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
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Section 11 – Injection Well and Storage Operations
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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

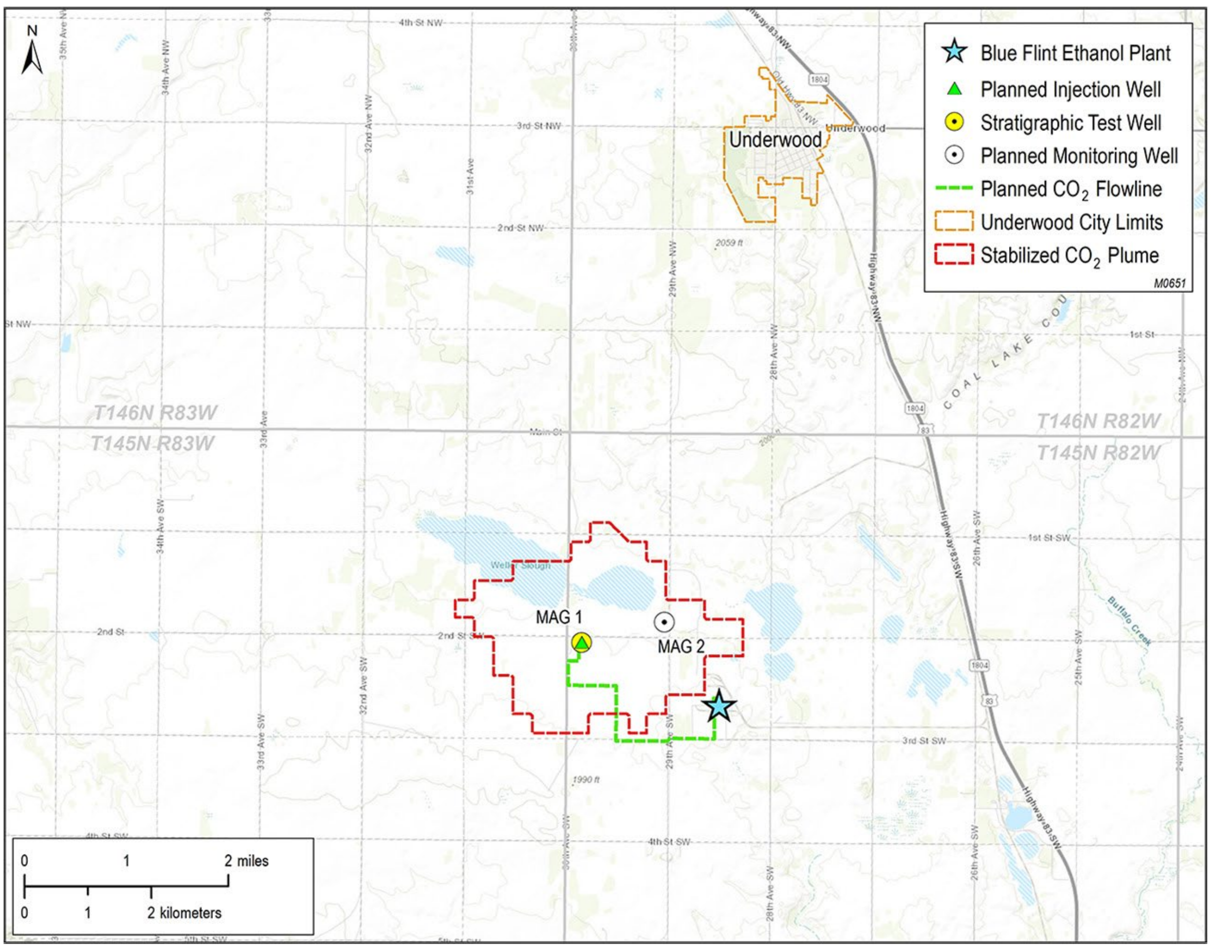

Figure 1-1. Location of the BFE facility, planned CO_2 flowline, and planned wells: CO_2 injection well (MAG 1) and monitoring well (MAG 2). The red outline indicates the projected stabilized CO_2 plume boundary.

