SUMMIT CARBON STORAGE #2, LLC, SUBPART RR MRV PLAN

Class VI CO_2 Injection Wells

Facility (GHGRP) ID: 586962

Submitted by

Summit Carbon Storage #2, LLC

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Version 1.2

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LIST OF ACRONYMS

2D	two-dimensional
3D	three-dimensional
AMA	active monitoring area
AOR	area of review
bgs	below ground surface
BTC	buttress thread connection
BUR	buildup rate
CCL	casing collar locator
CFR	Code of Federal Regulations
CIL	casing inspection log
CMR	combinable magnetic resonance
CO_2	carbon dioxide
CRA	corrosion-resistant alloy
CRC	company response crew
CST	company support team
DAS	distributed acoustic sensing
DMR-O&G	Department of Mineral Resources Oil & Gas Division
DST	drillstem test
DTS	distributed temperature sensing
DV	diversion valve
EOB	end of build
EPA	U.S. Environmental Protection Agency
ER	electrical resistance
ERRP	emergency and remedial response plan
EUE	external-upset-end
GHGRP	Greenhouse Gas Reporting Program
GL	ground level
GR	gamma ray
IC	incident commander
ICCP	impressed current cathodic protection
ICS	Incident Command System
ID	Identification
KB	kelly bushing
KOP	kickoff point
LDS	leak detection system
LRT	local response team
MCE	Midwest Carbon Express
MD	measured depth
MMA	maximum monitoring area
MMI	modified Mercalli intensity
MRV	monitoring, reporting, and verification

Continued . . .

LIST OF ACRONYMS (continued)

N.D.A.C.	North Dakota Administrative Code
N.D.C.C.	North Dakota Century Code
NDGS	North Dakota Geological Survey
NDIC	North Dakota Industrial Commission
PBTD	plug back total depth
P/T	pressure and temperature
PIG	pipeline inspection gauge
PNL	pulsed-neutron log
PPE	personal protective equipment
ppf	pounds per foot
PSAP	public safety answering point
QI	qualified individual
RCBL	radial cement bond log
SCADA	supervisory control and data acquisition
SCS	Summit Carbon Solutions, LLC
SCS CT	SCS Carbon Transport LLC
SCS PCS	SCS Permanent Carbon Storage LLC
SCS1	Summit Carbon Storage #1, LLC
SCS2	Summit Carbon Storage #2, LLC
SCS3	Summit Carbon Storage #3, LLC
SFA	storage facility area
SFP	storage facility permit
SLRA	screening-level risk assessment
SP	spontaneous potential
spf	shots per foot
STC	short-thread and coupled
TD	total depth
TEC	tubing encapsulated cable
TOC	top of cement
TVD	total vertical depth
UIC	underground injection control
USDW	underground source of drinking water
USGS	U.S. Geological Survey
VDL	variable density log

SUMMIT CARBON STORAGE #2, LLC, SUBPART RR MRV PLAN

EXECUTIVE SUMMARY

Summit Carbon Solutions, LLC (SCS) is developing the Midwest Carbon Express (MCE) Project. The MCE Project would capture or receive carbon dioxide (CO_2) from over 30 anthropogenic sources (biofuel and other industrial facilities) across the Midwest; transport the CO_2 via a 2,000-mile pipeline to multiple storage facilities within Mercer, Morton, and Oliver Counties, North Dakota; and inject up to 18 million tonnes of CO_2 annually over a 20-year period via underground injection control (UIC) Class VI wells in secure geologic formations for safe and permanent storage. Summit Carbon Storage #2, LLC (SCS2) would own and operate two UIC Class VI wells associated with the BK Fischer storage facility in Mercer County, North Dakota, and inject up to approximately 6 million tonnes of CO_2 annually over a 20-year period in support of the MCE Project.

SCS Permanent Carbon Storage (SCS PCS), a wholly owned subsidiary of SCS, prepared this Greenhouse Gas Reporting Program (GHGRP) Subpart RR monitoring, reporting, and verification (MRV) plan associated with the BK Fischer storage facility on behalf of SCS2. As required under Title 40 Code of Federal Regulations (CFR) § 98.448, the MRV plan includes 1) delineation of the maximum monitoring area (MMA) and active monitoring area (AMA); 2) identification of potential surface leakage pathways with supporting narrative describing the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways within the MMA; 3) a strategy for detecting and quantifying any surface leakage of CO_2; 4) a strategy for establishing the expected baselines for monitoring; 5) a summary of the CO_2 accounting (mass balance) approach; 6) well identification numbers for each UIC Class VI well associated with the BK Fischer storage facility; and 7) a date to begin collecting data for calculating the total amount of CO_2 sequestered.

Monitoring aspects of the MRV plan include sampling and monitoring of the CO_2 stream, a leak detection and corrosion-monitoring plan for the surface piping and injection wellheads, mechanical integrity testing and leak detection for both injection and reservoir-monitoring wells, and an environmental monitoring program that includes soil gas and groundwater sampling, as well as time-lapse seismic survey acquisition and pressure monitoring of the injection zone.

SUMMIT CARBON STORAGE #2, LLC, SUBPART RR MRV PLAN

1.0 PROJECT OVERVIEW

1.1 Project Description

Summit Carbon Solutions, LLC (SCS) is developing the Midwest Carbon Express (MCE) Project, as illustrated in Figure 1-1. The MCE Project would capture or receive carbon dioxide (CO_2) streams (95% to ≤99.9% CO_2) from over 30 anthropogenic sources (biofuel and other industrial facilities) across the Midwest; transport the CO_2 via a 2,000-mile pipeline system to multiple storage facilities within Mercer, Morton, and Oliver Counties, North Dakota; and inject up to 18 million tonnes of CO_2 annually over a 20-year period via underground injection control (UIC) Class VI wells in secure geologic formations for safe and permanent storage.

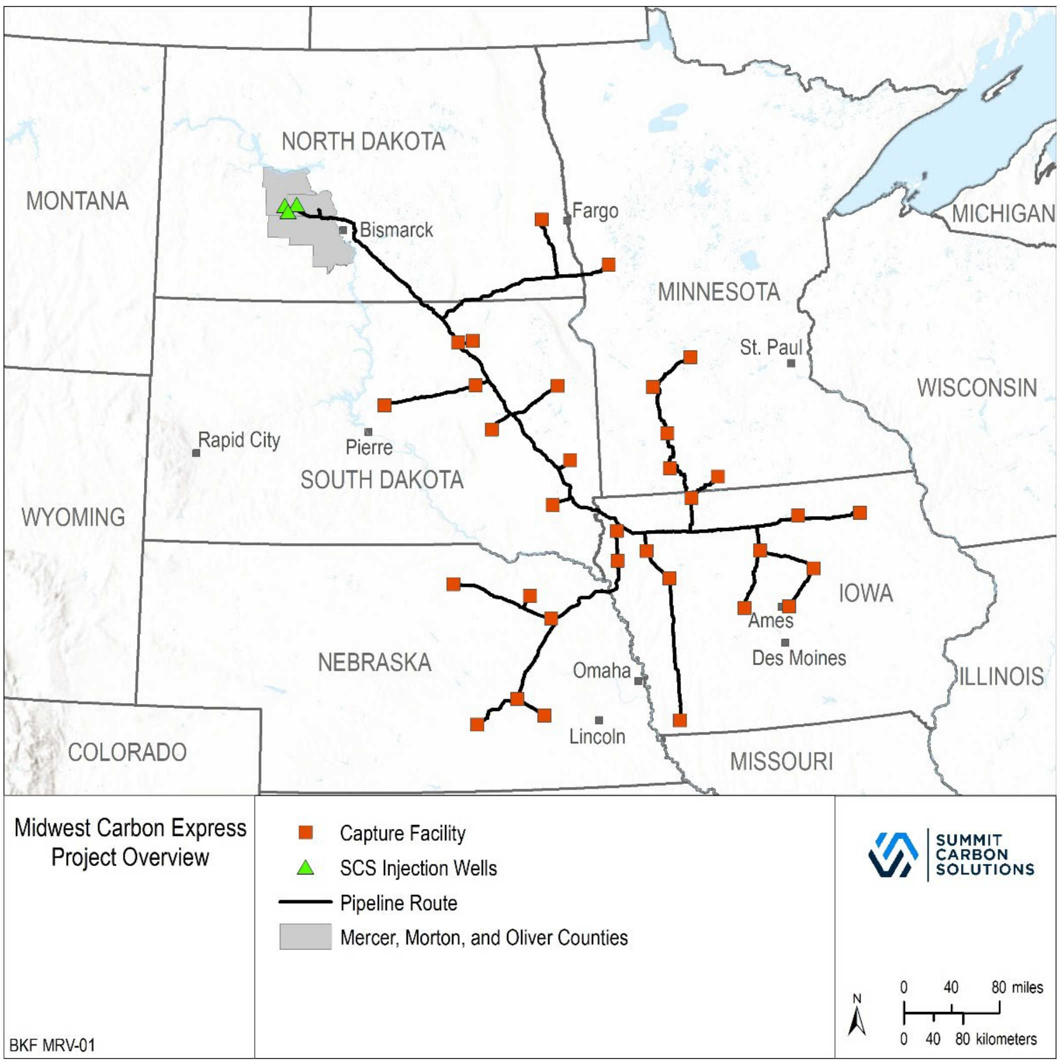

Figure 1-1. MCE Project overview.

Figure 1-2 outlines the established business structure and proposed reporting framework relative to the MCE Project and this Greenhouse Gas Reporting Program (GHGRP) Subpart RR monitoring, reporting, and verification (MRV) plan, respectively. Summit Carbon Storage #2, LLC (SCS2) would own and operate two UIC Class VI wells associated with the BK Fischer storage facility in Mercer County, North Dakota. The two UIC Class VI wells combined would be capable of injecting a total of up to approximately 6 million tonnes of CO_2 annually over a 20-year period. SCS Carbon Transport LLC (SCS CT), a wholly owned subsidiary of SCS, would operate the 2,000-mile pipeline system associated with the MCE Project.

SCS Permanent Carbon Storage (SCS PCS), another wholly owned subsidiary of SCS, prepared this MRV plan associated with the BK Fischer storage facility on behalf of SCS2. SCS PCS will manage this MRV plan and any related reporting (e.g., annual monitoring reporting required under Title 40 Code of Federal Regulations [CFR] § 98.446[f][12]). SCS PCS will also prepare and submit separate MRV plans for the TB Leingang and KJ Hintz storage facilities operated by Summit Carbon Storage #1, LLC (SCS1) and Summit Carbon Storage #3, LLC (SCS3), respectively, to ensure compliance and effective communication across all three plans. The TB Leingang, BK Fischer, and KJ Hintz injection sites are each registered as separate GHGRP facilities to accommodate one MRV plan per storage facility operator.

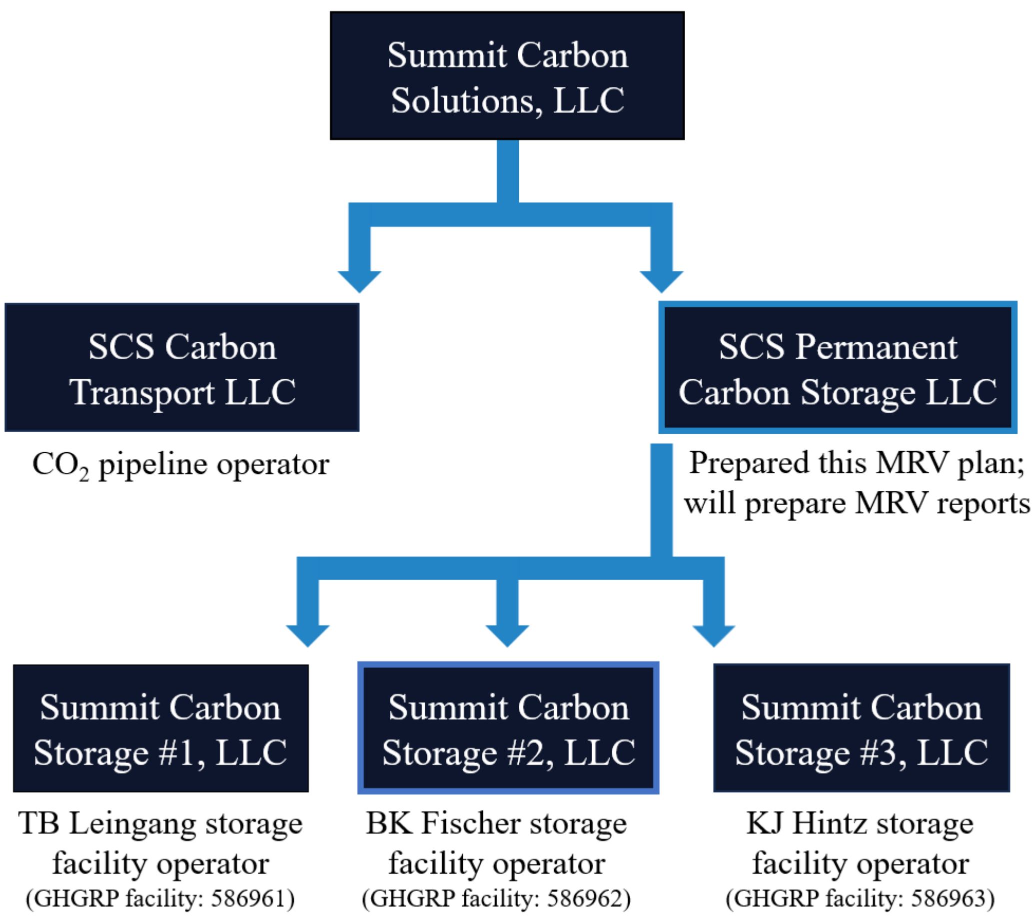

Figure 1-2. SCS business and reporting structure.

SCS2 submitted a North Dakota Class VI storage facility permit (SFP) application (Case No. 30873) to the North Dakota Industrial Commission (NDIC) Department of Mineral Resources Oil & Gas Division (DMR-O&G) in February 2024. The U.S. Environmental Protection Agency (EPA) granted North Dakota primary enforcement authority (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). The North Dakota SFP would establish a geologic storage reservoir and construct and operate two UIC Class VI wells associated with the BK Fischer storage facility, BK Fischer 1 and 2, as illustrated in Figure 1-3.

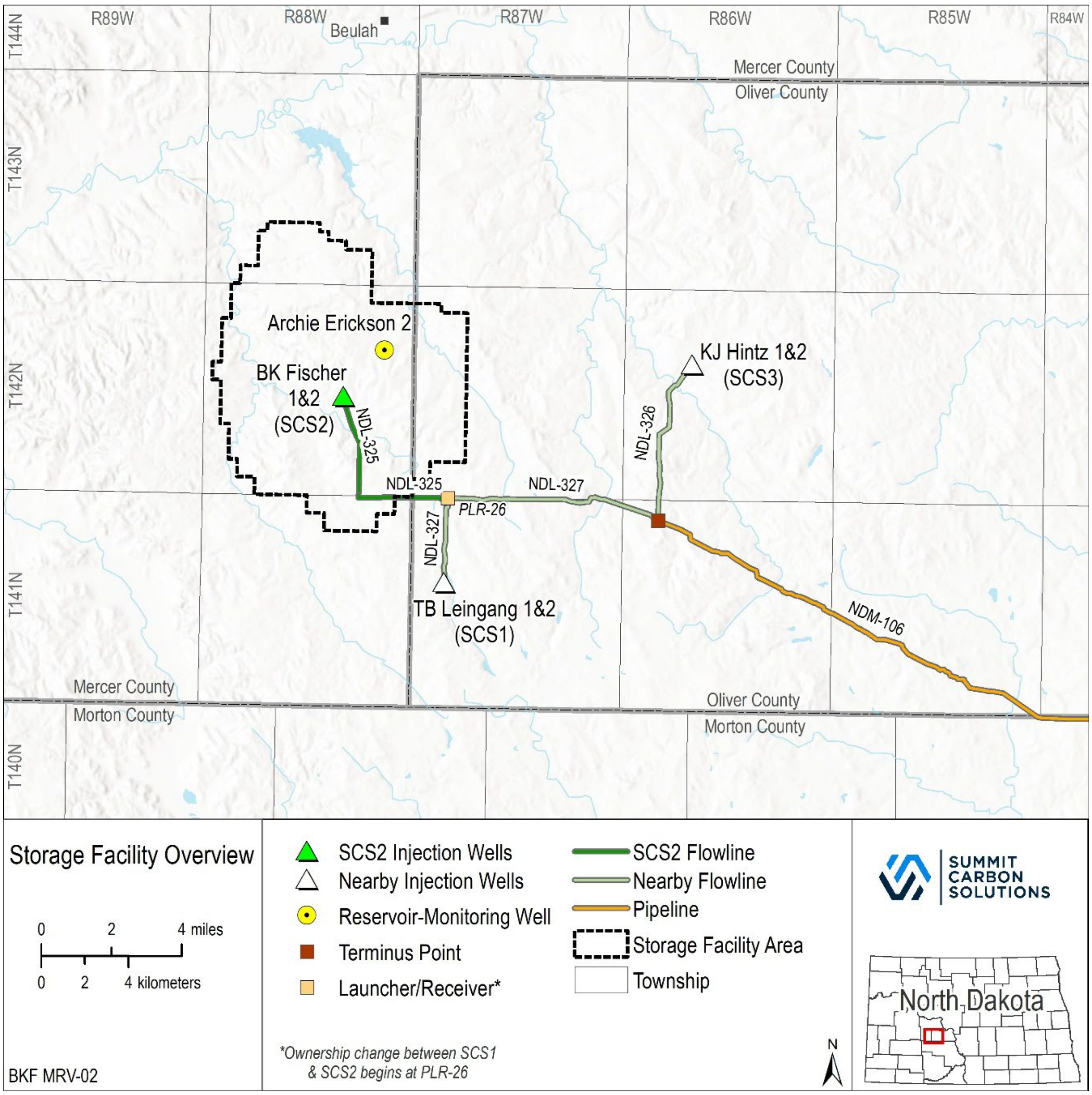

Figure 1-3. BK Fischer storage facility overview.

