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

OFFICE OF
AIR AND RADIATION

January 12, 2023

Mr. Daniel Whitley
Great Plains Synfuels Plant
420 County Road 26
Beulah, North Dakota 58523

Re: Monitoring, Reporting and Verification (MRV) Plan for Great Plains Synfuels Plant

Dear Mr. Whitley:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Great Plains Synfuels Plant, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Great Plains Synfuels Plant on August 10, 2022, as the final MRV plan. The MRV Plan Approval Number is 1002440-1. This decision is effective January 17, 2023 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78.

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

Sincerely,

Julius Banks, Chief
Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for the Great Plains Synfuels Plant

January 2023

Contents

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) Subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted by the Dakota Gasification Company's (DGC) Great Plains Synfuels Plant (GPSP) for carbon dioxide (CO2) capture and storage (CCS) project in the Williston Basin near Watford City, North Dakota. Note that this evaluation pertains only to the Subpart RR MRV plan, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations.

1 Overview of Project

GPSP indicates in Section 1 of the MRV plan that it has submitted its North Dakota CO_2 storage facility permit (SFP) to the North Dakota Industrial Commission (NDIC) on March 8, 2022, for its Great Plains CO_2 sequestration project. The MRV plan also states that an official hearing for the DGC's Great Plains CO_2 Sequestration Project was held on July 20, 2022. North Dakota has the authority to regulate the geologic storage of CO_2 and primacy to administer the North Dakota Underground Injection Control (UIC) Class VI Program (83 Federal Register 17758, 40 Code of Federal Regulations (CFR) 147). GPSP is located 5 miles northwest of Beulah, North Dakota along the southern flank of the Williston Basin, and has previously captured and transported more than 40 million tonnes (Mt) of CO_2 (>95% dry CO_2) from the gasification process for enhanced oil recovery purposes since 2000. The captured CO_2 has been transported via a 205-mile pipeline that has operated for the past 22 years. GPSP is currently constructing an additional 6.8 miles of pipeline to facilitate permanent sequestration of up to 2.7 Mt per year. The pipeline's design capacity is based on the total anticipated CO_2 output from the plant. Over the anticipated 12-year life of this project, the MRV plan projects that the project will sequester 26 Mt of CO_2.

The MRV plan states that four injection wells are anticipated initially (Coteau 1 through Coteau 4), with two additional wells planned (Coteau 5 and Coteau 6) as increased volumes in 2026 or beyond warrant. A map detailing these wells can be seen in Figure 1-1 in the MRV plan. The injection wells will store the captured CO_2 stream in the porous and permeable Broom Creek Formation located directly below the GPSP. The MRV plans further states that no other geologic storage project exists or is planned within 18.2 miles of the Great Plains CO_2 Sequestration Project.

In Section 1.2 of the MRV plan, GPSP describes the geologic setting of the Great Plains CO_2 Sequestration Project. The target CO_2 storage reservoir is the Broom Creek Formation, a predominantly sandstone interval lying about 5,900 feet below the GPSP. Silty mudstones and interbedded evaporites of the Opeche Formation unconformably overlie the Broom Creek and serve as the primary confining zone. Mixed layers of dolostone, mudstone, and anhydrite of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone. From stratigraphic bottom to top, the Amsden, Broom Creek, and Opeche comprise the CO_2 storage complex. About 1,100 feet of impermeable rock separates the Broom Creek Formation and the Inyan Kara Formation, which is the next overlying porous zone. Another 2,660 feet of impermeable rock separates the Inyan Kara Formation and the Fox Hills Formation, which is the lowest underground source of drinking water

(USDWs). A generalized stratigraphic column of the Williston Basin within the GPSP area can be seen in Figure 1-3 of the MRV plan.

According to Section 1.3 of the MRV plan, GPSP plans to capture and store 1.0 to 2.7 Mt of CO_2 per year over the course of 12 years of injection, followed by at least 10 years of post-injection site care. Figure 1-4 of the MRV plan is a process flow diagram showing the integration of major CCS components with the capture facility at GPSP. An underground transmission pipeline permitted through the North Dakota Public Service Commission (NDPSC) Case No. PU-21-150 connects the capture facility to the 6 injection wells.

The description of the project is determined to be acceptable and provides the necessary information for 40 CFR 98.448(a)(6).

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

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

Class VI UIC permits must define an Area of Review (AOR). The MRV plan states that the AOR for North Dakota is defined as the “region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity” (North Dakota Administrative Code [NDAC] § 43-05-01-01). According to the MRV plan, NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, the MRV plan states that NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The MRV plan also states that the storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). Therefore, GPSP elected to permit the storage facility area boundaries based on the reservoir model output, which is discussed in Reference 1, Section 4 of the MRV plan. GPSP then added a 1-mile buffer, rounding out to the nearest 40-acre tract.

GPSP proposes that because the AOR, as delineated in Reference 1, Section 4 of the MRV plan, exceeds the requirements of the AMA under Title 40, CFR § 98.449 (Subpart RR), the AOR will serve as the AMA for the Great Plains CO_2 Sequestration Project. GPSP also proposes that the delineated AOR and proposed AMA will also serve as the MMA for the GPSP, as it also exceeds the requirements for delineating the MMA under 40 CFR § 98.449 (Subpart RR). Maps of the AOR, plume boundary, AMA, and MMA can be seen in Figure 2-1 and 2-2 of the MRV plan.

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

3 Identification of Potential Surface Leakage Pathways

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

- Class I nonhazardous disposal wells
    - ANG #1 (NDDEQ Well No. 11308)
    - ANG #2 (NDDEQ Well No. 11309)
- Abandoned oil and gas wells
- Surface components
- Faults, fractures, bedding plane partings, and seismicity
    - Natural or induced seismicity
- Class VI injection wells
    - Coteau 1 (NDIC File No. 38379)
    - Coteau 2 Through Coteau 6 Planned CO_2 Injection Wells
- Confining zone limitations

3.1 Class I Nonhazardous Disposal wells

The MRV plan states that there are two active Class I disposal wells within the Great Plains CO_2 Sequestration Project area. Both wells were drilled in the 1980s to dispose of nonhazardous wastewater produced from GPSP operations in the Minnelusa Group (Broom Creek Formation) and Kibbey Formation under North Dakota Department of Health (NDDH) Permit Nos. ND-UIC-101 and ND-UIC-102. The MRV plan states that both permits were renewed under NDDH Permit No. ND-UIC-101-1 in 2018. The MRV plan also states that the North Dakota Department of Environmental Quality (NDDEQ) separated from the NDDH, and both Class I disposal wells were given well numbers by the NDDEQ in 2019.

ANG #1 (NDDEQ Well No. 11308)

The MRV plan states that this well was spudded in April 1982, completed in July 1982, and reaches a total depth of 6,784 feet into the Kibbey Formation. Additional perforations were added to the Kibbey Formation in 1983. GPSP states in the MRV plan that there was no evidence of hydrocarbons in the porous and permeable intervals of the Dakota, Minnelusa, and Kibbey Formations based on test data and core samples. The MRV plan also claims that injectivity tests demonstrated the Minnelusa (Broom Creek Formation) and Kibbey were the most viable for receiving wastewater at the injection rates and volumes specified in NDDH Permit No. ND-UIC-101. GPSP states that the ANG #1 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure, and a seal pot system on the annulus to detect annulus leaks. Moreover, GPSP notes that the ANG #1 is also monitored with temperature logs or tracer surveys about once every 5 years.

The MRV plan states that the ANG #1 was also reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and it was determined that no corrective action is needed for this well because the CO_2 plume is not expected to come into contact with the well.

GPSP concludes that the risk of leakage via the ANG #1 is unlikely and is mitigated through the wellbore leak detection plan described above. In addition, GPSP states that the plume is not expected to come into contact with the well based on reservoir simulation work and modeling suggests there is little interaction between injected disposal water and the CO_2 plume. Therefore, the MRV plan states that the anticipated magnitude of leakage from the ANG #1 in terms of volume of CO_2 or associated fluids over the life of the project is extremely low.

ANG #2 (NDDEQ Well No. 11309)

The MRV plan states that this well was spudded in September 1983 and reaches a total depth of 6,911 feet into the Kibbey Formation. The well was completed in both the Minnelusa (Broom Creek Formation) and Kibbey sands. Like ANG #1, GPSP notes that ANG #2 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure in the tubing-casing annulus, and a seal pot system on the annulus to detect annulus leaks. The ANG #2 is also monitored with temperature logs or tracer surveys about once every 5 years according to the MRV plan.

The MRV plan states that the ANG #2 was also reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and, similar to ANG #1, it was determined that no corrective action is needed in this well because the CO_2 plume is not expected to come into contact with the well.

Similar to ANG #1, GPSP concludes that the risk of leakage via the ANG #2 is unlikely and is mitigated through the wellbore leak detection plan. In addition, GPSP states that the plume is not expected to come into contact with the well, and modeling suggests there is little interaction between injected disposal water and the CO_2 plume. Therefore, the MRV plan states that the anticipated magnitude of leakage from the ANG #2 in terms of volume of CO_2 or associated fluids over the life of the project is extremely low.

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

3.2 Abandoned Oil and Gas Wells

The MRV plan states that the Herrmann 1 well was spudded in November 1966 and reaches a total depth of 8,057 feet into the Frobisher interval, which is stratigraphically equivalent to the Mission Canyon Formation in the Madison Group. The plan states that the well was also plugged and abandoned in December 1966. The MRV plan states that a drill stem test was conducted in the Frobisher interval, but the well was reported not to encounter any commercial accumulations of hydrocarbons.

According to the MRV plan, this well was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and is the only oil and gas well within 0.5 miles outside of the AOR. The MRV plan states that that no corrective action was needed, as the CO_2 plume is not expected to contact the well.

The MRV plan also states that the risk of leakage from the Herrmann 1 extremely low since the well is not expected to come in contact with the plume and also because the expected pressure increase is less than 100 psi during the duration of the project, and the Herrmann 1 has multiple cement plugs to prevent vertical migration of pressure or fluids outside the storage reservoir. .

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

3.3 Surface Components

The MRV plan states that surface equipment components present potential leakage pathways during the operational injection period for the Great Plains CO_2 Sequestration Project site. Surface equipment can be subject to deterioration due to normal aging throughout its functional life. In particular, the MRV plan notes that corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in these assets.

GPSP's CCS system includes a 6.8-mile-long transmission pipeline, six flowlines, and six injection wellheads, as seen in Figure 1-4 of the MRV plan. The transmission line consists of a 12-inch main line and six 6-inch lateral lines that branch off and connect with 4.5-inch flowlines near each well pad. Flow meters will also be installed at each metering station. The expected chemical composition of the CO_2 stream can be seen in Reference 1, Section 5.1.1, Table 5-2 of the MRV plan.

The risk of leakage via surface components is mitigated in several ways, according to the MRV plan: (1) Following the regulatory requirements for construction and operation of the site; (2) implementing the highest standards for selecting material and for the construction process; (3) applying best practices and a robust mechanical integrity program; and (4) monitoring continuously via automated systems and integrated databases.

GPSP states that the risk of leakage through surface components under normal operating conditions at the facility is unlikely. If a leak were to occur, GPSP states that it could range in size from a few pounds of CO_2 released over several hours from instrumentation or valves to several tons of CO_2 being released underground until the operator ceases the CO_2 supply.

In the event of a plant shutoff situation, the MRV plan states that the CO_2 stream can be routed back to the GPSP capture facility, where it can be passed through burners and then vented to the atmosphere.

The MRV plan also clarifies that at the end of the injection period, the injection wells will be properly plugged and abandoned following NDIC protocols and facility equipment decommissioned according to state regulatory requirements to further lower the risk of surface component leakage.

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

3.4 Faults, Fractures, Bedding Plane Partings, and Seismicity

According to the MRV plan, there is no known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow for fluid movement between formations that have been identified through site-specific characterization activities, prior studies, or previous oil and gas exploration activities.

Natural or Induced Seismicity

The MRV plan states that the history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment. GPSP found that 13 seismic events were detected within the North Dakota portion of the Williston Basin between 1870 and 2015, with the two closest events being 29.6 miles northwest and 36.8 miles southwest of the Coteau 1 injection wellsite. These events also had estimated Richter scale magnitudes of 1.9 and 2.3 respectively. A one year seismic forecast (including both induced and natural seismic events) released by the U.S. Geological Survey (USGS) in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage as stated in the MRV plan. The MRV plan further notes that only two historic earthquake events in North Dakota could be associated with oil and gas activities, and both were magnitude 2.6 or lower leading GPSP to conclude that the magnitude of any seismic event occurring near the project site would be expected to be less than 3.2 based on the historical record and would expected to cause little to no damage to subsurface or downhole equipment.

GPSP concludes that 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 all suggest that the probability that seismic interference with CO_2 containment is low. Furthermore, the plan states that will GPSP will operate below the maximum allowable injection pressure to maintain safe operations throughout the injection period.

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

3.5 Class VI Injection Wells

Coteau 1 (NDIC File No. 38379)

GPSP states that it spudded the Coteau 1 well in June 2021 as a stratigraphic test well to a depth of 6,483 feet into the Amsden Formation. This well was drilled to gather geologic data to support the development of a CO_2 SFP, with the intent of later converting it into a Class VI injection well for the Great Plains CO_2 Sequestration Project. The MRV plan states that the Coteau 1 will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues.

The MRV plan states that the risk of leakage via the Coteau I well is low and is mitigated through the prevention of corrosion of well materials, monitoring for leakage from surface operations and from the storage reservoir in the subsurface, and performing regular wellbore mechanical integrity testing (MIT). According to the MRV plan, the magnitude of any leakage during injection may vary according to the failure observed and could potentially represent a few pounds of CO_2 to several metric tons per hour released until operations are shut in and emergency protocols activated. The MRV plan also states that the risk of leakage will also be reduced to almost zero following the proper plugging and abandonment of the well by following NDIC protocols.

Coteau 2 Through Coteau 6 Planned CO_2 Injection Wells

GPSP states that they plan to spud the Coteau 2 (NDIC File No. 38916), Coteau 3 (NDIC File No. 38917), and Coteau 4 (NDIC File No. 38918) wells in the summer of 2022 as stratigraphic test wells for the Great Plains CO_2 Sequestration Project. The wells will be drilled to the Amsden Formation at planned depths of 6,345, 6,339, and 6,301 feet, respectively. The plan is for these stratigraphic test wells to be converted to Class VI injection wells after the SFP is issued. Like the Coteau 1, the wells will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues.

The Coteau 5 and Coteau 6 wells are planned to spud in 2026 and are conditional upon additional injection volumes of CO_2 becoming available from the capture facility. These wells will be monitored in the same manner as Coteau 1 through Coteau 4. Once injection ends, these wells will be properly plugged and abandoned per NDIC protocols, thus reducing the risk of leakage to almost zero according to the MRV plan.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected from Class VI Injection Wells.

3.6 Confining Zone Limitations

Lateral Migration

According to the MRV plan, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure. The cap rock is a laterally extensive formation that is 5,763 feet below the surface and 143 feet thick at Coteau 1. Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine). Thus, the MRV plan states that the risk of leakage via lateral migration is extremely low due to the geologic characteristics of the storage reservoir. GPSP states that this is supported by the modeling and simulation work.

Seal Diffusivity

The MRV plan also states that several other formations above the Opeche provide additional confinement. The Picard, Rierdon, and Swift Formations make up the first additional confining group. These formations have a combined thickness of 1,106 feet and will help prevent fluids in the Broom Creek Formation from migration upward. There are 2,657 feet of impermeable rock above the Inyan Kara Formation that will act as another seal between the Inyan Kara and Fox Hills Formations. The MRV plan characterizes this as having an extremely low leakage risk due to the combined 3,763 feet of overlying confining layers.

Drilling Through the CO_2 Area

According to the MRV plan, there has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the AOR, although production well testing did occur just outside the AOR (Herrmann 1). Due to the lack of known commercial drilling ventures, the MRV plan suggests that there is very little chance that drilling will occur through the storage complex.

If hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, the MRV plan discusses how a deviated or horizontal well could be used to produce the hydrocarbon while avoiding drilling directly through the CO_2 plume. A vertical well could also be drilled if using proper drilling procedures. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available, which will allow prospective operators to design an appropriate well control strategy via increased drilling mud weight and other controls. The maximum pressure increase in the center of the injection area is projected by computer modeling to be 400–450 psi, with lesser impacts extending radially. These pressure increases will lessen after the injection ceases and return to its pre-injection pressure profile. GPSP advises that any future wells drilled for hydrocarbon exploration or production should be designed to include an intermediate casing string made of CO_2-resistant material that should be placed across the storage reservoir to mitigate leakage risk. CO_2-resistant cement should also be used to anchor the casing in place to further lessen the risk for leakage.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected from confining zone limitations.

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

40 CFR 98.448(a)(3) requires that an MRV plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Section 4 of the MRV plan details DGC's strategy for monitoring and quantifying CO_2 leakage, and Section 5 of the MRV plan details strategies for establishing baselines for CO_2 leakage. The MRV plan explains how GPSP is proposing a monitoring program for the SFP that provides for a corrosion and mechanical integrity protocol, surveillance of injection performance, monitoring of near-surface conditions, and monitoring of the CO_2 plume. Table 4-1 of the MRV plan summarizes the monitoring strategy of each of the three project periods, while Table 4-2 of the MRV plan summarizes the leakage detection strategies. Both tables have been reproduced below.

Table 4-1. Summary of DGC's CCS Monitoring Strategy

Method (target area/structure)	Pre-injection (Baseline – 1 year)	Injection Period (12 years)	Post-injection (10 years)
CO_2 Stream Analysis (capture)	Start-up	Daily	NA[1]
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	Start-up	Real time	NA
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	Start-up	Real time	NA
H_2S Detection Stations (flowlines, wellheads, and well pads)	Start-up	Real time	NA
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	Start-up	Monthly in the first quarter, then quarterly in the next 2 years	NA
Platform Multifinger Imaging Tool (PMIT) or Ultrasonic Imaging Tool (USIT) (CO_2 injection wells)	NA	Starting in Year 2, a PMIT or USIT will be run during well workovers but not more frequently than once every 5 years	NA
SCADA[2] Automated Remote System (surface facilities)	Start-up	Real time	NA
Soil Gas Analysis (11 soil gas profile stations)	Three to four seasonal samples	Three to four seasonal samples each year	Three to four seasonal samples each year
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)	Provide historical water sampling results	NA	NA
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)	Baseline	NA	NA
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	Baseline	Three to four seasonal samples	Three to four seasonal samples
Cement Bond Logs (CO_2 injection wells)	After cementing	If needed	Prior to P&A[3]
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but not less than once every 5 years
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	Start-up	Real time	NA
Pulsed-Neutron Logs with Temperature and Bottomhole Pressure Readings (CO_2 injection wells)	Baseline	Quarterly using phased approach described in Reference 1, Section 5.1.2	NA
USIT Logs (CO_2 injection wells)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but not less than once every 5 years
Pressure Falloff Test (CO_2 injection wells)	Baseline	Every 5 years	NA
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	Baseline	Repeat survey 1 year after injection begins, then in Years 3, 5, and 10	Repeat survey 1 year after injection ceases, then in Years 3, 5, and 10
Vertical Seismic Profiles (VSP) (CO_2 plume)	Baseline	Repeat VSP 1 year after injection begins, then (if deemed beneficial) in Years 3, 5, and 10	NA

[1] Not applicable
[2] Supervisory control and data acquisition
[3] Plugging and abandonment

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

Monitoring Strategy (target area/structure) \ Potential Leakage Pathway	Wellbores*	Faults and Fractures	Flowline and Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis (capture)			X			
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	X		X			X
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	X		X	X		
H_2S Detection Stations (flowlines, wellheads, and well pads)	X		X	X		X
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	X		X	X		
PMIT or USIT (CO_2 injection wells)	X			X		
SCADA Automated Remote System (surface facilities)	X		X	X		
Soil Gas Analysis (11 soil gas profile stations)	X			X	X	X
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)				X	X	X
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)		X		X	X	X
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	X	X		X	X	X
Cement Bond Logs (CO_2 injection wells)	X			X		X
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	X			X		
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	X			X	X	
Pulsed-Neutron Logs with Temperature and Bottomhole Readings (CO_2 injection wells)	X			X	X	X
USIT Logs (CO_2 injection wells)	X			X		
Pressure Falloff Test (CO_2 injection wells)	X			X	X	
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	X	X		X	X	X
VSP (CO_2 plume)*	X	X		X	X	X

* Applies to all wellbores in project area if not otherwise specified under the monitoring strategy target area/structure column.

4.1 Detection of Leakage from Class I Nonhazardous Disposal Wells

As described in section 3.1 of the MRV plan, both Class I nonhazardous disposal wells are equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure, and a seal pot system on the annulus to detect annulus leaks. Both wells are also monitored with temperature logs or tracer surveys every 5 years. The plan states that routine visual inspection can also be used to detect leaks from wellbores, such as CO_2 leakage leads to the formation of bright while clouds and ice.

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

4.2 Detection of Leakage Through Abandoned Oil and Gas Wells

According to section 3.2 of the MRV plan, Herrmann 1, the only oil and gas well within 0.5 miles outside of the AOR, does not contact the CO_2 plume. Table 4-2 indicates water analysis will be used to monitor potential leakage from Herrmann 1.

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

4.3 Detection of Leakage Through Surface Components

As described in section 3.3 of the MRV plan, surface components of the injection system, including the flowlines and wellheads, will be monitored using leak detection equipment. Specifically, flowlines will be monitored with pressure gauges and H_2S detection stations. This leak detection equipment will be integrated with automated warning systems that notify the pipeline control center at GPSP, giving the operator the ability to remotely close the valves in the event of an anomalous reading. Injection will then resume only after written authorization of the UIC program director.

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

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

As described in section 3.4 of the MRV plan, no known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations have been identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration activities.

While leakage due to seismicity is unlikely according to the MRV plan, the leak would be detected through time-lapse 2D radial seismic surveys and vertical seismic profiles of the CO_2 plume should it occur.

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

4.5 Detection of Leakage Through Class VI Injection Wells

As described in Section 3.5 of the MRV plan, Coteau 1 through 6 will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues. Leaks can also be verified through routine visual inspection by looking for ice and white clouds. Table 4-2 of the MRV plan also points out more ways for potential CO_2 leakage to be detected for injection wells, such as USIT logs and pressure falloff tests.

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

4.6 Detection of Leakage Through Confining Zone Limitations

As described in Section 3.6 of the MRV plan, in the event the monitoring data or models and simulations predict that any part of the CO_2 plume migrates beyond the anticipated stabilized plume boundary over the project's life, because of a previously unidentified permeability pathway in the storage reservoir, the storage facility area and AOR will be recalculated. The MRV plan, including the testing and monitoring strategy, will also be updated as necessary. Per Table 4-2 of the MRV plan, other measures such as pressure falloff testing, time-lapse 2D radial seismic surveys, and vertical seismic profiles will be used to monitor lateral migration. Due to the thickness of the overlying confining layers, leakage due to seal diffusivity is unlikely according to the MRV plan. If a leak were to occur though, Table 4-2 of the MRV plan indicates that similar measures to those taken for leakage through wellbores may be taken to detect leakage through seal diffusivity.

Per the MRV plan, there is very little chance drilling through the CO_2 area occurs in the future. Should drilling happen and leakage occurs as a result, Table 4-2 details how the leakage will be monitored based on the appropriate pathway.

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

4.7 Determination of Baselines and Quantification of Potential CO_2 Leakage

Quantification of CO_2 Leakage

As stated in Section 4.2 of the MRV plan, any volume of CO_2 detected as leaking to the surface will be quantified using acceptable emission factors, engineering estimates of leak amount based on subsurface measurements, numerical models, history-matching of the reservoir performance, detailed analysis of the collected monitoring parameters, and/or delineation of the affected area, among others. Leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in an electronic central database.

Section 5.0 of the MRV plan describes how GPSP will establish pre-injection baselines by implementing a monitoring program prior to any CO_2 injection and during each of the four primary seasonal ranges. This baseline will be created by monitoring the targeted surface, near surface, and deep subsurface. The baseline will contain information pertaining to environmental media like surface water, soil gas in the vadose zone, shallow groundwater, and storage reservoir formation water.

Surface and Near-Surface Baselines

The MRV plan states that surface and near-surface sampling has been completed for the Great Plains CO_2 Sequestration Project. This baseline data gathering included measuring chemical concentrations of the soil gas (i.e., O_2, N_2, and CO_2) and groundwater (e.g., pH, total dissolved solids, alkalinity, major cations/anions and trace metals) as well as characterizing the naturally occurring stable and radiocarbon (^{14}C) isotopic signatures of the soil gas and groundwater for comparison with the isotopic signature of the injected CO_2 stream. The data was obtained from 11 soil gas-sampling locations and two existing groundwater wells from the northern and eastern portions of the AOR. Water samples will also be obtained from the Fox Hills Formation via five monitoring wells that will be drilled before the start of injection operations.

Subsurface Baselines

The MRV plan states that in each of the six injection wells in the Great Plains CO_2 Sequestration Project, pre-operational baseline data, such as ultrasonic imaging, pulsed-neutron, and temperature logs, bottomhole pressure surveys, tubing-casing annulus pressure tests, and pressure falloff tests will be collected. The data acquisition schedule for specific logs can be seen in Reference 1, Section 5.1.2 of the MRV plan. Time-lapse saturation data will be used as an assurance-monitoring technique for CO_2 inside the formation directly above the storage reservoir, while pressure and temperature data will help with geologic modeling and simulations. Pressure testing will also confirm wellbore mechanical integrity.

The MRV plan states that indirect monitoring methods will also track the extent of the CO_2 plume, which can be accomplished by performing time-lapse geophysical surveys of the AOR. A 2D radial seismic survey was also performed to establish baseline conditions within the reservoir, while a baseline VSP determined the feasibility of monitoring the CO_2 plume with this technology.

Thus, GPSP provides an acceptable approach for establishing CO_2 leakage monitoring baselines in accordance with 40 CFR 98.448(a)(4).

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

5.1 Calculation of Mass of CO_2 Stored

As stated in the MRV plan, GPSP will place a flowmeter downstream of the CO_2 compressor (start of the CO_2 transmission line) and near each of the injection wellheads. GPSP has proposed that the first metering station placed at the start of the CO_2 transmissions main line will be used as the main metering station for mass balance calculations. The MRV plan states that the use of a single metering station for the mass balance calculation (as opposed to using multiple metering stations near each wellhead) will help ensure accuracy of the measurements.

To calculate the annual mass of CO_2 that is stored in the storage complex, the GPSP will use Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

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

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

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

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

GPSP provides an acceptable approach for calculating the mass of CO_2 sequestered under Subpart RR.

5.2 Calculation of Mass of CO_2 Injected

The MRV plan states that GPSP will use volumetric flow metering to measure the flow of the injected CO_2 stream and will calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5 from 40 CFR Part 98, Subpart RR (Equation 2):

$$CO_{2,\mathrm{u}} = \sum_{\mathrm{p}=1}^{4} Q_{\mathrm{p,u}} * D * C_{\mathrm{CO_2,p,u}}$$

Where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for Flowmeter u in Quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

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

p = Quarter of the year.

u = Flowmeter.

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

5.3 Calculation of Mass of CO_2 Emitted by Surface Leakage

The MRV plan states that the likelihood of CO_2 surface leakage at GPSP is very low. Nevertheless, GPSP provides a detailed monitoring and surveillance plan in Reference 1, Section 5 of the MRV plan to detect any leakage and to define a baseline for monitoring. If the monitoring and surveillance plan detects deviation from the established threshold, GPSP will conduct a detailed analysis to quantify the volume of CO_2 leakage. The MRV plan states that 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.

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

$$CO_{2\mathrm{E}} = \sum_{\mathrm{x}=1}^{\mathrm{X}} CO_{2,\mathrm{x}}$$

Where:

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

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

x = Leakage pathway.

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

5.4 Calculation of Mass of CO_2 Emitted from Equipment leaks and Vented Emissions

The MRV plan states that the annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead (CO_{2FI}) will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W. Any CO_2 emitted from equipment leaks and vented emissions will be reconciled with the annual data collected through the monitoring plan proposed in Reference 1, Section 5 of the MRV plan.

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

6 Summary of Findings

The Subpart RR MRV plan for the Dakota Gasification Company's Great Plains Synfuels Plant meets the requirements of 40 CFR 98.238. The regulatory provisions of 40 CFR 98.238(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the GPSP MRV plan.

Subpart RR MRV Plan Requirement	GPSP MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 2 of the MRV plan describes the MMA and AMA. The MRV plan explains that the AOR exceeds the requirements for both AMA and MMA, so the AOR will serve as the AMA and MMA for GPSP.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 3 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: Class I nonhazardous disposal wells; abandoned oil and gas wells; Class VI injection wells; surface components; confining zone limitations; and faults, fractures,

	bedding plane partings, and seismicity. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways. GPSP determined that none of the proposed pathways required corrective action, and that the probability of leakage is low.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Sections 3 and 4 of the MRV plan describe a strategy for how the facility would detect and quantify potential CO_2 leakage to the surface should it occur, such as pressure gauges, flowmeters, CO_2 stream analysis, and soil gas analysis. The MRV plan states that quantification of CO_2 leakage will largely be done on a case-by-case basis with the use of acceptable emission factors, engineering estimates, etc.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 5 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage. GPSP will establish pre-injection baselines by implementing a monitoring program prior to any CO_2 injection and during each of the four seasonal periods.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 6 of the MRV plan describes GPSP's approach to determining the amount of CO_2 sequestered using the Subpart RR mass balance equations, including as related to calculation of total annual mass emitted from equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 1 of the MRV plan identifies all the injection wells within the GPSP and section 3 provides either their permit numbers or their permit application number. The MRV plan identifies two active, Class I wells using their UIC permit number. The MRV plan also identifies the 6 drilled or proposed Class VI wells (Coteau 1-6) by their permit application number.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 2 of the MRV plan states that the monitoring baselines will be established during the project's "pre-operational" period. This period is before CO_2 injection has commenced. The MRV plan states that an understanding of the repeatability and variability of each measurement is key to successfully determining

	the movement of CO_2 that is contained in the formation at any given time.

Appendix A: Final MRV Plan

GREAT PLAINS CO_2 SEQUESTRATION PROJECT MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Well

Reporting Number: 523812

TABLE OF CONTENTS

Continued . . .

TABLE OF CONTENTS (continued)

LIST OF FIGURES

LIST OF TABLES

STORAGE FACILITY PERMIT DESIGNATIONS

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

Reference 1: Great Plains CO_2 Sequestration Project, Mercer County, North Dakota

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

1.0 PROJECT DESCRIPTION

1.1 Project Characteristics

The Dakota Gasification Company's (DGC) Great Plains Synfuels Plant (GPSP), located 5 miles northwest of Beulah, North Dakota, is capable of gasifying 6 million tons of lignite coal per year (Figure 1-1). DGC, a wholly owned subsidiary of Basin Electric Power Cooperative (Basin), has owned and operated the facility since 1988. DGC has captured and transported more than 40 million tonnes (Mt) of carbon dioxide (CO_2) (>95% dry CO_2) from the gasification process for enhanced oil recovery purposes since 2000. The captured CO_2 is transported via a 205-mile pipeline that has successfully operated for the past 22 years. The CO_2 is first compressed to a pressure of ±2,500 pounds per square inch (psi), then transported north as a supercritical fluid. There currently exists excess compressor capacity, which makes the capture of an additional 1.0 Mt per year possible. DGC is currently constructing an additional 6.8 miles of pipeline to facilitate permanent sequestration of up to 2.7 Mt per year. The pipeline's design capacity is based on the total anticipated CO_2 output from the plant. Over the anticipated 12-year life of this project, sequestered volumes of CO_2 are expected to total 26 Mt. Four injection wells are anticipated initially (Coteau 1 through Coteau 4), with two additional wells planned (Coteau 5 and Coteau 6) as increased volumes in 2026 or beyond warrant (Figure 1-1). The injection wells will store the captured CO_2 stream in the porous and permeable Broom Creek Formation located below the GPSP.

DGC submitted its North Dakota CO_2 storage facility permit (SFP) to the North Dakota Industrial Commission (NDIC) on March 8, 2022, and an official hearing for DGC's Great Plains CO_2 Sequestration Project was held on July 20, 2022. North Dakota has the authority to regulate the geologic storage of CO_2 and primacy to administer the North Dakota Underground Injection Control (UIC) Class VI Program (83 Federal Register 17758, 40 Code of Federal Regulations [CFR] 147). If any material changes are made to the SFP after the hearing date that impact this MRV plan, DGC will notify EPA and submit an amended plan within 180 days.

No other geologic storage project exists or is planned within 18.2 miles of the Great Plains CO_2 Sequestration Project.

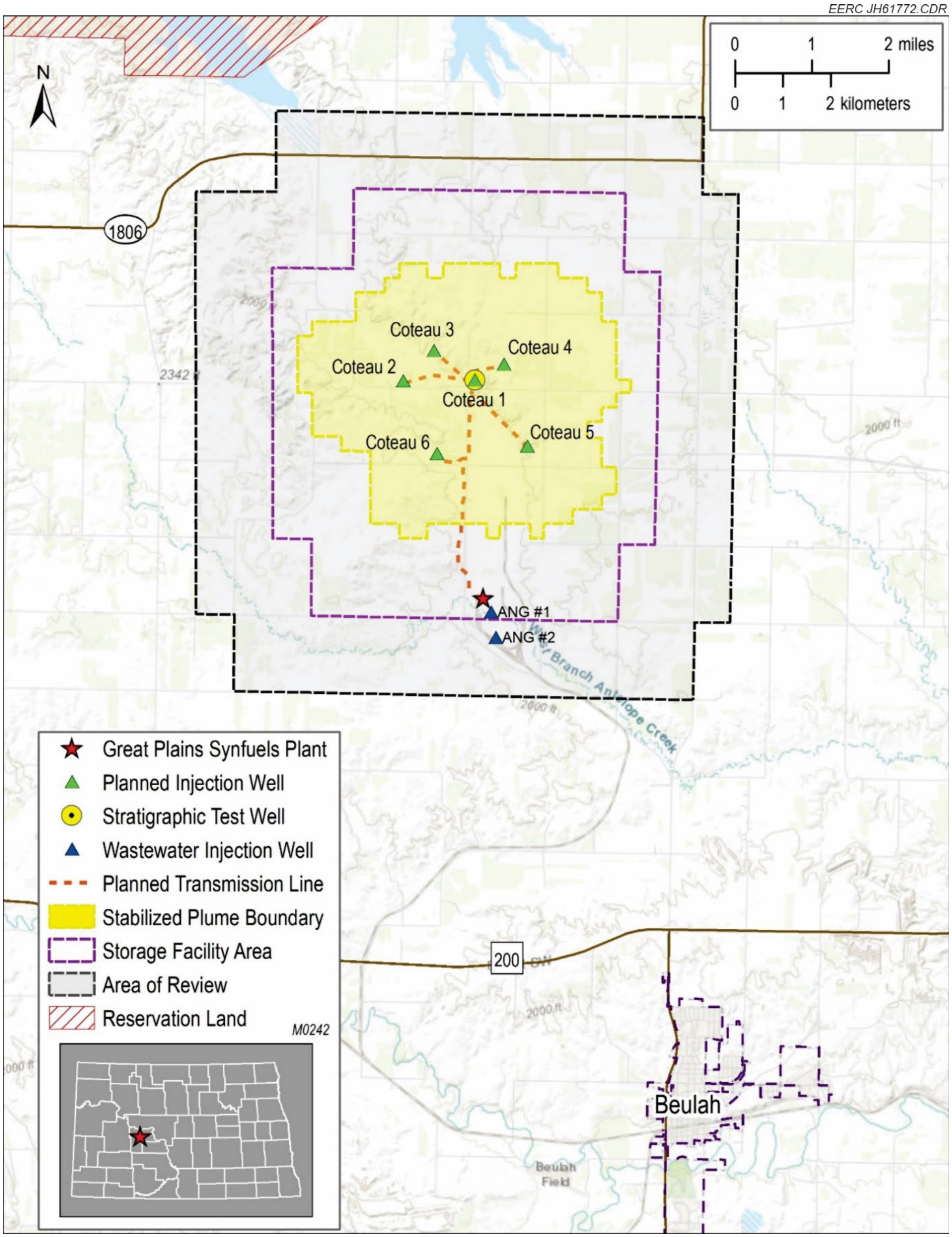

Figure 1-1. Location of the GPSP, Coteau 1 through Coteau 6 injection wells, and CO_2 transmission line. Also shown is the town of Beulah, with a population of about 3,200 people, the stabilized plume boundary, the storage facility area, and the area of review (AOR).

1.2 Environmental Setting

The Great Plains CO_2 Sequestration Project is located along the southern flank of the Williston Basin, a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Figure 1-2 shows the geographic distribution of oil fields in North Dakota, demonstrating there has been no exploration for or development of hydrocarbon resources within the AOR (Reference 1, Section 2.6). The Herrmann 1 (NDIC File No. 4177), a dry hole drilled in 1966 to the Frobisher interval (stratigraphically equivalent to the Mission Canyon Formation of the Madison Group), falls just outside the southwestern edge of the AOR. See Section 3.2 of this MRV plan for more information about the Herrmann 1 well.

A generalized stratigraphic column of the Williston Basin for the area of Beulah is provided in Figure 1-3. The target CO_2 storage reservoir for the Great Plains CO_2 Sequestration Project is the Broom Creek Formation, a predominantly sandstone interval lying about 5,900 feet below the GPSP (Reference 1, Section 2.3). Silty mudstones and interbedded evaporites of the Opeche Formation unconformably overlie the Broom Creek and serve as the primary confining zone (Reference 1, Section 2.4.1). Mixed layers of dolostone, mudstone, and anhydrite of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone (Reference 1, Section 2.4.3). From stratigraphic bottom to top, the Amsden, Broom Creek, and Opeche comprise the CO_2 storage complex. In addition to the Opeche Formation, there is about 1,100 feet of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation (Reference 1, Section 2.4.2). An additional 2,660 feet of impermeable rocks separate the Inyan Kara and the lowest underground source of drinking water (USDW): the Fox Hills Formation.

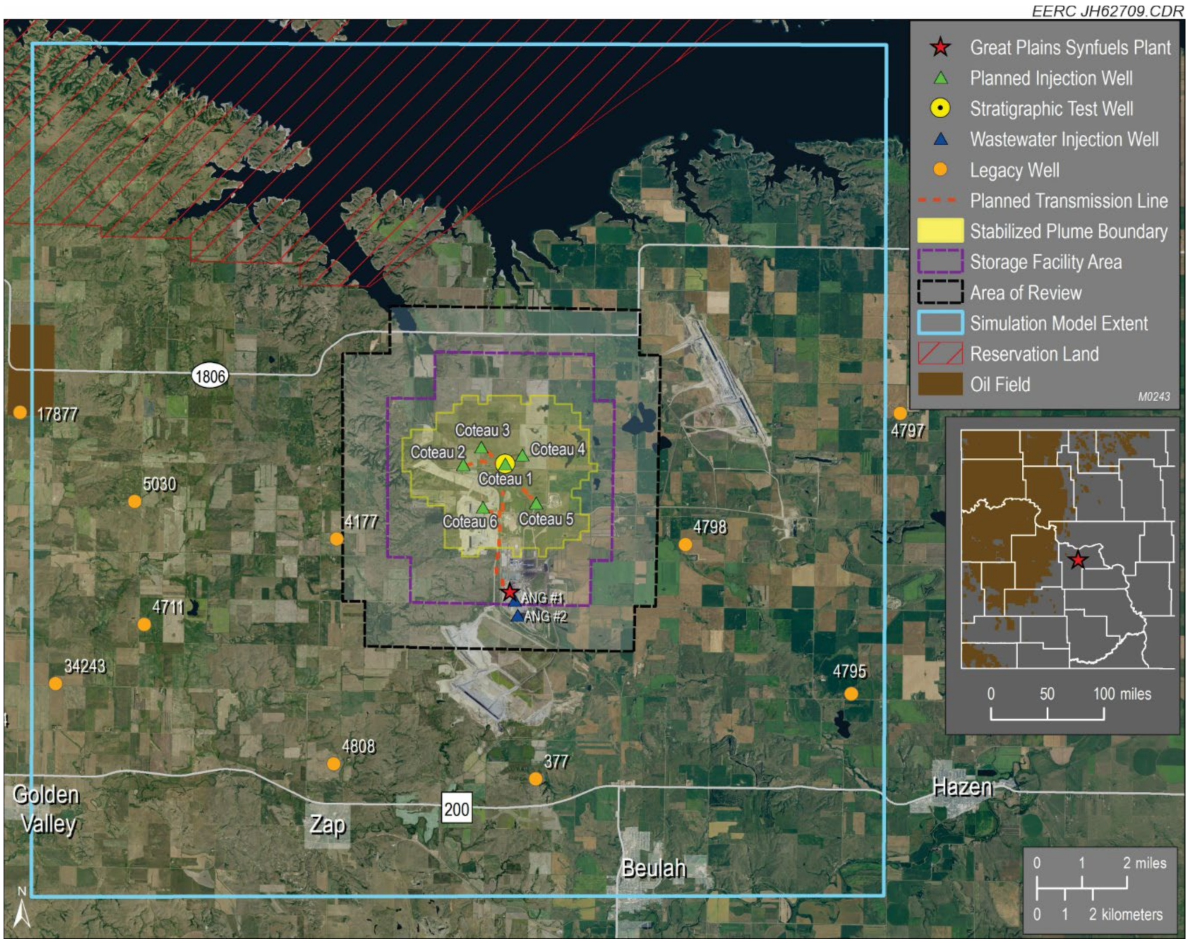

Figure 1-2. Map showing the simulation model extents of the Great Plains CO_2 Sequestration Project, legacy oil and gas wells, and geographic distribution of oil fields in North Dakota (i.e., western portion of the Williston Basin).

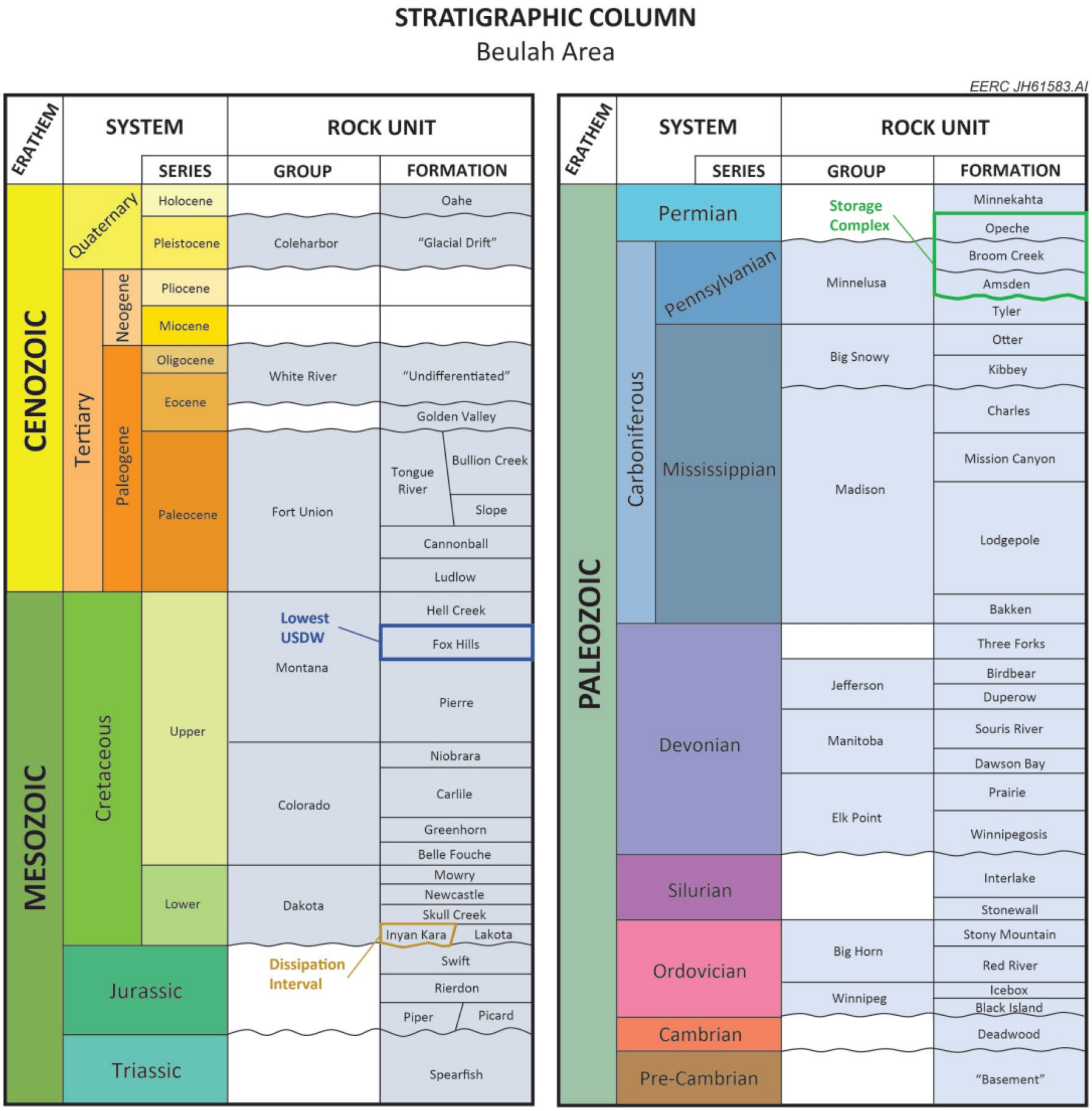

Figure 1-3. Generalized stratigraphic column of the Williston Basin for the Beulah area, identifying the storage complex (i.e., storage reservoir and primary confining zones) as well as the dissipation interval and lowest USDW underlying the Great Plains CO_2 Sequestration Project area. Figure modified after Murphy and others (2009) and Bluemle and others (1981).

1.3 Description of CO_2 Project Facilities and Injection Process

DGC plans to capture and store 1.0 to 2.7 Mt of CO_2 per year over the course of 12 years of injection, followed by at least 10 years of post-injection site care. Figure 1-4 shows integration

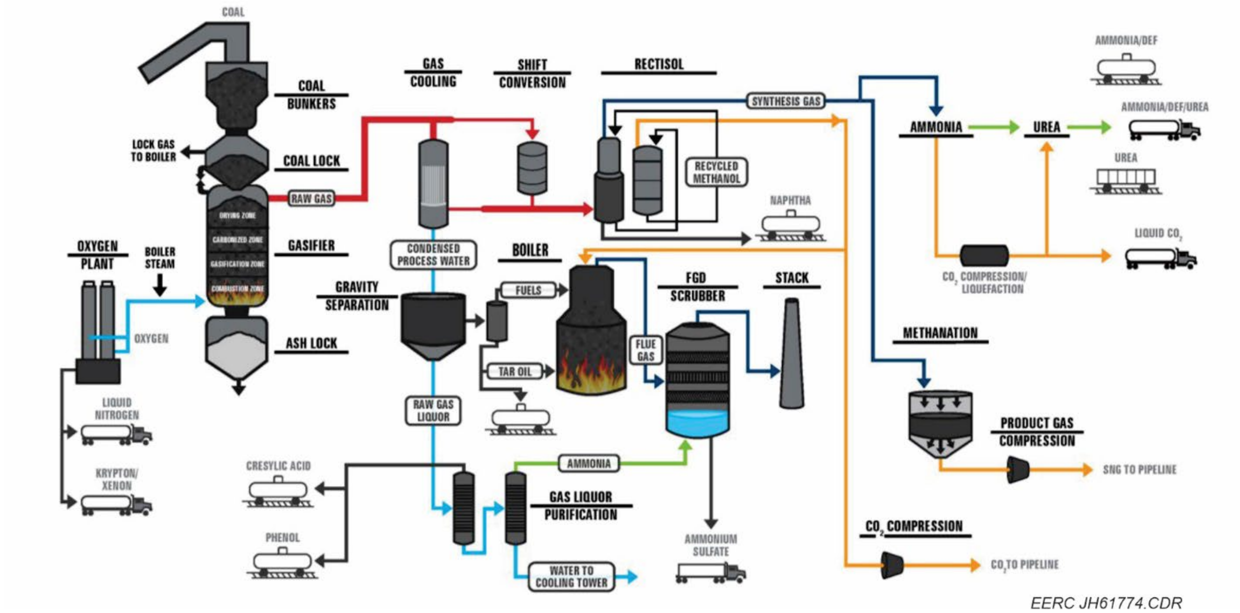

Figure 1-4a. Flow diagram of the CO_2 capture process at GPSP. The main metering station will be located downstream of the CO_2 compressors but upstream of the lateral for the Coteau 6 well, as shown in Figure 1-4b.

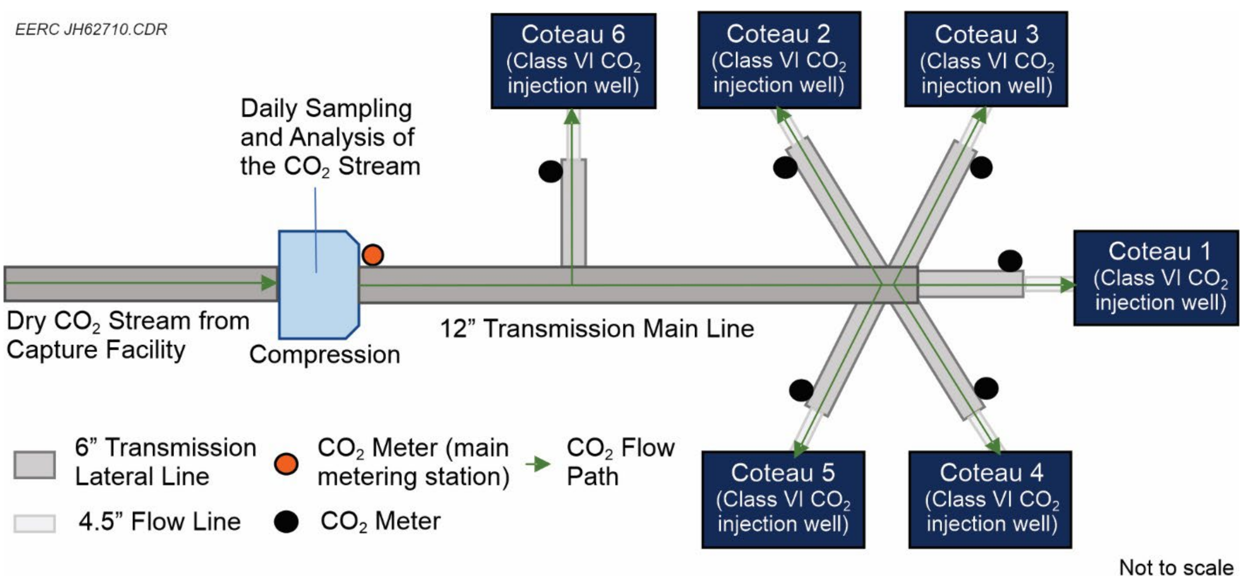

Figure 1-4b. Flow diagram illustrating major carbon capture and storage (CCS) components and the path of the CO_2 stream from the capture facility to the CO_2 injection wells.

of major CCS components with the capture facility at GPSP. The facility was designed to capture the CO_2 produced during the acid gas removal step of DGC's gasification process and compress the gaseous CO_2 stream to approximately 2,500 psi. The final compressed CO_2 stream would flow to the Coteau 1 through Coteau 6 injection wells for geologic storage into the Broom Creek Formation; an underground transmission pipeline permitted through the North Dakota Public Service Commission (NDPSC) Case No. PU-21-150 is installed on Basin, DGC, and Coteau Properties Company (CPC) property to connect the capture facility to the Coteau 1 through Coteau 6 injection wells. CPC, a wholly owned subsidiary of North American Coal Corporation, operates the Freedom Mine near the GPSP, supplying lignite coal feedstock to the plant.

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area: DGC AOR Delineation in Accordance with U.S. Environmental Protection Agency and North Dakota Rules

DGC proposes that because the AOR, as delineated in Reference 1, Section 4, exceeds the requirements of the active monitoring area (AMA) under Title 40, CFR § 98.449 (Subpart RR), the AOR will serve as the AMA for the Great Plains CO_2 Sequestration Project (Figure 2-1).

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). Therefore, DGC elected to permit the storage facility area boundaries based on the reservoir model output discussed in Reference 1, Section 4, and then, added a 1-mile buffer, rounding out to the nearest 40-acre tract.

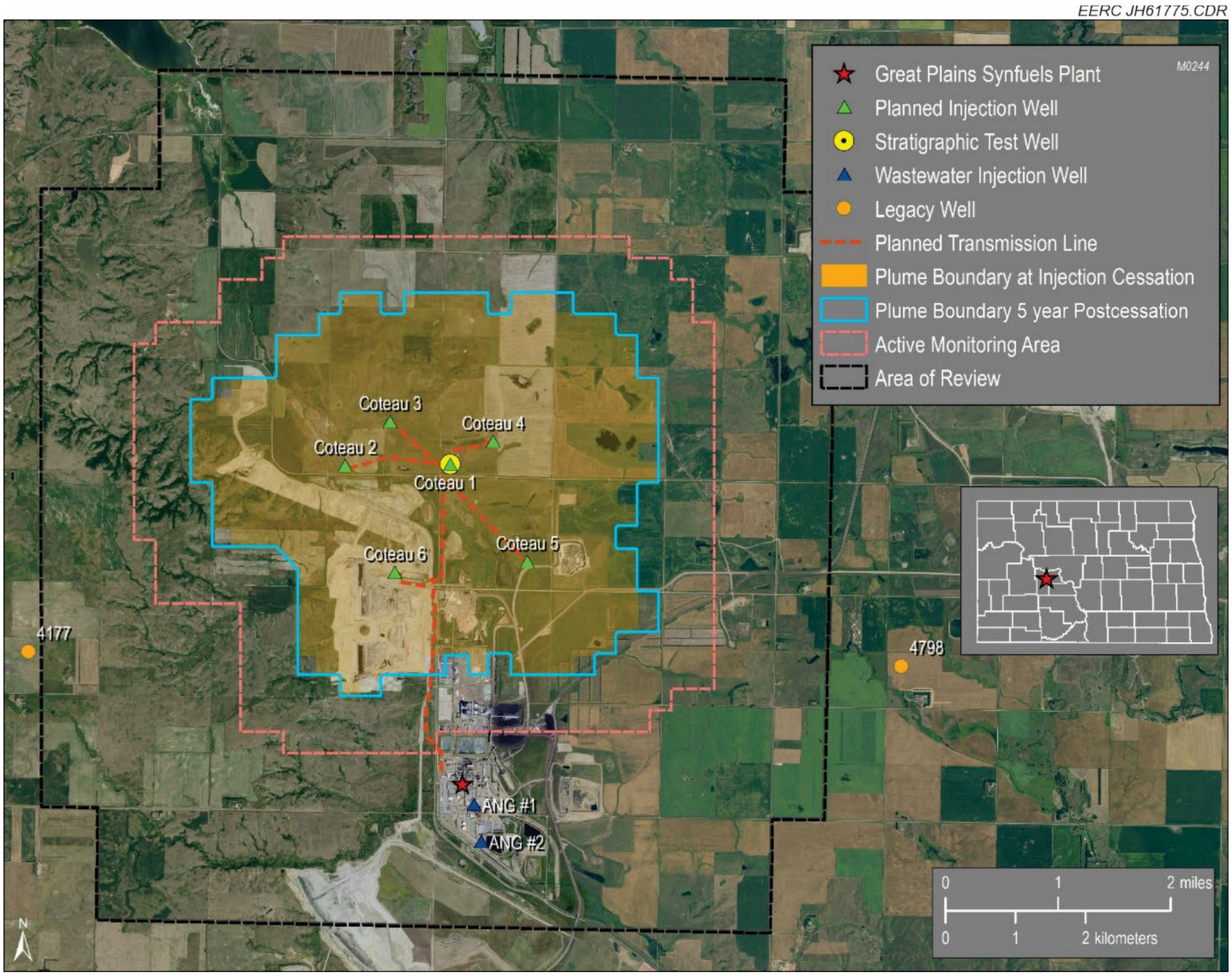

Figure 2-1. Map showing the AOR relative to the AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR), with "t" set equal to injection cessation (12 years). The AOR subsumes the AMA and exceeds requirements for the AMA; therefore, the AOR serves as the AMA for the Great Plains CO_2 Sequestration Project.

2.2 Maximum Monitoring Area

DGC proposes that the delineated AOR and proposed AMA from Figure 2-1 also serve as the maximum monitoring area (MMA) for the Great Plains CO_2 Sequestration Project (Figure 2-2), as it also exceeds the requirements for delineating the MMA under 40 CFR § 98.449 (Subpart RR).

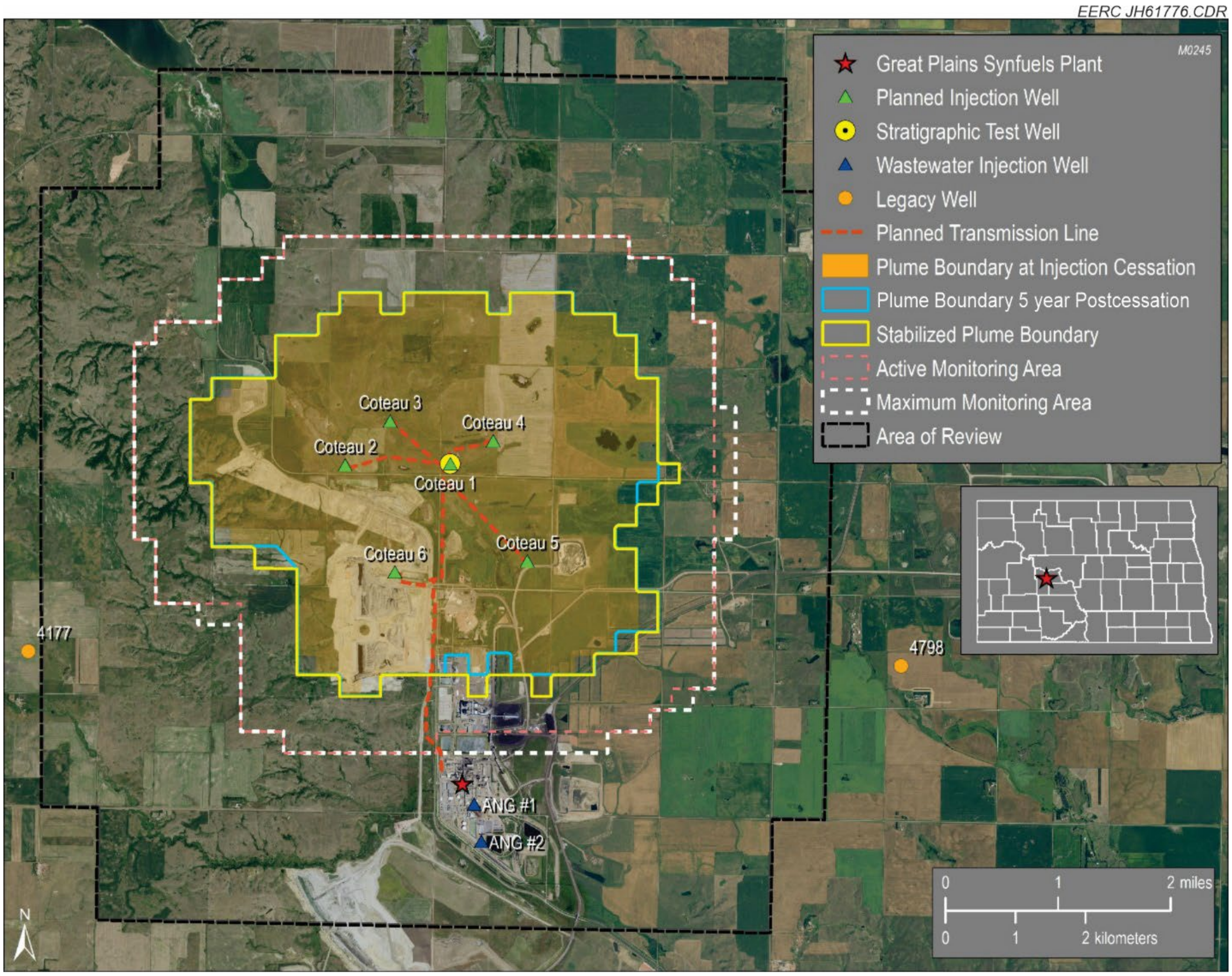

Figure 2-2. Map showing the AOR relative to the calculated MMA and AMA boundaries, calculated as prescribed under 40 CFR § 98.449 (Subpart RR). The AOR subsumes the calculated AMA and MMA and exceeds requirements for both AMA and MMA; therefore, the AOR serves as both the AMA and MMA for the Great Plains CO_2 Sequestration Project.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2 (Reference 1, Section 5) comprises three distinct periods: 1) pre-operational (pre-injection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) post-operational (post-injection of CO_2) monitoring. These monitoring periods, therefore, encompass the entire life cycle of the project. For purposes of this MRV plan, it is expected that reporting will be initiated during the operational period and continue through the post-injection period.

The storage system parameters that are monitored during each period are essentially identical; however, the duration of the monitoring period of the measurements performed varies. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

The pre-operational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and uncertainty associated with the measurement of each of the key storage system parameters. An understanding of the repeatability and variability of each measurement is key to successfully determining the movement of CO_2 that is contained in the formation at any given time.

The operational injection period is focused on validating and updating numerical models of the storage system to ensure that the geologic storage project is operating safely and protecting all USDWs. Lastly, the purpose of the post-operational monitoring is to verify the stability of the CO_2 plume location and assess the integrity of all decommissioned wells. The duration of these monitoring periods is a minimum of 12 and 10 years, respectively.

3.0 EVALUATION OF POTENTIAL LEAKAGE PATHWAYS

The potential leakage pathways for CO_2 arriving at the surface after injection or from surface equipment failures during operations were evaluated. Factors and equipment that could lead to leakage pathways were identified and placed into the following six categories:

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

This leakage assessment determined none of the pathways required corrective action and the probability of leakage is unlikely. However, a robust monitoring program, described in Reference 1, Section 5, and summarized in Table 5-1, was developed to form the basis of this MRV plan.

3.1 Class I Nonhazardous Disposal Wells

Two Class I disposal wells are active in the Great Plains CO_2 Sequestration Project area. Both wells were drilled in the 1980s to dispose of nonhazardous wastewater produced from GPSP operations in the Minnelusa Group (Broom Creek Formation) and Kibbey Formation under North Dakota Department of Health (NDDH) Permit Nos. ND-UIC-101 and ND-UIC-102. In 2018, both permits were renewed under NDDH Permit No. ND-UIC-101-1. In 2019, the North Dakota Department of Environmental Quality (NDDEQ) separated from the NDDH, and both Class I disposal wells were given well numbers by the NDDEQ.

3.1.1 ANG #1 (NDDEQ Well No. 11308)

The American Natural Gas No. 1 Disposal Well (ANG #1) spudded in April 1982 (NDDEQ Well No. 11308), reaching a total depth of 6,784 feet in the Kibbey Formation. Drillstem test data and core collected from porous and permeable intervals of the Dakota, Minnelusa, and Kibbey saw

no evidence of hydrocarbons. Injectivity tests demonstrated the Minnelusa (Broom Creek Formation) and Kibbey were the most viable for receiving wastewater at the injection rates and volumes specified in NDDH Permit No. ND-UIC-101. The well was completed in the Minnelusa in July 1982, and additional perforations were added to the Kibbey Formation in 1983. The ANG #1 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure, and a seal pot system on the annulus to detect annulus leaks. The ANG #1 is also monitored with temperature logs or tracer surveys about once every 5 years.

The ANG #1 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and it was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-4).

The risk of leakage via the ANG #1 is unlikely and is mitigated through the wellbore leak detection plan described hereto. The simulation work (presented in Reference 1, Section 2.3.3) also illustrates that the CO_2 plume does not come into contact with the well and suggests there is little interaction between the CO_2 plume and the injected disposal water, even after 10 years post-injection. Because the CO_2 plume does not come into contact with the well, the anticipated magnitude of leakage from the ANG #1 in terms of volume of CO_2 or associated fluids over the life of the project is extremely low.

3.1.2 ANG #2 (NDDEQ Well No. 11309)

The American Natural Gas No. 2 Disposal Well (ANG #2) spudded in September 1983 (NDDEQ Well No. 11309), reaching a total depth of 6,911 feet in the Kibbey Formation. The well was completed in both the Minnelusa (Broom Creek Formation) and Kibbey sands (NDDH Permit No. ND-UIC-102). The ANG #2 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure in the tubing-casing annulus, and a seal pot system on the annulus to detect annulus leaks. The ANG #2 is also monitored with temperature logs or tracer surveys about once every 5 years.

The ANG #2 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and it was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-5).

The risk of leakage via the ANG #2 is unlikely and is mitigated through the wellbore leak detection plan described hereto. The simulation work presented in Reference 1, Section 2.3.3, also illustrates that the CO_2 plume does not come into contact with the well and suggests there is little interaction between the CO_2 plume and the injected disposal water, even after 10 years post-injection. Because the CO_2 plume does not come into contact with the well, the anticipated magnitude of leakage from the ANG #2 in terms of volume of CO_2 or associated fluids over the life of the project is extremely low.

3.2 Abandoned Oil and Gas Wells

The Herrmann 1 (NDIC File No. 4177) well spudded in November 1966. The well was drilled to a depth of 8,057 feet into the Frobisher interval (stratigraphically equivalent to the Mission Canyon Formation of the Madison Group) and was plugged and abandoned in December of the same year. A drillstem test was conducted in the Frobisher interval, but the well encountered no commercial accumulations of hydrocarbons.

The Herrmann 1 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project and is the only oil and gas well within 0.5 miles outside of the AOR. It was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-3).

The risk of leakage via the Herrmann 1 of any magnitude and at any time over the life of the project is extremely low, as the well 1) never comes into contact with the CO_2 plume, 2) experiences a pressure increase of less than 100 psi over the life of the project (Reference 1, Section 6.1.1, Figures 6-1 and 6-2), and 3) has multiple cement plugs to prevent vertical migration of pressure or fluids outside the storage reservoir (Reference 1, Section 4.2, Figure 4-6).

3.3 Surface Components

Surface equipment components present potential leakage pathways during the operational injection period for the Great Plains CO_2 Sequestration Project site. Surface equipment can be subject to deterioration due to normal aging throughout its functional life. Corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in these assets.

The DGC CCS system includes a 6.8-mile-long transmission pipeline (NDPSC Case No. PU-21-150), six flowlines, and six injection wellheads (Figure 1-4b). The transmission line consists of a 12-inch main line and six 6-inch lateral lines that branch off and connect with 4.5-inch flowlines near each well pad. The flowlines will be connected to metering stations and located contiguous with the well pads (Reference 1, Section 5, Figures 5-1 and 5-2). Flowmeters will be installed at each metering station. The chemical composition of the CO_2 stream that will flow through the surface equipment is given in Reference 1, Section 5.1.1, Table 5-2.

Surface components of the injection system, including the flowlines and wellheads, will be monitored using leak detection equipment. The wellsite flowlines will be monitored continuously via multiple pressure gauges and H_2S detection stations located between the transmission line and the individual wellheads. This leak detection equipment will be integrated with automated warning systems that notify the pipeline control center at DGC, giving the operator the ability to remotely close the valves in the event of an anomalous reading. Further details of the surface leak detection system are given in Reference 1, Section 5.3.

The risk of leakage via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.

- Implementing the highest standards on material selection and construction processes for the flowlines and wells.
- Applying best practices and a robust mechanical integrity program as well as operating procedures.
- Monitoring continuously via an automated system and integrated databases.

The risk of leakage through surface equipment (under normal operating conditions) is unlikely, and the magnitude will vary according to the failure observed. A potential leakage event from instrumentation or valves could represent a few pounds of CO_2 released during several hours, while a puncture in the flowline could represent several tons of CO_2 released underground until the operator ceases the CO_2 supply. Note that should a shutoff situation occur, the CO_2 stream can be looped back to the DGC capture facility, passed through the burners, and be vented to the atmosphere.

This risk of leakage through surface equipment reduces to almost zero during the post-injection site care period. At cessation of the injection period, the injection wells will be properly plugged and abandoned following NDIC protocols and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the Class I wastewater injection wells, ANG #1 and ANG #2, identified as potential leakage pathways at the wellhead valves or in the instrumentation as discussed in Section 3.1.

3.4 Faults, Fractures, Bedding Plane Partings, and Seismicity

No known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations have been identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration activities (Reference 1, Section 2.5).

3.4.1 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 (Reference 1 Section 2.5). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The two closest recorded seismic events to the Great Plains CO_2 Sequestration Project occurred 29.6 miles to the northwest and 36.8 miles southwest of the Coteau 1 injection wellsite, with estimated magnitudes of 1.9 and 3.2, respectively (Reference 1, Section 2.5).

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

The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the absence of known or suspected local or regional faults suggest the probability that seismicity would interfere with CO_2 containment is low. In the event a seismic event occurs (natural or induced) near the project site, the magnitude of any seismic event would be expected to be less than 3.2 based on the historical record and would expected to cause little to no damage to subsurface or downhole equipment. In addition, DGC will operate below the maximum allowable injection pressure (Reference 1, Section 11, Table 11-1) to maintain safe operations throughout the injection period.

Through the geologic site characterization and corrective action review processes, leakage resulting from natural or induced seismicity was shown to be very unlikely.

3.5 Class VI Injection Wells

3.5.1 Coteau 1 (NDIC File No. 38379)

The Coteau 1 well spudded in June 2021 as a stratigraphic test well to a depth of 6,483 feet into the Amsden Formation. This well was drilled to gather geologic data to support the development of a CO_2 SFP and to later be converted into a Class VI injection well for the Great Plains CO_2 Sequestration Project. The Coteau 1 will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues.

The risk of leakage via the Coteau 1 is mitigated through:

- Preventing corrosion of well materials, following the preemptive measures in Reference 1, Section 5.2.2.
- Monitoring operations with a surface leak detection plan, as described in Reference 1, Section 5.3.
- Monitoring the storage reservoir with a subsurface leak detection plan, as described in Reference 1, Section 5.4.
- Performing wellbore mechanical integrity testing, as described in Reference 1, Section 5.1.2, and summarized in Reference 1, Section 5.7, Table 5-7.

The risk of leakage via the Coteau 1 during injection is low. The magnitude of any leakage during injection may vary according to the failure observed and could potentially represent a few pounds of CO_2 to several metric tons per hour released until operations are shut in and emergency protocols activated, as described in Reference 1, Section 7.4. Once the injection period ceases, the Coteau 1 will be properly plugged and abandoned following NDIC protocols, thereby reducing the risk for leakage from the well to almost zero.

3.5.2 Coteau 2 Through Coteau 6 Planned CO_2 Injection Wells

The Coteau 2 (NDIC File No. 38916), Coteau 3 (NDIC File No. 38917), and Coteau 4 (NDIC File No. 38918) wells are planned to spud in the summer of 2022 as stratigraphic test wells for the Great Plains CO_2 Sequestration Project. The wells will be drilled to the Amsden Formation at planned depths of 6,345, 6,339, and 6,301 feet, respectively. Once the SFP is issued, all

stratigraphic test wells will be converted to Class VI injection wells. Like the Coteau 1, the wells will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues. The Coteau 5 and Coteau 6 wells are planned to spud in 2026 and are conditional upon additional injection volumes of CO_2 becoming available from the capture facility. The Coteau 5 and Coteau 6 wells will be monitored after the same manner as the Coteau 1 through Coteau 4 wells. Once the injection period ceases, the Coteau 2 through Coteau 6 wells will be properly plugged and abandoned following NDIC protocols.

The discussion for assessing the risk of leakage via the Coteau 2 through Coteau 6 is the same as presented in Section 3.5.1 of this MRV plan. Once the injection period ceases, the Coteau 2 through Coteau 6 will be properly plugged and abandoned following NDIC protocols, thereby reducing the risk for leakage from the wells to almost zero.

3.6 Confining Zone Limitations

3.6.1 Lateral Migration

For the Great Plains CO_2 Sequestration Project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure (Reference 1, Section 2.3.2). The Opeche Formation is a laterally extensive formation that is 5,763 feet below the surface and 143 feet thick at the Coteau 1 wellsite (Reference 1, Section 2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), as discussed in Reference 1, Section 3.4.

The risk of leakage via lateral migration is extremely unlikely, as demonstrated by the geologic characteristics of the storage reservoir (Reference 1, Section 2.3) and upper confining zone (Reference 1, Section 2.4.1) (e.g., mineralogy, permeability/sealing capacity, and lateral continuity) coupled with the modeling and simulation work (Reference 1, Section 3) that was performed for the Great Plains CO_2 Sequestration Project. In the event that the monitoring data or models and simulations predict any part of the CO_2 plume may migrate beyond the anticipated stabilized plume boundary over the project's life because of a previously unidentified permeability pathway in the storage reservoir, the storage facility area and AOR will be recalculated, and the MRV plan, including the testing and monitoring strategy, will be updated as necessary.

3.6.2 Seal Diffusivity

Several other formations provide additional confinement above the Opeche Formation (Reference 1, Section 2.4.2). Impermeable rocks above the primary seal, the Opeche Formation, include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations. Together with the Opeche, these formations are 1,106 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 2,657 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation.

Confining layers above the Inyan Kara include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (see Figure 1-3 for stratigraphic reference).

The risk of leakage via the Herrmann 1 of any magnitude and at any time over the life of the project is extremely low, as there is a total of 3,763 feet of overlying confining layers, which presents a very low risk to the Great Plains CO_2 Sequestration Project. The presence of multiple thick impermeable layers and laterally extensive formations drastically reduces potential leakage pathways through geologic formations.

3.6.3 Drilling Through the CO_2 Area

There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the AOR. Although there was a historical oil and gas production well test from the Madison Group just outside the AOR (i.e., Herrmann 1), there are no known commercial accumulations of hydrocarbons in the AOR (Reference 1, Section 2.6). With no known commercial ventures drilling near the Great Plains CO_2 Sequestration Project area, there is very little chance of drilling through the storage complex.

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a deviated or horizontal well could be used to produce the hydrocarbon while avoiding drilling through the CO_2 plume or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available, which will allow prospective operators to design an appropriate well control strategy via increased drilling mud weight. The maximum pressure increase in the center of the injection area is projected by computer modeling to be 400–450 psi, with lesser impacts extending radially (Reference 1, Section 3, Figure 3-20). Pressure increases will relax post-injection as the area returns to its pre-injection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the CO_2 should be designed to include an intermediate casing string made of CO_2-resistant material and placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place.

3.7 Monitoring, Response, and Reporting Plan for CO_2 Loss

DGC proposes a robust monitoring program for the SFP (Reference 1, Section 5). The program covers a corrosion and mechanical integrity protocol (Reference 1, Section 5.2), surveillance of injection performance (Reference 1, Sections 5.3 and 5.4), monitoring of near-surface conditions (Reference 1, Sections 5.5 and 5.6), and direct and indirect monitoring of the CO_2 plume (Reference 1, Section 5.7). To compliment the monitoring program, DGC proposes a detailed emergency remedial and response plan (Reference 1, Section 7) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting in the event of an unplanned loss of CO_2 from the Great Plains CO_2 Sequestration Project area.

3.8 Summary

In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the emergency and remedial response plan. Estimating volumetric

losses of CO_2 would require consideration of the leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based upon the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

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

Table 4-1. Summary of DGC's CCS Monitoring Strategy

Method (target area/structure)	**Pre-injection (Baseline – 1 year)**	**Injection Period (12 years)**	**Post-injection (10 years)**
CO_2 Stream Analysis (capture)	Start-up	Daily	NA[1]
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	Start-up	Real time	NA
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	Start-up	Real time	NA
H_2S Detection Stations (flowlines, wellheads, and well pads)	Start-up	Real time	NA
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	Start-up	Monthly in the first quarter, then quarterly in the next 2 years	NA
Platform Multifinger Imaging Tool (PMIT) or Ultrasonic Imaging Tool (USIT) (CO_2 injection wells)	NA	Starting in Year 2, a PMIT or USIT will be run during well workovers but not more frequently than once every 5 years	NA
SCADA[2] Automated Remote System (surface facilities)	Start-up	Real time	NA
Soil Gas Analysis (11 soil gas profile stations)	Three to four seasonal samples	Three to four seasonal samples each year	Three to four seasonal samples each year
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)	Provide historical water sampling results	NA	NA
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)	Baseline	NA	NA
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	Baseline	Three to four seasonal samples	Three to four seasonal samples
Cement Bond Logs (CO_2 injection wells)	After cementing	If needed	Prior to P&A[3]
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but not less than once every 5 years
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	Start-up	Real time	NA
Pulsed-Neutron Logs with Temperature and Bottomhole Pressure Readings (CO_2 injection wells)	Baseline	Quarterly using phased approach described in Reference 1, Section 5.1.2	NA
USIT Logs (CO_2 injection wells)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but not less than once every 5 years
Pressure Falloff Test (CO_2 injection wells)	Baseline	Every 5 years	NA
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	Baseline	Repeat survey 1 year after injection begins, then in Years 3, 5, and 10	Repeat survey 1 year after injection ceases, then in Years 3, 5, and 10
Vertical Seismic Profiles (VSP) (CO_2 plume)	Baseline	Repeat VSP 1 year after injection begins, then (if deemed beneficial) in Years 3, 5, and 10	NA

[1] Not applicable
[2] Supervisory control and data acquisition
[3] Plugging and abandonment

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

Monitoring Strategy (target area/structure) \ Potential Leakage Pathway	Wellbores*	Faults and Fractures	Flowline and Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis (capture)			X			
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	X		X			X
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	X		X	X		
H_2S Detection Stations (flowlines, wellheads, and well pads)	X		X	X		X
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	X		X	X		
PMIT or USIT (CO_2 injection wells)	X			X		
SCADA Automated Remote System (surface facilities)	X		X	X		
Soil Gas Analysis (11 soil gas profile stations)	X			X	X	X
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)				X	X	X
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)		X		X	X	X
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	X	X		X	X	X
Cement Bond Logs (CO_2 injection wells)	X			X		X
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	X			X		
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	X			X	X	
Pulsed-Neutron Logs with Temperature and Bottomhole Readings (CO_2 injection wells)	X			X	X	X
USIT Logs (CO_2 injection wells)	X			X		
Pressure Falloff Test (CO_2 injection wells)	X			X	X	
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	X	X		X	X	X
VSP (CO_2 plume)*	X	X		X	X	X

* Applies to all wellbores in project area if not otherwise specified under the monitoring strategy target area/structure column.

4.1 Leak Verification

DGC's strategy to detect and verify leakage pathways is summarized in Table 4-2.

As part of the surveillance protocol, DGC will use reservoir simulation modeling, based on history-matched data obtained from the monitoring program, to compare the initial numerical model with the real development of the plume and pressure front. The model will be continuously calibrated with the acquisition of real-time data. Every 5 years, a formal AOR will be submitted, and the monitoring plan will be revised, if needed.

The model history match allows the project operator and owner to identify conditions that differ from those proposed by the numerical model and deviations in the operating conditions from the originals. For example, the injection well will be monitored, and if the injection pressure, temperature, or rate measurements deviate significantly from the specified set points, then a data flag will be automatically triggered by the automated system and field personnel will investigate the excursion. These excursions will be reviewed to determine if CO_2 leakage is occurring. Excursions are not necessarily indicators of leaks; rather, they indicate that injection rates, temperatures, and pressures are not conforming to the expected pattern of the injection plan. In many cases, problems are straightforward and easy to fix (e.g., a meter needs to be recalibrated), and there is no indication that CO_2 leakage has occurred. In the case of issues that are not readily resolved, a more detailed investigation will be initiated. If further investigation indicates a leak has occurred, efforts will be made to quantify its magnitude.

The model history-matching in combination with the mechanical integrity data, geophysical surveys, and near-surface monitoring form a powerful tool to appropriately follow changes in CO_2 concentration at the surface. Many variations of CO_2 concentration detected on the surface are the result of natural processes or external events not related to the CO_2 storage complex.

Because a CO_2 surface leak is of lower temperature than ambient conditions, it will often lead to the formation of bright white clouds and ice that are easily visually observed. With this understanding, DGC will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the Great Plains CO_2 Sequestration Project.

Response plan actions and activities will depend upon the circumstances and severity of the event. DGC will address an event immediately and, if warranted, communicate the event to the UIC program director within 24 hours of discovery.

If an event triggers cessation of injection and remedial actions, DGC will demonstrate the efficacy of the response/remedial actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations will only resume upon receipt of written authorization of the UIC program director.

4.2 Quantification of Leakage

As discussed above, the potential pathways for leakage include failure or issue in surface equipment or subsurface equipment (wellbores), faults or induced fractures, and competency of the seal to contain the CO_2 in the storage reservoir.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods to quantify the volume of CO_2 will be determined on a case-by-case basis. Any volume of CO_2 detected as leaking to the surface will be quantified using acceptable emission factors, engineering estimates of leak amount based on subsurface measurements, numerical models, history-matching of the reservoir performance, detailed analysis of the collected monitoring parameters, and delineation of the affected area, among others. Leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in an electronic central database.

5.0 DETERMINATION OF BASELINES

DGC will establish pre-injection baselines by implementing a monitoring program prior to any CO_2 injection and during each of the four primary seasonal ranges. This baseline will be created by monitoring the targeted surface, near-surface, and deep subsurface. The baseline will contain information on the characteristics of a range of environmental media, such as surface water, soil gas in the vadose zone, shallow groundwater, and storage reservoir formation water.

These baselines provide a basis for determining if CO_2 leaks are occurring by providing a foundation against which characteristics of these same media during CO_2 injection can be compared and evaluated. For example, changes in concentrations or levels of certain parameters in these media during injection might suggest that they have been impacted by leaking CO_2.

Determinations of these baselines are a critical component of a Class VI SFP. A detailed description of these baselines for both the surface and subsurface for the Great Plains CO_2 Sequestration Project area is provided in Reference 1, Sections 5.3 through 5.7.

5.1 Surface and Near-Surface Baselines

A baseline surface and near-surface sampling program has been completed for the Great Plains CO_2 Sequestration Project. Baseline data gathering included measuring chemical concentrations of the soil gas (i.e., O_2, N_2, and CO_2) and groundwater (e.g., pH, total dissolved solids, alkalinity, major cations/anions and trace metals) as well as characterizing the naturally occurring stable and radiocarbon (^{14}C) isotopic signatures of the soil gas and groundwater for comparison with the isotopic signature of the CO_2 stream. The data were obtained from 11 soil gas-sampling locations and two existing groundwater wells from the northern and eastern portions of the AOR. Baseline water samples are also planned to be obtained from five new Fox Hills monitoring wells that will be drilled prior to the start of injection operations. One of the groundwater monitoring wells will be placed near the Herrmann 1 well and the others will be placed adjacent to the Coteau 1 through Coteau 4 injection wells (Reference 1, Section 5.6,

Figure 5-4). For additional information regarding surface and near-surface baselines, refer to Reference 1, Sections 5.5.1–5.5.2 and Section 5.6, paragraph 1.

5.2 Subsurface Baselines

Pre-operational baseline data will be collected in each of the six injection wells for the Great Plains CO_2 Sequestration Project, including ultrasonic imaging, pulsed-neutron, and temperature logs, bottomhole pressure surveys, tubing-casing annulus pressure tests, and pressure falloff tests (Reference 1, Section 5.7, Table 5-7). The data acquisition schedule for the pulsed-neutron and temperature logs with a pressure-recording device attached is presented in Reference 1, Section 5.1.2. The time-lapse saturation data will be used as an assurance-monitoring technique for CO_2 in the formation directly above the storage reservoir, otherwise known as the above-zone monitoring interval. The pressure and temperature data will be useful for informing the geologic model and simulations, monitoring conditions in the storage reservoir, and confirming wellbore mechanical integrity. The pressure testing in each of the wellbores will also help to confirm wellbore mechanical integrity.

Indirect monitoring methods will also track the extent of the CO_2 plume within the storage reservoir and can be accomplished by performing time-lapse geophysical surveys of the AOR. A 2D radial seismic survey was collected to establish baseline conditions in the storage reservoir. A baseline VSP was also collected to determine the feasibility of monitoring the CO_2 plume during the injection phase with this technology. For additional information regarding subsurface baselines, refer to Reference 1, Section 5.7.2.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The Great Plains CO_2 Sequestration Project area is a geologic CO_2 storage site in a saline aquifer with no production associated from the storage complex. A flowmeter will be placed downstream of the CO_2 compressor (start of the CO_2 transmission line) and near each of the injection wellheads (Figure 1-4b). The proposed main metering station for mass balance calculation is identified as the first metering station placed at the start of the CO_2 transmission main line. The use of a single metering station for the mass balance calculation (as opposed to using multiple metering stations near each wellhead) will help ensure accuracy of the measurements.

To calculate the annual mass of CO_2 that is stored in the storage complex, the project will use Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

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

Where:

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

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

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

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

Mass of CO_2 Injected (CO_{2I}):
DGC will use volumetric flow metering to measure the flow of the injected CO_2 stream and will calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5 from 40 CFR Part 98, Subpart RR (Equation 2):

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

Where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for Flowmeter u in Quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

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

p = Quarter of the year.

u = Flowmeter.

Mass of CO_2 Emitted by Surface Leakage (CO_{2E}):
DGC characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in Reference 1, Section 5, to detect any leak and defined a baseline for monitoring.

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

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

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

Where:

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

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

Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions
Annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead (CO_{2FI}) will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan proposed in Reference 1, Section 5.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented starting September 2022 or within 90 days of EPA approval, whichever occurs later. Other greenhouse gas reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time. It is anticipated that the MRV program will be in effect from September 2022 to September 2036, during which time the Great Plains CO_2 Sequestration Project will be operated.

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for DGC monitoring techniques and data management is provided in the quality assurance and surveillance plan found in Reference 1, Appendix C.

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

CO_2 received:

- The quarterly flow rate of CO_2 will be reported from continuous measurement at the main metering station (identified in Figure 1-4b). In addition, the quarterly flow rate of CO_2 will be continuously measured by receiving meters at each of the injection well pads.

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

Flowmeter provision:

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

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

- Operated in conformance with consensus-based standards organizations including, but not limited to, American Society for Testing and Materials (ASTM) International, the American National Standards Institute, the American Gas Association, the American

Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

9.0 RECORDS RETENTION

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

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

- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

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

10.0 REFERENCES

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

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

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

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Appendix B: Submissions and Responses to Requests for Additional Information

GREAT PLAINS CO_2 SEQUESTRATION PROJECT MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Well

Reporting Number: 523812

TABLE OF CONTENTS

Continued . . .

TABLE OF CONTENTS (continued)

LIST OF FIGURES

LIST OF TABLES

STORAGE FACILITY PERMIT DESIGNATIONS

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

Reference 1: Great Plains CO_2 Sequestration Project, Mercer County, North Dakota

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

1.0 PROJECT DESCRIPTION

1.1 Project Characteristics

The Dakota Gasification Company's (DGC) Great Plains Synfuels Plant (GPSP), located 5 miles northwest of Beulah, North Dakota, is capable of gasifying 6 million tons of lignite coal per year (Figure 1-1). DGC, a wholly owned subsidiary of Basin Electric Power Cooperative (Basin), has owned and operated the facility since 1988. DGC has captured and transported more than 40 million tonnes (Mt) of carbon dioxide (CO_2) (>95% dry CO_2) from the gasification process for enhanced oil recovery purposes since 2000. The captured CO_2 is transported via a 205-mile pipeline that has successfully operated for the past 22 years. The CO_2 is first compressed to a pressure of ±2,500 pounds per square inch (psi), then transported north as a supercritical fluid. There currently exists excess compressor capacity, which makes the capture of an additional 1.0 Mt per year possible. DGC is currently constructing an additional 6.8 miles of pipeline to facilitate permanent sequestration of up to 2.7 Mt per year. The pipeline's design capacity is based on the total anticipated CO_2 output from the plant. Over the anticipated 12-year life of this project, sequestered volumes of CO_2 are expected to total 26 Mt. Four injection wells are anticipated initially (Coteau 1 through Coteau 4), with two additional wells planned (Coteau 5 and Coteau 6) as increased volumes in 2026 or beyond warrant (Figure 1-1). The injection wells will store the captured CO_2 stream in the porous and permeable Broom Creek Formation located below the GPSP.

DGC submitted its North Dakota CO_2 storage facility permit (SFP) to the North Dakota Industrial Commission (NDIC) on March 8, 2022, and an official hearing for DGC's Great Plains CO_2 Sequestration Project was held on July 20, 2022. North Dakota has the authority to regulate the geologic storage of CO_2 and primacy to administer the North Dakota Underground Injection Control (UIC) Class VI Program (83 Federal Register 17758, 40 Code of Federal Regulations [CFR] 147). If any material changes are made to the SFP after the hearing date that impact this MRV plan, DGC will notify EPA and submit an amended plan within 180 days.

No other geologic storage project exists or is planned within 18.2 miles of the Great Plains CO_2 Sequestration Project.

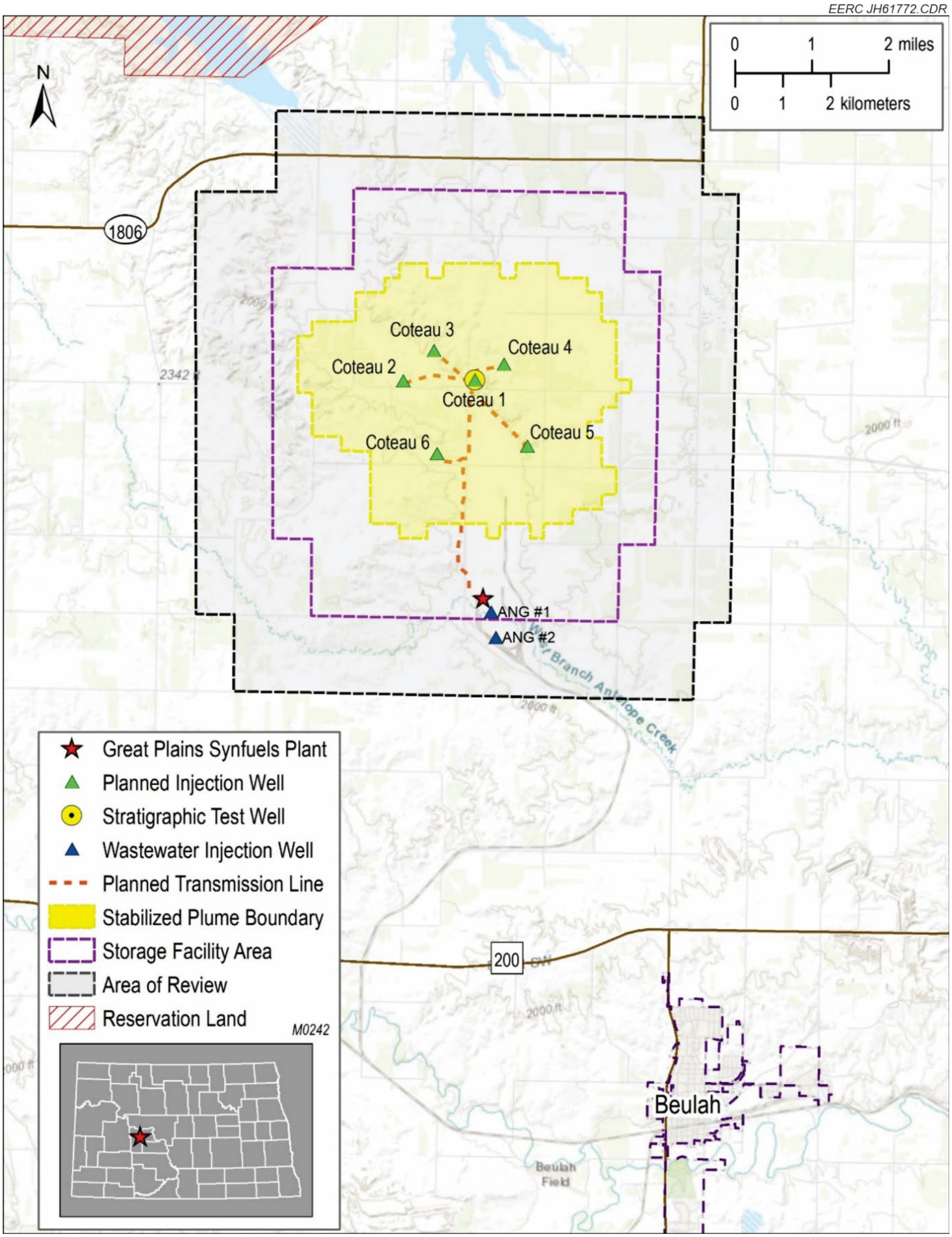

Figure 1-1. Location of the GPSP, Coteau 1 through Coteau 6 injection wells, and CO_2 transmission line. Also shown is the town of Beulah, with a population of about 3,200 people, the stabilized plume boundary, the storage facility area, and the area of review (AOR).

1.2 Environmental Setting

The Great Plains CO_2 Sequestration Project is located along the southern flank of the Williston Basin, a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Figure 1-2 shows the geographic distribution of oil fields in North Dakota, demonstrating there has been no exploration for or development of hydrocarbon resources within the AOR (Reference 1, Section 2.6). The Herrmann 1 (NDIC File No. 4177), a dry hole drilled in 1966 to the Frobisher interval (stratigraphically equivalent to the Mission Canyon Formation of the Madison Group), falls just outside the southwestern edge of the AOR. See Section 3.2 of this MRV plan for more information about the Herrmann 1 well.

A generalized stratigraphic column of the Williston Basin for the area of Beulah is provided in Figure 1-3. The target CO_2 storage reservoir for the Great Plains CO_2 Sequestration Project is the Broom Creek Formation, a predominantly sandstone interval lying about 5,900 feet below the GPSP (Reference 1, Section 2.3). Silty mudstones and interbedded evaporites of the Opeche Formation unconformably overlie the Broom Creek and serve as the primary confining zone (Reference 1, Section 2.4.1). Mixed layers of dolostone, mudstone, and anhydrite of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone (Reference 1, Section 2.4.3). From stratigraphic bottom to top, the Amsden, Broom Creek, and Opeche comprise the CO_2 storage complex. In addition to the Opeche Formation, there is about 1,100 feet of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation (Reference 1, Section 2.4.2). An additional 2,660 feet of impermeable rocks separate the Inyan Kara and the lowest underground source of drinking water (USDW): the Fox Hills Formation.

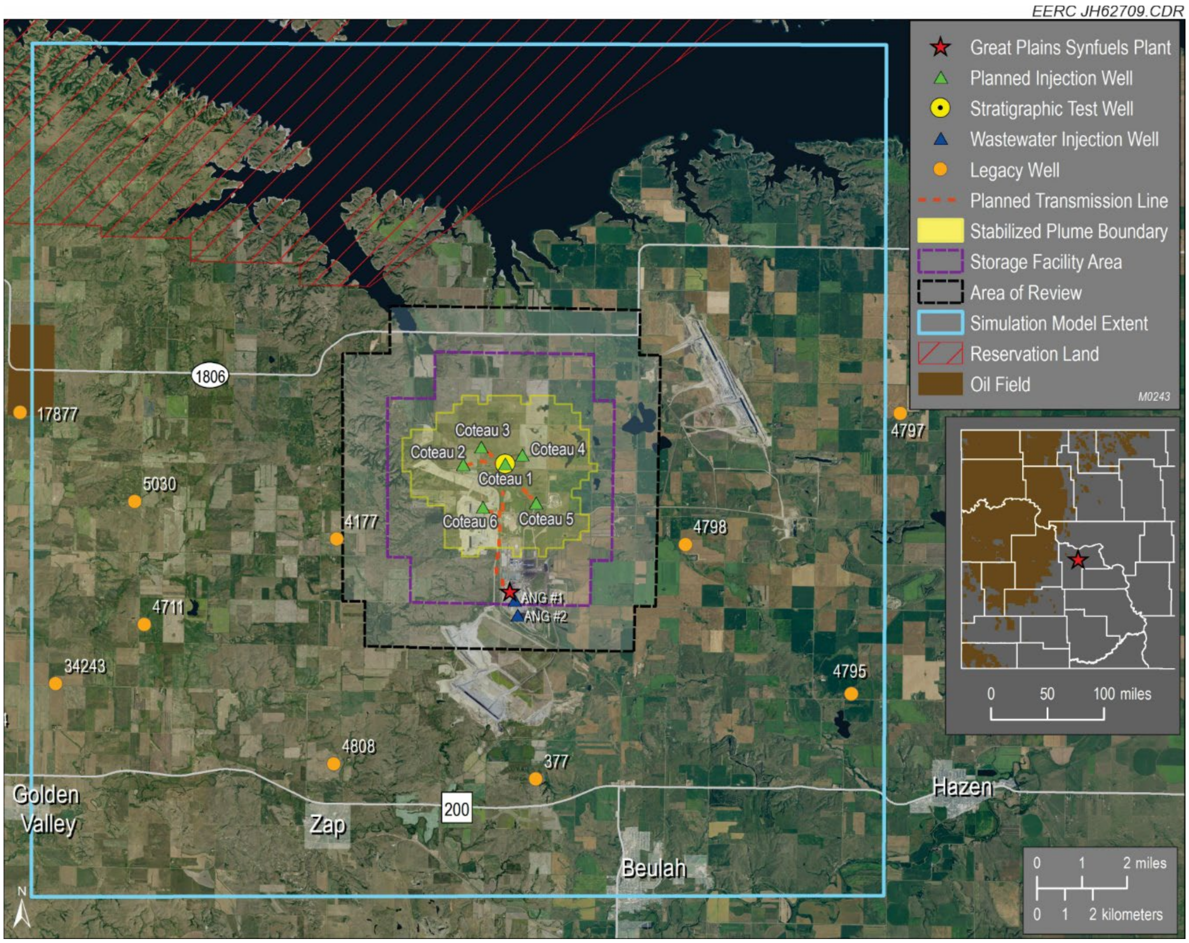

Figure 1-2. Map showing the simulation model extents of the Great Plains CO_2 Sequestration Project, legacy oil and gas wells, and geographic distribution of oil fields in North Dakota (i.e., western portion of the Williston Basin).

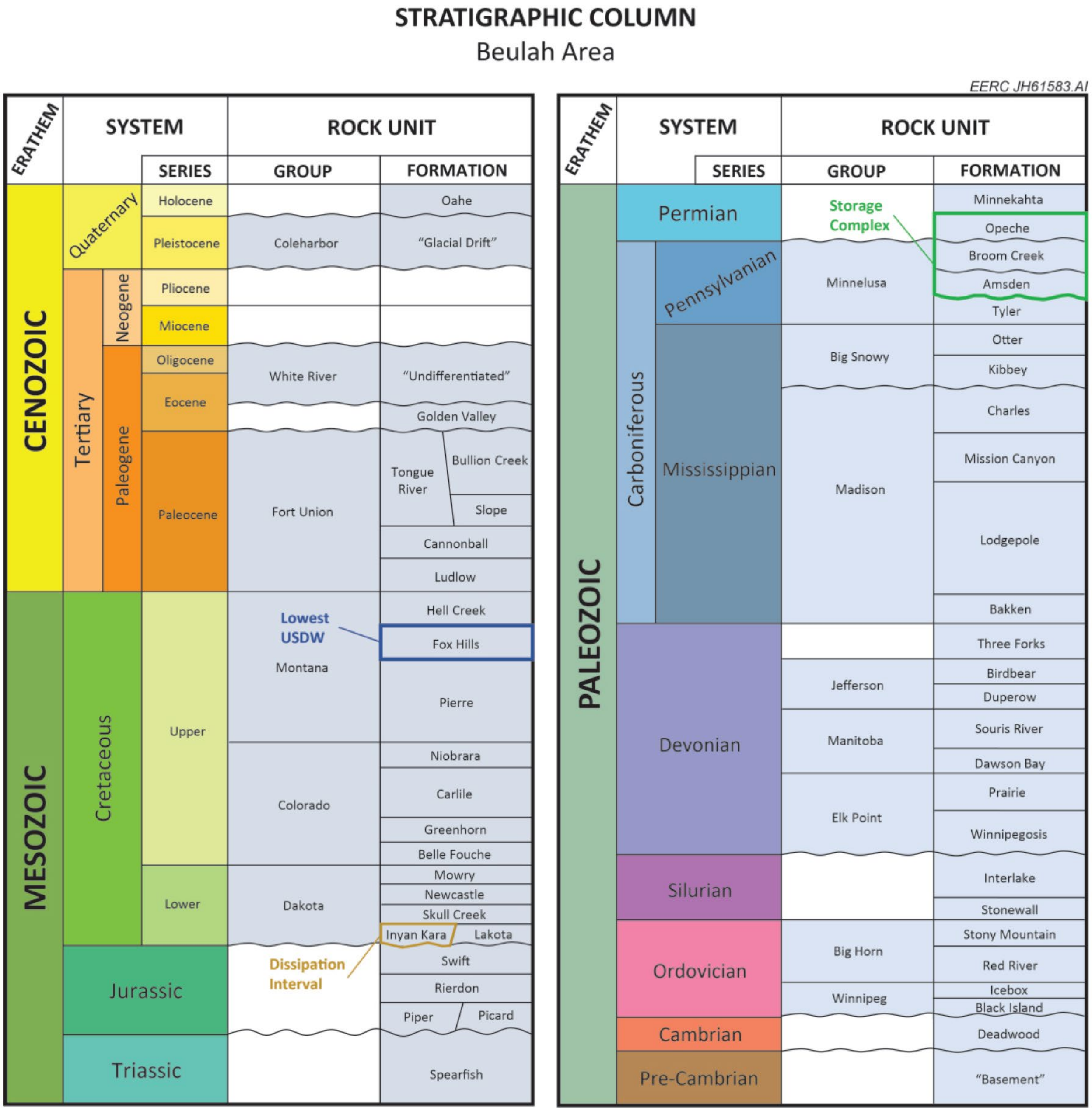

Figure 1-3. Generalized stratigraphic column of the Williston Basin for the Beulah area, identifying the storage complex (i.e., storage reservoir and primary confining zones) as well as the dissipation interval and lowest USDW underlying the Great Plains CO_2 Sequestration Project area. Figure modified after Murphy and others (2009) and Bluemle and others (1981).

1.3 Description of CO_2 Project Facilities and Injection Process

DGC plans to capture and store 1.0 to 2.7 Mt of CO_2 per year over the course of 12 years of injection, followed by at least 10 years of post-injection site care. Figure 1-4 shows integration

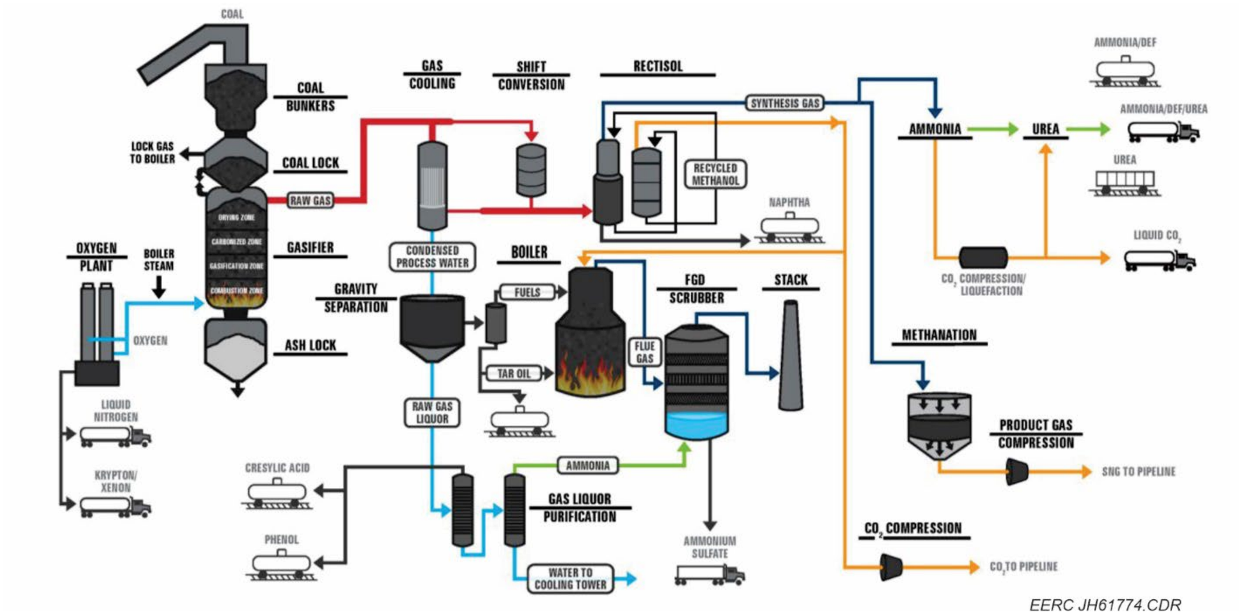

Figure 1-4a. Flow diagram of the CO_2 capture process at GPSP. The main metering station will be located downstream of the CO_2 compressors but upstream of the lateral for the Coteau 6 well, as shown in Figure 1-4b.

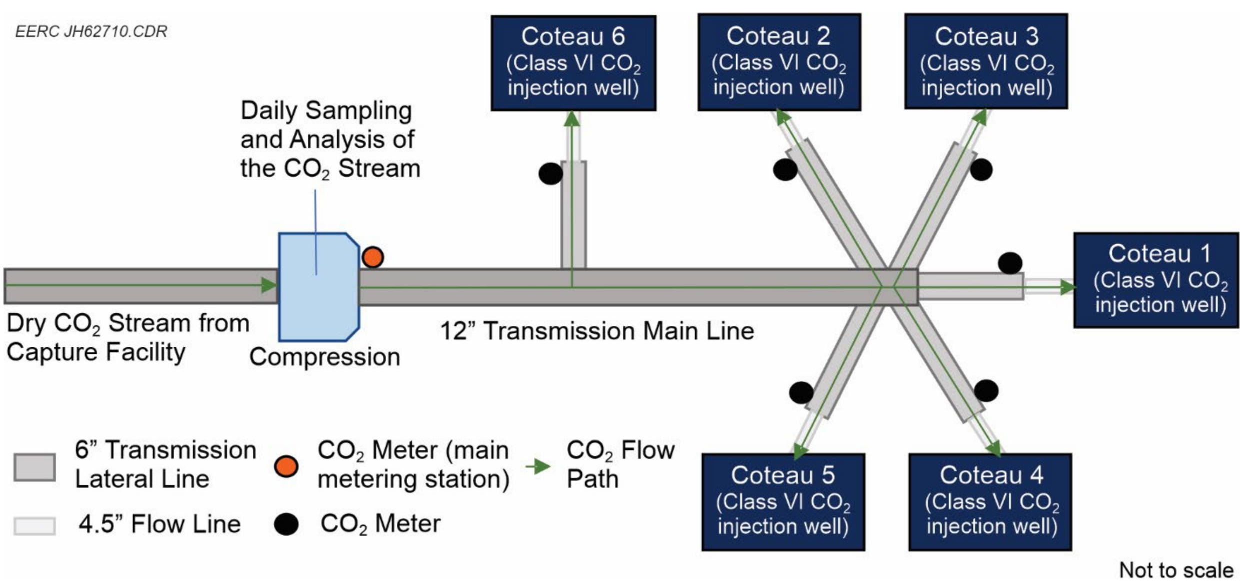

Figure 1-4b. Flow diagram illustrating major carbon capture and storage (CCS) components and the path of the CO_2 stream from the capture facility to the CO_2 injection wells.

of major CCS components with the capture facility at GPSP. The facility was designed to capture the CO_2 produced during the acid gas removal step of DGC's gasification process and compress the gaseous CO_2 stream to approximately 2,500 psi. The final compressed CO_2 stream would flow to the Coteau 1 through Coteau 6 injection wells for geologic storage into the Broom Creek Formation; an underground transmission pipeline permitted through the North Dakota Public Service Commission (NDPSC) Case No. PU-21-150 is installed on Basin, DGC, and Coteau Properties Company (CPC) property to connect the capture facility to the Coteau 1 through Coteau 6 injection wells. CPC, a wholly owned subsidiary of North American Coal Corporation, operates the Freedom Mine near the GPSP, supplying lignite coal feedstock to the plant.

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area: DGC AOR Delineation in Accordance with U.S. Environmental Protection Agency and North Dakota Rules

DGC proposes that because the AOR, as delineated in Reference 1, Section 4, exceeds the requirements of the active monitoring area (AMA) under Title 40, CFR § 98.449 (Subpart RR), the AOR will serve as the AMA for the Great Plains CO_2 Sequestration Project (Figure 2-1).

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). Therefore, DGC elected to permit the storage facility area boundaries based on the reservoir model output discussed in Reference 1, Section 4, and then, added a 1-mile buffer, rounding out to the nearest 40-acre tract.

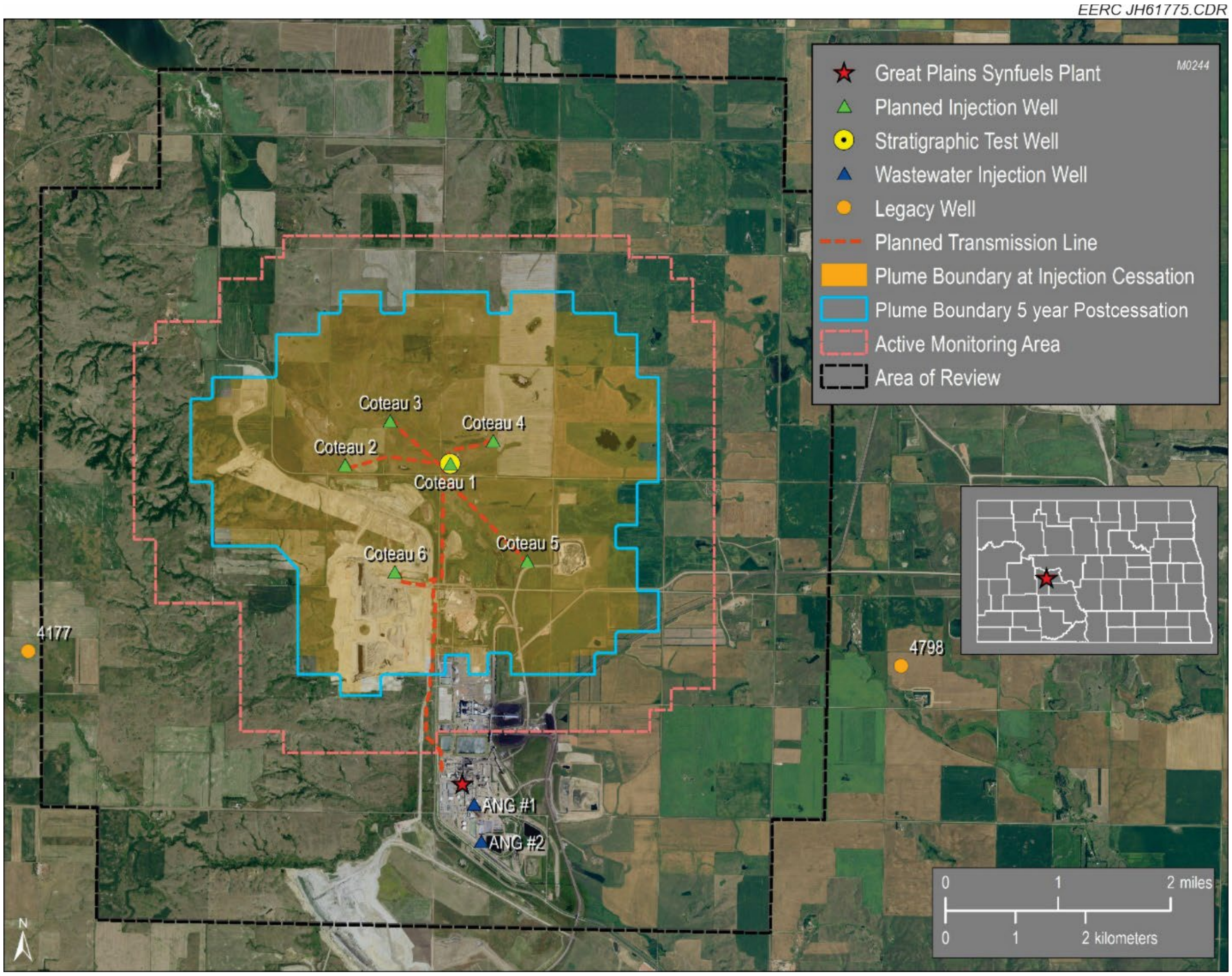

Figure 2-1. Map showing the AOR relative to the AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR), with "t" set equal to injection cessation (12 years). The AOR subsumes the AMA and exceeds requirements for the AMA; therefore, the AOR serves as the AMA for the Great Plains CO_2 Sequestration Project.

2.2 Maximum Monitoring Area

DGC proposes that the delineated AOR and proposed AMA from Figure 2-1 also serve as the maximum monitoring area (MMA) for the Great Plains CO_2 Sequestration Project (Figure 2-2), as it also exceeds the requirements for delineating the MMA under 40 CFR § 98.449 (Subpart RR).

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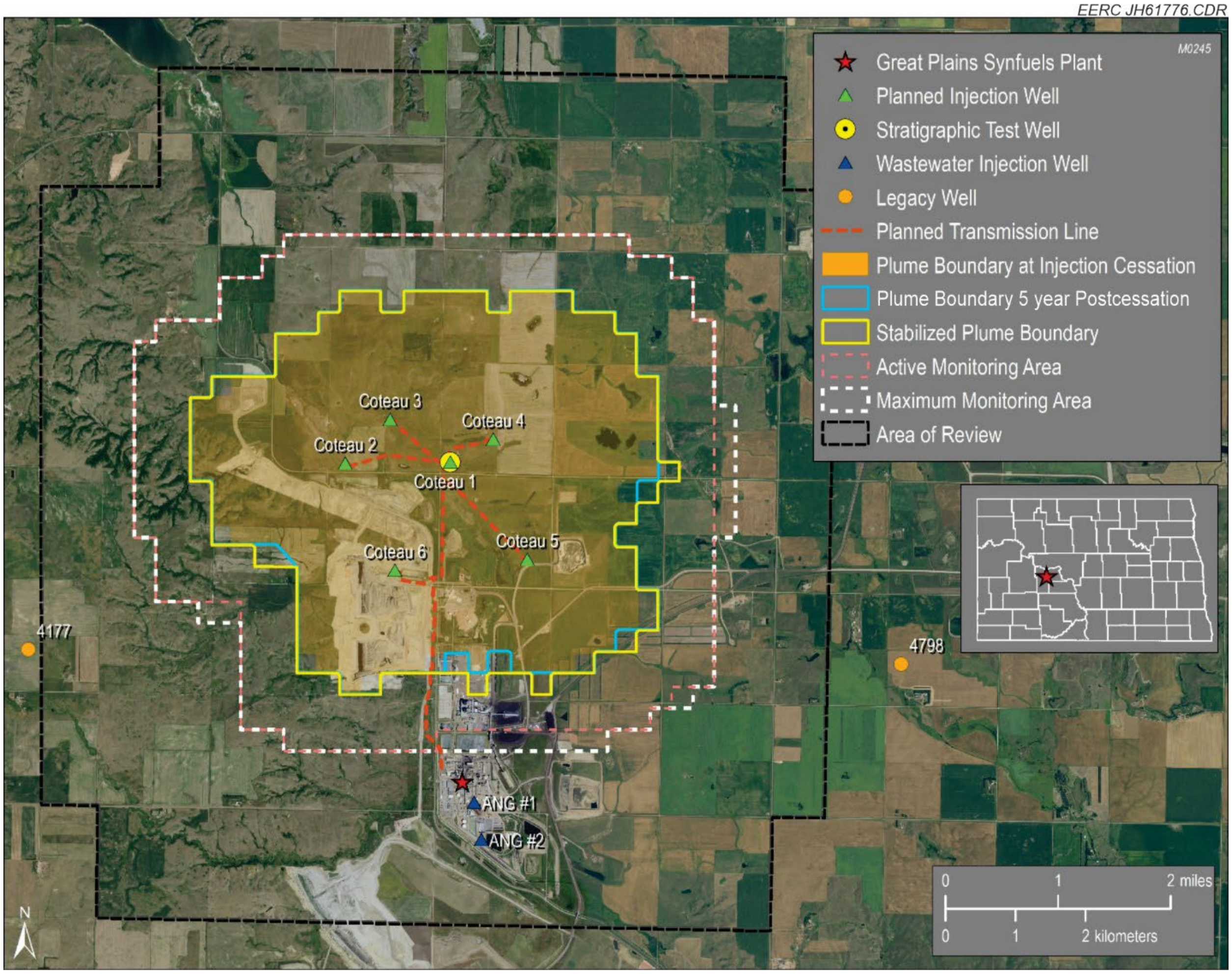

Figure 2-2. Map showing the AOR relative to the calculated MMA and AMA boundaries, calculated as prescribed under 40 CFR § 98.449 (Subpart RR). The AOR subsumes the calculated AMA and MMA and exceeds requirements for both AMA and MMA; therefore, the AOR serves as both the AMA and MMA for the Great Plains CO_2 Sequestration Project.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2 (Reference 1, Section 5) comprises three distinct periods: 1) pre-operational (pre-injection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) post-operational (post-injection of CO_2) monitoring. These monitoring periods, therefore, encompass the entire life cycle of the project. For purposes of this MRV plan, it is expected that reporting will be initiated during the operational period and continue through the post-injection period.

The storage system parameters that are monitored during each period are essentially identical; however, the duration of the monitoring period of the measurements performed varies. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

The pre-operational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and uncertainty associated with the measurement of each of the key storage system parameters. An understanding of the repeatability and variability of each measurement is key to successfully determining the movement of CO_2 that is contained in the formation at any given time.

The operational injection period is focused on validating and updating numerical models of the storage system to ensure that the geologic storage project is operating safely and protecting all USDWs. Lastly, the purpose of the post-operational monitoring is to verify the stability of the CO_2 plume location and assess the integrity of all decommissioned wells. The duration of these monitoring periods is a minimum of 12 and 10 years, respectively.

3.0 EVALUATION OF POTENTIAL LEAKAGE PATHWAYS

The potential leakage pathways for CO_2 arriving at the surface after injection or from surface equipment failures during operations were evaluated. Factors and equipment that could lead to leakage pathways were identified and placed into the following six categories:

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

This leakage assessment determined none of the pathways required corrective action and the probability of leakage is unlikely. However, a robust monitoring program, described in Reference 1, Section 5, and summarized in Table 5-1, was developed to form the basis of this MRV plan.

3.1 Class I Nonhazardous Disposal Wells

Two Class I disposal wells are active in the Great Plains CO_2 Sequestration Project area. Both wells were drilled in the 1980s to dispose of nonhazardous wastewater produced from GPSP operations in the Minnelusa Group (Broom Creek Formation) and Kibbey Formation under North Dakota Department of Health (NDDH) Permit Nos. ND-UIC-101 and ND-UIC-102. In 2018, both permits were renewed under NDDH Permit No. ND-UIC-101-1. In 2019, the North Dakota Department of Environmental Quality (NDDEQ) separated from the NDDH, and both Class I disposal wells were given well numbers by the NDDEQ.

3.1.1 ANG #1 (NDDEQ Well No. 11308)

The American Natural Gas No. 1 Disposal Well (ANG #1) spudded in April 1982 (NDDEQ Well No. 11308), reaching a total depth of 6,784 feet in the Kibbey Formation. Drillstem test data and core collected from porous and permeable intervals of the Dakota, Minnelusa, and Kibbey saw

no evidence of hydrocarbons. Injectivity tests demonstrated the Minnelusa (Broom Creek Formation) and Kibbey were the most viable for receiving wastewater at the injection rates and volumes specified in NDDH Permit No. ND-UIC-101. The well was completed in the Minnelusa in July 1982, and additional perforations were added to the Kibbey Formation in 1983. The ANG #1 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure, and a seal pot system on the annulus to detect annulus leaks. The ANG #1 is also monitored with temperature logs or tracer surveys about once every 5 years.

The ANG #1 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and it was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-4).

The risk of leakage via the ANG #1 is unlikely and is mitigated through the wellbore leak detection plan described hereto. The simulation work (presented in Reference 1, Section 2.3.3) also illustrates that the CO_2 plume does not come into contact with the well and suggests there is little interaction between the CO_2 plume and the injected disposal water, even after 10 years post-injection. Because the CO_2 plume does not come into contact with the well, the anticipated magnitude of leakage from the ANG #1 in terms of volume of CO_2 or associated fluids over the life of the project is extremely low.

3.1.2 ANG #2 (NDDEQ Well No. 11309)

The American Natural Gas No. 2 Disposal Well (ANG #2) spudded in September 1983 (NDDEQ Well No. 11309), reaching a total depth of 6,911 feet in the Kibbey Formation. The well was completed in both the Minnelusa (Broom Creek Formation) and Kibbey sands (NDDH Permit No. ND-UIC-102). The ANG #2 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure in the tubing-casing annulus, and a seal pot system on the annulus to detect annulus leaks. The ANG #2 is also monitored with temperature logs or tracer surveys about once every 5 years.

The ANG #2 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and it was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-5).

The risk of leakage via the ANG #2 is unlikely and is mitigated through the wellbore leak detection plan described hereto. The simulation work presented in Reference 1, Section 2.3.3, also illustrates that the CO_2 plume does not come into contact with the well and suggests there is little interaction between the CO_2 plume and the injected disposal water, even after 10 years post-injection. Because the CO_2 plume does not come into contact with the well, the anticipated magnitude of leakage from the ANG #2 in terms of volume of CO_2 or associated fluids over the life of the project is extremely low.

3.2 Abandoned Oil and Gas Wells

The Herrmann 1 (NDIC File No. 4177) well spudded in November 1966. The well was drilled to a depth of 8,057 feet into the Frobisher interval (stratigraphically equivalent to the Mission Canyon Formation of the Madison Group) and was plugged and abandoned in December of the same year. A drillstem test was conducted in the Frobisher interval, but the well encountered no commercial accumulations of hydrocarbons.

The Herrmann 1 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project and is the only oil and gas well within 0.5 miles outside of the AOR. It was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-3).

The risk of leakage via the Herrmann 1 of any magnitude and at any time over the life of the project is extremely low, as the well 1) never comes into contact with the CO_2 plume, 2) experiences a pressure increase of less than 100 psi over the life of the project (Reference 1, Section 6.1.1, Figures 6-1 and 6-2), and 3) has multiple cement plugs to prevent vertical migration of pressure or fluids outside the storage reservoir (Reference 1, Section 4.2, Figure 4-6).

3.3 Surface Components

Surface equipment components present potential leakage pathways during the operational injection period for the Great Plains CO_2 Sequestration Project site. Surface equipment can be subject to deterioration due to normal aging throughout its functional life. Corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in these assets.

The DGC CCS system includes a 6.8-mile-long transmission pipeline (NDPSC Case No. PU-21-150), six flowlines, and six injection wellheads (Figure 1-4b). The transmission line consists of a 12-inch main line and six 6-inch lateral lines that branch off and connect with 4.5-inch flowlines near each well pad. The flowlines will be connected to metering stations and located contiguous with the well pads (Reference 1, Section 5, Figures 5-1 and 5-2). Flowmeters will be installed at each metering station. The chemical composition of the CO_2 stream that will flow through the surface equipment is given in Reference 1, Section 5.1.1, Table 5-2.

Surface components of the injection system, including the flowlines and wellheads, will be monitored using leak detection equipment. The wellsite flowlines will be monitored continuously via multiple pressure gauges and H_2S detection stations located between the transmission line and the individual wellheads. This leak detection equipment will be integrated with automated warning systems that notify the pipeline control center at DGC, giving the operator the ability to remotely close the valves in the event of an anomalous reading. Further details of the surface leak detection system are given in Reference 1, Section 5.3.

The risk of leakage via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.

- Implementing the highest standards on material selection and construction processes for the flowlines and wells.
- Applying best practices and a robust mechanical integrity program as well as operating procedures.
- Monitoring continuously via an automated system and integrated databases.

The risk of leakage through surface equipment (under normal operating conditions) is unlikely, and the magnitude will vary according to the failure observed. A potential leakage event from instrumentation or valves could represent a few pounds of CO_2 released during several hours, while a puncture in the flowline could represent several tons of CO_2 released underground until the operator ceases the CO_2 supply. Note that should a shutoff situation occur, the CO_2 stream can be looped back to the DGC capture facility, passed through the burners, and be vented to the atmosphere.

This risk of leakage through surface equipment reduces to almost zero during the post-injection site care period. At cessation of the injection period, the injection wells will be properly plugged and abandoned following NDIC protocols and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the Class I wastewater injection wells, ANG #1 and ANG #2, identified as potential leakage pathways at the wellhead valves or in the instrumentation as discussed in Section 3.1.

3.4 Faults, Fractures, Bedding Plane Partings, and Seismicity

No known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations have been identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration activities (Reference 1, Section 2.5).

3.4.1 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 (Reference 1 Section 2.5). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The two closest recorded seismic events to the Great Plains CO_2 Sequestration Project occurred 29.6 miles to the northwest and 36.8 miles southwest of the Coteau 1 injection wellsite, with estimated magnitudes of 1.9 and 3.2, respectively (Reference 1, Section 2.5).

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

The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the absence of known or suspected local or regional faults suggest the probability that seismicity would interfere with CO_2 containment is low. In the event a seismic event occurs (natural or induced) near the project site, the magnitude of any seismic event would be expected to be less than 3.2 based on the historical record and would expected to cause little to no damage to subsurface or downhole equipment. In addition, DGC will operate below the maximum allowable injection pressure (Reference 1, Section 11, Table 11-1) to maintain safe operations throughout the injection period.

Through the geologic site characterization and corrective action review processes, leakage resulting from natural or induced seismicity was shown to be very unlikely.

3.5 Class VI Injection Wells

3.5.1 Coteau 1 (NDIC File No. 38379)

The Coteau 1 well spudded in June 2021 as a stratigraphic test well to a depth of 6,483 feet into the Amsden Formation. This well was drilled to gather geologic data to support the development of a CO_2 SFP and to later be converted into a Class VI injection well for the Great Plains CO_2 Sequestration Project. The Coteau 1 will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues.

The risk of leakage via the Coteau 1 is mitigated through:

- Preventing corrosion of well materials, following the preemptive measures in Reference 1, Section 5.2.2.
- Monitoring operations with a surface leak detection plan, as described in Reference 1, Section 5.3.
- Monitoring the storage reservoir with a subsurface leak detection plan, as described in Reference 1, Section 5.4.
- Performing wellbore mechanical integrity testing, as described in Reference 1, Section 5.1.2, and summarized in Reference 1, Section 5.7, Table 5-7.

The risk of leakage via the Coteau 1 during injection is low. The magnitude of any leakage during injection may vary according to the failure observed and could potentially represent a few pounds of CO_2 to several metric tons per hour released until operations are shut in and emergency protocols activated, as described in Reference 1, Section 7.4. Once the injection period ceases, the Coteau 1 will be properly plugged and abandoned following NDIC protocols, thereby reducing the risk for leakage from the well to almost zero.

3.5.2 Coteau 2 Through Coteau 6 Planned CO_2 Injection Wells

The Coteau 2 (NDIC File No. 38916), Coteau 3 (NDIC File No. 38917), and Coteau 4 (NDIC File No. 38918) wells are planned to spud in the summer of 2022 as stratigraphic test wells for the Great Plains CO_2 Sequestration Project. The wells will be drilled to the Amsden Formation at planned depths of 6,345, 6,339, and 6,301 feet, respectively. Once the SFP is issued, all

stratigraphic test wells will be converted to Class VI injection wells. Like the Coteau 1, the wells will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues. The Coteau 5 and Coteau 6 wells are planned to spud in 2026 and are conditional upon additional injection volumes of CO_2 becoming available from the capture facility. The Coteau 5 and Coteau 6 wells will be monitored after the same manner as the Coteau 1 through Coteau 4 wells. Once the injection period ceases, the Coteau 2 through Coteau 6 wells will be properly plugged and abandoned following NDIC protocols.

The discussion for assessing the risk of leakage via the Coteau 2 through Coteau 6 is the same as presented in Section 3.5.1 of this MRV plan. Once the injection period ceases, the Coteau 2 through Coteau 6 will be properly plugged and abandoned following NDIC protocols, thereby reducing the risk for leakage from the wells to almost zero.

3.6 Confining Zone Limitations

3.6.1 Lateral Migration

For the Great Plains CO_2 Sequestration Project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure (Reference 1, Section 2.3.2). The Opeche Formation is a laterally extensive formation that is 5,763 feet below the surface and 143 feet thick at the Coteau 1 wellsite (Reference 1, Section 2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), as discussed in Reference 1, Section 3.4.

The risk of leakage via lateral migration is extremely unlikely, as demonstrated by the geologic characteristics of the storage reservoir (Reference 1, Section 2.3) and upper confining zone (Reference 1, Section 2.4.1) (e.g., mineralogy, permeability/sealing capacity, and lateral continuity) coupled with the modeling and simulation work (Reference 1, Section 3) that was performed for the Great Plains CO_2 Sequestration Project. In the event that the monitoring data or models and simulations predict any part of the CO_2 plume may migrate beyond the anticipated stabilized plume boundary over the project's life because of a previously unidentified permeability pathway in the storage reservoir, the storage facility area and AOR will be recalculated, and the MRV plan, including the testing and monitoring strategy, will be updated as necessary.

3.6.2 Seal Diffusivity

Several other formations provide additional confinement above the Opeche Formation (Reference 1, Section 2.4.2). Impermeable rocks above the primary seal, the Opeche Formation, include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations. Together with the Opeche, these formations are 1,106 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 2,657 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation.

Confining layers above the Inyan Kara include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (see Figure 1-3 for stratigraphic reference).

The risk of leakage via the Herrmann 1 of any magnitude and at any time over the life of the project is extremely low, as there is a total of 3,763 feet of overlying confining layers, which presents a very low risk to the Great Plains CO_2 Sequestration Project. The presence of multiple thick impermeable layers and laterally extensive formations drastically reduces potential leakage pathways through geologic formations.

3.6.3 Drilling Through the CO_2 Area

There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the AOR. Although there was a historical oil and gas production well test from the Madison Group just outside the AOR (i.e., Herrmann 1), there are no known commercial accumulations of hydrocarbons in the AOR (Reference 1, Section 2.6). With no known commercial ventures drilling near the Great Plains CO_2 Sequestration Project area, there is very little chance of drilling through the storage complex.

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a deviated or horizontal well could be used to produce the hydrocarbon while avoiding drilling through the CO_2 plume or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available, which will allow prospective operators to design an appropriate well control strategy via increased drilling mud weight. The maximum pressure increase in the center of the injection area is projected by computer modeling to be 400–450 psi, with lesser impacts extending radially (Reference 1, Section 3, Figure 3-20). Pressure increases will relax post-injection as the area returns to its pre-injection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the CO_2 should be designed to include an intermediate casing string made of CO_2-resistant material and placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place.

3.7 Monitoring, Response, and Reporting Plan for CO_2 Loss

DGC proposes a robust monitoring program for the SFP (Reference 1, Section 5). The program covers a corrosion and mechanical integrity protocol (Reference 1, Section 5.2), surveillance of injection performance (Reference 1, Sections 5.3 and 5.4), monitoring of near-surface conditions (Reference 1, Sections 5.5 and 5.6), and direct and indirect monitoring of the CO_2 plume (Reference 1, Section 5.7). To compliment the monitoring program, DGC proposes a detailed emergency remedial and response plan (Reference 1, Section 7) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting in the event of an unplanned loss of CO_2 from the Great Plains CO_2 Sequestration Project area.

3.8 Summary

In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the emergency and remedial response plan. Estimating volumetric

losses of CO_2 would require consideration of the leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based upon the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

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

Table 4-1. Summary of DGC's CCS Monitoring Strategy

Method (target area/structure)	Pre-injection (Baseline – 1 year)	Injection Period (12 years)	Post-injection (10 years)
CO_2 Stream Analysis (capture)	Start-up	Daily	NA[1]
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	Start-up	Real time	NA
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	Start-up	Real time	NA
H_2S Detection Stations (flowlines, wellheads, and well pads)	Start-up	Real time	NA
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	Start-up	Monthly in the first quarter, then quarterly in the next 2 years	NA
Platform Multifinger Imaging Tool (PMIT) or Ultrasonic Imaging Tool (USIT) (CO_2 injection wells)	NA	Starting in Year 2, a PMIT or USIT will be run during well workovers but not more frequently than once every 5 years	NA
SCADA[2] Automated Remote System (surface facilities)	Start-up	Real time	NA
Soil Gas Analysis (11 soil gas profile stations)	Three to four seasonal samples	Three to four seasonal samples each year	Three to four seasonal samples each year
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)	Provide historical water sampling results	NA	NA
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)	Baseline	NA	NA
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	Baseline	Three to four seasonal samples	Three to four seasonal samples
Cement Bond Logs (CO_2 injection wells)	After cementing	If needed	Prior to P&A[3]
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but not less than once every 5 years
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	Start-up	Real time	NA
Pulsed-Neutron Logs with Temperature and Bottomhole Pressure Readings (CO_2 injection wells)	Baseline	Quarterly using phased approach described in Reference 1, Section 5.1.2	NA
USIT Logs (CO_2 injection wells)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but not less than once every 5 years
Pressure Falloff Test (CO_2 injection wells)	Baseline	Every 5 years	NA
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	Baseline	Repeat survey 1 year after injection begins, then in Years 3, 5, and 10	Repeat survey 1 year after injection ceases, then in Years 3, 5, and 10
Vertical Seismic Profiles (VSP) (CO_2 plume)	Baseline	Repeat VSP 1 year after injection begins, then (if deemed beneficial) in Years 3, 5, and 10	NA

[1] Not applicable
[2] Supervisory control and data acquisition
[3] Plugging and abandonment

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

Monitoring Strategy (target area/structure) \ Potential Leakage Pathway	Wellbores*	Faults and Fractures	Flowline and Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis (capture)			X			
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	X		X			X
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	X		X	X		
H_2S Detection Stations (flowlines, wellheads, and well pads)	X		X	X		X
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	X		X	X		
PMIT or USIT (CO_2 injection wells)	X			X		
SCADA Automated Remote System (surface facilities)	X		X	X		
Soil Gas Analysis (11 soil gas profile stations)	X			X	X	X
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)				X	X	X
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)		X		X	X	X
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	X	X		X	X	X
Cement Bond Logs (CO_2 injection wells)	X			X		X
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	X			X		
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	X			X	X	
Pulsed-Neutron Logs with Temperature and Bottomhole Readings (CO_2 injection wells)	X			X	X	X
USIT Logs (CO_2 injection wells)	X			X		
Pressure Falloff Test (CO_2 injection wells)	X			X	X	
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	X	X		X	X	X
VSP (CO_2 plume)*	X	X		X	X	X

* Applies to all wellbores in project area if not otherwise specified under the monitoring strategy target area/structure column.

4.1 Leak Verification

DGC's strategy to detect and verify leakage pathways is summarized in Table 4-2.

As part of the surveillance protocol, DGC will use reservoir simulation modeling, based on history-matched data obtained from the monitoring program, to compare the initial numerical model with the real development of the plume and pressure front. The model will be continuously calibrated with the acquisition of real-time data. Every 5 years, a formal AOR will be submitted, and the monitoring plan will be revised, if needed.

The model history match allows the project operator and owner to identify conditions that differ from those proposed by the numerical model and deviations in the operating conditions from the originals. For example, the injection well will be monitored, and if the injection pressure, temperature, or rate measurements deviate significantly from the specified set points, then a data flag will be automatically triggered by the automated system and field personnel will investigate the excursion. These excursions will be reviewed to determine if CO_2 leakage is occurring. Excursions are not necessarily indicators of leaks; rather, they indicate that injection rates, temperatures, and pressures are not conforming to the expected pattern of the injection plan. In many cases, problems are straightforward and easy to fix (e.g., a meter needs to be recalibrated), and there is no indication that CO_2 leakage has occurred. In the case of issues that are not readily resolved, a more detailed investigation will be initiated. If further investigation indicates a leak has occurred, efforts will be made to quantify its magnitude.

The model history-matching in combination with the mechanical integrity data, geophysical surveys, and near-surface monitoring form a powerful tool to appropriately follow changes in CO_2 concentration at the surface. Many variations of CO_2 concentration detected on the surface are the result of natural processes or external events not related to the CO_2 storage complex.

Because a CO_2 surface leak is of lower temperature than ambient conditions, it will often lead to the formation of bright white clouds and ice that are easily visually observed. With this understanding, DGC will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the Great Plains CO_2 Sequestration Project.

Response plan actions and activities will depend upon the circumstances and severity of the event. DGC will address an event immediately and, if warranted, communicate the event to the UIC program director within 24 hours of discovery.

If an event triggers cessation of injection and remedial actions, DGC will demonstrate the efficacy of the response/remedial actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations will only resume upon receipt of written authorization of the UIC program director.

4.2 Quantification of Leakage

As discussed above, the potential pathways for leakage include failure or issue in surface equipment or subsurface equipment (wellbores), faults or induced fractures, and competency of the seal to contain the CO_2 in the storage reservoir.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods to quantify the volume of CO_2 will be determined on a case-by-case basis. Any volume of CO_2 detected as leaking to the surface will be quantified using acceptable emission factors, engineering estimates of leak amount based on subsurface measurements, numerical models, history-matching of the reservoir performance, detailed analysis of the collected monitoring parameters, and delineation of the affected area, among others. Leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in an electronic central database.

5.0 DETERMINATION OF BASELINES

DGC will establish pre-injection baselines by implementing a monitoring program prior to any CO_2 injection and during each of the four primary seasonal ranges. This baseline will be created by monitoring the targeted surface, near-surface, and deep subsurface. The baseline will contain information on the characteristics of a range of environmental media, such as surface water, soil gas in the vadose zone, shallow groundwater, and storage reservoir formation water.

These baselines provide a basis for determining if CO_2 leaks are occurring by providing a foundation against which characteristics of these same media during CO_2 injection can be compared and evaluated. For example, changes in concentrations or levels of certain parameters in these media during injection might suggest that they have been impacted by leaking CO_2.

Determinations of these baselines are a critical component of a Class VI SFP. A detailed description of these baselines for both the surface and subsurface for the Great Plains CO_2 Sequestration Project area is provided in Reference 1, Sections 5.3 through 5.7.

5.1 Surface and Near-Surface Baselines

A baseline surface and near-surface sampling program has been completed for the Great Plains CO_2 Sequestration Project. Baseline data gathering included measuring chemical concentrations of the soil gas (i.e., O_2, N_2, and CO_2) and groundwater (e.g., pH, total dissolved solids, alkalinity, major cations/anions and trace metals) as well as characterizing the naturally occurring stable and radiocarbon (^{14}C) isotopic signatures of the soil gas and groundwater for comparison with the isotopic signature of the CO_2 stream. The data were obtained from 11 soil gas-sampling locations and two existing groundwater wells from the northern and eastern portions of the AOR. Baseline water samples are also planned to be obtained from five new Fox Hills monitoring wells that will be drilled prior to the start of injection operations. One of the groundwater monitoring wells will be placed near the Herrmann 1 well and the others will be placed adjacent to the Coteau 1 through Coteau 4 injection wells (Reference 1, Section 5.6,

Figure 5-4). For additional information regarding surface and near-surface baselines, refer to Reference 1, Sections 5.5.1–5.5.2 and Section 5.6, paragraph 1.

5.2 Subsurface Baselines

Pre-operational baseline data will be collected in each of the six injection wells for the Great Plains CO_2 Sequestration Project, including ultrasonic imaging, pulsed-neutron, and temperature logs, bottomhole pressure surveys, tubing-casing annulus pressure tests, and pressure falloff tests (Reference 1, Section 5.7, Table 5-7). The data acquisition schedule for the pulsed-neutron and temperature logs with a pressure-recording device attached is presented in Reference 1, Section 5.1.2. The time-lapse saturation data will be used as an assurance-monitoring technique for CO_2 in the formation directly above the storage reservoir, otherwise known as the above-zone monitoring interval. The pressure and temperature data will be useful for informing the geologic model and simulations, monitoring conditions in the storage reservoir, and confirming wellbore mechanical integrity. The pressure testing in each of the wellbores will also help to confirm wellbore mechanical integrity.

Indirect monitoring methods will also track the extent of the CO_2 plume within the storage reservoir and can be accomplished by performing time-lapse geophysical surveys of the AOR. A 2D radial seismic survey was collected to establish baseline conditions in the storage reservoir. A baseline VSP was also collected to determine the feasibility of monitoring the CO_2 plume during the injection phase with this technology. For additional information regarding subsurface baselines, refer to Reference 1, Section 5.7.2.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The Great Plains CO_2 Sequestration Project area is a geologic CO_2 storage site in a saline aquifer with no production associated from the storage complex. A flowmeter will be placed downstream of the CO_2 compressor (start of the CO_2 transmission line) and near each of the injection wellheads (Figure 1-4b). The proposed main metering station for mass balance calculation is identified as the first metering station placed at the start of the CO_2 transmission main line. The use of a single metering station for the mass balance calculation (as opposed to using multiple metering stations near each wellhead) will help ensure accuracy of the measurements.

To calculate the annual mass of CO_2 that is stored in the storage complex, the project will use Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

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

Where:

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

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

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

Mass of CO_2 Injected (CO_{2I}):
DGC will use volumetric flow metering to measure the flow of the injected CO_2 stream and will calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5 from 40 CFR Part 98, Subpart RR (Equation 2):

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

Where:
$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by Flowmeter u.
$Q_{p,u}$ = Quarterly volumetric flow rate measurement for Flowmeter u in Quarter p at standard conditions (standard cubic meters per quarter).
D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.
$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flowmeter.

Mass of CO_2 Emitted by Surface Leakage (CO_{2E}):
DGC characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in Reference 1, Section 5, to detect any leak and defined a baseline for monitoring.

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

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

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

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

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

Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions
Annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead (CO_{2FI}) will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan proposed in Reference 1, Section 5.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented starting September 2022 or within 90 days of EPA approval, whichever occurs later. Other greenhouse gas reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time. It is anticipated that the MRV program will be in effect from September 2022 to September 2036, during which time the Great Plains CO_2 Sequestration Project will be operated.

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for DGC monitoring techniques and data management is provided in the quality assurance and surveillance plan found in Reference 1, Appendix C.

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

CO_2 received:

- The quarterly flow rate of CO_2 will be reported from continuous measurement at the main metering station (identified in Figure 1-4b). In addition, the quarterly flow rate of CO_2 will be continuously measured by receiving meters at each of the injection well pads.

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

Flowmeter provision:

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

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

- Operated in conformance with consensus-based standards organizations including, but not limited to, American Society for Testing and Materials (ASTM) International, the American National Standards Institute, the American Gas Association, the American

Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

9.0 RECORDS RETENTION

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

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

- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

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

10.0 REFERENCES

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GREAT PLAINS CO_2 SEQUESTRATION PROJECT MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Well

Reporting Number: 523812

TABLE OF CONTENTS

Continued . . .

TABLE OF CONTENTS (continued)

LIST OF FIGURES

LIST OF TABLES

STORAGE FACILITY PERMIT DESIGNATIONS

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

Reference 1: Great Plains CO_2 Sequestration Project, Mercer County, North Dakota

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

1.0 PROJECT DESCRIPTION

1.1 Project Characteristics

The Dakota Gasification Company's (DGC) Great Plains Synfuels Plant (GPSP), located 5 miles northwest of Beulah, North Dakota, is capable of gasifying 6 million tons of lignite coal per year (Figure 1-1). DGC, a wholly owned subsidiary of Basin Electric Power Cooperative (Basin), has owned and operated the facility since 1988. DGC has captured and transported more than 40 million tonnes (Mt) of carbon dioxide (CO_2) (>95% dry CO_2) from the gasification process for enhanced oil recovery purposes since 2000. The captured CO_2 is transported via a 205-mile pipeline that has successfully operated for the past 22 years. The CO_2 is first compressed to a pressure of ±2,500 pounds per square inch (psi), then transported north as a supercritical fluid. There currently exists excess compressor capacity, which makes the capture of an additional 1.0 Mt per year possible. DGC is currently constructing an additional 6.8 miles of pipeline to facilitate permanent sequestration of up to 2.7 Mt per year. The pipeline's design capacity is based on the total anticipated CO_2 output from the plant. Over the anticipated 12-year life of this project, sequestered volumes of CO_2 are expected to total 26 Mt. Four injection wells are anticipated initially (Coteau 1 through Coteau 4), with two additional wells planned (Coteau 5 and Coteau 6) as increased volumes in 2026 or beyond warrant (Figure 1-1). The injection wells will store the captured CO_2 stream in the porous and permeable Broom Creek Formation located below the GPSP.

DGC submitted its North Dakota CO_2 storage facility permit (SFP) to the North Dakota Industrial Commission (NDIC) on March 8, 2022, and an official hearing for DGC's Great Plains CO_2 Sequestration Project was held on July 20, 2022. North Dakota has the authority to regulate the geologic storage of CO_2 and primacy to administer the North Dakota Underground Injection Control (UIC) Class VI Program (83 Federal Register 17758, 40 Code of Federal Regulations [CFR] 147). If any material changes are made to the SFP after the hearing date that impact this MRV plan, DGC will notify EPA and submit an amended plan within 180 days.

No other geologic storage project exists or is planned within 18.2 miles of the Great Plains CO_2 Sequestration Project.

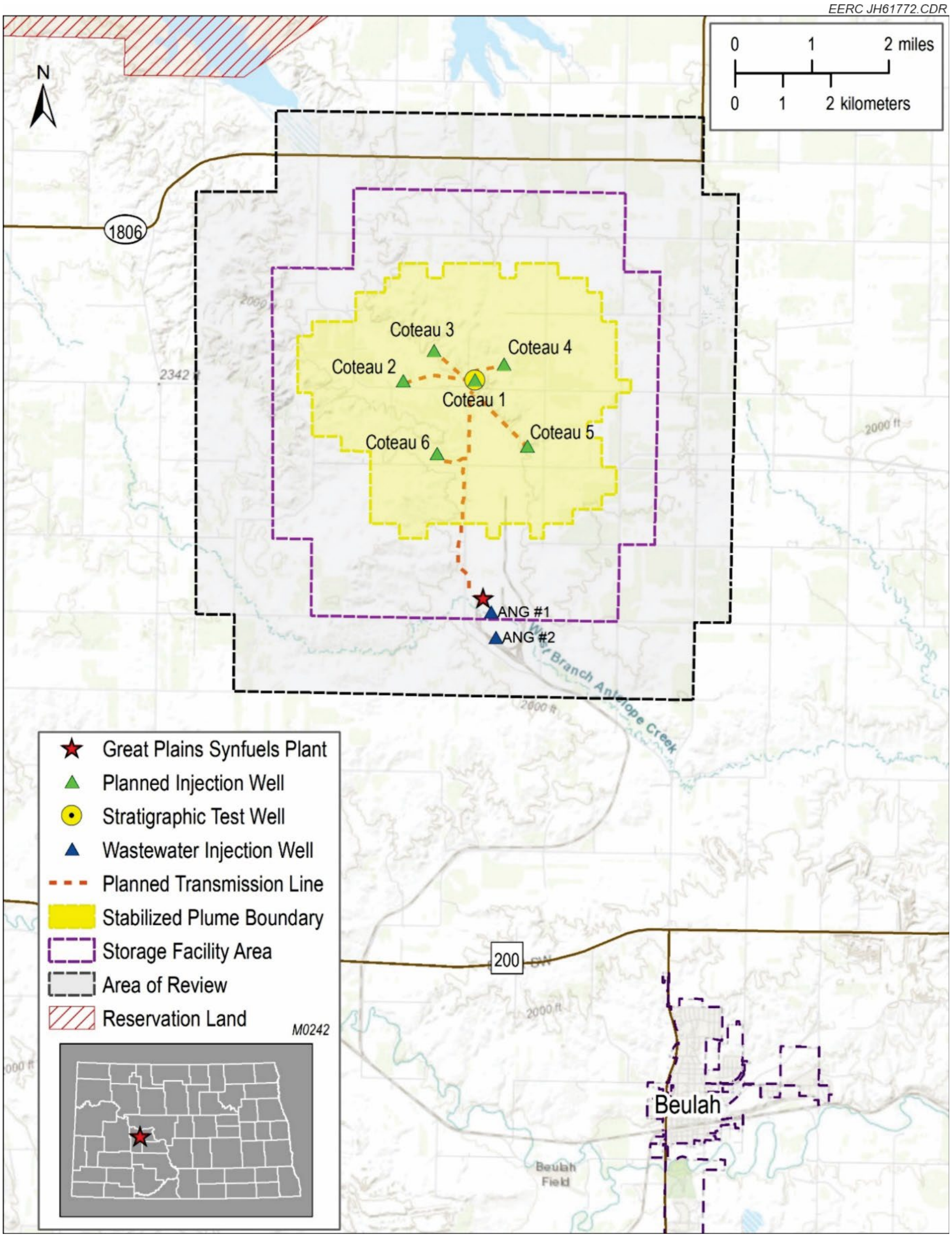

Figure 1-1. Location of the GPSP, Coteau 1 through Coteau 6 injection wells, and CO_2 transmission line. Also shown is the town of Beulah, with a population of about 3,200 people, the stabilized plume boundary, the storage facility area, and the area of review (AOR).

1.2 Environmental Setting

The Great Plains CO_2 Sequestration Project is located along the southern flank of the Williston Basin, a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Figure 1-2 shows the geographic distribution of oil fields in North Dakota, demonstrating there has been no exploration for or development of hydrocarbon resources within the AOR (Reference 1, Section 2.6). The Herrmann 1 (NDIC File No. 4177), a dry hole drilled in 1966 to the Frobisher interval (stratigraphically equivalent to the Mission Canyon Formation of the Madison Group), falls just outside the southwestern edge of the AOR. See Section 3.2 of this MRV plan for more information about the Herrmann 1 well.

A generalized stratigraphic column of the Williston Basin for the area of Beulah is provided in Figure 1-3. The target CO_2 storage reservoir for the Great Plains CO_2 Sequestration Project is the Broom Creek Formation, a predominantly sandstone interval lying about 5,900 feet below the GPSP (Reference 1, Section 2.3). Silty mudstones and interbedded evaporites of the Opeche Formation unconformably overlie the Broom Creek and serve as the primary confining zone (Reference 1, Section 2.4.1). Mixed layers of dolostone, mudstone, and anhydrite of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone (Reference 1, Section 2.4.3). From stratigraphic bottom to top, the Amsden, Broom Creek, and Opeche comprise the CO_2 storage complex. In addition to the Opeche Formation, there is about 1,100 feet of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation (Reference 1, Section 2.4.2). An additional 2,660 feet of impermeable rocks separate the Inyan Kara and the lowest underground source of drinking water (USDW): the Fox Hills Formation.

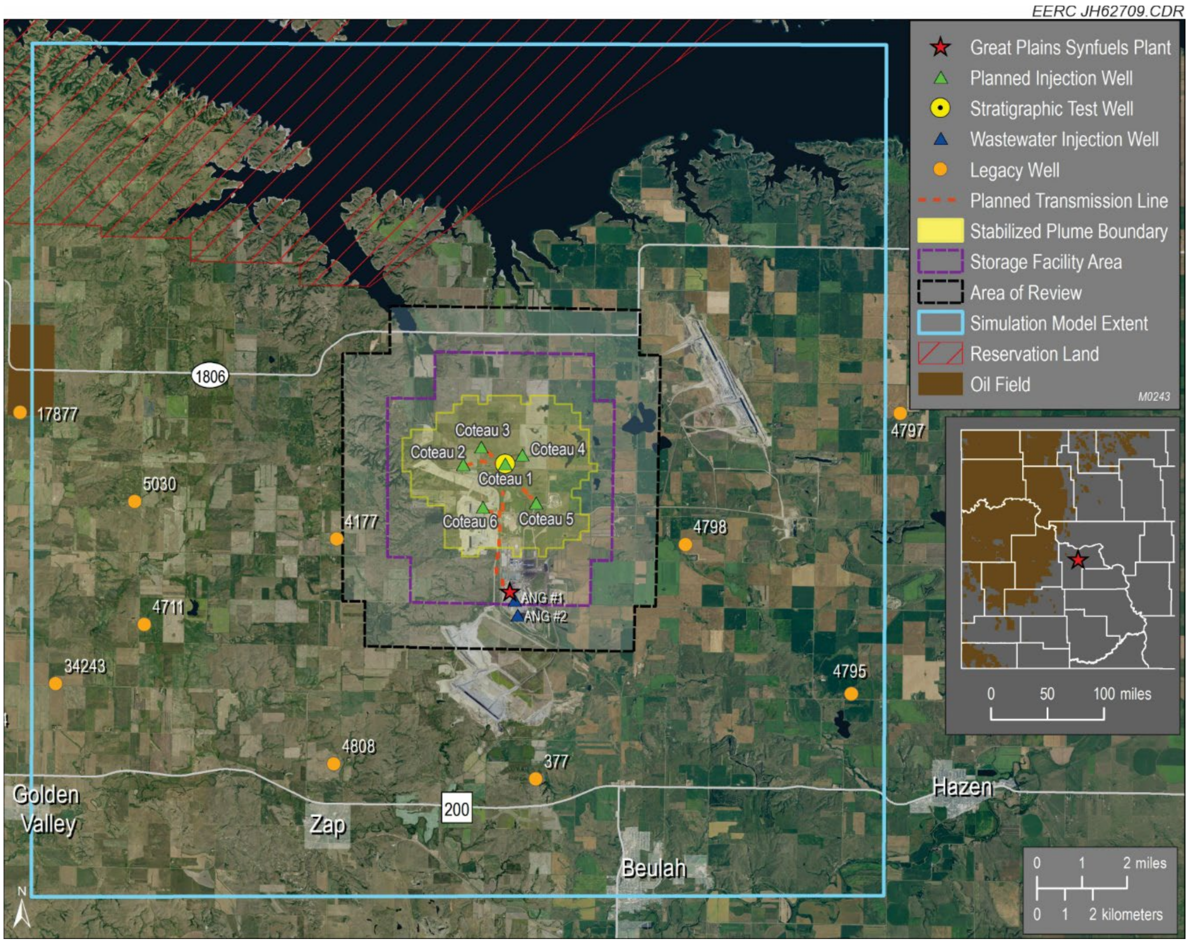

Figure 1-2. Map showing the simulation model extents of the Great Plains CO_2 Sequestration Project, legacy oil and gas wells, and geographic distribution of oil fields in North Dakota (i.e., western portion of the Williston Basin).

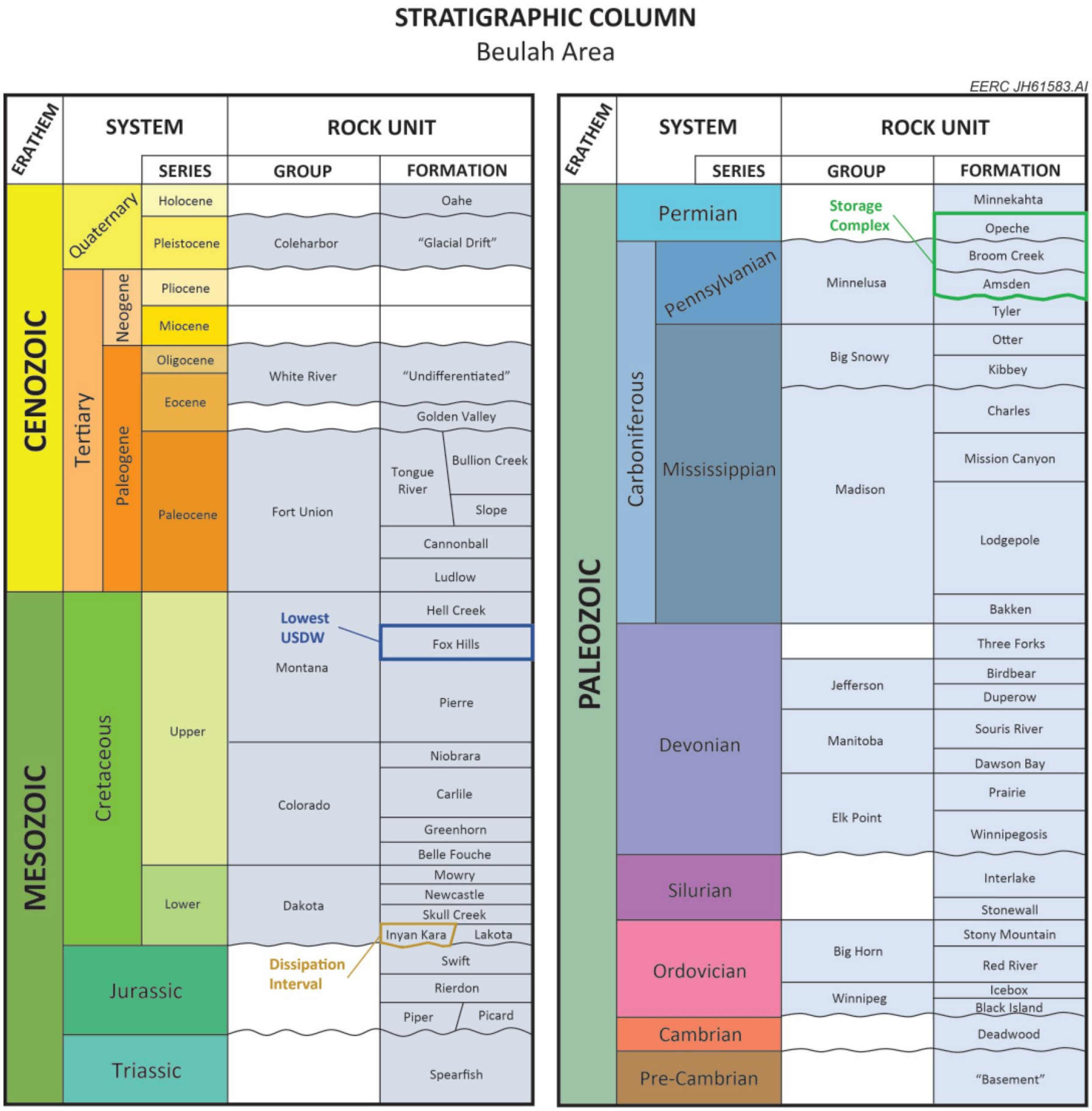

Figure 1-3. Generalized stratigraphic column of the Williston Basin for the Beulah area, identifying the storage complex (i.e., storage reservoir and primary confining zones) as well as the dissipation interval and lowest USDW underlying the Great Plains CO_2 Sequestration Project area. Figure modified after Murphy and others (2009) and Bluemle and others (1981).

1.3 Description of CO_2 Project Facilities and Injection Process

DGC plans to capture and store 1.0 to 2.7 Mt of CO_2 per year over the course of 12 years of injection, followed by at least 10 years of post-injection site care. Figure 1-4 shows integration

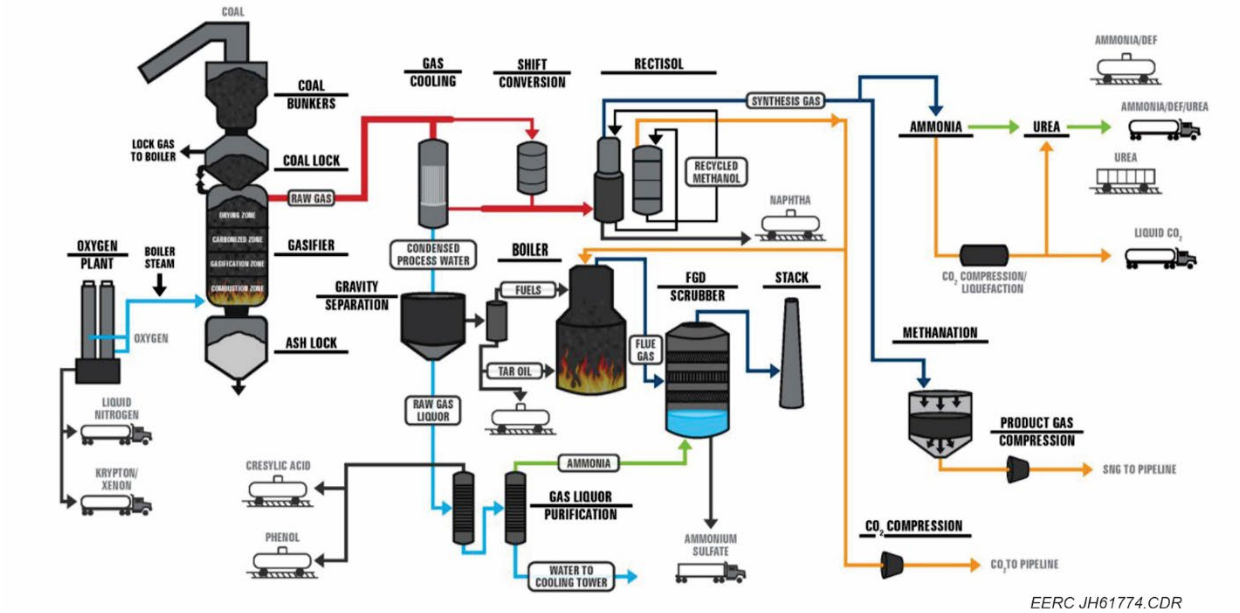

Figure 1-4a. Flow diagram of the CO_2 capture process at GPSP. The main metering station will be located downstream of the CO_2 compressors but upstream of the lateral for the Coteau 6 well, as shown in Figure 1-4b.

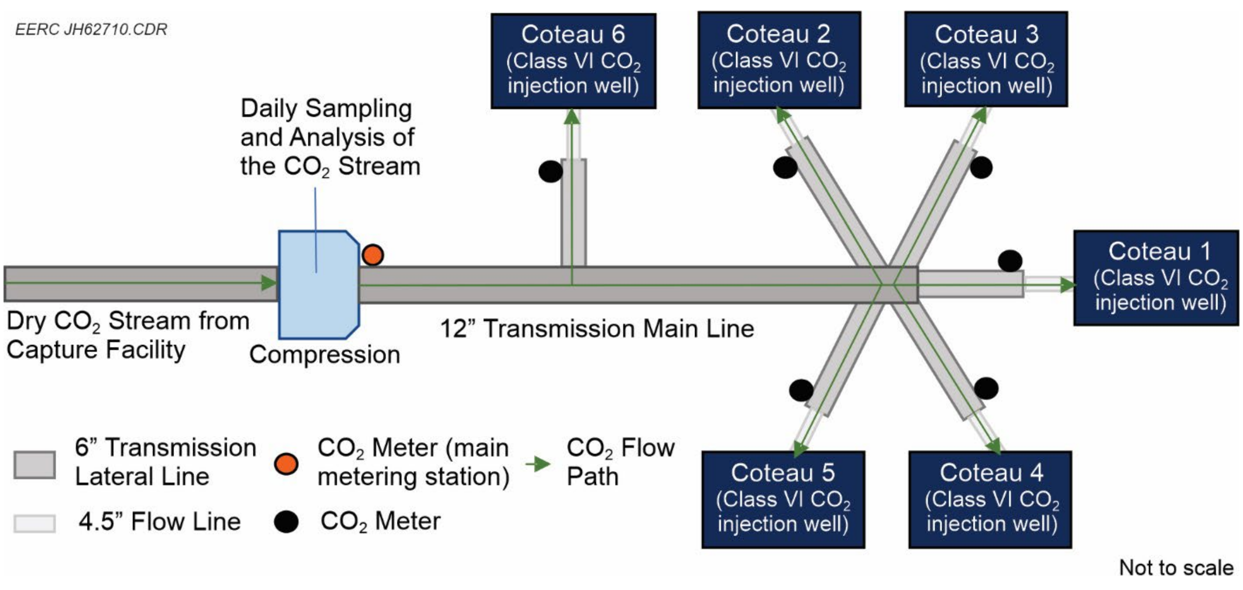

Figure 1-4b. Flow diagram illustrating major carbon capture and storage (CCS) components and the path of the CO_2 stream from the capture facility to the CO_2 injection wells.

of major CCS components with the capture facility at GPSP. The facility was designed to capture the CO_2 produced during the acid gas removal step of DGC's gasification process and compress the gaseous CO_2 stream to approximately 2,500 psi. The final compressed CO_2 stream would flow to the Coteau 1 through Coteau 6 injection wells for geologic storage into the Broom Creek Formation; an underground transmission pipeline permitted through the North Dakota Public Service Commission (NDPSC) Case No. PU-21-150 is installed on Basin, DGC, and Coteau Properties Company (CPC) property to connect the capture facility to the Coteau 1 through Coteau 6 injection wells. CPC, a wholly owned subsidiary of North American Coal Corporation, operates the Freedom Mine near the GPSP, supplying lignite coal feedstock to the plant.

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area: DGC AOR Delineation in Accordance with U.S. Environmental Protection Agency and North Dakota Rules

DGC proposes that because the AOR, as delineated in Reference 1, Section 4, exceeds the requirements of the active monitoring area (AMA) under Title 40, CFR § 98.449 (Subpart RR), the AOR will serve as the AMA for the Great Plains CO_2 Sequestration Project (Figure 2-1).

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). Therefore, DGC elected to permit the storage facility area boundaries based on the reservoir model output discussed in Reference 1, Section 4, and then, added a 1-mile buffer, rounding out to the nearest 40-acre tract.

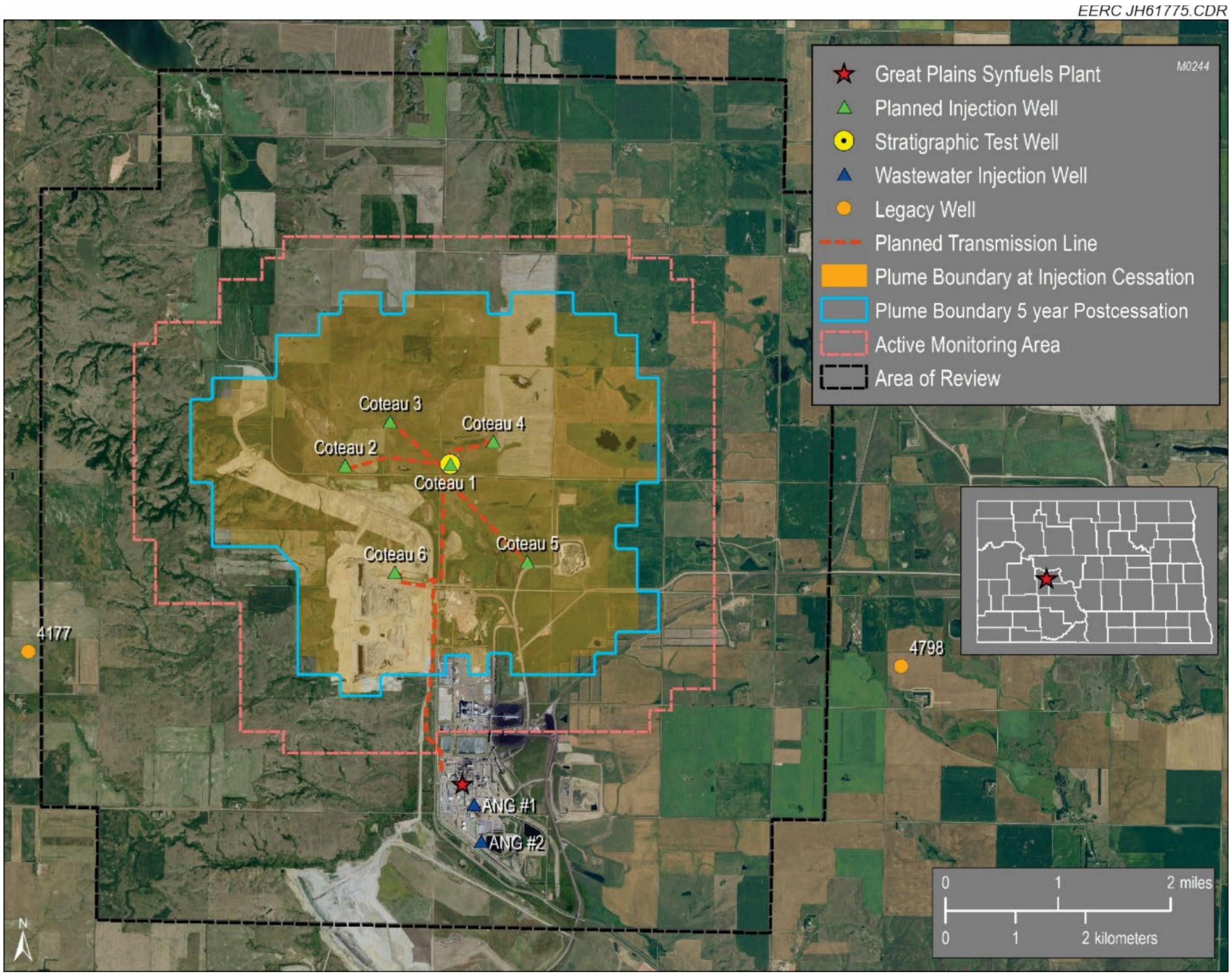

Figure 2-1. Map showing the AOR relative to the AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR), with "t" set equal to injection cessation (12 years). The AOR subsumes the AMA and exceeds requirements for the AMA; therefore, the AOR serves as the AMA for the Great Plains CO_2 Sequestration Project.

2.2 Maximum Monitoring Area

DGC proposes that the delineated AOR and proposed AMA from Figure 2-1 also serve as the maximum monitoring area (MMA) for the Great Plains CO_2 Sequestration Project (Figure 2-2), as it also exceeds the requirements for delineating the MMA under 40 CFR § 98.449 (Subpart RR).