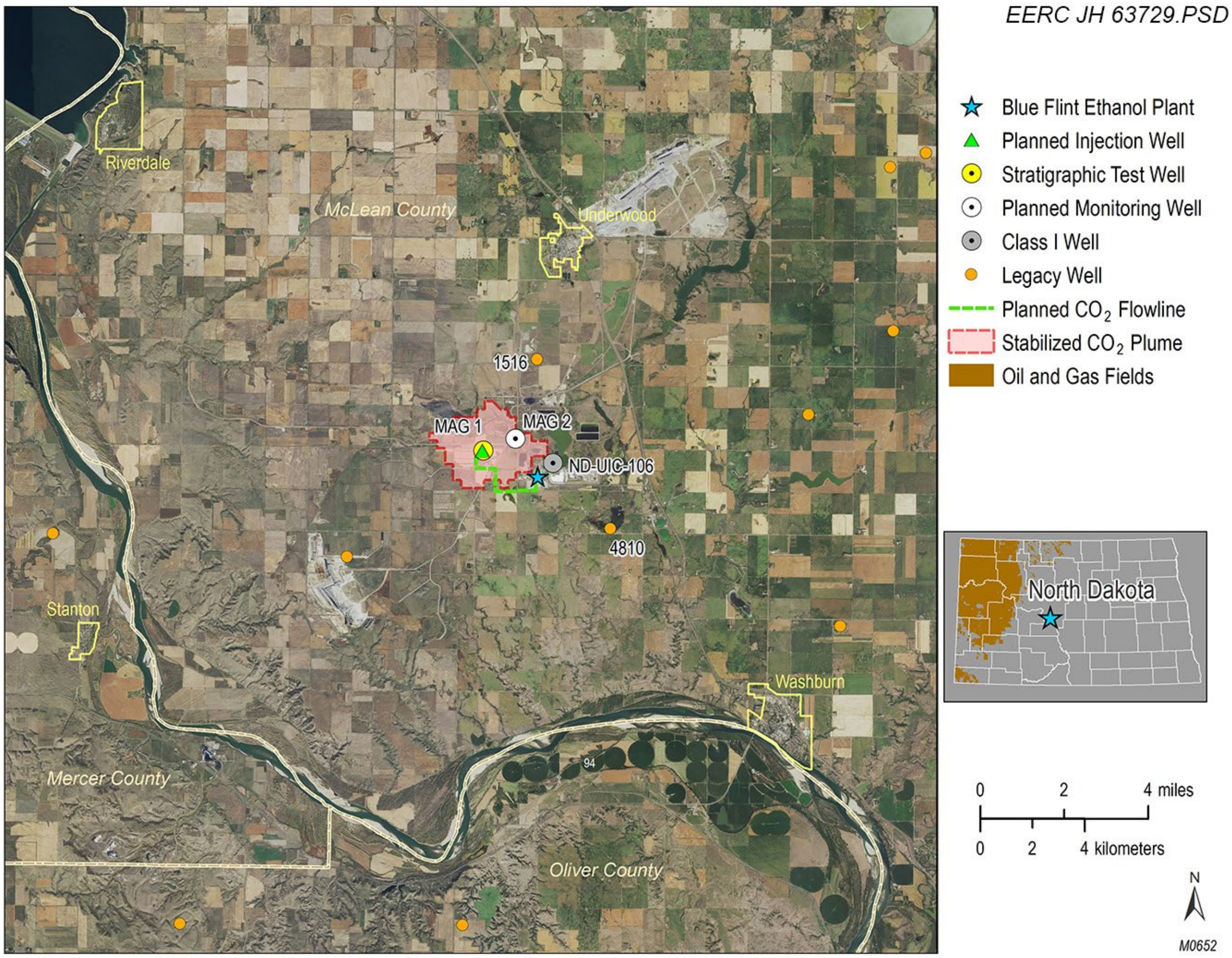

Figure 1-2. Map illustrating the locations of existing legacy wellbores around the projected stabilized CO_2 plume extent for the Blue Flint CO_2 storage project and nearby towns (outlined and labeled in yellow). The state reference map also reveals the geographic distribution of oil and gas fields in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