The northern edge of the BK Fischer storage facility is approximately 6 miles south of the town of Beulah, North Dakota. Key infrastructure associated with the BK Fischer storage facility includes two CO_2 injection wells (BK Fischer 1 and 2), one reservoir-monitoring well (Archie Erickson 2), and approximately 5.5 miles of 16- to 24-inch-diameter flowline (NDL-325). As illustrated in Figure 1-4, the flowline begins at the point of transfer (junction between NDL-325 and NDL-327 at PLR-26) and ends at the BK Fischer 1 and 2 injection wellheads.

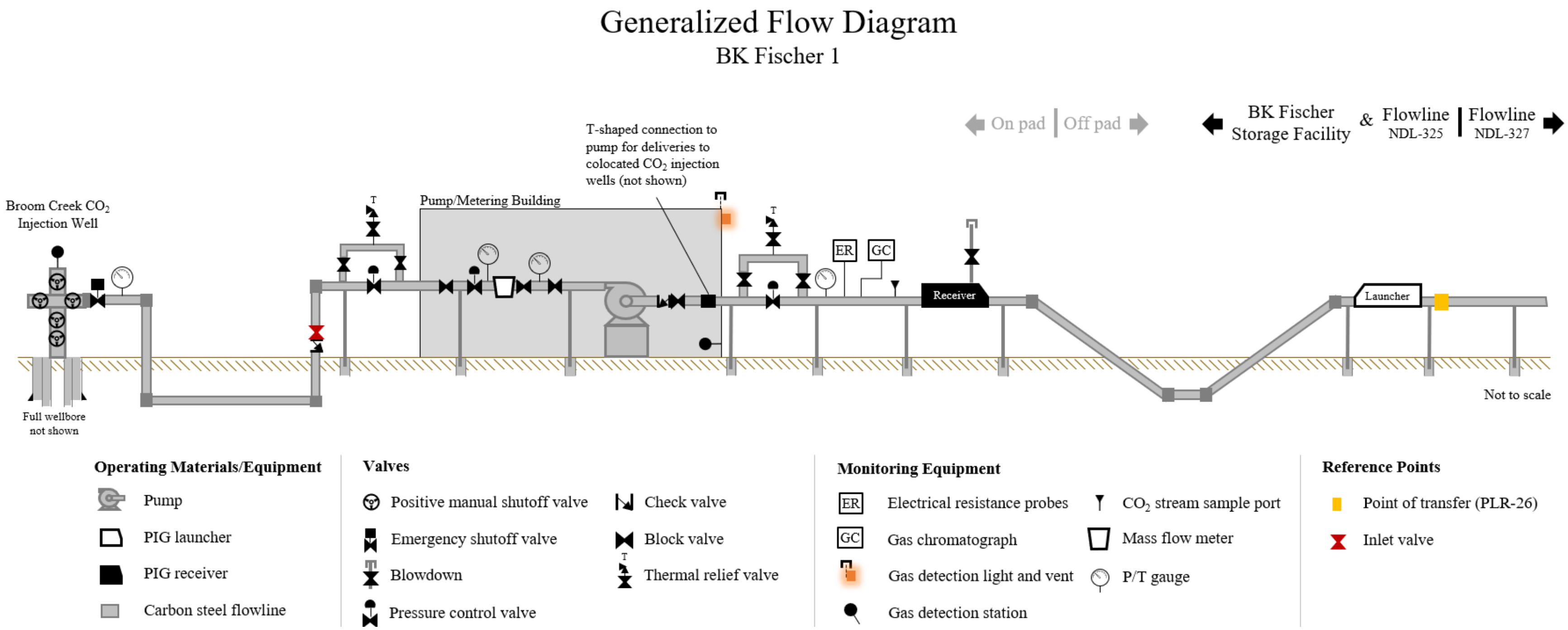

Figure 1-4. Generalized flow diagram from the point of transfer (junction between NDL-325 and NDL-327 at PLR-26) to the BK Fischer 1 CO_2 injection well, illustrating key surface facilities' connections and monitoring equipment along the transport path. The flow diagram is identical for the BK Fischer 2 CO_2 injection well (not shown).

1.2 Geologic Setting

The BK Fischer storage facility is located along the eastern flank of the Williston Basin where there has been some exploration for but no significant commercial production of hydrocarbon resources. The Williston Basin is a sedimentary intracratonic basin covering an approximate 150,000-square-mile area over portions of Saskatchewan and Manitoba in Canada as well as Montana, North Dakota, and South Dakota in the United States. The basin's depocenter is near Watford City, North Dakota. In North Dakota alone, over 40,000 wells have been drilled to support activities associated with exploration and production of commercial oil and gas accumulations from subsurface reservoirs. Although there is no historical commercial oil and gas production in or immediately surrounding the BK Fischer storage facility, a few legacy oil and gas exploration wells are present nearby, as illustrated in Figure 1-5. The closest established oil and gas fields to the BK Fischer storage facility are approximately 21 miles west of the storage facility area (SFA) boundary.

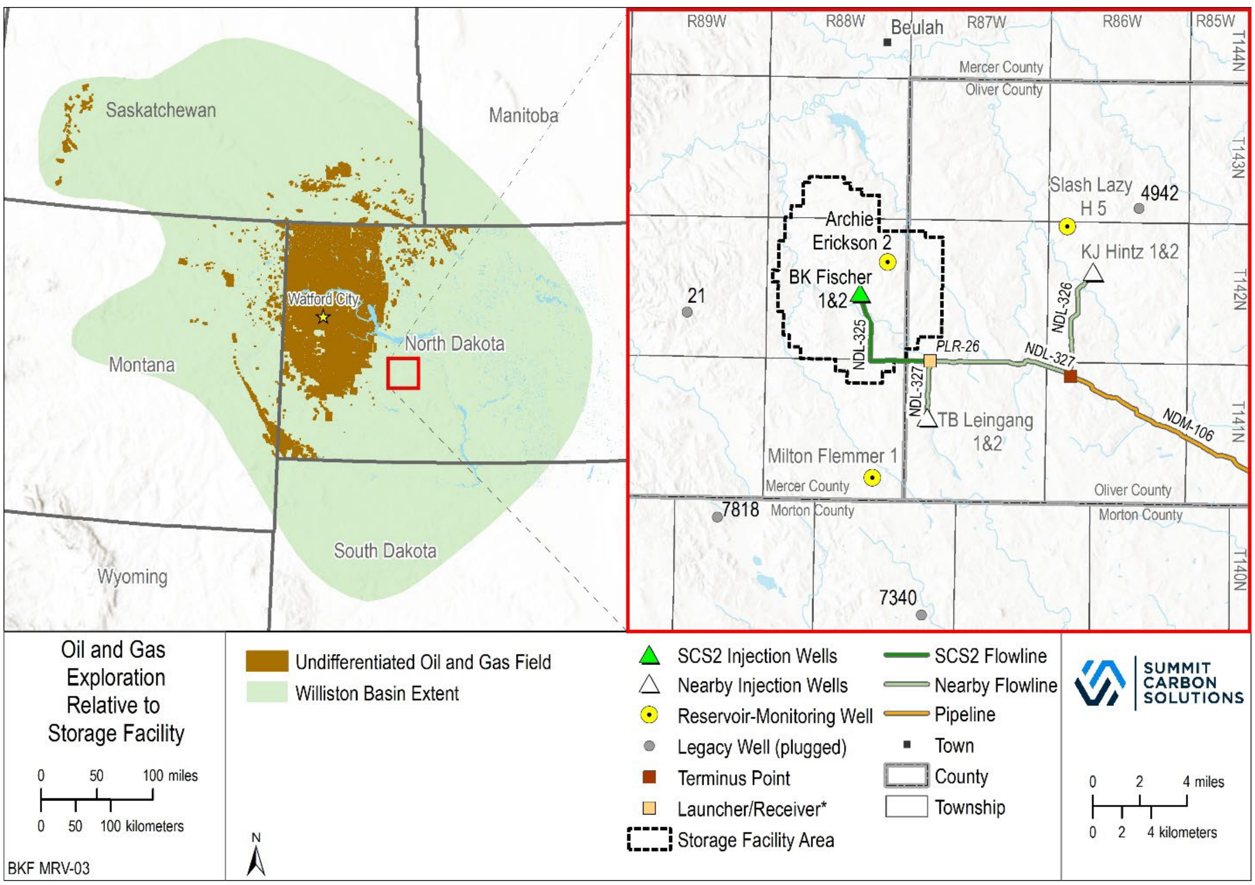

Figure 1-5. Oil and gas exploration relative to the BK Fischer storage facility and MCE Project. Distribution of established oil and gas fields (undifferentiated) across the basin (left) and nearest legacy wellbores relative to the storage facility and MCE Project – all of which are plugged – are shown.

Figure 1-6 presents a generalized stratigraphic column for Mercer, Morton, and Oliver Counties, North Dakota. The stratigraphic column identifies key geologic formations associated with the BK Fischer storage facility, including the storage complex (i.e., storage reservoir and associated confining zones), which consists of the Broom Creek Formation (storage reservoir); the Opeche, Minnekahta, and Spearfish Formations (inclusive of the upper confining zone); and the Amsden Formation (lower confining zone). In addition, the Inyan Kara Formation (dissipation zone above the storage reservoir) and the Fox Hills Formation (lowest underground source of drinking water [USDW]) are identified.

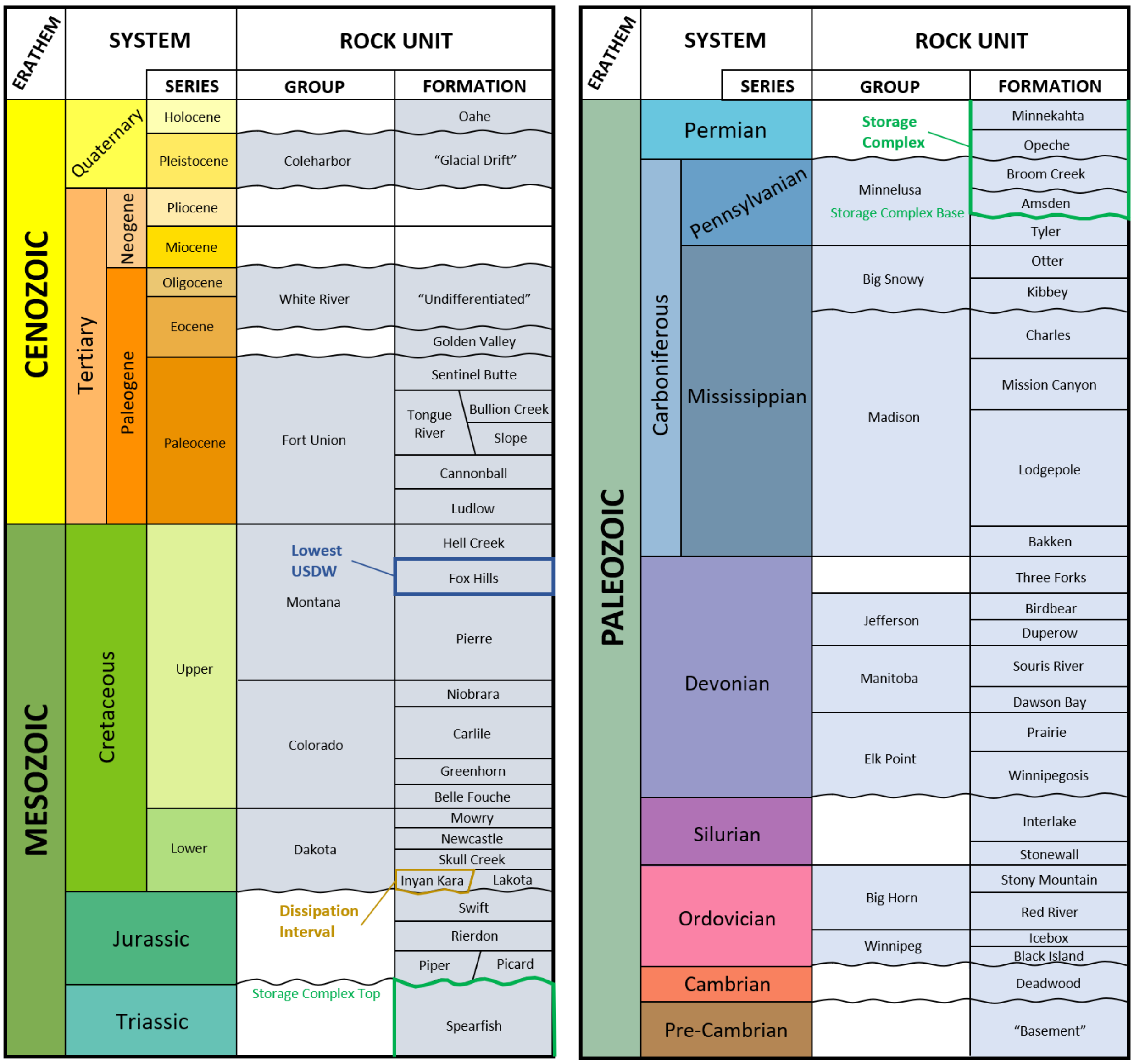

Figure 1-6. Stratigraphic column for Mercer, Morton, and Oliver Counties, North Dakota. The storage complex (i.e., storage reservoir and associated confining zones), first porous interval overlying the storage reservoir (i.e., dissipation interval), and the lowest USDW are identified in the figure. Figure modified after Murphy and others (2009) and Bluemle and others (1981).

Figure 1-7 illustrates the change in thickness of the Broom Creek Formation (storage reservoir) across the simulated model extent created for the MCE Project, inclusive of the BK Fischer storage facility. The Broom Creek Formation is a predominantly sandstone interval and porous and permeable saline aquifer. The top of the Broom Creek Formation is approximately 5,845 feet below ground surface (bgs) at the Archie Erickson 2 and 260 feet thick (on average) within the SFA. The simulation model extent was informed by wells with geophysical logs and formation top picks as well as 2D and 3D seismic datasets. Where available, the 2D/3D seismic data were used to inform the gridding algorithm and reflect known variations in the geology.

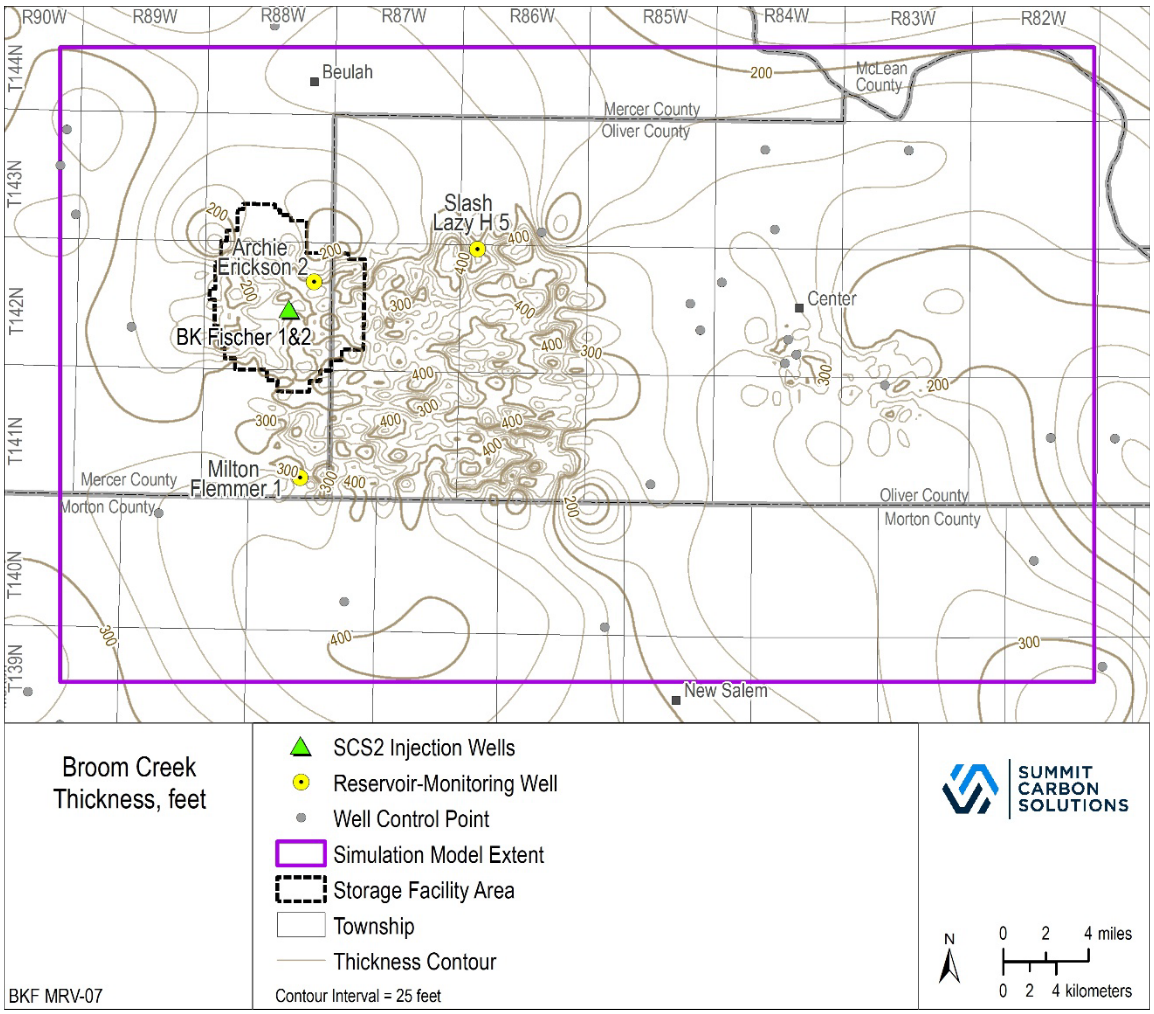

Figure 1-7. Thickness map of the Broom Creek Formation across the simulation model extent. A convergent interpolation gridding algorithm was used with well formation tops as well as two-dimensional (2D) and three-dimensional (3D) seismic in the creation of this map.

Figures 1-8 and 1-9 demonstrate the change in thickness of the upper and lower confining zones across the simulated model extent, respectively. Siltstones interbedded with dolostones and anhydrite of undifferentiated Opeche, Minnekahta, and Spearfish Formations (referred hereafter as Opeche/Spearfish Formation) unconformably overlie the Broom Creek Formation and serve as the upper (primary) confining zone. The Opeche/Spearfish Formation lies approximately 5,600 feet bgs in the Archie Erickson 2 and is 245 feet thick (on average) within the SFA. Mixed layers of dolostone, anhydrite, and sandstone of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone. The Amsden Formation lies approximately 6,150 feet bgs in the Archie Erickson 2 and is 265 feet thick (on average) within the SFA. Together, the Opeche/Spearfish, Broom Creek, and Amsden Formations comprise the storage complex.

