will be used to conduct each coupon test is described in Appendix C under Section 1.3. **5.6 Wellbore Corrosion Prevention and Detection Plan (p. 5-9)** To prevent corrosion of the well materials, the following preemptive measures will be implemented in the MAG 1 and MAG 2 wellbores: 1) cement in the injection well opposite the injection interval and extending 1850 feet uphole will be CO_2-resistant; 2) the well casing will also be CO_2-resistant from the bottomhole to a depth just above the Spearfish Formation (upper confining zone); 3) the well tubing (poly-lined) will be CO_2-resistant from the injection interval to surface; 4) the packer (Ni-Plated) will be CO_2-resistant; and 5) the packer fluid will be an industry standard corrosion inhibitor. To detect possible signs of corrosion in the MAG 1 and MAG 2, corrosion coupon samples will be used which will be constructed from the well materials. The corrosion coupon method is described in Section 5.3.2 of this testing and monitoring plan. In addition, the USIT or an equivalent wall thickness or imaging tool (e.g., EM CIL) may also be considered for detecting corrosion in the MAG 1 and MAG 2 wellbores. The USIT (or equivalent tool) may be used during workovers but no less than every 5 years.	**Figure 5-1.** Site map showing the surface facilities layout for the Blue Flint CO2 Storage Project. (p. 5-3) **Figure 5-2**. Diagram of surface connections and major components of the CCS system from the liquefaction outlet to the MAG 1 wellsite. (p. 5-4) **Table 5-2.** Chemical Content of the CO2 Stream (p. 5-3)

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description
(Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>Table 5-2. Chemical Content of the captured CO_2
<table>
<tr><th>Chemical Content</th><th>Volume %</th></tr>
<tr><td>Carbon Dioxide</td><td>99.98</td></tr>
<tr><td>Water, Oxygen, Nitrogen, Hydrogen Sulfide, C_2^+, and Hydrocarbons</td><td>Trace amounts of each (0.02 total)</td></tr>
<tr><td>Total</td><td>100.00</td></tr>
</table></td><td></td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(g)</td><td>NDAC § 43-05-01-05(1)
g. A leak detection and monitoring plan for all wells and surface facilities pursuant to section 43-05-01-14. The plan must:

(1) Identify the potential for release to the atmosphere;

(2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and

(3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.</td><td>e. A surface leak detection and monitoring plan for all wells and surface facilities pursuant to NDAC § 43-05-01-14;</td><td>5.2 Surface Facilities Leak Detection Plan (p. 5-3)
The purpose of this leak detection plan is to monitor the surface facilities from the liquefaction outlet to the injection wellsite during the operational phase of the Blue Flint CO_2 storage project.

Surface components of the injection system, including the flowline and CO_2 injection wellhead, will be monitored with leak detection equipment. The flowline will be monitored continuously via dual flowmeters located at the liquefaction outlet and near the wellhead for performing mass balance calculations. The flowline will also be regularly inspected for any visual or auditory signs of equipment failure and monitored continuously with one pressure gauge at the capture facility outlet and one at the wellhead. CO_2 detection stations will be located on the flowline risers and the CO_2 injection wellhead. The leak detection equipment will be integrated with automated warning systems that notify Blue Flint's operations center, giving the operator the ability to remotely close the valves in the event of an anomalous reading.

Performance targets designed for the Blue Flint CO_2 storage project to detect potential leaks in the flowline are provided in Table 5-3. The performance targets are dependent upon the actual performance of instrumentation (e.g., pressure gauges) and the SCADA system (described further in Attachment A-1 of Appendix C), which uses software to track the status of the flowline in real time by comparing live pressure and flow rate data to a comprehensive predictive model. The performance targets assume a flow rate of approximately 550 metric tons of CO_2 per day. An alarm will trigger on the SCADA system if a volume deviation of more than 1% is registered.

CO_2 detection stations will be mounted on the inside of the wellhead enclosures to detect any potential indoor leaks. An additional CO_2 detection station will be mounted outside the injection wellhead enclosure to detect any potential atmospheric leaks at the wellsite. The stations can detect CO_2 concentrations as low as 2% by volume and have an integrated alarm system for increases of from 0% to 0.4% and 0.4% to 0.8% by volume. The stations are further described in Appendix C (Attachment A-2).