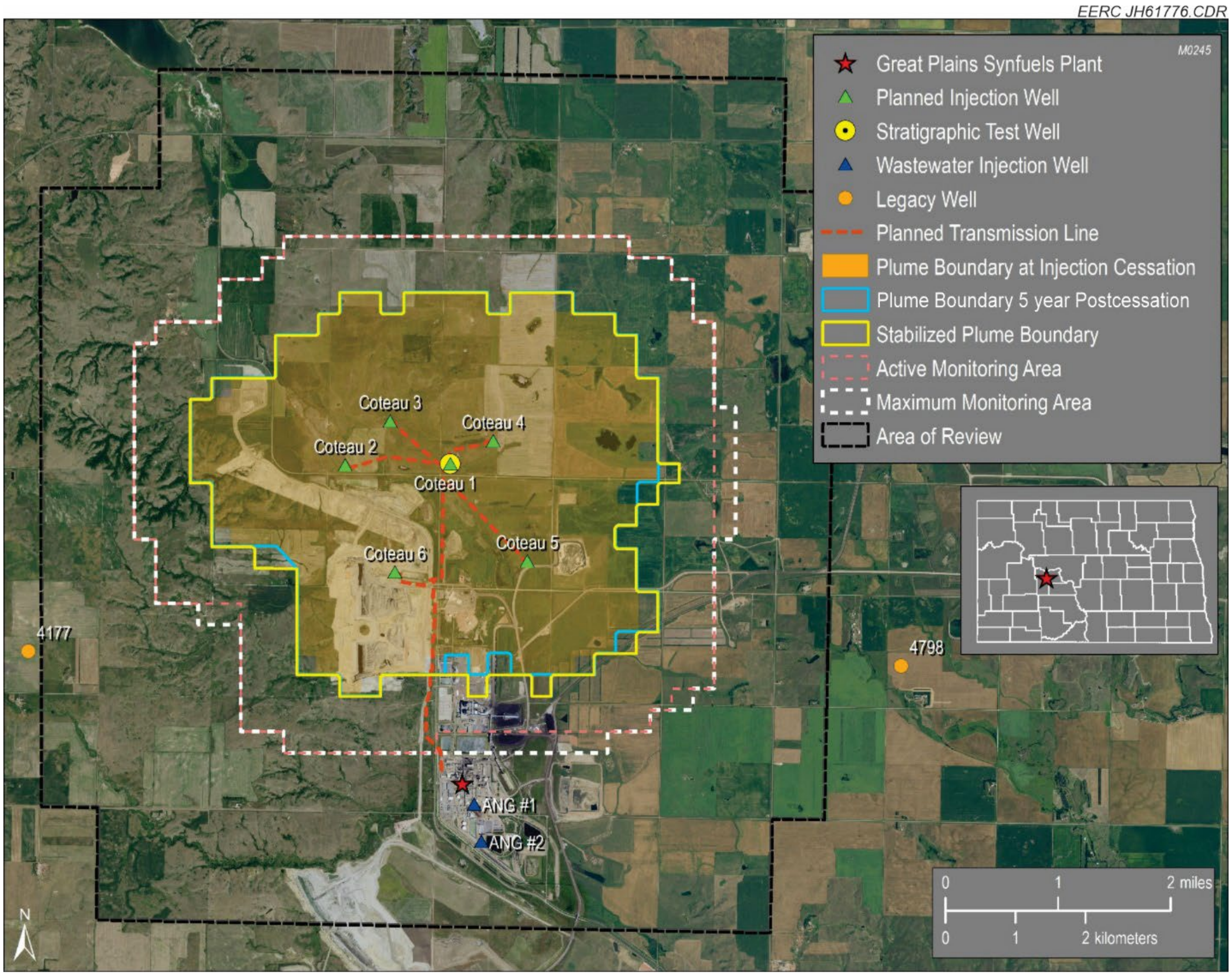

Figure 2-2. Map showing the AOR relative to the calculated MMA and AMA boundaries, calculated as prescribed under 40 CFR § 98.449 (Subpart RR). The AOR subsumes the calculated AMA and MMA and exceeds requirements for both AMA and MMA; therefore, the AOR serves as both the AMA and MMA for the Great Plains CO_2 Sequestration Project.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2 (Reference 1, Section 5) comprises three distinct periods: 1) pre-operational (pre-injection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) post-operational (post-injection of CO_2) monitoring. These monitoring periods, therefore, encompass the entire life cycle of the project. For purposes of this MRV plan, it is expected that reporting will be initiated during the operational period and continue through the post-injection period.

The storage system parameters that are monitored during each period are essentially identical; however, the duration of the monitoring period of the measurements performed varies. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

The pre-operational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and uncertainty associated with the measurement of each of the key storage system parameters. An understanding of the repeatability and variability of each measurement is key to successfully determining the movement of CO_2 that is contained in the formation at any given time.

The operational injection period is focused on validating and updating numerical models of the storage system to ensure that the geologic storage project is operating safely and protecting all USDWs. Lastly, the purpose of the post-operational monitoring is to verify the stability of the CO_2 plume location and assess the integrity of all decommissioned wells. The duration of these monitoring periods is a minimum of 12 and 10 years, respectively.

3.0 EVALUATION OF POTENTIAL LEAKAGE PATHWAYS

The potential leakage pathways for CO_2 arriving at the surface after injection or from surface equipment failures during operations were evaluated. Factors and equipment that could lead to leakage pathways were identified and placed into the following six categories:

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

This leakage assessment determined none of the pathways required corrective action and the probability of leakage is unlikely. However, a robust monitoring program, described in Reference 1, Section 5, and summarized in Table 5-1, was developed to form the basis of this MRV plan.

3.1 Class I Nonhazardous Disposal Wells

Two Class I disposal wells are active in the Great Plains CO_2 Sequestration Project area. Both wells were drilled in the 1980s to dispose of nonhazardous wastewater produced from GPSP operations in the Minnelusa Group (Broom Creek Formation) and Kibbey Formation under North Dakota Department of Health (NDDH) Permit Nos. ND-UIC-101 and ND-UIC-102. In 2018, both permits were renewed under NDDH Permit No. ND-UIC-101-1. In 2019, the North Dakota Department of Environmental Quality (NDDEQ) separated from the NDDH, and both Class I disposal wells were given well numbers by the NDDEQ.

3.1.1 ANG #1 (NDDEQ Well No. 11308)

The American Natural Gas No. 1 Disposal Well (ANG #1) spudded in April 1982 (NDDEQ Well No. 11308), reaching a total depth of 6,784 feet in the Kibbey Formation. Drillstem test data and core collected from porous and permeable intervals of the Dakota, Minnelusa, and Kibbey saw

no evidence of hydrocarbons. Injectivity tests demonstrated the Minnelusa (Broom Creek Formation) and Kibbey were the most viable for receiving wastewater at the injection rates and volumes specified in NDDH Permit No. ND-UIC-101. The well was completed in the Minnelusa in July 1982, and additional perforations were added to the Kibbey Formation in 1983. The ANG #1 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure, and a seal pot system on the annulus to detect annulus leaks. The ANG #1 is also monitored with temperature logs or tracer surveys about once every 5 years.

The ANG #1 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and it was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-4).

The risk of leakage via the ANG #1 is unlikely and is mitigated through the wellbore leak detection plan described hereto. The simulation work (presented in Reference 1, Section 2.3.3) also illustrates that the CO_2 plume does not come into contact with the well and suggests there is little interaction between the CO_2 plume and the injected disposal water, even after 10 years post-injection. Because the CO_2 plume does not come into contact with the well, the anticipated magnitude of leakage from the ANG #1 in terms of volume of CO_2 or associated fluids over the life of the project is extremely low.

3.1.2 ANG #2 (NDDEQ Well No. 11309)

The American Natural Gas No. 2 Disposal Well (ANG #2) spudded in September 1983 (NDDEQ Well No. 11309), reaching a total depth of 6,911 feet in the Kibbey Formation. The well was completed in both the Minnelusa (Broom Creek Formation) and Kibbey sands (NDDH Permit No. ND-UIC-102). The ANG #2 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure in the tubing-casing annulus, and a seal pot system on the annulus to detect annulus leaks. The ANG #2 is also monitored with temperature logs or tracer surveys about once every 5 years.

The ANG #2 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and it was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-5).

The risk of leakage via the ANG #2 is unlikely and is mitigated through the wellbore leak detection plan described hereto. The simulation work presented in Reference 1, Section 2.3.3, also illustrates that the CO_2 plume does not come into contact with the well and suggests there is little interaction between the CO_2 plume and the injected disposal water, even after 10 years post-injection. Because the CO_2 plume does not come into contact with the well, the anticipated magnitude of leakage from the ANG #2 in terms of volume of CO_2 or associated fluids over the life of the project is extremely low.

3.2 Abandoned Oil and Gas Wells

The Herrmann 1 (NDIC File No. 4177) well spudded in November 1966. The well was drilled to a depth of 8,057 feet into the Frobisher interval (stratigraphically equivalent to the Mission Canyon Formation of the Madison Group) and was plugged and abandoned in December of the same year. A drillstem test was conducted in the Frobisher interval, but the well encountered no commercial accumulations of hydrocarbons.

The Herrmann 1 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project and is the only oil and gas well within 0.5 miles outside of the AOR. It was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-3).

The risk of leakage via the Herrmann 1 of any magnitude and at any time over the life of the project is extremely low, as the well 1) never comes into contact with the CO_2 plume, 2) experiences a pressure increase of less than 100 psi over the life of the project (Reference 1, Section 6.1.1, Figures 6-1 and 6-2), and 3) has multiple cement plugs to prevent vertical migration of pressure or fluids outside the storage reservoir (Reference 1, Section 4.2, Figure 4-6).

3.3 Surface Components

Surface equipment components present potential leakage pathways during the operational injection period for the Great Plains CO_2 Sequestration Project site. Surface equipment can be subject to deterioration due to normal aging throughout its functional life. Corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in these assets.

The DGC CCS system includes a 6.8-mile-long transmission pipeline (NDPSC Case No. PU-21-150), six flowlines, and six injection wellheads (Figure 1-4b). The transmission line consists of a 12-inch main line and six 6-inch lateral lines that branch off and connect with 4.5-inch flowlines near each well pad. The flowlines will be connected to metering stations and located contiguous with the well pads (Reference 1, Section 5, Figures 5-1 and 5-2). Flowmeters will be installed at each metering station. The chemical composition of the CO_2 stream that will flow through the surface equipment is given in Reference 1, Section 5.1.1, Table 5-2.

Surface components of the injection system, including the flowlines and wellheads, will be monitored using leak detection equipment. The wellsite flowlines will be monitored continuously via multiple pressure gauges and H_2S detection stations located between the transmission line and the individual wellheads. This leak detection equipment will be integrated with automated warning systems that notify the pipeline control center at DGC, giving the operator the ability to remotely close the valves in the event of an anomalous reading. Further details of the surface leak detection system are given in Reference 1, Section 5.3.

The risk of leakage via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.

- Implementing the highest standards on material selection and construction processes for the flowlines and wells.
- Applying best practices and a robust mechanical integrity program as well as operating procedures.
- Monitoring continuously via an automated system and integrated databases.

The risk of leakage through surface equipment (under normal operating conditions) is unlikely, and the magnitude will vary according to the failure observed. A potential leakage event from instrumentation or valves could represent a few pounds of CO_2 released during several hours, while a puncture in the flowline could represent several tons of CO_2 released underground until the operator ceases the CO_2 supply. Note that should a shutoff situation occur, the CO_2 stream can be looped back to the DGC capture facility, passed through the burners, and be vented to the atmosphere.

This risk of leakage through surface equipment reduces to almost zero during the post-injection site care period. At cessation of the injection period, the injection wells will be properly plugged and abandoned following NDIC protocols and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the Class I wastewater injection wells, ANG #1 and ANG #2, identified as potential leakage pathways at the wellhead valves or in the instrumentation as discussed in Section 3.1.

3.4 Faults, Fractures, Bedding Plane Partings, and Seismicity

No known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations have been identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration activities (Reference 1, Section 2.5).

3.4.1 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 (Reference 1 Section 2.5). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The two closest recorded seismic events to the Great Plains CO_2 Sequestration Project occurred 29.6 miles to the northwest and 36.8 miles southwest of the Coteau 1 injection wellsite, with estimated magnitudes of 1.9 and 3.2, respectively (Reference 1, Section 2.5).

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

The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the absence of known or suspected local or regional faults suggest the probability that seismicity would interfere with CO_2 containment is low. In the event a seismic event occurs (natural or induced) near the project site, the magnitude of any seismic event would be expected to be less than 3.2 based on the historical record and would expected to cause little to no damage to subsurface or downhole equipment. In addition, DGC will operate below the maximum allowable injection pressure (Reference 1, Section 11, Table 11-1) to maintain safe operations throughout the injection period.

Through the geologic site characterization and corrective action review processes, leakage resulting from natural or induced seismicity was shown to be very unlikely.

3.5 Class VI Injection Wells

3.5.1 Coteau 1 (NDIC File No. 38379)

The Coteau 1 well spudded in June 2021 as a stratigraphic test well to a depth of 6,483 feet into the Amsden Formation. This well was drilled to gather geologic data to support the development of a CO_2 SFP and to later be converted into a Class VI injection well for the Great Plains CO_2 Sequestration Project. The Coteau 1 will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues.

The risk of leakage via the Coteau 1 is mitigated through:

- Preventing corrosion of well materials, following the preemptive measures in Reference 1, Section 5.2.2.
- Monitoring operations with a surface leak detection plan, as described in Reference 1, Section 5.3.
- Monitoring the storage reservoir with a subsurface leak detection plan, as described in Reference 1, Section 5.4.
- Performing wellbore mechanical integrity testing, as described in Reference 1, Section 5.1.2, and summarized in Reference 1, Section 5.7, Table 5-7.

The risk of leakage via the Coteau 1 during injection is low. The magnitude of any leakage during injection may vary according to the failure observed and could potentially represent a few pounds of CO_2 to several metric tons per hour released until operations are shut in and emergency protocols activated, as described in Reference 1, Section 7.4. Once the injection period ceases, the Coteau 1 will be properly plugged and abandoned following NDIC protocols, thereby reducing the risk for leakage from the well to almost zero.

3.5.2 Coteau 2 Through Coteau 6 Planned CO_2 Injection Wells

The Coteau 2 (NDIC File No. 38916), Coteau 3 (NDIC File No. 38917), and Coteau 4 (NDIC File No. 38918) wells are planned to spud in the summer of 2022 as stratigraphic test wells for the Great Plains CO_2 Sequestration Project. The wells will be drilled to the Amsden Formation at planned depths of 6,345, 6,339, and 6,301 feet, respectively. Once the SFP is issued, all

stratigraphic test wells will be converted to Class VI injection wells. Like the Coteau 1, the wells will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues. The Coteau 5 and Coteau 6 wells are planned to spud in 2026 and are conditional upon additional injection volumes of CO_2 becoming available from the capture facility. The Coteau 5 and Coteau 6 wells will be monitored after the same manner as the Coteau 1 through Coteau 4 wells. Once the injection period ceases, the Coteau 2 through Coteau 6 wells will be properly plugged and abandoned following NDIC protocols.

The discussion for assessing the risk of leakage via the Coteau 2 through Coteau 6 is the same as presented in Section 3.5.1 of this MRV plan. Once the injection period ceases, the Coteau 2 through Coteau 6 will be properly plugged and abandoned following NDIC protocols, thereby reducing the risk for leakage from the wells to almost zero.

3.6 Confining Zone Limitations

3.6.1 Lateral Migration

For the Great Plains CO_2 Sequestration Project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure (Reference 1, Section 2.3.2). The Opeche Formation is a laterally extensive formation that is 5,763 feet below the surface and 143 feet thick at the Coteau 1 wellsite (Reference 1, Section 2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), as discussed in Reference 1, Section 3.4.

The risk of leakage via lateral migration is extremely unlikely, as demonstrated by the geologic characteristics of the storage reservoir (Reference 1, Section 2.3) and upper confining zone (Reference 1, Section 2.4.1) (e.g., mineralogy, permeability/sealing capacity, and lateral continuity) coupled with the modeling and simulation work (Reference 1, Section 3) that was performed for the Great Plains CO_2 Sequestration Project. In the event that the monitoring data or models and simulations predict any part of the CO_2 plume may migrate beyond the anticipated stabilized plume boundary over the project's life because of a previously unidentified permeability pathway in the storage reservoir, the storage facility area and AOR will be recalculated, and the MRV plan, including the testing and monitoring strategy, will be updated as necessary.

3.6.2 Seal Diffusivity

Several other formations provide additional confinement above the Opeche Formation (Reference 1, Section 2.4.2). Impermeable rocks above the primary seal, the Opeche Formation, include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations. Together with the Opeche, these formations are 1,106 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 2,657 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation.

Confining layers above the Inyan Kara include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (see Figure 1-3 for stratigraphic reference).

The risk of leakage via the Herrmann 1 of any magnitude and at any time over the life of the project is extremely low, as there is a total of 3,763 feet of overlying confining layers, which presents a very low risk to the Great Plains CO_2 Sequestration Project. The presence of multiple thick impermeable layers and laterally extensive formations drastically reduces potential leakage pathways through geologic formations.

3.6.3 Drilling Through the CO_2 Area

There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the AOR. Although there was a historical oil and gas production well test from the Madison Group just outside the AOR (i.e., Herrmann 1), there are no known commercial accumulations of hydrocarbons in the AOR (Reference 1, Section 2.6). With no known commercial ventures drilling near the Great Plains CO_2 Sequestration Project area, there is very little chance of drilling through the storage complex.

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a deviated or horizontal well could be used to produce the hydrocarbon while avoiding drilling through the CO_2 plume or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available, which will allow prospective operators to design an appropriate well control strategy via increased drilling mud weight. The maximum pressure increase in the center of the injection area is projected by computer modeling to be 400–450 psi, with lesser impacts extending radially (Reference 1, Section 3, Figure 3-20). Pressure increases will relax post-injection as the area returns to its pre-injection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the CO_2 should be designed to include an intermediate casing string made of CO_2-resistant material and placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place.

3.7 Monitoring, Response, and Reporting Plan for CO_2 Loss

DGC proposes a robust monitoring program for the SFP (Reference 1, Section 5). The program covers a corrosion and mechanical integrity protocol (Reference 1, Section 5.2), surveillance of injection performance (Reference 1, Sections 5.3 and 5.4), monitoring of near-surface conditions (Reference 1, Sections 5.5 and 5.6), and direct and indirect monitoring of the CO_2 plume (Reference 1, Section 5.7). To compliment the monitoring program, DGC proposes a detailed emergency remedial and response plan (Reference 1, Section 7) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting in the event of an unplanned loss of CO_2 from the Great Plains CO_2 Sequestration Project area.

3.8 Summary

In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the emergency and remedial response plan. Estimating volumetric

losses of CO_2 would require consideration of the leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based upon the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

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

Table 4-1. Summary of DGC's CCS Monitoring Strategy

Method (target area/structure)	Pre-injection (Baseline – 1 year)	Injection Period (12 years)	Post-injection (10 years)
CO_2 Stream Analysis (capture)	Start-up	Daily	NA[1]
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	Start-up	Real time	NA
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	Start-up	Real time	NA
H_2S Detection Stations (flowlines, wellheads, and well pads)	Start-up	Real time	NA
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	Start-up	Monthly in the first quarter, then quarterly in the next 2 years	NA
Platform Multifinger Imaging Tool (PMIT) or Ultrasonic Imaging Tool (USIT) (CO_2 injection wells)	NA	Starting in Year 2, a PMIT or USIT will be run during well workovers but not more frequently than once every 5 years	NA
SCADA[2] Automated Remote System (surface facilities)	Start-up	Real time	NA
Soil Gas Analysis (11 soil gas profile stations)	Three to four seasonal samples	Three to four seasonal samples each year	Three to four seasonal samples each year
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)	Provide historical water sampling results	NA	NA
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)	Baseline	NA	NA
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	Baseline	Three to four seasonal samples	Three to four seasonal samples
Cement Bond Logs (CO_2 injection wells)	After cementing	If needed	Prior to P&A[3]
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	Baseline	Perform during workovers but not more than once every 5 years	Perform during workovers but not less than once every 5 years
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	Start-up	Real time	NA
Pulsed-Neutron Logs with Temperature and Bottomhole Pressure Readings (CO_2 injection wells)	Baseline	Quarterly using phased approach described in Reference 1, Section 5.1.2	NA
USIT Logs (CO_2 injection wells)	Baseline	Perform during workovers but not more than once every 5 years	Perform during workovers but not less than once every 5 years
Pressure Falloff Test (CO_2 injection wells)	Baseline	Every 5 years	NA
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	Baseline	Repeat survey 1 year after injection begins, then in Years 3, 5, and 10	Repeat survey 1 year after injection ceases, then in Years 3, 5, and 10
Vertical Seismic Profiles (VSP) (CO_2 plume)	Baseline	Repeat VSP 1 year after injection begins, then (if deemed beneficial) in Years 3, 5, and 10	NA

[1] Not applicable
[2] Supervisory control and data acquisition
[3] Plugging and abandonment

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

Monitoring Strategy (target area/structure) \ Potential Leakage Pathway	Wellbores*	Faults and Fractures	Flowline and Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis (capture)			X			
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	X		X			X
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	X		X	X		
H_2S Detection Stations (flowlines, wellheads, and well pads)	X		X	X		X
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	X		X	X		
PMIT or USIT (CO_2 injection wells)	X			X		
SCADA Automated Remote System (surface facilities)	X		X	X		
Soil Gas Analysis (11 soil gas profile stations)	X			X	X	X
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)				X	X	X
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)		X		X	X	X
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	X	X		X	X	X
Cement Bond Logs (CO_2 injection wells)	X			X		X
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	X			X		
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	X			X	X	
Pulsed-Neutron Logs with Temperature and Bottomhole Readings (CO_2 injection wells)	X			X	X	X
USIT Logs (CO_2 injection wells)	X			X		
Pressure Falloff Test (CO_2 injection wells)	X			X	X	
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	X	X		X	X	X
VSP (CO_2 plume)*	X	X		X	X	X

* Applies to all wellbores in project area if not otherwise specified under the monitoring strategy target area/structure column.

4.1 Leak Verification

DGC's strategy to detect and verify leakage pathways is summarized in Table 4-2.

As part of the surveillance protocol, DGC will use reservoir simulation modeling, based on history-matched data obtained from the monitoring program, to compare the initial numerical model with the real development of the plume and pressure front. The model will be continuously calibrated with the acquisition of real-time data. Every 5 years, a formal AOR will be submitted, and the monitoring plan will be revised, if needed.

The model history match allows the project operator and owner to identify conditions that differ from those proposed by the numerical model and deviations in the operating conditions from the originals. For example, the injection well will be monitored, and if the injection pressure, temperature, or rate measurements deviate significantly from the specified set points, then a data flag will be automatically triggered by the automated system and field personnel will investigate the excursion. These excursions will be reviewed to determine if CO_2 leakage is occurring. Excursions are not necessarily indicators of leaks; rather, they indicate that injection rates, temperatures, and pressures are not conforming to the expected pattern of the injection plan. In many cases, problems are straightforward and easy to fix (e.g., a meter needs to be recalibrated), and there is no indication that CO_2 leakage has occurred. In the case of issues that are not readily resolved, a more detailed investigation will be initiated. If further investigation indicates a leak has occurred, efforts will be made to quantify its magnitude.

The model history-matching in combination with the mechanical integrity data, geophysical surveys, and near-surface monitoring form a powerful tool to appropriately follow changes in CO_2 concentration at the surface. Many variations of CO_2 concentration detected on the surface are the result of natural processes or external events not related to the CO_2 storage complex.

Because a CO_2 surface leak is of lower temperature than ambient conditions, it will often lead to the formation of bright white clouds and ice that are easily visually observed. With this understanding, DGC will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the Great Plains CO_2 Sequestration Project.

Response plan actions and activities will depend upon the circumstances and severity of the event. DGC will address an event immediately and, if warranted, communicate the event to the UIC program director within 24 hours of discovery.

If an event triggers cessation of injection and remedial actions, DGC will demonstrate the efficacy of the response/remedial actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations will only resume upon receipt of written authorization of the UIC program director.

4.2 Quantification of Leakage

As discussed above, the potential pathways for leakage include failure or issue in surface equipment or subsurface equipment (wellbores), faults or induced fractures, and competency of the seal to contain the CO_2 in the storage reservoir.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods to quantify the volume of CO_2 will be determined on a case-by-case basis. Any volume of CO_2 detected as leaking to the surface will be quantified using acceptable emission factors, engineering estimates of leak amount based on subsurface measurements, numerical models, history-matching of the reservoir performance, detailed analysis of the collected monitoring parameters, and delineation of the affected area, among others. Leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in an electronic central database.

5.0 DETERMINATION OF BASELINES

DGC will establish pre-injection baselines by implementing a monitoring program prior to any CO_2 injection and during each of the four primary seasonal ranges. This baseline will be created by monitoring the targeted surface, near-surface, and deep subsurface. The baseline will contain information on the characteristics of a range of environmental media, such as surface water, soil gas in the vadose zone, shallow groundwater, and storage reservoir formation water.

These baselines provide a basis for determining if CO_2 leaks are occurring by providing a foundation against which characteristics of these same media during CO_2 injection can be compared and evaluated. For example, changes in concentrations or levels of certain parameters in these media during injection might suggest that they have been impacted by leaking CO_2.

Determinations of these baselines are a critical component of a Class VI SFP. A detailed description of these baselines for both the surface and subsurface for the Great Plains CO_2 Sequestration Project area is provided in Reference 1, Sections 5.3 through 5.7.

5.1 Surface and Near-Surface Baselines

A baseline surface and near-surface sampling program has been completed for the Great Plains CO_2 Sequestration Project. Baseline data gathering included measuring chemical concentrations of the soil gas (i.e., O_2, N_2, and CO_2) and groundwater (e.g., pH, total dissolved solids, alkalinity, major cations/anions and trace metals) as well as characterizing the naturally occurring stable and radiocarbon (^{14}C) isotopic signatures of the soil gas and groundwater for comparison with the isotopic signature of the CO_2 stream. The data were obtained from 11 soil gas-sampling locations and two existing groundwater wells from the northern and eastern portions of the AOR. Baseline water samples are also planned to be obtained from five new Fox Hills monitoring wells that will be drilled prior to the start of injection operations. One of the groundwater monitoring wells will be placed near the Herrmann 1 well and the others will be placed adjacent to the Coteau 1 through Coteau 4 injection wells (Reference 1, Section 5.6,

Figure 5-4). For additional information regarding surface and near-surface baselines, refer to Reference 1, Sections 5.5.1–5.5.2 and Section 5.6, paragraph 1.

5.2 Subsurface Baselines

Pre-operational baseline data will be collected in each of the six injection wells for the Great Plains CO_2 Sequestration Project, including ultrasonic imaging, pulsed-neutron, and temperature logs, bottomhole pressure surveys, tubing-casing annulus pressure tests, and pressure falloff tests (Reference 1, Section 5.7, Table 5-7). The data acquisition schedule for the pulsed-neutron and temperature logs with a pressure-recording device attached is presented in Reference 1, Section 5.1.2. The time-lapse saturation data will be used as an assurance-monitoring technique for CO_2 in the formation directly above the storage reservoir, otherwise known as the above-zone monitoring interval. The pressure and temperature data will be useful for informing the geologic model and simulations, monitoring conditions in the storage reservoir, and confirming wellbore mechanical integrity. The pressure testing in each of the wellbores will also help to confirm wellbore mechanical integrity.

Indirect monitoring methods will also track the extent of the CO_2 plume within the storage reservoir and can be accomplished by performing time-lapse geophysical surveys of the AOR. A 2D radial seismic survey was collected to establish baseline conditions in the storage reservoir. A baseline VSP was also collected to determine the feasibility of monitoring the CO_2 plume during the injection phase with this technology. For additional information regarding subsurface baselines, refer to Reference 1, Section 5.7.2.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The Great Plains CO_2 Sequestration Project area is a geologic CO_2 storage site in a saline aquifer with no production associated from the storage complex. A flowmeter will be placed downstream of the CO_2 compressor (start of the CO_2 transmission line) and near each of the injection wellheads (Figure 1-4b). The proposed main metering station for mass balance calculation is identified as the first metering station placed at the start of the CO_2 transmission main line. The use of a single metering station for the mass balance calculation (as opposed to using multiple metering stations near each wellhead) will help ensure accuracy of the measurements.

To calculate the annual mass of CO_2 that is stored in the storage complex, the project will use Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

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

Where:

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

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

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

Mass of CO_2 Injected (CO_{2I}):
DGC will use volumetric flow metering to measure the flow of the injected CO_2 stream and will calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5 from 40 CFR Part 98, Subpart RR (Equation 2):

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

Where:
$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by Flowmeter u.
$Q_{p,u}$ = Quarterly volumetric flow rate measurement for Flowmeter u in Quarter p at standard conditions (standard cubic meters per quarter).
D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.
$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flowmeter.

Mass of CO_2 Emitted by Surface Leakage (CO_{2E}):
DGC characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in Reference 1, Section 5, to detect any leak and defined a baseline for monitoring.

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

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

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

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

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

<u>Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions</u>
Annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead (CO_{2FI}) will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan proposed in Reference 1, Section 5.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented starting September 2022 or within 90 days of EPA approval, whichever occurs later. Other greenhouse gas reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time. It is anticipated that the MRV program will be in effect from September 2022 to September 2036, during which time the Great Plains CO_2 Sequestration Project will be operated.

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for DGC monitoring techniques and data management is provided in the quality assurance and surveillance plan found in Reference 1, Appendix C.

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

<u>CO_2 received</u>:

- The quarterly flow rate of CO_2 will be reported from continuous measurement at the main metering station (identified in Figure 1-4b). In addition, the quarterly flow rate of CO_2 will be continuously measured by receiving meters at each of the injection well pads.

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

<u>Flowmeter provision</u>:

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

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

- Operated in conformance with consensus-based standards organizations including, but not limited to, American Society for Testing and Materials (ASTM) International, the American National Standards Institute, the American Gas Association, the American

Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

9.0 RECORDS RETENTION

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

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

- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

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

10.0 REFERENCES

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

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

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

6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

This postinjection site care (PISC) and facility closure plan describes the activities that DGC will perform following the cessation of CO_2 injection to achieve final closure of the site. A primary component of this plan is a postinjection monitoring program that will provide evidence that the injected CO_2 plume is stable (i.e., CO_2 migration will be unlikely to move beyond the boundary of the storage facility area). Based on simulations of the predicted CO_2 plume movement following the cessation of CO_2 injection, it is projected that the CO_2 plume will stabilize within the storage facility area boundary (Section 3). Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current predictions of the CO_2 plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO_2 plume. The nature and duration of that extension will be determined based on an update of this plan and NDIC approval.

In addition to DGC executing the postinjection monitoring program, the Class VI injection wells will be plugged as described in the plugging plan of this permit application (Section 10), all surface equipment not associated with long-term monitoring will be removed, and the surface land of the site will be reclaimed to as close as is practical to its original condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site and submitted as part of a site closure report.

6.1 Predicted Postinjection Subsurface Conditions

6.1.1 Pre- and Postinjection Pressure Differential

Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of CO_2 injection. The simulations were conducted for 12 years of CO_2 injection at rates between 1.0 and 2.7 million metric tons per year, followed by a postinjection period of 10 years. Figure 6-1 illustrates the predicted pressure differential at the conclusion of 12 years of CO_2 injection. At the time that CO_2 injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of 400 to 450 psi at the location of the injection wells. There is insufficient pressure increase caused by CO_2 injection to move more than 1 cubic meter of formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the area of review (AOR) delineation of this permit application (Section 3). An illustration of the predicted decrease in this pressure profile over the 10-year postinjection period is provided in Figure 6-2. The pressure in the reservoir gradually decreases over time following the cessation of CO_2 injection, with the pressure at the injection well after 10 years of postinjection predicted to decrease 300 to 350 psi as compared to the pressure at the time CO_2 injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions.

GREAT PLAINS CO_2 SEQUESTRATION PROJECT MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Well

Reporting Number: 523812

TABLE OF CONTENTS

Continued . . .

TABLE OF CONTENTS (continued)

LIST OF FIGURES

LIST OF TABLES

STORAGE FACILITY PERMIT DESIGNATIONS

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

Reference 1: Great Plains CO_2 Sequestration Project, Mercer County, North Dakota

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

1.0 PROJECT DESCRIPTION

1.1 Project Characteristics

The Dakota Gasification Company's (DGC) Great Plains Synfuels Plant (GPSP), located 5 miles northwest of Beulah, North Dakota, is capable of gasifying 6 million tons of lignite coal per year (Figure 1-1). DGC, a wholly owned subsidiary of Basin Electric Power Cooperative (Basin), has owned and operated the facility since 1988. DGC has captured and transported more than 40 million tonnes (Mt) of carbon dioxide (CO_2) (>95% dry CO_2) from the gasification process for enhanced oil recovery purposes since 2000. The captured CO_2 is transported via a 205-mile pipeline that has successfully operated for the past 22 years. The CO_2 is first compressed to a pressure of ±2,500 pounds per square inch (psi), then transported north as a supercritical fluid. There currently exists excess compressor capacity, which makes the capture of an additional 1.0 Mt per year possible. DGC is currently constructing an additional 6.8 miles of pipeline to facilitate permanent sequestration of up to 2.7 Mt per year. The pipeline's design capacity is based on the total anticipated CO_2 output from the plant. Over the anticipated 12-year life of this project, sequestered volumes of CO_2 are expected to total 26 Mt. Four injection wells are anticipated initially (Coteau 1 through Coteau 4), with two additional wells planned (Coteau 5 and Coteau 6) as increased volumes in 2026 or beyond warrant (Figure 1-1). The injection wells will store the captured CO_2 stream in the porous and permeable Broom Creek Formation located below the GPSP.

DGC submitted its North Dakota CO_2 storage facility permit (SFP) to the North Dakota Industrial Commission (NDIC) on March 8, 2022. North Dakota has the authority to regulate the geologic storage of CO_2 and primacy to administer the North Dakota Underground Injection Control (UIC) Class VI Program (83 Federal Register 17758, 40 Code of Federal Regulations [CFR] 147). An official hearing date for DGC's Great Plains CO_2 Sequestration Project is expected July 2022. If any material changes are made to the SFP after the hearing date that impact this MRV plan, DGC will notify EPA and submit an amended plan within 180 days.

No other geologic storage project exists or is planned within 18.2 miles of the Great Plains CO_2 Sequestration Project.

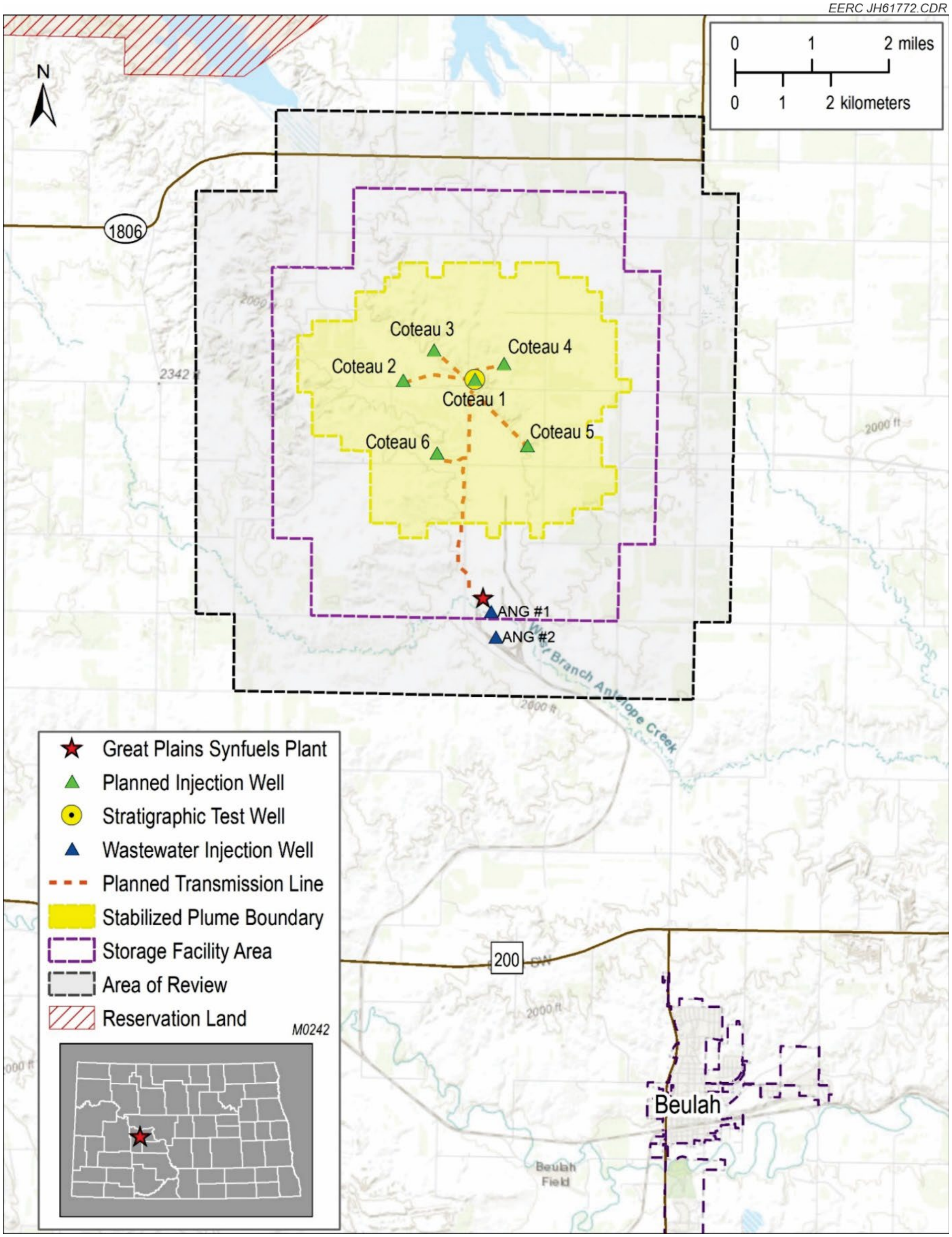

Figure 1-1. Location of the GPSP, Coteau 1 through Coteau 6 injection wells, and CO_2 transmission line. Also shown is the town of Beulah, with a population of about 3,200 people, the stabilized plume boundary, the storage facility area, and the area of review (AOR).

1.2 Environmental Setting

The Great Plains CO_2 Sequestration Project is located along the southern flank of the Williston Basin, a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Figure 1-2 shows the geographic distribution of oil fields in North Dakota, demonstrating there has been no exploration for or development of hydrocarbon resources within the AOR (Reference 1, Section 2.6). The Herrmann 1 (NDIC File No. 4177), a dry hole drilled in 1966 to the Frobisher interval (stratigraphically equivalent to the Mission Canyon Formation of the Madison Group), falls just outside the southwestern edge of the AOR. See Section 3.2 of this MRV plan for more information about the Herrmann 1 well.

A generalized stratigraphic column of the Williston Basin for the area of Beulah is provided in Figure 1-3. The target CO_2 storage reservoir for the Great Plains CO_2 Sequestration Project is the Broom Creek Formation, a predominantly sandstone interval lying about 5,900 feet below the GPSP (Reference 1, Section 2.3). Silty mudstones and interbedded evaporites of the Opeche Formation unconformably overlie the Broom Creek and serve as the primary confining zone (Reference 1, Section 2.4.1). Mixed layers of dolostone, mudstone, and anhydrite of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone (Reference 1, Section 2.4.3). From stratigraphic bottom to top, the Amsden, Broom Creek, and Opeche comprise the CO_2 storage complex. In addition to the Opeche Formation, there is about 1,100 feet of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation (Reference 1, Section 2.4.2). An additional 2,660 feet of impermeable rocks separate the Inyan Kara and the lowest underground source of drinking water (USDW): the Fox Hills Formation.

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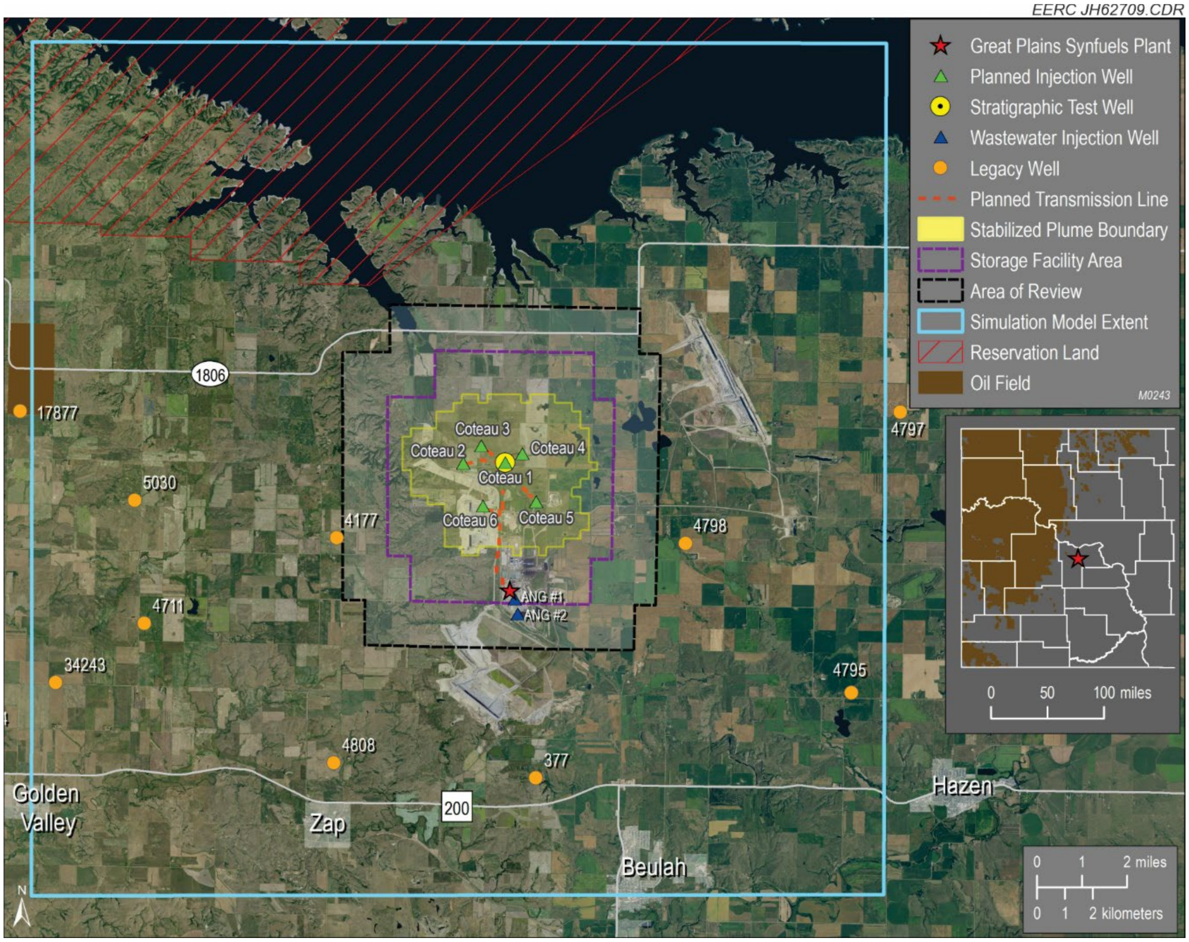

Figure 1-2. Map showing the simulation model extents of the Great Plains CO_2 Sequestration Project, legacy oil and gas wells, and geographic distribution of oil fields in North Dakota (i.e., western portion of the Williston Basin).

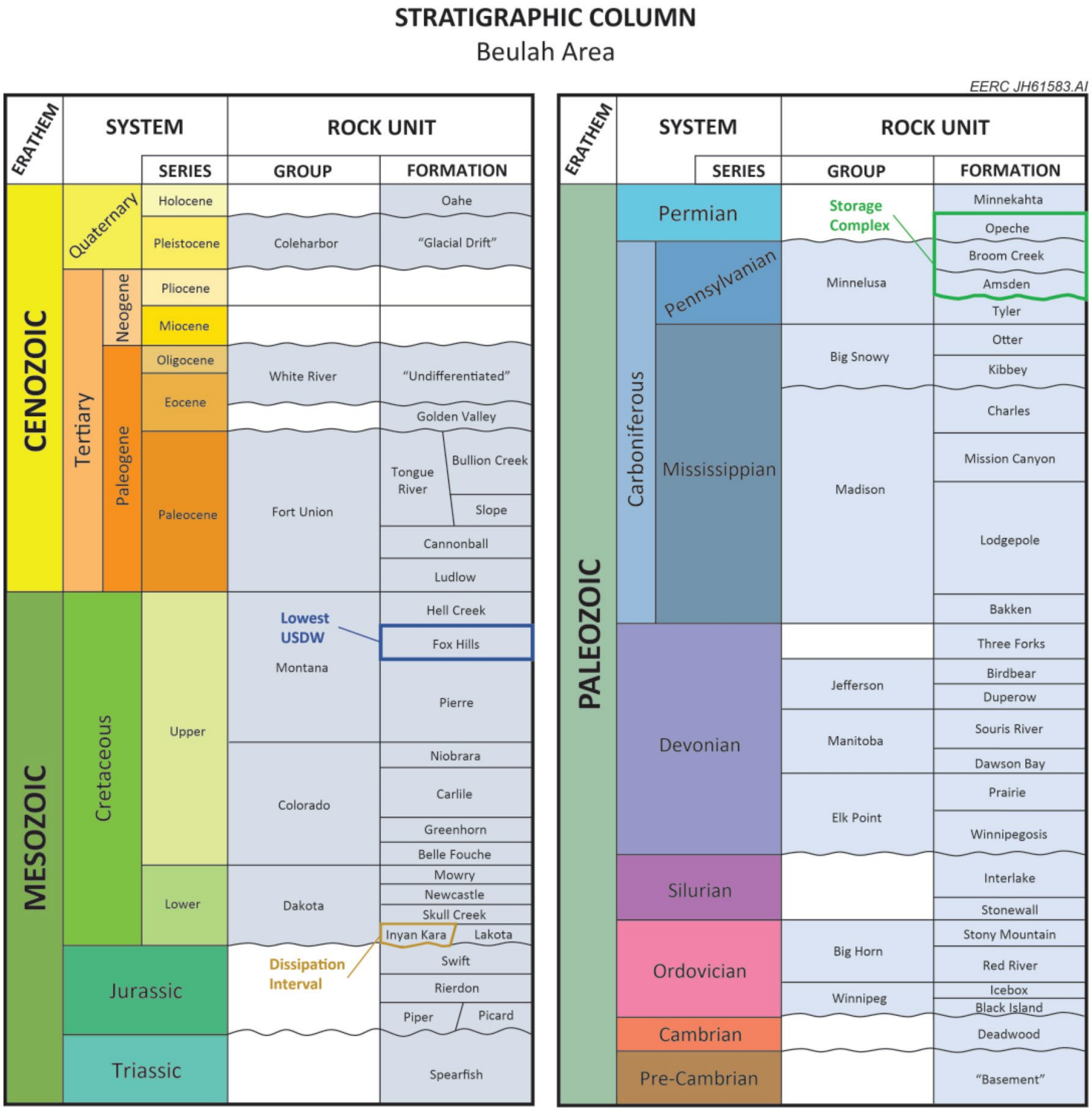

Figure 1-3. Generalized stratigraphic column of the Williston Basin for the Beulah area, identifying the storage complex (i.e., storage reservoir and primary confining zones) as well as the dissipation interval and lowest USDW underlying the Great Plains CO_2 Sequestration Project area. Figure modified after Murphy and others (2009) and Bluemle and others (1981).

1.3 Description of CO_2 Project Facilities and Injection Process

DGC plans to capture and store 1.0 to 2.7 Mt of CO_2 per year over the course of 12 years of injection, followed by at least 10 years of post-injection site care. Figure 1-4 shows integration

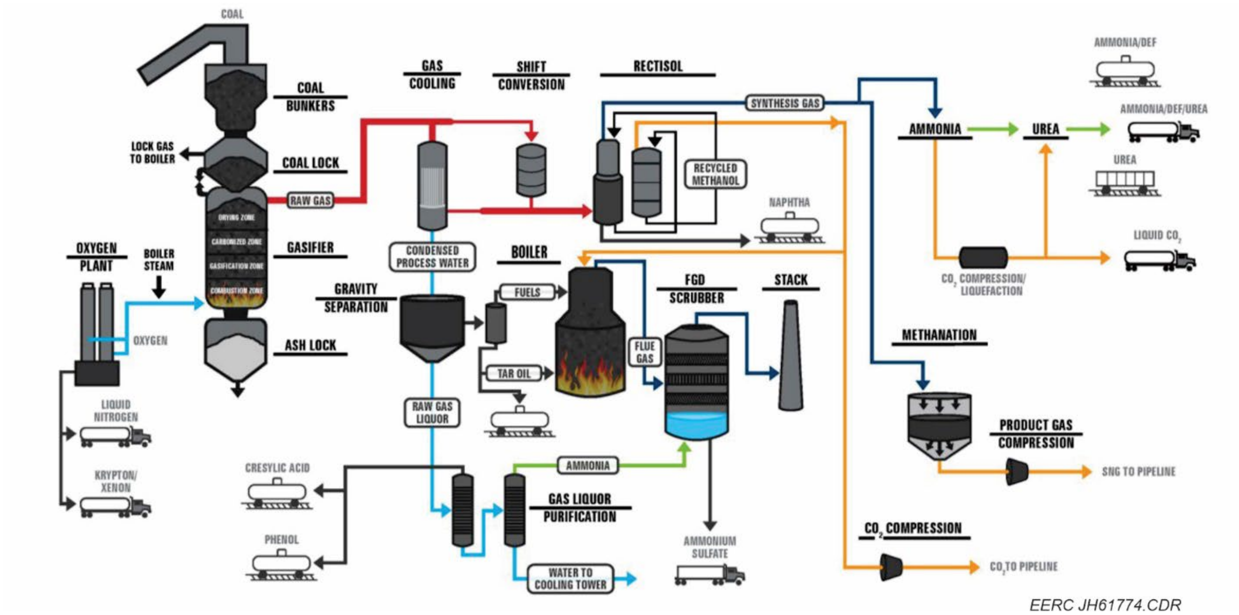

Figure 1-4a. Flow diagram of the CO_2 capture process at GPSP. The main metering station will be located downstream of the CO_2 compressors but upstream of the lateral for the Coteau 6 well, as shown in Figure 1-4b.

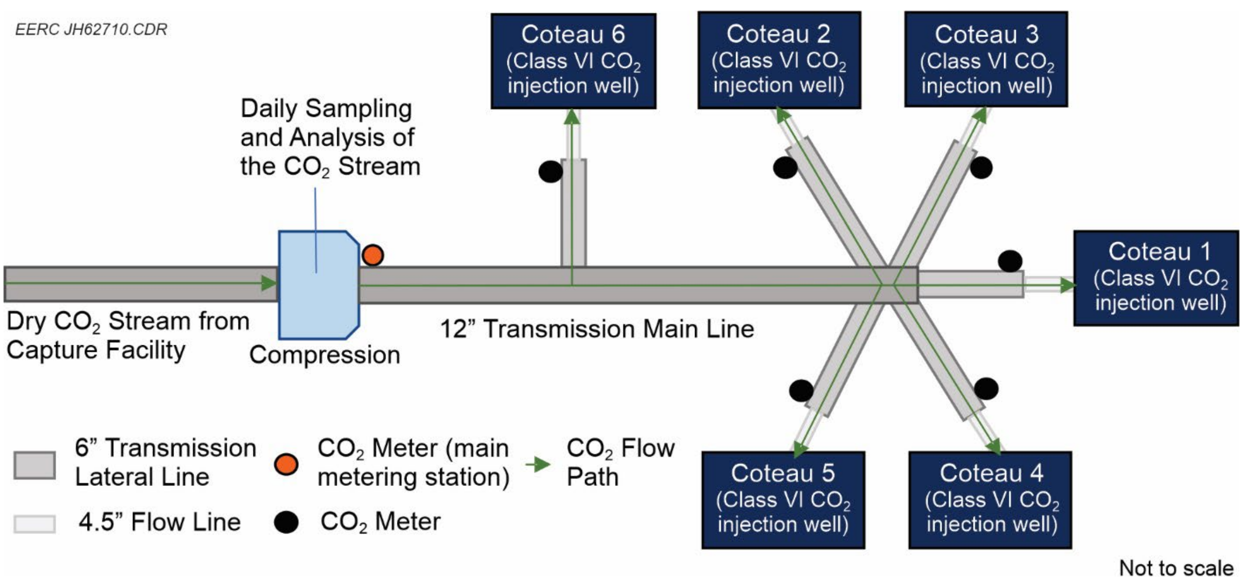

Figure 1-4b. Flow diagram illustrating major carbon capture and storage (CCS) components and the path of the CO_2 stream from the capture facility to the CO_2 injection wells.

of major CCS components with the capture facility at GPSP. The facility was designed to capture the CO_2 produced during the acid gas removal step of DGC's gasification process and compress the gaseous CO_2 stream to approximately 2,500 psi. The final compressed CO_2 stream would flow to the Coteau 1 through Coteau 6 injection wells for geologic storage into the Broom Creek Formation; an underground transmission pipeline permitted through the North Dakota Public Service Commission (NDPSC) Case No. PU-21-150 is installed on Basin, DGC, and Coteau Properties Company (CPC) property to connect the capture facility to the Coteau 1 through Coteau 6 injection wells. CPC, a wholly owned subsidiary of North American Coal Corporation, operates the Freedom Mine near the GPSP, supplying lignite coal feedstock to the plant.

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area: DGC AOR Delineation in Accordance with U.S. Environmental Protection Agency and North Dakota Rules

DGC proposes that because the AOR, as delineated in Reference 1, Section 4, exceeds the requirements of the active monitoring area (AMA) under Title 40, CFR § 98.449 (Subpart RR), the AOR will serve as the AMA for the Great Plains CO_2 Sequestration Project (Figure 2-1).

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). Therefore, DGC elected to permit the storage facility area boundaries based on the reservoir model output discussed in Reference 1, Section 4, and then, added a 1-mile buffer, rounding out to the nearest 40-acre tract.

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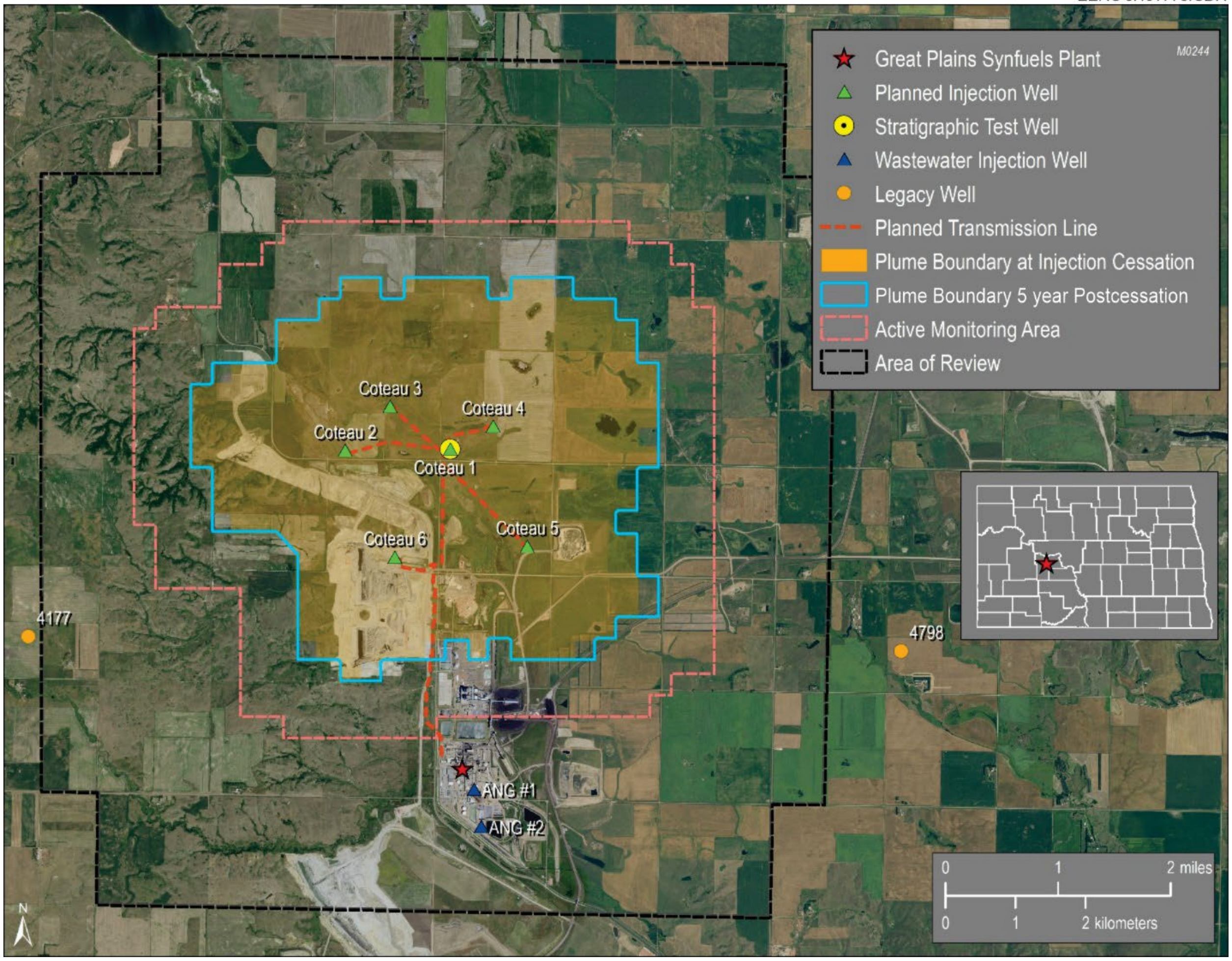

Figure 2-1. Map showing the AOR relative to the AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR), with "t" set equal to injection cessation (12 years). The AOR subsumes the AMA and exceeds requirements for the AMA; therefore, the AOR serves as the AMA for the Great Plains CO_2 Sequestration Project.

2.2 Maximum Monitoring Area

DGC proposes that the delineated AOR and proposed AMA from Figure 2-1 also serve as the maximum monitoring area (MMA) for the Great Plains CO_2 Sequestration Project (Figure 2-2), as it also exceeds the requirements for delineating the MMA under 40 CFR § 98.449 (Subpart RR).

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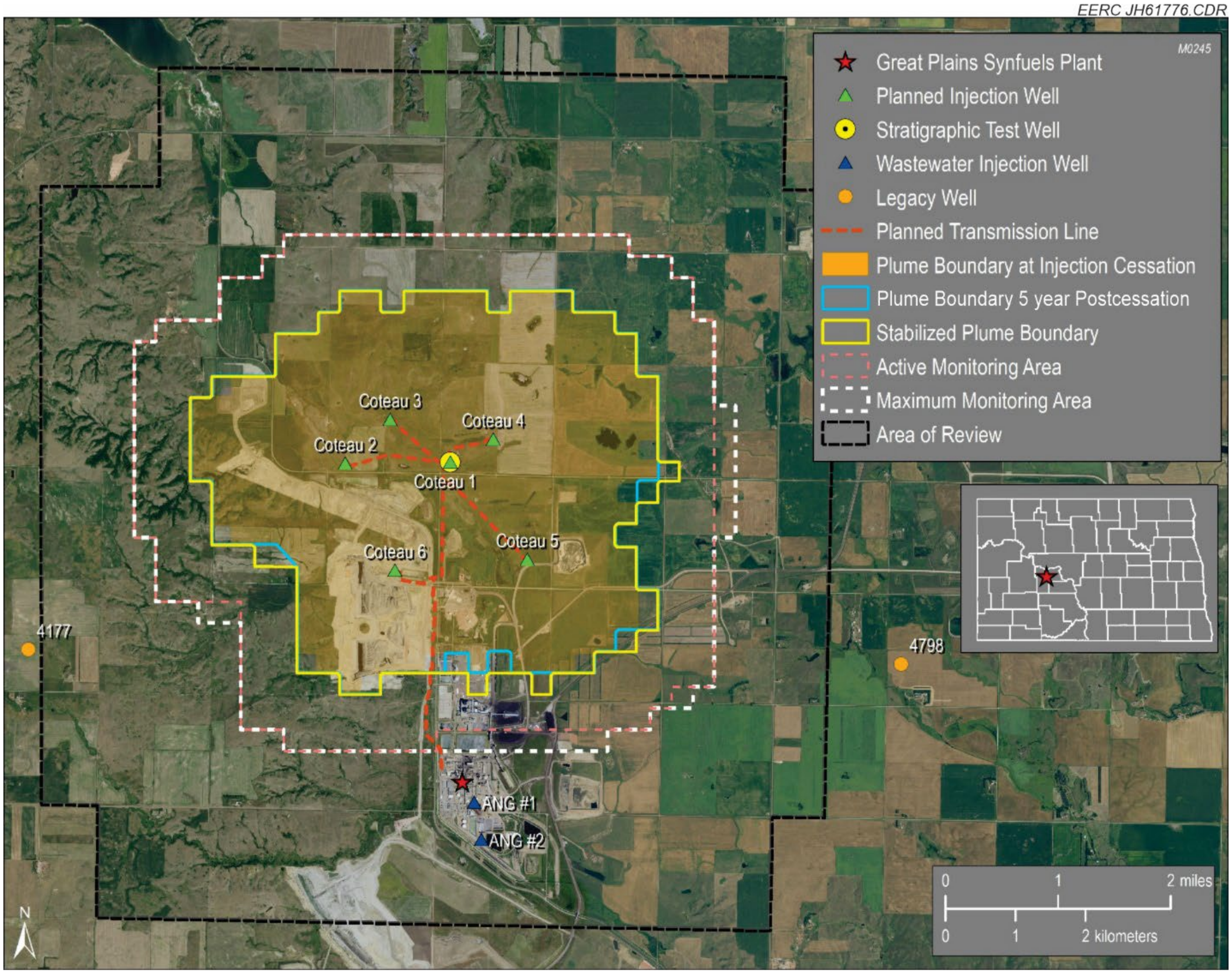

Figure 2-2. Map showing the AOR relative to the calculated MMA and AMA boundaries, calculated as prescribed under 40 CFR § 98.449 (Subpart RR). The AOR subsumes the calculated AMA and MMA and exceeds requirements for both AMA and MMA; therefore, the AOR serves as both the AMA and MMA for the Great Plains CO_2 Sequestration Project.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2 (Reference 1, Section 5) comprises three distinct periods: 1) pre-operational (pre-injection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) post-operational (post-injection of CO_2) monitoring. These monitoring periods, therefore, encompass the entire life cycle of the project. For purposes of this MRV plan, it is expected that reporting will be initiated during the operational period and continue through the post-injection period.

The storage system parameters that are monitored during each period are essentially identical; however, the duration of the monitoring period of the measurements performed varies. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

The pre-operational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and uncertainty associated with the measurement of each of the key storage system parameters. An understanding of the repeatability and variability of each measurement is key to successfully determining the movement of CO_2 that is contained in the formation at any given time.

The operational injection period is focused on validating and updating numerical models of the storage system to ensure that the geologic storage project is operating safely and protecting all USDWs. Lastly, the purpose of the post-operational monitoring is to verify the stability of the CO_2 plume location and assess the integrity of all decommissioned wells. The duration of these monitoring periods is a minimum of 12 and 10 years, respectively.

3.0 EVALUATION OF POTENTIAL LEAKAGE PATHWAYS

The potential leakage pathways for CO_2 arriving at the surface after injection or from surface equipment failures during operations were evaluated. Factors and equipment that could lead to leakage pathways were identified and placed into the following six categories:

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

This leakage assessment determined none of the pathways required corrective action and the probability of leakage is unlikely. However, a robust monitoring program, described in Reference 1, Section 5, and summarized in Table 5-1, was developed to form the basis of this MRV plan.

3.1 Class I Nonhazardous Disposal Wells

Two Class I disposal wells are active in the Great Plains CO_2 Sequestration Project area. Both wells were drilled in the 1980s to dispose of nonhazardous wastewater produced from GPSP operations in the Minnelusa Group (Broom Creek Formation) and Kibbey Formation under North Dakota Department of Health (NDDH) Permit Nos. ND-UIC-101 and ND-UIC-102. In 2018, both permits were renewed under NDDH Permit No. ND-UIC-101-1. In 2019, the North Dakota Department of Environmental Quality (NDDEQ) separated from the NDDH, and both Class I disposal wells were given well numbers by the NDDEQ.

3.1.1 ANG #1 (NDDEQ Well No. 11308)

The American Natural Gas No. 1 Disposal Well (ANG #1) spudded in April 1982 (NDDEQ Well No. 11308), reaching a total depth of 6,784 feet in the Kibbey Formation. Drillstem test data and core collected from porous and permeable intervals of the Dakota, Minnelusa, and Kibbey saw

no evidence of hydrocarbons. Injectivity tests demonstrated the Minnelusa (Broom Creek Formation) and Kibbey were the most viable for receiving wastewater at the injection rates and volumes specified in NDDH Permit No. ND-UIC-101. The well was completed in the Minnelusa in July 1982, and additional perforations were added to the Kibbey Formation in 1983. The ANG #1 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure, and a seal pot system on the annulus to detect annulus leaks. The ANG #1 is also monitored with temperature logs or tracer surveys about once every 5 years.

The ANG #1 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and it was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-4).

The risk of leakage via the ANG #1 is unlikely and is mitigated through the wellbore leak detection plan described hereto. The simulation work (presented in Reference 1, Section 2.3.3) also illustrates that the CO_2 plume does not come into contact with the well and suggests there is little interaction between the CO_2 plume and the injected disposal water, even after 10 years post-injection. Because the CO_2 plume does not come into contact with the well, the anticipated magnitude of leakage from the ANG #1 in terms of volume of CO_2 or associated fluids over the life of the project is extremely low.

3.1.2 ANG #2 (NDDEQ Well No. 11309)

The American Natural Gas No. 2 Disposal Well (ANG #2) spudded in September 1983 (NDDEQ Well No. 11309), reaching a total depth of 6,911 feet in the Kibbey Formation. The well was completed in both the Minnelusa (Broom Creek Formation) and Kibbey sands (NDDH Permit No. ND-UIC-102). The ANG #2 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure in the tubing-casing annulus, and a seal pot system on the annulus to detect annulus leaks. The ANG #2 is also monitored with temperature logs or tracer surveys about once every 5 years.

The ANG #2 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and it was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-5).

The risk of leakage via the ANG #2 is unlikely and is mitigated through the wellbore leak detection plan described hereto. The simulation work presented in Reference 1, Section 2.3.3, also illustrates that the CO_2 plume does not come into contact with the well and suggests there is little interaction between the CO_2 plume and the injected disposal water, even after 10 years post-injection. Because the CO_2 plume does not come into contact with the well, the anticipated magnitude of leakage from the ANG #2 in terms of volume of CO_2 or associated fluids over the life of the project is extremely low.

3.2 Abandoned Oil and Gas Wells

The Herrmann 1 (NDIC File No. 4177) well spudded in November 1966. The well was drilled to a depth of 8,057 feet into the Frobisher interval (stratigraphically equivalent to the Mission Canyon Formation of the Madison Group) and was plugged and abandoned in December of the same year. A drillstem test was conducted in the Frobisher interval, but the well encountered no commercial accumulations of hydrocarbons.

The Herrmann 1 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project and is the only oil and gas well within 0.5 miles outside of the AOR. It was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-3).

The risk of leakage via the Herrmann 1 of any magnitude and at any time over the life of the project is extremely low, as the well 1) never comes into contact with the CO_2 plume, 2) experiences a pressure increase of less than 100 psi over the life of the project (Reference 1, Section 6.1.1, Figures 6-1 and 6-2), and 3) has multiple cement plugs to prevent vertical migration of pressure or fluids outside the storage reservoir (Reference 1, Section 4.2, Figure 4-6).

3.3 Surface Components

Surface equipment components present potential leakage pathways during the operational injection period for the Great Plains CO_2 Sequestration Project site. Surface equipment can be subject to deterioration due to normal aging throughout its functional life. Corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in these assets.

The DGC CCS system includes a 6.8-mile-long transmission pipeline (NDPSC Case No. PU-21-150), six flowlines, and six injection wellheads (Figure 1-4b). The transmission line consists of a 12-inch main line and six 6-inch lateral lines that branch off and connect with 4.5-inch flowlines near each well pad. The flowlines will be connected to metering stations and located contiguous with the well pads (Reference 1, Section 5, Figures 5-1 and 5-2). Flowmeters will be installed at each metering station. The chemical composition of the CO_2 stream that will flow through the surface equipment is given in Reference 1, Section 5.1.1, Table 5-2.

Surface components of the injection system, including the flowlines and wellheads, will be monitored using leak detection equipment. The wellsite flowlines will be monitored continuously via multiple pressure gauges and H_2S detection stations located between the transmission line and the individual wellheads. This leak detection equipment will be integrated with automated warning systems that notify the pipeline control center at DGC, giving the operator the ability to remotely close the valves in the event of an anomalous reading. Further details of the surface leak detection system are given in Reference 1, Section 5.3.

The risk of leakage via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.

- Implementing the highest standards on material selection and construction processes for the flowlines and wells.
- Applying best practices and a robust mechanical integrity program as well as operating procedures.
- Monitoring continuously via an automated system and integrated databases.

The risk of leakage through surface equipment (under normal operating conditions) is unlikely, and the magnitude will vary according to the failure observed. A potential leakage event from instrumentation or valves could represent a few pounds of CO_2 released during several hours, while a puncture in the flowline could represent several tons of CO_2 released underground until the operator ceases the CO_2 supply. Note that should a shutoff situation occur, the CO_2 stream can be looped back to the DGC capture facility, passed through the burners, and be vented to the atmosphere.

This risk of leakage through surface equipment reduces to almost zero during the post-injection site care period. At cessation of the injection period, the injection wells will be properly plugged and abandoned following NDIC protocols and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the Class I wastewater injection wells, ANG #1 and ANG #2, identified as potential leakage pathways at the wellhead valves or in the instrumentation as discussed in Section 3.1.

3.4 Faults, Fractures, Bedding Plane Partings, and Seismicity

No known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations have been identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration activities (Reference 1, Section 2.5).

3.4.1 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 (Reference 1 Section 2.5). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The two closest recorded seismic events to the Great Plains CO_2 Sequestration Project occurred 29.6 miles to the northwest and 36.8 miles southwest of the Coteau 1 injection wellsite, with estimated magnitudes of 1.9 and 3.2, respectively (Reference 1, Section 2.5).

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

The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the absence of known or suspected local or regional faults suggest the probability that seismicity would interfere with CO_2 containment is low. In the event a seismic event occurs (natural or induced) near the project site, the magnitude of any seismic event would be expected to be less than 3.2 based on the historical record and would expected to cause little to no damage to subsurface or downhole equipment. In addition, DGC will operate below the maximum allowable injection pressure (Reference 1, Section 11, Table 11-1) to maintain safe operations throughout the injection period.

Through the geologic site characterization and corrective action review processes, leakage resulting from natural or induced seismicity was shown to be very unlikely.

3.5 Class VI Injection Wells

3.5.1 Coteau 1 (NDIC File No. 38379)

The Coteau 1 well spudded in June 2021 as a stratigraphic test well to a depth of 6,483 feet into the Amsden Formation. This well was drilled to gather geologic data to support the development of a CO_2 SFP and to later be converted into a Class VI injection well for the Great Plains CO_2 Sequestration Project. The Coteau 1 will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues.

The risk of leakage via the Coteau 1 is mitigated through:

- Preventing corrosion of well materials, following the preemptive measures in Reference 1, Section 5.2.2.
- Monitoring operations with a surface leak detection plan, as described in Reference 1, Section 5.3.
- Monitoring the storage reservoir with a subsurface leak detection plan, as described in Reference 1, Section 5.4.
- Performing wellbore mechanical integrity testing, as described in Reference 1, Section 5.1.2, and summarized in Reference 1, Section 5.7, Table 5-7.

The risk of leakage via the Coteau 1 during injection is low. The magnitude of any leakage during injection may vary according to the failure observed and could potentially represent a few pounds of CO_2 to several metric tons per hour released until operations are shut in and emergency protocols activated, as described in Reference 1, Section 7.4. Once the injection period ceases, the Coteau 1 will be properly plugged and abandoned following NDIC protocols, thereby reducing the risk for leakage from the well to almost zero.

3.5.2 Coteau 2 Through Coteau 6 Planned CO_2 Injection Wells

The Coteau 2 (NDIC File No. 38916), Coteau 3 (NDIC File No. 38917), and Coteau 4 (NDIC File No. 38918) wells are planned to spud in June 2022 as stratigraphic test wells for the Great Plains CO_2 Sequestration Project. The wells will be drilled to the Amsden Formation at planned depths of 6,345, 6,339, and 6,301 feet, respectively. Once the SFP is issued, all stratigraphic test wells will be converted to Class VI injection wells. Like the Coteau 1, the wells will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues. The Coteau 5 and Coteau 6 wells are planned to spud in 2026 and are conditional upon additional injection volumes of CO_2 becoming available from the capture facility. The Coteau 5 and Coteau 6 wells will be monitored after the same manner as the Coteau 1 through Coteau 4 wells. Once the injection period ceases, the Coteau 2 through Coteau 6 wells will be properly plugged and abandoned following NDIC protocols.

The discussion for assessing the risk of leakage via the Coteau 2 through Coteau 6 is the same as presented in Section 3.5.1 of this MRV plan. Once the injection period ceases, the Coteau 2 through Coteau 6 will be properly plugged and abandoned following NDIC protocols, thereby reducing the risk for leakage from the wells to almost zero.

3.6 Confining Zone Limitations

3.6.1 Lateral Migration

For the Great Plains CO_2 Sequestration Project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure (Reference 1, Section 2.3.2). The Opeche Formation is a laterally extensive formation that is 5,763 feet below the surface and 143 feet thick at the Coteau 1 wellsite (Reference 1, Section 2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), as discussed in Reference 1, Section 3.4.

The risk of leakage via lateral migration is extremely unlikely, as demonstrated by the geologic characteristics of the storage reservoir (Reference 1, Section 2.3) and upper confining zone (Reference 1, Section 2.4.1) (e.g., mineralogy, permeability/sealing capacity, and lateral continuity) coupled with the modeling and simulation work (Reference 1, Section 3) that was performed for the Great Plains CO_2 Sequestration Project. In the event that the monitoring data or models and simulations predict any part of the CO_2 plume may migrate beyond the anticipated stabilized plume boundary over the project's life because of a previously unidentified permeability pathway in the storage reservoir, the storage facility area and AOR will be recalculated, and the MRV plan, including the testing and monitoring strategy, will be updated as necessary.

3.6.2 Seal Diffusivity

Several other formations provide additional confinement above the Opeche Formation (Reference 1, Section 2.4.2). Impermeable rocks above the primary seal, the Opeche Formation, include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations. Together with the Opeche, these formations are 1,106 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 2,657 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation.

Confining layers above the Inyan Kara include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (see Figure 1-3 for stratigraphic reference).

The risk of leakage via the Herrmann 1 of any magnitude and at any time over the life of the project is extremely low, as there is a total of 3,763 feet of overlying confining layers, which presents a very low risk to the Great Plains CO_2 Sequestration Project. The presence of multiple thick impermeable layers and laterally extensive formations drastically reduces potential leakage pathways through geologic formations.

3.6.3 Drilling Through the CO_2 Area

There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the AOR. Although there was a historical oil and gas production well test from the Madison Group just outside the AOR (i.e., Herrmann 1), there are no known commercial accumulations of hydrocarbons in the AOR (Reference 1, Section 2.6). With no known commercial ventures drilling near the Great Plains CO_2 Sequestration Project area, there is very little chance of drilling through the storage complex.

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a deviated or horizontal well could be used to produce the hydrocarbon while avoiding drilling through the CO_2 plume or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available, which will allow prospective operators to design an appropriate well control strategy via increased drilling mud weight. The maximum pressure increase in the center of the injection area is projected by computer modeling to be 400–450 psi, with lesser impacts extending radially (Reference 1, Section 3, Figure 3-20). Pressure increases will relax post-injection as the area returns to its pre-injection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the CO_2 should be designed to include an intermediate casing string made of CO_2-resistant material and placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place.

3.7 Monitoring, Response, and Reporting Plan for CO_2 Loss

DGC proposes a robust monitoring program for the SFP (Reference 1, Section 5). The program covers a corrosion and mechanical integrity protocol (Reference 1, Section 5.2), surveillance of injection performance (Reference 1, Sections 5.3 and 5.4), monitoring of near-surface conditions (Reference 1, Sections 5.5 and 5.6), and direct and indirect monitoring of the CO_2 plume (Reference 1, Section 5.7). To compliment the monitoring program, DGC proposes a detailed emergency remedial and response plan (Reference 1, Section 7) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting in the event of an unplanned loss of CO_2 from the Great Plains CO_2 Sequestration Project area.

3.8 Summary

In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the emergency and remedial response plan. Estimating volumetric

losses of CO_2 would require consideration of the leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based upon the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

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

Table 4-1. Summary of DGC's CCS Monitoring Strategy

Method (target area/structure)	**Pre-injection (Baseline – 1 year)**	**Injection Period (12 years)**	**Post-injection (10 years)**
CO_2 Stream Analysis (capture)	Start-up	Daily	NA[1]
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	Start-up	Real time	NA
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	Start-up	Real time	NA
H_2S Detection Stations (flowlines, wellheads, and well pads)	Start-up	Real time	NA
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	Start-up	Monthly in the first quarter, then quarterly in the next 2 years	NA
Platform Multifinger Imaging Tool (PMIT) or Ultrasonic Imaging Tool (USIT) (CO_2 injection wells)	NA	Starting in Year 2, a PMIT or USIT will be run during well workovers but not more frequently than once every 5 years	NA
SCADA[2] Automated Remote System (surface facilities)	Start-up	Real time	NA
Soil Gas Analysis (11 soil gas profile stations)	Three to four seasonal samples	Three to four seasonal samples each year	Three to four seasonal samples each year
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)	Provide historical water sampling results	NA	NA
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)	Baseline	NA	NA
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	Baseline	Three to four seasonal samples	Three to four seasonal samples
Cement Bond Logs (CO_2 injection wells)	After cementing	If needed	Prior to P&A[3]
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	Baseline	Perform during workovers but not more than once every 5 years	Perform during workovers but not more than once every 5 years
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	Start-up	Real time	NA
Pulsed-Neutron Logs with Temperature and Bottomhole Pressure Readings (CO_2 injection wells)	Baseline	Quarterly using phased approach described in Reference 1, Section 5.1.2	NA
USIT Logs (CO_2 injection wells)	Baseline	Perform during workovers but not more than once every 5 years	Perform during workovers but not more than once every 5 years
Pressure Falloff Test (CO_2 injection wells)	Baseline	Every 5 years	NA
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	Baseline	Repeat survey 1 year after injection begins, then in Years 3, 5, and 10	Repeat survey 1 year after injection ceases, then in Years 3, 5, and 10
Vertical Seismic Profiles (VSP) (CO_2 plume)	Baseline	Repeat VSP 1 year after injection begins, then (if deemed beneficial) in Years 3, 5, and 10	NA

[1] Not applicable
[2] Supervisory control and data acquisition
[3] Plugged and abandoned

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

Monitoring Strategy (target area/structure) \ Potential Leakage Pathway	Wellbores*	Faults and Fractures	Flowline and Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis (capture)			X			
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	X		X			X
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	X		X	X		
H_2S Detection Stations (flowlines, wellheads, and well pads)	X		X	X		X
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	X		X	X		
PMIT or USIT (CO_2 injection wells)	X			X		
SCADA Automated Remote System (surface facilities)	X		X	X		
Soil Gas Analysis (11 soil gas profile stations)	X			X	X	X
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)				X	X	X
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)		X		X	X	X
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	X	X		X	X	X
Cement Bond Logs (CO_2 injection wells)	X			X		X
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	X			X		
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	X			X	X	
Pulsed-Neutron Logs with Temperature and Bottomhole Readings (CO_2 injection wells)	X			X	X	X
USIT Logs (CO_2 injection wells)	X			X		
Pressure Falloff Test (CO_2 injection wells)	X			X	X	
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	X	X		X	X	X
VSP (CO_2 plume)*	X	X		X	X	X

* Applies to all wellbores in project area if not otherwise specified under the monitoring strategy target area/structure column.

4.1 Leak Verification

DGC's strategy to detect and verify leakage pathways is summarized in Table 4-2.

As part of the surveillance protocol, DGC will use reservoir simulation modeling, based on history-matched data obtained from the monitoring program, to compare the initial numerical model with the real development of the plume and pressure front. The model will be continuously calibrated with the acquisition of real-time data. Every 5 years, a formal AOR will be submitted, and the monitoring plan will be revised, if needed.

The model history match allows the project operator and owner to identify conditions that differ from those proposed by the numerical model and deviations in the operating conditions from the originals. For example, the injection well will be monitored, and if the injection pressure, temperature, or rate measurements deviate significantly from the specified set points, then a data flag will be automatically triggered by the automated system and field personnel will investigate the excursion. These excursions will be reviewed to determine if CO_2 leakage is occurring. Excursions are not necessarily indicators of leaks; rather, they indicate that injection rates, temperatures, and pressures are not conforming to the expected pattern of the injection plan. In many cases, problems are straightforward and easy to fix (e.g., a meter needs to be recalibrated), and there is no indication that CO_2 leakage has occurred. In the case of issues that are not readily resolved, a more detailed investigation will be initiated. If further investigation indicates a leak has occurred, efforts will be made to quantify its magnitude.

The model history-matching in combination with the mechanical integrity data, geophysical surveys, and near-surface monitoring form a powerful tool to appropriately follow changes in CO_2 concentration at the surface. Many variations of CO_2 concentration detected on the surface are the result of natural processes or external events not related to the CO_2 storage complex.

Because a CO_2 surface leak is of lower temperature than ambient conditions, it will often lead to the formation of bright white clouds and ice that are easily visually observed. With this understanding, DGC will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the Great Plains CO_2 Sequestration Project.

Response plan actions and activities will depend upon the circumstances and severity of the event. DGC will address an event immediately and, if warranted, communicate the event to the UIC program director within 24 hours of discovery.

If an event triggers cessation of injection and remedial actions, DGC will demonstrate the efficacy of the response/remedial actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations will only resume upon receipt of written authorization of the UIC program director.

4.2 Quantification of Leakage

As discussed above, the potential pathways for leakage include failure or issue in surface equipment or subsurface equipment (wellbores), faults or induced fractures, and competency of the seal to contain the CO_2 in the storage reservoir.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods to quantify the volume of CO_2 will be determined on a case-by-case basis. Any volume of CO_2 detected as leaking to the surface will be quantified using acceptable emission factors, engineering estimates of leak amount based on subsurface measurements, numerical models, history-matching of the reservoir performance, detailed analysis of the collected monitoring parameters, and delineation of the affected area, among others. Leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in an electronic central database.

5.0 DETERMINATION OF BASELINES

DGC will establish pre-injection baselines by implementing a monitoring program prior to any CO_2 injection and during each of the four primary seasonal ranges. This baseline will be created by monitoring the targeted surface, near-surface, and deep subsurface. The baseline will contain information on the characteristics of a range of environmental media, such as surface water, soil gas in the vadose zone, shallow groundwater, and storage reservoir formation water.

These baselines provide a basis for determining if CO_2 leaks are occurring by providing a foundation against which characteristics of these same media during CO_2 injection can be compared and evaluated. For example, changes in concentrations or levels of certain parameters in these media during injection might suggest that they have been impacted by leaking CO_2.

Determinations of these baselines are a critical component of a Class VI SFP. A detailed description of these baselines for both the surface and subsurface for the Great Plains CO_2 Sequestration Project area is provided in Reference 1, Sections 5.3 through 5.7.

5.1 Surface and Near-Surface Baselines

A baseline surface and near-surface sampling program has been completed for the Great Plains CO_2 Sequestration Project. Baseline data gathering included measuring chemical concentrations of the soil gas (i.e., O_2, N_2, and CO_2) and groundwater (e.g., pH, total dissolved solids, alkalinity, major cations/anions and trace metals) as well as characterizing the naturally occurring stable and radiocarbon (^{14}C) isotopic signatures of the soil gas and groundwater for comparison with the isotopic signature of the CO_2 stream. The data were obtained from 11 soil gas-sampling locations and two existing groundwater wells from the northern and eastern portions of the AOR. Baseline water samples are also planned to be obtained from five new Fox Hills monitoring wells that will be drilled prior to the start of injection operations. One of the groundwater monitoring wells will be placed near the Herrmann 1 well and the others will be placed adjacent to the Coteau 1 through Coteau 4 injection wells (Reference 1, Section 5.6,

Figure 5-4). For additional information regarding surface and near-surface baselines, refer to Reference 1, Sections 5.5.1–5.5.2 and Section 5.6, paragraph 1.

5.2 Subsurface Baselines

Pre-operational baseline data will be collected in each of the six injection wells for the Great Plains CO_2 Sequestration Project, including ultrasonic imaging, pulsed-neutron, and temperature logs, bottomhole pressure surveys, tubing-casing annulus pressure tests, and pressure falloff tests (Reference 1, Section 5.7, Table 5-7). The data acquisition schedule for the pulsed-neutron and temperature logs with a pressure-recording device attached is presented in Reference 1, Section 5.1.2. The time-lapse saturation data will be used as an assurance-monitoring technique for CO_2 in the formation directly above the storage reservoir, otherwise known as the above-zone monitoring interval. The pressure and temperature data will be useful for informing the geologic model and simulations, monitoring conditions in the storage reservoir, and confirming wellbore mechanical integrity. The pressure testing in each of the wellbores will also help to confirm wellbore mechanical integrity.

Indirect monitoring methods will also track the extent of the CO_2 plume within the storage reservoir and can be accomplished by performing time-lapse geophysical surveys of the AOR. A 2D radial seismic survey was collected to establish baseline conditions in the storage reservoir. A baseline VSP was also collected to determine the feasibility of monitoring the CO_2 plume during the injection phase with this technology. For additional information regarding subsurface baselines, refer to Reference 1, Section 5.7.2.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The Great Plains CO_2 Sequestration Project area is a geologic CO_2 storage site in a saline aquifer with no production associated from the storage complex. A flowmeter will be placed downstream of the CO_2 compressor (start of the CO_2 transmission line) and near each of the injection wellheads (Figure 1-4b). The proposed main metering station for mass balance calculation is identified as the first metering station placed at the start of the CO_2 transmission main line. The use of a single metering station for the mass balance calculation (as opposed to using multiple metering stations near each wellhead) will help ensure accuracy of the measurements.

To calculate the annual mass of CO_2 that is stored in the storage complex, the project will use Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

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

Where:

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

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

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

Mass of CO_2 Injected (CO_{2I}):
DGC will use volumetric flow metering to measure the flow of the injected CO_2 stream and will calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5 from 40 CFR Part 98, Subpart RR (Equation 2):

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

Where:
$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by Flowmeter u.
$Q_{p,u}$ = Quarterly volumetric flow rate measurement for Flowmeter u in Quarter p at standard conditions (standard cubic meters per quarter).
D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.
$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flowmeter.

Mass of CO_2 Emitted by Surface Leakage (CO_{2E}):
DGC characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in Reference 1, Section 5, to detect any leak and defined a baseline for monitoring.

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

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

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

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

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

Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions
Annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead (CO_{2FI}) will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan proposed in Reference 1, Section 5.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented starting September 2022 or within 90 days of EPA approval, whichever occurs later. Other greenhouse gas reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time. It is anticipated that the MRV program will be in effect from September 2022 to September 2036, during which time the Great Plains CO_2 Sequestration Project will be operated.

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for DGC monitoring techniques and data management is provided in the quality assurance and surveillance plan found in Reference 1, Appendix C.

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

CO_2 received:

- The quarterly flow rate of CO_2 will be reported from continuous measurement at the main metering station (identified in Figure 1-4b). In addition, the quarterly flow rate of CO_2 will be continuously measured by receiving meters at each of the injection well pads.

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

Flowmeter provision:

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

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

- Operated in conformance with consensus-based standards organizations including, but not limited to, American Society for Testing and Materials (ASTM) International, the American National Standards Institute, the American Gas Association, the American

Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

9.0 RECORDS RETENTION

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

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

- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

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

10.0 REFERENCES

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

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

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

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

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

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

Request for Additional Information: Great Plains Synfuels Plant
June 14, 2022

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	1.2	4	The scale in the lower right-hand corner of Figure 1-2 looks connected to the inset map. Please clarify by providing separate scars bars or by using another method.	Please refer to Figure 1-2 on page 4, which has been updated to include two separate scale bars, as suggested.
2.	1.3	6	"… to approximately 2,500 **pounds per square inch**." Once defined on page 1, PSI is used throughout the document except here. Please change to ensure consistency.	The reference to "pounds per square inch" has now been abbreviated to psi, as the term is previously defined on page 1.
3.	3.1.1	11	"The ANG #1 was reviewed as part of the corrective action evaluation for the Great Plains Sequestration Project **and was determined** that no corrective…" The previous sentence is likely missing a word. Please adjust accordingly. The same issue occurs in Section 3.1.2.	This error has been corrected in Sections 3.1.1 and 3.1.2 on pages 11 and 12.
4.	3.3	12	"…ANG #1 and ANG #2, identified as potential leakage pathways at the wellhead valves or in the instrumentation." We recommend adding "… as discussed in Section 3.1." at the end of this sentence for clarity.	This sentence has been modified as requested (now on page 13).

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	3.0	10-15	Various leakage pathways are identified in section 3.0. Some of these pathways have explicit characterizations for likelihood, magnitude and timing of potential surface leakage and others do not. Please provide an explicit characterization of the likelihood, magnitude and timing of each identified leakage pathway, as required by 40 CFR 98.448(a)(2).	Each of the subsections in Section 3 of the MRV plan have been updated with one to two paragraphs to specifically comment on the likelihood, magnitude, and timing of each of the leakage risks identified in the project.
6.	3.4.1	13	Both natural and induced seismicity are concluded to be unlikely leakage pathways, but the preceding discussion appears to focus on natural seismicity only. Please provide additional information to support the characterization for induced seismicity.	Additional information has been added to Section 3.4.1 (pages 13 and 14) that points directly to characterization efforts on induced seismicity for the project.
7.	5.0	19-20	Section 5.0 discusses data that will be collected to establish surface and subsurface baselines. For example, the MRV plan discusses taking soil-gas and groundwater samples. Please elaborate in the MRV plan on what types of measurements (e.g., CO_2 concentration) will be taken from these samples. Furthermore, please indicate whether operational data (such as injection well pressures) will also be used to establish baselines.	The parameters to be measured for surface and near-surface baseline data sets are now outlined at a high level in Section 5.1. Section 5.2 further outlines the operational data that will be collected prior to the start of injection operations.
8.	6.0	20	"The proposed main metering station for mass balance calculation is identified as the first metering station placed at the start of the CO_2 transmission main line." Will this be downstream of the compressor station but upstream of the lateral for Coteau 6 as shown in figure 1-4a? If so, we recommended clarifying this here.	The figure caption for Figure 1-4a has been updated, and Figure 1-4b has been updated to clarify the placement of the main metering station.
9.	8.0	22	"The quarterly flow rate of CO_2 will be reported from continuous measurement at a receiving meter at each of the injection well pads." Section 6 indicates that a single flowmeter will be placed downstream of the compressor at the start of the pipeline to the injection wells in addition to meters at each injection well. Please clarify.	The text underneath "CO_2 received" in Section 8.0 has been updated to clarify which flowmeter will be used to report flow rate data vs. what flowmeters will be used for quality assurance and monitoring the CO_2 transmission line and flowlines.

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

May 5, 2022

Mr. Mark de Figueiredo
Climate Change Division
Office of Atmospheric Programs (MC-6207J)
Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, DC 20460

Dear Mr. de Figueiredo:

Subject: Monitoring, Reporting, and Verification (MRV) Plan for the Great Plains CO_2 Sequestration Project

Dakota Gasification Company (DGC), together with its partners and affiliates, respectfully submits the subject MRV Plan for the dedicated geologic storage of carbon dioxide (CO_2) at DGC's Great Plains Synfuels Plant in Mercer County, North Dakota.

Thank you for your time and attention during the meeting on April 18, 2022, where DGC and our partners provided an overview of the project.

Please contact me by phone at (701) 873-6635 or by e-mail at dalej@bepc.com with any questions.

Sincerely,

Dale A. Johnson
Vice President & Plant Manager
Dakota Gasification Company

c/att: Tyler Schilke, Basin Electric Power Cooperative
Kevin Solie, Basin Electric Power Cooperative
Van Spence, Rampart Energy
Kevin Connors, Energy & Environmental Research Center

RESPONSIBLE CARE® OUR COMMITMENT TO SUSTAINABILITY

GREAT PLAINS CO_2 SEQUESTRATION PROJECT MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Well

Reporting Number: 523812

TABLE OF CONTENTS

Continued . . .

TABLE OF CONTENTS (continued)

LIST OF FIGURES

LIST OF TABLES

STORAGE FACILITY PERMIT DESIGNATIONS

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

Reference 1: Great Plains CO_2 Sequestration Project, Mercer County, North Dakota

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

1.0 PROJECT DESCRIPTION

1.1 Project Characteristics

The Dakota Gasification Company's (DGC) Great Plains Synfuels Plant (GPSP), located 5 miles northwest of Beulah, North Dakota, is capable of gasifying 6 million tons of lignite coal per year (Figure 1-1). DGC, a wholly owned subsidiary of Basin Electric Power Cooperative (Basin), has owned and operated the facility since 1988. DGC has captured and transported more than 40 million tonnes (Mt) of carbon dioxide (CO_2) (>95% dry CO_2) from the gasification process for enhanced oil recovery purposes since 2000. The captured CO_2 is transported via a 205-mile pipeline that has successfully operated for the past 22 years. The CO_2 is first compressed to a pressure of ±2,500 pounds per square inch (psi), then transported north as a supercritical fluid. There currently exists excess compressor capacity, which makes the capture of an additional 1.0 Mt per year possible. DGC is currently constructing an additional 6.8 miles of pipeline to facilitate permanent sequestration of up to 2.7 Mt per year. The pipeline's design capacity is based on the total anticipated CO_2 output from the plant. Over the anticipated 12-year life of this project, sequestered volumes of CO_2 are expected to total 26 Mt. Four injection wells are anticipated initially (Coteau 1 through Coteau 4), with two additional wells planned (Coteau 5 and Coteau 6) as increased volumes in 2026 or beyond warrant (Figure 1-1). The injection wells will store the captured CO_2 stream in the porous and permeable Broom Creek Formation located below the GPSP.

DGC submitted its North Dakota CO_2 storage facility permit (SFP) to the North Dakota Industrial Commission (NDIC) on March 8, 2022. North Dakota has the authority to regulate the geologic storage of CO_2 and primacy to administer the North Dakota Underground Injection Control (UIC) Class VI Program (83 Federal Register 17758, 40 Code of Federal Regulations [CFR] 147). An official hearing date for DGC's Great Plains CO_2 Sequestration Project is expected July 2022. If any material changes are made to the SFP after the hearing date that impact this MRV plan, DGC will notify EPA and submit an amended plan within 180 days.

No other geologic storage project exists or is planned within 18.2 miles of the Great Plains CO_2 Sequestration Project.

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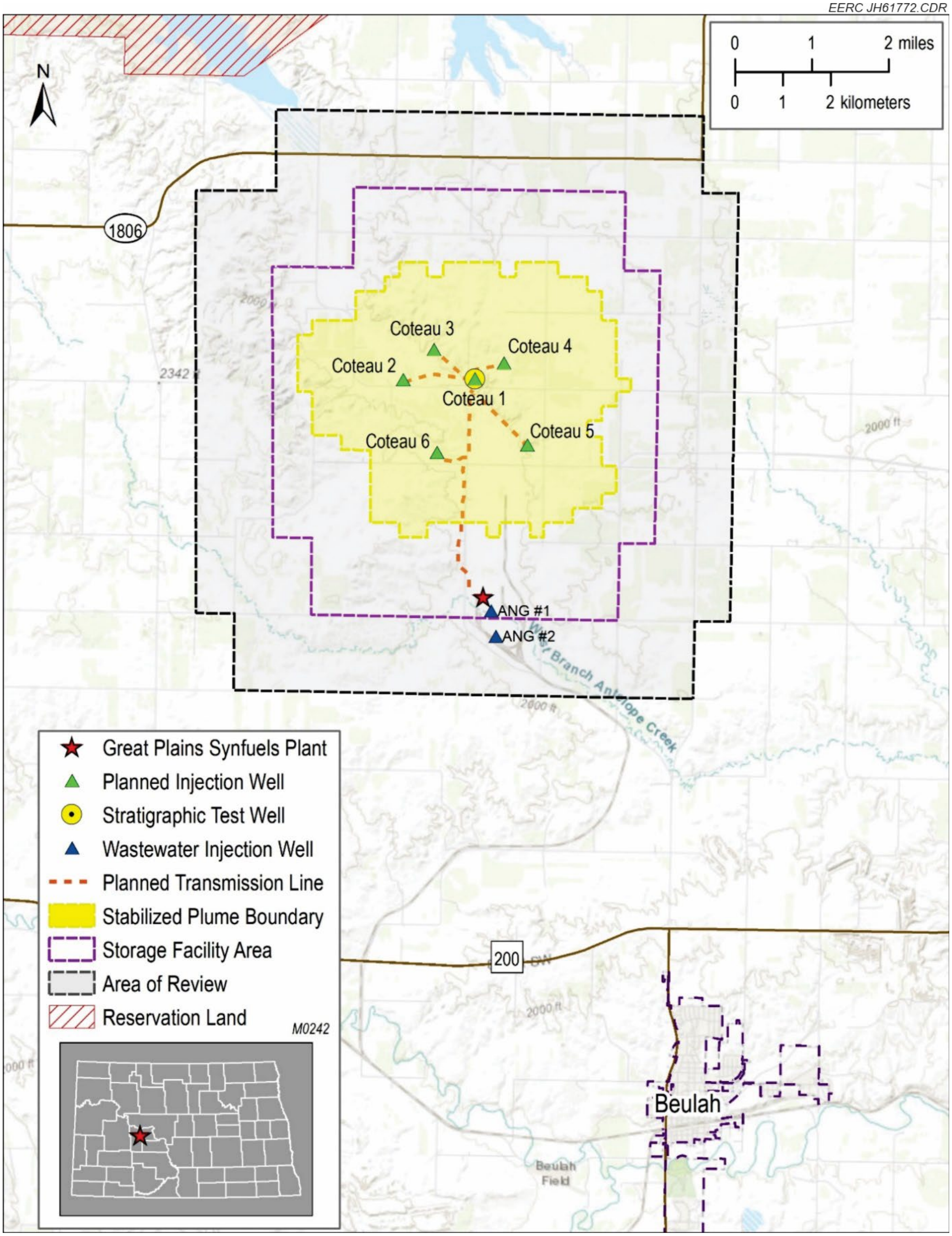

Figure 1-1. Location of the GPSP, Coteau 1 through Coteau 6 injection wells, and CO_2 transmission line. Also shown is the town of Beulah, with a population of about 3,200 people, the stabilized plume boundary, the storage facility area, and the area of review (AOR).

1.2 Environmental Setting

The Great Plains CO_2 Sequestration Project is located along the southern flank of the Williston Basin, a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Figure 1-2 shows the geographic distribution of oil fields in North Dakota, demonstrating there has been no exploration for or development of hydrocarbon resources within the AOR (Reference 1, Section 2.6). The Herrmann 1 (NDIC File No. 4177), a dry hole drilled in 1966 to the Frobisher interval (stratigraphically equivalent to the Mission Canyon Formation of the Madison Group), falls just outside the southwestern edge of the AOR. See Section 3.2 of this MRV plan for more information about the Herrmann 1 well.

A generalized stratigraphic column of the Williston Basin for the area of Beulah is provided in Figure 1-3. The target CO_2 storage reservoir for the Great Plains CO_2 Sequestration Project is the Broom Creek Formation, a predominantly sandstone interval lying about 5,900 feet below the GPSP (Reference 1, Section 2.3). Silty mudstones and interbedded evaporites of the Opeche Formation unconformably overlie the Broom Creek and serve as the primary confining zone (Reference 1, Section 2.4.1). Mixed layers of dolostone, mudstone, and anhydrite of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone (Reference 1, Section 2.4.3). From stratigraphic bottom to top, the Amsden, Broom Creek, and Opeche comprise the CO_2 storage complex. In addition to the Opeche Formation, there is about 1,100 feet of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation (Reference 1, Section 2.4.2). An additional 2,660 feet of impermeable rocks separate the Inyan Kara and the lowest underground source of drinking water (USDW): the Fox Hills Formation.

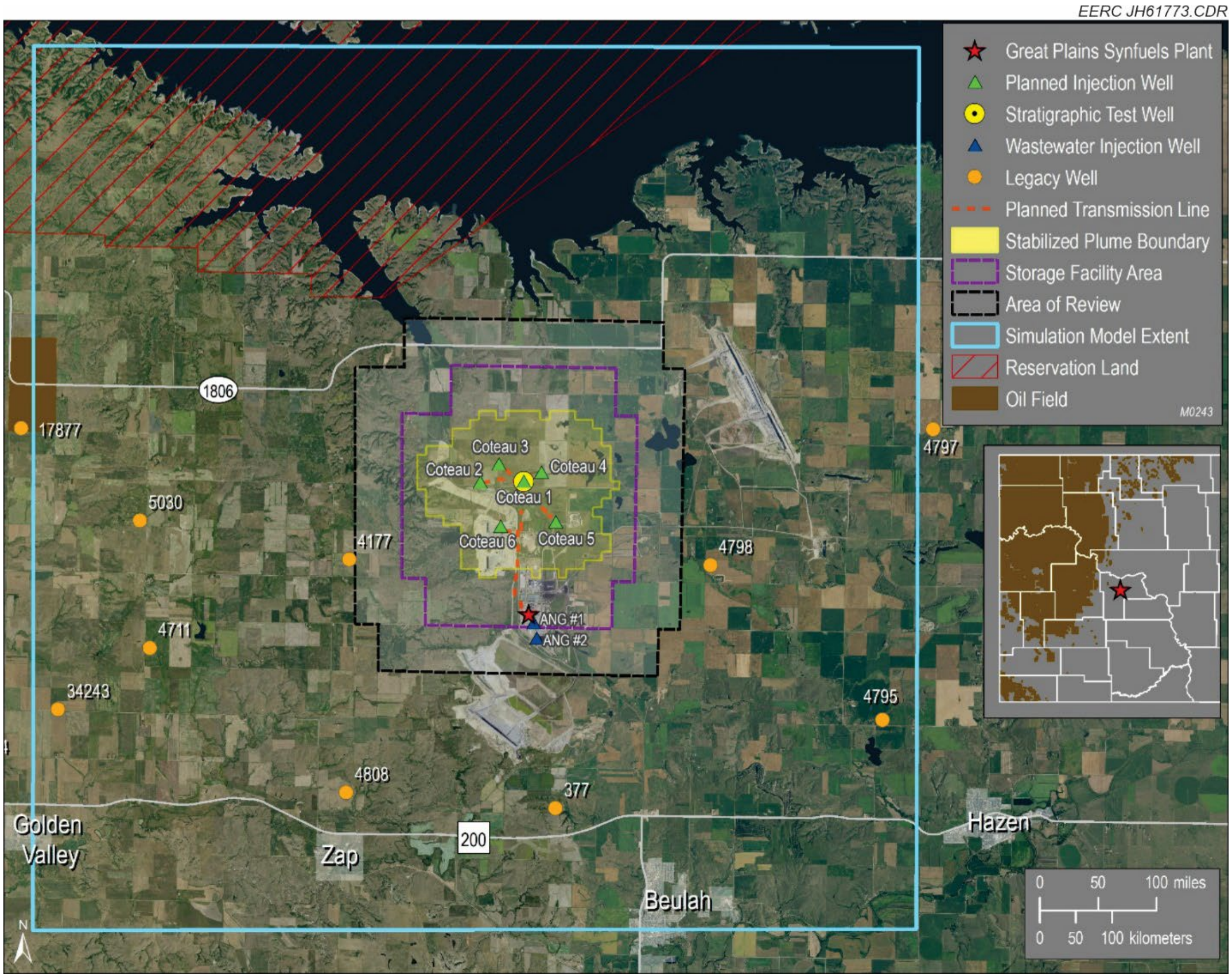

Figure 1-2. Map showing the simulation model extents of the Great Plains CO_2 Sequestration Project, legacy oil and gas wells, and geographic distribution of oil fields in North Dakota (i.e., western portion of the Williston Basin).

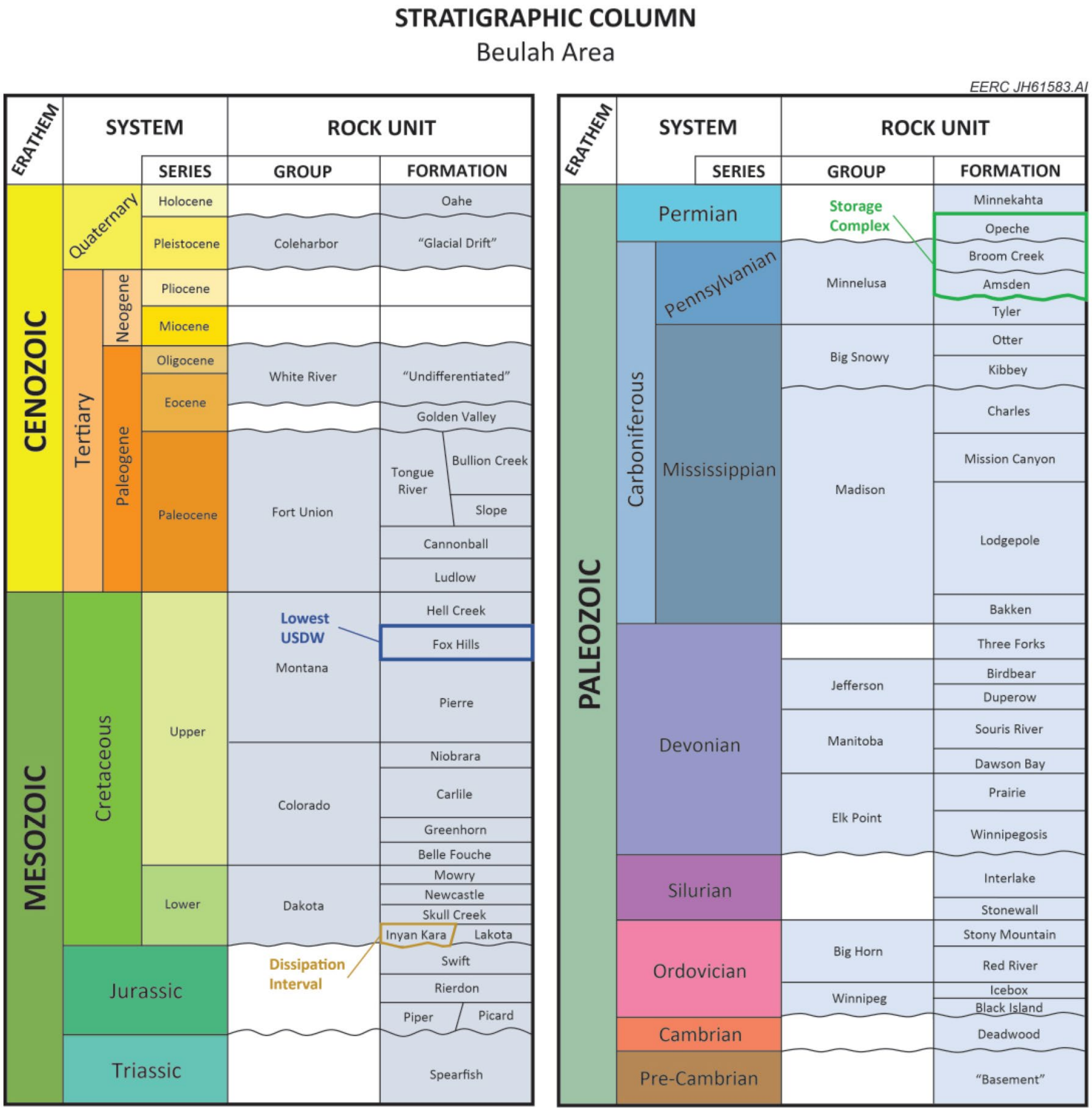

Figure 1-3. Generalized stratigraphic column of the Williston Basin for the Beulah area, identifying the storage complex (i.e., storage reservoir and primary confining zones) as well as the dissipation interval and lowest USDW underlying the Great Plains CO_2 Sequestration Project area. Figure modified after Murphy and others (2009) and Bluemle and others (1981).

1.3 Description of CO_2 Project Facilities and Injection Process

DGC plans to capture and store 1.0 to 2.7 Mt of CO_2 per year over the course of 12 years of injection, followed by at least 10 years of post-injection site care. Figure 1-4 shows integration

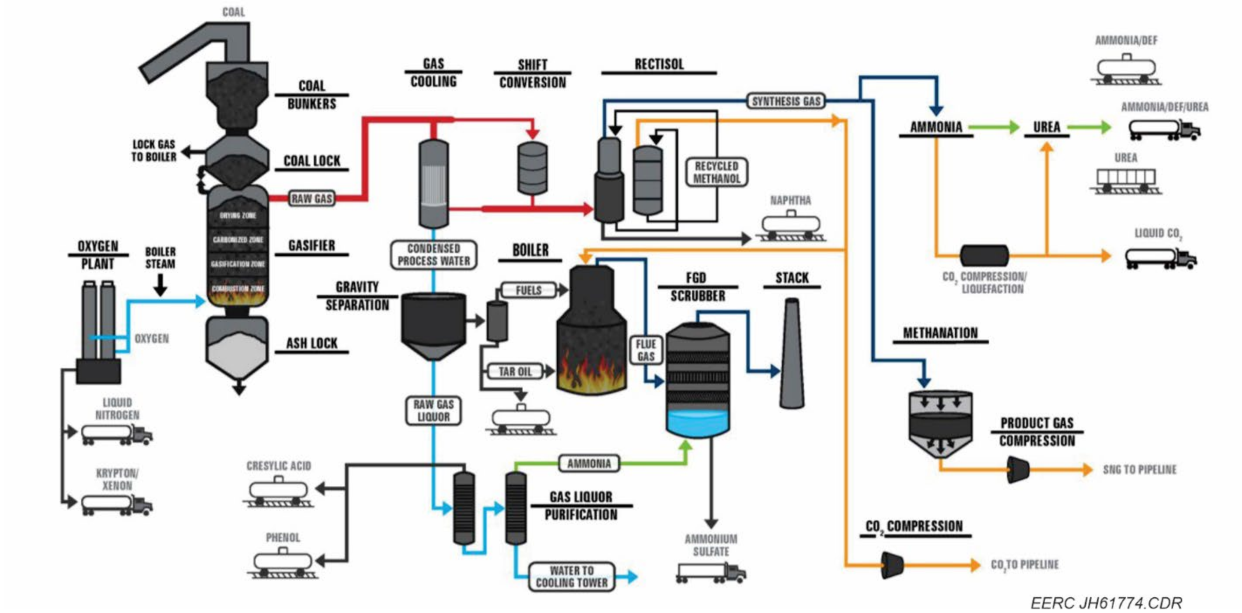

Figure 1-4a. Flow diagram of the CO_2 capture process at GPSP.

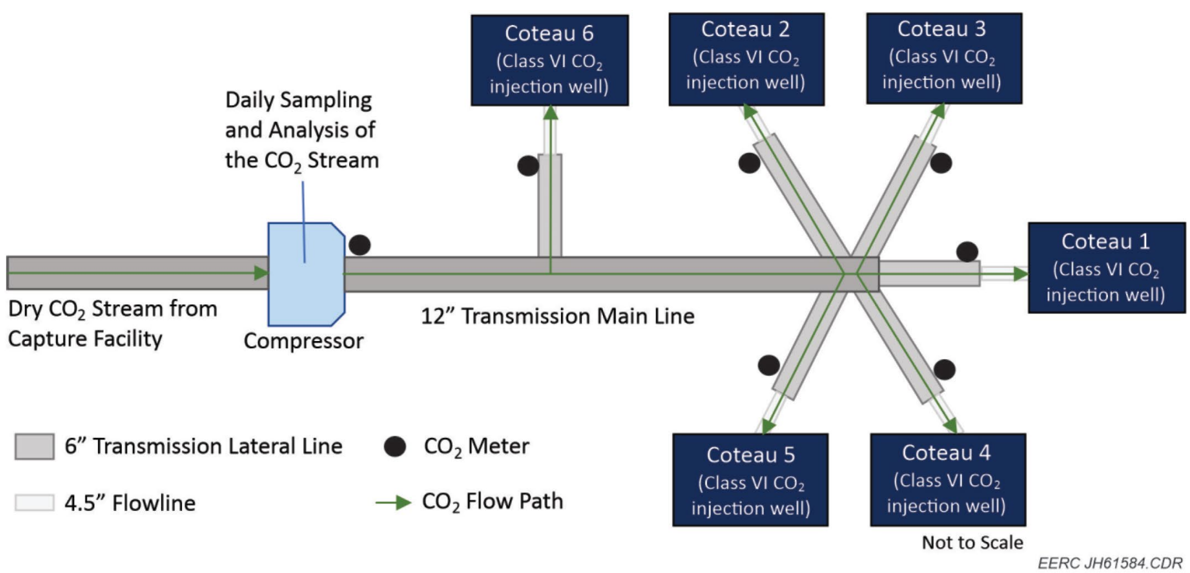

Figure 1-4b. Flow diagram illustrating major carbon capture and storage (CCS) components and the path of the CO_2 stream from the capture facility to the CO_2 injection wells.

of major CCS components with the capture facility at GPSP. The facility was designed to capture the CO_2 produced during the acid gas removal step of DGC's gasification process and compress the gaseous CO_2 stream to approximately 2,500 pounds per square inch. The final compressed CO_2 stream would flow to the Coteau 1 through Coteau 6 injection wells for geologic storage into the Broom Creek Formation; an underground transmission pipeline permitted through the North

Dakota Public Service Commission (NDPSC) Case No. PU-21-150 is installed on Basin, DGC, and Coteau Properties Company (CPC) property to connect the capture facility to the Coteau 1 through Coteau 6 injection wells. CPC, a wholly owned subsidiary of North American Coal Corporation, operates the Freedom Mine near the GPSP, supplying lignite coal feedstock to the plant.

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area: DGC AOR Delineation in Accordance with U.S. Environmental Protection Agency and North Dakota Rules

DGC proposes that because the AOR, as delineated in Reference 1, Section 4, exceeds the requirements of the active monitoring area (AMA) under Title 40, CFR § 98.449 (Subpart RR), the AOR will serve as the AMA for the Great Plains CO_2 Sequestration Project (Figure 2-1).

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). Therefore, DGC elected to permit the storage facility area boundaries based on the reservoir model output discussed in Reference 1, Section 4, and then, added a 1-mile buffer, rounding out to the nearest 40-acre tract.

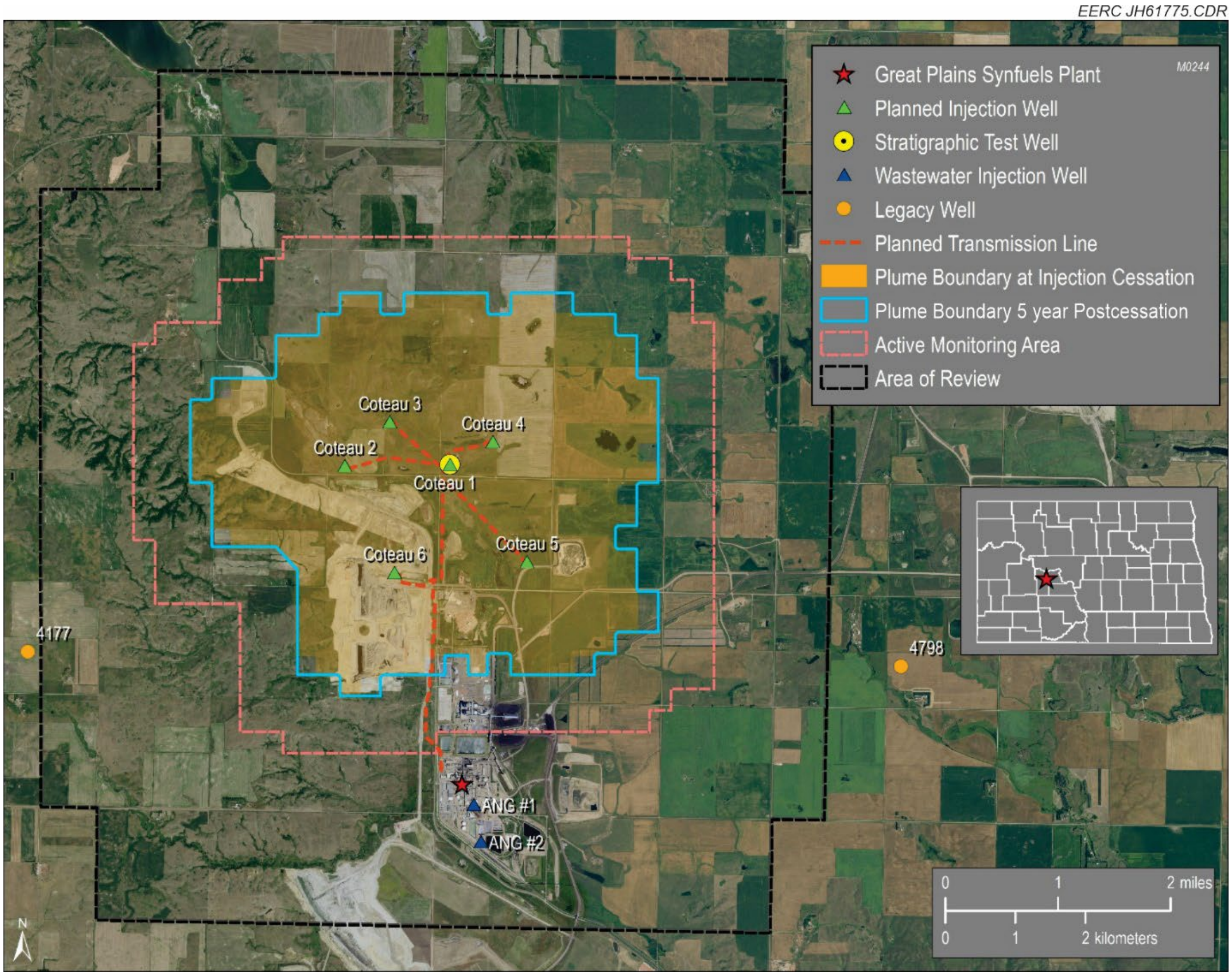

Figure 2-1. Map showing the AOR relative to the AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR), with "t" set equal to injection cessation (12 years). The AOR subsumes the AMA and exceeds requirements for the AMA; therefore, the AOR serves as the AMA for the Great Plains CO_2 Sequestration Project.

2.2 Maximum Monitoring Area

DGC proposes that the delineated AOR and proposed AMA from Figure 2-1 also serve as the maximum monitoring area (MMA) for the Great Plains CO_2 Sequestration Project (Figure 2-2), as it also exceeds the requirements for delineating the MMA under 40 CFR § 98.449 (Subpart RR).

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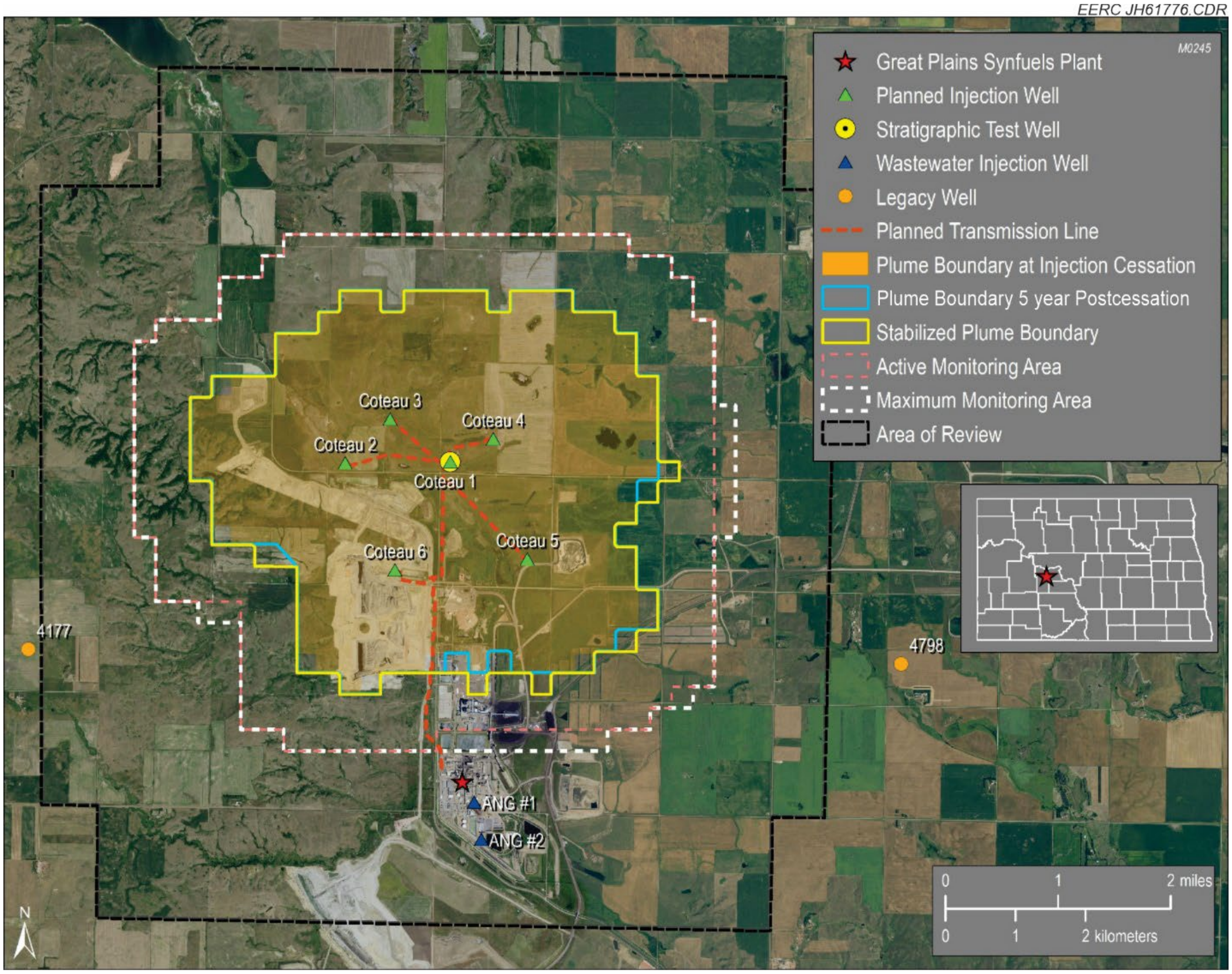

Figure 2-2. Map showing the AOR relative to the calculated MMA and AMA boundaries, calculated as prescribed under 40 CFR § 98.449 (Subpart RR). The AOR subsumes the calculated AMA and MMA and exceeds requirements for both AMA and MMA; therefore, the AOR serves as both the AMA and MMA for the Great Plains CO_2 Sequestration Project.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2 (Reference 1, Section 5) comprises three distinct periods: 1) pre-operational (pre-injection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) post-operational (post-injection of CO_2) monitoring. These monitoring periods, therefore, encompass the entire life cycle of the project. For purposes of this MRV plan, it is expected that reporting will be initiated during the operational period and continue through the post-injection period.

The storage system parameters that are monitored during each period are essentially identical; however, the duration of the monitoring period of the measurements performed varies. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

The pre-operational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and uncertainty associated with the measurement of each of the key storage system parameters. An understanding of the repeatability and variability of each measurement is key to successfully determining the movement of CO_2 that is contained in the formation at any given time.

The operational injection period is focused on validating and updating numerical models of the storage system to ensure that the geologic storage project is operating safely and protecting all USDWs. Lastly, the purpose of the post-operational monitoring is to verify the stability of the CO_2 plume location and assess the integrity of all decommissioned wells. The duration of these monitoring periods is a minimum of 12 and 10 years, respectively.

3.0 EVALUATION OF POTENTIAL LEAKAGE PATHWAYS

The potential leakage pathways for CO_2 arriving at the surface after injection or from surface equipment failures during operations were evaluated. Factors and equipment that could lead to leakage pathways were identified and placed into the following six categories:

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

This leakage assessment determined none of the pathways required corrective action and the probability of leakage is unlikely. However, a robust monitoring program, described in Reference 1, Section 5, and summarized in Table 5-1, was developed to form the basis of this MRV plan.

3.1 Class I Nonhazardous Disposal Wells

Two Class I disposal wells are active in the Great Plains CO_2 Sequestration Project area. Both wells were drilled in the 1980s to dispose of nonhazardous wastewater produced from GPSP operations in the Minnelusa Group (Broom Creek Formation) and Kibbey Formation under North Dakota Department of Health (NDDH) Permit Nos. ND-UIC-101 and ND-UIC-102. In 2018, both permits were renewed under NDDH Permit No. ND-UIC-101-1. In 2019, the North Dakota Department of Environmental Quality (NDDEQ) separated from the NDDH, and both Class I disposal wells were given well numbers by the NDDEQ.

3.1.1 ANG #1 (NDDEQ Well No. 11308)

The American Natural Gas No. 1 Disposal Well (ANG #1) spudded in April 1982 (NDDEQ Well No. 11308), reaching a total depth of 6,784 feet in the Kibbey Formation. Drillstem test data and core collected from porous and permeable intervals of the Dakota, Minnelusa, and Kibbey saw

no evidence of hydrocarbons. Injectivity tests demonstrated the Minnelusa (Broom Creek Formation) and Kibbey were the most viable for receiving wastewater at the injection rates and volumes specified in NDDH Permit No. ND-UIC-101. The well was completed in the Minnelusa in July 1982, and additional perforations were added to the Kibbey Formation in 1983. The ANG #1 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure, and a seal pot system on the annulus to detect annulus leaks. The ANG #1 is also monitored with temperature logs or tracer surveys about once every 5 years.

The ANG #1 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project and was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-4).

3.1.2 ANG #2 (NDDEQ Well No. 11309)

The American Natural Gas No. 2 Disposal Well (ANG #2) spudded in September 1983 (NDDEQ Well No. 11309), reaching a total depth of 6,911 feet in the Kibbey Formation. The well was completed in both the Minnelusa (Broom Creek Formation) and Kibbey sands (NDDH Permit No. ND-UIC-102). The ANG #2 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure in the tubing-casing annulus, and a seal pot system on the annulus to detect annulus leaks. The ANG #2 is also monitored with temperature logs or tracer surveys about once every 5 years.

The ANG #2 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project and was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-5).

3.2 Abandoned Oil and Gas Wells

The Herrmann 1 (NDIC File No. 4177) well spudded in November 1966. The well was drilled to a depth of 8,057 feet into the Frobisher interval (stratigraphically equivalent to the Mission Canyon Formation of the Madison Group) and was plugged and abandoned in December of the same year. A drillstem test was conducted in the Frobisher interval, but the well encountered no commercial accumulations of hydrocarbons.

The Herrmann 1 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project and is the only oil and gas well within 0.5 miles outside of the AOR. It was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-3).

3.3 Surface Components

Surface equipment components present potential leakage pathways during the operational injection period for the Great Plains CO_2 Sequestration Project site. Surface equipment can be subject to deterioration due to normal aging throughout its functional life. Corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in these assets.

The DGC CCS system includes a 6.8-mile-long transmission pipeline (NDPSC Case No. PU-21-150), six flowlines, and six injection wellheads (Figure 1-4b). The transmission line consists of a 12-inch main line and six 6-inch lateral lines that branch off and connect with 4.5-inch flowlines near each well pad. The flowlines will be connected to metering stations and located contiguous with the well pads (Reference 1, Section 5, Figures 5-1 and 5-2). Flowmeters will be installed at each metering station. The chemical composition of the CO_2 stream that will flow through the surface equipment is given in Reference 1, Section 5.1.1, Table 5-2.

Surface components of the injection system, including the flowlines and wellheads, will be monitored using leak detection equipment. The wellsite flowlines will be monitored continuously via multiple pressure gauges and H_2S detection stations located between the transmission line and the individual wellheads. This leak detection equipment will be integrated with automated warning systems that notify the pipeline control center at DGC, giving the operator the ability to remotely close the valves in the event of an anomalous reading. Further details of the surface leak detection system are given in Reference 1, Section 5.3.

The risk of leakage via surface equipment is mitigated through:

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

The risk of leakage through surface equipment (under normal operating conditions) is unlikely, and the magnitude will vary according to the failure observed. A potential leakage event from instrumentation or valves could represent a few pounds of CO_2 released during several hours, while a puncture in the flowline could represent several tons of CO_2 released underground until the operator ceases the CO_2 supply. Note that should a shutoff situation occur, the CO_2 stream can be looped back to the DGC capture facility, passed through the burners, and be vented to the atmosphere.

This risk of leakage through surface equipment reduces to almost zero during the post-injection site care period. At cessation of the injection period, the injection wells will be properly plugged and abandoned following NDIC protocols and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the Class I wastewater injection wells, ANG #1 and ANG #2, identified as potential leakage pathways at the wellhead valves or in the instrumentation.

3.4 Faults, Fractures, Bedding Plane Partings, and Seismicity

No known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations have been identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration activities (Reference 1, Section 2.5).

3.4.1 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 (Reference 1 Section 2.5). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The seismic event recorded closest to the Great Plains CO_2 Sequestration Project occurred 36.4 miles to the southwest of the Coteau 1 injection wellsite, with a magnitude of 3.2 (Reference 1, Section 2.5).

Studies completed by the U.S. Geological Survey indicate there is a low probability of damaging seismic events occurring in North Dakota, with less than two such events predicted to occur over a 10,000-year period (U.S. Geological Survey, 2019). Through the geologic site characterization and corrective action review processes, leakage resulting from natural or induced seismicity was shown to be very unlikely.

3.5 Class VI Injection Wells

3.5.1 Coteau 1 (NDIC File No. 38379)

The Coteau 1 well spudded in June 2021 as a stratigraphic test well to a depth of 6,483 feet into the Amsden Formation. This well was drilled to gather geologic data to support the development of a CO_2 SFP and to later be converted into a Class VI injection well for the Great Plains CO_2 Sequestration Project. The Coteau 1 will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues. Once the injection period ceases, the Coteau 1 will be properly plugged and abandoned following NDIC protocols.

3.5.2 Coteau 2 Through Coteau 6 Planned CO_2 Injection Wells

The Coteau 2 (NDIC File No. 38916), Coteau 3 (NDIC File No. 38917), and Coteau 4 (NDIC File No. 38918) wells are planned to spud in June 2022 as stratigraphic test wells for the Great Plains CO_2 Sequestration Project. The wells will be drilled to the Amsden Formation at planned depths of 6,345, 6,339, and 6,301 feet, respectively. Once the SFP is issued, all stratigraphic test wells will be converted to Class VI injection wells. Like the Coteau 1, the wells will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues. The Coteau 5 and Coteau 6 wells are planned to spud in 2026 and are conditional upon additional injection volumes of CO_2 becoming available from the capture facility. The Coteau 5 and Coteau 6 wells will be monitored after the same manner as the Coteau 1 through

Coteau 4 wells. Once the injection period ceases, the Coteau 2 through Coteau 6 wells will be properly plugged and abandoned following NDIC protocols.

3.6 Confining Zone Limitations

3.6.1 Lateral Migration

For the Great Plains CO_2 Sequestration Project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure (Reference 1, Section 2.3.2). The Opeche Formation is a laterally extensive formation that is 5,763 feet below the surface and 143 feet thick at the Coteau 1 wellsite (Reference 1, Section 2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine).

3.6.2 Seal Diffusivity

Several other formations provide additional confinement above the Opeche Formation (Reference 1, Section 2.4.2). Impermeable rocks above the primary seal, the Opeche Formation, include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations. Together with the Opeche, these formations are 1,106 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 2,657 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation. Confining layers above the Inyan Kara include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (see Figure 1-3 for stratigraphic reference).

The possibility of fluid migration through a total of 3,763 feet of overlying confining layers presents a very low risk to the Great Plains CO_2 Sequestration Project. The thick impermeable layers and laterally extensive formations drastically reduce potential leakage pathways through geologic formations.

3.6.3 Drilling Through the CO_2 Area

There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the AOR. Although there was a historical oil and gas production well test from the Madison Group just outside the AOR (i.e., Herrmann 1), there are no known commercial accumulations of hydrocarbons in the AOR (Reference 1, Section 2.6). With no known commercial ventures drilling near the Great Plains CO_2 Sequestration Project area, there is very little chance of drilling through the storage complex. In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a deviated or horizontal well could be used to produce the hydrocarbon while avoiding drilling through the CO_2 plume or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available, which will allow prospective operators to design an appropriate well control strategy via increased drilling mud weight. The maximum pressure increase in the center of the injection area is projected by computer modeling to be 400–450 psi, with lesser impacts extending radially (Reference 1, Section 3, Figure 3-20). Pressure increases will relax post-injection as the area returns to its pre-injection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the CO_2 should be designed to include an intermediate casing string made of CO_2-resistant material and placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place.

3.7 Monitoring, Response, and Reporting Plan for CO_2 Loss

DGC proposes a robust monitoring program for the SFP (Reference 1, Section 5). The program covers a corrosion and mechanical integrity protocol (Reference 1, Section 5.2), surveillance of injection performance (Reference 1, Sections 5.3 and 5.4), monitoring of near-surface conditions (Reference 1, Sections 5.5 and 5.6), and direct and indirect monitoring of the CO_2 plume (Reference 1, Section 5.7). To compliment the monitoring program, DGC proposes a detailed emergency remedial and response plan (Reference 1, Section 7) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting in the event of an unplanned loss of CO_2 from the Great Plains CO_2 Sequestration Project area.

3.8 Summary

In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the emergency and remedial response plan. Estimating volumetric losses of CO_2 would require consideration of the leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based upon the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

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

Table 4-1. Summary of DGC's CCS Monitoring Strategy

Method (target area/structure)	**Pre-injection (Baseline – 1 year)**	**Injection Period (12 years)**	**Post-injection (10 years)**
CO_2 Stream Analysis (capture)	Start-up	Daily	NA[1]
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	Start-up	Real time	NA
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	Start-up	Real time	NA
H_2S Detection Stations (flowlines, wellheads, and well pads)	Start-up	Real time	NA
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	Start-up	Monthly in the first quarter, then quarterly in the next 2 years	NA
Platform Multifinger Imaging Tool (PMIT) or Ultrasonic Imaging Tool (USIT) (CO_2 injection wells)	NA	Starting in Year 2, a PMIT or USIT will be run during well workovers but not more frequently than once every 5 years	NA
SCADA[2] Automated Remote System (surface facilities)	Start-up	Real time	NA
Soil Gas Analysis (11 soil gas profile stations)	Three to four seasonal samples	Three to four seasonal samples each year	Three to four seasonal samples each year
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)	Provide historical water sampling results	NA	NA
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)	Baseline	NA	NA
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	Baseline	Three to four seasonal samples	Three to four seasonal samples
Cement Bond Logs (CO_2 injection wells)	After cementing	If needed	Prior to P&A[3]
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	Baseline	Perform during workovers but not more than once every 5 years	Perform during workovers but not more than once every 5 years
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	Start-up	Real time	NA
Pulsed-Neutron Logs with Temperature and Bottomhole Pressure Readings (CO_2 injection wells)	Baseline	Quarterly using phased approach described in Reference 1, Section 5.1.2	NA
USIT Logs (CO_2 injection wells)	Baseline	Perform during workovers but not more than once every 5 years	Perform during workovers but not more than once every 5 years
Pressure Falloff Test (CO_2 injection wells)	Baseline	Every 5 years	NA
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	Baseline	Repeat survey 1 year after injection begins, then in Years 3, 5, and 10	Repeat survey 1 year after injection ceases, then in Years 3, 5, and 10
Vertical Seismic Profiles (VSP) (CO_2 plume)	Baseline	Repeat VSP 1 year after injection begins, then (if deemed beneficial) in Years 3, 5, and 10	NA

[1] Not applicable
[2] Supervisory control and data acquisition
[3] Plugged and abandoned

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

Monitoring Strategy (target area/structure) \ Potential Leakage Pathway	Wellbores*	Faults and Fractures	Flowline and Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis (capture)			X			
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	X		X			X
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	X		X	X		
H_2S Detection Stations (flowlines, wellheads, and well pads)	X		X	X		X
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	X		X	X		
PMIT or USIT (CO_2 injection wells)	X			X		
SCADA Automated Remote System (surface facilities)	X		X	X		
Soil Gas Analysis (11 soil gas profile stations)	X			X	X	X
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)				X	X	X
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)		X		X	X	X
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	X	X		X	X	X
Cement Bond Logs (CO_2 injection wells)	X			X		X
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	X			X		
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	X			X	X	
Pulsed-Neutron Logs with Temperature and Bottomhole Readings (CO_2 injection wells)	X			X	X	X
USIT Logs (CO_2 injection wells)	X			X		
Pressure Falloff Test (CO_2 injection wells)	X			X	X	
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	X	X		X	X	X
VSP (CO_2 plume)*	X	X		X	X	X

* Applies to all wellbores in project area if not otherwise specified under the monitoring strategy target area/structure column.

4.1 Leak Verification

DGC's strategy to detect and verify leakage pathways is summarized in Table 4-2.

As part of the surveillance protocol, DGC will use reservoir simulation modeling, based on history-matched data obtained from the monitoring program, to compare the initial numerical model with the real development of the plume and pressure front. The model will be continuously calibrated with the acquisition of real-time data. Every 5 years, a formal AOR will be submitted, and the monitoring plan will be revised, if needed.

The model history match allows the project operator and owner to identify conditions that differ from those proposed by the numerical model and deviations in the operating conditions from the originals. For example, the injection well will be monitored, and if the injection pressure, temperature, or rate measurements deviate significantly from the specified set points, then a data flag will be automatically triggered by the automated system and field personnel will investigate the excursion. These excursions will be reviewed to determine if CO_2 leakage is occurring. Excursions are not necessarily indicators of leaks; rather, they indicate that injection rates, temperatures, and pressures are not conforming to the expected pattern of the injection plan. In many cases, problems are straightforward and easy to fix (e.g., a meter needs to be recalibrated), and there is no indication that CO_2 leakage has occurred. In the case of issues that are not readily resolved, a more detailed investigation will be initiated. If further investigation indicates a leak has occurred, efforts will be made to quantify its magnitude.

The model history-matching in combination with the mechanical integrity data, geophysical surveys, and near-surface monitoring form a powerful tool to appropriately follow changes in CO_2 concentration at the surface. Many variations of CO_2 concentration detected on the surface are the result of natural processes or external events not related to the CO_2 storage complex.

Because a CO_2 surface leak is of lower temperature than ambient conditions, it will often lead to the formation of bright white clouds and ice that are easily visually observed. With this understanding, DGC will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the Great Plains CO_2 Sequestration Project.

Response plan actions and activities will depend upon the circumstances and severity of the event. DGC will address an event immediately and, if warranted, communicate the event to the UIC program director within 24 hours of discovery.

If an event triggers cessation of injection and remedial actions, DGC will demonstrate the efficacy of the response/remedial actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations will only resume upon receipt of written authorization of the UIC program director.

4.2 Quantification of Leakage

As discussed above, the potential pathways for leakage include failure or issue in surface equipment or subsurface equipment (wellbores), faults or induced fractures, and competency of the seal to contain the CO_2 in the storage reservoir.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods to quantify the volume of CO_2 will be determined on a case-by-case basis. Any volume of CO_2 detected as leaking to the surface will be quantified using acceptable emission factors, engineering estimates of leak amount based on subsurface measurements, numerical models, history-matching of the reservoir performance, detailed analysis of the collected monitoring parameters, and delineation of the affected area, among others. Leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in an electronic central database.

5.0 DETERMINATION OF BASELINES

DGC will establish pre-injection baselines by implementing a monitoring program prior to any CO_2 injection and during each of the four primary seasonal ranges. This baseline will be created by monitoring the targeted surface, near-surface, and deep subsurface. The baseline will contain information on the characteristics of a range of environmental media, such as surface water, soil gas in the vadose zone, shallow groundwater, and storage reservoir formation water.

These baselines provide a basis for determining if CO_2 leaks are occurring by providing a foundation against which characteristics of these same media during CO_2 injection can be compared and evaluated. For example, changes in concentrations or levels of certain parameters in these media during injection might suggest that they have been impacted by leaking CO_2.

Determinations of these baselines are a critical component of a Class VI SFP. A detailed description of these baselines for both the surface and subsurface for the Great Plains CO_2 Sequestration Project area is provided in Reference 1, Sections 5.3 through 5.7.

5.1 Surface Baselines

A baseline sampling program has been completed for the Great Plains CO_2 Sequestration Project. Baseline data were obtained from 11 soil gas-sampling locations and two existing groundwater wells from the northern and eastern portions of the AOR. Baseline water samples are also planned to be obtained from five new Fox Hills monitoring wells that will be drilled prior to the start of injection operations. One of the groundwater monitoring wells will be placed near the Herrmann 1 well and the others will be placed adjacent to the Coteau 1 through Coteau 4 injection wells (Reference 1, Section 5.6, Figure 5-4). For additional information regarding surface baselines, refer to Reference 1, Sections 5.5.1–5.5.2 and Section 5.6, paragraph 1.

5.2 Subsurface Baselines

Pre-operational baseline data will be collected in the injection and monitoring wells using pulsed-neutron logs. These time-lapse saturation data will be used as an assurance-monitoring technique for CO_2 in the formation directly above the storage reservoir, otherwise known as the above-zone monitoring interval.

Indirect monitoring methods will also track the extent of the CO_2 plume within the storage reservoir and can be accomplished by performing time-lapse geophysical surveys of the AOR. A 2D radial seismic survey was collected to establish baseline conditions in the storage reservoir. A baseline VSP was also collected to determine the feasibility of monitoring the CO_2 plume during the injection phase with this technology. For additional information regarding subsurface baselines, refer to Reference 1, Section 5.7.2.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The Great Plains CO_2 Sequestration Project area is a geologic CO_2 storage site in a saline aquifer with no production associated from the storage complex. A flowmeter will be placed downstream of the CO_2 compressor (start of the CO_2 transmission line) and near each of the injection wellheads (Figure 1-4b). The proposed main metering station for mass balance calculation is identified as the first metering station placed at the start of the CO_2 transmission main line. The use of a single metering station for the mass balance calculation (as opposed to using multiple metering stations near each wellhead) will help ensure accuracy of the measurements.

To calculate the annual mass of CO_2 that is stored in the storage complex, the project will use Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

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

Where:

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

<u>Mass of CO_2 Injected (CO_{2I})</u>:
DGC will use volumetric flow metering to measure the flow of the injected CO_2 stream and will calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the volumetric flow at standard conditions by the CO_2

concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5 from 40 CFR Part 98, Subpart RR (Equation 2):

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

Where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for Flowmeter u in Quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

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

p = Quarter of the year.

u = Flowmeter.

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

DGC characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in Reference 1, Section 5, to detect any leak and defined a baseline for monitoring.

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

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

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

Where:

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

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

x = Leakage pathway.

Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

Annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead (CO_{2FI}) will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan proposed in Reference 1, Section 5.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented starting September 2022 or within 90 days of EPA approval, whichever occurs later. Other greenhouse gas reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time. It is anticipated that the MRV program will be in effect from September 2022 to September 2036, during which time the Great Plains CO_2 Sequestration Project will be operated.

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for DGC monitoring techniques and data management is provided in the quality assurance and surveillance plan found in Reference 1, Appendix C.

DGC 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 a receiving meter at each of the injection well pads.
- The quarterly CO_2 concentration will be reported from near-continuous measurement upstream of the receiving meter on the injection well pads.

Flowmeter provision:

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

9.0 RECORDS RETENTION

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

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

- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

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

10.0 REFERENCES

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GREAT PLAINS CO_2 SEQUESTRATION PROJECT MERCER COUNTY, NORTH DAKOTA

North Dakota CO_2 Storage Facility Permit Application

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March 2022

TABLE OF CONTENTS

Continued . . .

TABLE OF CONTENTS (continued)

Continued . . .

TABLE OF CONTENTS (continued)

Continued . . .

TABLE OF CONTENTS (continued)

GREAT PLAINS CO_2 SEQUESTRATION PROJECT
MERCER COUNTY, NORTH DAKOTA

PERMIT APPLICATION SUMMARY

The Dakota Gasification Company (DGC), together with its partners and affiliates, requests consideration of this application for the dedicated geologic storage of carbon dioxide (CO_2) at DGC's Great Plains Synfuels Plant, located 5 miles northwest of Beulah, North Dakota.

Built in the 1970s as a response to America's quest for energy independence, the Great Plains Synfuels Plant has been owned and operated by DGC since 1988. Capable of gasifying 6 million tons of lignite coal per year, the facility generates approximately 150 million standard cubic feet (MMscf) of natural gas daily and is the only such plant of its kind in the country. Among the by-products of the gasification process is a nearly pure stream of CO_2 (95+% by volume).

The plant has captured and transported more than 40 million metric tons of CO_2 for enhanced oil recovery purposes since 2000. This is accomplished by means of a 205-mile pipeline that has operated without incident for the past 22 years. The CO_2 is first compressed to a pressure of ±2,500 psi, then transported north as a supercritical fluid. There currently exists excess compressor capacity which makes the capture of an additional 1.0 MMt/year possible. As additional compressed volumes become available over the next 4 years, on-site sequestration of 2.7 MMt/year is expected. Over the anticipated 12-year life of this project, sequestered volumes of CO_2 are expected to total 26 MMt. Four injection wells are anticipated initially, with two additional wells planned as increased volumes in 2026 or beyond warrant. Extensive reservoir simulations have been conducted to predict the full extent of the injected CO_2 plume in the subsurface over the life of the project, the results of which are displayed in Figure PS-1.

DGC is a wholly owned subsidiary of Basin Electric Power Cooperative (Basin), a consumer owned utility that serves over 3 million customers across nine states and is one of North Dakota's largest employers. Basin employees have played an integral role in the preparation of this application, as have representatives from the University of North Dakota's Energy & Environmental Research Center (EERC) and Denver's Carbon Vault Great Plains LLC (CV). The EERC has a 19-year history studying the CO_2 sequestration potential of North Dakota's Williston Basin in general and the Broom Creek sandstone formation specifically. The EERC also leads the Plains CO_2 Reduction (PCOR) Partnership, whose mission is "making safe practical carbon capture, utilization, and storage (CCUS) projects a reality." CV is a subsidiary of Rampart Energy Company (fka Duncan Energy Company), which has been a long-time oil and gas operator in the state and is lending its drilling, reservoir, operations, and injection well expertise to this project.

The target storage interval for the project is the Broom Creek sandstone formation, which underlies the synfuels plant and surrounding region. The Broom Creek Formation, and more specifically its CO_2 storage potential, has been the subject of numerous studies conducted by the North Dakota Geological Survey, the U.S. Geological Survey, and the EERC. It has been deemed an ideal storage candidate because of its superior reservoir quality, depth, impermeable upper and lower confining zones, and expansive areal extent. Preliminary estimates suggest a maximum storage capacity exceeding 10 billion metric tons of CO_2. The Coteau 1 stratigraphic test well was drilled in June 2021 and confirmed all expectations for the Broom Creek interval as the preferred sequestration zone at this location.

The operational plan calls for a 6.8-mile transmission line consisting of a 12" mainline and adjoining 6" lateral lines to the individual injection sites (permitted through the North Dakota Public Service Commission) to deliver CO_2 from the synfuels plant to the nearby sequestration area. Sequestration closer to the synfuels plant was originally considered but was ultimately adjusted northward because of possible interference with existing Class I Broom Creek water disposal wells associated with DGC plant operations. This transmission line will be operated and monitored in a manner consistent with the existing 205-mile CO_2 transmission line to Canada.

As the transmission lines dead-end at the individual wellsites, a pressure drop commensurate with anticipated injection conditions will take place, thus transitioning to the individual well flowlines included in this permit application.

The effluent from the synfuels plant operation includes other constituents beyond CO_2. Among these are ethane (1% by volume) and hydrogen sulfide (H_2S), 1.2% by volume. Exposure to H_2S can be harmful at very low concentrations. For that reason, continuous H_2S monitoring is planned, with automated alarms and emergency shutdown valves included. In addition, soil gas and Fox Hills water samples will be analyzed on a quarterly basis to detect any changes. The Fox Hills Formation represents the deepest subsurface formation that contains an underground source of drinking water (USDW). At this location, the base of the Fox Hills Formation is more than 4,500 feet above the Broom Creek injection interval, with both the Opeche Shale and the thousands of feet thick Pierre Shale in between.

The condition of downhole equipment will be monitored with multiple degrees of redundancy. Surface pressures will be tracked continuously for signs of anomalies, tubulars will be evaluated via ultrasonic electrical logs and/or caliper diagnoses, and regular mechanical integrity tests will be performed. Periodic pulse neutron logging will be conducted to monitor the near wellbore environment and confirm CO_2 is confined to the injection zone. As for the expansion of the CO_2 plume itself, periodic seismic surveys will be conducted, and compared to a preinjection baseline, to determine the extent of the plume's progression. Given the four to six injection wells anticipated with this project, sufficient operational flexibility will exist to maintain control of the stabilized plume within the anticipated project area.

Details of this sequestration opportunity are included in the pages to follow.

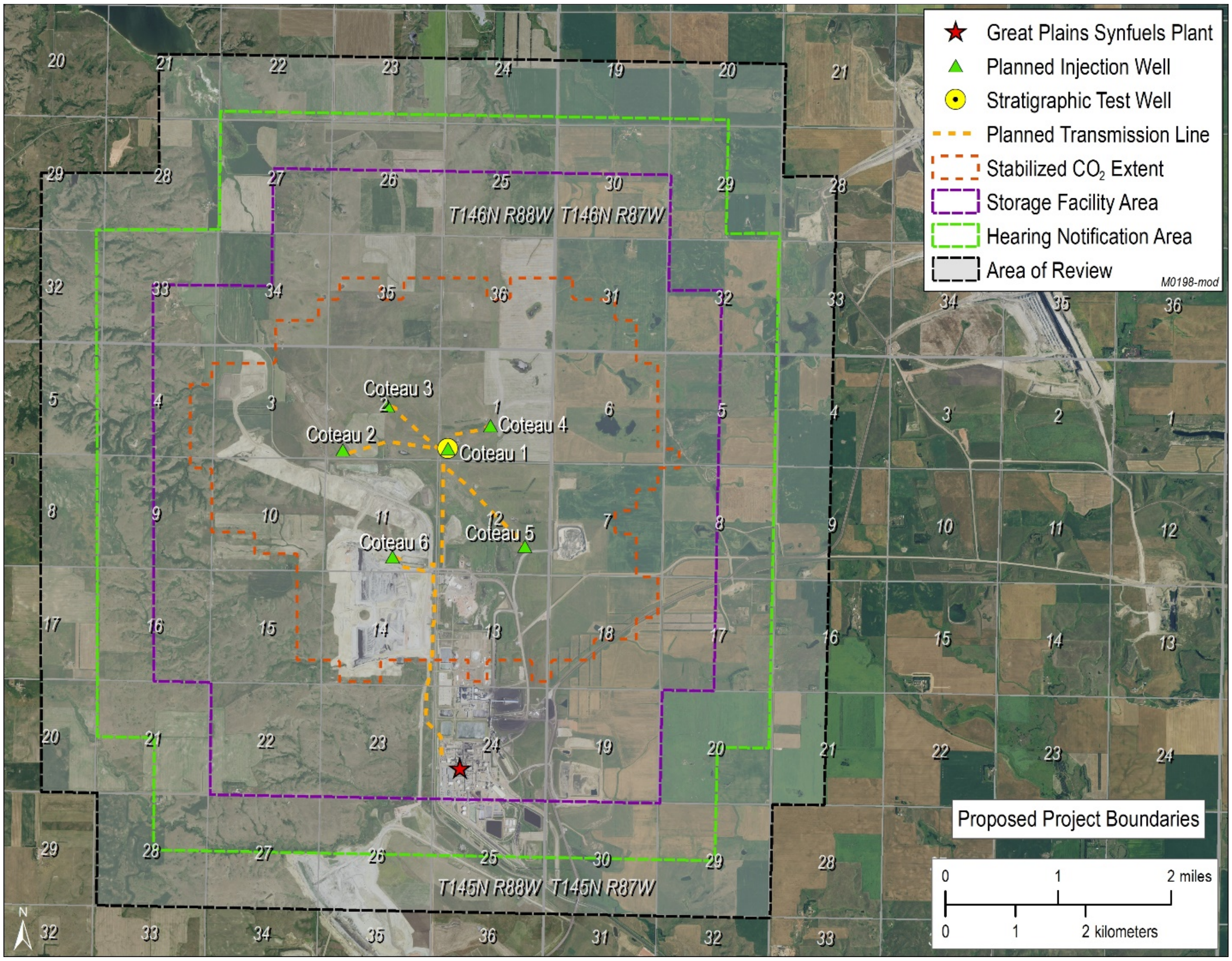

Figure PS-1. The projected stabilized CO_2 plume, storage facility area, notification area, and area of review.

1.0 PORE SPACE ACCESS

1.0 PORE SPACE ACCESS

North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate, i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] Chapter 47-31 – Subsurface Pore Space Policy). Prior to issuance of the storage facility permit (SFP), the storage operator is mandated by the North Dakota statute governing geologic storage of carbon dioxide (CO_2) to obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir. The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation. Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application (NDCC §§ 38-22-06[3] and 38-22-06[4] and North Dakota Administrative Code [NDAC] §§ 43-05-01-08[1] and 43-05-01-08[2]).

Dakota Gasification Company (DGC) has identified the owners (surface and mineral). In addition, with the exception of coal extraction, there are no mineral lessees or operators of mineral extraction activities within the facility area or within 0.5 miles of its outside boundary. DGC will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made.

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

Maps showing the extent of the pore space that will be occupied by CO_2 over the life of the project, including the storage reservoir boundary and 0.5 miles (0.8 kilometers) outside of the storage reservoir boundary with a description of pore space ownership, surface owner, and pore space lessees of record are illustrated in Figures 1-1 and 1-2.

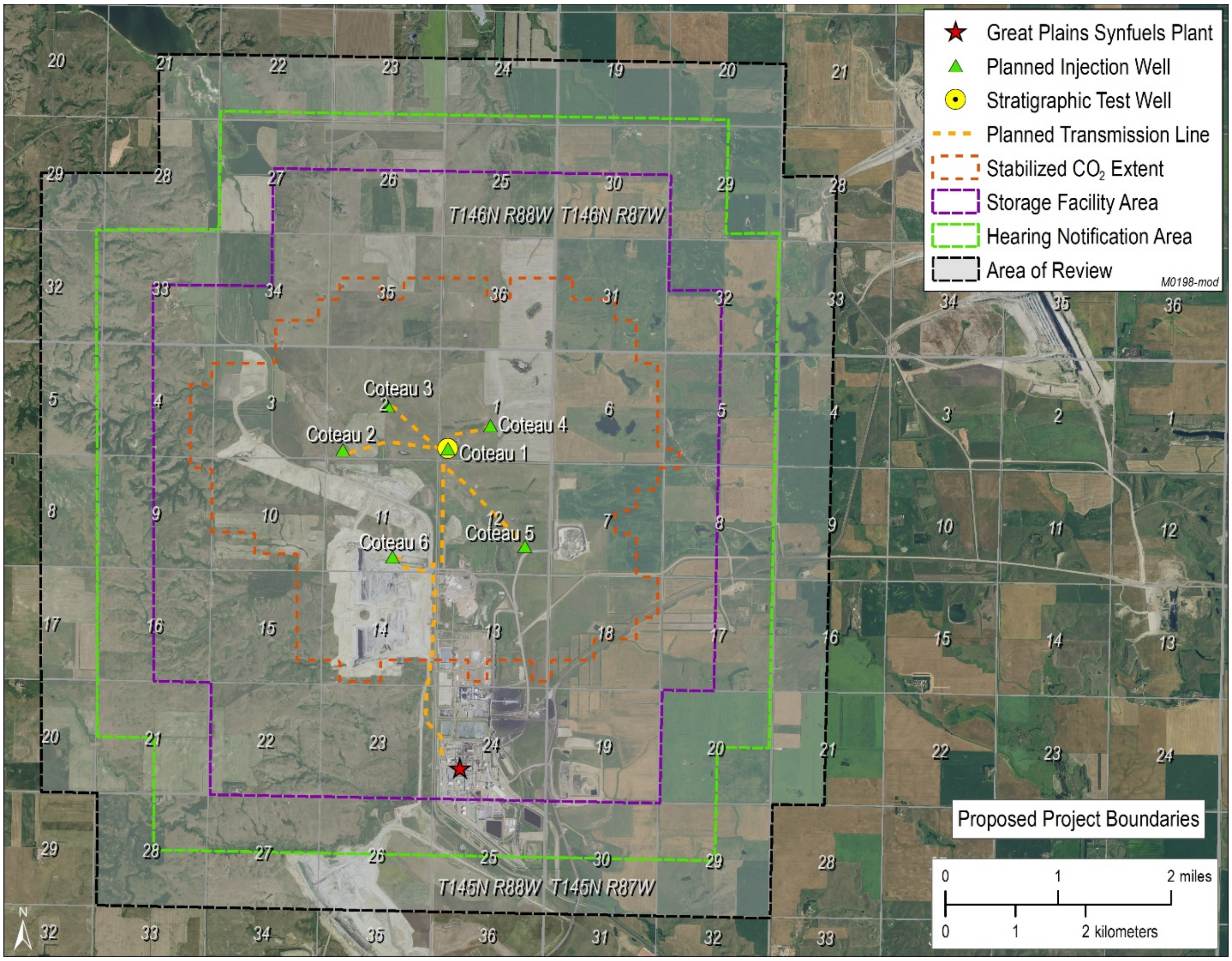

Figure 1-1. Storage facility area map.

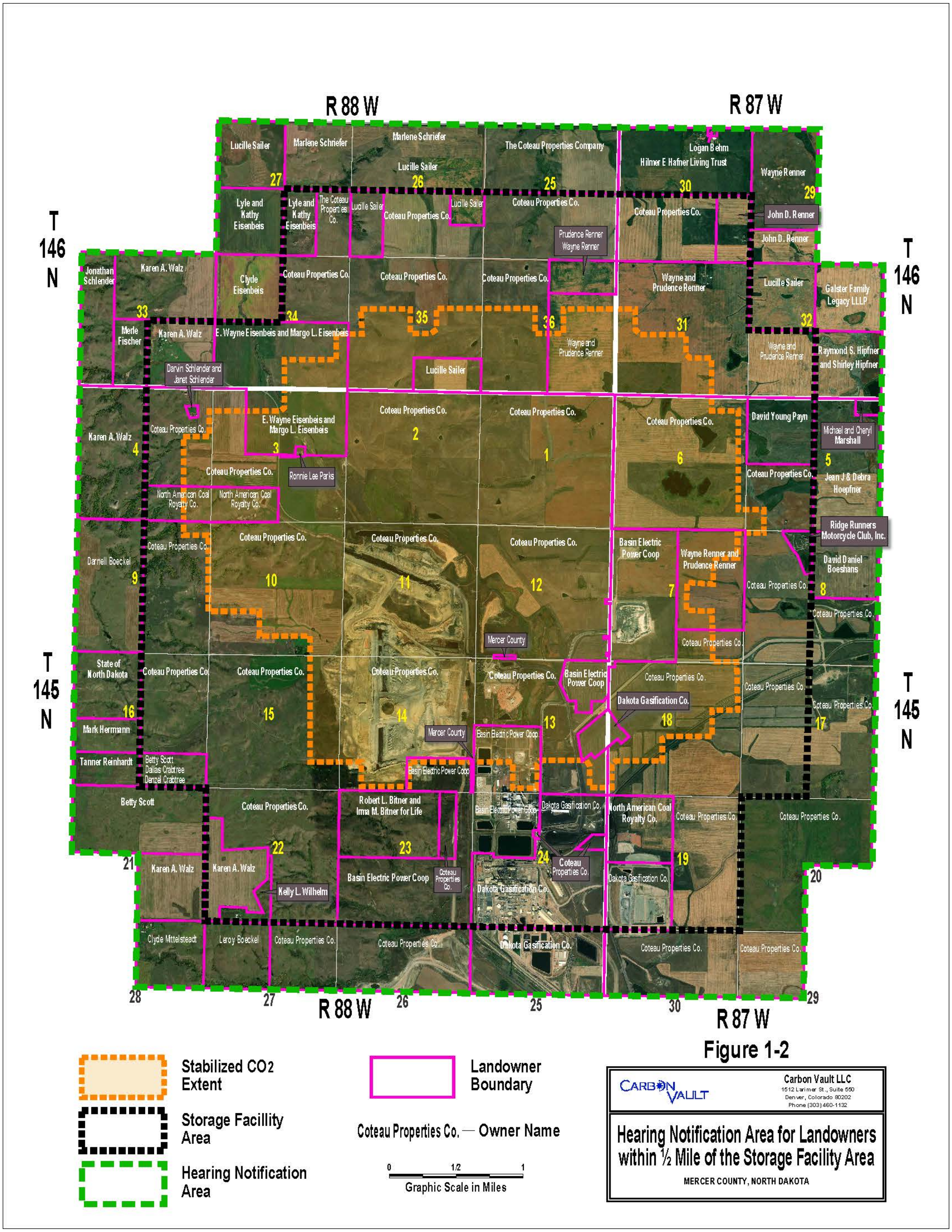

Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area.

2.0 GEOLOGIC EXHIBITS

2.0 GEOLOGIC EXHIBITS

2.1 Overview of Project Area Geology

The proposed DGC Great Plains CO_2 Sequestration Project will be situated near Beulah, North Dakota (Figure 2-1). This project site is on the central portion of the Williston Basin. The Williston Basin is an intracratonic sedimentary basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota.

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

The target CO_2 storage reservoir for the Great Plains CO_2 Sequestration Project is the Broom Creek Formation, a predominantly sandstone horizon lying about 5,900 ft below DGC's Great Plains Synfuels Plant (Figure 2-2). Mudstones, siltstones, and interbedded evaporites of the Opeche Formation unconformably overly the Broom Creek and serve as the primary confining zone (Figure 2-3). The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-3). Together, the Opeche, Broom Creek, and Amsden comprise the CO_2 storage complex for the Great Plains CO_2 Sequestration Project (Table 2-1).

Including the Opeche Formation, there is ~1,100 ft of impermeable formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation. An additional ~2,700 ft of impermeable intervals separates the Inyan Kara and the lowest USDW, the Fox Hills Formation (Figure 2-3).

2.2 Data and Information Sources

Several sets of data were used to characterize the injection and confining zones to establish their suitability for the storage and containment of injected CO_2. Data sets used for characterization included both existing data (sources and uses are discussed within Section 2.2) and site-specific data acquired by the applicant specifically to characterize the storage complex.

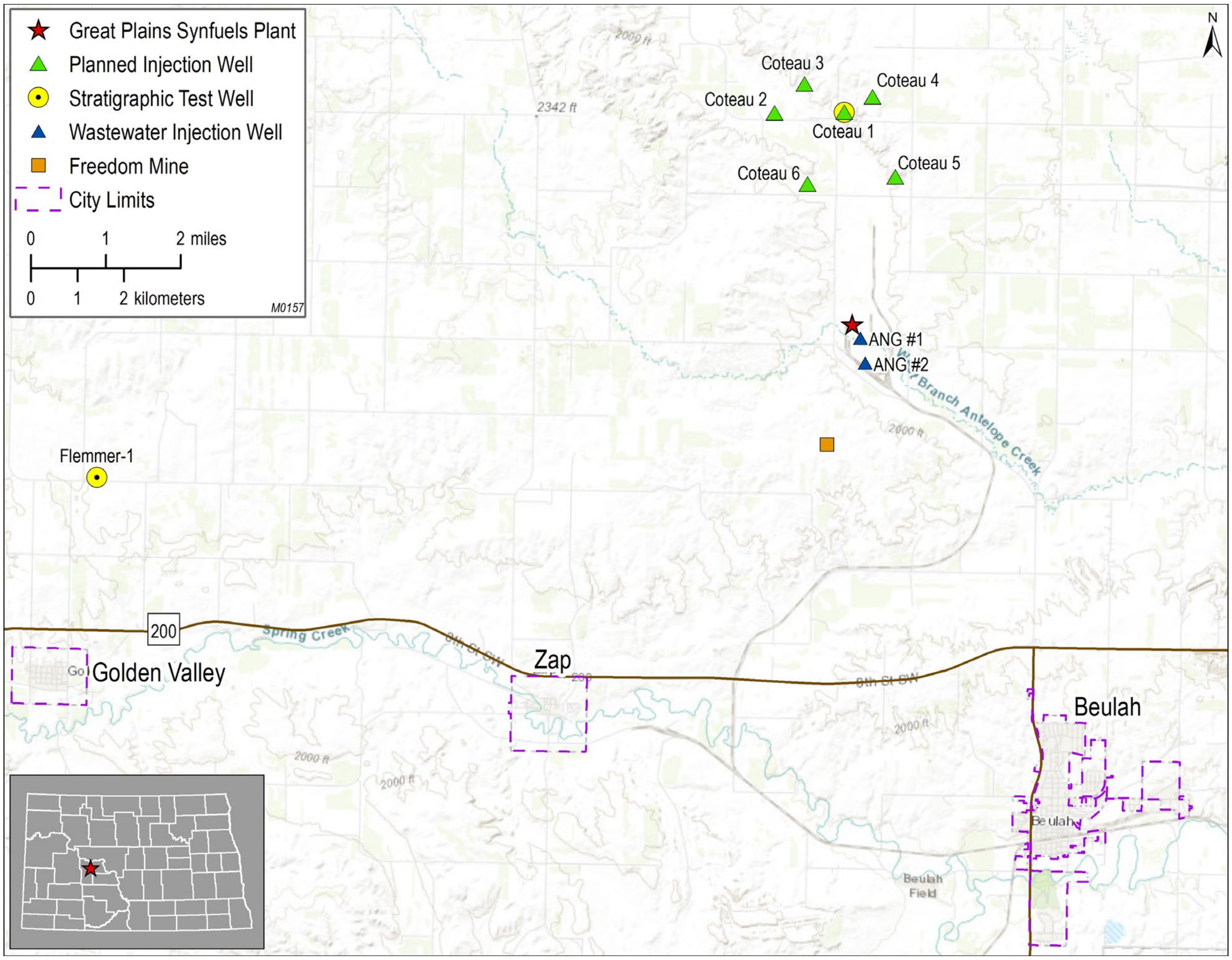

Figure 2-1. Topographic map of the Great Plains CO_2 Sequestration Project area showing well locations and the Great Plains Synfuels Plant.

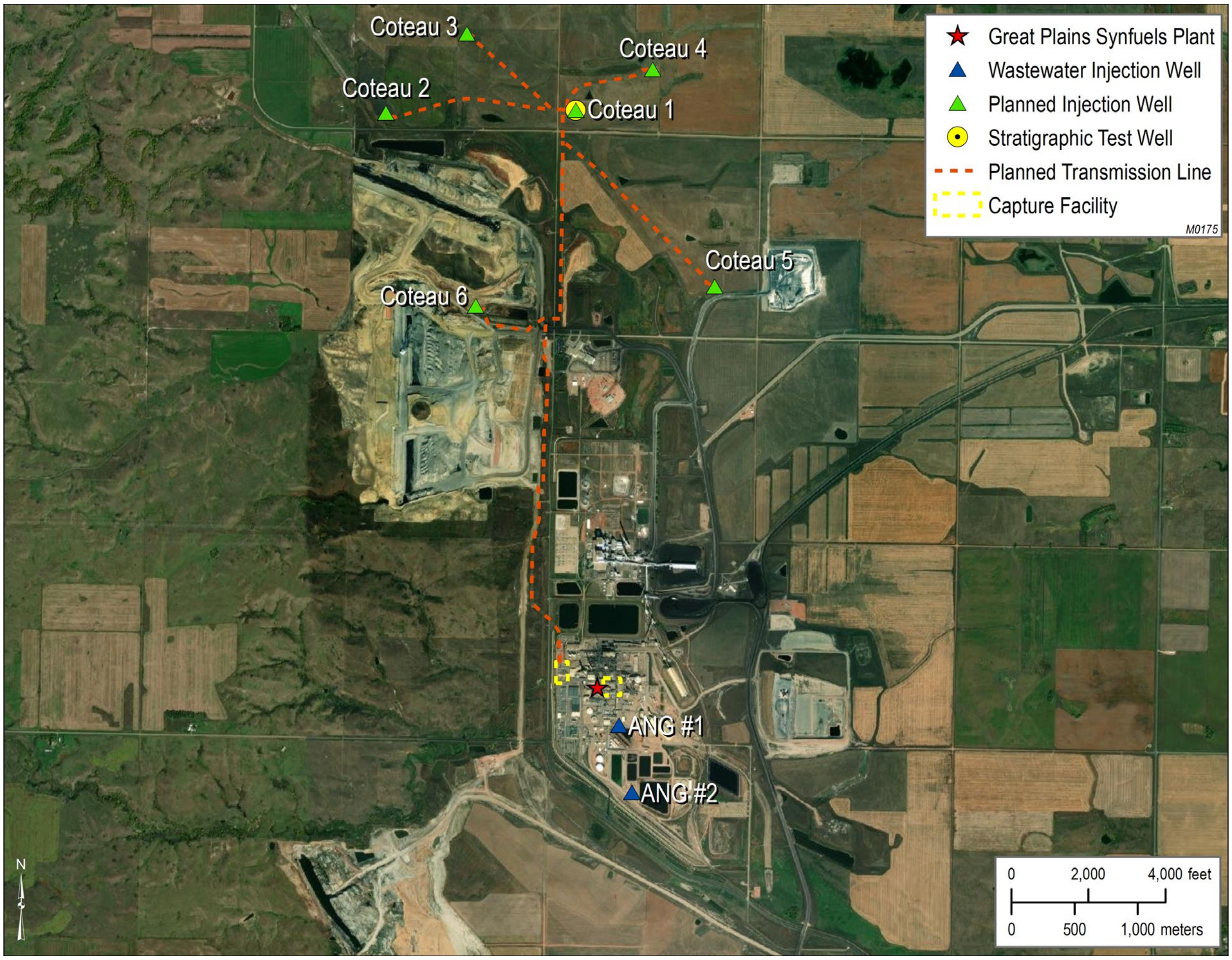

Figure 2-2. Map of the proposed CO_2 injection wells.

2.2.1 Existing Data

The existing data used to characterize the geology beneath the Great Plains CO_2 Sequestration Project site included publicly available well logs and formation top depths acquired from the NDIC online database. Well log data and interpreted formation top depths were acquired for 120 wellbores within a 5,472-mi^2 (72 × 76-mi) area centered on the proposed storage site (Figure 2-4). Well data were used to characterize the depth, thickness, and extent of the subsurface geologic formations.

Existing laboratory measurements from Broom Creek Formation core samples were available from five wells shown in Figure 2-5: Coteau 1 (NDIC File No. 38379), Flemmer 1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), J-LOC1 (NDIC File No. 37380), J-ROC1 (NDIC File No. 37672), and ANG #1 (North Dakota Department of Environmental Quality [NDEQ] No. 11308). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and integrated with newly acquired site-specific data.

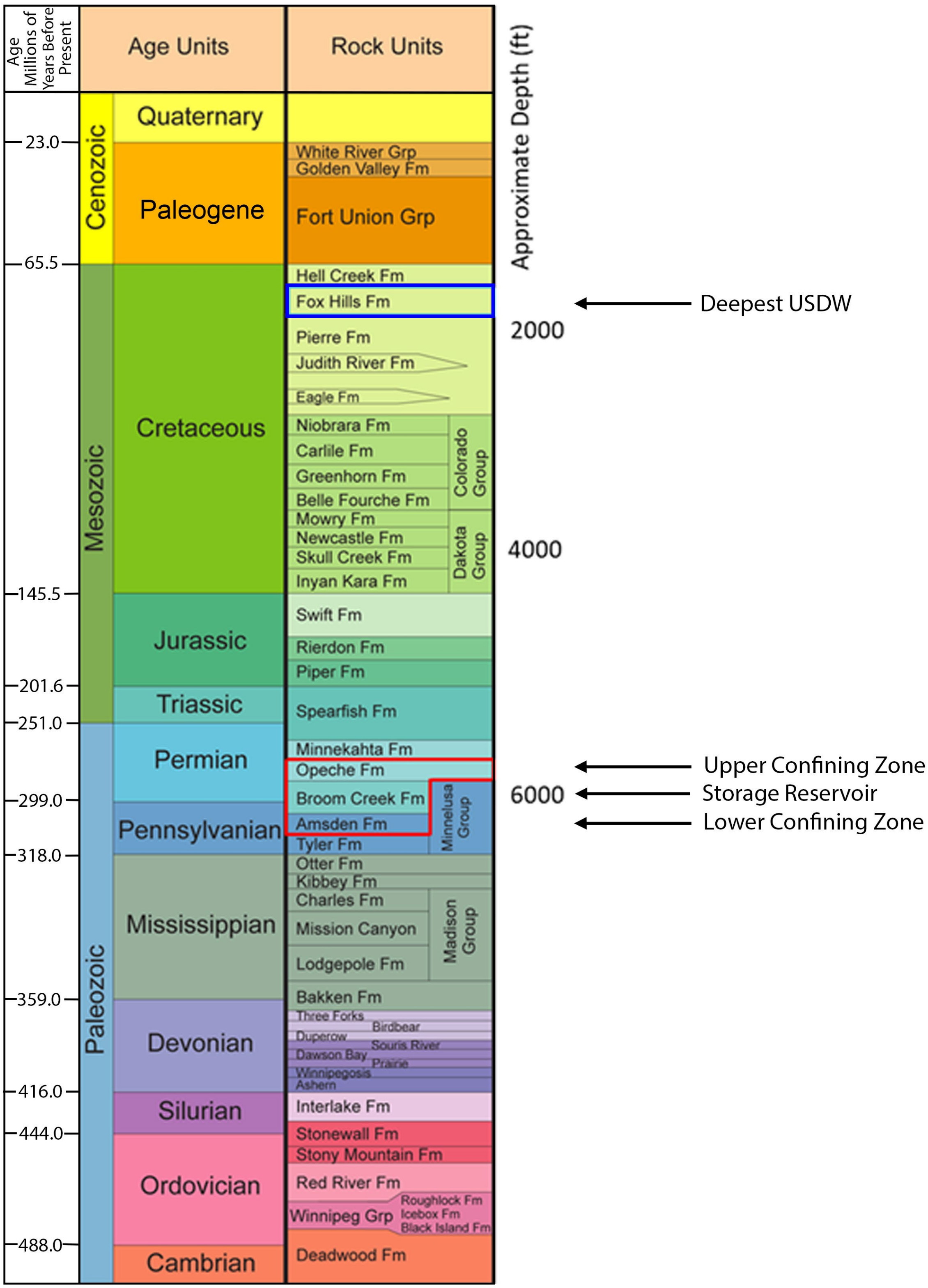

Figure 2-3. Stratigraphic column identifying the storage reservoir, confining zones, and lowest USDW addressed in this permit application for the Great Plains CO_2 Sequestration Project.