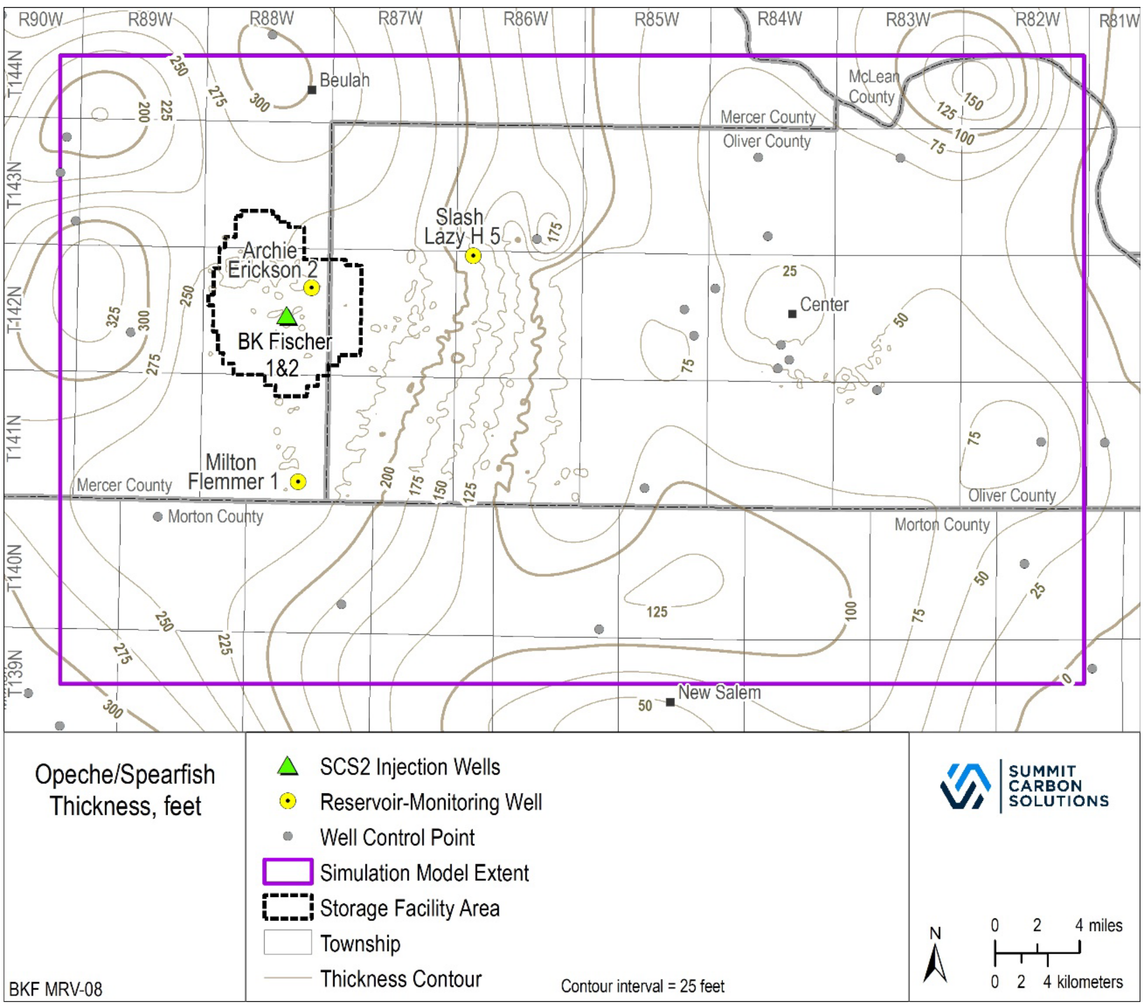

Figure 1-8. Thickness map of the Opeche/Spearfish Formation across the simulation model extent. A convergent interpolation gridding algorithm was used with well formation tops as well as 2D and 3D seismic in creation of this map.

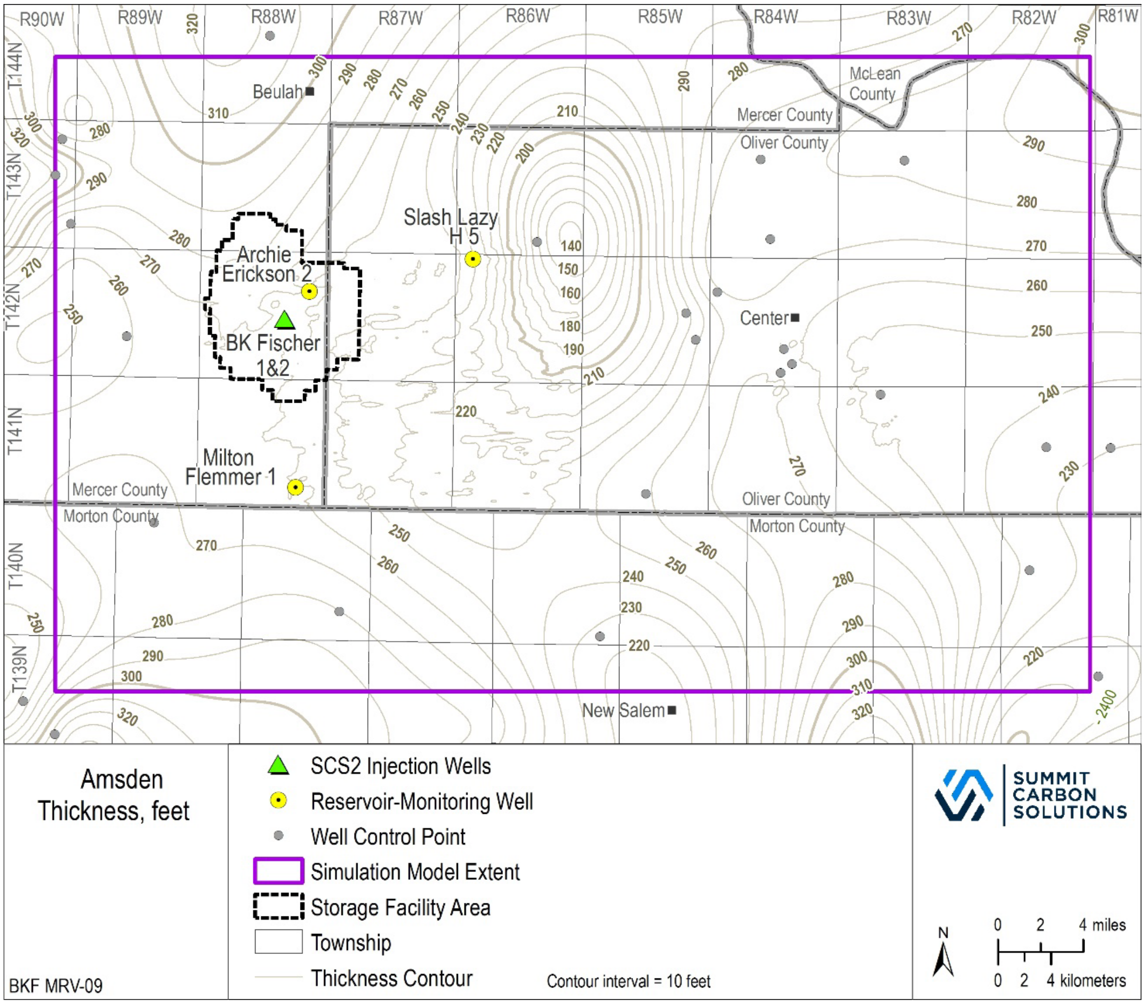

Figure 1-9. Thickness map of the Amsden Formation across the simulation model extent. The convergent interpolation gridding algorithm was used with well formation tops as well as 2D and 3D seismic in creation of this map.

In addition, there is an approximately 1,090 feet (on average) of impermeable rock, including the Opeche/Spearfish, Piper, Rierdon, and Swift Formations, between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation, and an additional 2,700 feet (on average) of impermeable rock, including the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations to the Fox Hills Formation (lowest USDW) across the SFA (Figure 1-6 provides stratigraphic reference).

1.2.1 Potential Mineral Zones

The North Dakota Geological Survey (NDGS) recognizes the Spearfish Formation as the only potential oil-bearing formation above the Broom Creek Formation in the state. However, production from the Spearfish Formation is limited to the northern tier of counties in North Dakota, as illustrated in Figure 1-10. There has been no exploration for nor development of hydrocarbon resources from the Spearfish Formation in or near the BK Fischer storage facility.

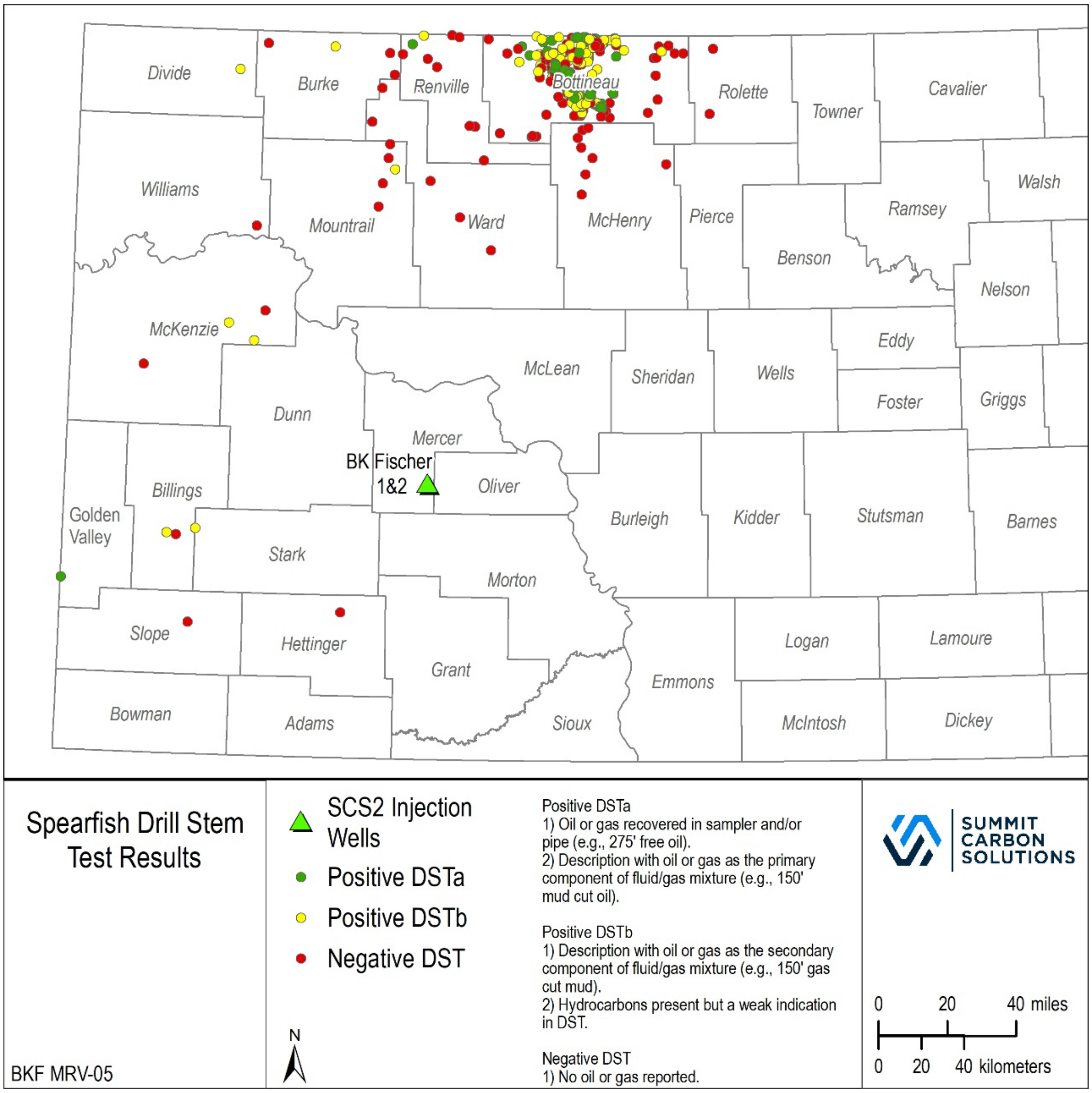

Figure 1-10. Drillstem test (DST) results, indicating the presence of oil in the Spearfish Formation samples (modified from Stolldorf, 2020).

The active Coyote Creek and reclaimed Beulah coal mines are approximately 4.0 miles northwest and 5.5 miles north of the BK Fischer storage facility, respectively, as illustrated in Figure 1-11. Coalbeds of the Sentinel Butte Formation of the Paleocene-age Fort Union Group (Figure 1-6 provides stratigraphic reference) are mined at the Coyote Creek Mine, but there are no plans to mine coal within the projected stabilized CO_2 plume extent during the storage facility's operational period.

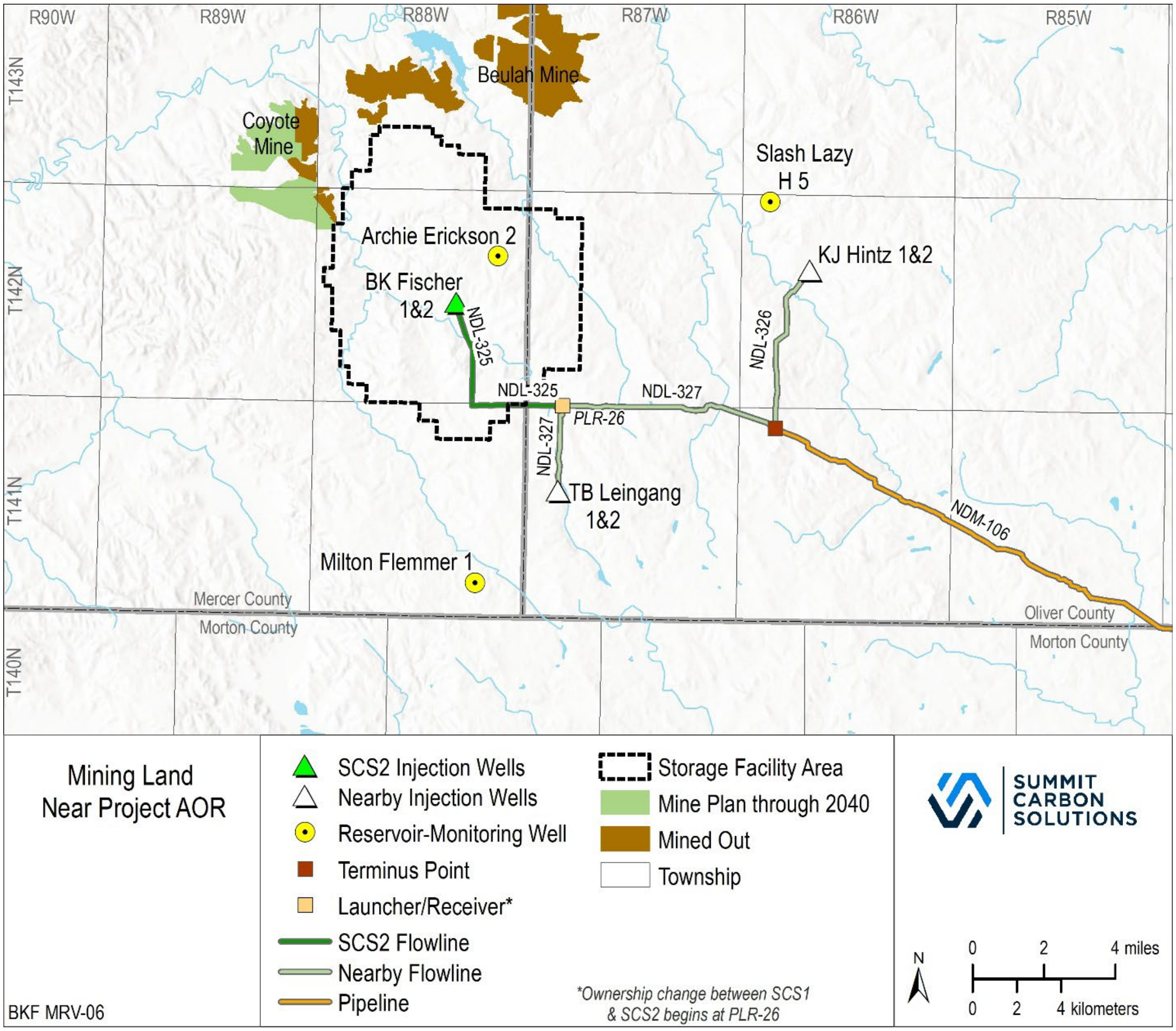

Figure 1-11. Mining plans for Coyote Creek and Beulah Mines through 2040.

1.3 Process Flow, Metering, and Data Sharing

Figure 1-12 illustrates the process flow diagram of CO_2 transport associated with the BK Fischer GHGRP facility, which includes the BK Fischer 1 and 2 wells, mass flow meters, and downstream surface piping and associated equipment. Mass flow meters, shown in Figure 1-12, will continuously measure the total volume of CO_2 received for each injection well at the wellsite.

During operations, the average composition of the CO_2 stream is expected to be ≥98.25% CO_2, with remaining components being ≤1.44% nitrogen (N_2), ≤0.31% oxygen (O_2), and trace amounts of water and hydrogen sulfide (H_2S); however, SCS2 has designed the surface facilities and wellbores to be operated with a CO_2 stream between 95% and ≤99.9% CO_2, ≤3% N_2, ≤2% O_2, and trace amounts of water and H_2S. The design specification provides SCS2 with flexibility to receive CO_2 from a variety of industrial sources. SCS2 would own the NDL-325 flowline and associated equipment up to the wellheads and be responsible for reporting GHG emissions associated with the surface piping section downstream of the main flow meters through Subpart RR of the GHGRP, as illustrated in Figure 1-12. SCS CT would operate the entire CO_2 pipeline system, inclusive of mainline NDM-106 and flowlines NDL-325, NDL-326, and NDL-327 up to the inlet valves near each injection wellhead. SCS CT and SCS2 would have working agreements in place to share operational data gathered along the entire NDL-325 flowline. The data would be collected by a supervisory control and data acquisition (SCADA) system integrated with monitoring equipment (e.g., flow meters and pressure–temperature [P/T] gauges) to continuously monitor mass balance of the entire system in real time.