Field personnel will have multigas detectors with them for wellsite visits or flowline inspections to detect potential leaks from the equipment. The multigas detectors will primarily monitor CO_2 levels in workspace atmospheres.

Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be made available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.</td><td>N/A</td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(h)</td><td>NDAC § 43-05-01-05(1)
h. A leak detection and monitoring plan to monitor any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile [1.61 kilometers] of the facility area's</td><td>f. A subsurface leak detection and monitoring plan to monitor for any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile of the facility area's outside boundary;</td><td>5.7 Environmental Monitoring Plan (p. 5-9, paragraphs 1, 3, and 4)
To verify the injected CO_2 is contained in the storage reservoir and to protect all USDWs, multiple environments will be monitored.

The deep subsurface environment, defined as the region from below the lowest USDW to the base of the storage reservoir, will be monitored with multiple methods, starting with the above-zone monitoring interval (AZMI) or the geologic interval from the Spearfish Formation to the Inyan Kara Formation. The AZMI will be monitored with DTS in the MAG 1 and MAG 2 as well as PNLs in the MAG 2 (further described in Attachment A-5 of Appendix C).

The storage reservoir will be monitored with both direct and indirect methods. Direct methods include DTS and BHP/T measurements in the MAG 1 and MAG 2, as well as PNLs in the MAG 2. Indirect methods include time-lapse seismic and passive seismicity. During injection operations, pressure falloff testing to demonstrate storage reservoir injectivity in the MAG 1 wellbore will be carried out at least once every 5 years. These efforts will provide additional assurance that surface and near-surface environments are protected and that the injected CO_2 is safely and permanently stored in the storage reservoir.</td><td></td></tr>
</table>

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
		outside boundary. Provisions in the plan will be dictated by the site characteristics as documented by materials submitted in support of the permit application but must: (1) Identify the potential for release to the atmosphere; (2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.		***5.7.3 Deep Subsurface Monitoring*** (p. 5-15) Blue Flint will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure relative to the permitted storage reservoir. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and postoperational periods. The methods described in Table 5-6 will be used to characterize the CO_2 plume's saturation and pressure within the AOR. Blue Flint will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan (Ayash and others, 2017) at least once every 5 years. During each review, monitoring and operational data will be analyzed, and the AOR will be reevaluated. Based on this reevaluation, it will either be demonstrated that 1) no amendment to the testing and monitoring program is needed or 2) modifications are necessary to ensure proper monitoring of storage performance is achieved moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by NDIC. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed. Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of the CO_2 plume and pressure distribution relative to the permitted geologic storage facility. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will, in turn, be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.	
	NDAC § 43-05-01-05(1)(l)	**NDAC § 43-05-01-05(1)** l. A testing and monitoring plan pursuant to section 43-05-01-11.4;	g. A testing and monitoring plan pursuant to NDAC Section 43-05-01-11.4;	See Section **5.0 TESTING AND MONITORING PLAN** and **APPENDIX C: QUALITY ASSURANCE SURVEILLANCE PLAN** Note: See Table 5-1 on p. 5-2; Table 5-4 on p. 5-7; Table 5-5 on pp. 5-8 through 5-9; and Table 5-6 on pp. 5-10 through 5-11, for detailed summaries of the testing and monitoring plan.	**Table 5-1.** Overview of Blue Flint's Testing and Monitoring Plan (p. 5-2) **Table 5-4.** Overview of Blue Flint's Mechanical Integrity Testing Plan (p. 5-7) **Table 5-5.** Testing and Logging Plan for the MAG 1 Wellbore (pp. 5-8 through 5-9) **Table 5-6.** Summary of Environmental Baseline and Operational Monitoring (pp. 5-10 through 5-11)
	NDAC § 43-05-01-05(1)(i)	**NDAC § 43-05-01-05 (1)** i. The proposed well casing and cementing program detailing compliance with section 43-05-01-09;	h. The proposed well casing and cementing program;	**9.0 WELL CASING AND CEMENTING PROGRAM** (p. 9-1)	**Figure 9-1.** MAG 1 as-constructed wellbore schematic. Note: top of cement (TOC), workover (WO). (p. 9-2) **Figure 9-2.** MAG 1 Proposed wellbore schematic as CO2 injector. (p. 9-3) **Figure 9-3.** Monitor Well MAG 2 proposed wellbore schematic. (p. 9-7)