Table 2-1. Formations Comprising the Great Plains CO_2 Sequestration Project Storage Complex (average values calculated from the simulation model and well log data)

	Formation	Purpose	Average Thickness, ft	Average Measured Depth (MD), ft	Lithology
Storage Complex	Opeche	Upper confining zone	150	4,887	Mudstone, siltstone, evaporites
	Broom Creek	Storage reservoir (i.e., injection zone)	248	5,348	Sandstone, dolostone, dolomitic sandstone, anhydrite
	Amsden	Lower confining zone	268	5,558	Dolostone, limestone, anhydrite

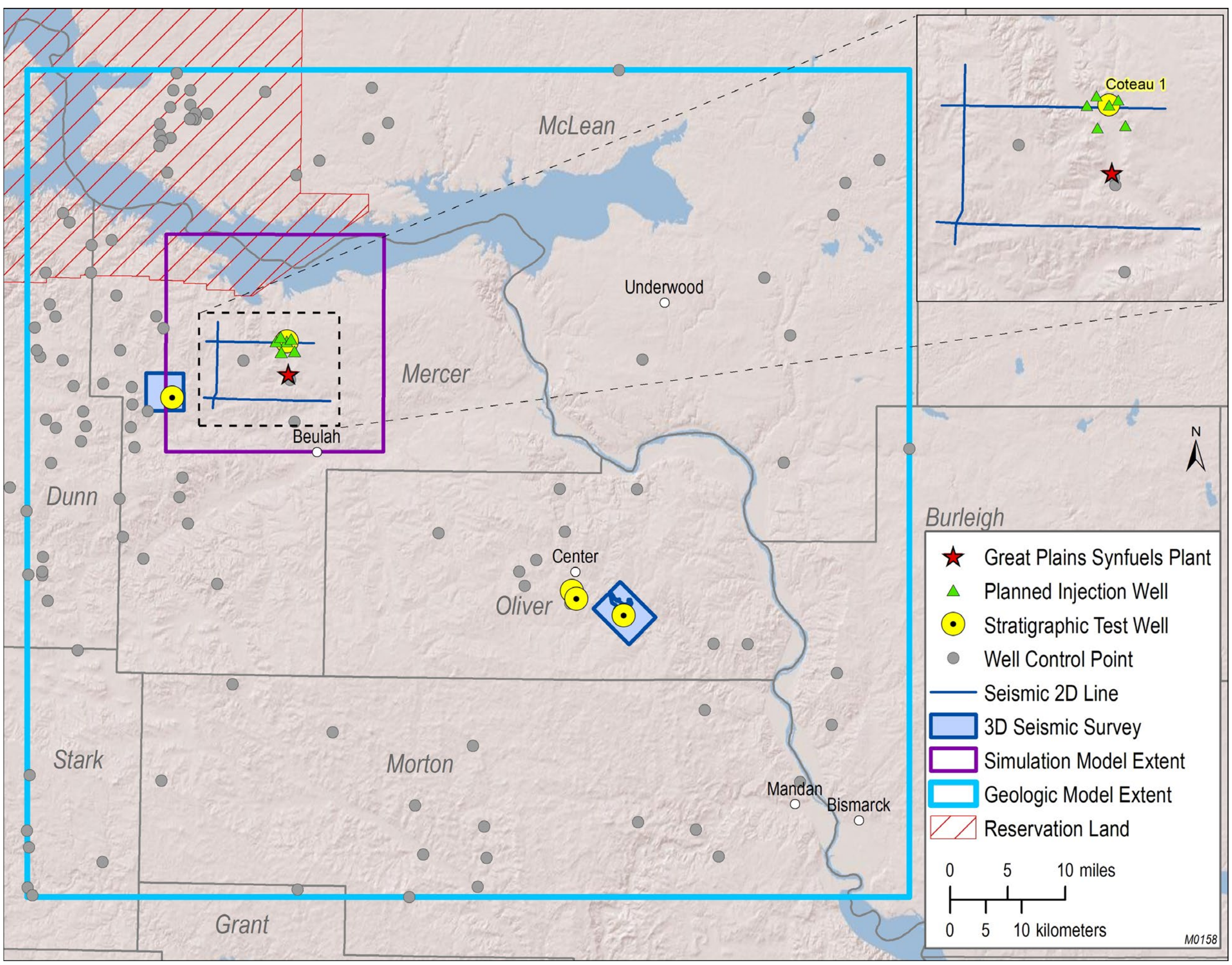

Figure 2-4. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones.

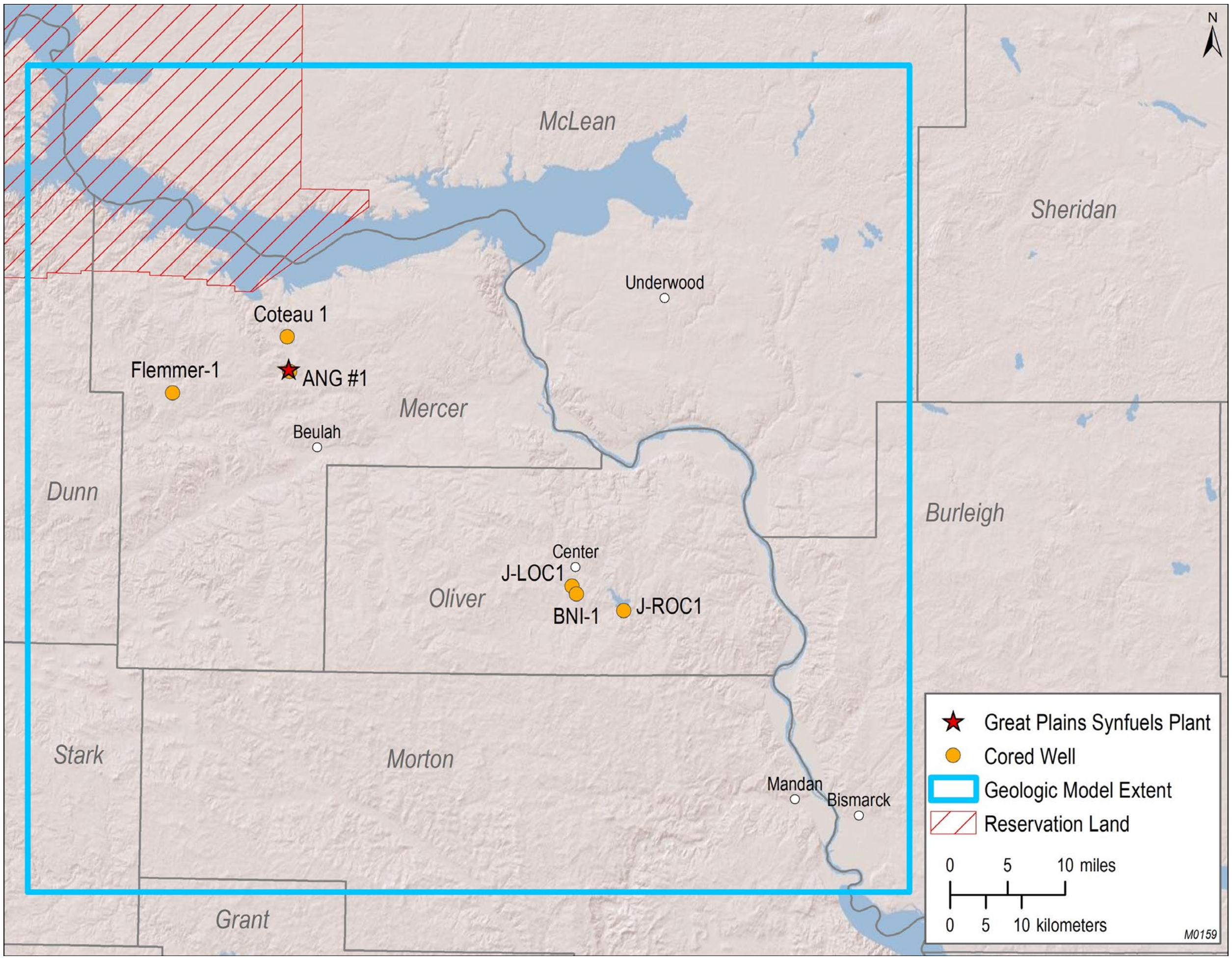

Figure 2-5. Map showing the spatial relationship between the Great Plains CO_2 Sequestration Project area and wells where the Broom Creek Formation core samples were collected. Wells with core data include the Coteau 1 (NDIC File No. 38379), Flemmer 1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), ANG #1 (NDEQ No. 11308), J-LOC1 (NDIC File No. 37380), and J-ROC1 (NDIC File No. 37672).

Ten square miles of legacy 3D seismic data from Mercer County, encompassing the Flemmer 1 wellsite, and twenty-eight miles of legacy 2D seismic data were licensed and examined to understand the heterogeneity and geologic structure of the Broom Creek Formation interval. Additionally, publicly available seismic interpretation products for the Broom Creek from a 3D seismic survey in Oliver County were used to inform structure and variogram distributions (Section 3.2). The structural configurations of the formations of interest generated from the interpretation of the two 3D seismic data sets along with formation tops interpreted from well log data were used to construct the geologic model. Variogram distributions derived from inversion volumes generated using the 3D seismic data were used to inform property distribution in the geologic model which was, in turn, used to simulate migration of the CO_2 plume (Section 3). These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 5).

2.2.2 Site-Specific Data

Site-specific efforts to characterize the proposed Broom Creek storage complex generated multiple data sets, including geophysical well logs, fluid analyses, and 2D seismic data. The Flemmer 1 well was drilled in 2017 to a depth of 6,790 ft in the Amsden Formation. The ANG #1 well was drilled in 1982 to a depth of 6,784 ft in the Amsden Formation. In 2021, the Coteau 1 well was drilled specifically to gather subsurface geologic data to support the development of a CO_2 storage facility permit. The Coteau 1 well was drilled to a depth of 6,484 ft. The downhole sampling and measurement program focused on the proposed storage complex (i.e., the Opeche, Broom Creek, and Amsden Formations) (Figure 2-6).

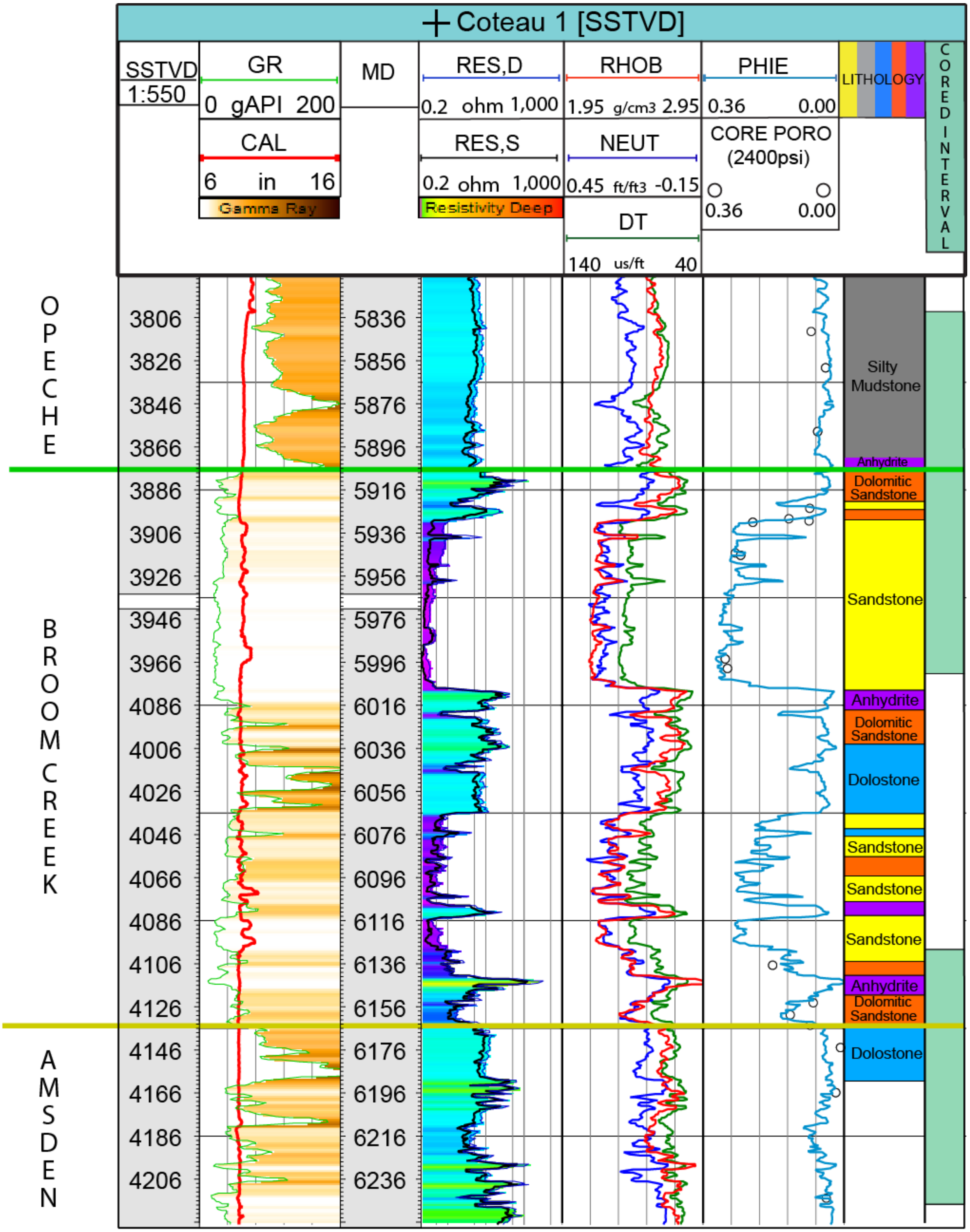

Figure 2-6. Schematic showing vertical relationship of coring (rightmost track) and core plug porosity (third track from right) intervals in the Opeche, Broom Creek, and Amsden Formations in the Coteau 1 well.

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

2.2.2.1 Geophysical Well Logs

Openhole wireline geophysical well logs were acquired in the Coteau 1 well along the entire open section of the wellbore. The logging suite included caliper, gamma ray (GR), density, porosity, dipole sonic, resistivity, combinable magnetic resonance (CMR) log, spectral GR, and fracture finder or image log. A similar logging suite was acquired from the Flemmer 1 well. The suite included caliper, GR, density, porosity, dipole sonic, spectroscopy, and spectral GR.

The acquired well logs were used to pick formation top depths, interpret lithology and petrophysical properties, and create synthetic seismic traces for tying depth to time. Formation top depths were picked from the top of the Pierre Formation to the top of the Amsden Formation. The site-specific formation top depths were added to the existing data of 120 wellbores within the 5472-mi^2 area covered by the model to understand the geologic extent, depth, and thickness of the subsurface geologic strata. The formation top depths were interpolated to create structural surfaces which served as inputs for geologic model construction.

2.2.2.2 Core Sample Analyses

Core (283 ft) was collected from the Broom Creek storage complex in the Coteau 1 well. This core was analyzed to characterize the lithologies of the Broom Creek, Opeche, and Amsden Formations and correlated to the well log data. Core analysis also included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), relative permeability testing, thin-section analysis, capillary entry pressure measurements, and triaxial geomechanics testing. The results were used to inform geologic modeling, predictive simulation inputs and assumptions, geochemical modeling, and geomechanical modeling.

2.2.2.3 Formation Temperature and Pressure

Temperature data recorded from logging the Coteau 1 and Flemmer 1 wellbores were used to derive a temperature gradient for the proposed injection site (Tables 2-2 and 2-3). In combination with depth, the temperature gradient was used to distribute a temperature property throughout the geologic model of the Great Plains CO_2 Sequestration Project area. The temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for the geochemical modeling.

The formation pressure and temperature at Coteau 1 were collected with a bottomhole pressure (BHP) gauge. In the Coteau 1 well, the Broom Creek was perforated at 5975 ft (1 foot, 4 shots per foot). After perforating, the BHP gauge was run to the perforation depth where temperature and pressure measurements were collected (Appendix C, “Pressure Survey Report”). The pressure data recorded in the Coteau 1 well are shown in Table 2-4.

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

Formation	Test Depth, ft	Temperature, °F
Broom Creek	5,975	151.85
Broom Creek Temperature Gradient, °F/ft	0.02*	

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

Table 2-3. Description of Flemmer 1 Temperature Measurements and Calculated Temperature Gradients

Formation	Test Depth, ft	Temperature, °F
Opeche/Spearfish	6,260	151.43
	6,261	151.83
Broom Creek	6,306	150.76
	6,308	149.46
	6,358	150.35
	6,367	149.31
	6,372	149.83
	6,402	149.87
	6,403	149.78
	6,426	149.24
	6,453	149.23
	6,454	149.36
	6,455	149.68
Mean Broom Creek Temp., °F	149.72	
Broom Creek Temperature Gradient, °F/ft	0.02*	

* The temperature gradient is an average of the MDT modular formation dynamics tester tool measured temperatures minus the average annual surface temperature of 40°F, divided by the associated test depth.

Flemmer 1 formation pressure and temperature measurements were performed with the Schlumberger MDT tool. The MDT tool is a wireline-conveyed tool assembly incorporated with a dual-packer module to isolate intervals, a large-diameter probe for formation pressure and temperature measurements, a pump-out module to pump unwanted mud filtrate, a flow control module, and sample chambers for formation fluid collection. The MDT tool formation pressure measurements from the Broom Creek Formation in the Flemmer 1 well are included in Table 2-5. The calculated pressure gradients from the Flemmer 1 and Coteau 1 wells were used to model formation pressure profiles for use in the numerical simulations of CO_2 injection.

Table 2-4. Description of Coteau 1 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Test Depth, ft	Formation Pressure, psi
Broom Creek	5,975	2,937.09
Broom Creek Pressure Gradient, psi/ft	0.49*	

* The pressure gradient is the BHP measured pressure minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.

Table 2-5. Description of Flemmer 1 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Test Depth, ft	Formation Pressure, psi
Broom Creek	6,306	3,093.67
Broom Creek	6,308	3,094.53
Broom Creek	6,367	3,125.21
Broom Creek	6,372	3,127.00
Broom Creek	6,454	3,168.26
Broom Creek	6,455	3,167.00
Mean Broom Creek Pressure, psi	3,129.28	
Broom Creek Pressure Gradient, psi/ft	0.49*	

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

2.2.2.4 Microfracture In Situ Stress Tests

Microfracture in situ stress tests were not performed in the Coteau 1 well. The in situ stresses for Coteau 1 were estimated using a 1D Mechanical Earth Model (1D MEM) that was generated using laboratory-derived core data and well log data from the Coteau 1 well. Discussion of the 1D MEM can be found in Sections 2.3 and 2.4.4.4. The Flemmer 1 microfracture in situ stress test results can be found in Sections 2.3 and 2.4.

2.2.2.5 Fluid Samples

A fluid sample from the Broom Creek Formation was collected from the Coteau 1 wellbore by perforating 1 foot at 5,975 ft and then swabbing the well until formation fluid flowed back to surface for collection. Results were analyzed by Minnesota Valley Testing Laboratories (MVTL), a state-certified lab. The results from the Coteau 1 sample are shown in Table 2-6. Fluid sample analysis results were used as inputs for geochemical modeling and dynamic reservoir simulations. Fluid sample analysis reports can be found in Appendix A.

Table 2-6. Description of Fluid Sample Test and Corresponding Total Dissolved Solids (TDS) Value

Formation	Well	Test Depth, ft	MVTL TDS, mg/L	EERC Lab TDS, mg/L
Broom Creek	Coteau 1	5,976	42,800	NA

2.2.2.6 Seismic Survey

The proximity of the site to an active coal mine and industrial facilities makes acquisition of 3D seismic data problematic. Placement of seismic source and receiver locations required for a 3D seismic survey would be restricted because of these surface uses potentially resulting in insufficient data quality to image the subsurface for characterization and monitoring purposes. Interpretation of 2D seismic data provides a practical alternative to acquiring and interpreting 3D seismic data. 2D seismic surveys can be used to evaluate the subsurface across large tracts of land, can be oriented to avoid surface obstacles such as those found at this site, can be acquired more frequently for future site monitoring, and eliminates the need to overshoot areas that have already been swept with CO_2.

Twenty-eight miles of 2D seismic lines that traverse the storage facility area and intersect the Coteau 1 well were licensed and interpreted (Figure 2-4). The 2D seismic lines were tied to the Coteau 1 well and used to evaluate the thickness and structure of the Broom Creek and upper and lower confining zones within the storage facility area. The interpreted surfaces for the formations of interest derived from the 2D seismic lines were used to confirm that the geologic model is representative of the reservoir thickness and structure within the storage facility area.

The 2D seismic data suggest there are no major stratigraphic pinch-outs or structural features with associated spill points in the Great Plains CO_2 Sequestration Project area. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the lowest USDW, the Fox Hills Formation, were observed in the seismic data. Twenty-eight miles of new 2D seismic data centered around the Coteau 1 well was acquired in January 2022 and will be used to confirm these interpretations.

2.3 Storage Reservoir (Injection Zone)

Locally, the Broom Creek Formation is laterally extensive (Figure 2-7) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone, siltstones, and evaporites of the Opeche Formation (Figure 2-3).

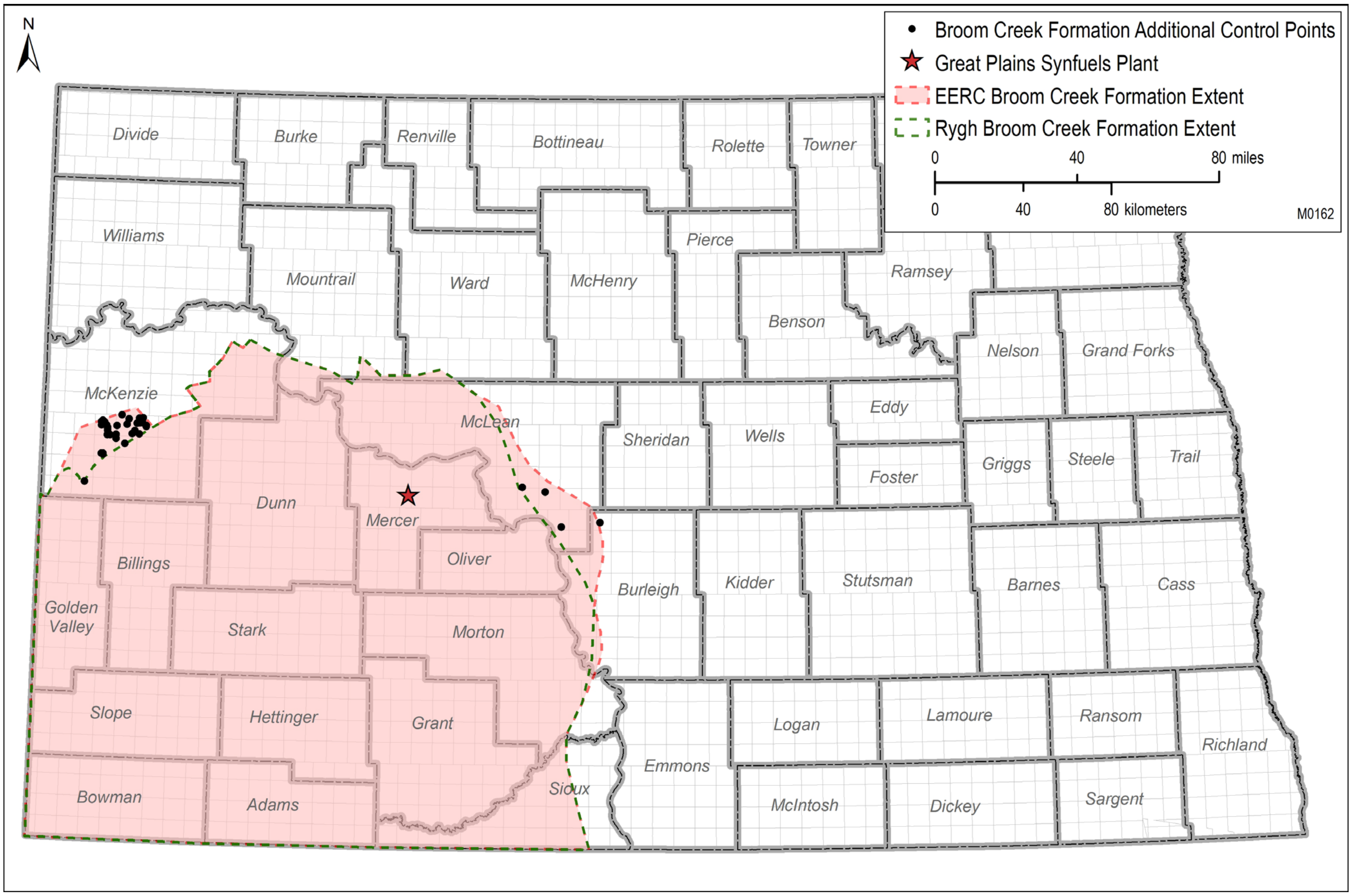

Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (modified from Rygh and others [1990]). Based on new well control shown outside of the green dashed line.

At Coteau 1, the Broom Creek Formation is 258 ft thick; is made up of 134 ft of sandstone, 35 ft of dolostone, 24 ft of anhydrite, and 65 ft of dolomitic sandstone; and is located at a depth of 5,906 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 163 to 322 ft (Figure 2-8), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 24 to 205 ft, with an average of 99 ft.

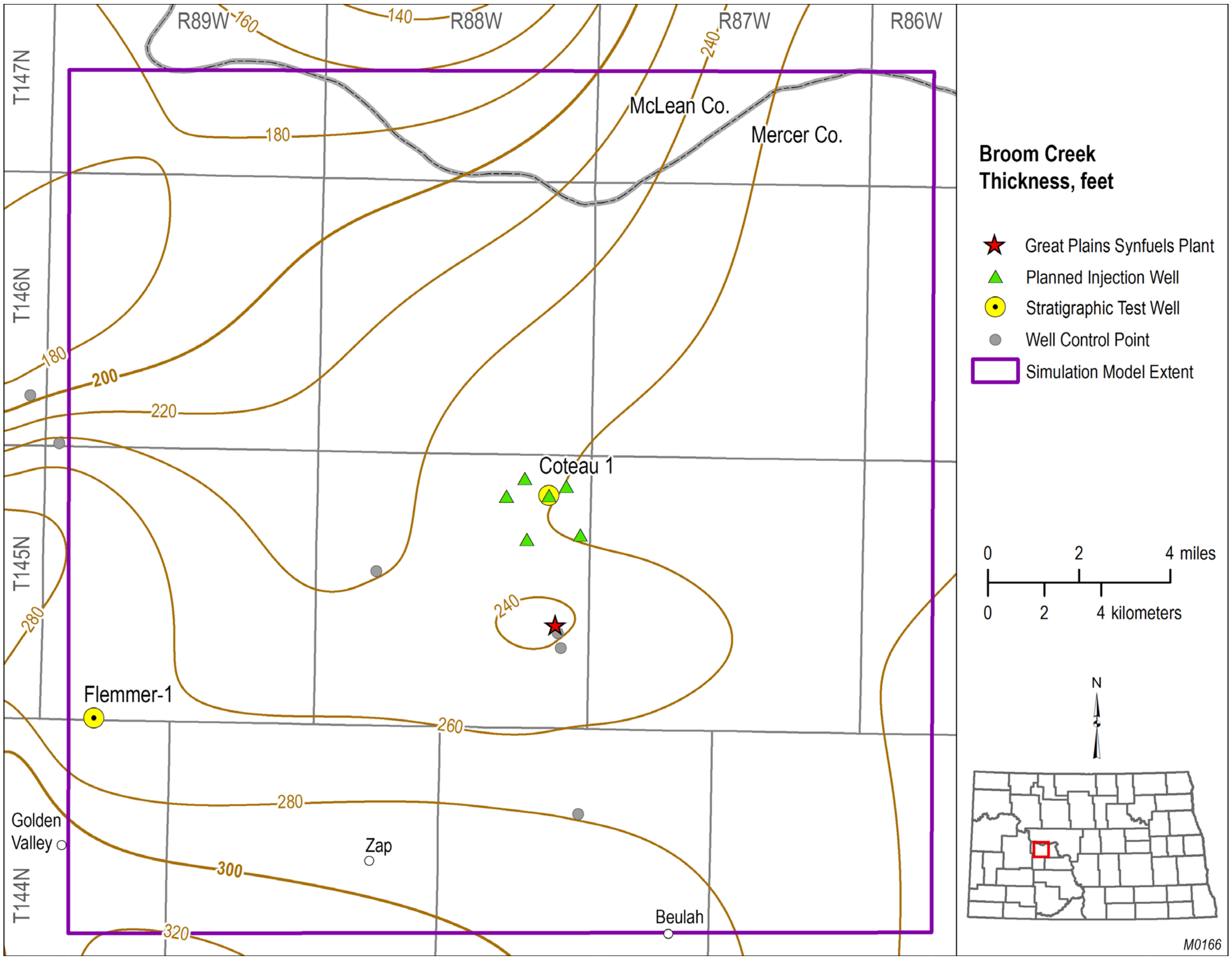

Figure 2-8. Isopach map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project area.

The top of the Broom Creek Formation was picked across the model area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-9). The top of the Amsden Formation was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that can be correlated across the entirety of the Great Plains CO_2 Sequestration Project area. 2D seismic data collected as part of site characterization efforts were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and analyses indicate that there should be few-to-no major reservoir stratigraphic discontinuities near the Coteau 1 well (Figures 2-10 and 2-11). The Broom Creek Formation is estimated to pinch out ~34 miles to the east of the Coteau 1 wellsite. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Great Plains CO_2 Sequestration Project area (Figure 2-12 and Figure 2-13).

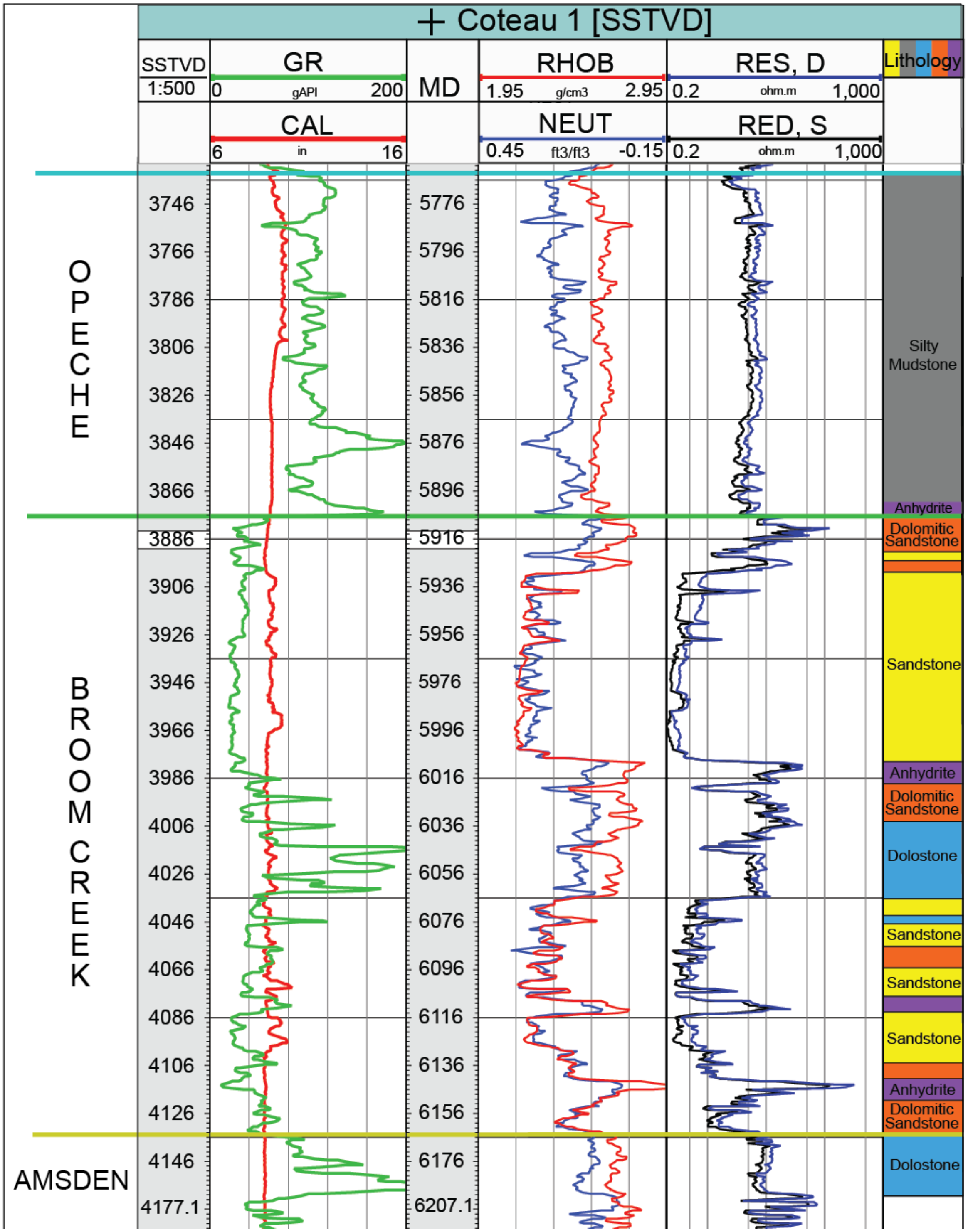

Figure 2-9. Well log display of the interpreted lithologies of the Opeche, Broom Creek, and upper Amsden Formations in the Coteau 1 well.

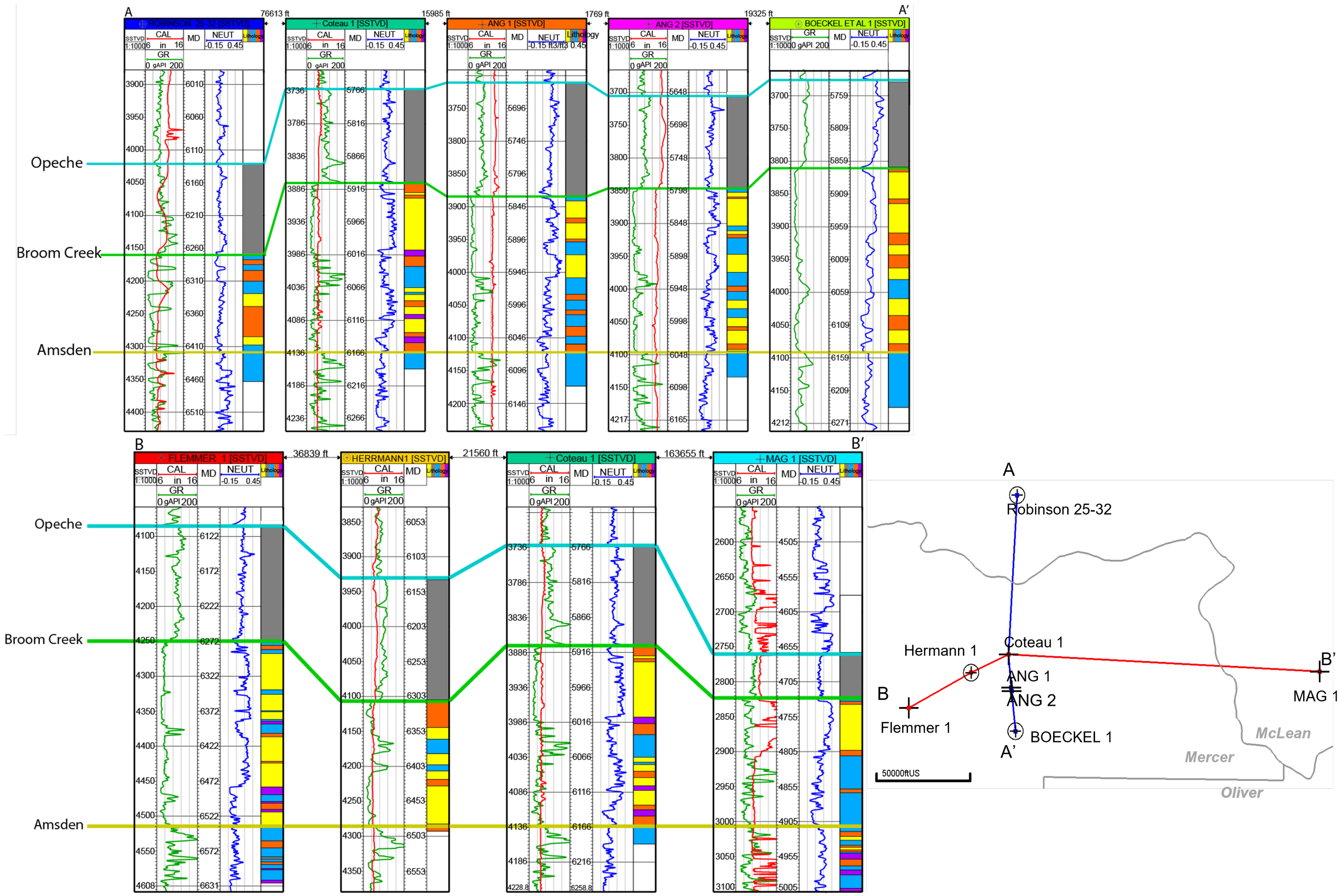

Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log.

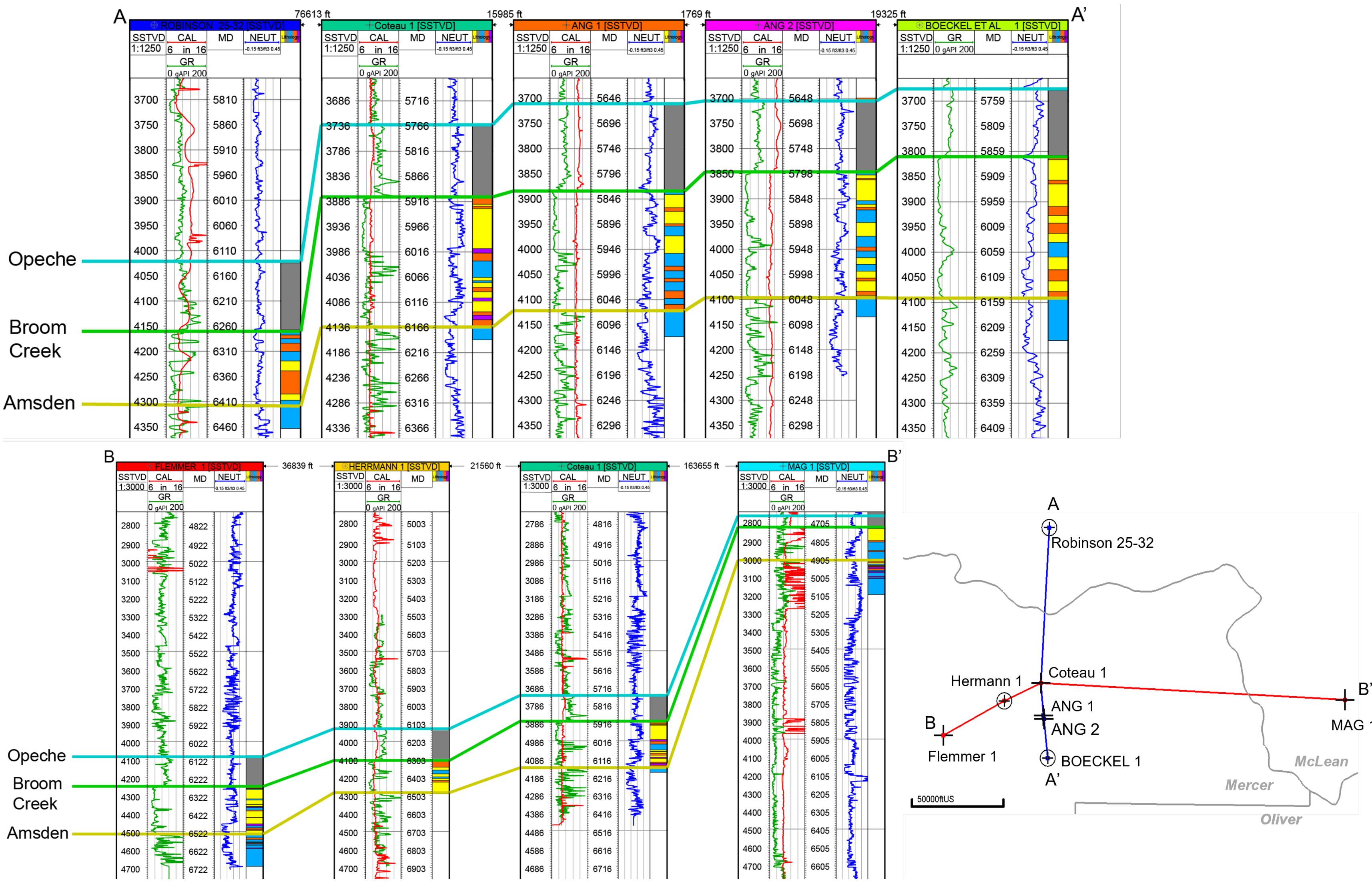

Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log.

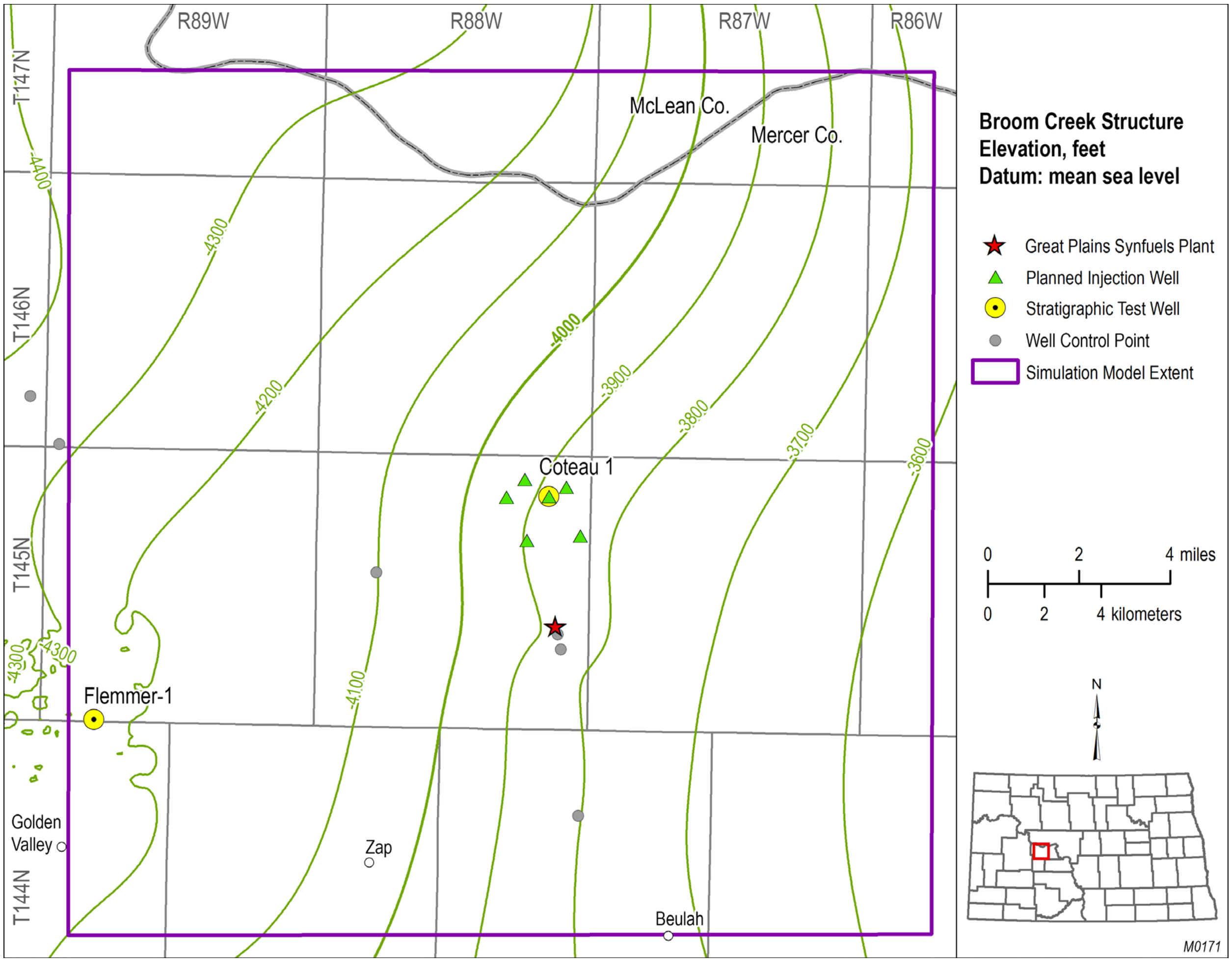

Figure 2-12. Structure map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops).

Twenty-two 1-inch-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the Coteau 1 well. From the twenty-two samples, three samples at 5,941.9', 5,969.9', and 5,994.4' were duplicated and oriented 90 degrees compared to the original core plug to investigate the possibility of any orientation-dependent permeability existing in the reservoir. The remaining nineteen core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the Coteau 1 Broom Creek Formation core samples have porosity values ranging from 1.41% to 34.39% at 800 psi and 7.88% to 30.34% at 2400 psi. Permeabilities range from 0.13 to 12,300 mD at 800 psi and 0.118 to 3,990 mD at 2,400 psi (Table 2-7). The wide range in porosity and permeability reflects the differences between the sandstone and dolostone lithofacies in the Broom Creek Formation. Portions of the Broom Creek Formation core revealed unconsolidated or poorly consolidated sandstone.

Table 2-7. Description of CO_2 Storage Reservoir (injection zone) at the Coteau 1 Well

Injection Zone Properties

Property	Description
Thickness, ft	Sandstone 134 Dolostone 35 Dolomitic sandstone 65 Anhydrite 24

Geologic Properties

Formation	Property	Laboratory Analysis	Simulation Model Property Distribution
Broom Creek (sandstone)	Porosity, %*	21.28 (7.88–30.34)	23.64 (3.65–35.77)
	Permeability, mD**	221.84 (2.92–3,990)	246.74 (0.001–3,379)
Broom Creek (dolostone)		8.79 (8.66–8.94)	5.68 (0.1–25.99)

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
** Permeability values are reported as the geometric mean followed by the range of values in parentheses.

Analysis of thirteen core samples from the sandstone portion of the Broom Creek Formation core from the Coteau 1 well showed porosity values ranging from 8.73% to 34.39% at 800 psi and 7.88% to 30.34% at 2,400 psi, with an average of 25.10% and 21.28% respectively. Permeability of the sandstone samples ranged from 3.22 to 9,660 mD at 800 psi and 2.92 to 3,990 mD at 2,400 psi, with a geometric average of 728.35 mD and 221.84 mD, respectively. Porosity values of dolostone samples from the Broom Creek Formation core ranged from 1.41% to 12.31% at 800 psi and 8.66% to 8.94% at 2400 psi, with an average of 6.64% and 8.79%, respectively. Dolostone permeability values ranged from 0.001 to 1.62 mD at 800 psi and 0.118 to 0.361 mD at 2,400 psi, with a geometric average of 0.109 mD and 0.180 mD, respectively (Table 2-7 and Figure 2-14).

Core-derived measurements were used as the foundation for the generation of porosity and permeability properties within the 3D geologic model. The core sample measurements showed good agreement with the wireline logs collected from the Coteau 1 well. This agreement allowed for confident extrapolation of porosity and permeability from offset well logs, thus creating a spatially and computationally larger data set to populate the geologic model. The model property distribution statistics shown in Table 2-7 are derived from a combination of the core analysis and larger data set derived from offset well logs.

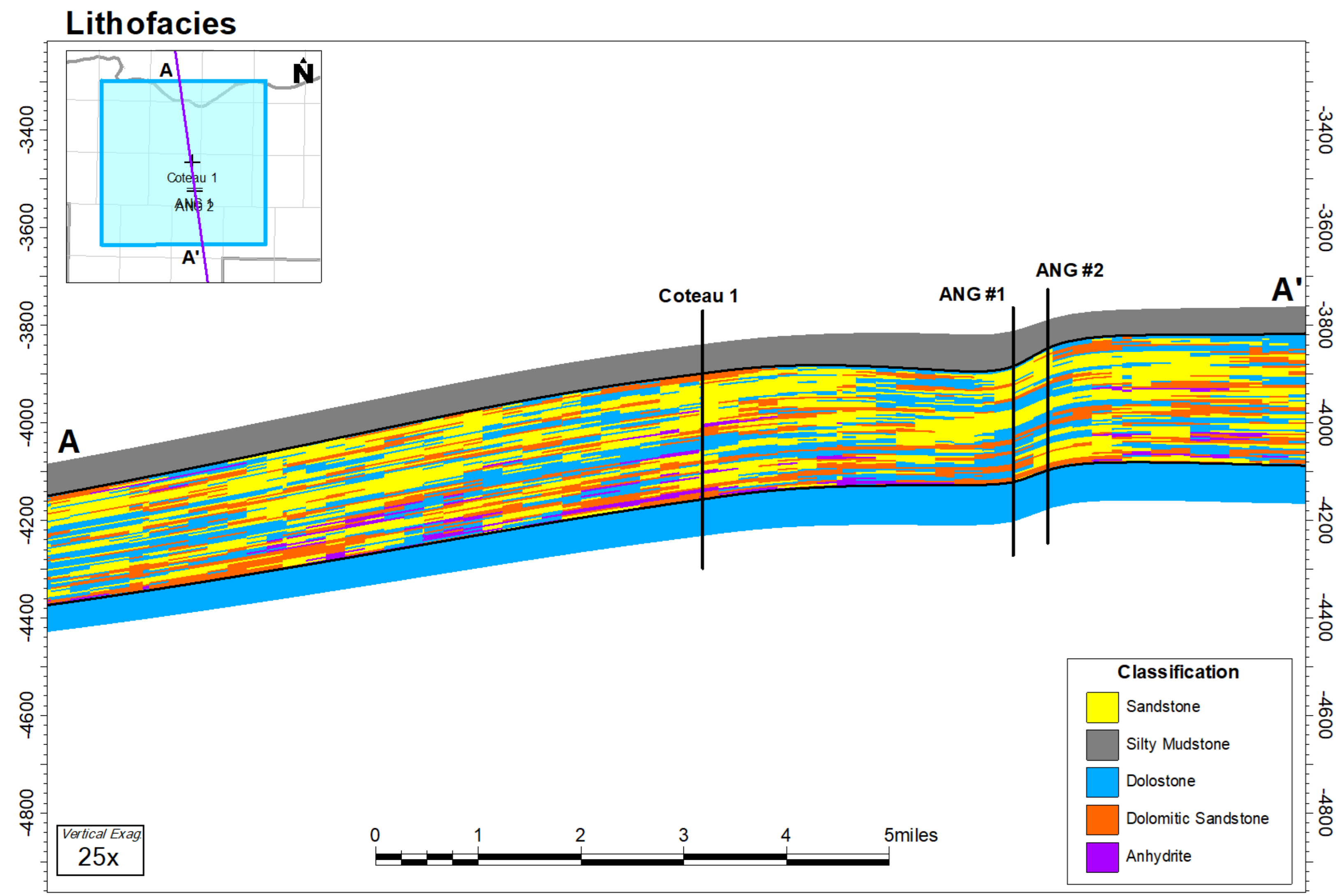

Figure 2-13. Cross section of the Great Plains CO_2 Sequestration Project storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level.

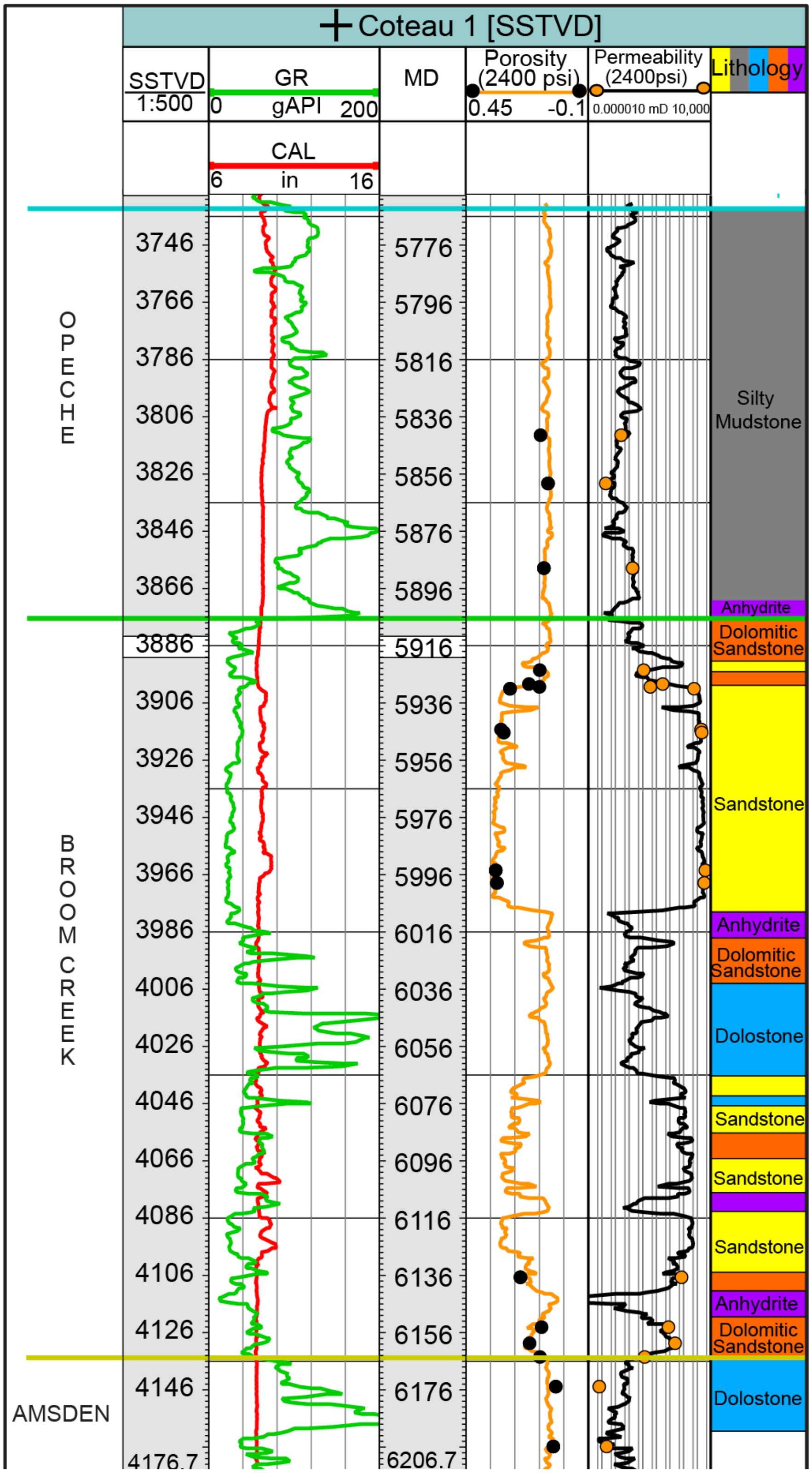

Figure 2-14. Vertical distribution of core-derived porosity and permeability values in the Great Plains CO_2 Sequestration Project storage complex.

Sandstone intervals in the Broom Creek Formation are associated with low GR, low density, high porosity (neutron, density, and sonic), low resistivity due to high porosity and brine salinity, and high sonic velocity measurements. The dolostone intervals in the formation are associated with an increase in GR measurements compared to the sandstone intervals, in addition to high density, low porosity (neutron, density, and sonic), high resistivity, and low sonic velocity measurements.

During drilling of the Coteau 1 well, the hole condition did not allow an openhole MDT microfracture in situ stress test to determine the formation breakdown pressure, fracture closure pressure, fracture propagation pressure, and minimum horizontal stress to be performed. To overcome this lack of data, a 1D MEM for Opeche, Broom Creek, and Amsden Formations was generated using laboratory-derived core data and well log data from the Coteau 1 well. A discussion of how the 1D MEM was generated can be found in Section 2.4.4.4.

The 1D MEM was used to determine the formation breakdown pressure, fracture closure pressure, and fracture propagation pressure for the Broom Creek Formation. The breakdown pressure was computed by setting the minimum tangential stress around the circumference of the well to zero and applying Kirsch (1898); Aadnoy (2008); and Grandi, Rao, and Toksoz (2002) equations. The fracture propagation pressure is assumed to be the same as the fracture pressure and allows the estimation of a maximum threshold whereby connected flow may be sustained. In this case, the estimated fracture pressure is considered to be the estimated fracture closure pressure. The fracture closure pressure was defined using the minimum horizontal stress (Shmin). Typically, Shmin, can be estimated from a modified Eaton calculation method and is viewed as a lower bound for the reservoir fracture closure pressure or the maximum stress prior to breakdown of the system competency. The modified Eaton formula used is shown in Equation 1. This equation has been widely used in the industry and has a good match with the field test data:

$$P = \frac{v}{1-v} * ((S_{v} - \alpha_{v}) * {}_{p}) + \alpha_{H} * {}_{p} \qquad \text{[Eq. 1]}$$

Where:

P is pressure.
v is Poisson's ration.
S_v is the vertical stress.
α_V is the vertical Biot's constant.
α_H is the horizonal Biot's constant.
P_p is pore pressure.

The estimated pressures were compared to MDT-deployed microfracture in situ stress test results from Flemmer 1. The Flemmer 1 microfracture in situ stress test in the Broom Creek Formation (6,358 ft depth) was conducted over 7 cycles of injection and falloff. The first two cycles reached approximately 7,250 psi and 8,000 psi, respectively, without breakdown. The breakdown occurred on the third cycle, with an initial breakdown pressure of 4,950 psi. Fracture reopening pressures increased to 5,214 psi, 6,255 psi, and, finally, 7,293 psi in Cycles 5, 6, and 7. Fracture reopening pressures are generally lower than initial breakdown pressure; however, Cycles 5 and 6 show a steady rise in measured closure pressure, indicating the possible formation of pore space plugging. Propagation pressure recorded in Cycle 4 was 4,384 psi. The average pressures of the stress test from prior tests on the Flemmer 1 and estimates for the Coteau 1 well results are shown in Table 2-8.

The average fracture propagation pressure gradient of 0.71 psi/ft for the Coteau 1 well agrees with the average fracture propagation values determined from microfracture in situ stress tests in other regional wells: the J-LOC 1 and BNI-1 (NDIC, 2021b). Because of the confidence in the calculated value for fracture propagation pressure gradient and the predicted maximum BHP (Table 3-5), there are no plans to run an MDT test in one of the other injection wells.

Table 2-8. Broom Creek Microfracture Results from Flemmer 1 and Interpreted Results from Coteau 1

	Coteau 1		Flemmer 1	
Depth, ft	NA		6358	
Pressure/Gradient	**psi**	**psi/ft**	**psi**	**psi/ft**
Breakdown	5,193	0.85	4,950	0.77
Avg. Fracture Propagation	4,263	0.71	4,384	0.69
Avg. Closure	4,014	0.71	4,195	0.66

Note: Flemmer 1 average fracture propagation and closure pressure are representative of Cycle 4 because of possible plugging in the later cycles.

2.3.1 Mineralogy

The combined interpretation of core, well logs, and thin sections shows that the Broom Creek Formation is dominated by fine- to medium-grained sandstone with lesser amounts of carbonates and anhydrites. Twenty-two depth intervals across 131.25 ft of the Broom Creek Formation were sampled for XRD mineralogical determination and XRF bulk chemical analysis. Out of 22 samples, 18 samples were selected to create thin sections. For the assessment below, thin sections and XRD provide independent confirmation of the mineralogical constituents of the Broom Creek Formation. No core was acquired for the interval of 6,001' to 6,130' (the middle dolomite-rich section of the Broom Creek Formation) because of the low rate of penetration.

Thin-section analysis of the upper Broom Creek interval shows that quartz (84%) is the dominant mineral. Throughout these intervals are minor occurrences of feldspar (6%), dolomite (5%), and anhydrite as cement (5%). Where present, anhydrite is crystallized between quartz grains and obstructs the intercrystalline porosity. The quartz minerals sometimes show overgrowth and, occasionally, dissolution. The contact between grains is long (straight) to tangential. In most cases, grains are surrounded/rimmed by a thin red brown to dark red iron oxides. The porosity ranges between 15% to 34%, except for a sample at the depth of 6,146 ft with a porosity of 9% that is extensively cemented by anhydrite. Figure 2-15 shows the primary features observed in thin sections within the upper sand of the Broom Creek Formation.

Within the intervals of core collected, occurrences of carbonates are notable in the 5,903'–6,001' interval. The first occurrence at 5,908'–5,924' (Figure 2-16) is a relatively thick carbonate that comprises a very fine- to fine-grained dolostone (75%), with quartz of variable size and shape (7%) and anhydrite (18%). The porosity averages 8% and is mainly intercrystalline and moldic in

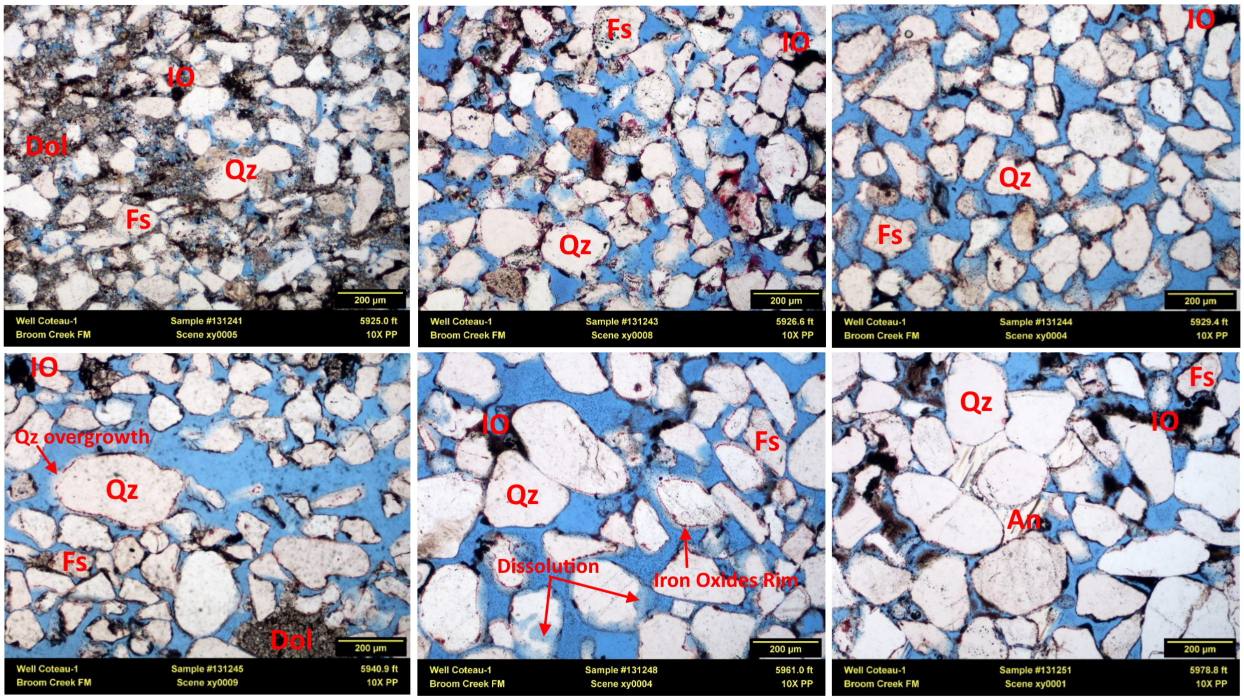

Figure 2-15. Thin sections from the upper sand interval of the Broom Creek Formation.

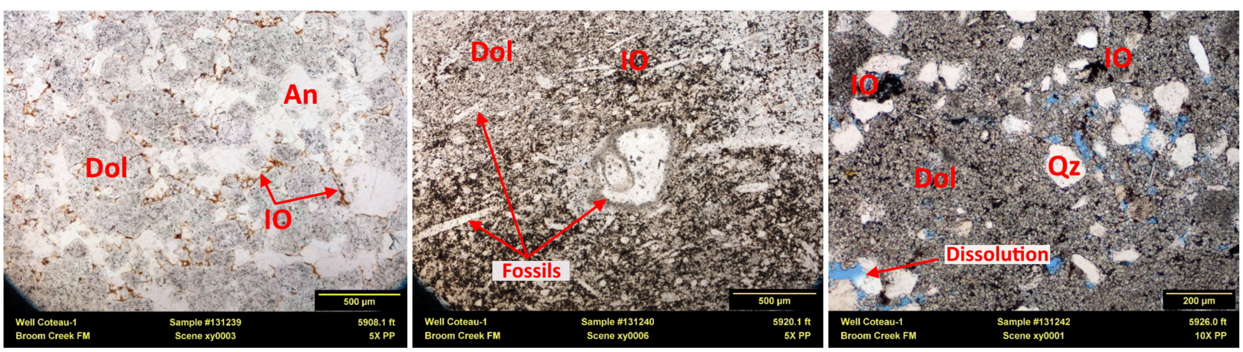

Figure 2-16. Thin sections from the three carbonate depth intervals of the upper Broom Creek Formation.

structure. Diagenesis is expressed by dolomitization of the original calcite grains. Fossils include some dolomitized bivalve shell fragments.

A small section of carbonate was penetrated at 5,999' to 6,001' prior to ceasing the first coring run. This bed is a pure dolomite (Figure 2-17) that comprises dolosparite/micro-dolosparite (78%). The presence of clay (11%) and iron oxides is noticeable in the rock matrix. Anhydrite as the clasts and veins is the other comprising mineral (7%). The quartz (very fine grains) presents in low content (4%). The observed thin-section porosity averages 7% and occurs as the dissolution of anhydrite and open fractures. It is noted that the scale of observed fractures in these carbonate intervals is on the micrometer scale and may be induced by the thin-section creation process.

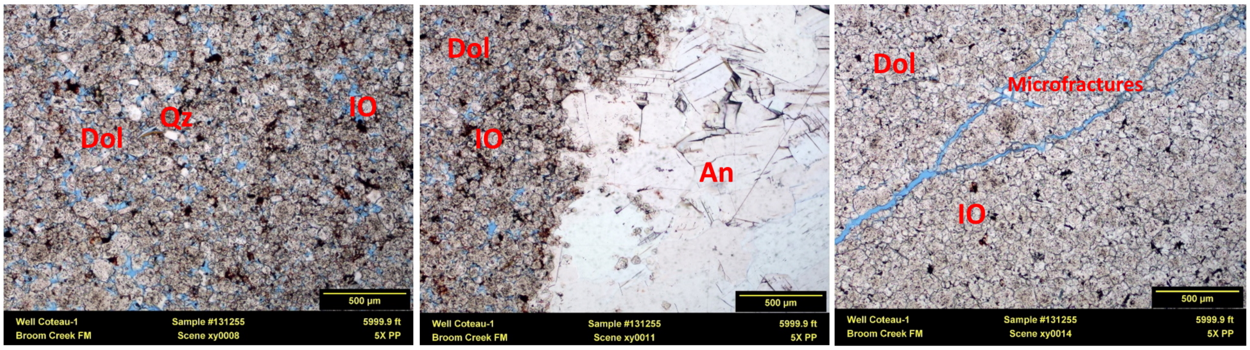

Figure 2-17. Thin section from the carbonate depth interval of the middle Broom Creek Formation.

The last occurrence of carbonates in the Broom Creek Formation is notable at the depth interval of 6,130'–6,163'. This occurrence of carbonate (6,160'–6,163.25') is much more quartz-rich dolomite (sandy dolomite) and comprises mainly micro-dolomite (54%), quartz (35%), feldspar (10%), and clay (1%). The presence of iron oxides is noticeable. The quartz minerals show some dissolution. The contact between grains is tangential and separated by a dolomitic matrix and locally by iron oxide cements. The observed porosity is due to the dissolution of feldspar and averages 9%. Figure 2-18 shows the characteristics observed within this carbonate.

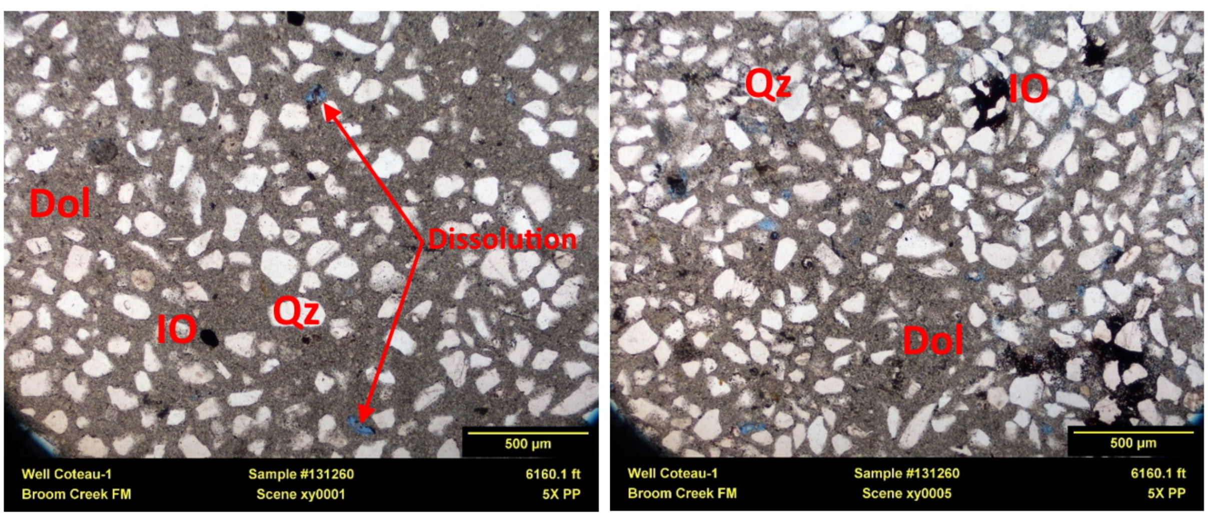

Figure 2-18. Thin section from a carbonate depth interval of the lower Broom Creek Formation.

XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation core primarily comprises quartz, feldspar, carbonates, anhydrite, clay, and other minor minerals (Figure 2-19).

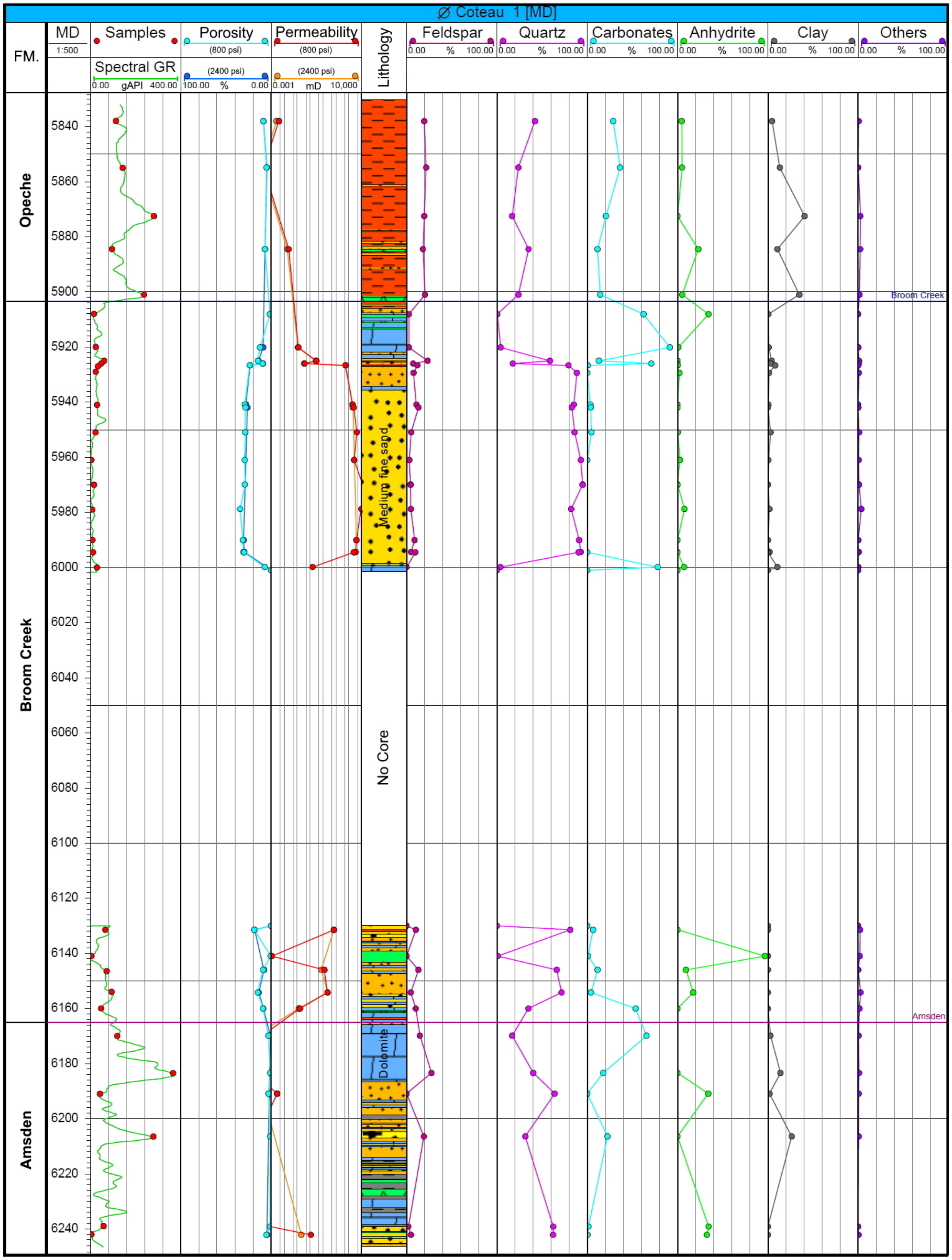

Figure 2-19. Described core and laboratory-derived mineralogic characteristics of the Opeche, Broom Creek, and Amsden Formations.

XRF data are shown in Figure 2-20 for the Broom Creek Formation. Sandstone and dolomite intervals are confirmed through the high percentages of SiO_2 (71%–98%), CaO (19%–36%), and MgO (13%–21%). The high percentage of CaO and SO_3 at 5,908, 6,141, and 6,154 ft indicate a presence of anhydrite beds. The formation shows little volumes of clay, with a range of 0.04% to 10.54% for all samples.

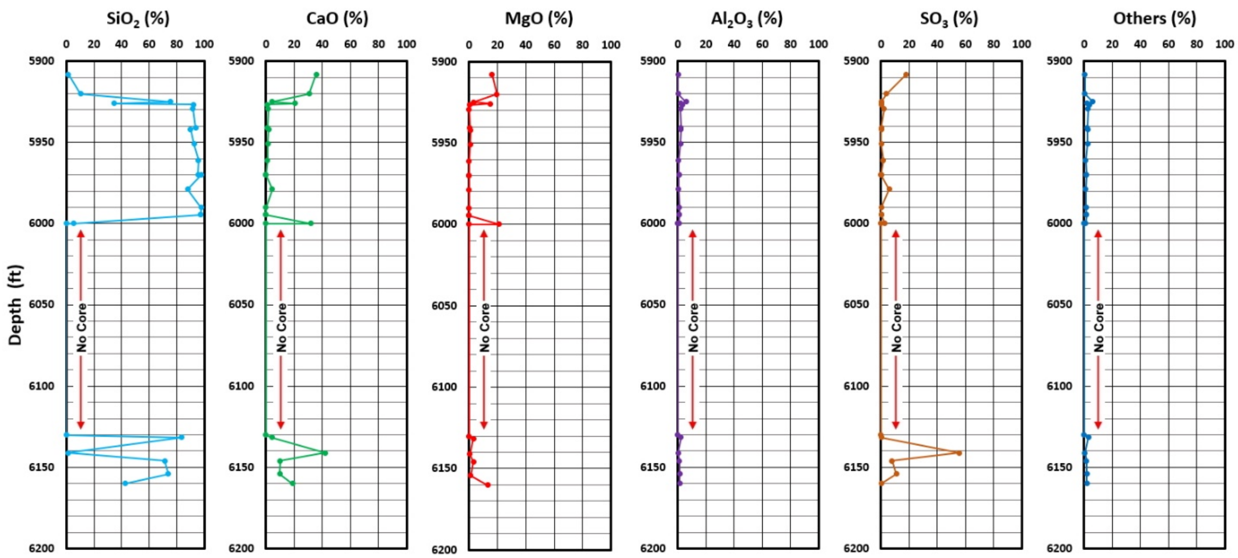

Figure 2-20. XRF data from the Broom Creek Formation from the Coteau 1.

2.3.2 *Mechanism of Geologic Confinement*

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

2.3.3 *Geochemical Information of Injection Zone*

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

The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package GEM. GEM is also the primary simulation software used for evaluation of the reservoir's dynamic behavior resulting from the expected CO_2 injection. For this geochemical modeling study, the injection scenario consisted of a single injection well injecting for a 12-year period with maximum BHP and maximum gas injection rate (STG) constraints of 3,833 psi and 25 MMcfd (468,000 tonnes/year), respectively. A postinjection period of 25 years was run in the model to evaluate any dynamic behavior and/or geochemical reaction after the CO_2 injection is stopped. This geochemical scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared (Figure 2-21).

Simulation results indicate that the low-salinity plume (TDS 8,050 ppm) associated with the ANG #1 and ANG #2 disposal water and the injected CO_2 plume for the six-well injection scenario discussed in Section 3 may have little interaction after 10 years of postinjection (Figure 2-22). Based on this limited interaction of the injected CO_2 and the injected disposal water and the chemical composition of the disposal water, the ANG disposal well injection was not included as part of the geochemical modeling for computational efficiency. The historical ANG well injection up to August 2021 was included during the modeling.

Geochemical alteration effects were seen in the geochemistry case, as described below. However, these effects were not significant enough to cause meaningful changes to the storage reservoir performance of the storage formation.

The scenario with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (86% of bulk reservoir volume) and average formation brine composition (14% of bulk reservoir volume). XRD data from the Coteau 1 well core samples were used to inform the mineralogical composition of the Broom Creek Formation (Table 2-9). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Kaolinite is the only other clay mineral that was identified in XRD data and was only identified in one of twenty-two samples analyzed. Ionic composition of the Broom Creek Formation water and the ANG disposal water chemistry are listed in Tables 2-10 and 2-11.

The injection stream is expected to be 95.9% CO_2. For input into CMG, this value was normalized along with the other constituents in the stream to sum to 100% mole fraction. The CO_2 composition in the gas stream used for the simulated injection stream was 96.45% CO_2. Other constituents represent 3.55% of the stream and are expected to include 1.23% hydrogen sulfide (H_2S) and 2.32% including methane, ethane, and propane. N_2, known to be an inert gas, was not included in the gas stream. Some of the other carbon constituents such as butane, ethylene, pentane, isobutane, isopentane, and n-pentane may also be present but in a negligible amount that would have no impact on geochemical reactions in the storage formation and were also not included. The simulated injection stream was 96.45% CO_2, 1.23 H_2S, and 2.32% CH_4. As in the model without geochemical reactions, the geochemistry case was run for the 12-year injection period followed by 25 years of postinjection monitoring.

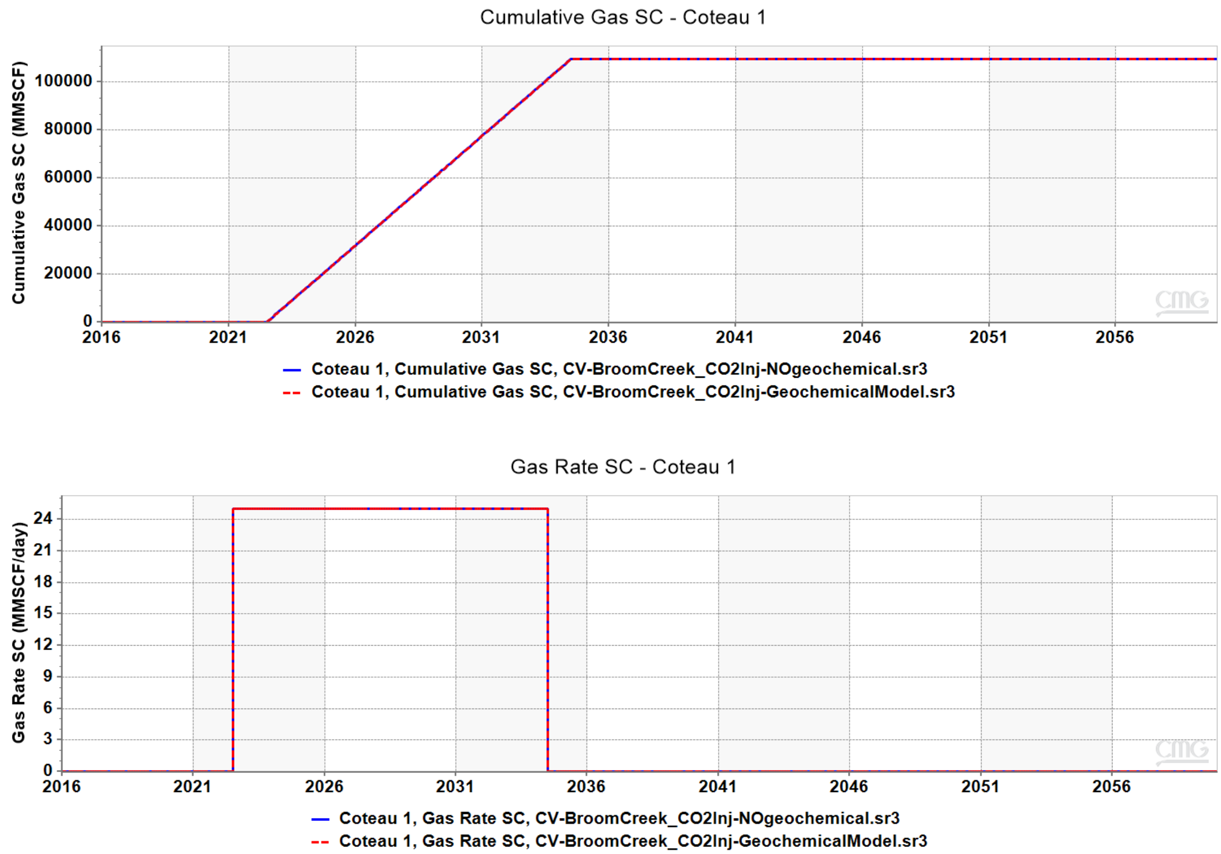

Figure 2-21. Upper graph shows cumulative injection vs. time; the bottom figure shows the gas injection rate vs. time. There is no observable difference in injection due to geochemical reactions.

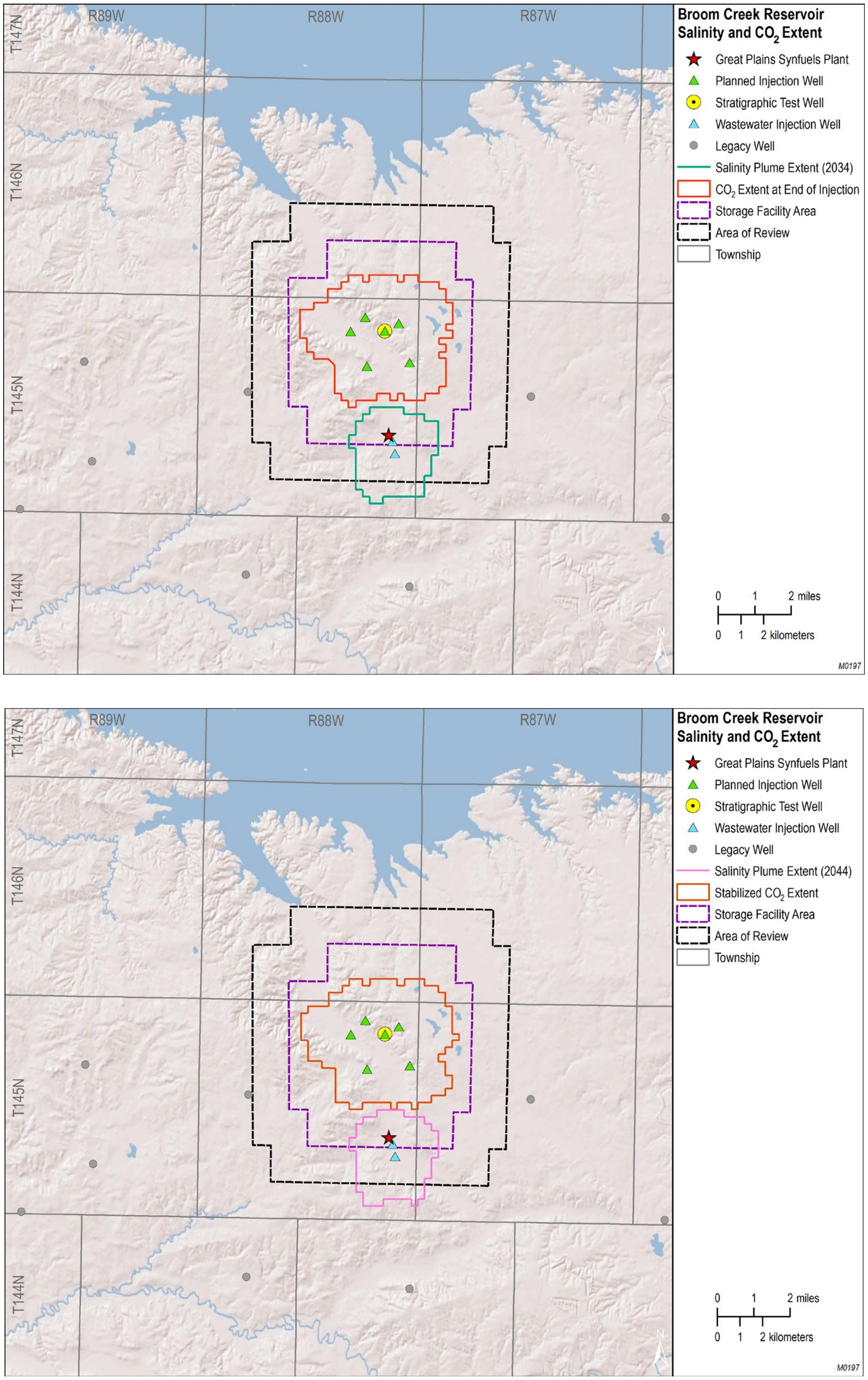

Figure 2-22. 2D map showing the water salinity plume from the disposal wells, ANG #1 and ANG #2, and the gas mole fraction (CO_2) for the expected injection scenario for this project described in Section 3 consisting of six CO_2 injection wells. The lower map shows the stabilized CO_2 plume vs. the salinity plume extent after 10 years postinjection, in July 2044.

Table 2-9. XRD Results for Coteau 1 Broom Creek Core Sample

Mineral Data	%
Albite	2.25
Anhydrite	15.17
Anorthite	1.96
Dolomite	23.91
Illite	2.85
Pyrite	0.13
Quartz	54.15

Table 2-10. Broom Creek Water Ionic Composition, expressed in molality

Component	mg/L, ppm	Molality
SO_4^{2-}	469	0.00474
K^+	516	0.01281
Na^+	12,800	0.54698
Ca^{2+}	1,860	0.04511
Mg^{2+}	212	0.00847
Fe^{3+}	392	0.00681
CO_3^{2-}	<20	0.00032
Cl^-	24,900	0.69829
HCO_3^-	853	0.01357
TDS, ppm	42,800	

Table 2-11. ANG #1 Water Ionic Composition, expressed in molality

Component	mg/L, ppm	Molality
SO_4^{2-}	2,280	0.02355
K^+	38.5	0.00098
Na^+	2,200	0.09495
Ca^{2+}	283	0.00699
Mg^{2+}	175	0.00713
Cl^-	2,880	0.08066
HCO_3^-	63	0.00102
TDS, ppm	8,050	

Figure 2-21 shows that reservoir performance results for the two cases are essentially identical. As a result of geochemical reactions in the reservoir, there is no observable difference in cumulative injection. The injection BHP and wellhead pressure (WHP) are shown in Figure 2-23. The two cases are also essentially the same, and no difference was appreciable between the case with and without geochemical modeling.

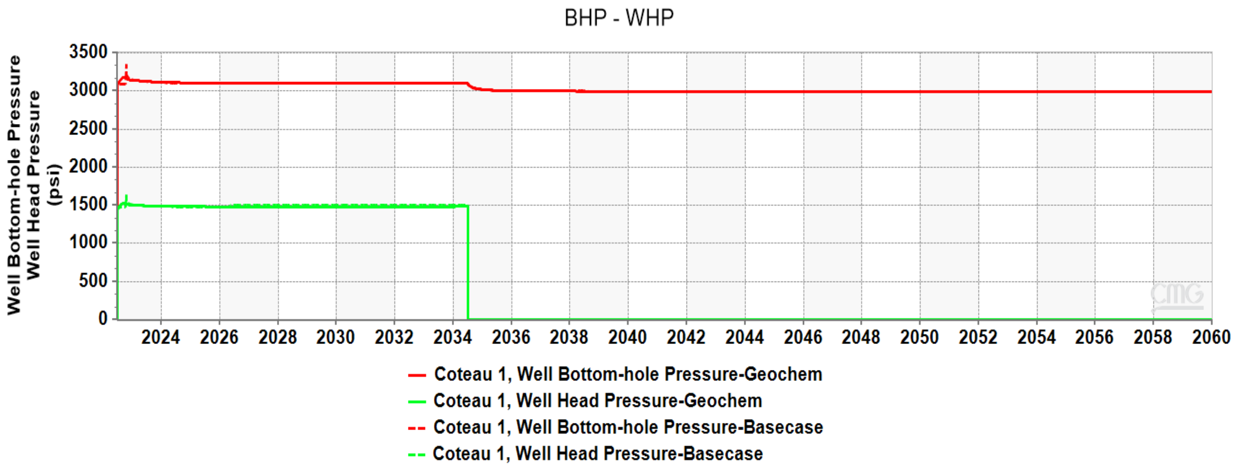

Figure 2-23. BHP and WHP vs. time. There is no observable difference in injection pressure due to geochemical reactions as compared to the results without the geochemical model.

Figures 2-24a and 2-24b show the concentration of CO_2, in molality, in the reservoir after 12 years of injection plus 25 years of postinjection for the geochemistry model case (upper figure) and for the non-geochemistry model (bottom figure) for comparisons. The results are not showing an evident difference in the CO_2 gas molality fraction between both cases as seen in the previous figures for volume injected and injection pressure simulation results.

The pH of the reservoir brine changes in the vicinity of the CO_2 accumulation, as shown in Figure 2-25. The pH of the Broom Creek native brine sample is 6.7 whereas the fluid pH declines to approximately 5.6 in the CO_2-flooded areas.

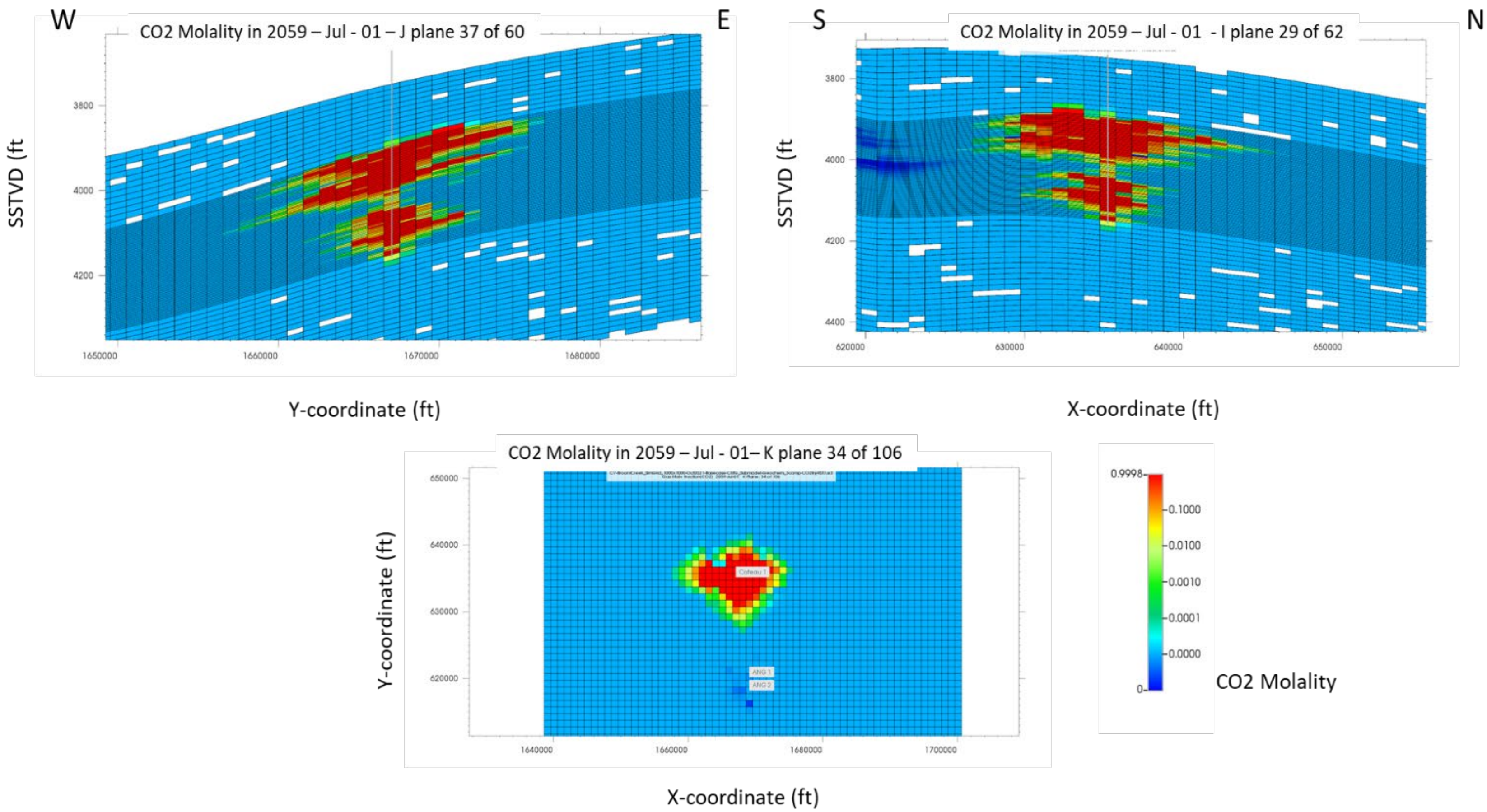

Figure 2-24a. CO_2 molality for the geochemistry case simulation results after 12 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east and right upper are north-south cross sections. Lower image is a planar view of simulation in layer k = 11. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

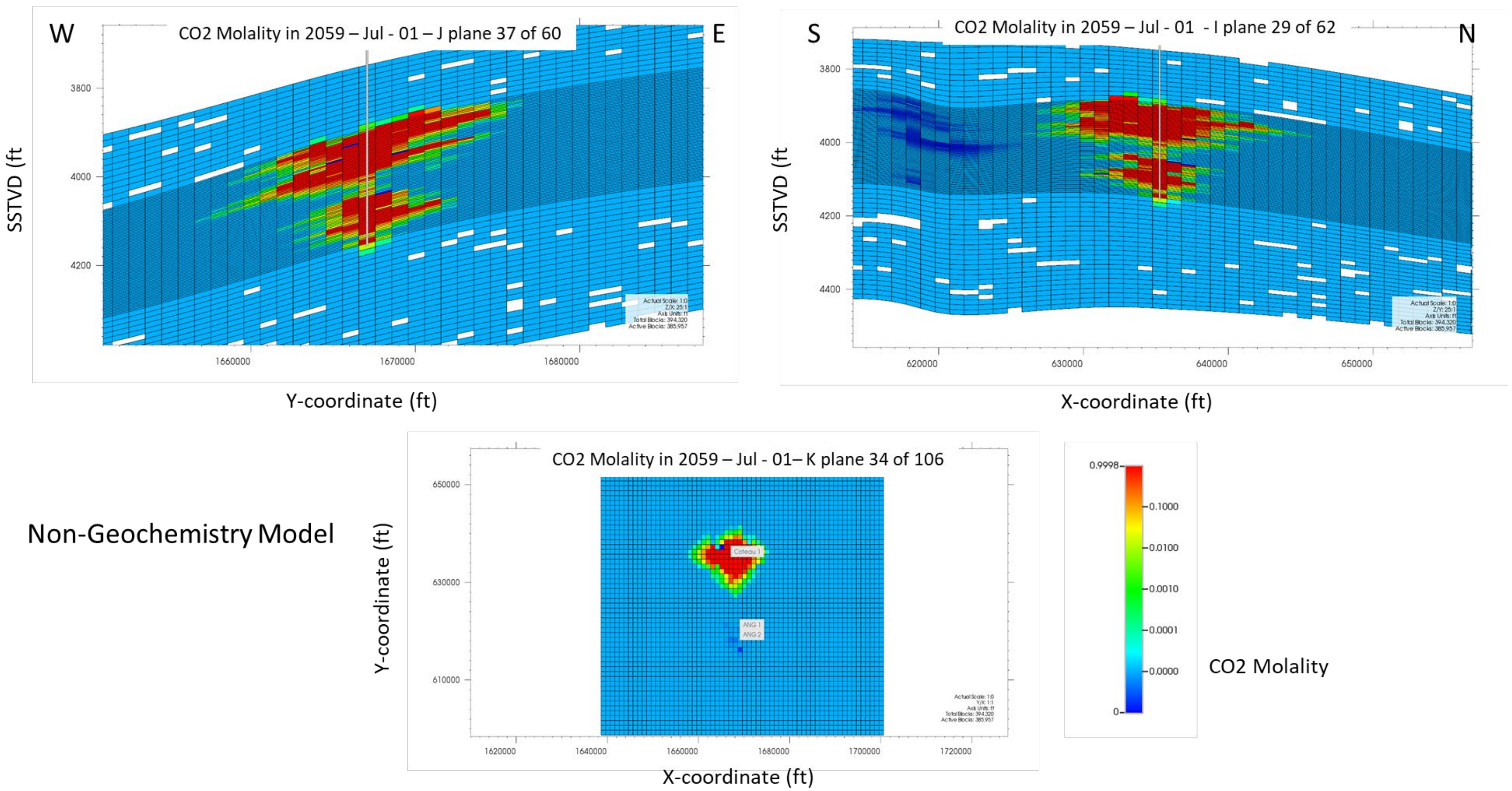

Figure 2-24b. CO_2 molality for the non-geochemistry model (bottom) results after 12 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east and right upper are north-south cross sections. Lower image is a planar view of simulation in layer k = 11. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

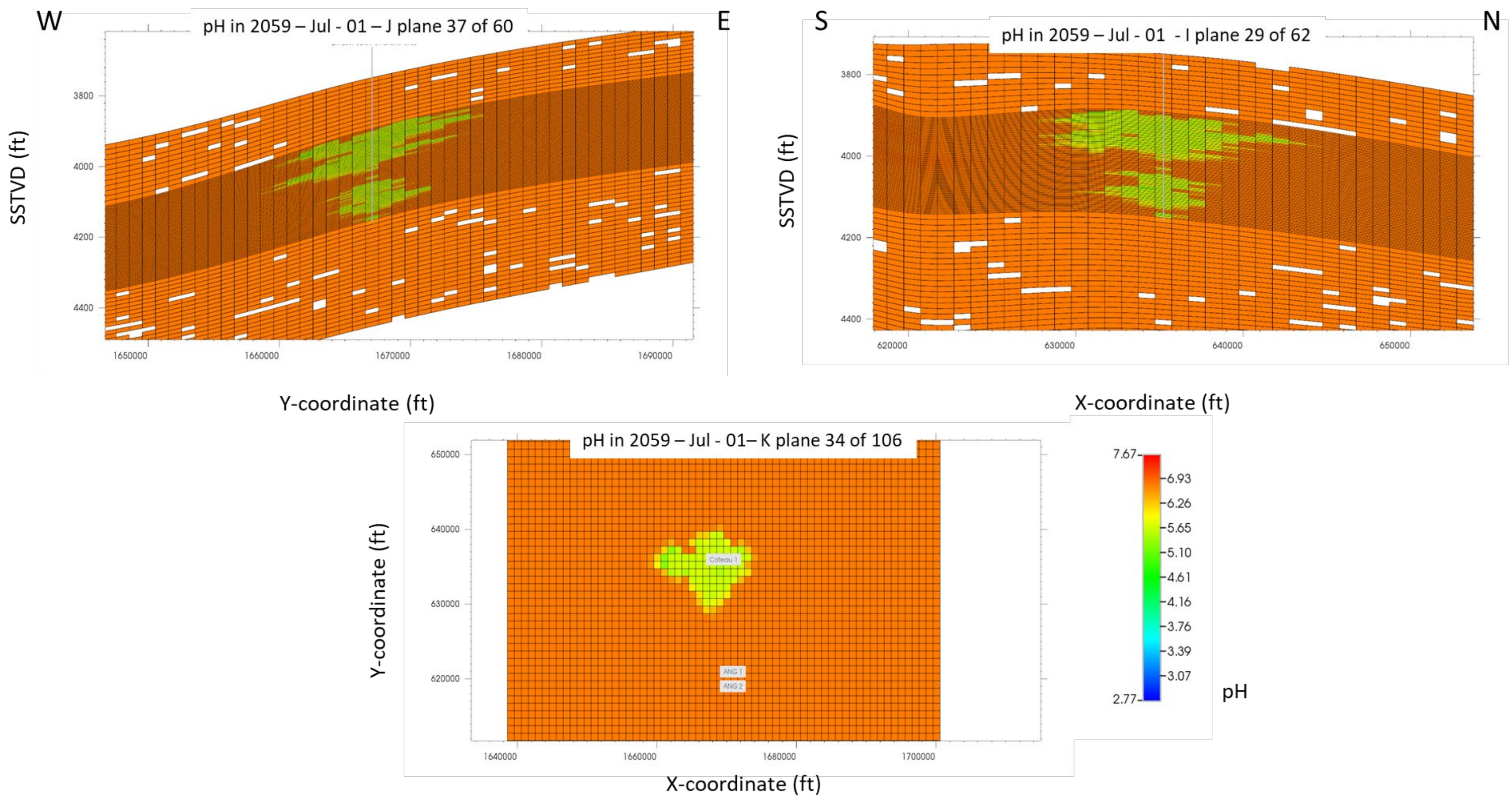

Figure 2-25. Geochemistry case simulation results after 12 years of injection + 25 years postinjection showing the pH of formation brine in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

Figure 2-26 shows the mass of mineral dissolution and precipitation due to geochemical reaction in the Broom Creek Formation. Anorthite is the most prominent dissolution mineral. Illite starts to dissolve and then precipitate after Year 2034, the year in which injection ends. Dolomite, albite, and pyrite are the primary precipitation minerals. Pyrite (FeS_2) precipitation is favored by the presence of dissolved H_2S in the gas stream injected and aqueous iron in the Broom Creek Formation water. There is a small amount of precipitation for quartz and anhydrite during the simulation period possibly due to the additional SiO_2 released by anorthite dissolution and the presence of Ca^{2+} and SO_4^{-2} ions in the water formation, respectively.

Figures 2-27 through 2-30 provide an indication of the change in distribution of the mineral that experienced the most dissolution, anorthite, and the minerals that have experienced significant precipitation: dolomite, albite, and pyrite.

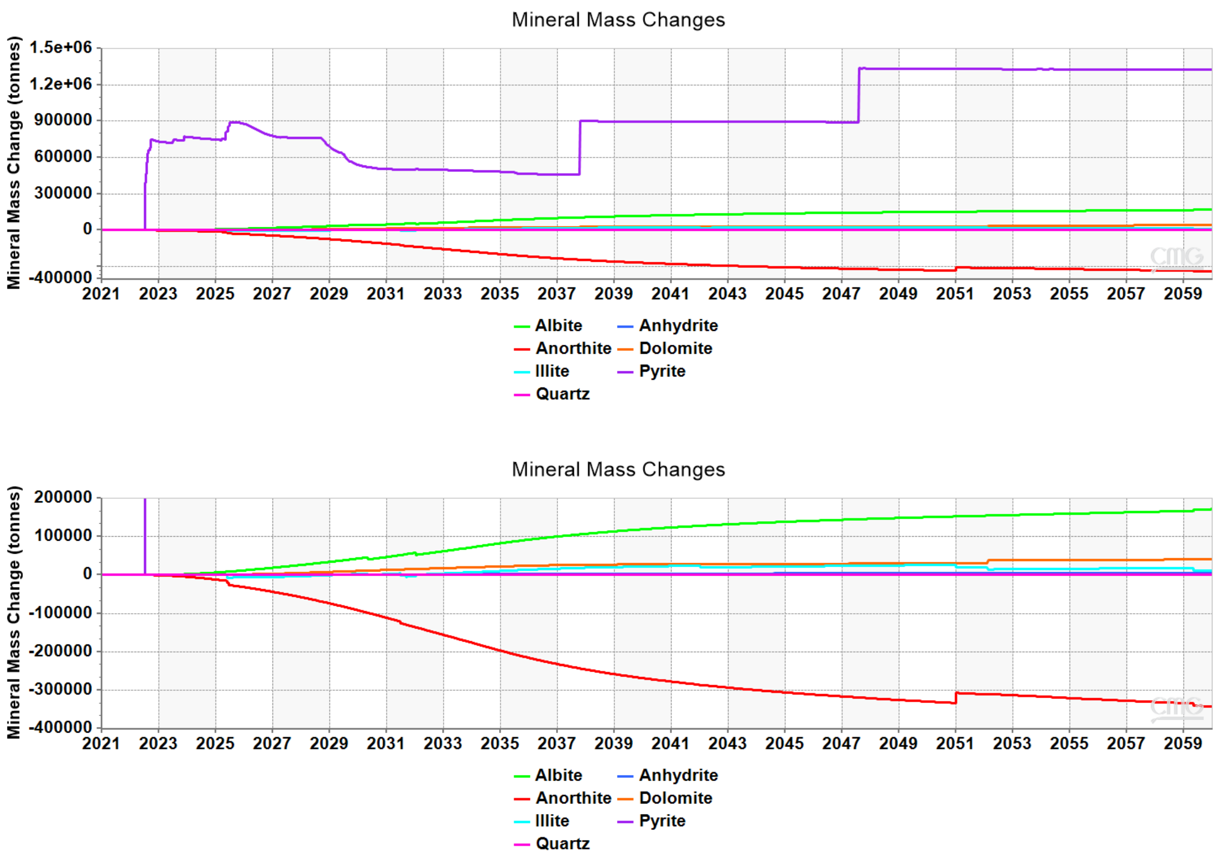

Figure 2-25. Dissolution and precipitation quantities of reservoir minerals because of CO_2 injection. Dissolution of anorthite with precipitation of pyrite, albite, and dolomite was observed. Upper figure shows all the minerals; the lower figure is rescaled for better view of the minerals mass change except pyrite.

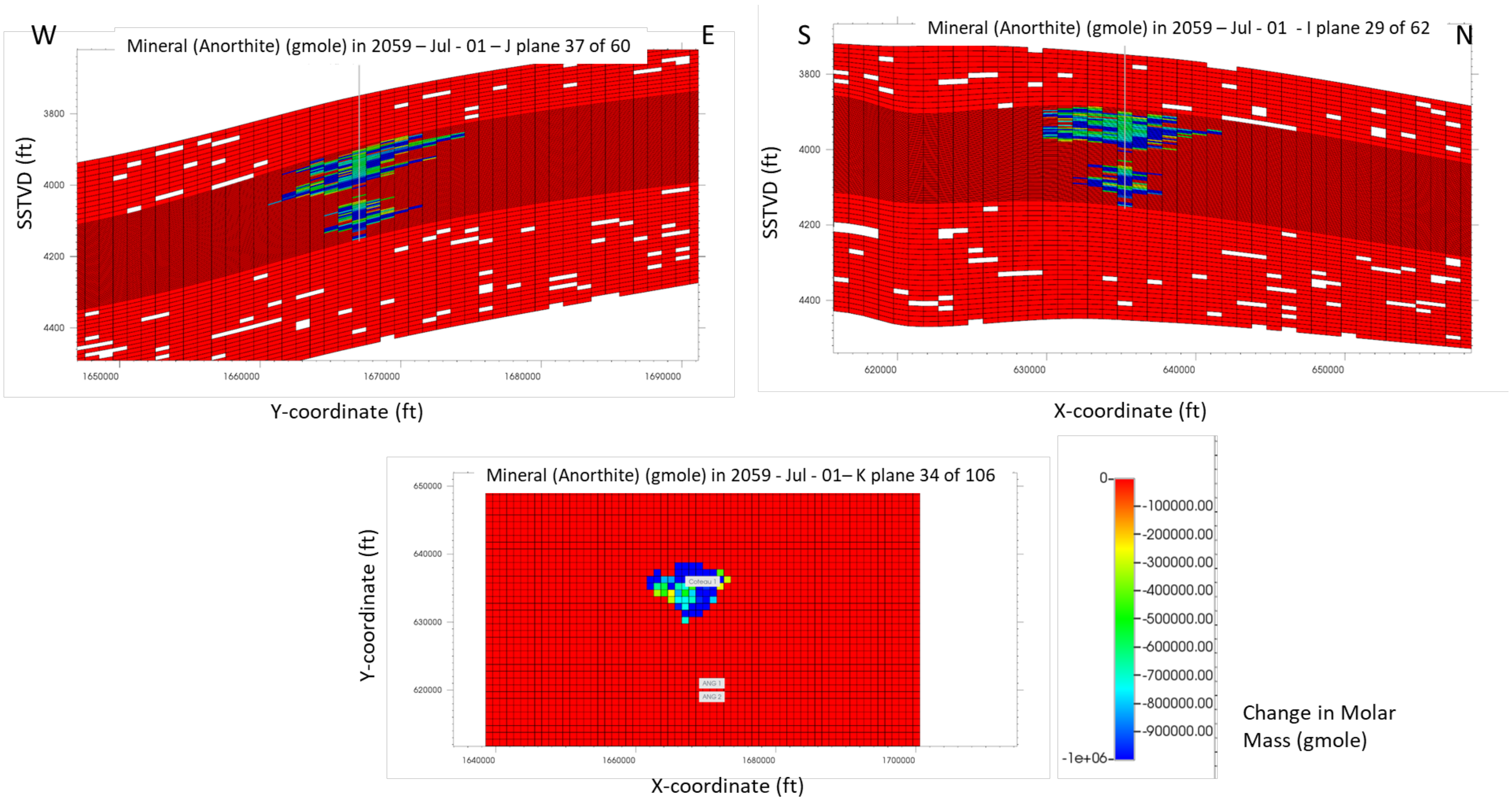

Figure 2-26. Change in molar distribution of anorthite, the most prominent dissolved mineral at the end of the 12-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

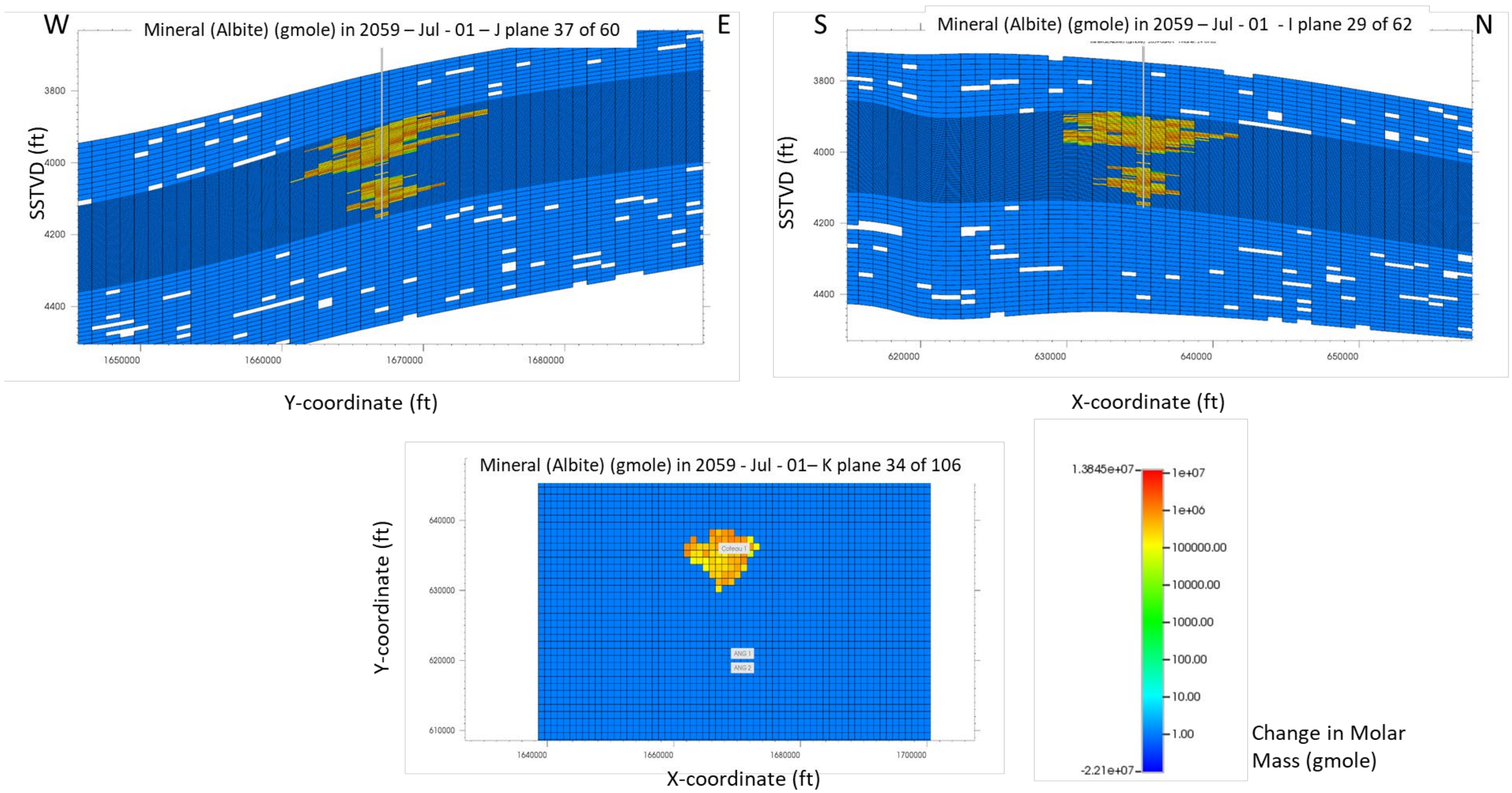

Figure 2-27. Change in molar distribution of albite, a precipitated mineral at the end of the 12-year injection + 25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

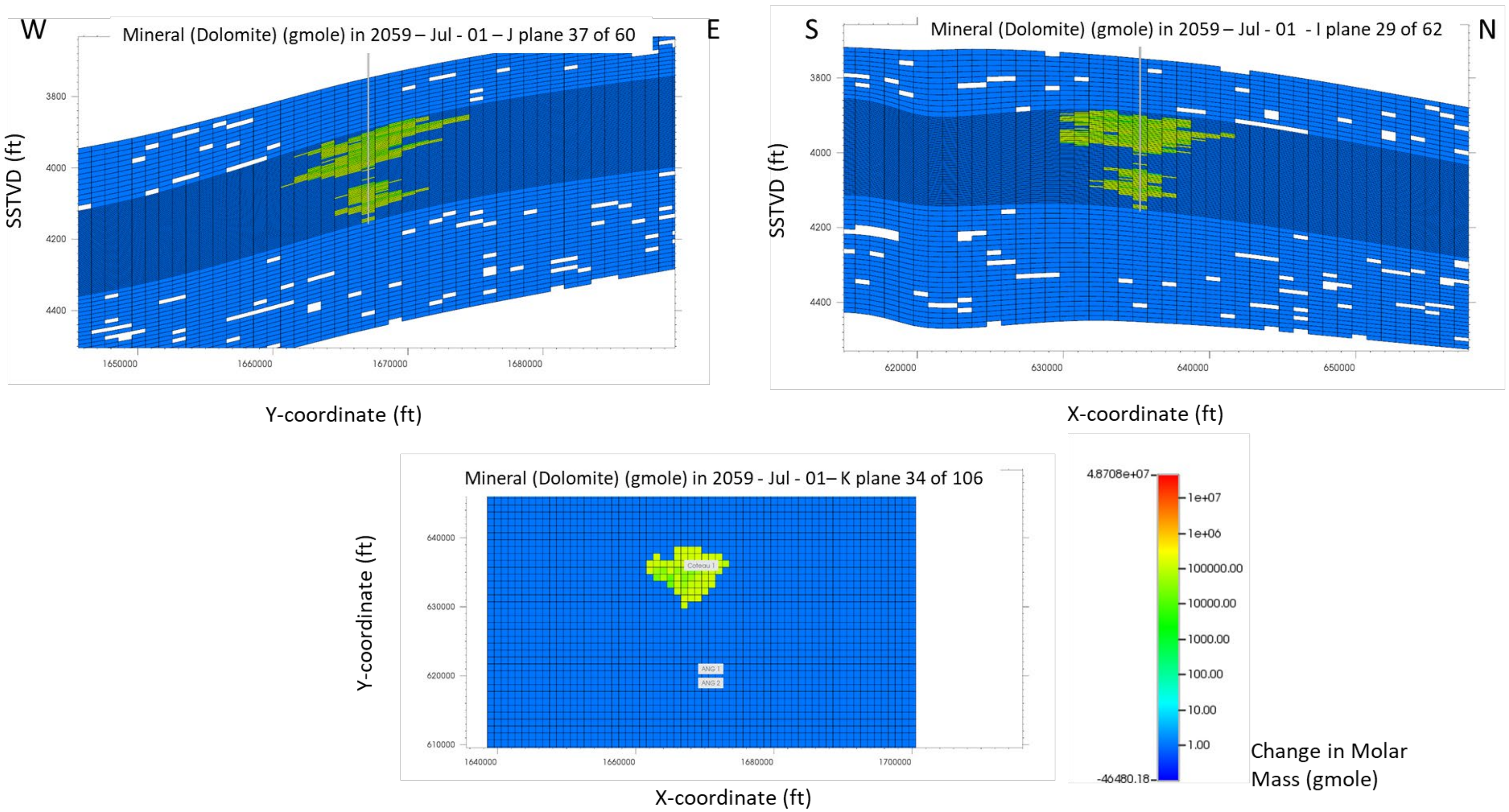

Figure 2-28. Change in molar distribution of dolomite, a precipitated mineral at the end of the 12-year injection + 25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

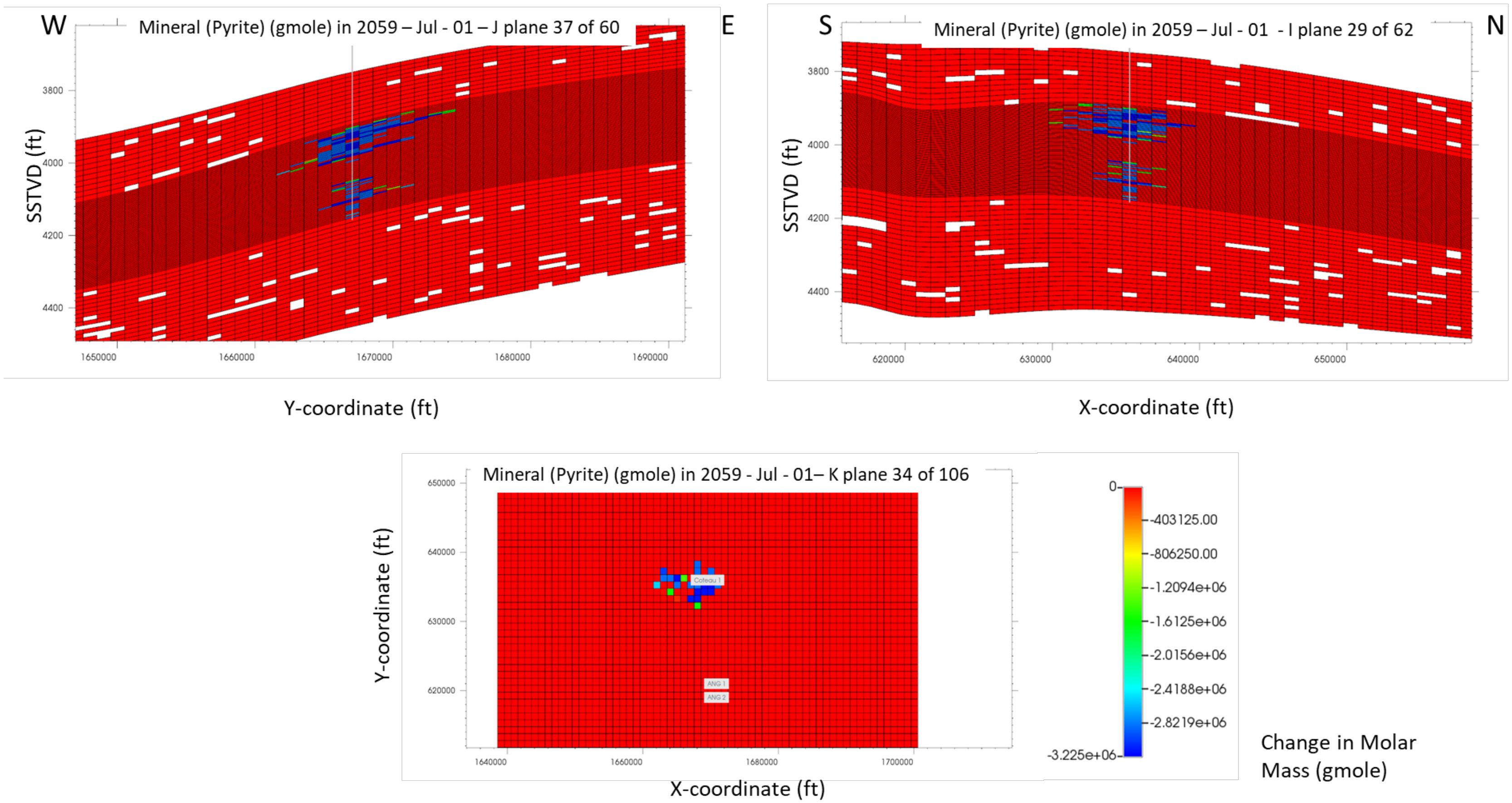

Figure 2-30. Change in molar distribution of pyrite, the most prominent precipitated mineral at the end of the 12-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

2.4 Confining Zones

The confining zones for the Broom Creek Formation are the Opeche interval and underlying Amsden Formation (Figure 2-3, Table 2-12). Both the Amsden and Opeche intervals consist of impermeable rock layers.

Table 2-12. Properties of Upper and Lower Confining Zones in Simulation Area (data based on the Coteau 1 well)

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Opeche	Amsden
Primary Lithology	Silty mudstone	Dolostone
Formation Top Depth, ft	5,763	6,164
Thickness, ft	143	300
Porosity, % (core data) *	6.93	2.40
Permeability, mD (core data) **	0.002878	0.00116
Capillary Entry Pressure (CO_2/brine), psi	138.68	251.27
Depth below Lowest Identified USDW, ft	4,658	5,059

* Porosity values are reported as the arithmetic mean.
** Permeability values are reported as the geometric mean.

2.4.1 Upper Confining Zone

In the Great Plains CO_2 Sequestration Project area, the Opeche Formation consists of silty mudstone and anhydrite. The upper confining zone (Opeche) is laterally extensive across the Great Plains CO_2 Sequestration Project area (Figure 2-31). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche interval is 5,763 ft below the land surface and 143 ft thick at the Coteau 1 wellsite (Table 2-12, Figures 2-32 and 2-33). The contact between the upper confining zone and underlying Broom Creek sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact (Figure 2-34).

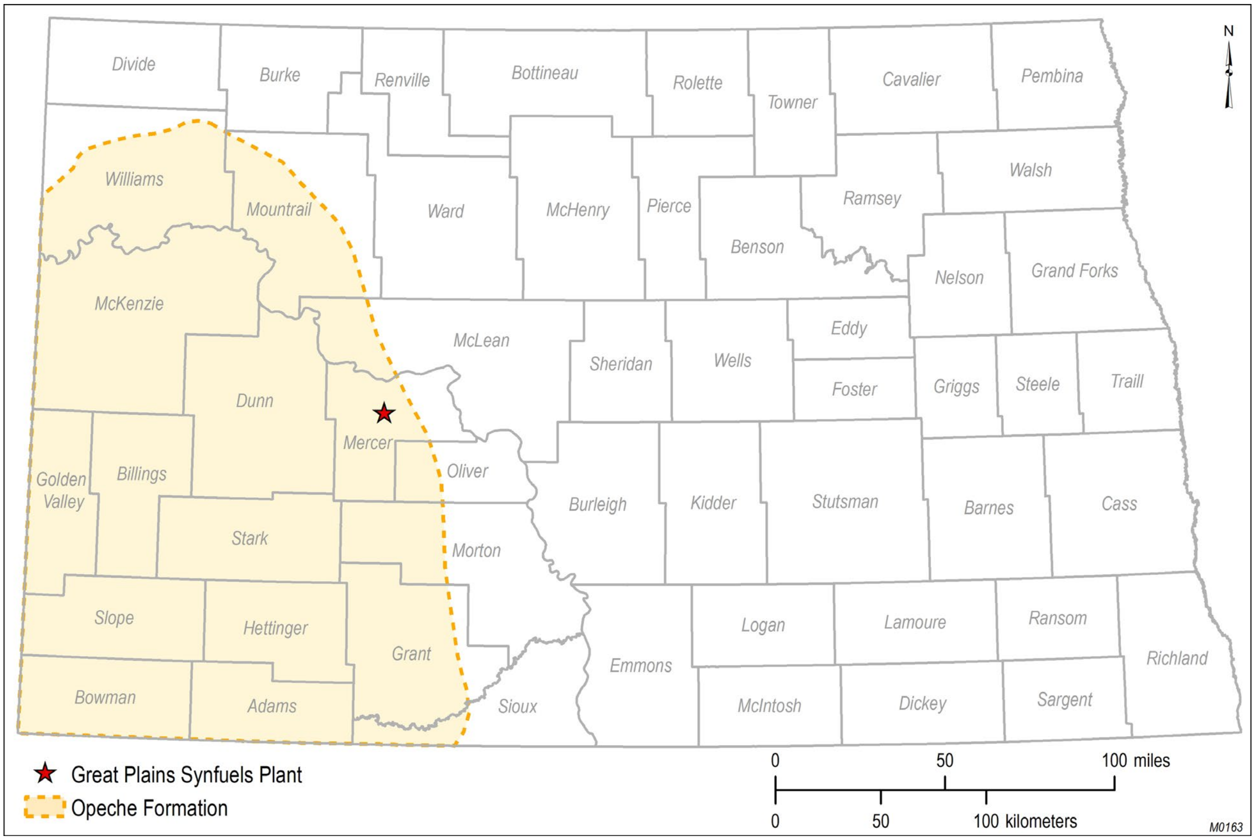

Figure 2-31. Areal extent of the Opeche Formation in North Dakota.

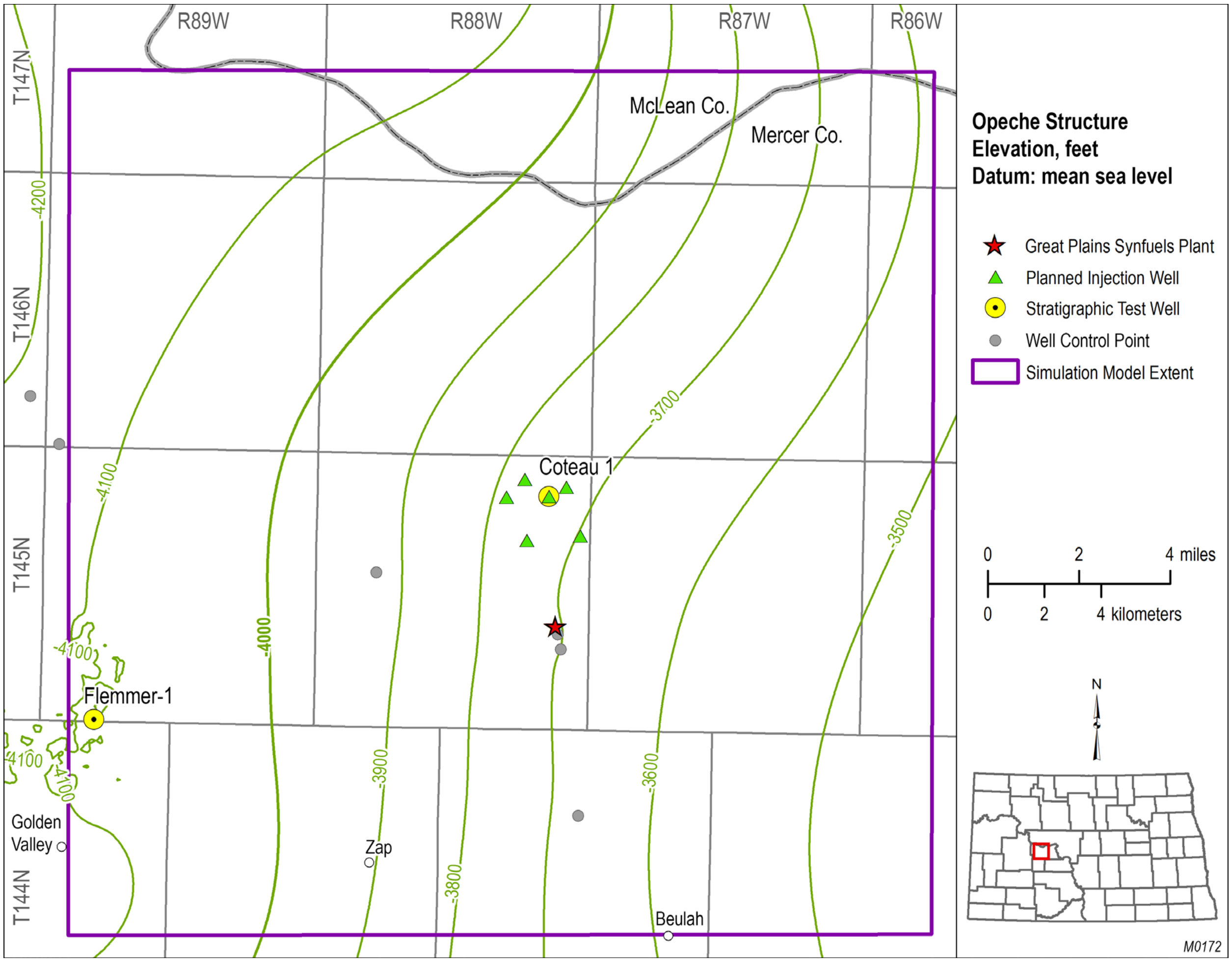

Figure 2-32. Structure map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops).

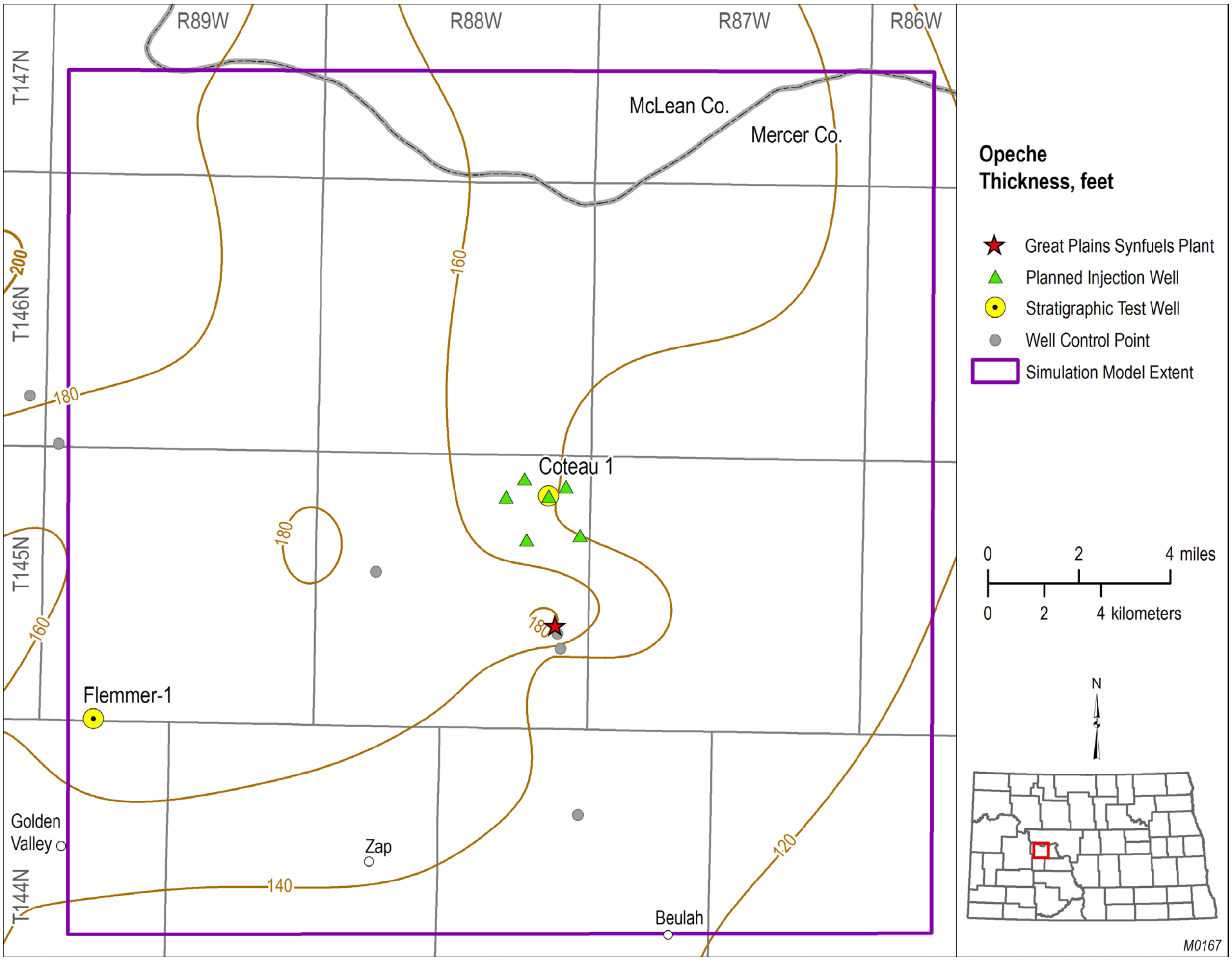

Figure 2-33. Isopach map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area.

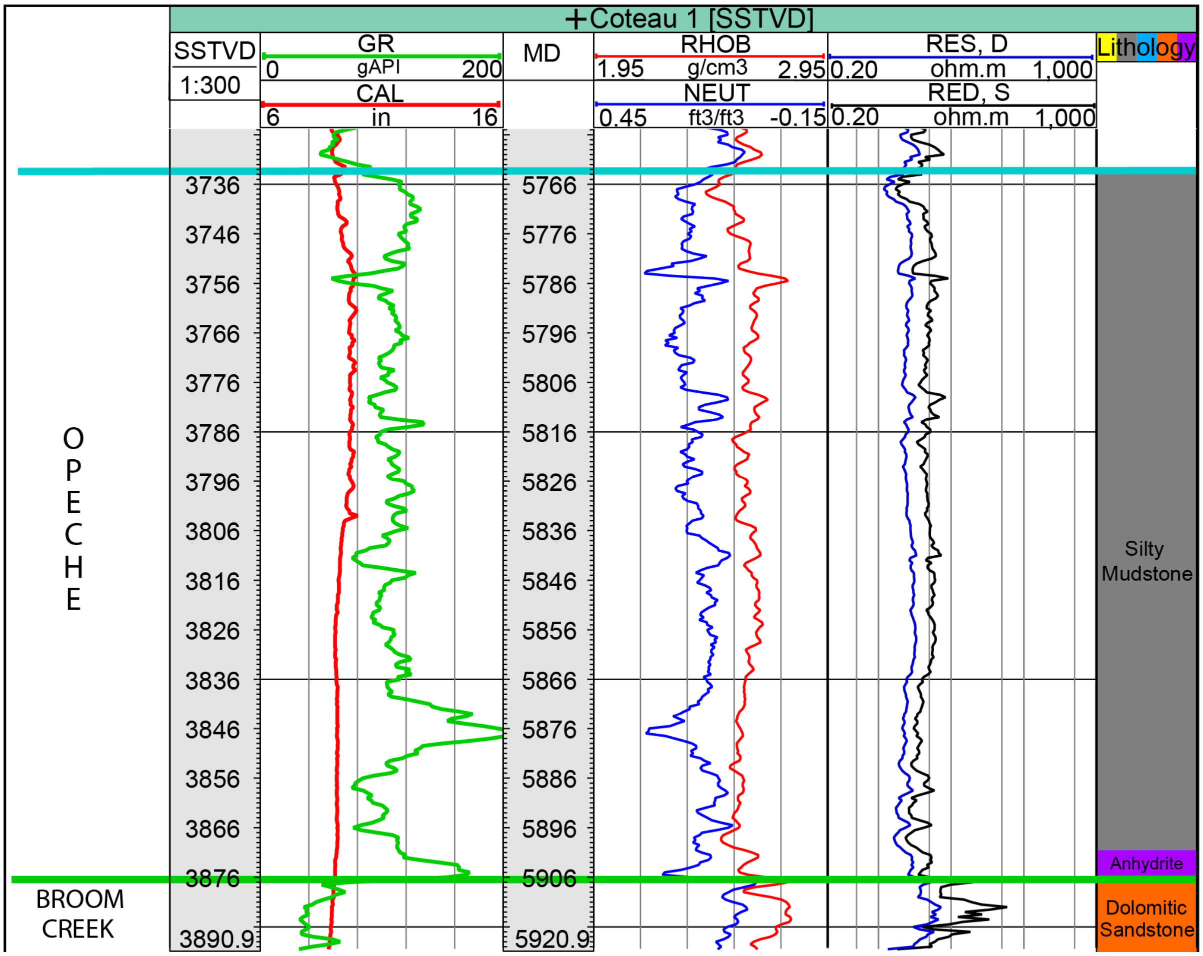

Figure 2-34. Well log display of the upper confining zone at the Coteau 1 well.

Microfracture in situ stress tests were not performed within the Opeche Formation in the Coteau 1 well. Microfracture in situ tests were performed using the MDT tool in the Flemmer 1 well, in the Opeche Formation, at a depth of 6,262 ft, which yielded results within good confidence. The MDT tool was able to cause breakdown in the formation at 8,157 psi. Propagation pressure for two cycles in close agreement were 4,879 and 5,085 psi, resulting in an average propagation pressure gradient of 0.80 psi/ft (Figure 2-35).

In situ fluid pressure testing was not performed in the Opeche Formation with the MDT tool. The CMR log shown in Figure 2-36 suggests that because of the low to almost zero permeability the fluid within the Opeche is pore- and capillary-bound fluid and not mobile. This is confirmed by unsuccessful attempts by others to extract fluid samples from the Opeche. The Tundra SGS (secure geologic storage) and Red Trail Energy storage facility permit applications describe unsuccessful attempts to draw down reservoir fluid in order to determine the reservoir pressure or to collect an in situ fluid sample; the formation was unable to rebound (build pressure) because of low to almost zero permeability (NDIC, 2021a, b). These unsuccessful attempts provide further evidence of the confining properties of the Opeche Formation, ensuring sufficient geologic integrity to contain the injected carbon dioxide stream.

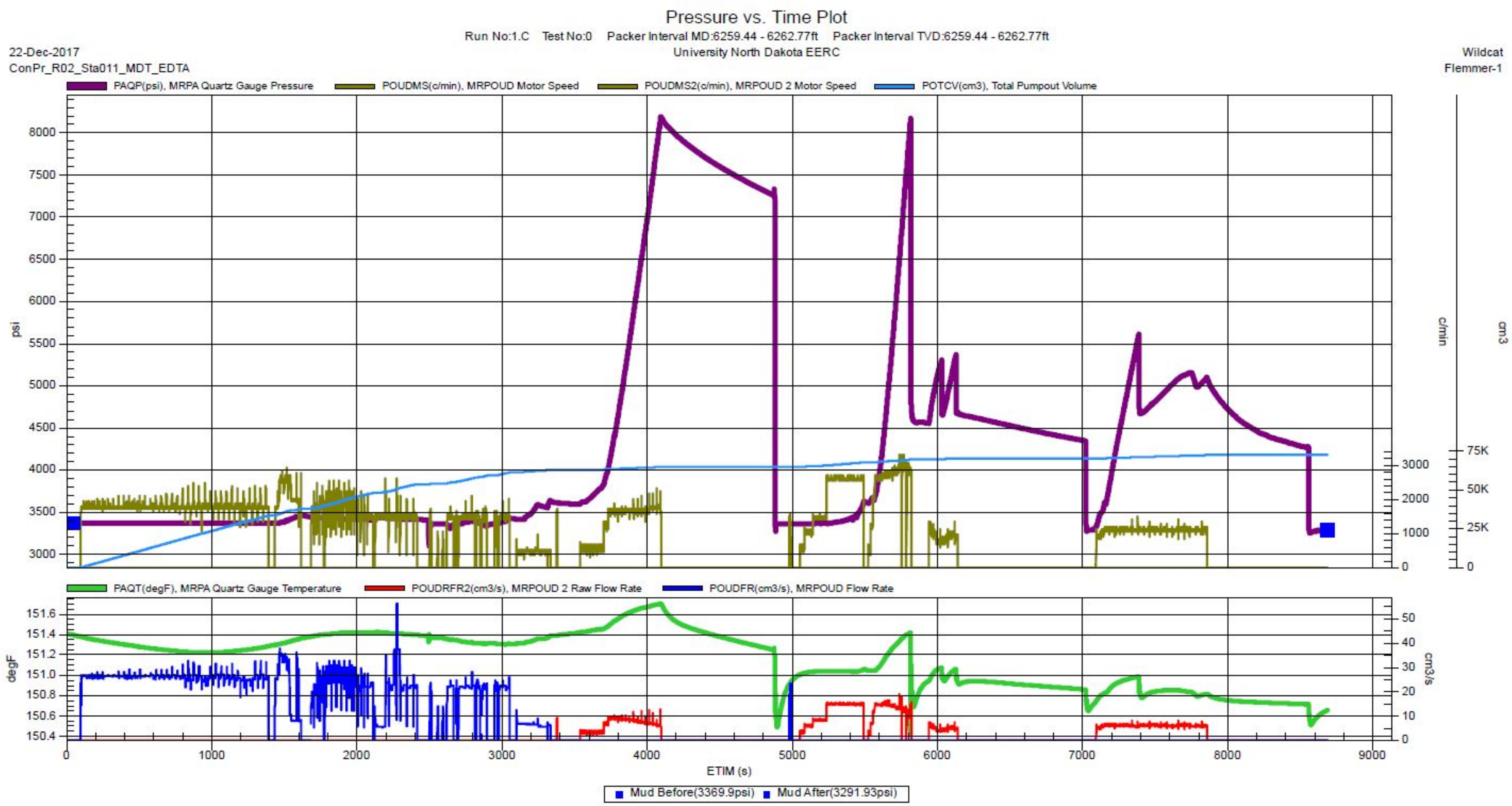

Figure 2-35. Flemmer 1 Opeche Formation MDT microfracture in situ stress pump cycle graph at 6,262 ft.

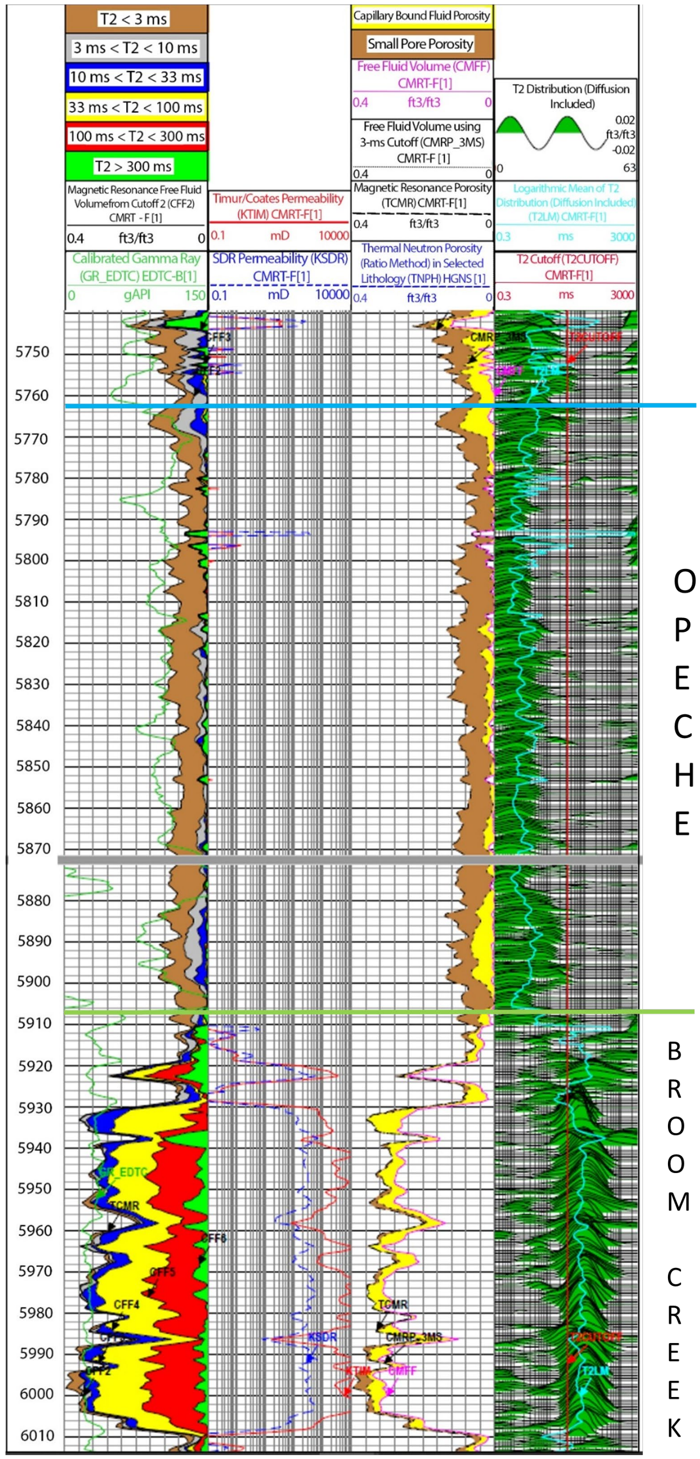

Figure 2-36. Well log display of the combinable magnetic resonance (CMR) log from the Coteau 1 well. Note: Small pore and capillary-bound fluid properties represent porosity containing immobile formation fluid. Fluid within the small pores cannot escape because of pore size, while capillary bound fluids cannot escape pores because of pressure constraints. T2 values smaller than the T2 cutoff, as seen in the fourth track, indicate smaller pore space and low permeabilities.

Laboratory measurements from the Opeche Formation core samples taken from the Coteau 1 well indicate a porosity value of 6.93% at 800 psi and 6.62% at 2,400 psi and geometric average permeability values of 0.002878 mD at 800 psi and 0.002083 mD at 2,400 psi. The lithology of the cored sections of the Opeche is primarily silty mudstone.

2.4.1.1 Mineralogy

Thin-section investigation shows that the Opeche Formation comprises alternating intervals of very fine silty mudstone and mudstone. In all, five thin sections were created over the 73 ft of core collected from the Opeche Formation. The mineral components present are clay, quartz, anhydrite, feldspar, dolomite, and iron oxides. The coarser grains are almost always surrounded by anhydrite or clay as cement or matrix. The observable porosity is very low and is due to the dissolution of quartz and feldspar. The porosity ranges between 5% and 9%. Permeability is very poor and ranges between 0.00026 to 0.0227 mD. Figure 2-37 shows examples of the texture, fabric, and nature of observable porosity for the intervals where thin sections were created. As shown, observable porosity (shown in blue) is generally isolated and not well connected throughout. Additionally, thin-section analysis shows the fine-grained, well-compacted nature of the intervals evaluated.

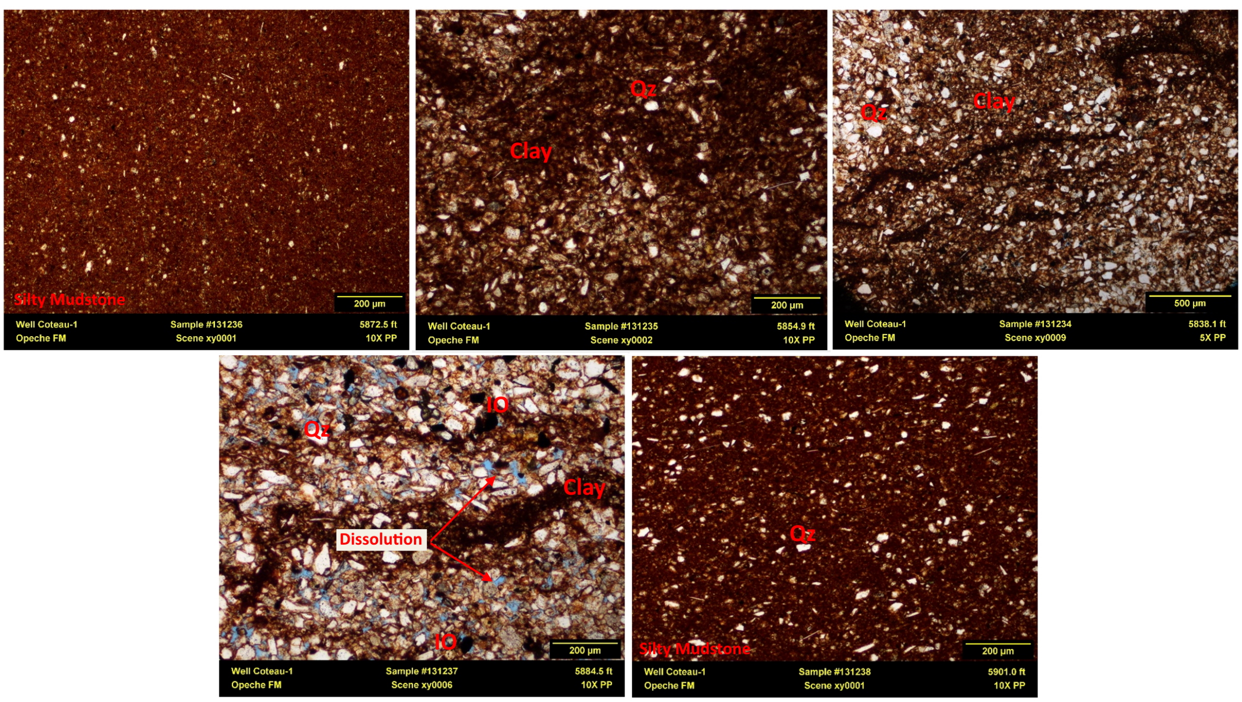

Figure 2-37. Thin sections from the five depth intervals of the Opeche Formation. As shown, the Opeche is composed of very fine silty mudstone and mudstone. Where porosity is shown (blue), it is generally isolated and disconnected.

XRD data from the five Opeche samples of the Coteau 1 core supported facies interpretations from core descriptions and thin-section analysis. The Opeche Formation mainly comprises clay, quartz, feldspar, dolomite, and anhydrite. Figure 2-38 shows the mineralogy determined from XRD data for the five samples tested through the cored interval of the Opeche Formation.

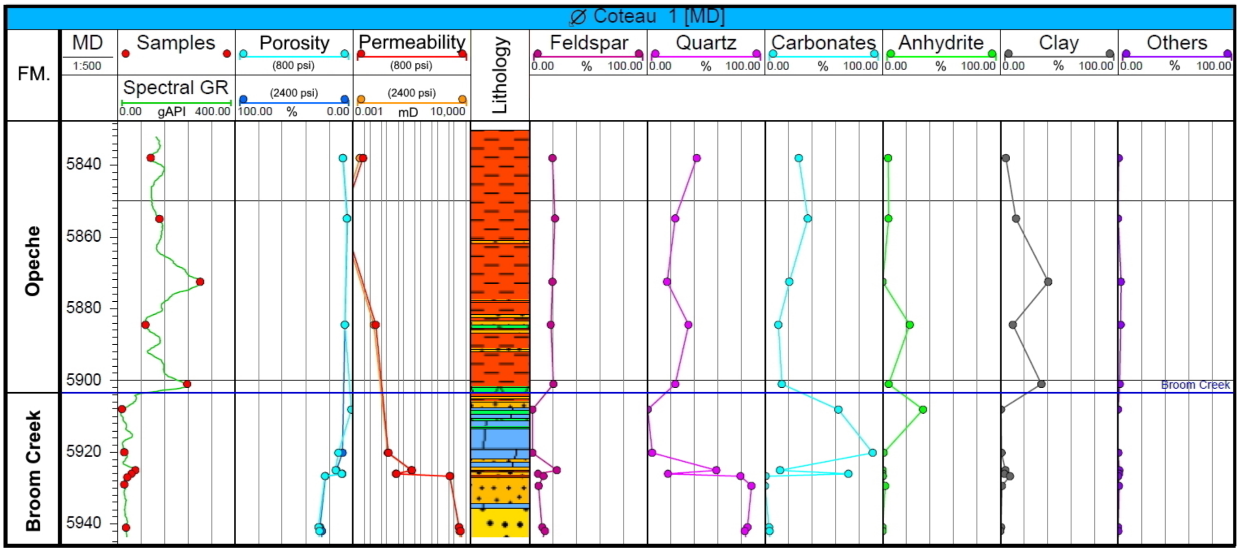

Figure 2-38. XRD data for the Opeche Formation from the Coteau 1.

XRF analysis of the Opeche Formation shown in Figure 2-39 identifies SiO_2 (44%–57%), Al_2O_3 (6%–18%), CaO (5%–15%), and MgO (3%–9%) as the major chemical constituents, correlating well with the silicate, carbonate, and aluminum-rich mineralogy determined by XRD. This is in good agreement with XRD, core description, and thin-section analysis.

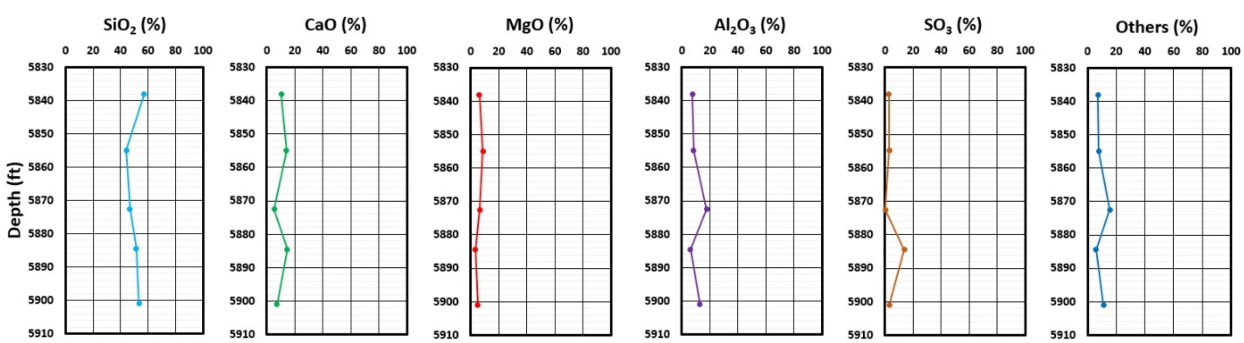

Figure 2-39. XRF data for the Opeche Formation from the Coteau 1.

2.4.1.2 Geochemical Interaction

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected CO_2 stream on the Opeche Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 and minor amounts of H_2S at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Opeche by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the Opeche Formation. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock –CO_2/H_2S exposure boundary. The mineralogical composition of the Opeche Formation was honored (Table 2-13). The XRD data used to define mineral composition in the model correspond to a mudstone sample from the Opeche Formation. Formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone below (Table 2-14). The CO_2 stream composition was as described in Table 2-15. 96.45 mol% of the stream is CO_2, and the rest represents other components, including H_2S, the second major component of the stream. 96 mol% of CO_2 was used in the simulation instead of 96.45 mol% to keep the model input simple (Table 2.15). The 4 mol% H_2S used for this simulation represents the sum of all other components (CH_4, C_2H_6, C_3H_8, N_2) and thus overstates the actual H_2S fraction of 1.23 mol% (Table 2-15). The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). This overestimate was done to ensure that the degree and pace of geochemical change would not be underestimated. This geochemical simulation was run for 37 years to match the reservoir injection zone geochemical model and represent 12 years of injection plus 25 years of postinjection. The simulation was performed at reservoir pressure and temperature conditions.

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

Minerals, wt%	
Illite	32.3
K-Feldspar	12.7
Albite	7.6
Quartz	24.0
Dolomite	13.1
Anhydrite	5.1

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

pH	6.7	TDS	42,800 mg/L
Total Alkalinity	853 mg/L $CaCO_3$	Calcium	1,860 mg/L
Bicarbonate	853 mg/L $CaCO_3$	Magnesium	212 mg/L
Carbonate	$<$20 mg/L $CaCO_3$	Sodium	12,800 mg/L
Hydroxide	$<$20 mg/L $CaCO_3$	Potassium	516 mg/L
Sulfate	469 mg/L	Strontium	70.8 mg/L
Chloride	24,900 mg/L	Iron	392 mg/L

Table 2-15. Composition of the Injection Stream with Constituents Normalized to 100% Mole Fraction

Component Flows	mol%	mol% Used in Simulation
CO_2	0.9645	0.960
H_2S	0.0123	0.04
CH_4	0.0054	
C_2H_6	0.0096	
C_3H_8	0.0028	
N_2	0.0054	

Results showed geochemical processes at work. Figures 2-40 through 2-43 show results from geochemical modeling. Figure 2-40 shows change in fluid pH over time as CO_2/H_2S enters the system. For the cell at the CO_2 interface, C1, the pH starts declining from an initial pH of 7.04 and stabilizes at a level of 5.34 after 12 years of simulation time. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH only begins to change after Year 27. Lastly, the pH is unaffected in Cell C3, indicating CO_2/H_2S does not penetrate this cell within the first 37 years.

Figure 2-41 shows the change in mineral dissolution and precipitation in grams per cubic meter of rock. The dashed lines are for Cell C1; solid lines that are only faintly seen in the figure are for Cell C2, 1.0 to 2.0 meters into the cap rock. The net change due to precipitation or dissolution in Cell C2 is less than 10 kg per cubic meter per year with little to no precipitation or dissolution taking place after injection ceases in Year 2034. Albite, K-feldspar, and anhydrite start to dissolve from the beginning of the simulation period while illite, quartz, and calcite start to precipitate for Cell C1. The presence of dissolved H_2S and aqueous iron in the Opeche Formation water (Table 2-14) favors minor amounts (less than 10 g) of pyrite precipitation. Any effects in Cell C3 are too small to represent at this scale.

Figure 2-42 represents the initial fractions of potentially reactive minerals in the Opeche Formation based on XRD data shown in Table 2-13. The overall Opeche lithology is characterized by a higher percentage of clay minerals. The expected dissolution of these minerals in weight percentage is also shown for Cells 1 and Cell 2 of the model. In Cell 1, albite, K-feldspar, and anhydrite are the primary minerals that go into dissolution. Dissolution (wt%) in Cell 2 is minimal (<0.5 wt%).

Figure 2-43 shows the change in porosity of the cap rock. Cell 1 experiences an initial increase in porosity as it is first exposed to CO_2/H_2S because of dissolution. The porosity decreases to nearly its initial condition after Year 13 because of precipitation. As dissolution occurs in Cell 1, reaction products move into Cell 2, where they precipitate, causing the porosity to slightly decrease. No significant change in porosity is seen in Cell 3 during the 37-year duration of the simulation. The net porosity changes from dissolution and precipitation are miniscule and unchanging in later years of the simulation. These results suggest that geochemical change from exposure to CO_2 and H_2S is minor and will not cause substantive deterioration of the Opeche cap rock.

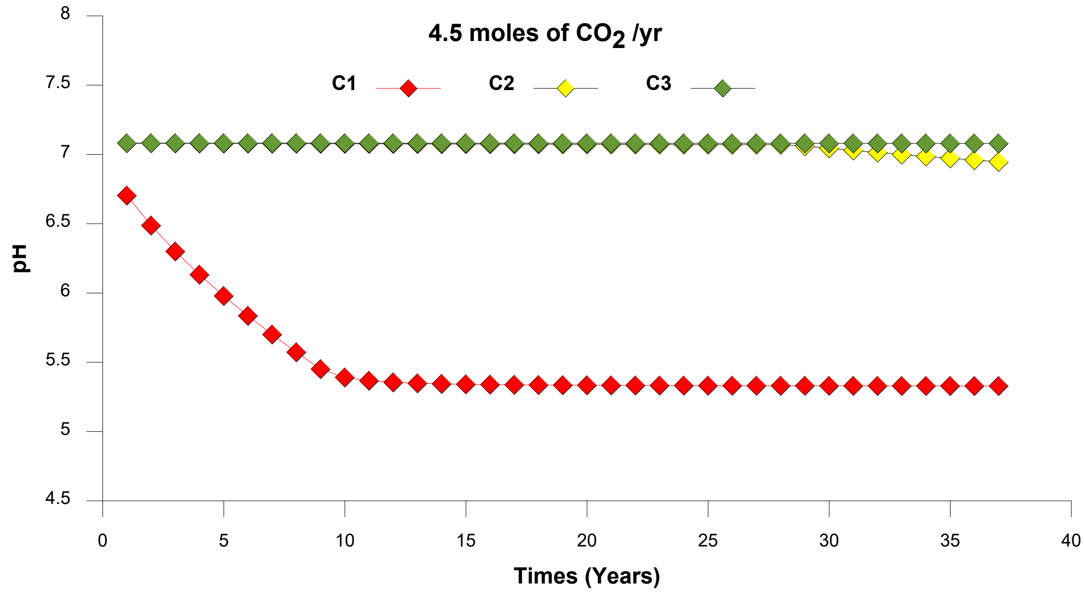

Figure 2-40. Change in fluid pH vs. time. The red line shows pH for the center of Cell C1, 0.5 meters above the Opeche cap rock base. The yellow line shows Cell C2, 1.5 meters above the cap rock base. The green line shows Cell C3, 2.5 meters above the cap rock base. pH for Cell C2 does not begin to change until after Year 27.

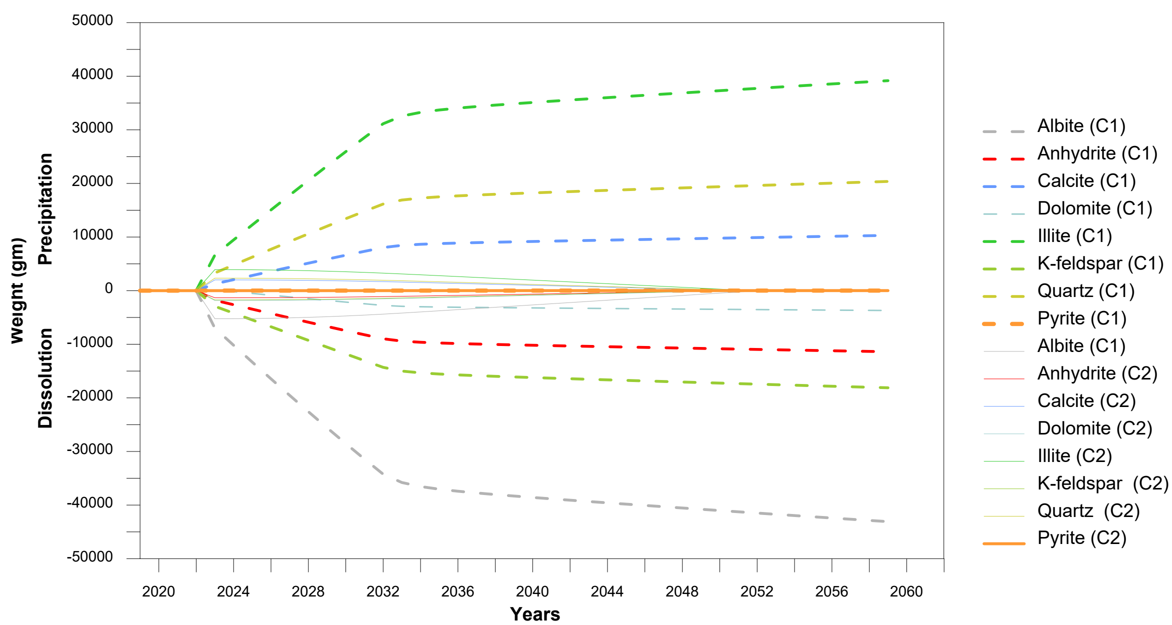

Figure 2-41. Dissolution and precipitation of minerals in the Opeche cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2, 1.5 meters above the cap rock base; these changes are barely visible. Results from Cell C3, 2.5 meters above the cap rock base, are not shown as they are too small to be seen at this scale.

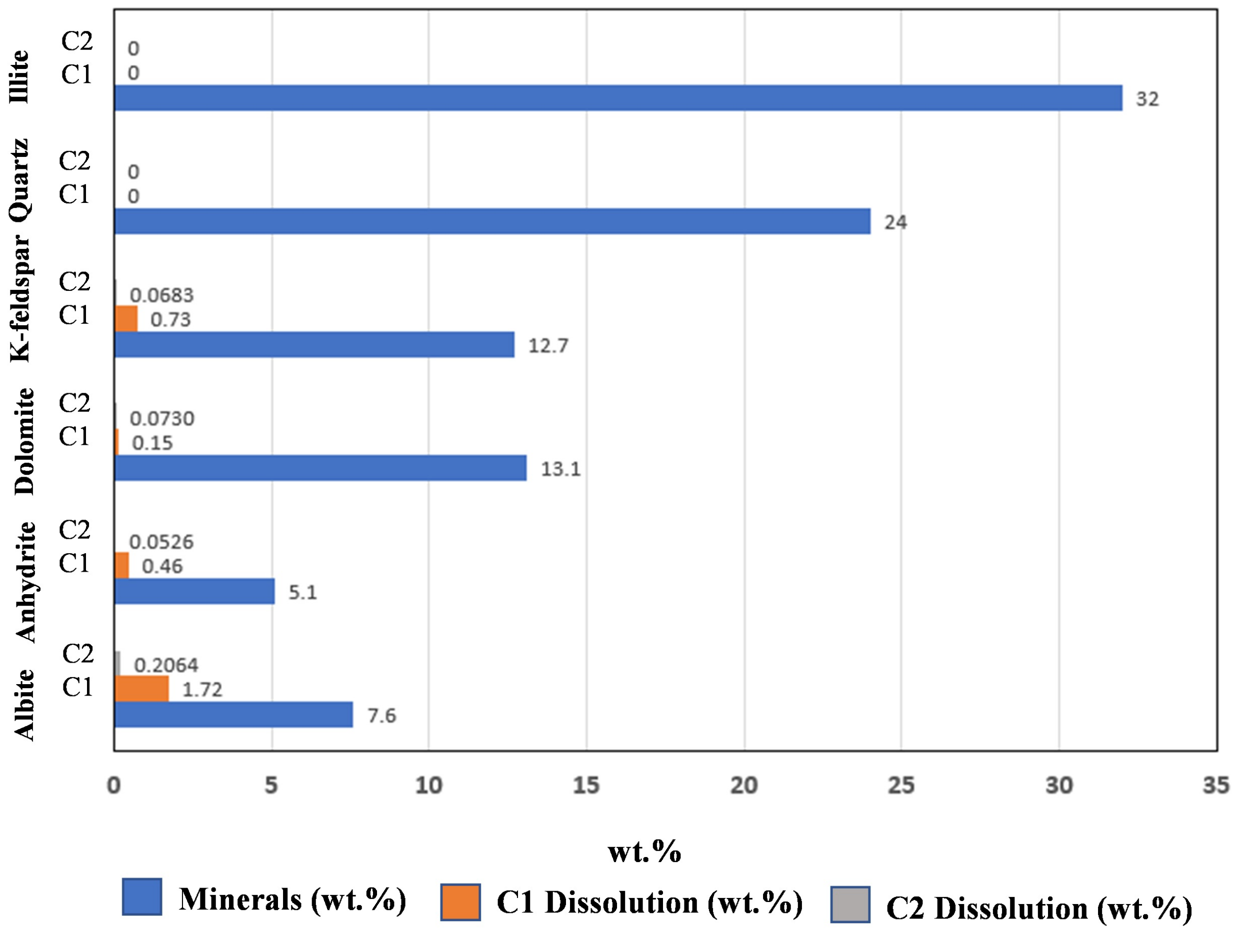

Figure 2-42. Weight percentage (wt.%) of potentially reactive minerals present in the Opeche Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray) after 12 years of injection plus 25 years of postinjection.

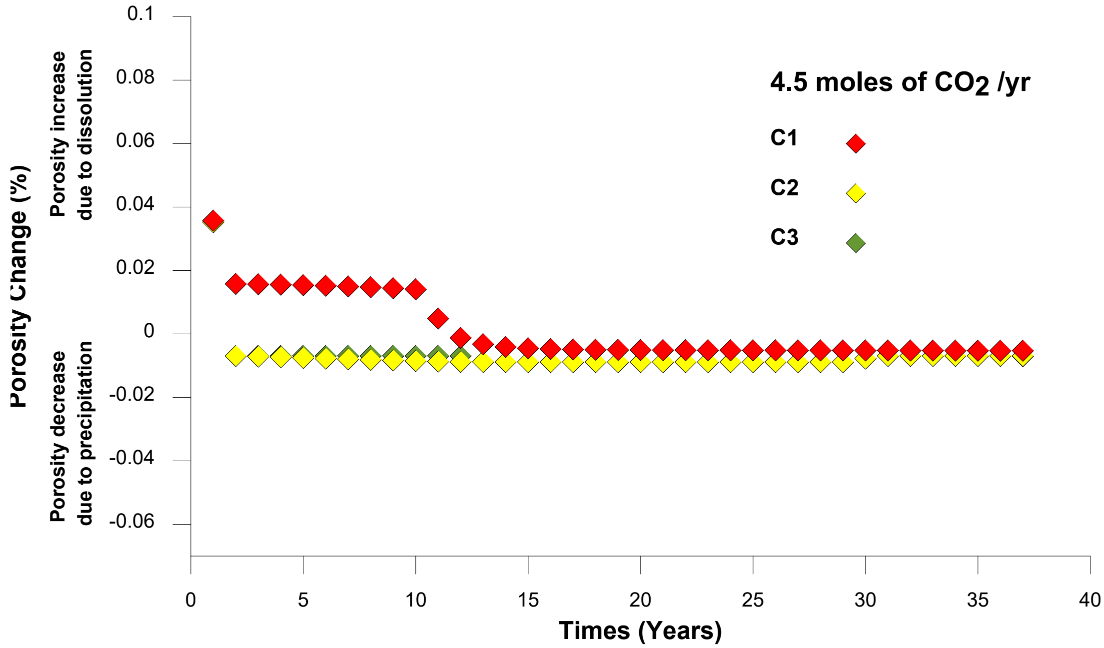

Figure 2-43. Change in percent porosity of the Opeche cap rock. Red line shows porosity change calculated for Cell C1 at 0.5 meters above the cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation.