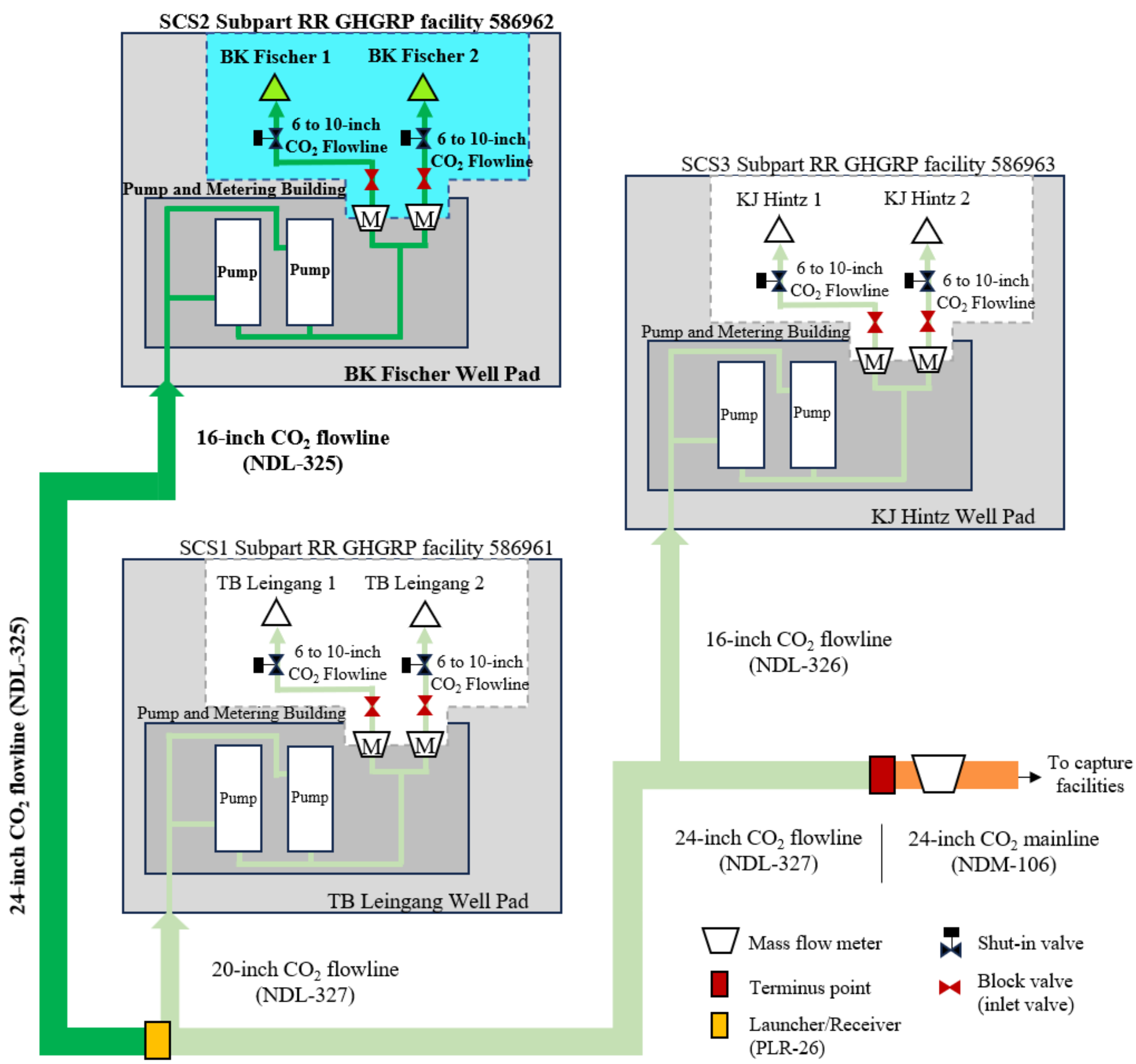

Figure 1-12. Process flow diagram of CO_2 transport to the BK Fischer 1 and 2 injection wells. Area in blue defines the extent of the BK Fischer Subpart RR GHGRP facility.

1.4 Facility Information

Table 1-1 identifies key information for the BK Fischer GHGRP facility, including the UIC permit class and well identification (ID) number for the CO_2 injection wells proposed in the North Dakota SFP application submitted to DMR-O&G, as required in 40 CFR § 98.448(a)(6).

Table 1-1. BK Fischer GHGRP Facility Information

Well Name	UIC Well Class	Well ID (NDIC File No.)
BK Fischer 1	Class VI	40124
BK Fischer 2	Class VI	40125

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

The area of review (AOR) boundary will serve as the maximum monitoring area (MMA) and the active monitoring area (AMA) until facility closure (i.e., the point at which SCS2 receives a certificate of project completion), as shown in Figure 2-1. The AOR boundary provides a 1-mile buffer around the stabilized CO_2 plume, generally rounding to the nearest 40-acre tract. This 1-mile buffer area is larger than the MMA and AMA, thereby exceeding the regulatory requirements for buffer areas around the free-phase CO_2 plume with respect to Subpart RR definitions. SCS2 will perform testing and monitoring activities within the AOR approximately 1 year prior to injection, during the 20-year injection phase of the project, and for a minimum of 10 years after injection ceases (or until plume stabilization is demonstrated, if after the 10 years). The testing and monitoring approach will be updated pursuant to 40 CFR § 98.448(d).

The stabilized CO_2 plume associated with the BK Fischer storage facility is anticipated to occur at or before Year 16 of post-injection using the approach in Regorrah and others (2023). The stabilized CO_2 plume is not projected to overlap with any other CO_2 plume (i.e., TB Leingang or KJ Hintz storage facilities); therefore, no impact to the testing and monitoring approach is anticipated. Through periodic acquisition and interpretation of seismic survey data (presented in Section 5.0) and regular evaluations of the testing and monitoring strategy as required through the North Dakota SFP, SCS2 will have multiple opportunities throughout the life of the project to verify the CO_2 plumes are not anticipated to overlap and adjust strategies (e.g., limit injection volume) as needed.

Subpart RR regulations require the operator to delineate a MMA and an AMA (40 CFR § 98.448[a][1]). 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 0.5 miles (40 CFR § 98.449). 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 0.5 mile or greater if known leakage pathways extend laterally more than 0.5 miles and 2) the area projected to contain the free-phase CO_2 plume at the end of year t + 5. SCS2 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 [N.D.A.C.] § 43-05-01-01). N.D.A.C. requires the operator to develop an AOR boundary and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (N.D.A.C. § 43-05-01-5.1). Further, N.D.A.C. requires a technical evaluation of the SFA plus a minimum buffer of 1 mile (N.D.A.C. § 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 [N.D.C.C.] § 38-22-08). The proposed AOR in Figure 2-1 is in accordance with the above regulations, providing a 1-mile buffer and generally rounding to the nearest 40-acre tract outside the modeled CO_2 plume boundary.

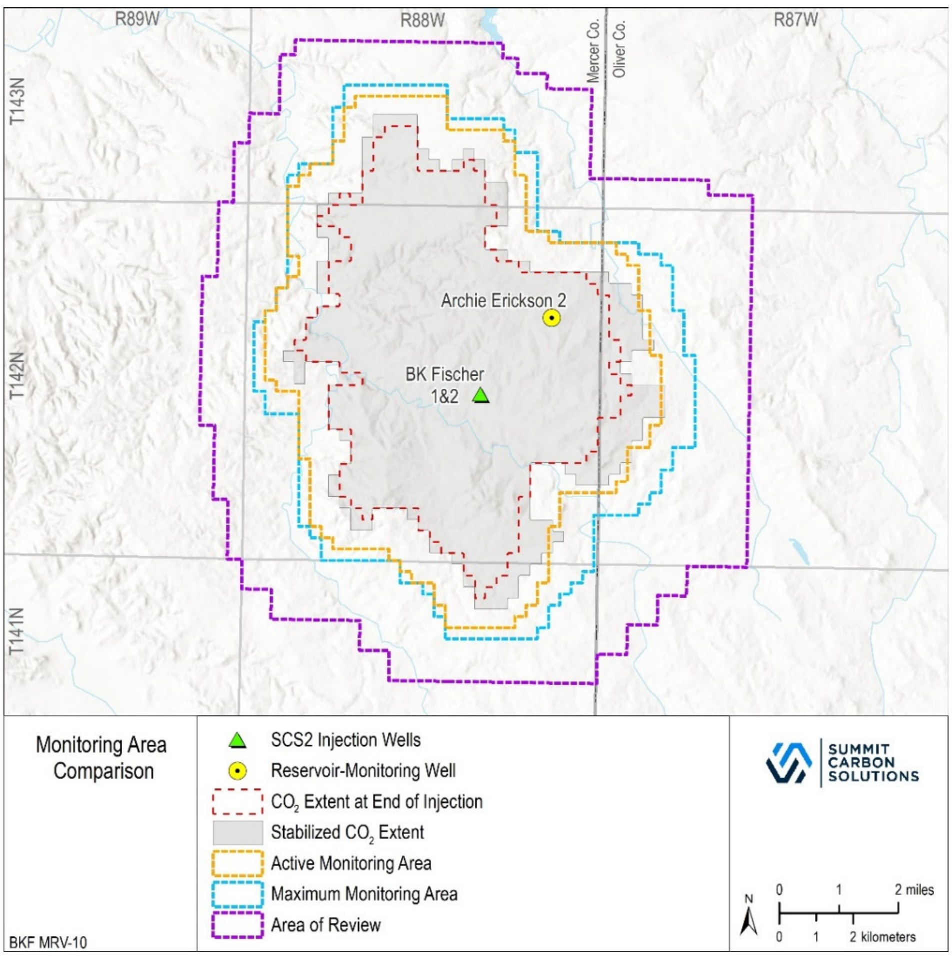

Figure 2-1. AOR relative to the calculated MMA and AMA boundaries. The MMA and AMA are for reference only, as the AOR will serve as the MMA and AMA for this MRV plan. In this case, n was set at Year 1 of injection and t was set at Year 20 (end of injection) to calculate the AMA, and Year 16 of post-injection was used to calculate the MMA.

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]). SCS2 identifies the potential surface leakage pathways as follows:

- Class VI injection wells
- Reservoir-monitoring well
- Surface components
- Legacy wells
- Faults, fractures, bedding plane partings, and seismicity
- Confining system pathways

3.1 Class VI Injection Wells

The UIC Class VI wells identified in Table 1-1 are planned to spud as stratigraphic test wells to the Amsden Formation. Each of the stratigraphic test wells will be completed to NDIC Class VI construction standards and converted to a UIC Class VI injection well prior to injection. Figures 3-1 through 3-3 illustrate the proposed completed wellhead and wellbore schematics for each of the CO_2 injection wells. Prior to injection, SCS2 will use an ultrasonic log or other equivalent casing inspection log (CIL), sonic array tool with a gamma ray (GR) log equipped, and a pulsed-neutron log (PNL) to establish initial external mechanical integrity. SCS2 will also install casing-conveyed distributed temperature sensing (DTS) and distributed acoustic sensing (DAS)-capable fiber-optic cable and run a temperature log in each well to compare with the fiber-optic temperature data. SCS2 will install digital surface P/T gauges on each injection wellhead to monitor the surface casing, tubing-casing annulus, and tubing pressures post-completion. Prior to injection, SCS2 will also conduct tubing-casing annulus pressure testing in each wellbore to verify the initial internal mechanical integrity.

During injection operations, the temperature profile of the wellbores will be continuously monitored with the casing-conveyed fiber-optic cable. If the casing-conveyed fiber-optic cable fails, a temperature log will be run annually. Ultrasonic or equivalent CIL will be acquired only as required by DMR-O&G and when tubing is pulled. The PNL will be repeated in each injection well in Year 1, Year 3, and at least once every 3 years thereafter for detecting any potential mechanical integrity issues behind the casing. SCS2 will conduct annulus pressure testing during workovers in cases where the tubing must be pulled and no less than once every 5 years. A nitrogen cushion with a seal pot system will maintain a constant positive pressure on the well annulus in each injection well. A comprehensive summary of testing and monitoring activities associated with the CO_2 injection wells is provided in Section 4.0 of this MRV plan.

The risk of surface leakage of CO_2 via the UIC Class VI wellbores is mitigated by:

- Following NDIC Class VI well construction standards.

- Performing wellbore mechanical integrity testing as described hereto.

- Actively monitoring well operations with continuous recording devices, including the fiber-optic cable, surface P/T gauges, and a seal pot system.

- Preventing corrosion of well materials, following the preemptive measures described in the proposed completed wellhead and wellbore schematics (Figures 3-1 through 3-3).

The likelihood of surface leakage of CO_2 from the UIC Class VI wells during injection or post-injection operations is very low because of well construction and active monitoring methods. Barriers associated with well construction that will prevent reservoir fluids from reaching the surface include surface valves, CO_2-resistant injection tubing fitted with a packer set above the injection zone, CO_2-resistant casing and annular cement, and surface casing (set at a minimum of 50 feet below the base of the Fox Hills) and cement. Cement on all casing strings is planned to be brought to the surface to seal the annulus from injection zone to the surface. The integrity of these barriers will be actively monitored with DTS fiber-optic cable along the casing, surface digital P/T gauges set on the surface casing, tubing-casing annulus, tubing, and a seal pot system for each well. Active monitoring will ensure the integrity of well barriers and early detection of leaks, including triggering of the (automated) emergency shutoff valve on the wellhead to limit the magnitude of any potential surface leakage to the volume of the wellbore. In addition, a SCADA system will be used to monitor operations, shut down the injection upon a condition existing outside the designed operating parameters, and provide the potential to estimate GHG emitted volumes.

The potential for surface leakage of CO_2 from the UIC Class VI injection wells 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 UIC Class VI wells will be properly plugged and abandoned following NDIC protocols, thereby further reducing any remaining risk of surface leakage from the wellbore.

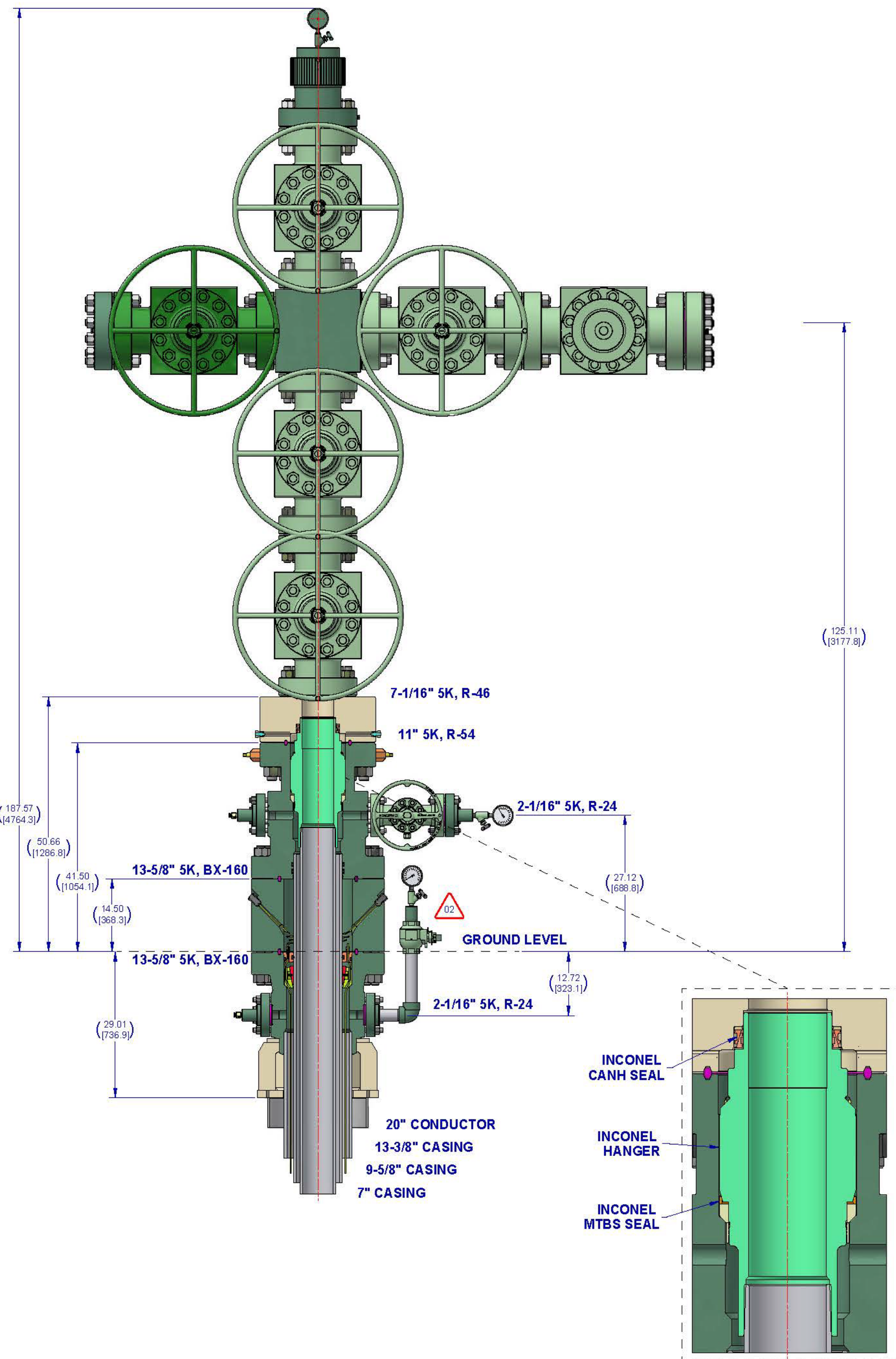

Figure 3-1. BK Fischer 1 and 2 proposed CO_2-resistant wellhead schematic. The lowest manual valve on the wellhead injection tree will be of Class HH material, and the tubing hanger mandrel will be constructed with corrosion-resistant alloy (CRA). The remainder of the injection tree will consist of Class FF and equivalent materials.