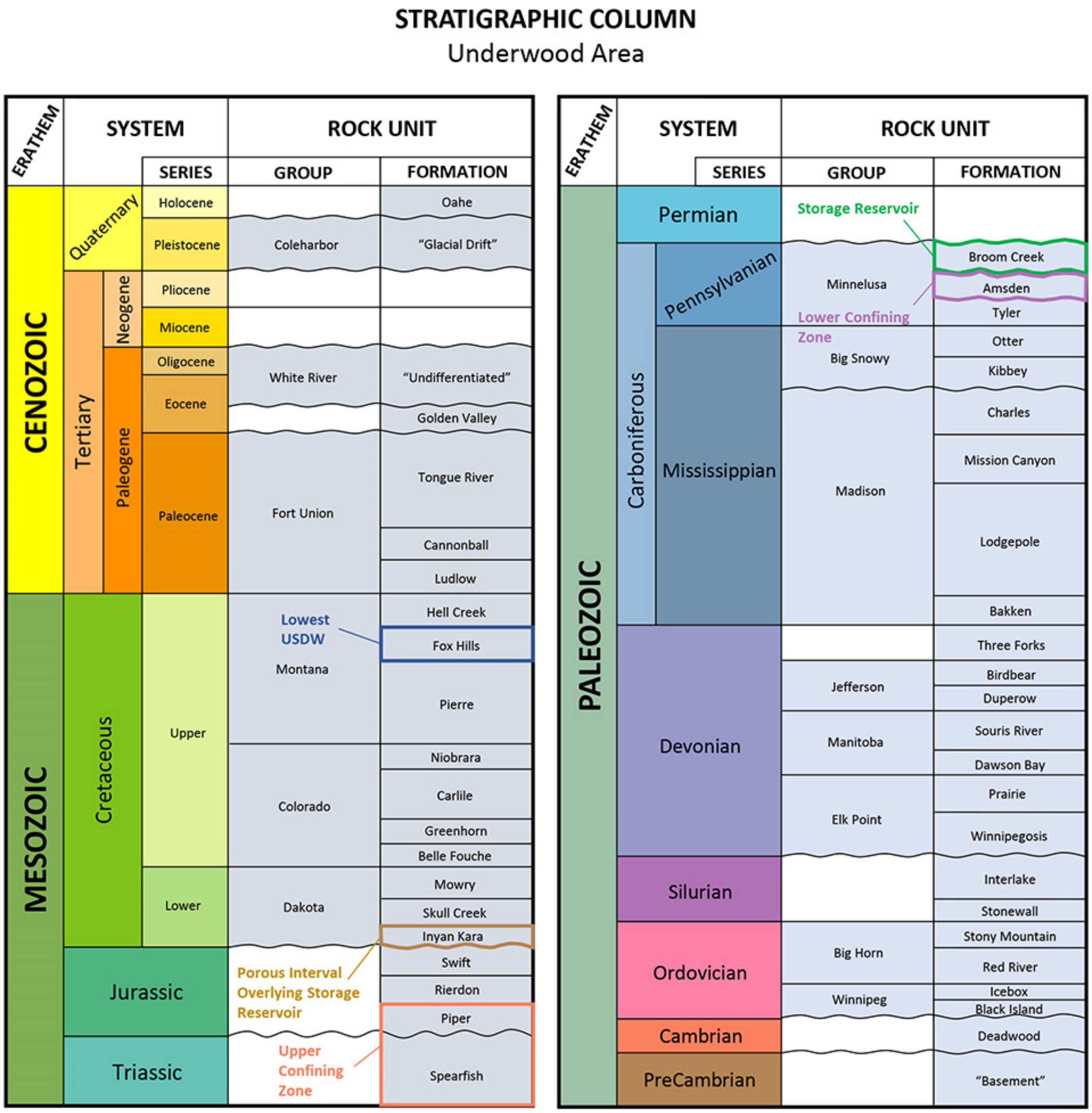

Figure 1-3. Stratigraphic column of the Williston Basin for the Underwood area, identifying the CO_2 storage complex as well as the next porous interval overlying the storage reservoir and lowest USDW underlying the Blue Flint CO_2 storage project area. Figure modified after Murphy and others (2009)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

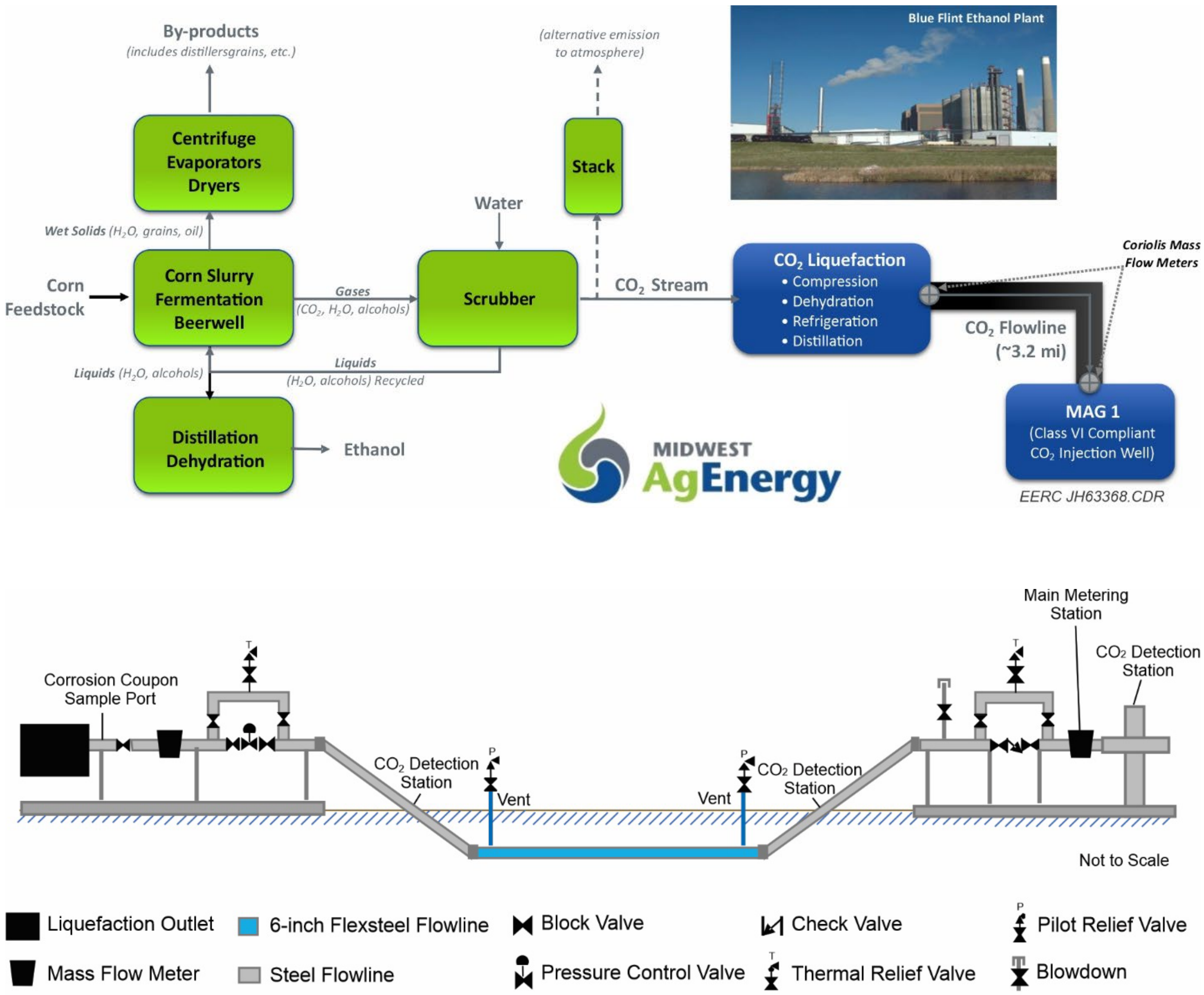

Figure 1-4. a) Process flow diagram of the CO_2 capture process at the BFE facility. b) Generalized flow diagram illustrating major CCS components of the surface facilities from the liquefaction outlet to the CO_2 injection well. The main metering station will be located adjacent to the injection wellhead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