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the Opeche interval. Impermeable rocks above the primary seal include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-16). Together with the Opeche interval, these formations are 1,106 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-44). Above the Inyan Kara Formation, 2,657 ft of impermeable rocks act as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (Figure 2-45). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-16).

Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (Opeche) (data based on the Coteau 1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,753	1,931	0
Greenhorn	Shale	3,685	376	1,931
Mowry	Shale	4,061	94	2,307
Skull Creek	Shale	4,156	254	2,402
Swift	Shale	4,800	411	3,046
Rierdon	Shale	5,212	205	3,458
Piper (Kline Member)	Limestone	5,417	112	3,663
Piper (Picard Member)	Shale	5,529	233	3,775

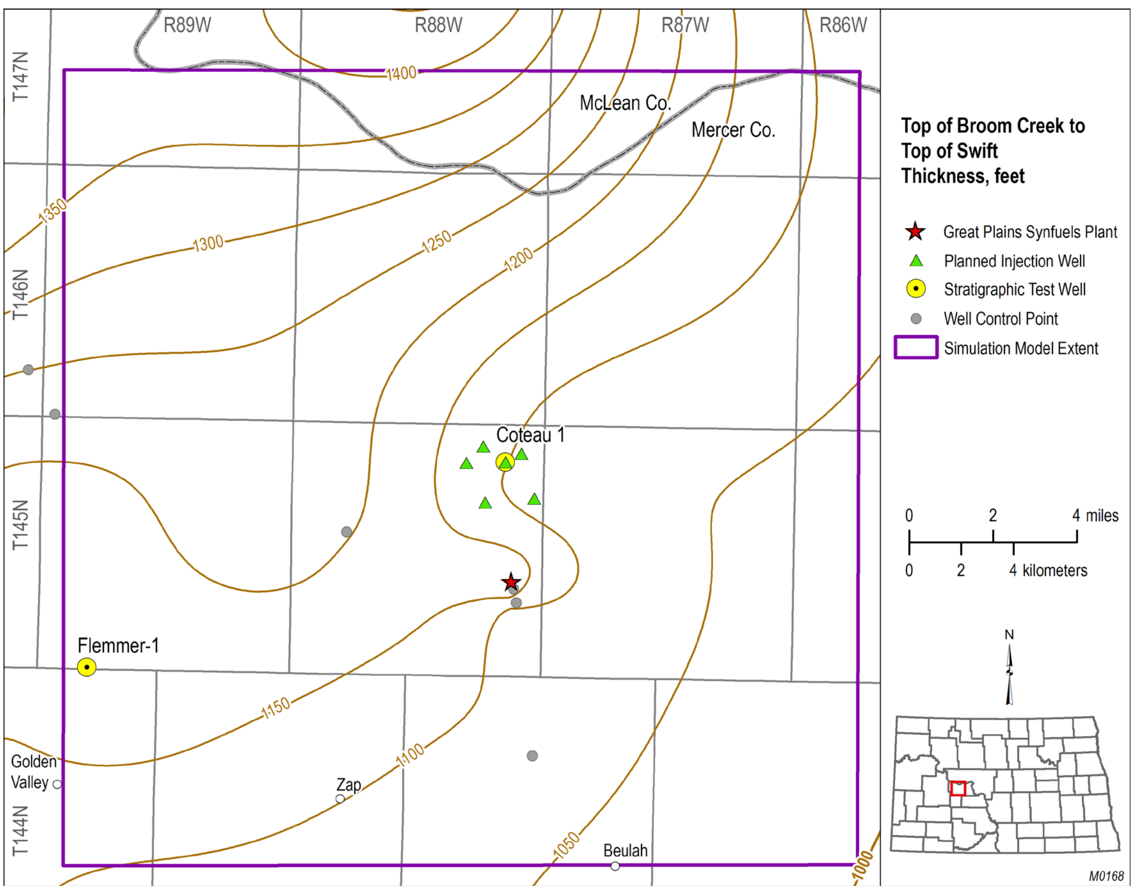

Figure 2-44. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones.

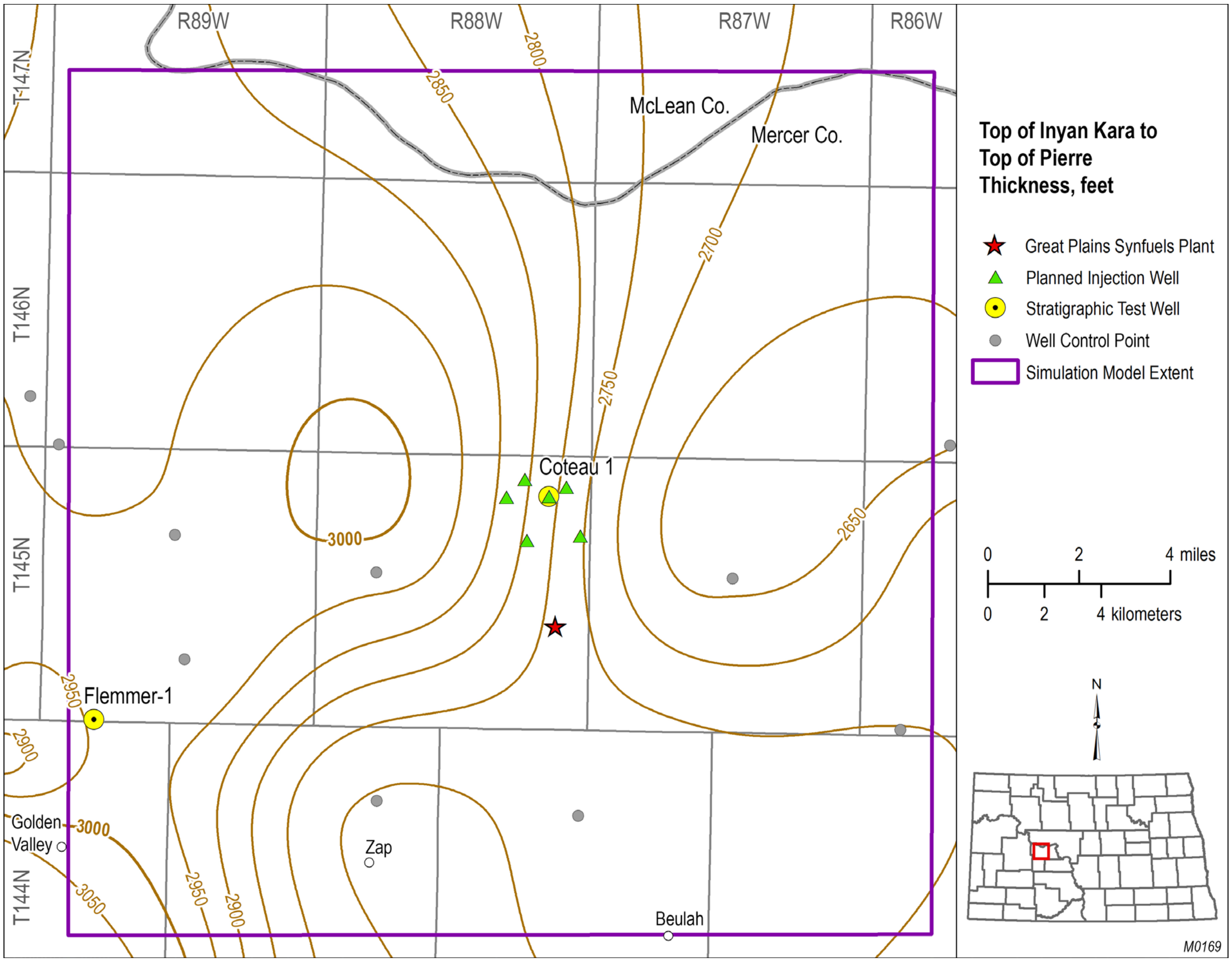

Figure 2-45. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone.

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

Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Inyan Kara Formation represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring using annual temperature and pulse neutron logging of the Inyan Kara Formation provides an additional opportunity for mitigation and remediation (Section 5). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at the Coteau 1 well is 4,512 ft, and the formation itself is 378 ft thick.

2.4.3 Lower Confining Zone

The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, mudstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that can be correlated across the Great Plains CO_2 Sequestration Project area (Figure 2-6). The Amsden Formation is 6,164 ft below land surface and approximately 300 ft thick at the Coteau 1 well (Figures 2-46 and 2-47, Table 2-12).

The contact between the overlying Broom Creek and Amsden Formations is evident on wireline logs as there is a lithological change from the porous sandstones of the Broom Creek Formation to the dolostone and anhydrite beds of the Amsden Formation. This lithologic change is recognized in the core from the Coteau 1 well. The lithology of the cored section of the Amsden Formation from the Coteau 1 well is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Data acquired from the six core plug samples taken from the

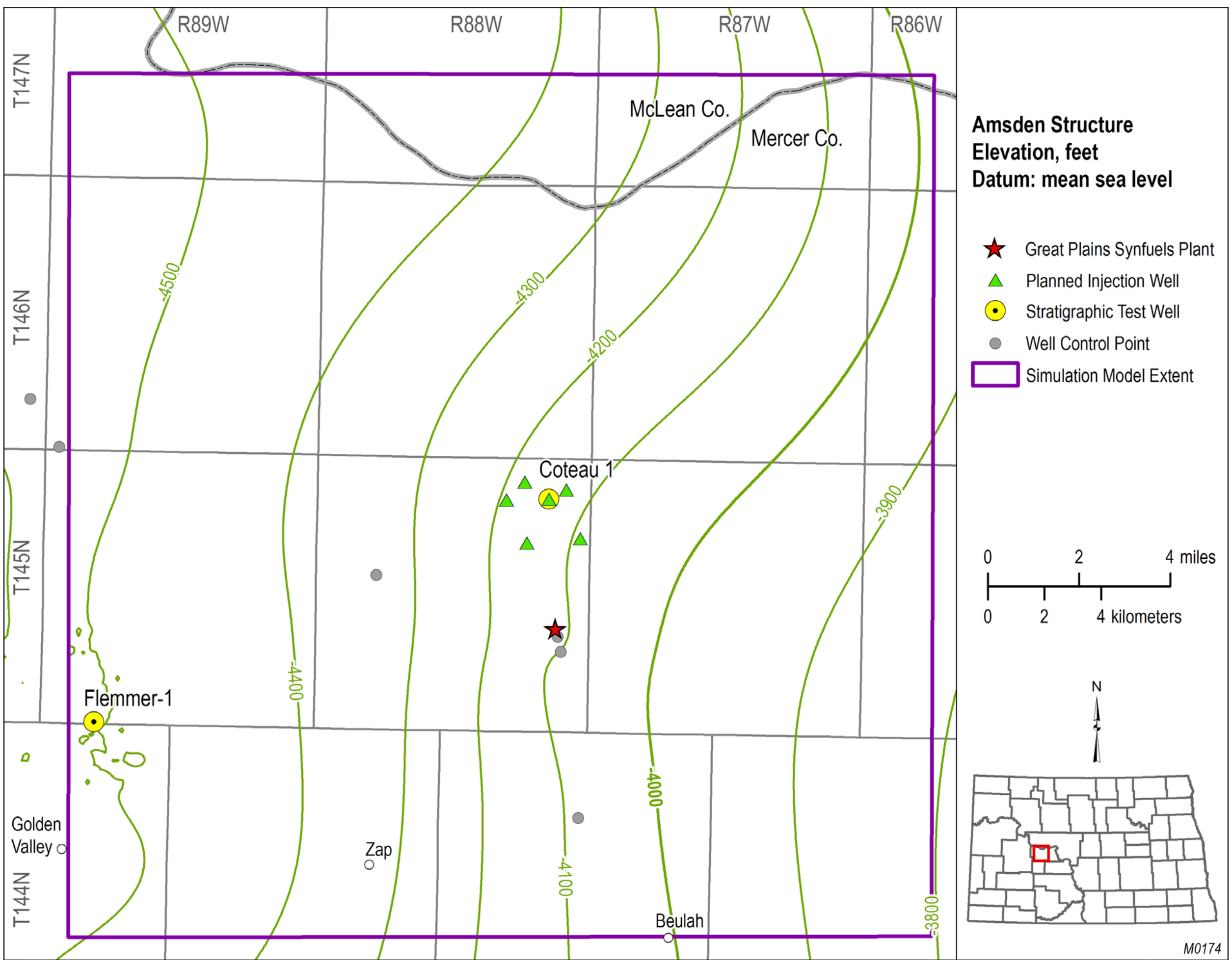

Figure 2-46. Structure map of the Amsden Formation across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops).

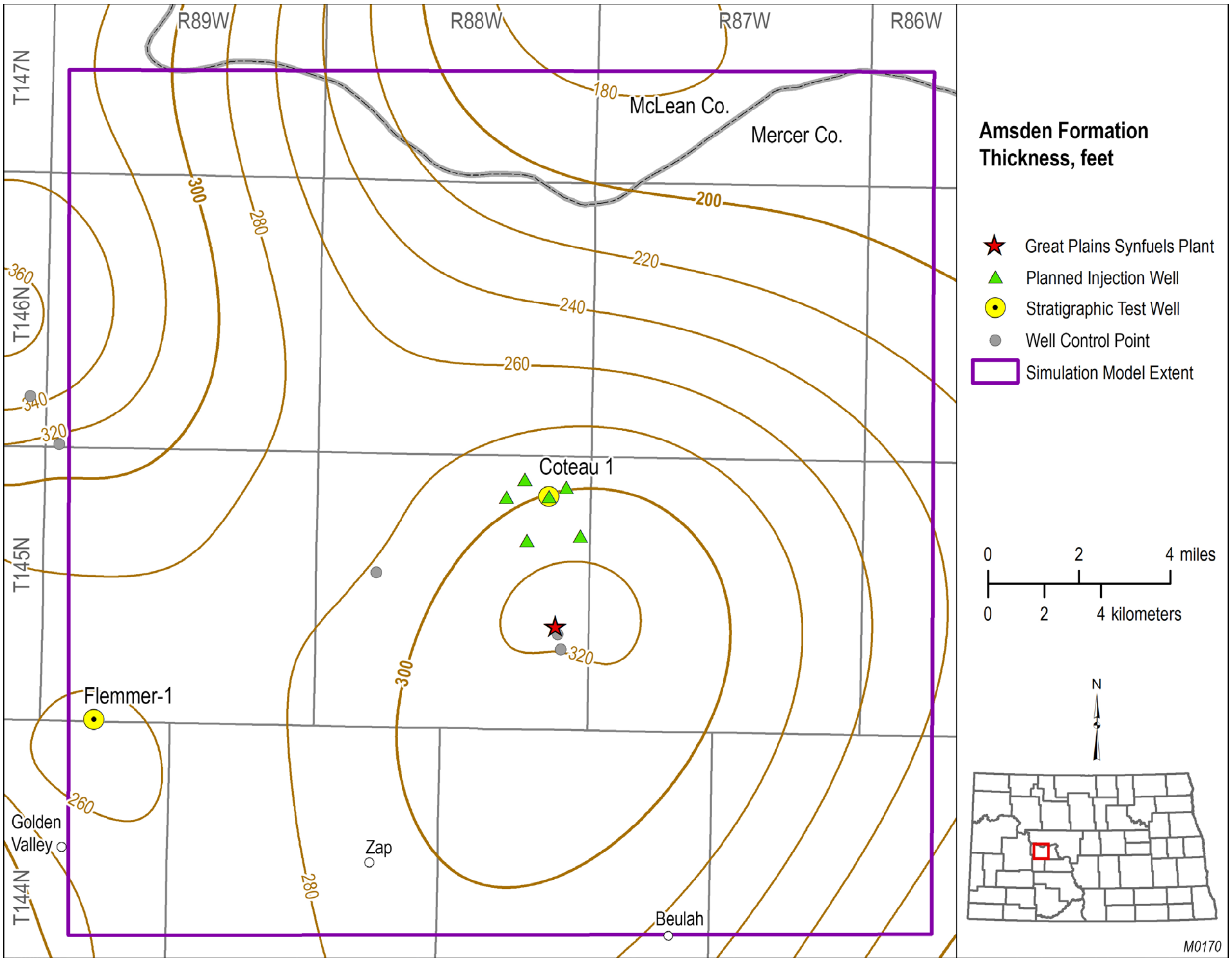

Figure 2-47. Isopach map of the Amsden Formation across the greater Great Plains CO_2 Sequestration Project area.

Amsden Formation show porosity values ranging from 1.00% to 5.27% at 800 psi and 0.91% to 4.54% at 2,400 psi. Permeability values range from 0.0000557 to 1.2 mD at 800 psi and 0.0000642 to 0.215 mD at 2,400 psi (Table 2-17).

Table 2-17. Amsden Core Sample Porosity and Permeability from Coteau 1

Sample Depth, ft	Porosity % (800 psi)	Permeability, mD (800 psi)
6,169	2.89	0.000198
6,183	1.04	0.0000557
6,190	2.96	0.00294
6,206	1.00	0.0000865
6,239	1.23	0.000709
6,242	5.27	1.2

2.4.3.1 Mineralogy

Thin-section analysis shows that the Amsden Formation comprises dolomite, anhydrite, sandy dolomite, and shaly sand. Six thin sections were created and described for the 83-ft cored Amsden section. The dolomite is expressed by very fine to fine-sized dolomite crystals with the presence of quartz of variable size and shape, feldspar, clay, anhydrite, and iron oxides. The porosity is very low and is mainly intragranular because of dissolution with an average of 2%.

Anhydrite is present as beds, nodules, and laminations in association with the dolomite intervals. Minor iron oxides inclusions are present. The porosity is almost nonexistent.

The dolomite is mainly composed of dolomite crystals and grains of quartz. Minor iron oxides and feldspar are present, with rare occurrence of anhydrite observed. The grains of quartz are almost always separated by dolomite matrix. The porosity is mainly due to the dissolution of feldspar and averages 1%.

Finally, the anhydritic sandstone interval is composed of quartz, clay, carbonates, and anhydrite. Iron oxides are present in some parts of the rock matrix as rims around some quartz grains and mostly fill the stylolite surfaces and some rare fractures. The grains of quartz are almost always separated by carbonate cement, clay minerals and, specifically, anhydrite cement. In this lithofacies, anhydrite acts as cement in most parts of the interval by connecting sand grains together and decreasing the overall porosity of the lithofacies. The porosity averages 3% and is mainly due to the dissolution of feldspar and quartz (Figure 2-48).

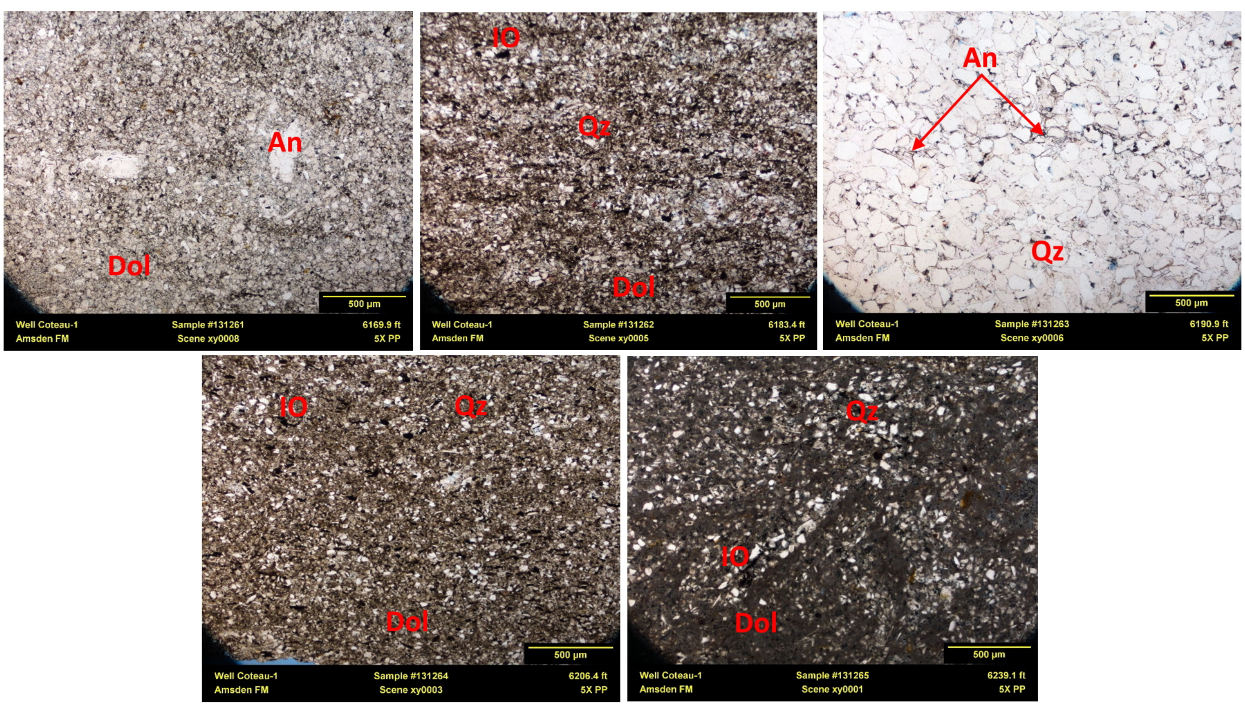

Figure 2-48. Thin sections from the five depth intervals of the Amsden Formation.

XRD was performed (Figure 2-49), and the results confirm the observations made during core analyses and thin-section description.

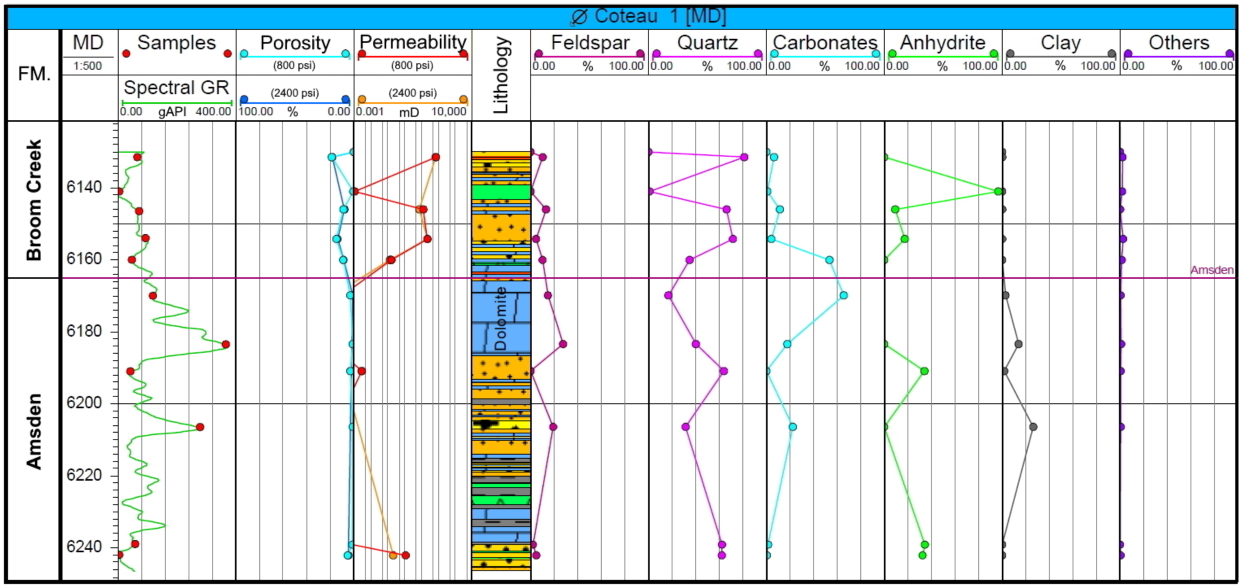

Figure 2-49. XRD data for the Amsden Formation from the Coteau 1.

XRF data shows that the Amsden Formation at the contact with the Broom Creek is dominated by CaO and MgO (major chemical components of dolomite). Deeper samples are more anhydrite-rich, fine- to medium-grained sandstones, as shown by the high percentage of SiO_2, CaO, and SO_3 (Figure 2-50).

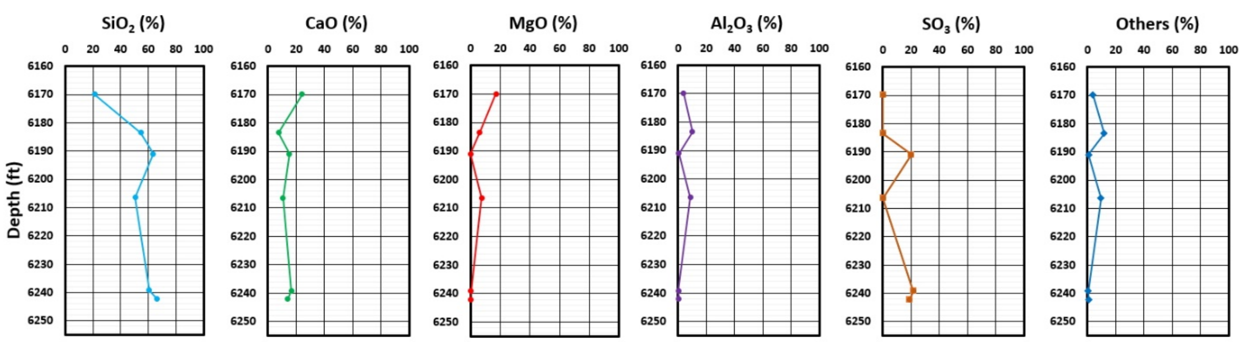

Figure 2-50. XRF data for the Amsden Formation from the Coteau 1.

2.4.3.2 Geochemical Interaction

The Broom Creek's underlying confining layer, the Amsden Formation, was investigated using PHREEQC geochemical software. A vertically oriented 1D simulation was created using a stack of six cells, each cell 1 meter in thickness. The formation was exposed to CO_2 and a minor amount of H_2S at the top boundary of the simulation which were allowed to enter the system by advection and dispersion processes. Direct contact between the Amsden and free-phase saturation from the injection stream is not expected to occur. Results were calculated at the center of each cell below the confining layer–CO_2/H_2S exposure boundary. The mineralogical composition of the Amsden was honored (Table 2-18). The Amsden formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone above. The CO_2 stream composition used is described in Section 2.4.1.2. The Amsden Formation temperature and pressure were collected from the 1D MEM. Two different pressure levels, 2,755 and 3,447 psi, were applied to the CO_2/H_2S saturated brine at the base of the Broom Creek Formation. These values represent the initial and potential maximum pore pressure levels. The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change.

Table 2-18. Mineral Composition of the Amsden Derived from XRD Analysis of Coteau 1 Core Samples at a Depth of 6,183 ft MD

	Sample Depth
	6,183 ft
Mineral	**wt%**
Illite/Muscovite	13.8
Fe Minerals	3.5
K-Feldspar	18.3
Albite	9.3
Quartz	40.1
Dolomite	14.3

Results show geochemical processes at work. Figures 2-51 through 2-56 show results from the geochemical modeling.

Figure 2-51 shows change in fluid pH over 37 years of simulation time as CO_2/H_2S enters the system. Initial change in pH in all of the cells from 7.04 to 7 is related to initial equilibration of the model. For the cell at the CO_2/H_2S interface, C1, the pH begins to decline after Year 7, declines to a level of 6.3 after 12 years of injection, and slowly declines further to 5.5 after an additional 25 years of post-injection. Progressively less or slower pH change occurs for each cell that is more distant from the CO_2/H_2S interface. The pH for Cells 5–6 did not decline over the 37 years of simulation time.

Figure 2-52 shows that CO_2 does not penetrate more than 4 meters (represented by Cells C5–C6) within the 37 years simulated.

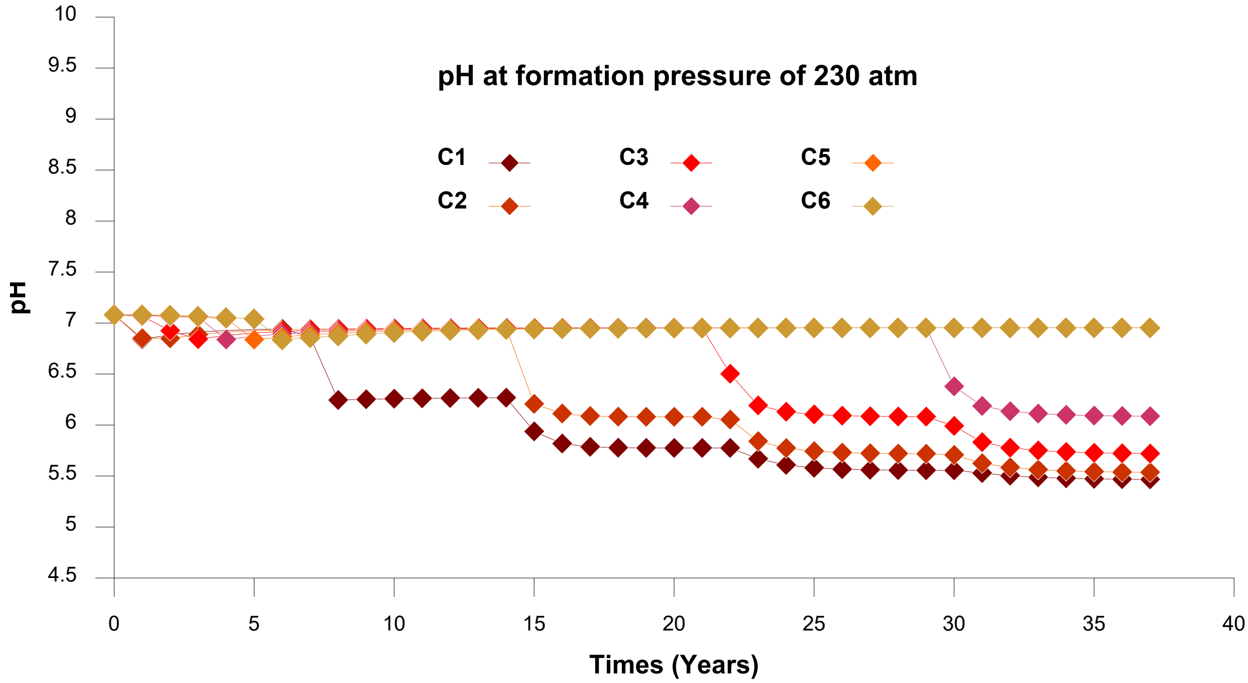

Figure 2-51. Change in fluid pH in the Amsden underlying confining layer for Cells C1-C6.

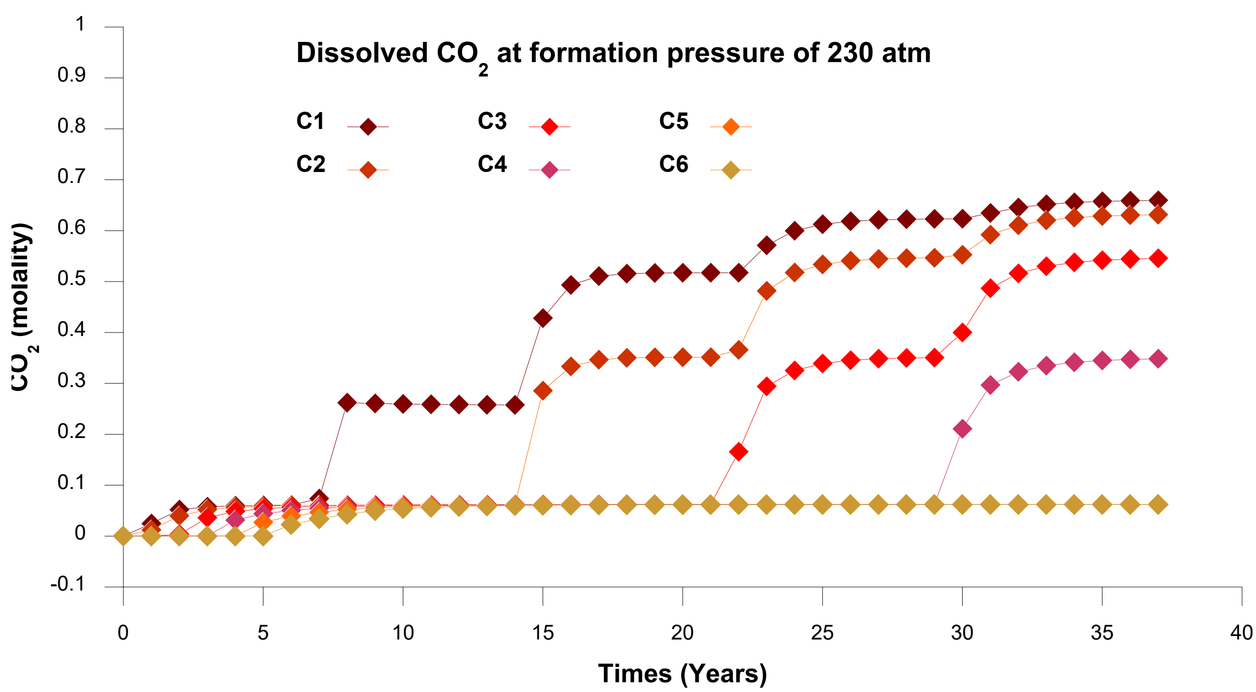

Figure 2-52. CO_2 concentration (molality) in the Amsden Formation underlying confining layer for Cells C1-C6.

Figure 2-53 shows the changes in mineral dissolution and precipitation in grams per cubic meter. For Cells C1 and C2, albite and K-feldspar start to dissolve from the beginning of the simulation period while quartz and illite clays start to precipitate and are largely a reflection of the paths of dissolution of albite and K-feldspar during the time of the simulation. Pyrite (FeS_2) precipitation is favored by the presence of dissolved H_2S and aqueous iron in the formation water.

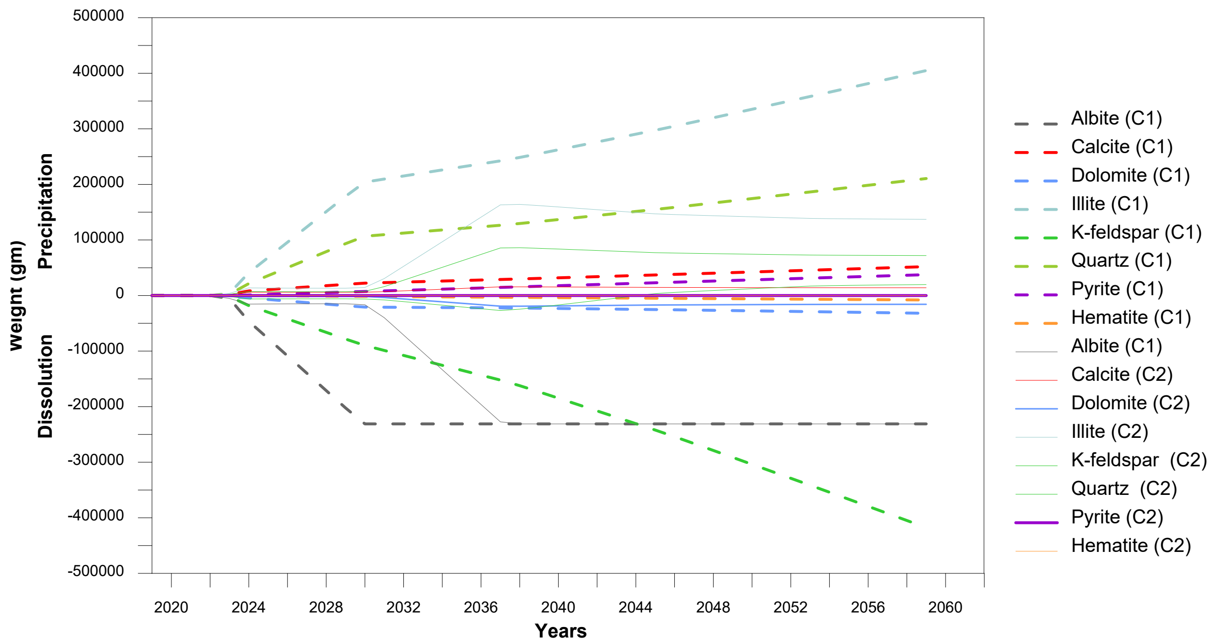

Figure 2-53. Dissolution and precipitation of minerals in the Amsden underlying confining layer. Dashed lines show results for Cell C1, 0 to 1 meter below the Amsden top. Solid lines show results for Cell C2, 1 to 2 meters below the Amsden top.

Figure 2-54 represents the initial fractions of potentially reactive minerals in the Amsden Formation based on the XRD data shown in Table 2-18. The expected dissolution of these minerals in weight percentage is also shown for Cells C1 and C2 of the model. In Cell 1, albite and K-feldspar are the primary minerals that go into dissolution. In Cell 2, albite and dolomite are the primary minerals that go into dissolution. No dissolution is observed for illite and quartz. These dissolved minerals are almost completely replaced by the precipitation of other minerals, as shown in Figure 2-55.

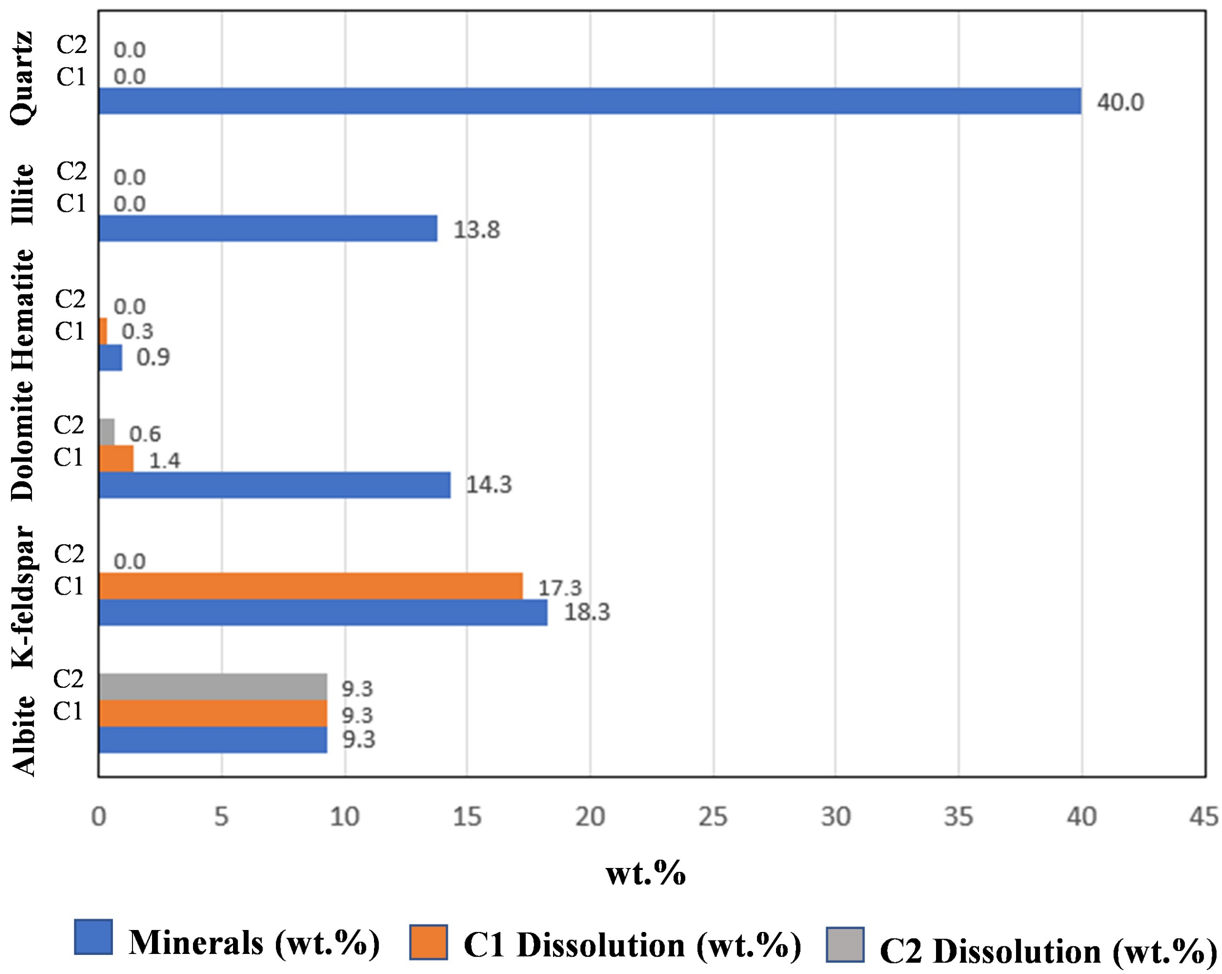

Figure 2-54. Weight percentage (wt.%) of potentially reactive minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 37 years of simulation time.

Figure 2-55 represents expected minerals to be precipitated in weight (%) shown for Cells C1 and C2 of the model. In Cell 1, illite, quartz, calcite, and pyrite are the minerals to be precipitated. In Cell 2, illite, quartz, calcite, and K-feldspar are the minerals to be precipitated. Pyrite precipitation is a result of the formation fluids reacting with the H_2S present in the CO_2 stream. While pyrite precipitation is also expected to occur if CO_2 encounters the overlying confining zone, the resulting weight (%) is negligible compared to the other minerals formed.

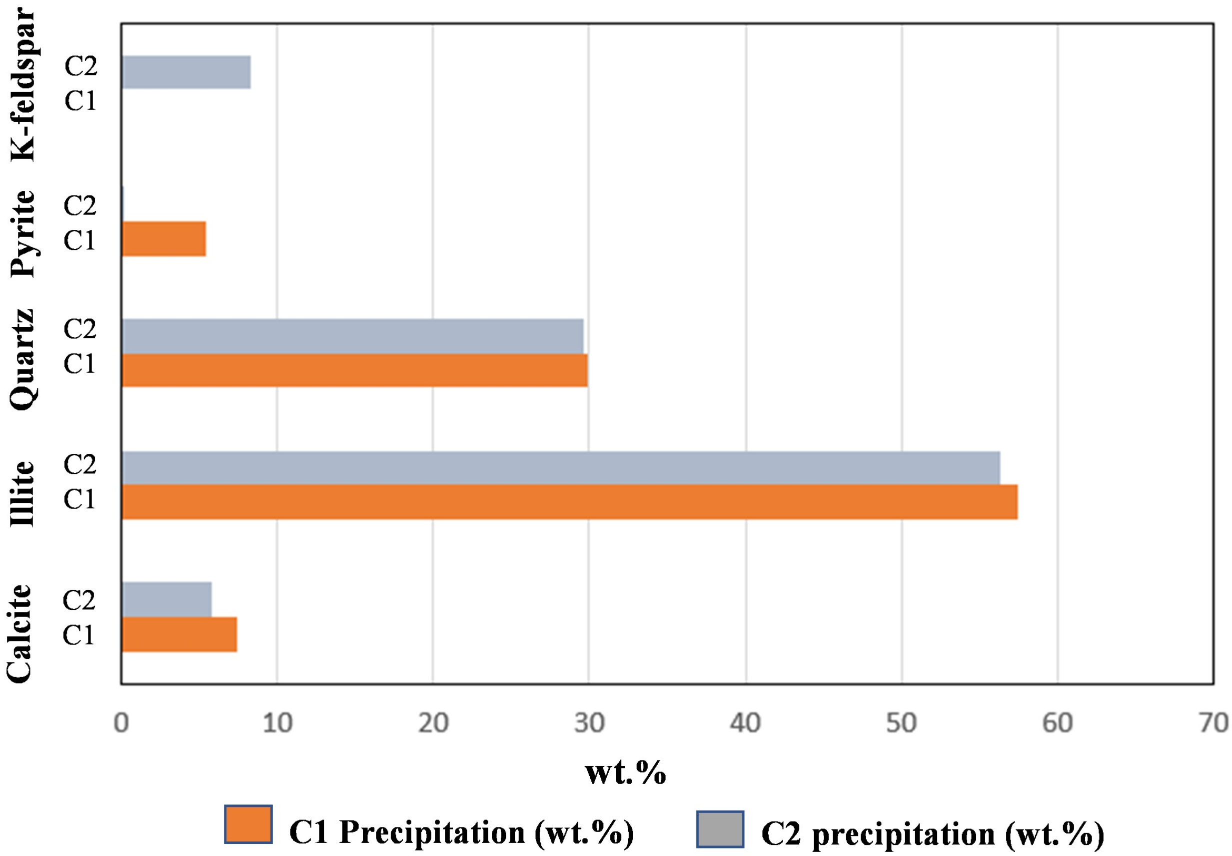

Figure 2-55. Weight percentage (wt.%) of precipitated minerals in the Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 37 years of simulation time.

Change in porosity (% units) of the Amsden underlying confining layer is displayed in Figure 2-56 for Cells C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 0.2% change during the life of the simulation. Cell C1 shows an initial porosity increase of 0.12%, but this change is temporary, and the cell quickly returns to its near initial porosity value of 2.0%. At later times, no significant porosity changes were observed. Cells C4–C6 showed similar results, with net porosity change being less than 0.03%.

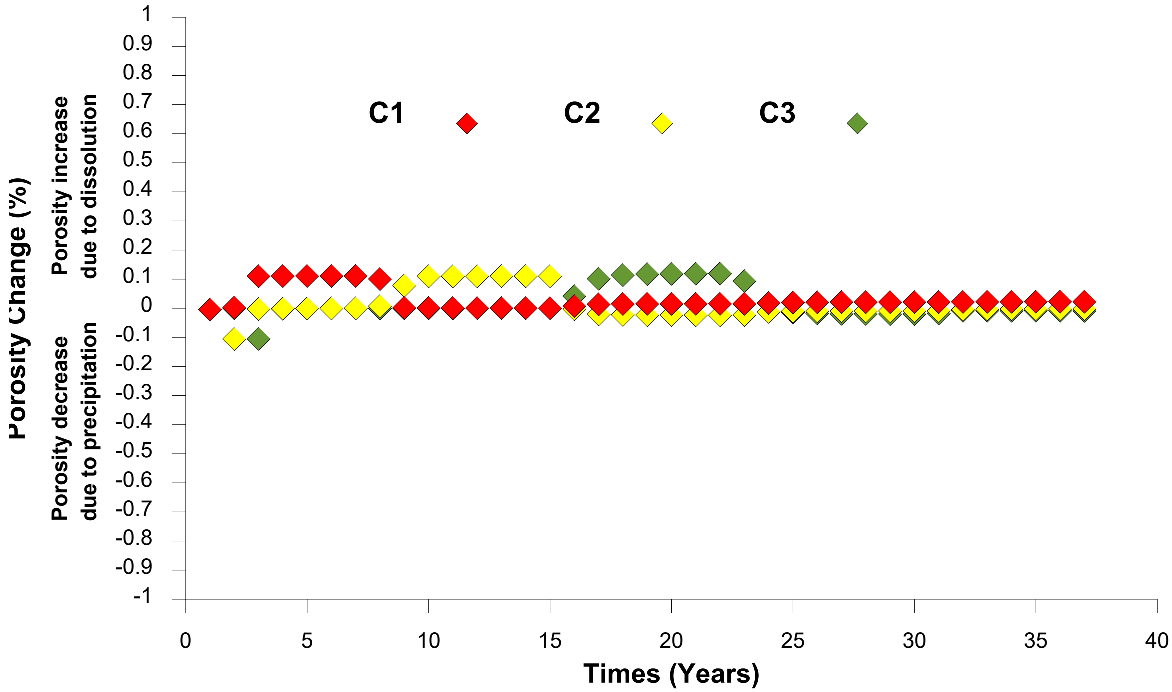

Figure 2-56. Change in percent porosity in the Amsden underlying confining layer red line shows porosity change for Cell C1, 0 to 1 meter below the Amsden Formation top. Yellow line shows Cell C2, 1 to 2 meters below the Amsden top. Green line shows Cell C3, 2 to 3 meters below the Amsden top. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation.

2.4.4 Geomechanical Information of Confining Zones

2.4.4.1 Fracture Analysis

Fractures within the Opeche Formation, the overlying confining zone, and the Amsden Formation, the underlying confining zone, have been assessed during the description of the Coteau 1 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural fractures and in situ stresses were assessed by Schlumberger through the interpretation of the fullbore formation microimager (FMI), bulk density (RHOB), dipole shear sonic (DTS), and dipole compressional sonic (DTC) logs acquired during the drilling of the Coteau 1 well.

2.4.4.2 Fracture Analysis Core Description

Fractures within the Opeche Formation are primarily litho-bound resistive fractures. They are commonly filled with anhydrite. However, some litho-bound conductive fractures are highlighted. The presence of microfaults is underlined mainly in the lower part of the Opeche Formation. The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. The aperture varies from closed to, in rare cases, centimeter-scale.

The Amsden Formation could be considered as a nonfractured interval. However, few litho-bound conductive fractures are commonly coincident with the horizontal compaction features (stylolite) observed.

2.4.4.3 Borehole Image Fracture Analysis (FMI)

Schlumberger's FMI log was chosen to evaluate the geomechanical condition of the formation in the subsurface. This log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed. Figure 2-57 shows examples of the interpreted FMI log for the Coteau 1 well. The examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche FMI borehole image analysis. The far-right track on Figure 2-57 provides information on surface boundaries, slump deformed, and notes the presence of electrically conductive and resistive features. The latter are interpreted as minor anhydrite-filled fractures. Figure 2-58 shows two sections of the interpreted borehole imagery and primary features observed. Figure 2-58 demonstrates that the tool provides information on slump deformation, conductive fractures, and microfaults. These microfaults are identified in Figure 2-58 and are likely clay-filled because of their electrically conductive signal. Figure 2-59 and Figure 2-60 show two thin-section images and give an indication of different minerals within the reservoir with observed changes in the electrical response shown on the FMI log. Also, some drilled-induced fractures are highlighted in the upper part of the Opeche Formation.

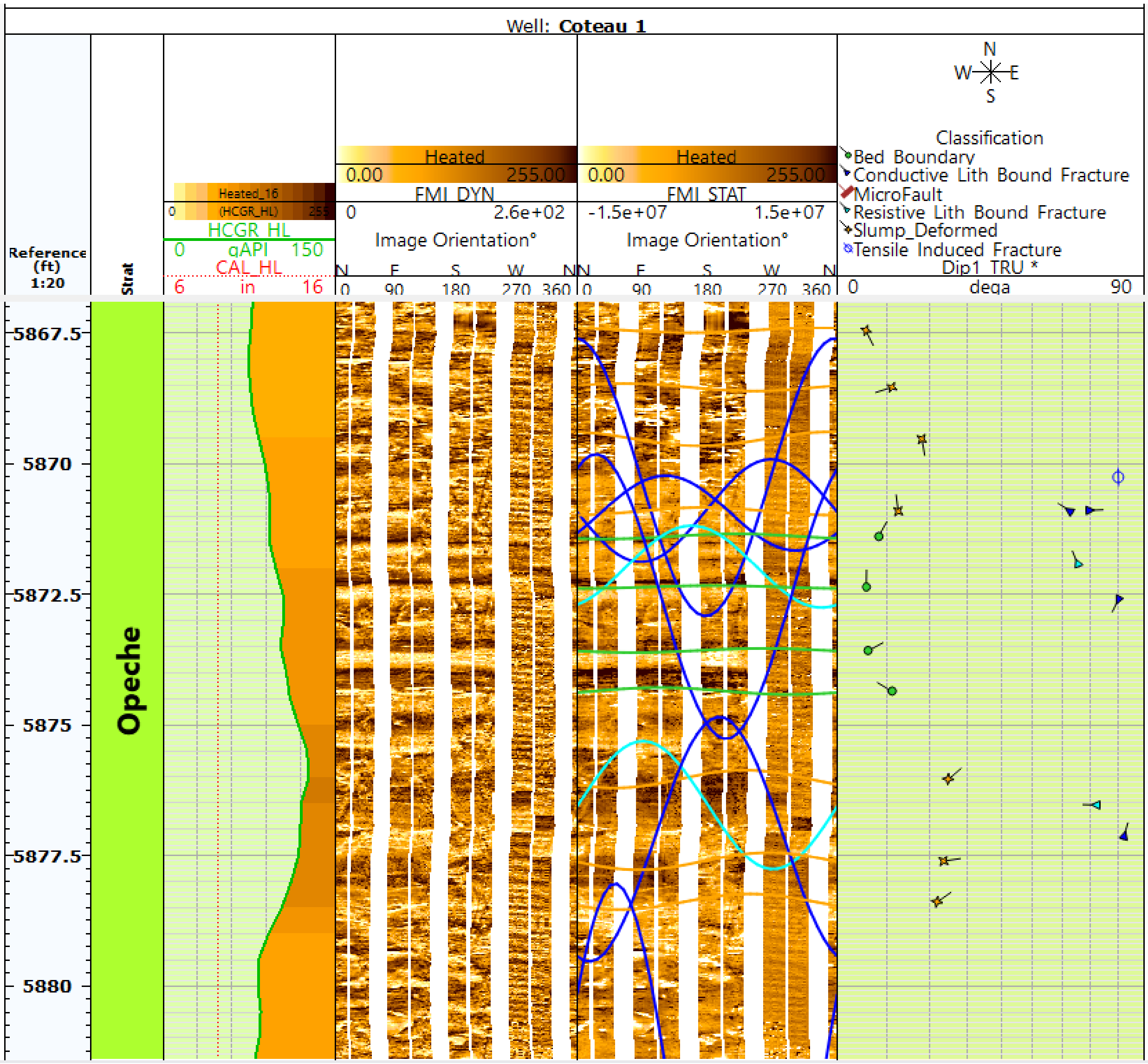

Figure 2-57. Examples of the interpreted FMI log for the Coteau 1 well. The examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche FMI borehole image analysis.

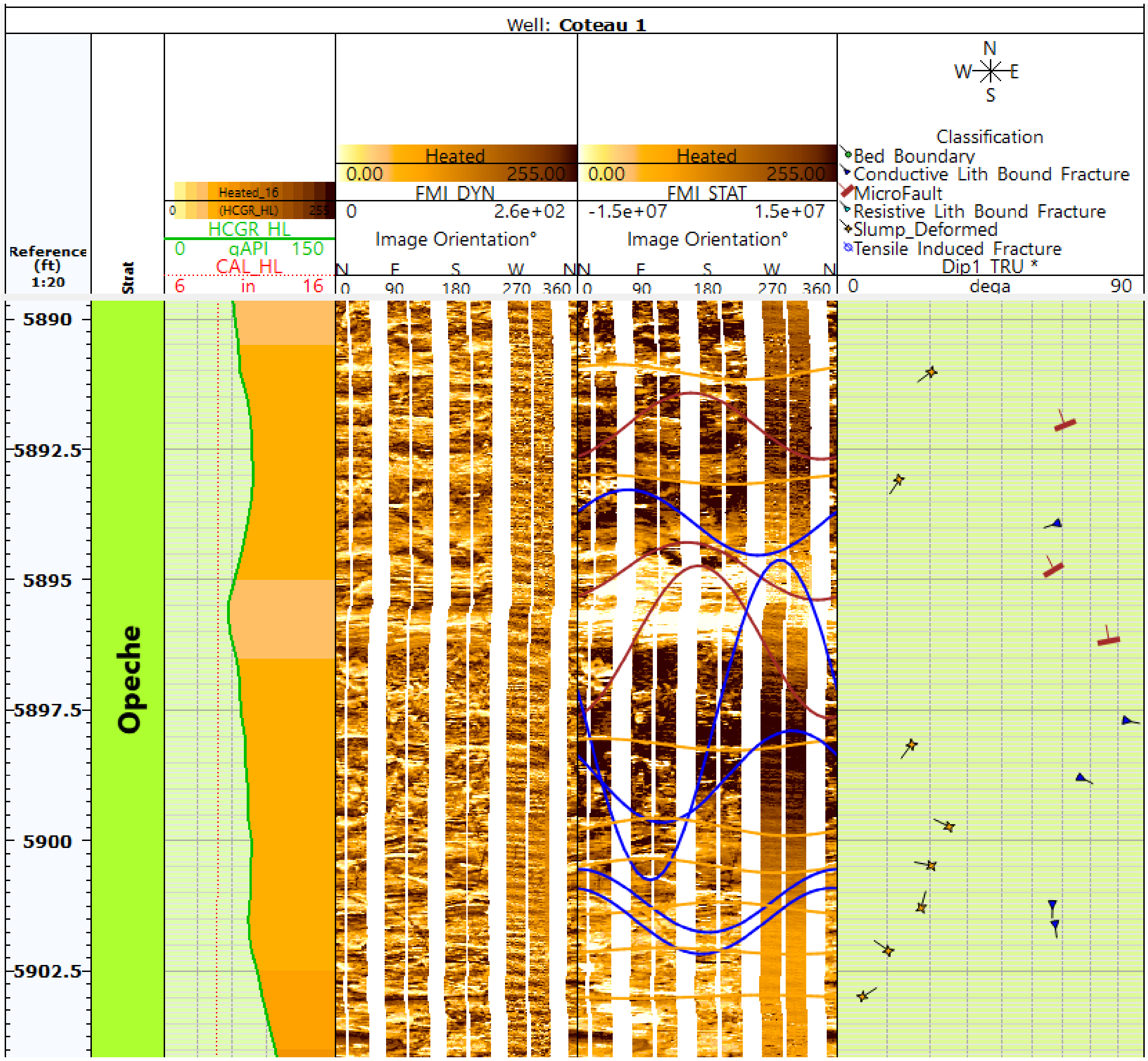

Figure 2-58. Examples of the interpreted FMI log for the Coteau 1 well. The examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche FMI borehole image analysis.

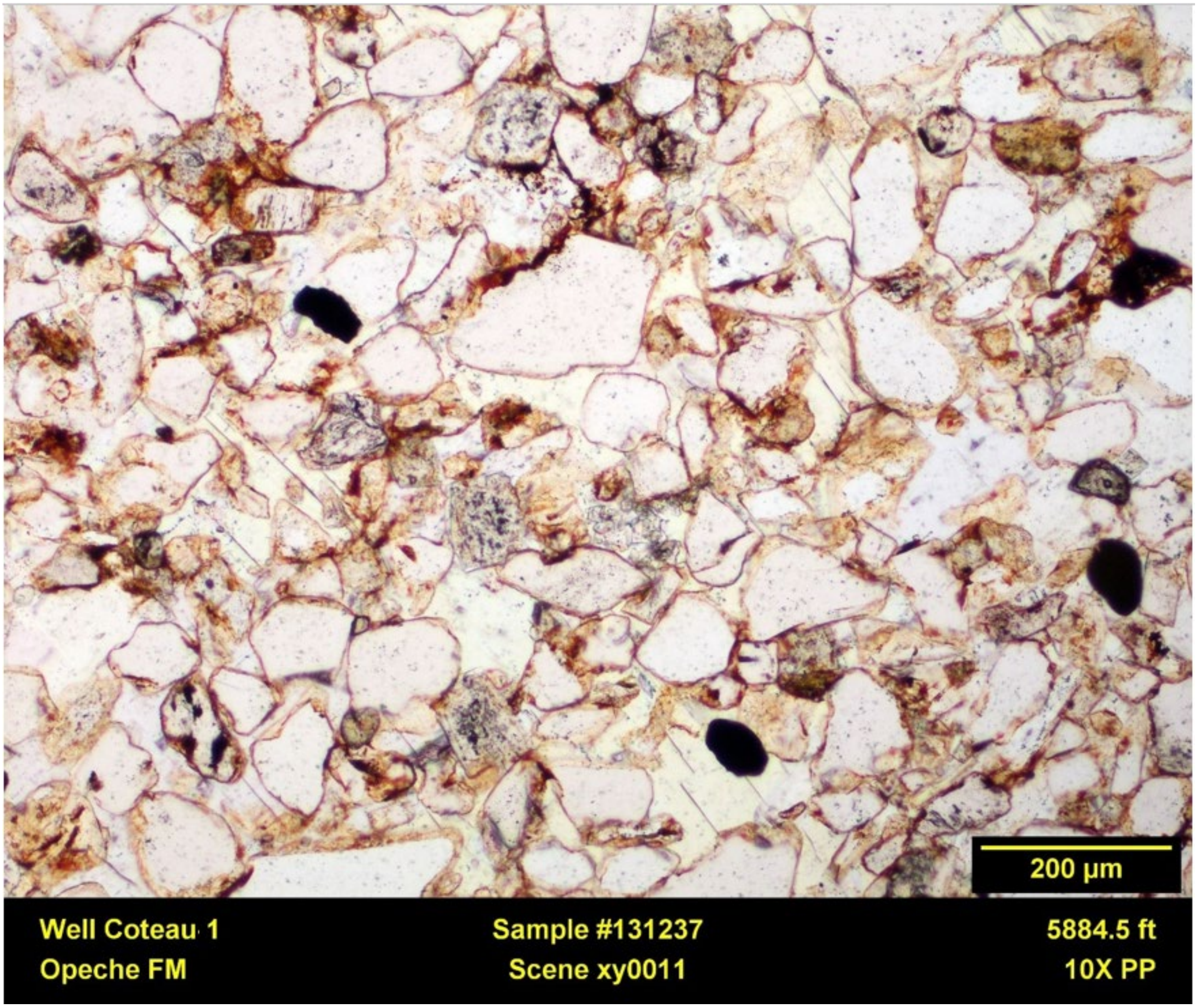

Figure 2-59. Plane-polarized light thin-section images from the Coteau 1 well Opeche Formation. This image shows the silt-rich nature of this interval of the Opeche Formation. On the example shown, the quartz grains (white) and iron oxides are rimmed by anhydrite.

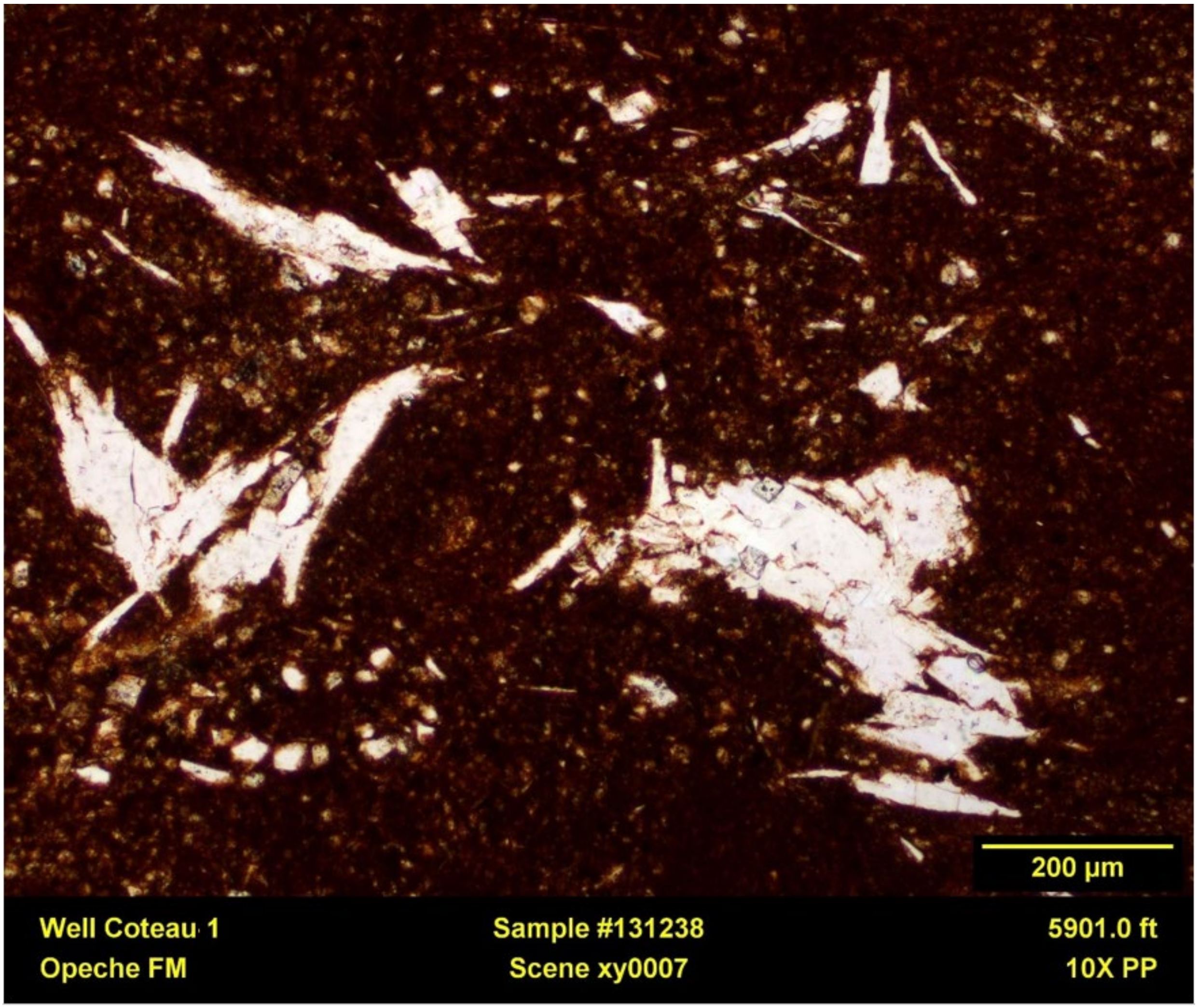

Figure 2-60. Plane-polarized light thin-section images from Coteau 1 well Opeche Formation. This image shows the heterogeneity of this interval. The dark material shown (between the white anhydrite and quartz grains) is clay and is likely responsible for the electrical conductivity identified on the FMI log.

Figure 2-61 shows the logged interval for the lower Opeche Formation at Coteau 1 well. As shown, the section closest to the Broom Creek Formation is dominated by litho-bound fractures and microfaults which are electrically conductive features likely due to the presence of clay. The rose diagrams shown in Figures 2-62 through 2-65 provide the orientation of the conductive, resistive, microfault, and drilling-induced features in the Opeche Formation. The drilling-induced fractures are oriented NE-SW and N-S which give an orientation of N060 and N000 to the maximum horizontal stress (Shmax), respectively.

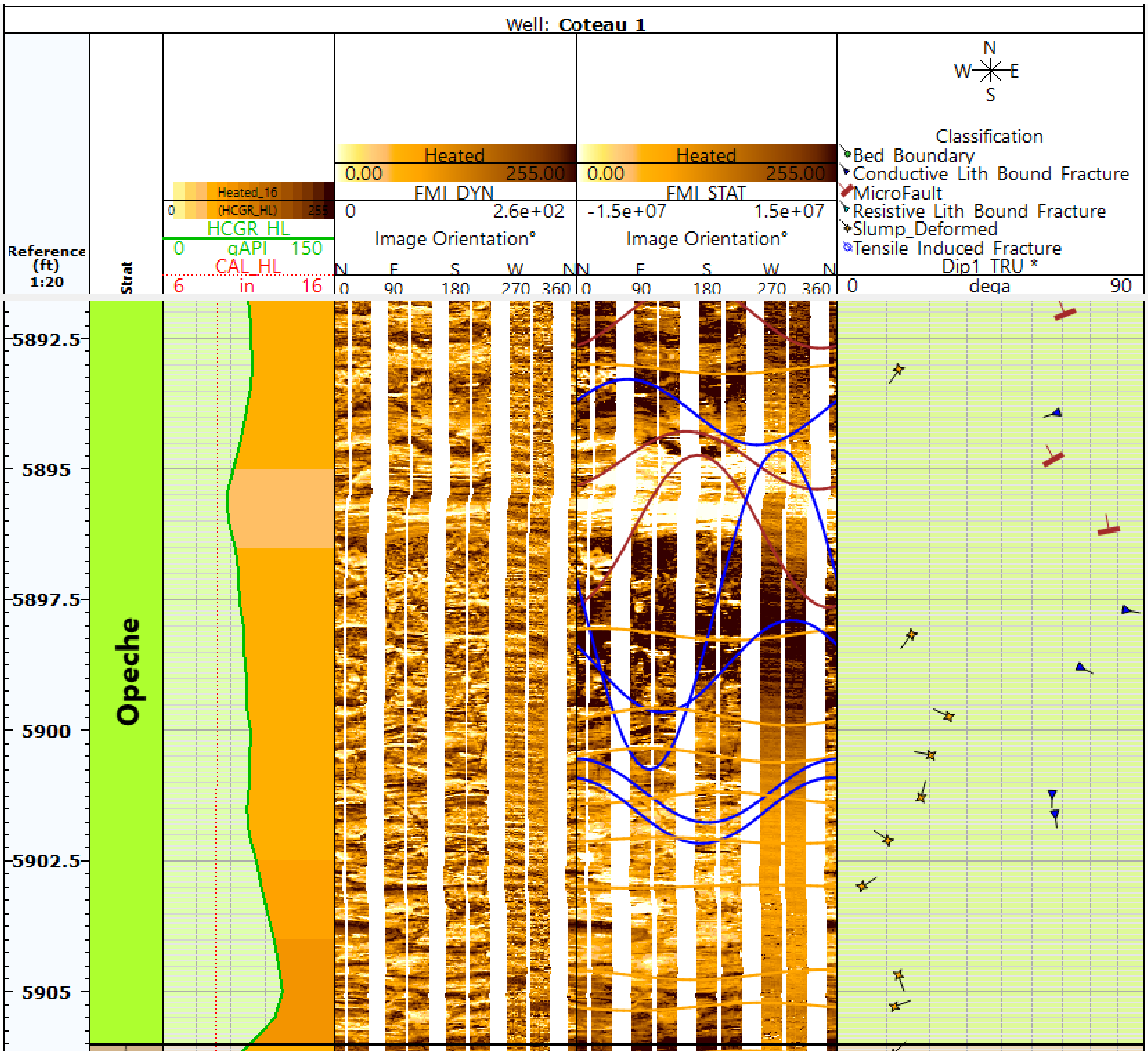

Figure 2-61. Interpreted FMI log through the lower Opeche Formation.

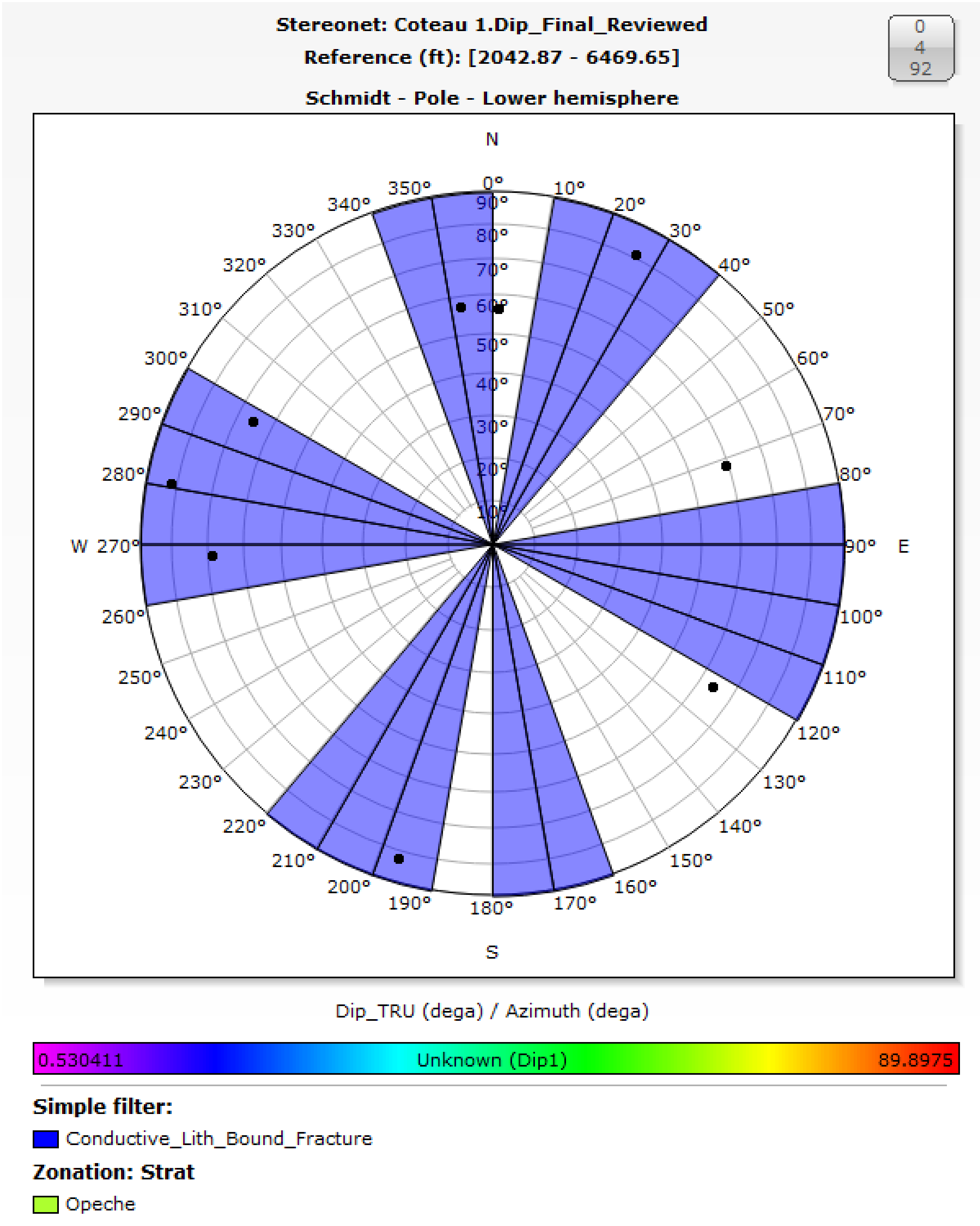

Figure 2-62. Conductive fracture orientation in the Opeche Formation.

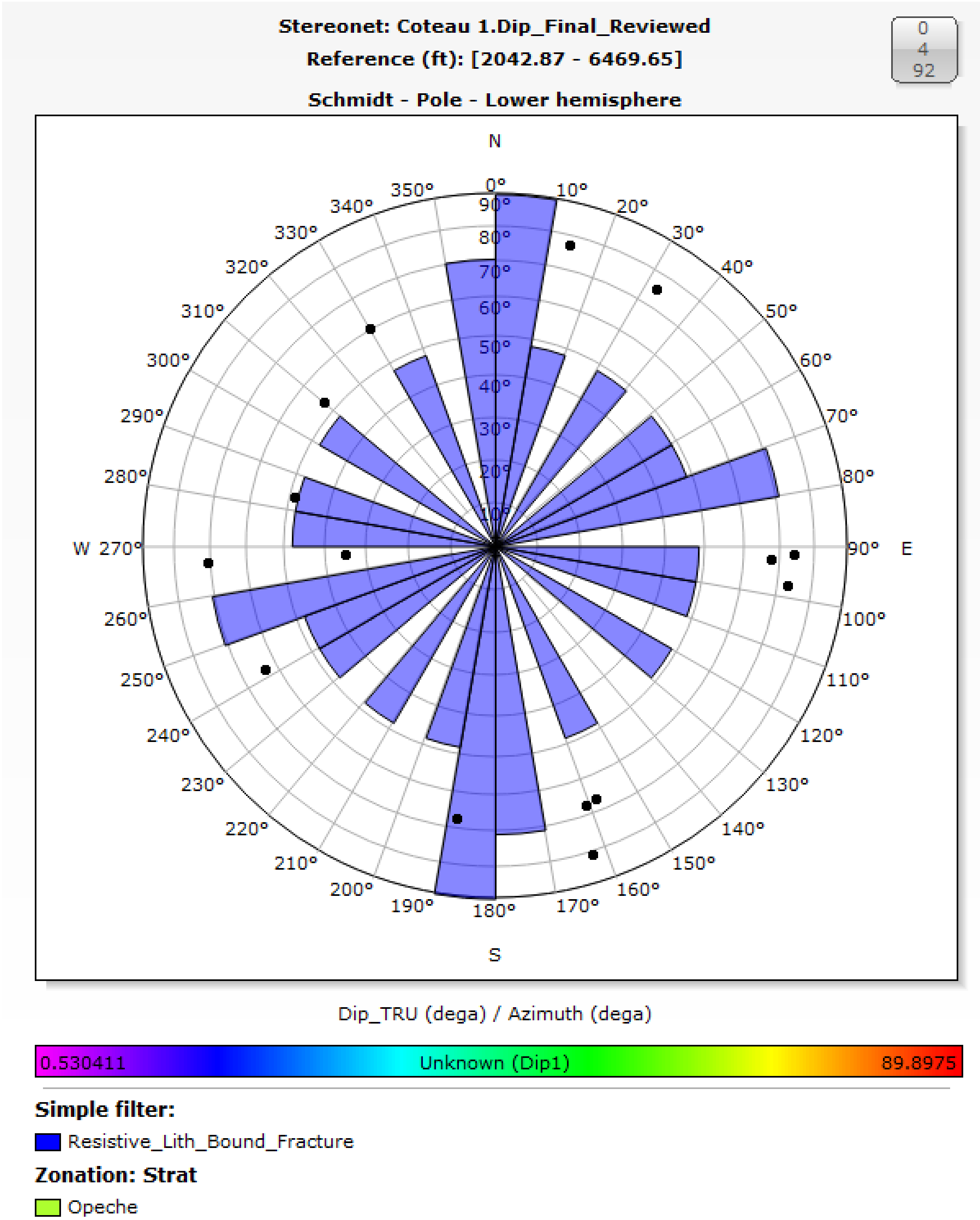

Figure 2-63. Resistive fracture orientation in the Opeche Formation.

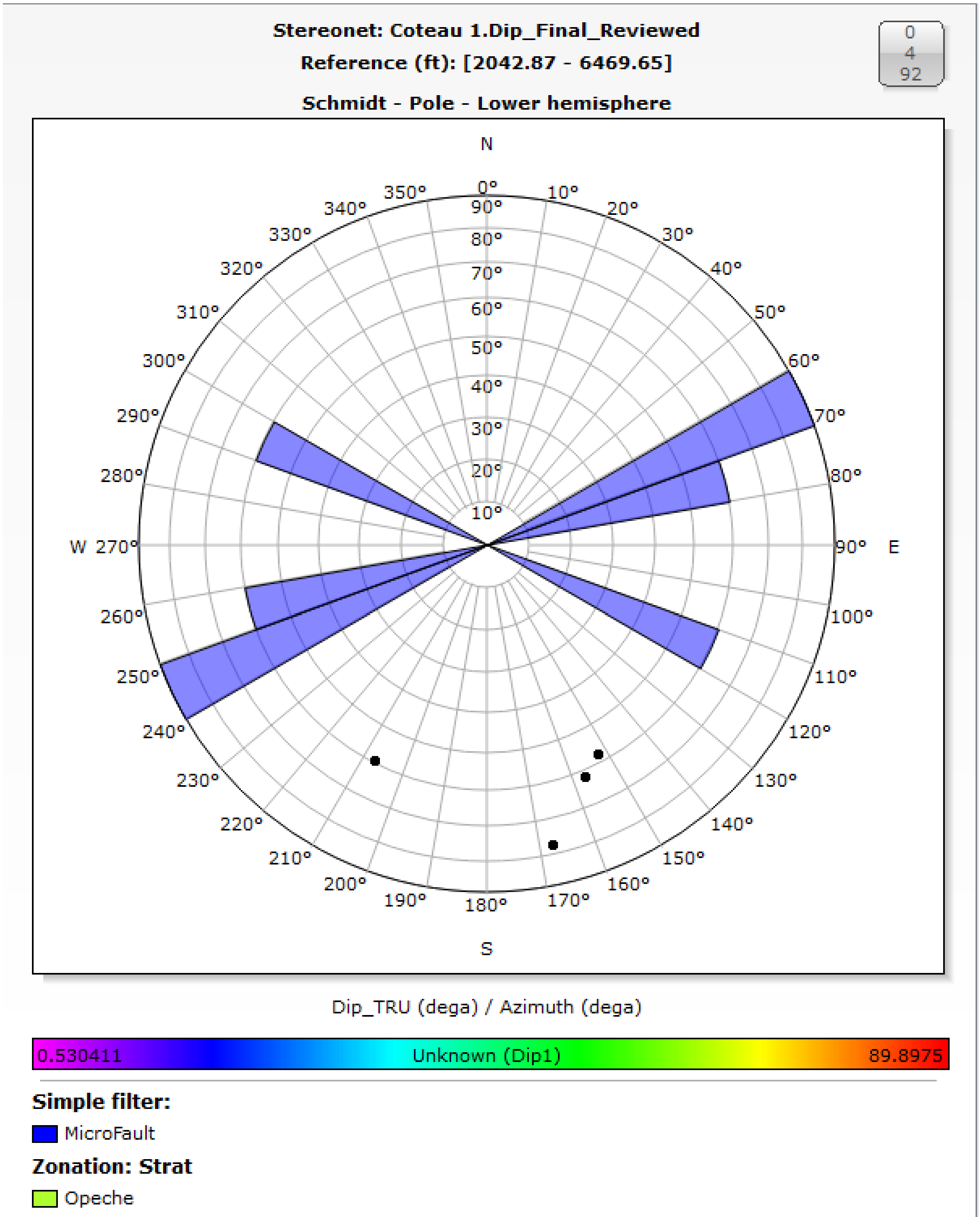

Figure 2-64. Microfault orientation in the Opeche Formation.

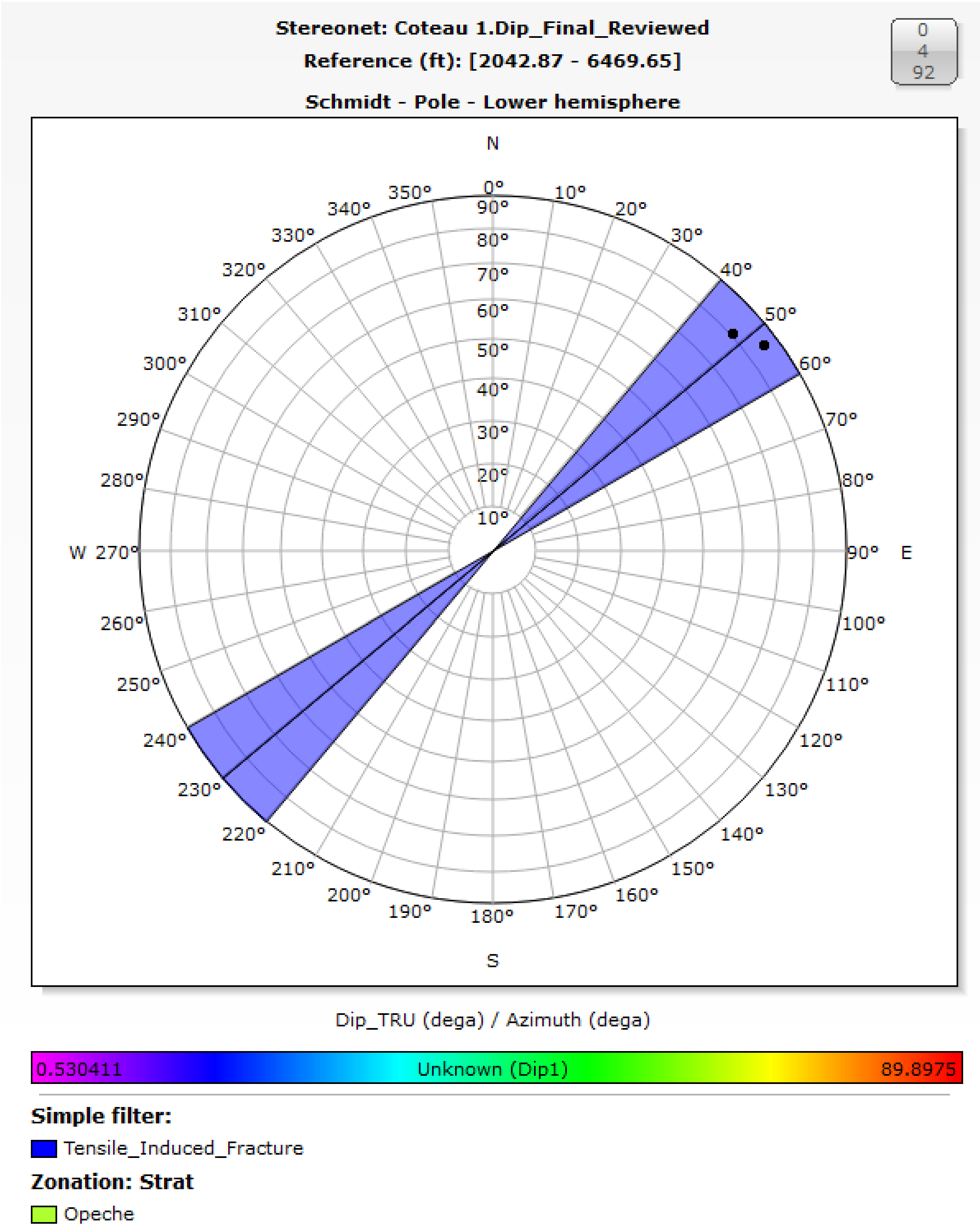

Figure 2-65. Drilling-induced fracture orientation in the Opeche Formation.

The logged interval of the Amsden Formation shows that the main features present are bed boundaries and slump deformation features (Figure 2-66). The depths 6,201.6 and 6,213.7 ft show some evidence of conductive fracture and drilling-induced fractures, respectively (Figure 2-67). The rose diagrams shown in Figures 2-67 and 2-68 provide the orientation of the conductive and drilling-induced fractures in the Amsden Formation. The drilling-induced fractures are oriented NE-SW which gives an orientation of N060 to the maximum horizontal stress (Shmax).

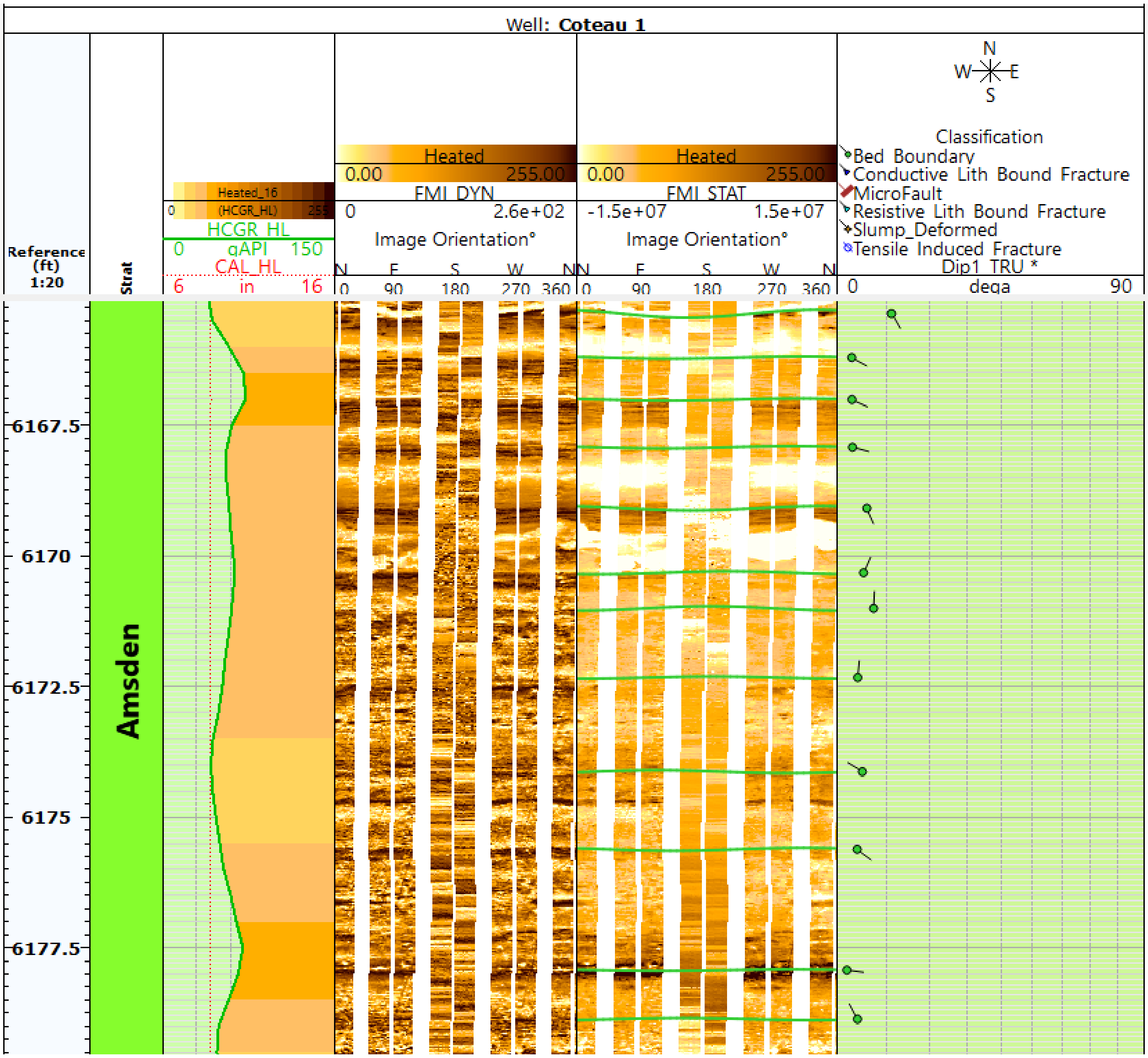

Figure 2-66. Interpreted FMI log through the upper Amsden Formation.

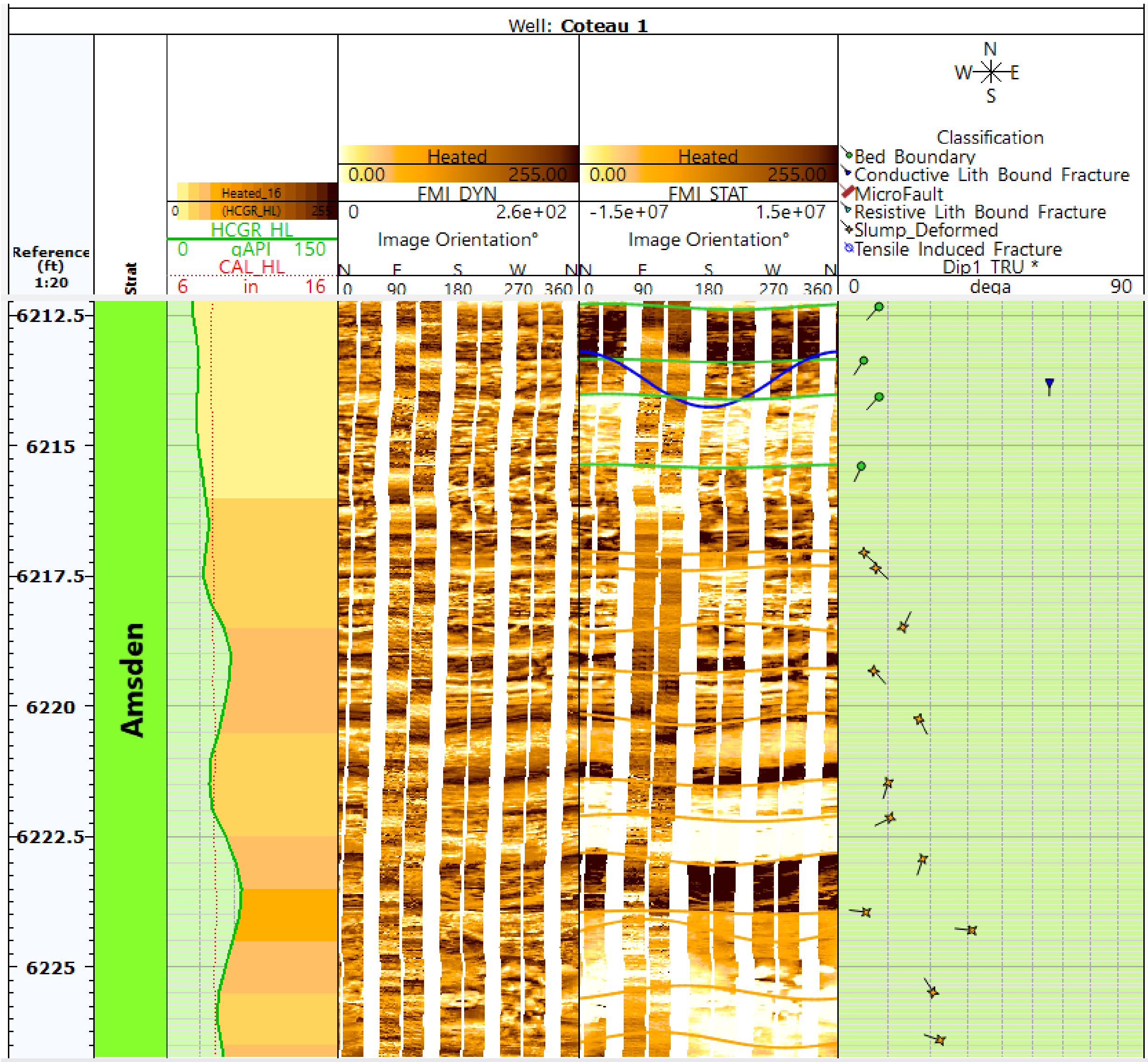

Figure 2-67. Interpreted FMI log through the lower Amsden Formation.

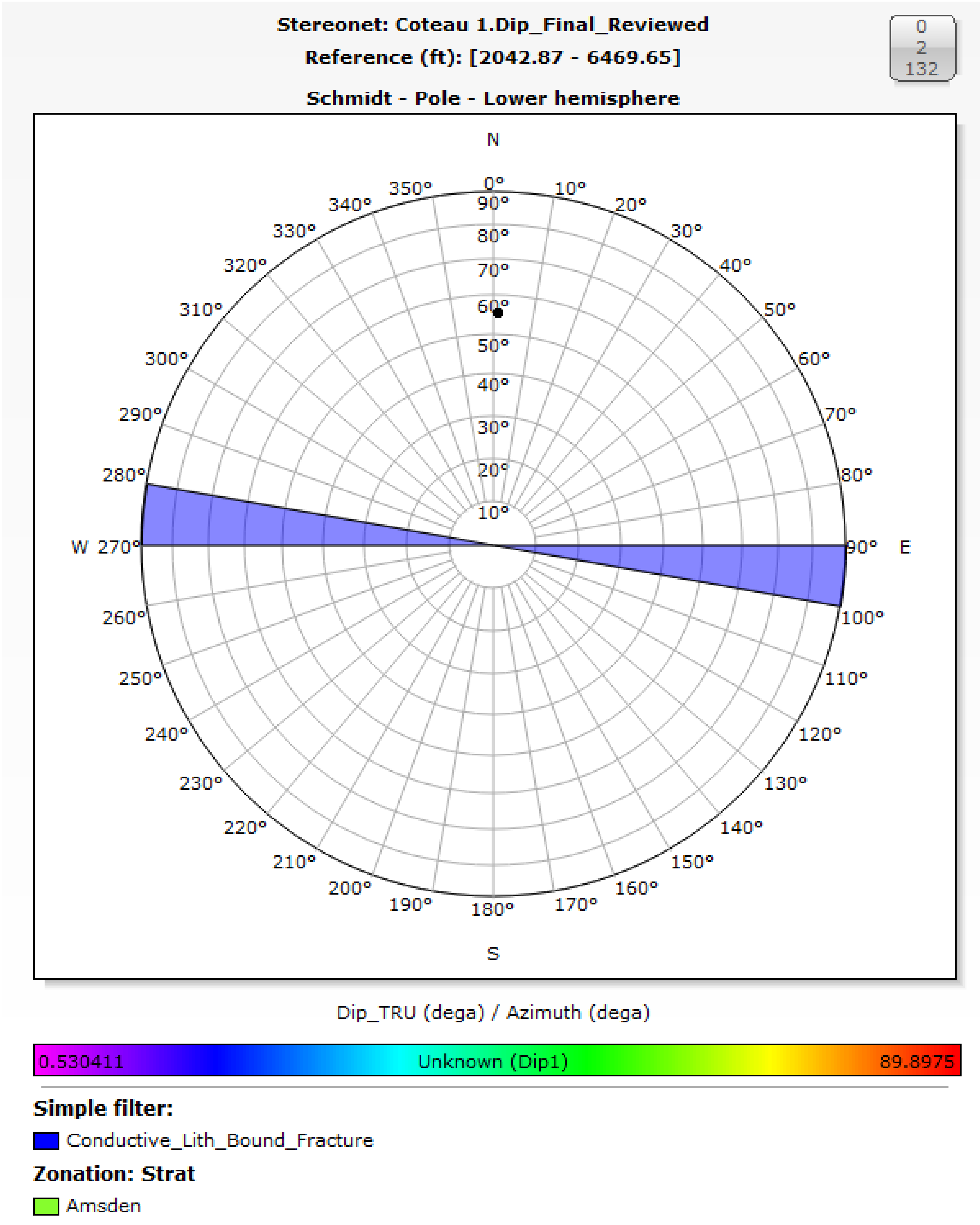

Figure 2-68. Conductive fracture orientation in the Amsden Formation.

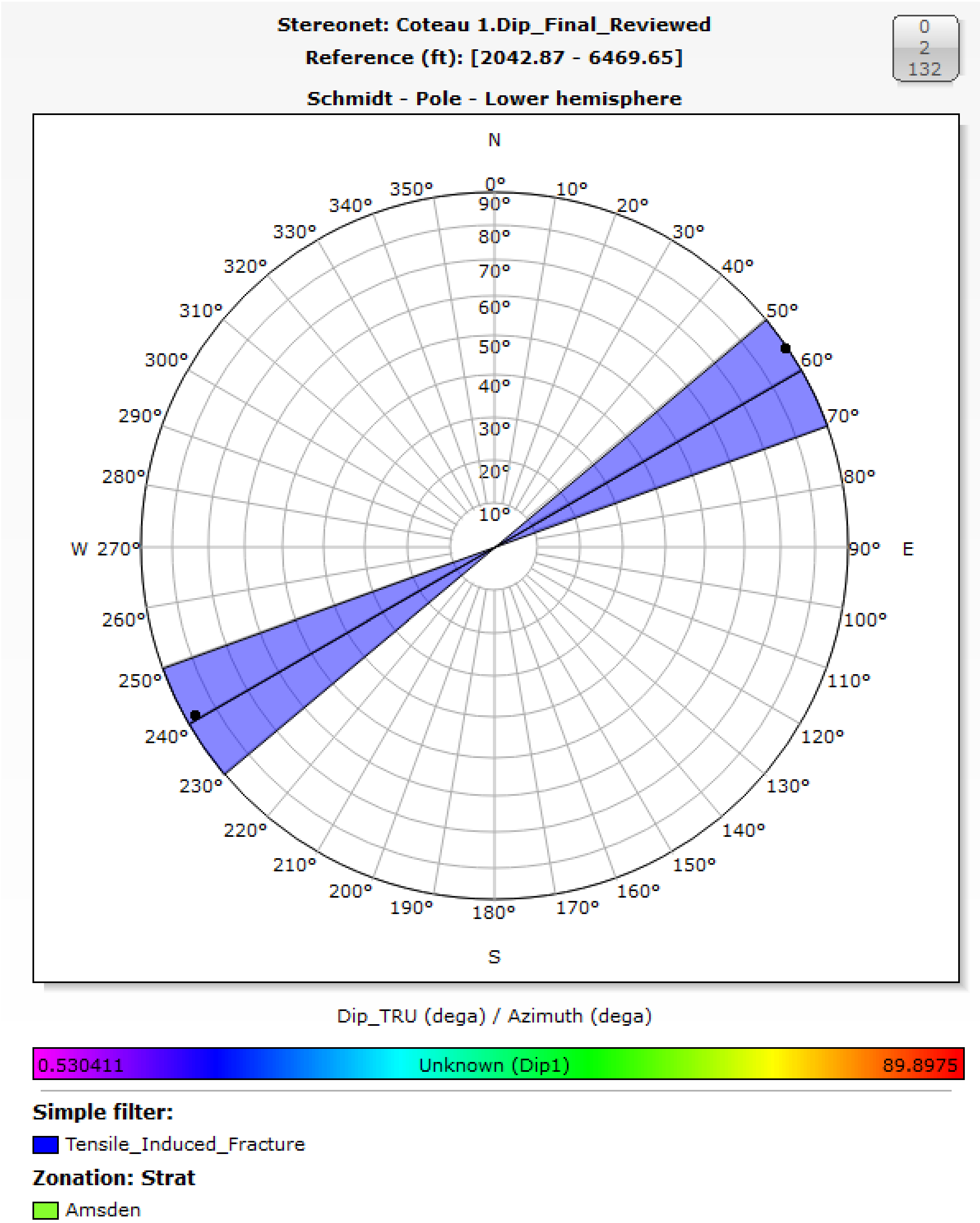

Figure 2-69. Drilling-induced fracture orientation in the Amsden Formation.

2.4.4.4 Stress

The 1D Mechanical Earth Model (MEM) for Opeche, Broom Creek, and Amsden Formations in Coteau 1 well was generated by Core Laboratories (Figures 2-70, 2-71, and 2-72). During construction of the 1D MEM, the effect of pore pressure on sonic transit time, accurate calculation of stress, and rock properties required corrections based on this effect. Dipole sonic logs (DTC, DTS) were corrected for formation pressure impedance and tool radius of investigation. The log corrections allow for a better match to core measurements and more robust geomechanical models.

The output data for the 1D MEM are vertical stress (Sv), pore pressure, pore pressure gradient, dynamic Poisson's ratio, dynamic Young's modulus, Biot factor, fracture closure pressure, fracture closure pressure gradient, fracture propagation pressure, fracture propagation pressure gradient, fracture breakdown pressure, and fracture breakdown pressure gradient. Laboratory-derived core measurements were used from the Coteau 1 well. The static and dynamic parameters from core including DTS, DTC, compressional wave velocity (Vp), shear wave velocity (Vs), dynamic Young's modulus, and dynamic Poisson's ratio were estimated for the Opeche, Broom Creek, and Amsden Formations and used to calibrate the geomechanical rock properties model.

The isotropic (dynamic) properties from well logs (Young's modulus and dynamic Poisson's ratio) were calculated based on the corrected DTC and DTS well logs and calibrated with core measurements. Pore pressure, pore pressure gradient, fracture closure pressure, fracture closure pressure gradient, fracture propagation pressure, fracture propagation fracture gradient, fracture breakdown pressure, and fracture breakdown pressure gradient were also estimated. Pore pressure was calibrated using the pressure and temperature data from the Coteau 1 well.

Triaxial tests were performed on 15 vertical samples: three in Opeche, nine in Broom Creek, and three in Amsden (Table 2-19 and 2-20). Static Young's modulus, Poisson's ratio, and compressive strength were measured at the confining pressure of 1,180 psi. Also, acoustic velocities (Vp, Vs) and dynamic moduli (Bulk modulus, Young's modulus, shear modulus, Poisson's ratio) were estimated under a confining pressure of 1,180 psi The triaxial outputs were calibrated with the estimated parameters using well logs. Figures 2-70–2-72 show the outputs of the 1D MEM for the Opeche, Broom Creek, and Amsden Formations.

In situ stresses such as vertical stress (Sv), maximum horizontal stress (Shmax), and minimum horizontal stress (Shmin) were calculated. The vertical stress is calculated using the density log (RHOB) and assumes 1 psi/ft above 1,500 ft where the RHOB data were not available. The minimum horizontal stress is estimated from a modified Eaton calculation method (Section 2.3). Shmax is estimated from Shmin and process zone stress as a function of porosity. Based on the calculated stresses, the stress regime of the Opeche, Broom Creek, and Amsden Formations is considered a normal stress regime where Sv > Shmax > Shmin.

Table 2-19. Triaxial Testing Results Showing the Calculated Static Young's Modulus, Poisson's Ratio, and Compressive Strength. The confining zone pressure was set at 1,180 psi for testing. The pore pressure used for calculations was assumed to be 0 psi.

Formation	Lithology	Depth (ft)	Sample Length (in.)	Sample Diameter (in.)	Length to Depth Ratio	Bulk Density (g/cm^3)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
Opeche	Silty-shale	5,872.80	2.0955	0.9725	2.15	2.47	15,954	1.67	0.17
	Silty-shale with anhydrite	5,884.75	2.0626	0.9870	2.09	2.57	20,329	3.25	0.18
	Shale with anhydrite	5,901.60	2.0358	0.9954	2.05	2.46	13,214	1.60	0.13
Broom Creek	Anhydrite	5,908.30	2.0566	0.9849	2.09	2.81	30,484	6.46	0.24
	Anhydritic-dolostone	5,920.40	2.1121	0.9898	2.13	2.47	19,474	4.52	0.31
	Sandy-dolostone	5,924.80	2.0576	0.9888	2.08	2.42	22,191	3.32	0.30
	Dolo-sandstone	5,928.70	2.0793	0.9875	2.11	2.51	25,379	3.91	0.34
	Sandstone	5,941.10	1.5251	0.9815	1.55	1.82	6,592	0.56	0.17
	Sandstone	5,989.60	1.7216	0.9953	1.73	1.76	7,678	0.76	0.23
	Anhydritic-sandstone	6,146.30	1.8015	0.9908	1.82	2.58	18,510	3.39	0.36
	Sandy-dolomite	6,160.10	2.1366	0.9881	2.16	2.49	24,511	3.75	0.33
Amsden	Dolostone	6,169.60	2.1593	0.9908	2.18	2.66	26,307	3.55	0.22
	Dolostone	6,183.20	2.1751	0.9903	2.20	2.55	17,558	2.49	0.17
	Anhydritic-sandstone	6,190.00	1.8448	0.9880	1.87	2.64	23,906	3.03	0.53

Table 2-20. Triaxial Testing Results Showing the Measured Acoustic Velocities and Calculated Dynamic Bulk Modulus, Young's Modulus, Poisson's Ratio, and Compressive Strength. The confining zone pressure was set at 1,180 psi for testing.

					Acoustic Velocity				Dynamic Elastic Parameters			
					Compressional		Shear					
Formation	Lithology	Depth (ft)	Axial Stress (psi)	Bulk Density (g/cm^3)	ft/sec	µs/ft	ft/sec	µs/ft	Bulk Modulus ($\times10^6$ psi)	Young's Modulus ($\times10^6$ psi)	Shear Modulus ($\times10^6$ psi)	Poisson's Ratio
Opeche	Shale silty-shale	5,872.80	3,000	2.47	15,413	64.9	7,450	134.2	5.45	4.99	1.85	0.35
	Silty-shale with anhydrite	5,884.75	100	2.57	14,170	70.6	8,897	112.4	3.30	6.44	2.74	0.17
	Shale with anhydrite	5,901.60	6,000	2.46	14,688	68.1	7,861	127.2	4.42	5.32	2.05	0.30
Broom Creek	Anhydrite	5,908.30	3,000	2.81	23,737	42.1	10,909	91.7	15.32	12.31	4.50	0.37
	Anhydritic-dolostone	5,920.40	3,000	2.47	19,888	50.3	10,366	96.5	8.39	9.39	3.57	0.31
	Sandy-dolostone	5,924.80	100	2.42	16,315	61.3	9,537	104.9	4.73	7.37	2.97	0.24
	Dolo-sandstone	5,928.70	2,000	2.51	17,993	55.6	9,896	101.1	6.54	8.50	3.31	0.28
	Sandstone	5,941.10	2,000	1.82	12,174	82.1	5,324	187.8	2.71	1.92	0.70	0.38
	Sandstone	5,951.75	2,000	1.86	13,339	75.0	6,413	155.9	3.09	2.79	1.03	0.35
	Sandstone	5,989.60	2,000	1.76	11,808	84.7	5,921	168.9	2.20	2.22	0.83	0.33
	Anhydritic-sandstone	6,146.30	3,000	2.57	19,027	52.56	9,623	103.91	8.28	8.54	3.21	0.33
	Sandy-dolomite	6,160.10	6,000	2.49	19,652	50.88	10,745	93.06	7.79	9.97	3.87	0.29
Amsden	Dolostone	6,169.60	3,000	2.66	18,842	53.07	10,622	94.14	7.34	10.26	4.05	0.27
	Dolostone	6,183.20	3,000	2.55	15,400	64.93	9,036	110.67	4.41	6.95	2.81	0.24
	Anhydritic-sandstone	6,190.00	8,000	2.64	20,663	48.40	10,942	91.39	9.52	11.12	4.26	0.31

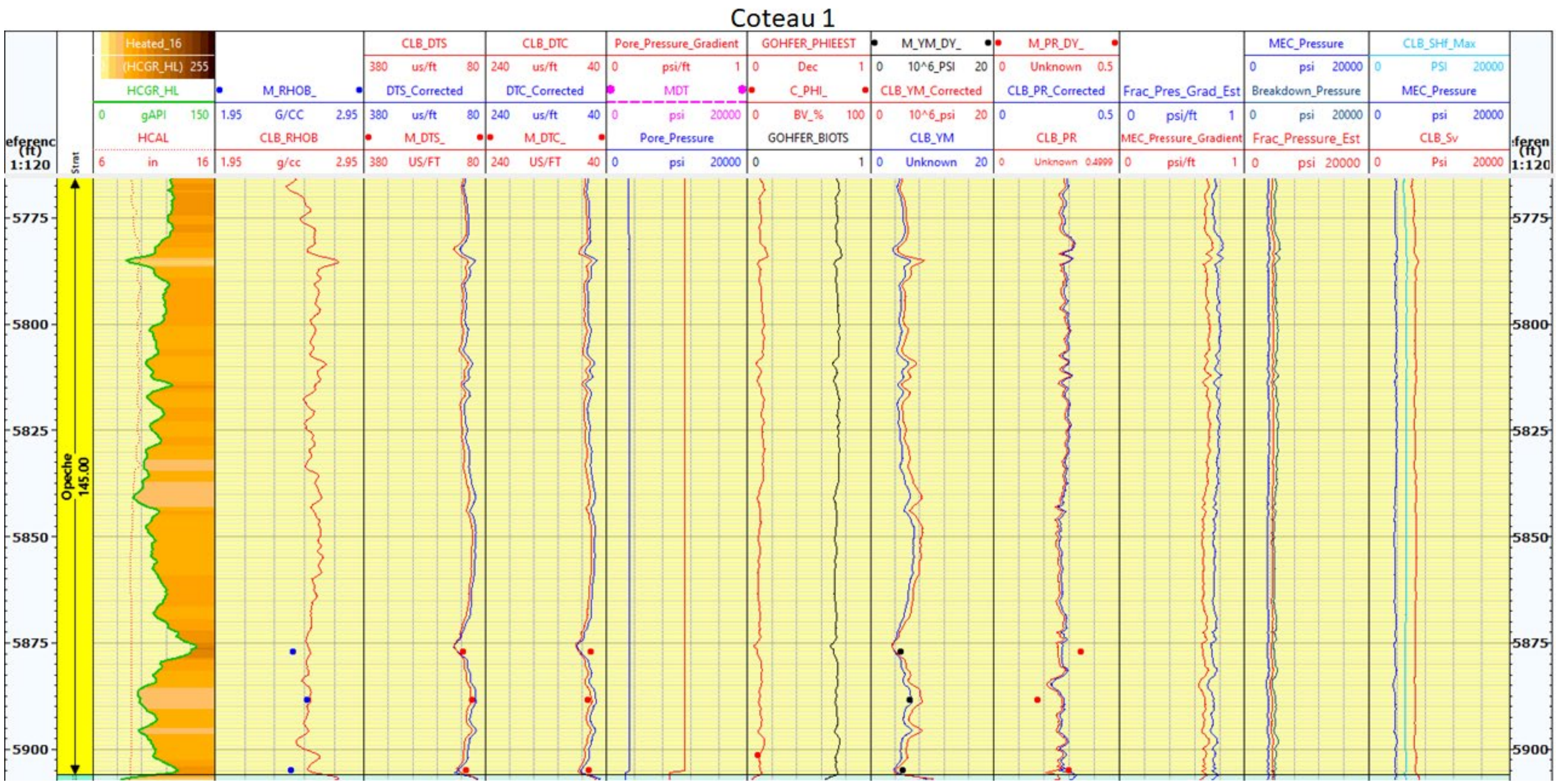

Figure 2-70. Calibrated geomechanical rock properties model in Opeche Formation.

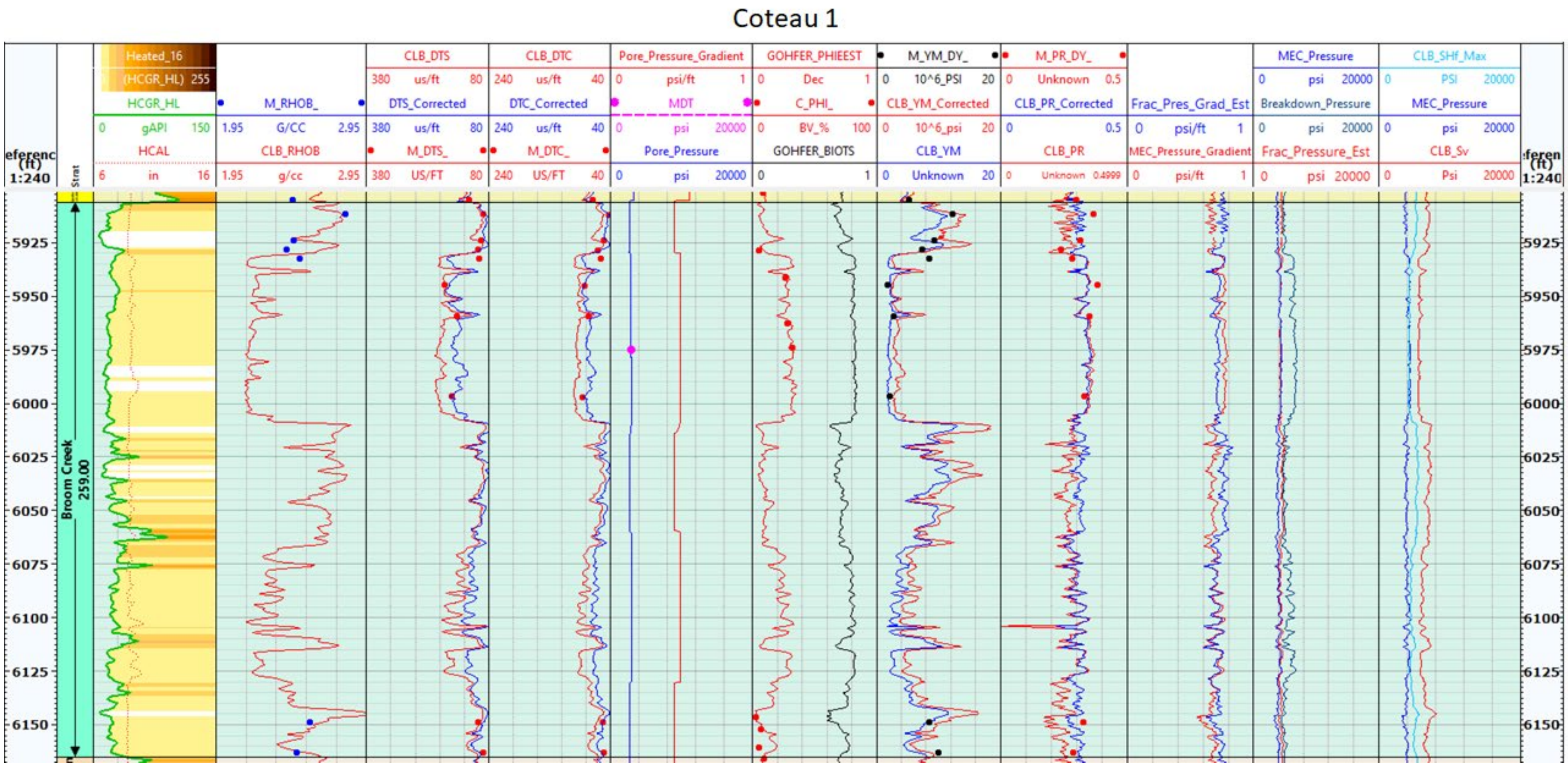

Figure 2-71. Calibrated geomechanical rock properties model in Broom Creek Formation.

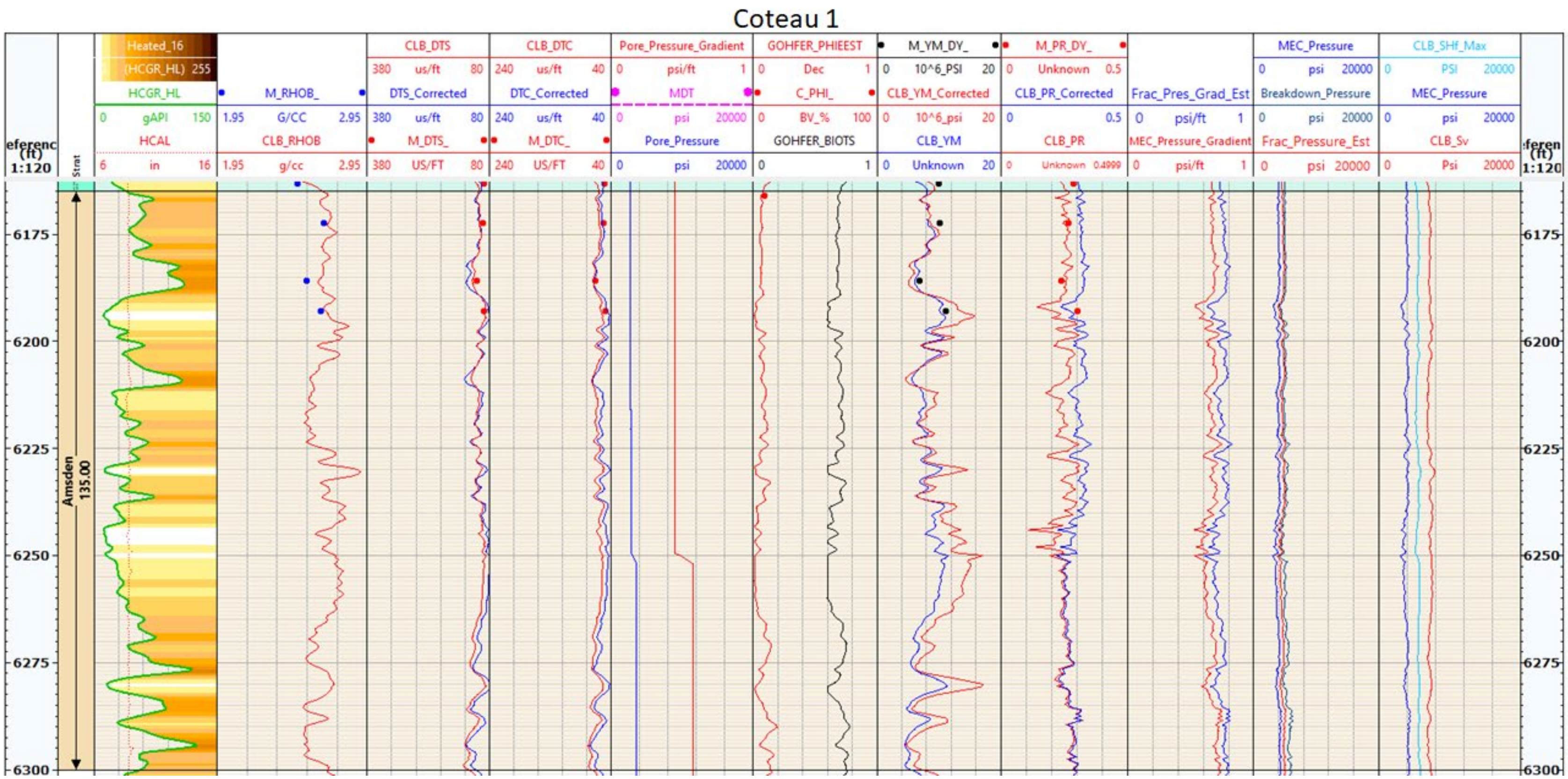

Figure 2-72. Calibrated geomechanical rock properties model in Amsden Formation.

2.5 Faults, Fractures, and Seismic Activity

In the Great Plains CO_2 Sequestration Project area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from Coteau 1 that suggest the injection interval, Broom Creek Formation (42,800 mg/L) is isolated from the next permeable interval, the Inyan Kara Formation (22,800 mg/L).

The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that "the Williston Basin as a whole is in an overburden compressive stress regime," which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2019).

Between 1870 and 2015, 13 earthquakes were detected within the North Dakota portion of the Williston Basin (Table 2-21) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-73). The seismic event recorded closest to the Great Plains CO_2 Sequestration Project storage facility area occurred 29.6 mi from the Coteau 1 well near Fort Berthold in southwestern North Dakota (Table 2-21). The magnitude of this seismic event is estimated to have been 1.9.

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

Date	Magnitude	Depth, miles	Longitude	Latitude	City or Vicinity of Earthquake	Map Label	Distance to the Coteau 1 Well, miles
Sept. 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	86.7
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	138.2
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	107.5
Aug. 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	29.6
Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	117.8
Nov. 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	85
Nov. 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	128.6
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	127.3
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	76.6
May 13, 1947	3.7**	U	−100.90	46.00	Selfridge	J	106.8
Oct. 26, 1946	3.7**	U	−103.70	48.20	Williston	K	102.6
April 29, 1927	3.2**	U	−102.10	46.90	Hebron	L	36.8
Aug. 8, 1915	3.7**	U	−103.60	48.20	Williston	M	98.5

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

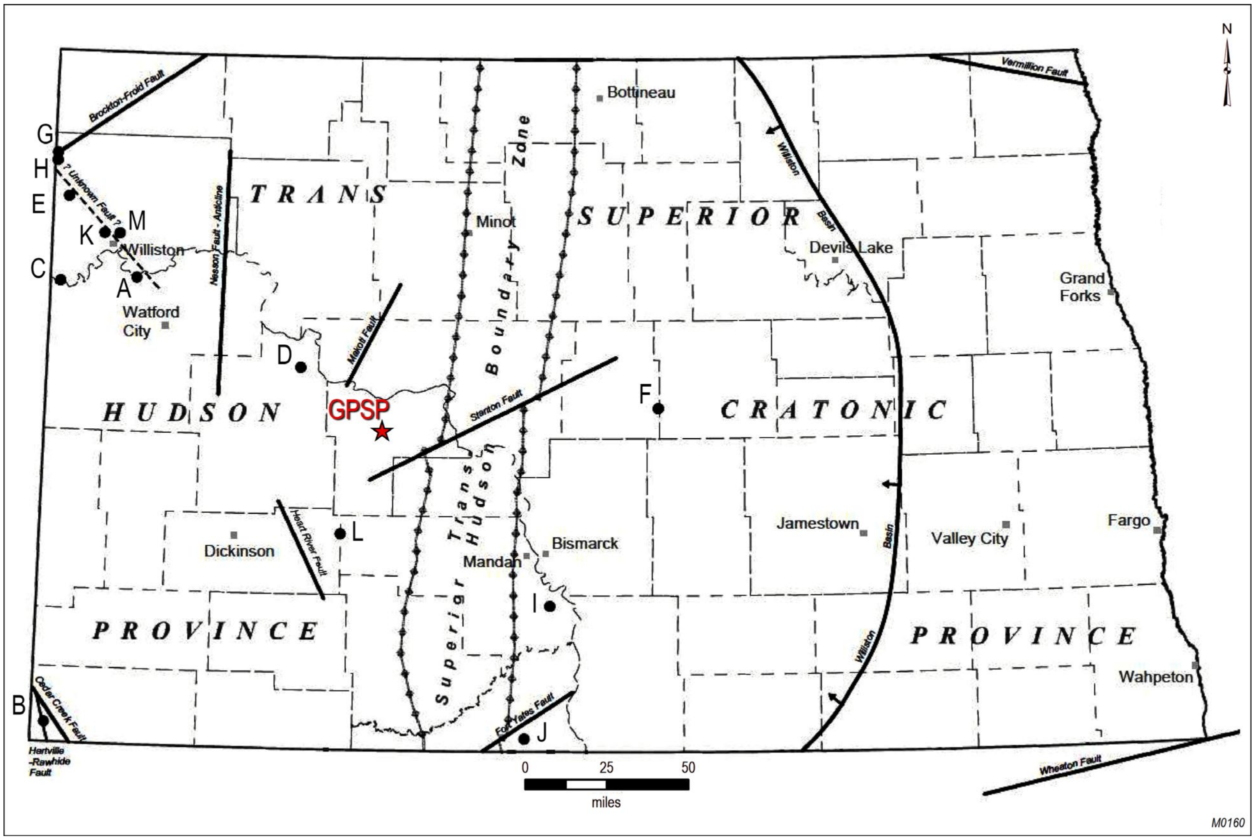

Figure 2-73. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-21.

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging earthquake events occurring in North Dakota, with less than two damaging earthquake events predicted to occur over a 10,000-year time period (Figure 2-74) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by USGS in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) state there is very little seismic activity near injection wells in the Williston Basin. They noted only two historic earthquake events in North Dakota that could be associated with nearby oil and gas activities. This indicates relatively stable geologic conditions in the region surrounding the potential injection site. The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the absence of known or suspected local or regional faults suggest the probability that seismicity would interfere with containment is low.

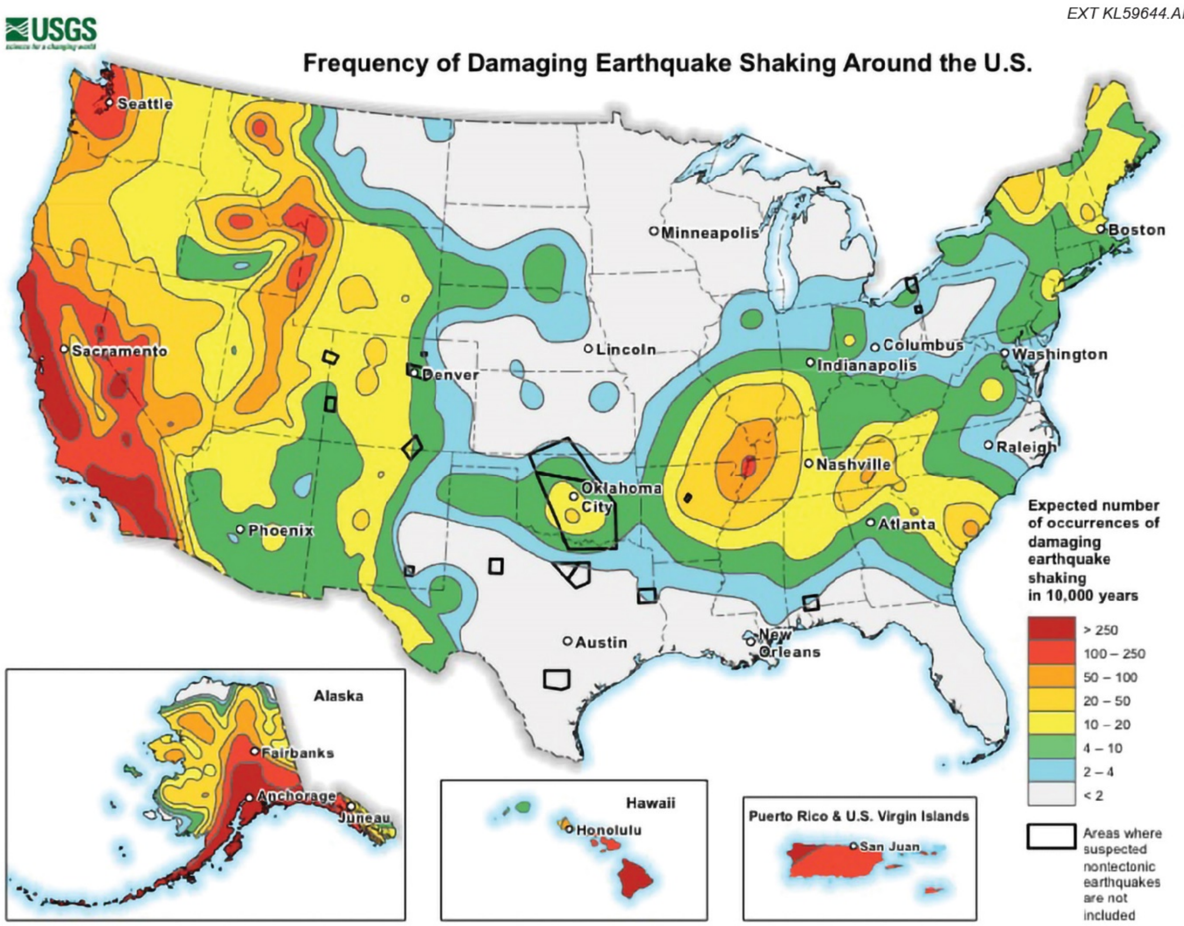

Figure 2-74. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

2.6 Potential Mineral Zones

There are no known producible accumulations of hydrocarbons in the storage facility area. The North Dakota Geological Survey recognizes the Spearfish Formation as the only potential oil-bearing formation above the Broom Creek Formation. However, production from the Spearfish Formation is limited to the northern tier of counties in western North Dakota (Figure 2-75). There has been no exploration for, nor development of, a hydrocarbon resource from the Spearfish Formation in the Great Plains CO_2 Sequestration Project area.

There has been no historic hydrocarbon exploration in, or production from, formations below the Broom Creek Formation in the storage facility area. The Herrmann 1 well (NDIC File No. 4177), the closest hydrocarbon exploration well to the storage facility area, located 4.1 miles from the Coteau 1 well, was drilled in 1966 to explore potential hydrocarbons in the Madison Group. The well was dry and did not suggest the presence of hydrocarbons. The closest

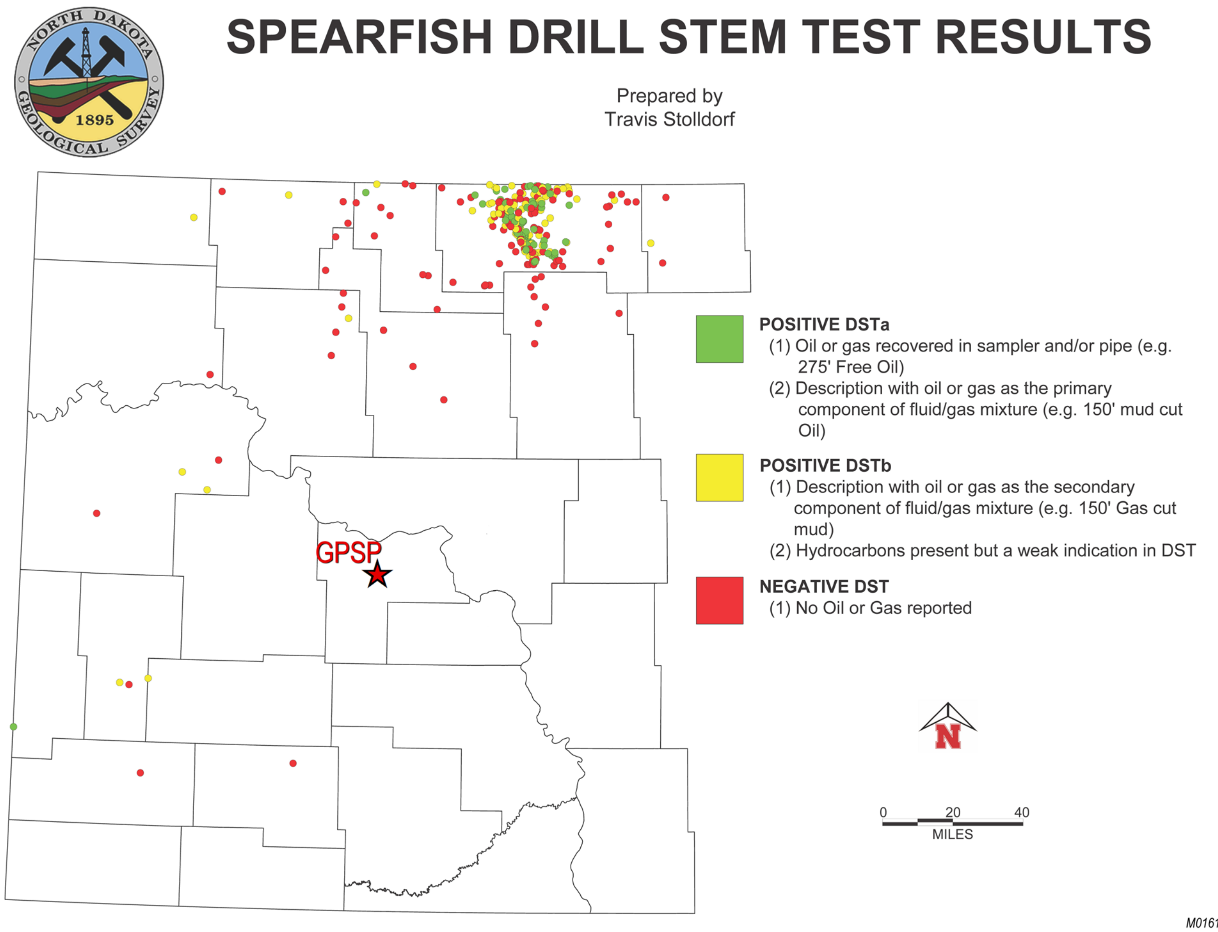

Figure 2-75. Drillstem test results indicating the presence of oil in the Spearfish Formation (modified from Stolldorf, 2020).

hydrocarbon producing well is Traxel 1-31H (NDIC File No. 17877), located 10.8 miles west from the Coteau 1 well (NDIC 38379). The Traxel 1-31H well was drilled in August 2009, producing a cumulative total of 12,021 bbl until December 2013. The well's current status is producer now abandoned (PNA) as of November 2014. Published studies suggest there are no economic deposits of hydrocarbons in the Bakken Formation in the storage facility area (Bergin, 2012; Theloy, 2016).

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a horizontal well could be used to produce the hydrocarbon while avoiding drilling through the CO_2 plume, or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available, which will allow prospective operators to design an appropriate well control strategy via increased drilling mud weight. The maximum pressure increase in the center of the injection area is projected by computer modeling to be 400–450 psi, with lesser impacts extending radially (Figure 3-20). Pressure increases will relax postinjection as the area returns to its preinjection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the CO_2 should be designed to include an intermediate casing string placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place.

Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations (NDCC 57-51-01) define shallow gas resources as “gas produced from a zone that consists of strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1,524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation (Jurassic), from which gas may be produced.”

Lignite reserves in the Sentinel Butte Formation of the Fort Union Group (the Beulah of the Beulah-Zap interval and Twin Butte coal beds) are mined to be used as feedstock for the GPSP coal gasification process and power generation feedstock at Basin Electric Power Cooperative’s Antelope Valley Station, located about 0.5 miles north of DGC’s GPSP. The lignite is obtained from the Freedom Mine, which is operated by Coteau Properties Company, a wholly owned subsidiary of North American Coal Corporation.

The thickness of the Beulah–Zap averages between 18 to 22 feet in thickness (Figure 2-76). Above the Beulah horizon are several thin beds of lignite. In ascending order, these are the Schoolhouse and Twin Butte beds. Overburden on top of the Beulah ranges from 95 to 145 feet (Figure 2-77). The Twin Butte has an average thickness of about 6 feet under 25–30 feet of overburden where it is actively mined (Zygarlicke and others, 2019). The Beulah, Twin Butte, and other coal seams thicken and deepen to the west. The Beulah–Zap and Twin Butte seams pinch out to the east. The underlying Hagel coal seam is mined farther to the east at the BNI Coal Mine near Center, North Dakota, and the Falkirk Mine near Falkirk, North Dakota.

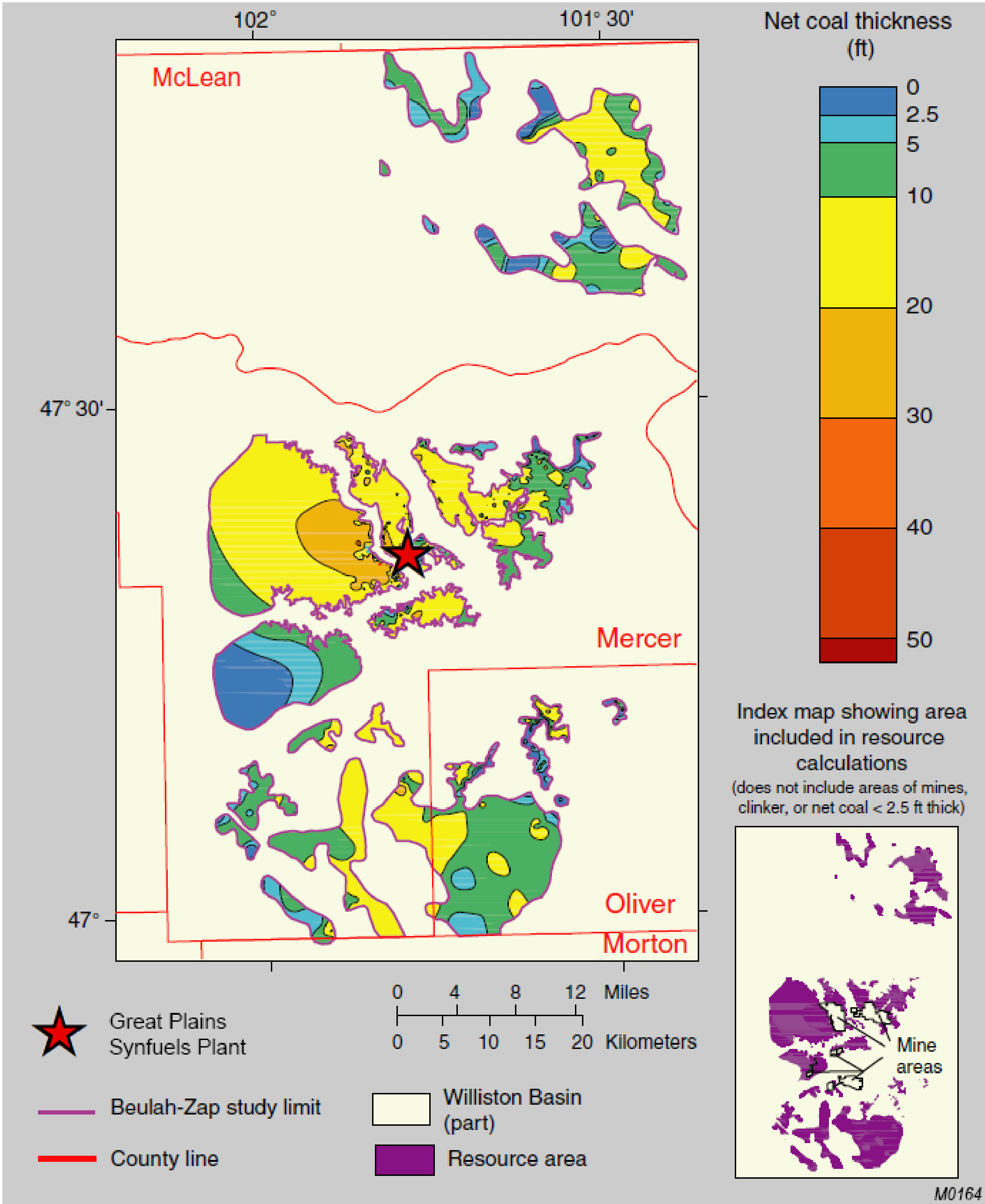

Figure 2-76. Beulah net coal isopach map (modified from Ellis and others, 1999).

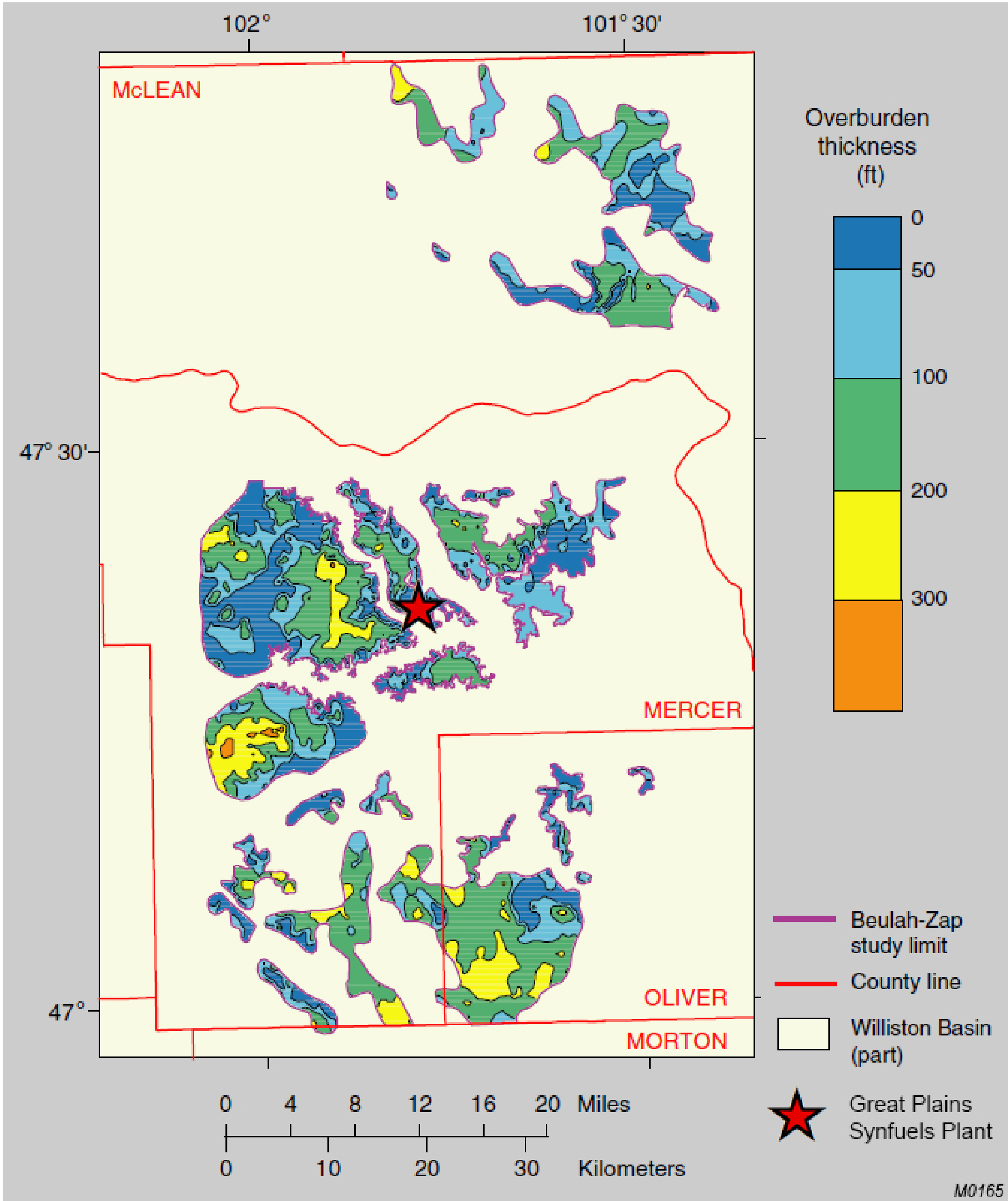

Figure 2-77. Beulah overburden isopach map (modified from Ellis and others, 1999).

The planned infrastructure for the Great Plains CO_2 Sequestration Project, the transmission line and injection well sites, will not impact mining of the lignite coal in the storage facility permit area. Injection well locations and the transmission line will be located in areas that have already been mined and since reclaimed or areas where no future mining is planned because of existing infrastructure such as powerlines, roadways, and other buried utilities (Figure 2-78).

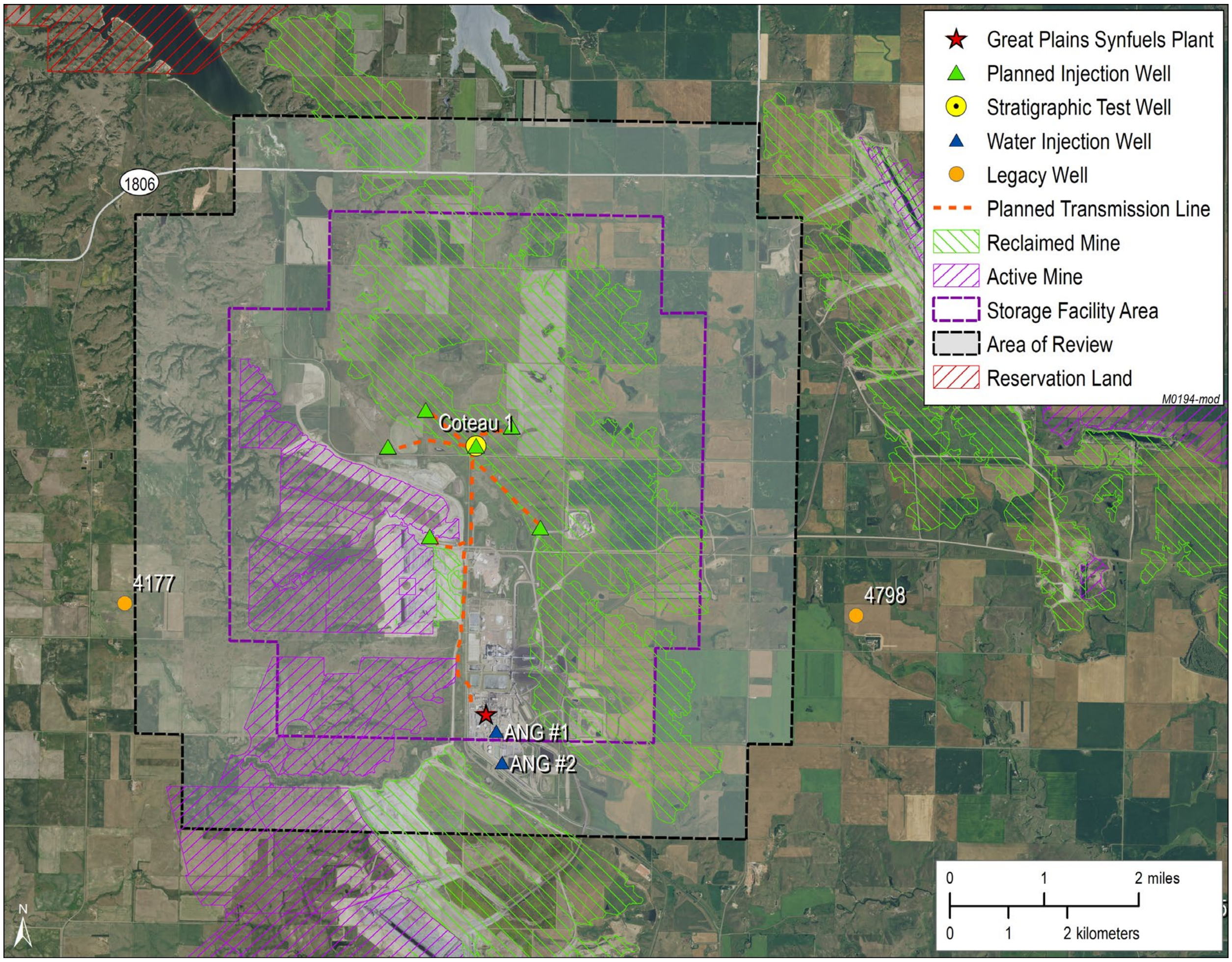

Figure 2-78. Map of the active and reclaimed mine land in the storage facility permit showing planned locations of project infrastructure (transmission line and injection wells).

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3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION

3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION

3.1 Introduction

Multiple sets of publicly available and newly acquired site-specific subsurface data were analyzed and interpreted (Section 2.2). The data and interpretations were used as inputs to Schlumberger's Petrel software (Schlumberger, 2020) to construct a geologic model of the injection zone: the Broom Creek Formation, the upper confining zone: the Opeche Formation, and the lower confining zone: the Amsden Formation. The geologic model encompasses a 76-mile × 72-mile area around the proposed storage site to characterize the geologic extent, depth, and thickness of the subsurface geologic strata (Figure 3-1). Geologic properties were distributed within the 3D model, including lithofacies, porosity, and permeability.

The geologic model and properties served as inputs for numerical simulations of CO_2 injection using Computer Modelling Group's (CMG's) GEM software (Computer Modelling

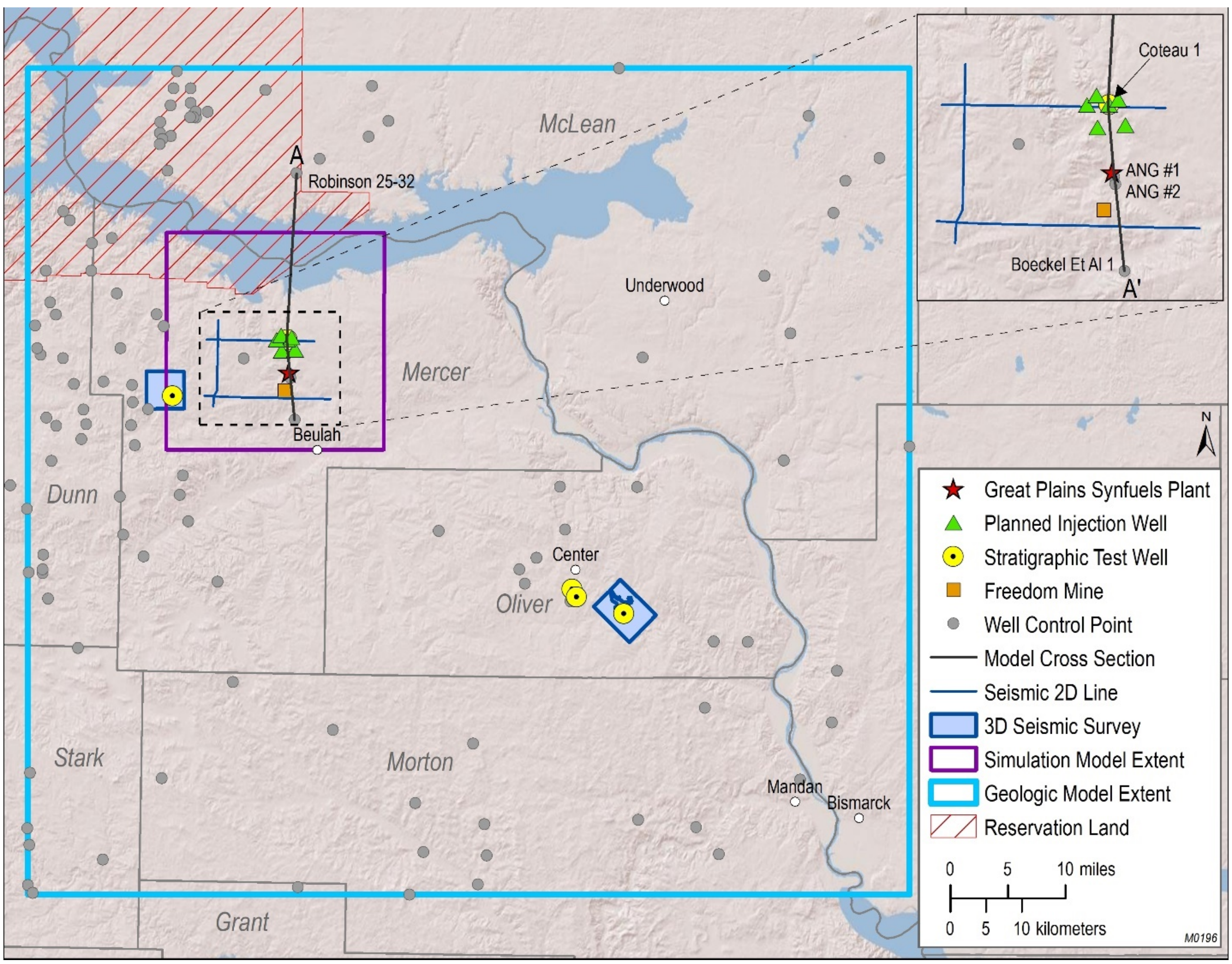


Figure 3-1. Map of the geologic model boundary (blue polygon), simulation model boundary (purple polygon), 3D seismic surveys, model cross section, and nearby Broom Creek wells.

Group, 2019). Numerical simulations of CO_2 injection were conducted to assess potential CO_2 injection rate, disposition of injected CO_2, wellhead pressure (WHP), bottomhole pressure (BHP), and pressure changes in the storage reservoir throughout the expected injection time frame and postinjection period. Results of the numerical simulations were then used to determine the project's area of review (AOR) pursuant to North Dakota's geologic CO_2 storage regulations.

3.2 Geologic Model Development

A geologic model was constructed to characterize the injection zone and upper and lower confining zones. Activities included data aggregation, structural framework creation, data analysis, and property distribution. Major inputs for the geologic model, which acted as control points during the distribution of the geologic properties throughout the modeled area, included seismic survey data, geophysical logs from nearby wells and core sample measurements.

Because of low well control and lack of site-specific 3D seismic data within the storage facility area, publicly available variograms were used to inform the distribution of the lithofacies and petrophysical properties in the geologic model. The variograms reported in the Tundra SGS (secure geologic storage) facility permit were selected as they provide a generalized representation of the property distributions expected within the Broom Creek Formation (North Dakota Industrial Commission, 2021).

3.2.1 Structural Framework Construction

Schlumberger's Petrel software was used to interpolate structural surfaces for the Opeche, Broom Creek, and Amsden Formations. Input data included formation top depths from the online NDIC database; data collected from the Coteau 1, Flemmer 1, ANG #1, J-LOC 1, J-ROC 1, and BNI-1 wells (Figure 2-5); and two 3D seismic surveys (Figure 3-1) conducted at Flemmer 1 and J-ROC 1 wellsites. The interpolated data were used to constrain the model extent in 3D space.

3.2.2 Data Analysis and Property Distribution

3.2.2.1 Confining Zones (Opeche and Amsden Formations)

The Opeche Formation was assigned a silty mudstone lithofacies designation, and the Amsden Formation was assigned a dolostone designation; both classifications were determined as primary lithologic constituents through core and well log analysis. Porosity logs, after comparison with core data sets, served as control points for property distribution. Available permeability measurements also served as control points. The control points were used in combination with variograms and a Gaussian random function simulation algorithm to distribute the properties. 4,000-ft major and minor axis length variogram structures in the lateral direction and a 6-ft vertical variogram length were used for the Opeche Formation. A major axis of 6,000-ft and a minor axis length of 3,000-ft were used for the Amsden Formation along an azimuth of 155° with a vertical variogram of 5 ft.

3.2.2.2 Injection Zone (Broom Creek Formation)

Prior variogram assessments completed for use in a similar storage facility permit application, the Tundra SGS CO_2 storage project, were used to assign variogram ranges within the injection zone. Variogram mapping investigations, as noted in the Tundra SGS application, investigated the size and shape of variograms in several different azimuthal directions, which indicated that geobody structures with the following dimensions were present in the Broom Creek Formation: major axis range of 5,000 ft, minor axis range of 4,500 ft, and an azimuth of 155° (NDIC, 2021). The Tundra SGS application used well logs recorded from the J-LOC 1, BNI-1, and J-ROC 1 wellbores to serve as the basis for deriving a vertical variogram length of 7 ft. The variogram ranges were used to distribute lithofacies and petrophysical properties.

Lithofacies classifications were determined from well log data and correlated with descriptions of core taken from the Coteau 1, Flemmer 1, ANG #1, J-LOC 1, J-ROC 1, and BNI-1 wells. Four predominant lithofacies were identified within the Broom Creek Formation: 1) sandstone, 2) dolomitic sandstone, 3) dolostone, and 4) anhydrite. Lithofacies were manually interpreted from these observations and upscaled to serve as control points for geostatistical distribution using a sequential indicator simulation (Figure 3-2).

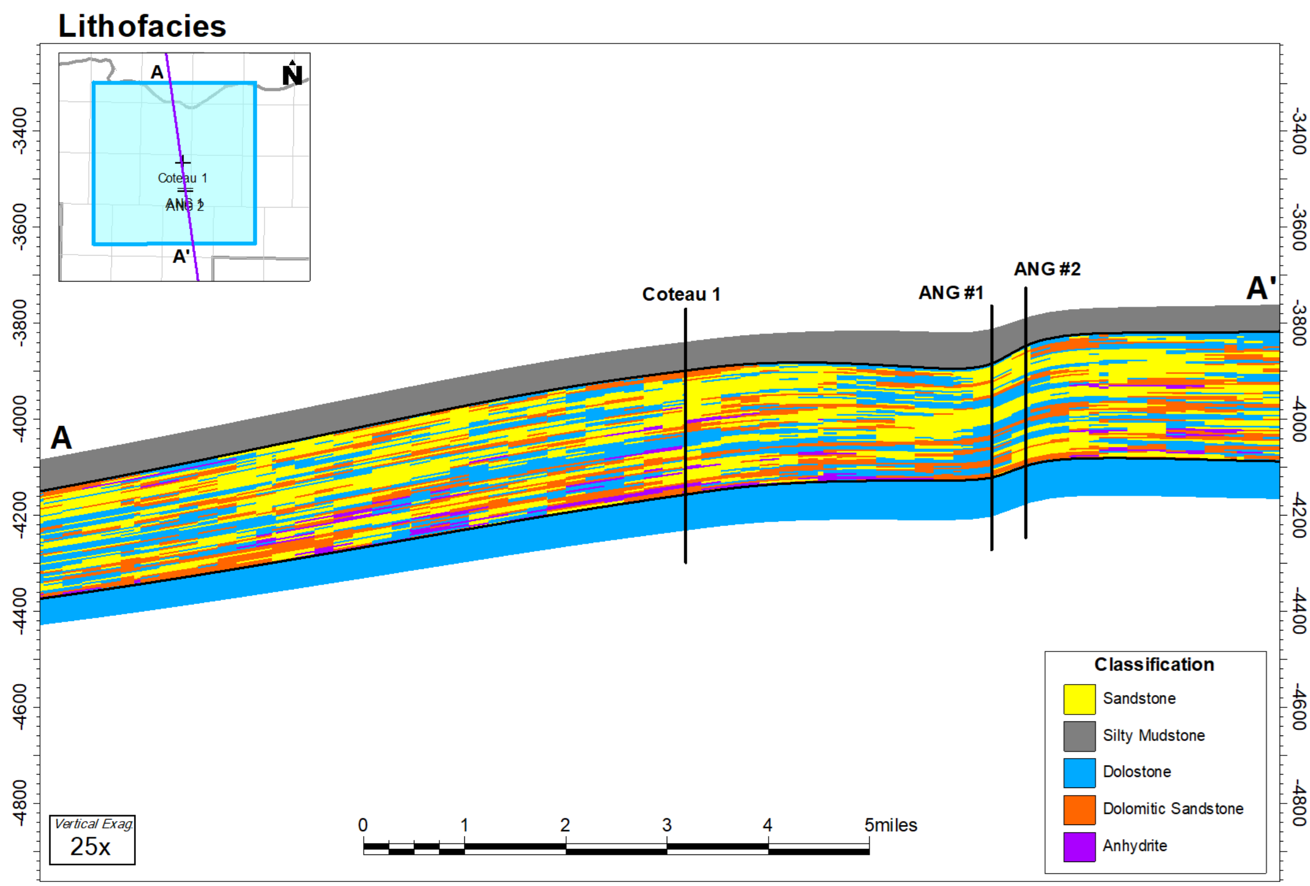


Figure 3-2. Cross-sectional view of lithofacies property. Vertical units on the y-axis are displayed as feet below sea level (25× vertical exaggeration shown).

Prior to distributing the porosity and permeability properties, core porosity and permeability measurements from Coteau 1, Flemmer 1, ANG #1, BNI-1, J-LOC 1, and J-ROC 1 wells were compared with effective porosity well logs and permeabilities estimated from the Wyllie-Rosa model (Wyllie and Rose, 1950) to ensure good agreement between the six data sets (Figure 3-3).

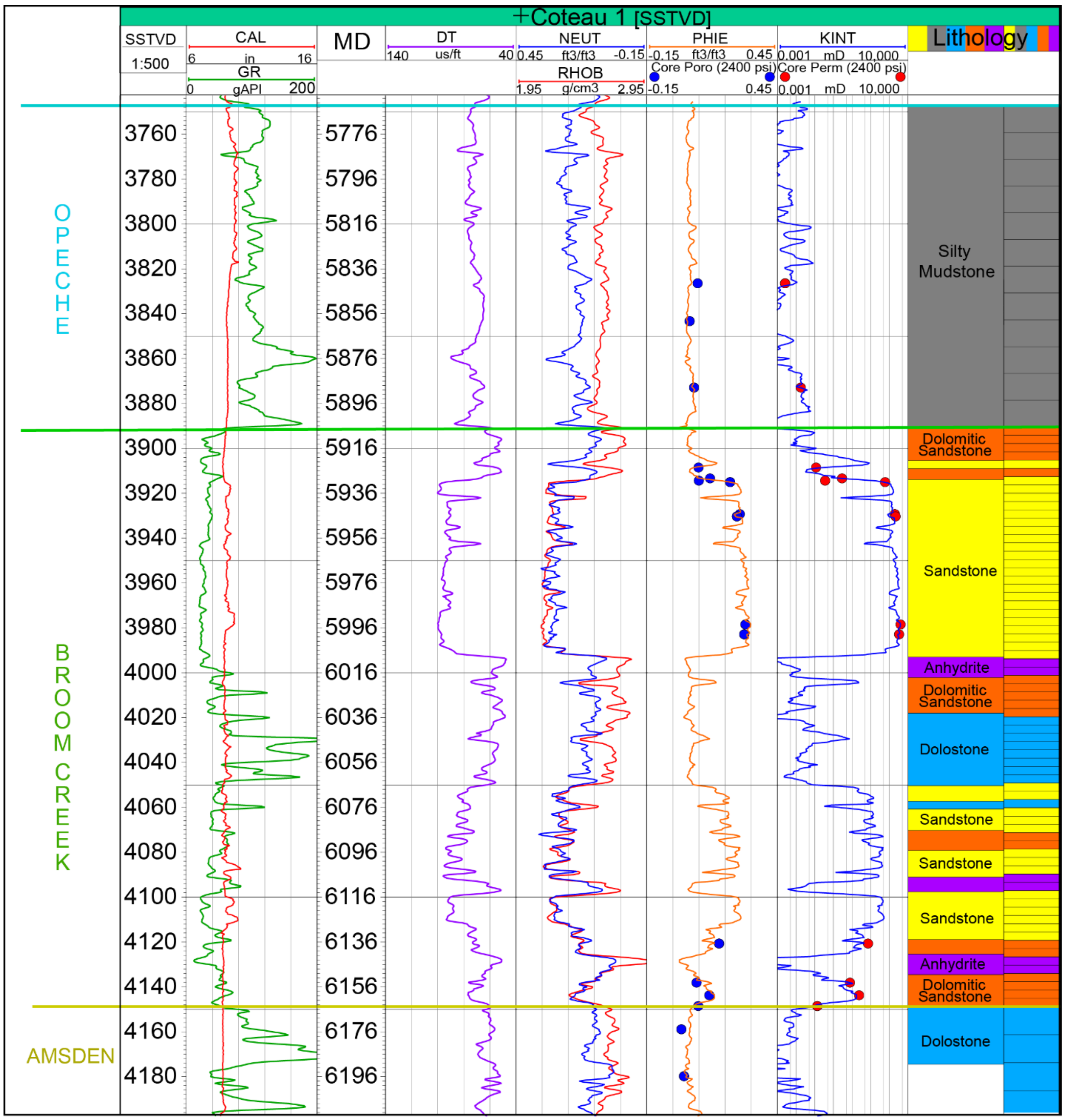


Figure 3-3. Lithofacies classification in Coteau 1 well. Well logs displayed in tracks from left to right are 1) gamma ray (green) and caliper (red), 2) delta time (purple), 3) neutron porosity (blue) and density (red), 4) effective porosity (orange) and core sample porosity (blue dots), 4) predicted intrinsic permeability (blue) and core sample permeability (red dots), 6) interpreted lithology, and 7) upscaled lithology.

A PHIE property (effective porosity; total porosity less occupied or isolated pore space) was distributed using calculated PHIE well logs, upscaled to the resolution of the 3D model as control points and variogram structures described previously with Gaussian random function simulation and conditioning to the distributed lithofacies. A permeability property was distributed using the same variables and algorithm, but cokriged to the PHIE volume (Figures 3-4 and 3-5).

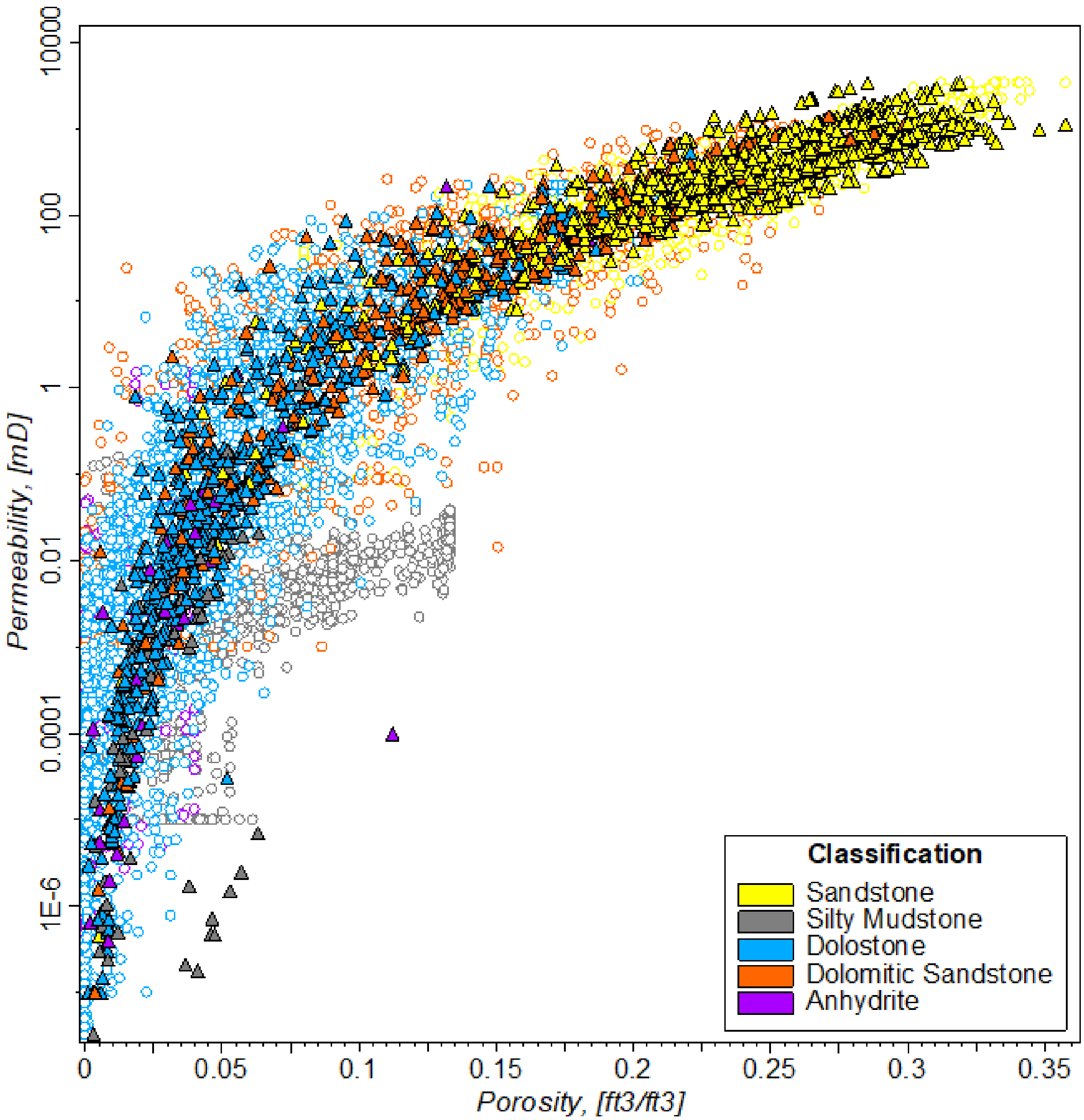


Figure 3-4. Illustration of the relationship between the modeled porosity and permeability. Upscaled well log values are represented by triangles, while circles represent distributed values. Values are colored according to lithofacies classification, as seen in Figure 3-3.

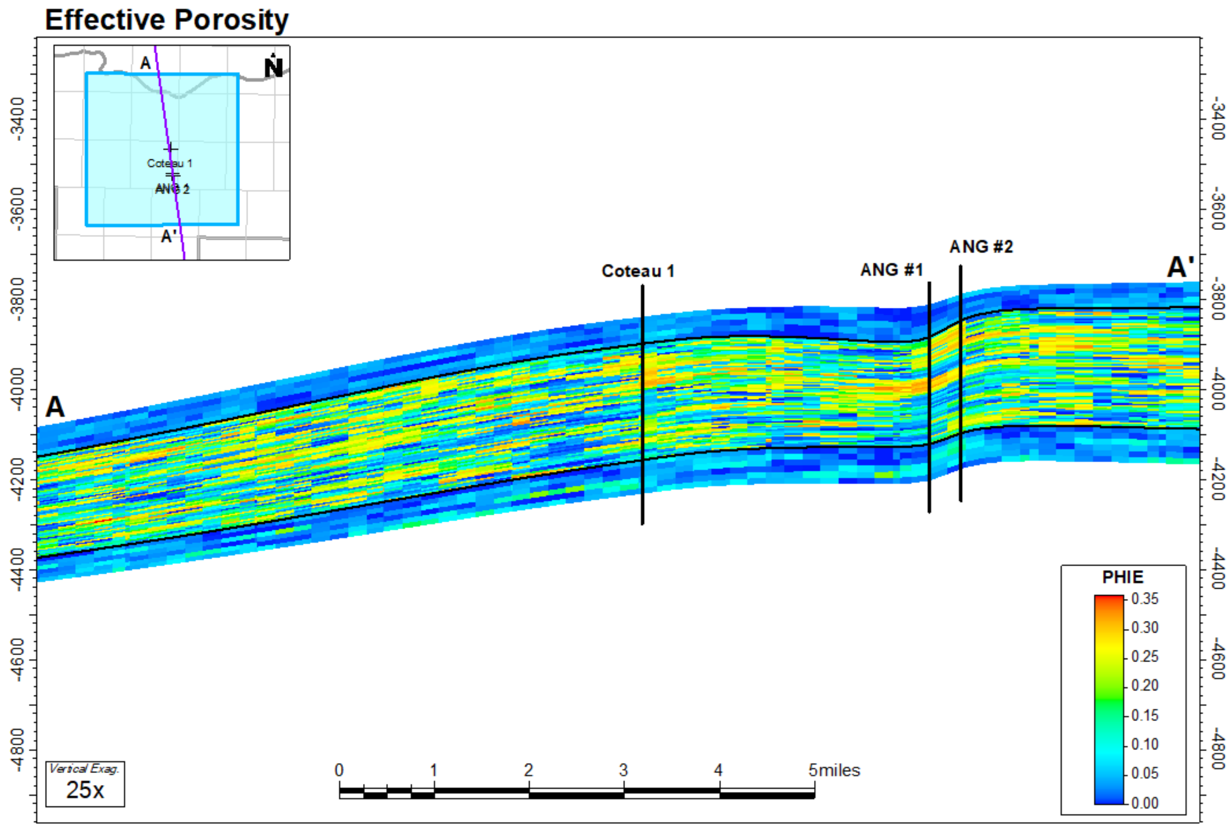


Figure 3-5. Distributed PHIE property along a NW-SE cross section. The distributed PHIE property was used to distribute permeability throughout the model. Units on the y-axis represent feet below mean sea level (25× vertical exaggeration shown).