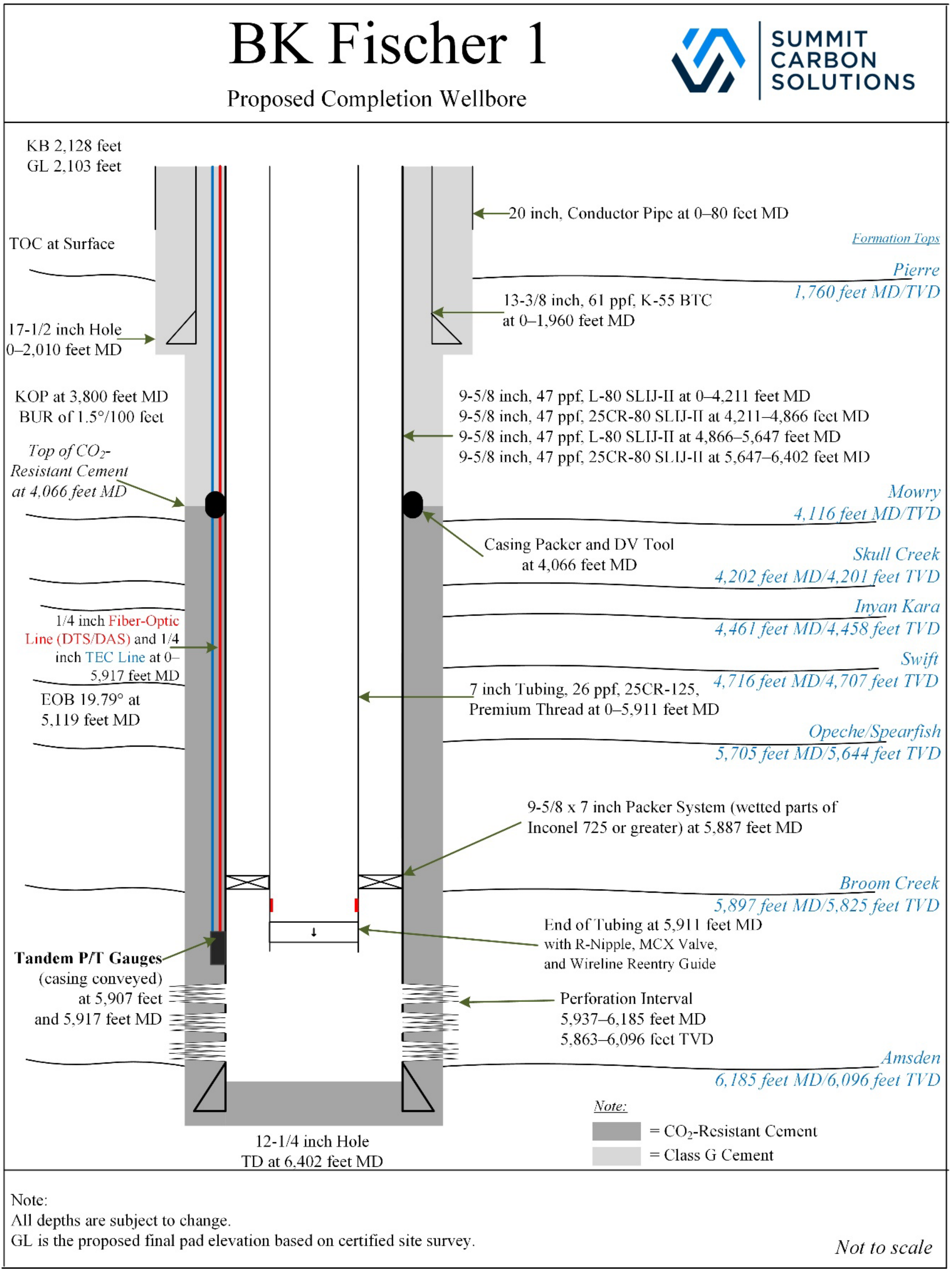

Figure 3-2. BK Fischer 1 proposed completed wellbore schematic. Refer to the list of acronyms preceding this MRV plan for definitions of abbreviated terms presented.

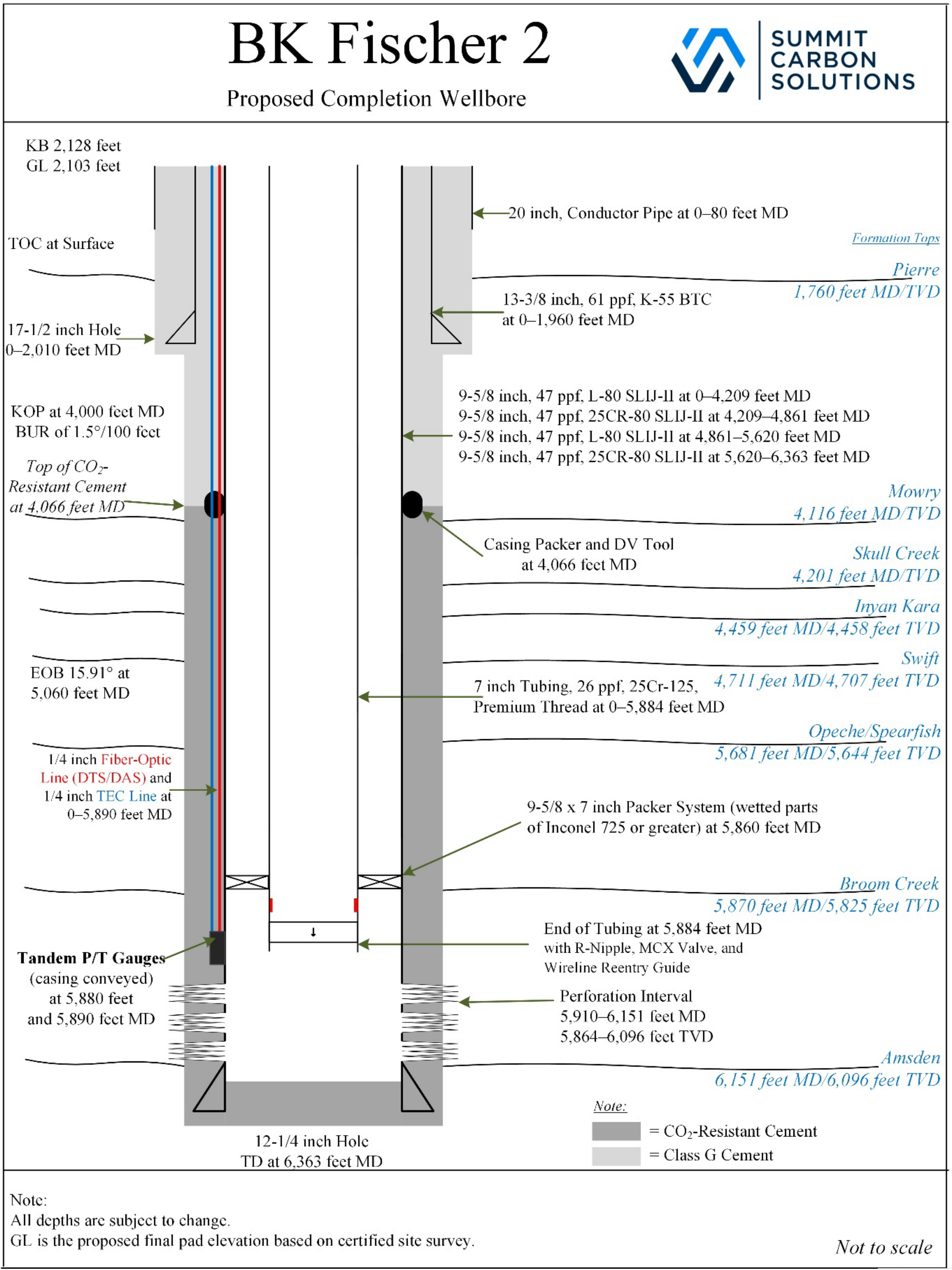

Figure 3-3. BK Fischer 2 proposed completed wellbore schematic.

3.2 Reservoir-Monitoring Well

The Archie Erickson 2 (NDIC File No. 38622) well was permitted and drilled as a stratigraphic test well by the original operator, SCS, to characterize subsurface conditions for establishing the BK Fischer storage facility associated with SCS2's North Dakota SFP application. As of December 2023, SCS has transferred ownership and operation of the Arche Erickson 2 well to SCS2. This stratigraphic test well was constructed to NDIC Class VI standards and will be converted into a reservoir-monitoring well prior to injection, as shown in the as-completed wellhead and wellbore schematics in Figures 3-4 and 3-5, respectively. The same set of pre-injection and operational well-logging activities, installation of equipment, and measures to prevent corrosion of the well materials will also occur with Archie Erickson 2, with the exception that no tubing or seal pot system will be installed. A comprehensive summary of testing and monitoring activities associated with the reservoir-monitoring well is provided in Section 4.0 of this MRV plan.

The risk of surface leakage of CO_2 via the reservoir-monitoring wellbore is mitigated by:

- Following NDIC Class VI well construction standards. In addition, the Archie Erickson 2 will not be perforated along the entire length of the wellbore.
- Performing wellbore mechanical integrity testing.
- Actively monitoring well operations with continuous recording devices, including the fiber-optic cable and surface P/T gauges.
- Preventing corrosion of well materials by implementing the preemptive measures described in the as-completed wellhead and wellbore schematics (Figures 3-4 and 3-5).

The likelihood of surface leakage of CO_2 from the reservoir-monitoring well during injection or post-injection operations is very low because of well construction and active monitoring methods. Barriers associated with well construction that will prevent reservoir fluids from reaching the surface include surface valves, CO_2-resistant casing and annular cement, and surface casing and cement, with the top of cement estimated at 23 feet (above the Fox Hills freshwater zone). The integrity of these barriers will be actively monitored with casing-conveyed DTS fiber-optic cable and surface digital P/T gauges set on the surface casing, and long-string casing. Active monitoring will ensure the integrity of well barriers and early detection of leaks. In addition, a SCADA system will be used to monitor for leaks, notify personnel if anomalous readings are detected or an alarm is triggered, and, if warranted, inform rapid respond to work over the wellbore or wellhead for limiting the magnitude of any potential surface leakage to the volume of the wellbore. The SCADA system also provides the potential the potential to estimate GHG emissions.

The potential for a surface leak from the reservoir-monitoring well is present from around Year 7 of injection (when model simulations of the injected CO_2 plume predict CO_2 may come into contact with Archie Erickson 2) through the post-injection period. The risk of a surface leak begins to decrease after injection ceases in the BK Fischer wells and greatly decreases as the reservoir approaches original pressure conditions. Once the post-injection period ceases, the reservoir-monitoring wells will either be properly plugged and abandoned following NDIC protocols or transferred to DMR-O&G for continued surveillance of the storage reservoir.

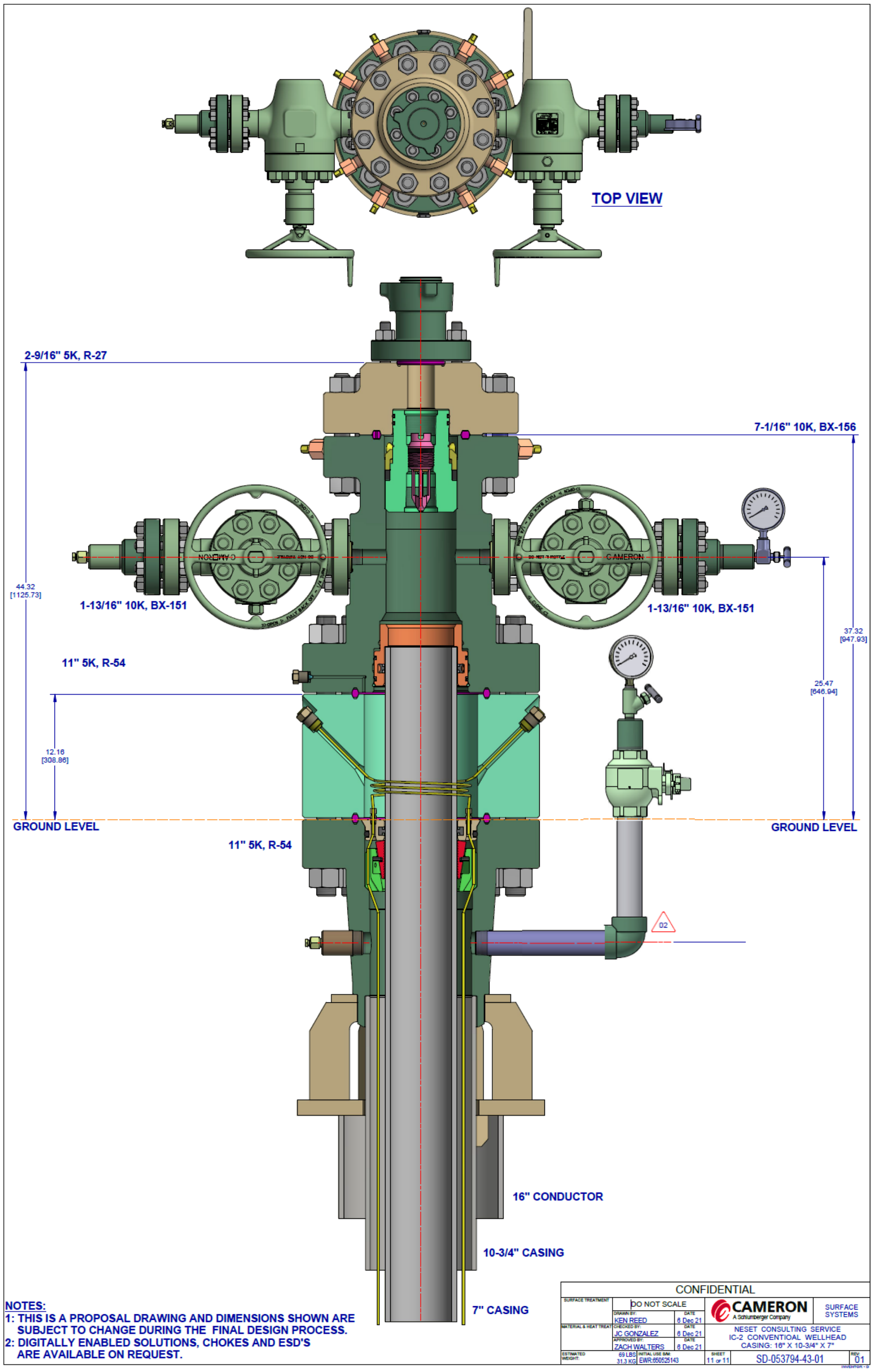

Figure 3-4. Archie Erickson 2 as-completed wellhead schematic.

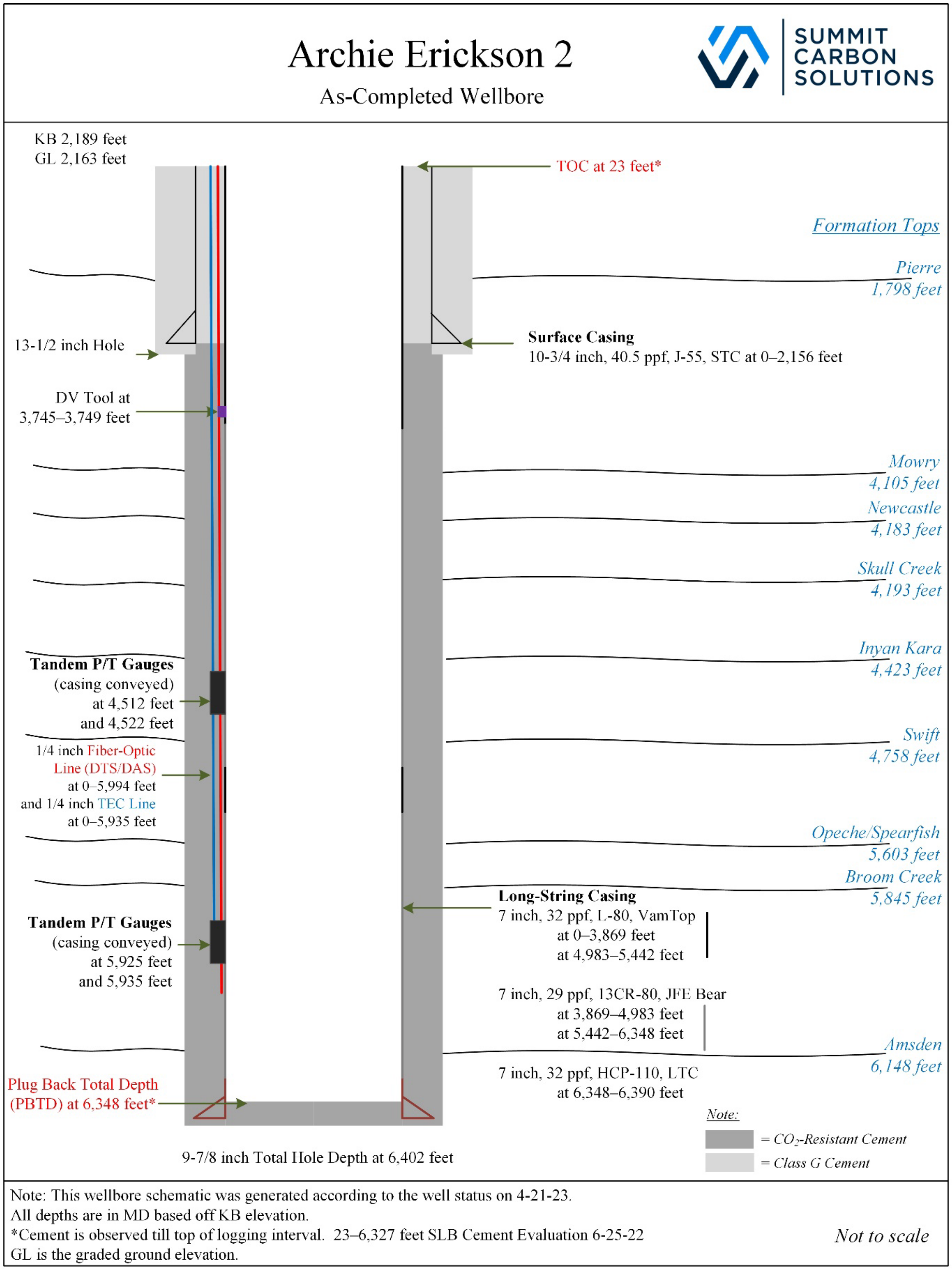

Figure 3-5. Archie Erickson 2 as-completed wellbore schematic.