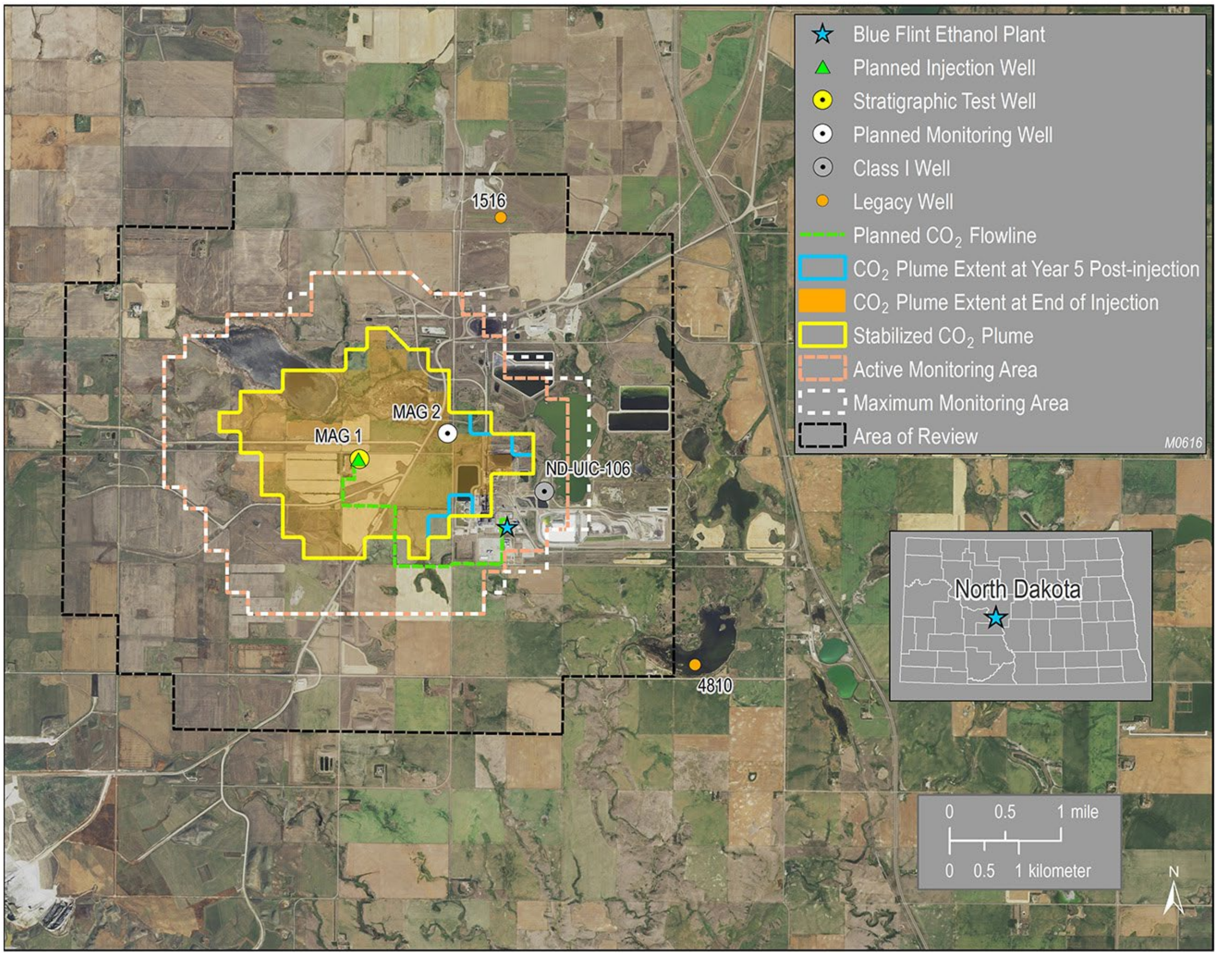

Figure 2-1. Map showing the AOR relative to the calculated MMA and AMA boundaries. In this case, "n" was set at Year 1 of injection and "t" set was set at Year 20 (end of injection) for calculating the AMA.

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.