3.3 Numerical Simulation of CO_2 Injection

Numerical simulations of CO_2 injection into the Broom Creek Formation were conducted using the geologic model described above in Section 3.2. Figure 3-6 displays the 3D view of the simulation model with the permeability property and Coteau 1 injection well. Simulations were carried out using CMG's GEM, a compositional reservoir simulation module. Both calculated temperature and pressure, along with the reference datum depth, were used to initialize the reservoir at equilibrium conditions for performing numerical simulation.

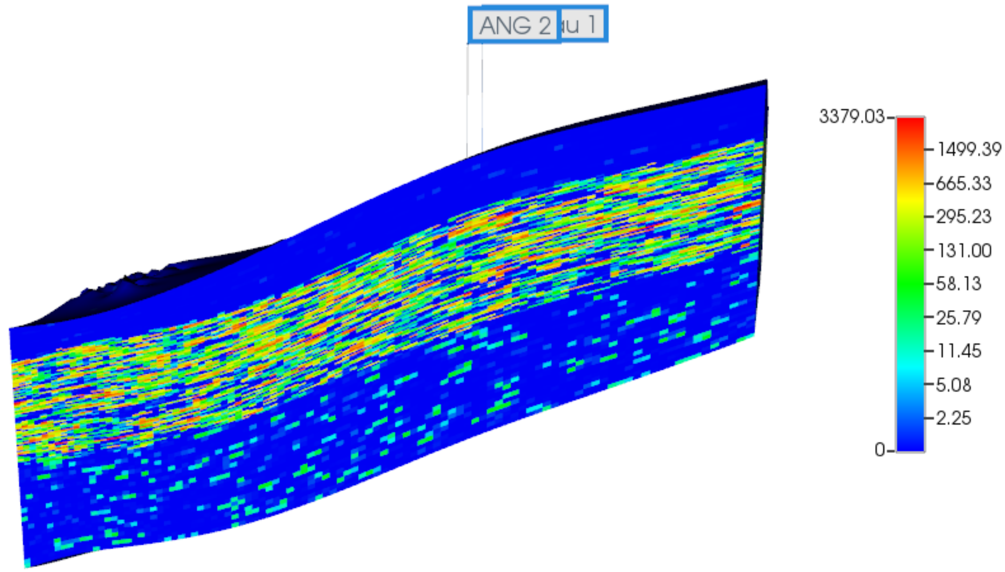


Figure 3-6. 3D view of the simulation model with the permeability property and injection wells displayed. Note the low-permeability layers (dark blue) at the top and bottom of the figure. These layers represent the Opeche Formation (upper) and the Amsden Formation (lower). The varied permeability of the Broom Creek is observed in between these layers.

The simulation model boundaries were assigned partially closed conditions as the Broom Creek Formation pinches out in the northern and eastern parts of the modeled area. From geologic interpretation for this model, distances to the formation pinch-out are assumed to be 170,016 feet (~32.2 miles) to the northeast and 158,400 feet (~30 miles) to the east from the edge of the simulation domain based on well log interpretation. The reservoir was assumed to be 100% brine-saturated with an initial formation salinity of 42,800-ppm total dissolved solids (TDS) based on the fluid sample analysis from the Coteau 1 well (Table 2-6).

CO_2 injection simulations performed allowed CO_2 to dissolve into the native formation brine. Both the relative permeability and the capillary pressure data for the Broom Creek Formation were analyzed and generated for four representative rock types in the simulation to describe the Broom Creek Formation: sandstone, dolostone, dolomitic sandstone, and anhydrite through Core Laboratory's MICP (mercury injection capillary pressure) evaluation and EERC laboratory analysis. Capillary pressure curves calculated from the MICP data were adapted to the permeability and porosity values from the numerical model.

Injection simulation scenarios were run using relative permeability and capillary pressure curves derived from the site-specific core samples from Coteau 1 well and compared to simulation scenarios that used publicly available values reported in the Project Tundra SGS facility permit (North Dakota Industrial Commission, 2021). In these scenarios, all other inputs and constraints besides relative permeability and capillary pressure curves were kept constant. Scenarios run with site-specific relative permeability and capillary pressure curves from Coteau 1 resulted in smaller plume sizes compared to the scenarios run with publicly available data (Figure 3-7 and 3-8). Based on these results, the decision was made to permit the scenario that uses the publicly available data to have a more conservative estimate for plume size.

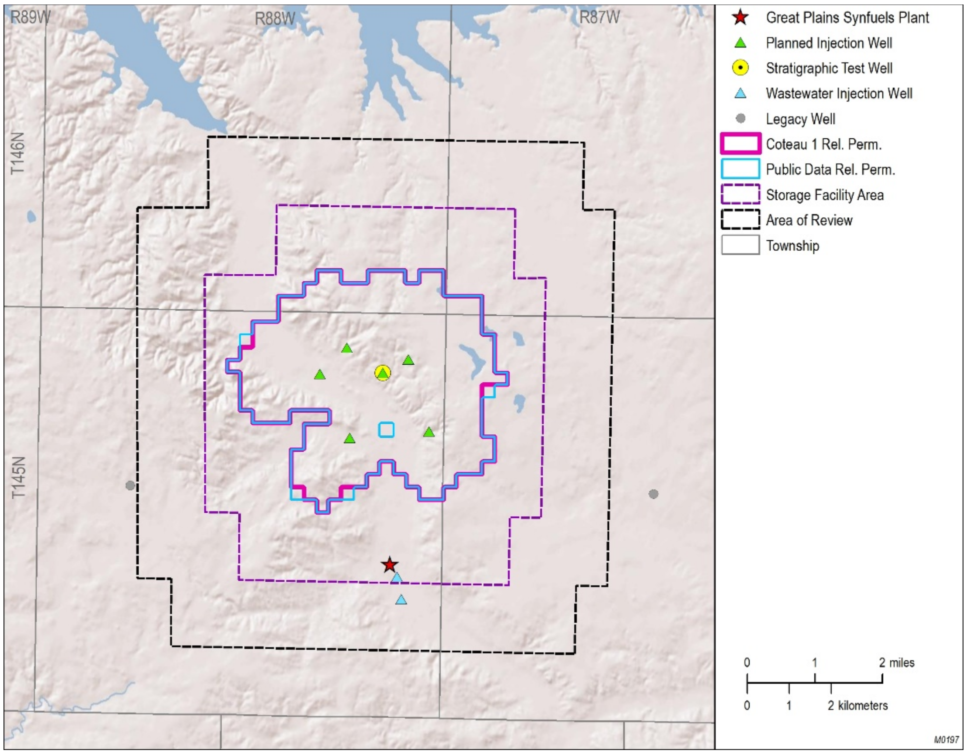


Figure 3-7. Simulated CO_2 plume extents at the end of 12 years of CO_2 injection for the scenario run using site-specific relative permeability data (pink) and the scenario run with publicly available relative permeability data (blue). The plume extent for the scenario using site-specific data is approximately 0.11 sq. mi. smaller.

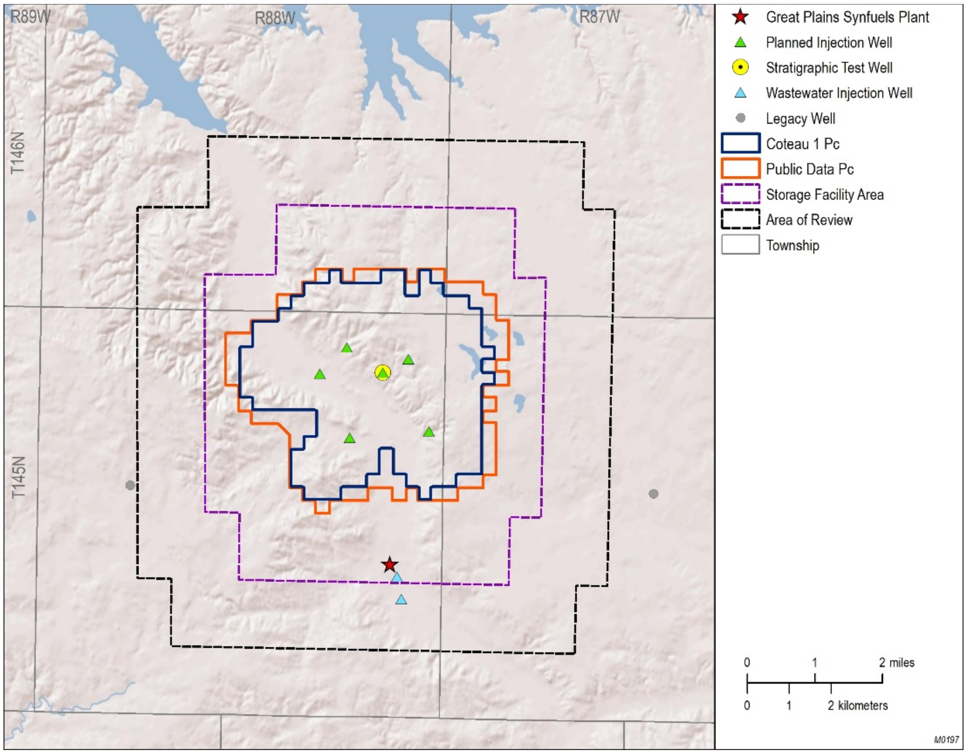
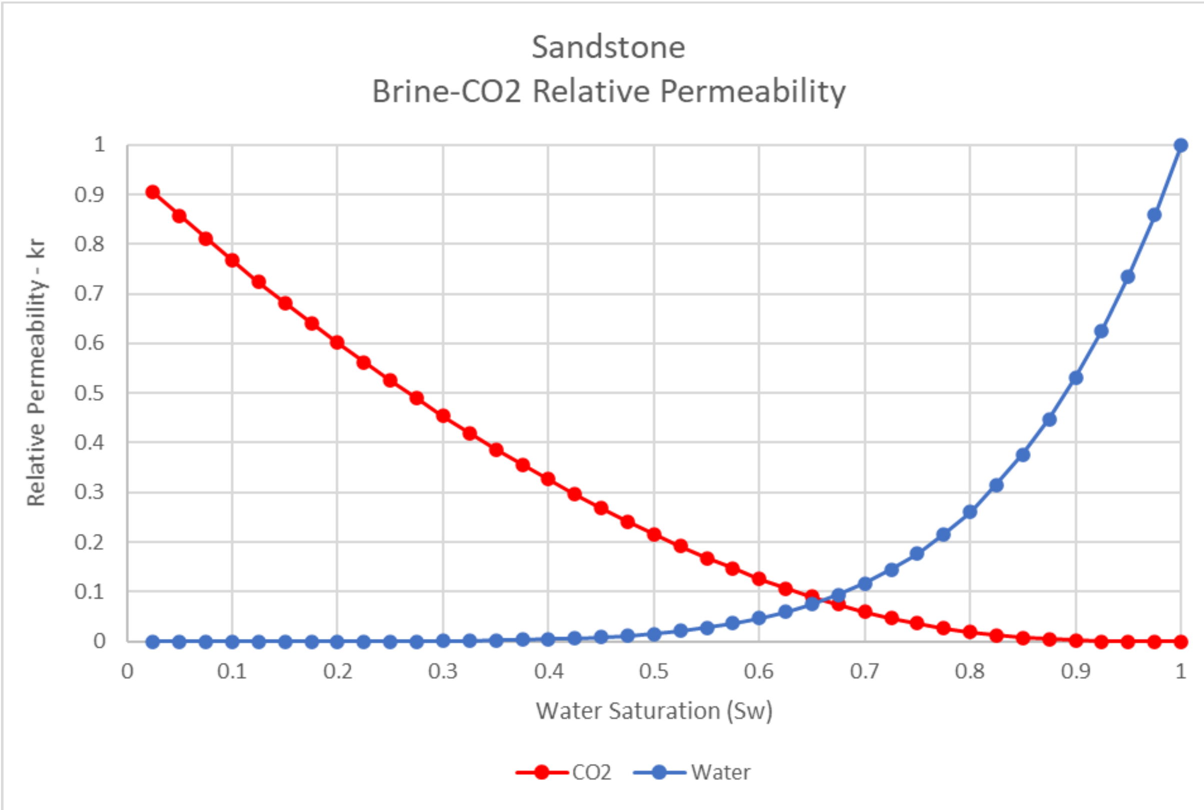


Figure 3-8. Simulated CO_2 plume extents at the end of 12 years of CO_2 injection for the scenario using site-specific relative permeability and capillary pressure (Pc) data (dark blue) and the scenario run with publicly available relative permeability and capillary data (orange). The plume extent for the scenario using site-specific data is approximately 2.2 sq. mi. smaller.

The publicly available capillary pressure curves used for the injection scenario presented in this permit are shown in Figures 3-9 through 3-12. Capillary entry pressures were determined from Broom Creek Formation core sample analysis and were assigned based on lithofacies. The assigned capillary entry pressures are 1) sandstone: 0.20 psi, 2) dolostone: 18.08 psi, and 3) mudstone and anhydrite: 168.10 psi. The dolostone pressure value, derived from a core sample within the Broom Creek Formation, was assigned to all dolostone lithofacies throughout the simulation model. Similarly, the mudstone and anhydrite pressure value, derived from a Broom Creek anhydrite core sample, was assigned to all mudstone and anhydrite lithofacies within the simulation model. The Opeche was assigned as silty mudstone, and the Amsden was assigned as dolostone.



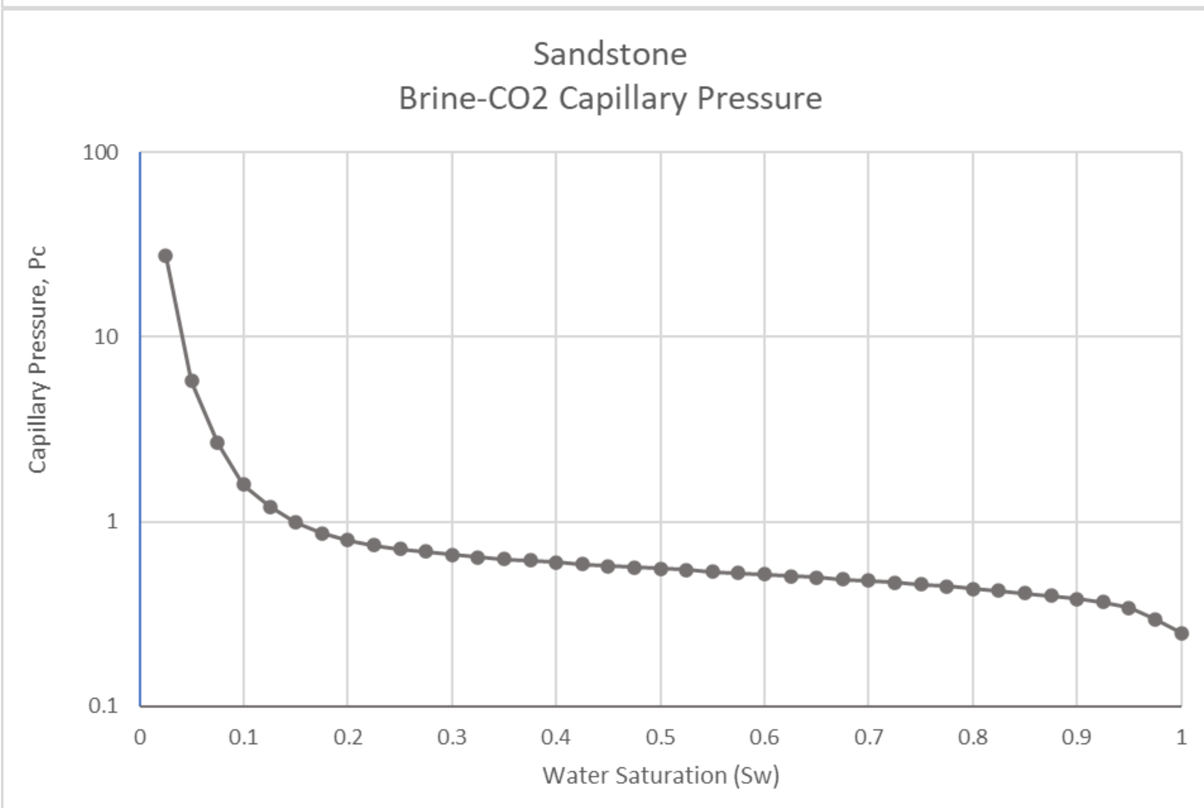


Figure 3-9. Relative permeability (top) and capillary pressure curves (bottom) for the sandstone rock type in the Broom Creek Formation.

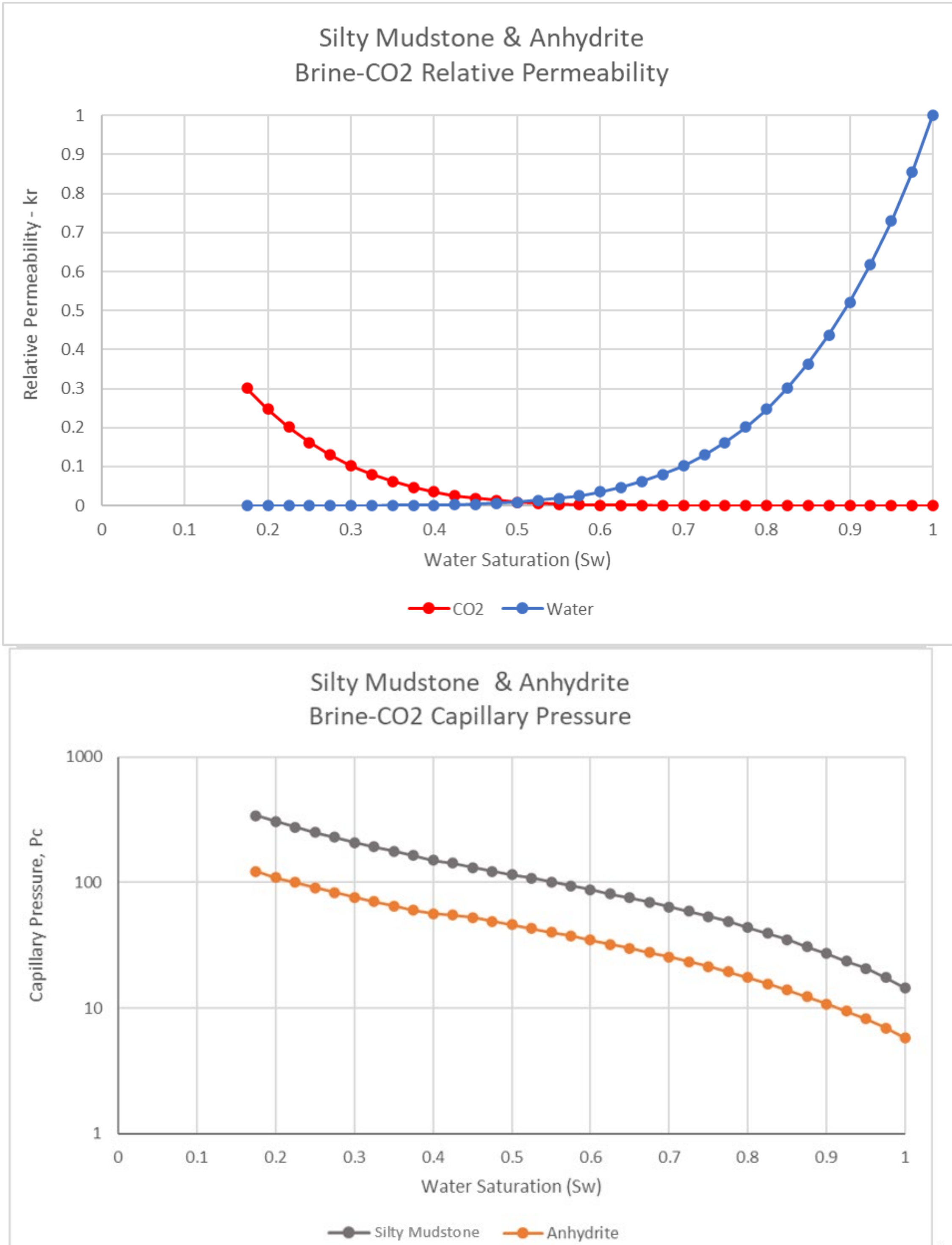
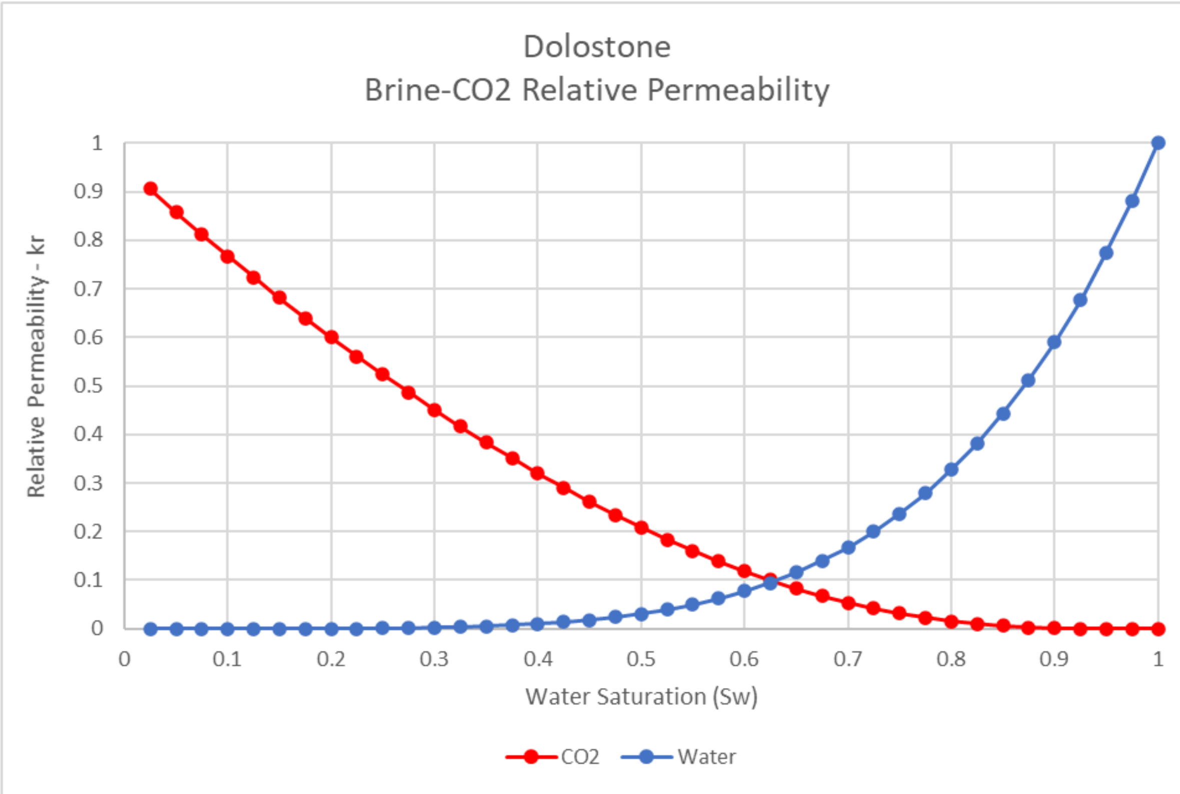


Figure 3-10. Relative permeability (top) and capillary pressure curves (bottom) for the silty mudstone rock type in the Opeche Formation and anhydrite rock type within in the Broom Creek Formation.



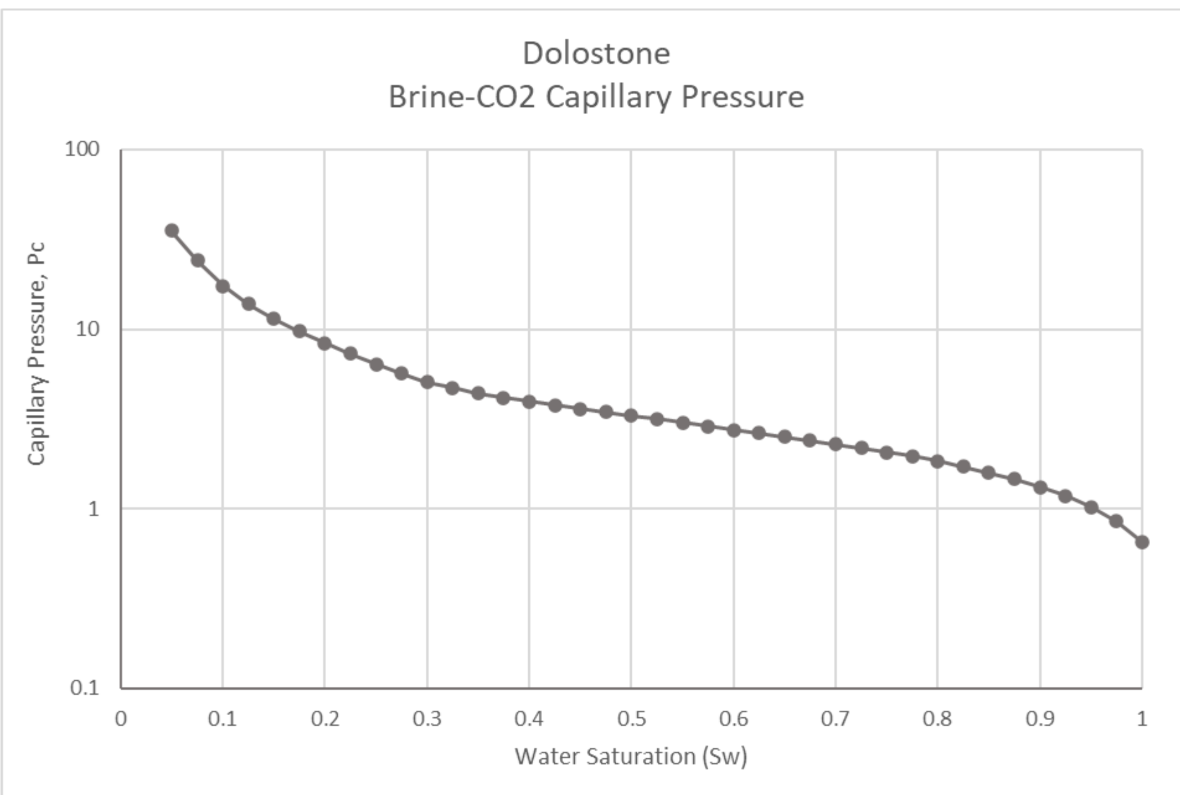
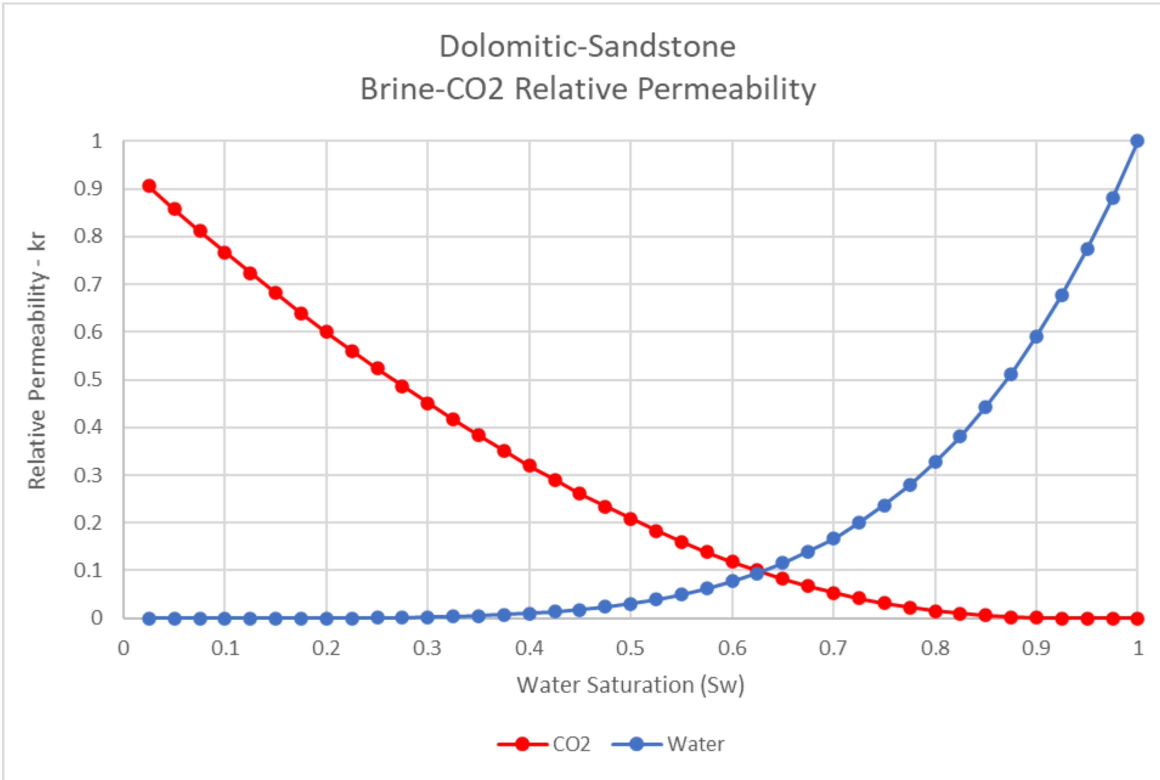


Figure 3-11. Relative permeability (top) and capillary pressure curves (bottom) for the dolostone rock types in the Broom Creek and Amsden Formations.



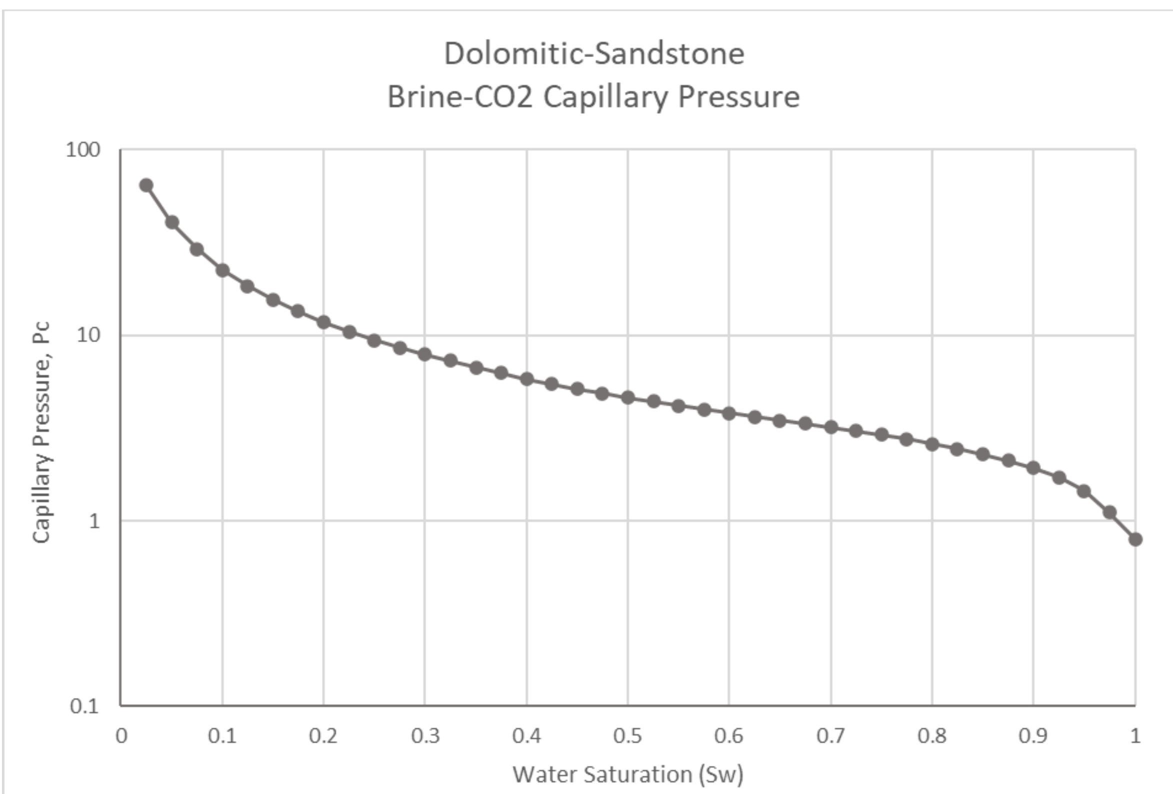


Figure 3-12. Relative permeability (top) and capillary pressure curves (bottom) for the dolomitic sandstone rock type in the Broom Creek Formation.

Temperature and pressure data recorded from a pressure test in the Coteau 1 were used to derive a temperature and pressure gradient to initialize the numerical simulation model for the proposed injection site. In combination with depth, this temperature gradient of 0.02°F/ft was used to calculate subsurface temperatures throughout the study area. A pressure reading recorded from the Broom Creek Formation was used to derive a pore pressure gradient of 0.49 psi/ft (Table 3-1). Table 3-2 shows the general properties used for numerical simulation analysis in this study.

Table 3-1. Pressure Measurement Recorded from the Coteau 1 Well and Derived Pressure Gradient

Test Depth, ft MD*	Formation Pressure, psi	Pressure Gradient, psi/ft
5,975.00	2,937.09	0.49

* Measured depth.

Table 3-2. Summary of Reservoir Properties in the Simulation Model

Formation	Average Permeability, mD	Average Porosity, %	Initial Pressure, P_i, psi	Salinity, ppm	Boundary Condition
Opeche	0.034	25.7	~2,937.1 (at 3,960.6 ft)	42,800	Partially closed
Broom Creek	241.2	14.5			
Amsden	2.55	4.4			

The CMG fluid property characterization tool, WinProp, was used to generate the fluid property input data for the simulation model. Only the major constituents in the gas stream were included for computational efficiency. After all the constituents were normalized to sum 100% mole fraction, the CO_2 composition in the gas stream was 96.45% CO_2. Other constituents represent 3.55% of the stream, including 1.23% hydrogen sulfide (H_2S) and 2.32% for methane, ethane, propane, and nitrogen.

The numerical simulation model was history-matched using the field injection data from the Class I injector wells located in the area of study, ANG #1 and ANG #2. The field injection data consisted of daily field data from Dakota Gasification Company (DGC) water injection into the ANG wells throughout July 1998 to August 2021. The field data provided were averaged per month and included in the numerical model for the history matching. The well skin factor was the parameter used to history-match the model based on data from a monitoring study conducted in the ANG wells in 2016. Figures 3-13 and 3-14 show a comparison between the WHP and water injection rate from the field data set and the predicted values from the history-matched model.

Six CO_2 injection wells, Coteau 1, Coteau 2, Coteau 3, Coteau 4, Coteau 5, and Coteau 6, were simulated as perforated across the entire Broom Creek Formation interval (Figure 2-2). The CO_2 injection well constraints and wellbore model inputs for the simulation model are shown in

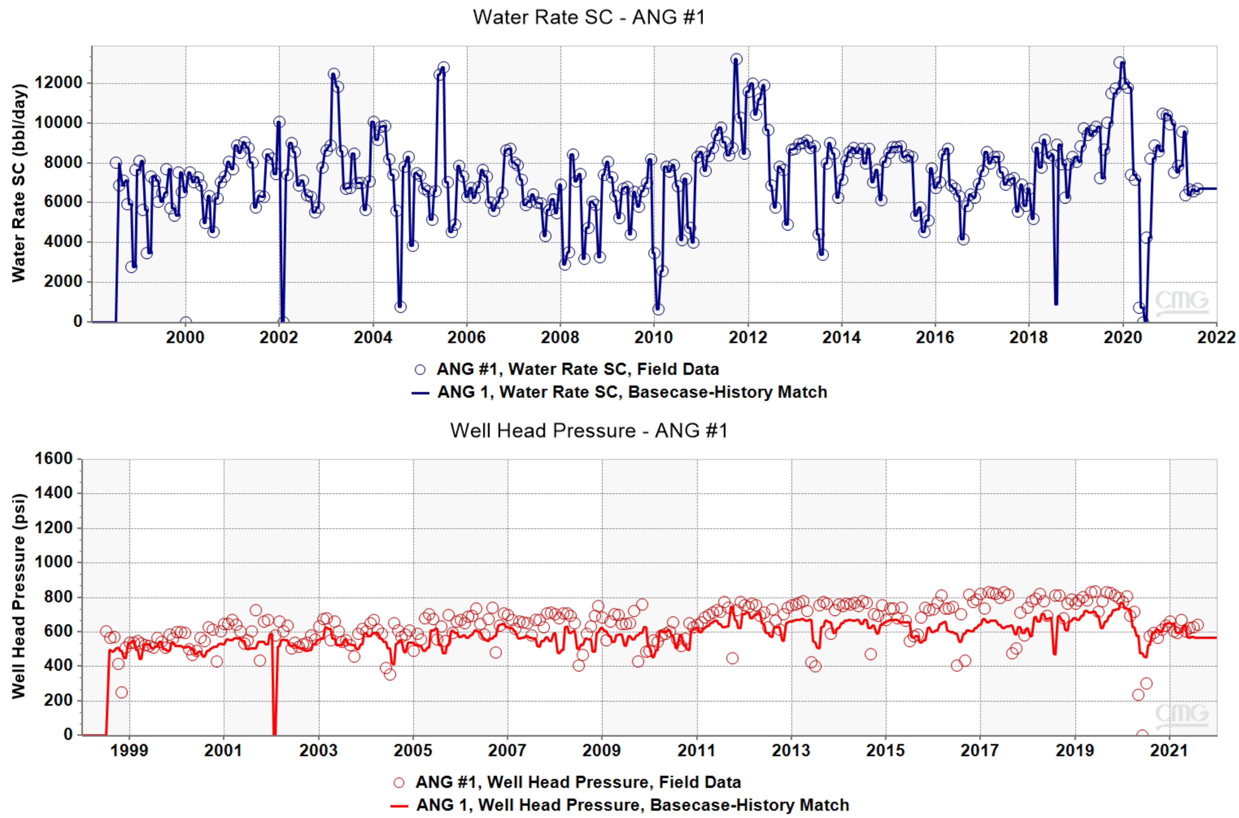


Figure 3-13. Water injection rate (top) and WHP curves (bottom) for the ANG #1 Class I disposal well. The circles represent the field data, and the lines represent the predicted values from the history-matched model.

Table 3-3. The CO_2 injection rate in the simulation model is based on initial CO_2 volumes expected to average 55 MMcfd (1.0 million metric tonnes per year [MMt/yr]), determined from existing compressor capacity and historical excess CO_2 availability after satisfying existing contractual arrangements. As additional volumes become available in the future, the daily rate is expected to increase to 70 MMcfd (1.3 MMt/yr) in January 2025, then to 140 MMcfd (2.7 MMt/yr) in May 2026 until the end of the 12-year CO_2 injection period.

The BHP constraint was calculated using the well depth at the top of the Broom Creek Formation (MD) and 90% of the formation fracture gradient. The fracture gradient was obtained from geomechanical modeling and core analysis, resulting in an average of 0.71 psi/ft fracture propagation pressure in the Coteau 1 well.

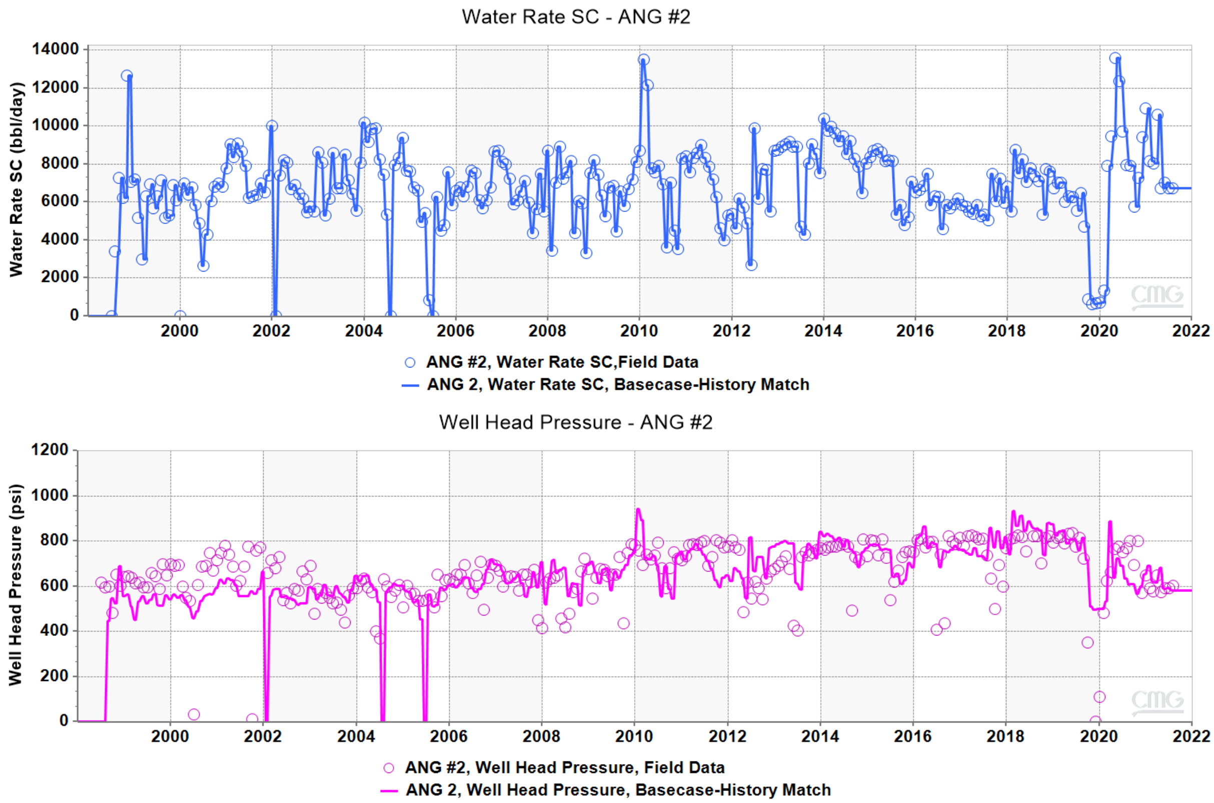


Figure 3-14. Water injection rate (top) and WHP curves (bottom) for the ANG #2 Class I disposal well. The circles represent the field data, and the lines represent the predicted values from the history-matched model.

Table 3-3. Well Constraints and Wellbore Model in the Simulation Model

Well Name	Start Date of Injection	Primary Well Constraint, maximum BHP	Secondary Well Constraint, maximum injection rate/well	Tubing Size	Wellhead Temperature	Downhole Temperature
Coteau 1*	July/2022	3,754 psi	25 MMcfd	4½ in.	90°F	151°F
Coteau 2*	July/2022	3,802 psi	17.5 MMcfd			
Coteau 3*	July/2022	3,772 psi	25 MMcfd			
Coteau 4*	July/2022	3,787 psi	25 MMcfd			
Coteau 5*	May/2026	3,776 psi	25 MMcfd			
Coteau 6*	May/2026	3,786 psi	25 MMcfd			

* Primary group constraint, injection rate: 55 MMcfd from July/2022 to Dec./2024, 70 MMcfd from Jan./2025 to April/2026, 140 MMcfd from May/2026 to July/2034.

Water injection conditions used for numerical simulation of the Class I disposal wells, ANG #1 and ANG #2, are shown in Table 3-4. The water injection rate constraint used for the ANG wells during the CO_2 injection period was determined from historical injection rates over the past 2 years. Water injection into ANG #1 and ANG #2 was held constant during the 12 years of the CO_2 injection period. For simulation evaluation purposes, it is assumed that water injection ceases at the end of CO_2 injection as the operations producing the water are likely to cease at the end of CO_2 injection.

Table 3-4. ANG #1 and ANG #2 Well Constraints in the Simulation Model

Primary Well Constraint, maximum water injection rate	Secondary Well Constraint, maximum permitted WHP
6,722.9 bpd for ANG #1	1,350 psi for ANG #1
6,722.4 bpd for ANG #2	1,100 psi for ANG #2

3.3.1 Sensitivity Analysis

Because the availability of data for this study included well logs, core sample data, and rock-fluid properties, the need for typical sensitivity studies of influential reservoir parameters has been reduced. A preliminary sensitivity analysis made to the wellbore model parameters suggested, at the given injection volume rates and BHP conditions, the wellhead temperature played a prominent role in determining WHP response. Thus a wellhead temperature value of 90°F was chosen that most closely represents the expected operational temperature.

3.4 Simulation Results

Simulations of CO_2 injection with the given well and group constraints, listed in Table 3-3, predicted the WHP of all six injector wells would not exceed 1,730 psi during injection (Figure 3-15). The predicted BHP for each of the CO_2 injection wells did not reach the maximum BHP constraint defined using 90% of the fracture pressure gradient (Table 3-5). The target

Table 3-5. BHP Constraint and Predicted from Simulations BHP and Associated Fracture Pressure Gradient

	Well Name					
	Coteau 1	**Coteau 2**	**Coteau 3**	**Coteau 4**	**Coteau 5**	**Coteau 6**
Max BHP Constraint,* psi	3,754	3,802	3,772	3,787	3,776	3,786
Max. BHP Predicted, psi	3,430	3,445	3,462	3,414	3,424	3,426
Fracture Pressure Gradient Associated with Predicted Max. BHP, ** psi/ft	0.585	0.580	0.587	0.577	0.580	0.580

* Calculated using 0.64 psi/ft (90% of the fracture pressure gradient) and the depth for the top of the Broom Creek Formation.
** Calculated using the depth for the top of the Broom Creek Formation.

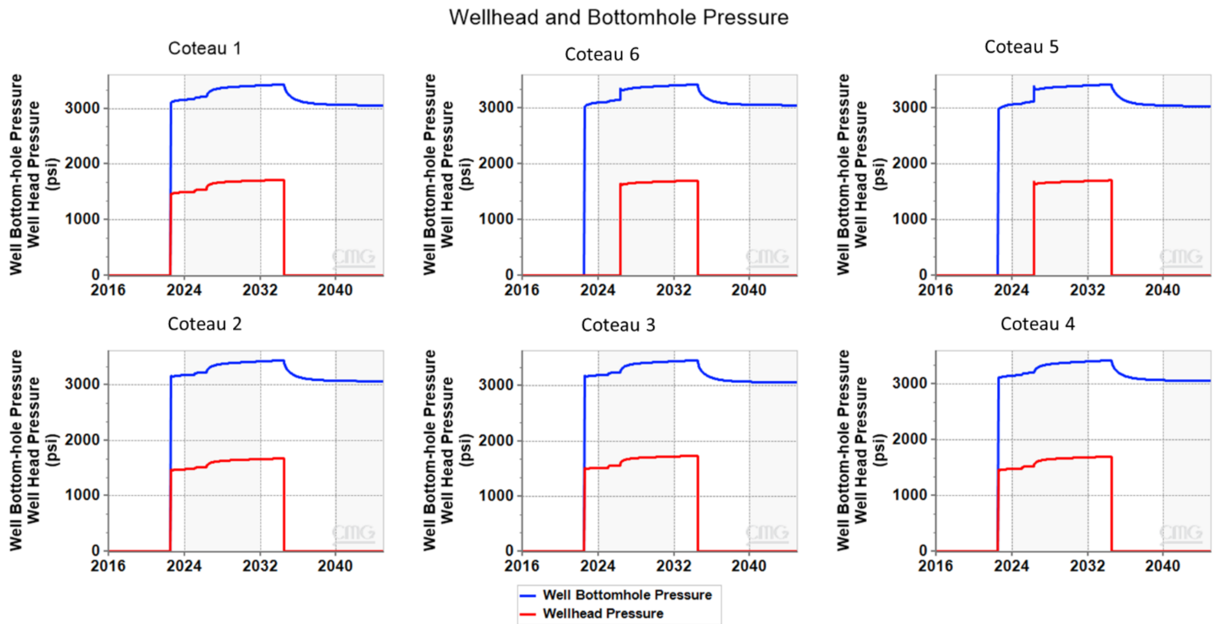


Figure 3-15.WHP and BHP response with the expected injection rate.

injection rates of 55 MMcfd from July 2022 to December 2024, 70 MMcfd from January 2025 to April 2026, and 140 MMcfd from May 2025 to July 2034 were achieved over the 12 years of injection (Figure 3-16).

A total of 25.61 MMt (501,755 MMscf) of CO_2 was injected into the Broom Creek Formation with six wells at the end of 12 years of simulated injection (Figure 3-17). The injected volume for each of the wells is shown in Table 3-6.

Simulation results showed that the maximum permitted WHP constraint for the ANG wells, Table 3-4, was not reached, and the WHP values for ANG #1 and ANG #2 did not exceed 833 and 829 psi, respectively, during the CO_2 injection period (Figure 3-18). Also, the water injection rate was not affected during the CO_2 injection period.

The simulation results did not show any interaction between the low salinity plume from the Class I disposal wells, ANG #1 and ANG #2, and the CO_2 plume at the end of the injection period. Any possible interaction during the CO_2 injection period is not affecting CO_2 injectivity. A limited interaction may occur between the low salinity plume and the CO_2 stabilized plume at 10 years postinjection. These simulation results can be seen in Section 2, Figure 2-22. However, no evidence from the simulation results indicates that this possible interaction will affect the CO_2 chemical behavior or storage performance.

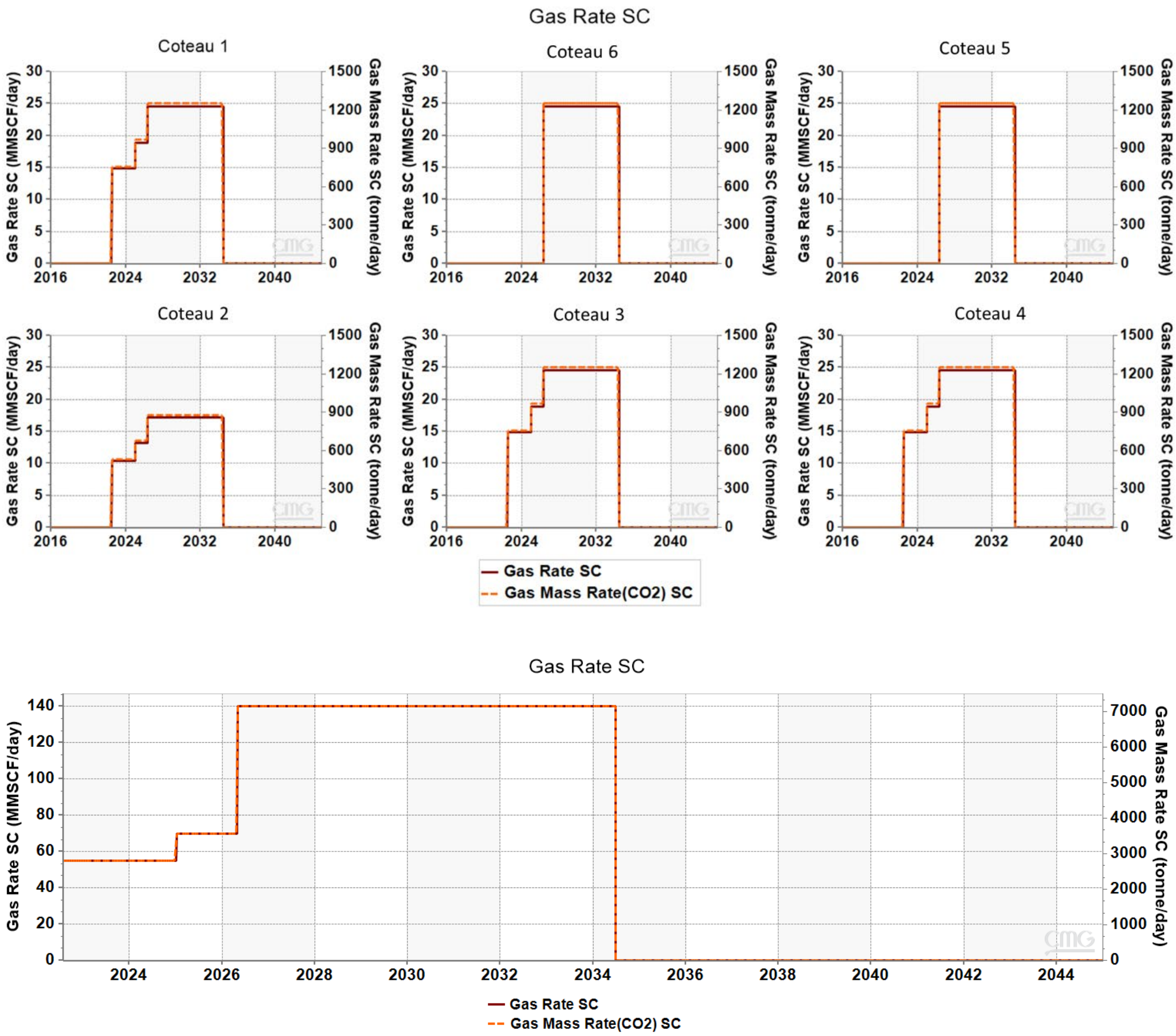


Figure 3-16. CO_2 injection rate (MMscf/day) response with the expected maximum injected rate per well (top) and group injection rate (bottom).

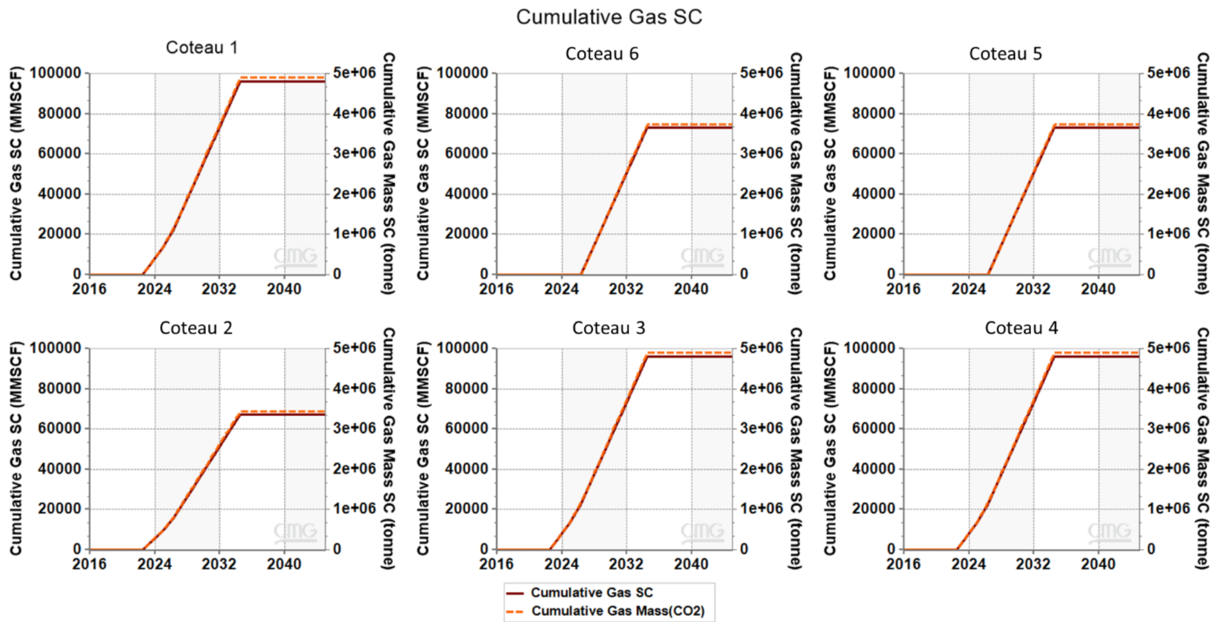


Figure 3-17. Cumulative injected CO_2 (MMscf) and CO_2 mass (metric tonnes) over 12 years of injection.

Table 3-6. CO_2 Volume Injected per Well

Well	CO_2 Volume Injected (MMscf)
Coteau 1	96,019
Coteau 2	67,213
Coteau 3	96,219
Coteau 4	96,219
Coteau 5	73,242
Coteau 6	73,242

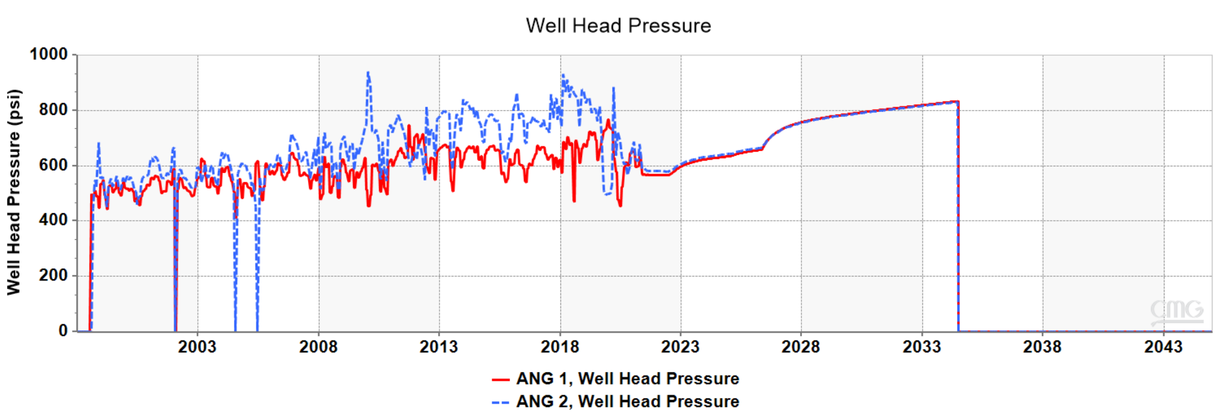


Figure 3-18. WHP response for the Class I disposal wells: ANG #1 and ANG #2.

During and after injection, supercritical CO_2 (free-phase CO_2) accounts for the majority of CO_2 observed in the modeled pore space. Throughout the injection operation, a portion of the free-phase CO_2 is trapped in the pore space through a process known as residual trapping. Residual trapping can occur as a function of low CO_2 saturation and inability to flow under the effects of relative permeability. CO_2 also dissolves into the formation brine throughout injection operations (and continues afterward), although the rate of dissolution slows over time. The free-phase CO_2 transitions to either residually trapped or dissolved CO_2 during the postinjection period, resulting in a decline in the mass of free-phase CO_2. The relative portions of supercritical, trapped, and dissolved CO_2 can be tracked throughout the duration of the simulation (Figure 3-19).

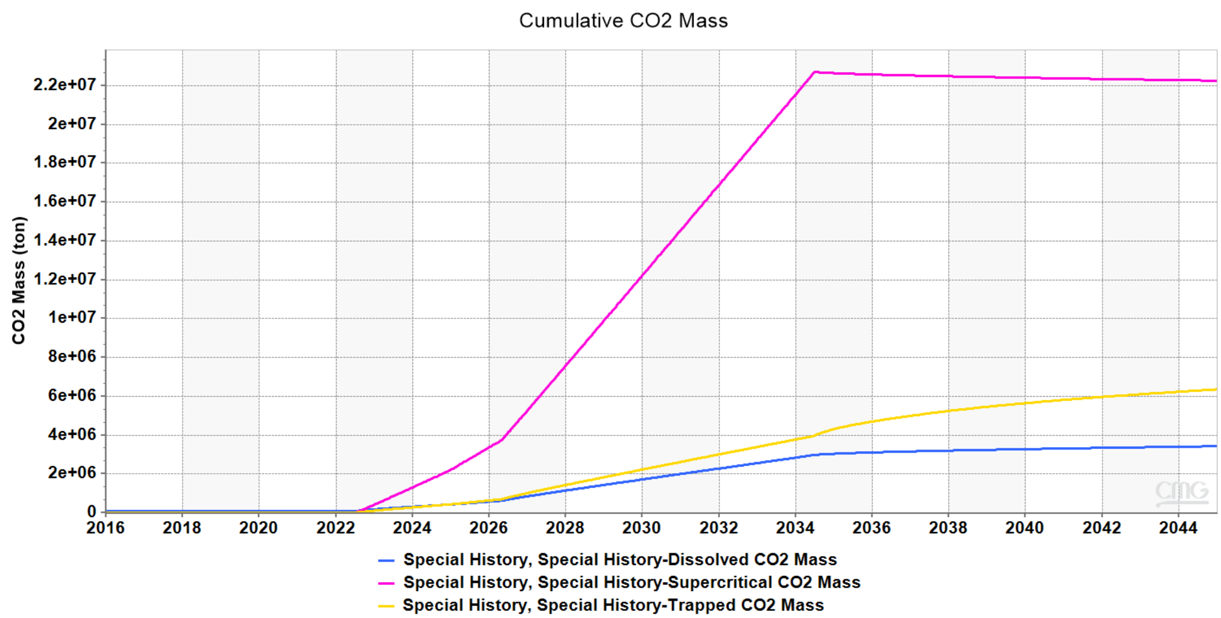


Figure 3-19. Simulated total supercritical free-phase CO_2, trapped CO_2, and dissolved CO_2 in brine.

The pressure front (Figure 3-20) shows the distribution of pressure increase throughout the Broom Creek Formation after 1, 5, and 12 years of injection as well as 8 years postinjection. A maximum increase of 436.53 psi is estimated in the near wellbore area at the end of the 12-year injection period.

Long-term CO_2 migration potential was also investigated through the numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase CO_2 injected into the formation rises to the bottom of the upper confining zone or lower-permeability layers present in the Broom Creek Formation and then outward. This process results in a higher concentration of CO_2 at the center which gradually spreads out toward the model edges where the CO_2 saturation is lower. Trapped CO_2 saturations, employed in the model to represent fractions of CO_2 trapped in small pores as immobile, tiny bubbles, ultimately immobilize the CO_2 plume and limit the plume's lateral migration and spreading. Figures 3-21 through 3-26 show the CO_2 saturation at the injection wells at the end of injection in north-to-south and east-to-west cross-sectional views.

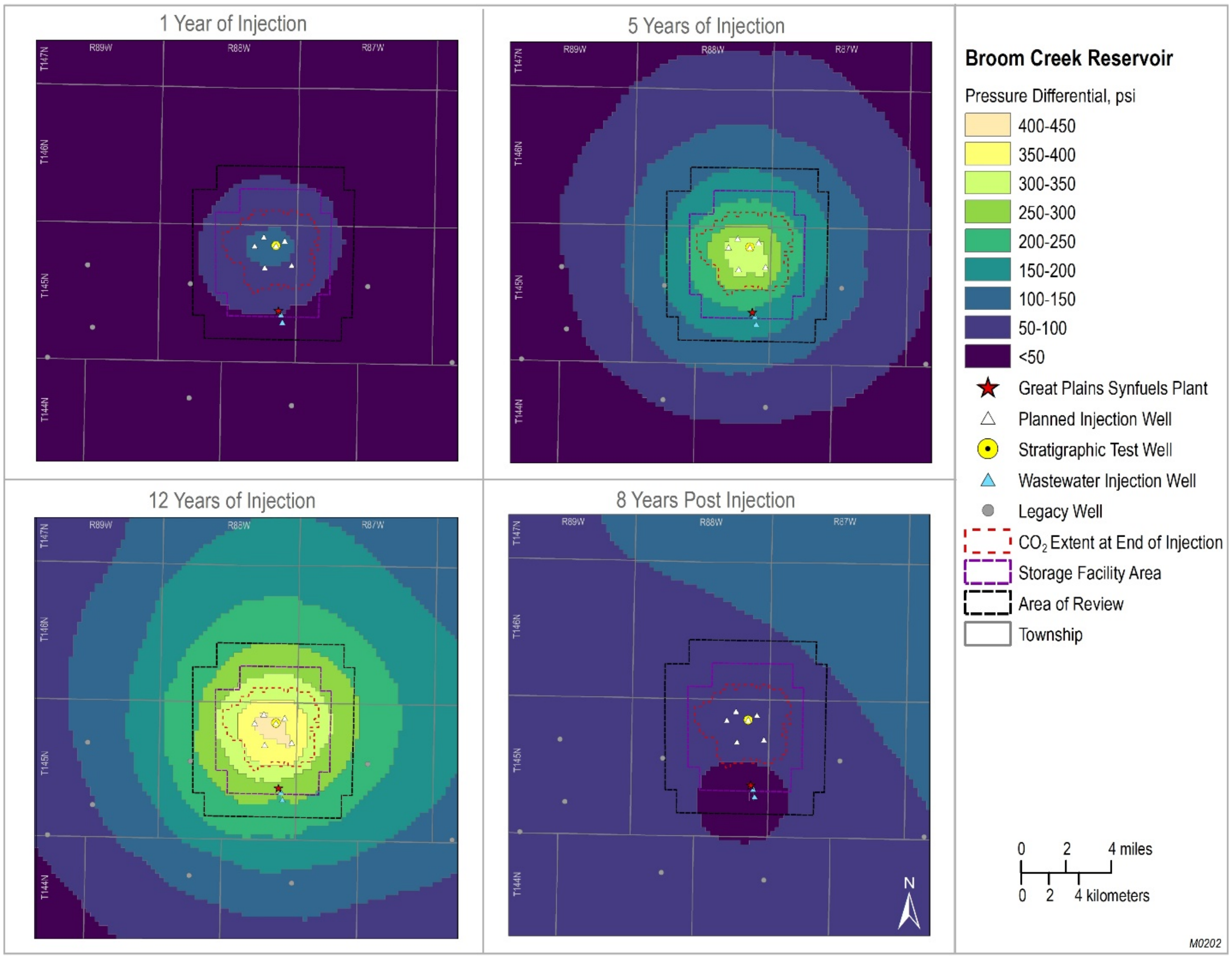


Figure 3-20. Average pressure increases within the Broom Creek Formation after 1, 5, and 12 years of simulated CO_2 injection operation as well as 8 years postinjection.

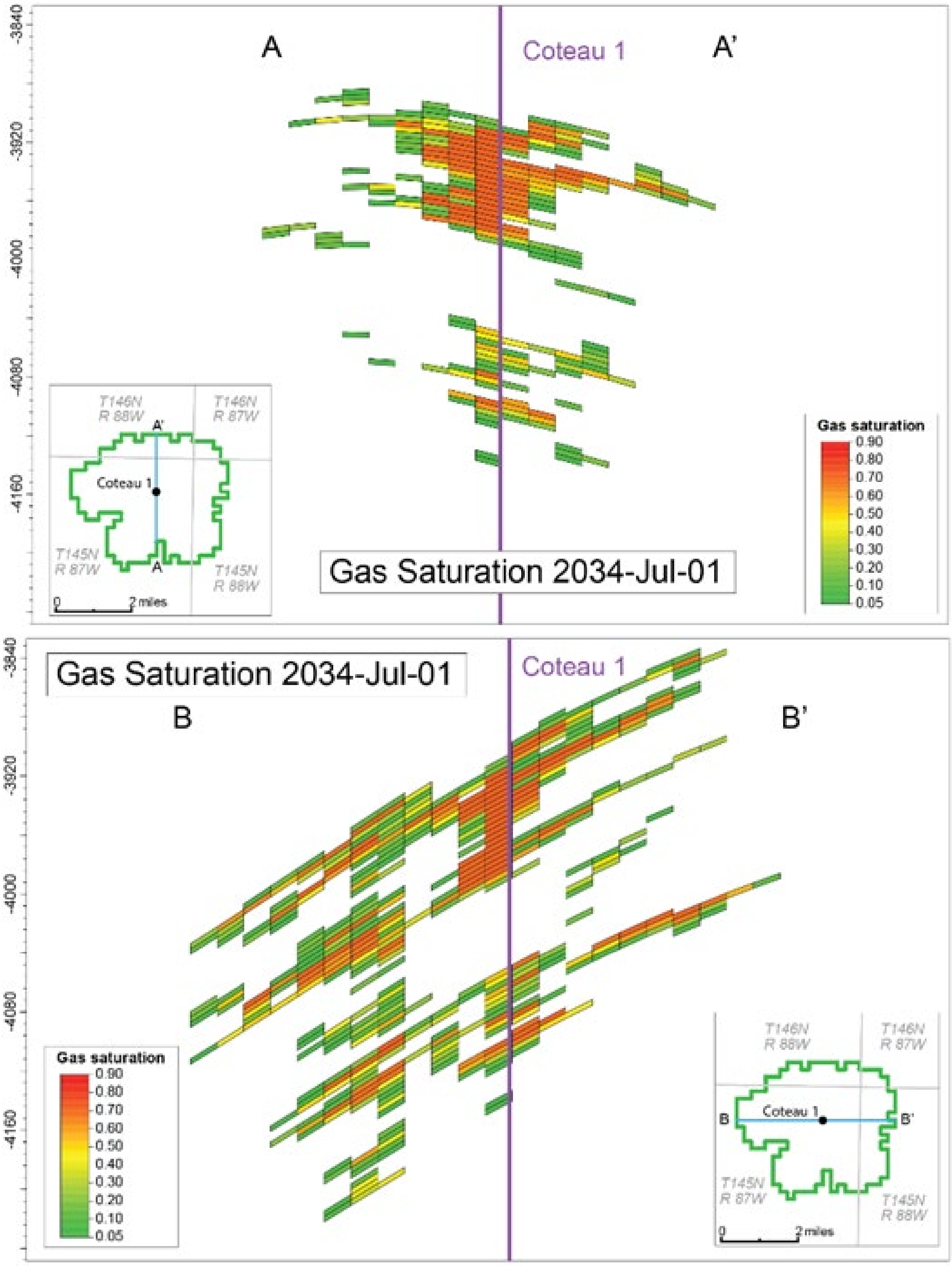


Figure 3-21. CO_2 plume cross section of Coteau 1 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

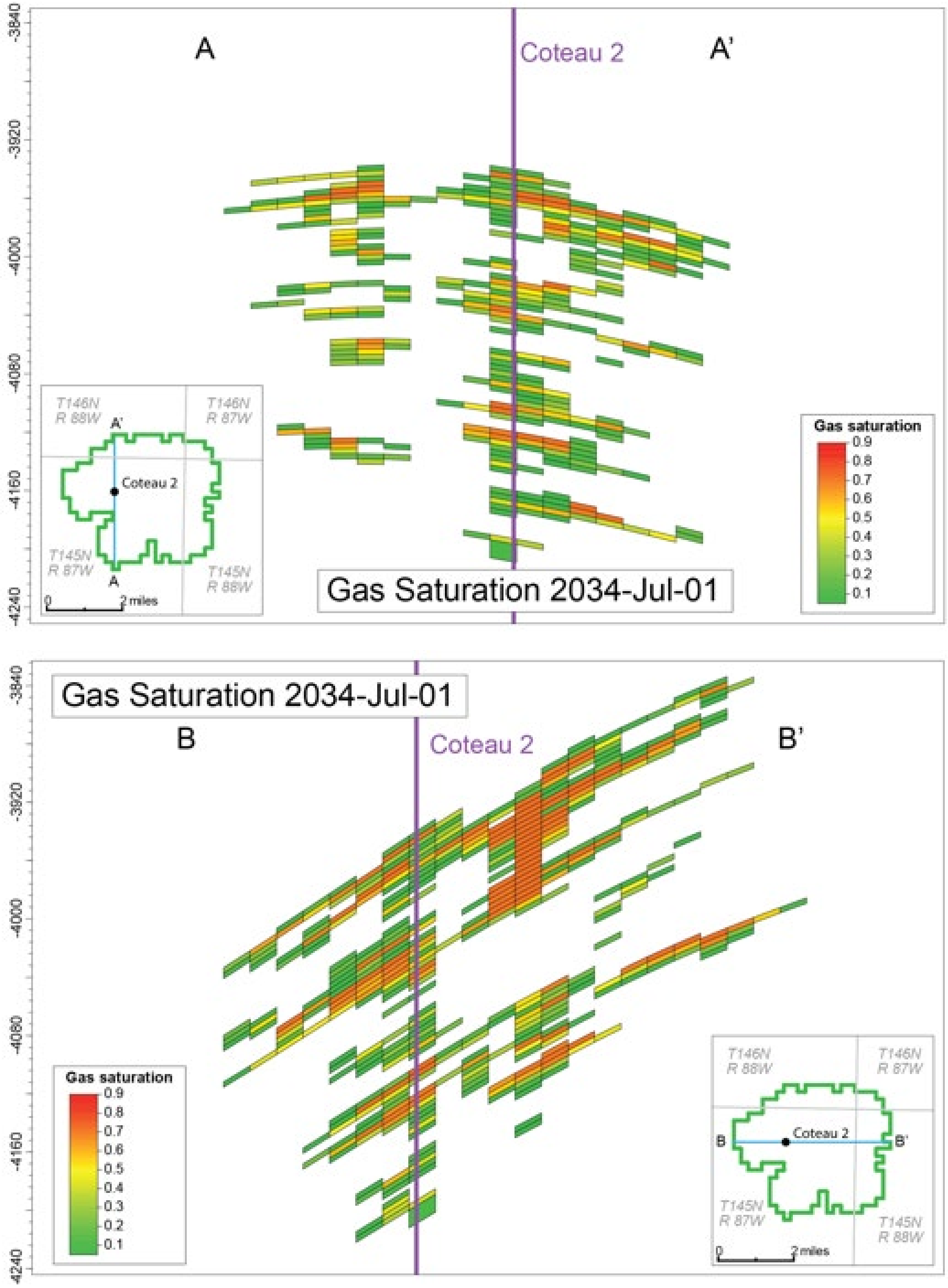


Figure 3-22. CO_2 plume cross section of Coteau 2 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

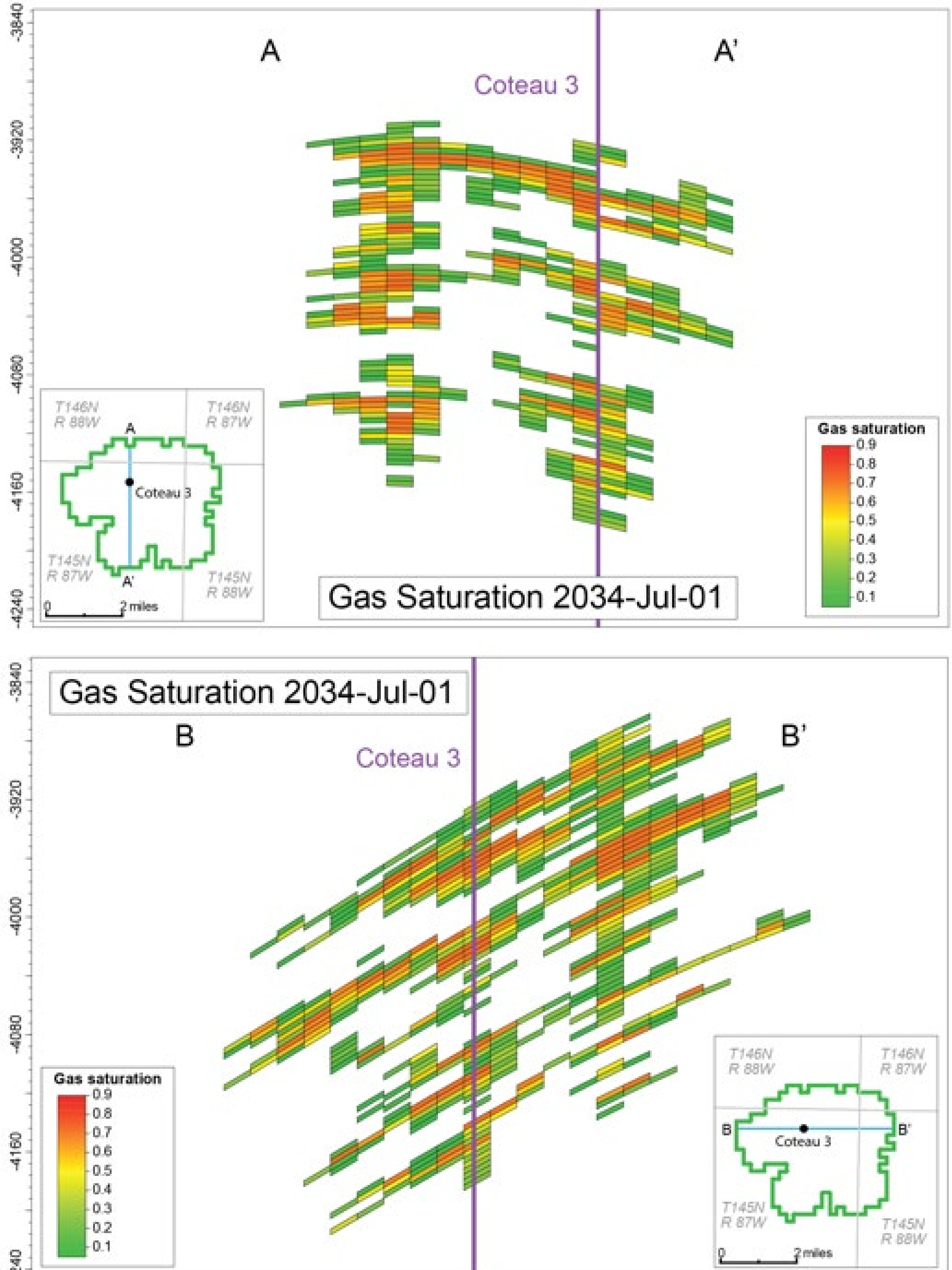


Figure 3-23. CO_2 plume cross section of Coteau 3 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

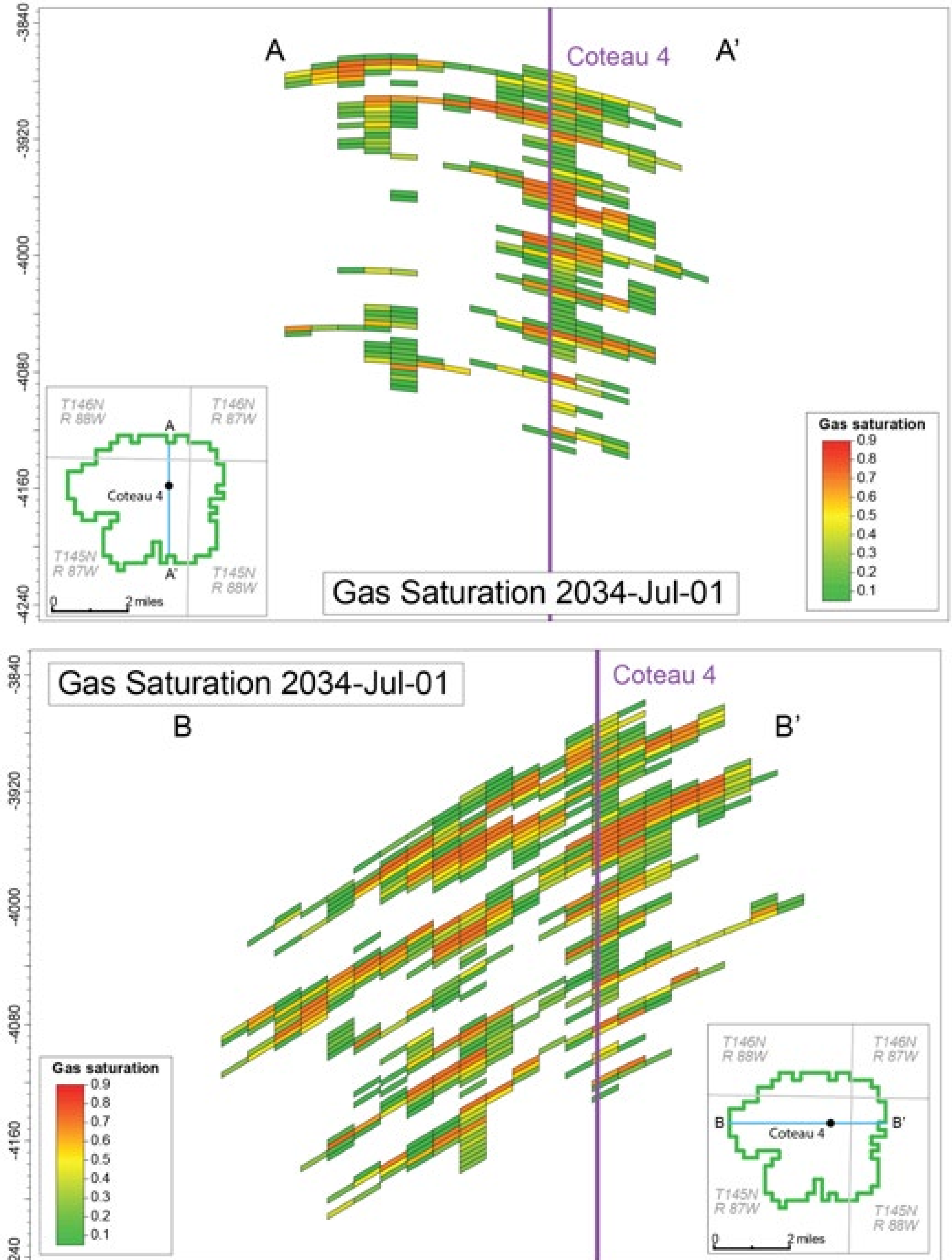


Figure 3-24. CO_2 plume cross section of Coteau 4 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

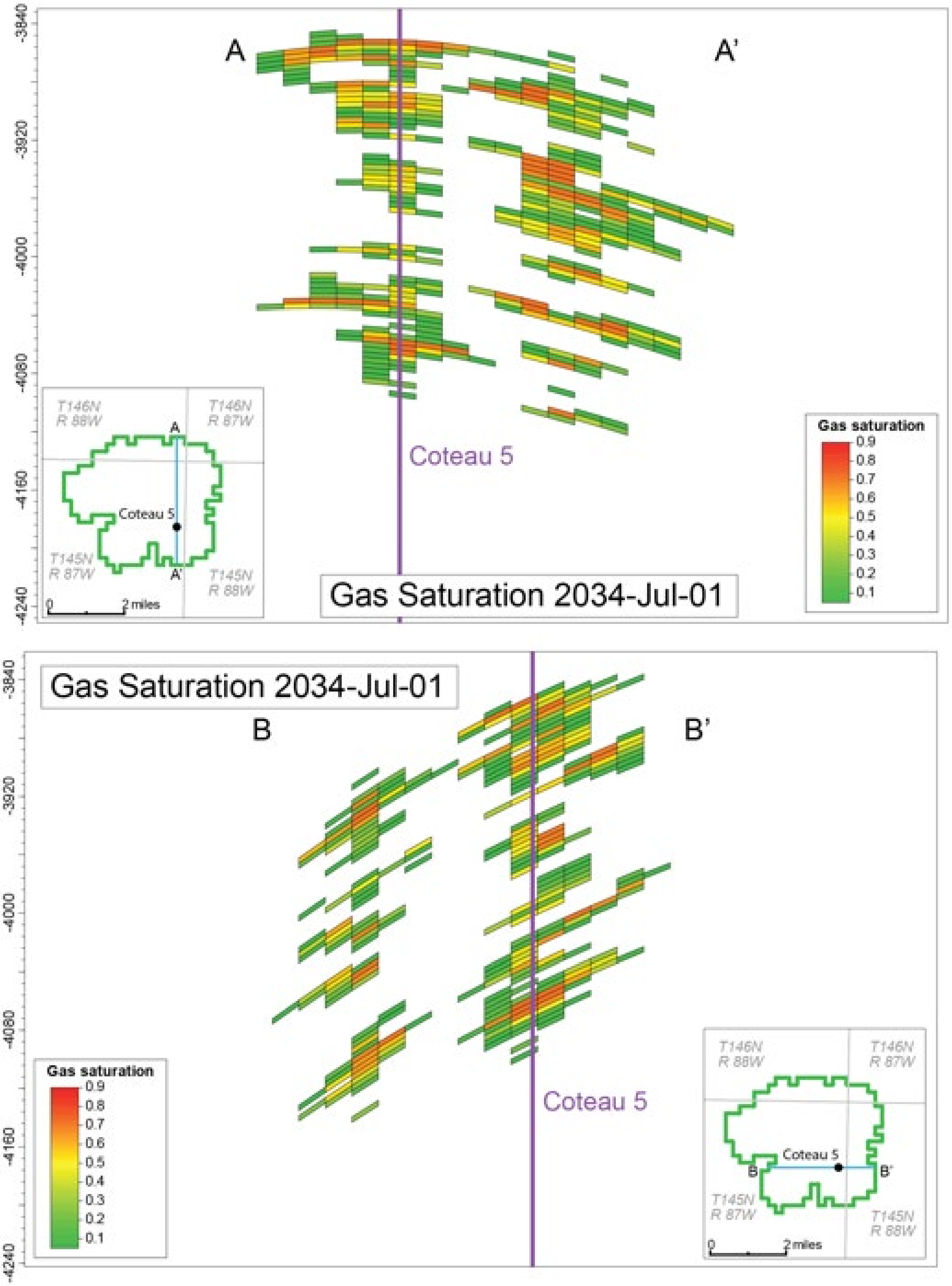


Figure 3-25. CO_2 plume cross section of Coteau 5 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

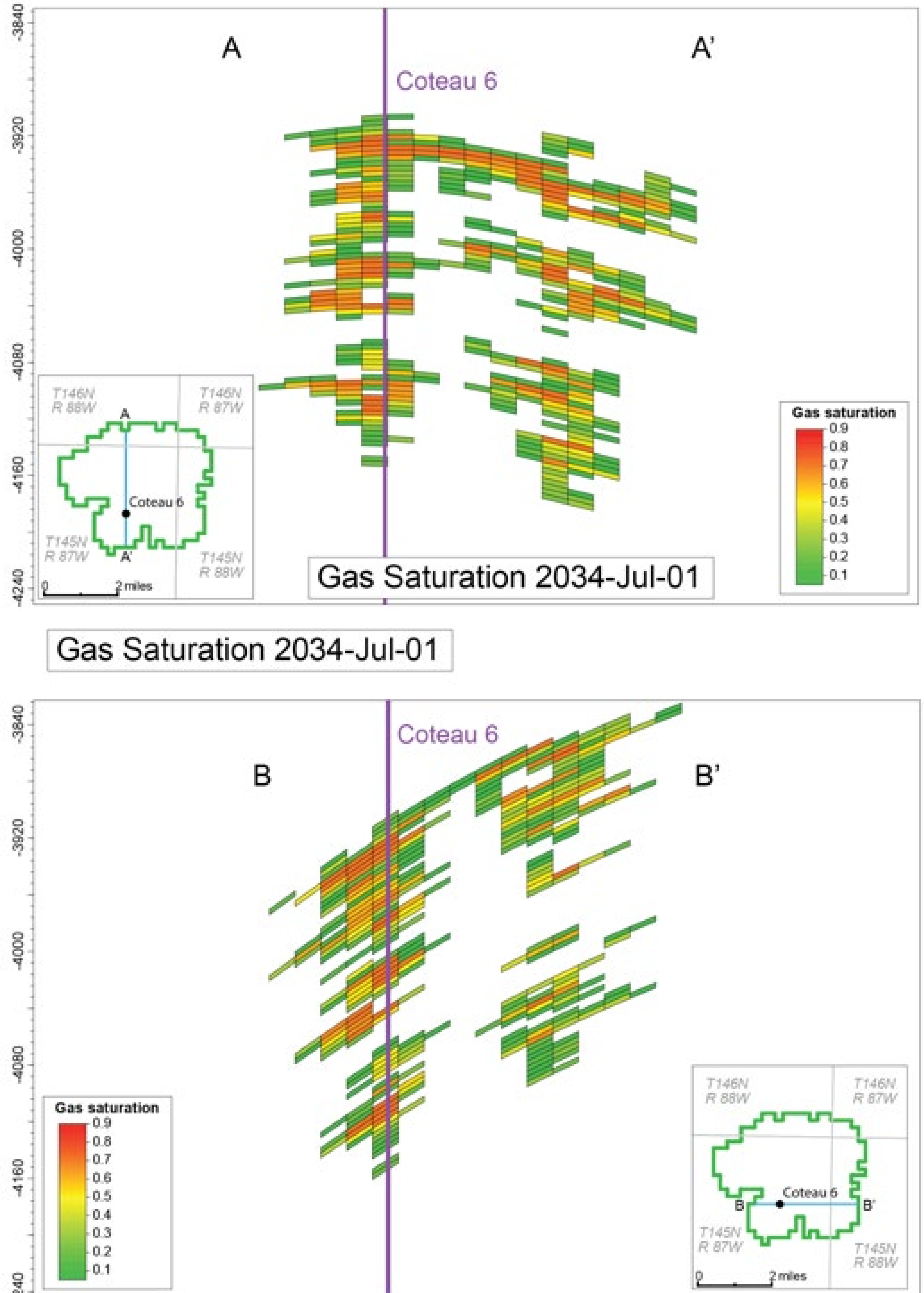


Figure 3-26. CO_2 plume cross section of Coteau 6 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

3.4.1 Maximum Surface Injection Pressure

An additional case was run to determine if the wells would ultimately be limited by maximum calculated downhole pressures of 3,754 psi for Coteau 1, 3,802 psi for Coteau 2, 3,772 psi for Coteau 3, 3,787 psi for Coteau 4, 3,776 psi for Coteau 5, and 3,786 psi for Coteau 6, Table 3-3.

The fracture propagation pressure gradient was used to calculate the maximum BHP constraints, based upon 90% of the fracture propagation pressure multiplied by the well depth at the top of the Broom Creek Formation. In this scenario, the group injection limit of 55 MMcfd from July 2022 to December 2024, 70 MMcfd from January 2025 to April 2026, and 140 MMcfd from May 2026 to July 2034, with the maximum injection rate constraint per well, was removed. Other parameters were kept the same as previously described for the additional tests.

The maximum BHPs were reached in the simulation. At the maximum BHP values, the corresponding predicted maximum wellhead injection pressure responses are shown in Figure 3-27.

In this scenario, the CO_2 injection wells were able to inject an average of 52.96 MMcfd of CO_2 per well (or 2685 tonnes/day of CO_2), with the planned 4½-in.-diameter tubing, thereby achieving a total injection volume of 64.18 MMt (1.257 Bcf) of CO_2.

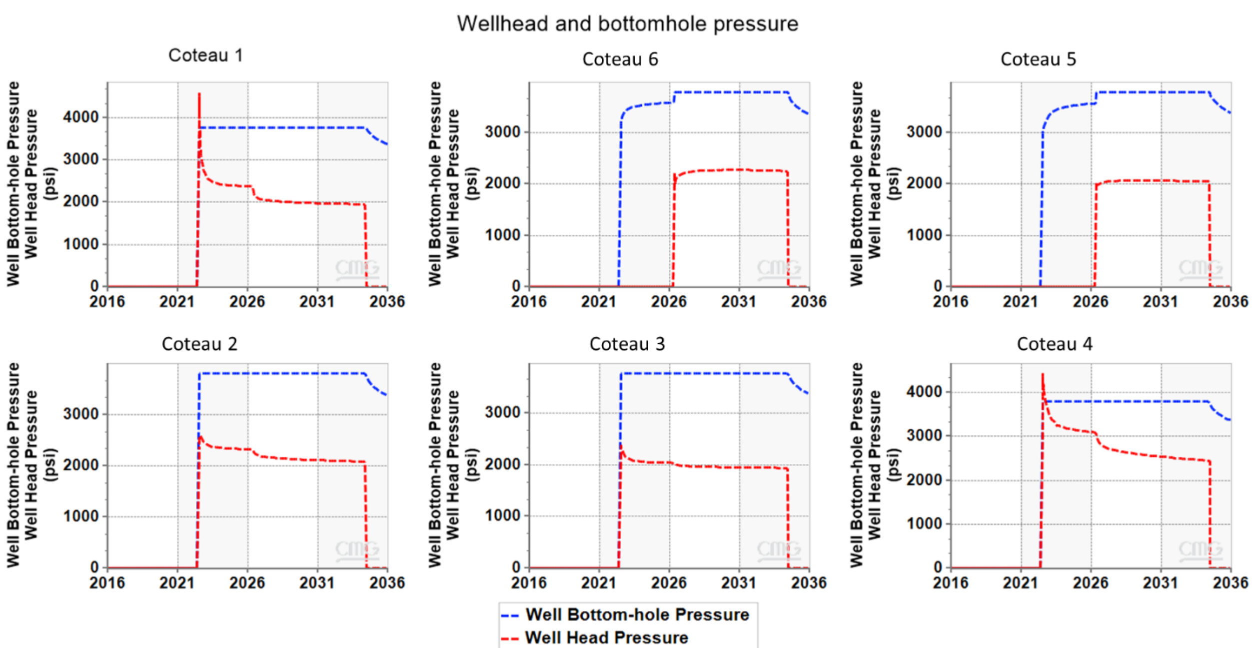


Figure 3-27. Maximum pressure responses (wellhead and bottomhole) when the wells were operated without any injection rate limits.

3.4.2 Stabilized Plume

Movement of the injected CO_2 plume is driven by the potential energy found in the buoyant force of the injected CO_2. As the plume spreads out within the reservoir and CO_2 is trapped residually through the effects of relative permeability and dissolution, the potential energy of the buoyant CO_2 is gradually lost. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized. The extent of the stabilized plume is important for determining the project's AOR and the corresponding scale and scope of the project's monitoring plans.

Plume stabilization can be visualized at the microscale as CO_2 being unable to exit its current pore space and enter the neighboring pore space, but at the macroscale, these interactions cannot be measured. Instead, plume stabilization may be estimated using the tools available to predict the CO_2 plume's extent. For the Great Plains CO_2 Project, stabilization was defined as the time when CO_2 no longer migrates to adjacent cells within the simulation model. CO_2 may still experience gradual redistribution within the plume, but the geographic extents of the plume remain unchanged.

The CO_2 plume was simulated in 5-year time steps until the rate of total areal extent change slowed to less than 0.25 square miles per 5-year time step to define the stabilized plume extent boundary and the associated buffers and boundaries (Figure 3-20). This estimate is anticipated to be regularly updated during the CO_2 storage operation as data collected from the site are used to update predictions made about the behavior of the injected CO_2.

3.5 Delineation of the Area of Review

The North Dakota Administrative Code (NDAC) defines the AOR as the region surrounding the geologic storage project where USDWs may be endangered by CO_2 injection activity (NDAC § 43-05-01-05). The primary endangerment risk is the potential for vertical migration of CO_2 and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the CO_2 plume within the storage reservoir.

However, the CO_2 plume has an associated pressure front where CO_2 injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the CO_2 plume. Therefore, the AOR encompasses both the areal extent of the CO_2 plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the CO_2 plume, AOR delineation focuses on the pressure front.

The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the Underground Injection Control (UIC) Program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure.

In this document, “storage reservoir” refers to the Broom Creek Formation (the injection zone), and the “lowest USDW” refers to the Fox Hills Formation.

3.5.1 EPA Methods 1 and 2: AOR Delineation for Class VI Wells

EPA (2013) guidance for AOR evaluation includes several computational methods for estimating the pressure buildup in the storage reservoir in response to CO_2 injection and the resultant areal extent of pressure buildup above a “critical threshold pressure” that could potentially drive higher salinity formation fluids from the storage reservoir up an open conduit to the lowest USDW. The following equations and analytical approach define the EPA methods used to delineate AOR. Each method can be applied both at a single location (e.g., the Coteau 1 stratigraphic well) using site-specific data or for each vertical stack of grid cells in a geocellular model, considering the varying stratigraphic thickness between storage reservoir and lowest USDW.

EPA (2013) Method 1 (*pressure front based on bringing the injection zone and USDW to equivalent hydraulic heads*) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW. Under Method 1, the maximum pressure increase that may be sustained in the injection zone (critical threshold pressure increase) is given by:

$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_i \qquad \text{[Eq. 1]}$$

Where:

P_u is the initial fluid pressure in the USDW (Pa).
ρ_i is the storage reservoir fluid density (mg/m^3).
g is the acceleration due to gravity (m/s^2).
z_u is the representative elevation of the USDW (m amsl).
z_i is the representative elevation of the injection zone (m amsl).
P_i is the initial pressure in the injection zone (Pa).
$\Delta P_{i,f}$ is the critical threshold pressure increase (Pa).

Equation 1 assumes that the hypothetical open borehole is perforated exclusively within the injection zone and USDW. If $\Delta P_{i,f}$ = 0, then the reservoir and USDW are in hydrostatic equilibrium; if $\Delta P_{i,f} > 0$, then the reservoir is underpressurized relative to the USDW; and if $\Delta P_{i,f}$ < 0, then the reservoir is overpressurized relative to the USDW.

In scenarios where the storage reservoir and USDW are in hydrostatic equilibrium ($\Delta P_{i,f}$ = 0), EPA Method 2 (*pressure front based on displacing fluid initially present in the borehole*) can be used to calculate the critical pressure threshold. Method 2 was originally presented by Nicot and others (2008) and Bandilla and others (2012). Method 2 calculates the critical threshold pressure increase (ΔP_c), which is the fluid pressure increase sufficient to drive formation fluids into the lowermost USDW. This ΔP_c is determined using Equations 2 and 3, assuming 1) hydrostatic conditions, 2) initially linearly densities in the borehole, and 3) constant density once the injection zone fluid is lifted to the top of the borehole (i.e., uniform density approach):

$$\Delta P_C = \frac{1}{2}\, g\, \xi\, (Z_u - Z_i)^2 \qquad \text{[Eq. 2]}$$

Where ξ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \qquad \text{[Eq. 3]}$$

Where:

ΔP_c is the critical threshold pressure increase (Pa).
g is the acceleration of gravity (m/s^2).
z_u is the elevation of the base of the lowermost USDW (m amsl).
z_i is the elevation of the top of the injections zone (m amsl).
ρ_i is the fluid density in the injection zone (kg/m^3).
ρ_u is the fluid density in the USDW (kg/m^3).

3.5.2 Risk-Based AOR Delineation

The methods described by EPA (2013) for estimating the AOR under the Class VI Rule were developed assuming that the storage reservoirs would be in hydrostatic equilibrium with overlying aquifers. However, in the state of North Dakota, and potentially elsewhere around the United States, candidate storage reservoirs are already overpressurized relative to overlying aquifers and thus subject to potential vertical formation fluid migration from the storage reservoir to the lowermost USDW even prior to the planned storage project. Consequently, applying EPA (2013) methods to these geologic situations essentially results in an infinite AOR, which makes regulatory compliance infeasible.

Several researchers have recognized the need for alternative methods for estimating the AOR for locations that are already overpressurized relative to overlying aquifers. For example, Birkholzer and others (2014) described the unnecessary conservatism in EPA's definition of critical pressure, which could lead to a heavy burden on storage facility permit applicants. As an alternative, Burton-Kelly and others (2021) proposed a risk-based reinterpretation of this framework that would allow for a reduction in the AOR while ensuring protection of drinking water resources.

A computational framework for estimating a risk-based AOR was proposed by Oldenburg and others (2014, 2016), who compared formation fluid leakage through a hypothetical open flow path in the baseline scenario (no CO_2 injection) to the incrementally larger leakage that would occur in the CO_2 injection case. The modeling for the risk-based AOR used semianalytical solutions to single-phase flow equations to model reservoir pressurization and vertical migration through leaky wells. These semianalytical solutions were extensions of earlier work for formation fluid leakage through abandoned wellbores by Raven and others (1990) and Avci (1994), which were creatively solved, coded, and compiled in FORTRAN under the name, ASLMA (Analytical Solution for Leakage in Multilayered Aquifers) and extensively described by Cihan and others (2011, 2012) (hereafter "ASLMA Model").

Recently, White and others (2020) outlined a similar risk-based approach for evaluating the AOR using the National Risk Assessment Partnership (NRAP) Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS). However, the NRAP-IAM-CS and subsequent open-sourced version (NRAP-Open-IAM) are constrained to the assumption that the storage reservoir is in hydrostatic equilibrium with overlying aquifers and, therefore, may not accurately estimate the AOR for storage projects located in regions where the storage reservoir is overpressurized relative to overlying aquifers.

Building a geologic model in a commercial-grade software platform (like Schlumberger Petrel) and running fluid flow simulations using numerical reservoir simulation in a commercial-grade software platform (like CMG's compositional simulator, GEM) provide the "gold standard" for estimating pressure buildup in response to CO_2 injection (e.g., Bosshart and others, 2018). However, these numerical reservoir simulations are typically limited to the storage reservoir and primary seal formation (cap rock) and do not include the geologic units overlying the cap rock because of the computational burden of conducting such a complex simulation. In addition, geologic modeling of the overlying units may add a substantial amount of time and effort during prefeasibility-phase projects that is unwarranted given the amount of uncertainty that may be present if only few nearby wells can be used for characterization activities. Earlier studies (e.g., Nicot and others, 2008; Birkholzer and others, 2009; Bandilla and others, 2012; Cihan and others, 2011, 2012) have shown that far-field fluid pressure changes outside of the CO_2 plume domain can be reasonably well described by a single-phase flow calculation by representing CO_2 injection as an equivalent-volume injection of brine (Oldenburg and others, 2014).

The semianalytical solutions embedded within the ASLMA Model have been shown to compare with the numerical model, TOUGH2-ECO2-N, and provided accurate results for pressures beyond the CO_2 plume zone (Birkholzer and others, 2009; Cihan and others, 2011, 2012). Therefore, the proposed workflow for delineating a risk-based AOR uses the ASLMA Model to examine pressure buildup in the storage reservoir and resultant effects of this buildup on the vertical migration of formation fluid via (single) hypothetical leaky wellbores located at progressively greater distances from the injection well (Figure 3-28).

An important distinction between EPA Methods 1 and 2, which both calculate a critical pressure threshold (either $\Delta P_{i,f}$ for Method 1 or ΔP_c for Method 2) and the risk-based AOR approach is that the risk-based approach 1) calculates and maps the potential incremental flow of formation fluids from the storage reservoir to the USDW that could occur and then 2) delineates the areal extent beyond which no significant leakage would occur. Therefore, the region beyond which no significant leakage would occur does not present an endangerment to the USDW; hence, the region inside of this areal extent is the risk-based AOR.

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). Inputs, assumptions, and results are discussed in the current document.

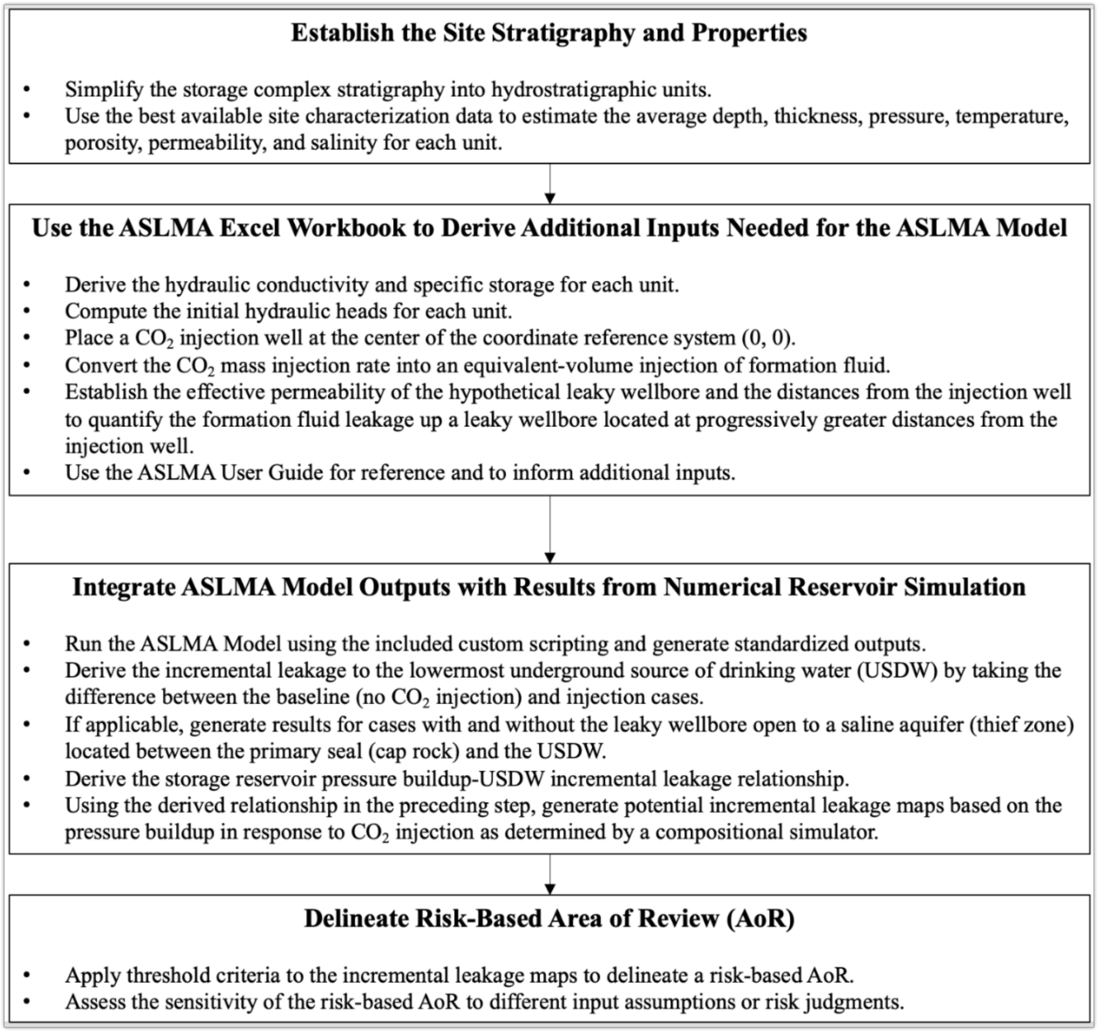


Figure 3-28. Workflow for delineating a risk-based AOR for a storage facility permit (modified from Burton-Kelly and others, 2021).

3.5.3 Critical Threshold Pressure Increase Estimation

For the purposes of delineating AOR for the Great Plains CO_2 Project study area, constant fluid densities for the lowermost USDW (Fox Hills Formation) and injection zone (Broom Creek Formation) were used in the calculations. A density of 1001 kg/m^3 was used to represent the USDW fluids (ρ_u), and a density of 1017 kg/m^3 was used to represent the injection zone fluids (ρ_i), which is estimated based on the in situ brine salinity, temperature, and pressure as measured with an MDT tool from the Coteau 1 stratigraphic test well.

Application of EPA Method 1 (Equation 1) using site-specific data from the Coteau 1 well shows that the injection zone in the Great Plains CO_2 Project area is overpressurized with respect to the lowest USDW (i.e., Method 1 $\Delta P_{i,f} < 0$). An example of the EPA Method 1 application showing negative $\Delta P_{i,f}$ (relative overpressure) is given in Table 3-7, with similar results when applied to each column of the grid cells in the Broom Creek Formation simulation model.

Table 3-7. EPA Method 1 Critical Threshold Pressure Increase Calculated at the Coteau 1 Wellbore Location Using MDT Data

Depth*		P_i Injection Zone Pressure	P_u USDW Pressure	ρ_i Injection Zone Density	Z_u USDW Base Elevation	Z_i Reservoir Elevation	$\Delta P_{i,f}$ Threshold Pressure Increase	
ft	m	MPa	MPa	kg/m^3	m amsl	m amsl	MPa	psi
5,975	1,811	20.25	5.12	1,017	102	−1,207	−2.08	−302

* Ground surface elevation is 608 m above mean sea level.

In accordance with EPA (2013) guidance, the combination of a) a Method 1 negative $\Delta P_{i,f}$ value across the Great Plains CO_2 Project area and b) lack of evidence for hydrostatic equilibrium between the reservoir and the USDW (i.e., Method 2 does not apply) indicates that a risk-based approach to AOR delineation may be pursued.

3.5.4 Risk-Based AOR Calculations

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). The inputs, assumptions, and results discussed here provide the necessary details for reproducing and verifying the results. A macro-enabled Microsoft Excel file was used to define the inputs and calculations that were employed used in the method (hereafter "ASLMA Workbook").

3.5.4.1 Initial Hydraulic Heads

The original ASLMA Model (Cihan and others, 2011) initially assumed hydrostatic pressure distributions in the entire system. The current work uses a modified version of the ASLMA Model to simulate pressure perturbations and leakage rates when there are initial head differences in the aquifers (Oldenburg and others, 2014). The initial hydraulic heads are calculated assuming an equivalent freshwater head based on the unit-specific elevations and pressures. The equivalent freshwater heads are entered into the ASLMA Model and establish the initial pressure conditions for the storage complex prior to CO_2 injection.

For example, the initial reference case equivalent freshwater heads for the storage reservoir (Aquifer 1), potential thief zone (Aquifer 2), and USDW (Aquifer 3) are 832, 613, and 623 m, respectively, which illustrate the state of overpressure in the storage complex, as Aquifer 1 has a greater initial hydraulic head than Aquifers 2 and 3. Therefore, the storage complex requires different treatment than the default AOR calculations described by EPA (2013). Details on the calculations of initial hydraulic head are provided in Burton-Kelly and others (2021).

3.5.4.2 CO_2 Injection Parameters

The ASLMA Model for the Great Plains CO_2 Project used a Broom Creek CO_2 injection rate that matched the simulation scenario. A single injector is placed at the center of the ASLMA model grid at an x,y-location of (0,0) in the coordinate reference system. The ASLMA Model requires the CO_2 injection rate to be converted into an equivalent-volume injection of formation fluid in units of cubic meters per day. Microsoft Excel VBA functions were used to estimate the CO_2 density from the storage reservoir pressure and temperature, which resulted in an estimated density of 672 kg/m^3. The CO_2 mass injection rate and CO_2 density are then used to derive the daily equivalent-volume injection rate of approximately 4,333 m^3 per day for 2.5 years followed by 5,515 m^3 per day for 1.3 years, followed by 11,030 m^3 per day for 8.2 years.

3.5.4.3 Hypothetical Leaky Wellbore

In the Great Plains CO_2 Project area, few wellbores are known to exist that penetrate the primary seal of the Broom Creek storage reservoir. However, for heuristic, "what-if" scenario modeling, which is needed to generate the data for delineating a risk-based AOR, a single hypothetical leaky wellbore is inserted into the ASLMA Model at 1, 2, …, 100 km from the CO_2 injection well. The pressure buildup in the storage reservoir at each distance, along with the recorded cumulative volume of formation fluid vertically migrating through the leaky wellbore from the storage reservoir to the USDW (i.e., from Aquifer 1 to Aquifer 3) throughout the 12-year injection period, provides the data set needed to derive the risk-based AOR.

Published ranges for the effective permeability of a leaky wellbore (Figure 3-27) have included an "open wellbore" with an effective permeability as high as 10^{-5} m^2 (10^{10} mD) to values more representative of leakage through a wellbore annulus of 10^{-12} to 10^{-10} m^2 (10^3 to 10^5 mD) (Watson and Bachu, 2008, 2009; Celia and others, 2011). Carey (2017) provides probability distributions for the effective permeability of potentially leaking wells at CO_2 storage sites and estimated a wide range from 10^{-20} to 10^{-10} m^2 (10^{-5} to 10^5 mD). For the Great Plains CO_2 Project Broom Creek ASLMA Model, the effective permeability of the leaky wellbore is set to 10^{-16} m^2 (0.1 mD), which is a relatively conservative (highly permeable) value near the top of the published range for the effective permeability of potentially leaking wells at CO_2 storage sites (Figure 3-29).

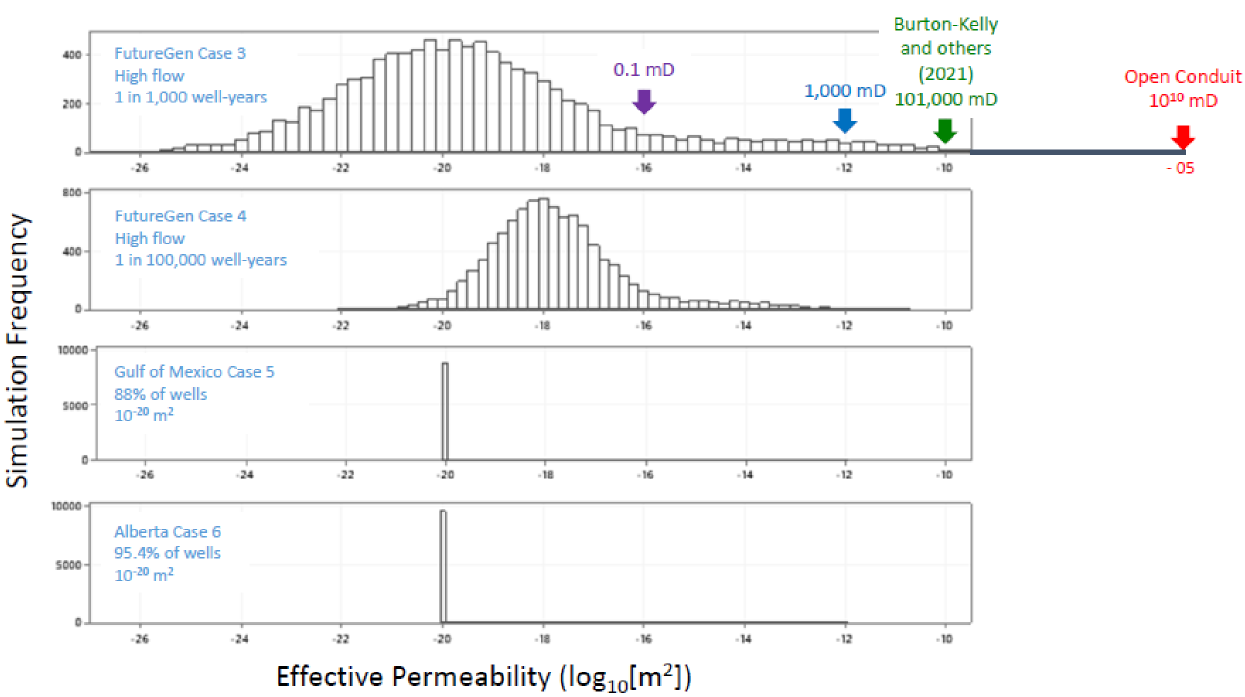


Figure 3-29. Histograms describing the expected frequency of leaky wellbore effective permeabilities under different scenarios. The ASLMA model used for AOR delineation used a value of approximately 0.1 mD. Constructed from data presented by Carey (2017).

The current work uses the ASLMA Model Type 1 feature (focused leakage only) for the nominal model response, which makes the conservative assumption that the aquitards are impermeable. This assumption prevents the pressure from diffusing into the overlying aquitards, resulting in a greater pressure buildup in the storage reservoir and a commensurately greater amount of formation fluid vertically migrating from the storage reservoir through the leaky wellbore. The conservative assumption of Model Type 1 rather than Model Type 3 (coupled focused and diffuse leakage) provides an added level of protection to the delineation of a risk-based AOR by projecting a larger pressure buildup in the storage reservoir than a scenario in which pressure is allowed to dissipate through the upper seal and, therefore, a greater leakage of formation fluid up the leaky wellbore.

3.5.4.4 Saline Aquifer Thief Zone

As shown in Table 3-7, a saline aquifer (Aquifer 2, Inyan Kara Formation) exists between the primary seal above the storage reservoir and USDW (Aquifer 3, Fox Hills Formation). Formation fluid migrating up a leaky wellbore that is open to Aquifer 2 will preferentially flow into Aquifer 2, and the continued flow up the wellbore and into the USDW will be reduced. Therefore, the presence of Aquifer 2 may act as a thief zone and reduces the potential for formation fluid impacts to the groundwater.

The thief zone phenomenon was described by Nordbotten and others (2004) as an “elevator model” by analogy with an elevator full of people on the main floor, who then get off at various floors as the elevator moves up, such that only very few people ride all the way to the top floor. The term “thief zone” is also used in the oil and gas industry to describe a formation encountered during drilling into which circulating fluids can be lost. Models with and without opening the leaky wellbore to Aquifer 2 (Inyan Kara Formation) were run and evaluated to quantify the effect of a thief zone on the risk-based AOR.

3.5.4.5 Aquifer- and Aquitard-Derived Properties

The ASLMA Model assumes homogeneous properties within each hydrostratigraphic unit (Table 3-7). For each unit shown in Table 3-7, pressure, temperature, porosity, permeability, and salinity are used to derive two key inputs for the ASLMA Model: hydraulic conductivity (HCON) and specific storage (SS). Average porosity and permeability values were derived as follows: Broom Creek, from distributed properties in the geologic model; Inyan Kara, from Coteau 1 well log data; and Fox Hills, from regional well log data. Porosity is represented as an arithmetic mean and permeability as a geometric mean values within each hydrostratigraphic unit (excluding non-sandstone rock types).

Visual Basic for Applications (VBA) functions included in the ASLMA Workbook are used to estimate the formation fluid density and viscosity from the aquifer or aquitard pressure, temperature, and salinity inputs, which are then used to estimate the HCON and SS. The estimated reference case HCON for the storage reservoir (Aquifer 1), thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-8. Details about the HCON and SS derivations are provided in Supporting Information for Burton-Kelly and others (2021).

Table 3-8. Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex

Hydrostratigraphic Unit	Depth to Top,* m	Thickness, m	Pressure, MPa	Temperature, °C	Salinity, ppm	Porosity, %	Permeability, mD	Permeability, m^2	HCON, m/d	Specific Storage, m^{-1}	Equivalent Freshwater Head, m
Overlying Units to Ground Surface (not directly modeled)	0	420									
Aquifer 3 (USDW–Fox Hills Fm)	420	89	4.7	19.6	1,800	34.4	280	2.76E-13	2.32E-01	7.82E-06	623
Aquitard 2 (Pierre Fm-Inyan Kara Fm)	509	849	9.3	33.3	22,800	10	0.1	9.87E-17	1.09E-04	1.25E-05	612
Aquifer 2 (Thief Zone–Inyan Kara Fm)	1,359	116	14.0	57.7	22,800	20.1	41.8	4.13E-14	6.92E-02	8.27E-06	634
Aquitard 1 (Swift—Broom Creek Fm) (primary upper seal)	1,474	355	16.4	54.3	42,800	10	0.1	9.87E-17	1.53E-04	1.28E-09	597
Aquifer 1 (Storage Reservoir – Broom Creek Fm)	1,829	77	20.8	70.8	42,800	14.5	246.7	2.44E-14	4.75E-01	8.46E-06	832

* Ground surface elevation 614 m amsl.

3.5.5 Risk-Based AOR Results

3.5.5.1 Relating Pressure Buildup to Incremental Leakage with ASLMA Model and Compositional Simulation

Figure 3-28 shows the relationship between the maximum pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 (USDW) for scenarios with and without the leaky wellbore open to Aquifer 2 (thief zone). In the case where the leaky wellbore is closed to Aquifer 2, there is no incremental leakage to Aquifer 2. The curvilinear relationship between pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 is used to predict the incremental leakage from the pressure buildup map produced by the compositional simulation of the geocellular model. The average simulated pressure buildup in the reservoir is represented by a raster (grid) map of pressure buildup values. For each raster value (grid cell map location), the relationship between pressure buildup and incremental leakage (Figure 3-30) is used to predict incremental leakage using a linear interpolation between the points making up the curve. The cumulative leakage potential from Aquifer 1 to Aquifer 3 along a hypothetical leaky wellbore without injection occurring (i.e., leakage due to natural overpressure) and no thief zone is estimated to be 0.01 m^3 over 20 years.

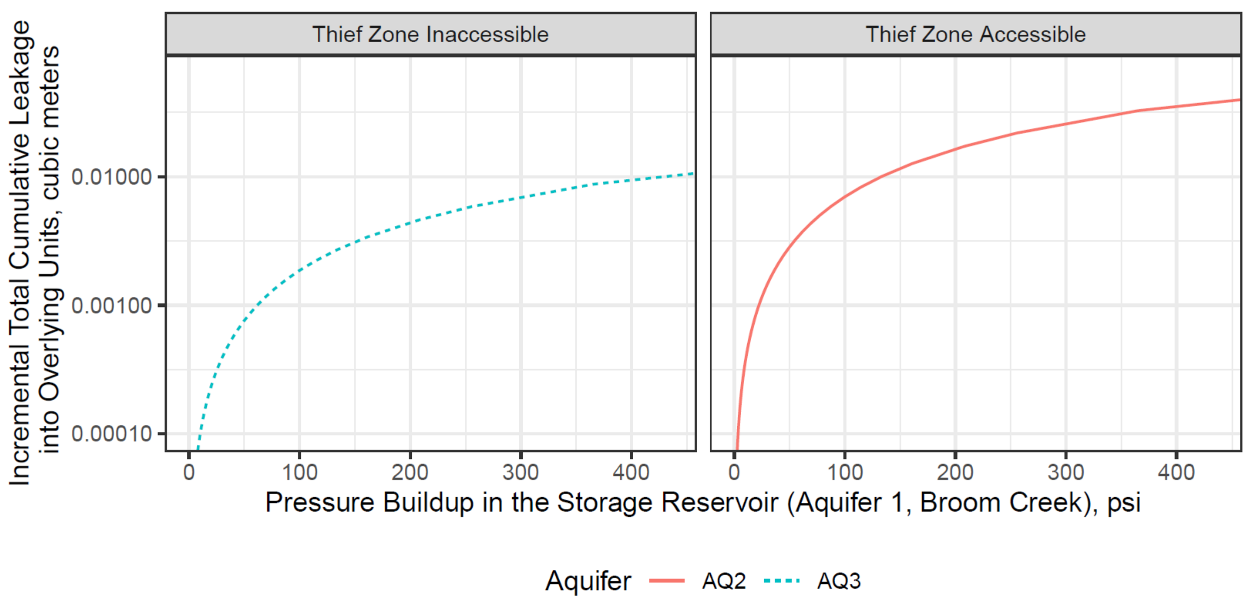


Figure 3-30. Relationship between pressure buildup (x-axis, psi) in the storage reservoir (Aquifer 1, Broom Creek) and incremental total cumulative leakage (y-axis, m^3) into Aquifer 2 (thief zone, Inyan Kara, red solid line) and Aquifer 3 (USDW, Fox Hills, dashed blue line). In the left-hand scenario, the leaky wellbore is closed to Aquifer 2 (Inyan Kara), so all flow is from the storage reservoir to the USDW. In the right-hand scenario, the leaky wellbore is open to Aquifer 2 (Inyan Kara), so the vast majority of flow is from the storage reservoir to the thief zone, and the curve showing flow into the USDW is not visible on this plot.

3.5.5.2 Incremental Leakage Maps and AOR Delineation

The pressure buildup-incremental leakage relationship, shown in Figure 3-28 results in the incremental leakage maps shown in Figure 3-31 which show the estimated total cumulative incremental leakage potential from a hypothetical leaky well into Aquifer 3 (USDW) over the entire 12-year period if the hypothetical leaky wellbore is not open to the thief zone.

The final step of the risk-based AOR workflow is to apply a threshold criterion to the incremental leakage maps to delineate a risk-based AOR. For the Broom Creek Formation injection at the Great Plains CO_2 Project site, a threshold of 1 m^3 of potential incremental flow into the Fox Hills Formation USDW along a hypothetical leaky wellbore over the 12-year injection period is established. A value of 1 m^3 is the lowest meaningful value that can be produced by the ASLMA Model; although the model can return smaller values, they likely represent statistical noise. This potential incremental flow threshold is greater than all calculated potential incremental flow values described by the curve in Figure 3-30. The maximum vertically averaged storage reservoir change in pressure at the end of the simulated injection period was 437 psi in a grid cell intersected by the injection well, which corresponds to less than 0.01 m^3 of flow over 12 years. This pressure is below the potential incremental flow threshold of 1 m^3. Therefore, the storage reservoir pressure buildup is not a deciding factor in determining the AOR extent.

The assumptions and calculations used to determine the risk-based AOR at the Great Plains CO_2 Project site incorporate at least four safety factors for the protection of groundwater resources. If the ASLMA model has resulted in an underestimation of the amount of potential leakage over the injection period, such underestimation is likely to be mitigated by:

- The statistical overestimation of hypothetical leaky wellbore permeability compared to known and estimated values in the literature—A more statistically likely hypothetical leaky wellbore permeability would be lower and allow less flow into the USDW.

- The lack of communication between the hypothetical leaky wellbore and Inyan Kara Formation, which would act as a thief zone—A real leaky wellbore would likely communicate with the Inyan Kara Formation, which would receive much, if not all, of the brine leaked from the storage reservoir.

- The low density of known legacy wellbores in the Great Plains CO_2 Project area—CO_2 injection is proposed to occur in an area with few available leakage pathways.

- The continued overpressurized nature of the Broom Creek Formation with respect to overlying saline aquifers—over relatively short (e.g., 50-year) timescales, overpressurized aquifers with leakage pathways would demonstrate a change in upward flow rate and corresponding pressure (Oldenburg and others, 2016).

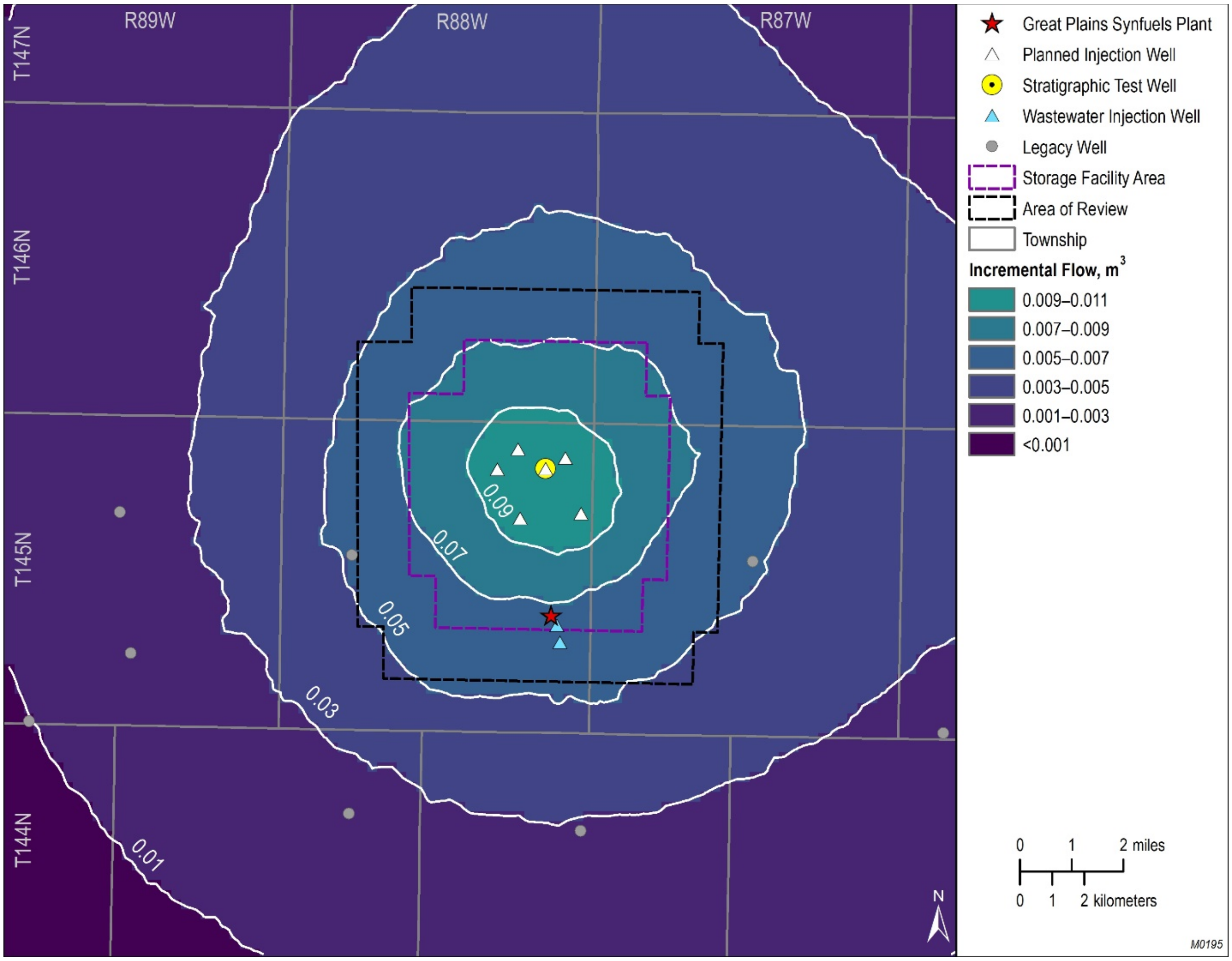


Figure 3-31. Incremental leakage maps at the end of 12 years of CO_2 injection for the scenario where the hypothetical leaky wellbore is closed to Aquifer 2 (thief zone).

Results of the risk-based method detailed above generate a minimum AOR extent which is equivalent to the storage facility area plus a 1-mile buffer. Within the AOR, the pressure increase is not expected to be large enough to cause incremental flow of more than 1 m^3 into the USDW over the injection period (Figure 3-32). As shown, the AOR is depicted by the gray shaded area, which includes the storage facility area. Figure 3-33 illustrates the land use within the AOR.

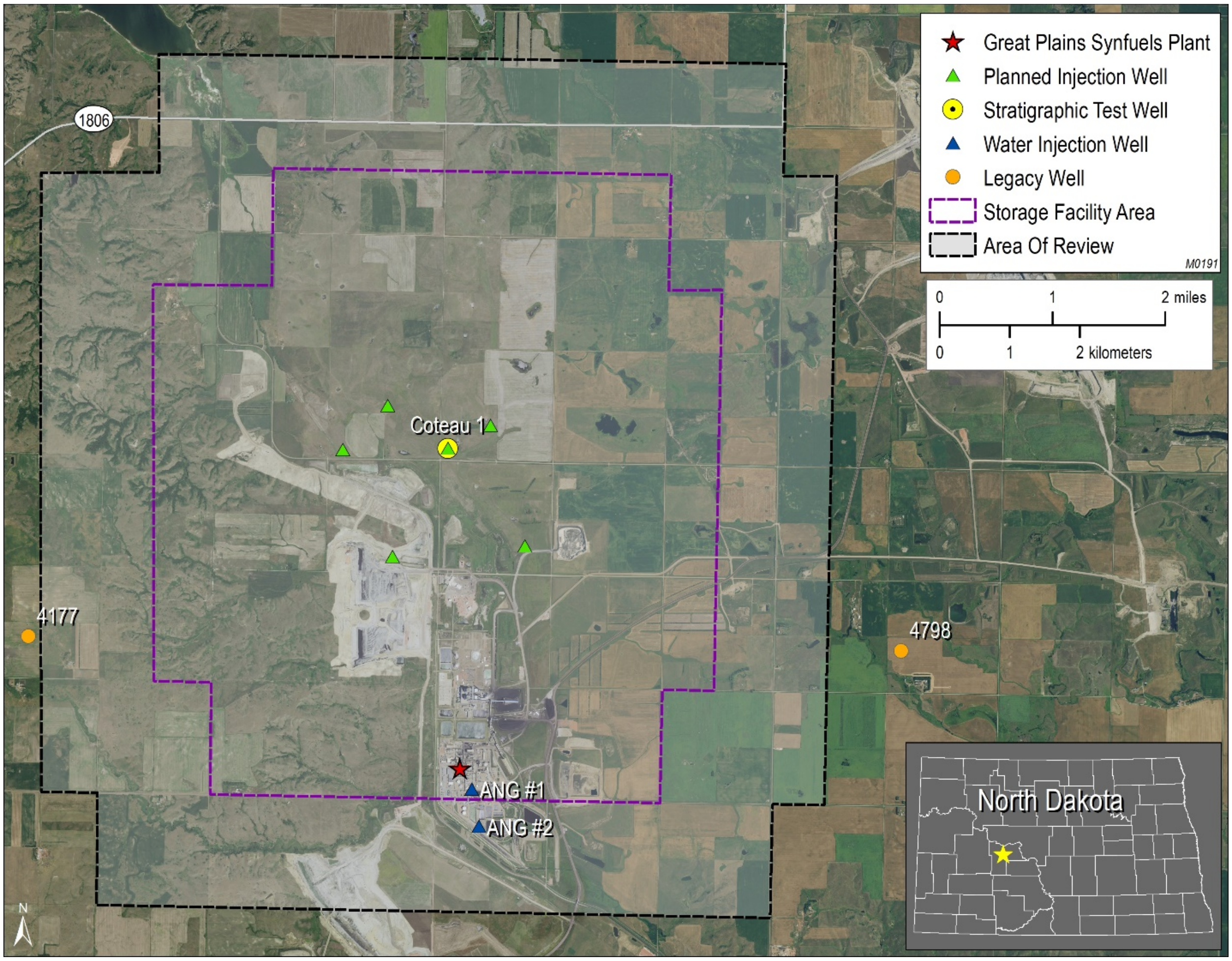


Figure 3-32. Final AOR estimations of the Great Plains CO_2 Project storage facility area in relation to nearby legacy wells. Shown is the storage facility area (purple boundary and shaded area) and area of review (black boundary and shaded area). Orange circles represent nearby legacy wells near the storage facility area.

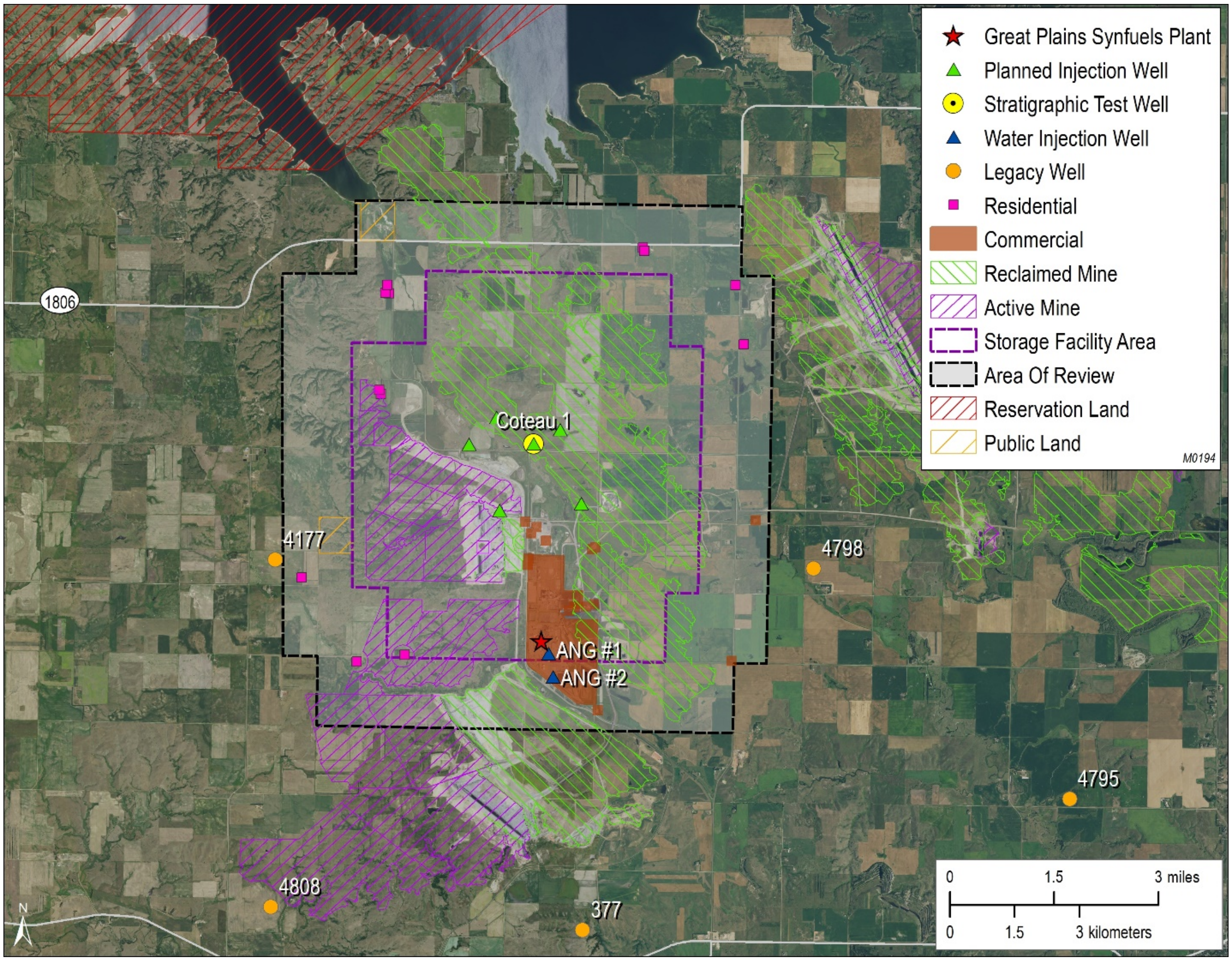


Figure 3-33. Land use in and around the AOR of the Great Plains CO_2 Project storage facility.

3.6 References

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4.0 AREA OF REVIEW

4.0 AREA OF REVIEW

4.1 Area of Review Delineation

4.1.1 Written Description

North Dakota geologic storage of CO_2 regulations require that each storage facility permit delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO_2 plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the Coteau 1 well (NDIC File No. 38379) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-7]).

Section 3 includes a detailed discussion on the computational modeling and simulations (e.g., storage facility area, pressure front, AOR boundary, etc.), assumptions, and justification used to delineate the AOR and method for delineation of the AOR.

NDAC § 43-05-01-05 subsection 1b(3) requires, "A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 4-1), the resulting AOR for the Great Plains CO_2 Sequestration Project is delineated as being 1 mile from the storage facility permit (SFP) boundary. This extent ensures compliance with existing state regulations.

All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 4-2 through 4-5) by a professional engineer pursuant to NDAC § 43-05-01-05 subsection 1b(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected CO_2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 through 4-6 and Figures 4-6 through 4-9).

An extensive geologic and hydrogeologic characterization performed by a team of geologists from the EERC resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.

This section of the SFP application is accompanied by maps and tables that include information required and in accordance with NDAC § 43-05-01-05 subsections 1(a) and 1(b) and 43-05-01-05.1 subsection 2, such as the storage facility area, location of any proposed injection wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05 subsections 1a and 1b(3) and 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AOR boundary were identified in Table 4-1.

4.1.2 Supporting Maps

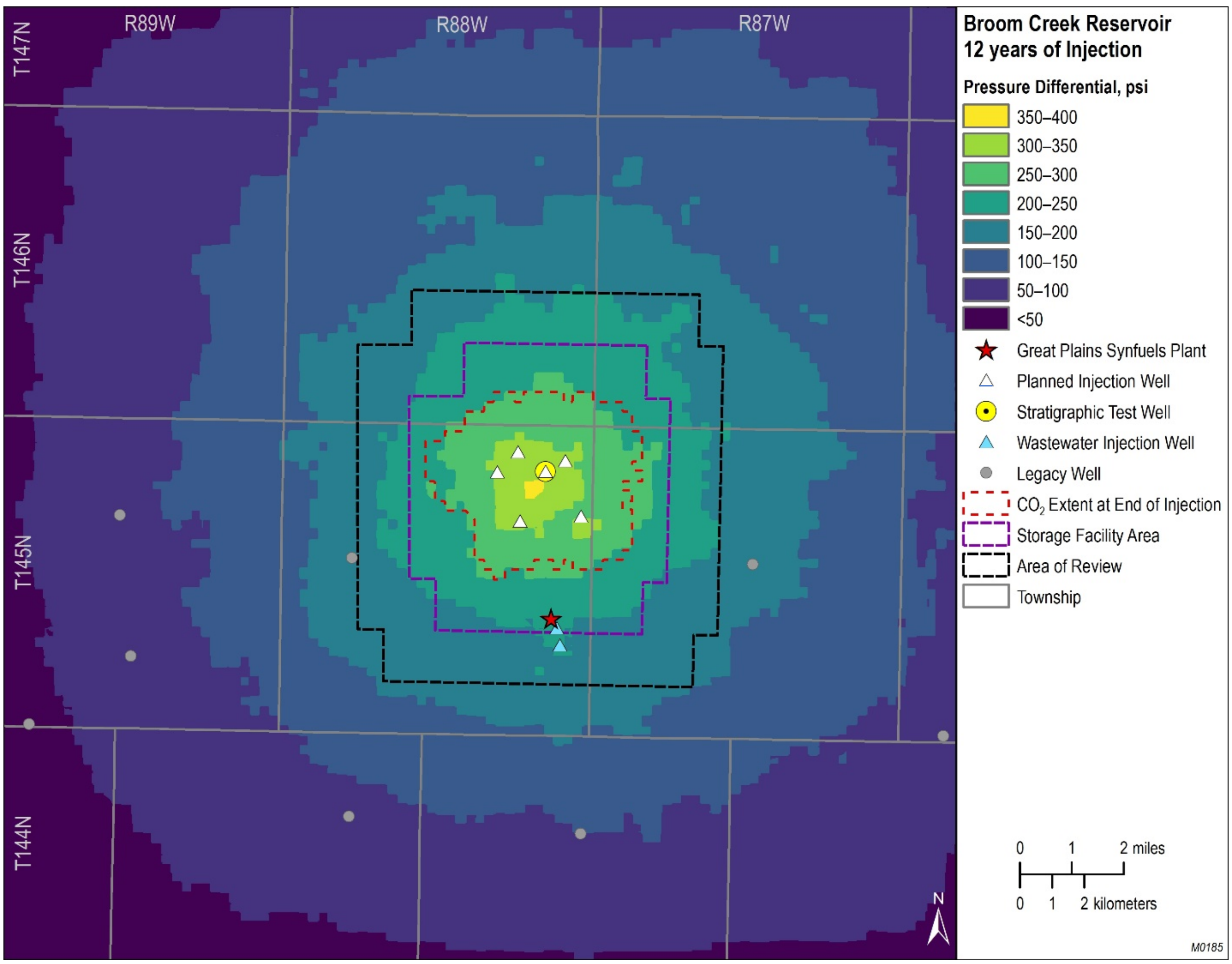


Figure 4-1. Pressure map showing the maximum subsurface pressure influence associated with CO_2 injection in the Broom Creek Formation. Shown is the CO_2 plume extent after end of injection, the storage facility area, and the 1-mile AOR boundary in relation to the maximum subsurface pressure influence.

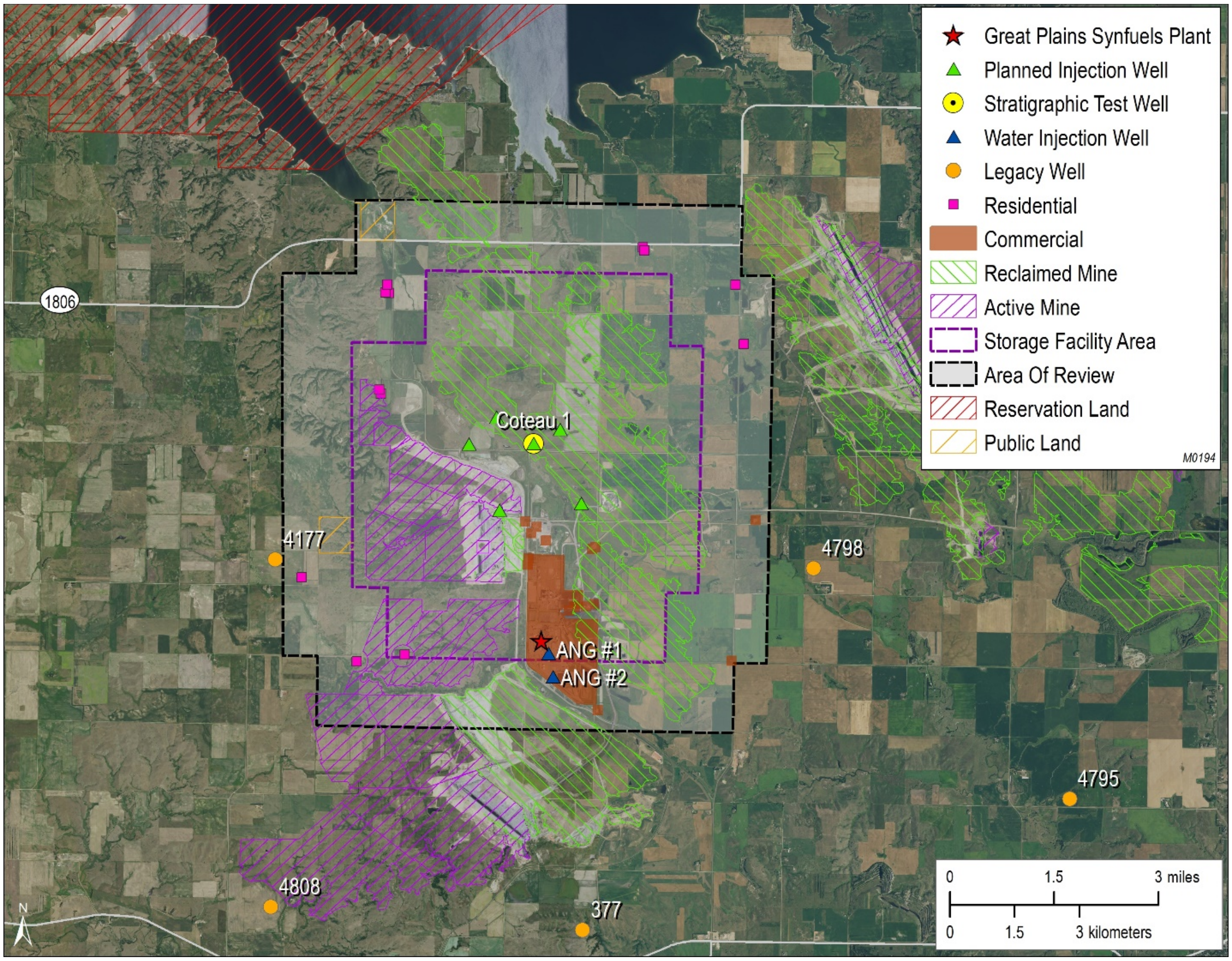


Figure 4-2. Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings.

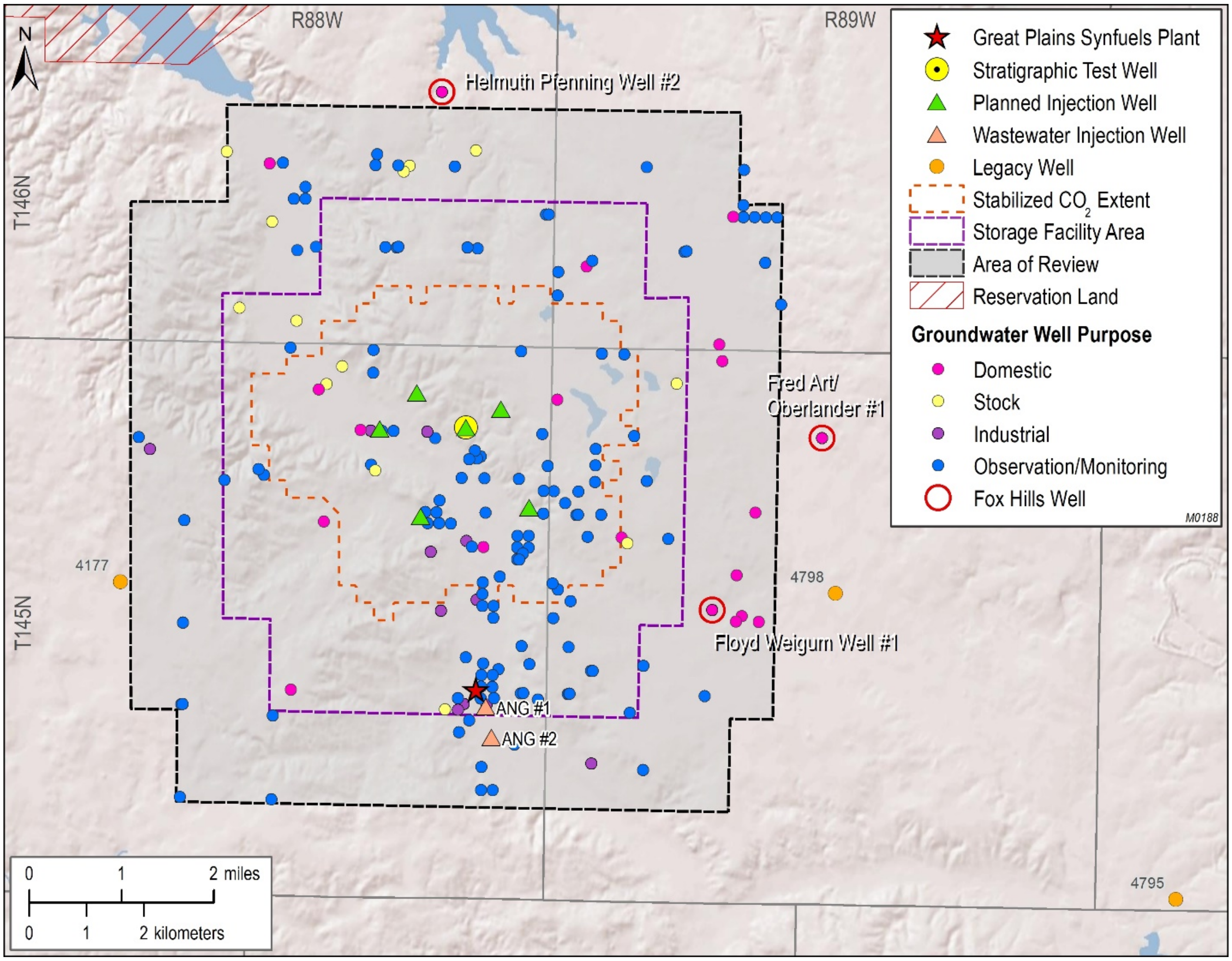


Figure 4-3. AOR map in relation to nearby legacy wells and groundwater wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR, and the light-orange triangles represent Class I ANG #1 and ANG #2 wells. All groundwater wells in the AOR are identified above. All observation/monitoring wells are shallow groundwater wells associated with the mine activities. No springs are present in the AOR.

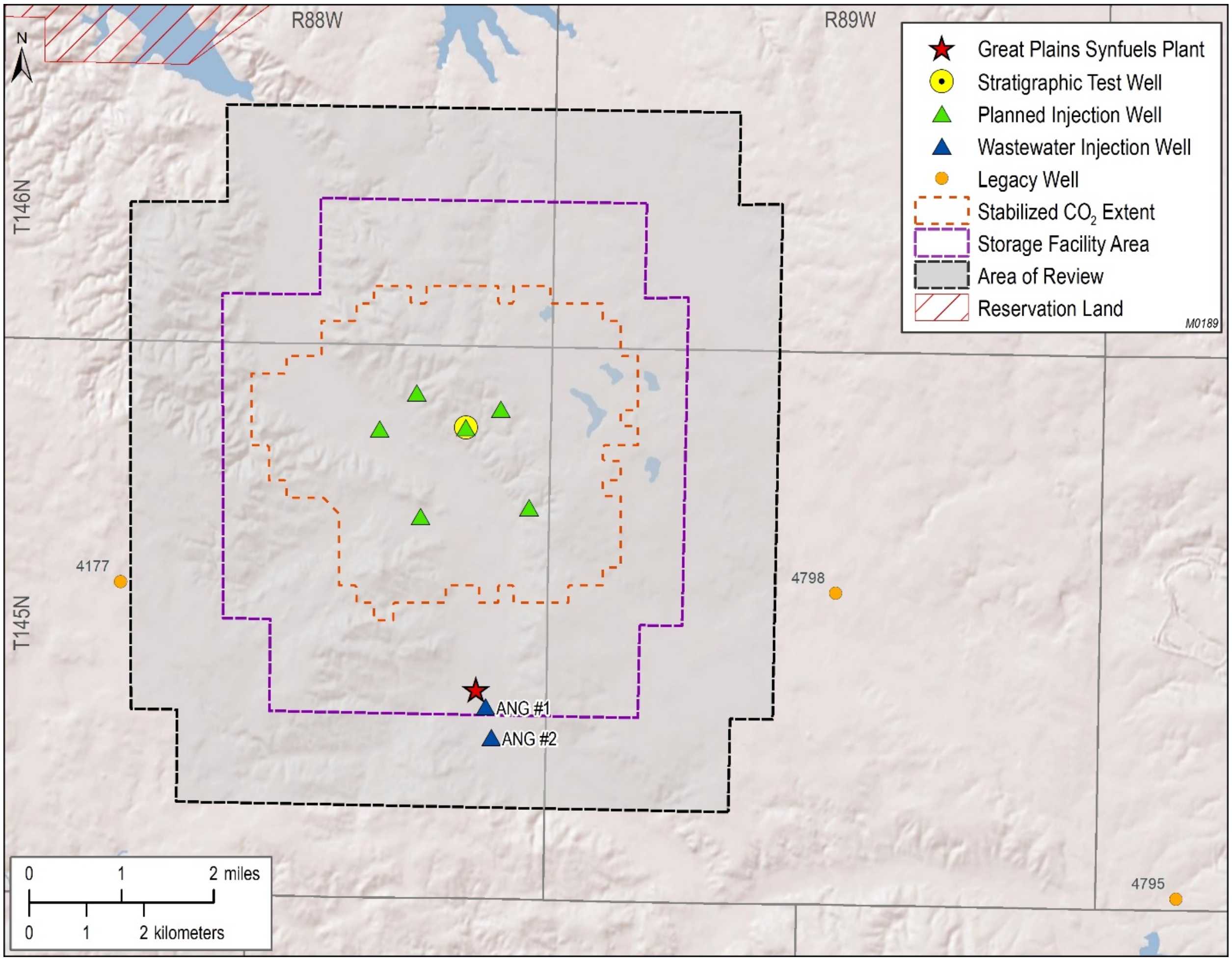


Figure 4-4. AOR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR and the Class I ANG #1 and ANG #2 wells are represented by blue triangles.

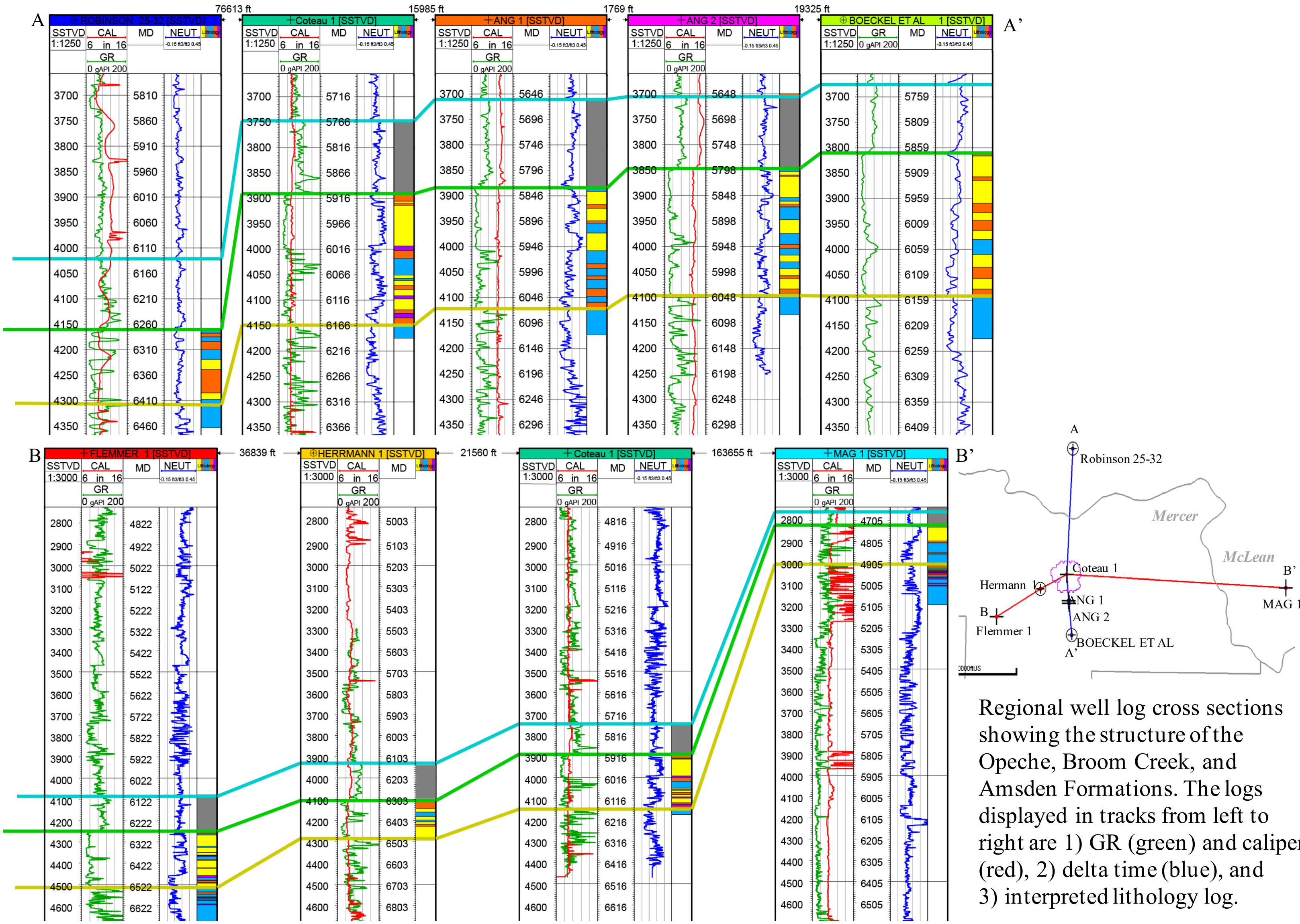


Figure 4-5. Cross section of the AOR from the geologic model showing lithofacies distribution in the Broom Creek Formation, the proposed injection well (Coteau 1), and the ANG #1 and ANG #2 wells within the AOR. Depths are referenced to mean sea level.

Table 4-1. Investigated and Identified Surface and Subsurface Features (Figures 4-1 through 4-5)

Surface and Subsurface Features	Investigated and Identified (Figures 4-1–4-5)	Investigated But Not Found in AOR
Producing (active) Wells		X
Abandoned Wells	X	
Plugged Wells or Dry Holes	X	
Deep Stratigraphic Boreholes	X	
Subsurface Cleanup Sites		X
Surface Bodies of Water	X	
Springs		X
Water Wells	X	
Mines (surface and subsurface)	X	
Quarries		X
Subsurface Structures (e.g., coal mines)	X	
Location of Proposed Wells	X	
*Location of Proposed Cathodic Protection Boreholes		X
Any Existing Aboveground Facilities	X	
Roads	X	
State Boundary Lines		X
County Boundary Lines		X
Indian Country Boundary Lines	X	
Class I Injection Wells	X	

*There are no plans for cathodic protection for the Great Plains CO_2 Sequestration Project injection wells (Coteau 1–6 wells).

4.2 Corrective Action Evaluation

Table 4-2. Wells in AOR Evaluated for Corrective Action

NDIC Well File No.	Operator	Well Name	Spud Date	Surface Casing, o.d., inches	Surface Casing Seat, ft	Long-String Casing, o.d., inches	Long-String Casing Seat, inches	Hole Direction	TD, ft	TVD, ft	Status	Plug Date	TWN	RNG	Section	Qtr/Qtr	County	Corrective Action Needed
NDDEQ11308	Dakota Gasification Company	ANG #1	4/17/1982	16	2,017	9.625	6,784	Vertical	6,784	6,784	Active injector	N/A	145 N	88 W	24	SE/SW	Mercer	No
NDDEQ11309	Dakota Gasification Company	ANG #2	9/2/1984	13.375	2,118	9.625	6,910	Vertical	6,911	6,911	Active injector	N/A	145 N	88 W	25	CE2/NW	Mercer	No
38379	Rampart Energy Company	Coteau 1	6/27/2021	9.625	2,033	7	6,473	Vertical	6,484	6,484	DNC	N/A	145 N	88 W	1	SW/SW	Mercer	No
4177	Pel-Tex Petroleum Co. & Conoco	Herrmann 1 (Located outside of AOR)	11/8/1966	9.625	622	N/A	N/A	Vertical	8,057	8,057	Dry	12/2/1966	145 N	88 W	17	NE/SW	Mercer	No

Table 4-3. Herrmann 1 (NDIC File No. 4177) Well Evaluation

Well Name: Herrmann 1 (NDIC File No. 4177)

Cement Plugs				
Number	Interval, ft		Thickness, ft	Volume, sacks
1	7,980	7,910	70	20
2	7,800	7,730	70	20
3	4,720	4,650	70	20
4	640	570	70	20
5	20	Surface	20	5

*Data and information are provided from well-plugging report found in NDIC database.

Formation		Cement Plug Remarks
Name	Estimated Top, ft	
9⅝" Casing Shoe	622	Cement Plug 4 isolates the 9⅝" casing shoe.
Pierre	1,893	
Mowry	4,334	Cement Plug 3 isolates the uppermost Inyan Kara porosity.
Inyan Kara	4,660	
Swift	5,146	
Rierdon	5,562	
Broom Creek	6,310	
Big Snowy Group	6,918	
Madison	7,346	
Ratcliffe	7,597	
Frobisher	7,814	Cement Plugs 1 and 2 isolate deeper, unsuccessful wildcat horizons below the Frobisher.

Spud Date: 11/08/1966
Total Depth: 8,057 (Madison Formation)

Openhole plugging

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Herrmann 1 (NDIC File No. 4177) well will not be in contact with the CO_2 plume, and pressure increase in the Broom Creek Formation at this well location is predicted to be approximately 150–200 psi. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled and plugged.

Table 4-4. ANG #1 (NDEQ File No. NDOH11308) Well Evaluation

Well Name: ANG 1 (NDEQ File No. NDOH11308)

Casing Program				
Section	Casing Outside Diameter (o.d.), in.	Weight, lb/ft	Casing Seat, ft	Grade
Surface	16"	75	2,017	K-55
Production	9⅝"	40	6,784	K-55

Cement Program				
Casing, in.	Cement Type	TOC	Excess, %	Volume, sacks
16"	Class G	Surface	33%	1,600
9⅝"	Class G	1,700	NA	2,590

Formation		Remarks
Name	Estimated Top, ft	
16” Casing Shoe	2,017	Class G cement isolates the 16” casing shoe and all shallow water zones.
Mowry	3,950	
Inyan Kara	4,293	Production casing and Class G cement isolate all formations below the shoe of the surface casing.
Swift	4,664	
Rierdon	5,098	
Spearfish	5,510	
Opeche	5,654	
Broom Creek	5,821	
Amsden	6,070	

Corrective Action: No corrective action is necessary.

Table 4-5. ANG #2 (NDEQ File No. NDOH11309) Well Evaluation

Well Name: ANG 2 (NDEQ File No. NDOH11309)

Casing Program				
Section	Casing Outside Diameter (o.d.), in.	Weight, lb/ft	Casing Seat, ft	Grade
Surface	13⅜”	54.5	2,118	J-55
Production	9⅝”	47	6,910	N-80

Cement Program				
Casing, in.	Cement Type	TOC	Excess, %	Volume, sacks
13-⅜”	Class G & Halliburton Lightweight	Surface	38%	1,827
9⅝”	Class G & Halliburton Lightweight	2,220' (plus a top off cement job from surface to 670')	NA	2,301

Formation		
Name	Estimated Top, ft	Remarks
13-3/8" Casing Shoe	2,118	Class G cement isolates the 13-3/8" casing shoe and all shallow water zones.
Mowry	3,940	
Inyan Kara	4,263	Production casing and Class G cement isolate all formations below a depth of 2,220'. Therefore, there exists a 102' gap in the openhole cement coverage from 2,220' to 2,118' opposite the impermeable Pierre Shale.
Swift	4,692	
Rierdon	5,098	
Spearfish	5,499	
Opeche	5,644	
Broom Creek	5,795	
Amsden	6,042	

Corrective Action: No corrective action is necessary.

Table 4-6. Coteau 1 (NDIC File No. 38379) Well Evaluation

Well Name: Coteau 1 (NDIC File No. 38379)

Casing Program				
Section	Casing Outside Diameter (o.d.), in.	Weight, lb/ft	Casing Seat, ft	Grade
Surface	9⅝"	36	2,023	J-55
Production	7"	32	5,772	L-80
Production	7"	32	6,473	13CR L80

Cement Program				
Casing, in.	Cement Type	TOC	Excess, %	Volume, sacks
9⅝"	Varicem	Surface	100	750
7”	Varicem	Surface	100	285
7”	Corrosacem	3205'	100	645

Formation		
Name	Estimated Top, ft	Remarks
Pierre	1,750	Class G cement isolates the 9⅝" casing shoe.
9⅝" Casing Shoe	2,023	
Mowry	4,065	Stage collar with ECP at 3,205' Halliburton Corrosacem (CO_2-resistant cement) from TD to stage collar
Inyan Kara	4,395	
Swift	4,800	
Rierdon	5,212	
Spearfish	5,623	
Opeche	5,762	7" 13CR L80 production casing and Halliburton Corrosacem (CO_2-resistant cement) to isolate the Broom Creek Formation
Broom Creek	5,905	
Amsden	6,177	

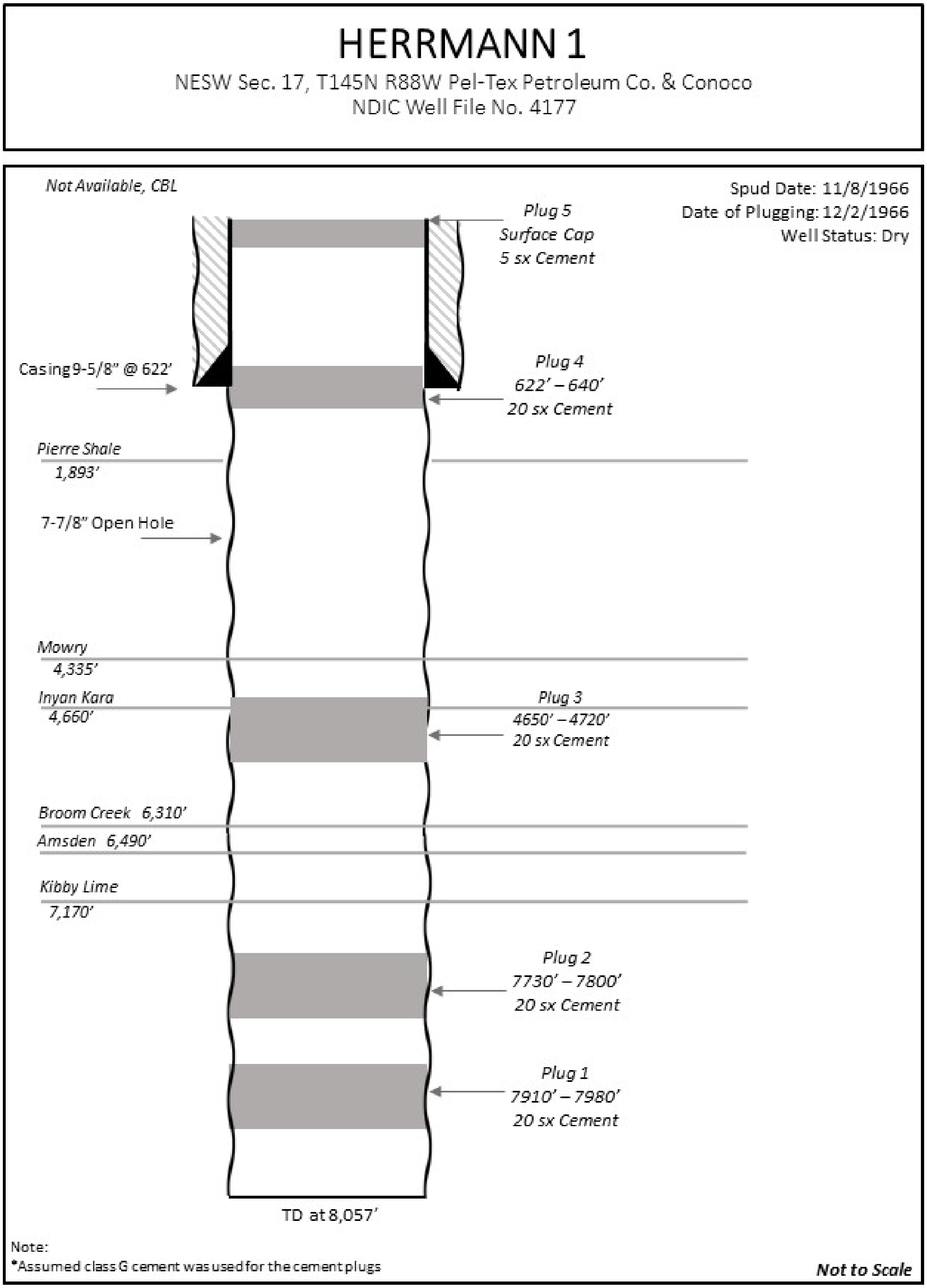
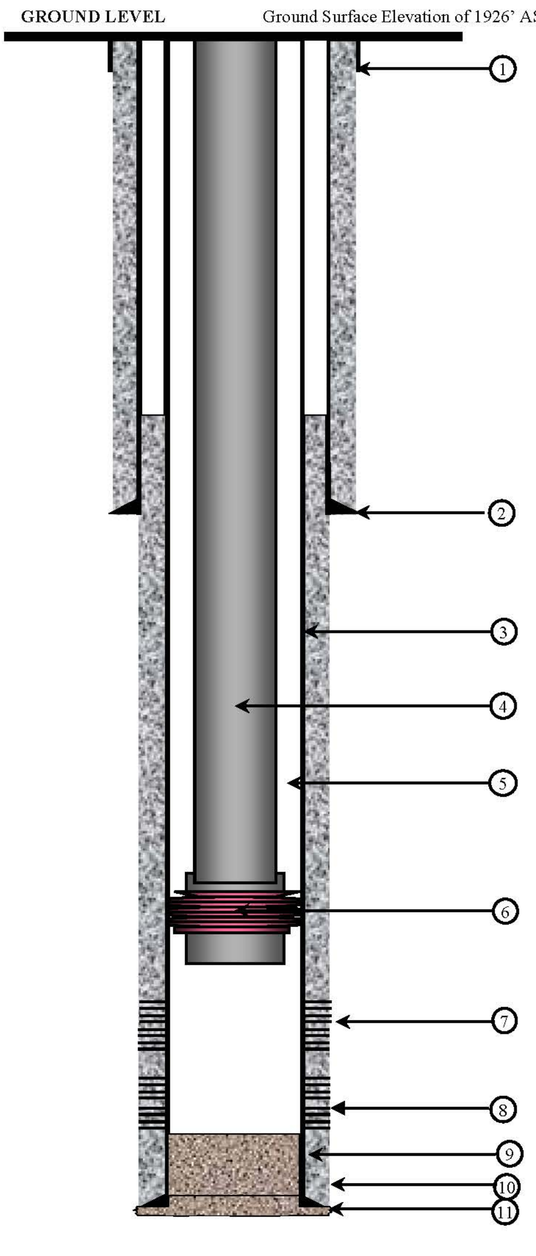


Figure 4-6. Herrmann 1 (NDIC File No. 4177) well schematic showing the location and thickness of cement plugs.

DAKOTA GASIFICATION COMPANY

DAKOTA GASIFICATION COMPANY
Mercer County, North Dakota
Injection Well No. 1 Schematic
Status: Active



COMPLETION DETAIL

1. Conductor Pipe: 24"set in 40" hole from surface to 80'. Cemented to surface.
2. Surface Casing: 16", 75.0-ppf, K-55, ST&C. Set from surface to ±2,017.28' in a 20" drilled hole. Cemented to surface with 1,600 sacks 65/35 Pozolan and 300 sacks Class G cement.
3. Protection Casing: 9-5/8" casing set to 6,784'. 9-5/8", 40.0-ppf, K-55, LT&C from 3,967' to 6,784', 9-5/8", 36.0-ppf, K-55, LT&C from 15' to 3,967', and 9-5/8", 40.0-ppf, K-55, LT&C surface to 15' in a 13-1/2" drilled hole from 2,017' to 4,469', 12-1/2" drilled hole from 4,469' to 5,800' and a 12-1/4" drilled hole form 5,800' to 6,784'. Cemented with 990 sacks of Class G cement in the first stage and 1,600 sacks of Class G cement in the second stage. Cementing stage tool was set at 5,347'. Top of cement at 1,700'.