3.3 Surface Components

Surface components of the injection system include the CO_2 injection wellheads (BK Fischer 1 and 2) and surface piping from the mass flow meters on NDL-325 at the injection wellsite to the injection wellheads. These surface components will be monitored with leak detection equipment, as shown on Figure 1-4, which includes a gas detection station mounted inside the pump and metering building, the mass flow meters, digital P/T gauges immediately downstream of the mass flow meters and just before the emergency shut-in valve on the injection wellheads, and the surface P/T gauges on each of the wellheads. The aboveground section of flowline downstream of the mass flow meters will also be regularly inspected for any visual or auditory signs of equipment failure. The leak detection equipment will be integrated into a SCADA system with automated warning systems and shutoffs that notify the operations center, giving SCS2 the ability to remotely isolate the system in the event of an emergency or shut down injection operations until SCS2 can clear the emergency.

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

- Adhering to regulatory requirements for well construction (N.D.A.C. § 43-05-01-11), well operation (N.D.A.C. § 43-05-01-11.3), and surface facilities-related testing and monitoring activities (N.D.A.C. § 43-05-01-11.4).

- Implementing the highest standards on material selection and construction processes for the flowlines and wells.

- Monitoring continuously via an automated and integrated SCADA system.

- Monitoring of the surface facilities with routine visual inspections and regular maintenance.

- Monitoring and maintaining the dew point of the CO_2 stream to ensure that the CO_2 stream remains properly dehydrated.

The likelihood of surface leakage of CO_2 through surface equipment during injection is very low, and the magnitude is typically 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 Legacy Wells

There are no legacy wells that penetrate the deep subsurface within the BK Fischer storage facility or AOR boundary other than Archie Erickson 2 (stratigraphic test well to be converted to a reservoir-monitoring well, discussed in Section 3.2); therefore, there is no potential for surface leakage through any legacy wells within the AOR. The two closest wells relative to the AOR boundary are Fritz Leutz 1 (NDIC File No. 21) and Wehri 1 (NDIC File No. 7818), located approximately 2.6 miles to the west and 6.3 miles to the south of the BK Fischer storage facility, respectively, as shown in Figure 1-5.

SCS2 will review the North Dakota SFP at least once every 5 years. In the event the CO_2 plume is migrating within the storage reservoir and monitoring results indicate CO_2 may leave the approved SFA boundary and approach a legacy wellbore identified above, SCS2 will reevaluate the monitoring strategy and propose appropriate revisions (e.g., additional groundwater-monitoring wells) to ensure that the likelihood, magnitude, and risk of surface leakage of CO_2 associated with these potential surface leakage pathways is minimal.

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.

3.5.1 Natural or Induced Seismicity

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment. Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The closest recorded seismic event to the BK Fischer storage facility occurred 20.01 miles to the southwest of the CO_2 injection wellsite, with an estimated magnitude of 3.2, as shown in Table 3-1 and Figure 3-6.

Table 3-1. Summary of Reported North Dakota Seismic Events (from Anderson, 2016)

Map Label	Date	Magnitude	Depth, mi	Longitude	Latitude	Event Location	Distance to the Injection Wells, mi
A	09/28/2012	3.3	0.4[1]	−103.48	48.01	Southeast of Williston	99.97
B	06/14/2010	1.4	3.1	−103.96	46.03	Boxelder Creek	126.78
C	03/21/2010	2.5	3.1	−103.98	47.98	Buford	118.12
D	08/30/2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	44.93
E	01/03/2009	1.5	8.3	−103.95	48.36	Grenora	132.08
F	11/15/2008	2.6	11.2	−100.04	47.46	Goodrich	87.87
G	11/11/1998	3.5	3.1	−104.03	48.55	Grenora	143.54
H	03/09/1982	3.3	11.2	−104.03	48.51	Grenora	141.67
I	07/08/1968	4.4	20.5	−100.74	46.59	Huff	61.98
J	05/13/1947	3.7[2]	U[3]	−100.90	46.00	Selfridge	87.95
K	10/26/1946	3.7[2]	U[3]	−103.70	48.20	Williston	116.11
L	04/29/1927	3.2[2]	U[3]	−102.10	46.90	Hebron	20.01
M	08/08/1915	3.7[2]	U[3]	−103.60	48.20	Williston	112.61

[1] Estimated depth.
[2] Magnitude estimated from reported modified Mercalli intensity (MMI) value.
[3] Unknown depth.

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging seismic events occurring in North Dakota, with less than five damaging seismic events predicted to occur every 100 years, as shown in Figure 3-7 (U.S. Geological Survey, 2023). 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 BK Fischer injection wellsite.

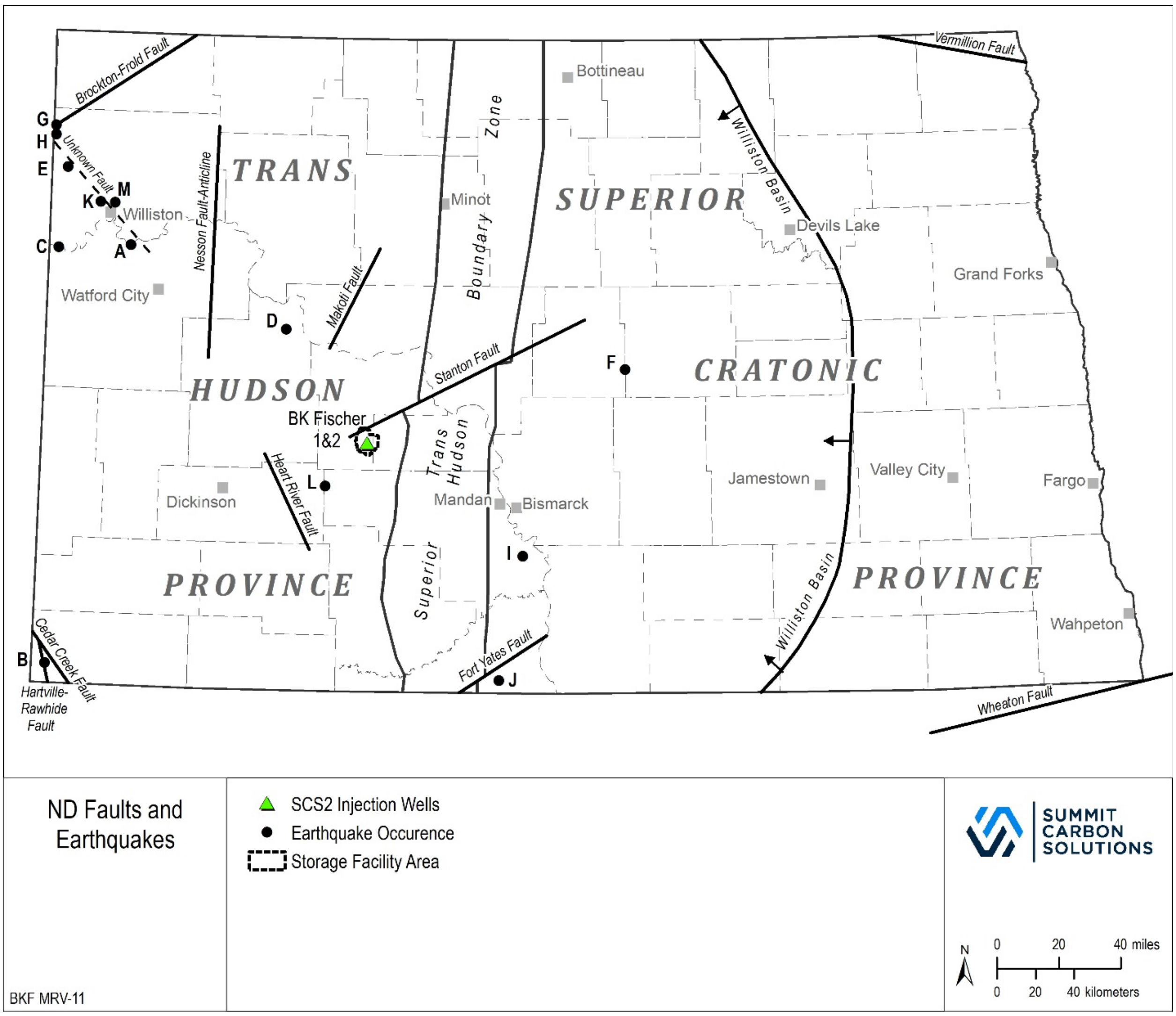

Figure 3-6. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016). Labeled black dots correspond to seismic events summarized in Table 3-1.

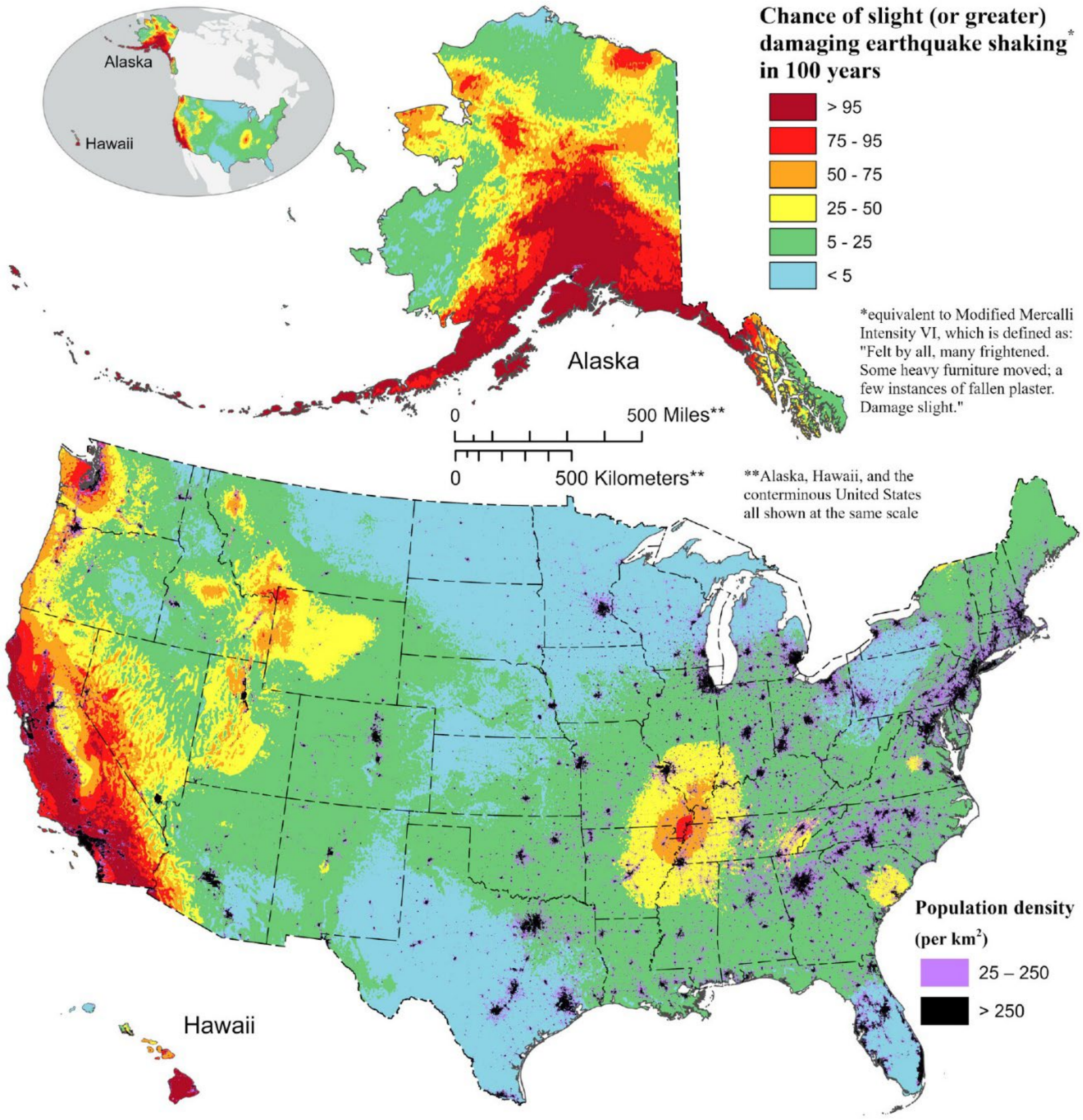

Figure 3-7. Probabilistic map showing how often scientists expect damaging seismic event shaking around the United States (U.S. Geological Survey, 2023). The map shows there is a low probability of damaging seismic events occurring in North Dakota.

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 within the storage complex and SFA suggest that the probability is very low for seismicity to interfere with CO_2 containment. The risk of induced seismicity is present from the start of injection until the storage reservoir returns to or close to its original reservoir pressure after injection ceases. The magnitude of natural seismicity in the vicinity is expected to be 3.2 or below based on precedent set by historical data.

Injection pressures are forecast to operate at a buffer below the maximum allowable injection pressure, minimizing the potential for induced seismicity from injection operations.

Despite the low risk for induced seismicity at the BK Fischer injection site, SCS2 will install multiple surface seismometer stations to detect potential seismicity events throughout the operational and post-injection phases and provide additional public assurance that the storage facility is operating safely and as permitted.

3.6 Confining System Pathways

Confining system pathways include potential for CO_2 to diffuse upward through confining zones, migration of CO_2 beyond the lateral extent of confining zones, and future wells that may penetrate confining zones or the storage reservoir.

3.6.1 Seal Diffusivity

For the BK Fischer storage facility, the primary mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be trapping by the upper confining zone (Opeche/Spearfish), which will contain the buoyant CO_2 under the effects of relative permeability and capillary pressure. Several other formations provide additional confinement above the Opeche/Spearfish interval, including the Piper, Rierdon, and Swift Formations, which make up the first group of additional confining zones. Together with the Opeche/Spearfish, these formations are 1,087 feet thick (at the Archie Erickson 2) 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, 2,625 feet of impermeable rock (at the Archie Erickson 2) 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 provides stratigraphic reference).

The risk of surface leakage of CO_2 via seal diffusivity is very low during operations, as there is a total of 3,712 feet of confining layers above the storage reservoir. This risk continues to diminish after injection ceases and the plume becomes more stable.

3.6.2 Lateral Migration

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) within the storage reservoir. In addition, the Opeche/Spearfish Formation is laterally extensive across the simulated model extent (refer to Figure 1-8).

The risk of surface leakage of CO_2 via lateral migration is very low during operations, as demonstrated by the numerical simulations performed, which predict stabilization of the CO_2 plume within the SFA boundary and the lateral extent of the Opeche/Spearfish Formation. Predictions about the CO_2 plume extent will be verified with monitoring data (discussed in Section 5.0). This risk diminishes after injection ceases and the CO_2 plume's rate of aerial expansion begins to decrease.

3.6.3 Drilling Through the CO_2 Plume

There is no commercial oil and gas activity within the AOR boundary (refer to Section 1.2), and it is unlikely that any future wells would be drilled through the CO_2 plume. DMR-O&G maintains authority to regulate and enforce oil and gas activity respective to the integrity of operations, including drilling of wells, underground storage of CO_2, and operator compliance with field rules established for CO_2 storage projects, which requires a public hearing for any proposed drilling through the CO_2 plume and DMR-O&G approval.

3.7 Monitoring, Response, and Reporting Plan for CO_2 Loss

SCS2 proposes a testing and monitoring plan as summarized in the next section of this MRV plan. The program covers surveillance of injection performance, corrosion and mechanical integrity protocols, baseline testing and logging plans for project wellbores, monitoring of near-surface conditions, and direct and indirect monitoring of the CO_2 plume and associated pressure front in the storage reservoir. To complement the testing and monitoring approach, SCS2 prepared an emergency and remedial response plan, in Appendix A, based on several risk-based scenarios that cover the actions to be implemented from detection, verification, analysis, remediation, and reporting in the event of an unplanned loss of CO_2 from the BK Fischer GHGRP facility. SCS2 will comply with data-reporting requirements under 40 CFR § 98.446 regarding losses of CO_2 associated with equipment leaks, vented emissions, or surface leakage of CO_2 through leakage pathways.

4.0 DETERMINATION OF BASELINES

SCS2 developed a pre-injection (baseline) testing and monitoring plan, as described in Table 4-1. The plan will be implemented approximately 1 year prior to injection and includes sampling and analysis of both near-surface and deep subsurface environments. Baselines are important for time-lapse comparison with operational and post-injection monitoring data to verify the project is operating as permitted.