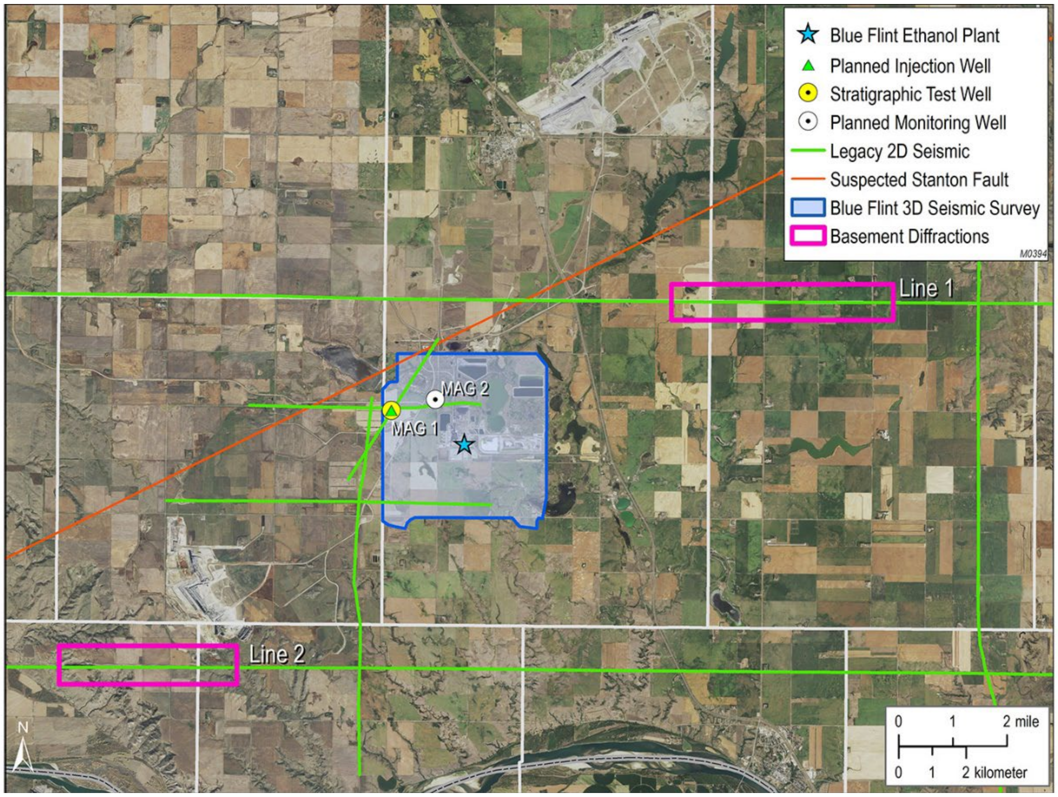

Figure 3-1. Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016) relative to the project wells and BFE facility. Also shown are legacy 2D seismic lines and a 3D seismic survey that were evaluated to characterize potential surface leakage pathways. Lines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

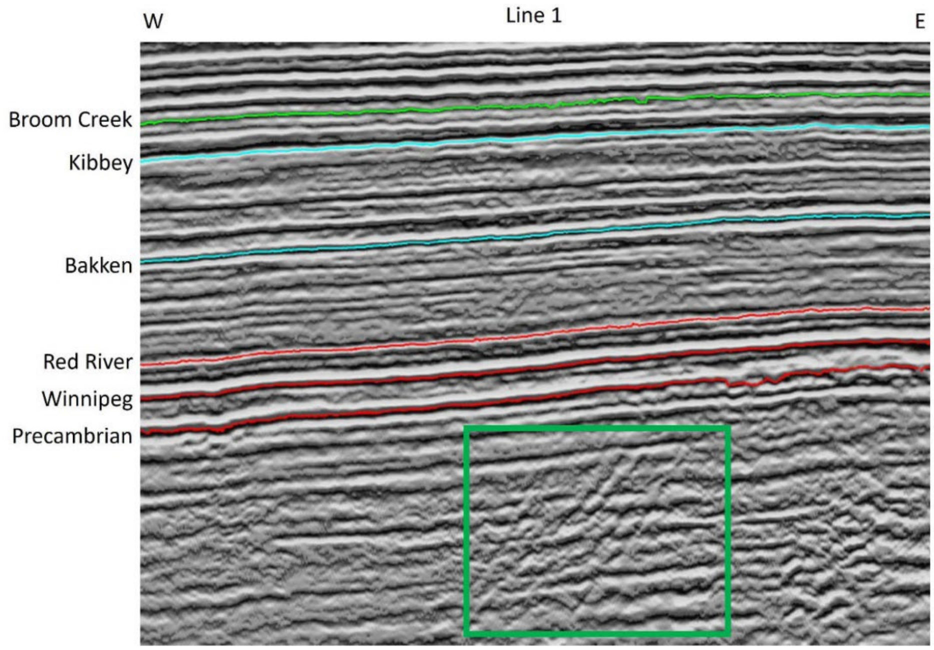

Figure 3-2. Cross section of Line 1, showing interpreted seismic horizons (colored lines) and area where diffractions are present within the Precambrian basement (green box).