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
	NDAC § 43-05-01-05(1)(m)	**NDAC § 43-05-01-05(1)** m. A plugging plan that meets requirements pursuant to section 43-05-01-11.5;	i. A plugging plan;	**10.1 MAG 1: P&A Program** (p. 10-1) **10.2 MAG 2 P&A Program** (p. 10-7)	**Figure 10-1**. Proposed CO2 injection well schematic for MAG 1. (p. 10-2) **Figure 10-2.** Schematic of proposed P&A plan for MAG 1. (p. 10-6) **Figure 10-3.** Proposed monitoring wellbore schematic for MAG 2. (p. 10-7) **Figure 10-4.** Schematic of proposed abandonment plan for monitoring well MAG 2. (p. 10-11)
	NDAC § 43-05-01-05(1)(n)	**NDAC § 43-05-01-05(1)** n. A postinjection site care and facility closure plan pursuant to section 43-05-01-19; and	j. A post-injection site care and facility closure plan.	**6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN (p. 6-1)** Note: Refer to Tables 6-1 on p. 6-4, and 6-2 on p. 6-5 for a summary of the postinjection site care monitoring plan.	**Table 6-1**. Overview of Blue Flint's PISC MAG 2 Mechanical Integrity Testing and Corrosion Monitoring Plan (p. 6-4) **Table 6-2.** Overview of Blue Flint's PISC Environmental Monitoring Plan. (p. 6-5)
Storage Facility Operations	NDAC § 43-05-01-05(1)(b)(4)	**NDAC § 43-05-01-05(1)(b)** (4) The proposed calculated average and maximum daily injection rates, daily volume, and the total anticipated volume of the carbon dioxide stream using a method acceptable to and filed with the commission;	The following items are required as part of the storage facility permit application: a. The proposed average and maximum daily injection rates;	**11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)** This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as documented in NDAC § 43-05-01-05 (Table 11-1) and § 43-05-01-11.3.	**Table 11.1.** Proposed Injection Well Operating Parameters (p. 11-1)
			b. The proposed average and maximum daily injection volume;		
			c. The proposed total anticipated volume of the carbon dioxide to be stored;		

Table 11-1. Proposed Injection Well Operating Parameters

Item	Values	Description/Comments
	Injected Volume	
Total Injected Volume	4,000,000 tonnes	Based on 200,000 tonnes/year for 20 years at an average daily injection rate of 548 tonnes/day
Injection Rates		
Average Injection Rate	548 tonnes/day (10.35 MMscf/day)	Based on 200,000 tonnes/year for 20 years of injection (using 365 operating days per year)
Average Maximum Daily Injection Rate	2,729 tonnes/day (51.56 MMscf/day)	Based on maximum bottomhole injection pressure (2,970 psi)