   Note: SLB USIT log (6/7/2020) identified reduced ID in jts 81 & 84, 3,641.7' & 3,760.0', probably 43.5 ppf, & reduced ID in jts 100 & 133, 4,422.5'& 5,731.4', probably 47.0 ppf.
4. Injection Tubing and Seal Assembly: 7", 26-ppf, J-55, LT&C from surface to ± 5740' with a 5-1/2" OD Baker Hughes GBH22 Locator Tubing Seal Assembly set to 5,751.5', minimum ID of 4.891". 5-1/2" OD Tail pipe extension to 5,762.2'.
5. Annulus filled with 10.4 lb/gal inhibited brine.
6. Injection Packer: Baker Model 194-60 "FB-1" Packer set at 5,740'.
7. Minnelusa Perforations:

5,835' to 5,836', 1'	5,836' to 5,867', 31'
5,867' to 5,870', 3'	5,870' to 5,880', 10'
5,880' to 5,884', 4'	5,884' to 5,894', 10'
5,894' to 5,900', 6'	5,920' to 5,952', 32'
5,952' to 5,954', 2'	

8. Kibbey Perforations:

6,621' to 6,631', 10'	6,637' to 6,657', 20'
6,659' to 6,669', 10'	

9. Fill Tagged at 6,721' on 6/25/2020 – Temperature Survey
10. Plugged back total depth of 6,728'
11. Drilled to a total depth of 6,784'.

Note: All depths referenced to original rotary kelly bushing of 20' above ground level unless otherwise noted.

GEOSTOCK SANDIA
ENTREPOSE
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Drawn by: WHA	Date: 11/20/2002	*Drawing not to scale*
Revision 4 – 7/17/2020		

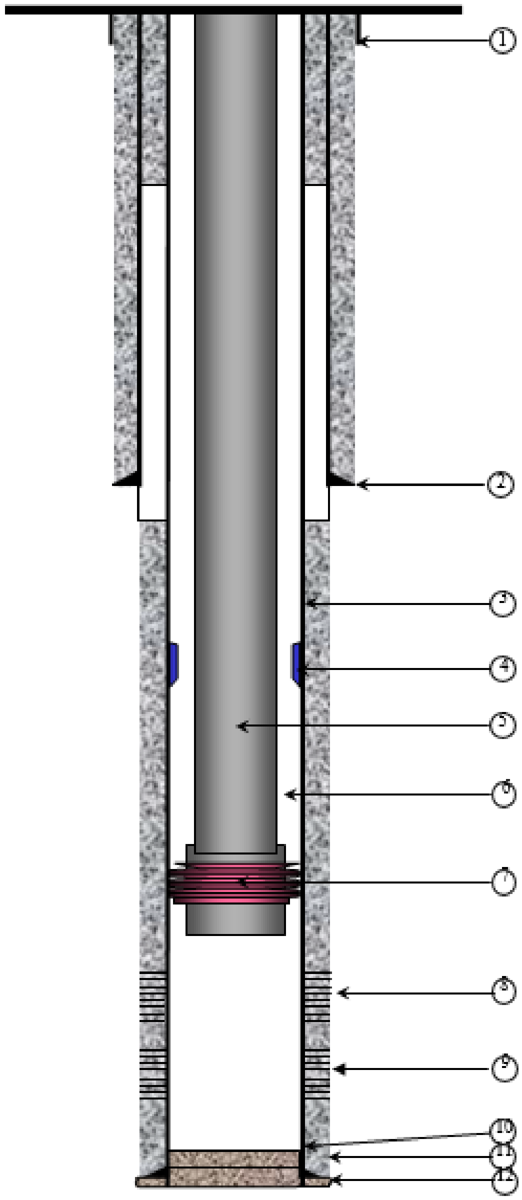
Figure 1: Injection Well No. 1 Schematic

Figure 4-7. ANG #1 (NDEQ File No. NDOH11308) well schematic.

DAKOTA GASIFICATION COMPANY

DAKOTA GASIFICATION COMPANY
Mercer County, North Dakota
Injection Well No. 2 Schematic
Status: Active

GROUND LEVEL Ground Surface Elevation of 1918.6' ASL



COMPLETION DETAIL

1. Conductor Pipe: 20" with ¼" wall set in 26" hole from surfaceto 60' below grade. Cemented to surface.
2. Surface Casing: 13-3/8", 54.5-ppf, J-55, ST&C. Set from surface to ±2,118' in a 17-1/2" drilled hole. Cemented to surface with 1,515 sacks Halliburton Lightweight cement plus 2% CaCl and 312 sacks Class G cement 2% CaCl.
3. Protection Casing: 9-5/8", 47-ppf, N-80, LT&C. Set from surface to 6,910' in a 12-1/4" drilled hole. ID of 8.681". Cemented with 454 sacks of Class G cement, 15.8 lb/sk lead and 857 sacks of Halliburton Lightweight, 13.1 lb/gal, tail in the first stage and 990 sacks of Class G cement in the second stage. Cementing stage tool was set at 3,697'. Top of cement at 2,220'. Annulus topped out with Class G cement, 15.8 lb/gal, from 670' to surface.
4. HOMCO 9-5/8", 47-ppf Internal Casing Patch set from 3,692' to 3,722'. ID through the patch is reduced to 8.381".
5. Injection Tubing and Seal Assembly: 7", 29-ppf, L-80, LT&C from surface to 5,772', locator seal assembly from 5,772' to 5,785', and a 5-1/2", 17-ppf, J-55, production tube with a ½ mule shoe bottom guide from 5,785' to 5,805', minimum ID of 4.875".
6. 7" x 9-5/8" Annulus filled w/ 10.5 lb/gal Brine containing 1.3% Nalco Champion CORR12264A Corrosion Inhibitor.
7. Injection Packer: Baker Model 194-60 "FB-1" Packer with 10' seal | bore extension set from 5,772' to 5,784'. Seal bore ID of 6".
8. Minnelusa Perforations:

5,800' to 5,854' 54'	5,858' to 5,864' 6'
5,894' to 5,924' 30'	5,990' to 6,004' 14'
6,010' to 6,016' 6'	6,018' to 6,023' 5'
6,025' to 6,035' 10'	6,039' to 6,043' 4'

9. Kibbey Perforations:

6,587' to 6,603' 16'	6,608' to 6,628' 20'
6,632' to 6,642' 10'	6,727' to 6,737' 10'

10. Filled tagged at 6,784' on 11/29/19 – Temperature Survey
11. Plugged back total depth of 6,865'
12. Drilled to a total depth of 6,911'.

Note: All depths referenced to original rotary kelly bushing measurement of 19.44' above the tubing hanger flange unless stated otherwise.

GEOSTOCK SANDIA
ENTREPOSE

Drawn by: WHA	Date: 10/26/2012	*Drawing not to scale*
Revision 2: 1/15/2020		

Figure 1: Injection Well No. 2 Schematic

Figure 4-8. ANG #2 (NDEQ File No. NDOH11309) well schematic.

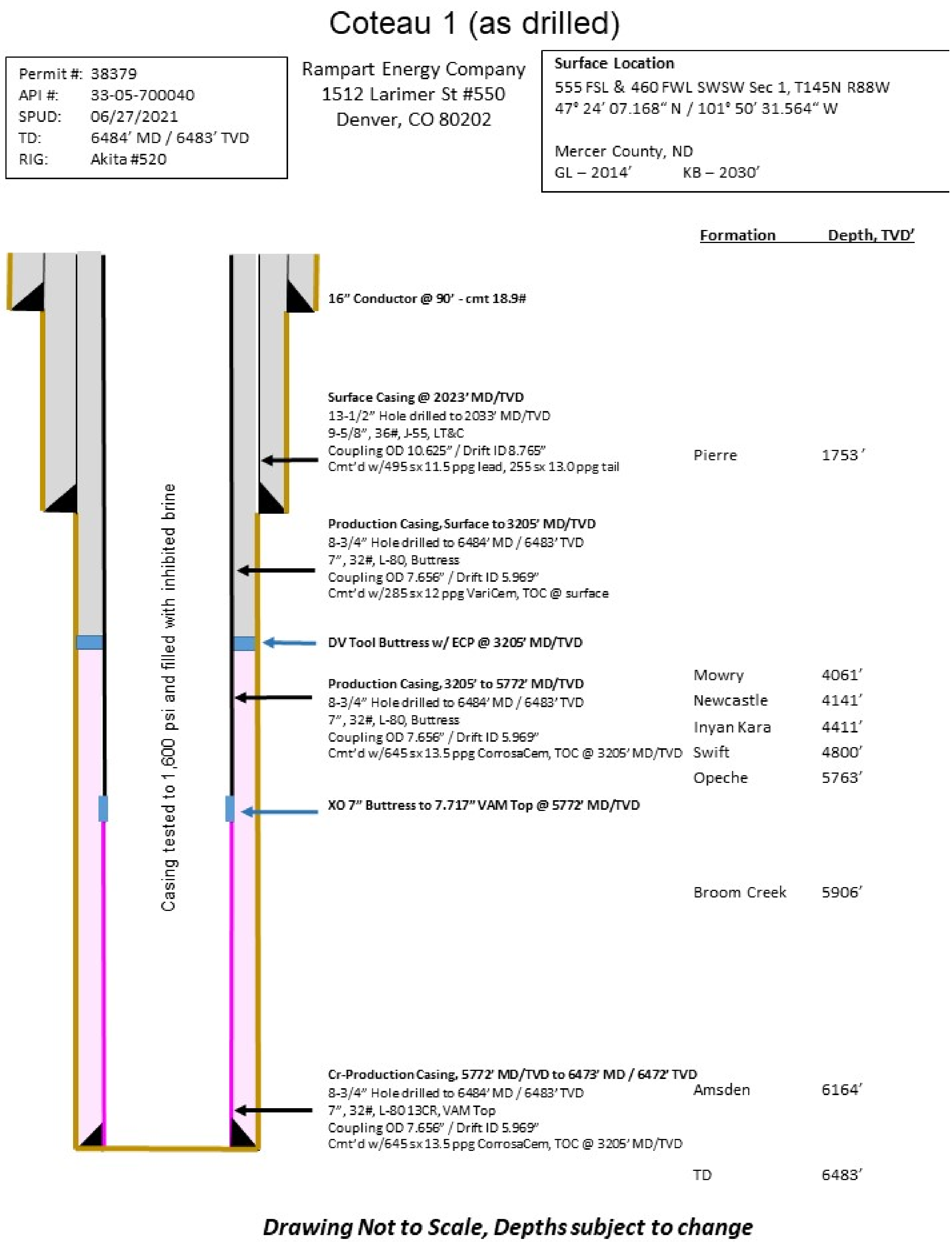


Figure 4-9. Coteau 1 (NDIC File No. 38379) well schematic.

4.3 Reevaluation of AOR and Corrective Action Plan

The Great Plains CO_2 Sequestration Project will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place not later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following:

- Any changes to the monitoring and operational data prior to the scheduled reevaluation date.

- Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and operational data to be utilized as the basis for that update will be identified.

- The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.

4.4 Protection of USDWs

4.4.1 Introduction of USDW Protection

The primary confining zone and additional overlying confining zones geologically isolate the Fox Hills Formation, the lowest USDW in the area of investigation from the underlying injection zone. The Opeche Formation is the primary confining zone for the injection zone with additional confining layers above, geologically isolating all USDWs from the injection zone. The uppermost confining layer is the Pierre Formation, an impermeable shale in excess of 1,000 ft thick, providing an additional seal for all USDWs in the region.

4.4.2 Geology of USDW Formations

The hydrogeology of western North Dakota comprises several shallow freshwater-bearing formations of the Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin (Figure 4-10). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1,000 and 1,500 ft thick (Thamke and others, 2014).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; the overlying Cannonball, Tongue River, and Sentinel Butte Formations of the Tertiary Fort Union Group; and the Tertiary Golden Valley Formation (Figure 4-11). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the area of investigation (Croft, 1973).

The lowest USDW in the area of investigation is the Fox Hills Formation, which, together with the overlying Hell Creek Formation, is a confined aquifer system. The Hell Creek Formation

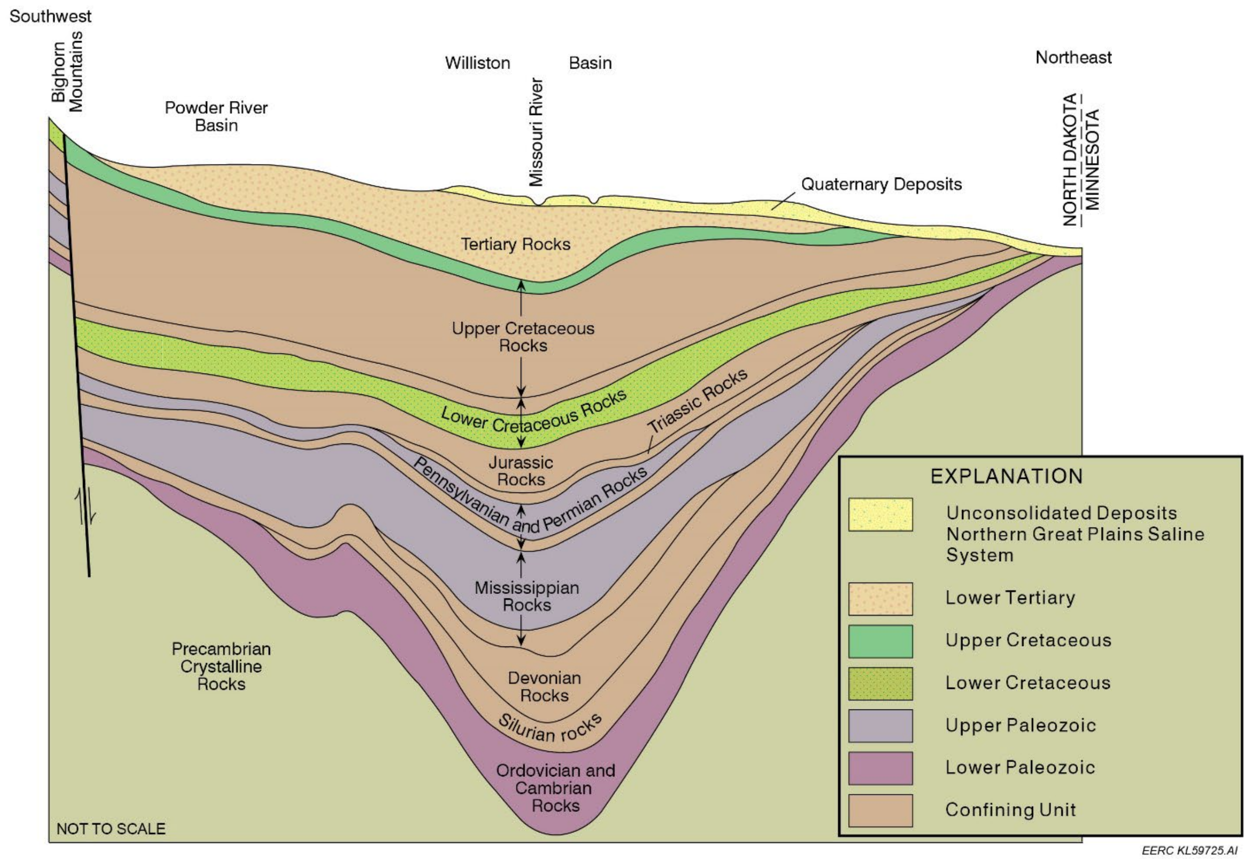


Figure 4-10. Major aquifer systems of the Williston Basin.

is a poorly consolidated unit composed of interbedded sandstone, siltstone, and claystones with occasional carbonaceous beds, all fluvial origin. The underlying Fox Hills Formation is interpreted as interbedded nearshore marine deposits of sand, silt, and shale deposited as part of the final Western Interior Seaway retreat (Fischer, 2013). The Fox Hills Formation in the area of investigation is approximately 1,100 to 1,400 ft deep and 200–340 ft thick (Croft, 1973). The structure of the Fox Hills and Hell Creek Formations follows that of the Williston Basin, dipping gently toward the center of the basin to the northwest of the area of investigation (Figure 4-12).

The Pierre Shale is a thick, regionally extensive shale unit which forms the lower boundary of the Fox Hills–Hell Creek system, also isolating all overlying freshwater aquifers from the deeper saline aquifer systems. The Pierre Shale is a dark gray to black marine shale and is typically over 1,000 ft thick in the area of investigation (Thamke and others, 2014).

ERATHEM	SYSTEM		SERIES	ROCK: GROUP	ROCK: FORMATION	FRESHWATER AQUIFER(S)	FRESHWATER AQUIFER(S) UNDER
CENOZOIC	Quaternary		Holocen		Oahe	No	
			Pleistocene	Coleharbor	“Glacial Drift”	Yes	
	Tertiary	Neoge	Pliocene		(Unnamed)	Yes	
			Miocene		Arikaree	No	
		Paleogene	Oligocene	White	Brule	No	
			Eocene		Chadron	No	
					Golden	No	
			Paleocene	Fort Union	Sentinel	Yes	
					Tongue River – Bullion	Yes	
					Tongue River – Slope	No	
					Cannonball	Yes	
					Ludlow	Yes	
MESOZOIC	Cretaceous		Upper	Montana	Hell Creek	Yes	
					Fox Hills	Yes	
					Pierre	No	

Modified from Murphy and others, 2009, NDGS MS 91

Figure 4-11. Upper stratigraphy of Mercer County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Murphy and others, 2009; NDGS MS 91).

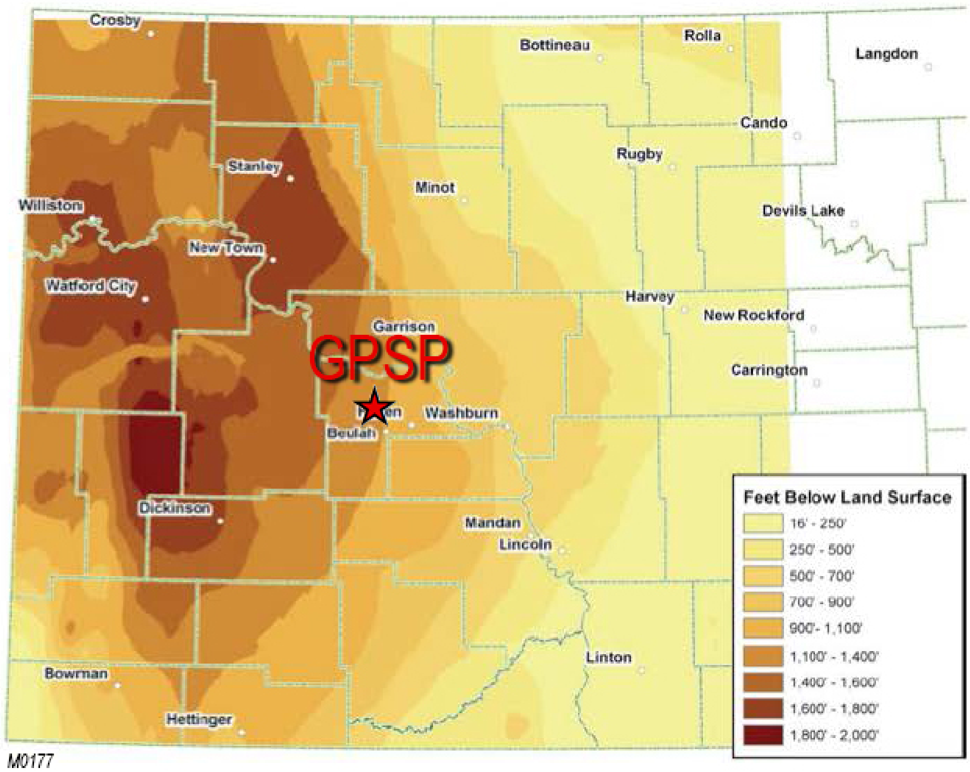


Figure 4-12. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

4.4.3 Hydrology of USDW Formations

Groundwater is obtained from both glacial drift and bedrock aquifers, with most of the water obtained from bedrock. Lignite beds and sands in the Sentinel Butte and Tongue River Formations provide shallow bedrock aquifers in most areas of Mercer County. Sandstones near the base of the Tongue River Formation and within the Hell Creek and Fox Hills Formations provide deeper artesian aquifers in many areas. Glacial drift is generally too thin or impermeable to provide good aquifers in the upland areas. However, in the valleys of the major streams and in the diversion channels, the glacial and alluvial fill provides adequate supplies of groundwater (Carlson, 1973).

The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the area of investigation is to the east (Figure 4-13). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,530 mg/L near the Great Plains CO_2 Sequestration Project area. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering.

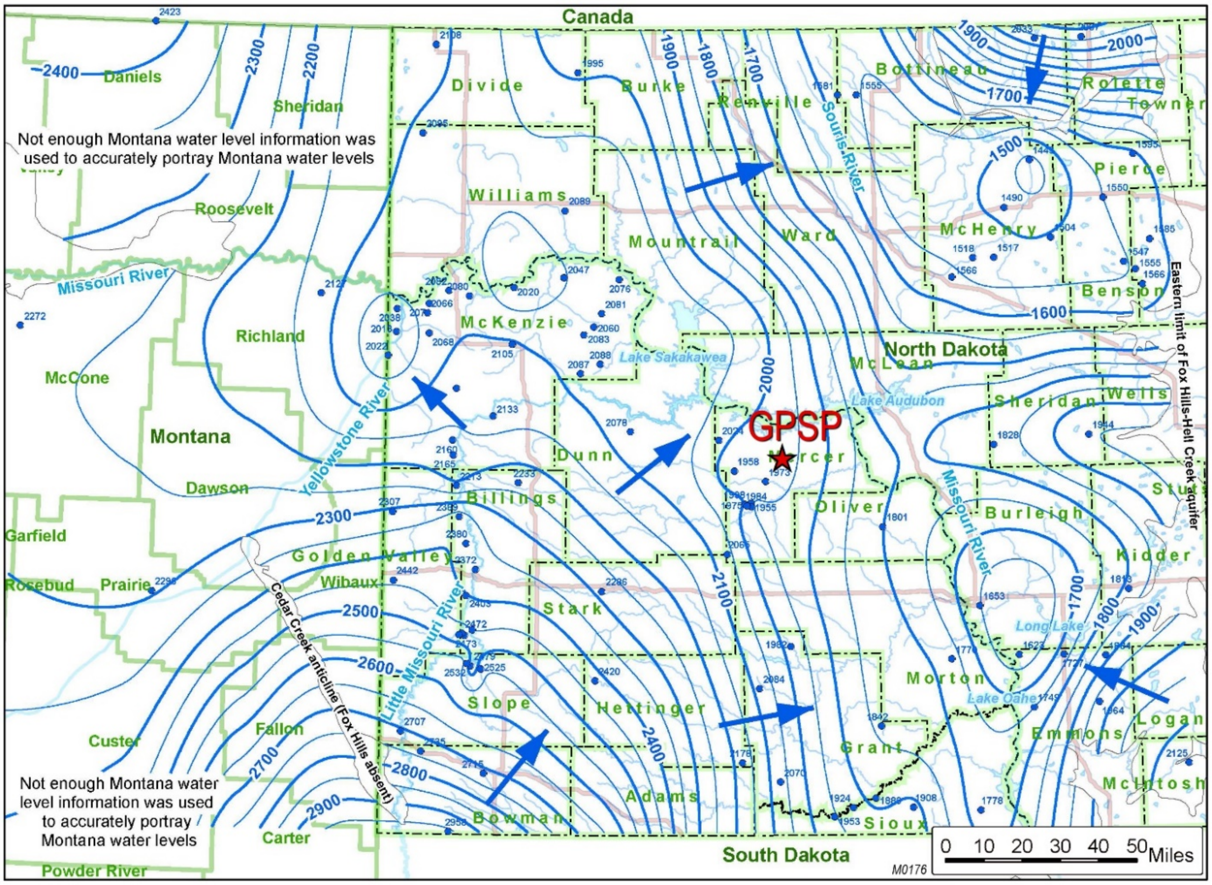


Figure 4-13. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in Mercer County (modified from Fischer, 2013).

There are several existing candidate groundwater wells to screen for sample collection in the area of investigation (Figure 4-14). Some of these wells are currently sampled as part of annual plant operational monitoring programs. Existing wells will be evaluated for inclusion into baseline, operational, and postinjection monitoring plans. Groundwater monitoring wells completed in the Fox Hills Formation will also be installed and sampled near injection well pads (one at each well for a total of six).

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the area of investigation (Figure 4-15). These formations are often used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1,000 ppm (Croft, 1973).

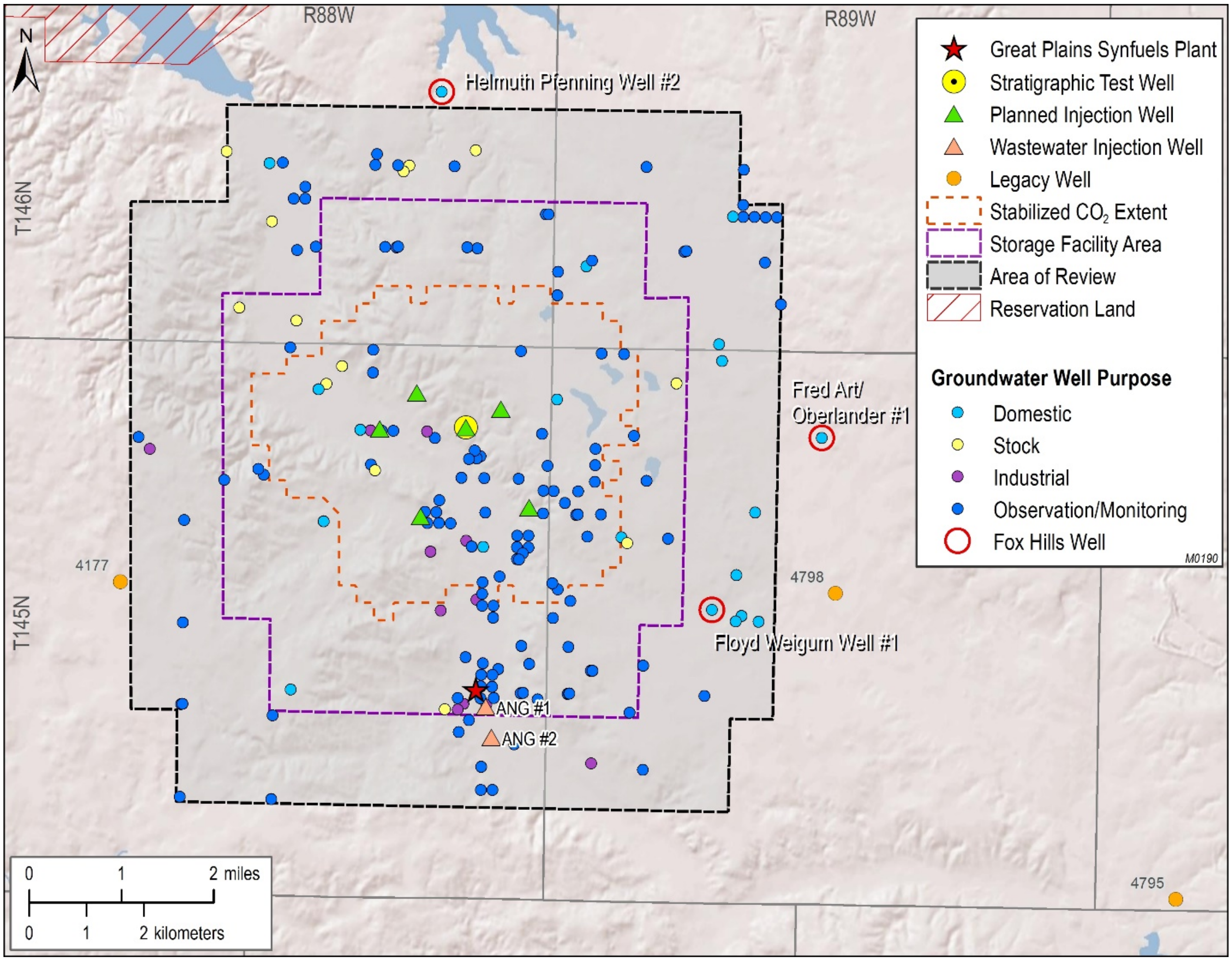


Figure 4-14. Map of water wells in the area of investigation in relation to the simulated plume.

The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. Generally, the upper Sentinel Butte is up to 300 ft thick in the area of investigation. TDS in the Sentinel Butte Formation range from approximately 400–1,000 ppm (Croft, 1973).

In general, coal seams and glacial washouts contribute to shallow sources of groundwater in the area. Locally, the primary source of shallow groundwater is the Beulah Trench, a typical glacially carved valley that winds its way from Beaver Creek Bay (Lake Sakakawea), through the project site, to a point about 4 miles north of Beulah where it divides and continues eastward toward Hazen and westward toward Zap.

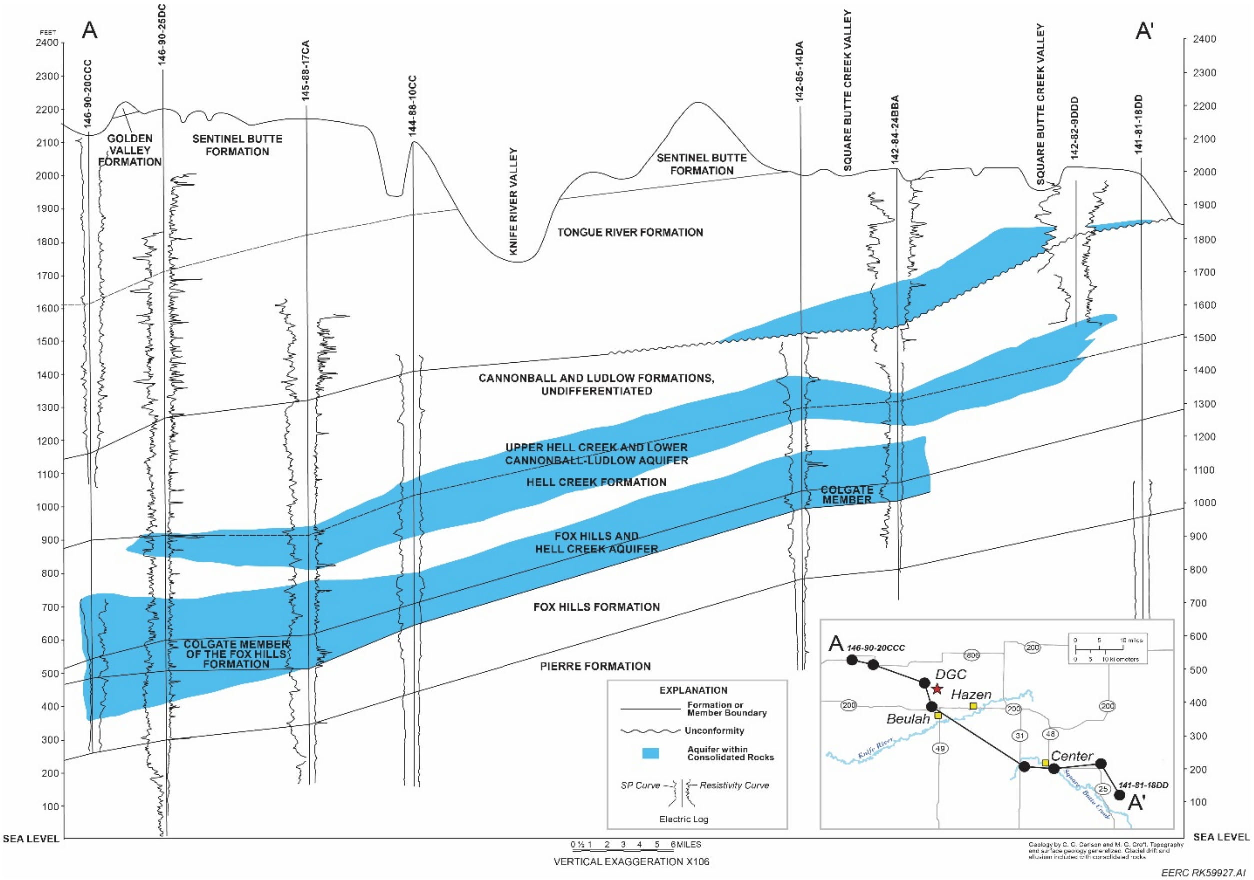


Figure 4-15. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section.

4.4.4 Protection for USDWs

The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AOR. The injection zone (Broom Creek Formation) and the lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and siltstone formations of Permian, Jurassic, and Cretaceous ages (Figure 4-10). The primary seal of the injection zone is the Permian-aged Opeche Formation with the shales of the Permian-aged Spearfish, the Jurassic-aged Piper (Picard), Rierdon, and Swift Formations, all of which overly the Opeche Formation. Above the Swift is the confined saltwater aquifer system of the Inyan Kara Formation, which extends across much of the Williston Basin. Above the Inyan Kara are the Cretaceous-aged shale formations Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre. The Pierre Formation is the thickest shale formation in the area of investigation and the tertiary geologic barrier between the USDWs and the injection zone (refer to Section 2.4.2 for additional overlying confining layers of the storage reservoir). The geologic strata overlying the injection zone consists of multiple impermeable rock layers that are free of transmissive faults or fractures and provide adequate isolation of the USDWs from CO_2 injection activities in the area of investigation.

4.5 References

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Trapp, H., and Croft, M.G., 1975, Geology and ground water resources of Hettinger and Stark Counties North Dakota: U.S. Geological Survey, County Ground Water Studies – 16.

5.0 TESTING AND MONITORING PLAN

5.0 TESTING AND MONITORING PLAN

Pursuant to North Dakota Administrative Code (NDAC) § 43-05-01-11.4, this testing and monitoring plan includes an analysis of the injected CO_2 stream, periodic testing of the injection wells, a corrosion monitoring plan for the CO_2 injection well components and surface facilities, a leak detection and monitoring plan for surface components of the CO_2 injection system, and a leak detection plan to monitor any movement of the CO_2 outside of the storage reservoir. As such, this plan simultaneously meets the permit requirements for two other required plans: 1) a surface/subsurface leak detection and monitoring plan (NDAC § 43-05-01-14) and 2) a corrosion monitoring and prevention plan (NDAC § 43-05-01-15).

The combination of the above monitoring efforts is used to verify that the geologic storage project is operating as permitted and is protecting all USDWs. An overview of these individual monitoring efforts is provided in Table 5-1 along with the target area that will be monitored.

A regular review of the monitoring program (i.e., a minimum of every 5 years) will be conducted to ensure that it remains appropriate for the site and is adequately tracking the injected CO_2, thereby providing an accurate assessment of the performance of the surface/subsurface equipment and subsurface geologic structures in containing the stored CO_2.

If needed, amendments to the monitoring program (i.e., technologies applied, frequency of testing, etc.) will be submitted for approval by the North Dakota Industrial Commission (NDIC). Results of pertinent analyses and data evaluations conducted as part of the monitoring program will be compiled and reported as required. Another goal of this monitoring program is to establish preinjection baseline data for the storage complex, including baseline data for soil gas, nearby groundwater wells, and the Fox Hills Formation (lowest USDW).

Additional details of the individual efforts of the monitoring program are provided in the remainder of this section.

Table 5-1. Overview of DGC's Testing and Monitoring Plan

Monitoring Type	Equipment/Testing	Target Area
Analysis of CO_2 Stream	Compositional and isotopic analysis of the CO_2 stream	CO_2 compressors at the capture facility
Wellsite Flowline Leak Detection System	H_2S detection stations, pressure gauges, and SCADA[1] system	Wellsite flowline to wellhead
Surface Corrosion	Ultrasonic testing of tubing test sections installed at wellheads	Wellsite flowline to well infrastructure
Downhole Corrosion	PMIT[2] and/or surface tubing inspection and USIT[3] (material wall thickness)	Downhole tubing and casing strings
Continuous Recording of Injection Pressure, Rate, and Volume	Flowmeters	Transmission line to well infrastructure
Well Annulus Pressure Between Tubing and Casing	Digital annular pressure gauges for continuous monitoring	Surface-to-reservoir (injection wells)
Internal and External Mechanical Integrity Testing	Tubing-casing annulus pressure testing (internal), USIT (internal and external) and temperature logs	Well infrastructure
Atmospheric	H_2S detection stations	Outside of wellhead enclosures
Near-Surface	Compositional and isotopic analysis of soil gas profile stations and dedicated Fox Hills[1] monitoring wells	Vadose zone and lowest USDW
Direct Reservoir	Pulsed-neutron logs with temperature and pressure readings, pressure falloff testing, and surface pressure gauges	Storage reservoir and dissipation intervals
Indirect Reservoir	Time-lapse 2D seismic surveys and vertical seismic profiles (VSPs)	Entire storage complex

[1] Supervisory Control and Data Acquisition
[2] Platform multifinger imaging tool.
[3] Ultrasonic imaging tool.

[1] The Fox Hills aquifer underlying the Great Plains CO_2 Sequestration Project site and western North Dakota is a confined aquifer system which does not receive measurable flow from overlying aquifers or the underlying Pierre Shale. The overlying confining layer in the Hell Creek Formation comprises impermeable clays, and the underlying Pierre Shale serves as the lower confining layer (Trapp and Croft, 1975). Recharge occurs hundreds of miles to the southwest in the Black Hills of South Dakota, where the corresponding geologic layers are exposed at the surface. Flow within the aquifer is to the east with a rate on the order of single feet per year. Thus groundwater in the Fox Hills aquifer at the Great Plains CO_2 Sequestration Project site is geochemically stable, as it is isolated from its source of recharge and does not receive other sources of recharge (Fischer, 2013). The aquifer itself is a quartz-rich sand and is not known to contain reactive mineralogy. Minimal geochemical variation can be expected to occur across the site, attributable to minor variations in the geologic composition of the aquifer sediments.

5.1 CO_2 Stream Analysis and Injection Well Mechanical Integrity Testing

5.1.1 CO_2 Stream Analysis

The CO_2 stream is analyzed daily at the capture facility, using methods and standards generally accepted by industry. The chemical content of the captured gas is 95.9 by volume percent CO_2 and 4.1 by volume percent other chemical components, as summarized in Table 5-2. The physical characteristics of the CO_2 stream, including its corrosiveness, temperature, and density are also measured daily at the capture facility.

Table 5-2. Chemical Content of the CO_2 Stream

Chemical Content	Volume Percent
Carbon Dioxide	95.9
C_2^+ and Hydrocarbons	1.8
Hydrogen Sulfide	1.2
Methane	0.6
Nitrogen	0.5
Total	100.0

5.1.2 Injection Well Mechanical Integrity Testing

A USIT, in combination with variable density and cement bond logs, was used to establish the baseline external mechanical integrity in the Coteau 1 well. The same suite of logging tools will also establish baseline conditions in the other injection wells, and the USIT will be run during well workovers but not more frequently than once every 5 years. Baseline temperature data will also be collected prior to operations and will be regularly performed using a phased approach (described in the following paragraph) to verify external mechanical integrity in the injection wells.

DGC's phased approach: pulsed-neutron logs (PNLs), which include a temperature log and bottomhole pressure (BHP) readings, will be run in an individual injection well quarterly. Each injection well will be placed on a rotating schedule to gather these downhole data, starting with Coteau 1 in the first quarter, Coteau 2 in the second quarter, Coteau 3 in the third quarter, and Coteau 4 in the fourth quarter, at which point the rotation will be repeated. Once drilled, the Coteau 5 and Coteau 6 wells will be added to the rotating schedule and the frequency adjusted to a bimonthly basis.

A BHP survey will be acquired each month during the first quarter of operations to supplement the phased approach described above. These supplemental BHP readings will confirm that the wellhead pressure (WHP):BHP correlation (pressure gradient) is accurate and reliable. If the WHP:BHP correlation is reconciled with the BHP data in the first quarter, BHP surveys will continue to be acquired at the frequency and schedule described in the phased approach.

Internal mechanical integrity of the injection wells will be demonstrated via tubing-casing annulus pressure tests prior to injection and during well workovers but not more frequently than once every 5 years. Pressure falloff tests will be performed in the injection wells prior to injection. During injection operations, pressure falloff testing will be carried out via surface pressure monitoring at least once every 5 years to demonstrate storage reservoir injectivity. In addition, the injection wells will be continuously monitored for surface and annular pressure anomalies by maintaining a consistent 200 pounds per square inch on the annulus with a nitrogen cushion that will be placed and maintained on top of the packer fluid. USITs may be run during workovers (including when tubing is pulled) but not more frequently than once every 5 years, to further assess the internal mechanical integrity of the injection wells.

5.2 Corrosion Monitoring and Prevention Plan

The purpose of the corrosion monitoring and prevention plan is to monitor the surface facilities and injection well components during the operational phase of the Great Plains CO_2 Sequestration Project to ensure that the materials meet the minimum standards for material strength and performance. Figure 5-1 illustrates the pad drawings for the Coteau 1 through Coteau 4 wells.

DGC permitted a new 6.8-mile-long transmission line through the North Dakota Public Service Commission (PSC) in July 2021 (PU-21-150). The transmission line implements a corrosion monitoring and prevention strategy that was approved by PSC and is not discussed in this storage facility permit application. At the transition from transmission line to flowline (Figure 5-2), DGC's efforts to monitor and prevent corrosion of the flowline and well materials at the injection wellsites are presented in Sections 5.2.1 and 5.2.2.

5.2.1 Corrosion Monitoring

DGC will install a 3-foot test section of 4½-inch L-80 tubing in the flowlines near each wellhead for regular testing and corrosion monitoring of the well material. The tubing joints will be inspected monthly via ultrasound equipment during the first quarter, then quarterly thereafter for the first 2 years. If the well materials (i.e., tubing) show no sign of corrosion within the first 2 years of the injection period, future internal monitoring of the tubing will be accomplished through a platform multifinger imaging tool (PMIT), or in the event a downhole tubing string is pulled for any reason, it will be inspected at the surface for corrosion and mechanical integrity. USITs may also be run during workovers (including when tubing is pulled), but not more frequently than once every 5 years, to further assess any corrosion of the injection string.

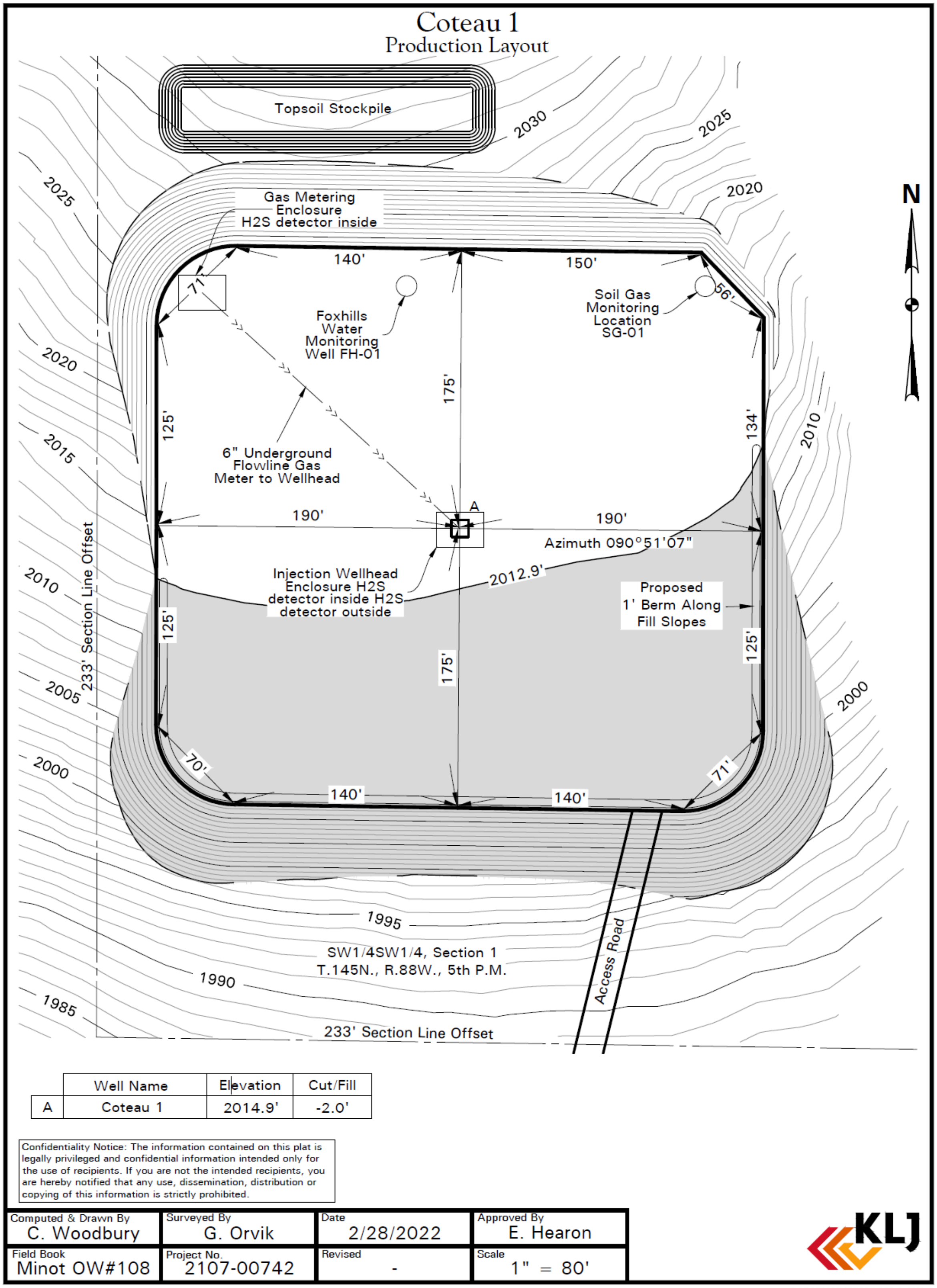


Figure 5-1A. Well pad drawing of the Coteau 1 well location.

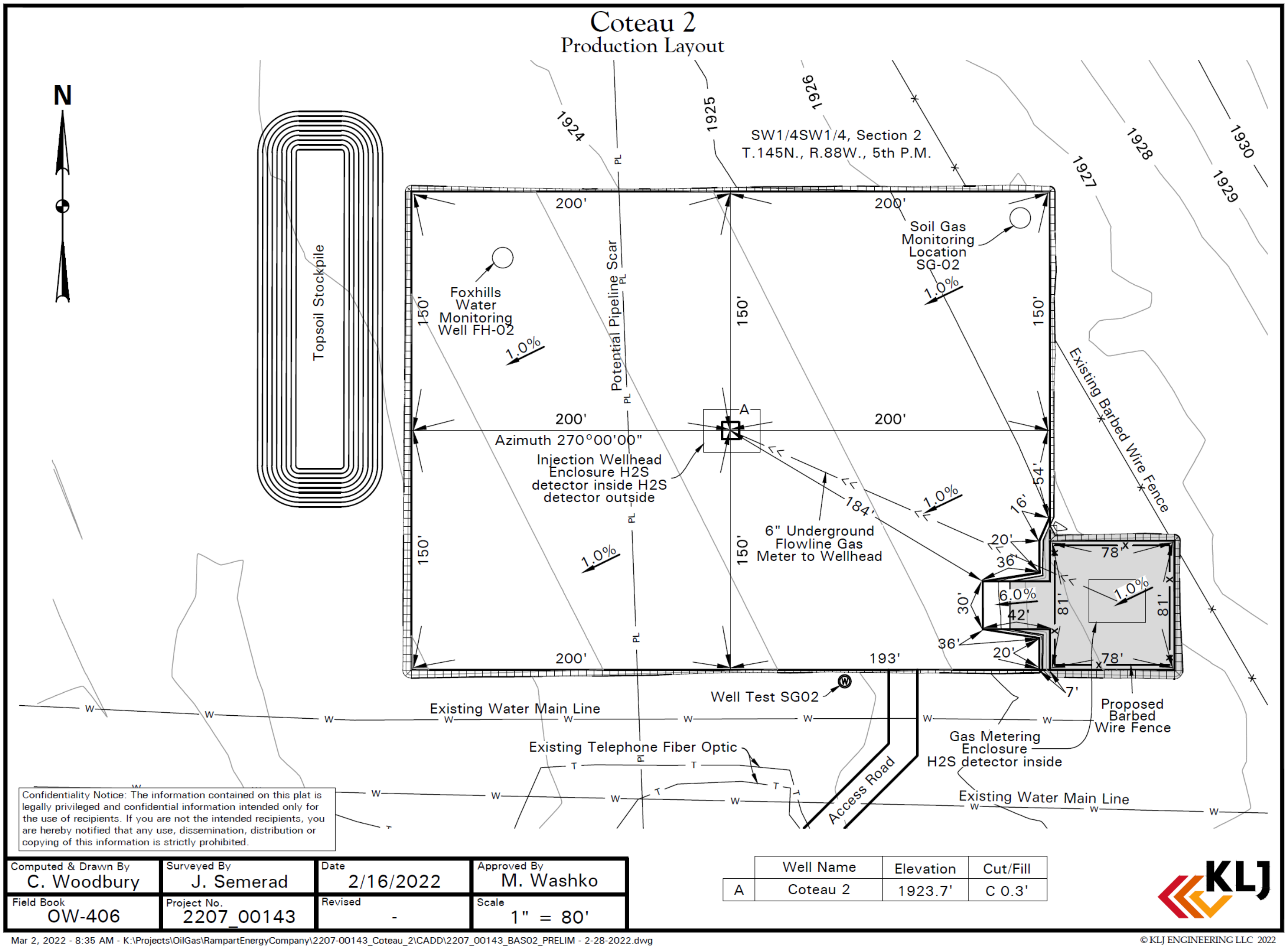


Figure 5-1B. Well pad drawing of the Coteau 2 well location.

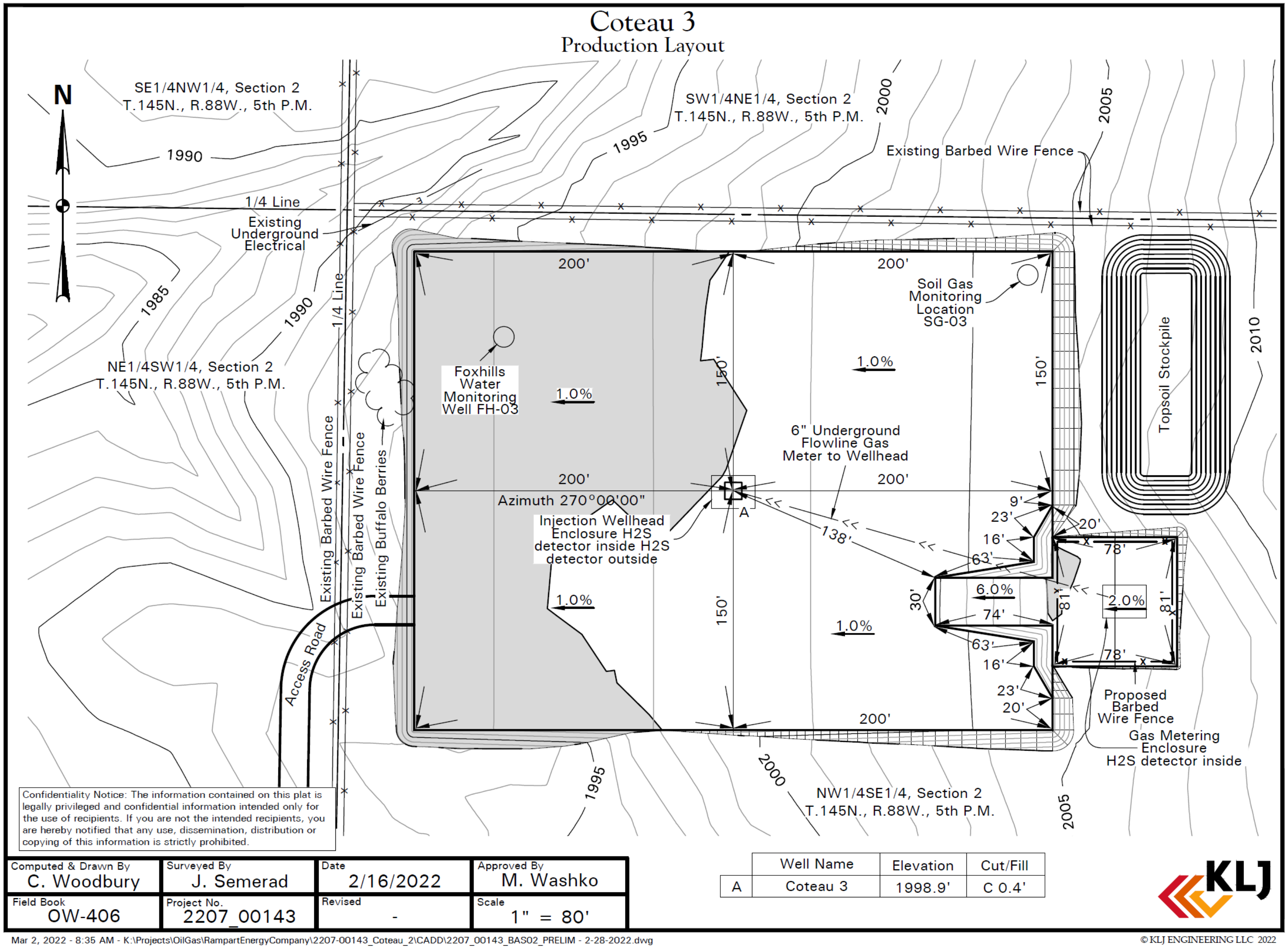
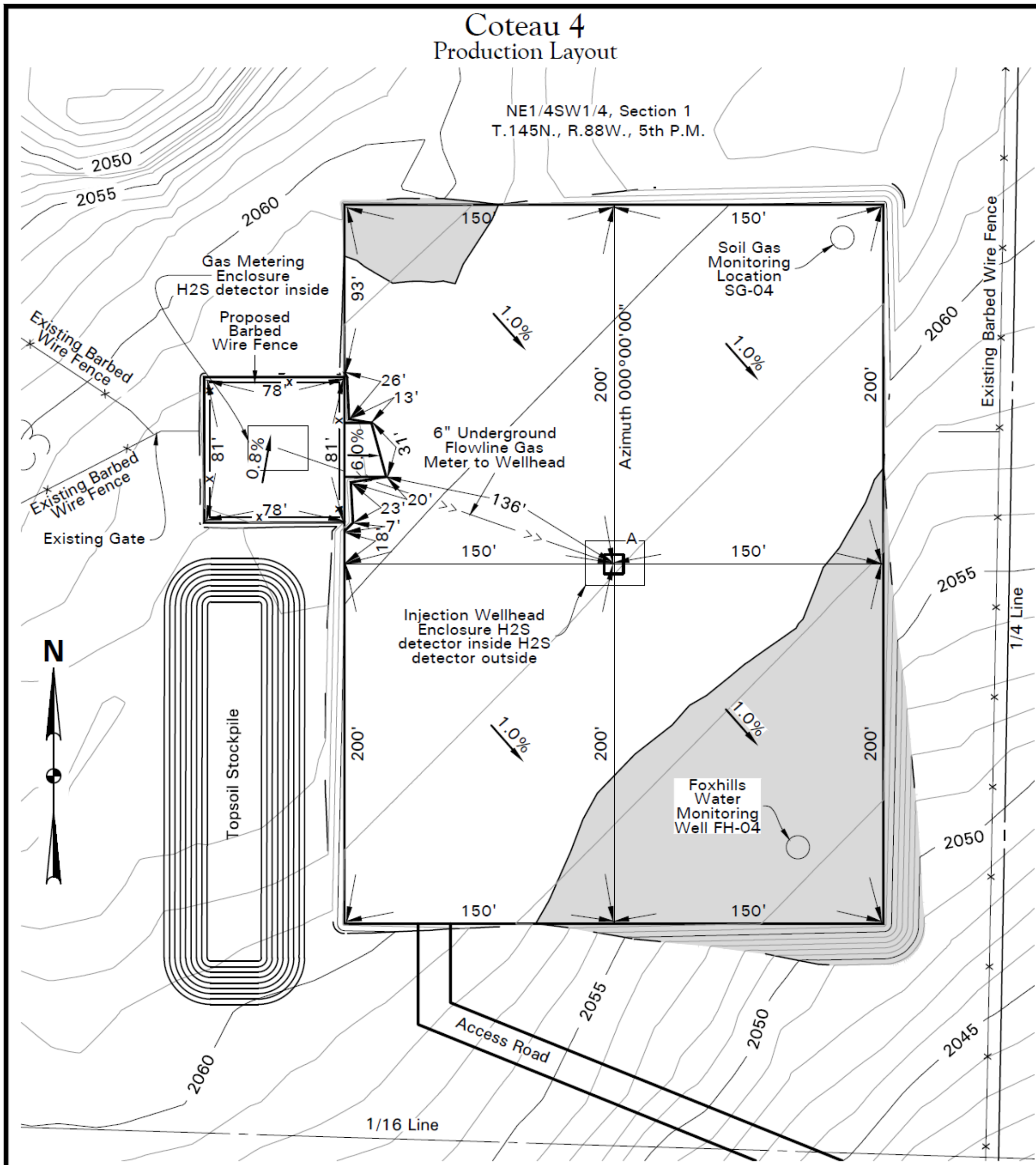


Figure 5-1C. Well pad drawing of the Coteau 3 well location.



	Well Name	Elevation	Cut/Fill
A	Coteau 4	2060.8'	C 1.7'

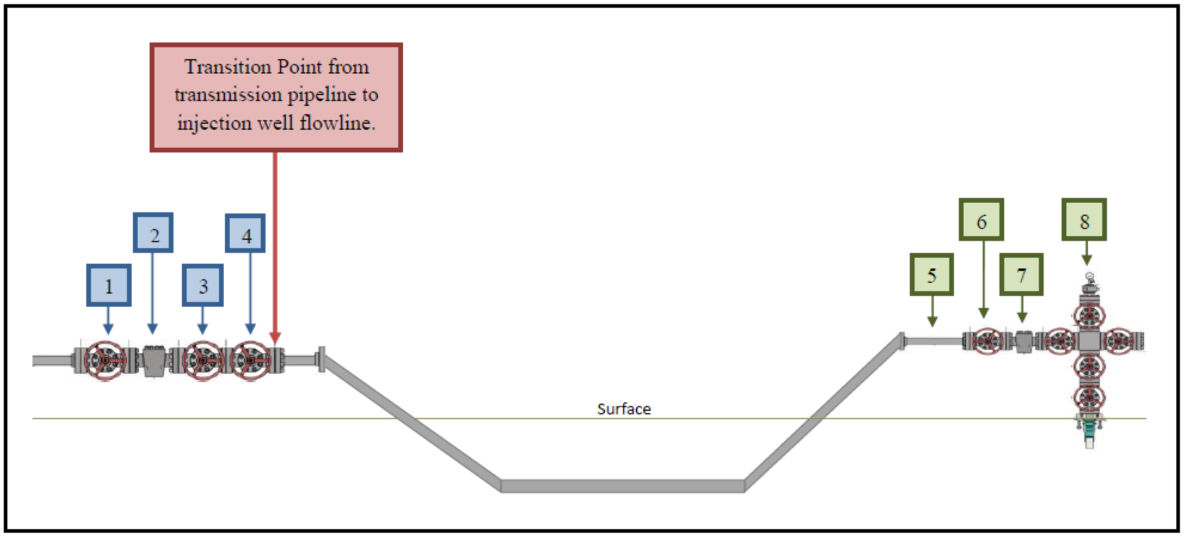
Computed & Drawn By	Surveyed By	Date	Approved By
C. Woodbury	J. Semerad	2/16/2022	M. Washko
Field Book	Project No.	Revised	Scale
OW-406	2207_00143	-	1" = 80'

KLJ

Mar 2, 2022 - 8:35 AM - K:\Projects\OilGas\RampartEnergyCompany\2207-00143_Coteau_2\CADD\2207_00143_BAS02_PRELIM - 2-28-2022.dwg

Figure 5-1D. Well pad drawing of the Coteau 4 well location.

Great Plains CO2 Sequestration Project
Coteau No. 1 Surface Connections



1. Block valve (capable of remote operation) - this valve will shut down CO_2 to the flowline in the event of a leak or other issue.
2. Flow Meter.
3. Pressure control valve.
4. Block valve (capable of remote operation) - this valve will shut off CO_2 to the well if for some reason the control valve outlet pressure approaches the maximum well head pressure.

5. 4 1/2" L-80 Tubing test section.
6. 4 1/16" 5M isolation wing valve.
7. One-way check valve to prevent backflow of CO2 from the reservoir in the event of an emergency shutdown.
8. 4 1/6' 5M Tree with 200 psi of static operating pressure held on the tubing-casing annulus. A deviation of 20% in either direction will trigger closure of the remote block valve, as will an alarm condition from the surface H2S monitors.

Figure 5-2. Diagram of surface connections at the Coteau 1 wellsite. The Coteau 2 through 5 wells will connect to a common gathering system at the Coteau 1 well pad. The Coteau 6 will be similarly equipped but will connect to a separate gathering system. The primary block valve (item 1 above) will be located at the Coteau 1 well while the rest of the equipment (Items 2 through 8 above) will be located on the well pads of each of the injection wells.

5.2.2 Corrosion Prevention

To prevent corrosion of the well materials, the following preemptive measures will be taken: 1) cement in the injection wells opposite the injection interval and extending more than 2,000 feet uphole will be CO_2-resistant, 2) the well casing (L-80 13Cr) will also be CO_2-resistant from the bottomhole to a depth just above the Opeche Formation in the injection wells, and 3) the packer fluid will be an industry standard corrosion inhibitor. In addition, the chemical composition of the CO_2 stream is highly pure (Table 5-2) and dry, with a moisture level for the CO_2 stream typically less than two parts per million by volume, both factors of which help to prevent corrosion of the surface and well materials.

5.3 Surface Leak Detection and Monitoring Plan

Surface components of the injection system, including the flowlines and wellheads, will be monitored using leak detection equipment. The wellsite flowlines will be monitored continuously via multiple pressure gauges and H_2S detection stations located between the transmission line and the individual wellheads. This leak detection equipment will be integrated with automated warning systems that notify the pipeline control center at DGC, giving the operator the ability to remotely close the valves in the event of an anomalous reading. Performance targets designed for the Great Plains CO_2 Sequestration Project to detect potential leaks in the flowline are provided in Table 5-3. The performance targets are dependent upon the actual performance of instrumentation (e.g., pressure gauges) and the supervisory control and data acquisition (SCADA) system, which uses software to track the status of the pipeline system in real time by comparing live pressure and flow rate data to a comprehensive predictive model. The performance targets assume a flow rate of 200 million standard cubic feet per day (MMSCFD) of CO_2. An alarm will trigger on the SCADA system if a volume deviation of more than 2% is registered. H_2S detection stations will also be mounted on the inside and outside of wellhead enclosures to detect any potential indoor and atmospheric leaks at the well pad locations, respectively. The stations can detect H_2S concentrations as low as 1 part per million (ppm) and have an integrated alarm system if a 10 ppm threshold is crossed. The stations are further described in Appendix C (Attachment A-7). Field personnel will have multi gas detectors with them for wellsite visits or flowline inspections to detect potential leaks from the equipment. The multi gas detectors will primarily monitor for CH_4, CO, O_2, and H_2S up to 100 feet from a surface leakage source. The multi gas detector will measure H_2S as low as 0.1 ppm with an incremental resolution of 0.1 ppm and has built-in alarms. Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

Table 5-3. Performance Targets for Detecting Potential Leaks in Surface Equipment with SCADA

Leak Size (MMSCFD)	Detection Time (minutes)
200	<2
>10	<5
<10 and >4	<60

5.4 Subsurface Leak Detection and Monitoring Plan

The monitoring plan for detecting subsurface leaks comprises “surface/near-surface” and deep subsurface monitoring programs. “Surface/near-surface” refers to the region from ground surface down to, and including, the lowest USDW as well as surface waters, soil gas (vadose zone), and shallow groundwater (e.g., stock wells, residential drinking water wells, etc.). The deep subsurface zone extends from the base of the lowest USDW to the base of the injection zone of the storage reservoir.

Subsurface leak detection will include multiple approaches to ensure confidence that surface (i.e., ambient and workspace atmospheres and surface waters) and near-surface (i.e., vadose zone, groundwater wells, and the lowest USDW) environments are protected, and the CO_2 is safely and permanently stored in the storage reservoir. More specifically, for DGC's geologic storage project, near-surface monitoring will include 11 soil gas profile stations and seven dedicated Fox Hills Formation monitoring wells within the AOR to detect if the lowest USDW is being impacted by operations. These monitoring efforts will provide additional lines of evidence to assess whether the surface/near-surface environment is being protected and whether the CO_2 is being safely and permanently stored in the storage reservoir.

To complement surface/near-surface monitoring, additional monitoring of the subsurface will ensure CO_2 is staying in the targeted storage reservoir. Operational monitoring at the injection wells, including injection rates, pressures, and temperatures will provide data to inform the monitoring approaches. Internal and external mechanical integrity of the injection wells will also be demonstrated to ensure no leakage pathway exist that may allow vertical movement of the CO_2. Additionally, geophysical (seismic) surveys conducted over regular intervals will monitor subsurface CO_2 plume movement.

More details regarding the surface, near-surface, and deep subsurface monitoring efforts are provided in sections 5.5 through 5.7.

5.5 Near-Surface Soil Gas and Groundwater Sampling and Monitoring

Near-surface environments will be monitored to ensure that an out-of-zone migration has not occurred. This will be accomplished by monitoring the environment within the delineated AOR via vadose zone soil gas and Fox Hills (lowest USDW) sampling prior to CO_2 injection (preoperational baseline), during active CO_2 injection (operational), and during the postoperational monitoring time frame. Figure 5-3 illustrates the baseline sampling program for vadose zone and groundwater in the Fox Hills Formation. In addition, baselines for shallow groundwater aquifers within the AOR, which may be used in the future to monitor the geologic storage project area, are included in Appendix B.

DGC initiated a seasonal baseline sampling program for soil gas (Figure 5-3) and plans to complete this part of the baseline program by July 2022. Eleven soil gas profile stations have been installed: one station near each wellsite (Coteau 1 through 6 wells) and five more spaced apart and located around the edge of the predicted 12-year CO_2 plume extent. Sample analysis of each profile station will be provided to NDIC prior to CO_2 injection operations. This initial sampling program and the results are provided in detail in Section 5.5.1.

DGC initiated a baseline groundwater sampling program in the Fox Hills Formation in the Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells (Figure 5-3). Upon field investigation, it was found that the Floyd Weigum #1 was abandoned and could not be sampled; therefore, its historical data will be used as a baseline instead. Archived water quality analyses on all three wells are available in Appendix B.

Prior to injection, DGC will install six dedicated Fox Hills Formation monitoring wells at each injection wellsite (Coteau 1 through 6 wells). A seventh Fox Hills Formation monitoring well will be placed along the western edge of the AOR near the Herrmann 1 well (NDIC File No. 4177). A state-certified laboratory analysis will be provided to NDIC prior to injection for all additional groundwater sampling in the Fox Hills Formation. This initial sampling program and the results are provided in detail in Section 5.5.2.

The near-surface monitoring plan, including the additional baseline sampling of groundwater, the Fox Hills Formation, and the soil gas profile stations, is provided in Section 5.6.

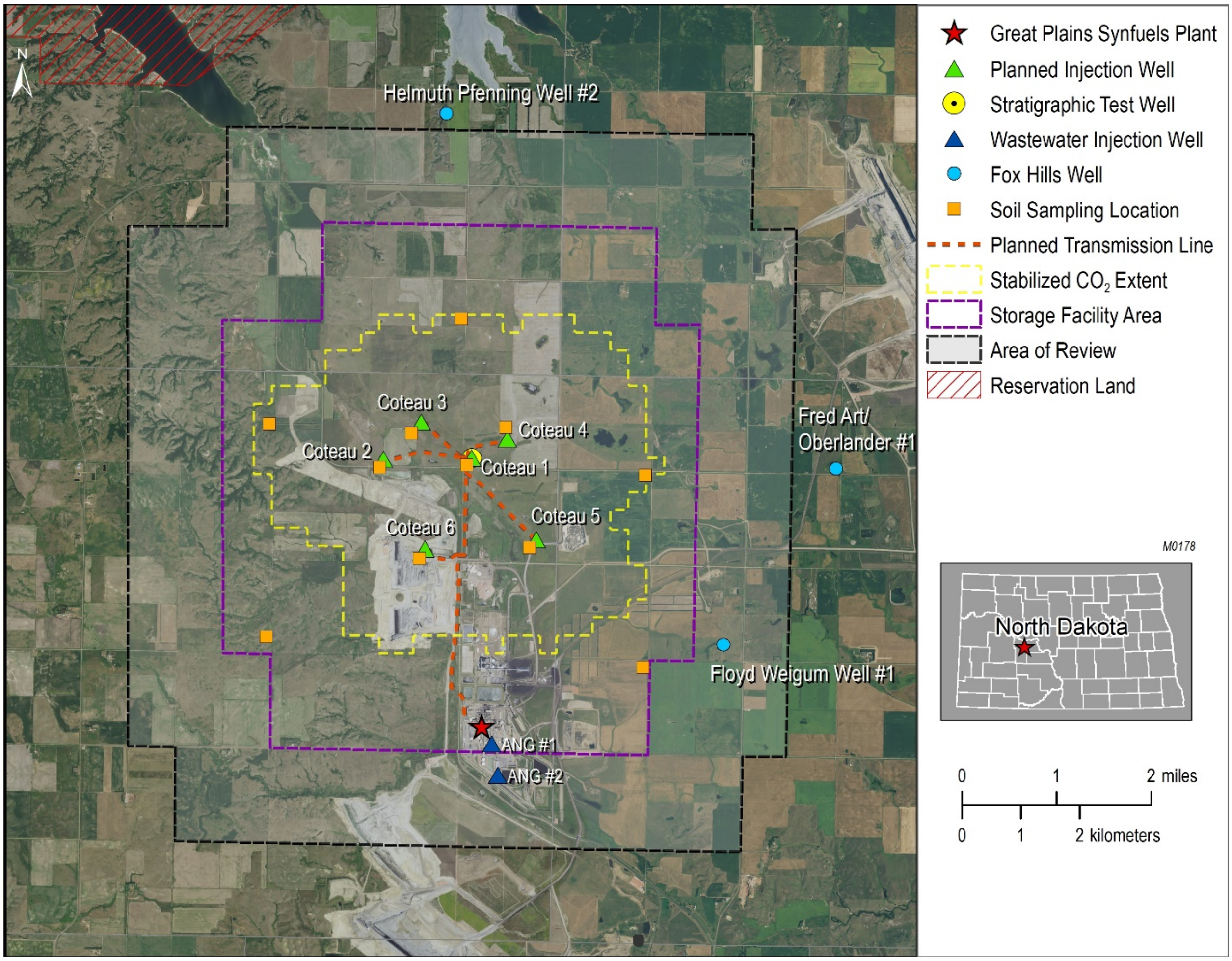


Figure 5-3. DGC's initiated baseline sampling program for vadose zone soil gas and groundwater in the Fox Hills Formation.

5.5.1 Soil Gas Baseline Sampling

Soil gas sampling and analyses have been initiated to establish seasonal baseline soil gas geochemical results, including concentrations of CO_2, O_2, and N_2 and isotopic ratios for $^{13}CO_2$, $^{13}C_1$, and δC_1. An initial set of samples and associated analyses were collected in October and November 2021, as shown in Table 5-4.

The sampling results from these efforts will provide a preoperational seasonal baseline of the soil gas geochemistry in the vadose zone in and around the CO_2 geologic storage project. DGC plans to sample and run analyses on the soil gas profile stations quarterly until July 2022. During operations, DGC will continue to collect soil gas concentrations quarterly from the 11 soil gas profile stations.

Table 5-4. DGC's Initial Soil Gas Geochemical Results – Fall 2021

Well No.	CO_2, ppm	O_2+Ar, ppm	N_2, ppm	$\delta^{13}CO_2$, ‰ VPDB[1]	$\delta^{13}C_1$, ‰ VPDB	δD_{C1}, ‰ VSMOW[2]
SG01[3]	305,420	16,923	685,166	−14.0	−13.1	−376
SG02[4,5]	2,402	194,468	796,541	−20.3		
SG03	193,032	27,421	786,850	−14.7		
SG04	209,353	11,773	784,351	−6.7		
SG05	202,316	51,148	760,674	−1.1		
SG06[4]	21,158	162,573	817,003	−20.5		
SG07[4,5]	2,582	215,422	781,419	−22.0		
SG08	213,591	13,855	781,768	−18.8		
SG09	135,306	13,292	863,995	−17.8		
SG10	158,590	89,475	767,489	−18.4		
SG11[4]	9,822	203,018	787,739	−17.1		

1 Vienna Pee Dee Belemnite $\delta^{13}C$ Standard.
2 Vienna Standard Mean Ocean Water.
3 Single well in data set with sufficient volume of measured methane levels to run stable isotope analysis.
4 Because of local variations in the water table, wells SG02, SG06, SG07, and SG11 were limited to sample depths from 4 to 9 feet below ground surface (bgs). All other locations obtained samples from 22 to 23 feet bgs.
5 Low isotopic signal results.

5.5.2 Groundwater Baseline Sampling

Two Fox Hills Formation samples were obtained in November 2021 from the Fred Art/ Oberlander #1 and Helmuth Pfenning #2 wells. State-certified laboratory results for these two wells found in Appendix B show little variation among the reports.

The locations of the wells investigated for establishing baseline conditions are shown in Figure 5-3, and the results of the baseline measurements for pH, specific conductivity, and alkalinity are provided in Table 5-5, with state-certified laboratory results for each sampling event provided in Appendix B. In addition, DGC plans to obtain a baseline water sample from the Fox Hills monitoring well that will be drilled near the Herrmann 1 well (NDIC File No. 4177) prior to injection operations.

Table 5-5. DGC's Initial Baseline Groundwater Sampling Results – Fall 2021

Well Name	pH (pH unit)	Conductivity, µmhos/cm	Total Alkalinity, mg/L $CaCO_3$
Fred Art/Oberlander #1	8.5	2519	1020
Helmuth Pfenning #2	8.4	2347	1280
Floyd Weigum #1*	N/A	N/A	N/A

* Wellbore was confirmed in the field to be abandoned and determined inaccessible for sampling.

5.6 Near-Surface (groundwater and soil gas) Monitoring Plan

Prior to injection operations, DGC will drill and construct a total of five dedicated groundwater monitoring wells in the Fox Hills Formation (i.e., lowest USDW). One groundwater monitoring well will be placed at each of the injection well locations (Coteau 1 through 4 wells initially) and another will be placed near the Hermann 1 well (NDIC File No. 4177) (Figure 5-4). Baseline Fox Hills Formation water samples will be collected from all five monitoring wells prior to CO_2 injection. Dedicated Fox Hills Formation monitoring wells will also be drilled and constructed for the Coteau 5 and the Coteau 6 injection wells after they are drilled and constructed prior to 2026. DGC plans to monitor the vadose zone using the 11 soil gas profile stations already installed.

Over the life of CO_2 injection activities, the 11 soil gas profile stations will be sampled quarterly along with the Fox Hills groundwater monitoring wells located near each of the injection wells. State-certified laboratory results of the groundwater wells will be filed with NDIC. A detailed near-surface monitoring plan is presented in Table 5-6, including the duration and frequency of the sampling that will be made during each phase (i.e., preinjection, operational, and postoperational) of the geologic CO_2 storage project.

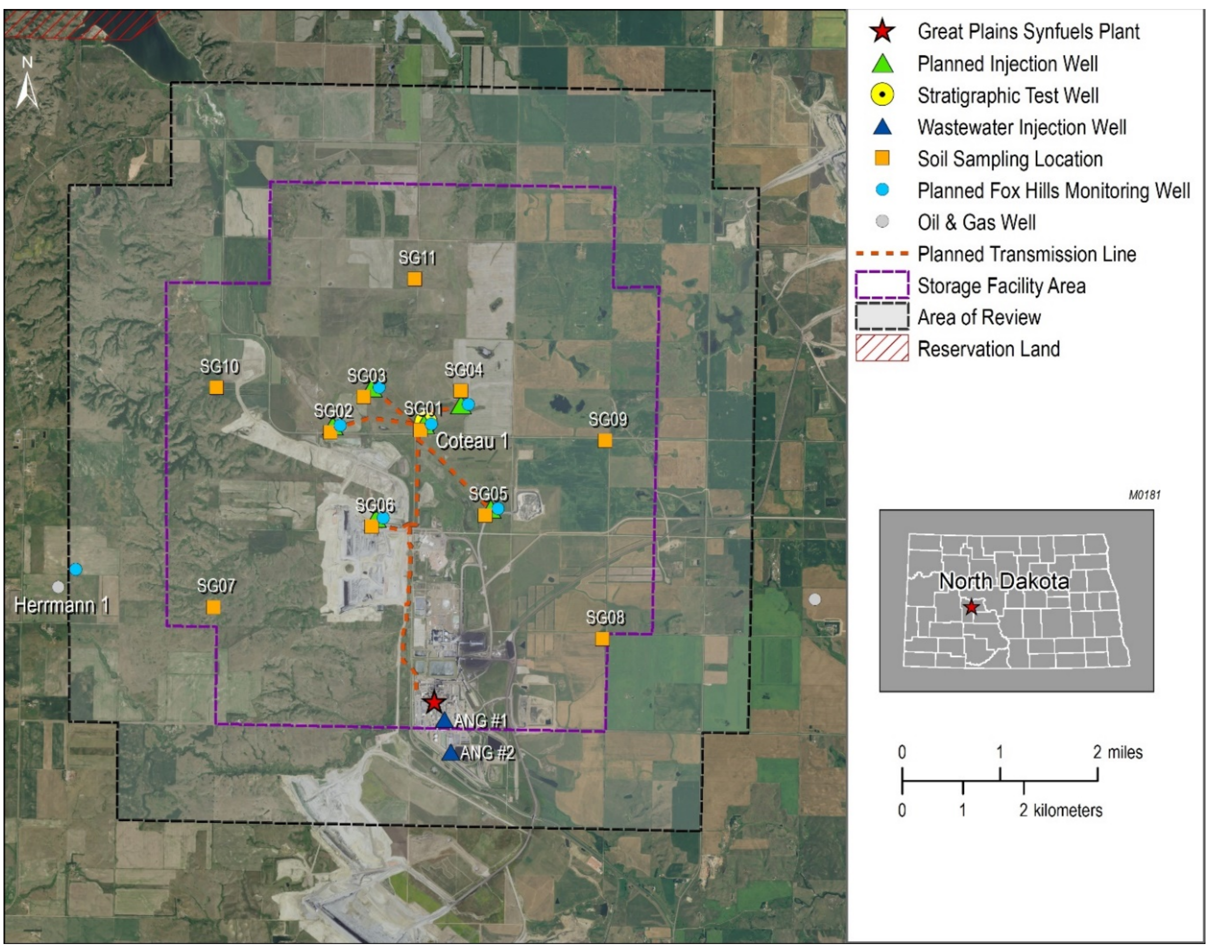


Figure 5-4. DGC's near-surface monitoring plan for seven Fox Hills Formation (lowest USDW) monitoring wells and the 11 soil gas profile stations around the storage facility area.

Table 5-6. Baseline (preinjection), Operational, and Postoperational Monitoring Duration and Frequency for Soil Gas and Groundwater

Monitoring Type	Baseline (preinjection)*	Operational	Postoperational
Soil Gas Monitoring			
Soil Gas Profile Stations (SG01 to SG11) (Figures 5-3 and 5-4)	Duration: Minimum one year Frequency: Sample 3–4 events per well to establish seasonal baseline Perform concentration and isotopic testing on all samples	Duration: 12 years Frequency: Sample 3–4 events per year to account for seasonal fluctuation Perform concentration testing on all samples	Duration: Minimum 10 years postinjection Frequency: Sample 3–4 events per year Perform concentration testing on all samples
Groundwater Monitoring			
Fred Art/Oberlander #1 and Helmuth Pfenning #2 (Figure 5-3) Fox Hills monitoring well by Herrmann 1 (Figure 5-4)	Duration: Prior to injection to establish baseline and verify historic geochemical data Frequency: Once to establish a baseline and verify consistency of historical well test data (Appendix B) Perform water quality and isotopic testing on all samples	None Shift sampling program to the dedicated Fox Hills monitoring wells	None
Six monitoring wells in the Fox Hills Formation (lowest USDW) at injection wellsites (Coteau 1 through 6 wells) (Figure 5-4)	Duration: Prior to injection Frequency: Sample 3–4 events per well annually Perform water quality testing on all samples	Duration: 12 years Frequency: Sample 3–4 events per well annually Perform water quality testing on all samples	Duration: Minimum 10 years postinjection Frequency: Sample 3–4 events per well annually Perform water quality testing on all samples

* The baseline (preinjection) monitoring effort has begun as of the writing of this permit application. As noted in the text, additional sampling will be performed between the submission date of this permit application and the start of CO_2 injection.

5.7 Deep Subsurface Monitoring of Free-Phase CO_2 Plume and Pressure Front

DGC will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure relative to the permitted storage reservoir. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and postoperational periods. The methods described in Table 5-7 will be used to characterize the plume and pressure within the AOR. DGC will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan (Ayash and others, 2017). During each review, monitoring and operational data will be analyzed, the AOR will be reevaluated, and if warranted, the testing and monitoring plan will be adjusted accordingly. The testing and monitoring plan will be reviewed in this manner at least once every 5 years. Based on this review, it will either be demonstrated that no amendment to the testing and monitoring program is needed or that modifications to the program are necessary to ensure proper monitoring of the storage performance is achieved and that the risk profile of the storage operations is addressed moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by NDIC. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of the CO_2 plume and pressure distribution relative to the permitted geologic storage facility. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will, in turn, be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

Table 5-7. Description of DGC's Deep Subsurface Monitoring Program

Monitoring Type	Preoperational (baseline)	Operational	Postoperational
Mechanical Integrity Testing (MIT)			
USIT (external MIT)	Prior to injection	Duration: 12 years Frequency: Perform when tubing is pulled but not more frequently than once every 5 years.	None Injection wells will be plugged.
Temperature Logs Run with PNL (external MIT)	Prior to injection	Duration: 12 years Frequency: Quarterly using phased approach described in Section 5.1.2	None Injection wells will be plugged.
200 psi Kept on Annulus, Between Tubing and Long-String (multifinger imaging tool [internal MIT])	Prior to injection Initial volume of packer fluid (corrosion inhibitor) and nitrogen cushion to fill casing	Duration: 12 years Frequency: Continuous Nitrogen cushion will be used to maintain a consistent pressure.	None Injection wells will be plugged.
Tubing-Casing Annulus Pressure Testing (internal MIT)	Prior to injection	Duration: 12 years Frequency: Perform during well workovers but not more frequently than once every 5 years.	None Tubing will be pulled from the injection wells, and the injection wells will be plugged.
Pressure Falloff Test in the Injection Zone (internal MIT)	Prior to injection	Duration: 12 years Frequency: Once every 5 years	None Injection wells will be plugged.
Storage Reservoir (Direct) Monitoring			
Flow Rate and Volume, Surface Injection Pressure, and Surface Injectate Temperature	At start of injection operations	Duration: 12 years Frequency: Continuous monitoring	None Injection operations will have ceased.
PNLs with Temperature Logs and Pressure Recording Devices Attached	Prior to injection	Duration: 12 years Frequency: Quarterly, using phased approach described in Section 5.1.2	None Injection wells will be plugged.

Continued…

Table 5-7. Description of DGC's Deep Subsurface Monitoring Program (continued)

Monitoring Type	Baseline (preoperational)	Operational	Postoperational
Surface Pressure Gauges on the ANG #1 and ANG #2	None	Duration: 12 years Frequency: Continuous monitoring of surface pressures to history match predictions	Duration: Minimum 10 years postinjection Frequency: Continuous monitoring of surface pressures to history match predictions
Above-Zone Monitoring Interval (AZMI)			
PNLs with Temperature Logs Attached	Prior to injection	Duration: 12 years Frequency: Quarterly, using phased approach described in Section 5.1.2	None Injection wells will be plugged.
Geophysical (Indirect) Monitoring			
Time-Lapse Seismic (Figure 5-7)	Prior to injection Collect baseline 2D seismic survey	Repeat 2D seismic one year after injection begins, then in Years 3, 5, and 10.	Time-lapse seismic surveys will continue as part of minimum 10-year postinjection monitoring plan and until stability of plume is demonstrated. Frequency: Perform 2D radial seismic surveys at the cessation of CO_2 injection, 1 year after injection ends, then in Years 3, 5, and 10
VSPs	Prior to injection	Repeat VSP 1 year after injection begins, then (if deemed beneficial) in Years 3, 5, and 10.	None

Table 5-8 describes the testing and logging program developed for the Coteau 1 wellbore. Included in the table is a description of fluid sampling and pressure testing performed. The logging and testing program for the Coteau 2 through 6 wells will be the same as what is presented in Table 5-8 but without the combinable magnetic resonance and dipole sonic logs. Wellbore data collected from the Coteau 1 have been integrated with the geologic model and to inform the reservoir simulations that are used to characterize the initial state of the reservoir before injection operations. The simulated CO_2 plumes based on the current geologic model and simulations are shown in Figures 5-5 and 5-6. These simulated CO_2 plume extents inform the timing and frequency of the application of the direct and indirect monitoring methods of the testing and monitoring plan.

Table 5-8. Testing and Logging Program for the Coteau 1 Wellbore

Log/Test	Justification	NDAC Section
Ultrasonic, CCL (casing collar locator), VDL (variable-density log), GR (gamma ray)	Identified cement bond quality radially. Interpreted good azimuthal cement coverage. Evaluated the cement top and zonal isolation.	43-05-01-11.2(1c[2])
Triple Combo (resistivity, density, porosity, GR, caliper, and spontaneous potential)	Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. Provided input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve test design and interpretations.	43-05-01-11.2(1c[1])
Combinable Magnetic Resonance (CMR)	Aided in interpreting reservoir permeability, packer setting depths, and stress testing depths. CMR and MDT data combined provided enhanced permeability evaluation, temperature variation, fluid identification, and fluid contacts.	43-05-01-11.2(1c[1])
Spectral GR	Identified clays and lithology that could affect injectivity. Also used for core to log depth correlation.	43-05-01-11.2(2)
Dipole Sonic	Identified mechanical properties including stress anisotropy. Provided compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.	43-05-01-11.2(1c[1])
Fracture Finder Log	Quantified fractures in the Broom Creek Formations and confining layers to ensure safe, long-term storage of CO_2.	43-05-01-11.2(1c[1])
Perforation-Flowback	Collected fluid sample and pressure-tested the Broom Creek	43-05-01-11.2(2)

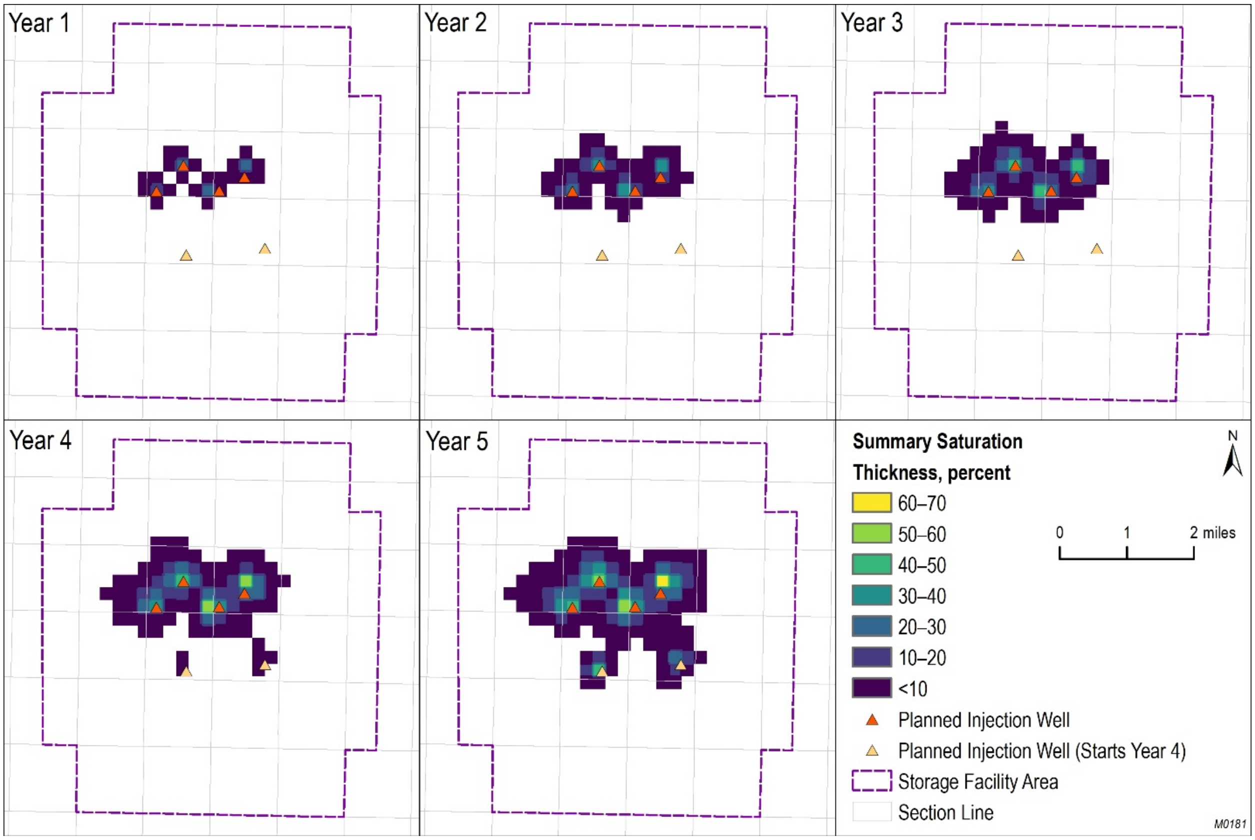


Figure 5-5. Simulated CO_2 plume saturation at the end of Years 1 through 5 after initial CO_2 injection. The simulated plume extent at 5 years (5.3 square miles) results in a CO_2 plume with an average radius of 6,442 feet.

Figure 5-6. Simulated extent of the CO_2 plume at the cessation of injection and the postinjection stabilized plume.

5.7.1 Direct Monitoring Methods

To directly monitor and track the extent of the CO_2 plume within the storage reservoir, PNLs with temperature logs and pressure data will be performed quarterly in the injection wells using the phased approach described in Section 5.1.2 of this storage facility permit The temperature and saturation data collected in the overlying Inyan Kara Formation, the nearest overlying, highly permeable interval above the storage reservoir and main sealing formations, will provide confirmation of seal capacity for the upper confining zone (i.e., Opeche Formation) for monitoring the performance of the storage complex (see Figure 2-3 for stratigraphic reference). Monitoring of the overlying interval can provide an early warning of out-of-zone migration of fluids, providing sufficient time for the development and implementation of mitigation strategies to ensure these migrating fluids do not impact a USDW or reach the surface.

Preoperational baseline PNL data have been collected from the Coteau 1 well. These time-lapse saturation data will be used to monitor for CO_2 in the formation directly above the storage reservoir, otherwise known as the AZMI, as an assurance-monitoring technique.

5.7.2 Indirect Monitoring Methods

Indirect monitoring methods will also track the extent of the CO_2 plume within the storage reservoir and can be accomplished by performing time-lapse 2D geophysical surveys and 2D VSPs (Figure 5-7). The 2D seismic acquisition lines indicated in Figure 5-7 will be extended over time to capture additional data as the CO_2 plume expands. Figure 5-8 illustrates the predicted extent of the injected free-phase CO_2 plume at the end of 12 years of injection relative to the baseline 2D seismic and storage facility area. To demonstrate conformance between the reservoir model simulation and site performance, a repeat 2D seismic survey and VSP will be collected to monitor the extent of the CO_2 plume after approximately 1 year of CO_2 injection. Additional 2D seismic data will be collected in Years 3, 5, and 10 to further delineate the CO_2 plume movement. Additional VSPs will be collected at the same frequency as the 2D seismic lines if the results of the first and second tests prove beneficial. These seismic monitoring data will provide confirmation of the simulation predictions and confirm the extents of the CO_2 plume within the AOR. Through the operational phase of the project, the time-lapse seismic monitoring plan will be adapted based on updated simulations of the predicted extents of the CO_2 plume. At the end of the operational phase, time-lapse seismic will be utilized during the postinjection period to confirm the stabilization of the CO_2 plume. These indirect monitoring methods for characterization of the deep subsurface CO_2 plume are commercially available and are proven time-lapse methods.

At the conclusion of the operating phase of the project, the planned monitoring program will continue to ensure the long-term containment and stability of the injected CO_2 in the storage complex (Table 6-1). Monitoring efforts in the postinjection phase will provide the data necessary for the required final assessment to prove long-term containment and stability of the injected CO_2 plume and secure a certificate of project completion from NDIC.

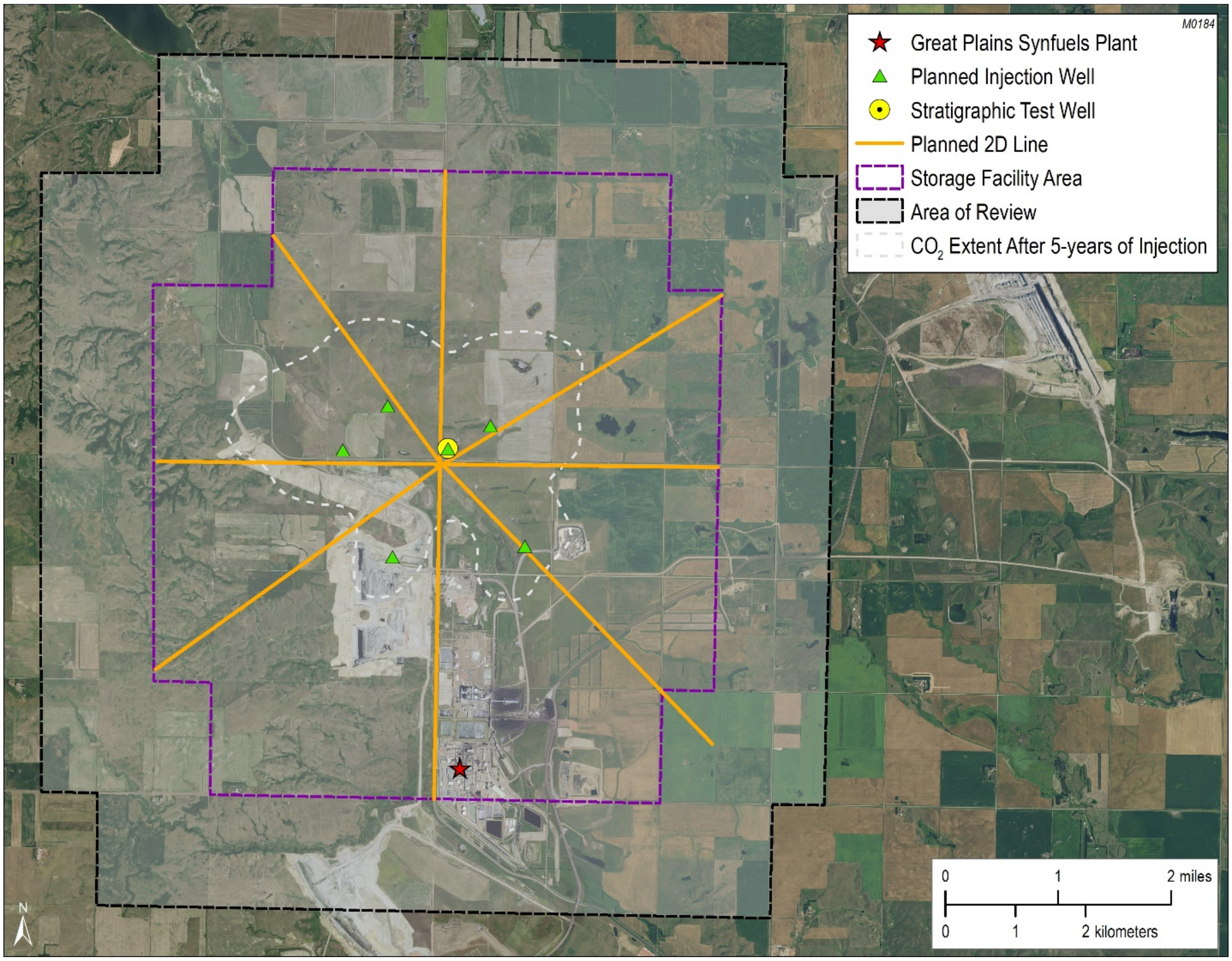


Figure 5-7. Locations of the planned 2D radial seismic lines near the Coteau 1 well to establish a baseline.

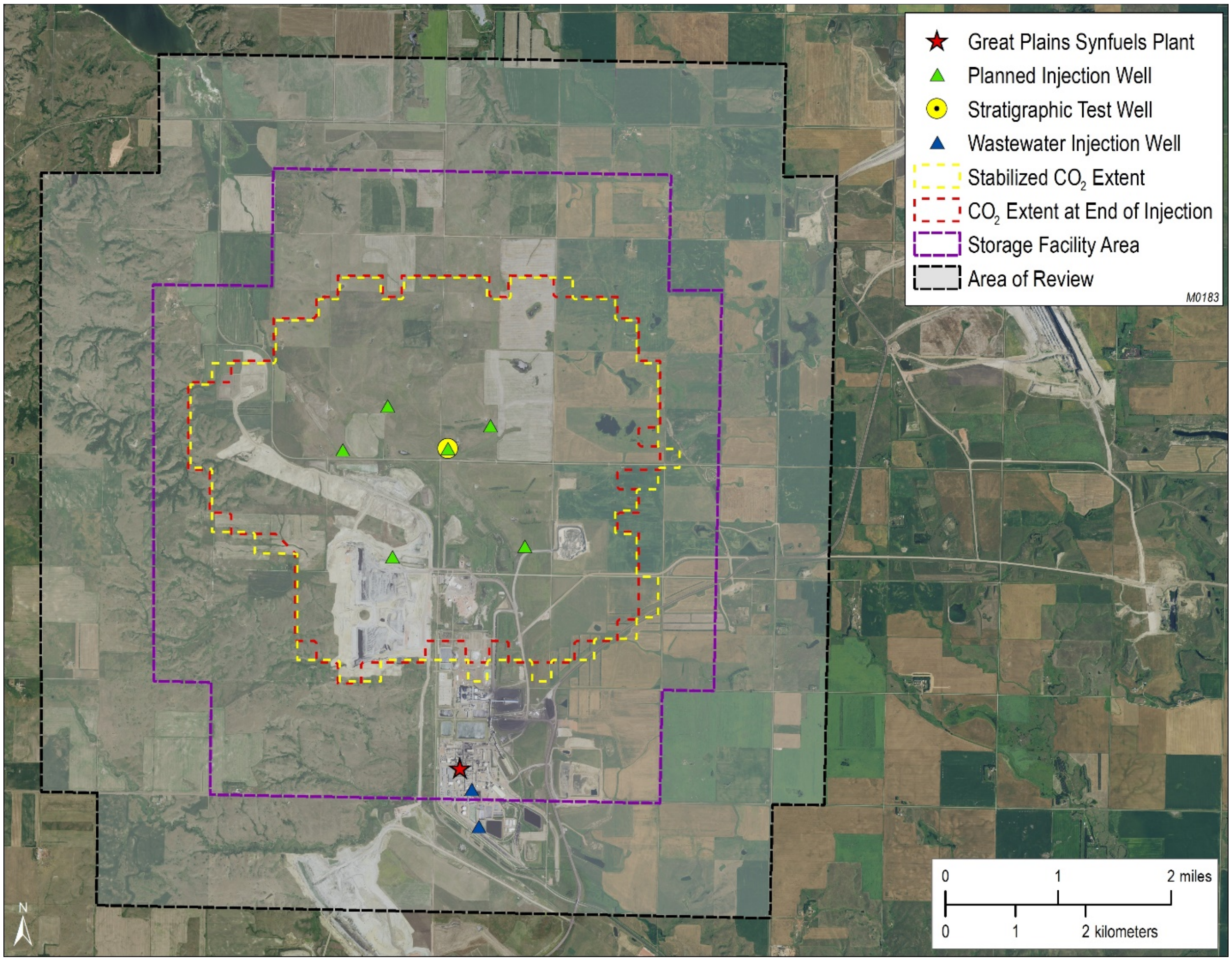


Figure 5-8. Simulated extent of the CO_2 plume at the end of injection operations in red and the stabilized CO_2 plume following the cessation of CO_2 injection in yellow.

5.8 References

Ayash, S.C., Nakles, D.V., Wildgust, N., Peck, W.D., Sorenson, J.A., Glazewski, K.A., Aulich, T.R., Klapperich, R.J., Azzolina, N.A., and Gorecki, C.D., 2017, Best practice for the commercial deployment of carbon dioxide geologic storage – the adaptive management approach: Plains CO_2 Reduction (PCOR) Partnership Phase III, Task 13 Deliverable D102/Milestone M59 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2017-EERC-05-01, Grand Forks, North Dakota, Energy and Environmental Research Center, August.

Fischer, K., 2013, Groundwater flow model inversion to assess water availability in the Fox Hills–Hell Creek Aquifer: North Dakota State Water Commission Water Resources Investigation 54.

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6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

This postinjection site care (PISC) and facility closure plan describes the activities that DGC will perform following the cessation of CO_2 injection to achieve final closure of the site. A primary component of this plan is a postinjection monitoring program that will provide evidence that the injected CO_2 plume is stable (i.e., CO_2 migration will be unlikely to move beyond the boundary of the storage facility area). Based on simulations of the predicted CO_2 plume movement following the cessation of CO_2 injection, it is projected that the CO_2 plume will stabilize within the storage facility area boundary (Section 3). Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current predictions of the CO_2 plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO_2 plume. The nature and duration of that extension will be determined based on an update of this plan and NDIC approval.

In addition to DGC executing the postinjection monitoring program, the Class VI injection wells will be plugged as described in the plugging plan of this permit application (Section 10), all surface equipment not associated with long-term monitoring will be removed, and the surface land of the site will be reclaimed to as close as is practical to its original condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site and submitted as part of a site closure report.

6.1 Predicted Postinjection Subsurface Conditions

6.1.1 Pre- and Postinjection Pressure Differential

Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of CO_2 injection. The simulations were conducted for 12 years of CO_2 injection at rates between 1.0 and 2.7 million metric tons per year, followed by a postinjection period of 10 years. Figure 6-1 illustrates the predicted pressure differential at the conclusion of 12 years of CO_2 injection. At the time that CO_2 injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of 400 to 450 psi at the location of the injection wells, which is insufficient to move formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the area of review (AOR) delineation of this permit application (Section 3). An illustration of the predicted decrease in this pressure profile over the 10-year postinjection period is provided in Figure 6-2. The pressure in the reservoir gradually decreases over time following the cessation of CO_2 injection, with the pressure at the injection well after 10 years of postinjection predicted to decrease 300 to 350 psi as compared to the pressure at the time CO_2 injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions.

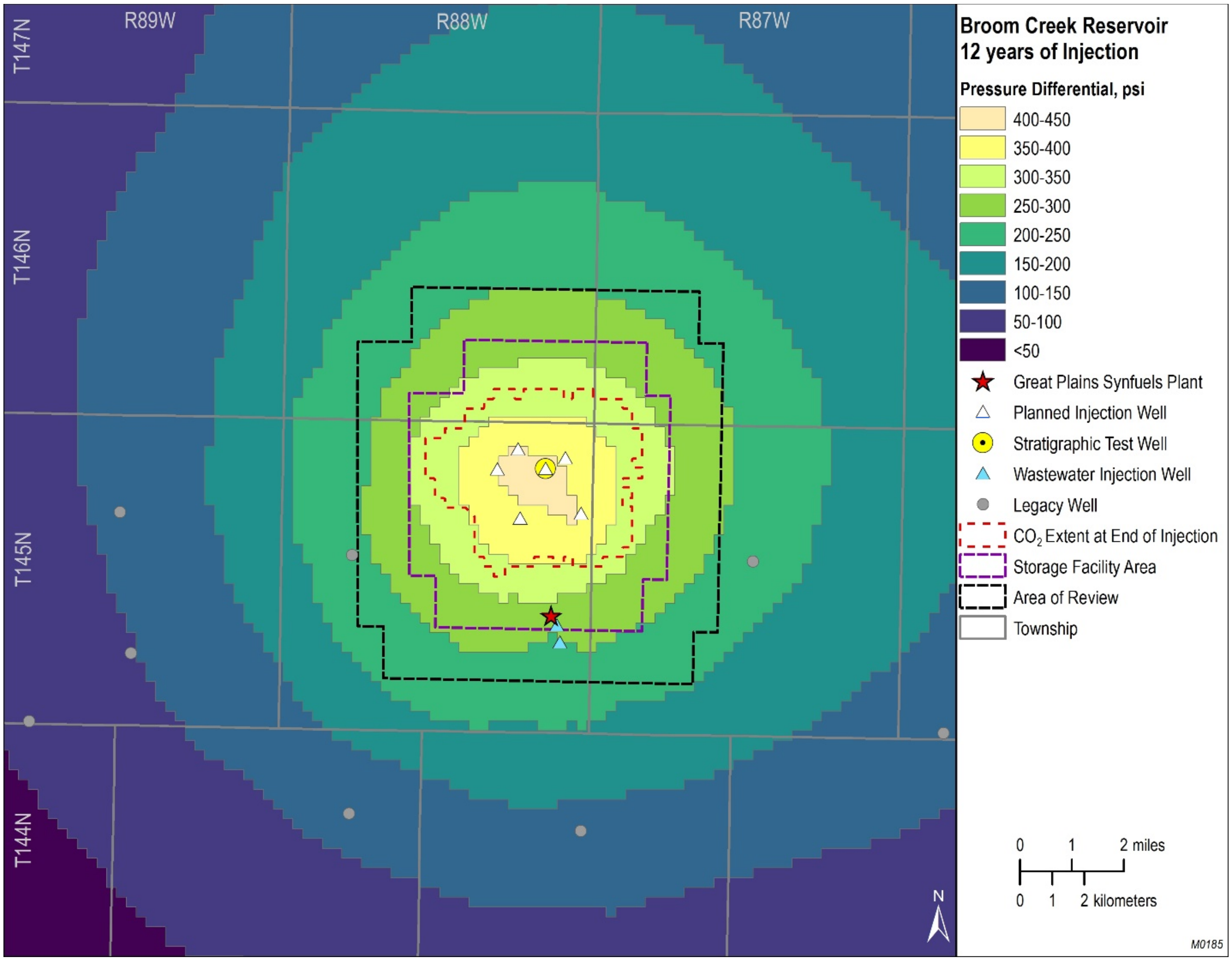

Figure 6-1. Predicted pressure differential in storage reservoir following 12 years of CO_2 injection at rates between 1.0 and 2.7 million metric tons per year.

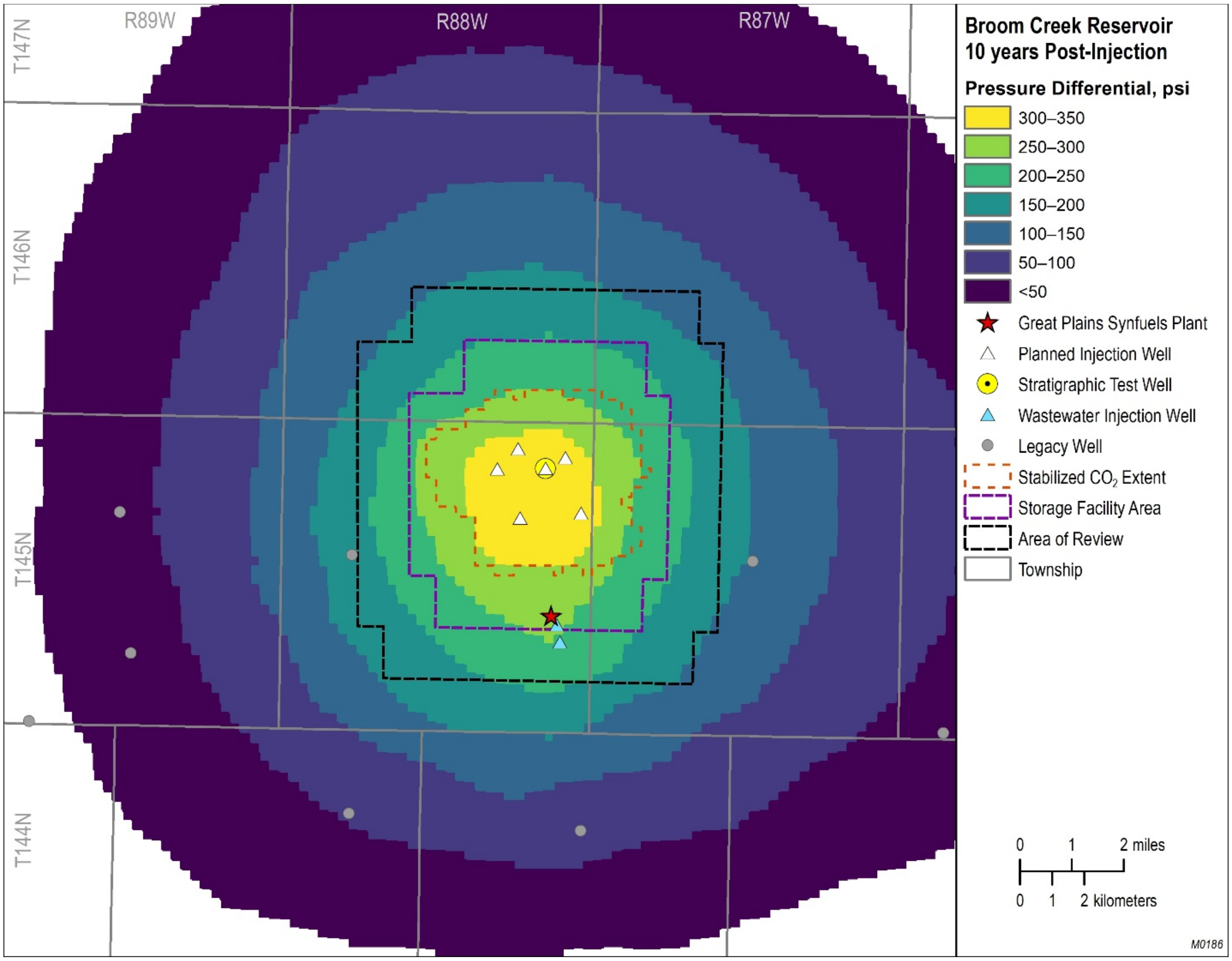

Figure 6-2. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection.

6.1.2 Predicted Extent of CO_2 Plume

Also shown in Figures 6-1 and 6-2 are numerical simulation predictions of the extent of the CO_2 plume at the time CO_2 injection was terminated (i.e., after 12 years of injection) and following the planned 10-year PISC period (also called the stabilized plume), respectively. The results of these simulations predict that 99% of the separate-phase CO_2 mass would be contained within an area of 11.28 mi^2 at the end of CO_2 injection (see Figure 6-1). As shown in Figure 6-2, the areal extent of the CO_2 plume is not predicted to change substantially over the planned 10-year PISC period.

Additional simulations beyond the 10-year PISC period were also performed and predict that at no time will the boundary of the stabilized plume at the site, which is shown in both Figures 6-1 and 6-2, extend beyond the boundary of the storage facility area. If such a determination can be made following the planned 10-year postinjection period, the CO_2 plume will meet the definition of stabilization as presented in NDCC § 38-22-17(5d) and qualify the geologic storage site for receipt of a certificate of project completion.

6.1.3 Postinjection Monitoring Plan

A summary of the postinjection monitoring plan that will be implemented during the 10-year postinjection period is provided in Table 6-1. The plan includes a combination of soil gas and groundwater/USDW monitoring as well as downhole and geophysical monitoring of the CO_2 plume in the storage reservoir.

Table 6-1. Summary of 10-year Postinjection Site Care Monitoring Plan

Type of Monitoring	Duration and Frequency	Justification
	Near-Surface Monitoring	
Soil Gas Profile Stations (SG01 to SG11) (Figure 6-3)	Duration: minimum 10 years Frequency: 3–4 seasonal sample events at soil gas stations SG01 to SG11	The sampling and analysis program will monitor the vadose zone for any signs of potential CO_2 leaks within the storage facility area.
Dedicated Fox Hills (lowest USDW) Monitoring Wells (Figure 6-3)	Duration: minimum 10 years Frequency: 3–4 seasonal sample events at each dedicated Fox Hills monitoring well	The sampling and analysis program will monitor the Fox Hills Formation at each injection well pad to ensure the USDW is not impacted by operations.
	Storage Reservoir Monitoring	
Surface Pressure Gauges on the ANG #1 and ANG #2 Wells (if WHP:BHP method is not satisfactory, DGC will perform a BHP survey in the first year of the PISC period)	Duration: minimum 10 years postinjection Frequency: continuous	Surface pressures will monitor the pressure decrease in the Broom Creek and history-match model predictions.
	Geophysical Monitoring	
Time-Lapse Seismic	Duration: minimum 10 years postinjection Frequency: perform 2D radial seismic surveys at the cessation of injection, 1 year after injection begins, then in Years 3, 5, and 10	Time-lapse seismic surveys will continue as part of the 10-year postinjection period to support a stabilization assessment of the CO_2 plume.

6.2 Groundwater and Soil Gas Monitoring

Eleven soil gas profile stations and six dedicated monitoring wells in the Fox Hills Formation (i.e., lowest USDW) will be sampled during the proposed 10-year PISC period. Figure 6-3 identifies the locations of the soil gas profile stations and dedicated Fox Hills Formation monitoring wells that will be included. It is proposed that these samples will be analyzed for the same list of parameters as described in the testing and monitoring plan (Section 5); however, it is anticipated that the final target list of analytical parameters will likely be reduced for the PISC period based on an evaluation of the monitoring results that are generated during the 12-year injection period of the storage operations.

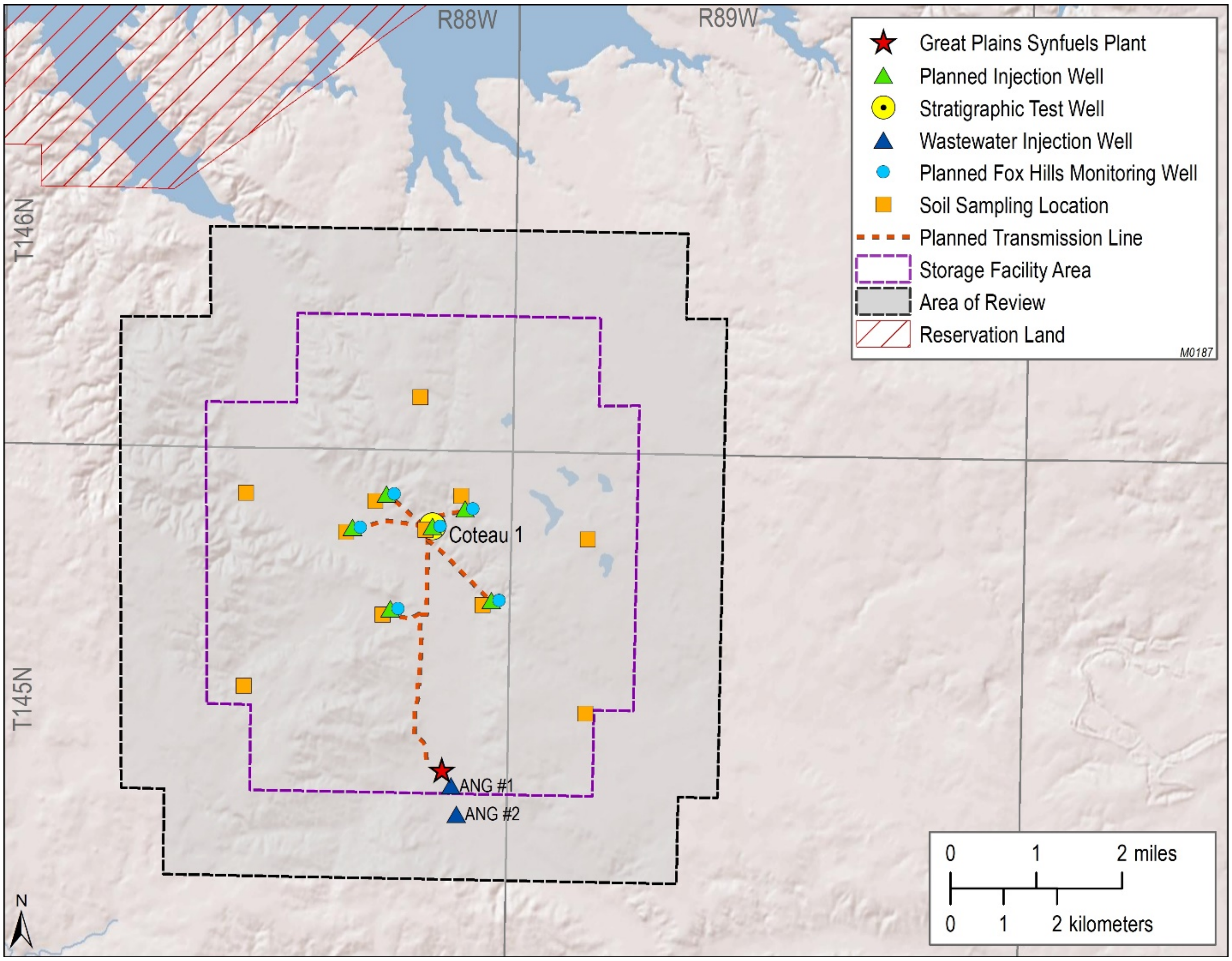

Figure 6-3. Soil gas and groundwater well sampling locations included in the PISC monitoring program.

6.3 CO_2 Plume Monitoring

Monitoring of the CO_2 plume migration in the subsurface will be conducted during the PISC period using the methods summarized in Table 6-1. Monitoring methods include a combination of near surface, deep subsurface, and geophysical techniques (i.e., surface seismic) that will monitor CO_2 saturation. Figure 6-4 illustrates the areal extents of the 2D seismic survey lines proposed during the PISC period in comparison to the areal extents of the stabilized CO_2 plume.

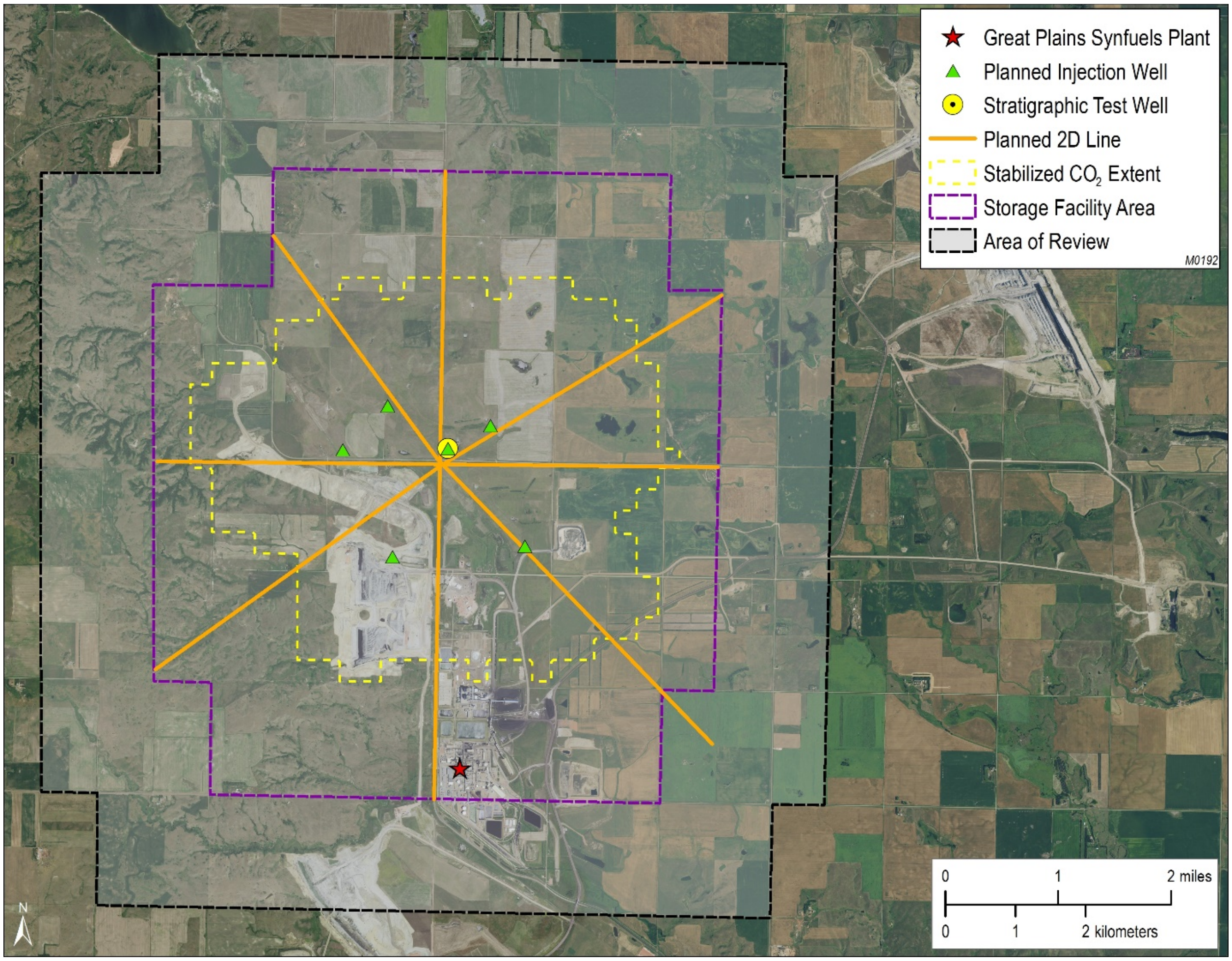

Figure 6-4. Areal extents of the 2D seismic survey lines proposed during the PISC period in comparison to the areal extents of the stabilized CO_2 plume.

6.3.1 Schedule for Submitting Postinjection Monitoring Results

All postinjection site care-monitoring data and monitoring results will be submitted to NDIC in annual reports. These reports will be submitted within 60 days of the anniversary date on which the CO_2 injection ceased.

The annual reports will contain information and data generated during the reporting period, including seismic data acquisition, formation-monitoring data, soil gas and groundwater sample analytical results, and simulation results from updated site models and numerical simulations.

6.3.2 Site Closure Plan

DGC will submit a final site closure plan and notify NDIC at least 90 days prior of its intent to close the site. The site closure plan will describe a set of closure activities that will be performed, following approval by NDIC, at the end of the postinjection site care period. Site closure activities will include the plugging of all wells that are not targeted for use as future subsurface observation wells; the decommissioning of storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring; and the reclaiming of the surface land of the site to as close as is practical to its original condition.

6.3.3 Submission of Site Closure Report, Survey, and Deed

A site closure report will be prepared and submitted to NDIC within 90 days of the execution of the postinjection site care and facility closure plan. This report will provide NDIC with a final assessment that documents the location of the stored CO_2 in the reservoir, describes its characteristics, and demonstrates the stability of the CO_2 plume in the reservoir over time. The site closure report will also document the following:

- Plugging records of the injection wells.
- Location of sealed injection wells on a plat survey that has been submitted to the local zoning authority.
- Notifications to state and local authorities as required by NDAC § 43-05-01-19.
- Records regarding the nature, composition, and volume of the injected CO_2.
- Postinjection monitoring records.

At the same time, DGC will also provide NDIC with a copy of an accurate plat certified by a registered surveyor that has been submitted to the county recorder's office designated by NDIC. The plat will indicate the location of the injection wells relative to permanently surveyed benchmarks pursuant to NDAC § 43-05-01-19.

Lastly, DGC will record a notation on the deed (or any other title search document) to the property on which the injection wells were located pursuant to NDAC § 43-05-01-19.

7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

This emergency and remedial response plan (ERRP) 1) describes the local resources and infrastructure in proximity to the site; 2) identifies events that have the potential to endanger all underground sources of drinking water (USDWs) during the construction, operation, and postinjection site care periods of the geologic storage project; and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing plant emergency plan and risk management plan of Dakota Gasification Company's (DGC's) Great Plains Synfuels Plant (GPSP) is described, emphasizing the command structure of DGC, the evacuation plan, hazmat (hazardous material) capabilities, and the emergency communication plan of the GPSP. Lastly, procedures are presented for regularly conducting and evaluating the adequacy of the ERRP and updating it, if warranted, over the lifetime of the Great Plains CO_2 Sequestration Project.

7.1 Background

CO_2 produced at GPSP (U.S. Environmental Protection Agency [EPA] Facility Identifier: NDD000690594) will be captured and geologically stored in close proximity to the plant location. The typical composition of the captured gas is 95.9% CO_2, 1.8% C^{2+} and hydrocarbons, 1.2% H_2S, 0.6% methane, and 0.5% nitrogen by volume. Figure 7-1 shows the location of the GPSP, which is in Mercer County, North Dakota, as well as the locations of CO_2 injection wells (Coteau 1 through Coteau 6 wells) and the planned CO_2 transmission lines from GPSP to the injection wells. The coordinates of the injection wells are provided in Table 7-1.

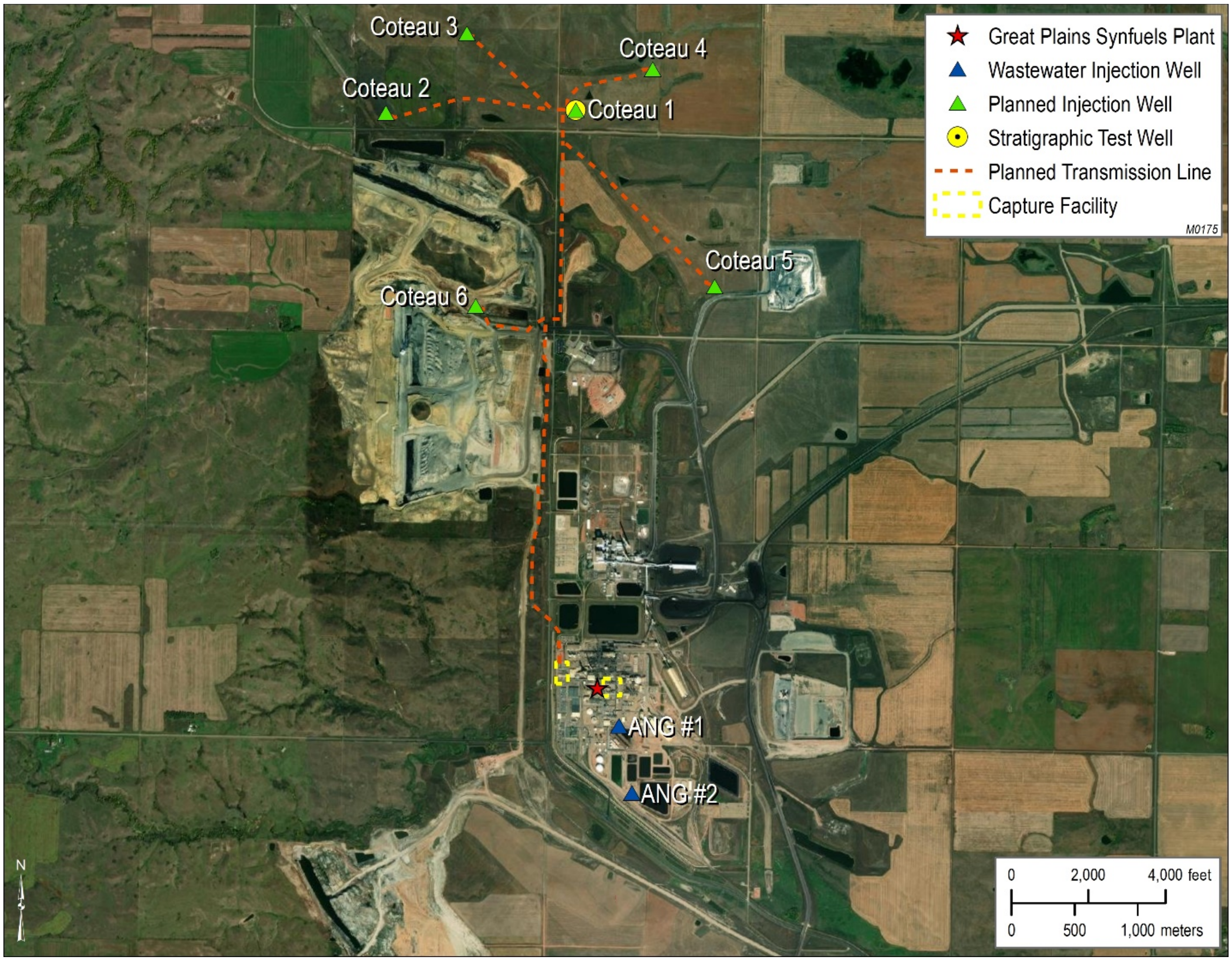

Figure 7-1. Locations of GPSP of DGC and the CO_2 injection wells (Coteau 1 through Coteau 6 wells). Also shown are the planned CO_2 transmission lines from GPSP to the injection wells.

Table 7-1. Well Names and Locations of the CO_2 Injection Wells of the DGC Geologic Storage Project

Well Name	Purpose	NDIC File No.	Quarter Call	Section	Township	Range	Latitude (NAD83*)	Longitude (NAD83*)
Coteau 1	CO_2 injection well	38379	SW/SW/SW	01	145N	88W	47.401991	−101.842101
Coteau 2	CO_2 injection well	TBD	SE/SW/SW	02	145N	88W	47.401572	−101.861988
Coteau 3	CO_2 injection well	TBD	NW/NW/SE	02	145N	88W	47.407308	−101.853618
Coteau 4	CO_2 injection well	TBD	NE/NE/SE	01	145N	88W	47.406940	−101.835330
Coteau 5	CO_2 injection well	TBD	SW/NE/SE	12	145N	88W	47.389640	−101.827219
Coteau 6	CO_2 injection well	TBD	NW/SW/SE	11	145N	88W	47.405000	−101.834090

* North American Datum of 1983.

The primary DGC contacts for the Great Plains CO_2 sequestration project and their contact information are as follows:

Primary DGC Project Contacts

Individual	Title	Contact Information
		Office Phone Number
Dale Johnson	VP & Plant Manager	701.873.6635
Trinity Turnbow	Operations & Assistant Plant Manager	701.873.6233
Daniel Whitley	Environmental Engineering Supervisor	701.873.6619

Primary Carbon Vault Project Contacts

Individual	Title	Contact Information
		Office Phone Number
Van Spence	President	303.588.5475
Rich McClure	Vice President – CO_2 Operations	720.635.1555
Gary Ramsdell	Operations Manager (Stanley, ND, Office)	701.629.1269

Contact names and information for other project personnel as well as key local emergency organizations/agencies are provided in a separate section of this ERRP (Section 7.6, Emergency Communications Plan).

7.2 Local Resources and Infrastructure

Local resources in the vicinity of the project that may be impacted as a result of an emergency event include 1) the holding ponds associated with GPSP and Antelope Valley Station; 2) Antelope Creek Aquifer; and 3) active and reclaimed mining land owned by Coteau Properties Company.

The infrastructure in the vicinity of the project that may be impacted as a result of an emergency event is shown in Figure 7-1 and includes 1) GPSP, 2) the CO_2 injection wellheads (Coteau 1 through Coteau 6), 3) the CO_2 transmission pipeline, 4) Antelope Valley Station, and 5) mining land owned by Coteau Properties Company. In addition, Figure 7-2 is provided to show residential, commercial, and public land use within 1 mile of the storage facility area boundary as required by North Dakota Administrative Code (NDAC) § 43-05-01-13.

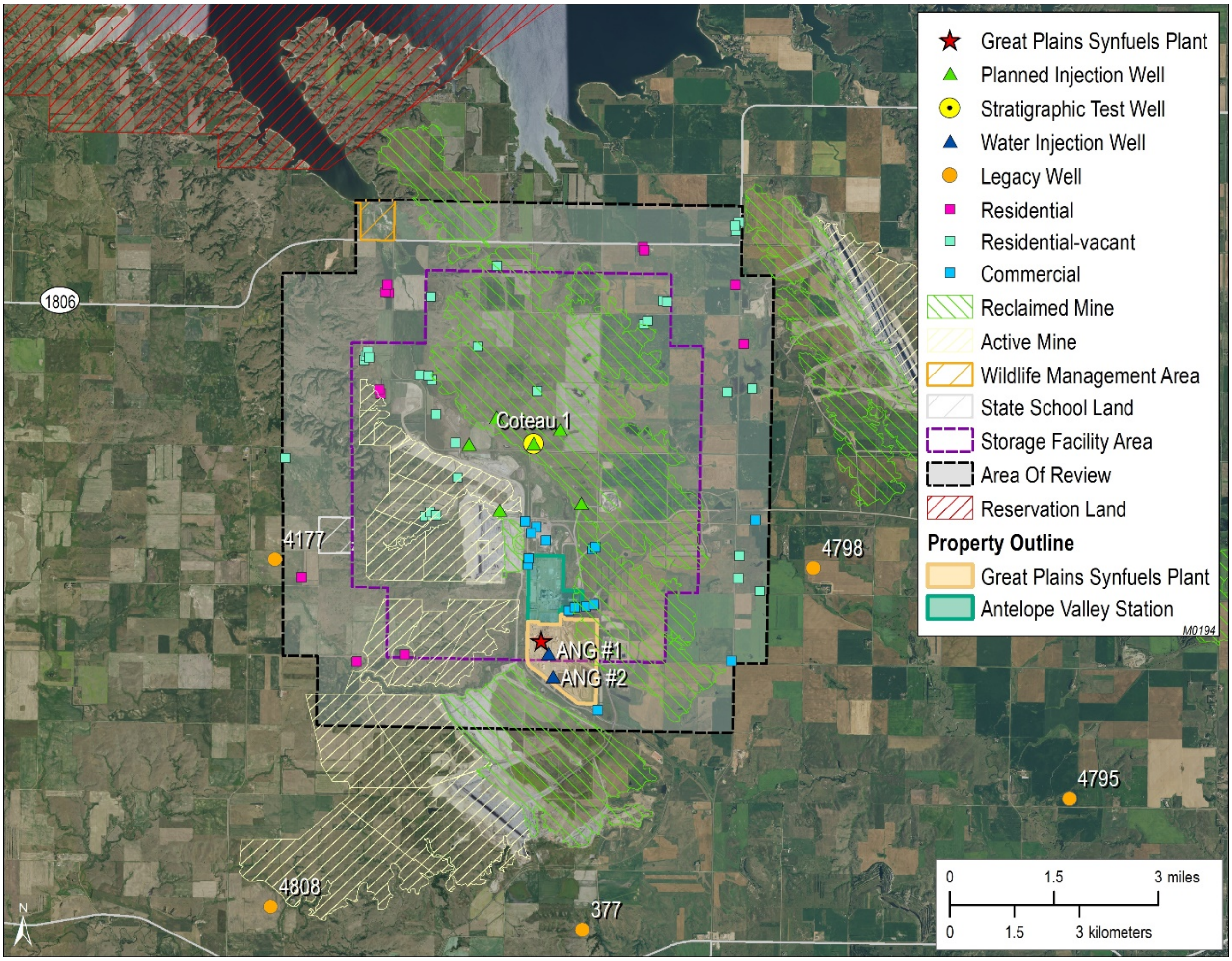

Figure 7-2. Residential, commercial, and public land use within 1 mile of the storage facility area.

7.3 Identification of Potential Emergency Events

7.3.1 Definition of an Emergency Event

An emergency event is an event that poses an immediate, or acute, risk to human health, resources, or infrastructure and requires a rapid, immediate response. This ERRP focuses on emergency events that have the potential to move the injected CO_2 stream or formation fluid in a manner that may endanger a USDW during operation or postinjection site care periods. Another emergency event of interest involves the accidental release of the CO_2 stream to the atmosphere.

7.3.2 Potential Project Emergency Events and Their Detection

Several potential technical project risks were considered and placed into the following five technical risk categories:

- Failure of surface equipment
- Integrity failure of an injection well

- Injection well monitoring equipment failure
- Inability of storage reservoir to contain the formation fluid or stored CO_2
- Natural disasters

Based on a review of these technical risk categories, a list of geologic storage project events that could potentially result in the movement of injection fluid or formation fluid in a manner that may endanger a USDW and require an emergency response was developed for inclusion in this ERRP. These events and means for their detection are provided in Table 7-2.

Table 7-2. Potential Project Emergency Events and Their Detection

Potential Emergency Events	Detection of Emergency Events
Failure of CO_2 Flowlines from CO_2 Capture System of DGC to CO_2 Injection Wellheads	Computational transmission pipeline and flowline continuous monitoring and leak detection system (LDS). Instrumentation at both ends of the transmission pipeline and the flowline for each injection well collects pressure, temperature, and flow data. The LDS software uses the pressure readings and flow rates in and out of the line to produce a real-time model and predictive model. By monitoring deviations between the real-time model and the predictive model, the software is able to detect pipeline leaks. Wellsite pressure and/or H_2S monitoring devices detect an anomaly.
Integrity Failure of Injection Wells	Pressure monitoring reveals wellhead pressure exceeds 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.
Injection Well Monitoring Equipment Failure	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.

In addition to these technical project risks, the occurrence of a natural disaster (e.g., naturally occurring earthquake, tornado, lightning strike, etc.) also represents an event for which an emergency response action may be warranted. For example, an earthquake or weather-related disaster (e.g., tornado or lightning strike) has the potential to result in injection well problems (integrity loss, leakage, or malfunction) and may also disrupt surface and subsurface storage operations. These events are addressed in the emergency plans of GPSP and will be extended to the geologic storage operations.

7.4 Emergency Response Actions

Discovery of an event triggers the corresponding response plan proposed herein. Specific response plan actions and activities will depend on the circumstances and severity of the event. The GPSP shift superintendent will address an event immediately and make all notifications as required by the emergency communications plan. The GPSP will be monitored in a manner consistent with the DGC's existing 205-mile CO_2 pipeline to Canada. Numerous automated safety features also exist along the CO_2 transmission line, the wellsite flowlines, and at the individual injection wellheads. Any alarm condition will be relayed to DGC's pipeline control room, which is manned continuously (7 days per week, 24 hours per day) by DGC personnel. An assessment of the alarm will be made by the control room operator, who will have the ability to remotely close any valve(s) necessary to isolate the problem and limit the duration and severity of the event.

The response actions that will be taken to address the events listed in Table 7-2, as well as the natural disasters, will follow the same protocol, which consists of the following actions:

- The GPSP shift superintendent (see Section 7.6, Emergency Communications Plan) will be notified and will immediately make an initial assessment of the automated response and the remote response and the severity of the event (i.e., does it represent an emergency event?).

- If designated as an emergency event, the DGC incident commander (IC) or designee shall notify the NDIC Department of Mineral Resources (DMR) Underground Injection Control (UIC) Program director pursuant to NDAC § 43-05-01-13 and implement the emergency communications plan. During this time, the GPSP shift superintendent will assume the role of incident commander.

- Following these actions, DGC will do the following:

  1. Ensure that the automated shutdown systems have isolated the event to the extent possible, and close additional isolation valves as required. If necessary, excess CO_2 volumes will be redirected back to the GPSP, where the CO_2 stream will be processed and safely released to the atmosphere.

  2. In the event of a leak to the surface, all H_2S precautions will be taken on-site, including, but not limited to, H_2S detectors and respirators, until natural dispersion returns the localized area to normal conditions. The nearest occupied dwellings are more than 1.5 miles from any wellsite, further under prevailing wind conditions, so evacuations should not be necessary. The IC should communicate with local authorities regarding the need for evacuations if deemed warranted.

  3. In the event of a mechanical integrity problem with one of the injection wellbores, the affected well will remain shut-in until an appropriate plan of action can be established by Carbon Vault personnel in coordination with NDIC DMR. The wellsite itself will remain secure as each location is to be fenced and locked at all times, with access only allowed by authorized personnel.

4. That portion of the CO_2 sequestration system that has been affected by the event will remain shut-in until DGC, the NDIC DMR, and other involved regulatory bodies are satisfied that a) the cause of the event has been identified and that b) it has been sufficiently addressed to resume operations. See Table 7-3 for details regarding the specific actions that will be taken to determine the cause and, if required, mitigate each of the events listed in Table 7-2.

The protocols described in this document are conceptual and may be adjusted based on actual circumstances and conditions of the event and any previous communication with governmental authorities having jurisdiction.

If an event triggers either a complete or partial cessation of injection and remedial actions, DGC shall demonstrate the efficacy of the response actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations shall only resume upon receipt of written authorization from the UIC program director.

Table 7-3. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions

Failure of CO_2 Transmission Pipeline from CO_2 Capture System of DGC to Each Well Injection Wellsite Flowline and CO_2 Injection Wellhead	• The CO_2 stream release and its location will be detected by the LDS, which will trigger an alarm condition in the DGC control room where operators have the ability to remotely shut down the transmission line and wellsite flowline. • If warranted, initiate an evacuation plan. • The transmission line and/or flowline failure will be inspected to determine the root cause of the failure. • Repair/replace the damaged transmission line or flowline, and if warranted, put in place the measures necessary to eliminate such events in the future.
Integrity Failure of Injection Wells	• Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure. • Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the NDIC DMR UIC program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions to address impacts (in consultation with the NDIC DMR UIC program director).

Continued . . .

Table 7-3. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Injection Well-Monitoring Equipment Failure	• Monitor well pressure, temperature, and annulus pressure (manually if necessary) to determine the cause and extent of failure. • Identify and, if necessary, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Storage Reservoir Unable to Contain Formation Fluid or Stored CO_2	• Collect a confirmation sample(s) of groundwater from the Fox Hills monitoring wells and soil gas profile stations and analyze them for indicator parameters (see testing and monitoring plan in Section 5.0 of the SFP). • If the presence of indicator parameters is confirmed, develop (in consultation with the NDIC DMR UIC program director) a case-specific work plan to: 1. Install additional monitoring points near the impacted area to delineate the extent of impact: a. If a USDW is impacted above drinking water standards, arrange for an alternate potable water supply for all users of that USDW. b. If a surface release of CO_2 stream to the atmosphere is confirmed, initiate an evacuation plan, if warranted by workspace and/or ambient air-monitoring results. c. If surface release of CO_2 stream to surface waters is confirmed, implement appropriate surface water-monitoring program to determine if water quality standards are being exceeded. 2. Proceed with efforts, if necessary, to a) remediate the USDW to achieve compliance with drinking water standards (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" the impacted drinking water to mitigate CO_2/brine impacts) and/or b) manage surface waters using natural attenuation (i.e., natural processes, such as biological degradation, that are active in the environment and can reduce contaminant concentrations) or active treatment to achieve compliance with applicable water quality standards. • Continue all remediation and monitoring at an appropriate frequency (as determined by DGC and the NDIC DMR UIC program director) until unacceptable adverse impacts have been fully addressed.

Continued . . .

Table 7-3. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Natural Disasters	• Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure. • If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate extent of any impacts. • If impacts or endangerment are detected, identify and implement appropriate response actions in accordance with the GSPS emergency plan (in consultation with the NDIC DMR UIC program director).
Natural Disasters (seismicity)	• Identify when the event occurred and the epicenter and magnitude of the event. If magnitude is greater than 2.0 (Richter magnitude scale): 1. Demonstrate all project wells have maintained mechanical integrity. 2. If a loss of CO_2 containment is determined, proceed as described above to evaluate, and if warranted, mitigate the loss of containment. • If a loss of CO_2 containment is determined, proceed as described above to evaluate, and if warranted, mitigate the loss of containment.

7.5 Response Personnel/Equipment and Training

7.5.1 Response Personnel and Equipment

GPSP personnel will have operations and emergency response training. In addition, DGC will consult with the Mercer County Local Emergency Planning Committee (LEPC) for inclusion in the county's multihazard mitigation plan. The emergency "out call" system, which is also referred to as the R911 system, is designed to notify those residents living or working within the pipeline corridor that a pipeline emergency has occurred with the potential to affect them.

Equipment needed in the event of an emergency and remedial response will vary, depending on the emergency event. Response actions (e.g., cessation of injection, transmission line, flowline, and/or well shut-in, and possible evacuation) will generally not require specialized equipment to implement. However, when specialized equipment (such as a workover rig, logging equipment, potable water hauling, etc.) is required, DGC planning superintendent shall be responsible for its procurement. Because of its historical operations in the area, DGC is uniquely qualified to respond to emergencies. Its existing GPSP is home to a fire station in addition to emergency technician and medical professionals.

7.5.2 *Staff Training and Exercise Procedures*

DGC will train personnel involved in the CO_2 geologic storage project on the proper emergency responses, maintenance, and operating procedures. The training efforts will be documented. DGC will also work with Mercer County LEPC to perform coordinated training exercises associated with potential emergency events.

7.6 Emergency Communications Plan

Prior to the commencement of CO_2 injection operations, DGC will communicate in writing with landowners living in and adjacent to the permitted storage area to provide a summary of the information contained within this ERRP, including, but not limited to, information about the nature of the operations, operator contact list, potential risks, and possible response approaches.

In the event of an emergency, the GPSP shift superintendent and Protection Services Control Center (PSCC) supervisor will be notified immediately. The DGC shift superintendent will assume the role of IC. The IC's responsibilities may include, but are not limited to, developing an incident action plan, managing incident operations, notifying proper plant personnel (as shown below), and properly applying all resources.

DGC Personnel and Contact Information

Position	DGC Employee	Office Phone Number
Shift Superintendent		701.873.6777
Communications Manager	Joan Dietz	701.557.5070
PSCC (business)		701.873.6677
PSCC (24-hour emergency)		701.873.6600
DGC Medical		701.873.6789
Safety and Industrial Hygiene Superintendent	Jeff Graney	701.873.6605
Planning Superintendent	Dave Knudson	701.873.6219

In addition to DGC personnel, the IC is responsible for establishing and maintaining communications with appropriate off-site persons and/or agencies, including, but not limited to, the following:

Beulah Police Department	701.873.5252
Beulah Fire Department	701.873.2121
Mercer County Ambulance	701.747.5558
Mercer County Emergency Manager	701.745.3302
Mercer County Sheriff's Office	701.745.3333
Hazen Police Department	701.747.2414
North Dakota Highway Patrol	701.327.2447
North Dakota Highway Department	701.327.9921
North Dakota Poison Control	800.222.1222
Hazen Fire Department	701.747.5550
Sakakawea Medical Center	701.747.2225
NDIC DMR UIC Program Director	701.327.8020
North Dakota Department of Emergency Services	833.997.7455

Lastly, the DGC plant emergency plan contains addresses and contact information for approximately 58 neighboring facilities and residences located within 4.5 miles of the GPSP. This information is based on DGC's latest population density survey. DGC will update this information to document any changes that may occur by conducting semi-annual surveys. DGC will utilize an emergency out call system which is designed to notify residents in the area if an emergency occurs.

7.7 ERRP Review and Updates

This ERRP shall be reviewed:

- At least annually following its approval by NDIC DMR.
- Within 1 year of an area of review (AOR) reevaluation.
- Within a prescribed period (to be determined by NDIC DMR) following any significant changes to the project, e.g., injection process, injection rate, etc.
- As required by NDIC DMR.

Should the operational monitoring (see Section 5.0, Testing and Monitoring Plan) of the geologic storage operations identify trends that warrant a modification to the ERRP prior to the scheduled annual review, DGC will move forward with revising the plan and submitting a revised ERRP to NDIC DMR within 6 months of that determination.

If the annual review indicates that no amendments to the ERRP are necessary, DGC will provide NDIC DMR with the documentation supporting a no-amendment-necessary determination. If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to NDIC DMR within 6 months following their identification.

8.0 WORKER SAFETY PLAN

8.0 WORKER SAFETY PLAN

The worker safety plan (WSP) describes the minimum safety programs and training requirements for DGC employees and contract personnel during the construction, operation, and postinjection site periods. DGC will give NDIC personnel sufficient access to perform wellsite inspections.

This WSP incorporates the existing occupational, safety, and industrial hygiene (OSIH) program utilized by DGC for employees and contractors and their personnel (including subcontractors) working at the Great Plains Synfuels Plant and other DGC facilities. The OSIH program is designed to prevent accidents, injuries, property losses, illnesses, and violations of government and company standards.

8.1 DGC Employee Safety Requirements and Training

DGC has established a process for employees to acquire the knowledge, skills, and abilities to competently operate the facility in accordance with DGC safe work practices, procedures, and operating manuals. The safety requirements for DGC employees include, but are not limited to, the following:

1. An orientation for all newly hired employees to ensure they are aware of company safety policies and procedures, safety and health hazards, safe work practices, and government safety regulations.

2. Instruction and training for each employee regarding:

    a. Safety expectations while on DGC property.

    b. What to do in an emergency, including evacuation routes and assembly points.

    c. Safety and industrial hygiene information about hazardous materials/conditions and immediate actions to take following an accidental exposure.

    d. When and how to report safety incidents.

    e. How to report unsafe conditions and behaviors.

    f. Safe work practices as defined by government and company standards.

8.1.2 DGC Contractor Safety Requirements and Training

The DGC OSIH program also establishes requirements for contractors to interface with DGC to ensure compliance with DGC safety procedures and federal, state, and local safety standards. The scope of the requirements covers all contractors and their personnel (including subcontractors) working at DGC's facilities.

The safety requirements and training required for a contractor to access and perform work at DGC facilities include, but are not limited to, the following:

1. Full compliance with all Energy Coalition for Contractor Safety (ECCS) guidelines for a "Class A contractor." (The ECCS guidelines can be found at the North Dakota Safety Council [NDSC] website at www.ndsc.org.).

2. Attendance at an annual DGC contractor safety orientation.

3. Negative drug test results within the last 12 months.

4. Availability of a contractor employee training record (CETR) within the last 12 months:

    a. Documents that the contractor has trained its personnel on DGC procedures and process descriptions.

    b. Ensures contractor employees are instructed in the known potential fire, explosion, or toxic release hazards and applicable provisions of the emergency response plan.

5. Documentation of a contractor employee background check within the last 5 years.

6. Successful completion of an Occupational Safety and Health Administration (OSHA) 10-hour class within the last 36 months.

7. A contractor safety manual evaluation completed by a third party, i.e., the North Dakota Safety Council (NDSC), to demonstrate compliance with federal, state, and DGC safety standards.

8. Demonstration of acceptable safety performance by submitting the last year's safety statistics to NDSC at www.ndsc.org.

9. Demonstration of qualification requirements for pipeline (off-site) contractors, which includes the following:

    a. Submision of a drug/alcohol plan that meets 49 Code of Federal Regulations (CFR) Part 40 and Part 199.

    b. Submission of an operator qualification plan in accordance with 49 CFR Part 192 and Part 195.

    c. Submission of qualification data for personnel performing operation, maintenance, or emergency response task(s) on the carbon dioxide (CO_2) pipeline.

    d. Other qualification requirements include:

        i. DGC access to drug/alcohol and operator qualification information for random record audits.

        ii. Submission of Department of Transportation (DOT) annual drug testing satistical data to DGC for inclusion in an annual DGC submittal to DOT.

Only DGC employees and contractor personnel who have been properly trained will participate in the project activities of drilling, construction, operations, and equipment repair.

9.0 WELL CASING AND CEMENTING PROGRAM

9.0 WELL CASING AND CEMENTING PROGRAM

Rampart Energy Company has drilled one well, Coteau 1 (NDIC File No. 38379) thus far on behalf of DGC. The well was permitted and drilled in June 2021 as a stratigraphic test well in compliance with Class VI underground injection control (UIC) injection well construction requirements. Application to convert Coteau 1 to a CO_2 storage injection well is being filed upon approval of this storage facility permit (SFP). The following information includes the current, as-constructed wellbore schematic (illustrated in Figure 9-1 and detailed in Tables 9-1 through 9-4) and a radial cement evaluation log summary for Coteau 1 (Figure 9-2). After drilling, the Broom Creek Formation was perforated with four shots at 5975 ft and a reservoir pressure and fluid sample were obtained. The perforations were then squeezed with 100 sacks of Class G cement and the casing pressured tested to 1600 psi with an inhibited brine solution.

Five additional injection wells are planned. Three of these, the proposed Coteau 2, Coteau 3, and Coteau 4, are expected to be drilled in the second quarter of 2022, followed by the proposed Coteau 5 and Coteau 6 in late 2025, to accommodate additional CO_2 injection volumes in the spring of 2026.

9.1 Coteau 1: As-Constructed CO_2 Injection Well Casing and Cementing Program

The as-constructed wellbore schematic for the Coteau 1 well is provided in Figure 9-1.

Tables 9-1 through 9-4 provide the casing and cement programs for the Coteau 1 well and have been updated according to the drilling performed in June 2021. The tables demonstrate compliance with North Dakota Administrative Code (NDAC) § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for conversion to a CO_2 storage injection well.

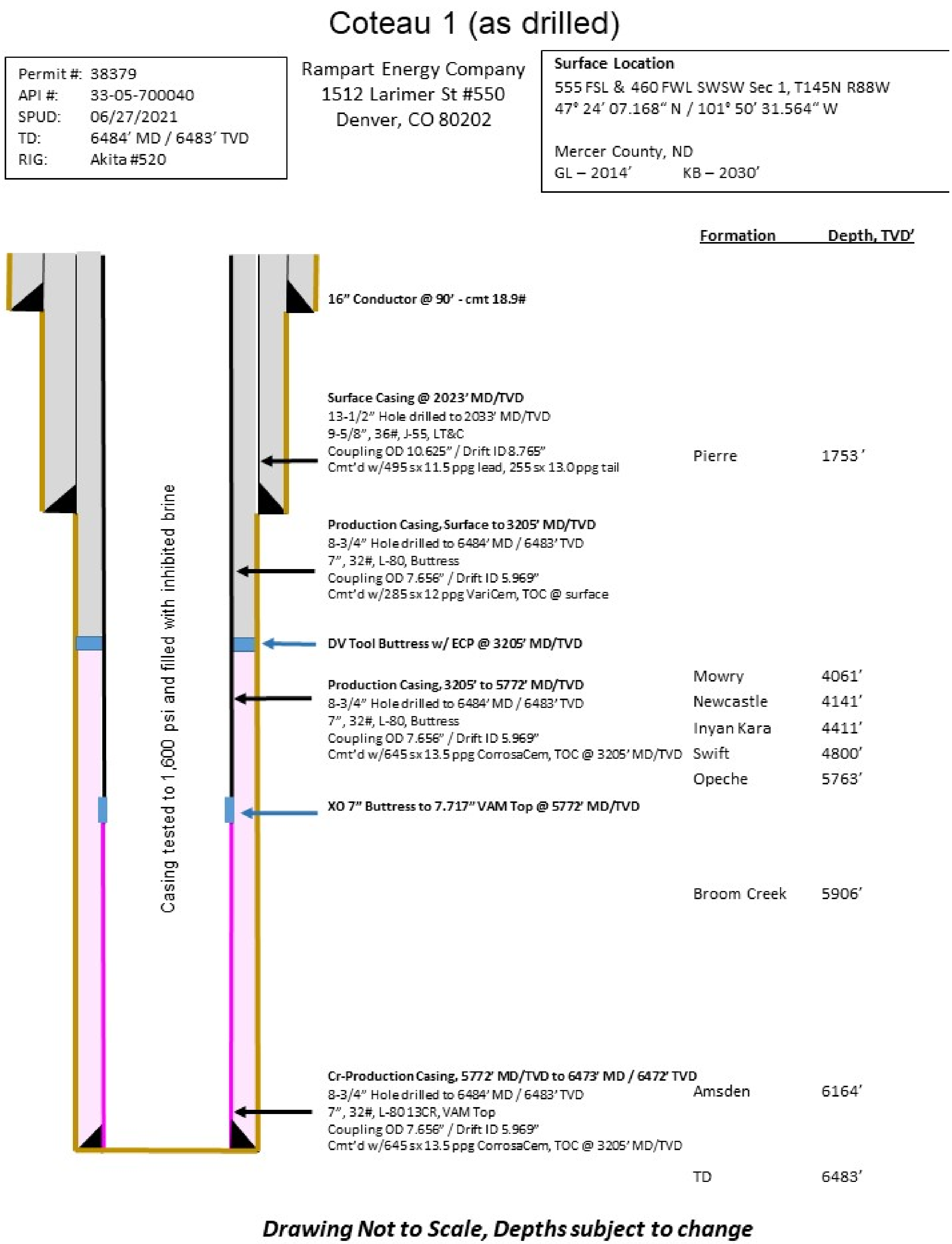

Figure 9-1. Coteau 1 as-constructed wellbore schematic.

Table 9-1. Coteau 1 As-Constructed Well Information

Well Name:	**Coteau 1**	**NDIC No.:**	**38379**	**API* No.:**	**33-057-00040**
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.1 T145N R88W	**Footages:**	555 FSL*, 60 FWL*	**Total Depth, ft:**	6484 MD

* API: American Petroleum Institute, FSL: from the south line, FWL: from the west line.

Table 9-2. Coteau 1 As-Constructed Casing Program

Section	Bit Size, in.	Casing OD*, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC*	Surface	2033	Cover freshwater aquifers
Production	8.75	7	32	L-80	Buttress	Surface	3205	Production casing
Production	8.75	DV* tool			Buttress	3205	3230	Stage collar with ECP*
Production	8.75	7	32	L-80	Buttress	3230	5772	Production casing
Production	8.75	7	32	13CR L80	VAM top*	5772	6474	CO_2-resistant production casing

* OD: outside diameter, LTC: long-thread and coupled, VAM top: premium thread and coupled, DV: differential valve: ECP: electrochemical pump.

Table 9-3. Coteau 1 As-Constructed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID*, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80	32	Buttress	6.094	5.969	9050	8610	745	791
7	13CR L80	32	VAM top	6.094	6.000	9060	8610	745	745

* ID: inside diameter.

Table 9-4. Coteau 1 As-Constructed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6474–3230	100	645
7	12.0 VariCem	3205–surface	OH 100	285

* The cement top was obtained from the radial cement evaluation. Figure 9.2 provides an evaluation of the isolation scanner performed on 9/17/2021. The top of cement is at the surface, while the top of CO_2-resistant cement is at 3205 ft.

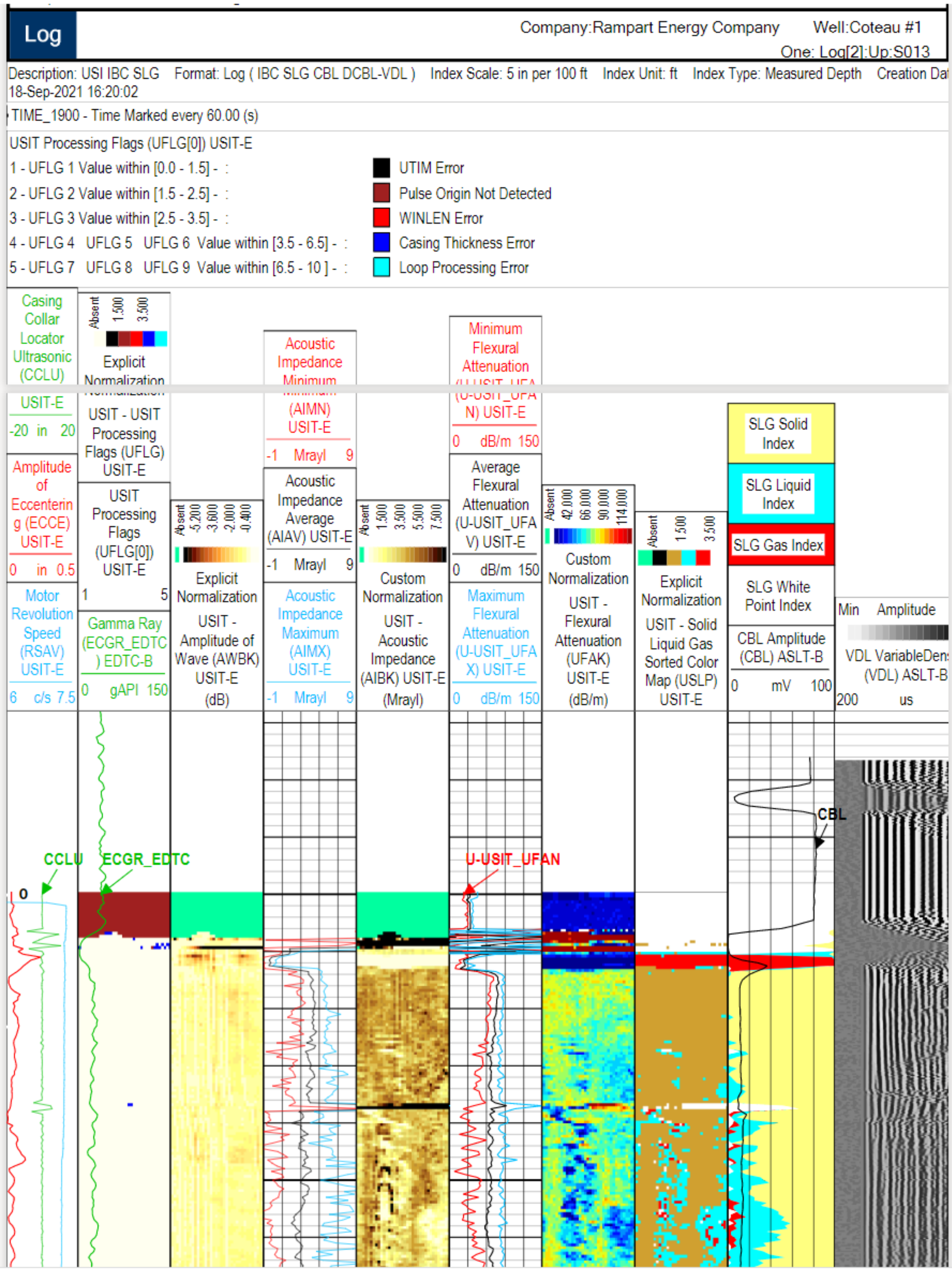

Figure 9-2. Coteau 1 isolation scanner results – radial cement evaluation log summary from Coteau 1 verifies the material behind the casing and the cement bond index. This enables the analyst to assess isolation in the CO_2 injection zone, confining zones, and underground sources of drinking water (USDWs) using a high-resolution image.

9.2 Coteau 2: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 2 well is expected to be drilled and completed in the second quarter of 2022. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-3.

Tables 9-5 through 9-8 include the proposed casing and cement programs for the Coteau 2 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

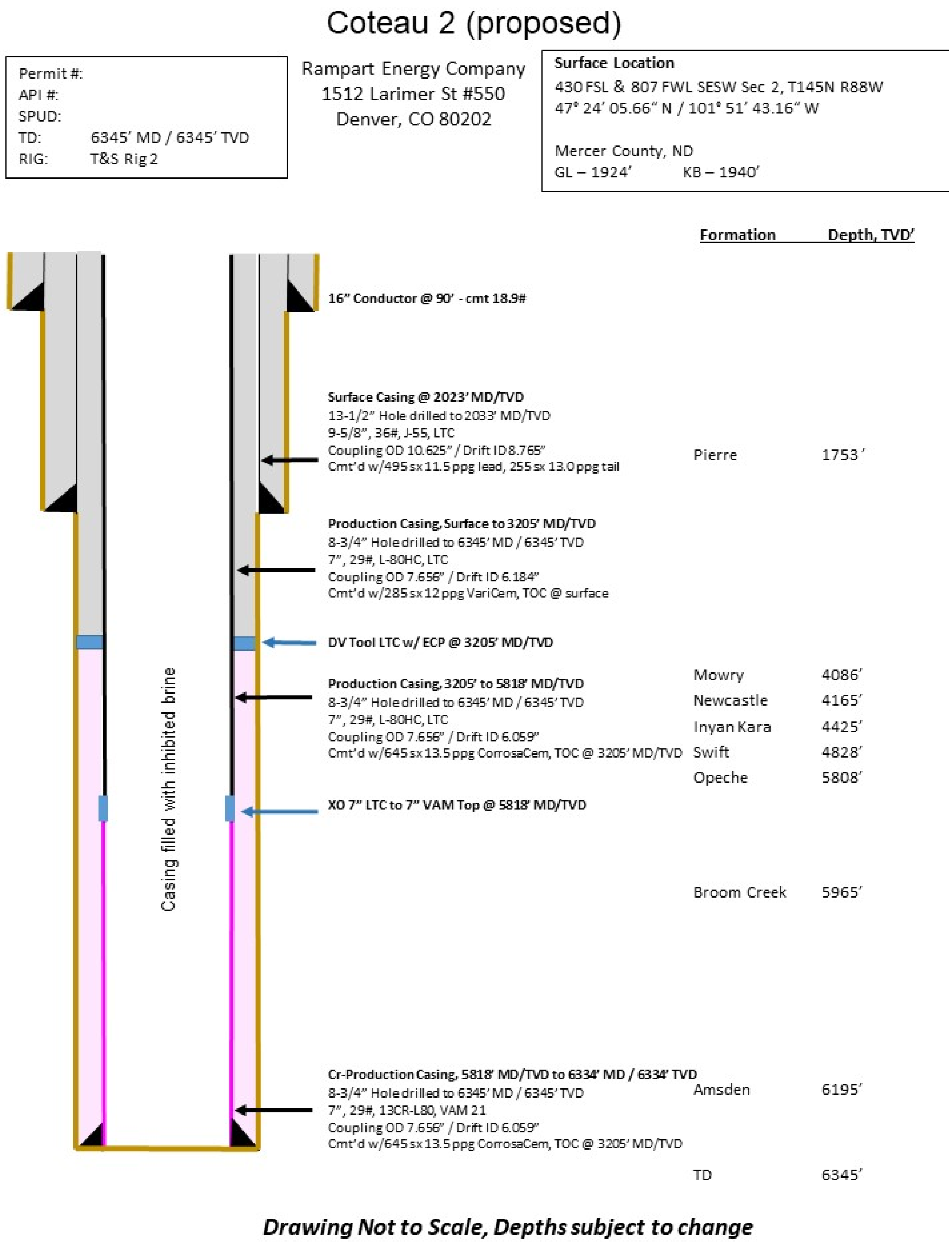

Figure 9-3. Coteau 2 proposed wellbore schematic.

Table 9-5. Coteau 2 Proposed Well Information

Well Name:	**Coteau 2**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.2 T145N R88W	**Footages:**	430 FSL, 807 FWL	**Total Depth, ft:**	6371 MD

Table 9-6. Coteau 2 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5829	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5829	6360	CO_2-resistant production casing

Table 9-7. Coteau 2 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7.717	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-8. Coteau 2 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6360–3205	100	625
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft.

9.3 Coteau 3: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 3 well is expected to be drilled and completed in the second quarter of 2022. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-4.

Tables 9-9 through 9-12 include the proposed casing and cement programs for the Coteau 3 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

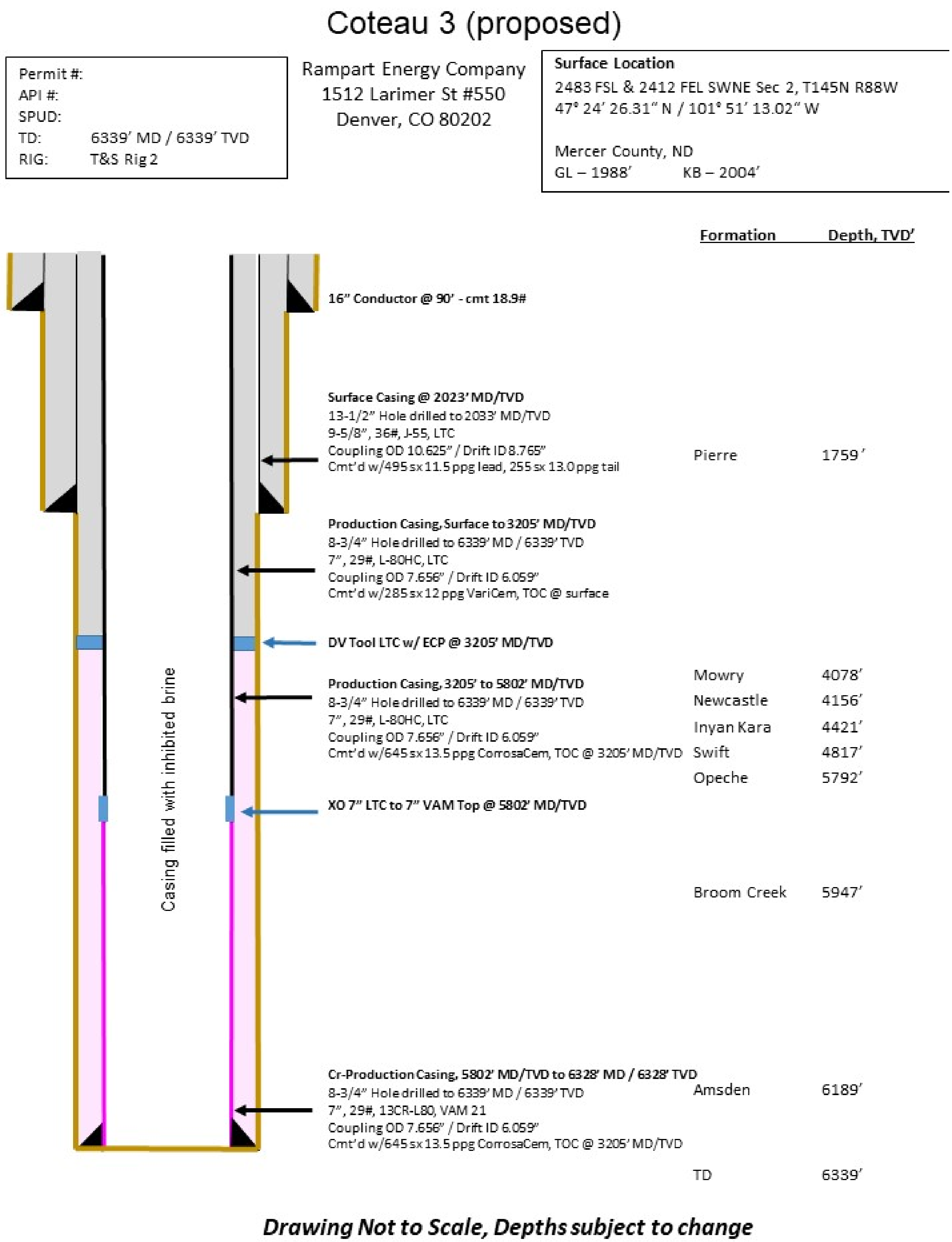

Figure 9-4. Coteau 3 proposed wellbore schematic.

Table 9-9. Coteau 3 Proposed Well Information

Well Name:	**Coteau 3**	**NDIC No.:**		**API No.:**	
County:		**State:**	ND	**Operator:**	Rampart Energy Company
				Total Depth, ft:	6361 MD

* FEL: from the east line.

Table 9-10. Coteau 3 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5815	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5815	6350	CO_2-resistant production casing

Table 9-11. Coteau 3 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7.717	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-12. Coteau 3 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6350–3205	100	620
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft.

9.4 Coteau 4: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 4 well is expected to be drilled and completed in the second quarter of 2022. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-5.