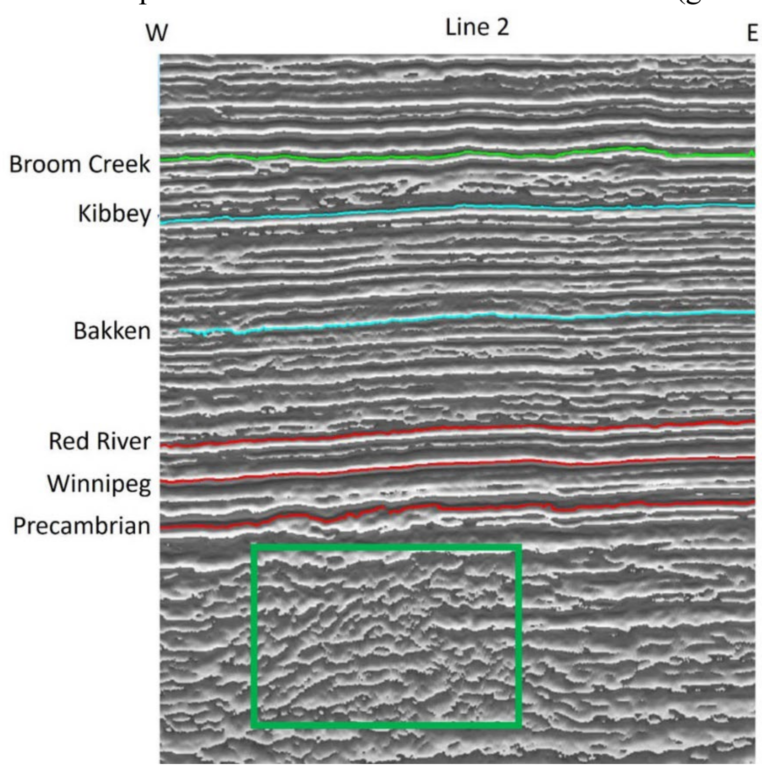

Figure 3-3. Cross section of Line 2, showing interpreted seismic horizons (colored lines) and area where diffractions are present within the Precambrian basement (green box).

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.

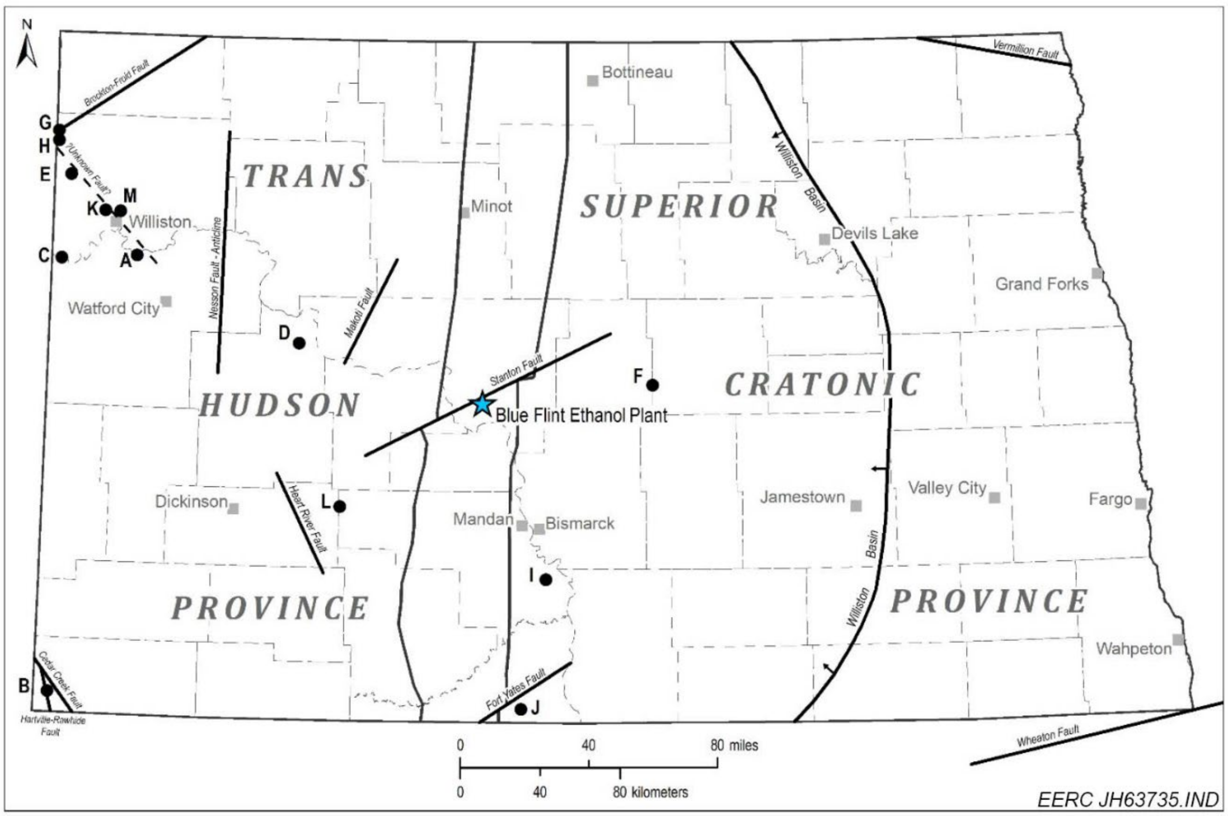

Figure 3-4. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 3-3.

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.