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<tbody>
<tr><td rowspan="4"></td><td rowspan="2">NDAC § 43-05-01-05(1)(b)(5)</td><td rowspan="2">NDAC § 43-05-01-05(1)(b)
(5) The proposed average and maximum bottom hole injection pressure to be utilized at the reservoir. The maximum allowed injection pressure, measured in pounds per square inch gauge, shall be approved by the commission and specified in the permit. In approving a maximum injection pressure limit, the commission shall consider the results of well tests and other studies that assess the risks of tensile failure and shear failure. The commission shall approve limits that, with a reasonable degree of certainty, will avoid initiating a new fracture or propagating an existing fracture in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water;</td><td>d. The proposed average and maximum bottom hole injection pressure to be utilized;</td><td rowspan="2"><table>
<tr><th>Pressures</th><th></th><th></th></tr>
<tr><td>Formation Fracture Pressure at Top Perforation</td><td>3,300 psi</td><td>Based on geomechanical analysis of formation fracture gradient as 0.69 psi/ft (see Section 2.0)</td></tr>
<tr><td>Average Surface Injection Pressure</td><td>1,158 psi</td><td>Based on 200,000 tonnes/year for 20 years at an average daily injection rate of 548 tonnes/day) using the designed 2.875-inch tubing</td></tr>
<tr><td>Surface Maximum Injection Pressure</td><td>4,300 psi</td><td>Based on maximum bottomhole injection pressure (2,970 psi) using the designed 2.875-inch tubing</td></tr>
<tr><td>Average Bottomhole Pressure (BHP)</td><td>2,570 psi</td><td>Based on average daily injection rate of 548 tonnes/day</td></tr>
<tr><td>Calculated Maximum BHP</td><td>2,970 psi</td><td>Based on 90% of the formation fracture pressure of 3,300 psi</td></tr>
</table></td><td rowspan="2"></td></tr>
<tr><td>e. The proposed average and maximum surface injection pressures to be utilized;</td></tr>
<tr><td rowspan="2">NDAC § 43-05-01-05(1)(b)(6)</td><td rowspan="2">NDAC § 43-05-01-05(1)(b)
(6) The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone pursuant to section 43-05-01-11.2;</td><td>f. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone;</td><td rowspan="2">5.5 Well Testing and Logging Plan (p. 5-7)
Table 5-5 describes the testing and logging plan developed for the MAG 1 wellbore (exclusive of any coring) to establish baseline conditions. Included in the table is a description of fluid sampling and pressure testing performed. The logging and testing plan for the MAG 2 wellbore will be the same as what is presented in Table 5-5, with the addition of a PNL but excluding dipole, elemental capture spectroscopy (ECS), fluid swab, and FMI. Table 5-4 and Table 5-6 (see Section 5.7) detail the frequency with which logging data will be acquired and in which wellbores throughout the operational period of the project.
See Appendix A: MAG 1 FORMATION FLUID SAMPLING

2.0 GEOLOGIC EXHIBITS
2.2 Data and Information Services (p. 2-4)
Several sets of data were used to characterize the injection and confining zones to establish their suitability for the storage and containment of injected CO_2. Data sets used for characterization included both existing data (e.g., from published literature, publicly available databases, private data from brokers) and site-specific data acquired specifically to characterize the storage complex.

2.2.2 Site-Specific Data (p. 2-6)
Site-specific efforts to characterize the proposed storage complex generated multiple data sets, including geophysical well logs, petrophysical data, and 3D seismic data. The MAG 1 well was drilled in 2020 specifically to gather subsurface geologic data to support the development of a CO_2 storage facility permit and serve as a future CO_2 injection well. Downhole logs were acquired, and sidewall core (SW Core) was collected from the proposed storage complex (i.e., the Lower Piper, Spearfish, Broom Creek, and Amsden Formations) at the time the well was drilled (Figure 2-5). In May 2022, fluid samples and temperature and pressure measurements were collected from the Broom Creek in the MAG 1 well.

2.2.2.2 Core Sample Analyses (p. 2-8)
Fifty 1.5" SW Core samples were recovered from the Broom Creek storage complex in MAG 1: five samples from the lower Piper Formation, twelve from the Spearfish Formation, twenty-three from the Broom Creek Formation, and ten from the Amsden Formation. Forty-two of the SW Core samples were analyzed to determine petrophysical properties. This core was analyzed to characterize the lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations and correlated to the well log data. Core analysis also</td><td rowspan="2">Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore (p. 5-8 through 5-9)</td></tr>
<tr><td>g. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the confining zone;</td></tr>
</tbody>
</table>

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
				included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), thin-section analysis, and capillary entry pressure measurements. The results were used to inform geologic modeling and predictive simulation inputs and assumptions.	

Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore

OH/CH* Depth, ft	Logging/Testing	Justification	NDAC § 43-05-01
Surface Section			
OH 1340-0	Triple combo (resistivity, bulk density, density and neutron porosity, GR, caliper, and spontaneous potential [SP])	Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume.	11.2(1)(b)(1)
CH 1260-0	Ultrasonic, casing collar locator (CCL), variable-density log (VDL), GR, and temperature log	Identified cement bond quality radially. Interpreted minor cement channeling throughout several isolated intervals and determined good azimuthal cement coverage and zonal isolation.	11.2(1)(b)(2)
Intermediate Section			
OH 4170-1334	Triple Combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP)	Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. Provided input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve test design and interpretations. Generated core-log correlations.	11.2(1)(c)(1)
OH 4170-1334	Dipole sonic	Identified mechanical properties in intermediate section.	11.2(1)(c)(1)
OH 4170-3070	Dielectric scanner	Quantified petrophysical properties and salinity calculations within the intermediate zones (Inyan Kara Formation). Provided information on rock properties and fluid distribution as inputs for reservoir evaluation and management.	11.2(4)
CH 4070-30	Ultrasonic, CCL, VDL, GR, and temperature log	Identified cement bond quality radially. Interpreted good azimuthal cement coverage and casing condition. Evaluated the cement top and zonal isolation.	11.2(1)(c)(2)

* OH/CH – openhole/cased-hole

Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore (continued)

OH/CH Depth, ft	Logging/Testing	Justification	NDAC Code § 43-05-01
Long-string Section			
OH 7068-4163	Triple combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP)	Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume.	11.2(1)(c)(1)
OH 7556-4163	Dipole sonic	Identified mechanical properties of the rock including stress anisotropy. Provided compression	11.2(1)(c)(1)

<table>
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<tr><td></td><td></td><td></td><td></td><td>
<table>
<tr><td></td><td></td><td>and shear waves for seismic tie in and quantitative analysis of seismic data.</td><td></td></tr>
<tr><td>OH
5250-4250</td><td>Fullbore FMI</td><td>Verified no fracture networks exist in the Broom Creek Formation or confining layers to ensure safe storage of CO_2.</td><td>11.2(1)(c)(1)</td></tr>
<tr><td>OH
4741 and 4735</td><td>BHP/T survey</td><td>Measured Broom Creek Formation pressure and temperature in the wellbore.</td><td>11.2(2)</td></tr>
<tr><td>OH
4740-4733</td><td>Fluid swab</td><td>Collected fluid sample from the Broom Creek Formation for analysis.</td><td>11.2(2)</td></tr>
<tr><td>CH**
TBD</td><td>Ultrasonic, CCL, VDL, and GR</td><td>Will identify cement bond quality radially and determine azimuthal cement coverage. Will evaluate the cement top and zonal isolation.</td><td>11.2(1)(b)(2)</td></tr>
</table>
** Planned activity at the time of writing this permit to be completed prior to injection.
</td><td></td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(7)</td><td>NDAC § 43-05-01-05(1)(b)
(7) The proposed stimulation program, a description of stimulation fluids to be used, and a determination that stimulation will not interfere with containment; and</td><td>h. The proposed stimulation program:
1. A description of the stimulation fluids to be used
2. A determination of the probability that stimulation will interfere with containment;</td><td>11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)
This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as documented in NDAC § 43-05-01-05 (Table 11-1) and § 43-05-01-11.3.

11.1 MAG 1 Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-1)
As described in Section 9.1, the MAG 1 well will be reentered and completed as a CO2 injector (Figures 11-1 and 11-2 and Tables 11-2 through 11-4). The following proposed completion procedure outlines the steps necessary to complete and test the well.

Note: See full procedure provided on pp. 11-1 through 11-3.</td><td>N/A</td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(8)</td><td>NDAC § 43-05-01-05(1)(b)
(8) The proposed procedure to outline steps necessary to conduct injection operations.</td><td>i. Steps to begin injection operations</td><td>11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)
This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as documented in NDAC § 43-05-01-05 (Table 11-1) and § 43-05-01-11.3.

11.1 MAG 1 Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-1)

Note: See full procedure provided on pp. 11-1 through 11-3.</td><td>N/A</td></tr>
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