Tables 9-13 through 9-16 include the proposed casing and cement programs for the Coteau 4 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

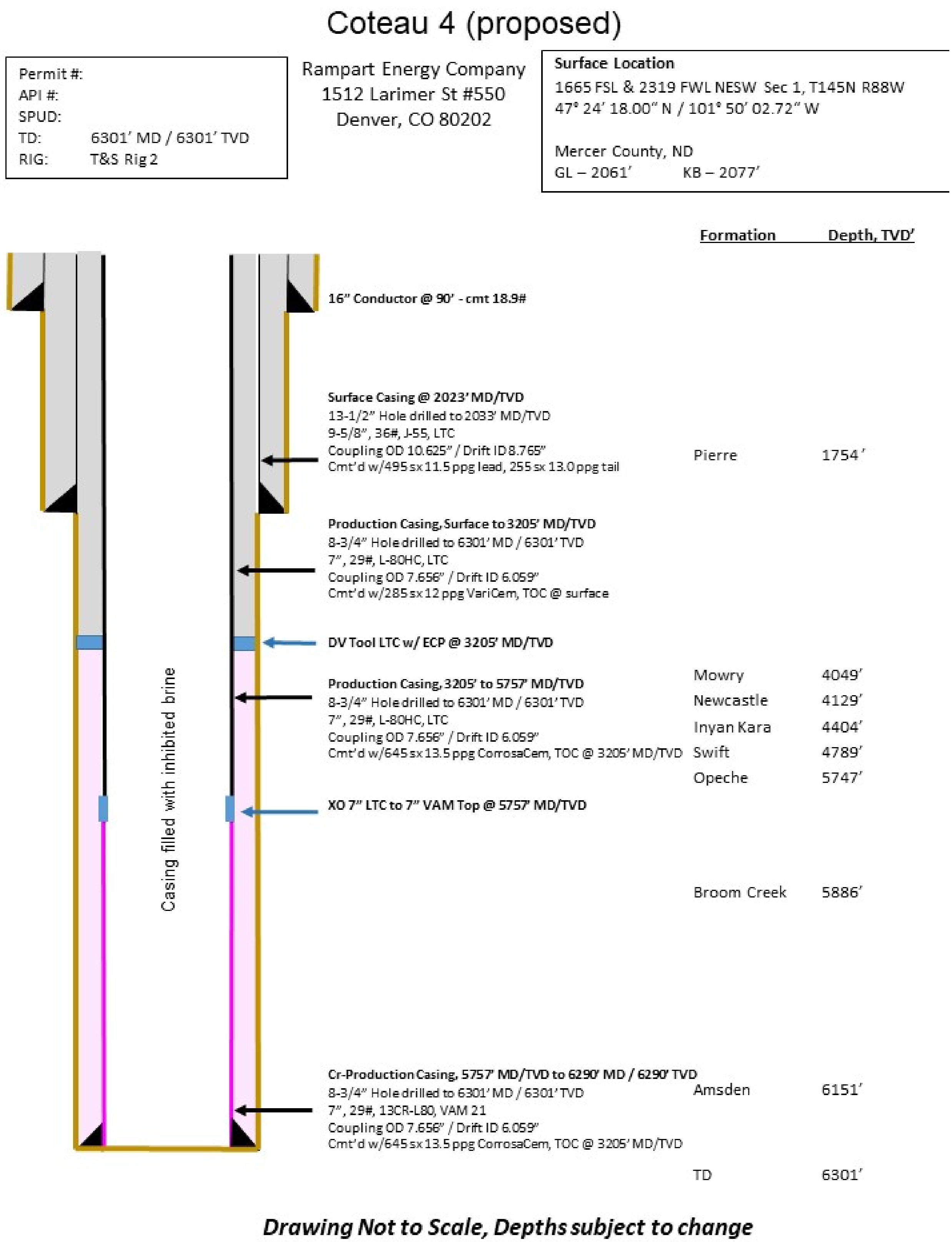

Figure 9-5. Coteau 4 proposed wellbore schematic.

Table 9-13. Coteau 4 Proposed Well Information

Well Name:	**Coteau 4**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.1 T145N R88W	**Footages:**	1665 FSL, 2319 FWL	**Total Depth, ft:**	6309 MD

Table 9-14. Coteau 4 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5769	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5769	6298	CO_2-resistant production casing

Table 9-15. Coteau 4 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-16. Coteau 4 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6298–3205	100	610
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft

9.5 Coteau 5: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 5 well is expected to be drilled and completed in late 2025. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-6.

Tables 9-17 through 9-20 include the proposed casing and cement programs for the Coteau 5 based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

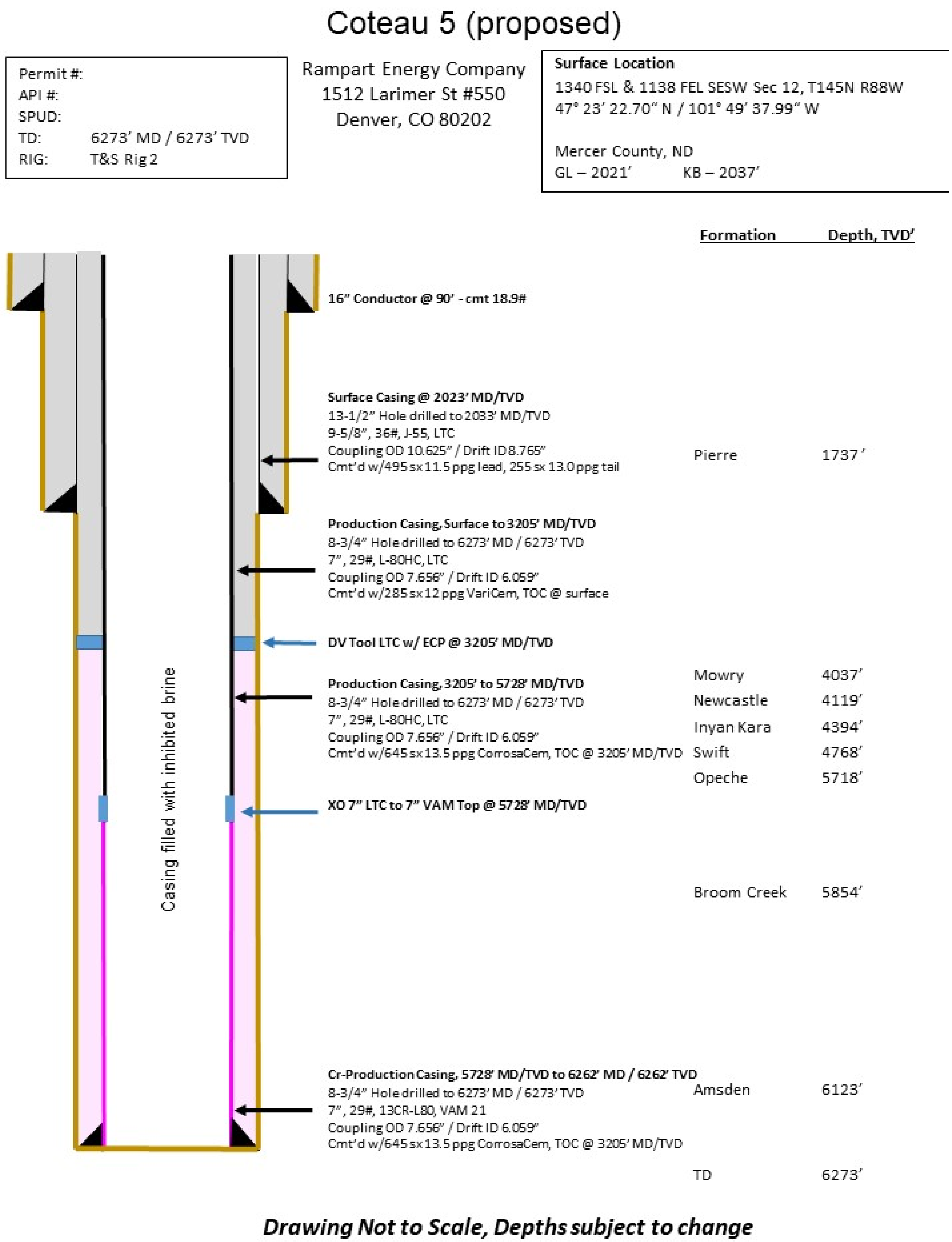

Figure 9-6. Coteau 5 proposed wellbore schematic.

Table 9-17. Coteau 5 Proposed Well Information

Well Name:	**Coteau 5**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.12 T145N R88W	**Footages:**	1340 FSL, 1138 FEL	**Total Depth, ft:**	6277 MD

Table 9-18. Coteau 5 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5741	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5741	6266	CO_2-resistant production casing

Table 9-19. Coteau 5 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-20. Coteau 5 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6266–3205	100	605
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft.

9.6 Coteau 6: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 6 well is expected to be drilled and completed in late 2025. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-7.

Tables 9-21 through 9-24 include the proposed casing and cement programs for the Coteau 6 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

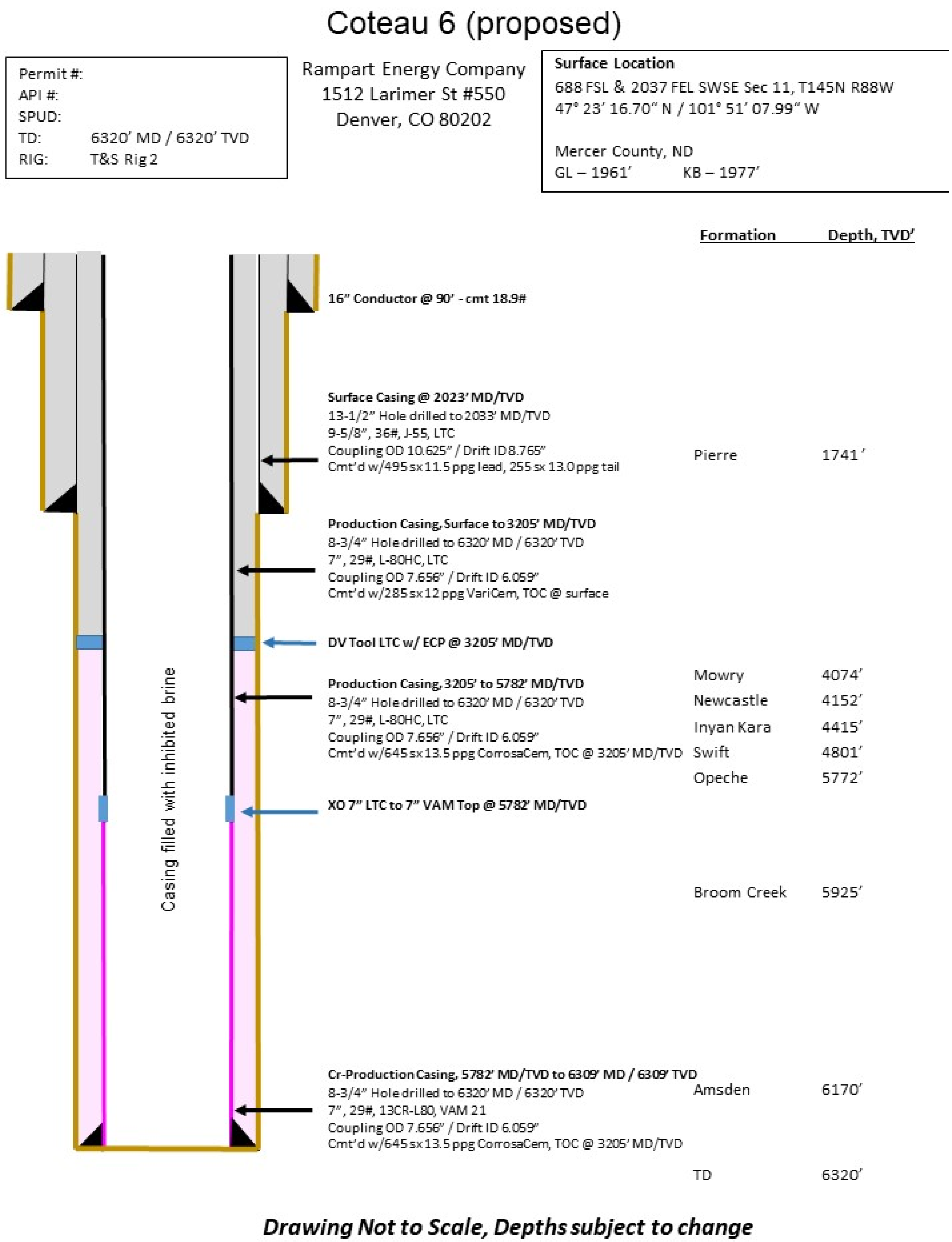

Figure 9-7. Coteau 6 proposed wellbore schematic.

Table 9-21. Coteau 6 Proposed Well Information

Well Name:	**Coteau 6**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.11 T145N R88W	**Footages:**	688 FSL, 2037 FEL	**Total Depth, ft:**	6335 MD

Table 9-22. Coteau 6 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2033	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5794	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5794	6324	CO_2-resistant production casing

9-21

Table 9-23. Coteau 6 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-24. Coteau 6 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6324–3230	100	615
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3,205 ft.

10.0 PLUGGING PLAN

10.0 PLUGGING PLAN FOR INJECTION WELLS

The plugging plans for all injection wells are intended to be interpreted as proposed conditions and do not reflect the current as-constructed state of a particular well. The schematics and procedure in this section illustrate what the estimated wellbore conditions will look like before and after the plugging and abandonment (P&A). The wells will be plugged and abandoned when CO_2 storage and injection operations cease.

The plugging plan will be provided to a representative from the NDIC, who will be present during the plugging operations. This will also be documented during workover reports. The plugging record will show that the material used will be compatible with CO_2 and isolate the injection zone.

10.1 Plugging & Abandonment (P&A) Program

A well schematic of the planned completion for the Coteau 1 well (NDIC File No. 38379) is provided in Figure 10-1 followed by a P&A procedure and a well-plugging schematic (Figure 10-2). The abandonment of subsequent injection wells, namely, the Coteau 2 through 6, will be performed in a manner consistent with that of the Coteau 1. The size and depths of the various plugs may vary as necessary to accomplish the zonal isolation, but in each instance, approval of specific P&A operations will be required from the NDIC prior to the initiation of fieldwork.

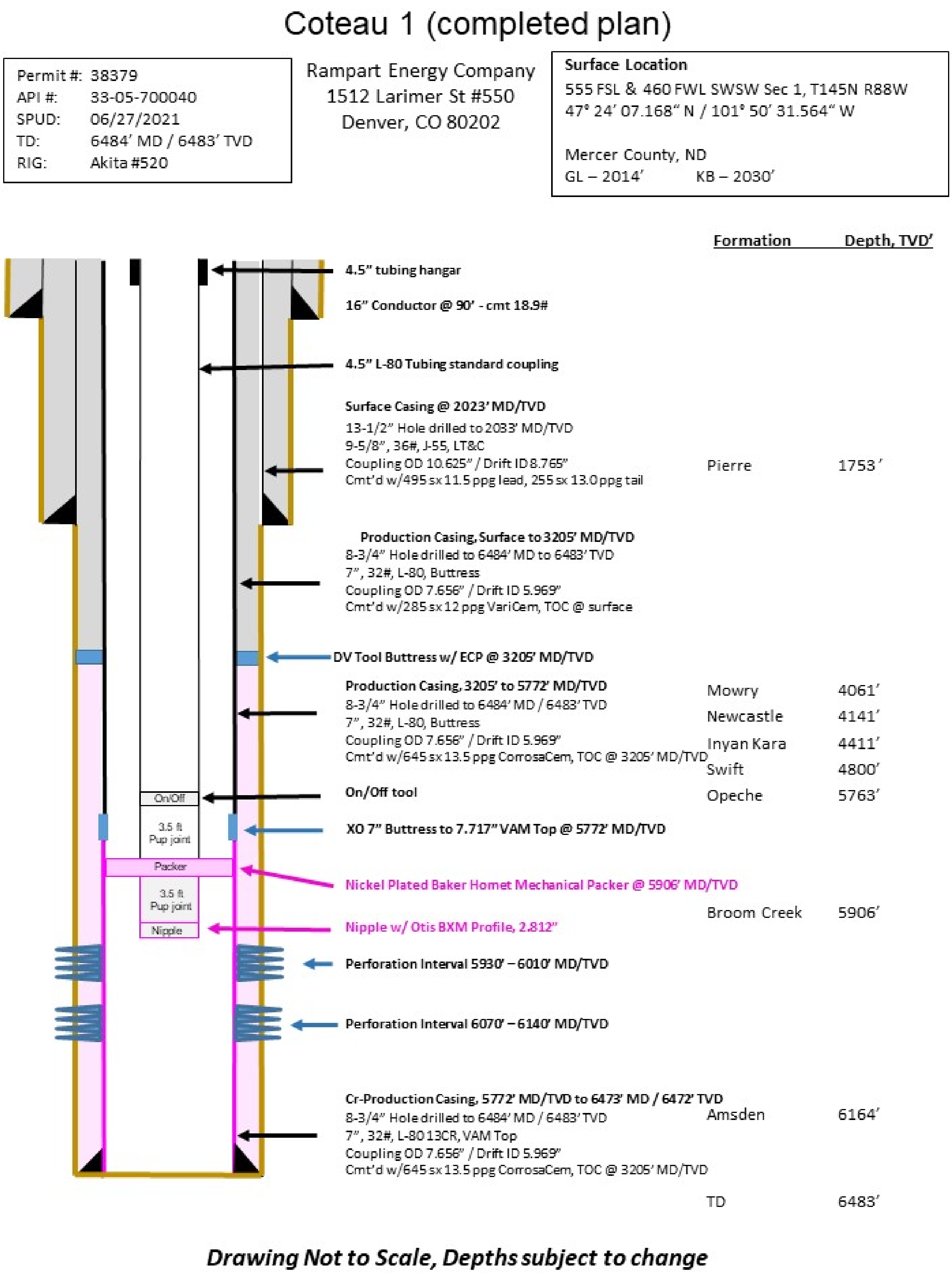

Figure 10-1. Coteau 1 CO_2 injection well schematic.

The NDIC will be contacted, and an intent to plug and abandon will be filed for approval. Final adjustments to the proposed P&A procedure will be made based on wellbore conditions at that time and NDIC field inspector recommendations. Currently, the proposed procedure for P&A of all wells is as follows.

The wellbore is to be plugged and abandoned at the end of the injection of CO_2. API standards, NDIC regulations, and best management practices will be employed to control the well at all times. Well work will be performed by experienced crews and contractors and supervised by Rampart Energy with other competent and experienced engineers and NDIC personnel on-site as necessary. Safety and environmental measures will be in place to ensure the well-being of all personnel and subsequent site reclamation. The protocol is as follows.

1. Capture and record bottomhole reservoir pressure for Broom Creek Formation using an electronic recording pressure gauge – NDAC § 43-05-01-11.5(2a).
   Note: calculate the required corrosion-inhibited kill fluid weight based on bottomhole reservoir pressure plus 100–300 psi for overbalanced pressure. Appropriate storage volume of weighted kill fluid will be stored in portable tanks on location.

2. Move in and rig up (MIRU) workover rig with 2⅞", work string.

3. Kill well by pumping calculated weight and volume of corrosion-inhibited kill fluid down 4.5" injection tubing. Ensure wellhead, tubing, and annular/casing pressures are showing 0 psi and stable.

4. Nipple down (ND) wellhead. Install blowout preventer (BOP), and test low/high 250 psi/ 4,000 psi.

5. While maintaining a hole full of kill fluid, trip out of hole (TOOH) with 4.5" injection tubing, seal assembly, and locator sub, and lay down 4.5" tubing with thread protectors. Also, remove injection packer at 5,906' ft.

6. MIRU wireline services to perform external mechanical integrity test, and set 7-in. cast iron cement retainer (CICR).

7. Install lubricator and pressure-test to 4,000 psi for 10 minutes.

8. Make up and run in hole (RIH) with ultrasonic log–variable-density log (VDL)–casing collar locator (CCL)–temperature–GR log from plug back total depth (PBTD) (anticipated at ~6,280 ft from GR–CCL log run September 17, 2021, to surface for external mechanical integrity test – NDAC § 43-05-01-11.5(2b).
   Note: The proposed logs satisfy requirements for determining external mechanical integrity – NDAC § 43-05-01-11.2(1d).

9. Make up and RIH with CICR. Set CICR at 5,906 ft or 25 ft above top perforation.

10. Rig down and move out (RDMO) wireline unit and crew.

Isolate Broom Creek Formation

Perforations will be isolated pursuant to NDAC § 43-05-01-11.5. They will be isolated with a CO_2-resistant cement.

11. RIH with 2⅞-in. L-80 work string and sting-in into the CICR.

12. Rig up (RU) cementing equipment. Mix and pump 75 sacks (sx) of CO_2-resistant cement to squeeze from 5,906 to 6,141 ft. Displace with corrosion-inhibited spacer fluid.
    Note: Assumptions on the cement properties are 14.2 ppg, 100% excess, and a yield of 1.33 ft^3*/sack.*

13. Unsting 2⅞-in. work string from CICR.

14. TOOH and lay down with work string to ± 5,906 ft. Mix and pump a cement plug of 51 sx CO_2-resistant cement to plug interval of 206 ft. Displace with corrosion-inhibited spacer fluid.
    Note: Assumptions on the cement properties are 14.2 ppg, 50% excess, and a yield of 1.33 ft^3*/sack.*

Isolate Dakota Group

The Inyan Kara Formation will be isolated pursuant to NDAC § 43-05-01-11.5. The method of isolation will be a CO_2-resistant cement plug placed inside of the casing.

15. TOOH and lay down with work string to ±4,841 ft. Mix and pump a balanced plug of 188 sx CO_2-resistant cement to plug interval of 820 ft. Displace with corrosion-inhibited spacer fluid.
    Note: Assumptions on the cement properties are 14.2 ppg, 50% excess, and a yield of 1.33 ft^3*/sack.*

Isolate Surface Casing Shoe

16. TOOH and lay down with work string to ±2,100 ft. Mix and pump a balanced plug of 131 sx Class G cement to plug interval of 500 ft. Displace with corrosion-inhibited spacer fluid.
    Note: Assumptions on the cement properties are 15.8 ppg, 50% excess, and a yield of 1.16 ft^3*/sack.*

Isolate Surface

17. TOOH and lay down with work string to ±120 ft. Mix and pump a balanced plug of 21 sx Class G cement to plug interval of 80 ft. Displace with corrosion-inhibited spacer fluid.
    Note: Assumptions on the cement properties are 15.8 ppg, 50% excess, and a yield of 1.16 ft^3*/sack.*

18. TOOH and lay down remainder of work string.

19. RD cementing equipment.

20. ND BOP and RDMO workover rig.

21. Dig out wellhead and cut off casing 5 ft below ground level (GL). Weld ½-in. steel cap on casing with well name, date inscribed (confined space entry), and information that it was used for CO_2 injection. Dig out deadmen if applicable – NDAC § 43-05-01-19(6).

22. Within 60 days, submit Form 7 plugging report after plugging operations are complete – NDAC § 43-05-01-11.5(4).

23. Submit notice of intent to reclaim to NDIC 30 days in advance prior to reclamation – NDAC § 43-05-01-18(10d).

The proposed P&A plan for the Coteau 1 is summarized in Table 10-1 and provided in Figure 10-2.

Table 10-1. Summary of P&A Plan

Cement Plug No.	Interval Range, ft		Thickness ft	Volume sacks	Note
1 Squeeze	5,906	6,141	235	75	CO_2-resistant cement plug from CICR to bottom perf. Squeezed cement will isolate perforations in the Broom Creek.
2	5,700	5,906	206	51	CO_2-resistant cement plug isolates the Broom Creek Formation and 50' above the top of the Opeche Formation.
3	4,021	4,841	820	188	CO_2-resistant cement plug isolates from 50' above the top of the Inyan Kara Formation to 50' below the base of the Inyan Kara Formation
4	1,600	2,100	500	131	Class G balanced plug to isolate the 9 ⅝" casing shoe
5	40	120	80	21	Class G balanced surface cement plug

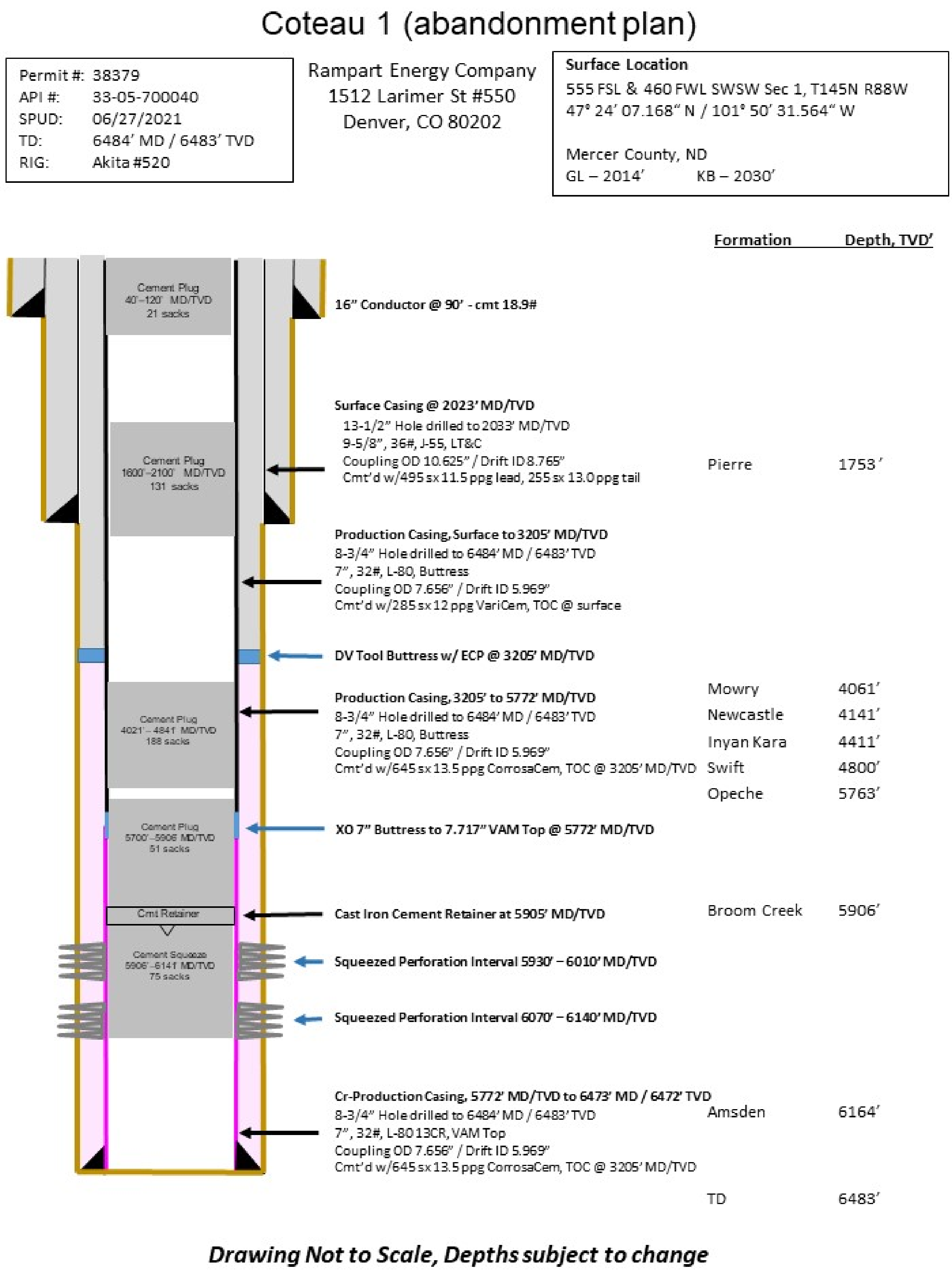

Figure 10-2. Schematic of proposed abandonment plan for each injection well.

11.0 INJECTION WELL AND STORAGE OPERATIONS

11.0 INJECTION WELL AND STORAGE OPERATIONS

This section of the storage facility permit (SFP) application presents the engineering criteria for completing and operating the injection wells in a manner that protects underground sources of drinking water (USDWs). The information that is presented meets the permit requirements for injection wells and storage operations as presented in North Dakota Administrative Code (NDAC) § 43-05-01-05 (SFP, Table 11-1) and NDAC § 43-05-01-11.3

Table 11-1. Proposed Injection Well Operating Parameters

Item	Coteau 1	Coteau 2	Coteau 3	Coteau 4	Coteau 5	Coteau 6	Total/Avg
Injected Volumes							
Total Injected Volume[1]	96.0 Bcf (4.9 MMt)	67.2 Bcf (3.4 MMt)	96.0 Bcf (4.9 MMt)	96.0 Bcf (4.9 MMt)	73.2 Bcf (3.7 MMt)	73.2 Bcf (3.7 MMt)	501.6 Bcf (25.6 MMt)
Injection Rates							
Predicted Average Injection Rate[2]	21.9 MMcfd (1,119 t/d)	15.3 MMcfd (783 t/d)	21.9 MMcfd (1,119 t/d)	21.9 MMcfd (1,119 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	114.5 MMcfd (5,845 t/d)
Predicted Maximum Injection Rate[2]	24.6 MMcfd (1,254 t/d)	17.2 mmcfd (878 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	140.0 MMcfd (7,146 t/d)
Injection Pressures							
Estimated Depth of Top Perforation (feet)[3]	5,930	5,998	5,981	5,928	5,901	5,961	5,950
Formation Fracture Pressure at Top Perforation (psi)[4]	4,210	4,259	4,247	4,209	4,190	4,232	4,224
Projected Avg Surface Injection Pressure (psi)[2]	1,628	1,597	1,644	1,604	1,682	1,677	1,639
Max Allowable Surface Injection Pressure (psi)[5]	1,976	1,998	1,993	1,975	1,966	1,986	1,982
Projected Avg Bottomhole Injection Pressure (psi)[2]	3,315	3,335	3,349	3,297	3,284	3,295	3,313
Projected Max. Bottomhole Injection Pressure (psi)[2]	3,430	3,445	3,462	3,414	3,424	3,426	3,434
Max. Bottomhole Pressure at Top Perforation (psi)[6]	3,801	3,845	3,834	3,800	3,782	3,821	3,814

[1] Assumes 55 MMcfd distributed between four wells (Coteau 1–4) from July/22 thru Dec/24, 70 MMcfd distributed between these same wells Jan/25 thru Apr/26, and 140 MMcfd distributed between six wells (Coteau 1–6) from May/26 through Jun/34.
[2] Per simulation modeling.
[3] Top perf. assumed to be 23 ft below the top of the Broom Creek Formation in all instances based on log results from Couteau 1.
[4] Based on a fracture pressure gradient of 0.71 psi/ft as calculated via CoreLabs D-Code algorithm.
[5] Based on a maximum allowable BHP equal to 90% of frac pressure and a CO_2 density of 0.306 psi/ft.
[6] Based on a maximum allowable BHP equalt to 90% of fracture pressure gradient at estimated depth of top perforation.

11.1 Coteau 1 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of the Dakota Gasification Company [DGC]) drilled and cased the Coteau 1 (Figure 9-1 and Tables 9-1 through 9-4) with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. The following proposed completion procedure outlines the steps necessary to complete the Coteau 1 well for injection purposes.

<u>Site and Well Work Preparation</u>

- Contact the NDIC and provide schedule to perform well work.
- Work road and location as needed for safe operations.
- Conduct safety meetings prior to shifts and treatments.
- Two 500-bbl tanks of 2% KCl water will be required for the step rate test.
- Well was left with no equipment in the hole, no open perforations, and filled with 2% KCl water (to a depth of 20' to avoid winter freezing).

<u>Clean Wellbore and Test Production Casing</u>

1. Move in and rig up (MIRU) workover rig.

2. Confirm zero pressure on wellhead gauges prior to removing night cap.

3. Nipple down 4-1/16" top valve and night cap.

4. Nipple up (NU) blowout preventer (BOP). Record BOP test with a low/high pressure of 250 psi/4,000 psi.

5. Pick up 2⅞" work string.

6. Trip in hole (TIH) open ended, confirm plug back total depth (PBTD). Trip out of hole (TOH).

7. Pressure-test production casing to 1,500 psi.
   a. Top off production casing with 2% KCl water.
   b. Pressure-test casing to 1,500 psi, record pressure for a minimum of 30 minutes.
   c. If casing pressure drops more than 10% variance (NDAC § 43-02-03-21), contact field engineer and DGC representative for further instructions.

<u>Run Cased-Hole Logs</u>

8. MIRU wireline service company.

9. RU wireline lubricator and pressure-test to 1,000 psi.

10. Run in hole (RIH) with temperature/gamma ray log and survey from PBTD to surface.

Perforate Broom Creek Formation

11. RIH with perforating guns and perforate the Broom Creek Formation from 5,930'–6,010' and 6,070'–6,140' (4 shots per foot, 90-degree phasing) utilizing the triple combo openhole log dated July 12, 2021, for correlation, Figure 11-1.

12. Rig down wireline service company.

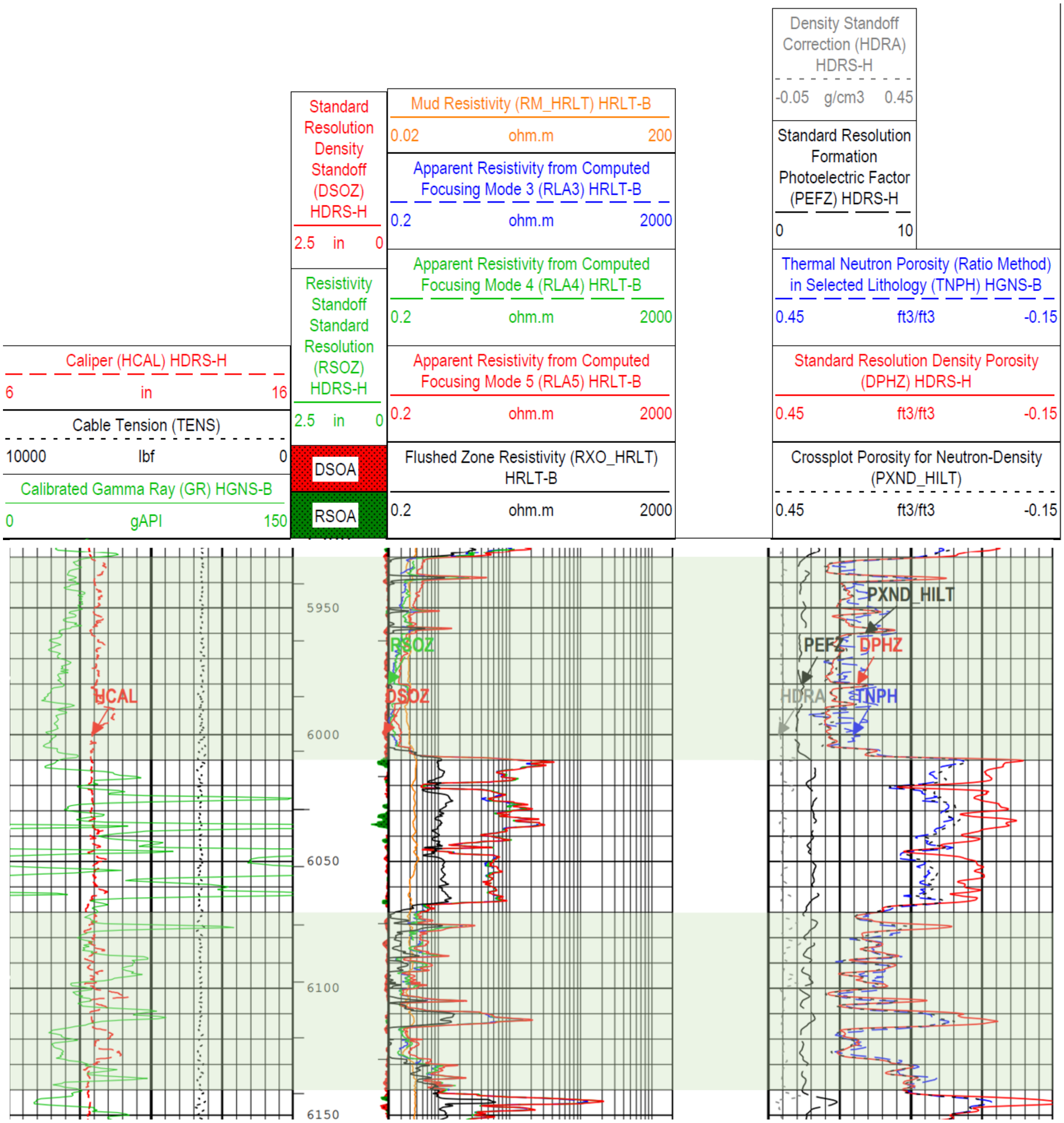

Figure 11-1. Coteau 1 proposed perforation intervals of the Broom Creek Formation (green-shaded sections based on the Coteau 1 triple combo openhole log July 2021).

Perform Step Test

13. PU 7" test packer on 2 7/8" work string, TIH, and set at ±5,900'.

14. Pressure-test packer via annulus to 2,000 psi for 30 minutes. If greater than 10% variance, contact field engineer and DGC representative for further instructions.

15. RU pump service company
    a. Pressure-test surface lines to 2,000 psi.
    b. Set pressure relief valve (PRV) at 2,000 psi or the maximum surface treating pressure.
    c. Monitor annulus with annular pressure gauge for communication.
    d. Perform proposed step rate injection test as follows:
        i. Inject at step rates of 1 barrel per minute.
        ii. Inject at constant rate for 15-min increments.
    e. After indication of formation breakdown (change in pressure slope):
        i. Continue to inject at breakdown rate for an additional 15 min.
        ii. Increase rate by 0.5 bpm for an additional 15 min.
    f. Continuously record rate vs. pressure data throughout the entire test.
    g. Shut down and record instant shut-in pressure (ISIP), 5-, 10-, and 15-min pressure readings.
    h. Shut-in well via master valve, and bleed pressure off surface lines back to pump truck.
    i. Monitor and record all pressures for initial reservoir radial flow, and continue to monitor for stable radial flow as required (NDAC § 43-05-01-11.2) and for pressure fall-off testing.
    j. RD pump service company.

16. TOH and lay down test packer and work string.

Run CO_2 Injection String

17. Change out the pipe rams from 2⅞" to 4½" and pressure-test (test low/high 250 psi/4,000 psi).

18. RU wireline service company.

19. Set 7" nickel-plated injection packer at ±5,905'.

20. Pressure-test packer to 1,500 psi.

21. RD wireline service company.

22. Make up seal assembly, locator subs, and necessary connections. RIH with 4½" L-80 tubing.

23. Pump 100 bbl corrosion-inhibited packer fluid down 4½" tubing and displace with 89 bbl 2% KCl water to displace packer fluid into the annulus.

24. Gently tag on/off tool, latch onto the on/off tool as directed by the tool hand. Verify the connection is made by slight overpull and by pumping into the tubing string. Space out and stack ±15,000-lb compression on packer, lock down, and secure. Pre-pressure-test annulus, packer, and seal bore to 1,000 psi for 30 min with rig pump. Record pressure readings every 5 min.

25. Contact NDIC to witness mechanical integrity test (MIT) 24 hr prior to official testing.
    a. Pressure well to 1,000 psi for 30 min, or as directed by NDIC while charting entire pressure test.
    b. NDIC must witness MIT in accordance with state regulations.

26. ND BOP and NU wellhead.

27. Pressure up tubing to ±2,250 psi to pump out the plug using the rig pump.

28. RDMO workover rig, continuing to be careful of wellhead equipment. Load out surplus equipment. Clear and clean location.

29. Well is to begin injection operations after NDIC approval, including approved MIT.

30. Well is completed as illustrated in Figure 11-2 and is ready for installation of surface equipment for injection operations.

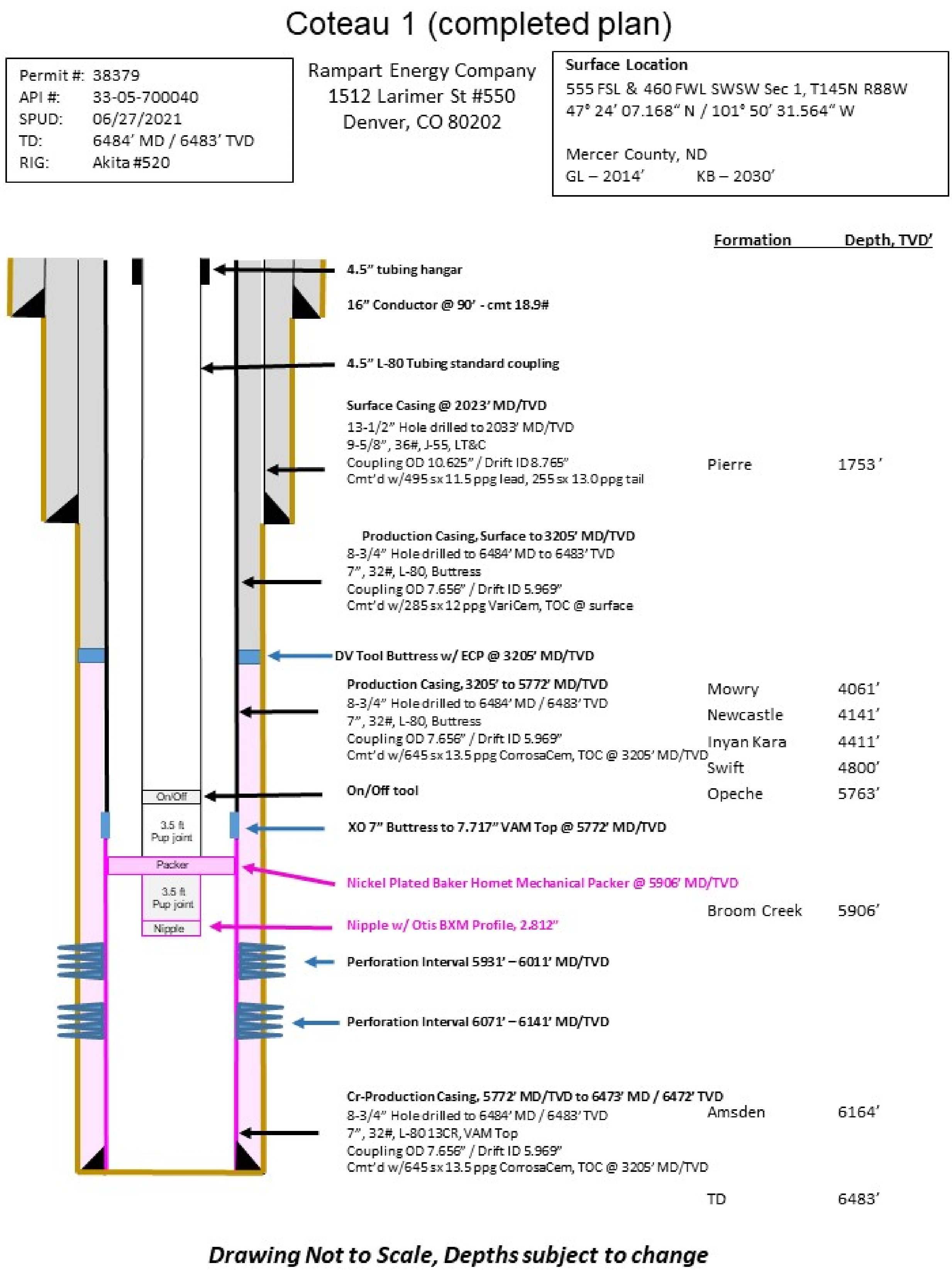

Figure 11-2. Coteau 1 proposed completed wellbore schematic.

11.2 Coteau 2 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 2 (Figure 9-3 and Tables 9-5 through 9-8) prior to project start-up in 2022, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 2 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 2 completed wellbore is shown in Figure 11-3.

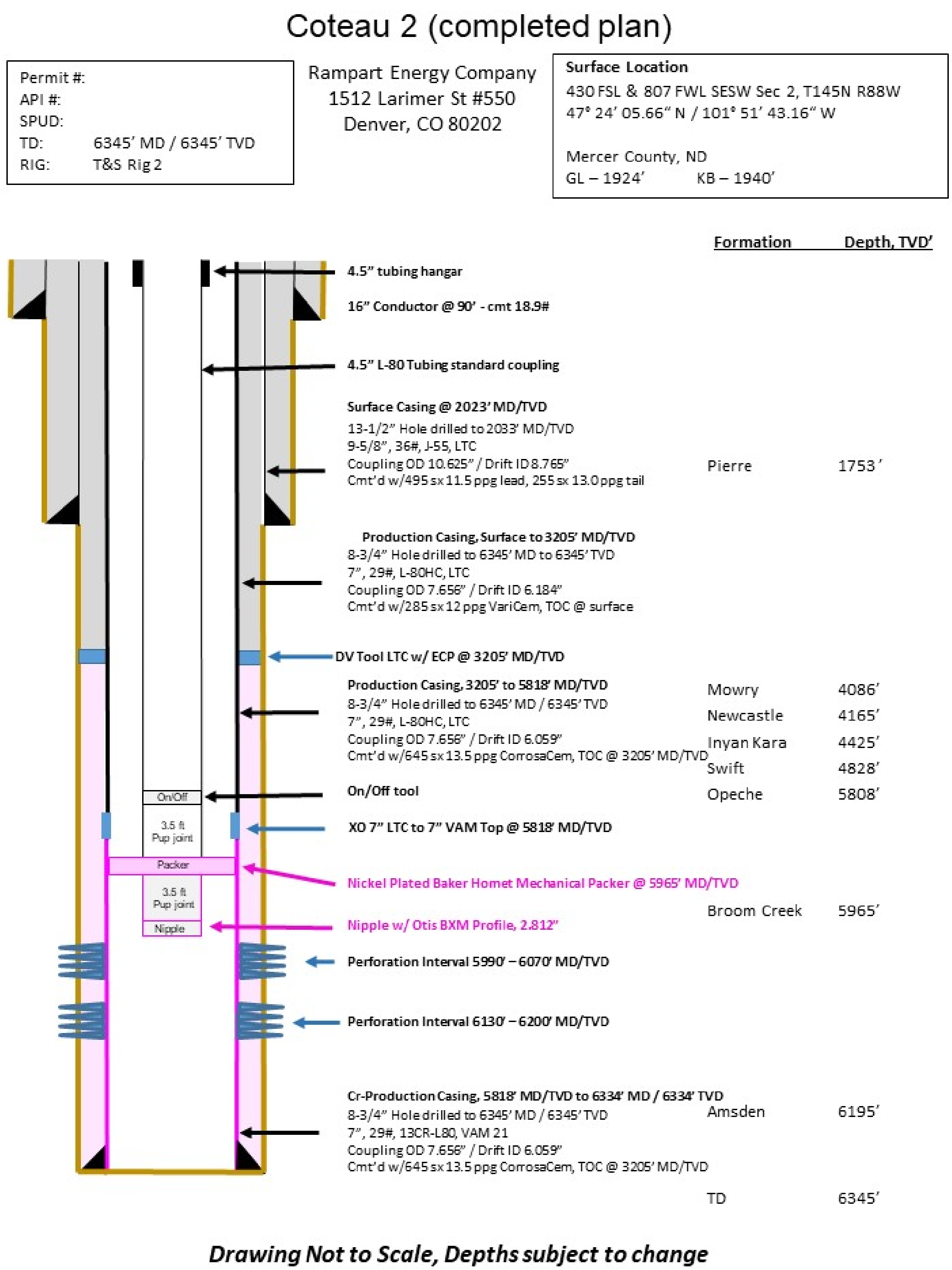

Figure 11-3. Coteau 2 proposed completed wellbore schematic.

11.3 Coteau 3 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 3 (Figure 9-4 and Tables 9-9 through 9-12) prior to project start-up in 2022, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 3 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 3 completed wellbore is shown in Figure 11-4.

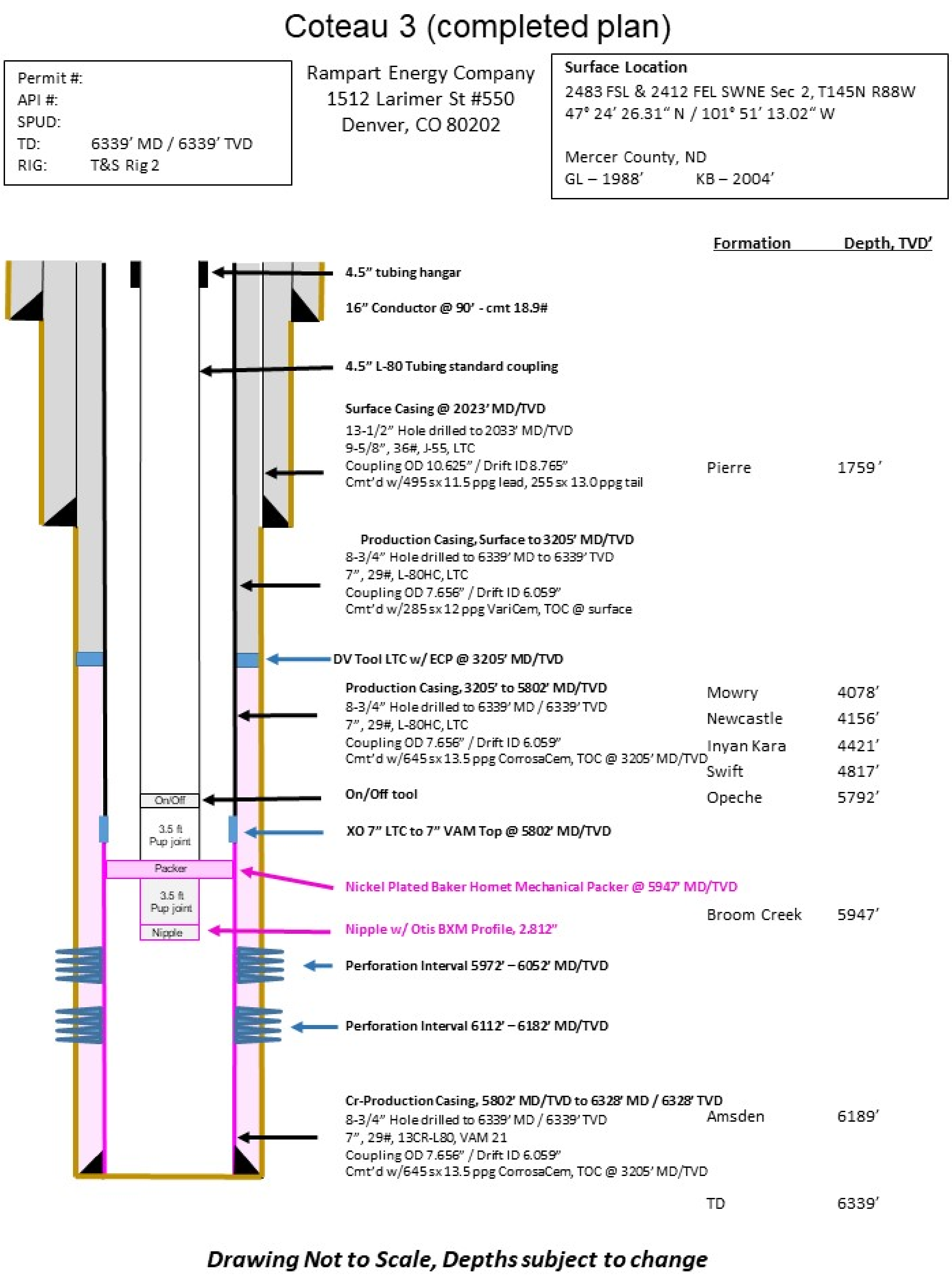

Figure 11-4. Coteau 3 proposed completed wellbore schematic.

11.4 Coteau 4 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 4 (Figure 9-5 and Tables 9-13 through 9-16) prior to project start-up in 2022, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 4 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 4 completed wellbore is shown in Figure 11-5.

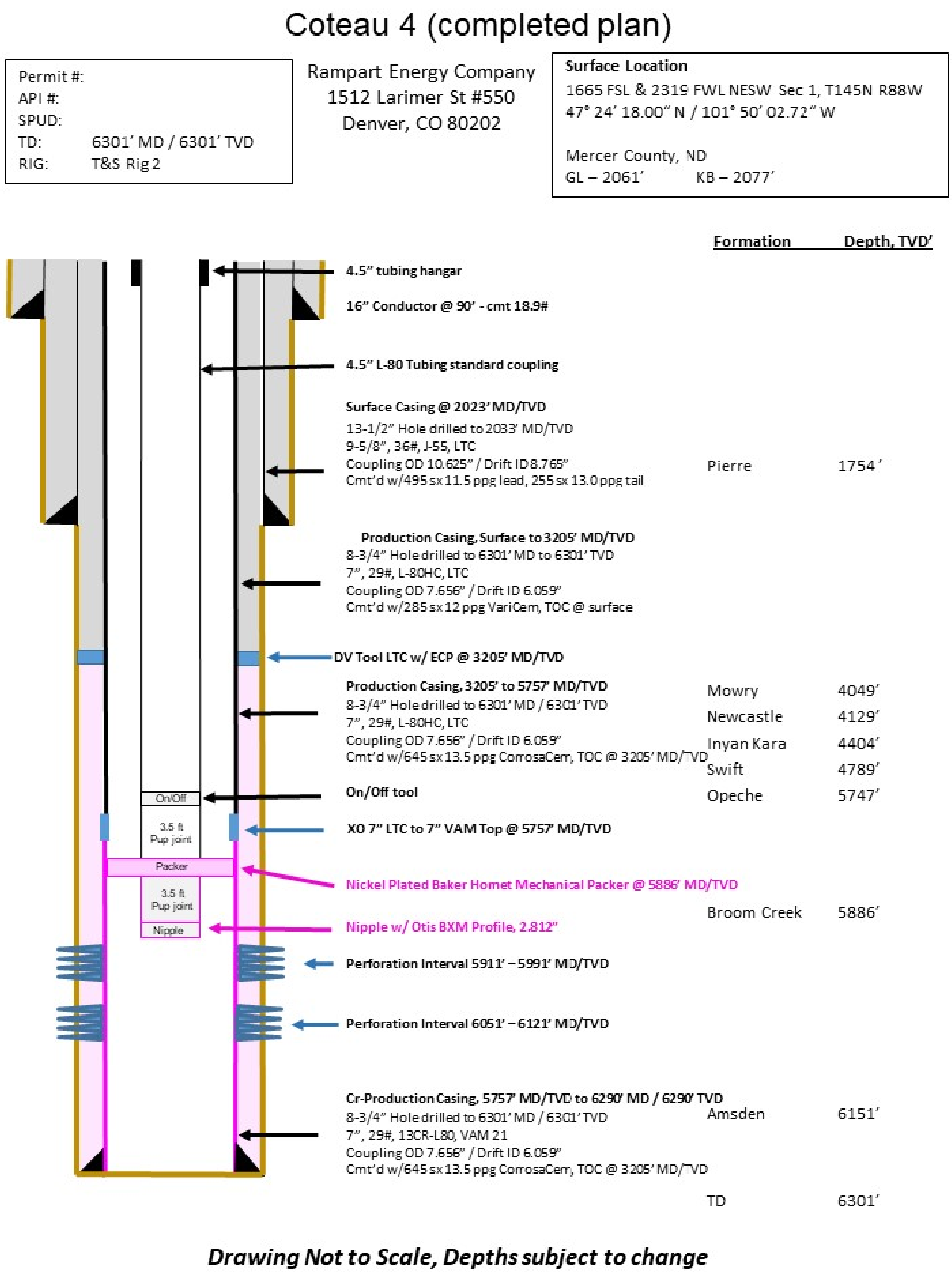

Figure 11-5. Coteau 4 proposed completed wellbore schematic.

11.5 Coteau 5 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 5 (Figure 9-6 and Tables 9-17 through 9-20) prior to an anticipated ramp-up in injection rates in 2026, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 5 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 5 completed wellbore is shown in Figure 11-6.

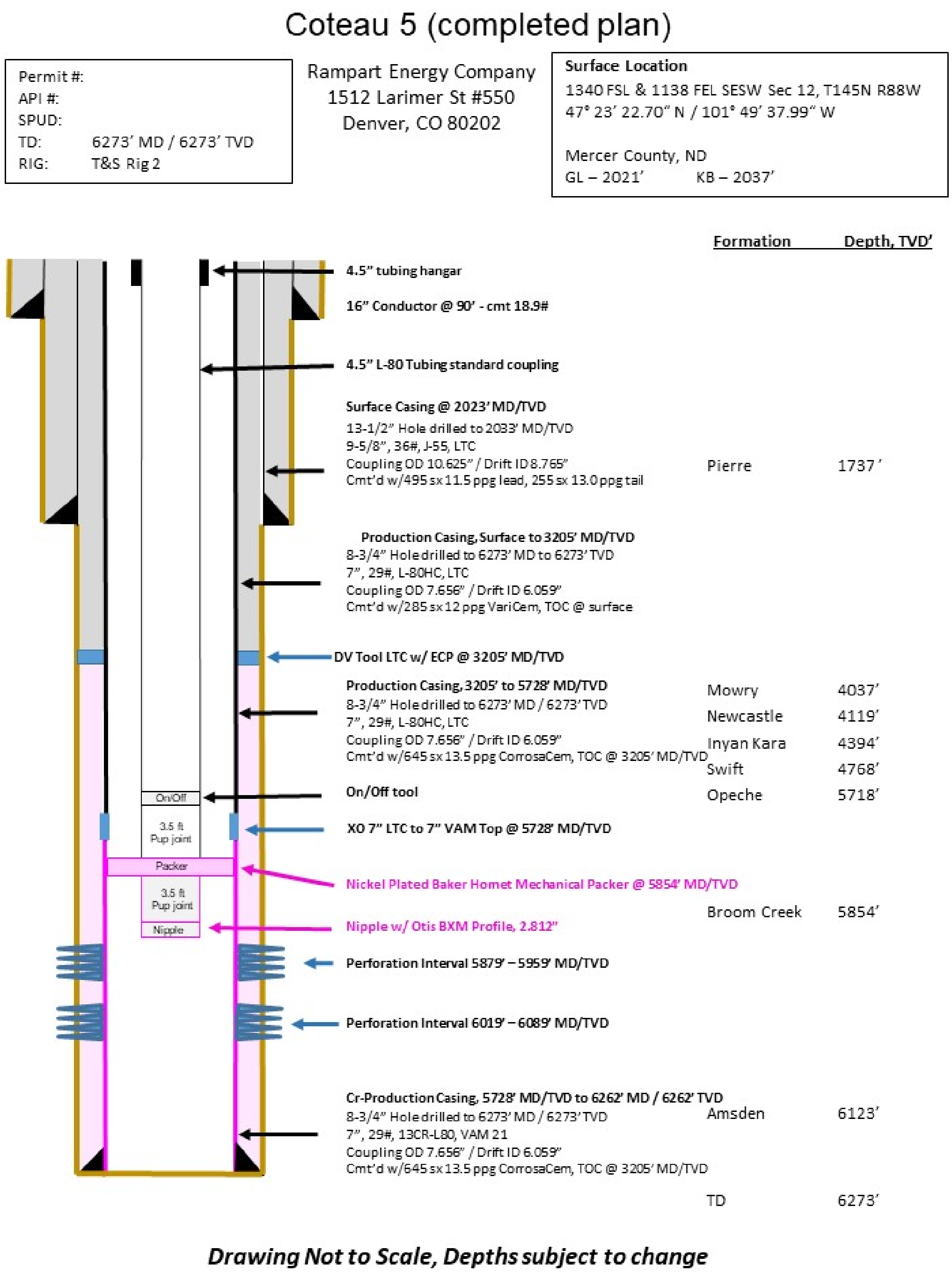

Figure 11-6. Coteau 5 proposed completed wellbore schematic.

11.6 Coteau 6 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 6 (Figure 9-7 and Tables 9-21 through 9-24) prior to an anticipated ramp-up in injection rates in 2026, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 6 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 6 completed wellbore is shown in Figure 11-7.

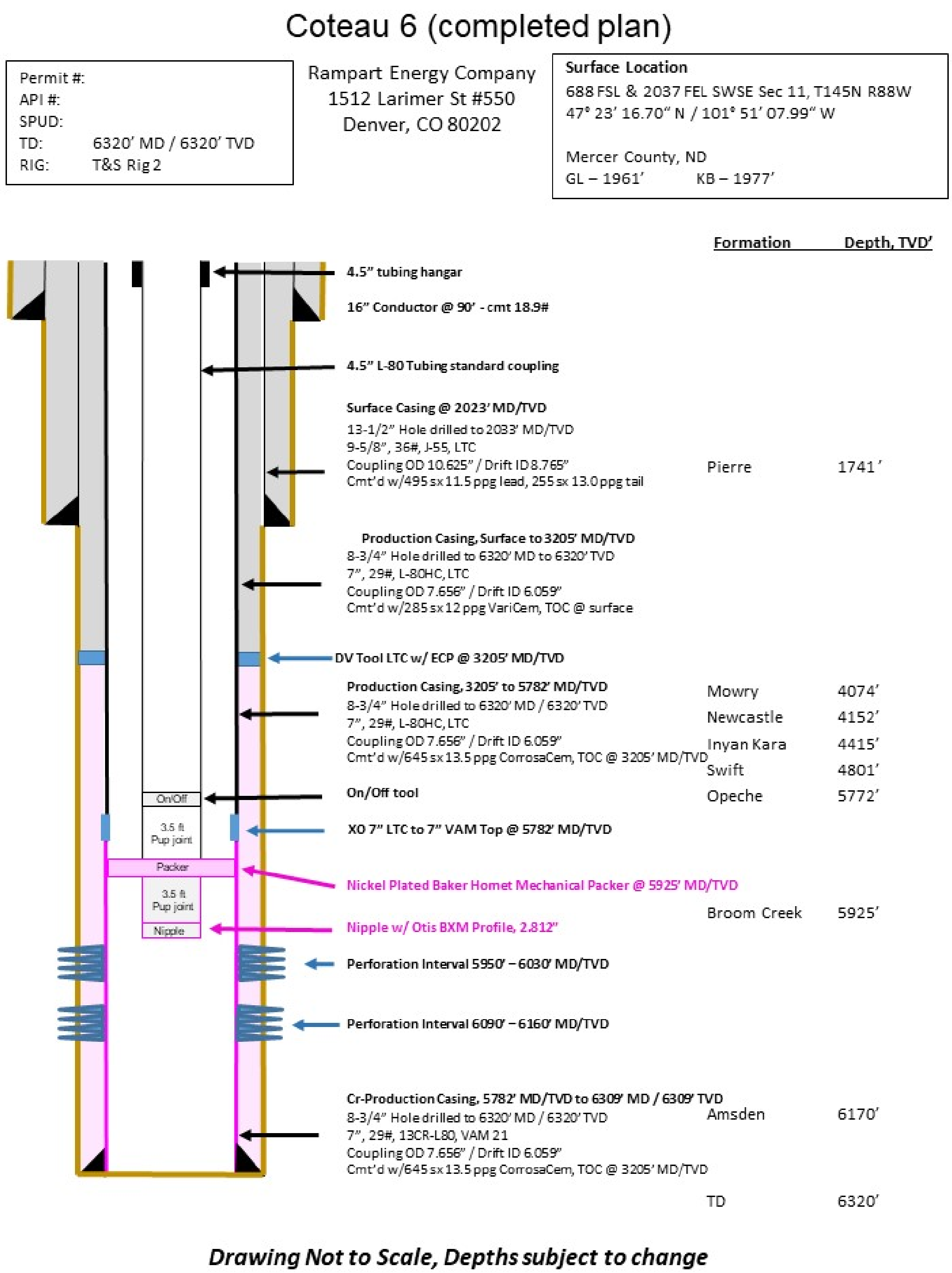

Figure 11-7. Coteau 6 proposed completed wellbore schematic.

11.7 Surface and Downhole Equipment Detail

Common packer and wellhead configurations are planned for each of the six injectors in the Great Plains CO_2 Sequestration Project (Figures 11-8 and 11-9).

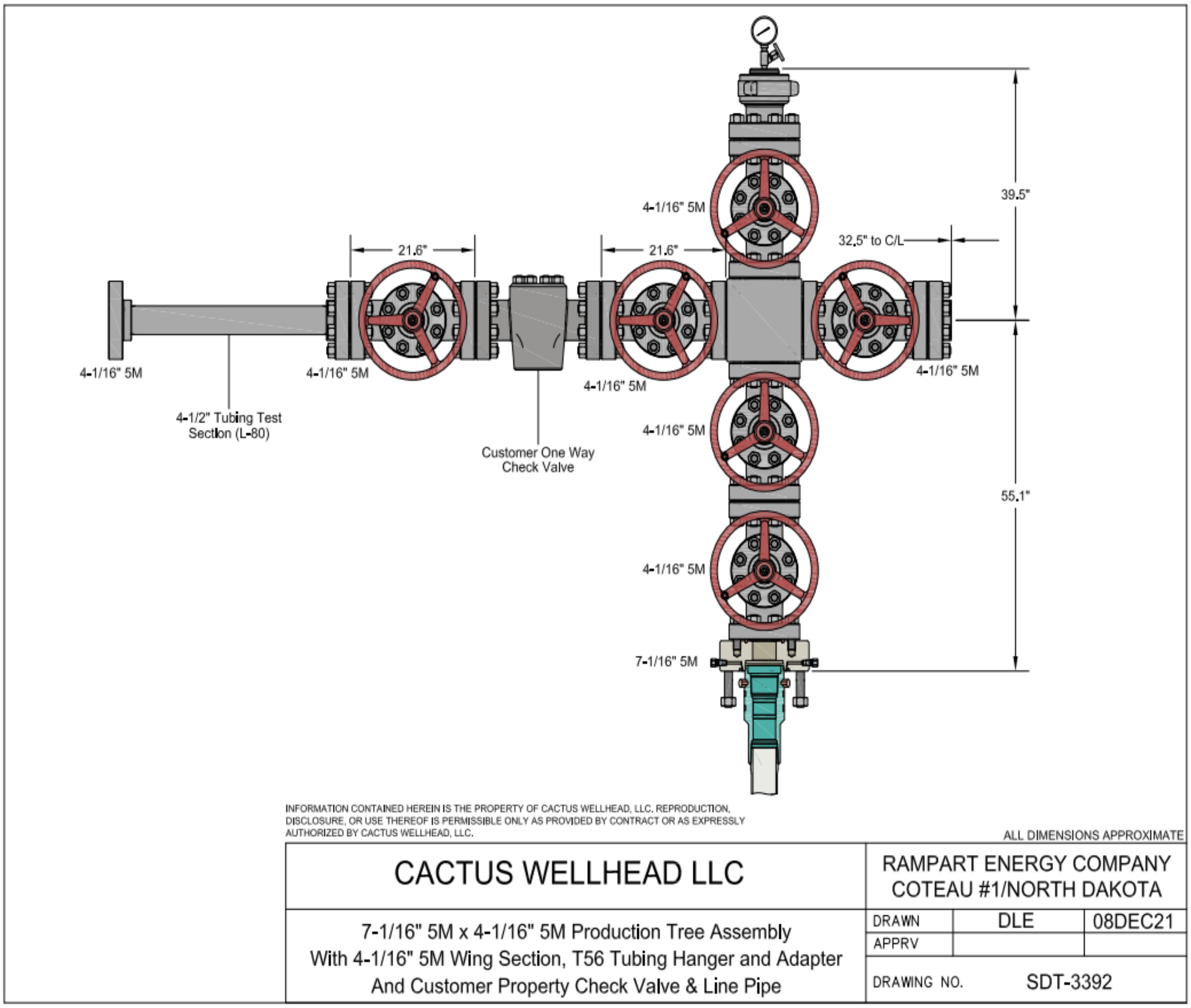

Figure 11-8. Proposed wellhead configuration for Coteau 1 through 6.

Baker Hughes

Proposed Completion Schematic

District: Minot- Bakken
District Ph:

Date Prepared: 19-Nov-2021
Prepared By: Kevin Harding

Proposal:
Revision:
Rev Date: 11/19/2021

Customer/Project	Field/Block	Lease	Well	County/Parish	State/Province
Nickel Coated Hornet Packer					

Customer Rep(s)	Rig Name	Fluid Type	Fluid Weight	BHP	BHT	Max Dev	PBTD
Bill Minnett							

Tubulars	OD (in)	Weight (lbs/ft)	ID (in)	Drift (in)	Grade	Thread	Top Depth	Bottom Depth	Comments
Casing 1	7	32.00	6.094	5.969	13Cr80	Vam Top			
Tubing 1	4 1/2				L-80				

Open Hole ID: **Hole Length:** **Casing Shoe Depth:**

Diagram	No	Description	OD (in)	ID (in)	Length (ft)	Depth (ft)
	1	3-1/2 EUE Pin X TBD Thread Box Nickel Plated	TBD	TBD	TBD	
	2	ON/OFF TL, L-10 3.500 2.813 X Profile Nickel Plated	5.500	2.810	2.48	
	3	HORNET Wireline PACKER 600-292 07.000 IN 23.0-29.0 Nickel Plated	6.000	2.920	9.71	
	4	COUPLING 3.5 Nickel Plated	4.479	N/A	0.48	
	5	6' PUP JOINT 3.5 IN EU 8RD Nickel Plated	3.507	2.956	5.54	
	6	SEATING NIPPLE W/OTIS PROFILE 2.812 BXN PROFILE 3.5 EUE BXP 9 CHROME	4.911	3.725	1.50	
	7	WLEG W/ POP Pinned 2000 PSI , 3.5" 9.2# EU B Nickel Plated	4.511	3.025	0.50	

Figure 11-9. Proposed packer assembly for Coteau 1 through 6.

12.0 FINANCIAL ASSURANCE AND DEMONSTRATION PLAN

12.0 FINANCIAL ASSURANCE AND DEMONSTRATION PLAN

This financial assurance demonstration plan (FADP) is provided to meet the regulatory requirements for the geologic storage of carbon dioxide (CO_2) as prescribed by the state of North Dakota in North Dakota Administrative Code (NDAC) § 43-05-01-09.1. The storage facility permit application must demonstrate that a financial instrument is in place that is sufficient to cover the costs associated with the following actions:

- Pursuant to NDAC § 43-05-01-05.1, corrective action on all active and abandoned wells, which are within the area of review (AOR) and penetrate the confining zone, that have the potential to endanger underground sources of drinking water (USDWs) through the subsurface movement of the injected CO_2 or other fluids.

- Pursuant to NDAC § 43-05-01-11.5, plugging of injection wells.

- Pursuant to NDAC § 43-05-01-19, implementation of postinjection site care (PISC) and facility closure activities, which includes the 10-year PISC monitoring program.

- Pursuant to NDAC § 43-05-01-13, implementation of emergency and remedial response plan (ERRP) actions.

This FADP identifies the financial instruments that will be established (Section 12.2) and provides cost estimates for each of the above actions (Section 12.3) based on the information that is provided in the storage facility permit application.

12.1 Facility Information

The facility name, facility contact, and injection well locations are provided below:

Facility Name:	Dakota Gasification Company (DGC) Great Plains Synfuels Plant
Facility Contact:	Dale Johnson, Vice President and Plant Manager
Injection Well Locations:	Coteau 1 (North Dakota Industrial Commission [NDIC] File No. 38379) SW/SW of Section 01 T145N, R88W (47.401991, -101.842101) Coteau 2 (NDIC File No. TBD) SW/SW of Section 02 T145N, R88W (47.401572, -101.861988) Coteau 3 (NDIC File No. TBD) NW/SE of Section 02 T145, R88W (47.407308, -101.853618) Coteau 4 (NDIC File No. TBD) NE/SE of Section 01 T145N, R88W (47.406940, -101.835330) Coteau 5 (NDIC File No. TBD) NE/SE of Section 12 T145N, R88W (47.389640, -101.827219) Coteau 6 (NDIC File No. TBD) SW/SE of Section 11 T145N, R88W (47.405000, -101.834090)

12.2 Financial Instruments

DGC is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments:

- DGC will establish an escrow account to cover the costs of corrective action in accordance with NDAC § 43-05-01-05.1, plug injection wells in accordance with NDAC § 43-05-01-11.5, and implement PISC and facility closure activities in accordance with NDAC § 43-05-01-19. DGC will make four annual payments of $1 million to the escrow account. The first payment will occur on or before the first day of operations, and the final payment will occur in 2025, bringing the account balance to $4 million.

- A third-party pollution liability insurance policy with an aggregate limit of $16 million will be secured to cover the costs of implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13.

The estimated total costs of these activities are presented in Table 12-1. Section 12.3 of this FADP provides additional details of the financial responsibility cost estimates for each activity.

Table 12-1. Cost Estimates for Activities to Be Covered

Activity	Estimated Total Cost
Corrective Action on Wells in the AOR	$0
Plugging of Injection Wells	$1,000,000
PISC and Facility Closure	$3,000,000
Emergency and Remedial Response (including endangerment to USDWs)	$16,000,000
Total	$20,000,000

The third-party insurance, which will identify DGC as the principal, will be provided by one or a combination of companies shown below. The companies meet all of the following criteria:

1. The company is authorized to transact business in North Dakota.

2. The company has either passed the specified financial strength requirements based on credit ratings or has met a minimum rating, minimum capitalization, and ability to pass the rating, when applicable.

3. The third-party insurance can be maintained until such time that NDIC determines that the storage operator has fulfilled its financial obligations.

The third-party insurance, which identifies DGC as the covered party, will be provided by one or a combination of the companies shown below. The coverage limits of the policy are summarized below:

DGC has procured indicated terms for commercial environmental impairment liability (EIL) insurance coverage to fund covered emergency and remedial response actions to protect USDWs arising out of sequestration operations. Coverage terms are of an estimated nature only at this time, as firm and bindable terms are not possible this far in advance of commencement of sequestration operations. At this time, a coverage limit of $25 million per occurrence/aggregate is contemplated and expected to be provided by one or a combination of the following insurers:

- Ascot Insurance Group – AM Best-Rated A (excellent)
- Aspen Insurance Group – AM Best-Rated A (excellent)
- W.R. Berkley Insurance Group – AM Best-Rated A+ (superior)

Final coverage terms and costs will be determined upon full underwriting and firm/bindable quotations to be issued by insurers 30 to 60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations.

The third-party insurance companies listed above meet both of the following criteria, as specified in NDAC §43-05-01-09.1(1)(g):

1. The companies satisfy financial strength requirements based on credit ratings in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa).

2. The companies meet a minimum rating (minimum rating based on an issuer, credit, securities, or financial strength rating as a demonstration of financial stability) and minimum capitalization (i.e., demonstration that minimum thresholds are met for the following financial ratios: debt–equity, assets–liabilities, cash return on liabilities, liquidity, and net profit) and are able to pass bond rating in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa), when applicable.

12.3 Financial Responsibility Cost Estimates

12.3.1 Corrective Action

DGC implemented the following workflow to estimate costs associated with corrective action activities: 1) delineate the AOR and 2) identify and evaluate active and abandoned legacy wells within the AOR (i.e., ANG#1 and ANG#2) to ensure they meet the minimum completion standards for geologic storage of CO_2 and need no corrective action. Based on the results of the well evaluations, no correction action was needed.

12.3.2 Plugging of Injection Wells

DGC implemented the following approach to estimate costs associated with the plugging of injection wells: assume plugging of six Class VI injection wells at a total cost of $1 million, or $167,000 per well.

12.3.3 Implementation of PISC and Facility Closure Activities

The breakdown of estimated costs totaling $3 million for implementing the PISC as described in the PISC and facility closure plan is provided in Table 12-2, which includes the following: a) near-surface monitoring (i.e., soil gas and Fox Hills Formation testing), b) formation monitoring (i.e., downhole pressure and temperature surveys, pulsed-neutron logs) and mechanical integrity well tests (i.e., injection well annulus pressure, ultrasonic logs), c) coordinated repeat 2D seismic, and d) estimated cost of site closure activities, which has been estimated at $100K based on the integrated environmental control.

Table 12-2. Cost Estimates for 10-year PISC Monitoring Efforts

Monitoring Type	Comments	Total Estimated Cost
Near-Surface Monitoring		
Soil Gas Sampling and Analysis	10 years at $25,000 per year	$250,000
Fox Hills Sampling and Analysis	10 years at $25,000 per year plus $300,000 for site closure activities	$550,000
Geophysical Monitoring		
2D Seismic Data Acquisition	Perform four 2D seismic surveys (PISC years 1, 3, 5, and 10) at $550,000 per survey	$2,200,000
	Total	**$3,000,000**

12.3.4 Implementation of Emergency and Remedial Response Actions

12.3.4.1 Emergency Response Actions

A review of the technical risk categories for DGC's Great Plains CO_2 Sequestration Project identified a list of events that could potentially result in the movement of injected CO_2 or formation fluids in a manner that may endanger a USDW and require an emergency response. These events are as follows:

- Failure of the surface equipment
- Integrity failure of injection well
- Injection well-monitoring equipment failure
- Storage reservoir is unable to contain the formation fluid or stored CO_2
- Natural disasters

If it is determined that one or more of these events have occurred, the emergency response actions that will be implemented are described in the ERRP (Section 7). These response actions are summarized in Table 12-3.

Table 12-3. Response Actions for Potential Emergency Events

Emergency Event	Response Action
Failure of CO_2 Transmission Line or Flow Lines from DGC CO_2 Capture System to CO_2 Injection Wellheads	• The CO_2 stream release and its location will be detected by the leak detection system, which will trigger an alarm and result in the automated shutdown of the transmission line and wellsite flow line. • If warranted, initiate an evacuation plan. • The transmission line and/or flow line failure will be inspected to determine the root cause of the failure. • Repair/replace the damaged transmission line or flow line, and if warranted, put in place the measures necessary to eliminate such events in the future.
Integrity Failure of Injection Well	• Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure. • Stop CO_2 injection, and purge CO_2 from surface facilities. • Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the NDIC Department of Mineral Resources (DMR) underground injection control (UIC) program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Injection Well-Monitoring Equipment Failure	• Monitor well pressure, temperature, and annulus pressure (manually if necessary) to determine the cause and extent of failure. • Stop CO_2 injection, and purge CO_2 from surface facilities. • Identify and, if necessary, implement appropriate remedial actions to repair/replace well-monitoring equipment (in consultation with the NDIC DMR UIC program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).

Continued . . .

Table 12-3. Response Actions for Potential Emergency Events (continued)

Emergency Event	Response Action
Storage Reservoir Unable to Contain Formation Fluid or Stored CO_2	• Collect confirmation sample(s) of groundwater, soil gas, ambient air, and/or surface water, and analyze them for indicator parameters (see testing and monitoring plan of the supporting plans of the storage facility permit application). • If the presence of indicator parameters is confirmed, develop (in consultation with the NDIC DMR UIC program director) a case-specific work plan to: 1. Install additional monitoring points near the impacted area to delineate the extent of impact. a. If a USDW is impacted above drinking water standards, arrange for an alternative potable water supply for all users of that USDW. b. If a surface release of CO_2 to the atmosphere is confirmed, initiate an evacuation plan, if warranted, in tandem with an appropriate workspace and/or ambient air-monitoring program at the plant boundary to monitor the presence of CO_2 and its natural dispersion following the termination of CO_2 injection, following practices similar to those described in the DGC risk management plan for analyzing the potential impacts of other chemical releases from the DGC plant. c. If surface release of CO_2 to surface waters is confirmed, implement appropriate surface water-monitoring program to determine if water quality standards are being exceeded. 2. Proceed with efforts, if necessary, to 1) remediate the USDW to achieve compliance with drinking water standards (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to air-strip CO_2 from the impacted water or implement other active remediation processes) and reinject treated water into the subsurface, 2) monitor CO_2 concentrations in the workspace and ambient air to

Continued . . .

Table 12-3. Response Actions for Potential Emergency Events (continued)

Emergency Event	Response Action
Storage Reservoir Unable to Contain Formation Fluid or Stored CO_2 (continued)	document reduction of CO_2 concentrations to background levels over time, and 3) monitor the reduction of impacts to surface waters to background levels as a result of natural attenuation processes or implement active/passive remediation of surface waters to achieve acceptable background levels of impacts. • Continue all remediation and monitoring at an appropriate frequency (as determined by DGC and the NDIC DMR UIC program director) until the unacceptable, adverse impacts have been fully addressed.
Natural Disasters (seismic event)	• Identify where (i.e., the epicenter) and when the event occurred. • Determine whether there is a connection with injection activities. • Determine mechanical integrity of all project wells and formation seals. • If warranted, stop CO_2 injection, purge CO_2 from surface facilities, and implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Natural Disasters (other)	• Monitor well pressure, temperature, and annulus pressure to verify status of wells and determine the cause and extent of any failure. • If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate extent of any impacts. • If impacts or endangerment of USDWs are detected, identify and implement appropriate response actions in accordance with the DGC emergency action plan (in consultation with the NDIC DMR UIC program director).

12.3.4.2 Estimation of Costs of Emergency Response Actions

Estimating the costs of implementing the emergency response actions in Table 12-3 is challenging since remediation measures specifically dedicated to CO_2 storage impacts are poorly documented, with one of the more important data gaps being the lack of precise knowledge of the leakage mechanisms and associated impacts (Manceau and others, 2014). Without this knowledge, it is not possible to design appropriate remedial measures. Furthermore, to date, no remediation action following CO_2 leakage after geologic storage has ever been implemented mainly because of the absence of established impacts (Manceau and others, 2014). Consequently, the degree of maturity of remediation measures in the carbon capture and storage (CCS) field is low, making it necessary to rely on literature that is primarily based on modeling or analogies with other pollutants, e.g., the analogy between CO_2 and volatile organic compounds, the latter having been addressed extensively in the literature. Additionally, for the remedial measures, costs and time for adequate removal are generally site-dependent, and no information is specifically available in this area in the CCS field.

Based on this current situation, two key technical manuscripts were relied upon to identify and estimate the costs of mitigation/remediation technologies to address undesired migration of CO_2 from a geological storage unit (Manceau and others, 2014, and Bielicki and others, 2014).

<u>12.3.4.2.1 Identification of Remediation Technologies</u>

Manceau and others (2014) identified several remediation technologies/strategies that are available to address the potential impacted media that may result from an emergency event. These impacted media and remediation measures are listed in Table 12-4. The impacted media in Table 12-4 include surface and groundwater/USDWs, vadose zone, indoor settings, and atmosphere; the remedial measures include a combination of active (e.g., air sparging) and passive (e.g., dispersion, natural attenuation) systems. However, it is important to note that, at this time, there is no widely accepted methodology for designing intervention and remediation plans for CO_2 geologic storage projects. Consequently, there remains a need for establishing the best field-applied and test practices for mitigating an undesired CO_2 migration. This effort will be based on a combination of available literature and experience that is gained over time in existing CO_2 storage projects.

Table 12-4. Proposed Technologies/Strategies for Remediation of Potential Impacted Media

Impacted Media	Potential Remedial Measures
Groundwater/USDW	Monitored natural attenuation
	Pump-and-treat
	Air sparging
	Permeable reactive barrier
	Extraction/injection
	Biological remediation
Vadose Zone	Monitored natural attenuation
	Soil vapor extraction
	pH adjustment (via spreading of alkaline supplements, irrigation, and drainage)
Surface Water	Passive systems, e.g., natural attenuation
	Active treatment systems
Atmosphere	Passive systems, e.g., natural mixing, dispersion
Indoor/Workplace Settings	Sealing of leak points
	Depressurization
	Ventilation

12.3.4.2.2 Estimation of Costs for Implementing Emergency Event Responses

Given the lack of a site-specific estimate of implementing the emergency event responses at the CO_2 geologic storage site of DGC, cost estimates developed by Bielicki and others (2014) were used to derive a cost range for the project related to the undesired migration of CO_2 from a geologic storage unit. Extrapolating these literature costs, which were based on a case study site in the Michigan Sedimentary Basin, to DGC's Great Plains CO_2 Sequestration Project only provides an order-of-magnitude estimate of the potential costs due to the significant site-specific differences in the storage projects; however, the range of costs estimated in this manner are believed to be conservatively high in nature, making them more than sufficient for informing the value of the financial instrument that must be secured for the project, as described in the financial responsibility demonstration plan.

Case Study Description

Bielicki and others (2014) examined the costs associated with remediating undesired migration of CO_2 from a geologic storage unit as part of a case study of an extreme leakage situation. The case study involved the continuous annual injection of 9.5 Mt (9,500,000 metric tons) of CO_2 into the Mt. Simon sandstone of the Michigan Sedimentary Basin over a period of 30 years. It assumed every well in the basin was a potential leakage pathway and that no action was taken to mitigate any of these leakage pathways. In addition, eight UIC Class I injection wells, which were located within approximately 1 mile of the CO_2 injection well, were also identified as leakage pathways. Four hundred probabilistic simulations of the CO_2 injection were performed and produced estimates of the area of the CO_2 plume as well as leakage rates of CO_2 from the storage reservoir to four aquifers as well as to the surface.

Cost Estimates

Story lines were developed for the site based on 1) risk assessments for the geologic storage of CO_2; 2) consequences of leakage; 3) lay and expert opinion of leakage risk; 4) modeling of CO_2 injection and leakage for the case study; and 5) input from local experts, oil and gas engineers, academics, attorneys, and other environmental professionals familiar with the Michigan Sedimentary Basin. Cost estimates for managing leakage events were then generated for first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) projects based on a low-cost and high-cost story line. These cost estimates provided a breakdown of the costs into the following categories:

- Find and fix a leak
- Environmental remediation
- Injection interruption
- Technical remedies for damages
- Legal costs
- Business disruption to others, e.g., natural gas storage
- Labor burden to others

Of interest for the financial responsibility demonstration plan is the environmental remediation cost estimate, which was provided for a leak scenario where there was interference with groundwater as well as a scenario where there was groundwater interference combined with CO_2 migration to the surface.

Environmental Remediation – Low-Cost and High-Cost Story Line

The low-cost and high-cost story lines for the two components of environmental remediation, groundwater interference and migration to the surface, are summarized in Table 12-5. As shown in Table 12-5, the low-cost story lines are characterized by independent leak scenarios that either result in interference with groundwater or CO_2 migration to the surface. On the other hand, the high-cost story lines are interrelated, where it is assumed that the high-cost story line for CO_2 migration to the surface is conditional upon the existence of the high-cost story line for groundwater interference.

Estimated Environmental Remediation Costs – FOAK and NOAK Projects

Based on the above story lines, the estimated environmental remediation costs for the high-cost story lines are basically the same for both FOAK and NOAK projects:

- High-cost story line – Groundwater interference alone: ~ $13MM
- High-cost story line – Groundwater interference with CO_2 migration to the surface: $15MM to $16MM

12.3.4.2.3 Input for the Financial Responsibility Demonstration Plan

The estimated costs for the environmental remediation of the high-cost story line for the case study, $15MM to $16MM, likely represents a conservatively high estimate of similar costs for DGC's Great Plains CO_2 Sequestration Project. This statement is based primarily on the fact that the quantity of CO_2 injection of the case study (9,500,000 metric tons of CO_2 per year) is significantly larger than the planned injection quantity of DGC's Great Plains CO_2 Sequestration Project (from 1.1 to 2.7 million metric tons of CO_2 per year). Furthermore, the case study site had 450,000 active and abandoned wells, 400,000 of which penetrate the shallow subsurface to provide for drinking water, irrigation, and industrial uses. In contrast, there are six proposed CO_2 injection wells and two wastewater disposal wells (ANG#1 and ANG#2) located in the area of DGC's Great Plains CO_2 Sequestration Project. As such, the extreme leakage scenario of the case study represents a more extensive leakage scenario that could exist at the DGC site. Accordingly, even though the same remedial technologies and strategies may be used at both sites to address CO_2 migration, it is assumed that the cost estimates provided for the case study represent a conservatively high maximum cost for DGC's Great Plains CO_2 Sequestration Project. It is on this basis that the value of $16MM has been used as one of the cost inputs into the determination of the financial instrument that will be put in place for DGC's Great Plains CO_2 Sequestration Project.

Table 12-5. Low-Cost and High-Cost Story Line for Environmental Remediation

	Low-Cost Story Line
Groundwater Interference	• A small amount of CO_2 migrates into a deep formation that has a total dissolved solids concentration of ~9000 ppm. By definition, this unit is a USDW, but the state has abundant water resources, and there are no foreseeable uses for water from this unit. • Regulators require that two monitoring wells be drilled into the affected USDW and three monitoring wells be drilled into the lowermost potable aquifer (total dissolved solids concentration of <1000 ppm) to verify the extent of the impacts of the leak. No legal action is taken. • Injection is halted from the time that the leak is discovered until monitoring confirms that containment is effective (9 months). • The UIC regulator determines that no additional remedial actions are necessary.
CO_2 Migration to the Surface	• A leaking well provides a pathway whereby CO_2 discharges directly to the atmosphere. • Neither CO_2 nor brine leaks into the subsurface formation outside the injection formation in significant quantities. • The CO_2 injection is halted for 5 days, and the leaking well is promptly plugged.
	High-Cost Story Line
Groundwater Interference	• A community water system reports elevated arsenic. Monitoring suggests that the native arsenic in the formation may have been mobilized by pH changes in the aquifer caused by CO_2 impacts to the aquifer. • A new water supply well is installed to serve the community, and the former water supply wells are plugged and capped. • Potable water is provided to the affected households during the 6 months required to drill the new water supply wells. • Groundwater regulators take legal action on the geologic storage operator to force remediation of the affected USDW using pump-and-treat technology. • UIC regulators require remedial action to remove, through a CO_2 extraction well, an accumulation of CO_2 that has the potential to affect the drinking water. • CO_2 injection is halted for 1 year during these remediation activities.
CO_2 Migration to the Surface	• The high-cost story line for groundwater is required. • A hyperspectral survey completed during the diagnostic monitoring program identifies surface leakage in a sparsely populated area. • Elevated CO_2 concentrations are detected by a soil gas survey and by indoor air quality sampling in the basements of several residences. • Affected residents are housed in a local hotel for several nights while venting systems are installed in their basements. • A soil-venting system is installed at the site. • CO_2 injection is halted for a year during these remediation activities.

To provide additional perspective for this $16MM cost estimate for environmental remediation, two other cost estimates for the remediation of potential environmental impacts associated with the geologic storage of CO_2 were found in the literature. These costs ranged from $9MM to $34MM. The source of the lower limit ($9MM) was a 2012 study (Trabucchi and others, 2012) which estimated the damages, i.e., dollars necessary to remediate or compensate for harm should a release occur at a commercial storage site (i.e., FutureGen 1.0 located in Jewett, Texas) that planned to inject 1,000,000 metric tons of CO_2 per year. This study estimated the “most likely (50th percentile)” total damages to be approximately $8.7MM and the “upper end (95th and 99th percentiles)” of the total damages to be approximately $20.1MM and $26.2MM, respectively (all estimates in 2020 dollars).

The upper limit of the range ($34MM) came from a Class VI UIC permit, which was issued to Archer Daniels Midland (ADM) by the U.S. Environmental Protection Agency (Underground Injection Control Permit – Class VI, Permit No. IL-115-6A-0001). As part of the financial responsibility demonstration plan of the ADM permit, a cost estimate of $33.8MM was provided for the cost element, emergency and remedial response, which is slightly higher than the 99th percentile cost estimate of $26.2MM for the FutureGen 1.0 site. The planned injection rate for the ADM geologic storage project was ~1,200,000 metric tons per year.[1]

12.4 References

Bielicki, J.M., Pollak, M.F., Fitts, J.P., Peters, C.A., and Wilson, E.J., 2013, Causes and financial consequences of geologic CO_2 storage reservoir leakage and interference with other subsurface resources: International Journal of Greenhouse Gas Control, v. 20, p. 272–284.

Manceau, J.C., Hatzignatiou, D.G., Latour, L.L, Jensen, N.B., and Réveillére, A., 2014, Mitigation and remediation technologies and practices in case of undesired migration of CO_2 from a geological storage unit—current status: International Journal of Greenhouse Gas Control, v. 22, p. 272–290.

Trabucchi, C., Donlan, M., Huguenin, M, Konopka, M., and Bolthrunis, S., 2012, Valuation of potential risks arising from a model, commercial-scale CCS project site: Prepared for CCS Valuation Sponsor Group, June 1, 2012.

[1] It should be noted that both of these examples are injecting CO_2 at a rate that is approximately the same planned injection at the DGC Great Plains Synfuels Plant CO_2 facility, which suggests that these cost estimates are likely similar to the costs that will be required for DGC’s Great Plains CO_2 Sequestration Project.

APPENDIX A

COTEAU 1 FORMATION FLUID SAMPLING

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 14 Oct 21
Lab Number: 21-W3667
Work Order #:82-2651
Account #: 72540
Date Sampled: 28 Sep 21 19:35

Date Received: 29 Sep 21 7:44
Sampled By: MVTL Field Service

Bill Minnett
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Broom Creek

Temp at Receipt: 4.1C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	29 Sep 21	AC
pH	* 6.7	units	N/A	SM4500-H+-B-11	29 Sep 21 17:00	EMS
Conductivity (EC)	62019	umhos/cm	N/A	SM2510B-11	29 Sep 21 17:00	EMS
pH - Field	7.04	units	NA	SM 4500 H+ B	28 Sep 21 19:35	JSM
Temperature - Field	20.2	Degrees C	NA	SM 2550B	28 Sep 21 19:35	JSM
Total Alkalinity	853	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Bicarbonate	853	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Conductivity - Field	48194	umhos/cm	1	EPA 120.1	28 Sep 21 19:35	JSM
Cation Summation	701	meq/L	NA	SM1030-F	5 Oct 21 13:41	Calculated
Anion Summation	729	meq/L	NA	SM1030-F	1 Oct 21 14:38	Calculated
Percent Error	-2.00	%	NA	SM1030-F	5 Oct 21 13:41	Calculated
Total Organic Carbon	98.0	mg/l	0.5	SM5310C-11	1 Oct 21 16:29	NAS
Sulfate	469	mg/l	5.00	ASTM D516-11	1 Oct 21 14:38	SD
Chloride	24900	mg/l	2.0	SM4500-Cl-E-11	29 Sep 21 15:49	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	30 Sep 21 12:06	SD
Ammonia-Nitrogen as N	111	mg/l	0.20	EPA 350.1	5 Oct 21 13:41	SD
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	6 Oct 21 14:13	MDE
Total Dissolved Solids	42800	mg/l	10	USGS I1750-85	1 Oct 21 14:57	AC
Calcium - Total	1860	mg/l	1.0	6010D	4 Oct 21 11:34	SZ
Magnesium - Total	212	mg/l	1.0	6010D	4 Oct 21 11:34	SZ
Sodium - Total	12800	mg/l	1.0	6010D	4 Oct 21 11:34	SZ
Potassium - Total	516	mg/l	1.0	6010D	4 Oct 21 11:34	SZ
Iron - Total	392	mg/l	0.10	6010D	1 Oct 21 11:03	SZ
Manganese - Total	3.94	mg/l	0.05	6010D	1 Oct 21 11:03	SZ
Barium - Dissolved	4.58	mg/l	0.10	6010D	14 Oct 21 8:48	SZ
Strontium - Dissolved	70.8	mg/l	0.10	6010D	14 Oct 21 8:48	SZ
Arsenic - Dissolved	< 0.008 @	mg/l	0.0020	6020B	13 Oct 21 11:45	MDE
Cadmium - Dissolved	< 0.002 @	mg/l	0.0005	6020B	13 Oct 21 11:45	MDE
Chromium - Dissolved	0.0117	mg/l	0.0020	6020B	13 Oct 21 11:45	MDE
Copper - Dissolved	< 0.02 @	mg/l	0.0020	6020B	13 Oct 21 11:45	MDE
Lead - Dissolved	0.0042	mg/l	0.0005	6020B	13 Oct 21 11:45	MDE
Molybdenum - Dissolved	0.7754	mg/l	0.0020	6020B	13 Oct 21 11:45	MDE
Selenium - Dissolved	0.0277	mg/l	0.0050	6020B	13 Oct 21 11:45	MDE
Silver - Dissolved	< 0.002 @	mg/l	0.0005	6020B	13 Oct 21 11:45	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 14 Oct 21
Lab Number: 21-W3667
Work Order #:82-2651
Account #: 72540
Date Sampled: 28 Sep 21 19:35

Bill Minnett
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Date Received: 29 Sep 21 7:44
Sampled By: MVTL Field Service

Project Name: Coteau #1
Sample Description: Broom Creek

Temp at Receipt: 4.1C ROI

	As Received Result	Method RL	Method Reference	Date Analyzed	Analyst

* Holding time exceeded

Approved by: Claudette K. Carroll CC 14OCT21

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Chain of Custody Record

Project Name: Coteau #1	Event:	Work Order Number: 82-2651
Report To: Rampart Energy Company Attn: Bill Minnett Address: 1512 Larimer St, Suite 550 Denver, CO 80202 Phone: 303-618-2696 Email: bminnett@earthlink.net	CC:	Collected By: Jeremy [signature]

Lab Number	Sample ID	Date	Time	Sample Type	1 Liter Raw	500 mL Nitric	500 mL Nitric (filtered)	250 mL Sulfuric	3 VOC	4 TOC	1 Liter Amber	1 Liter Amber HCL	Temp (°C)	Spec. Cond.	pH	Analysis Required
W3C067	Broom Creek	28 Sept21	1935	GW	2	X	X	X		X			20.18	48194	7.04	See Attachment

Comments:

	Time	Temp (°C)	Cond.	pH
Field Readings	1903	24.03	57300	6.84
	1929	21.31	53589	6.93
	1935	20.18	48194	7.04

Sample Appearance
Turbid Brown

Relinquished By		Sample Condition		Received By	
Name	Date/Time	Location	Temp (°C)	Name	Date/Time
1 [signature]	29 Sept21 0744	~~Log In~~ Walk In #2	4.1 R02 TM562 / ~~TM805~~	Emily Dolan	29Sept21 0744
2					

A-3

APPENDIX B

FRESHWATER WELL FLUID SAMPLING

MINNESOTA VALLEY TESTING LABORATORIES, INC.
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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4509
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 12:00

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Oberlander

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	17 Nov 21	RAA
pH	* 8.5	units	N/A	SM4500-H+-B-11	17 Nov 21 18:00	AC
Conductivity (EC)	2519	umhos/cm	N/A	SM2510B-11	17 Nov 21 18:00	AC
pH - Field	8.37	units	NA	SM 4500 H+ B	17 Nov 21 12:00	JSM
Temperature - Field	6.69	Degrees C	NA	SM 2550B	17 Nov 21 12:00	JSM
Total Alkalinity	1020	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Bicarbonate	987	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Carbonate	33	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Conductivity - Field	2574	umhos/cm	1	EPA 120.1	17 Nov 21 12:00	JSM
Tot Dis Solids(Summation)	1470	mg/l	12.5	SM1030-F	22 Nov 21 14:48	Calculated
Percent Sodium of Cations	101	%	NA	N/A	22 Nov 21 13:09	Calculated
Total Hardness as CaCO3	9.49	mg/l	NA	SM2340B-11	22 Nov 21 13:09	Calculated
Hardness in grains/gallon	0.55	gr/gal	NA	SM2340-B	22 Nov 21 13:09	Calculated
Cation Summation	25.7	meq/L	NA	SM1030-F	22 Nov 21 13:09	Calculated
Anion Summation	27.4	meq/L	NA	SM1030-F	22 Nov 21 14:48	Calculated
Percent Error	-3.15	%	NA	SM1030-F	22 Nov 21 14:48	Calculated
Sodium Adsorption Ratio	70.7		NA	USDA 20b	22 Nov 21 13:09	Calculated
Bromide	1.86	mg/l	0.100	EPA 300.0	24 Nov 21 17:55	RMV
Total Organic Carbon	2.1	mg/l	0.5	SM5310C-11	19 Nov 21 16:46	NAS
Dissolved Organic Carbon	2.1	mg/l	0.5	SM5310C-96	19 Nov 21 16:46	NAS
Fluoride	1.81	mg/l	0.10	SM4500-F-C	19 Nov 21 17:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	19 Nov 21 16:05	SD
Chloride	248	mg/l	2.0	SM4500-Cl-E-11	22 Nov 21 14:48	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 16:44	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 11:26	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 9:35	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 14:00	MDE
Total Dissolved Solids	1560	mg/l	10	USGS I1750-85	19 Nov 21 12:14	RAA
Calcium - Total	3.8	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Magnesium - Total	< 1	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Sodium - Total	599	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Potassium - Total	3.0	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Lithium - Total	0.076	mg/l	0.020	6010D	18 Nov 21 11:06	SZ

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! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4509
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 12:00

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Project Name: Coteau #1
Sample Description: Oberlander

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Aluminum - Total	< 0.1	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Iron - Total	0.29	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Silicon - Total	4.17	mg/l	0.10	6010D	29 Nov 21 14:40	MDE
Strontium - Total	0.14	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Zinc - Total	0.41	mg/l	0.05	6010D	19 Nov 21 11:52	SZ
Boron - Total	1.97	mg/l	0.10	6010D	24 Nov 21 11:57	SZ
Calcium - Dissolved	3.8	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Sodium - Dissolved	585	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Potassium - Dissolved	3.2	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Lithium - Dissolved	0.077	mg/l	0.020	6010D	18 Nov 21 11:06	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Iron - Dissolved	0.19	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Silicon - Dissolved	4.12	mg/l	0.10	6010D	29 Nov 21 14:40	MDE
Strontium - Dissolved	0.14	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Zinc - Dissolved	0.33	mg/l	0.05	6010D	19 Nov 21 13:52	SZ
Boron - Dissolved	1.95	mg/l	0.10	6010D	24 Nov 21 15:57	SZ
Antimony - Total	< 0.006 @	mg/l	0.0010	6020B	24 Nov 21 12:32	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Barium - Total	0.1168	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Lead - Total	0.0011	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Manganese - Total	0.0033	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	24 Nov 21 12:32	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Antimony - Dissolved	< 0.006 @	mg/l	0.0010	6020B	29 Nov 21 11:36	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Barium - Dissolved	0.1064	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	3 Dec 21 13:23	MDE

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MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4509
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 12:00

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Oberlander

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Lead - Dissolved	0.0007	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Manganese - Dissolved	0.0028	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 Nov 21 11:36	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 7 Dec 21

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4510
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 14:08

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Helmuth

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	17 Nov 21	RAA
Preservation Flag					17 Nov 21	RAA
pH	* 8.4	units	N/A	SM4500-H+-B-11	17 Nov 21 18:00	AC
Conductivity (EC)	2347	umhos/cm	N/A	SM2510B-11	17 Nov 21 18:00	AC
pH - Field	8.51	units	NA	SM 4500 H+ B	17 Nov 21 14:08	JSM
Temperature - Field	5.16	Degrees C	NA	SM 2550B	17 Nov 21 14:08	JSM
Total Alkalinity	1280	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Bicarbonate	1272	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Conductivity - Field	2353	umhos/cm	1	EPA 120.1	17 Nov 21 14:08	JSM
Tot Dis Solids(Summation)	1500	mg/l	12.5	SM1030-F	22 Nov 21 14:48	Calculated
Percent Sodium of Cations	102	%	NA	N/A	22 Nov 21 13:09	Calculated
Total Hardness as CaCO3	10.4	mg/l	NA	SM2340B-11	22 Nov 21 13:09	Calculated
Hardness in grains/gallon	0.61	gr/gal	NA	SM2340-B	22 Nov 21 13:09	Calculated
Cation Summation	28.1	meq/L	NA	SM1030-F	22 Nov 21 13:09	Calculated
Anion Summation	27.6	meq/L	NA	SM1030-F	22 Nov 21 14:48	Calculated
Percent Error	0.88	%	NA	SM1030-F	22 Nov 21 14:48	Calculated
Sodium Adsorption Ratio	89.2		NA	USDA 20b	22 Nov 21 13:09	Calculated
Bromide	0.580	mg/l	0.100	EPA 300.0	24 Nov 21 18:16	RMV
Total Organic Carbon	4.8	mg/l	0.5	SM5310C-11	19 Nov 21 16:46	NAS
Dissolved Organic Carbon	4.8	mg/l	0.5	SM5310C-96	19 Nov 21 16:46	NAS
Fluoride	1.99	mg/l	0.10	SM4500-F-C	19 Nov 21 17:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	19 Nov 21 16:27	SD
Chloride	70.1	mg/l	2.0	SM4500-Cl-E-11	22 Nov 21 14:48	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 16:44	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 11:26	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 9:35	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 14:00	MDE
Total Dissolved Solids	1530	mg/l	10	USGS I1750-85	19 Nov 21 12:14	RAA
Calcium - Total	2.5	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Magnesium - Total	1.0	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Sodium - Total	660	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Potassium - Total	3.0	mg/l	1.0	6010D	22 Nov 21 10:09	SZ

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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4510
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 14:08

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Temp at Receipt: 3.4C ROI

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Helmuth

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lithium - Total	0.082	mg/l	0.020	6010D	18 Nov 21 11:06	SZ
Aluminum - Total	0.13	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Iron - Total	0.92	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Silicon - Total	5.01	mg/l	0.10	6010D	29 Nov 21 14:40	MDE
Strontium - Total	0.15	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Zinc - Total	0.43	mg/l	0.05	6010D	19 Nov 21 11:52	SZ
Boron - Total	1.76	mg/l	0.10	6010D	24 Nov 21 11:57	SZ
Calcium - Dissolved	2.4	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Sodium - Dissolved	640	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Potassium - Dissolved	3.2	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Lithium - Dissolved	0.077	mg/l	0.020	6010D	18 Nov 21 11:06	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Iron - Dissolved	0.54	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Silicon - Dissolved	4.34	mg/l	0.10	6010D	29 Nov 21 14:40	MDE
Strontium - Dissolved	0.14	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Zinc - Dissolved	0.06	mg/l	0.05	6010D	19 Nov 21 13:52	SZ
Boron - Dissolved	1.70	mg/l	0.10	6010D	24 Nov 21 15:57	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	24 Nov 21 12:32	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Barium - Total	0.1308	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Copper - Total	0.0036	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Lead - Total	0.0221	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Manganese - Total	0.0134	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Molybdenum - Total	0.0164	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	24 Nov 21 12:32	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	29 Nov 21 11:36	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Barium - Dissolved	0.1186	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE

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! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

MINNESOTA VALLEY TESTING LABORATORIES, INC.
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MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4510
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 14:08

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Helmuth

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	3 Dec 21 13:23	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Lead - Dissolved	0.0019	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Manganese - Dissolved	0.0064	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Molybdenum - Dissolved	0.0153	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 Nov 21 11:36	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE

This sample was either unpreserved or needed additional preservation upon receipt at the laboratory. The following preservation was added by MVTL: sulfuric acid.

* Holding time exceeded

CC
Approved by: Claudette K. Carroll 7 Dec 21

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Chain of Custody Record

Project Name: Coteau #1	Event:	Work Order Number: 82-3203
Report To: Rampart Energy Attn: Rich McClure Address: Phone: 720-635-1555 Email: rfm@carbon-vault.com	CC: Rampart Energy Shawna Harrison 1512 Larimer St. Suite 550 Denver, CO 80202	Collected By: Jeremy [illegible]

Lab Number	Sample ID	Date	Time	Sample Type	1 Liter Raw	1 Liter Raw (filtered)	500 mL Nitric	500 mL Nitric (filtered)	250 mL Sulfuric	250 mL Sulfuric (filtered)	3 TOC	3 TOC (filtered)	125 mL Raw	Temp (°C)	Spec. Cond.	pH	Analysis Required
W4509	Oberlander	17 Nov 21	1200	GW	3	X	X	X	X	X	X	X	2	6.69	2574	8.37	see attachment
W4510	Helmuth	17Nov21	1408	GW	3	X	X	X	X	X	X	X	2	5.16	2353	8.51	

Comments:

	Relinquished By Name	Date/Time	Sample Condition Location	Sample Condition Temp (°C)	Received By Name	Date/Time
1	[signature]	17Nov21 1543	~~Log In~~ Walk In #2	Rol 3.4 ~~TM562~~/ TM805	[signature]	17Nov21 1543
2						

B-7

LABORATORIES, Inc.

MVTL

PO BOX 1673
BISMARCK, ND 58504-1673

PHONE (701) 258-9720 FAX (701) 258-9724

28 SEP 1990

FINAL ANALYSIS REPORT

Sample Number: 90-W1115
Client: Water Supply Inc.
P.O. Box 1191
Bismarck ND 58502

Report Date: 9/27/90
Work Order #: 82-980
PO #:
Payment Type::

Attn: Roger Schmid
(DAS 3/6/97)
FRED/ART OBERLANDER #1
~~Fred Oberlander #1~~

#1

Collection Date: 8/30/90
Collection Time: 16:12
Date Received: 8/31/90

Analyte	Result	Units	Comments
pH	8.5	units	
Specific Conductance	2585.	umhos/cm	
Total Alkalinity	980.	mg/l CaCO3	
Phenolphthalein Alk	14.0	mg/l CaCO3	
Bicarbonate	952.	mg/l CaCO3	
Carbonate	28.0	mg/l CaCO3	
Total Dissolved Solids	1520	mg/l	
Sulfate	9.00	mg/l	
Chloride	272.	mg/l	
Nitrate-Nitrite	< 1	mg/l	
Fluoride	4.70	mg/l	
Calcium - Total	5.2	mg/l	
Magnesium-Total	1.8	mg/l	
Sodium - Total	640.	mg/l	
Potassium - Total	3.8	mg/l	
Total Hardness as CaCO3	20.4	mg/l	
Hardness in grains/gallon	1.19	gr/gal	
Cation Summation	28.4		
Anion Summation	27.5		
Percent Error	1.61	%	
Sodium Adsorption Ratio	61.7		
Iron - Total	0.30	mg/l	
Manganese - Total	< 0.05	mg/l	

Approved by:
C. Leach

ENERGY LABORATORIES

ENERGY LABORATORIES, INC.

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LABORATORY REPORT

Lab. No. 82-6424

To Coteau Properties Date 11-9-82 CB

Address Kirkwood Office Tower Bismarck, North Dakota 58501

WATER ANALYSIS (DAS 3/6/97)

~~A. Oberlander #1~~ FRED/ART OBERLANDER #1

Sampled 10-14-82 @ 12:00

Sample Submitted 10-22-82

P.O. #12531

CONSTITUENT	MILLIGRAMS PER LITER	
Potassium	1	
Sodium	657	
Calcium	4	
Magnesium	1	
Sulfate	13	
Chloride	265	
Carbonate	0	
Bicarbonate	1,240	
Total Dissolved Solids @ 180°C	1,520	
Total Hardness as $CaCO_3$	13	
Total Alkalinity as $CaCO_3$	1,020	
Sum of Anions	28.1	meq/l
Sum of Cations	28.9	meq/l
Cation-Anion Balance, % difference	1.40	
Specific Conductance @ 25°C	2,480	micromhos/cm
pH	8.2	
Phenolphthalein Alkalinity as $CaCO_3$	0	
Nitrate as N	0.05	
Total Iron	0.50	
Manganese	<0.02	

Certified by:

[signature]

Chief Chemist

ANALYTICAL SERVICES — WATER, SOIL, PETROLEUM, COAL

MVTL LABORATORIES, Inc.
P.O. BOX 1873, 1411 S. 12th STREET
BISMARCK, ND 58502
PHONE (701) 258-9720 WATS (800) 279-6885 FAX (701) 258-9724

WE ARE AN EQUAL OPPORTUNITY EMPLOYER

FINAL ANALYSIS REPORT

Sample Number: 94-W4482 | Report Date: 11/10/94

Les Morgenstern
Braun Intertec Corporation
PO Box 2379
Bismarck ND 58502

Work Order #: 82-1398
PO #: CFEX-91-0014

Date Received 10/28/94

Sample Description: Standard Water Sample
Sample Site: H Pfennig #2
Sample Location: Rural Beulah, ND

Collection Date 10/27/94
Collection Time 18:34

Analyte	Results	Units
pH	8.4	units
Specific Conductance	2360	umhos/cm
Total Alkalinity	1267	mg/l CaCO3
Phenolphthalein Alk	32	mg/l CaCO3
Bicarbonate	1203	mg/l CaCO3
Bicarb as HCO3	1470	mg/l HCO3
Carbonate	64	mg/l CaCO3
Hydroxide	0.0	mg/l CaCO3
Total Dissolved Solids	1460	mg/l
Sulfate	10.0	mg/l
Chloride	59.1	mg/l
Nitrate-Nitrite as N	< 1	mg/l
Calcium - Total	3.5	mg/l
Magnesium - Total	0.8	mg/l
Sodium - Total	620	mg/l
Potassium - Total	2.3	mg/l
Total Hardness as CaCO3	12.0	mg/l
Cation Summation	27.3	
Anion Summation	27.2	
Percent Error	0.11	%
Sodium Adsorption Ratio	77.8	
Iron - Dissolved	0.16	mg/l
Manganese - Dissolved	< 0.05	mg/l

Approved By: AKoel

ENERGY LABORATORIES

ENERGY LABORATORIES, INC.

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LABORATORY REPORT

Lab. No. 82-6176

To Coteau Properties Company Date 10-21-82 pb

Address Kirkwood Office Tower Bismarck, North Dakota 58501

WATER ANALYSIS
P.O. No. 12531
F. Weigum #1
Sampled 10-11-82 @ 10:00 a.m.
Sample received 10-12-82

CONSTITUENT	MILLIGRAMS PER LITER	
Potassium	5	
Sodium	617	
Calcium	3	
Magnesium	-1	
Sulfate	22	
Chloride	184	
Carbonate	15	
Bicarbonate	1,320	
Total Dissolved Solids @ 180°C	1,410	
Total Solids, calculated	1,500	
Total Hardness as $CaCO_3$	9	
Total Alkalinity as $CaCO_3$	1,100	
Sum of Anions	27.7	meq/l
Sum of Cations	27.1	meq/l
Cation-Anion Balance, % difference	1.09	
Specific Conductance @ 25°C	2,330	micromhos/cm
pH	8.4	
Phenolphthalein Alkalinity as $CaCO_3$	0	
Nitrate as N	-0.05	
Total Iron	0.84	
Manganese	-0.02	

Certified by:

Chief Chemist

a minus sign (-) indicates less than

ANALYTICAL SERVICES – WATER, SOIL, PETROLEUM, COAL

The Coteau Properties Company (CPC), a wholly owned subsidiary of North American Coal Corporation, has implemented a shallow groundwater monitoring program since 1979 as part of its operations at the Freedom Mine, thereby establishing a baseline water quality database for select shallow freshwater aquifers within the area of review (AOR).

More than 500 monitoring site locations have been drilled by CPC over an area of about 84 square miles around the Freedom Mine. A total of 460 of the monitoring sites have at least one water quality test date in the database, and approximately 100 of the sites are currently active. The monitoring sites sample from either surficial glacial aquifers of the Coleharbor Group (Pleistocene) or water-bearing coalbed (lignite) horizons of the Sentinel Butte Formation of the Fort Union Group (Paleocene). Figure B-1 summarizes the stratigraphy and freshwater aquifers present within the AOR. Lignite beds of the Sentinel Butte Formation are among the most tapped water resources (Croft, 1973), as they are the primary supply of domestic and stock water resources to the local area (U.S. Department of the Interior, 2016).

A description of the locations, sampling horizon, screen depth, and well status of 19 wells from the CPC shallow groundwater database is provided in Table B-1. Figure B-2 provides a map of the 19 selected monitoring sites. The 19 monitoring sites were selected based on the following criteria and considerations:

The Beulah, Spaer, and Stanton coalbed sampling horizons were selected because they are the primary sources of groundwater within the AOR and also have the greatest areal extent over the CO_2 plume area (U.S. Department of the Interior, 2016).

The monitoring site locations fall within the predicted 12-yr CO_2 plume extent. This was done to identify the most relevant sampling location to this geologic storage project.

Monitoring sites within a quarter mile of one another were eliminated to limit redundancy of individual data points.

The bed screen depth was required to be greater than 100 feet. This was done to help ensure consistent geochemical results and avoid surficial effects from previous mining operations or farming activities.

If two or more locations had water quality test data in the same location, the monitoring site with the deeper screen depth was selected and included in the final data set. This was done to limit the redundancy of individual data points.

Summaries of the geochemical analyses from the 19 monitoring sites, including pH, alkalinity, and total dissolved solids, is provided in Table B-2. Just two of the 19 sites had trace metal analyses conducted on them, provided in Table B-3.

ERATHEM	SYSTEM		SERIES	ROCK UNIT: GROUP	ROCK UNIT: FORMATION	FRESHWATER AQUIFER(S)	FRESHWATER AQUIFER(S) UNDER SURVEILLANCE
CENOZOIC	Quaternary		Holocene		Oahe	No	
			Pleistocene	Coleharbor	"Glacial Drift"	Yes	Antelope Creek
	Tertiary	Neogene	Pliocene		(Unnamed)	Yes	
			Miocene		Arikaree	No	
		Paleogene	Oligocene	White River	Brule	No	
			Eocene		Chadron	No	
					Golden Valley	No	
			Paleocene	Fort Union	Sentinel Butte	Yes	Beulah, Spaer, and Stanton coalbed horizons
					Tongue River: Bullion Creek	Yes	
					Tongue River: Slope	No	
					Cannonball	Yes	
					Ludlow	Yes	
MESOZOIC	Cretaceous		Upper	Montana	Hell Creek	Yes	
					Fox Hills	Yes	Lowest USDW
					Pierre	No	

Modified from Murphy et al., 2009, NDGS MS 91

Figure B-1. Stratigraphic column of the major freshwater aquifer systems of North Dakota, with the aquifer systems under surveillance within the geologic storage project indicated.

Table B-1. Names, Locations, Sampling Horizons, Screen Depths, and Well Status of Selected Monitoring Sites

Monitoring Site Location	Quarter Call	S-T-R	Latitude NAD 83	Longitude NAD 83	Sampling Horizon	Screen Depth (ft)	Well Status
MP81-P21	BBB	14-145N-88W	47.3853676	−101.86519	Beulah	123–137	Active
MP81-P32*	CBC	15-145N-88W	47.3748245	−101.88645	Beulah	170–180	Active
MP93-P07A	BAA	31-146N-87W	47.4291821	−101.81276	Spaer	160–165	Inactive
MP03-RP01A	ABB	06-145N-87W	47.4146862	−101.81177	Spaer	184–189	Inactive
MP81-P01	DDA	01-145N-88W	47.4028258	−101.82273	Spaer	235–242	Inactive
MP81-P07	BBB	02-145N-88W	47.4145552	−101.86515	Spaer	181–188	Inactive
MP81-P22	DAA	14-145N-88W	47.3781632	−101.84589	Spaer	115–119	Inactive
MP81-P24*	AAD	23-145N-88W	47.3681521	−101.84585	Spaer	111–115	Active
MP93-RP01A	ACD	12-145N-88W	47.3925468	−101.8291	Spaer	187–192	Inactive
MP16-P01A	CAD	11-145N-88W	47.3911977	−101.85454	Spaer	179–181	Active
MP16-P02A	BCB	11-145N-88W	47.3947722	−101.86503	Spaer	196–197	Active
MP95-RP03A	DDD	06-145N-87W	47.4005739	−101.80184	Spaer	241–246	Active
MP95-RP04A	BCC	08-145N-87W	47.39329	−101.8013	Spaer	184–189	Inactive
M77-P01	DDD	18-145N-87W	47.3715152	−101.80157	Stanton	131–141	Inactive
M77-P18	DCD	07-145N-87W	47.3860116	−101.80748	Stanton	233–238	Inactive
M77-P22	CCC	07-145N-87W	47.3860271	−101.82205	Stanton	213–218	Inactive
MP81-P12	DAA	02-145N-88W	47.4023753	−101.84407	Stanton	246–251	Inactive
MP83-P01	BAA	22-145N-88W	47.3713922	−101.87622	Stanton	278–283	Active
MP03-RP03A*	BCC	31-146N-87W	47.422307	−101.82244	Stanton	191–196	Active

* Monitoring site locations with recent laboratory reports provided in Appendix B.

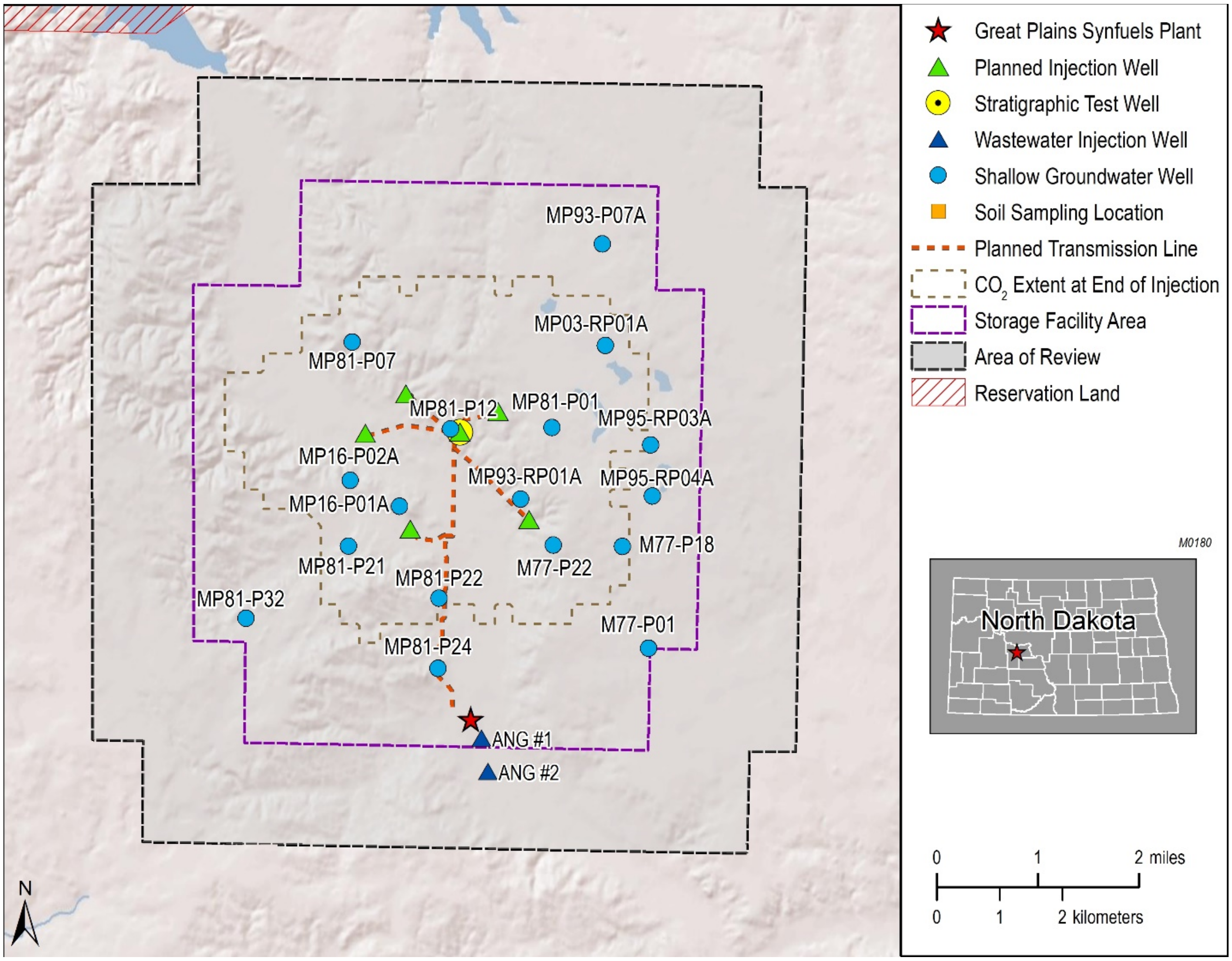

Figure B-2. Locations of the 19 monitoring sites operated by CPC.

Table B-2. Summarized Water Quality Test Results for 19 Monitoring Sites

Monitoring Site Location	Sampling Horizon	Mean* pH	pH Range	Mean* Alkalinity (mg/L $CaCO_3$)	Alkalinity Range (mg/L $CaCO_3$)	Mean* TDS (mg/L)	Range TDS (mg/L)
MP81-P21	Beulah	6.9	6.6–7.2	443	406–488	1,029	551–1,540
MP81-P32	Beulah	7.7	7.2–8.2	720	565–815	992	826–1,140
MP93-P07A	Spaer	7.8	6.7–8.2	1,593	950–1,770	3,160	2,910–5,070
MP03-RP01A	Spaer	8.2	8.1–8.3	1,755	1,740–1,770	3,278	3,180–3,380
MP81-P01	Spaer	8.1	7.8–8.5	1,670	1,488–1,750	1,917	1,680–2,270
MP81-P07	Spaer	7.4	7.2–7.9	577	543–648	1,402	1,291–1,480
MP81-P22	Spaer	7.5	7.1–8.8	476	252–574	929	603–1,170
MP81-P24	Spaer	8.2	7.7–8.9	637	333–810	1,250	620–1,708
MP93-RP01A	Spaer	8.2	7.9–8.7	882	817–992	1,507	1,350–1,670
MP16-P01A	Spaer	8.3	8.1–8.4	1,068	1,030–1,110	1,351	1,280–1,420
MP16-P02A	Spaer	8.4	8.2–8.6	880	843–928	1,243	1,190–1,300
MP95-RP03A	Spaer	8.0	7.6–8.3	1,537	512–1,820	2,070	894–2,460
MP95-RP04A	Spaer	8.2	7.8–8.4	1,574	1,420–1,680	1,819	1,600–2,160
M77-P01	Stanton	8.2	7.4–8.6	1,072	218–1,550	1,286	309–1,880
M77-P18	Stanton	8.0	7.6–8.3	1,129	256–1,492	1,373	372–1,720
M77-P22	Stanton	7.8	6.8–8.4	646	232–872	877	296–1,270
MP81-P12	Stanton	8.1	7.8–8.5	1,700	1,380–1,862	1,917	1,660–2,090
MP83-P01	Stanton	8.2	7.9–8.5	1,234	991–1,400	1,447	1,160–1,610
MP03-RP03A	Stanton	8.3	8.0–8.5	1,511	1,360–1,610	1,777	1,690–1,860

* Geometric mean.

Table B-3. Results of Trace Metal Analyses* (in mg/L) for Monitoring Sites in Table B-2

Monitoring Site Location	Sampling Horizon	Arsenic	Barium	Boron	Iron	Lead	Silver	Strontium
MP81-P01	Spaer	0.01	0.12	0.10	0.45	0.02	0.00	0.24
M77-P22	Stanton	0.00	0.21	0.53	0.80	0.25	0.01	0.25

* All water samples came back negative for Cd, Cr, Hg, Mo, and Se.

REFERENCES

Croft, M.G., 1973, Ground-water resources, Mercer and Oliver Counties, North Dakota: North Dakota Geological Survey Bulletin 56(III).

U.S. Department of the Interior, 2016, Environmental assessment for the Freedom Mine, West Mine Area, February 2016: U.S. Department of the Interior Office of Surface Mining Reclamation and Enforcement Report.

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MEMBER ACIL

Report Date: 30 Jun 21
Lab Number: 21-W1761
Work Order #: 82-1480
Account #: 002212
Date Sampled: 17 Jun 21 11:20
Date Received: 18 Jun 21 8:00
Sampled By: MVTL Field Services

Coteau Properties Company
204 County Road 15
Beulah ND 58523

Project Name: 2021 Coteau Groundwater

PO #: 570610 OP

Sample Description: GS21CW-52
Sample Site: MP81-P24
Event and Year: 2021

Temp at Receipt: 0.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	18 Jun 21	CC
pH	* 8.5	units	N/A	SM4500-H+-B-11	18 Jun 21 17:00	RAA
Conductivity (EC)	2172	umhos/cm	N/A	SM2510B-11	18 Jun 21 17:00	RAA
pH - Field	8.5	units	NA	4500 H+ B	17 Jun 21 11:20	DJN
Temperature - Field	11.2	Degrees C	NA	SM 2550B	17 Jun 21 11:20	DJN
Total Alkalinity	512	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Bicarbonate	487	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Carbonate	25	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Conductivity - Field	2123	umhos/cm	1	EPA 120.1	17 Jun 21 11:20	DJN
Tot Dis Solids(Summation)	1320	mg/l	12.5	SM1030-F	23 Jun 21 14:09	Calculat
Total Hardness as CaCO3	18.4	mg/l	NA	SM2340B-11	23 Jun 21 11:37	Calculat
Cation Summation	23.0	meq/L	NA	SM1030-F	24 Jun 21 13:24	Calculat
Anion Summation	20.5	meq/L	NA	SM1030-F	23 Jun 21 14:09	Calculat
Percent Error	5.57	%	NA	SM1030-F	24 Jun 21 13:24	Calculat
Sodium Adsorption Ratio	52.5		NA	USDA 20b	23 Jun 21 11:37	Calculat
Sulfate	480	mg/l	5.00	ASTM D516-11	21 Jun 21 14:46	SD
Chloride	10.8	mg/l	2.0	SM4500-Cl-E-11	18 Jun 21 15:38	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	23 Jun 21 14:09	SD
Calcium - Total	3.4	mg/l	1.0	6010D	23 Jun 21 11:37	MDE
Magnesium - Total	2.4	mg/l	1.0	6010D	23 Jun 21 11:37	MDE
Sodium - Total	517	mg/l	1.0	6010D	23 Jun 21 11:37	MDE
Potassium - Total	4.1	mg/l	1.0	6010D	23 Jun 21 11:37	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	24 Jun 21 13:24	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	24 Jun 21 13:24	MDE

* Holding time exceeded

Approved by: Claudette K. Carroll CC 1 JUL 21

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
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MEMBER ACIL

Report Date: 15 Jun 21
Lab Number: 21-W1599
Work Order #: 82-1362
Account #: 002212
Date Sampled: 8 Jun 21 11:01
Date Received: 9 Jun 21 8:00
Sampled By: MVTL Field Service

PO #: 570610 OP

Temp at Receipt: 3.4C

Coteau Properties Company
204 County Road 15
Beulah ND 58523

Project Name: 2021 Coteau Groundwater

Sample Description: GS20CW-11
Sample Site: MP81-P32
Event and Year: 2021

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	9 Jun 21	RAA
pH	* 7.8	units	N/A	SM4500-H+-B-11	9 Jun 21 18:00	RAA
Conductivity (EC)	1836	umhos/cm	N/A	SM2510B-11	9 Jun 21 18:00	RAA
pH - Field	7.2	units	NA	4500 H+ B	8 Jun 21 11:01	DJN
Temperature - Field	12.3	Degrees C	NA	SM 2550B	8 Jun 21 11:01	DJN
Total Alkalinity	676	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Bicarbonate	676	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Conductivity - Field	1811	umhos/cm	1	EPA 120.1	8 Jun 21 11:01	DJN
Tot Dis Solids(Summation)	1170	mg/l	12.5	SM1030-F	14 Jun 21 12:14	Calcula
Total Hardness as CaCO3	35.3	mg/l	NA	SM2340B-11	14 Jun 21 12:14	Calcula
Cation Summation	20.6	meq/L	NA	SM1030-F	14 Jun 21 12:14	Calcula
Anion Summation	19.7	meq/L	NA	SM1030-F	11 Jun 21 11:32	Calcula
Percent Error	2.37	%	NA	SM1030-F	14 Jun 21 12:14	Calcula
Sodium Adsorption Ratio	33.3		NA	USDA 20b	14 Jun 21 12:14	Calcula
Sulfate	285	mg/l	5.00	ASTM D516-11	11 Jun 21 11:32	SD
Chloride	7.8	mg/l	2.0	SM4500-Cl-E-11	10 Jun 21 11:22	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	10 Jun 21 15:04	SD
Calcium - Total	6.4	mg/l	1.0	6010D	14 Jun 21 12:14	SZ
Magnesium - Total	4.7	mg/l	1.0	6010D	14 Jun 21 12:14	SZ
Sodium - Total	455	mg/l	1.0	6010D	14 Jun 21 12:14	SZ
Potassium - Total	5.1	mg/l	1.0	6010D	14 Jun 21 12:14	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	11 Jun 21 12:06	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	11 Jun 21 12:06	SZ

* Holding time exceeded

Approved by: Claudette K. Carroll   CC 16 Jun 21

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix   # = Due to concentration of other analytes
! = Due to sample quantity   + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 29 Jun 20
Lab Number: 20-W1914
Work Order #: 82-1555
Account #: 002212
Date Sampled: 17 Jun 20 16:38
Date Received: 19 Jun 20 8:00
Sampled By: MVTL Field Services

Coteau Properties Company
204 County Road 15
Beulah ND 58523

Project Name: 2020 Coteau Groundwater

PO #: 556847

Sample Description: GS20CW-36
Sample Site: MP03-RP03A
Event and Year: 2020

Temp at Receipt: 3.0C

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	19 Jun 20	JD
pH	* 8.4	units	N/A	SM4500 H+ B	19 Jun 20 18:00	HT
Conductivity (EC)	2780	umhos/cm	N/A	SM2510-B	19 Jun 20 18:00	HT
pH - Field	8.0	units	NA	4500 H+ B	17 Jun 20 16:38	DJN
Temperature - Field	10.4	Degrees C	NA	SM 2550B	17 Jun 20 16:38	DJN
Total Alkalinity	1590	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Bicarbonate	1566	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Carbonate	24	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Conductivity - Field	2817	umhos/cm	1	EPA 120.1	17 Jun 20 16:38	DJN
Tot Dis Solids(Summation)	1850	mg/l	12.5	SM1030-F	25 Jun 20 14:04	Calculated
Total Hardness as CaCO3	26.4	mg/l	NA	SM2340-B	23 Jun 20 15:29	Calculated
Cation Summation	35.7	meq/L	NA	SM1030-F	25 Jun 20 12:24	Calculated
Anion Summation	33.6	meq/L	NA	SM1030-F	25 Jun 20 14:04	Calculated
Percent Error	2.93	%	NA	SM1030-F	25 Jun 20 14:04	Calculated
Sodium Adsorption Ratio	68.2		NA	USDA 20b	23 Jun 20 15:29	Calculated
Sulfate	38.5	mg/l	5.00	ASTM D516-11	25 Jun 20 9:08	EV
Chloride	37.1	mg/l	1.0	SM4500-Cl-E	22 Jun 20 9:48	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	25 Jun 20 14:04	EV
Calcium - Total	4.8	mg/l	1.0	6010D	23 Jun 20 15:29	MDE
Magnesium - Total	3.5	mg/l	1.0	6010D	23 Jun 20 15:29	MDE
Sodium - Total	805	mg/l	1.0	6010D	23 Jun 20 15:29	MDE
Potassium - Total	5.0	mg/l	1.0	6010D	23 Jun 20 15:29	MDE
Iron - Dissolved	0.30	mg/l	0.10	6010D	25 Jun 20 12:24	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	25 Jun 20 12:24	MDE

* Holding time exceeded

cc

Approved by: Claudette K. Carroll 9 JUL 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

APPENDIX C

QUALITY ASSURANCE SURVEILLANCE PLAN

1.0 QUALITY ASSURANCE AND SURVEILLANCE PLAN

The primary goal of the testing and monitoring plan of this storage facility permit application is to ensure that the geologic sequestration project is operating as permitted and is not endangering USDWs. In compliance with North Dakota Administrative Code (NDAC) § 43-05-01-11.4 (Testing and Monitoring Requirements), this Quality Assurance and Surveillance Plan (QASP) was developed and is being provided as part of the testing and monitoring program.

The testing and monitoring program for the project includes the analysis of the injected CO_2 stream, periodic testing of the injection wells, a corrosion monitoring plan for the CO_2 injection well components and surface facilities, a leak detection and monitoring plan for surface components of the CO_2 injection system, and a leak detection plan to monitor any movement of the CO_2 outside of the storage reservoir (see Table 5-1). The latter consists of a combination of soil gas and groundwater monitoring, storage reservoir monitoring, downhole monitoring, and geophysical monitoring. The quality assurance and surveillance procedures for this testing and monitoring plan are provided in the remainder of this QASP.

1.1 CO_2 Stream Analysis and Injection Well Mechanical Integrity Testing

1.1.1 CO_2 Stream Analysis

NDAC § 43-05-01-11.4(1a) requires analysis of the CO_2 stream in compliance with applicable analytical methods and standards generally accepted by industry and with sufficient frequency to yield data representative of its chemical and physical characteristics. DGC will collect samples of the injected CO_2 stream daily at the capture facility and analyze them to determine the concentrations of CO_2, nitrogen, oxygen, hydrogen, water, hydrogen sulfide, carbon monoxide, and a suite of hydrocarbons (e.g., ethane, propane, n-butane, and methane). This is consistent with the daily analysis DGC has performed on volumes delivered to Canadian oil fields since 1998. DGC uses an Agilent gas chromatograph with flame ionization and thermal conductivity detectors and complies with American Society for Testing and Materials Standards D7833, D1946, D2163, and UOP 539. Selected stable and radiogenic isotopes (i.e., isotopes of carbon dioxide [^{13}C and ^{14}C], methane [^{13}C and ^{14}C], and deuterium [^{2}H]) will also be sampled three to four times in the first year to establish a baseline. The isotopic analyses will be outsourced to commercial laboratories that will employ standard analytical quality assurance/quality control (QA/QC) protocols used in the industry.

1.1.2 Injection Well Mechanical Integrity Testing

The external mechanical integrity of the injection wells will be established prior to injection with a USIT (ultrasonic imager tool) in combination with variable density (VDL) and cement bond logs (CBL). The USIT (includes the VDL and CBL) will be performed during well workovers not more frequently than once every 5 years. It will also be useful for assessing the internal mechanical integrity of the injection wells. In addition, the injection wells will be monitored with a pulsed neutron log tool (PNX), to include temperature and pressure readings, using the phased approach described in Section 5.1.2 of this storage facility permit. The tool specifications of the USIT and the PNX are provided in Attachments A-1 and A-2, respectively.

Internal mechanical integrity of the injection wells will be demonstrated via tubing-casing annulus pressure tests prior to injection and during well workovers but not more frequently than once every 5 years. A detailed description of this test is provided in Attachment A-3. Pressure falloff tests will be performed in the injection wells prior to injection. During injection operations, pressure falloff testing will be carried out via surface pressure monitoring at least once every 5 years to demonstrate storage reservoir injectivity. In addition, the injection wells will be continuously monitored for surface and annular pressure anomalies by maintaining a consistent 200 pounds per square inch (psi) on the annulus with a nitrogen cushion that will be added on top of the packer fluid.

1.2 Corrosion Monitoring and Prevention Plan

1.2.1 Corrosion Monitoring

DGC will install a 3-foot test section of 4½-inch L-80 tubing in the flowlines near each wellhead for regular testing and corrosion monitoring of the well material (Figure 5-1 or the storage facility permit). The tubing joints will be inspected monthly via ultrasound equipment during the first quarter, then quarterly thereafter for the first 2 years. If the well materials (i.e., tubing) show no sign of corrosion within the first 2 years of the injection period, future internal monitoring of the tubing will be accomplished through a platform multifinger imaging tool (PMIT), or in the event a downhole tubing string is pulled for any reason, it will be inspected at the surface for corrosion and mechanical integrity. Wireline monitoring using the USIT, which will be run during workovers (including when tubing is pulled) but not more frequently than once every 5 years, will also be considered for assessing the corrosion of the casing in the injection wells. Details related to the PMIT and Tuboscope wellsite injection services are provided as Attachments A-4 and A-5, respectively.

1.2.2 Corrosion Prevention

To prevent corrosion of the well materials, the following preemptive measures will be taken: 1) cement in the injection wells opposite the injection interval and extending more than 2,000 feet uphole, will be CO_2-resistant, 2) the well casing (L-80 13Cr) will also be CO_2-resistant from the bottomhole to a depth just above the Opeche Formation, and 3) the packer fluid will be an industry standard corrosion inhibitor. In addition, the chemical composition of the CO_2 stream is highly pure (Table 5-2) and dry, with a moisture level for the CO_2 stream typically less than 2.00 parts per million by volume, both of which help prevent corrosion of the surface and well materials.

1.3 Surface Leak Detection and Monitoring Plan

Surface components of the injection system, including the flowlines and wellheads, will be monitored using leak detection equipment. The wellsite flowlines will be monitored continuously via multiple pressure gauges and H_2S detection stations (Attachment A-6) located inside each gas meter and wellhead enclosure. Another H_2S detection station will be installed on the exterior of each wellhead enclosure to monitor atmospheric conditions on the pad. This leak detection equipment will be integrated with automated warning systems capable of immediately notifying personnel in DGC's pipeline control center in the event of an anomalous reading. As an added measure for safety, field personnel will have multi gas detectors with them to monitor for H_2S (Attachment A-7). Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

1.4 Subsurface Leak Detection and Monitoring Plan

The monitoring plan for detecting subsurface leaks comprises "surface/near-surface" and deep subsurface monitoring programs. In this document, QA/QC information regarding the near-surface monitoring program is presented in Section 1.5, and QA/QC information regarding the deep subsurface monitoring programs is broken into Sections 1.6 and 1.7.

1.5 Near-Surface Soil Gas and Groundwater Monitoring

Near-surface sampling discussed herein comprises 1) sampling of soil gas in the shallow vadose zone and 2) sampling groundwater aquifers (lowest USDW). Sampling and chemical analysis of these zones provide concentrations of chemical constituents, including stable carbon isotopes [^{13}C and ^{12}C] of CO_2, which are focused on detecting movement of the CO_2 out of the reservoir. These monitoring efforts will provide data to confirm that near-surface environments are not adversely impacted by CO_2 injection and storage operations.

1.5.1 Soil Gas

Vadose zone soil gas monitoring directly measures the characteristics of the air space between soil components and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. A total of 11 soil gas sampling sites were drilled and installed in the storage facility area (SG01 through SG11 as shown in Figures 5-1, 5-2, and 5-3). All eleven locations (SG01 through SG11) are located on Coteau property.

1.5.1.1 Soil Gas Sampling and Analysis Protocol

<u>Soil Gas Locations: SG01 to SG11</u>

Fixed soil gas profile stations were installed for the sampling of soil gas at locations SG01 through SG11 prior to the initiation of CO_2 injection. Schematics of these soil gas profile stations are shown below in Figures C-1 and C-2. As shown, soil profile stations contain up to two isolated gas sampling intervals from which individual soil gas samples will be obtained.

Prior to the collection of each sample, a minimum of three casing volumes were removed, and the representativeness of the gas flow was determined by analyzing the soil gas for CO_2, hydrogen sulfide (H_2S), methane (CH_4), and O_2 using a Landtec GEM 5000 gas meter handheld multigas meter, which was calibrated daily based on manufacturer instructions. After these measurements of the soil gas composition stabilized, two soil gas samples were collected for characterization at each location using a Tedlar® bag, which was labeled with the appropriate sample number and site information and transported to the Dolan Integration Group (DIG) (Westminster, Colorado) for compositional and isotopic analysis. The target analytes for these analyses are shown below in Table C-1 and Table C-2, respectively.

NESTED VAPOR WELL CONSTRUCTION DETAILS

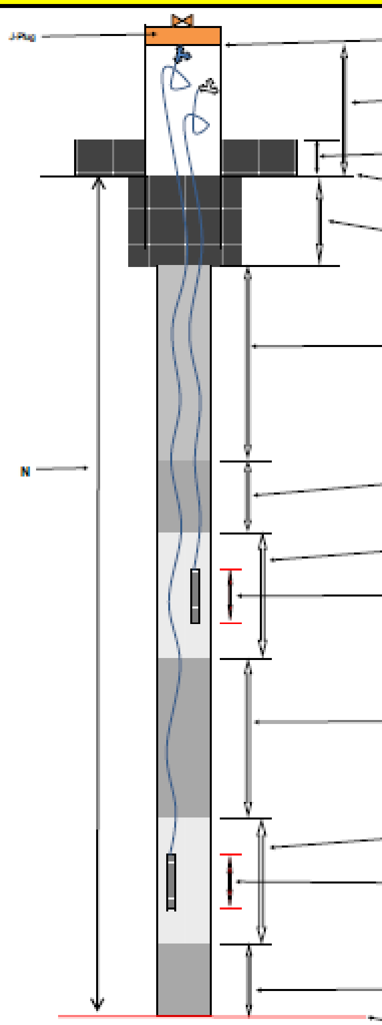
Project Name: CCS Soil Gas Monitoring Well Installation
Vista GeoScience Project #: 21215.01
Address: N/A
City: Beulah
State: North Dakota
Permit No.:

Location ID: SG-01
Shallow Vapor Well ID: SG-01S
Deep Vapor Well ID: SG-01D

D **Ground Surface Elevation:** ______ feet MSL
A **Top of Stick Up Elevation:** ______ feet MSL
Northing 47.40171198 **Easting** -101.841981

Type of Well: Nested Vapor Well
Type of Screen: 21" Stainless Steel Implant
Tubing Type: NYLAFLOW Nylon Tubing **ID Tubing** 0.19 inches
Boring Diameter: 2.5 inches **OD Tubing** 0.25 inches

Driller #1 Name: Davis Herschel
Driller #2 Name: David Fontana
Date Drilled: 10/24/2021 **Date Installed:** 10/24/2021



A Top of Well Vault

B **Stick Up:** Bot. 0 ags Top 2' ags Interval 2 ft
Material: 4" diameter PVC

C **Well Pad:** Bot. 0 ags Top 0.29' ags Interval 0.29 ft
Well Pad Material Description: 2' x 2' concrete pad with wood 2x4 frame

D Ground Surface

E **Surface Seal:** Bot. 3' bgs Top 0 bgs Interval 3 ft
Material Type: Concrete

F **Bentonite Seal:** Bot. 8' bgs Top 3' bgs Interval 5 ft
Material Type: Hydrated Bentonite Crumbles

G **Bentonite Seal:** Bot. 11' bgs Top 8' bgs Interval 3 ft
Material Type: Hydrated Bentonite Crumbles

H **Filter Pack:** Bot. 16' bgs Top 11' bgs Interval 5 ft
Material Type: 10-20 mesh sand

I **Shallow Screen Interval:** Bot. 14.3' bgs Top 12.55 bgs Interval 1.75 ft
Type: 21" Stainless Steel Implant Slot Size: n/a

J **Bentonite Seal:** Bot. 19.5' bgs Top 16' bgs Interval 3.5 ft
Material Type: Hydrated Bentonite Crumbles

K **Filter Pack:** Bot. 25' bgs Top 19.5' bgs Interval 5.5 ft
Material Type: 10-20 mesh sand

L **Deep Screen Interval:** Bot. 23.3' bgs Top 21.55' bgs Interval 1.75 ft
Type: 21" Stainless Steel Implant Slot Size: n/a

M **Backfill Material:** Bot. n/a bgs Top n/a bgs Interval n/a ft
Material Type: none

N **Total Boring Depth:** 25 ft bgs

Drilled By: Davis Herschel
Logged By: David Fontana
Drilling Method: H.S.A. [ ] S.S.A. [ ] D.P.T. [X]
Drilling Tooling Max. Diameter: 2.5 inches

General Notes:
Deep and Shallow wells are labeled with separate aluminum tags.
Each vapor well tubing is capped with a 3-way valve that has been left in the position which closes off the downhole opening of the valve.
Deep vapor wells have a blue 3-way valve and shallow vapor wells have a white 3-way valve.
Well Vault is capped with a 4" J-plug.
Vapor implant and tubing were centered in the borehole, filter pack, and bentonite seal as best as possible.

I hearby certify that the information on this form is true and correct to the best of my knowledge
Signature:
Printed Name: David Fontana

Figure C-1. Schematic of Soil Gas Profile Station SG01. Well design is the same for all stations except SG02 and SG11 (shown in Figure C-2).

Vista GeoScience

VAPOR WELL CONSTRUCTION DETAILS

Project Name: CCS Soil Gas Minitoring Well Installation
Vista GeoScience Project #: 21215.01
Address: N/A
City: Beulah
State: North Dakota

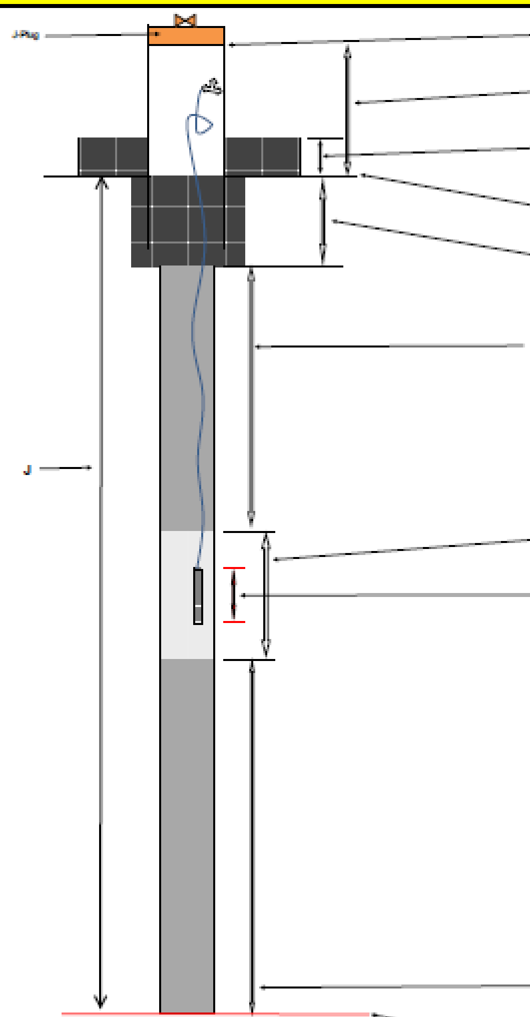
Permit No.:

Type of Well: Vapor Well
Type of Screen: 21" Stainless Steel Implant
Tubing Type: NYLAFLOW Nylon Tubing **ID Tubing** 0.19 inches
Boring Diameter: 2.5 inches **OD Tubing** 0.25 inches

Location ID: SG-02
Shallow Vapor Well ID: SG-02S
Deep Vapor Well ID: n/a

D **Ground Surface Elevation:** feet MSL
A **Top of Stick Up Elevation:** feet MSL
Northing 47.40115902 **Easting** -101.861667

Driller #1 Name: Davis Henschel
Driller #2 Name: David Fontana
Date Drilled: 10/21/2021 **Date Installed:** 10/21/2021



A Top of Well Vault

B **Stick Up:** Bot. 0 ags Top 3.25' ags Interval 3.25 ft
Material: 4" diameter PVC

C **Well Pad:** Bot. 0 ags Top 0.29' ags Interval 0.29 ft
Well Pad Material Description: 2' x 2' concrete pad with wood 2x4 frame

D Ground Surface

E **Surface Seal:** Bot. 1.75' bgs Top 0 bgs Interval 1.75 ft
Material Type: Concrete

F **Bentonite Seal:** Bot. 4' bgs Top 1.75' bgs Interval 2.25 ft
Material Type: Hyrdrated Bentonite Crumbles

G **Filter Pack:** Bot. 6' bgs Top 4' bgs Interval 2 ft
Material Type: 10-20 mesh sand

H **Deep Screen Interval:** Bot. 5.85 bgs Top 4.1 bgs Interval 1.75 ft
Type: 21" Stainless Steel Implant Slot Size: n/a

I **Backfill Material:** Bot. 15' bgs Top 6' bgs Interval 9 ft
Material Type: Bentonite chips and native material that collapsed into the borehole.

J **Total Boring Depth:** 15 ft bgs

Drilled By: Davis Henschel
Logged By: David Fontana

Drilling Method: H.S.A. ☐ S.S.A. ☐ D.P.T. ☒

Drilling Tooling Max. Diameter: 2.5 inches

General Notes:
The vapor well tubing is capped with a 3-way valve that has been left in the position which closes off the downhole opening of the valve.
Well Vault is capped with a 4" J-plug.
Vapor implant and tubing were centered in the borehole, filter pack, and bentonite seal as best as possible.
While backfilling the borehole collapsed to 6' bgs.
Groundwater was noted between 8 and 10' bgs and logged at 10.10' BGS during drilling.

I hearby certify that the information on this form is true and correct to the best of my knowledge
Signature:

Printed Name: David Fontana

Figure C-2. Schematic of Soil Gas Profile Station SG02. Well design is the same for SG11.

Table C-1. Soil Gas Analytes Identified with Field and Laboratory Instruments

Landtec GEM 5000	*U.S. EPA Method TO-17*
Analyte	**Analyte**
CO_2	1,1,1,2-Tetrachloroethane
O_2	1,1,1-Trichloroethane
H_2S	1,1,2,2-Tetrachloroethane
CH_4	1,1,2-Trichloroethane
	1,1,2-Trichlorotrifluoroethane (Fr_113)
	1,1-Dichloroethane
	1,1-Dichloroethene
	1,2,3-Trichlorobenzene
	1,2,3-Trichloropropane
	1,2,4-Trichlorobenzene
	1,2,4-Trimethylbenzene
	1,2-Dibromoethane (EDB)
	1,2-Dichlorobenzene
	1,2-Dichloroethane
	1,3,5-Trimethylbenzene
	1,3-Dichlorobenzene
	1,4-Dichlorobenzene
	1,4-Dioxane
	2-Methylnaphthalene
	Benzene
	Carbon tetrachloride
	Chlorobenzene
	Chloroform
	cis-1,2-Dichloroethene
	Ethylbenzene
	Isopropylbenzene
	Methyl-t-butyl ether
	Naphthalene
	o-Xylene
	p and m-Xylene
	Tetrachloroethene
	Toluene
	trans-1,2-Dichloroethene
	Trichloroethene
	Vinyl chloride

Table C-2. Isotope Measurements of Soil Gas Samples

Isotope	Units
$\delta^{13}C$ of CO_2*	‰ (per mil)
$\delta^{13}C$ of CH_4*	‰ (per mil)
δD of CH_4*	‰ (per mil)

* Only measured if high enough concentration detected.

1.5.1.2 Quality Assurance/Quality Control Procedures

Soil Gas Locations: SG01 to SG11

The standard sampling and analytical QA/QC protocols that will be applied by DIG at sample locations SG01 through SG11 were provided earlier in Section C.6.1.1 of this QASP (see also https://digforenergy.com/geochemical-laboratory/).

1.5.2 Groundwater/USDW

Groundwater/USDW monitoring measures the water's chemical components and characteristics of soil components and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. A total of six Fox Hills groundwater sampling sites were drilled and installed in the storage facility area (Figure 5-4). All six locations are located on Coteau property. In addition, DGC will add one Fox Hills groundwater monitoring well near the Herrmann 1 (NDIC File No. 4177) and obtain a baseline sample prior to the start of injection operations (Figure 5-14).

1.5.2.1 Groundwater Sampling and Analysis Protocol

Baseline Groundwater Wells (Fred Art/Oberlander 1 and Helmuth Pfenning 2)

Groundwater samples were collected by Minnesota Valley Testing Laboratories (MVTL) (Bismarck, North Dakota) from these wells using the wells' submersible pumps. MVTL applied the following standard procedure for sampling the wells:

1. Determine use of well prior to sample collection, (e.g., domestic, livestock, irrigation, municipal)

2. Purge the well, using a measured bucket to determine the pumping rate when the valve is fully open.

    a. The longer that the well has not been in use, the longer the well will need to be purged before sample collection. Purge time will also depend on the total depth of the well.
    b. For wells used daily, purge the well for 1–2 minutes. For wells used on a seasonal basis, such as livestock or irrigation, purge the well for 15 minutes, or longer if the well is over 100 feet deep. If the well has not been in use in the past year, three well volumes may need to be removed to ensure a freshwater sample can be collected.

3. Collect the sample.
    a. Once the well has been sufficiently purged, sample collection can proceed.

b. Record location of sample point.
c. Record pumping rate and volume purged.
d. Collect field readings: temperature, conductivity, and pH.
e. Fill appropriate sample containers for analysis.

Two laboratories were used to analyze the water samples: 1) MVTL analyzed samples for general parameters, anions, cations, metals (dissolved and total), and nonmetals (Tables C-3 and C-4) and 2) the Dolan Integration Group (DIG) laboratory analyzed samples for dissolved gas composition (Table C-5) and the stable isotopes (Table C-6).

The standard sampling and analytical QA/QC protocols that will be applied by MVTL and DIG as part of the monitoring efforts at these sample locations were provided earlier in this QASP (www.mvtl.com/QualityAssurance and https://digforenergy.com/geochemical-laboratory/).

Table C-3. Measurements of General Parameters for Groundwater Samples

Parameter	Method
pH	SM4500-H+-B-11
Conductivity	SM2510B-11
Alkalinity	SM[1] 2320B
Temperature	SM2550B
Total Dissolved Solids	SM 2540C
Total Inorganic Carbon	EPA[2] 9060
Dissolved Inorganic Carbon (DIC)	EPA 9060
Total Organic Carbon	SM 5310B
Dissolved Organic Carbon	SM 5310B
Total Mercury	EPA 7470A
Dissolved Mercury	EPA 245.2
Total Metals[3] (26 metals)	EPA 6010B/6020
Dissolved Metals[3] (26 metals)	EPA 200.7/200.8
Bromide	EPA 300.0
Chloride	EPA 300.0
Fluoride	EPA 300.0
Sulfate	EPA 300.0
Nitrite	EPA 353.2

[1] Standard method; American Public Health Association (2017).
[2] U.S. Environmental Protection Agency.
[3] See Table B-2 for entire sampling list of total and dissolved metals.

Table C-4. Total and Dissolved Metals and Cation Measurements for Groundwater Samples

Metals	Major Cations	Trace Metals
Antimony	Barium	Aluminum
Arsenic	Boron	Cobalt
Beryllium	Calcium	Lithium
Cadmium	Iron	Molybdenum
Chromium	Magnesium	Vanadium
Copper	Manganese	
Lead	Potassium	
Mercury	Silicon	
Nickel	Sodium	
Selenium	Strontium	
Silver	Phosphorus	
Thallium		
Zinc		

Table C-5. Gas Compositional Analysis – Dissolved Gas in Water

Dissolved Gases*
N_2
O_2 + Ar
CO_2
C_1 Methane
Ethane
Propane
iso-Butane
nor-Butane
iso-Pentane
nor-Pentane
Helium
H_2

* EPA RSK-175 – Sample Preparation and Calculations for Dissolved Gas Analysis in Water Samples Using a GC Headspace Equilibration Technique.

Table C-6. Stable Isotope Measurements and Dissolved Gases in Groundwater

Isotope	Units
δD H_2O	‰ (per mil)
$\delta^{18}O$ H_2O	‰ (per mil)
$\delta^{13}C$ DIC	‰ (per mil)
$\delta^{13}C$ Methane (if present)	‰ (per mil)
$\delta^{13}C$ Ethane (if present)	‰ (per mil)
$\delta^{13}C$ Propane (if present)	‰ (per mil)
δD Methane (if present)	‰ (per mil)
$\delta^{13}C$ CO_2 (if present)	‰ (per mil)

Operational and PISC Groundwater Wells

The operational and PISC groundwater wells that will be monitored include sampling of the six dedicated groundwater Fox Hills Formation monitoring wells installed at each of the injection wells. DIG will assist with the sampling of the wells to provide two samples for analysis from each well. One sample will be analyzed by a state-certified laboratory for the general parameters, anions, cations, metals (dissolved and total), and nonmetals listed in Tables C-3 and C-4; the other sample will be sent to DIG for the determination of the dissolved gases and isotopic signatures (see Table C-6).

1.5.2.2 Quality Assurance/Quality Control

Baseline Groundwater Wells (Fred Art/Oberlander 1 and Helmuth Pfenning 2)

The laboratory analyses conducted by MVTL and DIG were performed in accordance with their internal QA/QC procedures (Table C-3 and www.mvtl.com/QualityAssurance). In addition, duplicate samples were taken to assess the combined accuracy of the field sampling and laboratory analysis methods. These duplicate samples were collected at the same time and location for each of the groundwater wells.

Operational and PISC Groundwater Wells

The standard sampling and analytical QA/QC protocols that will be applied by MVTL and DIG as part of the monitoring efforts at these sample locations were provided earlier in this QASP.

1.6 Storage Reservoir Monitoring

Monitoring of the storage reservoir during the injection operation includes monitoring of the injection flow rates and volumes, wellhead injection temperatures and pressures, bottomhole injection pressures, temperature, and saturation profiles from the storage reservoir to the AZMI (above-zone monitoring interval), and the tubing-casing annulus pressure or casing pressure.

The storage monitoring will be accomplished using flowmeters and surface digital pressure and temperature gauges. Surface measurements will be taken at the flowmeter and the wellhead (tubing and casing). These readings will be recorded in real-time. These pressure/temperature data will be continuously recorded as part of the supervisory control and data acquisition (SCADA) (see Attachment A-8) system that is employed on-site. All data collected by the SCADA system is routed to DGC's pipeline control center.

1.7 Wireline Logging and Retrievable Monitoring

The wireline logging and retrievable monitoring that will be performed comprise pulsed-neutron logs (PNLs), which include temperature and pressure data, ultrasonic logs, injection zone pressure falloff tests, and corrosion monitoring. The information provided by these monitoring efforts is as follows:

- PNL: provides information regarding gas saturation in the formations, which can be used to determine if the injected CO_2 is contained within the storage formation as well as ground-truth information provided by the seismic surveys. The PNL is also capable of gathering downhole pressure and temperature data.

- USIT (ultrasonic imaging tool): provides an assessment of the external and internal mechanical integrity and assessment of corrosion of the wellbore.

- PMIT: provides a measure of change in thickness of the wellbore materials over time due to interaction of the wellbore with the injected CO_2 and formation fluids.

- Pressure falloff test: provides an assessment of the storage reservoir injectivity.

All wireline logging events will follow API (American Petroleum Institute) guidelines along with the standard operating procedures of a third-party wireline operator. More details regarding each of these monitoring techniques is provided below.

1.7.1 Pulsed-Neutron Logs

PNLs provide formation evaluation and reservoir monitoring in cased holes. PNL is deployed as a wireline logging tool with an electronic pulsed neutron source and one or more detectors that typically measure neutrons or gamma rays (Rose and others, 2015). High-speed digital signal electronics process the gamma ray response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the gamma ray energy and time relationship into concentrations of elements (Schlumberger, 2017).

Schlumberger's Pulsar Multifunction Spectroscopy Service (PNX) tool is a slim tool with an outer diameter (o.d.) of 1.72 in. for through-tubing access in cased hole environments. The housing is corrosion-resistant, allowing deployment in wellbore environments such as CO_2. The PNX tool can provide a direct volumetric measurement of gas-filled porosity and differentiate between gas-filled porosity, liquid-filled, and tight zones (Schlum20berger, 2017). Detection limits for CO_2 saturation for the PNX tool vary with the logging speed as well as the formation porosity as shown in Table C-7 below. Detailed measurement and mechanical specifications for the PNX tool are provided in Attachment A-2. The wireline operator will provide QA/QC procedures and tool calibration for their equipment.

Table C-7. Gas Saturation Detection Limits for PNL – PNX Tool

	Gas Saturation Detection Limit (%)	
Porosity Value (%)	**Minimum at Logging Speed of 1000 feet/hour**	**Minimum at Logging Speed of 200 feet/hour**
10	~39	~18
15	~22	~10
20	~18	~8

1.7.1.1 Description of Regular PNL Protocol

After the drilling and before CO_2 injection, a PNL will be run in each injector to confirm cement integrity and provide a baseline to which future PNL logging runs will be compared. Since the PNL tool also includes temperature and pressure measurements, profiles of both temperature and pressure will be constructed. The injection wells will be logged following the phased approach defined in Section 5.1.2 of this storage facility permit.

The following procedure will be followed when running a PNL in an injection well:

1. Hold a safety meeting and ensure that all personnel are wearing breathing equipment as the injection fluid contains H_2S:
   a. Rig up H_2S monitoring equipment
   b. Ensure that all safety precautions are taken

2. Shut well in by closing the outside wing valve and upper master valve.

3. Rig up lubricator, and pressure-test connections and seals to 2,000 pounds per square inch.

4. Open crown valve.

5. Open top master valve and proceed downhole to the injection packer with the PNL logging tool.

6. Make a 30-minute stop at the bottom of the hole, and record a static bottomhole pressure.

7. Proceed with running the PNL log making stops every 500' (approximately 12 stops) for 5 minutes each to record a static fluid pressure.

8. Once the logging tool is at the surface and in the lubricator, make a 5-minute stop to record the surface pressure in the tubing.

9. Close the crown valve and top master valve. Bleed pressure from the tree and lubricator.

10. Remove lubricator and replace the top cap and pressure gauge.

11. Open the top master valve, and again record the tubing and annular pressures.

12. Rig down the wireline company and clean the location.

13. Return the well to injection service by opening the outside wing valve.

1.7.2 Ultrasonic Imaging Tool

The USIT indicates the quality of the cement bond at the cement–casing interface and provides casing inspection (corrosion detection, monitoring, and casing thickness analysis). The tool is deployed on wireline with a transmitter emitting ultrasonic pulses and measuring the reflected ultrasonic waveforms received from the internal and external casing interfaces. The entire circumference of the casing is scanned, enabling the evaluation of the radial cement bond and the detection of internal and external casing damage or deformation. The high angular and vertical tool resolutions can detect cement channels as narrow as 1.2 inches (Attachment A-1). Detailed measurement and mechanical specifications for the USIT tool are provided in Attachment A-1. The wireline operator will provide QA/QC procedures and tool calibration for this equipment.

1.7.3 Platform Multifinger Tool

In instances where an individual tubing string has not been pulled for workover purposes, and thus made available for inspection at the surface, it may be useful to instead run a PMIT. The PMIT is a multifingered caliper tool that makes highly accurate radial measurements of the internal diameter of tubing and casing strings. In so doing it can quantify surface pitting and/or internal wall loss. Detailed measurements and mechanical specifications for the PMIT tool are provided in Attachment A-4.

1.7.4 Injection Zone Pressure Falloff Test

The injection zone pressure falloff test will be performed in the injection well prior to initiation of CO_2 injection activities and at least once every 5 years thereafter to demonstrate storage reservoir injectivity. Pressure data will be recorded during the pressure falloff test at the bottomhole.

1.8 Geophysical Monitoring Methods

The geophysical monitoring that is planned for the project includes time-lapse seismic surveys. This indirect monitoring method will characterize attributes associated with the injected CO_2, including the plume extents, mass changes, pressure changes, and potential seismicity. Details regarding the application and quality of this method are provided in the remainder of this section:

- Time-lapse seismic surveys: provide a measurement of the change in acoustic properties of the storage formation as injected CO_2 saturates the storage interval.

1.8.1 Time Lapse Seismic Surveys

Application of time-lapse seismic surveys for monitoring changes in acoustic properties requires a quality preoperational seismic survey for baseline conditions. The monitor survey should be repeated as closely to the baseline conditions and parameters as possible. The seismic monitor data should be reprocessed simultaneously with the original baseline data or processed with the same steps and workflow to ensure repeatability. Repeatability is a measure of 4D seismic quality (Lumley and others, 1997, 2000) that can be quantified once the processed data are analyzed by an experienced 4D seismic interpreter.

1.9 Completed Well Logging

Several continuous measurements of the storage formation properties were made in the Coteau 1 wellbore using wireline logging techniques. These logs, which are identified along with the justification for their use in Table 5-7, are listed below:

- Ultrasonic log
- Casing collar locator (CCL) log
- VDL
- CBL
- Gamma ray log
- Triple combo logs (i.e., resistivity, density, porosity, caliper, and spontaneous potential)
- Combinable magnetic resonance (CMR) log
- Spectral gamma ray log
- Dipole sonic log
- Fracture finder log

1.10 Perforation/Flowback Test (formation fluid and reservoir pressure)

Upon completion of initial drilling, casing, and cementing operations at the Coteau 1, the well was allowed to stand idle for a period of 3 months. Subsequently, the well was reentered, and a USIT was run to evaluate the cement bond to surface. A single foot of perforations was shot at 5,975 feet in the well in order to obtain a Broom Creek fluid sample and current reservoir pressure (Attachment A-9). The well was swabbed briefly and then began flowing back on its own. After the recovery of 50 barrels of formation fluid, multiple surface readings were taken to confirm consistent total dissolved solids readings. A fluid sample was then obtained for evaluation. After recording the bottomhole pressure, the perforations were squeeze-cemented. This cement was later drilled out, and the casing was tested to 1600 psi.

For future wells, namely, the Coteau 2 through 6, the flowback and pressure recording will be performed as part of their completion as CO_2 injection wells.

1.11 References

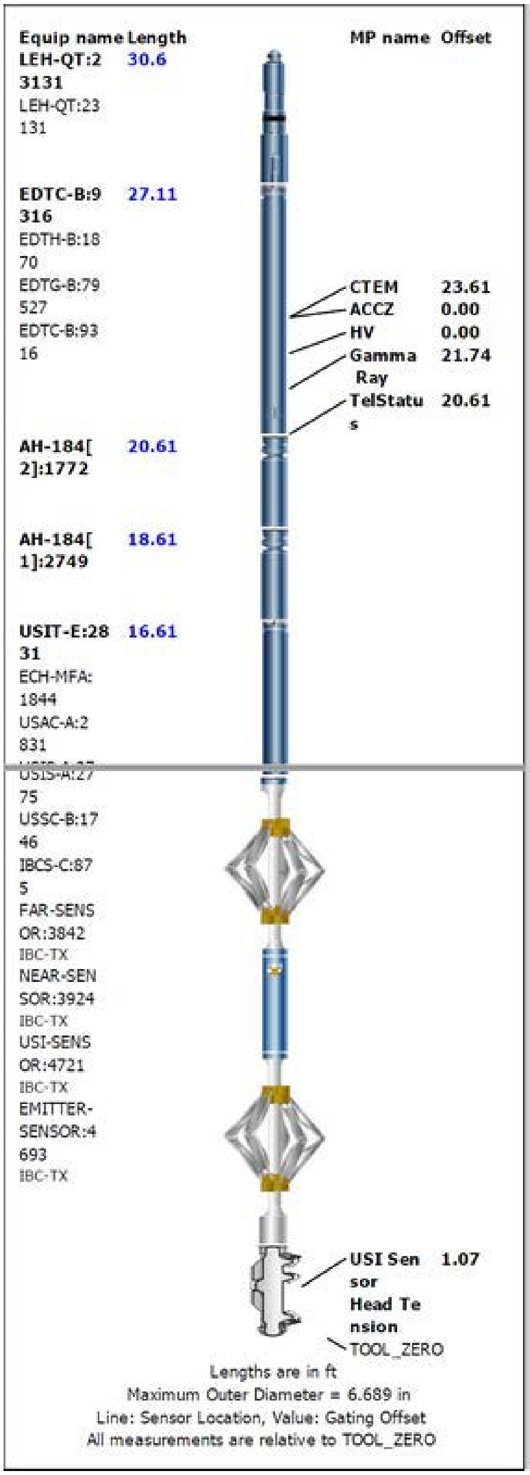
Lumley, D.E., Behrens, R.A., and Wang, Z., 1997, Assessing the technical risk of a 4-D seismic project: The Leading Edge, v. 16, p. 1287–1292, doi: 10.1190/1.1437784.

Lumley, D.E., Cole, S., Meadows, M.A., Tura, A., Hottman, B., Cornish, B., Curtis, M., and Maerefat, N., 2000, A risk analysis spreadsheet for both time-lapse VSP and 4D seismic reservoir monitoring: 70th Annual International Meeting, SEG, Expanded Abstracts, p. 1647–1650.

Rose D., Zhou, T., Beekman, S., Quinlan T., Delgadillo, M., Gonzalez, G., Fricke, S., Thornton, J., Clinton, D., Gicquel, F., Shestakova, I., Stephenson, K., Stoller, C., Philip, O., Miguel La Rotta Marin, J., Mainier, S., Perchonok, B., and Bailly, J.P., 2015, An innovative slim pulsed neutron logging tool: Society of Petrophysicists and Well Log Analysts 56th Annual Logging Symposium, Long Beach, California, July 2015.

Schlumberger, 2017, Pulsar multifunction spectroscopy tool: Society of Petrophysicists and Well Log Analysts 58th Annual Logging Symposium, Oklahoma City, Oklahoma, June 2017.

Attachment A-1 – Ultrasonic Imaging Tool



Measurement Specifications

	Isolation Scanner Tool
Output[†]	Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image
Max. logging speed	Standard resolution (6 in, 10° sampling): 823 m/h [2,700 ft/h] High resolution (0.6 in, 5° sampling): 172 m/h [563 ft/h]
Range of measurement	Min. casing thickness: 0.38 cm [0.15 in] Max. casing thickness: 2.01 cm [0.79 in]
Vertical resolution	High resolution: 1.52 cm [0.6 in] High speed: 15.24 cm [6 in]
Acoustic impedance[‡]	Range: 0 to 10 Mrayl Resolution: 0.2 Mrayl Accuracy: 0 to 3.3 Mrayl = ±0.5 Mrayl, >3.3 Mrayl = ±15%
Flexural attenuation	Range: 0 to 2 dB/cm[§] Resolution: 0.05 dB/cm[§] Accuracy: 0.01 dB/cm[§]
Min. quantifiable channel width	30 mm [1.2 in]
Depth of investigation[†]	Casing and annulus up to 7.62 cm [3 in]
Mud type or weight limitation[††]	Conditions simulated before logging
Combinability	Bottom only, combinable with most wireline tools Telemetry: fast transfer bus (FTB) or enhanced FTB (EFTB)
Special applications	H_2S service

[†] Investigation of annulus width depends on the presence of third-interface echoes. Analysis and processing beyond cement evaluation can yield additional answers through additional outputs, including the Variable Density log (VDL) of the annulus waveform and polar movies in AVI format.