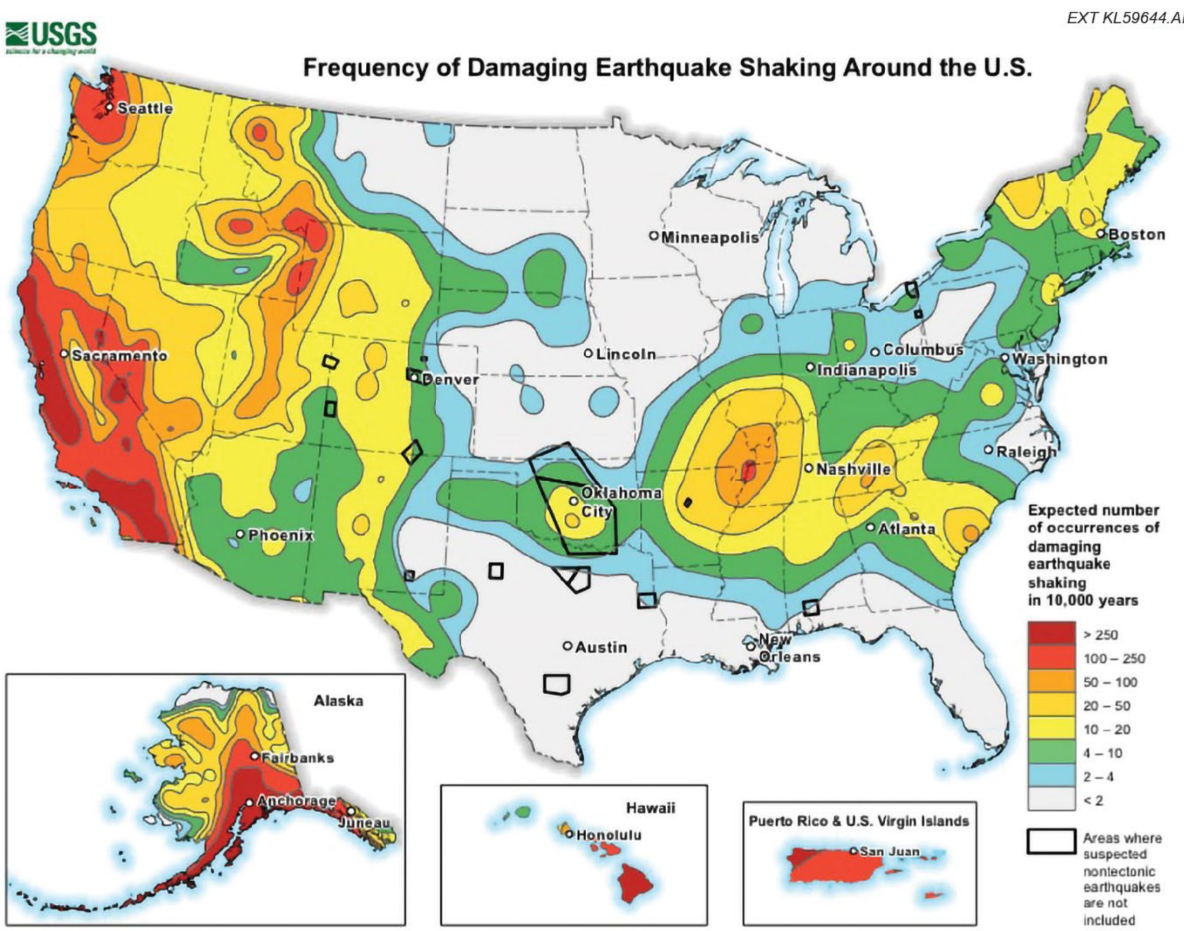

Figure 3-5. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

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

	Potential Surface Leakage Pathway							
Monitoring Strategy (target area/structure)	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.