Table 4-1. Overview of Major Components of the Testing and Monitoring Plan – Pre-Injection

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Schedule
CO_2 Stream Analysis	**Injection composition**	CO_2 stream sampling	CO_2 accounting and ensuring stream compatibility with project materials in contact with CO_2	Commercial laboratory metallurgical testing results based on CO_2 stream composition and injection zone conditions. Gas chromatograph and CO_2 stream compositional commercial laboratory results	Downstream of pipeline inspection gauge (PIG) receiver (Receiver in Figure 1-4)	At least once
Wellbore Mechanical Integrity (external)	**Casing wall thickness**	Ultrasonic logging or other equivalent CIL and sonic array logging (inclusive of casing collar locator [CCL], variable-density log [VDL], and radial cement bond log [RCBL]), and GR	Mechanical integrity demonstration and operational safety assurance	Ultrasonic or other equivalent CIL and sonic array tools (inclusive of CCL, VDL, and RCBL) and GR	CO_2 injection and reservoir-monitoring wells	Once per well
	Radial cement bond					
	Saturation profile (behind casing)	PNL		PNL tool	CO_2 injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	
	Temperature profile	Temperature logging		Temperature log	CO_2 injection and reservoir-monitoring wells	
		Real-time, continuous data recording via SCADA system		DTS casing-conveyed fiber-optic cable	Along the outside of the long-string casing of the CO_2 injection and reservoir-monitoring wells	Install at casing deployment
Wellbore Mechanical Integrity (internal)	**P/T**	Real-time, continuous data recording via SCADA system	Mechanical integrity demonstration and operational safety assurance	Digital surface P/T gauge	Between surface and long-string casing annulus on CO_2 injection and reservoir-monitoring wells	Install at well completion
	Annulus pressure	Tubing-casing annulus pressure testing		Pressure-testing truck with pressure chart	CO_2 injection and reservoir-monitoring wells	Once per well
	P/T	Real-time, continuous data recording via SCADA system		Digital surface P/T gauge	Between tubing and long-string casing annulus of CO_2 injection and long-string casing of reservoir-monitoring wells	Install at well completion
	Annular fluid level	Real-time, continuous data recording via SCADA system	Prevention of microannulus and monitoring annular fluid volume	Nitrogen cushion on tubing-casing annulus with seal pot system	On well pad for each CO_2 injection well	Add initial volumes to BK Fischer 1 and 2
	P/T	Real-time, continuous data recording via SCADA system	Mechanical integrity demonstration and operational safety assurance	Digital surface P/T gauge	Tubing of CO_2 injection wells	Install at well completion
	Saturation profile (tubing-casing annulus)	PNL		PNL tool	CO_2 injection wells (run log from Opeche/Spearfish Formation to surface)	Once per well
Downhole Corrosion Detection	**Saturation profile** (behind casing)	PNL	Corrosion detection of project materials in contact with CO_2 and operational safety assurance	PNL tool	CO_2 injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Once per well
	Casing wall thickness	Ultrasonic logging or other equivalent CIL and sonic array logging (inclusive of CCL, VDL, and RCBL), and GR		Ultrasonic or other equivalent CIL and sonic array tools (inclusive of CCL, VDL, and RCBL), and GR	CO_2 injection and reservoir-monitoring wells	

Continued…

Table 4-1. Overview of Major Components of the Testing and Monitoring Plan – Pre-Injection (continued)

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Schedule
Near-Surface	**Soil gas composition**	Soil gas sampling (refer to Figure 4-1)	Assurance near-surface environment is protected	Two soil gas profile stations: MSG02 and MSG05	One station per CO_2 injection and reservoir-monitoring well pad	3–4 seasonal samples per station (concentration analysis with isotopes)
	Soil gas isotopes		Source attribution			
	Water composition	Groundwater well sampling (refer to Figure 4-1)	Assurance that USDWs are protected	Up to five existing groundwater wells from the Tongue River, Cannonball-Ludlow, and Fox Hills Aquifers (e.g., MGW01, MGW03, MGW05, MGW06, and MGW08)	Within AOR	3–4 seasonal samples per well (water quality with isotopes)
	Water isotopes		Source attribution			
	Water composition		Assurance that lowest USDW is protected	Fox Hills monitoring well	MGW10 adjacent to CO_2 injection well pad	3–4 seasonal samples (water quality with isotopes)
	Water isotopes		Source attribution			
Above-Zone Monitoring Interval (Opeche/Spearfish to Skull Creek)	**Saturation profile**	PNL	Assurance of containment in the storage reservoir and protection of USDWs	PNL tool	CO_2 injection and reservoir-monitoring wells	Once per well
	Temperature profile	Real-time, continuous data recording via SCADA system		DTS casing-conveyed fiber-optic cable		Install at casing deployment
		Temperature logging		Temperature log		Once per well
Storage Reservoir (direct)	**P/T**	Real-time, continuous data recording via SCADA system	Storage reservoir monitoring and conformance with model and simulation projections	Casing-conveyed downhole P/T gauge	CO_2 injection and reservoir-monitoring wells	Install at casing deployment
	Temperature profile	Real-time, continuous data recording via SCADA system		DTS casing-conveyed fiber-optic cable		Install at casing deployment
		Temperature logging		Temperature log		Once per well
	Storage reservoir performance	Injectivity testing	Demonstration of storage reservoir performance	Pressure falloff test	CO_2 injection wells	Once per injection well
Storage Reservoir (indirect)	**CO_2 saturation**	3D time-lapse seismic surveys	Site characterization and CO_2 plume tracking to ensure conformance with model and simulation projections	Vibroseis trucks (source) and geophones and DAS fiber-optic cable (receivers)	Within AOR	Collect 3D baseline survey
	Seismicity	Continuous data recording	Seismic event detection and source attribution and operational safety assurance	Seismometer stations and DAS fiber optics	Area around injection wells (within 1 mile)	Install stations

Figure 4-1 illustrates the proposed sampling locations associated with the near-surface program. Two soil gas profile stations (MSG02 and MSG05), one new Fox Hills monitoring well (MGW10), and up to five existing groundwater wells (MGW01, MGW03, MGW05, MGW06, and MGW08) are included as part of the pre-injection near-surface sampling program.

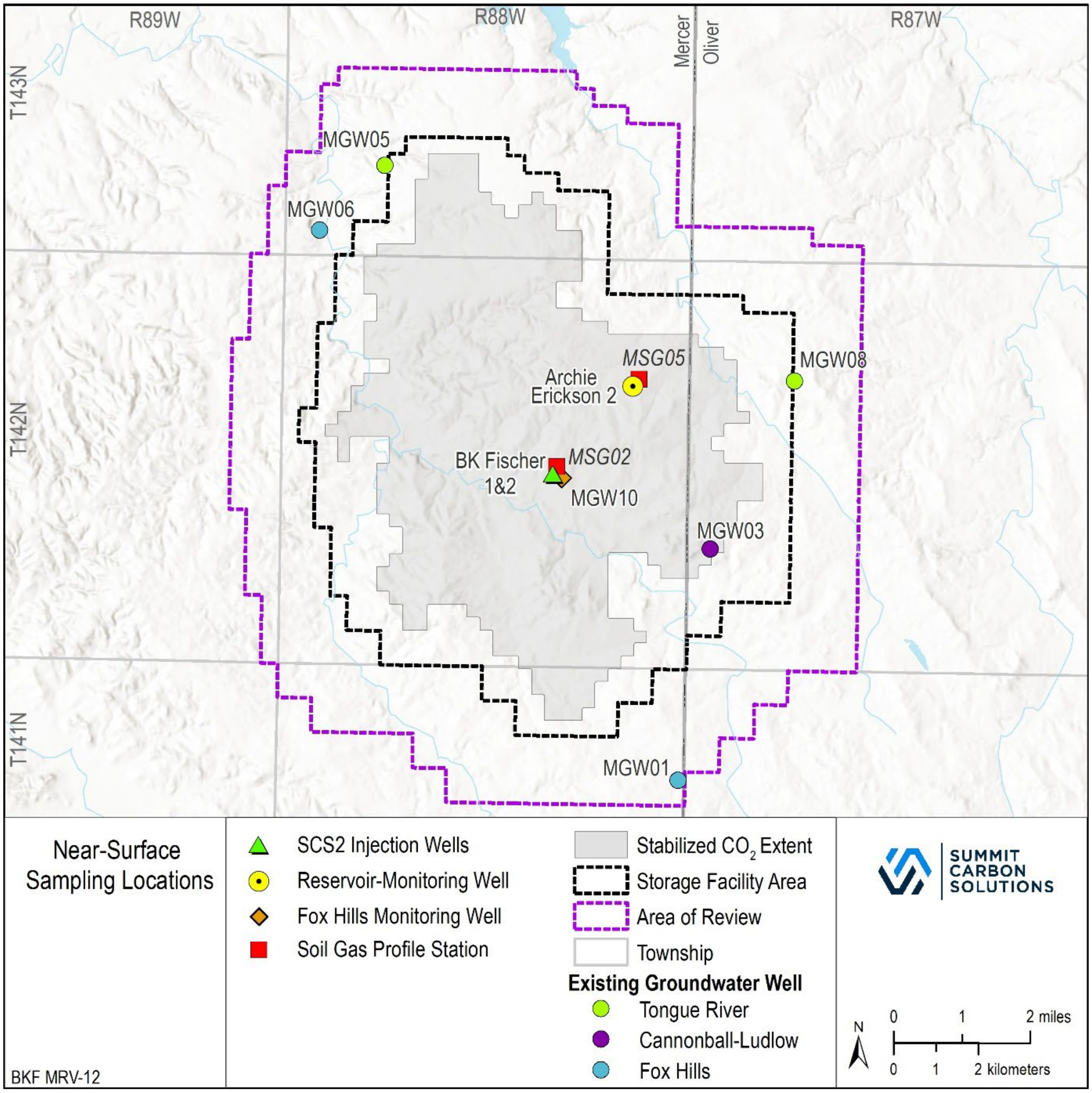

Figure 4-1. SCS2 near-surface sampling locations.

SCS2 has initiated collection of pre-injection data to determine baselines and inform the geologic model and numerical simulations for calculation of key project boundaries (e.g., AMA and MMA). A 200-square-mile seismic survey was acquired to characterize the subsurface geology within the BK Fischer storage facility, and Archie Erickson 2 (proposed reservoir-monitoring well) was drilled. Whole core was obtained from the storage complex and analyzed to measure or characterize lithology/mineralogy, fracture type and distribution, porosity, permeability, and pore throat size distribution that were incorporated into the geologic model. An initial well-testing and logging campaign has been completed for Archie Erickson 2, as summarized in Table 4-2.

Table 4-2. Completed Logging and Testing Activities for Archie Erickson 2

	Logging/Testing	Justification
Surface Section	Openhole logs: triple combo (resistivity and neutron and density porosity), dipole sonic, spontaneous potential (SP), GR, caliper, and temperature	Quantified variability in reservoir properties, such as resistivity and lithology, and measured hole conditions. Identified mechanical properties, including stress anisotropy. Provided compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.
	Cased-hole logs: ultrasonic and array sonic tools (inclusive of CCL, VDL, and RCBL), GR, and temperature	Identified cement bond quality radially, evaluated the cement top and zonal isolation, and established external mechanical integrity. Established baseline temperature profile.
Long-String Section	Openhole logs: triple combo and spectral GR	Quantified variability in reservoir properties, including resistivity, porosity, and lithology. Provided input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve interpretations. Identified mechanical properties, including stress anisotropy. Provided compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.
	Openhole log: dipole sonic	Identified mechanical properties, including stress anisotropy.
	Openhole log: fracture finder log	Quantified fractures in the Broom Creek Formation and confining layers to ensure safe, long-term storage of CO_2.
	Openhole log: combinable magnetic resonance (CMR)	Interpreted reservoir properties (e.g., porosity and permeability) and determined the best location for pressure test depths, formation fluid sampling depths, and stress testing depths.
	Openhole log: fluid sampling (modular formation dynamics tester)	Collected fluid samples from the Inyan Kara and Broom Creek Formation for analysis. Collected in situ microfracture stress tests in the Broom Creek and Opeche/Spearfish Formation for formation breakdown pressure, fracture propagation pressure, and fracture closure pressure.
	Cased-hole logs: ultrasonic and array sonic tools (inclusive of CCL, VDL, RCBL), GR, and temperature	Identified cement bond quality radially, evaluated the cement top and zonal isolation, confirmed mechanical integrity, and established baseline temperature profile.

5.0 SURFACE LEAKAGE DETECTION AND QUANTIFICATION STRATEGY

Table 5-1 summarizes the testing and monitoring strategy SCS2 will implement in the operations and post-injection phases, and Table 5-2 summarizes the strategy for detecting and quantifying surface leakage pathways associated with CO_2 injection.

Table 5-1. Overview of Major Components of the Testing and Monitoring Plan – Injection and Post-Injection

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Schedule	
						Injection (20 years)	**Post-Injection (minimum of 10 years)**
CO_2 Stream Analysis	**Injection volume/mass**	Real-time, continuous data recording with automated triggers and alarms via SCADA system	CO_2 accounting, leak detection, and operational safety assurance	Multiple mass flow meters	One flow meter per injection wellhead placed on flowline after flowline splits on injection pad	Continuous	None (injection has ceased)
	Injection flow rate						
	Injection P/T			Multiple P/T gauges	Along NDL-325; downstream or upstream of flow meters at injection pad; and upstream of injection wellheads		
	Injection composition	CO_2 stream sampling	CO_2 accounting and ensures stream compatibility with project materials in contact with CO_2	Gas chromatograph	Downstream of the PIG receiver (Receiver in Figure 1-4)		
			Verify accuracy of field measurements	CO_2 stream sampling with sample port	Upstream of the gas chromatograph	Quarterly with option to reduce sampling frequency with approval from DMR-O&G	
	Isotopes		Source attribution			Within first year of injection and within 1 year of adding new CO_2 source(s) (other than ethanol)	
Surface Facilities Leak Detection	**Mass balance**	Real-time, continuous data recording with automated triggers and alarms via SCADA system	CO_2 accounting, leak detection, and operational safety assurance	Leak detection system (LDS) software, multiple P/T gauges, and mass flow meters	Flow meter and P/T gauge near each injection wellhead in pump/metering building and flow meter and P/T gauge at point of transfer	Continuous	None (injection has ceased)
	Gas concentrations (e.g., CO_2 and CH_4)			Gas detection stations and safety lights	Stations on each injection and reservoir-monitoring wellhead; station inside pump/metering building and safety light mounted on building exterior; multigas detectors worn by field personnel		
CO_2 Flowline Corrosion Prevention and Detection	**Loss of mass**	Real-time, continuous data recording with automated triggers and alarms via SCADA system	Corrosion detection of project materials in contact with CO_2 and operational safety assurance	Electrical resistance (ER) probe	Flowline NDL-325 begins at the point of transfer and ends at the inlet valve upstream of the emergency shut off valve at each injection wellhead	Continuous	None (injection has ceased)
		In-line inspection		PIG	PIG receiver upstream of the gas chromatograph on NDL-325 flowline	Once every 5 years	
	Flow conditions (e.g., saturation point of water)	Real-time, continuous data recording with automated triggers and alarms via SCADA system		Real-time model with LDS software and multiple P/T gauges, mass flow meters, and dew point meters	Flow meter and P/T gauge near each injection wellhead, P/T gauge at point of transfer, and dew point meters at capture facilities	Continuous	
	Cathodic protection	Continuous data recording	Corrosion prevention of project materials	Impressed current cathodic protection (ICCP) system	Anodes buried along the length of NDL-325 flowline or impressed electric current applied to flowline.	Continuous (impressed current with monitoring program) or quarterly (anodes)	

Continued . . .

Table 5-1. Overview of Major Components of the Testing and Monitoring Plan – Injection and Post-Injection (continued)

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Schedule: Injection (20 years)	Sampling Schedule: Post-Injection (minimum of 10 years)
Wellbore Mechanical Integrity (external)	**Casing wall thickness**	Ultrasonic logging or other equivalent CIL and sonic array logging (inclusive of CCL, VDL, RCBL), and GR	Mechanical integrity demonstration and operational safety assurance	Ultrasonic or other equivalent CIL and sonic array tools (inclusive of CCL, VDL, and RCBL) and GR	CO_2 injection and reservoir-monitoring wells	Repeat when required and when tubing is pulled during workovers.	Same schedule as injection but only for reservoir-monitoring well (CO_2 injection wells will be plugged at injection cessation)
	Radial cement bond						
	Saturation profile (behind casing)	PNL		PNL tool	CO_2 injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Year 1, Year 3, and at least once every 3 years thereafter (e.g., Years 6, 9, 12, etc.)	Year 4 and Year 9 of post-injection (reservoir-monitoring well only)
	Temperature profile	Temperature logging		Temperature log	CO_2 injection and reservoir-monitoring wells	Annually only if DTS fails	Same schedule as injection but only for reservoir-monitoring well (CO_2 injection wells will be plugged at injection cessation)
		Real-time, continuous data recording via SCADA system		DTS casing-conveyed fiber-optic cable	Along the outside of the long-string casing of the CO_2 injection and reservoir-monitoring wells	Continuous	
Wellbore Mechanical Integrity (internal)	**P/T**	Real-time, continuous data recording via SCADA system	Mechanical integrity demonstration and operational safety assurance	Digital surface P/T gauge	Between surface and long-string casing annulus on CO_2 injection and reservoir-monitoring wells	Continuous	Same schedule as injection but only for reservoir-monitoring well (CO_2 injection wells will be plugged at injection cessation)
	Annulus pressure	Tubing-casing annulus pressure testing		Pressure-testing truck with pressure chart	CO_2 injection and reservoir-monitoring wells	Repeat during workover operations in cases where the tubing must be pulled and no less than once every 5 years.	
	P/T	Real-time, continuous data recording via SCADA system		Digital surface P/T gauge	Between tubing and long-string casing annulus of CO_2 injection and long-string casing of reservoir-monitoring wells	Continuous	
	Annular fluid level		Prevention of microannulus and monitoring annular fluid volume	N_2 cushion on tubing-casing annulus with seal pot system	On well pad for each CO_2 injection well		
	P/T		Mechanical integrity demonstration and operational safety assurance	Digital surface P/T gauge	Tubing of CO_2 injection wells		
	Saturation profile (tubing-casing annulus)	PNL		PNL tool	CO_2 injection wells (run log from Opeche/Spearfish Formation to surface)	Year 1, Year 3, and at least once every 3 years thereafter (e.g., Years 6, 9, 12, etc.)	Year 4 and Year 9 of post-injection (reservoir-monitoring well only)
Downhole Corrosion Detection	**Saturation profile** (behind casing)	PNL	Corrosion detection of project materials in contact with CO_2 and operational safety assurance	PNL tool	CO_2 injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Year 1, Year 3, and at least once every 3 years thereafter (e.g., Years 6, 9, 12, etc.)	Year 4 and Year 9 of post-injection (reservoir-monitoring well only)
	Casing wall thickness	Ultrasonic logging or other equivalent CIL and sonic array logging (inclusive of CCL, VDL, and RCBL), and GR		Ultrasonic or other equivalent CIL and sonic array tools (inclusive of CCL, VDL, and RCBL), and GR	CO_2 injection and reservoir-monitoring wells	Repeat when required and when tubing is pulled during workovers.	Same schedule as injection but only for reservoir-monitoring well (CO_2 injection wells will be plugged at injection cessation)

Continued…

Table 5-1. Overview of Major Components of the Testing and Monitoring Plan – Injection and Post-Injection (continued)