[‡] Differentiation of materials by acoustic impedance alone requires a minimum gap of 0.5 MRayl between the fluid behind the casing and a solid.

[§] For 8-mm [0.3-in] casing thickness.

[††] Max. mud weight depends on the mud formulation, sub used, and casing size and weight, which are simulated before logging.

Mechanical Specifications

	Isolation Scanner Tool
Max. temperature	177 degC [350 degF]
Pressure range	1 to 138 MPa [145 to 20,000 psi]
Casing size—min.[†]	4½ in (min. pass-through restriction: 4 in)
Casing size—max.[†]	9⅝ in
Outside diameter	IBCS-A: 8.57 cm [3.375 in] IBCS-B: 11.36 cm [4.472 in] IBCS-C: 16.91 cm [6.657 in]
Length without sub	6.01 m [19.73 ft]
Weight without sub	151 kg [333 lbm]
Sub length, weight	IBCS-A: 61.22 cm [24.10 in], 7.59 kg [16.75 lbm] IBCS-B: 60.32 cm [23.75 in], 9.36 kg [20.64 lbm] IBCS-C: 60.32 cm [23.75 in], 10.73 kg [23.66 lbm]
Sub max. tension	10,000 N [2,250 lbf]
Sub max. compression	50,000 N [12,250 lbf]

[†] Limits for casing size depend on the sub used. Data can be acquired in casing larger than 9⅝ in with low-attenuation mud (e.g., water, brine).

Attachment A-1. Schlumberger's isolation scanner USIT used to provide evidence of external mechanical integrity in injection wells Coteau 1 through Coteau 6.

Attachment A-2 – Through-Tubing Pulsed Neutron Tool

Pulsar

Multifunction spectroscopy service

Measurement Specifications	
Acquisition	Real time with surface readout
Output	
Time domain	Sigma (SIGM), porosity (TPHI), fast-neutron cross section (FNXS)
Energy domain	Inelastic and capture yields of various elements, carbon/oxygen ratio, total organic carbon
Logging speed†	
Inelastic capture mode	200 ft/h [61 m/h]
Inelastic gas, sigma, and hydrogen index (GSH) mode	3,600 ft/h [1,097 m/h]
Sigma lithology mode	1,000 ft/h [305 m/h]
Range of measurement	Porosity: 0 to 60 pu
Mud type or weight limitations	None
Combinability	Combinable with tools that use the PS Platform production services platform's telemetry system and ThruBit through-the-bit logging services
Special application	Qualified per the requirements of NACE MR0175 H_2S and CO_2 resistance

† Logging speed determined using the tool planner

Mechanical Specifications	
Temperature rating	350 degF [175 degC]
Pressure rating	15,000 psi [103.4 MPa]
Casing size—min.	2⅜ in [6.03 cm]
Casing size—max.	9⅝ in [24.45 cm]
Outside diameter	1.72 in [4.37 cm]
Length	18.3 ft [5.58 m]
Weight	88 lbm [40 kg]
Tension	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N]

*Mark of Schlumberger

Attachment A-2. Measurement and mechanical specifications for Schlumberger's PNX (through-tubing pulsed neutron) tool.

Attachment A-3 – Standard Annulus Pressure Test Procedure

The tubing/casing annular pressure test provides an assessment of the internal mechanical integrity of the wellbore between the tubing-casing annulus. The pressure test procedure will be generated following the North Dakota Industrial Commission (NDIC) Injection Well Construction and Completion Standards (NDAC § 43-05-01-11), which state the pressure must be applied for a period of 30 minutes and must have no decrease in pressure greater than 10% of the required minimum test pressure.

Pursuant to Section 43-05-01-11.1

1. Contact NDIC to witness mechanical integrity test (MIT) procedure a minimum of 24 hours prior to test.

2. Completely fill the tubing/casing annulus with corrosion-inhibited packer fluid. Temperature stabilization of the well and annulus fluid is necessary; therefore, injection shall either be ceased, or a stabilized injection rate and temperature will be maintained.

3. After stabilization, the annulus will be pressurized to the maximum allowable injection pressure or an alternate pressure approved by NDIC. A positive pressure differential between the annulus and the injection string shall be maintained throughout the entire annulus.

4. Following pressurization, the annulus will be isolated from the source of pressure by a closed valve.

5. The annulus will remain isolated for a period no less than 30 minutes or as otherwise approved by NDIC. Pressure measurements will be recorded every 5 minutes, as well as continuously charted.

6. If the pressure deviates more than 10% of the required minimum test pressure, check for seal leaks, otherwise repeat steps. If failure occurs, well will be shut in, report of the failure will be sent to NDIC, and isolation and repair of the leak will commence within 90 days, unless otherwise approved by NDIC.

Attachment A-4 – Platform Multifinger Imaging Tool

Schlumberger

PS Platform Multifinger Imaging Tool

APPLICATIONS

- Identification and quantification of corrosion damage
- Identification of scale, wax, and solids accumulation
- Monitoring of anticorrosion systems
- Location of mechanical damage
- Evaluation of corrosion increase through periodic logs
- Determination of absolute inside diameter (ID)

The PS Platform* Multifinger Imaging Tool (PMIT) is a multifinger caliper tool that makes highly accurate radial measurements of the internal diameter of tubing and casing strings. The tool is available in three sizes to address a wide range of through-tubing and casing size applications.

The tool deploys an array of hard-surfaced fingers, which accurately monitor the inner pipe wall. Eccentricity effects are minimized by equal azimuthal spacing of the fingers and a special processing algorithm. The PMIT-B and PMIT-C tools incorporate powerful motorized centralizers to ensure effective centering force even in highly deviated intervals. The centralizers are equipped with rollers to prevent casing and tubing damage. The inclinometer in the tool provides information on well deviation and tool rotation. The PMIT-C tool can be fitted with special extended fingers for logging large-diameter casings. The PMIT-A is similarly fitted with special extended fingers for logging casing through tubing. All versions of the PMIT can be run in either real-time or memory mode.

The PMIT is available in three sizes for radially measuring the internal diameter of tubing and casing strings.

Attachment A-4. Schlumberger's PMIT used as a possible alternative to surface tubing inspection in the Coteau 1 through Coteau 6 (continued).

PS Platform Multifinger Imaging Tool

Measurement Specifications

	PMIT-A	PMIT-B	PMIT-C
Output	Internal casing image from multiple internal radius measurements	Internal casing image from multiple internal radius measurements	Internal casing image from multiple internal radius measurements
Logging speed, m/h [ft/h]	Standard: 549 [1,800] Max.: 1,829 [6,000]	Standard: 549 [1,800] Max.: 1,829 [6,000]	Standard: 549 [1,800] Max.: 1,829 [6,000]
Minimum measurable casing ID, cm [in]	Standard or extended fingers: 5.08 [2]	7.62 [3]	Standard fingers: 12.7 [5] Extended fingers: 20.32 [8]
Maximum measurable casing ID, cm [in]	Standard fingers: 11.43 [4.5] Extended fingers: 17.78 [7]	17.78 [7]	Standard fingers: 25.4 [10] Extended fingers: 33.02 [13]
Vertical resolution at 529 m/h [1,800 ft/h], mm [in]	2.1 [0.082]	2.8 [0.11]	4.24 [0.167]
Radial resolution, mm [in]	Standard fingers: 0.10 [0.004] Extended fingers: 0.18 [0.007]	0.13 [0.005]	Standard fingers: 0.18 [0.007] Extended fingers: 0.23 [0.009]
Accuracy, mm [in]	Standard fingers: ±0.76 [±0.030] Extended fingers: ±1.07 [±0.042]	±0.76 [±0.030]	Standard fingers: ±0.76 [±0.030] Extended fingers: ±1.3 [±0.050]
Relative bearing accuracy, °	±5	±5	±5
Deviation accuracy at up to 70° deviation, °	±5	±5	±5
Depth of investigation	Casing inside surface	Casing inside surface	Casing inside surface
Borehole fluid limitations	None	None	None
Combinability	Real time: combinable with all PS Platform tools Memory mode: stand alone	Real time: combinable with all PS Platform tools Memory mode: stand alone	Real time: combinable with all PS Platform tools Memory mode: stand alone Bottom-only tool Extra centralizers required for casing larger than 9⅝ in
Special applications	H_2S service	H_2S service	H_2S service

Mechanical Specifications

	PMIT-A	PMIT-B	PMIT-C
Temperature rating, degF [degC]	302 [150]	302 [150]	PMIT-CA: 302 [150] PMIT-CB: 350 [177]
Pressure rating, MPa [psi]	103 [15,000]	103 [15,000]	PMIT-CA: 103 [15,000] PMIT-CB: 138 [20,000]
Outside diameter, cm [in]	Standard or extended fingers: 4.29 [1.6875]	6.99 [2.75]	Standard fingers: 10.16 [4] Extended fingers: 13.97 [5.5]
Fingers	24	40	60
Fingertip radius, mm [in]	1.5 [0.06]	1.27 [0.05]	1.52 [0.06]
Finger width, mm [in]	1.6 [0.063]	1.6 [0.063]	1.6 [0.063]
Length, m [ft]	3.62 [11.88] (with centralizers)	2.70 [8.86]	3.15 [10.34]
Weight, kg [lbm]	26 [56.5] (with centralizers)	40 [87.4]	54 [120]
Max. tensile strength, N [lbf]	44,480 [10,000]	44,480 [10,000]	44,480 [10,000]
Max. compressive strength, N [lbf]	8,230 [1,850]	11,120 [2,500]	11,120 [2,500]

www.slb.com/oilfield

Schlumberger

Attachment A-4 (continued). Schlumberger's PMIT used as a possible alternative to surface tubing inspection in the Coteau 1 through Coteau 6.

Attachment A-5 – Tuboscope Wellsite Tubing Inspection System

TuboChek™$_{C1D1}$ — Non Gamma Wellsite Tubing Inspection System

Tuboscope is pleased to announce the introduction of the TuboChek$_{C1D1}$ inspection system. This unit is certified and meets Class-1 Div-1 safety standards with intrinsically safe electronics and includes an encapsulated coil housing.

Similar to our WellChek system, TuboChek$_{C1D1}$ utilizes the same reporting and database soft-ware, providing you real-time tubing inspection, data management and evaluation of your used tubing.

This new system delivers an accurate evaluation of each tube using the same proven eddy current based split detection and Sonoscope EMI inspection for pitting and corrosion detection. Unique to this system, a flux integration method is used for cross-sectional area, calculated rod-wear and a flux leakage technique for magnetic field discrimination to determine rod strokes.

TuboChek$_{C1D1}$ increases the size range capabilities of inspected tubing to include: 2 ⅜" , 2 ⅞", 3 ½", 4" and 4 ½"

Benefits

- Professionally trained crew for efficient and safe operations
- Records exact defect and joint location in the well
- Real time usable information
- On-site inspection eliminates need for trucking to inspection facilities
- Immediate re-use of good tubing

Defect Detection

- Corrosion pitting
- Rod wear
- Wall loss
- Cracks
- Erosion
- Splits
- Cuts
- Holes
- 3-Dimensional Transverse Defects

MET Laboratories, Inc.

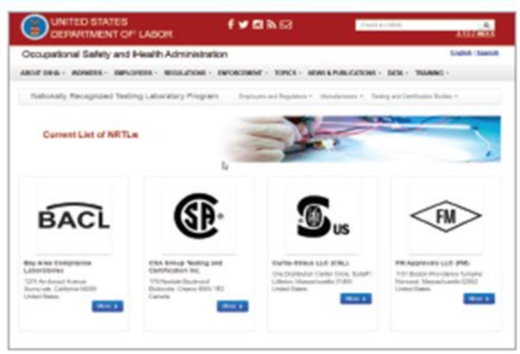
July 28, 2017

Mr. Raymond Marcelos
National Oilwell Varco (NOV)
2835 Holmes Rd.
Houston, TX 77051
USA

Subject: Wellchek III Inspection Head System
Listing Number E114005, MET Project Number 42615
Safety Standards:
- UL/CSA C22.2 No. 60079-0 Explosive atmospheres – Part 0: Equipment – General requirements
- UL/CSA C22.2 No. 60079-11 Explosive Atmospheres – Part 11: Equipment Protection by Intrinsic Safety "i"
- UL/CSA C22.2 No. 60079-18 Explosive atmospheres – Part 18: Equipment protection by encapsulation "m"

Dear Mr. Marcelos:

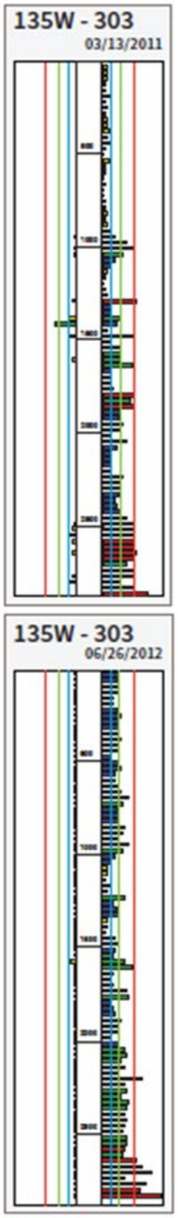
MET has determined the evaluated Wellchek III Inspection Head System to be compliant with the above referenced standards. Upon completion of a satisfactory Pre-Certification Factory Inspection,



Tuboscope | NOV Wellbore Technologies
2835 Holmes Road
Houston, Texas 77051, USA
Phone 346 223 6100
tuboscopesales@nov.com
nov.com/tuboscope

Attachment A-5. Tuboscope's wellsite tubing inspection service. This (or its equivalent) can be utilized for surface inspection of the Coteau 1 thru 6 tubing strings in the event they need to be pulled for any reason (continued).

TuboChek™$_{C1D1}$ — Non Gamma Wellsite Tubing Inspection System

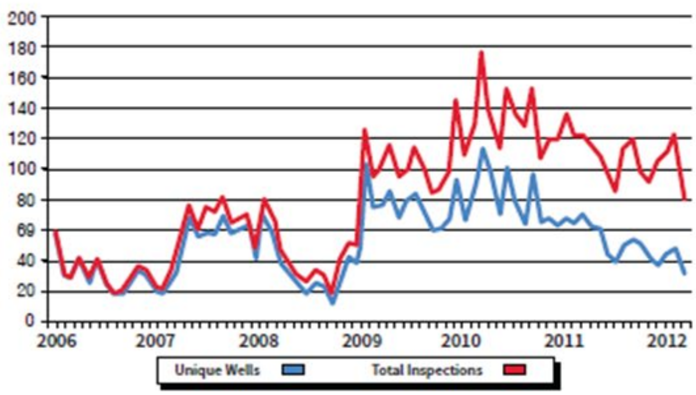


Sample Well

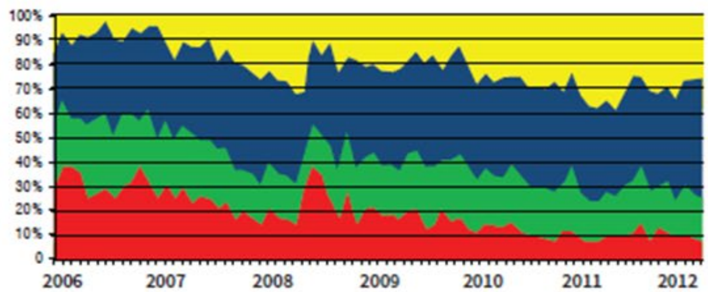
Well profiles show the rate of corrosion *(left bars)* and wall loss *(right bars)* by joint at precise depths.

WellTrak Tubing Data Management and Evaluation System provides production engineers, well managers, rig supervisors and others in tubing management programs access to TuboChek™$_{C1D1}$ inspection reports. The reports provide critical data at precise depths where string wear, corrosion, or failures have occurred.

Tubing Management decisions based on WellTrak's online historical database of well/field conditions can greatly assist in string design, treatments or mitigation techniques before the well is put back on production. This valuable information helps extend the run life of wells, measure the effectivenes of changes, and reduce overall tubing failures.



Inspections per month



Reject Rates per month

Continued application of on-site inspection at this field resulted in reduced reject rates and reduced tubing failures.

Benefits:

- Individual full inspection history
- Online access to well records
- Identify patterns or correlations among historical inspections
- Quick rod guide assessment can be established in conjunction with rod design programs
- Generalized statistics for inspections performed

The exclusive Tuboscope TuboChek™$_{C1D1}$ inspection coupled with WellTrak's data management system maximizes the potential of your tubing string, preventing future problems while reducing operating costs.

Tuboscope | NOV Wellbore Technologies
2835 Holmes Road
Houston, Texas 77051, USA
Phone 346 223 6100
tuboscopesales@nov.com nov.com/tuboscope

Attachment A-5 (continued). Tuboscope's wellsite tubing inspection service. This (or its equivalent) can be utilized for surface inspection of the Coteau 1 through 6 tubing strings in the event they need to be pulled for any reason.

Attachment A-6 – H_2S Detection Station Overview

Honeywell

Sensepoint XCD SPECIFICATIONS

Flammable, toxic and oxygen gas detector for industrial applications

Use	3 wire, 4-20mA and RS485 MODBUS output fixed point detector with in-built alarm and fault relays for the protection of personnel and plant from flammable, toxic and Oxygen hazards. Incorporates a transmitter with local display and fully configurable via non-intrusive magnetic switch interface.
Electrical	
Input Voltage Range	12 to 32VDC (24VDC nominal)
Max Power Consumption	Maximum power consumption is dependent on the type of gas sensor being used. Electrochemical cells = 3.7W, IR = 3.7W and catalytic = 4.9W. Maximum inrush current = 800mA at 24VDC
Current Output	Sink or source
Relays	3 x 5A@250VAC. Selectable normally open or normally closed (switch) and energized/de-energised (programmable) Alarm relays default normally open/de-energized. Fault relay default normally open/energized
Communication	RS485, MODBUS RTU
Construction	
Material	Housing: Epoxy painted aluminium alloy ADC12 or 316 stainless steel Sensor: 316 stainless steel
Weight (approx)	Aluminium Alloy LM25: 4.4lbs 316 Stainless Steel: 11lbs
Mounting	Integral mounting plate with 4 x mounting holes suitable for M8 bolts. Optional pipe mounting kit for horizontal or vertical pipe Ø1.5 to 3" (2" nominal)
Cable Entries	UL\cUL versions: 2 x ¾"NPT conduit entries. Suitable blanking plug supplied for use if only 1 entry used. Seal to maintain IP rating; ATEX/IECEx versions: 2 x M20 cable entries
Environmental	
IP Rating	IP66 in accordance with EN60529:1992
Certified Temperature Range	-40ºF to +149ºF (-40ºC to +65ºC)

Detectable Gases and XCD Sensor Performance

Gas	User Selectable Full Scale Range	Default Range	Steps	User Selectable Cal Gas Range	Default Cal Point	Response Time (T90) Secs	Accuracy	Operating Temperature Min	Operating Temperature Max	Default Alarm Points A1	Default Alarm Points A2
Electrochemical Sensors											
Oxygen	25.0%Vol. only	25.0%Vol.	n/a	20.9%Vol. (Fixed)	20.9%Vol.	<30	<±0.5%Vol.	-20°C / -4°F	55°C / 131°F	19.5%Vol. ▼	23.5%Vol. ▲
Hydrogen Sulfide*	10.0 to 100.0ppm	50.0ppm	0.1ppm	30 to 70% of selected full scale range	25ppm	<50	<±1ppm	-20°C / -4°F	55°C / 131°F	10ppm ▲	20ppm ▲
Carbon Monoxide**	100 to 1,000ppm	300ppm	100ppm		100ppm	<30	<±6ppm	-20°C / -4°F	55°C / 131°F	30ppm ▲	100ppm ▲
Hydrogen	1,000ppm only	1,000ppm	n/a		500ppm	<65	<±25ppm	-20°C / -4°F	55°C / 131°F	200ppm ▲	400ppm ▲
Nitrogen Dioxide***	10.0 to 50.0ppm	10.0ppm	5.0ppm		5.0ppm	<40	<±3ppm	-20°C / -4°F	55°C / 131°F	5.0ppm ▲	10.0ppm ▲
* Lowest Alarm Limit = 1ppm; Lowest Detection Limit = .5ppm ** Lowest Alarm Limit = 15 ppm; Lowest Detection Limit = 10ppm *** Lowest Alarm Limit = 0.6 ppm; Lowest Detection Limit = 0.3ppm											
Catalytic Bead Sensors											
Flammable 1 to 8	20.0 to 100.0%LEL	100%LEL	10%LEL		50%LEL	<25	<±1.5%LEL	-20°C / -4°F	55°C / 131°F	20%LEL ▲	40%LEL ▲
Infrared Sensors											
Methane	20.0 to 100.0%LEL	100%LEL	10%LEL		50%LEL	<30	<±1.5%LEL	-20°C / -4°F	50°C / 122°F	20%LEL ▲	40%LEL ▲
Propane	20 to 100%LEL	100%LEL	10%LEL		50%LEL	<30	<±1%LEL	-20°C / -4°F	50°C / 122°F	20%LEL ▲	40%LEL ▲
Carbon Dioxide	2%Vol. only	2%Vol.	n/a		1%Vol.	<30	<±0.04%Vol.	-20°C / -4°F	50°C / 122°F	0.4%Vol. ▲	0.8%Vol. ▲

NOTE: For Cat Bead and Infrared sensors, Lowest Detectable Limit is 5% LEL and Lowest Alarm Level is 10% LEL.

▲ - Rising Alarm ▼ - Falling Alarm

Certification	
US, Latin America, Canada	UL/c-UL - Class I, Division 1, Groups B, C and D, Class I, Division 2, Groups B, C & D, Class II, Division 1, Groups E, F & G, Class II, Division 2, Groups F & G. -40°C to +65°C
European	ATEX Ex II 2 GD Ex d IIC Gb T6 (Ta -40°C to +65°C) Ex tb IIIC T85°C Db IP66
International	IEC Ex d IIC Gb T6 (Ta -40ºC to +65ºC) Ex tb IIIC T85°C Db IP66
EMC	CE: EN50270:2006 EN6100-6-4:2007
Performance	UL508; CSA 22.2 No. 152 (flammable gasses, excludes infrared sensors); ATEX, IEC/EN60079-29-1:2007, EN45544, EN50104, EN50271; China: PA Pattern Measurement (for transmitter and toxic gas sensors) "CCCF" Shenyang for Flammable (fire dept approval)

Find out more

www.honeywellanalytics.com

Toll-free: 800.538.0363

Please Note:

While every effort has been made to ensure accuracy in this publication, no responsibility can be accepted for errors or omissions. Data may change, as well as legislation, and you are strongly advised to obtain copies of the most recently issued regulations, standards, and guidelines. This publication is not intended to form the basis of a contract.

SS01082_v4 3/14

Attachment A-7A – H_2S Detection Personnel Equipment

iBRiD® MX6

- 24 "Plug-and-Play" field-replaceable sensors including PID and Infrared options
- Up to 6 gases monitored simultaneously
- Simple, user-friendly, customizable, menu-driven navigation
- Five-way navigation button
- Durable, concussion-proof overmold
- Optional integral sampling pump with strong 30.5 meter (100 feet) sample draw
- Full-color graphic LCD is highly visible in a variety of lighting conditions
- Powerful, 95 dB audible alarm

Get ready to see hazardous levels of oxygen, toxic and combustible gas, and volatile organic compounds (VOCs) like never before.

The MX6 iBrid® is more than an intelligent hybrid of Industrial Scientific's best monitoring technologies—it's the most adaptable six-gas monitor on the market. With hundreds of possible sensor combinations, and a robust list of available configuration settings, the MX6 iBrid is ready to monitor oxygen, toxic and combustible gas, and volatile organic compounds (VOCs).

As your work changes, so can your MX6 iBrid. It uses five sensor slots to detect up to six gases. Each of those sensor slots accepts a variety of sensors, which means you can use the instrument with a PID sensor one day and an infrared sensor the next. What's more, settings allow you to adapt the instrument's behavior for your application. If you need to use a benzene PID response factor for one application, and butadiene for others, the familiar menu structure will allow you to quickly change settings.

The rugged MX6 iBrid carries our Guaranteed for Life™ warranty and is compatible with DSX™ Docking Stations. With a DSX Docking Station, maintenance is simplified and data becomes more than a spreadsheet filled with logged readings. Proactively manage your gas detection fleet—track trends, know when instrument maintenance will be required, and understand how your MX6 iBrid instruments are being used.

INDUSTRIAL SCIENTIFIC

Continued…

Attachment A-7A – H_2S Detection Personnel Equipment (continued)

SPECIFICATIONS*

INSTRUMENT WARRANTY
Warranted for as long as the instrument is supported by Industrial Scientific

CASE MATERIAL
Lexan/ABS/Stainless Steel with protective rubber overmold

DIMENSIONS
135 x 77 x 48 mm (5.3 x 3.05 x 1.9 in) without Pump
193 x 77 x 56 mm (7.6 x 3.1 x 2.2 in) with Pump

WEIGHT
409 g (14.4 oz) typical, without Pump
511 g (18.0 oz) typical, with Pump

DISPLAY/READOUT
Color Graphic Liquid Crystal Display

POWER SOURCE/RUN TIMES
Rechargeable, Extended-Range Lithium-ion Battery Pack (36 hours) without Pump
Rechargeable, Extended-Range Lithium-ion Battery Pack (20 hours) with Pump
Replaceable AA Alkaline Battery Pack (10.5 hours) without Pump

OPERATING TEMPERATURE RANGE
-20 °C to 55 °C (-4 °F to 131 °F)

OPERATING HUMIDITY RANGE
15% to 95% non-condensing (continuous)

CERTIFICATIONS
INGRESS PROTECTION IP64

ANZEx:	Ex ia s Zone 0 I; Ex ia s Zone 0 IIC T4
ATEX:	Ex ia IIC T4 Ga; II 1G (or Ex d ia IIC T4 Gb IR sensor); Ex ia I; Equipment Group and Category: I M1/II 1G
China CPC:	Metrology Approval
China Ex:	Ex ia d I/IIC T4
CMA:	Approval for Mining Products; CH_4, O_2, CO, CO_2
CSA:	Cl I, Gr A-D T4; Ex d ia IIC T4
EAC:	PBExiadI X; 1ExiadIICT4 X
IECEx:	Ex ia I (Ex ia d I IR sensor); Ex ia IIC T4 Ga; Ex d ia IIC T4 Gb
INMETRO:	Ex ia IIC T4 Ga
KC:	Ex d ia IIC T4
KIMM:	Ex d ia IIC T4
MDR:	Registration of Plant Design; CH_4, O_2, CO, H_2S, NO_2
MSHA:	30 CRF, Part 22, Intrinsically safe for methane/air mixtures
PA-DEP:	BFE 114-08 Permissible for PA Bituminous Underground Mines
UL:	Cl I, Div 1, Gr A-D, T4; Cl II, Groups F G; Cl I, Zone LEL 0, AEx ia d IIC T4 (or AEx ia d IIC T4 IR sensor)

MEASURING RANGES SENSOR	RANGE	RESOLUTION
CATALYTIC BEAD		
Combustible Gas	0-100% LEL	1%
Methane	0-5% vol	0.01%
ELECTROCHEMICAL		
Ammonia	0-500 ppm	1
Carbon Monoxide	0-1,500 ppm	1
Carbon Monoxide (High Range)	0-9,999 ppm	1
Carbon Monoxide/Hydrogen low	0-1,000 ppm	1
Chlorine	0-50 ppm	0.1
Chlorine Dioxide	0-1 ppm	0.01
Carbon Monoxide/ Hydrogen Sulfide (COSH)	CO: 0-1,500 ppm H_2S: 0-500 ppm	1 0.1
Hydrogen	0-2,000 ppm	1
Hydrogen Chloride	0-30 ppm	0.1
Hydrogen Cyanide	0-30 ppm	0.1
Hydrogen Sulfide	0-500 ppm	0.1
Nitric Oxide	0-1,000 ppm	1
Nitrogen Dioxide	0-150 ppm	0.1
Oxygen	0-30% vol	0.1%
Phosphine	0-5 ppm	0.01
Phosphine (High Range)	0-1,000 ppm	1
Sulfur Dioxide	0-150 ppm	0.1
INFRARED		
Hydrocarbons	0-100% LEL	1%
Methane (% vol)	0-100% vol	1%
Methane (% LEL)	0-100% LEL	1%
Carbon Dioxide	0-5% vol	0.01%
PHOTOIONIZATION		
VOC	0-2,000 ppm	0.1

* These specifications are based on performance averages and may vary by instrument.

AVAILABLE FOR RENT

For a list of classes, videos, or to download the GDME App, visit www.indsci.com/training

Which Accessories Will You Need?

CHECKLIST

- ☐ Docking Stations
- ☐ Calibration Stations
- ☐ Compliance Tracking Software (iNet Control)
- ☐ Probes
- ☐ Sample Tubing
- ☐ Confined Space Kits
- ☐ Spare Batteries
- ☐ Replacement Sensors
- ☐ Desktop Chargers
- ☐ Vehicle Chargers
- ☐ Multi-Unit Chargers
- ☐ Carrying Cases
- ☐ Filters

For a list of all accessories, visit: www.indsci.com/mx6

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Attachment A-7B – H_2S Detection Personnel Equipment

VENTIS MX4

The Ventis® MX4 is a four-gas monitor with the portability and size of a single-gas monitor. Eliminate the need for extra monitors and transition seamlessly from personal monitoring to confined space entry with the Ventis® Slide-on Pump—ideal for operators who wear their gas monitors primarily for personal protection but occasionally require a pump for confined space entries.

- Detect up to four gases with a wide range of sensor options
- Select alarm set points, set latch alarms, disable instrument shutdown while in alarm, and more
- Save time and reduce human error with maintenance and usage data available from iNet Control software
- Available with or without an integral pump, or with the Ventis Slide-on Pump for ultimate flexibility
- Non-pumped instruments compatible with 12-hour, 18-hour, or 20-hour batteries

The Ventis® Slide-on Pump

The Ventis® Slide-on Pump is ideally suited for operators who wear their gas monitors primarily for personal protection but occasionally require a pump for confined space entries. Available in black or safety orange and powered by its own battery, the slide-on pump is compatible with the Ventis MX4 and Ventis® Pro5 Multi-Gas Monitor.

- **Convenient Sampling** – Sample draw distance of up to 50 feet provides convenient sampling in a wide range of applications
- **Easy to Attach** – No tools are required to attach or remove the Ventis Slide-on Pump to or from the monitor
- **Uses Same Batterys and Chargers as Ventis** – Monitor and pump each use the same batterys, and can easily be exchanged between instruments
- **Flexible Battery Options** – Three available battery options make this pump extremely flexible in the field

Build and price your Ventis MX4 online
with the instrument builder
https://www.indsci.com/ventis-mx4-builder

Continued…

Attachment A-7B – H_2S Detection Personnel Equipment (continued)

SPECIFICATIONS*

WARRANTY
The following components are warranted for four (4) years from the device's date of manufacture: monitor, pump, and CO/H_2S/O_2/LEL sensors. All other components are warranted for two (2) years from the device's date of manufacture.**

CASE MATERIAL
Polycarbonate with protective rubber overmold

DIMENSIONS
103 x 58 x 30 mm (4.1 x 2.3 x 1.2 in) without pump, lithium-ion battery version
172 x 67 x 66 mm (6.8 x 2.6 x 2.6 in) with pump, lithium-ion battery version

WEIGHT
182 g (6.4 oz) without Pump, lithium-ion battery version
380 g (13.4 oz) with Pump, lithium-ion battery version

POWER SOURCE/RUN TIME
Rechargeable slim extended lithium-ion battery
(18 hours typical @ 20 °C) without Pump
Rechargeable lithium-ion battery
(12 hours typical @ 20 °C) without Pump
Rechargeable extended-range lithium-ion battery
(20 hours typical @ 20 °C) without Pump
(12 hours typical @ 20 °C) with Pump
Replaceable AAA alkaline battery
(8 hours typical @ 20 °C) without Pump
(4 hours typical @ 20 °C) with Pump

ALARMS
Ultra-bright LEDs, loud audible alarm (95 dB at 30 cm) and vibrating alarm

DISPLAY/READOUT
Backlit liquid crystal display (LCD)

TEMPERATURE RANGE
-20 °C to 50 °C (-4 °F to 122 °F) ***

HUMIDITY RANGE
15% to 95% Non-condensing (continuous)

SENSORS
Combustible gases/methane – Catalytic Bead
O_2, CO, CO/H_2 low, H_2S, NO_2, SO_2 – Electrochemical

MEASURING RANGES

Combustible Gases:	0-100% LEL in 1% increments
Methane (CH_4):	0-5% of vol in 0.01% increments
Oxygen (O_2):	0-30% of vol in 0.1% increments
Carbon Monoxide (CO/H_2 low):	0-1,000 ppm in 1 ppm increments
Carbon Monoxide (CO):	0-1,000 ppm in 1 ppm increments
Hydrogen Sulfide (H_2S):	0-500 ppm in 0.1 ppm increments
Nitrogen Dioxide (NO_2):	0-150 ppm in 0.1 ppm increments
Sulfur Dioxide (SO_2):	0-150 ppm in 0.1 ppm increments

CERTIFICATIONS
INGRESS PROTECTION IP66/67

ANZEx:	Ex ia s Zone 0 I/IIC T4
ATEX:	Ex ia IIC T4 Ga and Ex ia I Ma; Equipment Group and Category II 1G/I M1
China CMC:	Metrology approval
China CPC:	CPA 2017-C103
China Ex:	Ex ia IIC T4 Ga; Ex ia d I Mb
China KA:	Approved for Underground Mines with CO, H_2S, O_2 and CH_4
China MA:	Approved for Underground Mines with CO, H_2S, O_2 and CH_4 (Note: Diffusion 17144453 pack only)
CSA:	Cl I, Div 1, G A-D, T4; Ex d ia IIC T4
EAC:	PB Ex d ia I X/1Ex d ia IIC T4 X
IECEx:	Ex ia IIC T4 Ga
INMETRO:	Ex ia IIC T4 Ga
KC:	Ex d ia IIC T4
KIMM:	Ex d ia IIC T4
MSHA:	30 CFR Part 22; Permissible for underground mines; Li-ion
PA-DEP:	BFE 46-12 Permissible for PA Bituminous Underground Mines; Charger/docking station accessories; Category 1
SANS:	SANS 1515-1; Type A; Ex ia I/IIC T4; Li-ion
TIIS:	Ex ia IIC T4 X
UL:	Cl I, Div 1, Groups A-D, T4; Zone 0, AEx ia IIC T4; Cl II, Gr F-G (Carbonaceous and Grain dust)

SUPPLIED WITH MONITOR
Calibration Cup (without pump), Sample Tubing (with pump), Reference Guide

LANGUAGE
English (1), French (2), Spanish (3), German (4), Italian (5), Dutch (6), Portuguese (7), Russian (9), Polish (A), Czech (B), Chinese (C), Danish (D), Norwegian (E), Finnish (F), Swedish (G), Japanese (J)

* These specifications are based on performance averages and may vary by instrument.

**The 4-year warranty is strictly limited to the enumerated components in devices manufactured after December 31, 2019. Warranted components in devices manufactured before January 1st, 2020 are warranted for two (2) years from the device's date of manufacture.

*** Operating temperatures above 50 °C (122 °F) may cause reduced instrument accuracy. Operating temperatures below -20 °C (-4 °F) may cause reduced instrument accuracy and affect display and alarm performance. See Product Manual for details.

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Attachment A-8 – Supervisory Control and Data Acquisition (SCADA) System

The SCADA system is a computer-based system or systems used by personnel in a control room that aims to collect and display information about the Dakota Gasification Company (DGC) CO_2 storage injection operations in real time. This supervisory system collects data at an assigned time interval and stores the data in the historian server. Using DGC operator process control selections, the SCADA will have the ability to send commands and control the storage injection network (i.e., start or stop pumps, open or close valves, control process equipment remotely, etc.).

In addition to monitoring and control ability, the SCADA system will include warnings, both audible and visual, to alert the DGC control room, which is staffed 24/7, of near or excessive violations of set parameters within the system.

Attachment A-9 – Bottomhole Pressure Survey

Pressure Survey Report

EVOLUTION COMPLETIONS INC.

Williston, ND
(701) 572-2069
info@evolutioncompletions.com

www.evolutioncompletions.com

RAMPART ENERGY

COTEAU 1
COTEAU 1

SEP 27 - 28, 2021

Bottom Hole - Build-Up

Report Prepared by

E.S. KYLE INSTRUMENT LTD.

Red Deer, AB
PH 403.309.0980

Scott Brilz
Ref #: RD21-0365

Well Information

RAMPART ENERGY
COTEAU 1
COTEAU 1

SEP 27 - 28, 2021

Bottom Hole - Build-Up

AER Well License Number:			
Test Purpose:			
Field:	WILDCAT		
Formation Name:			
Well Fluid Status:	(01) Oil	H2S:	N
Well Type:	Vertical		
KB Elevation:	17.00	Open Hole:	N
CF Elevation:	0.00		
Production Interval:			
Mid Point Perfs.:	ft KB-TVD		
Producing Through:	Casing		

	in Tbg.		ft KB
7.00	in Csg.		ft KB
	PBTD:		ft KB

Test Summary

Start of Test:	2021 09 27 1557	
Well Shut-In:		Hrs
Final Test Time:	2021 09 28 2338	

Initial Tubing Pressure:		Final Tubing Pressure:		PSIA
Initial Casing Pressure:	300.0	Final Casing Pressure:	300.0	

	Run Depth:	5975.00	ft KB-TVD
Primary Gauge (1):	Final Pressure:	2937.09	PSIA
	Final Temperature:	151.85	Deg. F
	Gradient at Run Depth:		PSIA/ft
	Calculated Pressure at MPP:		PSIA
	Gauge Program:	5 SEC	

Report Prepared by:

E.S. KYLE INSTRUMENT LTD. Ref. #: RD21-0365

EVOLUTION COMPLETIONS INC.

Extended Test Data

RAMPART ENERGY
COTEAU 1
COTEAU 1

SEP 27 - 28, 2021

Formation:

Test Type: Bottom Hole - Build-Up

Initial Tubing Pressure:		PSIA	Final Tubing Pressure:		PSIA
Initial Casing Pressure:	300.0		Final Casing Pressure:	300.0	

Top Gauge					Bottom Gauge			
			253	Gauge Serial #	254			
% Acc.	0.024	KPAA	41369	Range	41369	KPAA	0.024	% Acc.
% Res.	0.0003		09/15/2021	Calibration Date	09/15/2021		0.0003	% Res.
			Cal-Scan Recorder - Strain	Gauge Type	Cal-Scan Recorder - Strain			
			09/27/21 15:57:00	Gauge Start Time	09/27/21 15:57:00			
		ft KB-TVD	5974.70	Run Depth	5975.00	ft KB-TVD		
		PSIA	2936.41	Pressure	2937.09	PSIA		
		Deg. F	151.79	Temperature	151.85	Deg. F		
		PSIA/ft		Gradient		PSIA/ft		

Gauge Event	Temp Deg. F	Pressure PSIA	Real Time (mm/dd/yy hh:mm:ss)	Temp Deg. F	Pressure PSIA	Duration of Event Hours
On Bottom	152.20	2932.03	09/27/21 16:55:50	152.15	2932.70	
Open to Flow						
Shut-In						
Off Bottom	151.79	2936.41	09/28/21 18:53:25	151.85	2937.09	26.0

		Pressure Corrected to Run Depth		
PSIA	2936.41	5975.00	2937.09	PSIA
		Calculated Pressure at MPP		
PSIA				PSIA

Remarks:

		Top Gauge			Bottom Gauge		
##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
912	2021 09 27 15:59:00	0.0333	13.46	95.18	0.0333	13.25	95.77
960	2021 09 27 16:03:00	0.1000	305.92	58.07	0.1000	309.82	58.60
					0.00 ft KB-TVD- Initial Surface		
1008	2021 09 27 16:07:00	0.1667	525.62	59.15	0.1667	526.31	59.02
1056	2021 09 27 16:11:00	0.2333	749.94	65.65	0.2333	750.88	65.53
1104	2021 09 27 16:15:00	0.3000	976.96	73.27	0.3000	977.55	73.00
1152	2021 09 27 16:19:00	0.3667	1201.53	82.84	0.3667	1202.26	82.63
1200	2021 09 27 16:23:00	0.4333	1426.41	91.98	0.4333	1427.25	91.92
1248	2021 09 27 16:27:00	0.5000	1655.05	103.44	0.5000	1655.59	101.99
1296	2021 09 27 16:31:00	0.5667	1852.01	114.18	0.5667	1852.03	113.02
1344	2021 09 27 16:35:00	0.6333	2074.32	127.18	0.6333	2075.26	125.48
1392	2021 09 27 16:39:00	0.7000	2286.38	135.12	0.7000	2287.18	134.43
1440	2021 09 27 16:43:00	0.7667	2538.85	140.96	0.7667	2539.50	140.06
1488	2021 09 27 16:47:00	0.8333	2736.96	147.66	0.8333	2738.49	146.99
1536	2021 09 27 16:51:00	0.9000	2889.52	151.95	0.9000	2889.52	151.81
1584	2021 09 27 16:55:00	0.9667	2932.92	152.17	0.9667	2933.57	152.13
1594	2021 09 27 16:55:50	0.9806	2932.03	152.20	0.9806	2932.70	152.15
					5975.00 ft KB-TVD- On Bottom		
1632	2021 09 27 16:59:00	1.0333	2931.99	152.23	1.0333	2932.58	152.21
1680	2021 09 27 17:03:00	1.1000	2932.26	152.23	1.1000	2932.89	152.25
1728	2021 09 27 17:07:00	1.1667	2932.53	152.23	1.1667	2933.16	152.26
1776	2021 09 27 17:11:00	1.2333	2932.80	152.23	1.2333	2933.38	152.26
1824	2021 09 27 17:15:00	1.3000	2933.03	152.22	1.3000	2933.60	152.27
1872	2021 09 27 17:19:00	1.3667	2933.25	152.23	1.3667	2933.87	152.27
1920	2021 09 27 17:23:00	1.4333	2933.49	152.23	1.4333	2934.10	152.27
1968	2021 09 27 17:27:00	1.5000	2933.70	152.23	1.5000	2934.35	152.27
2016	2021 09 27 17:31:00	1.5667	2933.94	152.23	1.5667	2934.54	152.27
2064	2021 09 27 17:35:00	1.6333	2934.13	152.23	1.6333	2934.76	152.27
2112	2021 09 27 17:39:00	1.7000	2934.33	152.23	1.7000	2934.94	152.27
2160	2021 09 27 17:43:00	1.7667	2934.50	152.22	1.7667	2935.14	152.27
2208	2021 09 27 17:47:00	1.8333	2934.71	152.22	1.8333	2935.30	152.26
2256	2021 09 27 17:51:00	1.9000	2934.84	152.22	1.9000	2935.53	152.26
2304	2021 09 27 17:55:00	1.9667	2935.04	152.22	1.9667	2935.68	152.26
2352	2021 09 27 17:59:00	2.0333	2935.17	152.22	2.0333	2935.89	152.26
2400	2021 09 27 18:03:00	2.1000	2935.33	152.21	2.1000	2936.01	152.25
2448	2021 09 27 18:07:00	2.1667	2935.51	152.21	2.1667	2936.09	152.25
2496	2021 09 27 18:11:00	2.2333	2935.62	152.21	2.2333	2936.24	152.24
2544	2021 09 27 18:15:00	2.3000	2935.74	152.20	2.3000	2936.32	152.24
2592	2021 09 27 18:19:00	2.3667	2935.79	152.20	2.3667	2936.45	152.23
2640	2021 09 27 18:23:00	2.4333	2935.84	152.20	2.4333	2936.48	152.23

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
2688	2021 09 27 18:27:00	2.5000	2935.87	152.19	2.5000	2936.49	152.23
2736	2021 09 27 18:31:00	2.5667	2935.88	152.19	2.5667	2936.52	152.22
2784	2021 09 27 18:35:00	2.6333	2935.92	152.18	2.6333	2936.52	152.22
2832	2021 09 27 18:39:00	2.7000	2935.92	152.17	2.7000	2936.56	152.21
2880	2021 09 27 18:43:00	2.7667	2935.93	152.16	2.7667	2936.53	152.21
2928	2021 09 27 18:47:00	2.8333	2935.94	152.14	2.8333	2936.61	152.20
2976	2021 09 27 18:51:00	2.9000	2935.95	152.11	2.9000	2936.58	152.20
3024	2021 09 27 18:55:00	2.9667	2935.94	152.08	2.9667	2936.58	152.19
3072	2021 09 27 18:59:00	3.0333	2935.97	152.06	3.0333	2936.61	152.19
3120	2021 09 27 19:03:00	3.1000	2935.97	152.03	3.1000	2936.65	152.18
3168	2021 09 27 19:07:00	3.1667	2936.00	152.01	3.1667	2936.62	152.17
3216	2021 09 27 19:11:00	3.2333	2935.95	152.00	3.2333	2936.60	152.17
3264	2021 09 27 19:15:00	3.3000	2936.00	151.98	3.3000	2936.59	152.16
3312	2021 09 27 19:19:00	3.3667	2936.01	151.97	3.3667	2936.63	152.16
3360	2021 09 27 19:23:00	3.4333	2936.05	151.96	3.4333	2936.69	152.15
3408	2021 09 27 19:27:00	3.5000	2935.99	151.95	3.5000	2936.65	152.14
3456	2021 09 27 19:31:00	3.5667	2936.01	151.94	3.5667	2936.66	152.11
3504	2021 09 27 19:35:00	3.6333	2936.04	151.94	3.6333	2936.66	152.08
3552	2021 09 27 19:39:00	3.7000	2936.08	151.94	3.7000	2936.65	152.05
3600	2021 09 27 19:43:00	3.7667	2936.04	151.93	3.7667	2936.68	152.03
3648	2021 09 27 19:47:00	3.8333	2936.05	151.93	3.8333	2936.71	152.01
3696	2021 09 27 19:51:00	3.9000	2936.06	151.93	3.9000	2936.70	152.00
3744	2021 09 27 19:55:00	3.9667	2936.08	151.92	3.9667	2936.66	151.99
3792	2021 09 27 19:59:00	4.0333	2936.08	151.92	4.0333	2936.66	151.99
3840	2021 09 27 20:03:00	4.1000	2936.04	151.92	4.1000	2936.71	151.98
3888	2021 09 27 20:07:00	4.1667	2936.07	151.91	4.1667	2936.70	151.98
3936	2021 09 27 20:11:00	4.2333	2936.05	151.91	4.2333	2936.70	151.98
3984	2021 09 27 20:15:00	4.3000	2936.07	151.91	4.3000	2936.68	151.97
4032	2021 09 27 20:19:00	4.3667	2936.11	151.91	4.3667	2936.70	151.97
4080	2021 09 27 20:23:00	4.4333	2936.11	151.91	4.4333	2936.72	151.97
4128	2021 09 27 20:27:00	4.5000	2936.08	151.91	4.5000	2936.72	151.96
4176	2021 09 27 20:31:00	4.5667	2936.09	151.91	4.5667	2936.72	151.96
4224	2021 09 27 20:35:00	4.6333	2936.09	151.90	4.6333	2936.72	151.96
4272	2021 09 27 20:39:00	4.7000	2936.09	151.90	4.7000	2936.76	151.96
4320	2021 09 27 20:43:00	4.7667	2936.08	151.90	4.7667	2936.70	151.96
4368	2021 09 27 20:47:00	4.8333	2936.13	151.90	4.8333	2936.74	151.95
4416	2021 09 27 20:51:00	4.9000	2936.09	151.89	4.9000	2936.76	151.95
4464	2021 09 27 20:55:00	4.9667	2936.14	151.89	4.9667	2936.76	151.95
4512	2021 09 27 20:59:00	5.0333	2936.10	151.89	5.0333	2936.75	151.95
4560	2021 09 27 21:03:00	5.1000	2936.14	151.89	5.1000	2936.75	151.95
4608	2021 09 27 21:07:00	5.1667	2936.14	151.89	5.1667	2936.77	151.95
4656	2021 09 27 21:11:00	5.2333	2936.14	151.89	5.2333	2936.76	151.94

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
4704	2021 09 27 21:15:00	5.3000	2936.15	151.88	5.3000	2936.73	151.94
4752	2021 09 27 21:19:00	5.3667	2936.08	151.88	5.3667	2936.78	151.94
4800	2021 09 27 21:23:00	5.4333	2936.14	151.88	5.4333	2936.82	151.94
4848	2021 09 27 21:27:00	5.5000	2936.11	151.88	5.5000	2936.75	151.93
4896	2021 09 27 21:31:00	5.5667	2936.12	151.88	5.5667	2936.75	151.93
4944	2021 09 27 21:35:00	5.6333	2936.08	151.87	5.6333	2936.77	151.93
4992	2021 09 27 21:39:00	5.7000	2936.11	151.87	5.7000	2936.75	151.93
5040	2021 09 27 21:43:00	5.7667	2936.13	151.87	5.7667	2936.77	151.93
5088	2021 09 27 21:47:00	5.8333	2936.12	151.87	5.8333	2936.79	151.93
5136	2021 09 27 21:51:00	5.9000	2936.12	151.87	5.9000	2936.78	151.93
5184	2021 09 27 21:55:00	5.9667	2936.16	151.87	5.9667	2936.79	151.93
5232	2021 09 27 21:59:00	6.0333	2936.09	151.87	6.0333	2936.77	151.92
5280	2021 09 27 22:03:00	6.1000	2936.11	151.87	6.1000	2936.75	151.92
5328	2021 09 27 22:07:00	6.1667	2936.10	151.86	6.1667	2936.76	151.92
5376	2021 09 27 22:11:00	6.2333	2936.17	151.86	6.2333	2936.80	151.92
5424	2021 09 27 22:15:00	6.3000	2936.10	151.86	6.3000	2936.79	151.92
5472	2021 09 27 22:19:00	6.3667	2936.16	151.86	6.3667	2936.76	151.92
5520	2021 09 27 22:23:00	6.4333	2936.15	151.86	6.4333	2936.75	151.92
5568	2021 09 27 22:27:00	6.5000	2936.13	151.86	6.5000	2936.81	151.92
5616	2021 09 27 22:31:00	6.5667	2936.18	151.86	6.5667	2936.77	151.92
5664	2021 09 27 22:35:00	6.6333	2936.14	151.86	6.6333	2936.79	151.91
5712	2021 09 27 22:39:00	6.7000	2936.15	151.86	6.7000	2936.80	151.91
5760	2021 09 27 22:43:00	6.7667	2936.15	151.86	6.7667	2936.77	151.91
5808	2021 09 27 22:47:00	6.8333	2936.15	151.85	6.8333	2936.81	151.91
5856	2021 09 27 22:51:00	6.9000	2936.18	151.85	6.9000	2936.85	151.91
5904	2021 09 27 22:55:00	6.9667	2936.17	151.85	6.9667	2936.81	151.91
5952	2021 09 27 22:59:00	7.0333	2936.15	151.85	7.0333	2936.83	151.91
6000	2021 09 27 23:03:00	7.1000	2936.18	151.85	7.1000	2936.80	151.91
6048	2021 09 27 23:07:00	7.1667	2936.13	151.85	7.1667	2936.81	151.90
6096	2021 09 27 23:11:00	7.2333	2936.18	151.85	7.2333	2936.79	151.90
6144	2021 09 27 23:15:00	7.3000	2936.16	151.85	7.3000	2936.79	151.90
6192	2021 09 27 23:19:00	7.3667	2936.15	151.84	7.3667	2936.82	151.90
6240	2021 09 27 23:23:00	7.4333	2936.19	151.85	7.4333	2936.85	151.90
6288	2021 09 27 23:27:00	7.5000	2936.18	151.84	7.5000	2936.82	151.90
6336	2021 09 27 23:31:00	7.5667	2936.19	151.85	7.5667	2936.82	151.90
6384	2021 09 27 23:35:00	7.6333	2936.19	151.84	7.6333	2936.84	151.90
6432	2021 09 27 23:39:00	7.7000	2936.20	151.84	7.7000	2936.80	151.90
6480	2021 09 27 23:43:00	7.7667	2936.18	151.84	7.7667	2936.82	151.90
6528	2021 09 27 23:47:00	7.8333	2936.17	151.84	7.8333	2936.84	151.90
6576	2021 09 27 23:51:00	7.9000	2936.18	151.84	7.9000	2936.80	151.90
6624	2021 09 27 23:55:00	7.9667	2936.18	151.84	7.9667	2936.84	151.90
6672	2021 09 27 23:59:00	8.0333	2936.19	151.84	8.0333	2936.80	151.89

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
6720	2021 09 28 00:03:00	8.1000	2936.20	151.84	8.1000	2936.87	151.89
6768	2021 09 28 00:07:00	8.1667	2936.19	151.84	8.1667	2936.85	151.89
6816	2021 09 28 00:11:00	8.2333	2936.20	151.84	8.2333	2936.83	151.89
6864	2021 09 28 00:15:00	8.3000	2936.18	151.83	8.3000	2936.87	151.89
6912	2021 09 28 00:19:00	8.3667	2936.19	151.83	8.3667	2936.86	151.89
6960	2021 09 28 00:23:00	8.4333	2936.20	151.84	8.4333	2936.82	151.89
7008	2021 09 28 00:27:00	8.5000	2936.19	151.83	8.5000	2936.82	151.89
7056	2021 09 28 00:31:00	8.5667	2936.22	151.83	8.5667	2936.84	151.89
7104	2021 09 28 00:35:00	8.6333	2936.20	151.83	8.6333	2936.86	151.89
7152	2021 09 28 00:39:00	8.7000	2936.19	151.83	8.7000	2936.85	151.89
7200	2021 09 28 00:43:00	8.7667	2936.20	151.83	8.7667	2936.81	151.89
7248	2021 09 28 00:47:00	8.8333	2936.21	151.83	8.8333	2936.86	151.89
7296	2021 09 28 00:51:00	8.9000	2936.21	151.83	8.9000	2936.85	151.89
7344	2021 09 28 00:55:00	8.9667	2936.20	151.83	8.9667	2936.87	151.89
7392	2021 09 28 00:59:00	9.0333	2936.19	151.83	9.0333	2936.84	151.88
7440	2021 09 28 01:03:00	9.1000	2936.19	151.83	9.1000	2936.85	151.89
7488	2021 09 28 01:07:00	9.1667	2936.20	151.83	9.1667	2936.88	151.88
7536	2021 09 28 01:11:00	9.2333	2936.21	151.83	9.2333	2936.87	151.88
7584	2021 09 28 01:15:00	9.3000	2936.16	151.83	9.3000	2936.84	151.88
7632	2021 09 28 01:19:00	9.3667	2936.22	151.83	9.3667	2936.82	151.88
7680	2021 09 28 01:23:00	9.4333	2936.17	151.83	9.4333	2936.86	151.88
7728	2021 09 28 01:27:00	9.5000	2936.23	151.82	9.5000	2936.85	151.88
7776	2021 09 28 01:31:00	9.5667	2936.18	151.82	9.5667	2936.85	151.88
7824	2021 09 28 01:35:00	9.6333	2936.22	151.83	9.6333	2936.85	151.88
7872	2021 09 28 01:39:00	9.7000	2936.20	151.82	9.7000	2936.85	151.88
7920	2021 09 28 01:43:00	9.7667	2936.19	151.82	9.7667	2936.87	151.88
7968	2021 09 28 01:47:00	9.8333	2936.20	151.82	9.8333	2936.90	151.88
8016	2021 09 28 01:51:00	9.9000	2936.22	151.82	9.9000	2936.88	151.88
8064	2021 09 28 01:55:00	9.9667	2936.22	151.82	9.9667	2936.86	151.88
8112	2021 09 28 01:59:00	10.0333	2936.24	151.82	10.0333	2936.86	151.88
8160	2021 09 28 02:03:00	10.1000	2936.21	151.82	10.1000	2936.89	151.88
8208	2021 09 28 02:07:00	10.1667	2936.22	151.82	10.1667	2936.88	151.88
8256	2021 09 28 02:11:00	10.2333	2936.22	151.82	10.2333	2936.83	151.88
8304	2021 09 28 02:15:00	10.3000	2936.27	151.82	10.3000	2936.87	151.88
8352	2021 09 28 02:19:00	10.3667	2936.22	151.82	10.3667	2936.90	151.88
8400	2021 09 28 02:23:00	10.4333	2936.20	151.82	10.4333	2936.92	151.88
8448	2021 09 28 02:27:00	10.5000	2936.22	151.82	10.5000	2936.88	151.88
8496	2021 09 28 02:31:00	10.5667	2936.24	151.82	10.5667	2936.89	151.87
8544	2021 09 28 02:35:00	10.6333	2936.24	151.82	10.6333	2936.90	151.87
8592	2021 09 28 02:39:00	10.7000	2936.22	151.82	10.7000	2936.91	151.87
8640	2021 09 28 02:43:00	10.7667	2936.26	151.82	10.7667	2936.87	151.87
8688	2021 09 28 02:47:00	10.8333	2936.22	151.82	10.8333	2936.91	151.87

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
8736	2021 09 28 02:51:00	10.9000	2936.19	151.82	10.9000	2936.86	151.87
8784	2021 09 28 02:55:00	10.9667	2936.20	151.82	10.9667	2936.90	151.87
8832	2021 09 28 02:59:00	11.0333	2936.25	151.82	11.0333	2936.87	151.87
8880	2021 09 28 03:03:00	11.1000	2936.23	151.82	11.1000	2936.91	151.87
8928	2021 09 28 03:07:00	11.1667	2936.25	151.82	11.1667	2936.88	151.87
8976	2021 09 28 03:11:00	11.2333	2936.23	151.81	11.2333	2936.90	151.87
9024	2021 09 28 03:15:00	11.3000	2936.23	151.81	11.3000	2936.89	151.87
9072	2021 09 28 03:19:00	11.3667	2936.25	151.82	11.3667	2936.91	151.87
9120	2021 09 28 03:23:00	11.4333	2936.25	151.81	11.4333	2936.88	151.87
9168	2021 09 28 03:27:00	11.5000	2936.23	151.81	11.5000	2936.88	151.87
9216	2021 09 28 03:31:00	11.5667	2936.29	151.82	11.5667	2936.90	151.87
9264	2021 09 28 03:35:00	11.6333	2936.25	151.81	11.6333	2936.91	151.87
9312	2021 09 28 03:39:00	11.7000	2936.24	151.81	11.7000	2936.93	151.87
9360	2021 09 28 03:43:00	11.7667	2936.23	151.81	11.7667	2936.88	151.87
9408	2021 09 28 03:47:00	11.8333	2936.21	151.81	11.8333	2936.90	151.87
9456	2021 09 28 03:51:00	11.9000	2936.23	151.81	11.9000	2936.91	151.87
9504	2021 09 28 03:55:00	11.9667	2936.25	151.81	11.9667	2936.88	151.87
9552	2021 09 28 03:59:00	12.0333	2936.27	151.81	12.0333	2936.90	151.87
9600	2021 09 28 04:03:00	12.1000	2936.25	151.81	12.1000	2936.90	151.87
9648	2021 09 28 04:07:00	12.1667	2936.28	151.81	12.1667	2936.91	151.87
9696	2021 09 28 04:11:00	12.2333	2936.23	151.81	12.2333	2936.91	151.87
9744	2021 09 28 04:15:00	12.3000	2936.24	151.81	12.3000	2936.93	151.87
9792	2021 09 28 04:19:00	12.3667	2936.23	151.81	12.3667	2936.89	151.87
9840	2021 09 28 04:23:00	12.4333	2936.25	151.81	12.4333	2936.91	151.87
9888	2021 09 28 04:27:00	12.5000	2936.24	151.81	12.5000	2936.89	151.87
9936	2021 09 28 04:31:00	12.5667	2936.25	151.81	12.5667	2936.88	151.87
9984	2021 09 28 04:35:00	12.6333	2936.27	151.81	12.6333	2936.93	151.86
10032	2021 09 28 04:39:00	12.7000	2936.24	151.81	12.7000	2936.93	151.87
10080	2021 09 28 04:43:00	12.7667	2936.24	151.81	12.7667	2936.95	151.86
10128	2021 09 28 04:47:00	12.8333	2936.27	151.81	12.8333	2936.96	151.87
10176	2021 09 28 04:51:00	12.9000	2936.26	151.81	12.9000	2936.92	151.87
10224	2021 09 28 04:55:00	12.9667	2936.27	151.81	12.9667	2936.94	151.86
10272	2021 09 28 04:59:00	13.0333	2936.25	151.81	13.0333	2936.97	151.87
10320	2021 09 28 05:03:00	13.1000	2936.26	151.81	13.1000	2936.96	151.87
10368	2021 09 28 05:07:00	13.1667	2936.27	151.81	13.1667	2936.96	151.86
10416	2021 09 28 05:11:00	13.2333	2936.28	151.81	13.2333	2936.93	151.87
10464	2021 09 28 05:15:00	13.3000	2936.24	151.81	13.3000	2936.94	151.87
10512	2021 09 28 05:19:00	13.3667	2936.25	151.81	13.3667	2936.94	151.86
10560	2021 09 28 05:23:00	13.4333	2936.26	151.81	13.4333	2936.94	151.86
10608	2021 09 28 05:27:00	13.5000	2936.24	151.81	13.5000	2936.97	151.86
10656	2021 09 28 05:31:00	13.5667	2936.28	151.81	13.5667	2936.98	151.86
10704	2021 09 28 05:35:00	13.6333	2936.24	151.81	13.6333	2936.96	151.86

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
10752	2021 09 28 05:39:00	13.7000	2936.26	151.81	13.7000	2936.97	151.86
10800	2021 09 28 05:43:00	13.7667	2936.26	151.81	13.7667	2936.95	151.86
10848	2021 09 28 05:47:00	13.8333	2936.29	151.81	13.8333	2936.98	151.86
10896	2021 09 28 05:51:00	13.9000	2936.30	151.81	13.9000	2936.94	151.86
10944	2021 09 28 05:55:00	13.9667	2936.27	151.81	13.9667	2936.95	151.86
10992	2021 09 28 05:59:00	14.0333	2936.31	151.81	14.0333	2936.94	151.86
11040	2021 09 28 06:03:00	14.1000	2936.32	151.81	14.1000	2936.99	151.86
11088	2021 09 28 06:07:00	14.1667	2936.30	151.81	14.1667	2936.95	151.86
11136	2021 09 28 06:11:00	14.2333	2936.29	151.81	14.2333	2936.96	151.86
11184	2021 09 28 06:15:00	14.3000	2936.28	151.80	14.3000	2936.95	151.86
11232	2021 09 28 06:19:00	14.3667	2936.30	151.80	14.3667	2936.99	151.86
11280	2021 09 28 06:23:00	14.4333	2936.28	151.80	14.4333	2936.97	151.86
11328	2021 09 28 06:27:00	14.5000	2936.33	151.80	14.5000	2936.94	151.86
11376	2021 09 28 06:31:00	14.5667	2936.30	151.80	14.5667	2936.98	151.86
11424	2021 09 28 06:35:00	14.6333	2936.27	151.80	14.6333	2936.97	151.86
11472	2021 09 28 06:39:00	14.7000	2936.32	151.80	14.7000	2936.96	151.86
11520	2021 09 28 06:43:00	14.7667	2936.27	151.80	14.7667	2936.98	151.86
11568	2021 09 28 06:47:00	14.8333	2936.29	151.80	14.8333	2936.98	151.86
11616	2021 09 28 06:51:00	14.9000	2936.31	151.80	14.9000	2936.98	151.86
11664	2021 09 28 06:55:00	14.9667	2936.29	151.80	14.9667	2936.95	151.86
11712	2021 09 28 06:59:00	15.0333	2936.32	151.80	15.0333	2936.97	151.86
11760	2021 09 28 07:03:00	15.1000	2936.29	151.80	15.1000	2936.98	151.86
11808	2021 09 28 07:07:00	15.1667	2936.29	151.80	15.1667	2936.99	151.86
11856	2021 09 28 07:11:00	15.2333	2936.29	151.80	15.2333	2936.98	151.86
11904	2021 09 28 07:15:00	15.3000	2936.33	151.80	15.3000	2936.97	151.86
11952	2021 09 28 07:19:00	15.3667	2936.32	151.80	15.3667	2936.97	151.86
12000	2021 09 28 07:23:00	15.4333	2936.30	151.80	15.4333	2936.98	151.86
12048	2021 09 28 07:27:00	15.5000	2936.32	151.80	15.5000	2936.98	151.86
12096	2021 09 28 07:31:00	15.5667	2936.31	151.80	15.5667	2937.00	151.86
12144	2021 09 28 07:35:00	15.6333	2936.31	151.80	15.6333	2936.99	151.86
12192	2021 09 28 07:39:00	15.7000	2936.33	151.80	15.7000	2936.99	151.86
12240	2021 09 28 07:43:00	15.7667	2936.30	151.80	15.7667	2936.98	151.86
12288	2021 09 28 07:47:00	15.8333	2936.30	151.80	15.8333	2937.00	151.86
12336	2021 09 28 07:51:00	15.9000	2936.35	151.80	15.9000	2937.00	151.86
12384	2021 09 28 07:55:00	15.9667	2936.33	151.80	15.9667	2936.99	151.85
12432	2021 09 28 07:59:00	16.0333	2936.32	151.80	16.0333	2936.99	151.86
12480	2021 09 28 08:03:00	16.1000	2936.32	151.80	16.1000	2936.98	151.85
12528	2021 09 28 08:07:00	16.1667	2936.33	151.80	16.1667	2937.00	151.86
12576	2021 09 28 08:11:00	16.2333	2936.34	151.80	16.2333	2937.00	151.86
12624	2021 09 28 08:15:00	16.3000	2936.31	151.80	16.3000	2936.98	151.86
12672	2021 09 28 08:19:00	16.3667	2936.33	151.80	16.3667	2936.99	151.86
12720	2021 09 28 08:23:00	16.4333	2936.34	151.80	16.4333	2936.99	151.86

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
12768	2021 09 28 08:27:00	16.5000	2936.35	151.79	16.5000	2936.96	151.86
12816	2021 09 28 08:31:00	16.5667	2936.35	151.80	16.5667	2937.00	151.86
12864	2021 09 28 08:35:00	16.6333	2936.33	151.80	16.6333	2937.02	151.86
12912	2021 09 28 08:39:00	16.7000	2936.36	151.80	16.7000	2936.99	151.86
12960	2021 09 28 08:43:00	16.7667	2936.33	151.80	16.7667	2936.98	151.85
13008	2021 09 28 08:47:00	16.8333	2936.34	151.80	16.8333	2936.98	151.86
13056	2021 09 28 08:51:00	16.9000	2936.32	151.80	16.9000	2937.01	151.85
13104	2021 09 28 08:55:00	16.9667	2936.32	151.80	16.9667	2936.99	151.86
13152	2021 09 28 08:59:00	17.0333	2936.34	151.80	17.0333	2937.01	151.86
13200	2021 09 28 09:03:00	17.1000	2936.30	151.80	17.1000	2936.99	151.85
13248	2021 09 28 09:07:00	17.1667	2936.34	151.80	17.1667	2937.00	151.86
13296	2021 09 28 09:11:00	17.2333	2936.34	151.80	17.2333	2936.97	151.85
13344	2021 09 28 09:15:00	17.3000	2936.31	151.79	17.3000	2937.02	151.85
13392	2021 09 28 09:19:00	17.3667	2936.32	151.80	17.3667	2937.00	151.85
13440	2021 09 28 09:23:00	17.4333	2936.34	151.80	17.4333	2937.02	151.85
13488	2021 09 28 09:27:00	17.5000	2936.34	151.79	17.5000	2936.99	151.85
13536	2021 09 28 09:31:00	17.5667	2936.37	151.79	17.5667	2937.04	151.85
13584	2021 09 28 09:35:00	17.6333	2936.35	151.80	17.6333	2936.99	151.85
13632	2021 09 28 09:39:00	17.7000	2936.32	151.79	17.7000	2937.02	151.85
13680	2021 09 28 09:43:00	17.7667	2936.33	151.79	17.7667	2936.99	151.85
13728	2021 09 28 09:47:00	17.8333	2936.34	151.79	17.8333	2937.00	151.85
13776	2021 09 28 09:51:00	17.9000	2936.34	151.79	17.9000	2937.01	151.85
13824	2021 09 28 09:55:00	17.9667	2936.31	151.80	17.9667	2936.99	151.85
13872	2021 09 28 09:59:00	18.0333	2936.35	151.79	18.0333	2937.02	151.85
13920	2021 09 28 10:03:00	18.1000	2936.34	151.79	18.1000	2937.02	151.85
13968	2021 09 28 10:07:00	18.1667	2936.33	151.79	18.1667	2937.03	151.86
14016	2021 09 28 10:11:00	18.2333	2936.32	151.79	18.2333	2937.03	151.86
14064	2021 09 28 10:15:00	18.3000	2936.31	151.79	18.3000	2937.03	151.86
14112	2021 09 28 10:19:00	18.3667	2936.36	151.80	18.3667	2937.00	151.85
14160	2021 09 28 10:23:00	18.4333	2936.34	151.79	18.4333	2937.05	151.85
14208	2021 09 28 10:27:00	18.5000	2936.36	151.80	18.5000	2937.01	151.85
14256	2021 09 28 10:31:00	18.5667	2936.33	151.79	18.5667	2937.02	151.85
14304	2021 09 28 10:35:00	18.6333	2936.34	151.79	18.6333	2936.99	151.85
14352	2021 09 28 10:39:00	18.7000	2936.34	151.79	18.7000	2937.00	151.85
14400	2021 09 28 10:43:00	18.7667	2936.33	151.79	18.7667	2937.04	151.85
14448	2021 09 28 10:47:00	18.8333	2936.35	151.79	18.8333	2937.04	151.85
14496	2021 09 28 10:51:00	18.9000	2936.33	151.79	18.9000	2936.99	151.85
14544	2021 09 28 10:55:00	18.9667	2936.35	151.79	18.9667	2937.01	151.85
14592	2021 09 28 10:59:00	19.0333	2936.36	151.79	19.0333	2937.01	151.85
14640	2021 09 28 11:03:00	19.1000	2936.39	151.80	19.1000	2937.03	151.85
14688	2021 09 28 11:07:00	19.1667	2936.36	151.79	19.1667	2937.01	151.85
14736	2021 09 28 11:11:00	19.2333	2936.33	151.79	19.2333	2937.04	151.85

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
14784	2021 09 28 11:15:00	19.3000	2936.39	151.79	19.3000	2937.00	151.85
14832	2021 09 28 11:19:00	19.3667	2936.34	151.79	19.3667	2937.01	151.85
14880	2021 09 28 11:23:00	19.4333	2936.35	151.79	19.4333	2937.04	151.85
14928	2021 09 28 11:27:00	19.5000	2936.35	151.79	19.5000	2937.06	151.85
14976	2021 09 28 11:31:00	19.5667	2936.33	151.79	19.5667	2937.02	151.85
15024	2021 09 28 11:35:00	19.6333	2936.33	151.79	19.6333	2937.03	151.85
15072	2021 09 28 11:39:00	19.7000	2936.38	151.79	19.7000	2937.05	151.85
15120	2021 09 28 11:43:00	19.7667	2936.34	151.79	19.7667	2937.00	151.85
15168	2021 09 28 11:47:00	19.8333	2936.37	151.79	19.8333	2937.03	151.85
15216	2021 09 28 11:51:00	19.9000	2936.36	151.79	19.9000	2937.02	151.85
15264	2021 09 28 11:55:00	19.9667	2936.37	151.79	19.9667	2937.05	151.85
15312	2021 09 28 11:59:00	20.0333	2936.32	151.79	20.0333	2937.03	151.85
15360	2021 09 28 12:03:00	20.1000	2936.35	151.79	20.1000	2937.04	151.85
15408	2021 09 28 12:07:00	20.1667	2936.36	151.79	20.1667	2937.04	151.85
15456	2021 09 28 12:11:00	20.2333	2936.34	151.79	20.2333	2937.03	151.85
15504	2021 09 28 12:15:00	20.3000	2936.35	151.79	20.3000	2937.03	151.85
15552	2021 09 28 12:19:00	20.3667	2936.34	151.79	20.3667	2937.03	151.85
15600	2021 09 28 12:23:00	20.4333	2936.35	151.79	20.4333	2937.01	151.86
15648	2021 09 28 12:27:00	20.5000	2936.36	151.79	20.5000	2937.00	151.85
15696	2021 09 28 12:31:00	20.5667	2936.37	151.79	20.5667	2937.00	151.85
15744	2021 09 28 12:35:00	20.6333	2936.38	151.80	20.6333	2937.04	151.85
15792	2021 09 28 12:39:00	20.7000	2936.38	151.79	20.7000	2937.06	151.85
15840	2021 09 28 12:43:00	20.7667	2936.31	151.79	20.7667	2937.02	151.85
15888	2021 09 28 12:47:00	20.8333	2936.33	151.79	20.8333	2937.02	151.85
15936	2021 09 28 12:51:00	20.9000	2936.36	151.79	20.9000	2937.05	151.85
15984	2021 09 28 12:55:00	20.9667	2936.35	151.79	20.9667	2937.03	151.85
16032	2021 09 28 12:59:00	21.0333	2936.36	151.79	21.0333	2937.03	151.85
16080	2021 09 28 13:03:00	21.1000	2936.36	151.79	21.1000	2937.04	151.85
16128	2021 09 28 13:07:00	21.1667	2936.33	151.79	21.1667	2937.00	151.85
16176	2021 09 28 13:11:00	21.2333	2936.36	151.79	21.2333	2937.01	151.85
16224	2021 09 28 13:15:00	21.3000	2936.38	151.79	21.3000	2937.04	151.85
16272	2021 09 28 13:19:00	21.3667	2936.34	151.79	21.3667	2937.03	151.85
16320	2021 09 28 13:23:00	21.4333	2936.37	151.79	21.4333	2937.03	151.85
16368	2021 09 28 13:27:00	21.5000	2936.36	151.79	21.5000	2937.03	151.85
16416	2021 09 28 13:31:00	21.5667	2936.35	151.79	21.5667	2937.03	151.85
16464	2021 09 28 13:35:00	21.6333	2936.36	151.79	21.6333	2937.03	151.85
16512	2021 09 28 13:39:00	21.7000	2936.38	151.79	21.7000	2937.01	151.85
16560	2021 09 28 13:43:00	21.7667	2936.37	151.79	21.7667	2937.05	151.85
16608	2021 09 28 13:47:00	21.8333	2936.37	151.79	21.8333	2937.03	151.85
16656	2021 09 28 13:51:00	21.9000	2936.37	151.79	21.9000	2937.06	151.85
16704	2021 09 28 13:55:00	21.9667	2936.39	151.79	21.9667	2937.05	151.85
16752	2021 09 28 13:59:00	22.0333	2936.35	151.79	22.0333	2937.02	151.85

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
16800	2021 09 28 14:03:00	22.1000	2936.36	151.79	22.1000	2937.02	151.85
16848	2021 09 28 14:07:00	22.1667	2936.40	151.79	22.1667	2937.02	151.85
16896	2021 09 28 14:11:00	22.2333	2936.39	151.79	22.2333	2937.07	151.85
16944	2021 09 28 14:15:00	22.3000	2936.37	151.79	22.3000	2937.04	151.85
16992	2021 09 28 14:19:00	22.3667	2936.36	151.79	22.3667	2937.03	151.85
17040	2021 09 28 14:23:00	22.4333	2936.38	151.79	22.4333	2937.04	151.85
17088	2021 09 28 14:27:00	22.5000	2936.38	151.79	22.5000	2937.05	151.85
17136	2021 09 28 14:31:00	22.5667	2936.37	151.79	22.5667	2937.04	151.85
17184	2021 09 28 14:35:00	22.6333	2936.40	151.79	22.6333	2937.03	151.85
17232	2021 09 28 14:39:00	22.7000	2936.35	151.79	22.7000	2937.05	151.85
17280	2021 09 28 14:43:00	22.7667	2936.37	151.79	22.7667	2937.04	151.85
17328	2021 09 28 14:47:00	22.8333	2936.36	151.79	22.8333	2937.03	151.85
17376	2021 09 28 14:51:00	22.9000	2936.39	151.79	22.9000	2937.07	151.85
17424	2021 09 28 14:55:00	22.9667	2936.37	151.79	22.9667	2937.03	151.85
17472	2021 09 28 14:59:00	23.0333	2936.37	151.79	23.0333	2937.02	151.85
17520	2021 09 28 15:03:00	23.1000	2936.37	151.79	23.1000	2937.05	151.85
17568	2021 09 28 15:07:00	23.1667	2936.33	151.79	23.1667	2937.04	151.85
17616	2021 09 28 15:11:00	23.2333	2936.33	151.79	23.2333	2937.02	151.85
17664	2021 09 28 15:15:00	23.3000	2936.38	151.79	23.3000	2937.02	151.85
17712	2021 09 28 15:19:00	23.3667	2936.37	151.79	23.3667	2937.02	151.85
17760	2021 09 28 15:23:00	23.4333	2936.35	151.79	23.4333	2937.04	151.85
17808	2021 09 28 15:27:00	23.5000	2936.35	151.79	23.5000	2937.03	151.85
17856	2021 09 28 15:31:00	23.5667	2936.37	151.79	23.5667	2937.05	151.85
17904	2021 09 28 15:35:00	23.6333	2936.38	151.80	23.6333	2937.01	151.85
17952	2021 09 28 15:39:00	23.7000	2936.35	151.80	23.7000	2937.08	151.86
18000	2021 09 28 15:43:00	23.7667	2936.37	151.79	23.7667	2937.06	151.85
18048	2021 09 28 15:47:00	23.8333	2936.36	151.79	23.8333	2937.03	151.86
18096	2021 09 28 15:51:00	23.9000	2936.37	151.79	23.9000	2937.02	151.86
18144	2021 09 28 15:55:00	23.9667	2936.35	151.79	23.9667	2937.01	151.85
18192	2021 09 28 15:59:00	24.0333	2936.36	151.79	24.0333	2937.07	151.86
18240	2021 09 28 16:03:00	24.1000	2936.38	151.80	24.1000	2937.00	151.85
18288	2021 09 28 16:07:00	24.1667	2936.36	151.79	24.1667	2937.03	151.85
18336	2021 09 28 16:11:00	24.2333	2936.37	151.79	24.2333	2937.02	151.85
18384	2021 09 28 16:15:00	24.3000	2936.39	151.79	24.3000	2936.99	151.85
18432	2021 09 28 16:19:00	24.3667	2936.39	151.79	24.3667	2937.02	151.85
18480	2021 09 28 16:23:00	24.4333	2936.38	151.79	24.4333	2937.05	151.85
18528	2021 09 28 16:27:00	24.5000	2936.35	151.79	24.5000	2937.02	151.85
18576	2021 09 28 16:31:00	24.5667	2936.37	151.79	24.5667	2937.04	151.85
18624	2021 09 28 16:35:00	24.6333	2936.37	151.79	24.6333	2937.04	151.85
18672	2021 09 28 16:39:00	24.7000	2936.36	151.79	24.7000	2937.07	151.85
18720	2021 09 28 16:43:00	24.7667	2936.36	151.79	24.7667	2937.03	151.85
18768	2021 09 28 16:47:00	24.8333	2936.34	151.79	24.8333	2937.02	151.85

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
18816	2021 09 28 16:51:00	24.9000	2936.37	151.79	24.9000	2937.02	151.85
18864	2021 09 28 16:55:00	24.9667	2936.36	151.79	24.9667	2937.01	151.85
18912	2021 09 28 16:59:00	25.0333	2936.35	151.79	25.0333	2937.06	151.85
18960	2021 09 28 17:03:00	25.1000	2936.37	151.79	25.1000	2937.01	151.85
19008	2021 09 28 17:07:00	25.1667	2936.39	151.79	25.1667	2937.04	151.85
19056	2021 09 28 17:11:00	25.2333	2936.36	151.79	25.2333	2937.04	151.85
19104	2021 09 28 17:15:00	25.3000	2936.38	151.79	25.3000	2937.01	151.85
19152	2021 09 28 17:19:00	25.3667	2936.39	151.79	25.3667	2937.02	151.85
19200	2021 09 28 17:23:00	25.4333	2936.36	151.79	25.4333	2937.07	151.85
19248	2021 09 28 17:27:00	25.5000	2936.37	151.79	25.5000	2937.04	151.85
19296	2021 09 28 17:31:00	25.5667	2936.38	151.79	25.5667	2937.02	151.85
19344	2021 09 28 17:35:00	25.6333	2936.39	151.79	25.6333	2937.04	151.85
19392	2021 09 28 17:39:00	25.7000	2936.31	151.79	25.7000	2937.03	151.85
19440	2021 09 28 17:43:00	25.7667	2936.35	151.80	25.7667	2937.05	151.85
19488	2021 09 28 17:47:00	25.8333	2936.39	151.79	25.8333	2937.04	151.85
19536	2021 09 28 17:51:00	25.9000	2936.36	151.79	25.9000	2937.03	151.85
19584	2021 09 28 17:55:00	25.9667	2936.34	151.79	25.9667	2937.06	151.86
19632	2021 09 28 17:59:00	26.0333	2936.38	151.79	26.0333	2937.06	151.86
19680	2021 09 28 18:03:00	26.1000	2936.38	151.79	26.1000	2937.02	151.85
19728	2021 09 28 18:07:00	26.1667	2936.35	151.79	26.1667	2937.02	151.85
19776	2021 09 28 18:11:00	26.2333	2936.37	151.80	26.2333	2937.05	151.85
19824	2021 09 28 18:15:00	26.3000	2936.36	151.79	26.3000	2937.02	151.85
19872	2021 09 28 18:19:00	26.3667	2936.42	151.79	26.3667	2937.07	151.85
19920	2021 09 28 18:23:00	26.4333	2936.37	151.79	26.4333	2937.05	151.85
19968	2021 09 28 18:27:00	26.5000	2936.37	151.79	26.5000	2937.00	151.85
20016	2021 09 28 18:31:00	26.5667	2936.33	151.79	26.5667	2937.04	151.85
20064	2021 09 28 18:35:00	26.6333	2936.35	151.79	26.6333	2937.03	151.85
20112	2021 09 28 18:39:00	26.7000	2936.39	151.79	26.7000	2937.03	151.85
20160	2021 09 28 18:43:00	26.7667	2936.36	151.79	26.7667	2937.04	151.85
20208	2021 09 28 18:47:00	26.8333	2936.38	151.79	26.8333	2937.03	151.85
20256	2021 09 28 18:51:00	26.9000	2936.34	151.79	26.9000	2936.99	151.85
20285	2021 09 28 18:53:25	26.9403	2936.41	151.79	26.9403	2937.09	151.85
					5975.00 ft KB-TVD- Off Bottom		
20304	2021 09 28 18:55:00	26.9667	2747.35	151.77	26.9667	2744.93	151.83
20352	2021 09 28 18:59:00	27.0333	2749.31	151.41	27.0333	2750.07	151.75
20400	2021 09 28 19:03:00	27.1000	2756.42	151.66	27.1000	2757.00	151.68
20448	2021 09 28 19:07:00	27.1667	2760.81	151.85	27.1667	2761.73	151.84
20496	2021 09 28 19:11:00	27.2333	2765.82	152.20	27.2333	2766.91	152.12
20544	2021 09 28 19:15:00	27.3000	2771.30	152.32	27.3000	2772.51	152.30
20592	2021 09 28 19:19:00	27.3667	2776.23	152.38	27.3667	2777.10	152.39
20640	2021 09 28 19:23:00	27.4333	2787.46	152.41	27.4333	2787.91	152.44
20688	2021 09 28 19:27:00	27.5000	2788.15	152.41	27.5000	2788.71	152.46

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
20736	2021 09 28 19:31:00	27.5667	2774.81	152.40	27.5667	2776.09	152.46
20784	2021 09 28 19:35:00	27.6333	2758.56	152.41	27.6333	2759.35	152.46
20832	2021 09 28 19:39:00	27.7000	2932.95	152.50	27.7000	2933.61	152.52
20880	2021 09 28 19:43:00	27.7667	2963.61	150.81	27.7667	2968.84	151.69
20928	2021 09 28 19:47:00	27.8333	2997.88	145.44	27.8333	3005.66	146.70
20976	2021 09 28 19:51:00	27.9000	3040.78	141.64	27.9000	3049.71	142.64
21024	2021 09 28 19:55:00	27.9667	2949.47	139.42	27.9667	2949.36	139.99
21072	2021 09 28 19:59:00	28.0333	2936.38	140.69	28.0333	2936.53	140.56
21120	2021 09 28 20:03:00	28.1000	2935.76	141.33	28.1000	2935.94	141.14
21168	2021 09 28 20:07:00	28.1667	2935.53	141.77	28.1667	2935.78	141.60
21216	2021 09 28 20:11:00	28.2333	2935.64	142.28	28.2333	2935.89	142.07
21264	2021 09 28 20:15:00	28.3000	2935.37	142.69	28.3000	2935.60	142.50
21312	2021 09 28 20:19:00	28.3667	2935.30	143.09	28.3667	2935.51	142.89
21360	2021 09 28 20:23:00	28.4333	2935.22	143.38	28.4333	2935.47	143.22
21408	2021 09 28 20:27:00	28.5000	2935.18	143.63	28.5000	2935.40	143.49
21438	2021 09 28 20:29:30	28.5417	2935.17	143.79	28.5417	2935.19	143.65
						Pulled Off Bottom	
21456	2021 09 28 20:31:00	28.5667	2908.06	144.95	28.5667	2908.44	144.46
21504	2021 09 28 20:35:00	28.6333	2907.48	145.88	28.6333	2908.00	145.73
21552	2021 09 28 20:39:00	28.7000	2878.16	146.01	28.7000	2875.12	145.99
21600	2021 09 28 20:43:00	28.7667	2798.66	144.65	28.7667	2799.14	144.84
21648	2021 09 28 20:47:00	28.8333	2719.79	142.78	28.8333	2714.63	143.16
21696	2021 09 28 20:51:00	28.9000	2629.59	140.11	28.9000	2630.01	140.93
21744	2021 09 28 20:55:00	28.9667	2515.15	137.19	28.9667	2509.25	138.01
21792	2021 09 28 20:59:00	29.0333	2432.27	134.64	29.0333	2432.47	135.49
21840	2021 09 28 21:03:00	29.1000	2315.63	131.83	29.1000	2320.02	132.32
21888	2021 09 28 21:07:00	29.1667	1946.30	130.35	29.1667	1939.87	130.18
21936	2021 09 28 21:11:00	29.2333	2116.73	128.61	29.2333	2117.35	128.81
21984	2021 09 28 21:15:00	29.3000	1863.48	131.17	29.3000	1864.03	130.87
22032	2021 09 28 21:19:00	29.3667	1715.35	131.94	29.3667	1709.50	131.28
22080	2021 09 28 21:23:00	29.4333	1674.00	131.87	29.4333	1674.16	130.67
22128	2021 09 28 21:27:00	29.5000	1314.92	130.24	29.5000	1241.41	130.20
22176	2021 09 28 21:31:00	29.5667	1161.92	124.85	29.5667	1215.69	124.95
22224	2021 09 28 21:35:00	29.6333	1334.67	119.26	29.6333	1335.20	119.56
22272	2021 09 28 21:39:00	29.7000	1231.57	119.61	29.7000	1224.47	119.71
22320	2021 09 28 21:43:00	29.7667	1194.94	112.92	29.7667	1195.07	113.29
22368	2021 09 28 21:47:00	29.8333	1080.17	109.49	29.8333	1080.05	109.77
22416	2021 09 28 21:51:00	29.9000	1069.25	106.48	29.9000	1069.57	106.57
22464	2021 09 28 21:55:00	29.9667	1036.89	106.12	29.9667	1037.06	105.87
22512	2021 09 28 21:59:00	30.0333	1005.20	104.25	30.0333	1005.45	104.17
22560	2021 09 28 22:03:00	30.1000	1005.50	103.01	30.1000	1005.68	103.10
22608	2021 09 28 22:07:00	30.1667	1005.54	101.93	30.1667	1005.69	102.12

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
22656	2021 09 28 22:11:00	30.2333	940.81	101.03	30.2333	941.01	100.93
22704	2021 09 28 22:15:00	30.3000	941.00	99.90	30.3000	941.18	99.88
22752	2021 09 28 22:19:00	30.3667	909.14	96.90	30.3667	909.28	97.07
22800	2021 09 28 22:23:00	30.4333	875.94	94.53	30.4333	876.07	94.78
22848	2021 09 28 22:27:00	30.5000	848.54	94.37	30.5000	848.04	94.48
22896	2021 09 28 22:31:00	30.5667	752.92	93.91	30.5667	764.76	93.49
22944	2021 09 28 22:35:00	30.6333	333.72	89.26	30.6333	564.03	89.12
22992	2021 09 28 22:39:00	30.7000	549.23	84.36	30.7000	539.07	84.07
23040	2021 09 28 22:43:00	30.7667	491.26	79.56	30.7667	490.68	79.56
23088	2021 09 28 22:47:00	30.8333	523.88	78.96	30.8333	516.81	79.11
23136	2021 09 28 22:51:00	30.9000	594.72	73.26	30.9000	595.80	72.92
23184	2021 09 28 22:55:00	30.9667	1716.90	70.66	30.9667	1709.33	71.12
23232	2021 09 28 22:59:00	31.0333	457.19	70.66	31.0333	456.41	71.04
23280	2021 09 28 23:03:00	31.1000	466.16	71.17	31.1000	467.09	71.29
23328	2021 09 28 23:07:00	31.1667	461.42	72.58	31.1667	461.52	72.51
23376	2021 09 28 23:11:00	31.2333	464.67	73.80	31.2333	465.66	73.58
23424	2021 09 28 23:15:00	31.3000	305.66	75.13	31.3000	294.68	75.07
23472	2021 09 28 23:19:00	31.3667	251.09	73.74	31.3667	251.38	74.05
23520	2021 09 28 23:23:00	31.4333	158.63	74.22	31.4333	158.81	73.96
23568	2021 09 28 23:27:00	31.5000	44.59	76.96	31.5000	43.58	76.84
23616	2021 09 28 23:31:00	31.5667	43.04	74.38	31.5667	43.78	74.16
23664	2021 09 28 23:35:00	31.6333	13.55	74.74	31.6333	13.42	74.72

APPENDIX D

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

Permit Item	NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
Pore Space Amalgamation	NDCC 38-22-06 §3 & 4 NDAC 43-05-01-08 §1 & 2	**NDCC 38-22-06** 3. Notice of the hearing must be given to each mineral lessee, mineral owner, and pore space owner within the storage reservoir and within one-half mile of the storage reservoir's boundaries. 4. Notice of the hearing must be given to each surface owner of land overlying the storage reservoir and within one-half mile of the reservoir's boundaries. **NDAC 43-05-01-08** 1. The commission shall hold a public hearing before issuing a storage facility permit. At least forty-five days prior to the hearing, the applicant shall give notice of the hearing to the following: a. Each operator of mineral extraction activities within the facility area and within one-half mile [.80 kilometer] of its outside boundary; b. Each mineral lessee of record within the facility area and within one-half mile [.80 kilometer] of its outside boundary; c. Each owner of record of the surface within the facility area and one-half mile [.80 kilometer] of its outside boundary; d. Each owner of record of minerals within the facility area and within one-half mile [.80 kilometer] of its outside boundary; e. Each owner and each lessee of record of the	a. An affidavit of mailing certifying that all pore space owners and lessees within the storage reservoir boundary and within one-half mile outside of its boundary have been notified of the proposed carbon dioxide storage project;	**1.0 PORE SPACE ACCESS (2nd paragraph, p. 1-1)** Dakota Gasification Company (DGC) has identified the owners (surface and mineral). In addition, with the exception of coal extraction, there are no mineral lessees or operators of mineral extraction activities within the facility area or within 0.5 miles of its outside boundary. DGC will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made.	N/A
			b. A map showing the extent of the pore space that will be occupied by carbon dioxide over the life of the project;	**1.0 PORE SPACE ACCESS (p. 1-1)** North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate, i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] Chapter 47-31 – Subsurface Pore Space Policy). Prior to issuance of the storage facility permit (SFP), the storage operator is mandated by the North Dakota statute governing geologic storage of carbon dioxide (CO_2) to obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir. The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation. Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application (NDCC §§ 38-22-06[3] and 38-22-06[4] and North Dakota Administrative Code [NDAC] §§ 43-05-01-08[1] and 43-05-01-08[2]). Dakota Gasification Company (DGC) has identified the owners (surface and mineral). In addition, with the exception of coal extraction, there are no mineral lessees or operators of mineral extraction activities within the facility area or within 0.5 miles of its outside boundary. DGC will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made. All owners, lessees, and operators that require notification have been identified in accordance with North Dakota law, which vests the title to the pore space in all strata underlying the surface of lands and water to the owner of the overlying surface estate (NDCC Chapter 47-31). The identification of pore space owners indicates that there was no severance of pore space or leasing of pore space to a third-party from the surface estate prior to 2009. Maps showing the extent of the pore space that will be occupied by CO_2 over the life of the project, including the storage reservoir boundary and 0.5 miles (0.8 kilometers) outside of the storage reservoir boundary with a description of pore space ownership, surface owner, and pore space lessees of record are illustrated in Figures 1-1 and 1-2.	Figure 1-1. Storage facility area map showing pore space ownership and Figure 1-2 (p. 1-2) Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area. (p. 1-3)
			c. A map showing the storage reservoir boundary and one-half mile outside of the storage reservoir boundary with a description of pore space ownership;		Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area. (p. 1-3).
			d. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each operator of mineral extraction activities;		Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area. (p. 1-3).
			e. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each mineral lessee of record;		
			f. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each surface owner of record;		Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area. (p 1-3).
			g. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each owner of record of minerals.		Figure 1-2. Hearing notification area for landowners within ½ mile of

		pore space within the storage reservoir and within one-half mile [.80 kilometer] of the reservoir's boundary; and f. Any other persons as required by the commission. 2. The notice given by the applicant must contain: a. A legal description of the land within the facility area. b. The date, time, and place that the commission will hold a hearing on the permit application. c. A statement that a copy of the permit application and draft permit may be obtained from the commission.			the storage facility area. (p. 1-3).
Geologic Exhibits	NDAC 43-05-01-05 §1b(1)	**NDAC 43-05-01-05 §1b(1)** (1) The name, description, and average depth of the storage reservoirs;	a. Geologic description of the storage reservoir: Name Lithology Average depth Average thickness	**2.1 Overview of Project Area Geology (p. 2-1)** The proposed DGC Great Plains CO_2 Sequestration Project will be situated near Beulah, North Dakota (Figure 2-1). This project site is on the central portion of the Williston Basin. The Williston Basin is an intracratonic sedimentary basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted via the PCOR Partnership, the Williston Basin has been identified as an excellent candidate for long-term CO_2 storage because of, in part, the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structure character and tectonic stability (Peck and others, 2014; Glazewski and others, 2015). The target CO_2 storage reservoir for the Great Plains CO_2 Sequestration Project is the Broom Creek Formation, a predominantly sandstone horizon lying about 5,900 ft below DGC's Great Plains Synfuels Plant (Figure 2-2). Mudstones, siltstones, and interbedded evaporites of the Opeche Formation unconformably overly the Broom Creek and serve as the primary confining zone (Figure 2-3). The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-3). Together, the Opeche, Broom Creek, and Amsden comprise the CO_2 storage complex for the Great Plains CO_2 Sequestration Project (Table 2-1). Including the Opeche Formation, there is ~1,100 ft of impermeable formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation. An additional ~2,700 ft of impermeable intervals separates the Inyan Kara and the lowest USDW, the Fox Hills Formation (Figure 2-3).	Figure 2-1. Topographic map of the Great Plains CO_2 Sequestration Project area showing well locations and the Great Plains Synfuels Plant (p. 2-2) Figure 2-2. Map of the proposed CO_2 injection wells (p. 2-3) Figure 2-3. Stratigraphic column identifying the storage reservoir, confining zones, and lowest USDW addressed in this permit application for the Great Plains CO_2 Sequestration Project (p. 2-4) Table 2-1. Formations Comprising the Great Plains CO2 Sequestration Project Storage Complex (p. 2-5)

				Table 2-1. Formations Comprising the Great Plains CO_2 Sequestration Project Storage Complex (average values calculated from the simulation model and well log data) | | Formation | Purpose | Average Thickness, ft | Average Measured Depth (MD), ft | Lithology | | **Storage Complex** | Opeche | Upper confining zone | 150 | 4,887 | Mudstone, siltstone, evaporites | | | Broom Creek | Storage reservoir (i.e., injection zone) | 248 | 5,348 | Sandstone, dolostone, dolomitic sandstone, anhydrite | | | Amsden | Lower confining zone | 268 | 5,558 | Dolostone, limestone, anhydrite |	
	NDAC 43-05-01-05 §1b(2)(k)	**NDAC 43-05-01-05 §1b(2)(k)** (k) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	b. Data on the injection zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs: Depth Areal extent Thickness Mineralogy Porosity Permeability Capillary pressure Facies changes	SOURCE OF THE DATA: ***2.2.1 Existing Data* (p. 2-3)** The existing data used to characterize the geology beneath the Great Plains CO_2 Sequestration Project site included publicly available well logs and formation top depths acquired from the North Dakota Industrial Commission's (NDIC's) online database. Well log data and interpreted formation top depths were acquired for 120 wellbores within a 5472-mi^2 (72 × 76-mi) area centered on the proposed storage site (Figure 2-4). Well data were used to characterize the depth, thickness, and extent of the subsurface geologic formations. Existing laboratory measurements from Broom Creek Formation core samples were available from five wells shown in Figure 2-5: Coteau 1 (NDIC File No. 38379), Flemmer 1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), J-LOC1 (NDIC File No. 37380), J-ROC1 (NDIC File No. 37672), and ANG #1 (North Dakota Department of Environmental Quality [NDEQ] No. 11308). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and integrated with newly acquired site-specific data. Ten square miles of legacy 3D seismic data from Mercer County, encompassing the Flemmer 1 wellsite, and twenty-eight miles of legacy 2D seismic data were licensed and examined to understand the heterogeneity and geologic structure of the Broom Creek Formation interval. Additionally, publicly available seismic interpretation products for the Broom Creek from a 3D seismic survey in Oliver County were used to inform structure and variogram distributions (Section 3.2). The structural configurations of the formations of interest generated from the interpretation of the two 3D seismic data sets along with formation tops interpreted from well log data were used to construct the geologic model. Variogram distributions derived from inversion volumes generated using the 3D seismic data were used to inform property distribution in the geologic model which was, in turn, used to simulate migration of the CO_2 plume. These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 5). DATA ON THE INJECTION ZONE: **2.3 Storage Reservoir (injection zone) (p. 2-12)** Locally, the Broom Creek Formation is laterally extensive (Figure 2-7) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). **2.3 Storage Reservoir (injection zone) (p. 2-12)** Locally, the Broom Creek Formation is laterally extensive (Figure 2-7) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone, siltstones, and evaporites of the Opeche Formation (Figure 2-3).	Figure 2-4. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones (p. 2-5) Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (modified from Rygh and others [1990]). Based on new well control shown outside of the green dashed line. (p. 2-13)

At Coteau 1, the Broom Creek Formation is 258 ft thick; is made up of 134 ft of sandstone, 35 ft of dolostone, 24 ft of anhydrite, and 65 ft of dolomitic sandstone; and is located at a depth of 5,906 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 163 to 322 ft (Figure 2-8), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 24 to 205 ft, with an average of 99 ft.

The top of the Broom Creek Formation was picked across the model area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-9). The top of the Amsden Formation was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that can be correlated across the entirety of the Great Plains CO2 Sequestration Project Area. 2D seismic data collected as part of site characterization efforts were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and analyses indicate that there should be few-to-no major reservoir stratigraphic discontinuities near the Coteau 1 well (Figures 2-10 and 2-11). The Broom Creek Formation is estimated to pinch out ~34 miles to the east of the Coteau 1 wellsite. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Great Plains CO2 Sequestration Project Area (Figure 2-12 and Figure 2-13). (p. 2-14)

Twenty-two 1-inch-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the Coteau 1 well. From the twenty-two samples, three samples at 5,941.95', 5,969.9', and 5,994.4' were duplicated and oriented 90 degrees compared to the original core plug to investigate the possibility of any orientation-dependent permeability existing in the reservoir. The remaining nineteen core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the Coteau 1 Broom Creek Formation core samples have porosity values ranging from 1.41% to 34.39% at 800 psi and 7.88% to 30.34% at 2400 psi. Permeabilities range from 0.13 to 12,300 mD at 800 psi and 0.118 to 3,990 mD at 2400 psi (Table 2-7). The wide range in porosity and permeability reflects the differences between the sandstone and dolostone lithofacies in the Broom Creek Formation. Portions of the Broom Creek Formation core revealed unconsolidated or poorly consolidated sandstone.

***2.3.1 Mineralogy* (p. 2-23)**

XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation core primarily comprises quartz, feldspar, carbonates, anhydrite, clay, and other minor minerals (Figure 2-19) .

XRF data are shown in Figure 2-20 for the Broom Creek Formation. Sandstone and dolomite intervals are confirmed through the high percentages of SiO_2 (71%–98%), CaO (19%–36%), and MgO (13%–21%). The high percentage of CaO and SO_3 at 5,908.1, 6,141, and 6,154.2 ft indicate a presence of anhydrite beds. The formation shows little volumes of clay, with a range of 0.04% to 10.54% for all samples.

Table 2-9. XRD Results for Coteau 1 Broom Creek Core Sample

Mineral Data	%
Albite	2.25
Anhydrite	15.17
Anorthite	1.96
Dolomite	23.91
Illite	2.85
Pyrite	0.13
Quartz	54.15

Figure 2-3. Stratigraphic column identifying the storage reservoir, confining zones, and lowest USDW addressed in this permit application for the Great Plains CO_2 Sequestration Project (p. 2-4)

Figure 2-8. Isopach map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project Area (p. 2-14)

Figure 2-9. Well log display of the interpreted lithologies of the Opeche, Broom Creek, and upper Amsden Formations in the Coteau 1 well (p. 2-15)

Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-16)

Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-17)

Figure 2-12. Structure map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops). (p. 2-18)

Figure 2-13. Cross section of the Great Plains CO_2 Sequestration Project storage complex from the geologic

Table 2-7. Description of CO_2 Storage Reservoir (injection zone) at the Coteau 1 Well Injection Zone Properties

Property	Description		
Formation Name	Broom Creek		
Lithology	Sandstone, dolostone, dolomitic sandstone, anhydrite		
Formation Top Depth, ft	5,906		
Thickness, ft	Sandstone 134 Dolostone 35 Dolomitic sandstone 65 Anhydrite 24		
Capillary Entry Pressure (CO_2/brine), psi	0.72		
Geologic Properties			
Formation	**Property**	**Laboratory Analysis**	**Simulation Model Property Distribution**
Broom Creek (sandstone)	Porosity, %*	21.28 (7.88–30.34)	23.64 (3.65–35.77)
	Permeability, mD**	221.84 (2.92–3,990)	246.74 (0.001–3,379)
Broom Creek (dolostone)	Porosity, %	8.79 (8.66–8.94)	5.68 (0.1–25.99)
	Permeability, mD	0.180 (0.118–0.361)	0.02 (0–220)

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
** Permeability values are reported as the geometric mean followed by the range of values in parentheses.

2.3.3 Geochemical Information of Injection Zone

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

The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package GEM. GEM is also the primary simulation software used for evaluation of the reservoir's dynamic behavior resulting from the expected CO_2 injection. For this geochemical modeling study, the injection scenario consisted of a single injection well injecting for a 12-year period with maximum BHP and maximum gas injection rate (STG) constraints of 3,833 psi and 25 MMcfd (468,000 tonnes/year), respectively. A postinjection period of 25 years was run in the model to evaluate any dynamic behavior and/or geochemical reaction after the CO_2 injection is stopped. This geochemical scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared (Figure 2-21).

model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. (p. 2-20)

Table 2-7. Description of CO_2 Storage Reservoir (injection zone) at the Coteau 1 Well Injection Zone Properties (p. 2-19)

Figure 2-19. Described core and laboratory-derived mineralogic characteristics of the Opeche, Broom Creek, and Amsden Formations (p. 2-26)

Figure 2-20. XRF data from the Broom Creek Formation from the Coteau 1 (p. 2-27)

Table 2-9. XRD Results for Coteau 1 Broom Creek Core Sample (p. 2-31)

Figure 2-21. Upper graph shows cumulative injection vs. time; the bottom figure shows the gas injection rate vs. time. There is no observable difference in injection due to geochemical reactions (p. 2-29)

Figure 2-22. 2D map showing the water salinity plume from the disposal wells, ANG #1 and ANG #2, and the gas mole fraction (CO_2) for the expected injection scenario for this project described in Section 3 consisting of six CO_2 injection wells. The lower map shows the stabilized CO_2 plume vs. the salinity plume extent after 10 years postinjection, in July 2044. (p. 2-30)

Table 2-9. XRD Results for Coteau 1 Broom Creek Core Sample (p. 2-31)

Table 2-10. Broom Creek Water Ionic Composition, expressed in molality (p. 2-31)

				Simulation results indicate that the low-salinity plume (TDS 8,050 ppm) associated with the ANG #1 and ANG #2 disposal water and the injected CO_2 plume for the six-well injection scenario discussed in Section 3 may have little interaction after 10 years of postinjection (Figure 2-22). Based on this limited interaction of the injected CO_2 and the injected disposal water and the chemical composition of the disposal water, the ANG disposal well injection was not included as part of the geochemical modeling for computational efficiency. The historical ANG well injection up to August 2021 was included during the modeling. Geochemical alteration effects were seen in the geochemistry case, as described below. However, these effects were not significant enough to cause meaningful changes to the storage reservoir performance of the storage formation. For more details regarding the geochemical information of injection zone, see Section 2.3.3 on page 2-27.	Table 2-11. ANG #1 Water Ionic Composition, expressed in molality (p. 2-31) Figure 2-23. BHP and WHP vs. time. There is no observable difference in injection pressure due to geochemical reactions as compared to the results without the geochemical model. (p. 2-32) Figure 2-24a. CO_2 molality for the geochemistry case simulation results after 12 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east and right upper are north-south cross sections. Lower image is a planar view of simulation in layer k = 11. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-33) Figure 2-24b. CO2 molality for the non-geochemistry model (bottom) results after 12 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east and right upper are north-south cross sections. Lower image is a planar view of simulation in layer k = 11. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-34) Figure 2-25. Geochemistry case simulation results after 12 years of injection + 25 years postinjection showing the pH of formation brine in log scale. White grid cells correspond to cells omitted from calculations because of having porosity

					and/or permeability values that round to zero. (p. 2-35) Figure 2-26. Dissolution and precipitation quantities of reservoir minerals because of CO_2 injection. Dissolution of anorthite with precipitation of pyrite, albite, and dolomite was observed. Upper figure shows all the minerals; the lower figure is rescaled for better view of the minerals mass change except pyrite. (p. 2-36) Figure 2-27. Change in molar distribution of anorthite, the most prominent dissolved mineral at the end of the 12-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-37) Figure 2-28. Change in molar distribution of albite, a precipitated mineral at the end of the 12-year injection + 25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-38) Figure 2-29. Change in molar distribution of dolomite, a precipitated mineral at the end of the 12-year injection + 25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-39) Figure 2-30. Change in molar distribution of pyrite, the most prominent precipitated mineral at the end of the 12-year injection + 25 years

postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-40)

c. Data on the confining zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:
   - Depth
   - Areal extent
   - Thickness
   - Mineralogy
   - Porosity
   - Permeability
   - Capillary pressure
   - Facies changes

SOURCE OF THE DATA:
See discussion above under 2.2.1 Existing Data (p. 2-3 and 2-6)

DATA ON THE CONFINING ZONE:
See Figures 2-10 through 2-12 and Figure 2-19

AND

2.4 Confining Zones (p. 2-41)
The confining zones for the Broom Creek Formation are the Opeche interval and underlying Amsden Formation (Figure 2-3, Table 2-12). Both the Amsden and Opeche intervals consist of impermeable rock layers.

Table 2-12. Properties of Upper and Lower Confining Zones in Simulation Area (data based on the Coteau 1 well)

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Opeche	Amsden
Primary Lithology	Silty mudstone	Dolostone
Formation Top Depth, ft	5,763	6,164
Thickness, ft	143	300
Porosity, % (core data) *	6.93	2.40
Permeability, mD (core data) **	0.002878	0.00116
Capillary Entry Pressure (CO_2/brine), psi	138.68	251.27
Depth below Lowest Identified USDW, ft	4,658	5,059

* Porosity values are reported as the arithmetic mean.
** Permeability values are reported as the geometric mean.

***2.4.1 Upper Confining Zone* (p. 2-41)**
In the Great Plains CO_2 Sequestration Project area, the Opeche Formation consists of silty mudstone and anhydrite. The upper confining zone (Opeche) is laterally extensive across the Great Plains CO_2 Sequestration Project area (Figure 2-31). The upper

Table 2-12. Properties of Upper and Lower Confining Zones in Simulation Area (p. 2-41)

Figure 2-31. Areal extent of the Opeche Formation in North Dakota (p. 2-42)

Figure 2-32. Structure map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (p. 2-43)

Figure 2-33. Isopach map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (p. 2-44)

Figure 2-34. Well log display of the upper confining zone at the Coteau 1 well (p. 2-45)

Figure 2-38. XRD data for the Opeche Formation from the Coteau 1 (p. 2-49)

				confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche interval is 5,763 ft below the land surface and 143 ft thick at the Coteau 1 wellsite (Table 2-12, Figures 2-32 and 2-33). The contact between the upper confining zone and underlying Broom Creek sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact (Figure 2-34). Microfracture in situ stress tests were not performed within the Opeche Formation in the Coteau 1 well. Microfracture in situ tests were performed using the MDT tool in the Flemmer 1 well, in the Opeche Formation, at a depth of 6,262 ft, which yielded results within good confidence. The MDT tool was able to cause breakdown in the formation at 8,157 psi. Propagation pressure for two cycles in close agreement were 4,879 and 5,085 psi, resulting in an average propagation pressure gradient of 0.80 psi/ft (Figure 2-35). In situ fluid pressure testing was not performed in the Opeche Formation with the MDT tool. The CMR log shown in Figure 2-36 suggests that because of the low to almost zero permeability the fluid within the Opeche is pore- and capillary-bound fluid and not mobile. This is confirmed by unsuccessful attempts by others to extract fluid samples from the Opeche. The Tundra SGS (secure geologic storage) and Red Trail Energy storage facility permit applications describe unsuccessful attempts to draw down reservoir fluid in order to determine the reservoir pressure or to collect an in situ fluid sample; the formation was unable to rebound (build pressure) because of low to almost zero permeability (NDIC, 2021a, b). These unsuccessful attempts provide further evidence of the confining properties of the Opeche Formation, ensuring sufficient geologic integrity to contain the injected carbon dioxide stream. Laboratory measurements from the Opeche Formation core samples taken from the Coteau 1 well indicate a porosity value of 6.93% at 800 psi and 6.62% at 2,400 psi and geometric average permeability values of 0.002878 mD at 800 psi and 0.002083 mD at 2,400 psi. The lithology of the cored sections of the Opeche is primarily silty mudstone. *2.4.1.1 Mineralogy* (p. 2-48) Thin-section investigation shows that the Opeche Formation comprises alternating intervals of very fine silty mudstone and mudstone. In all, five thin sections were created over the 73 ft of core collected from the Opeche Formation. The mineral components present are clay, quartz, anhydrite, feldspar, dolomite, and iron oxides. The coarser grains are almost always surrounded by anhydrite or clay as cement or matrix. The observable porosity is very low and is due to the dissolution of quartz and feldspar. The porosity ranges between 5% and 9%. Permeability is very poor and ranges between 0.00026 to 0.0227 mD. Figure 2-37 shows examples of the texture, fabric, and nature of observable porosity for the intervals where thin sections were created. As shown, observable porosity (shown in blue) is generally isolated and not well connected throughout. Additionally, thin-section analysis shows the fine-grained, well-compacted nature of the intervals evaluated. XRD data from the five Opeche samples of the Coteau 1 core supported facies interpretations from core descriptions and thin-section analysis. The Opeche Formation mainly comprises clay, quartz, feldspar, dolomite, and anhydrite. Figure 2-38 shows the mineralogy determined from XRD data for the five samples tested through the cored interval of the Opeche Formation. XRF analysis of the Opeche Formation shown in Figure 2-39 identifies SiO_2 (44%–57%), Al_2O_3 (6%–18%), CaO (5%–15%), and MgO (3%–9%) as the major chemical constituents, correlating well with the silicate, carbonate, and aluminum-rich mineralogy determined by XRD. This is in good agreement with XRD, core description, and thin-section analysis. *2.4.1.2 Geochemical Interaction (p. 2-50)* Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected CO2 stream on the Opeche Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 and minor amounts of H2S at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Opeche by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the Opeche Formation. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock –CO_2/H_2S exposure boundary. The mineralogical composition of the Opeche Formation was honored (Table 2-13). The XRD data used to define mineral composition in the model correspond to a mudstone sample from the Opeche Formation. Formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone below (Table 2-14). The CO_2 stream composition was as described in Table 2-15. 96.45 mol% of the stream is CO_2, and the rest represents other components, including H_2S, the second major component of the stream. 96 mol% of CO_2 was used in the simulation instead of 96.45 mol% to keep the model input simple (Table 2.15). The 4 mol% H2S used for this simulation represents the sum of all other components (CH_4, C_2H_6, C_3H_8, N_2) and thus overstates the actual H2S fraction of 1.23 mol% (Table 2-15). The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr.	Figure 2-39. XRF data for the Opeche Formation from the Coteau 1 (p. 2-49) Table 2-13. Mineral Composition of the Opeche Derived from XRD Analysis of Coteau 1 Core Samples (p. 2-50) Table 2-14. Formation Water Chemistry from Broom Creek Fluid Samples from Coteau 1 (p. 2-50) Table 2-15. Composition of the Injection Stream (p. 2-51) Table 2-16. Description of Zones of Confinements above the Immediate Upper Confining Zone (Opeche) (p. 2-50) Figure 2-46. Structure map of the Amsden Formation across the greater Great Plains CO_2 Sequestration Project area (p. 2-57) Figure 2-47. Isopach of the Amsden Formation across the greater Great Plains CO_2 Sequestration Project area (p. 2-58) Figure 2-48. XRD data for the Amsden Formation from the Coteau 1 (p. 2-60) Figure 2-49. XRF data for the Amsden Formation from the Coteau 1 (p. 2-60)

This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). This overestimate was done to ensure that the degree and pace of geochemical change would not be underestimated. This geochemical simulation was run for 37 years to match the reservoir injection zone geochemical model and represent 12 years of injection plus 25 years of postinjection. The simulation was performed at reservoir pressure and temperature conditions.

For more details on Geochemical interaction of the confining zone, refer to section 2.4.1.2 on page 2-51.

2.4.2 Additional Overlying Confining Zones **(p. 2-54)**
Several other formations provide additional confinement above the Opeche interval. Impermeable rocks above the primary seal include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-16). Together with the Opeche interval, these formations are 1,106 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-44). Above the Inyan Kara Formation, 2,657 ft of impermeable rocks act as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (Figure 2-44). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-16).

Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (Opeche) (data based on the Coteau 1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,753	1,931	0
Greenhorn	Shale	3,685	376	1,931
Mowry	Shale	4,061	94	2,307
Skull Creek	Shale	4,156	254	2,402
Swift	Shale	4,800	411	3,046
Rierdon	Shale	5,212	205	3,458
Piper (Kline Member)	Limestone	5,417	112	3,663
Piper (Picard Member)	Shale	5,529	233	3,775

2.4.3 Lower Confining Zones **(p. 2-57)**
The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, mudstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that can be correlated across the Great Plains CO_2 Sequestration Project area (Figure 2-6). The Amsden Formation is 6,164 ft below land surface and approximately 300 ft thick at the Coteau 1 well (Figures 2-46 and 2-47, Table 2-12).

The contact between the overlying Broom Creek and Amsden Formations is evident on wireline logs as there is a lithological change from the porous sandstones of the Broom Creek Formation to the dolostone and anhydrite beds of the Amsden Formation. This lithologic change is recognized in the core from the Coteau 1 well. The lithology of the cored section of the Amsden Formation from the Coteau 1 well is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Data acquired from the six core plug samples taken from the Amsden Formation show porosity values ranging from 1.00% to 5.27% at 800 psi and 0.91% to 4.54% at 2,400 psi. Permeability values range from 0.0000557 to 1.2 mD at 800 psi and 0.0000642 to 0.215 mD at 2,400 psi (Table 2-17).

2.4.3.1 Mineralogy (p. 2-59)
Thin-section analysis shows that the Amsden Formation comprises dolomite, anhydrite, sandy dolomite, and shaly sand. Six thin sections were created and described for the 83-ft cored Amsden section. The dolomite is expressed by very fine to fine-sized

				dolomite crystals with the presence of quartz of variable size and shape, feldspar, clay, anhydrite, and iron oxides. The porosity is very low and is mainly intragranular because of dissolution with an average of 2%. Anhydrite is present as beds, nodules, and laminations in association with the dolomite intervals. Minor iron oxides inclusions are present. The porosity is almost nonexistent. The dolomite is mainly composed of dolomite crystals and grains of quartz. Minor iron oxides and feldspar are present, with rare occurrence of anhydrite observed. The grains of quartz are almost always separated by dolomite matrix. The porosity is mainly due to the dissolution of feldspar and averages 1%. Finally, the anhydritic sandstone interval is composed of quartz, clay, carbonates, and anhydrite. Iron oxides are present in some parts of the rock matrix as rims around some quartz grains and mostly fill the stylolite surfaces and some rare fractures. The grains of quartz are almost always separated by carbonate cement, clay minerals and, specifically, anhydrite cement. In this lithofacies, anhydrite acts as cement in most parts of the interval by connecting sand grains together and decreasing the overall porosity of the lithofacies. The porosity averages 3% and is mainly due to the dissolution of feldspar and quartz (Figure 2-48). XRD was performed (Figure 2-49), and the results confirm the observations made during core analyses and thin-section description. XRF data shows that the Amsden Formation at the contact with the Broom Creek is dominated by CaO and MgO (major chemical components of dolomite). Deeper samples are more anhydrite-rich, fine- to medium-grained sandstones, as shown by the high percentage of SiO_2, CaO, and SO_3 (Figure 2-50).	
	NDAC 43-05-01-05 §1b(2) ¶	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or	d. A description of the storage reservoir's mechanisms of geologic confinement characteristics with regard to preventing migration of carbon dioxide beyond the proposed storage reservoir, including: Rock properties Regional pressure gradients Adsorption processes	*2.2.2.3 Formation Temperature and Pressure* (2nd paragraph, p. 2-9) Temperature data recorded from logging the Coteau 1 and Flemmer 1 wellbores were used to derive a temperature gradient for the proposed injection site (Tables 2-2 and 2-3). In combination with depth, the temperature gradient was used to distribute a temperature property throughout the geologic model of the Great Plains CO2 Sequestration Project area. The temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for the geochemical modeling. The formation pressure and temperature at Coteau 1 were collected with a bottomhole pressure (BHP) gauge. In the Coteau 1 well, the Broom Creek was perforated at 5975 ft (1 foot, 4 shots per foot). After perforating, the BHP gauge was run to the perforation depth where temperature and pressure measurements were collected (Appendix C, "Pressure Survey Report"). The pressure data recorded in the Coteau 1 well are shown in Table 2-4. (p. 2-9) ***2.3.2 Mechanism of Geologic Confinement*** For the Great Plains CO_2 Sequestration Project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure. Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.	Table 2-4. Description of Coteau 1 Formation Pressure Measurements and Calculated Pressure Gradients (p. 2-11) Table 2-5. Description of Flemmer 1 Formation Pressure Measurements and Calculated Pressure Gradients (p. 2-11)

		potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:			
	NDAC 43-05-01-05 §1b(2)(g)	**NDAC 43-05-01-05 §1b(2)(g)** (g) Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir;	e. Identification of all characteristics controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir, including: Structural spill points Stratigraphic discontinuities	*2.2.2.6 Seismic Survey* (p. 2-12) The proximity of the site to an active coal mine and industrial facilities makes acquisition of 3D seismic data problematic. Placement of seismic source and receiver locations required for a 3D seismic survey would be restricted because of these surface uses potentially resulting in insufficient data quality to image the subsurface for characterization and monitoring purposes. Interpretation of 2D seismic data provides a practical alternative to acquiring and interpreting 3D seismic data. 2D seismic surveys can be used to evaluate the subsurface across large tracts of land, can be oriented to avoid surface obstacles such as those found at this site, can be acquired more frequently for future site monitoring, and eliminates the need to overshoot areas that have already been swept with CO_2. Twenty-eight miles of 2D seismic lines that traverse the storage facility area and intersect the Coteau 1 well were licensed and interpreted (Figure 2-4). The 2D seismic lines were tied to the Coteau 1 well and used to evaluate the thickness and structure of the Broom Creek and upper and lower confining zones within the storage facility area. The interpreted surfaces for the formations of interest derived from the 2D seismic lines were used to confirm that the geologic model is representative of the reservoir thickness and structure within the storage facility area. The 2D seismic data suggest there are no major stratigraphic pinch-outs or structural features with associated spill points in the Great Plains CO_2 Sequestration Project area. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the lowest USDW, the Fox Hills Formation, were observed in the seismic data. Twenty-eight miles of new 2D seismic data centered around the Coteau 1 well was acquired in January 2022 and will be used to confirm these interpretations. **2.3 Storage Reservoir (injection zone) (last sentence in paragraph, p. 2-14)** The top of the Broom Creek Formation was picked across the model area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-9). The top of the Amsden Formation was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that can be correlated across the entirety of the Great Plains CO_2 Sequestration Project Area. 2D seismic data collected as part of site characterization efforts were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and analyses indicate that there should be few-to-no major reservoir stratigraphic discontinuities near the Coteau 1 well (Figures 2-10 and 2-11). The Broom Creek Formation is estimated to pinch out ~34 miles to the east of the Coteau 1 wellsite. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Great Plains CO_2 Sequestration Project Area (Figure 2-12 and Figure 2-13). ***2.3.2 Mechanism of Geologic Confinement*** For the Great Plains CO_2 Sequestration Project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure. Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.	Figure 2-9. Well log display of the interpreted lithologies of the Opeche, Broom Creek, and upper Amsden Formations in the Coteau 1 well (p. 2-15) Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-16) Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-17) Figure 2-12. Structure map of the Broom Creek Formation across the greater Great Plains CO2 Sequestration Project area (generated using 3D seismic horizons and well log tops). (p. 2-18) Figure 2-13. Cross section of the Great Plains CO2 Sequestration Project storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations

					are referenced to mean sea level. (p. 2-20)
	NDAC 43-05-01-05 §1b(2)c	**NDAC 43-05-01-05 §1b(2)c** (c) Any regional or local faulting;	f. Any regional or local faulting;	**2.5 Faults, Fractures, and Seismic Activity (First two paragraphs on p. 2-87)** In the Great Plains CO_2 Sequestration Project area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from Coteau 1 that suggest the injection interval, Broom Creek Formation (42,800 mg/L) is isolated from the next permeable interval, the Inyan Kara Formation (22,800 mg/L). The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that "the Williston Basin as a whole is in an overburden compressive stress regime," which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2019).	Figure 2-73. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (p. 2-89)
	NDAC 43-05-01-05 §1b(2)(j)	**NDAC 43-05-01-05 §1b(2)(j)** (j) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone in the area of review, and a determination that they would not interfere with containment;	g. Properties of known or suspected faults and fractures that may transect the confining zone in the area of review: Location Orientation Determination of the probability that they would interfere with containment	**2.5 Faults, Fractures, and Seismic Activity (1st paragraph, p. 2-87)** In the Great Plains CO2 Sequestration Project area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from Coteau 1 that suggest the injection interval, Broom Creek Formation (42,800 mg/L) is isolated from the next permeable interval, the Inyan Kara Formation (22,800 mg/L).	N/A
	NDAC 43-05-01-05 §1b(2) ¶ & §1b(2)(m)	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any	h. Information on any regional tectonic activity, and the seismic history, including: The presence and depth of seismic sources; Determination of the probability that seismicity would interfere with containment;	**2.5 Faults, Fractures, and Seismic Activity (3rd paragraph, p. 2-87 and p. 2-89)** Between 1870 and 2015, 13 earthquakes were detected within the North Dakota portion of the Williston Basin (Table 2-21) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-73). The seismic event recorded closest to the Great Plains CO_2 Sequestration Project storage facility area occurred 29.6 mi from the Coteau 1 well near Fort Berthold in southwestern North Dakota (Table 2-21). The magnitude of this seismic event is estimated to have been 1.9. Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging earthquake events occurring in North Dakota, with less than two damaging earthquake events predicted to occur over a 10,000-year time period (Figure 2-74) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by USGS in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) state there is very little seismic activity near injection wells in the Williston Basin. They noted only two historic earthquake events in North Dakota that could be associated with nearby oil and gas activities. This indicates relatively stable geologic conditions in the region surrounding the potential injection site. The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the absence of known or suspected local or regional faults suggest the probability that seismicity would interfere with containment is low.	Table 2-21. Summary of Earthquakes Reported to Have Occurred in North Dakota Figure 2-74. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (p. 2-90)

		productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following: **NDAC 43-05-01-05 §1b(2)(m)** (m) Information on the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment;			
	NDAC 43-05-01-05 §1b(2) ¶ NDAC 43-05-01-05 §1b(2)(n)	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include	i. Illustration of the regional geology, hydrogeology, and the geologic structure of the storage reservoir area: Geologic maps Topographic maps Cross sections	**2.1 Overview of Project Area Geology (1st paragraph, p. 2-1)** The proposed Dakota Gasification Company (DGC) Great Plains CO_2 Sequestration Project will be situated near Beulah, North Dakota (Figure 2-1). This project site is on the central portion of the Williston Basin. The Williston Basin is an intracratonic sedimentary basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. See also Figure 2-7 on p. 2-13, Figure 2-10 on p. 2-16, Figure 2-11 on p. 2-17, Figure 2-13 on p. 2-20, Figure 2-31 on p. 2-43, and Figure 2-72 on p. 2-88. ***4.4.3 Hydrology of USDW Formations* (p. 4-21)** Groundwater is obtained from both glacial drift and bedrock aquifers, with most of the water obtained from bedrock. Lignite beds and sands in the Sentinel Butte and Tongue River Formations provide shallow bedrock aquifers in most areas of Mercer County. Sandstones near the base of the Tongue River Formation and within the Hell Creek and Fox Hills Formations provide deeper artesian aquifers in many areas. Glacial drift is generally too thin or impermeable to provide good aquifers in the upland areas. However, in the valleys of the major streams and in the diversion channels, the glacial and alluvial fill provides adequate supplies of groundwater (Carlson, 1973). The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the area of investigation is to the east (Figure 4-13). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,530 mg/L near the Great Plains CO2 Sequestration Project area. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering. See also Figure 4-15 on p. 4-24.	Figure 2-1. Topographic map of the Great Plains CO_2 Sequestration Project area showing well locations and the Great Plains Synfuels Plant Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (modified from Rygh and others [1990]). Based on new well control shown outside of the green dashed line. (p. 2-13) Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-16) Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-17)

		exhibits and plan view maps showing the following: **NDAC 43-05-01-05 §1b(2)(n)** (n) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the facility area; and			Figure 2-13. Cross section of the Great Plains CO_2 Sequestration Project storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. (p. 2-20) Figure 2-32. Structure map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (p. 2-43) Figure 2-73. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (p. 2-89) Figure 4-13. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in Mercer County (modified from Fischer, 2013). (p. 4-22) Figure 4-15. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section. (p. 4-24)
	NDAC 43-05-01-05 §1b(2)(d)	**NDAC 43-05-01-05 §1b(2)(d)** (d) An isopach map of the storage reservoirs;	j. An isopach map of the storage reservoir(s);	See Figure 2-8 on p. 2-14	Figure 2-8. Isopach map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project Area (p. 2-14)
	NDAC 43-05-01-05 §1b(2)(e)	**NDAC 43-05-01-05 §1b(2)(e)** (e) An isopach map of the primary and any secondary containment barrier for the storage reservoir;	k. An isopach map of the primary containment barrier for the storage reservoir;	See Figure 2-33 on p. 2-44	Figure 2-33. Isopach map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area. (p. 2-44)

			l. An isopach map of the secondary containment barrier for the storage reservoir;	See Figure 2-44 on p. 2-55 and Figure 2-45 on p. 2-56	
	NDAC 43-05-01-05 §1b(2)(f)	**NDAC 43-05-01-05 §1b(2)(f)** (f)A structure map of the top and base of the storage reservoirs;	m. A structure map of the top of the storage formation;	See Figure 2-12 on p. 2-18	
			n. A structure map of the base of the storage formation;	See Figure 2-32 on p. 2-43	
	NDAC 43-05-01-05 §1b(2)(i)		o. Structural cross sections that describe the geologic conditions at the storage reservoir;	See Figure 2-11 on p. 2-17 and Figure 2-13 on p. 2-20	
			p. Stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	See Figure 2-10 on p. 2-16	

					of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-16)
	NDAC 43-05-01-05 §1b(2)(h)	**NDAC 43-05-01-05 §1b(2)(h)** (h) Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any;	q. Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any;	**3.4 Simulation Results (p. 3-22)** The pressure front (Figure 3-20) shows the distribution of pressure increase throughout the Broom Creek Formation at the end of the 12-year injection period. A maximum increase of 436.53 psi is estimated in the near wellbore area. ***6.1.1 Pre- and Postinjection Pressure Differential*** **(p. 6-1)** Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of CO_2 injection. The simulations were conducted for 12 years of CO_2 injection at rates between 1.1 and 2.7 million metric tons per year, followed by a postinjection period of 10 years. Figure 6-1 illustrates the predicted pressure differential at the conclusion of 12 years of CO_2 injection. At the time that CO_2 injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of 350 to 400 psi at the location of the injection wells, which is insufficient to move formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the AOR delineation of this permit application (Section 3). An illustration of the predicted decrease in this pressure profile over the 10-year postinjection period is provided in Figure 6-2. The pressure in the reservoir gradually decreases over time following the cessation of CO_2 injection, with the pressure at the injection well after 10 years of postinjection predicted to decrease 300 to 350 psi as compared to the pressure at the time CO_2 injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions.	Figure 3-20. Average pressure increases within the Broom Creek Formation at the end of a simulated 12-year CO_2 injection operation (p. 3-22) Figure 6-1. Predicted pressure differential in storage reservoir following 12 years of CO_2 injection at rates between 1.1 and 2.7 million metric tons per year (p. 6-2) Figure 6-2. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection (p. 6-3)
	NDAC 43-05-01-05 §1b(2)(l)	**NDAC 43-05-01-05 §1b(2)(l)** (l) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream;	r. Geomechanical information on the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide: Fractures Stress Ductility Rock strength In situ fluid pressure	*2.4.4.1 Fracture Analysis (p. 2-66)* Fractures within the Opeche Formation, the overlying confining zone, and the Amsden Formation, the underlying confining zone, have been assessed during the description of the Coteau 1 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural fractures and in situ stresses were assessed by Schlumberger through the interpretation of the fullbore formation microimager (FMI), bulk density (RHOB), dipole shear sonic (DTS), and dipole compressional sonic (DTC) logs acquired during the drilling of the Coteau 1 well. *2.4.4.2 Fracture Analysis Core Description* (p. 2-66) Fractures within the Opeche Formation are primarily litho-bound resistive fractures. They are commonly filled with anhydrite. However, some litho-bound conductive fractures are highlighted. The presence of microfaults is underlined mainly in the lower part of the Opeche Formation. The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. The aperture varies from closed to, in rare cases, centimeter-scale. The Amsden Formation could be considered as a nonfractured interval. However, few litho-bound conductive fractures are commonly coincident with the horizontal compaction features (stylolite) observed. *2.4.4.3 Borehole Image Fracture Analysis (FMI)* Schlumberger's FMI log was chosen to evaluate the geomechanical condition of the formation in the subsurface. This log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed. Figure 2-57 showsFigure 2-57 The far-right track on Figure 2-57 provides information on surface boundaries, slump deformed, and notes the presence of electrically conductive and resistive features. The latter are interpreted as minor anhydrite-filled fractures. Figure 2-58 shows two sections of the interpreted borehole imagery and primary features observed. Figure 2-58 demonstrates that the tool provides information on slump deformation, conductive fractures, and microfaults. These microfaults are identified in Figure 2-58 and are likely clay-filled because of their electrically conductive signal. Figure 2-59 and Figure 2-60 show two thin-section images and give an indication of different minerals within the reservoir with observed changes in the electrical response shown on the FMI log. Also, some drilled-induced fractures are highlighted in the upper part of the Opeche Formation.	Table 2-19 Triaxial Testing Results Showing the Calculated Static Young's Modulus, Poisson's Ratio, and Compressive Strength. The confining zone pressure was set at 1,180 psi for testing. The pore pressure used for calculations was assumed to be 0 psi. (p. 2-82) Table 2-20 Triaxial Testing Results Showing the Measured Acoustic Velocities and Calculated Dynamic Bulk Modulus, Young's Modulus, Poisson's Ratio, and Compressive Strength. The confining zone pressure was set at 1,180 psi for testing. (p. 2-83) Figure 2-70. Calibrated geomechanical rock properties model in Opeche Formation (p. 2-84)

				Figure 2-61 shows the logged interval for the lower Opeche Formation at Coteau 1 well. As shown, the section closest to the Broom Creek Formation is dominated by litho-bound fractures and microfaults which are electrically conductive features likely due to the presence of clay. The rose diagrams shown in Figures 2-62 through 2-65 provide the orientation of the conductive, resistive, microfault, and drilling-induced features in the Opeche Formation. The drilling-induced fractures are oriented NE-SW and N-S which give an orientation of N060 and N000 to the maximum horizontal stress (Shmax), respectively. The logged interval of the Amsden Formation shows that the main features present are bed boundaries and slump deformation features (Figure 2-66). The depths 6,201.6 and 6,213.7 ft show some evidence of conductive fracture and drilling-induced fractures, respectively (Figure 2-67). The rose diagrams shown in Figures 2-67 and 2-68 provide the orientation of the conductive and drilling-induced fractures in the Amsden Formation. The drilling-induced fractures are oriented NE-SW which gives an orientation of N060 to the maximum horizontal stress (Shmax). *2.4.4.4 Stress* (p. 2-81) The 1D Mechanical Earth Model (MEM) for Opeche, Broom Creek, and Amsden Formations in Coteau 1 well was generated by Core Laboratories (Figures 2-70, 2-71, and 2-72). During construction of the 1D MEM, the effect of pore pressure on sonic transit time, accurate calculation of stress, and rock properties required corrections based on this effect. Dipole sonic logs (DTC, DTS) were corrected for formation pressure impedance and tool radius of investigation. The log corrections allow for a better match to core measurements and more robust geomechanical models. The output data for the 1D MEM are vertical stress (Sv), pore pressure, pore pressure gradient, dynamic Poisson's ratio, dynamic Young's modulus, Biot factor, fracture closure pressure, fracture closure pressure gradient, fracture propagation pressure, fracture propagation pressure gradient, fracture breakdown pressure, and fracture breakdown pressure gradient. Laboratory-derived core measurements were used from the Coteau 1 well. The static and dynamic parameters from core including DTS, DTC, compressional wave velocity (Vp), shear wave velocity (Vs), dynamic Young's modulus, and dynamic Poisson's ratio were estimated for the Opeche, Broom Creek, and Amsden Formations and used to calibrate the geomechanical rock properties model. The isotropic (dynamic) properties from well logs (Young's modulus and dynamic Poisson's ratio) were calculated based on the corrected DTC and DTS well logs and calibrated with core measurements. Pore pressure, pore pressure gradient, fracture closure pressure, fracture closure pressure gradient, fracture propagation pressure, fracture propagation fracture gradient, fracture breakdown pressure, and fracture breakdown pressure gradient were also estimated. Pore pressure was calibrated using the pressure and temperature data from the Coteau 1 well. Triaxial tests were performed on 15 vertical samples: three in Opeche, nine in Broom Creek, and three in Amsden (Table 2-19 and 2-20). Static Young's modulus, Poisson's ratio, and compressive strength were measured at the confining pressure of 1180 psi. Also, acoustic velocities (Vp, Vs) and dynamic moduli (Bulk modulus, Young's modulus, shear modulus, Poisson's ratio) were estimated under a confining pressure of 1,180 psi The triaxial outputs were calibrated with the estimated parameters using well logs. Figures 2-70–2-72 show the outputs of the 1D MEM for the Opeche, Broom Creek, and Amsden Formations. In situ stresses such as vertical stress (Sv), maximum horizontal stress (Shmax), and minimum horizontal stress (Shmin) were calculated. The vertical stress is calculated using the density log (RHOB) and assumes 1 psi/ft above 1,500 ft where the RHOB data were not available. The minimum horizontal stress is estimated from a modified Eaton calculation method. Shmax is estimated from Shmin and process zone stress as a function of porosity. Based on the calculated stresses, the stress regime of the Opeche, Broom Creek, and Amsden Formations is considered a normal stress regime where Sv > Shmax > Shmin. ***4.1.1 Written Description* (p. 4-1 and p. 4-2)** An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.	Figure 2-71. Calibrated geomechanical rock properties model in Broom Creek Formation (p. 2-85) Figure 2-72. Calibrated geomechanical rock properties model in the Amsden Formation (p. 2-86)

	NDAC 43-05-01-05 §1b(2)(o)	**NDAC 43-05-01-05 §1b(2)(o)** (o) Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement, are free of transmissive faults or fractures, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	s. Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement: Free of transmissive faults Free of transmissive fractures Effect on pressure dissipation Utility for monitoring, mitigation, and remediation.	***2.4.2 Additional Overlying Confining Zones* (p. 2-54 and p. 2-57)** Several other formations provide additional confinement above the Opeche interval. Impermeable rocks above the primary seal include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-16). Together with the Opeche interval, these formations are 1,106 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-44). Above the Inyan Kara Formation, 2,657 ft of impermeable rocks act as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (Figure 2-44). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-16). These formations between the Broom Creek and Inyan Kara and between the Inyan Kara and the lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988). Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Inyan Kara Formation represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring using annual temperature and pulse neutron logging of the Inyan Kara Formation provides an additional opportunity for mitigation and remediation (Section 4). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at the Coteau 1 well is 4,512 ft, and the formation itself is 378 ft thick.	Table 2-16 (p. 2-55) Figure 2-44. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation (p. 2-55) Figure 2-45. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation (p. 2-56)
Area of Review Delineation	NDAC 43-05-01-05 §1j & §1b(3)	**NDAC 43-05-01-05 §1j** j. An area of review and corrective action plan that meets the requirements pursuant to section 43-05-01-05.1; **NDAC 43-05-01-05 §1b(3)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following:	The carbon dioxide storage reservoir area of review includes the areal extent of the storage reservoir and one mile outside of the storage reservoir boundary, plus the maximum extent of the pressure front caused by injection activities. The area of review delineation must include the following:	***4.1.1 Written Description*** North Dakota geologic storage of CO_2 regulations require that each storage facility permit delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO_2 plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the Coteau 1 well (NDIC File No. 38379) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-7]). Section 3 includes a detailed discussion on the computational modeling and simulations (e.g., storage facility area, pressure front, AOR boundary, etc.), assumptions, and justification used to delineate the AOR and method for delineation of the AOR. NDAC § 43-05-01-05 subsection 1b(3) requires, "A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 4-1), the resulting AOR for the Great Plains CO_2 Sequestration Project is delineated as being 1 mile from the storage facility permit (SFP) boundary. This extent ensures compliance with existing state regulations. All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 4-2 through 4-5) by a professional engineer pursuant to NDAC § 43- 05-01-05 subsection 1b(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected CO2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 through 4-6 and Figures 4-6 through 4-9). An extensive geologic and hydrogeologic characterization performed by a team of geologists from the EERC resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.	Figure 4-2. Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings. (p. 4-3) Figure 4-3. AOR map in relation to nearby legacy wells and groundwater wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR, and the light-orange triangles represent Class I ANG #1 and ANG #2 wells. All groundwater wells in the AOR are identified above. All observation/monitoring wells are shallow groundwater wells associated with the mine activities. No springs are present in the AOR. (p. 4-4)

				This section of the SFP application is accompanied by maps and tables that include information required and in accordance with NDAC § 43-05-01-05 subsections 1(a) and 1(b) and 43-05-01-05.1 subsection 2, such as the storage facility area, location of any proposed injection wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05 subsections 1a and 1b(3) and 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AOR boundary were identified in Table 4-1. See Figure 4-2 on p. 4-3, Figure 4-3 on p. 4-4, and Figure 4-4 on p. 4-5.	Figure 4-4. AOR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR and the Class I ANG #1 and ANG #2 wells are represented by blue triangles. (p. 4-5)
	NDAC 43-05-01-05 §1b(3) & §1a	**NDAC 43-05-01-05 §1b(3)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: **NDAC 43-05-01-05 §1a** a. A site map showing the boundaries of the storage reservoir and the location of all proposed wells, proposed cathodic protection boreholes, and surface facilities within the carbon dioxide storage facility area;	a. A map showing the following within the carbon dioxide reservoir area: i. Boundaries of the storage reservoir ii. Location of all proposed wells iii. Location of proposed cathodic protection boreholes iv. Any existing or proposed above ground facilities;	**4.1.2 Supporting Maps (p. 4-2)** See Figure 4-2 on p. 4-3	Figure 4-2 Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings. (p. 4-3)
	NDAC 43-05-01-05 §1b(2)(a)	**NDAC 43-05-01-05 §1b(2)(a)** (a) All wells, including water, oil, and natural gas exploration and development wells, and other manmade subsurface structures and activities, including coal mines, within the facility area and within one mile [1.61 kilometers] of its outside boundary;	b. A map showing the following within the storage reservoir area and within one mile outside of its boundary: i. All wells, including water, oil, and natural gas exploration and development wells ii. All other manmade subsurface structures and activities, including coal mines;	**4.1.2 Supporting Maps (p. 4-2)** See Figure 4-3 on p. 4-4 and Figure 4-4 on p. 4-5	Figure 4-3 AOR map in relation to nearby legacy wells and groundwater wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR, and the light-orange triangles represent Class I ANG #1 and ANG #2 wells. All groundwater wells in the AOR are identified above.

					All observation/monitoring wells are shallow groundwater wells associated with the mine activities. No springs are present in the AOR. (p. 4-4) Figure 4-4 AOR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR and the Class I ANG #1 and ANG #2 wells are represented by blue triangles. (p. 4-5)
	NDAC 43-05-01-05 §1c NDAC 43-05-01-05.1 §1a	**NDAC 43-05-01-05 §1c** c. The extent of the pore space that will be occupied by carbon dioxide as determined by utilizing all appropriate geologic and reservoir engineering information and reservoir analysis, which must include various computational **NDAC 43-05-01-05.1 §1a** a. The method for delineating the area of review, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	c. A description of the method used for delineating the area of review, including: i. The computational model to be used ii. The assumptions that will be made iii. The site characterization data on which the model will be based;	**3.5 Delineation of the Area of Review (p. 3-25)** The North Dakota Administrative Code (NDAC) defines the AOR as the region surrounding the geologic storage project where USDWs may be endangered by CO_2 injection activity (NDAC § 43-05-01-05). The primary endangerment risk is the potential for vertical migration of CO_2 and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the CO_2 plume within the storage reservoir. However, the CO_2 plume has an associated pressure front where CO_2 injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the CO_2 plume. Therefore, the AOR encompasses both the areal extent of the CO_2 plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the CO_2 plume, AOR delineation focuses on the pressure front. The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the Underground Injection Control (UIC) Program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure. In this document, "storage reservoir" refers to the Broom Creek Formation (the injection zone), and the "lowest USDW" refers to the Fox Hills Formation.	
	NDAC 43-05-01-05.1 §1b(1-4)	**NDAC 43-05-01-05.1 §1b(1-4)** b. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) The monitoring and operational conditions	d. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) Any monitoring and operational conditions that would warrant a reevaluation of the area of	**4.3 Reevaluation of AOR and Corrective Action Plan (p. 4-17)** DGC will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place not later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following: • Any changes to the monitoring and operational data prior to the scheduled reevaluation date. • Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and operational data to be utilized as the basis for that update will be identified.	N/A

		that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date; (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and (4) How corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	review prior to the next scheduled reevaluation date; (3)How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; (4)How corrective action will be conducted if necessary, including: a. What corrective action will be performed prior to injection b. How corrective action will be adjusted if there are changes in the area of review;	• The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.	
	NDAC 43-05-01-05 §1b(2)(b)	**NDAC 43-05-01-05 §1b(2)(b)** (b) All manmade surface structures that are intended for temporary or permanent human occupancy within the facility area and within one mile [1.61 kilometers] of its outside boundary;	e. A map showing the areal extent of all manmade surface structures that are intended for temporary or permanent human occupancy within the storage reservoir area, and within one mile outside of its boundary;	**4.1.2 Supporting Maps (p. 4-2)** See Figure 4-2 on p. 4-3	Figure 4-2 Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings. (p. 4-3)
	NDAC 43-05-01-05 §1b(2) ¶	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any	f. A map and cross section identifying any productive existing or potential mineral zones occurring within the storage reservoir area and within one mile outside of its boundary;	**2.6 Potential Mineral Zones (p. 2-89 through 2-91)** There are no known producible accumulations of hydrocarbons in the storage facility area. The North Dakota Geological Survey recognizes the Spearfish Formation as the only potential oil-bearing formation above the Broom Creek Formation. However, production from the Spearfish Formation is limited to the northern tier of counties in western North Dakota (Figure 2-75). There has been no exploration for, nor development of, a hydrocarbon resource from the Spearfish Formation in the Great Plains CO_2 Sequestration Project area. There has been no historic hydrocarbon exploration in, or production from, formations below the Broom Creek Formation in the storage facility area. The Herrmann 1 well (NDIC File No. 4177), the closest hydrocarbon exploration well to the storage facility area, located 4.1 miles from the Coteau 1 well, was drilled in 1966 to explore potential hydrocarbons in the Madison Group. The well was dry and did not suggest the presence of hydrocarbons. The closest hydrocarbon producing well is Traxel 1-31H (NDIC File No. 17877), located 10.8 miles east from the Coteau 1 well (NDIC 38379). The Traxel 1-31H well was drilled in August 2009,	Figure 2-75. Drillstem test results indicating the presence of oil in the Spearfish Formation (modified from Stolldorf, 2020). (p. 2-91)

		regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:		producing a cumulative total of 12,021 bbl until December 2013. The well's current status is producer now abandoned (PNA) as of November 2014. Published studies suggest there are no economic deposits of hydrocarbons in the Bakken Formation in the storage facility area (Bergin, 2012; Theloy, 2016). In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a horizontal well could be used to produce the hydrocarbon while avoiding drilling through the CO_2 plume, or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available, which will allow prospective operators to design an appropriate well control strategy via increased drilling mud weight. The maximum pressure increase in the center of the injection area is projected by computer modeling to be 400–450 psi, with lesser impacts extending radially (Figure 3-20). Pressure increases will relax postinjection as the area returns to its preinjection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the CO_2 should be designed to include an intermediate casing string placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place. Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations (NDCC 57-51-01) define shallow gas resources as "gas produced from a zone that consists of strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1,524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation (Jurassic), from which gas may be produced." Lignite reserves in the Sentinel Butte Formation of the Fort Union Group (the Beulah of the Beulah-Zap interval and Twin Butte coal beds) are mined to be used as feedstock for the GPSP coal gasification process and power generation feedstock at Basin Electric Power Cooperative's Antelope Valley Station, located about 0.5 miles north of DGC's GPSP. The lignite is obtained from the Freedom Mine, which is operated by Coteau Properties Company, a wholly owned subsidiary of North American Coal Corporation. The thickness of the Beulah–Zap averages between 18 to 22 feet in thickness (Figure 2-76). Above the Beulah horizon are several thin beds of lignite. In ascending order, these are the Schoolhouse and Twin Butte beds. Overburden on top of the Beulah ranges from 95 to 145 feet (Figure 2-77). The Twin Butte has an average thickness of about 6 feet under 25–30 feet of overburden where it is actively mined (Zygarlicke and others, 2019). The Beulah, Twin Butte, and other coal seams thicken and deepen to the west. The Beulah–Zap and Twin Butte seams pinch out to the east. The underlying Hagel coal seam is mined farther to the east at the BNI Coal Mine near Center, North Dakota, and the Falkirk Mine near Falkirk, North Dakota.	Figure 2-76. Beulah net coal isopach map (modified from Ellis and others, 1999). (p. 2-93) Figure 2-77. Beulah overburden isopach map (modified from Ellis and others, 1999). (p. 2-94)
	NDAC 43-05-01-05 §1b(3) NDAC 43-05-01-05.1 §2b	**NDAC 43-05-01-05 §1b(3)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following:	g. A map identifying all wells within the area of review, which penetrate the storage formation or primary or secondary seals overlying the storage formation.	See Figure 4-4 on p. 4-5	Figure 4-4 AOR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR and the Class I ANG #1 and ANG #2 wells are represented by blue triangles. (p. 4-5)

	NDAC 43-05-01-05 §1b(3)(a) NDAC 43-05-01-05 §1b(3)(b) NDAC 43-05-01-05 §1b(3)(c)				

	NDAC 43-05-01-05 §1b(3)(d) NDAC 43-05-01-05 §1b(3)(e) NDAC 43-05-01-05 §1b(3)(b)(f)	the area of review; their positions relative to the injection zone; and the direction of water movement, where known; **NDAC 43-05-01-05 §1b(3)(d)** (d)Maps and cross sections of the area of review; **NDAC 43-05-01-05 §1b(3)(e)** (e) A map of the area of review showing the number or name and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, state-approved or United States environmental protection agency-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features, including structures intended for human occupancy, state, county, or Indian country boundary lines, and roads;	b. The direction of water movement, where known c. General vertical and lateral limits d. Water wells e. Springs (5) Map and cross sections of the area of review; (6) A map of the area of review showing the following: a. Number or name and location of all injection wells b. Number or name and location of all producing wells c. Number or name and location of all abandoned wells d. Number of name and location of all plugged wells or dry holes e. Number or name and location of all deep stratigraphic boreholes f. Number or name and location of all state-approved or United States Environmental Protection Agency-approved subsurface cleanup sites g. Name and location of all surface bodies of water h. Name and location of all springs i. Name and location of all mines (surface and subsurface) j. Name and location of all quarries k. Name and location of all water wells l. Name and location of all other pertinent surface features m. Name and location of all structures intended for human occupancy n. Name and location of all state, county, or Indian country boundary lines o. Name and location of all roads		and thickness of cement plugs (p. 4-14) Figure 4-8. ANG 2 (NDEQ File No. NDOH11309) well schematic showing the location and thickness of cement plugs (p. 4-15) Figure 4-9. Coteau 1 (NDIC File No. 38379) well schematic showing the location and thickness of cement plugs (p. 4-16)

		NDAC-43-05-01-05 §1b(3)(b)(f) (f) A list of contacts, submitted to the commission, when the area of review extends across state jurisdiction boundary lines;	(7)A list of contacts, submitted to the Commission, when the area of review extends across state jurisdiction boundary lines.		
	NDAC 43-05-01-05 §1b(3)(g)	**NDAC 43-05-01-05 §1b(3)(g)** (g) Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review; and	i. Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review.	***5.5.2 Groundwater Baseline Sampling* (p. 5-13)** Two Fox Hills Formation samples were obtained in November 2021 from the Fred Art/Oberlander #1 and Helmuth Pfenning #2 wells. State-certified laboratory results for these two wells found in Appendix B show little variation among the reports. The locations of the wells investigated for establishing baseline conditions are shown in Figure 5-3, and the results of the baseline measurements for pH, specific conductivity, and alkalinity are provided in Table 5-5, with state-certified laboratory results for each sampling event provided in Appendix B. In addition, DGC plans to obtain a baseline water sample from the Fox Hills monitoring well that will be drilled near the Herrmann 1 well (NDIC File No. 4177) prior to injection operations. **Appendix B - FRESHWATER WELL FLUID-SAMPLING LABORATORY ANALYSIS** See Appendix B for detailed laboratory reports of geochemical data collected during the initial baseline sampling program	Figure 5-3. DGC's initiated baseline sampling program for vadose zone soil gas and groundwater in the Fox Hills Formation (p. 5-12) Table 5-4. DGC's Initial Baseline Groundwater Sampling Results – November 2021 (p. 5-13)
Required Plans	NDAC 43-05-01-05 §1k	**NDAC 43-05-01-05 §1k** k. The storage operator shall comply with the financial responsibility requirements pursuant to section 43-05-01-9.1;	a. Financial Assurance Demonstration	**12.2 Financial Instruments (p. 12-1 and p. 12-2)** DGC is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments: • DGC will establish an escrow account to cover the costs of corrective action in accordance with NDAC § 43-05-01-05.1, plugging of injection wells in accordance with NDAC § 43-05-01-11.5, and implementing postinjection site care and facility closure activities in accordance with NDAC § 43-05-01-19. DGC will make four annual payments of $1 million to the escrow account. The first payment will occur on or before the first day of operations, and the final payment will occur in 2025, bringing the account balance to $4 million. • A third-party pollution liability insurance policy with an aggregate limit of $16 million will be secured to cover the costs of implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13. The estimated total costs of these activities are presented in Table 12-1. Section 12.3 of this FADP provides additional details of the financial responsibility cost estimates for each activity.	Table 12-1. Cost estimates for Activities to Be Covered (p. 12-2)
	NDAC 43-05-01-05 §1d	**NDAC 43-05-01-05 §1d** d. An emergency and remedial response plan pursuant to section 43-05-01-13;	b. An emergency and remedial response plan;	**7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN (p. 7-1)** This emergency and remedial response plan (ERRP) 1) describes the local resources and infrastructure in proximity to the site; 2) identifies events that have the potential to endanger all underground sources of drinking water (USDWs) during the construction, operation, and postinjection site care periods of the geologic storage project; and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing plant emergency plan and risk management plan of Dakota Gasification Company's (DGC's) Great Plains Synfuels Plant (GPSP) is described, emphasizing the command structure of DGC, the evacuation plan, hazmat (hazardous material) capabilities, and the emergency communication plan of the GPSP. Lastly, procedures are presented for regularly conducting and evaluating the adequacy of the ERRP and updating it, if warranted, over the lifetime of the Great Plains CO2 Sequestration Project. Note: Refer to the following key tables instead: Table 7-2 on p. 7-6 and Table 7-3 on p. 7-8 through 7-10.	Table 7-2. Potential Project Emergency Events and Their Detection (p. 7-6) Table 7-3 Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (p. 7-8 through 7-10)
	NDAC 43-05-01-05 §1e	**NDAC 43-05-01-05 §1e** e. A detailed worker safety plan that addresses carbon	c. A detailed worker safety plan that addresses the following:	**8.1 DGC Employee Safety Requirements and Training (p. 8-1)**	N/A

		dioxide safety training and safe working procedures at the storage facility pursuant to section 43-05-01-13;	i. Carbon dioxide safety training ii. Safe working procedures at the storage facility;	DGC has established a process for employees to acquire the knowledge, skills, and abilities to competently operate the facility in accordance with DGC safe work practices, procedures, and operating manuals. The safety requirements for DGC employees include, but are not limited to, the following: 1. An orientation for all newly hired employees to ensure they are aware of company safety policies and procedures, safety and health hazards, safe work practices, and government safety regulations. 2. Instruction and training for each employee regarding: a. Safety expectations while on DGC property. b. What to do in an emergency, including evacuation routes and assembly points. c. Safety and industrial hygiene information about hazardous materials/conditions and immediate actions to take following an accidental exposure. d. When and how to report safety incidents. e. How to report unsafe conditions and behaviors. f. Safe work practices as defined by government and company standards. ***8.1.2 DGC Contractor Safety Requirements and Training* (p. 8-1 and p. 8-2)** The DGC OSIH program also establishes requirements for contractors to interface with DGC to ensure compliance with DGC safety procedures and federal, state, and local safety standards. The scope of the requirements covers all contractors and their personnel (including subcontractors) working at DGC's facilities. The safety requirements and training required for a contractor to access and perform work at DGC facilities include, but are not limited to, the following: 1. Full compliance with all Energy Coalition for Contractor Safety (ECCS) guidelines for a "Class A contractor." (The guidelines can be found at the North Dakota Safety Council [NDSC] website at www.ndsc.org.) 2. Attendance at an annual DGC contractor safety orientation. 3. Negative drug test results within the last 12 months. 4. Availability of a contractor employee training record (CETR) within the last 12 months: a. Documents that the contractor has trained its personnel on DGC procedures and process descriptions. b. Ensures contractor employees are instructed in the known potential fire, explosion, or toxic release hazards and applicable provisions of the emergency response plan. 5. Documentation of a contractor employee background check within the last 5 years. 6. Successful completion of an Occupational Safety and Health Administration (OSHA) 10-hour class within the last 36 months. 7. A contractor safety manual evaluation completed by a third party, i.e., the North Dakota Safety Council (NDSC), to demonstrate compliance with federal, state, and DGC safety standards. 8. Demonstration of acceptable safety performance by submitting the last year's safety statistics to NDSC at www.ndsc.org. 9. Demonstration of qualification requirements for pipeline (off-site) contractors, which includes the following: a. Submission of a drug/alcohol plan that meets 49 Code of Federal Regulations (CFR) Part 40 and Part 199. b. Submission of an operator qualification plan in accordance with 49 CFR Part 192 and Part 195. c. Submission of qualification data for personnel performing operation, maintenance, or emergency response task(s) on the carbon dioxide (CO_2) pipeline. d. Other qualification requirements include: i. DGC access to drug/alcohol and operator qualification information for random record audits. ii. Submission of Department of Transportation (DOT) annual drug testing statistical data to DGC for inclusion in an annual DGC submittal to DOT. Only DGC employees and contractor personnel who have been properly trained will participate in the project activities of drilling, construction, operations, and equipment repair.	
	NDAC 43-05-01-05 §1f	**NDAC 43-05-01-05 §1f** f. A corrosion monitoring and prevention plan for all wells and surface facilities pursuant to section 43-05-01-15;	d. A corrosion monitoring and prevention plan for all wells and surface facilities;	**5.2 Corrosion Monitoring and Prevention Plan (p. 5-4)** The purpose of the corrosion monitoring and prevention plan is to monitor the surface facilities and injection well components during the operational phase of the Great Plains CO_2 Sequestration Project to ensure that the materials meet the minimum standards for material strength and performance. Figure 5-1 illustrates the pad drawings for the Coteau 1 through Coteau 4 wells. DGC permitted a new 6.8-mile-long transmission line through the North Dakota Public Service Commission (PSC) in July 2021 (PU-21-150). The transmission line implements a corrosion monitoring and prevention strategy that was approved by PSC and is not discussed in this storage facility permit application. At the transition from transmission line to flowline (Figure 5-2), DGC's efforts	Figure 5-1A. Well pad drawing of the Coteau 1 well location (p. 5-5) Figure 5-1B. Well pad drawing of the Coteau 2 well location (p. 5-6)

	NDAC 43-05-01-05 §1g			N/A
	NDAC 43-05-01-05 §1h			

		boundary. Provisions in the plan will be dictated by the site characteristics as documented by materials submitted in support of the permit application but must: (1) Identify the potential for release to the atmosphere; (2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.		lines of evidence to assess whether the surface/near-surface environment is being protected and whether the CO_2 is being safely and permanently stored in the storage reservoir. To complement surface/near-surface monitoring, additional monitoring of the subsurface will ensure CO_2 is staying in the targeted storage reservoir. Operational monitoring at the injection wells, including injection rates, pressures, and temperatures will provide data to inform the monitoring approaches. Internal and external mechanical integrity of the injection wells will also be demonstrated to ensure no leakage pathway exist that may allow vertical movement of the CO_2. Additionally, geophysical (seismic) surveys conducted over regular intervals will monitor subsurface CO_2 plume movement. More details regarding the surface, near-surface, and deep subsurface monitoring efforts are provided in sections 5.5 through 5.7.	
	NDAC 43-05-01-05 §1l	**NDAC 43-05-01-05 §1l** l. A testing and monitoring plan pursuant to section 43-05-01-11.4;	g. A testing and monitoring plan pursuant to NDAC Section 43-05-01-11.4;	See Section 5.0 Testing and Monitoring Plan and Appendix C: Quality Assurance Surveillance Plan Note: See Table 5-1 on p. 5-2 Table 5-5 on p.5-11, Table 5-6 on p. 5-13 and 5-14, Table 5-7 on p. 5-15 for detailed summaries of the testing and monitoring plan.	Table 5-1. Overview of DGC's Testing and Monitoring Plan (p. 5-2) Table 5-5. Baseline, Operational, and Postoperational Monitoring Duration and Frequency for Soil Gas and Groundwater (p. 5-13) Table 5-6. Description of DGC's Deep Subsurface Monitoring Program (p. 5-16) Table 5-7. Testing and Logging Program for the Coteau 1 Wellbore (p. 5-18)
	NDAC 43-05-01-05 §1i	**NDAC 43-05-01-05 §1i** i. The proposed well casing and cementing program detailing compliance with section 43-05-01-09;	h. The proposed well casing and cementing program;	**9.0 WELL CASING AND CEMENTING PROGRAM (p. 9-1)** Rampart Energy Company has drilled one well, Coteau 1 (NDIC File No. 38379) thus far on behalf of DGC. The well was permitted and drilled in June 2021 as a stratigraphic test well in compliance with Class VI underground injection control (UIC) injection well construction requirements. Application to convert Coteau 1 to a CO_2 storage injection well is being filed upon approval of this storage facility permit (SFP). The following information includes the current, as-constructed wellbore schematic (illustrated in Figure 9-1 and detailed in Tables 9-1 through 9-4) and a radial cement evaluation log summary for Coteau 1 (Figure 9-2). After drilling, the Broom Creek Formation was perforated with four shots at 5975 ft and a reservoir pressure and fluid sample were obtained. The perforations were then squeezed with 100 sacks of Class G cement and the casing pressured tested to 1600 psi with an inhibited brine solution.	Figure 9-1. Coteau 1 as-constructed wellbore schematic (p. 9-2) Table 9-1. Coteau 1 As-Constructed Well Information (p. 9-3) Table 9-2. Coteau 1 As-Constructed Casing Program (p. 9-3)

				Five additional injection wells are planned. Three of these, the proposed Coteau 2, Coteau 3, and Coteau 4, are expected to be drilled in the second quarter of 2022, followed by the proposed Coteau 5 and Coteau 6 in late 2025, to accommodate additional CO2 injection volumes in the spring of 2026. Note: See also the proposed casing and cementing program details for the Coteau 2 through 6 wells on p. 9-7 through 9-20.	Table 9-3. Coteau 1 As-Constructed Casing Properties (p. 9-4) Table 9-4. Coteau 1 As-Constructed Cement Program (p. 9-4) Figure 9-2. Coteau 1 isolation scanner results (p. 9-5)
	NDAC 43-05-01-05 §1m	**NDAC 43-05-01-05 §1m** m. A plugging plan that meets requirements pursuant to section 43-05-01-11.5;	i. A plugging plan;	**10.1 Plugging & Abandonment (P&A) Program (p. 10-1)** A well schematic of the planned completion for the Coteau 1 well (NDIC File No. 38379) is provided in Figure 10-1 followed by a P&A procedure and a well-plugging schematic (Figure 10-2). The abandonment of subsequent injection wells, namely, the Coteau 2 through 6, will be performed in a manner consistent with that of the Coteau 1. The size and depths of the various plugs may vary as necessary to accomplish the zonal isolation, but in each instance, approval of specific P&A operations will be required from the NDIC Department of Mineral Resources (DMR) prior to the initiation of fieldwork.	Figure 10-1. Coteau 1 CO_2 injection well schematic (p. 10-2) Figure 10-2. Schematic of proposed abandonment plan for each injection well (p. 10-6)
	NDAC 43-05-01-05 §1n	**NDAC 43-05-01-05 §1n** n. A postinjection site care and facility closure plan pursuant to section 43-05-01-19; and	j. A post-injection site care and facility closure plan.	**6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN (p. 6-1)** This postinjection site care (PISC) and facility closure plan describes the activities that DGC will perform following the cessation of CO_2 injection to achieve final closure of the site. A primary component of this plan is a postinjection monitoring program that will provide evidence that the injected CO_2 plume is stable (i.e., CO_2 migration will be unlikely to move beyond the boundary of the storage facility area). Based on simulations of the predicted CO_2 plume movement following the cessation of CO_2 injection, it is projected that the CO_2 plume will stabilize within the storage facility area boundary (Section 3). Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current predictions of the CO_2 plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO_2 plume. The nature and duration of that extension will be determined based on an update of this plan and NDIC approval. In addition to DGC executing the postinjection monitoring program, the Class VI injection wells will be plugged as described in the plugging plan of this permit application (Section 10), all surface equipment not associated with long-term monitoring will be removed, and the surface land of the site will be reclaimed to as close as is practical to its original condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site and submitted as part of a site closure report. Note: Refer to Table 6-1 on p. 6-4 for a summary of the postinjection site care monitoring plan.	Table 6-1. Summary of 10-year Postinjection Site Care Monitoring Plan (p. 6-4)
Storage Facility Operations	NDAC 43-05-01-05 §1b(4)	**NDAC 43-05-01-05 §1b(4)** (4) The proposed calculated average and maximum daily injection rates, daily volume, and the total anticipated volume of the carbon dioxide stream using a method acceptable to and filed with the commission;	The following items are required as part of the storage facility permit application: a. The proposed average and maximum daily injection rates; b. The proposed average and maximum daily injection volume; c. The proposed total anticipated volume of the carbon dioxide to be stored;	**11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)** This section of the storage facility permit (SFP) application presents the engineering criteria for completing and operating the injection wells in a manner that protects underground sources of drinking water (USDWs). The information that is presented meets the permit requirements for injection wells and storage operations as presented in North Dakota Administrative Code (NDAC) § 43-05-01-05 (SFP, Table 11-1) and NDAC § 43-05-01-11.3	Table 11.1. Proposed Injection Well Operating Parameters (p. 11-1)

NDAC 43-05-01-05 §1b(5)

NDAC 43-05-01-05 §1b(5)
(5) The proposed average and maximum bottom hole injection pressure to be utilized at the reservoir. The maximum allowed injection pressure, measured in pounds per square inch gauge, shall be approved by the commission and specified in the permit. In approving a maximum injection pressure limit, the commission shall consider the results of well tests and other studies that assess the risks of tensile failure and shear failure. The commission shall approve limits that, with a reasonable degree of certainty, will avoid initiating a new fracture or propagating an existing fracture in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water;

d. The proposed average and maximum bottom hole injection pressure to be utilized;

e. The proposed average and maximum surface injection pressures to be utilized;

Table 11-1. Proposed Injection Well Operating Parameters

Item	Coteau 1	Coteau 2	Coteau 3	Coteau 4	Coteau 5	Coteau 6	Total/Avg
Injected Volumes							
Total Injected Volume[1]	96.0 Bcf (4.9 MMt)	67.2 Bcf (3.4 MMt)	96.0 Bcf (4.9 MMt)	96.0 Bcf (4.9 MMt)	73.2 Bcf (3.7 MMt)	73.2 Bcf (3.7 MMt)	501.6 Bcf (25.6 MMt)
Injection Rates							
Predicted Average Injection Rate[2]	21.9 MMcfd (1,119 t/d)	15.3 MMcfd (783 t/d)	21.9 MMcfd (1,119 t/d)	21.9 MMcfd (1,119 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	114.5 MMcfd (5,845 t/d)
Predicted Maximum Injection Rate[2]	24.6 MMcfd (1,254 t/d)	17.2 mmcfd (878 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	140.0 MMcfd (7,146 t/d)
Injection Pressures							
Estimated Depth of Top Perforation (feet)[3]	5,930	5,998	5,981	5,928	5,901	5,961	5,950
Formation Fracture Pressure at Top Perforation (psi)[4]	4,210	4,259	4,247	4,209	4,190	4,232	4,224
Projected Avg Surface Injection Pressure (psi)[2]	1,628	1,597	1,644	1,604	1,682	1,677	1,639
Max Allowable Surface Injection Pressure (psi)[5]	1,976	1,998	1,993	1,975	1,966	1,986	1,982
Projected Avg Bottomhole Injection Pressure (psi)[2]	3,315	3,335	3,349	3,297	3,284	3,295	3,313
Projected Max. Bottomhole Injection Pressure (psi)[2]	3,430	3,445	3,462	3,414	3,424	3,426	3,434
Max. Bottomhole Pressure at Top Perforation (psi)[6]	3,801	3,845	3,834	3,800	3,782	3,821	3,814

[1] Assumes 55 MMcfd distributed between four wells (Coteau 1–4) from July/22 thru Dec/24, 70 MMcfd distributed between these same wells Jan/25 thru Apr/26, and 140 MMcfd distributed between six wells (Coteau 1–6) from May/26 through Jun/34.
[2] Per simulation modeling.
[3] Top perf. assumed to be 23 ft below the top of the Broom Creek Formation in all instances based on log results from Couteau 1.
[4] Based on a fracture pressure gradient of 0.71 psi/ft as calculated via CoreLabs D-Code algorithm.
[5] Based on a maximum allowable BHP equal to 90% of frac pressure and a CO_2 density of 0.306 psi/ft.
[6] Based on a maximum allowable BHP equalt to 90% of fracture pressure gradient at estimated depth of top perforation

	NDAC 43-05-01-05 §1b(6)	**NDAC 43-05-01-05 §1b(6)** (6) The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone pursuant to section 43-05-01-11.2;	f. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone;	See Table 5-7 on p. 5-18 See Appendix A: WELL AND WELL FORMATION FLUID SAMPLING LABORATORY ANALYSIS	Table 5-7 (p. 5-18)
			g. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the confining zone;	See Table 5-7 on p. 5-18	
	NDAC 43-05-01-05 §1b(7)	**NDAC 43-05-01-05 §1b(7)** (7) The proposed stimulation program, a description of stimulation fluids to be used, and a determination that stimulation will not interfere with containment; and	h. The proposed stimulation program: 1. A description of the stimulation fluids to be used 2. A determination of the probability that stimulation will interfere with containment;	**11.1 Coteau 1 Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-2)** Rampart Energy (on behalf of the Dakota Gasification Company [DGC]) drilled and cased the Coteau 1 with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. The following proposed completion procedure outlines the steps necessary to complete the Coteau 1 well for injection purposes. Note: See a full procedure provided from p. 11-3.	N/A
	NDAC 43-05-01-05 §1b(8)	**NDAC 43-05-01-05 §1b(8)** (8) The proposed procedure to outline steps necessary to conduct injection operations.	i. Steps to begin injection operations	**11.1 Coteau 1 Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-2)** Rampart Energy (on behalf of the Dakota Gasification Company [DGC]) drilled and cased the Coteau 1 with intentions to conduct $CO2_2$ stream injection operations, as referenced in previous sections. The following proposed completion procedure outlines the steps necessary to complete the Coteau 1 well for injection purposes. Note: See a full procedure provided from p. 11-3.	