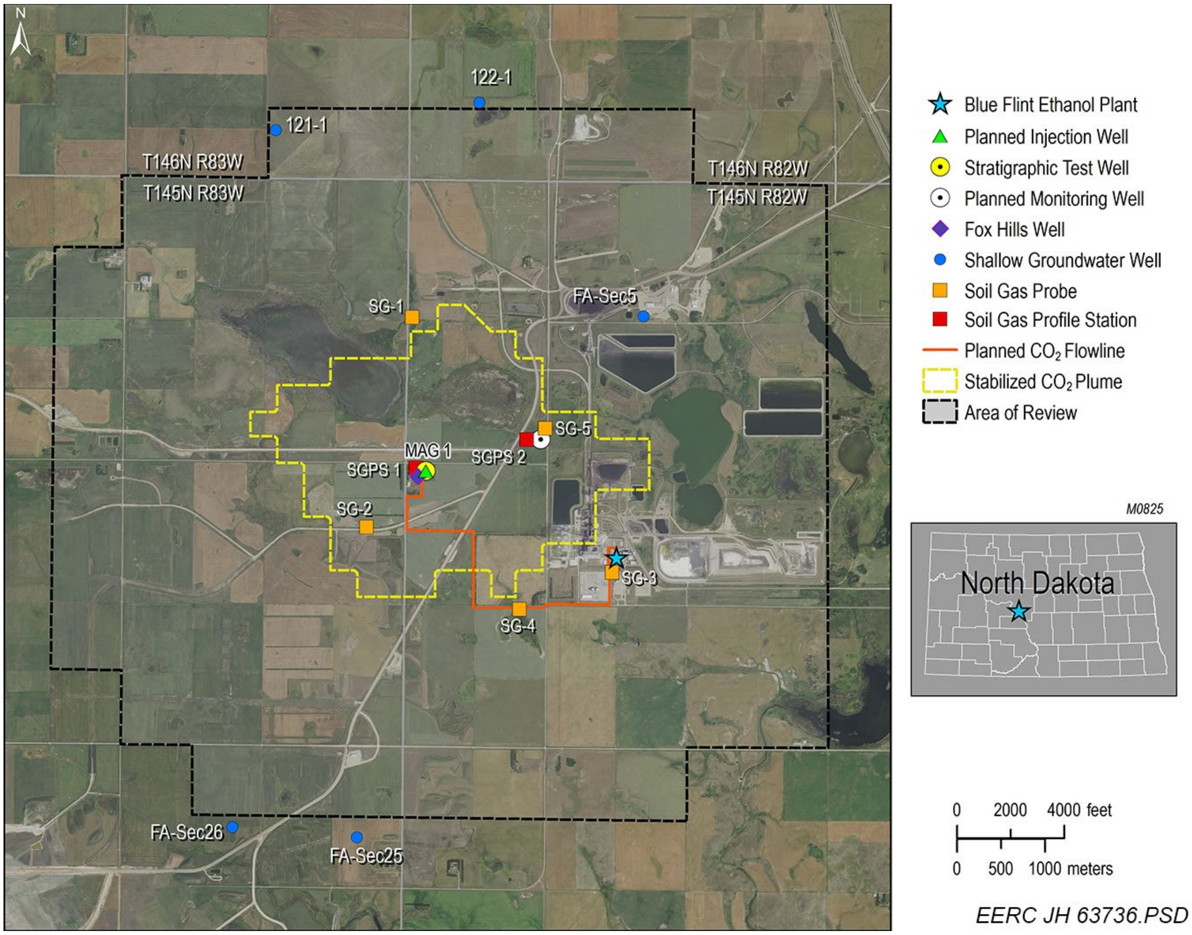

Figure 5-1. Blue Flint's planned baseline and monitoring program for soil gas, shallow groundwater aquifers, and the Fox Hills Aquifer.

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.

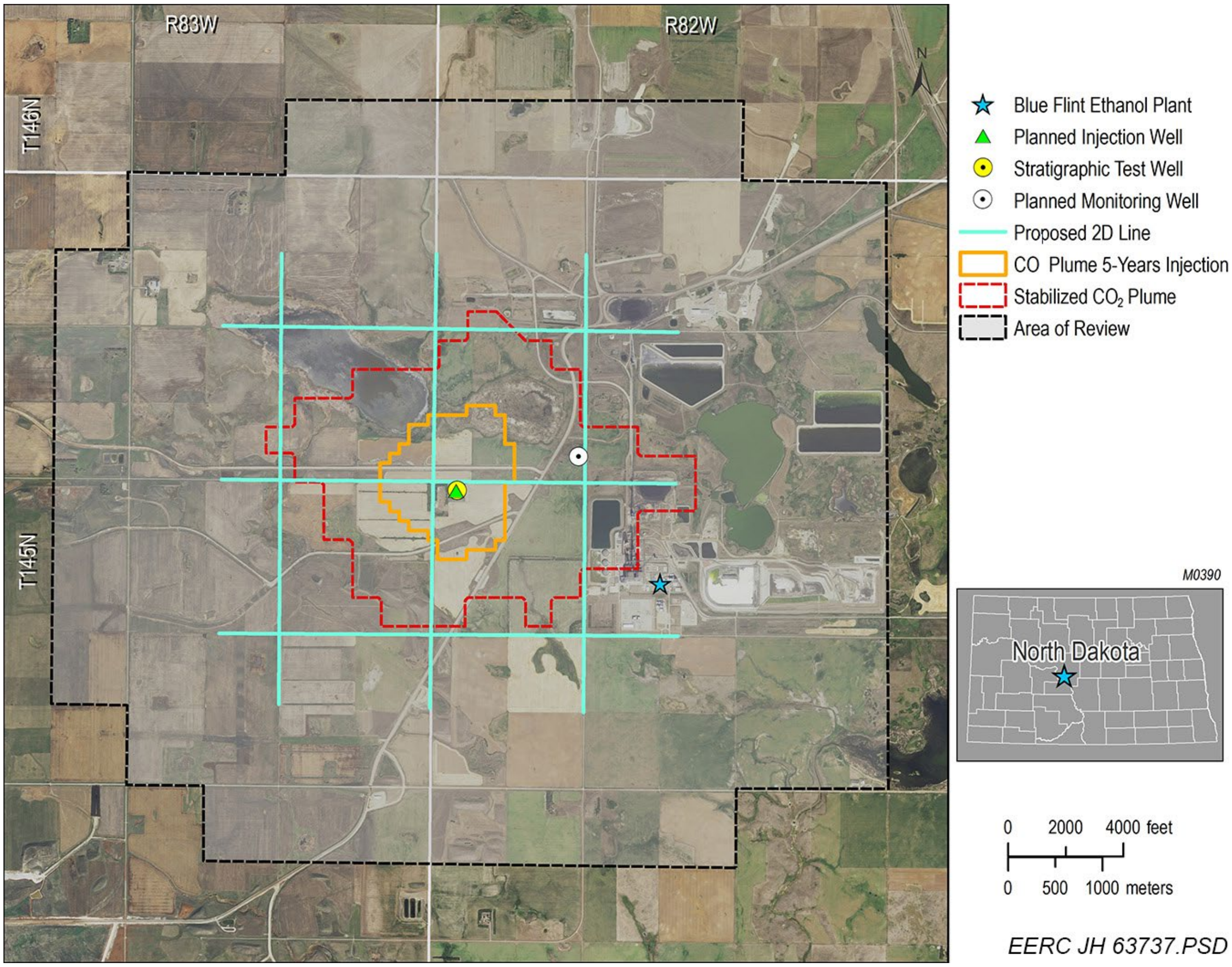

Figure 5-2. Planned 2D seismic design near the MAG 1 well to establish baseline conditions for tracking the CO_2 plume in the storage reservoir.

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):

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

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 (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.

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