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Schedule	
						Injection (20 years)	**Post-Injection (minimum of 10 years)**
Near-Surface	**Soil gas composition**	Soil gas sampling (see Figure 4-1)	Assurance near-surface environment is protected	Two soil gas profile stations: MSG02 and MSG05	One station per CO_2 injection and reservoir-monitoring well pad	Collect 3–4 seasonal samples annually per station (no isotopes).	Collect 3–4 seasonal samples per station in Year 1 and Year 3 of post-injection and every 3 years thereafter*.
	Water composition	Groundwater well sampling (see Figure 4-1)	Assurance that USDWs are protected	Up to five existing groundwater wells from the Tongue River, Cannonball–Ludlow, and Fox Hills Aquifers (e.g., MGW01, MGW03, MGW05, MGW06, and MGW08)	AOR	At start of injection, shift sampling program to MGW10; additional wells may be phased in overtime as the CO_2 plume migrates (no isotopes).	Collect 3–4 seasonal samples in Year 1 and Year 3 of post-injection and at least once every 3 years thereafter until facility closure* (MGW01); and prior to facility closure* (MGW03, MGW05, MGW06 and MGW08).
	Water composition		Assurance that lowest USDW is protected	Fox Hills monitoring well	MGW10 adjacent to CO_2 injection well pad; additional wells may be phased in overtime as the CO_2 plume migrates.	Collect 3–4 seasonal samples in Years 1–4 and reduce to annually thereafter (no isotopes).	Collect samples annually until facility closure*.
Above-Zone Monitoring interval Opeche/Spearfish to Skull Creek	**Saturation profile**	PNL	Assurance of containment in the storage reservoir and protection of USDWs	PNL tool	CO_2 injection and reservoir-monitoring wells	Year 1, Year 3, and at least once every 3 years thereafter (e.g., Years 6, 9, 12, etc.)	Same schedule as injection but only for reservoir-monitoring well (CO_2 injection wells will be plugged at injection cessation)
	Temperature profile	Real-time, continuous data recording via SCADA system		DTS casing-conveyed fiber-optic cable		Continuous	
		Temperature logging		Temperature log		Annually only if DTS fails	
Storage Reservoir (direct)	**P/T**	Real-time, continuous data recording via SCADA system	Storage reservoir monitoring and conformance with model and simulation projections	Casing-conveyed downhole P/T gauge	CO_2 injection wells	Continuous	Same schedule as injection but only for reservoir-monitoring well (CO_2 injection wells will be plugged at injection cessation)
	Temperature profile			DTS casing-conveyed fiber-optic cable	CO_2 injection and reservoir-monitoring wells		
		Temperature logging		Temperature log		Annually only if DTS fails	
	Storage reservoir performance	Injectivity testing	Demonstration of storage reservoir performance	Pressure falloff tests	CO_2 injection wells	Once every 5 years per well after the start of injection	None (Injection has ceased)
Storage Reservoir (indirect)	**CO_2 saturation**	3D time-lapse seismic surveys	Site characterization and CO_2 plume tracking to ensure conformance with model and simulation projections	Vibroseis trucks (source) and geophones and DAS fiber-optic cable (receivers)	Within AOR	Repeat 3D seismic survey by the end of Year 2 and in Years 4 and 9 and at least once every 5 years thereafter.	Multiple repeat time-lapse seismic surveys during post-injection, with the first survey occurring by Year 4 of post-injection.
	Seismicity	Continuous data recording	Seismic event detection and source attribution and operational safety assurance	Seismometer stations and DAS fiber optics	Area around injection wells (within 1 mile)	Continuous	None

* SCS2 will perform isotopic analysis on final samples collected prior to facility closure.

Table 5-2. 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 (CO_2 injection reservoir-monitoring wellheads and CO_2 flowline)	X		X			X	Surface 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.	Surface P/T gauge data may be needed in combination with metering data and valve shut-off times to accurately quantify volumes emitted by surface equipment.
Flow Metering (CO_2 injection wells 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 between flow meters and leak detection software calculations
Gas Detection Stations (flowline risers, injection wellheads, and wellhead enclosures)	X		X	X		X	Acoustic and CO_2 detection station data will detect any anomalous readings that require further investigation.	CO_2 concentration data may be used in combination with metering data and valve shut-off times to estimate any volumes emitted.
DTS (CO_2 injection wells)	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.	Not applicable
Temperature Log (CO_2 injection wells)	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.	Not applicable
Nitrogen Cushion with Seal Pot System on Well Annulus (CO_2 injection wells)	X		X				Pressure and fluid loss/addition measurements will be recorded continuously by the SCADA system and sent to the operations center to detect any anomalous readings that require further investigation.	Not applicable
Ultrasonic Logs (CO_2 injection reservoir-monitoring wells)	X			X			Ultrasonic (or alternative) log will be collected to detect potential pathways to the surface in the wellbore that require further investigation.	Not applicable
Soil Gas Analysis (two profile 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.
PNLs (CO_2 injection reservoir-monitoring wells)	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 PNL 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 (e.g., logging campaigns) would be needed to quantify the event.
Time-Lapse 3D 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.	Complementary field studies (e.g., soil gas or surface water sampling) and analysis (e.g., seismic or well log analysis) would be needed to provide an estimate of surface leakage of CO_2.
Natural or Induced Seismicity Monitoring (AOR)		X				X	Seismicity data will be collected and could locate zones of weakness or activation of fault planes that could open potential pathways for surface leakage of CO_2 that require further investigation.	Additional analysis (e.g., Coulomb failure or fault slip analysis) would be needed to further characterize the nature of the events.

6.0 MASS BALANCE EQUATIONS

Injection is proposed in a saline aquifer with no associated mineral production from the CO_2 storage complex. Mass flow meters for each injection well placed at the metering skid on the injection wellsite (shown with the letter "M" in Figure 1-12) will serve as the primary metering stations for each well.

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 sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

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

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 flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of this part.

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

SCS2 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 by the CO_2 concentration in the flow, 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 flow meter u.

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

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

p = Quarter of the year.

u = Flow meter.

The total annual CO_2 mass injected through all injection wells associated with this GHGRP facility will then be aggregated by summing the mass of all CO_2 injected through all injection wells in accordance with the procedure specified in Equation RR-6 from 40 CFR Part 98-Subpart RR (Equation 3).

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \quad \text{[Eq. 3]}$$

Where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) through all injection wells.
$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.
u = Flow meter.

Mass of CO_2 Emitted by Surface Leakage (CO_{2E}):
SCS2 characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario.

If the monitoring and surveillance plan detects a deviation from the threshold established for each method, SCS2 will conduct an analysis as necessary 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.

SCS2 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 4):

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \quad \text{[Eq. 4]}$$

Where:

CO_{2E} = Total annual CO_2 mass emitted by 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 (CO_{2FI})
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 flow meter used to measure injection quantity and injection wellhead will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W.

7.0 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 wells (BK Fischer 1 and 2) and storage reservoir-monitoring well (Archie Erickson 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 GHG reports are filed on or before March 31 of the year after the reporting year, and it is anticipated that the annual Subpart RR report will be filed on the same schedule.

This MRV plan will be in effect during the operational and post-injection monitoring periods. In the post-injection period, SCS2 will prepare and submit a facility closure application to North Dakota. The facility closure application 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, SCS2 will submit a request to discontinue reporting under this MRV plan consistent with North Dakota and Subpart RR requirements (refer to 40 CFR § 98.441[b][2][ii]).

8.0 QUALITY ASSURANCE PROGRAM

SCS2 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 stations (identified in Figure 1-12).

- The CO_2 concentration will be reported as a quarterly average from measurements obtained from the gas chromatograph or CO_2 sample points (Figure 1-4).

Flow meter 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 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.

8.1 Missing Data Procedures

In the event SCS2 is unable to collect data required for performing the mass balance calculations, procedures for estimating missing data in 40 CFR § 98.445 will be implemented as follows:

- Quarterly flow rate data will be estimated using a representative flow rate from the nearest previous time period, which may include deriving an average value from the sales contract from the capture facility or third-party entity or invoices associated with the commercial transaction.

- Quarterly CO_2 stream concentration data will be estimated using a representative concentration value from the nearest previous time period, which may include deriving an average value from a previous CO_2 stream sales contract, if the CO_2 was sampled in the quarter of the reporting period.

- Quarterly volume of CO_2 injected will be estimated using a representative quantity of CO_2 injected during the nearest previous period of time at a similar injection pressure.

- CO_2 emissions associated with equipment leaks or venting will be estimated following the missing data procedures contained in 40 CFR, Part 98 Subpart W.

9.0 MRV PLAN REVISIONS AND RECORDS RETENTION

This MRV plan will be revised and submitted to the EPA Administrator within 180 days for approval as required in 40 CFR § 98.448(d). SCS2 will follow the record retention requirements specified by 40 CFR § 98.3(g). In addition, it will follow the requirements in 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 mass 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 flow meter 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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APPENDIX A

EMERGENCY AND REMEDIAL RESPONSE PLAN

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1.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

Summit Carbon Storage #2, LLC (SCS2) requires all employees, contractors, and agents to follow the company emergency and remedial response plan (ERRP) for the BK Fischer storage facility. The purpose of the ERRP is to provide guidance for quick, safe, and effective response to an emergency to protect the public, all responders, company personnel, and the environment.

The ERRP for the geologic storage project 1) identifies events that have the potential to endanger underground sources of drinking water (USDWs) during the construction, operation, and post-injection site care phases of the geologic storage project, building upon a screening-level risk assessment (SLRA) performed, and 2) describes the response actions that are necessary to manage these risks to USDWs. In addition, 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 the ERRP are available at the company's nearest operational office and at the geologic storage facility.

1.1 Identification of Potential Emergency Events

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. The 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 carbon dioxide (CO_2) to the atmosphere during the construction, operation, or post-injection site care project phases.

SCS2 performed a SLRA for the project to identify a list of potential technical project risks (i.e., a risk register), which were placed into the following six technical risk categories:

1. Injection operations
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, SCS2 developed, to include in the ERRP, 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, in turn, require an emergency response. These events and means for their detection are provided in Table A1-1.

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 also addressed in the ERRP.

Table A1-1. Potential Project Emergency Events and Their Detection

Potential Emergency Events	Detection of Emergency Events
Failure of CO_2 Flowline NDL-325	• Computational flowline continuous monitoring and leak detection system (LDS). – Instrumentation at the flowline for each injection well on the well pad collects pressure, temperature, and flow data. – Pressure, temperature, and flow measurements will be measured at the Midwest Carbon Express (MCE) terminus point. – 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 the leak site may be observed. • CO_2 monitors located inside and outside of the process buildings 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 of 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.

1.2 Emergency Response Actions

1.2.1 General Emergency Response Actions

The response actions that will be taken to address the events listed in Table A1-1, 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) will be immediately notified and will make an initial assessment of the severity of the event (i.e., does it represent an emergency event?). The QI must make this assessment as soon as practical but must do so within 24 hours of the notification. This protocol will ensure SCS2 has taken all reasonable and necessary steps to identify and characterize any release pursuant to North Dakota Administrative Code (N.D.A.C.) § 43-05-01-13(2)(b).

- If an emergency event exists, the QI or designee shall notify, within 24 hours of the emergency event determination, the Department of Mineral Resources Oil and Gas Division (DMR-O&G) Director (N.D.A.C. § 43-05-01-13[2][c]). The QI shall also implement the emergency communications plan (N.D.A.C. § 43-05-01-13[2][d]) described in the next section.

Following these actions, the company will:

- Initiate a project shutdown plan and immediately cease CO_2 injection. However, in some circumstances, the company may determine whether gradual or temporary cessation of injection is more appropriate in consultation with the DMR-O&G Director.

- Shut in the CO_2 injection well (close the flow valve).

- Vent CO_2 from the surface facilities.

- Limit access to the wellhead to authorized personnel only, who will be equipped with appropriate personal protective equipment (PPE).

- If warranted, initiate the evacuation of the injection facilities and communicate with local emergency authorities to initiate evacuation plans of nearby residents.

- Perform the necessary actions to determine the cause of the event; identify and implement the appropriate emergency response actions in consultation with the DMR-O&G Director. Table A1-2 provides 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 A1-1.

Table A1-2. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions

Failure of CO_2 Flowline NDL-325	• The CO_2 release and its location will be detected by the LDS and/or CO_2 wellhead monitors, which will trigger a Pipeline Control* alarm, alerting system operators to take necessary action. • If warranted, initiate an evacuation plan in tandem with an appropriate workspace and/or ambient air-monitoring program, situated near the location of the failure, to monitor the presence of CO_2 and its natural dispersion following the shutdown of the flowline. • Inspect the flowline failure to determine the root cause. • 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 downhole equipment or wellhead (in consultation with the DMR-O&G 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 DMR-O&G 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 DMR-O&G Director).

* Pipeline Control refers to the controller monitoring MCE flowline operations.

Continued . . .

Table A1-2. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

<table>
<tr><td>Storage Reservoir Unable to Contain the Formation Fluid or Stored CO_2</td><td>

Collect a confirmation sample(s) of groundwater from the Fox Hills monitoring well(s) and soil gas profile station(s) and analyze the samples for indicator parameters.
If the presence of indicator parameters is confirmed, develop (in consultation with the DMR-O&G Director) a case-specific work plan to:

Install additional monitoring points near the impacted area to delineate the extent of impact:
<ol type="a">
If a USDW is impacted above drinking water standards, arrange for an alternate potable water supply for all users of that USDW.
If a surface release of CO_2 to the atmosphere is confirmed and, if warranted, initiate an evacuation plan in tandem with an appropriate workspace and/or ambient air-monitoring program situated at the appropriate incident boundary to monitor the presence of CO_2 and its natural dispersion following the termination of CO_2 injection.
If surface release of CO_2 to surface waters is confirmed, implement the appropriate surface water-monitoring program to determine if water quality standards are exceeded.

Proceed with efforts, if necessary, to:
<ol type="a">
Remediate the USDW to achieve compliance with drinking water standards (e.g., install a system to intercept/extract brine or CO_2 or “pump and treat” the impacted drinking water to mitigate CO_2/brine impacts), and/or
Manage surface waters using natural attenuation (i.e., natural processes, such as biological degradation, active in the environment that can reduce contaminant concentrations), or
Activate treatment to achieve compliance with applicable water quality standards.

Continue all remediation and monitoring at an appropriate frequency (as determined by company management designee and the DMR-O&G Director) until unacceptable adverse impacts have been fully addressed.

</td></tr>
</table>

Continued . . .

Table A1-2. 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 the magnitude is greater than 2.7, then: 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 the 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 DMR-O&G Director).

1.2.2 Incident-Specific Response Actions

If notification is received of a high-risk incident, the following procedures will be followed:

1. **Accidental/Uncontrolled Release of CO_2 from the Injection Facility or Associated Flowline(s)**

   - On-scene personnel shall confirm that Pipeline Control is aware of the incident. If appropriate, Pipeline Control will effectuate the shutdown of the pipeline and the closure of mainline valves to isolate the release and to minimize the amount of released CO_2.

   - Consideration should be given to notifying and evacuating the public downwind of the release and closing roads. Coordinate with nearby fire departments and law enforcement to aid in any evacuation efforts.

   - Pipeline Control will call the appropriate public safety answering point (PSAP) and nearby fire departments, law enforcement, and other appropriate agencies. Personnel on-scene during an incident may call 911 directly.

   - Pipeline Control dispatches the company response crew (CRC) to investigate the incident and notifies the QI.

- CRC arrives at the incident site and completes initial response actions. A designated CRC member will fill the initial incident commander (IC) position.

- The IC will conduct a risk assessment and coordinate with the QI to determine what National Incident Management System Incident Command System (ICS) positions need to be filled for the local response team (LRT).

- The QI or IC will establish liaison with the local emergency coordinating agencies, such as the 911 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entities.

- If the response exceeds local capabilities, the IC will coordinate with the QI to determine the need for mobilization of a company support team (CST).

2. Fire or Explosion Occurring near or Directly Involving the Injection Facility or Associated Flowline(s)

Note: CO_2 is not flammable, combustible, or explosive.

- Call for assistance from nearby fire departments and company personnel, as needed. Take all possible actions to keep fire from spreading.

- Shut down the pipeline for an explosion involving the injection facility.

- The IC will conduct a preliminary assessment of the situation upon arrival at the scene, evaluate the scene for potential hazards, and determine what product is involved.

- Assemble the LRT at the command post.

- Coordinate response efforts with on-scene fire department.

3. Operational Failure Causing a Hazardous Condition

- On-scene personnel will confirm that Pipeline Control is aware of the incident, which will, if appropriate, effectuate the shutdown of the pipeline, injection well(s), and closure of mainline valves to isolate the release and minimize a hazardous condition.

- Consideration should be given to evacuating the public downwind of the release and closing roads. Coordinate with nearby fire departments and law enforcement to aid in any evacuation efforts.

- Pipeline Control will call the appropriate PSAP and nearby fire departments, law enforcement, and other appropriate agencies. Personnel on-scene during an incident may call 911 directly.

- Pipeline Control dispatches LRT to investigate the incident and notifies the QI.

- CRC arrives at the incident site and completes initial response actions. A designated CRC member will fill the initial IC position.

- The IC will conduct a risk assessment and coordinate with the QI to determine what ICS positions need to be filled for the LRT.

- The QI or IC will establish liaison with the local emergency coordinating agencies, such as the 911 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity.

- If the response exceeds local capabilities, the IC will coordinate with the QI to determine the need for mobilization of a CST.

1.3 Emergency Communications Plan

In the event of an emergency, the facility response plan contains an ICS, which specifies the organization of a facility response team, team member roles, and team member responsibilities. The company organizational structure is still in development. The company will provide updated specific identification and contact information for each member of the facility response team. In the event of an emergency, as outlined in N.D.A.C. § 43-05-01-13(2), DMR-O&G will be notified within 24 hours (Table A1-3).

Table A1-3. DMR-O&G UIC Program Management Contact

Company	Service	Location	Phone
DMR-O&G	Class VI/CCUS	Bismarck, ND	701.328.8020

1.4 ERRP Review and Updates

The ERRP shall be reviewed:

- At least annually following its approval by DMR-O&G.

- Within 1 year of an AOR reevaluation.

- Within a prescribed period (to be determined by DMR-O&G) following any significant changes to the project, (e.g., injection process, the injection rate).

- As required by DMR-O&G.

If the review indicates that no amendments to the ERRP are necessary, the company will provide the documentation supporting the "no amendment necessary" determination to the DMR-O&G Director. If the review indicates that amendments to the ERRP are necessary, SCS2 will make and submit amendments to DMR-O&G as soon as reasonably practicable. In no event, however, shall it do so more than 1 year following the commencement of a review.